GE Energy

MS7001FA (PG7241) Gas Turbine Generator Thermal Performance Test Procedure
Termobarrancas – Barinas, Venezuela

Unit Number	Turbine Serial Number
1	298593

Thermal Performance Services
Schenectady, New York

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Revision Number -

RECORD OF REVISIONS				
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Document Approval

TERMOBARRANCAS, C.A.:	TERMOBARRANCAS, C.A. Rep Name here		
	Name	***Signature***	***Date***
GE:	GE Engineer Name here		
	Name	***Signature***	***Date***

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1.0 Introduction

1.1 This document describes the procedures to test and evaluate the thermal performance of one (1) GE MS7001FA gas turbine generator(s), model PG7241, at Barinas, Venezuela. The primary objective of the testing and evaluation is to measure the performance of the gas turbine-generator unit in accordance with the purchase contract. The parameters of primary concern are the generator net output and net heat rate of the gas turbine generator. This document has been written with ASME PTC 22-1997 as a guideline and in accordance with GEK 107551A provided for reference in Appendix E: Performance Test Guidelines. The turbine operating conditions for which thermal performance will be determined are listed in Table 1.

Table 1: Turbine Operating Conditions

Rated Case	Case 1
Load Condition:	Base
Fuel:	Natural Gas
Exhaust Configuration:	Simple
Inlet Air Treatment Type:	None

1.2 The test program will be conducted by GE Thermal Performance Services and/or their designated representatives (hereafter referred to as Conducting Party). Test activities will be witnessed by TERMOBARRANCAS, C.A. and/or their designated representatives (hereafter referred to as Witnessing Party).

1.3 This document details the test responsibilities shared between the Conducting Party and the Witnessing Party, the test set-up, the test instrumentation and measurements, the test preparations, and the operational conditions to be tested. It also presents the evaluation methodology by which results are to be determined and compared to the performance specifications.

1.4 The test procedure must be mutually approved prior to testing. In the event that GE does not receive disapproval prior to the test, this test procedure will be considered approved and final by all parties.

1.5 Once this procedure is mutually approved any changes to this procedure must be mutually agreed upon and documented in writing, including signatures, as appropriate. A revision log sheet containing the date of each revision, a listing of the items revised, and a space for the appropriate signatures, is included before the table of contents. If any deviations to the test plan established in this procedure are required before or during the performance test, the same must be mutually agreed to and shall be recorded in the test procedure deviation forms included in Appendix H: Test Procedure Deviation Forms.

1.6 There will be a series of pre-test activities to verify that the gas turbine is operating properly at full capability, that all pertinent instrumentation is functioning correctly, and is adequately prepared for the performance test. These activities are detailed in Section 5 of this test procedure.

1.7 A preliminary performance survey may be conducted prior to the performance test to verify that the unit control system settings have been correctly configured and that all pertinent instrumentation is functioning correctly.

1.8 The evaluation procedure utilizes correction factors to translate the measured performance at the test conditions to the rated conditions. This ensures an accurate evaluation that is consistent with the basis of the performance specifications.

1.9 The GE commissioning of a gas turbine and its combustion system may include revisions to control settings, relative to the estimated settings used in generating the pre tuning correction curves in Appendix A. This may influence the response of the gas turbine to changes in the parameters used to correct the measured performance (such as inlet temperature), which in turn may warrant the issuance of new correction curves such that the correction curves are consistent with the final control settings. Should this be the case, GE will issue updated performance test correction curves after the control settings have been finalized and prior to the performance test.

2.0 Performance Specifications

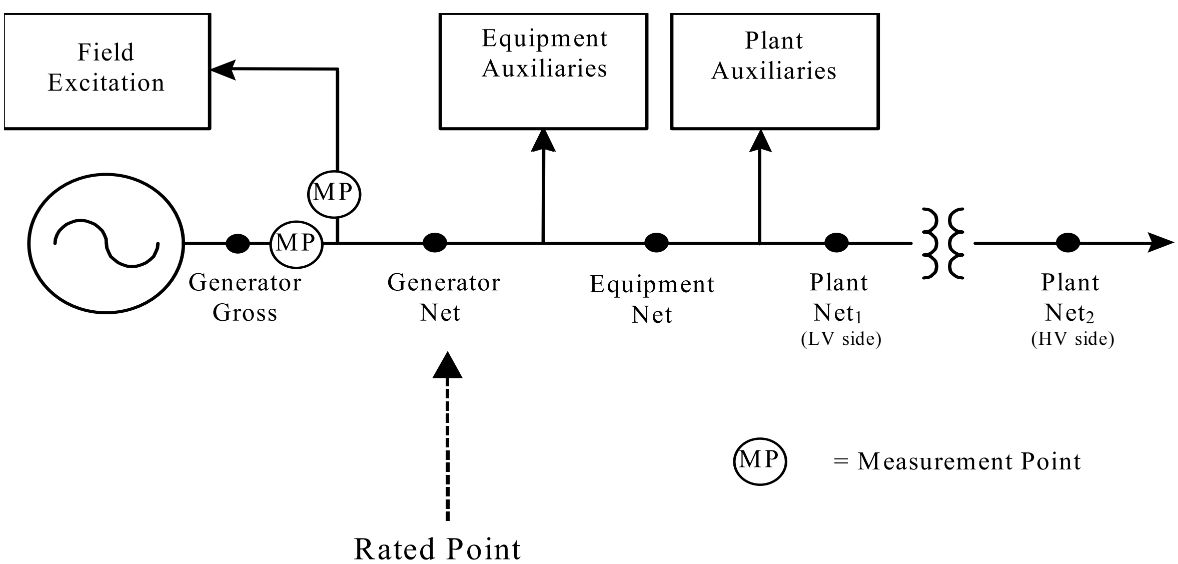
2.1 The measured performance will be compared to the following performance specifications to establish a basis for determining contract compliance. As defined by the purchase contract, the guaranteed performance for the gas turbine is provided in Table 2 below.

Table 2: Performance Guarantees

Rated Performance	**Case 1**
Generator Net Output	161,160 kW
Generator Net Heat Rate, LHV_p	9944 kJ/kWh (9425 BTU/kWh)

2.2 The generator net power output is determined from the power measured at the generator terminals less measured excitation power. The heat rate is determined from the gas turbine fuel consumption, the fuel lower heating value at constant pressure (LHV_P), and the generator net power output. For clarification purposes, the following diagram identifies the various points along the generator electrical output stream, including the point at which the performance specifications apply and the points at which the power measurements will be made.

Figure 1: Generator Electrical Output Stream



2.3 The measured performance of the gas turbine will be corrected to account for differences between the measured test conditions and the rated conditions. At a minimum, measured performance will be corrected to the rated conditions listed in Table 3.

Table 3: Rated Conditions

Correction Parameter	**Rated Value Case 1**
Ambient air temperature	26.5 °C (79.7°F)
Ambient air relative humidity	79 %
Barometric pressure	.9898 bar (14.356psia)
Gas turbine shaft speed	3600 rpm
Generator power factor	0.85 (lagging)
Gas turbine conditions	New and Clean, ≤ 200 Fired Hours
Inlet system pressure drop (@ contract rated conditions) **(Note 4)**	≤76.2 mm H_2O
Exhaust system pressure drop (@ contract rated conditions)	≤121.4 mm H_2O
Fuel	Natural Gas
Fuel supply temperature	28 °C (82.4°F)
Fuel composition **(Note 2)**	% volume
• Nitrogen (N_2)	0.28
• Carbon Dioxide (CO_2)	3.56
• Methane (CH_4)	93.69
• Ethane (C_2H_6)	1.58
• Propane (C3H8)	0.37
• N-Butane (C4H10)	0.27
• Iso-Butane (C4H10)	0
• N-Pentane (C5H12)	0.12

Correction Parameter	Rated Value Case 1
• Iso-Pentane (C5H12)	0
• Heptanes	0.03
• Hexanes +	0.09
Fuel lower heating value	45183 kJ/kg (19429 BTU/lb)
Fuel H/C ratio **(Note 3)**	3.916

Notes:

1. An additional correction will be made if the gas turbine control system cannot maintain the desired operational condition; such that by design the unit is not run to the exhaust temperature control curve prescribed in the control specification for reasons beyond the control of GE.

   An example would be fuel gas supplied to the gas turbine that had a BTU value that was significantly outside the design range thus causing the fuel stroke ratio valve to operate outside normal parameters causing the engine to operate below the base load temperature control curve demand.

   A second example would be if the power draw on the grid were insufficient to allow the gas turbine to produce enough output to reach its base load temperature control curve.

   A third example would be if the gas fuel composition at the time of commissioning is outside the design range such that the unit cannot be run in a manner consistent with the basis of the performance specifications. A possible solution may include commissioning the gas turbine in such a way that would allow operation, but at a less than optimal performance, and a correction would be required to account for the impact of the fuel composition being outside the design range.

2. The corrected output and heat rate will be determined from the test gas composition, inclusive of a correction to account for the difference in performance caused by the test gas composition being not precisely equal to the rated gas composition, but within the allowable design range.

3. For gaseous fuels, the H/C ratio is defined as the H/C atom ratio of the combustible components of the fuel.

4. Inlet pressure drop will not be a performance correction as the inlet system is within GE's scope of supply. However, if the inlet pressure drop is greater than the rated pressure drop for reasons out of GE's control then measured performance will be corrected from the measured inlet pressure drop to the rated inlet pressure drop using the GE supplied correction curves. Examples where the aforementioned methodology would apply:

   - TERMOBARRANCAS, C.A./owner installed additional filters, silencers, etc.
   - Improper inlet filter cleaning practice

Responsibilities

3.0 TERMOBARRANCAS, C.A. will be responsible for the following test activities:

- TERMOBARRANCAS, C.A. will take all necessary precautions, at all times, for the safety of site personnel. This includes, but is not limited to, indoctrination of TERMOBARRANCAS, C.A.'S safety practices, energizing / de-energizing of all power systems (electrical, mechanical and hydraulic) using a lock-out tag-out procedure.
- Provide outage time to perform the following: off-line compressor water wash, pre-test instrument calibration checks, and equipment installation and removal
- Provide qualified electrician for the purpose of installation of the precision watt hour meter connected to the station potential and current transformers. GE is not responsible for the installation of electric load measurement equipment. GE will only assist the qualified electrician in the communication of the measurement requirements
- Provide qualified craft labor to: open inlet access door for IGV inspection, remove gas fuel orifice plate from the natural gas flow section, and other possible site specific tasks
- Provide instrumentation specialist to recalibrate unit control system transmitters if they are found to be out of tolerance as listed in Table 5
- Provide detergent and water for the purposes of an off-line waterwash
- Perform the off-line compressor water wash within required time
- Provide load and fuel for the test program
- Provide test assistants to support data collection

3.1 There will be shared responsibility for the remaining test activities. The major test activities and the party responsible for each activity are listed in Table 4 below.

Table 4: Division of Test Responsibilities

Test Activity	Conducting Party	Witnessing Party
Prepare the thermal performance test procedure	☒	☐
Provide special instrumentation as specified herein	☒	☐
Provide suitable containers for the collection of fuel samples	☒	☐
Perform required station instrumentation calibration checks	☒	☐
Witness / Assist station instrumentation calibration checks	☐	☒
Install special test instrumentation	☒	☐
Direct the installation of special test instrumentation	☒	☒
Obtain calibration records and/or flow section dimensions for the fuel flow section	☒	☐
Execute of test program	☒	☐
Witness execution of test program	☐	☒

Provide copies of pertinent measured data to involved parties	☒	☐
Arrange for third party analysis of fuel samples	☒	☐
Remove special test instrumentation	☒	☐
Coordinate the shipment and return of GE-supplied test equip-ment	☐	☒
Calculate corrected performance results prior to demobilization from site and provide preliminary results to pertinent parties	☒	☒
Issue the final test report	☒	☐

4.0 Measurement and Instrumentation

4.1 Test data will be collected from temporary precision test instrumentation and selected station and control instrumentation.

4.2 Performance test data are of two classes:

Primary	Data used for performance test calculations
Secondary	Data not used for performance test calculations, but required for reference or diagnostic purposes

4.3 The Conducting Party will supply calibrated temporary instrumentation for the test. Each instrument will be identified by a serial number affixed to the device in a permanent fashion, such as etching. A calibration report will be supplied for each instrument and will list the serial number for cross-reference purposes in the field setup and test results. The calibration report shall provide a tabular comparison between the reading from the instrument and the reading from a calibration standard across a range of readings typical of the expected performance test conditions. The data produced from the calibration of the temporary precision instruments will be traceable to the U.S. National Institute of Standards and Technology (NIST), equivalent international standards, or other methods by which it can be proven that the ASME PTC 22 requirements are met. Copies of all instrument calibration records will be provided to the Witnessing Party prior to the test and will be included in the final test report.

4.4 A complete list of measurements, along with the class, instrument(s) used, number of independent sensors and data gathering source for each measurement, is provided in Appendix B: Measurement List.

4.5 Unless other wise agreed, within 24 hours after publication of preliminary results, the turbine will be shut down and placed on turning gear for a short outage for the purpose of removing all temporary precision instrumentation provided by GE. The instrumentation supplied by GE shall be returned to GE.

5.0 Pre-Test Preparation

5.1 An off-line water wash of the gas turbine compressor section should be conducted prior to the testing. The water wash procedures and guidelines specified in the GE Turbine Generator Manual supplied along with the gas turbine equipment should be followed. The compressor inlet and inlet plenum will be inspected by the GE performance engineer before and after the wash. If the compressor is judged by the GE Performance engineer to still be dirty after the initial wash, additional compressor washing and/or hand wiping may be required at the GE performance engineer's discretion to ensure compressor cleanliness. The compressor will not be washed when the ambient temperature is below 40 °F (4.4 °C). It is highly recommended that the performance test be started within 25 fired hours of the off-line water wash. If a performance test occurs between 25 and 100 fired hours then the GE performance representative at site shall have the right to inspect the compressor and request an offline waterwash if need be, else the testing can commence. If the test has not been started within 100 fired hours of the last offline waterwash the unit will be shut down and offline washed prior to the commencement of the testing program. If any of the above guidelines are not followed GE reserves the right to declare the performance results invalid.

5.2 The calibration and proper operation of the control system, pertinent station instrumentation and measurement devices, and recording systems will be verified jointly by the Conducting Party and the Witnessing Party prior to official testing. One of the primary purposes of these verification activities is to ensure that the control system is operating correctly, which in turn ensures that the performance of the gas turbine will be consistent with the basis of the performance specifications using properly functioning control sensors.

The Conducting Party will supply calibrated portable accuracy verification devices of 0.1% accuracy class, expressed as percent of the full range of the portable device. Care shall be taken to ensure that the range of the portable accuracy verification device is similar to the range of the instrument to be verified. Each device will be identified by a serial number affixed to the device in a permanent fashion, such as etching. An accuracy verification and/or calibration report if required will be supplied for each device and will list the serial number of the device for cross reference purposes in the field setup and test results. The accuracy verification and/or calibration report shall provide a tabular comparison between the reading from the instrument and the reading from the portable accuracy verification device across a range of readings typical of the expected performance test conditions. The data obtained from the calibration of the portable accuracy verification device will be traceable to the U.S. National Institute of Standards and Technology (NIST), equivalent international standards, or other methods by which it can be proven that the 0.1% specified accuracy levels are met.

All data and notes regarding the instrumentation verifications, unit and device inspections, special instrumentation set-up and general readiness of the unit shall be documented in the Pre-Test Readiness Report, an example of which is included in Appendix C: Pre-Test Field Calibration Verification Report (Typical). A copy of the report, including appropriate signatures, will be provided to the Witnessing Party prior to official testing. The original copy of the report shall be included in the final report.

5.2.1 The **gas turbine exhaust thermocouple** signal processing system will be confirmed to be operating to control specification. A thermocouple indicator/calibrator will be used to input a 1000 °F (538 °C) signal to the unit control system at the terminal strips where the unit thermocouple leads first terminate. At least three (3) thermocouple wire sets for each unit control system computer will be checked (R, S, and T) for a total of at least nine (9) wire sets. If proper operation cannot be confirmed, the control system must be corrected.

5.2.2 The calibration and proper operation of all pertinent **station pressure transmitters** will be verified. This will include a loop calibration check of each transmitter to the control system, read at the control system display device, to verify overall system signal accuracy. The transmitter signal read at the control system display must be within the specified ranges noted in Table 5, as compared to the portable accuracy verification check device noted in paragraph 5.2. The GE

Performance Engineer shall specify all transmitters to be verified during test set-up. These pressure transmitters must meet the accuracy criteria specified in Table 5 below.

Table 5: Station Pressure Transmitters Criteria

Station Pressure Transmitters	Allowable Difference (as read at the control system display) relative to the portable calibration check device as specified in section 5.2
Compressor discharge pressure	+/- 0.3 psig
Barometric pressure	+/- 0.1 in Hg
Compressor bellmouth differential pressure	+/- 0.35 in H_2O
Inlet duct differential pressure	+/- 0.1 in H_2O
Exhaust duct differential pressure	+/- 0.1 in H_2O
Gas fuel static pressure	+/- 0.5 psig
Gas fuel orifice differential pressure	+/- 0.3 in H_2O

During verification, pressure will be supplied to each transmitter with the portable accuracy verification device as described in section 5.2. The input pressure levels shall cover an appropriate estimated range of normal operation. If proper operation cannot be confirmed, the transmitter in question must be re-calibrated, or replaced if defective and calibrated, by TERMOBARRANCAS, C.A., or personnel responsible for maintenance of the unit control system. *GE Thermal Performance Services personnel will not change the calibration of the control system or related transmitters unless given expressed written consent from the TERMOBARRANCAS, C.A. or personnel responsible for maintenance of the unit control system.*

5.2.3 **Inlet Guide Vane (IGV)** angular position will be measured with a machinist's protractor at position(s) specified by the GE Performance Engineer. The angle will be measured on at least sixteen (16) vanes equally spaced around the inlet circumference. The average of these measurements will define the true position of the IGV's. The true angle will be compared to the feedback angle displayed by the unit control system. The control system angle must be in agreement with the measured angle to within ±0.5 degrees, or the control system must be re-calibrated. In addition, if one IGV blade is not within ±1.0 degree with respect to the average of the sixteen (16) measurements, then the manufacturers product service department will be contacted for resolution.

5.2.4 If the **fuel orifice** plate has already been placed into service, it will be removed from the measurement station and inspected to verify that the leading edge is clean and sharp. The orifice bore diameter will be confirmed. If the orifice bore diameter is confirmed as compared to the as built drawings for the flow section then the as built drawing dimensions will be used for the performance calculations. If the bore diameter does not match the as built drawing the root cause will be determined and the parties shall mutually agree to the dimensions to be used for performance calculations. The orifice plate will be replaced in the metering section in the proper orientation. However, if the orifice section has been calibrated before installation, then the orifice will not be inspected so as not to disturb the calibration unless otherwise mutually agreed. Copies of all calibration material should be supplied to the Witnessing Party prior to testing.

5.2.5 The exhaust **temperature control constants** will be documented by any one of the following methods.

- Printout from the control system immediately prior to the test

- Continuous data logging in the control system trend file
- Recorded in the Pre Test Readiness Report immediately prior to the test

The exhaust temperature control constants documentation mentioned herein will be included in the test report.

5.3 A fuel sampling location will be jointly identified prior to the test. The sampling point will be located as close as possible to the gas turbine and upstream of the metering station. Special care should be taken to ensure that the fuel sampling location is as far downstream of all filters, dryers, compressors, scrubbers, etc. as possible, so that the samples are true representations of the fuel actually being consumed by the gas turbine. To ensure consistent, quality natural gas fuel samples, the gas sampling procedure included in Appendix F: Natural Gas Fuel Sampling Procedure should be followed.

6.0 Conducting the Test

6.1 A minimum of three (3) test runs per rated case listed in Table 1 will be conducted. The test sequence and operating characteristics will be as shown in Table 6:

Table 6: Test Sequence Summary

Unit	Correction on Performance to Rated Case	Load	Fuel	Diluent Injection	Inlet Treat-ment	Exhaust Con-figuration	Test Run
1	1	Base	Gas	None	N/A	Simple	1 – 3

6.2 Each test run will be conducted with the gas turbine power plant and all test instrumentation functioning satisfactorily and in a steady-state condition.

6.2.1 Prior to and during each test run, the gas turbine wheel space temperatures will be monitored individually to verify thermal equilibrium. The gas turbine will be considered in a thermal equilibrium condition when each turbine wheel space temperature changes by no more than five (5) °F (2.8) °C over a fifteen (15) minute period. The unit thermal equilibrium will be documented by the control system trend file from the unit control system.

6.2.2 In accordance with ASME PTC 22-1997, additional parameters will be monitored during each test run to verify that the gas turbine and it's boundary conditions are in a steady-state condition. These parameters and corresponding limits of variation are listed in Table 7. The system will be considered in steady-state condition as long as the following is true for each parameter listed: the variation from the test run average does not exceed the defined limit.

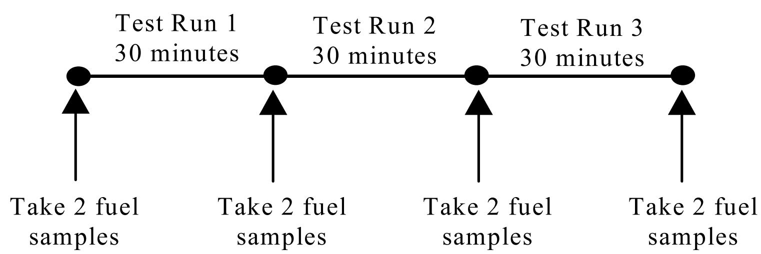
Table 7: Stability Requirement for Test Parameters

Parameter	Allowable Variation from Average
Ambient Temperature	$\pm$ 4.0 °F
Barometric Pressure	$\pm$ 0.5 %
Gas Fuel Supply Pressure	$\pm$ 1.0 %
Power Output	$\pm$ 2.0 %
Power Factor	$\pm$ 2.0 %
Turbine Speed	$\pm$ 1.0 %

6.3 In accordance with paragraph 3.3.4 of ASME PTC 22-1997, each test run will be conducted over a thirty (30) minute time period. Manual data will be recorded at five (5) minute intervals (or more frequently) throughout the duration of the test run for a minimum of seven (7) complete sets of instrument readings. Electronic control system and data acquisition data will be recorded at one (1) minute intervals (or more frequently) for a minimum of thirty-one (31) complete sets of instrument readings. In no instance should the test run period exceed thirty (30) minutes unless otherwise specified per contract and the requirements of Table 7 are met, nor should the manual data-recording interval exceed ten (10) minutes.

6.4 As a minimum, a set of two (2) fuel samples will be taken at the beginning and end of each test run for a total of eight (8 samples natural gas including duplicates. A timeline illustrating this sampling frequency for three (3) test runs is included below.

Figure 2: Schedule of Fuel Samples



Fuel samples may be taken more frequently, especially when unsteady fuel supply characteristics are suspected, provided that the fuel sampling process does not disturb the fuel flow measurements. To ensure consistent, quality natural gas fuel samples, the gas sampling procedure included in Appendix F: Natural Gas Fuel Sampling Procedure should be followed. One (1) fuel sample from each set of two (2) will be delivered to a qualified third party laboratory for analysis. As a back-up measure, the duplicate sample(s) will be retained at the site until all fuel analysis is completed.

6.5 The average data from each thirty (30) minute test run will be evaluated independently, in accordance with the methodology detailed in Section 7. The corrected results from the three (3) test runs will be averaged for comparison to the performance specifications, as detailed in Section 8.

6.6 Data is to be recorded manually on data sheets (**Error! Reference source not found.**), electronically from the unit's control system, power plant control room DCS (Distributed Control Center), and electronically from the temporary data acquisition system. DCS data may only be recorded if the EPC, Owner, or whoever may be responsible for the DCS system at the time of the test, can prove that there is no loss of data processing accuracy relative to the gas turbine control system trending functionality.

6.7 All data files, electronic and/or copies of the manual data hard copy sheets, which are relevant for performance testing and evaluation purposes will be given to the witnessing party immediately after the test. GE Proprietary data, which is not required to calculate the performance at rated contract conditions, will not be shared. The Witnessing Party and the Conducting Party at the conclusion of the test should sign the manual data sheets. Any discrepancies or questionable items shall be noted at this time. The original data sheets are to be kept by the Conducting Party for inclusion in the final report.

6.8 All testing should be conducted with the inlet bleed heat (IBH) system off. If the inlet bleed heat system is in operation during the official performance tests, for reasons such as, but not limited to compressor surge prevention or anti-icing on very cold days, then appropriate performance corrections will be applied to account for the extent to which the IBH flow would have been different if the test had been run at the contract rated conditions. The manual isolation valve shall not be manually closed. However, GE reserves the right to discard a test run if it is found that there is leakage originating from the inlet bleed heat control valve. The unit shall be shut down and a repair initiated prior to re-commencing the testing program.

6.9 Deviations from this procedure in any aspect of the test program should be discussed by the Conducting Party and the Witnessing Party. Both parties shall agree to the disposition of the test deviation and these shall be recorded using the Test Deviation forms included in Appendix H: Test Procedure Deviation Forms. The original test deviation forms will be retained by the Conducting Party for inclusion in the final report and a copy shall be supplied to the Witnessing Party.

7.0 Evaluation

The evaluation methodology detailed below contains all of the calculations required to determine gas turbine thermal performance, corrected to the rated conditions. A correction factor will be used to account for the difference between the rated value and the measured value for each parameter listed in Table 3. The appropriate correction factors, for each turbine operating condition, are to be obtained from the GE-supplied correction curves listed in Appendix A: Performance Correction Curves.

It is often the case that the correction curves that were supplied with the procedure will need to be updated prior to the commencement of the testing program. See section 1.9 of this test procedure for further explanation.

In the following sections, procedures are introduced by which to calculate the correction factor for each specific correction parameter listed in Table 3. Many of these correction factors, which are "dual read" interpolated from the applicable correction curve, are bi-variate. Bi-variate meaning that the correction curve includes families of curves, for the correction parameter of interest, at different compressor inlet temperatures. This is attributable to the fact that the compressor inlet temperature has a significant secondary performance effect on many of the correction parameters that must be accounted for. Care is taken during the generation of the correction curves to accurately model the bi-variate effects. The correction process shown throughout section 7 below includes simplifications to the correction factor calculation procedure which may appear to indicate that the compressor inlet temperature is being accounted for improperly. The following is an explanation on how the simplification is computed.

The following is an example of how to calculate the correction factor on performance for a correction variable that is bi-variate with compressor inlet temperature.

The full correction factor calculation process for a particular bi-variate performance correction parameter is the following,

$$corrfactor_{corrpara} = \frac{ref_{corrpara}meas_{cit}}{meas_{corrpara}meas_{cit}} \times \frac{rated_{corrpara}rated_{cit}}{ref_{corrpara}rated_{cit}}$$

where:

$Ref_{corrpara}$ $Meas_{cit}$	=	Correction factor interpolated from the applicable parameter's correction curve read at the reference value of the correction parameter and the test measured compressor inlet temperature. The reference value of the correction parameter is that value or characteristic which was used when generating the remainder of the correction curves
$Meas_{corrpara}$ $Meas_{cit}$	=	Correction factor interpolated from the applicable parameter's correction curve read at the test measured value of the correction parameter and the test measured compressor inlet temperature
$Rated_{corrpara}$ $Rated_{cit}$	=	Correction factor interpolated from the applicable parameter's correction curve read at the contract rated value of the correction parameter and the contract rated value of compressor inlet temperature
$Ref_{corrpara}$ $Rated_{cit}$	=	Correction factor interpolated from the applicable parameter's correction curve read at the reference value of the correction parameter and the contract rated value of compressor inlet temperature

During the correction curve generation process the reference value for a particular correction parameter is always used in the generation of the compressor inlet temperature correction curve. The reference value is defined as the nominal and it's subsequent correction factor is always 1.000 read at any of the different compressor inlet temperatures. Therefore the corrections $Ref_{corrpara}$ $Meas_{cit}$ and $Ref_{corrpara}$ Rat-

ed_{cit} are always the same value and subsequently cancel themselves out of the full correction factor equation leaving only the following equation.

$$corrfactor_{corrpara} = \frac{rated_{corrpara} rated_{cit}}{meas_{corrpara} meas_{cit}}$$

7.1 Gas Turbine Electrical Measurements and Calculations

7.1.1 Gas Turbine Generator Net Power Output

Gas turbine generator net power output will be calculated from the measured gross power measured at the generator terminals less the measured excitation power.

GNPO = Gas turbine generator net power output, kW

GNPO = $GGPO_P$ – EP

where:

$GGPO_P$ = Gas turbine generator gross power output, kW
EP = Generator excitation power, kW

7.1.1.1 Gas Turbine Generator Gross Power Output, Precision Instruments

Gas turbine generator gross power output will be calculated using the precision watt-hour meter connected to the station potential transformers and station current transformers.

$GGPO_P$ = Gas turbine generator gross power output, kW

$GGPO_P$ =

$$\frac{\sum_{\phi=1}^{2} (\text{Meter Reading} \times \text{MCF} \times \text{PTR} \times \text{PTRCF} \times \text{CTR} \times \text{CTRCF} \times 0.06)_{\phi}}{\text{Time}}$$

where:

ϕ = phase-to- phase generator measurement ("Open Delta method")

Meter Reading	=	Yokogawa load box, direct reading, Watt-hr
Time	=	Elapsed time period for meter reading, minutes
MCF	=	meter calibration factor
PTR	=	potential transformer ratio
PTRCF	=	PTR calibration factor = 1.0
CTR	=	current transformer ratio
CTRCF	=	CTR calibration factor = 1.0
0.06	=	Unit conversion, (60 min/hour) / (1000 watts/kW)

7.1.1 Gas Turbine Generator Power Factor, Precision Instruments

Gas turbine generator power factor will be calculated using the precision watt-hour meter connected to the station potential transformers and station current transformers.

PF_P = Gas turbine generator power factor, dimensionless

$$PF_P = \frac{GGPO_p}{\left(V_{ab}A_a + \frac{V_{ab}+V_{cb}}{2}A_b + V_{cb}A_c\right)}$$

where:

$GGPO_p$ = Generator Gross Power Output, kW from 7.1.1

V_{ab} = Phase A voltage referenced to phase B corrected for PTRCF and volt-meter calibration

V_{cb} = Phase C voltage referenced to phase B corrected for PTRCF and volt-meter calibration

A_a = Phase A current corrected for CTRCF and amp-meter calibration

A_b = Phase B current corrected for CTRCF and amp-meter calibration

A_c = Phase C current corrected for CTRCF and amp-meter calibration

7.2 Corrected Gas Turbine Generator Net Power Output

The gas turbine generator net power output will be corrected from the test conditions to the rated conditions in accordance with paragraph 2.3.

CGNPO = Corrected gas turbine generator net power output, kW

$$CGNPO = GNPO \times \prod_{i=1}^{12} Fi_P$$

where:

GNPO = Gas turbine generator net power output, kW

$F1_P$ = Factor to correct power from the measured compressor inlet temperature to the rated compressor inlet temperature

= $F1_{P(a)} / F1_{P(b)}$

where:

$F1_{P(a)}$ = Power Output correction factor at the rated compressor inlet temperature

$F1_{P(b)}$ = Power Output correction factor at the measured compressor inlet temperature

$F2_P$ = Factor to correct power from the measured compressor inlet relative humidity to the rated compressor inlet relative humidity.

= $F2_{P(a)}$ / $F2_{P(b)}$

where:

$F2_{P(a)}$ = Power output correction factor at the rated compressor inlet relative humidity and rated compressor inlet temperature

$F2_{P(b)}$ = Power output correction factor at the measured compressor inlet relative humidity and measured compressor inlet temperature

$F3_P$ = Factor to correct power from the measured barometric pressure to the rated barometric pressure

= $F3_{P(a)}$ / $F3_{P(b)}$

where:

$F3_{P(a)}$ = Power output correction factor at the rated barometric pressure and rated compressor inlet temperature

$F3_{P(b)}$ = Power output correction factor at the measured barometric pressure and measured compressor inlet temperature

$F4_P$ = Factor to correct power from the measured turbine shaft speed to the rated turbine shaft speed

= $F4_{P(a)}$ / $F4_{P(b)}$

where:

$F4_{P(a)}$ = Power output correction factor at the rated turbine shaft speed and rated compressor inlet temperature

$F4_{P(b)}$ = Power output correction factor at the measured turbine shaft speed and measured compressor inlet temperature

$F5_P$ = Factor to correct power from the measured generator power factor to the rated generator power factor

$$= 1 - \frac{F5_{P(a)} - F5_{P(b)}}{GNPO}$$

where:

$F5_{P(a)}$ = Generator losses at the measured generator net power output (GNPO) and rated generator power factor

$F5_{P(b)}$ = Generator losses at the measured generator net power output (GNPO) and measured generator power factor

$F6_P$ = Factor to correct power from the total fired hours accumulated prior to the test to the allowable total accumulated fired hours, as long as the total fired hours accumulated exceeds the allowable fired hours

$$= \quad 1 + \frac{F6_{P(b)} - F6_{P(a)}}{100}$$

where:

$F6_{P(a)}$ = Generator output degradation correction factor at the allowable total accumulated fired hours

$F6_{P(b)}$ = Generator output degradation correction factor at the total fired hours accumulated prior to the performance test

$F7_P$ = Factor to correct power from the measured inlet system pressure drop to the rated inlet system pressure drop. This factor is to be used only if the measured inlet system pressure drop is higher than the rated inlet system pressure drop

= $F7_{P(a)} / F7_{P(b)}$

where:

$F7_{P(a)}$ = Power output correction factor at the rated inlet system pressure drop and rated compressor inlet temperature

$F7_{P(b)}$ = Power output correction factor at the measured inlet system pressure drop and measured compressor inlet temperature

$F8_P$ = Factor to correct power from the measured exhaust system pressure drop to the rated exhaust system pressure drop. This correction is done in two steps. The first step is from the measured pressure drop at the measured compressor inlet temperature to the reference pressure drop curve at the measured compressor inlet temperature. The reference pressure drop curve is the pressure drop characteristic used when constructing the exhaust temperature control curve. The second step is from the reference pressure drop curve at the rated compressor inlet temperature to the rated pressure drop at the rated compressor inlet temperature. The change in pressure drop along the reference pressure drop curve is accounted for in the compressor inlet / ambient temperature correction curve This factor is to be used only if the measured exhaust system pressure drop is higher than the rated exhaust system pressure drop.

