ASME PTC 52-2020

Concentrating Solar Power Plants

Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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Two Park Avenue • New York, NY • 10016 USA

Date of Issuance: November 5, 2021

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The American Society of Mechanical Engineers
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NOTICE

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

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

When tests are run in accordance with a code, the test results themselves, without adjustment for uncertainty, yield the best available indication of the actual performance of the tested equipment. ASME Performance Test Codes do not specify means to compare those results with 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 with the contractual guarantees. It is beyond the scope of any code to determine or interpret how such comparisons shall be made.

FOREWORD

In the early 2000s, concentrating solar power (CSP) plants were being built in several locations around the world. The plants varied in size and in the type of technology they used, but they shared at least one difficulty: there was no industry standard for testing their performance. Recognizing the importance of developing a performance test code (PTC) for solar power plants, ASME brought together in July 2009 more than 30 electric-power industry volunteers from several countries to begin work on ASME PTC 52. This diverse group provided insight into each of the relevant technologies as well as expertise in plant design, power plant operation, and performance testing requirements. After agreeing that the industry needed a Code for acceptance testing of CSP plants, the Committee decided to limit the scope of the Code to CSP plants. The Code is intended for facilities that convert solar radiation into thermal energy for their own use. In most cases, the CSP plant is part of a complete electric power generation facility with CSP replacing fossil fuel as the thermal energy source. The Code does not address any photovoltaic solar fields or other systems where a heat balance at the boundary of the thermal system cannot be evaluated separately (e.g., dish-Stirling systems).

Initially, the Code was going to cover each CSP technology individually (tower, trough, linear Fresnel, storage, etc.). However, after a few meetings the Committee realized that if the solar field components were all kept within the test boundary and if the testing was concerned only with the energy streams crossing the boundary, all the technologies could be tested using the same guidelines. The final Code reflects this approach.

To prepare the Code, the Committee faced two fundamental differences between an acceptance test for a CSP plant and a test for a conventional fossil-fired system. The first difference is the transient nature of the energy source, and the second is the need to consider the role of an analytical performance model in the acceptance process. These factors bring into play the impacts of transient processes, uncertainties introduced by a model, and the need to test the accuracy of the model in predicting long-term performance. That means considering daily, seasonal, and annual solar cycles within the scope of the acceptance test procedure. Different types of tests are described in the Code, including short-term steady-state tests and longer multiday tests.

Facilities that include thermal energy storage facilities can also be tested using this Code, so long as the storage is within the test boundary. The Committee has also developed an appendix to discuss the approach for testing thermal energy storage systems independently.

The Committee recognizes that the development of new technologies, processes, and fluids is ongoing and may bring changes and improvements to the design, operation, efficiency, and output potential of the existing technologies, processes, and fluids. This Code has considered the range of conventional, proven CSP methods as those are relevant at this time. These technologies include

(a) parabolic trough with linear receiver(s)
(b) compact linear Fresnel reflectors with linear receiver(s)
(c) central tower receiver with a heliostat field (both open and cavity style receivers)
(d) thermal energy storage using a hot tank–cold tank system

Systems using different technologies than those listed can also be tested for acceptance using the guidance of ASME PTC 52.

This Code was approved by the PTC 52 Committee and the PTC Standards Committee on August 1, 2019. It was then approved as an American National Standard by the ANSI Board of Standards Review on March 23, 2020.

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Performance Test Codes

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

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

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

Proposing Revisions. Revisions are made periodically to the 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.

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

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

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

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

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

Subject:	Cite the applicable paragraph number(s) and the topic of the inquiry in one or two words.
Edition:	Cite the applicable edition of the 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. Please provide a condensed and precise question, composed in such a way that a "yes" or "no" reply is acceptable.
Proposed Reply(ies):	Provide a proposed reply(ies) in the form of "Yes" or "No," with explanation as needed. If entering replies to more than one question, please number the questions and replies.
Background Information:	Provide the Committee with any background information that will assist the Committee in understanding the inquiry. The Inquirer may also include any plans or drawings that are necessary to explain the question; however, they should not contain proprietary names or information.

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

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

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

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

Section 1
Object and Scope

1-1 OBJECT

This Code provides procedures, methods, and definitions for performance testing the solar-to-thermal conversion systems (i.e., solar thermal systems) associated with concentrating solar power (CSP) plants of parabolic trough, linear Fresnel, and power tower designs.

Accurate instrumentation and measurement techniques shall be used to determine the following performance results:

(a) thermal power output of solar field
(b) thermal energy production of solar field
(c) solar thermal efficiency
(d) heat transfer fluid (HTF) system parameters[1]
(e) auxiliary loads

This Code also provides methods for calculating performance test results.

The level to which the solar field can be tested is directly affected by the actual direct normal irradiance (DNI), performance of the downstream equipment (which is not part of this Code), and ambient conditions. Therefore, the parties to the test should pay particular attention to the combined effect of actual test conditions compared to the design values.

1-2 SCOPE

This Code applies to testing of solar-to-thermal conversion systems for parabolic trough, linear Fresnel, and power tower CSP systems. A unique feature of these systems is the variability of the input energy from the sun. Therefore, recommendations regarding the instrumentation required to measure the DNI are provided in this Code.

This Code also provides guidance on thermal energy storage systems that are often integral parts of CSP plant designs. This Code recognizes that many forms of energy storage systems with varying test goals are likely to be of interest to the industry. In the absence of any other Code-level guidance, this Code provides input related to testing thermal storage systems in Nonmandatory Appendix A.

This Code does not apply to systems where a heat balance at the boundary of the thermal system cannot be evaluated separately, such as

(a) concentrating photovoltaics (CPV) plants
(b) concentrating photovoltaics and thermal (CPT) plants
(c) concentrating thermophotovoltaics (CTPV) plants
(d) dish and engine plants

This Code contains methods for conducting and reporting performance tests of solar-energy-to-thermal-energy conversion systems that may include thermal energy storage systems. This Code includes requirements for pretest arrangements, testing methods, instrumentation, recommendations for measurement, and methods (or guidelines) for calculating test results and uncertainty. This Code does not apply to the determination of balance-of-plant or power-cycle performance.

1-3 UNCERTAINTY

A primary goal of this Code is to achieve test results of the lowest uncertainty consistent with the best engineering knowledge and practice in the industry while taking into account test costs and the value of information obtained from testing. The nature of CSP plants and their various design configurations result in a wide variation in the expected uncertainty of test results. Uncertainty levels are dependent on the technology used, varying ambient conditions, measurement uncertainty, and mode of operation during a test. There can be significant variation in the parameters that must be measured and the suitable instrumentation for doing so. For instance, testing in a location with a high

[1] Parameters include temperature, pressure, and flow.

variability of DNI due to changing cloud cover may cause the uncertainty to increase significantly. There are many site-specific ambient conditions that are unpredictable and uncontrollable.

Because of the significant variation in technology, types of measurements that must be made, and the differing levels of achievable uncertainty in individual measurements, it is not practical to define a fixed, Code-required maximum allowable test uncertainty that shall be met. Instead, an upper limit for the uncertainty of each type of measurement is established. The combination of uncertainty from all individual measurements then defines the acceptable upper limit of overall test uncertainty for a given configuration.

A pretest uncertainty analysis is required as part of this approach. It is used to determine the uncertainty for the actual test. The pretest analysis considers not only the test goals and the test boundary but also possible parameter-measurement locations and their related uncertainties. Thus, the pretest analysis helps identify measurement locations that have low uncertainties and meet test goals. The test uncertainty shall be calculated in accordance with the procedures defined herein and by ASME PTC 19.1.

A post-test uncertainty analysis is also required. It is used to determine the uncertainty for the actual test. This analysis should confirm the pretest systematic and random uncertainty estimates and validate the quality of the test results.

Deviations from the methods required in this Code are acceptable only if it can be demonstrated that they provide equal or lower uncertainty.

Test uncertainties are calculated solely to quantify the test quality and are not to be confused with other commercially negotiated quantities, such as test tolerances that may be contractually agreed to by parties to a test. Commercial agreements are beyond the scope of this Code.

1-4 REFERENCES

The applicable provisions of ASME PTC 1 are a mandatory part of this Code. To the extent they are applicable to CSP testing, the Instruments and Apparatus Supplements to ASME Performance Test Codes (ASME PTC 19 series) should be consulted when selecting the instruments and when calculating test uncertainties.

The following is a list of publications listed in this Code:

AGA Report No. 8-1992, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases
Publisher: American Gas Association (AGA), 400 North Capitol Street, NW, Washington, DC 20001 (www.aga.org)

ANSI/IEEE 120-1989, Master Test Guide for Electrical Measurements in Power Circuits
Publisher: Institute of Electrical and Electronics Engineers, Inc. (IEEE), 445 Hoes Lane, Piscataway, NJ 08854 (www.ieee.org)

ASME MFC 5.1-2011 (R2018), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters
ASME MFC 6-2013, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters
ASME PTC 1-2015, General Instructions
ASME PTC 4.4-2008 (R2013), Gas Turbine Heat Recovery Steam Generators
ASME PTC 12.4-1992 (R2019), Moisture Separator Reheaters
ASME PTC 19.1-2018, Test Uncertainty
ASME PTC 19.2-2010 (R2020), Pressure Measurement
ASME PTC 19.3-1974 (R2004), Temperature Measurement
ASME PTC 19.5-2004 (R2013), Flow Measurement
ASME PTC 19.6-2018, Electrical Power Measurements
ASME PTC 19.22-2007 (R2017), Data Acquisition Systems
ASME PTC 22-2014, Gas Turbines
ASME PTC 46-2015, Overall Plant Performance
Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ASTM D445, Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and Calculation of Dynamic Viscosity)
ASTM D1480, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer
ASTM D3588, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels
ASTM E903-12, Standard Test Method for Solar Absorptance, Reflectance, and Transmittance of Materials Using Integrating Spheres

ASTM E1137/E1137M-08(2014), Standard Specification for Industrial Platinum Resistance Thermometers
ASTM MNL 12, Manual on the Use of Thermocouples in Temperature Measurement
Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959 (www.astm.org)

IAPWS-IF97(2012), Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam
Publisher: The International Association for the Properties of Water and Steam (IAPWS) (www.iapws.org)

ISO 2186-07, Fluid flow in closed conduits — Connections for pressure signal transmissions between primary and secondary elements
Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

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

NREL/SR-5500-57272-2013, Utility-Scale Power Tower Solar Systems: Performance Acceptance and Test Guidelines
NREL/TP-550-47465-2010, Concentrating Solar Power: Best Practices Handbook for the Collection and Use of Solar Resource Data
Publisher: National Renewable Energy Laboratory (NREL), 15013 Denver West Parkway, Golden, CO 80401 (www.nrel.gov)

Section 2
Definitions and Descriptions of Terms

2-1 DEFINITIONS

absolute pressure: the pressure of a fluid relative to absolute vacuum, often calculated as the algebraic sum of the atmospheric pressure and gauge pressure.

absolute pressure transmitter: an instrument that measures pressure referenced to absolute zero pressure and transmits the information.

absorptance: the ratio of radiant energy absorbed to the total radiant energy incident upon a surface.

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

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

ambient air temperature: the air temperature as measured at agreed-on location(s). The parties to the test shall agree on the representative location(s). The word "ambient" as used in the Code shall mean the physical properties of the air at the agreed-on location(s).

aperture area: the projection of the active reflective surface of the collector, subtracting any gaps between mirrors, on the aperture plane. The aperture plane is the plane that contains the two noncoincident lines delineating the outer rims of the solar collector.

aperture normal irradiance (ANI): DNI vector normal to aperture plane.

atmospheric pressure: the force per unit area exerted by the atmosphere. Standard atmospheric pressure is 760 mm (22.92 in.) of mercury at 15°C (59°F). This is equivalent to 101.325 kPa (14.696 psia).

auxiliary firing: the combustion of fuel to heat the heat transfer fluid or working fluid.

auxiliary heat input: the thermal energy input to the heat transfer fluid or working fluid from pumps, heaters, and similar devices.

auxiliary power: the electric power used in the operation of the plant or elsewhere as defined by the test boundary. Also commonly referred to as "auxiliary load."

barometric pressure: the force per unit area exerted by the local atmosphere.

blowdown: water discharged from a system, such as from an evaporator, to control the concentration of minerals or other impurities.

calibration: the process of comparing the response of an instrument to a standard instrument over some measurement range and adjusting the instrument, if appropriate, to match the standard.

calibration drift: a shift in the calibration characteristics.

cleanliness factor: the ratio of energy flux reflected and/or transmitted by a soiled surface to energy flux reflected and/or transmitted by the same surface in perfectly clean condition. Sometimes the term soiling factor is used, and the meaning is the inverse of cleanliness factor.

coefficient of discharge, C_d: the ratio of the measured relieving capacity to the theoretical relieving capacity.

concentrating solar power (CSP): technologies used to collect and focus solar thermal energy.

confidence level:

(a) a percentage value such that if a very large number of determinations of a variable are made, there is a percent probability that the true value will fall within the interval defined by the mean plus or minus the uncertainty. A value for uncertainty is meaningful only if it is associated with a specific confidence level. As used in this Code, all uncertainties are assumed to be at the 95% confidence level. If the number of determinations of a variable is large and if the values are normally distributed, the uncertainty at the 95% confidence level is approximately twice the standard deviation of the mean of the values.

(b) the probability that the true value falls within the specified limits in a variable evaluated at a desired test operating point.

differential pressure: the difference between the inlet pressure and the discharge pressure.

direct normal irradiance (DNI): the direct (nondiffuse) solar radiation on a plane normal to the sun's ray.

dry-bulb temperature, td: the temperature measured by a dry thermometer or other dry sensor.

economizer: a heat recovery device designed to transfer heat between fluids, located upstream in the feedwater path of the evaporator. Also known as a preheater.

efficiency, conversion: the ratio of the useful energy produced by the system to that of the total energy entering the system.

empirical formulation: a mathematical formulation of observed data.

error: the difference between the measurand and its corresponding true value where the measurand is the particular quantity that is being measured or estimated.

error, bias: see *error, systematic*.

error, measurement: the true, unknown difference between the measured value and the true value.

error, precision: see error, random.

error, random, ε_r: 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, â: the portion of total error that remains constant in repeated measurements of the true value throughout a test process.

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

error, total (measurement), ä: the true, unknown difference between the assigned value of a parameter or test result and the true value.

evaporator: a heat transfer section wherein feedwater is vaporized. Also known as a boiler or steam generator.

feedwater: water entering an evaporator or economizer section.

field calibration: the process by which calibrations are performed under conditions that are less controlled than the laboratory calibrations with less rigorous measurement and test equipment than provided under a laboratory calibration.

flow metering run: the section(s) of piping consisting of the primary element, flow conditioner (if applicable), and upstream and downstream piping which conforms to the overall straight length and other manufacturing and installation requirements.

gauge pressure: the difference between the absolute pressure at a point and the pressure of the ambient atmosphere where the measuring gauge is located. It may be positive or negative.

gauge pressure transmitter: an instrument that measures pressure referenced to atmospheric pressure and transmits the information.

guaranteed performance model: the performance model that was used for contract negotiations, financial close, or both (as applicable).

heat: thermal energy in transit from a source at a higher temperature to a sink at a lower temperature.

heat balance: the utilization of the first law of thermodynamics (i.e., conservation of energy, wherein energy can be neither created nor destroyed, only converted from one form to another) to reconcile incoming and outgoing streams of energy.

heat collection element (HCE): an element of trough systems, typically concentric glass tubes under vacuum, that collects and transfers energy to the heat transfer fluid or working fluid. Also known as an absorber.

heater: a device used to increase the temperature of a fluid.

heat exchanger (HX): a device used to transfer heat from one higher temperature heat transfer fluid or reservoir to a second lower temperature heat transfer fluid or reservoir.

heat loss: energy quantity that leaves the test boundary outside defined exits.

heat transfer fluid (HTF): the fluid flowing through a solar collector or other equipment or system to transfer heat. HTF can be thermal oil, molten salt, water, steam, or other fluid, and may or may not be a working fluid.

heliostat: a structure consisting of a mirrored surface, drive system, and support structure, typically associated with power tower technology.

incidence angle, θ: the angle between a direct ray from the sun and the aperture plane of the collector (defined to be 0 deg when the rays are normal to the aperture plane).

influence coefficient: see *sensitivity*.

instrument: a tool or device used to measure physical dimensions of length, thickness, width, weight or any other value of a variable. These variables can include size, weight, pressure, temperature, fluid flow, voltage, electric current, density, viscosity, and power. Instruments can be sensors which may not, by themselves, incorporate a display but transmit signals to remote computer-type devices for display, processing, or process control. Instruments can also be ancillary pieces of equipment directly affecting the display of the primary instrument (e.g., ammeter shunt) or tools or fixtures used as the basis for determining part acceptability.

laboratory calibration: the process by which calibrations are performed under controlled conditions with highly specialized measuring and test equipment that has been calibrated by approved sources. To qualify as a laboratory calibration, the calibration must remain traceable to the National Institute of Standards and Technology (NIST), a recognized international standard organization, or a recognized natural, physical (intrinsic) constant through unbroken comparisons having defined uncertainties.

loop calibration: the calibration of an instrument through signal-conditioning equipment including a recording device.

maximum rated flow: 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).

net thermal energy: total energy collected minus system losses.

parameter: a direct measurement; also, a parameter is a physical quantity at a location which is sensed by direct measurement of a single instrument or determined by the averaged measurements of several similar instruments of the same physical quantity. Alternatively, a quantity that could be measured or taken from best available information, such as temperature, pressure, stress, or specific heat, used in determining a result. The value used is called the assigned value.

performance model: a computer model that calculates output based on environmental data using algorithms approximating actual plant parameters, geometries, and processes.

predicted performance: the performance as predicted by a performance model based on input parameters.

primary element: the component of a differential pressure flow metering run that is flanged or welded between specially manufactured pipe sections, across which the pressure drop is measured to calculate flow. The component may be an orifice plate, a nozzle, or a venturi.

primary parameter: A direct measurement of a physical quantity at a location as determined by a single instrument, or by the average of several similar instruments, that is used in the calculations of test results.

primary variables: the variables used in calculations of test results.

redundant instrumentation: two or more devices measuring the same parameter with respect to the same location.

reference conditions: a set of external values, for parameters outside the test boundary, affecting performance at which performance values are guaranteed. When performance testing is done at other values, test results are corrected to reference conditions.

reflectance: the ratio of radiant energy reflected to the total radiant energy incident upon a surface.

reflector surface: in context of CSP, this is the mirror surface used to collect and focus the sun's radiation onto the receiver. Reflector surfaces include heliostats, parabolic trough mirrors, and linear Fresnel mirrors.

repeatability: the random error of a method expressed as the agreement attainable between independent determinations performed by a single analyst.

result, R: a value calculated from a number of parameters.

run: comprises the readings and/or recordings sufficient to calculate performance at one operating condition.

secondary parameter: a direct measurement of a physical quantity at a location that is determined by a single instrument, or by the average of several similar instruments, that is not required to calculate test results, but that may be required to determine that the plant is operating properly.

secondary variable: a variable that is measured but does not enter into the calculation.

sensitivity: the rate of change in a result due to a change in a variable evaluated at a desired test operating point.

solar resource: the energy available from the sun's radiation.

solar system: the loop, section, or solar field and all essential equipment necessary to produce energy in a useful form.

solar thermal efficiency: the ratio of the thermal power output of the solar system normalized by the product of the incident direct beam radiation and the total aperture area of the solar field.

solar weighted reflectance: the reflectance weighted over the solar radiation spectrum.

solar weighted transmittance: transmittance weighted over the solar radiation spectrum.

spectral reflectance: reflectance measured as a function of the wavelength of the solar radiation.

spectral transmittance: transmittance measured as a function of the wavelength of the solar radiation.

specular reflectance: reflectance in the specular direction. The specular direction is the one forming an angle with normal to the surface equal to the angle of incidence of the incident radiation. The specular direction is on the same plane as the incident radiation and the normal to the surface and in the opposite direction of the incidence. Specular reflectance depends on the angle of the acceptance of the reflected radiation, which must be given.

specular transmittance: transmittance in the direction of the incident radiation.

standard atmospheric conditions: 101.325 kPa (14.696 psia), 288.15 K or 15°C (519°R or 59°F), and relative humidity of 60%. Also called standard temperature and pressure (STP).

standard deviation: several types of standard deviation are defined in statistical analysis (e.g., population standard deviation, sample standard deviation, standard deviation of the mean). In this Code, the term "standard deviation" refers to standard deviation of the mean unless otherwise specified.

student's t, t_{95}: the value of the student's *t* distribution is determined for each measurement based on the degrees of freedom for the measurement and a 95% confidence level.

test: a group of test runs comprising a series of points and results adequate to establish the performance over a specified range of operating conditions.

test boundary: a control volume defined by the scope of the test, and for which the mass and energy flows must be determined. Depending on the test, more than one boundary may be applicable. The definition of the test boundary or boundaries is an extremely important visual tool that aids in understanding the scope of the test and the required measurements.

test coordinator: the designated person responsible for the execution of the test in accordance with the test requirements.

test goal: the object or resulting parameter of interest of performing a test.

test plane: a reference plane for measurement or parameter designation.

test reading: one recording of all required test instrumentation.

test run: a group of test readings taken over a specific time period over which operating conditions remain constant or nearly so.

time of delivery (TOD): the stipulation sometimes included in power purchase agreements that puts greater value on production during periods of high energy demand. For example, nonholiday weekdays between noon and 6 p.m. May through September may represent a peak period that the power off-taker pays more for compared to weekend hours October through April from 8 a.m. to noon.

traceable: the established pedigree for a measurement based on the chain of calibrations that links or traces a measuring instrument to a primary standard. Alternatively, records demonstrating that the instrument can be traced through a series of calibrations to an appropriate ultimate reference such as the National Institute for Standards and Technology (NIST).

transmittance: the ratio of energy flux transmitted by a material to the energy flux of the radiation incident on it.

uncertainty, U: ±*U* is the interval about the measurement or result that contains the true value for a 95% confidence level.

uncertainty, measurement: estimated uncertainty associated with the measurement of a process parameter or variable.

uncertainty, random, 2S: an estimate of the ± limits of random error with a defined level of confidence. Often given for 2-σ (2 standard deviations) confidence level of about 95%.

uncertainty, systematic, B: an estimate of the ± limits of systematic error with a defined level of confidence (usually 95%).

uncertainty, test: the uncertainty associated with a corrected test result.

variable: a quantity subject to variation such that it can have different values that can be measured or counted. The quantity may be calculated from a number of measurands, where a measurand is a particular quantity that is being measured or estimated.

verification: a set of operations that establishes evidence by calibration or inspection that specified requirements have been met.

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

2-2 SYMBOLS

See Table 2-2-1 for definitions of the symbols used in this Code.

2-3 ABBREVIATIONS AND ACRONYMS

ANI = aperture normal irradiance
Aux = auxiliary load — electric or thermal
CSP = concentrating solar power
DNI = direct normal irradiance
HTF = heat transfer fluid
MDPT = multiday performance test
PTC = performance test code
RSR = rotating shadowband radiometer
RTD = resistance temperature detector
SF = solar field
STPT = short-term performance test
SWSR = solar-weighted specular reflectance
TES = thermal energy storage
TOD = time of delivery

Table 2-2-1 Nomenclature

Symbol	Description	Units: SI	Units: U.S. Customary
$2S$	Uncertainty (random)	...	...
A	Area	m^2	ft^2
b	Uncertainty (systematic)	...	...
C	Constant (generic)	(various)	(various)
C_p	Heat capacity, constant pressure	kJ/kg·K	Btu/lbm·°R
C_v	Heat capacity, constant volume	kJ/kg·K	Btu/lbm·°R
D	Diameter	m	ft
F	Vortex shedding frequency	s^{-1}	hr^{-1}
h	Enthalpy	kJ/kg	Btu/lbm
I	Electric current	amperes (A)	amperes (A)
i, j	Summation index (1, 2, 3,...n)	...	...
K	Proportional flow factor	m	ft
L	Level or length	m	ft
M	Mass	kg	lbm
m	Mass flow rate	kg/s	lbm/hr
n	Total number of incremental measurements	...	...
p	Pressure	kPa	psia
PF	Power factor	...	...
Q	Heat/thermal energy	kJ	Btu
q	Heat transfer rate/thermal power	kW	Btu/hr
RH	Relative humidity	%	%
St	Strouhal number	...	...
T	Temperature	°C (K)	°F (°R)
t	Time	s	hr
t_{95}	Student's t at 95% confidence interval	...	...
U	Uncertainty (total)	...	...
u	Velocity	m/s	ft/hr
V	Volume	m^3	ft^3
v	Volumetric flow rate	m^3/s	ft^3/hr
W	Work/electric energy	kWh	Btu
w	Work transfer rate/electric power	kW	Btu/hr
β	Error (systematic)	...	...
δ	Error (total)	...	...
Δ	Difference	(various)	(various)
Δp	Differential pressure	Pa	inH_2O
ΔT	Temperature difference	°C (K)	°F (°R)
η	Efficiency	%	%
ρ	Density	kg/m^3	lbm/ft^3
Σ	Sum	...	...
θ	Incidence angle	rad	deg
Θ_i	Sensitivity coefficient for parameter i	...	...

