

ASME PTC 22-2014
(Revision of ASME PTC 22-2005)

Gas Turbines

Performance Test Codes

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**The American Society of
Mechanical Engineers**

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Date of Issuance: December 31, 2014

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NOTICE

All Performance Test Codes must adhere to the requirements of ASME PTC 1, General Instructions. The following information is based on that document and is included here for emphasis and for the convenience of the user of the Code. It is expected that the Code user is fully cognizant of Sections 1 and 3 of ASME PTC 1 and has read them prior to applying this Code.

ASME Performance Test Codes provide test procedures that yield results of the highest level of accuracy consistent with the best engineering knowledge and practice currently available. They were developed by balanced committees representing all concerned interests and specify procedures, instrumentation, equipment-operating requirements, calculation methods, and uncertainty analysis.

When tests are run in accordance with a Code, the test results themselves, without adjustment for uncertainty, yield the best available indication of the actual performance of the tested equipment. ASME Performance Test Codes do not specify means to compare those results to contractual guarantees. Therefore, it is recommended that the parties to a commercial test agree before starting the test and preferably before signing the contract on the method to be used for comparing the test results to the contractual guarantees. It is beyond the scope of any Code to determine or interpret how such comparisons shall be made.

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FOREWORD

The original Performance Test Codes Committee No. 22 was established in 1945 to develop a test code on Gas Turbine Power Plants. This initial Code was published in 1953. Subsequent versions of the Code were published in 1966 and 1985, each time incorporating latest practices in accordance with the directives of PTC 1, General Instructions.

The 1997 version addressed for the first time the issue of measurement uncertainty, and also recognized the significant advances in gas turbine and instrumentation technologies.

The efforts on the 2005 version began during the publication period of the 1997 Code. Its objectives were to develop procedures for comparative (back-to-back, or before and after) testing and for determining exhaust flow and energy for heat recovery applications. The 2005 version incorporated these procedures, as well as updated calculations in many areas to reduce the uncertainty of the results.

Work on the current edition began in 2007. The key objectives of this revision were to correct errors and omissions, provide harmonization with other codes and standards, and provide clarification to the intent of the Code as a result of industry feedback and interpretations to the 2005 version. Some of the most significant changes included incorporating the methodology for determination of gas turbine exhaust energy, flow, and temperature into mandatory sections and a mandatory appendix when these performance results are part of the object of the Code. Similarly, when comparative performance is a test goal, the requirements and guidelines for comparative testing are included in mandatory sections of the Code. As a result of advances in instrumentation, Section 4 was revised to include additional flow metering technology. Section 7 on Test Uncertainty was revised to provide compliance with the methodology for determination of uncertainty used in the revised PTC 19.1, Test Uncertainty and incorporate the most current engineering analysis and experience.

This Code was approved and adopted as an American National Standard on June 9, 2014.

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Proposing Revisions. Revisions are made periodically to the Code to incorporate changes that appear necessary or desirable, as demonstrated by the experience gained from the application of the Code. Approved revisions will be published periodically.

The Committee welcomes proposals for revisions to this Code. Such proposals should be as specific as possible, citing the paragraph number(s), the proposed wording, and a detailed description of the reasons for the proposal, including any pertinent documentation.

Proposing a Case. Cases may be issued for the purpose of providing alternative rules when justified, to permit early implementation of an approved revision when the need is urgent, or to provide rules not covered by existing provisions. Cases are effective immediately upon ASME approval and shall be posted on the ASME Committee Web page.

Requests for Cases shall provide a Statement of Need and Background Information. The request should identify the Code and the paragraph, figure, or table number(s), and be written as a Question and Reply in the same format as existing Cases. Requests for Cases should also indicate the applicable edition(s) of the Code to which the proposed Case applies.

Interpretations. Upon request, the PTC Standards Committee will render an interpretation of any requirement of the Code. Interpretations can only be rendered in response to a written request sent to the Secretary of the PTC Standards Committee at go.asme.org/Inquiry.

The request for an interpretation should be clear and unambiguous. It is further recommended that the inquirer submit his/her request in the following format:

Subject:	Cite the applicable paragraph number(s) and the topic of the inquiry.
Edition:	Cite the applicable edition of the Code for which the interpretation is being requested.
Question:	Phrase the question as a request for an interpretation of a specific requirement suitable for general understanding and use, not as a request for an approval of a proprietary design or situation. The inquirer may also include any plans or drawings that are necessary to explain the question; however, they should not contain proprietary names or information.

Requests that are not in this format may be rewritten in the appropriate format by the Committee prior to being answered, which may inadvertently change the intent of the original request.

ASME procedures provide for reconsideration of any interpretation when or if additional information that might affect an interpretation is available. Further, persons aggrieved by an interpretation may appeal to the cognizant ASME Committee or Subcommittee. ASME does not "approve," "certify," "rate," or "endorse" any item, construction, proprietary device, or activity.

Attending Committee Meetings. The PTC Standards Committee and PTC Committees regularly hold meetings and/or telephone conferences that are open to the public. Persons wishing to attend any meeting and/or telephone conference should contact the Secretary of the PTC Committee. Future Committee meeting dates and locations can be found on the Committee Page at go.asme.org/PTCcommittee.

GAS TURBINES

Section 1 Object and Scope

1-1 OBJECT

This Test Code provides directions and rules for conduct and report of results of thermal performance tests for open cycle gas turbine power plants and gas turbine engines, hereafter referred to as *gas turbines*. The object is to determine the thermal performance of the gas turbine when operating at test conditions, and correcting these test results to Specified Reference Conditions. This Code provides explicit procedures for the determination of the following performance results:

- (a) corrected power
- (b) corrected heat rate (efficiency)
- (c) corrected exhaust flow
- (d) corrected exhaust energy
- (e) corrected exhaust temperature

Tests may be designed to satisfy different goals, including absolute performance and comparative performance.

It is the intent of the Code to provide results with the highest level of accuracy consistent with the best engineering knowledge and practice in the gas turbine industry. In planning the test, an uncertainty analysis must demonstrate that the proposed instrumentation and measurement techniques meet the requirements of the Code.

1-2 SCOPE

This Code provides for the testing of gas turbines supplied with gaseous or liquid fuels (or solid fuels converted to liquid or gas prior to entrance to the gas turbine). Tests of gas turbines with emission control and/or power augmentation devices, such as injection fluids and inlet-conditioning, are included. It may be applied to gas turbines in combined cycle plants or with other heat recovery systems.

This Code provides for comparative (back-to-back) tests designed to verify performance differentials of the gas turbine, primarily for testing before and after modifications, uprates, or overhauls. Improvements to achieve additional performance may include application of

advanced gas path components, modification of combustion system, control scheme changes, increased mass flow, and changes to the inlet and exhaust systems of the gas turbine.

The Code does not apply to the following:

- (a) gas turbines where useful output is other than power to drive a generator or other load device.
- (b) environmental compliance testing for gas turbines for stack emissions and sound levels. Procedures developed by regulatory agencies, ANSI, other ASME PTC Committees, or other equivalent standard, are available to govern the conduct of such testing.
- (c) overall plant power and thermal efficiency of gas turbine combined cycle and cogeneration facilities. Refer to ASME PTC 46 or equivalent standard.
- (d) absolute or comparative performance of specific components of the gas turbine.
- (e) performance of auxiliary systems of the gas turbine power plant, such as inlet cooling devices, fuel gas booster compressors, etc.
- (f) operational demonstration tests and reliability testing.
- (g) itemized performance changes that are the result of multiple actions, such as modifications, repairs, or cleanings (i.e., compressor, inlet air filtration systems, etc.).

1-3 TEST UNCERTAINTY

1-3.1 Absolute Performance Test Uncertainty

For absolute performance tests, this Code establishes a limit for the uncertainty of each required measurement (parameter or variable), and also limits the variation of the critical parameters during the test. The test uncertainty is then calculated in accordance with the procedures defined herein and by ASME PTC 19.1. The procedures include establishing a Code Limit test uncertainty. Both pre- and post-test uncertainty calculations are required.

Users of this Code shall develop their own site- and equipment-specific uncertainty. The overall test uncertainty will be unique for each Code test because of the

differences in the scope of supply, fuels used, turbine sensitivities, instruments selected, and driven equipment characteristics.

1-3.2 Comparative Performance Test Uncertainty

For comparative performance tests, this Code establishes a limit for the uncertainty of the performance result. The test uncertainty is then calculated in accordance with the procedures defined herein and by ASME PTC 19.1. The test uncertainty of the performance result expressed as the uncertainty of the difference shall be no greater than 10% of the expected change in performance. Both pre- and post-test uncertainty calculations are required. For comparative performance testing, unlike absolute level testing, the uncertainty is more complex since the desired result is the difference in performance rather than the absolute level. Difficulty in establishing the sensitivities (which depend on the age of the equipment and the extent of the restoration) must be considered, as well as the selection of instrumentation. Comparative performance between pre- and post-tests will typically result in differential performance values with lower uncertainty than the individual absolute value performance uncertainties, due to partial cancellation of systematic errors.

The parties must also assess the viability of the test, based on the uncertainty as a percentage of the expected differential. The comparative test uncertainty is strongly affected by whether or not the same instrumentation was used for both before and after tests, and by the sensitivities of the unit being tested. Thus the uncertainty values can have considerable variation.

1-4 OTHER REQUIREMENTS AND REFERENCES

The applicable provisions of ASME PTC 1 are a mandatory part of this Code. It should be reviewed and followed when preparing the procedure for a gas turbine test.

ASME PTC 2 defines many of the terms and numerical constants used in this Code. The ASME PTC 19 series, Supplements on Instruments and Apparatus, should be consulted when selecting the instruments used to measure the required test parameters, and when calculating test uncertainties.

This Code relies on many references for test procedures and data, such as ASTM, IEEE, etc. The parties shall agree to use other recognized international sources for these procedures and data, including applicable revisions.

Section 2

Definitions and Descriptions of Terms

2-1 GENERAL

Terms provided in this Section are confined to those for which clarification is considered to improve user's grasp of Code intent.

2-2 DEFINITIONS

absolute performance: performance [power, heat rate (efficiency), exhaust temperature, exhaust flow, and exhaust energy] of the gas turbine at a specific point in time.

auxiliary power: electrical power used in the operation of the gas turbine or elsewhere as defined by the test boundary.

calibration: the process of comparing the response of an instrument to a standard instrument over some measurement range or against a recognized natural physical (intrinsic) constant and adjusting the instrument to match the standard, if appropriate.

field calibration: the process by which calibrations are performed under conditions that are less controlled than the laboratory calibrations with less rigorous measurement and test equipment than provided under a laboratory calibration.

laboratory calibration: the process by which calibrations are performed under very controlled conditions with highly specialized measurement and test equipment that has been calibrated by approved sources and remains traceable to National Institute of Standards and Technology (NIST), a recognized international standard organization, or a recognized natural physical (intrinsic) constant through an unbroken comparisons having defined uncertainties.

Code Limit: the combination of applicable uncertainty limits for each of the measured parameters for that particular configuration and test.

comparative performance: change in performance of the gas turbine expressed as a differential or ratio.

control temperature: temperature or schedule of temperatures determined by the manufacturer that defines one of the operating conditions for the test. This temperature may or may not coincide with temperature of the working fluid exiting the gas turbine. Regardless of measurement location, control temperature is internal to the test boundary.

corrected performance: performance parameter adjusted mathematically to Specified Reference Conditions.

exhaust gas emissions: constituents of the working fluid exiting the gas turbine that may be used to define in part the operating conditions for the test.

exhaust gas energy: energy of the working fluid exiting the gas turbine at a point defined by the test boundary.

exhaust gas flow: flow of the working fluid exiting the gas turbine at a point defined by the test boundary.

exhaust gas temperature: mass weighted average temperature of the working fluid exiting the gas turbine at a point defined by the test boundary.

extraction air: a defined airstream that intentionally leaves the test boundary.

gas turbine: machine that converts thermal energy into mechanical work; it consists of one or several rotating compressors, a thermal device(s) that heats the working fluid, one or several turbines, a control system, and essential auxiliary equipment. Any heat exchangers (excluding exhaust heat recovery exchangers) in the main working fluid circuit are considered to be part of the gas turbine. It includes the gas turbine and all essential equipment necessary for the production of power in a useful form (e.g., electrical, mechanical, or thermal) within the test boundary.

gaseous fuel: mixture of combustibles with or without inerts in which each component is present as a superheated or saturated vapor under conditions of use.

heat input: the flow of fuel(s) multiplied by the higher or lower heating value of the fuel(s).

heat loss: energy quantity that leaves the test boundary outside defined exits.

heat rate: the ratio of the heat input to the power output produced by the gas turbine as measured at the test boundaries. The basis of the value should always be expressed as either lower heating value or higher heating value.

higher heating value (HHV) at constant pressure (gaseous fuels): the heat produced by the combustion of a unit quantity of gaseous fuel(s) at constant pressure under specified conditions. All water vapor formed by the combustion reaction is condensed to the liquid state.

higher heating value (HHV) at constant volume (liquid fuels): the heat produced by the combustion of a unit quantity

of liquid fuel at constant volume under specified conditions, as in an oxygen bomb calorimeter. All water vapor from the combustion reaction is condensed to the liquid state.

injection fluid: nonfuel gaseous or liquid stream that enters the test boundary.

inlet air-conditioning: the devices used to cool or heat the inlet air prior to entry into the gas turbine compressor. The test boundary must clearly state whether the device is inside or outside of the scope of the test.

liquid fuel: mixture of combustibles with or without inerts, which is composed almost entirely of liquid components under conditions of use.

lower heating value (LHV) (liquid or gaseous fuels): the heat produced by combustion of a unit quantity of fuel at conditions such that all of the water in the products remains in the vapor phase. It is calculated from the higher heating value at constant volume for liquid fuel(s), and from the high heating value at constant pressure for gaseous fuel(s).

measurement uncertainty: estimated uncertainty associated with the measurement of a process parameter or variable.

open cycle: working fluid is primarily atmospheric air with heat addition through a direct combustion of fuel.

parameter: a direct measurement; a physical quantity at a location that is determined by a single instrument, or by the average of several measurements of the same physical quantity.

power output: electrical or mechanical output based upon direct measurement at the test boundary.

random error, (ϵ): the portion of total error that varies randomly in repeated measurements of the true value throughout a test process.

Specified Reference Conditions: the values of all the conditions to which the test results are corrected.

systematic error, (β): sometimes called bias; the portion of total error that remains constant in repeated measurements of the true value throughout a test process.

test: group of test runs for which operating conditions may vary.

test boundary: thermodynamic control volume defined by the scope of the test, and for which the mass and energy flows must be determined. Depending on the test, more than one boundary may be applicable. Definition of the test boundary or boundaries is an extremely important visual tool that aids in understanding the scope of test and the required measurements.

test reading: one recording of all required test instrumentation.

test run: group of readings taken over a specific time period over which operating conditions remain constant or nearly so.

test uncertainty: uncertainty associated with a corrected test result.

thermal efficiency: ratio of the power produced to the fuel energy supplied per unit time. Thermal efficiency may be expressed on either a lower heating value or higher heating value basis.

tolerance: a commercial allowance for deviation from contract performance levels.

uncertainty: the interval about the measurement or result that contains the true value for a 95% confidence level.

variable: a quantity that cannot be measured directly, but is calculated from other measured parameters.

verification: a set of operations which establish evidence by calibration or inspection that specified requirements have been met.

2-2.1 Symbols and Subscripts

Symbols used in this Code are listed in Table 2-2.1-1. Subscripts used in this Code are listed in Table 2-2.1-2.

Table 2-2.1-1 Symbols

Symbol	Description	Units	
		U.S. Customary	SI
ACDC	AC to DC conversion efficiency factor	...	...
<i>B</i>	Expanded systematic uncertainty	...	...
<i>C</i>	Orifice discharge coefficient	...	...
<i>C_p</i>	Specific heat capacity at constant pressure	Btu/(lb*°R)	kJ/(kg*K)
CTR	Current transformer marked ratio	...	...
<i>D</i>	Diameter pipe	ft, in.	m, mm
<i>d</i>	Diameter orifice plate	ft, in.	m, mm
ExcLoss	Exciter power	kW	kW
<i>FC</i>	Field current	A	A
<i>FV</i>	Field voltage	V	V
<i>g_c</i>	Conversion constant	lbm-ft/lbf-sec ²	kg-m/N-s ²
<i>H</i>	Percent of hydrogen (H ₂)	...	...
<i>h</i>	Specific enthalpy	Btu/lb	kJ/kg
<i>H°</i>	Exhaust gas enthalpy	Btu/lb	kJ/kg
HHV	Fuel higher heating value	Btu/lb	kJ/kg
<i>HI</i>	Total heat input	Btu/hr	kJ/h
HR	Heat rate	Btu/kW-hr	kJ/kW-h
HV	Fuel heating value	Btu/lb	kJ/kg
<i>I</i>	Current	A	A
<i>k</i>	Isentropic exponent	...	...
LHV	Fuel lower heating value	Btu/lb	kJ/kg
<i>M</i>	Mass flow rate	lbm/hr, lbm/sec	kg/s
MCF	Meter calibration factor	...	...
<i>MF</i>	Mole fraction	...	...
<i>Mo</i>	Molar flow	lbmol/hr	kmol/h
<i>MW</i>	Molecular weight	lb/lbmol	kg/kmol
<i>P</i>	Power	kW, MW	kW, MW
<i>p</i>	Pressure	Psia	bar, MPa
PA	Phase angle	...	...
PF	Power factor	...	...
<i>Q</i>	Energy flow	Btu/hr	kJ/h
<i>q</i>	Volumetric flow rate	ft ³ /hr	m ³ /h
<i>S</i>	Standard deviation	...	...
SH	Sensible heat	Btu/lb	kJ/kg
<i>T</i>	Temperature	°F, °R	°C, K
<i>U</i>	Uncertainty	...	...
<i>V</i>	Voltage	volts	volts
vars	vars for three phases	vars	vars
VTR	Voltage transformer marked ratio	...	...
VTVD	Voltage transformer voltage drop	...	...
watts	Watts for three phases	...	...
<i>WF</i>	Weight fraction	...	...
<i>x</i>	Mole fraction of gas component	...	...
<i>y</i>	Height difference	ft	m
<i>Z</i>	Compressibility factor	...	...

Table 2-2.1-1 Symbols (Cont'd)

Symbol	Description	Units	
		U.S. Customary	SI
α	Shift in the power meter phase angle, coefficient of thermal expansion, or multiplicative correction factor for power	...	...
β	Shift in the current transformer phase angle, ratio of orifice and pipe diameters, multiplicative correction factor for heat rate, or systematic error	...	...
γ	Shift in the voltage transformer phase angle, or multiplicative correction factor for exhaust flow	...	...
$\Delta_f H^\circ$	Heat of formation	Btu/mol	J/mol
ΔP	Differential pressure	psi, in. H ₂ O	Pa, bar
δ	Additive correction factor for exhaust temperature	...	...
ϵ	Multiplicative correction factor for exhaust energy, expansion factor, or random error	...	...
η	Efficiency	...	...
θ	Sensitivity coefficient for uncertainty calculation	...	...
ρ	Density	lbm/ft ³	kg/m ³
τ	Torque	lbf*ft	N*m

Table 2-2.1-2 Subscripts

Subscript	Description
air	Air
atm	Atmospheric
avg	Average calculated
corr	Corrected
exc	Excitation
exh	Exhaust
ext	Extraction
f	Fuel, or fluid
FM	Fuel meter
gas	Gas
gen	Generator
HB	Heat balance
highside	Highside of the transformer
H ₂ O	Water
i	Constituent
Inj	Injection fluid
j	Fuel constituent
k	Non-water exhaust constituent
lowside	Lowside of the transformer
meas	Measured
net	Net
p	Constant pressure
PE	Orifice material
PP	Piping material
R	Result
ref	Reference
sat	Saturated
sen	Sensing line fluid
SL	Supply limit
T	Temperature
th	Thermal
Total	Total
V	Constant volume

Section 3

Guiding Principles

3-1 AGREEMENTS

3-1.1 General Agreements Before the Test

The parties to the test shall agree in writing on the scope of the test. Agreements shall be reached and written on the following:

- (a) objectives of test including specifying the parameters to be determined by the performance test
- (b) the division of responsibilities of each of the parties
- (c) schedule and location for the test to be conducted
- (d) test boundaries identifying inputs and outputs such as the location of compressor inlet and turbine exhaust interface points and identifying measurement locations
- (e) confirmation of Specified Reference Conditions and guarantees
- (f) acceptance criteria for the test results
- (g) test plan including test procedures
- (h) test final report format and contents
- (i) selection of alternative instruments and/or calculation procedures not covered by this Code
- (j) Code Limit test uncertainty
- (k) degradation, if applicable

These and all mutual agreements shall be approved, prior to the testing, by authorized signatures of all parties to the test.

3-1.2 Design, Construction, and Start-Up Considerations

The following recommendations should be considered concerning the requirements of instrumentation accuracy, calibration, recalibration documentation, and location of permanent plant and temporary test instrumentation, that will be used for performance testing.

- (a) The location of permanent plant and temporary test instrumentation that will be used for performance testing should consider the impact on test uncertainty and be reviewed with respect to the requirements of Section 4. This includes specifying the appropriate laboratory calibration and obtaining all laboratory calibration reports, certifications, or calibration results for all instrumentation used for the test, as applicable. The ability to do post-test recalibrations or verifications is required as described in this Code. As design progresses and installation is completed the location of this instrumentation will need to be reviewed to determine if there

are any issues with regard to their final orientation and/or location.

- (b) The connections and spool sections required for temporary test instrumentation such as pressure connections, thermowells, spool sections for flow meters, and electrical metering tie-ins for temporary test instrumentation should be incorporated into the plant design. Flow conditioners are recommended for differential pressure type and turbine flow meters. The flow element installation should occur after acid cleaning and/or flushes.

(c) The applicability of the instrumentation should be considered for measuring the desired test process value. Note in the test plan whether the recorded value is an instantaneous or average value. Note also the historical logging capabilities necessary for the testing.

- (d) Access and isolation capability is required for inspection, calibration, and any temporary instrument installation and removal.

(e) Review the quantity of devices and instrument ports available at each location to reduce uncertainty and provide contingency data acquisition. An example is using two single-element thermocouples or one dual-element thermocouple to measure critical temperatures.

- (f) Lay out the instrument loops to minimize measurement error. Precautions are listed in Section 4 of this Code. If instrument transformers are used, adequate wire size should be used to reduce voltage drops and a neutral cable should be provided to enable accurate three-phase watt metering.

(g) The design should include the ability to duplicate critical test measurements. This allows a validation of process values and includes a contingency plan for test measurements. A separate device should be identified to corroborate and backup a test measurement.

- (h) A review should be performed of the water leg correction necessary for accurate process variable measurement.

(i) Use the same instrumentation in accordance with this Code for comparative performance between pre- and post-test results to achieve the minimum uncertainty. The systematic error for instruments used for both tests, without being disturbed or recalibrated, will approach zero for most cases.

3-1.3 Responsibilities of Parties

The parties to the test shall agree on individual responsibilities required to prepare, conduct, analyze, and report the test in accordance with this Code. This

includes designation of a test coordinator who will be responsible for the execution of the test in accordance with the test requirements and will coordinate the setting of required operating conditions with the plant operations staff. Procurement and installation responsibilities for test equipment shall also be defined. Representatives from each of the parties to the test should be designated to observe the test, agree upon revisions to the test requirements during the test, and confirm that it was conducted in accordance with the test requirements.

3-1.4 Schedule and Location of Test Activities

A test schedule shall be prepared that should include the sequence of events and anticipated time of test, notification of the parties to the test, test plan preparations, test preparation and conduct, and preparation of the report of results. All parties shall be notified and mutually agree on the location of the test that will be either the actual plant site or at a test facility where control and ambient conditions are acceptable to the parties to the test.

3-1.5 Test Boundary and Required Measurements

The test boundary is an accounting concept used to define the streams that shall be measured to determine performance. All energy streams that cross the boundary shall be identified.

3-1.5.1 Generic Test Boundaries. The two typical test boundaries are

(a) the hardware scope boundary for determination of corrected performance [power output and heat rate (efficiency)] of the equipment within.

(b) the energy balance boundary for calculation of the exhaust gas mass flow and energy. This boundary is typically much tighter around the gas turbine unit.

For a particular test, the parties to the test shall establish the test boundaries specific to their machine configuration and testing requirements. Typical boundary locations are shown in Fig. 3-1.5.1-1.

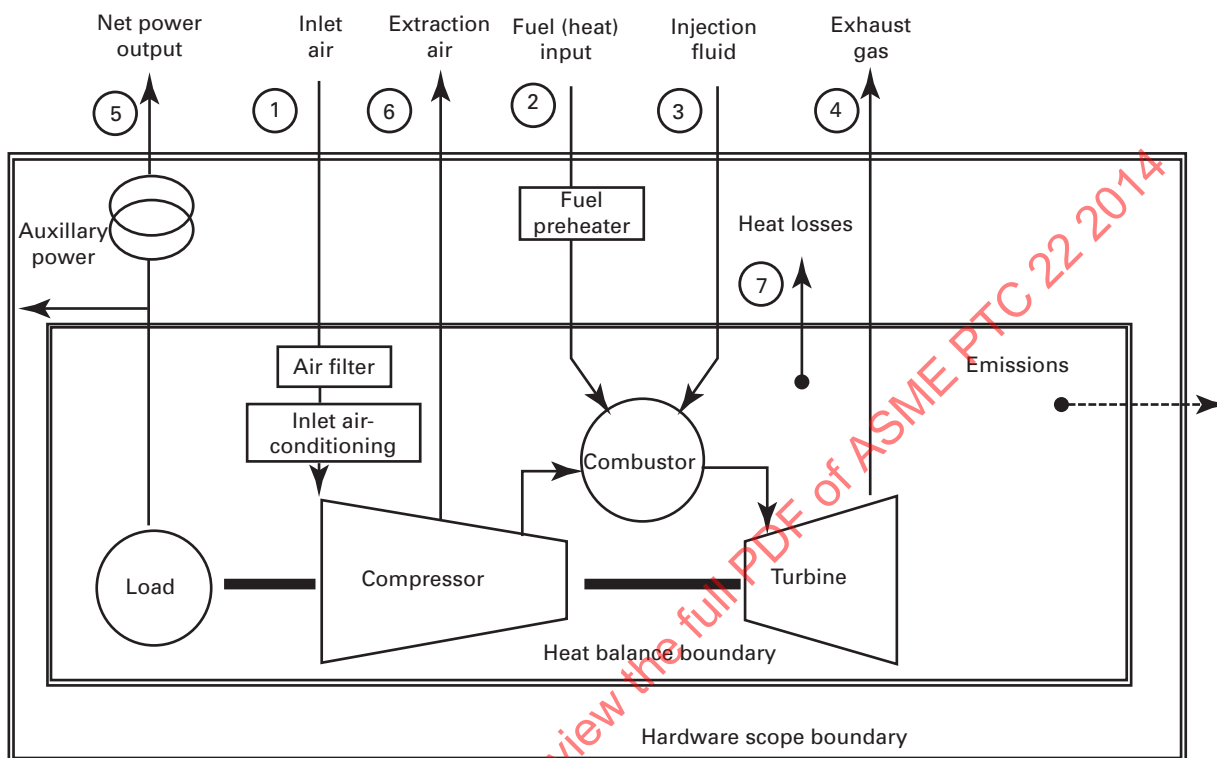
3-1.5.2 Required Measurements. Flexibility is required in defining the test boundary since it is dependent on a particular gas turbine design. In general, measurements or determinations are required for the streams noted in Table 3-1.5.2-1.

3-1.6 Test Plan

A detailed test plan shall be prepared prior to conducting a Code test. It will document agreements on all issues affecting the conduct of the test and provide detailed procedures for performing the test. It shall reflect any contract requirements that pertain to the test objectives, guarantees, the schedule of test activities, responsibilities of the parties to the test, test procedures, report of results, and provide any needed clarifications of contract issues. The test plan shall be approved, prior to the

testing, by authorized signatures of all parties to the test. The following are included in the test plan:

- (a) Test acceptance criteria for test completion
- (b) Specified Reference Conditions and guarantees
- (c) Defined test boundaries identifying inputs and outputs and measurements locations
- (d) Complete pretest uncertainty analysis, with systematic uncertainties established for each measurement
- (e) Specific type, location, and calibration requirements for all instrumentation and measurement systems
- (f) Method for establishing stabilization prior to test and maintaining constancy of load and other test conditions for the test
- (g) Fuel sample collection, handling, method of analysis, collection frequency, provision of duplicate samples for each party, and identification of testing laboratories to be used for fuel analyses
- (h) Allowable range of fuel conditions, including constituents and heating value
- (i) Required operating disposition or accounting for all internal thermal energy and auxiliary power consumers having a material effect on test results
- (j) Required levels of equipment cleanliness and inspection procedures
- (k) Control curves or control algorithms used to set the normal operating limit
- (l) Control parameters and allowable deviations of these parameters during the test
- (m) Procedure for recording test readings and observations
- (n) Number of test runs and durations of each run
- (o) Test loads and rotating speeds at which the test is to be conducted
- (p) Frequency of data acquisition, data acceptance and rejection criteria
- (q) The method for combining test runs to calculate the final test results
- (r) Numerical values, curves or algorithms for corrections and adjustments to be applied to test determinations when tests are conducted under conditions differing from the specified conditions
- (s) Procedures to account for performance degradation, if applicable
- (t) Sample calculations or detailed procedures specifying test run data reduction and calculation and correction of test results to Specified Reference Conditions
- (u) The requirements for data storage, document retention, data and test report distribution
- (v) Method for agreeing and documenting any modification to test plan

Fig. 3-1.5.1-1 Generic Test Boundaries**GENERAL NOTES:**

- Streams 1, 2, 3, 4, 5, and 6 required to determine power and heat rate calculations.
- Streams 1, 2, 3, 4, 5, 6, and 7 required to determine exhaust flow, energy, and temperature calculations.
- Emissions stream information is not required for either calculation.
- Agreement required on location of inlet air temperature measurement.

Table 3-1.5.2-1 Required Measurements

Energy Stream	Power and Heat Rate	Exhaust Flow, Energy, and Temperature
1 Inlet air	Temperature, pressure, humidity	Temperature, pressure, humidity
2 Fuel	Flow, temperature, pressure, composition	Flow, temperature, pressure, composition
3 Injection fluid	Flow, temperature, pressure, composition	Flow, temperature, pressure, composition
4 Exhaust gas	Temperature, pressure	Temperature
5 Power	Power output, power factor, shaft speed	Power output, power factor, shaft speed
6 Extraction air	Flow, temperature, pressure	Flow, temperature
7 Heat losses	...	Flow, temperature
[Note (1)]		

GENERAL NOTE: Determinations of *emissions* are outside the scope of this Code, and as such, no emission limitations or required measurements are specified. However, since emissions limits may have an effect on results, the Test Plan shall specify emission levels or limits, as required operating conditions for the test.

NOTE:

- The measurements of heat losses from generators, lube oil coolers, turbine enclosures, rotor air coolers, etc., where it crosses the test boundary is only necessary for exhaust flow or energy test. Estimated values may be used in lieu of actual measurements.

3-2 PREPARATIONS FOR TEST

3-2.1 Preliminary to Test

All parties to the test shall be given timely notification, as defined by prior agreement, to allow them the necessary time to respond and to prepare personnel, equipment, or documentation. Updated information shall be provided, as it becomes known.

3-2.2 Pretest Records

Dimensions and physical conditions of parts of the gas turbine required for calculations or other test purposes shall be determined and recorded prior to the test. Serial numbers and data from nameplates should be recorded to identify the gas turbine and auxiliary equipment tested. All instrumentation for the test shall be identified, and model and serial numbers recorded.

Documentation shall be provided for verification of algorithms, constants, scaling, calibration corrections, offsets, base points, and conversions to document the as-tested condition.

3-2.3 Preservation of Instrument Uncertainty

Instrumentation used for data collection shall be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can either be permanent plant instrumentation or temporary test instrumentation.

Multiple instruments should be used as needed to reduce overall test uncertainty. The frequency of data collection is dependent on the particular measurement and the duration of the test. To the extent practical, multiple readings should be collected to minimize the random error impact on the post-test uncertainty analysis. The use of automated data acquisition systems is recommended to facilitate acquiring sufficient data.

Calibration or adequate checks of all instruments prior to the test shall be carried out, and those records and calibration reports shall be made available. Following the test, verification is required for those instruments that present an observed inconsistency.

3-2.4 Equipment Inspection and Cleanliness

Prior to conducting a test, the cleanliness and condition of the equipment shall be determined by inspection of equipment or review of operational records, or both, and witnessed by all parties. Cleaning should be completed prior to the test and equipment cleanliness agreed upon.

The gas turbine should be checked to ensure that equipment and subsystems are installed and operating in accordance with their design parameters.

It should be noted that all gas turbines are subject to performance degradation over time at differing rates depending on fuels used, air and water quality, methods of dispatch, and care in operation and maintenance of the gas turbines. It is recommended that there be an

agreement by the parties to the test as to the definition of what constitutes a "new and clean" period for the gas turbine and then the agreed application method of any additional correction for performance degradation.

3-2.5 Preliminary Operation and Adjustment

Before starting the test, the gas turbine shall be operated for sufficient time to demonstrate that there is acceptable mechanical operation and stable control and that the operating variables are within the maximum permissible variation shown in Table 3-3.5-1. Verification shall be made that the gas turbine is operating in accordance with the control curve or control algorithm provided by the manufacturer. During this period, instruments shall be checked.

3-2.6 Preliminary Testing

Preliminary testing should be conducted sufficiently in advance of the start of the overall performance test to allow time to calculate preliminary results, make final adjustments, and modify the test requirements and/or test equipment. Results from the preliminary testing should be calculated and reviewed to identify any problems with the quantity and quality of measured data.

It is recommended that an energy balance calculation such as in Mandatory Appendix I be performed as part of the preliminary test to determine the exhaust flow. Suggested methods for checking confidence in exhaust flow results include reviewing one or more of the following:

- (a) Design exhaust flow
- (b) HRSG heat balance
- (c) O₂ calculated versus O₂ measured at the stack
- (d) CO₂ calculated versus CO₂ measured at the stack
- (e) Measured exhaust flow from traverses of exhaust gas

3-2.7 Pretest Considerations for Comparative Testing

3-2.7.1 The parties will have to agree on how the test results will be corrected. It may be appropriate to correct post-modification performance to conditions of the pre-modification test since the manufacturer will usually provide a new description of sensitivity factors for the post-modification condition. Testing over an ambient temperature range in both the pre- and post-tests may provide additional basis for correcting results to a common reference condition although extreme care must be taken in the interpretation of this type of test result. In any case it would be advantageous to conduct both tests at nearly the same ambient conditions.

3-2.7.2 It is common to do restorative action in multiple parts of the gas turbine package while it is in an outage period. Special cleaning of the compressor and replacement of inlet filters or damaged gas parts

are examples of restorative action. The parties to a comparative test need to recognize the value of this additional restorative work and how it may be factored into the final results.

3-2.7.3 Testing should be conducted just prior to shutdown for the outage and immediately following startup of the gas turbine at the conclusion of the outage. It is recommended that the pre-modification test be conducted following a compressor wash. The time frame for the test following such a wash is to be agreed to by all parties.

3-3 CONDUCT OF TEST

3-3.1 Specified Reference Conditions

These conditions are defined by the guarantees or object of the test and they form the baseline for the performance corrections. Every effort should be made to run the test as close to Specified Reference Conditions as possible, in order to minimize the effect of corrections.

3-3.2 Starting and Stopping Tests and Test Runs

The test coordinator is responsible for ensuring that all data collection begins at the agreed-upon start of the test, and that all parties to the test are informed of the starting time.

3-3.2.1 Starting Criteria. Prior to starting the performance test, the following conditions shall be satisfied:

(a) *Verification.* Check configuration of equipment and instrumentation noting any deficiencies in equipment or procedures, and the disposition for testing has been reached in accordance with the test requirements, including

- (1) equipment operation and method of control
- (2) availability of consistent fuel within the allowable limits of the fuel specification (by analysis as soon as practicable preceding the test)
- (3) gas turbine operation within the bounds of the performance correction curves, algorithms, or programs
- (4) equipment operation within allowable values, e.g., manufacturer and emissions limits
- (5) equipment tuning completed and documented with a printout of the control constants for baseline performance for inclusion in the final report
- (6) operating conditions will meet the requirements of para. 3-3.5.

(b) *Stabilization.* Before starting the test, the gas turbine shall be run until stable conditions have been established. Stability will be achieved when continuous monitoring indicates the readings have been within the maximum permissible variation established by the manufacturer.

(c) *Data Collection.* Data acquisition system(s) functioning, and test personnel in place and ready to collect samples or record data.

