ASME PTC 47.2-2019

Gasification Block of an Integrated Gasification Combined Cycle Power Plant

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Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of
Mechanical Engineers

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The American Society of Mechanical Engineers
Two Park Avenue • New York, NY • 10016 USA

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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 ASME PTC 1 and has read them prior to applying this Code.

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

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

FOREWORD

ASME Performance Test Codes (PTCs) have been developed and have long existed for determining the performance of most major components used in electric power production facilities. A PTC has heretofore not existed for determining the overall performance of an integrated gasification combined cycle (IGCC) power generation plant. The ability to fire a wide range of fuels has been a key advantage of gas turbines over competing technologies. Until recently, the typical fuels for gas turbines have been natural gas and liquid fuels. But today, due to environmental concerns and economic considerations, power generation suppliers are developing gasification systems that can use solid and liquid fuels (coal, biomass, waste, heavy oils, etc.). Preparation of an alternative fuel suitable for a gas turbine includes removal of ash, contaminants, erodents, and corrodents. The ASME Board on Performance Test Codes approved the formation of the PTC 47 Committee in 1993 with the charter of developing a code for the determining overall power plant performance for gasification power generation plants. The organizational meeting of the PTC 47 Committee was held in November 1993. The resulting committee included experienced and qualified users, manufacturers, and general interest personnel.

The Committee has striven to develop an objective Code that addresses the need for explicit testing methods and procedures while attempting to provide maximum flexibility in recognition of the wide range of plant designs.

This Code was approved by the PTC 47 Committee and the PTC Standards Committee on April 16, 2019. It was then approved as an American National Standard by the ANSI Board of Standards Review on July 17, 2019.

ASME PTC COMMITTEE
Performance Test Codes

(The following is the roster of the Committee at the time of approval of this Code.)

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General. ASME Standards are developed and maintained with the intent to represent the consensus of concerned interests. As such, users of this Standard may interact with the Committee by requesting interpretations, proposing revisions or a case, and attending Committee meetings. Correspondence should be addressed to:

Secretary, PTC Standards Committee
The American Society of Mechanical Engineers
Two Park Avenue
New York, NY 10016-5990
http://go.asme.org/Inquiry

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

The Committee welcomes proposals for revisions to this Standard. 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 to provide 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 Standard and the paragraph, figure, or table number(s), and be written as a Question and Reply in the same format as existing Cases. Requests for Cases should also indicate the applicable edition(s) of the Standard to which the proposed Case applies.

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

Requests for interpretation should preferably be submitted through the online Interpretation Submittal Form. The form is accessible at http://go.asme.org/InterpretationRequest. Upon submittal of the form, the Inquirer will receive an automatic e-mail confirming receipt.

If the Inquirer is unable to use the online form, he/she may mail the request to the Secretary of the PTC Standards Committee at the above address. The request for an interpretation should be clear and unambiguous. It is further recommended that the Inquirer submit his/her request in the following format:

Subject:	Cite the applicable paragraph number(s) and the topic of the inquiry in one or two words.
Edition:	Cite the applicable edition of the Standard 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. Please provide a condensed and precise question, composed in such a way that a "yes" or "no" reply is acceptable.
Proposed Reply(ies):	Provide a proposed reply(ies) in the form of "Yes" or "No," with explanation as needed. If entering replies to more than one question, please number the questions and replies.
Background Information:	Provide the Committee with any background information that will assist the Committee in understanding the inquiry. 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 the format described above may be rewritten in the appropriate format by the Committee prior to being answered, which may inadvertently change the intent of the original request.

Moreover, ASME does not act as a consultant for specific engineering problems or for the general application or understanding of the Standard requirements. If, based on the inquiry information submitted, it is the opinion of the Committee that the Inquirer should seek assistance, the inquiry will be returned with the recommendation that such assistance be obtained.

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

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

INTRODUCTION

ASME PTC 47 comprises five Performance Test Codes (PTCs) that describe testing procedures for an integrated gasification combined cycle (IGCC) power plant. ASME PTC 47, Integrated Gasification Combined Cycle Power Generation Plants, is used for testing the overall performance of an IGCC plant. If a plant passes the ASME PTC 47 test, no further testing is required. If a plant does not pass the ASME PTC 47 test, one or more secondary subsystems may be tested to isolate the problem(s), using the following PTCs:

(a) ASME PTC 47.1, Cryogenic Air Separation Unit of an Integrated Gasification Combined Cycle Power Plant, for testing the performance of the air separation unit (ASU)

(b) ASME PTC 47.2, Gasification Block of an Integrated Gasification Combined Cycle Power Plant, for testing the thermal performance of the gasification equipment

(c) ASME PTC 47.3, Syngas Conditioning Block of an Integrated Gasification Combined Cycle Power Plant, for testing the thermal performance of the syngas cleaning equipment (in development)

(d) ASME PTC 47.4, Power Block of an Integrated Gasification Combined Cycle Power Plant, for testing the thermal performance of the gas turbine combined cycle power block

It is recommended that overall plant and subsystems be tested separately rather than simultaneously to accommodate any boundary constraints and valve isolations and lineups that may be needed for subsystem testing. In highly integrated IGCC plants, the entire plant may need to be operating during a subsystem test, even though only subsystem performance parameters are being measured.

Plant owners can use test results to determine the fulfillment of contract guarantees. Plant owners can also use the test results to compare plant performance to a design number or to track plant performance changes over time. However, test results conducted in accordance with this Code will not provide a basis for comparing the thermoeconomic effectiveness of different plant designs.

APPLICATIONS AND LIMITATIONS. Gasification units that convert hydrocarbon feed into a combustible fuel gas (syngas), usually composed primarily of hydrogen, carbon monoxide, and methane, are included within the scope of this Code. This Code applies to the following types of gasifiers, some of which are depicted in Nonmandatory Appendix C.

(a) Moving-Bed (or Fixed-Bed) Gasifiers. These are gasifiers in which hydrocarbon and ash particles move slowly down through a bed while reacting with gases moving up through the bed.

(b) Fluidized-Bed Gasifiers. These are gasifiers in which the oxidizing gas is forced upward through the solid hydrocarbon feed at a superficial gas velocity either slightly less or greater than the terminal velocity of most of the individual particles.

(c) Entrained-Flow Gasifiers. These gasifiers are characterized by cocurrent flow of the hydrocarbon feed and oxidizing medium.

(d) Oxygen-Blown Gasifiers. These gasifiers use relatively pure oxygen as the oxidizing agent for partial combustion.

(e) Air-Blown Gasifiers. These gasifiers use air rather than oxygen as the oxidizing agent.

(f) Slagging Gasifiers. These are gasifiers from which the ash leaves as molten slag rather than as a nonagglomerated solid.

(g) Agglomerating-Ash Gasifiers. These gasifiers contain hot zones where ash particles are agglomerated into small pellets for removal.

(h) Dry-Ash Gasifiers. These are gasifiers from which ash leaves as either agglomerated or nonagglomerated solids rather than as molten slag.

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Section 1
Object and Scope

1-1 OBJECT

The object of this Code is to provide uniform test methods for determining the performance and effective syngas production of an integrated gasification combined cycle (IGCC) gasification block. These test procedures yield highly accurate results consistent with current engineering knowledge and practice.

1-1.1 Accuracy

The accuracy of a test may be affected by factors within the discretion of the operator. A test is considered an ASME Code test if the following conditions are met:

(a) Test procedures comply with the procedures and variations defined in this Code.

(b) The uncertainty values of the test results determined in accordance with Section 7 do not exceed the uncertainty limits defined in subsection 1-3.

1-1.2 Performance Characteristics

(a) This Code provides explicit procedures for determining the following performance characteristics:
  (1) corrected product syngas energy
  (2) corrected gasification effectiveness

(b) Tests may be designed to satisfy different performance goals, including
  (1) specified fuel consumption
  (2) specified oxygen consumption
  (3) specified syngas sensible and chemical energy rate
  (4) specified steam production

(c) These performance characteristics are typically required for
  (1) comparing actual performance with guaranteed performance
  (2) comparing actual performance with a reference
  (3) determining the performance of the equipment after modifications

1-2 SCOPE

This Code applies to gasifiers that convert liquid or solid feedstock into syngas by means of an oxygen- or air-blown gasification process. It can be used to measure the performance of a gasifier in its normal operating condition, with all equipment in new condition.

The Code addresses the boundaries of the gasification block and the principal streams moving through the gasification block that significantly affect its thermal performance (see Figure 3-2.2-1). This Code provides methods to measure the quality and quantity of product (e.g., syngas) and by-product (e.g., slag and ash), feedstock consumption rates, oxidant consumption, steam consumption and production, water consumption, inert gas consumption, and power use. The Code includes methods for calculating cold gas efficiency and carbon conversion as examples, but these calculations are not within the scope of this Code.

Gasifier performance tests conducted in accordance with this Code shall meet the following conditions:

(a) A means shall be available for determining, through direct or indirect measurement, all electric power feeds entering or exiting the test boundary.

(b) A means shall be available for determining, through direct or indirect measurement, the composition and condition of all pressurized flows entering or leaving the test boundary.

(c) A means shall be available for determining, through direct or indirect measurement, all parameters required to correct test results to a base reference condition.

(d) The test uncertainties shall be less than or equal to the specified uncertainty limits.

Table 1-3-1 Largest Expected Test Uncertainties of Performance Parameters

Test Result	Test Uncertainty
Corrected product syngas energy	1%
Corrected primary fuel energy	7%
Corrected auxiliary power	4%
Corrected gasification effectiveness	7%

Tests addressing other performance-related issues are outside the scope of this Code. These include but are not limited to the following:

(a) emissions tests
(b) operational demonstration tests pertaining to non-steady state or off-design conditions
(c) reliability tests conducted over periods of time beyond the required testing period

1-3 UNCERTAINTY

The explicit measurement methods and procedures to be used for an IGCC gasification block have been developed to provide guidelines for test procedures that yield results of the highest level of accuracy based on current engineering knowledge, taking into account test costs and the value of information obtained from testing. The uncertainty of performance test results shall be calculated in accordance with ASME PTC 19.1.

The test results for different types of gasifiers will have different levels of uncertainty.

A pretest uncertainty analysis shall be performed to establish the expected level of test uncertainty. Most tests conducted in accordance with this Code will result in uncertainties that are lower than those shown in Table 1-3-1. If the pretest uncertainty analysis indicates that the uncertainty is greater than the values shown in Table 1-3-1, the test shall be redesigned to lower the uncertainty, or the parties to the test may agree, in writing, to accept higher uncertainty. A post-test uncertainty analysis shall be completed to validate the test. If the post-test uncertainty analysis is higher than the previously defined maximum expected uncertainty, then the test is not valid. Examples of test uncertainty analysis are provided in Nonmandatory Appendix B.

The largest expected overall test uncertainties are given in Table 1-3-1. These values are not targets. A primary philosophy underlying this Code is that the lowest achievable test uncertainty is in the best interest of all parties to the test. Deviations from the methods recommended in this Code are acceptable only if they can demonstrate equal or lower uncertainty.

1-4 REFERENCES

The following is a list of publications referenced in this Code.

ANSI/IEEE Standard 120, Master Test Guide for Electrical Measurements in Power Circuits
Publisher: Institute of Electrical and Electronics Engineers, Inc. (IEEE), 445 Hoes Lane, Piscataway, NJ 08854 (www.ieee.org)

ASME MFC-3M, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi
ASME PTC 4-2013, Fired Steam Generators
ASME PTC 6, Steam Turbines with Errata
ASME PTC 12.4, Moisture Separator Reheaters
ASME PTC 19.1, Test Uncertainty
ASME PTC 19.3, Temperature Measurement
ASME PTC 19.3 TW, Thermowells
ASME PTC 19.5, Flow Measurement
ASME PTC 19.6, Electrical Power Measurements
Publisher: The American Society of Mechanical Engineers, Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

Annual Book of ASTM Standards, Section 5: Petroleum Products, Lubricants, and Fossil Fuels, Vol. 05.01–05.05
ASTM C25, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime
ASTM D95-13(2018), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation
ASTM D121, Standard Terminology of Coal and Coke
ASTM D240-19, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter

ASTM D482-19, Standard Test Method for Ash from Petroleum Products
ASTM D1298, Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1412, Standard Test Method for Equilibrium Moisture of Coal at 96 to 97 Percent Relative Humidity and 30°C
ASTM D1480, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer
ASTM D1552-16e1, Standard Test Method For Sulfur in Petroleum Products by High Temperature Combustion and Infrared (IR) Detection or Thermal Conductivity Detection (TCD)
ASTM D1945, Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D2013, Standard Practice for Preparing Coal Samples for Analysis
ASTM D2234/D2234M, Standard Practice for Collection of a Gross Sample of Coal
ASTM D2361-02, Standard Test Method for Chlorine in Coal
ASTM D2622-16, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry
ASTM D3172-13, Standard Practice for Proximate Analysis of Coal and Coke
ASTM D3173, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke
ASTM D3174, Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal
ASTM D3175, Standard Test Method for Volatile Matter in the Analysis Sample of Coal and Coke
ASTM D3180, Standard Practice for Calculating Coal and Coke Analyses from As-Determined to Different Bases
ASTM D3228-19, Standard Test Method for Total Nitrogen In Lubricating Oils and Fuel Oils By Modified Kjeldahl Method
ASTM D3302, Standard Test Method for Total Moisture in Coal
ASTM D3588, Standard Practice for Calculating Heat Value
ASTM D3682-13, Standard Test Method for Major and Minor Elements in Combustion Residues From Coal Utilization Processes
ASTM D4052, Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter
ASTM D4057-95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products
ASTM D4239-18e1, Standard Test Method for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion
ASTM D4294-03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectroscopy
ASTM D4809-18, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D5291-16, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants
ASTM D5373-16, Standard Test Methods for Determination of Carbon, Hydrogen and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke
ASTM D5865/D5865M, Standard Test Method for Gross Calorific Value of Coal and Coke
ASTM D7042, Standard Test Method for Dynamic Viscosity and Density of Liquids by Stabinger Viscometer (and the Calculation of Kinematic Viscosity)
ASTM D7582, Standard Test Methods for Proximate Analysis of Coal and Coke by Macro Thermogravimetric Analysis
ASTM D7833, Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography
ASTM E1137/E1137M, Standard Specification for Industrial Platinum Resistance Thermometers
ASTM MNL 12, Manual on the Use of Thermocouples in Temperature Measurement
Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959 (www.astm.org)

Dahl, A. I. "Stability of Base-Metal Thermocouples in Air From 800°F to 2,200°F," National Bureau of Standards, Washington, D.C., in *Temperature*, Vol. 1, Reinhold: New York, 1941, p. 1238

EPA-600/8-83-027, Environmental Monitoring Reference Manual for Synthetic Fuels Facilities, Industrial Environmental Research Laboratory, Research Triangle Park, NC

EPRI EA-3610, Time Variability of Elemental Concentrations in Power Plant Ash, 1984
Publisher: Electric Power Research Institute (EPRI), 2420 Hillview Avenue, Palo Alto, CA 94304 (www.epri.com)

Handbook for Sampling and Sample Preservation of Water and Wastewater, 1982

Hanschel, D. and J. Stemmle, Environmental Monitoring Reference Manual for Synthetic Fuels Facilities, 1983
Publisher: U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW, Washington, DC 20004 (www.epa.gov)

NIST Technical Note 1265, Guidelines for Realizing International Temperature Scale of 1990 (ITS-90)
Publisher: National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899 (www.nist.gov)

Section 2
Definitions and Descriptions of Terms

2-1 DEFINITIONS

This Section contains technical definitions used in this Code.

acceptance test: the evaluating action(s) used to determine if a new or modified piece of equipment satisfactorily meets its performance criteria, permitting the purchaser to accept it from the supplier.

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

additive: a substance added to a gas, liquid, or solid stream to cause a chemical or mechanical reaction to enhance collection efficiency.

agglomerating-ash gasifier: a type of fluid-bed gasifier that contains a hot zone in which the ash particles are agglomerated into small pellets for removal.

air, corrected theoretical: theoretical air adjusted for unburned carbon and the additional oxygen required to complete other reactions (e.g., the sulfation reaction).

air, theoretical: the amount of air required to supply the exact amount of oxygen necessary for complete combustion of a given quantity of fuel. Theoretical air and stoichiometric air are synonymous.

air-blown gasifier: a type of gasifier in which the gasification process uses air rather than oxygen as the oxidizing agent.

ambient air: this Code recognizes that significant differences in both the measured and corrected performance may impact the physical location(s) used to represent the contract, design, and test ambient-air conditions. Because contractual language may not always resolve the meaning of *ambient*, this Code requires that, before the test, the parties to the test agree on the location(s) to be used to represent the ambient-air conditions. For example, ambient conditions may be considered to be the average of conditions at several different locations within the boundary of the site or may be the conditions at the air inlet of equipment such as the gas turbine or the cooling tower. Once the parties have agreed on the representative location(s), the word *ambient* as used in the Code shall mean the physical properties of the air at the agreed-on location(s).

analysis, proximate: laboratory analysis of a fuel sample providing the mass percentages of fixed carbon, volatile matter, moisture, and noncombustibles (ash). Proximate analysis is done in accordance with the appropriate ASTM standard.

analysis, ultimate: laboratory analysis of a fuel sample providing the mass percentages of carbon, hydrogen, oxygen, nitrogen, sulfur, moisture, and ash. Ultimate analysis is done in accordance with the appropriate ASTM standard.

as-fired fuel: fuel in the condition in which it enters the unit boundary.

ash: the noncombustible mineral matter constituent of fuel that remains after complete burning of a fuel sample in accordance with appropriate ASTM standards.

ash, bottom: all residues removed from the gasification chamber other than that which is entrained in the flue gas. It includes slag from an entrained gasifier, the ash that is rejected in a fluidized-bed gasifier for being too large in particle size, or particularly the bottom ash from a nonslagging gasifier.

ash, fly: ash components from the gasified material that are not captured in the slag.

ash fusion temperatures: four temperatures (initial deformation, softening, hemispherical, and fluid) measured for a given fuel ash, as determined by the appropriate ASTM standard. Frequently used in the singular to indicate only the softening temperature, the ash fusion temperature is the temperature at which the test cone has deformed to a shape whose height and width are equal

auxiliary power: electric power consumed by all users in the IGCC plant. This power consumption is subtracted from the gross power output, measured at the gas and steam turbine generators' terminals, to obtain net plant power output.

bias error: see *error, systematic*.

British thermal unit (Btu): the amount of heat required to change the temperature of 1 lb of water by 1°F at sea level. A unit of energy defined by the relationship of 1 Btu/lb being equal to 2.326 kJ/kg exactly and called the International Table Btu. 1 Btu = 1 055.055 J.

calcination: the endothermic chemical reaction that takes place when carbon dioxide is released from calcium carbonate to form calcium oxide, or from magnesium carbonate to form magnesium oxide.

calcium-to-sulfur molar ratio (Ca/S): the total moles of calcium in the sorbent feed divided by the total moles of sulfur in the fuel feed.

calcium utilization: the percentage of calcium in the sorbent that reacts with sulfur in a gasifier to form calcium sulfate or calcium sulfide. It is sometimes called sorbent utilization.

calibration: a set of operations that establish, under specified conditions, the relationship between values indicated by a measuring instrument or system and the corresponding reference standard or known values derived from the reference standard. Calibration enables the estimation of errors of indication of the measuring instrument or measuring system, or the assignment of values to marks on arbitrary scales. The result of a calibration is sometimes expressed as a calibration factor or a series of calibration factors in the form of a calibration curve.

calibration, field: the process by which calibrations are performed under conditions that are less controlled (by measurement or test equipment) than laboratory-grade calibration. Field calibration measurement and test equipment requires calibration in a manner that provides traceability to the National Institute of Standards and Technology (NIST), another recognized international standard organization, or a defined natural physical constant.

calibration, laboratory-grade: the process by which calibrations are performed under controlled conditions with highly specialized measuring and test equipment that has been calibrated in a manner that provides traceability to NIST, another recognized international standard organization, or a defined natural physical constant.

calorie: a unit of energy equal to 4.1868 J exactly and called the International Table calorie.

capacity: the maximum flow rate from an individual equipment item or grouping of equipment items that is capable of being produced on a continuous basis under specified conditions. This is also frequently referred to as maximum continuous rating (MCR).

carbon conversion efficiency: an indicator of the degree to which the fuel carbon compounds are converted to carbon-containing gaseous components. These components include carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), carbonyl sulfide (COS), and hydrocarbon (CxHy) (CxHy includes organic gaseous compounds such as ethane, propane, and butane, and cyclic organic compounds such as benzene). Carbon conversion efficiency can also be determined as 1.0 minus carbon energy loss (the amount of energy in carbon compounds exiting the gasification system as solid and liquid streams, divided by the fuel carbon energy input).

char: the solid residue remaining after the removal of moisture, volatile matter, and possibly some fixed carbon from coal.

clinker: a large, solid mass of coal ash agglomerated by ash slagging.

coal-drying fuel: fuel burned to supply additional thermal energy for drying coal.

coal rank: a classification of coal based on fixed carbon, volatile matter, and heating value. It is an indication of the progressive alternation, or coalification, from lignite to anthracite: lignite, subbituminous coal, bituminous coal, and anthracite.

coke: the hard, porous material produced when volatile constituents have been driven off by heat, so that the fixed carbon and ash are fused together. In the steel industry, coke is made from bituminous coal or blends of coal. Petroleum coke is a similar material that is derived from oil refinery operations and usually contains a high sulfur content.

combustor: a heat source consisting of one or more chambers in which fuel burns or otherwise reacts with its working fluid to increase the temperature.

compressor: a mechanical rotary component that compresses a working fluid.

coverage: the percentage of observations (measurements) of a parameter that can be expected to differ from the true value of the parameter by no more than the uncertainty value.

credits: energy entering the defined envelope that is separate from the chemical energy in the as-fired fuel. Credits include sensible heat (a function of specific heat and temperature) in the fuel in the entering air, and in the atomizing steam, as well as energy from power conversion in the pulverizer, circulating pumps, primary air dehydration, and gas recirculation fans. Credits can be negative, such as when the air temperature is below the reference temperature.

cyclone: equipment in which centrifugal forces are used to separate particulate matter from a gas stream.

dilute phase: in a circulating fluidized-bed gasification chamber, the portion of the bed above the secondary air inlet ducts (primarily made up of the circulating particulate material).

dry-ash gasifier: a type of gasifier in which the ash leaves as either agglomerated or nonagglomerated solids rather than as molten slag.

energy balance method: a method of determining equipment efficiency by a detailed accounting of all energy entering and leaving the equipment envelope. Sometimes called the heat balance method.

entrained-flow gasifier: a type of gasifier characterized by cocurrent flow of the hydrocarbon feed and oxidizing medium. Flow may be upward or downward.

error, random: error resulting from the fact that repeated measurements of the same quantity by the same measuring system operated by the same personnel do not yield identical values. It is a statistical quantity that is expected to be normally distributed. Also called precision error.

error, systematic: the difference between the average of the total population and the true value, which characterizes every member of any set of measurements from the population. Sometimes called bias error.

error, total: the difference between the true value and the measured value, which includes both random and systematic error.

field calibration: see *calibration, field.*

fixed carbon: the carbonaceous residue less the ash remaining after the volatile matter has been driven off.

flare: equipment used for combusting vent gas, off-gas, or tail gas from the gasification process prior to emission into the atmosphere.

fluidized bed: a bed of combustible and noncombustible particles through which a fluid (predominantly air or oxygen and steam in fluidized-bed generators) is caused to flow upward at a velocity sufficient to suspend the particles and impart them with a fluid-like motion.

fluidized bed, bubbling: a fluidized bed in which the superficial gas velocity is less than the terminal velocity of most of the individual particles. Part of the gas passes through the bed as bubbles. This results in a distinct bed region because the fluidizing gases carry an insignificant amount of the bed away.

fluidized bed, circulating: a fluidized bed in which the fluidizing gas velocity exceeds the terminal velocity of most of the individual particles, so that they are carried from the combustion chamber and later reinjected.

free moisture: in coal, the portion of total moisture (see ASTM D3302) that is in excess of inherent moisture in coal (see ASTM D1412). It is not to be equated with weight loss upon coal air-drying. Free moisture is sometimes referred to as surface moisture in connection with coal or coke.

freeboard disengaging: an open area in the top of fluidized-bed gasification vessels for separation of solids from the gas.

fuel gas contaminants: compounds that are either potentially deleterious to the gas turbine and power block in general or are precursors to stack emissions. Examples of fuel gas contaminants include

(a) compounds containing sulfur [e.g., hydrogen sulfide (H_2S) and carbonyl sulfide (COS)]

(b) compounds containing nitrogen [e.g., ammonia (NH_3) and hydrogen cyanide (HCN)]

(c) compounds containing chlorine [e.g., hydrogen chloride (HCl)]

(d) tars and condensables (i.e., organic compounds designated as CxHy, which may either be long-chain hydrocarbons or cyclic compounds)

(e) particulates (i.e., inert ash and potentially corrosive components for the gas turbine including vanadium, lead, calcium, and nickel)

(f) volatilized alkali metals (i.e. sodium and potassium)

fuel gas rate: fuel gas (syngas) consumption per hour per unit output in which the turbine is charged with the supplied syngas quantity. Also called syngas rate.

gasification: the partial oxidation of a hydrocarbon feed into a combustible fuel gas (syngas), usually composed of hydrogen, carbon monoxide, and methane.

gasifier: a vessel in which gasification reactions take place.

gross heat of combustion at constant volume[1]*:* the heat produced by the combustion of unit quantity of solid or liquid fuel when burned at constant volume in an oxygen bomb calorimeter under specified conditions, with the resulting water condensed to a liquid. Expressed in MJ/kg (Btu/lbm).

heat input: the mass flow rate of fuel(s) multiplied by the high or low heat value of the fuel(s).

heat of combustion: the heat released from the complete oxidation of a fuel in which the reactant products are at a reference condition.

heat recovery duty: heat transferred from the very hot syngas and slag (or ash) and used to generate steam or heat water. As an additive correction, excessive heat recovery duty is subtracted from the product syngas energy.

heat recovery gasification process: a process employing one or more heat exchangers to transfer the heat (radiant and/or convective) from the synthesis gas exiting the gasification vessel to a medium such as steam. Equipment that performs this process includes

(a) radiant syngas coolers
(b) fire-tube boilers
(c) water-wall-type boilers

heating value: the energy released when a fuel and oxidant, normally at 25°C (77°F), are burned to completion and the products of combustion are cooled to a specified temperature, normally 25°C (77°F). Although the units of heating value may be energy per unit mole [MJ/kg-mol (Btu/lb-mol)] or energy per unit volume [MJ/Nm^3 (Btu/scf)], the units of heating value used in this Code are energy per unit mass (MJ/kg or Btu/lbm). Heating value may be reported as either lower (net) heating value or higher (gross) heating value, as long as all fuels, product gases, and syngases are reported using consistent terms. Lower heating value (LHV) is calculated as if all water in the combustion products remains in the vapor state. Higher heating value (HHV) is calculated as if all water in the combustion products is condensed and includes the heat released by that condensation, including any moisture initially present in the fuel and oxidant. Moisture in the fuel-oxidant mixture evaporates during combustion, consuming the same amount of energy as it releases during post-combustion condensation, so the net calculated condensation energy represents only the H_2O formed from the combustion of hydrogen.

higher heating value: see *heating value*.

hot gas desulfurization: a process to remove sulfur compounds from the syngas at elevated temperatures. Methods include direct injection of calcium-based sorbent into the gasifier or direct contact between syngas and a metal oxide sorbent.

hot gas particulate removal system: a system that removes particulate matter from the hot syngas by means of a barrier-type filter, such as the following:

(a) ceramic candle filter
(b) fiber filter
(c) screenless granular bed filter
(d) cross-flow filter

inert gas: a stable gas that typically contains less than 0.1% oxygen by volume. Examples include nitrogen and carbon dioxide.

inert gas generator: an IGCC plant system that generates an inert gas that is used for purging equipment or piping in which the presence of excess oxygen is undesirable.

inert matter:

(a) constituents of coal or gas that decrease its efficiency in use [e.g., mineral matter (ash) in coal and moisture in combustion fuel].

(b) nonreactive gases such as nitrogen or argon that may be contained in the air or oxygen used for the gasification process, in the transport gas for moving coal in dry gasifier processes, in the purge and blanketing gas used in the gasification and combined cycle processes. Also refers to carbon dioxide produced by combustion.

inherent moisture: in coal, moisture that exists as an integral part of the coal seam in its natural state and includes water in pores but not moisture that is present in macroscopically visible fractures.

instrument verification: a set of operations that establishes evidence that specified requirements have been met by calibration or inspection. It provides a means for checking that the deviations between values indicated by a measuring instrument and corresponding known values are consistently smaller than the defined limits of the permissible error.

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[1] This definition is adapted from that in ASTM D121.

integrated gasification combined cycle (IGCC) power plants: facilities that convert (partially combust) hydrocarbon fuel(s) into a gaseous stream of combustible components (hydrogen, carbon monoxide, methane, and other by-products) using reactions with oxygen, steam, and carbon dioxide as well as thermal decomposition. The resulting gas is fired in a gas turbine to produce power, followed by heat recovery in a steam turbine, in which the exhaust gases are used to make steam for additional power generation. IGCC plants may also produce export syngas and export steam.

joule: the work done when a force of 1 N acts on an object and the object is displaced a distance of 1 m in the direction of the force.

laboratory-grade calibration: see *calibration, laboratory-grade.*

lock hopper: a mechanical device that permits the introduction or withdrawal of bulk solid material into an environment of different pressure. A lock hopper usually consists of a pressure vessel with valves to contain and depressurize solids.

losses: the energy that exits an equipment envelope other than the energy in the output stream(s). Examples of losses include

(a) heat lost to the atmosphere
(b) energy loss caused by mechanical inefficiency
(c) heat loss from the steam turbine condenser

low-Btu gas: a synthesis gas produced by gasification with air. It has a higher heating value below 7 MJ/Nm^3 (180 Btu/scf).

lower heating value: see *heating value*.

main air compressor (MAC): a compressor that uses ambient air as feed and compresses it to the operating pressure of the air separation unit (ASU) or gasifier. The compressor may supply all or part of the air requirement of the ASU or gasifier.

medium-Btu gas: synthesis gas produced by gasification with oxygen. It has a higher heating value between 7 MJ/Nm^3 and 20 MJ/Nm^3 (180 Btu/scf and 500 Btu/scf).

mesh: measure of the fineness of a screen by the number of openings per inch.

moisture: see *free moisture* and *inherent moisture*. Moisture in fuel is determined by appropriate ASTM standards.

moving-bed gasifier: a type of gasifier in which hydrocarbon and ash particles move slowly down through a bed while reacting with gases moving up through the bed.

net heat of combustion at constant pressure[1]*:* the heat produced by combustion of a unit quantity of a solid or liquid fuel when burned at a constant pressure of 0.101325 MPa (1 atm), under conditions such that all the water in the products remains in vapor form. (Note that the net calorific value is a lower heating value that can be calculated from the gross calorific value by making a correction for the difference between a constant volume process and a constant pressure process, and a deduction for the water vaporization in the combustion products, including both the water initially present as moisture and that formed by combustion.)

organic sulfur: sulfur that is chemically bonded to coal hydrocarbons rather than to the inorganic ash constituents of coal.

oxygen-blown gasification: a type of gasification in which relatively pure oxygen (usually above 85% volumetric purity) is the oxidizing agent for the partial combustion of the gasifier feed(s).