Section 3
Guiding Principles

3-1 INTRODUCTION

This Section provides guidance on the conduct of concentrating solar power (CSP) plant testing and outlines the steps required to plan, conduct, and evaluate a Code test of CSP plant performance.

The subsections discuss the following:

(a) tests (subsection 3-2)
(b) test plan (subsection 3-3)
(c) test preparations (subsection 3-4)
(d) conduct of the test (subsection 3-5)
(e) calculation and reporting of results (subsection 3-6)

This Code includes procedures for testing CSP plants to determine performance results corresponding to test goals. It also provides guidance for multiple-party tests conducted to satisfy or verify guaranteed performance as specified in commercial agreements. This Code is not intended to provide performance information on individual components (mirrors, receivers, heat exchangers, etc.).

Each test shall be designed with the appropriate goal in mind to ensure proper procedures are developed, the appropriate operating mode during the test is followed, and the correct performance equations are applied. Potential test goals for each test setup are given in paras. 3-2.1.2 and 3-2.1.4. The parties to the test shall agree on the appropriate test goals for each test. Section 5 provides information on the general performance equations and variations of the equations to support specific test goals.

3-2 TESTS

This Code may be incorporated into contracts by reference to serve as a means to verify certain commercial guarantees for CSP plant performance. If this Code is used for guarantee acceptance testing or for any other tests where there are multiple parties represented, those parties shall mutually agree on the exact method of testing and the methods of measurement, as well as any deviations from the Code requirements.

During the design phase of the CSP system, consideration should be given to accurately conducting acceptance testing for overall performance for the specific type of CSP system. Consideration should also be given to the requirements of instrumentation accuracy, calibration, recalibration documentation, and the location of permanent plant instrumentation to be used for testing. Adequate provisions for installation of temporary instrumentation where CSP system instrumentation is not adequate to meet the requirements of this Code shall also be considered during the design stages. For example, proper allowance for the placement of suitably accurate flow measurement devices shall be considered if the CSP system's permanent flow instrumentation is not capable of the accuracy required under Section 4.

3-2.1 Performance Tests

For any test run, it is required to measure the input parameters required by the performance model. Input parameters may include direct normal irradiance (DNI), other meteorological conditions, and field status (e.g., active tracking area, reflectivity).

Test measurements shall be performed using instruments calibrated as specified in Section 4. All uncertainty calculations shall be performed according to the methods specified in Section 7.

The tests described in paras. 3-2.1.1 through 3-2.1.4 should be conducted following test procedures developed in accordance with this Code.

3-2.1.1 Short-Term Performance Test (STPT)

(a) Power Test at Available Conditions (PTAC). The object of the PTAC is to evaluate the performance and verify the CSP plant thermal power output at the available ambient conditions. The test run shall span, at minimum, a single 2-h period. The following are examples of when this test could be used:

(1) to demonstrate the CSP plant's thermal power (in megawatts) using a measured and constant active tracking area

(2) in the event testing cannot occur in optimum or summer conditions

(3) for performance testing relative to a model in off-design conditions

(b) *Full Power Test (FPT).* The object of the FPT is to evaluate and verify the solar field's ability to deliver full thermal power output. Full thermal power output is defined as the required heat transfer fluid (HTF) conditions exiting the test boundary that meet the steam turbine or other thermal load's power rating. The parties may or may not agree to reference this test to a performance model. The recommended duration of the test run shall be, at minimum, a single period of 2 h.

3-2.1.2 STPT Results. The following results can be determined during an STPT:

(a) thermal power output of solar field (in megawatts)

(b) solar thermal efficiency

(c) HTF system parameters

(d) auxiliary load consumption (thermal, electrical, or both)

3-2.1.3 Multiday Performance Test (MDPT). The object of the MDPT is to evaluate and verify the solar field's total thermal energy production measured over the course of a 24-hr/day multiday test period, which could be used for cumulative performance and also time-of-day performance. The result of this test shall be expressed as a direct measurement of thermal performance (total megawatt hours as determined by the test boundary). This Code recommends that a minimum 15-day test be considered. A 15-day test should be sufficient to demonstrate the plant's extended performance and its performance during transients including startup, shutdown, and solar resource interruptions.[1] The test should be continuous. During the test, test days that do not meet the MDPT requirements specified in para. 3-5.2.3 may be excluded from the test and the MDPT continued until the accrued days meet the specified test run duration.

The performance test may be conducted at any time of year as long as there is a reasonable period of time during each day with adequate DNI. Days with low or unstable DNI may be excluded from the sample and the test period extended accordingly.

The following are examples of how this test could be used:

(a) to determine the performance of the CSP plant over start-up, shutdown, and transient cycles compared to the performance predictions

(b) to verify expected plant performance over a variety of ambient conditions, operating conditions, or both

(c) to evaluate performance of the CSP plant under a time of delivery (TOD) situation

(d) to evaluate plant efficiency under conditions of interest (see para. 5-2.4)

It is anticipated that a performance model will be used to establish the expected test output against which the actual test output will be compared. In many cases this model will have been the basis for the production estimate used to determine financing or purchase price for the CSP plant. If the economic expectations of the plant were based on TOD pricing, the parties can agree to include TOD pricing in the economic calculations. This pricing structure can be important when considering the economic feasibility of a project.

3-2.1.4 MDPT Results. The following results can be determined during an MDPT:

(a) thermal energy production of solar field (in megawatt hours)

(b) HTF system parameters

(c) auxiliary load consumption (thermal, electrical, or both)

(d) thermal energy storage performance (if applicable, see Nonmandatory Appendix A)

3-2.2 Prior Agreements

The parties to the test shall agree on all material issues not explicitly prescribed by the Code as identified throughout the Code and summarized as follows:

(a) All parties to the test shall approve the test plan.

(b) Representatives from each of the parties to the test shall be designated to be part of the test team and observe the test to confirm that it was conducted in accordance with the test requirements. Those representatives should have the authority to approve any agreed upon revisions to the test requirements during the test.

(c) Parties shall have reasonable opportunity to examine the CSP system and agree that it is ready to test.

(d) All parties to the test shall agree on the following:

[1] This recommendation applies to a typical site with 250 days to 300 days of solar operation annually. During the 15 days, it is expected that there will be several days with clear solar conditions and several days with clouds, such that the test period is representative of a full year's operation. Since weather conditions vary from site to site, the parties may decide to specify a minimum ratio of clear to cloudy days for the test and extend the test period accordingly until these conditions are met. Alternatively, where there are significant seasonal differences in weather conditions (e.g., frost, frequency of cloudiness), the parties may agree to an additional MDPT in another season.

(1) contract or specification requirements regarding operating conditions, base reference conditions, performance guarantees, test boundary, and environmental compliance

(2) minimum requirements necessary to run a Code test, including environmental conditions (DNI, wind, etc.), test fuel supply (if applicable), and the thermal hosts' ability to accept loads

(3) notification requirements prior to test preparation to ensure all parties have sufficient time to be present for the test

(4) modifications to the test plan based on preliminary testing

(5) a defined equipment/system operating disposition list

(6) operations of equipment/system outside the scope of the suppliers' instructions

(7) actions to take if site conditions are outside the testing limits, including conditions for exclusion of hours or days in the MDPT

(8) CSP system parameters, operating range, and stability criteria prior to starting a test and during the test

(9) permissible adjustments to equipment/system operations during and between test runs

(10) duration and number of test runs

(11) resolution of unrepeatable test runs results

(12) rejection of test readings (see subsection 3-6.2)

(13) final model and test calculations, including the methodology for the model, provisions for data collection and inputs, and technical parameters

(14) requirements for data storage, document retention, and test report distribution

(15) any unique test report format, contents, inclusions, and index outside of Section 6 that are of interest to the parties to the test

(16) specific type, location, and calibration requirements for all instrumentation and measurement systems

(17) HTF thermophysical properties or data (or a method to specifically measure the HTF properties) and application thereof

(18) correlations for calculating wind speed at height based on ground measurements

(19) frequency of data acquisition

3-2.3 Data Records and the Test Log

Clear records shall be made to identify and distinguish the equipment to be tested and the exact method of testing. Descriptions, drawings, and photographs may be used to give a permanent, explicit record of the test. Instrumentation details including location and redundancy according to the guidelines in Section 4 shall be described in detail in test records.

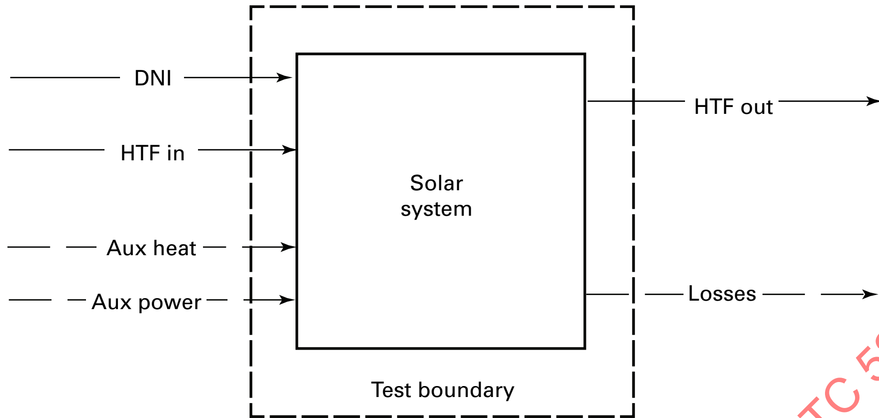
A complete set of data and a complete copy of the test log shall be provided to all parties to the test. All data and records of the test shall be prepared to allow for clear and legible reproduction. The completed data records shall include the date and time of day that each observation was recorded. The observations shall be the actual readings without application of any instrument corrections. The test log should constitute a complete record of events. Destruction or deletion of any data record, page of the test log, or of any recorded observation is not permitted. If corrected, the alteration shall be entered so that the original entry remains legible and an explanation of the change is included. For manual data collection, the test observations shall be entered on prepared forms that constitute original data sheets authenticated by the observers' signatures.

For automatic data collection, printed output or electronic files shall be authenticated by the test coordinator and other representatives of the parties to the test. The parties to the test shall agree in advance to the method used for authenticating, reproducing, and distributing the data. Electronic data relevant to the test, including data that indirectly affect test results, shall be made available or distributed to each of the parties to the test. The data shall be in a format that is easily accessible.

3-2.4 Test Boundary and Required Measurements

The test boundary defines the control volume and identifies the energy streams which must be measured to calculate results. The test boundary is an accounting concept used to define the streams that must have their parameters measured to determine performance. All input and output energy streams required for test calculations shall be determined with reference to the point at which they cross the boundary. At steady-state conditions, energy streams within the boundary need not be determined unless they verify operating conditions or unless they relate functionally to conditions outside the boundary. In contrast, at unsteady-state conditions that involve energy accumulation or depletion, energy streams within the boundary need to be determined and accounted for.

Figure 3-2.4-1 Sample Solar Field Test Boundary



GENERAL NOTE: Solid lines indicate energy or HTF crossing the test boundary, which have to be measured to calculate the results of a CSP system performance test. Dashed lines indicate energy or HTF streams that may be required for an energy and mass balance but may not have to be measured to calculate test results.

The methods and procedures of this Code have been developed to provide flexibility in defining the test boundary for a test and in choosing measurement locations. For example, the parties to the test may want to include the steam generation system within the test boundary or exclude the steam generation system from the test boundary depending on the technology, impact on overall test uncertainty, or on the test goals.

The specific test boundary for a particular test shall be established by the parties to the test. Some or all of the typical streams required for common systems are shown in Figure 3-2.4-1.

3-2.4.1 Required Measurements. Test measurement points depend on the goal of the test. Test measurement points should be located to best measure stream parameters as they cross the test boundary. Some flexibility is required by this Code in defining the test boundary, since it is somewhat dependent on the particular CSP system design. In general, measurements or determinations are required for the following:

(a) Solar Energy Input

(1) DNI

(2) date and time

(b) Solar Field Metrics

(1) active area of mirrors focused on the receiver(s), if applicable to the test

(2) effective mirror reflectance (to determine cleanliness factor unless parties agree to a fixed value)

(c) HTF System

(1) pressure, temperature, and flow

(2) thermal physical properties of HTF (e.g., density, heat capacity) unless parties agree to use correlations or prior data in place of measurements on unique samples from the system being tested

(3) heat added by sources other than solar (e.g., fuel-fired heat source, auxiliary equipment), to be determined by test boundary

(d) Electric Power Consumption. The parties to the test should determine the electric power measurements required for the test.

3-2.4.2 Other Measurements. The following additional measurements should be made where appropriate:

(a) Ambient Conditions

(1) air transmittance (if applicable and agreed to by the parties to the test)[2]

(2) dry bulb temperature

(3) wind speed and direction

(4) humidity

(5) barometric pressure

(b) Solar Field Metrics

[2] Air and glass transmittance may be primary dependent on technology, project requirements, or party discretion.

(1) glass transmittance of the receiver if applicable (to determine cleanliness factor)
(2) absorptance of the receiver if applicable
(3) field location (latitude and longitude)

3-2.5 Criteria for Selection of Measurement Locations

Measurement locations are selected to provide the lowest level of measurement uncertainty for energy streams where they cross the test boundary. The actual measurement may be made at a point different than the test boundary, either inside or outside, if a better measuring location is available and if the conditions of the energy stream at the metering point are equivalent to or can be accurately corrected to the conditions at the test boundary.

Instrumentation shall be located to minimize the effect of ambient conditions, e.g., temperature or temperature variations, on uncertainty. Care shall be used in routing lead wires to the data collection equipment to prevent electrical noise in the signal. Manual instruments shall be located so that they can be read precisely and easily by the observer. All instruments shall be marked uniquely and unmistakably for identification. Calibration tables, charts, or mathematical relationships shall be readily available to all parties to the test. Observers recording data shall be instructed on the desired degree of precision of readings.

3-3 TEST PLAN

Before conducting a Code test, the test coordinator shall prepare a detailed test plan documenting all issues affecting the conduct of the test and providing detailed procedures for performing the test. The test plan should include the schedule of test activities, designation and description of responsibilities of the test team, test procedures, and report of results.

3-3.1 Schedule of Test Activities

The test coordinator should prepare a test schedule including the sequence of events and anticipated time of the test, notification of the parties to the test, test plan preparations, test preparation and conduct, and preparation of the report of results.

3-3.2 Test Team

The test plan shall identify the test team organization that will be responsible for the planning, preparation, conduct, analysis, and reporting of the test in accordance with this Code. The test team should include test personnel needed for data acquisition, sampling, and analysis; operations personnel and other personnel needed to support the test preparations and implementation; and outside laboratory and other services.

The test coordinator is responsible for establishing a communication plan for all test personnel and all test parties. The test coordinator shall also ensure that complete written records of all test activities are prepared and maintained and coordinate the setting of required operating conditions with the plant operations staff.

3-3.3 Test Procedures

The test plan should include test procedures that provide details for the conduct of the test. The test procedures should include the following:

(a) object of test
(b) operating strategy, including startup conditions
(c) test acceptance criteria for test completion
(d) defined test boundary identifying inputs, outputs, and measurement locations
(e) HTF thermophysical property correlations or data
(f) operating, performance, and environmental requirements
(g) complete pretest uncertainty analysis with systematic and random uncertainties estimated
(h) specific type, location, and calibration requirements for all instrumentation and measurement systems
(i) frequency of data acquisition
(j) measurement requirements for applicable emissions, including measurement location, instrumentation, and frequency and method of recording
(k) sample, collection, handling, and analysis method and frequency for HTF and fuel (if applicable)
(l) allowable range for DNI and weather conditions
(m) identification of testing laboratories to be used for HTF and fuel (if applicable) analysis
(n) required operating disposition or accounting for all internal thermal energy and auxiliary power consumers having a material effect on test results

(o) required levels of equipment cleanliness and inspection procedures
(p) procedures to account for performance degradation (if applicable)
(q) valve lineup requirements
(r) preliminary testing requirements
(s) prerequisites such as functional tests
(t) pretest stabilization criteria
(u) stability criteria and methods of setting and maintaining operating conditions within these limits
(v) number of test runs and durations of each run
(w) test start and stop requirements
(x) data rejection criteria
(y) allowable range of HTF and fuel conditions (if applicable), including constituents and heating value
(z) identification of the performance model and instructions for its use, including provisions for data inputs, parameters, and exclusions
(aa) sample calculations or detailed procedures specifying test run data reduction and calculation of test results
(bb) method for combining test runs to calculate the final test results
(cc) requirements for data storage, document retention, and test report distribution
(dd) test report format, contents, inclusions, and index

3-4 TEST PREPARATIONS

All parties to the test shall be given timely notification, as defined by prior agreement, to allow them the necessary time to respond and to prepare personnel, equipment, and documentation. Updated information should be provided as it becomes known.

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

The safety of personnel and care of instrumentation and equipment involved in the test should be considered. For example, the following should be considered:
(a) provision for safe access to test point locations
(b) availability of suitable utilities and safe work areas for personnel
(c) potential damage to instrumentation or calibration shifting because of extreme ambient conditions such as temperature or vibration

Documentation shall be developed or be made available for calculated or adjusted data to provide independent verification of algorithms, constants, scaling, calibration corrections, offsets, base points, and conversions.

3-4.1 Test Apparatus

Test instruments are classified as described in para. 4-1.2.3. Instrumentation used for data collection shall be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can either be permanent CSP system instrumentation whenever possible or temporary test instrumentation.

Multiple instruments should be used as needed to reduce overall test uncertainty. The frequency of data collection is dependent on the particular measurement and the duration of the test. To the extent practical, at least one reading per minute should be collected to minimize the random-error impact on the post-test uncertainty analysis. The use of automated data-acquisition systems is recommended to facilitate acquiring sufficient data. Calibration or adequate checks of all instruments shall be carried out, and those records and calibration reports shall be made available.

The equipment or conditions should not be altered or adjusted in such a way that regulations, contracts, safety, or other stipulations are altered or voided. Adjustments to the equipment for test purposes should not prevent immediate, continuous, and reliable operation at all capacities or outputs under all specified operating conditions. Any actions taken shall be documented and immediately reported to all parties to the test.

3-4.2 Data Collection

Data shall be taken by automatic data-collecting equipment whenever possible. Manual data collection shall be made by a sufficient number of competent observers. Automatic data logging and advanced instrument systems shall be calibrated to the required accuracy. No observer shall be required to take such a quantity of readings that could result in insufficient care and precision. Consideration shall be given to specifying duplicate instrumentation and taking simultaneous readings for certain test points to attain the specified accuracy of the test.

3-4.3 Performance Model

When a performance model is required for a specific test, the parties to the test shall use a mutually agreed upon performance model to evaluate test results. This performance model provides a prediction of output based on algorithms approximating actual plant parameters, geometries, and processes. Therefore, correction curves should not be applied to measured data, as the performance model will provide the predicted performance at test conditions. The parties to the test shall agree on the number and frequency of predicted performance results generated by the model, but at minimum, results shall be generated once per hour. The parties should consider factors such as the variability of the DNI and the thermal inertia of the system in determining the proper time interval of the predicted performance results. The parties to the test shall mutually agree on the model, its output parameters, the weather data set, the physical property correlations used, and other plant parameters (see para. 3-2.4.1).

Examples of the performance model that could be used for this evaluation include

(a) the model that was used to develop the base case energy production estimates

(b) the model that was used to develop the power or energy guarantees of the project

(c) the model identified in the construction or equipment supply contract(s)

The performance model shall be a weather-adjusted model, where actual ambient conditions are used as the input to the performance model for comparison to the actual performance of the project. Upon mutual agreement between the parties to the test, specific model parameters can be modified to reflect actual equipment or component performance. Initial conditions of plant variables of the performance model shall be defined or taken into consideration [e.g., HTF initial temperature at solar field inlet, initial level of storage system (if applicable)]. For example, mirror reflectance values can use the assumptions in the performance model, or alternatively measured values could be introduced using measurements in the solar field at representative locations and frequencies.

3-4.4 Test Personnel

Test personnel are required in sufficient number and expertise to support the execution of the test. Operations personnel shall be familiar with the test procedure operating requirements in order to operate the equipment accordingly (see para. 3-3.2).

3-4.5 Equipment Inspection and Cleanliness

The CSP system should be checked to ensure that required equipment and subsystems are installed and operating in accordance with their design parameters and that the CSP system is ready to test. If the amount of reflective area to be utilized during the test is fixed, this shall be defined and fixed in advance of the test.

Parties may agree to take reflectance, absorptance, and transmittance measurements on a representative sample of reflectors or receivers prior to, during, or after the test to determine cleanliness. The number of measurements performed shall be sufficient on a statistical basis such that the uncertainty resulting from location and other error sources is less than the uncertainty associated with the measurement device. If sufficient measurements to meet this requirement are not possible, the design cleanliness should be used for all reflectance and transmittance calculations associated with this test, unless otherwise agreed to by the parties to the test.

3-4.6 Preliminary Testing

Preliminary test runs serve to determine whether equipment is in suitable condition to test, to check instruments and methods of measurement, to check adequacy of organization and procedures, and to train personnel. All parties to the test should conduct reasonable preliminary test runs as necessary. Observations during preliminary test runs should be carried through to the calculation of results as an overall check of procedure, layout, and organization. Some reasons for a preliminary run are

(a) to determine whether the CSP system equipment is in suitable condition to conduct the test

(b) to discover necessary adjustments that were not evident during the preparation of the test

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

(d) to ensure that the estimated uncertainty as determined by the pretest analysis is reasonable

(e) to ensure that the facilities operation can be maintained in a steady-state performance

(f) to ensure that the HTF and fuel (if applicable) characteristics, analysis, and heating value are within permissible limits, and that sufficient supplies are on hand to avoid interrupting the test

(g) to ensure that process boundary inputs and outputs are not constrained, other than by those constraints identified in the test requirements

(h) to familiarize test personnel with their assignments

(i) to retrieve enough data to fine tune the control system if necessary

3-5 CONDUCT OF THE TEST

This subsection provides guidelines on the actual conduct of the performance test and addresses the following areas:
(a) starting and stopping tests and test runs
(b) methods of operation prior to and during tests
(c) adjustments prior to and during tests
(d) duration and number of tests
(e) number of readings
(f) constancy of test conditions

3-5.1 Starting and Stopping Tests and Test Runs

For the STPT, it is particularly important for the starting and ending conditions to be as similar as possible in order to mitigate any accumulation or depletion of existing thermal energy within the test boundary.

3-5.1.1 Starting Criteria. Prior to starting each performance test, the operation, configuration, and stability criteria for testing shall be in accordance with the agreed upon test requirements, including
(a) ambient conditions (e.g., DNI, wind, temperature)
(b) process parameters, equipment operation, and method of control
(c) unit configuration
(d) valve lineup
(e) data acquisition system(s) functioning and test personnel in place and ready to collect samples or record data

3-5.1.2 Stopping Criteria. Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied. The test coordinator may extend or terminate the test if the requirements are not met. Data logging should be checked to ensure completeness and quality.

