ASME PTC 4.4-2023

[Revision of ASME PTC 4.4-2008 (R2013)]

Gas Turbine Heat Recovery Steam Generators

Performance Test Codes

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AN AMERICAN NATIONAL STANDARD

The American Society of
Mechanical Engineers

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The American Society of Mechanical Engineers
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NOTICE

All ASME Performance Test Codes (PTCs) shall adhere to the requirements of ASME PTC 1, General Instructions. It is expected that the Code user is fully cognizant of the requirements of ASME PTC 1 and has read them before applying ASME PTCs.

ASME PTCs provide unbiased test methods for both the equipment supplier and the users of the equipment or systems. The Codes are developed by balanced committees representing all concerned interests and specify procedures, instrumentation, equipment-operating requirements, calculation methods, and uncertainty analysis. Parties to the test can reference an ASME PTC confident that it represents the highest level of accuracy consistent with the best engineering knowledge and standard practice available, taking into account test costs and the value of information obtained from testing. Precision and reliability of test results shall also underlie all considerations in the development of an ASME PTC, consistent with economic considerations as judged appropriate by each technical committee under the jurisdiction of the ASME Board on Standardization and Testing.

When tests are run in accordance with a Code, the test results, without adjustment for uncertainty, yield the best available indication of the actual performance of the tested equipment. Parties to the test shall ensure that the test is objective and transparent. All parties to the test shall be aware of the goals of the test, technical limitations, challenges, and compromises that shall be considered when designing, executing, and reporting a test under the ASME PTC guidelines.

ASME PTCs do not specify means to compare test results to contractual guarantees. Therefore, the parties to a commercial test should 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 ASME PTC to determine or interpret how such comparisons shall be made.

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FOREWORD

ASME PTC 4.4 began as an appendix. In September 1973, the ASME PTC 4 Committee planned a new appendix for ASME PTC 4.1, Steam Generating Units, that would cover heat recovery steam generators (HRSGs) for combined cycles. During meetings in May 1976 and May 1977, the committee decided that the scope of their work was beyond the capacity of an appendix. Consequently, the ASME Performance Test Code (PTC) Supervisory Committee approved a charter for a separate PTC titled ASME PTC 4.4, Gas Turbine Heat Recovery Steam Generators. The ASME PTC 4 Committee presented the draft of ASME PTC 4.4 to the supervisory committee in February 1980, gaining final approval of the new PTC on January 26, 1981. ASME PTC 4.4-1981 was approved as an American National Standard by the American National Standards Institute (ANSI) Board of Standards Review on February 3, 1981.

In 2008, the ASME PTC 4.4 Committee revised the 1981 edition, providing a more specific HRSG testing procedure consistent with current industry practice. ASME PTC 4.4-2008 used two independent approaches to quantify unit capacity and added new sections related to measurement uncertainty.

ASME PTC 4.4-2023 updates the 2008 edition, adding practices on instrumentation and uncertainty calculation.

ASME PTC 4.4-2023 was approved by the ASME Board on Standardization and Testing on March 7, 2023. It was approved by the ANSI Board of Standards Review as an American National Standard on April 19, 2023.

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In addition, the committee may post errata on the committee web page. Errata become effective on the date posted. Users can register on the committee web page to receive e-mail notifications of posted errata.

This Code is always open for comment, and the committee welcomes proposals for revisions. Such proposals should be as specific as possible, citing the paragraph number, the proposed wording, and a detailed description of the reasons for the proposal, including any pertinent background information and supporting documentation.

Cases

(a) The most common applications for cases are

  (1) to permit early implementation of a revision based on an urgent need

  (2) to provide alternative requirements

  (3) to allow users to gain experience with alternative or potential additional requirements prior to incorporation directly into the Code

  (4) to permit the use of a new material or process

(b) Users are cautioned that not all jurisdictions or owners automatically accept cases. Cases are not to be considered as approving, recommending, certifying, or endorsing any proprietary or specific design, or as limiting in any way the freedom of manufacturers, constructors, or owners to choose any method of design or any form of construction that conforms to the Code.

(c) A proposed case shall be written as a question and reply in the same format as existing cases. The proposal shall also include the following information:

  (1) a statement of need and background information

  (2) the urgency of the case (e.g., the case concerns a project that is underway or imminent)

  (3) the Code and the paragraph, figure, or table number

  (4) the editions of the Code to which the proposed case applies

(d) A case is effective for use when the public review process has been completed and it is approved by the cognizant supervisory board. Approved cases are posted on the committee web page.

Interpretations. Upon request, the committee will issue an interpretation of any requirement of this Code. An interpretation can be issued only in response to a request submitted through the online Interpretation Submittal Form at https://go.asme.org/InterpretationRequest. Upon submitting the form, the inquirer will receive an automatic e-mail confirming receipt.

ASME does not act as a consultant for specific engineering problems or for the general application or understanding of the Code requirements. If, based on the information submitted, it is the opinion of the committee that the inquirer should seek assistance, the request will be returned with the recommendation that such assistance be obtained. Inquirers can track the status of their requests at https://go.asme.org/Interpretations.

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Interpretations are published in the ASME Interpretations Database at https://go.asme.org/Interpretations as they are issued.

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Section 1
Object, Scope, and References

1-1 OBJECT

The object of this Code is to establish procedures for conducting performance tests of heat recovery steam generators (HRSGs) used to recover gas turbine exhaust (GTE) energy. The steam generator may include supplemental firing. This Code provides standard test procedures yielding the highest level of accuracy consistent with current engineering knowledge and practice.

(a) The purpose of this Code is to determine the following:

(1) capacity of the unit at specified conditions
(2) energy input from GTE and supplementary firing
(3) gas-side pressure drop
(4) steam- and water-side pressure drops

(b) This Code provides methods for converting the performance at test conditions to specified operating conditions. A determination of any or all of the performance items listed above may be used for the following purposes:

(1) checking the actual performance against guarantee
(2) comparing these items at reference conditions
(3) comparing different conditions or methods of operation
(4) determining the specific performance of individual parts or sections of the HRSG unit
(5) comparing the performance when firing different fuels
(6) determining the effects of changes to equipment

1-2 SCOPE

(a) This Code addresses steam generators whose primary function is to recover heat from GTE. Methods noted in this document may also be used for testing other heat recovery units, which may include the following:

(1) units heating water only
(2) units using working fluids other than water
(3) units obtaining hot gas heat input from sources other than gas turbines (GTs)
(4) HRSGs with fresh air firing capability

(b) This Code does not cover the following testing:

(1) fired steam generators whose primary function does not include the recovery of heat from GTE. Fired steam generators are addressed in ASME PTC 4 and ASME PTC 34.
(2) auxiliary equipment such as pumps and fans, which are addressed in ASME PTC 8.2 and ASME PTC 11, respectively.
(3) deaerator performance, which is addressed in ASME PTC 12.3.
(4) equipment noise emissions, which are addressed in ASME PTC 36.
(5) gaseous emissions to atmosphere.
(6) steam purity.

1-3 TEST UNCERTAINTY

This Code requires an uncertainty analysis in accordance with ASME PTC 19.1 as detailed in Section 7. The pretest uncertainty analysis is used to develop unit-specific test procedures that result in meeting an agreed-upon target uncertainty. Typical values of test uncertainties, various unit configurations, and performance parameters are presented in Sections 3 and 4.

1-4 REFERENCES

The following publications are referenced in this Code. Unless otherwise specified, the latest edition shall apply.

AGA Report 8 (2017). Thermodynamic Properties of Natural Gas and Related Gases — Part 1, DETAIL and GROSS Equations of State. American Gas Association.
ASHRAE Handbook of Fundamentals. American Society of Heating, Refrigerating, and Air Conditioning Engineers.
ASME MFC-2M. Measurement Uncertainty for Fluid Flow in Closed Conduit. The American Society of Mechanical Engineers.
ASME PTC 4. Fired Steam Generators. The American Society of Mechanical Engineers.
ASME PTC 6.2. Steam Turbines in Combined Cycles. The American Society of Mechanical Engineers.
ASME PTC 8.2. Centrifugal Pumps. The American Society of Mechanical Engineers.
ASME PTC 11. Fans. The American Society of Mechanical Engineers.

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ASME PTC 12.3. Deaerators. The American Society of Mechanical Engineers.

ASME PTC 19.1. Test Uncertainty. The American Society of Mechanical Engineers.

ASME PTC 19.2. Pressure Measurement. The American Society of Mechanical Engineers.

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ASME PTC 19.5. Flow Measurement. The American Society of Mechanical Engineers.

ASME PTC 22. Gas Turbines. The American Society of Mechanical Engineers.

ASME PTC 34. Waste Combustors With Energy Recovery. The American Society of Mechanical Engineers.

ASME PTC 36. Measurement of Industrial Noise. The American Society of Mechanical Engineers.

ASME PTC 46. Overall Plant Performance. The American Society of Mechanical Engineers.

ASTM D445. Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and Calculation of Dynamic Viscosity). ASTM International.

ASTM D1480. Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer. ASTM International.

ASTM D1945. Standard Test Method for Analysis of Natural Gas by Gas Chromatography. ASTM International.

ASTM D4057. Standard Practice for Manual Sampling of Petroleum and Petroleum Products. ASTM International.

ASTM D4809. Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method). ASTM International.

ASTM D5287. Standard Practice for Automatic Sampling of Gaseous Fuels. ASTM International.

ASTM E220. Standard Test Method for Calibration of Thermocouples by Comparison Techniques. ASTM International.

ASTM E1137-97. Standard Specification for Industrial Platinum Resistance Thermometers. ASTM International.

ASTM MNL 12. In Manual on the Use of Thermocouples in Temperature Measurement. ASTM International.

Benedict, R. P. (1984). Fundamentals of Temperature Pressure and Flow Measurements (3rd ed.). John Wiley and Sons.

Dahl, A. I. (1941). "Stability of Base-metal Thermocouples in Air From 800 to 2200°F." Temperature: Its Measurement and Control. Reinhold.

Dittus, F. W., and Boelter, L. M. K. (1930). Heat Transfer in Automobile Radiators of the Tubular Type. University of California Publications in Engineering, 2, 443–461.

GPA 2145-16. Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry. GPA Midstream Association.

GPA 2166. Collecting and Handling of Natural Gas Samples for Analysis by Gas Chromatography. GPA Midstream Association.

IAPWS R7-97(2012). Revised Release on the IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam. International Association for the Properties of Water and Steam. http://iapws.org/relguide/IF97-Rev.html

NASA/TP–2002-211556 (2002, September). NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species. Glenn Research Center, National Aeronautics and Space Administration.

NIST Special Publication 811. Guide for the Use of the International System of Units (SI). National Institute of Standards and Technology, U.S. Department of Commerce.

NIST Technical Note 1265. Guidelines for Realizing the International Temperature Scale of 1990 (ITS-90). National Institute of Standards and Technology, U.S. Department of Commerce.

Perry, R. H., and Green, D. W. (1997). Perry's Chemical Engineer's Handbook (7th ed.). McGraw Hill.

Steam: Its Generation and Use (40th ed.) (1992). Babcock & Wilcox.

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Section 2
Definitions of Terms, Symbols, and Conversion Factors

2-1 DEFINITIONS

The following terms are either not defined elsewhere in this document or need more clarification:

absolute pressure: pressure above zero; the sum of the gauge and atmospheric pressures.

acid dew point: temperature at which the acid in the gas condenses. Generally, sulfuric acid is the most critical compound in the gas for which acid dew point needs to be determined.

ambient temperature: the temperature of the air surrounding the heat recovery steam generator.

ammonia injection grid: a system of pipes to introduce ammonia into the gas turbine exhaust for reaction with NOx in the presence of a catalyst to form nitrogen and water.

approach temperature: the difference between the saturation temperature in the drum and the water temperature entering the drum.

attemperation: see *desuperheating*.

auxiliary firing: combustion of fuel in the heat recovery steam generator to raise the gas turbine exhaust temperature and increase steam capacity.

auxiliary system: any system that uses fluids other than steam or water and exchanges energy with the gas turbine exhaust. These systems include air heaters, air coolers, fuel heaters, etc.

base load: a gas turbine generator operating on its control curve wherein the power produced is nominally 100%.

blowdown: discharge of water from an evaporator for the purpose of controlling the dissolved solids concentration.

burner auxiliary air: air introduced into the burner in addition to the gas turbine exhaust to facilitate the combustion process.

bypass: a passage for a fluid, permitting a portion or all the fluid to flow around certain heating surfaces through which it would normally pass.

bypass damper: a damper that is used to bypass gas turbine exhaust from the heat recovery steam generator to atmosphere.

capacity: the amount of steam flow at the given steam temperature and pressure.

cascading blowdown: a blowdown system wherein the water from a higher pressure level is blown down to a lower pressure level.

CO catalyst: a catalyst that is used to reduce the carbon monoxide level in the gas turbine exhaust.

condensate: water coming from the condenser.

condenser: the vessel that is used to condense the steam exiting the steam turbine.

continuous blowdown: the uninterrupted discharge of water from an evaporator section to control the dissolved solids concentration.

deaeration: removal of oxygen and other dissolved gases from water.

deaerator: the pressure vessel wherein the dissolved gases are removed from water.

desuperheater: a mixing chamber wherein higher temperature steam is mixed with a lower temperature steam or water to decrease the overall steam temperature.

desuperheating: reduction of steam temperature by mixing the superheated steam with either water or lower temperature steam.

duct burner: an in-duct burner system used for auxiliary or supplementary firing.

economizer: a heat transfer section wherein deaerated feedwater is heated before being introduced into an evaporator.

evaporator: a heat transfer section wherein feedwater is vaporized.

feedwater: water entering an evaporator or economizer section.

feedwater heater: see *preheater*.

flashing: the process where steam is produced when saturated water is reduced in pressure.

gas approach temperature: the minimum temperature difference at the inlet or outlet to a heat transfer section between the gas and tube-side fluid.

gas static pressure drop: the difference between the static pressure measured at the inlet test boundary and the atmosphere or the gas-side pressure drop across a heating section.

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gas turbine exhaust (GTE): the exhaust gas flowing through the heat recovery steam generator from the gas turbine.

gas turbine generator (GTG): the combination of gas turbine and electric generator.

GT: gas turbine.

heater: a section wherein fluid other than water or steam is heated.

heating surface: the surface that is exposed to the heating medium (gas turbine exhaust or hot gas) for absorption and transfer of heat to the heated medium (water, steam, or air).

higher heating value: the total heat obtained from the combustion of a unit amount of fuel that is at 60°F when combustion products are cooled to 60°F (GPA 2145-16).

HP: high pressure.

HRSG: heat recovery steam generator.

integral deaerator: a deaerator that is directly connected to the low-pressure drum.

interstage: between the heating surface sections.

IP: intermediate pressure.

lower heating value: the high heating value of fuel minus the latent heat of vaporization of the combustion products when combustion products are cooled to 60°F (GPA 2145-16).

LP: low pressure.

multiple-pressure HRSG: a heat recovery steam generator system that exports steam at more than one pressure.

part load: a gas turbine operating condition wherein the power produced is less than base load.

partial pressure: the contribution to total pressure of a constituent of a gaseous mixture.

peak load: a gas turbine operating condition wherein gas turbine power production is at maximum value.

pegging steam: higher pressure steam used to maintain a minimum pressure in a lower pressure system.

pinch point: the temperature difference between the gas temperature exiting the evaporator section and the saturation temperature of the water in the drum.

pinch temperature: the minimum terminal temperature difference between gas turbine exhaust and fluid.

preheater: heat transfer section where aerated water is heated.

recirculation: use of a portion of hot water from an economizer or feedwater preheater to increase the incoming water temperature.

reference temperature: a selected temperature from which all properties are based.

reheater: a heat transfer section where steam returning from the steam turbine is heated to a higher temperature for return back to the steam turbine.

remote deaerator: a standalone deaerator that is separate from the heat recovery steam generator.

saturation temperature: the temperature corresponding to a given pressure at which a fluid vaporizes.

selective catalytic reduction system: a system used to reduce the nitrogen oxides emissions in the gas turbine exhaust.

single-pressure HRSG: a heat recovery steam generator that exports steam at one pressure only.

stack: a vertical conduit to discharge the gas turbine exhaust to atmosphere.

stack damper: a damper located in a stack to stop air flow through the gas turbine and heat recovery steam generator while not in operation.

standard air composition (dry air molar basis): nitrogen, 78.0858%; oxygen, 20.94%; argon, 0.9342%; carbon dioxide, 0.04% (GPA 2145-16).

standard conditions: ambient conditions of 14.696 psia and 60°F.

standard gas compound names, symbols, and molecular weights:

Compound	**Symbol**	**Molecular Weight**
Argon	Ar	39.948
Butene	C_4H_8	56.1063
Carbon dioxide	CO_2	44.0095
Carbon monoxide	CO	28.0101
Ethane	C_2H_6	30.0690
Ethene	C_2H_4	28.0532
Helium	He	4.002602
Hexane	C_6H_{14}	86.1754
Hydrogen	H_2	2.01588
Hydrogen sulfide	H_2S	34.081
Isobutane	*iso*-C_4H_{10}	58.1222
Isopentane	*iso*-C_5H_{12}	72.1488
Methane	CH_4	16.0425
Nitrogen	N_2	28.0134
Normal butane	*n*-C_4H_{10}	58.1222
Normal pentane	*n*-C_5H_{12}	72.1488
Oxygen	O_2	31.9988
Pentene	C_5H_{10}	70.1329
Propane	C_3H_8	44.0956
Propene	C_3H_6	42.0797
Sulfur dioxide	SO_2	64.066
Water	H_2O	18.0153

steam bypass: a steam flow path bypassing a steam turbine.

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steam bypass: a steam flow path bypassing a superheater or part of a superheater.

steam purity: amount of total dissolved solids in the steam.

steam quality: percentage by weight of steam in a mixture of water and steam.

superheat: the temperature difference between the steam temperature and the saturation temperature for a given pressure.

superheated steam: steam at a temperature higher than its saturation temperature.

superheater: a heat transfer section where steam is superheated.

supplementary firing: see *auxiliary firing*.

water preheater: see *preheater*.

2-2 SYMBOLS

Table 2-2-1 defines variables and other symbols used in the equations of this Standard.

2-3 CONVERSION FACTORS

Table 2-3-1 lists factors for converting U.S. Customary units to the International System (SI) of units.

2-4 DESCRIPTIVE FIGURES

Figures 2-4-1 through 2-4-4 describe some generic configurations. Table 2-4-1 provides the legend for the figures. Job-specific figures should be generated in the test procedure.

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Table 2-2-1
Symbols Used in ASME PTC 4.4

Symbol	Description	Units
B	Systematic uncertainty of temperature grid	...
B_{TC}	Systematic uncertainty of a temperature element	...
B_S	Spatial contribution to systematic uncertainty	...
C	Capacity	lb/hr
C	Discharge coefficient	...
C_1	Capacity for a given heat balance method	lb/hr
C_2	Capacity for a given heat balance method	lb/hr
D	Flow element bore diameter	in.
D	Pipe diameter	in.
$\mathrm{DP}_{\mathrm{Cor}}$	Corrected pressure drop	lb/in.^{2}
$\mathrm{DP}_{S\ \mathrm{Cor}}$	Corrected steam pressure drop	lb/in.^{2}
$\mathrm{DP}_{S\ \mathrm{Test}}$	Steam pressure drop for a test	lb/in.^{2}
$\mathrm{DP}_{\mathrm{Test}}$	Pressure drop for a test	lb/in.^{2}
$\mathrm{DP}_{W\ \mathrm{Cor}}$	Corrected water pressure drop	lb/in.^{2}
$\mathrm{DP}_{W\ \mathrm{Test}}$	Water pressure drop for a test	lb/in.^{2}
g_c	Gravitational constant	ft/sec^2
h_A	Enthalpy of air	Btu/lb
$h_{A\ \mathrm{IN}}$	Enthalpy of air entering	Btu/lb
$h_{A\ \mathrm{OUT}}$	Enthalpy of air exiting	Btu/lb
h_{Ar}	Enthalpy of argon	Btu/lb
h_{AS}	Enthalpy of atomizing steam	Btu/lb
h_{BLD}	Enthalpy of bleed air	Btu/lb
h_{CO2}	Enthalpy of carbon dioxide	Btu/lb
h compound	Enthalpy of compound in gas	Btu/lb
h_{FG}	Enthalpy of fuel gas	Btu/lb
h_G	Gas enthalpy	Btu/lb
$h_{G\ \mathrm{IN}}$	Gas enthalpy into the HRSG	Btu/lb
$h_{G\ \mathrm{OUT}}$	Gas enthalpy out of the HRSG	Btu/lb
h_{H20}	Enthalpy of water	Btu/lb
h_i	Constituent enthalpy	Btu/lb
h_{N2}	Enthalpy of nitrogen	Btu/lb
h_{O2}	Enthalpy of oxygen	Btu/lb
HR	Humidity ratio	...
$\mathrm{HR}_{\mathrm{REL}}$	Relative humidity	%
$\mathrm{HR}_{\mathrm{SAT}}$	Saturated humidity ratio	...
h_{SO2}	Enthalpy of sulfur dioxide	Btu/lb
HT	Sensing line height	in.
$\mathrm{HV}_{\mathrm{NET}}$	Net heating value	Btu/lb
h_{WC}	Corrected differential pressure	in. H$_2$O
h_{WM}	Measured differential pressure	in. H$_2$O
L	Length	in.
L/D	Ratio of length to diameter	...
$\mathrm{MF}_{\mathrm{Ar}}$	Mole fraction of argon	...
$\mathrm{MF}_{\mathrm{CO2}}$	Mole fraction of carbon dioxide	...
$\mathrm{MF}_{\mathrm{H2O}}$	Mole fraction of water	...
MF_i	Constituent mole fraction	...
$\mathrm{MF}_{\mathrm{N2}}$	Mole fraction of nitrogen	...
$\mathrm{MF}_{\mathrm{O2}}$	Mole fraction of oxygen	...
$\mathrm{MF}_{\mathrm{SO2}}$	Mole fraction of sulfur dioxide	...
$\mathrm{MW}_{\mathrm{AVG}}$	Average molecular weight	...
MW compound	Molecular weight of compound in gas	...
$\mathrm{MW}_{\mathrm{FG}}$	Fuel gas molecular weight	...
$\mathrm{MW}_{G\ \mathrm{Ref}}$	Gas molecular weight for reference conditions	...
$\mathrm{MW}_{G\ \mathrm{Test}}$	Gas molecular weight for a test	...
MW_i	Constituent molecular weight	...
N	Number of samples	...
N	Units conversion	...
P_{ATM}	Atmospheric pressure	psia
$P_{\mathrm{ATM\ Ref}}$	Atmospheric pressure for reference conditions	psia
$P_{\mathrm{ATM\ Test}}$	Atmospheric pressure for a test	psia
P_V	Water vapor pressure	psia
P_W	Partial pressure of water	psia
P_1	Upstream pressure	psig
Q_{AA}	Heat flow of augmenting air	Btu/hr
Q_{AS}	Heat flow of atomizing steam	Btu/hr
Q_B	Heat flow of compressor bleed	Btu/hr
Q_{DB}	Heat input for duct burner	Btu/hr
Q_F	Heat input for fuel	Btu/hr
Q_{FS}	Fuel gas sensible heat	Btu/hr
Q_G	Total exhaust energy difference in and out of the HRSG	Btu/hr
$Q_{G\ \mathrm{IN}}$	Gas heat entering	Btu/hr
$Q_{G\ \mathrm{OUT}}$	Gas heat leaving	Btu/hr
Q_{HL}	Heat loss	Btu/hr
$Q_{\mathrm{HL\%}}$	Total exhaust heat lost by heat loss to the atmosphere	%
Q_I	Injected steam or water heat flow	Btu/hr
q_M	Mass flow rate	lb/hr
Q_P	Energy of gas turbine power output	Btu/hr
$Q_{\mathrm{WF\ IN}}$	Heat flow for entering working fluid	Btu/hr
$Q_{\mathrm{WF\ OUT}}$	Heat flow for leaving working fluid	Btu/hr
Re	Reynolds number	...
S_G	Specific gravity	...
S_S	Standard deviation of spatial temperature averages	°F
S_X	Standard deviation of the sample	...
S_x	Standard deviation of the sample average	...
t	Student's t for $(N - 1)$ degrees of freedom	...
T_{DB}	Dry-bulb temperature	°F
T_F	Fuel temperature	°F
T_R	Temperature	°R

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Table 2-2-1
Symbols Used in ASME PTC 4.4 (Cont'd)

Symbol	Description	Units
T_{WB}	Wet-bulb temperature	°F
U	Uncertainty	...
U_1	Uncertainty based upon a heat balance method	...
U_2	Uncertainty based upon a heat balance method	...
V_{FG}	Volumetric flow of fuel gas	Standard cubic feet per minute (scfm)
V_{fluid}	Specific volume of process fluid	$\mathrm{ft}^3/\mathrm{lb}$
V_{sen}	Specific volume of sensing line fluid	$\mathrm{ft}^3/\mathrm{lb}$
W_A	Airflow	lb/hr
W_{AA}	Augmenting airflow	lb/hr
W_{AC}	Wet air for combustion flow	lb/hr
W_{AS}	Atomizing steam flow	lb/hr
W_{BA}	Balance of wet airflow	lb/hr
W_{BLD}	GT bleed airflow	lb/hr
W_{DB}	Duct burner fuel flow	lb/hr
W_{FG}	Fuel gas flow	lb/hr
W_{FO}	Fuel oil flow	lb/hr
$W_{G\ \mathrm{IN}}$	Gas flow into the HRSG	lb/hr
$W_{G\ \mathrm{OUT}}$	Gas flow from the HRSG	lb/hr
$W_{G\ \mathrm{Ref}}$	Gas flow at reference conditions	lb/hr
$W_{G\ \mathrm{Test}}$	Gas flow at test conditions	lb/hr
W_{GTF}	GT fuel flow	lb/hr
$W_{S\ \mathrm{Ref}}$	Steam flow at reference conditions	lb/hr
$W_{S\ \mathrm{Test}}$	Steam flow at test conditions	lb/hr
$W_{W\ \mathrm{Ref}}$	Water flow at reference conditions	lb/hr
$W_{W\ \mathrm{Test}}$	Water flow at test conditions	lb/hr
$\mathrm{WF}_{\mathrm{Ar}}$	Weight fraction of argon	...
WF_{C}	Weight fraction of carbon in fuel oil	...
$\mathrm{WF}_{\mathrm{CO2}}$	Weight fraction of carbon dioxide	...
$\mathrm{WF}_{\mathrm{DA}}$	Weight fraction dry air	...
WF_{H}	Weight fraction of hydrogen in fuel oil	...
$\mathrm{WF}_{\mathrm{H2O}}$	Weight fraction of water	...
$\mathrm{WF}_{\mathrm{N2}}$	Weight fraction of nitrogen	...
$\mathrm{WF}_{\mathrm{O2}}$	Weight fraction of oxygen	...
WF_{S}	Weight fraction of sulfur in fuel oil	...
$\mathrm{WF}_{\mathrm{SO2}}$	Weight fraction of sulfur dioxide	...
$\mathrm{WM}_{\mathrm{Ar}}$	Molar flow of argon	lb mol/hr
$\mathrm{WM}_{\mathrm{CO2}}$	Molar flow of carbon dioxide	lb mol/hr
$\mathrm{WM}_{\mathrm{FG}}$	Molar flow of fuel gas	lb mol/hr
$\mathrm{WM}_{\mathrm{H2O}}$	Molar flow of water	lb mol/hr
$\mathrm{WM}_{\mathrm{N2}}$	Molar flow of nitrogen	lb mol/hr
$\mathrm{WM}_{\mathrm{O2}}$	Molar flow of oxygen	lb mol/hr
$\mathrm{WM}_{\mathrm{SO2}}$	Molar flow of sulfur dioxide	lb mol/hr
X_k	Datum value	...
x	Data average	...
Z	Gas compressibility	...
β	Flow element bore to pipe ratio	...
ΔP	Differential pressure	in. H_2O
ε	Expansion factor	...
ρ	Density	$\mathrm{lb}/\mathrm{ft}^3$
$\rho_{S\ \mathrm{Ref}}$	Steam average density for reference conditions	$\mathrm{lb}/\mathrm{ft}^3$
$\rho_{S\ \mathrm{Test}}$	Steam average density for a test	$\mathrm{lb}/\mathrm{ft}^3$

