AN AMERICAN NATIONAL STANDARD

ASME PTC 46-1996

Performance Test Code on Overall Plant Performance

PERFORMANCE TEST CODES

The American Society of Mechanical Engineers

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FOREWORD

(This Forword is not a part of ASME PTC 46-1996.)

Code Origins

ASME Performance Test Codes (PTCs) have been developed and have long existed for determining the performance of most major components used in electric power production facilities. A Performance Test Code has heretofore not existed to determine the overall performance of a power production facility. Changes in the electric power generation industry have increased the need for a code addressing overall power plant performance testing. In response to these needs, the ASME Board on Performance Test Codes approved the formation of a committee (PTC 46) in June 1991 with the charter of developing a code for the determination of overall power plant performance. The organizational meeting of this Committee was held in September 1991. The resulting Committee included experienced and qualified users, manufacturers, and general interest category personnel from both the regulated and non-regulated electric power generating industry.

In developing this Code, the Committee reviewed common industry practices with regard to overall power plant and cogeneration facility testing. The Committee was not able to identify any general consensus testing methods, and discovered many conflicting philosophies. The Committee has strived to develop an objective code which addresses the multiple needs for explicit testing methods and procedures, while attempting to provide maximum flexibility in recognition of the wide range of plant designs and the multiple needs for this Code.

This Code was approved by the PTC 46 Committee on May 10, 1996. It was then approved and adopted by the Council as a Standard practice of the Society by action of the Board on Performance Test Codes on October 14, 1996. It was also approved as an American National Standard by the ANSI Board of Standards Review on November 27, 1996.

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SECTION 0 — INTRODUCTION

0.1 APPLICATIONS AND LIMITATIONS

Power plants which produce secondary energy outputs (i.e., cogeneration facilities) are included within the scope of this Code. For cogeneration facilities, there is no requirement for a minimum percentage of the facility output to be in the form of electricity; however, the guiding principles, measurement methods, and calculation procedures are predicated on electricity being the primary output. As a result, a test of a facility with a low proportion of electric output may not be capable of meeting the expected test uncertainties of this Code.

This Code provides explicit procedures for the determination of power plant thermal performance and electrical output. Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. Test results can then be used as defined by a contract for the basis of determination of fulfillment of contract guarantees. Test results can also be used by a plant owner, for either comparison to a design number, or to trend performance changes over time of the overall plant. The results of a test conducted in accordance with this Code will not provide a basis for comparing the thermoeconomic effectiveness of different plant designs.

Power plants are comprised of many equipment components. Test data required by this Code may also provide limited performance information for some of this equipment; however, this Code was not designed to facilitate simultaneous code level testing of individual equipment. ASME PTCs which address testing of major power plant equipment provide a determination of the individual equipment isolated from the rest of the system. PTC 46 has been designed to determine the performance of the entire heat-cycle as an integrated system. Where the performance of individual equipment operating within the constraints of their design-specified conditions are of interest, ASME PTCs developed for the testing of specific components should be used. Likewise, determining overall thermal performance by combining the results of ASME code tests conducted on each plant component is not an acceptable alternative to a PTC 46 test.

0.2 GUIDANCE IN USING THIS CODE

As with all PTCs, PTC 46 was developed primarily to address the needs of contract acceptance or compliance testing. This is not intended, however, to limit or prevent the use of this Code for other types of testing where the accurate determination of overall power plant performance is required.

This Code is not a tutorial. It is intended for use by persons experienced in performance testing. A working knowledge of power plant operations, thermodynamic analysis, test measurement methods, and the use, control, and calibration of measuring and test equipment are presumed prerequisites. Proper use and interpretation of this Code also requires a working knowledge of ASME Performance Test Codes. At a minimum, users of this Code should be familiar and knowledgeable with the following:

- PTC 1, *General Instructions*
- PTC 19.1, *Measurement Uncertainty*

Other PTC 19 Instrument and Apparatus Supplement series codes and the applicable PTC 3 series on fuel sampling and analysis may need to be consulted during the planning and preparation phases of a test. In addition, some measurement methods specified in PTC 46 refer to PTCs for testing of specific equipment.

Use of PTC 46 is recommended whenever the performance of a heat-cycle power plant must be determined with minimum uncertainty. It is suitable for incorporation into commercial agreements as the means of determining fulfillment of contract obligations. However, incorporation of PTC 46 into a contract does not eliminate the need for test planning. PTC 46 provides the protocol, or framework, for a test. As defined in Section 3, the use of PTC 46 requires the development of a detailed test plan that must be approved by all parties to the test. This test plan must be reviewed and approved by all parties prior to the start of testing.