3-5.2 Methods of Operation During Tests

All equipment necessary for normal and sustained operation at the test conditions must be operated during the test or accounted for in the corrections. Intermittent operation of equipment within the test boundary should be accounted for in a manner agreeable to all parties (e.g., reflectors that are not used at peak DNI). Parties should recognize the different plant operating configuration for an STPT versus an MDPT, and account appropriately for the potential impacts to the test. Examples of operating equipment to consider include HTF handling equipment, water treatment equipment, the HTF recovery system, environmental control equipment, and blowdown equipment.

If parties agree, part of the MDPT may also be used for the STPT, provided the part adopted from the MDPT meets the requirements of the STPT.

3-5.2.1 Operating Mode. The operating mode of the CSP system during the test should be consistent with the goal of the test. If a specified corrected or measured load is desired, the CSP system's control system should be configured to maintain the load during the test. If a specified disposition is required (e.g., fixed active area), the control system should maintain the disposition and not make changes to the parameters, which should be fixed.

3-5.2.2 Short-Term Test. For the duration of the STPT, the CSP plant shall be operated in accordance with the following criteria:

(a) DNI shall be greater than 80% of the average peak hourly W/m^2 (considering location, date, and time) expected for the month of the test for the duration of the test period. The parties to the test shall agree on the appropriate source for expected DNI data (TMY, other data set, etc.).

(b) Mass flow, inlet temperature, and outlet temperature should remain stable during the test. Range and stability for these parameters shall be as agreed upon by the parties.

(c) No cleaning of the collectors subject to testing should take place during the test period.

(d) The plant shall be operated within normal operating procedures and conditions.

3-5.2.3 Multiday Performance Test. The MDPT should occur continuously until the required amount of valid days have been accumulated. For a day to qualify as valid for the MDPT, it should meet the following criteria:

(a) There is a minimum of 4 h with DNI continuously above 500 W/m^2. A value other than 500 W/m^2 may be agreed upon by the parties to the test.

(b) During daylight operating hours, wind speeds and wind gusts are less than the solar field's design wind protection speed (or lower as agreed between the parties). Wind speeds and gusts that cause a reduction in performance according to the performance model are allowed as long as defocusing of solar collectors is not required. Parties may agree to exclude

hours of nonoperation due to wind and not disqualify the entire day, provided the day includes 4 h of operation at a DNI continuously above 500 W/m^2.

(c) There is no downtime or derating caused by equipment or events outside the test boundary. Parties may agree on derating value and/or excluding hours for downtime, and not disqualify the entire day.

(d) Extraordinary operating or environmental conditions may be excluded as agreed upon between the parties [see para. 3-2.2(d)(8)].

(e) The plant shall be operated within normal operating procedures and conditions.

(f) Off-line cleaning of the solar field or downstream heat transfer surfaces (as applicable) shall be performed according to standard procedures or instructions of operations and maintenance for the plant.

Parties to the test shall agree upon accounting methods for any excluded days.

3-5.2.4 Valve Lineup. A valve lineup checklist shall be developed to identify the goals of the test. The size of this checklist will vary between various CSP technologies. The checklist should be divided into the following three categories:

(a) Manual Valve Isolation. This part of the checklist is a list of all manual valves that should be closed during normal operation and 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.

(b) Automatic Valve Isolation. This part of the checklist is a list of valves that should be closed during normal operation but may occasionally cycle open. As in (a), these are the valves that affect the accuracy or results of the test if they are not secured. These valve positions should be checked prior to the preliminary test and monitored during subsequent testing. To the extent possible in the plant control system, these valve positions should be continuously monitored during the test.

(c) Test Valve Isolation. This part of the checklist is a list of those valves that should be closed during the performance test. These valves should be limited to those that must be closed to accurately measure the plant performance during the test. For example, the steam generator blowdown may need to be closed during all or part of the test to accurately measure steam production. The blowdown valve position should be addressed in the test plan.

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

The valves on the test valve isolation part of the checklist should be closed prior to the preliminary test. The valves may need to be opened between test runs.

Effort should be made to eliminate leaks through valves that are required to be closed during the test. If any leaks can't be eliminated, the magnitude of valve leakage should be determined.

The parties to the test should agree to methods to quantify leakages. Some nonintrusive methods are frequency spectrum analysis, Doppler effect analysis, and transient analysis, which can be used for flow detection through valves.

3-5.2.5 Equipment Operation. CSP system equipment required for normal CSP system operation shall be operated and maintained as defined by the respective equipment suppliers' instructions and official operations and maintenance procedures. Equipment that is necessary for plant operation or that would normally be required for the CSP system to operate shall be operating or accounted for in determining auxiliary power loads. An equipment checklist shall be developed. The checklist should be divided into the following two parts:

(a) electrical auxiliaries

(b) nonelectric internal energy consumers

The checklist shall include a tabulation of the required operating disposition of all electric and nonelectric internal energy consumers.

A switchover to redundant equipment, such as a standby pump, is permissible. Intermittent nonelectric internal energy consumption and electrical auxiliary loads, such as prorating or proportioning, shall be accounted for in an equitable manner and applied to the power consumption of a complete equipment operating cycle over the test period. Examples of intermittent loads include blowdown, water treatment, and heat tracing.

3-5.2.6 Proximity to Design Conditions. During the STPT, the CSP system should be operated as closely as possible to the reference performance conditions and within the allowable design range of the operating parameters and equipment. Permitted deviations from reference performance conditions shall be agreed upon between the parties.

3-5.3 Adjustments Prior to and During Tests

This subsection describes the following three types of adjustments related to the test:

(a) permissible adjustments during stabilization periods or between test runs

(b) permissible adjustments during test runs

(c) impermissible adjustments

3-5.3.1 Permissible Adjustments During Stabilization Periods or Between Test Runs. Any necessary adjustments should be made to the equipment, operating conditions, or both. Sufficient stable operating time shall be allowed to stabilize the system. For example, if field balancing valve positions are altered, sufficient stable operating time shall be allowed to stabilize the loop temperature profile and flow distribution.

Typical adjustments prior to a test are those required to correct malfunctioning controls or instrumentation or to optimize plant performance for current operating conditions. Recalibration of suspected instrumentation or measurement loops is permissible if recalibration is possible without data loss or with redundant or replacement equipment. It is permissible to tune and optimize component or plant performance. Adjustments to avoid or minimize performance corrections are permissible.

3-5.3.2 Permissible Adjustments During Test Runs. Permissible adjustments during capacity tests are those required to correct malfunctioning controls, maintain equipment in safe operation, or maintain plant stability. Switching from automatic to manual control and adjusting operating limits or set points of instruments or equipment should be avoided during a test.

3-5.3.3 Impermissible Adjustments. Any adjustments that would result in equipment being operated beyond the manufacturer's operating, design, or safety limits or other specified operating limits are not permitted. Adjustments or recalibrations that would adversely affect the stability of a primary measurement during a test are also not permitted.

3-5.4 Duration of Runs, Number of Test Runs, and Number of Readings

3-5.4.1 Duration of Test Runs. The duration of a test run shall be long enough that the data reflect the average efficiency and performance of the plant. The duration of a test run includes consideration for deviations in the measurable parameters due to controls and typical concentrating solar system operating characteristics. The recommended test durations are provided in para. 3-2.1.

The test coordinator may determine if a longer test period is required. The recommended times shown in para. 3-2.1 are generally based on continuous data acquisition. Depending on the personnel available and the method of data acquisition, it may be necessary to increase the length of a test in order to obtain sufficient samples of the measured parameters to attain the required test uncertainty.

3-5.4.2 Number of Test Runs. Multiple runs are not required, but they offer several advantages. Conducting more than one run will

(a) provide a valid method of rejecting bad test runs.
(b) examine the validity of the results.
(c) verify the repeatability of the results. Results may not be repeatable due to variations in either test methodology (test variations) or the actual performance of the equipment being tested (process variations).

After completion of the first test run that meets the criteria for an acceptable test run (which may be the preliminary test run), the data should be consolidated, and preliminary results calculated and examined, to ensure that the results are reasonable.

3-5.4.3 Evaluation of Test Runs. When comparing results from two test runs (X_1 and X_2) and their uncertainty intervals, the three cases illustrated in Figure 3-5.4.3-1 should be considered.

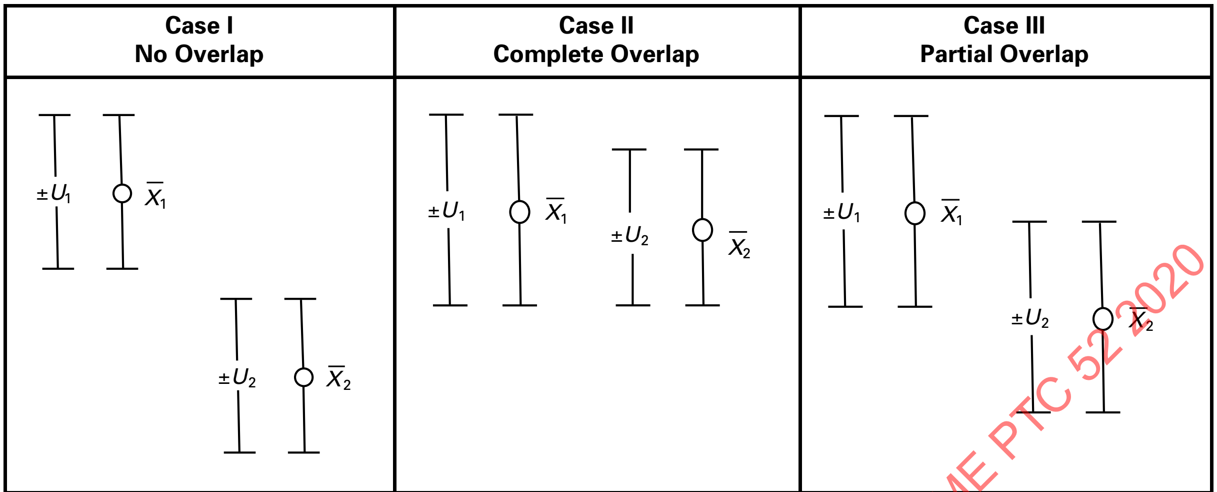
(a) *Case I.* A problem clearly exists when there is no overlap between uncertainty intervals. Either uncertainty intervals have been grossly underestimated, an error exists in the measurements, or the true value is not constant. Investigation to identify bad readings, overlooked or underestimated systematic uncertainty, etc., is necessary to resolve this discrepancy.

(b) *Case II.* When the uncertainty intervals completely overlap, as in this case, one can be confident that there has been a proper accounting of all major uncertainty components. The smaller uncertainty interval, $X_2 \pm U_2$, is wholly contained in the larger interval, $X_1 \pm U_1$.

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

Should a run or set of runs fall under Case I or Case III, the results from all of the runs should be reviewed in an attempt to explain the reason for excessive variation. If the reason for the variation cannot be determined, then either the uncertainty band needs to be increased to encompass the runs to make them repeatable, or more runs need to be conducted so that the random component of uncertainty may be calculated directly from the test results. The uncertainty of result is calculated in accordance with Section 7. Paragraphs 3-5.4.2 and 3-5.4.3 are not applicable to the MDPT.

Figure 3-5.4.3-1 Three Post-Test Cases



3-5.4.4 Number of Readings. Sufficient readings shall be taken within the test duration to yield total uncertainty. Ideally, at least one set of data per minute should be recorded for all nonintegrated measurements of primary parameters and variables. There are no specific requirements for the number of integrated readings or for measurements of secondary parameters and variables for each test run.

3-6 CALCULATION AND REPORTING OF RESULTS

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

Each Code test shall include pretest and post-test uncertainty analyses, and the results of these analyses shall fall within Code requirements for the type of concentrating solar system being tested.

3-6.1 Causes for Rejection of Readings

Upon completion of the test or during the test itself, the test data shall be reviewed to determine if data from certain time periods should be rejected prior to the calculation of test results. Refer to ASME PTC 19.1 for data rejection criteria. A test log shall be kept.

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.

An outlier analysis of spurious data should also be performed in accordance with ASME PTC 19.1 on all primary measurements after the test has ended. This analysis will highlight any other time periods that should be rejected prior to calculating the test results.

3-6.2 Uncertainty

3-6.2.1 General. Test uncertainty and test tolerance are not interchangeable terms. This Code does not address test tolerance, which is a contractual term.

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

This Code addresses test uncertainty in the following three Sections:

(a) Section 1 defines the uncertainty approach.

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

(c) Section 7 and Nonmandatory Appendix B provide applicable guidance for determining pretest and post-test uncertainty analysis results.

3-6.2.2 Pretest and Post-Test Uncertainty Analyses

(a) A pretest uncertainty analysis shall be performed so that the test can be designed to meet Code requirements. Estimates of systematic and random error for each of the proposed test measurements should be used to help determine where measurements should be made and the number and quality of test instruments required for compliance with Code or contract specifications. The pretest uncertainty analysis shall include an analysis of random uncertainties to establish permissible fluctuations of key parameters in order to attain allowable uncertainties. Pretest uncertainty analysis should be used to determine the accuracy level required for each measurement to maintain overall Code standards for the test.

(b) A post-test uncertainty analysis shall also be performed as part of a Code test. The post-test uncertainty analysis will reveal the actual quality of the test to determine whether the pretest uncertainty calculation has been realized.

3-6.3 Data Distribution and Test Report

Copies of all data will be distributed by the test coordinator to those requiring it at the conclusion of the test. A test report shall be written in accordance with Section 6 and distributed by the test coordinator to all parties to the test. A preliminary report incorporating calculations and results may be required before the final test report is submitted.

Section 4
Instruments and Methods of Measurement

4-1 GENERAL REQUIREMENTS

4-1.1 Introduction

This Section presents the mandatory provisions for instrumentation utilized in the implementation of an ASME PTC 52 test. Per the philosophy of ASME Performance Test Codes (ASME PTC 1) and subsection 1-3 herein, it does so in consideration of the minimum reasonably achievable uncertainty. The Instruments and Apparatus Supplements to ASME Performance Test Codes (ASME PTC 19 series) outline the details concerning instrumentation and the governing requirements of instrumentation for all ASME Code performance testing. The user of this Code shall be intimately familiar with ASME PTC 19.1, 19.2, 19.3, 19.5, and 19.22 as applicable to the instrumentation specified and explained in this Section. In light of the unique requirements of testing solar thermal power plants, the user of this Code should be familiar with other ASME publications regarding standards of instrumentation and metering equipment that are not covered in the ASME PTC 19 series.

This Section refers to but does not repeat portions of those supplements that directly apply to the requirements of this Code. However, this Section contains details of the instrumentation requirements of this Code that are not specifically addressed in the referenced supplements. Such details include classification of measurements for the purpose of instrumentation selection and maintenance, calibration and verification requirements, electrical metering, and other information specific to an ASME PTC 52 test.

Where reference to the ASME PTC 19 series is made, if the instrumentation requirements in the series become more rigorous as they are updated due to advances in the state of the art, ASME PTC 19 requirements will supersede those set forth in this Code.

4-1.2 Criteria for Selection of Instrumentation

4-1.2.1 Measurement Designation. Measurements may be designated as either a parameter or a variable. The terms "parameter" and "variable" are sometimes used interchangeably in the industry, and in some other ASME Codes. This Code distinguishes between the two.

A parameter is a direct measurement of a physical quantity at a specific location. The parameter is determined by the measurement from a single instrument or the average of measurements from several similar instruments. In the latter case, several instruments may be used to determine a parameter that has potential to display spatial gradient qualities (e.g., ambient air temperature). Similarly, multiple instruments may be used to determine a parameter simply for redundancy to reduce test uncertainty. For example, a test may include two temperature measurements of the fluid in a pipe in the same plane where the temperature gradient is expected to be insignificant. Typical parameters measured in an ASME PTC 52 test are temperature, pressure, and DNI.

A variable is an indirect measurement whose value is determined from an algebraic equation using directly measured parameters. The performance equations in Section 5 contain the variables used to calculate the performance results, including heat transfer fluid (HTF) mass flow rate and HTF enthalpy. Each variable can be thought of as an intermediate result needed to determine the performance result.

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

4-1.2.2 Measurement Classification. Parameters and variables are classified as primary or secondary depending on their usage in the execution of this Code. Parameters and variables used in the calculation of test results are considered primary parameters and primary variables. Alternatively, secondary parameters and secondary variables do not enter into the calculation of the results but are used to ensure that the required test conditions are not violated.

At a general level, it is more desirable to achieve high measurement accuracy for primary parameters than secondary parameters, because primary parameters and variables are used to calculate test results. However, the nature of the different parameters to be measured, both primary and secondary, prohibits using an arbitrary measurement accuracy that must be met for primary parameters and can be relaxed for secondary parameters. Measurements required for solar thermal testing range from primary parameters that are impractical to measure with high accuracy to secondary parameters that can easily be measured with high accuracy.

In parallel, the sensitivity of the measured parameter to the overall result must be considered. Key measurements such as DNI and HTF flow have very high sensitivities, while ambient temperature and relative humidity have low sensitivities. This Code takes into account sensitivities when recommending instrumentation and accuracy class for the different measured parameters.

The instrumentation employed to measure a parameter will have different required type, accuracy, redundancy, and handling depending on the use of the measured parameter and depending on how the measured parameter affects the performance result. This Code does not require that high-accuracy instrumentation be used to determine secondary parameters. The instruments that measure secondary parameters may be permanently installed plant instrumentation. This Code does require verification of instrumentation output prior to the test period. Instrumentation output can be verified by calibration or by comparison against two or more independent measurements of the parameters referenced to the same location. The instruments should have redundant or other independent instruments that can verify the integrity during the test period.

This Code makes requirements for instrumentation based on the general types of tests that the Code can be used for. For any specific test situation, the user of the Code may find that overall test measurement uncertainty can be reduced by applying a more stringent criteria for accuracy on a specific measurement than is required in this Code. In such cases the user may choose to use a more accurate instrument or more robust calibration in order to reduce uncertainty. This shows the value of the pretest uncertainty analysis.

4-1.2.3 Test Boundary Implications on Selection of Instrumentation. The boundary of an ASME PTC 52 test is to determine the thermal energy generated from solar thermal systems. For some types of applications, that thermal energy transfer is from an HTF (such as heat transfer oil or molten salt that is necessary for the system to operate) to a working fluid (such as water or steam) system across a set of heat exchangers. Measuring primary parameters on the water or steam side of the system has advantages over measuring process parameters on the HTF side of the system. In the former case, the ASME PTC 19 series of standards may be used to reduce overall measurement uncertainty. For example, flows measured in accordance with ASME PTC 19.5 have the advantage of known meter standards and acceptable measurement uncertainty boundaries for PTC applications. Flow measurement for HTF, however, can present significant challenges to achieving accurate, repeatable results. The HTFs themselves may not be conducive to the use of differential pressure-type devices, or the piping may be of such large diameter that use of differential pressure devices is infeasible. It is recognized that there can be a difference in measurement uncertainty between meters that are designed in accordance with ASME PTC 19.5 and meters that, out of necessity, must be of some other type in order to accommodate the requirements of the specific flow application.

The selection of which process streams to measure and where those measurements are located should be consistent with the overall test objective and the location of the test boundary. If the boundary is defined so that it is possible to take measurements on the water or steam side instead of the HTF side, and it is anticipated that measurements on the HTF side will result in higher measurement uncertainty, then it is recommended that measurements be made for water or steam flow. Measurements away from the HTF side may necessarily introduce the need to account for losses across a set of heat exchangers. Nevertheless, depending on the specific conditions, this approach may result in significantly less overall measurement uncertainty. In acceptance test planning and boundary definition at the contract stage, the types of instruments that can be used at different process points and the impact on instrumentation and measurement uncertainty should be considered.

4-1.3 Instrument Calibration and Verification

4-1.3.1 Definition of Calibration. Calibration is the set of operations that establishes, under specified conditions, the relationship between values indicated by a measuring instrument or measuring system and the corresponding reference standard or known values derived from the reference standard. Calibration permits the estimation of errors of indication in the measuring instrument, measuring system, or the assignment of values to marks on arbitrary scales. The result of a calibration is sometimes expressed as a calibration factor, or as a series of calibration factors in the form of a calibration curve. Calibrations shall be performed in a controlled environment to the extent necessary to ensure valid results. Due consideration shall be given to temperature, humidity, lighting, vibration, dust control, cleanliness, electromagnetic interference, and other factors affecting the calibration. Where pertinent, these factors shall be monitored and recorded, and as applicable, compensating corrections shall be applied to calibration results obtained in an environment that departs from acceptable conditions. Calibrations performed in accordance with this Code are categorized as either laboratory or field calibrations.

4-1.3.1.1 Laboratory Calibration. Laboratory calibration, as defined by this Code, is the process by which calibrations are performed under very controlled conditions with highly specialized measuring and test equipment that has been calibrated by approved sources and remains traceable to United States National Institute of Standards and Technology (NIST), a recognized international standard organization, or a recognized natural, physical (intrinsic) constant through unbroken comparisons having defined uncertainties. Laboratory calibrations shall be performed in strict compliance with established policy, requirements, and objectives of a laboratory's quality-assurance program. Consideration shall be given to ensuring proper space, lighting, and environmental conditions such as temperature, humidity, ventilation and low noise and vibration levels. Laboratory calibration applications shall be employed on instrumentation where the sensitivity coefficient of the corresponding parameter is greater than 0.2, except for on devices that can meet the uncertainty limits set forth in this Code without laboratory calibration.

4-1.3.1.2 Field Calibration. Field calibration, as defined by this Code, is the process by which calibrations are performed under conditions that are less controlled than the laboratory calibrations. Field calibration uses less rigorous measurement and test equipment than provided under a laboratory calibration. In field calibration, adequate measures shall be taken to ensure that the necessary calibration status is maintained during transportation to the location of a test and while on-site. The response of the reference standards to environmental changes or other relevant parameters shall be known and documented. Field calibration measurement and test equipment requires calibration by approved sources that remain traceable to NIST, a recognized international standard organization, or a recognized natural, physical (intrinsic) constant through unbroken comparisons having defined uncertainties. Field calibrations' achievable uncertainties can normally be expected to be larger than laboratory calibrations' due to aspects such as the environment at the place of calibration and other possible adverse effects such as those caused by the transportation of the calibration equipment. Field calibration applications are commonly used on instrumentation measuring secondary parameters that are identified as out of tolerance during field verification as described in para. 4-1.3.2. Field calibrations should include loop calibrations as defined in para. 4-1.3.8. Field calibrations should be used to check any instrumentation that is suspected to have drifted or that does not have redundancy.

4-1.3.2 Definition of Verification. Verification is a set of operations which establishes evidence by calibration or inspection that specified plant requirements have been met. It provides a way to check that the deviations between values indicated by a measuring instrument and corresponding known values are consistently smaller than the limits of the permissible error defined in a standard, regulation, or specification particular to the management of the measuring device. The result of the verification leads to a decision to restore to service, perform adjustments to, repair, downgrade, or declare obsolete the instrumentation being verified.

Verification techniques include field calibrations, nondestructive inspections, intercomparison of redundant instruments, check of transmitter zeros, and energy stream accounting practices. Nondestructive inspections include, but are not limited to, atmospheric pressure observations on absolute pressure transmitters, field checks including visual inspection, and no-load readings on power meters. Intercomparisons include, but are not limited to, water or electronic bath checks on temperature-measurement devices and reconciliations on redundant instruments. Energy stream accounting practices include, but are not limited to, mass, heat, and energy balance computations. The applicable field verification requirements shall be judged based on the unique requirements of each setup. As appropriate, manufacturer's recommendations and the Instruments and Apparatus Supplements to ASME Performance Test Codes should be referenced for further field verification techniques.

4-1.3.3 Reference Standards. Reference standards include all measuring and test equipment and reference materials that have a direct bearing on the traceability and accuracy of calibrations. Reference standards shall be routinely calibrated in a manner that provides traceability to NIST, a recognized international standard organization, or defined, natural, physical (intrinsic) constants, and they shall have accuracy, stability, range, and resolution for the intended use. They shall be maintained for proper calibration, handling, and usage in strict compliance with a calibration laboratory quality program. When it is necessary to use reference standards for field calibrations, adequate measures shall be taken to ensure that the necessary calibration status is maintained during transportation to the location of a test and while on-site. The integrity of reference standards shall be verified by proficiency testing or interlaboratory comparisons. All reference standards should be calibrated at a frequency specified by the manufacturer. The user may extend the manufacturer-specified calibration period provided the user has data to support the extension. Supporting data are historical calibration data that demonstrate a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The collective uncertainty of reference standards shall be known, and the reference standards should be selected so that the collective uncertainty of the standards used in the calibration contributes less than 25% to the overall calibration uncertainty. The overall calibration uncertainty of the calibrated instrument shall be determined at a 95% confidence level. A reference standard with a lower uncertainty may be employed if the uncertainty of the reference standard combined with the random uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument. For example, the 25% rule cannot be met for some kinds of flow metering. However, curve fitting from calibration is achievable from a 20-point calibration in a lab with an uncertainty of approximately 0.2%.

