ERRATA
TO
ASME PTC 22-1997
PERFORMANCE TEST CODE ON
GAS TURBINES

The Errata corrections listed below apply to ASME PTC 22-1997, Performance Test Code on Gas Turbines.

Page	*Location*	*Change*
27	SI Conversion Table	Under Multiplication Factor column, third entry is corrected to read 1.055056 E + 03
32	Table C1	Under Corrected Heat Rate, for Compr. inlet temp., U_{Ti} is corrected to read 0.7071
33	Table C2	Under Corrected Heat Rate, for Compr. inlet temp., U_{Ti} is corrected to read 0.7071

THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
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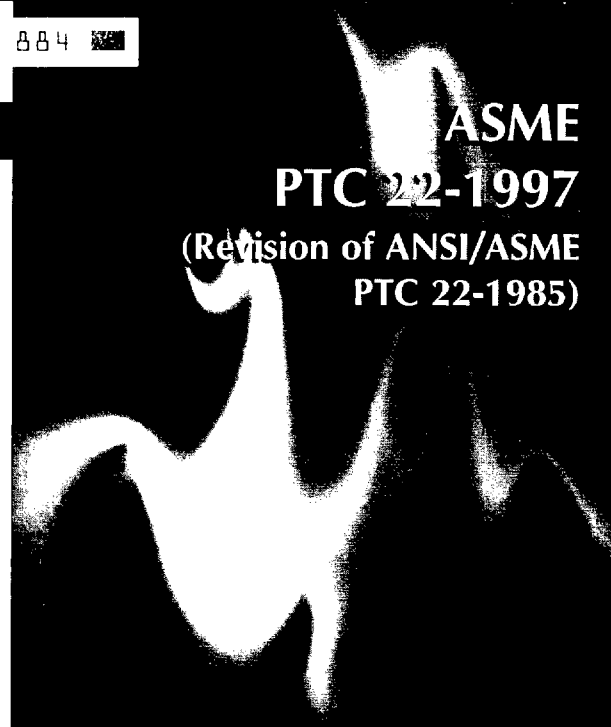
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ASME
PTC 22-1997
(Revision of ANSI/ASME
PTC 22-1985)



Performance Test Code on Gas Turbines

PERFORMANCE
TEST
CODES

The American Society of
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Performance Test Code on Gas Turbines

The American Society of Mechanical Engineers

PERFORMANCE TEST CODES

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FOREWORD

(This Foreword is not part of ASME PTC 22-1997.)

The original Performance Test Codes Committee No. 22 was established in 1945 to develop a test code on Gas Turbine Power Plants. This Code was eventually published in 1953.

Subsequent versions of the Power (eventually Performance) Test Code were published in 1966 and 1985, each time incorporating latest practice in accordance with the directives of PTC 1, General Instructions.

The current phase began shortly after the publication of the 1985 edition. The PTC 22 Committee took account of developments in gas turbine technology; it also addressed the increasingly important topic of measurement uncertainty as it characterizes gas turbine testing.

This Code was approved by the Board on Performance Test Codes on October 14, 1996. It was approved and adopted as an American National Standard on April 24, 1997.

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NOTICE

All Performance Test Codes MUST adhere to the requirements of 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 this Code. It is expected that the Code user is fully cognizant of Parts I and III of PTC 1 and has read them prior to applying this Code.

ASME Performance Test Codes provide test procedures which 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. They specify procedures, instrumentation, equipment operating requirements, calculation methods, and uncertainty analysis.

When tests are run in accordance with this 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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CONTENTS

Foreword iii
Committee Roster v

0 Introduction 1
1 Object and Scope 3
1.1 Object 3
1.2 Scope 3
1.3 Measurement Uncertainty 3
2 Definitions and Description of Terms 5
2.1 General Definitions 5
2.2 Equipment Definitions 6
2.3 Power Definitions 7
2.4 Test Parameter Definitions 7
2.5 Nomenclature 8
3 Guiding Principles 9
3.1 Agreements 9
3.2 Preparation for Test 9
3.3 Operation of Test 9
3.4 Records 10
3.5 Test Validity and Uncertainty 11
4 Instruments and Methods of Measurement 13
4.1 Calibration of Instruments and Apparatus 13
4.2 Checklist of Instruments and Apparatus Required for Primary Object Determinations 13
4.3 Determination of Output 13
4.4 Measurement of Electrical Output 13
4.5 Instrument Connections 14
4.6 Instruments 14
4.7 Instrument Transformers 14
4.8 Calibration of Electrical Instruments 14
4.9 Ammeter and Voltmeter Readings 15
4.10 Measurement of Shaft Power Output — Mechanical 15
4.11 Determination of Heat Input — Liquid Fuels 16
4.12 Determination of Heat Input — Gas Fuels 17
4.13 Pressure Measurement 19
4.14 Temperature Measurement 20
4.15 Humidity Measurement 21
4.16 Injection Fluid Flow Measurement 21

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5 Computation of Results 23
5.1 General 23
5.2 Computation of Power Output 23
5.3 Computation of Thermal Efficiency 23
5.4 Correction of Test Results to Specified or Standard Conditions 23
6 Test Report Requirements 25

Figures

2.1.9 Typical Gas Turbine Power Plant Station Locations 6
4.5.1 Typical Connections for Measurement of Output of Three-Phase, Four-Wire Generator 15

Tables

3.3.3 Maximum Permissible Variation in Test Conditions 10
4.12.6 Gas Properties of Perfect Gas 19

Appendices

A SI Conversion Table 27
B Computation of Power Output by Measurement of Gas Compressor Heat Balance 29
C Uncertainty Analysis 31
D Sample Liquid Fuel Calculation 35
E Sample Gas Fuel Calculation 39
F References and Bibliography 43

Figure

D1 Typical Plot of K-Factor vs (Frequency/Viscosity) for a Turbine Meter 36

Tables

C1 Sample Uncertainty Calculation for Generator Drive With Oil Fuel and Steam Injection 32
C2 Sample Uncertainty Calculation for Mechanical Drive With Gas Fuel 33
E1 Sample Calculation of Corrected Mole Fraction, Molecular Weight, and Low Heating Value 40

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SECTION 0 — INTRODUCTION

0.1 INTRODUCTION

0.1.1 This Test Code provides directions and rules for the conduct and report of results of test(s) for open-cycle gas turbine power plants and gas turbine engines, hereafter referred to as *gas turbines*. It provides test procedures which yield results of the highest level of accuracy consistent with the best engineering knowledge and practice in the gas turbine industry.

0.1.2 ASME PTC 1, General Instructions [1]; ASME PTC 2, Definitions and Values [2]; and ASME B133.1, Gas Turbine Terminology [3] were used as guides in the preparation of this Code and should be referred to when using this Code.

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SECTION 1 — OBJECT AND SCOPE

1.1 OBJECT

1.1.1 The object of the test is to determine the power output and thermal efficiency of the gas turbine when operating at the test conditions, and correcting these test results to standard or specified operating and control conditions. Procedures for conducting the test, calculating the results, and making the corrections are defined.

1.2 SCOPE

1.2.1 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 water or steam injection for emission control and/or power augmentation are included. It may be applied to gas turbines in combined-cycle power plants or with other heat recovery systems.

1.2.2 This Code is not applicable to gas turbines used for aircraft propulsion or to free piston power plants.

1.2.3 Compliance testing for gas turbines in the areas of stack emissions and sound levels is not covered by this Code. Procedures developed by regulatory agencies, ANSI, or other PTC Committees are available to govern the conduct of such testing.

1.2.4 The determination of data of a research nature or other special data is not covered by this Code.

1.3 MEASUREMENT UNCERTAINTY

1.3.1 An uncertainty analysis shall be performed prior to the test. The overall test uncertainty will vary because of the differences in the scope of supply, fuel(s) used, and driven equipment characteristics. This Code establishes a limit for the uncertainty of each measurement required; the overall uncertainty is then calculated in accordance with the procedures defined herein and by ASME PTC 19.1, Measurement Uncertainty [4]. Sample calculations and the resulting expected uncertainties are presented for two typical configurations. These typical uncertainties are:

	Power Output, %	Thermal Efficiency, %
Generator drive, oil fuel, steam injection	1.1	0.9
Compressor drive, gas fuel	1.8	1.7

1.3.2 A post-test uncertainty analysis should be performed to assure the parties that the actual test has met the requirements of this Code.

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SECTION 2 — DEFINITIONS AND DESCRIPTION OF TERMS

2.1 GENERAL DEFINITIONS

2.1.1 *units:* This Code uses U.S. Customary Units. For conversion to SI Units, see Appendix A.

2.1.2 *standard atmospheric conditions:* 14.696 psia (101.325 kPa), 59°F (288.15°K), and relative humidity of 60%

2.1.3 *rated power:* the power output of the gas turbine engine or power plant when operating at specified control and ambient conditions, in accordance with paras. 3.3.1 through 3.3.4

2.1.4 *thermal efficiency:* the ratio of the energy output to the energy supplied to the gas turbine, expressed as a percentage

2.1.5 *heat input:* the flow of fuel(s) multiplied by the high or low heat value of the fuel(s)

2.1.6 *high heat value (HHV) at constant volume (liquid fuels)*: the heat produced by 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.

2.1.7 *high heat 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.

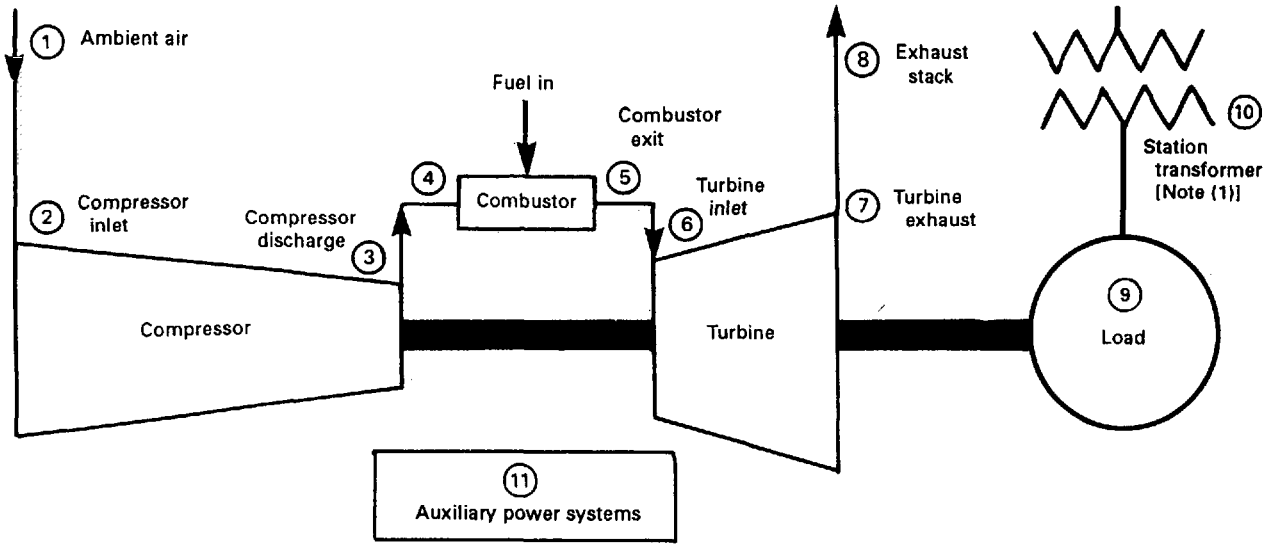
2.1.8 *low heat value (LHV) at constant pressure (liquid or gaseous fuels):* the heat produced by combustion of a unit quantity of fuel at constant pressure under conditions such that all of the water in the products remains in the vapor phase. It is calculated from the high heat value at constant volume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

2.1.9 Gas Turbine Power Plant Nomenclature. Figure 2.1.9 shows the basic nomenclature used in this Code. Depending on the scope of the test, some or all of the equipment shown may need to be considered for determining power plant performance. The station numbers refer to locations. Ambient air conditions are read at Station 1. Air conditions entering the compressor are read at Station 2. Between Stations 1 and 2 are typically inlet-air filtration and silencing devices, and, if applicable, air cooling or heating systems. Station 3 is the compressor discharge. Intermediate stations, as with multiple spool compressors and intercooling, may be identified as Stations 2.1, 2.2, etc. Station 4 is the entrance to the heat source. Between Stations 3 and 4 may be a recuperator or regenerator, or an aftercooler. Station 5 is the exit from the heat source, and Station 6 is the entrance to the turbine section. Station 6 is generally the plane at which the turbine inlet temperature is defined. For multiple section turbines, intermediate points would be defined as Stations 6.1, 6.2, etc. If a reheater were used, 6.1 would be the high pressure turbine exit, 6.2 the reheater inlet, 6.3 the reheater exit, and 6.4 the low pressure turbine inlet. Station 7 is at the turbine exit, and Station 8 represents the exhaust gas exit boundary for the test configuration. Between Stations 7 and 8 may be exhaust silencing, emission reduction devices, the recuperator or regenerator, or other heat recovery devices. Station 9 is the load measuring point. In the case of electrical power generation, Station 10, the transformer connecting the generator to the power grid, may be included. For cases where net plant power is to be determined, Station 11 needs to be considered. Included here may be fuel treatment systems, fuel supply pressurization, fuel atomization, lubricating oil pumps and conditioning, cooling water pumps and fans, compartment or building ventilation fans, hydraulic oil pumps, and control power. If the load device has its own lubrication system, then the auxiliaries required must also be considered. In addition to the above nomenclature, the following letters designate the type of fluid in various parts of the cycle:

f = fuel

g = gas after the heat source

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GENERAL NOTE:
Test scope and boundaries should be determined prior to the test [see para. 3.1.1 (m)].