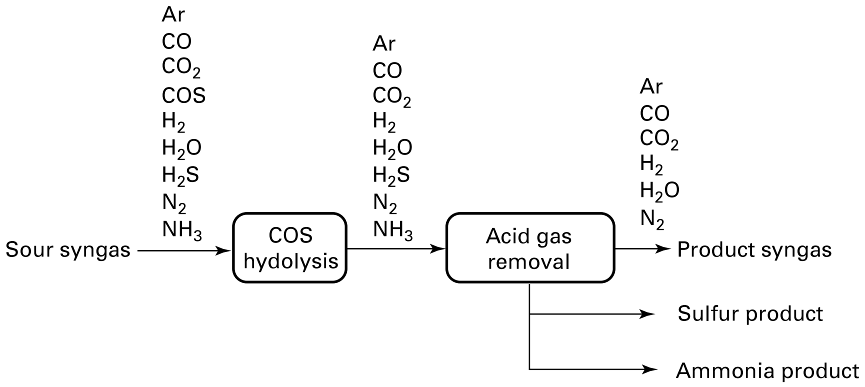
precision: the closeness of agreement between repeated measurements, usually measured by the precision index of the measurements.

precision error: see *error, random*.

pressure: see *standard pressure.*

primary measurement: measurement that is used in the calculation of test results.

product syngas: for the purposes of this Code, the product syngas comprises the syngas components that are in the fuel gas that is ultimately delivered to the power block, after contaminants such as hydrogen sulfide (H_2S), carbonyl sulfide (COS), and ammonia (NH_3) have been removed.



NOTE: Ar = argon; CH_4 = methane; CO = carbon monoxide; CO_2 = carbon dioxide; H_2 = hydrogen; H_2O = water; N_2 = nitrogen.

pulse cleaning gas: high-pressure gas, such as nitrogen, steam, or cleaned syngas, used for cleaning the hot gas filter elements by dislodging the accumulated filter cake.

purge: to introduce air, nitrogen, or another fluid into a piece of equipment in such volume and in such a manner that the new fluid completely replaces the air or gas–air mixture contained therein.

quench gasification process: a process employing cool liquid or gas in direct contact with a hot synthesis gas as a means of reducing the temperature of the synthesis gas exiting the gasification vessel.

random error: see *error, random*.

rank: see *coal rank*.

reactivity: a measure of a hydrocarbon's susceptibility to chemical change such as gasification. The higher the reactivity, the faster the rate of reaction at a given temperature.

recycle rate: the mass flow rate of material being reinjected into a piece of equipment, such as a furnace or combustion chamber, to reprocess unconverted material.

redundant instruments: two or more devices measuring the same parameter.

regenerable sorbent: sorbent used for removing impurities, such as sulfur compounds, from the syngas and having properties of being regenerated from an inactive (e.g., sulfided) form to an active (e.g., non-sulfided or oxide) form. The regeneration process may be of the online or off-line type.

regenerator: vessel in which the sulfided sorbent is regenerated to its active form. For metal oxide sorbents in a hot gas clean-up system, the regenerator converts the sorbent from the sulfide to oxide form.

reheater: a heat source in which additional thermal energy is added to a fluid after it has been initially and partially expanded.

reinjection: the return or recycle of material back to a piece of equipment, such as a furnace.

repeatability: agreement between two or more sets of results by the same laboratory, using the same operator and equipment, within specified limits.

reproducibility: agreement between results from two or more laboratories (different equipment, operators, test dates, and different portions of the same sample) within specified limits.

residue: the solid material remaining after gasification. Residue consists of materials that are normally discarded, such as fuel ash, spent sorbent, inert additives, and unburned matter.

run: a complete set of observations made over a period of time with one or more of the independent variables maintained as a virtual constant.

screw cooler: screw conveyor in which the flight and trough are cooled by a coolant such as water. It is used to cool and transport hot solids from a vessel.

secondary fuel input streams (multiple): all fuel input streams to the IGCC other than primary fuel.

secondary measurements: measurements that are not required to calculate test results, but which may be required to determine that the plant is operating properly.

shall: word used to denote a requirement.

should: word used to denote a recommendation.

slag: ash material that has been heated above its melting point and then solidified into an amorphous, glass-like form as it is cooled. An opening at the bottom of the gasifier (slag tap) is provided to allow the slag to exit from the gasifier. The slag is separated from water in an accumulator, where the slag settles and is subsequently depressurized.

slagging gasifier: a type of gasifier in which the ash leaves as a molten slag rather than as a nonagglomerated solid.

slurry: a mixture of liquid with solid particles, usually for enabling the solid to flow as if it were a liquid.

sorbent: a constituent that reacts with and captures another constituent.

sorbent transport system: a mechanical or pneumatic transport system for transporting the regenerated sorbent from one vessel to another.

spent bed material: the bed drain residue removed from a fluidized bed.

standard atmospheric conditions: defined as 101.325 kPa (14.696 psia), 288.5 K (59°F), and 60% relative humidity.

standard deviation: in this Code, standard deviation refers to sample standard deviation.

standard pressure: typically, a reference to standard atmospheric pressure at sea level, 0.1013245 MPa = 1.01325 bar (14.696 psia).There is no single universally accepted value for standard pressure or temperature, but there are several prevailing reference sets used as standards. There is no inherent advantage to using a particular standard, but performance calculations are simpler and less susceptible to error if a single set of standards is used for all calculations.

standard temperature: one of a number of commonly used standard temperatures, including 15.55°C (60°F) for industrial gases, 15°C (59°F) for ambient air, 0°C (32°F) for steam enthalpy tables, 400°R [−50.92°C (−59.67°F; 222.22 K)] for gas enthalpy tables, and 25°C (77°F) for chemical reactions.

standard volume of fuel gas (dry): the standard volume is based on a temperature of 15.5°C (60°F) and a pressure of 101.325 kPa (14.696 psia). In cases where gases being measured are partially saturated, corrections shall be applied to gas volume measurements to correct for actual water vapor content in the as consumed gas.

startup burner: a burner firing an auxiliary fuel (e.g., natural gas, propane, or light oil) used to preheat an equipment item to its near-normal operating temperature.

sulfidation: the exothermic chemical reaction that takes place when a metal oxide or other sorbent reacts with fuel sulfur to form metal sulfide.

sulfur retention: the fraction of sulfur that enters the gasifier with the gasifier fuel and does not leave as hydrogen sulfide (H_2S) and carbonyl sulfide (COS).

synthesis gas (syngas): the gas produced by partial oxidation of the hydrocarbon feed. Raw syngas is gas that has not undergone contaminant removal. Clean syngas has had the bulk of impurities removed. The primary use of syngas is to fuel a gas turbine. Also called fuel gas.

systematic error: see *error, systematic*.

temperature: see *standard temperature.*

test boundary: the imaginary line that surrounds the system or specific equipment to be tested.

test reading: a single recording of all required test instrumentation for determining performance characteristics.

test run: a group of test readings taken while the facility is operating at steady state at a specified operating condition.

test: a single run or the combination of a series of runs for determining performance characteristics. A test normally consists of two runs.

thermal efficiency: the ratio of the energy output to the energy supplied to the gasification section, expressed as a percent.

thermodynamic enthalpy: integrated specific heat–temperature relation between the reference temperature (at which the heat of formation is based) and stream temperature.

tolerance: the acceptable difference between the test result and its nominal or guaranteed value. Tolerances are contractual adjustments to test results or guarantees and are not part of the ASME Performance Test Codes.

unburned combustible: the combustible portion of fuel that is not completely oxidized.

uncertainty, random: a numerical estimate of random errors. It is usually quantified by the standard deviation of the mean for a set of test data.

uncertainty, systematic: numerical estimate of the systematic error.

uncertainty, test: a combination of random and systematic uncertainties.

volatile matter: the portion of mass minus water vapor driven off in a gaseous form when solid fuel is heated in accordance with the applicable ASTM standard.

Section 3
Guiding Principles

3-1 INTRODUCTION

This Section provides guidance on the conduct of gasification block testing, and outlines the steps required to plan, conduct, and evaluate a Code test for gasification block performance. The Code recognizes three different types of gasifiers: fixed bed, fluidized bed, and entrained flow, in both air-blown and oxygen-blown varieties. The methodology used in the Code can be used to test other gasifier designs.

Persons planning a test shall use Section 3 to define the test and secure agreements from all parties to the test; then use Section 5 to select the appropriate equations; then use Section 4 to select the instruments and methods of measurement needed to provide the values for the selected equations. The equations in Section 5 are used to calculate performance to support specific test goals. The equations in Section 7 are used to determine test result uncertainty. Section 6 outlines the form of the final test report.

The test shall be designed with the appropriate goal in mind to ensure that proper procedures are developed, the appropriate operating mode is followed during the test, and the correct performance equations are applied.

3-2 TEST BOUNDARY AND REQUIRED MEASUREMENTS

Paragraphs 3-2.1 through 3-2.4 describe the general methodology of this Code.

3-2.1 Defining the Test Boundary

The test boundary is an imaginary line that surrounds the system or the specific equipment to be tested. The test boundary is used to identify the energy streams that must be measured to calculate correct results. Parties to a test shall establish the specific test boundary in accordance with the test goals.

3-2.2 Identifying Streams Related to Test Result Calculations

All streams entering or exiting the test boundary shall be identified. Energy streams can consist of fluid or solid material flows having chemical, thermal, or potential energy. They can also consist of pure energy flows such as thermal radiation, thermal conduction, and electrical current.

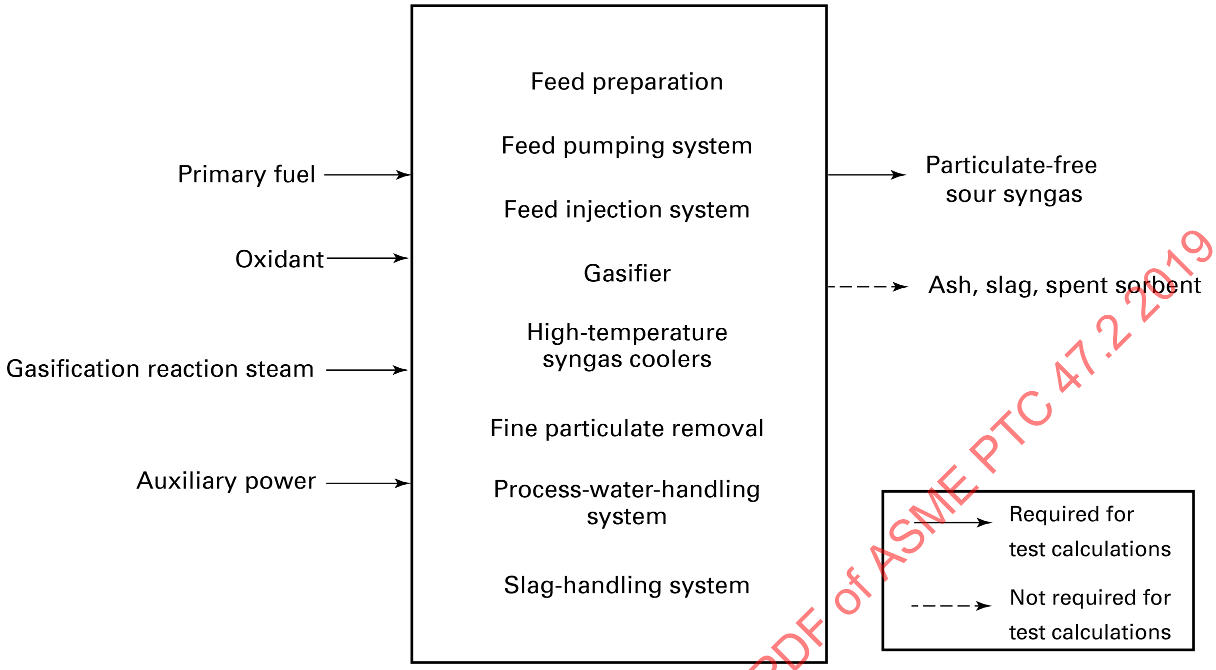
Physical properties of all energy streams required for test calculations shall be determined with reference to the point at which they cross the test boundary. Energy streams that exist only within the test boundary (e.g., slurry concentration) need not be determined unless they verify base operating conditions or relate functionally to conditions outside the boundary.

Typical streams required for a gasification block within an IGCC plant are shown in Figure 3-2.2-1. The solid lines indicate streams for which mass flow rate, thermodynamic conditions, chemical composition, and/or other properties must be determined to calculate the results of an overall plant performance test. The dashed lines indicate other streams, such as blowdown and wastewater, whose properties are not required for a Code test, even though they may be needed for an energy and mass balance.

The actual gasification block being tested is likely to include energy streams other than the typical streams identified in Figure 3-2.2-1. These other streams, which shall also be measured, may include char, coal-drying fuel, cooling duty, fluxing agent, fuel transport medium, gas liquor, heat recovery (cooling) steam or water, hydrocarbon liquids, nitrogen, quench water, recycled gases, recycled tar, secondary fuel, or sorbent.

Stream properties required for test calculations comprise three groups: uncontrollable stream properties, such as those influenced by ambient conditions or primary fuel composition; controllable stream properties that are adjusted to maintain stable conditions throughout the test; and product stream properties that indicate performance. Corrections are needed to account for uncontrollable and controllable stream property variations that cause product stream properties to deviate from their reference values.

Figure 3-2.2-1 Gasification Test Boundary



Corrections are only required for measured parameters that have relative sensitivity coefficients greater than 0.002, as specified in Section 7. The relative sensitivity coefficient of a measured parameter is the percent change in the corrected result caused by a unit change in the measured parameter. Relative sensitivity coefficients are calculated for all measured parameters during the pretest uncertainty analysis.

3-2.3 Identifying Required Measurements and Measurement Accuracy

Once all energy streams have been identified, a pretest uncertainty analysis, as described in Section 5, shall be performed to identify the primary energy flows whose physical properties must be measured and inputted into the test results calculation. The pretest uncertainty analysis is also used to determine the level of measurement accuracy required to maintain the accepted overall test uncertainty.

Measurement locations are selected to provide the lowest level of measurement uncertainty. The preferred location is the location closest to the equipment being tested.

Other measurements may be required, such as those used in the application of correction factors for off-design ambient conditions or those needed to ensure that the process does not exceed emissions or safety limits.

Equations used in the calculations of results shall be reviewed to verify that all heating value references are consistent (either all lower or all higher heating value) and that all correction curves and heat balance programs are based on the same definition of heating value.

Thermodynamic property values of all streams shall be based on an identical set of reference conditions (temperature, pressure, and state).

3-2.4 Primary and Secondary Measurements

Primary measurements are those that are required for calculating the corrected input and output energy streams of the IGCC plant's gasification block. Additional measurements may be required to determine that the plant is operating within environmental regulations and within limits established by the parties to the test or recommended by equipment suppliers. Secondary measurements are those that are not required for calculating test results. Secondary-measurement methods are not considered in this Code.

3-3 TEST PLAN

3-3.1 General

A detailed test plan shall be prepared prior to conducting a Code test. The test plan shall document agreements on all issues affecting the conduct of the test and provide detailed procedures for performing the test. The test plan shall be approved prior to testing by authorized signatures of all parties to the test. It shall reflect any contractual requirements that pertain to the test objectives and performance guarantees.

3-3.2 Object of Test

The object of the test shall be agreed to by the parties to the test and shall be defined in writing before the test begins.

In addition to documenting all prior agreements, the test plan shall include the schedule of test activities, responsibilities of the parties to the test, test procedures, and report formats.

3-4 TEST PREPARATIONS

3-4.1 General Precaution

Reasonable precautions shall be taken when preparing to conduct a Code test. Indisputable records shall be made to identify and distinguish the equipment to be tested and the exact method of testing. Descriptions, drawings, or photographs may be used to give a permanent, explicit record. Instrument location shall be predetermined, agreed to by the parties to the test, and described in detail in test records. Redundant, calibrated instruments shall be provided for those instruments susceptible to service failure or breakage.

3-4.2 Agreements

Before any tests, the parties to the test shall agree on the exact method of testing and the methods of measurement, including the following:

(a) object of test
(b) location and timing of test
(c) test boundaries
(d) selection of instruments: number, location, and type
(e) method of instrument calibration
(f) confidentiality of test results
(g) number of copies of original data required
(h) data to be recorded and method of recording and archiving data
(i) values of measurement uncertainty and method of determining overall test uncertainty
(j) method of operating the equipment being tested, including that of any auxiliary equipment (the performance of which may influence the test result)
(k) methods of maintaining constant operating conditions as near as possible to those specified
(l) method of determining duration of operation under test conditions before test readings are started
(m) system alignment or isolation
(n) organization of personnel, including designation of engineer in responsible charge of test
(o) duration and number of test runs
(p) frequency of observations
(q) base reference conditions
(r) methods of correction and values used for corrections for deviations from specified test conditions
(s) methods of computing results
(t) method of comparing test results with specified performance
(u) conditions for rejection of outlier data or runs
(v) pretest inspections

3-4.3 Test Apparatus

3-4.3.1 General. Test instruments are classified as described in Section 4. Instrumentation used for data collection shall be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can be either permanent plant instrumentation or temporary test instrumentation.

3-4.3.2 Frequency and Timing of Observations. The timing of instrument observations shall be determined by an analysis of the time lag of both the instrument and the process so that a correct mean value and departure from allowable operating conditions may be determined. Sufficient observations shall be recorded to prove that steady-state conditions existed during the test where this is a requirement. A sufficient number of observations shall be taken to reduce the random uncertainty to an acceptable level.

The frequency of data collection is dependent on the measurement being recorded, variability of plant operation, and duration of the test. To the extent practical, sufficient readings shall be collected to minimize the random error impact on the post-test uncertainty analysis (see para. 3-5.8). The use of automated data acquisition systems is recommended to facilitate data collection.

3-4.3.3 Location and Identification of Instruments. Transducers shall be located to minimize the effect of ambient conditions, e.g., temperature or temperature variations, on uncertainty. Care shall be used in routing 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 marked uniquely and unmistakably for identification. Calibration tables, charts, or mathematical relationships shall be readily available to all parties of the test. Observers recording data shall be instructed on the desired degree of precision for readings.

All test instruments used to calculate the test results in Table 1-3-1 shall be calibrated before the test, and it is recommended that they be recalibrated or calibration-checked following the test. The time between the initial calibration, performance testing, and recalibration should be agreed to by the parties to the test, but shall not exceed 1 yr.

When an automated data acquisition system is used, the calibration procedure shall include signal conditioners and data-logging devices to maintain the desired measurement accuracy from the primary sensor to the final readout or storage device.

3-4.3.4 Redundant Instrumentation. Redundant instruments are two or more devices measuring the same parameter. For each primary measurement, redundant instruments shall be considered and applied unless it can be demonstrated by pretest uncertainty analysis that the overall uncertainty of the final result will be incrementally reduced by less than 0.05%.

Redundant instrumentation might not be available for certain primary measurements, such as primary fuel flow. The pretest uncertainty analysis determines the ability of single or redundant instrumentation to meet the total uncertainty specified in Table 1-3-1.

Additional independent instruments in separate locations, such as a temperature grid, can also provide assurance of instrument integrity and reduce uncertainty due to spatial variation, and should be considered by the parties to the test. However, this is not a requirement.

3-4.3.5 Equipment Inspection. Before a test, the condition of the equipment shall be determined by inspection or review of operational records, or both.

In preparation for acceptance testing and other official tests, the manufacturer or supplier shall have reasonable opportunity to examine the equipment, correct defects, and render the equipment suitable to test. The manufacturer, however, is not permitted to alter or adjust equipment or conditions in such a way that regulations, contract, safety, or other stipulations are altered or voided. The manufacturer shall not adjust the equipment for the test in any way that may prevent immediate, continuous, and reliable operation under all specified operating conditions. The manufacturer shall document any actions taken and immediately report them to all parties to the test.

3-4.4 Preliminary Testing

3-4.4.1 Timing. It is recommended that preliminary testing be conducted sufficiently in advance of the official performance test to allow time to calculate preliminary results and perform an uncertainty analysis using the standard deviations observed during the test. Results from the preliminary testing shall be calculated and reviewed to identify any problems with the quantity and quality of measured data. The test equipment can be adjusted, if necessary, based on these preliminary testing results.

Before testing, all parties to the test shall agree on the validity of all computer models, corrections, and curves to be used to calculate and correct plant performance.

3-4.4.2 Preliminary Test Runs. Preliminary test runs and associated records serve to

(a) determine whether equipment is in suitable condition to test
(b) validate instruments and methods of measurement
(c) verify adequacy of organization and procedures
(d) train personnel

All parties to the test should conduct reasonable preliminary test runs as necessary to validate test readiness. Observations during preliminary test runs shall be carried through to the calculation of results as an overall check of procedure, layout, and organization. If a preliminary test run complies with all the necessary requirements of the appropriate test code, it may be used as an official test run within the meaning of the applicable code.

3-5 CONDUCT OF THE TEST

*(a) Personnel and Monitoring***.** The parties to the test shall designate a person to direct the test, hereafter called the test coordinator. Intercommunication arrangements shall be established between all test personnel, test parties, and the test coordinator. Complete written records of the test, including even seemingly irrelevant details, shall be reported. Controls by ordinary operating (indicating, reporting, or integrating) instruments, preparation of graphical logs, and close supervision shall be established to ensure that the equipment under test is operating in substantial accord with the intended conditions. If it is a commercial test, accredited representatives of the purchaser and the manufacturer or supplier shall be present at all times to assure themselves that the tests are being conducted in accordance with the test Code and prior agreement.

(b) Operating Philosophy. The tests shall be conducted as closely as possible to specified operating conditions to minimize the magnitude and number of corrections for deviation from specified conditions.

(c) Starting and Stopping. Acceptance and other official tests shall be conducted as promptly as possible following initial equipment operation and preliminary test runs. The equipment shall be operated for sufficient time to reach the intended test conditions (e.g., steady state). Agreement on procedures for and timing of the testing shall be reached before beginning the test.

3-5.1 Valve Lineup/Cycle Isolation

A cycle isolation checklist shall be developed to the satisfaction of all parties to the test. The checklist is a list of all the valves that should be closed during normal operation. These are the valves that affect the accuracy or results of the test if they are not secured. These valve positions shall be checked before and after the test. All automatic valve positions shall be checked before the preliminary test and monitored during subsequent testing.

No valves that are normally open shall be closed for the sole purpose of changing the performance of the plant.

3-5.2 Proximity to Design Conditions

The equipment being tested shall be operated within the boundaries of permissible fluctuations and specified deviations. To maintain compliance with test Code requirements, the actual test shall be conducted within the criteria given in Table 3-5.2-1 or other mutually agreed-on operating criteria that limit overall test uncertainty to the values referenced in Table 1-3-1. Variations of readings during a test are indicative of random error in an instrument or changing conditions during a test. Either situation can cause an increase in test uncertainty. For this reason, the variation during the test shall be maintained with the limits given in the first column of Table 3-5.2-1. Parties to the test shall conduct a sensitivity analysis to determine which parameters in the table need to be monitored.

The purpose of the correction procedure is to correct the tested performance to that at design conditions, resulting in minimum practical uncertainty. The following are two methods of correcting the tested performance to that at design conditions:

(a) the use of correction curves (whether in hard copy or electronic form)

(b) the use of a validated thermodynamic model

Correction curves have some uncertainty that generally increases with the magnitude of change of the input variable. The magnitude of the changes allowed by the correction curve method shall be restricted to minimize the uncertainty introduced by the curves themselves. If the deviation from design conditions is maintained within the limits of Table 3-5.2-1, the curves will not normally introduce significant uncertainty. Tests conducted outside the bounds given in Table 3-5.2-1 or for test-run durations shorter than those recommended in para. 3-5.6 may not be considered Code tests due to the potential for increased test result uncertainty.

3-5.3 Stabilization

Parties to the test shall agree on the necessary stable conditions before starting the test. The length of operating time necessary to achieve the required steady state will depend on previous operations, but typical gasifier stabilization time is 24 hr, regardless of gasifier type.

Table 3-5.2-1 Guidance for Establishing Permissible Deviations From Design Conditions

Criterion	Variation During Test	Deviation From Design
Thermal Efflux		
Steam flow	±5%	±10%
Steam temperature (superheated)	±6°C (±10°F)	±28°C (±50°F)
Steam temperature (saturated)	±3°C (±5°F)	±10°F
Steam pressure (superheated)	±5%	±10%
Particulate-free sour syngas flow	±5%	±10% [Note (1)]
Syngas heating value, LHV	±2%	±5%
Syngas temperature	±6°C (±10°F)	±28°C (±50°F)
Combustible constituents	±20%	±20%
Liquid hydrocarbons flow	±5%	±10%
Heat recovery water flow	±5%	±5%
Thermal Input		
Import steam for process heat, flow	±5%	±5%
Import steam temperature	±6°C (±10°F)	±28°C (±50°F)
Import steam pressure	±5%	±10%
Recycled gas(es) flow	±5%	±5%
Recycled gas(es) temperature	±6°C (±10°F)	±11°C (±20°F)
Recycled gas(es) constituents	±3%	±10%
Oxidant flow	±5%	±5%
Oxygen content	±2%	±2%
Sorbent active ingredients flow	±5%	±5%
Inert gas flow	±5%	±5%
Flux flow	±5%	±5%
Boiler feedwater temperature	±6°C (±10°F)	±11°C (±20°F)
Gasification steam flow	±5%	±5%
Water consumption flow	±5%	±5%
Primary Fuel Input [Note (2)]		
Primary fuel feed rate	±5%	±10% [Note (1)]
Primary fuel heating value, HHV	±5%	±5%
Primary fuel composition	±3% C ±3% H ±3% N ±3% S ±3% moisture ±3% ash	±3% C ±10% H ±25% N ±10% S ±30% moisture ±10% ash
Secondary Fuel Input		
Coal-drying fuel, HHV	±5%	±5%
Constituents including moisture	±5%	±5%
Electrical Parameters		
Auxiliary power	±5%	±5%

NOTES:
(1) Specify either syngas flow or primary flow.
(2) Each value is the percent of the fractional amount of each constituent.

3-5.4 Starting Criteria

The test coordinator is responsible for ensuring that all data collection begins at the agreed-on start of the test and that all parties to the test are informed of the starting time. The following conditions shall be satisfied before the start of each performance test:

(a) Operation and Configuration. The unit shall be in the proper configuration and shall be operating in accordance with the agreed-on test requirements.

(b) Stabilization. The plant shall be operated at test load long enough to demonstrate and verify stability in accordance with para. 3-5.3 criteria. All operating parameters shall be within the acceptable test range.

(c) Data Collection. Data collection system(s) shall be functioning, and test personnel shall be in place and ready to collect samples or record data. The data collection system shall be designed to accept multiple instrument inputs and shall be able to sample data from all the instruments within 2 min to 3 min to obtain all necessary data with the plant at the same condition.

Data shall be taken by automatic data-collecting equipment or by a sufficient number of competent observers. Automatic data-logging and advanced instrument systems shall be calibrated to the required accuracy. No observer shall be required to take so many readings that a lack of time may result in insufficient care and precision. Consideration shall be given to specifying duplicate instrumentation and capturing simultaneous readings at certain test points to attain the specified test accuracy.

(d) Readjustments. Once testing has started, any readjustment to the equipment that could influence the test results shall require repetition of any test runs conducted prior to the readjustment. No adjustments shall be permissible for the purpose of a test that are inappropriate for reliable and continuous operation following a test under any and all of the specified outputs and operating conditions.

3-5.5 Stopping Criteria

Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied (see paras. 3-5.6 and 3-5.7). The test coordinator shall verify that methods of operation during the test, specified in paras. 3-5.1 through 3-5.3, have been satisfied. The test coordinator may extend or terminate the test if the requirements have not been met.

3-5.6 Duration of Test Runs

The duration of a test run shall be of sufficient length that the data reflect the average efficiency and performance of the plant. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical plant operating characteristics. Recommended test-run duration is between 4 hr and 8 hr regardless of gasifier type. Test runs using blended or waste fuels may require a longer duration if fuel variations are significant. Transit sample time shall also be considered when determining the test run duration.

3-5.7 Number of Test Runs

A test shall comprise two or more test runs. A test run is a complete set of observations with the unit at stable operating conditions. If the results vary significantly between the first two runs, a third run shall be required.

After a preliminary run is complete, it may be declared an acceptable test run if all parties to the test agree that all requirements of a regular run have been met.

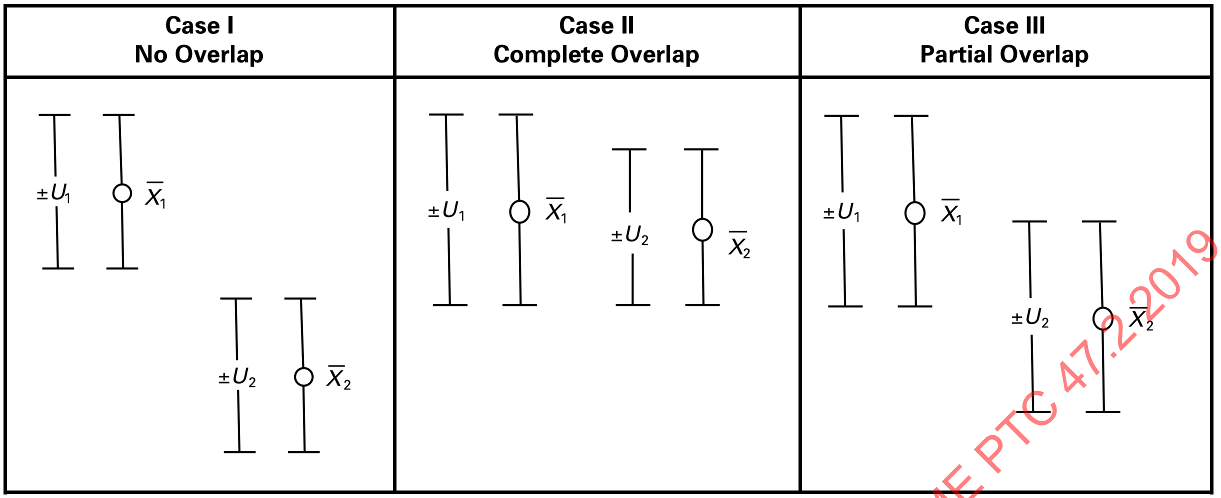
3-5.8 Number of Readings

Sufficient readings shall be taken during the test to yield total uncertainty consistent with Table 1-3-1. The pretest uncertainty analysis shall be used to determine the necessary number of readings for each measurement. Ideally at least 30 sets of data should be recorded for all nonintegrated measurements of primary variables.

Practical considerations may reduce the number of readings in some cases. For example, fuel quality samples taken every half hour, rather than every 5 min, would reduce offsite laboratory costs. Ash or slag quality samples may be limited, such as one reading every 4 hr, to accommodate a 4-hr holdup in the lock hopper. The pretest uncertainty analysis will determine the impact of a reduced number of readings and whether the overall test will meet the total uncertainty requirements specified in Table 1-3-1.

There are no specific requirements for the number of accumulated readings or for measurements of secondary variables for each test run, but sufficient data shall be available to determine the precision uncertainty of all primary accumulated readings.

