ASME PTC 4.4-2008

[Revision of ANSI/ASME PTC 4.4-1981 (R2003)]

Gas Turbine Heat Recovery Steam Generators

Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

SETTING THE STANDARD

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The American Society of Mechanical Engineers
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NOTICE

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

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

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

FOREWORD

PTC 4.4, Gas Turbine Heat Recovery Steam Generators, was originally formed as a reorganized PTC 4.1, Steam Generating Units, in September 1973 to prepare an Appendix 10 to PTC 4.1 to cover Heat Recovery Steam Generators for Combined Cycles. During the early meetings (May 11 and 12, 1976 and May 3 and 4, 1977) it was decided that the scope was beyond the capacity of an Appendix. At this point a charter was approved by the PTC Supervisory Committee to prepare a separate code entitled PTC 4.4, Gas Turbine Heat Recovery Steam Generators. The draft of PTC 4.4 was presented to the Supervisory Committee in February 1980 with final approval on January 26, 1981. This Performance Test Code was approved as an American National Standard by the ANSI Board of Standards Review on February 3, 1981.

The Committee completely and extensively revised the 1981 edition to a much more specific procedure consistent with current industry practice on the testing of Heat Recovery Steam Generators. The PTC 4.4 Code utilizes two independent approaches to quantify the unit capacity. New sections related to measurement uncertainty are added.

This revision was approved by the Board on Standardization and Testing on April 15, 2008 and by the ANSI Board of Standards Review as an American National Standard on April 25, 2008.

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Performance Test Codes

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Secretary, PTC Standards Committee
The American Society of Mechanical Engineers
Three Park Avenue
New York, NY 10016-5990

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

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

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

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

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

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

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

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

Attending Committee Meetings. The PTC Standards Committee holds meetings or telephone conferences, which are open to the public. Persons wishing to attend any meeting or telephone conference should contact the Secretary of the PTC Standards Committee or check our Web site at http://cstools.asme.org.

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GAS TURBINE HEAT RECOVERY STEAM GENERATORS

Section 1
Object and Scope

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 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 gas turbine exhaust and supplementary firing
  (3) gas side pressure drop
  (4) steam/water side pressure drop(s)

(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 gas turbine exhaust. 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
  (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 gas turbine exhaust. These are addressed in ASME PTC 4 and ASME PTC 34.
  (2) auxiliary equipment such as pumps and fans that are addressed in ASME PTC 8.2 and ASME PTC 11, respectively.
  (3) deaerator performance that is addressed in ASME PTC 12.3.
  (4) equipment noise emissions that 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.

Section 2
Definitions of Terms, Symbols, and Conversion Factors

2-1 DEFINITIONS OF TERMS

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 considered to be 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 HRSG.

ammonia injection grid (AIG): a system of pipes to introduce ammonia into the GTE for reaction with NO_x in the presence of 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: refer to *desuperheating*.

auxiliary firing: combustion of fuel in the HRSG to raise the GTE temperature and increase steam capacity.

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

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

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

burner auxiliary air: air introduced into the burner to facilitate the combustion process.

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

bypass damper: a damper that is used to bypass GTE from the HRSG 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 lower pressure levels.

CO catalyst: a catalyst that is used to reduce carbon monoxide level in the GTE.

condensate: water coming from the condenser.

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

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

deaeration: removal of oxygen and other dissolved gases from the 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 of producing steam by discharging water at saturation temperature into a region of lower pressure.

gas approach temperature: the difference of the gas temperature at the inlet or outlet to a heat transfer section and the corresponding fluid temperature.

gas side static pressure drop: the difference between the static pressure measured at the inlet test boundary and the atmosphere.

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

GT: gas turbine.

GTE: the flue gas flowing through the HRSG from the gas turbine exhaust.

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 (HHV): 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.

HP: high pressure.

HRSG: heat recovery steam generator.

integral deaerator: a deaerator that is directly connected to the LP drum.

interstage: between the heat transfer sections.

IP: intermediate pressure.

lower heating value (LHV): the HHV of fuel minus the latent heat of vaporization of the combustion products when combustion products are cooled to 60°F.

LP: low pressure.

multiple pressure HRSG: an HRSG 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 GT operating condition wherein GT power production is at maximum value.

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

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

pinch temperature: the minimal terminal temperature difference between GTE and fluid.

preheater: heat transfer section where aerated water is heated.

recirculation (economizer): use of a portion of hot water leaving 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.

remote deaerator: a deaerator that is separate from the HRSG.

RH: reheat.

saturation temperature: the temperature for a given pressure at which water vaporizes to steam.

SCR system: selective catalytic reduction system that is used to reduce the NO_x levels in the GTE.

single pressure HRSG: an HRSG that exports steam at one pressure only.

stack: a vertical conduit to discharge the GTE to atmosphere.

stack damper: a damper that is closed when the HRSG is not operating to conserve heat.

standard air composition (dry air molar basis): nitrogen, 78.0840%; oxygen, 20.9476%; argon, 0.9365%; carbon dioxide, 0.0319%.

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
Methane	CH_4	16.04726
Ethane	C_2H_6	30.06964
Ethene	C_2H_4	28.05376
Propane	C_3H_8	44.09652
Propene	C_3H_6	42.08064
Iso Butane	C_4H_{10}	58.1234
Normal Butane	C_4H_{10}	58.1234
Butene	C_4H_8	56.10752
Iso Pentane	C_5H_{12}	72.15028
Normal Pentane	C_5H_{12}	72.15028
Pentene	C_5H_{10}	70.1344
Hexane	C_6H_{14}	86.17716
Carbon Monoxide	CO	28.0104
Carbon Dioxide	CO_2	44.0098
Hydrogen Sulfide	H_2S	34.08188
Hydrogen	H_2	2.01588
Water	H_2O	18.01528
Helium	He	4.0026
Nitrogen	N_2	28.01348
Sulfur Dioxide	SO_2	64.0648
Oxygen	O_2	31.9988

steam bypass (steam turbine): steam bypassed around steam turbine to a condenser or some other heat sink.

steam bypass (superheater): amount of steam bypassed around a supereater or part of a superheater.

steam purity: amount of total dissolved solids (TDS) 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.

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

superheater: a heat transfer section where steam is heated to higher temperature.

supplementary firing: see *auxiliary firing*.

water preheater (feedwater): see *preheater*.

2-2 SYMBOLS

The symbols that are used in this document are defined as follows:

Symbol	Description	Units
B	Systematic uncertainty of temperature grid	…
B_{TC}	Systematic uncertainty of a temperature element	…
Bs	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.
DP_{Cor}	Corrected pressure drop	lb/in.^{2}
$DP_{S\,Cor}$	Corrected steam pressure drop	lb/in.^{2}
$DP_{S\,\mathrm{Test}}$	Steam pressure drop for a test	lb/in.^{2}
DP_{Test}	Pressure drop for a test	lb/in.^{2}
$DP_{W\,Cor}$	Corrected water pressure drop	lb/in.^{2}
$DP_{W\,\mathrm{Test}}$	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_G	Gas enthalpy	Btu/lb
$h_{G\,\mathrm{IN}}$	Gas enthalpy into the HRSG	Btu/lb

Symbol	Description	Units
$h_{G\,\mathrm{OUT}}$	Gas enthalpy out of the HRSG	Btu/lb
$h_{\mathrm{H_2O}}$	Enthalpy of water	Btu/lb
h_i	Constituent enthalpy	Btu/lb
$h_{\mathrm{N_2}}$	Enthalpy of nitrogen	Btu/lb
$h_{\mathrm{O_2}}$	Enthalpy of oxygen	Btu/lb
HR	Humidity ratio	…
HR_{REL}	Relative humidity	%
HR_{SAT}	Saturated humidity ratio	…
$h_{\mathrm{SO_2}}$	Enthalpy of sulfur dioxide	Btu/lb
HT	Sensing line height	in.
HV_{NET}	Net heating value	Btu/lb
h_{WC}	Corrected differential pressure	in. wc
h_{WM}	Measured differential pressure	in. wc
L	Length	in.
L/D	Ratio of length to diameter	…
MF_{Ar}	Mole fraction of argon	…
$MF_{\mathrm{CO_2}}$	Mole fraction of carbon dioxide	…
$MF_{\mathrm{H_2O}}$	Mole fraction of water	…
MF_i	Constituent mole fraction	…
$MF_{\mathrm{N_2}}$	Mole fraction of nitrogen	…
$MF_{\mathrm{O_2}}$	Mole fraction of oxygen	…
$MF_{\mathrm{SO_2}}$	Mole fraction of sulfur dioxide	…
MW_{AVG}	Average molecular weight	…
MW_{FG}	Fuel gas molecular weight	…
$MW_{G\,Ref}$	Gas molecular weight for reference conditions	…
$MW_{G\,\mathrm{Test}}$	Gas molecular weight for a test	…
MW_i	Constituent molecular weight	…
N	Number of samples	…
n	Units conversion	…
P_{ATM}	Atmospheric Pressure	psia
$P_{ATM\,Ref}$	Atmospheric pressure for reference conditions	psia
$P_{ATM\,\mathrm{Test}}$	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

Symbol	Description	Units
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
$Q_{G\,\mathrm{IN}}$	Gas heat entering	Btu/hr
$Q_{G\,\mathrm{OUT}}$	Gas heat leaving	Btu/hr
Q_{HL}	Heat loss	Btu/hr
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
$Q_{WF\,\mathrm{IN}}$	Heat flow for entering working fluid	Btu/hr
$Q_{WF\,\mathrm{OUT}}$	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	…
$S_{\overline{X}}$	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
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	Std ft^3/min
V_{fluid}	Specific volume of process fluid	ft^3/lb
V_{sen}	Specific volume of sensing line fluid	ft^3/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
$\mathrm{W_{BA}}$	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

Symbol	Description	Units
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
$W_{G\,Ref}$	Gas flow at reference conditions	lb/hr
$W_{G\,\mathrm{Test}}$	Gas flow at test conditions	lb/hr
$W_{GT\,F}$	GT fuel flow	lb/hr
$W_{S\,Ref}$	Steam flow at reference conditions	lb/hr
$W_{S\,\mathrm{Test}}$	Steam flow at test conditions	lb/hr
$W_{W\,Ref}$	Water flow at reference conditions	lb/hr
$W_{W\,\mathrm{Test}}$	Water flow at test conditions	lb/hr
WF_{Ar}	Weight fraction of argon	…
WF_C	Weight fraction of carbon in fuel oil	…
$WF_{\mathrm{CO_2}}$	Weight fraction of carbon dioxide	…
$\mathrm{WF_{DA}}$	Weight fraction dry air	…
WF_{H}	Weight fraction of hydrogen in fuel oil	…
$WF_{\mathrm{H_2O}}$	Weight fraction of water	…
$WF_{\mathrm{N_2}}$	Weight fraction of nitrogen	…
WF_O	Fuel oil flow	lb/hr
$WF_{\mathrm{O_2}}$	Weight fraction of oxygen	…
WF_{S}	Weight fraction of sulfur in fuel oil	…
$WF_{\mathrm{SO_2}}$	Weight fraction of sulfur dioxide	…
WM_{Ar}	Molar flow of argon	lb moles/hr
$WM_{\mathrm{CO_2}}$	Molar flow of carbon dioxide	lb moles/hr
WM_{FG}	Molar flow of fuel gas	lb moles/hr
$WM_{\mathrm{H_2O}}$	Molar flow of water	lb moles/hr
$WM_{\mathrm{N_2}}$	Molar flow of nitrogen	lb moles/hr
$WM_{\mathrm{O_2}}$	Molar flow of oxygen	lb moles/hr
$WM_{\mathrm{SO_2}}$	Molar flow of sulfur dioxide	lb moles/hr
X_k	Datum value	…
$\overline{x}$	Data average	…
Z	Gas compressibility	…
β	Flow element bore to pipe ratio	…
ΔP	Differential pressure	in. wc
ε	Expansion factor	…
ρ	Density	lb/ft^3
$\rho_{S\,Ref}$	Steam average density for reference conditions	lb/ft^3
$\rho_{S\,\mathrm{Test}}$	Steam average density for a test	lb/ft^3

2-3 CONVERSION FACTORS

To convert from	To	Multiply by	
Acceleration of free fall, standard (g_n)	meter per second squared (m/s^2)	**9.806 65**	**E + 00**
Atmosphere, standard (atm)	pascal (Pa)	**1.013 25**	**E + 05**
Atmosphere, standard (atm)	kilopascal (kPa)	**1.013 25**	**E + 02**
bar (bar)	kilopascal (kPa)	**1**	**E + 02**
British thermal unit (mean) (Btu)	joule (J)	1.055 87	E + 03
British thermal unit (59°F) (Btu)	joule (J)	1.054 80	E + 03
British thermal unit (60°F) (Btu)	joule (J)	1.054 68	E + 03
British thermal unit$_{IT}$ per hour (Btu$_{IT}$/h)	watt (W)	2.930 711	E − 01
British thermal unit$_{th}$ per hour (Btu$_{th}$/h)	watt (W)	2.928 751	E − 01
British thermal unit$_{IT}$ foot per hour square foot degree Fahrenheit [Btu$_{IT}$ · ft/(h · ft^2 · °F)]	watt per meter kelvin [W/(m · K)]	1.730 735	E + 00
British thermal unit$_{th}$ foot per hour square foot degree Fahrenheit [Btu$_{th}$ · ft/(h · ft^2 · °F)]	watt per meter kelvin [W/(m · K)]	1.729 577	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)	2.324 444	**E + 03**
British thermal unit$_{IT}$ per square foot hour [Btu$_{IT}$/(ft^2 · h)]	watt per square meter (W/m^2)	3.154 591	E + 00
British thermal unit$_{th}$ per square foot hour [Btu$_{th}$/(ft^2 · h)]	watt per square meter (W/m^2)	3.152 481	E + 00
Calorie (cal) (mean)	joule (J)	4.190 02	E + 00
Calorie (15°C) (cal$_{15}$)	joule (J)	4.185 80	**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)	5.555 556	E − 01
Degree Fahrenheit (temperature interval) (°F)	kelvin (K)	5.555 556	E − 01
Degree Rankine (°R)	kelvin (K)	T°K = (T°R)/**1.8**	E + 00
Degree Rankine (temperature interval) (°R)	kelvin (K)	5.555 556	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)	8.466 667	**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)	1.355 818	E − 00
Feet pound-force per hour (ft · lbf/hr)	watt (W)	3.766 161	E − 04
Inch (in.)	meter (m)	**2.54**	E − 02

To convert from	To	Multiply by	
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)	4.190 02	**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)	1.259 979	E − 04
Pound per minute (lb/min)	kilogram per second (kg/s)	7.559 873	E − 03
Pound per second (lb/sec)	kilogram per second (kg/s)	4.535 924	E − 01
Pound per square foot (lb/ft^2)	kilogram per square meter (kg/m^2)	4.882 428	E + 00
Pound per square inch (not pound-force) (lb/in.^{2})	kilogram per square meter	7.030 696	E + 02 (kg/m^2)
psi (pound-force per square inch) (lbf/in.^{2})	pascal (Pa)	6.894 757	E + 03
psi (pound-force per square inch) (lbf/in.^{2})	kilopascal (kPa)	6.894 757	E + 00
Square foot (ft^2)	square meter (m^2)	**9.290 304**	**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)	1.333 224	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)	1.550 003	E + 03
Watt second (W · sec)	joule (J)	**1**	E + 00

GENERAL NOTES:

(a) For more complete list and other explanatory details visit NIST site: **http://physics.nist.gov/Pubs/SP811**

(b) The numbers given in boldface are exact.

2-4 DESCRIPTIVE FIGURES

Figures 2-4-1, 2-4-2, 2-4-3, and 2-4-4 describe some generic configurations. Job-specific figures should be generated in the test procedure.

No.	Description	Flow Direction
1	Fuel to gas turbine	In
2	Steam injection into gas turbine	In
3	Water injection into gas turbine	In
4	Combustion air to gas turbine	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	HP main steam	Out
11	Spray water to HP attemperator	In
12	Auxiliary HP steam	Out
13	Hot reheater steam to the 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	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 DA 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

No.	Description	Flow Direction
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 losses	Out

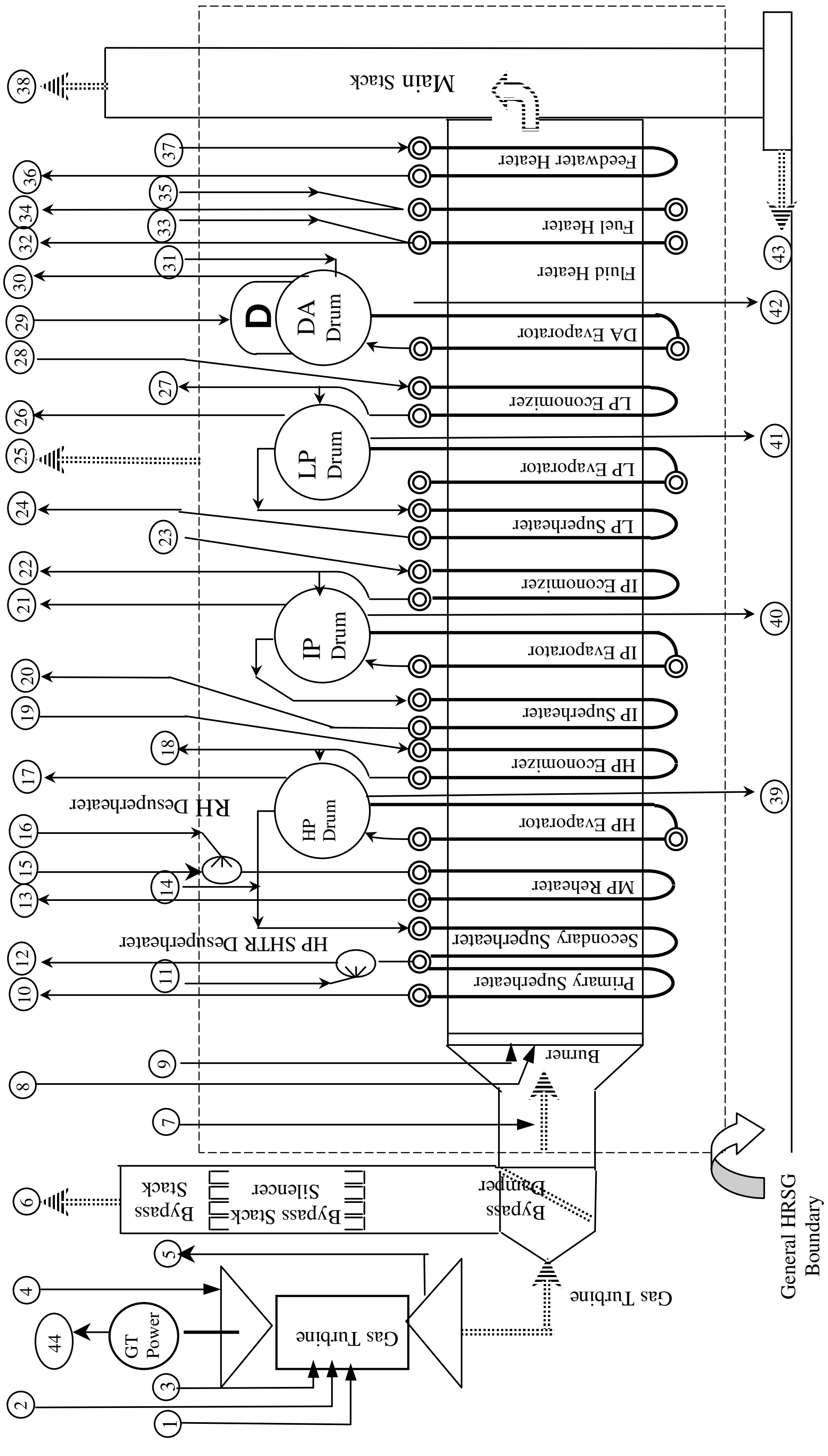


Fig. 2-4-1 Typical Gas Turbine Heat Recovery Steam Generator Diagram

Fig. 2-4-2 Typical Three Pressure Level HRSG With Supplementary Firing

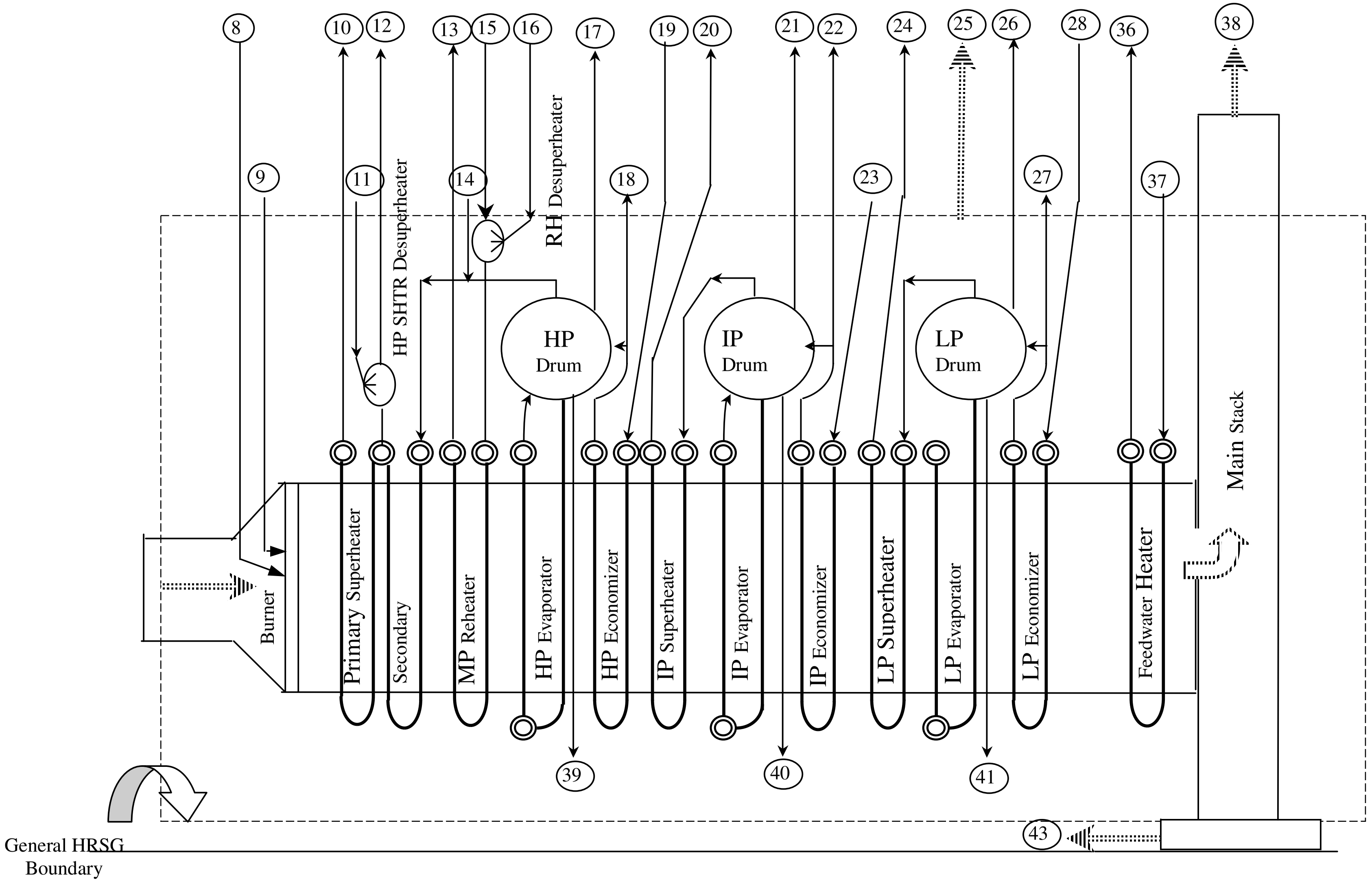


Fig. 2-4-3 Typical Two Pressure Level HRSG With Feedwater Heater and Supplementary Firing

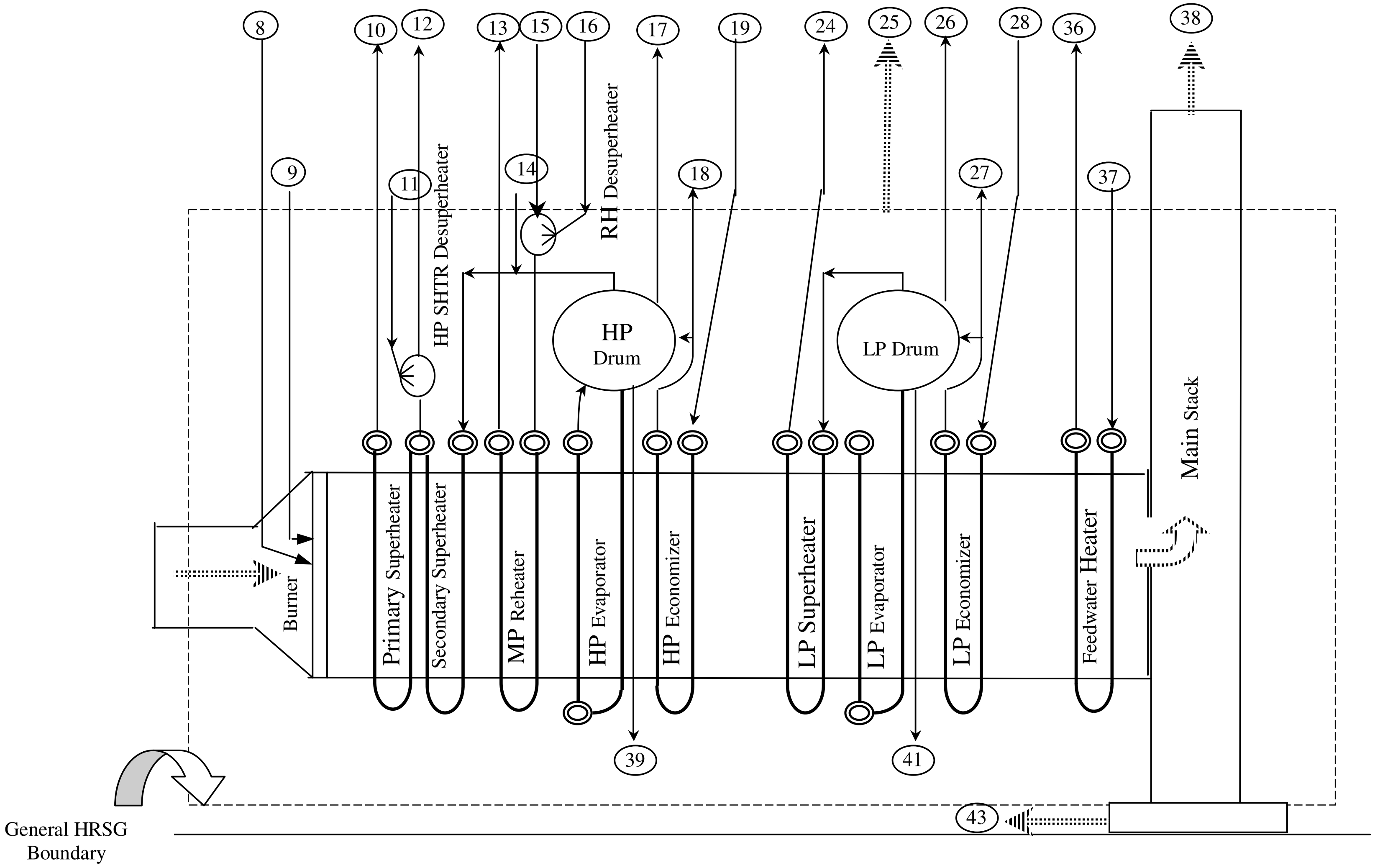
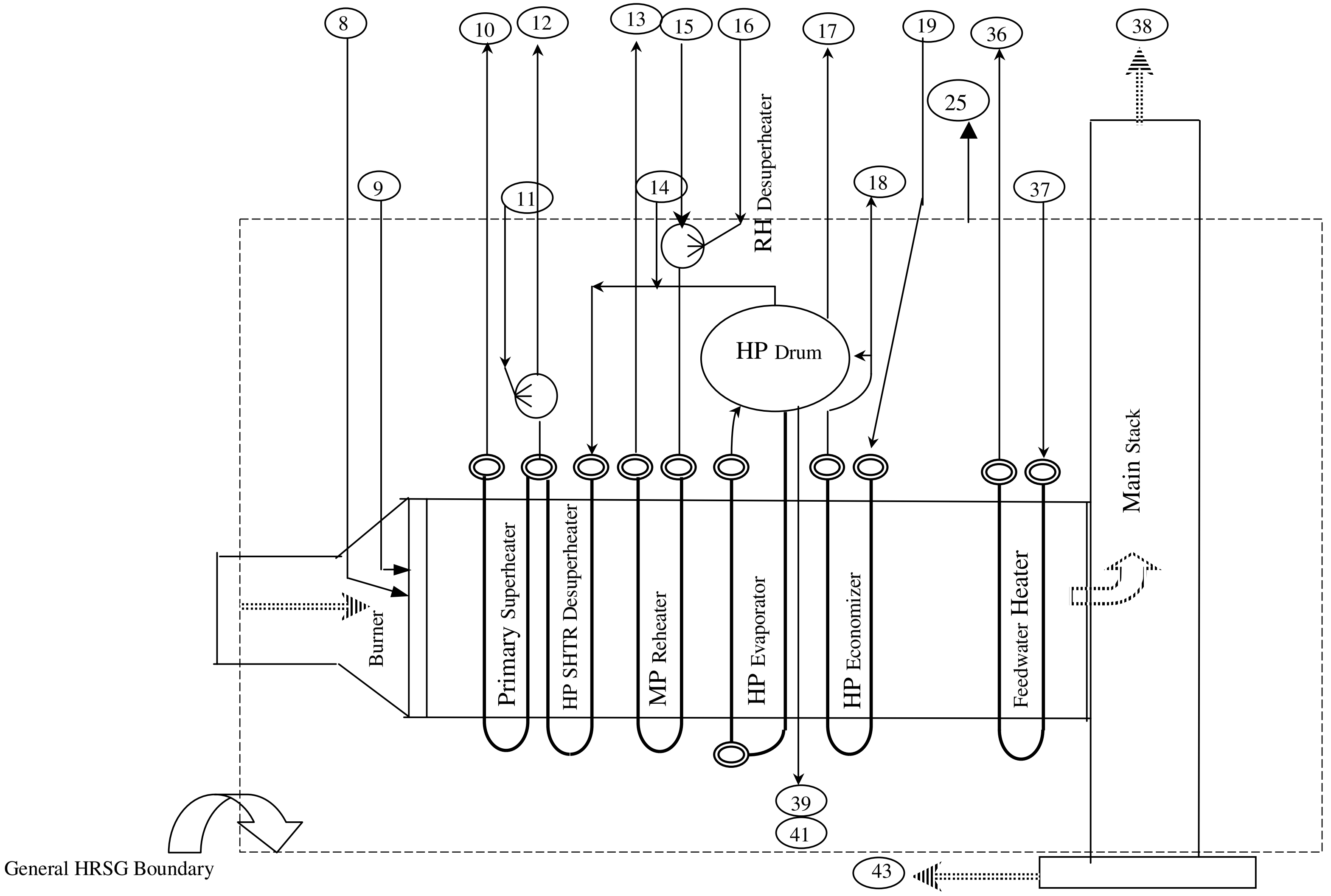


Fig. 2-4-4 Typical Single Pressure Level HRSG With Feedwater Heater and Supplementary Firing



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 heat recovery steam generator performance.