NOTE:
(1) If included in generator drive test.

FIG. 2.1.9 TYPICAL GAS TURBINE POWER PLANT STATION LOCATIONS

s = steam
a = air (or other working fluid)
w = water
b = bearing fluid

As an example in the use of the foregoing nomenclature, the temperature of the fuel at the entrance to the heat source would be designated as t_{f4}. It is recognized that many different systems of station location designators are in use other than that shown in Fig. 2.1.9.

2.2 EQUIPMENT DEFINITIONS

2.2.1 *aftercooler:* a heat exchanger for cooling the working fluid, following the last stage of compression

2.2.2 *combustor:* a component in which fuel burns or otherwise reacts with the working fluid to increase the temperature

2.2.3 *compressor:* a mechanical rotary component which compresses the working fluid

2.2.4 *gas generator:* an assemblage of equipment consisting of compressor(s), combustor(s), and turbine(s) which produces hot gases at elevated pressure. It may be either a single or multispool (rotor) assemblage.

2.2.5 *gas generator turbine:* the turbine portion of a gas generator

2.2.6 *gas turbine engine:* a machine which converts thermal energy into mechanical work. It consists of compressor(s), thermal device(s) which heats the working fluid, turbine(s), a control system, and auxiliary equipment.

2.2.7 *gas turbine power plant:* a gas turbine engine and all essential equipment necessary for the production of power in useful form

2.2.8 *intercooler:* a heat exchanger for cooling the working fluid between stages of compression

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2.2.9 *power turbine:* a turbine which is driven by the gases from a gas generator, producing useful work (sometimes referred to as a free turbine)

2.2.10 *precooler:* a heat exchanger or evaporative cooler which reduces the temperature of the working fluid before initial compression

2.2.11 *regenerator or recuperator:* a heat exchanger transferring heat from the exhaust gas to the working fluid before the working fluid enters the heat source

2.2.12 *reheater:* a heat source in which additional thermal energy is added to the working fluid after it has been initially heated and partially expanded

2.2.13 *single-shaft gas turbine engine:* a gas turbine engine in which all compressor and turbine stages are mechanically interconnected and operate at the same speed

2.2.14 *turbine:* a mechanical rotary component which produces work by expansion of the working fluid

2.3 POWER DEFINITIONS

2.3.1 *measured power output (electrical) [kW]:* power output measured at the generator terminals

2.3.2 *net power output (electrical) [kW]:* power output determined from the measured power output by application of charges and credits as described in Section 5

2.3.3 *measured shaft power output (mechanical) [hp]:* power output measured at the coupling or power take-off connection of the gas turbine engine

2.3.4 *net shaft power output (mechanical) [hp]:* power output determined from the measured shaft power output by application of charges and credits as described in Section 5

2.4 TEST PARAMETER DEFINITIONS

2.4.1 *absorption dynamometer:* a device which may be connected to the output shaft of a prime mover in place of the driven load, which absorbs the output of the prime mover while transmitting the torque to a stationary member where it can be measured accurately

2.4.2 *accuracy:* the closeness of agreement between a measured value and the true value

2.4.3 *error:* the difference between the true value and the measured value. It includes both bias (systematic) and precision (random) errors.

2.4.4 *heat rate (mechanical or electrical) [Btu/(hp-hr) or Btu/(kW-hr)]:* heat input per unit of power output, based on either the low or high heat value of the fuel

2.4.5 *pressure and temperature:* expressed as total values unless otherwise specified. The total or stagnation properties (pressure and temperature) of a fluid stream are those that would exist if the stream were diffused adiabatically and reversibly, i.e., isentropically, to zero velocity.

2.4.6 *rated speed [rpm]:* specified speed at the rated power output

2.4.7 *specific fuel consumption (mechanical or electrical) [ft^3/(hp-hr), ft^3/(kW-hr), lb/(hp-hr), or lb(kW-hr)]:* fuel consumption rate per unit of power output

2.4.8 *standard volume of fuel gas (dry) [ft^3]:* The standard volume of fuel gas used in this Code is based on a temperature of 60°F and a pressure of 14.696 psia. In cases where gases being measured are partially saturated, corrections shall be applied to gas volumetric measurements to correct for actual water vapor content in gas consumed (see para. 4.12.5).

2.4.9 *test reading:* one recording of all required test instrumentation (as specified in Section 4)

2.4.10 *test run:* a group of test readings taken while the engine is operating at steady state at a specified operating condition

2.4.11 *tolerance:* a commercial allowance for deviation from contract performance levels

2.4.12 *torque (measured) [lbf-ft]*: torque measured at the turbine coupling or power take-off connection

2.4.13 *torque (net) [lbf-ft]*: the resulting torque after applying corrections, charges, and credits to the measured torque, as described in Section 5

2.4.14 *transmission dynamometer:* a device which measures the torque transmitted from one machine to another, without appreciably affecting the torque

2.4.15 *uncertainty:* the estimated error limit of a measurement or result for a given coverage. A 95% coverage has been used in this Code.

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2.5 NOMENCLATURE

F = flowmeter frequency averaged over the test timing period (see para. 4.11.5)

g_c = proportionality constant relating mass and force (given) (see para. 4.13.4)

H = percentage of hydrogen by weight contained in the fuel gas or liquid fuel (calculated) (see paras. 4.11.6, 4.12.3)

h_g = specific enthalpy of the fuel gas at operating conditions (calculated) (see para. 4.12.7)

$h_{g,b}$ = specific enthalpy of the fuel gas at the standard base conditions (calculated) (see para. 4.12.7)

h_ℓ = specific enthalpy of the liquid fuel at operating temperature (calculated) (see para. 4.11.8)

$h_{\ell,77}$ = specific enthalpy of the liquid fuel at the standard temperature of 77°F (calculated) (see para. 4.11.8)

HHV_p = high heat value at constant pressure (measured or calculated) (see para. 4.11.6)

HHV_v = high heat value at constant volume (measured) (see para. 4.11.6)

HI = heat input (calculated) (see para. 5.3)

HI_g = heat input, gas fuel (calculated) (see para. 4.12.8)

HI_ℓ = heat input, liquid fuel (calculated) (see para. 4.11.9)

HR = heat rate (see para. 5.4.9.1)

K = flowmeter or turbine meter calibration factor (calculated) (see paras. 4.11.6, 4.12.3)

kW = power output (see para. 5.3)

LHV_p = low heat value at constant pressure (calculated) (see para. 4.11.7)

P_g = absolute fuel gas pressure at the flowmeter (measured) (see para. 4.12.2)

Q_g = average volumetric gas flow over the test timing period (calculated) (see para. 4.12.3)

Q_ℓ = average volumetric liquid flow over the test timing period (calculated) (see para. 4.11.5)

R_g = fuel gas constant (calculated) (see para. 4.12.2)

SH_p = sensible heat at constant pressure (calculated) (see para. 4.11.8)

T_g = absolute temperature at the flowmeter (measured) (see para. 4.12.2)

t = fuel gas or liquid fuel volume timing period (measured) (see paras. 4.11.5, 4.12.3)

V_g = fuel gas volume (measured) (see para. 4.12.3)

V_ℓ = liquid fuel volume (measured) (see para. 4.11.5)

x_w = mole fraction of the water in the saturated fuel gas (calculated) (see para. 4.12.6)

Z_g = fuel gas compressibility factor at the flowmeter (calculated) (see para. 4.12.2)

η = thermal efficiency (calculated) (see para. 5.3)

ρ_g = fuel gas density at the flowmeter (calculated) (see para. 4.11.9)

ρ_ℓ = density of the liquid fuel at operating temperature (calculated) (see para. 4.11.8)

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SECTION 3 — GUIDING PRINCIPLES

3.1 AGREEMENTS

3.1.1 General Agreements Before Test. Parties to the test shall agree in writing on the object, scope, and plan for the test. Agreements shall be reached prior to the test on the following items:

(a) personnel to direct and otherwise conduct the test. All parties to the test shall be privileged to be present at all times to certify that the test is conducted in accordance with the Code and any agreements made prior to the tests;

(b) designation of who is responsible for the preparation of the gas turbine for the test;

(c) place where test is to be conducted. This should preferably be either the actual site where the gas turbine will be used, or a test facility where control and ambient conditions are acceptable to the parties to the test;

(d) time when test is to be conducted. If the purpose of the test is verification of guaranteed performance under a contract, the test should be undertaken as soon as possible after the commissioning of a gas turbine, or immediately following an inspection and possible correction of defects which satisfies all parties that the equipment is suitable to undergo the test;

(e) procedure for recording readings and observations;

(f) time signals and frequency of observations and duration of test;

(g) determination that the number of significant figures is consistent with required and achieved values of accuracy;

(h) type and number of all instruments to be used; how and when they shall be installed; if and where they shall be calibrated, and any other special agreements needed;

(i) designation of the laboratory and any other facilities required for determining pertinent fuel characteristics;

(j) requisite facilities and details of methods for producing and maintaining constancy of load and other test conditions; time period of operation at test loads before readings are started and duration of each test run (see para. 3.3.4);

(k) resetting of specific controls, if any, after the test is underway;

(l) test loads and rotating speeds at which the test is to be conducted;

(m) auxiliaries requiring charges or credits for determination of net power output;

(n) numerical values or curves for corrections or adjustments to be applied to test determinations, if tests are conducted under conditions differing from those specified (see Section 5);

(o) type and number of tests to be run;

(p) location of compressor inlet and turbine exhaust interfaces;

(q) limit for deviation of test conditions from the machine's rated condition (see para. 5.4.1); and

(r) quantity and timing of fuel samples to be obtained during testing.

3.2 PREPARATION FOR TEST

3.2.1 Pretest Records. Dimensions and physical conditions of parts of the gas turbine required for calculations or other test purposes should 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.

3.2.2 Preliminary Operation and Adjustment. Before starting the test, the gas turbine should be operated for sufficient time to demonstrate mechanical operation and stable control of all the variables acceptable to the parties to the test. During this period, instruments shall be checked and personnel assigned to conduct the test.

3.2.3 Protection of Instrument Uncertainty. Parties to the test should agree on the timing of installation of calibrated devices in order to meet the uncertainty requirements of this Code.

3.3 OPERATION OF TEST

3.3.1 Specified Conditions. Every effort shall be made to run the test under the specified conditions

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TABLE 3.3.3
MAXIMUM PERMISSIBLE VARIATION IN TEST CONDITIONS

Variable	Variation of Any Station[1] Observation From Reported Average Test Condition During a Test Run
Power output (electrical)	± 2%
Torque	± 2%
Power factor	± 2%
Rotating speed	± 1%
Barometric pressure at site	± 0.5%
Inlet air temperature	± 4°F
Heat value — gaseous fuel per unit volume	± 1%
Pressure — gaseous fuel as supplied to engine	± 1%
Absolute exhaust back pressure at engine	± 0.5%
Absolute inlet air pressure at engine	± 0.5%
Coolant temperature — outlet [Note (2)]	± 5°F
Coolant temperature — rise [Note (2)]	± 5°F
Turbine control temperature [Note (3)]	± 5°F
Fuel flow [Note (3)]	± 2%

NOTES:
(1) Use average of multiple instruments if used for any station observation.
(2) Applicable where precoolers, intercoolers, and aftercoolers are used.
(3) Applicable where variations of power output (electrical) and/or torque and rotative speed are not specified.

such as output, pressures, and temperatures, or as close to specified conditions as possible, in order to avoid the application of corrections, should they become necessary.

3.3.2 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.

3.3.3 Maximum Permissible Variations in Operating Conditions. Each observation of an operating condition during a test run shall not vary from the computed average for that operating condition during the complete run by more than the amount shown in Table 3.3.3, except by written agreement among the parties to the test. If operating conditions vary during any test run beyond the limits prescribed in Table 3.3.3, and if such variations are not covered by written agreement, the results of the test run shall be discarded.

3.3.4 Duration of Test Run and Frequency of Readings. The duration of a test run and the frequency of the readings will be determined by the type of engine tested, the power output, and the fluctuations in the readings. A sufficient number of readings shall be spaced in time to show the range of fluctuations and to provide a reliable average for the test run and to meet the uncertainty requirements of this Code. In no case shall the interval between readings be greater than 10 min. Due to the sensitivity of gas turbine power plants to ambient conditions, the test run should not exceed 30 minutes.

3.4 RECORDS

3.4.1 Test Observations. Test observations shall be recorded on a data acquisition system or entered on log sheets and authenticated by the observers' signatures. For acceptance tests, a complete set of unaltered data acquisition sheets and recorded charts, or facsimiles thereof, shall become the property of each party to 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 Observations. Where direct observations of instrument readings are to be recorded at frequent intervals during a test, it is not always necessary to observe simultaneously all readings which are made at the same intervals. In cases where the average of a series of readings is used in calculating results, uniform time periods, adapted

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to conditions of the test and nature of data required, may be employed.