= $(1 / F8_{P(a)}) / (F8_{P(b)} / F8_{P(c)})$

where:

$F8_{P(a)}$ = Power output correction factor at the difference between the measured exhaust system pressure drop and the reference exhaust system pressure drop at the measured compressor inlet temperature (the difference is defined as measured exhaust system backpressure less the reference exhaust system backpressure)

$F8_{P(b)}$ = Power output correction factor at the rated exhaust system pressure drop

$F8_{P(c)}$ = Power output correction factor at the reference exhaust system pressure drop

Note: See "the effect of compressor inlet temperature on backpressure correction curve" to obtain the reference exhaust system pressure drop at the rated and the measured compressor inlet temperature

$F10_P$ = 1

$F11_P$ = Factor to correct power from the test fuel composition to the rated fuel composition.

= $F11_{P(a)} / F11_{P(b)}$

where:

$F11_{P(a)}$ = Power output correction factor at the rated gas fuel lower heating value and rated hydrogen-to-carbon (H/C) ratio

$F11_{P(b)}$ = Power output correction factor at the measured (as-tested) gas fuel lower heating value and measured hydrogen-to-carbon (H/C) ratio

$F12_P$ = Factor to correct power from the measured fuel supply temperature to the rated fuel supply temperature

= $F12_{P(a)} / F12_{P(b)}$

where:

$F12_{P(a)}$ = Power output correction factor at the rated fuel temperature

$F12_{P(b)}$ = Power output correction factor at the measured fuel temperature

7.3 Gas Turbine Generator Net Heat Rate

Gas turbine generator net heat rate will be calculated from the measured rate of heat consumption and the measured generator net power output.

GNHR = Gas turbine generator net heat rate, KJ/KWh

GNHR = HC / GNPO, KJ/KWh

where:

HC = Heat consumption rate, KJ/hr
GNPO = Generator net power output, kW

7.3.1 Gas Turbine Heat Consumption Rate

Gas turbine rate of heat consumption will be calculated from the measured fuel flow rate and the fuel lower heating value at constant pressure (LHV_P), as determined from laboratory analysis of the fuel samples.

HC = Gas turbine heat consumption rate, KJ/hr

HC = $W_{FG} \times LHV_P$, KJ/hr

where:

W_{FG} = Gas Fuel flow rate, kg/hr

LHV_P = Fuel lower heating value at constant pressure, KJ/kg

7.3.2 Gas Turbine Gas Fuel Flow Rate

The natural gas fuel flow rate into the gas turbine will be determined following the method outlined by the American Gas Association Report No. 3 and 8 for metering orifices, as follows:

W_{FG} = Gas fuel flow rate (Per AGA Rpt 3, Eqn 1-2 pg. 10), kg/hr

$$W_{FG} = 3600 \times N_1 \times C_d \times E_v \times Y \times d^2 \times \sqrt{\rho_{t,P} \times \Delta P}$$

where:

3600 = Units conversion, 3600 sec/hr

N_1 = Constant = 0.000351241 (Per AGA Rpt 3, Table 1-2)

C_d = Coefficient of discharge from calibration report (See Appendix G Fuel Flow Metering Calibration Data)

E_v = Velocity of approach factor (Per AGA Rpt 3, Eqn. 1-5)

Y = Upstream expansion factor (Per AGA Rpt 3, Eqn 1-24 through 1-26)

d = Orifice Plate Bore Diameter in Millimeter (per AGA Rpt 3, Eqn. 1-7, pg. 11)

$\rho_{t,P}$ = Density of flowing fluid (Per AGA Rpt 8, Eqn. 6), kg/m^3

ΔP = Differential Pressure millibar

7.4 Gas Fuel Heating Value and Density

The gas fuel constituents will be determined by gas chromatography in accordance with ASTM D1945. The fuel heating value will be determined from the constituents in accordance with ASTM D 3588 - 91. The characteristics used to evaluate each individual test run will be based on the average of the characteristics for the samples taken prior to and after each test run.

7.5 Corrected Gas Turbine Generator Net Heat Rate

Gas turbine generator net heat rate will be corrected from the test conditions to the rated conditions in accordance with paragraph 2.3:

CGNHR = Corrected gas turbine generator net heat rate, KJ/kWh

$$CGNHR = GNHR \times \prod_{i=1}^{12} Fi_{HR}$$

where:

GNHR = Gas turbine generator net heat rate, KJ/kWh.

$F1_{HR}$ = Factor to correct heat rate from the measured compressor inlet temperature to the rated compressor inlet temperature

= $F1_{HR(a)}$ / $F1_{HR(b)}$

where:

$F1_{HR(a)}$ = Heat rate correction factor at the rated compressor inlet temperature

$F1_{HR(b)}$ = Heat rate correction factor at the measured compressor inlet temperature

$F2_{HR}$ = Factor to correct heat rate from the measured compressor inlet relative humidity to the rated compressor inlet relative humidity.

= $F2_{HR(a)}$ / $F2_{HR(b)}$

where:

$F2_{HR(a)}$ = Heat rate correction factor at the rated compressor inlet relative humidity and rated compressor inlet temperature

$F2_{HR(b)}$ = Heat rate correction factor at the measured compressor inlet relative humidity and measured compressor inlet temperature

$F3_{HR}$ = Factor to correct heat rate from the measured barometric pressure to the rated barometric pressure

= $F3_{HR(a)}$ / $F3_{HR(b)}$

where:

$F3_{HR(a)}$ = Heat rate correction factor at the rated barometric pressure and rated compressor inlet temperature

$F3_{HR(b)}$ = Heat rate correction factor at the measured barometric pressure and measured compressor inlet temperature

$F4_{HR}$ = Factor to correct heat rate from the measured turbine shaft speed to the rated turbine shaft speed

= $F4_{HR(a)}$ / $F4_{HR(b)}$

where:

$F4_{HR(a)}$ = Heat rate correction factor at the rated turbine shaft speed and rated compressor inlet temperature

$F4_{HR(b)}$ = Heat rate correction factor at the measured turbine shaft speed and measured compressor inlet temperature

$F5_{HR}$ = Factor to correct heat rate from the measured generator power factor to the rated generator power factor

$$= \quad 1 + \frac{F5_{HR(a)} - F5_{HR(b)}}{GNPO}$$

where:

$F5_{HR(a)}$ = Generator losses at the measured generator net power output (GNPO) and rated generator power factor

$F5_{HR(b)}$ = Generator losses at the measured generator net power output (GNPO) and measured generator power factor

$F6_{HR}$ = Factor to correct heat rate from the total fired hours accumulated prior to the test to the allowable total accumulated fired hours, as long as the total fired hours accumulated exceeds the allowable fired hours

$$= \quad 1 - \frac{F6_{HR(b)} - F6_{HR(a)}}{100}$$

where:

$F6_{HR(a)}$ = Thermal efficiency degradation correction factor at the allowable total accumulated fired hours

$F6_{HR(b)}$ = Thermal efficiency degradation correction factor at the total fired hours accumulated prior to the performance test

$F7_{HR}$ = Factor to correct heat rate from the measured inlet system pressure drop to the rated inlet system pressure drop. This factor is to be used only if the measured inlet system pressure drop is higher than the rated inlet system pressure drop

= $F7_{HR(a)}$ / $F7_{HR(b)}$

where:

$F7_{HR(a)}$ = Heat rate correction factor at the rated inlet system pressure drop and rated compressor inlet temperature

$F7_{HR(b)}$ = Heat rate correction factor at the measured inlet system pressure drop and measured compressor inlet temperature

$F8_{HR}$ = Factor to correct heat rate from the measured exhaust system pressure drop to the rated exhaust system pressure drop. This correction is done in two steps. The first step is from the measured pressure drop at the measured compressor inlet temperature to the reference pressure drop curve at the measured compressor inlet temperature. The reference pressure drop curve is the pressure drop characteristic used when constructing the exhaust temperature control curve. The second step is from the reference pressure drop curve at the rated compressor inlet temperature to the rated pressure drop at the rated compressor inlet temperature. The change in pressure drop along the reference pressure drop curve is accounted for in the compressor inlet / ambient temperature correction curve. This factor is to be used only if the measured exhaust system pressure drop is higher than the rated exhaust system pressure drop

= $(1 / F8_{HR(a)}) / (F8_{HR(b)} / F8_{HR(c)})$

where:

$F8_{HR(a)}$ = Heat Rate correction factor at the difference between the measured exhaust system pressure drop and the reference exhaust system pressure drop at the measured compressor inlet temperature (the difference is defined as measured exhaust system backpressure less the reference exhaust system backpressure)

$F8_{HR(b)}$ = Heat Rate correction factor at the rated exhaust system pressure drop

$F8_{HR(c)}$ = Heat Rate correction factor at the reference exhaust system pressure drop

Note: See "the effect of compressor inlet temperature on backpressure correction curve" to obtain the reference exhaust system pressure drop at the rated and the measured compressor inlet temperature

$F9_{HR}$ = 1

$F10_{HR}$ = 1

$F11_{HR}$ = Factor to correct heat rate from the test fuel composition to the rated fuel composition

= $F11_{HR(a)} / F11_{HR(b)}$

where:

$F11_{HR(a)}$ = Heat Rate correction factor at the rated gas fuel lower heating value and rated hydrogen-to-carbon (H/C) ratio

$F11_{HR(b)}$ = Heat Rate correction factor at the measured (as-tested) gas fuel lower heating value and measured hydrogen-to-carbon (H/C) ratio

$F12_{HR}$ = Factor to correct heat rate from the test fuel supply temperature to the rated fuel supply temperature

= $F12_{HR(a)} / F12_{HR(b)}$

where:

$F12_{HR(a)}$ = Heat rate correction factor at the rated fuel temperature

$F12_{HR(b)}$ = Heat rate correction factor at the measured fuel temperature

8.0 Comparison to Guarantees

The following criteria will be used to determine the extent to which the test results indicate measured performance that is compliant with the performance specifications:

a) If the measured output, when corrected to contract rated conditions and surrounded by the allowance for test uncertainty, equals or exceeds the guaranteed output, then the measured output will be considered in compliance with the guarantee.

b) If the measured heat rate, when corrected to contract rated conditions and surrounded by the allowance for test uncertainty , is less than or equal to the guaranteed heat rate, then the measured heat rate will be considered in compliance with the guarantee.

The allowances for test measurement uncertainty were defined as per GEK 107551A.

These allowances are listed in Table 8.

Table 8: Allowances for Test Uncertainty

	GEK 107551A Test
Output	**± 2.00 %**
Heat Rate (Gas Fuel)	**± 1.70 %**

Appendix A: Performance Correction Curves

Performance Correction Curves
Base Load, Natural Gas

Effect of	on Parameter	Correction Factor	Curve Number	Rev	Sheet
Compressor Inlet Temperature	Output	$F1_P$	102HA2793	-	3
Compressor Inlet Relative Humidity	Output	$F2_P$	102HA2793	-	5
Barometric Pressure	Output	$F3_P$	102HA2793	-	17
Shaft Speed	Output	$F4_P$	102HA2793	-	7
Generator Power Factor	Output	$F5_P$	F307T139	-	
Total Fired Hours	Output	$F6_P$	519HA772-1	A	-
Inlet System Pressure Drop	Output	$F7_P$	102HA2793	-	11
Exhaust System Back Pressure	Output	$F8_{P(a)}$	102HA2793	-	2 & 13
Exhaust System Back Pressure	Output	$F8_{P(b)}$	102HA2793	-	2 & 15
Exhaust System Back Pressure	Output	$F8_{P(c)}$	102HA2793	-	2 & 15
Fuel Composition	Output	$F11_P$	102HA2793	-	19
Fuel Supply Temperature	Output	$F12_P$	102HA2793	-	9
Compressor Inlet Temperature	Heat Rate	$F1_{HR}$	102HA2793	-	4
Compressor Inlet Relative Humidity	Heat Rate	$F2_{HR}$	102HA2793	-	6
Barometric Pressure	Heat Rate	$F3_{HR}$	102HA2793	-	18
Shaft Speed	Heat Rate	$F4_{HR}$	102HA2793	-	8
Generator Power Factor	Heat Rate	$F5_{HR}$	F307T139	-	
Total Fired Hours	Heat Rate	$F6_{HR}$	519HA772-1	A	-
Inlet System Pressure Drop	Heat Rate	$F7_{HR}$	102HA2793	-	12
Exhaust System Back Pressure	Heat Rate	$F8_{HR(a)}$	102HA2793	-	2 & 14
Exhaust System Back Pressure	Heat Rate	$F8_{HR(b)}$	102HA2793	-	2 & 16
Exhaust System Back Pressure	Heat Rate	$F8_{HR(c)}$	102HA2793	-	2 & 16
Fuel Composition	Heat Rate	$F11_{HR}$	102HA2793	-	20
Fuel Supply Temperature	Heat Rate	$F12_{HR}$	102HA2793	-	10

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Reference Conditions and Corresponding Correction Curves

	Units		
Fuel		Gas	
Fuel LHV	kJ/kg	See Gas Constituents	
Load		Base	
IGV Angle	degrees	86	
Diluent Injection Fluid		None	
Generator Frequency	hertz	60	
Generator Power Factor	ratio	0.85	
Cycle Deck Version Used		PG7241-03A-0403	
Summary Page			Sheet 1
Reference Exhaust DP			Sheet 2

Applicable Correction Curve Sheet Numbers

	Units	Value	Output	Heat Rate	Exhaust Flow	Exhaust Temp	Heat Consumption
Ambient Temperature & Humidity (Evap or SPRITS)		N/A	N/A	N/A	N/A	N/A	N/A
Ambient Wetbulb Temperature	C	23.63	N/A	N/A	N/A	N/A	N/A
Compressor Inlet Temperature	C	26.50	Sheet 3	Sheet 4	N/A	N/A	N/A
Compressor Inlet Relative Humidity	%	79.0%	Sheet 5	Sheet 6	N/A	N/A	N/A
Shaft Speed	rpm	3600	Sheet 7	Sheet 8	N/A	N/A	N/A
Fuel Temperature	C	28	Sheet 9	Sheet 10	N/A	N/A	N/A
Inlet Pressure Loss	mmH2O	76.20	Sheet 11	Sheet 12	N/A	N/A	N/A
Exhaust Pressure Loss (Rated)	mmH2O	139.70	Sheet 13	Sheet 14	N/A	N/A	N/A
Exhaust Pressure Loss (Reference @ Rated CIT)	mmH2O	121.40	Sheet 15	Sheet 16	N/A	N/A	N/A
Barometric Pressure	mbara	989.81	Sheet 17	Sheet 18	N/A	N/A	N/A
Diluent Injection	kg/sec	N/A	N/A	N/A	N/A	N/A	N/A
Diluent Injection Pressure	bara	N/A	N/A	N/A	N/A	N/A	N/A
Diluent Injection Temperature	C	N/A	N/A	N/A	N/A	N/A	N/A
Gas Fuel Composition		See Gas Constituents	Sheet 19	Sheet 20	N/A	N/A	N/A
Fuel Oil LHV	kJ/kg	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Bleed Heat Flow	kg/sec	0	N/A	N/A	N/A	N/A	N/A
Inlet Bleed Heat Tx Suppression	F	0	N/A	N/A	N/A	N/A	N/A
Partload Effects			N/A	N/A	N/A	N/A	N/A

Fuel Composition (Used for Gas Fuel)	Units	Value
METHANE (CH4)	mol frac	0.9369
ETHANE (C2H6)	mol frac	0.0158
PROPANE (C3H8)	mol frac	0.0037
iso-BUTANE (C4H10)	mol frac	0.0027
n-BUTANE (C4H10)	mol frac	0.0000
iso-PENTANE (C5H12)	mol frac	0.0012
n-PENTANE (C5H12)	mol frac	0.0000
HEXANE (C6H14)	mol frac	0.0009
HEPTANES (C7H16)	mol frac	0.0003
CARBON MONOXIDE (CO)	mol frac	0.0000
CARBON DIOXIDE (CO2)	mol frac	0.0356
HYDROGEN SULFIDE (H2S)	mol frac	0.0000
HYDROGEN (H2)	mol frac	0.0000
OXYGEN (O2)	mol frac	0.0000
NITROGEN (N2)	mol frac	0.0028
WATER (H2O)	mol frac	0.0000
NITRIC OXIDE (NO)	mol frac	0.0000
NITROGEN DIOXIDE (NO2)	mol frac	0.0000
METHANOL (CH3OH)	mol frac	0.0000
OCTANE (C8H18)	mol frac	0.0000
DISTILLATE (C12H26)	mol frac	0.0000
ETHYLENE (C2H4)	mol frac	0.0000
ACETYLENE (C2H2)	mol frac	0.0000
AMMONIA (NH3)	mol frac	0.0000
ARGON (AR)	mol frac	0.0000
CARBONYL SULFIDE (COS)	mol frac	0.0000
ETHYL ALCOHOL (C2H5OH)	mol frac	0.0000
DECAHYDRONAPTHALENE (C10H18)	mol frac	0.0000
Gas Fuel LHV - per ASTM D3588	kJ/kg	45180
Gas Fuel H/C Ratio	ratio	3.916

Additional Notes:

Inlet Bleed Heat Not Modeled in this Package

Pre-Integrated Tuning Correction Curves

Control Curve Constants

Description	Units	Value
Control Curve Type	-	Xc
Segment 1 Slope	deg F / Xc	-23.705
Segment 1 Corner	Xc	12.592
Curve Isotherm	F	1200.000
TCD or CTIM Bias	deg F / deg F	0.000
TCD or CTIM Offset	F	0.000
IGV Bias	deg F / deg	0.000
IGV Offset	deg	0.000
Segment 2 Slope	deg F / Xc	-44.698
Segment 2 Corner	Xc	14.287
1st Breakpoint	Xc	16.201
Segment 3 Slope	deg F / Xc	
Segment 3 Corner	Xc	
2nd Breakpoint	Xc	
Spec. Humidity bias	deg F / lb/lb	0.000
SH Ref Breakpoint	lb/lb	0.000

NOTE: These performance test correction curves and tables are provided for the sole purpose of correcting performance test data from the boundary conditions present at the time of test to the design, guarantee, or reference conditions listed on this sheet. The performance characteristics on these sheets do not constitute any new performance guarantee(s) or any change to existing performance guarantee(s). Please refer to the GE Performance Test Procedure for proper interpretation and use of these sheets.

General Electric Model PG7241 Gas Turbine
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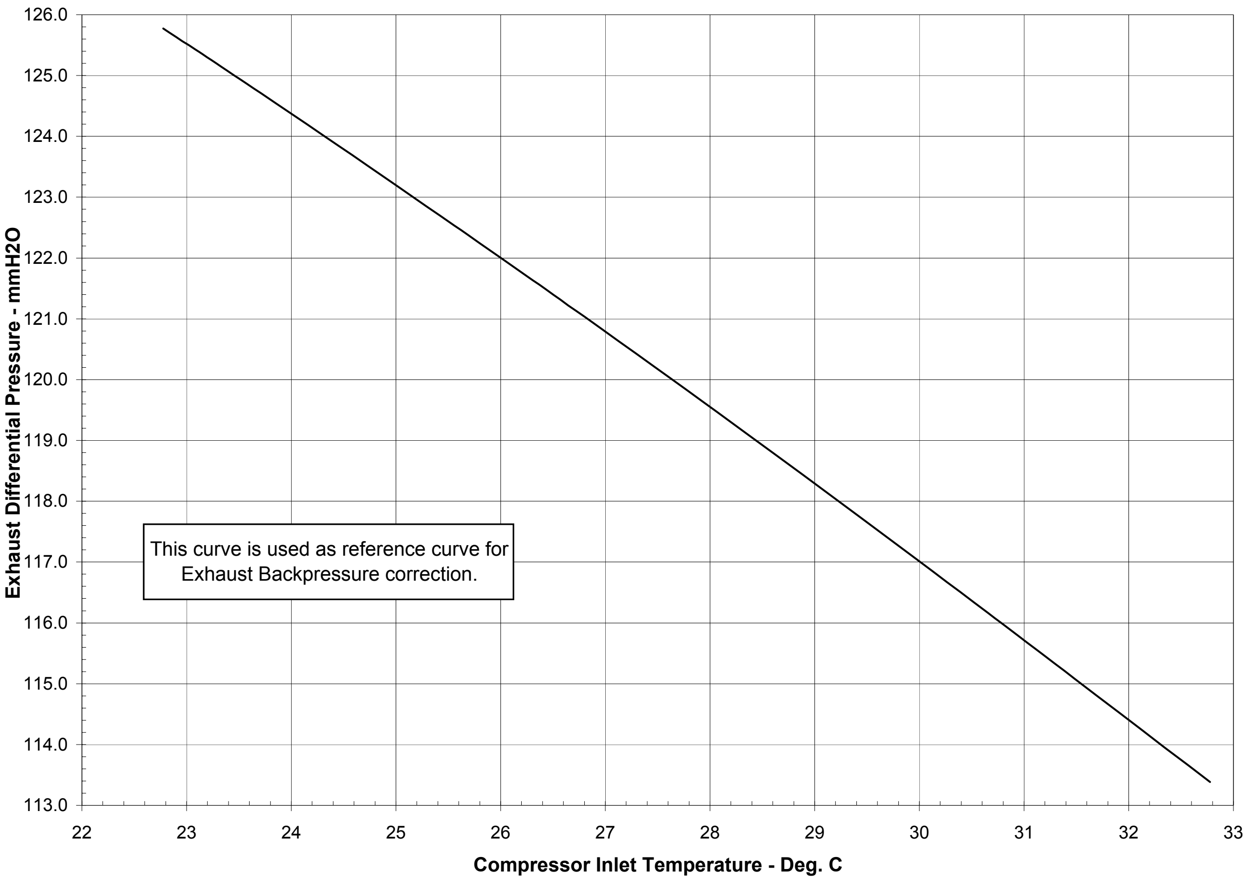
Effect of Compressor Inlet Temperature on Exhaust Pressure

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



	Units										
Compressor Inlet Temperature	C	22.78	23.33	24.44	25.56	26.50	27.78	28.89	30.00	31.11	32.78
Exhaust DP	mmH2O	125.78	125.14	123.85	122.54	121.40	119.83	118.43	117.01	115.57	113.38

Ralph Gunst
09/22/07

102HA2793 Rev -
Sheet 2

General Electric Model PG7241 Gas Turbine
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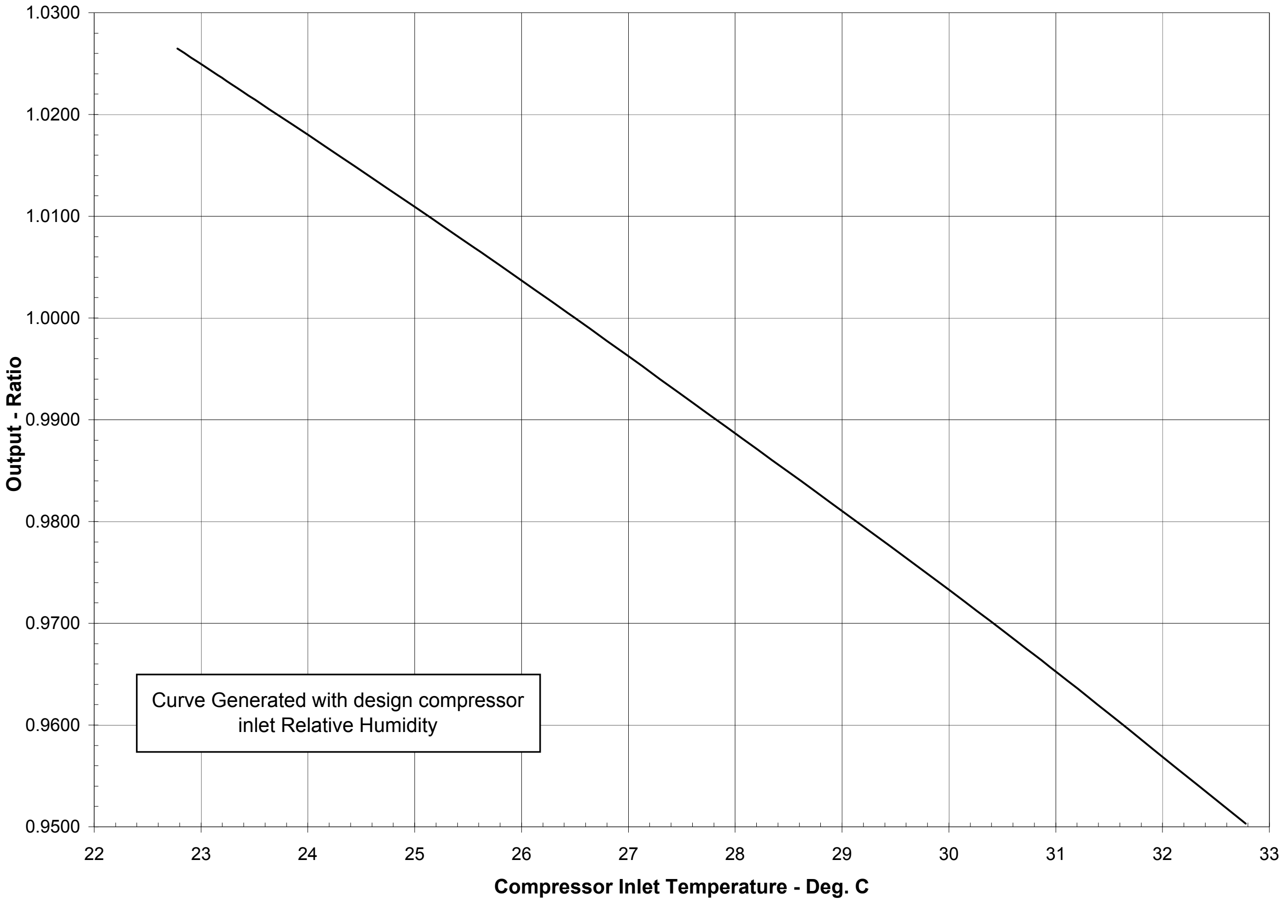
Estimated Performance

Effect of Compressor Inlet Temperature on Output

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



	Units										
Compressor Inlet Temperature	C	22.78	23.33	24.44	25.56	26.50	27.78	28.89	30.00	31.11	32.78
Output Ratio		1.02647	1.02264	1.01486	1.00692	1.00000	0.99035	0.98190	0.97330	0.96434	0.95030

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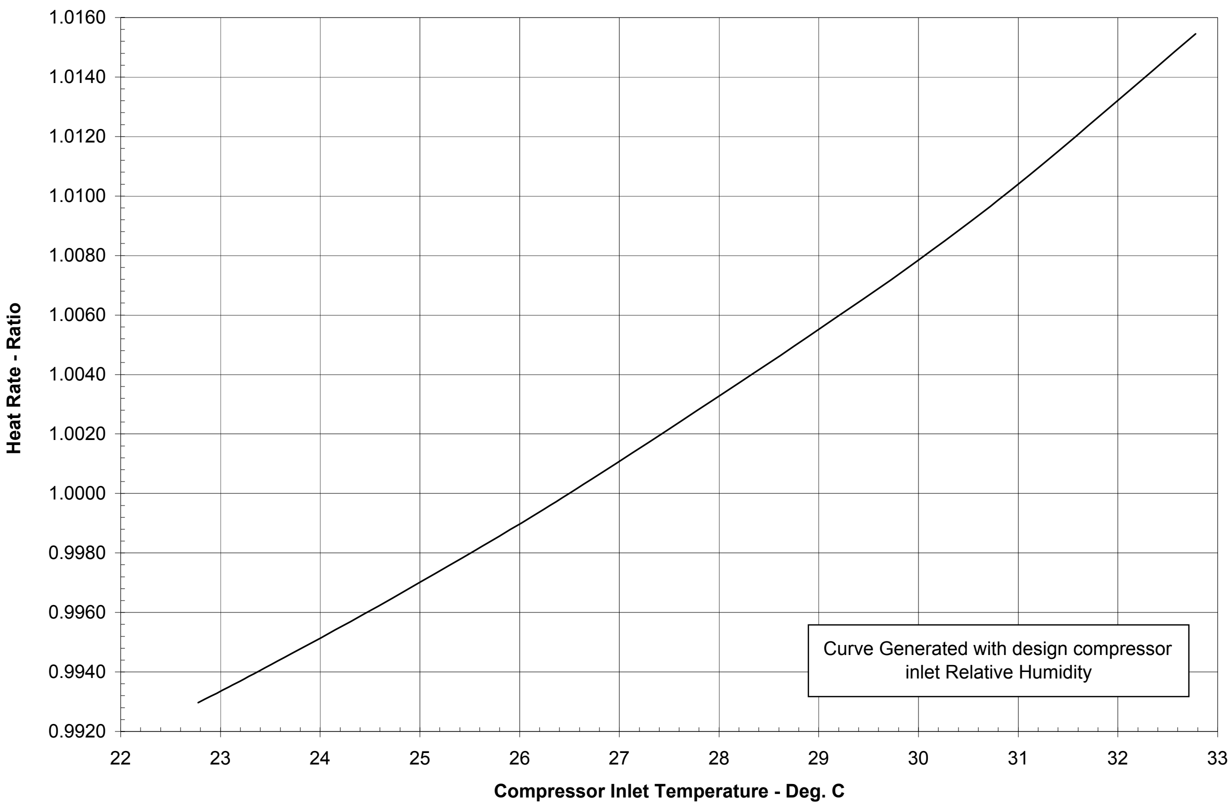
Estimated Performance

Effect of Compressor Inlet Temperature on Heat Rate

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



	Units										
Compressor Inlet Temperature	C	22.78	23.33	24.44	25.56	26.50	27.78	28.89	30.00	31.11	32.78
Heat Rate Ratio		0.99297	0.99394	0.99596	0.99808	1.00000	1.00279	1.00526	1.00784	1.01069	1.01546

Ralph Gunst
09/22/07

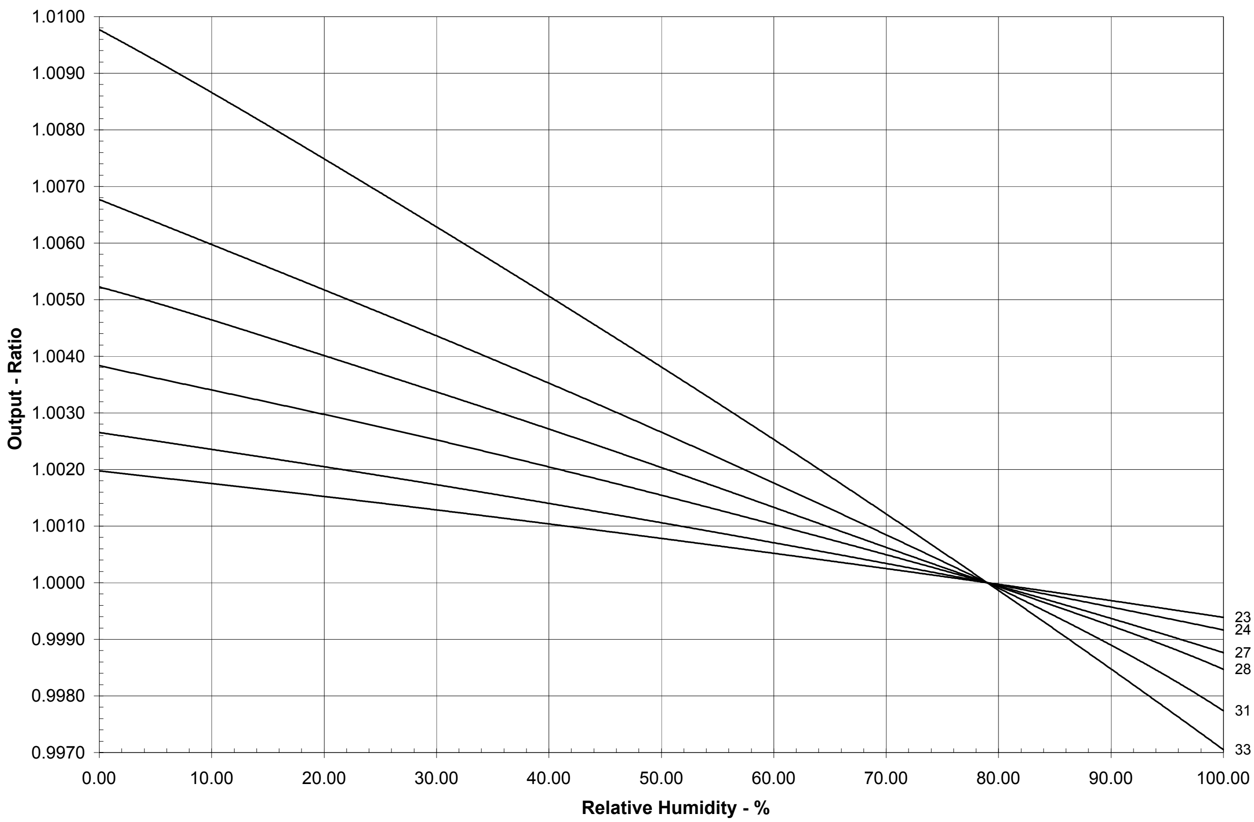
102HA2793 Rev -
Sheet 4

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Relative Humidity on Output at Different Compressor Inlet Temperatures