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

4-1.3.4 Environmental Conditions. Instruments used to measure primary parameters should be calibrated in a manner that replicates the conditions under which the instruments will be used to make the test measurements. As it is often not practical or possible to perform calibrations under replicated environmental conditions, additional elemental error sources shall be identified and estimated. Error source considerations shall be given to all process and ambient conditions that may affect the measurement system, including temperature, pressure, humidity, electromagnetic interference, radiation, etc. Since some types of ASME PTC 52 tests may have a duration of weeks or months, the potential range of ambient conditions is large and should be accounted for in the estimated error.

4-1.3.5 Instrument Ranges and Calibration Points. The number of calibration points depends on the classification of the parameter the instrument will measure. The classifications are discussed in para. 4-1.2.2. The calibration should have points that bracket the expected measurement range. In some cases of flow measurement, it may be necessary to extrapolate a calibration.

4-1.3.5.1 Primary Parameters

(a) High-Sensitivity Instruments. The instruments for measuring those primary parameters and variables with the highest sensitivity to the test results (e.g., DNI, steam and HTF flow, enthalpy) should be laboratory calibrated at a minimum of two points more than the order of the calibration curve fit. This should be the case whether it is necessary to apply the calibration data to the measured data, or if the instrument is of the quality that the deviation between the laboratory calibration and the instrument reading is negligible in terms of affecting the test result. Flow metering that requires calibration should have a 20-point calibration.

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

Some instruments cannot practically be calibrated over the instrument's entire operating range. For example, flow measuring devices are often calibrated at flows lower than the maximum operating range, and the calibration data are extrapolated. This extrapolation is described in subsection 4-5. In addition, because of the wide variation in HTF flow that is expected over multiday performance tests, flow rates may also be at or below the low end of the calibration range and will require extrapolation in that direction.

If a device demonstrates that it meets the uncertainty requirements set forth in this Code without being calibrated, the device is not required by this Code to be calibrated.

(b) All Other Instruments. All other instruments should be calibrated at a minimum of the number of points equal to the order of the calibration curve fit. If the instrument can be shown to typically have a hysteresis of less than the required accuracy, the measuring point need only be approached from one direction (either increasing or decreasing to the point).

4-1.3.5.2 Secondary Parameters. The instruments measuring secondary parameters should undergo field verifications as described in para. 4-1.3.2, and if calibrated, need only be calibrated at one point in the expected operating range.

4-1.3.6 Timing of Calibration. Because of the variance in different types of instrumentation and their care, no mandate is made regarding the time interval between the initial laboratory calibration and the test period. Treatment of the device is much more important than the elapsed time since calibration. An instrument may be calibrated one day and mishandled the next. Conversely, an instrument may be calibrated and placed on a shelf in a controlled environment, and the calibration may remain valid for an extended time period. Similarly, the instrument may be installed in the field but valved-out of service, and it may, in many cases, be exposed to significant cycling. In these cases, the instrumentation is subject to vibration or other damage, and should undergo a field verification.

All test instrumentation for measurement of those primary parameters and variables with the highest sensitivity to the test results (e.g., DNI, steam and HTF flow, enthalpy) shall be laboratory calibrated prior to the test and shall meet specific manufacturing, installation, and operating requirements, as specified in the ASME PTC 19 series supplements, to the extent these supplements are applicable. There is no mandate regarding quantity of time between the laboratory calibration and the test period. Test instrumentation used to measure all other primary parameters and secondary parameters does not require laboratory calibration other than that performed in the factory for certification, but it does require field verification prior to the test.

Following a test, it is required to conduct field verifications on instruments measuring parameters where there is no redundancy or for which data are questionable. For the purposes of redundancy, plant instrumentation may be used in the field verification. If results indicate unacceptable drift or damage, then further investigation is required. Flow element devices meeting the requirements set forth by this Code to measure primary parameters and variables need not undergo inspection following the test if the devices have not experienced conditions that would violate their integrity. Such conditions include steam blows and chemical cleaning.

In all instances, the manufacturer's recommendations for timing of calibration should be followed.

4.1.3.7 Calibration Drift. Calibration drift is defined as a shift in the calibration characteristics. When field verification indicates the drift is less than the instrument accuracy, the drift is considered acceptable and the pretest calibration is used as the basis for determining the test results. Occasionally, the instrument calibration drift is unacceptable. Should the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable.

Calibration drift can result from instrument malfunction, transportation, installation, or removal of the test instrumentation. When a field verification indicates drift that does not meet the uncertainty requirements of the test, further investigation is required.

A post-test laboratory calibration may be required, and engineering judgment shall be used to determine whether the initial or recalibration is correct. This is done by evaluating the field verifications. The following are some recommended field verification practices that lead to the application of good engineering judgment:

(a) When instrumentation is transported to the test site between the calibration and the test period, a single-point check prior to and following the test period can isolate when the drift may have occurred. Examples of this check would be verifying the zero-pressure point on the vented pressure transmitters, the zero-load point on the wattmeters, or the ice point on the temperature instrument.

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

4-1.3.8 Loop Calibration. All analog instruments used to measure primary parameters should be loop calibrated. Loop calibration involves calibrating the instrument through the signal-conditioning equipment. This may be accomplished by calibrating instrumentation using the test signal-conditioning equipment either in a laboratory or on-site during test setup before the instrument is connected to process. Alternatively, the signal-conditioning device may be calibrated separately from the instrument by applying a known signal to each channel using a precision signal generator.

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

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

4-1.3.9 Quality Assurance Program. Each calibration laboratory shall have a quality assurance program in place. This program is a method of documentation that includes the following information:

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

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

The parties to the test should be allowed access to the calibration facility for auditing. The quality assurance program should also be made available during such a visit.

4-1.4 Plant Instrumentation

Permanent plant instrumentation is recommended for measuring primary and secondary parameters and variables. It is acceptable to use plant instrumentation for primary parameters and primary variables. However, any plant instruments that are used shall follow the calibration standards in this Section and be demonstrated to have individual uncertainties (including signal-conditioning equipment) that support the overall test uncertainty requirements.

In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from metering device) shall be made available.

4-1.5 Redundant Instrumentation

Redundant instruments are two or more devices measuring the same parameter with respect to the same location. Where experience in the use of a particular model or type of instrument dictates that calibration drift can be unacceptable, and no other device is available, redundancy is recommended. Redundant instruments should be used to measure all primary parameters. Exceptions are redundant flow elements and redundant electrical metering devices, because they would result in a large increase in costs.

Other independent instruments in separate locations can also monitor instrument integrity. A sample case would be a constant enthalpy process where pressure and temperature in a steam or HTF line at one point verify the pressure and temperature of another location in the line by comparing enthalpies.

4-2 SOLAR DIRECT NORMAL IRRADIANCE MEASUREMENT

4-2.1 Introduction

This subsection presents requirements and guidance regarding measurement of direct normal irradiance (DNI) for purposes of determining the solar energy crossing the test boundary as input to the solar thermal cycle. This measurement is analogous in its significance to the measurement of fuel input in traditional thermal cycles, as it measures the primary source of energy entering the test boundary for purposes of producing usable work, energy, or both. Therefore, DNI measurement is a key measurement in a solar thermal performance test. However, measurement of DNI presents unique challenges. The selection of instruments for measuring DNI, the number of instruments, the location of instruments in the covered test area, and the maintenance of instruments prior to and during the test period are all critical to support overall test objectives.

The measurement of DNI should consider and balance the following:

(a) overall uncertainty of DNI measurement for the area of the solar field being defined as the test boundary in order to meet the objectives of this Code

(b) the number of instruments that must be used, and the location of these instruments, to obtain a satisfactory set of measurements that are considered representative of the entire area

(c) the purchase or rental cost of DNI instrumentation as well as the cost of their calibration

(d) the required maintenance of instruments that is necessary to obtain high-quality readings

For a given performance test application for initial acceptance of a facility, it is possible that instrumentation for DNI measurement has been in place for a period of months or years prior to the time that the test is conducted. These initial or historical types of measurements are typically to support development activities to evaluate and/or confirm the quality of the solar resource in a given location prior to major capital investment in the project. This instrumentation, provided it meets the accuracy requirement, can also be used for ASME PTC 52 testing.

Similarly, DNI measurement will be part of normal, long-term operations of the facility. This regular use is in parallel to DNI measurement for purposes of conducting solar thermal performance tests, either short term or long term, as part of the acceptance of a facility. Thus, instrumentation for DNI measurement that is part of long-term operations plans can be used for initial performance testing, provided the uncertainty requirements are met.

4-2.2 Uncertainty

In discussing the uncertainty of the DNI instrumentation, care must be taken regarding how the uncertainty is defined. Since measurement of DNI and the instruments involved are complex, there are more sources of error in the overall measurement than is typical for most other types of measurements. All of these individual sources of error affect the overall DNI measurement uncertainty.

For ASME PTC 52 testing, the maximum total uncertainty for each DNI instrument in regular service (i.e., with frequent readings) is ±2.5%. This value includes the uncertainty of the raw reading itself plus the contributing uncertainty of the optical alignment (tracking error), cleanliness, temperature, data logging, and any other sources of error.

Table 4-2.3-1 Contributing Factors to Overall DNI Measurement Uncertainty

Type A Error Source	U_{std} TP [Note (1)]	U_{std} Si [Note (2)]	Type B Error Source	U_{std} TP [Note (1)]	U_{std} Si [Note (2)]
Fossilized calibration error	0.615	0.615	Fossilized calibration error	0.665	0.665
Data logger precision (±50 μV/10 mV) [Note (3)]	0.5	0.5	Data logger precision (1.7 μV/10 mV) [Note (3)]	0.02	0.02
Si detector cosine response	0	0.5	Si detector cosine response	0	1.5
Pyrheliometer detector temperature response [20°C (68°F)]	0.25	0.05	Detector temperature response	0.25	0.05
Pyrheliometer detector Linearity	0.10	0.10	Day-to-day temperature bias [10°C (50°F)]	0.125	0.10
Solar alignment variations (tracker or shade band) and pyranometer level for Si	0.2	0.1	Solar alignment variations (tracker or shade band) and pyranometer level for Si	0.125	0.10
Pyrheliometer window spectral transmittance	0.1	1.0	Pyrheliometer window spectral transmittance	0.5	1.0
Optical cleanliness (blockage)	0.2	0.1	Optical cleanliness (blockage)	0.25	0.1
Electromagnetic interference and electromagnetic field	0.005	0.005	Electromagnetic interference and electromagnetic field	0.005	0.005
TOTAL Type A [Note (4)]	**0.889**	**1.382**	**TOTAL Type B [Note (4)]**	**0.934**	**1.938**

GENERAL NOTE: This table is adapted from Table 5-4 of NREL/SR-5500-57272, which in turn is adapted from Table 3-7 of NREL/TP-550-47465. As noted in NREL/SR-5500-57272, the combined uncertainty of DNI measurements can be determined from the standard uncertainties in the errors illustrated in this table for each detector type by summing in quadrature. The resulting standard uncertainty is 1.3% for a pyrheliometer option and 2.4% for an RSR option. The expanded uncertainty, representing a 95% confidence interval as described in Section 6, is 2.6% for the pyrheliometer and 4.8% for the RSR.

NOTES:
(1) A thermopile detector (TP) is used for a pyrheliometer.
(2) A silicon (Si) diode pyranometer detector is used for an RSR.
(3) A typical manufacturer-specified accuracy is ±0.05% of full-scale range (typically 50 mV) −25°C to 50°C (−13°F to 122°F); assume a 10-mV signal to ±50 μV (0.5%) with 1.67-μV resolution (0.02%).
(4) This is summed under quadrature.

Cleanliness and alignment are critical, and care should be taken to ensure DNI instrumentation is deployed and used properly.

4-2.3 Acceptable Instrumentation

This Code does not dictate a specific type of instrument that must be used for solar energy measurement. Rather, the Code is intended to set overall criteria for DNI measurement uncertainty that must be met. However, at the current time, only one type of instrument can meet this uncertainty requirement. This Code leaves open the possibility for future developments in DNI instrumentation that also meet the uncertainty requirement.

The two types of instrument commonly used for DNI measurement are the 2-axis tracking pyrheliometer and the rotating shadowband radiometer (RSR). The pyrheliometer makes a direct reading of DNI and has a significantly better measurement uncertainty than the RSR. The RSR makes an indirect reading of DNI and also has higher uncertainty in measurement, though it requires less maintenance during operation.

Where pyrheliometers are used, their receiving surfaces shall be aimed directly at the sun with measurement made through a small precision aperture in order to take a reading of DNI. The half angle of the aperture shall be about 2.5 deg, for a total field of view of 5 deg. The pyrheliometer shall be designed for continuous measurement and data collection. The construction of the pyrheliometer mounting shall allow for the rapid and smooth adjustment of the azimuth and elevation angles. Automatic sun-following equipment (sun tracker) is necessary to assure a direct view of the sun. A typical sighting device is a small spot of light or solar image that falls upon a mark in the center of the target when the receiving surface is exactly normal to the direct solar beam. The sighting device shall be able to automatically track and align the instrument.

Instruments used to measure DNI shall be designed for unattended measurement. During use, the pyrheliometer must be well maintained and cleaned on a daily basis, or as determined based on site conditions.

Refer to Table 4-2.3-1 for an indication of the many factors that contribute to overall measurement uncertainty of DNI measurement and a simple comparison of the pyrheliometer and RSR types of instrument.

4-2.4 Number of Instruments and Spatial Considerations

An ASME PTC 52 test shall be conducted with at least three DNI instruments that each meet the required uncertainty. The readings taken from multiple instruments at the same location shall be compared. The difference between these readings shall be within the allowed uncertainty range. Any differences larger than the uncertainty range shall be promptly investigated and addressed in order to maintain the necessary accuracy for multiday performance tests (MDPT).

A minimum of three DNI instruments shall be placed at one or more locations that provide a representative reading of the entire solar field. Chosen locations shall also be deemed to provide a representative reading of the entire solar field for multiday tests. In multiday tests, the short-term impact on DNI due to cloud cover or other temporary shading becomes insignificant given the longer period of testing. For short-term tests where cloud cover of a portion of the field can be significant and would not be identified because of a central location of the DNI instruments, the instruments may be placed in different locations within the solar field. Additional DNI measurements may also be considered at all locations based on the DNI variation of the specific site.

In fields where instruments are separated, data reduction methods should be agreed to by the parties to the test. Inconsistencies between instruments may be due to instrument malfunction or due to actual spatial variation of DNI, and data should be reduced accordingly.

4-3 PRESSURE MEASUREMENT

4-3.1 Introduction

This subsection presents requirements and guidance regarding the measurement of pressure. For additional guidance and requirements, refer to the current version of ASME PTC 19.2.

Due to the state of the art and general practice, it is recommended that electronic pressure measurement equipment be used for primary parameters and primary variables to minimize systematic and random error. Electronic pressure measurement equipment is preferred due to inherent compensation procedures for sensitivity, zero balance, thermal effect on sensitivity, and thermal effect on zero. Other devices that meet the uncertainty requirements of this Section may be used. The accuracy class and total uncertainty of the pressure measurement system shall satisfy the overall test uncertainty calculated in the pretest uncertainty analysis. Test personnel shall consider effects including, but not limited to

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

The piping between the process and secondary elements shall accurately transfer the pressure to obtain accurate measurements. Six possible sources of error are pressure transfer, leaks, friction loss, trapped fluid (e.g., gas in a liquid line, liquid in a gas line), trapped solids (e.g., frozen solids in impulse lines), and density variations between legs.

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

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

Some pressure transmitters have the capability to change their range once they are installed. The transmitters shall be calibrated at each range that will be used during the test period.

Where appropriate for synthetic oil, molten salts, steam, water, and other heat transfer fluids, the readings from all static pressure transmitters and any differential pressure transmitters with taps at different elevations (such as on vertical flow elements) shall be adjusted to account for elevation head in the leg established by the fluid (e.g., water legs). This adjustment shall be applied at the transmitter, in the control system or data acquisition system, or manually by the user after the raw data are collected. Care shall be taken to ensure this adjustment is applied properly, particularly at low static pressures, and that it is only applied once.

4-3.2 Uncertainty

The allowable uncertainty will depend on the type of parameters and variables being measured. Refer to para. 4-1.2.2 for discussion on measurement classification.

Primary parameters and variables shall be determined with 0.10% accuracy class pressure transmitters or equivalent that have an instrument systematic uncertainty of ±0.30% or better of calibrated span.

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

4-3.3 Recommended Pressure Measurement Devices

Pressure transmitters are the recommended pressure measurement devices. There are three types of pressure transmitters due to application considerations.

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

4-3.3.1 Absolute Pressure Measurements. Absolute pressure measurements are pressure measurements that are below or above atmospheric pressure. Absolute pressure transmitters are recommended for these measurements. Absolute pressure measurements in an ASME PTC 52 test may include barometric and vacuum pressure measurements.

The barometric pressure measurements should always be outdoors and away from any direct draft.

4-3.3.2 Gauge Pressure Measurements. Gauge pressure measurements are pressure measurements that are at or above atmospheric pressure. These measurements may be made with gauge pressure transmitters or absolute pressure transmitters. Gauge pressure transmitters are recommended, since they are easier to calibrate and to check in situ. Gauge pressure measurements in an ASME PTC 52 test may include HTF pressure, auxiliary fuel pressure, and thermal storage fluid pressure.

The pressure measurements should be located close to the temperature measurements when they are being used to quantify a fluid energy level.

4-3.3.3 Differential Pressure Measurements. Differential pressure measurements are used to determine the fluid level of a storage tank or the difference between the inlet pressure and the discharge pressure of a primary flow element. Differential pressure transmitters are recommended for these measurements. Differential pressure measurements in an ASME PTC 52 test may include the differential pressure of steam, water, HTF or auxiliary fuel through a flow element, or pressure loss in a pipe or duct. The differential pressure transmitter measures this pressure difference or pressure drop, which is used to calculate the fluid flow.

4-3.4 Pressure Instrumentation Installation

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

(a) Keep the impulse tubing as short as possible for the conditions of the process fluid.

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

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

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

(e) Use impulse tubing large enough to avoid friction effects and prevent blockage (see Table 4-3.4-1).

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

(g) When using a sealing fluid for differential pressure transmitters, fill both impulse legs to the same level.

Table 4-3.4-1 Impulse Line Diameters

Transmitter Fluid Type	Impulse Line Length	
	0–16 m	16–45 m
Water/steam and dry air/gas	7–9 mm	10 mm
Wet air/wet gas	13 mm	13 mm
Oils with low to medium viscosity	13 mm	19 mm
Very dirty fluids	25 mm	25 mm

GENERAL NOTE:

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

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

For high temperature HTF applications, care should be taken when connecting the sensing lines to the transmitters. Damage could occur to the transmitter or, in the case of molten salts, the HTF could harden which would affect the data acquisition. In such cases, the use of an intermediate impulse sensing line or diaphragm may be necessary. In the case of molten salt application, the molten salt typically freezes at 240°C (465°F) (freezing point may vary based on project-specific molten salt composition). Therefore, it is recommended to heat trace the impulse tubing for the pressure measurement to avoid freezing the molten salt. Minor temperature variations in the impulse tubing caused by heat tracing can introduce small changes of density, which introduce error in the pressure measurement. The magnitude of error is relatively low in cases of absolute or gauge pressure measurement. However, the magnitude of error is significantly amplified in the case of differential pressure measurement.

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

Differential pressure transmitters should be installed using a five-way manifold (see Figure 4-3.4-1). This manifold is recommended rather than a three-way manifold, because the five-way manifold mitigates the possibility of leakage past the equalizing valve. The vent valve acts as a telltale for leakage detection past the equalizing valves.

When a differential pressure meter is installed on a flow element that is located in a vertical line, the measurement shall be corrected for the difference in sensing line height and fluid head change. The exception to this rule is if the upper sensing line is installed against a steam or water line inside the insulation down to where the lower sensing line protrudes from the insulation. The correction for the noninsulated case is shown in Figure 4-3.4-2.

4-4 TEMPERATURE MEASUREMENT

4-4.1 Introduction

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

Figure 4-3.4-1 Five-Way Manifold

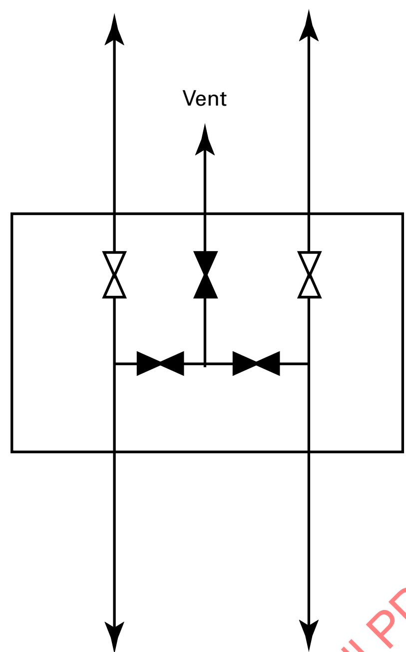
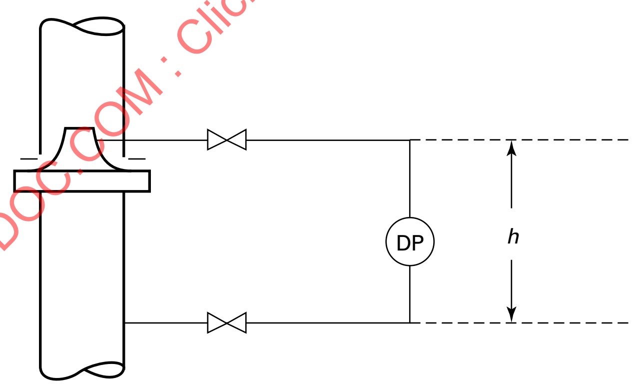


Figure 4-3.4-2 Water Leg Correction for Flow Measurement



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

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

4-4.2 Uncertainty

The allowable uncertainty will depend on the type of parameters and variables being measured. Refer to para. 4-1.2.2 for discussion on measurement classification.

(a) Temperature measurement of primary parameters made on the primary HTF and water or steam systems shall be determined with temperature measurement devices that have an instrument systematic uncertainty of no more than ±0.20°C (±0.36°F) for temperatures less than 93°C (200°F) and no more than ±0.50°C (±0.9°F) for temperatures more than 93°C (200°F).

(b) All other primary parameters and variables, as well as secondary parameters and variables, should be determined with temperature measurement devices that have an instrument systematic uncertainty of no more than ±2.0°C (±3.6°F).

The uncertainty limits in (a) and (b) are exclusive of any temperature spatial gradient uncertainty effects, which are considered to be systematic.

4-4.3 Location and Redundancy

The location at which the primary temperature measurements are taken for use in determining enthalpy shall be as close as possible to the points at which the corresponding pressures are to be measured. Thermowells should be installed downstream of pressure taps, or, if upstream, they should not be in the same longitudinal plane as the pressure traps. Thermowells shall be installed within four pipe diameters of each other and may be in line, axially, if installed at least two pipe diameters apart. If installed within two pipe diameters, the thermowells shall be at least 45 deg apart measured circumferentially.

Redundant instruments are two or more devices measuring the same parameter with respect to the same location. Redundant measurements are required for primary parameters made on primary HTF and working fluid systems.

The mean of the redundant readings shall be considered the measurement of the fluid. Discrepancies between the readings must be resolved if they exceed 0.56°C (1°F). Temperature differences caused by flow stratification shall be minimized by locating the temperature sensor sufficiently downstream of an elbow to allow mixing of the stratified flow before the measurement point.