3.4.3 Certified Data. During acceptance tests, it is recommended that data considered to be especially important be taken and recorded by at least two observers. A comparison of these observations should be made as soon as possible and any discrepancies reconciled before the end of the test.

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 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.

3.4.5 Test Recording Errors. In case of error in a recorded observation, a line shall be drawn through the incorrect entry; the correct reading is to be recorded above the incorrect entry and initialed, and an explanation entered in the proper place in the test records.

3.5 TEST VALIDITY AND UNCERTAINTY

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 which 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 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 instrument calibrations only having been applied; and

(b) as corrected for deviations of the operating conditions from the specified conditions.

3.5.3 Objectives. The application of uncertainty analysis to a Code test procedure has two objectives:

(a) determines compliance of the test procedure with the uncertainty requirements of the Code; and

(b) reduces the risk of making an erroneous decision when evaluating the results.

3.5.4 Definitions. The definitions of uncertainty and tolerance need to be fully understood by the parties in the context in which they are used for Performance Test Codes.

uncertainty: an estimate, based on statistical analysis and engineering judgment, of the error limit in the test results

tolerance: a commercial allowance for deviation from the contract performance guarantee values. Tolerances are not part of Performance Test Codes.

3.5.5 Uncertainty Calculations. Reference should be made to ASME PTC 19.1 for definitions and theory behind uncertainty analyses, as well as for the mathematical derivations of the formulas used.

3.5.5.1 This Code provides a test procedure that produces results with the lowest practicable uncertainties. However, no measurement is error-free, and the uncertainty of each test result should be evaluated by the parties.

3.5.5.2 To assist the parties in developing an uncertainty analysis, Appendix C contains an outline of the procedure, sample calculations, and guidance on the application of the analysis.

3.5.5.3 All uncertainty values that have been determined and agreed upon by the parties to a test shall be included in the report (see Section 6).

3.5.6 Uncertainty Limits. As illustrated by the examples in Appendix C, it is not possible to define a single value of uncertainty in order to be designated a Code test. The Code defines uncertainty limits for each of the measured parameters; depending on the configuration of the power plant under test, the combination of the applicable limits will determine the Code value for that particular configuration and test. This will be determined by the pre-test uncertainty analysis and agreed to by the parties.

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SECTION 4 — INSTRUMENTS AND METHODS OF MEASUREMENT

This Section describes the instruments, methods, and precautions that shall be employed in testing gas turbines under this Code.

4.1 CALIBRATION OF INSTRUMENTS AND APPARATUS

4.1.1 Instruments and apparatus used for determinations under this Code shall be calibrated in accordance with the ASME PTC 19 series of Instruments and Apparatus Supplements.

4.2 CHECKLIST OF INSTRUMENTS AND APPARATUS REQUIRED FOR PRIMARY OBJECT DETERMINATIONS

4.2.1 Tests appropriate for the primary object of this Code require the use of the following apparatus at the test site, selected and calibrated as required to meet stated uncertainties.

(a) for mechanical power output: speed and torque measuring devices

(b) for gas turbine with generator: instruments for measurement of the electrical output of the generator

(c) for a liquid-fueled gas turbine: flow measurement device

(d) for gas-fueled gas turbine: flow measurement device

(e) for water or steam injection: flow measurement device

(f) for on-site gas fuel analysis (if used): gas chromatograph

(g) for temperature measurements: temperature sensors

(h) for measurement of inlet and outlet pressures: manometers (see ASME PTC 19.2 [5]) or transducers

(i) for measuring fuel gas pressure: pressure gage or transducer

(j) for barometric pressure: barometer

(k) for humidity: psychrometer or hygrometer

(l) for speed indication: electronic speed measuring device

(m) for time measurement: clocks, watches, or electronic timing apparatus

(n) for electronic recording of test data: calibrated acquisition system

4.3 DETERMINATION OF OUTPUT

4.3.1 Gas Turbine Power Output. Gas turbine power output shall be measured by the determination of electric generator output or by the determination of force or torque and speed to be used in calculation of power output.

4.3.2 Gas Turbine Energy Output. Whenever useful energy is extracted from the gas turbine in any form, a method for evaluating such energy shall be agreed upon by all parties prior to the test. Examples of extractable energy are:

(a) compressed air from the compressor section for auxiliary purposes;

(b) heat for local nonturbine use.

4.4 MEASUREMENT OF ELECTRICAL OUTPUT

4.4.1 Power Output. Power output of a gas turbine generator set is normally measured at the electric generator terminals. Gas turbine shaft power output can then be obtained by applying corrections appropriate to account for generator losses. Reference is made to IEEE Standard 120 [6].

4.4.2 Net Electrical Power Output. Net electrical power output of a gas turbine power plant with a generator is equal to the electrical output at the generator terminals minus the electrical power separately supplied for generator excitation and other specified plant auxiliaries.

4.4.3 Measurement of Auxiliary Power. The uncertainty of this measurement shall be no greater than 5%.

4.4.4 Transformer Loss. If the determination of electrical power output is required on the high side

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of the system transformer, then the transformer losses as determined from the curves supplied by the transformer manufacturer shall be subtracted from the net electrical power output.

4.4.5 Net Mechanical Power Output. Net mechanical power output of the gas turbine output shaft shall be equal to the mechanical equivalent of the net electrical output plus the mechanical equivalent of losses determined from heat balance applied at:

(a) generator lubrication and cooling systems;

(b) reduction gear (if reduction gear which is utilized is not part of the gas turbine engine).

4.4.6 Electrical power output of ac generators shall be measured using separate instruments for each phase. Subject to agreement by the parties to the test, the two-wattmeter method is acceptable if there is a three-wire system, or, in case of a grounded neutral, if no current flows in the neutral. The power output of dc generators shall be measured in accordance with IEEE Standard 120.

4.5 INSTRUMENT CONNECTIONS

4.5.1 Voltage and current connections for test instruments are normally made on the generator (primary) side of the power transformer(s). Current connections shall be made at the generator terminals, or, on the generator side, of any external connections of the power circuit by which power can enter or leave this circuit. Typical instrument connections are shown in Fig. 4.5.1.

4.6 INSTRUMENTS

4.6.1 ac Generators. Either indicating or integrating instruments may be used for measuring electrical output of each phase of the generator. Calibrated wattmeters with uncertainty not greater than 0.15% are required. Solid state watthour meters shall be of comparable quality.

4.6.2 Indicating ac voltmeters and ac ammeters shall be in the measuring circuit in order to determine power factor and load conditions during the test, and enabling proper instrument corrections [6].

The power-measuring instruments shall be calibrated against secondary standards before the test. It is desirable that the instruments have their best operating characteristics in the range of test values. Extreme care must be exercised in the transportation of calibrated instruments. A comparison calibration check shall be made at the test site.

4.6.3 An accurate record of the watthour meters and of the time they are read shall be made. All wattmeters shall be read simultaneously.

4.6.4 dc Generators. Portable indicating dc ammeters and shunts, and dc voltmeters with an uncertainty no greater than 0.25%, shall be used. The instruments shall be calibrated. Extreme care must be exercised in the transportation of the calibrated instruments to the test site. Suitable means shall be provided to spot check the accuracy of the instruments at the test site.

4.7 INSTRUMENT TRANSFORMERS

4.7.1 Calibrated instrument current and potential transformers of 0.3% accuracy class (uncertainty no greater than 0.3%) of proper ratings shall be used. Values of ratio corrections and phase-angle corrections for the conditions of loading equivalent to the test instruments and leads used during the test shall be obtained by a recognized calibration procedure appropriate to the range of test values of current and voltage [6]. It is recommended that potential transformers be used which have no burden other than that of the test instrument and leads.

4.8 CALIBRATION OF ELECTRICAL INSTRUMENTS

4.8.1 The electrical instruments shall be calibrated against transfer standards under conditions simulating test conditions. Ammeters and voltmeters shall be calibrated preferably using the anticipated wave form of current and voltage to be measured during the gas turbine power plant test.

4.8.2 Electrical instruments shall be calibrated before the gas turbine power plant test.

4.8.3 Portable instruments shall be calibrated. Switchboard instruments, if used, should be calibrated in place.

4.8.4 All wattmeters or watthour meters shall be compared in place immediately before and immediately after each test run. If such comparisons indicate differences of more than 0.20%, the test shall be rejected.

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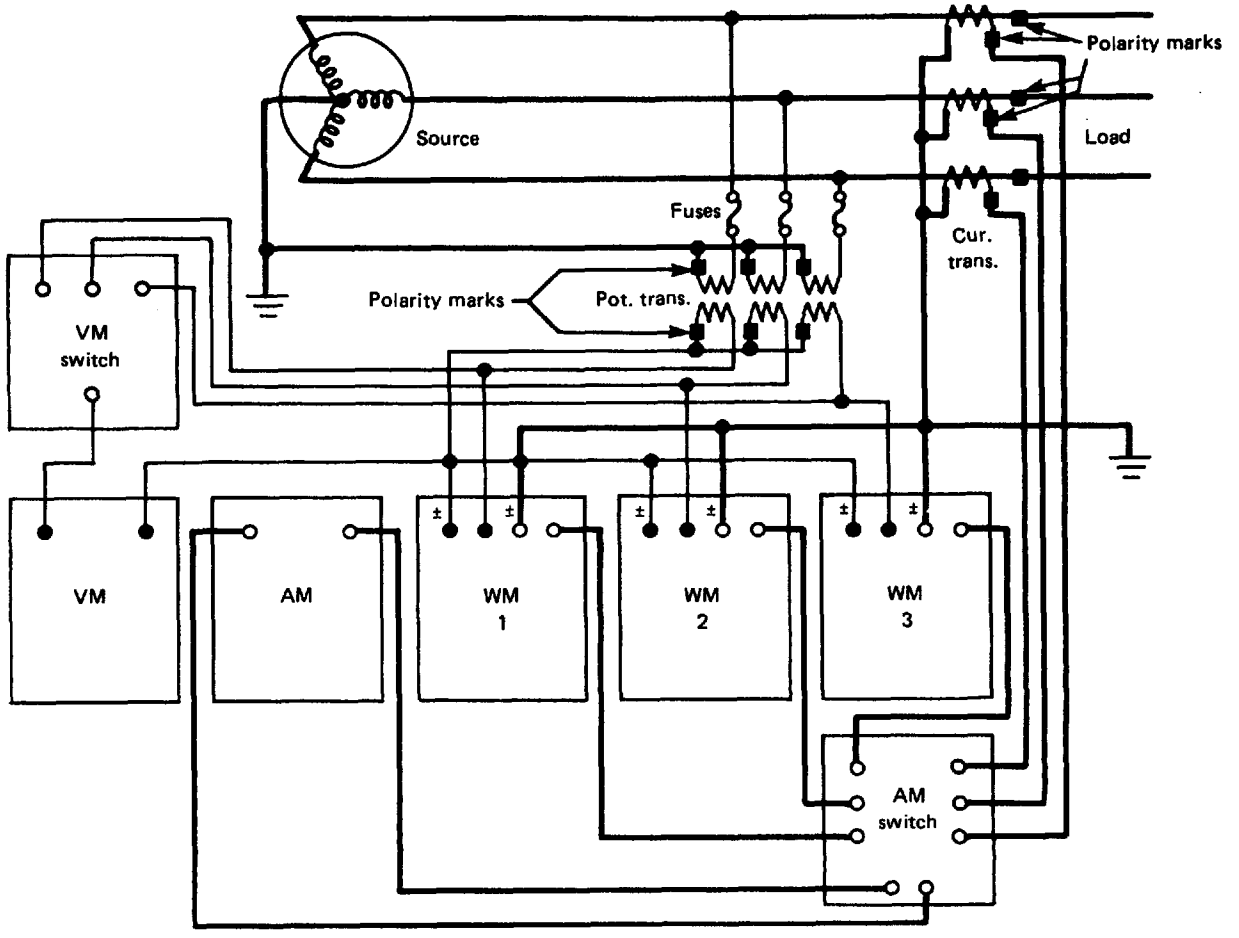


FIG. 4.5.1 TYPICAL CONNECTIONS FOR MEASUREMENT OF OUTPUT OF THREE-PHASE, FOUR-WIRE GENERATOR

4.9 AMMETER AND VOLTMETER READINGS

4.9.1 Ammeter and voltmeter readings of dc generator output, and ammeter, voltmeter, and wattmeter readings of ac generator output, shall be taken at frequent intervals during a test. The power output and load conditions should be maintained within maximum permissible variations given in Table 3.3.3. The readings shall then be averaged, and these averaged values shall be used in the determination of ac or dc power output.

4.9.2 All other forms of input or output, other than mechanical and electrical, shall be determined by methods consistent with this Code, decided and defined by written agreement.

4.10 MEASUREMENT OF SHAFT POWER OUTPUT — MECHANICAL

4.10.1 For gas turbines driving compressors or pumps, the determination of shaft output is generally required. Reference is made to ASME PTC 19.7 [7].

4.10.2 For tests performed at the power plant site, a torque-measuring device shall be installed on the coupling between the gas turbine and its driven load. The torque-measuring device shall be calibrated before and after the test, and should have an uncertainty no greater than 1.5%. A speed sensor is also required, with an uncertainty no greater than 0.1%.

