Integrated Gasification Combined Cycle Power Generation Plants

Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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Three Park Avenue • New York, NY 10016

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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 Performance Test Code has heretofore not existed to determine 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 traditional fuels for gas turbines have been natural gas and distillate fuels. Today, future environmental concerns and future economic scenarios are causing power generation suppliers to develop gasification systems that can use solid and liquid fuels (e.g., coal, biomass, waste, heavy oils, etc.). Preparation of an alternative fuel suitable for a gas turbine includes removal of ash, contaminants, and erodents/corrodents. In response to these needs, the ASME Board on Performance Test Codes approved the formation of a committee (PTC 47) in 1993 with the charter of developing a Code for the determination of overall power plant performance for gasification power generation plants. The organizational meeting of this committee was held in November 1993. The resulting committee included experienced and qualified users, manufacturers, and general interest category personnel.

The committee has striven to develop an objective code that addresses the multiple needs for explicit testing methods and procedures, while attempting to provide maximum flexibility in recognition of the wide range of plant designs and the multiple needs for this Code.

The PTC 47 Committee approved the Code on March 28, 2006. It was also approved by the PTC Standards Committee on March 28, and approved and adopted as a Standard practice of the Society by action of the Board on Standardization and Testing on May 18, 2006. Finally, it was approved as an American National Standard by the ANSI Board of Standards Review on July 26, 2006.

PERFORMANCE TEST CODE COMMITTEE 47 ON INTEGRATED GASIFICATION COMBINED CYCLE POWER GENERATION PLANT PERFORMANCE TESTING

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

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SPECIAL NOTE:

The Committee acknowledges, with appreciation, the contribution to the development of this Code by former members Ronald Bannister, David Breton, Mark Mirolli, and Arthur Smith.

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

Secretary, PTC 47 Committee The American Society of Mechanical Engineers Three Park Avenue New York, NY 10016-5990

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

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

Interpretations. Upon request, the PTC 47 Committee will render an interpretation of any requirement of the Code. Interpretations can only be rendered in response to a written request sent to the Secretary of the PTC 47 Committee.

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

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

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

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

Attending Committee Meetings. The PTC 47 Committee holds meetings or telephone conferences, which are open to the public. Persons wishing to attend any meeting or telephone conference should contact the Secretary of the PTC 47 Committee or check our Web site, http://cstools.asme.org.

INTRODUCTION

Applications and Limitations

This Code provides procedures for the determination of integrated gasification combined cycle (IGCC) power plant thermal performance, electrical output, and product gas and/or process steam output. Test results provide measures and evaluations of the overall thermal performance of an IGCC power plant and other subsystems at a specified cycle configuration, operating disposition, and/or fixed power level, and at a specific set of base reference conditions.

Test results can be used as defined by a contract to determine the fulfillment of contract guarantees. Test results can also be used by a plant owner to compare plant performance to a design number, or to trend plant performance changes in time. However, the results of a test conducted in accordance with this Code will not provide a basis for comparing the thermoeconomic effectiveness of different plant designs.

Power plants are composed of many equipment components. Test data required by this Code may also provide limited performance information for some of this equipment. PTC 47, in conjunction with PTC 46, has been designed to determine the performance of the entire gasification combined cycle power generation plant as a whole system. Where the performance of individual equipment operating within the constraints of its design-specified conditions is of interest, ASME PTCs developed for testing of the specific components should be used.

This document is part of the following set of proposed related documents:

(*a*) PTC 47, Integrated Gasification Combined Cycle Plants, for testing the overall plant performance of an IGCC plant.

(*b*) PTC 47.1, Cryogenic Air Separation Unit, for testing the performance of the air separation unit (ASU). If the physical IGCC plant includes an ASU, the inclusion of the ASU within the overall test envelope is recommended, but not required.

(*c*) PTC 47.2, Gasification System, for testing the thermal performance of the combined gasifier and fuel gas cleaning equipment.

(*d*) PTC 47.3, Fuel Gas Cleaning, for testing the contaminant content of gas delivered to the power block.

(e) PTC 47.4, IGCC Power Block, for testing the thermal performance of the gas turbine combined cycle power block.

The term *IGCC plant* as used within this Code refers to any plant that converts a hydrocarboncontaining feed or primary fuel into a clean fuel gas for a gas turbine combined cycle. The term *integration* is not precisely defined; it refers to the general coupling of gasification equipment and power generation equipment within a single facility. Integration, within IGCC plants, may also refer to gasifiers with heat recovery connected to the steam power cycle, extraction steam from the power block used for gasification, an ASU that delivers oxygen to an oxygen-blown gasifier or nitrogen to the gas turbine, or an ASU that receives some or all of its air supply or power supply from the gas turbine combined cycle.

IGCC plants may also generate products other than electricity, such as synthesis gas and process steam.

Guidance in Using This Code

As with all Performance Test Codes, PTC 47 was developed primarily to address the needs of contract acceptance or compliance testing. This is not intended, however, to limit or prevent the use of this Code for other types of testing where the accurate determination of overall power plant performance is required.

This Code is not a tutorial. It is intended for persons experienced in performance testing. A working knowledge of power plant operations; thermodynamic analysis; test measurement methods; and the use, control, and calibration of measuring and test equipment are presumed prerequisites. Proper use and interpretation of this Code also requires a working knowledge of

ASME Performance Test Codes. At a minimum, users of this Code should be familiar and knowledgeable with PTC 1, General Instructions, and PTC 19.1, Test Uncertainty.

Other PTC 19 Instrument and Apparatus supplement series codes may need to be consulted during the planning and preparation phases of a test. In addition, some measurement methods specified in PTC 47 refer to other PTCs for testing of specific equipment.

PTC 47 is recommended for use whenever the performance of an IGCC plant must be determined with minimum uncertainty. It is suitable for incorporation into commercial agreements to serve as the means of determining fulfillment of contract obligations. However, incorporation of PTC 47 into a contract does not eliminate the need for test planning. PTC 47 provides the protocol, or framework, for a test. As defined in Section 3, the use of PTC 47 requires the development of a detailed test plan that must be reviewed and approved by all parties prior to the start of testing.

INTEGRATED GASIFICATION COMBINED CYCLE POWER GENERATION PLANTS

Section 1 Object and Scope

1-1 OBJECT

This Code provides procedures for performance testing of integrated gasification combined cycle (IGCC) power plants to determine fuel gas flow and quality, thermal efficiency (heat rate), and power output at specified operating conditions.

It also provides procedures to determine the flow and quality of cleaned fuel gas produced by the IGCC plant.

(*a*) If electric power is the only product of the IGCC plant, this Code provides procedures for determining

- (1) corrected net power
- (2) corrected heat rate
- (3) corrected heat input

(*b*) If the IGCC plant performance test also includes exported synthesis gas and/or process steam, this Code provides procedures for determining

- (1) corrected net power
- (2) corrected heat input
- (3) export syngas pressure
- (4) export syngas temperature
- (5) export syngas composition
- (6) export syngas flow
- (7) export syngas heating value

(8) product gas contaminant content (see subsection 1-2)

(9) export steam pressure

(10) export steam temperature

(11) export steam composition

(12) export steam flow

(*c*) Tests may be designed to satisfy different goals. Two such tests are

(1) Specified Corrected Net Power Test

(2) Specified Disposition Test

1-2 SCOPE

This Code covers a defined range of primary fuel characteristics, but is limited to combined-cycle, powergeneration systems using gas and steam turbines.

This Code defines the boundaries of the overall IGCC power plant to encompass three major plant sections the air separation unit (ASU, for oxygen-blown gasifiers or plants that use nitrogen), the gasification process (including gas cleanup), and the power block. Tests conducted by this Code determine the quantity and quality of fuel gas by its flow rate, temperature, pressure, composition, heating value, and its content of contaminants. Contaminants are compounds that are potentially deleterious to the gas turbine and power block in general, or are precursors to stack emissions. Contaminants to be measured are sodium (Na), potassium (K), vanadium (V), lead (Pb), calcium (Ca), barium (Ba), manganese (Mn), phosphorus (P), sulfur compounds (H₂S and COS), nitrogen compounds (HCN and NH₃), chlorine compounds (HCl), and particulate matter.

Recommendations are included for the following in pretest agreements: testing procedures, types of instruments, methods of measurement, methods of calculation, and contents of test reports.

Regulatory compliance testing of IGCC power plants is not covered by this Code.

1-3 UNCERTAINTY

Calculation procedures in accordance with those set forth in PTC 19.1 are presented to determine the uncertainty in measurements and performance parameters associated with the specified test procedures of this Code.

Under typical conditions and with currently available instruments, the largest expected total uncertainties in the test results are those in Table 1-3.

A post-test uncertainty analysis is required. However, a post-test uncertainty analysis is optional if parties to the test agree that the test adhered to all instrumentation requirements and procedures contained in this Code and to the agreed test procedure.

Corrected Values	Power Only	Multiple Products	
Input fuel flow	3%	3%	
Input fuel heating value	1%	1%	
Export syngas temperature		3°C (5°F)	
Export syngas pressure (abs.)		0.5%	
Product export syngas composition		1%	
Export syngas volumetric flow		1%	
Export syngas heating value		1%	
Export steam temperature [Note (1)]		3°C (5°F)	
Export steam pressure (abs.)		0.5%	
Export steam flow		1%	
Power plant thermal efficiency	3.5%	Note (2)	
Power plant electrical output	1%	1%	

Table 1-3 Largest Expected Test Uncertainties

NOTES:

(1) Steam is assumed to be superheated.

(2) Not technically definable. Thermal efficiency and heat rate are succinctly defined for a power-only plant, but a single "efficiency" calculation for a multiple-product plant requires agreement on the relative usefulness of each product. The code performance test measures all significant streams entering and leaving the plant, from which a variety of ratios can be calculated if desired.

Section 2 Definitions and Descriptions of Terms

This Section contains technical definitions used in this Code, and symbols and subscripts used in the equations.

2-1 DEFINITIONS

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

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

acid gas: contaminants in the syngas, consisting of hydrogen sulfide (H₂S), carbonyl sulfide (COS), and carbon dioxide (CO₂). Acid gas may also refer to a concentrated stream of one or more of these components.

acid gas removal process: process that removes one or more of the acid gas components from the syngas, also referred to as the gas cleanup process. NH₃, HCN, and HCl have several and varied methods of removal, such as a water wash, which goes to subsequent water cleanup before discharge. See *ambient temperature acid gas removal process*, *cold acid gas removal process*, and *hot acid gas removal process*.

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

aftercooler: heat exchanger for cooling a fluid, following the last stage of compression.

agglomerating ash gasifier: 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 additional oxygen required to complete other reactions, i.e., the sulfation reaction.

air, excess: air supplied to burn a fuel in addition to the minimum necessary for complete combustion. Excess air is expressed as a percentage of the corrected theoretical air in this Code.

air, infiltration: influx of air into the steam generator envelope.

air, theoretical: 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:* gasification process in which the oxidizing agent is supplied as air rather than oxygen.

air integrated air separation unit: air separation process that receives all, or a part of, the total air feed requirement by extraction of a portion of the compressed air from the gas turbine.

air pretreatment: a unit that removes water, carbon dioxide, and some hydrocarbon contaminants from the compressed air stream prior to processing in the cryogenic sections of the ASU. Pretreatment is usually based on a cyclical, adsorption/desorption (molecular sieve) based, ambient temperature process using heated, dry nitrogen produced by the ASU for regeneration of the adsorbent.

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

ambient temperature acid gas removal process: acid gas removal process operating at 90°F to 120°F, usually employing a chemical or mixed chemical/physical solvent to react with the acid gases, followed by regeneration of the solvent by heating. Examples of solvents and processes include methyldiethanolamines (MDEA), Sulfinol, Purisol, Selefining, and Selexol.

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

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

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

ash: 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; 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 which are not captured in the slag.

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

attemperator: see desuperheater.

auxiliary power: electrical 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.

booster compressor: centrifugal compressor used to increase air pressure from gas turbine air compressor discharge to a pressure required by the gasification process. It is used mainly in air-blown gasification processes.

bottoming cycle: lower-temperature thermodynamic power cycle of a combined cycle system.

Btu (*British thermal unit*): 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 one Btu/lb being equal to 2.326 kJ/kg, exactly, and called the *International Table Btu*. One Btu is equal to 1055.05585262 joules.

calcination: 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*): total moles of calcium in the sorbent feed divided by the total moles of sulfur in the fuel feed.

calcium utilization: percent 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.

calorie: unit of energy, defined as equal to 4.1868 joules, exactly, and called the *International Table calorie*.

capacity, maximum: 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: indicator of the degree to which the fuel carbon compounds are converted to carbon-containing gaseous components. These gaseous components include CO, CO₂, CH₄, COS, and C_xH_y (C_xH_y includes organic gaseous compounds such as ethane, propane, butane, etc., and cyclic organic compounds such as benzene, etc.). Carbon conversion efficiency can also be determined as 1.00 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: solid residue remaining after the removal of moisture, volatile matter, and possibly some fixed carbon from coal.

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

coal rank: 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: in general, coke is made from bituminous coal (or blends of bituminous coal) from which the volatile constituents have been driven off by heat, so that the fixed carbon and ash are fused together. Coke is hard and porous. Petroleum coke is a similar material that is derived from oil refinery operations and usually contains a high sulfur content.

cold acid gas removal process: acid gas removal process operating below ambient temperature, usually employing a physical solvent to react with the acid gases.

cold box: enclosure containing cryogenic equipment that is part of the ASU.

combined cycle: two sequential thermodynamic power conversion systems operating at different temperatures. For the purposes of this Code, a combined cycle plant is composed of a gas turbine cycle followed by a steam turbine cycle generally supplied by the hot exhaust energy of the gas turbine.

combustion chamber: enclosed space provided for the combustion of fuel.

combustor: heat source consisting of chamber(s) in which fuel burns or otherwise reacts with its working fluid to increase the temperature.

compressor: mechanical rotary component that compresses a working fluid.

control range: capacity range over which the gas turbine, steam turbine, and main steam temperature and/or

reheat steam temperature can be maintained at the rated conditions.

coverage: 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.

credits: energy entering the defined envelope other than the chemical energy in the as-fired fuel. These credits include "sensible heat" (a function of specific heat and temperature) in the fuel, "sensible heat" as in the entering air, "sensible heat" as 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.

dehydration: endothermic chemical reaction that takes place when water is released from calcium hydroxide to form calcium oxide, or from magnesium hydroxide to form magnesium oxide.

desulfurizer: vessel where sulfur gases are removed from the syngas by means of a sorbent.

desuperheater: apparatus for reducing and controlling the temperature of a superheated vapor (attemperator).

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

dry ash gasifier: type of gasifier in which the ash leaves as either agglomerated or nonagglomerated solids, rather than as a molten slag. For example, the Tampella and KRW gasifiers are agglomerating types, but the ash exiting the gasifier is dry and not molten slag.

economizer: heat recovery device designed to transfer heat between fluids, usually from the products of combustion to boiler feedwater.

elevated pressure air separation unit: air separation process that operates at air feed pressures above the level required to produce oxygen and nitrogen products at near atmospheric pressures.

energy balance method: 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: type of gasifier that is characterized by cocurrent flow of the hydrocarbon feed and oxidizing medium. Flow may be either upward or downward.

error, random: sometimes called precision error, random error is a statistical quantity that is expected to be normally distributed. Random error results 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. *error, systematic:* sometimes called bias error. The difference between the average of the total population and the true value. The true systematic or fixed error, which characterizes every member of any set of measurements from the population.

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

fixed carbon: carbonaceous residue less the ash remaining in the test container after the volatile matter has been driven off in making the proximate analysis of a solid fuel in accordance with the appropriate ASTM standard.

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

flue gas: gaseous products of combustion, including excess air.

fluidized bed: bed of suitably sized 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 sufficient velocity to suspend the particles and to impart to them a fluidlike motion.

fluidized bed, bubbling: 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: 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.

freeboard: volume from the upper surface of the expanded bed to the entrance of the convection pass. This definition applies to a fluidized bed of dense solids (bubbling bed) in which there is an identifiable bed surface. It does not apply to a circulating fluidized bed.

freeboard disengaging: open area in the top of fluidizedbed gasification vessels for separation of solids from the gas.

fuel gas contaminants: syngas contaminants include those compounds that are either potentially deleterious to the gas turbine and power block in general or are precursors to stack emissions. These include compounds that include elements such as sulfur (i.e., H₂S and COS), nitrogen (i.e., NH₃ and HCN), chlorine (i.e., HCl), tars and condensables (i.e., organic compounds designated as C_xH_y which may either be long chain hydrocarbons or cyclic compounds), particulates (i.e., inert ash and potentially corrosive components for the gas turbine, including vanadium, lead, calcium, and nickel), and volatilized alkali metals (i.e., sodium and potassium).

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

gas generator: assemblage of equipment consisting of a compressor(s), combustor(s), and a turbine(s) that produces hot gases at elevated pressure. It may be either a single- or multi-spool (rotor) assemblage.

gas generator turbine: turbine portion of a gas generator.

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

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

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

gasifier: vessel in which the gasification reactions take place.

gross heat of combustion at constant volume: 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: mass flow rate of fuel(s) multiplied by the high or low heat value of the fuel(s).

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

heat rate (mechanical or electrical): heat input per unit of power output.

(*a*) For gas turbine heat rate, the turbine is charged with the aggregate heat content (heat of combustion plus enthalpy) of the fuel gas supplied plus any chargeable aggregate enthalpy added by other feed stream and feed stream heaters. It is credited with the aggregate enthalpy of any compressed air streams leaving the turbine envelope. Turbine-generator performance is normally defined on the basis of the gross power output at the generator terminals less the power used by the minimum electrically driven turbine auxiliaries and excitation equipment, supplied as part of the turbine-generator unit, required for reliable and continuous operation.

(*b*) For steam turbine heat rate, the turbine is charged with the aggregate enthalpy of the steam supplied plus any chargeable aggregate enthalpy added by the reheaters. It is credited with the aggregate enthalpy of the feedwater returned from the cycle to the steam generator. Turbine-generator performance is normally defined

on the basis of the gross power output at the generator terminals less the power used by the minimum electrically driven turbine auxiliaries and excitation equipment, supplied as part of the turbine-generator unit, required for reliable and continuous operation.

heat recovery gasification process: process employing a heat exchanger(s) to transfer the heat (radiant and/or convective) contained in the synthesis gas exiting the gasification vessel to a medium such as steam. Examples of this equipment include radiant syngas coolers, firetube boilers, and waterwall type boilers.

heat recovery steam generator (HRSG): heat exchanger(s) to transfer the heat (radiant and/or convective) contained in the exhaust gas from a gas turbine to steam.

heating value: 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/N-m³, 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 H₂O in the combustion products remains in the vapor state. Higher heating value (HHV) is calculated as if all H₂O in the combustion products were condensed, and includes the heat released by that condensation of all H₂O in the combustion products, 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 H₂O formed from the combustion of hydrogen.

higher heating value: see heating value.

hot acid gas removal process: acid gas removal process operating at elevated temperatures and employing gas/solid reactions to remove acid gases.

hot gas desulfurization: process to remove sulfur compounds from the syngas at elevated temperatures. Examples are direct injection of calcium-based sorbent into the gasifier or direct contact of syngas with metaloxide sorbent.

hot gas particulate removal system: system to remove particulate matter from the hot syngas using a barrier-type filter, including ceramic candle filter, fiber filter, screenless granular bed filter, and cross-flow filter.

HRSG: see heat recovery steam generator.

inert gas generator: system of the GCC plant that generates an inert gas (i.e., gas typically containing less than 0.1% oxygen by volume) such as nitrogen or carbon dioxide. The inert gas is used for purging equipment or piping, where the presence of excess oxygen is undesirable.

inert matter: constituents of coal or gas that decrease its efficiency in use, e.g., mineral matter (ash) in coal and moisture in fuel for combustion. Also refers to nonreactive gases such as nitrogen or argon that may be contained in the air or oxygen used for the gasification process, transport gas for moving coal in dry gasifier processes, purge and blanketing gas used in the gasification and combined cycle processes, and carbon dioxide produced by combustion.

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

integration: linking of process streams between the major subsystems of the GCC facility, other than major product streams such as syngas from the gasifier to the gas turbine. Examples of integration include steam produced in the gasifier being sent to the combined cycle, air being extracted from the gas turbine and sent to the air separation unit, and nitrogen produced in the air separation unit being sent to the gas turbine.

intercooler: heat exchanger for cooling a fluid between stages of compression.

joule: work done when the point of application of a force of 1 N is displaced a distance of 1 m in the direction of the force.

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

losses: energy that exits an equipment or group of equipment envelope other than the energy in the output stream(s). Examples are heat lost to the atmosphere, losses because of mechanical inefficiencies, and steam turbine condenser heat loss.

low-Btu gas: synthesis gas produced by gasification with air, having a higher heating value below 7 MJ/N-m³ (180 Btu/scf).

lower heating value: see heating value.

main air compressor: compressor that takes ambient air as feed and compresses it to the operating pressure of the 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, having a higher heating value between 7 MJ/N-m³ and 20 MJ/N-m³ (180 Btu/scf and 500 Btu/scf).

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

moisture: moisture in fuel is determined by appropriate ASTM standards. Free moisture in coal is that portion of total moisture (ASTM test method D 3302) that is in excess of inherent moisture in coal (ASTM method D 1412); it is not to be equated with the weight loss upon air-drying. Free moisture is sometimes referred to as surface moisture in coal is moisture that exists as an integral part of the coal seam in its natural state, including water in pores, but not that present in macroscopically visible fractures. Also water, in liquid or vapor phase, present in another substance.

moving-bed gasifier: type of gasifier characterized by the slow movement of hydrocarbon and ash particles down through a bed while reacting with gases moving up through the bed.

net heat of combustion at constant pressure: 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 the form of vapor. (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 vaporization of the water in the combustion products, including both the water initially present as moisture and that formed by combustion.)

open cycle: thermodynamic power cycle in which the working fluid passes through the system only once and is then exhausted to the atmosphere.

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

oxygen-blown gasification: 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).

peat: an unconsolidated, hydrophilic, yellowish-brown to brownish-black, carbonaceous sediment, formed by accumulation of partially fragmented and decomposed plant remains in swamps and marshes, which retains more than 75% inherent moisture and less than 12% mineral matter in saturated natural deposits.

plant heat rate, gross: total heat input [MJ/h (Btu/hr)] from all fuels and other energy streams to the IGCC

plant divided by the gross power output at the gas and steam turbine generator(s) output terminals (kW). The calculation may be based on either higher heating value or lower heating value, as long as the selected heating value is consistently applied in all calculations.

plant heat rate, net: total heat input [MJ/h (Btu/hr) HHV basis] from all fuels and other energy streams to the IGCC plant divided by the net power output from the plant. The net power output is the difference between the sum of the gross power outputs from the gas and steam turbine generators' terminals, less all electrical power consumed by the plant as auxiliary power.

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

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

precision error: see error, random.

precooler: heat exchanger or evaporative cooler that reduces the temperature of a fluid before initial compression.

pressure and temperature: pressure and temperature are static unless otherwise specified (also see *standard pressure and temperature*).

primary measurement: those measurements that are used in the calculation of the test results.

product compressor(s): compressors that take oxygen or nitrogen products from the ASU and compress them to the pressures required by the gasification or gas turbine units.

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 or from a piece of equipment in such volume and in a manner as to completely replace the air or gas–air mixture contained therein.

quench gasification process: process employing cool liquid or cool 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.

rated power: power output of the gas turbine engine or power plant when operating at specified control and ambient conditions.

rated power output (continuous rating): power output, stated or guaranteed under specified operating conditions and on the basis of continuous operation.

rated speed: specified speed at the rated power output.

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

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

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

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

reinjection: 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, date of test, and different portions of the same sample), within specified limits.

residue: 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: complete set of observations made over a period of time with one or more of the independent variables maintained virtually 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.

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

slag: ash material that has been heated above its melting point and then solidified into an amorphous, glasslike form as it is cooled, typically by being quenched in

water. An opening at the bottom of the gasifier (slag tap) is provided to allow this slag to exit from the gasifier. The slag is separated from the water in an accumulator where the slag settles and is subsequently depressurized.

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

slurry: mixture of liquid with solid particles, usually for enabling the solid to "flow."

sorbent: additive that reacts with and captures a pollutant or, more generally, a constituent that reacts with and captures another constituent.

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

specific fuel consumption (mechanical or electrical): fuel consumption rate per unit of power output.

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

stand-alone air separation unit: air separation process that is not integrated with the gas turbine, having its own supply of feed air and providing products only to the gasification process, and usually characterized by low air pressure operation.

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

standard deviation: several types of standard deviation are defined in statistical analysis — population standard deviation, sample standard deviation, and standard deviation of the mean (sometimes referred to as precision index). In this Code, the term standard deviation refers to sample standard deviation.

standard pressure and temperature: There are no single universally accepted values for standard pressure or temperature, but there are several prevailing reference sets used as standards. There is no inherent advantage to using any particular standard, but performance calculations are simpler and less susceptible to error if a single set of standards is used for all calculations. Standard pressure normally refers to standard atmospheric pressure at sea level, 0.1013245 MPa = 1.01325 bar (14.696 psia). Commonly used standard temperatures include 60°F (15.55°C) for industrial gases, 15°C (59°F) for ambient air, 0°C (32°F) for steam enthalpy tables, 400° R (-59.67°F = 222.22 K = -50.92°C) for gas enthalpy tables, and 25°C (77°F) for chemical reactions.

standard volume of fuel gas (dry): 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. *start-up burner:* burner firing an auxiliary fuel (such as natural gas, propane, or light oil) used to preheat an equipment item to near its normal operating temperature.

steam turbine: turbine that is driven by steam produced in the gasification area and/or heat recovery steam generator coupled to the gas turbine, producing useful work.

sulfation: exothermic chemical reaction that takes place when calcium sulfide reacts with oxygen to form calcium sulfate.

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

sulfider: see desulfurizer.

sulfur capture: see sulfur retention.

sulfur recovery: conversion of sulfur-containing compounds in a concentrated acid gas stream to elemental sulfur or sulfuric acid. A commercial example is the Claus process, which partially oxidizes hydrogen sulfide to elemental sulfur and water.

sulfur retention: fraction of the sulfur that enters with the gasifier fuel that does not leave the gasifier as H_2S and COS.

supplemental fuel: fuel burned to supply additional thermal energy to the steam generator or to support combustion.

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

systematic error: see error, systematic.

tail gas: off-gas from the regeneration process of the sorbent that is regenerated. This gas typically contains significant quantities of contaminants, such as H₂S and SO₂, and needs cleaning treatment prior to admission to the atmosphere.

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

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

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

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

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

topping cycle: higher temperature thermodynamic power cycle of a combined cycle system.

transmission dynamometer: device that measures the torque transmitted from one machine to another, without appreciably affecting the torque.

turbine: mechanical rotary component that produces work by action of the working fluid.

tuyeres: injection ports through which oxidant is fed into certain types of gasification vessels.

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

uncertainty, random: numerical estimate of the 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: test uncertainty combines random and systematic uncertainties.

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

working fluid: gas or liquid stream from which work is extracted, such as by powering a gas turbine.