3-3.2.2 Stopping Criteria. Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied (see para. 3-3.4). The test coordinator shall verify that modes of operation during test, specified in para. 3-3.3, have been satisfied. The test coordinator may extend or terminate the test if the requirements are not met.

3-3.3 Operation Prior To and During Tests

All equipment necessary for normal and sustained operation at the specified conditions shall be operated during the test or accounted for in the corrections. Intermittent operation of equipment within the test boundary should be accounted for in a manner agreeable to all parties.

3-3.3.1 Operating Mode. The gas turbine shall be operated in a manner consistent with the basis of design or guarantee, and in a manner that will permit correction from test operating conditions to Specified Reference Conditions. The gas turbine operating mode shall be in accordance with the bounds of the correction curves provided prior to commencement of the test. It is mandatory that the control constants and inputs affecting turbine performance be recorded during the test.

3-3.3.2 Auxiliary Equipment Operation. Equipment that is necessary for operation or that would normally be required for the gas turbine to operate at Specified Reference Conditions shall be operating or accounted for in determining auxiliary power loads. Intermittent auxiliary loads shall also be accounted for in an equitable manner and applied to the power consumption. Examples of intermittent loads are heaters and heat tracing.

3-3.3.3 Inlet Air-Conditioning (Evaporative Coolers, Chillers, Foggers, Heaters). The decision to include air-conditioning equipment in operation during a performance test is the choice of the parties to the test and should be part of the agreement in writing. The performance testing guidelines in this Code address solely the performance of the gas turbine. When testing with inlet air-conditioning in service, the ambient air conditions shall be within the equipment operational requirements. The parties to the test shall agree on acceptable ambient conditions during a performance test. If it is required to test with the inlet air-conditioning in operation, it is strongly recommended that at least one run be performed with the inlet air-conditioning out of service before a performance run with the inlet air-conditioning in service.

3-3.3.4 Adjustments Prior To and During Tests. Prior to the start of the actual test run, adjustments are permitted provided that stabilization as defined in para. 3-3.2.1(b) is established. Once the test run has started, no adjustments are permitted except by agreement of all the parties to the test.

Table 3-3.5-1 Maximum Permissible Variations in Operating Conditions

Variable	Sample Standard Deviation
Power output (electrical)	0.65%
Torque	0.65%
Barometric pressure	0.16%
Inlet air temperature	1.3°F (0.7°C)
Fuel flow	0.65%
Rotating speed	0.33%

3-3.4 Duration of Test Run and Frequency of Readings

The duration of a test run and the frequency of the readings shall be selected to provide a reliable average of the readings. A 30-min test run is recommended to be in compliance with Table 3-3.5-1 and to meet the uncertainty requirements of this Code. A test can be a single 30-min run or the average of a series of runs, each being separately corrected, then averaged. While this Code does not require multiple runs, the advantages of multiple runs should be recognized as providing a means for valid rejection of questionable test runs, reducing random uncertainty and to verify the repeatability of results.

3-3.5 Maximum Permissible Variations in Operating Conditions

The calculated standard deviation of the data sample shall not exceed the values given in Table 3-3.5-1. If operating conditions vary during any test run beyond the limits prescribed in Table 3-3.5-1, the results of the test run shall be discarded.

For inlet air temperature, the limits are given as absolute standard deviation of the sample calculated as:

$$S_N = \sqrt{\left(\frac{1}{N-1}\right) \sum_{i=1}^N (x_i - \bar{x})^2}$$

where

$$\bar{x} = \frac{1}{N} \sum_{i=1}^N x_i$$

For all other variables, the limit is given as the relative standard deviation of the sample calculated as:

$$S_N = \frac{\sqrt{\left(\frac{1}{N-1}\right) \sum_{i=1}^N (x_i - \bar{x})^2}}{\bar{x}}$$

where

$$\bar{x} = \frac{1}{N} \sum_{i=1}^N x_i$$

3-4 TEST RECORDS

3-4.1 Test Readings

To the extent possible, test readings shall be recorded on a data acquisition system. A complete set of unaltered data acquisition sheets and recorded charts, electronic media or facsimiles thereof, shall become the property of each party to the test at the end of the test. The observations shall include the date and time of day. They shall be the actual readings without application of any corrections. The log sheets and all recorded charts constitute a complete record.

3-4.2 Direct Readings

Direct manual readings of instruments are to be recorded at uniform frequent intervals during a test. It is preferable to observe simultaneously all instruments at the same intervals.

3-4.3 Certified Data

It is recommended that data considered to be especially important be confirmed by a second observer.

3-4.4 Test Log

Every event connected with the progress of a test, however unimportant it may appear at the time, should be recorded on the test log sheets together with the time of occurrence and the name of the observer. Particular care should be taken to record any adjustments made to any equipment under test, whether made during a run or between runs. The reasons for each adjustment shall be stated in the test records. This information shall be included in the final report.

3-4.5 Test Recording Errors

Manual data shall be recorded in ink. In case of error in a recorded observation, a line shall be drawn in ink through the incorrect entry, the correct reading is to be recorded in ink and initialed above the incorrect entry, and an explanation entered in the proper place in the test records. A comparison of these observations should be made as soon as possible and any discrepancies reconciled before the end of the test.

3-5 TEST VALIDITY

3-5.1 Validity of Results

If, during the conduct of a test or during the subsequent analysis or interpretation of the observed data, an inconsistency is found that affects the validity of the results, the parties should make every reasonable effort to adjust or eliminate the inconsistency by mutual agreement. Failure to reach such agreement will constitute a rejection of the run or test.

3-5.2 Reporting of Results

In all cases, the test results shall be reported

- (a) as calculated from the test observations, with only instrument calibration adjustments having been applied
- (b) as corrected for deviations of the test condition from the Specified Reference Conditions

3-5.3 Causes for Rejection of Readings

Upon completion of test or during the test itself, the test data shall be reviewed to determine if any data should be rejected prior to the calculation of test results. Should serious inconsistencies which affect the results be detected, the run shall be invalidated completely, or it may be invalidated only in part if the affected part is at the beginning or at the end of the run. Refer to ASME PTC 19.1 for data rejection criteria.

3-6 UNCERTAINTY

3-6.1 Objectives

The application of uncertainty analysis to a Code test has four objectives. It

- (a) demonstrates compliance of the test procedure with the uncertainty requirements of the Code
- (b) reduces the risk of making an erroneous decision when evaluating the results
- (c) identifies the contribution of each measurement to the overall uncertainty
- (d) provides a mechanism for improving the quality of the test

3-6.2 Uncertainty Calculations

This Code provides a test procedure that produces results with the lowest practical uncertainties. However, no measurement is without error, and the uncertainty of each measurement should be evaluated by the parties. All uncertainty values that have been determined and agreed upon shall be included in the report (see Section 6). Calculations shown in Section 7 are in accordance with ASME PTC 19.1.

3-6.3 Differences in Uncertainties

This Code specifies procedures for typical acceptance type tests for power output and heat rate (efficiency); energy balance tests for exhaust flow, energy, and/or temperature; and comparative tests for later uprates and modifications. The uncertainty calculation method for each type is different, and Section 7 provides an outline of the procedure, sample calculations, and guidance on the application of the analysis.

3-6.4 Uncertainty Analyses

3-6.4.1 Absolute Performance Tests. For absolute performance tests it is not possible to define a single value of uncertainty in order to be designated a Code

test. The test uncertainty is a function of the number of components included in the gas turbine or power plant, the sensitivity of that turbine to the ambient and other corrections that shall be applied to determine its performance at the Specified Reference Conditions, the type of fuel used, and the ability to measure the power output of the driven equipment. The Code defines uncertainty limits for each of the measured parameters; the combination of the applicable limits will determine the Code Limit for that particular configuration and test.

This Code requires the procedures specified in paras. 3-6.4.1.1 through 3-6.4.1.3 for establishing test uncertainties that qualify as Code tests for an absolute performance test goal.

3-6.4.1.1 A pretest uncertainty analysis shall be performed so that the test can be designed to meet Code requirements. Calculate a maximum uncertainty by using the Code Limit for each measurement (from Table 4-1.2.1-1) along with the appropriate sensitivity coefficients for the turbine being tested. This will establish the Code Limit test uncertainty.

Due to the significant influence of inlet air temperature on test results, and the variation of this sensitivity over the ambient temperature range, it is recommended that Code Limits be established for several inlet air temperatures, or range of temperatures, so that the final post-test uncertainty can be compared directly to a Code Limit test uncertainty at or near the test inlet air temperature.

3-6.4.1.2 The parties shall then select the number and type of instrument(s) for each parameter that will result in an uncertainty equal to or less than the required Code uncertainty. This should provide some margin below the Code Limit to allow for unexpected deviations during the test, as determined in the post-test analysis.

3-6.4.1.3 A post-test uncertainty analysis shall also be performed to reveal the actual quality of the test. If the post-test analysis shows that the uncertainty of any measurement exceeds the Code Limit, but the exceeded measurement(s) do not result in an overall test uncertainty greater than the Code Limit from para. 3-6.4.1, the test should be considered valid. A post-test result that exceeds the Code Limit will require the parties to decide on acceptance or rejection of the test.

3-6.4.2 Comparative Performance Tests. For comparative performance tests this Code establishes a limit for the uncertainty of the performance result as described in subsection 7-4. The test uncertainty of the performance result expressed as the uncertainty of the difference shall be no greater than 10% of the expected change in performance. In this case the difference between two tests is of interest, and the uncertainty calculation method will not be the same as for para. 3-6.4.1. Both pre- and post-test uncertainty calculations are required. For comparative testing, the parties

shall agree beforehand whether a test can be designed with an uncertainty that is significantly lower than the expected performance benefit. Experience has shown that as-tested uncertainty can be a value as large, or larger, than the performance benefit to be verified resulting in an inconclusive test. In addition, the parties should realize that a cost/benefit analysis of the modification and its comparative test should determine the scope, cost, and required accuracy of the test.

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Section 4

Instruments and Methods of Measurement

4-1 GENERAL REQUIREMENTS

4-1.1 Introduction

This Section presents the mandatory requirements for instrumentation selection and application. The Instruments and Apparatus Supplement (ASME PTC 19 Series) outlines the governing requirements for all ASME performance testing. This Code will refer to the pertinent ASME PTC 19 Code for each type of measuring device. New devices and methods may be employed in lieu of any instrumentation recommended in this Code as they become available, provided that they meet the maximum allowable uncertainty limits specified herein. U.S. Customary units are primary and the SI units are secondary and shown in parentheses. However, any other consistent set of units may be used.

4-1.2 Maximum Uncertainties

4-1.2.1 Absolute Test Uncertainty. This Code identifies specific uncertainty limits that shall be met for each test measurement. Table 4-1.2.1-1 summarizes these maximum allowable uncertainties for absolute performance tests. These mandatory uncertainty limits represent the total uncertainty of each particular measurement including all systematic (which include spatial) and random effects. These values are to be compared to the actual uncertainty for each measurement individually prior to multiplying by the relative sensitivity factors to calculate an overall test uncertainty for the tested parameter [power, heat rate (efficiency), exhaust flow, exhaust energy, or exhaust temperature]. If the uncertainties in this table are met, the test shall be deemed a valid Code test with respect to meeting measurement uncertainty requirements. These uncertainties may be achieved by the methods described in this Section 4 or by other means mutually acceptable by the parties to the test.

4-1.2.2 Comparative Test Uncertainty. This Code specifies a limit for the uncertainty of the performance result and, unlike an absolute performance test, does not specify uncertainty limits for each test measurement.

Agreement must be reached on the type of instrumentation (existing station instrumentation, test grade instrumentation, and/or calibrated to known standards or not) that will be used for the test. The use of plant grade instruments becomes possible in a comparative test due to the potential for reduced effect of systematic error in the uncertainty of performance differences. The

Table 4-1.2.1-1 Maximum Allowable Measurement Uncertainties

Parameter or Variable	Uncertainty
AC power	0.25%
Auxiliary power	5%
DC power	0.5%
Torque	1.5%
Speed	0.1%
Time	0.05%
Inlet air temperature	1°F (0.6°C)
Barometric pressure	0.075%
Humidity: Wet bulb, or	3°F (2°C)
RH from meter	2%
Extraction/injection flows (water, steam, N_2 , rotor cool)	2%
Extraction/injection temperature	5°F (3°C)
Gas fuel heat input [Note (1)]	0.75%
Oil fuel heat input [Note (1)]	0.65%
Gas fuel temperature (for sensible heat calculation)	3°F (2°C)
Oil fuel temperature (for sensible heat calculation)	3°F (2°C)
Inlet total pressure drop	10%
Exhaust static pressure drop	10%
Exhaust temperature (Mandatory Appendix I)	10°F (6°C)

NOTE:

- (1) For guidance in evaluation the uncertainties of the various measurements required for Heat Input, refer to the appropriate paragraphs in Sections 4 and 7.

reduced effect of systematic error is achieved by using the same instruments in both the pre-modification and post-modification tests, provided also that the systematic errors are known to remain constant in both pre- and post-tests.

In some instruments systematic errors may not remain constant. Drift and sensitivity to ambient conditions may be reasons for changing systematic error. To overcome this change in systematic error, it may be necessary to upgrade some instruments prior to pretest. Recalibration or other maintenance of instruments during the outage would be a cause for systematic error to change and should be avoided. In the event the calibration drift is expected to be unacceptable, a recalibration should be considered utilizing the same calibration techniques and reference standards as prior to the pretest to reduce the

effect of the systematic error below that which would occur as a result of the calibration drift. Care must be taken with instruments that will be removed during the outage that they be replaced and used in the same manner in which they were used in the pretest.

4-1.3 Instrument Calibration and Verification

4-1.3.1 Calibration. Calibration is the set of operations which establish, under specified conditions, the relationship between values indicated by a measuring instrument or measuring system, and the corresponding reference standard or known values derived from the reference standard. The result of a calibration permits the estimation of errors of indication of the measuring instrument, measuring system, or the assignment of values to marks on arbitrary scales. The result of a calibration is sometimes expressed as a calibration factor, or as a series of calibration factors in the form of a calibration curve. Calibrations shall be performed in a controlled environment to the extent necessary to ensure valid results. Due consideration shall be given to temperature, humidity, lighting, vibration, dust control, cleanliness, electromagnetic interference, and other factors affecting the calibration. Where pertinent, these factors shall be monitored and recorded, and, as applicable, compensating corrections shall be applied to calibration results obtained in an environment which departs from acceptable conditions. Calibrations performed in accordance with this Code are categorized as either laboratory or field calibrations.

4-1.3.1.1 Laboratory Calibration. Laboratory calibrations shall be performed in strict compliance with established policy, requirements, and objectives of a laboratory's quality assurance program. Consideration must be taken to ensure proper space, lighting, and environmental conditions such as temperature, humidity, ventilation, and low noise and vibration levels.

4-1.3.1.2 Field Calibration. Adequate measures shall be taken to ensure that the necessary calibration status of reference standards is maintained during transportation and while on-site. The response of the reference standards to environmental changes or other relevant parameters shall be known and documented. Field calibration measurement and test equipment requires calibration by approved sources that remain traceable to NIST, a recognized national or international standard organization, or a recognized natural physical (intrinsic) constant through unbroken comparisons having defined uncertainties. Field calibration achievable uncertainties can normally be expected to be larger than laboratory calibrations due to allowances for aspects such as the environment at the place of calibration and other possible adverse effects such as those caused by transportation of the calibration equipment.

4-1.3.2 Verification. Verification provides a means for checking that the deviations between values indicated by a measuring instrument and corresponding known values are consistently smaller than the limits of the permissible error defined in a standard, regulation, or specification particular to the management of the measuring device. The result of the verification leads to a decision either to restore to service, or to perform adjustments, or to repair, or to downgrade, or to declare obsolete.

Verification techniques include field calibrations, non-destructive inspections, intercomparison of redundant instruments, check of transmitter zeros, and energy stream accounting practices. Nondestructive inspections include, but are not limited to, atmospheric pressure observations on absolute pressure transmitters, field checks including visual inspection, and no load readings on power meters. Intercomparisons include, but are not limited to, water or electronic bath checks on temperature measurement devices and reconciliations on redundant instruments. Energy stream accounting practices include, but are not limited to, mass, heat, and energy balance computations. The applicable field verification requirements shall be judged based on the unique requirements of each setup. As appropriate, manufacturer's recommendations and the Instruments and Apparatus Supplements to ASME Performance Test Codes should be referenced for further field verification techniques.

4-1.3.3 Reference Standards. Reference standards are generally of the highest metrological quality from which the measurements made at that location are derived. Reference standards include all measurement and test equipment and reference materials that have a direct bearing on the traceability and accuracy of calibrations. Reference standards shall be routinely calibrated in a manner that provides traceability to NIST, a recognized international or national standard organization, or defined natural physical (intrinsic) constants and have accuracy, stability, range, and resolution for the intended use. They shall be maintained for proper calibration, handling, and usage in strict compliance with a calibration laboratory quality program. When it is necessary to utilize reference standards for field calibrations, adequate measures shall be taken to ensure that the necessary calibration status is maintained during transportation and while on-site. The integrity of reference standards shall be verified by proficiency testing or interlaboratory comparisons. All reference standards should be calibrated as specified by the manufacturer or other frequency as the user has data to support extension of the calibration period. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The collective uncertainty of reference standards shall be known and the reference standards should be selected such that the collective uncertainty of the standards used in the calibration contributes less than 25% to the overall calibration uncertainty. The overall calibration uncertainty of the calibrated instrument shall be determined at a 95% confidence level. A reference standard with a higher uncertainty may be employed if the uncertainty of the reference standard combined with the random uncertainty of the instrument being calibrated is less than the uncertainty requirement of the instrument. For example, for some kinds of flow metering, the 25% rule cannot be met.

4-1.3.4 Environmental Conditions. Calibration of instruments should be performed in a manner that considers the conditions under which the instrument will be used to make the test measurements. As it is often not practical or possible to perform calibrations under replicated environmental conditions, additional elemental error sources should be identified and estimated error source considerations should be given to all ambient conditions which may significantly affect the measurement uncertainty.

4-1.3.5 Instrument Ranges and Calibration. The number of calibration points depends upon the magnitude of the measurement's sensitivity factor relative to the tested parameter. The calibration should bracket the expected measurement values as close as possible. All instruments should be calibrated such that the expected values are approached from a higher value as well as a lower value. This approach will minimize hysteresis effects. Test instruments should be calibrated at two points more than the order of calibration curve fit. Instruments with variable ranges of operations must be calibrated at each range that might be used during the test.

Instruments used to measure variables not directly input into test calculations can be checked in place with two or more instruments measuring the variable with respect to the same location or can be calibrated against a previous calibrated instrument. The calibration of the instrument is sufficient at one point in the expected range of operation.

4-1.3.6 Timing of Calibration. Calibrations should take place as close to the test date as possible. The Code does not mandate a period of time between the initial calibration, the test period and the recalibration. Equipment manufacturers' requirements and indications should be used as a basis for determination of the optimum time interval needed to keep the calibration drift to a minimum.

The Code recommends conducting a post-test instrument calibration if the recorded data indicates a possibility of instrument error. The post-test checking should

include at least a loop calibration, as defined below, or a site verification using an additional instrument.

4-1.3.7 Calibration Drift. Calibration drift is defined in the calibration correction as a percent of reading. When a post-test calibration indicates the drift is less than the instrument bias uncertainty, the drift is considered acceptable and the pretest calibration is used as the basis for determining the test results. Occasionally the instrument calibration drift is unacceptable. Should the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable. Calibration drift results from many sources including instrument malfunction, transportation, installation, or removal of the test instrument. Should unacceptable calibration drift occur, engineering judgment must be used to determine whether the initial calibration or the recalibration is correct. Below are some practices that lead to the application of good engineering judgment.

(a) When instrumentation is transported to the test site between the calibration and the test period, a single point check prior to and following the test period can isolate when the drift may have occurred. Examples of this check include vented pressure transmitters, equalized ΔP transmitters, no load on power meters, and ice point temperature instrument checks.

(b) In locations where redundant instrumentation is employed, calibration drift should be analyzed to determine which calibration data (the initial or recalibration) produces better agreement between redundant instruments.

(c) Consult the equipment manufacturer about potential problems if such potential is suspected.

4-1.3.8 Loop Calibration. All test instruments should be loop-calibrated when practicable. Loop calibration involves the calibration of the test instrument through the test signal conditioning equipment. This is normally accomplished by pairing the instrument and the signal conditioner prior to calibration, then calibrating both at the same time. When this is done, the instrument and signal conditioner must remain paired for the loop calibration to remain valid.

When a loop calibration is not possible, the instrument and signal conditioner may be calibrated separately. The instrument is calibrated using a known process and a high accuracy signal conditioner. The signal conditioner is calibrated by applying a known input signal generated by a precision signal generator. When this method is used, the total measurement uncertainty is the combination of the instrument and signal conditioner uncertainties. The combined uncertainty of both the instrument and signal conditioner must still meet the measurement system accuracy requirements described herein.

4-1.3.9 Quality Assurance Program. Each calibration laboratory must have in place a quality assurance program. This program is a method of documentation where the following information can be found:

- (a) calibration procedures
- (b) calibration technician training
- (c) standard calibration records
- (d) standard calibration schedule
- (e) instrument calibration histories

The quality assurance program should be designed to ensure that the laboratory standards are calibrated as required. The program also ensures that properly trained technicians calibrate the equipment in the correct manner.

All parties to the test should be allowed access to the calibration facility as the instruments are calibrated. The quality assurance program should also be made available during the visit.

4-1.4 Data Collection and Handling

4-1.4.1 Data Collection and Calculation Systems.

The data collection system should be carried out in accordance with accepted practice and procedures as discussed in ASME PTC 19.22. A data collection system should be designed to accept multiple instrument inputs and be able to sample and record data from all of the instruments within one minute. The data collection systems should be time synchronized to provide consistent time based data sampling and recording.

The data calculation system should have the ability to average each input collected during the test and calculate test results based on the averaged results. The system should also calculate standard deviation and coefficient of variance for each instrument. The system should have the ability to locate and eliminate spurious data from the average. The system should also have the ability to plot the test data and each instrument reading over time to look for trends and outliers.

4-1.4.2 Data Management. Signal inputs from the instruments should be stored to permit post test data correction for application of new calibration corrections. The engineering units for each instrument along with the calculated results should be stored for reporting and future reference. Prior to leaving the test site all test data should be stored in removable media (such as floppy disks, CDs, and/or hard copy printouts) in case collection system equipment is damaged during transport. It is always recommended to leave a copy of all data at the site or to transport it by alternate means (i.e., hand carry originals, mail copies).

Some test programs may require some data to be recorded manually. The data sheets should each identify

the data point number and time, test site location, date, and name of the person recording.

4-1.4.3 Design of Data Collection Systems. With advances in computer technology, data collection system configurations have a great deal of flexibility. These can consist of a centralized processing unit or distributed processing to multiple plant locations. Each measurement loop must be designed with the ability to be loop calibrated separately, and so that it can individually be checked for continuity and power supply, if applicable, to trace problems during equipment setup and checkout. Each instrument cable should be designed with a shield around the conductor, and the shield should be grounded on one end to drain any stray induced currents.

When considering the accuracy of a measurement, the accuracy of the entire measurement loop must be considered. This includes the instrument and the signal conditioning loop or process. Ideally, when an instrument is calibrated it should be connected to the position on the data collection system that will be employed during the test. Should this be impractical, each piece of equipment in the measurement loop should be individually calibrated. Separate pieces of equipment include current sources, volt meters, electronic ice baths, and resistors in the measurement loop. If the system is not loop calibrated prior to the test, the parties to the test should be allowed to spot check the measurement loop using a signal generator to satisfy that the combined inaccuracy of the measurement loop is within the expected value.

The Code does not prohibit the use of the plant measurement and control system for a test. However, the system must meet the requirements of this Section. Some cautions are mentioned below.

(a) Plant measurement and control systems typically do not calculate flows in a rigorous manner. Often the flow is merely based on a simple ratio relationship with some compensation factors. Flow calculations for a Code test should be in accordance with the applicable methods described in this Section.

(b) Often the plant systems do not have the ability to apply calibration correction electronically. The output of some instrumentation like thermocouples cannot be modified so electronic calibration is necessary.

(c) Some plant systems do not allow the raw instrument signal to be displayed or stored prior to conditioning. This raw signal must be available in order to check the signal conditioning for error.

(d) Distributed control systems typically only report changes in a variable when it exceeds a preset threshold (or deadband) value. The threshold value must be low enough so that all data signals sent to the distributed control system during a test are reported and stored to a sufficient precision level.

4-2 PRESSURE MEASUREMENT

4-2.1 General

All pressure measurements should be carried out in accordance with ASME PTC 19.2. Calibrated transmitters, calibrated transducers, manometers, deadweight gages or calibrated elastic gages shall be used for reading pressures.

Pressure instruments should be installed with an isolation valve at the end of the sensing line upstream of the instrument. The line should be vented before the instrument installation. For steam service, a sufficient time should be allowed to form a water leg in the sensing line before any reading is taken.

4-2.2 Pressure Instruments

4-2.2.1 Transmitters and Transducers

4-2.2.1.1 It is recommended that electronic transmitters and transducers be used for the low-uncertainty measurements to minimize random error.

4-2.2.1.2 Two redundant transmitters are recommended for quality readings.

4-2.2.1.3 Prior to calibration, the pressure transducer range may need to be altered to better match the process. Some pressure transducers have the capability of changing the range once the transmitter is installed. All transmitters must be calibrated at each range to be used during the test period.

4-2.2.1.4 Pressure transmitters should be temperature compensated. If temperature compensation is not available, the ambient temperature at the measurement location during the test period must be compared to the temperature during calibration to allow compensation or to determine if the decrease in accuracy is acceptable.

4-2.2.1.5 Transmitters should be installed in the same orientation they are calibrated. Digital signals are preferred between the transmitters and recorders to eliminate the digital-to-analog and analog-to-digital conversions and to preclude signal interference. All analog signal cables must have a grounded shield to drain any induced currents from nearby electrical equipment. All analog signal cables are to be installed as much away as possible from EMF producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

4-2.2.2 Manometers. Manometers should be of the vertical U-tube or single leg type. A bore of $\frac{5}{16}$ in. (7.94 mm) or more is required. In a single-leg manometer, means should be available for adjusting the zero of the scale while the instrument is in use. Manometers shall be selected such that the scale length and the fluid density permit reading to the uncertainty required by this Code, per Table 4-1.2.1-1.

4-2.2.3 Elastic Gages. Bourdon gages or other elastic gages may be used for measurement of pressure greater than 20 psig (1.38 bar) provided that they are calibrated with a deadweight gage before and after test. The temperature at the gage during calibration shall be within 20°F (11°C) of the average temperature during the test. Elastic gages shall be selected such that the scale diameter and graduations permit reading to the uncertainty required by this Code, per Table 4-1.2.1-1.

4-2.3 Typical Gas Turbine Measurement Parameters

4-2.3.1 Barometric Pressure. Absolute pressure transmitters or electronic cells are recommended for sensing barometric pressure. Two barometers are required. The barometers shall be located outdoors in a stable environment. The barometers shall be positioned upright (to be the same as when calibrated) at the same elevation as the gas turbine shaft centerline. The elevation of the barometer (or a photo recording its location) shall be included in the test report.

4-2.3.2 Inlet Total Pressure. Inlet pressure is the absolute total pressure at the mutually agreed upon inlet interface. Unless agreed otherwise, inlet pressure is considered to be atmospheric barometric pressure. Total pressure readings at the gas turbine inlet may be taken at multiple centers of equal areas using Kiel probes; i.e., shrouded Pitot tubes. If it is not possible to acquire total pressure readings at the gas turbine inlet due to physical arrangement, the total pressure may be computed using calculated velocity and the average of at least two separate static pressure readings from locations equally spaced around the gas turbine inlet. The total pressure is then

$$P_{\text{total}} = (\text{Air Density})(\text{Velocity})^2/2g_c + \text{Static Pressure} \quad (4-2.1)$$

where g_c is the conversion constant, the proportionality constant relating mass, and force.

When the bellmouth throat is outfitted with pressure indication, the pressure should be recorded, for baseline flow information, unless agreed otherwise.

4-2.3.3 Static Pressure in Ducts. Static pressure in ducts shall be the average of the readings at a minimum of three stations equally spaced around the duct in the same plane, and each read separately. Where duct walls are smooth and parallel, static pressure taps are preferred to pressure probes. The diameter of the static tap hole shall not exceed $\frac{1}{16}$ in. (1.59 mm). The length of the static hole shall have a minimum length of 2.5 times the tap hole diameter and a maximum length of 6 times the tap hole diameter. Where the duct walls are not suitable for pressure taps because of irregularities in shape, static pressure probes (e.g., pancake probes or guide plates) may be used instead. Care shall be taken to assure that static pressure probes are oriented along

flow streamlines and are not located in regions of steep pressure gradients.

4-2.3.4 Compressor Discharge Pressure/Combustion Chamber Pressure. For units that use the subject pressure as part of the fuel control algorithm, the compressor discharge pressure being used for control shall be recorded, along with a test instrument for verification.

4-2.3.5 Exhaust Pressure. Exhaust pressure is the static pressure at the turbine exhaust duct plus barometric pressure. For method of measurement, refer to para. 4-2.3.3 on static pressure in ducts.

The exhaust pressure shall be measured at the exhaust connection or at a mutually agreed interface point. This point is usually at the limit of supply of the gas turbine manufacturer. Any equipment installed downstream of this point will result in backpressure which must be considered in the performance test results. Adjustment for any difference in this measured value and the Specified Reference Conditions must be made using the correction factors. Any velocity component of the exhaust pressure at this interface point is to be considered as lost, the same as would occur if the gas turbine were exhausting to the atmosphere at this point.

4-2.3.6 Injection Fluid Pressure. Where steam or water injection is utilized, static pressure should be measured at the flow element on the upstream side of the flow element.

4-2.3.7 Gas Fuel Pressure. For gas fuel applications, static gas fuel pressure shall be measured at the flow element on the upstream side of the flow element.

4-2.3.8 Differential Pressure (as for Fuel Flow).

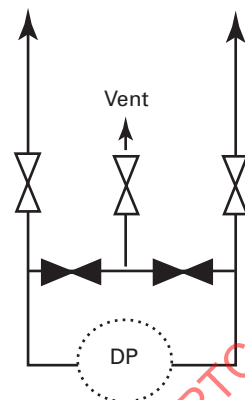
When fuel flow is measured with a differential pressure device (nozzle or orifice), two differential pressure instruments are required. The differential pressure shall be recorded (and not just the calculated flow) so the flow calculation can be verified.

Differential pressure transmitters shall be installed using a five-way manifold as shown in Fig. 4-2.3.8-1. This manifold is required rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve, a frequent source of error. Two three-way manifolds are acceptable, providing it has been verified that there is no leakage past the equalizing valve of each differential pressure transmitter.

Once the instrument is installed in the field, at the expected test process line static pressure the differential pressure shall be equalized and a zero value read. This zero bias must be subtracted from the test-measured differential pressure or if applicable the differential pressure instrument trimmed to minimize the effects of the process static line pressure and mounting position.

During test preparations or during the test, the vent must be checked to ensure the equalizing valves are not leaking, and so noted in the test report.

Fig. 4-2.3.8-1 Five-Way Manifold for Differential Pressure (DP) Instruments



For differential pressure transmitters on flow devices, the transmitter output is often an extracted square root value unless the square root is applied in the plant control system. Care should be taken to ensure that the square root is applied only once. The transmitter output may also be computed flow. The flow calculation contained in the transmitter must be verified as containing the full flow equation. When possible, the calculated flow should be treated as a backup reading, in favor of the raw differential pressure, temperature and static pressure readings.

For vacuum or gaseous service, sensing lines are installed with the sensing line sloping continuously upwards to the instrument so any condensed liquid will flow out of the sensing lines. For gaseous service, it is recommended that differential pressure taps located near the bottom of the flowmeter for a horizontal installation not to be used due to the potential for liquid hydrocarbon accumulation at this location.

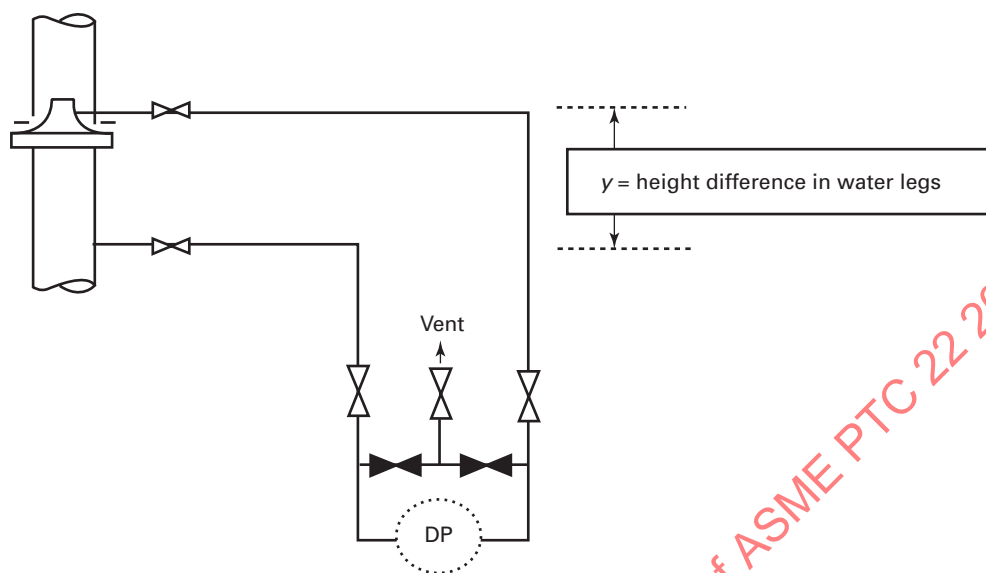
4-2.3.8.1 Liquid in Sensing Lines (Water Legs).

For vacuum or gaseous service, sensing lines are installed with the sensing line sloping continuously upwards to the instrument so any condensed liquid will flow out of the sensing lines. If this is not possible, the low points must be drained, before reading the instrument.

For steam and liquid processes at pressures larger than barometric pressure, the sensing lines are installed with the sensing line sloping continuously downwards to the instrument to eliminate any gas pockets. If this is not possible, the high points must be vented, before reading the instrument.

The "water leg" is the liquid in the sensing line. This liquid causes a static pressure head to develop in the sensing line. This static head must be subtracted from the pressure measurement. The static head is calculated by multiplying the sensing line vertical height by local gravity and the density of the water in the sensing line

Fig. 4-2.3.9-1 Differential Pressure (DP) Correction for Flow in Nonhorizontal Lines



at the sensing line temperature. This static head adjustment may be applied at the transmitter, in the data acquisition system, or manually by the user after the raw data is collected. Care must be taken to ensure this adjustment is applied properly and that it is only applied once.

4-2.3.9 Differential Pressure Meters for Flow in Nonhorizontal Lines. When a differential pressure meter is installed on a flow element that is located in a nonhorizontal line, the measurement must be corrected for the difference in sensing line height (see Fig. 4-2.3.9-1). For steam, the sensing lines should be uninsulated, and should protrude horizontally roughly 2 ft (0.6 m) from the pipe. This horizontal length will allow condensation to form completely so the downward portion will be completely full of water. The correction is as follows:

$$\Delta P_{\text{corr}} = \Delta P_{\text{meas}} + y \times (\rho_{\text{sen}} - \rho_{\text{fluid}}) / g_c \quad (4-2.2)$$

$$\times (g_L / \text{Conv}^3)$$

where

ΔP_{corr} = corrected differential pressure, lbf/in.² (N/m² = Pa)

ΔP_{meas} = measured differential pressure, lbf/in.² (N/m² = Pa)

y = downstream tap elevation – upstream tap elevation, in. (cm)

NOTE: y will be positive for flow up and negative for flow down.

ρ_{sen} = density of sensing line fluid, lbm/ft³ (kg/m³)

ρ_{fluid} = density of process fluid, lbm/ft³ (kg/m³)

g_c = conversion constant = 32.1740486 (lbm-ft)/(lbf-sec²) [or for SI, 1 (kg-m)/(N-s²)]

g_L = local acceleration due to gravity, ft/sec² per an acknowledged source, or may be estimated as:

$$g_L = 32.17245 \times \{1 - 0.0026373 \times \cos(2 \times \text{degrees latitude} \times \pi/180) + 0.0000059 \times [\cos^2(2 \times \text{degrees latitude} \times \pi/180)]\} - 0.000003086 \times \text{feet elevation}$$

$$\text{or for SI, } g_L = \text{m/sec}^2 = 9.80616 \times \{1 - 0.0026373 \times \cos(2 \times \text{degrees latitude} \times \pi/180) + 0.0000059 \times [\cos^2(2 \times \text{degrees latitude} \times \pi/180)]\} - 0.000003086 \times \text{meters elevation}$$

NOTE: The conversion constant, g_c , is not necessary with the SI units used here. Conv = 12 in./ft (100 cm/m).