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4.10.3 An alternate method for determining power output for gas-turbine driving compressors in pipeline or process service is described in Appendix B of this Code. This is not a Code test but may be utilized by mutual agreement or as an adjunct to para. 4.10.2.

4.10.4 For factory tests, where a dynamometer is to be used, these tests shall be in accordance with ASME PTC 19.7.

4.11 DETERMINATION OF HEAT INPUT — LIQUID FUELS

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

(a) kinematic viscosity

(b) density at test temperature (with volume measuring flowmeters)

(c) volumetric flow

(d) heat value

(e) hydrogen content (percentage by weight)

A sample calculation is presented in Appendix D.

4.11.2 Sampling. Samples shall be taken during the test. The sampling procedure outlined by ASME PTC 3.1 shall be followed [8].

4.11.3 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. The example calculated in para. D1 shows the effect of liquid viscosity on the calibration K-factor of a generic turbine flowmeter. Measurement of kinematic viscosity shall be done according to ASTM D 445 [9].

4.11.4 Density. To obtain a correlation of density and temperature, the sample should be analyzed at three temperatures, with a temperature range encompassing all the liquid fuel temperatures recorded during the test. Density should be determined per ASTM D 1480, "Test Method for Density and Specific Gravity of Viscous Materials by Bingham Pycnometer." The density at the test conditions can be read from the curve plotted from the three sample test density readings [10].

4.11.5 Volumetric Flow. The flow measuring system shall be suitably calibrated throughout the range of flows expected in the test. Whenever volumetric flowmeters are used, the temperature at the flowmeter and the flow shall be measured simultaneously. The volumetric flow shall be determined from the totalized volume of liquid fuel (i.e., in gallons) measured over a period of time not less than 4 minutes, and the time measured with an accurate stopwatch or electronic timer.

$$V_\ell = \text{final volume} - \text{starting volume}$$

$$Q_\ell = V_\ell / t$$

where

Q_ℓ = average volumetric flow calculated over the test timing period, gallons/second

V_ℓ = liquid fuel volume recorded with a totalizer, gallons

t = liquid fuel volume timing period, seconds

For example, if turbine meters are used and the flowmeter frequency is recorded during the test, the equation to calculate the volumetric flow is:

$$Q_\ell = F/K$$

where

F = flowmeter frequency averaged over the test timing period, pulses-Hz or pulses/second

K = flowmeter calibration factor calculated for the actual kinematic viscosity of the liquid fuel used during the test, pulses-Hz/gallon

The uncertainty of the mass flow of the liquid fuel (= volumetric flow multiplied by density) shall not exceed 0.8%.

4.11.6 Heat Value. For the purpose of determining the heat value, the procedures specified in ASTM D 4809, shall be followed [11]. The high heat value at constant volume HHV_v is determined by measuring the heat of combustion or the amount of heat rejected by the constant-volume system in the bomb when burning a carefully weighed quantity of liquid fuel in the oxygen-filled calorimeter bomb. All heat values are referenced to a standard temperature base of 77°F (25°C). The low heat value at constant volume LHV_v is the high heat value at constant volume minus the latent heat of the condensed water vapor at the same base temperature of 77°F.

In gas turbine combustors, the process is assumed to be a complete and adiabatic combustion, which

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occurs at constant pressure; therefore, the high and low heat values shall be determined at constant pressure.

$$HHV_p = HHV_v + 2.64\ (H)$$

where

2.64 = a factor calculated in para. D2
H = percentage of hydrogen H_2 by weight contained in the liquid fuel and determined in accordance with ASTM 1018 [12]
HHV_p = calculated high heat value at constant pressure, Btu/lbm
HHV_v = measured high heat value at constant volume, Btu/lbm, in accordance with ASTM D 4809 [11]

4.11.7 Low Heat Value. For gas turbine cycle calculation with the exhaust-gas exit boundary for the test configuration defined in para. 2.1.9, the low heat value at constant pressure LHV_p is the characteristic parameter, since the water content in the exhaust gas at this boundary is still in gaseous (not condensed) state. The low heat value at constant pressure is calculated from the high heat value at constant volume (measured according to ASTM D 4809) as follows:

$$LHV_p = HHV_v - 91.20\ (H)$$

where

91.20 = a factor calculated in para. D2

4.11.8 Sensible Heat. If the measured liquid fuel temperature is different from the standard temperature base for heat values at 77°F, then an adjustment in the heat input should be made to account for the additional energy defined as sensible heat. The sensible heat at constant pressure can be calculated as:

$$SH_p = Q_\ell \cdot \rho_\ell\ (h_\ell - h_{\ell,77})$$

where

SH_p = sensible heat at constant pressure, Btu/sec
Q_ℓ = volumetric flow, gallons/sec
ρ_ℓ = density of the liquid fuel at operating temperature, lbm/gallon
h_ℓ = specific enthalpy of the liquid fuel at operating temperature, Btu/lbm
$h_{\ell,77}$ = specific enthalpy of the liquid fuel at the standard temperature of 77°F, Btu/lbm

The specific enthalpies of the liquid fuel shall be determined according to para. D3.

4.11.9 Heat Input. Heat input is calculated from the following equations, using the heat value mutually agreed upon by the parties to the test:

$$HI_\ell = Q_\ell\ \rho_\ell\ (LHV_p) + SH_p, \text{ when based on } LHV$$

$$HI_\ell = Q_\ell\ \rho_\ell\ (HHV_p) + SH_p, \text{ when based on } HHV$$

where

HI_ℓ = heat input, Btu/sec

4.12 DETERMINATION OF HEAT INPUT — GAS FUELS

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

(a) density at test operating conditions
(b) volume flow
(c) composition, including moisture content
(d) heat value

A sample calculation is presented in Appendix E.

4.12.2 Density. The fuel gas density may be measured by a densitometer or calculated from the pressure, temperature, compressibility factor, and fuel gas composition, all recorded at the flowmeter. The equation for calculating fuel gas density based on temperature, pressure, compressibility factor, and composition is:

$$\rho_g = 144\ \frac{P_g}{Z_g R_g T_g}$$

where

ρ_g = fuel gas density at the flowmeter, lbm/ft^3
P_g = absolute fuel gas pressure at the flowmeter, psia
Z_g = fuel gas compressibility factor at the flowmeter
R_g = fuel gas constant, ft-lbf/lbm-R
T_g = absolute temperature at the flowmeter, R

The compressibility factor Z_g shall be determined by the methods detailed in AGA Report No. 8 [13]. For gas mixtures not covered by the Report, parties will have to agree on the method to be used.

4.12.3 Volume Flow. The flow measuring system shall be suitably calibrated throughout the range of flows expected during the test in accordance with the applicable ASME flowmeter codes. Whenever volumetric flowmeters are used, the density and

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the flow shall be measured simultaneously. The volumetric flow shall be determined from the totalized volume of fuel gas (i.e., in ft^3) measured over a period of time not less than 4 minutes, and the time measured with an accurate stopwatch or electronic timer.

$$V_g = \text{final volume} - \text{starting volume}$$

$$Q_g = V_g/t$$

For example, if turbine meters are used and the flowmeter frequency is recorded during the test, the equation to calculate the volumetric flow is:

$$Q_g = F/K$$

where

Q_g = average volumetric flow calculated over the test timing period, ft^3/seconds
V_g = fuel gas volume recorded with a totalizer, ft^3
t = fuel gas volume timing period, seconds
F = flowmeter frequency averaged over the test timing period, Hz
K = turbine meter calibration factor, pulses/ft^3

The uncertainty of the mass flow of the fuel gas (= volumetric flow multiplied by density) shall not exceed 0.8%.

4.12.4 Gas Composition. Methods of gas fuel sampling and composition determination shall be in accordance with the standard procedures set forth in ASME PTC 3.3 [14].

4.12.5 Moisture Content. When the fuel is pipeline quality natural gas, the moisture content should be very small (less than 4 pounds per million standard cubic feet); it will therefore have a negligible effect on the gas heat value and gas constant. In such cases, and when agreed upon by all parties, the moisture content can be taken from the supplier's records, eliminating the need for a dew point tester.

If required, the gas moisture content shall be determined by installing a dew point tester in the fuel gas line. The dew point tester shall be installed and operated in accordance with ASME PTC 3.3 [14]. The fuel heat value shall be adjusted in accordance with procedures of ASTM D 3588 (see sample calculation in Appendix E) [15].

4.12.6 Heat Value. The heat value shall be determined with an uncertainty no greater than 0.4%. The preferred method of determining the heat value is by use of a chromatograph in accordance with ASTM D 1945 [16]. Based on the composition, the high and low heat values shall be calculated using constituent properties from GPSA Engineering Data Book, latest edition [17], or ASTM D 3588. (A sample calculation is included; see Table 4.12.6.)

If a calibrated continuous calorimeter is installed, this may be used for the heat value determination, using the procedure defined by ASTM D 1826 [18]. The calorimeter measures the high heat value at constant pressure (saturated). The high heat value of the dry gas can be calculated by dividing the high heat value (saturated) by the term $(1\text{-}x_W)$, where x_W is the mole fraction of the water in the saturated fuel gas.

The low heat value at constant pressure (LHV_p) can be calculated from the high heat value at constant pressure (HHV_p) as follows:

$$LHV_p = HHV_p - 94.73\ (H)$$

where

94.73 = factor calculated in para. E2
H = percentage of hydrogen H_2 by weight contained in the fuel gas and calculated from the fuel gas composition obtained in accordance with ASTM D 1945 [16]
LHV_p = low heat value at constant pressure, Btu/lbm
HHV_p = high heat value at constant pressure, Btu/lbm

Since a calculated heat value will also be available, the parties shall determine how the results will be used in the heat input calculation.

4.12.7 Sensible Heat. If the measured fuel gas temperature and pressure are different from the standard base conditions for heat values of 60°F and 14.696 psia, then an adjustment in the heat input should be made to account for the additional energy defined as sensible heat. The sensible heat at constant pressure can be calculated as:

$$SH_p = Q_g \rho_g\ (h_g - h_{g,b})$$

where

SH_p = sensible heat at constant pressure, Btu/sec
Q_g = volumetric flow, ft^3/sec
ρ_g = density of the fuel gas at operating conditions, lbm/ft^3
h_g = specific enthalpy of the fuel gas at operating conditions, Btu/lbm
$h_{g,b}$ = specific enthalpy of the fuel gas at the standard base condition of 60°F and 14.696 psia, Btu/lbm

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TABLE 4.12.6
GAS PROPERTIES OF PERFECT GAS[1]

No.	Component	Formula	Molecular Weight	Gas Constant [(ft-lb)/(lbm-°R)]	Heat Value (Btu/ft³) Low Dry	Heat Value (Btu/ft³) High Dry	Specific Heat C_p
1	Methane	CH_4	16.043	96.326	909.4	1010.0	0.52669
2	Ethane	C_2H_6	30.070	51.392	1618.7	1769.6	0.40782
3	Propane	C_3H_8	44.097	35.044	2314.9	2516.1	0.38852
4	Isobutane	C_4H_{10}	58.123	26.588	3000.4	3251.9	0.38669
5	n-Butane	C_4H_{10}	58.123	26.588	3010.8	3262.3	0.39499
6	Isopentane	C_5H_{12}	72.150	21.419	3699.0	4000.9	0.38440
7	n-Pentane	C_5H_{12}	72.150	21.419	3706.9	4008.9	0.38825
9	n-Hexane	C_6H_{14}	86.177	17.932	4403.8	4755.9	0.38628
14	n-Heptane	C_7H_{16}	100.204	15.422	5100.0	5502.5	0.38447
31	Ethene	C_2H_4	28.054	55.085	1499.1	1599.8	0.35697
32	Propene	C_3H_6	42.081	36.723	2181.8	2332.7	0.35714
33	1-Butene	C_4H_8	56.108	27.542	2878.7	3079.9	0.35446
34	cis-Butene	C_4H_8	56.108	27.542	2871.0	3072.2	0.33754
35	trans-Butene	C_4H_8	56.108	27.542	2866.8	3068.0	0.35574
36	Isobutene	C_4H_8	56.108	27.542	2859.9	3061.1	0.37690
37	1-Pentene	C_5H_{10}	70.134	22.034	3575.0	3826.5	0.36351
52	Carbon Monoxide	CO	28.010	55.171	320.5	320.5	0.24847
53	Carbon Dioxide	CO_2	44.010	35.114	0.0	0.0	0.19911
54	Hydrogen Sulphide	H_2S	34.080	45.345	586.8	637.1	0.23827
57	Air	$N_2 + O_2$	28.963	53.356	0.0	0.0	0.23988
58	Hydrogen	H_2	2.016	766.581	273.8	324.2	3.40380
59	Oxygen	O_2	31.999	48.294	0.0	0.0	0.21892
60	Nitrogen	N_2	28.013	55.165	0.0	0.0	0.24828
62	Water	H_2O	18.015	85.780	0.0	0.0	0.44457
63	Helium	He	4.003	386.087	0.0	0.0	1.24040

GENERAL NOTES:
(a) Adapted from *GPSA Engineering Data Book*, Section 23, Gas Processors Suppliers Association, 1986 edition, Tulsa, OK (used by permission).
(b) Also useful is ASTM D 3588–91, *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels.* ASTM International, Philadelphia, PA.