Figure 3-5.9-1 Uncertainty Intervals



3-5.9 Evaluation of Test Runs

When comparing results and uncertainty intervals from two test runs (X_1 and X_2), the parties to the test shall consider the three cases shown in Figure 3-5.9-1 (from ASME PTC 19.1).

(a) Case I. A problem clearly exists when there is no overlap between uncertainty intervals. This situation may be due to uncertainty intervals being grossly underestimated, errors in the measurements, or abnormal fluctuations in the measurement values. Investigation to identify bad readings, overlooked or underestimated systematic uncertainty, etc., is necessary to resolve this discrepancy.

(b) Case II. When the uncertainty intervals completely overlap, one can be confident that there has been a proper accounting of all major uncertainty components. The smaller uncertainty interval, $\overline{X}_2 \pm U_2$, is wholly contained within the interval $\overline{X}_1 \pm U_1$.

(c) Case III. A case in which there is a partial overlap of the uncertainty is the most difficult to analyze. For both the test run results and uncertainty intervals to be correct, the most probable value lies in the region where the uncertainty intervals overlap. Consequently, the larger the overlap, the more confidence there is in the validity of the measurements and the estimate of the uncertainty intervals. As the difference between the two measurements increases, the overlap region shrinks.

If a run or set of runs follows Case I or Case III, the results from all runs shall be reviewed in an attempt to explain the reason for excessive variation. If no reason is obvious, the user of the Code shall reevaluate the uncertainty band or conduct more test runs to calculate the precision component of uncertainty directly from the test results. Conducting additional tests may also validate the previous testing.

The results of the valid runs shall be averaged to determine the mean result. The uncertainty of the result is calculated in accordance with ASME PTC 19.1.

3-5.10 Constancy of Test Conditions

(a) General. The primary criterion for steady-state test conditions is that the average of the data reflect balance between energy input from fuel and energy output to thermal and/or electrical generation. The primary uncontrollable parameters affecting the steady-state conditions of a test are typically the ambient conditions. See Table 3-5.2-1 for additional parameters. Testing durations and schedules shall be such that changes in ambient conditions are minimized.

(b) Analysis and Interpretation. During a test or the subsequent analysis or interpretation of the observed data, an obvious inconsistency may be found. If so, reasonable effort shall be made to adjust or eliminate the inconsistency. Failing this, the test run shall be repeated.

3-6 CALCULATION AND REPORTING OF RESULTS

3-6.1 Data Records and the Test Log

For all acceptance and other official tests, a complete set of data and a complete copy of the test log shall be supplied to all parties to the test. The original log; data sheets, files, and disks; recorder charts; tapes; etc., being the only evidence of actual test conditions shall permit clear and legible reproduction. Copying by hand is not permitted. The completed data records shall include the date and time an observation was recorded. The observations shall be the actual readings without application of any instrument corrections. The test log shall constitute a complete record of events, including even details that may have seemed trivial or irrelevant during the test. Destruction or deletion of any data record, page of the test log, or any recorded observation is not permitted. If a correction is required, the alteration shall be entered with an explanation and in such a way that the original entry remains legible. For manual data collection, the test observations shall be entered on prepared forms that constitute original data sheets authenticated by the observers' signatures. For automatic data collection, printed output or electronic files shall be authenticated by the engineer in charge and other representatives of the parties to the test. When no paper copy is generated, the parties to the test shall agree in advance on the method for authenticating, reproducing, and distributing the data. Copies of the electronic data files shall be copied onto tape or disks and distributed to all parties to the test. The data files shall be in a format that is easily accessible by all parties. Data residing on a machine shall not remain there unless a permanent backup copy is made.

The data taken during the test shall be reviewed for compliance with the test condition requirements (see para. 3-5.9). Each test shall include pretest and post-test uncertainty analyses, and the results of these analyses shall fall within Code requirements for the type of plant being tested (see Table 1-3-1).

3-6.2 Causes for Rejection of Test Runs

If serious inconsistencies that affect test results are 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 data 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 of the parties to the test.

An outlier analysis of spurious data shall also be performed in accordance with ASME PTC 19.1 on all critical measurements after the test has ended.

If any measurement influencing the result of a test is inconsistent with a similar measurement, although either or both may have been recorded in strict accordance with the rules of the individual test Code, the cause of the inconsistency shall be identified and eliminated.

3-6.3 Uncertainty

A post-test uncertainty analysis shall be performed as part of the test calculations. The post-test uncertainty analysis will reveal the actual quality of the test to determine whether the calculated results fall within the required uncertainty limits stated in Section 1.

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

3-6.4 Application of Correction Methods

The calculation of results described by this Code requires adjusting the test-determined values of product syngas energy and gasification effectiveness by the application of correction methods described in Section 5. These corrections may be applied as additive and multiplicative correction factors for individual variables, as algorithms in multivariate computer models, or as a hybrid combination of these two correction methods. These corrections adjust for allowable variations in controllable operating parameters and uncontrollable external effects, such as ambient temperature. All corrections must result in no correction if all test conditions are equal to the base reference conditions.

Section 4
Instruments and Methods of Measurement

4-1 INTRODUCTION

This Section describes measurement equipment and methods used to calculate the gasifier block performance in terms of the results in Table 1-3-1. This Section is organized as follows:

(a) General Requirements, subsection 4-2
(b) Pressure Measurement, subsection 4-3
(c) Temperature Measurement, subsection 4-4
(d) Solid Flow Measurement, subsection 4-5
(e) Liquid Flow Measurement, subsection 4-6
(f) Steam Flow Measurement, subsection 4-7
(g) Gas Flow Measurement, subsection 4-8
(h) Material Analysis, subsection 4-9
(i) Input and Output Heat Measurement, subsection 4-10
(j) Auxiliary Electric Power Measurement, subsection 4-11
(k) Data Collection and Handling, subsection 4-12

4-2 GENERAL REQUIREMENTS

4-2.1 Introduction

This Section presents the mandatory requirements for instrumentation used in an ASME PTC 47.2 test. Per the philosophy of ASME PTC 1 and subsection 1-1, it does so in consideration of the minimum reasonably achievable uncertainty. The Instruments and Apparatus Supplements to ASME Performance Test Codes (ASME PTC 19 series) outline the details concerning instrumentation and the governing requirements of instrumentation for all ASME Code performance testing. The user of this Code should be intimately familiar with the ASME PTC 19 series as it applies to the instrumentation specified and explained in this Section.

For the convenience of the user, this Section reviews the critical highlights of portions of those supplements that directly apply to the requirements of this Code. This Section also contains details of the instrumentation requirements of this Code that are not specifically addressed in the referenced supplements. These details include classification of measurements for the purpose of instrumentation selection and maintenance, calibration and verification requirements, electrical metering, and other information specific to an ASME PTC 47.2 test.

If the instrumentation requirements in the ASME PTC 19 series become more rigorous as they are updated due to technology advances, those requirements will supersede those in this Code.

Both SI units and U.S. Customary units are shown for the equations in this Section. In text, tables, and figures, the SI value is followed by the U.S. Customary value in parentheses. However, any other consistent set of units may be used.

4-2.2 Measurements

4-2.2.1 Measurement Designation. Measurements may be designated as either a parameter or a variable. The terms parameter and variable are sometimes used interchangeably in the industry and in some other ASME Codes. This Code distinguishes between the two.

A parameter is considered a direct measurement and is a physical quantity at a location that is determined by a single instrument, or by the average of the measurements from several similar instruments. In the latter case, several instruments may be used to determine a parameter that has potential to display spatial gradient qualities, such as inlet air temperature. Similarly, multiple instruments may be used to determine a parameter simply for redundancy to reduce test uncertainty, such as utilization of two temperature measurements of the fluid in a pipe in the same plane, where the temperature gradient is expected to be insignificant. Typical parameters measured in an ASME PTC 47.2 test are temperature, static and differential pressure and flow, and stream constituents.

A variable is considered an indirect measurement and is an unknown quantity in an algebraic equation that is determined by parameters. The performance equations in Section 5 contain the variables used to calculate the performance results, including corrected effective syngas flow rate, corrected gasification effectiveness, and corrected specific fuel consumption. Typical variables in these equations are flow, enthalpy, and correction factors. Each variable can be thought of as an intermediate result needed to determine the performance result.

Parameters are therefore the quantities measured directly to determine the value of the variables needed to calculate the performance results per the equations in Section 5. Examples of such parameters are temperature and pressure to determine the variable enthalpy; temperature, pressure, or differential pressure for the calculation of the variable flow; and secondary fuel and syngas composition for the calculation of primary and secondary fuel and syngas heating value.

4-2.2.2 Measurement Classification. A parameter or variable is classified as primary or secondary depending on its usage in the execution of this Code. Parameters and variables used in the calculation of test results are considered primary parameters and variables. Alternatively, secondary parameters and variables do not enter into the calculation of the results but are used to ensure that the required test condition was not violated.

Primary parameters and variables are further classified as Class 1 or Class 2, depending on their relative sensitivity coefficient to the results of the test. Class 1 primary parameters and variables have a relative sensitivity coefficient of 0.2% or greater. The primary parameters and variables that have a relative sensitivity coefficient of less than 0.2% are Class 2 primary parameters and variables.

4-2.3 Instrumentation

4-2.3.1 General. Measuring equipment shall be selected to minimize test uncertainty. Critical parameters shall be measured with instruments that have sufficient accuracy to ensure that target uncertainties will be achieved. Typical station-recording instruments are designed for reliability and ease of use and maintenance, rather than for accuracy. Therefore, measurements made by station-recording instruments may increase test uncertainty beyond agreed-on limits. All instruments shall be checked to verify that they are the specified type, properly installed, working as designed, and functioning over the range of expected input.

4-2.3.2 Instrumentation Categorization. The instrumentation employed to measure a parameter will have different required type, accuracy, redundancy, and handling depending on how the measured parameter is used and how it affects the performance result. This Code does not require high-accuracy instrumentation for determining secondary parameters. The instruments that measure secondary parameters may be permanently installed plant instrumentation. This Code does require verification of instrumentation output prior to the test period. This verification can be by calibration or by comparison against two or more independent measurements of the parameters referenced to the same location. The instruments shall also have redundant or other independent instruments that can verify the integrity during the test period. Instrumentation is categorized as Class 1 or Class 2, depending on the instrumentation requirements defined by the parameter. Care shall be taken to ensure the instrumentation meets the classification requirements set forth in this Code.

4-2.3.2.1 Class 1 Instrumentation. Class 1 instrumentation shall be used to determine Class 1 primary parameters. Class 1 instrumentation is high accuracy instrumentation with precision laboratory calibration that meets specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements.

4-2.3.2.2 Class 2 Instrumentation. Class 2 instrumentation shall be used to determine Class 2 primary parameters. Class 2 instrumentation does not require laboratory calibrations other than that performed in the factory for certification, but does require field verification by techniques described in this Code.

4-2.3.3 Plant Instrumentation. It is acceptable to use plant instrumentation for primary parameters only if the plant instrumentation (including signal-conditioning equipment) can be demonstrated to meet the overall uncertainty requirements. Many times this is not the case. In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from metering device) shall be made available, as plant conversions to flow are often not rigorous enough for the required uncertainty.

4-2.3.4 Redundant Instrumentation. If previous experience indicates that a particular model or type of instrument is prone to unacceptable calibration drift, and no other device is available, redundancy is recommended. Redundant instruments shall be used to measure all primary parameters except flow and electrical input. Redundant flow elements and redundant electrical-metering devices are not required because of the large increase in cost associated with redundancy but shall be considered when developing a test plan. Other independent instruments in separate locations can also monitor instrument integrity. A sample case would be a constant enthalpy process, where pressure and temperature at one point in a steam line verify the pressure and temperature of another location in the line by comparing enthalpies.

4-2.4 Instrument Calibration

Calibrations performed in accordance with this Code are categorized as either laboratory or field calibrations.

4-2.4.1 Laboratory-Grade Calibration. Laboratory-grade calibrations shall be performed in strict compliance with established policy, requirements, and objectives of a laboratory quality assurance program. Laboratory calibration applications shall be employed on Class 1 instrumentation with the exception of fluid-metering devices that strictly adhere to specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements.

4-2.4.2 Field Calibration. Field calibration applications are commonly used on instrumentation measuring secondary parameters and Class 2 instrumentation that are identified as out-of-calibration during field verification as described in para. 4-2.5.

4-2.4.3 Reference Standards. Reference standards are generally of the highest metrological quality available at a given location from which the measurements made at that location are derived. Reference standards include all measuring and test equipment and reference materials that have a direct bearing on the traceability and accuracy of calibrations. Reference standards shall be routinely calibrated in a manner that provides traceability to NIST or defined natural physical constants and shall be maintained for proper calibration, handling, and usage in strict compliance with an accredited calibration laboratory quality program. The integrity of reference standards shall be validated by proficiency testing or inter-laboratory comparisons. All reference standards shall be calibrated at the frequency specified by the manufacturer unless the user has data to support extension of the calibration period. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

Reference standards shall be selected so that the collective uncertainty of the standards used in the calibration contributes less than 25% to the overall calibration uncertainty. The overall calibration uncertainty of a calibrated instrument shall be determined at a 95% confidence level. A reference standard with a lower uncertainty may be employed if the uncertainty of the reference standard combined with the random uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument.

With the exception of flowmeter instrumentation, all Class 1 and Class 2 instrumentation used to measure primary parameters shall be calibrated against reference standards traceable to NIST, another recognized international standard organization, or recognized natural physical constants with values assigned or accepted by NIST. Instrumentation used to measure secondary variables does not need to be calibrated against a reference standard. These instruments may be calibrated against a calibrated instrument.

4-2.4.4 Environmental Conditions. Calibration of instruments used to measure primary parameters shall be performed in a manner that replicates the condition under which the instrument will be used to take test measurements. As it is often not practical or possible to perform calibrations under replicated environmental conditions, additional elemental error sources shall be identified and estimated. Error source considerations shall be given to all process and ambient conditions that may affect the measurement system, including temperature, pressure, humidity, electromagnetic interference, and radiation.

4-2.4.5 Instrument Ranges and Calibration Points. The number of calibration points depends on the classification of the parameter the instrument will measure. The classifications are discussed in para. 4-2.2.2. The calibration shall have points that bracket the expected measurement range. In some cases of flow measurement, it may be necessary to extrapolate a calibration. All installed instrumentation shall undergo field verification (see para. 4-2.5) before testing begins.

4-2.4.5.1 Class 1 Instrumentation. The instruments measuring Class 1 primary parameters shall be laboratory-grade calibrated at 2 points more than the order of the calibration curve fit. This shall be done whether it is necessary to apply the calibration data to the measured data, or the instrument is of such quality that the deviation between the laboratory calibration and the instrument reading has a negligible effect on the test result. Flow metering that requires calibration shall have a 20-point calibration. Instrument transformers do not require calibration at 2 points more than the order of the calibration curve fit and shall be calibrated in accordance with para. 4-2.4.7.

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

Some devices cannot practically be calibrated over the entire operating range. For example, flow-measuring devices are often calibrated at flows lower than the operating range and the calibration data is extrapolated. This extrapolation is described in subsection 4-6.

4-2.4.5.2 Class 2 Instrumentation. If calibration for instruments measuring Class 2 primary parameters is to be curve-fitted, the calibration shall contain, at minimum, one point more than the order of the calibration curve fit. If the instrument can be shown to typically have a hysteresis of less than the required accuracy, the measuring point need only be approached from one direction (either increasing or decreasing to the point).

4-2.4.6 Secondary Parameters. The instruments measuring secondary parameters shall undergo field verifications as described in para. 4-2.5 and if calibrated, need only be calibrated at one point in the expected operating range.

4-2.4.7 Timing of Calibration. Due to the variance in different types of instrumentation and their care, this Code does not mandate a time interval between the initial laboratory calibration and the test period. Treatment of the device is much more important than the elapsed time since calibration. An instrument may be calibrated one day and mishandled the next. Conversely, an instrument may be calibrated and placed on a shelf in a controlled environment, and the calibration will remain valid for an extended time period. Similarly, the instrument may be installed in the field but valved-out of service, or it may be exposed to significant cycling. In these cases, the instrumentation is subject to vibration or other damage and shall undergo field verification.

All test instrumentation used to measure Class 1 primary parameters shall be laboratory-grade calibrated prior to the test and/or shall meet specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements. This Code does not mandate a quantity of time between the laboratory calibration and the test period. The quantity of time between the laboratory calibration and the test period should, however, be kept to a minimum to obtain an acceptable calibration drift as determined by the manufacturer's specifications and demonstrated by field verification. Similarly, the quantity of time between the field verification and the test period shall be kept to a minimum to minimize instrument drift. Test instrumentation used to measure Class 2 parameters and secondary parameters does not require laboratory calibration other than that performed in the factory for certification. It does require field verification before the test.

Following a test, field verifications shall be conducted on instruments measuring parameters where there is no redundancy or for which data is questionable. For the purposes of redundancy, plant instrumentation may be used for field verification. If results indicate unacceptable drift or damage, then further investigation is required. Flow element devices used to measure Class 1 primary parameters that do not have redundancy shall require field verification, including nondestructive inspection, following the test. Flow element devices used to measure Class 2 primary parameters do not need to be inspected following the test if the devices have not experienced conditions (steam blow, chemical cleaning, etc.) that would violate their integrity.

By nature, flow-measuring devices and current and potential transformers are not conducive to post-test calibration. In the case of flow-measuring devices used to measure Class 1 primary variables, the device should be inspected following the test rather than recalibrated. Flow element devices used to measure Class 2 primary variables do not need be inspected following the test if the devices have not experienced steam blow or chemical cleaning.

4-2.4.8 Calibration Drift. Calibration drift is defined as a shift in the calibration characteristics. When the field verification indicates the drift is less than the instrument accuracy, the drift is considered acceptable and the pretest calibration shall be used as the basis for determining the test results. If the calibration drift combined with the reference standard accuracy (the square root of the sum of the squares) exceeds the required accuracy of the instrument, it is unacceptable.

Calibration drift can result from instrument malfunction, transportation, installation, or removal of the test instrumentation. When a field verification of calibration indicates unacceptable drift, further investigation is required.

A post-test laboratory calibration may be ordered. If so, the Code user shall evaluate the field verifications and use engineering judgment to determine whether the initial calibration or the recalibration is correct. Below are some recommended field verification practices that lead to the application of good engineering judgment.

(a) When instrumentation is transported to the test site between the calibration and the test period, a single-point check before and after the test period can isolate when the drift may have occurred. For example, verify the zero-pressure point on the vented pressure transmitters, the zero-load point on the wattmeters, or the ice point on the temperature instrument.

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

4-2.4.9 Loop Calibration. All analog instruments used to measure primary parameters shall be loop calibrated. Loop calibration involves the calibration of the instrument through the signal-conditioning equipment. This may be accomplished by calibrating instrumentation using the test signal-conditioning equipment either in a laboratory or on-site during test setup before the instrument is connected to process. Alternatively, the signal-conditioning device may be calibrated separately from the instrument by applying a known signal to each channel using a precision signal generator.

Where loop calibration is not practical, an uncertainty analysis shall be performed to ensure that the combined uncertainty of the measurement system meets the uncertainty requirements described in Table 1-3-1.

Instrumentation with digital output need only be calibrated through to the digital signal output. There is no further downstream signal-conditioning equipment, as the conversion of the units of measure of the measured parameter has already been performed.

4-2.4.10 Quality Assurance Program. Each calibration laboratory shall have a quality assurance program that documents the following information:

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

The quality assurance program shall be designed to ensure that the laboratory standards are calibrated as required and that properly trained technicians calibrate the equipment in the correct manner. The parties to the test shall be allowed access to the calibration facility for auditing. The quality assurance program shall also be made available during such a visit.

4-2.5 Instrument Verification

Before the test, all installed instrumentation shall undergo field verifications of all secondary measured parameters. The verifications shall demonstrate that the instrumentation and systems are within acceptable limits of error as defined in this Section. Verification techniques may include field calibrations, nondestructive inspections, and comparison of redundant instruments.

Elemental error sources arising from the methods of measurement shall be evaluated during the field verifications to identify the uncertainty sources beyond those contained in the calibration or manufacturer's specification, data acquisition, and data reduction that may significantly affect the assessment of the verification. Some common examples include vibration effects, mounting position effects, electromagnetic effects, external temperature and humidity effects, and static temperature effects. The errors may be either systematic or random, depending on their effect on the measurement.

4-2.6 Instrumentation Systematic Uncertainty

Estimating the systematic uncertainty in a measurement involves evaluating all components of a measurement system. The potential systematic uncertainties for various instruments are listed in Table 4-2.6-1, which is based on ASME PTC 4-2013, Table 4-3.6-1. These uncertainties tend to be conservative and may not be representative of any specific measurement situation.

4-3 PRESSURE MEASUREMENT

4-3.1 Introduction

This subsection presents requirements and guidance regarding pressure measurement. The use of electronic pressure measurement equipment is recommended for primary measurements to minimize systematic and random error. Electronic pressure measurement equipment provides inherent compensation procedures for sensitivity, zero balance, thermal effect on sensitivity, and thermal effect on zero. Deadweight gauges, manometers, and other measurement devices that meet the uncertainty requirements of this Section may be used. Factors affecting the uncertainty of the pressure measurement include, but are not limited to, ambient temperature, resolution, repeatability, linearity, hysteresis, vibration, power supply, stability, mounting position, radio frequency interference (RFI), static pressure, water leg, warm-up time, data acquisition, spatial variation, and primary element quality.

The piping between the process and secondary elements shall accurately transfer the pressure to obtain accurate measurements. Possible sources of error include pressure transfer, leaks, friction loss, trapped fluid (i.e., gas in a liquid line or liquid in a gas line), and density variations between legs.

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

Table 4-2.6-1 Potential Instrumentation Systematic Uncertainty

Instrument	Systematic Uncertainty [Note (1)]
Data Acquisition	**Note (2)**
Digital data logger	Negligible
Plant control computer	±0.1%
Handheld temperature indicator	±0.25%
Handheld potentiometer (including reference junction)	±0.25%
Temperature	**Note (3)**
Thermocouple	...
NIST-traceable calibration	Note (4)
Premium Grade Type E	...
0°C–316°C (32°F–600°F)	±1.1°C (2°F)
316°C–871°C (600°F–1,600°F)	±0.4%
Premium Grade Type K	...
0°C–277°C (32°F–530°F)	±1.1°C (2°F)
277°C–1 260°C (530°F–2,300°F)	±0.4%
Standard Grade Type E	...
0°C–316°C (32°F–600°F)	±1.7°C (3°F)
316°C–871°C (600°F–1,600°F)	±0.5%
Standard Grade Type K	...
0°C–277°C (32°F–530°F)	±2.2°C (4°F)
277°C–1 260°C (530°F–2,300°F)	±0.8%
Resistance temperature device (RTD)	...
NIST-traceable calibration standard	Note (4)
0°C (32°F)	±0.03%
93°C (200°F)	±0.08%
204°C (400°F)	±0.13%
299°C (570°F)	±0.18%
399°C (750°F)	±0.23%
499°C (930°F)	±0.28%
594°C (1,100°F)	±0.33%
704°C (1,300°F)	±0.38%
Temperature gauge	±2% of span
Mercury-in-glass thermometer	±0.5 gradation
Pressure	**Note (5)**
Gauge	...
Test	±0.25% of span
Standard	±1% of span
Manometer	±0.5 gradation
Transducer and transmitter	...
High accuracy	±0.1% of span
Standard	±0.25% of span
Aneroid barometer	±0.05 in. Hg
Weather station	Note (6)
Velocity	**...**
Standard pitot tube	...
Calibrated	±5% [Note (7)]
Uncalibrated	±8% [Note (7)]
S-type pitot tube	...
Calibrated	±5% [Note (7)]
Uncalibrated	±8% [Note (7)]
3-hole probe	...
Calibrated	±2% [Note (7)]
Uncalibrated	±4% [Note (7)]
Hot wire anemometer	±10%
Turbometer	±2%
Flow (Air and Flue Gas)	**...**
Multipoint pitot tube (within range)	...
Calibrated and inspected (directional velocity probe)	±5%
Calibrated with S-type or standard	±10%
Uncalibrated and inspected	±8%
Uncalibrated and uninspected	±20%
Airfoil	...
Calibrated	±5%
Uncalibrated	±20%
Flows (Steam and Water)	**Note (8)**
Flow nozzle	...
ASME PTC 6 (with flow straighteners)	...
Calibrated and inspected	±0.25%
Uncalibrated and inspected	±0.75%
Uncalibrated and uninspected	±2%
Pipe taps	...
Calibrated and inspected	±0.5% steam ±0.4% water
Uncalibrated and inspected	±2.2% steam ±2.1% water
Uncalibrated and uninspected	New plant: see above Existing plant: variable
Venturi	...
Throat taps	...
Calibrated and inspected	±0.5% steam ±0.4% water
Uncalibrated and inspected	±1.2% steam ±1.1% water
Uncalibrated and uninspected	New plant: see above Existing plant: variable
Orifice	**Note (9)**
Calibrated and inspected	±0.5% steam ±0.4% water
Uncalibrated and inspected	±0.75% steam ±0.7% water
Uncalibrated and uninspected	New plant: see above Existing plant: variable
Weir	±5%
Blowdown valve	±15%
Coriolis flowmeter (for liquid)	±0.1%

Table 4-2.6-1 Potential Instrumentation Systematic Uncertainty (Cont'd)

Instrument	Systematic Uncertainty [Note (1)]
Liquid Fuel Flow (Calibrated)	**...**
Flowmeter	...
Positive displacement meter	±0.5%
Turbine meter	±0.5%
Orifice (for larger pipes, uncalibrated)	±1%
Coriolis flowmeter	±0.1%
Weigh tank	±1%
Volume tank	±4%
Gaseous Fuel Flow	**Note (9)**
Orifice	...
Calibrated and inspected	±0.5%
Calibrated and uninspected	±2%
Uncalibrated and inspected	±0.75%
Turbometers	...
Non-self-correcting	±1%
Self-correcting	±0.75%
Coriolis flowmeter	±0.35%
Solid Fuel and Sorbent Flow	**...**
Gravimetric feeders	...
Calibrated with weigh tank	±2%
Calibrated with standard weights	±5%
Uncalibrated	±10%
Volumetric feeders	...
Belt	...
Calibrated with weigh tank	±3%
Uncalibrated	±15%
Screw, rotary valve, etc.	...
Calibrated with weigh tank	±5%
Uncalibrated	±15%
Weigh bins	...
Weigh scale	±5%
Strain gauges	±8%
Level	±10%
Impact meters	±10%
Residue Flow	**...**
Isokinetic dust sampling	±10%
Weigh bins	...
Weigh scale	±5%
Strain gauges	±8%
Level	±20%
Screw feeders, rotary valves, etc.	...
Calibrated with weigh tank	±5%
Uncalibrated	±15%
Assumed split (bottom ash/fly ash)	10% of total ash
Solid Fuel and Sorbent Sampling	**See ASME PTC 4-2013, Tables 4-3.6-2 and 4-3.6-3**
Stopped belt	±0%
Full cut	≥1%
"Thief" probe	≥2%
Time-lagged	≥5%
Liquid and Gaseous Fuel Sampling	**See ASME PTC 4-2013, Tables 4-3.6-4 and 4-3.6-5**
Flue Gas Sampling	**...**
Point-by-point traverse	See Section 7
Composite grid	See Section 7
Unburned Carbon (UBC) in Residue	**Note (10)**
Isokinetic dust sampling	±5%
"Thief" probe	±200%
Bottom ash	±50%
Bed drain	±20%
Fuel Handling and Storage	**−10% of moisture value**
Limestone handling and storage	+5% of moisture value
Residue	0
Flue Gas Analysis	**...**
Oxygen analyzer	...
Continuous electronic analyzer	±1% of span
Orsat analyzer	±0.2 points
Portable analyzer	±5% of reading ±2% of span
Calibrated on air	...
Calibrated on cal gas	...
Carbon monoxide	...
Continuous electronic analyzer	±20 ppm
Orsat analyzer	±0.2 points
Sulfur dioxide	...
Continuous electronic analyzer	±10 ppm
CEM electronic analyzer	±50 ppm
Oxides of nitrogen	...
Chemiluminescent	±20 ppm
CEM electronic analyzer	±50 ppm
Hydrocarbons	...
Flame ionization detector	±5%

Table 4-2.6-1 Potential Instrumentation Systematic Uncertainty (Cont'd)

Instrument	Systematic Uncertainty [Note (1)]
Electric Power	Note (11)
Voltage or current	...
Current transformer (CT), Class A/B	±0.3%
Voltage transformer (VT), Class A/B	±0.3%
Clamp-on measurements	±2%
Watts	...
Wattmeter, Class C	±0.5%
Humidity	...
Hygrometer	±2% RH
Sling psychrometer	±0.5 gradation
Weather station	Note (6)

NOTES:
(1) All systematic uncertainties are percent of reading unless noted otherwise.
(2) For thermocouples, error may be introduced depending on the method of correcting for a reference junction. Also, the algorithm for conversion of thermocouple millivolts to temperature may introduce errors.
(3) See ASME PTC 19.3 for applicability.
(4) NIST-traceable instruments have a systematic uncertainty equal to the accuracy of the calibration device. These systematic uncertainties do not include drift.
(5) See ASME PTC 19.2 for applicability.
(6) Systematic uncertainty shall be corrected for elevation and distance from weather station.
(7) These systematic uncertainties include user-induced errors such as probe location.
(8) Nozzles should be calibrated at the test Reynolds number or else ASME PTC 6 should be used for nozzle extrapolation. For uncalibrated devices, flow coefficients and uncertainties can be calculated in accordance with ASME PTC 19.5.
(9) Uncalibrated orifice uncertainty is generally not greater than beta ratio (d/D).
(10) The carbon content of all ash streams should be minimized.
(11) See ASME PTC 19.6 for applicability.

Prior to calibration, the pressure transducer range may be altered to more accurately match the process. However, the sensitivity to ambient temperature fluctuation may increase as the range is altered. Additional points will increase the accuracy but are not required. During calibration, the measuring point shall be approached from an increasing and decreasing manner to minimize the hysteresis effects.

Some pressure transducers allow the user to change the range once the transmitter is installed. The transmitters shall be calibrated at each range to be used during the test period.

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

4-3.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-2.2.2 and 4-2.3.1 for discussion on measurement classification and instrumentation categorization. Table 4-2.6-1 provides guidelines for typical systematic uncertainties for pressure measurements.

Class 1 primary parameters and variables shall be measured with 0.1% accuracy class pressure transmitters or equivalents that have a total calibrated uncertainty span of ±0.3% or better. Pressure transmitters should be temperature compensated. If temperature compensation is not available, the ambient temperature at the measurement location during the test period shall be compared to the temperature during calibration to determine if the decrease in accuracy is acceptable.

Class 2 primary parameters and variables shall be measured with 0.25% accuracy class pressure transmitters or equivalent that have a total uncertainty of ±0.5% or better of calibrated span. These pressure transmitters do not need to be temperature compensated.

Secondary variables can be measured with any type of pressure transmitter or equivalent device.

4-3.3 Recommended Pressure Measurement Devices

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

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

4-3.3.1 Absolute Pressure Transmitters

4-3.3.1.1 Application. Absolute pressure transmitters measure pressure referenced to absolute zero pressure. Absolute pressure transmitters shall be used on all measurement locations with a pressure equal to or less than atmospheric. Absolute pressure transmitters may also be used to measure pressures above atmospheric pressure.