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

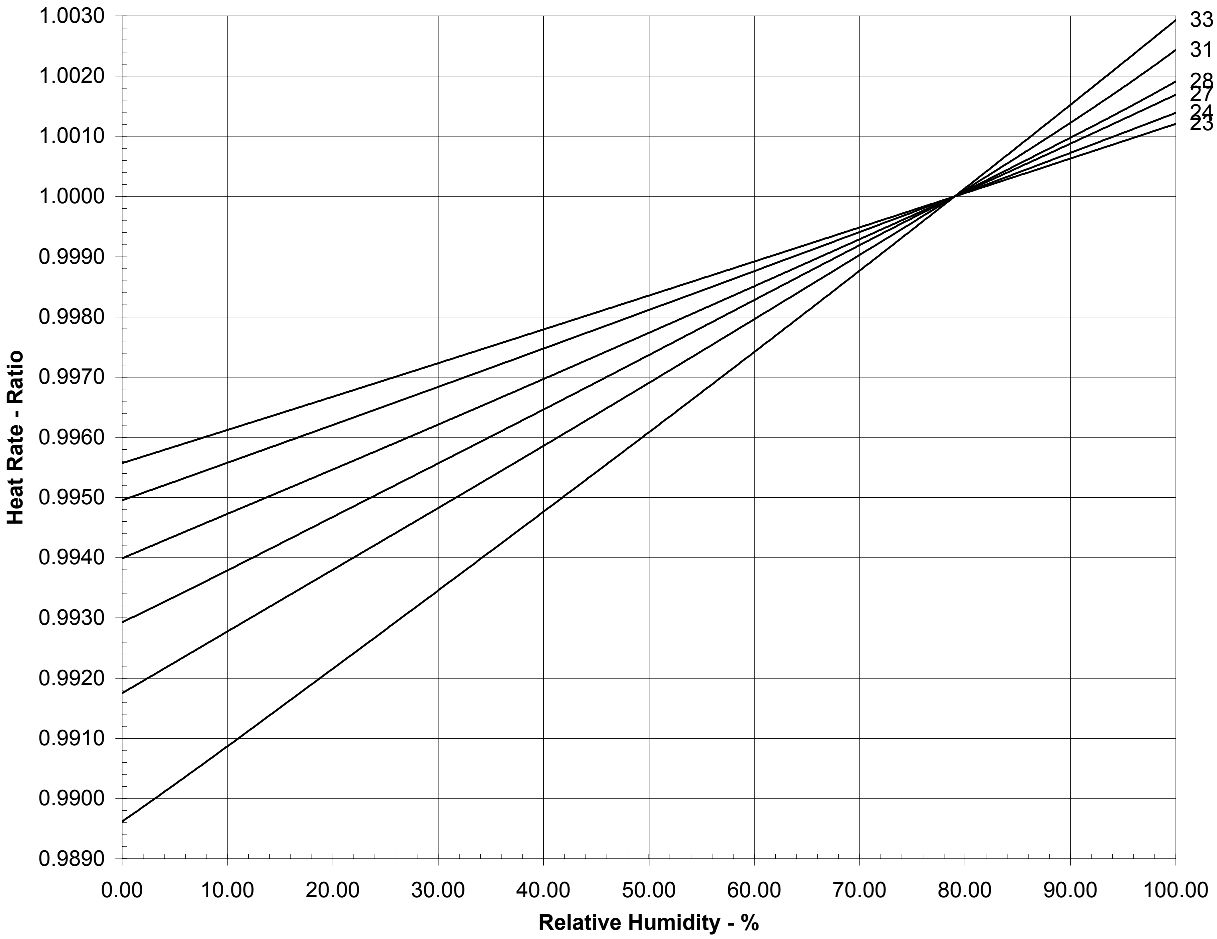
Relative Humidity - %	22.8	24.4	26.5	28.3	30.6	32.8
79.0	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00197	1.00265	1.00383	1.00522	1.00677	1.00977
20	1.00152	1.00205	1.00297	1.00401	1.00517	1.00749
40	1.00104	1.00140	1.00205	1.00272	1.00353	1.00506
50	1.00078	1.00106	1.00155	1.00203	1.00266	1.00381
60	1.00052	1.00071	1.00103	1.00133	1.00176	1.00253
70	1.00025	1.00034	1.00050	1.00062	1.00085	1.00121
80	0.99997	0.99996	0.99994	0.99993	0.99990	0.99986
100	0.99939	0.99917	0.99876	0.99847	0.99774	0.99705

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Relative Humidity on Heat Rate at Different Compressor Inlet Temperatures

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

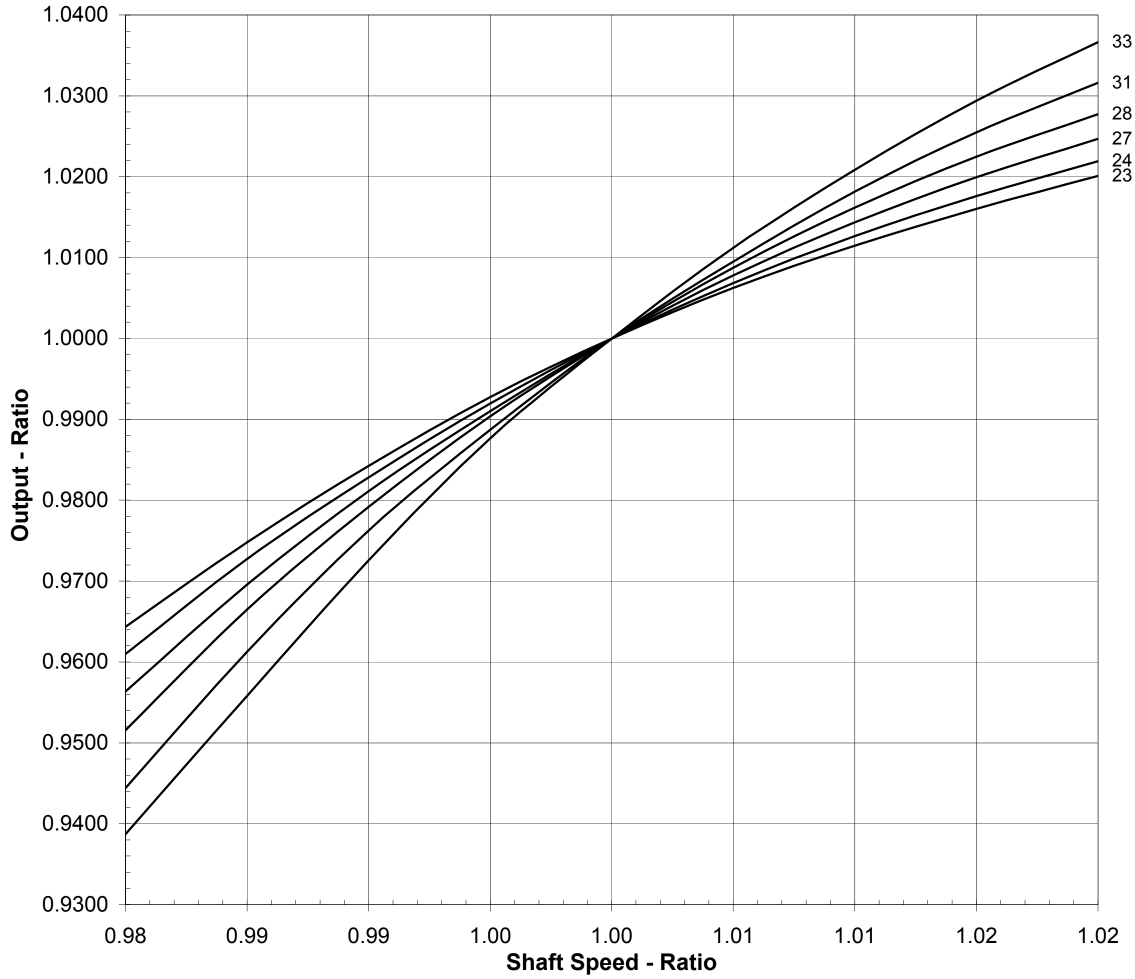
Relative Humidity - %	22.8	24.4	26.5	28.3	30.6	32.8
79.0	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	0.99557	0.99495	0.99399	0.99293	0.99175	0.98962
20	0.99668	0.99621	0.99547	0.99468	0.99380	0.99216
40	0.99779	0.99747	0.99697	0.99646	0.99586	0.99477
50	0.99836	0.99812	0.99774	0.99737	0.99690	0.99608
60	0.99892	0.99876	0.99851	0.99828	0.99796	0.99742
70	0.99949	0.99941	0.99929	0.99919	0.99903	0.99877
80	1.00006	1.00007	1.00008	1.00009	1.00011	1.00014
100	1.00121	1.00139	1.00169	1.00191	1.00244	1.00293

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Shaft Speed on Output at Different Compressor Inlet Temperatures

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

Shaft Speed Ratio	22.8	24.4	26.5	28.3	30.6	32.8
0.980	0.96435	0.96100	0.95636	0.95155	0.94440	0.93872
0.985	0.97478	0.97274	0.96958	0.96648	0.96125	0.95581
0.990	0.98424	0.98282	0.98113	0.97917	0.97625	0.97256
0.995	0.99275	0.99196	0.99101	0.99038	0.98873	0.98765
1.000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.005	1.00623	1.00683	1.00777	1.00876	1.00950	1.01118
1.010	1.01147	1.01265	1.01436	1.01618	1.01817	1.02083
1.015	1.01602	1.01759	1.01993	1.02245	1.02548	1.02939
1.020	1.02010	1.02193	1.02469	1.02771	1.03163	1.03664

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

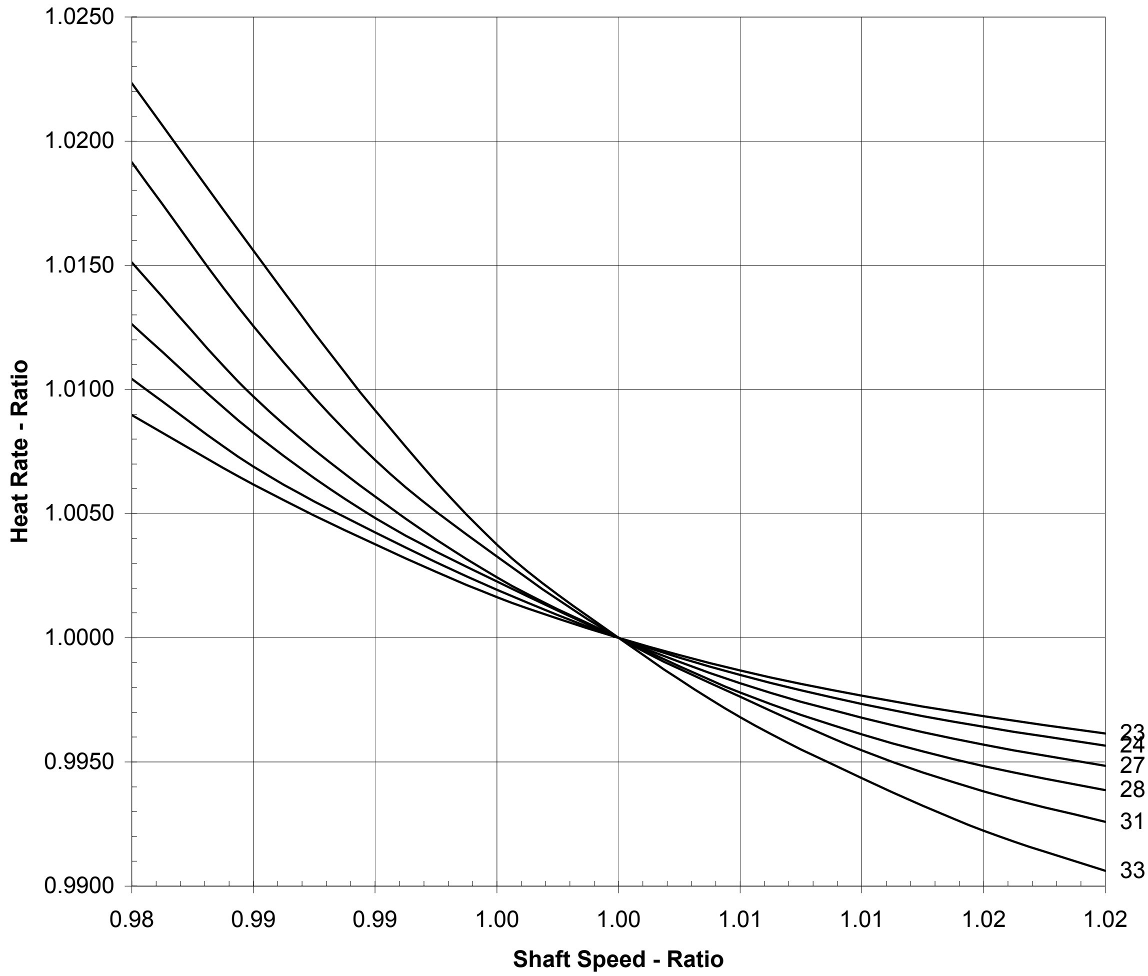
Effect of Shaft Speed on Heat Rate at Different Compressor Inlet Temperatures

Design Values Referenced on 102HA2793 Rev - Sheet 1

Fuel: Gas

Mode: Base

Gas Turbine Generator(s) 298593 ONLY

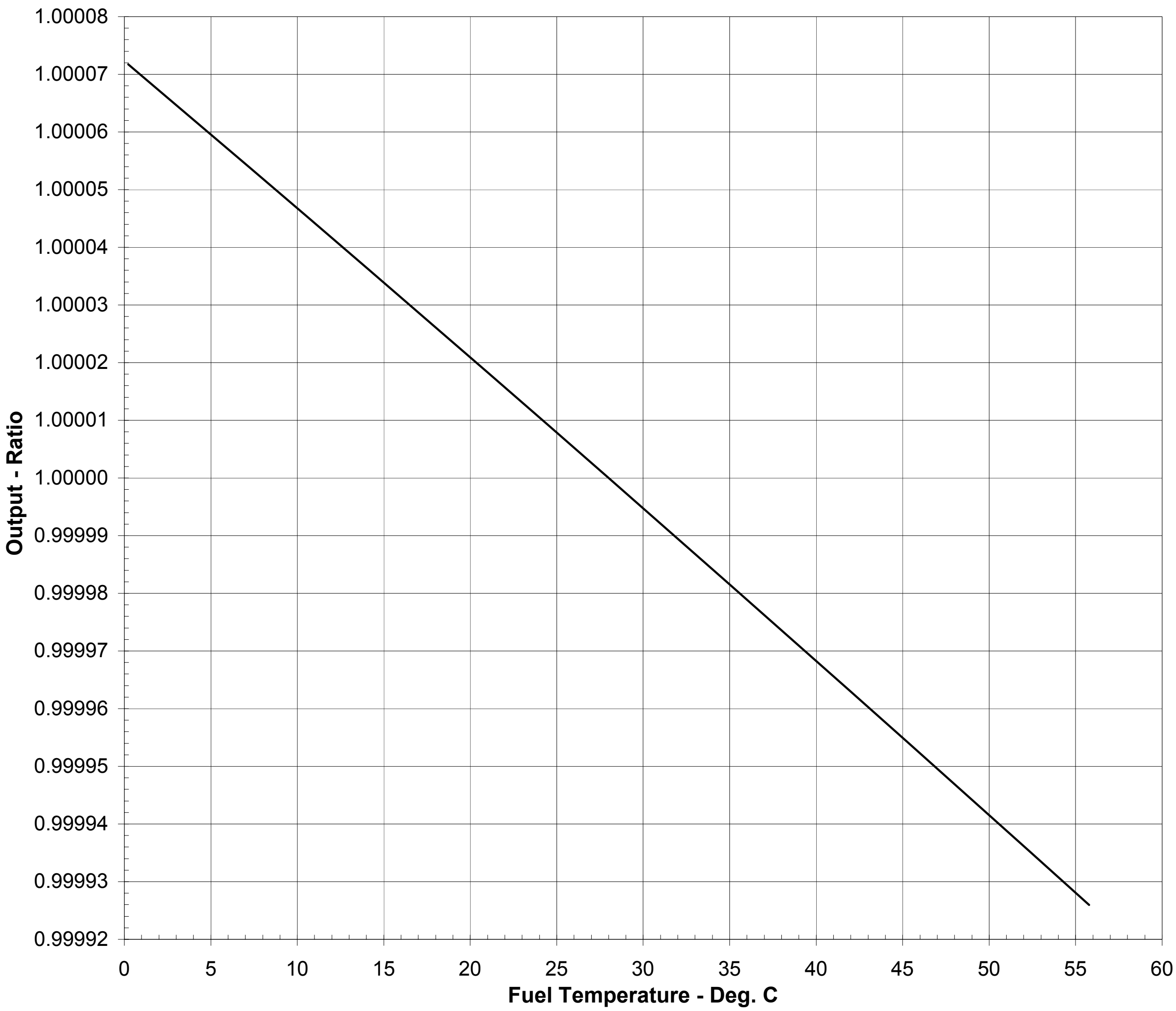


Compressor Inlet Temperature - Deg. C

Shaft Speed Ratio	22.8	24.4	26.5	28.3	30.6	32.8
0.980	1.00897	1.01043	1.01263	1.01511	1.01914	1.02234
0.985	1.00617	1.00689	1.00826	1.00972	1.01256	1.01559
0.990	1.00376	1.00424	1.00482	1.00568	1.00716	1.00915
0.995	1.00164	1.00194	1.00227	1.00244	1.00328	1.00375
1.000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.005	0.99869	0.99851	0.99817	0.99779	0.99763	0.99680
1.010	0.99767	0.99733	0.99678	0.99611	0.99546	0.99434
1.015	0.99685	0.99641	0.99570	0.99483	0.99382	0.99223
1.020	0.99615	0.99566	0.99485	0.99386	0.99259	0.99062

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance
Effect of Fuel Temperature on Output
Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



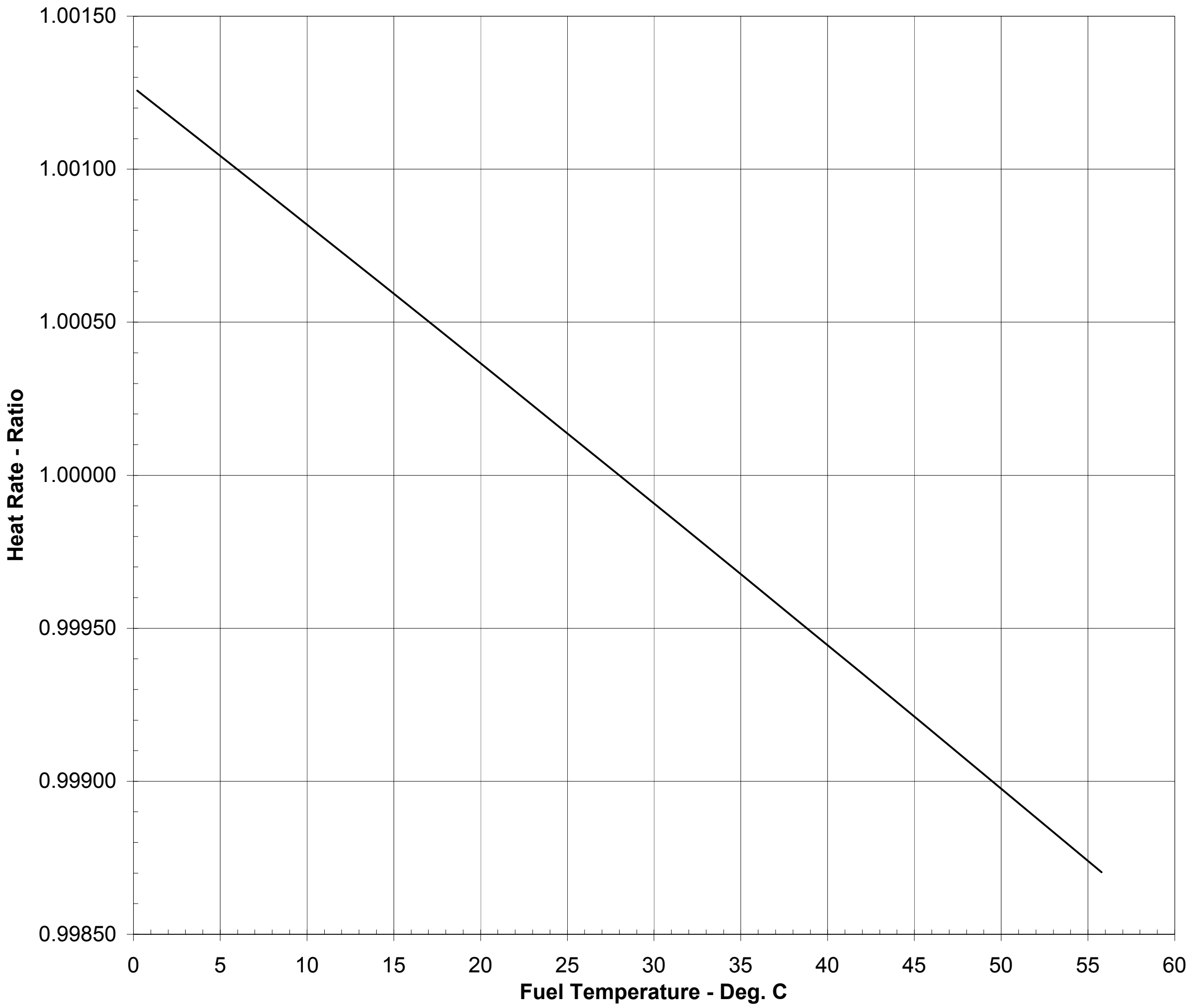
	Units									
Fuel Temperature	C	0.2	7.2	14.1	21.1	28.0	34.9	41.9	48.8	55.8
Output Ratio		1.00007	1.00005	1.00004	1.00002	1.00000	0.99998	0.99996	0.99994	0.99993

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Fuel Temperature on Heat Rate

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



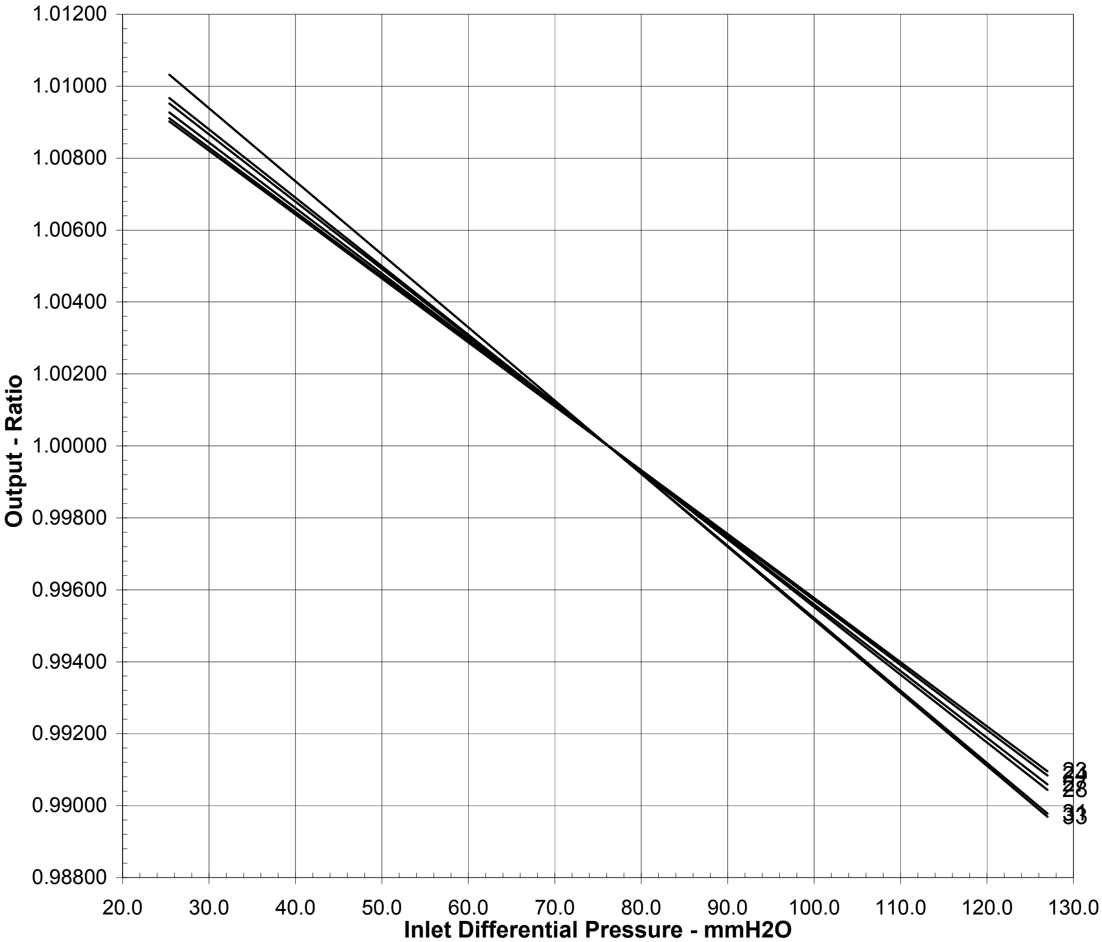
	Units									
Fuel Temperature	C	0.2	7.2	14.1	21.1	28.0	34.9	41.9	48.8	55.8
Heat Rate Ratio		1.00126	1.00095	1.00063	1.00032	1.00000	0.99968	0.99936	0.99903	0.99870

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Inlet Differential Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

Inlet dP (mmH2O)	22.8	24.4	26.5	28.3	30.6	32.8
25.400	1.00902	1.00911	1.00927	1.00951	1.00967	1.01032
38.100	1.00677	1.00684	1.00696	1.00714	1.00725	1.00774
50.800	1.00451	1.00456	1.00464	1.00477	1.00484	1.00516
63.500	1.00225	1.00228	1.00232	1.00238	1.00242	1.00258
76.200	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
88.900	0.99775	0.99772	0.99766	0.99761	0.99745	0.99742
101.600	0.99549	0.99543	0.99530	0.99522	0.99489	0.99484
114.300	0.99322	0.99313	0.99295	0.99283	0.99233	0.99227
127.000	0.99096	0.99084	0.99058	0.99044	0.98978	0.98969

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

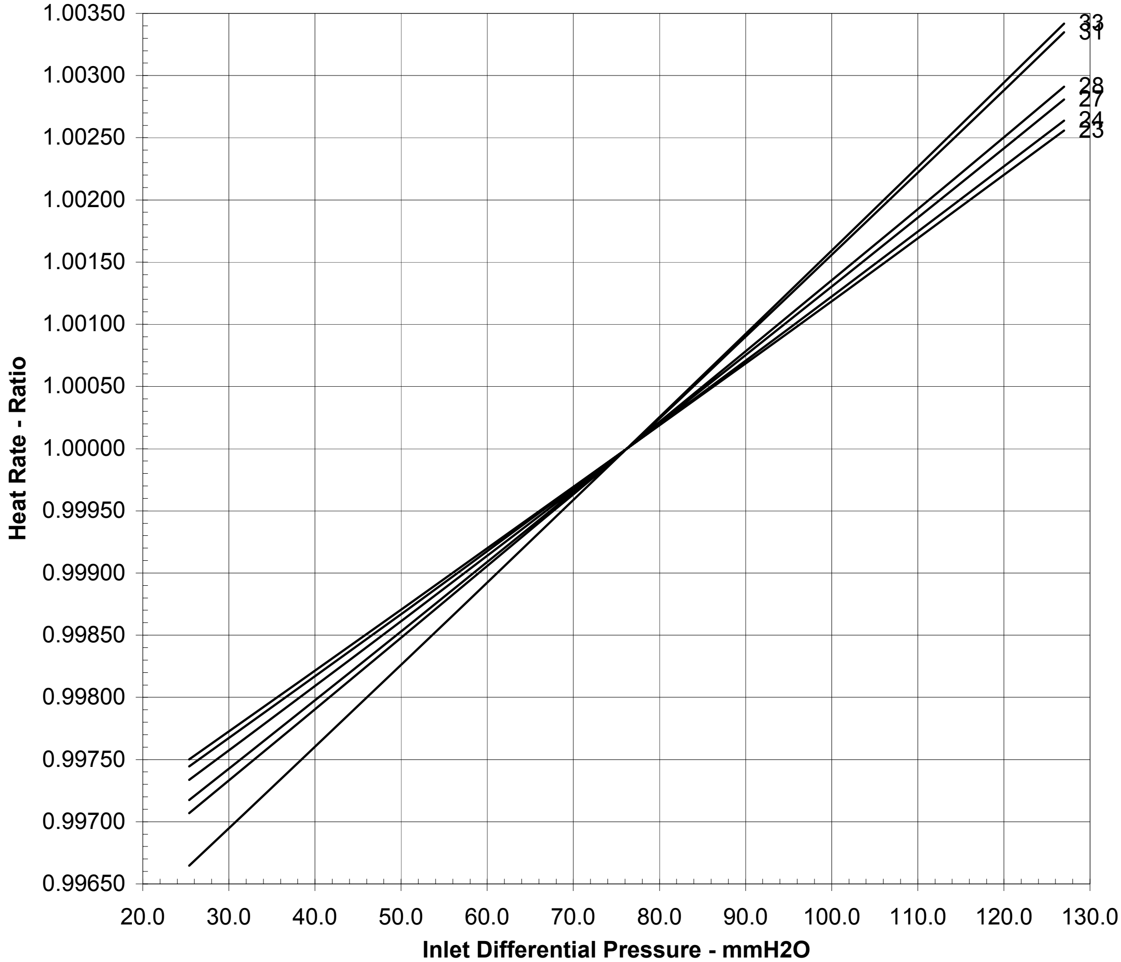
Effect of Inlet Differential Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 102HA2793 Rev - Sheet 1

Fuel: Gas

Mode: Base

Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

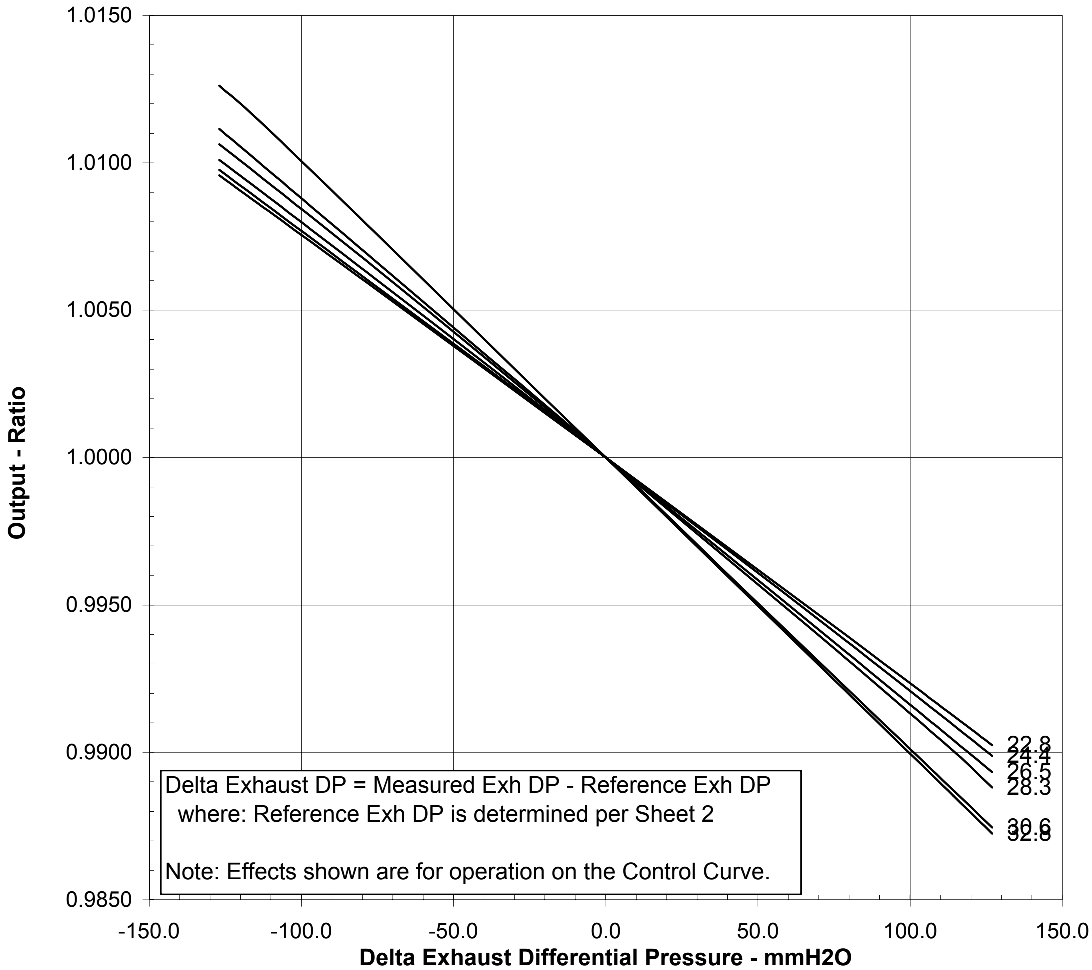
Inlet dP (mmH2O)	22.8	24.4	26.5	28.3	30.6	32.8
25.400	0.99750	0.99745	0.99734	0.99717	0.99707	0.99665
38.100	0.99812	0.99807	0.99799	0.99787	0.99780	0.99748
50.800	0.99875	0.99871	0.99866	0.99858	0.99853	0.99832
63.500	0.99937	0.99935	0.99932	0.99929	0.99926	0.99916
76.200	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
88.900	1.00063	1.00065	1.00069	1.00072	1.00083	1.00085
101.600	1.00127	1.00131	1.00139	1.00144	1.00166	1.00170
114.300	1.00191	1.00197	1.00210	1.00217	1.00250	1.00256
127.000	1.00256	1.00264	1.00281	1.00291	1.00335	1.00342

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Exhaust Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

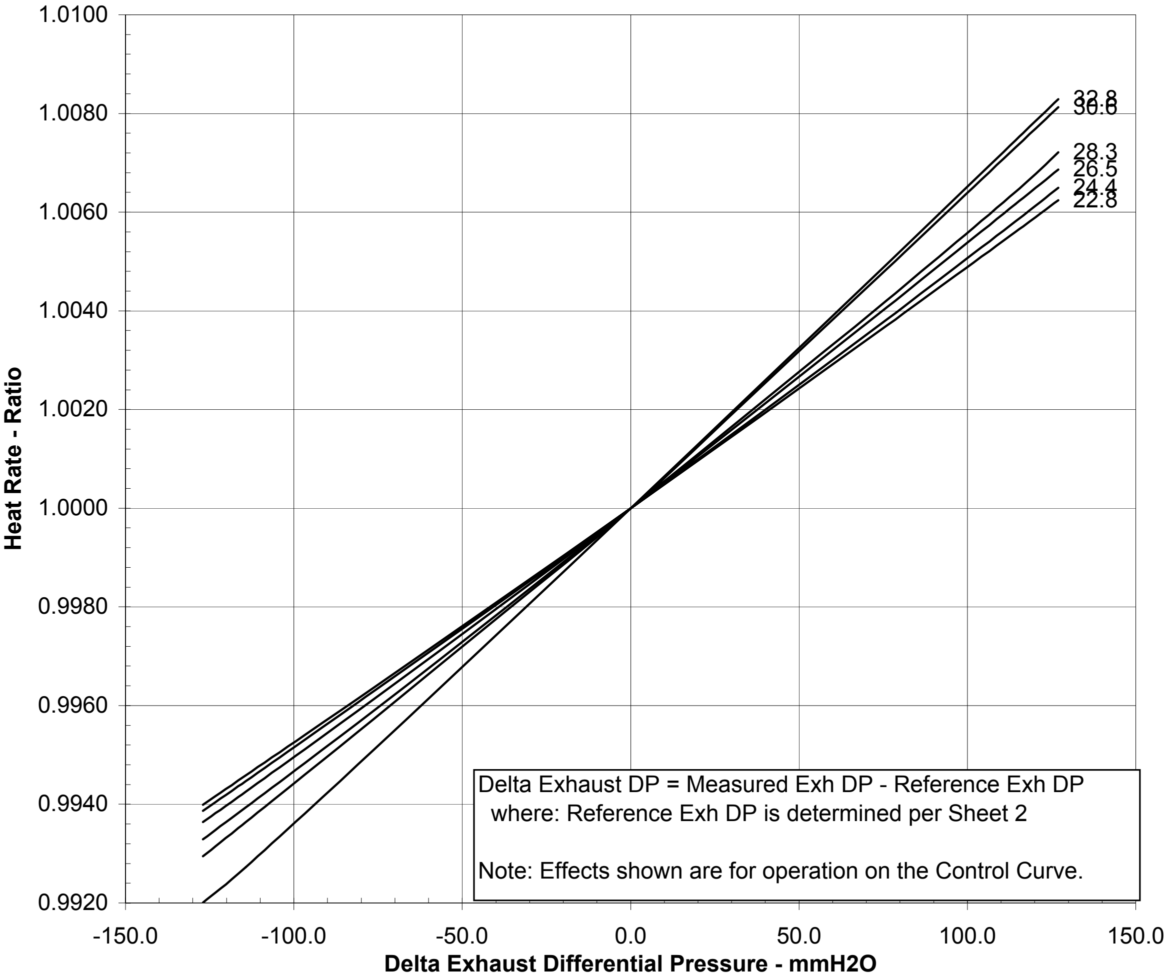
Delta Exhaust Differential Pressure - mmH2O	22.8	24.4	26.5	28.3	30.6	32.8
-127.00	1.00957	1.00975	1.01010	1.01063	1.01114	1.01261
-114.30	1.00862	1.00878	1.00911	1.00960	1.01004	1.01146
-76.20	1.00576	1.00586	1.00610	1.00647	1.00671	1.00768
-38.10	1.00288	1.00295	1.00307	1.00325	1.00336	1.00384
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
38.10	0.99711	0.99702	0.99684	0.99672	0.99624	0.99617
76.20	0.99419	0.99401	0.99364	0.99343	0.99247	0.99234
114.30	0.99124	0.99092	0.99041	0.99005	0.98871	0.98852
127.00	0.99025	0.98988	0.98933	0.98881	0.98745	0.98725