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Table 2-3-1
Conversion Factors

To Convert From	To	Multiply by [Note (1)]
Acceleration of free fall, standard (g_n)	meter per second squared (m/s^2)	**9.80665 E+00**
Atmosphere, standard (atm)	pascal (Pa)	**1.01325 E+05**
Atmosphere, standard (atm)	kilopascal (kPa)	**1.01325 E+02**
bar (bar)	kilopascal (kPa)	**1 E+02**
British thermal unit (mean) (Btu)	joule (J)	1.05587 E+03
British thermal unit (59°F) (Btu)	joule (J)	1.05480 E+03
British thermal unit (60°F) (Btu)	joule (J)	1.05468 E+03
British thermal unit$_{IT}$ per hour (Btu$_{IT}$/h)	watt (W)	2.930711 E−01
British thermal unit$_{th}$ per hour (Btu$_{th}$/h)	watt (W)	2.928751 E−01
British thermal unit$_{IT}$ foot per hour square foot degree Fahrenheit [$Btu_{IT}\cdot ft/(h\cdot ft^2\cdot °F)$]	watt per meter kelvin [$W/(m \cdot K)$]	1.730735 E+00
British thermal unit$_{th}$ foot per hour square foot degree Fahrenheit [$Btu_{th}\cdot ft/(h\cdot ft^2\cdot °F)$]	watt per meter kelvin [$W/(m \cdot K)$]	1.729577 E+00
British thermal unit$_{IT}$ per pound (Btu$_{IT}$/lb)	joule per kilogram (J/kg)	**2.326 E+03**
British thermal unit$_{th}$ per pound (Btu$_{th}$/lb)	joule per kilogram (J/kg)	**2.324444 E+03**
British thermal unit$_{IT}$ per square foot hour [$Btu_{IT}/(ft^2\cdot h)$]	watt per square meter (W/m^2)	3.154591 E+00
British thermal unit$_{th}$ per square foot hour [$Btu_{th}/(ft^2\cdot h)$]	watt per square meter (W/m^2)	3.152481 E+00
Calorie (cal) (mean)	joule (J)	4.19002 E+00
Calorie (15°C) (cal$_{15}$)	joule (J)	4.18580 **E+00**
Degree Celsius (temperature) (°C)	kelvin (K)	T°K = T°C + **273.15**
Degree Celsius (temperature interval) (°C)	kelvin (K)	**1** E+00
Degree Fahrenheit (temperature) (°F)	degree Celsius (°C)	T°C = (T°F − **32**)/**1.8** E+00
Degree Fahrenheit (temperature) (°F)	kelvin (K)	T°K = (T°F + **459.67**)/**1.8** E+00
Degree Fahrenheit (temperature interval) (°F)	degree Celsius (°C)	5.555556 E−01
Degree Fahrenheit (temperature interval) (°F)	kelvin (K)	5.555556 E−01
Degree Rankine (°R)	kelvin (K)	T°K = (T°R)/**1.8** E+00
Degree Rankine (temperature interval) (°R)	kelvin (K)	5.555556 E−01
Dyne (dyn)	Newton (N)	**1.0 E−05**
Dyne per square centimeter (dyn/cm^2)	pascal (Pa)	**1 E−01**
Feet per hour (ft/hr)	meter per second (m/s)	8.466667 **E−05**
Feet per minute (ft/min)	meter per second (m/s)	**5.08 E−03**
Feet per second (ft/sec)	meter per second (m/s)	**3.048** E−01
Feet pound-force (ft-lbf)	joule (J)	1.355818 E−00
Feet pound-force per hour (ft-lbf/hr)	watt (W)	3.766161 E−04
Inch (in.)	meter (m)	**2.54** E−02
Inch (in.)	centimeter (cm)	**2.54** E+00
Inch per second (in./sec)	meter per second (m/s)	**2.54** E−02
Kelvin (K)	degree Celsius (°C)	T°C = T°K− 273.15 E+00
Kilocalorie$_{IT}$ (kcal)	joule (J)	**4.1868** E+03
Kilocalorie$_{th}$ (kcal$_{th}$)	joule (J)	**4.184** E+03
Kilocalorie (mean) (kcal)	joule (J)	4.19002 **E+03**
Kilocalorie$_{th}$ per minute (kcal$_{th}$/min)	watt (W)	6.973 333 **E+01**
Kilocalorie$_{th}$ per second (kcal$_{th}$/sec)	watt (W)	**4.184 E+03**
Kilowatt hour (kW·hr)	joule (J)	**3.6** E+06
Kilowatt hour (kW·hr)	megajoule (MJ)	**3.6** E+00
Mho	siemens (S)	**1 E−00**
Millibar (mbar)	pascal (Pa)	1 E+02
Millibar (mbar)	kilopascal (kPa)	1 E−01
Pound per hour (lb/h)	kilogram per second (kg/s)	1.259979 E−04

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Table 2-3-1
Conversion Factors (Cont'd)

To Convert From	To	Multiply by [Note (1)]
Pound per minute (lb/min)	kilogram per second (kg/s)	7.559873 E−03
Pound per second (lb/sec)	kilogram per second (kg/s)	4.535924 E−01
Pound per square foot (lb/ft^2)	kilogram per square meter (kg/m^2)	4.882428 E+00
Pound per square inch (not pound-force) (lb/in.^{2})	kilogram per square meter	7.030696 E+02 (kg/m^2)
psi (pound-force per square inch) (lbf/in.^{2})	pascal (Pa)	6.894757 E+03
psi (pound-force per square inch) (lbf/in.^{2})	kilopascal (kPa)	6.894757 E+00
Square foot (ft^2)	square meter (m^2)	**9.290304** E−02
Square inch (in.^{2})	square meter (m^2)	**6.4516** E−04
Square inch (in.^{2})	square centimeter (cm^2)	**6.4516** E+00
torr (Torr)	pascal (Pa)	1.333224 E+02
Watt hour (W · hr)	joule (J)	**3.6** E+03
Watt per square centimeter (W/cm^2)	watt per square meter (W/m^2)	**1** E−04
Watt per square inch (W/in.^{2})	watt per square meter (W/m^2)	1.550003 E+03
Watt second (W · sec)	joule (J)	**1** E+00

GENERAL NOTE: Conversion factors are from NIST Special Publication 811. For a more complete list and other explanatory details, visit National Institute of Standards and Technology (NIST) website: https://www.nist.gov/physical-measurement-laboratory/special-publication-811.

NOTE: (1) The numbers in boldface are exact.

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Figure 2-4-1
Typical GT HRSG Diagram

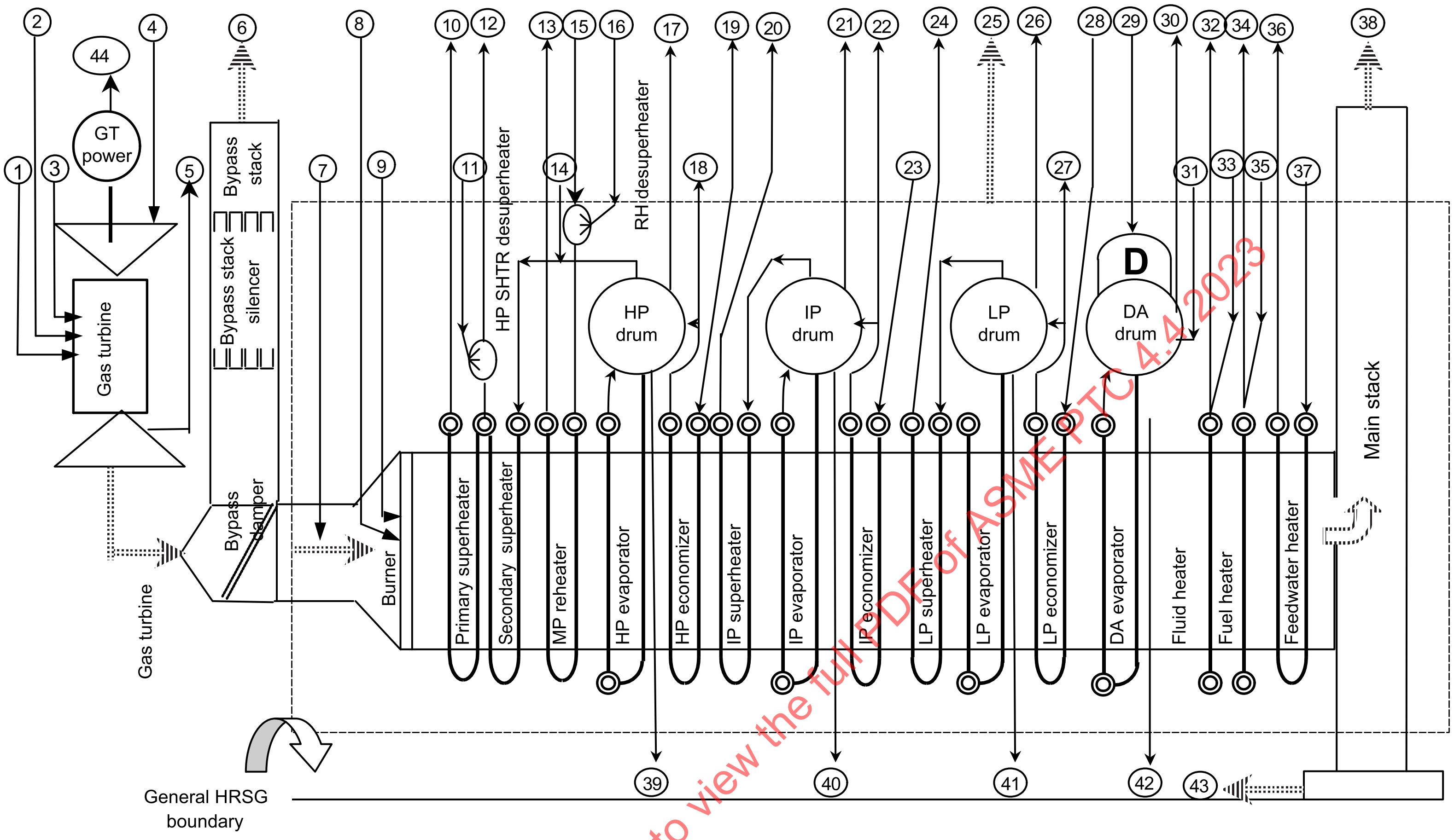

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Figure 2-4-2
Typical Three-Pressure-Level HRSG With Supplementary Firing

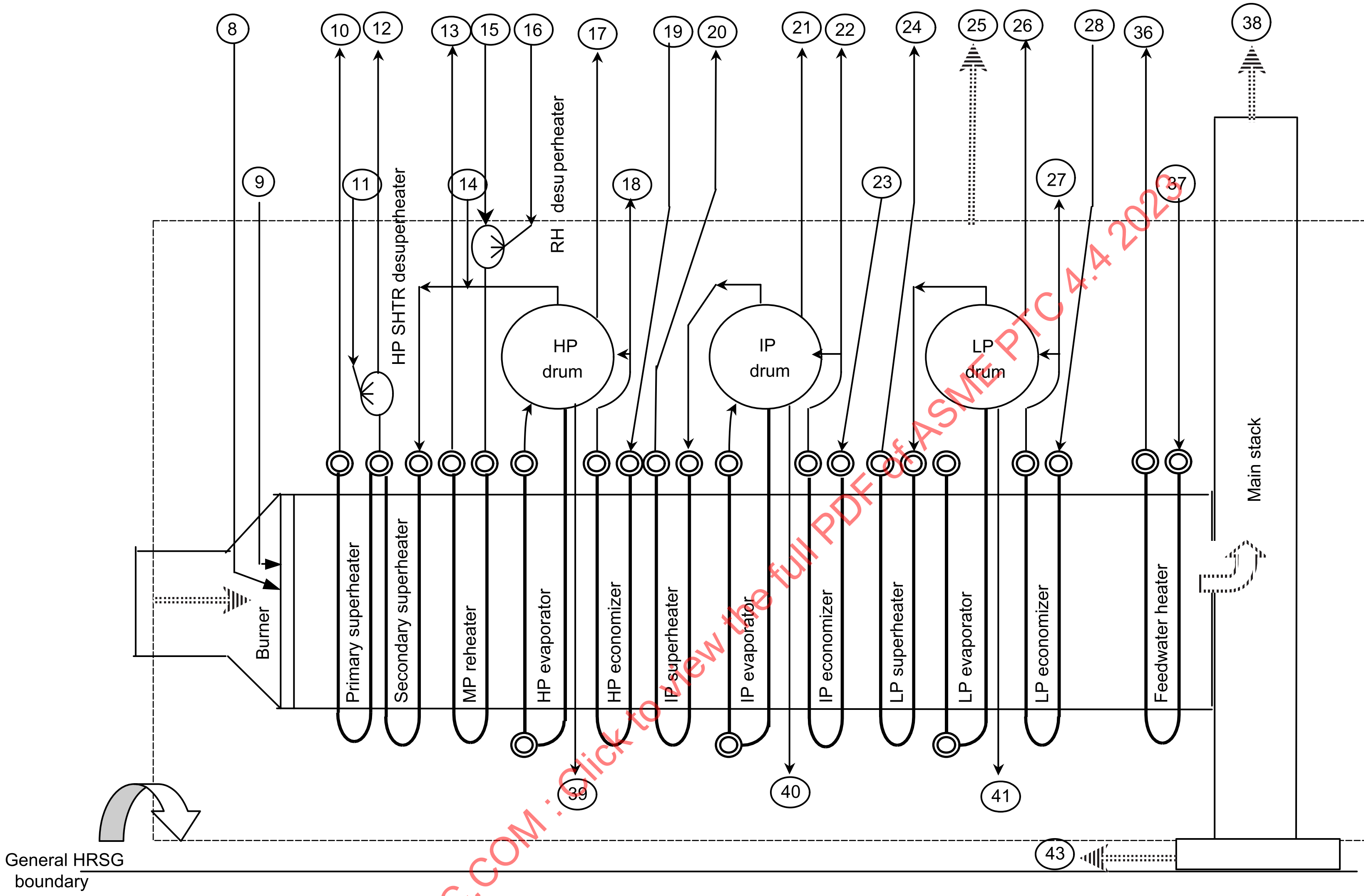

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Figure 2-4-3
Typical Two-Pressure-Level HRSG With Feedwater Heater and Supplementary Firing

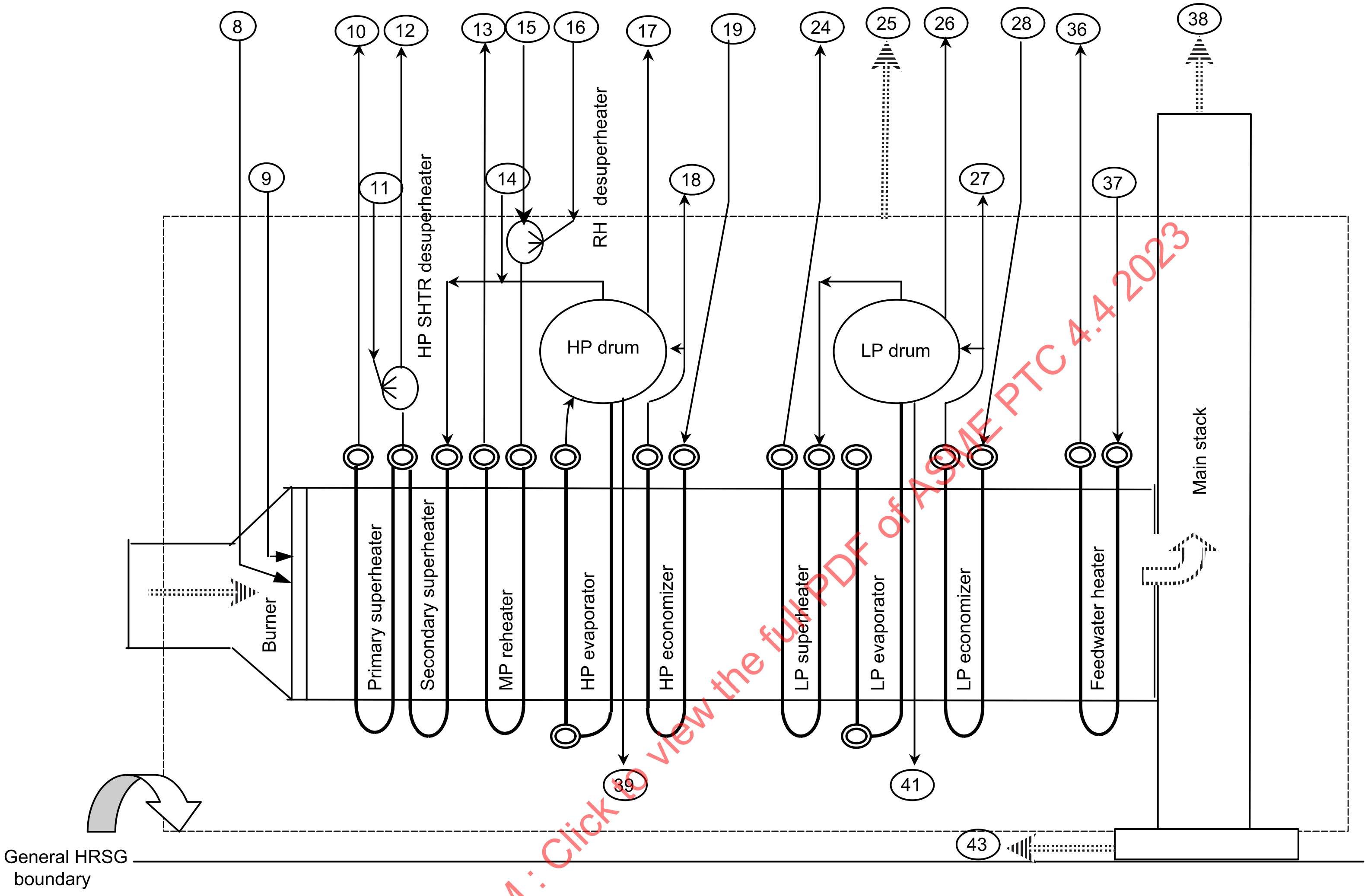

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Figure 2-4-4
Typical Single-Pressure-Level HRSG With Feedwater Heater and Supplementary Firing

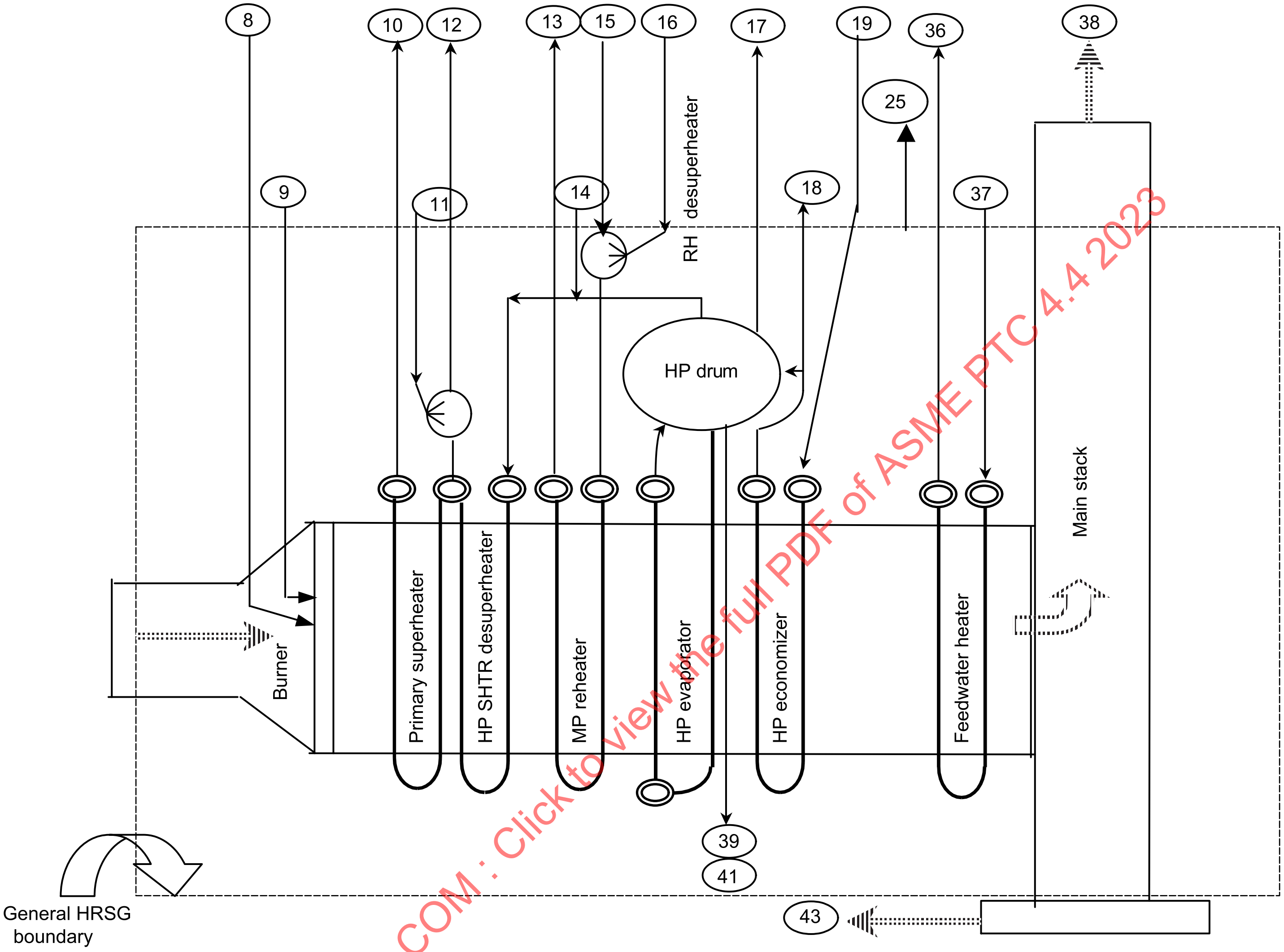

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Table 2-4-1
Legend for Figures 2-4-1 Through 2-4-4

Number	Description	Flow Direction
1	Fuel to GT	In
2	Steam injection into GT	In
3	Water injection into GT	In
4	Combustion air to GT	In
5	Gas leakage out of the GTE exhaust	Out
6	Bypass stack gas leakage	Out
7	Exhaust gas into HRSG	In
8	Burner auxiliary air	In
9	Burner fuel for auxiliary firing	In
10	High-pressure (HP) main steam	Out
11	Spray water to HP attemperator	In
12	Auxiliary HP steam	Out
13	Hot reheater steam to the intermediate pressure (IP) turbine	Out
14	Auxiliary HP steam to the HRSG	In
15	Cold steam from HP turbine to reheater	In
16	Spray water to reheater attemperator	In
17	HP saturated steam export	Out
18	Recirculation from HP economizer	Out
19	Feedwater to the HP system	In
20	IP superheated steam	Out
21	IP saturated steam for export	Out
22	Recirculation water from IP economizer	Out
23	Feedwater to the IP system	In
24	Low-pressure (LP) superheated steam	Out
25	HRSG heat loss across the HRSG boundary	Out
26	LP saturated steam	Out
27	Recirculation water from LP economizer	Out
28	Feedwater to LP system	In
29	Condensate or preheated water to HRSG	In
30	LP steam	Out
31	Pegging steam into dry air drum	In
32	Any other fluid out of the HT section	Out
33	Any other fluid into the HT section	In
34	Gaseous fuel heated in HRSG	Out
35	Gaseous fuel heated in HRSG	In
36	Preheated water out of the feedwater heater	Out
37	Condensate into the feedwater heater	In
38	Exhaust gas from HRSG to stack	Out
39	HP blowdown	Out
40	IP blowdown	Out
41	LP blowdown	Out
42	Feedwater to HP, IP, and LP feedwater pumps	Out
43	Water and other condensables from gas	Out
44	GT output	Out

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Section 3
Guiding Principles

3-1 INTRODUCTION

The purpose of this Section is to provide guidance on HRSG testing and to outline the steps required to plan, conduct, and evaluate a Code test of the HRSG performance.

This ASME PTC 4.4 Code uses heat balances around the HRSG and the GT to determine the primary heat input to the HRSG in the form of flow, temperature, and composition. This Code references ASME PTC 22 for the methodology of conducting a GT heat balance. Each of these heat inputs is then used to determine the corrected capacity of the HRSG. A method of uncertainty weighting of these capacities is used to combine them.

This Code details procedures for conducting tests to meet the objectives outlined in Section 1 to ensure that proper procedures are developed and the correct performance equations are applied. The procedures detailed in this Code represent current industry and good engineering practice for the determination of HRSG performance. The nature of HRSGs and the various design configurations result in a wide variation in the expected uncertainty of test results. For example, a fired HRSG with high firing may result in a significant reduction in IP and LP steam flows and corresponding increases in uncertainty. Table 3-1-1 presents a range of values typical of the uncertainty that may be observed when conducting tests in accordance with this Code on the configuration types identified. Due to the wide range of potential uncertainties possible, this Code requires agreement on the uncertainty required.

Table 3-1-1
Typical Ranges of Uncertainties

HRSG Configuration [Notes (1), (2)]	Uncertainty Range, %		
	HP Capacity	IP Capacity	LP Capacity
Single pressure level	0.7 to 2	NA	NA
Two pressure level	0.7 to 2	NA	1.5 to 5
Three pressure level	0.7 to 2.5	1 to 4	1.5 to 7
Three pressure level, fired with reheat	0.7 to 1.5	1 to 15	1.5 to 15

NOTES:
(1) Gas-side pressure drop = 0.4 in. H_2O to 0.8 in. H_2O.
(2) Steam- and water-side pressure drop = 4.0% to 8.0%.

3-2 PLANNING FOR THE TEST

Planning for the test shall be developed well in advance of the test. A test procedure shall be prepared and agreed to before the test. This procedure shall outline the test goals, schedule of test activities, responsibilities, and the procedure for conducting the test and shall detail and clarify all prior agreements (see subsection 3-3 for a list of prior agreements).

3-2.1 Test Procedure

A detailed test procedure shall be prepared. The parties to the test shall agree on the testing procedure before the start of the test. The procedure shall detail how this Code will be applied for preparing, conducting, and reporting of the test. The test procedure shall reflect any contract requirements that pertain to the test objectives and performance guarantees as well as the understanding of the parties as to the interpretation of this Code. It shall provide clarification to resolve any contract, omissions, or ambiguities. This test procedure shall identify all parties to the test and their representatives.