4-3.3.1.2 Calibration. Absolute pressure transmitters can be calibrated using one of two methods. The first method involves connecting the test instrument to a device that develops an accurate vacuum at desired levels. Such a device can be a deadweight gauge in a bell jar referenced to zero pressure or a divider piston mechanism with the low side referenced to zero pressure.

The second method uses a suction-and-bleed control mechanism to develop and hold a constant vacuum in a chamber to which the test instrument and the calibration standard are both connected. The chamber shall be maintained at constant vacuum during instrument calibration. Other devices may be utilized to calibrate absolute pressure transmitters provided that the same level of care is taken.

4-3.3.2 Gauge Pressure Transmitters

4-3.3.2.1 Application. Gauge pressure transmitters measure pressure referenced to atmospheric pressure. To obtain absolute pressure, the test site atmospheric pressure shall be added to the gauge pressure. This test site atmospheric pressure shall be measured by an absolute pressure transmitter. Gauge pressure transmitters may be used only on measurement locations with pressures higher than atmospheric. Gauge pressure transmitters are preferred over absolute pressure transmitters in measurement locations above atmospheric pressure because they are easier to calibrate.

4-3.3.2.2 Calibration. Gauge pressure transmitters can be calibrated by an accurate deadweight gauge. The pressure generated by the deadweight gauge shall be corrected for local gravity, air buoyancy, piston surface tension, piston area deflection, actual mass of weights, actual piston area, and working medium temperature. If the above corrections are not used, the pressure generated by the deadweight gauge may be inaccurate. The actual piston area and mass of weights are determined each time the deadweight gauge is calibrated. Other devices may be utilized to calibrate gauge pressure transmitters provided that the same level of care is taken.

4-3.3.3 Differential Pressure Transmitters

4-3.3.3.1 Application. Differential pressure transmitters are used where flow is determined by a differential pressure meter, or where pressure drops in a duct or pipe must be determined.

4-3.3.3.2 Calibration. Differential pressure transmitters used to measure Class 1 primary parameters and variables shall be calibrated at line static pressure. Calibration at line static pressure is not required if information is available to describe the effect of such pressure on the transmitter and demonstrate compliance to the uncertainty requirements of para 4-2.2. Calibrations at line static pressure are performed by applying the actual expected process pressure to the instrument as it is being calibrated. Calibrations at line static pressure can be accomplished by one of the following methods:

(a) two highly accurate deadweight gauges
(b) a deadweight gauge and divider combination
(c) one deadweight gauge and one differential pressure standard

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

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

4-3.4 Absolute Pressure Measurements

4-3.4.1 Introduction. Absolute pressure measurements are pressure measurements that are below or above atmospheric pressure. Absolute pressure transmitters shall be used for these measurements. Typical absolute pressure measurements include ambient pressure.

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

4-3.4.2 Installation. Absolute pressure transmitters used for absolute pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and radio frequency interference (RFI). Transmitters shall be installed in the same orientation as when they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements shall be installed in accordance with manufacturer's specifications. In general, the following guidelines shall be used to determine transmitter location and placement of impulse tubing:

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

(b) Slope the impulse tubing at least 8 cm/m (1 in./ft) upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 8 cm/m (1 in./ft) downward from the transmitter toward the process connection for gas service.

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

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

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

In steam service, the sensing line shall extend at least 0.6 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

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

All vacuum measurement sensing lines shall slope continuously upward from the source to the instrument. The Code recommends using a purge system that isolates the purge gas while measuring the process. A continuous purge system may be used; however, it shall be regulated to have no influence on the reading. Prior to the test period, readings from all purged instrumentation shall be taken successively with the purge on and then with the purge off to prove that the purge air has no influence.

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

Once transmitters are connected to the process, a leak check shall be conducted. For vacuum measurements, the leak check is performed by isolating first the purge system and then the source. If the sensing line is free of leaks, the instrument reading will not change. For nonvacuum measurements, the leak check is performed using a leak detection fluid on the impulse tubing fittings.

Ambient pressure transmitters shall be installed in the same general area and at the same general elevation as the gauge pressure transmitters and shall be protected from air currents that could influence the measurements.

4-3.5 Gauge Pressure Measurements

4-3.5.1 Introduction. Gauge pressure measurements are pressure measurements that are at or above atmospheric pressure. These measurements may be made with gauge or absolute pressure transmitters. Gauge pressure transmitters are recommended since they are easier to calibrate and check in situ. Typical gauge pressure measurements include gas fuel pressure and process return pressure.

Caution shall be used with low-pressure measurements because they may enter the vacuum region at part-load operation.

4-3.5.2 Installation. Gauge pressure transmitters used for gauge pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters shall be installed in the same orientation as when they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements shall be installed in accordance with manufacturer specifications. In general, the following guidelines shall be used to determine transmitter location and placement of impulse tubing:

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

(b) Slope the impulse tubing at least 8 cm/m (1 in./ft) upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 8 cm/m (1 in./ft) downward from the transmitter toward the process connection for gas service.

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

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

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

In steam service, the sensing line shall extend at least 0.6 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

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

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

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

4-3.6 Differential Pressure Measurements

4-3.6.1 Introduction. Differential pressure measurements are used to determine the difference in static pressure between pressure taps in a primary device. Differential pressure transmitters shall be used for these measurements. Typical differential pressure measurements include the differential pressure of gas fuel or process return through a flow element or pressure loss in a pipe or duct. The differential pressure transmitter measures the pressure difference or pressure drop that is used to calculate the fluid flow.

4-3.6.2 Installation. Differential pressure transmitters used for differential pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters shall be installed in the same orientation as when they were calibrated. If the transmitter is mounted in a position other than that at which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements shall be installed in accordance with manufacturer specifications. In general, the following guidelines shall be used to determine transmitter location and placement of impulse tubing:

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

(b) Slope the impulse tubing at least 8 cm/m (1 in./ft) upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 8 cm/m (1 in./ft) downward from the transmitter toward the process connection for gas service.

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

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

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

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

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

In steam service, the sensing line shall extend at least 0.6 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid. Each pressure transmitter shall be installed with an isolation valve at the end of the sensing line upstream of the instrument. The instrument sensing line shall be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing line of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct. Differential pressure transmitters shall be installed utilizing a five-way manifold, as shown in Figure 4-3.6.2-1.

This manifold is recommended rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve. The vent valve acts as a telltale for leakage detection past the equalizing valves. Once transmitters are connected to process, a leak check shall be conducted. The leak check is performed using a leak detection fluid on the impulse tubing fittings. When a differential pressure meter is installed on a flow element located in a vertical steam or water line, the measurement shall be corrected for the difference in sensing line height and fluid head change. This measurement correction is required unless the upper sensing line is installed against a steam or water line inside the insulation down to where the lower sensing line protrudes from the insulation. The correction for the non-insulated case is shown in Figure 4-3.6.2-2.

For differential pressure transmitters on flow devices, the transmitter output is often an extracted square root value, unless the square root is applied in the plant control system. Care shall be taken to ensure the square root is applied only once.

4-4 TEMPERATURE MEASUREMENT

4-4.1 Introduction

This subsection presents requirements and guidance regarding temperature measurement. Recommended temperature measurement devices and their calibration and application are discussed. Given the state of the art and general practice, it is recommended that electronic temperature measurement equipment be used for primary measurements to minimize systematic and random error. Factors affecting the uncertainty of the temperature measurement include, but are not limited to, stability, environment, self-heating, parasitic resistance, parasitic voltages, resolution, repeatability, hysteresis, vibration, warm-up time, immersion or conduction, radiation, spatial variation, and data acquisition.

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

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

4-4.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-2.2.2 and 4-2.3.2 for discussion on measurement classification and instrumentation categorization. Table 4-2.6-1 provides guidelines for typical systematic uncertainties for temperature measurements.

Class 1 primary parameters and variables shall be measured with temperature measurement devices that have an instrument systematic uncertainty of no more than ±0.28°C (±0.50°F) for temperatures less than 93°C (200°F) and no more than ±0.56°C (±1.0°F) for temperatures greater than 93°C (200°F).

Class 2 primary parameters and variables shall be measured with temperature measurement devices that have an instrument systematic uncertainty of no more than ±1.7°C (±3.0°F).

Secondary variables shall be measured with temperature measurement devices that have an instrument systematic uncertainty of no more than ±2.8°C (±5.0°F).

4-4.3 Recommended Temperature Measurement Devices

Thermocouples, resistance temperature detectors, and thermistors are the recommended temperature measurement devices. Economic, application, and uncertainty factors shall be considered in the selection of the most appropriate temperature measurement device.

4-4.3.1 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 93°C (200°F). The maximum temperature is dependent on the type of thermocouple and sheath material used. Thermocouples may be used for measurements below 93°C (200°F) if caution is used. The thermocouple is a differential-type device.

The thermocouple measures the difference between the temperature at the measurement location in question and a reference temperature. The greater this difference, the higher the EMF from the thermocouple. Below 93°C (200°F), the EMF becomes low and subject to induced noise, causing increased systematic uncertainty and inaccuracy.

Figure 4-3.6.2-1 Five-Way Manifold

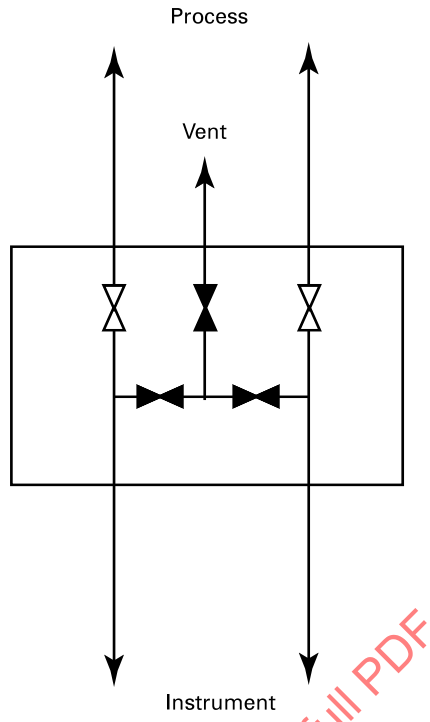
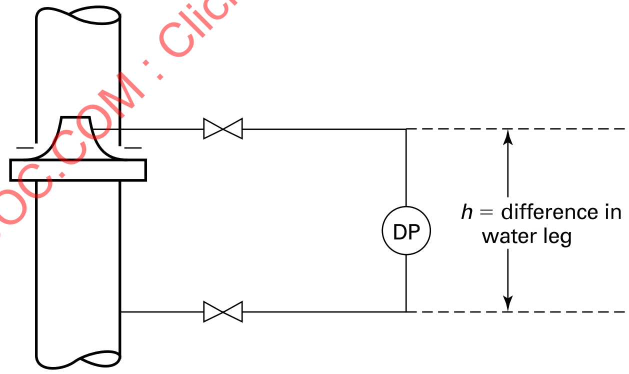


Figure 4-3.6.2-2 Water Leg Correction for Flow Measurement



GENERAL NOTE:
For upward flow: $\Delta p_{\text{true}} = \Delta p_{\text{meas}} + (\rho_{\text{amb}} - \rho_{\text{pipe}})(g/g_c)h$
For downward flow: $\Delta p_{\text{true}} = \Delta p_{\text{meas}} - (\rho_{\text{amb}} - \rho_{\text{pipe}})(g/g_c)h$
where

g = local gravitational force per unit mass; approximately 9.81 m/s^2 (32.17 ft/sec^2)
g_c = gravitational dimensional constant
= 1.00 $(kg\text{-}m)/(N\text{-}s^2)$ [32.17 $(lbm\text{-}ft)/(lbf\text{-}sec^2)$]
h = difference in water leg, m (ft)
Δp_{meas} = measured pressure difference, Pa (lbf/ft^2)
Δp_{meas} = true pressure difference, Pa (lbf/ft^2)
ρ_{amb} = fluid density at ambient conditions, kg/m^3 (lbm/ft^3)
ρ_{pipe} = fluid density at conditions within pipe, kg/m^3 (lbm/ft^3)

Measurement errors associated with thermocouples typically derive from the following primary sources:
(a) junction connection
(b) decalibration of thermocouple wire
(c) shunt impedance
(d) galvanic action
(e) thermal shunting
(f) noise and leakage currents
(g) thermocouple specifications
ASME PTC 19.3 describes the operation of the thermocouple as follows:

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

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

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

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

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

Thermocouples can be used effectively in high-vibration areas such as main or high-pressure inlet steam to the steam turbine. High-vibration measurement locations may not be conducive to other measurement devices. This Code recommends that the highest EMF per degree be used in all applications. NIST has recommended temperature ranges for each specific type of thermocouple (see subsection 1-4).

4-4.3.1.1 Class 1 Primary Parameters. Thermocouples used to measure Class 1 primary parameters shall have continuous leads from the measuring junction to the connection on the reference junction. These high-accuracy thermocouples shall have a reference junction at 0°C (32°F) or an ambient reference junction that is well insulated and calibrated.

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[1] ASME PTC 19.3-1974 (R2004), chapter 9, p. 106, para. 70.

[2] A. I. Dahl (1941), p. 1238; see subsection 1-4.

4-4.3.1.2 Class 2 Primary Parameters. Thermocouples used to measure Class 2 primary parameters can have junctions in the sensing wire. The junction of the two sensing wires shall be maintained at the same temperature. The reference junction may be at ambient temperature, provided the ambient is measured and the measurement is compensated for changes in the reference junction temperature.

4-4.3.1.3 Reference Junctions. The temperature of the reference junction shall be measured accurately using either software or hardware compensation techniques. The accuracy with which the temperature of the measuring junction is measured can be no greater than the accuracy with which the temperature of the reference junction is known. The reference junction temperature shall be held at the ice point or at the stable temperature of an isothermal reference. When thermocouple reference junctions are immersed in an ice bath consisting of a mixture of melting shaved ice and water, the bulb of a precision thermometer shall be immersed at the same level as the reference junctions and in contact with them. Any deviation from the ice point shall be promptly corrected.

Each reference junction shall be electrically insulated. When the isothermal–cold junction reference method is used, it shall employ an accurate temperature measurement of the reference sink acceptable to the parties to the test. When electronically controlled reference junctions are used, they shall have the capability to control the reference temperature to within ±0.03°C (±0.05°F). Particular attention shall be paid to the terminals of any reference junction, since errors can be introduced by temperature variation, material properties, or by wire mismatching.

The overall reference system shall be validated by calibration to have an uncertainty of less than ±0.1°C (±0.2°F). Isothermal thermocouple reference blocks furnished as part of digital systems may be used in accordance with this Code provided the accuracy is equivalent to the electronic reference junction. Commercial data acquisition systems employ a measured reference junction, and the accuracy of this measurement is incorporated into the manufacturer's specification for the device. The uncertainty of the reference junction shall be included in the calculation of the measurement uncertainty to determine if the measurement meets the requirements of this Code.

4-4.3.1.4 Thermocouple Signal Measurement. Many instruments are available to measure the output voltage. The use of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter. Use of Provisional Low Temperature Scale of 2000 (PLTS-2000) software compensation techniques is recommended for thermocouple signal conversion.

4-4.3.2 Resistance Temperature Detectors (RTDs). Resistance temperature detectors (RTDs) may be used in testing from any low temperature to the highest temperature allowed by the RTDs' mechanical configuration and the method by which they were manufactured. RTDs can measure temperatures from −270°C to 850°C (−454°F to 1,562°F). ASTM E1137 provides standard specifications for industrial platinum resistance thermometers that include requirements for manufacture, pressure, vibration, and mechanical shock to improve the performance and longevity of these devices.

Measurement errors associated with RTDs typically derive from the following primary sources:

(a) self-heating
(b) environmental factors
(c) thermal shunting
(d) thermal EMF
(e) instability
(f) immersion

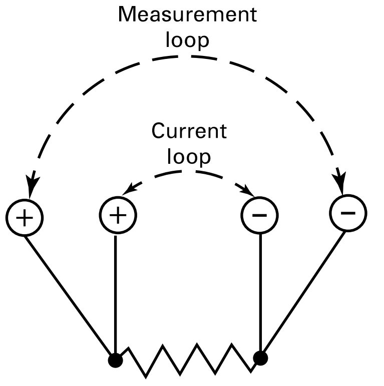
RTDs are considered a more linear devices than thermocouples. RTDs are more susceptible to vibrational applications. As such, Code users shall consider RTD stability when specifying and applying these measurement devices. Field verification techniques shall be used to demonstrate that the stability of the device is within the uncertainty requirements of para. 4-4.2.

4-4.3.2.1 Class 1 Primary Parameters. Class 1 primary parameters shall be measured with grade A four-wire platinum RTDs, as shown in Figure 4-4.3.2.1-1, illustration (a), if they can be shown to meet the uncertainty requirements in para. 4-4.2.

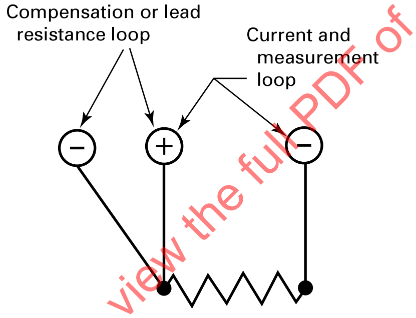
4-4.3.2.2 Class 2 Primary Parameters. Class 2 primary parameters shall be measured with grade A three-wire platinum RTDs, as shown in Figure 4-4.3.2.1-1, illustration (b), if they can be shown to meet the uncertainty requirements in para. 4-4.2. The four-wire technique is preferred to minimize effects associated with lead wire resistance due to dissimilar lead wires.

4-4.3.2.3 RTD Signal Measurement. Many instruments are available to measure output resistance. The use of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter. It is recommended that the Callandar−Van Dusen equation be used for curve fitting the RTD signal conversion. The values

Figure 4-4.3.2.1-1 Three- and Four-Wire RTDs



(a) Four-Wire RTD



(b) Three-Wire RTD

for the coefficients α, β, and δ shall be taken from the calibration coefficients. RTDs shall be calibrated in accordance with the methods detailed in NIST Technical Note 1265, subsection 4-6.

4-4.3.3 Thermistors. Thermistors are constructed of a ceramic-like semiconducting material that acts as a thermally sensitive variable resistor. This device may be used on any measurement below 149°C (300°F). Above this temperature, the signal is low and susceptible to error from current-induced noise. Although positive temperature coefficient units are available, most thermistors have a negative temperature coefficient (TC); that is, unlike an RTD, their resistance decreases with increasing temperature. The negative TC can be as large as several percent per degree Celsius, allowing the thermistor circuit to detect minute changes in temperature that could not be observed with an RTD or thermocouple circuit. As such, the thermistor is best characterized for its sensitivity, while the thermocouple is the most versatile and the RTD the most stable.

Measurement errors associated with thermistors typically derive from the following primary sources:

(a) self-heating
(b) environmental factors
(c) thermal shunting
(d) recalibration
(e) instability
(f) immersion

Due to the high resistivity of thermistors, the four-wire resistance measurement is not required for thermistors as it is for RTDs. The measurement lead resistance produces an error magnitude that is lower than the equivalent RTD error. Thermistors are generally more fragile than RTDs and thermocouples and shall be carefully mounted and handled in accordance with manufacturer specifications to avoid crushing or bond separation.

4-4.3.3.1 Thermistor Signal Measurement. Many instruments are available to measure output resistance. The use of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter. The Steinhart–Hart equation for curve fitting should be used for thermistor signal conversion. The values for coefficients A, B, and C shall be taken from the calibration coefficients. Thermistors shall be calibrated in accordance with the methods detailed in NIST Technical Note 1265, subsection 4-6.

4-4.4 Calibration of Primary Parameter Temperature Measurement Devices

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

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

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

4-4.5 Temperature Scale

The Provisional Low Temperature Scale of 2000 (PLTS-2000) is realized and maintained by NIST to provide a standard scale of temperature in the United States.

Temperatures on the PLTS-2000 can be expressed in terms of International Kelvin Temperatures, represented by the symbol T_{2000}, or in terms of International Celsius Temperatures, represented by the symbol t_{2000}–. T_{2000} values are expressed in units of kelvin (K), and t_{2000} values in degrees Celsius (°C). The relation between T_{2000} and t_{2000} is

$$t_{2000} = T_{2000} - 273.15$$

Values of Fahrenheit temperature, t_f, in degrees Fahrenheit (°F), are obtained from the conversion formula

$$t_f = \left(\frac{9}{5}\right)t_{90} + 32$$

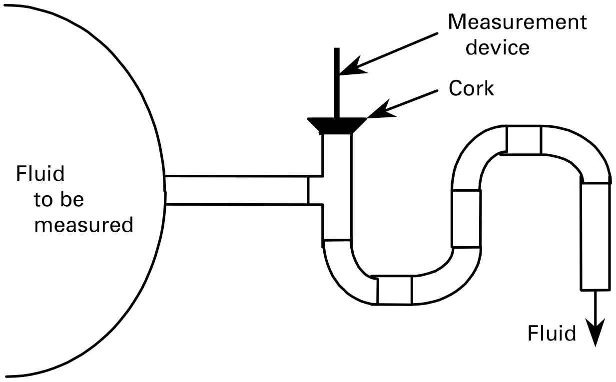
The PLTS-2000 was designed so that its temperature values very closely approximate Kelvin thermodynamic temperature values. PLTS-2000 temperatures are defined in terms of equilibrium states of pure substances (defining points), interpolating instruments, and equations that relate the measured property to T_{2000}. The defining equilibrium states and their assigned temperature values are listed in NIST Technical Note 1265 and ASTM MNL 12.

4-4.6 Typical Applications for Temperature Measurement

4-4.6.1 Temperature Measurement of Fluid in a Pipe or Vessel. Temperature measurement of fluid in a pipe or vessel is accomplished by installing a thermowell. A thermowell is a pressure-tight device that protrudes from a pipe or vessel wall into the contained fluid. Thermowells are designed to protect the temperature measurement device from harsh environments, high pressure, and flows.

A thermowell can be installed into a system by a threaded, socket-welded, or flanged connection and has a bore extending to near the tip to facilitate the immersion of a temperature measurement device. Thermowells shall be designed and installed to meet the requirements of ASME PTC 19.3 TW. The thermowell bore shall be sized to allow adequate

Figure 4-4.6.2-1 Flow-Through Well



clearance between the temperature measurement device and the well. Often the temperature measurement device can bend, making insertion of the device difficult.

The bottom of the thermowell bore shall be the same shape as the tip of the temperature measurement device. Tubes and wells shall be as thin as possible, consistent with safe stress and other ASME PTC 19.3 TW requirements. The inner diameters of the wells shall be clean, dry, and free from corrosion or oxide. The bore shall be cleaned with high-pressure air prior to insertion of the device.

Unless limited by design considerations, the temperature sensor shall be immersed in the fluid at least 75 mm (3 in.) but not less than one-quarter of the pipe diameter. If the pipe is less than 100 mm (4 in.) in diameter, the temperature sensor shall be arranged axially in the pipe by inserting it into an elbow or tee. If such fittings are not available, the piping shall be modified to render this possible.

The thermowell shall 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, the second thermowell shall be installed on the opposite side of the pipe and not directly downstream of the first thermowell.

When the temperature measurement device is installed, it shall be spring-loaded to ensure positive thermal contact between the temperature measurement device and the thermowell.

For Class 1 primary parameter measurements, the portion of the thermowell, or lag section, protruding outside the pipe or vessel shall be insulated, along with the device itself, to minimize conduction losses. The locations at which Class 1 primary temperature measurements are taken for use in determining enthalpy shall be as close as possible to the points at which the corresponding pressures are to be measured.

For measuring the temperature of desuperheated steam, the thermowell shall be located where the desuperheating fluid has thoroughly mixed with the steam. This can be accomplished by placing the thermowell downstream of two elbows in the steam line, past the desuperheating spray injection point.

4-4.6.2 Temperature Measurement of Low-Pressure Fluid in a Pipe or Vessel. As an alternative to installing a thermowell in a pipe, if the fluid is at low pressure, the temperature measurement device can be installed directly into the pipe or vessel, or flow-through wells may be used.

The temperature measurement device can be installed directly into the fluid using a bored-through-type compression fitting. The fitting shall be an appropriate size to clamp onto the device. A plastic or Teflon-type ferrule is recommended so that the device can be removed easily and used elsewhere. The device shall protrude through the boundary layer of the fluid. The device shall not protrude so far that fluid flow causes it to vibrate. If the fluid is a hazardous gas such as natural gas or propane, the fitting shall be checked for leaks.

A flow-through well is shown in Figure 4-4.6.2-1. This arrangement is applicable only for water in a cooling system where the fluid is not hazardous and can be disposed of inexpensively. The principle of the flow-through well is to allow the fluid to flow out of the pipe or vessel and over the tip of the temperature measurement device.

4-4.6.3 Temperature Measurement in a Duct. Measurement of the fluid temperature in a duct requires several measurement points to minimize the uncertainty effects of temperature gradients. Typically, the duct pressures are low or negative and thermowells or protection tubes are not needed. A long-sheathed thermocouple or an unsheathed thermocouple attached to a rod is sufficient.

The number of required measurement points 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 average temperature value. 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 velocity profile, the temperature gradients, and the time variation of the readings. The parties to the test shall, to the extent practical, locate the measurement plane at a point of uniform temperatures and velocities. Points shall be located every 0.84 m^2 (9 ft^2) or less, with a minimum of 4 points and a maximum of 36 points.

ASME PTC 19.1 describes the method of calculating the uncertainty of the average of multiple measurements that vary with time.

For circular ducts, the measurement points shall be installed in two diameters 90 deg from each other, as shown in Figure 4-4.6.3-1. This figure also shows the method of calculating the measurement-point spacing. The point spacing is based on locating the measurement points at the centroids of equal areas.

For square or rectangular ducts, the same concept (locating the measurement points at centroids of equal areas) shall be used. The measurement points shall be laid out in a rectangular pattern that takes into account the horizontal and vertical temperature gradients at the measurement cross section. The direction with the highest temperature gradient shall have the closest point spacing.

4-5 SOLID FLOW MEASUREMENT

Solid-fuel, sorbent, and residual flow measurement is difficult because of solid material variability. ASME PTC 4 provides recommended methods for measuring solid flow, sampling solids, and estimating associated systematic errors. Sections of ASME PTC 4 have been extracted and modified here for relevance to gasifier feed and residue measurement. Numerous methods are referenced in paras. 4-5.1 and 4-5.2 for measuring flow of solids, sorbent, and residue and for estimating systematic error for these flow measurements. Solid-fuel-, sorbent-, and residue-sampling methods, sample size, sample collection, and associated sampling systematic error are referenced in paras. 4-5.3 and 4-5.4.

This subsection addresses the following four subjects:

(a) solid-fuel and sorbent flow measurement, including methods of measurement and of estimating systematic error

(b) solid-fuel and sorbent sampling

(c) residue splits (i.e., amount of by-product ash and slag), including methods of measurement and of estimating systematic error

(d) residue sampling (i.e., sampling of by-product ash and slag)

4-5.1 Solid-Fuel and Sorbent Flow Measurement

Accurate measurement of solid flow is difficult because of solid material variability.

4-5.1.1 Method of Measurement. Numerous methods are available to measure the flow of solids. Typical methods include gravimetric feeders, volumetric feeders, isokinetic particulate sampling, weigh bins or timed weights, and impact meters. Reducing uncertainty of any of these methods to less than 10% requires extensive calibration against a reference. The calibration can involve collecting solid material into a container that can be weighed. For example, the output of a gravimetric feeder can be directed to a container suspended by load cells, and the indicated feed rate can be compared to the timed catch in the container.

It is even more difficult to assess the accuracy of volumetric feeders. This assessment requires assumptions about the volume of material passed per revolution and the density of the material. The rotor may not be full, the density may vary as a result of size distribution or other factors, and all parameters may vary over time.

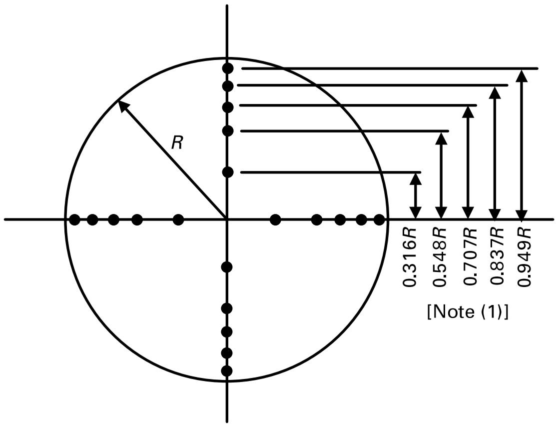
Calibration of solid flow measurement devices shall be conducted just prior to the performance test and at frequent intervals to minimize systematic error.

4-5.1.2 Estimate of Systematic Error. The systematic error from a solid flow measurement device is one of the most difficult parameters to determine. Code users shall consider systematic error from instrument response variation resulting from size distribution, uneven loading on the weigh scale, or varying densities. Table 4-2.6-1 provides typical systematic uncertainties for solid flow measurements.

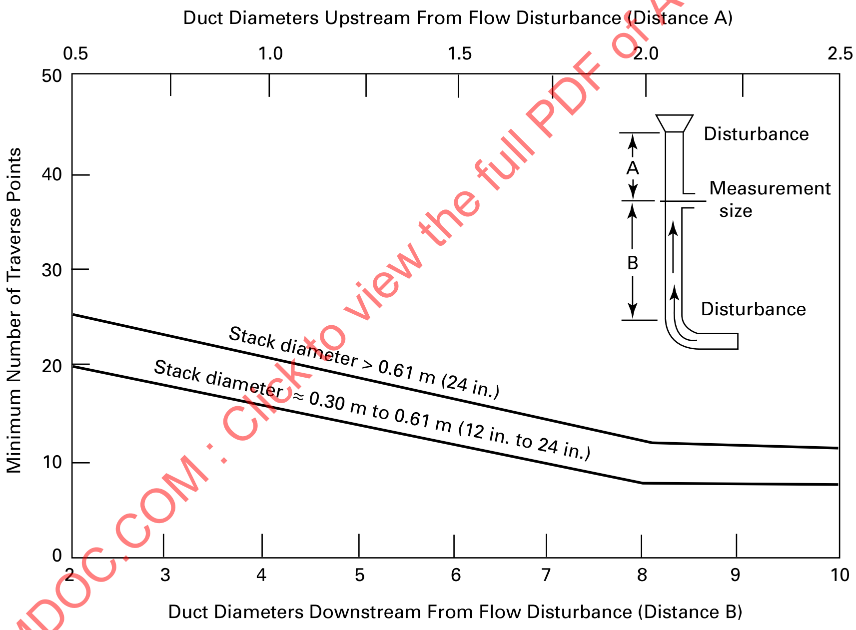
4-5.2 Solid-Fuel and Sorbent Sampling

The methods of solid-fuel and sorbent sampling shall be agreed on by all parties to the test and shall be described in the test report. An appropriate uncertainty shall be assigned for the test-sampling method.