2-2 SYMBOLS USED IN EQUATIONS

- A = additive correction factor, same units as base equation
- HV = heating value (lower or higher), MJ/kg (Btu/lbm)
 - h = enthalpy, kJ/kg (Btu/lb)
 - I = electric current, amperes
- *M* = multiplicative correction factor, dimensionless

P = power, kW

- PL = power loss, kW
- Q = thermal or chemical heat, MWt (Btu/hr)

$$R = result$$

RH = relative humidity of air, %

RSC = relative sensitivity coefficient, decimal

W = weight flow, kg/s (lbm/sec)

X = measured parameter

2-3 SUBSCRIPTS USED IN EQUATIONS

ash = by-product ash

- avg = average value
- bar = by-product argon
 bd = steam generator blowdown
- $bn = by-product N_2$
- $bo = by product N_2$ $bo = by - product O_2$
- c = corrected
- *cond* = outside condenser
- ea = export compressed air
- ecw = export cooling water
 - *ee* = net export electric power output
- epw = export process water
 - es = export steam
 - ia = inlet air
- *ica* = import cooling air
- *icw* = import cooling water
- ie = import electric power
- $in = import N_2$
- $io = import O_2$
- *is* = import steam
- line = line loss
 - m = measured
- PF = primary fuel
- SF = secondary fuel
- sg = export syngas
- srb = sorbent
- *sulf* = sulfur/sulfuric acid
- *wmu* = makeup water/condensate
- xfmr = transformer loss

Section 3 Guiding Principles

3-1 INTRODUCTION

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

Persons planning a test should 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, and to determine the uncertainty of the test results. Section 6 outlines the form of the final test report.

Regardless of the test goals or operating mode, the results of a Code test will be Corrected Net Power and either Corrected Heat Rate or Corrected Heat Input. The test must be designed with the appropriate goal in mind to ensure that proper procedures are developed, the appropriate operating mode during the test is followed, and the correct performance equations are applied.

The remaining paragraphs in this section discuss

- (a) test boundary and required measurements
- (b) test plan
- (c) test preparations
- (*d*) conduct of test
- (e) calculation and reporting of results

3-2 TEST BOUNDARY AND REQUIRED MEASUREMENTS

The general methodology of the Code involves the steps described below.

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 corrected results. For a particular test, the specific test boundary must be established by the parties to the test, based on the goals of the test.

3-2.2 Identify Energy Streams Related to the Calculation of the Test Results

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

Physical properties of all input and output energy streams, required for test calculations, must be determined with reference to the point at which they cross the test boundary. Energy streams within the test boundary need not be determined unless they verify base operating conditions or they relate functionally to conditions outside the boundary.

Some or all of the typical streams required for common IGCC plant cycles are shown in Fig. 3-2.2-1 for plants with an air separation unit (ASU) and in Fig. 3-2.2-2 for plants without an ASU. Solid lines indicate some or all of mass flow rate, thermodynamic conditions, and chemical analysis of streams crossing the test boundary, which have to be determined to calculate the results of an overall plant performance test. The properties of the other streams, such as blowdown and wastewater, are not required for a Code test, even though they may be needed for an energy and mass balance. These streams are indicated by dashed lines.

3-2.3 Identify Required Measurements and Determine the Required Accuracy of Measurement

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 for each measurement in order to maintain the agreed upon overall test uncertainty.

Measurement locations are selected to provide the lowest level of measurement uncertainty. The preferred location is at the test boundary, but only if the measurement location is the best location for determining required parameters.

Other measurements may be required, such as those used in the application of correction factors for off-design ambient conditions or those needed to insure





Fig. 3-2.2-2 IGCC Plants Without Air Separation Unit (Air-Blown, or Oxygen-Blown With Separate ASU)



that the process does not exceed emissions or safety limits.

Equations utilized in the calculations of results should be reviewed to verify that all references to heating value are consistent (either all lower or all higher), and that all correction curves and heat balance programs are based on the same definition of heating value. The use of higher heating value is customary, but lower heating value may also be used. The equations in Section 5 are applicable for either higher or lower heating value.

3-2.4 Primary and Secondary Measurements

Those measurements required to calculate the corrected heat input to the IGCC plant and the various corrected energy output streams are termed primary measurements. Additional measurements may be required to determine that the plant is operating within environmental regulations (such as the NO_x level in the stack gas) and within limits recommended by equipment suppliers (such as the firing temperature of the gas turbine). Such measurements not required to calculate test results — input and output — are termed secondary measurements. Methods for making the various secondary measurements are not considered in this Code.

3-3 TEST PLAN

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

In addition to documenting all prior agreements, the test plan should 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 Test Apparatus

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

The frequency of data collection is dependent on the particular measurement, variability of plant operation, and the duration of the test. To the extent practical, sufficient readings should 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 acquiring sufficient data.

All test instruments used to calculate the test results in subsection 1-1 will be calibrated prior to the test and recommended to be recalibrated or calibration checked following the tests. The quantity of time between initial calibration, performance testing, and recalibration should be agreed to by the parties to the test, but should not exceed 1 year. If the devices are not overloaded, posttest calibration of current and potential transformers is not required, because these devices are inherently stable.

Calibrate or adequately check all instruments prior to the test; those records and calibration reports must be made available. Following the test, recalibration or adequate reconfirmation or verification is required. When using an automated data acquisition system, the calibration procedure shall include signal conditioners and data logging devices, such that the desired measurement accuracy is maintained from the primary sensor to the final readout or storage device.

3-4.2 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%.

Certain primary variables, such as primary fuel flow rate, might not have redundant instrumentation. The pretest uncertainty analysis will determine the ability of single or redundant instrumentation to meet the total uncertainty specified in Table 1-3.

Application of 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 Equipment Inspection

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

3-4.4 Preliminary Testing

Preliminary testing should be conducted sufficiently in advance of the start 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. Based on the results of the preliminary testing, final test equipment adjustments and modifications can be made. Results from the preliminary testing should be calculated and reviewed to identify any problems with the quantity and quality of measured data. Prior to testing, all parties to the test must agree on the validity of all computer models, corrections, and curves to be used to calculate and correct plant performance.

3-5 CONDUCT OF TEST

This subsection provides guidelines on the actual conduct of the performance test and addresses the following areas:

- (*a*) cycle isolation, valve lineup
- (b) proximity to design conditions
- (c) stabilization
- (d) starting and stopping criteria
- (e) duration and number of test runs

3-5.1 Valve Lineup/Cycle Isolation

A Cycle Isolation Checklist should be developed to the satisfaction of all parties to the test. The checklist should be an exhaustive 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 should be checked before and after the test. All automatic valve positions should be checked prior to the preliminary test and monitored during subsequent testing.

No valves normally open should be closed for the sole purpose of changing the performance of the plant.

3-5.2 Proximity of Design Conditions

To maintain compliance with test code requirements, the actual test should be conducted within the criteria given in Tables 3-5.2-1 and 3-5.2-2 or other mutually agreed-upon operating criteria that limit overall test uncertainties to those in Table 1-3. Variations of readings during a test are indicative of either random error in an instrument or changing conditions during a test. Either situation can cause an increase of test uncertainty. For this reason, the variation during the test should be maintained with the limits given in the second column of Table 3-5.2-1.

The purpose for the correction procedure is to correct the tested performance to that at the design conditions. Deviation of the average reading during a test should be maintained within the limits given in the third column of Table 3-5.2-1 to ensure that the corrections will be valid.

Tests conducted outside the bounds given in Table 3-5.2-1 or for shorter times than those given in Table 3-5.2-2 may not be considered Code tests, due to the potential for increased uncertainty of test results.

3-5.3 Stabilization

Agreement must be reached 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, using Table 3-5.2-2 as a guide.

3-5.4 Starting Criteria

The Test Coordinator is responsible for ensuring that all data collection begins at the agreed-upon start of the test, and that all parties to the test are informed of the starting time. Prior to starting each performance test, the following conditions must be satisfied:

(*a*) Operation and Configuration. The unit is in the proper configuration and being operated in accordance with the agreed-upon test requirements.

(*b*) *Stabilization*. Prior to starting a test, the plant must be operated for a sufficient period of time at test load 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 acquisition system(s) is functioning, and test personnel are in place and ready to collect samples or record data.

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 should 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 are not met.

3-5.6 Durations of Runs

The duration of a test run shall be of sufficient length that the data reflect the average efficiency and/or performance of the plant. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical plant operating characteristics. The recommended test durations are tabulated in Table 3-5.2-2.

When point-by-point traverses are required, the test run should be long enough to complete two full traverses. Test runs using blended or waste fuels may also require longer durations if variations in the fuel are significant. Test run duration should also consider transit times of samples.

3-5.7 Number of Test Runs

A test shall be comprised of 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, then a third run will be required.

After a preliminary run has been made, it may be declared an acceptance run if agreed to and provided that all the requirements of a regular run have been met.

3-5.8 Number of Readings

Sufficient readings must be taken within the test duration to yield total uncertainty consistent with Table 1-3. 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

Criterion	Variation During Test	Deviation From Desigr	
Inlet Air			
Inlet air temperature	±6°C (±10°F)	±17°C (±30°F)	
Inlet air pressure	±70 mb (±1 psia)	±70 mb (±1 psia)	
Inlet air relative humidity	±20 percentage points		
Heat Sink			
Cooling air temperature at test boundary	±6°C (±10°F)	±17°C (±30°F)	
Cooling (circulating) water temperature or	±6°C (±10°F)	±11°C (±20°F)	
condenser pressure at test boundary	±17 mb (±0.5 in. Hg)	±34 mb (±1 in. Hg)	
Thermal Efflux			
Export steam pressure	±5%	±5%	
Temperature	±6°C (±10°F)	±11°C (±20°F)	
Export syngas heating value, LHV	±5%	±5%	
Combustible constituents	±5%	±5%	
Process water temperature	±6°C (±10°F)	±17°C (±30°F)	
Compressed air flow rate	±5%		
By-product ash flow rate	±5%		
By-product sulfur/H ₂ SO ₄ flow rate	±5%		
By-product O_2 , N_2 , argon flow rate	±5%		
Thermal Input			
Import steam pressure	±5%	±5%	
Temperature	±6°C (±10°F)	±11°C (±20°F)	
Sorbent active ingredients	±5%		
Nitrogen inlet flow rate	±5%	±5%	
Oxygen inlet flow rate	±5%	±5%	
Condensate return temperature at test boundary	±6°C (±10°F)	±17°C (±30°F)	
Primary Fuel Input			
Fuel heating value, HHV	±5%	±5%	
Combustible constituents	±5%	±5%	
Secondary Fuel Input			
Fuel heating value, HHV	±5%	±5%	
Combustible constituents	±5%		
Electrical Parameters			
Power factor	±1%	±1%	
Voltage	±1%	±1%	
Frequency	±0.5%	±0.5%	
Import power	±5%	±5%	

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

Type of Gasifier	Stabilization, hr	Test Run, hr	
Entrained flow	24	4	
Fluidized bed	24	4	
Moving bed	24	4	

Table 3-5.2-2	Typical	Stabiliz	ation	Times	and
Recomm	ended T	est Run	Durat	ions	

recorded for all nonintegrated measurements of primary variables.

Practical considerations may reduce the number of readings in some cases. Coal quality samples taken every half hour would reduce offsite laboratory costs. Ash or slag quality samples might be limited to one reading every 4 hr to accommodate a 4-hr holdup in the lockhopper. Sulfur production is often measured by a single reading for each tank car or truckload. The pretest uncertainty analysis will determine the impact of reduced numbers of readings and whether the overall test will meet the total uncertainty requirements specified in Table 1-3.

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.

3-5.9 Constancy of Test Conditions

The primary criterion for steady-state test conditions is that the average of the data reflects equilibrium 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. Testing durations and schedules must be such that changes in ambient conditions are minimized. See Tables 3-5.2-1 and 3-5.2-2.

3-6 CALCULATION AND REPORTING OF RESULTS

The data taken during the test should be reviewed and rejected in part or in whole if not in compliance with the requirements for the constancy of test conditions. 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.

3-6.1 Causes for Rejection of Test Runs

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

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

3-6.2 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 required uncertainty limits stated in Section 1 have been met.

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

3-6.3 Application of Correction Methods

The calculation of results described by this Code requires adjusting the test-determined values of thermal input, *Q*, and power, *P*, by the application of correction methods as described in subsection 5-4. 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

This Section describes measurement equipment and methods used to calculate the performance of IGCC plants in terms of the results in Table 1-3. The section is organized by type of measured parameter.

4-1 GENERAL REQUIREMENTS

4-1.1 Introduction

This Code presents the mandatory requirements for instrumentation employed and the use of such devices. The instrumentation recommended herein may be replaced by new technology as it becomes available. The Instruments and Apparatus supplements (ASME PTC 19 series) outline the governing requirements for all ASME performance testing. If the instrumentation requirements in the Instrument and Apparatus supplements become more rigorous as they are updated due to advances in the state of the art, those requirements will supersede those set forth in this Code.

4-1.2 Calibration and Reference Standards

In general, all instrumentation used to determine primary measurements should be calibrated against reference standards traceable to the National Institute of Standards and Technology (NIST), another recognized international standards organization, or recognized physical constants. All reference standards should be calibrated as frequently as specified by the manufacturer or at another frequency if data supports an extension of the calibration period. An extension of calibration frequency shall only be applied if adequate supporting data, in the form of historical calibration data, clearly demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period. Calibration documentation should be issued prior to the tests and verified by all parties concerned.

4-1.3 Instrument Ranges and Calibration Points

The calibration should cover the actual measurement range encountered during the test. Some devices cannot practically be calibrated over the entire operating range. A possible example of this limitation is the calibration of a liquid flowmeter. These devices are often calibrated at flows lower than the operating range and the calibration data are extrapolated. This extrapolation is described in subsection 4-5.

4-1.4 Calibration Drift

Calibration drift is defined as the time variation (difference) in the calibration correction as a percent of reading. A post-test drift check shall be made for each primary instrument. When the post-test calibration indicates the drift is less than the instrument systematic uncertainty, the drift is considered acceptable and the pretest calibration is used as the systematic error for determining the test results. If the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceeds the required accuracy of the instrument, it is unacceptable. In this case, the parties to the test shall agree to repeat the test or increase the test uncertainty as required to account for the actual drift.

4-1.5 Loop Calibration

Loop calibration is the calibration of the measurement system including the primary sensing device (instrument) through the signal conditioning equipment and readout or recording device. All measurement systems and instruments shall be loop-calibrated. This may be accomplished by calibrating instrumentation employing the test signal conditioning equipment either in a laboratory or on-site during test setup before the instrument is connected to process. Alternatively, the signalconditioning 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 accuracy requirements described herein.

4-2 PRESSURE MEASUREMENT

This subsection presents methods of measurement and precautions regarding the measurement of pressure. Primary measurements should be done with 0.1% accuracy-class pressure devices that have a total uncertainty of 0.3% or better of calibrated span. For additional guidance and requirements, refer to ASME PTC 19.2, Pressure Measurement.

Pressure is measured with gages, manometers, or transducers. The output of these devices is either visual or a signal, which can be read with a meter or a data logger. Manometers shall be of the vertical U-tube, or single-leg, type with a bore of 8 mm ($\frac{5}{16}$ in.) or more.

In a single-leg manometer, means shall be available for adjusting the zero of the scale while the instrument is in use. Manometers shall be selected such that the scale length and the fluid density permit reading accuracy within 0.5% of the measured pressure or pressure differential. Manometer fluid density shall be determined at site temperature and pressure. PTC 19.2 provides further information on pressure measurement techniques.

4-2.1 Air and Gas: Static and Differential Pressure

The static pressure in air and gas ducts may be required to determine the pressure drop in the gas turbine and heat recovery steam generator (HRSG). Pressure-drop determinations should be performed using differential measuring apparatus rather than two separate instruments. The measurement should be based on the average of four separate measurement points. The measurement points may be manifolded into a common measurement device.

4-2.2 Steam and Water: Static and Differential Pressure

The static pressure in steam and water piping may be required to determine fluid properties for flow measurement and enthalpy determination. Gage pressure transmitters are recommended for static pressure measurements, since they are easier to calibrate and to check once on-site. Each static pressure transmitter shall be installed with an isolation valve at the end of the sensing line upstream of the instrument.

Pressure-drop determinations should be performed using differential measuring apparatus rather than two separate instruments.

PTC 19.2 should be adhered to in the installation of pressure measuring devices. Differential pressure transmitters should be installed utilizing a five-way manifold. This manifold is suggested rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve.

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

When a differential pressure meter is installed on a flow element that is located in a vertical steam or water line, the measurement must be corrected as described in subsection 5-3.

4-2.3 Barometric Pressure

Barometric pressure is required to determine local ambient conditions. Barometric pressure shall be measured with a minimum error of 0.35 mb (0.01 in. Hg). The preferred method for determining barometric pressure is from a barometer or other calibrated absolute pressure gage at the test site.

4-3 TEMPERATURE MEASUREMENT

Commercially available calibrated temperature sensors shall be used with a systematic uncertainty of no more than 0.3° C (0.5° F) for temperatures less than 95° C (200° F) and no more than 0.6° C (1° F) for temperatures more than 95° C (200° F).

4-3.1 Acceptable Temperature Measurement Devices

4-3.1.1 Mercury-in-Glass Thermometers.

Mercury-in-glass thermometers are typically used where the number of readings required for a measurement point are limited and the measurement frequency is low, because the measurements are taken and recorded manually. Mercury-in-glass thermometers are good candidates for a remote location, because no electrical cables are needed.

The mercury-in-glass thermometers need to have graduations within the necessary measurement accuracy. These devices are typically very sensitive to the distance the device is immersed into the working fluid (immersion depth). They should be used at the same immersion depth experienced during calibration or an immersion correction should be applied per ASME PTC 19.3, Temperature Measurement.

4-3.1.2 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 95°C (200°F). The maximum temperature is dependent on the type of thermocouple and sheath material used.

Thermocouples may be used for measurements below 95°C (200°F) if extreme caution is used. The thermocouple is a differential-type device. The thermocouple measures the difference between the measurement location in question and a reference temperature. The greater this difference, the higher the emf signal from the thermocouple. Therefore, below 95°C (200°F), the emf signal becomes low and subject to induced noise, causing inaccuracy.

The temperature calculated from the emf voltage generated by the thermocouple should be in accordance with NIST Monograph 175, 1993.

This Code recommends that the highest emf per degree be used in all cases. This can be accomplished by type E (Chromel-Constantan) thermocouples for measurements from 95°C to 760°C (200°F to 1400°F). Type E thermocouples have the highest emf per degree in this range.

For temperatures above 760°C to 1350°C (1400°F to 2450°F), type K (Chromel-Alumel) thermocouples have the highest emf per degree. If temperature-controlled ovens are used, then extreme care should be taken to ensure that the oven reference temperature is within the specified overall uncertainty levels.

Thermocouples that are used to measure primary variables must be continuous lead from the measurement tip to the connection on the cold junction. These high-accuracy thermocouples must have a cold junction reference of 0°C (32°F) or ambient if the junction is well insulated and the reference-measuring device is calibrated. The ice-point reference can be either a stirred ice bath or a calibrated electronic ice bath.

This Code recommends that thermocouples used for high-accuracy measurements have a suitable calibration history (three or four sets of calibration data). This calibration history should include the temperature level the thermocouple experienced between calibrations. A thermocouple that is stable after being used at lower temperatures may not be stable at higher temperatures.

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

Thermocouples used to measure secondary variables can have junctions in the sensing wire. The junctions of the two sensing wires must be maintained at the same temperature. The cold junction may be at ambient temperature for these less-accurate thermocouples, provided that the ambient is measured and the measurement is compensated for changes in cold junction temperature.

Thermocouples should be constructed according to ASME PTC 19.3.

Thermocouples can effectively be used 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.

4-3.1.3 Resistance Temperature Device (RTD). The Resistance Temperature Device (RTD) may be used in testing from any low temperature to the highest temperature recommended by the RTD manufacturer. Typical RTDs can measure temperatures in excess of 1200°F.

Temperatures of primary variables are best measured by a four-wire type and made of platinum as presented in Fig. 4-3.1.3-1. Three-wire RTDs as shown in Fig. 4-3.1.3-2 and described in the following paragraph may be used for primary variables if they can be shown to have the accuracy as required herein. They must, however, be made of platinum.

Temperature measurements of secondary variables can be made accurately with either four-wire or threewire devices that do not necessarily need to be made of platinum.

Fig. 4-3.1.3-1 Four-Wire RTDs



Fig. 4-3.1.3-2 Three-Wire RTDs



The calculation of temperature from the resistance should be done according to equations in IPTS 68 as given in NIST Monograph 126, subsection 6-1. RTDs should be constructed in accordance with ASME PTC 19.3.

4-3.1.4 Thermistors. Thermistors are constructed with ceramic-like semiconducting material that acts as a thermally sensitive variable resistor. However, unlike RTDs, the resistance increases with decreasing temperature, so that this device is useful at low temperatures.

This device may be used on any measurement below 300°F. Above this temperature, the signal is low and susceptible to error from current-induced noise.

4-3.2 Calibration of Primary Variable Temperature Measurement Devices

The calibration of temperature measurement devices is accomplished by inserting the candidate temperature measurement device into a calibration medium along with a temperature standard. 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 device are sampled to determine the systematic error of the candidate temperature device. See ASME PTC 19.3 for a more-detailed discussion of calibration methods.

4-3.3 Typical Applications

4-3.3.1 Temperature Measurement of Fluid in a Pipe or Vessel. Temperature measurement of a fluid in a pipe or vessel is accomplished by installing a thermowell. A thermowell is a pressure-tight device that protrudes from the pipe or vessel wall into the fluid. The thermowell has a bore extending to near the tip to facilitate the immersion of a temperature measurement device.

The bore should be sized to allow adequate clearance between the measurement device and the well. Often the temperature measurement device becomes bent, causing difficulty in the insertion of the device.

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

The thermowell should be installed in a manner that the tip protrudes through the boundary layer of the fluid to be measured. The thermowell should be located in an area where the fluid is well mixed and has no potential gradients. If the location is near the discharge of a boiler, turbine, condenser, or other power plant component, the thermowell should be downstream of an elbow in the pipe.

If more than one thermowell is installed in a given pipe location, they should be installed on opposite sides of the pipe at least 90 deg apart and not directly downstream of another thermowell.

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

This Code recommends for high-accuracy measurements that the portion of the thermowell that protrudes outside the pipe or vessel be insulated along with the device itself to minimize conduction losses.

For measuring the temperature of desuperheated steam, the thermowell location relative to the desuperheating spray injection must be carefully chosen. The thermowell must be located where the desuperheating water has thoroughly mixed with the steam. This can be accomplished by placing the thermowell downstream of two elbows in the steam line past the desuperheat injection point.

4-3.3.2 Temperature Measurement of Low Pressure Fluid in a Pipe or Vessel. As an alternate to installing a thermowell in a pipe, if the fluid is at low pressure, the temperature measurement device can either 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 should be of proper 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 must protrude through



the boundary layer of the fluid. Care must be used so that the device does not protrude into the fluid enough to cause vibration of the device from the flowing fluid. If the fluid is a flammable gas, such as natural gas or propane, the fitting should be checked for leaks.

A flow-through well is shown in Fig. 4-3.3.2. This arrangement is only applicable for water in a cooling system where the fluid is not hazardous and can be disposed of without great cost. The principle is to allow the fluid to flow out of the pipe or vessel, over the tip of the temperature measurement device.

4-3.3.3 Temperature Measurement in Large Con-duits. This Code recognizes the following methods for calculating average values from multiple point samples:

- (a) multiple midpoint
- (b) triple midpoint
- (c) composite midpoint

All of these methods require specific placement of sampling points. The minimum number of points is given in all cases, but increasing the number of points can reduce uncertainty. The following rules should apply to location of sampling points in all cases:

4-3.3.1 Rectangular Ducts. Rectangular ducts shall be divided to form a grid with equal areas. Samples shall be taken at the centroid of each equal area. For ducts larger than 1 m^2 (10 ft²), there should be from 4 to 36 sampling points, based on the cross-sectional area of the duct. Each equal area should be no larger than 1 m^2 (10 ft²) unless there are more than 35 points. In such cases, the equal areas may be larger than 1 m^2 (10 ft²). The Code does not require more than 36 points.

There should be a minimum of two points spanning each dimension (height and width) of the duct cross section. In ducts with severe stratification, it is recommended that points be added in the direction of the steepest gradient.

Since the systematic error due to numerical integration decreases as the square of the number of points, using more points has a significant effect on that component of the uncertainty.

Fig. 4-3.3.2 Flow-Through Well

The shape of the equal areas should be one of the following:

(*a*) A rectangle with the ratio of height to width the same as that of the cross section of the duct, so that it is of the same geometrical shape as the cross section, as shown in Fig. 4-3.3.3.1, sketch (a). This is the preferred method.

(*b*) Any rectangle, as shown in Fig. 4-3.3.3.1, sketch (b), that is more nearly square than the geometric shape in Fig. 4-3.3.3.1, sketch (a).

(c) A square, as shown in Fig. 4-3.3.3.1, sketch (c).

If the shape of the equal area is not square, the long dimension should align with the long dimension of the cross section. If a greater number of measurement points is being used than is recommended, the additional points may be added without concern for the aspect ratio.

4-3.3.22 Circular Ducts. Circular ducts should be divided into equal areas of 1 m^2 (10 ft²) or less. There should be from 4 to 36 sampling points, based on the cross-sectional area of the duct. Parties to the test may agree to divide the cross section into four, six, or eight sectors. The location of each sampling point must be at the centroid of each equal area. The location of these sampling points may be determined by the method shown in the example in Fig. 4-3.3.3.2, which shows the use of 20 points and four sectors. There must be at least one point per sector.

(*a*) Additional Rules for Using the Triple Midpoint Calculation Method. When the triple midpoint sampling method is being used to determine average value, the guidance regarding rectangular ducts is followed. However, the grid must contain a multiple of 3 points in each direction, and a circular duct must have six equal sectors. If the parties to the test agree to use a greater number of points, there must still be a multiple of 3 in each direction for rectangular ducts and 3 in each sector for circular ducts.

(b) Additional Rules for Using the Composite Midpoint Calculation Method. To use the composite midpoint method to determine the average value, the number of grid points must be a multiple of 3 in one direction only. This may be in either direction for rectangular ducts. If six sectors are used, there may be any number of points in the sector. If either four or eight sectors are used, the number of points in each sector must be a multiple of 3. If the parties to the test agree to use a greater number of points, a multiple of 3 must be used in one direction.

4-3.3.4 Inlet Dry Bulb Air Temperature. The dry bulb temperature is the static temperature at the inlet to the plant equipment. The temperature sensor must be shielded from solar and other sources of radiation, and must have a constant air flow across the sensing element. Although not required, a mechanically aspired psychrometer, as described below, may be used. If a psychrometer is used, a wick should not be placed over

the sensor (as is required for measurement of wet bulb temperature). If the air velocity across the sensing element is greater than 8 m/s (1,500 ft/min), shielding of the sensing element is required to minimize stagnation effects.