3-2.2 Responsibilities of Parties

The parties to the test shall agree on individual responsibilities for the test in accordance with this Code. A test coordinator who is knowledgeable in all the technical and operational facets of the test, including the details of this Code, shall be designated. The coordinator shall have the responsibility for implementation of the test in accordance with the test procedures.

Representatives from each of the parties to the test, who are to observe the test and confirm that it is conducted in accordance with the test procedures, shall be identified. They shall have the authority, if necessary, to approve any agreed-upon revisions to the test procedures during the test.

3-2.3 Test Boundary

The test boundary of an energy system is a control volume, with various input and output streams crossing the boundary. These streams carry energy into or out of the system. The energy and capacity of these streams shall be measured to calculate the corrected results and determine the performance.

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Generally, energy or capacity of the internal stream that does not cross the boundary need not be measured. However, measurements of internal streams may be required if these streams verify the case operating condition or are functionally related to streams crossing the boundary.

The specific test boundary shall be established. Figures 2-4-1 through 2-4-4 show typical HRSGs with generally used test boundaries. These figures should be treated as generic and will be customized for a particular test.

3-2.4 Required Measurements

Once the test boundary has been identified, those streams that cross the boundary will need the associated energy flow contained in them quantified for the test. The parameters described in 3-2.4.1 through 3-2.4.7 need to be determined for a valid test. Additions or deletions may be necessary for a specific test arrangement.

3-2.4.1 GT Exhaust. The primary heat input to an HRSG is the GTE. The flow and constituents shall be calculated based on the combination of heat balances around the GT and HRSG. GTE and stack temperatures are total temperatures and are measured with an array of temperature sensors.

3-2.4.2 Ambient Conditions. The barometric pressure, dry-bulb temperature, and humidity or wet-bulb temperature shall be measured.

3-2.4.3 Water and Steam Streams. For all steam and water streams, flow, pressure, temperature, and quality shall be defined as required to determine the change in energy of the stream. Sufficient flow measurements shall be made to determine the distribution of fluid within the system. It is generally considered more accurate to measure water flow than steam flow and, therefore, the feedwater flow stream is measured. Directly measured steam flow may be more accurate than one calculated by taking the difference of two feedwater flow measurements. Blowdown flow shall be measured if the blowdown is not secured during the test.

3-2.4.4 Auxiliary Firing Input. If the HRSG has an auxiliary firing system, the flow, pressure, temperature, and constituents of the fuel shall be measured. The flow, pressure, and temperature of any air, steam, and water stream into the burner shall also be determined.

3-2.4.5 Auxiliary Systems. The flow, pressure, temperature, and constituents of streams to and from auxiliary systems such as fuel heaters need to be determined if they cross the test boundary.

3-2.4.6 Gas-Side Pressure Drop. Since one of the critical variables is the HRSG gas-side pressure drop, measurement of the static pressure at the HRSG inlet is necessary.

3-2.4.7 Steam and Water Pressure Drop. The steam and water pressure drops shall be determined during the test, if required.

3-2.5 Design, Construction, and Startup Considerations

During the design phase of the plant, consideration should be given on how to accurately conduct the test, including the requirements of instrumentation accuracy, calibration, recalibration documentation requirements, and location of permanent plant instrumentation to be used for testing. Adequate provisions for installation of temporary instrumentation, where plant instrumentation is not adequate to meet the requirements of the Code, must be considered during the design phase.

Consideration should also be given to the personnel and instrumentation involved in the test. Examples include safe access to test points, availability of suitable utilities, and safe work areas for personnel, as well as potential damage to instrumentation or calibration shift due to extreme ambient conditions such as temperature or vibration.

Consideration should also be given to the timing of flow element installation with respect to chemical cleaning and steam blows. Piping arrangements should provide sufficient upstream and downstream straight lengths as outlined in ASME PTC 19.5 for accurate measurements.

3-3 PRIOR AGREEMENTS

Before an HRSG performance test is conducted, there shall be a written agreement on the specific subjects affecting the test. Agreement on the following items shall be included:

(a) acceptance criteria.
(b) uncertainty targets for test objectives.
(c) identification of instruments, measurements, and sampling requirements.
(d) objective of test and method of operation.
(e) schedule for test and advance notification required of all parties.
(f) scope of testing and number of different conditions.
(g) if ASME PTC 4.4 is to be conducted in conjunction with an overall plant test such as ASME PTC 46, any special requirements that will be part of that test.
(h) when the test will be conducted, and what to do if it is delayed.
(i) defined test boundaries identifying inputs and outputs and having clarity to their position of measurements.
(j) contract requirements that pertain to the test objectives and performance guarantees and provide any needed clarification of contract issues.
(k) data acceptance and rejection criteria.
(l) requirements for steady-state operation.

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(m) maximum deviation from design for which the correction methodology is valid.

(n) test continuous operating time or duration and number of runs.

(o) fuels to be fired, their analysis, heating value, and method of sampling.

(p) identification of test corrections to be imposed shall be clearly described commensurate with the test boundaries. References or Codes or software required, incorporating performance correction curves, computations or tables, etc., shall be clearly identified. The documentation to be provided shall be clearly identified. The methods to incorporate such corrections shall be clearly described to ensure conformity and accuracy of computation.

(q) the methods and biases for the uncertainty analysis shall be identified and agreed to for the pretest and posttest uncertainty analysis.

(r) method of measurement shall describe frequency of observation, locations, types, accuracy, and indicate permanent plant instruments and temporary test instruments.

(s) control and calibration procedures and requirements for instrumentation.

(t) permissible variations of test conditions at the test boundary shall be identified such as, but not limited to, ambient temperature, process services to/from the plant, and fuel variations (heating value and composition).

(u) weather conditions and procedures to be followed to ensure personnel safety.

(v) required levels of cleanliness for testing. If remedial cleanliness measures are not undertaken nor practical, then the conditions affecting performance shall be reviewed and the parties shall agree to any corrections in HRSG expected performance.

(w) procedures to account for degradation and impact on the test uncertainty, if applicable.

(x) operating equipment: a list of plant equipment that is required to be operational during the test or to be accounted for in the corrections.

(y) a detailed valve lineup for the HRSG.

(z) preliminary testing and stabilization.

(aa) if a testing laboratory is required for analysis, it shall be identified.

(bb) calculation and correction to reference condition methodology.

(cc) agreement on the steam properties to be used if not those from IAPWS R7-97(2012).

(dd) test report format, contents, inclusions, and index. Agreement shall be reached on how to handle the sectional deviations. The amount of heat available to downstream sections is dependent upon the actual heat absorbed by upstream sections. Based upon second law considerations, equivalent heat absorbed in lower pressure sections has a lower potential of work energy.

(ee) bypass damper leakage if applicable (see Nonmandatory Appendix A).

(ff) HRSG and GT losses.

(gg) test duration.

3-4 TEST PREPARATIONS

Suitable notification of the test preparations shall be made to all involved to provide the necessary time to respond and to prepare personnel, equipment, or documentation. Updated information should be provided as it becomes known. Participating organizations and other third parties to the test shall also be notified.

3-4.1 Schedule of Test Activities

A test schedule shall be prepared denoting anticipated time of test, notification of the parties to the test, test plan preparation, and preparation of the results report.

3-4.2 Test Apparatus

Instrumentation used for data collection shall be at least as accurate as instrumentation identified in the pretest uncertainty analysis and as described in Section 4. This instrumentation can either be permanent plant instrumentation or temporary test instrumentation.

Instruments shall be calibrated before the test, and calibration records and reports made available. After the test, calibration or checks shall be made of the instruments. Redundant instruments should be used as practical to reduce overall test uncertainty. Refer to Section 4 for detailed information regarding instrumentation and calibration requirements.

Data storage, document retention, and test report distribution shall be established before the test. Data storage decisions for test data, results, and reports shall include consideration of longevity, retrieval access, and usefulness of stored information. Storage format (electronic, magnetic, paper, or other) should be defined for test data, results, and reports. Types and quantities of copies of such information and responsibility for storage and ownership of these items shall also be resolved.

3-4.3 Test Personnel

Test personnel shall be identified in sufficient quantity and expertise to support the execution of the test. The personnel shall be familiar with the test procedures to ensure that they can maintain safe and steady operation of the plant as required for an accurate test.

3-4.4 Equipment Inspection

Before the test begins, the cleanliness, condition, and age of the equipment shall be determined by inspection of equipment and operational records. Any cleaning shall be agreed upon and completed before the test. Equipment shall be inspected for leakage.

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All parties shall have reasonable opportunity to examine the HRSG. The HRSG shall be checked to ensure that equipment and subsystems are installed and operating within their design parameters and are suitable to undergo testing.

Thorough preparations shall be completed before conducting the test. Detailed records shall be made to define the plant boundaries of the test and the exact method of test selected. Descriptions, drawings, diagrams, or photographs may all be used to give a permanent record.

3-4.5 Preliminary Run

A preliminary run should be conducted immediately before the test. As a result of the preliminary run, agreements to any test modifications should be made before conducting the test. A preliminary run may be declared an official run if all requirements of an official run are achieved.

Reasons for a preliminary run include the following:

(a) to determine whether the equipment is in suitable condition for the conduct of the test

(b) to make adjustments, the needs of which were not evident during the preparation of the test

(c) to check the operation of all instruments, controls, and data acquisition systems (DASs)

(d) to ensure that the facilities can be maintained at a steady-state condition

(e) to ensure that process conditions are not constrained other than those identified in the test procedure

(f) to familiarize test personnel with their assignments

3-4.6 Documentation of Correction Methodology

Documentation shall be developed for calculated or adjusted data to provide visibility to algorithms, constants, scaling, calibration corrections, offsets, base points, and conversions as necessary. It is not the intent of this paragraph that Code users disclose proprietary design algorithms.

3-5 CONDUCTING THE TEST

The purpose of this subsection is to provide guidelines for conducting the test.

3-5.1 Starting and Stopping Tests and Test Runs

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

3-5.1.1 Starting Criteria. Before the start of each test, the following conditions must be satisfied:

(a) General. Operation, configuration, and disposition for testing have been reached in accordance with the test procedure, including the following:

  (1) steady-state operation
  (2) equipment operation and method of control
  (3) unit configuration, including required process flow rate and valve lineup
  (4) HRSG operation within the bounds of the performance correction methods, algorithms, or programs
  (5) equipment operation within allowable limits
  (6) for a series of test runs, completion of internal adjustments required for repeatability

(b) Stabilization. The HRSG has operated for a sufficient period at test load to demonstrate and verify stability in accordance with para. 3-5.3 criteria.

(c) Data Collection. DASs are functioning, and test personnel are in place and ready to collect samples or record data.

3-5.1.2 Stopping Criteria. Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied. The test coordinator may extend the test or terminate the test if the requirements are not met.

Data logging shall be checked to ensure completeness.

3-5.2 Methods of Operation Before and During Tests

A test log shall be developed that shall be maintained during the test to record any occurrences affecting the test, the time of the occurrence, and the observed resultant effect. This log will become part of the permanent record of the test.

All equipment necessary for normal operation at the test conditions must be operating during the test or accounted for in the corrections. Nothing within the plant shall be run or shut down abnormally to affect the capacity. Any environmental control system must be operating and within normal parametric ranges, gas flow, inlet and outlet emission concentrations, pH, and solid and liquid concentrations.

HRSG equipment shall be operated in a manner consistent with the basis of design or guarantee.

Process energy (process steam and condensate) must be controlled in the most stable manner possible. This may require operation in manual mode or venting to the atmosphere if the host is unable to satisfy stability or quantity criteria.

3-5.2.1 Equipment Operation. The HRSG shall be functioning as specified within its design characteristics and operational ratings as defined by the HRSG supplier's instructions, unless mutually agreed.

Evaporative coolers and chillers, if installed, should be out of service. If a test is required with them in service, the test uncertainty will increase.

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Table 3-5.2.2-1
Suggested Maximum Permissible Variations From Design Conditions

Variable	Suggested Maximum Permissible Variations From Design Conditions: Single or Dual Pressure	Suggested Maximum Permissible Variations From Design Conditions: Triple Pressure, Reheat Design
Feedwater flow	±10%	±10%
Feedwater temperature to preheater or economizer	±20°F	±20°F
HP steam flow leaving boundary	±7%	±7%
HP steam temperature leaving boundary	±15°F [Note (1)]	±15°F [Note (1)]
HP steam pressure leaving boundary	±30 psi	±25 psi
IP pressure leaving boundary	N/A	±20
LP pressure leaving boundary	±10 psi	±10 psi
Cold reheat flow entering boundary	N/A	±7%
Cold reheat temperature entering boundary	N/A	±15°F
Cold reheat pressure entering boundary	N/A	±25 psi
Hot reheat flow leaving boundary	N/A	±7%
Hot reheat temperature leaving boundary	N/A	±15°F [Note (1)]
Hot reheat pressure leaving boundary	N/A	±25 psi
Supplemental fuel flow	±5%	±5%
GT exhaust flow	±10% [Note (2)]	±10% [Note (2)]
GT exhaust temperature	±20°F [Note (2)]	±20°F [Note (2)]

NOTES:
(1) If the attemperator is on, the range is expected to be much lower than the ±15°F noted (nominally ±2°F control range).
(2) This variation shall be used in the absence of ranges supplied by the GT manufacturer (typically in the form of GT corrections).

3-5.2.2 Proximity to Design Conditions. It is desirable to operate the HRSG during the test as closely as possible to the reference performance conditions to limit the magnitude of corrections to capacity.

If operating conditions vary beyond the limits prescribed in Table 3-5.2.2-1, the variations shall be discussed by all parties with the intent of arriving at mutual agreements or identifying corrective action (if applicable).

3-5.2.3 Blowdown. All blowdown should be isolated during the test. If a test is required with blowdown in service, the test uncertainty will increase. If blowdown cannot be closed, provisions for blowdown flow measurement shall be agreed upon by all parties. If applicable, the impact on the uncertainty analysis shall be included in the test uncertainty.

3-5.3 Adjustments Before and During the Test

Permissible adjustments during the test are those required to maintain equipment in safe operation, to maintain plant stability, or to correct malfunctioning controls.

Any adjustments that would result in equipment being operated beyond the manufacturer's operating, design, or safety limits, and specified operating limits are not permissible at any time before or during testing.

Adjustments that adversely affect the stability of a primary measurement during a test are not permitted. If during any test run the operating conditions vary beyond the limits prescribed in Table 3-5.3-1, the test run shall be discarded.

EXCEPTION: The parties to the test may agree before the test on permissible variations other than those in Table 3-5.3-1.

Table 3-5.3-1
Suggested Maximum Permissible Variations in Test Conditions

Variable	Variation of Any Station Observation From the Reported Average Test Condition
Feedwater flow	±2%
Drum pressure	±2% or 10 psi, whichever is greater
Desuperheating water flow	±½% of steam flow
Fuel flow to GT	±2%
Supplemental fuel flow	±2%
GT power output	±2%
Average GTE temperature	±10°F
Feedwater temperature to economizer	±5°F
Steam temperature leaving superheater	±5°F

3-5.4 Application of Corrections

A major objective of this Code is to produce the corrected capacity of the HRSG. Section 5 provides detailed instructions for the determination and application of the necessary corrections. Due to the complex nature of modern, multi-pressure-level HRSGs, this Code recommends the use of computer programs for the determination of as-tested performance and for correction to reference conditions.

When the HRSG equipment manufacturer provides performance or correction information in the form of curves or evaluation software, the range of applicability shall meet, at a minimum, the suggested maximum permissible variations from design conditions shown in Table 3-5.3-1.

3-5.5 Duration of Runs

The duration of a test run shall be of sufficient length that the data reflect the average performance of the HRSG. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical plant operating characteristics. The test duration shall not be less than 1 hr.

The test coordinator may determine that a longer test period is required. The minimum time is generally based upon continuous data acquisition. Depending upon the personnel available and the method of data acquisition, it may be necessary to increase the length of a test in order to obtain a sufficient number of readings of the measured parameters to attain the required test uncertainty. Test runs should not last longer than 2 hr.

3-5.6 Number of Test Runs

A run is a complete set of observations made over a period of time with the unit at stable operating conditions. A test is the combination (average) of a series of runs for the purpose of determining performance characteristics. A test shall consist of a minimum of two runs, one of which may be the preliminary run.

3-5.7 Number of Readings

Sufficient readings must be taken within the test duration to yield total uncertainty consistent with Table 3-1-1. At least 30 sets of data shall be recorded for all electronic measurements. There are no specific requirements for the number of integrated readings. These readings should not be smoothed or averaged. See Section 4 for details.

3-6 CALCULATION, ANALYSIS, AND REPORTING OF RESULTS

The data taken during the test should be reviewed and, upon acceptance, shall be averaged over the test period. Each Code test shall include pretest and post-test uncertainty analyses and the results of these analyses shall fall within the agreed-upon test uncertainty. Section 5 provides information on the general performance equations.

3-6.1 Causes for Rejection of Readings

Upon completion of the test or during the test itself, the test data shall be reviewed to determine if data from certain periods should be rejected before calculation of the test results. Refer to ASME PTC 19.1 and ASME MFC-2M, Appendix C for data rejection criteria. A test log should be kept, and for any plant upsets that cause test data to violate the requirements of Table 3-5.3-1, the run or portion shall be rejected. A minimum of 10 min following the recovery of these criteria shall pass to allow for restabilization.

Should serious inconsistencies that affect the results be detected during a test run or during the calculation of the results, the run shall be invalidated completely, or it may be invalidated only in part if the affected part is at the beginning or at the end of the run. A run that has been invalidated shall be repeated, if necessary, to attain the test objectives. The decision to reject a run shall be the responsibility of the designated representatives.

During the test, should any control system set points be modified that affect stability of operation beyond Code limits, test data shall be considered for rejection from the calculations of test results. The period rejected shall start immediately before the change and end no less than 10 min following the recovery of the criteria found in Table 3-5.3-1.

An outlier analysis of spurious data should also be performed in accordance with ASME PTC 19.1 on all critical measurements after the test has ended. This analysis will highlight any points that should be reviewed and possibly rejected before calculation of the test results. The Modified Thompson Tau method, as with other statistical methods, identifies potential outliers; points so identified should be reviewed and rejected only if, in the judgment of the engineer, they are invalid. It should be noted that data rejection criteria should not be applied to grid data or data varying in space. The criteria should only be applied to a single point over time. Any points rejected should be identified in the test report.

3-6.2 Repeatability of Test Runs

After completing the first test run that meets the criteria for an acceptable test run (which may be the preliminary test run), the data should be consolidated and preliminary results calculated and examined to ensure that the results are reasonable. If it is agreed, the test may be concluded at the end of any test run.

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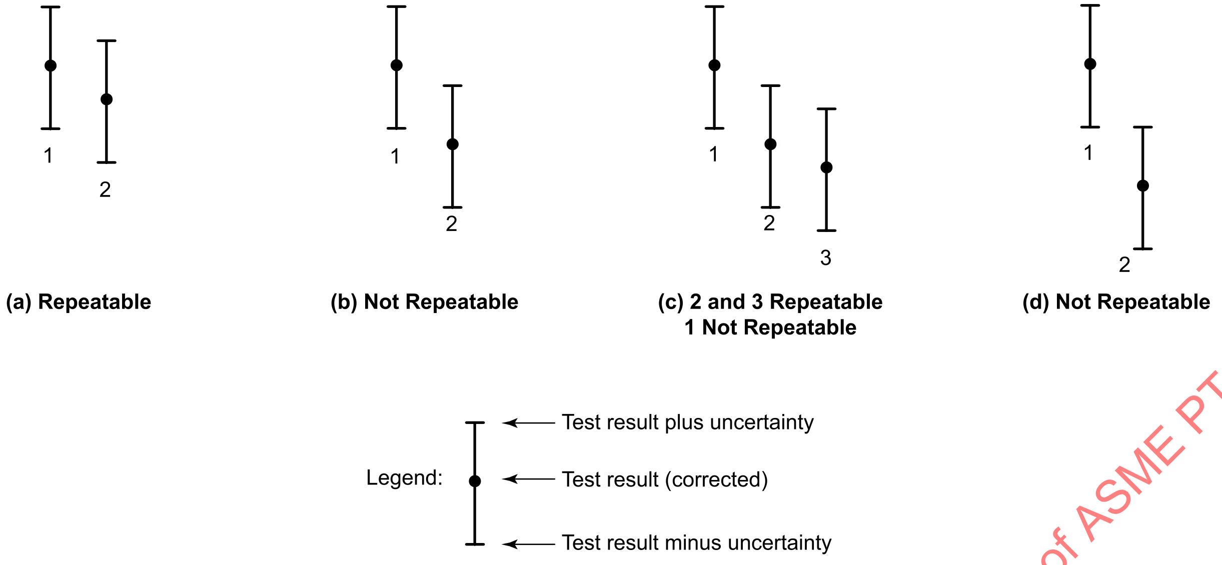
Figure 3-6.2-1
Repeatability of Runs



The criterion for repeatability between test runs is that the results of two or more runs each lie within the uncertainty interval of the other. Refer to Figure 3-6.2-1 for examples of runs that meet and do not meet this criterion.

Should a run or set of runs fail to meet the repeatability criteria, the results from all runs should be reviewed in an attempt to explain the reason for excessive variation. Should no reason become obvious, the uncertainty band can be increased to encompass the runs and therefore make them repeatable, or more runs may be conducted, which will allow calculation of the precision component of uncertainty directly from the test results.

The results of multiple runs that meet the criterion for repeatability and other Code requirements shall be averaged to determine the mean result. The uncertainty shall be reported for individual runs.

3-6.3 Comparison of Capacity From GT and HRSG Heat Balances

The capacity determined by GT energy balance shall be compared to the capacity determined by HRSG heat balance. The difference between the results of the two independent tests must be within the square root of the sum of the squares of the uncertainty of each test:

$$\text{difference} \leq \sqrt{(U_1^2 + U_2^2)}$$

Ninety-five percent of all test values will theoretically be within this difference. This requirement must be met to assure that the two test results are within the 95% confidence level. Should the values fail to meet this criterion, the uncertainty estimates are probably too low and the data should be reviewed in an attempt to identify the excessive variation. Should no reason become obvious, the uncertainty bands may be increased.

3-6.4 Test Uncertainty

3-6.4.1 General. Procedures relating to test uncertainty are based on concepts and methods described in ASME PTC 19.1. ASME PTC 19.1 specifies procedures for evaluating measurement uncertainties from both random and systematic errors and the effects of these errors on the uncertainty of a test result.

This Code addresses test uncertainty in four of its sections:

(a) Section 3 identifies typical uncertainties for different types of units. The parties to the test shall agree on the uncertainty targets for the test.

(b) Section 3 defines the requirements for pretest and post-test uncertainty analyses and how they are used in the test. These uncertainty analyses and limits of error are defined and discussed below. It also includes constancy limits for key variables to limit temporal precision uncertainty.

(c) Section 4 describes the accuracy required for each test measurement.

(d) Sections 5 and 7 provide applicable guidance for determining pretest and post-test uncertainty analysis results.

3-6.4.2 Pretest and Post-Test Uncertainty Analyses. A pretest uncertainty analysis must be performed so that the test can be designed to meet Code requirements. Estimates of random and systematic error for each of the proposed test measurements should be used to help

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determine the number and quality of test instruments required for compliance with Code or contract specifications.

The pretest uncertainty analysis should be used to determine the level of accuracy required for each measurement to maintain overall Code standards for the test. For simplicity and economic considerations, the Code allows using plant instrumentation for insignificant measurements or even for the assumption of some parameters. However, the effect of these actions must be demonstrated to have a small effect (less than 0.05%) on overall test uncertainty, and the test must still meet uncertainty targets set to be considered a Code test.

A post-test uncertainty analysis must also be performed as part of a Code test. The post-test uncertainty analysis will reveal the actual quality of the test to determine whether the required uncertainty targets have been met.

3-6.5 Test Report

Parties to the test have the right to have copies of all raw data at the conclusion of the test. Agreement shall be reached on how the test data are to be distributed. The report shall include all specific subjects affecting the conducting of the test.

Before the issuance of the final report, all parties shall have the opportunity to review the calculations and the results. Any disagreements shall be noted in the final report.

The results of the test should be presented as a formal document that is certified by all parties to the test. The contents of the test report are described in Section 6 of this Code.

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Section 4
Instruments and Methods of Measurement

4-1 INTRODUCTION

This Section covers choice of instruments, uncertainty of instruments, and calibration corrections to readings and measurements specific to this Code. Instructions as to methods of measurement, location of measuring systems, and precautions to be taken are also included in this Section. The instrumentation recommended herein may be replaced by new technology as it becomes available, provided this new technology meets the uncertainty requirements of this Code.

A method shall be selected for measuring each parameter that, when considered with all the other parameters, produces results within the uncertainty requirements of the test.

A parameter is classified as primary or secondary dependent upon usage in the execution of this Code. Parameters used in the calculation of test results are considered primary. Primary parameters are further classified as Class 1 or Class 2, depending on their relative sensitivity coefficient to the results of the test. Class 1 primary parameters are those that have a relative sensitivity coefficient of 0.25% per percent or greater. The primary parameters that have a relative sensitivity coefficient of less than 0.25% per percent are classified as Class 2 primary parameters. Due to an arbitrary zero point, in the case of temperature measurements for primary parameters and primary variables, the relative sensitivity coefficient of 0.25% per percent shall be substituted as 0.25% per degrees Celsius (or the corresponding percent per degrees Fahrenheit).

4-2 GENERAL

4-2.1 Supplements

The ASME PTC 19 Series contains guidance for developing test uncertainty and descriptions of instruments, devices, and methods of measurement likely to be required in any test of equipment. They include directions regarding instrument applications, limits and sources of error, range, sensitivity and random uncertainties, and methods of calibration. Instruments should be selected to ensure that

(a) the requisite degree of accuracy of measurement is attainable

(b) the selected test apparatus and methods are practical

4-2.2 Location and Identification of Instruments

Transducers shall be located to minimize the impact of environmental conditions such as vibration, temperature, and humidity. Care shall be used in the selection and routing of lead wires to the data collection equipment to prevent electrical noise in the signal. Manual instruments shall be located so that they can be read with precision and convenience by the observer. All instruments shall be clearly and properly marked for identification. Calibration tables or charts, if applicable, shall be readily available. Observers shall be instructed as to desired degree of precision of readings.

4-2.3 Sources of Error

Sources of error that influence the accuracy of a test include the following:

(a) instrument errors

(b) errors of observation

(c) errors resulting from failure to obtain representative samples

(d) errors resulting from failure to place instruments at the required point of measurement

(e) errors resulting from instruments having insufficient sensitivity

(f) errors due to signal

Errors are discussed at length in each edition of the ASME PTC 19 series.

4-2.4 Instrument Calibration

4-2.4.1 Definition of Calibration. Calibration of an instrument is the act of applying process conditions to the candidate instrument and to a reference standard in parallel. Readings are taken from both the candidate instrument and the reference standard. The output of the instrument may then be adjusted to the standard reading. As an alternative, the difference between the instrument and the reference standard may be recorded and applied to the instrument reading. This alternative method may be required in the case of flow elements or thermocouples because their output cannot be easily altered. The ASME PTC 19 series provides guidance on the use and application of calibration data.