This ASME PTC 4.4 Code uses heat balances around the HRSG and the gas turbine 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 gas turbine 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.

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 prior to conducting the test. This procedure shall outline the schedule of test activities, responsibilities, and the procedure for conducting the test and shall detail and clarify all prior agreements (refer to subsection 3-3 for a list of prior agreements).

Table 3-1-1 Typical Range of Uncertainties

Configuration	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

Gas Side Pressure Drop 0.4 – 0.8 in.WC
Steam and Waterside Pressure Drop 4.0% to 8.0%

3-2.1 Test Procedure

A detailed test procedure shall be prepared. The procedures for testing shall be mutually agreed prior to starting the test and will 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.

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 will be 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 was 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/or capacity of these streams shall be measured to calculate the corrected results and determine the performance.

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 following parameters need to be determined for a valid test. Additions or deletions may be necessary for a specific test arrangement.

3-2.4.1 Gas Turbine Exhaust. The primary heat input to an HRSG is the gas turbine exhaust (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.

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, etc., 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 point locations, availability of suitable utilities and safe work areas for personnel, as well as potential damage to instrumentation or calibration shifting 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/or 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

Prior to conducting an HRSG performance test, there shall be a written agreement on the specific subjects affecting the test. Agreement on the following items must 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 PTC 4.4 is to be conducted in conjunction with an overall plant test such as PTC 46, any special requirements that will be required to 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.

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

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

(o) fuel(s) 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 post-test 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, 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 the IAPWS-IF97 ASME Industrial Formulation.

(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 dependant 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.

(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.

Calibration of the instruments shall be carried out prior to the test and those records and calibration 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 prior to the test. Data storage decisions for test data, results, and report 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 report. 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

Prior to conducting the test, the cleanliness, condition, and age of the equipment is to be determined by inspection of equipment and operational records. Any cleaning shall be agreed upon and completed prior to the test. Equipment shall be inspected for leakage.

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 prior to 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
(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 section that proprietary design algorithms be disclosed.

3-5 CONDUCTING THE TEST

The purpose of this section is to provide guidelines on 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. Prior to starting each test, the following conditions must be satisfied:

(a) 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.* Prior to starting the test, the HRSG must operate for a sufficient period of time at test load to demonstrate and verify stability in accordance with para. 3-5.3 criteria.

(c) *Data Collection.* Data acquisition system(s) functioning, and test personnel 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 Prior to and During Tests

A test log shall be developed which 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 their design characteristics and operational ratings as defined by the HRSG suppliers' 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.

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.

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.

3-5.3 Adjustments Prior to 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 manufacturer's operating limits, design or safety limits, and/or specified operating limits are not permissible at any time prior to or during testing.

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

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	±1/2% of steam flow
Fuel flow to gas turbine	±2%
Supplemental fuel flow	±2%
Gas turbine power output	±2%
Average gas turbine exhaust 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.

3-5.5 Duration of Runs

The duration of a test run shall be of sufficient length that the data reflects 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 to 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 time periods should be rejected prior to the calculation of 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 re-stabilization.

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 prior to 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 prior to calculating 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.

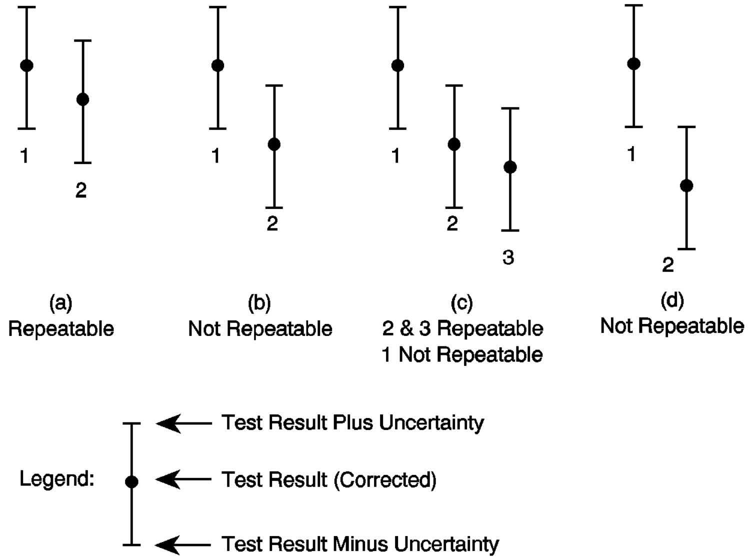
3-6.2 Repeatability of Test Runs

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.

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 Fig. 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 of the 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.

Fig. 3-6.2-1 Repeatability of Runs



The results of multiple runs that meet the criteria 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.

Difference $< =$ sqrt$(U1^2 + U2^2)$

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 band(s) may be increased.

3-6.4 Test Uncertainty

Procedures relating to test uncertainty are based on concepts and methods described in PTC 19.1, Test Uncertainty. 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.

3-6.4.1 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 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 assuming 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 is to be distributed. The report shall include all specific subjects affecting the conducting of the test.

Prior to 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.

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 which, when considered with all the other parameters, produces results within the uncertainty requirements of the test.

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, humidity, etc. 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) error 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 then may 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.

4-2.4.2 Reference Standards. In general, all test instrumentation that is to be calibrated shall be calibrated against reference standards traceable to the National Institute of Standards and Technology (NIST), other recognized international standard organizations, or recognized physical constants. All reference standards shall be calibrated at the frequency recommended by the manufacturer or other frequency as user has data to support extension of the calibration period. Supporting data are historical calibration data that demonstrate a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The reference standards should have an uncertainty at least four times better (less) than the test instrument to be calibrated. A reference standard with a higher uncertainty may be employed if the uncertainty of the standard combined with the random uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument. If the instrument being calibrated for use in the test is at least as accurate as the calibration device being used, the instrument being calibrated should only be "calibration checked" (i.e., calibration of the instrument should not be changed, but simply confirmed to be within the specified uncertainty band).

4-2.4.3 Ambient Conditions. Calibration of instruments should be performed in a manner that replicates the condition under which the instrument will be used to make the test measurements. Consideration must be given to all process and ambient conditions that may affect the measurement, including temperature, pressure, humidity, electromagnetic interference, radiation, etc.

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 will be calibrated prior to 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 re-calibration, but all instruments should be within their normal calibration cycle (typically up to 1 yr). If premium grade thermocouple (TC) wire from a given batch is used for temporary TC 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. Calibration drift is defined as the difference in the calibration correction as a percent of the reading. When the post-test calibration indicates that the drift is less than the instrument systematic uncertainty, the drift is considered acceptable and the pretest calibration is used as the systematic uncertainty for determining the test results. Occasionally, the instrument calibration drift is unacceptable.

Should the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable.

Calibration drift can result from instrument malfunction, transportation, installation, or removal of the test instrumentation. Should calibration drift occur, engineering judgment must be used to determine whether the initial calibration or recalibration is correct. Good practices that lead to the application of good engineering judgment include the following:

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

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

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 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 Data Acquisition System (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 later 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. In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from metering device) must be made available, as plant conversions to flow are often not rigorous enough for the required 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 the 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.

4-3 TEMPERATURE MEASUREMENT

4-3.1 General

Temperature is typically measured with thermocouples (TCs), resistance temperature devices (RTDs), or mercury in glass thermometers (thermometers). These devices produce either a direct reading or a signal, which can be read with a meter, transmitter, or data logger. Details on use and installation can be found in ASME PTC 19.3 and ASTM Manual 12, Manual on the use of thermocouples and temperature measurement.

Data measurement devices must be allowed to reach thermal equilibrium in the environment where the measurements will be taken. An RTD or a thermocouple with continuous leads should be used for measurements having a product of relative sensitivity coefficient and instrument uncertainty of 0.25 or greater. For other measurements, thermocouple extension wires should be of the same quality and composition as the TCs. ASTM E 230 provides guidance on the selection of thermocouples. Thermocouple lead wires shall be placed in a nonparallel position relative to electrical sources to avoid possible electrical interference.

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 RTDs. ASME PTC 19.3 provides guidance on the application of the calibration data.

The following items may also influence temperature measurements:

(a) thermowell location/geometry/design
(b) temperature sensor design
(c) calibration
(d) pad weld (insulated/uninsulated)
(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) data acquisition system
(s) velocity

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

Item	Uncalibrated Systematic Uncertainty	Calibrated Systematic Uncertainty	Range, °F
TC Type E Precision Grade	±2°F or ±0.4%, whichever is greater	See Note (1)	32 – 1,600
TC Type E Standard Grade	±3°F or ±0.5%, whichever is greater		32 – 1,600
TC Type K Precision Grade	±2°F or ±0.4%, whichever is greater	See Note (1)	32 – 2,300
TC Type K Standard Grade	+4°F or +0.8%, whichever is greater		32 – 2,300
Resistance Temperature Device (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°F
	±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 E 220 for systematic uncertainties associated with thermocouples.

4-3.3 Typical Applications

4-3.3.1 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 the 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 prior to 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. 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 the 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/or reheater outlets or their respective terminal points to minimize error from heat loss. Feedwater temperatures shall be measured as close to the economizer inlet and boiler inlet as possible.

4-3.3.2 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 gas turbine discharge or near a flow disturbance, such as a bend or transition. 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 be ganged together to produce a single output.

The total temperature of the gas flowing is required and 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.[1]

(U.S. Customary Units)

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

where

T_t = the total temperature, °F

T = the measured temperature, °F

V = the gas velocity (ft/sec)

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

g_c = the gravity constant as defined in Section 2, 32.1741 lbm·ft/lbf s^2

C_p = the specific heat, Btu/lbm °F

T_v = the dynamic temperature, °F

(SI Units)

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

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[1] Robert P. Benedict, Fundamentals of Temperature Pressure, and Flow Measurements, Third Edition, Copyright 1984 John Wiley and Sons, Equation 11.7, page 204

where

T_t = the total temperature, °C

T = the measured temperature, °C

V = the gas velocity (m/sec)

J = the mechanical equivalent of heat, 1000 $kg \cdot m^2/kJ\ s^2$

C_p = the specific heat, kJ/kg °C

T_v = the dynamic temperature, °C

This Code requires independent measurements of

(a) exhaust gas temperature at the gas turbine 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 structure or a test fixture will suffice.

The number of measurement points necessary to be used 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 CT/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:

HRSG Inlet

Axial Discharge	Side Discharge
Located every 25 ft^2	Located every 25 ft^2
A minimum of 12 points	A minimum of 18 points
A maximum of 36 points	A maximum of 36 points

Stack

Typically, 12 points in a well-mixed HRSG outlet stream will 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.

4-3.3.3 Inlet Air Temperature. The dry-bulb temperature is the static temperature at the inlet to the gas turbine (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 gas turbine heat balance will increase.

4-3.3.4 Inlet Air Moisture Content. The moisture content of the gas turbine 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 section presents methods of measurement and precautions regarding the measurement of pressure. For additional guidance and requirements, refer to the current version of ASME PTC 19.2, Pressure Measurement.

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 (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

4-4.3 Air and Gas—Static and Differential Pressure

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

4-4.3.1 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.

Table 4-4.2-1 Potential Pressure Systematic Uncertainty Limits

Instrument	Systematic Uncertainty Limits [Note (1)]
Pressure	Note (2)
Gauge	
Test (0.25% Class)	±0.25% of span
Standard (1.0% Class)	±1% of span
Manometer	±0.5 graduation
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) All systematic uncertainty limits are percent of reading unless noted otherwise.
(2) Refer to ASME PTC 19.2, Pressure Measurement, for applicability.

4-4.4 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.

4-4.4.1 Method of Measurement. The ASME PTC 19.2 guidelines should be adhered to in the installation of pressure measuring devices.

4-4.4.2 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 that is 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

$$h_{wc} = h_{wm} + \frac{Ht}{62.32\, s_g}\left(\frac{1}{V_{sen}} - \frac{1}{V_{fluid}}\right)$$

(b) for downward flow

$$h_{wc} = h_{wm} - \frac{Ht}{62.32\, s_g}\left(\frac{1}{V_{sen}} - \frac{1}{V_{fluid}}\right)$$

where

h_{wc} = corrected differential pressure, in. H_2O
h_{wm} = measured differential pressure, in. H_2O
Ht = sensing line height difference, in.
62.32 = conversion factor
V_{sen} = specific volume of sensing line, ft^3/lbm
V_{fluid} = specific volume of process, ft^3/lbm
S_g = specific gravity at the "sensing line" temperature

4-4.5 Barometric Pressure

Barometric pressure is required to determine local ambient conditions.

4-4.5.1 Method of Measurement. The preferred method for determining barometric pressure is from a barometer at the test site in the vicinity of the gas turbine air inlet.

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 of the 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 the Table 4-5.2-1:

Table 4-5.2-1 Maximum Allowable Flow Measurement Uncertainty

Instrument	Systematic Uncertainty Limits [Note (1)]
HP Steam Flow	0.5%
IP Steam Flow	1.0%
LP Steam Flow	1.0%
Supplemental Fuel Flow	0.75%

GENERAL NOTE: Refer to ASME PTC 19.5, Flow Measurement, for applicability.

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

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 flowmetering. While stored during steam blows, the flowmetering 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 flowmetering 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 flowmetering may be in the HRSG manufacturer's scope. Utilization of waterside flowmetering avoids damage problems from pre-operational steam blows. Operational procedures requiring attemperation spray, desuperheating flow and fuel heating need to be considered in the design of the flowmetering 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.

4-5.2.4 Calculation of Flow. Calculation of flow shall be in accordance with ASME PTC 19.5.

4-5.2.5 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 is 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.

4-5.2.6 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.

4-5.2.7 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 gas turbine 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 gas turbine heat balance, respectively. Required gas turbine measurements for a gas turbine heat balance are described in Section 4 of ASME PTC 22, Performance Test Code on Gas Turbines. ASME PTC 22 should be used as the basis for the gas turbine balance measurements.

4-5.4 Liquid Fuel

If liquid-fueled 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 gas turbine fuel flow measurements.

4-5.4.1 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. Other flowmeters or uncalibrated meters are permitted so long as a measurement error of 0.75% or less can be achieved. Refer to ASTM D 1480 for liquid fuel density and ASTM D 445 for liquid fuel viscosity.

4-5.5 Gaseous Fuel

If gaseous-fueled duct burners are employed, the quantity of gaseous fuel burned must be determined.

4-5.5.1 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 data acquisition system. The method and procedure detailed in American Gas Association Gas Measurement Committee Report No. 8 shall be followed for the determination of gas density. Linear flowmeters should be calibrated at the expected working pressure to reduce the flow error. Uncalibrated flowmeters are acceptable if the measurement uncertainty is demonstrated to be less than 0.75%.

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 D 4057 or ASTM D 5287.

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/geometry

(b) number and location of sample points

(c) ambient conditions at sample location

(d) fuel/variability

(e) sample handling/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 Standard 2166, Method of Obtaining Natural Gas Samples for Analysis by Gas Chromatography, 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 prior to 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 D 1945. 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 D 4809.

4-7 POWER MEASUREMENT

Power measurement is required for determination of exhaust flow by gas turbine heat balance. Methods of measuring gas turbine output are described in ASME PTC 22, Performance Test Code on Gas Turbines.

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 of 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 data 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. Prior to leaving the test site, all test data should be stored in 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 prior to leaving the test site. All manually collected data should be made available to all parties to the test prior to leaving 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 prior to 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 section. 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 prior to 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.

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 the 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 the 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 the GT gas flow and composition by the means of an HRSG heat balance. Enough GT data is required in order 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 taken into account.

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 or not 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 in part in order 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. It is this averaged data that is to 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 composition is assumed. The assumed molar composition is taken from the NASA Reference Publication 1311 (Gordon 1982).

Nitrogen	78.0840%
Oxygen	20.9476%
Argon	0.9365%
Carbon dioxide	0.0319%
	100.000%

The dry air composition is corrected for humidity and atmospheric pressure effects via humidity calculations taken from the American Society of Heating, Refrigerating, and Air Conditioning Engineers *Handbook of Fundamentals*, 1997. This section determines the mass fractions and molar flows of the air constituents entering the GT.

5-2.1.2 Data Required

(a) airflow, lb/hr

(b) atmospheric pressure, psia

(c) dry bulb temperature, ºF

(d) wet bulb temperature, ºF
or relative humidity, %

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:

$$\ln(P_v) = C_1/T_R + C_2 + C_3T_R + C_4T_R^2 + C_5T_R^3 + C_6T_R^4 + C_7\ln(T_R)$$

where $T_R = T_{WB} + 459.67$

For the vapor pressure of ice over the temperature range of –148ºF to 32ºF, the constants are:

$C_1 = -1.0214165 \text{ E} + 4$

$C_2 = -4.8932428$

$C_3 = -5.3765794 \text{ E} - 3$

$C_4 = -1.9202377 \text{ E} - 7$

$C_5 = -3.5575832 \text{ E} - 10$

$C_6 = -9.0344688 \text{ E} - 14$

$C_7 = 4.1635019$

For the vapor pressure of water over the temperature range of 32ºF to 392ºF, the constants are:

$C_1 = -1.0440397 \text{ E} + 4$

$C_2 = -11.294650$

$C_3 = -2.7022355 \text{ E} - 2$

$C_4 = -1.2890360 \text{ E} - 5$

$C_5 = -2.4780681 \text{ E} - 9$

$C_6 = 0$

$C_7 = 6.5459673$

If the relative humidity is known, go to Step 2.

If the wet bulb temperature is known, go to Step 4.

Step 2: The vapor pressure should be calculated as in Step 1 using the dry bulb temperature instead of the wet bulb temperature. Calculate the partial pressure of water in the gas by multiplying this vapor pressure times the relative humidity and dividing by 100.

$$P_W = P_V * H_{REL} / 100$$

Step 3: Calculate the fraction of dry air by subtracting the partial pressure of water from the atmospheric pressure and dividing this difference by the atmospheric pressure.

$WF_{DA} = (P_{ATM} - P_W)/P_{ATM}$

The humidity ratio is the difference of the inverse of the weight fraction of dry air minus one, times the molecular weight of water divided by the molecular weight of dry air.

$HR = (1/WF_{DA} - 1) * 18.01528/28.96518$

Go to Step 7.

Step 4: Calculate the saturated humidity ratio from the atmospheric pressure and vapor pressure by the following equation:

$$HR_{SAT} = \frac{0.62198 * (1.0039 * Pv)}{(P_{ATM} - 1.0039 * Pv)}$$

Step 5: Calculate the actual humidity ratio from the saturated humidity ratio, wet bulb temperature, and dry bulb temperature by the following equation:

$$HR = \frac{(1093 - 0.556 * T_{WB}) * HR_{SAT} - 0.240 * (T_{DB} - T_{WB})}{1093 + 0.444 * T_{DB} - T_{WB}}$$

Step 6: Calculate the fraction of dry air from the actual humidity ratio by the following equation:

$$WF_{DA} = \frac{18.01528}{28.9651785 * HR + 18.01528}$$

Step 7: The wet air mole fractions can now be calculated. The fraction of dry air multiplied by the dry air mole fraction will give the actual air constituent mole fraction.

Nitrogen mole fraction $= MF_{N_2} = WF_{DA} * 0.780840$

Oxygen mole fraction $= MF_{O_2} = WF_{DA} * 0.209476$

Argon mole fraction $= MF_{Ar} = WF_{DA} * 0.009365$

Carbon dioxide mole fraction $= MF_{CO_2} = WF_{DA} * 0.000319$

The molar composition of water is one minus the fraction of dry air.

Water mole fraction $= MF_{H_2O} = 1.0 - WF_{DA}$

The composition of Sulfur Dioxide in air is zero.

Sulfur Dioxide mole fraction $= MF_{SO_2} = 0.0$

Step 8: Calculate the air average molecular weight by the following equation:

$$\begin{aligned} MW_{AVG} = {} & MF_{N_2} * 28.01348 + MF_{O_2} * 31.9988 + MF_{CO_2} * 44.0098 \\ & + MF_{H_2O} * 18.01528 + MF_{Ar} * 39.948 + MF_{SO_2} * 64.0648 \end{aligned}$$

Step 9: 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:

Nitrogen molar flow $= WM_{N_2} = MF_{N2} * W_A/MW_{AVG}$

Oxygen molar flow $= WM_{O_2} = MF_{O_2} * W_A/MW_{AVG}$

Carbon Dioxide molar flow $= WM_{CO_2} = MF_{CO_2} * W_A/MW_{AVG}$

Water molar flow $= WM_{H_2O} = MF_{H_2O} * W_A/MW_{AVG}$

Argon molar flow $= WM_{Ar} = MF_{Ar} * W_A/MW_{AVG}$

Sulfur Dioxide molar flow $= WM_{SO_2} = MF_{SO_2} * W_A/MW_{AVG}$

Step10: Calculate the air constituent weight fraction by multiplying the constituent mole fraction by its molecular weight and dividing by the air average molecular weight.

Nitrogen weight fraction $= WF_{N_2}$ $= MF_{N_2} * 28.01348/MW_{avg}$

Oxygen weight fraction $= WF_{O_2}$ $= MF_{O_2} * 31.9988/MW_{avg}$

Carbon Dioxide weight fraction $= WF_{CO_2}$ $= MF_{CO_2} * 44.0098/MW_{avg}$

Water weight fraction $= WF_{H_2O}$ $= MF_{H_2O} * 18.01528/MW_{avg}$

Argon weight fraction $= WF_{Ar}$ $= MF_{Ar} * 39.948/MW_{avg}$

Sulfur Dioxide weight fraction $= WF_{SO_2}$ $= MF_{SO_2} * 64.0648/MW_{avg}$

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 the each compound of a fuel gas stream.

5-2.2.2 Data Required

(a) either fuel gas flow, lb/hr
or fuel gas flow, Standard ft^3/min
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 would pass 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.

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_4H_8	0	−6	4	4	0	0
C_5H_{12}	0	−8	5	6	0	0
C_5H_{10}	0	−7.5	5	5	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
H2	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
Ar	0	0	0	0	1	0

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.

$$MW_{FG} = \Sigma[MF_i * MW_i]$$

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

$$\text{Fuel Gas Molar Flow} = WM_{FG} = \frac{W_{FG}}{MW_{FG}}$$

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

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

where standard conditions are defined as 60°F and 14.696 psia.

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 air flow for combustion is the dry air flow multiplied by one plus the humidity ratio of air (para. 5-2.1.3, Step 3 or Step 5).

$$W_{AC} = \frac{\Delta WM_{O_2}}{0.209476} * 28.9651785 * HR$$

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

(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 28.01348.

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 12.011, the hydrogen weight fraction divided by 4.03176, and the sulfur weight fraction divided by 32.066. Multiply the result times the fuel oil flow.

$$\Delta WM_{O_2} = (WF_O/31.9988 - WF_C/12.011 - WF_H/4.03176 - WF_S/32.066) * W_{FO}$$

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 12.011.

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 32.066.

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 one plus the humidity ratio of air (para. 5-2.1, Step 3 or Step 5).

$$W_{AC} = \frac{\Delta WM_{O_2}}{0.209476} * 28.9651785 * HR$$

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

(a) fuel gas compound mole fractions

(b) fuel gas temperature

5-2.4.3 Fuel Compound Heating Value Table. Table 5-2.4.3-1 is taken from ASTM D 3588-98. It has been updated based upon GPA Standard 2145-03 in accordance with ASTM D 3588 Table 1, Footnote A. The most current version of these standards should be used. The heating values for butanes, pentanes, and hexanes are average values for the various isomers. The heats of combustion are based upon 60ºF and 14.696 psia.

5-2.4.4 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.

Step 2: Calculate the heating value contribution of each fuel gas compound by computing the product of the fuel gas compound mole fraction, the fuel gas compound molecular weight, and the fuel gas compound heat of combustion and dividing by the total fuel weight.

Step 3: Calculate the fuel gas ideal heating value by summing the heating value contributions of all fuel gas compounds.

Table 5-2.4.3-1 Fuel Compound Heating Values

Compound Name	Compound Symbol	Molecular Weight	Heat of Combustion, Btu/lb
Methane	CH_4	16.04276	21,503
Ethane	C_2H_6	30.06964	20,432
Ethene	C_2H_4	28.05376	20,278
Propane	C_3H_8	44.09652	19,923
Propene	C_3H_6	42.08064	19,678
Iso Butane	C_4H_{10}	58.1234	19,587
Normal Butane	C_4H_{10}	58.1234	19,659
Butene (avg)	C_4H_8	56.10752	19,450
Iso Pentane	C_5H_{12}	72.15028	19,456
Normal Pentane	C_5H_{12}	72.15028	19,498
Pentene (avg)	C_5H_{10}	70.1344	19,328
Hexane (avg)	C_6H_{14}	86.17716	19,353
Nitrogen	N_2	28.01348	0
Carbon Monoxide	CO	28.0104	4,342
Carbon Dioxide	CO_2	44.0098	0
Water	H_2O	18.01528	0
Hydrogen Sulfide	H_2S	34.08188	6,534
Hydrogen	H_2	2.01588	51,566
Helium	He	4.0026	0
Oxygen	O_2	31.9988	0
Argon	Ar	39.948	0

Step 4: The following equation is used to calculate the sensible heat content of the fuel. It is adequate for natural gas. For nonstandard fuels, especially fuels with hydrogen, a different method may be required. See Nonmandatory Appendix C.

$$Q_{FS} = T_F^2/4720 + 0.491*T_F - 30.2$$

Step 5: The fuel net heating value is the sum of the fuel gas ideal heating value and the fuel 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 for oil is to be determined by a bomb calorimeter test performed in accordance with ASTM D 4809.

5-2.5.2 Data Required

(a) fuel oil ideal heating value, Btu/lb

(b) fuel temperature, ºF

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's Chemical Engineering Handbook, 7th Edition, page 27-10. See Nonmandatory Appendix C.

$$Q_{FS} = T_F^2/4132 + 0.417 * T_F - 25.9$$

Step 2: The fuel net heating value is the sum of the fuel oil ideal heating value and the fuel sensible heat.

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 (Ref. NASA Reference Publication 2002-211556, September 2002).

5-2.6.2 Data Required

(a) gas temperature, ºF

(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 dual range correlations with a change at 1,800°R. The correlations require the temperature to be in °R. See Table 5-2.6.3-1.