Note that for process liquids, the correction is small, being due only to the difference in temperature between the sensing line fluid and the process fluid.

4-2.4 Calibration of Pressure Instruments

4-2.4.1 Calibration of Absolute Pressure Instruments (e.g., Barometers).

Absolute pressure instruments can be calibrated using one of two methods. The first method involves connecting the test instrument to a device that develops an accurate vacuum at desired levels. Such a device can be a deadweight gage in a bell jar referenced to zero pressure or a divider piston mechanism with the low side referenced to zero pressure. The second method calibrates by developing and holding a constant vacuum in a chamber using a suction and bleed control mechanism. The test instrument and the calibration standard are both connected to the chamber. The chamber must be maintained at constant vacuum during the calibration

of the instrument. Other devices can be utilized to calibrate absolute pressure instruments provided that the same level of care is taken.

4-2.4.2 Calibration of Gage Pressure Instruments.

Gage pressure instruments can be calibrated by an accurate deadweight gage. The pressure generated by the deadweight gage must be corrected for local gravity, air buoyancy, piston surface tension, piston area deflection, actual mass of weights, actual piston area, and working medium temperature. The actual piston area and mass of weights is determined each time the deadweight gage is calibrated. Other devices can be utilized to calibrate gage pressure instruments provided that the same level of care is taken.

4-2.4.3 Calibration of Differential Pressure Instruments. Differential pressure instruments used to measure low-uncertainty variables must be calibrated at line static pressure unless information is available about the effect of high line static pressure on the instrument accuracy. Calibrations at line static pressure are performed by applying the actual expected process pressure to the instrument as it is being calibrated. Calibrations at line static pressure can be accomplished by one of three methods:

- (a) two highly accurate deadweight gages
- (b) a deadweight gage and divider combination, or
- (c) one deadweight gage and one differential pressure standard

Differential pressure instruments used to measure secondary variables do not require calibration at line static pressure and can be calibrated using one accurate deadweight gage connected to the “high” side of the instrument. If line static pressure is not used, the span must be corrected for high line static pressure shift unless the instrument is internally compensated for the effect.

Other devices can be utilized to calibrate differential pressure instruments provided that the same level of care is taken.

4-3 TEMPERATURE MEASUREMENT

4-3.1 General

Temperature measurement should be carried out in accordance with accepted practice and procedures as discussed in ASME PTC 19.3. Temperature shall be measured with resistance thermometers or calibrated thermocouples used with precision-reading instruments. If not prohibited, calibrated mercury in-glass thermometers may be used for such secondary readings as temperatures at manometer and barometer. Stagnation type devices shall be used, or computed velocity corrections applied where such correction exceeds 1°F (0.6°C).

4-3.2 Temperature Instruments

4-3.2.1 Resistance Temperature Detectors (RTDs).

Resistance Temperature Detectors (RTDs) should only

Fig. 4-3.2.1-1 Four-Wire RTDs

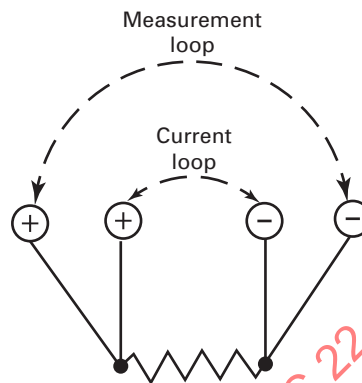
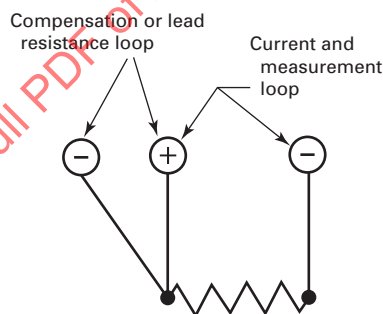


Fig. 4-3.2.1-2 Three-Wire RTDs



be used to measure from -454°F to 1562°F (-270°C to 850°C). ASTM E1137 provides standard specifications for industrial platinum resistance thermometers which includes requirements for manufacture, pressure, vibration, and mechanical shock to improve the performance and longevity of these devices.

Measurement errors associated with RTDs are typically comprised of the following primary sources:

- (a) self-heating
- (b) environmental
- (c) thermal shunting
- (d) thermal emf
- (e) stability
- (f) immersion

Although RTDs are considered a more linear device than thermocouples, due to manufacturing technology, RTDs are more susceptible to vibrational applications. As such, care should be taken in the specification and application of RTDs with consideration for the effect on the devices stability.

Grade A four-wire platinum resistance thermometer as presented in Fig. 4-3.2.1-1 should be used. Three-wire RTDs (see Fig. 4-3.2.1-2) are acceptable only if they can be shown to meet the uncertainty requirements of this

Code. The four-wire technique is preferred to minimize effects associated with lead wire resistance due to dissimilar lead wires.

4-3.2.2 Thermistors. Thermistors are constructed with ceramic like semi-conducting material that acts as a thermally sensitive variable resistor. This device may be used on any measurement below 300°F (149°C). Above this temperature, the signal is low and susceptible to error from current induced noise. Although positive temperature coefficient units are available, most thermistors have a negative temperature coefficient (TC); that is, unlike an RTD, their resistance decreases with increasing temperature. The negative TC can be as large as several percent per degree Celsius, allowing the thermistor circuit to detect minute changes in temperature that could not be observed with an RTD or thermocouple circuit. As such, the thermistor is best characterized for its sensitivity while the thermocouple is the most versatile and the RTD the most stable.

Measurement errors associated with thermistors are typically comprised of the following primary sources:

- (a) self-heating
- (b) environmental
- (c) thermal shunting
- (d) decalibration
- (e) stability
- (f) immersion

The four-wire resistance measurement is not required for thermistors due to its high resistivity. The measurement lead resistance produces an error magnitude less than the equivalent RTD error. Thermistors are generally more fragile than RTDs and thermocouples and must be carefully mounted and handled in accordance with the manufacturer's specifications to avoid crushing or bond separation.

4-3.2.3 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 200°F (93°C). The maximum temperature is dependent on the type of thermocouple and sheath material used. Thermocouples should not be used for measurements below 200°F (93°C). The thermocouple is a differential-type device. The thermocouple measures the difference between the measurement location in question and a reference temperature. The greater this difference, the higher the emf from the thermocouple. Therefore, below 200°F (93°C) the emf becomes low and subject to induced noise causing increased systematic uncertainty and inaccuracy.

Measurement errors associated with thermocouples are typically comprised of the following primary sources:

- (a) junction connection
- (b) decalibration of thermocouple wire
- (c) shunt impedance
- (d) galvanic action

- (e) thermal shunting
- (f) noise and leakage currents
- (g) thermocouple specifications

"The emf developed by a thermocouple made from homogeneous wires will be a function of the temperature difference between the measuring and the reference junction. If, however, the wires are not homogeneous, and the inhomogeneity is present in a region where a temperature gradient exists, extraneous emf's will be developed, and the output of the thermocouple will depend upon factors in addition to the temperature difference between the two junctions. The homogeneity of the thermocouple wire, therefore, is an important factor in accurate measurements."¹

"All base-metal thermocouples become inhomogeneous with use at high temperatures, however, if all the inhomogeneous portions of the thermocouple wires are in a region of uniform temperature, the inhomogeneous portions have no effect upon the indications of the thermocouple. Therefore, an increase in the depth of immersion of a used thermocouple has the effect of bringing previously unheated portion of the wires into the region of temperature gradient, and thus the indications of the thermocouple will correspond to the original emf-temperature relation, provided the increase in immersion is sufficient to bring all the previously heated part of the wires into the zone of uniform temperature. If the immersion is decreased, more inhomogeneous portions of the wire will be brought into the region of temperature gradient, thus giving rise to a change in the indicated emf. Furthermore a change in the temperature distribution along inhomogeneous portions of the wire nearly always occurs when a couple is removed from one installation and placed in another, even though the measured immersion and the temperature of the measuring junction are the same in both cases. Thus the indicated emf is changed."²

The elements of a thermocouple must be electrically isolated from each other, from ground and from conductors on which they may be mounted, except at the measuring junction. When a thermocouple is mounted along a conductor, such as a pipe or metal structure, special care should be exercised to ensure good electrical insulation between the thermocouple wires and the conductor to prevent stray currents in the conductor from entering the thermocouple circuit and vitiating the readings. Stray currents may further be reduced with the use of guarded integrating A/D techniques. Further, to reduce the possibility of magnetically induced noise, the thermocouple wires should be constructed in a twisted uniform manner.

¹ ASME PTC 19.3-1974 (R2004), Chapter 9, para. 70, page 106.

² A.I. Dahl, "Stability of Base-metal Thermocouples in air from 800 to 2200°F." National Bureau of Standards, Washington, D.C. in *Temperature*, vol. 1, Reinhold, New York, 1941, page 1,238.

Thermocouples are susceptible to drift after cycling. Cycling is the act of exposing the thermocouple to process temperature and removing to ambient conditions. The number of times a thermocouple is cycled should be kept to a minimum.

Thermocouples can effectively be used in high vibration areas. High vibration measurement locations may not be conducive to other measurement devices. This Code recommends that the highest emf per degree be used in all applications. NIST has recommended temperature ranges for each specific type of thermocouple.

4-3.3 Typical Gas Turbine Measurement Parameters

4-3.3.1 Inlet Air Temperature. It is recommended that the inlet air temperature be measured at the test boundary; however, there may be cases where the measurement upstream or downstream may be more practical and result in a measurement of lower uncertainty such as selecting to measure temperature inside the inlet air duct instead of at the inlet of the duct (i.e., filter house inlet) because of better mixing to attain a more representative bulk temperature measurement.

If measurements are made at locations other than the test boundary, the location selected shall be such that no heat addition or loss occurs between the test boundary and the selected measurement location.

Measurement frequency and locations shall be sufficient to account for stratification of the inlet air temperature after applications with inlet air-conditioning systems. In applications with inlet air-conditioning equipment in operation, the temperature sensing devices shall be capable of measuring dry-bulb temperature at the test boundary without the effects of condensation or water droplet impingement. The number of locations and frequency of measurements shall be determined by the pre-test uncertainty analysis. At the specified location, the temperature of the air shall be measured such that the total uncertainty will not exceed the requirements of Table 4-1.2.1-1. If a nonuniform profile exists, the profile shall be determined by other measurable means. After determining the profile, the number and arrangement of sensors shall be selected such that the average of their readings shall be within 1°F (0.6°C) of the temperature determined from the temperature profile measurement. As a rule of thumb, it is recommended that one temperature sensing device be used for every 100 ft² (9.3 m²) of duct cross-sectional area, generally between at least four up to a maximum of 16 devices per measurement plane. Additional measurement points greater than the maximum specified above may be required depending upon the spatial variation to meet the maximum allowable inlet air temperature measurement uncertainty.

Inlet air temperature should be measured using RTDs or thermistors. Thermocouples should not be used because the voltage signal generated by a thermocouple

is proportional to the temperature difference between the measurement junction and the reference junction. Since both temperatures are nearly identical for air inlet temperature measurement, the voltage signal is extremely small, thereby increasing the uncertainty of the measurement.

4-3.3.2 Exhaust Gas Temperature. The exhaust gas temperature must be measured near the test boundary, which is often the interface plane between the gas turbine and HRSG or the gas turbine exhaust stack. The exhaust gas from a gas turbine usually has a non-uniform temperature and velocity profile. Therefore, the exhaust gas temperature shall be calculated on a mass weighted average basis. The parties to the test shall agree on how the mass weighted average is to be calculated. The preferred method is for the manufacturer to provide a calculation method based on either field test data from other similar units, or from analytical means such as CFD modeling. The alternate method is to conduct velocity, total temperature and total pressure traverses at several locations in the exhaust duct to determine the basis of the mass weighted average. Refer to ASME PTC 19.5 for guidance on velocity traverse methods.

The required number of exhaust gas temperature measurement devices shall be determined to meet a maximum exhaust gas temperature uncertainty of 10°F (6°C). Large spatial variations in exhaust gas temperature readings will most likely require a significant number of measurement points. The recommended number of measurement points is as follows:

- (a) located every 25 ft² (2.3 m²)
- (b) for axial discharge, a minimum of 12 points and maximum of 36 points
- (c) for side discharge, a minimum of 18 points and maximum of 36 points

Additional measurement points greater than the maximum specified above may be required depending upon the spatial variation to meet the maximum allowable exhaust gas temperature measurement uncertainty. For round ducts, the test points may be installed in two locations (diameters) 90-deg apart. The measurement point spacing is based on locating the measurement points at the centroids of equal areas along each diameter.

For square or rectangular ducts, the same concept of locating the measurement points at centroids of equal areas should be used. The aspect ratio should be between 0.67 and 1.333.

If permanent exhaust gas temperature measurement devices are provided with the gas turbine, these may be used to determine mass weighted average exhaust gas temperature provided they meet the uncertainty requirement specified above. In the event that the uncertainty requirement cannot be met using permanent devices, temporary devices must be utilized.

The total temperature of the gas stream is required and if the average velocity in the area of temperature measurement exceeds 100 ft/sec (30.5 m/s), then it is suggested that the individual temperature reading be adjusted for velocity effect.

(U.S. Customary Units)

$$T_t = T + V^2/(2Jg_cC_p) = T + T_v$$

where

C_p = the specific heat, Btu/lbm °F

g_c = the conversion constant as defined in Section 2, 32.1741 lbm ft/lbf sec²

J = the mechanical equivalent of heat, 778.1692623 ft lbf/Btu

T = the measured temperature, °F

T_t = the total temperature, °F

T_v = the dynamic temperature, °F

V = the gas velocity (ft/sec)

(SI Units)

$$T_t = T + V^2/(2JC_p) = T + T_v$$

where

C_p = the specific heat, kJ/kg °C

J = the mechanical equivalent of heat, 1 000 kg·m²/kJ·s²

T = the measured temperature, °C

T_t = the total temperature, °C

T_v = the dynamic temperature, °C

V = the gas velocity, m/s

Exhaust gas combustion products flowing into and through a duct are subject to spatial variations such as nonuniform velocity, varying flow angle, temperature, and composition. This is especially true at the inlet of a duct or near a flow disturbance, such as a bend, tee, fan, vane, damper, or transition. Spatial variation effects, if not addressed by the measurement approach, are considered errors of method and contributors to the systematic uncertainty in the measurement system. Generally, the temperature uncertainty can be reduced either by sampling more points in a plane perpendicular to the flow or by using more sophisticated calculation methods such as flow/velocity weighting and flow angle compensation.

The measurement plane should be located away from bends, constrictions, or expansions of the duct. Temperature measurements shall be read individually and not be grouped together to produce a single output. As such, the number and location of temperature measurement devices and flow velocity measurements points should be determined such that the overall systematic uncertainty of the average exhaust gas temperature measurement devices is minimized as much as practically possible.

It is recommended that the exhaust gas temperature be measured at the test boundary; however, there may be cases where the measurement upstream or downstream may be more practical and result in a measurement of lower uncertainty such as selecting to measure temperature inside the duct at the interface plane between the gas turbine and HRSG or the gas turbine exhaust stack because of better mixing to attain a more representative bulk temperature measurement. If measurements are made at locations other than the test boundary, the location selected shall be such that no heat addition or loss occurs between the test boundary and the selected measurement location.

4-3.3.3 Fuel Temperature. Fuel temperatures of fuel supply and, if applicable for liquid fuel, of fuel return lines, shall be measured at representative locations close to the corresponding flowmeters. Two different measurement locations may be required, one for fuel flow measurement, and one for the sensible heat at the test boundary.

Refer to ASME PTC 19.5 for guidance as to the proper location for these temperature measurements.

4-3.3.4 Extraction/Injection Fluid Temperature.

Extraction/injection fluid temperature measurements (such as water, steam, nitrogen, air) shall be provided to determine the heat content of the fluid.

4-3.4 Calibration of Temperature Instruments

This Code recommends that instrumentation used in the measurement of temperature have a suitable calibration history (three or four sets of calibration data). The calibration history should include the temperature level the device experienced between calibrations. A device that is stable after being used at low temperatures may not be stable at higher temperatures. Hence, the calibration history of the device should be evaluated to demonstrate the required stability of the parameter.

During the calibration of any thermocouple, the reference junction shall be held constant preferably at the ice-point with an electronic reference junction, isothermal reference junction or in an ice bath. The calibration shall be made by an acceptable method, with the standard being traceable to a recognized international or national standards laboratory such as the National Institute of Standards and Technology. The calibration shall be conducted over the temperature range in which the instrument is used.

The calibration of temperature measurement devices is accomplished by inserting the candidate temperature measurement device into a calibration medium along with a traceable reference standard. The calibration medium type is selected based upon the required calibration range and commonly consists of a block calibrator, fluidized sand bath, or circulating bath. The temperature of the calibration medium is then set to the calibration temperature setpoint. The temperature of the

calibration medium is allowed to stabilize until the temperature of the standard is fluctuating less than the accuracy of the standard. The signal or reading from the standard and the candidate temperature measurement device are sampled to determine the bias of the candidate temperature device. See ASME PTC 19.3 for a more detailed discussion of calibration methods.

4-4 GAS FUEL HEAT INPUT

4-4.1 General

To determine the heat input while operating on gas fuel, the following parameters shall be determined:

- (a) mass flow
- (b) composition, including moisture content
- (c) heat value
- (d) sensible heat

For comparative testing, flow elements should not be cleaned or replaced during the outage. Any maintenance should be done *before* the pre-modification test.

4-4.2 Gas Fuel Test Boundary

Per para. 3-1.5, each energy stream is to be determined with reference to the point at which they cross the test boundary. The choice of the test boundary can have a significant impact on the test results. It may be at a different location depending on what parameter is being determined (i.e., heat rate vs. exhaust energy via heat balance). Figure 4-4.2-1 provides some typical test boundaries that should be considered when determining the gas fuel heat input.

Leakage and unmetered return flows may exist during the test ($M_1 \neq M_2$) and care should also be taken to minimize and account for such flows (e.g., separate metering in the return flow lines). Instances of leakage and unmetered return flows should be treated on a case-by-case basis and the method for accounting for such flows should be agreed upon.

4-4.3 Gas Fuel Flowmeters

4-4.3.1 Gaseous Fuel Flowmeters. Gas fuel flows shall be measured using a fuel flow device that has been calibrated in compliance with para. 4-1.3. The following paragraphs will describe the specific requirements of various flowmeters. Any flowmeter is permitted if it meets the uncertainty requirements of Table 4-1.2.1-1. In order to achieve the highest level of accuracy consistent with the object of the Code, it is recommended to use gas fuel flowmeters that have an accuracy of 0.35% or better. The calibration laboratory facilities should be able to demonstrate a calibration accuracy consistent with this criteria. Higher accuracy levels can often be achieved by utilizing mass flowmeters versus volumetric flowmeters due, in part, to mass flowmeters direct mass flow measurement and its elimination of the requirement for the gas fuel density compensation

unlike volumetric flowmeters. It is further recommended that the calibration curves or data obtained from the calibration process be applied within the flowmeter's processor or output signals to correct the measured values.

Application, restriction of use, calibration and installation requirements of gas fuel flow measuring devices shall be in accordance with ASME PTC 19.5. Fuel flow measurement devices shall be put in service prior to the conduct of the test to avoid damage that can affect the device calibration. On-site inspection of the fuel flow devices prior to the conduct of the test is recommended only if the inspection does not invalidate the calibration results. Any activity that invalidates the calibration results, including on-site inspection of the fuel flow device, shall not be permitted.

Start-up procedures must ensure that spool pieces are provided during conditions that may violate the integrity of the flow measurement device to avoid altering the devices characteristics. Such conditions may include line blows. While the flow measurement device is stored, it must be capped and protected from environmental damage such as moisture and dirt. During operation it is recommended that a strainer be installed upstream of the flow measurement device to protect the meter from objects and debris.

The calibration results from a properly calibrated flow device shall be used as the primary source in the determination of the mass flow of the gas fuel.

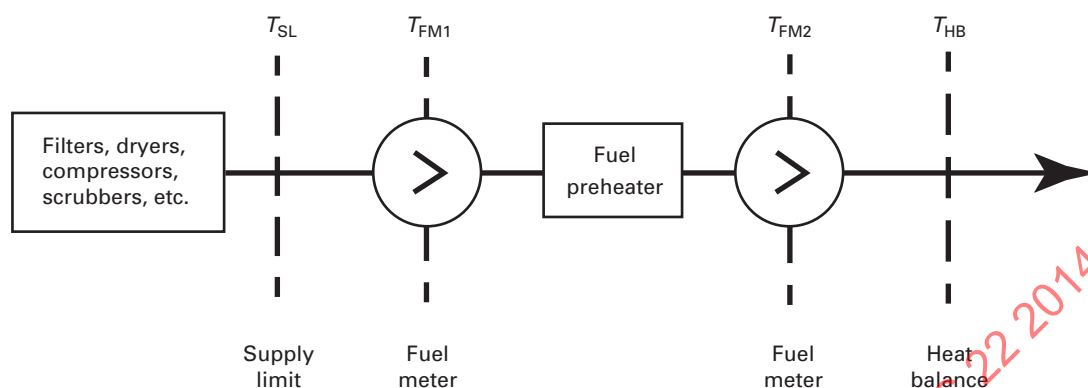
4-4.3.1.1 Differential Pressure Flowmeters (e.g., Flange-Tap Orifice Flowmeter). Calibration of the flowmeters may be conducted with either water or natural gas. However special consideration should be given to the applicability of each type.

Calibrations conducted with water as the calibration fluid usually do not allow for calibration data to be taken at flow ranges experienced during normal base load operation of the gas turbine. For these situations, extrapolation of the calibration data shall be in accordance with ASME PTC 19.5 or equivalent standard.

Paragraphs 5-3.1.1 through 5-3.1.5 outline the applicable equations for the volumetric gas fuel flow measurements using a metering orifice flowmeter.

4-4.3.1.2 Linear Scale Meters (e.g., Positive Displacement Flowmeter or Turbine Flowmeter). Turbine meter calibrations conducted with natural gas as the calibration fluid shall be conducted at design pressures and temperatures and calibration data points shall be taken at flow rates that surround the range of flow rates expected during the test.

Whenever volumetric flowmeters are used, the temperature of the gas fuel (at a location consistent with para. 4-4.2) and the fuel flow shall be measured simultaneously. The volumetric flow shall be determined from

Fig. 4-4.2-1 Generic Gas Fuel Test Boundary**LEGEND:**

•Temperature Reference Points:

 T_{FM} = fuel temperature at fuel meters T_{HB} = fuel temperature at heat balance boundary T_{SL} = fuel temperature at supply limit— Fuel Meter Upstream of Fuel Preheater: $T_{SL} = T_{FM1} \neq T_{HB}$ — Fuel Meter Downstream of Fuel Preheater: $T_{SL} \neq T_{FM2} = T_{HB}$

NOTE: Whenever a fuel preheater is included as part of the scope of supply, the fuel temperature shall be measured both upstream and downstream of the preheater.

•Mass Flow Reference Points:

 M_1 = mass flow upstream of fuel meter M_2 = mass flow downstream of fuel meter

the totalized volume of gas fuel measured over a continuous period of not less than 4 min, and the time measured with an accurate stopwatch or electronic timer. Care must be taken that the measured totalized volume of gas fuel is not temperature compensated.

4-4.3.1.3 Ultrasonic Flowmeters. Ultrasonic flowmeters measure velocity of the flowing fluid by which volumetric flow can be calculated by known physical dimensions of the metering section. ASME PTC 19.5 Section 10 describes ultrasonic flowmeters in more detail.

Due to the sensitivity on velocity profile on its measurement, a flow conditioner shall be used as well as adequate upstream and downstream straight-run lengths. To ensure proper application, manufacturers often provide ultrasonic flowmeters complete with flow conditioner and spool pieces of necessary straight-run length and are calibrated in the lab in a complete assembled configuration.

The lab calibration of ultrasonic flowmeters is typically conducted with natural gas at flow rates that surround the range of flow experienced during base load operation of the gas turbine. Care must be taken such that the constants and algorithms within the meter's processing that exist during lab calibrations are identical to those present in the meter when it is put into operation and during performance testing. Such constants and algorithms compensate for physical, electrical, and sensor characteristics. In addition, it should be confirmed

that the calibration factors determined during lab calibration are also applied correctly in the meter's processor.

4-4.3.1.4 Mass Flowmeters (e.g., Coriolis Flowmeter). Coriolis flowmeters measure mass flow directly. Due to the meters insensitivity to velocity profile distortion and swirl, no straight-run or flow conditioning requirements are typically required.

The calibration of the coriolis flowmeter is generally conducted with water. Other fluids may be used because the constants are valid for other fluids provided the maximum allowable measurement uncertainty is met. The calibration points shall be taken at flow rates that surround the range of flow rates expected during the test. The effect of operating pressure and temperature on the flowmeter during the test should be applied to the meters operation to correct for the influence of operating conditions different than calibration conditions and improve the overall flowmeter performance.

4-4.3.2 Density. The density for each fuel sample is calculated from the pressure, temperature, compressibility factor, and gas fuel composition, all recorded at a location consistent with para. 4-4.2. The applicable equation for calculating gas fuel density is outlined in para. 5-3.1.5. Compressibility factor, Z_f , shall be determined by the methods detailed in AGA Report No. 8 — Detailed Characterization Method. For gas mixtures not

covered by this Report, then an alternate method shall be used.

4-4.4 Gas Fuel Composition

Methods of gas fuel composition determination shall be in accordance with the standards set forth in ASTM D1945. Alternative methods may be used if they are equivalent in accuracy and are mutually agreed upon by all parties prior to the test.

Recognizing the importance of the gas composition as one of the main contributors to the determination of the heat rate, the Code makes the following recommendations, which may reduce the error level.

The preferred solution for the determination of the gas composition is the analysis in a laboratory using methods and standards that are traceable to U.S. National Institute of Standards and Technology (NIST). Increasing the number of laboratories where fuel samples are analyzed will reduce the correlated component of the measurement uncertainty. Further reduction of the random part of the uncertainty may be achieved by increasing the frequency of the fuel sample collection. Prior to the onset of any activities all parties to the test shall agree upon the laboratory(s) that will be used to conduct the analysis of the test gas fuel samples. It should be noted that the recommended values of the ASTM D1945 for repeatability and reproducibility should be considered the upper limit for determination of the errors. Conducting audits on quality of the laboratory(s), following the recommendations of the analyzing equipment manufacturer and using experienced technicians could significantly reduce these types of errors.

The use of calibrated on-line gas chromatographs is acceptable provided that a laboratory certifies the quality of the results. Special care should be given to the frequent calibration of the on-line gas chromatograph and use of high quality calibration gases.

4-4.4.1 Moisture Content. When the fuel is pipeline quality natural gas, the moisture content should be minute (less than 4 lb per million standard cubic feet or 64 milligrams per cubic meter). It will therefore have a negligible effect on the gas heat value and the gas constant. In such cases, if it is mutually agreeable upon by all parties to the test, the moisture content can be taken from the supplier's records.

If required, the gas moisture content shall be determined in accordance with the standards set forth in ASTM D1142. The fuel heat value shall be adjusted in accordance with procedures delineated in ASTM D3588.

4-4.5 Gas Fuel Heating Value

The heating value shall be determined with an uncertainty that, combined with that of the mass flow measurement, does not exceed the gas fuel heat input requirement of Table 4-1.2.1-1. As a guide, the heating value uncertainty should be 0.4% or less. The preferred

method for determining the gas constituents is the use of a chromatograph in accordance with ASTM D1945. Alternate methods may be used if they are equivalent in accuracy and are mutually agreed upon by all parties prior to the test. The fuel heating value shall be calculated in accordance with procedures delineated in ASTM D3588. The values for the constituent properties shall be taken from GPA 2145. GPA 2145 is based on combustion reference conditions of 60°F (15°C) and 14.696 psia (1013 mbar). Other industry publications provide various combustion reference conditions such as 15°C, 20°C, and 25°C. Variations of heat of combustion due to changes in combustion reference temperature are relatively small and generally complex, so it is not necessary or practical to account for this provided the selected data set is agreed by all parties prior to the test.

4-4.6 Gas Fuel Sensible Heat

For an exhaust flow or energy test, the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the user selected enthalpy reference temperature. For a heat rate test, if the heat rate is specified to include the latent heat and the sensible heat, then the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the Specified Reference Temperature [not to be confused with the combustion reference temperature of 60°F (15°C) as specified in GPA 2145]. If the heat rate is specified to include only the latent heat, variations from the Specified Reference Temperature may be accounted for by applying a correction factor to heat rate which can be determined from a calculation of sensible heat or application of a manufacturer supplied correction factor. The calculation of sensible heat is described in para. 5-3.1.11.

4-4.7 Gas Fuel Sampling

Fuel samples shall be taken in accordance with GPA Standard 2166. A fuel sampling location shall be jointly identified and mutually agreed upon by all parties prior to the test. If it is suspected that the sampling procedure may result in a substantial gas fuel flow loss, the sampling point shall be located as close as possible to the test boundary, upstream of the metering station, such that the gas sample represents the bulk of the gas flowing through the flowmeter device. Special care shall be taken to ensure that the fuel sampling location is as far downstream of all processes outside of the test boundary that may change the composition of the gas (e.g., filters, dryers, compressors, scrubbers, etc.), such that the samples are a true representations of the fuel actually crossing the test boundary.

A set of at least two gas fuel samples shall be taken at the beginning and end of each test run. 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. One fuel sample from each set will be delivered to a qualified laboratory for analysis. The duplicate samples from each set will be retained until all fuel analysis is completed and results are concluded to be acceptable. The criteria for acceptability and method for combining the analysis results shall be as specified in the test plan. The fuel characteristics used for test run analysis shall be determined from the average of the characteristics from the individual fuel samples taken before and after each test run.

4-5 LIQUID FUEL HEAT INPUT

4-5.1 General

To determine the heat input while operating on liquid fuel, the following parameters shall be determined:

- (a) mass flow
- (b) heat value
- (c) sensible heat

For comparative testing, flow elements should not be cleaned or replaced during the outage. Any maintenance should be done *before* the pre-modification test.

4-5.2 Liquid Fuel Test Boundary

Per para. 3-1.5, each energy stream is to be determined with reference to the point at which they cross the test boundary. This is particularly significant with respect to liquid fuel heat input. The choice of the test boundary can have a significant impact on the measured flow, temperature, and test results. It may be at a different location depending on what parameter is being determined (i.e., heat rate vs. exhaust energy via heat balance). Figure 4-5.2-1 provides some typical test boundaries that should be considered when determining the liquid fuel heat input.

Leakage and unmetered return flows may exist during the test ($M_1 \neq M_2$) and care should also be taken to minimize and account for such flows (e.g., separate metering in the return flow lines). Instances of leakage and unmetered return flows should be treated on a case-by-case basis and the method for accounting for such flows should be agreed upon.

4-5.3 Liquid Fuel Mass Flow

The uncertainty of the method to determine the mass flow of the liquid fuel shall not exceed the values listed in Table 4-1.2.1-1.

4-5.3.1 Flow Measurement. Any flowmeter is permitted if the uncertainty of the mass flow measurement specified in Table 4-1.2.1-1 can be met.

Liquid fuel flows shall be measured using a fuel flow device that has been calibrated in compliance with para. 4-1.3. Calibration data points shall be taken at flow rates that surround the range of flow rates expected during the test. The calibration results from a properly

calibrated flow device shall be used as the primary source in the determination of the mass flow of the liquid fuel.

Whenever volumetric flowmeters are used, the temperature of the liquid fuel (at a location consistent with para. 4-5.2) and the fuel flow shall be measured at the same location. The volumetric flow shall be determined from the totalized volume of liquid fuel measured over a continuous period of not less than 10 min, and the time measured with an accurate stopwatch or electronic timer. Care must be taken that the measured totalized volume of liquid fuel is not temperature compensated.

Application, restriction of use, calibration, and installation requirements of liquid fuel flow measuring devices shall be in accordance with ASME PTC 19.5. On-site inspection of the fuel flow devices prior to the conduct of the test is recommended only if the inspection does not invalidate the calibration results.

Subsection 5-3 outlines the applicable equations for liquid fuel flow measurements using a metering orifice, a positive displacement flowmeter and a turbine flowmeter.

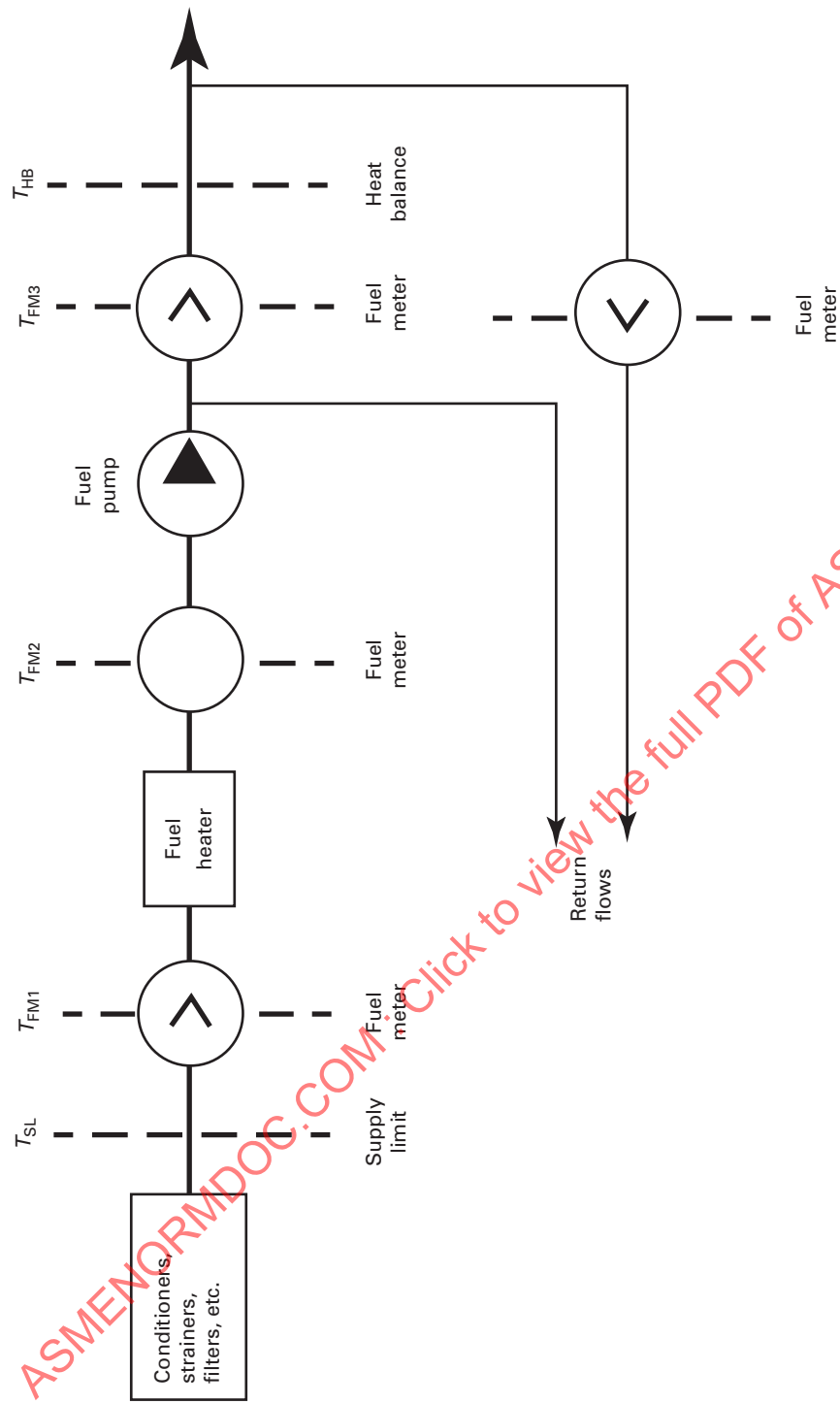
4-5.3.2 Density and Relative Density (Specific Gravity). The density or relative density for each fuel sample shall be determined from a fuel analysis conducted in accordance with ASTM D1480 or equivalent standard. To obtain a correlation of density (or relative density) and temperature, each sample shall be analyzed for at least two different temperatures, with a temperature range encompassing all of the liquid fuel temperatures recorded during the test runs. The density (or relative density) at the test conditions for each individual fuel sample shall be determined from the interpolation of the analysis results and flowing temperature during the test run.