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4-2.4.2 Reference Standards. Reference standards shall be routinely calibrated in a manner that provides traceability to NIST, other recognized international standard organization, or defined natural physical (intrinsic) constants and have accuracy, stability, range, and resolution for the intended use. They shall be maintained for proper calibration, handling, and usage in strict compliance with a calibration laboratory quality program. When it is necessary to utilize reference standards for field calibrations, adequate measures shall be taken to ensure that the necessary calibration status is maintained during transportation and while on-site. The integrity of reference standards shall be verified by proficiency testing or inter-laboratory comparisons. All reference standards should be calibrated as specified by the manufacturer or other frequency as the user has data to support extension of the calibration period. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The collective uncertainty of reference standards shall be known and the reference standards should be selected such that the collective uncertainty of the standards used in the calibration contributes less than 25% to the overall calibration uncertainty. The overall calibration uncertainty of the calibrated instrument shall be determined at a 95% confidence level. A reference standard with a lower uncertainty may be employed if the uncertainty of the reference standard combined with the random uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument. For example, for some kinds of flow metering, the 25% rule cannot be met. However, curve fitting from calibration is achievable from a twenty-point calibration in a lab with an uncertainty of better than 0.2%.

In general, all Class 1 and Class 2 instrumentation used to measure primary (Class 1 and Class 2) parameters shall be calibrated against reference standards traceable to NIST, other recognized international standard organization, or recognized natural physical (intrinsic) constants with values assigned or accepted by NIST. Instrumentation used to measure secondary parameters need not be calibrated against a reference standard. These instruments may be calibrated against a calibrated instrument.

4-2.4.3 Environmental Conditions. Calibration of instruments used to measure primary parameters (Class 1 or Class 2) should be performed in a manner that replicates the condition under which the instrument will be used to make the test measurements. As it is often not practical nor possible to perform calibrations under replicated environmental conditions, additional elemental error sources must be identified and estimated. Error source considerations must be given to all process and ambient conditions that may affect the measurement system including temperature, pressure, humidity, electromagnetic interference, and radiation.

4-2.4.4 Instrument Ranges and Calibration Points. Instrumentation used to measure primary variables with a product of relative sensitivity coefficient and instrument uncertainty of 0.25 or greater should be calibrated at least two points more than the order of the calibration curve fit, whether it is necessary to apply the calibration data to the measured data, or if the instrument is of the quality that the deviation between the laboratory calibration and the instrument reading is negligible in terms of affecting the test result.

Each instrument should also be calibrated such that the measuring point is approached in an increasing and decreasing manner. This exercise minimizes the possibility of any hysteretic effects. Some instruments are built with a mechanism to alter the range once the instrument is installed. In this case, the instrument must be calibrated at each range to be used during the test period.

Other instruments may be calibrated at the number of points equal to the calibration curve fit. If the instrument can be shown to typically have a hysteresis of less than the required accuracy, the calibration points need only be approached from one direction.

4-2.4.5 Timing of Calibration. Test instrumentation for all variables used in test calculations that have a product of relative sensitivity coefficient and instrument uncertainty of 0.25 or greater of the total uncertainty shall be calibrated before testing and calibrated or checked following the tests. The calibration requirement is not mandated for instruments used for variables in test calculations that have a product of relative sensitivity coefficient and instrument uncertainty of less than 0.25 of the total uncertainty. No mandate is made regarding quantity of time between the initial calibration, the test period, and the recalibration, but all instruments should be within their normal calibration cycle (typically up to 1 yr). If premium-grade thermocouple wire from a given batch is used for temporary thermocouple installations, a section taken from each end of the batch can be used for calibration.

Flow measuring devices and current and potential transformers, by nature, are not conducive to post-test calibration. In the case of flow measuring devices, the element may be inspected following the test rather than recalibrating the device. Flow elements need not be inspected following the test if the devices have not experienced steam blow or chemical cleaning. Post-test calibration of current and potential transformers is not required.

4-2.4.6 Calibration Drift. Should the calibration drift, when combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable.

4-2.4.7 Loop Checks. All instruments should be loop checked. Loop checking is the process of checking the instrumentation loop to confirm that the calibrated

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instrument signal is properly processed through the signal conditioning equipment to the display. This may be accomplished by applying a calibrated output signal at the instrument termination point and observing the expected display at the DAS. Components of the loop may be calibrated (in the case of the sensor) and checked (in the case of the signal and conditioning equipment) separately. This latter approach is particularly true of digital systems.

4-2.4.8 Quality Assurance Program. A quality assurance program must be in place at facilities that conduct calibration activities for the test. This program is a method of documentation where the following information can be found:

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

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

Access to the calibration facility should be provided as the instruments are calibrated. The quality assurance program should also be made available during such a visit.

4-2.5 Plant Instrumentation

It is acceptable to use plant instrumentation if the plant instrumentation (including signal conditioning equipment) can be demonstrated to meet the uncertainty requirements of the test. In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from a metering device) must be made available, as plant conversions to flow are often not rigorous enough for the required test accuracy.

4-2.6 Redundant Instrumentation

Redundant instruments are two or more devices measuring the same parameter with respect to the same location. Redundant instruments should be used for those measurements that have the greater impact on test uncertainty. Redundant instruments can be used to reduce measurement uncertainty. An example of a redundant measurement is two wells with separate thermocouples at the same location; by contrast, a dual-element thermocouple in a single well does not represent a redundant measurement.

Other independent instruments in separate locations, including plant instrumentation, can also monitor instrument integrity. An example case is a constant enthalpy process, where pressure and temperature in a steam line at one point can verify the pressure and temperature of another location in the line by comparing enthalpies.

If the difference between redundant instruments is greater than the expected uncertainty of the individual measurements, the cause of the discrepancy shall be investigated.

4-3 TEMPERATURE MEASUREMENT

4-3.1 General

This subsection presents requirements and guidance regarding the measurement of temperature for this Code. It also discusses recommended temperature measurement devices, calibration of temperature measurement devices, and application of temperature measurement devices. Due to the state of the art and general practice, it is recommended that electronic temperature measurement equipment be used for primary measurements to minimize systematic and random error. The uncertainty of the temperature measurement shall consider effects including, but not limited to, stability, environmental, self-heating, parasitic resistance, parasitic voltages, resolution, repeatability, hysteresis, vibration, warm-up time, immersion or conduction, radiation, dynamic, spatial variation, and data acquisition.

Since temperature measurement technology will change over time, this Code does not limit the use of other temperature measurement devices not currently available or not currently reliable. If such a device becomes available and is shown to be of the required uncertainty and reliability, it may be used.

All signal cables should have a grounded shield or twisted pairs to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from electromotive force (emf)-producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

4-3.2 Measurement Systematic Uncertainty for Temperature

When estimating the overall uncertainty of a temperature measurement, test personnel should consider the list of potential sources and range of typical errors as shown in Table 4-3.2-1.

Table 4-3.2-1 identifies the calibrated systematic uncertainty of thermocouples and resistance temperature detectors (RTDs). ASME PTC 19.3 provides guidance on the application of calibration data.

The following items may also influence temperature measurements:

(a) thermowell location, geometry, and design
(b) temperature sensor design
(c) calibration
(d) pad weld (insulated or uninsulated)

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Table 4-3.2-1
List of Potential Sources and Typical Ranges of Uncertainties

Item	Uncalibrated Systematic Uncertainty	Calibrated Systematic Uncertainty	Range, °F
Thermocouple			
Type E precision grade	±2°F or ±0.4%, whichever is greater	[Note (1)]	32–1,600
Type E standard grade	±3°F or ±0.5%, whichever is greater	…	32–1,600
Type K precision grade	±2°F or ±0.4%, whichever is greater	[Note (1)]	32–2,300
Type K standard grade	±4°F or ±0.8%, whichever is greater	…	32–2,300
RTD NIST-traceable calibration standard	±0.5°F or ±0.3%, whichever is greater	0.2°F < 200°F 1°F < 1,000°F 2°F > 1,000°F	Up to 32
	±0.5°F or ±0.8%, whichever is greater		32–200
	±1.3%		200–400
	±1.8%		400–570
	±2.3%		570–750
	±2.8%		750–930
	±3.3%		930–1,100
	±3.8%		1,100–1,300
Mercury in glass thermometer	±0.5 graduation	…	…

GENERAL NOTE: Percentages are expressed in terms of Fahrenheit scale reading.

NOTE: (1) Refer to ASTM E220 for systematic uncertainties associated with thermocouples.

(e) stratification of flowing fluid
(f) grid size
(g) grid location
(h) ambient conditions at junctions
(i) ambient conditions at meter
(j) electrical noise
(k) heat conduction and radiation
(l) reference junction accuracy
(m) drift
(n) hysteresis
(o) thermometer nonlinearity
(p) parallax
(q) temperature transmitter
(r) DAS
(s) velocity

4-3.3 Recommended Temperature Measurement Devices

Thermocouples, RTDs, and thermistors are the recommended temperature measurement devices. Economics, application, and uncertainty considerations should be used in the selection of the most appropriate temperature measurement device.

4-3.3.1 Thermocouples. Thermocouples may be used to measure the temperature of any fluid above 200°F except for exhaust stack temperatures, which may be measured by thermocouple for temperatures as low as 150°F. The maximum temperature is dependent on the type of thermocouple and sheath material used. The thermocouple is a differential-type device. The thermocouple measures the difference between the measurement location in question and a reference temperature. The greater this difference, the higher the emf from the thermocouple. Therefore, at lower temperatures, the emf becomes low and is subject to induced noise that causes increased systematic uncertainty and inaccuracy.

The following are primary sources of error in thermocouple measurements:

(a) junction connection
(b) decalibration of thermocouple wire
(c) shunt impedance
(d) galvanic action
(e) thermal shunting
(f) noise and leakage currents
(g) thermocouple specifications

ASME PTC 19.3-1974 (R2004) describes the operation of the thermocouple as follows:

> The emf developed by a thermocouple made from homogeneous wires will be a function of the temperature difference between the measuring and the reference junction. If, however, the wires are not homogeneous, and the inhomogeneity is present in a region where a temperature gradient exists, extraneous emf will be developed, and the output of the thermocouple will depend upon factors in addition to the temperature difference between the two junctions. The homogeneity of the thermocouple wire, therefore, is an important factor in accurate measurements. (p. 106)

Dahl (1941) gives the following guidance on the application of the thermocouple:

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> All base-metal-metal thermocouples become inhomogeneous with use at high temperatures, however, if all the inhomogeneous portions of the thermocouple wires are in a region of uniform temperature, the inhomogeneous portions have no effect upon the indications of the thermocouple. Therefore, an increase in the depth of immersion of a used couple has the effect of bringing previously unheated portion of the wires into the region of temperature gradient, and thus the indications of the thermocouple will correspond to the original emf-temperature relation, provided the increase in immersion is sufficient to bring all the previously heated part of the wires into the zone of uniform temperature. If the immersion is decreased, more inhomogeneous portions of the wire will be brought into the region of temperature gradient, thus giving rise to a change in the indicated emf. Furthermore, a change in the temperature distribution along inhomogeneous portions of the wire nearly always occurs when a couple is removed from one installation and placed in another, even though the measured immersion and the temperature of the measuring junction are the same in both cases. Thus the indicated emf is changed. (p. 1238)

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

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

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

4-3.3.1.1 Class 1 Primary Parameters. Thermocouples used to measure Class 1 primary parameters must have continuous leads from the measuring junction to the connection on the reference junction. These high-accuracy thermocouples must have a reference junction at 32°F or an ambient reference junction that is well insulated and calibrated.

4-3.3.1.2 Class 2 Primary Parameters. Thermocouples used to measure Class 2 primary parameters can have junctions in the sensing wire. The junction of the two sensing wires must be maintained at the same temperature. The reference junction may be at ambient temperature, provided that the ambient is measured and the measurement is compensated for changes in the reference junction temperature.

4-3.3.1.3 Reference Junctions. The temperature of the reference junction shall be measured accurately with either software or hardware compensation techniques. The accuracy with which the temperature of the measuring junction is measured can be no greater than the accuracy with which the temperature of the reference junction is known. The reference junction temperature shall be held at the ice point or at the stable temperature of an isothermal reference. When thermocouple reference junctions are immersed in an ice bath consisting of a mixture of melting shaved ice and water (ASTM MNL 12, Chapter 7, "Reference Junctions"), the bulb of a precision thermometer shall be immersed at the same level as the reference junctions and in contact with them. Any deviation from the ice point shall be promptly corrected. Each reference junction shall be electrically insulated. When the isothermal cold-junction reference method is used, it shall employ an accurate temperature measurement of the reference sink. When electronically controlled reference junctions are used, they shall have the ability to control the reference temperature to within ±0.05°F. Particular attention must be paid to the terminals of any reference junction, since errors can be introduced by temperature variation, material properties, or wire mismatching. The overall reference system shall be verified by calibration to have an uncertainty of less than ±0.2°F. Isothermal thermocouple reference blocks furnished as part of digital systems may be used in accordance with the Code provided the accuracy is equivalent to the electronic reference junction. Commercial DASs employ a measured reference junction and the accuracy of this measurement is incorporated into the manufacturer's specification for the device. The uncertainty of the reference junction shall be included in the uncertainty calculation of the measurement to determine if the measurement meets the standards of this Code.

4-3.3.1.4 Thermocouple Signal Measurement. Many instruments are used today to measure output voltage. The use of each of these instruments in a system to determine temperature requires them to meet the uncertainty requirements for the parameter. It is recommended that the thermocouple signal conversion use ITS-90 software compensation techniques.

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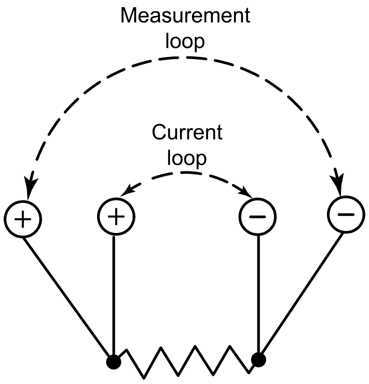
Figure 4-3.3.2.1-1
Four-Wire RTDs



4-3.3.2 RTDs. RTDs should only be used to measure from −454°F to 1,562°F. ASTM E1137-97 provides standard specifications for industrial platinum resistance thermometers that includes requirements for manufacture, pressure, vibration, and mechanical shock to improve the performance and longevity of these devices.

The following are primary sources of error in RTD measurements:

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

Although RTDs are considered a more linear device than thermocouples, RTDs are more susceptible to vibrational applications due to manufacturing technology. As such, care should be taken in the specification and application of RTDs with consideration for the effect on the device's stability. Field verification techniques should be used to demonstrate the stability is within the uncertainty requirements of para. 4-3.2.

4-3.3.2.1 Class 1 Primary Parameters. RTDs used to measure Class 1 primary parameters should be measured with a Grade A four-wire platinum resistance thermometer as presented in Figure 4-3.3.2.1-1. Three-wire RTDs are acceptable only if they can be shown to meet the uncertainty requirements of this Code.

4-3.3.2.2 Class 2 Primary Parameters. RTDs used to measure Class 2 primary parameters can be measured with Grade A three-wire platinum resistance thermometers as presented in Figure 4-3.3.2.2-1. The four-wire technique is preferred to minimize effects associated with lead wire resistance due to dissimilar lead wires.

4-3.3.2.3 RTD Signal Measurement. Many devices are available to measure output resistance. The use of each of these instruments in a system to determine temperature requires them to meet the uncertainty requirements for the parameter.

4-3.3.3 Thermistors

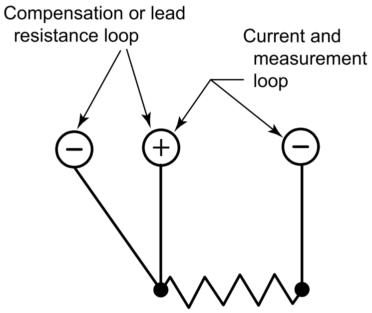
4-3.3.3.1 General. Thermistors are constructed with ceramic-like semi-conducting material that acts as a thermally sensitive variable resistor. This device may be used on any measurement below 300°F. Above this temperature, the signal is low and susceptible to error from current-induced noise. Although positive temperature coefficient units are available, most thermistors have a negative temperature coefficient; that is, unlike an RTD, their resistance decreases with increasing temperature. The negative temperature coefficient can be as large as several percent per degree Celsius, allowing the thermistor circuit to detect minute changes in temperature that could not be observed with an RTD or thermocouple circuit. As such, the thermistor is best characterized for its sensitivity, while the thermocouple is the most versatile and the RTD the most stable.

The following are primary sources of error in thermistor measurements:

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

Typically the four-wire resistance measurement is not required for thermistors as it is for RTDs measuring Class 1 primary parameters due to its high resistivity. Thus the measurement lead resistance produces an error magnitude less than the equivalent RTD error. However, in the case where long lead length wires or wires with high resistance are used that were not part of the calibration, the lead wire resistance must be compensated for in the measurement. Thermistors are generally more fragile than RTDs and thermocouples and must be carefully mounted and handled in accordance

Figure 4-3.3.2.2-1
Three-Wire RTDs



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with the manufacturer's specifications to avoid crushing or bond separation.

4-3.3.3.2 Thermistor Signal Measurement. Many instruments are used today to measure output resistance. The use of each of these instruments in a system to determine temperature requires them to meet the uncertainty requirements for the parameter.

4-3.4 Calibration of Primary Parameter Temperature Measurement Devices

This Code recommends that primary (Class 1 or Class 2) parameter instrumentation used in the measurement of temperature have a suitable calibration history (three or four sets of calibration data). The calibration history should include the temperature level the device experienced between calibrations. A device that is stable after being used at low temperatures may not be stable at higher temperatures. Therefore, the calibration history of the device should be evaluated to demonstrate the required stability of the parameter.

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

The calibration of temperature measurement devices is accomplished by inserting the candidate temperature measurement device into a calibration medium along with a traceable reference standard. The calibration medium type is selected based upon the required calibration range and commonly consists of either a block calibrator, fluidized sand bath, or circulating bath. The temperature of the calibration medium is then set to the calibration temperature set point. The temperature of the calibration medium is allowed to stabilize until the temperature of the standard is fluctuating less than the accuracy of the standard. The signal or reading from the standard and the candidate temperature measurement device are sampled to determine the bias of the candidate temperature device. See ASME PTC 19.3 for a more detailed discussion of calibration methods.

4-3.5 Temperature Scale

The International Temperature Scale of 1990 (ITS-90) is realized and maintained by NIST to provide a standard scale of temperature for use by science and industry in the United States.

Temperatures on the ITS-90 can be expressed in terms of international Kelvin temperatures, with the symbol T_{90}, or in terms of international Celsius temperatures, with the symbol t_{90}. The units of T_{90} and t_{90} are Kelvin (K) and degree Celsius (°C), respectively. The relation between T_{90} (in K) and t_{90} (in °C) is

$$t_{90} = T_{90} - 273.15 \tag{4-3-1}$$

Values of Fahrenheit temperature, t_f, °F, are obtained from the conversion formula

$$t_f = (9/5)t_{90} + 32 \tag{4-3-2}$$

ITS-90 was designed in such a way that the temperature values on it very closely approximate Kelvin thermodynamic temperature values. Temperatures on the ITS-90 are defined in terms of equilibrium states of pure substances (defining points), interpolating instruments, and equations that relate the measured property to T_{90}. The defining equilibrium states and the values of temperature assigned to them are listed in NIST Technical Note 1265 and ASTM MNL 12.

4-3.6 Typical Applications

4-3.6.1 Temperature Measurement of Fluid in a Pipe or Vessel. Temperature measurement of a fluid in a pipe or vessel is usually accomplished by installing a thermowell. A thermowell is a pressure-tight device that protrudes from the pipe or vessel wall into the fluid. The thermowell has a bore extending to near the tip to facilitate the immersion of a temperature measurement device.

The bore should be sized to allow adequate clearance between the measurement device and well. Care should be exercised when inserting the temperature measurement device to prevent it from bending, which would cause difficulty in the insertion of the device.

The bottom of the bore of the thermowell should be the same shape as the tip of the temperature measurement device. The bore should be cleaned with high-pressure air before insertion of the device.

The thermowell should be installed in a manner so that the tip protrudes through the boundary layer of the fluid to be measured. The thermowell should be located in an area where the fluid is well mixed and has no potential gradients.

If more than one thermowell is installed in a given pipe location, they should be installed 90 deg to 180 deg apart and not directly downstream of another thermowell.

When the temperature measurement device is installed, it should be spring loaded to ensure that the tip of the device remains against the bottom of the thermowell.

For high-accuracy measurements, it is recommended that the portion of the thermowell that protrudes outside the pipe or vessel be insulated along with the device itself to minimize conduction losses.

For measuring the temperature of desuperheated steam, the thermowell location relative to the desuperheating spray injection must be carefully chosen to

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meet or exceed the vendor's recommended minimum distances. The thermowell must be located where the desuperheating water has thoroughly mixed with the steam. This can be accomplished by placing the thermowell downstream of one or more elbows in the steam line past the desuperheat injection point.

Steam and water flowing in pipes typically have an approximately uniform temperature distribution.

Selection of the method of measurement and the temperature measuring instruments depends upon the conditions of the individual case. Steam and water temperatures are usually measured by inserting the sensing device (RTD or thermocouple) into a thermowell located in the piping. Refer to ASME PTC 19 Series for installation of temperature devices.

Saturated steam temperature may be determined by the pressure in the steam drum. The temperature of superheated steam shall be measured as close as possible to the superheater and reheater outlets or their respective terminal points to minimize error from heat loss. Feedwater temperatures shall be measured as close to the economizer and boiler inlets as possible.

4-3.6.2 Temperature Measurement of Products of Combustion in a Duct. Air and gas flowing through a duct usually have nonuniform velocity, temperature, and composition. This is especially true at the GT discharge or near a flow disturbance, such as a bend or transition. Refer to ASME PTC 19.5 for guidance on velocity traverse methods.

Generally, sampling more points can reduce temperature uncertainty. To compensate for stratification and to obtain a representative average, multiple points must be sampled in a plane perpendicular to the flow. The measurement plane should be located away from bends, constrictions, or expansions of the duct. Thermocouples shall be read individually and not combined to produce a single output.

The parties to the test shall agree on how the average temperature is to be calculated if there is variation in the temperature profile. Potential methods include an arithmetic average of the temperatures or a mass weighted average. Possible methods of mass weighting are where the manufacturer provides a calculation method based on either field test data from similar units or from analytical means such as computational fluid dynamics modeling. Another possible method would be to conduct velocity, total temperature, and total pressure traverses at several locations in the exhaust duct to determine the mass flow at the measured temperature locations.

The total temperature of the gas flowing is required. If the average velocity in the area of temperature measurement exceeds 100 ft/sec, then it is suggested that the temperature reading be adjusted for velocity effect (Benedict, 1984, p. 204, eq. 11.7):

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

where

C_p = specific heat, Btu/lbm °F
g_c = gravitational constant as defined in Section 2
= 32.1741 lbm·ft/lbf sec^2
J = mechanical equivalent of heat
= 778.1692623 ft·lbf/Btu
T = measured temperature, °F
T_t = total temperature, °F
T_v = dynamic temperature, °F
V = gas velocity, ft/sec

This Code requires independent measurements of

(a) exhaust gas temperature at the GT outlet following requirements of ASME PTC 22

(b) HRSG inlet temperature as noted in this Code

Typically, the duct pressures are low or negative so that thermowells are not needed. A long-sheathed thermocouple or an unsheathed thermocouple attached to the HRSG or a test fixture will suffice.

The number of measurement points necessary is determined experimentally or by experience from the magnitude of the temperature variations at the desired measurement cross section and the required maximum uncertainty of the value of the average temperature. The total uncertainty of the average temperature is affected by the uncertainty of the individual measurements, the number of points used in the averaging process, the temperature gradients, and the time variation of the readings. The parties to the test should locate HRSG inlet temperature measurement as close to the combustion turbine–HRSG interface as possible. The stack measurement plane should be located at least two diameters from any obstructions or transitions. The recommended number of points is as follows:

	Points of Measurement	
Location	**Number**	**Spacing**
HRSG inlet		
Axial discharge	12 min., 36 max.	Every 25 ft^2
Side discharge	18 min., 36 max.	Every 25 ft^2
Stack	12 [Note (1)]	Equally spaced

NOTE: (1) Twelve points in a well-mixed HRSG outlet stream will typically provide desired results.

For round ducts, the test points may be installed in two locations (diameters) 90 deg apart. The measurement point spacing is based on locating the measurement points at the centroids of equal areas along each diameter.

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

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4-3.6.3 Inlet Air Temperature. The dry-bulb temperature is the static temperature at the inlet to the GT (upstream of any evaporative cooler or chiller systems). The temperature sensor must be shielded from solar and other sources of radiation and must have a constant airflow across the sensing element. Although not required, a mechanically aspirated psychrometer, as described below, may be used. If a psychrometer is used, a wick should not be placed over the sensor (as is required for measurement of wet-bulb temperature). If the air velocity across the sensing element is less than 1,500 ft/min, shielding of the sensing element is required to minimize stagnation effects. The evaporative cooler or chiller system should be turned off to reduce the uncertainty, or the uncertainty of the GT heat balance will increase.

4-3.6.4 Inlet Air Moisture Content. The moisture content of the GT compressor inlet may be determined by the measurement of adiabatic wet-bulb or relative humidity. Measurements to determine moisture content should be made in proximity with measurements of inlet air dry-bulb temperature to provide the basis for determination of air properties. Descriptions of acceptable devices for measurement of moisture content are discussed below:

(a) Wet-Bulb Temperature. The thermodynamic wet-bulb temperature is the air temperature that results when air is adiabatically cooled to saturation. Wet-bulb temperature can be inferred by a properly designed mechanically aspirated psychrometer. The process by which a psychrometer operates is not adiabatic saturation, but one of simultaneous heat and mass transfers from the wet-bulb sensing element. The resulting temperature achieved by a psychrometer is sufficiently close to the thermodynamic wet-bulb temperature over most condition ranges. However, a psychrometer should not be used for temperatures below 40°F or when the relative humidity is less than 15%.

The mechanically aspirated psychrometer should incorporate the following features:

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

(2) The sensing element is suspended in the air stream and is not in contact with the shield walls.

(3) The sensing element is snugly covered by a clean cotton wick that is kept wetted from a reservoir of distilled water.

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

(5) Air is drawn across the sensing element in such a manner that it is not heated by the fan motor or other sources of heat.

(6) The psychrometer should be located at least 5 ft above ground level and should not be located within 5 ft of vegetation or surface water.

(b) Cooled Mirror Dew Point Hygrometer. The dew point temperature is the temperature of moist air when it is saturated at the same ambient pressure and with the same specific humidity. A cooled mirror dew point hygrometer uses a cooled mirror to detect the dew point. Air is drawn across a mirror that is cooled to the temperature at which vapor begins to form on the mirror. A temperature sensor mounted in the mirror measures the surface temperature. Manual devices are available. There are also commercially available instruments that automatically control the mirror temperature, detect the inception of condensation, and provide temperature readout.

The advantages of using dew point hygrometers include the following:

(1) Calibration can be verified by using sample gases prepared with known concentrations of moisture.

(2) Dew point can be measured over the full range of ambient conditions, including below freezing.