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Exhaust Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

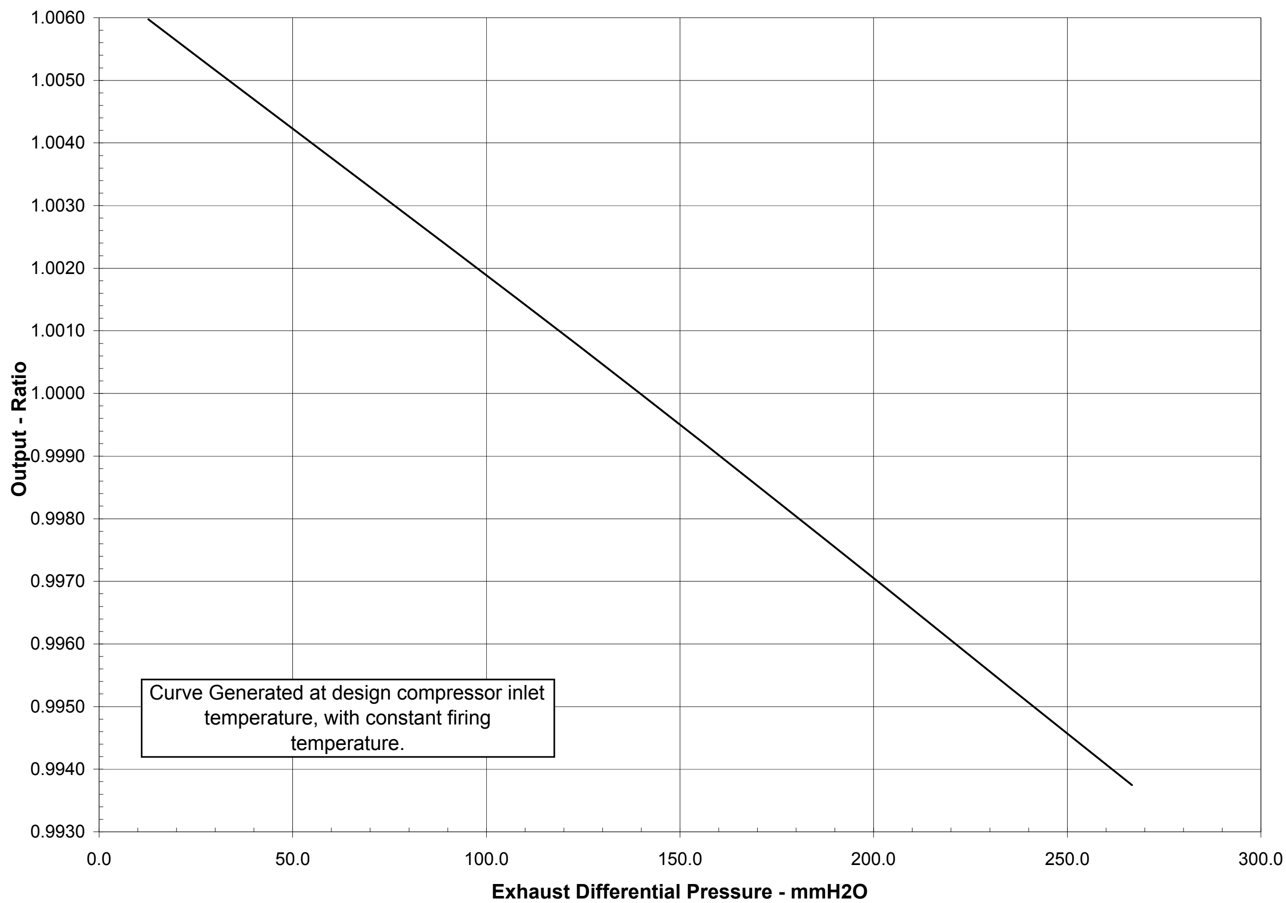
Delta Exhaust Differential Pressure - mmH2O	22.8	24.4	26.5	28.3	30.6	32.8
-127.00	0.99399	0.99387	0.99364	0.99329	0.99295	0.99201
-114.30	0.99458	0.99447	0.99426	0.99394	0.99364	0.99272
-76.20	0.99637	0.99630	0.99614	0.99590	0.99574	0.99511
-38.10	0.99818	0.99813	0.99805	0.99793	0.99786	0.99755
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
38.10	1.00184	1.00190	1.00202	1.00210	1.00242	1.00247
76.20	1.00371	1.00383	1.00408	1.00422	1.00485	1.00495
114.30	1.00560	1.00582	1.00616	1.00641	1.00731	1.00745
127.00	1.00624	1.00649	1.00686	1.00722	1.00813	1.00829

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Exhaust Differential Pressure on Output

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



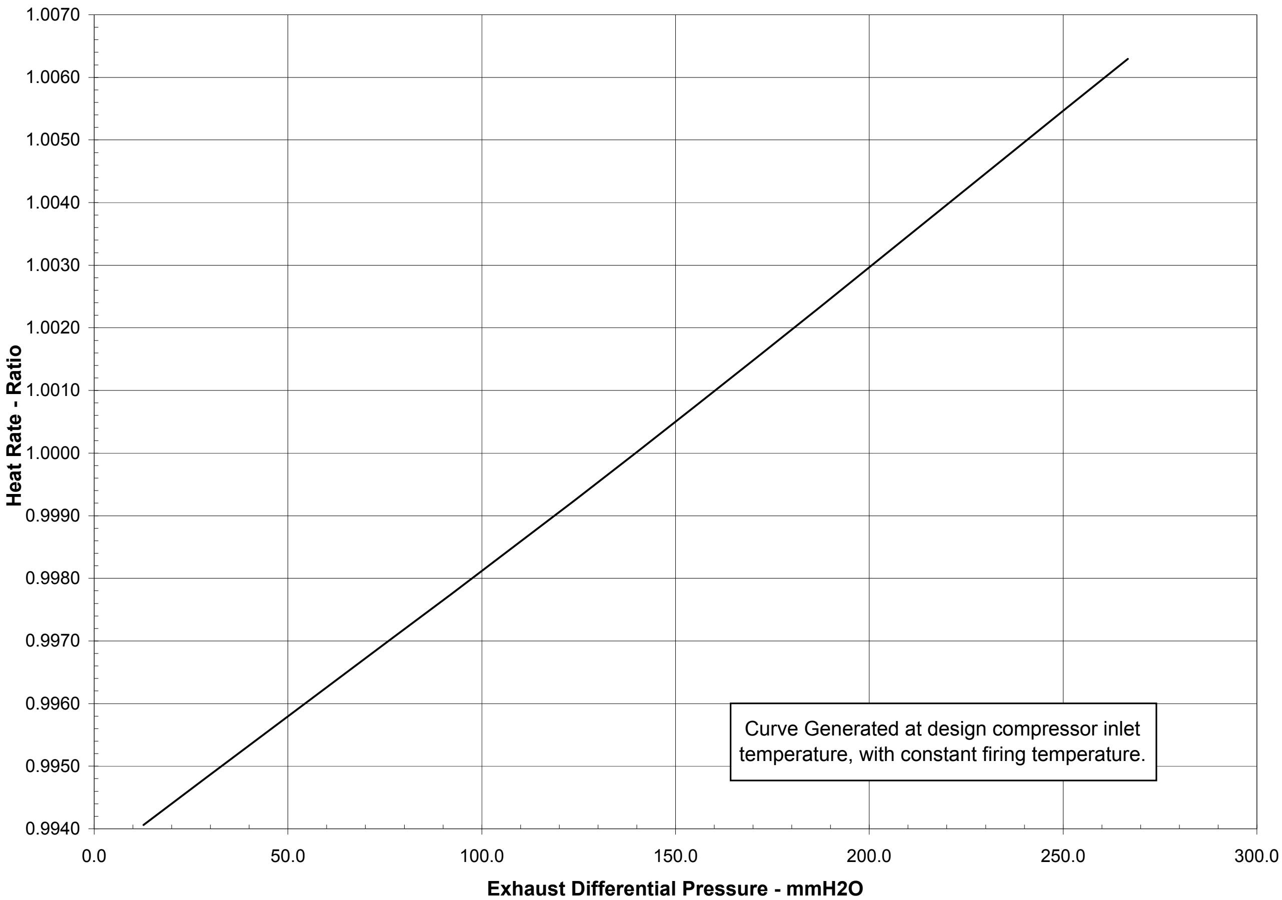
	Units			
Exhaust DP	mmH2O	12.70	139.70	266.70
Output Ratio		1.00598	1.00000	0.99374

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Exhaust Differential Pressure on Heat Rate

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



	Units			
Exhaust DP	mmH2O	12.70	139.70	266.70
Heat Rate Ratio		0.99406	1.00000	1.00630

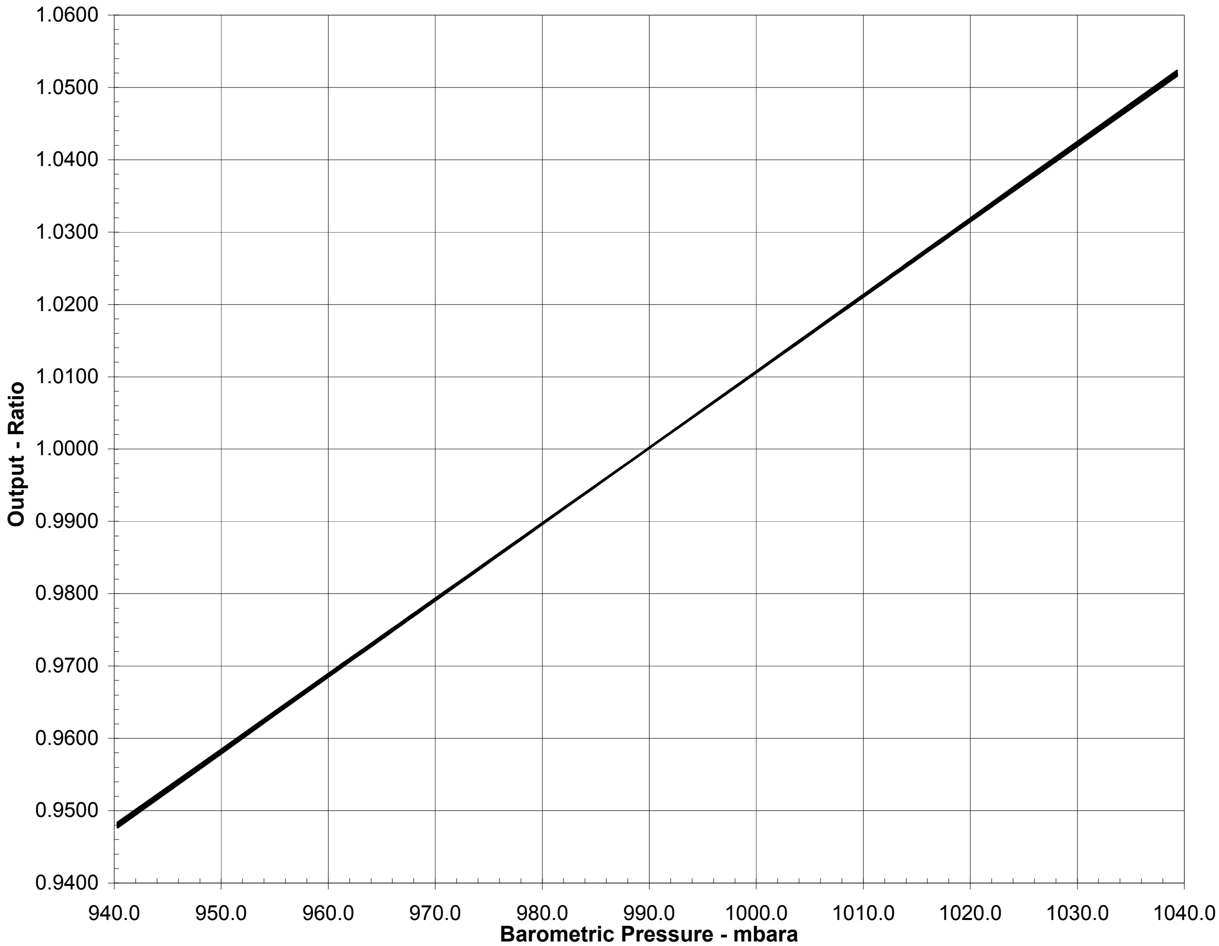
Ralph Gunst
09/22/07

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Barometric Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

Barometric Pressure - mbara	22.8	24.4	26.5	28.3	30.6	32.8
940.32	0.94837	0.94830	0.94818	0.94810	0.94784	0.94770
950.22	0.95870	0.95865	0.95855	0.95848	0.95827	0.95816
960.12	0.96902	0.96899	0.96892	0.96886	0.96871	0.96862
970.02	0.97935	0.97933	0.97928	0.97924	0.97914	0.97908
989.81	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1009.61	1.02065	1.02067	1.02071	1.02075	1.02080	1.02092
1019.51	1.03097	1.03100	1.03107	1.03113	1.03120	1.03137
1029.40	1.04129	1.04134	1.04142	1.04150	1.04160	1.04183
1039.30	1.05160	1.05167	1.05177	1.05187	1.05200	1.05228

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

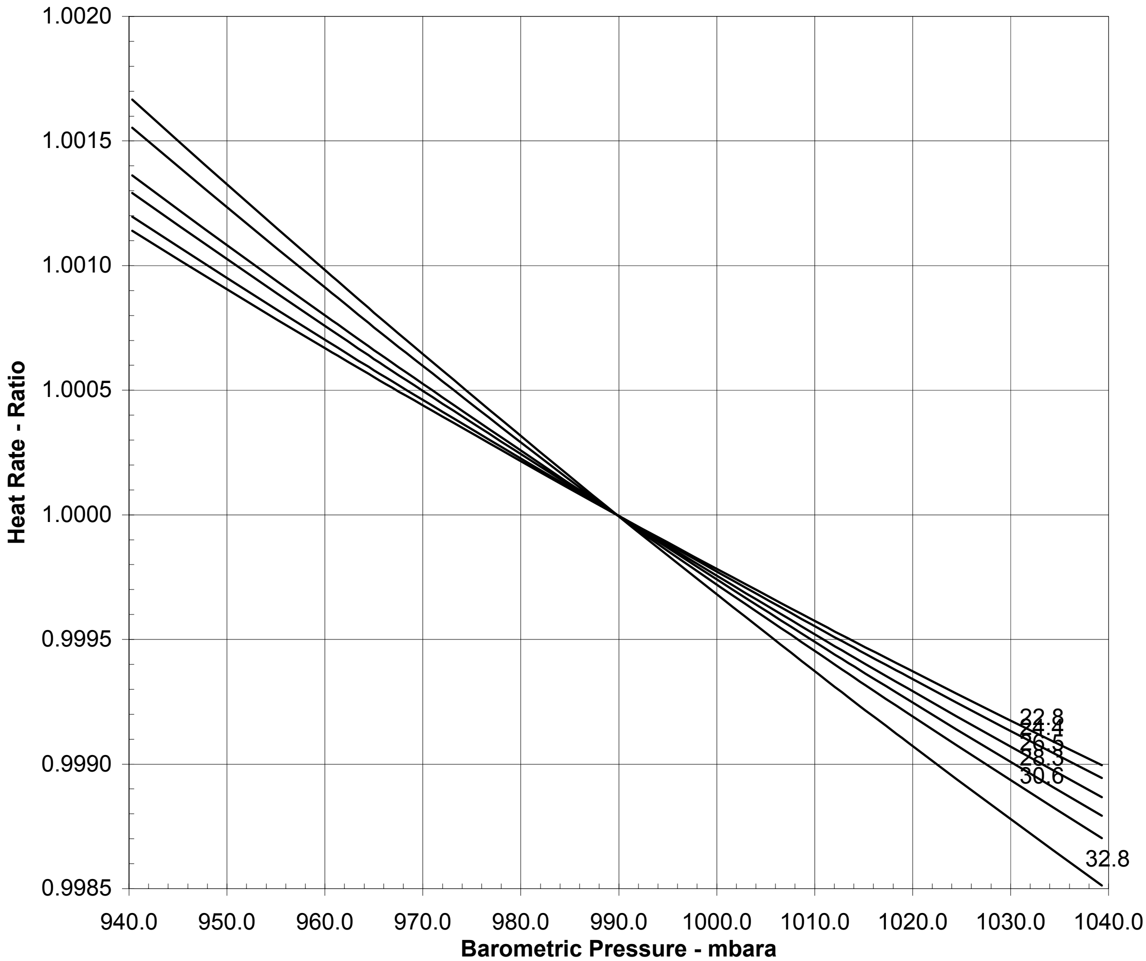
Effect of Barometric Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 102HA2793 Rev - Sheet 1

Fuel: Gas

Mode: Base

Gas Turbine Generator(s) 298593 ONLY



Compressor Inlet Temperature - Deg. C

Barometric Pressure - mbara	22.8	24.4	26.5	28.3	30.6	32.8
940.32	1.00114	1.00120	1.00129	1.00136	1.00155	1.00167
950.22	1.00090	1.00094	1.00102	1.00108	1.00123	1.00132
960.12	1.00067	1.00070	1.00075	1.00080	1.00091	1.00098
970.02	1.00044	1.00046	1.00050	1.00052	1.00060	1.00064
989.81	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1009.61	0.99958	0.99956	0.99953	0.99950	0.99946	0.99938
1019.51	0.99938	0.99935	0.99930	0.99926	0.99920	0.99909
1029.40	0.99919	0.99914	0.99908	0.99902	0.99895	0.99880
1039.30	0.99900	0.99894	0.99887	0.99879	0.99870	0.99851

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

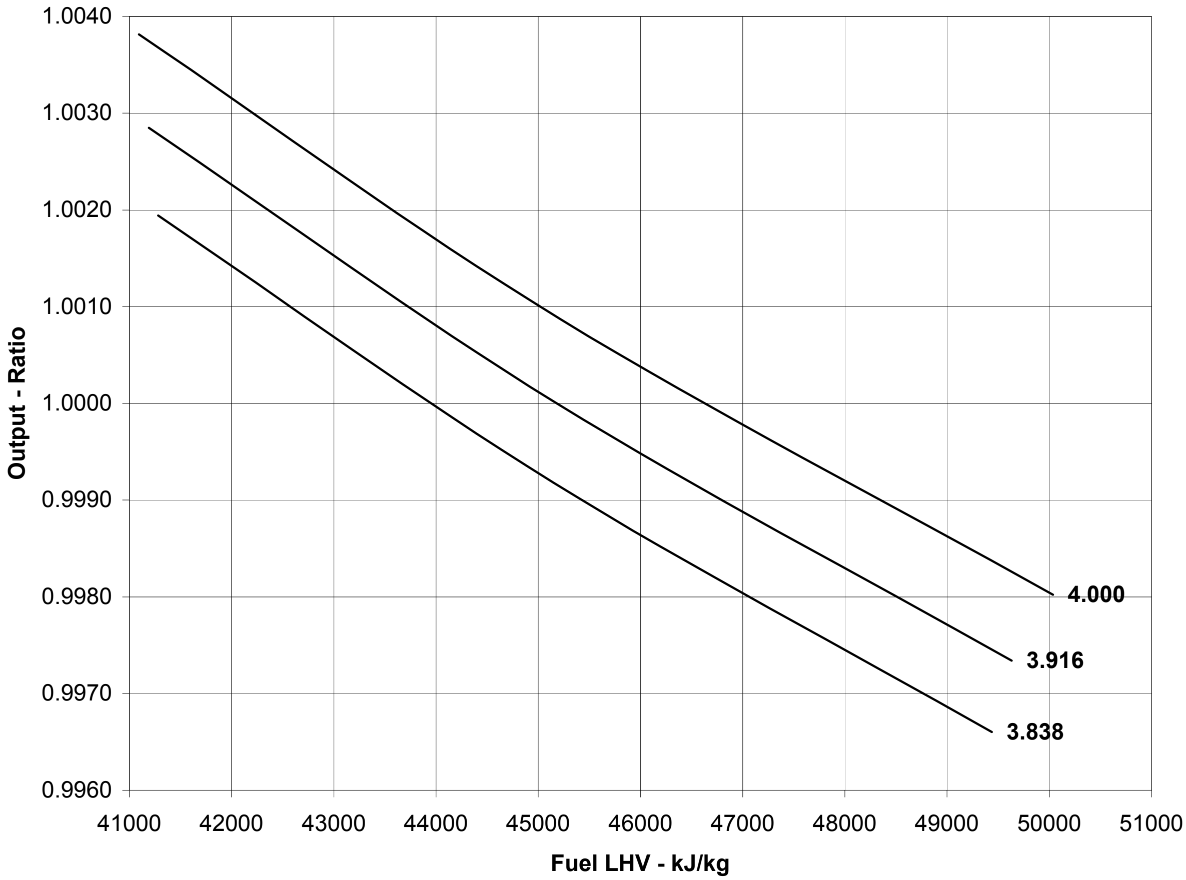
Effect of Gas Fuel Composition on Output

Design Values Referenced on 102HA2793 Rev - Sheet 1

Fuel: Gas

Mode: Base

Gas Turbine Generator(s) 298593 ONLY



Fuel LHV - kJ/kg	Fuel H/C 4.00
50035	0.99802
45213	1.00087
41095	1.00382

Fuel LHV - kJ/kg	Fuel H/C 3.92
49630	0.99734
45180	1.00000
41191	1.00285

Fuel LHV - kJ/kg	Fuel H/C 3.84
49438	0.99660
45148	0.99918
41281	1.00194

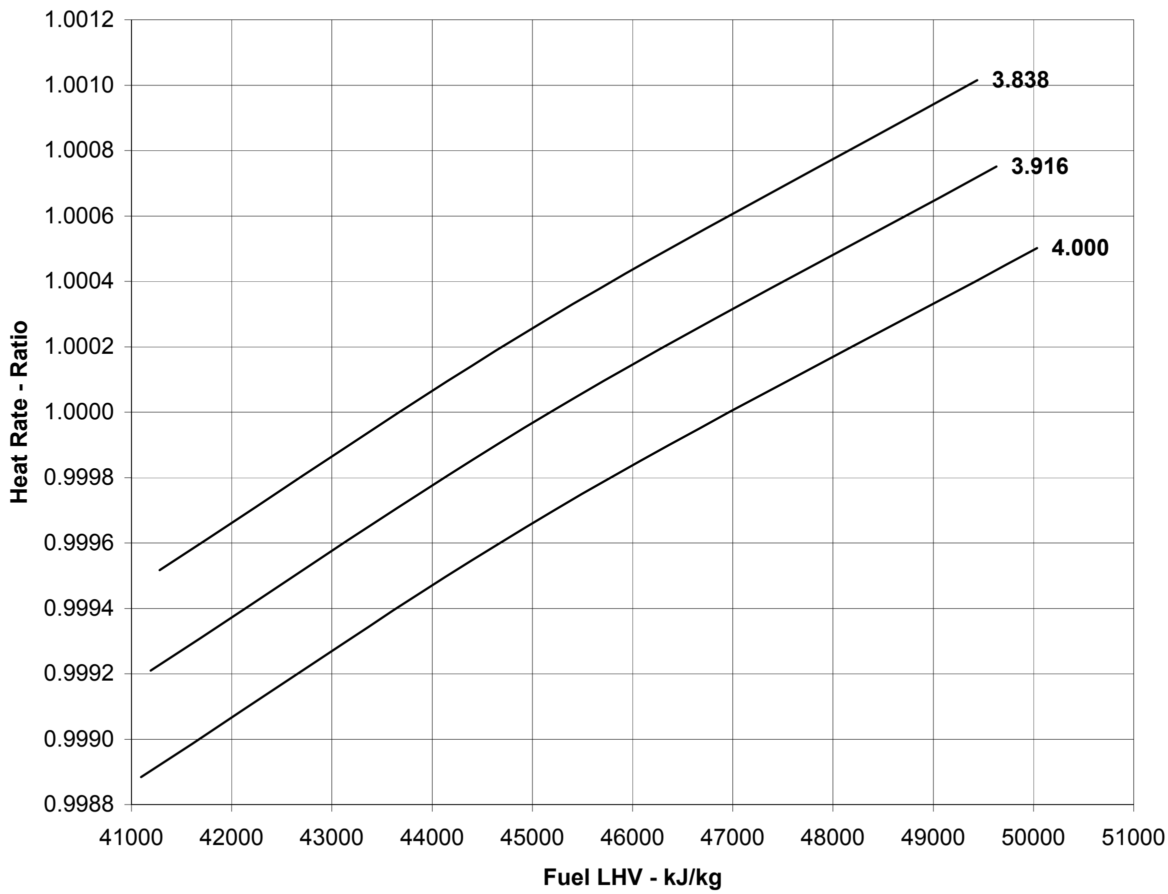
NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

General Electric Model PG7241 Gas Turbine
TermoBarrancas GR1007

Estimated Performance

Effect of Gas Fuel Composition on Heat Rate

Design Values Referenced on 102HA2793 Rev - Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 298593 ONLY



Fuel LHV - kJ/kg	Fuel H/C 4.00
50035	1.00050
45213	0.99970
41095	0.99888

Fuel LHV - kJ/kg	Fuel H/C 3.92
49630	1.00075
45180	1.00000
41191	0.99921

Fuel LHV - kJ/kg	Fuel H/C 3.84
49438	1.00101
45148	1.00028
41281	0.99952

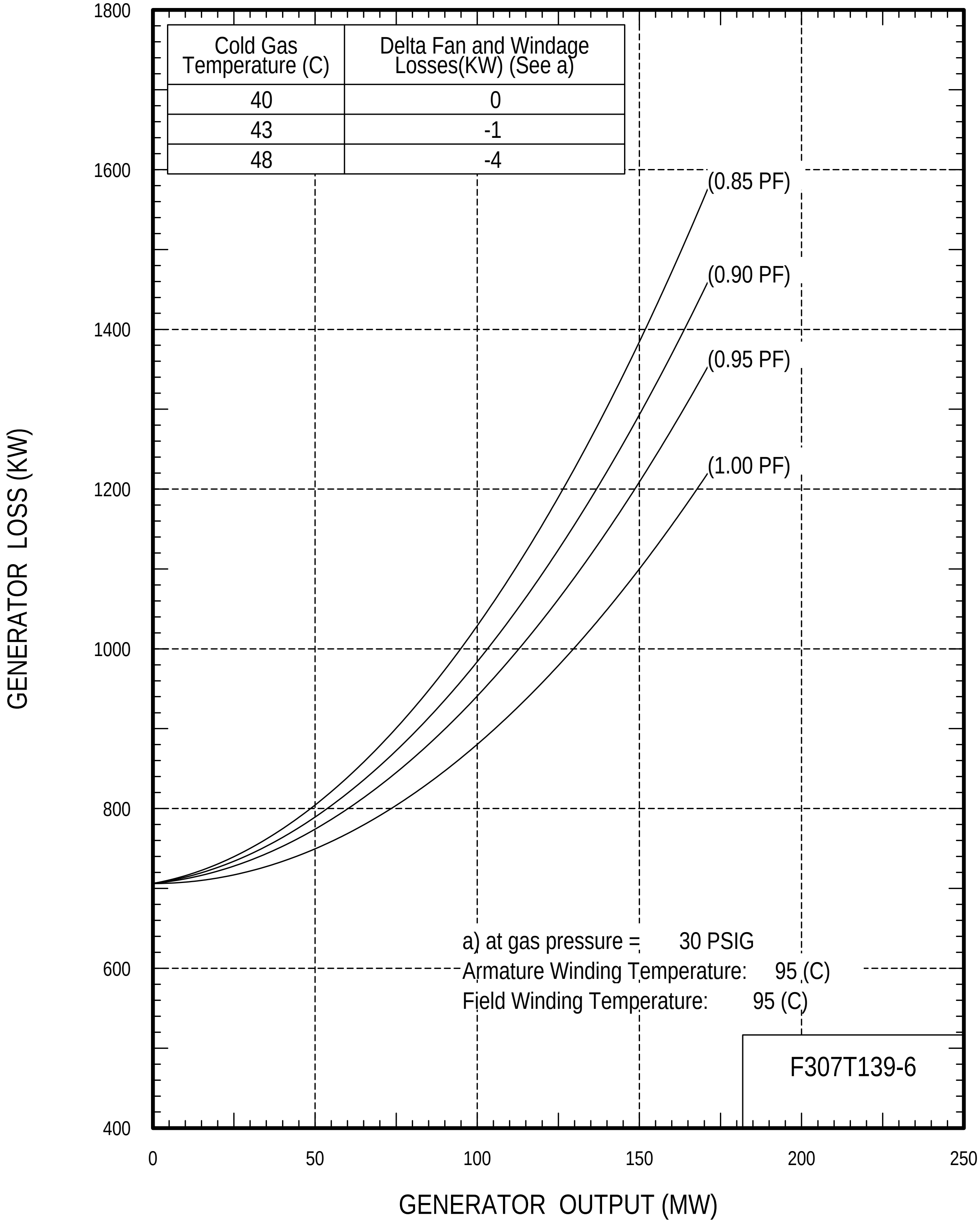
NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

GENERATOR LOSS CURVE

2 Pole 3600 RPM 201200 kVA 18000 Volts 0.850 PF

0.570 SCR 30.00 PSIG H2 Pressure 300 Volts Excitation

40 Deg. C Cold Gas 600 Ft. Altitude

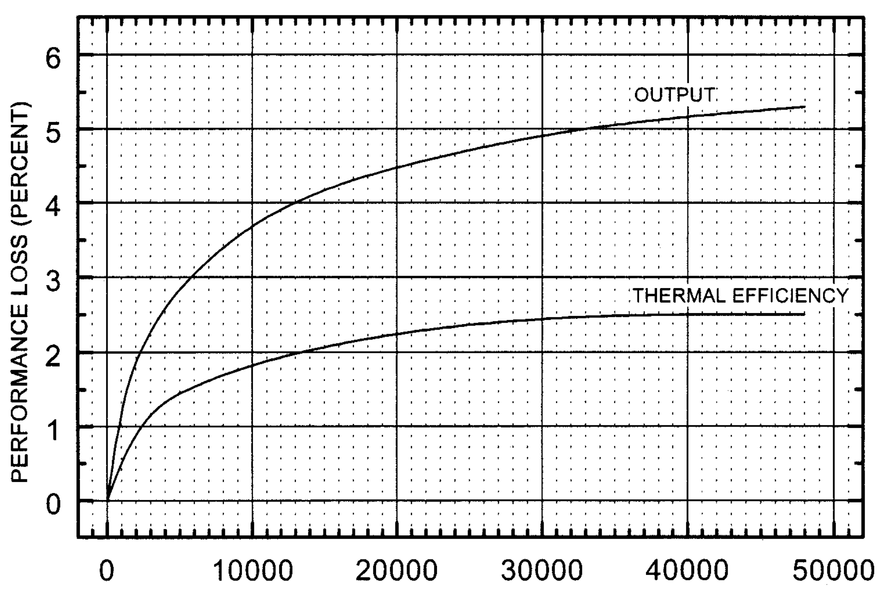


GE Power Systems

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

* PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
* ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
* ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
* A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
* GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
* THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
* DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



R. BUSWELL
REV A FEB. 9, 1995

519HA772

Appendix B: Measurement List

Performance Test Instrumentation and Measurements

Measurement	Notation	CLASS	Instrument	# of	Location	Source	Reference
Ambient Pressure	P_M	P	Absolute Pressure Transmitter	1	GT Centerline	D	4.13.8 of PTC-22
Ambient Pressure	AFPAP	S	Absolute Pressure Transmitter	3	GT Centerline	C	N/A
Ambient Humidity	RH	P	Electronic Humidity Sensor	1	Near GT Inlet	D	4.15 of PTC-22
Comp Inlet Humidity	CMHUM	S	Electronic Humidity Sensor	1	GT Inlet Duct	C	N/A
Comp Inlet Temp	T_{CI}	P	Resistance Temperature Device	4	GT Inlet Duct	D	4.14.2 od PTC-22
Comp Inlet Temp	CTIM	S	Resistance Temperature Device	3	GT Inlet Duct	C	N/A
Comp Inlet System Total Pressure Drop	$P_{T(inlet)}$	P	Kiel Probes w/ Transmitter	2	GT Inlet Duct	D	4.13.4 of PTC-22
Comp Inlet System Total Pressure Drop	AFPCS	S	Kiel Probes w/ Transmitter	2	GT Inlet Duct	C	N/A
Comp Bellmouth Static Pressure Drop	$P_{S(inlet)}$	S	Pressure Taps w/ Transmitter	6	GT Inlet Bellmouth	D	4.13.4 of PTC-22
Comp Bellmouth Static Pressure Drop	AFPBD	S	Pressure Taps w/ Transmitter	1	GT Inlet Bellmouth	C	N/A
Comp Inlet Air Flow	AFQ	S	Calculation	1	N/A	C	N/A
GT IGV Angle	CSGV	S	LVDT Pickup	1	N/A	C	N/A
Inlet Bleed Heat Valve Position	CSBHX	S	Feedback Calculation	1	N/A	C	N/A
Comp Discharge Pressure	CPD	S	Pressure Taps w/ Transmitter	1	Comp Discharge	D	4.13.2 of PTC-22
Comp Discharge Pressure	CPD	S	Pressure Taps w/ Transmitter	3	Comp Discharge	C	N/A
Comp Discharge Temp	CTD	S	Thermocouple	3	Comp Discharge	C	N/A
Wheelspace Temp 1st Fwd Inner	TTWS1FI1, TTWS1FI2	S	Thermocouple	2	Turbine Wheelspace	C	N/A
Wheelspace Temp 1st Fwd Outer	TTWS1FO1, TTWS1FO2	S	Thermocouple	2	Turbine Wheelspace	C	N/A
Wheelspace Temp 1st Aft	TTWS1AO1, TTWS1AO2	S	Thermocouple	2	Turbine Wheelspace	C	N/A
Wheelspace Temp 2nd Fwd	TTWS2FO1, TTWS2FO2	S	Thermocouple	2	Turbine Wheelspace	C	N/A
Wheelspace Temp 2nd Aft	TTWS2AO1, TTWS2AO2	S	Thermocouple	2	Turbine Wheelspace	C	N/A