4-5.3.3 Kinematic Viscosity. The kinematic viscosity of the liquid fuel at the test temperature is usually different from the fluid used for the flowmeter calibration. The effect of kinematic viscosity on the flowmeter calibration K-factor is unique. Hence, the flowmeter manufacturer's curves shall be used to adjust the calibration K-factor to the actual kinematic viscosity of the liquid fuel at the test conditions. Measurement of kinematic viscosity shall be in accordance with ASTM D445 or equivalent standard. To obtain a correlation of kinematic viscosity and temperature, each sample shall be analyzed at three different temperatures, with a temperature range encompassing all of the liquid fuel temperatures recorded during the test runs. The kinematic viscosity at the test conditions for each individual fuel sample shall be determined from the interpolation of the analysis results and flowing temperature during the test run.

4-5.4 Liquid Fuel Heating Value

The heating value shall be determined with an uncertainty no greater than the value listed in Table 4-1.2.1-1.

Fig. 4-5.2-1 Generic Liquid Fuel Test Boundary



LEGEND:

- Temperature Reference Points:
 - T_F = fuel temperature at fuel meters
 - T_{HB} = fuel temperature at heat balance boundary
 - T_{SL} = fuel temperature at supply limit
 - Fuel Meters at Supply Limit: $T_{SL} = T_{FM1} \neq T_{HB}$ (fuel temperature required to be measured in two locations)
 - Fuel Meter After Fuel Heater but Before Pump: $T_{SL} \neq T_{FM2} \neq T_{HB}$ (fuel temperature required to be measured in three locations)
 - Fuel Meter After Pump: $T_{SL} \neq T_{FM3} = T_{HB}$ (fuel temperature required to be measured in two locations)
- Mass Flow Reference Points:
 - M_1 = mass flow upstream of fuel meter
 - M_2 = mass flow downstream of fuel meter

The heating value of each fuel sample shall be determined in accordance with the procedures specified in ASTM D4809 or equivalent standard.

4-5.4.1 Heat Value at Constant Volume. The higher heating value at constant volume (HHV_v) is determined by measuring the amount of heat liberated when a carefully weighed quantity of liquid fuel is burned in an oxygen-filled calorimeter bomb of constant volume. All heating values are referenced to a standard temperature base of 77°F (25°C). The lower heating value at constant volume (LHV_v) is the higher heating value at constant volume minus the latent heat of condensed water vapor at the same base temperature of 77°F (25°C).

4-5.4.2 Heating Value at Constant Pressure. In gas turbine combustors, the process is assumed to be a complete and adiabatic combustion, which occurs at constant pressure. Therefore, the higher and lower heating values shall be determined at constant pressure. Additionally, for gas turbine cycle calculation with the exhaust-gas exit boundary for the test configuration defined in para. 3-1.5, the lower heating value at constant pressure (LHV_p) is the characteristic parameter since the water content in the exhaust gas at the boundary is still in gaseous (noncondensed) state. The higher and lower heating values at constant pressure shall be calculated from the higher heating value at constant volume using the equations outlined in para. 5-3.1.9.

4-5.4.3 Hydrogen Content. The hydrogen content of each fuel sample shall be determined in accordance with the procedures specified in ASTM D1018 or equivalent standard.

4-5.5 Liquid Fuel Sensible Heat

For an exhaust flow or energy test, the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the user selected enthalpy reference temperature. For a heat rate test, if the heat rate is specified to include the latent heat and the sensible heat, then the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the Specified Reference Temperature [not to be confused with the combustion reference temperature of 77°F (25°C)]. If the heat rate is specified to include only the latent heat, variations from the Specified Reference Temperature may be accounted for by applying a correction factor to heat rate which can be determined from a calculation of sensible heat or application of a manufacturer supplied correction factor. The calculation of sensible heat is described in para. 5-3.1.10.

4-5.6 Liquid Fuel Sampling

Fuel samples shall be taken in accordance with ASTM D4057. A fuel sampling location shall be jointly identified prior to the test. The sampling point shall be

located as close as possible to the test boundary, upstream of the metering station, such that the liquid fuel sample represents the bulk of the liquid fuel flowing through the flowmeter device. Special care shall be taken to ensure that the fuel sampling location is as far downstream of all processes outside of the test boundary that may change the composition of the liquid fuel (e.g., filters, strainers, conditioners, etc.), such that the samples are a true representations of the fuel actually crossing the test boundary.

A set of at least two liquid fuel samples shall be taken at the beginning and end of each test run. 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. One fuel sample from each set will be delivered to a qualified laboratory for analysis. The duplicate samples from each set will be retained until all fuel analysis is completed and results are concluded to be acceptable. The criteria for acceptability and method for combining the analysis results shall be as specified in the test plan. The fuel characteristics used for test run analysis shall be determined from the average of the characteristics from the individual fuel samples taken before and after each test run.

4-6 ELECTRICAL GENERATION MEASUREMENT

4-6.1 Introduction

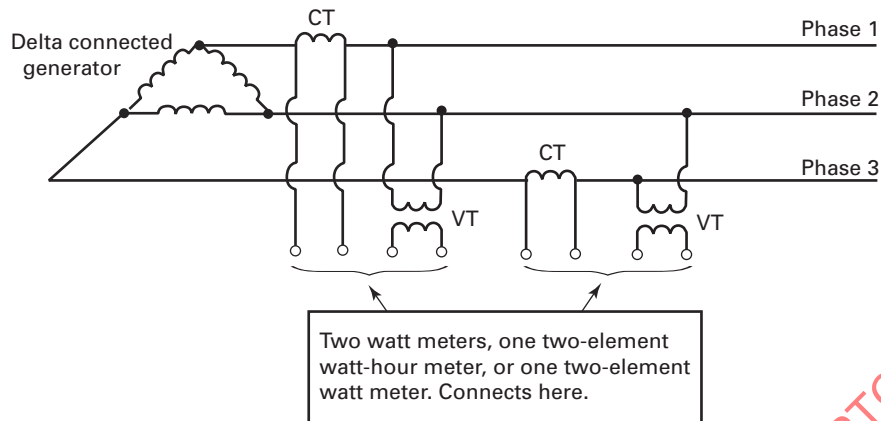
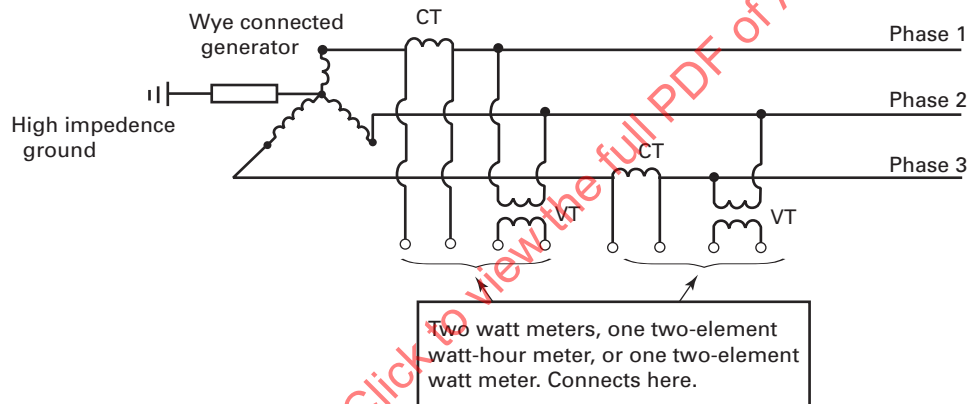
Electrical parameters required for the evaluation of gas turbine performance include gross electrical output, power factor, exciter power, and other auxiliary electrical loads. This subsection of the Code provides guidance and requirements for the determination of these parameters. IEEE Standard 120 and ASME PTC 19.6 should be consulted for additional information and for measurement requirements not included in this Code.

4-6.2 Electrical Measurement System Connections

The connection of the primary elements for measurement of polyphase alternating current power systems is subject to required uncertainty and the degree of unbalance between phases, which may be experienced. Many different and special connections can be used for measuring polyphase alternating current; however, the connections covered in this Code will be for three-wire or four-wire type systems and are recommended for meeting the uncertainty requirements of this Code. The minimum metering methods required for use on each of these three-phase systems are as follows:

- (a) three-wire generator connections — two single-phase meters or one two-phase meter
- (b) four-wire generator connections — three single-phase meters or one three-phase meter

The following describes different types of three- and four-wire generator connections that may exist.

Fig. 4-6.2.1-1 Two-Meter Metering System for Use on Three-Wire Delta Connected Power Systems**Fig. 4-6.2.1-2 Two-Meter Metering System for Use on Three-Wire Wye Connected Power Systems**

4-6.2.1 Three-Wire Power Systems. Examples of three-wire power generation systems are shown in Figs. 4-6.2.1-1 and 4-6.2.1-2. Various three-wire power systems exist due to the type of the connected generator. It is recommended to review the particular type and the site arrangement before deciding which one is suitable to a given measurement application.

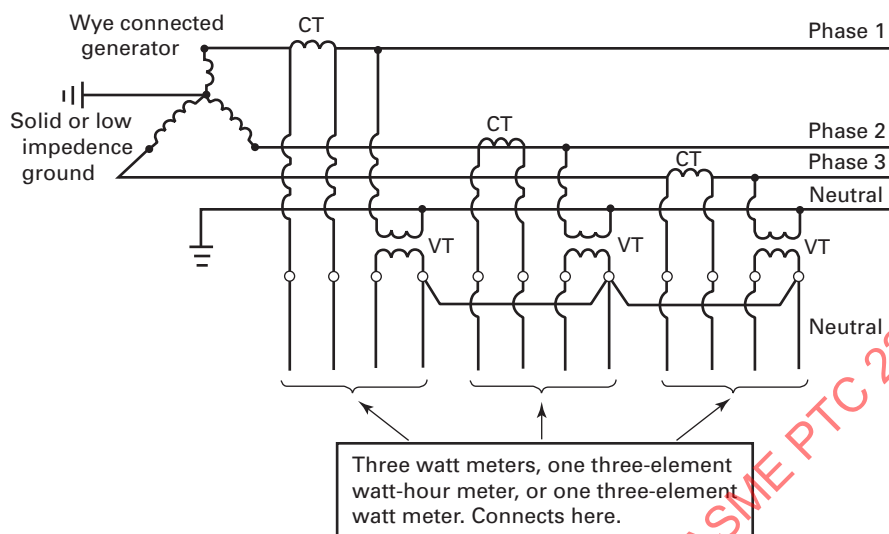
Power and energy in three-wire power systems can be measured using two voltage transformers (VTs) and two current transformers (CTs). The two-meter metering system is shown in Figs. 4-6.2.1-1 and 4-6.2.1-2 for a Delta connected and a Wye connected generator, respectively.

Several types of metering devices can be used in connection with these instrument transformers: two watt meters, two watt-hour meters, two element watt-hour meters, or a two-element watt-hour meter. A var-type meter is the recommended method to measure reactive

power to establish the power factor. Power factor calculation is provided in para. 5-1.2.1 including the case for balanced three-phase sinusoidal circuits.

4-6.2.2 Four-Wire Power Systems. A typical four-wire power system is shown in Fig. 4-6.2.2-1. In addition, with the exception of the “Open Delta” generator connection, all of the three-wire systems described in para. 4-6.2.1 can also be measured using the four-wire measurement system described in this Section.

The measurement of power and energy in a four-wire power system is made using three VTs and three CTs as shown in Fig. 4-6.2.2-1. Several metering devices can be used in connection with these instrument transformers: three watt/var meters, three watt-hour/var-hour meters, a three-element watt/var meter, or a three-element watt-hour/var-hour meter.

Fig. 4-6.2.2-1 Three-Meter Metering System for Use on Four-Wire Power Systems

Power factor calculation is provided in para. 5-1.2.2 including the option where each phase voltage and current (volt-amps) is measured.

4-6.3 Instrument Transformers

Instrument transformers are used for the purpose of (a) reducing the voltages and current to values which can be conveniently measured, typically to ranges of 120 V and 5 A, respectively

(b) insulating the metering instruments from the high potential that may exist on the circuit under test. Instrument transformer practice is described in detail in IEEE C57.13

The impedances in the transformer circuits must be constant during the test. Protective relay devices or voltage regulators shall not be connected to the instrument transformers used for the test. Normal station instrumentation may be connected to the test transformers if the resulting total burden is known and is within the range of calibration data.

Table 4-1.2.1-1 requires an overall power measurement uncertainty of 0.25%. In order to achieve this, the instrument transformer uncertainties should be in the range of 0.1% to 0.15%. Current transformers shall be operated within their rated burden range during the test and should be operated near 100% of rated current to minimize instrument error.

Instrument transformers accuracy ratings are typically specified in terms of accuracy class. Accuracy class for revenue metering is based on the requirement that the transformer correction factor (TCF) of the voltage transformer or of the current transformer shall be within specified limits when the power factor (lagging) of the metered load has any value from 0.6 to 1.0, under specified conditions as established in IEEE C57.13. The limits

of transformer correction factor for a standard 0.3% accuracy class voltage transformer (at 90% to 100% rated voltage) is 0.997 minimum and 1.003 maximum. The limits of transformer correction factor for a standard 0.3% accuracy class current transformer at 100% rated current is 0.997 minimum and 1.003 maximum and at 10% rated current is 0.994 minimum and 1.006 maximum.

For revenue metering applications, the maximum uncertainties for accuracy tests and calculation shall be $\pm 0.1\%$ for ratio and ± 0.9 mrad (3 min) for phase angle as established in IEEE C57.13. NIST publications^{3,4} indicate the IEEE C57.13 uncertainty figures are relatively modest uncertainties, with significantly lower calibration uncertainties for ratio correction factor and phase angle being achievable. Sources of error in the calibration of instrument transforms should be evaluated to determine the actual uncertainty associated with the ratio correction factor and phase angle. Sources of error for the calibration of voltage transformers may include, but not be limited to, bridge measurement, secondary voltage setting, burden setting, transformer self-heating, and capacitance ratio measurement. Sources of error for the calibration of current transformers may include, but not be limited to, core magnetization, burden, transformer temperature, current value, primary winding position, and electromagnetic interference.

³ NBS Measurement Services: A Calibration Service for Voltage Transformers and High-Voltage Capacitors, Special Publication 250-33, William E. Anderson, U.S. Department of Commerce, June 1998.

⁴ NIST Measurement Services: A Calibration Service for Current Transformers, NIST Special Publication 250-36, John D. Ramboz and Oskars Petersons, U.S. Department of Commerce, June 1991.

4-6.3.1 Voltage Transformers. Voltage transformers measure either phase-to-phase voltage or phase-to-neutral voltage. The voltage transformers serve to convert the line or primary voltage to a lower or secondary voltage safe for metering (typically 120 V for phase-to-phase systems and 69 V for phase-to-neutral systems). For this reason the secondary voltage measured by the voltage transformer must be multiplied by a turns ratio to calculate the primary voltage that actually exists in the generator.

Correctly rated voltage transformers of at least 0.3% accuracy class (metering type) shall be used for the tests. The transformers shall be calibrated for correction of ratio and phase angle error prior to the test over the ranges of voltage, current, and burden expected to be experienced during the test. Accuracy tests shall be made on each transformer and shall consist of measurement of ratio and phase angle from approximately 90% to 110% of rated primary voltage, when energized at rated frequency with zero burden, and with the maximum standard burden for which the transformer is rated at its best accuracy class. The method of calibration shall permit the determination of the turns ratio and phase angle to an uncertainty of at least $\pm 0.1\%$ and ± 0.9 mrad (3 min), respectively. The voltage transformer ratio correction factors shall be applied at the actual burdens of the test, which may be determined by calculation from lead impedances, or by direct measurement. Actual volt-ampere burdens shall be determined either by calculation from lead impedances or by direct measurement. Corrections for voltage drop of the connecting lines should be determined and applied as shown in Nonmandatory Appendix A-2.

4-6.3.2 Current Transformers. The current transformers convert the line or primary current to a lower secondary current safe for metering. For this reason, the secondary current measured by the current transformers must be multiplied by a turns ratio to calculate the primary current that actually exists in the generator output wiring.

For the measurement of generator output in a gas turbine test, at least 0.3% accuracy class current transformers shall be used. Accuracy tests should be made on each transformer and should consist of measurement of ratio and phase angle at approximately 100% and at 10% of rated current, when energized at rated frequency with zero burden, and with maximum standard burden for which the transformer is rated at its best accuracy class.

Accuracy test results may be used from factory type (design) tests in the determination of turns ratio and phase angle correction factors. Type tests are commonly performed on at least one transformer of each design group that may have a different characteristic in a specific test.

4-6.3.3 Instrument Transformer Connections. Test plans shall include a sketch showing the measurement and the test boundary locations.

The leads to the instruments shall be arranged so that inductance or any other similar cause will not influence the readings. Inductance may be minimized by utilizing twisted and shielded pairs for instrument leads. It is desirable to check the whole arrangement of instruments for stray fields.

In order to minimize the voltage drop in the voltage circuit, wire gauge shall be chosen considering the length of wiring, the load of the voltage transformer circuit, and the resistance of the safety fuses. The errors due to wiring resistance (including fuses) shall always be taken into account, either by direct voltage drop measurement or by calculation. An illustration of these measurements and corrections is shown in the sample calculation provided in Nonmandatory Appendix A-2.

4-6.3.4 Precautions in the Use of Instrument Transformers. Current transformer cores may be permanently magnetized by inadvertent operation with the secondary circuit opened, resulting in a change in the ratio and phase-angle characteristics. If magnetization is suspected, it should be removed as described in IEEE 120, under "Precaution in the Use of Instrument Transformers."

4-6.3.5 Utilization of Existing Plant Instrument Transformers. Existing station voltage or current transformers may be used for the test if they meet the requirements of this Code.

4-6.4 Electrical Metering Equipment

The following are the five types of electrical metering equipment that may be used to measure electrical energy:

- (a) watt meters
- (b) watt-hour meters
- (c) var meters
- (d) var-hour meters
- (e) power factor meters

Single or polyphase metering equipment may be used.

These meters are described in paras. 4-6.4.1 through 4-6.4.5.

4-6.4.1 Watt Meters. Watt meters measure instantaneous active power.

The instantaneous active power must be measured frequently during a test run and averaged over the test run period to determine average power (kilowatts) during the test. Should the total active electrical energy (kilowatt-hours) be desired, the average power must be multiplied by the test duration in hours.

Watt meters measuring generator output must have a systematic uncertainty equal to or less than 0.1% of reading and a sampling rate of at least once per minute during the test.

4-6.4.2 Watt-hour Meters. Watt-hour meters measure cumulative active energy (kilowatt-hours) during a test period. The measurement of watt-hours must be divided by the test duration in hours to determine average active power (kilowatts) during the test period.

Watt-hour meters measuring generator output must have an uncertainty equal to or less than 0.1% of reading.

The resolution of watt-hour meter output is often so low that high inaccuracies can occur over a typical test period. Often watt-hour meters will have an analog or digital output with a higher resolution that may be used to increase the resolution. Some watt-hour meters will often also have a pulse type output that may be summed over time to determine an accurate total energy during the test period.

For disk type watt-hour meters with no external output, the disk revolutions can be timed and counted during a test to increase resolution. Some electronic watt-hour meters also display blinking lights or LCD elements that correspond to disk revolutions that can be timed to determine the generator electrical output. In such cases, much higher resolution can be achieved usually by timing a discrete repeatable event (e.g., a certain number of blinks of an LCD or complete rotations of a disk) rather than counting the number of events in a fixed amount of time (e.g., number of rotations of a disk in 5 min).

4-6.4.3 Var Meters. Var meters measure instantaneous reactive power. The instantaneous reactive power must be measured frequently during a test run and averaged over the test run period to determine average reactive power (kilovars) during the test. Should the total reactive electrical energy (kilovar-hours) be desired, the average power must be multiplied by the test duration in hours.

Var meters measuring generator reactive power must have an uncertainty equal to or less than 0.5% of range and a sampling rate of at least once per minute.

4-6.4.4 Var-hour Meters. Var-hour meters measure reactive energy (kilovar-hours) during a test period. The measurement of var-hours must be divided by the test duration in hours to determine average reactive power (kilovars) during the test period.

Var-hour meters measuring generator output must have an uncertainty equal to or less than 0.5% of range.

The acceptable var-hour meters will have an analog or digital output with a higher resolution or a pulse type output that may be summed over time to determine an accurate total energy during the test period.

4-6.4.5 Power Factor Meters. Power factor may be measured directly using three-phase power factor transducers when balanced load and frequency conditions prevail. Power factor transducers must have an uncertainty equal to or less than 0.01 PF of the indicated power factor.

4-6.4.6 Existing Power Plant Instrumentation.

Existing station instrumentation may be used for measurement of any of these parameters if it meets all of the requirements of this Code.

4-6.5 Electrical Generation Instrumentation Calibration

4-6.5.1 Watt and Watt-hour Meter Calibration. Watt and watt hour meters, collectively referred to as power meters, are calibrated by applying power through the test power meter and a power meter standard simultaneously. Should polyphase metering equipment be used, the output of each phase must be available or the meter must be calibrated with all phases simultaneously in three-phase operating condition.

Portable instruments shall be calibrated in a controlled laboratory environment if there is an indication of a problem with the measurement. The value of the voltage maintained on the potential circuit of the instruments during calibration shall cover the range of expected test values, based on the manufacturer's recommendations for required uncertainty. Polyphase meters, or metering systems which cannot be verified to be made up of separate single-phase meters, shall not be used unless they can be calibrated three-phase.

4-6.5.2 Var and Var-hour Meter Calibration. In order to calibrate a var or var-hour meter, one must either have a var standard or a watt meter standard and an accurate phase angle measuring device. Also the device used to supply power through the standard and test instruments must have the capability of shifting phase to create several different stable power factors. These different power factors create reactive power over the calibration range of the instrument.

Should a var meter standard be employed, the procedure for calibration outlined above for watt meters should be used. Should a watt meter standard and phase angle meter be used, simultaneous measurements from the standard, phase angle meter, and test instrument should be taken. The var level will be calculated from the average watts and the average phase angle.

Var and var-hour meters should be calibrated at the electrical line frequency of the equipment under test, i.e., do not calibrate meters at 60 Hz and use on 50 Hz equipment. Var and var-hour meters are particularly sensitive to frequency and should be used within 0.5 Hz of the calibration frequency.

4-6.6 Excitation Power Measurement

If the exciter is powered by current supplied from the main generator bus at a point after the gross electrical output metering, the power supplied to the exciter must be determined. There are two methods, as follows:

(a) *Derivation From Breaker Currents.* Exciter power and any other auxiliary gas turbine loads included in the gas turbine vendor scope of supply can be calculated

from the current and voltage input to the exciter power transformer or breaker. Since this is a measure of the actual power, which comes off of the main generator bus, this is the preferred method of determining exciter power required. The calculation is given in para. 5-1.3.1.1.

(b) *Derivation From Field Voltage and Current.* Power supplied to the exciter can also be estimated by calculating the power output by the exciter and by correcting for an assumed AC to DC conversion efficiency. The calculation is given in para. 5-1.3.1.2.

4-6.7 Measurement of Auxiliary Loads

If the test requires obtaining a net power output value for the gas turbine, auxiliary loads associated with the turbine must normally be measured. This is required when the gross electrical power metering is located upstream of the place where the auxiliary load power is supplied. Besides excitation power (see para. 4-6.6), the auxiliary loads generally consist of the electrical loads of the lubrication and hydraulic systems; water injection skids, external cooling air systems, etc. Another significant auxiliary load is the power required by the gas fuel compressor, necessary sometimes to boost the supply line gas pressure to the pressure required by the combustion system. The measurement of the auxiliary loads can be done with station permanent meters or locally using temporary instrumentation. In modern power stations, the permanent instrumentation used for this purpose can be found at the Motors Control Centers (MCC), where the electrical load is measured and displayed either as active power, or as voltage and current. It is recommended to create a list of all the auxiliary loads, measuring locations, and clearly identify which system is fed through which corresponding MCC. The data could be collected manually or automated, but at least three readings shall be taken for each performance run. For loads measured locally by temporary instrumentation, the exact measuring point has to be clearly identified and qualified personnel should connect the meters to avoid accidents.

4-6.8 Measurement of Step-up and Step-down Transformers

In many cases, the transformer losses of step-up and step-down transformers must be determined for a test. Since the power loss for a step-up/down transformer cannot be accurately measured in the field, it is necessary to use the results of the transformer's factory performance tests. Normally the factory tests determining the power loss are conducted at 0% and 100% rated load of the transformer and at various voltages.

In order to calculate the transformer power loss, measurements of the voltage and current at the high side of the transformer must be recorded. The calculation is then performed using the methodology described in

IEEE C57.12.90 as shown in Nonmandatory Appendix A-4.

4-7 MECHANICAL POWER MEASUREMENT

4-7.1 Torque and Speed Measurement

For gas turbines driving compressors, the determination of output shaft power is generally required. Reference should be made to ASME PTC 19.7 for guidance in these measurements.

A torque-measuring device shall be installed on the coupling between the gas turbine and its driven load (or load gear). This device shall be calibrated before the test, and if not left in place should be calibrated after the test. Speed of all gas turbine shafts shall be recorded.

4-7.2 Other Parameters and Variables

As required for generator drives, all other cycle and ambient data shall be recorded to permit correction of test data to Specified Reference Conditions. Since the operation of the turbine may be restricted by the pipeline or process conditions, it is important to also record the control parameters such as exhaust (or control) temperature.

4-8 SPEED MEASUREMENT

Shaft speed is normally measured from either the shaft connected to the electrical generator in multi-shaft turbines or the shaft driving the mechanical load in mechanical load turbines. Typically, for nongear turbines the shaft speed shall be 3,600 rpm for 60 Hz applications and 3,000 rpm for 50 Hz applications.

The shaft speed may be measured by standard speed sensors used in the turbine control system. For gas turbines connected to AC electrical generators, the line frequency measured at the generator terminals may be used instead of shaft speed to correct gas turbine performance since the shaft speed is directly coupled to the line frequency. The chosen method must meet the uncertainty requirement in this Code.

4-9 HUMIDITY MEASUREMENT

The moisture content of inlet air shall be measured directly with a hygrometer or indirectly by measuring the adiabatic wet-bulb temperature. The measurement location shall be upstream of any inlet air-conditioning device and preferably in close proximity to the dry-bulb temperature measurement. The measurement location shall be shielded from direct sunlight.

4-9.1 Direct Measurement

This method is required if freezing conditions are present during the test. The most common type of direct humidity measurement is a capacitive type hygrometer.

Appropriate calibration standards for field calibration or recent factory calibration certification needs to be available in order to ensure compliance with the measurement uncertainty requirement. Be aware that uncertainty levels for a capacitive type device often increase at extreme low and extreme high humidity levels.

4-9.2 Indirect Measurement via Wet-Bulb Temperature

This method does not require special calibration standards (other than what is needed for the temperature-sensing element). It can be used whenever conditions are above freezing. Wet-bulb temperature is measured by snugly covering the temperature-sensing element with a wetted cotton sock. Distilled water shall be used as a wetting agent. Air velocity across the sensing element shall be kept between 800 ft/min to 1,200 ft/min (4 m/s to 6 m/s) to ensure continuous evaporation of the distilled water. If the existing air velocity at the measurement location is insufficient by being less than 800 ft/min (4 m/s), the air can be forced across the sensing element using a fan.

Wet-bulb temperature can be inferred by a properly designed mechanically aspirated psychrometer. The mechanically aspirated psychrometer should incorporate the following features:

(a) The sensing element is shielded from direct sunlight and any other surface that is at a temperature other than the dry-bulb temperature. If the measurement is to be made in direct sunlight, the sensor must be enclosed by a double-wall shield that permits the air to be drawn across the sensor and between the walls.

(b) The sensing element is suspended in the airstream and is not in contact with the shield walls.

(c) The sensing element is snugly covered by a clean, cotton wick that is kept wetted from a reservoir of distilled water. The length of the wick shall be sufficient to minimize the sensing element stem conduction effects and ensure it is properly wetted.

(d) The air velocity across the sensing element is maintained constant in the range of 800 ft/min to 1,200 ft/min (4 m/s to 6 m/s).

(e) Air is drawn across the sensing element in such a manner that it is not heated by the fan motor or other sources of heat. The psychrometer should be located at least 4.9 ft (1.5 m) above ground level and should not be located within 4.9 ft (1.5 m) of vegetation or surface water.

4-10 HEAT LOSSES

Gas turbine heat losses are all system losses that cross the test boundary. Gas turbine heat losses have a very small influence on the final calculated exhaust energy or flow, and therefore are often calculated from data provided by the manufacturer rather than measured directly. Manufacturers may identify and categorize heat

losses differently, but they can generally be placed into four major categories: generator losses, gearbox losses, fixed losses, and variable losses.

Where the measurement of heat loss from lubricant coolers and other sources is required, the accuracy of temperature and flow measurement is such that determination of heat rejection may be accomplished with an uncertainty not greater than 10%. Where the actual measurement of heat loss is deemed unnecessary or impractical, the means of determining heat loss shall be determined by agreement among the parties to the test.

4-10.1 Generator Losses

Generator losses typically include exciter and collector losses, which are a function of generator output and power factor, and windage losses, which are a function of the generator cooling medium temperature. It is not practical to measure these losses directly during a test; therefore, they must be determined from curves provided by the generator manufacturer. Generator losses are typically on the order of 1% to 2% of the gross electrical output.

4-10.2 Gearbox Losses

Gearbox losses must be determined for applications that require load gears for speed reduction between the turbine rotor and the generator rotor. Gearbox losses are typically determined from data provided by the gearbox manufacturer. Gearbox losses can vary greatly, but are typically on the order of 1% to 2% of shaft output.

4-10.3 Fixed Losses

Fixed losses remain relatively constant across the range of base load operating conditions and may include mechanical losses of the turbine rotor bearings and any shaft driven accessories. The value for these losses should be provided by the manufacturer. Some fixed losses may be quantified by measuring the lube oil flow and the temperatures in and out of the lube oil cooler. However, caution should be used in cases where the cooler is partially bypassed to maintain a constant fluid temperature.

4-10.4 Variable Losses

Variable losses include heat rejected from the turbine rotor cooling system, overboard air or gas leakages, and heat radiated from the turbine casings. The algorithms for determining these losses should be provided by the manufacturer.

4-11 OTHER MEASUREMENTS

Various other measurements may be helpful for documenting the test. Some common ones are listed in paras. 4-11.1 through 4-11.3.

4-11.1 Time

Precision timing may be required in conjunction with certain instruments that are time sensitive. Examples include watt-hour meters for power measurement and fluid displacement meters for flow measurement. In these cases, a precision timing device such as a digital stopwatch with a resolution to 0.1 sec is sufficient.

4-11.2 Flow

Flow measurements other than liquid or gas fuel should be in accordance with ASME PTC 19.5 and Table 4-1.2.1-1 of this Code.

4-11.3 Turbine Control Parameters

Gas turbines maintain a steady load by the use of turbine control parameters that adjust the fuel flow. These control parameters should be measured during a test because applicability of the manufacturer's correction curves depends on the appropriate operating conditions; however, these parameters do not have their own correction curves. The manufacturer determines which parameters are the controlling parameters and how each parameter is measured during a test. Some turbine control parameters are variable guide vane position, turbine control temperature, compressor discharge or combustion chamber pressure, and fuel flow fractions.

4-11.3.1 Variable Guide Vane Position. Gas turbine installations may use variable geometry in the airflow path to control the volume of air passing through the gas turbine. In many gas turbine designs, variable geometry is achieved through the use of mechanically actuated guide vanes. Frequently, the definition of a load point, such as base load, at which a test is to be conducted, may depend on a specific guide vane angle. The position of each of the guide vanes should be measured prior to the test to ensure that the mean angle is consistent with both the manufacturer's specification and the indication in the turbine control system. Typically, the

manufacturer's specification will include a recommended method of measurement and the allowable deviation for the mean guide vane angle.

4-11.3.2 Turbine Control Temperature. The turbine control temperature is a critical parameter used by the control algorithm to set the gas turbine load level and turbine inlet temperature. Generally, turbine inlet temperature is virtually impossible to reliably measure, so the manufacturer chooses a lower temperature region for temperature measurement devices. The relationship between the turbine control temperature and the turbine inlet temperature is defined in a control algorithm determined by the manufacturer. The manufacturer, through experience, shall determine the number, type, and location of the control temperature measurements to account for expected temperature levels and inherent spatial variations.

For comparative testing, differences in the turbine control temperature determination may exist between the pre-modification and the post-modification test. This can change as a result of even changing one thermocouple during the outage. Change in the spatial distribution of this temperature due to modifications of the turbine or its operating condition (such as increased turbine inlet temperature or change in air management) is also likely. Since power is so sensitive to any shift in turbine control temperature, it is advisable to perform any thermocouple replacements and/or calibrations prior to the pretest to minimize uncertainty.

4-11.3.3 Compressor Discharge or Combustion Chamber Pressure. Along with the turbine control temperature, compressor discharge or combustion chamber pressure is also often required as an input into the manufacturer's control algorithm. This pressure is often divided by the inlet pressure measurement to estimate a compression ratio. The manufacturer will determine the number, type, and location of the measurement(s). The pressure is measured using one or more static pressure transmitter(s) in accordance with subsection 4-2.

Section 5

Computation of Results

This Section includes the details required for computing power output and heat rate (efficiency). Additional computations are provided in Mandatory Appendix I for exhaust flow, exhaust energy, and exhaust temperature.

5-1 ELECTRICAL POWER CALCULATIONS

5-1.1 Introduction

Electrical measurements required for the evaluation of gas turbine performance include gross electrical output, power factor, exciter power, and other auxiliary electrical loads. The measurement is discussed in subsection 4-6. This subsection of the Code provides guidance and requirements for the calculation of these measurements. The calculation method for average power or total energy should be performed in accordance with IEEE 120 for the specific type of measuring system used. Power measurements must be corrected for actual voltage transformer ratio and for phase angle errors in accordance with the procedures of IEEE C57.13.

A detailed sample calculation for electric power output is given in Nonmandatory Appendix A-2.

5-1.2 Electrical Measurement System Connections

Electrical measurement is based on the type of metering methods, as follows:

(a) three-wire power systems — two single-phase meters or one two-phase meter

(b) four-wire power systems — three single-phase meters or one three-phase meter

Paragraphs 5-1.2.1 and 5-1.2.2 describe calculations for the two types of three- and four-wire power systems that may exist.

5-1.2.1 Three-Wire Power Systems Power Factor Calculation. Power factor is then determined using the following formula:

$$PF = \frac{Watts_{total}}{\sqrt{Watts_{total}^2 + Vars_{total}^2}}$$

where

PF = power factor

$Vars_{total}$ = total vars for three phases

$Watts_{total}$ = total watts for three phases

Alternatively, for balanced three-phase sinusoidal circuits, power factor may be calculated from the two-meter power measurement method using the following formula:

$$PF = \frac{1}{\sqrt{1 + 3 \left[\frac{Watts_{1-2} - Watts_{3-2}}{Watts_{1-2} + Watts_{3-2}} \right]^2}}$$

where

PF = power factor

$Watts_{1-2}$ = real power phase 1 to 2

$Watts_{3-2}$ = real power phase 3 to 2

5-1.2.2 Four-Wire Power Systems Power Factor Calculation. Power factor can be calculated from the watt and var meters using the following formula:

$$PF = \frac{Watts_{total}}{\sqrt{Watts_{total}^2 + Vars_{total}^2}}$$

where

PF = power factor

$Vars_{total}$ = total vars for three phases

$Watts_{total}$ = total watts for three phases

Alternatively, power factor may be determined by measuring each phase voltage and current (Volt-Amps), with the following equation:

$$PF = \frac{Watts_{total}}{\sum V_i I_i}$$

where

I_i = phase current for each of the three phases

PF = power factor

V_i = phase voltage for each of the three phases

5-1.3 Excitation Power Calculation

5-1.3.1 Measured Excitation. If the exciter is powered by current supplied from the main generator bus at a point after the gross electrical output metering, the power supplied to the exciter must be determined, as described in para. 4-6.6. Two methods for determining the power supplied to the exciter are as specified in paras. 5-1.3.1.1 and 5-1.3.1.2.

5-1.3.1.1 Derivation From Breaker Currents.

Exciter power and any other auxiliary gas turbine loads included in the gas turbine vendor scope of supply can

be calculated from the current and voltage input to the exciter power transformer or breaker. Since this is a measure of the actual power, which comes off of the main generator bus, this is the preferred method of determining exciter power:

$$\text{ExcLoss} = \frac{\sqrt{3} \times V_{\text{avg}} \times I_{\text{avg}} \times PF}{1,000}$$

where

ExcLoss = exciter power, kW

I_{avg} = average phase current, A — measured value

PF = power factor — measured or calculated value

V_{avg} = average phase voltage, V — measured value

1,000 = conversion factor from watts (W) to kilowatt (kW)

If the measurement point is downstream of a step-down transformer, a correction should be applied for the transformer loss.