Figure 4-4.6.3-1 Duct Measurement Points



Cross Section of Circular Gas Passage



NOTE: (1) Dots indicate location of sample points. To calculate the distance from the sampling point to center of pipe, use the following equation:

$$r_p = R\sqrt{\frac{2(2p-1)}{n}}$$

where

n = total number of points
= $\Pi \times R^2/A_{c\max}$, rounded to the next multiple of 4, but no fewer than 4 and no more than 36
$A_{c\max}$ = maximum area per centroid
= 0.8 m^2 (9 ft^2)
p = sampling point number, numbered from the center outward; all four points on the same circumference have the same number
R = radius of duct (in the same units as r_p), m (ft)
r_p = distance from center of duct to point p, m (ft)

For example, with 20 total points, the radius of point r_3 is

$$\begin{aligned} r_3 &= R \times \{[2 \times (2 \times 3 - 1)]/20\}^{1/2} \\ &= R \times 0.5^{1/2} \\ &= 0.707R \end{aligned}$$

The samples shall be representative of the respective solid streams. In addition, the variation in the composition of solids directly affects the uncertainty of the result. In this subsection, the methods used to determine variances, standard deviations, and precision indices for test samples are discussed. The estimation of systematic error is also addressed.

Slurry density can be measured using methods described in ASTM D1480, ASTM D4052, or ASTM D7042.

4-5.2.1 Methods of Solid Sampling. Fuel, sorbent (if applicable), and residue solids shall be sampled from a flowing stream as near to the gasifier as practical to ensure that samples are representative. If it is not possible or practical to sample near the gasifier, a time lag may be incurred between when the sample is taken and when the flowing material is injected into or removed from the gasifier. This time lag shall be determined based on estimated flow rates between the sample location and the gasifier. It is important that the time-lagged sample be representative of the actual material injected into or removed from the gasifier. Thief sampling, the process of taking a partial cut sample from silos or hoppers, typically results in large associated systematic errors. However, this method may be acceptable for sampling sorbent, which is homogenous in most cases. Parallel streams, such as coal feed with belt feeders, have the potential for stream-to-stream variation due to different flow rates, particle sizes, and chemical composition. Therefore, unless the chemical constituents of the samples are shown to be uniform, samples shall be taken from each of the parallel streams and combined. If the flows for the parallel streams are unequal, the sample amount of each parallel stream shall be flow-weighted for the composite sample. The flow for each stream shall be continuous throughout the test.

Depending on the costs associated with laboratory analyses and the availability of a historical database, different analysis procedures may be selected for different sample constituents (i.e., coal, sorbent, residue). Tables 4-5.2.1-1 and 4-5.2.1-2 identify the ASTM procedures that may be used for analysis.

Fuel, sorbent, and residue samples collected upstream of silos, tanks, or hoppers typically have larger systematic errors than samples collected downstream. Sampling upstream of silos, tanks, and hoppers is classified as an alternative procedure because of the possibility that the samples will not be representative of the fuel fired during the test. Alternative procedures shall not be used for acceptance tests. If alternate procedures are used for other test purposes, the parties to the test shall assign appropriate systematic errors.

4-5.2.2 Sample Size. Sample size is based on several factors, including size distribution, chemical composition variability, feed methods, flow capacities, and number of samples. In general, larger samples result in lower variances. However, large samples must be reduced to a size suitable for laboratory analysis; therefore, as sample size increases, so do sample preparation costs. For manual sampling of coal or sorbent, samples typically weighing 1 kg to 4 kg (2 lb to 8 lb) are collected. For automatic sampling devices, much larger samples may be collected.

The weight of the individual test sample shall be equal to or greater than the weight of the samples used from a historical database. Otherwise, the variance of the test data could be greater than the variance of the historical data.

As stated previously, it is important that a sample represent the average composition of the actual stream as closely as possible. In addition, since there is a direct correlation between the individual sample weight and variance, individual samples shall weigh enough to minimize the variance.

Generally, a complete cross section is the best representation of the flowing stream. This criterion, however, can mean different sample size requirements for different types of solid streams. For example, a particulate residue stream sample shall be obtained from isokinetic particulate sampling. This sample is typically very small. However, assuming it is taken from a complete and controlled traverse of the duct, the sample is representative. In this case, the small quantity does not negatively affect the reliability of the sample.

Sorbent is another material for which a small sample may be acceptable. The size of the samples may vary, but the chemical composition is unlikely to vary across the size range or among different lots of sorbent. Therefore, a small sample can be representative of the entire sorbent feed during the test.

The parties to the test shall agree on the sample size. They shall use the previously noted factors, combined with good engineering judgment, costs, and desired analytical accuracy, to determine the proper sample size. ASTM D2234, Table 2 provides more information about sample size.

4-5.3 Residue Flow Measurement and Splits

The amount of residue (by-product ash and slag) leaving the gasifier boundary is a required value for determining the sensible heat loss in the residue streams and the weighted average of unburned carbon in the residue. The residue is periodically or continuously removed from mechanical dust collector rejects, scrubbers, cyclones, and candle filters, and from particulate and slag leaving the unit.

Table 4-5.2.1-1 Typical ASTM Test Uncertainties for Properties of Coal and Coke

Property or Constituent of Coal or Coke	Analysis Procedure	Test Uncertainty [Note (1)]
Air-dry moisture [Note (2)]	ASTM D3302	±0.31% for bituminous coals ±0.33% for subbituminous coals ±0.3% for coke
Ash content	ASTM D3172-13, proximate or ultimate analysis	See ASTM D3174 [Note (3)]
	ASTM D3174	±0.15% for bituminous coals with no carbonate ±0.25% for subbituminous coals with carbonate ±0.5% for coals with more than 12% ash with carbonate and pyrite
	ASTM D7582, proximate analysis, automated method	$0.07 + 0.115x$ [Note (4)]
Carbon	ASTM D3172-13, ultimate analysis	See ASTM D5373-16 [Note (3)]
	ASTM D5373-16	±1.25% (1 − %H_2O/100) [Notes (5), (6)]
Chlorine	ASTM D2361	
Fixed carbon	ASTM D3172-13, proximate analysis	100 − (% moisture + % ash + % volatile matter)
	ASTM D7582, proximate analysis, automated method	100 − (% moisture + % ash + % volatile matter)
HHV, gross calorific value	ASTM D5865	0.16 MJ/kg (69 Btu/lb), dry basis for anthracite/bituminous 0.14 MJ/kg (59 Btu/lb), dry basis for subbituminous/lignite
Hydrogen	ASTM D3172-13, ultimate analysis	See ASTM D5373-16
	ASTM D5373-16	±0.15% (1 − % H_2O/100) [Notes (5), (6)]
Major and minor elements in coal combustion residues [Note (7)]	ASTM D3682-13	Varies
Moisture	ASTM D3172-13, proximate or ultimate analysis	See ASTM D3173 [Note (3)]
	ASTM D3173	±0.15% for fuels <5% moisture [Note (8)] ±0.25% for fuels >5% moisture [Note (8)]
	ASTM D7582, proximate analysis, automated method	$0.12 + 0.017x$ [Note (4)]
Nitrogen	ASTM D5373-16, method B	±0.09% (1 − % H_2O/100) [Note (6)]
Oxygen	ASTM D3172-13, ultimate analysis	100% − (sum of the other components of the ultimate analysis) [Note (3)]
Sulfur	ASTM D3172-13, ultimate analysis	See ASTM D4239-18e1 [Note (3)]
	ASTM D4239-18e1	±0.5% for fuels <2% sulfur ±0.1% for fuels >2% sulfur ±0.03% for coke ±0.05% for bituminous ±0.07% subbituminous and lignite
Volatile matter	ASTM D3172-13, proximate analysis	See ASTM D3175
	ASTM D7582, proximate analysis, automated method	$0.31 + 0.0235x$ [Note (4)]

NOTES:
(1) All test uncertainties are absolute unless otherwise indicated.
(2) This property is not applicable to coal–water slurry.
(3) See ASTM D3172-13 for repeatability of component values from ultimate analyses.
(4) x = mean value of the concentration measurements.
(5) These estimates are based on repeatable tests.
(6) Sample must be larger than 100 mg (0.00022 lb).
(7) These elements may include aluminum oxide, calcium oxide, ferric oxide, magnesium oxide, potassium oxide, silicon oxide, sodium oxide, and titanium oxide.
(8) These estimates are valid for samples with 1% to 21% moisture.

Table 4-5.2.1-2 Typical Systematic Uncertainties for Limestone Properties Determined From ASTM C25, Test Method 31

Limestone Property	Typical Systematic Uncertainty [Note (1)]
Calcium oxide	±0.16%
Magnesium oxide	±0.11%
Free moisture	±10% of measured value
Inert content by difference	±5% of measured value

NOTE: (1) All systematic uncertainties are absolute unless otherwise indicated.

4-5.3.1 Method of Measurement. The calculated total residue mass flow rate, which is based on the weight of material collected over a period of time, is often used because it is typically more accurate than the direct flow-rate measurement. Therefore, the percent of the total residue that leaves each location shall be determined. One of the following methods may be used to determine the residue split between the various locations:

(a) The residue mass flow rate and residue-stream composition shall be measured at each location.

(b) The residue mass flow rate and residue-stream composition shall be measured at one or more locations (usually the locations with the highest loading), and the quantities at the other locations shall be calculated by difference. Where there is more than one unmeasured location, the split between these locations shall be estimated, or the residue percentage leaving each location may be estimated based on the typical results for the type of fuel and gasification method.

Before the test, the parties to the test shall agree and document which streams will be measured and what values will be used for any estimated splits.

The mass flow rate of residue discharged in a dry state may be determined from weigh bins or timed weights (e.g., the number of rotations of rotary feeders, screw speed, or impact meters). See Section 7 for considerations regarding calibration and sources of uncertainty.

Determining the mass flow rate of residue discharged from sluice systems (wet ash and slag) is even more difficult than determining the flow rate of dry material. Generally, the total discharge flow must be captured in bins or trucks, the free-standing water drained off, and the bin or truck weighed and compared against the tare weight. Since residue leaves the unit in a dry state, moisture content of the sample must be determined, and the measured wet mass flow rate corrected for moisture. The quantity of slag discharged from sluice systems and lock hoppers is generally small, so this residue rate can be measured every 4 hr.

4-5.3.2 Estimating Systematic Error. When splits are estimated, a mean value shall be selected such that the same positive and negative estimate of systematic error can be used. A systematic error that would produce a split of less than zero or more than 100% shall not be used. Where mass flow is determined from volumetric devices, considerations include repeatability of the fullness of the volume chamber and density and size distribution of the material.

4-5.4 Residue Sampling

Samples shall be taken from the various output streams of gasification units that contain ash. These streams typically include slag, particulate, and bottom ash. Obtaining representative samples from each of these streams can be challenging. The best method for obtaining a representative particulate sample is to isokinetically sample the ash in the gas upstream of as many ash collection hoppers as possible. This method provides a sample that has a representative cross section of particle size and carbon content. It also ensures that the sample is representative of the testing period.

Obtaining a representative sample of bottom ash is also challenging because bottom ash often contains large, unevenly distributed chunks of residue. For example, a single sample may contain a chunk of coal not typically found in other samples or it may have no carbon content. Multiple samples and several analyses of each sample may be required to obtain representative results.

4-5.4.1 Systematic Error for Residue Sampling. There is an associated systematic error for the ash collected from the bottom ash, slag, or fines, or from any hoppers located upstream of the particulate collection point. If multiple samples are analyzed using multiple analyses for the bottom ash, slag, or fines, the resulting information can be used to estimate the associated systematic error. The sampling procedure shall also be reviewed to determine if other sources of systematic error are present.

4-5.4.2 Slag-Sampling Methods. For slag, the preferred sample-collection method is to take the sample with a multi-holed probe extending the width of the sluice stream. EPRI EA-3610 illustrates a multihole probe. Alternatively, a portion of the slag may be diverted to a collection device where the slag can settle before the sample is taken.

4-5.4.3 Residue Streams Excluded From Sampling. In some cases, the parties to the test may decide not to sample a residue stream that does not significantly contribute to energy loss. An example of such a stream is slag that contains insignificant amounts of sensible heat and unburned combustible material. Alternatively, samples of slag can yield a result that is no more certain than using an assumed value. If a solid stream is not sampled, an appropriate systematic error shall be assigned and the historical evidence documented in the final report.

4-6 LIQUID FLOW MEASUREMENT

For information about flow-measuring devices, refer to ASME MFC-3M for differential measuring devices (orifice plates, venturis, and nozzles) and ASME PTC 19.5 for all other flow measurements. Table 4-2.6-1 provides guidelines for typical systematic errors for liquid flow measurements.

4-6.1 Water

4-6.1.1 Water Flow. Water flows can be measured more accurately than steam flows. Whenever possible, it is best to configure the tests so that water flows are measured and used to calculate steam flows. Flow is usually determined with a mass (Coriolis) flowmeter or with a differential pressure meter using two independent differential pressure instruments.

4-6.1.2 Class 1 Flow-Measuring Devices. The flow section containing a throat tap nozzle as described in ASME PTC 6 is recommended for the Class 1 primary flow measurements when the test Reynolds number is greater than the maximum calibrated Reynolds number.

4-6.1.3 Other Flow-Measuring Devices. Information relative to the construction, calibration, and installation of other differential flow-measuring devices appears in ASME MFC-3M. For meters other than differential pressure devices, refer to ASME PTC 19.5. Meters other than differential pressure devices can be used for Class 2 and secondary flow measurements, and can also be used for Class 1 primary flow measurements when Reynolds number extrapolation is not required.

(a) Class 1 primary flow measurement devices require calibration.

(b) For Class 2 primary and secondary flows, the appropriate reference coefficient for the device given in ASME MFC-3M may be used.

4-6.1.4 Water Flow Characteristics. Flow measurements shall not be undertaken unless the flow is steady or fluctuates only slightly with time. Fluctuations in the flow shall be suppressed before the beginning of a test by careful adjustment of flow and level controls or by introducing a combination of conductance (e.g., pump recirculation) and resistance (e.g., throttling the pump discharge). Hydraulic damping devices on instruments do not eliminate errors due to pulsations and, therefore, shall not be used.

While passing through the flow-measuring device, the water shall not flash into steam. To avoid cavitation, the minimum throat static pressure shall be higher than the saturation pressure corresponding to the temperature of the flowing water by at least 20% of the throat velocity head.

4-6.2 Liquid Fuel and Hydrocarbon Products

4-6.2.1 General. Liquid fuel flows shall be measured using flowmeters that are calibrated throughout the Reynolds number range expected during the test using the actual flow. For volume flowmeters, the temperature of the fuel shall also be accurately measured to correctly calculate the flow. Table 4-6.2-1 lists individual laboratory test repeatability criteria for fuel oil property measurements.

4-6.2.2 Positive Displacement Oil Flowmeter. Use of oil flowmeters is recommended without temperature compensation. The effects of temperature on fluid density can be accounted for by calculating the mass flow based on the specific gravity at the flowing temperature.

Fuel analyses shall be completed on samples taken during testing. The lower and higher heating value and specific gravity of the fuel shall be determined from these fuel analyses. The specific gravity shall be evaluated at three temperatures that cover the range of temperatures measured during testing. The specific gravity at flowing temperatures shall then be determined by interpolating between the measured values to the correct temperature.

An evaluation of the variability of heating value shall be made to determine the impact on the test uncertainty. The number of samples required during the test is dependent upon conforming to uncertainty requirements. 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 shall choose a certified laboratory. ASTM provides guidelines for typical lab-to-lab reproducibility. In general, the systematic uncertainty is taken as one-half the reproducibility.

Table 4-6.2-1 Typical ASTM Standard Test Systematic Uncertainty for Fuel Oil Properties

Fuel Oil Property	Analysis Procedure	ASTM Standard Test Systematic Uncertainty [Note (1)]
API gravity	ASTM D1298	0.25 deg API for opaque (heavy oil) 0.15 deg API for transparent (distillate)
Ash	ASTM D482-19	0.003 for fuels <0.08% ash 0.012 for fuels of 0.08% to 0.18% ash
Carbon	ASTM D5291-16 [Note (2)]	$0.009(x + 48.48)$ [Note (3)]
Heating value	ASTM D240-19 [Note (4)]	0.20 MJ/kg (86 Btu/lb)
	ASTM D4809-18	0.14 MJ/kg (59 Btu/lb), all fuels
Hydrogen	ASTM D5291-16 [Note (2)]	$0.1157(x^{0.5})$ [Note (3)]
Nitrogen	ASTM D3228-19, Kjeldahl method	$0.095(\text{concentration})^{0.5}$
	ASTM D5291-16 [Note (2)]	$0.1670x$ [Note (3)]
Sulfur	ASTM D1552-16e1, high-temperature method	0.05(concentration)
	ASTM D2622-16, X-ray fluorescence	$0.02651(\text{concentration})^{0.9}$
	ASTM D4294-03, X-ray fluorescence	0.02894(concentration + 0.1691)
Water	ASTM D95-13(2018)	0.1% for fuels <1% water 5% of measured value for >1% water

NOTES:
(1) All values are standard ASTM procedure repeatability.
(2) ASTM D5291-16 test methods were tested on samples with the following component concentrations:
  (a) carbon: 75% mass to 87% mass
  (b) hydrogen: 9% mass to 16% mass
  (c) nitrogen: 0.75% mass to 2.5% mass
(3) x = mean value of concentration measurements.
(4) ASTM D240-19 covers the determination of the heat of combustion of liquid hydrocarbon fuels ranging in volatility from that of light distillates to that of residual fuels.

4-7 STEAM FLOW MEASUREMENT

Table 4-2.6-1 provides guidelines for typical systematic errors for steam flow measurements.

4-7.1 Steam Flow Characteristics

In passing through the flow-measuring device, the steam must remain superheated. For steam lines with desuperheaters, the flow section shall be installed ahead of desuperheaters. The total flow is determined by the sum of steam flow and the desuperheater water flow.

4-7.2 Secondary Steam Flow Measurements

The calculation of steam flow through a nozzle, orifice, or venturi shall be based on upstream conditions of pressure, temperature, and viscosity. To avoid the disturbing influence of a thermowell located upstream of a primary element, downstream pressure and temperature measurements can be used to determine the enthalpy of the steam, which is assumed to be constant throughout a well-insulated flow measurement section. Based on this enthalpy and the upstream pressure, the desired upstream properties can be computed from the steam tables.

4-7.3 Two-Phase Steam-Water Mixtures

There are instances when it is desirable to measure the flow rate of a two-phase mixture. ASME PTC 12.4 describes methods for measurement of two-phase flow.

4-8 GAS FLOW MEASUREMENT

Oxygen, gaseous auxiliary fuel, and syngas flows shall be measured using differential measurement devices in compliance with ASME MFC-3M or other flow devices in compliance with ASME PTC 19.5. The accuracy of these devices shall be determined by uncertainty analysis. Measurements used to determine the mass flow rate (e.g., fuel analysis to determine density), static and differential pressures, temperature, and frequency (for turbine meters) shall be within an uncertainty range to meet the requirements set by ASME MFC-3M or ASME PTC 19.5. Table 4-2.6-1 provides guidelines for typical systematic errors for gas flow measurements.

The quantity of gas is determined at reference conditions. The reference conditions shall be clearly identified prior to the tests or during the contract stages. The quantity may be expressed in terms of mass instead of volume, although the actual volume (not corrected to reference conditions) that flows through the installation is needed for operational and contractual or legal metrology purposes. The flows are corrected with measured specific gravities, temperatures, and pressures to give absolute syngas volumetric flow rates in normal meter cubed per hour (Nm^3/h) [standard cubic feet per minute (scfh)].

For definitions of gaseous fuel heating values, see ASTM D3588.

4-8.1 Digital Computation of Gas Flow Rate

Mass flow rate as shown by flow computer is not acceptable without showing intermediate results and the data that is used for the calculations. Intermediate results for an orifice include the discharge coefficient, corrected diameter for thermal expansion, expansion factor, etc. Raw data includes static and differential pressures and temperature. For a turbine meter, intermediate results include the turbine meter constant(s) used in the calculation and how it was determined from the calibration curve of the meter. Data includes frequency, temperature, and pressure. For both devices, gas analysis and the intermediate results used in the density calculation are required. The methods described in ASTM D1945 shall be used to analyze natural gas, and the methods described in ASTM D7833 shall be used to analyze syngas.

4-8.2 Oxygen Purity Measurements

This paragraph presents the requirements and guidance for measuring gas purity in air and product gases. Any gas purity measurement method consistent with this test Code may be used. Gas chromatographs are typically used to measure gas purity, but new measurement devices may be used provided the device accuracy is consistent with the uncertainty requirements of this test Code. Gas purity may be measured with a number of different devices.

(a) Chemiluminescent analyzers are used to determine the concentrations of nitrogen oxides (NO and NO_x).

(b) Fourier transform infrared spectrometry (FTIR) can detect all contaminant species rapidly and simultaneously, with detection limits in the parts-per-billion range.

(c) Gas chromatography is used to analyze mixtures of gaseous or volatile liquid compounds.

(d) Mass spectrometry is commonly used for gas analysis, even in standard operations monitoring.

(e) Nondispersive infrared photometers (NDIR) can detect concentrations of carbon monoxide as low as 0 ppm to 10 ppm or concentrations of carbon dioxide as low as 0 ppm to 5 ppm.

(f) Paramagnetic sensors can measure oxygen concentrations as low as 0% to 1%.

(g) Plasma detectors exploit the principle of electroluminescence without the aid of lamps in an electromagnetic field.

(h) A thermal conductivity detector (TCD) is a bulk property and chemical-specific detector commonly used in the analysis of the permanent gases argon, oxygen, nitrogen, and carbon dioxide.

(i) Trace oxygen sensors (galvanic fuel cell) can measure oxygen concentrations as low as 0 ppm to 10 ppm.

4-9 MATERIAL ANALYSIS

For fuel quality analyses and other chemical/physical analyses necessary to assess system performance, appropriate sampling and analytical techniques shall be selected based on their ability to meet the established precision and accuracy requirements of the performance test. Due to the dynamic and variable nature of most processes and materials, method selection cannot rely solely on the precision and accuracy estimates of the analytical method. Consideration shall be given to the potential variability of process materials in the system, and in some cases the sample's stability, to assess the impact of sample collection frequency and handling.

Testing methods and accuracy ranges for fuel, sorbent, and residue solids are presented in Tables 4-5.2.1-1 and 4-6.2-1, and the potential systematic uncertainties of other instrumentation devices are listed in Table 4-2.6-1.

4-9.1 Sample Collection

Basic guidelines for representative sampling of process streams and fuels can be found in various ASTM and EPA publications.[3] For most process streams, multiple grab samples are necessary to provide a representation of the process over time and, more importantly, to provide data that enables an assessment of sample variability. Sample composites may also be prepared to obtain a single representative sample over time; however, assessment of sample-to-sample

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[3] Annual Book of ASTM Standards, Section 5; EPA-600/8-83-027; and Handbook of Sampling and Sample Preservation of Water and Wastewater; see subsection 1-4.

variability is lost if samples are combined. Duplicate composite samples, i.e., separate samples collected simultaneously during the same period and under the same conditions, may also be prepared and analyzed to provide an indication of sampling variability.

Other factors affecting the representative sampling of process materials include sample stability, sample preparation requirements, and sampling locations. Many test components in synthesis gas and other gasification process samples are susceptible to oxidation and may be reactive to materials in sampling systems and containers, causing the sample to degrade immediately upon collection. Nonhomogeneous, multiphase, and other sample materials that are not directly analyzed shall be prepared for analysis. The net effect on the analytical result shall be considered. In addition, the sample collection point with respect to related process temperature, pressure, and flow measurement devices may affect mass flow rate determinations. The performance test plan shall address these issues and describe how sampling precision, accuracy, and representativeness will be assessed.

4-9.2 Analytical Techniques

Analytical techniques shall be selected based on the performance test criteria for measurement data quality. For any given test parameter, there may be multiple analytical methods, each with an applicable concentration range, sensitivity, detection limit, and susceptibility to interference. Process analytical chemists or other individuals familiar with both chemical analysis methods and the characteristics of the samples shall direct the selection of test methods. All parties to the test shall agree upon the methods. The compatibility of each method with the sample matrix and its ability to meet the data quality objectives for precision and accuracy are critical if useful data are to be obtained.

Since most analytical methods do not provide performance specifications, the test plan shall provide specifications for laboratory quality control parameters that are necessary to meet the test objectives.

A thorough analytical plan provides the necessary data to validate and defend the laboratory results.

4-10 INPUT AND OUTPUT HEAT MEASUREMENT

4-10.1 Direct Measurement Method

4-10.1.1 Dry Solid Fuels. In the direct measurement method of dry solid fuels, the primary heat input is equal to the product of the fuel mass flow rate and the fuel's higher heating value (HHV). The mass flow rate is typically measured with gravimetric weigh belt feeders upstream of the coal preparation equipment. HHV is determined post-test in a bomb calorimeter according to ASTM D5865-01 or other acceptable technique. Fuel samples shall be taken throughout the test period and either combined to yield a composite sample for analysis or analyzed individually and averaged arithmetically to represent the test period.

An alternative measurement technique for dry feed gasifiers may be available with measurements from load cells on the lock hoppers. By tracking the difference between the full and empty weights of each lock-hopper cycle, one will have a better measurement of the total mass of coal fed to the gasifier. Refer to subsection 4-4 for more details on measuring the mass flows of solid fuels.

4-10.1.2 Fuel Slurries. In a typical slurry configuration, the solid fuel is finely ground in rod or ball mills. In order to produce the desired slurry solids concentration, the solid fuel is placed on a weigh belt feeder and fed to the wet mills with treated water that is recycled from other areas of the gasification plant. A fluxing agent may be added to the mills. Prepared slurry is stored in an agitated tank. The tank capacity is sufficiently large to supply slurry without interrupting gasifier operations when the wet mills undergo planned maintenance.

In the direct measurement of slurry, the fuel's heating value is determined by ASTM laboratory techniques. Magnetic flowmeters are the preferred flow measurement devices for high-pressure slurries. If the solids are suspended in a relatively uniform fashion, the flow can also be measured with calibrated orifices. If the solids can settle out, then flow can be measured with an eccentric orifice, a segmental orifice, or an eccentric venturi.

During the performance test, at least one sample shall be taken per hour. The slurry sample is withdrawn, weighed, and the completely dried solids portion of the sample is weighed and tested for heating value. The sample shall be taken as close to the gasifier as practical. The water portion of the slurry is identified as having no heat of combustion value.

Slurry density can be measured using methods described in ASTM D1480, ASTM D4052, or ASTM D7042.

4-10.1.3 Liquid or Gaseous Fuels. Liquid or gaseous fuels shall have heating values that vary no more than the amounts specified in Table 3-5.2-1 over the course of a performance test. The heat input from liquid or gaseous fuels is usually determined by direct measurement of fuel flow and the laboratory or on-line chromatograph-determined heating value. Consistent heat input from liquid or gaseous fuels may also be determined by calculation, as is done for solid fuels.

Subsections 4-6 and 4-7 discuss measurement of liquid and gaseous fuel flow. If the direct method is used, the flow is multiplied by the heating value of the stream to obtain the heat flow. The heating value of gaseous fuels can be measured by an on-line analyzer such as a gas chromatograph or mass spectrometer , or by sampling the stream periodically (at least three samples per test) and analyzing each sample individually in the laboratory. An evaluation of the variability of gas heating value shall be made to determine the impact on the test uncertainty. The number of auxiliary gas samples required during the test is dependent upon minimizing the test uncertainty. The analysis of gas, by either on-line chromatography or the sampling method described above, yields the gas's chemical composition. This data is then used for calculating the gas's heating value. Natural gas shall be analyzed by online chromatography in accordance with ASTM D1945. For all gases, heating values shall be calculated in accordance with ASTM D3588.

4-10.1.4 Syngas. The gas component analysis is used with standard heating values to calculate the syngas heating value in megajoules per normal cubic meter (British thermal units per standard cubic foot). The gas analysis and heating value calculation processes are described in para. 4-10.1.3. The product of the total volumetric flow and syngas heating value yields the chemical energy flow in megajoules per hour (British thermal units per hour).

4-10.1.5 Liquid Hydrocarbon Feeds. If liquid fuel is used, the quantity that is burned shall be determined. Liquid fuel flows can be measured using a flow orifice installed in accordance with ASME MFC-3M or other measurement devices such as positive displacement flowmeters or turbine flowmeters calibrated in accordance with ASME PTC 19.5. The flowmeters shall be calibrated for the Reynolds number range expected during the test. For volume flowmeters, the fuel temperature must be measured accurately to calculate the flow correctly. A sampling point shall be located as close as possible to the test boundary, upstream of the metering station, such that the liquid fuel sample represents the liquid fuel flowing through the flowmeter device. Fuel oil and natural gas typically have more consistent composition than coal or other solid fuels, and therefore require fewer samples. Liquid fuel analyses shall be completed on samples taken during the test. The lower and higher heating values and the specific gravity of the fuel shall be determined from these fuel samples. The heating value of each fuel sample shall be determined in accordance with the procedures specified in ASTM D4809 or equivalent standard.

4-10.1.6 Methods of Solid Fuel Analysis. For solid-fuel-fired gasifiers, the minimum fuel information required to determine efficiency is the ultimate analysis, proximate analysis, and the higher heating value. Table 4-5.2.1-1 identifies the ASTM procedures to be used for analysis. ASTM D3180 defines the procedures for converting the analysis from one basis to another. The latest versions of these procedures shall be utilized. If ASTM adds a new or revised procedure that is agreeable to both parties to the test, that procedure may be used.

The determination of other solid fuel qualities such as fusion temperature, free-swelling index, grindability, ash chemistry, and fuel sizing is important to judge the equivalence of the test fuel and the specified fuel and may be required for other test objectives.

4-10.1.7 Methods of Sorbent and Residue Analysis. The minimum information needed to determine the sulfur capture efficiency is the sorbent ultimate analysis (calcium, magnesium, moisture, and inert). Table 4-5.2.1-2 identifies the applicable ASTM analysis procedures. Chromium concentration is determined by atomic absorption spectroscopy. The determination of other solid sorbent qualities (such as sorbent sizing) may be required, depending on the test objectives.

4-10.2 Indirect Measurement Method

The indirect measurement method of fuels is based on a carbon balance of the gasification system, in which the carbon in the input fuel is calculated as the sum of the carbon in the untreated syngas plus the carbon contained in the ash. The carbon flow in the untreated syngas is determined from gas chromatography and flow measurement of the untreated syngas. The carbon flow in the ash is determined from the ash analysis and flow measurement of the ash. The mass flow rate of the primary input fuel is calculated from its calculated carbon flow and ultimate analysis, and the HHV of the primary fuel is determined as described in para. 4-10.1.

4-11 AUXILIARY ELECTRIC POWER MEASUREMENT

4-11.1 Introduction

This subsection presents requirements and guidance regarding the measurement of electrical power consumption. This Code recommends that power consumption be measured by sufficient instrumentation to ensure that no additional uncertainty is introduced by the metering method for all test conditions. Reference ANSI/IEEE Standard 120-1989 for measurement requirements not included in this subsection.