P = Primary
S = Seconday
M = Manual
D = Electronic Data Acquistion
C = Control System
T = Tape Printout

PTC-22 = ASME PTC 22-1997
PTC-6R = ANSI/ASME PTC 6 Report-1985
PTC-4.4 = ANSI/ASME PTC 4.4 – 1981

Performance Test Instrumentation and Measurements

Measurement	Notation	CLASS	Instrument	# of	Location	Source	Reference
Wheelspace Temp 3rd Fwd	TTWS3FO1, TTWS3FO2	S	Thermocouple	2	Turbine Wheelspace	C	N/A
Wheelspace Temp 3rd Aft	TTWS3AO1, TTWSAO2	S	Thermocouple	2	Turbine Wheelspace	C	N/A
Shaft Speed	TNH_RPM	P	Speed Pickup	1	Turbine Shaft	C	4.10.2 of PTC-22
GT Exhaust Temp	TTXM	S	Control System TCs	27	Gas Turbine Exhaust Diffuser	C	4.14.3 of PTC-22
Demand Exhaust Temp	TTRX	S	Calculation	1	N/A	C	N/A
Exhaust Temp Spread	TTXSP1	S	Calculation	1	N/A	C	N/A
GT Exhaust Back Pressure	$P_{S(exh)}$	P	Pancake Probe w/ Transmitter	2	Gas Turbine Exhaust Diffuser Outlet Plane	D	4.13.5 of PTC-22
GT Exhaust Back Pressure	AFPEP	S	Pancake Probe w/ Transmitter	2	Gas Turbine Exhaust Diffuser	C	N/A
Generator Power Output	DWATT	S	Watt Transducer	1	Generator Terminals	C	N/A
Generator Power Output (per phase)	Meter Reading ($GGPO_P$)	P	Watt-hour Transducer	3	Generator Terminals	D	4.6.1 of PTC-22
Generator Line Voltage		S	Potential Transformer	2	Generator Terminals	Wired to Watt-hour meter	4.7.1 of PTC-22
Generator Line Current		S	Current Transformer	3	Generator Terminals	Wired to Watt-hour meter	4.7.1 of PTC-22
Generator Power Factor	PF	P	VAR Transducer	3	Generator Terminals	D	N/A
Generator Power Factor	DPF	S	Calculation	1	Generator Terminals	C	N/A
Exciter Field Voltage	DVF_EX	P	Volt-meter	1	Exciter Field	C	N/A
Exciter Field Current	DAF_EX	P	Ammeter	1	Exciter Field	C	N/A
Gas Fuel Flow Rate	FQG	S	Calculation	1	N/A	C	N/A
Gas Fuel Orifice Static Pressure	P_{Fuel}	P	Flange Tap w/ Transmitter	1	Metering Orifice	D	4.13.6 of PTC-22
Gas Fuel Orifice Static Pressure	FPG3	S	Flange Tap w/ Transmitter	1	Metering Orifice	C	4.13.6 of PTC-22
Gas Fuel Orifice Differential Pressure	ΔP	P	Flange Tap w/ Transmitter	1	Metering Orifice	D	4.13.6 of PTC-22

P = Primary
S = Seconday
M = Manual
D = Electronic Data Acquistion
C = Control System
T = Tape Printout

PTC-22 = ASME PTC 22-1997
PTC-6R = ANSI/ASME PTC 6 Report-1985
PTC-4.4 = ANSI/ASME PTC 4.4 – 1981

Performance Test Instrumentation and Measurements

Measurement	Notation	CLASS	Instrument	# of	Location	Source	Reference
Gas Fuel Orifice Differential Pressure	FDG1 or FDG2	S	Flange Tap w/ Transmitter	1	Metering Orifice	C	4.13.6 of PTC-22
Gas Fuel Flow Temperature	$T_{Fuel,G}$	P	Thermocouple or RTD	1	Metering Orifice	D	4.14.5 of PTC-22
Gas Fuel Flow Temperature	FTG	S	Thermocouple	1	Metering Orifice	C	4.14.5 of PTC-22

P = Primary
S = Seconday
M = Manual
D = Electronic Data Acquistion
C = Control System
T = Tape Printout

PTC-22 = ASME PTC 22-1997
PTC-6R = ANSI/ASME PTC 6 Report-1985
PTC-4.4 = ANSI/ASME PTC 4.4 – 1981

Appendix C: Pre-Test Field Calibration Verification Report (Typical)

Project Information

Description	Entry
Site Name	TermoBarrancas
Location	Barinas, Venezuela
Test Description	Precision
Turbine Serial Number	298593
Turbine Unit Number	1
Frame Size	PG7241 7FA+e
Anticipated Test Date(s)	
Set-up/ Inspection Date(s)	12-Apr-2007

Parties to the Test

Function	Company	Name
Customer Representative	Site Manager	N/A
Customer Representative	N/A	N/A
Customer Representative	N/A	N/A
Customer Representative	N/A	N/A
Lead Test Engineer	GE	N/A
Test Engineer	N/A	N/A
Test Engineer	N/A	N/A
Instrumentation Specialist	GE	N/A
Instrumentation Specialist	GE	N/A
Instrumentation Specialist	N/A	N/A
DLN TA	GE	N/A
Project Manager	GE	Vilhelm Lund
Site Manager	GE	N/A
Lead TA	GE	N/A
Start-up/ Controls TA	GE	N/A

The calibration and proper operation of the control system, pertinent station instrumentation and measurement devices, and recording systems was verified by the GE Performance Evaluation Services (PES) prior to official testing. PES has supplied NIST traceable, portable calibration devices for verifying station instrumentation. All data and notes regarding the instrumentation verifications, unit and device inspections, special instrumentation set-up and general readiness of the unit has been documented in this Pre-Test Readiness Report (PTRR).

This original signed copy of the PTR Report shall be included in the final report.

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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	
Time	

Turbine Historical Operating Information

Total Fired Hours	
Total Starts	
Total Unit Trips	
Total Peak Hours	

Base Load Control Curve Definition (from Control System)

Description	**As Found Value 1/0/1900**	**As Left Value 1/0/1900**
Curve Type (Xc, PCD)		
TTK0_I		
TTK0_S		
TTK0_C		
Breakpoint 1		
TTK1_I		
TTK1_S		
TTK1_C		
Breakpoint 2		
TTK2_I		
TTK2_S		
TTK2_C		
Exhaust TC Coefficient		

Date	
Time	

Compressor Inlet Inspection Observations and Comments

Compressor Inlet Inspection (Before Off-line Water Wash) - Observations and Comments

Inlet Area Condition
Inlet Guide Vanes Condition
Compressor Condition

Compressor Inlet Inspection (After Off-line Water Wash) - Observations and Comments

Inlet Area Condition
Inlet Guide Vanes Condition
Compressor Condition

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Date	17-May-2006		
Time	13:00	0.000	0.000
		-1.000	0.000

Overall Avg Tolerance (Degrees) 0.5 Δ between calc AVG and Input
Max blade field Tolerance (Degrees) 1.0 Δ between the high and low values (as measured in the field of data)

Indicated IGV Angle: **87** 1.000 0.000

IGV Angle Calibration Verification

Vane Set	**As Found IGV Angle** degrees	**Difference** degrees	**As Left IGV Angle** degrees	**Difference** degrees
1	86.0	-1.0	Re-Cal Data	
2	86.5	-0.5	Re-Cal Data	
3	87.0	0.0	Re-Cal Data	
4	87.0	0.0	Re-Cal Data	
5	86.0	-1.0	Re-Cal Data	
6	86.0	-1.0	Re-Cal Data	
7	86.5	-0.5	Re-Cal Data	
8	86.5	-0.5	Re-Cal Data	
9	87.0	0.0	Re-Cal Data	
10	87.0	0.0	Re-Cal Data	
11	87.0	0.0	Re-Cal Data	
12	86.5	-0.5	Re-Cal Data	
13	86.0	-1.0	Re-Cal Data	
14	87.0	0.0	Re-Cal Data	
15	87.0	0.0	Re-Cal Data	
16	87.0	0.0	Re-Cal Data	
Average	86.63	-0.38		
Max minus Min Blade Angle		1.0	Max minus Min Blade Angle	0.0

<u>* IGV Overall Average Response within Tolerance</u>

<u>* IGV Max Field Deviation within Tolerance</u>

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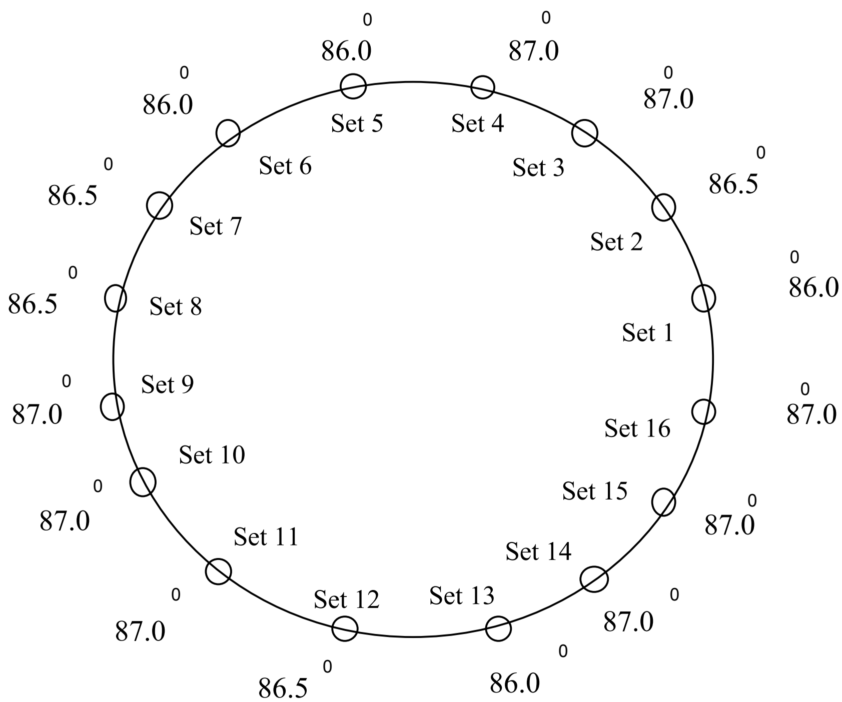
Difference Between Actual and Indicated IGV Angle by Location
(Looking Into Inlet - Streamwise)



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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Barometric Pressure Transmitter Calibration Verification Procedure

Date	
Time	

CalibrationRange and Tolerancing

Upper Range Value	2.00	inHgG
Lower Range Value	-2.00	inHgG
Max Tolerance (+/-)	0.05	inHg

Manufacturer		Control System Designation
Serial Number A		
Serial Number B		
Serial Number C		

A

Hand Held Baro	Input Signal	Calc Input	Indicated / As Found	Difference
" HgA	" HgG	" HgA	" HgA	" Hg
5.00	3.00	8.00	4.00	**-4.00**
		0.00		0.00
		0.00		0.00

A

Hand Held Baro	Input Signal	Calc Input	Indicated / As Left	Difference
" HgA	" HgG	" HgA	" HgA	" Hg
		0.00		0.00
		0.00		0.00
		0.00		0.00

B

Hand Held Baro	Input Signal	Calc Input	Indicated / As Found	Difference
" HgA	" HgG	" HgA	" HgA	" Hg
		0.00		0.00
		0.00		0.00
		0.00		0.00

B

Hand Held Baro	Input Signal	Calc Input	Indicated / As Left	Difference
" HgA	" HgG	" HgA	" HgA	" Hg
		0.00		0.00
		0.00		0.00
		0.00		0.00

C

Hand Held Baro	Input Signal	Calc Input	Indicated / As Found	Difference
" HgA	" HgG	" HgA	" HgA	" Hg
		0.00		0.00
		0.00		0.00
		0.00		0.00

C

Hand Held Baro	Input Signal	Calc Input	Indicated / As Left	Difference
" HgA	" HgG	" HgA	" HgA	" Hg
		0.00		0.00
		0.00		0.00
		0.00		0.00

*** Calibration of Individual Transmitters Required as indicated by those with Red Cells Above**

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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	
Time	

Bellmouth ΔP Transmitter Information

Manufacturer	
Serial Number	
Control System Designation	

Lower Range Value (inH_2O)	0.00
Upper Range Value (inH_2O)	138.5
Max Tolerance (inH_2O)	0.35

Bellmouth ΔP Transmitter Calibration Verification

Input Signal	**Indicated As Found**	**Difference**
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

Input Signal	**Indicated As Left**	**Difference**
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

GE Rep___________________ Customer Rep __________________

Date	
Time	

Inlet ΔP Transmitter Information

Manufacturer	
Serial Number	
Control System Designation	

Lower Range Value (inH_2O) 0.0
Upper Range Value (inH_2O) 11.8
Max Tolerance (inH_2O) 0.1

Inlet ΔP Transmitter Calibration Verification

Input Signal	**Indicated (Control Sys) As Found**	**Difference**
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

Input Signal	**Indicated (Control Sys) As Left**	**Difference**
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Compressor Discharge Pressure Transmitter Calibration Verification Procedure

Date	
Time	

CalibrationRange and Tolerancing

Lower Range Value	0.00	PSIG
Upper Range Value	295.00	PSIG
Max Tolerance	0.300	PSIG

Manufacturer		Control System Designation
Serial Number A		
Serial Number B		
Serial Number C		

A

Input Signal	Indicated / As Found	Difference
psig	psig	psig
		0.00
		0.00
		0.00
		0.00
		0.00

B

Input Signal	Indicated / As Found	Difference
psig	psig	psig
		0.00
		0.00
		0.00
		0.00
		0.00

C

Input Signal	Indicated / As Found	Difference
psig	psig	psig
		0.00
		0.00
		0.00
		0.00
		0.00

A

Input Signal	Indicated / As Left	Difference
psig	psig	psig
		0.00
		0.00
		0.00
		0.00
		0.00

B

Input Signal	Indicated / As Left	Difference
psig	psig	psig
		0.00
		0.00
		0.00
		0.00
		0.00

C

Input Signal	Indicated / As Left	Difference
psig	psig	psig
		0.00
		0.00
		0.00
		0.00
		0.00

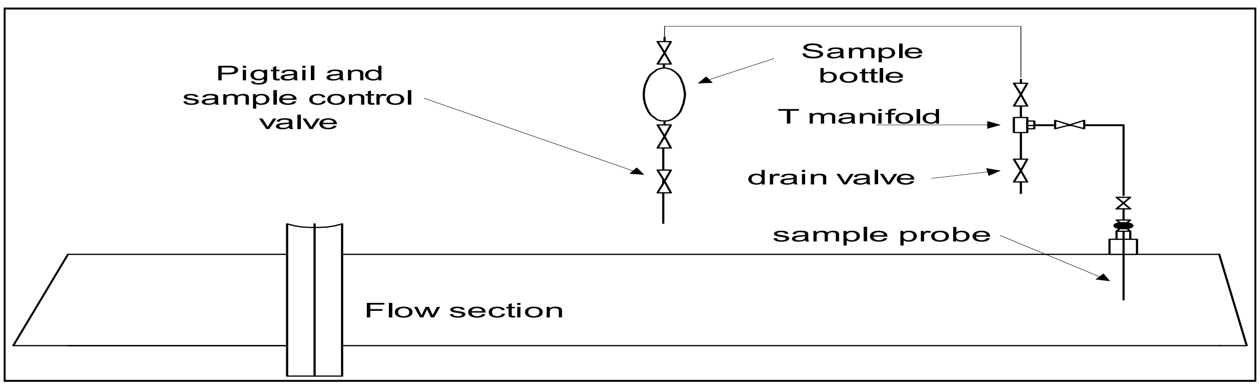
GE Rep__________________ Customer Rep _________

Date	
Time	

Gas Fuel Sampling Information

Gas probe installed? (Yes / No)
Purge paths installed per PES guidelines? (Yes / No)

Sketch of Fuel Sampling Arrangement:



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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date of Inspection	
Time of Inspection	

Gas Fuel Piping Information

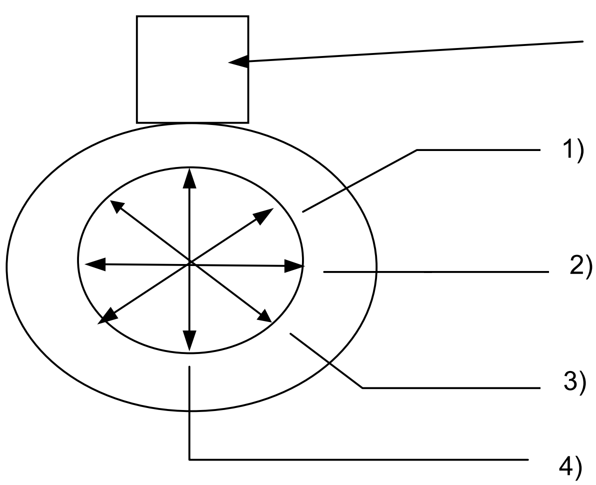
Orifice Serial Number	
Nominal Pipe Outside Diameter (in) (stamped)	
Schedule Pipe (stamped)	
Orifice Inside Diameter (in) (stamped)	
Pipe Material Coefficient of Thermal Exp.	9.20E-06
Manufacturers Reference Temperature (F)	68

Gas Fuel Orifice Inspection

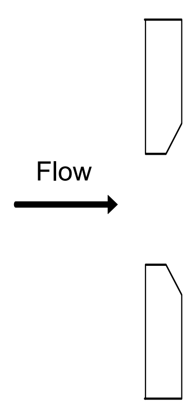
		Within Tolerance?
Orifice Temperature at time of measurement		
Orifice Inside Diameter Measurement 1 (in)		
Orifice Inside Diameter Measurement 2 (in)		
Orifice Inside Diameter Measurement 3 (in)		
Orifice Inside Diameter Measurement 4 (in)		

Orifice Chamfered ? (yes, no)	
Orifice Direction Correct ? (yes, no)	
Mean Diameter (in) at Measured Temp	
Max Allowable AGA Deviation (in) from Mean	
Mean Diameter (in) at Manufacturers Temp	
Difference between stamped value	

Gas Fuel Metering Orifice, Front View



Gas Fuel Metering Orifice, Chamfered Cross-



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Customer Rep __________________

Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	
Time	

Gas Fuel Static Pressure Transmitter Information

Manufacturer	
Serial Number	
Control System Designation	

Lower Range Value (PSIG) 0.0
Upper Range Value (PSIG) 500.0
Max Deviation (PSI) 0.5

Gas Fuel Static Pressure Tap Location

Tap Location (flange or pipe, upstream or down)	
Approximate Distance from Orifice Section	

Gas Fuel Static Pressure Transmitter Calibration Verification

Input Signal	**Indicated (Field Communicator) As Found**	**Difference**
psig	psig	psi
		0.00
		0.00
		0.00
		0.00
		0.00

Gas Fuel Static Pressure Transmitter Re-Calibration Verification

Input Signal	**Indicated (Field Communicator) As Left**	**Difference**
psig	psig	psi
		0.00
		0.00
		0.00
		0.00
		0.00

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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	
Time	

Gas Fuel ΔP Transmitter Information

Manufacturer	
Serial Number	
Control System Designation	

Lower Range Value (inH_2O)	0.00
Upper Range Value (inH_2O)	150.00
Max Deviation (inH_2O)	0.30

Gas Fuel ΔP Tap Location

Tap Location (flange or pipe)	
Approximate Distance from Orifice	

Gas Fuel ΔP Transmitter Calibration Verification

Input Signal	**Indicated (Control Sys) As Found**	**Difference**
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

Input Signal	**Indicated (Control Sys) As Left**	**Difference**
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

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Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	
Time	

Exhaust ΔP Transmitter Information

Manufacturer	
Serial Number	
Control System Designation	

Lower Range Value (inH_2O)	0.00
Upper Range Value (inH_2O)	27.70
Max Tolerance (inH_2O)	0.10

Exhaust ΔP Transmitter Calibration Verification

Input Signal	Indicated (Control Sys) As Found	Difference
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

Input Signal	Indicated (Control Sys) As Left	Difference
inches H_2O	inches H_2O	inches H_2O
		0.00
		0.00
		0.00
		0.00
		0.00

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Exhaust TC Wiring Layout

Newer Units
1-17 SAME AS ON LEFT

		Yellow +	Red -	Frame Size	Newer Units			*Newer 9FA's	
1	R	399	400						
2	S	401	402						
3	T	403	404						
4	R	405	406						
5	S	407	408						
6	T	409	410						
7	R	411	412						
8	S	413	414						
9	T	415	416						
10	R	417	418						
11	S	419	420						
12	T	421	422						
13	R	2449	2450						
14	S	2499	3400						
15	T	3401	3402						
16	R	3403	3404						
17	S	3405	3406						
18	T	3407	3408	6B, 7E, 7EA	3433	3434	18		
19	R	3409	3410		3435	3436	19		
20	S	3411	3412		3437	3438	20		
21	T	3413	3414	6FA	3439	3440	21		
22	R	3415	3416		3441	3442	22		
23	S	3417	3418		3443	3444	23		
24	T	3419	3420	9E	3445	3446	24		
25	R	3421	3422		3447	3448	25		
26	S	3423	3424		3449	3450	26		
27	T	3425	3426	7FA	3451	3452	27		
28	R	3429	3430		4412	4413	28	3453	3454
29	S	3431	3432		4424	4425	29	3455	3456
30	T	3433	3434		4434	4435	30	3457	3458
31	R	3435	3434	9FA	4414	4415	31	3459	3460

Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	12-Apr-2007
Time	10:00

27 Exhaust TC's

Input Signal (oF):

Exhaust Thermocouple Wiring Verification **TC Coefficient**

Thermocouple	**Indicated** (°F) (Control System)	**Thermocouple**	**Indicated** (°F) (Control System)
TTXD1_1		TTXD1_15	
TTXD1_2		TTXD1_16	
TTXD1_3		TTXD1_17	
TTXD1_4		TTXD1_18	
TTXD1_5		TTXD1_19	
TTXD1_6		TTXD1_20	
TTXD1_7		TTXD1_21	
TTXD1_8		TTXD1_22	
TTXD1_9		TTXD1_23	
TTXD1_10		TTXD1_24	
TTXD1_11		TTXD1_25	
TTXD1_12		TTXD1_26	
TTXD1_13		TTXD1_27	
TTXD1_14		**Average**	**#DIV/0!**

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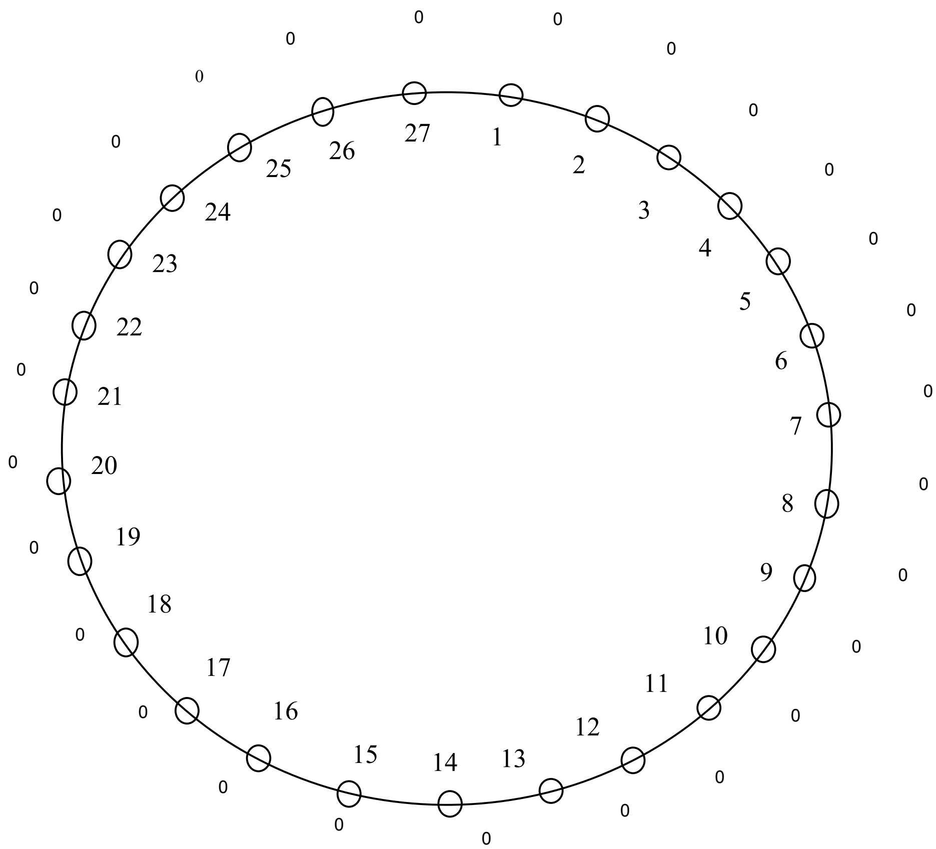
Indicated Exhaust Temperatures (^{0} F) by Location, Aft Looking Forward,



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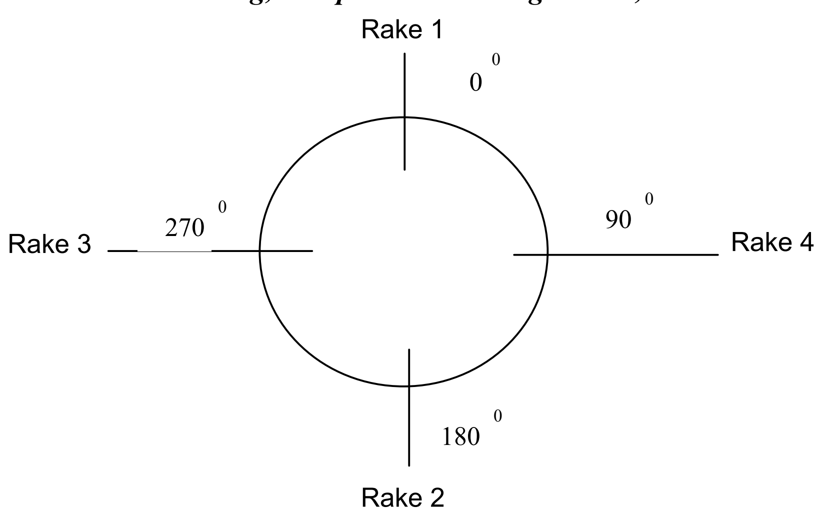
Date	
Time	

Compressor Discharge Temperature Rake Information 0 deg = TDC

Rake	Angular Position (degrees, forward looking aft)	Serial Number	Thermocouple Type
1	0		E
2	180		E
3	270		E
4	90		E

Temperature Rake Positioning, Compressor Discharge Plane, Forward Looking

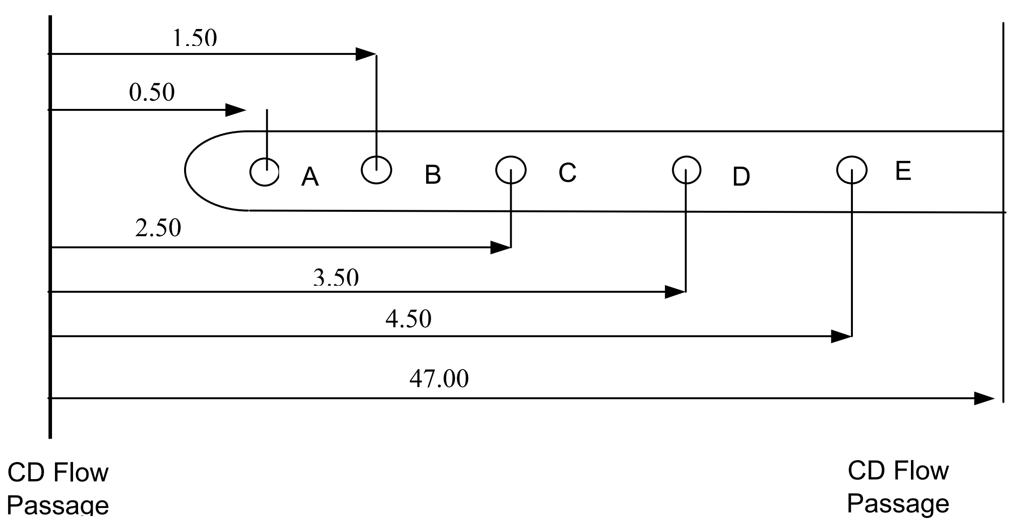


Date	1/0/1900
Time	0:00

Compressor Discharge Rake Radial Positioning

Description	Radial Location (as measured from inner wall, in)
Thermocouple A	0.50
Thermocouple B	1.50
Thermocouple C	2.50
Thermocouple D	3.50
Thermocouple E	4.50
Outer Wall	47.00

CDT Rake Radial Positioning



Gas Turbine Performance, Pre-Test Readiness Report

TermoBarrancas

Date	
Time	

Generator Power Measurement, Station W-hr Meter Information

Manufacturer	
Model Number	
Serial Number	
Meter Constant, K	
Current Transformer Ratio, Ctr	
Potential Transformer Ratio, Ptr	
Meter Factor, Pkh = Ptr x Ctr x K	

Generator Power Measurement, Station Digital Meter Information

Manufacturer	
Model Number	
Serial Number	
Type	

Auxiliary Power Measurement, Station W-hr Meter Information

Manufacturer	
Model Number	
Serial Number	
Meter Constant, K	
Current Transformer Ratio, Ctr	
Potential Transformer Ratio, Ptr	
Meter Factor, Pkh = Ptr x Ctr x K	

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Gas Turbine Performance, Pre-Test Readiness Report
TermoBarrancas

Special Instrumentation Identification

Device Description	Serial Number
Ambient Pressure Transmitter	
Humidity Sensor 1	
Humidity Sensor 2	
Dry RTD 1	
Dry RTD 2	
Dry RTD 3	
Dry RTD 4	
Dry RTD 5	
Wet RTD 6	
Wet RTD 7	
Wet RTD 8	
Wet RTD 9	
Wet RTD 10	
Shielded RTD 11	
Shielded RTD 12	
Shielded RTD 13	
Shielded RTD 14	
Shielded RTD 15	
Inlet Drop Pressure Transmitter 1	
Inlet Drop Pressure Transmitter 2	
Inlet Drop Pressure Transmitter 3	
Inlet Drop Pressure Transmitter 4	
Inlet Flow Rake 1	
Inlet Flow Rake 2	
Inlet Flow Rake 3	
Inlet Flow Rake 4	
Bellmouth Static Transmitter 1	
Bellmouth Static Transmitter 2	
Bellmouth Static Transmitter 3	
Bellmouth Static Transmitter 4	
Bellmouth Static Transmitter 5	
Bellmouth Static Transmitter 6	
CPD Transmitter	
9th Stage Extr. Static Transmitter 1	
9th Stage Extr. Static Transmitter 2	
9th Stage Extr. ΔP Transmitter 1	
9th Stage Extr. ΔP Transmitter 2	

Device Description
13th Stage Extr. Static Xmitter 1
13th Stage Extr. Static Xmitter 2
13th Stage Extr. ΔP Transmitter 1
13th Stage Extr. ΔP Transmitter 2
9th Stage Extr. Temp RTD
13th Stage Extr. Temp RTD
Hot Gas Fuel T/C
Hot Gas Fuel Static Transmitter
Hot Gas Fuel Static Transmitter
Hot Gas Fuel ΔP Transmitter
Cold Gas Fuel T/C
Cold Gas Fuel Static Xmitter 1
Cold Gas Fuel Static Xmitter 2
Cold Gas Fuel DP Transmitter 1
Cold Gas Fuel DP Transmitter 2
Stage 2 Nozzle Cavity Pressure 1
Stage 2 Nozzle Cavity Pressure 2
Stage 3 Nozzle Cavity Pressure 1
Stage 3 Nozzle Cavity Pressure 2
Exhaust Frame Blw Static Xmitter
Exhaust Frame Blower Temp T/C
A042 Inlet Pressure Xmitter 1
A042 Inlet Pressure Xmitter 2
A042 Inlet Pressure Xmitter 3
A042 Inlet Pressure Xmitter 4
A042 Outlet Pressure Xmitter 1
A042 Outlet Pressure Xmitter 2
A042 Outlet Pressure Xmitter 3
A042 Outlet Pressure Xmitter 4

Calibration Equipment Identifica

Device Description
Thermocouple Calibrator
Beta Gauge
Druck Meter
Vernier Caliper

GE Rep___________________ Customer Rep

Gas Turbine Performance, Pre-Test Readiness Report

PROJECT NAME

Date	22-May-2006
Time	15:00

Off-Line Water-Wash Information

Water Wash System Supplier	Midland Combustion Ltd
Detergent Type	ZOK27
Target Flow (gpm)	58.5
Target Water/Detergent Mixing Ratio	5.7
Calculated Target Detergent Flow (gpm)	8.7

Measurements

Water Temperature (F)	180
Pressure at Pump Discharge (psig)	118
Pressure at Spray Manifold (psig)	85
IGV angle during Wash & Rinse (deg)	84
Wash and Rinse Crank Speed (%)	12
Flowmeter Value (gpm)	9.0
Total Number of Rinses	40
Makeup Water Conductivity (μS/cm)	2.7
Final Conductivity at Combustion Drain (μS/cm)	7.9