T_R = Temperature [°R] = (Temperature [°F] + 459.67)

$$h_i = -A_1/T_R + A_2\ln(T_R) + A_3*T_R + A_4*T_R^2 + A_5*T_R^3 + A_6*T_R^4 + A_7*T_R^5 - A_8$$

Table 5-2.6.3-1 Constituent Enthalpy Equation Constants

$T_R <= 1{,}800$°R

	A_1	A_2	A_3	A_4*10^5	A_5*10^9	A_6*10^{14}	A_7*10^{19}	A_8
N_2	5076.903444	–48.72474552	0.431208942	–16.79893331	100.9860003	–2925.146767	34031.29176	–123.5670205
O_2	–6888.073538	54.14599817	0.069447256	7.402341031	–4.364913417	–538.2934954	12285.5047	406.9617332
CO_2	7227.711078	–50.87920389	0.239235281	3.138394549	–0.987579956	–148.749738	2449.873977	–199.50475
H_2O	–14100.39482	114.2053432	0.102713623	22.11623913	–83.27114025	2341.441933	-28077.80325	844.3000544
Ar	0	0	0.124279476	0	0	0	0	64.58431507
SO_2	–5333.964877	50.72160967	–0.073060273	18.98189113	–80.07268636	1921.86454	–19897.19608	330.8196608

$T_R > 1{,}800$°R

	A_1	A_2	A_3	A_4*10^5	A_5*10^9	A_6*10^{14}	A_7*10^{19}	A_8
N_2	134989.0343	–285.7350587	0.43008964	–1.209016552	1.088015054	–5.844054022	14.34281709	–1809.588277
O_2	–208707.2821	261.9417179	0.112934906	2.185673559	–1.397060777	5.463669086	–9.687873053	2037.040157
CO_2	17207.41433	–145.2915082	0.374147054	–0.115607258	0.022579091	–0.365792061	5.44194572	–758.4598037
H_2O	369646.9091	–478.7281864	0.512156854	7.018191588	–7.753574689	44.54356391	–101.277945	–3313.267173
Ar	3.238297928	–0.005362306	0.124282926	–5.51268E-05	6.16422E-05	–0.000387631	0.001021528	64.54706733
SO_2	–11325.49719	–46.04550381	0.236090695	–0.172156415	0.180366793	–0.724777306	1.723497991	–151.4826348

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.

$$h_G = WF_{N_2}*h_{N_2} + WF_{O_2}*h_{O_2} + WF_{CO_2}*h_{CO_2} + WF_{H_2O}*h_{H_2O} + WF_{Ar}*\mathrm{h}_{Ar} + WF_{SO_2}*h_{SO_2}$$

5-2.7 Gas Turbine Gas Composition

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

5-2.7.2 Data Required

(a) airflow, lb/hr

(b) steam/water injection, lb/hr

(c) fuel flow, lb/hr

(d) air molar flow, moles/hr (para. 5-2.1.3, Step 9)

(e) change in molar flow, moles/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/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/water injection molar flow.

Step 6: The argon molar flow is the argon molar flow from the air.

Step 7: The sulfur dioxide molar flow is the sum of the sulfur dioxide molar flow from the air and the change in molar flow of sulfur dioxide 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/water injection flow.

Step 9: Calculate the gas constituent mass fractions. A gas constituent mass fraction is the constituent molar flow times 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

(a) steam temperature before water spray, ºF
(b) steam temperature after water spray, ºF
(c) steam pressure at spray point, psig
(d) spray water temperature, ºF
(e) spray water pressure, psig
(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 times 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 water enthalpy.

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

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

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 times 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 the 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 would be the energy associated with the gas heat from the HRSG, the working fluid leaving the HRSG and heat losses. The energy balance is:

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

Each term is quantified except for the gas energy in and out. These are defined as the gas flow times 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 the other stream is the balance of air that is the air in excess of that required for combustion. For the combustion stream, the gas flow and composition in to 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 gas flow in is the sum of the balance of air flow and the combustion stream in to the HRSG. The reference temperature for the calculations is 60°F.

5-3.1.2 Data Required

(a) Ambient
  (1) either wet bulb temperature, ºF or relative humidity, %
  (2) dry bulb temperature,ºF
  (3) barometric pressure, psia
(b) GT
  (1) either fuel flow, lb/hr or fuel flow, SCFM, and gas compressibility
  (2) fuel composition
  (3) steam/water injection flow, lb/hr
(c) working fluid duty, Btu/hr
(d) HRSG
  (1) gas inlet temperature, ºF
  (2) gas outlet temperature, ºF
  (3) heat loss, Btu/hr
(e) duct burner
  (1) fuel flow,lb/hr
  (2) fuel temperature, ºF
  (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, ºF

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. The wet airflow for combustion is also determined.

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 to the HRSG 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 from the HRSG is calculated as described in para. 5-2.6 with the same gas constituents mass fractions as 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 as 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 from the HRSG 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 times the stream enthalpy. The air enthalpy is calculated by using the air composition from Step 1 in para. 5-2.6 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 60ºF. 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 such as those in subsection 2-4. The duty is the stream flow times its enthalpy. The duty associated with a stream crossing the boundary going to the HRSG would be negative. The duty with a stream leaving the HRSG would be positive. The streams will typically be water and the ASME steam tables are to 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.

Energy In = Energy Out

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

Step 14: The total gas flow in to the HRSG is the sum of the balance of air flow 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 has to 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

duct burner fuel flow, SCFM
gas compressibility

(f) gas molar low, moles/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, moles/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 times 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 times 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 times 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 times the water mole fraction in air divided by the air molecular weight.

Step 6: The argon molar flow is the argon molar flow for the GT gas and the augmenting airflow times 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 times the constituent molecular weight divided by the total duct burner gas mass flow.

5-3.3 HRSG Heat Loss

The heat loss is estimated from the HRSG as a function of the GT gas flow. The test uncertainty analysis typically does not warrant detailed calculations. The heat loss would be for typical systems. Unusual cases may require additional calculations. More guidance is available in Nonmandatory Appendix F.

The heat loss is approximated by the following equation:

$$Q_{HL\%} = -1.38\times10^{-10}\times\left(\frac{Q_{G\,IN}}{10^6}\right)^3 + 8.83\times10^{-7}\times\left(\frac{Q_{G\,IN}}{10^6}\right)^2 - 1.66\times10^{-3}\times\left(\frac{Q_{G\,IN}}{10^6}\right) + 1.24$$

$$Q_{HL} = Q_{HL\%}\times100\times\left(Q_{G\,IN} - Q_{G\,OUT}\right)$$

The above equation is based on a base loaded, unfired operating condition. HRSGs with supplemental firing will have a minor impact on the calculated heat loss in Btu/hr and this equation should be used based upon the heat input from the GT only. The range of heat input that this equation is valid for is from 100 million Btu/hr to 1,500 million Btu/hr. For heat inputs outside this range the user is referred to Nonmandatory Appendix F.

5-4 GAS FLOW BY GAS TURBINE ENERGY BALANCE

5-4.1 Gas Turbine Gas Flow Calculations

5-4.1.1 General. 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.

Energy In = Energy Out

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

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 steams; 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 in to 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 Mandatory Appendix I.

5-5 WEIGHTED CAPACITY

5-5.1 General

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

5-5.2 Data Required

(a) $C1$ — Capacity Value 1
(b) $U1$ — Uncertainty 1
(c) $B1$ — Systematic Uncertainty 1
(d) $S1$ — Random Uncertainty 1
(e) $C2$ — Capacity Value 2
(f) $U2$ — Uncertainty 2
(g) $B2$ — Systematic Uncertainty 2
(h) $S2$ — Random Uncertainty 2

5-5.3 Calculations

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

$$W1 = \frac{U2^2}{U2^2 + U1^2}$$

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

$$W2 = \frac{U1^2}{U2^2 + U1^2}$$

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

$$Bw = (W1 * B1 + W2 * B2)^{0.5}$$

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

$$Sw = (W1 * S1 + W2 * S2)^{0.5}$$

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

$$Cw = W1 * C1 + W2 * C2$$

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

$$Uw = 2 * [(Bw/2)^2 + Sw^2\,]^{0.5}$$

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.

5-6 CORRECTION OF TEST CONDITIONS TO GUARANTEE

5-6.1 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 would 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, which 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 prior to correcting to reference conditions.

5-6.2 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 will be dependent upon all of the factors necessary to originally design the HRSG. The performance factors would 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/water outlet pressure for all pressure levels

Predicted steam temperatures and flows for a test will 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 would be 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 would be added to each of the corrections. The resultant steam flow and temperatures would 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 would be able to predict the steam capacity that should be produced for the test conditions. A computer model has the advantage of taking into account all performance factors simultaneously. It would also take into account any secondary interaction effects between performance factors. A computer model would be able to better predict results with factors quite different than originally specified conditions.

Once the capacity is established for the test conditions, it can be compared to the corresponding measured value. The measured value would be 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.

5-6.3 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 would be 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 will be dependent upon all of the factors necessary to originally design the HRSG. The performance factors would 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/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 would be 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 would be added to each of the corrections. The resultant fuel flow would 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. A computer model would be able to predict the fuel flow for any set of performance parameters. It has the advantage of taking into account all performance factors simultaneously. It would also take into account any secondary interaction effects between performance factors. A computer model would be able to 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 would be 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.

5-6.4 Gas Side Pressure Drop

5-6.4.1 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 would be through the use of a computer model or detailed manual calculation. In the absence of these approaches the following method 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 following method should not be used.

5-6.4.2 Data Required. The following data is required for Test and Reference Conditions:

- *(a)* GTE flow, lb/hr
- *(b)* GTE molecular weight
- *(c)* atmospheric pressure, psia
- *(d)* gas pressure drop, inches of water

5-6.4.3 Calculations. The gas pressure drop of the test is corrected by multiplying the measured pressure drop times 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.

$$DP_{\mathrm{Cor}} = DP_{\mathrm{Test}} * (W_{G\,\mathrm{Ref}}/W_{G\,\mathrm{Test}})^2 * P_{ATM\,\mathrm{Test}}/P_{ATM\,\mathrm{Ref}} * MW_{G\,\mathrm{Test}}/MW_{G\,\mathrm{Ref}}$$

The 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.

5-6.5 Steam Side Pressure Drop

5-6.5.1 General. The steam/water side pressure drop usually is not a critical factor in the design of the HRSG. The pressure drop is a function of the steam/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 would be through the use of 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 following approach can be used. The assumption for this method is that the average steam/water temperatures through the HRSG are the same as the reference conditions.

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

5-6.5.2 Data Required. The following data is 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, ºF

(e) inlet temperature of superheater, ºF

(f) pressure drop in sections and piping for heating water, psig

(g) steam/water flow, lb/hr

5-6.5.3 Calculations

Step 1: The average steam density is determined from the steam tables using the average of the superheater inlet and outlet pressure and average of the superheater inlet and outlet temperature. The density would 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 steam coils pressure drop is equal to the measured pressure drop times the ratio of reference flow divided by the measured flow squared, times the test average density divided by the reference average density.

$$DP_{S\ \mathrm{Cor}} = DP_{S\ \mathrm{Test}} * (W_{S\ \mathrm{Ref}}/W_{S\ \mathrm{Test}})^2 * (\rho_{S\ \mathrm{Test}}/\rho_{S\ \mathrm{Ref}})$$

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

$$DP_{W\ \mathrm{Cor}} = DP_{W\ \mathrm{Test}} * (W_{W\ \mathrm{Ref}}/W_{W\ \mathrm{Test}})^2$$

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

Section 6
Report of Results

6-1 GENERAL

The report shall formally and clearly present the pretest agreements and the observed data, calculations, and results. It shall include sufficient information to demonstrate that all objectives of the test have been met.

The title page shall include the report number, report date, test date(s), test title, location, Owner, Purchaser, HRSG manufacturer, and HRSG identification (tag number and service).

The table of contents shall include the following major sections and subsections as needed.

6-2 SECTION 1: EXECUTIVE SUMMARY

The Summary shall consist of a single page noting the objectives, actual test results, corrected test results, guarantee requirements, conclusions, and uncertainty of the test. It shall also include a statement that the corrected test results are believed correct and that the post-test uncertainty is within the agreed upon allowance for uncertainty.

6-3 SECTION 2: INTRODUCTION

The Introduction shall 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 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) a description of the operating history of the HRSG and auxiliary equipment since initial startup, including any items that may affect the test results

6-4 SECTION 3: TEST DATA

Test data shall consist of a summary of actual measurements and observations and a complete description of date and time and any methods of testing or measurement, including any differences from the pretest agreement or not prescribed by this Code.

6-5 SECTION 4: DATA REDUCTION, CORRECTIONS, AND RESULTS

Data reduction, corrections, and results shall 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 discussion of the tests, results, and conclusions, including test observations and descriptions of any differences from the methods agreed to or allowed by this Code, and the resolution of the differences

6-6 SECTION 5: APPENDICES

The Appendices should include the following:

(a) the pretest agreement and 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) the instrument calibration methods used and calibration data for instrumentation used in the test with appropriate approval initials
(f) the raw test data
(g) a list of personnel directing, conducting, witnessing, and determining results of the test with their affiliations and titles
(h) any other supporting information required to make the report a complete, self-contained document of the entire undertaking

Section 7
Uncertainty Analysis

7-1 INTRODUCTION

(a) 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, 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 Section describes the methodology that shall be used for the required pretest and the required post-test uncertainty analyses. Specifically, this Section addresses the following:

(1) how to determine individual random uncertainties and how they are combined

(2) how to combine individual systematic uncertainties

(3) how to combine the random and systematic uncertainties

(4) how to calculate the uncertainty of test results

Additional information on uncertainty is available in ASME PTC 19.1, Test Uncertainty.

7-1.1 Pretest Uncertainty Analysis and Test Planning

A pretest uncertainty analysis is an excellent aid in test planning. The parties to a test can use a pretest uncertainty analysis to assist in reaching many of the agreements required in Section 3. Decisions regarding number and types of instruments, number of readings, number of sampling points in a grid, and number of fuel samples can be made based on their predicted influence on the uncertainty of the test results.

A careful pretest uncertainty analysis can help control the costs of testing by keeping the number of readings or samples at the minimum necessary to achieve the target uncertainty and by revealing when it is not necessary or cost-effective to make certain measurements.

7-2 UNCERTAINTY CALCULATION

7-2.1 Pretest and Post-Test Uncertainty

The uncertainty calculation described in para. 7-2.2 is applicable for both a pretest and post-test uncertainty calculation. When performing a pretest uncertainty calculation, the design values can be used in place of the measured test results, which are not available. The random uncertainties can be estimated based on preliminary observation of equipment operating conditions and prior experience.

7-2.2 Uncertainty Calculation Procedure

(a) To complete the uncertainty analysis the following will be required:

(1) a method for calculating a heat balance around the gas turbine-generator (see Mandatory Appendix I)

(2) a method for calculating a heat balance around the HRSG (see Section 5 of this Code)

(3) a computer program that can be used to determine the sensitivities of each measured parameter on the final result

(b) The following procedure is used to determine the uncertainty. Two Uncertainty calculations are generated for each test result parameter, i.e., HP Capacity, IP Capacity, LP Capacity, Gas Side Pressure Drop, and RH Pressure Drop. One calculation is for the determination of the test result parameter by using the HRSG Energy Balance; the other calculation is for the determination of the test result parameter by using the Gas Turbine Energy Balance. Each calculation is comprised of a sensitivity worksheet and an uncertainty worksheet.

  (1) Sensitivity Worksheet (Nonmandatory Appendix H):

    (a) For each Uncertainty calculation, the sensitivity worksheet "Measured Parameter" column is filled in by listing all the measured values that are used to predict or measure the test result parameter by the specific Energy Balance method used.

    (b) Fill in the column "Average Value" by recording the measured average value of each measured parameter of the performance test.

    (c) All average values of test data are used to determine an exhaust flow by the selected method. This exhaust flow is then used in a predictive model to determine the Base Value of Result.

    (d) Sensitivity coefficients are calculated either analytically or numerically in accordance with ASME PTC 19.1. Specifically, Section 7.2 and 10.5.4.1 of ASME PTC 19.1-1998 shall be followed for determination of Sensitivity Coefficients. Fill in the column "Incremental Change" with the value of the incremental change. The incremental change should be large enough to indicate a nominal change in predicted performance.

    (e) Fill in the column "New Value of Parameter" by recording the new value, which is the average value plus the incremental change.

    (f) Using the new value for only one measured parameter and the average value for the remaining measured parameters, calculate a new exhaust gas flow by the appropriate energy balance method. Record this value in the column "New Exhaust Flow With New Parameter."

    (g) Using the new value for only one measured parameter, the exhaust flow calculated in para. 7-2.2(b)(1)(f), and the average value for the remaining measured parameters, determine the corrected test result parameter, i.e., HP Capacity, IP Capacity, LP Capacity, Gas Side Pressure Drop, RH Pressure Drop. If the measured parameter is an input to the performance prediction model such as exhaust temperature, the exhaust flow and the new value should be changed in order to determine the new test result. Record this value in the column "New Steam Flow at New Exhaust Flow" and new parameter.

    (h) Fill in the column "Absolute Sensitivity Coefficient" with the difference of the new result minus the base value of result and divide by the incremental change of the measured parameter.

    (i) Fill in the column "Relative Sensitivity Coefficient" by recording the relative sensitivity coefficient, which is the absolute sensitivity coefficient times the average value of the parameter divided by the base value of result.

    (j) Repeat steps in para. 7-2.2(b)(1)(f) through (i) for each measured parameter.

  (2) Uncertainty Worksheet (Nonmandatory Appendix H):

    (a) For the Uncertainty worksheet, fill in the columns "Measured Parameter," "Average Value" and "Absolute Sensitivity Coefficient" from the Sensitivity worksheet. When the Uncertainty for a Test Result has that same value included in the uncertainty analysis as a Measured Parameter, the value to be filled into the "Absolute Sensitivity Coefficient" of the Uncertainty Worksheet is one minus the calculated "Absolute Sensitivity Coefficient" from the Sensitivity Worksheet. An example of this is shown in Nonmandatory Appendix C with a brief summary as follows:

(1) HRSG Heat Balance HP Steam Flow Uncertainty

(2) Sensitivity Worksheet
HP Steam Flow (Feedwater) Absolute Sensitivity Coefficient = 0.7901

(3) Uncertainty Worksheet
HP Steam Flow (Feedwater) Absolute Sensitivity Coefficient = 0.2099

(b) Fill in the column "Sample Deviation" by recording the standard deviation of the sample data for each measured value. The standard deviation is determined by summing for all data points, the square of the difference between the measured value and the average of all data points. This sum is divided by one less than the number of data points and then the square root is taken, using the following formula:

$$S_x = \sqrt{\sum_{k=1}^{N} \frac{(X_k - \overline{X})^2}{N-1}}$$

X_k = datum value

$\overline{X}$ = data average

N = number of sample points

S_x = standard deviation

(c) Fill in the column "Number of Samples" by recording the number of data samples taken.

(d) Fill in the column "Sample Deviation of Average" by recording the standard deviation of the average using the following formula:

$$S_{\bar{x}} = \sqrt{\frac{S_x^{\,2}}{N}}$$

where

S_x = standard deviation of the sample

N = number of sample points

$S_{\bar{x}}$ = standard deviation of the sample average

(e) Fill in the column "Degrees of Freedom." The number of degrees of freedom is the number of samples minus 1.

(f) Calculate the "Absolute Sensitivity × Sample Deviation of Ave," also called the Precision Index of the Result by recording the product of absolute sensitivity coefficient and the sample deviation of the average

(g) Calculate the Overall Degrees of Freedom by filling in the column "(Ab Sens × SDA)^4/Deg of Fdm" by recording the product of the absolute sensitivity coefficient and the sample deviation of the average, raised to the 4th power, and divided by the number of degrees of freedom.

(h) Fill in the column "Random Uncertainty %" by recording the result of "Absolute Sensitivity × Sample Deviation of Ave" divided by the base value of the result times 100%. Terms with larger absolute values have more influence on the random uncertainty of the result.

(i) Fill in the column "Systematic Uncertainty for Parameter" by recording the estimated systematic uncertainty for the parameter in the same units as the measured parameter. The systematic uncertainty is estimated based on the method used to determine the measured parameter. Guidance on estimating systematic uncertainty is included in Section 4. Sample worksheets are included in Nonmandatory Appendix H. Refer to ASME PTC 19.5 and ASME PTC 4 for further assistance in the determination of individual systematic uncertainty.

(j) Fill in the column "Abs Sensitivity × Systematic Uncert-Para" by recording the product of absolute sensitivity times systematic uncertainty for the parameter.

(k) Fill in the column "Systematic Uncertainty %" by recording the result of "Abs Sensitivity × Systematic Uncert-Para" divided by the base value of the result times 100%. Terms with larger absolute values have more influence on the systematic uncertainty of the result.

(l) Determine the "Random Uncertainty of Result" by taking the square root of the sum of the squares of the values in the column "Absolute Sensitivity × Sample Deviation of Ave."

(m) Determine the "Degrees of Freedom for Random Uncertainty of Result" by taking the random uncertainty of result raised to the 4th power divided by the sum of the values in the column "(Ab Sens × SDA)^4/Deg of Fdm".

(n) Fill in the value 2 for the "Student's *t* Value" for the uncertainty. This is based on the combined degrees of freedom for the systematic and random components of uncertainty.

(o) Determine the "Systematic Uncertainty of Result – 95% Confidence Level" by taking the square root of the sum of the squares of the values in the column "Abs Sensitivity × Systematic Uncert-Para".

(p) Determine the "Total Uncertainty" by multiplying 2 by the square root of the sum of "Random Uncertainty of Result" squared and ("Systematic Uncertainty of Result-95% Confidence Level" divided by 2) squared.

(q) Determine the "Uncertainty Percent" by dividing the total uncertainty by the base value of the result.

(r) Determine the weighted value of the test result by combining the results determined by the HRSG and gas turbine energy balances as described in subsection 5-5.

When calculating the new test result at new exhaust flow on the sensitivity worksheet [para. 7-2.2(b)(1)(g)], the exhaust gas composition should be determined from the average value test data. Perturbing individual measured parameters will result in small changes in the exhaust gas composition. These small changes may be ignored in the calculation of the new test result.

7-3 GUIDANCE FOR DETERMINING SYSTEMATIC ERRORS

The systematic error is the "built-in" component of the error. The systematic error is what remains after all reasonable attempts to eliminate it (such as calibrating instruments) have been made. An essential characteristic of the systematic error is that it cannot be determined directly from the test data. It is always necessary to estimate the systematic error. Sometimes, models based on the test data or observations of conditions during the test can be used in making estimates, but they remain estimates nevertheless. A second essential fact concerning the systematic error is that its value(s) is unique to the measurement system employed in a specific test and to the process and ambient conditions during the test.

This Section gives certain mandatory rules for making systematic error estimates and for mathematical manipulation of them. It also provides guidance and some models for estimating values of systematic errors. Users of this Code are free to adopt, modify, or reject any models for systematic error set forth in this Section, provided that the parties to the test agree to do so and agree on an appropriate substitute.

7-3.1 General Rules

Systematic errors used in this Code have the following characteristics:

(a) Systematic errors shall be agreed upon by the parties to the test.

(b) Systematic errors should be estimated at a 95% confidence level; the maximum conceivable values of the systematic error should not be used.

(c) If the parties to the test agree that there are nonsymmetrical or one-sided systematic errors, then it is necessary to refer to ASME PTC 19.1 for the procedure on handling nonsymmetrical systematic errors.

Although the actual systematic error in any measurement or result is a fixed value, an estimate of the systematic error is a random variable. This Code specifies that systematic errors shall be combined by using the root-sum-square method.

Generally, the same systematic error will be used for both pretest and post-test uncertainty analyses. Observations of conditions during the test may indicate that it is allowable to decrease one or more systematic errors or that it is advisable to increase one or more systematic errors. This shall be permitted if both parties to the test agree.

7-3.2 Systematic Error in Measured Parameters From Instrumentation

There are a number of sources of instrumentation systematic error in any measurement; among those are: primary element, primary sensor, transducer, amplifier, analog/digital converter, recording device, drift, and environmental effects. The following documents may be consulted for general information on instrumentation systematic error: ASME Performance Test Codes, ASME MFC, ISA Standard ANSI/ISA S51.1. This Section provides general guidelines and rules for combining these elemental systematic errors.

If separate components of an instrumentation loop or the entire loop has been calibrated and the calibration data are incorporated into the test data, the systematic error shall be reduced to account for the uncertainty of the calibration.

7-3.3 Systematic Error in Gas Turbine HRSG Exhaust Temperature and Stack Temperature

The GT exhaust temperature and stack temperature uncertainty is made up of two components: random uncertainty and systematic uncertainty.

The random component is determined from the variation of the average exhaust temperatures at each time period. It is calculated like the random component of flow, temperature, or pressure.

The systematic component needs to include the systematic uncertainty of the thermocouples used and the spatial variation from one temperature measurement point to another. The systematic uncertainty of the thermocouple is a function of the type of thermocouple being used, the transmitter, wiring, etc. For a type K thermocouple measuring 1,100°F, this would be approximately 11°F or 1% of the measured value. The spatial variation is estimated from the variation of the temperatures between measurement locations using the following equation:

$$Bs = t * Ss/(N^{**}0.5)$$

where

Bs = spatial contribution to systematic uncertainty

Ss = standard deviation of the spatial temperature averages[1]

t = the Student t for (N-1) degrees of freedom

N = number of samples

---

[1] The temperatures at each location are averaged for the entire test set. The standard deviation, Ss, is of these average temperatures.

The systematic uncertainty of the gas turbine exhaust or stack temperature is then calculated using the following equation:

$B = (B_{T/C}**2 + Bs**2)**0.5$

where

B = systematic uncertainty of temperature grid

$B_{T/C}$ = systematic uncertainty of temperature measurement

Bs = spatial contribution to systematic uncertainty

MANDATORY APPENDIX I
EXHAUST FLOW BY GAS TURBINE ENERGY BALANCE

I-1 INTRODUCTION

The Committees of PTC 4.4 and PTC 22 have been working together to come up with a common procedure for calculating heat balance. This procedure will be incorporated into ASME PTC 22 when it is issued. In the interim, this procedure will be utilized for the calculation of gas turbine heat balance.

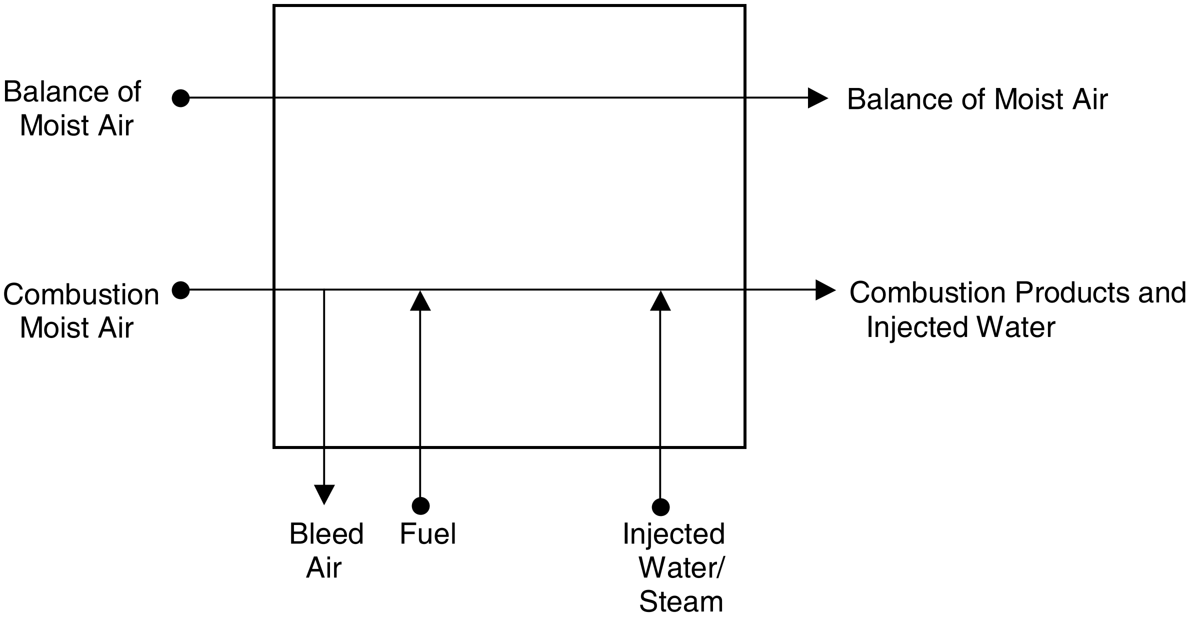
I-2 GENERAL

The calculations in this Section are for the determination of the GT exhaust flow and composition by the means of a GT heat balance. GT data is required in order to calculate the GT gas composition, which in turn allows for the determination of the gas enthalpies.

The airflow through the GT is the only unknown with GT fuel flow, bleed air, and injection streams being measured. In order to define the gas composition leaving the GT, the 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 and steam or water injection. The flow and composition of this stream can be defined. The balance of air stream is just moist air.

The exhaust 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 turbine.

Fig. I-2-1 Exhaust Flow



The energy from the system is from the exhaust leaving the turbine, electrical energy generated, bleed air stream, and heat losses. The only unknown is the balance of airflow, which can be solved directly. Once this is defined, the entire exhaust stream flow and composition can be computed. See Fig. I-2-1.

The reference temperature for the calculations is 60°F.

I-3 DATA REQUIRED

Note that the air temperature and humidity conditions must be characteristic of the air as it enters the compressor inlet section of the GT.