4-3.3.5 Inlet Air Moisture Content. The moisture content of the ambient air may be determined by the measurement of adiabatic wet-bulb temperature, dew point temperature, or relative humidity. Measurements to determine moisture content must be made in proximity with measurements of ambient dry bulb temperature to provide the basis for determination of air properties. Descriptions of acceptable devices for measurement of moisture content are discussed below.

(a) Wet Bulb Temperature. The thermodynamic wet bulb temperature is the air temperature that results when air is adiabatically cooled to saturation. Wet bulb temperature can be inferred by a properly designed mechanically aspired psychrometer. The process by which a psychrometer operates is not adiabatic saturation, but one of simultaneous heat and mass transfer from the wet bulb sensing element. The resulting temperature achieved by a psychrometer is sufficiently close to the thermodynamic wet bulb temperature over most ranges of conditions. However, a psychrometer should not be used for temperatures below 4°C (40°F) or when the relative humidity is less than 15%. Within the allowable range of use, a properly designed psychrometer can provide a determination of wet bulb temperature with an uncertainty of approximately $\pm 0.15^{\circ}C$ ($\pm 0.25^{\circ}F$), based on a temperature sensor uncertainty of ±0.08°C (±0.15°F).

The mechanically aspirated psychrometer should incorporate the following features:

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

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

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

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

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

The psychrometer should be located at least 1.5 m (5 ft) above ground level and should not be located within 1.5 m (5 ft) of vegetation or surface water.

(b) Cooled Mirror Dew Point Hygrometer. The dew point temperature is the temperature of moist air when



Fig. 4-3.3.3.1 Sampling Grids for Rectangular Ducts

(a) Same Geometric Shape as Cross Section (a/b = A/B)



(b) More Nearly Square Than Sketch (a) (a/b < A/B and a > b)



(c) Square (*a* = *b*)





GENERAL NOTE: The formula for determining location points in a circular duct is as follows:

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

where

- n = total number of points
- p = sampling point number, to be numbered from the center outward (all four points on the same circumference have the same number)

- R = radius of duct, in same units as r_p r_p = distance from center of duct to point p

Example: distance to point r_3 , 20 points total

$$r_{3} = \sqrt{\frac{2R^{2}[(2)(3) - 1]}{20}}$$
$$= \sqrt{\frac{2R^{2}(5)}{20}}$$
$$= \sqrt{0.5R^{2}}$$
$$= 0.707R$$
it is saturated at the same ambient pressure and with the same specific humidity. A cooled mirror dew point hygrometer uses a cooled mirror to detect the dew point. Air is drawn across a mirror that is cooled to the temperature at which vapor begins to form on the mirror. A temperature sensor mounted in the mirror measures the surface temperature. Manual devices are available. There are also commercially available instruments that automatically control the mirror temperature, detect the inception of condensation, and provide temperature readout. Commercially available cooled mirror dew point hygrometers measure the dew point temperature with an uncertainty of approximately 0.30°C (0.50°F).

The advantages of using dew point hygrometers include that:

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

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

(c) Relative Humidity Hygrometers. Thin film capacitance and polymer resistance sensors provide a direct measurement of relative humidity. Measurement uncertainties vary with sensor type and design. Their usual range is from $\pm 1\%$ to $\pm 2\%$ of range from relative humidities between 0% and 90%. Measurement uncertainties for relative humidities above 90% are usually higher. Accuracies of these types of instruments are dependent on proper calibration.

The advantages of relative humidity hygrometers include

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

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

4-4 SOLIDS FLOW MEASUREMENT

Solid fuel, sorbent, and residual flow measurement is difficult because of solid material variability. ASME PTC 4 provides examples of recommended solids flow measurements, potential instrumentation systematic error, solids sampling, and potential systematic error for coal, sorbent, and residue properties. Sections of ASME PTC 4 have been extracted and modified for relevance to gasifier feed and residue measurement. Numerous methods are referenced in paras. 4-4.1 and 4-4.2 to measure the flow of solids, sorbent, and residue, and estimates of systematic error for these flow measurements. Solid fuel, sorbent, and residue sampling methods, sample size, sample collection, and their sampling systematic error are referenced in paras. 4-4.3 and 4-4.4. Fuel, sorbent, and residue analysis are addressed in para. 4-4.5. This subsection addresses the following six subjects:

(*a*) solid fuel and sorbent flow measurement, including measurement method and estimating systematic error (*b*) residue splits (by-product ash and slag), including measurement method and estimating systematic error

- (c) solid fuel and sorbent sampling
- (d) residue sampling (by-product ash and slag)
- (e) sorbent and residue analysis
- (f) sulfur and sulfuric acid measurement

4-4.1 Solid Fuel and Sorbent Flow Measurement

The accurate measurement of solid flow is difficult because of solid material variability.

4-4.1.1 Method of Measurement. Numerous methods are available to measure the flow of solids. Typical methods include gravimetric feeders, volumetric feeders, isokinetic particulate sample, weigh bins/timed weights, and impact meters. To reduce uncertainty of any of these methods below 5% to 10% requires extensive calibration against a reference. The calibration can involve the collection of the solid material into a container that can be weighed rather than placing weights on the belt. For example, the output of a gravimetric feeder can be directed to a container suspended by load cells, and the rate of feed indicated by the feeder can then 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 these parameters may vary over time.

Calibrations of solids flow measurement devices should be conducted just prior to the testing and at frequent intervals to ensure the minimum systematic error.

4-4.1.2 Estimate of Systematic Error. The systematic error from a solids flow measurement is one of the most difficult parameters to determine. Systematic error from instrument response variation resulting from size distribution, uneven loading on the weigh scale, or varying densities should be considered.

Table 4-4.1.2 provides guidelines for typical systematic errors for flow measurements.

4-4.2 Residue Splits (By-Product Ash and Slag)

The amount of residue leaving the gasifier boundary is required to determine the sensible heat loss in the residue streams and the weighted average of unburned carbon in the residue. Typical locations where the residue is removed periodically or continuously are mechanical dust collector rejects, and fly ash and slag leaving the unit.

4-4.2.1 Method of Measurement. The calculated total residue mass flow rate is often used, since it is normally more accurate than a direct measurement. Therefore, the percent of the total residue that leaves

Instrument	Typical Systematic Uncertainty
Solid Fuel and Sorbent Flow	
(a) Gravimetric feeders	
(1) Calibrated with weigh tank	±1%
(2) Calibrated with standard weights	±1%
(3) Uncalibrated	±10%
(b) Volumetric feeders	To be used for constant density material
(1) Belt	
(a) Calibrated with weigh tank	±5% raw ±2% pulverized
(b) Uncalibrated	±15%
(2) Screw, rotary valve, etc.	. 50/
(a) Calibrated with weigh tank	±5%
(D) Uncalibrated	±15%
(c) Weigh Dins	
(1) Shall gauges	+10%
(d) Weigh helt scale	+5% calibrated with the weighted material
(a) Impact meters	+10% to 15%
(e) impact meters	
Solid Fuel and Sorbent Flow	
(a) Gravimetric feeders	
(1) Calibrated with weigh tank	±1% crushed
(2) Calibrated with standard weights	±1%
(3) Uncalibrated	±10%
(b) Volumetric reeders	
(1) Dell (2) Calibrated with weigh tank	+ E 0/
(d) Calibrated with weigh talik	±0 %
(D) Olicalibiated	113/0
(2) Silew, locally valve, etc.	+5%
(a) Calibrated with weigh tank	+15%
(c) Weigh hins	21976
(1) Weigh scale	+5%
(2) Strain gauges	+8%
(3) Level	±10%
(d) Impact meters	±10%
Residue Flow	
(a) Isokinetic dust sampling	±10%
(b) Weigh bins	
(1) Weigh scale	±5%
(2) Strain gauges	±8%
(3) Level	±20%
(c) Screw requers, rolary valves, etc.	
(1) Calibrated with weigh tank	±5%
(2) Uncalibrated (d) Assumed split (bottom asb/fly asb)	$\pm 10\%$
(d) Assumed split (bottom asilyity asil)	
Solid Fuel and Sorbent Sampling	See Tables 4-4.5.2-1 and 4-4.5.2-2
(a) Stopped belt	±0%
(b) Full cut	≥1%
(c) "Thief" probe	≥2%
(d) Time-lagged	≥5%
Residue Sampling	
(a) Isokinetic dust sampling	±5%
(b) "Thief" probe	±200%
(c) Bottom ash	±50% [Note (1)]
(d) Bed drain	±20%

Table 4-4.1.2	Typical S	Systematic	Uncertainty	for F	low N	Measurements
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NOTE:

(1) Bottom ash carbon content should be less than 10% of total ash in feedstock.

each location must be determined. The residue streams need to be sampled at each location in order to determine the composition of the streams. The following methods may be used to determine the split between the various locations:

(*a*) the mass flow rate and composition should be measured at each location, or

(*b*) the residue at one or more locations should be measured (usually the locations with the highest loading) and the quantity at the other locations should be calculated by difference. Where there is more than one unmeasured location, the split between these locations should be estimated, or

(*c*) the residue percentage leaving each location may be estimated based on the typical results for the type of fuel and method of firing

The parties to the test shall reach agreement on what streams are to be measured and values for any estimated splits prior to the test.

The mass flow rate of residue discharged from hoppers or grates in a dry state may be determined from weigh bins/timed weights, e.g., the number of rotations of rotary feeders, screw speed, impact meters, etc. See Nonmandatory Appendix A 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 dry state. Generally, the total discharge flow must be captured in bins or trucks, free-standing water drained off, and the bin or truck weighed and compared against the tare weight. Since residue is considered to leave 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 lockhoppers is normally a small quantity, so this residue rate can be measured every 4 hr.

4-4.2.2 Estimating Systematic Error. When splits are estimated, a mean value should 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 0% or more than 100% must 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. Also refer to subsection A-3.

4-4.3 Solid Fuel and Sorbent Sampling

The methods of sampling shall be agreed upon by all parties to the test and must be described in the test report. An appropriate uncertainty must be assigned for the method of sampling used for a test.

When identifying losses of unconverted fuel, a major energy loss is the residue (based on carbon concentration). If samples are not representative of the respective solid streams, the IGCC heat rate result is questionable. In addition, the variation in the composition of solids directly affects the uncertainty of the heat rate. In this paragraph, the methods used to determine variances, standard deviations, and precision indices for the samples obtained during the test are discussed. The estimation of systematic error is also addressed.

4-4.3.1 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 it is actually injected or removed from the gasifier. This time lag must 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 or removed from the gasifier. "Thief" sampling or taking a partial cut sample from silos or hoppers have large associated systematic errors. One possible exception to this is sorbent, which in most cases is homogeneous. Parallel streams such as coal feed with belt feeders have the potential for variation from stream to stream because of different flow rates, particle sizes, and chemical composition. Therefore, unless the chemical constituents of the samples can be shown to be uniform, the samples must be taken from each of the parallel streams and combined. If the flows for the parallel streams are unequal, the amount of samples of each parallel stream must be flow weighted for the composite sample. The flow for each of the parallel streams must be continuous throughout the test.

Depending on the costs associated with laboratory analyses and the availability of a historical database, different options may be selected for different sample constituents (i.e., coal, sorbent, residue).

Fuel, sorbent, and residue samples collected from upstream of silos, tanks, or hoppers typically have larger systematic errors than samples collected downstream from silos, tanks, and hoppers. Samplings from upstream of silos, tanks, and hoppers are classified as alternate procedures because of the possibility of samples not being representative of fuel fired during the test. Alternate procedures should not be used for acceptance tests. For other test purposes, if alternate procedures are used, the parties to the test shall assign appropriate systematic errors.

4-4.3.2 Sample Size. As stated previously, it is extremely important that any sample be as representative of the composition of the actual stream as possible. In addition, since there is a direct correlation between individual sample weight and variance, sufficient weight of individual samples is required to minimize the variance.

Generally, a complete cross section of the flowing stream is the most representative. This criterion, however, can mean different sample size requirements for different types of solid streams. For example, the fly ash residue stream sample should be obtained from isokinetic particulate sampling. This sample is typically very small. However, since it is taken from a complete and controlled traverse of the duct, the sample is representative. In this case, the small quantity is a minor factor in regard to the reliability of the sample.

Another example of the acceptability of a small quantity of sample is sorbent sampling. The size of sorbent may vary, but it is likely that the chemical composition does not 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.

In summary, the actual sample size must be based on several factors, including size distribution, chemical composition variability, feed methods, flow capacities, and number of samples. In general, larger size samples result in lower variances. However, as sample size increases, so do sample preparation costs for reducing to a size for laboratory analysis. For manual sampling of coal or sorbent, samples typically weighing from 1 to 4 kg (2 to 8 lb) are collected. For automatic sampling devices, much larger samples can be collected.

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

The factors previously noted, combined with good engineering judgment, costs, agreement between parties, and desired accuracy of sample analyses, should be used by the testing participants to determine the proper sample size. Table 2 of ASTM D 2234 provides more information about sample size.

4-4.4 Residue Sampling (By-Product Ash and Slag)

Solid fuels that contain ash require samples of the various streams leaving the unit containing the ash. These streams typically include slag, fly ash, and bottom ash. Obtaining representative samples from each of these streams is a difficult task. The best method for obtaining a representative fly ash sample is to isokinetically sample the ash in the flue gas upstream of as many ash collection hoppers as possible. This obtains 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.

Sampling the bottom ash also presents challenges in the form of large chunks and poor distribution. A number of samples and several analyses of each sample may be required to obtain representative results. A single sample may contain a chunk of coal not typically found in other samples or may have no carbon content. **4-4.4.1 General.** Fly ash may be sampled isokinetically as particulate by drawing a gas sample through a filter and weighing the amount of particulate gathered on the filter. The weight of the sample and the flue gas volume recorded during this process determine the particulate concentration in the flue gas stream. To avoid altering the concentration of the gas stream, the velocity of the stream entering the sample nozzle must equal the velocity of gas at that point in the duct. This process is known as *isokinetic sampling*. Multiple points are sampled in the testing plane to compensate for nonuniform velocity distributions and stratification of the particulate concentration.

4-4.4.2 Systematic Error for Residue Sampling. Isokinetic sampling is the reference method prescribed by this Code. The systematic error associated with this method is assumed to be zero. There is still an associated systematic error for the ash collected in the bottom ash as well as any hoppers located upstream of the fly ash collection point. If multiple samples are analyzed using multiple analysis for the bottom ash, an estimate of the associated systematic error can be made from this information. The procedure should also be reviewed to determine if other sources of systematic error are also present.

4-4.4.3 Fly Ash Sampling Methods. All apparatus and test procedures shall be in accordance with either ASME PTC 38, Determining the Concentration of Particulate Matter in a Gas Stream, or U.S. EPA Reference Method 17 as described below.

(*a*) ASME PTC 38. The particulate sampling train generally consists of a nozzle, probe, filter, condenser, dry gas meter, orifice meter, and vacuum pump or aspirator. ASME PTC 38 illustrates different configurations of sampling trains and should be consulted for the type of train to be used on specific installations.

(*b*) *U.S. EPA Method* 17. The U.S. Environmental Protection Agency has established two reference methods for particulate sampling. Methods 5 and 17 are similar, except that Method 17 uses an in-stack filter, whereas Method 5 uses an external filter. Method 17 is preferred, since all of the particulate catch remains in the filter holder. Method 5 requires an acetone wash of the probe assembly, which may not be suitable for analysis for carbon. Detailed procedures for these methods are contained in 40CFR60, Appendix A.

Isokinetic sampling of the flue gas is both the reference and the preferred method for sampling fly ash. The number of grid points on the traverse sampling plane must be in accordance with ASME PTC 38.

4-4.4.4 Bottom Ash Sampling Methods. For a bottom ash sluice stream, the preferred method of sample collection is to take the sample with a multiholed probe extending the width of the sluice stream. EPRI Report EA-3610 illustrates a multihole probe. Alternatively, a

portion of the sluice stream may be diverted to a collection device where the ash is allowed to settle and a sample then taken.

4-4.4.5 Other Residue Stream Sampling Methods.

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

4-4.5 Sorbent and Residue Analysis

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

4-4.5.1 Systematic Uncertainty for Sorbent and Residue Analysis. ASTM provides guidelines for typical laboratory reproducibility. These values are listed in Table 4-4.1.2 for use in estimating the systematic uncertainty of a sample analysis.

4-4.5.2 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. Tables 4-4.5.2-1 and 4-4.5.2-2 identify the ASTM procedures to be used for analysis. ASTM D 3180 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 are important to judge the equivalence of the test fuel and the specified fuel, and may be required for other test objectives.

4-4.5.3 Methods of Sorbent and Residue Analysis.

The minimum information needed to determine the sulfur capture and efficiency is the sorbent ultimate analysis (calcium, magnesium, moisture, and inert). The determination of other solid sorbent qualities such as sorbent sizing may be required, depending on the objectives of the particular test.

4-4.6 Sulfur and Sulfuric Acid Measurement

Sulfur and sulfuric acid should be measured only if the IGCC plant is designed to produce a specified amount of either of these by-products. The following are the three main options for measuring IGCC sulfur removal efficiency:

(a) Measure Accumulation of Liquid Sulfur in the Sulfur Pit. All of the liquid sulfur normally drains from the condensers to a below-grade concrete pit. Typically, one sulfur pit accommodates multiple SRU trains installed as part of one project. A long test — up to 24 hr at design capacity — is needed to obtain reasonable accuracy (±5% or better).

(b) Measure Stack Gas Sulfur Content and Flow Rate. Most new and proposed IGCC plants recycle the hydrogenated Claus tail gas back to the syngas upstream of COS hydrolysis and the AGR absorber. This recycling eliminates the tail gas incinerator and leaves the HRSG stacks as the only exit point for any sulfur not removed by the AGR/SRU. Since the HRSG stacks have continuous monitoring for SO_x and flow, additional instrumentation is not needed. Also, since the primary objective of the AGR/SRU is to ensure that the HRSG stack gas is in compliance with allowable sulfur emissions, using the stack gas data matches performance with compliance.

(c) Calculate Sulfur Removal Efficiency From Carbon and Sulfur Elemental Balances. Pritchard uses this method for refinery SRU performance testing. This calculation uses the carbon and sulfur concentrations in the acid gas and fuel gas to the SRU and in the tail gas, along with the acid gas and fuel gas flow rates (the tail gas flow rate is not needed).

4-5 LIQUID FLOW MEASUREMENT

4-5.1 Water and Steam

4-5.1.1 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. The usual method of determining flow is with a differential pressure meter, using two independent differential pressure instruments.

4-5.1.2 Flow Section. The flow section with a throat tap nozzle described in PTC 6 is recommended for the primary flow measurements when the test Reynolds numbers are greater than the maximum calibrated Reynolds number.

4-5.1.3 Other Flow Measuring Devices. Information relative to the construction, calibration, and installation of flow measuring devices other than those listed above is described in ASME PTC 19.5. These devices can be used for secondary flow measurements and can also be used for primary flow measurement when Reynolds number extrapolation is not required.

(*a*) The beta ratio should be limited to the range of 0.25 to 0.50 for wall-tap nozzles and venturis, and 0.30 to 0.60 for orifices.

(b) Primary flow measurement requires calibration.

Coal Property	Analysis Procedure	ASTM Standard Test Repeatability	Comments
Sampling	ASTM D 2234-00 ⁶¹	This practice covers procedures for the col- lection of a sample under various condi- tions of sampling	
Sample preparation	ASTM D 2013-00a ^{€1}	This method covers the reduction and divi- sion of gross or divided samples, col- lected in accordance with D 2234, up to and including the individual portions for laboratory analysis	
Standard method for total moisture in coal	ASTM D 3302-00a	0.14% for bituminous coals 0.42% for subbituminous and lignite coals 0.3% for coke	Not applicable to coal-water slurry
Ash content	ASTM D 3174-00	0.30% for bituminous coals 0.33% for subbituminous and lignite coals	
Proximate analysis of coal and coke	ASTM D 5142-90	Moisture: 0.20 + 0.12 (concentration) Ash: 0.07 + 0.02 (concentration) Volatile matter: 0.29 + 0.014 (concentration)	Automated method
	ASTM D 3172-89	Fixed carbon, % = 100 - (% moisture + % ash + % volatile matter) Moisture: D 3173 Ash: D 3174 Volatile matter: D 3175 Fixed carbon, % = 100 - (% moisture + % ash + % volatile matter)	
Moisture in analysis sam- ple of coal and coke	ASTM D 3173-00	0.09 + 0.01 (concentration)	Sample with 1–21% moisture
Carbon	ASTM D 5373-93 ASTM D 3178-84	0.64% 0.3%	
Hydrogen	ASTM D 5373-93 ASTM D 3178-84	0.16% 0.07%	
Nitrogen	ASTM D 5373-93 ASTM D 3179-89	0.11% (0.31 × concentration) – 0.24	> 100 mg sample Kjeldahl method
Sulfur	ASTM D 4239-00 ASTM D 3177-89	0.05% for bituminous coals 0.08% for subbituminous and lignite coals 0.005% for fuels < 2% sulfur 0.1% for fuels > 2% sulfur 0.03% for coke	
HHV, gross calorific value	ASTM D 5865-01	69 Btu/lb, dry basis for anthracite/bitu- minous 60 Btu/lb, dry basis for subbituminous/lig- nite	
Converting analysis to dif- ferent basis	ASTM D 3180	None	Information
HHV, refuse-derived fuels	ASTM E 711-87(1996)	None	Bomb calorimeter

Coal Property	Analysis Procedure	ASTM Standard Test Repeatability	Comments
Ultimate analysis of coal and coke	ASTM D 3172-89	Carbon and hydrogen: D 3178 Sulfur: D 4239 or D 3177 Nitrogen: D 3179 Ash: D 3174 Oxygen: 100% – (sum of the other compo- nents of the ultimate analysis) Moisture: D 3173	See D 3172 for repeat- ability of compo- nent values Chlorine may be deter- mined by D 2361
Major and minor elements in combustion residues from coal	ASTM D 3682-00	Elements such as aluminum oxide, calcium oxide, ferric oxide, magnesium oxide, potassium oxide, silicon oxide, sodium oxide, titanium oxide	

Table 4-4.5.2-1 Typical ASTM Standard Test Repeatability for Coal and Coke Properties (Cont'd)

GENERAL NOTE: All systematic uncertainties are absolute unless otherwise indicated.

Table 4-4.5.2-2	Typical Systemat	ic Uncertainty for	Limestone P	roperties
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Limestone Property	Analysis Procedure	Typical Systematic Uncertainty	Comments
Limestone constituents	ASTM C 25	Calcium oxide ±0.16%	Test method 31
		Magnesium oxide ±0.11%	Test method 31
		Free moisture ±10% value	
		Inert by difference ±5.0% of value	
Sampling	See para. 4-4.3	±2.0% "thief" sample ±5.0% other	

GENERAL NOTE: All systematic uncertainties are absolute unless otherwise indicated.

(*c*) For secondary flows, the appropriate reference coefficient for the actual device given in ASME PTC 19.5 may be used.

4-5.1.4 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 very careful adjustment of flow and level controls or by introducing a combination of conductance (such as pump recirculation) and resistance (such as throttling the pump discharge) in the line between the pulsation sources and the flow measuring device. Hydraulic damping devices on instruments do not eliminate errors due to pulsations and, therefore, should not be used.

In passing through the flow-measuring device, the water should not flash into steam. 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, to avoid cavitation.

4-5.1.5 Steam Flow Characteristics. In passing through the flow-measuring device, the steam must remain superheated. For steam lines with desuperheaters, the flow section should be installed ahead of desuperheaters and the total flow is determined from the sum of steam flow and the desuperheater water flow.

4-5.1.6 Secondary Measurements. The calculation of steam flow through a nozzle, orifice, or venturi should be based on upstream conditions of pressure, temperature, and viscosity. In order to avoid the disturbing influence of a thermowell located upstream of a primary element, downstream measurements of pressure and temperature are 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.

4-5.1.7 Enthalpy Drop Method for Steam Flow Determination. The enthalpy drop method may be employed for the determination of steam flow, but is applicable only to a noncondensing or backpressure turbine having a superheated exhaust. Separate generator tests must be available from which electrical losses can be computed or their design value must be agreed upon. The parties to the test must assign and agree upon values for the mechanical losses of the turbine. The steam flow is calculated from an energy balance based on measurements of pressure and temperature of all steam entering and leaving the turbine, including consideration of leak-offs, generator output, and the agreed-upon mechanical and electrical losses.

4-5.1.8 Additional Flow Measurements

(*a*) *Feedwater Heater Extraction Flows.* If the extraction steam is superheated, the extraction flow can be determined by heat balance calculation. The uncertainty of the result increases as the temperature rise across the heater diminishes. It should be noted that errors in temperature measurement will be translated into extraction flow errors. For instance, an error of 0.5 K (1°F) in the temperature rise of a heater with an increase of 17 K (30°F) will result in an expected uncertainty in extraction flow of approximately 3.3%.

(b) 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.

4-5.2 Liquid Fuel

Liquid fuel flows shall be measured using flowmeters that are calibrated throughout their Reynolds number range expected during the test using the actual flow. For volume flowmeters, the temperature of the fuel also must be accurately measured to correctly calculate the flow. Table 4-5.2 lists individual laboratory test repeatability criteria for fuel oil property measurements.

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

It is the intent of this Code that the samples be analyzed in accordance with the latest methods and procedures. When choosing a laboratory, the parties to the test should choose a certified laboratory. ASTM provides guidelines for typical lab-to-lab reproducibility. These values are listed in Table 4-5.2 for use in estimating the systematic uncertainty of a sample analysis. In general, the systematic uncertainty is taken as one-half the reproducibility.

4-6 GASEOUS FLOW MEASUREMENT

4-6.1 Gaseous Fuel

Gaseous fuel flows may be measured using orifices or turbine-type flowmeters. The fuel mass flow must be determined with a total uncertainty of no greater than 0.8%. Measurements used to determine the mass flow rate, such as fuel analysis to determine density, the static and differential pressures, temperature, and frequency (for turbine meters), must be within an uncertainty range to meet this requirement. Other flowmeters are permitted if it can be demonstrated that the total uncertainty of mass flow rate is 0.8% or less.

ASME PTC 19.5, Flow Measurement, details the calculation of the uncertainty of an orifice-metering run manufactured and installed correctly. The manufacturer is required to demonstrate that the meter was manufactured in accordance with the appropriate references, as shown in para. 4-6.1.1.

Uncertainty of turbine meters is usually by statement of the manufacturer as calibrated in atmospheric air or water, with formulations for calculating the increased uncertainty when used in gas flow at higher temperatures and pressures. Sometimes, a turbine meter is calibrated in pressurized air. The turbine meter calibration report must be examined to confirm the uncertainty as calibrated in the calibration medium. There are facilities available to calibrate flowmeters at operating temperatures and pressures in gas flows, mainly in Europe and the USA.

The quantity of the gas is usually expressed in terms of volume at "base" or "standard" atmospheric conditions. This is the volume that the gas would occupy if the pressure and temperature were adjusted to the standard atmospheric temperature and pressure. The pressure is mostly taken at 1.01325 bar (14.696 psia), which is the average absolute atmospheric pressure at sea level. For the standard temperature, three references are used: 0°C, 15°C, and 60°F. The reference conditions should 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 mostly needed for operational and contractual or legal metrology purposes.