4-4.4 Recommended Temperature Measurement Devices

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

4-4.4.1 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 93°C (200°F). The maximum temperature is dependent on the type of thermocouple and the sheath material used.

Thermocouples should not be used for measurements below 93°C (200°F). Measurement errors associated with thermocouples typically derive from the following sources:

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

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

Thermocouples are susceptible to drift after cycling. Cycling is the act of exposing the thermocouple to process temperature and removing it to ambient conditions. Where possible, the number of times a thermocouple is cycled should be kept to a minimum. Since multiday performance tests will result in daily temperature cycling, thermocouples used as primary instruments should be monitored for drift during an MDPT and recalibrated as appropriate.

Thermocouples used to measure primary parameters shall have continuous leads from the measuring junction to the connection on the reference junction. These high-accuracy thermocouples shall have a reference junction at 0°C (32°F) or an ambient reference junction that is well-insulated and calibrated. Alternatively, equipment with cold junction compensation may be used in lieu of an ice bath or insulated reference junction.

Thermocouples used to measure all other temperature parameters can have junctions in the sensing wire. The junction of the two sensing wires shall be maintained at the same temperature. The reference junction may be at ambient temperature provided that the ambient temperature is measured, and the measurement is compensated for changes in the reference junction temperature. Alternatively, equipment with cold junction compensation may be used in lieu of an ice bath or insulated reference junction.

4-4.4.1.1 Reference Junctions. The temperature of the reference junction shall be measured accurately with either software or hardware compensation techniques. The reference junction temperature shall be held at the ice point or at the stable temperature of an isothermal reference. When thermocouple reference junctions are immersed in an ice bath, consisting of a mixture of melting shaved ice and water,[1] the bulb of a precision thermometer shall be immersed at the same level as the reference junctions and in contact with them. Any deviation from the ice point shall be promptly corrected. Each reference junction shall be electrically insulated. When the isothermal-cold junction reference method is used, it shall employ an accurate temperature measurement of the reference sink. When electronically controlled reference junctions are used, they shall have the ability to control the reference temperature to within ±0.03°C (±0.05°F). Particular attention shall be paid to the terminals of any reference junction, since temperature variation, material properties, or the mismatching of wires can introduce errors. The overall reference system shall be verified by calibration to have an uncertainty of less than ±0.1°C (±0.2°F). Isothermal thermocouple reference blocks furnished as part of digital systems may be used in accordance with the Code provided the accuracy is equivalent to the electronic reference junction. Commercial data acquisition systems employ a measured reference junction, and the accuracy of this measurement is incorporated into the manufacturer's specification for the device. The uncertainty of the reference junction shall be included in the uncertainty calculation of the measurement to determine if the measurement meets the standards of this Code.

4-4.4.1.2 Thermocouple Signal Measurement. Many instruments are available to measure the output voltage. The use of each of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter.

4-4.4.2 Resistance Temperature Detectors (RTDs). RTDs should only be used to measure temperatures from −270°C to 850°C (−454°F to 1,562°F). ASTM E1137-97 provides standard specifications for industrial platinum resistance thermometers which include requirements for manufacture, pressure, vibration, and mechanical shock to improve the performance and longevity of these devices.

Measurement errors associated with RTDs are typically derived from the following sources:

(a) self heating
(b) environmental
(c) thermal shunting
(d) thermal EMF
(e) stability
(f) immersion
(g) installation errors
(h) lead wire resistance that is not properly compensated

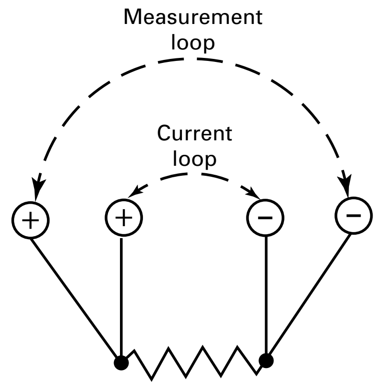
RTDs are considered more linear devices than thermocouples, but RTDs are more susceptible to calibration drift or failure when used in vibrational applications. This means that care should be taken in the specification and application of RTDs with consideration for drift on the devices' stability. Field verification techniques should be used to demonstrate the stability is within the uncertainty requirements of para. 4-3.2.

Class 1 primary parameters shall be measured with a Grade A four-wire platinum RTD as presented in Figure 4-4.4.2-1, illustration (a). The four-wire technique is preferred to minimize effects associated with lead wire resistance caused by dissimilar lead wires. All other parameters may be measured with Grade A three-wire platinum RTDs as presented in Figure 4-4.4.2-1, illustration (b).

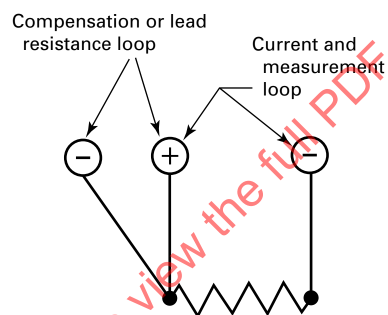
Many devices are available to measure the output resistance. The use of each of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter.

[1] ASTM MNL 12

Figure 4-4.4.2-1 Three- and Four-Wire RTDs



(a) Four-Wire RTD



(b) Three-Wire RTD

4-4.4.3 Temperature Scale. The International Temperature Scale of 1990 (ITS-90) is realized and maintained by NIST to provide a standard scale of temperature for use by science and industry in the United States. This scale was adopted by the International Committee of Weights and Measures at its meeting in September 1989 and it became the official international temperature scale on January 1, 1990. The ITS-90 supersedes the International Practical Temperature Scale of 1968 (IPTS-68), the amended edition of 1975 [IPTS-68 (75)], and the 1976 Provisional 0.5 to 30 K Temperature Scale (EPT-76).

Temperatures on the ITS-90 can be expressed in terms of international kelvins (K), represented by the symbol T_{90}, or in terms of international Celsius (°C), represented by the symbol t_{90}. The relation between T_{90} and t_{90} is

$$t_{90} = T_{90} - 273.15$$

Fahrenheit temperatures, t_f, (°F), are obtained from the conversion formula

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

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

4-4.5 Calibration of Primary Parameter Temperature Measurement Devices

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

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

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

4-4.6 Typical Applications

4-4.6.1 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 to protect the temperature measurement device from harsh environments, high pressure, and flows. The thermowell can be installed into a system by a threaded, socket-weld, or flanged connection and 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 temperature measurement device and the well. The temperature measurement device often 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. Tubes and wells should be as thin as possible, consistent with safe stress and other ASME Code requirements, and the inner diameters of the wells should be clean, dry, and free from corrosion or oxide. The bore should be cleaned with high-pressure air prior to insertion of the device.

The thermowell should be installed so that the tip protrudes through the boundary layer of the fluid to be measured. Unless limited by design considerations, the temperature sensor shall be immersed in the fluid at least 75 mm (3 in.) but not less than one-quarter of the pipe diameter. If the pipe is less than 100 mm (4 in.) in diameter, the temperature sensor shall be arranged axially in the pipe by inserting it in an elbow or tee. If such fittings are not available, the piping should be modified to make this possible. The thermowell should be located in an area where the fluid is well mixed and has minimal 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 and not directly downstream from the other thermowell.

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

For primary parameter measurements, this Code recommends that the portion of the thermowell or lag section protruding outside the pipe or vessel be insulated, along with the measurement device itself, to minimize conduction losses.

4-4.6.2 Temperature Measurement of Ambient Air. The dry bulb air temperature is the static temperature measured at the equipment boundary. The temperature sensor shall be shielded from solar and other sources of radiation and shall have a constant air flow across the sensing element. A minimum of two concentric, cylindrical radiation shields should be employed. The outermost shield should be white while the inner shield should be black. A mechanically aspirated psychrometer 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 7.5 m/s (25 ft/sec), shielding of the sensing element is required.

There can be several ambient temperature measurement points for a solar power plant. The parties to the test may agree that a single reading of ambient air temperature is adequate. Consideration should be given to the logistics associated with instrumenting a large area of a solar plant to avoid long leads before the temperature measurements reach the data acquisition system.

4-5 FLOW MEASUREMENT

4-5.1 Introduction

This subsection presents requirements and guidance regarding the measurement of flow. It also discusses recommended flow measurement devices, calibration of flow measurement devices, and application of flow measurement devices.

The selection of flow measurement instrument types and their associated measurement uncertainties is greatly impacted by the size of the associated piping, the process fluid temperature, and the fluid being measured. As described in para. 4-1.2.3, flow measurement on the water or steam side may be accomplished in accordance with ASME PTC 19.5, whereas flow measurement on the HTF side, by necessity, may require metering of some other type with a larger measurement uncertainty.

The need to accommodate widely varying flow rates during long-term, multiday tests complicates accurate flow measurement. Differential pressure meters have acceptable levels of uncertainty for normal operating range but have limited turndown capabilities and larger uncertainties as flow decreases to levels that may exist during low load operations, which will be seen on a daily basis. Ultrasonic and vortex meters have better turndown characteristics but a higher uncertainty. The selection of flow measurement instrument types must balance these different demands.

Regardless of the type of meter selected, start-up procedures must ensure that spool pieces are provided during conditions that may violate the integrity of the flow measurement device to avoid altering the device's characteristics. Such conditions include steam blows and chemical cleanings. While the flow measurement device is stored, it shall be capped and protected from environmental damage such as moisture and dirt. During operation, it is recommended that a strainer be installed upstream of the flow measurement device to protect the meter from objects and debris.

If the fluid does not remain in a single phase while passing through the flow measurement device, or if it has two phases when entering the meter, then it is beyond the scope of this Code. Water should not flash into steam when passing through the flow measurement device. Steam should remain superheated when passing through the flow measurement device. ASME PTC 12.4 describes methods for measurement of two-phase flow in instances when a lack of other methods makes it necessary to measure the flow rate of a two-phase mixture. However, the high uncertainty of doing so should encourage other measurement locations and methods of flow measurement.

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

Mass flow rate as shown by computer printout or flow computer is not acceptable unless the intermediate results and the data used for the calculations are also reported. In the case of a differential pressure class meter, intermediate results include the discharge coefficient, corrected diameter for thermal expansion, expansion factor, etc. Raw data include static pressure, differential pressure, and temperature. In the case of a mechanical, ultrasonic, or vortex meter, intermediate results include the meter constant(s) used in the calculation and how it is determined from the calibration curve of the meter. Data include frequency, temperature, and pressure. For all types of flow measurement devices, intermediate results used in the calculation of the fluid density are required.

When a flow measurement device is laboratory calibrated, the entire primary device shall be calibrated. This shall include the primary element, upstream and downstream metering runs, and flow conditioners. The entire primary device shall be shipped as one piece, dirt and moisture free, and not disassembled for shipping, installation, inspection, or any other reason in order for the laboratory calibration to remain valid. If a metering run is taken apart at the primary element's flanges, or the primary element is removed for inspection, then the empirical formulations for discharge coefficient and the associated uncertainty should be used for that meter unless a positive, mechanical alignment method is in place to replicate the precise position of the meter run or primary element when it was calibrated.

CSP Plant Special Considerations. The flow rate of molten salt is best measured with noncontact devices. Ultrasonic and radar measurements avoid the possibility of sensor damage from high temperature or fluid freezing/solidification. Flow of molten salt should be measured in a cold temperature zone, but care should be taken to ensure the temperature of the fluid stays above the melting point of the salt.

4-5.2 Uncertainty

There is potential in solar thermal testing for diverse types of instruments to be used for flow measurement, depending on the fluid type, pipe size, and desired level of measurement uncertainty. The maximum allowable uncertainty required by this Code depends on the specifics of the flow measurement. For example, even though the flow rate for HTF is critical to the overall measurement uncertainty of the test, depending on the situation, small uncertainties typical of ASME PTC 19.5 flow measurements simply cannot be achieved.

Table 4-5.2-1 lists typical measurement uncertainties for flow measurement instruments. If a differential-type flowmeter is used for measurement of the HTF in the main circuit, it shall have a laboratory calibration performed unless the device can demonstrate a systematic uncertainty lower than ±0.5% without calibration. All other flowmeters do not require laboratory calibration.

Secondary parameters and variables can be measured with any type of flow measurement device.

4-5.3 Recommended Flow Measurement Devices

Table 4-5.3-1 lists recommended flowmeters for specific applications.

The uncertainty of flow measurement depends on many factors, including

(a) type of instrument used for the measurement
(b) type of fluid
(c) temperature and pressure (hence the density) of the fluid
(d) viscosity of the fluid
(e) flow velocity and Reynolds number (laminar or turbulent)
(f) compressibility of the fluid
(g) size of the pipe
(h) type of flow, e.g., continuous or pulsating

The selection of the flow measurement instrument for the test should follow ASME PTC 19 recommendations for uncertainty for the type of instrument that will be used, to the extent the type of instrument is covered in ASME PTC 19. Table 4-5.2-1 lists uncertainties associated with various types of flow instruments. The information in the table should be used in the selection of the flow measurement instrument. Due to specific flow conditions (size of the pipe, temperature, velocity, etc.), the uncertainty of the flow measurement may be outside the typical value identified in Table 4-5.2-1.

Meter types other than those recommended in Table 4-5.3-1 or whose typical uncertainty levels are outside those listed in Table 4-5.2-1 are acceptable as long as the overall test uncertainty goals are met. Cost, application, and uncertainty should be considered in the selection of a flow measurement device. Since flow measurement technology will change over time, this Code does not limit the use of other flow measurement devices not currently available or not currently reliable. If such devices become available and are shown to be of the required uncertainty and reliability, they may be used.

The different types of devices are discussed in paras. 4-5.3.1 through 4-5.3.2.4.

Table 4-5.2-1 Typical Maximum Measurement Uncertainties for Flow Measurement Instruments

Type of Flow Measurement Instrument	Typical Maximum Measurement Uncertainty, %
Orifice	0.6 to 1.0
Venturi	<0.75 to 1.5
Throat tap nozzle	<0.35 to 0.5
Wall tap nozzle	<0.75 to 1.25
Turbine	0.25 to 1.0
Magnetic	0.5 to 1.0
Ultrasonic	1.0 to 5.0
Coriolis	0.1 to 0.2
Positive displacement	1.0 to 1.5

Table 4-5.3-1 Recommended Flowmeter as a Function of Application

Application		
Type of Flow	Nominal Diameter of Piping	Recommended Flowmeter Type
Water or low-pressure steam	≥8 cm (≥3 in.)	Differential pressure orifice, nozzle, or venturi in accordance with ASME PTC 19.5
Steam or gas	≥10 cm (≥4 in.)	Differential pressure nozzle or venturi in accordance with ASME PTC 19.5
Oil, including HTF oil	<8 cm (<3 in.)	Turbine or positive displacement
HTF oil	≥8 cm and ≤30 cm (≥3 in. and ≤12 in.)	Differential pressure orifice, nozzle, or venturi in accordance with ASME PTC 19.5
	>30 cm (>12 in.)	Ultrasonic flowmeters in accordance with ASME MFC-5.1 or vortex shedding flowmeters in accordance with ASME MFC-6
Molten salt	All diameters	Ultrasonic flowmeters in accordance with ASME MFC-5.1 or vortex shedding flowmeters in accordance with ASME MFC-6

4-5.3.1 Differential Pressure Meters. In this paragraph, the application and calibration requirements for the differential pressure meters (i.e., orifice, nozzle, venturi) are introduced. Where differential pressure–type devices are selected, they should be designed and installed in accordance with ASME PTC 19.5.

All differential pressure meters used in the measurement of an HTF circuit shall be laboratory calibrated. If flow straighteners or other flow conditioning devices are used in the test, they shall be included in the meter piping run when the calibration is performed. Qualified hydraulic laboratories commonly calibrate within an uncertainty of approximately 0.2%. Thus, with inherent curve-fitting inaccuracies, uncertainties of less than 0.3% in the discharge coefficients of laboratory-calibrated meters can be achieved. Differential pressure meters used in the measurement of all other primary parameters and variables may use the empirical formulations for the discharge coefficient for differential pressure class meters if the uncertainty requirements are met and the meter is manufactured, installed, and operated in strict accordance with ASME PTC 19.5.

In order for a differential pressure meter to be used for the HTF main circuit, it shall be manufactured, calibrated, installed, and operated in strict accordance with ASME PTC 19.5, and the flow shall be calculated in accordance with that Code. This includes the documentation on factory measurements of manufacturing requirements per ASME PTC 19.5 and dimensional specifications of the installation, including upstream and downstream disturbances. The start-up procedures shall be examined to validate compliance with the requirements of ASME PTC 19.5.

HTF main circuit flow shall be measured with a minimum of two sets of differential pressure taps, each with independent differential pressure measurement devices. It is recommended that the sets of pressure taps be separated by 90 deg or 180 deg. Additionally, it is recommended for the throat tap nozzle that the meter be manufactured with four sets of differential pressure taps located 90 deg apart and that they be individually measured. Further, the flow calculation should be done separately for each pressure tap pair, and all calculations should then be averaged. Investigation is needed if the results differ from each tap set calculation by more than the flow measurement uncertainty. In cases where the metering run is installed downstream of a bend or tee, it is recommended that the pairs of single taps be installed so that their axes are perpendicular to the plane of the bend or tee.

Differential pressure meters should be assembled, calibrated (if applicable), and left intact for the duration of the test. Once manufactured and calibrated (if applicable), the flowmeter assembly should not be disassembled at the primary element flanges. If it is necessary to disassemble the flowmeter assembly for inspection or any other reason prior to the test, provisions for the accurate realignment and reassembly, such as pins, shall be built into the section to replicate the precise position of the flow element when it was manufactured and calibrated (if applicable), or the empirical formulation shall be used in the calculation of flow. Additionally, gaskets or seal rings (if used) shall be inserted in such a way that they do not protrude at any point inside the pipe (or across the pressure tap or slot when corner tap orifice meters are used).

4-5.3.1.1 Orifice Meters

4-5.3.1.1.1 Application. Orifice meters are recommended for measuring the flow rate of water or low-pressure steam through pipe greater than 8 cm (3 in.) in diameter.

In accordance with ASME PTC 19.5, three types of tap geometries are recommended: flange taps, D and $D/2$ taps (where D = diameter), and corner taps. This Code recommends that only flange taps or corner taps be used with orifice meters that measure for primary variables.

The lip-like upstream side of the orifice plate that extends out of the pipe, called the tag, shall be permanently marked with the following information:

(a) identification as the upstream side
(b) measured bore diameter to five significant digits
(c) measured upstream pipe diameter to five significant digits, if the tag is from the same supplier as the orifice plate
(d) instrument or orifice identifying number

4-5.3.1.1.2 Calibration. Water calibration of an orifice meter does not increase the measurement uncertainty when the meter is used in gas measurements. The uncertainty of the expansion factor of the fundamental flow is the same whether the orifice is water or air calibrated. The procedure for curve fitting, including extrapolation if necessary, and evaluating the curve for the coefficient of discharge shall be conducted in compliance with ASME PTC 19.5.

4-5.3.1.2 Nozzle Meters

4-5.3.1.2.1 Application. Nozzle meters are recommended for measuring the flow rate of water or high-pressure steam through pipes 10 cm (4 in.) in diameter or larger.

The nozzle meters shall be installed in accordance with ASME PTC 19.5, with the three types of ASME primary elements that are recommended therein.

4-5.3.1.2.2 Calibration. At least 20 calibration points should be run over the widest possible range of Reynolds numbers that applies to the performance test. The procedure for determining whether the calibration curve parallels the theoretical curve shall be conducted in accordance with ASME PTC 19.5. The procedure for fitting, including extrapolation if necessary, and evaluating the curve for the coefficient of discharge shall also be conducted in compliance with ASME PTC 19.5.

4-5.3.1.3 Venturi Meters

4-5.3.1.3.1 Application. Venturi meters are recommended for measuring the flow rate of water or high-pressure steam in pipes 10 cm (4 in.) in diameter or larger.

In accordance with ASME PTC 19.5, the ASME (classical Herschel) venturi is the recommended type of primary element. Other venturis may be used if an equivalent level of care is taken in their fabrication and installation and if they are calibrated in a laboratory with the same care and precision as required in ASME PTC 19.5 and herein. The convergent cone of a venturi is effective as a flow conditioner for the throat section. As such, the upstream length requirements for venturi meters are commonly less than those of alternative differential pressure class meters for the same upstream conditions.

4-5.3.1.3.2 Calibration. Calibration shall be in accordance with ASME PTC 19.5, due to similar design considerations.

4-5.3.2 Mechanical Meters. In this subsection, the application and calibration requirements for the use of turbine and positive displacement meters are presented. Turbine meters will be presented first, and positive displacement meters follow. Turbine meters are commonly classified as inference meters, as they measure certain properties of the fluid stream and infer a volumetric flow. Positive displacement meters are commonly classified as direct meters, as they measure volumetric flow directly by continuously separating (isolating) a flow stream into discrete volumetric segments and counting them.

A fundamental difference between differential pressure meters and mechanical meters is the flow equation derivation. For differential pressure meters, flow calculation may be based on fluid flow fundamentals using a first law of thermodynamics derivation where deviations from theoretical expectation may be assumed under the discharge coefficient. Thus, one can manufacture, install, and operate a differential pressure meter of known uncertainty. Conversely, mechanical meter operation is not rooted deeply in the fundamentals of thermodynamics. Mechanical meters have performance characteristics established by design and calibration. Periodic maintenance, testing, and recalibration is required, because the calibration will shift over time due to wear, damage, contamination, or a combination of these factors.

All mechanical meters used in the measurement of primary parameters and variables shall be laboratory calibrated. These calibrations shall be performed on each meter using fluid, operating conditions, and piping arrangements as nearly identical to the test conditions as practical. If flow straighteners or other flow conditioning devices are used in the test, they shall be included in the meter piping run when the calibration is performed.

4-5.3.2.1 Turbine Meters

4-5.3.2.1.1 Application. Turbine meters are recommended for measuring the flow rate of water through pipes less than 8 cm (3 in.) in diameter.

The turbine meter is an indirect volumetric meter. Its main component is an axial turbine wheel that turns freely in the flowing fluid. The turbine wheel is set in rotation by the fluid at a speed which is directly proportional to the average velocity of the fluid in the free cross section of the turbine meter. The speed of the turbine wheel is therefore directly proportional to the volumetric flow rate of the fluid, with the number of revolutions proportional to the volume that has passed through the meter. There are two basic turbine meter designs: electromagnetic and mechanical.

The electromagnetic turbine meter has a rotor and bearings. The rotor velocity is monitored by counting the pulses generated as the rotor passes through a magnetic flux field created by a pickup coil located in the measurement module. A meter factor, or *K* factor, is determined for the meter in a flow calibration laboratory by counting the pulses for a known volume of flow. The meter factor is normally expressed as pulses per actual cubic foot (acf). This *K* factor is unique to the meter and defines the meter's accuracy.

The mechanical style meter uses a mechanical gear train to determine the rotor's relationship to volume. The gear train is commonly comprised of a series of worm gears, drive gears, and intermediate gear assemblies that translates the rotor movement to a mechanical counter. In the mechanical style meter, a proof curve is established in a flow calibration laboratory, and a combination of change gears is installed to shift the proof curve to 100%.

Turbine meter performance is commonly defined by rangeability, linearity, and repeatability. Rangeability is a measure of the stability of the output under a given set of flow conditions. It is defined as the ratio of the maximum meter capacity to the minimum meter capacity for a set of operating conditions, and during which the meter maintains its specified accuracy. Linearity is defined as the total deviation in the meter's indication over a stated flow range and is commonly expressed by meter manufacturers to be within ±0.5% over limited flow ranges. High-accuracy meters have typical linearities of ±0.15% for liquids and ±0.25% for gases, usually specified over a 10:1 dynamic range below maximum rated flow. Repeatability is defined as the ability of the meter to indicate the same reading each time the same conditions exist and is normally expressed as ±0.1% for liquids and ±0.25% for gases. Accuracy shall be expressed as a composite statement of repeatability and linearity over a stated range of flow rates.