5-1.3.1.2 Derivation From Field Voltage and Current. Power supplied to the exciter can also be estimated by calculating the power output of the exciter and by correcting for an assumed AC to DC conversion efficiency using the following formula:

$$\text{ExcLoss} = \frac{FV \times FC}{1,000 \times \text{ACDC}}$$

where

ACDC = AC to DC conversion efficiency factor (typically 0.975, assumed value)

ExcLoss = exciter power (kW)

FC = field current (DC amps) — measured value

FV = field voltage (DC volts) — measured value

1,000 = conversion factor from watts (W) to kilowatt (kW)

5-1.3.2 Excitation Power Calculations From Supplier Information. Excitation power may be determined from supplier information based on load and power factor at the test conditions.

5-1.4 Instrument Transformers

The instrument transformers introduce errors when converting the high primary voltage/current to a low secondary voltage/current. These errors result in a variation of the true ratio from the marked ratio and also the variation of the phase angle from the ideal (zero). The magnitude of the errors depends on

(a) the burden (number and kinds of instruments connected to the transformer)

(b) the secondary current (in the case of current transformers)

(c) in the case of power measurement, the power factor of the device being measured

The correction methodology is presented in Nonmandatory Appendix A.

5-1.4.1 Voltage Transformers. The secondary voltage measured by the voltage transformer must be multiplied by the voltage transformer marked ratio (VTR) and by the voltage transformer ratio correction factor (VTR_{corr}) in order to calculate the primary voltage on the high side of the transformer. For the typical case where VTs are dedicated to voltage measurement and not to relays or voltage regulators, the secondary burden can be assumed to be close to zero. Therefore, the calibration data at zero burden plus 0.0005 may be assumed, leading to an estimated uncertainty of $\pm 0.05\%$.

5-1.4.2 Current Transformers. The current transformer ratio correction factor (CTR_{corr}) is calculated in a similar manner as the voltage transformer correction factor (VTR_{corr}). However, typical values at rated primary current vary little between 0.9999 and 1.0. Values outside this range should be accounted for. It should be emphasized that the CTR_{corr} for operation at conditions less than the rated primary current increases significantly and should not be neglected. The error at 10% current is permitted to be two times the value of the error at 100% rated primary current. CT calibration should therefore be provided at two different burdens and a function of load as detailed in para. 4-6.3.2.

5-1.4.3 Calculation of Corrected Primary Power. The power for each phase is corrected by applying calibration data from the instrument transformers and the power meter as follows:

$$P_{\text{highside}} = P_{\text{lowside}} \times \text{VTR} \times \text{CTR} \times \text{MCF} \times \text{VTR}_{\text{corr}} \times \text{CTR}_{\text{corr}} \times \text{PA}_{\text{corr}} \times \text{VTVD}_{\text{corr}}$$

where

CTR = the current transformer marked ratio

CTR_{corr} = the current transformer ratio correction factor from calibration data

MCF = the meter correction factor from calibration

P_{highside} = the corrected power on the high side of the transformer

P_{lowside} = the power measured on the low side of the transformer

PA_{corr} = the phase angle correction factor from calibration data

VTR = the voltage transformer marked ratio

VTR_{corr} = the voltage transformer ratio correction factor from calibration data

$\text{VTVD}_{\text{corr}}$ = the voltage transformer voltage drop correction

The meter correction factor (MCF) is determined from calibration data. Each phase of the meter should be

calibrated as a function of secondary current. The process should be done at a minimum of two different secondary voltages and at two different power factors. The actual MCF at test conditions could then be interpolated.

Phase angle correction factor for each phase (PA_{corr}) accounts for the phase shift that occurs in the voltage transformer (λ), current transformer (β), and the power meter (α). The Code will provide a more rigorous calculation; however, in most cases a linear interpolation as discussed below will provide a sufficiently accurate correction.

The phase shifts of each transformer could have an offsetting effect. For example, if the CT shifts the current waveform to the right and the VT shifts the voltage waveform in the same direction, the power meter output is not affected by a phase shift. Each of the phase shifts should be determined from calibration data.

$$PA_{corr} = \frac{\cos(\theta - \alpha + \beta - \gamma)}{\cos(\theta)} = \frac{\cos(\theta - \alpha + \beta - \gamma)}{(\text{Power Factor})}$$

where

- α = shift in the power meter phase angle
- β = shift in the current transformer phase angle
- γ = shift in the voltage transformer phase angle
- θ = arccos (power factor)

A good approximation in practice will be to assume that when power factor is 1, the PA_{corr} will also be equal to 1.

5-2 MECHANICAL POWER OUTPUT CALCULATION

5-2.1 Mechanical Drive Power

Power at the gas turbine shaft is the product of the torque and speed, with appropriate unit conversion constants.

(U.S. Customary Units)

$$SHP = \frac{\text{Torque} \times \text{Speed}}{5,252.1}$$

where

SHP = shaft horsepower, with Torque in lbf-ft and Speed in rpm

(SI Units)

$$\text{Power} = \text{Torque} \times \text{Speed} \times 2\pi/60$$

where Power is in watts, with Torque in N-m, and Speed in rpm

5-2.1.1 Correction to Specified Reference Conditions. If the gas turbine can be run at rated power, the corrections proceed as shown for generator drives. In the event that system conditions do not permit running the test at rated load, the parties will need to agree

on the method of adjusting the output and heat rate to the specified conditions. Two methods are commonly employed.

(a) The manufacturer may supply correction curves or cycle data that will allow adjusting the data to rated speed(s) and control temperature, from which the corrections to Specified Reference Conditions may be made.

(b) The gas turbine may be run at several points through a load and/or speed range to permit interpolation or extrapolation of the data to the rated load point. This generally involves normalizing the test results by applying dimensionless parameters, which are described in most thermodynamic textbooks.

It is expected that the first system will be more prevalent, given the availability and accuracy of gas turbine cycle performance programs.

5-2.2 Efficiency

Heat rate, conventionally used for generator drives, may not be the preferred parameter for mechanical drives. If thermal efficiency is required, it is

$$\eta_{th} = SHP \times \frac{2,544.43}{\text{Heat Input}}$$

where heat input (Btu/hr in this case) is from subsection 5-3. Heat rate, in Btu/hp-hr, can be calculated from Heat Input/SHP.

In SI Units, thermal efficiency can be calculated by

$$\eta_{th} = \text{Power} \times 3.6 / \text{Heat Input}$$

where power is in watts, and heat input (kJ/hr in this case) is from subsection 5-3. Heat rate, in kJ/W-hr, can be calculated from Heat Input/Power.

5-3 HEAT RATE CALCULATIONS

5-3.1 Fuel Heat Input

Calculation procedures for gas and liquid fuel heat input are presented here. A sample calculation for gas fuel heat input can be found in Nonmandatory Appendix A-1.

5-3.1.1 Differential Pressure Meter. The general equation for mass flow rate through a differential pressure class meter for both liquids and gases is as follows:

$$M_f = \frac{\pi}{4} * d^2 * C * \epsilon * \sqrt{\frac{2 * \rho(T,P) * \Delta P * g_c}{1 - \beta^4}} \quad (5-3.1)$$

where

C = orifice discharge coefficient (determined from calibration report)

D = diameter of pipe at flowing fluid temperature

d = diameter of orifice at flowing fluid temperature

Table 5-3.1.1-1 Typical Values for Unit Conversion Factor, N_1 , Using Common Units of Measure

Symbol	U.S. Units	U.S. Units	U.S. Units	SI Units	SI Units	SI Units
Calculation Constants						
π	3.14159	3.14159	3.14159	3.14159	3.14159	Universal constant
g_c	32.1740	32.1740	32.1740	NA	NA	lbm*ft/(lbf*sec ²)
g_c	NA	NA	NA	1.0000	1.0000	kg*m/(N*sec ²)
Units of Measure						
d	in.	in.	in.	mm	mm	...
ΔP	lbf/in. ²	in.H ₂ O60°F	in.H ₂ O68°F	mbar	kPa	...
$\rho(T,P)$	lbm/ft ³	lbm/ft ³	lbm/ft ³	kg/m ³	kg/m ³	...
M_f	lbm/sec	lbm/sec	lbm/sec	kg/s	kg/s	...
N_1	0.525021	0.0997424	0.0997019	0.000351241	0.0000351241	...

g_c = units conversion constant

M_f = fuel mass flow rate

ΔP = differential pressure across orifice

β = ratio of orifice and pipe diameter (d/D), both diameters at the flowing fluid temperature

ϵ = expansion factor

$\rho(T,P)$ = fluid density at flowing temperature and pressure

NOTE: Measurement units for the above parameters and variables are given in Table 5-3.1.1-1.

This equation can be further reduced to the following format:

$$M_f = N_1 \times d^2 \times C \times \epsilon \times E_v \times \sqrt{\rho(T,P) \times \Delta P} \quad (5-3.2)$$

where

$$E_v = \text{velocity of approach factor} = \frac{1}{\sqrt{1 - \beta^4}}$$

N_1 = unit conversion factor

5-3.1.2 Orifice Dimensions. If the flowing temperature of the fluid is different than the temperature at which the pipe and orifice dimensions were determined, the measured orifice and pipe dimensions must be corrected to compensate for the temperature variations.

$$d = \left[1 + \alpha_{PE} * (T_f - T_{meas}) \right] * d_{meas} \quad (5-3.3)$$

$$D = \left[1 + \alpha_{PP} * (T_f - T_{meas}) \right] * D_{meas} \quad (5-3.4)$$

where

D_{meas} = measured diameter of the pipe at T_{meas}

d_{meas} = measured diameter of the orifice at T_{meas}

T_f = temperature of the flowing fluid

T_{meas} = temperature of the orifice or pipe material when the diameters were measured

α_{PE} = coefficient of thermal expansion for the orifice material

α_{PP} = coefficient of thermal expansion for the pipe material

Refer to ASME PTC 19.5, Section 2, for thermal expansion data.

5-3.1.3 Expansion Factor. The expansion factor, ϵ , compensates for the change in density due to a decrease in pressure when the fluid flows through the orifice:

$$\epsilon = 1 - (0.41 + 0.35 * \beta^4) \times \frac{\Delta P}{N_2 * k * P_f} \quad (5-3.5)$$

where

k = isentropic exponent

= $C_p / (C_p - 1.986 / MW_f)$, where

C_p = specific heat at constant pressure

MW_f = molecular weight of fluid

N_2 = unit conversion factor

P_f = upstream static pressure of fluid

β = ratio of orifice and pipe diameter (d/D), both diameters at the flowing fluid temperature

ΔP = differential pressure

Typical values for unit conversion factor, N_2 , are given in Table 5-3.1.3-1.

5-3.1.4 Compressibility. Fluid compressibility, Z_f , at flowing conditions shall be calculated based upon the methods outlined in AGA Report No. 8 utilizing the Detail Characterization Method (Input of individual gas constituents). Subsection 8.1 and Nonmandatory Appendix A of AGA Report No. 8 present detailed information for the Detail Characterization.

5-3.1.5 Density — Gas Fuel. Gas fluid density at flowing fluid conditions is calculated from the following equation:

$$\rho(T,P) = \frac{MW_{gas} P_f}{Z_f R T_f} \quad (5-3.6)$$

where

MW_{gas} = molecular weight of the gas mixture

$$MW_{gas} = \sum_{j=1}^n x_j * MW_j$$

Table 5-3.1.3-1 Typical Values for Unit Conversion Factor, N_2 , Using Common Units of Measure

Symbol	U.S. Customary Units	U.S. Units	U.S. Units	Metric Units	Metric Units	Metric Units
ΔP	lb/in. ²	in.H ₂ O 60°F	in.H ₂ O 68°F	kPa	mbar	Mbar
P	lb/in. ²	lb/in. ²	lb/in. ²	MPa	bar	MPa
N_2	1.00000	27.7070	27.7300	1000.00	1000.00	0.0100000

MW_j = molecular weight of gas component j
 n = total number of components
 P_f = static pressure of fluid before orifice
 R = universal gas constant
 T_f = temperature of fluid (absolute, °R or K)
 x_j = mole fraction of gas component j
 Z_f = fluid compressibility at flowing pressure and temperature
 $\rho(T,P)$ = gas fluid density at flowing fluid temperature and pressure

5-3.1.6 Volumetric Meter. The general equation for mass flow rate through a volumetric meter for both liquids and gases is as follows:

$$M_f = q_v * \rho(T,P) * MCF \quad (5-3.7)$$

where

MCF = meter calibration factor
 M_f = fuel mass flow rate
 q_v = actual volume flow rate
 $= V_g/\Delta t$
 V_g = totalized volume of fluid measured during test
 $=$ final volume – starting volume
 Δt = fluid volume timing period
 $\rho(T,P)$ = fluid density at flowing fluid temperature and pressure

5-3.1.7 Density – Liquid Fuel. Liquid fuel density is determined from the following equation:

$$\rho_T = \rho_{H_2O} * sg_T \quad (5-3.8)$$

where

sg_T = specific gravity of the liquid fuel at the flowing temperature
 ρ_{H_2O} = density of water which was used to define specific gravity of fuel
 ρ_T = fluid density at flowing fluid temperature

5-3.1.8 Heating Values – Gas Fuel. The higher heating value (HHV) and lower heating value (LHV) of a gas fuel mixture are given by

$$HHV = \sum_{j=1}^n x_j * MW_j * HHV_j / \sum_{j=1}^n x_j * MW_j \quad (5-3.9)$$

$$LHV = \sum_{j=1}^n x_j * MW_j * LHV_j / \sum_{j=1}^n x_j * MW_j \quad (5-3.10)$$

where

HHV_j = higher heating value per unit mass for component j
 LHV_j = lower heating value per unit mass for component j
 MW_j = molecular weight of gas component j
 n = total number of components
 x_j = mole fraction of gas component j

5-3.1.9 Heating Values – Liquid Fuel. For liquid fuels, the higher heating value at constant volume is determined by fuel analysis per para. 4-5.4.1. The higher and lower heating values at constant pressure are determined from the following equations.

For heating values in Btu/lbm:

$$HHV_p = HHV_v + 2.64 * H \quad (5-3.11)$$

$$LHV_p = LHV_v - 91.20 * H \quad (5-3.12)$$

For heating values in kJ/kg:

$$HHV_p = HHV_v + 6.14 * H \quad (5-3.13)$$

$$LHV_p = LHV_v - 212.13 * H \quad (5-3.14)$$

where

H = percent of hydrogen (H_2) by weight contained in the liquid fuel
 HHV_p = higher heating value at constant pressure
 HHV_v = higher heating value at constant volume
 LHV_p = lower heating value at constant pressure

5-3.1.10 Sensible Heat – Liquid Fuel. The sensible heat for liquid fuels is calculated as:

$$SH_p = M_f * (h_T - h_{Ref}) \quad (5-3.15)$$

where

h_{Ref} = specific enthalpy of the liquid fuel at the reference temperature.
 h_T = specific enthalpy of the liquid fuel at the flowing temperature
 M_f = actual mass flow
 SH_p = sensible heat at constant pressure

NOTE: Reference temperature for heat rate determination is fuel temperature at Specified Reference Conditions. Reference temperature for heat balance determination is user specified enthalpy reference temperature.

The specific enthalpy of liquid fuel is defined in D.W. Gould's equation from *The Science of Petroleum*, Vol. 2, page 1,250 (out of print), and reads as follows:

$$h = C_1 + C_2(^{\circ}\text{API}) + [C_3 + C_4(^{\circ}\text{API})](T) + [C_5 + C_6(^{\circ}\text{API})](T^2)$$

where, for specific enthalpy in Btu/lbm

$$C_1 = -30.016$$

$$C_2 = -0.11426$$

$$C_3 = 0.373$$

$$C_4 = 0.00143$$

$$C_5 = 2.18 \times 10^{-4}$$

$$C_6 = 7.0 \times 10^{-7}$$

h = specific enthalpy in Btu/lbm

T = temperature in $^{\circ}\text{F}$

$^{\circ}\text{API}$ = API gravity

and, for specific enthalpy in kJ/kg,

$$C_1 = -41.535$$

$$C_2 = -0.15766$$

$$C_3 = 1.6201$$

$$C_4 = 0.006175$$

$$C_5 = 1.64 \times 10^{-3}$$

$$C_6 = 5.28 \times 10^{-6}$$

h = specific enthalpy in kJ/kg

T = temperature in $^{\circ}\text{C}$

$^{\circ}\text{API}$ = API gravity

5-3.1.11 Sensible Heat — Gas Fuel. The sensible heat input for gaseous fuels is calculated as:

$$SH = M_f * (h_T - h_{\text{Ref}}) \quad (5-3.16)$$

where

h_{Ref} = specific enthalpy of the gaseous fuel at the reference temperature

h_T = specific enthalpy of the gaseous fuel at the flowing temperature

M_f = actual mass flow

SH = sensible heat of gaseous fuel

NOTE: Reference temperature for heat rate determination is fuel temperature at Specified Reference Conditions. Reference temperature for heat balance determination is user specified enthalpy reference temperature.

The specific enthalpy of the actual gaseous fuel can be derived from gas properties published by NIST and others.

5-3.1.12 Heat Input. Calculation of heat input. The total heat input is calculated as:

$$HI = M_f * HV + SH$$

where

HI = total heat input

HV = fuel heating value

M_f = fuel mass flow

(a) For power output and heat rate test, HV = lower or higher heating value (LHV or HHV) of the fuel as defined in Specified Reference Conditions.

(b) For exhaust flow or energy test, HV = lower heating value (LHV) of the fuel because the heat of vaporization for water is not recovered inside the heat balance boundary.

SH = sensible heat input (may be different for power/heat rate test and heat balance calculation, see paras. 5-3.1.10 and 5-3.1.11)

NOTE: Often the agreed calculation of heat input for a heat rate test is based solely on latent heat with no sensible heat component. In such cases, test correction curves may be used to account for variations in fuel supply temperature.

5-3.2 Heat Rate

The measured gas turbine heat rate is calculated as a ratio of the total heat input to power output. Heat rate is typically expressed in units of Btu/kWh, Btu/hp-hr, or kJ/kWh.

The general equation to calculate heat rate from measured test data is:

$$HR_{\text{meas}} = \frac{HI_{\text{meas}}}{P_{\text{meas}}}$$

where

HI_{meas} = the measured total heat input value of the fuel (see para. 5-3.1.12)

P_{meas} = the measured value of power output (see subsection 5-1 or subsection 5-2)

Heat rate is directly related to thermal efficiency by the following conversion:

$$\eta_{\text{th}} = C/HR_{\text{meas}}$$

where

$C = 3,412.14$ when HR_{meas} is expressed in Btu/kWh

$= 2,544.43$ when HR_{meas} is expressed in Btu/hp-hr

$= 3,600$ when HR_{meas} is expressed in kJ/kWh

η_{th} = thermal efficiency

5-4 CORRECTION OF TEST RESULTS — FUNDAMENTAL PERFORMANCE EQUATIONS

The following fundamental performance equations for correcting calculated test values to the Specified Reference Conditions are applicable to any of the gas turbine types covered by this Code.

Corrected power is expressed as

$$P_{\text{corr}} = \frac{P_{\text{meas}} + \sum_{i=1}^m \Delta i}{\prod_{n=1}^K \alpha_n}$$

Table 5-4-1 Summary of Additive Correction Factors for Power Fundamental Performance Equation

Power	Uncontrollable External Condition Requiring Correction	Comments
Δ_1 (*)	Generator power factor	Measured at the power measurement location
Δ_2	Generator excitation power	When excitation power is supplied after power measurement
Δ_3	Auxiliary loads	If required by test boundary
Δ_4	Transformer losses	If required by test boundary

GENERAL NOTE: The asterisk (*) indicates that either term is acceptable for generator power factor but not both.

Table 5-4-2 Summary of Correction Factors in All Fundamental Performance Equations

Power	Heat Rate	Exhaust Flow	Exhaust Energy	Exhaust Temperature	Uncontrollable External Condition Requiring Correction
α_1	β_1	γ_1	ϵ_1	ζ_1	Inlet air temperature
α_2	β_2	γ_2	ϵ_2	ζ_2	Barometric pressure
α_3	β_3	γ_3	ϵ_3	ζ_3	Inlet humidity
α_4	β_4	γ_4	ϵ_4	ζ_4	Fuel composition
α_5	β_5	γ_5	ϵ_5	ζ_5	Injection fluid flow
α_6	β_6	γ_6	ϵ_6	ζ_6	Injection fluid enthalpy
α_7	β_7	γ_7	ϵ_7	ζ_7	Injection fluid composition
α_8	β_8	γ_8	ϵ_8	ζ_8	Exhaust pressure loss
α_9	β_9	γ_9	ϵ_9	ζ_9	Shaft speed
α_{10}	β_{10}	γ_{10}	ϵ_{10}	ζ_{10}	Turbine extraction
α_{11}	β_{11}	γ_{11}	ϵ_{11}	ζ_{11}	Fuel temperature
α_{12}	β_{12}	γ_{12}	ϵ_{12}	ζ_{12}	Inlet pressure loss
α_{13} (*)	...	...	...	...	Generator power factor

GENERAL NOTE: The asterisk (*) indicates that either term is acceptable for generator power factor but not both.

Corrected heat rate is expressed as

$$HR_{\text{corr}} = \left(\frac{1}{IF_{n=1}^K \beta_n} \right) \left(\frac{HR_{\text{meas}}}{P_{\text{meas}} + \sum_{i=1}^m \Delta i} \right)$$

Corrected exhaust flow is expressed as

$$m_{\text{exh,corr}} = \frac{m_{\text{exh}}}{IF_{n=1}^K \gamma_n}$$

Corrected exhaust energy is expressed as

$$Q_{\text{exh,corr}} = \frac{Q_{\text{exh}}}{IF_{n=1}^K \xi_n}$$

Corrected exhaust temperature is expressed as

$$t_{\text{exh,corr}} = t_{\text{exh}} + \sum_{n=1}^x \delta_n \text{ or } t_{\text{exh,corr}} = \frac{t_{\text{exh}}}{IF_{n=1}^K \delta_n}$$

Multiplicative correction factors α_n , β_n , γ_n , ϵ_n , and δ_n , and additive correction factors Δi and δ_n are used to correct measured results back to the Specified Reference Conditions. Attention should be paid to the basis of measured power and heat rate, as either net or gross,

to make sure that the correction curves use the same basis. Table 5-4-1 summarizes the additive corrections for the power fundamental performance equation. Table 5-4-2 summarizes the correction factors used in all the fundamental performance equations.

While these correction factors are intended to account for all variations from Specified Reference Conditions, it is possible that performance could be affected by processes or conditions that were not foreseen at the time this Code was written. In this case, additional correction factors, either additive or multiplicative, would be required.

For special gas turbine operating modes such as power limit or part load, the correction methodology would require use of parameters not included in Table 5-4-2. For instance, in heavy duty gas turbines, IGV modulation may have an effect and should be considered. For aeroderivative gas turbines, IGV modulation is not an active method of control; however, all other methods of control should be considered. In lieu of additional correction curves or factors, original equipment manufacturers (OEMs) may provide a model-based correction method for these special operating modes. The correction factors that are not applicable to the specific type

of gas turbine configuration being tested, or to the test objective, are simply set equal to unity or zero, depending on whether they are multiplicative correction factors or additive correction factors, respectively.

All correction factors must result in a zero correction if all test conditions are equal to the Specified Reference Conditions. Some correction factors may be significant only for unusually large deviations from Specified Reference Conditions, or not at all, in which case they can also be ignored. An example of this is the fuel composition correction. If the pre-test uncertainty analysis shows a correction to be insignificant, these corrections can be ignored. An insignificant correction is one that results in a correction of less than 0.05%.

The applicable corrections to use in the fundamental performance equations for a particular test depend on the type of gas turbine being tested and the goal of the test. Specific examples of the fundamental performance equations for different gas turbine configurations and boundary conditions are provided in Nonmandatory Appendix, para. A-3.

For comparative tests correcting the test data to Specified Reference Conditions may be the largest contributor to the test uncertainty, therefore corrections used should be limited to those needed to establish the objective. Rather than use a full set of envelope corrections around the test boundary as described in this Code, the parties can agree to a limited amount of correction factors based on the scope of modifications or restorative actions performed. For example, it may be advisable to correct the post-modification results to the same ambient, etc., conditions of the pre-modification test. This will eliminate one set of corrections, which additionally may be very advantageous since preparing accurate correction curves for a deteriorated turbine will likely be difficult.

5-4.1 Alternate Corrected Gas Turbine Exhaust Energy

The determination of gas turbine exhaust energy is outlined in Mandatory Appendix I and can be evaluated at any condition including one that is consistent with the Specified Reference Conditions. Utilizing inputs already corrected to Specified Reference Conditions results in the evaluation of exhaust energy at the conditions of interest, eliminating the need, as an alternative, for applying correction factors on exhaust energy. Expressed as

$$Q_{\text{exh,corr}} = Q_{\text{air,corr}} + Q_{\text{fuel,corr}} + Q_{\text{inj,corr}} - Q_{\text{elect,corr}} - Q_{\text{loss,corr}} - Q_{\text{ext,corr}} \quad (5-4.1)$$

where the subscript “corr” denotes corrected to Specified Reference Conditions.

For example, with a test configuration without extraction or injection, and with the inlet air temperature set to the enthalpy reference temperature, the use of corrected

output ($Q_{\text{elect,corr}}$) and corrected heat consumption ($Q_{\text{fuel,corr}} = \text{corr Power} \times \text{corr Heat rate}$) will result in exhaust energy evaluated at the Specified Reference Conditions. (The remaining term, $Q_{\text{loss,corr}}$, has little influence and can be estimated easily.)

5-5 APPLICATION OF CORRECTION FACTORS

The format of the fundamental equations allows decoupling of the appropriate correction effects (ambient conditions, injection fluids, etc.) relative to the measured prime parameters of power, heat rate, exhaust flow or energy, and exhaust temperature so that measured performance can be corrected to the Specified Reference Conditions. Corrections are calculated for parameters at the test boundary different than Specified Reference Conditions, which affect measured performance results.

Since the variation in power, heat rate, exhaust flow or energy, and exhaust temperature due to various external conditions is unique to each gas turbine, the manufacturer may generate a set of site specific correction curves to be incorporated into the site specific test procedures prior to the test. Each correction factor is calculated by varying only one parameter over the possible range of deviations from the base reference condition. Some of the correction factors are summations of smaller corrections or require a family of curves. For example, the correction for fuel composition may be split into two or more components to better characterize the impact of fuel composition on gas turbine performance.

Manufacturers sometimes supply curves that are referenced to standard conditions other than the Specified Reference Conditions. In this case, relative corrections relating the measured test conditions and Specified Reference Conditions must be calculated as shown in the examples below

$$\alpha_1 = \frac{\alpha_{1a}}{\alpha_{1b}}$$

$$\delta_1 = [\delta_{1a} - \delta_{1b}]$$

where the subscripts signify

- a = correction from measured point to standard condition
- b = correction from Specified Reference Condition to standard condition

In lieu of application of the equations and correction curves, a gas turbine simulation model provided by the manufacturer may be applied after the test using the appropriate test data and boundary conditions so that all of the corrections for the particular test run are calculated simultaneously. Studies of different gas turbine cycles using the performance curves and equations instead of the simulation model have demonstrated that interactivity between correction factors usually results

in differences of less than 0.3%. An advantage of the post-test model simulation is a reduction or elimination of the efforts put forth to generate the correction curves and to apply the correction curves to actual test data.

The gas turbine power, heat rate, exhaust energy or flow, and exhaust temperature can be corrected to Specified Reference Conditions based on ambient conditions and other external quantities using the multiplicative and additive correction factors as described in paras. 5-5.1 through 5-5.12.

5-5.1 Inlet Air Temperature Correction ($\alpha_1\beta_1\gamma_1\epsilon_1\delta_1$)

Correction is made to gas turbine performance based on the inlet air temperature crossing the test boundary. The inlet air temperature shall be measured in accordance with subsection 4-3.

5-5.2 Barometric Pressure Correction ($\alpha_2\beta_2\gamma_2\epsilon_2\delta_2$)

Correction is made to gas turbine performance based on the site barometric pressure (or other pressure measurement location if agreed upon by the parties). Barometric pressure is measured in accordance with subsection 4-2.

5-5.3 Inlet Humidity Correction ($\alpha_3\beta_3\gamma_3\epsilon_3\delta_3$)

Correction is made to gas turbine performance based on humidity of the air crossing the test boundary. Typically the humidity of the air will be equal to the ambient humidity and will be measured in accordance with subsection 4-9.

5-5.4 Fuel Composition Correction ($\alpha_4\beta_4\gamma_4\epsilon_4\delta_4$)

Differences in fuel properties between the reference fuel analysis and the measured fuel analysis affect the performance of the gas turbine. The fuel analysis shall be measured near the test boundary in accordance with subsection 4-4 for gaseous fuels and subsection 4-5 for liquid fuels.

The fuel composition correction factors may be determined as a combination of multiple factors to better characterize the impact of the variance in composition on gas turbine performance. As another alternative, the fuel composition correction factors may be determined by the manufacturer's thermal performance simulation model after the test, if agreed upon by the parties. The manufacturer should provide a sample correction calculation in the detailed test procedures prior to the test.

5-5.5 Injection Fluid Flow Correction ($\alpha_5\beta_5\gamma_5\epsilon_5\delta_5$)

Correction is made to gas turbine performance based on the injection fluid flow crossing the test boundary. The injection fluid flow shall be measured in accordance with subsection 4-11.

5-5.6 Injection Fluid Enthalpy Correction ($\alpha_6\beta_6\gamma_6\epsilon_6\delta_6$)

Correction is made to gas turbine performance based on the injection fluid enthalpy crossing the test boundary. The injection fluid enthalpy shall be calculated in accordance with the applicable version of the ASME Steam Tables or other appropriate standard for the given injection fluid. Injection fluid pressure shall be measured in accordance with subsection 4-2. Injection fluid temperature shall be measured in accordance with subsection 4-3.

5-5.7 Injection Fluid Composition Correction ($\alpha_7\beta_7\gamma_7\epsilon_7\delta_7$)

Differences in injection fluid composition between the reference injection fluid composition and the measured injection fluid composition affects the performance of the gas turbine. Typically, the injection fluid is either water or steam where the multiplicative correction factors are equal to 1.0 and the additive correction factor is equal to zero. If the injection fluid is a gaseous mixture such as a nitrogen/oxygen mixture in an IGCC plant, then the composition of the injection fluid will impact gas turbine performance and shall be determined in accordance with subsection 4-4.

5-5.8 Exhaust Pressure Loss Correction ($\alpha_8\beta_8\gamma_8\epsilon_8\delta_8$)

Correction is made to gas turbine performance based on the turbine static exhaust pressure loss at the test boundary. The need for this correction may depend on the scope of equipment within the test boundary. If necessary, the exhaust gas static pressure loss is measured in accordance with subsection 4-2.

5-5.9 Shaft Speed Correction ($\alpha_9\beta_9\gamma_9\epsilon_9\delta_9$)

Correction is made to gas turbine performance based on deviations of the shaft speed from the Specified Reference Conditions. See subsection 4-8 for speed measurement methods.

5-5.10 Turbine Extraction Correction ($\alpha_{10}\beta_{10}\gamma_{10}\epsilon_{10}\delta_{10}$)

Correction is made to gas turbine performance based on the flow rate of any extractions from the gas turbine measured where they cross the test boundary. Typically, this correction might apply to an IGCC plant where large quantities of compressor exit air are extracted for use in the coal gasification process. Extraction flows shall be measured in accordance with subsection 4-11, as appropriate.

5-5.11 Fuel Temperature Correction ($\alpha_{11}\beta_{11}\gamma_{11}\epsilon_{11}\delta_{11}$)

Correction is made to gas turbine performance based on the measured fuel temperature at the test boundary. The fuel temperature shall be measured near the test

boundary in accordance with subsection 4-4 for gaseous fuels and subsection 4-5 for liquid fuels.

5-5.12 Inlet Pressure Loss Correction ($\alpha_{12}\beta_{12}\gamma_{12}\epsilon_{12}\delta_{12}$)

Correction is made to gas turbine performance based on the turbine inlet total pressure loss at the test boundary. The need for this correction may depend on the

scope of equipment within the test boundary. If necessary, the inlet air total pressure loss is measured in accordance with subsection 4-2.

5-6 DEGRADATION

The corrected results from subsection 5-5 represent the thermal performance of the gas turbine at the Specified Reference Conditions at the time of the performance test. If required by the contract or the parties, an additional correction for performance degradation may be applied.

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Section 6

Report of Results

6-1 GENERAL REQUIREMENTS

The test report shall provide definitive statements of the purpose of the test, the methodology for attainment of the objectives, and descriptions of the results. It shall also clearly and concisely document all data generated by the test as well as all ensuing computations.

The test report shall contain all the information described below.

6-2 SUMMARY

- (a) General information about the plant and the test, such as the location, plant turbine type and operating configuration, and the test objective
- (b) Date and time of the test
- (c) Summary of the results of the test compared to the contractual guarantees for acceptance type tests
- (d) Calculated post-test uncertainty
- (e) Any agreements among the parties to the test to allow any major deviations from the test requirements

6-3 TEST DESCRIPTION

- (a) Test description and objectives
- (b) General information about the plant and the test, such as:
 - (1) Brief history of the unit operation, from start up through the performance tests
 - (2) Description of the equipment to be tested and all such ancillary equipment that may influence the test
 - (3) Cycle diagram showing the test boundary
- (c) Listing of the representatives of the parties to the test
- (d) Organization of the test personnel
- (e) All test agreements

6-4 TEST EQUIPMENT

- (a) Tabulation of test equipment used, including quantity, make, model number, etc.
- (b) Description of the location of the test equipment
- (c) Means of data collection for each data point, e.g., temporary data acquisition system printout, plant control computer printout, or manual data sheet, and any identifying tag number and/or address of each
- (d) Description of data acquisition system(s) used
- (e) Summary of test equipment calibration

6-5 CALCULATIONS AND RESULTS

- (a) Tabulation of the operating conditions and results during all testing including any observations.
- (b) Statement of the general performance equation that is used based on the test goal and the applicable corrections
- (c) Tabulation of the reduced data necessary to calculate the results, summary of additional operating conditions not part of such reduced data
- (d) Calculation of test results from the reduced data (see Nonmandatory Appendix A for examples of step-by-step calculations for each plant type and test goal)
- (e) Detailed calculation of fuel flow rates from applicable data, including intermediate results, if required
- (f) Detailed calculations of fuel properties density, heating value (specifically state as higher or lower), constituent properties
- (g) Identification and rationale for any elimination of data
- (h) Comparison of repeatability of test runs, if more than one test run was performed
- (i) Clarify as to whether reported heat rate is based on higher heating value or lower heating value
- (j) Discussion of results as applicable

6-6 APPENDICES

- (a) Test procedures, including correction curves or methodology and sample calculations
- (b) Copies of original data sheets and/or electronically acquired data in mutually agreed format
- (c) Copies of test logs, messages or alarms, or other record of operating activity during each test
- (d) Documentation indicating operation in the required configuration (such as inlet air-conditioning, compressor guide vane angle, and/or fluids injection, etc.)
- (e) Documentation of control settings affecting performance
- (f) Results of laboratory fuel analysis
- (g) Instrumentation calibration results from laboratories, certification from manufacturers
- (h) Measurement uncertainty calculation, pre- and post-test.
- (i) Any pretest inspection sheets showing signatures of witnesses.

Section 7

Test Uncertainty

7-1 INTRODUCTION

This Section contains sample calculations for gas turbine tests defined by this Code: unit output and thermal efficiency (subsection 7-3), comparative tests (subsection 7-4), and exhaust energy and flow calculations (subsection 7-5). It also summarizes some of the key uncertainty considerations from ASME PTC 19.1 (subsection 7-2).

7-2 UNDERSTANDING TEST UNCERTAINTY

7-2.1 Uncertainty Versus Error

Random and systematic *uncertainties* are the estimates of the standard deviation of the elemental *error* sources. As the objective of this Section is to calculate test uncertainty, the discussion will concentrate on understanding uncertainty.

7-2.1.1 Systematic and Random Components of Measurement Errors. The total error, δ_j , for each measurement has two components, as follows:

- (a) systematic, β
- (b) random, ϵ_j , as shown in Fig. 7-2.1.1-1

Values of the two components are determined by calculation or estimation of each of the contributing error sources.

7-2.2 Random Standard Uncertainty, S_X

Several error sources associated with the test instrumentation are reflected as scatter in the data over the test time interval. It is generally assumed that this scatter is normally distributed, and can be approximated statistically. For a sample measurement, the mean value is given by

$$\bar{X} = \frac{\sum_{j=1}^N X_j}{N}$$

where X_j represents the value of each individual measurement in the sample and N is the number of sample measurements. The standard deviation of the sample s_X is given by

$$s_X = \sqrt{\frac{\sum_{j=1}^N (X_j - \bar{X})^2}{N - 1}}$$

The random standard uncertainty (RSU) is the standard deviation of the mean, or

$$s_{\bar{X}} = \frac{s_X}{\sqrt{N}}$$

For the required 95% confidence level, with $N > 30$, $2s_{\bar{X}}$ is equal to the expanded random uncertainty.