(a) Ambient

(1) wet bulb temperature, °F
(2) dry bulb temperature, °F

(b) Either barometric pressure, psia, or relative humidity, %

(c) Gas Turbine

(d) Either

(1) fuel flow, lb/hr

or

fuel flow, SCFM
gas compressibility
(2) fuel composition
(3) fuel heating value (oil), Btu/lb
(4) steam/water injection flow, lb/hr
(5) steam/water injection temperature, °F
(6) steam/water injection pressure, psig
(7) injection flow state (liquid/vapor)
(8) GT exhaust outlet temperature, °F
(9) GT heat loss, Btu/hr
(10) power, MW
(11) bleed airflow, lb/hr
(12) bleed air outlet temperature, °F

I-4 CALCULATIONS

The calculations will consist of a series of steps, many of which involve calculations performed in other sections.

Step 1: The GT inlet 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: The GT inlet air enthalpy is calculated in para. 5-2.6 by using the air composition from Step 1 and the given dry bulb temperature. The bleed air enthalpy is calculated with the same air composition and the given bleed air temperature. The balance of air outlet enthalpy is also calculated with the same air composition and the GT gas outlet temperature.

Step 4: The gas outlet composition is calculated using the total wet air molar flow for combustion as determined in Step 1 and adding the change in molar flow due to the combustion of fuel in the GT from Step 2. The gas molar flow 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.

Step 5: The gas enthalpy from the GT is calculated in para. 5-2.6 with the gas constituent mass fractions as determined from Step 4 and the gas turbine gas outlet temperature.

Step 6: The GT 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 7: The enthalpy of a steam or water stream injected into the GT is determined from the stream temperature, pressure, and state (liquid or vapor). The stream enthalpy is determined by subtracting 1,087.73 Btu/lb from the steam table enthalpy to adjust the reference temperature to a vapor at 60°F.

Step 8: The electrical energy generated is determined by multiplying the megawatts produced by 3,412,140 Btu/hr/megawatt.

Step 9: The GT heat loss is determined. See subsection I-4.

Step 10: The balance of airflow is now the only unknown parameter in the heat balance equation and can be directly solved.

$$\text{Energy In} = \text{Energy Out}$$

$$(W_{BA} + W_{BLD} + W_{AC}) * h_{A\ \mathrm{IN}} + W_{INJ} * h_{INJ} + W_{GT\ F} * HV_{\mathrm{NET}}$$

$$= Q_{HL} + W_{BLD} * h_{BLD} + (W_{AC} + W_{INJ} + W_{GT\ F}) * h_{G\ \mathrm{OUT}} + W_{BA} * h_{A\ \mathrm{OUT}}$$

Step 11: The total gas flow from the GT is the sum of the balance of airflow from Step 10 and the combustion air inlet flow plus the injection flow plus the GT fuel flow.

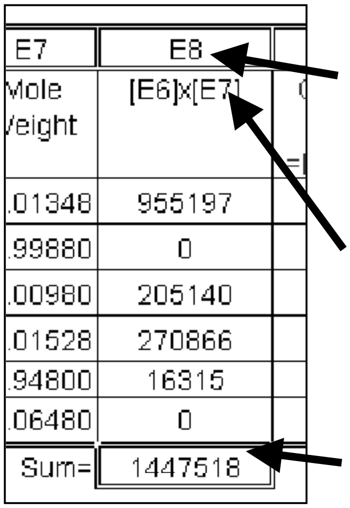
Step 12: The balance of air inlet constituent molar flow is determined by dividing the balance of airflow by the air molecular weight determined in para. 5-2.1.3, Step 7 and multiplying by the constituent mole fraction for each constituent from para. 5-2.1.3, Step 8. The combustion gas constituent molar 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.

I-5 GAS TURBINE MISCELLANEOUS HEAT LOSS

The GT heat loss is a combined value of variable and fixed losses. The variable losses would include generator efficiency and would be estimated by the generator efficiency curve. The fixed losses would be lube oil losses and other losses that would not vary. These losses must be given by the GT manufacturer. It is possible to quantify some of the losses and this should be done where practical.

NONMANDATORY APPENDIX A
SAMPLE HRSG HEAT BALANCE CALCULATIONS

The sheets in this Appendix are included to demonstrate the calculation procedure. Guidance is included on the sheets in order to help the user know where numbers need to be transferred within or between sheets. The following describes the reference convention.



E7	E8
Mole eight	[E6]x[E7]
.01348	955197
.99880	0
.00980	205140
.01528	270866
.94800	16315
.06480	0
Sum=	1447518

Column Reference

Each sheet except the MAIN sheet is characterized by a letter designation from A to J. Columns on the sheets are numbered so a reference to a column on a specific sheet would be a letter followed by a number. **These are not worksheet cell references**.

Column references are shown in brackets.

The sum of a column of numbers is designated by the word **Sum** followed by the column reference. This for example points to **Sum [E8]**.

DESCRIPTION: Sample Case

MAIN SHEET

DUTY SUMMARY TABLE

	Flow (lb/hr)	x	**Enthalpy** (Btu/lb)	x	**Duty** Btu/hr	
Comb Air In+GT Fuel+Injection	1447518	Sum[E8]	315.56	Sum[I4]	-456781807	Flow*Enthalpy (Negative Value)
Burner Fuel	0	Input	0.00	[K-HV Net]	0	Flow*Enthalpy (Negative Value)
Augmenting Air	0	Input	0.00	Sum[J8]	0	Flow*Enthalpy (Negative Value)
Atomizing Steam	0	Input	0.00	Input	0	Flow*Enthalpy (Negative Value)
Gas Out of Stack	1447518	Sum above	72.66	Sum[I7]	105177465	Flow*Enthalpy
				Working Fluid Duty	757997656	Sum[B7]
				Heat Loss	2273993	Input
			Total Balance of Moist Air Heat=		408667306	Sum Above
Change in Bal of Air Enthalpy	206.818	Btu/lb	Sum[J4]-Sum[J6]			
Balance of Airflow	1975978	lb/hr	=Total Balance of Moist Air Heat/Change in Bal Air h			

(*)Steam Enthapy - Steam Enthalpy at T_{REF}= h - 1087.73 Btu/lb

GENERAL NOTE: See Sheet E for GT total exhaust flow and composition[E12]

DESCRIPTION: SHEET A

AIR COMPOSITION- SAMPLE CASE

Atmospheric Pressure	14.3	psia
Wet Bulb Temperature	64.50	°F
Dry Bulb Temperature	70.00	°F
Relative Humidity		%

$$\mathrm{Ln}(P_{vapor}) = C_1 / T + C_2 + C_3{*}T + C_4{*}T^2 + C_5{*}T^3 + C_6{*}T^4 + C_7{*}\mathrm{Ln}(T)$$

for t below 32°F (over ice)		for t above 32°F (over water)	
C_1 =	-1.0214165E+04	C_1 =	-1.0440397E+04
C_2 =	-4.8932428E+00	C_2 =	-1.1294650E+01
C_3 =	-5.3765794E-03	C_3 =	-2.7022355E-02
C_4 =	1.9202377E-07	C_4 =	1.2890360E-05
C_5 =	3.5575832E-10	C_5 =	-2.4780681E-09
C_6 =	-9.0344688E-14	C_6 =	0
C_7 =	4.1635019E+00	C_7 =	6.5459673E+00

Relative Humidity Input

$T = t_{dry\ bulb} + 459.67 =$ °R $\quad P_{vapor} =$ psia

$P_{H2O} = \%RH{*}P_{vapor} =$ psia

$FDA = (P_{atm} - P_{H2O})/P_{atm} =$

$$\text{Humidity Ratio} = \left(\frac{1}{FDA} - 1\right) * \frac{18.01528}{28.96518} =$$

$T_{wet\ bulb}$ Input

$T = t_{wet\ bulb} + 459.67 =$ 524.17°R $\quad P_{vapor} =$ 0.3004 psia

Saturated Humidity Ratio = $HR_{sat} = 0.62198 * [(1.0039{*}P_{vapor} / (P - 1.0039{*}P_{vapor})]$

$HR_{sat} =$ 0.013402 #H_2O / #DA

Continued

$$\text{Humidity Ratio} = \frac{(1093 - 0.556 * t_{\text{wet bulb}}) * HR_{\text{sat}} - 0.240 * (t_{\text{dry bulb}} - t_{\text{wet bulb}})}{(1093 + 0.444 * t_{\text{dry bulb}} - t_{\text{wet bulb}})}$$

Humidity Ratio = 0.012125 #H_2O / #DA

$$\text{Fraction Dry Air (FDA)} = \frac{18.01528}{(28.9651785) * (\text{Humidity Ratio}) + 18.01528}$$

Fraction Dry Air (FDA) = 0.9809

A1	A2	A3	A4	A5	A6
Compound	Calculation	Air Mole Fraction	MW	[A3]x[A4]	Air wt. fraction [A5] / Sum [A5]
N_2	0.780840 * FDA	0.7659	28.01348	21.4558	0.7461
O_2	0.209476 * FDA	0.2055	31.9988	6.5748	0.2286
CO_2	0.000319 * FDA	0.0003	44.0098	0.0138	0.0005
H_2O	1 - FDA	0.0191	18.01528	0.3445	0.0120
Ar	0.009365 * FDA	0.0092	39.948	0.3670	0.0128
			Moist Air Molecular Weight	28.7558	

DESCRIPTION: SHEET B

WORKING FLUID DUTY - SAMPLE CASE

B1	B2	B3	B4	B5	B6	B7
Stream Name	State 0 = water 1= steam	Temperature °F	Pressure psig	Enthalpy Btu/lb	Flow lb/hr (+out / -in)	Duty 10^6 Btu/hr B5 *B6
HP FW In		313.0	1535.0	285.78	-418460	-119.587
HP Spray		313.0	1535.0	285.78	-14510	-4.147
HP Steam	1	1002.0	1362.0	1495.10	432970	647.334
Cold RH	1	626.0	290.0	1329.11	-428000	-568.858
RH Spray		377.0	305.0	350.55	-1260	-0.442
Hot RH	1	1005.0	260.0	1529.55	429260	656.576
IP FW In		306.0	325.0	276.39	-151920	-41.989
IP FW Extract		377.0	305.0	350.55	78160	27.399
IP Steam Out	1	604.0	301.0	1316.27	73760	97.088
LP Steam Out	1	605.0	38.0	1335.19	56850	75.906
LP FW In		230.0	61.0	198.45	-56850	-11.282
				Sums		757.998

DESCRIPTION: SHEET C
FUEL GAS COMBUSTION MOLE CHANGE-SAMPLE CASE
Fuel Flow = 76831 lb/hr

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C13	C14	C15	C16
Compound	Fuel Mole Fraction	Mol. wt.	C2 x C3		N_2 [(*) x C5]		O_2 [(*) x C7]		CO_2 [(*) x C9]		H_2O [(*) x C11]		Ar [(*) x C13]		SO_2 [(*) x C15]
CH_4	0.9500	16.04276	15.241	0	0	-2	-8657	1	4328	2	8657	0	0	0	0
C_2H_6	0.0300	30.06964	0.902	0	0	-3.5	-478	2	273	3	410	0	0	0	0
C_2H_4	0.0000	28.05376		0		-3		2		2		0		0	
C_3H_8	0.0000	44.09652		0		-5		3		4		0		0	
C_3H_6	0.0000	42.08064		0		-4.5		3		3		0		0	
Iso-C_4H_{10}	0.0000	58.12340		0		-6.5		4		5		0		0	
N-C_4H_{10}	0.0000	58.12340		0		-6.5		4		5		0		0	
C_4H_8	0.0000	56.10752		0		-6		4		4		0		0	
Iso-C_5H_{12}	0.0000	72.15028		0		-8		5		6		0		0	
N-C_5H_{12}	0.0000	72.15028		0		-8		5		6		0		0	
C_5H_{10}	0.0000	70.13440		0		-7.5		5		5		0		0	
C_6H_{14}	0.0000	86.17716		0		-9.5		6		7		0		0	
N_2	0.0100	28.01348	0.280	1	46	0	0	0	0	0	0	0	0	0	0
CO	0.0000	28.01040		0		-0.5		1		0		0		0	
CO_2	0.0100	44.00980	0.440	0	0	0	0	1	46	0	0	0	0	0	0
H_2O	0.0000	18.01528		0		0		0		1		0		0	
H_2S	0.0000	34.08188		0		-1.5		0		1		0		1	
H_2	0.0000	2.01588		0		-0.5		0		1		0		0	
He	0.0000	4.00260		0		0		0		0		0		0	
O_2	0.0000	31.9988		0		1		0		0		0		0	
Ar	0.0000	39.94800		0		0		0		0		1		0	
Average Molecular Weight=			16.863		46		-9135		4647		9067		0		0
					= mole change of N_2		= mole change of O_2		= mole change of CO_2		= mole change of H_2O		= mole change of Ar		= mole change of SO_2

(*) = [C2] x (FUEL FLOW) / Sum [C4]

Combustion Mole Change for [E4]

1263163 = Lbs Dry Air = Moles Change O_2*28.9651785 / 0.209476
X 1.012125 = 1+ lbs.Water per lb Dry Air (Humidity Ratio)
1278479 = lbs Moist Air for "INLET GAS COMPOSITION- Comb Air for GT Fuel"

DESCRIPTION: SHEET E

INLET GAS COMPOSITION-SAMPLE CASE

Comb Air for DB fuel= 0 lb/hr
Comb Air for GT fuel= 1278479 lb/hr
Air Molecular Weight= 28.7558

GT Fuel Flow= 76831 lb/hr
Water or Steam Injection Flow= 92208 lb/hr
Balance of Airflow= 1975978 lb/hr (from Summary Table)

E1	E2	E3	E4	E5	E6	E7	E8	E9
Compound	Air Composition [A3]	Mole / hr (*)	Combustion Mole Change SHT C or D	Water / Steam Injection (* *)	Resultant Moles / hr = [E3]+[E4]+[E5]	Mole Weight	[E6] * [E7]	Gas Mass Fraction = [E8] / Sum [E8]
N_2	0.7659	34052	46	0	34098	28.01348	955197	0.6599
O_2	0.2055	9135	-9135	0	0	31.99880	0	0.0000
CO_2	0.0003	14	4647	0	4661	44.00980	205140	0.1417
H_2O	0.0191	850	9067	5118	15035	18.01528	270866	0.1871
Ar	0.0092	408	0	0	408	39.94800	16315	0.0113
SO_2	0.0000	0	0	0	0	64.06480	0	0.0000
				Sum=	54203	Sum=	1447518	

* = [E2] x (Comb Air for DB Fuel + Comb Air for GT Fuel) / Air Molecular Weight

* * = (Water or Steam Flow) / 18.01528

* * * = Balance of Air Flow * [E2] / Air Molecular Weight

		HRSG Inlet
E10	E11	E12
Bal of M Air Mole/Hr (* * *)	Total Mole/Hr =[E6]+[E10]	Gas Mole Fraction =[E11]/Sum[E11]
52630	86728	0.70557
14119	14119	0.11487
22	4683	0.03810
1314	16349	0.13301
631	1040	0.00846
0	0	0.00000
Sum=	122919	

GT Total Exhaust Flow= 3423496 lb/hr
=Sum[E8]+Balance of Airflow

DESCRIPTION:	SHEET I

GAS ENTHALPY-SAMPLE CASE

Gas Inlet T= 1123 °F

Gas Outlet T= 319

I1	I2	I3	I4
Compound	Gas Mass Fraction [E9]	Compound Enthalpy (eqns below)	[I2]x[I3]
N_2	0.660	273.690	180.604
O_2	0.000	252.728	0.000
CO_2	0.142	266.545	37.774
H_2O	0.187	511.395	95.694
Ar	0.011	132.109	1.489
SO_2	0.000	189.435	0.000
			315.562
			Btu/lb

I5	I6	I7
Gas Mass Fraction [H9]	Compound Enthalpy (eqns below)	[I2]x[I3]
0.660	64.470	42.543
0.000	57.637	0.000
0.142	55.861	7.917
0.187	116.706	21.839
0.011	32.188	0.363
0.000	40.608	0.000
		72.661
		btu/lb

Compound Enthalpies

$T_r = T(°F) + 459.67°R =$

Reference Temperature

$T_{REF} = 60$

$$h = -A_1/T_r + A_2 \ln(T_r) + A_3(T_r) + A_4(T_r)^2 + A_5(T_r)^3 + A_6(T_r)^4 + A_7(T_r)^5 - A_8$$

N_2

	$T_r < 1800°R$	**$T_r > 1800°R$**
A_1	5076.9034	134989.03
A_2	-48.724746	-285.73506
A_3	0.43120894	0.43008964
A_4	-1.6798933E-04	-1.2090166E-05
A_5	1.0098600E-07	1.0880151E-09
A_6	-2.9251468E-11	-5.8440540E-14
A_7	3.4031292E-15	1.4342817E-18
A_8	-123.56702	-1809.5883

O_2

	$T_r < 1800°R$	**$T_r > 1800°R$**
A_1	-6888.0735	-208707.28
A_2	54.145998	261.94172
A_3	0.069447256	0.11293491
A_4	7.40234103E-05	2.1856736E-05
A_5	-4.3649134E-09	-1.3970608E-09
A_6	-5.3829350E-12	5.4636691E-14
A_7	1.2285505E-15	-9.6878731E-19
A_8	406.96173	2037.0402

Continued

CO_2

	T_r < 1800°R	T_r > 1800°R
A_1	7227.7111	17207.414
A_2	-50.879204	-145.29151
A_3	0.23923528	0.37414705
A_4	3.1383945E-05	-1.1560726E-06
A_5	-9.8757996E-10	2.2579091E-11
A_6	-1.4874974E-12	-3.6579206E-15
A_7	2.4498740E-16	5.4419457E-19
A_8	-199.50475	-758.45980

H_2O

	T_r < 1800°R	T_r > 1800°R
A_1	-14100.395	369646.91
A_2	114.20534	-478.72819
A_3	0.10271362	0.51215685
A_4	2.2116239E-04	7.0181916E-05
A_5	-8.3271140E-08	-7.7535747E-09
A_6	2.3414419E-11	4.4543564E-13
A_7	-2.8077803E-15	-1.0127794E-17
A_8	844.30005	-3313.2672

Ar

	T_r < 1800°R	T_r > 1800°R
A_1	0	3.2382979
A_2	0	-0.0053623
A_3	0.12427948	0.12428293
A_4	0	-5.51268011E-10
A_5	0	6.16422179E-14
A_6	0	-3.87630833E-18
A_7	0	1.02152826E-22
A_8	64.584315	64.54707

SO_2

	T_r < 1800°R	T_r > 1800°R
A_1	-5333.9649	-11325.497
A_2	50.721609673	-46.045503810
A_3	-0.073060273	0.2360907
A_4	1.8981891E-04	-1.7215642E-06
A_5	-8.0072686E-08	1.8036679E-10
A_6	1.9218645E-11	-7.2477731E-15
A_7	-1.9897196E-15	1.7234980E-19
A_8	330.81966	-151.48263

DESCRIPTION:	SHEET H

OUTLET GAS COMPOSITION-SAMPLE CASE

Water or Steam Injection = 0 lb/hr
Duct Burner Fuel Flow = 0 lb/hr
Augmenting Airflow = 0 lb/hr

H1	H2	H3	H4	H5	H6	H7	H8	H9
Compound	Gas Inlet Moles/Hr [E6]	Combustion Mole Change SHT F or G	Water / Steam Injection moles/hr (*)	Augmenting Air $= \frac{\text{AIR FLOW * [A3]}}{\text{Sum [A5]}}$	Resultant Moles/hr = [H2]+[H3]+ [H4]+[H5]	Mole wt.	[H6]x[H7]	Outlet Gas Mass Fraction = [H8] / Sum [H8]
N_2	34098	0	0	0.000	34098	28.01348	955197	0.6599
O_2	0	0	0	0.000	0	31.9988	0	0.0000
CO_2	4661	0	0	0.000	4661	44.0098	205140	0.1417
H_2O	15035	0	0	0.000	15035	18.01528	270866	0.1871
Ar	408	0	0	0.000	408	39.948	16315	0.0113
SO_2	0	0	0	0.000	0	64.0648	0	0.0000
						sum =	1447518	

(*) = (water or steam flow) / 18.01528

DESCRIPTION: SHEET J

AIR ENTHALPY-SAMPLE CASE

Air at Inlet T= 1123.00 °F

Air at Outlet T= 319.00 °F

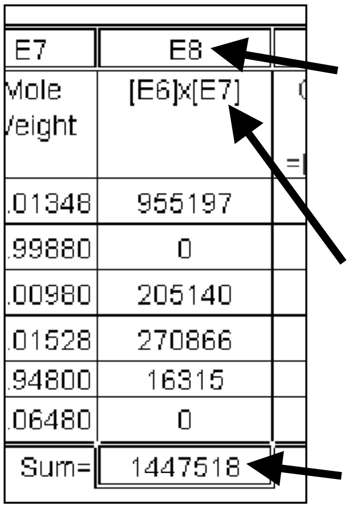
Augmenting Air T= 60.00 °F

J1	J2	J3	J4	J5	J6	J7	J8
Compound	Gas Mass Fraction [A6]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J3]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J5]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J7]
N_2	0.7461	273.690	204.210	64.470	48.103	0.000	0.000
O_2	0.2286	252.728	57.784	57.637	13.178	0.000	0.000
CO_2	0.0005	266.545	0.128	55.861	0.027	0.000	0.000
H_2O	0.0120	511.395	6.126	116.706	1.398	0.000	0.000
Ar	0.0128	132.109	1.686	32.188	0.411	0.000	0.000
SO_2	0.0000	189.435	0.000	40.608	0.000	0.000	0.000
		Air Enthalpy=	269.935	Air Enthalpy=	63.117	Air Enthalpy=	0.000

GENERAL NOTE: See "Gas Enthalpy" sheet for species specific enthalpy formulations.

NONMANDATORY APPENDIX B
SAMPLE GAS TURBINE HEAT BALANCE CALCULATIONS

The sheets in this Appendix are included to demonstrate the calculation procedure. Guidance is included on the sheets in order to help the user know where numbers need to be transferred within or between sheets. The following describes the reference convention.



E7	E8
Mole /eight	[E6]x[E7]
.01348	955197
.99880	0
.00980	205140
.01528	270866
.94800	16315
.06480	0
Sum=	1447518

<u>Column Reference</u>

Each sheet except the MAIN sheet is characterized by a letter designation from A to K. Columns on the sheets are numbered so a reference to a column on a specific sheet would be a letter followed by a number. **These are not worksheet cell references**.

Column references are shown in brackets.

The sum of a column of numbers is designated by the word **Sum** followed by the column reference. This for example points to **Sum [E8]**.

DESCRIPTION: PTC TEST CASE

DUTY SUMMARY TABLE

	Flow (lb/hr)	x	Enthalpy (Btu/lb)	=	Duty Btu/hr	
Bleed+Comb. Wet Air	1278479	Sum[E8]	2.42	Sum[J4]	3098501	Flow*Enthalpy
Fuel	76831	Input	20626.54	[K-HV Net]	1584757945	Flow*Enthalpy
Steam/Water Injection*	92208	Input	198.07	(*)	18263233	Flow*Enthalpy(may be Negative)
Compressor Bleed	0	Input	0.00	Sum[J6]	0.00	Flow*Enthalpy (Negative Value)
Comb Prod + Inj	1447518	Sum above	315.56	Sum[I7]	-456781807	Flow*Enthalpy (Negative Value)
				Power	-588594150	Input MW*3.41214e6 (Negative Value)
				Heat Loss	-33000000	Input (Negative Value)
Total Balance of Moist Air Heat=					527743722	Sum Above
Change in Bal of Air Enthalpy	267.511	Btu/lb	Sum[J8]-Sum[J4]			
Balance of Airflow	1972791	lb/hr	=Total Balance of Moist Air Heat/Change in Bal Air h			

(*)Steam or Water Enthapy - Steam Enthalpy at T_{REF}= h - 1087.73 Btu/lb

GENERAL NOTE: See Sheet E for GT total exhaust flow and composition[E12]

DESCRIPTION:	SHEET A

AIR COMPOSITION-PTC TEST CASE

Atmospheric Pressure	14.3	psia
Wet Bulb Temperature	64.5	°F
Dry Bulb Temperature	70	°F
Relative Humidity		%

$\mathrm{Ln}(P_{vapor})$: $C_1 / T + C_2 + C_3{*}T + C_4{*}T^2 + C_5{*}T^3 + C_6{*}T^4 + C_7{*}\mathrm{Ln}(T)$

for t below 32°F (over ice)		for t above 32°F (over water)	
C_1 =	-1.0214165E+04	C_1 =	-1.0440397E+04
C_2 =	-4.8932428E+00	C_2 =	-1.1294650E+01
C_3 =	-5.3765794E-03	C_3 =	-2.7022355E-02
C_4 =	1.9202377E-07	C_4 =	1.2890360E-05
C_5 =	3.5575832E-10	C_5 =	-2.4780681E-09
C_6 =	-9.0344688E-14	C_6 =	0
C_7 =	4.1635019E+00	C_7 =	6.5459673E+00

Relative Humidity Input

$T = t_{dry\ bulb} + 459.67 =$ °R $\quad P_{vapor} =$ psia

$P_{H2O} = \%RH{*}P_{vapor} =$ psia

$FDA = (P_{atm} - P_{H2O})/P_{atm} =$

$$\text{Humidity Ratio} = \left(\frac{1}{FDA} - 1\right) * \frac{18.01528}{28.965179} =$$

$T_{wet\ bulb}$ Input

$T = t_{wet\ bulb} + 459.67 =$ 524.17°R $\quad P_{vapor} =$ 0.3004 psia

Saturated Humidity Ratio = $HR_{sat} = 0.62198 * [1.0039{*}P_{vapor} / (P - 1.0039{*}P_{vapor})]$

$HR_{sat} =$ 0.013402 #H_2O / #DA

$$\text{Humidity Ratio} = \frac{(1093 - 0.556 * t_{wet\ bulb}) * HR_{sat} - 0.240 * (t_{dry\ bulb} - t_{wet\ bulb})}{(1093 + 0.444 * t_{dry\ bulb} - t_{wet\ bulb})}$$

Humidity Ratio = 0.012125 #H_2O / #DA

Continued

$$\text{Fraction Dry Air (FDA)} = \frac{18.01528}{(28.9651785) * (\text{Humidity Ratio}) + 18.01528}$$

Fraction Dry Air (FDA) = 0.9808781

A1	A2	A3	A4	A5	A6
Compound	Calculation	Air Mole Fraction	MW	[A3]x[A4]	Air wt. fraction [A5] / Sum [A5]
N_2	0.780840 * FDA	0.765909	28.01348	21.4558	0.7461
O_2	0.209476 * FDA	0.205470	31.9988	6.5748	0.2286
CO_2	0.000319 * FDA	0.000313	44.0098	0.0138	0.0005
H_2O	1 - FDA	0.019122	18.01528	0.3445	0.0120
Ar	0.009365 * FDA	0.009186	39.948	0.3670	0.0128
			Moist Air Molecular Weight	28.7558	

DESCRIPTION: SHEET C

FUEL GAS COMBUSTION MOLE CHANGE-PTC TEST CASE

Fuel Flow = 76831 lb/hr

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C13	C14	C15	C16
Compound	Fuel Mole Fraction	Mol. wt.	C2 x C3		N_2 (*) x [C5]		O_2 (*) x [C7]		CO_2 (*) x [C9]		H_2O (*) x [C11]		Ar (*) x [C13]		SO_2 (*) x [C15]
CH_4	0.9500	16.04276	15.241	0	0	-2	-8657	1	4328	2	8657	0	0	0	0
C_2H_6	0.0300	30.06964	0.902	0	0	-3.5	-478	2	273	3	410	0	0	0	0
C_2H_4	0.0000	28.05376		0		-3		2		2		0		0	
C_3H_8	0.0000	44.09652		0		-5		3		4		0		0	
C_3H_6	0.0000	42.08064		0		-4.5		3		3		0		0	
Iso-C_4H_{10}	0.0000	58.12340		0		-6.5		4		5		0		0	
N-C_4H_{10}	0.0000	58.12340		0		-6.5		4		5		0		0	
C_4H_8	0.0000	56.10752		0		-6		4		4		0		0	
Iso-C_5H_{12}	0.0000	72.15028		0		-8		5		6		0		0	
N-C_5H_{12}	0.0000	72.15028		0		-8		5		6		0		0	
C_5H_{10}	0.0000	70.13440		0		-7.5		5		5		0		0	
C_6H_{14}	0.0000	86.17716		0		-9.5		6		7		0		0	
N_2	0.0100	28.01348	0.280	1	46	0	0	0	0	0	0	0	0	0	0
CO	0.0000	28.01040		0		-0.5		1		0		0		0	
CO_2	0.0100	44.00980	0.440	0	0	0	0	1	46	0	0	0	0	0	0
H_2O	0.0000	18.01528		0		0		0		1		0		0	
H_2S	0.0000	34.08188		0		-1.5		0		1		0		1	
H_2	0.0000	2.01588		0		-0.5		0		1		0		0	
He	0.0000	4.00260		0		0		0		0		0		0	
O_2	0.0000	31.9988		0		1		0		0		0		0	
Ar	0.0000	39.94800		0		0		0		0		1		0	
Average Molecular Weight=			16.863		46		-9135		4647		9067		0		0
					= mole change of N_2		= mole change of O_2		= mole change of CO_2		= mole change of H_2O		= mole change of Ar		= mole change of SO_2