For definitions of heating values, references should be obtained from ISO 6976.

4-6.1.1 Calculation of Natural Gas Fuel Flow Using an Orifice. Natural gas fuel flow may be calculated using measurements from a flange-tapped orifice meter, provided that the orifice-metering run meets the straight length requirements of ISO 5167, and the manufacturing and other installation requirements of ASME PTC 19.5. Requirements include circularity and diameter determination of orifice and pipe, pipe surface smoothness, orifice edge sharpness, plate and edge thickness, and other requirements, detailed in ASME PTC 19.5.

Flow calculations must be done in strict accordance with PTC 19.5. Densitometers of the vibrating type are now available and have been used successfully in gas metering stations. It is essential that the density of the gas in the densitometer is equal to the density at the appropriate point in the volumetric flowmeter. If the

Fuel Oil	Analysis Procedure	ASTM Standard Test Repeatability	Comments
Sampling	ASTM D 4057-95	±0.5% for multiple samples	
		±1% for single sample	
API gravity	ASTM D 1298	0.25 API for opaque (heavy oil)	
		0.15 API for transparent (distillate)	
Water content	ASTM D 95-99	0.1% for fuels < 1% water	
		5% of measured value for > 1% water	
Ash	ASTM D 482-00a	0.003 for fuels < 0.08% ash	
		0.007 for fuels of 0.08–0.18% ash	
Sulfur	ASTM D 1552-00	0.05 (concentration)	High temp. method
	ASTM D 2622-98	0.02651 (concentration) ^{0.9}	X-ray fluorescence
	ASTM D 4294-98	0.02894 (concentration + 0.1691)	X-ray fluorescence
Carbon	ASTM D 5291-96	(x + 48.48) 0.0072, where $x =$ mean value	Concentration range 75% to 87% (mass)
Hydrogen	ASTM D 5291-96	$(x^{0.5})$ 0.1162, where $x =$ mean value	Concentration range 9% to 16% (mass)
Nitrogen	ASTM D 5291-96	0.1670, where $x =$ mean value	Concentration range 0.75% to 2.5% (mass)
	ASTM D 3228-96	0.066 (concentration) ^{0.5}	Kjeldahl method
Heating value	ASTM D 240-00	0.13 MJ/kg	Covers light distillates to
-	ASTM D 4809-00	0.097 MJ/kg, all fuels	residual fuels
	ASTM D 5468-95	Note (1)	

 Table 4-5.2
 Typical ASTM Standard Test Repeatability for Fuel Oil Properties

GENERAL NOTE: All values in third column are standard ASTM procedure repeatability. NOTE:

(1) Test method for gross calorific and ash value of waste materials.

flowmeter has been provided with a pressure reference point, the pressure in the densitometer should be identical to the pressure at that point. The temperature of the gas in the densitometer should be equal to the gas temperature in the meter. Correlations for compressibility have become accurate enough so that flow calculations based on pressure, temperature, and compressibility are as accurate as flow measurements using the densitometer.

4-6.1.2 Turbine Meters for Natural Gas Fuel Flow Measurement. Turbine meters may be used as an alternative to orifice gas flow measurement, but insertion turbine meters are not recommended for primary measurements. The turbine meter measures actual volume flow. The turbine meter rotates a shaft connected to a display. The rotational shaft speed is adjusted through a series of gears so that the counter displays in actual volume units per unit time, such as actual cubic meters or cubic feet per minute. This value must be adjusted for actual gas density and temperature, using equations in ISO 5167, to obtain the correct mass flow units.

Details of pipe layouts and operations of the turbine flowmeters should be referred to the new ISO 9951 standard, Measurement of Gas Flow in Closed Conduits — Turbine Meters.

4-6.1.3 Digital Computation of Fuel Flow Rate. Mass flow rate as shown by computer printout or flow computer is not acceptable without showing intermediate results and the data that is used for the calculations. Intermediate results for an orifice would 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 is determined from the calibration curve of the meter. Data includes frequency, temperature, and pressure. For both devices, fuel analysis and the intermediate results used in the calculation of density are required.

4-6.2 Syngas Fuel or Product

Syngas fuel or syngas product flows may be measured using orifices or turbine-type flowmeters. The same

qualifications for syngas mass flow total uncertainty and the orifice metering uncertainty, as described in para. 4-6.1, are appropriate for syngas.

When measuring syngas, its energy is generally the parameter sought, as it quantifies the value of the syngas utilized. The chemical energy input/output is determined from the quantity of gas and the gas heating value (HHV or LHV; the latter for gas turbine fuel input). In the case where the heating value of the syngas can be assumed to be constant, the energy can be directly calculated by multiplying the quantity being measured by this heating value. The heating value may either be monitored continuously or sampled periodically to check the validity of the assumption. If the heating value is fluctuating, then this calculation may be done online continuously.

The quantity of syngas is usually expressed in terms of volume at base or standard atmospheric conditions. This is the volume that the gas would occupy if the pressure and temperature were adjusted to standard atmospheric temperature and pressure. These standard reference conditions should be clearly identified prior to the tests. The quantity of syngas may also be expressed in terms of mass instead of volume.

The flows are corrected with measured specific gravities, temperatures, and pressures to give absolute syngas volumetric flow rates in N-m³/h (scfh). The syngas composition is measured by gas chromatography.

4-7 MATERIAL ANALYSIS

For fuel quality analyses and other chemical/physical analyses necessary to assess system performance, appropriate sampling and analytical techniques must 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 must 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.

4-7.1 Sample Collection

Basic guidelines for representative sampling of process streams and fuels can be found in various ASTM¹ and EPA^{2,3} publications. For most process streams, multiple grab samples are necessary to provide a representation of the process over time and, more importantly, provide data enabling an assessment of sample variability. Sample composites may also be prepared to obtain a single representative sample over time; however, an assessment of sample-to-sample variability is lost. Duplicate composite samples, i.e., separate samples collected simultaneously during the same time period and 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 selection of sampling locations. Many test parameters in synthesis gas and other gasification process samples are susceptible to oxidation and may be reactive to sampling containers, causing degradation of the sample immediately upon collection. Nonhomogeneous, multiphase, and other sample materials not analyzed directly must be prepared for analysis. The net effect on the analytical result must 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 should address these issues and describe how sampling precision, accuracy, and representativeness will be assessed.

4-7.2 Analytical Techniques

Analytical techniques should 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, limit of detection, and susceptibility to interference. Process analytical chemists or other individuals familiar with the principles of chemical analysis methods and the characteristics of the samples should direct the selection of test 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 is to be obtained.

The performance test plan should identify the analytical methods and the data quality objectives for precision and accuracy of each test parameter. In addition, since most analytical methods do not provide performance specifications, the test plan should provide specifications for laboratory quality control parameters necessary to meet the test objectives. Acceptable criteria for calibration accuracy, calibration check standard frequency and recovery, method blanks, duplicate precision, matrix spike recovery, etc., and appropriate corrective actions for failure to meet the acceptance criteria are necessary components of a comprehensive analytical plan. A thorough analytical plan will provide the necessary data to validate and defend the laboratory results.

4-8 INPUT AND OUTPUT HEAT MEASUREMENT 4-8.1 Direct Measurement Method

4-8.1.1 Dry Solid Fuels. In the direct measurement method of dry solid fuels, the primary heat input is

¹ Annual Book of ASTM Standards, Section 5: Petroleum Products, Lubricants, and Fossil Fuels, Vols. 05.01 through 05.05, ASTM International, West Conshohocken, PA.

² Handbook for Sampling and Sample Preservation of Water and Wastewater, EPA-600/4-82-029, Environmental Monitoring and Support Laboratory, Cincinnati, OH, 1982.

³ Environmental Monitoring Reference Manual for Synthetic Fuels Facilities, EPA-600/8-83-027, Industrial Environmental Research Laboratory, Research Triangle Park, NC.

equal to the product of the fuel mass flow rate and the fuel higher heating value (HHV). The mass flow rate is typically measured with gravimetric weight belt feeders upstream of the coal preparation equipment. HHV is determined post-test in a bomb calorimeter according to ASTM D 5865-01 or other acceptable technique. Fuel samples will 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 lockhoppers. By tracking the difference between the full and empty weights of each lockhopper 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.

4-8.1.2 Fuel Slurries. In a typical slurry configuration, the solid fuel is finely ground in rod mills 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 flux 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 while the wet mills undergo planned maintenance.

In the direct measurement of slurry, the fuel's heating value is determined by ASTM laboratory techniques and the flow of high pressure slurry is measured with calibrated orifices or magnetic flowmeters. During the performance test, at least one sample should be taken per hour. The slurry sample is withdrawn and weighed, and the completely dried solids portion of this slurry sample is weighed and tested for heating value. The water portion of the slurry is identified as having no heat of combustion value. The slurry viscosity and density are measured externally.

4-8.1.3 Biomass. Biomass gasification continues to be developed for wood and forestry wastes and for agricultural waste from processing sugarcane (called bagasse). Other agricultural wastes, including coconut waste and rice husk, animal waste such as slurries from a cow shed, chicken wastes that are dried and pelletized, separated household waste, and landfill waste, are all being researched. Some demonstration plants have been constructed, but no full-scale plant is yet in operation.

It is perceived that the biomass will be sized, dried, and compacted to concentrate the available fuel energy for gasification. The measurement of the primary biomass fuel is therefore not identified for this Code at this writing.

4-8.1.4 Consistent Liquid or Gaseous Fuels. Consistent liquid or gaseous fuels are those with heating values that vary less than 1.0% over the course of a performance

test. Since liquid and gas flows and heating values can be determined with high accuracy, the heat input from these type fuels is usually determined by direct measurement of fuel flow and the laboratory or online chromatograph-determined heating value. Consistent liquid or gaseous fuels heat input can also be determined by calculation as with solid fuels.

Homogeneous gas and liquid fuel flows are usually measured directly for gas-turbine-based power plants. For steam turbine plants, the lowest uncertainty method should be employed depending on the specific site.

Subsections 4-5 and 4-6 include a discussion of the measurement of liquid and gaseous fuel flow. Should the direct method be employed, the flow is multiplied by the heating value of the stream to obtain the facility heat input to the cycle. The heating value of gaseous fuels can be measured by an online gas chromatograph (GC), mass spectrometer (MS), or by sampling the stream periodically (at least three samples per test) and analyzing each sample individually for heating value in the laboratory. The analysis of gas, either by online chromatography or from laboratory samples, in accordance with ASTM D 1945 for natural gas, results in the amount and kind of gas constituents, from which heating value is calculated in accordance with ASTM D 3588. Liquid fuel heating value may be determined by calorimeter in accordance with ASTM D 240.

4-8.1.5 Export Syngas. The gas chromatography component analysis is used with component standard heating values to calculate the heating value of the syngas in MJ/N-m³ (Btu/scf). The analysis of gas, either by online chromatography or from laboratory samples, in accordance with ASTM D 1946, results in the amount and kind of gas constituents, from which heating value is calculated in accordance with ASTM D 3588. The product of total flow and syngas heating value is the flowing MJ/h (Btu/hr).

4-8.2 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, and 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 the direct measurement method.

4-9 ELECTRICAL GENERATION MEASUREMENT

Electrical measurements required for the evaluation of gas turbine and steam turbine performance may include

C	onfiguration		Restri	ctions
Code	Application	Connection	Voltage	Load
1.5E	1 ¹ / ₂ -element	Three-phase, three-wire	Balanced	Balanced
2E	Two-element	Three-phase, three-wire	None	None
3E	Three-element	Three-phase, three-wire	None	None
2.5E	$2^{1}/_{2}$ -element	Three-phase, four-wire	Balanced	Balanced
3E	Three-element	Three-phase, four-wire	None	None

Table 4-9.1 Metering Method Restrictions Summary

gross electrical output, power factor, exciter power, and other auxiliary electrical loads. This subsection provides guidance and requirements for the determination of these measurements, and includes the following:

(*a*) The measurement of polyphase (three-phase) alternating current (AC) real (active) and reactive power output. Typically, the polyphase measurement will be net or overall plant generation, the direct measurement of generator output (gross generation), or power consumption of balance of plant equipment.

(*b*) The measurement of direct current (DC) power output. Typically, the direct current measurement will be on the generator side of any connections to the power circuit by which power can enter or leave the circuit and as close to the generator terminals as physically possible.

ANSI/IEEE Std 120-1989, IEEE Master Test Guide for Electrical Measurements in Power Circuits, should be consulted for additional information and for measurement requirements not included in this Code.⁴

4-9.1 Electric Measurement System Connections

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

The minimum metering methods required for use on each of these three-phase systems are as follows:

(*a*) for three-wire power systems, two single-phase meters or one two-phase meter

(*b*) for four-wire power systems, three single-phase meters or one three-phase meter

Table 4-9.1 provides guidance on the restrictions of various connection metering methods to ensure the appropriate metering method is selected to meet the uncertainty requirements as described herein. It should be noted that in the two-element configuration of the three-phase, three-wire connection, if the load is unbalanced, i.e., the phase currents are unbalanced, this method could result in an error in calculating the total power factor, since only two VA measurements are used in the calculation. As such, the three-element configuration of the three-phase, three-wire connection is the recommended configuration in the determination of power factor, due to insensitivity in the load balance of a three-wire power system.

Various three-wire and four-wire power systems exist due to the types of connections that can exist between the generator and transformers: Wye–Delta, Delta–Wye, Wye–Wye, and Delta–Delta. It is recommended to review the particular type and the site arrangement before deciding which one is suitable to a given measurement application. Paragraphs 4-9.1.1 and 4-9.1.2 describe different types of three- and four-wire power systems that may exist.

4-9.1.1 Three-Wire Power Systems. Examples of three-wire power metering systems are shown in Fig. 4-9.1.1. Various three-wire power systems exist, due to the type of the connected generator.

Power and energy in three-wire power systems can be measured using two "Open Delta" connected voltage transformers (VTs) and two current transformers (CTs). The two-metering system is shown in Figs. 4-9.1.1 and 4-9.1.2 for a Wye connected and a Delta connected generator, respectively.

Several types of metering devices can be used in connection with these instrument transformers: two watt/var meters, two watt-hour/var-hour meters, a two-element watt/var meter, or a two-element watt-hour/var-hour meter. A var type meter is the recommended method to measure reactive power to establish the power factor. Power factor calculation is provided in para. 4-9.6.2(a), including the case for balanced three-phase sinusoidal circuits.

4-9.1.2 Four-Wire Power Systems. A typical four-wire power metering system is shown in Fig. 4-9.1.2. In addition, with the exception of the "Open Delta" generator connection, all of the three-wire systems described in para. 4-9.1.1 can also be measured

⁴ This reference shall be superseded upon the publication of ASME PTC 19.6, which is currently under development.



Fig. 4-9.1.1 Three-Wire Metering Systems





(b) Connections for Three Wattmeters or One Three-Element Watt-Hour Meter







(d) Connections for Three Wattmeters or One Three-Element Watt-Hour Meter



Fig. 4-9.1.2 Four-Wire Metering Systems: Connections for Three Wattmeters or One Three-Element Watt-Hour Meter

using the four-wire measurement system described in this paragraph.

The measurement of power and energy in a four-wire power system is made using three VTs and three CTs as shown in Fig. 4-9.1.2. The following metering devices can be used in connection with these instrument transformers: three watt/var meters, three watt-hour/var-hour meters, a three-element watt/var meter, or a three-element watt-hour/var-hour meter. A var type meter is the recommended method to measure reactive power to establish the power factor. Power factor calculation is provided in para. 4-9.6.2(b), including the option where each phase voltage and current (volt-amps) is measured.

4-9.2 Instrument Transformers

Instrument transformers are used for the purpose of reducing the voltages and current to values that can be conveniently measured, typically to ranges of 120 V and 5 A, respectively, and insulating the metering instruments from the high potential that may exist on the circuit under test. Instrument transformer practice is described in detail in IEEE Std C57.13-1993, IEEE Standard Requirements for Instrument Transformers.

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

It is recommended to test near a power factor of unity to minimize the sensitivity of the measured power to the phase-angle errors arising from the power meter (α), current transformers (β), and voltage transformers (γ). **4-9.2.1 Voltage Transformers.** Voltage transformers measure either phase-to-phase voltage or phase-to-neutral voltage. The voltage transformers serve to convert the line or primary voltage to a lower or secondary voltage safe for metering (typically 120 V for phase-to-phase systems and 69 V for phase-to-neutral systems). For this reason, the secondary voltage measured by the voltage transformer must be multiplied by a marked ratio to calculate the primary voltage that actually exists in the generator.

For the measurement of generator output in a gas turbine test, correctly rated voltage transformers of at least 0.3% accuracy class (metering type) shall be used. Voltage transformers must be calibrated for turns ratio and phase angle, and operated within their rated burden range. The method of calibration should permit the determination of the turns ratio and phase angle to uncertainties of ±0.1% and ±0.9 mrad (3 min), respectively. The calibration shall consist of ratio and phase angle tests from 90% to 110% percent of rated primary voltage at rated frequency with zero burden, and with the maximum standard burden for which the transformer is rated at its best accuracy class. The magnitudes of such corrections depend upon (1) the burden (number and kinds of instruments connected to the transformer) and (2) in the case of power measurement, the power factor of the device being measured. The ratio is usually from 0.1% to 0.3% below the nominal value for a small burden, while the phase angle is commonly negligible, being slightly leading. Voltage transformer ratio correction factors shall be applied for the actual burdens that exist during the test. Actual volt-ampere burdens shall be determined either by calculation from lead impedances or by direct measurement. IEEE Std C57.13-1993 should be consulted for determining the associated equations in providing an analytical determination of the transformer ratio correction factor, *RCF_C*. Corrections for voltage drop of the connecting lines should be determined and applied.

4-9.2.2 Current Transformers. The current transformers convert the line or primary current to a lower secondary current safe for metering. For this reason, the secondary current measured by the current transformers must be multiplied by a marked ratio to calculate the primary current that actually exists in the generator output wiring.

For the measurement of generator output in a gas turbine test, correctly rated current transformers of at least 0.3% accuracy class (metering type) shall be used. It is recommended that each current transformer should be calibrated for turns ratio and phase angle at zero external burden (0 VA) and at least one burden that exceeds the maximum expected during the test at 10% and 100% of rated primary current. Accuracy test results may be used from factory type (design) tests in the determination of turns ratio and phase angle correction factors. Type tests are commonly performed on at least one transformer of each design group that may have a different characteristic in a specific test. Current transformers shall be operated within their rated burden range during the test and shall be operated near 100% of rated current to minimize instrument error.

Near the rated current outputs, ratio and phase angle correction factors for current transformers may be neglected due to their minimal impact on measurement uncertainty; however, if the ratio or phase angle correction factor is expected to exceed 0.02% at actual test conditions, actual correction factors should be applied.

4-9.2.3 Instrument Transformer Connections. Connections for voltage and current measuring instruments should be made on the generator side of step-up transformers as close to the generator terminals as possible. Current connections shall be made on the generator side of any external connections of the power circuit by which power can enter or leave this circuit. The leads to the instruments shall be arranged so that inductance or any other similar cause will not influence the readings. Inductance may be minimized by utilizing twisted and shielded pairs for instrument leads. It is desirable to check the whole arrangement of instruments for stray fields.

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

4-9.2.4 Precautions in the Use of Instrument Transformers. In using potential transformers, care should be taken to avoid short-circuiting the secondary. In using current transformers, care should be taken never to open the secondary circuit while current is in the primary winding, because of the dangerously high voltage that may be developed and the excessive temperature rise that may ultimately take place due to high losses in the transformer. Also, current transformer cores may be permanently magnetized by inadvertent operation with the secondary circuit opened, resulting in a change in the ratio and phase angle characteristics. If magnetization is suspected, it should be removed as described in ANSI/IEEE Std 120-1989, under "Nature of Deviations from Nominal Ratio in Current Transformers." When it is necessary to open the secondary circuit while current is in the primary winding, e.g., in order to change the instrument, the secondary winding should be shortcircuited, preferably at the transformer terminals.

4-9.2.5 Utilization of Existing Plant Instrument Transformers. Existing station voltage or current transformers may be used for the test if they meet the requirements of this Code.

4-9.3 Electrical Metering Equipment

There are five types of electrical metering equipment that may be used to measure electrical energy — wattmeters, watt-hour meters, var meters, var-hour meters, and power factor meters. Single or polyphase metering equipment may be used. These meters are described below.

The warm-up time of electrical metering equipment shall be in accordance with the manufacturer's recommendations to ensure instrument specifications are met. Electrical metering equipment with various measurement range settings should be selected to minimize the reading error while encompassing the test conditions. The systematic uncertainty associated with digital power analyzers that use some form of digitizing technique to convert an analog signal to digital form accuracy specifications shall consider influence quantities including, but not limited to, environmental effects such as ambient temperature, magnetic fields, electric fields, and humidity; power factor; crest factor; D/A output accuracy; timer accuracy (integration time); and long-term stability.

To reduce the effect of instrumental loss on measurement accuracy, power metering equipment should be selected that uses a separate source of power and that has high-impedance voltage inputs (i.e., 2.4 M Ω) and low-impedance current inputs (i.e., 6 m Ω).

Extreme care must be exercised in the transportation of calibrated portable instruments. The instruments should be located in an area as free of stray electrostatic and magnetic fields as possible. Where integrating meters are used, a suitable timing device shall be provided to accurately determine the real power during the test time period.

4-9.3.1 Wattmeters. Wattmeters measure instantaneous active power. The instantaneous active power must be measured frequently during a test run and average over the test run period to determine average power (kilowatts) during the test. Should the total active electrical energy (kilowatt-hours) be desired, the average power must be multiplied by the test duration in hours. Wattmeters measuring generator active power output must have a systematic uncertainty equal to or less than 0.15% of reading and a sampling rate of at least once per minute during the test.

4-9.3.2 Watt-Hour Meters. Watt-hour meters measure cumulative active energy (kilowatt-hours) during a test period. The measurement of watt-hours must be divided by the test duration in hours to determine average active power (kilowatts) during the test period. Watt-hour meters measuring generator active power output must have an uncertainty equal to or less than 0.15% of reading.

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

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

4-9.3.3 Var Meters. Var meters measure instantaneous reactive power. The instantaneous reactive power must be measured frequently during a test run and averaged over the test run period to determine average reactive power (kilovars) during the test. Should the total reactive electrical energy (kilovar-hours) be desired, the average power must be multiplied by the test duration in hours. Var meters measuring generator reactive power output must have a systematic uncertainty equal to or less than 0.5% of range and a sampling rate of at least once per minute.

4-9.3.4 Var-Hour Meters. Var-hour meters measure reactive energy (kilovar-hours) during a test period. The

measurement of var-hours must be divided by the test duration in hours to determine average reactive power (kilovars) during the test period. Var-hour meters measuring generator reactive power output must have an uncertainty equal to or less than 0.5% of range.

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

4-9.3.5 Power Factor Meters. Power factor may be measured directly using three-phase power factor transducers when balanced load and frequency conditions prevail. Power factor transducers must have an uncertainty equal to or less than 0.01*PF* of the indicated power factor.

4-9.3.6 Existing Power Plant Instrumentation.

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

4-9.4 Electrical Metering Equipment Calibration

4-9.4.1 Watt and Watt-Hour Meter Calibration. Wattand watt-hour meters, collectively referred to as power meters, are calibrated by applying power through the test power meter and a wattmeter or watt-hour meter standard simultaneously. This comparison should be conducted at several power levels (at least five) across the expected power range. The difference between the test and standard instruments for each power level should 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 should be used. The selected power levels should be approached in an increasing and decreasing manner. The calibration data at each power level should be averaged to minimize any hysteresis effect. Should polyphase metering equipment be used, the output of each phase must be available or the meter must be calibrated with all three phases simultaneously.

Portable instruments shall be calibrated in a controlled laboratory environment if there is an indication of a problem with the measurement. The value of the voltage maintained on the voltage circuit of the instruments during calibration shall cover the range of expected test values, based on the manufacturer's recommendations for required uncertainty.

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

Wattmeters should be calibrated at the electrical line frequency of the equipment under test, i.e., do not calibrate meters at 60 Hz and use on 50 Hz equipment.

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

4-9.4.2 Var and Var-Hour Meter Calibration. In order to calibrate a var or var-hour meter, one must either have a var standard or a wattmeter standard and an accurate phase angle measuring device. Also, the device used to supply power through the standard and test instruments must have the capability of shifting phase to create several different stable power factors. These different power factors create reactive power over the calibration range of the instrument.

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

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

When calibrating var-hour meters, the output from the var meter standard or wattmeter/phase angle meter combination should be measured with frequency high enough to reduce the random error during calibration so the total uncertainty of the calibration process meets the required level. The average output can be multiplied by the calibration time interval to compare against the var-hour meter output.

Should polyphase metering equipment be used, the output of each phase must be available or the meter must be calibrated with all three phases simultaneously.

4-9.5 Excitation Power Measurement

If the exciter is powered by current supplied from the main generator bus at a point after the gross electrical output metering, the power supplied to the exciter must be determined. There are two methods, as described in paras. 4-9.5.1 and 4-9.5.2.

4-9.5.1 Derivation From Breaker Currents. Exciter power and any other auxiliary gas turbine loads included in the gas turbine vendor scope of supply can be calculated from the current and voltage input to the exciter power transformer or breaker. Since this is a measure of the actual power that comes off of the main generator bus, this is the preferred method of determining exciter power required. The calculation is done in para. 4-9.6.3(a).

4-9.5.2 Derivation From Field Voltage and Current. Power supplied to the exciter can also be estimated by calculating the power output by the exciter and by correcting for an assumed AC to DC conversion efficiency. The calculation is given in para. 4-9.6.3(b).

4-9.6 Electrical Power Calculations

4-9.6.1 Introduction. Electrical measurements required for the evaluation of IGCC plant performance may include gross electrical output, power factor, exciter power, and other auxiliary electrical loads. The following paragraphs provide guidance and requirements for the calculation of these measurements. The calculation method for average power or total energy should be performed in accordance with ANSI/IEEE Std 120-1989 for the specific type of measuring system used. Power measurements must be corrected for actual voltage transformer ratio and for phase angle errors in accordance with the procedures of IEEE Std C57.13-1993 as presented in Appendix E.

4-9.6.2 Electrical Measurement System Connections. Electrical measurement system connections are based on the type of metering methods, either three-wire power systems (two single-phase meters or one two-phase meter) or four-wire power systems (three single-phase meters) or one three-phase meter).