The RSU can be reduced by increasing the number of instruments, and sometimes by increasing the number of readings (for cases where $N < 30$). Typically the RSUs are estimated for the pretest uncertainty analysis and calculated by the data acquisition system where N is usually greater than 30. If N is significantly less than 30, refer to ASME PTC 19.1 for methods of determining the RSU.

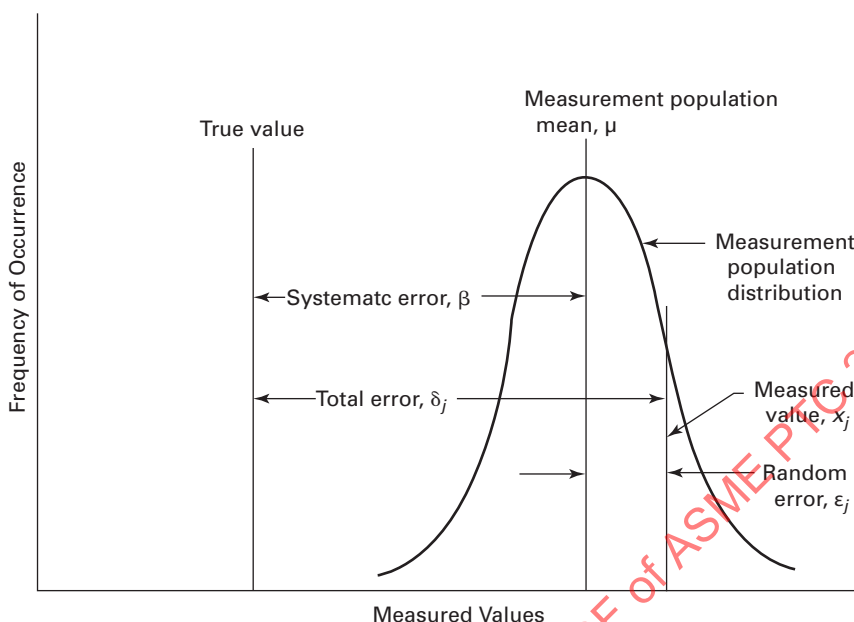
7-2.3 Systematic Standard Uncertainty, b_i

This is an estimate, based on experience, of the error of the average value not eliminated through calibration. It is a constant value despite repeated measurements. The systematic error can be reduced by better instrument calibration and, if uncorrelated, by increasing the quantity of instruments.

7-2.3.1 Estimating Systematic Uncertainties, b_X

Systematic uncertainties, b_X , are estimated using the experience of the parties, and the suggestions and analyses presented in ASME PTC 19.1. Estimates should reflect the 95% confidence level (2^*b_X) used for ASME Performance Test Codes. For assistance in establishing reasonable values for the systematic uncertainty, consider the following:

- (a) ASME PTC 19.1 on test uncertainty.
- (b) ASME PTC 19 series on instrumentation (pressure, temperature, flow, power, data acquisition).
- (c) the spatial variation expected, and the quantity of instruments used.
- (d) the cumulative test experience of the parties.
- (e) calibration lab's accuracy and their experiences with varieties of instrument types.
- (f) laboratory standards for inter-laboratory agreement. For example, the allowed variation in fuel properties when the same fuel is submitted to different labs.
- (g) comparison of measurements that depend on different principles.

Fig. 7-2.1.1-1 Illustration of Measurement Errors

(h) experience with duplicate instruments measuring the same quantity, or with different instruments measuring the same quantity.

(i) the data acquisition system to be used (If manual readings, how accurately can the scale be read? If automatic, will the data acquisition system be calibrated, will deadbands be removed, etc.).

7-2.3.2 Spatial Effects on Systematic Uncertainty.

The systematic uncertainty may be a combination of the instrument accuracy and the spatial variation. For gas turbine tests, measurement of inlet air temperature in the area of the filter house, and measurement of exhaust temperature in front of the HRSG, are potential sources of spatial effects. Spatial effects are considered to be systematic, not random, and can be evaluated statistically.

The spatial contribution can be calculated from

$$b_{\text{spatial}} = \frac{s_{\text{spatial}}}{\sqrt{J}}$$

$$s_{\text{spatial}} = \sqrt{\frac{\sum_{i=1}^J (\bar{X}_i - \bar{\bar{X}})^2}{J - 1}}$$

where

J = number of sensors (i.e., spatial measurement locations)

s_{spatial} = standard deviation of the multiple sensor time-averaged values

$\bar{X}_i$ = average for the sampled measurand

$\bar{\bar{X}}$ = grand average for all averaged measurands

For the 95% confidence level, b_{spatial} needs to be multiplied by 2.

$$B_{\text{spatial}} = 2 \times b_{\text{spatial}}$$

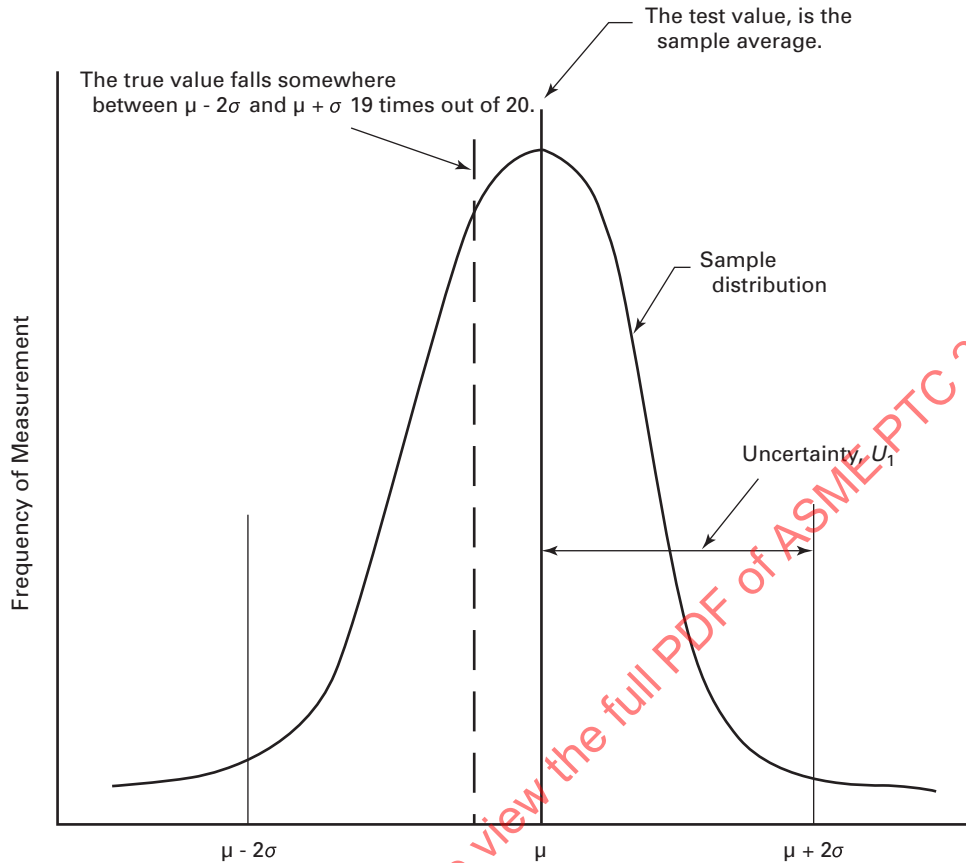
When spatial variation is expected, careful planning for the number and location of sensors is critical to reducing this impact on uncertainty.

7-2.3.3 Combining Systematic Uncertainties. When all the systematic influences have been evaluated, at the 95% confidence level B_k , they are combined into a single $B_{\bar{X}}$ factor for the measurement by the root sum square method.

$$B_{\bar{X}} = \left[\sum_{k=1}^K (B_k)^2 \right]^{1/2}$$

7-2.3.4 Correlated Versus Uncorrelated Systematic Uncertainty. This equation assumes that the systematic standard uncertainties of the measured parameters are all independent of each other. There are, however, many practical situations where this is not true; for example, using the same instruments to measure different parameters, or calibrating different instruments against the same standard. In these cases, some of the systematic errors are said to be correlated, and these nonindependent errors must be considered in the determination of the systematic standard uncertainty of the result. The parties should refer to ASME PTC 19.1 for details on calculating correlation effects, and to the examples shown later in this Section.

Fig. 7-2.4-1 Test Uncertainty Diagram



7-2.4 Confidence Interval

Figure 7-2.4-1 illustrates the 95% confidence interval as ± 2 standard deviations (2σ) from the mean (μ). There is a 95% probability that the unknown true value lies within the test mean $\pm 2\sigma$.

7-2.4.1 Coverage Factor. The use of “2” as the multiplier to obtain the 95% confidence level assumes that the degrees of freedom, ν , are above a certain level, nominally 30. The Student’s t distribution tabulates the degrees of freedom required for several confidence intervals. ASME PTC 19.1, Nonmandatory Appendix B, discusses this subject and provides methods for determining ν . Since uncertainty is not an exact science, adherence to rigorous application of the t value may not be justified. For example, the value of t at $\nu = 10$ is 2.228, for 95% confidence, which is about 10% higher than the value at $\nu = 30$ ($t = 2.042$). Considering these factors, there is considerable justification for the use of “2” except in cases where ν is in the low single digits.

7-2.5 Combining $B_{\bar{X}}$ and $s_{\bar{X}}$ for the Total Measurement Uncertainty

The total uncertainty, $U_{\bar{X}}$, for each parameter being measured is calculated from the root sum square (RSS)

of the systematic and random components. With the systematic contributors estimated at the expanded 95%, or two standard deviation, level, and the random component at the one standard deviation level, the total expanded uncertainty of the measurement is

$$U_{\bar{X}} = 2 \times \sqrt{(B_{\bar{X}}/2)^2 + (s_{\bar{X}})^2}$$

where

$B_{\bar{X}}$ = the expanded systematic uncertainty of the measurand mean

$s_{\bar{X}}$ = the random standard uncertainty of the measurand mean

$U_{\bar{X}}$ = the total uncertainty at a 95% confidence level

7-2.6 Sensitivity Coefficients, or Influence Coefficients, ϕ_i

The sensitivity coefficients are equal to the slope of the correction curves at the conditions of the test run. Most sensitivities are unique to each gas turbine design, and are provided by the manufacturer. The parties must agree on the source of these values before conducting any uncertainty analyses. In the pretest analysis, use the slope at the Specified Reference Condition, or, if known,

at the condition expected during the test. In the post-test analysis, use the slope at the test conditions.

7-2.7 Combining Measurement Uncertainties Into the Uncertainty of the Result

The uncertainty of the result, U_R , is the RSS value of the systematic and random standard uncertainties of each measurement multiplied by the sensitivity coefficient, θ_i , for that parameter. Thus:

$$S_R = \sqrt{\sum_{i=1}^I (\theta_i s_{\bar{X}_i})^2}$$

$$B_R = \sqrt{\sum_{i=1}^I (\theta_i B_{\bar{X}_i})^2}$$

$$U_R = 2 \times \sqrt{(B_R/2)^2 + (S_R)^2}$$

where

- $B_{\bar{X}_i}$ = the expanded systematic uncertainty for measurement i
- $s_{\bar{X}_i}$ = the random standard uncertainty for measurement i
- U_R = the uncertainty of the result
- θ_i = sensitivity coefficient for measurement i

7-2.8 Uncertainty Is Not Affected by Turbine Control Parameters Inside the Test Boundary

The calculations include only those measurements, and their associated sensitivity θ_i values, necessary to adjust the test point results to the Specified Reference Conditions. Internal control variables (such as compressor discharge pressure or exhaust temperature) are generally not part of the uncertainty analysis for output or heat rate.

7-2.9 Post-test Uncertainty Analysis

The data shall be plotted and examined for sudden shifts and outliers. A post-test uncertainty analysis shall be conducted to replace the assumptions made in the pretest analysis. In particular, the random uncertainty can now be calculated and incorporated. Also, in accordance with para. 3-6.4, the sensitivities can now be recalculated at the test values (in other words, the slopes at the applicable portion of the correction curves may now be used in Table 7-3.1-3).

7-3 UNIT OUTPUT AND THERMAL EFFICIENCY

7-3.1 Uncertainty Calculation Logic

The three-step process defined in subsection 3-6 is recommended for establishing the pre- and post-test uncertainties. First, for pretest, an uncertainty limit is calculated based on the Code Limits for each parameter from Table 4-1.2.1-1. The information required for this first uncertainty is the power measurement (electrical or mechanical), fuel type, scope of supply (in this case

water injection and air extraction are included), and the sensitivities of the turbine being tested. Tabulate these in a format similar to Table 7-3.1-1. This calculation will yield the maximum test uncertainty allowed for this particular Code Test, which will be referred to as the Code Limit. The example in the Tables is for a differential pressure fuel measurement system; an orifice in this case.

The second step is to assess the instrumentation expected to be used for the test. The parties should attempt to improve on the uncertainties allowed by the Code, in order to assure that the post-test uncertainty will come in at or below the Code Limit. Accordingly, Table 7-3.1-2 is prepared, using the best estimates for each parameter based on the selected instrumentation, their calibration levels, and the experience of the parties. Note that the electrical power and heat input measurements have been broken down into their individual measurements, such that the results are within the values from Table 4-1.2.1-1.

The third step, after the test, is to calculate the post-test uncertainty. This reflects the values for the actual instrumentation used and the random uncertainties calculated from the data. From an uncertainty standpoint, the test shall be considered successful if the post-test uncertainty does not exceed the Code Limit uncertainty. Table 7-3.1-3 is a sample calculation for the post-test case. This shows that the corrected heat rate uncertainty is below the pretest plan, and well within the Code Limit.

7-3.2 Uncertainty Calculations

As specified in para. 7-2.7, the uncertainties in power output and thermal efficiency are equal to the RSS value of the uncertainty of each parameter multiplied by its Sensitivity Coefficient. The calculations include the measurements and θ values necessary to adjust the test point results to the Specified Reference Conditions.

The calculation procedure is as follows:

(a) After systematic and random components are established, the total uncertainty U_x is calculated from the RSS of the two components.

(b) The sensitivity θ is multiplied by B_x and $2S_x$ and squared.

(c) All the U_x^2 factors are summed and the square root taken to determine the uncertainty for the output or efficiency.

(d) Gas turbine tests normally cannot be run at the Specified Reference Conditions of inlet air temperature and barometric pressure, therefore the test results must be corrected to the Specified Reference Conditions. The corrected power uncertainty is obtained in the same manner as the measured power uncertainty, considering the uncertainty and sensitivity for the added parameters of inlet air temperature, barometric pressure, inlet humidity, and others as required.

Table 7-3.1-1 Step 1: Code Limit Uncertainty (Example)

Result	Parameter	Measured By	Table 4-1.2.1-1		Pretest Uncert.		Sens θ [Note (1)]	$(U_B \cdot \theta)^2$	$(U_{25x} \cdot \theta)^2$	Total UNC $(U_T)^2$	Pretest Code Limit
			Limit	B	25 _x						
Power	Watt hours	3 meter method	...	...	...	...	...	...	...	...	...
	Volts (ratio)	Calib. VT's	...	...	...	...	...	...	...	...	...
	Amps (ratio)	0.3% class CT's	...	...	...	...	...	...	...	...	...
	Time (if req'd)	Digital watch	...	...	...	...	...	...	...	...	...
	Gross power	...	0.25%	...	...	1	...	...	...	0.0625	0.250
	Aux power	Station meter	5.00%	...	...	0.015	...	...	...	0.005625	...
Heat Input	Net power	...	...	...	...	...	SUM	0.068125	...	0.261	...
	Flow coeff. C	From calib.	...	...	1	...	...	...	...	...	...
	Exp factor ϵ	4 Δ P/P	...	...	1	...	...	...	...	...	...
	Compress Z	AGA 8	...	...	-0.5	...	...	...	...	...	...
	ΔP	Diff. pr. transd.	...	...	0.5	...	...	...	...	...	...
	Fuel press P	Press. transd.	...	...	0.5	...	...	...	...	...	...
Heat Rate	Fuel temp. T	RTD	...	...	-0.5	...	...	...	...	...	...
	DP factors	...	...	...	1	...	...	...	...	...	...
	Mol % of fuel*	ASTM 1945	...	...	1	...	...	...	...	...	...
	Heat input	...	...	...	...	...	...	0.5625	...	0.750	...
	RSS of net power and heat input	...	...	...	...	...	SUM	0.630625	...	0.794	...
	Heat rate	...	...	...	...	...	...	...	...	...	...
Corrected Power	Inlet temp.	Multiple RTD's	1°F	...	...	0.3	...	...	...	0.09	...
	Bar. pressure	Abs. pr. transd.	0.075%	...	...	1	...	...	...	0.005625	...
	Rel. humidity	Hygrometer	2%	...	...	0.004	...	...	...	0.000064	...
	Power factor	Volts, amps, kW	...	...	0.015	...	...	0.00056	...	...	...
	Water inj. flow	Orifice	2%	...	...	0.035	...	...	...	0.0049	...
	Air extr. flow	Orifice	2%	...	...	-0.021	...	...	...	0.001764	...
Corrected Heat Rate	Net power	...	...	...	...	...	...	0.068125	...	...	...
	Corrected Power	...	...	...	...	...	...	0.171038	...	0.414	...
	Inlet temp	...	1°F	...	...	0.08	...	...	...	0.0064	...
	Rel. humidity	...	2%	...	...	0.0076	...	...	...	0.000231	...
	Water inj. flow	...	2%	...	...	0.013	...	...	...	0.000676	...
	Water inj. T	...	5°F	...	...	0.004	...	...	...	0.0004	...
Corr Heat Rate	Air extr. flow	...	2%	...	...	0.011	...	...	...	0.000484	...
	Heat rate	...	...	...	1	...	...	0.630625	...	...	...
	Corr Heat Rate	...	...	...	...	...	SUM	0.638816	...	0.799	...
	Corr Heat Rate	...	...	...	...	...	...	...	...	...	...

GENERAL NOTE: See Table 7-3.3.2.2-1 for actual calculation of the uncertainty for Mol%.

NOTE:

(1) These sensitivities are assumed for this example. Every test will have its own set depending on the characteristics of the tested turbine's equipment.

Table 7-3.1-2 Step 2: Pretest Uncertainty Calculation (Example)

Result	Parameter	Measured By	Correlated	Target UNC	Pretest Uncert.		Sens. θ [Note (1)]	$(U_B \cdot \theta)^2$	$(U_{2sx} \cdot \theta)^2$	Total UNC $(U_T)^2$	Pretest UNC	Code Limit
					B	2s _x						
Power	Watt-hours	3 meter method	Yes	0.10%	0.1	0	1	0.01	...	0.01	...	...
	Volts (ratio)	Calib. V.P.s	Yes	0.10%	0.1	0	1	0.01	...	0.01	...	...
	Amps (ratio)	0.3% class CT's	Yes	0.15%	0.15	0	1	0.0225	...	0.0225	...	...
	Time (if req'd)	Digital watch	...	0.05%	NR	...	...	...	...	...	...	...
Heat Input	Gross power	...	...	...	...	...	...	...	SUM	0.0425	0.206	0.250
	Aux power	Station meter	...	5%	3	...	0.015	0.002025	0	0.002025	...	...
	Net power	...	...	...	...	...	...	...	SUM	0.044525	0.211	0.261
	Flow coeff. C	From calib.	...	0.25%	0.25	0	1	0.0625	0	0.0625	...	...
Heat Rate	Exp factor ϵ	4AP/P	...	0.05%	0.05	...	1	0.0025	0	0.0025	...	...
	Compress Z	AGA 8	...	0.10%	0.1	...	-0.5	0.0025	...	0.0025	...	...
	ΔP	Diff. p t/d	...	0.25%	0.2	0.1	0.5	0.01	0.0025	0.0125	...	...
	T	RTD	...	0.25%	1	0.2	0.09	0.0225	0.00140625	0.023906	...	...
	P	t/d	...	0.25%	0.2	0.1	0.5	0.01	0.0025	0.0125	...	...
	DP factors	...	...	...	...	...	...	...	...	0.116406	0.341	...
	Mol % of fuel	Chromatograph	...	0.60%	...	...	...	...	...	0.36	...	...
	DP factors	From above	...	...	...	...	1	...	...	0.116406	...	...
	Heat input	...	...	...	...	...	...	...	...	0.476406	0.690	0.750
	Net power	From above	...	...	...	...	...	...	...	0.044525	...	...
Corrected Power	Heat input	From above	...	...	...	...	...	...	...	0.476406	...	...
	Heat rate	...	...	...	...	...	...	...	...	0.520931	0.722	0.794
	Inlet temp.	Multiple RTD's	Yes	1°F	0.65	0.15	0.3	0.038025	0.00646416	0.044489	...	...
	Bar. pressure	Abs. p t/d	...	0.75%	0.075	0	1	0.005625	0	0.005625	...	...
	Rel. humidity	Hygrometer	...	2%	2	0	0.004	0.000064	0	0.000064	...	...
	Power factor	Volts, amps, kW	...	0.2%	0.2	0	0.015	0.00009	0	0.00009	...	...
	Water inj. flow	Orifice	...	2%	1.75	0.75	0.035	0.003752	0.000689063	0.004441	...	...
	Air extr. flow	Orifice	...	2%	1.75	0.75	-0.021	0.001351	0.000248063	0.001599	...	...
	Net power	...	...	...	...	...	1	...	...	0.044525	...	...
	Corr. Net Power	...	...	...	...	...	...	...	...	0.100751	0.317	0.414
Corrected Heat Rate	Inlet temp	...	...	1°F	0.65	0.15	0.08	0.002704	3.31776E-05	0.002737	...	...
	Rel. humidity	...	...	2%	2	0	0.0076	0.000231	0	0.000231	...	...
	Water inj. flow	...	...	2%	1.75	0.75	0.013	0.000518	9.50625E-05	0.000613	...	...
	Water inj. T	t/c	...	5°F	3	2	0.004	0.000145	6.46416E-05	0.00021	...	...
	Air extr. flow	...	...	2%	1.75	0.75	0.011	0.000371	6.80625E-05	0.000439	...	...
	Heat rate	...	...	...	...	...	1	...	...	0.520931	...	...
	Corr. Heat Rate	...	...	...	...	...	...	...	...	0.525161	0.725	0.799

NOTE:

(1) These values assumed for this example [see Note (1) in Table 7-3.1-1].

Table 7-3.1.1-3 Step 3: Post-Test Uncertainty Calculation (Example)

Result	Parameter	Test Uncertainty		Sens. θ [Note (1)]	$(U_B \cdot \theta)^2$	$(U_{2s} \cdot \theta)^2$	Total UNC (U_T) ²	Test UNC Step 3	Pretest UNC Step 2	Code Limit Step 1
		B	2s _x							
Power	Watts	0.1	0	1	0.01	...	0.01	...	...	...
	Volts (ratio)	0.1	0	1	0.01	...	0.01	...	...	...
	Amps (ratio)	0.15	0	1	0.0225	...	0.0225	...	...	...
	Time (if req'd)	NR	...	...	...	...	...	...	...	...
	Gross power	3	...	...	...	SUM	0.0425	0.206	0.206	0.250
Heat Input	Aux power	3	1.6	0.015	0.002025	0.000576	0.002601	...	...	...
	Net power	...	...	...	...	SUM	0.045101	0.212	0.211	0.261
	Flow coeff. C	0.25	0	1	0.0625	0	0.0625	...	...	...
	Exp factor	0.04	...	1	0.0016	0	0.0016	...	...	...
	Compress Z	0.1	...	-0.5	0.0025	...	0.0025	...	...	...
Heat Rate	ΔP	0.25	0.1	0.5	0.015625	0.0025	0.018125	...	...	...
	T°F	0.185	0.05	0.5	0.008556	0.000625	0.009181	...	...	...
	p	0.25	0.1	0.5	0.015625	0.0025	0.018125	...	...	...
	DP factors	...	...	...	...	...	0.112031	0.335	0.341	...
	Mol % of fuel*	0.538	...	...	...	...	0.289774	...	...	...
Heat Rate	[Note (2)]	...	...	...	...	SUM	0.401805	0.634	0.690	0.750
	Heat input	...	...	...	...	...	0.045101	...	...	...
	Net power	...	...	...	...	...	0.401805	...	...	...
	Heat input	...	...	...	...	...	0.446906	0.669	0.722	0.794
	Heat rate	...	...	...	...	SUM	0.023793	...	...	...
Corrected Power	Inlet temp F	0.513	0.0346	0.3	0.023685	0.00010774	0.005625	...	...	...
	Bar. pressure	0.075	0	1	0.005625	0	0.00064	...	...	...
	Rel. humidity	2	0	0.004	0.000064	0	3.24E-06	...	...	...
	Power factor	0.1	0	0.018	3.24E-06	0	0.004977	...	...	...
	Water inj. flow	1.75	1	0.035	0.003752	0.001225	0.001792	...	...	...
Corrected Heat Rate	Air extr. flow	1.75	1	0.021	0.001351	0.000441	0.045101	...	...	...
	Net power	...	...	1	...	...	0.081354	0.285	0.317	0.414
	Corr. Net Power	...	...	...	...	...	0.002644	...	...	...
	Inlet Temp F	0.513	0.0346	0.1	0.002632	1.1972E-05	0.000231	...	...	...
	Rel. humidity	2	0	0.0076	0.000231	0	0.000681	...	...	...
Corrected Heat Rate	Water inj. flow	1.75	1	0.013	0.000518	0.000169	0.000286	...	...	...
	W/Inj temp F	2.2	1	0.007	0.000237	0.000049	0.000492	...	...	...
	Air extr. flow	1.75	1	0.011	0.000371	0.000121	0.447	...	...	...
	Heat rate	...	...	1	...	...	0.451245	0.672	0.725	0.799
	Corr. Heat Rate	...	...	...	...	...	...	...	...	...

NOTES:

- (1) These values assumed for this example [see Note (1) in Table 7-3.1-1].
 (2) See Table 7-3.3.2.2-1 for actual calculation of the uncertainty for Mol%.

(e) Heat rate is equal to heat input divided by power. The corrected heat rate uncertainty is obtained similarly; by establishing the sensitivities of each of the parameters affecting heat rate and proceeding as above.

7-3.3 Sample Calculation

An example will illustrate the uncertainty calculation procedure. Table 7-3.1-1 tabulates the parameters necessary to obtain the test results for the particular turbine under test, and the instrumentation expected to be used. This is a gas fired turbine with air extraction and water injection (and is based on the same performance as the example for exhaust energy in Mandatory Appendix I). The measurement uncertainty limit from Table 4-1.2.1-1 is recorded for each.

Then Table 7-3.1-2 is completed with assumed values of random and systematic uncertainties based on the specific instrumentation the parties intend to use. In some cases the random uncertainty is taken as zero, where the number is a single value or calculation (e.g., orifice flow coefficient) or a fixed factor (e.g., VT and CT values).

The three most critical calculations are for power, heat input, and inlet air temperature, and are detailed in paras. 7-3.3.1 through 7-3.3.4.

7-3.3.1 Power. With the three watt-hour meter method, total gross power is the sum of the three-phase measurements.

$$P_g = P_1(CT_1)(VT_1) + P_2(CT_2)(VT_2) + P_3(CT_3)(VT_3)$$

Since P_1 , P_2 , and P_3 are nearly equal, the partial derivatives (normalized) will yield $\theta = 1/3$. For calibrated watt-hour meters, and CTs and VTs per para. 4-6.3, the systematic components of uncertainty have been assumed to be

Instrument	Symbol	Uncertainty
Whr meter	B_p	0.1%
VT	B_{vt}	0.1%
CT	B_{ct}	0.15%

Based on the uncertainty limits provided by IEEE C57.13, voltage transformer total uncertainties can be estimated as $\pm 0.1\%$ when using $\pm 0.3\%$ accuracy class voltage transformers that are calibrated for turns ratio and phase angle and operated within their rated burden range.

Based on the factory type (design) test information, the current transformer total uncertainties can be estimated as $\pm 0.15\%$ when operated within their rated burden range during the test and operated near 100% of rated current.

As was discussed in para. 7-2.3.4, it is likely that these parameters are correlated, as they were probably calibrated at their facility against the same standard.

Therefore, the gross power systematic uncertainty is calculated from (Reference Section 8 of ASME PTC 19.1):

$$B_{gp} = \{[(\theta_1 B_{p1})^2 + (\theta_2 B_{p2})^2 + (\theta_3 B_{p3})^2 + 2\theta_1 \theta_2 B_{p12} + 2\theta_1 \theta_3 B_{p13} + 2\theta_2 \theta_3 B_{p23}] + [(\theta_1 B_{ct1})^2 + (\theta_2 B_{ct2})^2 + (\theta_3 B_{ct3})^2 + 2\theta_1 \theta_2 B_{ct12} + 2\theta_1 \theta_3 B_{ct13} + 2\theta_2 \theta_3 B_{ct23}] + [(\theta_1 B_{vt1})^2 + (\theta_2 B_{vt2})^2 + (\theta_3 B_{vt3})^2 + 2\theta_1 \theta_2 B_{vt12} + 2\theta_1 \theta_3 B_{vt13} + 2\theta_2 \theta_3 B_{vt23}]\}^{0.5}$$

The arithmetic here will show $B_{gp} = 0.206\%$. It can be shown that this is the same as the RSS value of the individual uncertainties: 0.1, 0.1, and 0.15. If the meters and/or the transformers were not correlated, B_{gp} would be less than 0.206%, since the appropriate $2\theta\theta B$ terms would be dropped.

For net power $P_{net} = P_g - P_{aux}$, if aux power is 1.5% of gross, $\theta_{aux} = 0.015$.

To evaluate the uncertainty in corrected power output, from Section 5:

$$P_{corr} = (P_{net} + \Delta's) / (\alpha_1 \alpha_2 \dots \alpha_n)$$

NOTE: The form of this equation depends on how the guarantee was made and on the corrections provided.

Since the Δ 's are relatively small and are assumed to have no uncertainties, they can be neglected in the uncertainty analysis.

The alpha terms are taken directly from the manufacturer's correction curves or data and assumed to have no uncertainty. Each one, however, depends on a measured variable or parameter that does have uncertainty. The relationships of corrected power vs. inlet temperature, humidity, air extraction, and water injection are unique to each turbine model, and are usually provided in the form of % power per unit change in the variable, as shown in Table 7-3.1-2. The normalized values become the sensitivities θ to be used in the uncertainty calculation.

7-3.3.2 Heat Input — Gas Fuel. The complexity of the uncertainty calculations for heat input is a function of the method used to arrive at the mass flow. A meter which determines mass flow directly, such as a Coriolis meter, simplifies the calculation, as the heat input uncertainty is $2\sqrt{(B_{Mf}/2)^2 + (Sx_{Mf})^2 + (B_{HV}/2)^2}$. A positive displacement meter measuring volume flow adds the density uncertainty to the equation. For a differential pressure meter measuring gas flow, however, there are several parameters that are dependent upon the constituent analysis: molecular weight MW , heat value HV , and expansion factor ϵ . This case will be examined first.

7-3.3.2.1 Mass Flow by Differential Pressure (Orifice) Meter. To organize the calculation, three groups of numbers will be calculated, as follows: items relying on the fuel constituent analysis, items remaining from the orifice equation, and all others.

(a) The orifice equation for mass flow shows a dependence on the mol fractions MF_i in several places: the density ρ (molecular weight MW and compressibility Z), and the expansion factor ϵ (density again, and the specific heat ratio κ is a function of the MW). To calculate heat input, the LHV is required, which is dependent on MF_i as well. Therefore, to determine the sensitivities for MF_i the entire heat input equation must be differentiated.

To simplify the calculus, an examination of the expansion factor shows that its sensitivity to MF_i is very weak compared to that for the density and the heat value. Therefore, it will not be included in the following analysis. Similarly, the compressibility Z is not a straightforward function of composition, and can be more easily handled by including it in the orifice factors directly.

The basic equations that rely on MF_i are:

$$\text{Density, } \rho = (P \cdot MW) / (R \cdot T \cdot Z)$$

$$\text{Molecular Weight, } MW = \sum (MF_i \cdot MW_i)$$

$$\text{Mass Flow (from orifice equation)} = f(\sqrt{\rho})$$

$$\text{Heat Value, } LHV = \sum MF_i \cdot MW_i \cdot LHV_i / MW$$

$$\text{Heat Input, } HI = M_f \cdot LHV$$

where i is for each constituent C_1 to C_n , plus inerts, if any.

Using the Chain Rule:

$$\delta HI / \delta MF_i = \delta HI / \delta M_f \cdot \delta M_f / \delta MF_i + \delta HI / \delta LHV \cdot \delta LHV / \delta MF_i$$

and,

$$\begin{aligned} \delta M_f / \delta MF_i &= \delta M_f / \delta MW \cdot \delta MW / \delta MF_i \\ MW &= \sum MF_i \cdot MW_i \\ \delta MW / \delta MF_i &= MW_i \\ LHV &= \sum (MF_i \cdot MW_i \cdot LHV_i) / MW \\ \delta LHV / \delta MF_i &= MW_i \cdot LHV_i / MW \\ \delta M_f / \delta MW &= M_f / 2MW \end{aligned}$$

Then $\delta HI / \delta MF_i = MF_i \cdot MW_i / MW (0.5 + LHV_i / LHV)$, when the differentiation is normalized by multiplying by $MF_i / (M_f \cdot LHV)$.

The sensitivities can now be calculated. To complete the analysis, each parameter's uncertainty is assigned. For the fuel constituents, the chromatograph will provide the mol percentages. In accordance with Nonmandatory Appendix B, the uncertainties can be related to the reproducibility figures given in ASTM D1945 by dividing by the square root of 2.

Constituent, %	Reproducibility	B_{MF_i}
0 to 0.1	0.02	0.014
0.1 to 1.0	0.07	0.05
1.0 to 5.0	0.10	0.07
5.0 to 10	0.12	0.085
Over 10	0.15	0.106

The reproducibility numbers are absolute, not percent of the mol percentage. For instance, for the example case the mol percent for C_1 is 82.78. The uncertainty for percentages over 10 is 0.106, so the percent uncertainty is $0.106/82.78$, or 0.128%.

The MF_i uncertainty increases with fuel compositions of many constituents, particularly if their percentages are low.

(b) Looking at the orifice equation, the parameters not a function of MF_i can be examined for their contribution to the uncertainty calculation. For a calibrated metering section, there should be negligible uncertainty in diameters d and D and their ratio β . This leaves P , ΔP , T , Z , ϵ , and C . Their sensitivities are straightforward:

Parameter	Sensitivity, θ
C	1
ΔP	0.5
P	0.5
T	-0.5
Z	-0.5
ϵ	1

For this example, the only other variable to consider is the fuel sensible heat. It will be neglected here, but if a test is run with much higher fuel temperature it should be included.

For C , a calibrated orifice section should have an uncertainty no greater than 0.25%, per ASME PTC 19.5.

As discussed in ASME PTC 19.5, the uncertainty in the expansion factor calculated from the variables in the equation is very small; however, there is considerably more uncertainty in the accuracy of the equation. It is recommended that the uncertainty in ϵ be $4\Delta P/P$, expressed as a percentage. For the sample case here, this is $4 \cdot 111.24 / (400 \cdot 27.7)$, where 27.7 converts inches of water to psi, and the uncertainty equals 0.04%.

The remaining unknown is the uncertainty of Z . AGA Report No. 8 presents a chart of target uncertainties for natural gas as a function of fuel temperature and pressure. For fuels at less than 1,750 psi, and between 17°F and 143°F, the target uncertainty is 0.1%.

Table 7-3.1-2 presents the sensitivity and uncertainty calculations for the fuel constituents and the orifice factors, and the resultant heat input uncertainty of 0.690%.

For all the calculations in this section, and as recommended in ASTM D3588, the uncertainties in the tabular values of molecular weight and heat value have been neglected, as they are small compared to the uncertainty of the composition.

The uncertainty for heat input for this example using a calibrated orifice meter is over 0.6%. Experience as well as the sensitivities emphasize that an accurate fuel analysis is critical, and frequently difficult to obtain. The use of multiple samples and labs is strongly recommended.

7-3.3.2.2 Mass Flowmeter. In this case the complexity is reduced since all the variables in the orifice

equation are eliminated. The sensitivity for the constituents on the heat value must be calculated. The heat input uncertainty is

$$U_{HI} = 2\sqrt{(B_{Mf}/2)^2 + (Sx_{Mf})^2 + (B_{HV}/2)^2}$$

Using the same data as in the prior example, the uncertainty calculation is shown in Table 7-3.3.2.2-1.