(*) = [C2] x (FUEL FLOW) / Sum [C4]

Combustion Mole Change for [E4]

1263163 = Lbs Dry Air = Moles Change O_2*28.9651785 / 0.209476
X 1.012125 = 1+ lbs.Water per lb Dry Air
1278479 = lbs Moist Air for "GAS COMPOSITION"

DESCRIPTION:	SHEET E

GAS COMPOSITION-PTC TEST CASE

Combustion Moist Airflow=	1278479	lb/hr
Balance Moist Airflow=	1972791	lb/hr
Moist Air Molecular Weight=	28.7558	
Water or Steam Injection Flow=	92208	lb/hr

E1	E2	E3	E4	E5	E6	E7	E8	E9
Compound	Air Composition [A3]	Comb M Air Moles/Hr (*)	Combustion Mole Change SHT C or D	Water / Steam Injection (* *)	Resultant Moles / Hr =[E3]+[E4]+[E5]	Mole Weight	[E6]x[E7]	Gas Mass Fraction =[E8]/Sum[E8]
N_2	0.765909	34052	46	0	34098	28.01348	955197	0.65989
O_2	0.205470	9135	-9135	0	0	31.99880	0	0.00000
CO_2	0.000313	14	4647	0	4661	44.00980	205140	0.14172
H_2O	0.019122	850	9067	5118	15035	18.01528	270866	0.18712
Ar	0.009186	408	0	0	408	39.94800	16315	0.01127
SO_2	0.000000	0	0	0	0	64.06480	0	0.00000
				Sum=	54203	Sum=	1447518	

* = [E2] x (Combustion Moist Air Flow) / Moist Air Molecular Weight

* * (Water or Steam Flow) / 18.01528

* * * = [E2} x (Balance Moist Air Flow] / Moist Air Molecular Weight

GT Total Exhaust Flow= 3420309 lb/hr

=Sum[E8]+Balance of Airflow

E1	E10	E11	E12	E13
Compound	Bal M Air Moles/Hr (* * *)	Gas Moles/Hr =[E6}+[E10]	Gas Composition =[E11]/SUM[E11]	Gas Composition =[E11] / Dry SUM[E11]
N_2	52545	86643	0.70552	0.81385
O_2	14096	14096	0.11478	0.13241
CO_2	21	4683	0.03813	0.04399
H_2O	1312	16347	0.13311	
Ar	630	1039	0.00846	0.00976
SO_2	0	0	0.00000	0.00000
	Sum=	122808		
	Dry Sum=	106461		

DESCRIPTION: SHEET I

GAS ENTHALPY-PTC TEST CASE

Gas T= 1123

I1	I5	I6	I7
Compound	Gas Mass Fraction [H9]	Compound Enthalpy (eqns below)	[I5]x[I6]
N_2	0.660	273.690	180.604
O_2	0.000	252.728	0.000
CO_2	0.142	266.545	37.774
H_2O	0.187	511.395	95.694
Ar	0.011	132.109	1.489
SO_2	0.000	189.435	0.000
		Gas Enthalpy=	315.562 btu/lb

Compound Enthalpies

$T_r = T(°F) + 459.67°R$

Reference Temperature

$T_{REF}=$ 60°F

$$h = -A_1/T_r + A_2 \mathrm{Ln}(T_r) + A_3(T_r) + A_4(T_r)^2 + A_5(T_r)^3 + A_6(T_r)^4 + A_7(T_r)^5 - A_8$$

N_2

	T_r < 1800°R	**T_r > 1800°R**
A_1	5076.9034	134989.03
A_2	-48.724746	-285.73506
A_3	0.43120894	0.43008964
A_4	-1.6798933E-04	-1.2090166E-05
A_5	1.0098600E-07	1.0880151E-09
A_6	-2.9251468E-11	-5.8440540E-14
A_7	3.4031292E-15	1.4342817E-18
A_8	-123.56702	-1809.5883

O_2

	T_r < 1800°R	**T_r > 1800°R**
A_1	-6888.0735	-208707.28
A_2	54.145998	261.94172
A_3	0.069447256	0.11293491
A_4	7.40234103E-05	2.1856736E-05
A_5	-4.3649134E-09	-1.3970608E-09
A_6	-5.3829350E-12	5.4636691E-14
A_7	1.2285505E-15	-9.6878731E-19
A_8	406.96173	2037.0402

Continued

CO_2

	$T_r < 1800°R$	$T_r > 1800°R$
A_1	7227.7111	17207.414
A_2	-50.879204	-145.29151
A_3	0.23923528	0.37414705
A_4	3.1383945E-05	-1.1560726E-06
A_5	-9.8757996E-10	2.2579091E-11
A_6	-1.4874974E-12	-3.6579206E-15
A_7	2.4498740E-16	5.4419457E-19
A_8	-199.50475	-758.45980

H_2O

	$T_r < 1800°R$	$T_r > 1800°R$
A_1	-14100.395	369646.91
A_2	114.20534	-478.72819
A_3	0.10271362	0.51215685
A_4	2.2116239E-04	7.0181916E-05
A_5	-8.3271140E-08	-7.7535747E-09
A_6	2.3414419E-11	4.4543564E-13
A_7	-2.8077803E-15	-1.0127794E-17
A_8	844.30005	-3313.2672

Ar

	$T_r < 1800°R$	$T_r > 1800°R$
A_1	0	3.2382979
A_2	0	-0.0053623
A_3	0.12427948	0.12428293
A_4	0	-5.51268011E-10
A_5	0	6.16422179E-14
A_6	0	-3.87630833E-18
A_7	0	1.02152826E-22
A_8	64.584315	64.54707

SO_2

	$T_r < 1800°R$	$T_r > 1800°R$
A_1	-5333.9649	-11325.497
A_2	50.721609673	-46.045503810
A_3	-0.073060273	0.2360907
A_4	1.8981891E-04	-1.7215642E-06
A_5	-8.0072686E-08	1.8036679E-10
A_6	1.9218645E-11	-7.2477731E-15
A_7	-1.9897196E-15	1.7234980E-19
A_8	330.81966	-151.48263

DESCRIPTION: SHEET J

MOIST AIR ENTHALPY-PTC TEST CASE Compressor

Inlet Air T= 70.00 °F Bleed Air T= 60.00 °F GT T out= 1123.00 °F

J1	J2	J3	J4	J5	J6	J7	J8
Compound	Stream Mass Fraction [A6]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J3]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J5]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J7]
N_2	0.7461	2.483	1.853	0.000	0.000	273.690	204.210
O_2	0.2286	2.191	0.501	0.000	0.000	252.728	57.784
CO_2	0.0005	1.999	0.001	0.000	0.000	266.545	0.128
H_2O	0.0120	4.449	0.053	0.000	0.000	511.395	6.126
Ar	0.0128	1.243	0.016	0.000	0.000	132.109	1.686
SO_2	0.0000	1.476	0.000	0.000	0.000	189.435	0.000
		Air Enthalpy=	2.424	Air Enthalpy=	0.000	Air Enthalpy=	269.935

GENERAL NOTE: See "Gas Enthalpy" sheet for species specific enthalpy formulations.

DESCRIPTION: SHEET K
FUEL HEATING VALUE-PTC TEST CASE

Fuel Temperature= 239 °F

FUEL GAS

K1	K2	K3	K4	K5	K6	K7	K8	K9
Compound	Fuel Mole Fraction	Mol. Wt.	[K2]x[K3]	Fuel Wt. Fraction = [K4] / Sum [K4]	Heat of Combustion Btu/lb	[K5]x[K6]	Heat of Combustion Btu/lb	[K5]x[K8]
CH_4	0.950	16.04276	15.241	0.904	21503	19434	23892	21593
C_2H_6	0.030	30.06964	0.902	0.053	20432	1093	22334	1195
C_2H_4	0.000	28.05376	0.000	0.000	20278	0	21640	0
C_3H_8	0.000	44.09652	0.000	0.000	19923	0	21654	0
C_3H_6	0.000	42.08064	0.000	0.000	19678	0	21039	0
Iso-C_4H_{10}	0.000	58.1234	0.000	0.000	19587	0	21232	0
N-C_4H_{10}	0.000	58.1234	0.000	0.000	19659	0	21300	0
$C_4H_{8\text{-avg}}$	0.000	56.10752	0.000	0.000	19450	0	20811	0
Iso-C_5H_{12}	0.000	72.15028	0.000	0.000	19456	0	21044	0
N-C_5H_{12}	0.000	73.15028	0.000	0.000	19498	0	21085	0
$C_5H_{10\text{-avg}}$	0.000	70.1344	0.000	0.000	19328	0	20691	0
$C_6H_{14\text{-avg}}$	0.000	86.17716	0.000	0.000	19353	0	20904	0
N_2	0.010	28.01348	0.280	0.017	0	0	0	0
CO	0.000	28.0104	0.000	0.000	4342	0	4342	0
CO_2	0.010	44.0098	0.440	0.026	0	0	0	0
H_2O	0.000	18.01528	0.000	0.000	0	0	1059.8	0
H_2S	0.000	34.08188	0.000	0.000	6534	0	7093.8	0
H_2	0.000	2.01588	0.000	0.000	51566	0	61022	0
He	0.000	4.0026	0.000	0.000	0	0	0	0
O_2	0.000	31.9988	0.000	0.000	0	0	0	0
Ar	0.000	39.948	0.000	0.000	0	0	0	0
		Sum =	16.863		Sum =	20527	HHV=	22788
					LHV Input =	0		
						20542.496		

HHV not used in any calculations!

Fuel Gas

$$\textbf{HV Net} = LHV + T_{fuel}^2 / 4720 + 0.491 * T_{fuel} - 30.2 = \boxed{20627} \text{ Btu/lb}$$

FUEL OIL

LHV Input = ☐ Btu/lb

Fuel Oil Sensible Heat Adjustment

$$\textbf{HV Net} = LHV + T_{fuel}^2 / 4132 + 0.417 * T_{fuel} - 25.9 = \boxed{0} \text{ Btu/lb}$$

NONMANDATORY APPENDIX C
UNCERTAINTY SAMPLE CALCULATION

The sheets in this Appendix are included to demonstrate the calculation procedure for the test uncertainty. There are Appendices for HP, IP, and LP capacity.

NONMANDATORY APPENDIX C

C-1 IP STEAM FLOW UNCERTAINTY: COMBINING THE STEAM FLOW AND UNCERTAINTY FROM GT AND HRSG HEAT BALANCES

Using Calculated Uncertainties

	GT Heat Balance	HRSG Heat Balance	Weighted
Steam Flow	432970	432970	
Uncertainty on HP Steam Flow	1.72%	0.81%	
Weight	0.180	0.820	
Systematic Uncertainty	6988	3329	3006
Random Uncertainty	1307	525	491
Total Uncertainty			3162
HP Steam Flow			432970
Total Uncertainty %			0.730%

NONMANDATORY APPENDIX C: UNCERTAINTY WORKSHEET

HP Steam Flow by Gas Turbine Heat Balance

Project: PTC 4.4
Test:3 Pressure HRSG
Date:
Engineer:

			Random Component							Systematic Component		
	Measured Parameter	Average Value	Sample Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensitivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Systematic Uncertainty for Parameter	Abs Sensivty x Systematic Uncert-Para	Systematic Uncertainty %
1	Amb Dry Bulb Temp	70.00	**1.10**	12	0.32	11.00	11.43	3.63	1.58E+01	**1.000**	11.43	0%
2	Wet Bulb Temp	64.50	**1.10**	12	0.32	11.00	-246.15	-78.16	3.39E+06	**1.000**	-246.15	0%
3	Amb Press	14.30	**0.0429**	12	0.01	11.00	300.00	3.72	1.73E+01	**0.036**	10.73	0%
4	GT Comp Inlet Temp	70.00	**1.10**	12	0.32	11.00	387.14	122.93	2.08E+07	**1**	387.14	0%
5	GT Fuel Flow	76831.00	**460.99**	30	84.16	29.00	9.35	786.52	1.32E+10	**384.155**	3589.95	26%
6	GT Fuel Temp	259.00	**2.90**	30	0.53	29.00	19.23	10.18	3.71E+02	**4**	76.92	0%
7	GT Fuel LHV	20534.00	*30.00*	3	17.32	2.00	35.70	618.30	7.31E+10	**82.136**	2932.05	18%
8	GT Steam Inj. Flow	92208.00	**553.25**	30	101.01	29.00	-0.02	-1.86	4.15E-01	**922.08**	-17.00	0%
9	GT Steam Inj. Temp	547.00	**2.90**	30	0.53	29.00	23.82	12.61	8.72E+02	***5***	119.09	0%
10	GT Steam Inj. Press	282.00	**2.90**	30	0.53	29.00	-5.71	-3.03	2.89E+00	**2.82**	-16.11	0%
11	GT Megawatt Output	172.50	**1.04**	30	0.19	29.00	-1594.12	-301.23	2.84E+08	**0.69**	-1099.94	2%
12	GT Heat Loss	33000000	*0.00*	30	0.00	29.00	-0.0005	0.0000	2.12E-50	**8250000**	-4000.00	33%
13	GT Exhaust Temp	1123.00	**2.90**	30	0.53	29.00	-5.18	-2.74	1.95E+00	**11**	-57.00	0%
14												
15	HP Steam Flow	432970.00	**3896.73**	30	711.44	29.00	1.00	711.44	8.83E+09	**2164.85**	2164.85	10%
16	HP Feedwater Temp	313.00	**2.90**	30	0.53	29.00	-1.61	-0.85	1.83E-02	**2**	-3.23	0%
17	HP Stm Temp	1002.00	**2.90**	30	0.53	29.00	-266.60	-141.16	1.37E+07	**4.008**	-1068.53	2%
18	HP Steam Press	1362.00	**2.90**	30	0.53	29.00	-20.29	-10.74	4.59E+02	**5.448**	-110.55	0%
19	Cold Reheat Flow	428000.00	**3852.00**	30	703.28	29.00	0.01	8.22	1.57E+02	**2568.000**	30.00	0%
20	Cold Reheat Temp	626.00	**2.90**	30	0.53	29.00	101.27	53.62	2.85E+05	**4.695**	475.46	0%
21	Hot Reheat Press	260.00	**2.90**	30	0.53	29.00	-2.31	-1.22	7.69E-02	**1.040**	-2.40	0%
22	Hot Reheat Temp	1005.00	**2.90**	30	0.53	29.00	487.00	257.85	1.52E+08	**4.020**	1957.74	8%
23												
24	IP Feedwater Temp	306.00	**2.90**	30	0.53	29.00	-4.52	-2.39	1.13E+00	**4.000**	-18.06	0%
25	IP FW Extract Flow	78160.00	**703.44**	30	128.43	29.00	0.01	0.82	1.57E-02	**781.600**	5.00	0%
26	IP FW Extract Temp	377.00	**2.90**	30	0.53	29.00	1.32	0.70	8.12E-03	**4.000**	5.26	0%
27	IP Steam Flow	73760.00	**663.84**	30	121.20	29.00	-0.09	-11.17	5.36E+02	**737.600**	-67.96	0%
28	IP Steam Temp	604.00	**2.90**	30	0.53	29.00	-5.17	-2.74	1.93E+00	**2.416**	-12.48	0%
29	IP Steam Press	301.00	**2.90**	30	0.53	29.00	-4.00	-2.12	6.94E-01	**1.204**	-4.82	0%
30	LP Steam Flow	56850.00	**511.65**	30	93.41	29.00	-0.06	-5.60	3.39E+01	**568.500**	-34.09	0%
31	LP Steam Temp	605.00	**2.90**	30	0.53	29.00	-2.00	-1.06	4.34E-02	**2.420**	-4.84	0%
32	LP Steam Press	38.00	**2.90**	30	0.53	29.00	-15.00	-7.94	1.37E+02	**0.152**	-2.28	0%
33	LP FW Temperature	230.00	**2.90**	30	0.53	29.00	-2.17	-1.15	6.05E-02	**4.000**	-8.70	0%
34												
35												
36												
37												
38												
39												
40												

Base Value of Result	432970
Random Uncertainty of Result	1307
Degrees of Freedom for Random Uncertainty of Result	30.56
Student t Value	2.000

Systematic Uncertainty of Result - 95% Confidence Level		6988
Total Uncertainty	±	7461
Uncertainty Percent	±	1.72%

NONMANDATORY APPENDIX C: SENSITIVITY WORKSHEET

Project: PTC 4.4

Date:

HP Steam Flow by Gas Turbine Heat Balance

Test: 3 Pressure HRSG

Engineer:

Percent Change for Sensitivity: 1.00

	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	New Steam Flow at New Exhaust Flow and New Parameter	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1	Amb Dry Bulb Temp	70.0	0.70	70.7	3433084.0	432978	11.4286	0.0018
2	Wet Bulb Temp	64.5	0.65	65.2	3431382.0	432810	-246.1538	-0.0367
3	Amb Press	14.3	0.14	14.44	3432998.0	433012	300.0000	0.0099
4	GT Comp Inlet Temp	70.0	0.70	70.7	3434812.0	433241	387.1429	0.0626
5	GT Fuel Flow	76831.0	768.00	77599.0	3490259.0	440147	9.3451	1.6583
6	GT Fuel Temp	259.0	2.60	261.6	3433065.0	433020	19.2308	0.0115
7	GT Fuel LHV	20534.0	205.00	20739.0	3491391.0	440288	35.6976	1.6930
8	GT Steam Inj. Flow	92208.0	922.00	93130.0	3432513.0	432953	-0.0184	-0.0039
9	GT Steam Inj. Temp	547.0	5.50	552.5	3433701.0	433101	23.8182	0.0301
10	GT Steam Inj. Press	282.0	2.80	284.8	3432524.0	432954	-5.7143	-0.0037
11	GT Megawatt Output	172.5	1.70	174.2	3410932.0	430260	-1594.1176	-0.6351
12	GT Heat Loss	33000000.0	330000.00	33330000.0	3431382.0	432810	-0.0005	-0.0370
13	GT Exhaust Temp	1123.0	11.00	1134.0	3391952.0	432913	-5.1818	-0.0134
14	0	0.0	0.00	0.0				
15	HP Steam Flow	432970.0	-4330.00	428640.0	3432616.0	428640	1.0000	1.0000
16	HP Feedwater Temp	313.0	3.10	316.1	3432616.0	432965	-1.6129	-0.0012
17	HP Stm Temp	1002.0	-10.00	992.0	3432616.0	435636	-266.6000	-0.6170
18	HP Steam Press	1362.0	13.70	1375.7	3432616.0	432692	-20.2920	-0.0638
19	Cold Reheat Flow	428000.0	-4280.00	423720.0	3432616.0	432920	0.0117	0.0115
20	Cold Reheat Temp	626.0	6.30	632.3	3432616.0	433608	101.2698	0.1464
21	Hot Reheat Press	260.0	2.60	262.6	3432616.0	432964	-2.3077	-0.0014
22	Hot Reheat Temp	1005.0	-10.00	995.0	3432616.0	428100	487.0000	1.1304
23	0	0.0	0.00	0.0				
24	IP Feedwater Temp	306.0	3.10	309.1	3432616.0	432956	-4.5161	-0.0032
25	IP FW Extract Flow	78160.0	782.00	78942.0	3432616.0	432975	0.0064	0.0012
26	IP FW Extract Temp	377.0	3.80	380.8	3432616.0	432975	1.3158	0.0011
27	IP Steam Flow	73760.0	738.00	74498.0	3432616.0	432902	-0.0921	-0.0157
28	IP Steam Temp	604.0	6.00	610.0	3432616.0	432939	-5.1667	-0.0072
29	IP Steam Press	301.0	3.00	304.0	3432616.0	432958	-4.0000	-0.0028
30	LP Steam Flow	56850.0	567.00	57417.0	3432616.0	432936	-0.0600	-0.0079
31	LP Steam Temp	605.0	6.00	611.0	3432616.0	432958	-2.0000	-0.0028
32	LP Steam Press	38.0	0.40	38.4	3432616.0	432964	-15.0000	-0.0013
33	LP FW Temperature	230.0	2.30	232.3	3432616.0	432965	-2.1739	-0.0012
34								
35								
36								
37								
38								
39								
40								

Base Value of Result	432970

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX C: UNCERTAINTY WORKSHEET	Project: PTC 4.4	Date:
HP Steam Flow Uncertainty from HRSG Heat Balance	Test3 Pressure HRSG	Engineer:

			Random Component							Systematic Component		
	Measured Parameter	Average Value	Sample Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensi-tivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Systematic Uncertainty for Parameter	Abs Sensivty x Systematic Uncert-Para	Systematic Uncertainty %
1	Amb Dry Bulb Temp	70	1.10	12	0.32	11	77.1429	24.50	3.27E+04	1.000	77.14	0%
2	Wet Bulb Temp	64.5	1.10	12	0.32	11	-270.7692	-85.98	4.97E+06	1.000	-270.77	1%
3	Amb Press	14.3	0.043	12	0.01	11	957.1429	11.85	1.79E+03	0.036	34.22	0%
4	GT Fuel Flow	76831	461	30	84.16	29	-0.2786	-23.45	1.04E+04	384.155	-107.04	0%
5	GT Steam Injection Flow	92208	553	30	101.01	29	-0.1204	-12.16	7.54E+02	922.08	-111.01	0%
6	GT Exhaust Temp	1123.0	2.90	30	0.53	29	-137.3636	-72.73	9.65E+05	9	-1236.27	14%
7	HRSG Stack Temp	319.0	2.90	30.00	0.53	29	543.1250	287.57	2.36E+08	2.5	1357.81	17%
8	HRSG Heat Loss	2274000	0.00	1	0.00	1	0.0004	0.00	2.47E-46	1137000	450.79	2%
9	HP Steam Flow	432970	3896.73	30	711.44	29	0.2099	149.33	1.71E+07	*2164.85*	454.40	2%
10	HP Feedwater Temp	313	2.90	30	0.53	29	-261.9355	-138.69	1.28E+07	2	-523.87	2%
11	HP Steam Temp	1002	2.90	30	0.53	29	-94.1000	-49.82	2.12E+05	4.008	-377.15	1%
12	HP Steam Press	1362	2.9	30	0.53	29	-26.7153	-14.1448	1.38E+03	5.448	-145.55	0%
13	Cold Reheat Flow	428000	3852.00	30	703.28	29	0.1336	93.99	2.69E+06	2568	343.20	1%
14	Cold Reheat Temp	626	2.90	30	0.53	29	-39.3651	-20.8424	6.51E+03	2.504	-98.57	0%
15	Hot Reheat Press.	260.0	2.90	30	0.53	29	-9.6154	-5.09	2.32E+01	1.04	-10.00	0%
16	Hot Reheat Temp	1005.0	2.90	30	0.53	29	624.1000	330.44	4.11E+08	4.02	2508.88	57%
17												
18	IP Feedwater Temp	306.0	2.90	30	0.53	29	-115.4839	-61.14	4.82E+05	2	-230.97	0%
19	IP FW Extract Flow	78160	703	30	128.43	29	-0.0192	-2.46	1.27E+00	781.600	-14.99	0%
20	IP FW Extract Temp	377	2.90	30	0.53	29	52.1053	27.59	2.00E+04	2.000	104.21	0%
21	IP Steam Flow	73760	664	30	121.20	29	0.5339	64.71	6.04E+05	737.600	393.79	1%
22	IP Steam Temp	604	2.90	30	0.53	29	20.0000	10.59	4.34E+02	2.416	48.32	0%
23	IP Steam Press	301	2.90	30	0.53	29	-6.6667	-3.53	5.35E+00	1.204	-8.03	0%
24	LP Steam Flow	56850	512	30	93.41	29	0.5697	53.21	2.77E+05	568.500	323.85	1%
25	LP Steam Temp	605	2.90	30	0.53	29	22.6667	12.00	7.15E+02	2.420	54.85	0%
26	LP Steam Press	38	2.90	30	0.53	29	-120.0000	-63.54	5.62E+05	0.152	-18.24	0%
27	LP FW Temperature	230	2.90	30	0.53	29	-35.6522	-18.88	4.38E+03	2.000	-71.30	0%
28												
29												
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Base Value of Result	432970
Random Uncertainty of Result	525
Degrees of Freedom for Random Uncertainty of Result	110.53
Student t Value	2.000

Systematic Uncertainty of Result - 95% Confidence Level		3329
Total Uncertainty	±	3491
Uncertainty Percent	±	0.81%

NONMANDATORY APPENDIX C: SENSITIVITY WORKSHEET **Project: PTC 4.4** **Date:**

HP Steam Flow by HRSG Heat Balance **Test: 3 Pressure HRSG** **Engineer:**

	Percent Change for Sensitivity:	1.00				and New Parameter		
	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	New Steam Flow at New Exhaust Flow	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1	Amb Dry Bulb Temp	70	0.7	70.7	3433091	433024	77.1429	0.0125
2	Wet Bulb Temp	64.5	0.65	65.15	3431259	432794	-270.7692	-0.0403
3	Amb Press	14.3	0.14	14.44	3433004	433104	957.1429	0.0316
4	GT Fuel Flow	76831	768	77599	3430925	432756	-0.2786	-0.0494
5	GT Steam Injection Flow	92208	922	93130	3431776	432859	-0.1204	-0.0256
6	GT Exhaust Temp	1123	11	1134	3380179	431459	-137.3636	-0.3563
7	HRSG Stack Temp	319	3.2	322.2	3446600	434708	543.1250	0.4002
8	HRSG Heat Loss	2274000	22700	2296700	3432727	432979	0.0004	0.0021
9	HP Steam Flow	432970	-4330	428640	3407153	429549	0.7901	0.7901
10	HP Feedwater Temp	313	3.1	316.1	3426143	432158	-261.9355	-0.1894
11	HP Steam Temp	1002	-10	992	3420208	433911	-94.1000	-0.2178
12	HP Steam Press	1362	13.7	1375.7	3431726	432604	-26.7153	-0.0840
13	Cold Reheat Flow	428000	-4280	423720	3428444	432398	0.1336	0.1321
14	Cold Reheat Temp	626	6.3	632.3	3425512	432722	-39.3651	-0.0569
15	Hot Reheat Press.	260	2.6	262.6	3432460	432945	-9.6154	-0.0058
16	Hot Reheat Temp	1005	-10	995	3421600	426729	624.1000	1.4486
17	0	0	0	0				
18	IP Feedwater Temp	306	3.1	309.1	3430258	432612	-115.4839	-0.0816
19	IP FW Extract Flow	78160	782	78942	3432898	432955	-0.0192	-0.0035
20	IP FW Extract Temp	377	3.8	380.8	3434153	433168	52.1053	0.0454
21	IP Steam Flow	73760	738	74498	3436348	433364	0.5339	0.0910
22	IP Steam Temp	604	6	610	3433804	433090	20.0000	0.0279
23	IP Steam Press	301	3	304	3432535	432950	-6.6667	-0.0046
24	LP Steam Flow	56850	567	57417	3435750	433293	0.5697	0.0748
25	LP Steam Temp	605	6	611	3433428	433106	22.6667	0.0317
26	LP Steam Press	38	0.4	38.4	3432609	432922	-120.0000	-0.0105
27	LP FW Temperature	230	2.3	232.3	3432001	432888	-35.6522	-0.0189
28								
29								
30								
31								
32								
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40								

Base Value of Result	432970

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX C

C-2 IP STEAM UNCERTAINTY: COMBINING THE STEAM FLOW AND UNCERTAINTY FROM GT AND HRSG HEAT BALANCES

Using Calculated Uncertainties

	GT Heat Balance	HRSG Heat Balance	Weighted
Steam Flow	73760	73760	
Uncertainty on IP Stm Flow	3.42%	1.74%	
Weight	0.205	0.795	
Systematic Uncertainty	2284	1242	1093
Random Uncertainty	537	162	169
Total Uncertainty			1144
HP Steam Flow			73760
Total Uncertainty %			1.551%

NONMANDATORY APPENDIX C: UNCERTAINTY WORKSHEET

IP Steam Flow by Gas Turbine Heat Balance

Project: PTC 4.4
Test: 3 Pressure HRSG
Date:
Engineer:

			Random Component							Systematic Component		
	Measured Parameter	Average Value	Sample Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensitivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Systematic Uncertainty for Parameter	Abs Sensivty x Systematic Uncert-Para	Systematic Uncertainty %
1	Amb Dry Bulb Temp	70.00	**1.10**	12	0.32	11.00	14.29	4.54	3.85E+01	**1.000**	14.29	0%
2	Wet Bulb Temp	64.50	**1.10**	12	0.32	11.00	-46.15	-14.66	4.19E+03	**1.000**	-46.15	0%
3	Amb Press	14.30	**0.0429**	12	0.01	11.00	42.86	0.53	7.21E-03	**0.036**	1.53	0%
4	GT Comp Inlet Temp	70.00	**1.10**	12	0.32	11.00	65.71	20.87	1.72E+04	**1**	65.71	0%
5	GT Fuel Flow	76831.00	**460.99**	30	84.16	29.00	1.65	138.96	1.29E+07	**384.155**	634.26	8%
6	GT Fuel Temp	259.00	**2.90**	30	0.53	29.00	2.69	1.43	1.42E-01	**4**	10.77	0%
7	GT Fuel LHV	20534.00	*30.00*	3	17.32	2.00	6.31	109.25	7.12E+07	**82.136**	518.06	5%
8	GT Steam Inj. Flow	92208.00	**553.25**	30	101.01	29.00	-0.01	-0.55	3.10E-03	**922.08**	-5.00	0%
9	GT Steam Inj. Temp	547.00	**2.90**	30	0.53	29.00	3.82	2.02	5.76E-01	***5***	19.09	0%
10	GT Steam Inj. Press	282.00	**2.90**	30	0.53	29.00	-1.79	-0.95	2.76E-02	**2.82**	-5.04	0%
11	GT Megawatt Output	172.50	**1.04**	30	0.19	29.00	-281.76	-53.24	2.77E+05	**0.69**	-194.42	1%
12	GT Heat Loss	33000000	*0.00*	30	0.00	29.00	0.00	0.0000	2.62E-53	**8250000**	-750.00	11%
13	GT Exhaust Temp	1123.00	**2.90**	30	0.53	29.00	-87.27	-46.21	1.57E+05	**11**	-960.00	18%
14												
15	HP Steam Flow	432970.00	**3896.73**	30	711.44	29.00	-0.66	-473.04	1.73E+09	**2164.85**	-1439.40	40%
16	HP Feedwater Temp	313.00	**2.90**	30	0.53	29.00	34.84	18.45	3.99E+03	**2**	69.68	0%
17	HP Stm Temp	1002.00	**2.90**	30	0.53	29.00	-61.70	-32.67	3.93E+04	**4.008**	-247.29	1%
18	HP Steam Press	1362.00	**2.90**	30	0.53	29.00	25.99	13.76	1.24E+03	**5.448**	141.57	0%
19	Cold Reheat Flow	428000.00	**3852.00**	30	703.28	29.00	0.01	3.94	8.34E+00	**2568.000**	14.40	0%
20	Cold Reheat Temp	626.00	**2.90**	30	0.53	29.00	-15.56	-8.24	1.59E+02	**4.695**	-73.03	0%
21	Hot Reheat Press	260.00	**2.90**	30	0.53	29.00	-0.77	-0.41	9.49E-04	**1.040**	-0.80	0%
22	Hot Reheat Temp	1005.00	**2.90**	30	0.53	29.00	-26.50	-14.03	1.34E+03	**4.020**	-106.53	0%
23												
24	IP Feedwater Temp	306.00	**2.90**	30	0.53	29.00	32.58	17.25	3.05E+03	**4.000**	130.32	0%
25	IP FW Extract Flow	78160.00	**703.44**	30	128.43	29.00	0.43	55.35	3.24E+05	**781.600**	336.83	2%
26	IP FW Extract Temp	377.00	**2.90**	30	0.53	29.00	88.68	46.96	1.68E+05	**4.000**	354.74	2%
27	IP Steam Flow	73760.00	**663.84**	30	121.20	29.00	1.00	121.20	7.44E+06	**737.600**	737.60	10%
28	IP Steam Temp	604.00	**2.90**	30	0.53	29.00	-35.50	-18.80	4.30E+03	**2.416**	-85.77	0%
29	IP Steam Press	301.00	**2.90**	30	0.53	29.00	-134.67	-71.30	8.91E+05	**1.204**	-162.14	1%
30	LP Steam Flow	56850.00	**511.65**	30	93.41	29.00	-0.11	-10.38	4.00E+02	**568.500**	-63.17	0%
31	LP Steam Temp	605.00	**2.90**	30	0.53	29.00	-30.17	-15.97	2.24E+03	**2.420**	-73.00	0%
32	LP Steam Press	38.00	**2.90**	30	0.53	29.00	-12.50	-6.62	6.62E+01	**0.152**	-1.90	0%
33	LP FW Temperature	230.00	**2.90**	30	0.53	29.00	-1.30	-0.69	7.84E-03	**4.000**	-5.22	0%
34												
35												
36												
37												
38												
39												
40												

Base Value of Result	73760
Random Uncertainty of Result	537
Degrees of Freedom for Random Uncertainty of Result	45.77
Student t Value	2.000

Systematic Uncertainty of Result - 95% Confidence Level		2284
Total Uncertainty	±	2524
Uncertainty Percent	±	3.42%

NONMANDATORY APPENDIX C: SENSITIVITY WORKSHEET	Project: PTC 4.4	Date:
IP Steam Flow by Gas Turbine Heat Balance	Test: 3 Pressure HRSG	Engineer:

	Percent Change for Sensitivity: 1.00							
	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	New Steam Flow at New Exhaust Flow and New Parameter	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1	Amb Dry Bulb Temp	70.0	0.70	70.7	3433084.0	73770	14.2857	0.0136
2	Wet Bulb Temp	64.5	0.65	65.2	3431382.0	73730	-46.1538	-0.0404
3	Amb Press	14.3	0.14	14.44	3432998.0	73766	42.8571	0.0083
4	GT Comp Inlet Temp	70.0	0.70	70.7	3434812.0	73806	65.7143	0.0624
5	GT Fuel Flow	76831.0	768.00	77599.0	3490259.0	75028	1.6510	1.7198
6	GT Fuel Temp	259.0	2.60	261.6	3433065.0	73767	2.6923	0.0095
7	GT Fuel LHV	20534.0	205.00	20739.0	3491391.0	75053	6.3073	1.7559
8	GT Steam Inj. Flow	92208.0	922.00	93130.0	3432513.0	73755	-0.0054	-0.0068
9	GT Steam Inj. Temp	547.0	5.50	552.5	3433701.0	73781	3.8182	0.0283
10	GT Steam Inj. Press	282.0	2.80	284.8	3432524.0	73755	-1.7857	-0.0068
11	GT Megawatt Output	172.5	1.70	174.2	3410932.0	73281	-281.7647	-0.6590
12	GT Heat Loss	33000000.0	330000.00	33330000.0	3431382.0	73730	-0.0001	-0.0407
13	GT Exhaust Temp	1123.0	11.00	1134.0	3391952.0	72800	-87.2727	-1.3287
14								
15	HP Steam Flow	432970.0	-4330.00	428640.0	3432616.0	76639	-0.6649	-3.9029
16	HP Feedwater Temp	313.0	3.10	316.1	3432616.0	73868	34.8387	0.1478
17	HP Stm Temp	1002.0	-10.00	992.0	3432616.0	74377	-61.7000	-0.8382
18	HP Steam Press	1362.0	13.70	1375.7	3432616.0	74116	25.9854	0.4798
19	Cold Reheat Flow	428000.0	-4280.00	423720.0	3432616.0	73736	0.0056	0.0325
20	Cold Reheat Temp	626.0	6.30	632.3	3432616.0	73662	-15.5556	-0.1320
21	Hot Reheat Press	260.0	2.60	262.6	3432616.0	73758	-0.7692	-0.0027
22	Hot Reheat Temp	1005.0	-10.00	995.0	3432616.0	74025	-26.5000	-0.3611
23								
24	IP Feedwater Temp	306.0	3.10	309.1	3432616.0	73861	32.5806	0.1352
25	IP FW Extract Flow	78160.0	782.00	78942.0	3432616.0	74097	0.4309	0.4567
26	IP FW Extract Temp	377.0	3.80	380.8	3432616.0	74097	88.6842	0.4533
27	IP Steam Flow	73760.0	738.00	74498.0	3432616.0	74498	1.0000	1.0000
28	IP Steam Temp	604.0	6.00	610.0	3432616.0	73547	-35.5000	-0.2907
29	IP Steam Press	301.0	3.00	304.0	3432616.0	73356	-134.6667	-0.5495
30	LP Steam Flow	56850.0	567.00	57417.0	3432616.0	73697	-0.1111	-0.0856
31	LP Steam Temp	605.0	6.00	611.0	3432616.0	73579	-30.1667	-0.2474
32	LP Steam Press	38.0	0.40	38.4	3432616.0	73755	-12.5000	-0.0064
33	LP FW Temperature	230.0	2.30	232.3	3432616.0	73757	-1.3043	-0.0041
34								
35								
36								
37								
38								
39								
40								

Base Value of Result	73760

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX C: UNCERTAINTY WORKSHEET								Project: PTC 4.4		Date:			
IP Steam Flow Uncertainty from HRSG Heat Balance								Test: 3 Pressure HRSG		Engineer:			

			Random Component							Systematic Component		
	Measured Parameter	Average Value	Sample Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensi-tivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Systematic Uncertainty for Parameter	Abs Sensivty x Systematic Uncert-Para	Systematic Uncertainty %
1	Amb Dry Bulb Temp	70	**1.10**	12	0.32	11	11.4286	3.63	1.58E+01	**1.000**	11.43	0%
2	Wet Bulb Temp	64.5	**1.10**	12	0.32	11	-50.7692	-16.12	6.14E+03	**1.000**	-50.77	0%
3	Amb Press	14.3	**0.043**	12	0.01	11	42.8571	0.53	7.21E-03	**0.036**	1.53	0%
4	GT Fuel Flow	76831	**461**	30	84.16	29	-0.0521	-4.38	1.27E+01	**384.155**	-20.01	0%
5	GT Steam Injection Flow	92208	**553**	30	101.01	29	-0.0228	-2.30	9.66E-01	**922.08**	-21.00	0%
6	GT Exhaust Temp	1123.0	**2.90**	30	0.53	29	-110.0909	-58.29	3.98E+05	**9**	-990.82	64%
7	HRSG Stack Temp	319.0	**2.90**	30.00	0.53	29	95.3125	50.46	2.24E+05	**2.5**	238.28	4%
8	HRSG Heat Loss	2274000	0.00	1		0	0.0000			**1137000**	-50.09	0%
9	HP Steam Flow	432970	**3896.73**	30	711.44	29	-0.0319	-22.67	9.11E+03	***2164.85***	-69.00	0%
10	HP Feedwater Temp	313	**2.90**	30	0.53	29	-10.9677	-5.81	3.92E+01	**2**	-21.94	0%
11	HP Steam Temp	1002	**2.90**	30	0.53	29	-35.4000	-18.74	4.26E+03	**4.008**	-141.88	1%
12	HP Steam Press	1362	**2.9**	30	0.53	29	24.3796	12.9081	9.57E+02	**5.448**	132.82	1%
13	Cold Reheat Flow	428000	**3852.00**	30	703.28	29	0.0271	19.06	4.55E+03	**2568**	69.60	0%
14	Cold Reheat Temp	626	**2.90**	30	0.53	29	-40.4762	-21.4307	7.27E+03	2.504	-101.35	1%
15	Hot Reheat Press.	260.0	**2.90**	30	0.53	29	-1.9231	-1.02	3.71E-02	**1.04**	-2.00	0%
16	Hot Reheat Temp	1005.0	**2.90**	30	0.53	29	-2.3000	-1.22	7.58E-02	**4.02**	-9.25	0%
17												
18	IP Feedwater Temp	306.0	**2.90**	30	0.53	29	16.4516	8.71	1.99E+02	**2**	32.90	0%
19	IP FW Extract Flow	78160	**703**	30	128.43	29	-0.0192	-2.46	1.27E+00	**781.600**	-14.99	0%
20	IP FW Extract Temp	377	**2.90**	30	0.53	29	94.4737	50.02	2.16E+05	**2.000**	188.95	2%
21	IP Steam Flow	73760	**664**	30	121.20	29	0.8198	99.36	3.36E+06	**737.600**	604.68	24%
22	IP Steam Temp	604	**2.90**	30	0.53	29	-27.6667	-14.65	1.59E+03	**2.416**	-66.84	0%
23	IP Steam Press	301	**2.90**	30	0.53	29	-135.3333	-71.65	9.09E+05	1.204	-162.94	2%
24	LP Steam Flow	56850	**512**	30	93.41	29	0.0511	4.78	1.80E+01	**568.500**	29.08	0%
25	LP Steam Temp	605	**2.90**	30	0.53	29	-28.5000	-15.09	1.79E+03	**2.420**	-68.97	0%
26	LP Steam Press	38	**2.90**	30	0.53	29	-5.0000	-2.65	1.69E+00	**0.152**	-0.76	0%
27	LP FW Temperature	230	**2.90**	30	0.53	29	-6.9565	-3.68	6.35E+00	**2.000**	-13.91	0%
28												
29												
30												
31												
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37												
38												
39												
40												

Base Value of Result	73760
Random Uncertainty of Result	162
Degrees of Freedom for Random Uncertainty of Result	133.56
Student t Value	2.000

Systematic Uncertainty of Result - 95% Confidence Level		1242
Total Uncertainty	±	1283
Uncertainty Percent	±	1.74%

NONMANDATORY APPENDIX C: SENSITIVITY WORKSHEET	Project: PTC 4.4	Date:
IP Steam Flow by HRSG Heat Balance	Test: 3 Pressure HRSG	Engineer:

Percent Change for Sensitivity: 1.00

	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	and New Parameter New Steam Flow at New Exhaust Flow	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1	Amb Dry Bulb Temp	70	0.7	70.7	3433091	73768	11.4286	0.0108
2	Wet Bulb Temp	64.5	0.65	65.15	3431259	73727	-50.7692	-0.0444
3	Amb Press	14.3	0.14	14.44	3433004	73766	42.8571	0.0083
4	GT Fuel Flow	76831	768	77599	3430925	73720	-0.0521	-0.0543
5	GT Steam Injection Flow	92208	922	93130	3431776	73739	-0.0228	-0.0285
6	GT Exhaust Temp	1123	11	1134	3380179	72549	-110.0909	-1.6761
7	HRSG Stack Temp	319	3.2	322.2	3446600	74065	95.3125	0.4122
8	HRSG Heat Loss	2274000	22700	2296700	3432727	73759	0.0000	-0.0014
9	HP Steam Flow	432970	-4330	428640	3407153	73898	-0.0319	-0.1871
10	HP Feedwater Temp	313	3.1	316.1	3426143	73726	-10.9677	-0.0465
11	HP Steam Temp	1002	-10	992	3420208	74114	-35.4000	-0.4809
12	HP Steam Press	1362	13.7	1375.7	3431726	74094	24.3796	0.4502
13	Cold Reheat Flow	428000	-4280	423720	3428444	73644	0.0271	0.1573
14	Cold Reheat Temp	626	6.3	632.3	3425512	73505	-40.4762	-0.3435
15	Hot Reheat Press.	260	2.6	262.6	3432460	73755	-1.9231	-0.0068
16	Hot Reheat Temp	1005	-10	995	3421600	73783	-2.3000	-0.0313
17	0	0	0	0				
18	IP Feedwater Temp	306	3.1	309.1	3430258	73811	16.4516	0.0683
19	IP FW Extract Flow	78160	782	78942	3432898	73745	-0.0192	-0.0203
20	IP FW Extract Temp	377	3.8	380.8	3434153	74119	94.4737	0.4829
21	IP Steam Flow	73760	738	74498	3436348	73893	0.1802	0.1802
22	IP Steam Temp	604	6	610	3433804	73594	-27.6667	-0.2266
23	IP Steam Press	301	3	304	3432535	73354	-135.3333	-0.5523
24	LP Steam Flow	56850	567	57417	3435750	73789	0.0511	0.0394
25	LP Steam Temp	605	6	611	3433428	73589	-28.5000	-0.2338
26	LP Steam Press	38	0.4	38.4	3432609	73758	-5.0000	-0.0026
27	LP FW Temperature	230	2.3	232.3	3432001	73744	-6.9565	-0.0217
28								
29								
30								
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Base Value of Result	73760

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX C

C-3 LP STEAM FLOW UNCERTAINTY: COMBINING THE STEAM FLOW AND UNCERTAINTY FROM GT AND HRSG HEAT BALANCES

Using Calculated Uncertainties

	GT Heat Balance	HRSG Heat Balance	Weighted
Steam Flow	56850	56850	
Uncertainty on IP Stm Flow	3.59%	2.27%	
Weight	0.285	0.715	
Systematic Uncertainty	1886	1220	1025
Random Uncertainty	388	207	185
Total Uncertainty			1089
HP Steam Flow			56850
Total Uncertainty %			1.916%

NONMANDATORY APPENDIX C: UNCERTAINTY WORKSHEET	Project: PTC 4.4	Date:
LP Steam Flow by Gas Turbine Heat Balance	Test: 3 Pressure HRSG	Engineer:

			Random Component							Systematic Component		
	Measured Parameter	Average Value	Sample Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensitivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Systematic Uncertainty for Parameter	Abs Sensivty x Systematic Uncert-Para	Systematic Uncertainty %
1	Amb Dry Bulb Temp	70.00	**1.10**	12	0.32	11.00	18.57	5.90	1.10E+02	**1.000**	18.57	0%
2	Wet Bulb Temp	64.50	**1.10**	12	0.32	11.00	-29.23	-9.28	6.75E+02	**1.000**	-29.23	0%
3	Amb Press	14.30	**0.0429**	12	0.01	11.00	64.29	0.80	3.65E-02	**0.036**	2.30	0%
4	GT Comp Inlet Temp	70.00	**1.10**	12	0.32	11.00	58.57	18.60	1.09E+04	**1**	58.57	0%
5	GT Fuel Flow	76831.00	**460.99**	30	84.16	29.00	1.31	110.47	5.13E+06	**384.155**	504.20	7%
6	GT Fuel Temp	259.00	**2.90**	30	0.53	29.00	3.85	2.04	5.93E-01	**4**	15.38	0%
7	GT Fuel LHV	20534.00	*30.00*	3	17.32	2.00	5.01	86.86	2.85E+07	**82.136**	411.88	5%
8	GT Steam Inj. Flow	92208.00	**553.25**	30	101.01	29.00	0.00	0.11	4.97E-06	**922.08**	1.00	0%
9	GT Steam Inj. Temp	547.00	**2.90**	30	0.53	29.00	3.82	2.02	5.76E-01	***5***	19.09	0%
10	GT Steam Inj. Press	282.00	**2.90**	30	0.53	29.00	0.36	0.19	4.41E-05	**2.82**	1.01	0%
11	GT Megawatt Output	172.50	**1.04**	30	0.19	29.00	-220.00	-41.57	1.03E+05	**0.69**	-151.80	1%
12	GT Heat Loss	33000000	*0.00*	30	0.00	29.00	0.00	0.0000	4.21E-54	**8250000**	-475.00	6%
13	GT Exhaust Temp	1123.00	**2.90**	30	0.53	29.00	-68.64	-36.34	6.01E+04	**11**	-755.00	16%
14												
15	HP Steam Flow	432970.00	**3896.73**	30	711.44	29.00	-0.37	-260.59	1.59E+08	**2164.85**	-792.95	18%
16	HP Feedwater Temp	313.00	**2.90**	30	0.53	29.00	302.90	160.38	2.28E+07	**2**	605.81	10%
17	HP Stm Temp	1002.00	**2.90**	30	0.53	29.00	-38.90	-20.60	6.21E+03	**4.008**	-155.91	1%
18	HP Steam Press	1362.00	**2.90**	30	0.53	29.00	3.94	2.09	6.54E-01	**5.448**	21.47	0%
19	Cold Reheat Flow	428000.00	**3852.00**	30	703.28	29.00	0.00	1.64	2.51E-01	**2568.000**	6.00	0%
20	Cold Reheat Temp	626.00	**2.90**	30	0.53	29.00	-9.37	-4.96	2.08E+01	**4.695**	-43.97	0%
21	Hot Reheat Press	260.00	**2.90**	30	0.53	29.00	1.15	0.61	4.80E-03	**1.040**	1.20	0%
22	Hot Reheat Temp	1005.00	**2.90**	30	0.53	29.00	-19.90	-10.54	4.25E+02	**4.020**	-80.00	0%
23												
24	IP Feedwater Temp	306.00	**2.90**	30	0.53	29.00	69.35	36.72	6.27E+04	**4.000**	277.42	2%
25	IP FW Extract Flow	78160.00	**703.44**	30	128.43	29.00	-0.65	-83.27	1.66E+06	**781.600**	-506.74	7%
26	IP FW Extract Temp	377.00	**2.90**	30	0.53	29.00	-133.42	-70.64	8.59E+05	**4.000**	-533.68	8%
27	IP Steam Flow	73760.00	**663.84**	30	121.20	29.00	-0.78	-94.10	2.70E+06	**737.600**	-572.69	9%
28	IP Steam Temp	604.00	**2.90**	30	0.53	29.00	1.00	0.53	2.71E-03	**2.416**	2.42	0%
29	IP Steam Press	301.00	**2.90**	30	0.53	29.00	89.00	47.12	1.70E+05	**1.204**	107.16	0%
30	LP Steam Flow	56850.00	**511.65**	30	93.41	29.00	1.00	93.41	2.63E+06	**568.500**	568.50	9%
31	LP Steam Temp	605.00	**2.90**	30	0.53	29.00	-3.50	-1.85	4.07E-01	**2.420**	-8.47	0%
32	LP Steam Press	38.00	**2.90**	30	0.53	29.00	5.00	2.65	1.69E+00	**0.152**	0.76	0%
33	LP FW Temperature	230.00	**2.90**	30	0.53	29.00	0.87	0.46	1.56E-03	**4.000**	3.48	0%
34												
35												
36												
37												
38												
39												
40												

Base Value of Result	56850
Random Uncertainty of Result	388
Degrees of Freedom for Random Uncertainty of Result	101.33
Student t Value	2.000

Systematic Uncertainty of Result - 95% Confidence Level		1886
Total Uncertainty	±	2040
Uncertainty Percent	±	3.59%

NONMANDATORY APPENDIX C: SENSITIVITY WORKSHEET	**Project: PTC 4.4**	**Date:**
LP Steam Flow by Gas Turbine Heat Balance	**Test: 3 Pressure HRSG**	**Engineer:**

Percent Change for Sensitivity: 1.00

	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	and New Parameter New Steam Flow at New Exhaust Flow	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1	Amb Dry Bulb Temp	70.0	0.70	70.7	3433084.0	56863	18.5714	0.0229
2	Wet Bulb Temp	64.5	0.65	65.2	3431382.0	56831	-29.2308	-0.0332
3	Amb Press	14.3	0.14	14.44	3432998.0	56859	64.2857	0.0162
4	GT Comp Inlet Temp	70.0	0.70	70.7	3434812.0	56891	58.5714	0.0721
5	GT Fuel Flow	76831.0	768.00	77599.0	3490259.0	57858	1.3125	1.7738
6	GT Fuel Temp	259.0	2.60	261.6	3433065.0	56860	3.8462	0.0175
7	GT Fuel LHV	20534.0	205.00	20739.0	3491391.0	57878	5.0146	1.8113
8	GT Steam Inj. Flow	92208.0	922.00	93130.0	3432513.0	56851	0.0011	0.0018
9	GT Steam Inj. Temp	547.0	5.50	552.5	3433701.0	56871	3.8182	0.0367
10	GT Steam Inj. Press	282.0	2.80	284.8	3432524.0	56851	0.3571	0.0018
11	GT Megawatt Output	172.5	1.70	174.2	3410932.0	56476	-220.0000	-0.6675
12	GT Heat Loss	33000000	330000	33330000	3431382.0	56831	-0.0001	-0.0334
13	GT Exhaust Temp	1123.0	11.00	1134.0	3391952.0	56095	-68.6364	-1.3558
14								
15	HP Steam Flow	432970.0	-4330.00	428640.0	3432616.0	58436	-0.3663	-2.7896
16	HP Feedwater Temp	313.0	3.10	316.1	3432616.0	57789	302.9032	1.6677
17	HP Stm Temp	1002.0	-10.00	992.0	3432616.0	57239	-38.9000	-0.6856
18	HP Steam Press	1362.0	13.70	1375.7	3432616.0	56904	3.9416	0.0944
19	Cold Reheat Flow	428000.0	-4280.00	423720.0	3432616.0	56840	0.0023	0.0176
20	Cold Reheat Temp	626.0	6.30	632.3	3432616.0	56791	-9.3651	-0.1031
21	Hot Reheat Press	260.0	2.60	262.6	3432616.0	56853	1.1538	0.0053
22	Hot Reheat Temp	1005.0	-10.00	995.0	3432616.0	57049	-19.9000	-0.3518
23								
24	IP Feedwater Temp	306.0	3.10	309.1	3432616.0	57065	69.3548	0.3733
25	IP FW Extract Flow	78160.0	782.00	78942.0	3432616.0	56343	-0.6483	-0.8914
26	IP FW Extract Temp	377.0	3.80	380.8	3432616.0	56343	-133.4211	-0.8848
27	IP Steam Flow	73760.0	738.00	74498.0	3432616.0	56277	-0.7764	-1.0074
28	IP Steam Temp	604.0	6.00	610.0	3432616.0	56838	1.0000	0.0106
29	IP Steam Press	301.0	3.00	304.0	3432616.0	57117	89.0000	0.4712
30	LP Steam Flow	56850.0	567.00	57417.0	3432616.0	57417	1.0000	1.0000
31	LP Steam Temp	605.0	6.00	611.0	3432616.0	56829	-3.5000	-0.0372
32	LP Steam Press	38.0	0.40	38.4	3432616.0	56852	5.0000	0.0033
33	LP FW Temperature	230.0	2.30	232.3	3432616.0	56852	0.8696	0.0035
34								
35								
36								
37								
38								
39								
40								

Base Value of Result	56850

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX C: UNCERTAINTY WORKSHEET		Project: PTC 4.4	Date:
LP Steam Flow Uncertainty from HRSG Heat Balance		Test: 3 Pressure HRSG	Engineer:

			Random Component							Systematic Component		
	Measured Parameter	Average Value	Sample Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensitivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Systematic Uncertainty for Parameter	Abs Sensivty x Systematic Uncert-Para	Systematic Uncertainty %
1	Amb Dry Bulb Temp	70	**1.10**	12	0.32	11	15.7143	4.99	5.64E+01	**1.000**	15.71	0%
2	Wet Bulb Temp	64.5	**1.10**	12	0.32	11	-32.3077	-10.26	1.01E+03	**1.000**	-32.31	0%
3	Amb Press	14.3	**0.043**	12	0.01	11	64.2857	0.80	3.65E-02	**0.036**	2.30	0%
4	GT Fuel Flow	76831	**461**	30	84.16	29	-0.0352	-2.96	2.64E+00	**384.155**	-13.51	0%
5	GT Steam Injection Flow	92208	**553**	30	101.01	29	-0.0130	-1.31	1.03E-01	**922.08**	-12.00	0%
6	GT Exhaust Temp	1123.0	**2.90**	30	0.53	29	-86.8182	-45.97	1.54E+05	**9**	-781.36	41%
7	HRSG Stack Temp	319.0	**2.90**	30.00	0.53	29	76.8750	40.70	9.46E+04	**2.5**	192.19	2%
8	HRSG Heat Loss	2274000	**0.00**	1		0	0.0002			**1137000**	200.35	3%
9	HP Steam Flow	432970	**3896.73**	30	711.44	29	0.0115	8.22	1.57E+02	***2164.85***	25.00	0%
10	HP Feedwater Temp	313	**2.90**	30	0.53	29	266.1290	140.91	1.36E+07	**2**	532.26	19%
11	HP Steam Temp	1002	**2.90**	30	0.53	29	-18.0000	-9.53	2.84E+02	**4.008**	-72.14	0%
12	HP Steam Press	1362	**2.9**	30	0.53	29	2.7737	1.4686	1.60E-01	**5.448**	15.11	0%
13	Cold Reheat Flow	428000	**3852.00**	30	703.28	29	0.0192	13.47	1.14E+03	**2568**	49.20	0%
14	Cold Reheat Temp	626	**2.90**	30	0.53	29	-29.0476	-15.3797	1.93E+03	**2.504**	-72.74	0%
15	Hot Reheat Press.	260.0	**2.90**	30	0.53	29	0.0000	0.00	0.00E+00	**1.04**	0.00	0%
16	Hot Reheat Temp	1005.0	**2.90**	30	0.53	29	-0.7000	-0.37	6.51E-04	**4.02**	-2.81	0%
17												
18	IP Feedwater Temp	306.0	**2.90**	30	0.53	29	56.7742	30.06	2.82E+04	**2**	113.55	1%
19	IP FW Extract Flow	78160	**703**	30	128.43	29	-0.0038	-0.49	2.03E-03	**781.600**	-3.00	0%
20	IP FW Extract Temp	377	**2.90**	30	0.53	29	-121.5789	-64.37	5.92E+05	**2.000**	-243.16	4%
21	IP Steam Flow	73760	**664**	30	121.20	29	-0.4946	-59.94	4.45E+05	**737.600**	-364.80	9%
22	IP Steam Temp	604	**2.90**	30	0.53	29	1.6667	0.88	2.09E-02	**2.416**	4.03	0%
23	IP Steam Press	301	**2.90**	30	0.53	29	88.6667	46.95	1.67E+05	**1.204**	106.75	1%
24	LP Steam Flow	56850	**512**	30	93.41	29	0.9400	87.81	2.05E+06	**568.500**	534.39	19%
25	LP Steam Temp	605	**2.90**	30	0.53	29	-1.5000	-0.79	1.37E-02	**2.420**	-3.63	0%
26	LP Steam Press	38	**2.90**	30	0.53	29	10.0000	5.29	2.71E+01	**0.152**	1.52	0%
27	LP FW Temperature	230	**2.90**	30	0.53	29	-3.0435	-1.61	2.33E-01	**2.000**	-6.09	0%
28												
29												
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38												
39												
40												

Base Value of Result	56850
Random Uncertainty of Result	207
Degrees of Freedom for Random Uncertainty of Result	107.47
Student t Value	2.000

Systematic Uncertainty of Result - 95% Confidence Level		1220
Total Uncertainty	±	1288
Uncertainty Percent	±	2.27%

NONMANDATORY APPENDIX C: SENSITIVITY WORKSHEET	Project: PTC 4.4	Date:
LP Steam Flow by HRSG Heat Balance	Test: 3 Pressure HRSG	Engineer:

Percent Change for Sensitivity: 1.00

	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	and New Parameter New Steam Flow at New Exhaust Flow	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1	Amb Dry Bulb Temp	70	0.7	70.7	3433091	56861	15.7143	0.0193
2	Wet Bulb Temp	64.5	0.65	65.15	3431259	56829	-32.3077	-0.0367
3	Amb Press	14.3	0.14	14.44	3433004	56859	64.2857	0.0162
4	GT Fuel Flow	76831	768	77599	3430925	56823	-0.0352	-0.0475
5	GT Steam Injection Flow	92208	922	93130	3431776	56838	-0.0130	-0.0211
6	GT Exhaust Temp	1123	11	1134	3380179	55895	-86.8182	-1.7150
7	HRSG Stack Temp	319	3.2	322.2	3446600	57096	76.8750	0.4314
8	HRSG Heat Loss	2274000	22700	2296700	3432727	56854	0.0002	0.0070
9	HP Steam Flow	432970	-4330	428640	3407153	56800	0.0115	0.0879
10	HP Feedwater Temp	313	3.1	316.1	3426143	57675	266.1290	1.4652
11	HP Steam Temp	1002	-10	992	3420208	57030	-18.0000	-0.3173
12	HP Steam Press	1362	13.7	1375.7	3431726	56888	2.7737	0.0665
13	Cold Reheat Flow	428000	-4280	423720	3428444	56768	0.0192	0.1442
14	Cold Reheat Temp	626	6.3	632.3	3425512	56667	-29.0476	-0.3199
15	Hot Reheat Press.	260	2.6	262.6	3432460	56850	0.0000	0.0000
16	Hot Reheat Temp	1005	-10	995	3421600	56857	-0.7000	-0.0124
17								
18	IP Feedwater Temp	306	3.1	309.1	3430258	57026	56.7742	0.3056
19	IP FW Extract Flow	78160	782	78942	3432898	56847	-0.0038	-0.0053
20	IP FW Extract Temp	377	3.8	380.8	3434153	56388	-121.5789	-0.8062
21	IP Steam Flow	73760	738	74498	3436348	56485	-0.4946	-0.6417
22	IP Steam Temp	604	6	610	3433804	56860	1.6667	0.0177
23	IP Steam Press	301	3	304	3432535	57116	88.6667	0.4695
24	LP Steam Flow	56850	567	57417	3435750	56884	0.0600	0.0600
25	LP Steam Temp	605	6	611	3433428	56841	-1.5000	-0.0160
26	LP Steam Press	38	0.4	38.4	3432609	56854	10.0000	0.0067
27	LP FW Temperature	230	2.3	232.3	3432001	56843	-3.0435	-0.0123
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Base Value of Result	56850

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX D
FUEL SENSIBLE HEAT

D-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.