NOTE:
(1) Base pressure = 14.696 psia
Base temperature = 60.000°F

The method of calculating enthalpy of the gas fuel from the measured composition shall be agreed upon by the parties. The preferred method is detailed in the GPSA Engineering Data Book.

4.12.8 Gaseous Fuel Heat Input. The fuel gas heat input is calculated from the following equations, using the heat value mutually agreed upon by the parties to the test:

$$HI_g = Q_g \rho_g (LHV_p) + SH_p$$

$$HI_g = Q_g \rho_g (HHV_p) + SH_p$$

where
HI_g = heat input, Btu/second
Q_g = volumetric flow, ft³/sec
ρ_g = density of the fuel gas at operating conditions, lbm/ft³
LHV_p = calculated low heat value at constant pressure, Btu/lbm
HHV_p = measured or calculated high heat value at constant pressure, Btu/lbm
SH_p = sensible heat at constant pressure, Btu/sec

4.13 PRESSURE MEASUREMENT

4.13.1 Pressure measurement shall be carried out in accordance with ASME PTC 19.2, Pressure Measurement. Manometers, transducers, or calibrated

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STD.ASME PTC 22-ENGL 1997 ■ 0759670 0584077 154 ■

elastic gages shall be used for reading pressures. Manometers shall be of the vertical U-tube, or single-leg, type with a bore of $^5/_{16}$ in. or more. In a single-leg manometer, means shall 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 with an uncertainty no greater than 0.5% of the measured pressure of pressure differential. Manometer fluid density shall be determined at site temperature.

4.13.2 Bourdon gages or other elastic gages may be used for measurement of pressure greater than 20 psig 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 of the average temperature during the test. The diameter of the scales and the arrangement of graduations shall permit reading with a maximum uncertainty of 0.5%.

4.13.3 Static Pressure. Static pressure of the working fluid shall be taken as the arithmetic average of the readings at four stations equally spaced around the duct in the same plane, and each read separately. Where duct walls are smooth and parallel, the preferred measuring instrument is a static pressure tap at each station. The diameter of the static hole shall not exceed $^1/_{16}$ in. with a minimum length of 2.5 times the taphole diameter. Where the duct walls are not suitable for pressure taps because of irregularities in shape, static pressure probes may be used instead. Care shall be taken to assure that static pressure probes are oriented along flow stream lines and are not located in regions of steep pressure gradients.

4.13.4 Inlet Pressure. Inlet pressure is defined as absolute total pressure at the mutually agreed upon inlet interface. In those cases where no inlet duct is provided, inlet pressure is considered to be barometric. When the inlet structure requires an evaluation of inlet pressure loss, this determination should be made with a maximum uncertainty of 10%. Total pressure readings at the gas turbine inlet may be taken at multiple centers of equal areas. 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 four static pressure readings from locations equally spaced around the gas turbine inlet. The total pressure is then equal to the average static pressure plus the product of the air density times the velocity squared divided by $2g_c$ (where g_c is the proportionality constant relating mass and force).

$$\text{Total Pressure} = \text{Static Pressure} + \frac{(\text{Air Density})\,(\text{Velocity})^2}{2g_c}$$

4.13.5 Outlet Pressure. Outlet pressure is defined as the static pressure at the turbine outlet duct plus barometric pressure. For method of measurement, refer to para. 4.13.3. If no outlet duct is used, outlet pressure shall be taken as barometric pressure.

The outlet 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 output and heat rate figures. Adjustment for any difference in this measured value and the specified operating condition must be made using the manufacturer's correction criteria.

Any velocity component of the outlet 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.

4.13.6 Gas Fuel Pressure. Gas fuel pressure shall be measured with an uncertainty not greater than 0.2%.

4.13.7 Injection Fluid Pressure. Where steam injection is utilized, the metering system for the steam shall include a measure of the actual line pressure at the meter device. The uncertainty of the pressure measurement shall not exceed 5%.

4.13.8 Barometric Pressure. Barometric pressure shall be measured with a maximum uncertainty of 0.04%. The barometer shall be located in a stable environment at the test site and shall sense the same pressure as that registered by the gages and manometers used.

4.14 TEMPERATURE MEASUREMENT

4.14.1 Temperature measurement shall be carried out in accordance with accepted practice and procedures as discussed in ASME PTC 19.3, Temperature Measurement [19]. Temperature shall be measured with resistance thermometers or calibrated thermocouples used with precision-reading instruments.

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Calibrated mercury-in-glass thermometers may be used for inlet air temperatures and such secondary readings as temperatures at manometer and barometer. Stagnation type thermocouples shall be used, or computed velocity corrections applied where such correction exceeds 1°F.

4.14.2 Air Inlet Temperature. At the specified location, the temperature of the air shall be measured to an accuracy such that the total uncertainty will not exceed 1°F. If a nonuniform temperature profile exists, the profile shall be determined by preliminary traverses, following which a number and arrangement of sensors shall be selected such that the average of their readings shall be within 1°F of the temperature determined from the temperature profile.

4.14.3 Turbine Control Temperature. Operation of the gas turbine at its design temperature(s) is fundamental to the determination of output and efficiency. Generally, gas turbines are designed on the basis of turbine inlet temperature, which is virtually impossible to measure. Therefore, some lower temperature region is selected by the manufacturer for installation of thermocouples. Usually, a plane in the exhaust plenum or in the interstage area (on multiple shaft engines) is selected. The relationship between the average of the measured temperatures and the design turbine-inlet temperature shall be established by the manufacturer. The manufacturer, through experience, shall determine the number and location of the control temperature measurement devices, accounting for known inherent spatial variations. In addition to determination of performance, these thermocouples are an input to the fuel control system. Because of their critical function and predetermined location, temperature measurements from the specified location must be used to adjust the gas turbine to the test condition.

The total uncertainty of the temperature measurement system due to instrument accuracy, data acquisition, data reduction, and random error shall be no greater than 7°F.

4.14.4 Fuel Oil Temperature. Fuel oil temperatures of fuel supply and, if applicable, of fuel return lines, shall be measured at representative locations close to the corresponding flowmeters with an uncertainty not greater than 2°F.

4.14.5 Fuel Gas Temperature. The fuel gas temperature shall be measured with an uncertainty not greater than 1°F.

4.14.6 Injection Fluid Temperature. Steam or water temperature measurement shall be provided to determine the heat content of the fluid. The uncertainty of the temperature measurement shall not be greater than 5°F.

4.14.7 Heat Rejection Temperature. Where primary-object determination requires measurement of heat rejection from lubricant cooler, intercoolers and vents, the accuracy of temperature, and flow measurements should permit determination of heat rejection with an uncertainty not greater than 10%. Temperatures shall be measured with calibrated thermocouples read by precision indicating or recording instruments. Where such measurements are not required for primary-object determinations, the means of measurement and the accuracy of measurement shall be determined by agreement among the parties to the test.

4.15 HUMIDITY MEASUREMENT

When the moisture content of the air entering the compressor must be measured, an instrument with the capability of determining specific humidity within 0.002 lb/lb shall be used. The humidity (lbm of moisture/lbm of dry air) indicating parameters are wet-bulb temperature, relative humidity, dew/frost point, and parts per million of moisture by volume or by mass.

The instrument reading can be converted to any of the common expressions of moisture content by means of a psychrometric chart or table if the barometric pressure, the dry-bulb temperature, and the instrument reading are known.

4.16 INJECTION FLUID FLOW MEASUREMENT

Where the gas turbine under test is equipped with steam or water injection, the water or steam flow shall be measured utilizing appropriate meter methods providing an uncertainty not greater than 2%. The metering installation shall be in accordance with the ASME MFC series [20].

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SECTION 5 — COMPUTATION OF RESULTS

5.1 GENERAL

5.1.1 Determination of power output and thermal efficiency at specified operating conditions are the primary objects of this test. Thermal efficiency can also be expressed as a specific fuel consumption or heat rate. Conversion of thermal efficiency to these alternate expressions are to be made according to para. 5.4.9.

5.1.2 In computation of results, a test result is computed from the averaged values of observations made during a single test run, after applying instrument and other corrections as necessary and as prescribed in this Code.

5.1.3 For a test involving several runs, it is suggested that plots of heat input versus power output be made to indicate test runs that may have significant errors. Any test runs leading to suspect results that are to be used for guarantee determination should be rerun.

5.2 COMPUTATION OF POWER OUTPUT

5.2.1 For gas turbines driving electrical generators, the generator output power is read directly from wattmeters. Calibration factors shall be applied as defined in para. 4.6.2.

5.2.2 If the gas turbine plant has a net plant output rating, the input power of the auxiliaries agreed upon as chargeable to the plant shall be deducted from the output determined in para. 5.2.1.

5.2.3 For gas turbines driving compressors or other nonelectrical devices, the power is calculated from the measured torque and speed values by the following general formula:

$$\text{Power (hp)} = \frac{[\text{Speed(rpm)}]\ [\text{Torque(lbf-ft)}]}{5252.1}$$

5.2.4 As in para. 5.2.2, auxiliary power measurements or agreements to be assigned for net plant power output shall be subtracted from the shaft power determined from para. 5.2.3.

5.3 COMPUTATION OF THERMAL EFFICIENCY

Thermal efficiency is calculated from the heat input and power measurements as follows:

$$\eta = \frac{(3412.14)(kW)}{HI}$$

where

η = efficiency (percentage)
kW = power output (kW) (see para. 4.4)
HI = heat input (Btu/hr) (see para. 4.11.9 or para. 4.12.8)

The result should be clearly identified as to the type of fuel used and either lower or higher heat value (*LHV* or *HHV*).

Constants for other frequently used units are given below.

Power Output	Heat Input	Constant
hp	Btu/hr	2544.43
kW	kJ/sec	1

5.4 CORRECTION OF TEST RESULTS TO SPECIFIED OR STANDARD CONDITIONS

5.4.1 The procedure for correction of test results to specified conditions depends on the type of gas turbine engine and its load device. It is necessary to have the test conditions within limits agreed to by the parties to the test, to avoid running the gas turbine at extreme conditions far from its design or specified condition, which could make the determination of accurate corrections impossible.

5.4.2 The off-design characteristics of each gas turbine engine are unique. Hence, the manufacturer's published performance curves for the particular engine must be used to correct the actual test data to rated or standard conditions. Unless otherwise

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agreed by the parties to the test, these correction curves (or data) are applied without any uncertainty.

5.4.3 A step-by-step method of correcting test data will be prepared by the manufacturer. The user will review this procedure and any discrepancies must be resolved prior to the start of the test.

5.4.4 Humidity. High specific humidity levels at the compressor inlet may affect gas turbine output and efficiency. If the specified operating conditions include specific humidity as an object of the test, then an adjustment for test humidity to gas-turbine capacity and thermal efficiency must be made in accordance with the manufacturer's procedure mentioned in para. 5.4.3.

5.4.5 Electrical Generator Drives. For electrical generator drives operating at synchronous speed (50 or 60 Hz), the basic data of power output, heat input, control parameter (temperature, pressure, or speed), air inlet temperature, and atmospheric pressure shall be recorded. The manufacturer must supply curves which will permit adjustment of the power output and heat input (or thermal efficiency) to the design values of air inlet temperature and atmospheric pressure. If the control parameter during the test run deviates from the specified value at test conditions, a curve or calculation showing the effect of control parameter on power output and heat input will be needed.

5.4.6 Test power output and heat input are first adjusted to the specified control parameter. Manufacturer's curves for ambient correction usually apply only when the gas turbine is operating at the control parameter level.

5.4.7 The adjusted power output and heat input can then be corrected to the design-point pressure and temperature conditions, and compared with the guarantee values.

5.4.8 Mechanical Drives. For mechanical drives, the characteristics of the process or pipeline often preclude operating the gas turbine at the rated speed(s) and/or control temperature. Two methods are recommended for establishing what the power output and heat input would be at the design-point conditions. These methods are described in paras. 5.4.8.1 and 5.4.8.2.

5.4.8.1 The first method is an extension of the method used for the generator drives. The manufacturer may supply additional adjustment curve(s) for speed so that the test point can be adjusted for both control temperature and speed of compressor(s) and turbine, as applicable. Correction to the design point can then be made as described in paras. 5.4.5 to 5.4.7.

5.4.8.2 The second method involves running the unit at power levels above and below the rated point. Each test point is to be corrected to specified conditions as per agreed upon corrections. A best line or least-squares fit is then plotted through the corrected test points. The rated performance can then be determined from the graphs generated.

5.4.9 Thermal efficiency is frequently represented in alternate forms such as heat rate or specific fuel consumption. Calculation of these parameters is defined in paras. 5.4.9.1 and 5.4.9.2.

5.4.9.1 Heat rate (HR) is basically a reciprocal of thermal efficiency. It can be calculated from the test data or from the thermal efficiency (see para. 5.3). Heat rate is calculated as heat input divided by power output, and is typically in units of Btu/(kW-hr), Btu/(hp-hr), or kJ/(kW-hr). Conversion to heat rate from thermal efficiency involves elimination of the constant. For example:

$$HR(\text{Btu/kW-hr}) = \frac{3412.14}{\eta_{th}}$$

$$HR(\text{Btu/hp-hr}) = \frac{2544.43}{\eta_{th}}$$

$$HR(\text{kJ/kW-hr}) = \frac{3600}{\eta_{th}}$$

5.4.9.2 Specific fuel consumption is similar to heat rate, except that the weight flow of fuel is used rather than the heat input. Specific fuel consumption can readily be obtained from the test data by dividing the fuel weight flow by the power output, and is typically expressed in units of lb/(hp-hr), lb/(kW-hr), or kg/(kW-hr). Specific fuel consumption can also be calculated by dividing the heat rate by the fuel heat value.