7-3.3.3 Heat Input — Liquid Fuel. This example is for a distillate fuel measured with a volumetric flowmeter, and LHV and hydrogen content determined by ASTM D4809 and D1018, respectively. The heat input will be

$$HI = M_f * LHV_p$$

where M_f is fuel mass flow which equals $\rho V(\text{MCF})/t$ per eq. (5-3.7). The sensible heat has been neglected in this uncertainty calculation, as it is very small compared to the heat value. However, the sensible heat should be included in the performance calculations. LHV_p is calculated from the ASTM D4809 value of HHV_v by

$$LHV_p = HHV_v - 0.2122 * \%H \text{ (SI units)}$$

Thus, $HI = (\rho V(\text{MCF})/t) * (HHV_v - 0.2122H)$

Uncertainties are summarized in Table 7-3.3.3-1.

For this example, assume the following fuel values:

$$HHV_v = 45.78 \text{ MJ/kg, so uncertainty} = 0.169 / 45.78 = 0.369\%$$

$$LHV_p = 42.93 \text{ MJ/kg}$$

$$H = 13.4\%, \text{ so uncertainty} = 0.127 / 13.4 = 0.95\%$$

Sensitivities from eq. (5-3.7) are:

$$V = 1$$

$$LHV = HHV_v / LHV_p = 1.066$$

$$\%H = -0.2122 * (\%H / LHV_p) = 0.066$$

and the Heat Input uncertainty =

$$\sqrt{(1 * 0.2)^2 + (0.369 * 1.066)^2 + (0.066 * 0.95)^2} = 0.446\%$$

7-3.3.4 Inlet Air Temperature. The most critical parameter for obtaining corrected power is usually the inlet air temperature. This Code requires that the total uncertainty be no greater than 1°F. An example will show how the parties can assure themselves that this limit will not be exceeded.

For the cycle used as an example in Mandatory Appendix I, the airflow is approximately 2.7 million lb/hr, which at 80°F and 14.696 psia barometric pressure is about 10,000 ft³/sec.

If the inlet velocity to the filter house is restricted to 10 ft/sec, the flow area needs to be 1,000 ft². The recommendation in para. 4-3.2 is one measurement device per 100 ft², so say 10 RTDs are used. Assume the following data are taken:

RTD	T_i °F	S_{iT}
1	78.6	0.3
2	79.4	0.4
3	80.1	0.4
4	80.7	0.1
5	80.9	0.3
6	79.2	0.2
7	80.6	0.4
8	80.6	0.3
9	79.9	0.3
10	80.0	0.1

Here S_{iT} is the sample standard deviation of each of the 30 readings taken during the test, obtained from the DAS. The random standard uncertainty of the inlet air temperature is

$$RSU = s_{Tbar} = \left[\sum_{i=1}^{10} (\theta s_{iTbar})^2 \right]^{0.5}$$

$$\begin{aligned} \theta &= \text{sensitivity} = 1/10 S_{iTbar} \\ &= \text{standard deviation of the mean} \\ &= S_{iT} / \sqrt{N}, \text{ and } N = 30 \end{aligned}$$

For this case $s_{Tbar} = 0.0173^\circ\text{F}$

Assume the systematic standard uncertainty has two components: the RTDs and the spatial variation.

$$b_t = \sqrt{b_{sp}^2 + b_{RTD}^2}$$

Assume $b_{RTD} = 0.1^\circ\text{F}$

For the spatial variation, $b_{sp} = s_{sp} / \sqrt{J}$ and

$$s_{sp} = \left[\sum_{i=1}^{10} \left(\frac{(T_i - T_{avg})^2}{J-1} \right) \right]^{0.5}, \text{ where } T_{avg} = 80^\circ\text{F and}$$

$J = 10$. The value of s_{sp} is 0.745°F , and $b_{sp} = 0.236^\circ\text{F}$.

Then $b_T = 0.256^\circ\text{F}$ and $u_T = (b_T^2 + s_{Tbar}^2)^{0.5} = 0.2566^\circ\text{F}$. For the 95% confidence level, U_T would usually be close to $2 * u_T$ if the degrees of freedom v_T were 20 or higher. In this example v_T is about 9, with a Student's t of 2.26. Thus U_T would be 0.58°F . Based on the discussion in para. 7-2.4.1, and considering the uncertainty in the estimates for the systematic uncertainties, the use of 2 is likely a reasonable compromise, which would make $U_T = 0.513^\circ\text{F}$.

The resulting uncertainty of 0.51°F to 0.58°F is within the 1°F requirement of Table 4-1.2.1-1, and the 0.513°F value is used in Table 7-3.1-3.

7-3.4 Test Uncertainty

Similarly, the rest of the uncertainties are calculated by RSS of the individual effects. The required post-test uncertainty, shown in Table 7-3.1-3, reflects the actual

Table 7-3.3.2.2-1 Heat Input Uncertainty for Mass Flow MeterSTEP 1: Find Sensitivity $\delta HI / \delta MF_i = MF_i * MW_i * LHV_i / (MW * LHV)$

	MF_i	MW_i	$MW \text{ Fract}$	LHV_i	$LHV \text{ Fract}$	LHV_i / LHV	Sensitivity, $\theta_{MF_i} \delta HI / \delta MF_i$
C1	82.78	16.0425	13.27998	21511.9	14600.744	1.0208498	0.692880064
C2	10.92	30.069	3.283535	20429.2	3428.4018	0.9694702	0.162695226
C3	5	44.0956	2.20478	19922.2	2244.9222	0.9454104	0.106533055
iC4	0.5	58.1222	0.290611	19589.8	290.96502	0.9296363	0.013807781
nC4	0.5	58.1222	0.290611	19657.8	291.97502	0.9328633	0.01385571
iC5	0.1	72.1488	0.072149	19455.9	71.74294	0.9232821	0.00340457
nC5	0.2	72.1488	0.144298	19497.2	143.79047	0.925242	0.006823594
	100		19.56596		21072.541		

STEP 2: Calculate Uncertainties for MF_i

	MF_i	R Absolute	%R % of MF	B_{MF_i} %R/ $\sqrt{2}$	$(B_{MF_i} * \theta_{MF_i})^2$
C1	82.78	0.15	0.181203	0.1281494	0.007884
C2	10.92	0.15	1.373626	0.9714472	0.0249797
C3	5	0.1	2	1.4144272	0.0227054
iC4	0.5	0.06	12	8.4865629	0.0137313
nC4	0.5	0.06	12	8.4865629	0.0138268
iC5	0.1	0.06	60	42.432815	0.0208703
nC5	0.2	0.06	30	21.216407	0.020959
	100			SUM	0.1249566
				$U_{MF_i} =$ SQRT	0.353492

STEP 3: Heat Input Uncertainty = $\text{SQRT}(U_{MF_i}^2 + U_{MF}^2)$ Mass flow meter $U_{MF}^2 = (B_m^2 + 2s_m^2)$

B_m	0.35	U_{MF}^2	0.132500
s_m	0.05		
$U_{MF_i}^2$			0.1249566
		SUM	0.2574566
HEAT INPUT UNCERTAINTY		SQRT	0.5074018

Table 7-3.3.3-1 Heat Input Uncertainties for Liquid Fuel

Parameter	Uncertainty
Density, ρ	Slope of density vs. oil temperature is very shallow; if oil temperature is measured within 1° to 2°, then error is small compared to heat value
Volume flow	Calibrated meter uncertainty = 0.2%
MCF	Meter Calibration Factor is assumed to have no uncertainty
Time, t	Time interval over which V is measured should be within 0.05%, and is therefore a negligible influence on test uncertainty
HHV_p	ASTM reproducibility R is 0.239 MJ/kg, so $B_{HHV} = 0.239 / \sqrt{2} = 0.169 \text{ MJ/kg}$
%H	$R = 0.18, B_H = 0.127$

systematic values from the instrumentation used in the test, and the random values calculated from the data.

7-3.5 Uniqueness of Tests

The uncertainties in this sample calculation are not the Code Limits. The uncertainties in corrected power and efficiency (heat rate) in the tables are indicative only of the levels achievable when performing a Code test on a turbine with the assumed sensitivities. As stated in para. 3-6.4, each test will have its own value of uncertainty, depending on the sensitivities, the scope of supply, fuel used, type of load device, etc. It is important that this matrix of variables (Table 7-3.1-1) be established and agreed upon prior to the test, so that a proper uncertainty level can be determined that will reflect the quality of a Code test.

7-3.6 Multiple Unit Tests

For a block of power, usually consisting of multiple gas turbines of the same model and rating, the uncertainty must be calculated carefully. For this case, block power is

$$P_{\text{block}} = P_1 + P_2 + P_3 + \dots P_n$$

where

n = number of units

If the units are equal in power, and there is no correlation among the instruments used, then the sensitivity $\theta = 1/n$, and the block's uncertainty will be $U_{p_{\text{block}}} = [\sum (\theta U_i)^2]^{0.5}$, or $U_i/\sqrt{n}$. It is likely, however, that the VTs, CTs, and power meters are from the same source, as may be the fuel properties, flowmeters and other instruments. These correlations will tend to make the systematic component of $U_{p_{\text{block}}}$ approach the value in U_i , when all the $2\theta\theta B$ terms are added. An analysis similar to Table 7-3.1-3 can be done for the block, separating the correlated and uncorrelated measurements, and combining the results by root sum square to obtain the systematic uncertainty. The random component will be equal to $\sqrt{\sum (\theta * 2S_i)^2}$.

7-4 COMPARATIVE TESTING UNCERTAINTY

7-4.1 General

To assist in minimizing the uncertainty of comparative tests, which must be less than 10% of the expected change in performance, it is strongly recommended that the following two procedures be utilized:

(a) Use the same instrumentation for both the before and after tests. This will substantially reduce the systematic uncertainties when they are correlated.

(b) Correct the after test to the before test conditions for the comparison. This eliminates the problem of obtaining correction factors for the turbine in its deteriorated condition.

7-4.2 Comparative Testing Uncertainty Procedure

When conducting gas turbine tests before and after a modification, the parameter of interest is the change in performance. Using the logic presented in ASME PTC 19.1, the improvement in power η can be expressed as a ratio P_{ca}/P_b , where P_{ca} is the power after modification corrected to the conditions of the before power, P_b . The sensitivities will be the partial derivatives of η combined with the sensitivity coefficients θ as determined previously for each measured quantity. The partials for η are

$$\delta\eta/\delta P_{ca} = 1/P_b; \text{ on a relative basis } * P_{ca}/\eta = 1$$

$$\delta\eta/\delta P_b = -P_a/P_b^2; \text{ on a relative basis } * P_b/\eta = -1$$

The sensitivities will be $\delta\eta/\delta P_{ca} * \theta_{ia}$ and $\delta\eta/\delta P_b * \theta_{ib}$, or θ_{ia} and $-\theta_{ib}$.

The systematic uncertainty will take into account the correlation of the instruments used for both tests. As shown previously in para. 7-3.3.1

$$U_{\eta}^2 = \sum_{i=1}^i (b_i \theta_i)^2 + 2 \sum_{i=1}^i \sum_{k=1}^k (\theta_i \theta_k b_{ik})$$

7-4.3 Sample Calculation for Difference

A simplified example, with only power, barometer, and inlet air temperature to correct for, will show the impact of having non-correlated measurements. Assume that a comparative test for a 5% improvement used all the same instrumentation for both tests, except the inlet air temperature. The thought was that a substantial improvement of this measurement would enhance the results. The resultant test uncertainty is, for the difference

$$U_D = \sqrt{\sum (B\theta)^2 + \sum (2S_X\theta)^2}$$

The calculations are shown in Table 7-4.3-1.

The resultant test uncertainty is above the 10% limit (10% of 5% improvement = 0.5%).

It should be apparent that using the same instrumentation for the inlet air temperature for both tests would be advantageous in reducing the test uncertainty. Even if the poorer before instrumentation were retained, the U value drops to 0.35%; if the better instrumentation is used for both, U drops to 0.16%. The latter would be a good investment for assuring higher confidence in the test result.

7-4.3.1 Heat Rate. Although the sensitivities θ may be less, the fact that improvement in heat rate is likely to be less than that of power will put pressure on keeping within the 10% goal. The fuel flow can easily be measured before and after with the same device, but there is potentially a problem with the heat value, particularly with gas fuel. If the gas supply composition is consistent over time and the same lab(s) are used for the analyses, an uncertainty in the range of 0.1 to 0.2 could be

Table 7-4.3-1 Comparative Test Example

	With Correlated Power and Barometer Instruments										CORR. TERM	SUM
	BEFORE					AFTER						
	<i>B</i>	<i>2s_x</i>	<i>Θ</i>	<i>(BΘ)²</i>	<i>(2s_xΘ)²</i>	<i>B</i>	<i>2s_x</i>	<i>Θ</i>	<i>(BΘ)²</i>	<i>(2s_xΘ)²</i>	<i>2BaBbΘaΘb</i>	
Power	0.45	0.1	−1	0.2025	0.01	0.45	0.085	1	0.2025	0.007225	−0.405	0.017225
Inlet air	1.6	1	−0.25	0.16	0.0625	0.75	0.25	0.18	0.018225	0.002025	...	0.24275
Barometer	0.1	0	−1	0.01	0	0.1	0	1	0.01	0	−0.02	0
				0.3725	0.0725				0.230725	0.00925	−0.425	0.259975

GENERAL NOTES:

(a) $U\eta = \text{SQRT} = 0.509877$.(b) U value exceeds 10% uncertainty limit.

assumed, depending on the composition (see para. 7-3.3.2). If not, then before and after uncertainties can be in the 0.3% to 0.5% range, resulting in uncertainties approaching the total improvement in heat rate.

7-4.4 Calculation Information

It is suggested that the format for absolute performance (Tables 7-3.1-1 through 7-3.1-3) be used for comparative tests, although Tables 7-3.1-1 and 7-3.1-2 can probably be combined. In dealing with small differences it is important to carry the calculations to several decimal places to minimize arithmetic errors.

Although the procedure recommends correcting the after test data to the before test conditions, the uncertainties in the before data must still be considered. This procedure skips the step of reporting corrected values of both tests to Specified Reference Conditions, but the calculation is similar: $P_{ac} = P_a * (P_{src} / P_a @ \text{after conditions}) * (P_a / P_{src} @ \text{before conditions})$. Hence the sensitivities for the before data remain part of the correction.

7-5 UNCERTAINTY OF FLOW CALCULATION FROM HEAT BALANCE

7-5.1 Heat Balance

When the airflow, exhaust flow, and/or exhaust energy is determined from the gas turbine heat balance, the uncertainty of the result can be calculated from the heat balance equation and the sensitivities obtained through partial differentiation of the equation. For example, if the exhaust flow is the desired result, the heat balance equation

$$Q_{\text{air}} + Q_{\text{fuel}} + Q_{\text{inj}} = Q_{\text{ext}} + Q_{\text{elect}} + Q_{\text{loss}} + Q_{\text{exh}} \quad (7-5.1)$$

where $Q_n = m_n * h_n$ can be solved for the exhaust flow M_{exh} :

$$M_{\text{exh}} = \frac{[(M_{\text{air}})(h_{\text{air}}) + (M_{\text{fuel}} * LHV) + (M_{\text{inj}})(h_{\text{inj}}) - Q_{\text{elect}} - Q_{\text{loss}} - (M_{\text{ext}})(h_{\text{ext}})]}{h_{\text{ext}}} \quad (7-5.2)$$

The uncertainty is

$$U = \sqrt{\sum_{i=1}^i (\Theta_i U_i)^2} \quad (7-5.3)$$

7-5.2 Sensitivities

For each of the variables the partial derivatives are determined. The normalized, or relative, sensitivities are most useful, as errors are usually expressed as a percent of the parameter measured. For example:

Parameter	Partial	Normalized
M_{air}	$h_{\text{air}}/h_{\text{exh}}$	$(h_{\text{air}}/h_{\text{exh}}) * M_{\text{air}}/M_{\text{exh}} = Q_{\text{air}}/Q_{\text{exh}}$

Similarly, the remaining normalized partials are:

Parameter	Partial
h_{air}	$Q_{\text{air}}/Q_{\text{exh}}$
M_{fuel}	$Q_{\text{fuel}}/Q_{\text{exh}}$
LHV	$Q_{\text{fuel}}/Q_{\text{exh}}$
M_{inj}	$Q_{\text{inj}}/Q_{\text{exh}}$
h_{inj}	$Q_{\text{inj}}/Q_{\text{exh}}$
Q_{elect}	$-Q_{\text{elect}}/Q_{\text{exh}}$
Q_{loss}	$-Q_{\text{loss}}/Q_{\text{exh}}$
M_{ext}	$-Q_{\text{ext}}/Q_{\text{exh}}$
h_{ext}	$-Q_{\text{ext}}/Q_{\text{exh}}$
h_{exh}	-1

Note that these sensitivities are considerably different than those (the influence coefficients) associated with a turbine test, as the heat balance equation puts a strong emphasis on the exhaust temperature and the heat input.

To evaluate the normalized partial derivatives, the performance or rating data for the gas turbine must be available. For this example, the data from the Mandatory Appendix I will be used:

Measure	Unit	Value
Output	MW	120.2
Heat input	Million Btu/hr (<i>LHV</i>)	1,149.4
<i>LHV</i>	Btu/lb (<i>LHV</i>)	21,072.5
Inlet air <i>T</i>	°F	80
Exhaust <i>T</i>	°F	1,000
Inlet flow	Million lb/hr	2.688
Fuel flow	lb/hr	54,545
Exhaust flow	Million lb/hr	2.782
Water inj	lb/hr	50,000
Air extr	lb/hr	10,000
Losses	Million Btu/hr	8.96

Table 7-5.4-1 Exhaust Flow Uncertainty

MEAS	θ	B	$2sx$	$(B\theta)^2$	$(2sx\theta)^2$	SUM
Heat Input	1.6841	0.634	0	1.140024717	0	1.140025
Exh T	...	8	2	...	...	...
then Exh h	-1	0.92	0.23	0.8464	0.0529	0.8993
Power	-0.6009	0.212	0	0.016228416	0	0.016228
Losses	-0.0131	5	0	0.00429025	0	0.00429
Inj Flow	0.0679	1.75	1	0.014119381	0.00461	0.01873
Inj T	...	2.2	1	...	...	...
then Inj h	0.0679	1.3	0.6	0.007791593	0.00166	0.009451
Extr Flow	-0.00188	1.75	1	1.08241E-05	3.53E-06	1.44E-05
Extr T	...	3	1.5	...	...	...
then Extr h	-0.00188	0.59	0.3	1.23032E-06	3.18E-07	1.55E-06
						2.08804

GENERAL NOTES:

(a) U exh. flow = SQRT 1.445005.

(b) The exhaust flow uncertainty for this example is 1.445%.

7-5.3 Heat Equivalents and Enthalpies

The heat equivalent of the power output is $120.2 \times 3,412.14 = 410.14$ million Btu/hr.

The enthalpies of the fluid streams must either be referenced to the inlet temperature, which simplifies the calculations by essentially eliminating hair, or to a "standard" reference temperature like 15°C (59°F). In this case an 80°F reference was used and the enthalpies for air and exhaust are from the Mandatory Appendix I formulae, which uses a 77°F reference temperature

Parameter	T - °F	h at T , Btu/lb	h at 80°F	h at T - h at 80°F
h_{exh}	1,000	246.09	0.76	245.33
h_{air}	80	0.73	0.73	0
h_{inj}	200	1,146	1,096	-928 (heat of vapor = -978)
h_{extr}	600	129.14	0.73	128.41

The values for the sensitivities may now be calculated.

Partial for	Term	Value
M_{fuel}	θ_{Mf}	1.6841
LHV	θ_{LHV}	1.6841
h_{exh}	θ_{hexh}	-1.0
Q_{elect}	θ_{elect}	-0.6009
Q_{loss}	θ_{loss}	-0.0131
h_{inj}	θ_{inj}	0.0679
M_{inj}	θ_{Minj}	0.0679
h_{extr}	θ_{hextr}	-0.00188
M_{extr}	θ_{Mextr}	-0.00188

7-5.4 Uncertainties

The uncertainty in the exhaust flow determined by the heat balance can now be calculated from a simple spreadsheet (see Table 7-5.4-1). Measurement uncertainties have been taken as the limit specified by this Code; in an actual test, the agreed upon levels should be used.

The exhaust flow uncertainty for this example is 1.445%.

7-5.5 Emphasis on Exhaust Temperature and Fuel Flow

This calculation shows the predominance of the exhaust temperature and heat input measurements. Every effort should be made to minimize the errors in these measurements if the heat balance method is to be used. The 10°F uncertainty in exhaust temperature could possibly be reduced, considering the plane of the turbine exhaust temperature measurement, the extent of closure of the heat balance, adding more thermocouples or rakes, and previous experience with the turbine model.

7-5.6 Exhaust Energy

The uncertainty in the exhaust energy (Q_{exh}) will be less than that for exhaust flow, since the uncertainty for exhaust enthalpy does not appear. In Table 7-5.6-1, the uncertainties for Q_{inj} and Q_{extr} are the RSS of the flow and enthalpy values. The exhaust energy uncertainty is 1.11%.

7-5.7 Corrected Values

The uncertainty in the *corrected* exhaust flow, temperature or energy will be slightly higher than the value shown above. For this case one would need to know the correction factors for water injection and extraction air, as well as the sensitivity to inlet air temperature. The resultant uncertainty would then be calculated from the RSS value of the sensitivity times the measurement uncertainty as shown above.

Table 7-5.6-1 Exhaust Energy Uncertainty

MEAS	θ	$(B\theta)^2$	$(2sx\theta)^2$	SUM
Q_{fuel}	1.6841	1.14002472	0	1.140024717
Q_{inj}	0.0679	0.02191097	0.00627	0.028181131
Q_{ext}	-0.00188	1.2054E-05	3.85E-06	1.59069E-05
Q_{elect}	-0.6009	0.01622842	0	0.016228416
Q_{loss}	-0.0131	0.00429025	0	0.00429025
				1.188740421

GENERAL NOTE: $U_{\text{exh. energy}} = \text{SQRT } 1.090293732$.

7-5.7.1 Uncertainty — Alternate Method. Paragraph 5-4.1 indicates that, in some straightforward cases, corrected values of the Q heat factors may be used directly to obtain exhaust energy. Equation (5-4.1) would become:

$$Q_{\text{exh,corr}} = Q_{\text{fuel,corr}} - Q_{\text{elect,corr}} - Q_{\text{loss,corr}} \quad (7-5.7)$$

Since $Q_{\text{fuel,corr}} = kW_{\text{corr}} * HR_{\text{corr}} = Q_{\text{fuel}} / \Pi\alpha\beta$, sensitivities derived from this equation are

- (a) Power, $-Q_{\text{elect,corr}} / Q_{\text{exh,corr}}$
- (b) Heat Input, $Q_{\text{fuel}} / \Pi\alpha\beta / Q_{\text{exh,corr}}$
- (c) Loss, $Q_{\text{loss,corr}} / Q_{\text{exh,corr}}$

The uncertainty calculations can proceed similarly to para. 7-5.4.

7-5.8 HRSG Heat Balance

In many cases a heat balance will also be performed around the heat recovery device, to provide a check on the value determined by the gas turbine balance. The uncertainties of the two methods may be combined to give the most realistic assessment of the uncertainty of the exhaust flow or energy that has been determined. ASME PTC 4.4, Gas Turbine Heat Recovery Steam Generators, presents the methods for calculating the HRSG heat balance and combined uncertainties.

MANDATORY APPENDIX I

DETERMINATION OF GAS TURBINE EXHAUST ENERGY, FLOW, AND TEMPERATURE

I-1 INTRODUCTION

The first edition of ASME PTC 22 was published in 1953. At that time the majority of the gas turbine designs were principally used for driving compressors or utility peaking applications. Therefore, the Code addressed only gas turbine power output and efficiency testing. As time progressed and gas turbine designs improved both in efficiency and power output ratings, it became common to install gas turbines in base loaded combined cycle plants. These plants were typically designed and built by the gas turbine OEM, so the only testing dictated by the market was power output and efficiency which was reflected in later revisions of the Code. In today's market it is typical for a customer to purchase the major components of a combined cycle plant from several different vendors. Therefore, in addition to power output and efficiency, gas turbine exhaust temperature and flow or energy are now critical measurements. The exhaust flow and temperature are necessary inputs to determine the performance of the HRSGs and bottoming cycle performance.

The PTC Committee investigated several different means for determining exhaust flow and energy such as inlet flow measuring devices, exhaust flow measuring devices, HRSG heat balance, exhaust gas constituent analysis, and gas turbine heat balance. Based on reasonable economic considerations per the requirements of ASME PTC 1, the gas turbine heat balance method has been selected as the method of choice.

I-2 TEST METHODOLOGY

The following summarizes the general test methodology for tests conducted for the evaluation of exhaust temperature, exhaust flow, and/or exhaust energy.

The gas turbine exhaust temperature is determined in accordance with Section 4.

The gas turbine exhaust flow and energy are determined by an energy and mass balance around the gas turbine as described in para. I-3.1. A test boundary is drawn around the gas turbine that identifies the energy streams that must be measured to calculate corrected results. The test boundary is an accounting concept used to define the streams that must be measured to determine performance. All input and output energy streams required for test calculations must be determined with

reference to the point at which they cross the boundary. Energy streams within the boundary need not be determined unless they verify Specified Reference Conditions or unless they relate functionally to conditions outside the boundary.

The specific test boundary for a particular test must be established by the parties to the test. Typical energy streams crossing the test boundary for common gas turbine cycles are shown in Fig. 3-1.5.1-1. Stream properties for the output and heat rate test are typically determined at the outer test boundary as indicated in Fig. 3-1.5.1-1. Stream properties for the exhaust energy or flow test are typically determined at the inner test boundary as indicated in Fig. 3-1.5.1-1.

For the determination of exhaust energy, a simple energy balance is performed around the test boundary. The exhaust energy may be determined directly if the reference temperature of all enthalpies is chosen as the measured inlet air temperature ($h_{\text{air}} = 0$, $Q_{\text{air}} = 0$).

For the determination of exhaust energy where the reference temperature is different from the inlet air temperature ($h_{\text{air}} \neq 0$, $Q_{\text{air}} \neq 0$), or for the determination of exhaust flow, a mass balance must also be performed around the test boundary and solved simultaneously with the energy balance.

I-3 CALCULATIONS AND RESULTS: GENERAL

The following paragraphs describe the detailed procedures required for application of the gas turbine heat balance method. Due to length and complexity, these calculations are provided here for convenience rather than in Section 5 of this Code.

Determination of gas turbine exhaust energy or flow and temperature, corrected to Specified Reference Conditions, are the primary objects of this test. Test results are computed from the averaged values of observations made during a single test run, after applying instrument calibrations and other corrections as necessary, and as prescribed in this Appendix. A printout of a sample calculation spreadsheet is provided at the end of this Appendix.

I-3.1 Gas Turbine Energy Balance

The following paragraphs provide the detailed calculations for the determination of exhaust energy and

exhaust flow by gas turbine energy balance as outlined above. The measurement of exhaust gas temperature is as described in para. 4-3.3.2.

I-3.1.1 Exhaust Energy. The exhaust energy is determined by an energy balance around the gas turbine. The energy into the system includes the air, fuel, and injection streams to the gas turbine. The energy from the system includes the exhaust leaving the gas turbine, compressor extractions, electrical or mechanical power, and heat losses. Therefore, the energy equation is as follows:

$$\text{Energy In} = \text{Energy Out}$$

$$Q_{\text{air}} + Q_{\text{fuel}} + Q_{\text{inj}} = Q_{\text{ext}} + Q_{\text{elect}} + Q_{\text{exh}} + Q_{\text{loss}}$$

where

$$Q_n = m_n h_n$$

To determine the exhaust energy term, one must identify a reference temperature to which the calculated exhaust energy is indexed. Selection of the reference temperature varies in the industry and can be chosen as any temperature. All terms of the equation must be evaluated at the chosen reference temperature. The determination of exhaust energy is greatly simplified if the chosen reference temperature is the measured inlet air temperature into the compressor which eliminates the need to determine exhaust temperature, inlet air flow, inlet air moisture content, and inlet air enthalpy resulting in $Q_{\text{air}} = 0$. However, if corrections must be applied to the calculated exhaust energy for comparison to a standard value, the calculated exhaust energy must be based on the same reference temperature as the standard value. Therefore, rather than specifying a reference temperature, this Appendix allows the user to select the appropriate reference temperature on a test-specific basis.

For any selected reference temperature other than the measured compressor inlet temperature, the exhaust flow calculation process described below must be followed to determine the exhaust energy.

I-3.1.2 Exhaust Flow. The exhaust flow is determined by an energy and mass balance around the gas turbine. The energy into the system includes the air, fuel, and injection streams to the gas turbine. The energy from the system includes the exhaust leaving the gas turbine, compressor extractions, electrical or mechanical power, and heat losses. Therefore, the energy and mass balance equations are as follows:

$$\text{Energy In} = \text{Energy Out}$$

$$Q_{\text{air}} + Q_{\text{fuel}} + Q_{\text{inj}} = Q_{\text{ext}} + Q_{\text{elect}} + Q_{\text{exh}} + Q_{\text{loss}}$$

where

$$Q_n = m_n h_n$$

$$\text{Mass In} = \text{Mass Out}$$

$$m_{\text{air}} + m_{\text{fuel}} + m_{\text{inj}} = m_{\text{ext}} + m_{\text{exh}}$$

Each term of the energy and mass balances in this format can be quantified by direct measurement or assumption except the exhaust flow and inlet air flow. However, this is not a simple case of two equations with two unknowns that can be solved simultaneously because the exhaust stream enthalpy is dependent upon the mass fraction of fuel flow to air flow.

Therefore, one of either of two methods may be used to calculate the exhaust flow. For the first method, the air flow and exhaust flow are determined iteratively. This is accomplished by assuming an air flow and proceeding through the calculations to determine both the heat entering and leaving the gas turbine. The correct air flow and exhaust flow are determined when both sides of the energy equation are equal.

The second method removes the need for iterations, but requires the inlet air and exhaust streams to be separated into combustion streams and noncombustion streams. The idea is to identify the air flow required for complete stoichiometric combustion and the excess air flow not required for combustion. With this approach, one can solve for all quantities directly with no iterations. This is the preferred method described herein.

The following additional definitions allow this non-iterative method to be implemented, along with the calculation of the mass flow required for stoichiometric combustion as described in para. I-3.2.4.

$$Q_{\text{air}} = Q_{\text{air,excess(in)}} + Q_{\text{air,comb}}$$

$$Q_{\text{exh}} = Q_{\text{combprod}} + Q_{\text{air,excess(out)}}$$

$$m_{\text{combprod}} = m_{\text{air,comb}} + m_{\text{fuel}} + m_{\text{inj}}$$

$$m_{\text{exh}} = m_{\text{combprod}} + m_{\text{air,excess}}$$

The reference temperature for these calculations can be selected by the user. The calculated exhaust flow result should be the same regardless of the chosen reference temperature, provided all terms of the energy balance equation are properly adjusted to the chosen reference temperature.

I-3.1.3 Required Data. The following data are required inputs to the calculations. The measurements and calculations required to determine these items are described in Section 4 of this Code.

- (a) barometric pressure, psia
- (b) compressor inlet air dry-bulb temperature, °F (°C)
- (c) compressor inlet air wet-bulb temperature, °F (°C) or relative humidity, %

- (d) fuel gas or oil mass flow, lb/hr
- (e) fuel gas molar analysis or liquid fuel ultimate (mass) analysis
- (f) fuel lower heating value, Btu/lb
- (g) fuel temperature, °F
- (h) injection flow, lb/hr
- (i) injection enthalpy, Btu/lb
- (j) extraction air flow, lb/hr
- (k) extraction air temperature, °F (°C)
- (l) exhaust gas temperature, °F (°C)
- (m) selected enthalpy reference temperature, °F (°C)
- (n) gas turbine losses, Btu/hr or kW
- (o) power output, kW

I-3.1.4 Calculations. The calculations for determination of gas turbine exhaust energy or flow are presented in the following series of steps, many of which involve intermediate calculations detailed in para. I-3.2.

- Step 1:** Determine the gas turbine inlet air humidity ratio and wet air molar composition based on the ambient conditions as described in para. I-3.2.1.3.
- Step 2:** Determine the change in molar flow of the air to exhaust gas constituents due to the combustion of the gas turbine fuel as described in para. I-3.2.2 for fuel gas and para. I-3.2.3 for liquid fuel.
- Step 3:** Determine the mass flow of air required for stoichiometric combustion as described in para. I-3.2.4.
- Step 4:** Determine the gas turbine inlet air molar flows to the combustor based on the ambient conditions and the calculated combustor air mass flow as described in para. I-3.2.1.4.
- Step 5:** Determine the composition of combustion products using the combustor air molar flow as determined in Step 4 and adding the change in molar flow due to the combustion of fuel in the gas turbine from Step 2. The turbine exhaust molar flow must also include the molar flow of steam or water injection into the gas turbine. The calculation of combustion product constituent mass fractions can then be calculated as described in para. I-3.2.5.
- Step 6:** Determine the combustion products enthalpy at turbine exhaust per para. I-3.2.6 with the combustion products constituent mass fractions as determined from Step 5 and the measured gas turbine exhaust temperature.
- Step 7:** Determine the gas turbine inlet air enthalpy per para. I-3.2.6 with the inlet air composition from Step 2 of I-3.2.1.4 and the measured dry-bulb temperature. The compressor extraction air enthalpy is calculated with the same composition and the measured extraction air temperature. The excess air enthalpies are

calculated using the same moist air composition, the inlet dry-bulb temperature, and the turbine exhaust temperature.

- Step 8:** Determine the fuel heating value including the sensible heat of the fuel per para. I-3.2.7 for fuel gas and para. I-3.2.8 for liquid fuel.
- Step 9:** Determine the duty of a steam or water injection stream by multiplying the measured flow by the adjusted enthalpy. The adjusted enthalpy is determined by subtracting the saturated vapor enthalpy at the selected reference temperature from the ASME Steam Tables enthalpy [ref. 32°F (0°C)] at the measured pressure and temperature.
- Step 10:** Determine the electrical energy generated by multiplying the kilowatts produced by 3,412.14 Btu/hr/kW.
- Step 11:** Determine the gas turbine heat losses in accordance with subsection 4-10.
- Step 12:** The excess air flow is now the only unknown parameter in the heat balance equation. Solve the equation for the excess air flow.

$$m_{\text{air,excess}}(h_{\text{air,inlet}} - h_{\text{air,exh}}) = m_{\text{ext}}h_{\text{ext}} + Q_{\text{elect}} + Q_{\text{loss}} + m_{\text{combprod}}h_{\text{combprod}} - m_{\text{air,comb}}h_{\text{air,inlet}} - m_{\text{fuel}}(\text{LHV}) - m_{\text{inj}}h_{\text{inj}}m_{\text{combprod}} = m_{\text{air,comb}} + m_{\text{fuel}} + m_{\text{inj}}$$

- Step 13:** The turbine exhaust gas flow is finally calculated as the mass flow of combustion products plus the excess air flow.

$$m_{\text{exh}} = m_{\text{combprod}} + m_{\text{air,excess}}$$

I-3.2 Intermediate Calculations

I-3.2.1 Wet Air Composition and Molar Flows to Combustor. This section determines the mass fractions and molar flows of the wet air constituents entering the gas turbine combustor.

I-3.2.1.1 General. The following inlet dry air molar composition is assumed:

Element/Compound	Composition, %
Nitrogen	78.084
Oxygen	20.9476
Argon	0.9365
Carbon dioxide	0.0319
	100.000

The dry air composition is corrected for humidity and atmospheric pressure effects via humidity calculations taken from the ASHRAE 2013 *Handbook of Fundamentals* as described in the following calculations.

I-3.2.1.2 Data Required

- (a) barometric pressure, psia
- (b) dry-bulb temperature, °F (°C)
- (c) wet-bulb temperature, °F (°C), or relative humidity, %

I-3.2.1.3 Wet Air Composition and Humidity Ratio Calculations. The wet air molar analysis and humidity ratio are determined by the following steps. When required to calculate the water vapor saturation pressure, use the following relationship:

$$\ln(\rho_{\text{vapor}}) = \frac{C_1}{T} + C_2 + C_3T + C_4T^2 + C_5T^3 + C_6T^4 + C_7\ln(T)$$

where

$$\begin{aligned} p_{\text{vapor}} &= \text{psia} \\ T &= ^\circ\text{R} \\ &= t + 459.67 \\ t &= ^\circ\text{F} \end{aligned}$$

For the vapor pressure over ice in the temperature range of -148°F to 32°F , the constants are

$$C_1 = -1.0214165 \times 10^4$$

$$C_2 = -4.8932428$$

$$C_3 = -5.3765794 \times 10^{-3}$$

$$C_4 = 1.9202377 \times 10^{-7}$$

$$C_5 = 3.5575832 \times 10^{-10}$$

$$C_6 = -9.0344688 \times 10^{-14}$$

$$C_7 = 4.1635019$$

For the vapor pressure over water in the temperature range of 32°F to 392°F , the constants are

$$C_1 = -1.0440397 \times 10^4$$

$$C_2 = -1.1294650 \times 10^1$$

$$C_3 = -2.7022355 \times 10^{-2}$$

$$C_4 = 1.2890360 \times 10^{-5}$$

$$C_5 = -2.4780681 \times 10^{-9}$$

$$C_6 = 0.0$$

$$C_7 = 6.5459673$$

Step 1: If the relative humidity is known, go to Step 2. If the wet-bulb temperature is known, go to Step 6.