Detergent Tank Details

Inner Diameter (in)	29.5
Tank Height (in)	49.2
Initial Level (in)	38.6

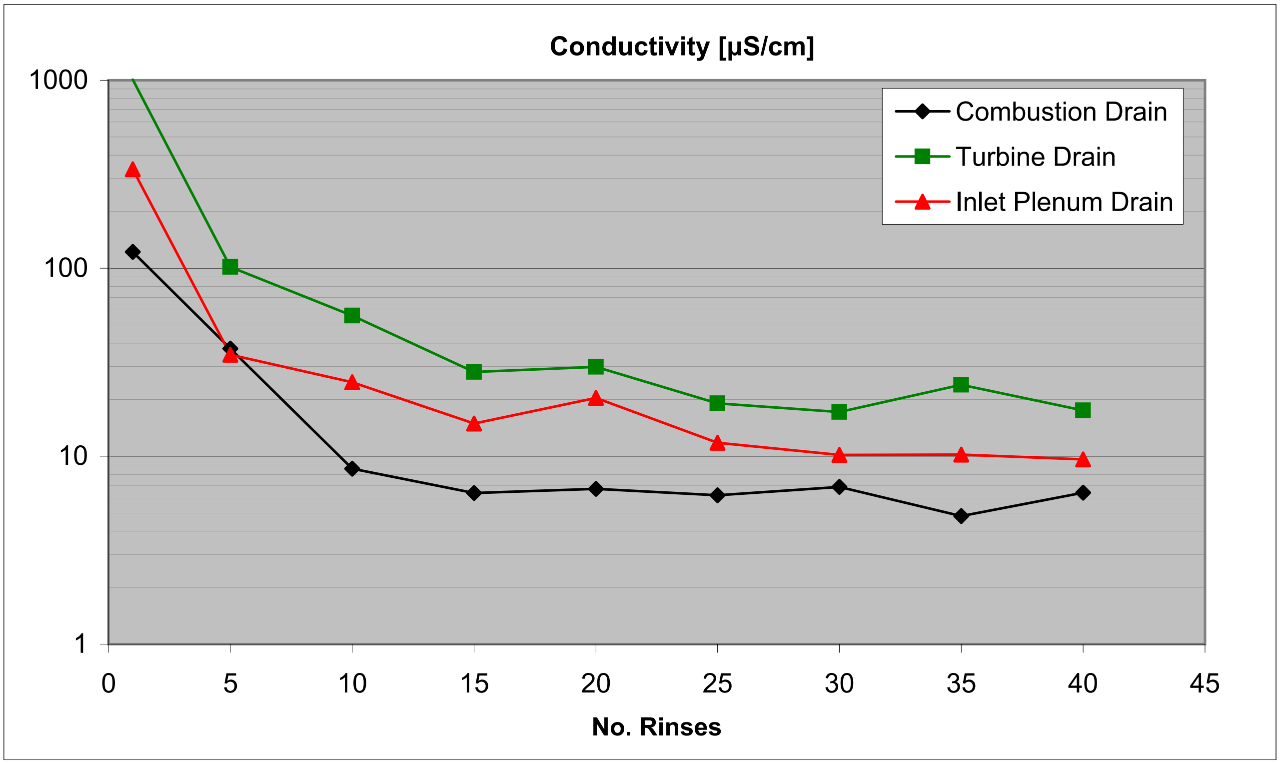
Wash Pulse	Tank Level (in)	Pulse Duration (min)	Displaced Volume (in3)	Displaced Volume (gal)	Displaced Volume (liters)
1	34.6	1.0	2696	11.7	44.2
2	31.7	1.0	2022	8.8	33.1
3	28.9	1.0	1887	8.2	30.9
4	26.2	1.0	1887	8.2	30.9
5	23.4	1.0	1887	8.2	30.9
6	20.7	1.0	1887	8.2	30.9
7	17.9	1.0	1887	8.2	30.9
8	15.2	1.0	1887	8.2	30.9
Total	199	8	16041	69.4	262.9
Average	25	1	2005	8.7	32.9

Estimated Water/Detergent Ratio for Design 58.5 gpm @ 85 psig discharge: 5.74

GE Rep_________________ Customer Rep _________________

Date	22-May-2006

Measured Conductivity Data from Drains



Rinse Stopping Criteria (all to be verified):

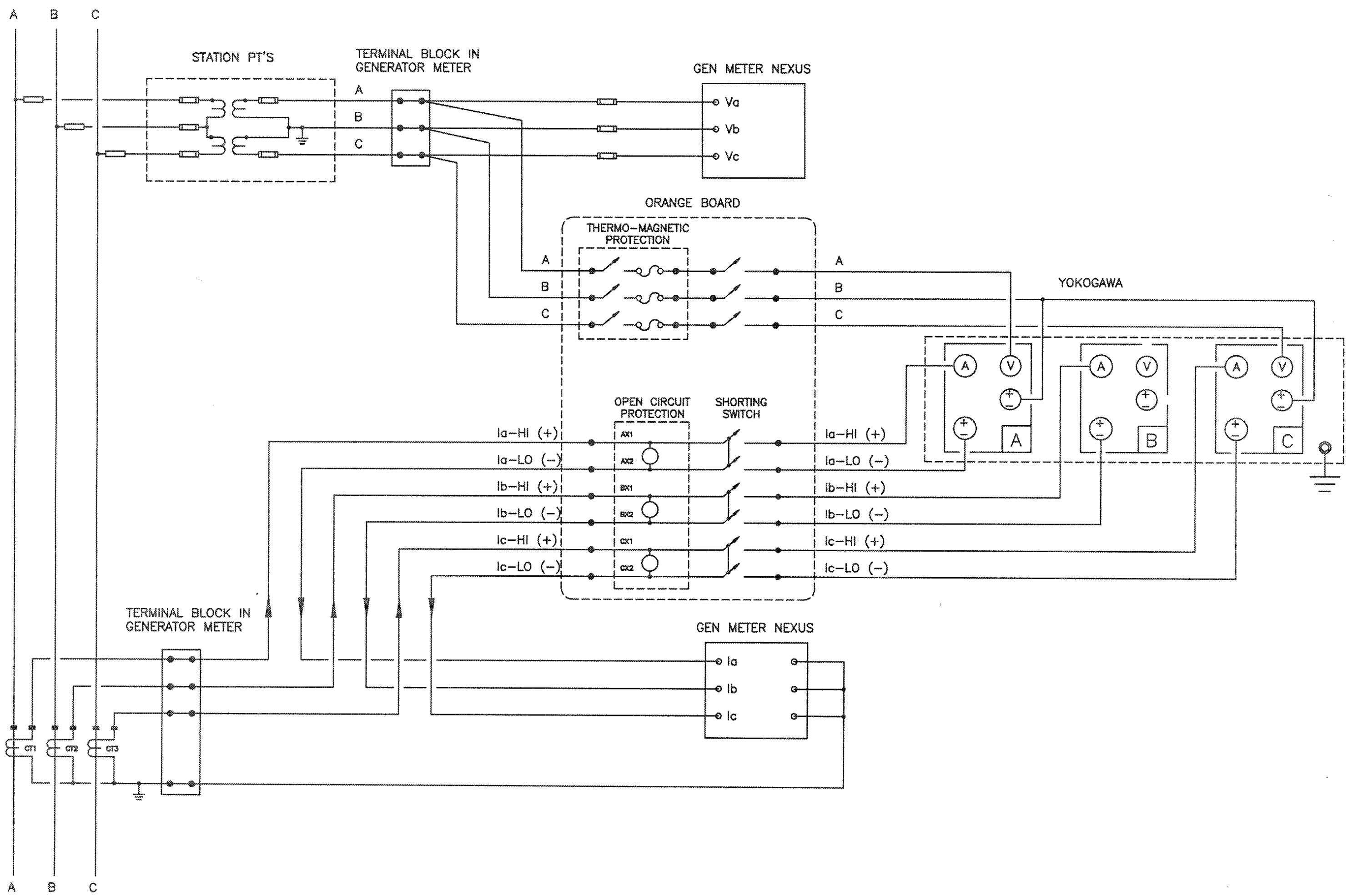
1) Complete programmed rinses (#30)
2) Difference between combustion drain conductivity and makeup water should be within 5-10 µS/cm
3) Combustion drain conductivity should not change by more than 1 µS/cm for the duration of 5 rinses
4) Satisfactory visual inspection of bellmouth, IGV and R0

Notes:

GE Rep__________________ Customer Rep _________________

Appendix D: Circuit Diagram, Precision Power Measurement, Generic

OPEN–DELTA CONFIGURATION



Appendix E: Performance Test Guidelines, GEK 107551A

GEK 107551a
Revised March 2002
Replaces GEK28106a

GE Power Systems

Standard Field Performance Testing Philosophy

I. INTRODUCTION

This document provides guidance for conducting a standard performance test of GE heavy duty gas turbines. Station instruments for power and fuel flow are utilized along with a combination of station instruments and special instruments for other parameters that must be determined.

The objective of the test will be to determine performance characteristics of the gas turbine in accordance with requirements of the purchase agreement.

This document is not a procedure for conducting the test. A detailed procedure for conducting the test and evaluating the results must be issued and agreed upon prior to conducting a test. GE will provide the procedure and conduct the test. When the Customer delegates these activities to parties other than GE, then GE approval for the test procedure and test must be obtained.

Proper preparation of the gas turbine for test is essential. This preparation is not considered part of normal commissioning activity. It is required that GE inspect the equipment to be tested and provide instruction as to restorative action that is required prior to conducting the test. A pre-test readiness report that demonstrates the equipment has been properly prepared must be issued to General Electric prior to conducting the test.

Uncertainties in the measurements will be unavoidable. Based on extensive experience in conducting such tests and complete understanding of the equipment and its response to the environment, GE has developed uncertainties for a standard performance test. Depending on specific needs, the Customer and GE may agree to some modifications in the test that may alter the uncertainties.

The estimated uncertainties will be considered tolerance bands for the purpose of equipment acceptance. In the event that the equipment fails to meet acceptance criteria, then post-test uncertainty analysis may be required to determine whether the problem is measurement related. The Customer and GE will then agree as to interpretation of test results.

II. OBJECT AND SCOPE

The Standard Field Performance Test Philosophy is intended for full load testing new and clean gas turbines with generator loads. Performance characteristics of interest would be:

- Generator Electrical Power Output
- Gas Turbine-Generator Heat Rate
- Gas Turbine Exhaust Gas Temperature
- Gas Turbine Exhaust Gas Flow Rate
- Gas Turbine Exhaust Gas Energy

Not all quantities are required for all tests. In the majority of cases, the quantities of interest are power output and heat rate. Testing will be confined to gas turbines that operate on natural gas or light distillate liquid fuels.

The Standard Field Performance Test Philosophy represents a simpler alternative to ASME PTC-22. Testing will be based upon use of existing station instruments for measurement of generator power and gas turbine fuel flow. The balance of the instrumentation will be a combination of existing gas turbine devices and special devices that are intended to provide measurement accuracy consistent with goals for overall test uncertainty.

Prior to the test, compressor cleaning will be completed as a minimum action to ensure the gas turbine is in a condition suitable for test. In addition, the gas turbine will be inspected, and major control functions that affect full load operation will be verified to be operating correctly.

When completed, the Standard Field Performance Test will be expected to have overall uncertainties of approximately +/-2% for corrected power output and +/-1.7% for corrected heat rate for the gas turbine operating with natural gas fuel at maximum load.

III. GUIDING PRINCIPLES

The primary purpose of the test shall be the measurement of generator power and gas turbine fuel heat consumption at full load. Sufficient supporting data will be recorded to enable correction of the test results to conditions of rating, as stated in the appropriate sections of the purchase order, so that a comparison may be made between results from testing and rated machine capability at specified operating conditions. Correction factors, most up-to-date versions will be provided by GE prior to the test. The quantity and format of the correction factors applied to a particular project will depend on the contractual basis of the performance guarantee as stated in the purchase contract. The following list presents potential correction factors:

- Inlet Air Temperature
- Inlet Air Humidity
- Barometric Pressure
- Generator Power Factor
- Water/Steam Injection Flow Rate
- Fired Hours
- Rotational Speed
- Fuel Temperature
- Fuel Composition
- Inlet System Pressure Differential, when equipment is outside General Electric scope.
- Exhaust System Pressure Differential, when equipment is outside General Electric scope.

The subject gas turbine shall be capable of reliable operation at full load before conduct of the test. Inlet guide vane position in the full open position will be verified by manual measurement of at least 16 vanes. Exhaust temperature control parameters will be verified to be at specified values, including verification of the exhaust thermocouple signal processor via input of a known millivolt level at the first thermocouple junction closest to the exhaust gas thermocouples.

General Electric will inspect the gas turbine and determine the actions necessary to place it in a new and clean condition. In most cases, the turbine will be considered new if it has operated less than 100 fired hours and in accordance with General Electric instructions. It will be necessary to clean the compressor and/or turbine in almost every case, regardless of the amount of fired hours. Visual inspection of the compressor inlet area, including bellmouth, inlet guide vanes and compressor blades, following water wash will be required to insure cleanliness. In some cases, it may be necessary to conduct more than one wash cycle to achieve the required cleanliness. General Electric may require that the wash process be supplemented by a manual wiping of the inlet surfaces which are readily accessible from the bellmouth area, including the bellmouth surface, support struts, inlet guide vanes, and first stage blades.

If prior to the test, the turbine has accumulated more than 100 fired hours a degradation correction will be applied to the test results to account for the amount of degradation that can not be recovered through off-line washing.

Fuel flow measurement will be made using General Electric recommended devices, or their equivalent. Liquid fuel flow measurement devices will be calibrated prior to test if they have been placed into service during commissioning or their original calibrations do not meet accepted industry standards. When used for gas fuel flow measurement, orifice meters will not be placed in service prior to the test. Verification of orifice plate size and orientation will be done prior to installation. In the event the orifice metering tube has been specially calibrated as a unit, removal of the orifice plate will not be required.

Instruments for the test will consist mostly of those that are used to operate and control the gas turbine provided they meet accuracy requirements for the overall test. Control system sensors that affect direct evaluation of thermal performance must have their calibration verified before the test. The accuracy of the signals from the following control variables will be verified by portable NIST traceable field calibration devices. Loop calibration will be conducted.

- Barometric Pressure
- Air Inlet Pressure Differential
- Compressor Bellmouth Pressure Differential
- Compressor Discharge Pressure
- Exhaust System Pressure Differential
- Gas Fuel Line Pressure at Metering Orifice
- Gas Fuel Metering Orifice Differential Pressure

Special instruments will be required for the test in accordance with overall test uncertainty requirements. A list of measurements to be recorded with precision test instruments is provided as follows:

- Inlet Air Temperature (Multiple sensors mandatory)
- Inlet Air Humidity
- Barometric Pressure
- Air Inlet Pressure Differential

- Compressor Bellmouth Pressure Differential
- Compressor Discharge Pressure
- Exhaust System Pressure Differential

Preparations for test as outlined above are to be completed immediately prior to test. Calibrations and checks made during commissioning normally do not meet the stricter requirements of the performance test.

A log of additional parameters will be required to establish documentation that the gas turbine was operated in accordance with General Electric specifications and in a stable manner throughout the test run. These additional parameters will be identified in the official test procedure.

It is estimated that preparations for test including offline water/detergent wash installation of special instruments will require between one and two days.

The test should commence as soon as possible after the turbine is in a new and clean condition with no more than 24 fired hours of operation having elapsed after cleaning. If compressor fouling is suspected to be a problem during this 24 hour period, it may be necessary to inspect the compressor prior to declaring the test results valid.

The gas turbine should be thermally stable and operating according to control specifications prior to start of test. A test point will consist of a half hour period during which sufficient readings of all instruments will be made to ensure time variations do not result in abnormally large uncertainties. The number of test points will be sufficient to demonstrate performance over the range of operation specified in the purchase order and to demonstrate repeatability of the test set-up.

Samples of fuel from the testing will be taken using recognized standards and submitted to recognized laboratories for analysis. The number of samples will be sufficient to establish fuel variability.

Test results are based on averaged data taken during the test point. The averaged results are corrected to account for differences between test operating conditions and those which are specified in the purchase order. Correction factors will be supplied by General Electric and may consist of curves, tables or computer programs.

Preliminary results from testing will be available to all affected parties within one day of completion of testing. Final results will be available by mutual agreement of the parties to the test.

Exhaust Gas Energy, Gas Fue Decisions based on test results will recognize the measurement uncertainties inherent in the tests. For testing per these guidelines, these uncertainties are expected to be:

Power Output	+/- 2%
Heat Rate, Gas Fuel	+/- 1.7%
Heat Rate, Oil Fuel	+/- 1.45%
Exhaust Gas Temperature	+/- 11°F
Exhaust Gas Flow	+/- 3.3%

Exhaust Gas Energy, Gas Fuel	+/- 3.35%
Exhaust Gas Energy, Oil Fuel	+/- 3.1%

The test uncertainties will be considered to be minimum tolerance bands in the commercial evaluation of the test.

GE Power Systems

General Electric Company
One River Road, Schenectady, NY 12345
518 • 385 • 2211 TX: 145354

Appendix F: Natural Gas Fuel Sampling Procedure

Guidelines for sampling natural gas fuel

1. Background information

These guidelines are provided in order to ensure gas samples are collected in a consistent manner and that the gas analyzed represents the bulk of the gas flowing through the flow-metering assembly.

Capturing a quantity of gas for later analysis is referred to as "spot" sampling. The quality of a spot sample is strongly dependent on the sampling technique.

Natural gas may be categorized as either ""wet" or "dry". "Wet" gas contains heavy hydrocarbon components that may be liquid at room temperatures. The natural gas delivered to the power plant is normally considered a "dry" gas by pipeline standards but is likely to contain measurable amounts of "wet" constituents.

The calculated heat rate for the combustion turbine is sensitive to the gas sample results in two ways:

The heating value of the fuel determines the caloric content.
The density of the fuel determines the mass flow rate.

A sample containing an excess of heavy, wet constituents will result in an erroneously high fuel density being applied to the gas flow equation. Conversely, analysis of samples depleted of their heavier constituents by improper purging techniques or excessively long sample lines yield erroneously low fuel densities.

Even small errors in fuel density can be extremely significant to the final calculated heat rate.

Obtaining quality samples requires a combination of careful sample point selection, proper equipment, and proper technique.

Sample point selection is discussed in section 3, "Amplifying remarks.

Step by step sampling technique is provided in section 2, ""Required methods" and discussed in section 3.

The required sampling apparatus consists of three sections:

Flow Probe assembly
T manifold (or moisture separator)
Sample bottle ***with pigtail assembly***

These three assemblies are described in detail in the section 3, "Amplifying remarks".

Safety Warnings

To avoid painful burns from hot gas the probe should not be installed or removed with the gas heater in service.

Do not use plastic ferrules in the sample apparatus since the gas may be hot enough to melt the ferrules during the sample purge.

Some gas will escape during the probe insertion – take appropriate safety precautions.

The ferrule swaged near the sample probe tip will prevent the probe from being ejected during removal from a pressurized pipe. (It will also prevent droplets from traveling down the tube and becoming entrained in the sample flow.)

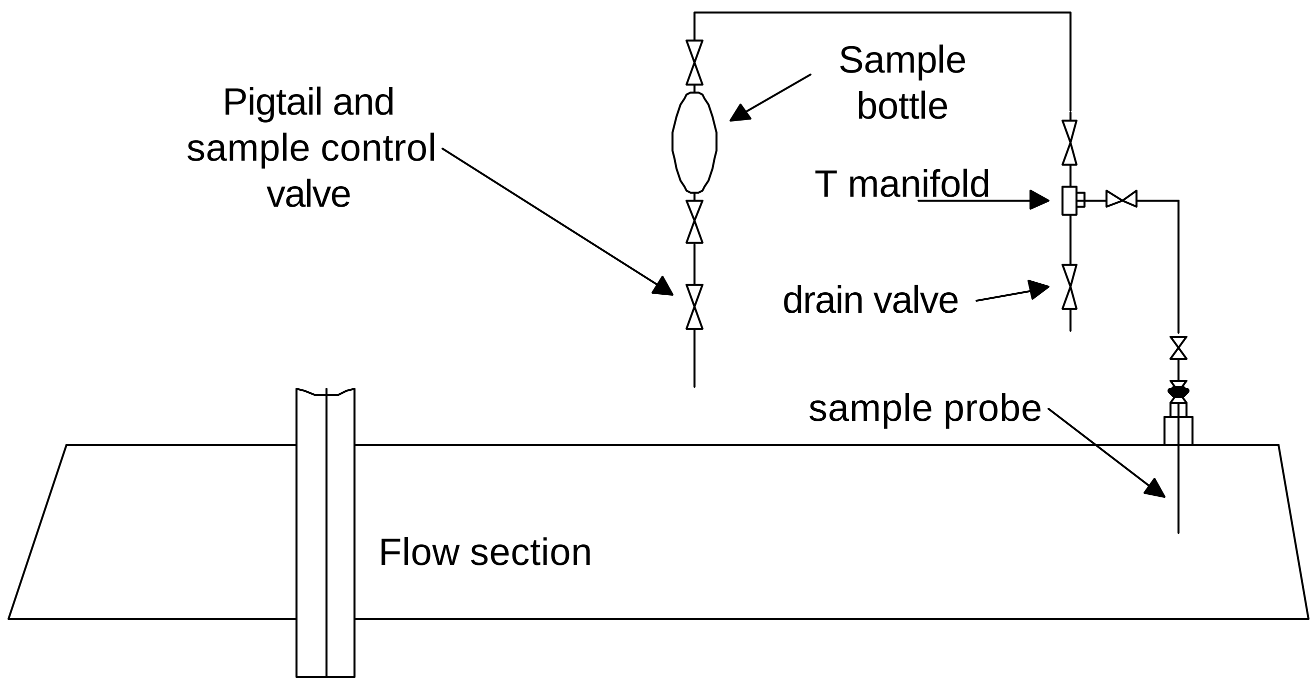
2. Required Methods and Materials

Choose a sample point as near the flow metering device as possible without effecting the flow through the flow section.

Install a sample probe to collect gas from the center of the pipe.

Assemble the sample apparatus as shown below:

Flow thru the sample bottle **must** be vertical in the downward direction
A 2-foot tubing section with a control valve **must** be attached to the sample bottle vent. (the "pigtail")



To capture a spot sample:

1. Before connecting the sample bottle assembly to the T manifold purge the sample lines through the T manifold drain valve until clean, dry gas issues. Purge a small volume of gas through the sample bottle connection on the T manifold. (Or moisture separator) by opening and shutting the T manifold sample outlet valve.

2. Open both valves on the sample bottle and connect the sample bottle to the T manifold by means of a short length of U shaped tubing. Flow through the sample bottle must be down. Attach the pigtail assembly with the sample control valve shut.

3. Purge gas through the T manifold drain until no moisture is present. Then shut the T manifold drain valve.

4. Open the T manifold sample outlet valve.

5. Crack open the sample control valve to obtain a minimal flow rate.

6. Purge the sample bottle of air by maintaining this flow rate for about 30 seconds.
7. Shut the sample control valve and allow the bottle pressure to equalize with line pressure.

8. Shut the T manifold sample outlet valve.

9. Crack open the sample control valve and slowly vent the sample bottle through the sample control valve to almost atmospheric pressure. Shut the sample control valve.

10. Re-open the T manifold sample outlet valve and allow the sample bottle to equalize with line pressure.

11. Repeat steps 8 thru 10 to "fill and empty" the sample bottle a minimum of 5 times. If moisture appears at the end of the sample pigtail at any time start over. A moisture separator may be required.

12. Shut both sample bottle isolation valves and vent the sample line residual pressure through the T manifold drain valve.

13. Remove the sample bottle. Record the sample date, time, location, gas temperature and pressure.

14. Cap or plug the sample bottle isolation valve ports and leak check the bottle by water immersion.

3. Amplifying remarks

1. Selecting the sampling point

Pre-test checklist

The lead performance engineer should communicate these sampling requirements to the site as required by the pre-test checklist. Provide enough lead-time to ensure a suitable sample point is available.

Sample point selection

The fuel flow-metering device will be specified by the contract. The gas sample must be representative of the gas flow at the metering point in order to properly determine the fuel density and accurately calculate the mass flow rate.

The preferred tap location is from the top of a horizontal pipe.

The flow metering point may be upstream of processes that might change the composition of the gas (scrubbers, compressors, moisture separators, etc.). In this case the gas delivered for combustion may have a slightly different heating value than the fuel gas being metered. A second "diagnostic" sample may be drawn nearer the combustion turbine in order to evaluate the significance of any change in heating value from the "official" sample drawn at the flow metering point.

Tubing considerations

Tubing runs should be short and direct. Condensation in long tubing runs can be a significant issue in trying to collect high quality samples.

2. Sample probes

Purpose

Wet gas constituents will tend to collect on the wall of the pipe. Drawing samples from pipe wall taps may result in non-representative samples. This is particularly true if sampling near the bottom of a long length of vertical pipe.

Using a sample probe ensures the sample is drawn from the region of highest flow and therefore most representative of the gas.

Construction

A sample probe can easily be constructed from materials available in the lab. A straight length of quarter inch stainless steel tubing is cut and then filed at a 45-degree angle. A stainless steel ferrule is swaged about 2 inches from the angled end. The other end of the probe is left as-is until ready to install.

Installation

The sample pipe tap should have a ball or gate valve installed which will allow the probe to be installed through the body of the valve. If this valve assembly is not available one should be manufactured and installed. Ensure the components are suitable for the system pressures. (when in doubt use schedule 80 pipe and fittings)

Once on site the sample probe is cut to length and the prepared end inserted into the gas main sample pipe tap until it contacts the ball valve. A bored-through reducer fitting is slid over the unprepared end of the probe and threaded into the short pipe extension on the sample tap ball valve. The ferrule is snugged but not swaged in order to allow insertion of the probe. A valve is swaged to the exposed end of the sample probe. This sample probe valve is then shut.

The ball valve is opened (see the safety warnings) and the probe inserted to the required depth. The ferrule is then swaged down. The 45-degree cut should be oriented so that the exposed opening faces downstream – it should **not** act as a sample scoop.

<u>Safety Warnings</u>
To avoid painful burns from hot gas the probe should not be installed or removed with the gas heater in service.

Do not use plastic ferrules in the sample apparatus since the gas may be hot enough to melt the ferrules during the sample purge.

Some gas will escape during the probe insertion – take appropriate safety precautions.

The ferrule swaged near the sample probe tip will prevent the probe from being ejected during removal from a pressurized pipe. (It will also prevent droplets from traveling down the tube and becoming entrained in the sample flow.)

3. T manifold and moisture separator

<u>Purpose</u>
A moisture separator may be required if the gas is extremely wet or the sample lines are very cold. If purging the sample lines is not effective in obtaining moisture-free sample flow then install a separating chamber.

If a dry sample can be obtained without a moisture separator a T fitting can be used to provide the required purge and drain paths.

<u>Construction</u>
The T manifold assembly contains a T fitting and two or three valves:
a **sample drain valve** to purge the line
a **sample outlet valve** to isolate the bottle
a **sample inlet valve** to isolate the T fitting

(Try to keep the sample lines short enough to use the sample probe valve for this function)

If the gas is very wet (moisture is still visible after considerable purging) then a moisture separating chamber should be used instead of a T fitting.
A moisture separator can be made from a 1-inch pipe tee (or larger) with adapter fittings. Commercial moisture separators with internal metal filters can be purchased if required.

<u>Installation</u>
Direction of flow is an important factor. Avoid establishing flow paths that would allow condensation in the sample lines to reach the sample bottle or remain in the sample bottle.

4. Sample bottle pigtail

<u>Purpose</u>
Condensation may occur when the pressurized gas expands to atmospheric pressure. It is important to ensure this expansion does not occur into the sample bottle or across the sample bottle vent valve because the resulting sample enrichment will give an unacceptable fuel density result.

To control the point of expansion a short length of tubing and a **sample control valve** must be attached to the sample bottle vent valve. The sample control valve is always throttled to ensure the gas expansion occurs across the sample control valve seat.

<u>Installation</u>
Install the sample bottle so flow through the bottle and pigtail assembly is in the downward direction.

5. Purge sequence

<u>Purpose</u>
Flow paths and purge sequences are the critical elements in obtaining quality samples.

Initial purging of the sample lines through the gas sample bottle should be avoided at all costs. The resulting contamination of the sample bottle can seriously skew the analysis and damage the analysis equipment. The inability to reconcile subsequent sample results with the contaminated sample may compromise the performance test results.

Initial purge should be through a T manifold drain line (see figure). Once the sample line is passing clean gas the T manifold sample outlet valve should be opened briefly to purge the short path to where the sample bottle will be attached.

A thorough purge sequence should be performed for each group of samples drawn. The preferred method of drawing multiple samples is to connect the bottles in series with a pipe nipple. This allows simultaneous purging and sample isolation.

Once the sample bottle is attached to the T manifold the sample drain line is again opened to check for moisture. When clean gas is being passed the sample drain valve is shut and the fill and purge sequence is started. The slow purge and rapid fill sequence described in the procedure has been shown to be the best field capture technique that does not require special equipment.

A continuous purge has been proven to be unreliable and does not produce repeatable results.

6. Cold weather considerations

In order to prevent rapid condensation of heavy gas constituents observe the following additional precautions when temperatures are below 50 deg F.

Purging

Purge the sample lines through the T manifold drain until the entire sample line is at the gas main temperature. Consider insulating the sample lines.

Prior to sampling

Do not store sample bottles outside. Sample bottles should be kept at room temperature (or above) until just prior to use.

Moisture separators

Use of an unheated moisture separator chamber should be avoided.

4. References:

1. GPA Standard 2166-86, “Obtaining Natural Gas Samples for Analysis by Gas Chromatography.” Gas Processors Association revised 1986.
2. GRI-99/0194, “Topical Report, Metering Research Facility Program, Natural Gas Sample Collecting and Handling – Phase 1”, Gas Research Institute, August 1999.

Appendix G Fuel Flow Metering Calibration Data

CONSOLIDATED CONFAB FABRICATORS
A DIVISION OF BRADEN MANUFACTURING LLC

Gas Fuel Flow Measurement System

GE P/O Number:	180893111-1
GE Ordering Drawing:	216A1236P001
GE Requisition Number:	GR1007
GE MLI/CC:	0639
CFI Job Number	9838

Meter Tube Supporting Data

A. Certificate of Conformance

B. Meter Tube Dimensional Data

C. Final FE-Sizer

D. Alden Flow Test Record

E. Rosemount Programmed Data

1. Q4 Report from Rosemount
2. Fluid Report
3. Primary Element Report
4. Natural Gas Report

GE Power Generation		GENERAL ELECTRIC COMPANY Schenectady, NY	
VENDOR SUPPLIED DRAWING GE NOT TO REVISE; GE REVISION LEVEL IS AS SHOWN ON THIS APPLIQUE. THIS DOCUMENT IS FILED UNDER THE GE DRAWING NUMBER THIS DOCUMENT SHALL BE REVISED IN ITS ENTIRETY. ALL SHEETS OF THIS DOCUMENT ARE THE SAME REVISION LEVEL AS INDICATED IN THIS VENDOR SUPPLIED DRAWING APPLIQUE. FIRST MADE FOR: GR1007 1 OF 32			
GE SIGNATURES	DATE	GE DRAWING NUMBER	REV
CHECKED: KISHORE KUMAR.K	06-06-13	213A1317	-
ISSUED: VIJAY.V	06-06-13		

CONSOLIDATED FABRICATORS CONFAB

A DIVISION OF BRADEN MANUFACTURING LLC

A

Certificate of Conformance

GE DRAWING NUMBER	REV
213A1317	—
FIRST MADE FOR	SHEET 2

CONSOLIDATED CONFAB FABRICATORS

A DIVISION OF BRADEN MANUFACTURING LLC

Certificate of Compliance

AGA REPORT No. 3 Part 2

Date: 4/3/2006

Job Number:	9838
Serial Number/s:	9838
Vendor Code:	43691
GE P.O. Number:	180893111-1
Line Item Number:	001
GE Drawing Number:	216A1236P001

Description: 8" 600# Orifice Flange Meter Tube, all 304L Stainless Steel material with 316 Stainless Steel Orifice Plate and 316 Flow Conditioner Plate.

The above referenced was manufactured in accordance with the specifications and recommendations of the American Gas Association's AGA Committee Report 3 Part 2. All dimensional requirements were checked and recorded using instruments that are calibrated regularly (traceable to N.I.S.T.) and were found to be in compliance with AGA3. Based on independent laboratory flow calibration the above items have a calibrated accuracy of +/- .25%.

Timothy Presbrey

Signature Valid

Digitally signed by Timothy Presbrey DN: cn=Timothy Presbrey, c=US Date: 2006.03.13 15.25.29 -05'00'

Quality Technician

GE DRAWING NUMBER	REV
213A1317	—
FIRST MADE FOR	SHEET 3

Consolidated Fabricators Inc. 17 St mark Street Auburn MA 01501 (508)-832-9686

CONSOLIDATED FABRICATORS CONFAB

A DIVISION OF BRADEN MANUFACTURING LLC

B

Meter Tube Dimensional Data

GE DRAWING NUMBER	REV
Z13A1317	—
FIRST MADE FOR	SHEET 4

Job Order Number: 9838
Drawing Number: 216A1239P001

GE Purchase OrderNo 180893111
Description: Gas Fuel Measuring System

ORIFICE RUN MEASUREMENT DIMENSIONS (INCHES)

"UL1"	"UL2"	"UTA"	"UTB"	"DL"	"DTA"	"DTB"
52.816	82.5000	0.8750	0.8930	41.7450	0.8660	0.8680

Gasket Thickness 0.1000 Orifice thickness 0.25 Overall Length 177.961 HT# U.S. Pipe: HT# U.S. Flg.:
"C1" 6.000 Straightening Vain .25 HT# D.S. Pipe: HT# D.S. Flg.:

UPSTREAM LOCATIONS					DOWNSTREAM LOCATIONS				
AXIS	"A" @ TAP	"B" @ WELD	"C" 2D FROM ORF. PLT.	"D" 6" FROM END	"E" @ TAP	"F" @ WELD	"G" 2D FROM ORF. PLT.	"H" 6" FROM END	AXIS
V	7.9920	7.9990	7.9990	7.9780	7.9900	7.9840	7.9820	7.9830	V
RV	7.9920	7.9820	7.9970	7.9670	7.9900	7.9780	7.9770	7.9790	RV
H	7.9920	7.9780	7.9950	7.9800	7.9900	7.9750	7.9810	7.9670	H
LV	7.9920	7.9950	7.9950	7.9690	7.9900	7.9720	7.9710	7.9880	LV
AVG.	7.9920	7.9885	7.9965	7.9735	7.9900	7.9773	7.9778	988.0000	AVG.
CALIBRATED SIZE:			7.99200		CALIBRATED SIZE:	7.99000			

WALL THINKNESS READINGS						
	W1-W8	W9-W16	W17-W24	W25-W32	W33-W40	W41-W48
	0.331	0.334	0.336	0.332	0.323	0.323
	0.339	0.340	0.328	0.323	0.329	0.328
	0.34	0.343	0.321	0.317	0.334	0.340
	0.33	0.332	0.328	0.329	0.338	0.338
	0.325	0.325	0.329	0.328	0.335	0.334
	0.329	0.322	0.332	0.331	0.321	0.334
	0.335	0.320	0.335	0.341	0.324	0.325
	0.325	0.321	0.336	0.337	0.326	0.328
AVG.	0.3318	0.3296	0.3306	0.3298	0.3288	0.3313

Mic'd Orifice Bore: 4.9710 Nominal pipe size 8 Inches
Meter tube temp. when measurements were made at 68 degrees F Beta Ratio: 0.62

ECCENTRICITY:

E<= 0.0025(Dm) / 0.1 + 2.3bm4
Where,
Dm = 7.992
β = 0.62200
E<= 0.04497 Max Deviation
Deviation is within tolerance

	Calc. Radius to cL of Dowel	Measured Radius	Deviation
U.S. 1	6.5000	6.4970	0.0030
U.S. 2	6.5000	6.5180	0.0180
D.S. 1	6.5000	6.4940	0.0060
D.S. 2	6.5000	6.5020	0.0020

Orifice Plate Measurements			
"V"	4.9710	"OD"	12.6200
"RV"	4.9710	"T"	0.2460
"H"	4.9710	"t"	0.1250
"LV"	4.9710	"L"	4.9950
Average	4.9710	"W"	1.5030

Eccentricity Measurments Figure 2.5 (AGA)			
X	1.4980		
X'	1.5230	0.0125	
Y	1.4910		
Y'	1.5300	0.0195	

INSIDE PIPE CONDITION

Measure the internal surface roughness of the meter tube at approximately the same axial locations as those used to determine and verify the meter tube internal diameter (Dm) as those shown in Eccentricity table above.