A separate transformer and associated load metering may be available to measure the auxiliary loads. Station permanent instrumentation can be used for measuring the electrical load to the gasification block, where the electrical load is measured and displayed either as active power or as voltage and current. When power metering is not available, individual input power to an electric load can be estimated by taking RMS voltage and current measurements. The measurements can be made with handheld instruments, such as clamp-on ammeters and multimeters, or with a power factor meter. Auxiliary load, Aux (in kilowatts), is calculated by the following equation and inputs:

$$\mathrm{Aux} = \frac{\sqrt{3} \times V \times I \times \mathrm{PF}}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
$\sqrt{3}$ = value that accounts for use of phase-to-phase voltage measurement on a three-phase system
I = average root-mean-square (RMS) phase current, A
PF = power factor, as a decimal
V = average phase-to-phase voltage, V

NOTE: Do not attempt to make direct voltage measurements above 600 V RMS. If the motor supply voltage is higher than 600 V, a voltage transformer shall be used. The three-phase input power, *Pt* (in kilowatts), to the motor can be calculated from the same equation as used for auxiliary power. Measurement of all three phases shall be made and the average value used for the calculation. This applies to the voltage, current, and power factor measurements, all of which can usually be made at the motor starter box. Refer to ASME PTC 19.6, subsections 3-6 and 3-7 for additional information on measuring auxiliary power.

4-11.2 Electrical Metering Equipment

Two types of electrical metering equipment may be used to measure electrical energy: wattmeters and watt-hour meters. Single- or polyphase metering equipment may be used. However, if polyphase equipment is used, the output from each phase shall be available or the meter shall be calibrated three-phase. These meters are described in paras. 4-11.2.1 through 4-11.2.3.

4-11.2.1 Wattmeters. Wattmeters measure instantaneous active power. The instantaneous active power shall be measured frequently during a test run and averaged over the test run period to determine average power (kilowatts) during the test. If the total active electrical energy (kilowatt-hours) is needed, the average power shall be multiplied by the test duration in hours.

Wattmeters measuring a Class 1 primary variable shall have a bias uncertainty equal to or less than 0.2% of the reading. Metering with an uncertainty equal to or less than 0.5% of the reading may be used for the measurement of Class 2 primary variables. There is no metering accuracy requirement for measurement of secondary variables. The output from the wattmeters shall be sampled with a frequency high enough to attain an acceptable precision. This is a function of the variation of the power measured. A general guideline is a frequency of at least once each minute.

4-11.2.2 Watt-Hour Meters. Watt-hour meters measure active energy (kilowatt-hours) during a test period. The measurement of watt-hours shall be divided by the test duration in hours to determine average active power (kilowatts) during the test period.

Watt-hour meters measuring a Class 1 primary variable shall have an uncertainty equal to or less than 0.2% of the reading. Metering with an uncertainty equal to or less than 0.5% of the reading shall be used for measurement of Class 2 primary variables. There are no metering accuracy requirements for measurement of secondary variables.

The resolution of watt-hour meter output is often so low that high inaccuracies can occur over a typical test period. Often watt-hour meters have an analog or digital output with a higher resolution that may be used to increase the resolution. Some watt-hour meters also have a pulse-type output that may be summed over time to determine an accurate total energy value during the test period. For disk-type watt-hour meters with no external output, the disk revolutions can be counted during a test to increase resolution.

4-11.2.3 Wattmeter and Watt-Hour Meter Calibration. Wattmeters and watt-hour meters, collectively referred to as power meters, are calibrated by simultaneously applying power through the test power meter and a standard wattmeter or watt-hour meter. This comparison shall be conducted at several power levels (at least five) across the expected test power range. The difference between the test and standard instruments for each power level shall be calculated and applied to the power measurement data from the test. For test points between the calibration power levels, a curve fit or linear interpolation shall be used. The selected power levels shall be approached in an increasing and decreasing manner. The calibration data at each power level shall be averaged to minimize any hysteresis effect. If polyphase metering equipment is used, the output of each phase shall be available or the meter shall be calibrated with all three phases simultaneously.

When calibrating watt-hour meters, the output from the wattmeter standard shall be measured with a frequency high enough to reduce the precision error during calibration so the total uncertainty of the calibration process meets the required level. The average output from the wattmeter standard can be multiplied by the calibration time interval to compare against the watt-hour meter output.

Wattmeters shall be calibrated at the electrical line frequency of the equipment being tested (e.g., do not calibrate meters at 60 Hz for use on 50 Hz equipment).

Wattmeter standards shall be allowed to have power flow through them prior to calibration to ensure the device is adequately warmed up. The standard shall be checked for zero reading each day prior to calibration.

4-11.3 Measurement of Step-Up and Step-Down Transformers

The transformer losses of step-up and step-down transformers may be required for a test or a test correction. Since power loss for these transformers is difficult to measure in the field, it may be necessary to use the results of the transformer's factory performance tests. Normally the factory tests for determining power loss are conducted at 0% and 100% of the transformer's rated load at various voltages. In order to calculate the transformer power loss, the measurements of the voltage and current at the high side of the transformer shall be recorded.

4-12 DATA COLLECTION AND HANDLING

4-12.1 Introduction

This subsection presents requirements and guidance regarding the acquisition and handling of test data. It also describes the fundamental elements that are essential to a comprehensive data acquisition and handling system.

This Code recognizes that technologies and methods for data acquisition and handling will continue to change and improve. If new technologies and methods become available and are shown to meet the required standards stated within this Code, they may be used.

4-12.1.1 Data Acquisition System. The purpose of a data acquisition system is to collect data and store it in a form suitable for processing or presentation. Systems may be as simple as a person manually recording data or as complex as a digital computer-based system. Regardless of its complexity, a data acquisition system shall be capable of recording, sampling, and storing the data within the requirements of the test and target uncertainty set by this Code.

4-12.1.2 Manual System. In some cases, it may be necessary or advantageous to record data manually. It shall be recognized that this type of system introduces additional uncertainty in the form of human error, and such uncertainty shall be accounted for accordingly. Further, due to their limited sampling rate, manual systems may require longer periods of time or additional personnel for a sufficient number of samples to be taken. A test period duration shall be selected that allows enough time to gather the number of samples required by the test. Data collection sheets shall be prepared prior to the test. The data collection sheets shall identify the test site location, date, time, and type of data collected, and shall delineate the sampling time required for the measurements. Sampling times shall be clocked using a digital stopwatch or other appropriate timing device. If it is necessary to edit data sheets during the test, all edits shall be made using black ink, and all errors shall be marked through with a single line and initialed and dated by the editor.

4-12.2 Data Management

4-12.2.1 Data Collected With an Automated System. All data collected using an automated data acquisition system shall be recorded in its uncorrected, uncalculated state on both permanent and removable media to permit post-test application of any necessary calibration corrections. Immediately after the test and prior to leaving the test site, the data shall be copied to a removable medium and distributed among the parties to the test to prevent the data from being accidentally lost, damaged, or modified. Similar steps shall be taken with any corrected or calculated test results.

4-12.2.2 Manually Collected Data. All manually collected data recorded on data collection sheets shall be reviewed for completeness and correctness. Immediately after the test and prior to leaving the test site, photocopies of the data collection sheets shall be made and distributed among the parties to the test to prevent the data from being accidentally lost, damaged, or modified. If photocopying is not available, manual replication of the data collection sheets shall be made and the replicated data collection sheets shall be clearly marked as a replication and signed off by the parties to the test.

4-12.2.3 Data Calculation System. The data calculation system shall have the capability to average each input collected during the test and calculate the test results based on the average values. The system shall also calculate standard deviation and the coefficient of variance of each instrument. The system shall have the ability to locate spurious data and exclude it from the calculation of the average. The system shall also be able to plot the test data and each instrument reading over time to look for trends and outlying data.

4-12.3 Data Acquisition System Selection

4-12.3.1 Data Acquisition System Requirements. Prior to selection of a data acquisition system, it is necessary to have the test procedure in place that dictates the system requirements. The test procedure shall clearly dictate the type of measurements to be made, number of data points needed, the length of the test, the number of samples required, and the frequency of data collection to meet the target test uncertainty set by this Code. This information shall serve as a guide in the selection of equipment and system design.

Each measurement loop shall be designed with the ability to be loop calibrated and checked for continuity and power supply problems. To prevent signal degradation due to noise, each instrument cable shall be designed with a shield around the conductor, and the shield shall be grounded on one end to drain any stray induced currents.

4-12.3.2 Temporary Automated Data Acquisition System. This Code encourages the use of temporary automated data acquisition systems for testing purposes. These systems can be carefully calibrated and their proper operation confirmed in the laboratory and then transported to the testing area, thus providing traceability and control of the complete system. Temporary systems limit the instruments' exposure to the elements and avoid the problems associated with construction and ordinary plant maintenance.

Site layout and ambient conditions shall be considered when determining the type and application of temporary systems. Instruments and cabling shall be selected to withstand or minimize the impact of any stresses, interference, or ambient conditions to which they may be exposed.

4-12.3.3 Existing Plant Measurement and Control System. This Code does not prohibit the use of the plant measurement and control system for Code testing. However, the system shall meet the requirements set forth in this Code. Further, users shall recognize the limitations and restrictions of these systems for performance testing, including the following:

(a) Most distributed plant control systems apply threshold or dead-band restraints on data signals. This results in data that are reported only when change in a parameter exceeds a set threshold value. All threshold values on the distributed control system shall be set low enough that all data signals generated during a test are reported and stored.

(b) Most plant systems do not calculate flow rates in accordance with this Code, but instead use simplified relationships. This includes, for example, constant discharge coefficient or even expansion factor. A plant system indication of flow rate shall not be used in the execution of this Code, unless the fundamental input parameters are also logged, and the calculated flow is confirmed to be in accordance with this Code and ASME MFC-3M.

Section 5
Calculations and Results

5-1 INTRODUCTION

The major objective of a gasification plant performance test is to determine the effectiveness of chemical conversion and fuel utilization and to ensure that all stream conditions are converted to a common basis. Most streams within a gasification block of an IGCC system contain thermal energy (sensible heat) and chemical energy (heating value). To properly specify thermal–chemical properties of an energy stream in the power plant, this Code defines enthalpy as the sum of thermodynamic enthalpy [integrated specific heat–temperature relation between the reference temperature (at which the heat of formation is based) and stream temperature] and heat of formation. This definition avoids inconsistency of energy calculation for different types of flows, and unifies mass–energy balance calculations between the subsections and systems.

The test boundaries for the gasification block are shown in Figure 3-2.2-1. Selected properties of these streams need to be measured separately as described in this Section to evaluate the performance of an IGCC gasification block. The first three input streams — primary fuel, secondary fuel, and coal-drying fuel — are chemical inputs into the IGCC gasification block test boundary. Syngas is the primary energy output, and measurements of some or all of the remaining streams are used to determine corrections.

The calculations in this Section cover the most common energy streams crossing the test boundary, but the specific gasification block undergoing the test is likely to include other energy streams that shall be measured and used for corrections. The selection of the stream properties to be measured depends on their sensitivity coefficients as defined in Section 7.

Ambient conditions are assumed to have a negligible effect on the gasification block performance.

5-2 DATA REDUCTION

Following each test, all completed test logs and records shall be examined to determine if the permissible deviations from specified operating conditions have exceeded those prescribed by the individual test code. Adjustments of any kind shall be agreed to by all parties to the test and explained in the test report. If the parties to the test cannot agree on adjustments, the test run(s) may have to be repeated. Inconsistencies in the test record or test result may require tests to be repeated in whole or in part in order to attain test objectives. Corrections resulting from deviations of any of the test operating conditions from those specified are applied when the test results are calculated.

5-3 FUNDAMENTAL EQUATIONS

This subsection provides the equations necessary for evaluating whether a gasification block's performance complies with the vendor's guarantees. The equations are exemplary in nature and are subject to change based on the needs of the testing parties.

5-3.1 Nomenclature

(a) Symbols used in the equations are as follows:

AF = additive correction for primary fuel energy, kJ/kg (Btu/lbm)
AP = additive correction for auxiliary power, kW
AS = additive correction for product syngas energy, kJ/kg (Btu/lbm)
B = coefficient
Eff = gasification effectiveness, dimensionless
H = enthalpy, kJ/kg (Btu/lbm)
HRD = heat recovery duty, kJ/s = kW (Btu/sec)
LHV = lower heating value, kJ/Nm^3 (Btu/scf)
MF = multiplicative correction for primary fuel energy, dimensionless

MF2 = multiplicative correction for secondary fuel energy, dimensionless
MP = multiplicative correction for auxiliary power, dimensionless
MS = multiplicative correction for product syngas energy, dimensionless
Nsv = normal specific volume, Nm^3/kg (scf/lbm)
P = pressure, kPa (psia)
PW = power, kW
Q = energy flow, kJ/s = kW (Btu/sec)
Rsv = normal-to-actual specific volume ratio of syngas at temperature and pressure, Nm^3/m^3 (scf/acf)
SG = specific gravity, dimensionless, water = 1.0
sv = specific volume, m^3/kg (ft^3/lbm)
T = temperature, °C (°F)
U = uncertainty, dimensionless
V = normal volumetric flow, Nm^3/s (scfm)
W = mass flow, kg/s (lb/sec)
XM = moisture content, kg/kg (lbm/lbm)
XS = solids concentration in slurry, kg (lb) solids/kg (lb) slurry, volume fraction, dimensionless

(b) Subscripts used in the equations are as follows:
ax = auxiliary
CH4 = methane
CO = carbon monoxide
corr = corrected (based on correction curves)
es = export steam
fw = feedwater
H2 = hydrogen
ox = oxidant
pf = primary fuel (e.g., coal)
pg = product syngas
ref = reference
rc = recycle
sf = secondary fuel (e.g., natural gas)
sg = sour syngas
st = steam
sy = slurry
test = test
x = slag

5-3.2 Corrected Product Syngas Energy

Equation (5-3-1) is the fundamental performance equation for corrected product syngas energy. Product syngas energy does not include sensible heat or contaminants such as H_2S, COS, or NH_3. The corrected value is calculated based on its measured value with additive and multiplicative corrections. Sensible heat is not included in the corrected product syngas energy.

$$Q_{\mathrm{pg,corr}} = \left(V_{\mathrm{pg}} \times \mathrm{LHV}_{\mathrm{pg}} + \sum \mathrm{AS}_i\right) \times \Pi \mathrm{MS}_j \tag{5-3-1}$$

where
AS_i = additive correction, kJ/s = kW (Btu/sec)
i = individual additive correction of n corrections
= 1, n
j = individual multiplicative correction of m corrections
= 1, m
$\mathrm{LHV}_{\mathrm{pg}}$ = product syngas lower heating value, kJ/Nm^3 (Btu/scf)
MS_j = multiplicative correction, dimensionless
$Q_{\mathrm{pg,corr}}$ = corrected product syngas energy, kJ/s = kW (Btu/sec)
V_{pg} = product syngas volumetric flow, Nm^3/s (scf/sec)

5-3.3 Corrected Gasification Effectiveness

Equation (5-3-2) is the fundamental performance equation for gasification effectiveness. The corrected effectiveness, $\mathrm{Eff}_{\mathrm{corr}}$, is adjusted by additive and multiplicative corrections.

$$\mathrm{Eff}_{\mathrm{corr}} = \frac{Q_{\mathrm{pg,corr}}}{\left(Q_{\mathrm{pf,corr}} + Q_{\mathrm{sf,corr}} + \mathrm{PW}_{\mathrm{ax,corr}}\right)} \tag{5-3-2}$$

where

$\mathrm{Eff}_{\mathrm{corr}}$ = corrected gasification effectiveness, dimensionless
$\mathrm{PW}_{\mathrm{ax,corr}}$ = corrected auxiliary power, kW
$Q_{\mathrm{pf,corr}}$ = corrected primary fuel input energy, kJ/s = kW (Btu/sec × 1.05506)
$Q_{\mathrm{pg,corr}}$ = corrected product syngas energy, kJ/s = kW (Btu/sec × 1.05506)
$Q_{\mathrm{sf,corr}}$ = corrected secondary fuel input energy, kJ/s = kW (Btu/sec × 1.05506)

The parameters within the performance test criteria equations are calculated as follows:

$$Q_{\mathrm{pf,corr}} = \left(W_{\mathrm{pf}} \times \mathrm{LHV}_{\mathrm{pf}} + \sum \mathrm{AF}_i\right) \times \Pi \mathrm{MF}_j \tag{5-3-3}$$

where

AF_i = additive correction, kJ/s = kW (Btu/sec)
i = individual additive correction of n corrections
= 1, n
j = individual multiplicative correction of m corrections
= 1, m
$\mathrm{LHV}_{\mathrm{pf}}$ = primary fuel lower heating value, kJ/kg (Btu/lb)
MF_j = multiplicative correction, dimensionless
$Q_{\mathrm{pf,corr}}$ = corrected primary fuel input energy, kJ/s = kW (Btu/sec)
W_{pf} = primary fuel flow, kg/s (lb/sec)

$$Q_{\mathrm{sf,corr}} = \left(W_{\mathrm{sf}} \times \mathrm{LHV}_{\mathrm{sf}} + \sum \mathrm{AF2}_i\right) \times \Pi \mathrm{MF2}_j \tag{5-3-4}$$

where

$\mathrm{AF2}_i$ = additive correction, kJ/s = kW (Btu/sec)
i = individual additive correction of n corrections
= 1, n
j = individual multiplicative correction of m corrections
= 1, m
$\mathrm{LHV}_{\mathrm{sf}}$ = secondary fuel lower heating value, kJ/kg (Btu/lb)
$\mathrm{MF2}_j$ = multiplicative correction, dimensionless
$Q_{\mathrm{sf,corr}}$ = Corrected secondary fuel input energy, kJ/s = kW (Btu/sec)
W_{sf} = secondary fuel flow, kg/s (lb/sec)

If the empirical relationship between primary fuel flow and total auxiliary load is known, eq. (5-3-5) can be used to calculate corrected auxiliary power.

$$\mathrm{PW}_{ax,\mathrm{corr}} = \left(\mathrm{PW}_{\mathrm{ax}} + \sum \mathrm{AP}_i\right) \times \Pi \mathrm{MP}_j \tag{5-3-5}$$

where

AP_i = additive correction, kW
i = individual additive correction of n corrections
= 1, n
j = individual multiplicative correction of m corrections
= 1, m
MP_j = multiplicative correction, dimensionless
$\mathrm{PW}_{\mathrm{ax}}$ = measured auxiliary power, kW

$PW_{ax,corr}$ = corrected auxiliary power, kW

If the effect of primary fuel flow on total auxiliary load is not known, the corrected power requirement for each auxiliary element shall be determined separately using eq. (5-3-6), after which the individual corrected power requirements are combined into the total corrected auxiliary power using eq. (5-3-7).

$$PW_{k,\mathrm{corr}} = \left(PW_k + \sum AP_{ki}\right) \times \Pi MP_{kj} \tag{5-3-6}$$

$$PW_{ax,\mathrm{corr}} = \sum PW_{k,\mathrm{corr}} \times k \tag{5-3-7}$$

where

APk_i = additive correction for element k, kW
i = individual additive correction of "n" corrections
= 1, n
j = individual multiplicative correction of "m" corrections
= 1, m
k = individual auxiliary element of nk elements
= 1, nk
MP_{kj} = multiplicative correction for element k, dimensionless
$PW_{ax,corr}$ = total corrected auxiliary power for element k
PW_k = measured power for auxiliary element k, kW
$PW_{k,corr}$ = corrected power for auxiliary element k, kW

5-3.4 Carbon Conversion Efficiency

Although carbon conversion efficiency (CCE) is a widely used gasifier performance criterion, it is not a test criterion for the complete gasification block. CCE represents the percentage of total carbon in the gasifier feedstock (i.e., coal or biomass) converted to product gases, which contain carbon [i.e., carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), acetylene (C_2H_2), ethylene (C_2H_4), and ethane (C_2H_6)].

$$\mathrm{CCE} = 12Y_{\mathrm{dry\ gas}} \times \frac{(\mathrm{CO} + \mathrm{CO_2} + \mathrm{CH_4}) + 2(\mathrm{C_2H_2} + \mathrm{C_2H_4} + \mathrm{C_2H_6})}{22.4C} \tag{5-3-8}$$

where

C = carbon in the dry feedstock, %wt
CCE = carbon conversion efficiency, %
CO, CO_2, CH_4, C_2H_2, C_2H_4, and C_2H_6 = percent of the gas, in %vol = %mol
$Y_{\mathrm{dry\ gas}}$ = dry gas yield per kilogram of dry feedstock, Nm^3/kg

NOTE: Tar is considered as gas impurity and is not included in the calculation.

5-3.5 Gasifier Energy Efficiency

Although gasifier energy efficiency is a widely used gasifier performance criterion, it is not a test criterion for the complete gasification block. Gasifier energy efficiency can be expressed using two efficiencies: cold gas efficiency (CGE) and hot gas efficiency (HGE) per the following formulas:

$$\mathrm{CGE} = \frac{\mathrm{CE} \times Y_{\mathrm{dry\ gas}} \times 100}{\mathrm{DBE} + \mathrm{SE}} \tag{5-3-9}$$

$$\mathrm{HGE} = \frac{(\mathrm{CE} + \mathrm{PE}) \times Y_{\mathrm{dry\ gas}} \times 100}{\mathrm{DBE} + \mathrm{SE}} \tag{5-3-10}$$

where

CE = chemical energy of dry gas, MJ/Nm^3 (Btu/lb)
CGE = cold gas efficiency, %
DBE = energy content of dry feedstock, MJ/kg (Btu/lb)
HGE = hot gas efficiency, %
PE = sensible energy of dry gas, MJ/Nm^3 (Btu/lb)
SE = sensible energy of oxidizing agent, MJ/kg (Btu/lb)
$Y_{\text{dry gas}}$ = dry gas yield per kilogram of dry feedstock, Nm^3/kg

NOTE: Tar is considered a gas impurity and is not included in the calculation.

5-4 CORRECTIONS

Typically, the parties to the test agree upon a set of reference conditions at which the gasification block is expected to operate during the performance test. These conditions include the following:

(a) ambient conditions such as air pressure, temperature, and humidity; fuel temperature and composition; oxidant temperature, pressure, and composition; and cooling water temperature

(b) secondary, controlled operating conditions such as grind quality (particle size distribution), slurry concentration, and quantity and quality of various recycled gaseous, water, and solid streams

If ambient and secondary operating conditions are within accepted limits but the contracted reference conditions are not, it is necessary to adjust or correct test results (e.g., gasification block input, output, and effectiveness) calculated from the test measurements. Corrections distinguish the effects of the off-reference ambient and gasification block operating conditions from the effects of deficient design and equipment.

Test results shall be reported as calculated from test observations, corrected for instrument calibration and test deviations from reference conditions, but shall have no other adjustments.

The calculation of the uncertainty of the performance test results shall be based on the uncertainty of measurements made during the test as applied to the tested performance and the performance correction procedure. It shall not include any uncertainty attributed to either the correction curves or the modeling method used to calculate the performance corrections.

Paragraph 5-4.2 identifies the parameters that influence the performance of an IGCC power plant gasification block and describe appropriate correction methods that may be used to compensate for variations in those parameters.

5-4.1 Gasification Block Model

The gasification block model is a model of the thermal systems contained within the test boundary of an IGCC gasification block. The model is used to create correction curves that are applied to performance measured during a test. Each correction is calculated by running the heat balance model with a variance in only the parameter to be corrected over the possible range of deviation from the reference conditions. The correction curves thus developed are incorporated into the specific test procedure document.

This Code permits the parties to the test to input test data into a heat balance computer program so that the corrected performance can be calculated using data from a single heat balance run.

The main functional requirements of the gasification block model are completeness, flexibility, and accuracy.

5-4.1.1 Model Completeness. The model shall be able to predict changes in the gasification block performance in response to changes in the test boundary conditions. These include ambient conditions such as temperature, pressure, and fuel composition; process steam and water flow conditions; and secondary thermal and electrical inputs and outputs.

5-4.1.2 Model Flexibility. The normal range of the model is expected to be at base load with the expected variations in ambient conditions and of streams that cross the test boundary. Inputs to and outputs from the model shall include input and output terms that are measured for the specific gasification system being tested.

5-4.1.3 Model Accuracy. The methods and calculations used to develop the gasification block plant model, including property methods, convergence techniques, and engineering models, shall be of sufficient accuracy to satisfy the needs of the acceptance test. Consistency and relative accuracy of the calculations are more important than absolute accuracy since the primary purpose of the model is to correct plant performance to reference conditions. This means that the ability to accurately predict changes in performance due to a change in a test boundary condition (Δ) is more important than matching the actual plant output or heat consumption at a given set of conditions. The final results shall be accurate enough to meet the uncertainty levels defined in Table 1-3-1.

5-4.1.4 Model Validation. Model validation is desirable, but the proprietary nature of comprehensive plant models may preclude complete validation. The uncertainties of corrections, curves, and models cannot normally be ascertained due to the proprietary nature of such information. This aspect of uncertainty has not been included in Table 1-3-1.

The basic gasification block model is based on the equipment supplier's data and expected performance over a range of conditions. The individual component performance used in the comprehensive plant model shall be validated to match the equipment supplier's expected performance for the component. If the equipment supplier provides performance curves or data, the model shall be adjusted to allow comparison of the plant model's predicted performance against the equipment supplier's curves or data. The comparison shall be made at the rating point and at the extremes of the equipment supplier's predicted performance.

The limit of the model's use and accuracy is restricted to the limit of the components used as inputs to the plant model.

5-4.1.4.1 Comparison With Measured Data. To the extent practicable before the test, the model results shall be compared with measured data from the plant. This comparison permits the model to be refined and tuned so that it matches the actual operation of the plant as closely as possible.

Adjustable model parameters shall be limited to equipment characteristics, such as heat exchanger heat transfer coefficients and correlation coefficients that affect the model outputs over a range of conditions in the same way as at test conditions. Directly measured variables shall not be adjusted.

5-4.1.4.2 Extremes and End Points. Ideally, the test should be conducted at the reference conditions to minimize the amount and size of corrections to the measured performance. If the model is used for test corrections, it will in effect be interpolating within its valid range rather than extrapolating beyond it.

5-4.1.4.3 Limits. It is important to identify the limits of the gasification block model during the development, testing, and tuning of the model. Limits are those operating regions where the accuracy of the model is reduced or is unacceptable for the purposes of testing. The model cannot be used for testing plant operation beyond the validated limits.

5-4.2 Additive and Multiplicative Corrections

Influencing variables are all of the variables that are deviations from reference conditions during the test and that affect the performance of the gasification block. They include variables that cause deviations from design and operating conditions, input and output streams, and control equipment and instrumentation. Some of these variables can have major impacts on the syngas flow, fuel consumption, and oxygen consumption, while others may have insignificant impacts. These variables can be quantified by modeling the plant in detail.

To correctly calculate test results, Code users shall adjust measured parameters to correct for allowable variations in both controllable operating parameters and uncontrollable external effects, such as ambient temperature. Streams crossing the test boundary are measured during the test, and their deviations from reference values are used as the basis for additive and multiplicative corrections. These corrections are applied to the measured performance equations to produce the corrected performance values.

Additive and multiplicative correction factors and the parameters to which they apply are listed in Table 5-4.2-1.

5-4.2.1 Corrections to Product Syngas Energy

5-4.2.1.1 Additive Correction to Sorbent Feed Rate. Sorbent properties can affect syngas composition. This is an additive correction for variations in sorbent feed rate if the sorbent is added to the gasification process.

5-4.2.1.2 Additive Correction to Heat Recovery Duty. The syngas cooler cools the syngas by heating feedwater to produce hot water or steam for the steam turbine cycle. In most cases, the product is saturated steam. The heat recovery duty (HRD) is calculated from the feedwater flow, feedwater inlet temperature, and saturated steam exit pressure. Variations in any of these three measured parameters change the amount of heat transferred from the syngas to the steam side, whether those changes are caused by syngas cooler fouling or other reasons. As an additive correction, excessive HRD provides additional steam to the steam turbine in the combined cycle and therefore improves the product syngas energy performance parameter.

$$\mathrm{HRD} = W_{\mathrm{fw}} \times (h_{\mathrm{es}} - h_{\mathrm{fw}}) \tag{5-4-1}$$

where

h_{es} = export steam enthalpy determined as a function of pressure and temperature, kJ/kg (Btu/lbm)
h_{fw} = feedwater enthalpy determined as a function of temperature, kJ/kg (Btu/lbm)
HRD = heat recovery duty, kJ/s (Btu/sec)
W_{fw} = feedwater flow, kg/s (lb/sec)

Table 5-4.2-1 Additive and Multiplicative Corrections

Correction Factor Number	Parameter	Correction Factor for Product Syngas Energy	Correction Factor for Primary Fuel Energy	Correction Factor for Secondary Fuel Energy	Correction Factor for Auxiliary Power
Additive [Note (1)]					
1	Sorbent feed rate	AS_1	AF_1	0	AP_1
2	Heat recovery duty	AS_2	0	0	0
3	Primary fuel flow	0	0	0	AP_3
Multiplicative [Note (2)]					
1	Fuel composition	MS_1	MF_1	$MF2_1$	1
2	Primary fuel supply temperature [Note (3)]	1	MF_2	1	1
3	Secondary fuel supply temperature [Note (4)]	1	1	$MF2_3$	1
4	Sorbent input properties	MS_4	MF_4	1	1
5	Slurry concentration (for slurry-fed systems)	MS_5	MF_5	1	MP_5
6	Oxygen concentration	1	MF_6	1	1
7	Oxidant temperature	1	MF_7	1	1
8	Syngas demand	MS_8	MF_8	1	1

NOTES:

(1) Additive corrections are set equal to zero if they do not apply to the measured results for the specific type of plant being tested or to the test objectives.

(2) Multiplication corrections are set equal to unity if they do not apply to the measured results for the specific type of plant being tested or to the test objectives.

(3) The primary fuel is the fuel-water slurry for slurry-fed systems and the fuel itself for all other types of gasifiers.

(4) The secondary fuel is the pilot fuel used in gasifiers that are not lined with refractory material.

$$AS_2 = \frac{\mathrm{HRD}_{\mathrm{test}} \times W_{\mathrm{pg,test}}}{W_{\mathrm{sg,test}} - \mathrm{HRD}_{\mathrm{ref}} \times W_{\mathrm{pg,ref}}/W_{\mathrm{sg,ref}}} \tag{5-4-2}$$

where

AS_2 = additive HRD correction, kJ/s (Btu/sec)
$\mathrm{HRD}_{\mathrm{ref}}$ = heat recovery duty in reference case, kJ/s (Btu/sec)
$\mathrm{HRD}_{\mathrm{test}}$ = heat recovery duty in test case, kJ/s (Btu/sec)
$W_{\mathrm{pg,ref}}$ = reference product syngas flow, kg/s (lb/sec)
$W_{\mathrm{pg,test}}$ = test product syngas flow, kg/s (lb/sec)
$W_{\mathrm{sg,ref}}$ = reference sour syngas flow, kg/s (lb/sec)
$W_{\mathrm{sg,test}}$ = test sour syngas flow, kg/s (lb/sec)

5-4.2.1.3 Multiplicative Correction to Primary Fuel Properties. Primary fuel properties can affect syngas composition. This is a multiplicative correction for variations in primary fuel input properties.

5-4.2.1.4 Multiplicative Correction to Sorbent Input Properties. Sorbent properties can affect syngas composition. This is a multiplicative correction for variations in sorbent input properties.