The following describes calculations for the two types of three- and four-wire power systems that may exist:

(a) Three-Wire Power Systems Power Factor Calculation. The power factor is determined using the formula

$$PF = \frac{Watts_t}{\sqrt{Watts_t^2 + Vars_t^2}}$$

where

PF = power factor $Vars_t$ = total vars for three phases $Watts_t$ = total watts for three phases

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

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

where

PF = power factor $Watts_{1-2}$ = real power phase 1 to 2 $Watts_{3-2}$ = real power phase 3 to 2

(b) Four-Wire Power Systems Power Factor Calculation. The power factor can be calculated from the watt and var meters using the formula

$$PF = \frac{Watts_t}{\sqrt{Watts_t^2 + Vars_t^2}}$$

where

PF = power factor $Vars_t$ = total vars for three phases $Watts_t$ = total watts for three phases

Alternatively, the power factor may be determined by measuring each phase voltage and current (volt-amps), with the formula

$$PF = \frac{Watts_t}{\sum V_i I_i}$$

where

PF = power factor

 I_i = phase current for each of the three phases

 V_i = phase voltage for each of the three phases

4-9.6.3 Excitation Power Calculation. If the exciter is powered by current supplied from the main generator bus at a point after the gross electrical output metering, the power supplied to the exciter must be determined. Two methods for determining the power supplied to the exciter are as follows:

(*a*) Derivation From Breaker Currents. Exciter power and any other auxiliary gas turbine loads included in the gas turbine vendor scope of supply can be calculated from the current and voltage input to the exciter power transformer or breaker. Since this is a measure of the actual power which comes off of the main generator bus, this is the preferred method of determining exciter power

$$ExcLoss = \frac{\sqrt{3} \times V \times A \times PF}{1,000}$$

where

A = average phase field current (measured value), A

ExcLoss = exciter power, kW

PF = power factor (measured or calculated value)

V = average field voltage (measured value), V

1,000 = conversion factor from watts to kilowatts

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

(b) Derivation From Field Voltage and Current. Power supplied to the exciter can also be estimated by calculating the power output by the exciter and by correcting for an assumed AC to DC conversion efficiency using the formula

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

where

- ACDC = AC to DC conversion efficiency factor (assumed value, typically 0.975)
- *ExcLoss* = exciter power, kW
 - FC = field current (measured value), A DC
 - FV = field voltage (measured value), V DC
 - 1,000 = conversion factor from watts to kilowatts

4-9.6.4 Instrument Transformers. The instrument transformers introduce errors when converting the high primary voltage/current to a low secondary voltage/current. These errors result in a variation of the true ratio from the marked ratio and also the variation of the phase angle from the ideal (zero). The magnitude of the errors depends on the burden (number and kinds of instruments connected to the transformer), the secondary current (in the case of current transformers), and the power factor of the device being measured (in the case of power measurement). The correction methodology is exemplified in Nonmandatory Appendix E.

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

(b) Current Transformers. The current transformer ratio correction factor, $CTRCF_C$, is calculated in a similar manner as the voltage transformer correction factor, $VTRCF_C$. However, typical values at rated primary current vary very little between 0.9999 and 1.0, and therefore may be ignored. It should be emphasized that the $CTRCF_C$ for operation at conditions less than the rated primary current increases significantly and should not be neglected. The error at 10% current is permitted to be two times the value of the error at 100% rated primary current. CT calibration should therefore be provided at two different burdens and a function of load.

4-9.6.5 Calculation of Corrected Primary Power. The error for each phase is corrected by applying calibration data from the transformers and the power meter as follows:

$$Power_{highside} = Power_{lowside} \times VTR \times CTR \times MCF$$
$$\times VTRCF_{C} \times CTRCF_{C} \times PACF_{C} \times VTVDC$$

where

CTR = current transformer marked ratio

- $CTRCF_C$ = current transformer ratio correction factor from calibration data
 - *MCF* = meter correction factor from calibration

$PACF_C =$	phase angle correction factor from
	calibration data

- *Power*_{highside} = power corrected on the high side of the transformer
- *Power*_{lowside} = power measured on the low side of the transformer
 - *VTR* = voltage transformer marked ratio
 - $VTRCF_C$ = voltage transformer ratio correction factor from calibration data
 - *VTVDC* = voltage transformer voltage drop correction

The meter correction factor, *MCF*, is determined from calibration data. Each phase of the meter should be calibrated as a function of secondary current. The process should be done at a minimum of two different secondary voltages and at two different power factors. The actual *MCF* at test conditions could then be interpolated.

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

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

$$PACF_{C} = \frac{\cos (\theta - \alpha + \beta - \gamma)}{\cos (\theta)} = \frac{\cos (\theta - \alpha + \beta - \gamma)}{PF}$$

where

PF = power factor

 α = shift in power meter phase angle

 β = shift in current transformer phase angle

 γ = shift in voltage transformer phase angle

$$\theta = \arccos(PF)$$

A good approximation in practice will be to assume that when PF = 1, PACF = 1.

When a full calculation is not warranted, the following linear interpolation will apply:

$$PACF = 0.006667(PF) + 0.99333$$

Sample calculations are shown in Nonmandatory Appendix E.

4-10 COLLECTION AND HANDLING

4-10.1 Data Collection and Calculation Systems

4-10.1.1 Data Collection Systems. A data collection system should be designed to accept multiple instrument inputs and be able to sample data from all of the

instruments within 2 to 3 min to obtain all necessary data with the plant at the same condition. The system should be able to collect data and store data and results within 3 min.

4-10.1.2 Data Calculation Systems. The data calculation system should have the ability to average each input collected during the test and calculate the test results based on the averaged values. The system should also calculate standard deviation and coefficient of variance of each instrument. The system should have the ability to locate and eliminate spurious data from the average. The system should also have the ability to plot the test data and each instrument reading over time to look for trends and outlying data.

4-10.2 Data Management

4-10.2.1 Storage of Data. Signal inputs from the instruments should be stored to permit post-test data correction for application of new calibration corrections. The engineering units for each instrument along with the calculated results should be stored if developed onsite. Prior to leaving the test site, all test data should be stored in a removable medium to secure against equipment damage during transport.

4-10.2.2 Manually Collected Data. Most test programs will require some data to be taken manually. The data sheets should each identify the data point, test site location, date, data collector, collection times, and data collected.

4-10.2.3 Distribution of Data. The averaged data in engineering units should be available to all parties to the test prior to leaving the test site. All manually collected data should be made available to all parties to the test prior to leaving the test site.

4-10.3 Construction of Data Collection Systems

4-10.3.1 Design of Data Collection System Hardware. With advances in computer technology, data collection system configurations have a great deal of flexibility. They can consist of a centralized processing unit or distributed processing to multiple locations in the plant.

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

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

4-10.3.2 Calibration of Data Collection Systems.

When considering the accuracy of a measurement, the

accuracy of the entire measurement loop must be considered. This includes the instrument and the signal conditioning loop or process. Ideally, when an instrument is calibrated, it should be connected to the position on the data collection system that will be employed during the test. Should this be impractical, each piece of equipment in the measurement loop should be individually calibrated. Separate pieces of equipment include current sources, voltmeters, electronic ice baths, and resistors in the measurement loop.

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

4-10.3.3 Use of Existing Plant Measurement and Control System. The Code does not prohibit the use of the plant measurement and control system for testing. However, this system must meet the requirements of this paragraph. Below are some caution areas.

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

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

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

(*d*) Data historians that are used to archive data from distributed control systems typically only update a value based on exception, i.e., a value for a given parameter will only change if the new measurement falls outside of a predetermined band around the previously stored value. This scheme is used to reduce the size of the data archive files. During the test, the bandwidth must be narrow enough so that all data signals sent to the distributed control system during the test are reported and stored.

(*e*) When using a distributed control system for test measurements, each instrument loop used shall be loop calibrated up to and including the operator display or data archive value.

(*f*) Special care should be used in cases where the main plant electric meters are to be used to determine plant output for a test and they are located on multiple transmission lines out of the plant. If the meters are bidirectional, there could be a flow in from one meter and out through the other meter. If this metering situation exists, it could cause a significant increase in the uncertainty of the plant output because

(1) the meters might be much oversized to accommodate the flow-through electricity plus the plant output

(2) the flow-through situation requires the readings of the two meters to be subtracted to obtain the output of the plant. When subtracting the readings of two meters, the second function of Table C.1 of ASME PTC 19.1-1998 shows that the combined percent uncertainty could be higher than that of either meter or than that of the two meters when added.

Section 5 Calculations and Results

The calculations in this Section include test result calculations, corrections of measured results to account for differences between test conditions and reference conditions, effectiveness calculations to evaluate the performance of the IGCC plant, and calculations to determine the uncertainty in the test results.

Code tests should be conducted under conditions that minimize corrections, such as holding secondary inputs and outputs at or near their reference values.

IGCC plants typically operate with constant, specified maximum power output, based on gasifier capacity. The base set of correction factors in this document corresponds to this operating mode. To allow for application of this Code to other control strategies, additional correction factors could be required, as described in this section.

5-1 TEST RESULT EQUATIONS

Test results are presented in four categories — primary results (power output and fuel input), secondary energy inputs, energy export streams, and derived results.

5-1.1 Primary Results

The primary results — corrected net power and corrected primary fuel input — are measured results that are corrected to reference conditions. The corrections may be determined by a multivariate computer model, by the combined effects of various correction factors, or by a hybrid combination of these two correction methods. The measured terms are discussed in subsection 5-3 and correction procedures are discussed in subsection 5-4.

The primary energy input, including total energy input from the primary fuels and import steam, is also energy input to the gasification plant.

5-1.1.1 Corrected Net Power. If a multivariate computer model is used, the corrected net power is calculated by the algorithms in that model, as described in para. 5-4.2.1. If corrected net power is calculated from measured net power and correction factors, the general form of the calculation for the *i* and *j* terms listed below is

$$P_c = [P_m + \Sigma(AP_i)] \prod MP_j \tag{1}$$

where

 AP_1 = additive correction factor for variations in cooling tower inlet air pressure

- AP_2 = additive correction factor for variations in cooling tower inlet air temperature
- AP_3 = additive correction factor for variations in cooling tower inlet air humidity
- AP_4 = additive correction factor for variations in air input flow rate
- *AP*₅ = additive correction factor for variations in generator(s) power factor(s)
- AP_6 = additive correction factor for variations in steam generator blowdown
- AP₇ = additive correction factor for variations in circulating water temperature for once-through condenser cooling system or air-cooled condenser inside the test boundary
- AP_8 = additive correction factor for variations in condenser pressure for the heat rejection system outside the test boundary
- AP_{10} = additive correction factor for variations in thermal and electrical auxiliary loads
- AP_{11} = additive correction factor for variations in export syngas energy
- AP_{12} = additive correction factor for variations in export steam energy
- AP_{13} = additive correction factor for variations in export process water energy
- AP_{14} = additive correction factor for variations in by-product ash energy
- AP_{15} = additive correction factor for variations in by-product sulfur or sulfuric acid energy
- AP_{16} = additive correction factor for variations in by-product oxygen energy
- AP_{17} = additive correction factor for variations in by-product nitrogen energy
- AP_{18} = additive correction factor for variations in by-product argon energy
- AP_{23} = additive correction factor for variations in export compressed air energy
- MP_1 = multiplicative correction factor for variations in gas turbine inlet air temperature
- MP_2 = multiplicative correction factor for variations in gas turbine inlet air pressure
- MP_3 = multiplicative correction factor for variations in gas turbine inlet air humidity
- MP_4 = multiplicative correction factor for variations in air or oxidant input components
- MP_5 = multiplicative correction factor for variations in cooling water input temperature

- MP_6 = multiplicative correction factor for variations in condensate return temperature
- MP_7 = multiplicative correction factor for variations in sorbent input properties
- MP_8 = multiplicative correction factor for variations in primary fuel supply temperature
- MP_9 = multiplicative correction factor for variations in primary fuel heating value
 - P_c = corrected net power at the busbar, which is the IGCC test boundary during the test
- P_m = measured total net power at the busbar

IGCC plants typically operate with constant, specified maximum power output, based on gasifier capacity. The base set of correction factors listed above corresponds to this operating mode. To allow for application of this Code to other control strategies, the following additional correction factor could be required:

AP₉ = additive correction factor for measured power different from predetermined or required power

5-1.1.2 Corrected Primary Fuel Input. If a multivariate computer model is used, the corrected primary fuel input is calculated by the algorithms in that model, as described in para. 5-4.2.1. If corrected primary fuel input is calculated from measured fuel input and correction factors, the general form of the calculation for the *i* and *j* terms listed below is

$$Q_{pf,c} = [Q_{pf,m} + \Sigma(APF_i)] \prod MPF_j$$
(2)

where

- APF_{19} = additive correction factor for variations in sorbent feed rate if the sorbent is added into the gasification process
- MPF_7 = multiplicative correction factor for variations in sorbent input properties
- MPF_8 = multiplicative correction factor for variations in primary fuel supply temperature
- MPF_9 = multiplicative correction factor for variations in primary fuel heating value
- $Q_{pf,c}$ = corrected total energy in the primary fuel flows entering the gasifier
- $Q_{pf,m}$ = measured total energy in the primary fuel flows entering the gasifier during the test, as determined in subsection 5-2

IGCC plants typically operate with constant, specified maximum power output, based on gasifier capacity. The base set of correction factors listed above corresponds to this operating mode. To allow for application of this Code to other control strategies, the following additional correction factors could be required:

APF₉ = additive correction factor for measured power different from predetermined or required power

- MPF_1 = multiplicative correction factor for variations in gas turbine inlet air temperature
- MPF_2 = multiplicative correction factor for variations in gas turbine inlet air pressure
- MPF_3 = multiplicative correction factor for variations in gas turbine inlet air humidity
- MPF_4 = multiplicative correction factor for variations in air or oxidant input components
- MPF_5 = multiplicative correction factor for variations in cooling water input temperature
- MPF_6 = multiplicative correction factor for variations in condensate return temperature

5-1.2 Secondary Inputs

The secondary inputs are measured results that are corrected to reference conditions. The secondary inputs are

- (a) secondary fuel input (see para. 5-1.2.1)
- (b) import steam energy (see para. 5-1.2.2)
- (c) condensate input (see subsection 5-2)
- (*d*) auxiliary power input (see subsection 5-2)

Secondary inputs should be kept at or near reference conditions in order to minimize corrections. Multiple secondary input streams should be calculated separately and combined calculations should be avoided. The measured terms are discussed in subsection 5-3 and correction procedures are discussed in subsection 5-4.

5-1.2.1 Corrected Secondary Fuel Input. If a multivariate computer model is used, the corrected secondary fuel input is calculated by the algorithms in that model, as described in para. 5-4.2.1. If corrected secondary fuel input is calculated from measured secondary fuel input and correction factors, the general form of the calculation for the *i* and *j* terms listed below is

$$Q_{sf,c} = [Q_{sf,m} + \Sigma (ASF_i)] \prod MSF_j$$
(3)

where

ASF₂₀ = additive correction factor for variations in secondary heat input for process return or/and make-up temperature requirement

$$MSF_{10}$$
 = multiplicative correction factor for varia-
tions in secondary fuel supply temperature

$$MSF_{11}$$
 = multiplicative correction factor for varia-
tions in secondary fuel input heating value

- $Q_{sf,c}$ = corrected total energy in the secondary fuel injected into the HRSG
- $Q_{sf,m}$ = measured total energy in the secondary fuel injected into the HRSG during the test, as determined in subsection 5-2

The secondary fuel input is also energy input to the power plant.

5-1.2.2 Corrected Import Steam Energy. If a multivariate computer model is used, the corrected import steam energy is calculated by the algorithms in that

model, as described in para. 5-4.2.1. If corrected import steam energy is calculated from measured import steam energy and correction factors, the general form of the calculation for the i and j terms listed below is

$$Q_{is,c} = [Q_{is,m} + \Sigma (AIS_i)] \prod MIS_j$$
(4)

where

- AIS_{21} = additive correction factor for variations in import steam flow rate
- MIS_{12} = multiplicative correction factor for variations in import steam temperature
- MIS_{13} = multiplicative correction factor for variations in import steam pressure
- MIS_{14} = multiplicative correction factor for variations in makeup water input temperature
- $Q_{is,c}$ = corrected total energy of the import steam flows into the IGCC test boundary
- $Q_{is,m}$ = measured total energy of the import steam flows from individual steam flows into the IGCC test boundary during the test, as calculated in subsection 5-2

5-1.3 Exports

The export energy streams — synthesis gases, export steam, and by-products — are measured results that are corrected to reference conditions. Secondary outputs should be kept at or near reference conditions in order to minimize corrections. Multiple export streams should be calculated separately and combined calculations should be avoided. The measured terms are discussed in subsection 5-3 and correction procedures are discussed in subsection 5-4.

Corrected export energy streams are also output streams from the gasification plant.

5-1.3.1 Corrected Synthesis Gas Energy. If a multivariate computer model is used, the corrected synthesis gas energy is calculated by the algorithms in that model, as described in para. 5-4.2.1. If corrected synthesis gas energy is calculated from measured synthesis gas energy and correction factors, the general form of the calculation for the i and j terms listed below is

$$Q_{sg,c} = [Q_{sg,m} + \Sigma(ASG_i)] \prod MSG_j$$
(5)

where

- ASG₂₂ = additive correction factor for export syngas flow rate
- MSG_{15} = multiplicative correction factor for export syngas heating value
 - $Q_{sg,c}$ = corrected total energy of individual synthesis gas flows from the gasifier out the IGCC test boundary
 - $Q_{sg,m}$ = measured total energy of individual synthesis gas flows from the gasifier out the

IGCC test boundary during the test as calculated in subsection 5-2

5-1.3.2 Corrected Export Steam Energy. If a multivariate computer model is used, the corrected export steam energy is calculated by the algorithms in that model, as described in para. 5-4.2.1. If corrected export steam energy is calculated from measured export steam energy and correction factors, the general form of the calculation for the i and j terms listed below is

$$Q_{es,c} = [Q_{es,m} + \Sigma (AES_i)] \prod MES_i$$
(6)

where

- AES_6 = additive correction factor for variations in steam generator blowdown
- AES_{11} = additive correction factor for variations in export syngas energy
- AES_{12} = additive correction factor for variations in export steam energy
- AES_{13} = additive correction factor for variations in export process water energy
- AES₁₄ = additive correction factor for variations in by-product ash energy
- AES₁₅ = additive correction factor for variations in by-product sulfur or sulfuric acid energy
- AES_{16} = additive correction factor for variations in by-product oxygen energy
- AES_{17} = additive correction factor for variations in by-product nitrogen energy
- AES_{18} = additive correction factor for variations in by-product argon energy
- AES_{23} = additive correction factor for variations in export compressed air energy
- MES_{16} = multiplicative correction factor for variations in export steam temperature
- MES_{17} = multiplicative correction factor for variations in export steam pressure
- MES_{24} = multiplicative correction factor for variations in export compressed air temperature
 - $Q_{es,c}$ = corrected total energy of individual export steam flows out the IGCC test boundary
 - Q_{es,m} = measured total energy of individual export steam flows out the IGCC test boundary during the test as determined in subsection 5-2

5-1.3.3 Corrected Export Process Water Energy. If a multivariate computer model is used, the corrected energy of the export process water is calculated by the algorithms in that model, as described in para. 5-4.2.1. If corrected export process water energy is calculated from measured parameters and correction factors, the calculation should follow the form below for the *i* and *j* terms listed

$$Q_{pw,c} = [Q_{pw,m} + \Sigma (APW_i)] \prod MPW_i$$
(7)

where

- APW_{24} = additive correction factor for variations in process water flow rate
- MPW_{18} = multiplicative correction factor for variations in process water temperature
 - $Q_{pw,c}$ = corrected energy of the export process water flow
 - $Q_{pw,m}$ = measured energy of the export process water flow, as determined in subsection 5-2

5-1.3.4 Corrected Export Compressed Air Energy. If a multivariate computer model is used, the corrected energy of the export compressed air is calculated by the algorithms in that model, as described in para. 5-4.2.1. If the corrected export compressed air energy is calculated from measured parameters and correction factors, the calculation should follow the form below for the *i* and *j* terms listed

$$Q_{eca,c} = [Q_{eca,m} + \Sigma (AECA_i)] \prod MECA_i$$
(8)

where

- $AECA_{30}$ = additive correction factor for variations in compressed air flow rate
- *MECA*₂₄ = multiplicative correction factor for variations in compressed air temperature
 - $Q_{eca,c}$ = corrected energy of the export compressed air flow
 - $Q_{eca,m}$ = measured energy of the export compressed air flow, as determined in subsection 5-2

5-1.3.5 Corrected By-Product Energy. If a multivariate computer model is used, the corrected energy of each by-product stream is calculated by the algorithms in that model, as described in para. 5-4.2.1. If the corrected energy of each by-product stream is calculated from measured parameters with correction factors, the calculations should follow the forms below for the *i* and *j* terms listed.

(a) By-Product Ash

$$Q_{ash,c} = [Q_{ash,m} + \Sigma (AASH_i)] \prod MASH_i$$
(9)

where

- $AASH_{25}$ = additive correction factor for variations in by-product ash flow rate
- $MASH_{19}$ = multiplicative correction factor for variations in by-product ash properties
 - $Q_{ash,c}$ = corrected energy of the by-product ash flow
 - $Q_{ash,m}$ = measured energy of the by-product ash flow, as determined in subsection 5-2

(b) By-Product Sulfur or Sulfuric Acid

$$Q_{sulf,c} = [Q_{sulf,m} + \Sigma (ASULF_i)] \Pi MSULF_j$$
(10)

where

- ASULF₂₆ = additive correction factor for variations in by-product sulfur or sulfuric acid flow rate
- MSULF₂₀ = multiplicative correction factor for variations in by-product sulfur or sulfuric acid properties
 - *Q*_{sulf,c} = corrected energy of the by-product sulfur or sulfuric acid flow
 - $Q_{sulf,m}$ = measured energy of the by-product sulfur or sulfuric acid flow, as determined in subsection 5-2
- (c) By-Product Oxygen

$$Q_{bo,c} = [Q_{bo,m} + \Sigma (ABO_i)] \prod MBO_j$$
(11)

where

- ABO₂₇ = additive correction factor for variations in by-product oxygen flow rate
- *MBO*₂₁ = multiplicative correction factor for variations in by-product oxygen properties
 - $Q_{bo,c}$ = corrected energy of the by-product oxygen flow
 - $Q_{bo,m}$ = measured energy of the by-product oxygen flow, as determined in subsection 5-2
- (d) By-Product Nitrogen

$$Q_{bn,c} = [Q_{bn,m} + \Sigma (ABN_i)] \prod MBN_j$$
(12)

where

- ABN_{28} = additive correction factor for variations in by-product nitrogen flow rate
- MBN_{22} = multiplicative correction factor for variations in by-product nitrogen properties
 - $Q_{bn,c}$ = corrected energy of the by-product nitrogen flow
 - $Q_{bn,m}$ = measured energy of the by-product nitrogen flow, as determined in subsection 5-2
- (e) By-Product Argon

$$Q_{bar,c} = [Q_{bar,m} + \Sigma (ABAR_i)] \prod MBAR_j$$
(13)

where

- $ABAR_{29}$ = additive correction factor for variations in by-product argon flow rate
- *MBAR*₂₃ = multiplicative correction factor for variations in by-product argon properties
 - $Q_{bar,c}$ = corrected energy of the by-product argon flow
 - $Q_{bar,m}$ = measured energy of the by-product argon flow, as determined in subsection 5-2

5-1.4 Derived Results

A major performance test objective for a power plant is to determine effectiveness of energy conversion and utilization. Heat rate, defined as ratio of the fuel heat input to the net power output, has been traditionally used in a power generation system in which fuel heat is the only energy input and electricity is the only energy output. Therefore, heat rate, as defined in ASME PTC 46, Overall Plant Performance, is an adequate performance parameter for a conventional combined cycle system. However, heat rate is not an appropriate performance indicator for an IGCC plant with multiple inputs and multiple products, because a significant portion of the total input energy is converted into nonelectrical energy, such as synthesis gases, steam, and by-products.

This paragraph describes the following types of effectiveness calculations that may be used to evaluate the performance of the IGCC plant:

(*a*) corrected heat rate, for IGCC plants that produce only electric power

(*b*) corrected electrical efficiency, for IGCC plants that produce only electric power

(*c*) corrected thermal efficiency, based on first-law analysis of plant input and output streams

The parties to the test may select the type of effectiveness calculation to be used, or they may decide to use the set of corrected values for input and output streams as a performance vector, or as calculation inputs to a plant financial model. The Code takes no position regarding the relative merits of these criteria, and does not require that effectiveness be calculated. However, if an effectiveness calculation is performed, it must be based on results that have been corrected for the differences between test conditions and reference conditions.

5-1.4.1 Corrected Heat Rate. For electrical generating plants, the corrected heat rate is the ratio of corrected fuel input to corrected net power

$$HR_c = (Q_{pf,c} + Q_{sf,c}) / P_c \tag{14}$$

where

 HR_c = corrected heat rate

 P_c = corrected net power

 $Q_{pf,c}$ = corrected primary fuel input

 $Q_{sf,c}$ = corrected secondary fuel input

5-1.4.2 Corrected Electric Efficiency. For electrical generating plants, electricity efficiency, η_e , defines effectiveness of energy conversion from thermal and chemical forms into electricity within the IGCC plant

$$\eta_e = P_c / (Q_{pf,c} + Q_{sf,c} + Q_{is,c})$$
(15)

where

 P_c = corrected net power

 $Q_{is,c}$ = corrected import steam energy

 $Q_{pf,c}$ = corrected primary fuel input

 $Q_{sf,c}$ = corrected secondary fuel input

 η_e = electrical efficiency

5-1.4.3 Thermal Efficiency. Thermal efficiency, η_{th} , is the total net energy output (power, steam export, syngas export, and by-products) divided by the total energy input (primary fuel, secondary fuel, and import steam) across the test boundary. Thermal efficiency defines an overall effectiveness of energy conversion and utilization in the IGCC plant

$$\eta_{ih} = (P_c + Q_{sg,c} + Q_{es,c} + Q_{pw,c} + Q_{eca,c} + Q_{ash,c} + Q_{sulf,c} + Q_{bo,c} + Q_{bn,c} + Q_{bar,c}) / (Q_{pf,c} + Q_{sf,c} + Q_{is,c})$$
(16)

where

 P_c = corrected net power

 $Q_{ash,c}$ = corrected energy of the by-product ash flow

$$Q_{bar,c}$$
 = corrected energy of the by-product argon flow

- $Q_{bn,c}$ = corrected energy of the by-product nitrogen flow
- $Q_{bo,c}$ = corrected energy of the by-product oxygen flow
- $Q_{eca,c}$ = corrected energy of the export compressed air flow
- $Q_{es,c}$ = corrected energy of the export steam flows
- $Q_{is,c}$ = corrected import steam energy
- $Q_{pf,c}$ = corrected primary fuel input
- $Q_{pw,c}$ = corrected energy of the export process water flow
- $Q_{sf,c}$ = corrected secondary fuel input
- $Q_{sg,c}$ = corrected energy of the export synthesis gas flows
- $Q_{sulf,c}$ = corrected energy of the by-product sulfur or sulfuric acid flow
- η_{th} = thermal efficiency

5-2 CALCULATED (DERIVED) TERMS

The test result equations in subsection 5-1 are based on measured results that are corrected to reference conditions. The measured results are either direct measurements (see subsection 5-3) or terms that are calculated from direct measurements. Direct measurements are listed in subsection 5-3 and calculated terms are described below.