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SECTION 6 — TEST REPORT REQUIREMENTS

The test report shall clearly and concisely document all data generated by the test as well as all ensuing computations. Definitive statements of the purpose of the test and attainment of the objectives should be provided. The following paragraphs cite the minimum essential information that should be provided.

(a) Title Page shall include the following:

(1) report number

(2) date of test

(3) title of test

(4) location of test

(5) equipment owner

(6) equipment identification

(7) parties conducting test

(8) parties responsible for test report

(9) date of report

(10) report acceptance

(b) Table of Contents follows the title page and identifies the major subdivisions of the report.

(c) Body of the Report shall include the following:

(1) test objective and all agreements among the parties to the test;

(2) description of equipment to be tested and all such ancillary equipment that may influence the test results;

(3) schematics identifying mechanical and thermal cycle configurations;

(4) identification, location, and operating conditions of test equipment used;

(5) documentation of all measurements;

(6) instrument calibration curves and methods of calculation employed in data reduction;

(7) applicable correction factors due to any deviations of test conditions from specified conditions;

(8) performance on the basis of:

(a) actual operating conditions during the test;

(b) corrections applied to specified conditions, if the specified conditions differ from test conditions.

(9) documentation of the test results; and

(10) discussion of the test, including a brief history of the unit operation from start-up, the results, and conclusions.

(d) Summary shall concisely address the test objectives, results, and conclusions.

(e) Appendices as necessary and as agreed to by the parties to the test, may document additional (to the main text of the test report) description of equipment, test method, calculations employed in data reduction, instrument calibrations, testing apparatus, and other supporting information necessary to achieve a complete documentation of the performance test.

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APPENDIX A — SI CONVERSION TABLE

Tabulated below are the factors necessary to convert test parameters in the US Customary system of units to the SI system.

Quantity	Conversion	Multiplication Factor
Density	lbm/gallon to kg/m^3	1.198264 E + 02
	lbm/ft^3 to kg/m^3	1.601846 E + 01
Energy, work, heat	Btu to J	1.0555056 E + 03
Frequency	cps (sec^{-1}) to Hz	1.000000 E + 00
Fuel gas constant	(ft–lbf)/(lbm–R) to J/(kg–K)	5.380320 E + 00
Heat input	Btu/hr to W	2.930711 E – 01
Heat rate	Btu/(kW–hr) to kJ/kWh	1.055056 E + 00
	Btu/(hp–hr) to J/(W–s)	3.390148 E – 04
	Btu/(hp–hr) to J/kWh	1.414853 E + 03
Heat value	Btu/lbm to J/kg	2.326000 E + 03
	Btu/ft^3 to J/m^3	3.725894 E + 04
Length	in. to cm	2.540000 E + 00
Mass	lbm to kg	4.535924 E – 01
Mass flow	lbm/sec to kg/s	4.535924 E – 01
Power	hp to W	7.456999 E + 02
Pressure	lbf/in.^{2} to kPa	6.894757 E + 00
Rotational speed	rpm to rps	1.666667 E – 02
Sensible heat	Btu/sec to J/s	1.055056 E + 03
Specific enthalpy	Btu/lbm to J/kg	2.326000 E + 03
Specific fuel consumption	ft^3/(hp–hr) to m^3/kWh	3.797352 E – 02
	lbm/(hp–hr) to kg/kWh	6.082774 E – 01
Specific volume	ft^3/lbm to m^3/kg	6.242797 E – 02
Temperature	F(t_F) to C(t_C)	$t_C = (t_F - 32)/1.8$
	F(t_F) to K(t_K)	$t_K = (t_F + 459.67)/1.8$
	R(t_R) to K(t_K)	$t_K = t_R/1.8$
Torque	lb–ft to N–m	1.355818 E + 00
Volume	gallons to m^3	3.785412 E – 03
	ft^3 to m^3	2.831685 E – 02
Volumetric flow	ft^3/sec to m^3/s	2.831685 E – 02
	ft^3/min to m^3/s	4.719475 E – 04

GENERAL NOTE: The factors are written as a number greater than 1 and less than 10 with six decimal places. The number is followed by the letter *E* (*exponent*), a plus or minus symbol, and two digits which indicate the power of 10 by which the number must be multiplied to obtain the correct value.

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APPENDIX B — COMPUTATION OF POWER OUTPUT BY MEASUREMENT OF GAS COMPRESSOR HEAT BALANCE

This method of computation of gas-turbine power output may be used in the case of a gas turbine used to drive a gas compressor, or where an acceptable torque measurement device as defined in para. 4.10.1 of ASME PTC 22 is not available. This method is particularly intended for use on site tests of gas pipeline compressors, process plant compressors, and closed-loop test facilities. For further information refer to ASME PTC 10, Compressors and Exhausters [21], and ASME PTC 19.7, Measurement of Shaft Power [7].

B1 INSTRUMENTATION

B1.1 A gas flowmeter shall be set up in the gas circuit at a location close to the compressor, preferably on the compressor's suction side, where there is unlikely to be any significant temperature profile across the gas stream.

B1.2 The flowmeter shall be calibrated and be in accordance with ASME MFC-4M or ISO 5167 [22], and shall be demonstrated to have an uncertainty no greater than 2.0%.

B1.3 The flowmeter shall be properly installed in accordance with the manufacturer's specifications, with adequate flow-straightening devices and pipe-runs upstream and downstream, subject to agreement among parties to the test.

B1.4 Instrumentation planes shall be established in straight lengths of pipe at least three diameters away from any fitting which might distort the flow, and as close as possible to the suction and delivery flanges of the compressor. The internal diameters of the pipe at the measurement planes shall be measured and recorded.

B1.5 Each instrumentation plane shall be equipped to measure the temperature of the gas, as indicated in para. 4.13.1 of ASME PTC 22. The accuracy of measurement shall be better than 0.5% of the anticipated temperature at each plane of measurement.

B1.6 Each instrumentation plane shall be equipped with wall static-pressure taps, as indicated in para. 4.14.4 of ASME PTC 22, with pressure accurate to within 0.5%.

B2 TEST PREPARATION

B2.1 The composition of the working fluid shall be determined.

B2.2 The methods of calculating thermodynamic properties of the gas from the measured composition shall be agreed upon by the parties to the test and shall be consistent with the best engineering knowledge and practice in the gas processing industry.

B2.3 All necessary charts, tables, or computer programs shall be prepared and checked prior to the commencement of the test.

B2.4 The transmission efficiency, taking account of power losses through windage bearings, and gearbox losses, shall be stated by the manufacturer.

B2.5 The radiation heat loss, as a function of operating conditions, shall be stated by the manufacturer.

B3 TEST PROCEDURE

B3.1 Gas samples shall be taken during the test, as required.

B3.2 If the compressor is operating on a closed loop of pipe containing a gas of purity acceptable to the parties to the test, one test sample shall be taken during each test run.

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B3.3 If the compressor is operating on an open circuit with a relatively constant gas composition — for example, on a pipeline — gas samples shall be taken at the beginning and end of each test run.

B3.4 If the gas composition cannot be assured to be constant within limits acceptable to the parties to the test, a gas sample shall be taken at each test point.

B3.5 At each test reading, the gas flowmeter readings, compressor suction temperature and pressure, and compressor discharge temperature and pressure shall be stabilized within limits acceptable to the parties to the test and recorded.

B4 COMPUTATION OF RESULTS

B4.1 The composition of the gas at each test reading shall be established in accordance with ASME PTC 3.3, Gaseous Fuels.

B4.2 The flow of gas W shall be calculated from the flowmeter readings and converted to units of mass per unit of time (e.g., lbm/sec).

B4.3 The stagnation pressure at each measurement plane shall be calculated by adding the dynamic head of the gas (calculated from the flow rate, measured conditions, and flow area) to the measured static pressure.

B4.4 The gas enthalpy at the suction plane h_1 and the delivery plane h_2 of the compressor shall be calculated by the method established in para. B2.2.

B4.5 The heat loss by radiation Q_R from the compressor shall be determined from the manufacturer's data as stated in para. B2.5.

B4.6 The compressor gas power shall then be calculated from the following expression.

$$\text{Power} = W\frac{(h_2 - h_1) + Q_R}{\text{Constant}}$$

For various systems of units, the constant shall be as follows:

Mass Flow	Enthalpy	Power	Constant
lb/sec	Btu/lb	hp	0.7068
kg/sec	J/kg	kW	1000

B4.7 The shaft power of the turbine shall be calculated by dividing the gas power from para. B4.6 by the transmission efficiency from para. B2.4:

$$\text{Shaft Power} = \frac{\text{Gas Power}}{\eta_{tr}}$$

where η_{tr} is the transmission efficiency.

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APPENDIX C — UNCERTAINTY ANALYSIS

C1 INPUTS REQUIRED FOR UNCERTAINTY ANALYSIS

C1.1 To perform an uncertainty analysis on the power output and thermal efficiency of gas turbine power plants, two sets of inputs are required:

C1.1.1 Estimates of the uncertainties of each of the measurements required to determine power output and thermal efficiency of the power plant being tested. Two types of uncertainties make up the total uncertainty:

(a) Random or precision error. Due principally to the nonrepeatability of the measurement system, the random error varies during repeated measurements. It may be reduced by increasing both the number of instruments used to measure a given parameter, and the number of readings taken.

(b) Systematic, bias, or fixed error. This is usually an accumulation of individual errors not eliminated through calibration. It is a constant value despite repeated measurements, and is frequently difficult to quantify.

The total uncertainty is calculated from the root sum square of the random and systematic components (see ASME PTC 19.1, Test Uncertainty [23], and Eq. C1.2).

C1.1.2 Sensitivities, or influence coefficients, defined here as Sensitivity Coefficients Θ. Each of the parameters measured has an influence on power output and thermal efficiency. These sensitivities are a function of the gas turbine design, and must be provided by the manufacturer in the same fashion as the off-design characteristics (para. 5.4.2 of ASME PTC 22).

C1.2 The uncertainty of the result is the root mean square value of the uncertainty of each measurement multiplied by the Sensitivity Coefficient for that parameter. From ASME PTC 19.1:

$$U_R = 2\ [\Sigma\ (\Theta_i B_i/2)^2 + \Sigma\ (\Theta_i S_i)^2]^{0.5} \qquad \text{(C1.1)}$$

or

$$U_R = 2\ [\Sigma \Theta^2{}_i\ \{(B_i/2)^2 + S^2{}_i\}]^{0.5} \qquad \text{(C1.2)}$$

or

$$U_R = [\Sigma \Theta_i\ \{B_i^2 + (2S_i)^2\}]^{0.5} \qquad \text{(C1.3)}$$

or

$$U_R = [\Sigma \Theta_i^2\ U_{Ti}{}^2]^{0.5} \qquad \text{(C1.4)}$$

or

$$U_R = [\Sigma\ U_i^2]^{0.5} \qquad \text{(C1.5)}$$

where

U_R = uncertainty of the result
Θ = sensitivity coefficient
B_i = systematic error
S_i = standard deviation of the mean
U_T = combined random and systematic error

For each parameter, the random error has been estimated as $2S_i$ and the systematic error has been estimated at 95% confidence as B_i which reflects the desire to have a 95% confidence level that the true value lies within $\pm U_{Ti}$ of the mean. S_i can be calculated from:

$$S_i = 1/\sqrt{N}\left[\Sigma_{k=1}^{N}\ \frac{(X_k - \overline{X})^2}{N-1}\right]^{0.5} \qquad \text{(C1.6)}$$

where

N = number of measurements
X_k = individual measurement value
$\overline{X}$ = mean

C1.3 Prior to the test, the parties should agree on the measurements to be taken, and tabulate them and their Sensitivity Coefficients in a format similar to Table C1 or C2. These two tables are examples of uncertainty calculations for a generator drive gas turbine on oil fuel with steam injection, and for a mechanical drive with gas fuel and no diluent injection.