Measurement 1	126	Microinches (Ra)			Measurement 2	184	Microinches (Ra)
Measurement 3	162	Microinches (Ra)			Measurement 4	172	Microinches (Ra)

Average surface finish		161.5	Microinches (Ra)

Is the average surface finish less than 250 microinches (Ra)?	YES
Is the pipe free of irregularities such as grooves, scoring, ETC.?	YES

SECTION 1 - WITHIN THE FIRST DIAMETER (Dm) UPSTREAM OF THE ORIFICE PLATE

Largest Dia.=	7.999	Dmax		Smallest Dia.=	7.978	Dmin	

Dmax - Dm / Dm	x 100=	0.08759%		< or = 0.25%	Within Tolerance
Dmin - Dm / Dm	x 100=	0.17518%		< or = 0.25%	Within Tolerance

0.039915

SECTION 2 - ALL METER TUBE DIAMETER MEASUREMENTS UPSTREAM OF THE ORIFICE PLATE

Largest Dia.=	7.999	Dmax	Smallest Dia.=	7.978	Dmin

Dmax - Dmin / Dm x 100= 0.26276% < or = 0.50% .... Within Tolerance

SECTION 3 - ALL METER TUBE DIAMETER MEASUREMENTS DOWNSTREAM OF THE ORIFICE PLATE

Largest Dia.=	7.990	Dmax	Smallest Dia.=	7.971	Dmin

Dmax - Dm / Dm	x 100=	0.00000%		< or = 0.50%	Within Tolerance
Dmin - Dm / Dm	x 100=	0.23780%		< or = 0.50%	Within Tolerance

FLANGE TAP CONSTRUCTION

Specified tap location from face of flange 0.9000 Inches
Measured tap location for "UTA" 0.8750 Inches........**Tap hole is within tolerance**
Measured tap location for "UTB" 0.8930 Inches........**Tap hole is within tolerance**
Measured tap location for "DTA" 0.8660 Inches........**Tap hole is within tolerance**
Measured tap location for "DTB" 0.8680 Inches........**Tap hole is within tolerance**

The tap location tolerance for NPS 4" and larger is 0.035" for 0.75 beta ratio 0.035
The tap location tolerance for NPS smaller than 4" is 0.015" for 0.75 beta ratio

Specified drill thru diameter 0.5000 Inches
Measured drill thru diameter for "UTA" 0.5090 Inches........**Drill thru is within tolerance**
Measured drill thru diameter for "UTB" 0.5090 Inches........**Drill thru is within tolerance**
Measured drill thru diameter for "DTA" 0.5090 Inches........**Drill thru is within tolerance**
Measured drill thru diameter for "DTB" 0.5090 Inches........**Drill thru is within tolerance**

The drill thru for NPS 4" and larger is 0.500" +/-0.0156"
The drill thru for NPS 2" and 3" is 0.375" +/-0.0156"
The drill thru for NPS 1 1/2" and smaller is 0.25" +/-"0.0156"

TAP HOLE CONDITION

[X] Good - Burr free edge
[ ] Fair - Burr free edge, rounded but within 0.0625d
[ ] Poor - Burrs or corrosion present

Orifice Meter Tube Is Accepted X
Inspected and recorded By: Steven Gormley 0
Date: April 10, 2006 0

GE DRAWING NUMBER	REV
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CONSOLIDATED FABRICATORS CONFAB

A DIVISION OF BRADEN MANUFACTURING LLC

C

Final FE-Sizer

GE DRAWING NUMBER	REV
213A1317	—
FIRST MADE FOR	SHEET 6

Consolidated Fabricators Inc.
17 St. Mark Street, Auburn, MA 01501
508 832-9686

FE-Sizer for Windows 95/98/Me/NT/2000/Xp, Version 3.0 - Release 3.20

Licensed to: Consolidated Fabricators, Inc.

Service Data

Tag:	216A1236-9838final	Client:	General Electric
Serv:	8" SS 600# Natural Gas	Project:	Techicas Reunidas
Line No.:	1	J.O./P.O. No.:	9838/GR1007

Calculation Method & Base Conditions

Sizing Parameter:	FLOWMETER dP	C-Std:	API 2530/AGA 3 (1992)
Atm Press, Patm:	14.350 psia	Tap Loc:	UPSTREAM

Meter/Pipe Data

Meter Type:	ORIFICE PLATE	Meter Matl:	316/316L SS
Meter Style:	CONCENTRIC	Tap Style:	FLANGE TAPS
Nom Pipe Size:	8.00 in	Pipe Matl:	304/304L SS
Pipe I.D., D(ref):	7.992 in	Pipe Sched:	NON-STD

Sizing Data

Maximum Flow, Wm:	22.0600 lb/s
Normal Flow, Wn:	15.4500 lb/s
Orifice Bore, d (60.0 deg F):	4.9710 in

Fluid Data

Fluid:	RK-GAS/VAPOR
State-Units-Equation-Condition:	VAPOR-MASS-PVT-FLOWING
Specific Gravity, Gg:	0.6101
Compressibility (Flowing), Zf1:	0.9400
Pressure (Flowing), Pf1:	410.00 psig
Temperature (Flowing), Tf1:	75.0 deg F
Viscosity, U:	0.01145 cPoise
Specific Heat Ratio (Cp/Cv), k:	1.2966

Calculated Results

Sizing Factor, Sm:	0.253031
Pipe Reynolds Number @ Maximum Flow, RD:	5480975
Pipe Reynolds Number @ Normal Flow, RD:	3838670
Discharge Coefficient, C:	0.604309
Expansion Factor, Y	0.997998
Bore Expansion Factor, Fad:	1.000067
Pipe Expansion Factor, FaD:	1.000067
Permanent dP Loss:	59.55 %
Throat Velocity @ Max Flow:	117.74 ft/s
Beta, B (68.0 deg F):	0.62200
Maximum Differential, dPm (ref dP - H2O @ 60.0 deg F):	134.68 in WC
Normal Differential, dPn (ref dP - H2O @ 60.0 deg F):	66.060 in WC
Orifice Uncertainty, Uo:	0.62 %

Calc Number: ________________ Sht: ___ of ___ Chk: _____
By: Rev: 0 Date: Mar 30, 2006

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CONSOLIDATED CONFAB FABRICATORS

A DIVISION OF BRADEN MANUFACTURING LLC

D

Alden Flow Test Record

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CALIBRATION OF

8" METER TUBE

CONSOLIDATED FABRICATORS, INC.

PURCHASE ORDER NUMBER 101040-00

MARCH 2006 REPORT NO. 2006-077/C1072

CERTIFIED BY

James B. Nystrom

ALDEN RESEARCH LABORATORY, INC.

30 SHREWSBURY STREET

HOLDEN, MASSACHUSETTS 01520

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All Client supplied information and calibration results are considered proprietary and confidential to the Client. If a third party is a witness are during calibrations or if the Client requests transmittal of data to a third party, Alden considers that the Client has waived confidentiality for the Witness.

In the event the Client distributes any report issued by Alden outside its own organization, such report shall be used in its entirety, unless Alden approves a summary or abridgment for distribution.

No advertising or publicity containing any reference to Alden or any employee, either directly or by implication, shall be made use of by Client without Alden's written approval.

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INTRODUCTION

One 8" Meter Tube, Serial Number 9838, was calibrated at Alden Research Laboratory, Inc. (Alden) for Consolidated Fabricators, Inc. under their Purchase Order Number 101040-00 using Alden's standard test procedures, QA-AGF-7-86, Revision 6.1. Flow element performance is presented as discharge coefficient, C, versus Reynolds number, in both tabular and graphical format.

FLOW ELEMENT INSTALLATION

The flow element was installed in Test Line 3 in the Allen High Reynolds Number Facility, which is shown in plan view on Figure 1. A 350 horsepower centrifugal pump, rated at head of 300 ft at a flow of about 12 ft^3/s, drew water from a heated 180,000 gallon sump under the test floor.

The detailed piping arrangements in Test Line 3 used for the calibration, immediately upstream and downstream of the flow element, are shown in Figure 2, including all significant fittings and pipe lengths. Careful attention was given to align the flow element with the test line piping, and to assure no gaskets between flanged sections protruded into the flow. Vents were provided at critical locations of the test line to purge the system of air.

TEST PROCEDURE

The test technician verified proper installation of the flow element in the test line prior to introducing water into the system to equalize test line piping and primary element temperature to water temperature. After attaining thermal equilibrium, the test line downstream control valve was then closed and vent valves in the test line were opened to remove air from the system. With the line flow shut off, the flow meter output was checked for zero flow indication. Prior to the test run, the control valve was set to produce the desired flow, while the flow was directed to waste. Sufficient time was allowed to stabilize both the flow and the instrument readings, after which the weigh tank discharge

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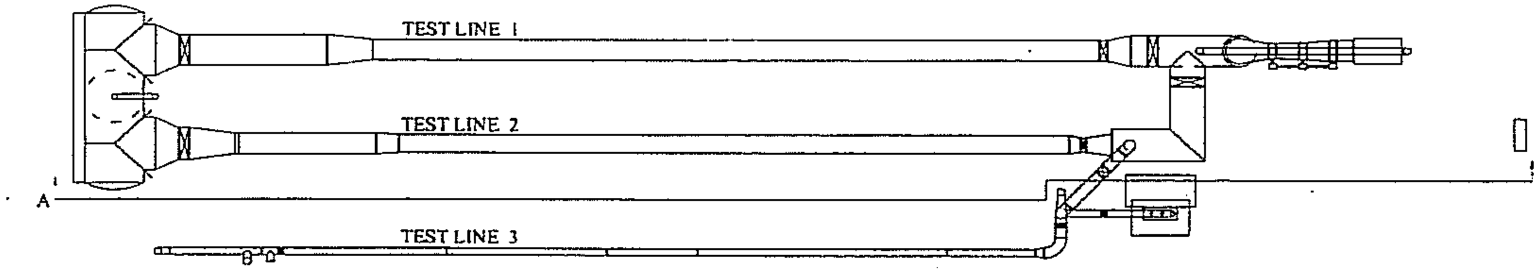
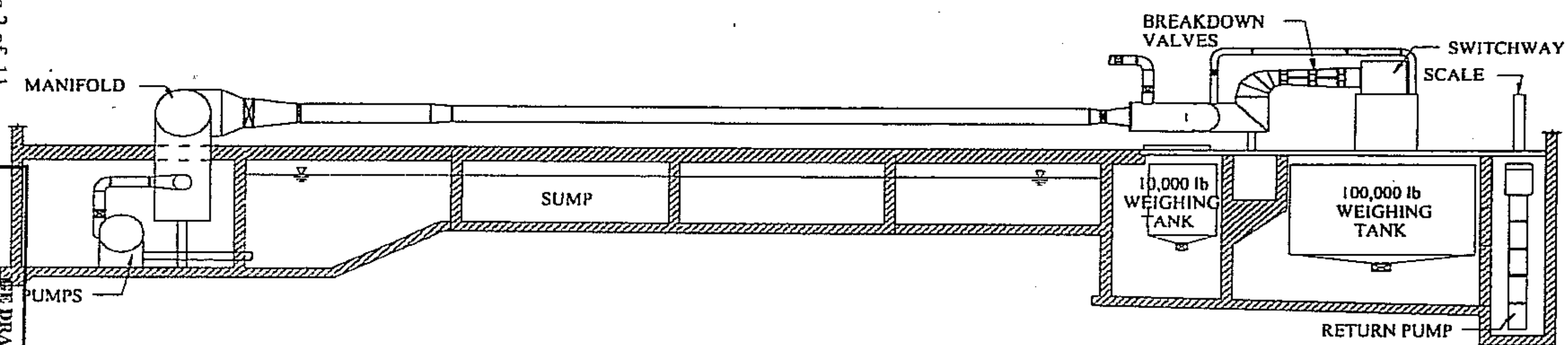
Figure 1





SECTION A-A

Plan View of Allen High Reynolds Number Facility
Test Lines 1,2 and 3

ALDEN

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valve was closed and the weigh tank scale indicator and the electric timer were both zeroed. To begin the test run, flow was diverted into the weigh tank, which automatically started the timer.

At the start of the water collection a computer based data acquisition system was activated to read the meter output, such that the meter output was averaged while the weigh tank was filling. At the end of the run, flow was diverted away from the weigh tank and the timer and data acquisition system were stopped to terminate the test run. The weight of water in the tank, elapsed time, water temperature, and average meter output were recorded on a data sheet. The data were entered into the computer to determine the flow and the results were plotted so that each test run was evaluated before the next run began. The control valve was then adjusted to the next flow and the procedure repeated.

FLOW MEASUREMENT METHOD

Flow was measured by the gravimetric method using a tank mounted on scales having a capacity of 100,000 pounds with a resolution of 2 lbs. Water passing through the flow element was diverted into the tank with a hydraulically operated knife edge passing through a rectangular jet produced by a diverter head box. A Hewlett-Packard 10 MHz Frequency Counter with a resolution 0.001 sec was started upon flow diversion into the tank by an optical switch, which is positioned at the center of the jet. The timer was stopped upon flow diversion back to waste and the elapsed diversion time was recorded. A thermistor thermometer measured water temperature to allow calculation of water density. Volumetric flow was calculated by Equation (1).

$$q_a = \frac{W}{T\rho_w B_c} \tag{1}$$

where q_a = actual flow, $\frac{ft^3}{sec}$

W = mass of water collected, lb_m

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T = time, sec

ρ_w = water density, $\frac{lb_m}{ft^3}$

B_c = buoyancy correction, $1-\frac{\rho_a}{\rho_w}$

ρ_a = air density, $\frac{lb_m}{ft^3}$

The buoyancy correction includes air density calculated by perfect gas laws with the standard barometric pressure, a relative humidity of 75%, and measured air temperature. The weigh tank is periodically calibrated to full scale by the step method using 10,000 lb_m of cast iron weights, whose calibration is traceable to NIST. Flow calculations are computerized to assure consistency. Weigh tank calibration data and water density as a function of temperature, are stored on disk file. Data were recorded manually and on disk file for later review and reporting.

DISCHARGE COEFFICIENT CALCULATIONS

Discharge coefficient, C, is defined by Equation (2) and plotted versus pipe or throat Reynolds number. The discharge coefficient relates the theoretical flow to the actual flow.

$$C=\frac{q_a}{q_{th}}=\frac{q_a}{F_a K_m \sqrt{\Delta h}} \qquad (2)$$

where C = discharge coefficient, dimensionless

q_{th} = theoretical flow,

F_a = thermal expansion factor, dimensionless

Δh = differential head, ft at line temperature

K_m = meter constant, $\frac{ft^{2.5}}{sec}$

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The theoretical proportionality constant, K_M, between flow and square root of differential head is a function of the meter throat area, the ratio of throat to pipe diameter, and the local gravitational

$$K_m = \frac{a_t\sqrt{2g_l}}{\sqrt{1-\beta^4}} \tag{3}$$

constant, as defined by Equation (3).

where a_t = throat area, $\frac{\pi d^2}{4}$, ft^2

d = throat diameter, ft

g_l = local gravitational constant, $32.1625 \frac{ft}{sec^2}$ at Alden

β = ratio of throat to pipe diameter, $\frac{d}{D}$, dimensionless

D = pipe diameter, ft

The effect of fluid properties, viscosity and density, on the discharge coefficient is determined by Reynolds number, the ratio of inertia to viscous forces. Pipe Reynolds number, R_D, is determined by Equation (4).

$$R_D = \frac{q_a D}{a_p \gamma} \tag{4}$$

where a_p = pipe area, $\frac{\pi D^2}{4}$, ft^2

γ = kinematic viscosity, $\frac{ft^2}{sec}$

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FLOW METER SIGNAL RECORDING

The secondary element, which converts the primary element signal into engineering units, was one of several "Smart" differential pressure transmitters having ranges of 250" W.C., 1000" W.C. and 100 psid. Each transmitter was calibrated with a pneumatic or a hydraulic dead weight tester having an accuracy of 0.02% of reading. Transmitter signals were recorded by a PC based data acquisition system having a 16 bit A to D board. Transmitter calibrations were conducted with the PC system such that an end to end calibration was achieved. Transmitter output was read simultaneously with the diversion of flow into the weigh tank at a rate of about 34 Hz for each test run (flow) and averaged to obtain a precise differential head. For primary elements with multiple tap sets, individual transmitters were provided for each tap set and all transmitters were read simultaneously. Average transmitter reading was converted to feet of flowing water using a linear regression analysis of the calibration data and line water temperatures to calculate appropriate specific weight.

TEST RESULTS

The results are presented in individual tables and graphs. The measured values of weight, time and line temperature, which were used to calculate the listed flow, are shown in the tables. 8" Orifice Meter, Serial Number 9838, performance is given as discharge coefficient versus pipe Reynolds number from 192,700 to 1,851,500 for Tap Set "C".

Analysis indicates that the flow measurement uncertainty is within 0.25% of the true value for each test run. Calibrations of the test instrumentation (temperature, time, weight, and length measurements) are traceable to the National Institute of Standards and Technology (formerly the National Bureau of Standards) and ALDEN's Quality Assurance Program is designed to meet ANSI/NCSL Z540-1-1994 "Calibration Laboratories and Test Equipment-General Requirements" (supercedes MIL-STD-45662A).

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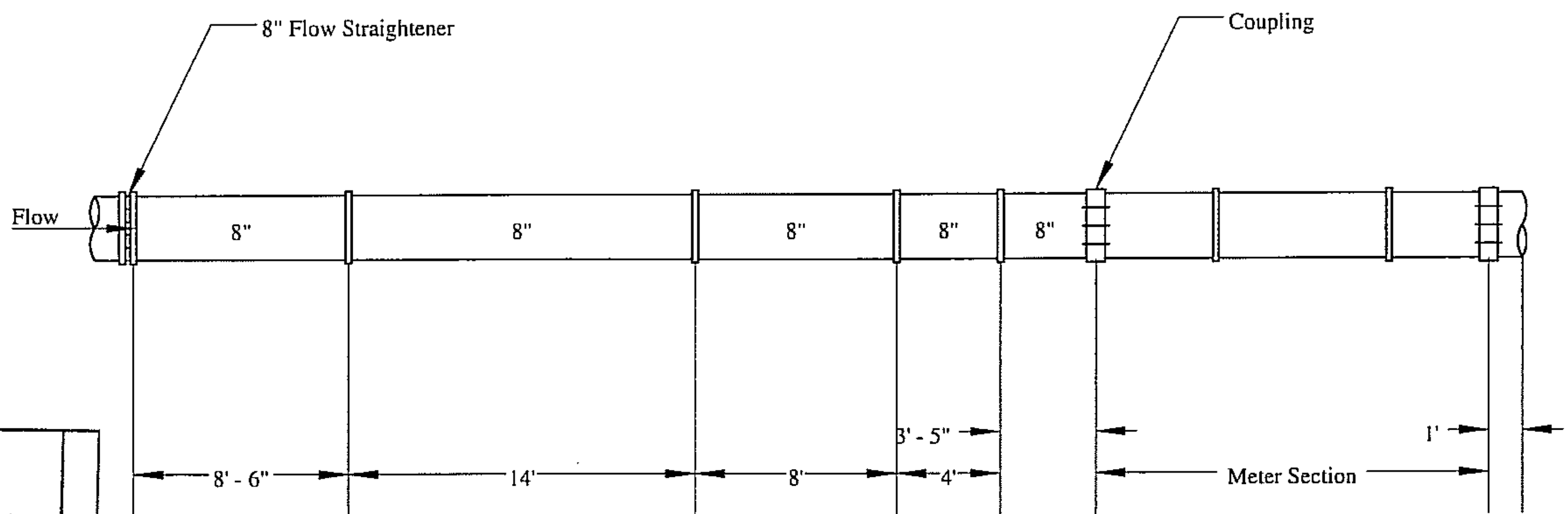
Figure 2 Plan View Allen Facility Line 3



CONSOLIDATED FABRICATORS
Purchase Order Number: 101040-00
8" GAS FUEL FLOW METER
Serial Number: 9838
March 29, 2006

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CONSOLIDATED FABRICATORS

Purchase Order Number: 101040-00
8" GAS FUEL FLOW METER
Serial Number: 9838

CALIBRATION
DATE: March 29, 2006
PIPE DIAMETER = 7.9920
THROAT DIAMETER = 4.9710

TAP SET C

Run #	Line Temp Deg F	Air Temp Deg F	Net Weight lb.	Run Duration secs.	Output [see note]	Flow GPM	H Line FT H20	Pipe Rey. # x 10^6	Coef
1	92	75	95558	196.640	6.178~	3516.	122.343	1.8515	0.6041
2	92	75	95214	212.674	5.540~	3240.	103.754	1.7095	0.6044
3	92	75	95036	232.272	4.952~	2961.	86.616	1.5606	0.6045
4	92	75	95150	254.460	4.460~	2706.	72.305	1.4278	0.6047
5	92	75	95066	283.133	7.536~	2430.	58.315	1.2821	0.6046
6	92	75	95008	315.235	6.458~	2181.	46.990	1.1508	0.6045
7	92	75	95090	363.515	5.351~	1893.	35.363	0.9988	0.6048
8	92	75	95052	419.303	4.514~	1640.	26.570	0.8656	0.6047
9	92	75	95010	501.034	9.075~	1372.	18.570	0.7257	0.6051
10	93	75	65538	415.409	6.892~	1141.	12.841	0.6051	0.6054
11	93	75	65526	540.605	4.882~	877.2	7.565	0.4649	0.6060
12	93	75	36365	431.497	3.388~	609.9	3.644	0.3233	0.6071
13	93	75	25285	503.307	2.489~	363.6	1.286	0.1927	0.6091

~ dp transmitter volts

The data reported on herein was obtained by measuring equipment the calibration of which is traceable to NIST, following the installation and test procedures referenced in this report, resulting in a flow measurement uncertainty of +/- 0.25% or less.

CALIBRATED BY: S.V.K.

CERTIFIED BY:

ARL

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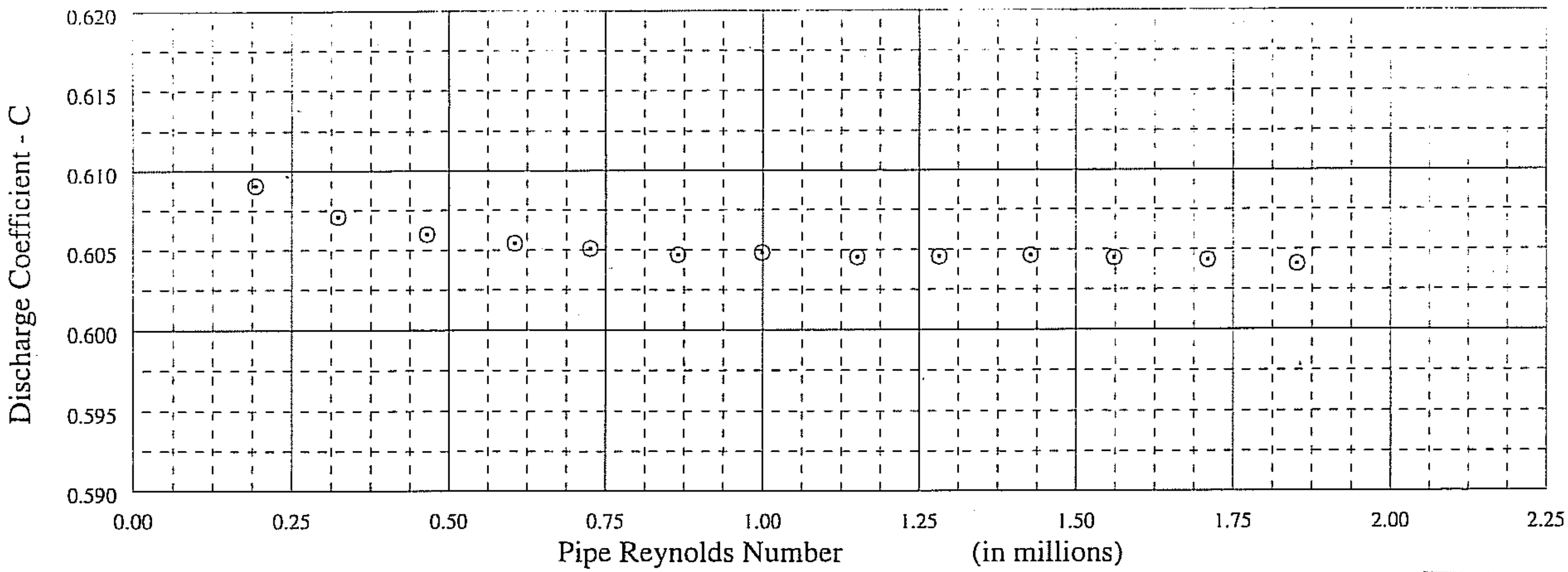

$$q_a = C F_a K_M \sqrt{\Delta h}$$

q_a	=	Actual Flow (ft^3/sec)		
C	=	Discharge Coefficient (Dimensionless)		
Δh	=	Pressure Differential (Feet of Water at Run Temperature)		
K_M	=	Meter Constant = $\dfrac{a\sqrt{2g}}{\sqrt{1 - \beta^4}}$	=	1.1722
F_a	=	Average Thermal Expansion Factor	=	1.0004
a	=	Throat Area (ft^2)	=	0.1348
g	=	Local Acceleration of Gravity (ft/sec^2)	=	32.1625
ß	=	Ratio of Throat to Pipe Diameter (Dimensionless)	=	0.6220
		Pipe Diameter (Inches)	=	7.9920
		Throat Diameter (Inches)	=	4.9710

Dimensions By: CONCOLIDATED FABRICATORS

CONSOLIDATED FABRICATORS
Purchase Order Number: 101040-00
8" GAS FUEL FLOW METER
Serial Number: 9838
March 29, 2006

TAP SET C

Certified By: James B Wexton

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ARL

Thermal Expansion Factor

The dimensions of a differential producing flow meter are affected by the operating temperature, requiring a Thermal Expansion Factor (F_a) to be included in the calculations. The calculation requires the temperature at which the meter dimensions were measured be known. If this information is not available, an ambient temperature of 68°F is assumed. The Thermal Expansion Factor is calculated according to the American Society of Mechanical Engineers Standard ASME MFC-3M-1989, Equation 17 (pg 11).

$$F_a = 1 + \frac{2}{\left(1-\beta^4\right)}\left(\alpha_{PE} - \beta^4_{meas}\,\alpha_p\right)\left(t - t_{meas}\right)$$

where
- β = ratio of throat diameter to pipe diameter, dimensionless
- α_{PE} = thermal expansion factor of primary element, °F
- α_p = thermal expansion factor of pipe, °F
- t = temperature of flowing fluid, °F
- t_{meas} = temperature of measurements, °F

Thermal expansion factors, α, excerpted from MFC-3M-1989, are listed in the Table below for six typically used materials at three temperatures. Linear interpolation is used to determine the coefficients at flowing temperature.

Thermal Expansion Factors x 10^{-6}

Material	-50°F	70°F	200°F
Carbon Steel (low chrome)	5.80	6.07	6.38
Intermediate Steel (5 to 9 Cr-Mo)	5.45	5.73	6.04
Austenitic stainless steels	8.90	9.11	9.34
Straight chromium stainless steel	5.00	5.24	5.50
Monel (67Ni-30Cu)	7.15	7.48	7.84
Bronze	9.15	9.57	10.03

WATER DENSITY

Temperature Fahrenheit	Density lb_m / ft^3	Temperature Fahrenheit	Density lb_m / ft^3	Temperature Fahrenheit	Density lb_m / ft^3
32	62.4179	62	62.3549	92	62.0903
33	62.4201	63	62.3489	93	62.0788
34	62.4220	64	62.3427	94	62.0671
35	62.4235	65	62.3363	95	62.0552
36	62.4246	66	62.3296	96	62.0432
37	62.4255	67	62.3228	97	62.0311
38	62.4260	68	62.3157	98	62.0188
39	62.4262	69	62.3084	99	62.0063
40	62.4261	70	62.3010	100	61.9937
41	62.4257	71	62.2933	101	61.9810
42	62.4250	72	62.2855	102	61.9681
43	62.4240	73	62.2774	103	61.9551
44	62.4227	74	62.2692	104	61.9419
45	62.4211	75	62.2608	105	61.9286
46	62.4193	76	62.2522	106	61.9151
47	62.4171	77	62.2434	107	61.9015
48	62.4147	78	62.2344	108	61.8878
49	62.4121	79	62.2252	109	61.8739
50	62.4092	80	62.2159	110	61.8599
51	62.4060	81	62.2063	111	61.8458
52	62.4025	82	62.1966	112	61.8315
53	62.3988	83	62.1868	113	61.8172
54	62.3949	84	62.1767	114	61.8027
55	62.3907	85	62.1665	115	61.7880
56	62.3863	86	62.1561	116	61.7733
57	62.3816	87	62.1456	117	61.7584
58	62.3768	88	62.1348	118	61.7434
59	62.3716	89	62.1239	119	61.7284
60	62.3663	90	62.1129	120	61.7132
61	62.3607	91	62.1017	121	61.6978

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CONSOLIDATED CONFAB FABRICATORS

A DIVISION OF BRADEN MANUFACTURING LLC

E

Rosemount Programmed Data

GE DRAWING NUMBER	REV
213A1317	—
FIRST MADE FOR	SHEET 22

12 January, 2006

Emerson Process Management
Rosemount Inc.
8200 Market Blvd
Chanhassen, MN U.S. 55317-9786

EMERSON. Process Management

Calibration Data Sheet Consistent with ISO 10474 2.1 or EN 10204

Customer Information	Manufacturer Information
Name: CONSOLIDATED FABRICATORS INC **PO:** 019307-00	**Sales Order:** 1634624 **Line:** 1

Device Information	Calibration Information
Device Type: Pressure Transmitter **Tag No:** **Serial No:** 0157419 **Model No:** 3095MA2CA0013AA10NBBS5Q4N120 **Module Serial No:** 2886811 **Output:** Linear JOB# 9838	**Factory:** CHANHASSEN, MN, USA **Station Name:** XS30 **Operator ID:** 13687 **Calibration Date:** 1/12/2006 3:37:45PM

Attached Models

0305AC62B11B4L4

Equipment Used

EqNumber:	EqName:
E3-53384	LOAD BOX
E3-54290	MULTIMETER
P3-53733	ELECTRONIC BAROMETER
P3-54244	VACUUM METER

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Calibration Data

DP

Range: 0.00 TO 250.00 InH2O@68degF

% of Range	Applied Pressure	Requested Applied Pressure	Digital Output (InH2O@68 degF)	% Span Error	Pass/Fail
99.994	9.015 PSI	249.98400 InH2O@68degF	249.99350	0.0038	PASS
79.995	7.212 PSI	199.98700 InH2O@68degF	200.00160	0.0058	PASS
59.996	5.409 PSI	149.99100 InH2O@68degF	150.01210	0.0084	PASS
39.997	3.606 PSI	99.99400 InH2O@68degF	100.01410	0.0080	PASS
19.999	1.803 PSI	49.99700 InH2O@68degF	50.01230	0.0061	PASS
0.000	0.000 PSI	0.00000 InH2O@68degF	0.01600	0.0064	PASS

SP

Range: 0.00 TO 800.00 PSI

% of Range	Applied Pressure	Requested Applied Pressure	Digital Output (PSI)	% Span Error	Pass/Fail
100.000	800.000 PSI	800.00000 PSI	800.00380	0.0005	PASS
80.000	640.000 PSI	640.00000 PSI	639.97020	-0.0037	PASS
60.000	479.999 PSI	479.99900 PSI	480.00620	0.0009	PASS
40.000	320.000 PSI	320.00000 PSI	320.03650	0.0046	PASS
20.000	160.000 PSI	160.00000 PSI	159.98860	-0.0014	PASS
0.000	0.000 PSI	0.00000 PSI	0.00300	0.0004	PASS

PT

Range: -150.00 TO 1,500.00 DEG F

% of Range	Applied Resistence	Applied Resistence	Digital Output (DEG F)	Error DEG C	Pass/Fail
100.000	380.330 Ohms	1500.00000 DEG F	1502.17200	2.1720	PASS
80.000	324.000 Ohms	1170.00000 DEG F	1170.59400	0.5940	PASS
60.000	263.800 Ohms	840.00000 DEG F	840.13850	0.1385	PASS
40.000	199.710 Ohms	510.00000 DEG F	509.84940	-0.1506	PASS
20.000	131.740 Ohms	180.00000 DEG F	179.39430	-0.6057	PASS
0.000	59.810 Ohms	-150.00000 DEG F	-149.98410	0.0159	PASS

This is to certify that the listed product meets the applicable Rosemount Specifications. Measuring and test equipment used in the manufacture and inspection of the listed product are traceable to the National Institute of Standards and Technology. The calibration system was designed to meet the intent of ANSI Z540-1-1994.