(c) Relative Humidity Hygrometers. Thin film capacitance and polymer resistance sensors provide a direct measurement of relative humidity. Measurement uncertainties vary with sensor type and design. They usually range from 1% to 2% for relative humidity between 0% and 90%. Measurement uncertainties for relative humidity value above 90% are usually higher. The accuracy of these types of instruments is dependent on proper calibration. The advantages of relative humidity hygrometers include the following:

(1) Calibration can be verified by using sample gases prepared with known concentrations of moisture.

(2) Relative humidity can be measured over the full range of ambient conditions, including below freezing.

4-4 PRESSURE MEASUREMENT

4-4.1 General

This subsection presents requirements and guidance regarding the measurement of pressure. Due to the state of the art and general practice, it is recommended that electronic pressure measurement equipment be used for primary measurements to minimize systematic and random error. Electronic pressure measurement equipment is preferred due to inherent compensation procedures for sensitivity, zero balance, thermal effect on sensitivity, and thermal effect on zero. Other devices that meet the uncertainty requirements of this Section may be used. The uncertainty of the pressure measurement shall consider effects including, but not limited to, ambient temperature, resolution, repeatability, linearity, hysteresis, vibration, power supply, stability,

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mounting position, radio frequency interference (RFI), static pressure, water leg, warm-up time, data acquisition, spatial variation, and primary element quality.

The piping between the process and secondary element must accurately transfer the pressure to obtain accurate measurements. Six possible sources of error include

(a) pressure transfer
(b) leaks
(c) friction loss
(d) trapped fluid (i.e., gas in a liquid line or liquid in a gas line)
(e) density variations within leg (i.e., water leg)
(f) density variations between legs (differential pressure only)

All signal cables should have a grounded shield or twisted pairs to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from emf-producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

Before calibration, the pressure transmitter range may be altered to match the process better. However, the sensitivity to ambient temperature fluctuation may increase as the range is altered.

Additional calibration points will increase device accuracy but are not required. During calibration, the measuring point should be approached from an increasing and decreasing manner to minimize the hysteresis effects.

Some pressure transmitters have the capability of changing the range once the transmitter is installed. The transmitters must be calibrated at each range to be used during the test period.

Where appropriate for steam and water processes, the readings from all static pressure transmitters and any differential pressure transmitters with taps at different elevations (such as on vertical flow elements) must be adjusted to account for elevation head in water legs. This adjustment must be applied at the transmitter, in the control system or DAS, or manually by the user after the raw data is collected. Care must be taken to ensure this adjustment is applied properly, particularly at low static pressures, and that it is only applied once.

4-4.2 Measurement Systematic Uncertainty for Pressure

When estimating the systematic uncertainty of a pressure measurement, test personnel should consider the following list of potential sources. The accuracy class and total uncertainty of the pressure measurement system must satisfy the overall test uncertainty calculated in the pretest uncertainty analysis (see Table 4-4.2-1).

(a) water leg
(b) specify gravity of manometer fluid
(c) ambient conditions at sensor
(d) ambient conditions at meter
(e) hysteresis
(f) electrical noise
(g) data acquisition
(h) drift
(i) transducer nonlinearity
(j) parallax
(k) gauge, manometer, transducer, or transmitter type
(l) calibration
(m) tap (location, geometry, flow impact)
(n) probe design
(o) number and location of measurements

Table 4-4.2-1
Potential Pressure Systematic Uncertainty Limits

Instrument	Systematic Uncertainty Limits [Notes (1), (2)]
Pressure gauge	
Test (0.25% class)	±0.25% of span
Standard (1.0% class)	±1% of span
Manometer	±0.5 graduation
Pressure transducer and transmitter	
High accuracy (0.1% class)	±0.23% of span
Standard (0.25% class)	±0.32% of span
Aneroid barometer	±0.05 in. Hg

NOTES:
(1) See ASME PTC 19.2 for applicability.
(2) All systematic uncertainty limits are a percent of reading unless noted otherwise.

4-4.3 Recommended Pressure Measurement Devices

Pressure transmitters are the recommended pressure measurement devices. There are three types of pressure transmitters, as follows, with varying application considerations:

(a) absolute pressure transmitters
(b) gage pressure transmitters
(c) differential pressure transmitters

4-4.3.1 Absolute Pressure Transmitters

(a) Application. Absolute pressure transmitters measure pressure referenced to absolute zero pressure. Absolute pressure transmitters should be used on all measurement locations with a pressure equal to or less than atmospheric. Absolute pressure transmitters may also be used to measure pressures above atmospheric pressure.

(b) Calibration. Absolute pressure transmitters can be calibrated using one of two methods. The first method involves connecting the test instrument to a device that develops an accurate vacuum at desired pressure levels. Such a device can be a deadweight gage in a

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bell jar referenced to zero pressure or a divider piston mechanism with the low side referenced to zero pressure.

The second method calibrates the transmitter by developing and holding a constant vacuum in a chamber using a suction and bleed control mechanism. The test instrument and the calibration standard are both connected to the chamber. The chamber must be maintained at constant vacuum during the calibration of the instrument. Other devices can be utilized to calibrate absolute pressure transmitters provided that the same level of care is taken.

4-4.3.2 Gage Pressure Transmitters

(a) Application. Gage pressure transmitters measure pressure referenced to atmospheric pressure. The test site atmospheric pressure must be subtracted from the absolute pressure to obtain gage pressure, p_g:

$$p_g = p_{\text{abs}} - p_{\text{baro}} \tag{4-4-1}$$

where

p_{abs} = absolute pressure, psia
p_{baro} = barometric pressure, psia

This test site atmospheric pressure should be measured by an absolute pressure transmitter. Gage pressure transmitters may only be used on measurement locations with pressures higher than atmospheric. Gage pressure transmitters are preferred over absolute pressure transmitters in measurement locations above atmospheric pressure because they are easier to calibrate.

(b) Calibration. Gage pressure transmitters can be calibrated by an accurate deadweight gage. The pressure generated by the deadweight gage must be corrected for local gravity, air buoyancy, piston surface tension, piston area deflection, actual mass of weights, actual piston area, and working medium temperature. If the above corrections are not used, the pressure generated by the deadweight gage may be inaccurate. The actual piston area and mass of weights are determined each time the deadweight gage is calibrated. Other devices can be utilized to calibrate gage pressure transmitters provided that the same level of care is taken.

4-4.3.3 Differential Pressure Transmitters

(a) Application. Differential pressure transmitters are used where flow is determined by a differential pressure meter, or where pressure drops in a duct or pipe must be determined and it is practical to route the pressure tubing.

(b) Calibration. Differential pressure transmitters used to determine Class 1 primary parameters and variables must be calibrated at line static pressure unless information is available detailing the effect of line static pressure on the instrument accuracy that demonstrates compliance with the uncertainty requirements of para. 4-2.2. Calibrations at line static pressure are performed by applying the actual expected process pressure to the instrument as it is being calibrated. Calibrations at line static pressure can be accomplished by one of three methods:

(1) two highly accurate deadweight gages
(2) a deadweight gage and divider combination
(3) one deadweight gage and one differential pressure standard

Differential pressure transmitters used to determine Class 2 primary parameters and variables or secondary parameters and variables do not require calibration at line static pressure and can be calibrated using one accurate deadweight gage connected to the high side of the instrument.

If line static pressure calibration is not used, the span must be corrected for high line static pressure shift unless the instrument is internally compensated for the effect. Once the instrument is installed in the field, the differential pressure from the source should be equalized and a zero value read. This zero bias must be subtracted from the test-measured differential pressure. Other devices can be utilized to calibrate differential pressure transmitters provided that the same level of care is taken.

4-4.4 Absolute Pressure Measurements

4-4.4.1 Introduction. Absolute pressure measurements are pressure measurements that are below or above atmospheric pressure. Absolute pressure transmitters are recommended for these measurements. Typical absolute pressure measurements in an ASME PTC 46 test may include barometric pressure and condenser pressure.

For vacuum pressure measurements, differential pressure transmitters may be used with the low side of the transmitter connected to the source to effectively result in a negative gage that is subtracted from atmospheric pressure to obtain an absolute value. This method may be used but is not recommended for Class 1 primary parameters and variables since these measurements are typically small and the difference of two larger numbers may result in error.

4-4.4.2 Installation. Absolute pressure transmitters used for absolute pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters should be installed in the same orientation as they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing shall be installed and the transmitter mounted in accordance with the manufacturer's specifications. In general, the following guidelines should be used to determine transmitter location and placement of impulse tubing:

(a) Keep the impulse tubing as short as possible.

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(b) Slope the impulse tubing at least 1 in./ft upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 1 in./ft downward from the transmitter toward the process connection for gas service.

(d) Avoid high points in liquid lines and low points in gas lines.

(e) Use impulse tubing large enough to avoid friction effects and prevent blockage.

(f) Keep corrosive or high-temperature process fluid out of direct contact with the sensor module and flanges.

In steam service, the sensing line should extend at least 2 ft horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

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

All vacuum-measurement sensing lines should slope continuously upwards from the source to the instrument. The Code recommends that a purge system be used that isolates the purge gas during measurement of the process. A continuous purge system may be used; however, it must be regulated to have no influence on the reading. Before the test period, readings from all purged instrumentation should be taken successively with the purge on and off to prove that the purge air has no influence.

Each pressure transmitter should be installed with an isolation valve at the end of the sensing line upstream of the instrument. The instrument sensing line should be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing line of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct.

Once transmitters are connected to the process, a leak check must be conducted. For vacuum measurements, the leak check is performed by isolating first the purge system and then the source. If the sensing line has no leaks, the instrument reading will not change. For non-vacuum measurements, the leak check is performed using a leak detection fluid on the impulse tubing fittings.

Barometric pressure devices should be installed in the same general area and elevation that is most representative of the test boundary and minimizes test uncertainty.

4-4.5 Gage Pressure Measurements

4-4.5.1 Introduction. Gage pressure measurements are pressure measurements that are made at or above atmospheric pressure. These measurements may be made with gage or absolute pressure transmitters. Gage pressure transmitters are recommended since they are easier to calibrate and to check in situ. Typical gage pressure measurements in an ASME PTC 46 test may include gas fuel pressure and process return pressure. Caution must be used with LP measurements because they may enter the vacuum region at part-load operation.

4-4.5.2 Installation. Gage pressure transmitters used for gage pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters should be installed in the same orientation as they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing shall be installed and the transmitter mounted in accordance with the manufacturer's specifications. In general, the following guidelines should be used to determine transmitter location and placement of impulse tubing:

(a) Keep the impulse tubing as short as possible.

(b) Slope the impulse tubing at least 1 in./ft upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 1 in./ft downward from the transmitter toward the process connection for gas service.

(d) Avoid high points in liquid lines and low points in gas lines.

(e) Use impulse tubing large enough to avoid friction effects and prevent blockage.

(f) Keep corrosive or high-temperature process fluid out of direct contact with the sensor module and flanges.

In steam service, the sensing line should extend at least 2 ft horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

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

Each pressure transmitter should be installed with an isolation valve at the end of the sensing line upstream of the instrument. The instrument sensing line should be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing line of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct.

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Once transmitters are connected to the process, a leak check must be conducted. The leak check is performed using a leak detection fluid on the impulse tubing fittings.

4-4.6 Differential Pressure Measurements

4-4.6.1 Introduction. Differential pressure measurements are used to determine the difference in static pressure between pressure taps in a primary element. Differential pressure transmitters are recommended for these measurements. Typical differential pressure measurements in an ASME PTC 46 test may include the differential pressure of gas fuel, process return through a flow element, or pressure loss in a pipe or duct. The differential pressure transmitter measures this pressure difference or drop that is used to calculate the fluid flow.

4-4.6.2 Installation. Differential pressure transmitters used for differential pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters should be installed in the same orientation as they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements should be installed in accordance with manufacturer's specifications. In general, the following guidelines should be used to determine transmitter location and placement of impulse tubing:

(a) Keep the impulse tubing as short as possible.

(b) Slope the impulse tubing at least 1 in./ft upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 1 in./ft downward from the transmitter toward the process connection for gas service.

(d) Avoid high points in liquid lines and low points in gas lines.

(e) Ensure both impulse legs are at the same temperature.

(f) When using a sealing fluid, fill both impulse legs to the same level.

(g) Use impulse tubing large enough to avoid friction effects and prevent blockage.

(h) Keep corrosive or high-temperature process fluid out of direct contact with the sensor module and flanges.

In steam service, the sensing line should extend at least 2 ft horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

Each pressure transmitter should be installed with an isolation valve at the end of the sensing lines upstream of the instrument. The instrument sensing lines should be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing lines of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct.

Differential pressure transmitters should be installed utilizing a five-way manifold shown in Figure 4-4.6.2-1. This manifold is recommended rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve. The vent valve acts as a telltale for leakage detection past the equalizing valves.

Once transmitters are connected to process, a leak check must be conducted. The leak check is performed using a leak detection fluid on the impulse tubing fittings.

When a differential pressure meter is installed on a flow element located in a vertical steam or water line, the measurement must be corrected for the difference in sensing line height and fluid head change unless the upper sensing line is installed against a steam or water line inside the insulation down to where the lower sensing line protrudes from the insulation. The correction for the non-insulated case shown in Figure 4-4.6.2-2 is as follows:

- For upward flow

$$\Delta p_{\text{true}} = \Delta p_{\text{meas}} + (\rho_{\text{amb}} - \rho_{\text{pipe}})(g/g_0) \times \Delta z \tag{4-2-6}$$

- For downward flow

$$\Delta p_{\text{true}} = \Delta p_{\text{meas}} - (\rho_{\text{amb}} - \rho_{\text{pipe}})(g/g_0) \times \Delta z \tag{4-2-7}$$

where

g = local gravitational force per unit mass; approximately 32.17 ft/sec^2

g_0 = gravitational dimensional constant = 32.17 lbm-ft/lbf-sec^2

Δp_{meas} = measured instrument differential pressure (DP), in. H_2O

Δp_{true} = corrected DP, in. H_2O

ρ_{amb} = water density at ambient temperature, lbm/ft^3

ρ_{pipe} = fluid density, lbm/ft^3

Δz = height difference between pressure taps, in.

4-4.7 Air and Gas — Static and Differential Pressure

4-4.7.1 General. The static pressure in the gas duct at the HRSG inlet is required to determine gas-side pressure drop in the unit. Should the pressure drop not be between the inlet and atmosphere, then a differential pressure transmitter or manometer shall be used. The HRSG inlet pressure is a static pressure measurement. Pressure drop across components should be performed using a differential pressure measuring apparatus rather than two separate instruments. The measurement should be

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Figure 4-4.6.2-1
Five-Way Manifold

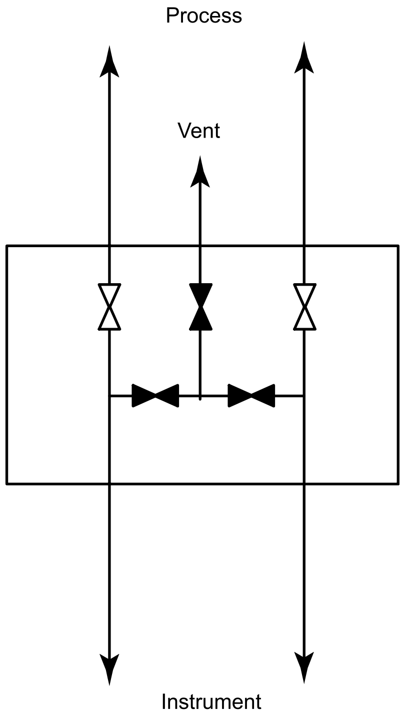
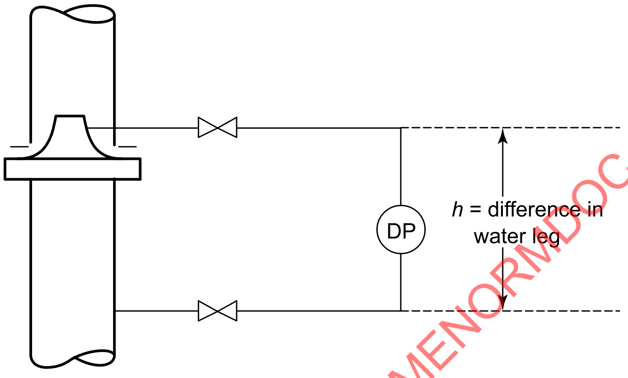


Figure 4-4.6.2-2
Water Leg Correction for Flow Measurement



based on the average of four separate measurement points in the same plane.

4-4.7.2 Method of Measurement. Pressure shall be measured with gauges, manometers, or transducers. The output of these devices is either visual or a signal, which can be read with a meter or a data logger. ASME PTC 19.2 provides further information on pressure measurement techniques.

4-4.8 Steam and Water — Static and Differential Pressure

The static pressure in steam and water piping is required to determine fluid properties for flow measurement and enthalpy determination as well as for obtaining corrected results. Reheater pressure drop determinations shall be performed using a differential measuring apparatus rather than two separate instruments.

4-4.8.1 Method of Measurement. ASME PTC 19.2 guidelines should be followed in the installation of pressure measuring devices.

4-4.8.2 Installation. If the instrument is used in gas service, the sensing lines should slope upward to the instrument. This eliminates the possibility of error due to moisture condensing in the sensing lines.

Differential pressure transmitters used in steam, water, or other liquid service should be installed with the sensing lines sloping downward to the instrument. The sensing lines for differential transmitters in steam service should extend 2 ft horizontally before the downward slope begins. This will ensure that the vertical length of sensing line is full of liquid.

The flow element should be installed in horizontal piping. When a differential pressure meter is installed on a flow element located in a vertical steam or water line, the measurement must be corrected for the difference in sensing line height and fluid head change. If vertical, the correction for sensing lines is as follows:

(a) For upward flow

$$h_{\mathrm{WC}} = h_{\mathrm{WM}} + \frac{\mathrm{HT}}{62.32\, S_G}\left(\frac{1}{V_{\mathrm{sen}}} - \frac{1}{V_{\mathrm{fluid}}}\right)$$

(b) For downward flow

$$h_{\mathrm{WC}} = h_{\mathrm{WM}} - \frac{\mathrm{HT}}{62.32\, S_G}\left(\frac{1}{V_{\mathrm{sen}}} - \frac{1}{V_{\mathrm{fluid}}}\right)$$

where 62.32 = conversion factor.

4-4.9 Barometric Pressure

Barometric pressure is required to determine local ambient conditions. The preferred method for determining barometric pressure is from a barometer at the test site in the vicinity of the GT air inlet.

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Table 4-5.2-1
Maximum Allowable Flow Measurement Uncertainty

Type of Flow	Systematic Uncertainty Limits, % [Note (1)]
HP steam flow	0.5
IP steam flow	1.0
LP steam flow	1.0
Class 1 supplemental fuel flow	0.75
Class 2 supplemental fuel flow	1.25

GENERAL NOTE: See ASME PTC 19.5 for applicability.

NOTE: (1) All systematic uncertainty limits are percent of reading unless noted otherwise.

4-5 FLOW MEASUREMENT

4-5.1 General

This Code recommends ASME PTC 19.5 laboratory-calibrated venturi, orifice, or flow nozzle metering runs to measure the inlet water or steam flow to each pressure level of the HRSG and the supplementary fired fuel flow. Water inventory in all steam drums must be determined at the beginning and end of each test run to correct steam flow for volume changes because steam flow is determined based on water flow.

4-5.2 Flowmeters

In most power plant applications, use of differential pressure meters (orifices, nozzles, and venturis) is common, as is the class of meters recommended and discussed by this Code. However, other types of flowmeters may be used if they can be demonstrated to be of the same or better levels of uncertainty required by this Code, which are shown in Table 4-5.2-1.

4-5.2.1 Compliance With Code Requirements. It is emphasized that in order for a flowmeter to be used, it must be designed, fabricated, and installed in strict accordance with ASME PTC 19.5 and the calculation of flow must be performed in accordance with that Code.

Start-up procedures must also ensure that spool sections are provided for use during any steam blows to avoid damage to the flowmeter. While stored during steam blows, the flowmeter must be capped and protected from environmental damage such as moisture and dirt.

Special care must therefore be taken in the specifications for the design of the plant to ensure that all plant flowmeters to be used for an ASME PTC 4.4 Code test meet these requirements.

4-5.2.2 Plant Design Considerations. There are many combinations of flowmeters that will meet the uncertainty requirements of this Code. It is very important as early as the specification stages of the plant design to consider testing requirements to optimize all design considerations such that the test uncertainty limits of this Code will not be exceeded.

Compliance with ASME PTC 19.5 requirements for metering for determination of flow at primary locations shall be considered during the design phases of the plant.

Water or steam flowmeters may be in the HRSG manufacturer's scope. Use of water-side flowmeters avoids damage problems from preoperational steam blows. Operational procedures requiring attemperation spray, desuperheating flow, and fuel heating need to be considered in the design of the flowmeter system.

The design uncertainty study should be used to develop the HRSG mass balance metering flows.

Reheat steam flow can be determined by subtracting HP steam turbine gland losses from the HP turbine throttle steam flow. See ASME PTC 6.2 for guidance.

4-5.2.3 Calculation of Flow. Calculation of flow shall be in accordance with ASME PTC 19.5.

4-5.2.4 Accuracy and Other Characteristics of Flowmeters. This Code mandates calibration of the meter or meters used for determination of flow for each pressure level of the HRSG, or use of alternative meters that meet the requirements of Table 4-5.2-1. Investigation is needed if the results differ from each tap set calculation by more than the measurement uncertainty.

The procedures for fitting a curve through laboratory calibration data are given in detail for each type of differential pressure meter run in ASME PTC 19.5. The procedures for extrapolation of a calibration to higher Reynolds numbers than available in the laboratory are also given for each type of device in ASME PTC 19.5.

4-5.2.5 Selection of Flowmeters. The complexities associated with the selection of flowmeters are such that they cannot be covered in this Code. The Code user is referred to ASME PTC 19.5 for this information.

4-5.2.6 Energy and Mass Balance Calculation. Certain flows, such as superheat and reheat spray, may be calculated by energy balance. Energy balance would be the preferred method when the flows are relatively low. Direct flow measurement may be preferable when the flows are high or there is water impingement on the downstream thermocouple.

4-5.3 Air and Exhaust Gas

The total mass flow of turbine exhaust gas crossing the HRSG boundary shall be calculated by energy balance. This Code requires a GT and an HRSG energy balance to be used for these calculations. Refer to subsections 5-3 and 5-4 for discussions of exhaust gas flow determination by HRSG heat balance and GT heat balance, respectively. Required GT measurements for a GT heat balance are described in ASME PTC 22, Section 4. ASME PTC 22 should be used as the basis for the GT balance measurements.

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4-5.4 Liquid Fuel

4-5.4.1 General. If liquid fuel duct burners are employed, the quantity of liquid fuel burned must be determined.

Refer to ASME PTC 22 and ASME PTC 19.5 for liquid-fueled GT fuel flow measurements.

4-5.4.2 Method of Measurement. Liquid fuel flows can be measured using either a flow orifice installed in accordance with ASME PTC 19.5 or other measurement devices, such as positive displacement flowmeters or turbine flowmeters that are calibrated throughout the Reynolds number range expected during the test. For volume flowmeters, the temperature of the fuel must be measured accurately to calculate the flow correctly. Uncalibrated flowmeters are acceptable if the measurement uncertainty meets the Table 4-5.2-1 requirements. Refer to ASTM D1480 for liquid fuel density and ASTM D445 for liquid fuel viscosity.

4-5.5 Gaseous Fuel

4-5.5.1 General. If gaseous fuel duct burners are employed, the quantity of gaseous fuel burned must be determined. Refer to ASME PTC 22 and ASME PTC 19.5 for gaseous-fueled GT fuel flow measurements.

4-5.5.2 Method of Measurement. Measurement of the gaseous fuel flow requires the use of a venturi, orifice, flow nozzle, ultrasonic, or turbine meter. For orifices, venturis, or nozzles, refer to ASME PTC 19.5 for installation guidelines as well as the calculation procedure. For differential pressure meters, the pressure drop shall be measured using a differential pressure transducer. Outputs from these devices can be read manually via meters or with a DAS. The method and procedure detailed in AGA Report 8 (2017), Part 1, shall be followed for the determination of gas density. Linear flowmeters should be calibrated at the expected working pressure to reduce flow error. Uncalibrated flowmeters are acceptable if the measurement uncertainty meets the Table 4-5.2-1 requirements.

4-6 LIQUID AND GASEOUS FUEL SAMPLING

4-6.1 General

A representative sample of the fuel fired during the performance test should be obtained using the methods described in ASTM D4057 or ASTM D5287.

4-6.2 Measurement Systematic Uncertainty for Sampling

When the systematic uncertainty of a sampling procedure is estimated, the test engineer should consider the following potential sources. There may be other sources and not all sources listed are applicable to all measurements.

(a) sampling location and geometry
(b) number and location of sample points
(c) ambient conditions at sample location
(d) fuel and its variability
(e) sample handling and storage
(f) duration of test
(g) quantity of sample obtained

An estimate of the systematic uncertainty from a sample is a combination of systematic limits from sample acquisition, location, and stream consistency.

4-6.3 Methods of Liquid or Gas Sampling

GPA 2166 should be used for the proper procedures and equipment for sampling liquid or gas. Evacuated gas cylinders are recommended versus the flow-through cylinder method, which would concentrate the heavy hydrocarbons. At least three samples should be taken (start, middle, and end of test) if the gas supply composition is consistent. If consistency is not assured, then five equally spaced samples should be obtained. An on-line gas chromatograph may be used if its accuracy is confirmed before the test and confirmed with limited (once per test) samples for laboratory analysis and confirmation of the on-line chromatograph within 0.4% (of heat content) uncertainty band. Backup samples should also be taken in case there is a problem with the chromatograph during the test.

An estimate of the systematic uncertainty from a sample is a combination of systematic limits from sample acquisition, location, and stream consistency.

4-6.4 Fuel Analysis

4-6.4.1 General. It is the intent of this Code that the samples be analyzed in accordance with the latest methods and procedures. When choosing a laboratory, the parties to the test should choose a certified laboratory.

4-6.4.2 Measurement Systematic Uncertainty for Fuel. ASTM provides guidelines for typical lab-to-lab systematic uncertainties for use in estimating the systematic uncertainty of a sample analysis. In addition, a reference sample may be obtained from NIST and sent to the lab for analysis. ASME PTC 22 refers to a 0.4% expected measurement systematic uncertainty (of heat content) for gaseous fuel analysis.

4-6.5 Methods of Fuel Analysis

Gaseous fuel should be analyzed using gas chromatography in accordance with ASTM D1945. Higher heating value is calculated in accordance with para. 5-2.4 of this Code. Liquid fuel heating value should be determined by bomb calorimeter in accordance with ASTM D4809.

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4-7 POWER MEASUREMENT

Power measurement is required for determination of exhaust flow by GT heat balance. Methods of measuring GT output are described in ASME PTC 22.

4-8 DATA COLLECTION AND HANDLING

4-8.1 Data Collection and Calculation Systems

The analog-to-digital converter shall be at least 14 bits or greater to reduce uncertainty to less than 0.01% of the span.

4-8.1.1 Data Collection Systems. A data collection system should be designed to accept multiple instrument inputs and should be able to sample data from all the instruments within 1 min to 2 min to obtain all necessary data with the plant at the same condition. The system should be able to collect and store data and results within 2 min. All data collected shall be time stamped.