Step 2: Calculate the water vapor saturation pressure at the dry-bulb temperature.

Step 3: Calculate the partial pressure of water by multiplying the vapor pressure times the relative humidity.

$$p_{\text{H}_2\text{O}} = p_{\text{vapor}} * RH/100$$

Step 4: Calculate the fraction of dry air (FDA) by subtracting the partial pressure of water from

the atmospheric pressure and dividing this difference by the atmospheric pressure.

$$FDA = (\rho_{\text{atm}} - \rho_{\text{H}_2\text{O}}) / \rho_{\text{atm}}$$

Step 5: Calculate the humidity ratio as a function of the fraction of dry air.

$$\bar{w} = \left(\frac{1}{FDA} - 1 \right) * 18.01528 / 28.9651159$$

Go to Step 10.

Step 6: Calculate the water vapor saturation pressure at the wet-bulb temperature.

Step 7: Calculate the saturated humidity ratio from the atmospheric pressure and vapor pressure by the following equation:

$$\text{Saturated Humidity Ratio } (\bar{w}_{\text{sat}}) = 0.621945 * p_{\text{vapor}} / (p_{\text{atm}} - p_{\text{vapor}})$$

Step 8: Calculate the actual humidity ratio from the saturated humidity ratio, wet-bulb temperature, and dry-bulb temperature by the following equation:

$$\begin{aligned} \text{Humidity Ratio } (\bar{w}) &= \\ &= \frac{(1.093 - 0.556 * t_{\text{wetbulb}}) * \bar{w}_{\text{sat}} - 0.240 * (t_{\text{drybulb}} - t_{\text{wetbulb}})}{1.093 + 0.444 * t_{\text{drybulb}} - t_{\text{wetbulb}}} \end{aligned}$$

Step 9: Calculate the fraction of dry air from the actual humidity ratio by the following equation:

$$FDA = \frac{18.01528}{28.9651159\bar{w} + 18.01528}$$

Step 10: The wet air mole fractions can now be calculated. The fraction of dry air multiplied by the dry air mole fraction will give the actual air constituent mole fraction.

$$\text{Nitrogen mole fraction} = MF_{\text{N}_2} = FDA * 0.780840$$

$$\text{Oxygen mole fraction} = MF_{\text{O}_2} = FDA * 0.209476$$

$$\text{Argon mole fraction} = MF_{\text{Ar}} = FDA * 0.009365$$

$$\text{Carbon dioxide mole fraction} = MF_{\text{CO}_2} = FDA * 0.000319$$

The mole fraction of water is one minus the fraction of dry air.

$$\text{Water mole fraction} = MF_{\text{H}_2\text{O}} = 1.0 - FDA$$

The assumed mole fraction of sulfur dioxide in air is zero.

$$\text{Sulfur dioxide mole fraction} = MF_{\text{SO}_2} = 0.0$$

Step 11: Calculate the average molecular weight of the wet air by the following equation. Molecular weights are given in Table I-3.2.1.3-1.

$$MW_{\text{air}} = \sum [MF_i * MW_i]$$

Table I-3.2.1.3-1 Elemental Molecular Weights

Element	Molecular Weight, lb/lbmol
Argon	39.948
Carbon	12.0107
Helium	4.002602
Hydrogen	1.00794
Nitrogen	14.0067
Oxygen	15.9994
Sulfur	32.065

GENERAL NOTE: Molecular weights adapted from Coursey, J.S., Schwab, D.J., and Dragoset, R.A. (2003), *Atomic Weights and Isotopic Compositions (version 2.4)*. [Online] Available: <http://physics.nist.gov/Comp/>[January 2004]. National Institute of Standards and Technology, Gaithersburg, MD.

where

- i = subscript denoting a given air constituent
- MF = mole fraction
- MW = molecular weight, lb/lbmol

I-3.2.1.4 Calculation of Molar Flows to Combustor.

The wet air molar flows to the combustor are determined by the following steps. In addition to the parameters determined in the previous section, this calculation requires the mass flow of air to combustor ($m_{\text{air,comb}}$) as calculated in para. I-3.2.4.

Step 1: Calculate the air molar flow to the combustor by dividing the air mass flow to the combustor by the average molecular weight. The air constituent molar flow to the combustor is the air molar flow times the constituent mole fraction.

$$M_i = m_{\text{air,comb}} \times MF_i / MW_{\text{air}}$$

where

- i = subscript denoting a given air constituent
- M = molar flow, mol/hr
- $m_{\text{air,comb}}$ = air mass flow to the combustor, lb/hr
- MF = mole fraction
- MW_{air} = molecular weight of the wet air mixture, lb/lbmol

Step 2: Calculate the air constituent mass fraction by multiplying the constituent mole fraction by its molecular weight and dividing by the average molecular weight. The mass fractions are required only for determining enthalpy.

$$mF_i = MF_i \times MW_i / MW_{\text{air}}$$

where

- i = subscript denoting a given air constituent
- MF = mole fraction
- mF = mass fraction
- MW = molecular weight

I-3.2.2 Molar Flow Change Due to Fuel Gas Combustion

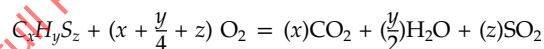
I-3.2.2.1 General. This section determines the molar flow change of the air to the exhaust stream constituents due to the complete stoichiometric combustion of each constituent of the fuel gas.

I-3.2.2.2 Data Required

- (a) fuel gas flow, lb/hr
- (b) fuel gas molar analysis

I-3.2.2.3 Table of Combustion Ratios.

Table I-3.2.2.4-1 provides the ratios of air constituent molar flow change per mole of fuel gas constituent resulting from complete stoichiometric combustion. The molar flow of any inert compound in the fuel gas, such as nitrogen or carbon dioxide, would pass directly into the combustion products on a mole per mole basis. The table values are determined from an oxidation chemical reaction for a unit mole of each fuel gas constituent in accordance with the following generic oxidation equation. The coefficients for oxygen are negative because oxygen is consumed in the reaction.



I-3.2.2.4 Calculations

Step 1: Calculate the fuel gas average molecular weight by summing, for all fuel gas constituents, the product of the constituent mole fraction and molecular weight. For molecular weights see Table I-3.2.1.3-1.

$$MW_{\text{fuel}} = \Sigma[MF_j \times MW_j]$$

Step 2: Calculate the fuel gas molar flow by dividing the fuel gas mass flow by the fuel gas average molecular weight.

$$M_{\text{fuel, mol/hr}} = \frac{m_{\text{fuel, lb/hr}}}{MW_{\text{fuel}}}$$

Step 3: Calculate the change in molar flow due to combustion of each air constituent by summing, for all fuel gas constituents, the product of the fuel gas molar flow, the fuel gas constituent mole fraction, and the corresponding combustion ratio for the given air constituent. Traces of helium in the fuel gas can usually be combined with argon.

$$\Delta M_i = \Sigma[M_{\text{fuel}} \times MF_j \times CR_{ij}]$$

where

- CR = combustion ratio from Table I-3.2.2.4-1
- i = subscript denoting a given air constituent
- j = subscript denoting a given fuel gas constituent
- M_{fuel} = fuel gas molar flow from Step 2, mol/hr

Table I-3.2.2.4-1 Fuel Gas Combustion Ratios

Fuel Gas Constituent	Air Constituent					
	N ₂	O ₂	CO ₂	H ₂ O	Ar	SO ₂
CH ₄	0	-2	1	2	0	0
C ₂ H ₆	0	-3.5	2	3	0	0
C ₃ H ₈	0	-5	3	4	0	0
C ₄ H ₁₀	0	-6.5	4	5	0	0
C ₅ H ₁₂	0	-8	5	6	0	0
C ₆ H ₁₄	0	-9.5	6	7	0	0
N ₂	1	0	0	0	0	0
CO	0	-0.5	1	0	0	0
CO ₂	0	0	1	0	0	0
H ₂ O	0	0	0	1	0	0
H ₂	0	-0.5	0	1	0	0
H ₂ S	0	-1.5	0	1	0	1
He	0	0	0	0	1 [Note(1)]	0
O ₂	0	1	0	0	0	0
Ar	0	0	0	0	1	0

NOTE:

(1) Helium, as an inert gas, is carried through the equations as argon.

Table I-3.2.3.3-1 Liquid Fuel Combustion Ratios

Fuel Gas Constituent	Air Constituent					
	N ₂	O ₂	CO ₂	H ₂ O	Ar	SO ₂
C	0	-1	1	0	0	0
H	0	-0.25	0	0.5	0	0
O	0	0.5	0	0	0	0
N	0.5	0	0	0	0	0
S	0	-1	0	0	0	1

 MF = mole fraction ΔM = change in molar flow due to combustion, mol/hr**I-3.2.3 Molar Flow Change Due to Liquid Fuel Combustion**

I-3.2.3.1 General. This section determines the molar flow change of the air to the exhaust stream constituents due to the complete stoichiometric combustion of each constituent of the liquid fuel.

I-3.2.3.2 Data Required

- (a) liquid fuel flow, lb/hr
- (b) liquid fuel ultimate analysis (weight fractions)

I-3.2.3.3 Table of Combustion Ratios.

Table I-3.2.3.3-1 provides the ratios of air constituent molar flow change per mole of liquid fuel constituent resulting from complete stoichiometric combustion.

I-3.2.3.4 Calculations

Step 1: Calculate the liquid fuel molar flow for each element in the liquid fuel analysis by multiplying the liquid fuel mass flow by the constituent mass fraction divided by the elemental molecular weight (see Table I-3.2.1.3-1).

$$M_j = m_{\text{fuel}} \times mF_j / MW_j$$

where

j = subscript denoting a given liquid fuel elemental constituent

M = liquid fuel constituent molar flow, mol/hr

m_{fuel} = liquid fuel mass flow, lb/hr

mF = mass fraction of liquid fuel constituent

MW = molecular weight, lb/lbmol

Step 2: Calculate the change in molar flow due to combustion of each air constituent by summing,

for all liquid fuel constituents, the product of the liquid fuel molar flow and the corresponding combustion ratio for the given air constituent.

$$\Delta M_i = \sum [M_i \times CR_{ij}]$$

where

CR = combustion ratio from Table I-3.2.3.3-1

i = subscript denoting a given air constituent

j = subscript denoting a given liquid fuel elemental constituent

M = liquid fuel molar flow from Step 1, mol/hr

ΔM = change in molar flow due to combustion, mol/hr

I-3.2.4 Combustion Air Flow

I-3.2.4.1 General. This section describes the method for determining the mass flow of wet combustion air required for complete stoichiometric combustion. The determination allows for the direct calculation of the mass and energy balances with no iterations required.

I-3.2.4.2 Data Required

(a) humidity ratio (ω), lb H₂O/lb dry air (para. I-3.2.1.3)

(b) change in molar flow of O₂, mol/h (para. I-3.2.2 for fuel gas, para. I-3.2.3 for liquid fuel)

I-3.2.4.3 Calculations

Step 1: Calculate the mass flow of dry air to the combustor.

$$m_{\text{air,comb(dry)}} = \frac{\Delta M_{\text{O}_2}}{MF_{\text{O}_2}} \times MW_{\text{air(dry)}}$$

where

ΔM_{O_2} = change in molar flow of O₂ due to combustion, mol/hr

$MF_{\text{O}_2(\text{dry})}$ = mole fraction of O₂ in dry air = 0.209476

$MW_{\text{air(dry)}}$ = molecular weight of dry air = 28.9651159

Step 2: Calculate the mass flow of moist air to the combustor.

$$m_{\text{air,comb}} = m_{\text{air,comb(dry)}}(1 + \omega)$$

I-3.2.5 Combustion Products Exhaust Composition

I-3.2.5.1 General. This section determines the gas turbine combustion products exhaust composition for the purpose of calculating the combustion products exhaust gas enthalpy. The exhaust constituents will include some or all of the following compounds: nitrogen, oxygen, carbon dioxide, water, argon, and sulfur dioxide.

I-3.2.5.2 Data Required

- (a) combustor air flow, lb/hr (para. I-3.2.4.3, Step 2)
- (b) steam/water injection flow, lb/hr
- (c) fuel flow, lb/hr
- (d) combustor air molar flow, mol/hr (para. I-3.2.1.4, Step 1)
- (e) change in molar flow, mol/hr (para. I-3.2.2.4, Step 3 for fuel gas; para. I-3.2.3.4, Step 2, for liquid fuel)

I-3.2.5.3 Calculations

Step 1: Calculate the molar flow of steam/water injection by dividing the injection mass flow by the molecular weight of water

$$M_{\text{inj}} = m_{\text{inj}}/MW_{\text{H}_2\text{O}}$$

where

M_{inj} = injection water/steam molar flow, mol/hr

m_{inj} = injection water/steam mass flow, lb/hr

$MW_{\text{H}_2\text{O}}$ = molecular weight of water, lb/mol

Step 2: Calculate the water molar flow in the exhaust stream as the sum of the water molar flow from the air, the change in molar flow of water from the combustion of the fuel, and the steam or water injection molar flow calculated in Step 1.

$$M_{\text{combprod,H}_2\text{O}} = M_{\text{air,H}_2\text{O}} + \Delta M_{\text{H}_2\text{O}} + M_{\text{inj}}$$

where

$M_{\text{air,H}_2\text{O}}$ = molar flow of water in combustion air, lb/lbmol

$M_{\text{combprod,H}_2\text{O}}$ = molar flow of water in combustion products, lb/lbmol

M_{inj} = injection water/steam molar flow, mol/hr

$\Delta M_{\text{H}_2\text{O}}$ = change in molar flow of water due to combustion

Step 3: Calculate the molar flow for all other exhaust constituents as the sum of the molar flow from the air and the change in molar flow due to combustion of the fuel.

$$M_{\text{combprod}k} = M_{\text{air}k} + \Delta M_k$$

where

k = subscript denoting a given combustion products constituent (non-water in this case)

M_{air} = combustion air molar flow, lb/lbmol

M_{combprod} = combustion products molar flow, lb/lbmol

ΔM = change in molar flow due to combustion

Step 4: Calculate the mass fraction of each gas turbine combustion products exhaust constituent as

the product of the molar flow and the molecular weight for that constituent divided by the total combustion products mass flow.

$$m_{\text{combprod}} = m_{\text{air,comb}} + m_{\text{fuel}} + m_{\text{inj}}$$

$$mF_{\text{combprod}k} = M_{\text{combprod}k} \times MW_k / m_{\text{combprod}}$$

where

mF_{combprod} = combustion products mass fraction

M_{combprod} = combustion products molar flow, lb/lbmol

MW = constituent molecular weight, lb/lbmol

k = subscript denoting any combustion products constituent

I-3.2.6 Gas Enthalpy

I-3.2.6.1 General. This section describes the method for determining the enthalpies in the exhaust gas and air streams. The gas or air stream enthalpy is a mass weighted value of the stream constituent enthalpies. The constituent enthalpy equations and coefficients are adapted from McBride, B.J., Zehe, M.J., and Gordon, S. (September 2002), *NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species*, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, OH. This database is periodically updated as new research is completed, therefore the user should periodically confirm that the constants used in the enthalpy equations are consistent with the latest available research. Updates can be confirmed online at the NASA Glenn Chemical Equilibrium with Applications (CEA) computer program website:

<http://www.grc.nasa.gov/WWW/CEAWeb/ceaHome.htm>

using the available *Thermo-Build* function or the *CEAgui* program. The constants to be used should be agreed upon prior to conducting a test. An alternative source of enthalpy data that the parties may agree upon is ASME STP-TS-012-1, *Thermophysical Properties of Working Gases Used in Working Gas Turbine Applications*.

I-3.2.6.2 Data Required

- gas temperature, °F
- gas constituent mass fractions
- selected enthalpy reference temperature, °F

I-3.2.6.3 Enthalpy Equation Constants. The enthalpy is calculated for each constituent in a gas stream as a function of the gas temperature. The NASA enthalpy correlations provided here for each constituent are applicable up to 1 000 K (1,340.33°F) which is sufficient for the objectives of this Mandatory Appendix and for the current gas turbine technologies. Higher range correlations are available from the NASA database.

The correlations require the temperature to be expressed in kelvin.

$$T_K = \text{temperature}[K] = (t[°F] + 459.67)/1.8$$

For a given exhaust constituent, the enthalpy, expressed as Btu/lb, and referenced to zero at 77°F (298.15 K) is determined by the following equation:

$$H^\circ = \left[\left(-\frac{A_1}{T_K} + A_2 \ln(T_K) + A_3 T_K + \frac{A_4 T_K^2}{2} + \frac{A_5 T_K^3}{3} + \frac{A_6 T_K^4}{4} + \frac{A_7 T_K^5}{5} + A_8 \right) * R - \Delta_f H^\circ \right] / 2.326 / MW$$

where

Ax = coefficients as given in Table I-3.2.6.3-1

$H^\circ = H^\circ(T_K) - H^\circ(298.15 \text{ K}) = \text{enthalpy (ref = 77°F), Btu/lb}$

MW = molecular weight

R = 8.31451 J/mol-K

T_K = temperature, K

$\Delta_f H^\circ$ = heat of formation, J/mol

For instances that require a reference temperature different than 77°F, the enthalpy relation must be evaluated twice.

$$H^\circ(T_K)_{\text{NewRef}} = H^\circ(T_K)_{77^\circ\text{F}} - H^\circ(\text{NewRef})_{77^\circ\text{F}}$$

I-3.2.6.4 Calculations

- Step 1:** Calculate the enthalpy for each gas constituent for the given temperature at the selected reference temperature using the appropriate correlation coefficients.
- Step 2:** Calculate the gas enthalpy for the gas mixture as the sum of the products of the constituent enthalpy and constituent weight (mass) fraction for all constituents.

$$h_m = H^\circ(T_K)_{\text{mixture}} = \sum [mF_n \times H^\circ(T_K)_n]$$

I-3.2.7 Fuel Gas Heating Value

I-3.2.7.1 General. The heat of combustion used in all calculations is the lower heating value. This is not to be confused with the higher heating value which includes the heat of vaporization for water. The heating value for fuel gas is a calculated number based upon the fuel gas composition as described in Section 5. The heating value should always be calculated based on the latest available publication of GPA 2145, or other agreed upon source such as ASTM D3588 or the GPSA Engineering Data Book. The reference data presented in this Code is from GPA-2145-03 and is based on combustion reference conditions of 60°F and 14.696 psia. Other industry publications provide various combustion reference conditions such as 15°C, 20°C, and 25°C. Variations of heat of combustion due to changes in combustion reference temperature are relatively small and generally complex, so it is not necessary or practical to account

Table I-3.2.6.3-1 Enthalpy Equation Constants

Constituent	A ₁	A ₂	A ₃	A ₄	A ₅	A ₆	A ₇	A ₈	ΔH°	MW
CH ₄	-176685.0998	2786.18102	-12.0257785	0.039176193	-3.61905E-05	2.02685E-08	-4.97671E-12	-23313.1436	-74600	16.04246
C ₂ H ₆	-186204.4161	3406.19186	-19.51705092	0.075658356	-8.20417E-05	5.06114E-08	-1.31928E-11	-27029.3289	-83851.544	30.06904
C ₃ H ₈	-243314.4337	4656.27081	-29.39466091	0.118895275	-1.37631E-04	8.81482E-08	-2.34299E-11	-35403.3527	-104680	44.09562
iso-C ₄ H ₁₀	-383446.933	7000.03964	-44.400269	0.174618345	-2.07820E-04	1.33979E-07	-3.55168E-11	-50340.1889	-134990	58.12220
n-C ₄ H ₁₀	-317587.254	6176.33182	-38.9156212	0.158465428	-1.86005E-04	1.19968E-07	-3.20167E-11	-45403.6339	-125790	58.12220
iso-C ₅ H ₁₂	-423190.339	6497.1891	-36.8112697	0.153242473	-1.54879E-04	8.74990E-08	-2.07055E-11	-51554.1659	-153700	72.14878
n-C ₅ H ₁₂	-276889.4625	5834.28347	-36.1754148	0.1533333971	-1.52840E-04	8.19109E-08	-1.79233E-11	-46653.7525	-146760	72.14878
n-C ₆ H ₁₄	-581592.67	10790.97724	-66.3394703	0.252371516	-2.90434E-04	1.80220E-07	-4.61722E-11	-72715.4457	-166920	86.17536
N ₂	22103.715	-381.846182	6.08273836	-0.008530914	1.38465E-05	-9.62579E-09	2.51971E-12	710.846086	0	28.01340
CO	14890.45326	-292.2285939	5.72452717	-0.008176235	1.45690E-05	-1.08775E-08	3.02794E-12	-13031.31878	-110535.196	28.01010
CO ₂	49436.5054	-626.411601	5.30172524	0.002503814	-2.12730E-07	-7.68999E-10	2.84968E-13	-45281.9846	-393510	44.00950
H ₂ O	-39479.6083	575.573102	0.931782653	0.007222713	-7.34256E-06	4.95504E-09	-1.33693E-12	-33039.7431	-241826	18.01528
H ₂ S	9543.80881	-68.7517508	4.05492196	-0.000301456	3.76850E-06	-2.23936E-09	3.08686E-13	-3278.45728	-20600	34.08088
H ₂	40783.2321	-800.918604	8.21470201	-0.012697145	1.75361E-05	-1.20286E-08	3.36809E-12	2682.484665	0	2.01588
He	0	0	2.5	0	0	0	0	-745.375	0	4.002602
O ₂	-34255.6342	484.700097	1.11901096	0.004293889	-6.83630E-07	-2.02337E-09	1.03904E-12	-3391.4549	0	31.99880
Ar	0	0	2.5	0	0	0	0	-745.375	0	39.94800
SO ₂	-53108.4214	909.031167	-2.356891244	0.0220445	-2.51078E-05	1.44630E-08	-3.36907E-12	-41137.5212	-296810	64.06380

GENERAL NOTE: Enthalpy correlations adapted from McBride, B.J., Zehe, M.J., and Gordon S. (September 2002), NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, Ohio.

for this provided the selected data set is agreed by all parties prior to the test. However, account must be made for the sensible heat difference between the selected enthalpy reference temperature for the heat balance calculation and the actual flowing temperature of the fuel.

There are several acceptable methods that may be used to calculate the sensible heat of the fuel gas. (See para. 5-3.1.11.)

The most accurate way is to access specific heat or enthalpy data from NIST or GPSA databases at the actual temperature and partial pressure of each of the fuel gas constituents, then combining them to obtain an overall enthalpy or specific heat value for the compressed mixture.

A simplified method considers the fuel composition variance but ignores the pressure effects by determining enthalpies at 1 atm which can lead to calculated exhaust flows which may be as much as 0.1% low. This is the same method used for the air and exhaust gas enthalpies at atmospheric pressure by applying the NASA formulations and coefficients adapted from NASA/TP-2002-211556. For consistency with the other enthalpy calculations in this overall heat balance, this method of determining sensible heat is demonstrated in the sample calculation at the end of this Mandatory Appendix. The NASA coefficients are provided in Table I-3.2.6.3-1.

I-3.2.7.2 Data Required

- (a) fuel gas constituent analysis
- (b) fuel gas temperature, °F
- (c) selected reference temperature, °F

I-3.2.7.3 Calculations

Step 1: Calculate the total fuel mass by summing the products of fuel gas compound mole fraction and compound molecular weight for all fuel gas compounds.

$$\text{Total Mass of Fuel} = \sum (MF_j \times MW_j)$$

Step 2: Calculate the heating value contribution of each fuel gas compound by computing the product of the fuel gas compound mole fraction, the fuel gas compound molecular weight, and the fuel gas compound heat of combustion (in Btu/lb) and dividing by the total fuel weight.

$$LHV_j = MF_j \times MW_j \times HC_j / \text{Total Mass of Fuel}$$

Step 3: Calculate the fuel gas ideal heating value by summing the heating value contributions of all fuel gas compounds.

$$LHV_{\text{chem}} = \sum LHV_j$$

Step 4: Calculate the sensible heat content (specific enthalpy) of the fuel in accordance with para. I-3.2.7.1. Calculate the fuel net heating value as the sum of the fuel gas ideal heating value and the fuel sensible heat, then adjust from the measured fuel temperature to the selected reference temperature.

$$LHV = LHV_{\text{chem}} + LHV_{\text{sens}}$$

I-3.2.8 Liquid Fuel Heating Value

I-3.2.8.1 General. The heat of combustion used in all calculations is the lower heating value. This is not to be confused with the higher heating value, which includes the heat of vaporization for water. The heating value for liquid fuel is to be determined in accordance with the Code. Care should be taken to ensure the liquid fuel heating value is properly adjusted to the selected reference temperature. For most liquid fuels (No. 1 through No. 6 fuel oils) in the typical API gravity range, the empirical approximation provided in para. 5-3.1.10 of this Code is sufficient to determine the sensible heat above 77°F.

I-3.2.8.2 Data Required

- (a) liquid fuel ideal lower heating value, Btu/lb
- (b) liquid fuel temperature, °F
- (c) selected reference temperature, °F

I-3.2.8.3 Calculations

Step 1: The Code is used to calculate the sensible heat content of the liquid fuel.

Step 2: The fuel net heating value is the sum of the liquid fuel ideal heating value and the fuel sensible heat.

$$LHV = LHV_{\text{chem}} + LHV_{\text{sens}}$$

I-4 SAMPLE EXHAUST FLOW BY GAS TURBINE HEAT BALANCE CALCULATION

This section presents an analysis program to simplify the calculation procedures in the Test Code (see Figs. I-4-1 through I-4-11). It has been the intention to design a user-friendly example, which is the reason for using multiple sheets. The different sheets modularize the calculations. The "Main" worksheet is the main input/output sheet. This is the only sheet required for most cases. Intermediate calculations are on the other sheets. Some cases could require inputs on other sheets.

The reference temperature basis for gas calculations is 77°F. The reference temperature basis for steam/water enthalpy is 32°F (0°C). The example corrects all enthalpies to a user selected reference temperature.

Assumptions are as follows:

- (a) Injection streams are always water or steam.
- (b) Extraction streams are always a compressor air bleed.

- (c) Pressure has negligible impact on compressor bleed enthalpy.
- (d) Fuel gas pressure effects on sensible heat of the fuel are ignored.
- (e) Gas enthalpy calculations are only valid up to 1 000 K.
- (f) Water and steam enthalpies are based on the 1967 ASME Steam Tables.

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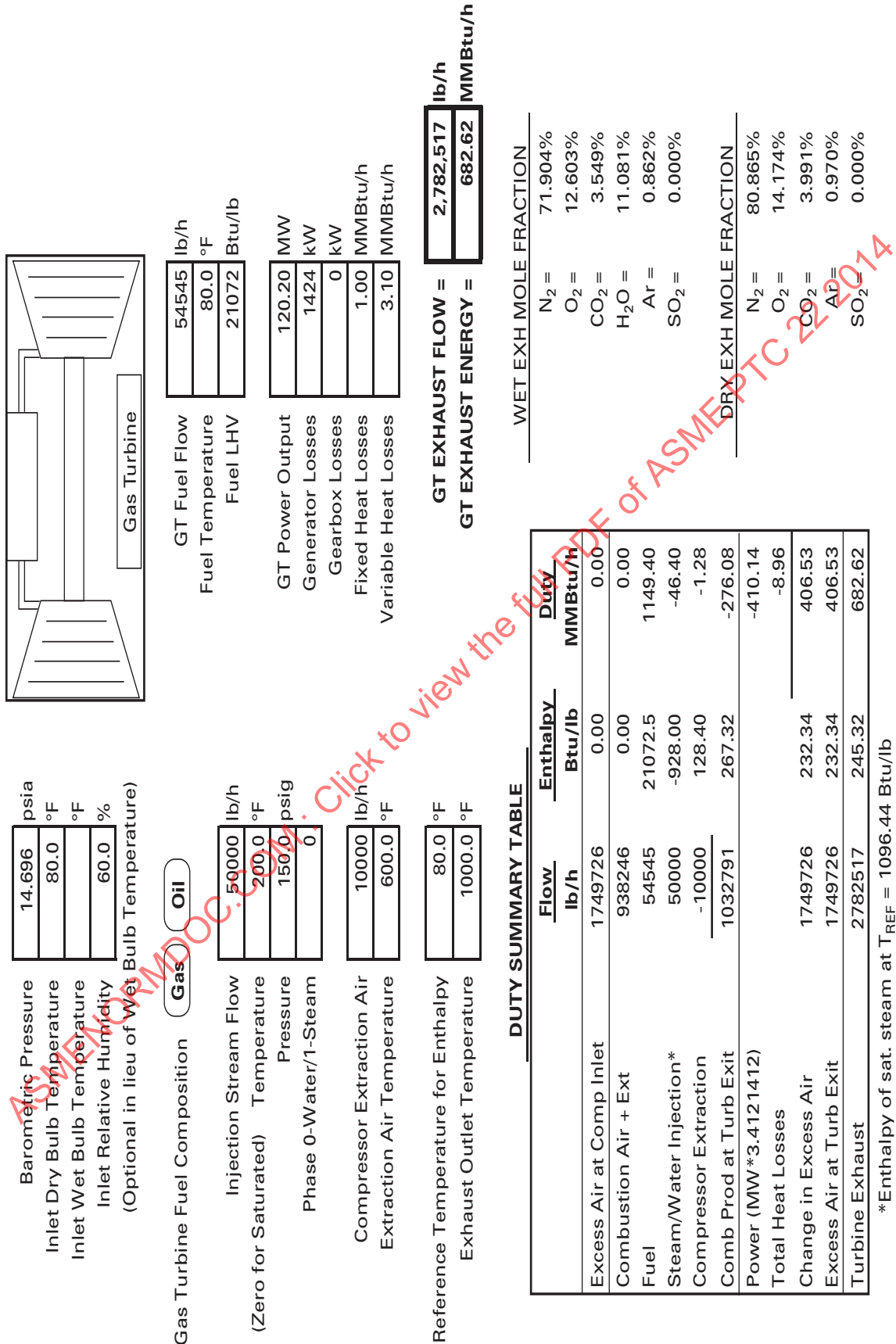
Fig. I-4-1 Sample Exhaust Flow by Gas Turbine Heat Balance Calculations

Fig. I-4-2 Sample Calculation of Wet Air Composition and Molar Flow**CALCULATION OF WET AIR COMPOSITION AND MOLAR FLOW**

Barometric Pressure	14.696	psia
Dry Bulb Temperature	80.0	°F
Wet Bulb Temperature		°F
Relative Humidity	60.0	%
Moist Air Flow to Combustor	928,246	lb/h
Excess Air Flow	1,749,726	lb/h

$$\ln(P_{\text{vapor}}) = C_1/T + C_2 + C_3 \cdot T + C_4 \cdot T^2 + C_5 \cdot T^3 + C_6 \cdot T^4 + C_7 \cdot \ln(T)$$

For $T \leq 32^\circ\text{F}$

$C_1 =$	-1.0214165E+04
$C_2 =$	-4.8932428E+00
$C_3 =$	-5.3765794E-03
$C_4 =$	1.9202377E-07
$C_5 =$	3.5575832E-10
$C_6 =$	-9.0344688E-14
$C_7 =$	4.1635019E+00

For $T > 32^\circ\text{F}$

$C_1 =$	-1.0440397E+04
$C_2 =$	-1.1294650E+01
$C_3 =$	-2.7022355E-02
$C_4 =$	1.2890360E-05
$C_5 =$	-2.4780681E-09
$C_6 =$	0
$C_7 =$	6.5459673E+00

Calculations for Case of Known Relative Humidity

$$T = t_{\text{dry bulb}} + 459.67 = 539.67 \text{ } ^\circ\text{R}$$

$$P_{\text{vapor}} = 0.5074 \text{ psia}$$

$$p_{\text{H}_2\text{O}} = \%RH \cdot P_{\text{vapor}} = 0.3044 \text{ psia}$$

$$\text{FDA} = (p_{\text{atm}} - p_{\text{H}_2\text{O}}) / p_{\text{atm}} = 0.979286$$

$$\text{Humidity Ratio} = (1/\text{FDA} - 1) \times \text{MW}_{\text{H}_2\text{O}} / \text{MW}_{\text{dry air}} = 0.013156 \text{ lb H}_2\text{O} / \text{lb dry air}$$

Calculations for Case of Known Wet Bulb Temperature

$$T = t_{\text{wet bulb}} + 459.67 = \text{ } ^\circ\text{R}$$

$$P_{\text{vapor}} = \text{\#VALUE! psia}$$

$$\text{Saturated Humidity Ratio} = \text{HR}_{\text{sat}} = 0.621945 \cdot P_{\text{vapor}} / (P_{\text{atm}} - P_{\text{vapor}})$$

$$\text{HR}_{\text{sat}} = \text{lb H}_2\text{O} / \text{lb dry air}$$

$$\text{Humidity Ratio} = \frac{(1093 - .556 \cdot T_{\text{wet bulb}}) \cdot \text{HR}_{\text{sat}} - .240 \cdot (T_{\text{dry bulb}} - T_{\text{wet bulb}})}{(1093 + .444 \cdot T_{\text{dry bulb}} - T_{\text{wet bulb}})}$$

$$\text{Humidity Ratio} = \text{lb H}_2\text{O} / \text{lb dry air}$$

$$\text{Fraction Dry Air (FDA)} = \frac{18.01528}{(28.9651159) \cdot (\text{Humidity Ratio}) + 18.01528}$$

Fig. I-4-2 Sample Calculation of Wet Air Composition and Molar Flow (Cont'd)**MOIST AIR TO COMBUSTOR**

A1	A2	A3	A4	A5	A6	A7
Compound	Calculation	Air Mole Fraction	Molecular Weight	[A3]x[A4]	Moist Air Molar Flow to Combustor lb/h x [A3] / Sum [A5] = mol/h	Air Weight Fraction [A5] / Sum [A5]
N ₂	.780840 * FDA	0.7647	28.0134	21.4209	24699	0.7454
O ₂	.209476 * FDA	0.2051	31.9988	6.5641	6626	0.2284
CO ₂	.000319 * FDA	0.0003	44.0095	0.0137	10	0.0005
H ₂ O	1 - FDA	0.0207	18.01528	0.3732	669	0.0130
Ar	.009365 * FDA	0.0092	39.948	0.3664	296	0.0127
Average Molecular Weight				28.7383		

DRY AIR TO COMBUSTOR

A1	A8	A9	A10
Compound	Air Mole Fraction	Molecular Weight	[A8]x[A9]
N ₂	0.7808	28.0134	21.8740
O ₂	0.2095	31.9988	6.7030
CO ₂	0.0003	44.0095	0.0140
H ₂ O		18.01528	
Ar	0.0094	39.948	0.3741
Average Molecular Weight			28.9651

EXCESS AIR

A1	A11	A12	A13	A14	A15	A16
Compound	Calculation	Air Mole Fraction	Molecular Weight	[A12] x [A13]	Excess Moist Air Molar Flow lb/h x [A12] / Sum [A14] = mol/h	Air Weight Fraction [A14] / Sum [A14]
N ₂	.780840 * FDA	0.7647	28.0134	21.4209	46557	0.7454
O ₂	.209476 * FDA	0.2051	31.9988	6.5641	12490	0.2284
CO ₂	.000319 * FDA	0.0003	44.0095	0.0137	19	0.0005
H ₂ O	1 - FDA	0.0207	18.01528	0.3732	1261	0.0130
Ar	.009365 * FDA	0.0092	39.948	0.3664	558	0.0127
Average Molecular Weight				28.7383		

Fig. I-4-3 Sample Mass Flow Calculations**MASS FLOW CALCULATIONS**

Molar Flow Change of O ₂	6,625.9	mol/h
Molecular Weight of Dry Air	28.9651	lb/lbmol
O ₂ Mole Fraction of Dry Air	0.20948	
Dry Air to Combustor	916,193	lb/h
Specific Humidity	0.01316	lbwater/lbdryair
Moist Air to Combustor	928,246	lb/h
Total Inlet Air	2,687,972	lb/h
Compressor Bleed Air	10,000	lb/h
Wet Excess Air	1,749,726	lb/h
Wet Combustion Air	928,246	lb/h
Fuel Flow	54,545	lb/h
Injection Flow	50,000	lb/h
Total Combustor Flow	1,032,791	lb/h
Turbine Exhaust Flow	2,782,517	lb/h