D-2 FUEL OIL

The specific heat for fuel oil is taken from Perry's [1]. The specific heat is evaluated at the average temperature in degree Fahrenheit (°F) 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 would be 0.8251 and 0.9861, respectively. This would result in sensible heat errors of +2.3% and –6.3%.

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

The sensible heat of the fuel oil is calculated by multiplying the specific heat times the difference of the fuel temperature in degree Fahrenheit (°F) and the reference temperature of 60°F.

$$h = Cp * (T - 60) = [0.417 + 0.000484 * (T + 60) / 2] * (T - 60)$$

This reduces to the equation:

$$h = T^2 / 4132 + 0.417T - 25.9 \quad \text{(Btu/lb)} \tag{1}$$

An alternate method is described in the reference STEAM [2]. This equation requires that the fuel API gravity be known which is the reason the method was not recommended.

$$h = -30.016 - 0.11426API + 0.373T + 1.43e - 3(API)(T) + (2.184e - 4 + 7e - 7API)(T) \tag{2}$$

An example comparison was done to illustrate the results of the two methods.

	Equation 1	Equation 2		
		#2 F.O.	#6 F.O.	
API		33	12.6	
$h@T = 200$	55.4	59.9	55.8	(Btu/lb)

D-3 FUEL GAS

Fuel gas sensible heat is a function of temperature, pressure, and composition. Some simplifying assumptions were made in this derivation, which are as follows:

(a) Fuel gas is composed of 92% methane and 8% ethane on a volume basis.

(b) Fuel Pressure is 100 psia.

The assumption of a fixed pressure is illustrated in Table D-3-1 calculated from Reference [3]. The specific heat of methane varies only slightly over a significant pressure range. Table D-3-1 also shows that the specific heat of propane and ethane are very similar so that the assumption that nonmethane constituents are ethane is acceptable. The assumptions that the gas stream is 92% methane and that the average fuel pressure is 100 psia are arbitrary.

Table D-3-1 Specific Heat at 124°F

	14.7 psia	100 psia	300 psia
Methane	0.5488	0.5556	0.5724
Ethane		0.4633	
Propane		0.4623	

Specific heat is calculated on a weight basis so the composition is converted from a volume basis by the following:

$$\text{Methane Wt \%} = 0.92 * 16 / (0.92 * 16 + 0.08 * 30) = 0.86$$

$$\text{Ethane Wt \%} = 0.08 * 30 / (0.92 * 16 + 0.08 * 30) = 0.14$$

The combined gas stream specific heat was calculated as a fraction of the pure methane specific heat.

$$F = [(0.86 * 0.5556) + (0.14 * 0.4633)] / 0.5556 = 0.9767$$

Methane specific heat as a function of temperature was determined from Reference [3] and is shown in Table D-3-2.

Table D-3-2 Specific Heat at 100 psia

Average temperature	32°F	124°F	216°F	308°F	400°F
Methane	0.5189	0.5556	0.5953	0.6364	0.6783

It was found that the specific heat could be accurately correlated by a linear curve fit in this temperature range by the following equation with the temperature in degree Fahrenheit (°F)

$$Cp = 0.503081 + 4.34348\text{e} - 4 * T_{AVG} \qquad [\text{error max./min.} = 0.27 / -0.37\%]$$

This correlation was multiplied by the factor calculated from above to correct it for nonmethane hydrocarbons. The equation then becomes

$$Cp = 0.491 + T_{AVG} / 2360$$

The sensible heat of the fuel gas is calculated by multiplying the specific heat times the difference of the fuel temperature in degree Fahrenheit (°F) and the reference temperature of 60°F.

$$h = Cp * (T - 60) = [0.491 + (T + 60) / 2 / 2360] * (T - 60)$$

This reduces to the equation

$$h = T^2 / 4720 + 0.491T - 30.2 \ \ (\text{Btu/lb})$$

An example of this calculation for a fuel gas at 300°F results in a sensible heat of 136.9 Btu/lb. If the fuel lower heating value is 20,000 Btu/lb, the sensible heat represents a 0.7% increase in the net heating value.

D-4 REFERENCES

[1] Perry's Chemical Engineering Handbook 6th Edition, Eq. 9−12.

[2] "STEAM", B&W 40th ed., pg 9−18.

[3] Reid, Prausnitz, and Poling, "The Properties of Liquids and Gases", McGraw Hill, 1987.

NONMANDATORY APPENDIX E
GAS ENTHALPY EQUATION DERIVATION

This Appendix shows the derivation of the gas enthalpy equations used in this Code. If changes to the NASA correlations occur, the equations in this Code can be updated following the same derivation approach.

NONMANDATORY APPENDIX E - Derivation of Gas Enthalpy Constants from NASA Correlations of the JANAF Data

NASA/TP-2002-211556 NASA Glen Coefficients for Calculating Thermodynamic Properties of Individual Species September 2002. Rev 1/29/03

NASA Coeficients to calculate $(H\text{-}H^0)/RT$.

EQN: $(H\text{-}H^o)/RT = -A_1/T^2 + A_2{*}Ln(T)/T + A_3 + A_4{*}T/2 + A_5{*}T^2/3 + A_6{*}T^3/4 + A_7{*}T^4/5$ **Units H - J/mole; T - K.**

T Range	Component	A_1	A_2	A_3	A_4	A_5	A_6	A_7	b_1	Mole Weight	Temp Range(°K)	
Low	O_2	-3.425563420E+04	4.84700097E+02	1.119010961E+00	4.293889240E-03	-6.836300520E-07	-2.023372700E-09	1.039040018E-12	-3.39145487E+03	31.9988	200 / 1000	page106
High	O_2	-1.037939022E+06	2.34483028E+03	1.819732036E+00	1.267847582E-03	-2.188067988E-07	2.053719572E-11	-8.193467050E-16	-1.689010929E+04	31.9988	1000 / 6000	
Low	N_2	2.210371497E+04	-3.818461820E+02	6.082738360E+00	-8.530914410E-03	1.384646189E-05	-9.625793620E-09	2.519705809E-12	7.108460860E+02	28.0134	200 / 1000	page156
High	N_2	5.877124060E+05	-2.239249073E+03	6.066949220E+00	-6.139685500E-04	1.491806679E-07	-1.923105485E-11	1.061954386E-15	1.283210415E+04	28.0134	1000 / 6000	
Low	Ar	0.000000000E+00	0.000000000E+00	2.500000000E+00	0.000000000E+00	0.000000000E+00	0.000000000E+00	0.000000000E+00	-7.453750000E+02	39.9480	200 / 1000	page55
High	Ar	2.010538475E+01	-5.992661070E-02	2.500069401E+00	-3.992141160E-08	1.205272140E-11	-1.819015576E-15	1.078576636E-19	-7.449939610E+02	39.9480	1000 / 6000	
Low	SO_2	-5.310842140E+04	9.090311670E+02	-2.356891244E+00	2.204449885E-02	-2.510781471E-05	1.446300484E-08	-3.369070940E-12	-4.113752080E+04	64.0638	200 / 1000	page183
High	SO_2	-1.127640116E+05	-8.252261380E+02	7.616178630E+00	-1.999327610E-04	5.655631430E-08	-5.454316610E-12	2.918294102E-16	-3.351308690E+04	64.0638	1000 / 6000	
Low	H_2O	-3.947960830E+04	5.755731020E+02	9.317826530E-01	7.222712860E-03	-7.342557370E-06	4.955043490E-09	-1.336933246E-12	-3.303974310E+04	18.01528	200 / 1000	page131
High	H_2O	1.034972096E+06	-2.412698562E+03	4.646110780E+00	2.291998307E-03	-6.836830480E-07	9.426468930E-11	-4.822380530E-15	-1.384286509E+04	18.01528	1000 / 6000	
Low	CO_2	4.943650540E+04	-6.264116010E+02	5.301725240E+00	2.503813816E-03	-2.127308728E-07	-7.689988780E-10	2.849677801E-13	-4.528198460E-04	44.0095	200 / 1000	page85
High	CO_2	1.176962419E+05	-1.788791477E+03	8.291523190E+00	-9.223156780E-05	4.863676880E-09	-1.891053312E-12	6.330036590E-16	-3.908350590E+04	44.0095	1000 / 6000	

NASA Coeficients multiplied by gas constant (R=8314.51 j/kgmole K), divided by the Molecular Weight, dividied by conversion constant 2326 (j/kg)/(btu/lb)

EQN: $(H\text{-}H^0)/T = -A1'/T^2 + A2'{*}Ln(T)/T + A3' + A4'{*}T/2 + A5'{*}T^2/3 + A6'{*}T^3/4 + A7'{*}T^4/5$ **[Units H - btu/lb; T - K]**

T Range	Component	A_1	A_2	A_3	A_4	A_5	A_6	A_7	b_1
Low	O_2	-3.8267075E+03	5.414599817E+01	1.250050615E-01	4.796716988E-04	-7.636852514E-08	-2.260315919E-10	1.160714827E-13	-3.788604754E+02
High	O_2	-1.159484901E+05	2.619417179E+02	2.032828301E-01	1.416316466E-04	-2.444297536E-08	2.294216504E-12	-9.152947454E-17	-1.886799347E+03
Low	N_2	2.820501914E+03	-4.872474552E+01	7.761760956E-01	-1.088570878E-03	1.766851061E-06	-1.228280828E-09	3.215221996E-13	9.070614367E+01
High	N_2	7.499390795E+04	-2.857350587E+02	7.741613529E-01	-7.834427256E-05	1.903591138E-08	-2.453941660E-12	1.355086411E-16	1.637415899E+03
Low	Ar	0.000000000E+00	0.000000000E+00	2.237030560E-01	0.000000000E+00	0.000000000E+00	0.000000000E+00	0.000000000E+00	-6.669706615E+01
High	Ar	1.799054404E+00	-5.362306380E-03	2.237092661E-01	-3.572216710E-09	1.078492244E-12	-1.627677373E-16	9.651235585E-21	-6.666297032E+01
Low	SO_2	-2.963313821E+03	5.072160967E+01	-1.315084917E-01	1.230026546E-03	-1.400951721E-06	8.069986078E-10	-1.879855250E-13	-2.295368243E+03
High	SO_2	-6.291942883E+03	-4.604550381E+01	4.249632506E-01	-1.115573572E-05	3.155697409E-09	-3.043368898E-13	1.628333326E-17	-1.869944370E+03
Low	H_2O	-7.833552678E+03	1.142053432E+02	1.848845217E-01	1.433132295E-03	-1.456911870E-06	9.831808336E-10	-2.652745926E-13	-6.555753190E+03
High	H_2O	2.053593940E+05	-4.787281864E+02	9.218823365E-01	4.547788149E-04	-1.356565428E-07	1.870402066E-11	-9.568578195E-16	-2.746704376E+03
Low	CO_2	4.015395043E+03	-5.087920389E+01	4.306235054E-01	2.033679668E-04	-1.727869892E-08	-6.246060999E-11	2.314601735E-14	-3.677951244E-05
High	CO_2	9.559674628E+03	-1.452915082E+02	6.734646968E-01	-7.491350313E-06	3.950437815E-10	-1.535975497E-13	5.141463245E-17	-3.174490482E+03

Equation multiplied by temperature. Temperature converted to °R by substituting T/1.8 for T. Denomenators are incorporated into constants to give in equation of the form

EQN: $(H\text{-}H^0) = -A1/T + A2Ln(T) + A3{*}T + A4{*}T^2 + A5{*}T^3 + A{*}6T^4 + A7{*}T^5$ **[Units H - btu/lb; T - °R]**

T Range	Component	A_1	A_2	A_3	A_4	A_5	A_6	A_7	b_1
Low	O_2	-6.8880735E+03	5.4145998E+01	6.9447256E-02	7.4023410E-05	-4.3649134E-09	-5.3829350E-12	1.2285505E-15	-3.7886048E+02
High	O_2	-2.0870728E+05	2.6194172E+02	1.1293491E-01	2.1856736E-05	-1.3970608E-09	5.4636691E-14	-9.6878731E-19	-1.8867993E+03
Low	N_2	5.0769034E+03	-4.8724746E+01	4.3120894E-01	-1.6798933E-04	1.0098600E-07	-2.9251468E-11	3.4031292E-15	9.0706144E+01
High	N_2	1.3498903E+05	-2.8573506E+02	4.3008964E-01	-1.2090166E-05	1.0880151E-09	-5.8440540E-14	1.4342817E-18	1.6374159E+03
Low	Ar	0.0000000E+00	0.0000000E+00	1.2427948E-01	0.0000000E+00	0.0000000E+00	0.0000000E+00	0.0000000E+00	-6.6697066E+01
High	Ar	3.2382979E+00	-5.3623064E-03	1.2428293E-01	-5.5126801E-10	6.1642218E-14	-3.8763083E-18	1.0215283E-22	-6.6662970E+01
Low	SO_2	-5.3339649E+03	5.0721610E+01	-7.3060273E-02	1.8981891E-04	-8.0072686E-08	1.9218645E-11	-1.9897196E-15	-2.2953682E+03
High	SO_2	-1.1325497E+04	-4.6045504E+01	2.3609069E-01	-1.7215642E-06	1.8036679E-10	-7.2477731E-15	1.7234980E-19	-1.8699444E+03
Low	H_2O	-1.4100395E+04	1.1420534E+02	1.0271362E-01	2.2116239E-04	-8.3271140E-08	2.3414419E-11	-2.8077803E-15	-6.5557532E+03
High	H_2O	3.6964691E+05	-4.7872819E+02	5.1215685E-01	7.0181916E-05	-7.7535747E-09	4.4543564E-13	-1.0127794E-17	-2.7467044E+03
Low	CO_2	7.2277111E+03	-5.0879204E+01	2.3923528E-01	3.1383945E-05	-9.8757996E-10	-1.4874974E-12	2.4498740E-16	-3.6779512E-05
High	CO_2	1.7207414E+04	-1.4529151E+02	3.7414705E-01	-1.1560726E-06	2.2579091E-11	-3.6579206E-15	5.4419457E-19	-3.1744905E+03

*Note - Conversion from °K to °R results in a constant that will ultimately be included in an A8 term

Low	N_2	-1.2356702E+02
High	N_2	
Low	Ar	6.4584315E+01
High	Ar	
Low	SO_2	3.3081966E+02
High	SO_2	
Low	H_2O	8.4430005E+02
High	H_2O	
Low	CO_2	-1.9950475E+02
High	CO_2	

EQN: $(H - H^{519.67}) = -A1/T + A2*Ln(T) + A3*T + A4*T^2 + A5*T^3 + A6*T^4 + A7*T^5 - A8 = 0$ [Units H - btu/lb; T - °R]

Evaluation of low temperature range equation (H-$H^{519.67}$) at 1800°R (1000K) with A8.
Evaluation of high temperature range equation (H-H^0) at 1800°R (1000K) without A8.
High temperature range A8 is the difference between the previous evaluations.

T Range	Component	Low Range (H-H0)	High Range (H-H0)	A8(High Range)
Low	O_2	3.0880971E+02		
High	O_2		2.3458499E+03	2.0370402E+03
Low	N_2	3.3360339E+02		
High	N_2		-1.4759849E+03	-1.8095883E+03
Low	Ar	1.5911874E+02		
High	Ar		2.2366581E+02	6.4547067E+01
Low	SO_2	2.3300303E+02		
High	SO_2		8.1520392E+01	-1.5148263E+02
Low	H_2O	6.2811811E+02		
High	H_2O		-2.6851491E+03	-3.3132672E+03
Low	CO_2	3.2968412E+02		
High	CO_2		-4.2877568E+02	-7.5845980E+02

Enthalpy equation with reference temperature of 60°F.

EQN: $H_{60} = -A1/T + A2*Ln(T) + A3*T + A4*T^2 + A5*T^3 + A6*T^4 + A7*T^5 - A8$ [Units H - btu/lb; T - °R.]

T Range	Component	A1	A2	A3	A4	A5	A6	A7	A8	$H^{519.67}$ (@60°F)	H - $H^{519.67}$(@1800°R)
Low	O_2	-6.88807354E+03	5.41459982E+01	6.94472564E-02	7.40234103E-05	-4.36491342E-09	-5.38293495E-12	1.22855047E-15	4.06961733E+02	0.000000000	308.809709182
High	O_2	-2.08707282E+05	2.61941718E+02	1.12934906E-01	2.18567356E-05	-1.39706078E-09	5.46366909E-14	-9.68787305E-19	2.03704016E+03		308.809709182
Low	N_2	5.07690344E+03	-4.87247455E+01	4.31208942E-01	-1.67989333E-04	1.00986000E-07	-2.92514677E-11	3.40312918E-15	-1.23567020E+02	0.000000000	333.603388035
High	N_2	1.34989034E+05	-2.85735059E+02	4.30089640E-01	-1.20901655E-05	1.08801505E-09	-5.84405402E-14	1.43428171E-18	-1.80958828E+03		333.603388035
Low	Ar	0.00000000E+00	0.00000000E+00	1.24279476E-01	0.00000000E+00	0.00000000E+00	0.00000000E+00	0.00000000E+00	6.45843151E+01	0.000000000	159.118740952
High	Ar	3.23829793E+00	-5.36230638E-03	1.24282926E-01	-5.51268011E-10	6.16422179E-14	-3.87630833E-18	1.02152826E-22	6.45470673E+01		159.118740952
Low	SO_2	-5.33396488E+03	5.07216097E+01	-7.30602732E-02	1.89818911E-04	-8.00726864E-08	1.92186454E-11	-1.98971961E-15	3.30819661E+02	0.000000000	233.003026880
High	SO_2	-1.13254972E+04	-4.60455038E+01	2.36090695E-01	-1.72156415E-06	1.80366793E-10	-7.24777306E-15	1.72349799E-19	-1.51482635E+02		233.003026880
Low	H_2O	-1.41003948E+04	1.14205343E+02	1.02713623E-01	2.21162391E-04	-8.32711403E-08	2.34144193E-11	-2.80778032E-15	8.44300054E+02	0.000000000	628.118107591
High	H_2O	3.69646909E+05	-4.78728186E+02	5.12156854E-01	7.01819159E-05	-7.75357469E-09	4.45435639E-13	-1.01277945E-17	-3.31326717E+03		628.118107591
Low	CO_2	7.22771108E+03	-5.08792039E+01	2.39235281E-01	3.13839455E-05	-9.87579956E-10	-1.48749738E-12	2.44987398E-16	-1.99504750E+02	0.000000000	329.684121629
High	CO_2	1.72074143E+04	-1.45291508E+02	3.74147054E-01	-1.15607258E-06	2.25790913E-11	-3.65792061E-15	5.44194572E-19	-7.58459804E+02		329.684121629

NONMANDATORY APPENDIX F
HRSG HEAT LOSS

F-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 F-1.1 is an example of the variation that can be expected.

F-1.1 Insulated Casing Design Criteria

(a) For 140°F casing temperature with 80ºF 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 be multiplying the insulated casing design heat flux times the square footage of casing. This will result in a higher than expected heat loss because minimum insulation thickness may control at the cold end of the HRSG. This is compensated by heat losses from piping and drums.

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. The inside casing heat transfer rate is assumed to be that calculated by the Dittus Bolder equation for turbulent heat transfer in a cylinder.

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

where

h_i = heat transfer coefficient

d = stack diameter

k = gas conductivity

Re = Reynolds number

Pr = Prandtl number

This can be reduced to the following equation:

$$h_i = C \frac{W^{0.8}}{d^{1.8}} \quad \frac{Cp^{0.4} \; k^{0.6}}{VIS^{0.4}} \qquad (2)$$

where

C = constant

W = gas flow (lb/hr)

D = stack diameter (in.)

Cp = gas specific heat

VIS = gas viscosity

A gas turbine composition is assumed as follows:

(1) nitrogen, 75.6%

(2) oxygen, 13.5%

(3) carbon dioxide, 3.5%

(4) water, 6.5%

(5) argon, 0.9%

A table of physical properties for this composition can be determined. A linear correlation of the physical property portion of eq. (2) is developed.

TEMP	Cp	VIS	k	$\frac{Cp^{0.4}\,k^{0.6}}{VIS^{0.4}}$	CORR	% ERROR
100	0.2440	0.0453	0.0148	0.15656	0.1580	0.89
200	0.2485	0.0506	0.0174	0.16626	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

$$\text{Correlation of property function} = 0.1506 + T / 13{,}520 \tag{3}$$

T = gas temperature (°F)

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

The correlation constant for eq. (4) is:

$$C = 12 * 0.023 * (12 * 4 / 3.14159)^{0.8} = 2.444 \tag{5}$$

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

$$h_i = \frac{W^{0.8}}{d^{1.8}}\left(0.368 + \frac{\text{TEMP}}{5{,}530}\right) \tag{6}$$

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

$$qc = 0.296 * (T_C - T_A)^{1.25} * [(\text{V} * 5{,}280 / 60 + 68.9) / 68.9]^{0.5}$$

$$qr = 0.1714 * 0.8 * \{[(T_C + 460) / 100]^4 - [(T_A + 460) / 100]^4\}$$

where

qc = convective heat flux

qr = radiant heat flux

TC = casing temperature

TA = ambient temperature

The heat flux from the gas to the casing equals the flux from the casing to ambient

$$q = h_i * (T_G - T_C) = qc + qr$$

where

q = total heat flux, Btu/hr ft^2

T_G = gas temperature, °F

The total heat flux can be solved by iteration. The heat loss is the total heat flux times the uninsulated casing surface area.

NONMANDATORY APPENDIX G
BYPASS DAMPER LEAKAGE

G-1 GENERAL

Bypass dampers have been used in the power industry as a means to isolate, modulate, and divert gas flows. In the gas turbine 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 gas turbine exhaust 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.

G-2 DAMPER LEAKAGE

The gas turbines are brought on- and off-line 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 gas turbine and causes infiltration of seal air rather than exfiltration of exhaust gases.

G-3 LEAKAGE RATE

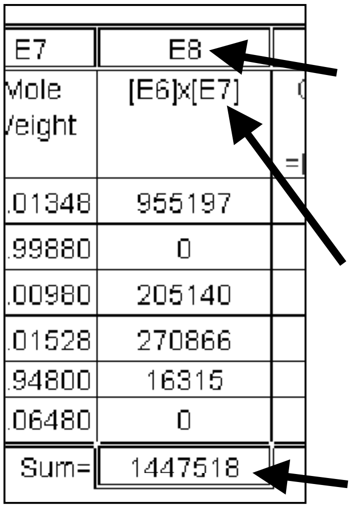
The exact amount of leakage experienced for a damper with and without a seal air system is hard to determine. Manufacturers may quote a leakage rate for a new damper without seal air system, and this leakage may increase with thermal cycling. The new damper with seal air system may have zero leakage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

For damper without seal air system, leakage means exfiltration of exhaust gas that will result in reduced exhaust gas flow through HRSG. For damper with seal air system, leakage means infiltration of seal air that will result in reduced exhaust gas temperature entering HRSG. For both cases, the damper installation will influence 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 gas turbine exhaust pressure. This would result in an air infiltration that would have 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.

NONMANDATORY APPENDIX H
UNCERTAINTY WORKSHEET FORM

The sheets in this Appendix are included to facilitate the calculation procedure. Guidance is included on the sheets in order to help the user know where numbers need to be transferred within or between sheets. The following describes the reference convention.



E7	E8
Mole eight	[E6]x[E7]
.01348	955197
.99880	0
.00980	205140
.01528	270866
.94800	16315
.06480	0
Sum=	1447518

Column Reference

Each sheet except the MAIN sheet is characterized by a letter designation from A to K. Columns on the sheets are numbered so a reference to a column on a specific sheet would be a letter followed by a number. **These are not worksheet cell references**.

Column references are shown in brackets.

The sum of a column of numbers is designated by the word **Sum** followed by the column reference. This for example points to **Sum [E8]**.