4-8.1.2 Data Calculations. Paragraph 5-1.2 discusses data reduction and calculations.

4-8.2 Data Management

4-8.2.1 Storage of Data. Signal inputs from the instruments should be stored to permit post-test data correction for application of new calibration corrections. The engineering units for each instrument along with the calculated results should be stored if developed onsite. Before leaving the test site, the parties to the test should store data to a removable medium to secure against equipment damage and loss of data during transport.

4-8.2.2 Manually Collected Data. Most test programs will require some data to be taken manually. The data sheets should each identify the data point, test site location, date, time, data collector, collection times, and data collected.

4-8.2.3 Distribution of Data. The data in engineering units should be available to all parties to the test before the parties leave the test site. All manually collected data should be made available to all parties to the test before the parties leave the test site.

4-8.3 Construction of Data Collection Systems

4-8.3.1 Design of Data Collection System Hardware. With advances in computer technology, data collection system configurations have a great deal of flexibility. They can consist of a centralized processing unit or distributed processing to multiple locations in the plant.

Each measurement loop must be designed with the ability to be loop calibrated separately. Each measurement loop should be designed so that it can individually be checked for continuity and power supply, if applicable, to locate problems during equipment setup.

Each instrument signal cable should be designed with a shield around the conductor and the shield should be grounded on one end to drain any stray induced currents.

4-8.3.2 Calibration of Data Collection Systems. When considering the accuracy of a measurement, the accuracy of the entire measurement loop must be considered. This includes the instrument and the signal conditioning loop or process. Ideally, when an instrument is calibrated, it should be connected to the position on the data collection system that will be employed during the test. Should this be impractical, each piece of equipment in the measurement loop should be individually calibrated. Separate pieces of equipment include current voltage sources and resistors in the measurement loop.

If the system is not loop calibrated before the test, parties to a test should be allowed to spot check the measurement loop using a signal generator to confirm that the combined inaccuracy of the measurement loop is within the expected value.

4-8.3.3 Use of Existing Plant Measurement and Control System. The Code does not prohibit the use of the plant measurement and control system for Code testing. However, this system must meet the requirements of this paragraph. Some areas of caution are as follows:

(a) Typically, plant measurement and control systems do not calculate flows in a rigorous manner. Often, the flow is based on a ratio relationship with compensation factors. Calculation of flow shall follow subsection 4-5.

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

(c) Some plant systems do not allow the instrument signal before conditioning to be displayed or stored. The raw signal must be available to check the signal-conditioning calculation for error.

(d) Distributed control systems typically only report changes or store values of a variable that exceed a set threshold value. The threshold value must be low enough so that all data signals sent to the distributed control system during a test are reported and stored.

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Section 5
Calculations

5-1 INTRODUCTION

5-1.1 General Discussion

The objective of these calculations is to determine the corrected capacity, gas-side pressure drop, and steam-side pressure drop. To predict the performance at test conditions, the GTE flow and composition must be determined. The approach of this Code is to calculate the GTE flow by calculating heat balances around both the GT and HRSG. These results are then used to predict the performance for the test conditions. These values are then combined using an uncertainty weighting procedure to establish a single predicted value.

The calculations deal mainly with the determination of GT gas flow and composition by means of an HRSG heat balance. Enough GT data are required to calculate the GT gas composition, which in turn allows for the determination of the gas enthalpies. If a duct burner is in operation during a test, the change in composition and heat input is also considered.

The airflow through the GT is the only unknown with GT fuel flow and injection streams being measured. The total heat given up by the gas is equal to the heat absorbed by the working fluid plus heat losses. In order to define the gas compositions entering and leaving the HRSG, the GT airflow is split into two streams: air for combustion and the balance of air. The air for combustion stream includes any changes for fuel combustion, steam or water injection, augmenting air, and atomizing steam. The flow and composition of this stream are defined. The balance of air stream is just moist air. The total heat is equal to the difference in gas enthalpy entering and exiting the HRSG multiplied by the flow for both streams.

With the calculated gas flow and composition along with other measured test data, the predicted capacity can be determined for the test conditions. The predicted capacity can then be compared to the measured capacity. These results can then be used to correct the measured capacity to the guaranteed conditions.

5-1.2 Data Reduction

Following the test, when all test logs and records have been completed and assembled, they should be critically examined to determine whether the limits of permissible variations have been exceeded. Inconsistencies in the test record or test results may require tests to be repeated in whole or part to attain the test objectives.

Test data should be reviewed for outliers in accordance with guidance provided in ASME PTC 19.1. The remaining data should be averaged to determine values for use in the calculations. These averaged data shall be used in the calculations to determine unit performance.

5-2 INTERMEDIATE CALCULATIONS

5-2.1 Air Composition Calculations

5-2.1.1 General. The inlet dry air molar composition is taken from GPA 2145-16 with slight adjustment to add up to 100%.

Constituent	% of Dry Air
Nitrogen	78.0858
Oxygen	20.940
Argon	0.9342
Carbon dioxide	0.04
	100.000

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The dry air composition is corrected for humidity and atmospheric pressure effects via humidity calculations taken from the ASHRAE Handbook of Fundamentals. This section determines the mass fractions and molar flows of the air constituents entering the GT.

5-2.1.2 Data Required. The following data are required for the air composition calculations:
(a) airflow, lb/hr
(b) atmospheric pressure, psia
(c) dry-bulb temperature, °F
(d) wet-bulb temperature, °F

5-2.1.3 Calculations

Step 1. Calculate the vapor pressure (psia) of water or ice at the wet-bulb temperature by the following equation:

$$\ln\left(P_v\right) \;=\; C_1/T_R + C_2 + C_3T_R + C_4{T_R}^2 + C_5{T_R}^3 + \; C_6{T_R}^4 + C_7\ln\left(T_R\right)$$

where $T_R = T_{\text{WB}} + 459.67$.

For a wet-bulb temperature less than or equal to 32°F, the constants for the vapor pressure of ice (over the temperature range of −148°F to 32°F) are as follows:
C_1 = −1.0214165 E+4
C_2 = −4.8932428
C_3 = −5.3765794 E−3
C_4 = 1.9202377 E−7
C_5 = 3.5575832 E−10
C_6 = −9.0344688 E−14
C_7 = 4.1635019

For the vapor pressure of water over the temperature range of 32°F to 392°F, the constants are as follows:
C_1 = −1.0440397 E+4
C_2 = −11.294650
C_3 = −2.7022355 E−2
C_4 = 1.2890360 E−5
C_5 = −2.4780681 E−9
C_6 = 0
C_7 = 6.5459673

Step 2. Calculate the saturated humidity ratio from the atmospheric pressure and vapor pressure by the following equation. [Reference data for correlation constant is ASHRAE Handbook of Fundamentals, Tables 2 and 3. Correlation error from −32°F to 120°F is 0.01% average, −0.05% minimum, and 0.10% maximum.]

$$\text{HR}_{\text{SAT}} = \frac{18.0153/28.9658 \times (1.00441333 \times P_V)}{(P_{\text{ATM}} - 1.00441333 \times P_V)}$$

Step 3. Calculate the actual humidity ratio from the saturated humidity ratio, wet-bulb temperature, and dry-bulb temperature by one of the following equations:
(a) For dry-bulb temperatures above 32°F

$$\text{HR} = \frac{(1{,}093 - 0.556 \times T_{\text{WB}}) \times HR_{\text{SAT}} - 0.24 \times (T_{\text{DB}} - T_{\text{WB}})}{1093 + 0.444 \times T_{\text{DB}} - T_{\text{WB}}}$$

(b) For dry-bulb temperatures below 32°F

$$\text{HR} = \frac{(1{,}220 - 0.4 \times T_{\text{WB}}) \times HR_{\text{SAT}} - 0.240 \times (T_{\text{DB}} - T_{\text{WB}})}{1{,}220 + 0.444 \times T_{\text{DB}} - 0.48 \times T_{\text{WB}}}$$

Step 4. Calculate the fraction of dry air from the actual humidity ratio by the following equation:

$$WF_{DA} = \frac{18.0153}{28.9658 \;\times \text{HR} + 18.0153}$$

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Step 5. Calculate the wet air mole fractions. The fraction of dry air multiplied by the dry air mole fraction will give the actual air constituent mole fraction.

(a) Nitrogen mole fraction

$$\mathrm{MF_{N2}} = \mathrm{WF_{DA}} \times 0.780858$$

(b) Oxygen mole fraction

$$\mathrm{MF_{O2}} = \mathrm{WF_{DA}} \times 0.2094$$

(c) Carbon dioxide mole fraction

$$\mathrm{MF_{CO2}} = \mathrm{WF_{DA}} \times 0.0004$$

(d) Argon mole fraction

$$\mathrm{MF_{Ar}} = \mathrm{WF_{DA}} \times 0.009342$$

The molar composition of water is 1 minus the fraction of dry air:

$$\mathrm{MF_{H2O}} = 1.0 - \mathrm{WF_{DA}}$$

Step 6. Calculate the air average molecular weight by the following equation:

$$\mathrm{MW_{AVG}} = \mathrm{MF_{N2}} \times 28.0134 + \mathrm{MF_{O2}} \times 31.9988 + \mathrm{MF_{CO2}} \times 44.0095 + \mathrm{MF_{H2O}} \times 18.0153 + \mathrm{MF_{Ar}} \times 39.9480$$

Step 7. Calculate the air molar flow by dividing the airflow by the average molecular weight. The air constituent molar flow is the air molar flow times the constituent mole fraction.

(a) Nitrogen molar flow

$$\mathrm{WM_{N2}} = \mathrm{MF_{N2}} \times W_A/\mathrm{MW_{AVG}}$$

(b) Oxygen molar flow

$$\mathrm{WM_{O2}} = \mathrm{MF_{O2}} \times W_A/\mathrm{MW_{AVG}}$$

(c) Carbon dioxide molar flow

$$\mathrm{WM_{CO2}} = \mathrm{MF_{CO2}} \times W_A/\mathrm{MW_{AVG}}$$

(d) Water molar flow

$$\mathrm{WM_{H2O}} = \mathrm{MF_{H2O}} \times W_A/\mathrm{MW_{AVG}}$$

(e) Argon molar flow

$$\mathrm{WM_{Ar}} = \mathrm{MF_{Ar}} \times W_A/\mathrm{MW_{AVG}}$$

Step 8. Calculate the air constituent weight fraction by multiplying the constituent mole fraction by its molecular weight and dividing it by the air average molecular weight.

(a) Nitrogen weight fraction

$$\mathrm{WF_{N2}} = \mathrm{MF_{N2}} \times 28.0134/\mathrm{MW_{AVG}}$$

(b) Oxygen weight fraction

$$\mathrm{WF_{O2}} = \mathrm{MF_{O2}} \times 31.9988/\mathrm{MW_{AVG}}$$

(c) Carbon dioxide weight fraction

$$\mathrm{WF_{CO2}} = \mathrm{MF_{CO2}} \times 44.0095/\mathrm{MW_{AVG}}$$

(d) Water weight fraction

$$\mathrm{WF_{H2O}} = \mathrm{MF_{H2O}} \times 18.0153/\mathrm{MW_{AVG}}$$

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(e) Argon weight fraction

$$WF_{Ar} = MF_{Ar} \times 39.9480/MW_{AVG}$$

5-2.2 Molar Flow Change Due to Fuel Gas Combustion

5-2.2.1 General. Paragraph 5-2.2 determines the molar flow change of the air or gas stream constituents due to the complete stoichiometric combustion of each compound of a fuel gas stream.

5-2.2.2 Data Required. The following data are required to calculate the composition of the product of fuel gas combustion:

(a) either fuel gas flow (pound per hour) or fuel gas flow [standard cubic feet per minute (scfm)] gas compressibility
(b) fuel gas constituent mole fraction

5-2.2.3 Table of Combustion Ratios. Table 5-2.2.3-1 shows the ratios of air constituent molar flow change per mole of fuel gas compound combusted. The molar flow of any inert compound in the fuel gas such as nitrogen or carbon dioxide passes directly into the combustion products on a mole-per-mole basis. The table values are determined from an oxidation chemical equation for a unit mole of fuel gas compound in accordance with the following generic oxidation equation:

$$C_xH_yS_z + (x + y/4 + z)O_2 = (x)CO_2 + (y/2)H_2O + (z)SO_2$$

The coefficients for oxygen must be negative because oxygen is consumed in the reaction.

5-2.2.4 Calculations

Step 1. Calculate the fuel gas average molecular weight by adding for all fuel gas compounds the product of the compound mole fraction and the compound molecular weight. Molecular weights for some typical compounds are listed in Section 2.

$$MW_{FG} = \sum \left(MF_i \times MW_i \right)$$

Step 2. Calculate the molar fuel gas flow by dividing the fuel gas mass flow by the fuel gas average molecular weight:

$$WM_{FG} = \frac{W_{FG}}{MW_{FG}}$$

Table 5-2.2.3-1
Combustion Ratios

Fuel Gas Compound	N_2	O_2	CO_2	H_2O	Ar	SO_2
CH_4	0	−2	1	2	0	0
C_2H_6	0	−3.5	2	3	0	0
C_2H_4	0	−3	2	2	0	0
C_3H_8	0	−5	3	4	0	0
C_3H_6	0	−4.5	3	3	0	0
C_4H_{10}	0	−6.5	4	5	0	0
C_5H_{12}	0	−8	5	6	0	0
C_6H_{14}	0	−9.5	6	7	0	0
N_2	1	0	0	0	0	0
CO	0	−0.5	1	0	0	0
CO_2	0	0	1	0	0	0
H_2O	0	0	0	1	0	0
H_2	0	−0. 5	0	1	0	0
H_2S	0	−1.5	0	1	0	1
He	0	0	0	0	0	0
O_2	0	1	0	0	0	0
SO_2	0	0	0	0	0	1
Ar	0	0	0	0	1	0

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Sometimes the fuel gas flow is known in terms of standard cubic feet per minute. If this is the case, the fuel gas molar flow can be determined by the following equation:

$$\mathrm{WM_{FG}} = \frac{V_{\mathrm{FG}} \times 60}{379.67 \times Z}$$

Step 3. Calculate the change in molar flow of nitrogen. Multiply the fuel gas molar flow by the mole fraction of nitrogen in the fuel gas.

Step 4. Calculate the change in molar flow of oxygen. Sum for all fuel gas compounds, the product of the fuel gas molar flow, the fuel gas compound mole fraction, and the fuel gas compound oxygen combustion ratio.

Step 5. Calculate the change in molar flow of carbon dioxide. Sum for all fuel gas compounds, the product of the fuel gas molar flow, the fuel gas compound mole fraction, and the fuel gas compound carbon dioxide combustion ratio.

Step 6. Calculate the change in molar flow of water. Sum for all fuel gas compounds, the product of the fuel gas molar flow, the fuel gas compound mole fraction, and the fuel gas compound water combustion ratio.

Step 7. Calculate the change in molar flow of argon. Multiply the fuel gas molar flow by the mole fraction of argon in the fuel gas.

Step 8. Calculate the change in molar flow of sulfur dioxide. Sum for all fuel gas compounds, the product of the fuel gas molar flow, the fuel gas compound mole fraction, and the fuel gas compound sulfur dioxide combustion ratio.

Step 9. The dry air for combustion is the change in molar flow of oxygen from Step 4 divided by the fraction of oxygen in dry air multiplied by dry air molecular weight. The moist airflow for combustion is the dry airflow multiplied by 1 plus the humidity ratio of air (para. 5-2.1.3, Step 3 or Step 5).

$$W_{\mathrm{AC}} = \frac{\Delta \mathrm{WM_{O_2}}}{0.20940} \times 28.9658 \times \mathrm{HR}$$

5-2.3 Molar Flow Change Due to Fuel Oil Combustion

5-2.3.1 General. Paragraph 5-2.3 determines the molar flow change of the air or gas stream constituents due to the complete stoichiometric combustion of each element of a fuel oil stream.

5-2.3.2 Data Required. The following data are required to calculate the composition of the product of fuel oil combustion:

(a) fuel oil flow, lb/hr
(b) fuel elemental weight fractions

5-2.3.3 Calculations

Step 1. Calculate the change in molar flow of nitrogen. Multiply the fuel oil flow by the elemental weight fraction of nitrogen in the fuel oil and divide by 28.0134.

Step 2. Calculate the change in molar flow of oxygen. Subtract from the oxygen weight fraction divided by 31.9988, the sum of the carbon weight fraction divided by 12.0107, the hydrogen weight fraction divided by 4.03176, and the sulfur weight fraction divided by 32.065. Multiply the result by the fuel oil flow:

$$\mathrm{WM_{O2}} = (\mathrm{WF_{O2}}/31.9988 - \mathrm{WF_C}/12.0107 - \mathrm{WF_H}/4.03176 - \mathrm{WF_S}/32.065) \times \mathrm{W_{FO}}$$

Step 3. Calculate the change in molar flow of carbon dioxide. Multiply the fuel oil flow by the carbon weight fraction in the fuel oil and divide by 12.0107.

Step 4. Calculate the change in molar flow of water. Multiply the fuel oil flow by the hydrogen weight fraction in the fuel oil and divide by 2.01588.

Step 5. There is no change in the molar flow of argon due to combustion.

Step 6. Calculate the change in molar flow of sulfur dioxide. Multiply the oil fuel flow by the sulfur weight fraction in the fuel oil and divide by 32.065.

Step 7. The dry air for combustion is the change in molar flow of oxygen from Step 2 divided by the fraction of oxygen in dry air multiplied by dry air molecular weight. The moist airflow for combustion is the dry airflow multiplied by 1 plus the humidity ratio of air (para. 5-2.1.3, Step 3 or Step 5).

$$\mathrm{W_{AC}} = \frac{\Delta \mathrm{WM_{O2}}}{0.20940} \times 28.9658 \times \mathrm{HR}$$

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Table 5-2.4.3-1
Fuel Compound Heating Values

Fuel Gas Compound	Heating Value, Btu/lb	
	Lower	Higher
CH_4	21,525	23,907
C_2H_6	20,443	22,349
C_2H_4	20,292	21,654
C_3H_8	19,936	21,669
C_3H_6	19,692	21,054
iso-C_4H_{10}	19,603	21,247
n-C_4H_{10}	19,671	21,316
iso-C_5H_{12}	19,469	21,058
n-C_5H_{12}	19,510	21,099
C_6H_{14}	19,406	20,958
N_2	0	0
CO	4,345	4,345
CO_2	0	0
H_2O	0	1,061
H_2S	6,538	7,099
H_2	51,586	61,064
He	0	0
O_2	0	0
SO_2	0	0
Ar	0	0

GENERAL NOTE: T_{Ref} = 60°F.

5-2.4 Fuel Gas Heating Value

5-2.4.1 General. The heat of combustion used in all calculations is the lower heating value. This is not to be confused with the higher heating value, which includes the heat of vaporization for water. The heating value for fuel gas is a calculated number based upon the fuel gas composition.

5-2.4.2 Data Required. The following data are required to calculate the composition of the products of fuel gas combustion:

(a) fuel gas compound mole fractions
(b) fuel gas temperature, °F

5-2.4.3 Fuel Compound Heating Value Table. Table 5-2.4.3-1 information is taken from GPA 2145-16. The heats of combustion are based upon 60°F and 14.696 psia.

5-2.4.4 Fuel Sensible Heat. Table 5-2.4.4-1 is taken from NASA correlations (NASA/TP–2002-211556) for fuel gas compound specific heat. The fuel gas constituent enthalpy from 60°F (288.71K) reference condition is determined by the following equation. The fuel gas enthalpy unit is British thermal units per pound. The temperature, *T*, is in Kelvin.

$$h\text{ compound} = \frac{\left(-\frac{a_1}{T} + a_2\ln(T) + a_3T + \frac{a_4T^2}{2} + \frac{a_5T^3}{3} + \frac{a_6T^4}{4} + \frac{a_7T^5}{5} - \mathrm{C}\right) \times 8341.51}{2.326 \times (\mathrm{MW\ compound})}$$

where

a_x = coefficients from Table 5-2.4.4-1 for the specific fuel gas compound
C = constituent constant from Table 5-2.4.4-1
T = temperature, K
= (temperature °F + 459.67)/1.8

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The fuel gas combined enthalpy is determined by the following equation:

$$h_{\mathrm{FG}} = \sum (\text{weight fraction})_i \, (h \text{ compound})_i$$

5-2.4.5 Calculations

Step 1. Calculate the total fuel gas molecular weight by summing the products of fuel gas compound mole fraction and compound molecular weight for all fuel gas compounds, *N*:

$$\mathrm{MW}_{\mathrm{FG}} = \sum\nolimits_1^N \mathrm{MF}_i \times \mathrm{MW}_i$$

Step 2. Calculate the fuel gas sensible heat for each gas constituent per para. 5-2.4.4.

Step 3. Calculate the weight fraction of each fuel gas compound, *i*, by computing the product of the fuel gas compound mole fraction and the fuel gas compound molecular weight and dividing by the total fuel molecular weight:

$$\mathrm{WF}_i = \mathrm{MF}_i \times \mathrm{MW}_i \div \mathrm{MW}_{\mathrm{FG}}$$

Step 4. Calculate the net heating value contribution of each compound by multiplying the compound weight fraction by the sum of the compound heating value and compound sensible heat.

5-2.5 Fuel Oil Heating Value

5-2.5.1 General. The heat of combustion used in all calculations is the lower heating value. This is not to be confused with the higher heating value, which includes the heat of vaporization for water. The heating value of the fuel oil at T = 60°F, 14.696 psia (standard conditions) shall be determined by a bomb calorimeter test performed in accordance with ASTM D4809.

5-2.5.2 Data Required. The following data are required for the fuel oil combustion products composition calculation:

(a) fuel oil heating value at standard conditions, Btu/lb

(b) fuel temperature, °F

5-2.5.3 Calculations

Step 1. The following equation is used to calculate the sensible heat content of the fuel oil. It is taken from Perry and Green (1997, pp. 27–10). See Nonmandatory Appendix B.

$$Q_{\mathrm{FS}} = T_F{}^2/4{,}132 + 0.417 \times T_F - 25.9$$

Step 2. The fuel net heating value, $\mathrm{HV}_{\mathrm{NET}}$, is the sum of the fuel oil ideal heating value, HV, (typically provided by laboratory analysis) and the fuel sensible heat:

$$\mathrm{HV}_{\mathrm{NET}} = \mathrm{HV} + Q_{\mathrm{FS}}$$

5-2.6 Gas Enthalpy

5-2.6.1 General. The gas stream enthalpy is a mass weighted value of the stream constituent enthalpies. The constituent enthalpy equations are derived from NASA correlations (NASA/TP–2002-211556).

5-2.6.2 Data Required. The following data are required to calculate the fuel gas products of combustion composition:

(a) gas temperature, °F

(b) gas constituent mass fractions

5-2.6.3 Enthalpy Equation Constants. The enthalpy is calculated for each constituent in a gas stream as a function of the gas temperature. The enthalpy correlations for each constituent are applicable from 200 K to 1,000 K. The correlations require the temperature to be in Kelvin.

$$h \text{ compound} = \frac{\left(-\dfrac{a_1}{T} + a_2\ln(T) + a_3T + \dfrac{a_4T^2}{2} + \dfrac{a_5T^3}{3} + \dfrac{a_6T^4}{4} + \dfrac{a_7T^5}{5} - \mathrm{C}\right) \times 8{,}341.51}{2.326 \times (\text{MW compound})}$$

where

a_x = coefficients from Table 5-2.4.4-1 for the specific fuel gas compound

C = constituent constant from Table 5-2.4.4-1

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T = temperature, K
= (temperature °F + 459.67)/1.8

5-2.6.4 Calculations

Step 1. Calculate the enthalpy for each gas constituent for the given temperature and appropriate correlation coefficients.

Step 2. The gas enthalpy is the sum of the products of the constituent enthalpy and constituent mass fraction for all constituents:

$$h_G = \mathrm{WF}_{\mathrm{N2}} \times \mathrm{h}_{\mathrm{N2}} + \mathrm{WF}_{\mathrm{O2}} \times h_{\mathrm{O2}} + \mathrm{WF}_{\mathrm{CO2}} \times h_{\mathrm{CO2}} + \mathrm{WF}_{\mathrm{H2O}} \times h_{\mathrm{H2O}} + \mathrm{WF}_{\mathrm{Ar}} \times h_{\mathrm{Ar}} + \mathrm{WF}_{\mathrm{SO2}} \times h_{\mathrm{SO2}}$$

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Table 5-2.4.4-1
Gas Enthalpy Correlation Constants

Fuel Gas Compound	**NASA Glenn Coefficients [Note (1)]**			
	a_1	a_2	a_3	a_4
CH_4	−1.766850998 E+05	2.786181020 E+03	−1.202577850 E+01	3.917619290 E−02
C_2H_4	−1.163605836 E+05	2.554851510 E+03	−1.609746428 E+01	6.625779320 E−02
C_2H_6	−1.862044161 E+05	3.406191860 E+03	−1.951705092 E+01	7.565835590 E−02
C_3H_6	−1.912462174 E+05	3.542074240 E+03	−2.114878626 E+01	8.901484790 E−02
C_3H_8	−2.433144337 E+05	4.656270810 E+03	−2.939466091 E+01	1.188952745 E−01
iso-C_4H_{10}	−3.834469330 E+05	7.000039640 E+03	−4.440026900 E+01	1.746183447 E−01
n-C_4H_{10}	−3.175872540 E+05	6.176331820 E+03	−3.891562120 E+01	1.584654284 E−01
iso-C_5H_{12}	−4.231903390 E+05	6.497189100 E+03	−3.681126970 E+01	1.532424729 E−01
n-C_5H_{12}	−2.768894625 E+05	5.834283470 E+03	−3.617541480 E+01	1.533339707 E−01
n-C_6H_{14}	−5.815926700 E+05	1.079097724 E+04	−6.633947030 E+01	2.523715155 E−01
CO	1.489045326 E+04	−2.922285939 E+02	5.724527170 E+00	−8.176235030 E−03
H_2	4.078323210 E+04	−8.009186040 E+02	8.214702010 E+00	−1.269714457 E−02
H_2S	9.543808810 E+03	−6.875175080 E+01	4.054921960 E+00	−3.014557336 E−04
He	0.000000000 E+00	0.000000000 E+00	2.500000000 E+00	0.000000000 E+00
N_2	2.210371497 E+04	−3.818461820 E+02	6.082738360 E+00	−8.530914410 E−03
O_2	−3.425563420 E+04	4.847000970 E+02	1.119010961 E+00	4.293889240 E−03
CO_2	4.943650540 E+04	−6.264116010 E+02	5.301725240 E+00	2.503813816 E−03
H_2O	−3.947960830 E+04	5.755731020 E+02	9.317826530 E−01	7.222712860 E−03
SO_2	−5.310842140 E+04	9.090311670 E+02	−2.356891244 E+00	2.204449885 E−02
Ar	0.000000000 E+00	0.000000000 E+00	2.500000000 E+00	0.000000000 E+00

NOTE: (1) NASA Glenn coefficients are from NASA/TP–2002-211556.