Turbine meters are susceptible to over registration due to contaminants, positive swirl, nonuniform velocity profile, and pulsations. In gas flow, contaminants can build on internal meter parts and reduce the flow area which results in higher-velocity fluid, a faster-moving rotor, and a skewed rotor exit angle. The increased velocity and the altered exit angle of the fluid cause the rotor to over register. For all fluids, positive upstream swirl may be caused by a variety of conditions that may include out-of-plane elbows, insufficient flow conditioning, partially blocked upstream filters, or damaged internal straightening vanes. The positive swirl causes the fluid flow to strike the rotor at an accentuated angle, causing the rotor to over register. If there is a distortion of the velocity profile at the rotor inlet introduced by upstream piping configuration, valves, pumps, flange misalignments, or other obstructions, the rotor speed at a given flow will be affected. For a given average flow rate, a nonuniform velocity profile generally results in a higher rotor speed than a uniform velocity profile. In pulsating flow, the fluid velocity increases and decreases, resulting in a cyclical acceleration and deceleration of the rotor causing a net measurement over registration. Dual-rotor turbine meters with self-checking and self-diagnostic capabilities are recommended to aid measurement accuracy and to detect and adjust for mechanical wear, fluid friction, and upstream swirl. Additionally, dual-rotor meters' electronics and flow algorithms detect and make partial adjustments for severe jetting and pulsation. ASME PTC 19.5 should be consulted for guidance on assessing flow disturbances that may affect meter performance and standardized tests.

4-5.3.2.1.2 Calibration. In accordance with ASME PTC 19.5, an individual calibration shall be performed on each turbine meter at conditions as close as possible to the test conditions under which the meter is to operate. This shall include using the fluid, operating conditions (temperature and pressure), and piping arrangements as nearly identical to the test conditions as is practical. Calibration data points shall be taken at flow rates that surround the range of expected test flows. The orientation of the turbine meter influences the nature of the load on the rotor bearings, and thus the performance of the meter at low flow rates. For optimum accuracy, the turbine meter should be installed in the same orientation in which it was calibrated. The turbine meter calibration report shall be examined to confirm the uncertainty as calibrated in the calibration medium.

As the effect of viscosity on the turbine meter calibration *K* factor is unique, turbine meters measuring liquid fuel flow rate shall be calibrated at two kinematic viscosity points surrounding the test fluid viscosity. Each kinematic viscosity point shall have three different calibration temperatures that encompass the liquid fuel temperature expected during the test. It is recommended that a universal viscosity curve be developed to establish the sensitivity of the meter's *K* factor as a function of the ratio of the output frequency to the kinematic viscosity. The universal viscosity curve reflects the combined effects of velocity, density, and absolute viscosity acting on the meter. The latter two effects are combined into a single parameter by using kinematic viscosity.

The result of the turbine meter calibration shall include

(a) the error at the minimum flow and maximum flow and the error at the following flow rates in between: 10% of maximum flow, 25% of maximum flow, 40% of maximum flow, and 70% of maximum flow

(b) the name and location of the calibration laboratory

(c) the method of calibration (bell prover, sonic nozzles, critical flow orifice, master meters, etc.)

(d) the estimated uncertainty of the method, calculated using ASME PTC 19.1

(e) the nature and conditions (pressure, temperature, viscosity, specific gravity) of the test fluid
(f) the position of the meter (horizontal, vertical–flow up, vertical–flow down)

In presenting the calibration data, either the relative error or its opposite (the correction) or the volumetric efficiency or its reciprocal (the meter factor) shall be plotted versus the meter bore Reynolds number. The meter's bore shall be measured accurately as part of the calibration process.

4-5.3.2.2 Positive Displacement Meters

4-5.3.2.2.1 Application. This Code recommends positive displacement meters for liquid flows for all size pipes, but in particular for pipes less than 8 cm (3 in.) in diameter. There are many designs of positive displacement meters, including wobble plate, rotating piston, rotating vanes, and gear or impeller types. All of these designs measure volumetric flow directly by continuously separating (isolating) a flow stream into discrete volumetric segments and counting them. As such, positive displacement meters are often called volumeters. Because each count represents a discrete volume of fluid, positive displacement meters are ideally suited for automatic batching and accounting. Unlike differential pressure meters and turbine meters, positive displacement meters are relatively insensitive to piping installations and otherwise poor flow conditions. They are more of a flow disturbance than practically anything else upstream or downstream in plant piping.

Positive displacement meters provide high accuracy (±0.1% of actual flow rate in some cases) and good repeatability (±0.05% of reading in some cases), and accuracy is not significantly affected by pulsating flow unless it entrains air or other gas in the fluid. Turndowns as high as 100:1 are available, although ranges of 15:1 or lower are more common.

Use of positive displacement meters 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.

$$m = \rho \times \nu$$

(See subsection 2-1 for nomenclature.)

4-5.3.2.2.2 Calibration. The recommended practice is to calibrate positive displacement meters in the same fluid at the same temperature and flow rate that is expected in their intended performance test environment or service. If the calibration laboratory does not have the identical fluid, the next best procedure is to calibrate the meter in a similar fluid over the same range of viscosity-pressure drop factors expected in service. This recommendation implies duplicating the absolute viscosity of the two fluids.

4-5.3.2.3 Ultrasonic Flowmeters. Ultrasonic flowmeters measure flow velocity using sound waves. An ultrasonic flowmeter transmits a sound wave over the pipe and in the same direction as the liquid flow. Then the sound wave is reflected back in the opposite direction to the flow direction. The difference in sound transit time between the sound wave traveling in the opposite direction to the liquid flow and the transit time in the same direction as the flow indicates the flow velocity in the pipe. Since delay time is measured at short intervals, both in and against flow direction, viscosity and temperature have no influence on measurement accuracy.

The ultrasonic transducers function as both transmitters and receivers of the ultrasonic signals. Measurement is performed by determining the time it takes the ultrasonic signal to travel with and against the flow between two points, A and B. The principle can be expressed as follows:

$$\begin{aligned} u &= K \times \frac{t_{\mathrm{B,A}} - t_{\mathrm{A,B}}}{t_{\mathrm{B,A}} \times t_{\mathrm{A,B}}} \\ &= K \times \frac{\Delta t}{t^2} \end{aligned}$$

where

K = proportional flow factor for the ultrasonic meter
t = transit time
$t_{\mathrm{A,B}}$ = transit time of sound wave from point A to point B
$t_{\mathrm{B,A}}$ = transit time of sound wave from point B to point A
u = average flow velocity

This measuring principle offers the advantage that it is independent of variations in the actual sound velocity of the liquid, i.e., it is independent of temperature. Proportional factor K is determined by calibration.

Ultrasonic flowmeters can be used in pipe sizes ranging from 100 mm (4 in.) to 1 220 mm (48 in.).

The overall uncertainty of the measurement should not exceed the uncertainty requirement of the parameter on which the instrument is deployed.

Ultrasonic flowmeters can have temperature limitations. These limits should be considered prior to selection and the measurement location should be selected accordingly.

Several techniques can be used to obtain a measure of the average effective speed of propagation of an acoustic pulse in a moving liquid in order to determine the average axial flow velocity along an acoustic path line. Two approaches, time domain and frequency domain, are discussed here.

(a) Time Domain. The basis of this technique is the direct measurement of the transit time of acoustic signals as they propagate between a transmitter and a receiver. The velocity of propagation of the ultrasonic signal is the sum of the speed of sound, c, and the flow velocity in the direction of propagation.

(b) Frequency Domain. The basis of this technique (often called a sing around) is the reception of an acoustic signal at the receiver that is then used as a reference for generating a subsequent acoustic signal at the transmitter. Assuming no delays other than the propagation time of the acoustic pulses in the liquid, the frequency at which the pulses are generated or received is proportional to the reciprocal of their transit time.

ASME MFC 5.1 provides detailed information on ultrasound flowmeters and their application and provides detailed calculation methods based on flow calculations.

4-5.3.2.4 Vortex Shedding Flowmeters. Vortex shedding flowmeters measure the flow rate through the pipe using the Von Karman vortex shedding principle. The flowmeter consists of a bluff body inside the flow path. As the fluid flows around the bluff body, vortices are induced in the wake of the bluff body. A piezoelectric sensor is placed in this area so that for each vortex it sees, there is an electric signal generated as a result of pressure fluctuation from the vortex. The frequency of the electric signal is directly proportional to the flow velocity of the fluid. The principle can be expressed as follows:

$$F = \frac{\mathrm{St} \times u}{L}$$

where

F = measured vortex shedding frequency
L = characteristic length of the bluff body
St = Strouhal number (usually a fixed value for geometry)
u = flow velocity

The advantages of a vortex shedding flowmeter are that it has high accuracy, it can be used at a relatively high temperature, and it does not require impulse tubing like a venturi meter. The output of a vortex shedding flowmeter is a volumetric flow rate measurement that is uninfluenced by density, temperature, and pressure. This is particularly advantageous for fluids like molten salt, because with those fluids there is concern about keeping the impulse tubing warm and errors generated due to varying temperature of the fluid inside the impulse tubing. Moreover, a vortex shedder is free of any holes or openings where salt could get stuck and freeze.

Vortex shedding flowmeters have an accuracy of 0.65% of the maximum rated flow. They can be used to temperatures as high as 425°C (797°F). Thus, for an application like molten salt receiver, it is recommended to use vortex shedding flowmeters in the inlet or low temperature section. This type of flowmeter may not be available for large pipe sizes.

In order to have a good measurement, it is necessary to have an incoming flow that is free of external flow disturbances. It is recommended to have a minimum of ten flow diameters of straight length pipe upstream and five flow diameters of straight length pipe downstream of the flowmeter.

ASME MFC 6 provides detailed information on vortex shedding flowmeters including principles of operation, application, installation, and calibration, along with detailed flow calculation methods.

4-6 HUMIDITY MEASUREMENT

4-6.1 Introduction

This subsection presents requirements and guidance regarding the measurement of ambient humidity and recommended humidity measurement devices. Humidity may be an input variable to solar performance models and is therefore considered a primary variable, though one with a low sensitivity coefficient. Due to the state of the art and general practice, it is recommended that electronic humidity measurement equipment be used for primary parameters and primary variables to minimize systematic and random error.

Measurements to determine moisture content should be made in general proximity to measurements of ambient dry bulb temperature to provide the basis for determination of air properties. Despite the large physical size of solar fields, the insensitivity of relative humidity to the results is such that one instrument in a central location is generally adequate. The instrument for relative humidity may be one measurement of a general weather station.

4-6.2 Required Uncertainty

Relative humidity should be measured to within ±2% measurement accuracy, which is achievable using available devices and proper calibrations.

4-6.3 Recommended Humidity Measurement Devices

The recommended, and most common, humidity measurement device is the capacitive hygrometer-type relative humidity meter. Other types of measurement devices, such as wet and dry bulb psychrometers and chilled mirror dew point meters, are not excluded, but they provide little additional value for their additional effort and expense.

To ensure compliance with the measurement uncertainty requirements, the user shall either calibrate the hygrometer in the field using appropriate calibration standards or have certification of a recent factory calibration. The uncertainty levels for a capacitive-type device increase at extreme-low and extreme-high humidity levels. Measurements of extreme-low and extreme-high humidity shall be verified with at least two independent measurements to achieve acceptable uncertainty.

4-7 WIND SPEED AND DIRECTION

4-7.1 Introduction

This subsection presents requirements and guidance regarding the measurement of wind speed and direction. It also discusses the recommended wind measurement devices, calibration of wind measurement devices, and the application of wind measurement devices. Due to the state of the art and general practice, it is recommended that electronic wind measurement equipment be used for primary parameters and primary variables to minimize systematic and random error.

4-7.2 Required Uncertainty

Though primary variables, wind speed and direction have relatively low sensitivity coefficients. Uncertainty requirements are assigned accordingly. Wind speed shall be measured with wind measurement devices capable of ±2% accuracy or better. Wind direction shall be measured with devices capable of accuracy ±5 deg. The instrument(s) for wind speed and direction may be part of a general weather station, provided the other conditions in this Section are met.

4-7.3 Recommended Wind Measurement Devices

Cost, application, and uncertainty should be considered in the selection of wind measurement devices. Sonic-type anemometers and cup-type anemometers can both meet the uncertainty requirements and are suitable for wind measurement. The uncertainty in wind speed measurement derives from three sources: the calibration of the instrument, the operational characteristics of the anemometer, and the flow distortion due to instrument mounting effects. All of these sources of uncertainty need to be considered in the overall uncertainty of the measurement.

A single measurement location is adequate, but multiple measurements at different locations may be performed if there is any reason to believe a single measurement location would not represent wind conditions over the entire field.

The anemometer shall be mounted on the meteorological mast at a tower height of 10 m (33 ft) relative to the ground, ±2.5% of the mast's total height.

Care shall be taken in locating the meteorological mast. It shall not be located so close to the solar collector that it will affect wind speed. The mast shall be located a distance of 2 to 4 times the width of the solar receiver away from the solar receiver's edge. A distance of 2.5 times the solar receiver's width is recommended.

Prior to carrying out the performance evaluation test, and to help select the location of the meteorological mast, account should be taken of the need to ensure that both the mast and the turbine will not be subject to flow disturbances.

In most cases, the best location for the meteorological mast is upwind of the solar collector in the direction from which most valid wind is expected to come during the test.

For tower-type solar thermal receivers, it is necessary to measure wind speed at the top of the tower (where the receiver is located) to calculate the convective heat loss from the solar receiver. Ground wind speed may not be appropriate, since the wind speed increases higher up in the elevation. It is difficult to place the anemometer on or near the receiver surface, since it might get exposed to high heat flux from the mirror field.

The wind speed should be measured accurately on the ground, and then that measurement should be correlated to wind speeds at increasing elevations to calculate the wind speed at the top of the tower. Parties involved in the test need to agree on this wind speed correlation. Alternatively, radar may be used to measure wind speed at the top of the tower.

4-7.4 Wind Direction

If a sonic anemometer is used for wind speed measurement, then wind direction can typically be measured from the same instrument. If a cup-type anemometer is used for wind speed, then wind direction should be measured with a wind vane. A wind vane used for this purpose shall be mounted on the meteorological mast on a boom. The combined calibration, operation, and orientation uncertainty of the wind direction measurement should be less than 5 deg.

4-8 LEVEL MEASUREMENT

4-8.1 Introduction

This subsection presents requirements and guidance regarding liquid-level measurement in a tank or vessel and recommended level measurement devices. Liquid level may be an input variable to solar performance models, and it is therefore considered a primary variable. Due to the state of the art and general practice, it is recommended that electronic level measurement equipment be used for primary parameters and primary variables to minimize systematic and random error.

Since level measurement technology has changed over time, this Code does not limit the use of new level measurement devices not identified or currently available. If such a device becomes available and meets the required uncertainty and reliability in this Code, it may be used.

Measurements to determine fluid level in a tank or vessel shall be made in proximity to measurements of fluid temperature and vessel pressure to provide the basis for determining the actual level and hence the total inventory of the liquid being determined.

For large tanks and vessels with continuous in and out flow, at least two level measurements should be made at opposite ends (180 deg apart) for accurate determination of fluid inventory.

4-8.2 Required Uncertainty

Liquid level should be measured to within ±2% measurement accuracy, which is achievable using available devices and proper calibrations.

4-8.3 Recommended Liquid-Level Measurement Devices

Liquid-level measurement devices are classified into three categories based on their method of level detection: sight glasses, hydrostatic measurement devices, and distance measurement devices. These three device types are described below, and examples of available instruments are listed.

(a) *Sight Glass.* The sight glass is the simplest and oldest industrial level-measuring device. A manual approach to measurement, sight glasses have a number of limitations. The material used for transparency can suffer catastrophic failure, with ensuing environmental and safety issues, hazardous conditions for personnel, and/or fire and explosion. Seals are prone to leak, and buildup, if present, can obscure the visible level. However, sight glasses are simple and used for manually recording level where freezing of the fluid under ambient conditions is not an issue.

(b) *Hydrostatic Devices.* Displacers, bubblers, and differential pressure transmitters are all hydrostatic measurement devices. Any change in temperature will therefore cause a shift in the liquid's specific gravity, as will changes in pressure that affect the specific gravity of the vapor over the liquid. These changes result in reduced measurement accuracy. Therefore, when using hydrostatic devices, proper temperature and pressure compensation should be applied.

(c) *Distance Measurement Devices.* These are devices that measure the distance to the fluid surface by using a timing measurement. Magnetostrictive, ultrasonic, guided-wave radar, and laser transmitters are among the most versatile distance measurement devices available. Such systems use the sharp change of some physical parameter (density, dielectric constant, sonic reflection, or light reflection) at the process fluid surface to identify the level.

4-8.3.1 Air Bubbler. Bubbler tubes provide a simple and inexpensive, but less accurate (±1% to 2%), level measurement system for corrosive and slurry-type applications.

Bubblers use compressed air or an inert gas (usually nitrogen) introduced through a dip pipe. Gas flow is regulated at a constant rate. A differential pressure regulator across a rotameter maintains constant flow while the tank level determines the back pressure. As the level drops, the end of the dip pipe should be located far enough above the tank bottom so that sediment or sludge will not plug it.

4-8.3.2 Differential Pressure Transmitters. Differential pressure transmitters measure level via a float or displacer that depends on the density differences between the liquid and vapor phase. Level measurement based on pressure measurement is also referred to as hydrostatic level measurement. It works on the principle that the difference between the two pressures (d/p) level over wide ranges if the density of the liquid is constant. When a d/p cell is used, it will cancel out the effects of barometric pressure variations, because both the liquid in the tank and the low-pressure side of the d/p cell are exposed to the pressure of the atmosphere. The d/p cell reading will represent the tank level.

4-8.3.3 Floats. The buoyant force available to operate a float level switch (i.e., its net buoyancy) is the difference between the weight of the displaced fluid (gross buoyancy) and the weight of the float.

Floats are available in spherical and a variety of other shapes. They can be made of stainless steel, Teflon®, Hastelloy, Monel, and various plastic materials.

4-8.3.4 Magnetic Level Gauges. Magnetic level gauges are the preferred replacements for sight glasses. They are similar to float devices, but they communicate the liquid surface location magnetically. In a magnetic level gauge, the float, carrying a set of strong permanent magnets, rides in an auxiliary column (float chamber) attached to the vessel by means of two process connections. This column confines the float laterally so that it is always close to the chamber's side wall. As the float rides up and down with the fluid level, a magnetized shuttle or bar graph indication moves with it, showing the position of the float and thereby providing the level indication. The system can work only if the auxiliary column and chamber walls are made of nonmagnetic material.

4-8.3.5 Capacitance Transmitters. Capacitance transmitters operate on the principle that process fluids generally have dielectric constants, ε, significantly different from that of air, which has a dielectric constant very close to 1.0. Capacitive level sensors measure the change in capacitance between two plates produced by changes in level. Two versions are available, one for fluids with high dielectric constants and another for those with low dielectric constants.

Oils have dielectric constants from 1.8 to 5, and aqueous solutions have dielectric constants between 50 and 80. This technology requires a change in capacitance that varies with the liquid level, created by either an insulated rod attached to the transmitter and the process fluid, or an uninsulated rod attached to the transmitter and either the vessel wall or a reference probe. As the fluid level rises and fills more of the space between the plates, the overall capacitance rises proportionally. An electronic circuit called a capacitance bridge measures the overall capacitance and provides a continuous level measurement.

4-8.3.6 Magnetic Level Gauges and Transmitters. Paragraph 4-8.3.4 describes the advantages of using a float with magnets to determine liquid level, and magnetostriction is a proven technology for precisely reading the float's location. Instead of mechanical links, magnetostrictive transmitters use the speed of a torsional wave along a wire to find the float and report its position. In a magnetostrictive system, the float carries a series of permanent magnets.

In this system, a sensor wire is connected to a piezoceramic sensor at the transmitter, and a tension fixture is attached to the opposite end of the piezoceramic sensor tube. The tube either runs through a hole in the center of the float or is adjacent to the float outside of a nonmagnetic float chamber.

To locate the float, the transmitter sends a short current pulse down the sensor wire, setting up a magnetic field along its entire length. Simultaneously, a timing circuit is triggered on. The field created by the pulse interacts with the field generated by the magnets in the float. The overall effect is that during the brief time the current flows, a torsional force is produced in the wire, much like an ultrasonic vibration or wave. This force travels back to the piezoceramic sensor at a characteristic speed. When the sensor detects the torsional wave, it produces an electrical signal that notifies the timing circuit that the wave has arrived and stops the timing circuit. The timing circuit measures the time interval (TOF) between the start of the current pulse and the wave's arrival. From this information, the float's location is very precisely determined and presented as a level signal by the transmitter. Key advantages of this technology are that the signal speed is known and constant with process variables such as temperature and pressure, and the signal is not affected by foam, beam divergence, or false echoes. Another benefit is that the only moving part is the float that rides up and down with the fluid's surface.

4-8.3.7 Ultrasonic Level Transmitters. Ultrasonic level sensors measure the distance between the transducer and the surface using the TOF required for an ultrasound pulse to travel from a transducer to the fluid surface and back. These sensors use frequencies in the tens of kilohertz range; transit times are about 6 ms/m. The speed of sound [340 m/s in air at 15°C (1,115 ft/sec at 60°F)] depends on the mixture of gases in the headspace and their temperature. While the sensor temperature is compensated for (assuming that the sensor is at the same temperature as the air in the headspace), this technology is limited to atmospheric pressure measurements in air or nitrogen.

4-8.3.8 Laser Level Transmitters. Designed for bulk solids, slurries, and opaque liquids such as dirty sumps, milk, and liquid styrene, laser level transmitters operate on a principle very similar to that of ultrasonic level transmitters. Instead of using the speed of sound to find the level, however, they use the speed of light. A laser transmitter at the top of a vessel fires a short pulse of light down to the process liquid surface, which reflects the light back to the detector. A timing circuit measures the TOF and calculates the distance. The key is that lasers have virtually no beam spread (0.2-deg beam divergence) and no false echoes, and they can be directed through spaces as small as 650 mm^2 (2 in.^{2}). Lasers are precise, even in vapor and foam. They are ideal for use in vessels with numerous obstructions and can measure distances up to 450 m (1,500 ft). For high-temperature or high-pressure applications, such as in HTF tanks or vessels, lasers shall be used in conjunction with specialized sight windows to isolate the transmitter from the process. These glass windows shall pass the laser beam with minimal diffusion and attenuation and shall contain the process conditions.

4-8.3.9 Radar Level Transmitters. Through-air radar systems beam microwaves downward from either a horn or a rod antenna at the top of a vessel. The signal reflects off the fluid surface back to the antenna, and a timing circuit calculates the distance to the fluid level by measuring the TOF. If the fluid's dielectric constant is low, it can present measurement problems. The reason is that the amount of reflected energy at microwave (radar) frequencies is dependent on the dielectric constant of the fluid, and if ε is low, most of the radar's energy enters or passes through the fluid surface. Water (ε_r = 80) produces an excellent reflection at the change or discontinuity in ε_r.

In through-air radar systems, the radar waves suffer from the same beam divergence that afflicts ultrasonic transmitters. Internal piping, deposits on the antenna, and multiple reflections from tank buildup and obstructions can cause erroneous readings. To overcome these problems, complex algorithms using fuzzy logic must be incorporated into the transmitter. Transmitter setup can be tedious and changes in the process environment (buildup, etc.) can be problematic.

Guided wave radar (GWR) systems avoid these issues. In this type of system, a rigid probe or flexible cable antenna system guides the microwave down from the top of the tank to the liquid level and back to the transmitter. As with through-air radar, a change from a lower to a higher ε_r causes the reflection. Guided wave radar is 20 times more efficient than through-air radar, because the guide provides a more focused energy path. Different antenna configurations allow measurement down to ε_r = 1.4 and lower. Moreover, GWR systems can be installed either vertically or, in some cases, horizontally. The guide can be bent up to 90 deg or angled and still provide a clear measurement signal. GWR is known to have a maximum operating temperature limit and should be deployed per manufacturer's recommendations.

GWR exhibits most of the advantages and few of the liabilities of ultrasound, laser, and open-air radar systems. Radar's wave speed is largely unaffected by vapor space gas composition, temperature, or pressure. It works in a vacuum with no recalibration needed and can measure through most foam layers. Confining the wave to follow a probe or cable eliminates beam-spread problems and false echoes from tank walls and structures.