MAIN: GT HEAT BALANCE FORM

DUTY SUMMARY TABLE

	Flow (lb/hr)	x	**Enthalpy** (Btu/lb)	=	**Duty** Btu/hr	
Bleed+Comb. Wet Air		Sum[E8]		Sum[J4]		Flow*Enthalpy
Fuel		Input		[K-HV Net]		Flow*Enthalpy
Steam/Water Injection*		Input		(*)		Flow*Enthalpy(may be Negative)
Compressor Bleed		Input		Sum[J6]		Flow*Enthalpy (Negative Value)
Comb Prod + Inj		Sum above		Sum[I7]		Flow*Enthalpy (Negative Value)
				Power		Input MW*3.41214e6 (Negative Value)
				Heat Loss		Input (Negative Value)
			Total Balance of Moist Air Heat=			Sum Above
Change in Bal of Air Enthalpy		Btu/lb	Sum[J8]-Sum[J4]			
Balance of Airflow		lb/hr	=Total Balance of Moist Air Heat/Change in Bal Air h			

(*)Steam or Water Enthapy - Steam Enthalpy at T_{REF}= h - 1087.73 Btu/lb

Note: See Sheet E for GT total exhaust flow and composition[E12]

SHEET A

GT HEAT BALANCE FORM: AIR COMPOSITION

Atmospheric Pressure		psia
Wet Bulb Temperature		°F
Dry Bulb Temperature		°F
Relative Humidity		%

$Ln(P_{vapor})\ :\ C_1 / T + C_2 + C_3{*}T + C_4{*}T^2 + C_5{*}T^3 + C_6{*}T^4 + C_7{*}Ln(T)$

for t below 32°F (over ice)		for t above 32°F (over water)	
C_1 =	-1.0214165E+04	C_1 =	-1.0440397E+04
C_2 =	-4.8932428E+00	C_2 =	-1.1294650E+01
C_3 =	-5.3765794E-03	C_3 =	-2.7022355E-02
C_4 =	1.9202377E-07	C_4 =	1.2890360E-05
C_5 =	3.5575832E-10	C_5 =	-2.4780681E-09
C_6 =	-9.0344688E-14	C_6 =	0
C_7 =	4.1635019E+00	C_7 =	6.5459673E+00

Relative Humidity Input

$T = t_{dry\ bulb} + 459.67 =$ °R $P_{vapor} =$ psia

$P_{H2O} = \%RH{*}P_{vapor} =$ psia

$FDA = (P_{atm} - P_{H2O})/P_{atm} =$

$$\text{Humidity Ratio} = \left(\frac{1}{FDA} - 1\right) * \frac{18.01528}{28.965179} =$$

$T_{wet\ bulb}$ Input

$T = t_{wet\ bulb} + 459.67 =$ °R $P_{vapor} =$ psia

$\text{Saturated Humidity Ratio} = HR_{sat} = 0.62198 * [1.0039{*}P_{vapor} / (P - 1.0039{*}P_{vapor})]$

$HR_{sat} =$ $\#H_2O / \#DA$

$$\text{Humidity Ratio} = \frac{(1093 - 0.556 * t_{wet\ bulb}) * HR_{sat} - 0.240 * (t_{dry\ bulb} - t_{wet\ bulb})}{(1093 + 0.444 * t_{dry\ bulb} - t_{wet\ bulb})}$$

Continued

Humidity Ratio = $\#H_2O$ / #DA

$$\text{Fraction Dry Air (FDA)} = \frac{18.01528}{(28.9651785) * (\text{Humidity Ratio}) + 18.01528}$$

Fraction Dry Air (FDA) =

A1	A2	A3	A4	A5	A6
Compound	Calculation	Air Mole Fraction	MW	[A3]x[A4]	Air wt. fraction [A5] / Sum [A5]
N_2	0.780840 * FDA		28.01348		
O_2	0.209476 * FDA		31.9988		
CO_2	0.000319 * FDA		44.0098		
H_2O	1 - FDA		18.01528		
Ar	0.009365 * FDA		39.948		
			Moist Air Molecular Weight		

SHEET C

GT HEAT BALANCE FORM: FUEL GAS COMBUSTION MOLE CHANGE

Fuel Flow = ☐ lb/hr

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C13	C14	C15	C16
Compound	Fuel Mole Fraction	Mol. wt.	C2 x C3		N_2 (*) x [C5]		O_2 (*) x [C7]		CO_2 (*) x [C9]		H_2O (*) x [C11]		Ar (*) x [C13]		SO_2 (*) x [C15]
CH_4		16.04276		0		-2		1		2		0		0	
C_2H_6		30.06964		0		-3.5		2		3		0		0	
C_2H_4		28.05376		0		-3		2		2		0		0	
C_3H_8		44.09652		0		-5		3		4		0		0	
C_3H_6		42.08064		0		-4.5		3		3		0		0	
Iso-C_4H_{10}		58.12340		0		-6.5		4		5		0		0	
N-C_4H_{10}		58.12340		0		-6.5		4		5		0		0	
C_4H_8		56.10752		0		-6		4		4		0		0	
Iso-C_5H_{12}		72.15028		0		-8		5		6		0		0	
N-C_5H_{12}		72.15028		0		-8		5		6		0		0	
C_5H_{10}		70.13440		0		-7.5		5		5		0		0	
C_6H_{14}		86.17716		0		-9.5		6		7		0		0	
N_2		28.01348		1		0		0		0		0		0	
CO		28.01040		0		-0.5		1		0		0		0	
CO_2		44.00980		0		0		1		0		0		0	
H_2O		18.01528		0		0		0		1		0		0	
H_2S		34.08188		0		-1.5		0		1		0		1	
H_2		2.01588		0		-0.5		0		1		0		0	
He		4.00260		0		0		0		0		0		0	
O_2		31.9988		0		1		0		0		0		0	
Ar		39.94800		0		0		0		0		1		0	
Average Molecular Weight=													0		0
					= mole change of N_2		= mole change of O_2		= mole change of CO_2		= mole change of H_2O		= mole change of Ar		= mole change of SO_2

(*) = [C2] x (FUEL FLOW) / Sum [C4]

Combustion Mole Change for [E4]

X ________ = Lbs Dry Air = Moles Change O_2*28.9651785 / 0.209476

= 1+ lbs.Water per lb Dry Air

= lbs Moist Air for "<u>GAS COMPOSITION</u>"

SHEET D

GT HEAT BALANCE FORM: FUEL OIL COMBUSTION MOLE CHANGE

Fuel Flow = ______ lb/hr

D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Compound	Weight Fraction	Mol. wt.	MOLES (*)		N_2 [D4] x [D5]		O_2 [D4] x [D7]		CO_2 [D4] x [D9]		H_2O [D4] x [D11]		SO_2 [D4] x [D13]
C		12.011		0		-1		1		0		0	
H		1.00794		0		-0.3		0		0.5		0	
O		15.9994		0		0.5		0		0		0	
N		14.00674		0.5		0		0		0		0	
S		32.066		0		-1		0		0		1	
Inert		0		0		0		0		1		0	
		Sum =											
					= mole change of N_2		= mole change of O_2		= mole change of CO_2		= mole change of H_2O		= mole change of SO_2

(*) = FUEL FLOW x [D2] / [D3]

Combustion Mole Change for [E4]

= Lbs Dry Air = Moles Change O_2*28.9651785 / 0.209476

X ______ = 1+ lbs.Water per lb Dry Air

= lbs Moist Air for "GAS COMPOSITION"

SHEET E

GT HEAT BALANCE FORM: GAS COMPOSITION

Combustion Moist Airflow= lb/hr
Balance Moist Airflow= lb/hr
Moist Air Molecular Weight=
Water or Steam Injection Flow= lb/hr

E1	E2	E3	E4	E5	E6	E7	E8	E9
Compound	Air Composition [A3]	Comb M Air Moles/hr (*)	Combustion Mole Change SHT C or D	Water / Steam Injection (* *)	Resultant Moles/hr =[E3]+[E4]+[E5]	Mole Weight	[E6]x[E7]	Gas Mass Fraction =[E8]/Sum[E8]
N_2						28.01348		
O_2						31.99880		
CO_2						44.00980		
H_2O						18.01528		
Ar						39.94800		
SO_2						64.06480		
				Sum=		Sum=		

* = [E2] x (Combustion Moist Airflow) / Moist Air Molecular Weight

* * (Water or Steam Flow) / 18.01528

* * * = [E2} x (Balance Moist Airflow] / Moist Air Molecular Weight

GT Total Exhaust Flow= **lb/hr**

=Sum[E8]+Balance of Airflow

E1	E10	E11	E12	E13
Compound	Bal M Air Moles/hr (* * *)	Gas Moles/hr =[E6}+[E10]	Gas Composition =[E11]/SUM[E11]	Gas Composition =[E11] / Dry SUM[E11]
N_2				
O_2				
CO_2				
H_2O				
Ar				
SO_2				
	Sum=			
	Dry Sum=			

SHEET I

GT HEAT BALANCE FORM: GAS ENTHALPY

Gas T=

I1	I5	I6	I7
Compound	Gas Mass Fraction [H9]	Compound Enthalpy (eqns below)	[I5]x[I6]
N_2			
O_2			
CO_2			
H_2O			
Ar			
SO_2			
		Gas Enthalpy=	

btu/lb

Compound Enthalpies

$T_r = T(°F) + 459.67°R$

Reference Temperature

T_{REF}= 60 °F 519.67

$$h = -A_1/T_r + A_2Ln(T_r) + A_3(T_r) + A_4(T_r)^2 + A_5(T_r)^3 + A_6(T_r)^4 + A_7(T_r)^5 - A_8$$

N_2

	T_r < 1800°R	**T_r > 1800°R**
A_1	5076.9034	134989.03
A_2	-48.724746	-285.73506
A_3	0.43120894	0.43008964
A_4	-1.6798933E-04	-1.2090166E-05
A_5	1.0098600E-07	1.0880151E-09
A_6	-2.9251468E-11	-5.8440540E-14
A_7	3.4031292E-15	1.4342817E-18
A_8	-123.56702	-1809.5883

O_2

	T_r < 1800°R	**T_r > 1800°R**
A_1	-6888.0735	-208707.28
A_2	54.145998	261.94172
A_3	0.069447256	0.11293491
A_4	7.40234103E-05	2.1856736E-05
A_5	-4.3649134E-09	-1.3970608E-09
A_6	-5.3829350E-12	5.4636691E-14
A_7	1.2285505E-15	-9.6878731E-19
A_8	406.96173	2037.0402

Continued

CO_2

	T_r < 1800°R	T_r > 1800°R
A_1	7227.7111	17207.414
A_2	-50.879204	-145.29151
A_3	0.23923528	0.37414705
A_4	3.1383945E-05	-1.1560726E-06
A_5	-9.8757996E-10	2.2579091E-11
A_6	-1.4874974E-12	-3.6579206E-15
A_7	2.4498740E-16	5.4419457E-19
A_8	-199.50475	-758.45980

H_2O

	T_r < 1800°R	T_r > 1800°R
A_1	-14100.395	369646.91
A_2	114.20534	-478.72819
A_3	0.10271362	0.51215685
A_4	2.2116239E-04	7.0181916E-05
A_5	-8.3271140E-08	-7.7535747E-09
A_6	2.3414419E-11	4.4543564E-13
A_7	-2.8077803E-15	-1.0127794E-17
A_8	844.30005	-3313.2672

Ar

	T_r < 1800°R	T_r > 1800°R
A_1	0	3.2382979
A_2	0	-0.0053623
A_3	0.12427948	0.12428293
A_4	0	-5.51268011E-10
A_5	0	6.16422179E-14
A_6	0	-3.87630833E-18
A_7	0	1.02152826E-22
A_8	64.584315	64.54707

SO_2

	T_r < 1800°R	T_r > 1800°R
A_1	-5333.9649	-11325.497
A_2	50.721609673	-46.045503810
A_3	-0.073060273	0.2360907
A_4	1.8981891E-04	-1.7215642E-06
A_5	-8.0072686E-08	1.8036679E-10
A_6	1.9218645E-11	-7.2477731E-15
A_7	-1.9897196E-15	1.7234980E-19
A_8	330.81966	-151.48263

SHEET J

GT HEAT BALANCE FORM: MOIST AIR ENTHALPY

Compressor Inlet Air T= °F

Bleed Air T= °F

Stack T= °F

J1	J2	J3	J4	J5	J6	J7	J8
Compound	Stream Mass Fraction [A6]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J3]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J5]	Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J7]
N_2							
O_2							
CO_2							
H_2O							
Ar							
SO_2							
		Air Enthalpy=		Air Enthalpy=		Air Enthalpy=	

GENERAL NOTE: See "Gas Enthalpy" sheet for species specific enthalpy formulations.

SHEET K GT HEAT BALANCE DATA FORM

FUEL HEATING VALUE

Fuel Temperature= °F

FUEL GAS

K1	K2	K3	K4	K5	K6	K7
Compound	Fuel Mole Fraction	Mol. Wt.	[K2]x[K3]	Fuel Wt. Fraction = [K4] / Sum [K4]	Heat of Combustion Btu/lb	[K5]x[K6]
CH_4		16.04276			21503	
C_2H_6		30.06964			20432	
C_2H_4		28.05376			20278	
C_3H_8		44.09652			19923	
C_3H_6		42.08064			19678	
Iso-C_4H_{10}		58.1234			19587	
N-C_4H_{10}		58.1234			19659	
$C_4H_{8\text{-avg}}$		56.10752			19450	
Iso-C_5H_{12}		72.15028			19456	
N-C_5H_{12}		73.15028			19498	
$C_5H_{10\text{-avg}}$		70.1344			19328	
$C_6H_{14\text{-avg}}$		86.17716			19353	
N_2		28.01348			0	
CO		28.0104			4342	
CO_2		44.0098			0	
H_2O		18.01528			0	
H_2S		34.08188			6534	
H_2		2.01588			51566	
He		4.0026			0	
O_2		31.9988			0	
Ar		39.948			0	
		Sum =			Sum =	
					LHV Input =	

K8	K9
Heat of Combustion Btu/lb	[K5]x[K8]
23892	
22334	
21640	
21654	
21039	
21232	
21300	
20811	
21044	
21085	
20691	
20904	
0	
4342	
0	
1059.8	
7093.8	
61022	
0	
0	
0	
HHV=	

HHV not used
in any calculations!

Continued

Fuel Gas

HV Net = $LHV + T_{fuel}^{2} / 4720 + 0.491 * T_{fuel} - 30.2$ = ☐ Btu/lb

---

FUEL OIL

LHV Input = ☐ Btu/lb

Fuel Oil Sensible Heat Adjustment

HV Net = $LHV + T_{fuel}^{2} / 4132 + 0.417 * T_{fuel} - 25.9$ = ☐ Btu/lb

---

MAIN: HRSG DATA FORM

DUTY SUMMARY TABLE

	Flow (lb/hr)	x	**Enthalpy** (Btu/lb)	=	**Duty** Btu/hr	
Bleed+Comb. Wet Air		Sum[E8]		Sum[J4]		Flow*Enthalpy
Fuel		Input		[K-HV Net]		Flow*Enthalpy
Steam/Water Injection*		Input		(*)		Flow*Enthalpy(may be Negative)
Compressor Bleed		Input		Sum[J6]		Flow*Enthalpy (Negative Value)
Comb Prod + Inj		Sum above		Sum[I7]		Flow*Enthalpy (Negative Value)
				Power		Input MW*3.41214e6 (Negative Value)
				Heat Loss		Input (Negative Value)
			Total Balance of Moist Air Heat=			Sum Above
Change in Bal of Air Enthalpy		Btu/lb	Sum[J8]-Sum[J4]			
Balance of Airflow		lb/hr	=Total Balance of Moist Air Heat/Change in Bal Air h			

(*)Steam or Water Enthapy - Steam Enthalpy at T_{REF}= h - 1087.73 Btu/lb

GENERAL NOTE: See Sheet E for GT total exhaust flow and composition[E12]

SHEET A

HRSG DATA FORM: AIR COMPOSITION

Atmospheric Pressure		psia
Wet Bulb Temperature		°F
Dry Bulb Temperature		°F
Relative Humidity		%

$$\mathrm{Ln}(P_{vapor}) = C_1 / T + C_2 + C_3{}^*T + C_4{}^*T^2 + C_5{}^*T^3 + C_6{}^*T^4 + C_7{}^*\mathrm{Ln}(T)$$

for t below 32°F (over ice)		for t above 32°F (over water)	
C_1 =	-1.0214165E+04	C_1 =	-1.0440397E+04
C_2 =	-4.8932428E+00	C_2 =	-1.1294650E+01
C_3 =	-5.3765794E-03	C_3 =	-2.7022355E-02
C_4 =	1.9202377E-07	C_4 =	1.2890360E-05
C_5 =	3.5575832E-10	C_5 =	-2.4780681E-09
C_6 =	-9.0344688E-14	C_6 =	0
C_7 =	4.1635019E+00	C_7 =	6.5459673E+00

Relative Humidity Input

$T = t_{dry\ bulb} + 459.67 =$ °R $P_{vapor} =$ psia

$P_{H2O} = \%RH{}^*P_{vapor} =$ psia

$FDA = (P_{atm} - P_{H2O})/P_{atm} =$

$$\text{Humidity Ratio} = \left(\frac{1}{FDA} - 1\right) * \frac{18.01528}{28.965179} =$$

$T_{wet\ bulb}$ Input

$T = t_{wet\ bulb} + 459.67 =$ °R $P_{vapor} =$ psia

$$\text{Saturated Humidity Ratio} = HR_{sat} = 0.62198 * [1.0039{}^*P_{vapor} / (P - 1.0039{}^*P_{vapor})]$$

$HR_{sat} =$ $\#H_2O / \#DA$

$$\text{Humidity Ratio} = \frac{(1093 - 0.556 * t_{wet\ bulb}) * HR_{sat} - 0.240 * (t_{dry\ bulb} - t_{wet\ bulb})}{(1093 + 0.444 * t_{dry\ bulb} - t_{wet\ bulb})}$$

Continued

Humidity Ratio = $\#H_2O / \#DA$

Fraction Dry Air (FDA) = $\dfrac{18.01528}{(28.9651785) * (\text{Humidity Ratio}) + 18.01528}$

Fraction Dry Air (FDA) =

A1	A2	A3	A4	A5	A6
Compound	Calculation	Air Mole Fraction	MW	[A3]x[A4]	Air wt. fraction [A5] / Sum [A5]
N_2	0.780840 * FDA		28.01348		
O_2	0.209476 * FDA		31.9988		
CO_2	0.000319 * FDA		44.0098		
H_2O	1 - FDA		18.01528		
Ar	0.009365 * FDA		39.948		
			Moist Air Molecular Weight		

SHEET C

HRSG DATA FORM: FUEL GAS COMBUSTION MOLE CHANGE

Fuel Flow = ▨ lb/hr

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C13	C14	C15	C16
Compound	Fuel Mole Fraction	Mol. wt.	C2 x C3		N_2 (*) x [C5]		O_2 (*) x [C7]		CO_2 (*) x [C9]		H_2O (*) x [C11]		Ar (*) x [C13]		SO_2 (*) x [C15]
CH_4	▨	16.04276		0		-2		1		2		0		0	
C_2H_6	▨	30.06964		0		-3.5		2		3		0		0	
C_2H_4	▨	28.05376		0		-3		2		2		0		0	
C_3H_8	▨	44.09652		0		-5		3		4		0		0	
C_3H_6	▨	42.08064		0		-4.5		3		3		0		0	
Iso-C_4H_{10}	▨	58.12340		0		-6.5		4		5		0		0	
N-C_4H_{10}	▨	58.12340		0		-6.5		4		5		0		0	
C_4H_8	▨	56.10752		0		-6		4		4		0		0	
Iso-C_5H_{12}	▨	72.15028		0		-8		5		6		0		0	
N-C_5H_{12}	▨	72.15028		0		-8		5		6		0		0	
C_5H_{10}	▨	70.13440		0		-7.5		5		5		0		0	
C_6H_{14}	▨	86.17716		0		-9.5		6		7		0		0	
N_2	▨	28.01348		1		0		0		0		0		0	
CO	▨	28.01040		0		-0.5		1		0		0		0	
CO_2	▨	44.00980		0		0		1		0		0		0	
H_2O	▨	18.01528		0		0		0		1		0		0	
H_2S	▨	34.08188		0		-1.5		0		1		0		1	
H_2	▨	2.01588		0		-0.5		0		1		0		0	
He	▨	4.00260		0		0		0		0		0		0	
O_2	▨	31.9988		0		1		0		0		0		0	
Ar	▨	39.94800		0		0		0		0		1		0	
Average Molecular Weight=													0		0
					= mole change of N_2		= mole change of O_2		= mole change of CO_2		= mole change of H_2O		= mole change of Ar		= mole change of SO_2

(*) = [C2] x (FUEL FLOW) / Sum [C4]

Combustion Mole Change for [E4]

X ________ = **Lbs Dry Air = Moles Change O_2*28.9651785 / 0.209476**
= 1+ lbs.Water per lb Dry Air
= lbs Moist Air for "<u>GAS COMPOSITION</u>"

SHEET D

HRSG DATA FORM: FUEL OIL COMBUSTION MOLE CHANGE

Fuel Flow = ▨ lb/hr

D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Compound	Weight Fraction	Mol. wt.	MOLES (*)		N_2 [D4] x [D5]		O_2 [D4] x [D7]		CO_2 [D4] x [D9]		H_2O [D4] x [D11]		SO_2 [D4] x [D13]
C	▨	12.011		0		-1		1		0		0	
H	▨	1.00794		0		-0.3		0		0.5		0	
O	▨	15.9994		0		0.5		0		0		0	
N	▨	14.00674		0.5		0		0		0		0	
S	▨	32.066		0		-1		0		0		1	
Inert	▨	0		0		0		0		1		0	
	▨												
	▨												
		Sum =											
					= mole change of N_2		= mole change of O_2		= mole change of CO_2		= mole change of H_2O		= mole change of SO_2

(*) = FUEL FLOW x [D2] / [D3]

Combustion Mole Change for [E4]

= **Lbs Dry Air = Moles Change O_2*28.9651785 / 0.209476**

X ________ = 1+ lbs.Water per lb Dry Air

= lbs Moist Air for "<u>GAS COMPOSITION</u>"

SHEET E

HRSG DATA FORM: GAS COMPOSITION

Combustion Moist Airflow= lb/hr
Balance Moist Airflow= lb/hr
Moist Air Molecular Weight=
Water or Steam Injection Flow= lb/hr

E1	E2	E3	E4	E5	E6	E7	E8	E9
Compound	Air Composition [A3]	Comb M Air Moles/hr (*)	Combustion Mole Change SHT C or D	Water / Steam Injection (* *)	Resultant Moles/hr =[E3]+[E4]+[E5]	Mole Weight	[E6]x[E7]	Gas Mass Fraction =[E8]/Sum[E8]
N_2						28.01348		
O_2						31.99880		
CO_2						44.00980		
H_2O						18.01528		
Ar						39.94800		
SO_2						64.06480		
				Sum=		Sum=		

* = [E2] x (Combustion Moist Airflow) / Moist Air Molecular Weight

* * (Water or Steam Flow) / 18.01528

* * * = [E2} x (Balance Moist Airflow] / Moist Air Molecular Weight

GT Total Exhaust Flow= **lb/hr**

=Sum[E8]+Balance of Airflow

E1	E10	E11	E12	E13
Compound	Bal M Air Moles/hr (* * *)	Gas Moles/hr =[E6}+[E10]	Gas Composition =[E11]/SUM[E11]	Gas Composition =[E11] / Dry SUM[E11]
N_2				
O_2				
CO_2				
H_2O				
Ar				
SO_2				
	Sum=			
	Dry Sum=			

SHEET I

HRSG DATA FORM: GAS ENTHALPY

Gas T=

I1	I5	I6	I7
Compound	Gas Mass Fraction [H9]	Compound Enthalpy (eqns below)	[I5]x[I6]
N_2			
O_2			
CO_2			
H_2O			
Ar			
SO_2			

Gas Enthalpy= Btu/lb

Compound Enthalpies

$T_r = T(°F) + 459.67°R$

Reference Temperature

$T_{REF} =$ 60°F

$$h = -A_1/T_r + A_2 Ln(T_r) + A_3(T_r) + A_4(T_r)^2 + A_5(T_r)^3 + A_6(T_r)^4 + A_7(T_r)^5 - A_8$$

N_2

	$T_r < 1800°R$	**$T_r > 1800°R$**
A_1	5076.9034	134989.03
A_2	-48.724746	-285.73506
A_3	0.43120894	0.43008964
A_4	-1.6798933E-04	-1.2090166E-05
A_5	1.0098600E-07	1.0880151E-09
A_6	-2.9251468E-11	-5.8440540E-14
A_7	3.4031292E-15	1.4342817E-18
A_8	-123.56702	-1809.5883

O_2

	$T_r < 1800°R$	**$T_r > 1800°R$**
A_1	-6888.0735	-208707.28
A_2	54.145998	261.94172
A_3	0.069447256	0.11293491
A_4	7.40234103E-05	2.1856736E-05
A_5	-4.3649134E-09	-1.3970608E-09
A_6	-5.3829350E-12	5.4636691E-14
A_7	1.2285505E-15	-9.6878731E-19
A_8	406.96173	2037.0402

Continued

CO_2

	T_r < 1800°R	T_r > 1800°R
A_1	7227.7111	17207.414
A_2	-50.879204	-145.29151
A_3	0.23923528	0.37414705
A_4	3.1383945E-05	-1.1560726E-06
A_5	-9.8757996E-10	2.2579091E-11
A_6	-1.4874974E-12	-3.6579206E-15
A_7	2.4498740E-16	5.4419457E-19
A_8	-199.50475	-758.45980

H_2O

	T_r < 1800°R	T_r > 1800°R
A_1	-14100.395	369646.91
A_2	114.20534	-478.72819
A_3	0.10271362	0.51215685
A_4	2.2116239E-04	7.0181916E-05
A_5	-8.3271140E-08	-7.7535747E-09
A_6	2.3414419E-11	4.4543564E-13
A_7	-2.8077803E-15	-1.0127794E-17
A_8	844.30005	-3313.2672

Ar

	T_r < 1800°R	T_r > 1800°R
A_1	0	3.2382979
A_2	0	-0.0053623
A_3	0.12427948	0.12428293
A_4	0	-5.51268011E-10
A_5	0	6.16422179E-14
A_6	0	-3.87630833E-18
A_7	0	1.02152826E-22
A_8	64.584315	64.54707

SO_2

	T_r < 1800°R	T_r > 1800°R
A_1	-5333.9649	-11325.497
A_2	50.721609673	-46.045503810
A_3	-0.073060273	0.2360907
A_4	1.8981891E-04	-1.7215642E-06
A_5	-8.0072686E-08	1.8036679E-10
A_6	1.9218645E-11	-7.2477731E-15
A_7	-1.9897196E-15	1.7234980E-19
A_8	330.81966	-151.48263

SHEET J

HRSG DATA FORM: MOIST AIR ENTHALPY

Compressor Inlet Air T= ▨ °F

Bleed Air T= ▨ °F

Stack T= ▨ °F

J1	J2
Compound	Stream Mass Fraction [A6]
N_2	▨
O_2	▨
CO_2	▨
H_2O	▨
Ar	▨
SO_2	▨

J3	J4
Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J3]
Air Enthalpy=	

J5	J6
Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J5]
Air Enthalpy=	

J7	J8
Compound Enthalpy (Gas Enthalpy Sheet)	[J2]x[J7]
Air Enthalpy=	

GENERAL NOTE: See "Gas Enthalpy" sheet for species specific enthalpy formulations.

SHEET K

HRSG DATA FORM: FUEL HEATING VALUE

Fuel Temperature= ▨ °F

FUEL GAS

K1	K2	K3	K4	K5	K6	K7
Compound	Fuel Mole Fraction	Mol. Wt.	[K2]x[K3]	Fuel Wt. Fraction = [K4] / Sum [K4]	Heat of Combustion Btu/lb	[K5]x[K6]
CH_4	▨	16.04276			21503	
C_2H_6	▨	30.06964			20432	
C_2H_4	▨	28.05376			20278	
C_3H_8	▨	44.09652			19923	
C_3H_6	▨	42.08064			19678	
Iso-C_4H_{10}	▨	58.1234			19587	
N-C_4H_{10}	▨	58.1234			19659	
$C_4H_{8\text{-avg}}$	▨	56.10752			19450	
Iso-C_5H_{12}	▨	72.15028			19456	
N-C_5H_{12}	▨	73.15028			19498	
$C_5H_{10\text{-avg}}$	▨	70.1344			19328	
$C_6H_{14\text{-avg}}$	▨	86.17716			19353	
N_2	▨	28.01348			0	
CO	▨	28.0104			4342	
CO_2	▨	44.0098			0	
H_2O	▨	18.01528			0	
H_2S	▨	34.08188			6534	
H_2	▨	2.01588			51566	
He	▨	4.0026			0	
O_2	▨	31.9988			0	
Ar	▨	39.948			0	
		Sum =			Sum =	
					LHV Input =	

K8	K9
Heat of Combustion Btu/lb	[K5]x[K8]
23892	
22334	
21640	
21654	
21039	
21232	
21300	
20811	
21044	
21085	
20691	
20904	
0	
4342	
0	
1059.8	
7093.8	
61022	
0	
0	
0	
HHV=	

HHV not used

in any calculations!

Fuel Gas

HV Net = $LHV + T_{fuel}^2 / 4720 + 0.491 * T_{fuel} - 30.2$ = ☐ Btu/lb

---

FUEL OIL

LHV Input = ☐ Btu/lb

Fuel Oil Sensible Heat Adjustment

HV Net = $LHV + T_{fuel}^2 / 4132 + 0.417 * T_{fuel} - 25.9$ = ☐ Btu/lb

---

NONMANDATORY APPENDIX H: SENSITIVITY WORKSHEET

Test Result Parameter:

Project:

Date:

Test:

Engineer:

Percent Change for Sensitivity: 1.00

	Measured Parameter	Average Value	Incremental Change	New Value of Parameter	New Exhaust Flow With New Parameter	New Steam Flow at New Exhaust Flow	Absolute Sensitivity Coefficient	Relative Sensitivity Coefficient
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Base Value of Result	

Notes: The percent change is the amount the parameter is altered from the average value in order to obtain "New Value of Result due to Increment".
The values of "New Value of Result due to Increment" are inputs from computer simulation.

NONMANDATORY APPENDIX H: UNCERTAINTY WORKSHEET FORM

Test Result Parameter:

Project:

Test:

Date:

Engineer:

			Random Component								**Systematic Component**		
	Measured Parameter	Average Value	Standard Deviation	Number of Samples	Sample Deviation of Average	Degrees of Freedom	Absolute Sensitivity Coefficient	Absolute Sensitivity x Sample Deviation of Ave	(Ab Sens x SDA)^4/ Deg of Fdm	Random Uncertainty %	Systematic Uncertainty for Parameter	Abs Sensitivity x Systematic Uncert-Para	Systematic Uncertainty %
1													
2													
3													
4													
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
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29													
30													
31													
32													
33													
34													
35													
36													
37													
38													
39													
40													

Base Value of Result	

Random Uncertainty of Result	
Degrees of Freedom for Random Uncertainty of Result	
Student t Value	2.0

Systematic Uncertainty of Result - 95% Confidence Level	

Total Uncertainty	±
Uncertainty Percent	±

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