5-4.2.1.5 Multiplicative Correction to Syngas Demand. Gas turbine operation and syngas demand is affected by ambient air pressure and temperature, resulting in part-load operation for the gasifier.

$$MS_8 = \frac{W_{\mathrm{pg,ref}} \times \mathrm{LHV}_{\mathrm{pg,ref}}}{W_{\mathrm{pg,test}} \times \mathrm{LHV}_{\mathrm{pg,test}}} \tag{5-4-3}$$

where

$\mathrm{LHV}_{\mathrm{pg,ref}}$ = reference product syngas LHV, kJ/kg (Btu/lb)

$LHV_{pg,test}$ = test case product syngas LHV, kJ/kg (Btu/lb)
MS_8 = multiplicative syngas demand correction, dimensionless
$W_{pg,ref}$ = reference product syngas mass flow, kg/s (lb/sec)
$W_{pg,test}$ = test case product syngas mass flow, kg/s (lb/sec)

5-4.2.2 Corrections to Primary Fuel Input. The primary fuel is the principal source of energy for the gasification block. If a blend of solid fuels is used, the combined properties of the blended fuel are used to define the primary fuel. Corrections for primary fuel input are described below.

5-4.2.2.1 Additive Correction to Primary Fuel Sorbent Feed Rate. This is an additive correction for variations in sorbent feed rate if the sorbent is added to the gasification process.

5-4.2.2.2 Multiplicative Correction to Primary Fuel Composition. A computer model based on fuel ultimate analysis is normally used to determine the correction for a primary fuel that is not the reference fuel. The model predicts the performance of the gasification unit on a coal that is other than the reference coal. This comprehensive correction eliminates the need for correction curves for individual fuel characteristics such as ultimate analysis constituents. If a computer model is not available, the primary fuel can be corrected for heating value.

5-4.2.2.3 Multiplicative Correction to Primary Fuel Supply Temperature. The primary fuel is the fuel–water slurry for slurry-fed systems and the fuel itself for all other types of gasifiers. In slurry-fed systems, slurry temperature is affected by ambient water temperature and residual heat from coal grinding, so it is considered an uncontrollable variable for which correction curves are needed. Slurry temperatures do not typically vary by more than 3°C (5.4°F). In fuel-only systems, a supply temperature correction would only be used if the change in primary fuel sensible heat exceeded the 0.2% sensitivity threshold specified in Section 7.

5-4.2.2.4 Multiplicative Correction to Sorbent Input Properties. This is a multiplicative correction for variations in sorbent input properties.

5-4.2.2.5 Multiplicative Correction to Slurry Concentration. Slurry concentration can be measured but is difficult to control, so it is considered an uncontrollable variable for which a correction curve is needed. The dry (moisture-free) portion of the fuel shall be considered the solids concentration, since the moisture in the fuel is part of the water portion of the slurry.

5-4.2.2.6 Multiplicative Correction to Oxygen Concentration. The composition (purity) of oxygen product entering the gasification block is considered an uncontrollable variable for which a correction curve is needed.

5-4.2.2.7 Multiplicative Correction to Oxidant Temperature. The temperature of air of oxygen product entering the gasification block is considered an uncontrollable variable for which a correction curve is needed.

5-4.2.2.8 Multiplicative Correction to Syngas Demand. Gas turbine operation and syngas demand is affected by ambient air pressure and temperature, resulting in part-load operation for the gasifier. The oxygen product flow from the air separation unit (ASU) can also be limited by ambient air pressure and temperature. Gasifier part-load operation between 75% and 100% load is expected to affect the gasifier inlet and exit flows but have negligible effects on other performance parameters.

5-4.2.3 Corrections to Secondary Fuel Input. The secondary fuel is the pilot fuel used in gasifiers that are not lined with refractory material. The secondary fuel is a supplemental source of energy for the gasification block. If a blend of secondary fuels is used, the combined properties of the blended fuel are used to define the secondary fuel. Corrections for secondary fuel input are described below.

5-4.2.3.1 Multiplicative Correction to Secondary Fuel Composition. A computer model based on fuel constituents is normally used to determine the correction for a secondary fuel that is not the reference fuel. The model predicts the performance of the gasification unit on a coal that is other than the reference coal. This comprehensive correction eliminates the need for correction curves for individual fuel constituents. If a computer model is not available, the secondary fuel can be corrected for heating value.

5-4.2.3.2 Multiplicative Correction to Secondary Fuel Supply Temperature. A correction for secondary fuel supply temperature is used only if the change in secondary fuel sensible heat exceeds the 0.2% sensitivity threshold specified in Section 7.

5-4.2.4 Corrections to Auxiliary Power. Gasification block auxiliaries primarily include coal and sorbent handling, coal milling, sour water slurry recycle pump, slag handling, quench water pump, and scrubber pumps used for particulate removal.

5-4.2.4.1 Additive Correction to Sorbent Feed Rate. This is an additive correction for variations in sorbent feed rate if a sorbent is added to the gasification process.

5-4.2.4.2 Additive Correction to Primary Fuel Flow. Variations in primary fuel flow affect the power requirements of some auxiliaries while others have relatively constant power requirements regardless of operating conditions. The additive correction in eq. (5-4-4) is the change in auxiliary power resulting from the change in primary fuel flow. This relationship can be approximated as a linear function when operating near reference conditions.

$$\mathrm{AP}_3 = B_{\mathrm{ax}} \times (W_{\mathrm{pf,ref}} - W_{\mathrm{pf,meas}}) \tag{5-4-4}$$

where

B_{ax} = change in auxiliary power, kWs/kg (kWs/lb)
= $d\mathrm{PW}/dW_{\mathrm{pf}}$
$d\mathrm{PW}$ = change in auxiliary power, kW
dW_{pf} = change in primary fuel flow, kg/s (lb/sec)
$W_{\mathrm{pf,meas}}$ = measured primary fuel flow, kg/s (lb/sec)
$W_{\mathrm{pf,ref}}$ = reference primary fuel flow, kg/s (lb/sec)

5-4.2.4.3 Multiplicative Corrections to Slurry Concentration. The power requirement of slurry-handling equipment is roughly proportional to the specific gravity of the slurry. Multiplicative corrections to the power requirements of slurry mixers, slurry pumps, and slurry recycle pumps are based on the ratio of reference specific gravity to test specific gravity. The approximations below can be used if empirical power corrections are not available.

$$\begin{aligned}\mathrm{MP}_{5,j} &= \frac{SG_{\mathrm{ref},j}}{SG_{\mathrm{meas},j}} \\ &= \frac{[(1-\mathrm{XS}_{\mathrm{ref},j}) + \mathrm{XS}_{\mathrm{ref},j} \times \mathrm{SG}_{\mathrm{pf,ref},j}]}{[(1-\mathrm{XS}_{\mathrm{meas},j}) + \mathrm{XS}_{\mathrm{meas},j} \times \mathrm{SG}_{\mathrm{pf,meas},j}]}\end{aligned} \tag{5-4-5}$$

where

j = equipment identifier
= 1 for slurry mixture
= 2 for slurry pump
= 3 for slurry recycle pump
MP_5 = multiplicative correction to slurry concentration, dimensionless
SG = specific gravity of slurry, referred to water, dimensionless
$\mathrm{SG}_{\mathrm{pf}}$ = specific gravity of primary fuel, referred to water, dimensionless
= 0.64, typically, for ground coal
$\mathrm{XS}_{\mathrm{ref}j}$ = reference concentration of solids in slurry, kg (lb) solids/kg (lb) slurry, volume fraction, dimensionless
$\mathrm{XS}_{\mathrm{meas}j}$ = measured concentration of solids in slurry, kg (lb) solids/kg (lb) slurry, volume fraction, dimensionless

All auxiliary systems in the gasification block shall be included in the analysis and their performance corrected as indicated in Table 5-4.2.4.3-1. Typical items are listed in the table, but the list is not all-inclusive. Note that auxiliary elements that are not affected by test conditions do not need corrections.

5-5 PARAMETERS USED IN THE FUNDAMENTAL EQUATIONS

This subsection identifies the measured and calculated parameters that are used in the Code performance calculations.

Table 5-4.2.4.3-1 Typical Auxiliary Equipment and Corrections

Auxiliary Equipment	Correction for Slurry Concentration	Correction for Primary Fuel Flow
Coal-handling equipment	...	AP_3
Coal conveyors	...	AP_3
Coal-milling equipment	...	AP_3
Grinders	...	AP_3
Pneumatic feed system (compressors, etc.)	...	AP_3
Quench water pump	...	...
Scrubber pumps (if a water scrubber is used for environmental control)	...	...
Slag-handling equipment	...	...
Slurry mixers	MP_5	AP_3
Slurry pumps	MP_5	AP_3
Slurry recycle pump	MP_5	AP_3
Vacuum pumps	...	...

5-5.1 Primary Fuel Input Calculations

The primary fuel thermal input is the fuel flow multiplied by its heating value.

$$Q_{pf} = W_{pf} \times LHV_{pf} \tag{5-5-1}$$

where

LHV_{pf} = primary fuel lower heating value, kJ/kg (Btu/lb)
Q_{pf} = primary fuel thermal input, kW(t) (Btu/s)
W_{pf} = primary fuel flow, kg/s (lb/s)

Heating value is determined from the ultimate analysis of the primary fuel using methods specified in Section 4.

Two methods shall be used to calculate the primary fuel flow. If the primary fuel is fed to the gasifier as a coal–water slurry, the carbon balance method and the slurry measurement method shall be used. For all other feed systems, the carbon balance method and the direct measurement method shall be used. Agreement between the two primary fuel flow measurements requires overlapping uncertainty bands (as shown in Section 7), and the flow will be the weighted average of the two measurements, with the weight of each measurement being inversely proportional to its uncertainty.

5-5.1.1 Carbon Balance Method. The carbon-balance method is based on the fact that all coal inlet carbon is converted into either syngas carbon or ash/slag carbon. In the ultimate analysis, the coal feed rate equals syngas carbon plus ash/slag carbon, divided by the carbon weight fraction in the ultimate analysis.

$$W_{pf} = \frac{W_{sg} \times XC_{sg} + W_x \times XC_x}{XC_{pf}} \tag{5-5-2}$$

where

W_{pf} = primary fuel flow, kg/s (lb/s)
W_{sg} = syngas flow, kg/s (lb/s)
W_x = slag or ash flow, kg/s (lb/s)
XC_{pf} = primary fuel carbon content in ultimate analysis, kg/kg (lb/lb)
XC_{sg} = syngas carbon content, kg/kg (lb/lb)
XC_x = slag or ash carbon content, kg/kg (lb/lb)

5-5.1.2 Slurry Measurement Method. If a coal–water slurry (CWS) feeds the gasifier, the primary fuel flow is calculated from the measured CWS flow, CWS solids concentration, recycle slurry flow, and recycle slurry solids concentration.

$$W_{pf} = \frac{(W_{sy} \times XS_{sy}) - (W_{rc} \times XS_{rc})}{1 - XM_{pf}} \tag{5-5-3}$$

where

W_{pf} = primary fuel flow, kg/s (lb/sec)

W_{rc} = recycle slurry flow, kg/s (lb/sec)
W_{sy} = CWS flow, kg/s (lb/sec)
XM_{pf} = primary fuel moisture content, kg/kg (lb/lb)
XS_{rc} = recycle slurry solids concentration, kg/kg (lb/lb)
XS_{sy} = CWS solids concentration, kg/kg (lb/lb)

5-5.1.3 Solid Flow Direct Measurement. The solid flow direct measurement method is used for dry-fed gasifiers. Solid fuel flow can be measured with 2% uncertainty using a calibrated gravimetric feeder.

5-5.1.4 Weighted Average Primary Fuel Flow. The fuel flow is the weighted average of the flows calculated by two of the methods above, with the weight of each flow being inversely proportional to the square of its uncertainty.

$$W_{pf} = \frac{\left[W_{pf1} \times \left(\frac{1}{U_1}\right)^2\right] + \left[W_{pf2} \times \left(\frac{1}{U_2}\right)^2\right]}{\left(\frac{1}{U_1}\right)^2 + \left(\frac{1}{U_2}\right)^2} \tag{5-5-4}$$

where
W_{pf} = weighted average primary fuel flow, kg/s (lb/hr)
W_{pf1} = primary fuel flow calculated by first method, kg/s (lb/hr)
W_{pf2} = primary fuel flow calculated by second method, kg/s (lb/hr)
U_1 = uncertainty of first method, percent
U_2 = uncertainty of second method, percent

5-5.2 Heating Value, LHV

The heating values of the primary and secondary fuels entering the gasification block are determined from laboratory tests of the fuels as described in Section 4.

The heating value of the product syngas, LHV_{pg}, is calculated by eq. (5-5-5).

$$LHV_{pg} = (y_{H2} \times LHV_{H2}) + (y_{CO} \times LHV_{CO}) + (y_{CH4} \times LHV_{CH4}) \tag{5-5-5}$$

where
LHV_{CH4} , LHV_{CO}, LHV_{H2} = lower heating value of methane, carbon monoxide, and hydrogen, respectively
y_{CH4}, y_{CO}, y_{H2} = mole fraction of methane, carbon monoxide, and hydrogen, respectively

Equation (5-5-1) shall be modified to include other combustible species (e.g., ethane, ethylene, and other components of product syngas) that, if present, would contribute to the syngas heating value at the power block.

5-5.3 Product Syngas Energy Flow, Q_{pg}

Product syngas energy flow represents usable chemical energy in particle-free syngas that is exiting the gasifier boundary before gas conditioning occurs. It does not consider sensible heat in the gas.

$$Q_{pg} = V_{pg} \times LHV_{pg} \tag{5-5-6}$$

where
LHV_{pg} = product syngas lower heating value, kJ/Nm^3 (Btu/scf)
V_{pg} = product syngas normal volumetric flow, Nm^3/s (scf/sec)

Section 6
Report of Results

6-1 GENERAL REQUIREMENTS

At a minimum, the test report shall include the following distinctive sections:

(a) executive summary (see subsection 6-2), containing
  (1) a brief description of the object, result, and conclusions reached
  (2) signature of the test director(s)
  (3) signature of the reviewer(s)
  (4) approval signature(s)

(b) introduction (see subsection 6-3), containing
  (1) authorization for the tests, the object of the tests, contractual obligations and guarantees, stipulated agreements, the name of the person directing the test, and the representative parties to the test
  (2) a description of the equipment tested and any other auxiliary apparatus, the operation of which may influence the test results
  (3) method of test, including arrangement of testing equipment, instruments used and their locations, operating conditions, and a complete description of methods of measurement not prescribed by this Code

(c) calculations and results (see subsection 6-4), containing
  (1) a summary of measurements and observations.
  (2) methods of calculation from observed data and calculation of probable uncertainty.
  (3) correction factors to be applied because of deviations, if any, of test conditions from those specified. If parties to the test agree to use a plant integrated thermal model to calculate correction factors, the report shall contain specific identification of the model used and copies of all input and output data (in lieu of correction curves). If the model is proprietary to one party to the test, that party shall be required to retain a version of the model configured for the as-tested plant. Documentation of any model used shall be included in the test report.
  (4) primary measurement uncertainties, including method of application.
  (5) the test performances stated under the following headings:
    (-a) test results computed on the basis of the test operating conditions, instrument calibrations only having been applied
    (-b) test results corrected to specified conditions if test operating conditions have deviated from those specified
  (6) tabular and graphical presentation of the test results.

(d) instrumentation (see subsection 6-5)

(e) conclusions (see subsection 6-6), containing
  (1) discussion and details of the test results and uncertainties
  (2) discussion of the test, its results, and conclusions

(f) appendices (see subsection 6-7), containing
  (1) further description and illustrations to clarify the circumstances, equipment, and methodology of the test
  (2) a description of methods of calibrations of instruments
  (3) an outline of details of calculations, including a sample set of computations, descriptions, and statements depicting special testing apparatus
  (4) results of preliminary inspections and trials
  (5) any supporting information required to make the report a complete, self-contained document of the entire undertaking

This outline is a recommended report format. Other formats are acceptable; however, a report of an overall plant performance test shall contain all the information described in subsections 6-2 through 6-7.

6-2 EXECUTIVE SUMMARY

The executive summary is a brief synopsis of the full report and contains only the most essential information in a concise format. The following items shall be contained in the executive summary:

(a) general information about the plant and the test, such as the plant type and operating configuration and the test objectives

(b) date and time of the test

(c) summary of the results of the test, including uncertainty

(d) comparison with the contract guarantees

(e) any agreements among the parties to the test that allow any major deviations from the test requirements, e.g., if the test requirements call for three test runs, and all parties agree that two are sufficient

6-3 INTRODUCTION

The introduction to the test report gives general background information necessary for the reader to understand the circumstances leading up to, and the reasons for, the test. This section of the test report includes the following topics:

(a) any additional general information about the plant and the test not included in the executive summary

(b) an historical perspective, if appropriate

(c) one or more diagrams showing the test boundary and streams (refer to the diagrams for specific plant type or test goal)

(d) a list of the representatives of the parties to the test and their involvement and responsibilities in the testing process

(e) any pretest agreements that were not listed in the executive summary

(f) the organization of the test personnel, including number and type of personnel supplied by each organization and the tasks for which each organization was responsible during the test

(g) test goals per Sections 3 and 5 of this Code

6-4 CALCULATIONS AND RESULTS

The goal of the calculations and results section of the test report is to describe all calculation procedures used in the analysis phase of the test. By using the detailed description and sample calculations, the reader should be able to understand and reproduce any results contained in the report. The following shall be included in detail:

(a) the format of the general performance equation that is used, based on the test goals and applicable corrections.

(b) tabulation of the reduced data necessary to calculate the results, and a summary of additional operating conditions that are not part of the reduced data.

(c) step-by-step calculation of test results from the reduced data. Refer to Nonmandatory Appendices A and B for examples of step-by-step calculations for each plant type and test goal.

(d) detailed calculation of primary flows from applicable data, including intermediate results, if required.

(e) detailed calculations of stream properties, i.e., density, purity, enthalpy, and heating value. Values of constituent properties used in the detailed calculations shall be shown.

(f) any calculations showing elimination of data for outlier reason, or for any other reason.

(g) comparison of the repeatability of test runs.

6-5 INSTRUMENTATION

The instrumentation section of the test report contains a detailed description of all instrumentation used during the test and its accuracy, and how each measurement conforms to the Code requirements. The following shall be included:

(a) tabulation of instrumentation used for the primary and secondary measurements, including make and model number

(b) description of the instrumentation location

(c) means of data collection for each data set, such as temporary data acquisition system printouts, plant control computer printouts, or manual data sheets, and any identifying tag number and/or address of each document

(d) identification of the instrument used as backup

(e) description of data acquisition system(s) used; summary of pretest and post-test calibration

6-6 CONCLUSIONS

The conclusions section of the test report shall include

(a) a more detailed discussion of the test results, if required
(b) recommended changes to future test procedures due to lessons learned

6-7 APPENDICES

Appendices to the test report shall include
(a) the test requirements
(b) copies of original data sheets and/or data acquisition system(s) printouts
(c) copies of operator logs or other recording of operating activity during each test
(d) copies of signed isolation checklists and valve lineup sheets, and other documents and disposition
(e) results of laboratory fuel analysis
(f) instrumentation calibration results from laboratories and certification from manufacturers

Section 7
Uncertainty Analysis

7-1 INTRODUCTION

This Section describes the methodology that shall be used in developing the uncertainty analysis of the performance test. Uncertainty calculations provide pretest and post-test estimates of the accuracy expected from the test methods proposed in this Code. They also help to identify measurements that significantly affect the test results and the required correction factors. Uncertainty calculations are required for every test carried out in accordance with the test Code. Pretest uncertainty calculations shall be included in the test procedure. Post-test uncertainty calculations shall be included in the test report.

Test uncertainty is an estimate of a test result's limit of error. It is the interval about the test result that contains the true value within a level of confidence. The test Code uses a 95% confidence interval for uncertainty calculations. The primary technical reference for uncertainty calculations is ASME PTC 19.1, which provides general procedures for determining the uncertainties in individual test measurements for both random and systematic errors, and for tracking the propagation of these errors into the uncertainty of a test result. Pretest and post-test uncertainty analyses are indispensable parts of a performance test.

7-1.1 Pretest Uncertainty Analysis

A pretest uncertainty analysis allows corrective action to be taken prior to a test, either to decrease the uncertainty to a level consistent with the overall objective of the test, or to reduce the cost of the test while still attaining the objective. This is most important when deviations from Code-specified instruments or methods are expected. An uncertainty analysis is useful for determining the number of observations required to meet the test code criteria.

7-1.2 Post-Test Uncertainty Analysis

A post-test uncertainty analysis determines the uncertainty for the actual test. This analysis should confirm the pretest systematic and random uncertainty estimates. It serves to validate the quality of the test results, or to expose problems.

A sample calculation for uncertainty is shown in Nonmandatory Appendix B.

Test results shall be reported using the following form: $R \pm U_R$.

7-2 OBJECTIVE OF UNCERTAINTY ANALYSIS

The objective of a test uncertainty analysis is to estimate the limit of error of the test results.

This Code does not cover nor discuss test tolerances; test tolerances are defined as contractual agreements regarding an acceptable range of test results.

7-3 DETERMINATION OF OVERALL UNCERTAINTY

There are two types of uncertainty that comprise the overall uncertainty, as follows:

(a) Systematic Error. Systematic error is the portion of the total error that remains constant in repeated measurement of the true value in a test process. Systematic error is caused by measurement characteristics that are inherent to a particular method of measurement, not to a particular plant or test. The estimated value of each systematic error is obtained by nonstatistical methods, and it has many potential sources. This is usually an accumulation of individual errors that are not eliminated through calibration.

(b) Random Error. Random error is due to limitations or repeatability of measurements. Random error is the portion of total error that varies in repeated measurements of the true value throughout the test process. Estimates of random error are derived by statistical analysis of repeated independent measurements. The random error may be reduced by increasing the number of measuring instruments or the number of readings taken.

Table 7-5-1 Expected Uncertainty Limits

Measurement Result	Expected Uncertainty Limit
Product syngas energy	1%
Primary fuel energy	7%
Auxiliary power	4%
Gasification effectiveness	7%

In general, the overall uncertainty of a measurement is calculated as the square root of the sum of the squares (RSS) of the systematic and random uncertainties. Sensitivity coefficients are used to correct the individual parameter's uncertainty for the impact on the total uncertainty.

7-4 SOURCES OF ERROR

Code users shall identify sources of error that affect the test result to determine if they are random or systematic. Error sources may be grouped into the following categories:

(a) calibration error — a residual error not removed by the calibration process

(b) installation error — an error resulting from nonideal instrumentation installation

(c) data acquisition error — an error typically resulting from analog-to-digital conversion

(d) data reduction error — an error introduced through truncation, round-off, nonlinear curve fitting, or data storage algorithms

(e) sampling error — an error introduced from sampling techniques

(f) correction methodology error — an error resulting from use of a correction formula

(g) interpolation error — an error resulting from curve fitting or from the shape of a curve between discrete formulation points

(h) model error — an error that occurs when equipment and system models do not properly account for changes in input parameters or actual unit response

7-5 CALCULATION OF UNCERTAINTY

The corrected test results for an IGCC gasification block have the expected uncertainties shown in Table 7-5-1.

The elements of uncertainty calculations for a complete test can be presented in tabular form, as shown in Table 7-5-2. Typical stream measurements for an IGCC gasification block are listed in the table, but they are not all used in all configurations.

The test uncertainty associated with each measured parameter includes the effects of its sensitivity, systematic uncertainty, and random uncertainty. Each systematic and random uncertainty entry in Table 7-5-2 is specified at a 95% confidence interval, as is the overall combined expanded uncertainty of the results.

Table 7-5-2 Format of Uncertainty Calculations

Measured Parameter	**Sensitivity Coefficient, (θ_i)**	**Systematic Uncertainty (95% CI),** $\pm\left(b_{\overline{X}_i}\right)$	**Systematic Uncertainty Contribution,** $\left(\theta_i b_{\overline{X}_i}\right)^2$	**Random Uncertainty (95% CI),** $\pm\left(s_{\overline{X}_i}\right)$	**Random Uncertainty Contribution,** $\left(\theta_i s_{\overline{X}_i}\right)^2$
[Measured parameter]					
[Measured parameter]					
[Measured parameter]					
Correlated Uncertainties					
Sum of squares			...		
Combined Expanded Uncertainty of the Results, $U_{R,95}$, %					

Table 7-5-3 Measured Parameters Needed for Uncertainty Calculations

Measured Parameter	Product Syngas Energy	Primary Fuel Energy	Auxiliary Power	Gasification Effectiveness
Primary fuel moisture	...	X	...	X
Primary fuel-slurry flow	...	X	...	X
Recycle slurry flow	...	X	...	X
Recycle slurry solids	...	X	...	X
HP boiler-feedwater flow	X	X	...	X
HP boiler-feedwater temperature	X	X	...	X
HP steam pressure (saturated)	X	X	...	X
HP steam temperature	X	X	...	X
Sour syngas mass flow	X	X	X	X
Sour syngas composition [Note (1)]				
Ar	X	X	X	X
CH_4	X	X	X	X
CO	X	X	X	X
CO_2	X	X	X	X
H_2	X	X	X	X
H_2O	X	X	X	X
N_2	X	X	X	X
Product syngas composition [Note (1)]				
CH_4	X	...	...	X
CO	X	...	...	X
H_2	X	...	...	X

NOTE: (1) Ar = argon; CH_4 = methane; CO = carbon monoxide; CO_2 = carbon dioxide; H_2 = hydrogen; H_2O = water; N_2 = nitrogen.

The parameters used to calculate the uncertainty are as follows:

(a) measured parameter: the fluid or energy stream parameter that crosses the test boundary. See Table 7-5-3 for the list of measured parameters.

(b) sensitivity coefficient, θ_i: the percent change in a corrected result caused by a unit change in the measured parameter.

(c) systematic uncertainty, $b_{\overline{X}}$: inherent systematic error for a specific type of measurement.

(d) systematic uncertainty contribution, $(\theta_i b_{\overline{X}})^2$: the square of the product of sensitivity and systematic uncertainty.

(e) random uncertainty, $s_{\overline{X}_i}$: the standard deviation of the mean that is statistically determined from multiple measurements of the same variable.

(f) random uncertainty contribution, $\left(\theta_i s_{\overline{X}_i}\right)^2$: the square of the product of the sensitivity and standard deviation.

The overall uncertainty of a measurement, $U_{\overline{X}}$, is the root-sum-square total of overall systematic and random uncertainties.

$$U_{\overline{X}} = \sqrt{\left(b^2_{\overline{X}} + s^2_{\overline{X}}\right)} \tag{7-5-1}$$

where

$b_{\overline{X}}$ = the systematic uncertainty of the measurement
$s_{\overline{X}}$ = the random uncertainty of the measurement

The uncertainty of the result is calculated from the test's overall random and systematic uncertainty terms. Each systematic and random uncertainty entry in Table 7-5-1 is specified at a 95% confidence interval, so the overall combined expanded uncertainty of the result, U_R, at 95% confidence is calculated from the sum of systematic and random uncertainty contributions.

$$U_R = \sqrt{\left(b_R^2 + s_R^2\right)} \tag{7-5-2}$$

where

b_R = the systematic uncertainty of the result, the sum of systematic uncertainty contributions
s_R = the random uncertainty of the result, the sum of random uncertainty contributions

The expanded uncertainty at 95% confidence is given by

$$U_{R,95} = 2u_R \tag{7-5-3}$$

Table 7-5-3 shows the measured parameters used to calculate uncertainty for test criteria. The same tabular format and calculation procedures shown in Table 7-5-1 can be used to calculate each uncertainty value.

7-6 SENSITIVITY COEFFICIENTS

Sensitivity coefficients indicate a measured parameter's absolute or relative effect on the test result. Relative sensitivity coefficients, which are calculated during the pretest uncertainty analysis, identify the parameters with the largest impact on test objectives. A relative sensitivity coefficient shall be calculated for each measured parameter to determine its influence on test results. Correction calculations are required for all measured parameters with relative sensitivity coefficient values greater than 0.002. The relative sensitivity coefficient, θ, is calculated by either of the following equations:

(a) Partial Differential Form

$$\theta = \frac{\left(\dfrac{\partial R}{R}\right)}{\left(\dfrac{\partial X}{X_{\text{avg}}}\right)} = \frac{X_{\text{avg}}}{R} \times \left(\frac{\partial R}{\partial X}\right) \tag{7-6-1}$$

where

R = corrected test result
X_{avg} = average value of the measured parameter
∂R = change (partial differential) in the corrected test result
∂X = change (partial differential) in the measured parameter

(b) Finite Difference Form

$$\theta = \frac{\left(\dfrac{\Delta R}{R}\right)}{\left(\dfrac{\Delta X}{X_{\text{avg}}}\right)} = \frac{X_{\text{avg}}}{R} \times \left(\frac{\Delta R}{\Delta X}\right) \tag{7-6-2}$$

where R and X_{avg} are the same as in (a) and

ΔR = change (finite difference) in the corrected test result
ΔX = change (finite difference) in the measured parameter, typically $0.01X_{\text{avg}}$

7-7 SYSTEMATIC UNCERTAINTY

Identifying systematic error is an important step of the uncertainty analysis. Failure to identify a significant systematic error will lead to underestimating the accuracy of the test. The process requires a thorough understanding of the test objectives and methods of the test. Published data, calibration information, and engineering judgement shall be used to understand and, if possible, eliminate the systematic errors in measurements.

Systematic uncertainty of a measurement is identified as b_X. The individual systematic uncertainties can be combined into the systematic uncertainty of the result, b_R. The systematic uncertainty of the result can be calculated according to the square root of the sum of squares rule.

$$b_R = \sqrt{\sum_{i=1}^{n} \left(b_{X_i}\theta_i\right)^2} \tag{7-7-1}$$

where

b_R = the systematic uncertainty of the result
b_{X_i} = the systematic uncertainty of the result of a measured parameter, i
n = the number of measured parameters
θ_i = the relative sensitivity coefficient for a measured parameter, i

The systematic uncertainty is assumed to have a normal distribution. If the positive and negative systematic uncertainty limits are not symmetrical, positive and negative values of the random uncertainty shall be calculated separately. If different values of the systematic uncertainty have been calculated for positive and negative systematic uncertainty limits, the larger value shall be used to compute the total uncertainty.

7-8 RANDOM STANDARD UNCERTAINTY FOR SPATIALLY UNIFORM PARAMETERS

The standard deviation, s_X, is a measurement of the dispersion of the sample measurements, the standard deviation of the mean, $s_{\overline{X}}$, and a characteristic degree of freedom ($\upsilon = N - 1$). Test measurements shall be reduced to average values and the standard deviation calculated before the performance and uncertainty calculations can be executed. The random standard uncertainty is calculated using the sample standard deviation. For a corrected test result, R, calculated from many measured parameters, there is a combined standard uncertainty for the result, s_R, for the combined measurement parameters.