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Table 5-2.4.4-1
Gas Enthalpy Correlation Constants

Fuel Gas Compound	NASA Glenn Coefficients [Note (1)]			
	a_5	a_6	a_7	C for T_{ref} = 60°F
CH_4	−3.619054430 E−05	2.026853043 E−08	−4.976705490 E−12	1.430052942 E+04
C_2H_4	−7.885081860 E−05	5.125224820 E−08	−1.370340031 E−11	1.244224759 E+04
C_2H_6	−8.204173220 E−05	5.061135800 E−08	−1.319281992 E−11	1.688537355 E+04
C_3H_6	−1.001429154 E−04	6.267959390 E−08	−1.637870781 E−11	1.763270058 E+04
C_3H_8	−1.376308269 E−04	8.814823910 E−08	−2.342987994 E−11	2.273078405 E+04
iso-C_4H_{10}	−2.078195348 E−04	1.339792433 E−07	−3.551681630 E−11	3.399640145 E+04
n-C_4H_{10}	−1.860050159 E−04	1.199676349 E−07	−3.201670550 E−11	3.016395747 E+04
iso-C_5H_{12}	−1.548790714 E−04	8.749897120 E−08	−2.070547710 E−11	3.293520959 E+04
n-C_5H_{12}	−1.528395882 E−04	8.191092000 E−08	−1.792327902 E−11	2.886798932 E+04
n-C_6H_{14}	−2.904344705 E−04	1.802201514 E−07	−4.617223680 E−11	5.247972126 E+04
CO	1.456903469 E−05	−1.087746302 E−08	3.027941827 E−12	−2.960314454 E+02
H_2	1.753605076 E−05	−1.202860270 E−08	3.368093490 E−12	−2.715200551 E+03
H_2S	3.768497750 E−06	−2.239358925 E−09	3.086859108 E−13	7.620139053 E+02
He	0.000000000 E+00	0.000000000 E+00	0.000000000 E+00	7.217638889 E+02
N_2	1.384646189 E−05	−9.625793620 E−09	2.519705809 E−12	−7.439261766 E+02
O_2	−6.836300520 E−07	−2.023372700 E−09	1.039040018 E−12	3.358109354 E+03
CO_2	−2.127308728 E−07	−7.689988780 E−10	2.849677801 E−13	−2.088054505 E+03
H_2O	−7.342557370 E−06	4.955043490 E−09	−1.336933246 E−12	3.916796713 E+03
SO_2	−2.510781471 E−05	1.446300484 E−08	−3.369070940 E−12	5.394623639 E+03
Ar	0.000000000 E+00	0.000000000 E+00	0.000000000 E+00	7.217638889 E+02

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5-2.7 GT Gas Composition

5-2.7.1 General. The GT gas composition must be determined in order to determine the gas enthalpy. The composition is the summation of the GT inlet air and steam or water injection plus the changes due to the combustion of the fuel.

5-2.7.2 Data Required. The following data are required to determine the combined excess air and combustion product composition:
(a) airflow, lb/hr
(b) steam or water injection, lb/hr
(c) fuel flow, lb/hr
(d) air molar flow, mol/hr (para. 5-2.1.3, Step 7)
(e) change in molar flow, mol/hr (para. 5-2.2.4, Steps 3 and 8 for fuel gas; para. 5-2.3.3, Steps 1 and 6 for fuel oil)

5-2.7.3 Calculations

Step 1. Calculate the molar flow of steam or water injected by dividing the injection flow by 18.01528.
Step 2. The nitrogen molar flow is the sum of the nitrogen molar flow from the air and the change in molar flow of nitrogen from the combustion of the fuel.
Step 3. The oxygen molar flow is the sum of the oxygen molar flow from the air and the change in molar flow of oxygen from the combustion of the fuel.
Step 4. The carbon dioxide molar flow is the sum of the carbon dioxide molar flow from the air and the change in molar flow of carbon dioxide from the combustion of the fuel.
Step 5. The water molar flow is the sum of the water molar flow from the air, the change in molar flow of water from the combustion of the fuel, and the steam or water injection molar flow.
Step 6. The argon molar flow is the argon molar flow from the air.
Step 7. The sulfur dioxide flow is the molar flow of water from the combustion of the fuel.
Step 8. The GT gas mass flow is the sum of the airflow, the fuel flow, and the steam or water injection flow.
Step 9. Calculate the gas constituent mass fractions. A gas constituent mass fraction is the constituent molar flow multiplied by the constituent molecular weight divided by the total gas mass flow.

5-2.8 Desuperheater Spray Water Flow by Heat Balance

5-2.8.1 General. The spray water flow should be directly measured by means of a flowmeter. A less desirable alternative is to establish the water flow by heat balance. Note that the water temperature should be measured close to the spray point. The water temperature can vary significantly from that of the water source.

The steam flow to the desuperheater is taken as the feedwater flow. This assumes that there is no blowdown or other water extractions after the feedwater flowmeter.

5-2.8.2 Data Required. The following data are required to calculate the desuperheater heat balance:
(a) steam temperature before water spray, °F
(b) steam temperature after water spray, °F
(c) steam pressure at spray point, psig or psia
(d) spray water temperature, °F
(e) spray water pressure, psig or psia
(f) feedwater flow, lb/hr

5-2.8.3 Calculations

Step 1. The enthalpy for the steam before the desuperheater is determined based on the steam temperature before the desuperheater and the steam pressure.
Step 2. The enthalpy for the steam after the desuperheater is determined based on the steam temperature after the desuperheater and the steam pressure.
Step 3. The water enthalpy is determined based on the water temperature and pressure.
Step 4. The spray water flow is equal to the feedwater flow multiplied by the difference of steam enthalpy before desuperheater and the steam enthalpy after desuperheater divided by the difference of the steam enthalpy after desuperheater and the spray water enthalpy:

$$\text{spray water flow} = \frac{\text{feedwater flow} \times (h_{\text{steam before}} - h_{\text{steam after}})}{h_{\text{steam before}} - h_{\text{spray water}}}$$

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5-2.9 Extraction Flow by Heat Balance

5-2.9.1 General. Any stream flow crossing the test boundary should be determined by direct measurement. A less desirable alternative is to establish a flow by heat balance. For example, an extraction stream could be a water flow extraction used to preheat a fuel gas in an external heat exchanger. For this approach, all terminal temperatures, pressures, and the fuel gas stream flow must be known with the only unknown being the extraction water flow.

5-2.9.2 Data Required. The following data are required to determine extraction flow by heat balance around an external heat exchanger such as a fuel gas heater:

(a) water inlet temperature, °F
(b) water outlet temperature, °F
(c) water inlet pressure, psig or psia
(d) water outlet pressure, psig or psia
(e) nonwater stream flow, lb/hr
(f) nonwater stream inlet temperature, °F
(g) nonwater stream outlet temperature, °F
(h) nonwater stream specific heat, Btu/lb-°F

5-2.9.3 Calculations

Step 1. The water inlet/outlet enthalpies are calculated for the inlet/outlet temperature and pressure conditions.

Step 2. The heat transferred to the nonwater stream is equal to the stream flow times the specific heat multiplied by the difference between the outlet temperature and the inlet temperature.

Step 3. The extraction water flow is equal to the heat transferred divided by the difference between the water inlet enthalpy and outlet enthalpy.

5-3 GAS FLOW BY HRSG ENERGY BALANCE

5-3.1 HRSG Gas Flow Calculations

5-3.1.1 General. Gas flow is determined by an energy balance. The heat into the HRSG is the energy associated with the GT exhaust, any duct burner stream, and the working fluid entering the HRSG. The heat from the HRSG is the energy associated with the gas heat from the HRSG, the working fluid leaving the HRSG, and heat losses. The energy balance is

$$Q_{G\ IN} + Q_{DB} + Q_{AA} + Q_{AS} + Q_{WF\ IN} = Q_{G\ OUT} + Q_{WF\ OUT} + Q_{HL}$$

Each term is quantified except for the gas energy in and out. These are defined as the gas flow multiplied by the inlet and outlet gas enthalpy, respectively. The gas flow is the airflow into the GT plus the GT fuel flow and any GT injection stream flow. The airflow being an unmeasured stream is thus the only unknown.

The heat for the gas in and gas out is split into two streams: one stream for fuel combustion plus any other added stream, and one stream for the balance of air in excess of that required for combustion. For the combustion stream, the gas flow and composition into the HRSG is based upon the stoichiometric combustion of the GT fuel and any steam or water injection. Any duct burner stream can be added to the combustion stream so that the gas outlet flow and composition is also defined. The heat flow for this stream in and out of the HRSG can then be determined.

The balance of air stream has the composition of moist air, so the enthalpies in and out of the HRSG are known. The balance of airflow can then be directly determined. The incoming gas flow is the sum of the balance of airflow and the combustion stream into the HRSG. The reference temperature for the calculations is 60°F.

5-3.1.2 Data Required. The following data are required to determine the exhaust flow through an HRSG by a heat balance around the HRSG:

(a) Ambient Conditions
  (1) either wet-bulb temperature, °F, or relative humidity, %
  (2) dry-bulb temperature, °F
  (3) barometric pressure, psia
(b) GT Data
  (1) fuel flow, lb/hr or scfm
  (2) gas compressibility
  (3) fuel composition
  (4) steam or water injection flow, lb/hr

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(c) working fluid duty, Btu/hr
(d) *HRSG Data*
  (1) gas inlet temperature, °F
  (2) gas outlet temperature, °F
  (3) heat loss, Btu/hr
(e) *Duct Burner Data*
  (1) fuel flow, lb/hr
  (2) fuel temperature, °F
  (3) fuel composition
  (4) fuel heating value (oil), Btu/lb
  (5) atomizing steam flow, lb/hr
  (6) atomizing steam enthalpy, Btu/lb
  (7) augmenting airflow, lb/hr
  (8) augmenting air temperature, °F

5-3.1.3 Calculations. The calculations consist of a series of steps, many of which involve calculations performed in other sections.

Step 1. The air composition is determined from the ambient conditions as described in para. 5-2.1.

Step 2. The change in molar flow due to the combustion of the GT fuel is calculated as described in para. 5-2.2 for fuel gas and para. 5-2.3 for fuel oil. The wet airflow for combustion is also determined.

Step 3. If there is a duct burner, the change in molar flow due to the combustion of the duct burner fuel is calculated as described in para. 5-2.2 for fuel gas and para. 5-2.3 for fuel oil using the wet airflow for combustion.

Step 4. If there is a duct burner, the duct burner fuel heating value including the sensible heat of the fuel is determined in para. 5-2.4 for gas and para. 5-2.5 for oil.

Step 5. The inlet gas composition is calculated using the total wet airflow for combustion as determined in Steps 2 and 3 and adding the change in molar flow due to the combustion of fuel in the GT from Step 2 only. The inlet gas composition must also include the molar flow of steam or water injection into the GT. The gas constituent mass fractions can then be calculated. These calculations are described in para. 5-2.7. The combustion gas inlet mass flow is the sum of the combustion wet airflow, the GT fuel flow, and any steam or water injection flow.

Step 6. The gas enthalpy at the HRSG inlet is calculated in para. 5-2.6 with the gas constituents' mass fractions as determined from Step 5 and the HRSG gas inlet temperature.

Step 7. If there is a duct burner, go to Step 8. Otherwise, the gas enthalpy at the HRSG outlet is calculated as described in para. 5-2.6 with the same gas constituents' mass fractions determined in Step 5 and the HRSG gas outlet temperature. Skip to Step 11.

Step 8. The HRSG outlet gas composition is calculated using the GT molar flows determined in Step 5 and adding the change in molar flow due to the combustion of the duct burner fuel from Step 3. The HRSG outlet gas molar flow must also include the molar flow of air or steam associated with the burner operation. The gas constituent mass fractions can then be calculated. These calculations are described in para. 5-3.2.

Step 9. The gas enthalpy at the HRSG outlet is calculated in para. 5-2.6 with the gas constituents' mass fractions from Step 8 and the HRSG gas outlet temperature.

Step 10. The duty associated with any stream injected into the gas stream such as augmenting air or atomizing steam must be calculated by multiplying the stream flow by the stream enthalpy. The air enthalpy described in para. 5-2.6 is calculated using the air composition from Step 1 for the given air temperature. For steam atomization, the steam enthalpy is determined by subtracting 1087.734 Btu/lb from the steam table enthalpy to adjust to the reference temperature of steam at 60°F. The fuel and injected stream mass flows must be added to the combustion gas stream mass flow.

Step 11. The working fluid duty must be included. A theoretical system envelope around the HRSG is defined in subsection 2-4. The duty is the stream flow multiplied by its enthalpy. The duty associated with a stream crossing the boundary going to the HRSG is negative. The duty with a stream leaving the HRSG is positive. The streams will typically be water or steam, and IAPWS R7-97(2012) shall be used to determine the stream enthalpy. Sometimes stream flows are not measured directly. They can be determined by heat balance (see paras. 5-2.8 and 5-2.9).

Step 12. The HRSG heat loss is estimated in para. 5-3.3.

Step 13. The balance of airflow is now the only unknown parameter in the heat balance equation and can be directly solved:

$$\text{energy in} = \text{energy out}$$

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$$W_{BA} \times h_{A\ IN} + W_{G\ IN} \times h_{G\ IN} + W_{DB} \times HV_{NET} + W_{AA} \times h_{A} + W_{AS} \times h_{AS} + Q_{WF\ IN}$$
$$= Q_{WF\ OUT} + Q_{HL} + (W_{G\ IN} + W_{DB} + W_{AA} + W_{AS}) \times h_{G\ OUT} + W_{BA} \times h_{A\ OUT}$$

Step 14. The total gas flow into the HRSG is the sum of the balance of airflow from Step 13 and the combustion gas inlet flow from Step 5.

Step 15. The balance of air inlet constituent molar flow is determined by dividing the flow by the air molecular weight determined in para. 5-2.1.3, Step 7 and multiplying by the constituent mole fraction for each constituent from para. 5-2.1.3, Step 8. The combustion gas constituent molar flow is added to the balance of air constituent molar flow to determine the total inlet constituent molar flow. The inlet constituent mole fraction for each constituent is the constituent molar flow divided by the sum of molar flows for all constituents.

5-3.2 Duct Burner Gas Composition

5-3.2.1 General. The gas composition after the duct burner must be determined in order to determine the gas enthalpy out of the HRSG. The composition is a function of the gas and duct burner streams plus the changes due to the combustion of the duct burner fuel.

5-3.2.2 Data Required

(a) GT gas flow, lb/hr
(b) atomizing steam, lb/hr
(c) augmenting airflow, lb/hr
(d) air molecular weight (para. 5-2.1.3, Step 6)
(e) duct burner fuel flow, lb/hr or scfm gas compressibility
(f) gas molar flow, mol/hr (para. 5-2.7.3, Steps 2 and 7)
(g) air mole fraction (para. 5-2.1.3, Step 7)
(h) change in molar flow, mol/hr (para. 5-2.2.4, Steps 3 and 8 for fuel gas; para. 5-2.3.3, Steps 1 and 6 for fuel oil)

5-3.2.3 Calculations

Step 1. Calculate the molar flow of augmenting steam by dividing the flow by 18.01528.

Step 2. The nitrogen molar flow is the sum of the nitrogen molar flow from the GT gas, the change in molar flow of nitrogen for the combustion of the fuel, and the augmenting airflow multiplied by the nitrogen mole fraction in air divided by the air molecular weight.

Step 3. The oxygen molar flow is the sum of the oxygen molar flow from the GT gas, the change in molar flow of oxygen from the combustion of the fuel, and the augmenting airflow multiplied by the oxygen mole fraction in air divided by the air molecular weight.

Step 4. The carbon dioxide molar flow is the sum of the carbon dioxide molar flow from the GT gas, the change in molar flow of carbon dioxide from the combustion of the fuel, and the augmenting airflow multiplied by the carbon dioxide mole fraction in air divided by the air molecular weight.

Step 5. The water molar flow is the sum of the water molar flow from the GT gas, the change in molar flow of water from the combustion of the fuel, the atomizing steam molar flow, and the augmenting airflow multiplied by the water mole fraction in air divided by the air molecular weight.

Step 6. The argon molar flow is the sum of the argon molar flow for the GT gas and the augmenting airflow multiplied by the argon mole fraction in air divided by the air molecular weight.

Step 7. The sulfur dioxide molar flow is the sum of the sulfur dioxide molar flow from the GT gas and the change in molar flow of sulfur dioxide from the combustion of the fuel.

Step 8. The duct burner gas mass flow is the sum of the GT gas flow, the duct burner fuel flow, the augmenting airflow, and the atomizing steam flow.

Step 9. Calculate the duct burner constituent mass fractions. The duct burner gas constituent mass fraction is the constituent molar flow multiplied by the constituent molecular weight divided by the total duct burner gas mass flow.

5-3.3 HRSG Heat Loss

The HRSG heat loss should be agreed to by the parties to a test. The heat loss can be estimated as a function of the total heat loss of the exhaust in millions of British thermal units per hour:

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$$Q_G = W_G \times (h_{G\,\mathrm{IN}} - h_{G\,\mathrm{OUT}}) \div 10^6$$

The heat loss is approximated by the following equation:

$$Q_{\mathrm{HL\%}} = 0.2733 \times \exp\left(\frac{120.8}{Q_G}\right)$$

$$Q_{\mathrm{HL}} = \frac{Q_{\mathrm{HL\%}}}{100} \times Q_G$$

The heat loss should be limited to a maximum of 0.5%. The test uncertainty analysis typically does not warrant detailed calculations. The heat loss estimate would be for typical systems. Unusual cases may require additional calculations. More guidance for determining heat loss is available in Nonmandatory Appendix C.

5-4 GAS FLOW BY GT ENERGY BALANCE

The gas flow is determined by an energy balance around the GT. The energy into the system is from the fuel, air, and injection streams to the GT. The energy from the system is from the gas leaving the GT, electrical energy generated, bleed air, and heat losses.

$$\text{energy in} = \text{energy out}$$
$$Q_{G\,\mathrm{IN}} + Q_F + Q_I = Q_P + Q_{\mathrm{HL}} + Q_{G\,\mathrm{OUT}} + Q_B$$

Each term associated with these energy flows is quantified except for the gas flow. The unknown portion of the gas flow is the airflow into the GT. The heat for the gas in and gas out is split into two streams: one stream for fuel combustion and any other added stream, and the balance of air stream. For the combustion stream, the airflow into the GT is based upon the stoichiometric combustion of the GT fuel. The injection stream, bleed stream, and fuel flow and composition effects can be added to the inlet air stream so that the gas outlet flow and composition is also defined. The heat flow for this stream in and out of the HRSG can then be determined.

The balance of air stream has the composition of moist air so the enthalpies in and out of the GT are known. The balance of airflow can then be directly determined. The gas flow in is the sum of the balance of airflow and the combustion stream into the HRSG. The gas outlet composition is determined from the constituent molar flows of both gas outlet streams. The calculations for this method are in ASME PTC 22.

5-5 CORRECTION OF TEST CONDITIONS TO GUARANTEE

5-5.1 Correction of Steam Flow for Superheat

Steam flow must be corrected for the superheated steam outlet temperature in order to compare measured and predicted steam flows. Differences in heat absorbed in a superheater create differences in heat available in evaporator sections. It is not the intent of this correction to adjust the steam temperature for the purpose of comparison to a predicted steam temperature, rather only to adjust the flow on a consistent energy basis.

The excess energy in the steam is calculated by multiplying the measured steam flow by the difference in the measured and predicted steam outlet enthalpy. The steam flow adjustment that is added to the measured flow is the excess energy divided by the difference in predicted steam outlet enthalpy and the inlet feedwater enthalpy for the same pressure level. This correction is made before correcting to reference conditions.

5-5.2 Capacity

Once a test has been performed, the gas flow and composition can be computed by heat balance. The steam capacity (flow and temperature) can then be predicted for the test conditions. The predicted steam capacity is dependent upon all the factors necessary to originally design the HRSG. The performance factors include

(a) gas flow
(b) gas temperature
(c) gas composition
(d) duct burner heat input
(e) feedwater inlet temperature for all pressure levels
(f) steam or water outlet pressure for all pressure levels

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Predicted steam temperatures and flows for a test serve as comparative values to what was actually measured. Two different methods can be used to predict the steam capacity. One method utilizes correction curves. This method consists of a series of curves that reflect the impact of each performance parameter on the steam flow or temperature of each pressure level. The impact on steam flow or temperature can be presented as a multiplier or absolute difference. The steam flow or temperature corrections for each performance parameter are the product of the reference flow or temperature and all the other corrections in the case of percentages. In the case of an absolute difference, the reference flow or temperature is added to each of the corrections. The resultant steam flow and temperatures represent the predicted values for the test conditions. This approach is not recommended for multiple-pressure HRSGs.

The other method consists of a computer model of the HRSG heat transfer sections. This model can predict the steam capacity that should be produced for the test conditions. A computer model has the advantage of considering all performance factors simultaneously. It also considers any secondary interaction effects between performance factors. A computer model can better predict results with factors quite different than originally specified conditions.

Once the predicted capacity is established for the test conditions, it can be compared to the corrected measured value. The predicted value is the uncertainty-weighted value as calculated in subsection 5-5. The ratio between the measured and predicted capacities is assumed to be equal to the ratio of the true capacity to the reference condition capacity. The basic process is illustrated in Figure 5-5.2-1.

5-5.3 Duct Burner Fuel Flow

The correction of results for duct burner fuel flow is a special case of the correction of results. For this case, the duct burner fuel flow rate is adjusted in order to achieve an established steam flow. It must be clear that during the test, the fuel flow is adjusted to a pre-established set point. The predicted fuel flow is dependent upon all the factors necessary to originally design the HRSG. The performance factors include

(a) gas flow
(b) gas temperature
(c) gas composition
(d) steam flow and temperature for all pressure levels
(e) feedwater inlet temperature for all pressure levels
(f) steam or water outlet pressure for all pressure levels

The correction curve method consists of a series of curves that show the impact of each performance parameter on duct burner fuel flow. The impact on fuel flow can be presented as a multiplier or absolute difference. The duct burner fuel flow corrections for each performance parameter are the product of the reference flow or temperature and all the other corrections in the case of percentages. In the case of an absolute difference, the reference fuel flow is added to each of the corrections. The resultant fuel flow represents the predicted values for the test conditions. This approach is not recommended for multiple-pressure HRSGs.

The other method consists of a computer model of the HRSG heat transfer sections. A computer model can predict the fuel flow for any set of performance parameters. It has the advantage of considering all performance factors simultaneously. It can also consider any secondary interaction effects between performance factors. A computer model can better predict results with factors quite different than originally specified conditions.

Once the fuel flow is established for the test conditions, it can be compared to the corresponding measured value. The measured value is the uncertainty-weighted value as calculated in subsection 5-5. The ratio between the measured and predicted capacities is assumed to be equal to the ratio of the true capacity to the reference condition capacity.

5-5.4 Gas-Side Pressure Drop

5-5.4.1 General. The pressure drop is a function of the GTE flow and gas density and thus requires corrections for these parameters. The density is a function of the gas temperature through the HRSG, GTE composition, and pressure. The most accurate method to predict the pressure drop for the test conditions is to use a computer model or detailed manual calculation. In the absence of these approaches, the method described in 5-5.4.3 can be used. The assumption for this method is that the gas average temperature through the HRSG is the same as the reference conditions. If the temperatures vary from the reference conditions such as the difference between a duct-fired and unfired case, the method described in 5-5.4.3 should not be used.

5-5.4.2 Data Required. The following data are required for test and reference conditions:

(a) GTE flow, lb/hr
(b) GTE molecular weight
(c) atmospheric pressure, psia
(d) gas pressure drop, in. H_2O

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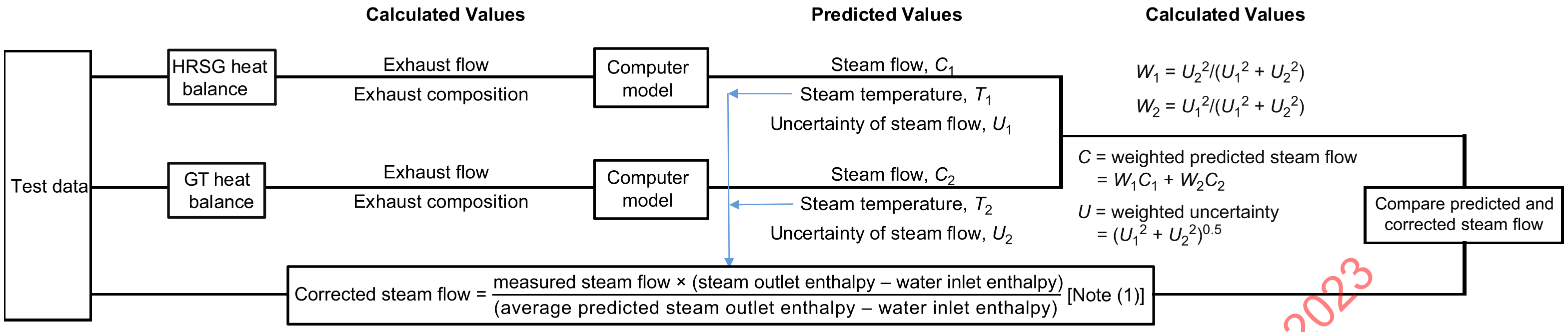
Figure 5-5.2-1
Measured Capacity Comparison to Predicted Capacity



NOTE: (1) Average predicted steam outlet enthalpy is a function of $(T_1 + T_2)/2$ and outlet pressure.

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5-5.4.3 Calculations. The gas pressure drop of the test is corrected by multiplying the measured pressure drop by the ratio of reference GTE flow divided by the test GTE flow squared. This product is multiplied by the atmospheric pressure of the test divided by the reference atmospheric pressure. This product is multiplied by the test GTE molecular weight divided by the reference gas molecular weight. The atmospheric pressure approximates the average gas pressure in the HRSG.

$$\mathrm{DP_{Cor}} = \mathrm{DP_{Test}} \times (W_{G\ \mathrm{Ref}}/W_{G\ \mathrm{Test}})^2 \times P_{\mathrm{ATM\ Test}}/P_{\mathrm{ATM\ Ref}} \times \mathrm{MW}_{G\ \mathrm{Test}}/\mathrm{MW}_{G\ \mathrm{Ref}}$$

The $\mathrm{DP_{Cor}}$ is calculated using the gas flows determined from the GT and HRSG heat balances. The corrected gas pressure drop is determined by the weighting process described in subsection 5-5.

5-5.5 Steam-Side Pressure Drop

5-5.5.1 General. The steam- or water-side pressure drop usually is not a critical factor in the design of an HRSG. The pressure drop is a function of the steam or water flow and the associated density and thus requires corrections for these parameters. The density is a function of the temperatures and operating pressures through the HRSG. The most accurate method to predict the pressure drop for the test conditions is to use a computer model or detailed manual calculation. This is especially true for coil sections for superheating steam that can be impacted by desuperheater spray flow conditions. Extractions or additions of flow can also have a significant impact. In the absence of these methods, the approach described in 5-5.5.3 can be used. The assumption for this method is that the average steam or water temperatures through the HRSG are the same as reference conditions.

A reheater would be synonymous with a superheater in the calculations of 5-5.5.3. The calculations of 5-5.5.3 are not applicable to all situations; for example, a forced circulation evaporator or two-phase flow exiting economizers are special cases that must use methods beyond the scope of this test Code.