For calculations that include the heating value (HV), either LHV or HHV may be used as long as it is consistently used in all calculations. If the contract specifies either LHV or HHV, the test should match the contract.

5-2.1 Net Power

The net power for an IGCC plant with multiple prime generators is equal to the gross power output less the total auxiliary power consumption, the power loss in the main step-up transformer, the power loss in the bus line between generator and transformer, and any import power. The import power is the sum of all the power inputs entering the boundaries of the IGCC. The terms in the net power equation that are used for a specific test depend on the test boundaries for that test. The net power stream shown in Figs. 3-2.2-1 and 3-2.2-2 is a general representation of net power and does not depict the level of detail described in these equations.

$$P_m = (\Sigma P_{m,n}) - P_{aux} - PL_{xfmr} - PL_{line} - P_{ie}$$
(17)

$$PL_{xfmr} = P_{xfmr,0} + P_{xmfr,100} \times (I_{\text{meas}} / I_{\text{rated}})^2$$
(18)

$$PL_{\text{line}} = P_{\text{line},100} \times (I_{\text{meas}} / I_{\text{rated}})^2$$
(19)

$$P_{ie} = \Sigma P_{ie,k} \tag{20}$$

where

 I_{meas} = measured current on low-voltage side

- I_{rated} = rated current on low-voltage side
 - k = individual auxiliary power input stream
 - n = individual generator

 P_{aux} = in-plant auxiliary power use

 P_{ie} = import power

- $P_{\text{line},100} = \text{load}$ at the rated current
 - P_m = measured power
- $P_{xfmr,0}$ = no-load transformer loss determined from transformer shop test
- $P_{xfmr,100}$ = load transformer loss at rated current, I_{rated} , determined from transformer shop test at normal tap
 - *PL*_{line} = power loss in the bus line between generator and transformer
- *PL_{xfmr}* = power loss in the main step-up transformer

5-2.2 Primary Fuel Input

Chemical energy input from primary fuel(s) to the IGCC plant is expressed as

$$Q_{pf} = \Sigma \left[(HV_{pf,k})(W_{pf,k}) \right]$$
(21)

where

- $HV_{pf,k}$ = heating value of an individual primary fuel stream (the parties to the test may select either higher heating value or lower heating value, provided that all calculations in the test use the same type of heating value)
 - k = individual fuel input
 - *Q_{pf}* = total chemical energy input from the primary fuel(s)
- $W_{pf,k} = \text{mass flow rate of an individual primary fuel}$ stream

If blends of several fuels or multiphase fuels are used as the primary fuel, then Q_{pf} is the sum of the separate chemical energy calculations for each fuel or fuel phase.

In the overall plant efficiency tests for nonsolid-fueled conventional power generating cycles, *Q_{vf}* can be directly

derived through measurements. However, for solid-fueled IGCC cycles, variations in fuel constituents and heating value can result in significant fluctuation value in Q_{pf} even when the plant is operating at nominal steady-state condition. Consequently, Q_{pf} is determined from computational results based on either direct or indirect measurement methods.

5-2.3 Secondary Fuel Energy Input

Chemical energy input from secondary fuel(s), which can be directly determined through measurements at the power block, is expressed as

$$Q_{sf} = \Sigma \left[(HV_{sf,k})(W_{sf,k}) \right]$$
(22)

where

- $HV_{sf,k}$ = heating value of an individual secondary fuel stream (either higher or lower heating values may be selected by the parties to the test, provided they are used consistently in all equations)
 - *k* = individual nonsolid-fuel input to the power block
 - Q_{sf} = total chemical energy input from the secondary fuel(s)
- $W_{sf,k}$ = mass flow rate of an individual secondary fuel stream

5-2.4 Import Energy Streams

Thermal energy may be added to the IGCC plant in the form of import steam, makeup water, or import condensate. Import energy calculations are described below.

(a) Import Steam Energy

$$Q_{is} = \Sigma \left[(W_{is,k})(h_{is,k}) \right]$$
(23)

where

- $h_{is,k}$ = enthalpy of an individual import steam stream
 - *k* = individual steam input going either to the gasification block or to the power block
- Q_{is} = total thermal energy of the import steam stream(s)
- $W_{is,k}$ = mass flow rate of an individual import steam stream
- (b) Makeup Water and Condensate Energy

$$Q_{wmu} = \Sigma \left[(W_{wmu,k})(h_{wmu,k}) \right]$$
(24)

where

- $h_{wmu,k}$ = enthalpy of an individual makeup water or condensate stream
- Q_{wmu} = total thermal energy of the makeup water and import condensate stream(s)
- $W_{wmu,k}$ = mass flow rate of an individual makeup water or condensate stream

Other import streams, such as import oxygen and nitrogen in IGCC plants without ASUs (Fig. 3-2.2-2), should also be included as import energy streams.

5-2.5 Export Energy Streams

Thermal energy may be produced by the IGCC plant in the form of export steam, syngas, or compressed air. Export energy calculations are described below.

(a) Export Steam Energy

$$Q_{es} = \Sigma \left[(W_{es,k}) (h_{es,k}) \right]$$
(25)

where

- $h_{es,k}$ = enthalpy of an individual export steam stream
 - k = individual stream of export steam
- *Q_{es}* = total thermal energy of the export steam stream(s)
- $W_{es,k}$ = mass flow rate of an individual export steam stream

The steam flow rate, W_{st} , is directly measured, and the steam enthalpy, h_{st} , is calculated based on measured steam pressure and temperature.

(b) Export Syngas Energy. Net energy output contained in the clean syngas streams flowing across the test boundary is expressed as

$$Q_{sg} = \sum [(W_{sg,k})(h_{sg,k})]_{ex} - \sum [(W_{sg,l})(h_{sg,l})]_{im}$$
(26)

where

- h_{sg} = enthalpy of an individual export steam stream
- \tilde{k} = individual input clean syngas stream
- l = individual output clean syngas stream
- Q_{sg} = total, net thermal energy output of the import and export syngas stream(s)
- W_{sg} = mass flow rate of an individual export steam stream

The clean syngas flow rate, W_{sg} , is directly measured and the enthalpy, h_{sg} , including sensible heat and heat of combustion, is calculated based on measured syngas pressure, temperature, and composition.

(c) Export Compressed Air Energy. Net energy output contained in the compressed air flowing across the test boundary is expressed as

$$Q_{eca} = (W_{eca})(h_{eca}) \tag{27}$$

where

- h_{eca} = compressed air enthalpy
- Q_{eca} = total thermal energy of the export compressed air stream

 W_{eca} = compressed air mass flow rate

(d) Export Process Water

$$Q_{epw} = \Sigma \left[(W_{epw,k})(h_{epw,k}) \right]$$
(28)

where

- $h_{epw,k}$ = enthalpy of an individual process water stream
- *Q_{epw}* = total thermal energy of the export process water stream(s)
- $W_{epw,k}$ = mass flow rate of an individual process water stream

5-2.6 By-Product Energy Streams

By-products from an IGCC plant may include ash, sulfur or sulfuric acid, oxygen, nitrogen, and argon. Multiple by-product streams should be calculated separately and combined calculations should be avoided. The net energy output associated with each by-product is expressed as

$$Q_{ash} = (W_{ash})(h_{ash}) \tag{29}$$

$$Q_{sulf} = (W_{sulf})(h_{sulf})$$
(30)

$$Q_{bo} = (W_{bo})(h_{bo})$$
 (31)

$$Q_{bn} = (W_{bn})(h_{bn}) \tag{32}$$

$$Q_{bar} = (W_{bar})(h_{bar}) \tag{33}$$

where

h = by-product enthalpy

Q = energy of the by-product stream

W = by-product flow rate

The by-product flow rate, *W*, is directly measured and the enthalpy, *h*, which includes sensible heat and heat of combustion, is calculated based on measured stream pressure, temperature, and composition.

5-3 MEASURED TERMS

Measurements of the terms listed in Table 5-3 should follow the recommendations of this Code, as described in Section 4, on measurement equipment and methods to test IGCC plants and their major subsystem.

When a differential pressure meter is installed on a flow element that is located in a vertical steam or water line, the measurement must be corrected for the difference in sensing line height and fluid head change. Two versions of the correction equation for noninsulated sensing lines are presented below. The equation in SI units is

$$h_{wc} = h_w + Ht/(10\ 179\ sg) \times (1/V_{\text{sen}} - 1/V_{\text{fluid}})$$
 (34)

where

 h_w = measured differential pressure, mb

 h_{wc} = corrected differential pressure, mb

Ht = sensing line height difference, mm

sg = specific gravity at the sensing line temperature

Measurements
Kilowatts and load power factor at boundary [Note (1)]
Flow rate and composition (if connected to gasification process)
Flow rate and composition (if connected to gasification process)
Flow rate and composition (if connected to gasification process), temperature, and pressure
Flow rate and composition (if connected to gasification process), temperature, and pressure
Flow rate and composition (if connected to gasification process), temperature, and pressure
Input temperature
Flow rate and temperature
Flow rate and temperature
Flow rate, pressure, and temperature
In and out flow rates, pressures, temperatures, and compositions
Circulating water temperature
Condenser pressure
Flow rate, pressure, and temperature
Pressure, temperature, and humidity at cooling tower and turbine inlet
Temperature
Kilowatts, frequency, low-voltage current, and load power factor at boundary [Note (1)]
Composition, pressure, temperature, and now rate
Temperature, composition, meaning value [Note (2)], and now rate [Note (3)]
Temperature
Total energy from process return or/and makeup temperature requirement
Composition and feed rate (if used in the gasification process) [Note (3)]
Flow rate, temperature
Measured current on low voltage side

Table 5-3 List of Measured I	erms
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NOTES:

(1) The net power for an IGCC plant with multiple prime generators is equal to the gross power output less the total auxiliary power consumption, the power loss in the main step-up transformer, the power loss in the bus line between generator and transformer, and any import power. See para. 5-2.1.

(2) Either higher heating value (HHV) or lower heating value (LHV) may be used, provided that all calculations in the test use the same type of heating value.

(3) See subsection 4-4 for solid flow measurement methods.

 V_{fluid} = specific volume of process, m³/kg V_{sen} = specific volume of sensing line, m³/kg 10 179 = conversion factor

The same equation in U.S. customary units is

$$h_{wc} = h_w + Ht/(62.32 \ sg) \times (1/V_{\text{sen}} - 1/V_{\text{fluid}})$$
 (35)

where

$$h_w$$
 = measured differential pressure, in. H₂O

- h_{wc} = corrected differential pressure, in. H₂O
- Ht = sensing line height difference, in.
- *sg* = specific gravity at the sensing line temperature

 $V_{\rm fluid}$ = specific volume of process, ft³/lbm

$$V_{\rm sen}$$
 = specific volume of sensing line, ft³/lbm

62.32 = conversion factor

5-4 CORRECTIONS

The performance test of an overall power plant customarily envisions operation at an agreed-upon set of reference conditions as follows:

(*a*) ambient conditions such as air pressure, temperature, and humidity; fuel temperature and composition; cooling water temperature (or steam turbine backpressure); and generator load factor

(*b*) secondary, controlled operating conditions such as process heat, steam, and/or synthesis gas flows from a trigeneration plant; condensate return temperature and flow; and blowdown from a boiler

If such ambient and secondary operating conditions are within accepted limits but not at reference conditions agreed upon, then it is necessary to adjust or "correct" test results — plant input, output, and effectiveness — calculated from the test measurements. Corrections distinguish the effects of off-reference ambient and plant operating conditions from the effects of deficient plant design and equipment.

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

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

This paragraph identifies the parameters that influence IGCC plant performance, and describes appropriate correction methods that may be used to compensate for variations in those parameters.

5-4.1 Influencing Parameters

All the parameters that will cause a deviation of IGCC performance from the reference conditions during a test are considered as influencing parameters. These include variables that impact deviation from IGCC design, operating conditions, input and output streams, and control equipment and instrumentation. Some of these variables can have major impacts on the power output and heat rate, while others may have insignificant impacts on the same. These parameters can be quantified by modeling the plant in detail.

(a) Input and Output Measured Streams

(1) primary fuel heating value, composition, temperature, mass flow

(2) secondary fuel heating value, composition, temperature, mass flow

(3) electricity voltage, power factor, frequency

(4) export syngas

(5) steam export and import streams' mass flow, temperature, pressure

(6) condensate/water export and import streams' mass flow, temperature

- (b) Other Measured Streams
 - (1) gasifier moderation water/steam supply
 - (2) oxidant supply
 - (3) syngas cooler heat recovery
 - (4) syngas heating value, composition, temperature
 - (5) air extraction conditions from gas turbine

(6) nitrogen or other inert matter injection conditions at gas turbine inlet

(7) steam and/or water injection conditions at gas turbine inlet

(c) Ambient or Inlet

(1) inlet air temperature, pressure, and humidity (see the definition of *ambient air* in Section 2)

(2) cooling sink temperature

- (d) Control Equipment and Instrumentation
 - (1) gas turbine firing temperature control
 - (2) exhaust temperature thermocouples
 - (3) emissions such as NO_x and vanadium levels

Relative sensitivity coefficients are calculated during the pretest uncertainty analysis to identify the parameters with the largest impacts on the test objectives. A relative sensitivity coefficient should 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, *RSC*, may be supplied by the equipment vendor or else calculated by either of the equations below.

(a) Partial Differential Form

$$RSC = (\partial R/R)/(\partial X/X_{avo}) = X_{avo}/R \times (\partial R/\partial X)$$
(36)

(b) Finite Difference Form

$$RSC = (\Delta R/R)/(\Delta X/X_{avg}) = X_{avg}/R \times (\Delta R/\Delta X) \quad (37)$$

where

- R = corrected test result
- *RSC* = relative sensitivity coefficient, decimal
- X_{avg} = measured parameter, average value
- $\Delta \vec{R}$ = change (finite difference) in corrected test result
- ΔX = change (finite difference) in measured parameter, typically $0.01X_{avg}$
- ∂R = change (partial differential) in corrected test result
- ∂X = change (partial differential) in measured parameter

5-4.2 Correction Methods

Power plant performance is the result of equipment operating within a given set of boundary conditions, such as inlet air pressure, temperature, and humidity; heat sink flows and temperatures; secondary thermal and electrical inputs and outputs; and electrical interactions with the power grid. Ideal tests would be run when all boundary conditions matched their design assumptions, but real tests are run under off-design conditions. Corrections are needed to distinguish the effects of offdesign boundary conditions from the effects of aberrant equipment.

Corrections may be applied as correction factors for individual variables, as algorithms in multivariate computer models for complex systems with interactions among variables, or as a hybrid mixture of the two types. Correction factors are often based on correction curves, which are typically calculated by heat balance computer models of the thermal systems contained within the test boundaries of subsystem blocks. A plant correction curve generated this way requires running the model within each block and then integrating the results into the overall system. With this approach, all interface variables between sections must be considered and corrected using predicted correction curves. Multivariate correction algorithms, if they are available, are more accurate than single-term corrections (correction factors and correction curves), because they can account for simultaneous excursions by several variables, including secondary effects, while ensuring that mass and energy balances are maintained.

Correction calculations can be based on correction factors, multivariate performance models, or a hybrid combination of these two basic correction methods. This paragraph describes each type of correction method and provides guidance in choosing the best type to apply to specific test results.

5-4.2.1 Correction Models. Multivariate correction models use computer algorithms to calculate each corrected result as a function of the measured result and the boundary set of ambient and imposed conditions

$$R_c = f(R_m, X_1, X_2, \dots X_n)$$
(38)

where

f	=	multivariate	computer	model
-		function	-	
D	_	compated modul	F	

 R_c = corrected result

 R_m = measured result

 $X_1, X_2, \dots X_n$ = ambient and imposed conditions (see subsection 5-4)

If the ambient and imposed conditions match their reference values, then the calculated result will match the measured result.

(*a*) Functional Requirements. The main functional requirements of the model are completeness, flexibility, and accuracy.

(1) Completeness and Flexibility. The model must be able to predict changes in IGCC system performance in response to changes in all boundary conditions of concern to the parties to the test. These would likely include ambient conditions (temperature, pressure, humidity), load settings, process steam and water flow conditions, and secondary thermal and electrical inputs and outputs. The normal range of the model must extend from minimum stable generation (at which point all environmental requirements are met) to base load. Inputs to the model should include at least all of the measured terms listed in Table 5-3. Outputs from the model should include the primary results identified in para. 5-1.1.

(2) Accuracy. The methods and calculations used in building the subsystem and complete plant model, including property methods, convergence techniques, and engineering models, must be of sufficient accuracy to satisfy the needs of the acceptance test. For the primary purpose of correcting plant performance back to reference conditions, consistency and relative accuracy of the calculations are more important than absolute accuracy. The final results should be accurate enough to meet the uncertainty levels in Table 1-3.

(*b*) *Model Validation*. Model validation is desirable, but the proprietary nature of comprehensive plant models may preclude complete validation. Normally, the uncertainties of correction factors, curves, and models cannot be ascertained because of the proprietary nature of such information, so this aspect of uncertainty has not been included in Table 1-3. Acceptance of an overall plant performance model by the parties to the test should include consideration of the issues described below.

(1) Comparing With Measured Data. As much as possible prior to the test, the model results should be compared with measured data from the plant. This comparison is needed to refine and tune the models to match the actual operation of the plant as closely as possible.

Selected parameters in the plant model should be adjusted based on test measurements so that calculated dependent variables from the model run under the test conditions match the corresponding actual measured test values. All parties involved in a test should agree to such adjustments before the test. Adjustable parameters should be limited to equipment characteristics, such as design turbine blade path efficiencies, design heat exchanger heat transfer coefficients, and key correlation coefficients that affect the model outputs over a range of conditions in the same way as at test conditions. Directly measured variables should not be adjusted.

(2) *Extremes and End Points.* It is important to try and capture measured data from the plant at the expected end points or extremes of operation (within the identified modeling limits) and use this data to compare with and tune the model. In this way, when the model is used in the testing procedure, the model will in effect be interpolating between the validated end points rather than extrapolating beyond them.

(3) *Limits.* It is important during the development, testing, and tuning of the subsystem and complete plant model to identify and study the limits of the models, i.e., those operating regions where the accuracy of the model is reduced or is unacceptable for the purposes of testing. The model cannot then be used for testing purposes for plant operation beyond the validated limits.

5-4.2.2 Correction Factors. If the parties to the test have elected to use correction factors, the correction factors they have agreed upon are used to calculate the effects of off-reference ambient and plant operating conditions on the test results. The two types of correction factors, additive and multiplicative, are applied to the measured parameters to get corrected results, using the equations in subsection 5-1. The correction factors are

Equation	Parameter	Additive Correction Factors	Multiplicative Correction Factors
(3)	Corrected net power	AP_1 through AP_8 , AP_{10} through AP_{18} , and AP_{23}	MP_1 through MP_9
(3)	Corrected net power when applying to non- standard control strategies	AP ₉	
(4)	Corrected primary fuel input	APF ₁₉	MPF ₇ through MPF ₉
(4)	Corrected primary fuel input when applying to nonstandard control strategies	APF ₉	MPF ₁ through MPF ₆
(5)	Corrected secondary fuel input	ASF ₂₀	MSF_{10} and MSF_{11}
(6)	Corrected import steam energy	AIS ₂₁	MIS ₁₂ through MIS ₁₄
(7)	Corrected export syngas energy	ASG ₂₂	MSG ₁₅
(8)	Corrected export steam energy	AES ₆ , AES ₁₁ through AES ₁₈ , and AES ₂₃	MES_{16} , MES_{17} , and MES_{24}
(9)	Corrected export process water energy	APW ₂₄	MPW ₁₈
(10)	Corrected export compressed air energy	AECA ₃₀	MECA ₂₄
(11)	Corrected by-product ash energy	AASH ₂₅	MASH ₁₉
(12)	Corrected by-product sulfur or sulfuric acid energy	ASULF ₂₆	MSULF ₂₀
(13)	Corrected by-product oxygen energy	ABO ₂₇	MBO ₂₁
(14)	Corrected by-product nitrogen energy	ABN ₂₈	MBN ₂₂
(15)	Corrected by-product argon energy	ABAR ₂₉	MBAR ₂₃

 Table 5-4.2.2-1
 Additive and Multiplicative Correction Factors

GENERAL NOTES:

(a) The numerical terms for the additive and multiplicative correction factors are identified in Tables 5-4.2.2-2 and 5-4.2.2-3, respectively.

(b) IGCC plants typically operate with constant, specified maximum power output, based on gasifier capacity. The base set of correction factors in this Table corresponds to this operating mode. To allow for application of this Code to other, nonstandard control strategies, additional correction factors could be required, as noted in the Table.

identified in Table 5-4.2.2-1 (see also Tables 5-4.2.2-2 and 5-4.2.2-3). Additive correction terms that are not needed for a specific plant type or test objective are set equal to zero (0.0). Multiplicative correction factor terms that are not needed for a specific plant type or test objective are set equal to zero set equal to unity (1.0).

5-4.2.3 Hybrid Corrections. Instead of choosing to apply only the correction models method described in para. 5-4.2.1 or only the correction factors method described in para. 5-4.2.2, the parties to the test may agree to apply a hybrid correction method, applying both correction models and correction factors to adjust the test results for the effects of off-reference ambient and plant operating conditions. With a hybrid correction method, the parties will directly use multivariate computer models to determine subsets of the additive or multiplicative correction factors described in the equations in subsection 5-1, but will continue to use conventional sources such as correction curves for the remaining corrections. The parties shall agree in advance where the correction factors and the correction models approaches will be applied to the correction calculations. The correction models used for subsets of the corrections when employing a hybrid correction method shall still be subject to the considerations and limitations described in para. 5-4.2.1.

5-4.2.4 Correction Selection. Where multivariate complete-plant IGCC computer models are available for use for plant performance tests, they are the preferred correction method, because they can account for simultaneous excursions by several variables, including secondary effects, while ensuring that mass and energy balances are maintained. But when a complete-plant IGCC plant correction model is unavailable or impractical, conventional correction factor methods can be employed when both parties are in agreement. Complete-plant IGCC models may be unavailable, for example, due to the proprietary nature of some IGCC subsystem models needed to construct an accurate model, or due to cost and time required to construct and tune such a model. If a complete-plant IGCC correction model is not available, correction models can be employed for subsystems of the plant, in combination with conventional correction factors for the remaining plant corrections, in a hybrid correction approach, as described in para. 5-4.2.3.

Table 5-4.2.2-2 Addi	tive Correction Terms
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Table 5-4.2.2-3 Multiplicative Correction Terms

Term	Measured Parameter Causing Correction	Term	Measured Parameter Causing Correction
1	Inlet air pressure, cooling tower	1	Inlet air temperature, gas turbine
2	Inlet air temperature, cooling tower	2	Inlet air pressure, gas turbine
3	Inlet air humidity, cooling tower	3	Inlet air humidity, gas turbine
4	Inlet air flow rate, gas turbine	4	Air or oxidant input components
5	Generator(s) power factor(s)	5	Cooling water input temperature
6	Steam generator blowdown	6	Condensate return temperature
7	Circulating water temperature for once-	7	Sorbent input properties
	through condenser cooling system or	8	Primary fuel supply temperature
	air-cooled condenser inside the test	9	Primary fuel heating value
	boundary	10	Secondary fuel supply temperature
8	Condenser pressure for the heat rejection	11	Secondary fuel heating value
	system outside the test boundary	12	Import steam temperature
9	Measured power different than predeter-		
	mined or required power	13	Import steam pressure
10	Thermal and electrical auxiliary loads	14	Makeup water input temperature
11	Export syngas energy	15	Export syngas heating value
12	Export steam energy	16	Export steam temperature
		17	Export steam pressure
13	Export process water energy	18	Export process water temperature
14	By-product ash energy		
15	By-product sulfur or sulfuric acid energy	19	By-product ash properties
16	By-product oxygen energy	20	By-product sulfur or sulfuric acid properties
17	By-product nitrogen energy	21	By-product oxygen properties
18	By-product argon energy	22	By-product nitrogen properties
		23	By-product argon properties
19	Sorbent feed rate	24	Export compressed air temperature
20	Process return or/and makeup temperature		
21	Import steam flow rate		
22	Export syngas flow rate		
23	Export compressed air energy		
24	Export process water flow rate		
25	By-product ash flow rate		
26	By-product sulfur or sulfuric acid flow rate		
27	By-product oxygen flow rate		
28	By-product nitrogen flow rate		
29	By-product argon flow rate		
30	Export compressed air flow rate		

Section 6 Report of Results

6-1 GENERAL REQUIREMENTS

The test report for a performance test should incorporate the following general requirements:

- (a) executive summary
- (b) introduction
- (c) calculation and results
- (d) instrumentation
- (e) conclusions
- (f) appendices

This outline is a recommended report format; other formats are acceptable, however, as long as the report of an overall plant performance test contains all the information described in subsections 6-2 through 6-7 in a suitable location.

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 should 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 test

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

(d) comparison with the contract guarantee

(*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 were sufficient

6-3 INTRODUCTION

This section of 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 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*) a cycle diagram showing the test boundary (refer to the diagrams for specific plant type or test goal)

(*d*) a listing of the representatives of the parties to the test and involvement in the testing process

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

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

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

6-4 CALCULATIONS AND RESULTS

The goal of the calculation section is to lay out all calculation procedures that were 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 should 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 summary of additional operating conditions not part of such reduced data

(*c*) step-by-step calculation of test results from the reduced data (refer to the appendices for examples of step-by-step calculations for each plant type and test goal)

(*d*) detailed calculation of primary flow rates from applicable data, including intermediate results, if required (primary flow rates are fuel flow rates and, if cogeneration, process flow rates)

(e) detailed calculations of fuel properties — density, 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 reasons

(g) comparison of the repeatability of test runs

6-5 INSTRUMENTATION

The instrumentation section contains detailed descriptions of all instrumentation used during the test, including their accuracy and how each measurement made conforms to the Code requirements. This includes the following:

(*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 printout, plant control computer printout, or manual data sheet, and any identifying tag number and/or address of each

(*d*) identification of the instrument that was used as backup

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

6-6 CONCLUSIONS

The conclusions section includes the following:

(*a*) a more detailed discussion of the test results, if required

(*b*) any recommended changes to future test procedures due to lessons learned

6-7 APPENDICES

Appendices to the test report should include the following:

(a) test requirements

(*b*) copies of original data sheets and/or data acquisition system(s) printouts

(*c*) copies of operator logs or other recordings 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, certification from manufacturers

NONMANDATORY APPENDIX A UNCERTAINTY ANALYSIS

A-1 INTRODUCTION

Uncertainty calculations are required for every test carried out in accord with the Code, and these calculations must be included in the test report. This section describes the methodology to 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, and also help identify those measurements that significantly affect the test results and the correction factors that should be determined.

The primary technical reference for uncertainty calculations is ASME PTC 19.1, which specifies procedures for determining the uncertainties in individual test measurements for both random errors and systematic errors, and for tracking the propagation of these errors into the uncertainty of a test result.

A-2 OBJECTIVES OF UNCERTAINTY ANALYSIS

The objective of a test uncertainty analysis is to estimate the limit of error of the test results, which is the interval about a test result that contains the true value within a given level of confidence.