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TABLE C1
SAMPLE UNCERTAINTY CALCULATION FOR GENERATOR DRIVE WITH OIL FUEL AND STEAM INJECTION

Variable	Units	Uncertainty Level B_i	Uncertainty Level $2S_i$	Uncertainty Level U_{Ti}	Code Limit	Θ	U_i^2	U_R
Power (Net) at Test Conditions								
Electric power	%	0.1	0.1	0.1414	0.1500	1.0000	0.0200	
PTs	%	0.2	0.2	0.2828	0.3000	1.0000	0.0800	
CTs	%	0.2	0.2	0.2828	0.3000	1.0000	0.0800	
Aux power	%	4	2	4.4721	5.0000	0.0100	0.0020	
Measured power uncertainty							0.1820	0.4266
Corrected Power								
Measured power	%						0.1820	
Compr. inlet temp.	°F	0.5	0.5	0.7071	1.0000	0.4	0.0800	
Barometer	%	0.03	0.02	0.0361	0.0400	1	0.0013	
Spec. humidity	lb/lb	0.001	0.001	0.0014	0.0020	13	0.0003	
Control temp.	°F	6	2	6.3246	7.0000	0.15	0.9000	
Steam inj. flow	%	1.5	1	1.8028	2.0000	0.035	0.0040	
Corrected power uncertainty							1.1676	1.0806
Heat Rate (Oil Fuel) at Test Conditions								
Oil flow	%	0.5	0.25	0.5590		1.0000	0.3125	
Time	%	0.05	0.05	0.0707		1.0000	0.0050	
Viscosity	%	0.5	0.75	0.9014		0.0200	0.0003	
Density	%	0.4	0.2	0.4472		1.0000	0.2000	
Mass flow rate uncertainty					0.8000		0.5178	0.7196
Oil heat value	%	0.25	0.1	0.2693	0.3000	1.0000	0.0725	
Mass flow rate							0.5178	
Heat input uncertainty							0.5903	0.7683
Measured power							0.1820	
Heat input							0.5903	
Measured heat rate uncertainty							0.7723	0.8788
Corrected Heat Rate								
Measured heat rate							0.7723	
Compr. inlet temp.	°F	0.5	0.5	0.8602	1.0000	0.0800	0.0047	
Spec. humidity	lb/lb	0.001	0.001	0.0014	0.0020	40.0000	0.0032	
Control temp.	°F	6	2	6.3246	7.0000	0.0150	0.0090	
Steam flow	%	1.5	1	1.8028	2.0000	0.0150	0.0007	
Steam temp.	°F	4	2	4.4721	5.0000	0.0040	0.0003	
Corrected heat rate uncertainty							0.7903	0.8890

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TABLE C2
SAMPLE UNCERTAINTY CALCULATION FOR MECHANICAL DRIVE WITH GAS FUEL

Variable	Units	Uncertainty Level B_i	Uncertainty Level $2S_i$	Uncertainty Level U_{Ti}	Code Limit	θ	U_i^2	U_R
Power (Gross) at Test Conditions								
Torque	%	1.25	0.75	1.4577	1.5000	1.0000	2.1250	
Speed	%	0.1	0	0.1000	0.1000	1.0000	0.0100	
Measured power uncertainty							2.1350	1.4612
Corrected Power								
Measured power	%						2.1350	
Compr. inlet temp.	°F	0.5	0.5	0.7071	1.0000	0.4	0.0800	
Barometer	%	0.03	0.02	0.0361	0.0400	1	0.0013	
Spec. humidity	lb/lb	0.001	0.001	0.0014	0.0020	13	0.0003	
Control temp.	°F	6	2	6.3246	7.0000	0.15	0.9000	
Power turb. speed	%	0.1	0	0.1000	0.1000	0.035	0.0000	
Corrected power uncertainty							3.1167	1.7654
Heat Rate (Gas Fuel) at Test Conditions								
Gas flow	%	0.5	0.25	0.5590		1.0000	0.3125	
Time	%	0.1	0	0.1000		1.0000	0.0100	
Pressure	%	0.3	0.1	0.3162		1.0000	0.1000	
Temperature	°F	1	1	1.4142		0.2000	0.0800	
Gas constant	%	0.05	0	0.0500		1.0000	0.0025	
Compressibility	%	0.1	0	0.1000		1.0000	0.0100	
Mass flow rate uncertainty					0.8000		0.5150	0.7176
Gas heat value	%	0.33	0.2	0.3859	0.4000	1.0000	0.1489	
Mass flow rate							0.5150	
Heat input uncertainty							0.6639	0.8148
Measured power							2.1350	
Heat input							0.6639	
Measured heat rate uncertainty							2.7989	1.6730
Corrected Heat Rate								
Measured heat rate							2.7989	
Compr. inlet temp.	°F	0.5	0.5	0.8602	1.0000	0.0800	0.0047	
Spec. humidity	lb/lb	0.001	0.001	0.0014	0.0020	40.0000	0.0032	
Control temp.	°F	6	2	6.3246	7.0000	0.0150	0.0090	
Power turb. speed	%	0.1	0	0.1000	0.1000	0.0150	0.0000	
Corrected heat rate uncertainty							2.8158	1.6780

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C1.4 Uncertainties should be 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 used for PTC Codes. The values used in Tables C1 and C2 are representative of those achievable with appropriate selection of instruments, number of readings, etc. As shown, the total uncertainty for each parameter meets the Code requirement for that measurement.

C1.5 A post-test uncertainty analysis should be conducted to verify the assumptions made in the pre-test uncertainty analysis. In particular, the data should be examined for sudden shifts and outliers. The assumptions for random errors should be checked by determining the degrees of freedom and the standard deviation of each measurement.

C2 METHOD OF CALCULATING UNCERTAINTY

C2.1 As defined in Eq. C1.1, the uncertainties in power output and thermal efficiency are equal to the root-sum-square value of the uncertainty in each parameter multiplied by its Sensitivity Coefficient. The calculations include measurements and Θ values necessary to adjust the test point results to the specified operating conditions.

C2.2 Tables C1 and C2 show the systematic (bias) and random (precision) errors assumed for each parameter, and also show the limits expressed in the Code for each. In some cases, the random error is taken as zero, since with many sensors and multiple test readings, the error becomes negligible compared to the systematic error. Calculated values such as the gas fuel heat value are assumed to have no random error. If the degrees of freedom ν of a parameter (number of instruments multiplied by number of readings) is less than 30, the prefix 2 in Eq. C1.1 may need to be modified. ASME PTC 19.1 shows how to obtain the proper prefix (Student t factor) for $\nu < 30$.

The calculation procedure is as follows:

(a) After systematic and random components are established, the total uncertainty U_{Ti} is calculated from the root sum square of the two components.

(b) The sensitivity Θ_i is multiplied by U_{Ti} and squared, giving the factor U_i^2.

(c) All the U_i^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 conditions of ambient temperature and pressure, and the test results must be corrected to the specified 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 compressor inlet temperature, barometric pressure, specific humidity, and control temperature. For Table C1, it was assumed that the steam injection flow had to be adjusted to the level at the specified conditions.

(e) The Corrected Heat Rate uncertainty is obtained similarly by establishing the sensitivities of each of the parameters on heat rate and proceeding as above.

C2.3 The uncertainties in Corrected Power and Efficiency (Heat Rate) in Tables C1 and C2 are indicative of the levels achievable when performing a Code test. As stated in para. 3.5.6, each test will have its own value of uncertainty, depending on scope of supply, fuel used, type of load device, etc. It is important that this matrix of variables be established and agreed upon prior to the test, so that a proper uncertainty level can be determined which will reflect the quality of a Code test.

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APPENDIX D — SAMPLE LIQUID FUEL CALCULATION

GENERAL INFORMATION

From test data:

- Operating temperature of the liquid fuel at the flowmeter is 90°F.
- Flowmeter average frequency during the timing period is 602 Hz.

From flowmeter manufacturer:

- Calibration K-factor [pulses-Hz/gallon] versus frequency/kin. viscosity [pulses-Hz/cSt] for different kinematic viscosities encompassing the one at the operating temperature of the liquid fuel. A typical plot is shown in Fig. D1.
- Pulse (squarewave or sinusoidal) output from a flowmeter is usually scaled so that 1 pulse indicates a specific quantity of fluid passing through the meter.

From laboratory analyses:

- Density of the liquid fuel for three temperatures encompassing the operating temperature of 90°F;

or

- Relative density (spec. gravity) at 60°F is 0.834. API gravity is calculated to be 38.16 deg.
- HHV_v measured with the bomb calorimeter is 19,681 Btu/lbm (at 77°F).
- Kinematic viscosity of the liquid fuel at the operating temperature of 90°F is 3 cSt.
- Hydrogen content in the liquid fuel is 13.4% by weight.

D1 EFFECT OF KINEMATIC VISCOSITY; CALCULATION OF DENSITY; CALCULATION OF VOLUMETRIC FLOW

D1.1 Effect of Kinematic Viscosity

$$\frac{\text{Frequency}}{\text{Kin. Viscosity}} = 602/3$$

$$= 200.7 \text{ (pulses-Hz)/cSt}$$

or pulses/(s-cSt)

From interpolation in Fig. D1, the flowmeter calibration K-factor for the operating condition is determined to be 321 pulses/gallon.

D1.2 Calculation of Density. From interpolation between the three density values, the density at 90°F was calculated to be 6.854 lbm/gallon.

D1.3 Calculation of Volumetric Flow. Volumetric flow is calculated as follows:

$$Q_\ell = 602/321 = 1.875 \text{ gallons/sec (or 112.5 gpm)}$$

D2 CALCULATION OF HEAT VALUES

D2.1 Derivation of Constants Used

$$HHV_p = HHV_v - \rho\Delta V/J = HHV_v$$

$$- RT\,(n_{CO2} - n_{O2}) \text{ Btu/mol of fuel}$$

The difference between the number of mols of gaseous products and reactants is calculated using the oxygen atomic balance during a combustion reaction of 1 mol of fuel:

$$O: 2n_{O2} = n_{H2O} + 2\,n_{CO2}$$

or

$$n_{O2} = 1/2\,n_{H2O} + n_{CO2}$$

then

$$n_{CO2} - n_{O2} = n_{CO2} - 1/2\,n_{H2O} - n_{CO2} = -1/2\,n_{H2O}$$
$$= -1/2(m_{H2}/m_{Fuel})(m_{Fuel}/M_{H2})$$

and

$$RT/M_{Fuel}(-1/2 n_{H2O}) = -(RT/2)(m_{Fuel}/M_{Fuel})$$
$$(1/M_{H2})\,[(m_{H2}/m_{Fuel})\,100]/100$$

applying that for 1 mol of fuel

$$n_{Fuel} = m_{Fuel}/M_{Fuel} = 1$$

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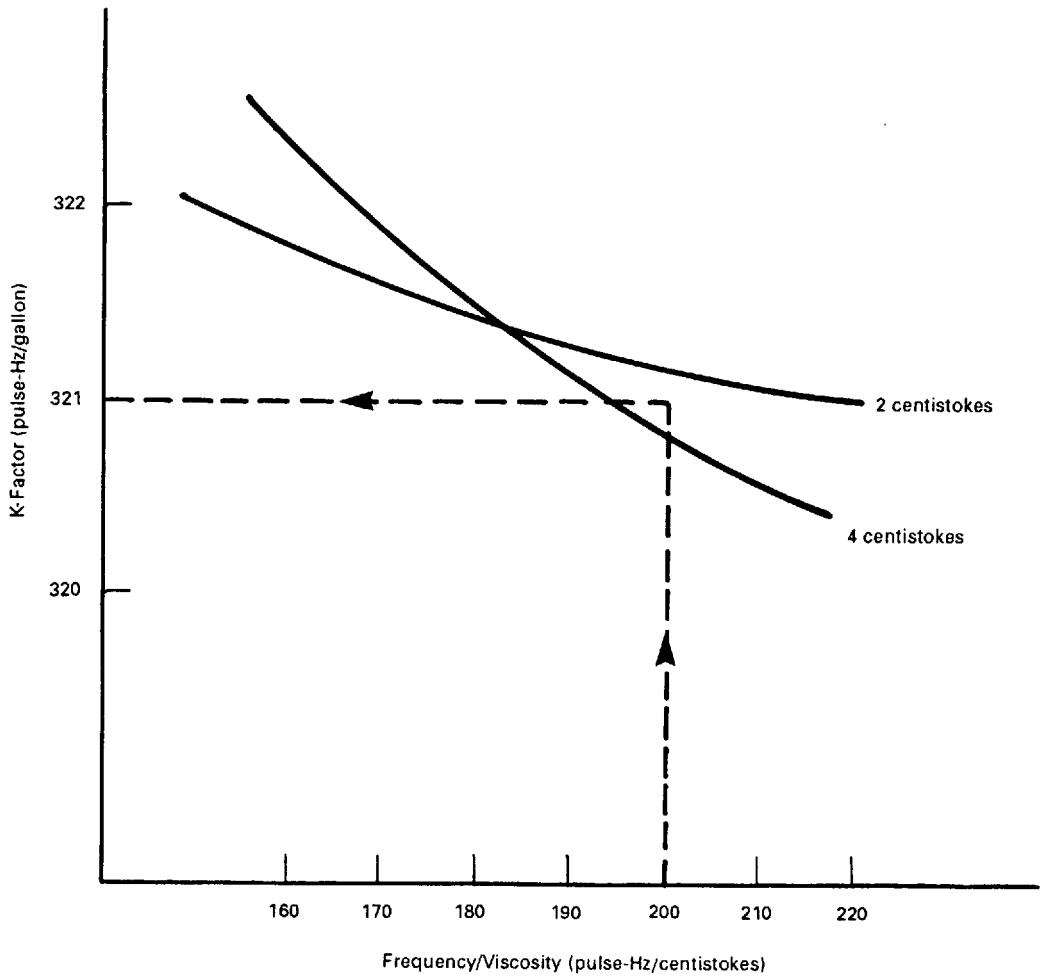


FIG. D1 TYPICAL PLOT OF K-FACTOR vs (FREQUENCY/VISCOSITY) FOR A TURBINE METER

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and having

$$H = m_{H2}/m_{Fuel} \cdot 100$$

(= lbs hydrogen/lbs fuel · 100 = % by weight)

$$RT/M_{Fuel}\ (-1/2\ n_{H2O}) = -(RT/2)(1/M_{H2})\ (H)/100$$

$$HHV_p = HHV_v - [RT/M_{Fuel}\ (-1/2\ n_{H2O})] = HHV_v + RT/(2\ M_{H2})/100]\ (H),\ \text{Btu/lbm}$$

$$RT/(2\ M_{H2})/100]\ (H) = 1.98586 \cdot 536.36/(2 \cdot 2.016)/100\ (H) = 2.6432\ (H) = 2.64\ (H)$$