5-5.5.2 Data Required. The following data are required for both the test and reference conditions:

(a) pressure drop in coil sections and piping for superheating steam, psig
(b) outlet pressure of sections for superheating steam, psig
(c) inlet pressure of sections for superheating steam, psig
(d) outlet temperature of superheater, °F
(e) inlet temperature of superheater, °F
(f) pressure drop in sections and piping for heating water, psig
(g) steam or water flow, lb/hr

5-5.5.3 Calculations

Step 1. The average steam density is determined from IAPWS R7-97(2012) using the average of the superheater inlet and outlet pressure and average of the superheater inlet and outlet temperature. The density must be determined for both the test and reference conditions.

Step 2. The pressure drop in coils for superheated steam is proportional to the steam flow squared and inversely proportional to the average steam density. The corrected pressure drop in the steam coils is equal to the measured pressure drop multiplied by the ratio of reference flow divided by the measured flow squared, multiplied by the test average density divided by the reference average density:

$$\mathrm{DP}_{S\ \mathrm{Cor}} = \mathrm{DP}_{S\ \mathrm{Test}} \times (W_{S\ \mathrm{Ref}}/W_{S\ \mathrm{Test}})^2 \times (\rho_{S\ \mathrm{Test}}/\rho_{S\ \mathrm{Ref}})$$

Step 3. The pressure drop in coils for heating water is proportional to the water flow squared. The corrected pressure drop in the water coils is equal to the measured pressure drop multiplied by the ratio of reference flow divided by the measured flow squared:

$$\mathrm{DP}_{W\ \mathrm{Cor}} = \mathrm{DP}_{W\ \mathrm{Test}} \times (W_{W\ \mathrm{Ref}}/W_{W\ \mathrm{Test}})^2$$

Step 4. The total corrected pressure drop is the sum of the steam coils' pressure drop and the water coils' pressure drop.

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Section 6
Report of Results

The report should formally and clearly present the pretest agreements and the observed data, calculations, and results. The table of contents shall include the following major sections and subsections as needed. The report should include persons preparing and approving the report.

6-1 SECTION 1: EXECUTIVE SUMMARY

The executive summary should consist of a single page noting the objectives, actual test results, corrected test results, guarantee requirements, conclusions, uncertainty of the test, and any deviations from the test procedure. It should also include a statement that the corrected test results are believed to be correct and that the post-test uncertainty is within the agreed-upon allowance for uncertainty.

6-2 SECTION 2: INTRODUCTION

The introduction should consist of the following:

(a) a description of the HRSG, including nameplate data of the HRSG and auxiliary equipment involved in the test

(b) the objectives of the test, i.e., to verify guarantees or establish performance at specified conditions

(c) a description of the age, operating history, and condition of the HRSG, instrumentation, and auxiliary equipment at the time of the test, including any items that may affect the test results

(d) date and time of day of the test, along with names, titles, and affiliations of the personnel directing, conducting, witnessing, and determining results of the test

6-3 SECTION 3: TEST DATA

The test data section should provide a summary of actual measurements and observations, a complete description of date and time, and any methods of testing or measurement, including any differences from the pretest agreement prescribed by this Code.

6-4 SECTION 4: DATA REDUCTION, CORRECTIONS, AND RESULTS

Data reduction, corrections, and results should include the following:

(a) a description of the final test data reduction methods used and test data reduction

(b) the uncorrected test results, including calculations to establish performance at the actual test conditions

(c) the corrected test results, including calculations, factors, or methods used for correcting the actual test results to the specified or guaranteed operating and performance conditions

(d) a post-test uncertainty analysis

(e) a check for test condition stability

(f) a discussion of the tests, results, and conclusions, including test observations and descriptions of any differences from the procedures and methods agreed to or allowed by this Code, and the resolution of the differences

6-5 SECTION 5: APPENDICES

The appendices should include the following:

(a) the pretest agreement and any modifications to the pretest agreement

(b) the pretest and post-test uncertainty analyses.

(c) the design and performance data that the test is to verify.

(d) any sketches or data required to describe and show locations of any temporary testing equipment or instruments used in the test.

(e) flow element data sheets for those flow elements used during the test with tap set identified. These sheets should include the physical data of the flow element such as pipe diameter, bore diameter, pipe and element material specifications, and any calibration reports for the element. This information shall be included for all meters and elements for the test, both permanent and temporary.

(f) the instrument calibration methods used and calibration data for instrumentation used in the test with appropriate approval initials.

(g) the raw test data.

(h) any other supporting information required to make the report a complete, self-contained document of the entire undertaking.

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Section 7
Test Uncertainty

7-1 INTRODUCTION

(a) Test uncertainty is an estimate of the limit of error of a test result. It is the interval about a test result that contains the true value with a given probability or level of confidence. It is based on calculations utilizing probability theory, instrumentation information, calculation procedure, and actual test data. ASME PTC 4.4 requires that uncertainty be reported with a 95% level of confidence.

An uncertainty analysis provides numerical estimates of systematic uncertainties, random uncertainties, and the combination of these into a total uncertainty with an approximate confidence level. Measurement uncertainty analysis is useful because it

(1) identifies dominant sources of error, their effects on a test result, and estimates of their limits and uncertainties

(2) facilitates communication regarding measurement results

(3) facilitates the choice of appropriate and cost-effective measurement devices and procedures

(4) reduces the risk of making erroneous decisions

(5) demonstrates compliance with agreements

(b) This Code addresses test uncertainty in the following four Sections:

(1) Section 1 defines maximum allowable test uncertainties above which the test is not acceptable for each type or configuration of power plant. The maximum uncertainty presented in Section 1 is a limit and is not a target in designing a test.

(2) Section 3 defines the requirements for pretest and post-test uncertainty analyses and how they are used in the test. These uncertainty analyses and limits of error are defined and discussed in para. 3-6.4.1.

(3) Section 4 describes the systematic uncertainty required for each test measurement.

(4) Section 7 and Nonmandatory Appendix D provide applicable guidance for calculating pretest and post-test uncertainty.

7-2 PRINCIPLES OF AN UNCERTAINTY ANALYSIS

ASME PTC 19.1 is the Performance Test Code Supplement that covers general procedures for calculation of test uncertainty. A sample calculation is shown in Nonmandatory Appendix E.

7-3 PRETEST UNCERTAINTY ANALYSIS

A pretest uncertainty analysis is required as stated in para. 3-5.2.1 of this Code to allow corrective action to be taken before the test, either to decrease the uncertainty to a level consistent with the overall objective of the test or to reduce the cost of the test while still attaining the objective. An uncertainty analysis is also useful for determining the number of observations that will be required.

7-4 POST-TEST UNCERTAINTY ANALYSIS

A post-test uncertainty analysis is required to determine the uncertainty intervals for the actual test. A post- test uncertainty analysis shall be conducted to verify the assumptions made in the pretest 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. This analysis serves to validate the quality of the test results or to expose problems.

7-5 INPUTS FOR AN UNCERTAINTY ANALYSIS

To perform an uncertainty analysis for an overall plant, test inputs are required to estimate the uncertainty of each of the required measurements and the sensitivity of each of the required measurements on corrected results. Guidance on estimating the uncertainty and calculating the required sensitivity coefficients can be found in ASME PTC 19.1.

The following is a sample list of some of the items that should be considered when developing a pre- and post-test uncertainty analysis:

(a) calibration methodology

(b) linearity or nonlinearity of instruments

(c) spatial uncertainty

(d) method of calibration and corresponding regression

(e) actual operating conditions for instrument versus designed use of instrument

(f) signal degradation, manipulation, compression, or dead band application before reading

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7-6 WEIGHTED CAPACITY

7-6.1 General

More than one determination of capacity value requires an averaging of the values. An example of this is the averaging of the steam flow results from the GT heat balance and the HRSG heat balance. The average must be a weighted average as a function of the steam flow uncertainties. For more information, see ASME PTC 19.1 on Test Uncertainty.

7-6.2 Data Required

The following data are required to determine a weighted capacity using the results of a HRSG heat balance and gas turbine heat balance with their respective test uncertainties:

(a) capacity value 1, C_1
(b) uncertainty 1, U_1
(c) systematic uncertainty 1, B_1
(d) random uncertainty 1, S_1
(e) capacity value 2, C_2
(f) uncertainty 2, U_2
(g) systematic uncertainty 2, B_2
(h) random uncertainty 2, S_2

7-6.3 Calculations

Step 1. The weighting, W, for value 1 is uncertainty 2 squared divided by the sum of uncertainty 1 squared and uncertainty 2 squared:

$$W_1 = \frac{U_2{}^2}{U_1{}^2 + U_2{}^2}$$

Step 2. The weighting for value 2 is uncertainty 1 squared divided by the sum of uncertainty 1 squared and uncertainty 2 squared:

$$W_2 = \frac{U_1{}^2}{U_1{}^2 + U_2{}^2}$$

Step 3. The weighted systematic uncertainty, B_w, is the square root of the sum of the products of weighting and systematic uncertainty for each value:

$$B_w = \sqrt{W_1 B_1 + W_2 B_2}$$

Step 4. The weighted random uncertainty, S_w, is the square root of the sum of the products of weighting and random uncertainty for each value:

$$S_w = \sqrt{W_1 S_1 + W_2 S_2}$$

Step 5. The weighted capacity, C_w, is the sum of the products of weighting and capacity for each value:

$$C_w = W_1 C_1 + W_2 C_2$$

Step 6. The weighted uncertainty, U_w, is two times the square root of the sum of the random uncertainty squared and the systematic uncertainty divided by 2 squared:

$$U_w = 2\sqrt{(B_w/2)^2 + S_w{}^2}$$

Note that if the weighted uncertainty is greater than either of the individual uncertainties, the lowest individual uncertainty is the overall test uncertainty and the overall capacity is the capacity of the lowest uncertainty test. As an alternative, a combined uncertainty calculation for simultaneous tests for both heat balance methods can be determined.

7-7 ADDITIONAL CONSIDERATIONS

Users of this Code should be aware of the following factors when preparing results of a test:

(a) A separate uncertainty analysis that focuses on the determination of the exhaust gas flow is required. It is this specific analysis that is used in the determination of the uncertainty weighted average exhaust flow. This specific analysis is not to be considered the overall test uncertainty.

(b) With the increased use of correction software provided by the original equipment manufacturer, its impact on uncertainty must be considered. This is done by conducting a sensitivity analysis on the program inputs and then incorporating them into the overall test uncertainty. See Nonmandatory Appendix D for additional information.

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NONMANDATORY APPENDIX A
BYPASS DAMPER LEAKAGE

A-1 GENERAL

Bypass dampers have been used in the power industry as a means to isolate, modulate, and divert gas flows. In GT combined cycle applications, dampers have been used to isolate the bypass stack during combined cycle operation and to isolate the exhaust ductwork to the HRSG during simple cycle operation. This application locates the damper in the GTE duct, where the damper is subjected to high exhaust gas temperatures and high mass flow rates. Unless the damper is periodically maintained and exposed to uniform temperatures, the potential for seal damage and frame and blade deformation exists.

A-2 DAMPER LEAKAGE

The GTs are brought on- and offline frequently, thereby exposing the damper to a wide range of exhaust gas temperatures. This thermal cycling can cause deformations to the damper frame and blades/disc, causing the damper to leak. The damper industry can provide a seal air system that pressurizes a cavity around the point of contact between the frame and blade/disc. This seal air is maintained at pressures above the exhaust gas from the GT and causes infiltration of seal air rather than exfiltration of exhaust gases. Measuring the flue gas temperature grid as far downstream from bypass damper as possible, in the lowest velocity region ahead of first heating surface, is best to capture the effects of seal air in-leakage.

A-3 LEAKAGE RATE

The exact amount of leakage experienced for a damper with and without a seal air system is hard to determine. Manufacturers may quote a leakage rate for a new damper without seal air system and this leakage may increase with thermal cycling. The new damper with seal air system may have zero leakage out at initial operation but will have a slight leakage after being subjected to thermal cycling.

For a damper without seal air system, leakage means exfiltration of exhaust gas that results in reduced exhaust gas flow through the HRSG. For a damper with seal air system, leakage means infiltration of seal air that results in reduced exhaust gas temperature entering the HRSG. For both cases, the damper installation influences the results of performance testing. The user shall review with the bypass damper manufacturer to resolve all issues associated with the leakage rate.

If the system has seal air, it is balanced such that the seal air pressure is slightly higher than the GTE pressure. This results in air infiltration that has a negligible impact on HRSG performance. If the system has no seal air, the committee personnel are not aware of a reliable accurate method to determine the exhaust gas leakage.

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NONMANDATORY APPENDIX B
FUEL SENSIBLE HEAT

B-1 INTRODUCTION

The sensible heat of a fuel has a minor impact on an HRSG performance test; therefore, this Code has adopted a modified procedure for calculating the fuel sensible heat. A more rigorous determination is required for fuel gas that deviates significantly from U.S. pipeline natural gas. A simplified approximation has been derived to quantify and adjust the net fuel heat input for the given fuel temperature from the reference temperature of 60°F. These derived equations should be adequate for most fuel oil and natural gas streams in which the components are almost entirely hydrocarbons. A gas stream with even a few percent hydrogen can have different results.

B-2 FUEL OIL

The specific heat for fuel oil is taken from Perry and Green (1997), eq. 9-12. The specific heat, Cp, is evaluated at the average temperature in degrees Fahrenheit, T_{AVG}, and divided by the fuel specific gravity. The specific gravity is assumed to be 0.8654, typical for No. 2 fuel oil. Specific gravities for No. 1 and No. 6 fuel oil are 0.8251 and 0.9861, respectively. This results in sensible heat errors of +2.3% and −6.3%.

$$Cp = \frac{0.388 + 0.00045 \times T_{\mathrm{AVG}}}{\sqrt{S_G}} \ (\mathrm{Btu/lb°F})$$

The sensible heat, Q_{FS}, of the fuel oil is calculated by multiplying the specific heat by the difference of the fuel temperature in degrees Fahrenheit and the reference temperature of 60°F.

$$\begin{aligned} Q_{\mathrm{FS}} &= Cp \times (T - 60) \\ &= [0.417 + 0.000484 \times (T + 60)/2] \times (T - 60) \end{aligned}$$

This reduces to the equation

$$Q_{\mathrm{FS}} = T^2/4{,}132 + 0.417T - 25.9 \ (\mathrm{Btu/lb}) \qquad \text{(B-2-1)}$$

An alternate method is described in Steam: Its Generation and Use (1992, pp. 9–18). This equation requires that the American Petroleum Institute (API) gravity of the fuel be known, which is the reason this method is not recommended.

$$\begin{aligned} Q_{\mathrm{FS}} = &-30.016 - 0.11426\mathrm{API} + 0.373T \\ &+ 1.43\mathrm{e}^{-3}(\mathrm{API})(T) \\ &+ \left[(2.184\mathrm{e}^{-4} + 7\mathrm{e}^{-7}(\mathrm{API})(T)\right] \end{aligned} \qquad \text{(B-2-2)}$$

The following table shows the results of the two methods:

Equation	API gravity	*h*, Btu/lb, at 200°F
(B-2-1)	...	55.4
(B-2-2)		
For No. 2 fuel oil	33	59.9
For No. 6 fuel oil	12.6	55.8

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NONMANDATORY APPENDIX C
HRSG HEAT LOSS

C-1 HRSG HEAT LOSS

Insulated casing heat loss does not vary much with ambient conditions. The insulated casing heat flux can be estimated by the casing design conditions. Paragraph C-2 is an example of the variation that can be expected.

C-2 INSULATED CASING DESIGN CRITERIA

(a) For 140°F casing temperature with 80°F ambient temperature and no wind

$$\text{calculated heat flux} = q = 110.6\ \text{Btu/hr-ft}^2$$

If the ambient conditions change to 30°F ambient and no wind and the heat flux is recalculated

$$q = 114.7\ \text{Btu/hr-ft}^2$$

(b) For 30°F ambient and 10-mph wind

$$q = 118.0\ \text{Btu/hr-ft}^2$$

Insulated casing heat loss can be approximated by multiplying the insulated casing design heat flux by the square footage of casing.

The heat loss from uninsulated casing and stacks has to be calculated considering gas heat transfer to the wall and heat transfer from the wall to ambient temperature. The inside casing heat transfer rate is assumed to be that calculated by the Dittus–Boelter equation (Dittus and Boelter, 1930) for turbulent heat transfer in a cylinder:

$$(h_i d)/(12k) = 0.23\ \text{Re}^{0.8}\text{Pr}^{0.4} \tag{C-1-1}$$

where

d = stack diameter, in.
h_i = heat transfer coefficient, Btu/hr·ft^2·°F
k = gas thermal conductivity, Btu/hr·ft·°F
Re = Reynolds number
Pr = Prandtl number

Equation (C-1-1) can be reduced to the following equation:

$$h_i = \text{C}\frac{W^{0.8}}{d^{1.8}}\frac{Cp^{0.4}\,k^{0.6}}{\text{VIS}^{0.4}} \tag{C-1-2}$$

where

C = constant
Cp = gas specific heat, Btu/lb·°F
VIS = gas viscosity, lb/ft·hr
W = gas flow, lb/hr

A GT exhaust is assumed as follows:

Element	GT Exhaust, %
Nitrogen	75.6
Oxygen	13.5
Carbon dioxide	3.5
Water	6.5
Argon	0.9

Table C-2-1 shows the physical properties determined for this composition. A linear correlation of the physical property portion of eq. (C-1-2) is developed:

$$\text{correlation of property function} = 0.1506 + T/13{,}520 \tag{C-1-3}$$

$$h_i = C\frac{W^{0.8}}{d^{1.8}}(0.1506 + T/13{,}520) \tag{C-1-4}$$

where T = gas temperature, °F.

The correlation constant for eq. (C-1-4) is

$$\text{C} = 12 \times 0.023 \times (12 \times 4/3.14159)^{0.8} = 2.444 \tag{C-1-5}$$

The resulting equation for the heat transfer to the uninsulated casing is

$$h_i = \frac{W^{0.8}}{d^{1.8}}\left(0.368 + \frac{T}{5{,}530}\right) \tag{C-1-6}$$

The heat transfer from the casing to ambient is defined by two equations:

$$\begin{aligned} q_c &= 0.296 \times (T_C - T_A)^{1.25} \\ &\quad \times [(\text{V} \times 5{,}280/60 + 68.9)/68.9]^{0.5} \end{aligned}$$

$$\begin{aligned} q_r &= 0.1714 \times 0.8 \times \Big\{[(T_C + 460)/100]^4 \\ &\quad - [(T_A + 460)/100]^4\Big\} \end{aligned}$$

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Table C-2-1
Physical Properties of Example Gas Composition

Temp, °F	C_p, Btu/lb·°F	VIS, lb/ft·hr	k, btu/hr·ft·°F	$\frac{C_p{}^{0.4}k^{0.6}}{\text{VIS}^{0.4}}$	CORR [Note (1)]	% Error
100	0.2440	0.0453	0.0148	0.15656	0.1580	0.89
200	0.2485	0.0506	0.0174	016626	0.1654	−0.54
300	0.2524	0.0557	0.0198	0.17398	0.1728	−0.69
400	0.2560	0.0607	0.0221	0.18057	0.1802	−0.22
500	0.2594	0.0655	0.0243	0.18640	0.1876	0.64

NOTE: (1) CORR is a calculated value of $Cp^{0.4}k^{0.6}$/VIS using the linear correlation, eq. (C-1-3).

where

q_c = convective heat flux, Btu/hr·ft^2
q_r = radiant heat flux, Btu/hr·ft^2
T_A = ambient temperature, °F
T_C = casing temperature, °F
V = wind speed, miles/hr

The heat flux from the gas to the casing equals the flux from the casing to ambient:

$$q_{\text{TOT}} = h_i \times (T - T_C) = q_c + q_r$$

where

q_{TOT} = total heat flux, Btu/hr ft^2
T = gas temperature, °F
T_c = casing or stack metal temperature, °F

The total heat flux can be solved by iteration. The heat loss is the total heat flux multiplied by the uninsulated casing surface area.

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NONMANDATORY APPENDIX D
UNCERTAINTY SAMPLE CALCULATION

D-1 INTRODUCTION

This Appendix provides the basic calculation steps for conducting HRSG-related uncertainty calculations. The following are discussed in this Appendix:

(a) basics of an uncertainty analysis

(b) example 1, determination of measured HP steam flow uncertainty

(c) example 2, determination of predicted HP steam flow uncertainty for the HRSG heat balance method

(d) example 3, determination of predicted HP steam flow uncertainty for the gas turbine heat balance method

(e) example 4, determination of predicted HP steam flow uncertainty using uncertainty weighted averaging

D-2 BASICS OF AN UNCERTAINTY ANALYSIS

An uncertainty analysis is conducted to determine the impact a series of measurements has on a final outcome; e.g., determination of HRSG steam flow or calculation of GTE flow. Refer to ASME PTC 19.1 for further information and details regarding uncertainty.

The elements of an uncertainty analysis are as follows:

(a) Systematic Uncertainty. A function of instrumentation and the methods of measurement, systematic uncertainty is a value that quantifies the dispersion of a systematic error associated with the mean. Simply put, systematic uncertainty is a portion of the total uncertainty that remains constant in repeated measurements of the true value throughout a test process.

(b) Random Uncertainty. A function of the data collected, random uncertainty is a value that quantifies the dispersion of a sample mean. Simply put, random uncertainty is a portion of the total uncertainty that varies randomly in repeated measurements of the true value throughout a test process.

(c) Sensitivity. A function of each of the required measurements on corrected results, sensitivity is the rate of change in a result due to a change in a variable evaluated at a desired test operating point. Simply put, sensitivity is the impact a small change in a measured value has on the final calculated outcome.

Example 1 is a feedwater flow uncertainty analysis comprising a sensitivity calculation table (Figure D-3-1) and an uncertainty calculation table (Figure D-3-2). This is a simple example of a typical uncertainty analysis. Note that instrument accuracies recommended in Table 4-4.2-1 are used in the development of the systematic uncertainty.

Example 2 is a sample determination of the predicted HP steam flow sensitivities (Figure D-4-1) and uncertainty (Figure D-4-2) by the HRSG energy balance method. Example 3 is a sample determination of the predicted HP steam flow sensitivities (Figure D-5-1) and uncertainty (Figure D-5-2) by the GT energy balance method.

A computer performance model is typically used to predict the steam flow in the HRSG from the calculated exhaust flow and other test conditions. An exhaust flow is determined by either the HRSG heat balance (calculations of Section 5) or by the GT heat balance (ASME PTC-22).

To determine steam flow sensitivity to various input data associated with the heat balance, a perturbation method must be used to calculate a new exhaust flow. The new exhaust flow is then used in the performance model to predict a new steam flow. This is in addition to the sensitivity determination of other test data on the steam flow. This process applies to each pressure level of steam produced.

Example 4 is the steam flow determined by each of the two heat balance methods combined by uncertainty weighting (Table D-6-1) to define the final predicted steam flow for the test conditions. The calculation also determines the combined weighted uncertainty for the steam flow. The calculations for the weighting are as follows:

Step 1. The weighting for value 1, W_1, is determined by the following equation:

$$W_1 = \frac{{U_2}^2}{{U_1}^2 + {U_2}^2}$$

Step 2. The weighting for value 2, W_2, is determined by the following equation:

$$W_2 = \frac{{U_1}^2}{{U_1}^2 + {U_2}^2}$$

Step 3. The weighted systematic uncertainty, B_w, is determined by the following equation:

$$B_w = \sqrt{(W_1B_1)^2 + (W_2B_2)^2}$$

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Step 4. The weighted random uncertainty, S_w, is determined by the following equation:

$$S_w = \sqrt{(W_1 S_1)^2 + (W_2 S_2)^2}$$

Step 5. The weighted capacity, C_w, is determined by the following equation:

$$C_w = W_1 C_1 + W_2 C_2$$

Step 6. The weighted uncertainty, U_w, is determined by the following equation:

$$U_w = 2\sqrt{(B_w/2)^2 + {S_w}^2}$$

where

B_1 = systematic uncertainty 1
B_2 = systematic uncertainty 2
C_1 = capacity value 1
C_2 = capacity value 2
S_1 = random uncertainty 1
S_2 = random uncertainty 2
U_1 = uncertainty 1
U_2 = uncertainty 2

Note that if the weighted uncertainty is greater than either of the individual uncertainties, the lowest individual uncertainty is the overall test uncertainty, and the overall capacity is the capacity of the lowest uncertainty test. As an alternative, a combined uncertainty calculation for simultaneous tests for both heat balance methods can be determined.

D-3 EXAMPLE 1: FEEDWATER FLOW UNCERTAINTY ANALYSIS

See Figures D-3-1 and D-3-2.

D-4 EXAMPLE 2: PREDICTED HP STEAM FLOW SENSITIVITIES AND UNCERTAINTY BY THE HRSG ENERGY BALANCE METHOD

See Figures D-4-1 and D-4-2.

D-5 EXAMPLE 3: PREDICTED HP STEAM FLOW SENSITIVITIES AND UNCERTAINTY BY THE GT ENERGY BALANCE METHOD

See Figures D-5-1 and D-5-2.

D-6 EXAMPLE 4: HP STEAM FLOW UNCERTAINTY BY WEIGHTED AVERAGE

See Table D-6-1.

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Figure D-3-1
Sensitivity Calculation Table for the Measured HP Steam Flow Uncertainty Example

Measured Parameter	Measurement Class	Input Value	Perturbed Value	Input Value A	Input Value B	Corrected Value	Corrected Value A	Corrected Value B	Sensitivity A Relative	Sensitivity B Relative	Average Sensitivity Relative	Average Sensitivity Absolute	Average Sensitivity (%/Abs)
HP drum temperature	Class 2	530.0954	5.300954	535.3964	524.7945	133032.9	133032.9	133033.1	−3.1E−05	−8.3E−05	−5.7E−05	−0.01434	−1.1 E−07
HP drum pressure	Class 2	900.09	9.0009	909.0909	891.0891	133032.9	133033	133032.9	1.51E−06	1.51E−06	1.51 E−06	0.000223	1.67 E−09
HP drum level — Start	Class 1	−24.3068	−0.24307	−24.5498	−24.0637	133032.9	133164.5	132901.4	0.09889	0.09889	0.09889	−541.232	−0.00407
HP drum level — End	Class 1	−24.2785	−0.24278	−24.5213	−24.0357	133032.9	132901.5	133164.4	−0.09877	−0.09877	−0.09877	541.2321	0.004068
Change in HP drum level equivalent flow	Class 2	15.30479	0.153048	15.45784	15.15175	133032.9	133033.1	133032.8	0.000115	0.000115	0.000115	1	7.52 E−06
Barometric pressure	Secondary	14.296	0.14296	14.43896	14.15304	133032.9	133032.9	133032.9	0	0	0	0	0
Feedwater flow pressure	Class 2	939.4594	9.394594	948.854	930.0648	133032.9	133035.5	133030.4	0.001893	0.001894	0.001894	0.268132	2.02E−06
HP feedwater flow temperature	Class 1	292.1856	2.921856	295.1074	289.2637	133032.9	132935.3	133129.8	−0.07342	−0.07277	−0.0731	−33.2813	−0.00025
HP feedwater flow differential pressure	Class 1	67.43617	0.000659	67.45725	67.4151	133032.9	133053.7	133012.2	0.499931	0.500009	0.49997	986.3022	0.007414
Calibrated leading discharge coefficient	Class 1	1.002387	0.010024	1.012411	0.992363	133032.9	134374.8	131691.1	1.008679	1.008658	1.008668	133866.6	1.006266

GENERAL NOTE: See Section 5 calculations for applicable units of measure.

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