(a) Sample Mean. The mean, $\overline{X}$, for the sample is calculated from

$$\overline{X} = \frac{1}{N}\sum_{i=1}^{N} X_i \tag{7-8-1}$$

where

N = number of readings for each set
$X_{\rm i}$ = average value for measurement set i

(b) Pooled Averages. For parameters measured several times during a test period that have M sets of measurements with N readings for each set, the average value for measurement set k is as follows:

$$\overline{\overline{X}} = \frac{1}{M}\sum_{k=1}^{M} \overline{X}_k \tag{7-8-2}$$

where

M = number of sets of measurements
$\overline{\overline{X}}$ = pooled average of the sample set
$\overline{X}_k$ = average value for measurement set k

(c) Sample Standard Deviation. For measurements that do not exhibit spatial variations, the standard deviation, s_X, of an averaged measurement, $\overline{X}$, based on statistical analysis is calculated from the N multiple measurements of X according to the equation

$$s_X\left[\sum_{i=1}^{N} \frac{(X_i - \overline{X})^2}{N - 1}\right]^{1/2} \tag{7-8-3}$$

where

N = the number of times the parameter is measured

(d) Random Standard Uncertainty of the Mean. The random standard uncertainty of the mean of an averaged measurement, $\overline{X}$, based on statistical analysis is calculated from N multiple measurements of X according to the equation

$$s_{\overline{X}} = \frac{s_X}{\sqrt{N}} \tag{7-8-4}$$

where

$s_{\overline{X}}$ = the standard deviation of the mean

(e) Random Standard Uncertainty of the Result. The random uncertainty of the result is determined from the propagation equation (see ASME PTC 19.1). There are two forms.

The absolute random standard uncertainty is determined using

$$S_R = \left[\sum_{i=1}^{l} \left(\theta_i s_{\overline{X}_i} \right)^2 \right]^{1/2} \tag{7-8-5}$$

where

θ = absolute sensitivity coefficient

l = counter for correlated sources of systematic error

The relative random standard uncertainty of a result is determined using

$$\frac{S_R}{R} = \left[\sum_{i=1}^{l} \left(\theta'_i \frac{s_{\overline{X}_i}}{\overline{X}_i} \right)^2 \right]^{1/2} \tag{7-8-6}$$

where

θ' = relative sensitivity coefficient

l = counter for correlated sources of systematic error

7-9 RANDOM STANDARD UNCERTAINTY FOR SPATIALLY NONUNIFORM PARAMETERS

The spatial contribution to the systematic standard uncertainty for a given parameter is calculated as follows:

$$b_{\text{spatial}} = \frac{S_{\text{spatial}}}{\sqrt{J}} \tag{7-9-1}$$

where

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

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

$$= \sqrt{\frac{\sum_{i=1}^{J} (\overline{X}_i - \overline{\overline{X}})}{J - 1}}$$

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

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

7-10 CORRELATED SYSTEMATIC STANDARD UNCERTAINTY

For multiple measurements where systematic errors are not independent, systematic errors are correlated. Examples include measurements of different parameters taken with the same instrument, or multiple instruments calibrated with the same standard. For these cases, Code users shall consult ASME PTC 19.1 to address the proper approach for uncertainty calculations. The general equation for calculating the correlated systematic uncertainty is

$$b_R = \sum_{i=1}^{l} (\theta i b i)^2 + 2 \sum_{i=1}^{l-1} \sum_{k=i+1}^{l} \theta_i \theta_k b_{ik} \tag{7-10-1}$$

NONMANDATORY APPENDIX A
SAMPLE CALCULATION: IGCC GASIFICATION BLOCK

A-1 INTRODUCTION

This Appendix provides a sample calculation for how this test Code is applied for the gasification block of an IGCC power plant at test conditions that are different than the design reference conditions. The example identifies how correction factors are used to correct key measurements to design (reference) conditions. (Equations in this example are given in SI units only.)

A-2 CYCLE DESCRIPTION

The gasification block of the IGCC power plant used in this sample calculation is shown in Figures A-2-1 and A-2-2. The plant configuration is based on the original design of the IGCC plant (Tampa Electric Polk Power Station). In this example, as in most cases, the gasification block is connected to the rest of an operating IGCC plant during the test. Another option is to flare the raw syngas during the test, although environmental restrictions often preclude this option.

There is a single train throughout the plant, which includes one air separation unit, one gasification train, one gas turbine, and one steam turbine. The gasifier is a slurry fed (coal or other solids), pressurized, oxygen-blown, entrained flow reactor. A radiant syngas cooler and convective coolers extract high-level heat from the syngas exiting the gasifier.

For the test associated with this sample calculation, the gas turbine is base loaded, and the power output is governed by the ambient conditions and the syngas composition. All the synthesis gas from the process island is used in the gas turbine to produce power and there is no export of steam or syngas. For this reason, the gasifier production rate is set by the gas turbine load. The sample calculations given below are only for the gasification block of the IGCC plant. The ASU, syngas conditioning, and power block are outside the scope of this example.

The IGCC parameters relevant to this example are described below. All other areas of the IGCC plant are configured to support the 192-MW gas turbine and the 136-MW steam turbine.

(a) Gas Turbine. 192 MW nominal rating at inlet conditions of 15°C, 1 009 mbar, 60% relative humidity (RH) (59°F, 14.63 psia, 60% RH)

(b) Steam Turbine. Condensing type, 136 MW nominal rating

(c) Gasifier. Oxygen-blown, entrained-flow, slurry-fed, slagging gasifier

(d) Syngas LHV. 10.12 MJ/kg at 25°C (4,349 Btu/lb at 77°F)

A-3 BASIS FOR EXAMPLE CASE

A commercially available thermodynamic modeling tool was used to calculate gasification block performance using data available in the public domain. Site conditions and design data for the coal and oxidant are shown in Table A-3-1, and the block flow diagrams of the power plant and the gasification island are shown in Figures A-2-1 and A-2-2.

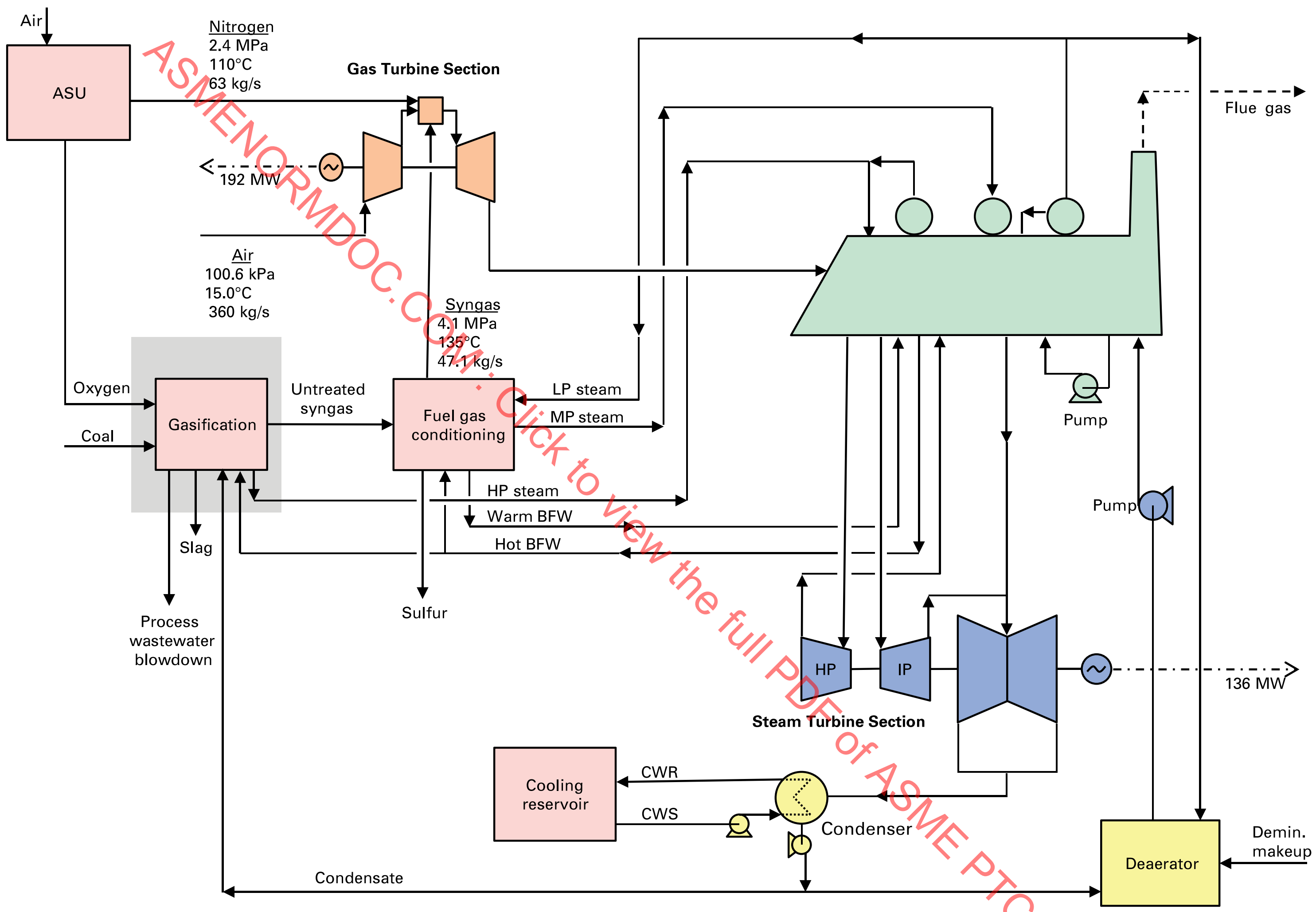
A-4 TEST BOUNDARY

The gasification block test boundary is shown in the grey highlighted area of Figures A-2-1 and A-2-2. All energy streams entering or exiting this highlighted area can easily be identified. Physical properties of all input and output energy streams must be determined with reference to the point at which they cross the test boundary.

A-5 TEST CORRECTIONS

Table A-5-1 lists the additive and multiplicative correction factors applied to the measured parameters in this sample calculation, and Figures A-5.5-1, A-5.6-1, A-5.8-1, and A-5.9-1 show the corresponding correction curves. These curves and fitted equations are based on this specific plant model and should not be used generically for any ASME PTC 47.2 test.

Figure A-2-1 A Simplified Sketch Separating the Gasification Block From an Integrated Gasification and Combined Cycle Plant



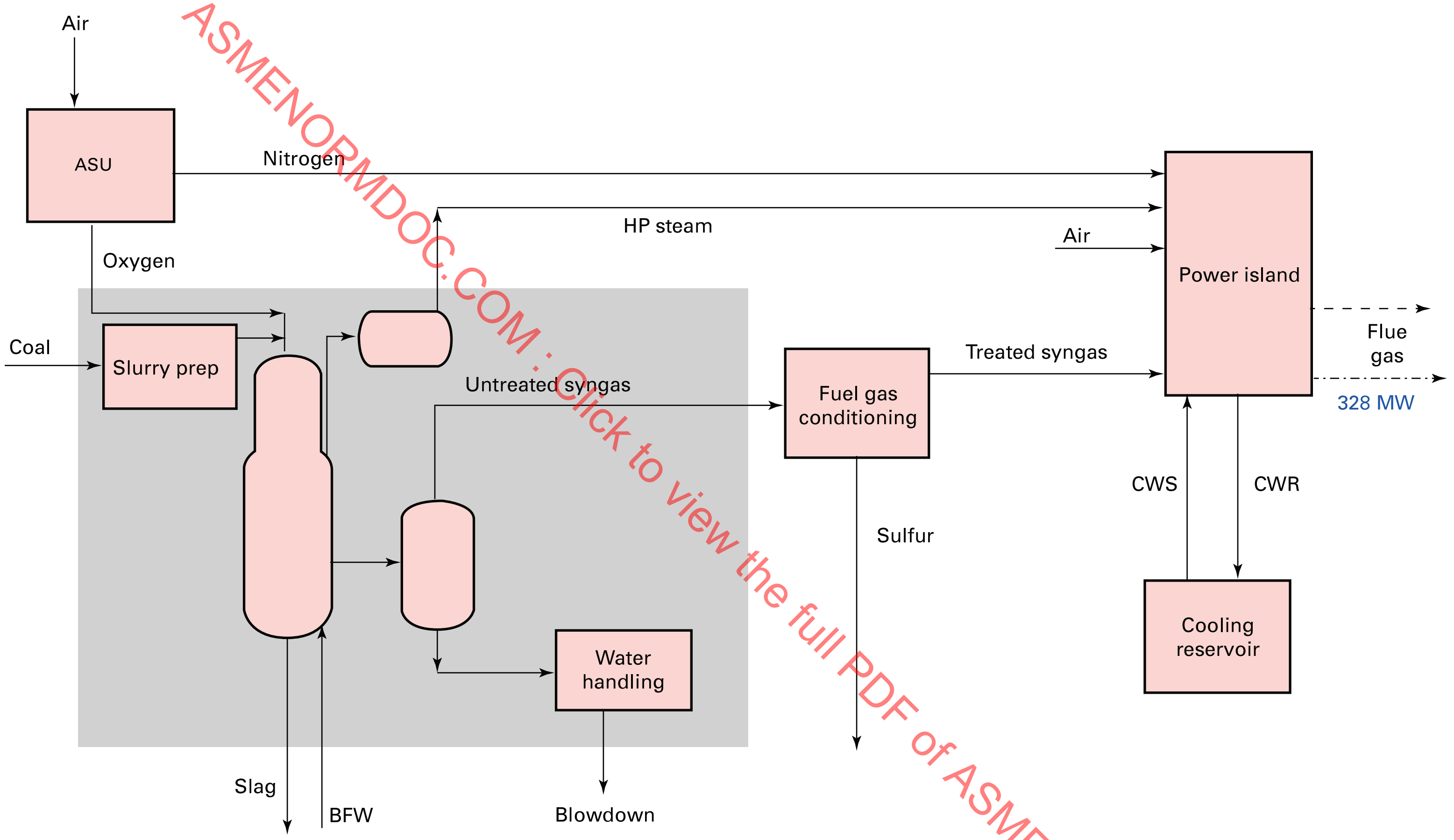
GENERAL NOTES:

(a) The gasification block is shown in gray.

(b) Abbreviations are defined as follows:

ASU = air separation unit
BFW = boiler feedwater
CWR = cooling water return
CWS = cooling water supply
DA = deaerator
HP = high pressure
IP = inlet pressure
LP = low pressure
MP = medium pressure

Figure A-2-2 A Simplified Block Diagram Illustrating the General Configuration of the Gasification Block



GENERAL NOTES:
(a) The gasification block is shown in gray.
(b) See Figure A-2-1, General Note (b) for definitions of the abbreviations.

Table A-3-1 Reference Design Data for the Tampa Electric Polk Power Station

Parameter	Value, SI Units (U.S. Customary Units)
Site Conditions	
Ambient temperature	15°C (59°F)
Relative humidity	60%
Elevation	38.1 m (125 ft)
Ambient pressure	1 009 mbar (14.63 psia)
Properties of Coal as Received [Note (1)]	
Carbon	69.36% wt
Hydrogen	5.18% wt
Nitrogen	1.22% wt
Oxygen	5.41% wt
Sulfur	2.89% wt
Ash and chlorine	9.94% wt
Moisture	6.00% wt
Higher heating value	29 751 kJ/kg (12,791 Btu/lb)
Lower heating value	28 474 kJ/kg (12,242 Btu/lb)
Oxidant Composition	
Oxygen	95.9% mol
Nitrogen	1.43% mol
Argon	2.66% mol

NOTE: (1) Coal properties and related values are for Pittsburgh No. 8 coal.

Additive correction factors are set equal to 0 if they are not applicable to the measured results for the specific type of plant being tested, or to the test objectives. Multiplication correction factors are set equal to unity if they are not applicable to the measured results for the specific type of plant being tested, or to the test objectives.

A-5.1 Syngas Energy Correction for Heat Recovery Duty, AS_2

The additive correction AS_2 is based on the heat recovery duty (HRD).

$$\mathrm{AS}_2 = \frac{\mathrm{HRD}_{\mathrm{tst}} \times W_{\mathrm{pg,tst}}}{W_{\mathrm{sg,tst}} - \mathrm{HRD}_{\mathrm{ref}} \times W_{\mathrm{pg,ref}}/W_{\mathrm{sg,tst}}} \tag{A-5-1}$$

$$\begin{aligned} \mathrm{HRD}_{\mathrm{ref}} &= W_{\mathrm{fw,ref}} \times (H_{\mathrm{stm,ref}} - h_{\mathrm{fw,ref}}) \\ &= 69.82\,\mathrm{kg/s} \times (2\,716.72\,\mathrm{kJ/kg} - 1\,443.\,03\,\mathrm{kJ/kg}) = 88\,933\,\mathrm{kW(t)} \end{aligned} \tag{A-5-2}$$

$$\begin{aligned} \mathrm{HRD}_{\mathrm{tst}} &= W_{\mathrm{fw,tst}} \times (H_{\mathrm{stm,tst}} - h_{\mathrm{fw,tst}}) \\ &= 67.02\,\mathrm{kg/s} \times (2\,716.72\,\mathrm{kJ/kg} - 1\,451.87\,\mathrm{kJ/kg}) = 84\,775\,\mathrm{kW(t)} \end{aligned} \tag{A-5-3}$$

$$\begin{aligned} \mathrm{AS}_2 &= \frac{84\,775\,\mathrm{kW(t)} \times 47.109\,\mathrm{kg/s}}{47.820\,\mathrm{kg/s} - 88\,933\,\mathrm{kW(t)} \times 49.997\,\mathrm{kg/s}\ /\ 50.712\,\mathrm{kg/s}} \\ &= 4\,163\,\mathrm{kW(t)} \end{aligned}$$

Table A-5-1 Additive and Multiplicative Corrections

Correction Factor Number	Parameter	Correction Factor for: Product Syngas Energy	Primary Fuel Energy	Secondary Fuel Energy	Auxiliary Power
Additive					
1	Sorbent feed rate	$AS_1 = 0$ [Note (1)]	$AF_1 = 0$ [Note (1)]	0	$AP_1 = 0$ [Note (1)]
2	Heat recovery duty	AS_2 [Note (2)]	0	0	0
3	Primary fuel flow	0	0	0	AP_3 [Note (3)]
Multiplicative					
1	Fuel composition	MS_1, Figure A-5.5-1	MF_1, Figure A-5.8-1	$MF2_1 = 1$ [Note (4)]	1
2	Primary fuel supply temperature	1	$MF_2 = 1$ [Note (5)]	1	1
3	Secondary fuel supply temperature	1	1	$MF2_3 = 1$ [Note (4)]	1
4	Sorbent input properties	$MS_4 = 1$ [Note (1)]	$MF_4 = 1$ [Note (1)]	1	1
5	Slurry concentration (for slurry-fed systems)	MS_5, Figure A-5.6-1	MF_5, Figure A-5.9-1	1	MP_5 [Note (3)]
6	Oxygen concentration	1	$MF_6 = 1$ [Note (6)]	1	1
7	Oxidant temperature	1	$MF_7 = 1$ [Note (6)]	1	1
8	Syngas demand	MS_8 [Note (7)]	MF_8 [Note (7)]	1	1

NOTES:

(1) Sorbent is not used in this example; therefore AS_1, AF_1, AP_1, MS_4, and MF_4 are not relevant to the sample calculations.

(2) The heat recovery duty correction is a direct calculation that does not need a correction curve.

(3) Auxiliary power corrections for primary fuel flow and slurry concentration are direct calculations that do not need correction curves.

(4) Secondary fuel is not used in this example; therefore, $MF2_1$ and $MF2_3$ are not relevant to the sample calculation.

(5) The primary fuel slurry temperature in the test is the same as in the reference case; therefore MF_2 is not relevant to the sample calculation.

(6) Oxidant concentration and temperature are the same as in the reference case; therefore MF_6 and MF_7 are not relevant to the sample calculation.

(7) The syngas demand correction is a direct calculation that does not need a correction curve.

A-5.2 Auxiliary Power Correction for Coal Receiving and Handling, AP_{3crh}

The auxiliary power correction for coal receiving and handling, AP_{3crh}, is determined from the following equation:

$$AP_{3crh} = B_{ax} \times (W_{pf,ref} - W_{pf,meas}) \quad \text{(A-5-4)}$$

where

AP_{3crh} = additive fuel flow correction, kW
B_{ax} = auxiliary power sensitivity to coal flow, kWs/kg (kWs/lb)
$W_{pf,ref}$ = reference primary fuel flow, kg/s (lb/s)
$W_{pf,meas}$ = measured primary fuel flow, kg/s (lb/s)

$$AP_{3crh} = 3.946\,\text{kWs/kg} \times (22.50\,\text{kg/s} - 25.20\,\text{kg/s}) = -11\,\text{kW} \quad \text{(A-5-5)}$$

A-5.3 Auxiliary Power Correction for Slurry Preparation and Feed, AP_{3prep}

The auxiliary power correction for slurry preparation and feed, AP_{3prep}, is determined from the following equation:

$$AP_{3prep} = 35.522\,\text{kWs/kg} \times (22.50\,\text{kg/s} - 25.20\,\text{kg/s}) = -96\,\text{kW} \quad \text{(A-5-6)}$$

A-5.4 Auxiliary Power Correction for Slurry Recycle Pump, AP_{3rc}

The auxiliary power correction for slurry recycle pump, AP_{3rc}, is determined from the following equation:

$$AP_{3rc} = 3.946\,\text{kWs/kg} \times (22.50\,\text{kg/s} - 25.20\,\text{kg/s}) = -11\,\text{kW} \quad \text{(A-5-7)}$$

A-5.5 Syngas Energy Correction for Primary Fuel LHV, MS_1

See Figure A-5.5-1.

A-5.6 Syngas Energy Correction for Slurry Concentration, MS_5

See Figure A-5.6-1.

A-5.7 Corrections for Syngas Demand, MS_8 and MF_8

Multiplicative corrections MS_8 for syngas energy and MF_8 for primary fuel energy are both equal to the reference product syngas energy divided by the test product syngas energy.

$$\begin{aligned} MS_8 &= \frac{W_{sg,ref} \times LHV_{sg,ref}}{W_{sg,test} \times LHV_{sg,test}} \\ &= \frac{MF_8 = 49.997\ \text{kg/s} \times 9\,639.9\ \text{kJ/kg}}{47.109\ \text{kg/s}\ \times 9\,827.1\ \text{kJ/kg}} = 1.04108 \end{aligned} \tag{A-5-8}$$

where

$LHV_{sg,ref}$ = reference LHV of product syngas , kJ/kg (Btu/lb)
$LHV_{sg,test}$ = test case LHV of product syngas, kJ/kg (Btu/lb)
MF_8 = multiplicative primary fuel energy correction
MS_8 = multiplicative syngas demand correction, dimensionless
$W_{sg,ref}$ = reference mass flow of product syngas, kg/s (lb/s)
$W_{sg,test}$ = test case mass flow of product syngas, kg/s (lb/s)

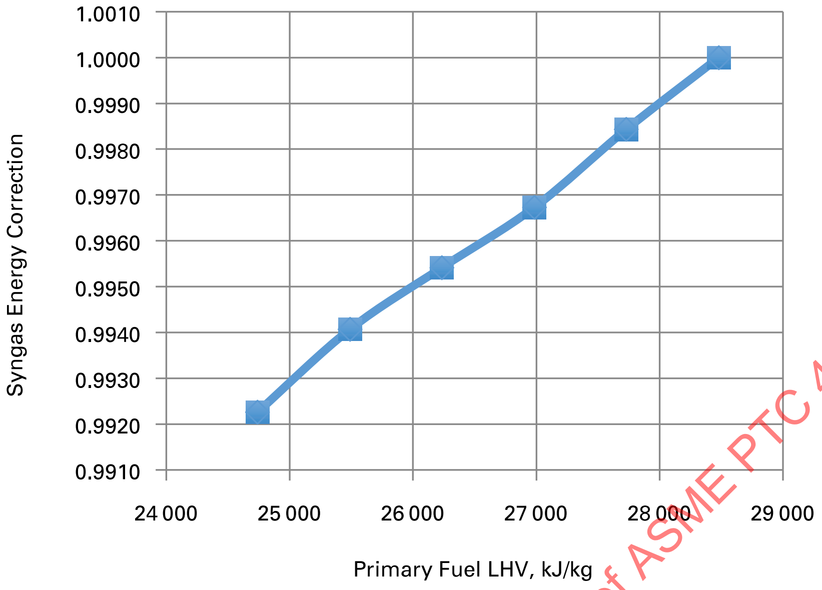
A-5.8 Primary Fuel Energy Correction for Primary Fuel LHV, MF_1

See Figure A-5.8-1.

A-5.9 Primary Fuel Energy Correction for Slurry Concentration, MF_5

See Figure A-5.9-1.

Figure A-5.5-1 Syngas Energy Correction for Primary Fuel LHV, MS_1



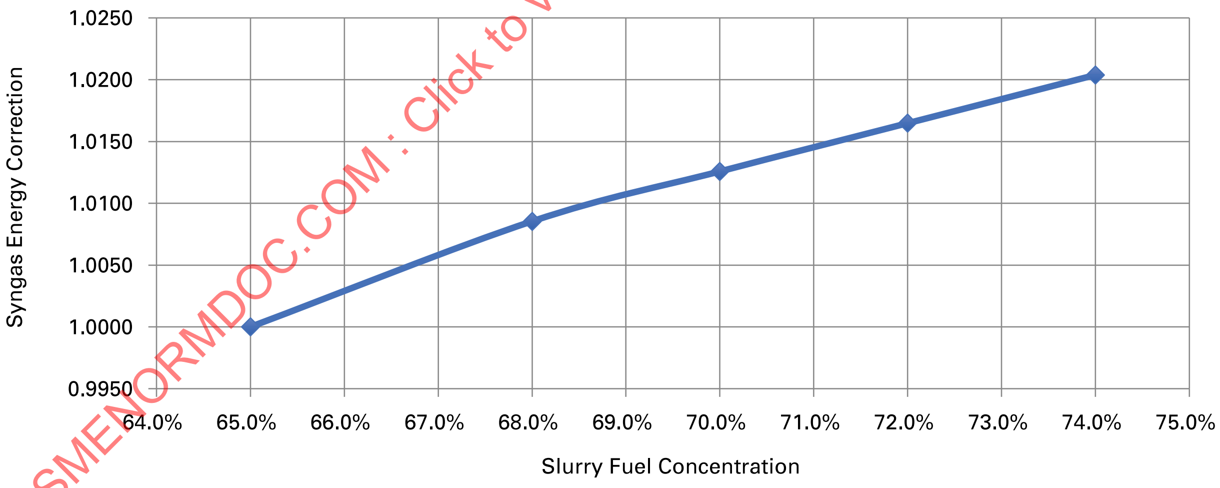
GENERAL NOTE: MS_1 shows corrections to product syngas energy for various lower heating values of primary fuel.

$$MS_1 = 7.95957\,E{-}13 \times (LHV)^3 - 2.72815\,E{-}08 \times (LHV)^2 + 0.000315994 \times LHV - 0.240107788$$

where

LHV = lower heating value of primary fuel, kJ/Nm^3 (Btu/scf)

Figure A-5.6-1 Syngas Energy Correction for Slurry Concentration, MS_5



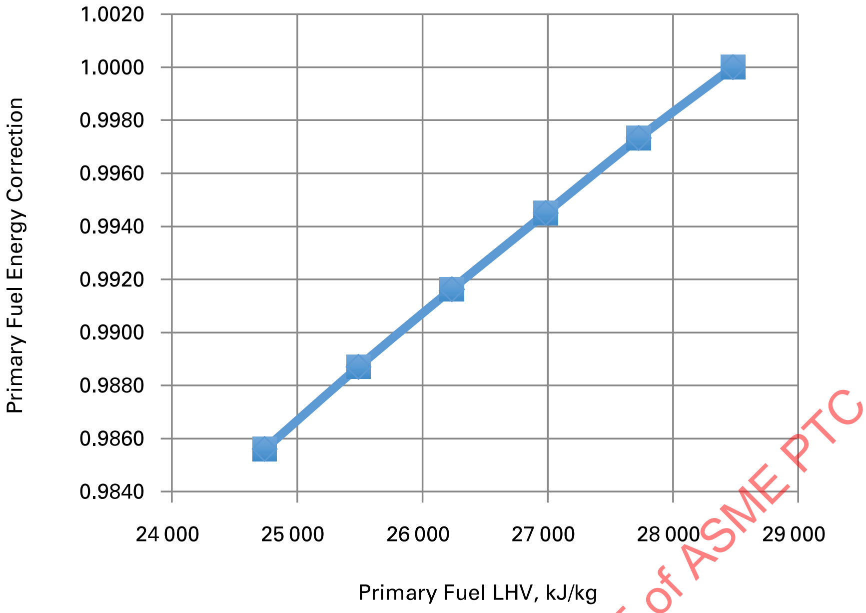
GENERAL NOTE: MS_5 shows corrections to product syngas energy for various values of slurry concentration.

$$MS_5 = 13.60923665 \times (CinS)^3 - 29.10976471 \times (CinS)^2 + 20.94076204 \times CinS - 4.050048954$$

where

CinS = concentration of carbon in slurry, %

Figure A-5.8-1 Primary Fuel Energy Correction for Primary Fuel LHV, MF_1



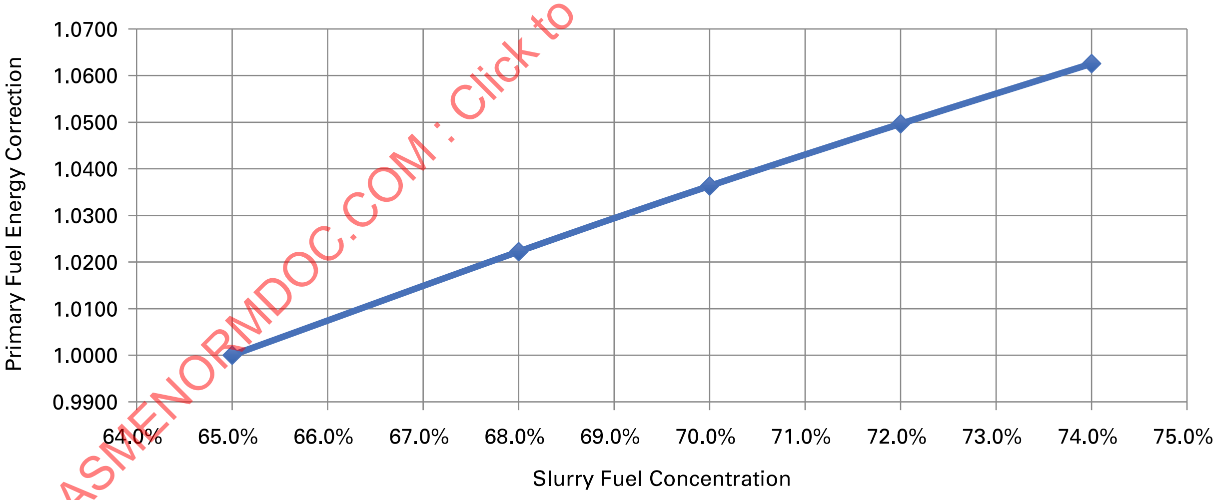
GENERAL NOTE: MF_1 shows corrections to primary fuel energy for various lower heating values of primary fuel.

$$MF_1 = 1.50706\,E{-}14 \times (LHV)^3 - 9.67259\,E{-}10 \times (LHV)^2 + 2.51682\,E{-}05 \times LHV + 0.80919301$$

where

LHV = lower heating value of primary fuel, kJ/Nm^3 (Btu/scf)

Figure A-5.9-1 Primary Fuel Energy Correction for Slurry Concentration, MF_5



GENERAL NOTE: MF_5 shows corrections for primary fuel energy for various values of slurry concentration.

$$MF_5 = 1.103559641 \times (LHV)^3 - 3.070774761 \times (LHV)^2 + 3.361905455 \times LHV - 0.190905066$$

where

LHV = lower heating value of primary fuel, kJ/Nm^3 (Btu/scf)