This Code does not cover or discuss test tolerances; test tolerances are defined as contractual agreements regarding an acceptable range of test results.

A-3 DETERMINATION OF OVERALL UNCERTAINTY

In general, the overall uncertainty of a measurement is calculated as the square root of the sum of the squares of the systematic and precision (random) uncertainties.

Systematic errors (formerly called bias errors) are 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.

Random errors (formerly called precision errors) are errors due to limitations of reproducibility of measurements. Estimates of random errors are derived by statistical analysis of repeated independent measurements. The random uncertainty component is the standard deviation of the mean multiplied by Student's t_{95} . Above 30 deg of freedom, the Student's t_{95} is usually assumed to be equal to 2. Random errors are neither predictable nor repeatable; they follow the normal distribution curve and can be minimized by repeated readings.

The elements of uncertainty calculations for a complete test can be presented in tabular form, as shown in Table A-3. The test uncertainty associated with each measured parameter includes the effects of its sensitivity, systematic uncertainty, and random uncertainty. The column headings in the Table are as follows:

measured parameter: the fluid or energy stream parameter that crosses the test boundary, required for test calculation (see Table 5-3 for the list of measured parameters).

sensitivity: the percent change in corrected result (either corrected output, corrected heat rate, or corrected heat input, as determined by the parties to the test) caused by a unit change in the measured parameter (see subsection A-4).

systematic uncertainty: inherent systematic error for the type of measurement (see subsection A-5).

systematic uncertainty contribution: the product of sensitivity and systematic uncertainty.

standard deviation of the mean (precision index): statistically determined for multiple measurements of the same variable (see subsection A-6 for spatially uniform variables or subsection A-7 for spatially nonuniform variables).

random uncertainty contribution: the product of sensitivity and twice the standard deviation.

The overall systematic uncertainty, RSS_s , and random uncertainty, RSS_n are root-sum-square totals of the systematic uncertainty contribution and random uncertainty contribution columns, respectively. The total uncertainty, RSS_t , is the root-sum-square total of overall systematic and random uncertainties. The total uncertainty of the result, *UNC*, is calculated from the overall test random and systematic uncertainty limit terms using the equation

$$UNC = \sqrt{BIASR^2 + UPC^2}$$

where

BIASR = systematic limit of the result

UNC = overall uncertainty of each measurement

UPC = precision component (random uncertainty) of each measurement

If different values of *BIASR* have been calculated for positive and negative systematic uncertainty limits, the larger value should be used to compute *UNC*.
Measured Parameter	Sensitivity, A (% per %, % per °F, or % per °C)	Systematic Uncertainty, <i>B</i> (%, °F, or °C)	Systematic Uncertainty Contribution, <i>AB</i> (%)	Standard Deviation of the Mean, <i>C</i> (%, °F, or °C)	Random Uncertainty Contribution, 2AC (%)
Import power					
Export steam					
Export syngas					
Primary fuel flow					
Primary fuel heating value					
Other parameters as needed					
Transformer, line losses					
Systematic Uncertainty			RSS₅		
Random Uncertainty				-	RSS _r
Total Uncertainty					RSS _t

Table A-3 Uncertainty of Corrected IGCC Output

A-4 SENSITIVITY COEFFICIENTS

Sensitivity coefficients indicate the absolute or relative effect of a measured parameter on the test result. Relative sensitivity coefficients, which are calculated during the pretest uncertainty analysis, identify the parameters with the largest impacts on the test objectives. A relative sensitivity coefficient should 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, *RSC*, is calculated by either of the equations below.

(a) Partial Differential Form

$$RSC = \frac{\left(\frac{\partial K}{R}\right)}{\left(\frac{\partial X}{X_{\text{avg}}}\right)} = \frac{X_{\text{avg}}}{R} \times \left(\frac{\partial R}{\partial X}\right)$$

 $\langle n \rangle$

(b) Finite Difference Form

$$RSC = \frac{\left(\frac{\Delta R}{R}\right)}{\left(\frac{\Delta X}{X_{avg}}\right)} = \frac{X_{avg}}{R} \times \left(\frac{\Delta R}{\Delta X}\right)$$

where

R = corrected test result

- RSC = relative sensitivity coefficient, decimal
- X_{avg} = measured parameter, average value
- $\Delta \vec{R}$ = change (finite difference) in corrected test result
- ΔX = change (finite difference) in measured parameter, typically $0.01X_{avg}$
- ∂R = change (partial differential) in corrected test result

 ∂X = change (partial differential) in measured parameter

A-5 SYSTEMATIC UNCERTAINTY

The systematic uncertainty of the result, *BIASR*, can be calculated according to the root-sum-square rule as follows:

$$BIASR = \sqrt{\sum}(RSC_i \times BIAS_i)^2 \text{ for } i = 1, n$$

where

- $BIAS_i$ = systematic uncertainty for measured parameter *i*
 - n = number of measured parameters
- RSC_i = relative sensitivity coefficient for measured parameter *i*

If the positive and negative systematic uncertainty limits are not symmetrical, positive and negative values of *BIASR* must be calculated separately.

A-6 STANDARD DEVIATION OF THE MEAN FOR SPATIALLY UNIFORM PARAMETERS

Test measurements need to be reduced to average values before performance and uncertainty calculations can be performed. Each measured parameter has a precision index, *PI*, also called the standard deviation of the parameter from the mean, *STDDEVMN*, and a characteristic degree of freedom, *DEGFREE*. For a result, *R*, calculated from many measured parameters, there is an overall precision index, *PIR*, and characteristic degrees of freedom, *DEGFREER*, for all measurement parameters combined.

For measurements that do not exhibit spatial variations, the precision index of an averaged measurement, *XAVE*, based on statistical analysis is calculated from the *N* multiple measurements of *X* according to the equations

$$PI = STDDEVMN$$
$$STDDEV = \left[\frac{1}{N(N-1)}\sum_{i=1}^{N} \left(X_i - XAVE\right)^2\right]^{1/2} \text{ for } i = 1, N$$
$$DEGEREE = N - 1$$

where

- DEGFREE = number of degrees of freedom for the precision index of the parameter
 - N = number of times the parameter is measured
 - PI = precision index (also called standard deviation of XAVE from the mean, which is a quantitative measure of the difference between the measured average and the true mean of the multiple measurements of a characteristic X)
- STDDEV = standard deviation of the sample STDDEVMN = standard deviation of the mean of N measurements
 - XAVE = averaged measurement X_i = an individual measurement

Data acquisition systems exhibit subsets of average values and subsets of standard deviations for measured parameters several times during a test period. These give rise to pooled averages. For a test series that has M sets of measurements with N readings for each set, the average value, $XAVE_k$, for measurement set k is as follows:

For an individual measured parameter in each set

$$XAVE_k = \frac{1}{N} \sum_{i=1}^{N} X_i \text{ for } i = 1, N$$

The overall average, *XAVE*, determined from all measurements in the test series is

$$XAVE = \frac{1}{M} \sum_{k=1}^{M} XAVE_k$$

where

M = number of sets of measurements

N = number of readings for each set

 $XAVE_k$ = average value for measurement set k

For this set of pooled averages, the standard deviation of the subset k is:

$$STDDEV_k = \sqrt{\frac{1}{N(N-1)} \sum_{i=1}^{N} (X_i - XAVE)^2} \text{ for } i = 1, N$$

The standard deviation for the set of all measurements is

STDDEV =
$$\sqrt{\frac{1}{M(M-1)} \sum_{k=1}^{M} (N-1) STDDEV_k^2}$$
 for $k = 1, M$

The standard deviation of the mean, which is the precision index, *PI*, for the set of all measurements, is

$$STDDEVMN = \sqrt{\frac{STDDEV^2}{MN}}$$

The degrees of freedom for the precision index and standard deviation of the mean are

$$DEGREE = M(N-1)$$

A-7 PRECISION INDEX FOR SPATIALLY NONUNIFORM PARAMETERS

For parameters with spatial variations, the precision index and the standard deviation of the mean are best computed using integration methods. The most common integration method follows the multiple midpoint rule. The precision index according to the multiple midpoint rule average is

$$PI = \frac{1}{M} \sqrt{\sum_{i=1}^{M} PI_{i}^{2}}$$
 for $i = 1, M$

The associated equation for degrees of freedom is

$$DEGFREE = \frac{PI^4}{\sum_{i=1}^{M} \frac{PI_i^4}{M^4 DEGFREE_i}} \text{ for } i = 1, M$$

where

- DEGFREE = degrees of freedom for the average parameter
- $DEGFREE_i$ = degrees of freedom of the parameter at point *i*

M = number of grid points

- *PI* = precision index for a measured parameter
- PI_i = precision index of the parameter at point *i*

The degrees of freedom must fall between a minimum and a maximum value based on the number of readings taken at each grid point and the number of grid points. The minimum possible degrees of freedom is the smaller of the following numbers: either the number of points in the grid, M, or one less than the number of readings at each grid point, N - 1; the maximum possible degrees of freedom is the product of these two numbers, M(N - 1).

NONMANDATORY APPENDIX B SAMPLE CALCULATION FOR AIR-BLOWN IGCC

B-1 CYCLE DESCRIPTION

The integrated gasification combined cycle/cogeneration plant uses an air-blown gasifier and a single gas turbine exhausting to a dual pressure, heat recovery steam generator (HRSG). Compressed air is extracted from the last stage of the gas turbine compressor and used to supply combustion air to the gasifier.

GCC plants typically operate with constant, specified maximum power output, based on gasifier capacity. The base set of correction factors in this document corresponds to this operating mode. To allow for application of this Code to other control strategies, additional correction factors would be required, as described in this example. The example in this Appendix represents one of these other control strategies.

The gas turbine is base loaded and its power output governed by ambient conditions. Process or export steam, at design levels, is a mixture of extraction steam from the LP turbine and LP steam from the HRSG. The HP turbine extraction steam is used for NO_x control in the gas turbine. All of the gasifier product gas is burned in the gas turbine.

(a) Gas Turbine

(1) 82 MW at ISO conditions: 10°C (50°F), 60% RH, and sea level

(2) 10.16 cm wg inlet (4 in. wg) and 30.5 cm wg (12 in. wg) exhaust pressure drop

(3) steam injection for NO_x control to 25 ppm

(b) Heat Recovery Steam Generator

(1) two steam pressure levels with separate deaerator

(2) HP steam outlet conditions: 88.3 bar (1280.7 psig) at 482°C (900°F)

(3) LP steam outlet conditions: 1.568 bar (22.75 psig) at 260°C (500°F)

- (c) Steam Turbine
 - (1) 46 MW nominal rating

```
(2) exhaust pressure 67.7 mb Hg (2 in. Hg)
```

(d) Condenser

- (1) shell and tube axial design
- (2) design inlet temperature 26.7°C (80°F)
- (3) design rise 6.6°C (20°F)
- (e) Export Steam

(1) from HRSG LP section, 11.37 bar, 218.3°C (165 psig, 425°F)

- (2) design flow 22 679.62 kg/h (50,000 lb/hr)
- (3) design enthalpy 593.4 kJ/kg (1,240 Btu/lb)

B-2 TEST BOUNDARY

The test boundary is shown in Fig. B-2. A pretest uncertainty analysis will determine the relative sensitivity of each measured parameter on the final result. From this analysis, the test engineer can remove streams that have an insignificant effect on the calculated result. The test engineer can also improve the accuracy of instrumentation measuring parameters of significant streams to improve overall test uncertainty.

- (a) The measured streams for this case are as follows:(1) Input Streams
 - (a) primary fuel input to the gasifier (coal)
 - (b) secondary fuel input to the duct burners (nat-

ural gas)

- (c) sorbent flow
- (2) Output Streams

(*a*) combined net power output from the gas and steam turbine generator excluding auxiliary power

- (b) steam to condenser
- (c) blowdown from HRSG
- (*d*) cogeneration steam flow to user
- (b) The following parameters were also measured:
 - (1) condenser pressure
 - (2) ambient temperature at the gas turbine inlet
 - (3) ambient barometric pressure

B-3 TEST REFERENCE CONDITIONS

For the sample calculation that follows, the design reference conditions are

Condition	SI Units	U.S. Customary Units
Ambient temperature	15.6°C	60°F
Relative humidity	60%	60%
Plant site elevation	1 371.6 m	4,500 ft
Process steam flow	22 679.62 kg/h	50,000 lb/hr
Process steam pressure	10.34 bar	150 psig
Process steam tem- perature	189.4°C	373°F
Blowdown flow	6 350.3 kg/h	14,000 lb/hr
Condenser pressure	67.7 mb	2.0 in. Hg
Coal heating value, HHV	5 982.1 kJ/kg	12,500 Btu/lb
Natural gas heating value, HHV	50 070 kJ/kg	21,526 Btu/lb
Net plant output	128 000 kW	128,000 kW
Net plant heat rate, HHV	8 404.6 kJ/kW•h	7,966 Btu/kW•hr

B-4 BASIC EQUATIONS

For this test, the guaranteed design parameter to be calculated is the corrected heat rate, HR_{corr} . The corrected heat rate equation for this specific test is as follows:

$$HR_{\rm corr} = \frac{(Q_{\rm meas} + AES_{12})(MPF_1)(MPF_2)}{P_{\rm meas} + AP_8} \tag{1}$$

where

- AES_{12} = correction to thermal heat input for export steam different from design
 - AP_8 = correction to thermal heat input for condenser pressure different from design

 MPF_1 = correction to heat rate for ambient temperature different from design

 MPF_2 = correction to heat rate for barometric pressure different from design

 P_{meas} = measured net power

 Q_{meas} = measured heat input

B-5 REQUIRED CORRECTIONS

- (a) Additive Corrections to Thermal Heat Input
 - (1) export steam flow
 - (2) condenser pressure different from design
- (b) Multiplicative Correction Factors
 - (1) ambient temperature
 - (2) ambient pressure
- (c) Insignificant Corrections or Not Required
 - (1) HRSG blowdown flow
 - (2) makeup water temperature
 - (3) ambient relative humidity (insignificant)
 - (4) condensate return

The standard deviation of the mean associated with the correction factors are all zero, since there is no random uncertainty error in the calculation. For the purpose of this example, systematic uncertainty error in the correction curves has been assumed to be zero as well.

B-6 CALCULATION METHOD

(*a*) *Test Results.* Tables B-6-1, B-6-2, and B-6-3 show calculated results of the test using actual test measurements. Table B-6-1 represents the numerator of eq. (1) in subsection B-4 and Table B-6-2 represents the denominator.

(b) Uncertainty Analysis. Tables B-6-4 through B-6-7 show the results of the uncertainty analysis of the test heat rate calculation. Sensitivity coefficients are determined by incrementally changing each test parameter's average by 1% and recalculating the test result. The relative sensitivity of the test result due to an incremental change in each parameter is the difference between the

base result and the incremental result divided by the base result.

(c) Overall Test Uncertainty. Table B-6-8 tabulates the overall uncertainty.

B-7 CORRECTION CURVES AND FITTED EQUATIONS

Curves used in this example are for illustrative purposes only and are not to be used in actual test calculations.

B-7.1 Process Steam Flow Correction (See Fig. B-7.1)

Additive correction to thermal heat input to account for process efflux (i.e., process steam) different from design

 $\begin{array}{rl} AES_{12} &=& 37,132,177.19 + 1,243.24083H + 223.1656409F \\ &-& 0.69956074FH \end{array}$

where

F = process steam flow, lb/hr

H = process steam enthalpy, Btu/lb

B-7.2 Condenser Pressure Correction (See Fig. B-7.2)

Additive correction to power to account for condenser pressure different from design

 $AP_8 = [-4.7716 + 0.16134P - 0.002171(P^2) + 0.0000147(P^3) - 0.000000376178(P^4)] \times 1000$

where

P = condenser pressure, mb absolute

B-7.3 Ambient Temperature Correction Factor (See Fig. B-7.3)

Correction factor to thermal heat input to account for ambient temperature different from design

 $MPF_1 = 1.013999 - 0.0009T$

where

T = ambient temperature, °C

B-7.4 Barometric Pressure Correction Factor (See Fig. B-7.4)

Correction factor to thermal heat input to account for ambient pressure different from design

$$MPF_2 = 1.6172 - 0.01188049P + 0.00005713(P^2)$$

where

P = ambient pressure, kPa

Thermal Inputs and Corrections	Metric, kJ/h	U.S. Customary, Btu/hr
Coal	1 081 415 550	1,024,984,000
Sorbent	0	0
Natural gas	55 127 070	52,250,380
Uncorrected total thermal input	1 136 542 620	1,077,235,000
Thermal efflux, <i>AES</i> ₁₂	514 685	487,827.3
Sum of Additive Corrections	514 685	487,827.3
Ambient temperature correction, M_1	0.9850	0.9850
Ambient pressure correction, M_2	1.0176	1.0176
Corrected thermal input	1 139 743 318	1,086,268,000

Table B-6-2Corrected Power Output

Table B-6-3 Corrected Heat Rate

Component	Power, kW
Gas turbine net generation	82 000
Steam turbine power net generation	46 120
Total gross power generation	128 120
Condenser pressure correction, AP ₈	905
Corrected gross power generation	129 025

Calculated Results	kJ/kW•h	Btu/kW•hr
Uncorrected net unit heat rate	8 870.9	8,408.0
Corrected net unit heat rate	8 833.5	8,372.5

				Negative	
Parameters	Source	Device	Positive (+) Systematic Uncertainty, %	(−) Systematic Uncertainty, %	Source Systematic Uncertainty Basis
Cool flow	Mancurad	Crovimatric foodor	2 000	2 000	Accumption
Cual higher heating value	Measured	Laboratory analysis	2.000	2.000	Assumption
Carborne flave lb /br	Measured		1.000	1.000	Assumption
Sorbent now, ib/m	Measured		2.000	2.000	Assumption
Sorbent nigher heating value	Measured	Laboratory analysis	2.000	2.000	Assumption
Ambient air temperature	Measured	Thermocouple	0.500	0.500	PTC 4
Natural gas flow (duct burner)	Measured	Orifice plate	0.500	0.500	PTC 4
Gas fuel higher heating value	Measured	Laboratory analysis	2.000	2.000	Assumption
Barometric pressure	Measured	Barometer	0.100	0.100	PTC 4
Condenser pressure	Measured	Transmitter	0.100	0.100	PTC 6
Output Streams					
Gas turbine net generation	Measured	Watt meter	0.100	0.100	ASME
Steam turbine net generation	Measured	Watt meter	0.100	0.100	ASME
Export steam flow. lb/hr	Measured	Orifice	2.000	2.000	Assumption
Export steam temperature, °F	Measured	Thermocouple	0.800	0.800	PTC 4
Export steam pressure	Measured	Transmitter	1.000	1.000	PTC 4
Export steam enthalpy	Calculated	Steam tables	0.100	0.100	Assumption
Correction Factors					
Additive					
Thermal efflux CF (process steam)	Curve fit	Derived	0.00	0.00	OEM
Steam turbine condenser pressure CF	Curve fit	OEM	0.00	0.00	OEM
Multiplicative					
Ambient temperature CF	Curve fit	OEM	0.00	0.00	OEM
Ambient pressure CF	Curve fit	OEM	0.00	0.00	OEM

Table B-6-4 Inputs, Outputs, and Corrections

Table B-6-5	Measured	Parameters
-------------	----------	------------

			Standard		Standard	-
		A	Deviation	N	Deviation	Degrees
Parameters	Units	Average Value	From Test Run	No. or Samples	of the Mean	or Freedom
Input Stroome				F		
	1 /1	2740400	705 7	20	122 (0	20
Coal flow	Kg/n (lbm/hr)	(82,000)	725.7 (1,600)	30	(292.1187)	29
Fuel higher heating value	kJ/kg (Btu/lb)	29 075 (12,500)	465 (200)	8	164.4023 (70.7)	7
Sorbent flow	kg/h	2 111	22.7	30	4.144	29
Sorbent higher heating value	kJ/kg (Btu/lb)	(4,054.91) 0	0	8	0	7
Ambient air temperature	°C (°F)	32.22 (90)	0.5 (0.9)	30	0.0913 (0.164)	29
Natural gas flow (duct burner)	kg/h (lbm/hr)	1 101 (2,427)	26 (57.3)	30	4.7469 (10.46)	29
Gas fuel higher heating value	kJ/kg (Btu/lb)	50 070 (21,526)	785 (337)	8	277.54 (119.32)	7
Barometric pressure	kPa (psia)	86.2 (12.5)	0.344 (0.05)	30	0.0628 (0.0091)	29
Condenser pressure	mb (in. Hg)	118.5 (3.5)	11.8 (0.1)	30	2.1544 (0.06)	29
Output Streams						
Combustion turbine net generation	kW	82 000	100	30	18.2574	29
Steam turbine net generation	kW	46 120	100	30	18.2574	29
Export steam flow	kg/h (lbm/hr)	22 679 (50,000,00)	226.79 (500)	30	41.4060 (91.2871)	29
Export steam temperature	°C (°F)	210 (410)	1.6 (3)	30	0.30	29
Export steam pressure	bar (psia)	10.34 (150.00)	0.103	30	0.0189	29
Export steam enthalpy	kJ/kg (Btu/lb)	2 850 (1.225.44)	0	30	0	29
Additive Correction Factors						
Thermal efflux CF (process steam)	kJ/h (Btu/hr)	514 376 (487,534)	0	30	0.0000	8
Steam turbine condenser pressure CF	kW	905	0	30	0.0000	9
Multiplicative Correction Factors						
Ambient temperature CF		0.9850	0	30	0.0000	3
Ambient pressure CF		1.0176	0	30	0.0000	3

						Delta Heat						
		Change	Incrementa	Average Due	Recalculated Heat Rate, b1/bW.h	Rate, kJ/kW•h (Btii/	Absolute	Relative Sensitivity	Precision Index of Becult	Overall Degrees of Freedom	Total Positive Svetematic	Total Negative Svetematic
Parameter	Units	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	Change	Increment	(Btu/kW•hr)	kW•hr)	Coefficient		Calculation	Contribution	Uncertainty	Uncertainty
Input Streams												
Coal flow	kg/h	1	371.94	37 565.94	8 917.5	-84.01	0.2259	0.9511	29.927	27,661	743.88	743.88
	(lb/hr)		(820)	(82,820)	(8,452.2)	(-79.6)						
Fuel HHV	kJ/kg	1	290.75	29 365.75	8 917.5	-84.01	0.2890	0.9511	47.50	727,499	290.75	290.75
	(Btu/lb)		(125)	(12,625.0)	(8,452.2)	(-79.6)						
Sorbent flow	kg/h (lb/hr)	1	21.11 (46.54)	2 132.11 (4.701.46)	8 833.5 (8.372.5)	0.0	0.00	0.0000	0	0.0000	42.22	42.22
Sorbent HHV	kJ/kg (Btu/lb)	4	0	0	(8,372.5)	0.0	0.0	0.0000	0	0.0000	0	0
Ambient air temperature	Ŝ	Ļ	0.3220	32.52	8 830.9	2.59	8.07	0.0294	0.7367	0.0102	0.16	0.16
	(°F)		(6.0)	(6.06)	(8, 370.1)	(2.45)						
Natural gas flow (duct burner)	kg/h	1	11.01	1 112.01	8 837.8	-4.28	0.3889	0.0485	1.8465	0.4008	5.51	5.51
	(lb/hr)		(24.27)	(2, 451.6)	(8,376.6)	(-4.06)						
Gas fuel HHV	kJ/kg	1	500.70	50 570.70	8 837.8	-4.28	0.00855	0.0485	2.3739	4.537	1,001.4	1,001.4
	(Btu/lb)		(215.3)	(21,741.48)	(8,376.6)	(-4.06)						
Barometric pressure	kPa	1	0.8620	87.06	8 818.7	14.83	17.205	0.1679	1.0806	0.047	0.09	0.09
	(psia)		(0.125)	(12.627)	(8, 358.5)	(14.06)						
Condenser pressure	mb (in Hø)	Ч	1.1850 (0.035)	119.69 (3.53)	8 832.3 (8 371 4)	1.26 (1_19)	1.064	0.0143	2.2934	0.9539	0.12	0.01
	(Q. 1)											
Output Streams												
Gas turbine net generation	kW	1	820.0	82 820	8 777.74	55.7	0.068	0.6315	1.2421	0.0821	82.00	82.00
				(82,820)	(8,319.69)	(52.8)	(0.029)					
Steam turbine net generation	κW	1	461.2	46 581.2 (46 581 2)	8 802.1 (8 34,7 78)	31.46 (70.8)	0.0682	0.3562	1.2455	0.0830	46.12	46.12
Evenet ctoom flow	ار <i>مہ</i> ا	Ţ				(0./4)					01 017	01 017
	NS/II (IL/LA	-	(UU)	61.CUE 22	(2 0 2 C 0)				0600.0	00000	00.004	00.004
	(111/01) of	,	(UUC)	(000,00)	(0,209.0)	(4.2)					7	0 7
Export steam temperature	ر (٥٤)	-	01.2	(1 / 1 / 1)	8 832.9 (8 371 97)	(53 O)	0.2696 (0 1150)	0.0064	0./8//	5510.0	1.00	1.00
Exnort steam pressure	har	.	0 1034	10 44	8 833 K		0 6086	2000 0			010	010
באטטון טוימוון איינטעניי	(psia)	4	(1.5)	(151.5)	(8,372.63)	(-0.059)	(0.2616)		>>>	>>>	> 1 • >	>1.>

Table B-6-6 Sensitivity Analysis

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Uncertainty Parameter	kJ/kW•h (Btu/kW•hr)	Percent
Standard deviation of the mean of result	56.32 (53.4)	
Overall degrees of freedom	13.33	
Student's <i>t</i> value	1.9600	
Precision component of uncertainty	110.39 (104.6)	1.25
Positive systematic uncertainty of result	188.29 (178.4)	2.13
Negative systematic uncertainty of result	188.29 (178.4)	2.13
Positive total uncertainty	218.27 (206.9)	2.47
Negative total uncertainty	218.27 (206.9)	2.47

Table B-6-7Overall Uncertainty





Fig. B-7.1 Correction to Thermal Heat Input for Thermal Efflux (SI Units)

GENERAL NOTE: Plant gross output 145 000 kW, gas turbine base loaded, natural gas fuel.



Fig. B-7.2 Correction to Net Power Output for Steam Turbine Condenser Pressure (SI Units)

Condenser Pressure, mb



Fig. B-7.3 Correction to Plant Heat Rate for Ambient Temperature (SI Units)

GENERAL NOTE: Natural gas fuel, gas turbine base loaded.



Fig. B-7.4 Correction to Plant Heat Rate for Ambient Pressure (SI Units)

GENERAL NOTE: Natural gas fuel, combustion gas base loaded, 15.5°C ambient temperature.