4-9 AUXILIARY OR SUPPLEMENTAL FUEL INPUT MEASUREMENT

4-9.1 Introduction

If the HTF receives energy from an auxiliary firing system during a test, the flow, pressure, temperature, and constituents of the fuel shall be measured. The flow, pressure, temperature, and constituents of streams to and from the auxiliary firing systems (i.e., fuel heaters, etc.) need to be determined if they cross the test boundary. Refer to subsections 4-2 and 4-3 respectively for measurement requirements for temperature and pressure. Liquid and gaseous fuel sampling shall be in accordance with ASME PTC 4.4, subsection 4-6.

This subsection presents requirements and guidance regarding the measurement of supplementary firing fuel flow. The recommended flow measurement devices, calibration, and application are also discussed. Due to the state of the art and general practice, it is recommended that electronic fuel flow measurement equipment be used for primary parameters and primary variables to minimize systematic and random error.

Fuel analyses should be completed on samples taken during testing. The lower and higher heating value 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 covering the range of temperatures measured during testing. The specific gravity at flowing temperatures should then be determined by interpolating between the measured values and the correct temperature.

4-9.2 Required Uncertainty

For supplementary firing fuel flow measurement, this Code recommends flowmeters that can be demonstrated to have no more than 0.75% systematic uncertainty.

4-9.3 Recommended Supplementary Devices for Fired-Fuel Flow Measurement

This Code recommends ASME PTC 19.5 laboratory-calibrated venturi, orifice, or flow nozzle metering runs to measure the supplementary fired fuel flow. However, other types of flowmeters may be used if they can be demonstrated to have the same or better levels of uncertainty required by this Code

4-9.3.1 Measurement Method for Liquid Fuel. If liquid-fueled supplementary firing is employed, the quantity of liquid fuel burned shall be determined. Refer to ASME PTC 22 and ASME PTC 19.5 for liquid-fueled gas turbine fuel flow measurements.

Liquid fuel flows can be measured using either a flow orifice installed in accordance with ASME PTC 19.5 or other measurement devices, such as positive displacement flowmeters or turbine flowmeters that are calibrated throughout the Reynolds number range expected during the test. For volume flowmeters, the temperature of the fuel shall be measured accurately to calculate the flow correctly.

Other flowmeters or uncalibrated meters are permitted so long as a measurement error of 0.75% or less can be achieved. Refer to ASTM D1480 for methods of determining liquid fuel density and ASTM D445 for methods of determining liquid fuel viscosity.

4-9.3.2 Measurement Method for Gaseous Fuel. If gaseous fuels are employed, the quantity of gaseous fuel burned, and its heating value, shall be determined. Heating value of the fuel shall be determined per ASTM D3588.

Measurement of the gaseous fuel flow requires the use of a venturi, orifice, flow nozzle, ultrasonic, or turbine meter. For orifices, venturis, or nozzles, refer to ASME PTC 19.5 for installation guidelines as well as the calculation procedure. For differential pressure meters, the pressure drop shall be measured using a differential pressure transducer. Outputs from these devices can be read manually via meters or with a data acquisition system. Gas density shall be determined in accordance with the procedure in AGA Report No. 8. Linear flowmeters should be calibrated at the expected working pressure to reduce the flow error. Uncalibrated flowmeters are acceptable if the measurement uncertainty is demonstrated to be less than 0.75%.

4-9.4 Location of Instruments

Flow measurement devices shall be located to minimize the impact of environmental conditions such as vibration, temperature, and humidity. See subsection 4-1 for location and identification requirements.

4-10 ELECTRIC POWER MEASUREMENT

4-10.1 Introduction

This subsection presents requirements and guidance regarding the measurement of auxiliary electric power that crosses the test boundary and is consumed by the solar conversion system. Per subsection 1-2, this Code does not apply to measurement of thermal power cycle performance, including measurement of electrical generator power output. Therefore, the current section does not address measurement of electric power from a generator.

Measurement of auxiliary electric power may be part of an ASME PTC 52 test. If this measurement is part of an ASME PTC 52 test, it would typically be done as a separate measurement, calculation, and presentation of results independent from the main test purpose of measuring solar-to-thermal conversion performance. However, the guidance in this subsection should be followed regardless of how an auxiliary electrical load measurement result is applied in a contractual setting.

4-10.2 Required Uncertainty

Electric power measurement primary parameters and variables should be measured with 0.5% or better accuracy class power metering.

Secondary parameters and variables can be measured with any type of power measurement device.

Less accurate instrumentation may be used if the requirements for the overall uncertainty of the result are met and if the parties to the test agree.

4-10.3 Measurement Recommendations

ANSI/IEEE 120-1989 should be referenced for measurement requirements not included in this subsection or for any additionally required instruction.

Auxiliary loads may consist of feedwater booster pumps, molten salt pumps, trough or heliostat drive motors, and a number of other types of electrical loads distributed by motor control centers or power panels.

The measurement of the auxiliary electric power can be done with station permanent meters or locally using temporary instrumentation. The station permanent instrumentation can normally be found in the motor control centers (MCC) where electric power is displayed as either active power or voltage and current. A list should be created identifying all auxiliary loads and measurement locations and clearly identifying which system is fed through which MCC or power panel.

Auxiliary loads can be broadly placed into two categories: there are loads that have little variation over a normal test period and loads that either are intermittent or have large variation over a normal test period. Loads that have little variation over a short-term test may have large variation over a long-term test. Test personnel should consider the expected variation in the load when determining the methods for measuring load during the test and the frequency of data readings.

The following calculation may be used in lieu of field measurement to estimate the total load from a trough or heliostat drive motor:

$$\text{total load} = \text{power requirement} \times \text{number of drives}$$

Data can be collected either manually or automatically. For short-term tests, at least three readings should be taken for each test period for loads that have little variation. For long-term tests, readings should be taken at least hourly. For intermittent or large-variation loads, readings shall be taken with enough frequency to obtain an accurate average power measurement over the course of the test period. In some cases, the only practical measurement may be a totalizing type of meter at the MCC.

4-11 ATMOSPHERIC ATTENUATION

Atmospheric attenuation or transmissivity may have significance for tower-type CSP applications that are dependent on energy being reflected from multiple locations to one central receiver. It is possible that in unusual occurrences atmospheric conditions will be different enough from design to influence the energy received.

Though the possibility for attenuation is real, there is no consensus of standards or measurement techniques for attenuation. Attenuation is not addressed in this Code. If attenuation is a factor in the base reference conditions of a guarantee, then the parties shall agree to a standard of reference and a method of measurement.

4-12 RECEIVER ABSORPTANCE

Receiver absorptance is an important measurement, particularly for the tower-type CSP applications. Heat flux on a tower-type CSP receiver is of a very high magnitude (as high as 1 000 kW/m^2), and small changes in the receiver absorptance can result in relatively big changes in the total heat absorbed by the receiver. The absorptance of high-radiation absorption coating, along with the method of application for the coating, is usually provided by the coating manufacturer. However, the absorptance of receiver coating can change with time and usually degrades slowly when exposed to ambient conditions in combination with incident heat flux. This exposure results in reduced thermal absorption by the receiver. Therefore, based on the mutual agreement between the parties involved in performance testing, receiver absorptance measurement may be included in the performance test.

The absorptance measurement can be done using laboratory measurement instruments or handheld instruments. However, handheld absorptance measurement is preferred for performance tests. It is recommended to have absorptance measured at several locations along the receiver surface to get a spatial distribution of the absorptivity. The degradation of coating absorptance may be a function of operating temperature and tube material. Therefore, measurement of absorptance at several locations provides a better picture of the average absorptance of the receiver. Absorptance measurement may be performed during a planned outage (before or after the performance test), and the results of the measurement may be used in the performance test calculation.

Handheld absorptance measuring devices use a spherical measuring head to measure absorptance for the specified wavelength range. These devices can be used for flat surfaces and surfaces up to 152 mm (6 in.) convex or 305 m (12 in.) concave.

ASTM E903-12 provides guidelines for absorptance measurement.

4-13 FLUID PROPERTIES

4-13.1 Introduction

HTF properties, including specific heat capacity, viscosity, density, thermal conductivity, freezing point, chemical stability and their variations with temperature and pressure, may be required inputs to the performance model. Parties to the test should agree upon the properties of the process fluid being measured, and these agreed properties should be used in the performance model.

Where an international standard for the fluid properties is available, the standard should be used. For water or steam, it is recommended to use IAPWS-IF97 steam tables. For other fluids, the parties should use a standard if available or mutually agree upon the fluid properties. For fluids where property standards are not available, or if the fluid has been contaminated or degraded since those standards were applicable, a laboratory test may be required to quantify the fluid properties. It is not recommended to use values published by the HTF vendor. However, in a case where this is the only possibility, a higher value of uncertainty should be used.

4-13.2 Uncertainty

Fluid properties can be a major source of uncertainty in the overall calculation of solar thermal power plant performance, because their sensitivity is large. Fluid properties are typically used in both terms of the equation for energy, Q:

$$Q = m \times \Delta h$$

Fluid properties are required when calculating mass flow rate, m, from a volumetric flowmeter and when calculating enthalpy, h. If uncertainty in the fluid properties is high, it is recommended to either reduce the uncertainty by performing a high-quality laboratory test or measure mass flow rate directly. Mass flow rate can be measured directly with a Coriolis-type flowmeter, but these meters typically cost far more than a laboratory test of the fluid properties.

The required uncertainty will depend on the type of parameters and variables being measured. Refer to para. 4-1.2.2 for discussion of measurement classification.

4-14 CLEANLINESS

4-14.1 Introduction

This subsection presents requirements and guidance regarding the measurement of cleanliness. Cleanliness is the ratio of the system's optical properties (i.e., reflectance and transmittance) at the time of the performance test to the optical properties at a reference condition. The reference condition is typically defined by the parties to the test or included in supplier specifications, but it may reference the condition of the system in a like-new condition, immediately after installation, or in a recently cleaned state. Thus, the cleanliness factor provides a measurement of the amount of soiling or degradation at the time of the performance test.

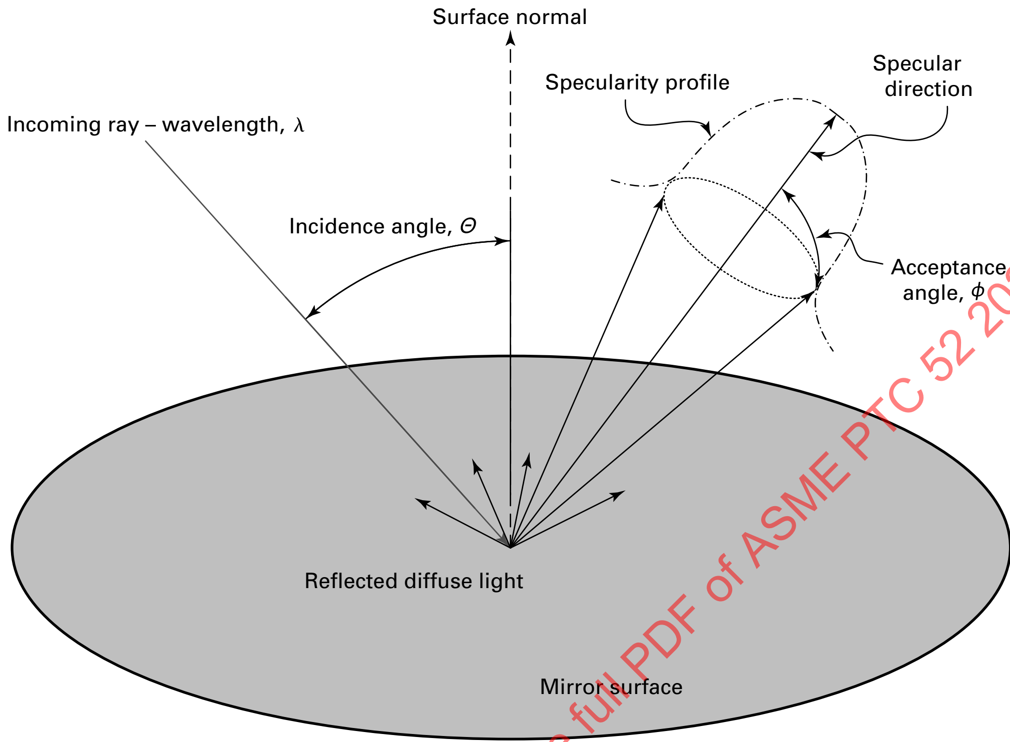
In general, the solar field cleanliness factor is calculated by taking reflectance measurements on both soiled and cleaned mirrors. The ratio of the soiled and cleaned data sets is the mirror cleanliness factor of the solar field. In systems that include a transparent envelope between the reflector and the receiver (e.g., glass around the receiver), the cleanliness of the envelope shall also be accounted for. In many cases, direct measurement of the cleanliness of the envelope is not possible in an operational power plant. Thus, it is common practice to assume the envelope cleanliness to be 0.5 times the reflector cleanliness, because light passes through the surface of the reflector twice, but through the envelope only once. In systems where the rate of soiling is deemed to vary between the reflector surface and the receiver envelope, alternate weighting fractions may be adopted, so long as they are agreed to by the parties to the test.

The information provided herein defines acceptable techniques for the measurement of reflectance, measurement devices, measurement locations, instrument calibration, and quantification of uncertainty. Where applicable, glass or air transmittance should be included in the calculation of system cleanliness, but it is inherently difficult to measure. Methods for quantification of transmittance should be agreed to by the parties to the test and are not described in detail in this Section.

4-14.2 Reflectance Measurement Techniques

The quantification of a surface's reflectance may be defined in a variety of ways, and it is important for the parties to the test to agree upon the measurement technique prior to the performance test and prior to the initial test at base reference conditions. When reflectance is initially calculated for use in performance estimates, it is typical to use a weighted value such as solar-weighted specular reflectance (SWSR). SWSR is a measurement of reflectance weighted across the solar

Figure 4-14.2-1 Incidence Angle, Acceptance Angle, and Specularity



spectrum within an acceptance angle that is representative of the type of system installed and representative of a specific range of angles of incident light. The acceptance angle required for a central receiver system is generally smaller than that required for a linear Fresnel or parabolic trough system, because the concentration ratio of a central receiver system is significantly higher.

But while the SWSR is an important value when initially predicting the performance of a solar field, the parties to the test may instead agree to measure cleanliness at a single wavelength, a single incident angle, and a specific acceptance angle that is representative of the reflector system. For example, the parties to the test may agree that if the cleanliness of the reflector is 0.9 at 660 nm with a 15-deg incidence angle and a 25-mrad acceptance angle, then the cleanliness is most likely also 0.9 as a measurement of SWSR. It should be noted, however, that one effect of reflector soiling is decreased specularity (i.e., decreased reflectance for a given acceptance angle).

Determination of SWSR typically requires many measurements for each location, while measurement of reflectance at a single wavelength and specific acceptance angle requires only one measurement per location. In practice, the uncertainty of cleanliness can be reduced with many measurements throughout the solar field. It is important for the parties to the test to agree to the definition of the measured reflectance prior to the test at base reference conditions and to maintain that definition during the performance test. If the collector field surface is large and it is infeasible to have many measurements, the parties may agree to take a lower sample of measurements prior to the test period. To better illustrate the concepts presented above, Figure 4-14.2-1 provides a schematic to illustrate incidence angle, acceptance angle, and specularity.

The best characterizations measure the surface's reflectance at various wavelengths to determine solar-weighted reflectance. For characterization of cleanliness, however, it may be suitable to measure at only one representative wavelength. With this approach, it is conventional to measure reflectance at a wavelength with high irradiance, such as the range between 500 nm and 700 nm.

4-14.3 Measurement Devices

Reflectance is typically measured with either a specular reflectometer or a spectrophotometer. These devices are widely available and offer a number of features including a variable wavelength, acceptance angle, and/or incident angle. ASTM E903-12 may be referenced for instruments that make use of integrating spheres in their measurements.

While some reflectometers and spectrophotometers may provide SWSR outputs directly, these are typically laboratory-scale instruments and are not suitable for use outdoors or in solar fields. For that reason, if the parties to the test decide to require SWSR measurement, it may be required to use two or more measurement devices and to post-process the data to determine SWSR.

It is common practice in industrial applications to use a device with a fixed wavelength, fixed aperture, and fixed incidence angle (e.g., 660 nm, 25-mrad acceptance, 15-deg incidence) to quantify the cleanliness of a surface.

4-14.4 Instrument Calibration

Any instrument used for the soiling test should be recalibrated within its required duration and before each day of testing. A calibration standard (mirror) is typically provided with the measurement device and can be used to calibrate the instrument in the field. Vendor recommendations for calibration should be rigorously followed. In the absence of a provided calibration standard, it is preferred that the same calibration mirror be used during both the reference test and the performance test periods.

4-14.5 Measurement Locations

Mirror cleanliness is most typically influenced by material degradation and soiling of the mirror surface. While degradation is typically uniform across the solar field, soiling occurs at different rates depending on the reflector's position in the field. Reflectance measurements should be taken at interior and exterior collectors, as well as collectors nearby access roads, nearby steam or other process equipment, and at varying elevations from the ground. Reflectance disparities within a single mirror should also be considered. A representative pattern should be adopted so that the solar field reflectance is reported as an average value that represents the entire test boundary.

4-14.6 Uncertainty

The required uncertainty will depend upon the type of parameters and variables being measured. Refer to para. 4-1.2.2 for discussion of measurement classification.

If not otherwise specified by this Code, parameters and variables shall be determined with reflectance measurement devices that have a systematic uncertainty of no more than ±0.5% of measured value. The measurement devices for primary parameters and variables shall be laboratory calibrated unless the device can demonstrate a systematic uncertainty lower than ±0.5% without calibration.

Determination of field average reflectance or field average cleanliness typically requires that a sufficient number of measurements be taken across a random pattern in the entire test boundary such that the standard deviation of the measurement values is within a limit specified by the parties to the test. If the standard deviation is outside the acceptable range, additional measurements shall be taken until the standard deviation falls within the acceptable range.

4-15 DATA COLLECTION AND HANDLING

4-15.1 Introduction

This subsection presents requirements and guidance regarding the acquisition and handling of test data. Also presented are the fundamental elements that are essential to the makeup of an overall data acquisition and handling system.

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

4-15.1.1 Data Acquisition System. The purpose of a data acquisition system is to collect data and store them in a form suitable for processing or presentation. Systems may be as simple as a person manually recording data or as complex as a digital computer-based system. Regardless of the complexity of the system, a data acquisition system shall be capable of recording, sampling, and storing the data within the requirements of the test and the allowable uncertainty set by this Code.

4-15.1.2 Manual System. In some cases, it may be necessary or advantageous to record data manually. It should be recognized that this type of system introduces additional uncertainty in the form of human error, and that potential for error should be accounted for accordingly. Further, manual sampling may require more time and personnel than does automated sampling. Test periods should be selected with this in mind, allowing personnel enough time to take the number of samples required for the test. Data collection sheets should be prepared prior to the test. The data collection sheets should identify the test site location, date, time, and type of data collected. The data collection sheets should also delineate the sampling time required for the measurements. Sampling times should be clocked using a digital stopwatch or other accurate timing device. If it becomes necessary to edit data sheets during the testing, all edits shall be made using black ink, and all errors shall be marked through with a single line and initialed and dated by the editor.

4-15.1.3 Automated System. Automated data collection system configurations have a great deal of flexibility. Automated systems are beneficial in that they allow for the collection of data from multiple sources at high frequencies while recording the time interval with an internal digital clock. Rapid sampling rates serve to reduce test uncertainty and test duration. These systems can consist of a centralized processing unit or distributed processing to multiple locations in the plant.

Automated data acquisition systems shall be functionally checked after installation. At a minimum, a pretest data run should be performed to verify that the system is operating properly. The details of the automated system's setup, programming, channel lists, signal conditioning, and operational accuracies and lists of the equipment making up the system should be compiled and supplied in the test report.

4-15.2 Data Management

4-15.2.1 Automated Collected Data. All automated collected data should be recorded in their uncorrected, uncalculated state on both permanent and removable media to permit post-test application of any necessary calibration corrections. Alternatively, corrections and/or calibration calculations can be provided with the data supplied with corrections already applied. Immediately after a test and prior to the person(s) collecting test data leaving the test site, copies of the automated collected data should be made on a removable medium and distributed among the parties of the test. This will prevent loss, damage, or unauthorized modification of the data. Similar steps should be taken with any corrected or calculated results from the test.

4-15.2.2 Manually Collected Data. All manually collected data recorded on data collection sheets shall be reviewed for completeness and correctness. Immediately after a test and prior to leaving the test site, photocopies of the data collection sheets should be made and distributed between the parties to the test to eliminate the chance of such data being accidentally lost, damaged, or modified.

4-15.2.3 Data Calculation Systems. The data calculation system should have the capability to average all inputs collected during the test and calculate the test results based on the average values. The system should also calculate the standard deviation and the coefficient of variance of each instrument. The system should have the ability to locate and eliminate spurious data from the calculation of the average. The system should also be able to plot the test data and each instrument reading over time to look for trends and outlying data.

4-15.3 Data Acquisition Systems Selection

4-15.3.1 Data Acquisition System Requirements. Prior to selecting a data acquisition system, it is necessary to have a test procedure in place that dictates the requirements of the system. The test procedure should clearly dictate the type of measurements to be made, the number of data points needed, the length of the test, the number of samples required, and the frequency of data collection needed to meet the allowable test uncertainty set by this Code. This information will serve as a guide in the selection of equipment and system design.

Each measurement loop shall be designed with the ability to be loop calibrated so that the measurement loop can be checked for continuity and power supply problems. To prevent signal degradation due to noise, each instrument 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.

4-15.3.2 Temporary Automated Data Acquisition System. This Code encourages the use of temporary automated data acquisition systems for testing purposes. These systems can be carefully calibrated and their proper operation confirmed in the laboratory, and then they can be transported to the testing area. This process provides traceability and control of the complete system. Instruments are limited in their exposure to the elements and avoid the problems associated with construction and ordinary plant maintenance.

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

4-15.3.3 Existing Plant Measurement and Control System. This Code does not prohibit the use of the plant measurement and control system for testing. However, if used for performance testing, the system shall meet the requirements set forth in this Code. In addition, users should recognize the system's limitations and restrictions.

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

Most plant systems do not calculate flow rates in accordance with this Code, but rather by simplified relationships. These simplified flow calculations include, for example, using a constant discharge coefficient or even expansion factor. A plant system indication of flow rate is not to be used in the execution of this Code, unless the fundamental input parameters are also logged and the calculated flow is confirmed to be in accordance with this Code and ASME PTC 19.5.

Section 5
Calculations and Results

5-1 INTRODUCTION

5-1.1 General

The objective of these calculations is to determine the performance of the concentrating solar system. The approach of this Code is to directly measure the primary parameters needed to calculate or predict performance at the test conditions.

With the heat transfer fluid (HTF) flow and composition, along with other measured test data, the predicted capacity can be determined for the test conditions. The predicted performance can then be compared to the as-tested performance.

5-1.2 Data Reduction

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

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

5-2 CALCULATIONS

5-2.1 Common Parameters and Variables

The following parameters are representative of the inputs used to predict the concentrating solar system performance at the test conditions as well as those needed to calculate the actual (as-tested) performance of the system. This list is neither exhaustive nor required for all systems or models. All concentrating solar systems have some differences in their designs, components, inputs, outputs, and model complexities. The specific test plan for the performance test should address the specific needs of the concentrating solar system being tested.