Tim Layer
Vice-President of Global Quality

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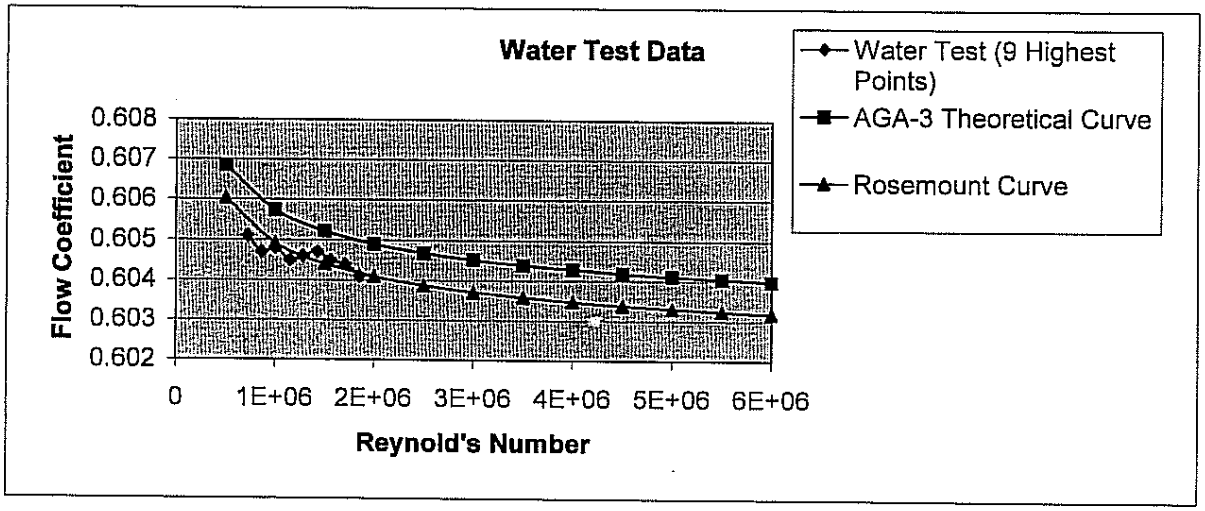
Program for Determining Rosemount 3095 MV Flow Coefficient Curve

9838

9838

	Reynold's Number	Flow Coefficient	AGA Flow Coefficient	Diff	Rd	Corr'd C	Nom C		
INPUT 1									
INPUT 2								Error	0.13%
INPUT 3	1851500	0.6041	0.6050	0.0009	6000000	0.6032	0.6040	Ave Diff=	0.00081
CHECK	1709500	0.6044	0.6051	0.0007	5500000	0.6032	0.6040		
OUTPUT	1560600	0.6045	0.6052	0.0007	5000000	0.6033	0.6041	Min. Gas Flow (#/s)=	5.450
	1427800	0.6047	0.6053	0.0006	4500000	0.6034	0.6042	Max. Gas Flow (#/s)=	22.060
	1282100	0.6046	0.6054	0.0008	4000000	0.6035	0.6043	Fluid Visc (cPoise)=	0.01145
	1150800	0.6045	0.6055	0.0010	3500000	0.6036	0.6044		
	998800	0.6048	0.6057	0.0009	3000000	0.6037	0.6045	Calculating Reynold's Number	
	865600	0.6047	0.6059	0.0012	2500000	0.6039	0.6047	Min. Reynold's # =	1353877
	725700	0.6051	0.6062	0.0011	2000000	0.6041	0.6049	Max. Reynold's # =	5480097
	605100	0.6054	0.6065	0.0011	1500000	0.6044	0.6052		
	464900	0.606	0.6070	0.0010	1000000	0.6049	0.6057		
	323300	0.6071	0.6068	-0.0003	500000	0.6060	0.6068		



Flange Tapped Meter Flow Coefficient
(per AGA-3 (Report))

Water Temp. (F)=		92
Cold Pipe ID (in)=		7.992
Cold Orifice Dia (in)		4.971
Reynold's Number=		1851500
Hot Pipe ID (in)=		7.9938226
Hot Orifice Dia (in)=		4.9721336
Beta=		0.621997
Upstrm=		0.0024248
Dnstrm=		-0.002456
Tap Term=		-3.09E-05
C1(CT)=		0.6022279
C1(FT)=		0.602197
B=		0.1760228
M1=	-5.1938	0
L1=		0.1250966
M2=		0.6618815
A=		0.0175394
C=		0.8060588
e=		2.71828
Flow Coefficient=		0.60498

1	0.000879
1	0.000665
1	0.000667
1	0.000571
1	0.000801
1	0.001038
1	0.000927
1	0.00123
1	0.001098
1	0.001097
1	0.000976
1	-0.00026
12	0.009689
Ave Diff=	0.00081

92	92	92	92	92	92	92	92	92	92	92	92
5.0E+05	4.6E+05	6.1E+05	7.3E+05	8.7E+05	1.0E+06	1.2E+06	1.3E+06	1.4E+06	1.6E+06	1.7E+06	1.9E+06
7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992
4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971
7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938
4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721

0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220
0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024
-0.0024	-0.0024	-0.0024	-0.0024	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022
0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022
0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760
0	0	0	0	0	0	0	0	0	0	0	0
0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251
0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619
0.0500	0.0530	0.0429	0.0371	0.0322	0.0287	0.0257	0.0235	0.0216	0.0201	0.0187	0.0175
1.2746	1.3074	1.1922	1.1188	1.0518	1.0004	0.9520	0.9167	0.8828	0.8558	0.8289	0.8061
2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183
0.6068	0.6070	0.6065	0.6062	0.6059	0.6057	0.6055	0.6054	0.6053	0.6052	0.6051	0.6050
92	92	92	92	92	92	92	92	92	92	92	92
5.0E+05	1.0E+06	1.5E+06	2.0E+06	2.5E+06	3.0E+06	3.5E+06	4.0E+06	4.5E+06	5.0E+06	5.5E+06	6.0E+06
7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992	7.992
4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971	4.971
7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938	7.9938
4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721	4.9721
0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220	0.6220
0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024
-0.0024	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025	-0.0025
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022
0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022	0.6022
0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760	0.1760
0	0	0	0	0	0	0	0	0	0	0	0
0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251	0.1251
0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619	0.6619
0.0500	0.0287	0.0208	0.0165	0.0138	0.0119	0.0105	0.0095	0.0086	0.0079	0.0073	0.0068
1.2746	1.0000	0.8677	0.7846	0.7256	0.6808	0.6450	0.6156	0.5907	0.5693	0.5506	0.5341
2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183	2.7183
0.6068	0.6057	0.6052	0.6049	0.6047	0.6045	0.6044	0.6043	0.6042	0.6041	0.6040	0.6040

GE DRAWING NUMBER	REV
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Transmitter Report

Rosemount 3095MV

Client:	GE	**Project:**	CFI 216A1236P001
Unit:	GR1007/180893111	**Location:**	VN502250

General Information

Tag:

Descriptor:

Transmitter

Manufacturer:	Rosemount			
Pressure Transmitter Type:	3095MV			
DP Sensor Range:	-250	to	250	inH2O
SP Sensor Range:	0.500	to	800	psi(gauge)
PT Sensor Range:	-299	to	1510	degF

Body

Process Flange Type:	Spcl
Drain/Vent:	None
Process Flange:	Spcl
Wetted O-ring:	PTFE

Element

Isolating Diaphram:	316 SST
Fill Fluid:	Silicone oil

Output

4-20 mA range(Analog):	0	to	50	lb/s
PV:	Flow Rate	in	lb/s	
SV:	Differential Pressure	in	inH2O	
TV:	Gauge Pressure	in	psi	
4V:	Process Temperature	in	degF	

RTD

RTD Mode:	Normal	
Set Temperature:	68	degF

Flow Configuration

Fluid designation category:	Natural Gas	
Fluid/Type method:	Detail Characterization Method	
Fluid name:	natural gas	
Category:	Orifice Plate	
Primary Element:	Unknown	
DP Flow Low Cut-Off:	0.0200	inH20-68 degF

Primary Element Size

Min Diameter:	4.9710	inches at 68 °F
Material:	316 Stainless Steel	
Meter tube Diameter:	7.9920	inches at 68 °F
Material:	304 Stainless Steel	

GE DRAWING NUMBER	REV
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Operating Conditions

Pressure range:	395.0000	to	475.0000	psig
Temperature range:	65.0000	to	85.0000	°F

Transmitter Report

Rosemount 3095MV

Client:	GE	**Project:**	CFI 216A1236P001
Unit:	GR1007/180893111	**Location:**	VN502250

Standard Conditions

Pressure:	14.7300	psia
Temperature:	60.0000	°F
Atmospheric Pressure:	14.3500	psia

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Fluid Report

Rosemount 3095MV

Client:	GE	**Project:**	CFI 216A1236P001
Unit:	GR1007/180893111	**Location:**	VN502250
Tag:		**Filename:**	CFI_9838_216A1236P001

Fluid Name: Natural Gas

Fluid Type/Method: Detail Characterization Method

Fluid Category: Natural Gas

Density Properties

Reference compressibility: 0.997787

Temperature (°F)	Pressure (psig)	Compressibility	Temperature (°F)	Pressure (psig)	Compressibility
65.000000	395.000000	0.941019	75.000000	445.000000	0.938516
65.000000	405.000000	0.939600	75.000000	455.000000	0.937209
65.000000	415.000000	0.938182	75.000000	465.000000	0.935904
65.000000	425.000000	0.936765	75.000000	475.000000	0.934601
65.000000	435.000000	0.935351	78.333328	395.000000	0.946360
65.000000	445.000000	0.933938	78.333328	405.000000	0.945077
65.000000	455.000000	0.932526	78.333328	415.000000	0.943796
65.000000	465.000000	0.931117	78.333328	425.000000	0.942516
65.000000	475.000000	0.929709	78.333328	435.000000	0.941239
68.333328	395.000000	0.942408	78.333328	445.000000	0.939963
68.333328	405.000000	0.941024	78.333328	455.000000	0.938689
68.333328	415.000000	0.939641	78.333328	465.000000	0.937417
68.333328	425.000000	0.938261	78.333328	475.000000	0.936147
68.333328	435.000000	0.936882	81.666672	395.000000	0.947611
68.333328	445.000000	0.935505	81.666672	405.000000	0.946359
68.333328	455.000000	0.934129	81.666672	415.000000	0.945110
68.333328	465.000000	0.932755	81.666672	425.000000	0.943862
68.333328	475.000000	0.931384	81.666672	435.000000	0.942616
71.666672	395.000000	0.943760	81.666672	445.000000	0.941372
71.666672	405.000000	0.942411	81.666672	455.000000	0.940130
71.666672	415.000000	0.941063	81.666672	465.000000	0.938891
71.666672	425.000000	0.939717	81.666672	475.000000	0.937653
71.666672	435.000000	0.938372	85.000000	395.000000	0.948830
71.666672	445.000000	0.937030	85.000000	405.000000	0.947609
71.666672	455.000000	0.935690	85.000000	415.000000	0.946391
71.666672	465.000000	0.934351	85.000000	425.000000	0.945174
71.666672	475.000000	0.933014	85.000000	435.000000	0.943959
75.000000	395.000000	0.945077	85.000000	445.000000	0.942746
75.000000	405.000000	0.943761	85.000000	455.000000	0.941535
75.000000	415.000000	0.942447	85.000000	465.000000	0.940327
75.000000	425.000000	0.941135	85.000000	475.000000	0.939120
75.000000	435.000000	0.939824			

GE DRAWING NUMBER	REV
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FIRST MADE FOR	SHEET 29

Fluid Report

Rosemount 3095MV

Client:	GE	**Project:**	CFI 216A1236P001
Unit:	GR1007/180893111	**Location:**	VN502250
Tag:		**Filename:**	CFI_9838_216A1236P001

Viscosity Properties

Temperature (°F)	Viscosity (Centipoise)
65.000000	0.010268
71.666672	0.010268
78.333328	0.010268
85.000000	0.010268

Additional Fluid Characteristics

Isentropic Exponent:	1.300000
Molecular Weight:	16.952753

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Primary Element Report

Rosemount 3095MV

Client:	GE	**Project:**	CFI 216A1236P001
Unit:	GR1007/180893111	**Location:**	VN502250
Tag:		**Filename:**	CFI_9838_216A1236P001

Primary Element: Calibrated Cd:Flange, Corner, D & D/2 Taps : ISO 5167(2002)
Category: Orifice Plate

Primary Element Sizing

Minimum Diameter: 4.9710 inches at 68.0000 °F
Material: 316 Stainless Steel

Meter Tube Sizing

Diameter (Pipe I.D.): 7.9920 inches at 68.0000 °F
Material: 304 Stainless Steel

Calibrated Discharge Coefficient

Primary Element Name: 9839

Reynolds Number	Cd
6000000	0.603200
5500000	0.603200
5000000	0.603300
4500000	0.603400
4000000	0.603500
3500000	0.603600
3000000	0.603700
2500000	0.603900
2000000	0.604100
1500000	0.604400
1000000	0.604900
500000	0.606000

GE DRAWING NUMBER	REV
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Natural Gas Report

Rosemount 3095MV

Client:	GE	**Project:**	CFI 216A1236P001
Unit:	GR1007/180893111	**Location:**	VN502250
Tag:		**Filename:**	CFI_9838_216A1236P001

Fluid Name: Natural Gas

Fluid Type/Method: Detail Characterization Method

Fluid Category: Natural Gas

Density Properties

Component	Mole %
Methane (CH4)	93.6891
Nitrogen (N2)	0.2850
Carbon Dioxide (CO2)	3.5610
Ethane (C2H6)	1.5830
Propane (C3H8)	0.3690
Water (H2O)	0.0000
Hydrogen Sulfide (H2S)	0.0000
Hydrogen (H2)	0.0000
Carbon Monoxide (CO)	0.0000
Oxygen (O2)	0.0000
i-Butane (C4H10)	0.1440
n-Butane (C4H10)	0.1260
i-Pentane (C5H12)	0.0820
n-Pentane (C5H12)	0.0410
n-Hexane (C6H14)	0.0930
n-Heptane (C7H16)	0.0250
n-Octane (C8H18)	0.0020
n-Nonane (C9H20)	0.0000
n-Decane (C10H22)	0.0000
Helium (He)	0.0000
Argon (Ar)	0.0000

GE DRAWING NUMBER	REV
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GEII Performance Evaluation Services

Extrapolation Of Discharge Coefficient from Calibration Data

Output:

Test CD	**0.0000**
Offset from AGA	**-0.0008**

Orifice Data

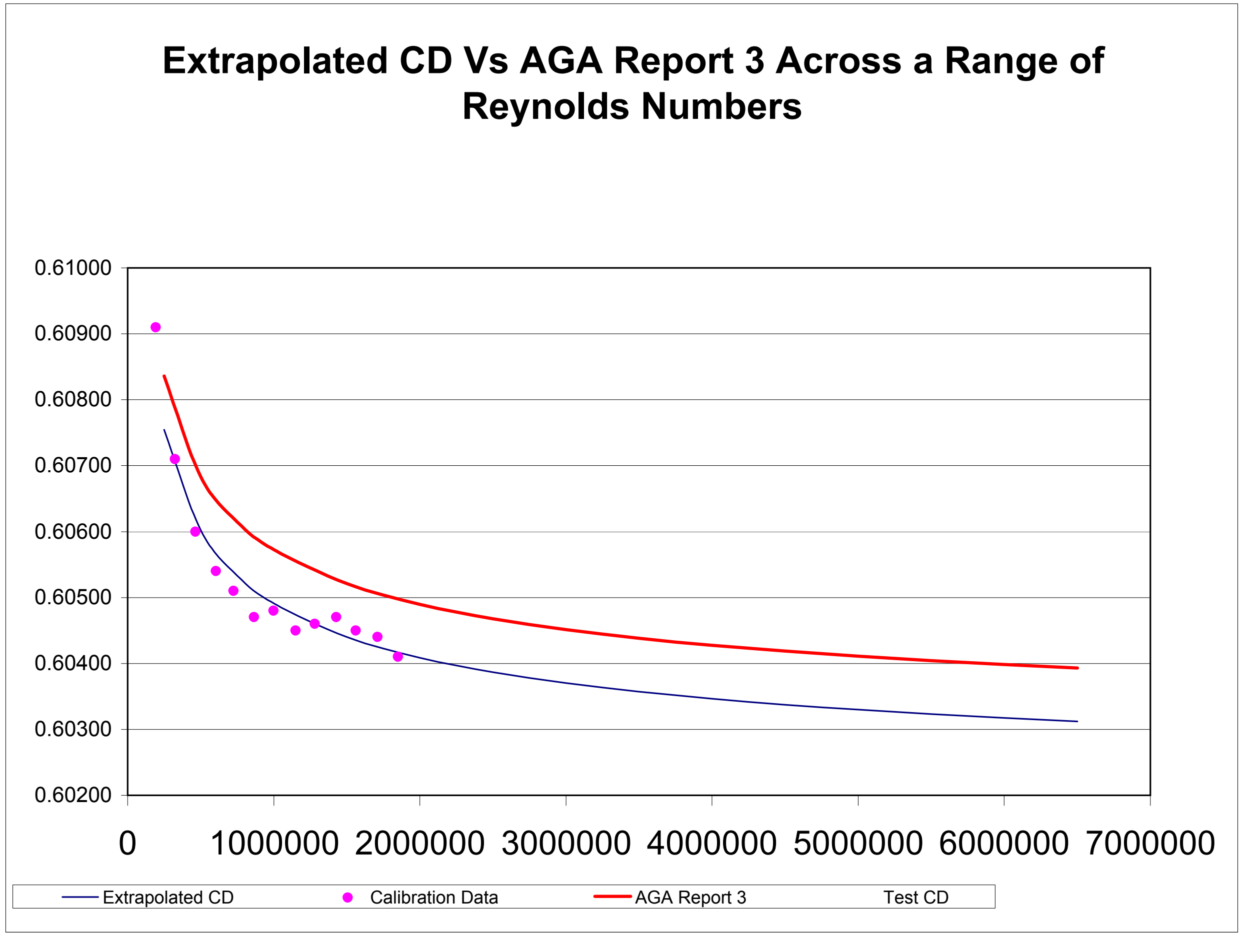
Pipe Diameter	7.9920
Orifice Diameter	4.9710
Test Re	

Measurement Information

Calibration Fluid Flowing Temp	92
Pipe Alpha	0.00000925
Measured Pipe Temp	68
Orifice Alpha	0.00000925
Measured Orifice Temp	68

Data from Calibration Report

Pipe RE	Coef
1851500	0.6041
1709500	0.6044
1560600	0.6045
1427800	0.6047
1282100	0.6046
1150800	0.6045
998800	0.6048
865600	0.6047
725700	0.6051
605100	0.6054
464900	0.6060
323300	0.6071
192700	0.6091



Thermal Expansion Coefficients for Common Orifice Materials

Material	α
304 & 613 Stainless	0.00000925
Monel	0.00000795
Carbon Steel	0.0000062

Unit Number: **1**
Turbine Serial Number: **298593**

Test Point: 1
TermoBarrancas

Appendix H: Test Procedure Deviation Forms

TOPIC: Test Deviations to Performance Test Procedure for TERMOBARRANCAS, C.A. SITE LOCATION
Date: DATE

Description of Deviation:	Disposition:	Documented by
EXAMPLE: All but 3 penetrations in the inlet duct were used by station instrumentation. Hence, 4 precision RTDs could not be installed in the inlet duct.	EXAMPLE: It was agreed to use 3 RTDs to measure the average inlet temperature. This has no effect on the test results but does increase the measurement uncertainty.	J. Doe

____

GE Representative

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TERMOBARRANCAS, C.A. Representative

Appendix I: References

1.	GEK 107551A	Standard Field Performance Testing Procedures
2.	ASME PTC 22-1997	Performance Test Code on Gas Turbines
3.	AGA Report No. 3 Part I-1990	Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids
4.	AGA Report No. 8 – 1994	Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases
5.	ASTM D1945 (2001)	Standard Test Method for Analysis of Natural Gas by Gas Chromatography

Appendix J: Performance Guarantee excerpt from purchase contract

3. Performance Data

NOTE: Latest revisions of Reference Documents mentioned herein can be found in the Reference Documents section of this proposal

3.1 Guarantees

3.1.1 Guaranteed Performance on Natural Gas Fuel

Measurement	Value
Net Output (base)	161160 kW
Net Heat rate (base)	9944 kJ/kWh

3.1.1.1 Basis for Unit Performance Guarantee

The performance guarantees listed above are based on the scope of equipment supply as defined in the proposal and as stated for the following operating conditions and parameters:

Measurement	Value
Elevation	203 m
Ambient Pressure	0.9898 bar
Ambient temperature	26.5°C
Relative humidity	79%
Inlet system pressure drop	76.2 mm H2O
Exhaust system pressure	139.7 mm H2O
Natural gas fuel heating value (LHV)	45183 kJ/kg
Combustion system type	DLN

- The above Performance Guarantee is based on the following natural gas analysis assumption:

Fuel	Volume
CH4	93.69 %
C2H6	1.58 %
C3H8	0.37 %
C4H10	0.27%
C5H12	0.12%
C6H14+	0.09%

C7H16	0.03 %
N2	0.28 %
CO2	3.56 %
Total	100.0 %
Fuel gas temp. @ base load	28.0ºC above fuel water and hydrocarbon dew point

- Performance is measured at the generator terminals and includes allowances for excitation power.
- Guarantees are based on new and clean condition of the gas turbine. New and clean condition is defined by the following:
  - The gas turbine has less than 100 fired hours
  - The gas turbine has been subjected to an offline water/detergent wash within 25 hours of the performance test
  - A GE representative has been allowed access to the inlet to inspect the condition of the compressor inlet surfaces
- Tests to demonstrate guaranteed performance shall be conducted in accordance with the testing document stated in the Reference Documents chapter of this proposal and per the Commercial Terms and Conditions of this offer.
- Performance curves for both the turbine and generator are included the Performance Curves chapter of this proposal. From these curves it is possible to determine estimated performance at ambient temperature, percent loads, and barometric conditions differing from those listed in the above Design Basis table. These performance curves are provided for reference only and do not constitute performance guarantees at any conditions other than those listed in the performance guarantee section. An additional set of site-specific curves may be issued at the time of the performance test to which the measured performance from test conditions will be corrected.
- The natural gas fuel is in compliance with Seller's Gas Fuel Specification GEI-41040.

- Gas Fuel Supply Pressure Requirements:

Parameter	Value
Maximum Mechanical Design Pressure psig	550
Maximum Operating Pressure psig	475
Minimum Operating Pressure psig	395
Maximum Temperature at Minimum Pressure, ºC	25

Please refer to the Fuel Supply Pressure Requirements section located in the Customer Scope of Supply tab of this proposal for further details.

- Gas turbine is operating at steady state baseload.
- Compressor air extraction from the gas turbine = 0.

3.1.2 Emissions Guarantees

Natural Gas Fuel:

Measurement	Guaranteed Value	Load Range %	Ambient Range ºC
NOx @ 15% O2 (ppmvd)	25	100	22.78 – 32.78
CO (ppmvd)	15	100	22.78 – 32.78

3.1.2.1 Basis for Unit Emissions Guarantees

- For emission compliance, refer to U. S. Standard Field Testing Procedure for Emission Compliance, GEK 28172 included in the Reference Documents chapter of this proposal.
- The natural gas fuel is in compliance with Seller's Gas Fuel Specification, GEI 41040.
- Testing and system adjustments are conducted in accordance with GEK 28172, Standard Field Testing Procedure for Emissions Compliance included in the Reference Documents chapter of this proposal.
- The NOx emission testing and related oxygen testing are conducted in accordance with U.S. EPA Method 20, as modified by GEK 28172, section B.
- The CO emission testing is conducted in accordance with U.S. EPA Method 10, as modified by GEK 28172, section C.

- Sampling and analysis of the unburned hydrocarbons must be on a wet basis to avoid condensing out of the higher hydrocarbons. The UHC emission testing is conducted in accordance with U.S. EPA Method 25A, as modified by GEK 28172, section D.

- The VOC emission testing is conducted in accordance with U.S. EPA Method 18, as modified by GEK 28172, section E.

- The PM10, front-half filterable particulate matter emission testing is conducted in accordance with U.S. EPA Method 5, as modified by GEK 28172, section H.

- Emissions are per gas turbine on a one-hour average basis.

- Sulfur emissions are a function of the sulfur present in the incoming air and fuel flows. Since the gas turbine(s) sulfur emissions are solely a function of this sulfur present in the incoming air and fuel, sulfur-based emissions are not guaranteed.

- GE reserves the right to determine the emission rates on a net basis wherein emissions at the gas turbine inlet are subtracted from the measured exhaust emission rate if required to demonstrate guarantee rate.

3.1.3 Acoustics Guarantees

3.1.3.1 Near Field Noise Values

Natural Gas	Base	85 dBA (Average)

The average sound pressure levels (SPL) (re: 20 micropascals) from the indoor and/or outdoor Supplier equipment defined in this proposal, shown in the outline drawing of this proposal, shall not exceed the value stated above, when measured 1 m (3 ft) in the horizontal plane and at an elevation of 1.5 m (5 ft) above the gas turbine operating level and generator operating level (if different) identified on the General Arrangement drawings with the equipment operating at base load in accordance with contract specifications. Walkways and/or platforms that are not easily accessible by stairs are excluded from the above guarantee.

Near field guarantees apply to areas outside along a site-specific Source Envelope(s), determined by a line established 1 meter (3 ft.) from the outermost surface of the equipment defined in the proposal scope of supply (including noise abatement equipment). Depending on the site arrangement and relationship of equipment locations, multiple source envelopes may be designated. (See sample figure below)

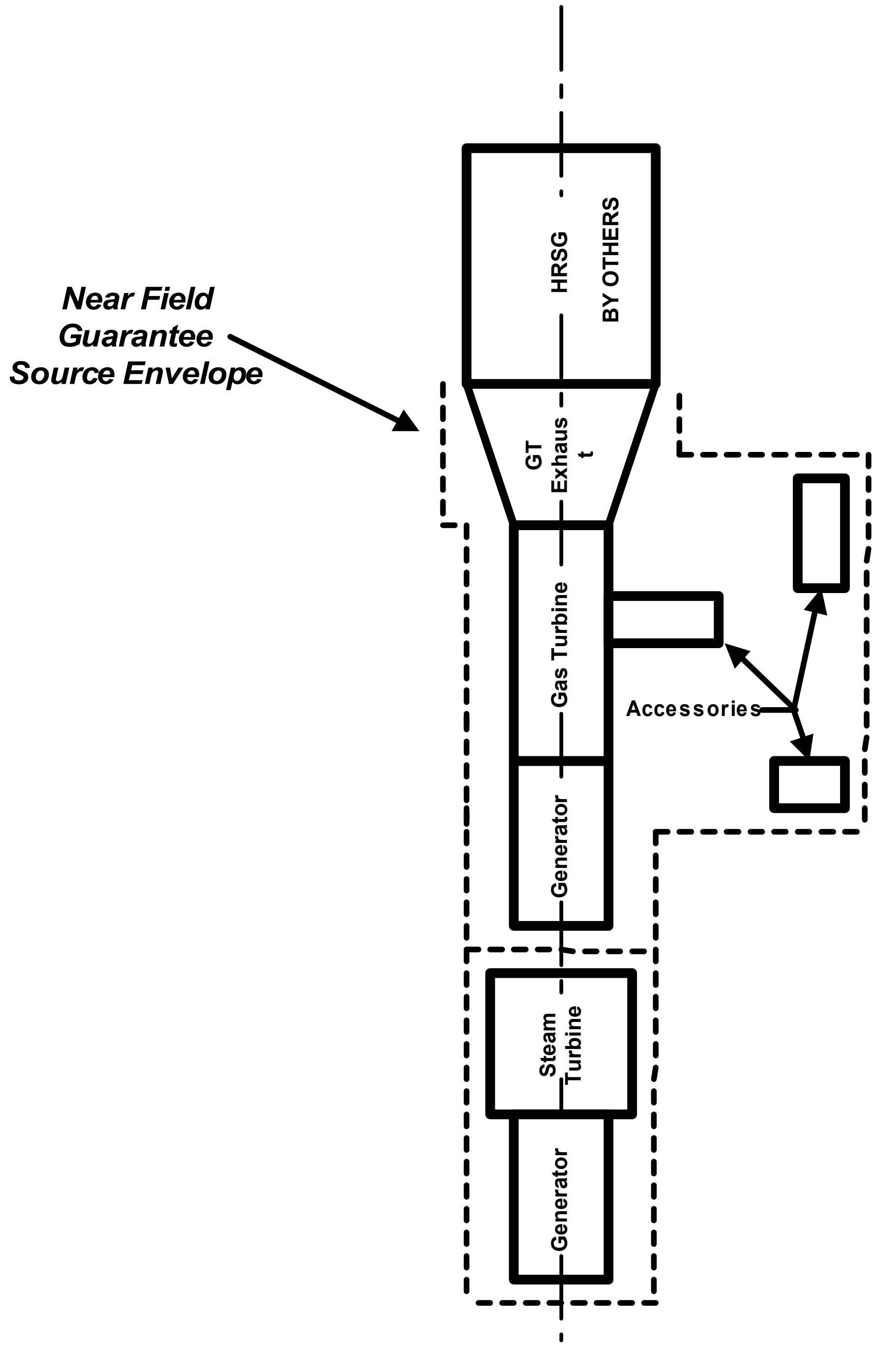

Figure 3.4 - 1

(For reference only. Envelope should include all GE supplied equipment and will be determined by site conditions and layout)

3.1.3.1.1 Basis for Near Field Noise Guarantee

A. The GE supplied equipment will be deemed compliant with the acoustic guarantee if the arithmetic average resulting from measurements taken at agreed upon locations along the source envelope(s), after background and other corrections for environmental influences and test factors have been applied, does not exceed the noise limit(s) specified above. For cases where noise abatement equipment is included to meet the guaranteed sound pressure level, all measurements for compliance verification will be taken outside of the noise abatement equipment.

B. Testing will be conducted in accordance with a project specific test plan agreed to by both the Owner and GE. The test plan must adhere to the requirements listed in the GEK 110392 "Standard Noise Assessment Procedure" included in the Reference Documents section in this proposal. There is no single test standard that adequately addresses acoustic test requirements relating to power generation equipment; therefore the referenced GEK document is a compilation and adaptation of available ISO and ANSI test standards to address acoustic measurement of power facility equipment.

C. Equipment is operated in a new and clean condition when measurements are taken. All access compartments, doors, panels and other temporary openings are fully closed, all silencing hardware is fully installed and all systems designed to be airtight are sealed. Inspection of installation quality will be conducted prior to compliance testing. Identified defects must be corrected prior to compliance testing.

D. Corrections for background noise will be made to the measured SPL as referenced in the GEK 110392 "Standard Noise Assessment Procedure" document. Background noise is defined as the noise measured with all equipment identified in the proposal scope of supply not operating and all other plant equipment in operation. If the above guaranteed SPL is greater than 10 dBA above the measured background noise, no correction to the measured SPL is necessary.

E. Free field conditions must exist at measurement locations. Testing for, and corrections to, a free field condition are per the applicable standards, ISO 3744/46 and/or ANSI/ASME PTC 36 1985.

F. Noises of an interim nature such as steam blowdown valves, filter pulse noise and startup/shutdown/steam turbine bypass activities are not included in the above guarantee.

G. Measurements shall be taken 1 m (3 ft) away from the outermost exterior surfaces of equipment including piping, conduit, framework, barriers, noise abatement equipment and personnel protection devices if provided.

H. Measurements shall not be taken in any location where there is an airflow velocity greater than 1.5 m/s (5 ft/s) including nearby air intakes or exhausts. Outdoor measurements shall not be taken when wind speeds exceed 1.5 m/s (3 mi/hr).

I. Responsibility for measurement and development of the project specific test plan will be stated in the contract. Testing shall be conducted in accordance with GEK 110392 “Standard Noise Assessment Procedure”, included in the Reference Documents section of this proposal. The test plan must be submitted a minimum of 30 days prior to the noise test for review and approval of all parties. If the Owner performs the compliance measurements, GE reserves the right to audit or parallel these measurements.

3.2 Estimated Performance

TERMOBARRANCAS

ESTIMATED PERFORMANCE PG7241 (* guarantee values)

Load Condition		BASE
Exhaust Pressure Loss	mm H2O	121.4
Ambient Temperature	deg C	26.5
Fuel Type		Cust Gas
Fuel LHV	kJ/kg	45,183
Fuel Temperature	deg C	28
Output - Net	kW	161160*
Heat Rate (LHV) - Net	kJ/kWh	9944*
Exhaust Flow	x10^3 kg/hr	1521.3
Exhaust Temperature	deg C	611.7
Exhaust MolWt	kg/kgmol	28.23
Exhaust Energy	GJ/hr	977.2
EMISSIONS		
NOx	ppmvd @ 15% O2	25
CO	ppmvd	15
CO	mg/Nm^3, dry	11.3
UHC	ppmvw	7
VOC	ppmvw	1.4
Particulates	kg/hr	4
(PM10 Front-half Filterable Only)		

EXHAUST ANALYSIS	% VOL.
Argon	0.86
Nitrogen	73.06
Oxygen	12.2
Carbon Dioxide	3.9
Water	9.98

SITE CONDITIONS

Elevation	meter	203
Site Pressure	bar	0.9898
Inlet Loss	mm H2O	76.2
Exhaust Loss	mm H2O	139.7 @ ISO Conditions
Relative Humidity	%	79
Application		Hydrogen-Cooled Generator
Power Factor (lag)		0.85
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Normal (N) is defined at 0 °C and 1.013 bars(a)

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3.3 Generator Performance Specifications

3.3.1 Performance Rating Conditions

Measurement	Value
Elevation	600 ft
Stator insulation	Class F
Rotor insulation	Class F
Hydrogen gas temperature	40°C
Hydrogen pressure	30 psig
Required cooling water flow	1600 gal/min
Required temperature of inlet cooling water	33.2°C rated
Coolant type	100% fresh water
Fouling factor	0.001
Rating and dielectric test standards	ANSI

3.3.2 Performance Rating, Synchronous Generator

Note	Design
Following values based on generator design number	502250G

Measurement	Base
kVA	201200
Power Factor	0.85
kW	171020
rpm	3600
Number of poles	2
Number of phases	3
Frequency (Hz)	60
Voltage	18.0 kV
Amperes	6453
Connection	WYE
Short Circuit Ratio	0.57

Dielectric Tests (between coils and frame, ac voltage for 1 minute)	Value
Armature	37000V
Field	2880V

Excitation (maximum required)	Value
kW	555
Voltage	350

Calculated Generator Reactances (base load)	Value
Xdi	1.81
X'di	0.23
X'dv	0.2
X"dv	0.13
X2v	0.13
X0i	0.11