NONMANDATORY APPENDIX C SAMPLE CALCULATION FOR OXYGEN-BLOWN IGCC INCLUDING ASU



Fig. C-1 Test Boundary of Typical Oxygen-Blown Integrated-Gasification Combined-Cycle Power Plant

C-1 CYCLE DESCRIPTION

The integrated gasification combined cycle plant for the sample calculations in this Appendix is generally shown in Fig. C-1. This plant is based on an oxygen-blown, entrained-flow, slurry-fed gasification system feeding two gas turbines, with each GT exhausting to a three-pressure-level heat recovery steam generator. The steam from both HRSGs is combined to feed a single condensing steam turbine, condenser, and mechanical-draft cooling tower. There are no duct burners in the HRSG. The process design includes partial integration between the gas turbine and the air separation plant — compressed air from the gas turbine compressor is used to supply some of the air required by the air separation plant and compressed nitrogen is returned from the ASU back to the gas turbine combustor. The syngas cleanup train includes a convective syngas cooler, dry solid removal system, acid-gas removal system (e.g., Selexol), and a fuel-gas saturator. High-pressure boiler feedwater (BFW) is supplied from the HRSGs to the gas cleanup train, and high-pressure saturated steam is returned to the HRSGs.

IGCC plants typically operate with constant, specified maximum power output, based on gasifier capacity. The base set of correction factors in this document corresponds to this operating mode. To allow for application of this Code to other control strategies, additional correction factors would be required, as described in this example. The example in this Appendix represents one of these other control strategies. For this test, the gas turbine is base loaded so that its power output is governed by the ambient and fuel conditions. All of the gasifier product gas is burned in the gas turbine, so the gasifier output and therefore the fuel input are determined by the gas turbine load.

(a) Gas Turbine

(1) 196.8 MW at ISO conditions, 15°C (59°F), 60% RH, and sea level

(2) 7.5 mb inlet (3.0 in. $\rm H_2O)$ and 49.8 mb (20.0 in. $\rm H_2O)$ exhaust pressure drop

(3) air extraction to oxygen plant, nitrogen injection from oxygen plant

(b) Heat Recovery Steam Generator

(1) three steam pressure levels with separate deaerator

(2) HP steam outlet conditions: 125.1 bar (1,815 psia) at 538°C (1,000°F)

(3) IP steam outlet conditions: 27.9 bar (405 psia) at 537°C (999°F)

(4) LP steam outlet conditions: 1.72 bar (25.0 psia) at 157°C (315°F)

(5) HP BFW supplied to gas cleanup: 149.3 bar (2,165 psia)

(6) HP steam from gas cleanup: 132.0 bar (1,915 psia)

(c) Steam Turbine

(1) condensing type, 252.1 MW nominal rating

(2) exhaust pressure 68.9 mb (2 in. Hg)

(3) extractions at 17.24 bar (250 psia) and 4.48 bar (65 psia)

(d) Condenser

(1) shell and tube design

(2) design cooling water inlet temperature 17.2°C (62.9°F)

(3) design rise 11.1°C (20°F)

(e) Cooling Tower

(1) mechanical draft with five bays

(2) design approach $6.9^{\circ}C$ (12.5°F)

(3) design air–water ratio 1.0

(4) design auxiliary power consumption 2 511 kW (f) *Gasifier*

(1) oxygen-blown, entrained-flow, slurry-fed slagging gasifier

(2) design coal feed rate (as received) 43.8 kg/s (3,780 tons/day)

(3) design exit syngas conditions: 56.2 bar (815 psia), 1 338°C (2,440°F)

(4) design syngas LHV: 9 811 kJ/kg (4,218 Btu/lb) (g) Oxygen Plant

(1) utilizes air extraction from gas turbine, and returns nitrogen to gas turbine

(2) design oxygen production 3,600 tons/day at 70.7 bar (1,025 psia)

(3) design auxiliary power consumption (including O_2 and N_2 compressors) 82.1 MW

(h) Gas Cleanup

(1) utilizes convective syngas cooling, dry solid removal, acid gas removal system (e.g., Selexol) with assumed 95% sulfur recovery (Claus plant)

(2) high-pressure BFW at 149.3 bar (2,165 psia) is supplied from HRSGs

(3) high-pressure saturated steam at 132.0 bar (1,915 psia) is returned to HRSGs

C-2 TEST BOUNDARY

The test boundary is shown in Fig. C-1. A pretest uncertainty analysis will determine the relative sensitivity of each measured parameter on the final result. From this analysis, the test engineer can remove streams that have insignificant effect on the calculated result. The test engineer can also improve the accuracy of instrumentation measuring parameters of significant streams to improve overall test uncertainty.

C-2.1 Measured Streams

The measured streams for this case are as follows:

(a) primary fuel input to the gasifier (coal)

(*b*) combined net power output from the gas and steam turbine generator, excluding in-plant auxiliary power

C-2.2 Other Measured Parameters

The following parameters were also measured:

(*a*) temperature, pressure, and relative humidity at the gas turbine inlet

(*b*) temperature, pressure, and relative humidity at the cooling tower inlet

(c) makeup water temperature

C-3 TEST REFERENCE CONDITIONS

For the sample calculation that follows, the design reference conditions are:

Condition	SI Units	U.S. Customary Units
Ambient temperature	15.6°C	60°F
Relative humidity	60%	60%
Plant site elevation	0 m/1.013 bar	0 ft/14.7 psia
Makeup water tem- perature	12.8°C	55°F
Coal heating value, HHV (as received)	30 843 kJ/kg	13,260 Btu/lb
Net plant output	563 520 kW	563,520 kW
Net plant heat rate, HHV	8 622 kJ/kW•h	8,172 Btu/kW•hr

C-4 CORRECTION FACTORS

The test requirements are based on fixed unit disposition, based on base-loaded gas turbines (there are no duct burners). For this test, the guaranteed design parameters to be calculated are corrected net power and corrected heat rate.

The general equation for corrected net power from Section 5 is

$$P_c = [P_m + \Sigma(AP_i)] \prod MP_i$$

The general equation for corrected primary fuel input from Section 5 is

$$Q_{pf,c} = [Q_{pf,m} + \Sigma(APF_i)] \prod MPF_i$$

The overall general heat rate equation is

$$HR_c = (Q_{pf,c} + Q_{sf,c})/P_c$$

(*a*) The following assumptions can be made based upon the cycle and test configuration:

(1) There are no export or by-product streams for this configuration (electric power is the only output), so there are no corrections associated with export and by-product flows.

(2) There are no secondary fuels or sorbent flows for this configuration and test, so there are no corrections associated with secondary fuels or sorbent flows.

(3) The condenser and cooling tower are within the test boundaries, so there are no corrections for cooling water temperature, condenser pressure, or circulating water temperature.

(4) Since the test is for base-loaded power generation (power floats), there is no additive correction for measured power different than predetermined or required power.

(*b*) Other simplifying assumptions made with regard to this test include

(1) Gas turbine and steam turbine generator power factors are specified as a constant of 0.9 lead and will not vary; thus their corresponding corrections become 0.0.

(2) The steam generator blowdown flows do not vary from their design values, so no corrections are made for their variation.

(3) Variations in makeup water temperature over the expected test conditions were found to have an insignificant impact on the unit performance, so no corrections are included for this parameter.

(4) For this test, gas turbine inlet relative humidity had no significant impact on unit performance, so no corrections are included for this parameter.

(5) Cooling tower inlet pressure had no significant impact on unit performance, so no corrections are included for this parameter.

The complete list of additive and multiplicative corrections from Section 5 that are applicable for this unit configuration and the boundary conditions described above are listed in paras. C-4.1 through C-4.3.

C-4.1 Additive Corrections to Power

(a) AP_2 = cooling tower inlet temperature

(b) AP_3 = cooling tower inlet relative humidity

C-4.2 Multiplicative Corrections to Power

- (a) MP_1 = gas turbine inlet temperature
- (b) MP_2 = gas turbine inlet pressure
- (c) MP_9 = primary fuel heating value

C-4.3 Multiplicative Corrections to Primary Fuel Input

- (a) MPF_1 = gas turbine inlet temperature
- (b) MPF_2 = gas turbine inlet pressure
- (c) MPF_9 = primary fuel heating value

C-4.4 Specific Form of Correction Equations

Reducing the general correction equations, the corrected equations for power, primary fuel input, and heat rate for this specific test are as follows:

$$P_{c} = [P_{m} + AP_{2} + AP_{3}) \times MP_{1} \times MP_{2} \times MP_{9}$$
$$Q_{pf,c} = Q_{pf,m} \times MPF_{1} \times MPF_{2} \times MPF_{9}$$
$$HR_{c} = Q_{pf,c}/P_{c}$$

where

 HR_c = corrected heat rate P_c = corrected net power P_m = measured net power $Q_{pf,c}$ = corrected primary fuel input $Q_{pf,m}$ = measured primary fuel input

and the correction factors are as listed above.

C-5 CORRECTION CURVES AND FITTED EQUATIONS

The correction factors are best determined using a multivariate computer model of the entire plant. The following figures show a graph of each correction factor resulting from the plant model calculations for different ranges of the boundary values. For each parameter, the correction factors were curve fit [signified by a ' (prime) symbol] using a polynomial fit. The resulting equations are listed below. Note that the correction curves used in this example are for illustrative purposes only and are not to be used in actual test calculations.

C-5.1 Cooling Tower Inlet Air Temperature Correction to Power (See Fig. C-5.1)

Additive correction to net power to account for variations in cooling tower inlet air temperature is

$$AP_2 = 4.21067E - 01 T^3 - 2.52299E + 00 T^2 + 1.58480E + 02 T - 3.54931E + 03$$

where

 $T = \text{cooling tower inlet temperature, }^{\circ}C$

C-5.2 Cooling Tower Inlet Air Humidity Correction to Power (See Fig. C-5.2)

Additive correction to net power to account for variations in cooling tower inlet air humidity is

$$AP_3 = 4.00131E+03 RH^3 - 3.99189E+03 RH^2 + 5.40522E+03 R - 2.63779E+03$$

where

RH = cooling tower inlet relative humidity (fraction)

C-5.3 Gas Turbine Inlet Air Temperature Correction to Power (See Fig. C-5.3)

Multiplicative correction to net power to account for variations in gas turbine inlet air temperature is

$$MP_1 = 2.665355E - 04 T^2 - 7.594787E - 03 T + 1.051901$$

where

 $T = \text{gas turbine inlet temperature, }^{\circ}C$

C-5.4 Gas Turbine Inlet Air Pressure Correction to Net Power (See Fig. C-5.4)

Multiplicative correction to net power to account for variations in gas turbine inlet air pressure is

$$MP_2 = -6.8269650E - 06 P^4 + 2.7193290E - 03 P^3$$

- 4.0497475E - 01 P² + 2.6720431E + 01 P
- 6.5792840E + 02

where

P = gas turbine inlet pressure, kPa

C-5.5 Primary Fuel Heating Value Correction to Net Power (See Fig. C-5.5)

Multiplicative correction to net power to account for variations in primary fuel heating value is

$$MP_9 = -5.960507E - 09 HV^2 + 3.445228E - 04 HV - 3.955785$$

where

HV = primary fuel heating value, kJ/kg

C-5.6 Primary Fuel Heating Value Correction to Primary Fuel Input (See Fig. C-5.5)

Multiplicative correction to primary fuel input to account for variations in primary fuel heating value is

$$MPF_9 = -1.110257E - 08 HV^2 + 6.647388E - 04 HV - 8.940335$$

where

HV = primary fuel heating value, kJ/kg

C-5.7 Gas Turbine Inlet Air Temperature Correction to Primary Fuel Input

Multiplicative correction to primary fuel input to account for variations in gas turbine inlet air temperature is

 $MPF_1 = 2.346445E-04 T^2 - 6.016601E-03 T + 1.036028$

where

 $T = \text{gas turbine inlet temperature, }^{\circ}C$

C-5.8 Gas Turbine Inlet Air Pressure Correction to Primary Fuel Input

Multiplicative correction to primary fuel input to account for variations in gas turbine inlet air pressure is

 $MPF_2 = -6.049324E - 06 P^4 + 2.405428E - 03 P^3$ $- 3.576548E - 01 P^2 + 2.356148E + 01 P$ - 5.790934E + 02

where

P = gas turbine inlet pressure, kPa

C-6 SAMPLE CALCULATION DATA

The measured data for the sample calculations are shown in Table C-6-1.

Using the values from the sample test data, the resulting additive and multiplicative correction factors are calculated based on the curve fit equations presented previously. These correction factors are then applied to correct the power and total thermal input as shown in Tables C-6-2 and C-6-3. Since the assumed test plant is producing only electricity, heat rate is an appropriate performance indicator; the uncorrected and corrected heat rates are presented in Table C-6-4.



Fig. C-5.1 Additive Correction to Net Power for Cooling Tower Inlet Air Temperature



Fig. C-5.2 Additive Correction to Net Power for Cooling Tower Inlet Air Humidity



Fig. C-5.3 Multiplicative Corrections for Gas Turbine Inlet Temperature

Gas Turbine Inlet Temperature, °C



Fig. C-5.4 Multiplicative Corrections for Gas Turbine Inlet Pressure

Gas Turbine Inlet Pressure, kPa



Fig. C-5.5 Multiplicative Corrections for Primary Fuel Heating Value

Primary Fuel Heating Value, kJ/kg

Measurement	Metric Units	U.S. Customary Unit	
Ambient temperature	17.2°C	63°F	
Ambient site pressure	1.000 bar	14.5 psia	
Ambient relative humidity	0.7	0.7	
Coal flow rate (as received)	43.873 kg/s	348,200 lb/hr	
Coal heating value (HHV, as received)	30 587 kJ/kg	13,150 Btu/lb	
Net plant power	559.2 MW	559.2 MW	
Makeup water temperature	13.9°C	57°F	

Table C-6-2 Corrected mermal input	Table	C-6-2	Corrected	Thermal	Input
------------------------------------	-------	-------	-----------	---------	-------

Parameter	Metric Units	U.S. Customary Units
Thermal input		
Coal flow rate (as received)	43.873 kg/s	348,200 lb/hr
Coal heating value (HHV, as received)	30 587 kJ/kg	13,150 Btu/lb
Uncorrected total thermal input	1 341.9 MW	4,578.8 MMBtu/hr
Multiplicative correction factors		
Primary fuel heating value, MPF9	1.0049	1.0049
Gas turbine inlet air temperature, MPF_1	1.0020	1.0020
Gas turbine inlet air pressure, MPF ₂	1.0022	1.0022
Corrected thermal input	1 354.0 MW	4,620.2 MMBtu/hr

Table C-6-3Corrected Power Output

Parameter	Value
Measured net plant power	559 200 kW
Additive correction factors	
Cooling tower inlet temperature, AP ₂	573 kW
Cooling tower inlet humidity, AP ₃	562 kW
Sum of additive corrections	1 135 kW
Multiplicative correction factors	
Gas turbine inlet air temperature, MP_1	1.0001
Gas turbine inlet air pressure, MP ₂	0.9997
Primary fuel heating value, MP9	1.0057
Corrected net plant power	563 426 kW
Guaranteed net plant power	563 520 kW
Variance in net plant power	–94 kW

Table C-6-4Calculated Results for Net Unit HeatRate

Calculated Results	kJ/kW•h	Btu/kW•hr
Uncorrected net unit heat rate	8 639	8,188
Corrected net unit heat rate	8 652	8,200
Guaranteed net unit heat rate	8 622	8,172
Variance in net unit heat rate	+30	+28

NONMANDATORY APPENDIX D INLET AIR CONDITIONS AND CORRECTIONS

D-1 INTRODUCTION

The performance levels of the ASU, cooling tower, and gas turbine are sensitive to the temperature and relative humidity of their respective inlet air streams. In an ideal plant arrangement, the properties of the inlet air precisely match the properties of the ambient air surrounding the plant. The physical arrangement of an actual plant, however, may prevent air-consuming equipment from having access to unchanged ambient air. Even in a well-designed plant, the wind may shift from its prevailing direction to a direction that causes the inlet air to be warmed by exhaust stacks and heatrejecting equipment that are normally downstream from the air inlets. In a poorly designed plant, exhaust stacks or heat-rejecting equipment may be located upwind from the air-consuming equipment, causing increased inlet air temperatures.

ASME PTC 47 requires measurements to determine the dry bulb temperature, specific humidity, and barometric pressure of air at the inlet to combustion equipment or heat rejection equipment. The purpose of this Appendix is to explain why inlet air conditions have been specified instead of ambient air conditions, and to show a sample correction for different inlet air temperatures for different parts of the plant.

D-2 REASONS FOR SPECIFICATION OF INLET AIR CONDITIONS

The performance of plant combustion or heat rejection equipment is functionally related to the condition of the air entering the equipment. Heat rate and net power must be corrected for differences between the design conditions and test conditions of ambient air. The test boundary described in Section 3 of this Code is required to be drawn so that the inputs crossing it are not influenced by conditions within it. This restriction may not be possible for air at the inlet to plant equipment. The temperature or humidity of the air entering plant equipment may be affected by plant heat losses, which are highly dependent on plant design, component orientation, site conditions, wind speed, and wind direction at the time of the test. Steam vents, cooling tower exhaust plumes, and other heat losses may be entrained into the ambient air as it is drawn into combustion or heat rejection equipment.

It may seem more appropriate to measure ambient air conditions at a location upwind of the plant, but this is generally not practical. The air entering the combustion and heat rejection equipment is drawn in from all directions, and the average conditions of air drawn into the equipment can vary significantly from the conditions measured at any single upwind location. In addition, variations will occur over time with changes in ambient lapse rate (changes in temperature with elevation), wind conditions, and the ground effects upwind of the plant. Since there is no practical way of correlating ambient air to the air that enters the equipment, multiple tests based on measurements of ambient air would indicate widely scattered results due to the effects of variations in wind speed, wind direction, and ambient lapse rate. Therefore, inlet air is specified instead of ambient air.

The entrainment of heat losses into the air entering equipment can have a significant detrimental effect on the actual output and performance of the plant. Because an ASME PTC 47 test will not reveal the effects of these heat losses on plant performance, it is especially important to consider their potential effects during plant design, equipment specification, and development of the overall plant performance test plan.

D-3 CORRECTION FOR DIFFERENT TEMPERATURES AT COOLING TOWER INLET, ASU INLET, AND GAS TURBINE INLET

The basic calculation of IGCC performance assumes that the inlet air conditions at the ASU inlet, gas turbine compressor inlet(s), and cooling tower air inlet(s) are identical. Figures D-3-1 and D-3-2 show how correction curves can be represented for a typical combined cycle power plant with different temperatures at each location.

Figure D-3-1 is based on the dry-bulb temperature measured at the inlet to a typical gas turbine compressor, with a base point at 59°F. Figure D-3-2 is the correction for the difference in wet-bulb temperature between the compressor inlet and the cooling tower inlet, with a base point at 0°F difference.

For the sample case in Fig. D-3-2, with a 59°F gas turbine compressor inlet temperature, the correction to plant power is approximately 20 kW for each degree difference between the gas turbine compressor inlet and the cooling tower inlet.



Fig. D-3-1 Combined Cycle Power Correction for Gas Turbine Inlet Temperature



Fig. D-3-2 Combined Cycle Power Correction for Gas Turbine–Cooling Tower Temperature Difference

 T_{db} = dry-bulb temperature T_{wb} = wet-bulb temperature

NONMANDATORY APPENDIX E SAMPLE CALCULATION FOR ELECTRIC POWER GENERATION

This Appendix shows sample calculation of the test electrical output for a three-wattmeter method. See Table E-1 for voltage transformer (VT) test data and Table E-2 for VT calibration data. The complete formula is The simplified formula, ignoring PF and PA errors, is

$$VTRCF_S = RCF_o + (B_c/B_t) \times RCF_d$$

$$VTRCF_C = RCF_o + (B_c/B_t)[RCF_d \times \cos(PA_t - PA_c) + (1/3428) \\ \times \sin(PA_t - PA_c) \times G_d]$$

See Table E-3 for the VT voltage drop, Table E-4 for cooling tower (CT) corrections, and Table E-5 for the gross generation.

Parameter	Label	Units	Phase 1	Phase 2	Phase 3
Voltage (measured)	V	V AC	69.28	68.95	69.63
Current (measured)	1	mA	360	350	410
Volt-amperes ($V \times I/1,000$)	Bc	VA	24.941	24.133	28.548
Phase angle (measured)	PAc	deg	8	0	12
Power factor [cos (PA)]	PF	Ratio	0.990268	1	0.978148

Table F-1	Voltage	Transformer	Test	Data
	vullage	Indiasionine	ICSL	ναια

luste E 2 Voltage Hullstonner eutstation buta							
Parameter	Label	Units	Phase 1	Phase 2	Phase 3		
Burden at zero	B ₀	VA	0	0	0		
Burden at calibration test point (Z)	B_t	VA	200	200	200		
Power factor at calibration test point (Z)	PF_t	Ratio	0.85	0.85	0.85		
Phase angle at calibration test point (Z)	PA_t	deg	31.78833	31.78833	31.78833		
RCF at 0 VA	RCF ₀	Ratio	0.9979	0.9979	0.9979		
RCF at 200 VA, $PF = 0.85$	<i>RCF</i> _t	Ratio	1.00105	1.00105	1.00105		
Phase angle error at 0 VA	G_0	min	0.5	0.5	0.5		
Phase angle error at 200 VA, $PF = 0.85$	G_t	min	-0.46	-0.46	-0.46		
RCF difference ($RCF_t - RCF_0$)	<i>RCF</i> _d	Ratio	0.00315	0.00315	0.00315		
Phase angle difference $(G_t - G_0)$	G_d	min	-0.96	-0.96	-0.96		
Ratio correction factor	VTRCF _c	Ratio	0.998022	0.998242	0.998133		
Simplified RCF (see explanation in Appendix text)	VTRCF _S	Ratio	0.998293	0.99828	0.99835		
Added uncertainty due to simplification	UVTRCF _S	Percent	0.027125	0.003838	0.021656		

Table E-2 Voltage Transformer Calibration Data

Tab	le I	-3	Voltag	e Ti	ransf	ormer	Vo	ltage	Drop
-----	------	----	--------	------	-------	-------	----	-------	------

Parameter	Label	Units	Phase 1	Phase 2	Phase 3
Voltmeter 1 at VT	V1 ₀	V AC	69.28		
Voltmeter 2 at VT	V20	V AC	69.14		
VM difference $(V1_0 - V2_0)$	V_d	V AC	0.14	0.14	0.14
Voltmeter 1 at test wattmeter	$V1_t$	V AC	69.28	68.95	69.63
Voltmeter 2 at test wattmeter	$V2_t$	V AC	69.12	68.77	69.43
Corrected reading at test wattmeter ($V2_t + V_d$)	$V2_c$	V AC	69.26	68.91	69.57
Voltage drop $(V1_t - V2_c)$	VTVD	V AC	0.02	0.04	0.06
Voltage drop correction factor $(1 + VTVD/V1_t)$	VTVDC	Ratio	1.000289	1.00058	1.000862

Parameter	Label	Units	Phase 1	Phase 2	Phase 3
Measured current	1	Amps	4,875.515	4,875.515	4,875.515
Rated current	I _r	Amps	8,000	8,000	8,000
Percent of rating	I _p	Percent	60.94394	60.94394	60.94394
Ratio correction factor	CTRCF _c	Ratio	1.00014	1.00014	1.00014

 Table E-4
 Current Transformer Corrections

Parameter	Label	Units	Phase 1	Phase 2	Phase 3
Secondary watts at meter (measured)	SW	Watts	209.0553	210.1042	207.5398
Voltage drop correction factor	VTVDC	Ratio	1.000289	1.00058	1.000862
Secondary watts at VT (SW \times VTVDC)	SW _{vt}	Watts	209.1156	210.2261	207.7186
Simplified VTRCF	VTRCFs	Ratio	0.998293	0.99828	0.99835
Phase angle correction factor					
$[0.006667 \times PF + 0.99333 \text{ (approximation)}]$	PACF	Ratio	0.999932	1	0.999851
Current transformer ratio correction factor	CTRCF _C	Ratio	1.00014	1.00014	1.00014
Corrected secondary watts ($SW_{vt} \times VTRCF_{s} \times PACF \times CTRCF_{c}$)	SWc	Watts	208.7737	209.8939	207.374
VT marked ratio	VTR	Ratio	120	120	120
CT marked ratio	CTR	Ratio	1,600	1,600	1,600
Corrected primary watts ($SW_c \times VTR \times CTR/1,000$) [Note (1)]	PWc	kW	40,084.55	40,299.63	39,815.8

Table E-5 Gross Generation

NOTE:

(1) Total power from all three phases is 120,200.0 kW.

PERFORMANCE TEST CODES (PTC)

General Instructions	PTC 1-2004
Definitions and Values	PTC 2-2001
Fired Steam Generators	PTC 4-1998
Coal Pulverizers	PTC 4.2-1969 (R2003)
Air Heaters	PTC 4.3-1968 (R1991)
Gas Turbine Heat Recovery Steam Generators	PTC 4.4-1981 (R2003)
Steam Turbines	PTC 6-2004
Steam Turbines in Combined Cycles	PTC 6.2-2004
Appendix A to PTC 6, The Test Code for Steam Turbines	PTC 6A-2000
PTC 6 on Steam Turbines – Interpretations 1977–1983	PTC 6
Guidance for Evaluation of Measurement Uncertainty in Performance Tests of Steam Turbines	. PTC 6 Report-1985 (R2003)
Procedures for Routine Performance Tests of Steam Turbines	PTC 6S-1988 (R2003)
Centrifugal Pumps	PTC 8.2-1990
Performance Test Code on Compressors and Exhausters	PTC 10-1997 (R2003)
Fans	PTC 11-1984 (R2003)
Closed Feedwater Heaters	PTC 12.1-2000
Performance Test Code on Steam Surface Condensers	PTC 12.2-1998
Performance Test Code on Deaerators	PTC 12.3-1997 (R2004)
Moisture Separator Reheaters	PTC 12.4-1992 (R2004)
Single Phase Heat Exchangers	PTC 12.5-2000
Reciprocating Internal-Combustion Engines	PTC 17-1973 (R2003)
Hydraulic Turbines and Pump-Turbines	PTC 18-2002
Test Uncertainty	PTC 19.1-2005
Pressure Measurement	PTC 19.2-1987 (R2004)
Temperature Measurement	PTC 19.3-1974 (R2004)
Flow Measurement	PTC 19.5-2004
Measurement of Shaft Power	PTC 19.7-1980 (R1988)
Flue and Exhaust Gas Analyses	PTC 19.10-1981
Steam and Water Sampling, Conditioning, and Analysis in the Power Cycle	PTC 19.11-1997 (R2004)
Digital Systems Techniques	PTC 19.22-1986 (R2003)
Guidance Manual for Model Testing	PTC 19.23-1980 (R1985)
Particulate Matter Collection Equipment	PTC 21-1991
Gas Turbines	PTC 22-2005
Atmospheric Water Cooling Equipment	PTC 23-2003
Ejectors	PTC 24-1976 (R1982)
Pressure Relief Devices	PTC 25-2001
Speed-Governing Systems for Hydraulic Turbine-Generator Units	PTC 29-2005
Air Cooled Heat Exchangers	PTC 30-1991 (R1998)
lon Exchange Equipment	PTC 31-1973 (R1985)
Measurement of Industrial Sound	PTC 36-2004
Determining the Concentration of Particulate Matter in a Gas Stream	PTC 38-1980 (R1985)
Steam Traps	PTC 39-2005
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