(a) Solar Resource and Ambient Conditions
- *(1)* direct normal irradiance (DNI) (measured)
- *(2)* wind speed (measured)
- *(3)* wind direction (measured)
- *(4)* ambient temperature (measured)
- *(5)* ambient pressure and equivalent elevation (measured)
- *(6)* ambient wet bulb temperature and relative humidity (measured)
- *(7)* reflectance (measured or assumed, depending on the model)
- *(8)* soiling or cleanliness (measured or assumed, depending on the model)
- *(9)* atmospheric attenuation (measured or assumed, depending on model)
- *(10)* solar field aperture area (measured)
- *(11)* latitude
- *(12)* longitude
- *(13)* time of day
- *(14)* day of year
- *(15)* slope of collector(s)

(b) HTF
- *(1)* HTF static pressure (measured)
- *(2)* HTF temperature (measured)
- *(3)* HTF mass flow (calculated or measured)
- *(4)* HTF composition (measured)

(c) Other Items to Be Considered

(1) auxiliary loads, electrical and thermal (measured)

(2) HTF amount or energy content within test boundary (unsteady state)

(3) nonstandard HTF streams entering or leaving test boundary (e.g., blowdown, bypass, overflow, ullage)

5-2.2 Calculated Thermal Power Output

Thermal power output is calculated as follows:

$$q_{\text{field,calc}} = \frac{\sum_{j=1}^{n} (m_{\text{HTF,out},j} \times h_{\text{HTF,out},j} - m_{\text{HTF,in},j} \times h_{\text{HTF,in},j}) \times \Delta t_j}{\sum_{j=1}^{n} \Delta t_j} \tag{5-2-1}$$

where

$h_{\text{HTF,in},j}$ = enthalpy of HTF into the test boundary, kJ/kg (Btu/lbm)
$h_{\text{HTF,out},j}$ = enthalpy of HTF out of the test boundary, kJ/kg (Btu/lbm)
$m_{\text{HTF,in},j}$ = mass flow rate of HTF entering test boundary, kg/s (lbm/hr)
$m_{\text{HTF,out},j}$ = mass flow rate of HTF exiting test boundary, kg/s (lbm/hr)
$q_{\text{field,calc}}$ = calculated thermal power delivered by the solar field, kW (Btu/hr)
Δt = time interval between data measurements, s (hr)

NOTES:
(1) The equation represents only one energy stream crossing into and out of the boundary. For systems with more than one stream, the equation should be expanded to calculate the sum of all streams for each sample interval.
(2) The time interval between data measurements should be selected to provide a reasonable sample size based on the overall duration of the test. Time intervals may vary in duration.

5-2.3 Thermal Energy Production (Multiday Performance Test)

The multiday production of thermal energy is calculated as follows:

$$H_{\text{MDPT,calc}} = \sum_{j} [(m_{\text{HTF,out},j} \times h_{\text{HTF,out},j} - m_{\text{HTF,in},j} \times h_{\text{HTF,in},j})\Delta t_j] \tag{5-2-2}$$

where

$H_{\text{MDPT,calc}}$ = calculated thermal energy delivered by the field, kJ (Btu)
$h_{\text{HTF,in},j}$ = enthalpy of HTF into the test boundary, kJ/kg (Btu/lbm)
$h_{\text{HTF,out},j}$ = enthalpy of HTF out of the test boundary, kJ/kg (Btu/lbm)
$m_{\text{HTF,in},j}$ = mass flow rate of HTF entering test boundary, kg/s (lbm/hr)
$m_{\text{HTF,out},j}$ = mass flow rate of HTF exiting test boundary, kg/s (lbm/hr)
Δt = time interval between data measurements, s (hr)

NOTES:
(1) The equation represents only one energy stream crossing into and out of the boundary. For systems with more than one stream, the equation should be expanded to calculate the sum of all streams for each sample interval.
(2) The time interval between data measurements should be selected to provide a reasonable sample size based on the overall duration of the test.
(3) It is recommended that the interval match the incremental time period in the performance model.

5-2.4 Solar Thermal Efficiency

The equation for calculation of solar thermal energy varies depending on the type of concentrating solar system.

(a) For Linear Focus-Type Concentrating Solar Systems

$$\eta_{\text{field,calc}} = \frac{q_{\text{field,calc}}}{\text{DNI}_{\text{avg}} \times \cos\theta \times A_{\text{aperture}}} \tag{5-2-3}$$

where

$A_{aperture}$ = solar field aperture area, m^2 (ft^2)

DNI_{avg} = average direct normal irradiance for n number readings, W/m^2 (Btu/hr-ft^2)

= $\dfrac{\sum_j DNI_j}{n}$

DNI_j = direct normal irradiance, W/m^2 (Btu/hr-ft^2)

$q_{field,calc}$ = calculated thermal power delivered by the field [see eq. (5-2-2)]

$\eta_{field,calc}$ = calculated solar thermal efficiency, %

θ = incidence angle, based on latitude and longitude of site, time of day, and day of year

(b) For Point Focus-Type Concentrating Solar Systems

$$\eta_{field,calc} = \frac{q_{field,calc}}{DNI_{avg} \times A_{aperture}} \tag{5-2-4}$$

where all parameters are defined as in (a).

For tower concentrating solar power (CSP) systems, the denominator in eq. (5-2-4) is not a direct measurement of the solar energy input. In these systems, the reflector angle is variable throughout the field, while blocking and shadowing according to the sun's position will change the active reflective surface area at any given time. Therefore, the solar thermal efficiency for power tower CSP systems is a representative value and not a physical value.

5-2.5 HTF Enthalpy

Refer to Section 4 for applicable enthalpy determination methods.

5-2.6 Fluid Flow Rate

Refer to Section 4 for applicable flow measurement devices and methods.

5-2.7 Auxiliary Electrical Consumption

The equipment power consumption should be measured at each source point to the concentrating solar equipment. Each motor control center (MCC) should be monitored and recorded following methods described in Section 4. Equipment may include (and is not limited to) pumps, fans, control panels, compressors, and heat tracing. The following equations apply for each electrical auxiliary energy source where power is not directly measured:

$$\text{single-phase source} \quad \text{Aux}_i = \frac{I_i \times E_i \times \text{PF}}{1{,}000} \tag{5-2-5}$$

$$\text{three-phase sources} \quad \text{Aux}_i = \frac{I_i \times E_i \times \text{PF} \times \sqrt{3}}{1{,}000} \tag{5-2-6}$$

where

Aux_i = power consumption for source i, kW (Btu/hr)

E_i = electric voltage for source i

I_i = electric current for source i

PF = power factor

The auxiliary electrical energy consumption is the sum of power consumption from all individual sources over the testing period.

$$\text{Aux} = \sum_j \left(\sum_i \text{Aux}_i \right) \times \Delta t_j \tag{5-2-7}$$

where

Δt_j = time interval between data measurements, s (hr)

5-2.8 Auxiliary Thermal Consumption

Thermal energy consumption of the equipment, if applicable, shall be determined from the measured flow, pressure, and temperature of the auxiliary fluid as indicated in Section 4. The following equation applies:

$$H_{\text{Aux}} = \sum_{j} [(m_{\text{Aux,in},j} \times h_{\text{Aux,in},j}) \times \Delta t_j - (m_{\text{Aux,out},j} \times h_{\text{Aux,out},j}) \times \Delta t_j] \tag{5-2-8}$$

where

H_{Aux} = calculated thermal energy consumption, kJ (Btu)
$h_{\text{Aux,in},j}$ = enthalpy of auxiliary fluid into the system, kJ/kg (Btu/lbm)
$h_{\text{Aux,out},j}$ = enthalpy of auxiliary fluid out of the system, kJ/kg (Btu/lbm)
$m_{\text{Aux,in},j}$ = mass flow rate of auxiliary fluid into the system, kg/s (lbm/hr)
$m_{\text{Aux,out},j}$ = mass flow rate of auxiliary fluid out of the system, kg/s (lbm/hr)
Δt_j = time interval between data measurements, s (hr)

If the HTF is steam or water, then consumption shall be determined using the current ASME or International Association for the Properties of Water Steam (IAWPS) steam table formulations for enthalpy.

5-3 COMPARISON OF AS-TESTED PERFORMANCE TO PREDICTED PERFORMANCE

Due to the complexity of concentrating solar systems and the interaction of many influential parameters, it is difficult to correct the as-tested performance to reference conditions. It would likely be very difficult to develop a complete set of correction curves and factors. As such, the use of a performance model is preferred. This performance model should be able to predict the performance at the test conditions. A performance model has the advantage of considering all performance factors simultaneously and would also take into account any secondary interaction effects between various performance factors.

It is typically the responsibility of the concentrating solar system design firm to provide the performance model. The performance model is typically used by the construction contractor during contract negotiations and for financing the project. The performance model used for the construction contract and financial closing is typically locked and becomes the guaranteed performance model. Any subsequent changes to the guaranteed performance model shall be approved by the involved parties. The guaranteed performance model should allow the user to input all necessary test condition parameters. Once the predicted performance at the test conditions is established by the guaranteed performance model, it can be directly compared to the corresponding as-tested value.

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, described in subsection 6-2
(b) introduction, described in subsection 6-3
(c) calculations and results, described in subsection 6-4
(d) instrumentation, described in subsection 6-5
(e) conclusions, described in subsection 6-6
(f) appendices, described in subsection 6-7

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

6-2 EXECUTIVE SUMMARY

The executive summary is brief and should include the following:
(a) general information about the plant and the test, such as the plant type, the operating configuration, and the test objective, including the test objective values
(b) date and time of the test
(c) signature of test coordinator(s)
(d) signature of reviewer(s)
(e) approval signature(s)
(f) summary of the results of the test including uncertainty and conclusions reached
(g) comparison with the contract guarantee
(h) any agreements among the parties to the test to allow any major deviations from the test requirements including a description of why the deviation occurred

6-3 INTRODUCTION

The introduction to the test report should include the following information:
(a) authorization for the tests, their object, contractual obligations and guarantees, stipulated agreements, and names of the directors of the test and the representative parties to the test
(b) any additional general information about the plant and the test not included in the executive summary, such as
(1) a historical perspective, if appropriate
(2) a cycle diagram showing the test boundary (see figures in appendices for examples of test boundary diagrams for specific plant types or test goals)
(3) a description of the equipment tested and any other auxiliary apparatus, the operation of which may influence the test result
(c) a listing of the representatives of the parties to the test
(d) any pretest agreements that were not tabulated in the executive summary, including a detailed description of deviations from the test procedure during the test, resolution of those deviations, and impact of the deviations to the test results
(e) the organization of the test personnel
(f) the test goal per Sections 3 and 5 of this Code

6-4 CALCULATIONS AND RESULTS

The calculations and results section of the test report should include, in detail, the following information:
(a) the method of the test and operating conditions

(b) the format of the general performance equation that is used based on the test goal and the applicable corrections (this is repeated from the test requirements for convenience)
(c) a tabular summary of measurements and observations including the reduced data necessary to calculate the results and a summary of additional operating conditions not part of the reduced data
(d) a step-by-step calculation of test results from the reduced data including the probable uncertainty (see Nonmandatory Appendices A and B for examples of step-by-step calculations for each plant type and test goal)
(e) a detailed calculation of primary flow rates (i.e., HTF flow rates) from applicable data, including intermediate results, if required
(f) the HTF thermophysical property tables or correlations used in calculating secondary properties such as density, heat capacity, and enthalpy
(g) any calculations showing elimination of data for outlier reasons, or for any other reasons
(h) a comparison of the repeatability of the test runs
(i) the correction factors to be applied because of deviations, if any, from specified test conditions
(j) the primary measurement uncertainties, including method of application
(k) a comparison of predicted performance from the guaranteed performance model at as-tested conditions to the actual as-tested value.
(l) a tabular and graphical presentation of the test results
(m) a discussion and details of the test results' uncertainties
(n) a discussion of the test, its results, and the conclusions

6-5 INSTRUMENTATION

The instrumentation section of the test report should include the following information:
(a) a tabulation of instrumentation used for the primary and secondary measurements, including make, model number, tag name and number, calibration date, and bias value
(b) a description of the instrumentation location
(c) the means of data collection for each data point, such as temporary data acquisition system printout, plant control computer printout, or manual data sheet, and any identifying tag number or address of each
(d) an identification of the instrument that was used as backup
(e) a description of data acquisition system(s) used
(f) a complete description of methods of measurement not prescribed by the individual Code
(g) a summary of pretest and post-test calibration

6-6 CONCLUSIONS

The conclusions section of the test report should include the following information:
(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 information:
(a) the test requirements
(b) copies of original data sheets and/or data acquisition system printouts
(c) copies of operator logs or other recordings of operating activity during each test
(d) copies of signed valve lineup sheets and other documents indicating operation in the required configuration and disposition
(e) the performance model description and/or calculations
(f) instrumentation calibration results from laboratories and certification from manufacturers

Section 7
Uncertainty Analysis

7-1 INTRODUCTION

Test uncertainty is an estimate of the limit of error of a test result. It is the interval about a test result that contains the true value with a given probability (i.e., level of confidence). Test uncertainty is based on calculations involving probability theory, instrumentation information, calculation procedure, and actual test data. ASME PTC 19.1 covers general procedures for calculation of test uncertainty. ASME PTC 52 requires uncertainty to be calculated for a 95% level of confidence.

(a) This Code addresses test uncertainty in the following four sections:

(1) Section 1 defines the uncertainty approach.

(2) Section 3 defines the requirements for pretest and post-test uncertainty analyses and how uncertainty analyses are used in the test.

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

(4) This Section provides applicable guidance for calculating pretest and post-test uncertainties for the four test goals of this Code.

(b) Because it is required that the parties to the test agree to the quality of the test (measured by test uncertainty), pretest and post-test uncertainty analyses are an indispensable part of a meaningful performance test. An evaluation of the test uncertainty

(1) provides a measure of the quality of the test goal.

(2) helps identify actions needed to achieve the desired uncertainty. The contribution of each individual measurement to the overall uncertainty is identified. Efforts can then be concentrated on improving the most significant contributions to achieve the desired level of test accuracy.

(3) provides test run validation.

(4) demonstrates compliance with agreements.

7-2 PRETEST UNCERTAINTY ANALYSIS

In planning a test, a pretest uncertainty analysis is required as stated in para. 3-6.2.1. This analysis allows corrective action to be taken prior to the test, to either decrease the uncertainty to a level consistent with the overall objective of the test or reduce the cost of the test while still attaining the objective. An uncertainty analysis is also useful to determine the number of observations that are required for the test.

7-3 POST-TEST UNCERTAINTY ANALYSIS

A post-test uncertainty analysis shall be conducted to determine the uncertainty intervals for the actual test and to verify the assumptions made in the pretest uncertainty analysis. In particular, the data should be examined for sudden shifts and outliers. Any outliers that are the result of spurious data as determined by ASME PTC 19.1 should be eliminated to avoid inflating the post-test uncertainty. The assumptions for random error should be checked by determining the degrees of freedom and the standard deviation of each measurement. This analysis serves to validate the quality of the test results or to expose problems.

7-4 INPUTS FOR AN UNCERTAINTY ANALYSIS

To perform an uncertainty analysis for a concentrating solar power (CSP) plant, test inputs are required to estimate the uncertainty of each of the required measurements. Test inputs are also required to estimate the sensitivity of each of the required measurements on corrected results. Guidance on estimating the uncertainty and calculating the required sensitivity coefficients can be found in ASME PTC 19.1.

The following two types of uncertainties make up the total uncertainty:

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

(b) Systematic Error. Also known as bias error, systematic error is usually an accumulation of individual errors that are not eliminated through calibration. It is a constant value despite repeated measurements and is frequently difficult to quantify.

The total uncertainty is calculated from the root sum square of the random and systematic components (see ASME PTC 19.1).

7-5 CORRELATED AND UNCORRELATED APPROACHES TO UNCERTAINTY MEASUREMENT

When listing all sources of uncertainty from different categories, the sources should be defined where possible so that the uncertainties in the various sources are independent of each other. The parameters and their associated uncertainties are then considered uncorrelated. When the parameters or the uncertainty in those parameters are not independent of each other, they are considered correlated. The correlation can be either positive or negative and can be between 0% and 100%. There are many situations where systematic errors from some of the parameters are correlated. For example, errors are correlated when the same instrument is used to measure different parameters, different instruments are calibrated against the same standard, or similar instruments are used to measure the same parameter. In these cases, some of the systematic errors are said to be correlated and these errors shall be considered in the determination of the systematic uncertainty. For example, a group of potential transformers purchased from the same factory at the same time may exhibit a characteristic bias resulting from the specific equipment, materials, and processes used in their manufacture. Similar effects may be seen in flow-metering devices, temperature measurement devices, and pressure transmitters. The handling of correlated uncertainties can be difficult. It can be particularly difficult in cases of partial correlation, because this requires the use of mathematically complex procedures to establish the covariances. As such, for most practical applications, the simpler techniques described below should be used to estimate the effects of correlated systematic uncertainties. If the mathematical relationship of the correlated parameters cannot be redefined to eliminate the correlations, experience and engineering judgment is required to estimate the degree of correlation. One approach is to use an analysis technique that divides the sources of uncertainty into correlated and uncorrelated categories and to carry out parallel analyses adding contributions linearly for the correlated sources and by root sum square for the uncorrelated sources as described in ASME PTC 19.1. An alternate approach is to perform uncertainty analyses based on fully correlated and uncorrelated measurements to establish a range.

7-6 UNCERTAINTY CALCULATIONS

This subsection details the calculations that shall be completed to determine the systematic and random uncertainties of the measurements and result as well as the combined result uncertainty.

7-6.1 Systematic Standard Uncertainties

7-6.1.1 Measurement Systematic Standard Uncertainty, $b_{\overline{X}}$. As previously stated, this is the error, associated with a measurement, that cannot be eliminated by calibration of the instrument. Section 4 provides guidelines for estimated systematic standard uncertainties based on measurement and instrument types.

7-6.1.2 Systematic Standard Uncertainty Due to Spatial Variation, b_{spatial}. An additional systematic uncertainty may be attributed to multiple measurements of a parameter that are spatially distributed. Spatial effects are considered to be systematic, not random, and can be evaluated statistically.

$$b_{\text{spatial}} = \frac{s_{\text{spatial}}}{\sqrt{J}} \tag{7-6-1}$$

where

J = number of sensors (i.e., spatial measurement locations)

s_{spatial} = standard deviation of the multiple sensor time-averaged values

$$= \sqrt{\frac{\sum_{i=1}^{J}(\overline{X}_i - \overline{\overline{X}})^2}{J-1}}$$

$\overline{X}_i$ = average for the sampled location

$\overline{\overline{X}}$ = grand average for all averaged parameter measurement locations

When spatial variation is expected, careful planning for the number and location of sensors is critical to reducing the impact of spatial variation on uncertainty.

7-6.2 Measurement Random Standard Uncertainty, $s_{\overline{X}}$

The measurement random standard uncertainty is attributable to the nonrepeatability of the measurement system as follows:

$$\overline{X} = \frac{\sum_{j=1}^{N} X_j}{N} \tag{7-6-2}$$

where
N = number of sample measurements
$\overline{X}$ = average of the measurements over the test period
X_j = value of each individual measurement in the sample

The standard deviation of the sample s_X is given by

$$s_X = \sqrt{\sum_{j=1}^{N} \frac{(X_j - \overline{X})^2}{N - 1}} \tag{7-6-3}$$

The random standard uncertainty is the standard deviation of the mean, or

$$s_{\overline{X}} = \frac{s_X}{\sqrt{N}} \tag{7-6-4}$$

7-6.3 Sensitivity Coefficients, Θ_i

The sensitivity coefficients may be numerically determined by using the design model to evaluate the effect of perturbation of a single measurement value on the result.

$$\Theta_i = \frac{\partial R}{\partial X_i} \tag{7-6-5}$$

where
∂R = change in result
∂X_i = change in measurement
Θ_i = sensitivity coefficient for parameter i

7-6.4 Combined Uncertainty of the Result, U_R

The combined uncertainty of the result, U_R, for a given parameter is the residual sum of squares value of the systematic and random standard uncertainties of each measurement multiplied by the sensitivity coefficient, Θ_i, for that parameter. Alternate equivalent formulations are

$$b_R = \sqrt{\sum_{i=1}^{I} (\Theta_i b_{\overline{X}_i})^2} \tag{7-6-6}$$

$$s_R = \sqrt{\sum_{i=1}^{I} (\Theta_i s_{\overline{X}_i})^2} \tag{7-6-7}$$

$$U_R = t_{95} \times \sqrt{(b_R)^2 + (s_R)^2} \tag{7-6-8}$$

where

b_{Ri} = systematic standard uncertainty component of a result

$b_{\overline{X}_i}$ = $\sqrt{b_{\text{spatial}}^2 + b_{\overline{X}}^2}$ (see para. 7-6.1.1)

s_R = random standard uncertainty component of a result

$s_{\overline{X}i}$ = random standard uncertainty for parameter i

t_{95} = value of the student's t

U_R = uncertainty of the result with 95% confidence interval

Θ_i = sensitivity coefficient for parameter i

Therefore, the interval within which the true result should lie with 95% confidence is the measured result $\pm U_R$.

NONMANDATORY APPENDIX A
THERMAL ENERGY STORAGE

A-1 OBJECT AND SCOPE

A-1.1 Object

All principles, procedures, methods, and definitions in the Code are applicable for this Appendix as well. The purpose of this Appendix is to provide procedures, methods, and definitions that are not included in the main portion of the Code, but which are relevant for performance testing of the solar-to-thermal conversion systems where they include thermal energy storage (TES) systems. See Figures A-1.1-1 and A-1.1-2 for examples of typical direct and indirect TES systems.

It is intended that accurate instrumentation and measurement techniques shall be used to determine the following performance results, as required:

(a) storage capacity
(b) thermal efficiency
(c) storage charging rate
(d) storage discharging rate
(e) auxiliary load consumption
(f) thermal losses of storage tanks

A-1.2 Scope

This Appendix is provided for guidance only and is not a mandatory part of the Code. The specific testing shall be agreed upon between the parties. It is anticipated that this Appendix will eventually be superseded by a specific ASME PTC.

This Appendix contains methods for conducting and reporting of performance for hot tank–cold tank TES systems.

NOTE: Phase change material and thermocline storage system characteristics and test parameters are different from two-tank systems characteristics and test parameters, and therefore phase change material and thermocline storage systems are not covered by this Appendix. Parameters and test methods for these storage systems, including allowances for items such as chemical degradation and temperature hysteresis, shall be agreed upon between the parties to the test.

A-1.3 Uncertainty

The methods for calculating uncertainty in the Code apply to this Appendix. The acceptable uncertainty values shall be agreed to by the parties to the test.

A-2 DEFINITIONS AND DESCRIPTIONS OF TERMS

The symbols and definitions described in Section 2 of the Code shall apply to this Appendix.

A-3 GUIDING PRINCIPLES

The guiding principles discussed in Section 3 of the Code apply to this Appendix. TES-specific tests described here are all short-term performance tests. Multiday performance tests may or may not include TES within the test boundary and are described in the main portion of the Code.

A-3.1 Tests

The test goals include the following:

(a) storage capacity
(b) thermal efficiency
(c) storage charging rate
(d) storage discharging rate

Figure A-1.1-1 Typical Direct TES Hot Tank–Cold Tank Configuration With Discharge Heat Exchanger

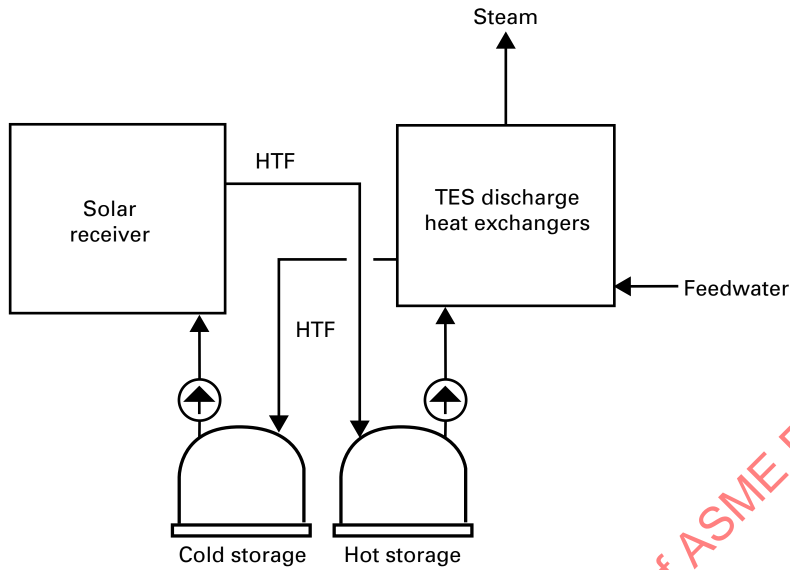


Figure A-1.1-2 Typical Indirect TES Hot Tank–Cold Tank Configuration With Charge and Discharge Heat Exchanger