SECTION 1 — OBJECT AND SCOPE

1.1 OBJECT

The objective of this Code is to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and cogeneration facilities.

This Code provides explicit procedures for the determination of the following performance results:

- corrected net power
- corrected heat rate
- corrected heat input

Tests may be designed to satisfy different goals, including:

- specified disposition
- specified net corrected power
- specified net power

1.2 SCOPE

This Code applies to any plant size. It can be used to measure the performance of a plant in its normal operating condition, with all equipment in a clean and fully-functional condition. This Code provides explicit methods and procedures for combined-cycle power plants and for most gas, liquid, and solid fueled Rankine cycle plants. There is no intent to restrict the use of this Code for other types of heat-cycle power plants, providing the explicit procedures can be met. It does not, however, apply to simple-cycle gas turbine power plants (see ASME PTC 22 instead). The scope of this Code begins for a gas turbine-based power generating unit when a heat-recovery steam generator is included within the test boundary.

To test a particular power plant or cogeneration facility, the following conditions must be met.

(a) a means must be available to determine, through either direct or indirect measurements, all of the heat inputs entering the test boundary and all of the electrical power and secondary outputs leaving the test boundary;

(b) a means must be available to determine, through either direct or indirect measurements, all of the parameters to correct the results from the test to the base reference condition;

(c) the test result uncertainties are expected to be less than or equal to the uncertainties given in Subsection 1.3 for the applicable plant type; and

(d) the working fluid for vapor cycles must be steam. This restriction is imposed only to the extent that other fluids may require measurements or measurement methods different from those provided by this Code for steam cycles. In addition, this Code does not provide specific references for the properties of working fluids other than steam.

Tests addressing other power plant performance-related issues are outside the scope of this Code. These include the following:

emissions tests: testing to verify compliance with regulatory emissions levels (e.g., airborne gaseous and particulate, solid and wastewater, noise, etc.), or required for calibration and certification of emission-monitoring systems.

operational demonstration tests: the various standard power plant tests typically conducted during start-up, or periodically thereafter, to demonstrate specified operating capabilities (e.g., minimum load operation, automatic load control and load ramp rate, fuel switching capability, etc.).

reliability tests: tests conducted over an extended period of days or weeks to demonstrate the capability of the power plant to produce a specified minimum output level or availability. The measurement methods, calculations, and corrections to design conditions included herein may be of use in designing tests of this type; however, this Code does not address this type of testing in terms of providing explicit testing procedures or acceptance criteria.

1.3 TEST UNCERTAINTY

The explicit measurement methods and procedures have been developed to provide a test of the highest

TABLE 1.1
LARGEST EXPECTED TEST UNCERTAINTIES

Type of Plant	Description	Corrected Heat Rate (%)	Corrected Net Power (%)
Simple cycle with steam generation	Gas turbine with exhaust heat used for steam generation	1.5	1.0
Combined cycles	Combined gas turbine and steam turbine cycles with or without supplemental firing to a steam generator	1.5	1.0
Steam cycle	Direct steam input (e.g. geothermal)	1.5	1.0
Steam cycle	Consistent liquid or gas fuel	1.5	1.0
Steam cycle	Consistent solid fuel	3.0	1.0

level of accuracy consistent with practical limitations. Any departure from Code requirements could introduce additional uncertainty beyond that considered acceptable to meet the objectives of the Code.

It is recognized there is a diverse range of power plant designs which can be generally categorized for purposes of establishing testing methods and uncertainties. The uncertainty levels achievable from testing in accordance with this Code are dependent on the plant type, specific design complexity, and consistency of operation during a test. The largest expected test uncertainties are given in Table 1. If a plant design does not clearly fall under one of the categories included in Table 1, the parties must reach agreement on the most appropriate category.

The Table 1 values are not targets. A primary philosophy underlying this Code is that the lowest achievable uncertainty is in the best interest of all parties to the test. Deviations from the methods recommended in this Code are acceptable only if it can be demonstrated they provide equal or lower uncertainty.

A pretest uncertainty analysis shall be performed to establish the expected level of uncertainties for the test. Most tests conducted in accordance with this Code will result in uncertainties that are lower than those shown in Table 1. If the pretest uncertainty analysis indicates that the test uncertainty is greater than that listed in Table 1, the test must be redesigned so as to lower the test uncertainty or the parties to the test may agree, in writing, to higher uncertainty. A post-test uncertainty analysis is also required to validate the test. If the post-test uncertainty is higher than the agreed upon maximum expected uncertainty, then the test is not valid.