The final equation is:

$$HHV_p = HHV_v + 2.64 \cdot (H)\ \text{Btu/lbm}$$

Calculation of Low Heat Values:

$$LHV_v = HHV_v - (U_{fg}/M_{H2O})W_w \text{ and } LHV_p = HHV_p - (h_{fg}/M_{H2O})W_w$$

$$LHV_p = HHV_v + 2.64\ (H) - (h_{fg}/M_{H2O})W_w$$

$$W_w = m_{H2O}/m_{Fuel} = (M_{H2O}/M_{H2})[(m_{H2}/m_{Fuel})\ 100]/100 = (M_{H2O}/M_{H2})(H)/100$$

$$W_w = 18.016/2.016/100 \cdot (H) = 0.0894\ (H)$$

$$h_{fg} = U_{fg} + \rho\ v/J = U_{fg} + RT \text{ and } U_{fg} = h_{fg} - RT\ \text{Btu/mol}$$

$$h_{fg}/M_{H2O} = U_{fg}/M_{H2O} + \rho\ v/J/M_{H2O} \text{ and } U_{fg}/M_{H2O} = h_{fg}/M_{H2O} - RT/M_{H2O}\ \text{Btu/lbm}$$

$$h_{fg}/M_{H2O} = 1050.06\ \text{Btu/lbm}$$

$$U_{fg}/M_{H2O} = 1050.06 - 1.98586\ (536.67)/18.016 = 990.904\ \text{Btu/lbm}$$

$$(h_{fg}/M_{H2O})W_w = 0.0894 \cdot 1050.06 \cdot (H) = 93.84\ (H)\ \text{Btu/lbm}$$

$$(U_{fg}/M_{H2O})W_w = 0.0894 \cdot 990.904 \cdot (H) = 88.55\ (H)\ \text{Btu/lbm}$$

and consequently:

$$LHV_p = HHV_v + 2.64\ (H) - (h_{fg}/M_{H2O})W_w = HHV_v + 2.64\ (H) - 93.84\ (H)$$

$$LHV_p = HHV_v - 91.20\ (H)\ \text{Btu/lbm}$$

where

H = percentage of hydrogen H_2 by weight contained in the liquid fuel and determined in accordance with ASTM D 1018, Test Method for Hydrogen in Petroleum Fractions

HHV_p, LHV_p = calculated high and low heat values at constant pressure, Btu/lbm

HHV_v, LHV_v = measured high and low heat values at constant volume, Btu/lbm (in accordance with ASTM D 4809)

W_w = mass of H_2O formed during combustion, lbm water/lbm fuel

T = absolute base temperature for the heat values, 536.67°R (=77°F)

R = molar universal gas constant, 1.98586 Btu/mol-R (= 8314.41 J/kmol-K)

M = molecular weight, M_{H2O} = 18.016 lbm/mol, M_{H2} = 2.016 lbm/mol

h_{fg}/M_{H2O} = enthalpy change of H_2O during vaporization at 77°F (latent heat of vaporization) = 1050.06 Btu/lbm (according to the ASME Steam Tables)

U_{fg}/M_{H2O} = internal energy change of H_2O during vaporization at 77°F

J = Joule's constant (work equivalence of 1 Btu), 778.169262 ft-lbf/Btu

n_{H2O}, n_{O2}, n_{CO2}, n_{Fuel} = number of mols for the different components

m_{H2O}, m_{H2}, m_{Fuel} = mass flows (lbm) of the different components

D2.2 Heat Values Calculation

$$HHV_p = HHV_v + 2.64\ (H) = 19{,}681 + 2.64\ (13.4) = 19{,}716\ \text{Btu/lbm}$$

$$LHV_p = HHV_v - 91.20\ (H) = 19{,}861 - 91.20\ (13.4) = 18{,}459\ \text{Btu/lbm}$$

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D3 CALCULATION OF SENSIBLE HEAT OF LIQUID FUEL

A polynomial equation is provided to obtain specific enthalpy of the liquid fuel as a function of API gravity (deg API) and temperature T (°F), (D. W. Gould's equation from *The Science of Petroleum* — Vol. 2, p. 1250) [23].

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

The following coefficients were determined:

$C_1 = -30.016$
$C_2 = -0.11426$
$C_3 = 0.373$
$C_4 = 0.143/100$
$C_5 = 0.218/1000$
$C_6 = 0.7/1{,}000{,}000$

Using this equation, the following values were calculated:

$$h_{\ell,77} = 7.8 \text{ Btu/lbm (reference value)}$$
$$h_{\ell,90} = 13.9 \text{ Btu/lbm}$$

$$h_\ell - h_{\ell,77} = 13.0 - 7.8 = 6.1 - 0.0 = 6.1 \text{ Btu/lbm}$$

The sensible heat of the liquid fuel is then:

$$SH_p = Q_\ell\,\rho_\ell\,(h_\ell - h_{\ell,77}) = 1.875\,(6.854)\,(13.9 - 7.8) = 78.39 \text{ Btu/sec}$$

D4 CALCULATION OF HEAT INPUT

$$HI_\ell = Q_\ell\,\rho_\ell\,(LHV_p) + SH_p$$
$$= 1.875\,(6.854)\,(18{,}459) + 78.39$$
$$= 237{,}299.62 \text{ Btu/sec}$$
$$= 854.28 \cdot 10^6 \text{ Btu/h (when based on } LHV)$$

$$HI_\ell = Q_\ell\,\rho_\ell\,(HHV_p) + SH_p$$
$$= 1.875\,(6.854)\,(19{,}716) + 78.39$$
$$= 253{,}453.64 \text{ Btu/sec}$$
$$= 912.43 \cdot 10^6 \text{ Btu/h}$$
(when based on *HHV*)

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APPENDIX E — SAMPLE GAS FUEL CALCULATION

E1 GENERAL INFORMATION

From test data:

- Operating temperature of the fuel gas at the flowmeter is 122°F.
- Operating pressure of the fuel gas at the flowmeter is 681.96 psia.
- Measured fuel gas dew point temperature is 6°F.
- Average turbine meter frequency during the test period is 563 Hz.

From flowmeter manufacturer:

- Calibration K-factor (pulses/ft^3) versus frequency is 600 pulses/ft^3.

The pulse (squarewave or sinusoidal) output from a flowmeter is usually scaled so that 1 pulse indicates a specific quantity of fluid passing through the meter.

From chromatograph analyses:

Gas Composition (Dry)	Mole Fraction
Methane	0.96121
Ethane	0.02172
Propane	0.0022
iso-Butane	0.00036
n-Butane	0.00028
iso-Pentane	0.0001
n-Pentane	0.00004
n-Hexane	0.00006
Carbon Dioxide	0.00469
Nitrogen	0.00934

E1.1 Calculation of Water in Fuel Gas. From ASHRAE Handbook of Fundamentals [24], the fuel gas dew point pressure is 0.02521 psia.

Mole fraction of water in the fuel gas

$$x_W = 0.02521/14.696 = 0.001715$$

E1.2 Calculation of Wet Fuel Gas Composition, Molecular Weight, and Heat Value. Since the chromatograph analysis is on a dry basis, the analysis must be converted to a wet basis per ASTM D 3588 (see Table E1):

$$x_j(\text{cor}) = x_j\,(1 - x_w)$$

where

x_j = mole fraction dry
x_w = mole fraction of water in the fuel gas
x_j(cor) = mole fraction corrected for water content

The molar mass calculation per ASTM D 3588 is (see Table E1):

$$M = \sum_{j=1}^{n} x_j M_j$$

$$M = 16.6936$$

where

M = mixture molar mass
x_j = mole fraction dry
M_j = constituent molar mass

The net heat value at 60°F and 14.696 psia (*LHV*) is also calculated per ASTM D 3588 (see Table E1):

$$h_m = \sum_{j=1}^{n} x_j M_j h_{mj} / \sum_{j=1}^{n} x_j M_j$$

$$h_m = 347{,}420/16.6936 = 20{,}812 \text{ Btu/lbm}$$

where

h_m = sample low heat value per unit mass
M = constituent molar mass
h_{mj} = constituent low heat value per unit mass
n = number of constituents

E1.3 Calculation of Density. The density at the flowmeter is calculated from the equation:

$$\rho_g = 144\,\frac{P_g}{Z_g R_g T_g}$$

$$\rho_g = 144\,\frac{681.96}{0.9405(1545.3/16.6936)(122 + 459.67)}$$

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TABLE E1
SAMPLE CALCULATION OF CORRECTED MOLE FRACTION, MOLECULAR WEIGHT, AND LOW HEATING VALUE

Compound	Mole Fraction, x_j	Corr. Mole Fraction, x_j(corr)	Molar Mass, M_j	Molar Mass Fraction, x_j(corr)M_j	Low Heat Value, H_{mj}	Low Heat Value Fraction, x_j(corr)$M_j H_{mj}$
Methane	0.96121	0.95956	16.0430	15.3942	21,511	331,146
Ethane	0.02172	0.02168	30.0700	0.6520	20,429	13,320
Propane	0.00220	0.00220	44.0970	0.0968	19,922	1,929
n-Butane	0.00036	0.00036	58.1230	0.0209	19,658	411
Isobutane	0.00028	0.00028	58.1230	0.0162	19,590	318
n-Pentane	0.00010	0.00010	72.1500	0.0072	19,481	140
Isopentane	0.00004	0.00004	72.1500	0.0029	19,456	56
n-Hexane	0.00006	0.00006	86.1770	0.0052	19,393	100
Carbon dioxide	0.00469	0.00468	44.0100	0.2061	0	0
Nitrogen	0.00934	0.00932	28.0134	0.2612	0	0
Water	0.00000	0.00172	18.0153	0.0309	0	0
Total	1.00000	1.00000		16.6936		347,420

$$\rho_g = 1.939 \text{ lbm/ft}^3$$

where

ρ_g = density of gas mixture
P_g = operating pressure of fuel gas at the flowmeter
Z_g = compressibility factor of gas mixture obtained from AGA Report No. 8
R_g = gas constant
T_g = operating temperature of fuel gas at the flowmeter

E1.4 Calculation of Volume Flow. The volumetric flow is calculated as follows:

$$Q_g = F/K$$

$$Q_g = 563/600 = 0.9384 \text{ ft}^3/\text{sec}$$

E1.5 Calculation of Sensible Heat. From the GPSA Engineering Data Book, enthalpy of the fuel gas at 122°F and 681.96 psia is 263.7 Btu/lbm.

From the GPSA Engineering Data Book, enthalpy of the fuel gas at 60°F and 14.696 psia is 248.1 Btu/lbm.

The sensible heat is then calculated as follows:

$$SH_p = Q_g \rho_g (h_g - h_{g,b})$$

$$SH_p = 0.9384 \times 1.939 \times (263.7 - 248.1)$$

$$SH_p = 28.39 \text{ Btu/sec}$$

E1.6 Calculation of Heat Input. The heat input is calculated as follows:

$$HI_g = Q_g \rho_g (LHV_p) + SH_p$$

$$HI_g = 0.9384 \times 1.939 \times 20{,}812 + 28.39$$

$$HI_g = 37{,}897 \text{ Btu/sec}$$

E2 CALCULATION OF HEAT VALUES USING A CONTINUOUS RECORDING CALORIMETER

E2.1 Derivation of Constants Used. The high heat value for gas fuel can be measured using a continuous recording calorimeter, where the gas is burned at constant pressure. The low heat value at constant pressure is calculated as follows:

$$LHV_p = HHV_p - (h_{fg}/M_{H2O}) W_w \text{ Btu/lbm}$$

$$W_w = m_{H2O}/m_{Fuel} = (M_{H2O}/M_{H2})$$

$$[(m_{H2}/m_{Fuel})\ 100]/100 = (M_{H2O}/M_{H2})(H)/100$$

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$$W_W = 18.016/2.016/100 \cdot (H) = 0.0894\ (H)$$

The current standard temperature for heats of combustion for gas fuels is 60°F.

$$h_{fg}/M_{H2O} = 1059.64 \text{ Btu/lbm}$$

$$(h_{fg}/M_{H2O})W_w = 0.0894 \cdot 1059.64 \cdot (H) = 94.73\ (H) \text{ Btu/lbm}$$

and consequently:

$$LHV_p = HHV_p - 94.73\ (H) \text{ Btu/lbm}$$

where

H = percentage of hydrogen H_2 by weight contained in the gas fuel and determined in accordance with ASTM D 1945

HHV_p, LHV_p = measured (ASTM D 1826) high and calculated low heat values at constant pressure, Btu/lbm

W_w = mass of H_2O formed during combustion, lbm water/lbm fuel

M = molecular weight, M_{H2O} = 18.016 lbm/mol, M_{H2} = 2.016 lbm/mol

h_{fg}/M_{H2O} = enthalpy change of H_2O during vaporization at 60°F (latent heat of vaporization) = 1059.64 Btu/lbm (according to the ASME Steam Tables) [25]

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