SECTION 2 — DEFINITIONS AND DESCRIPTION OF TERMS

2.1 SYMBOLS

ω_1,Δ_1: additive correction factors to thermal heat input and power, respectively, to correct to base reference thermal efflux

ω_2,Δ_2: additive correction factors to thermal heat input and power, respectively, to correct to base reference generator power factor

ω_3,Δ_3: additive correction factors to thermal heat input and power, respectively, to correct to base reference steam generator blowdown

ω_4,Δ_4: additive correction factors to thermal heat input and power, respectively, to correct to base reference secondary heat inputs

ω_{5A},Δ_{5A}: additive correction factors to thermal heat input and power, respectively, to correct to base reference air heat sink conditions

ω_{5B},Δ_{5B}: additive correction factors to thermal heat input and power, respectively, to correct to base reference circulation water temperature

ω_{5C},Δ_{5C}: additive correction factors to thermal heat input and power, respectively, to correct to base reference condenser pressure

ω_6,Δ_6: additive correction factors to thermal heat input and power, respectively, to correct to base reference auxiliary loads

ω_7,Δ_7: additive correction factors to thermal heat input and power, respectively, to correct for measured power different from specified if test goal is to operate at a predetermined power. Can also be used if required unit operating disposition is not as required.

β_1,α_1,f_1: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference inlet temperature

β_2,α_2,f_2: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference inlet pressure

β_3,α_3,f_3: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference inlet humidity

β_4,α_4,f_4: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference fuel supply temperature

β_5,α_5,f_5: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference fuel composition

f_n: multiplicative correction factors to measured plant heat rate, dimensionless

HR: heat rate, Btu/kW-hr

HV: heating value, Btu/lbm

P: power, kW or MW

Q: subscripted with "meas" or "corr," *Q* is thermal heat input from fuel, Btu/hr. Otherwise refers to other sources of heat in the same units.

qm or *m*: mass flow, lbm/hr

α_n: multiplicative correction factors to measured plant power, dimensionless

β_n: multiplicative correction factors to measured plant thermal heat input, dimensionless

Δ_n: additive correction factors to measured plant power, kW

λ_n: multiplicative correction factors to auxiliary loads

ω_n: additive correction factors to measured plant heat input

2.1.1 Abbreviations Used in Subscripts

corr: corrected result to base reference conditions

GT: gas turbine

meas: measured or determined result prior to correcting to base reference conditions

ST: steam turbine

2.2 TERMS

base reference conditions: the values of all the external parameters, i.e., parameters outside the test boundary to which the test results are corrected. Also, the specified secondary heat inputs and outputs are base reference conditions.

bias (systematic) uncertainty: refer to PTC 19.1 for definition

consistent liquid or gas fuels: fuels with a heating value that varies less than one percent over the course of a performance test

consistent solid fuels: fuels with a heating value that varies less than two percent over the course of a performance test

cogeneration plant: any cycle which produces both electric power and at least one secondary output for use in a process external to the test boundary

corrected heat input: the primary heat input entering the test boundary corrected to base reference conditions

corrected heat rate: the test calculated heat rate corrected to specified base reference and secondary output conditions

corrected net power: the net power leaving the test boundary at the test-specified operating conditions and corrected to the specified base and secondary output conditions

coverage: refer to PTC 19.1 for definition

error (measurement, elemental, random, sampling, bias, precision): refer to PTC 19.1 for definition

net power: the net plant electrical power leaving the test boundary

heat sink: the reservoir to which the heat rejected to the steam turbine condenser is transferred. For a cooling pond, river, lake, or ocean cooling system, the reservoir is the body of water. For an evaporative or dry air cooled heat exchanger system, the reservoir is the ambient air.

precision (random) uncertainty: refer to PTC 19.1 for definition

primary heat input: energy supplied to the cycle from fuel or other source (such as steam) available for conversion to net power plus secondary outputs

primary variables: those used in calculations of test results. They are further classified as:

Class 1: primary variables are those which have a relative sensitivity coefficient of 0.2 or greater

Class 2: primary variables are those which have a relative sensitivity coefficient of less than 0.2

secondary heat inputs: the additional heat inputs to the test boundary which must be accounted for, such as cycle make-up and process condensate return

secondary outputs: any useful nonelectrical energy output stream which is used by an external process

secondary variables: variables that are measured but do not enter into the calculation of the results

sensitivity coefficient, absolute or relative: refer to PTC 19.1 for definition

specified corrected net power test: a test run at a specified corrected net power that is near to the design value of interest, for example, an acceptance test of a steam cycle plant where heat rate is guaranteed at a specific load, and partial-load tests for development of heat rate curve conditions

specified disposition test: a test run at a specified plant disposition with both load and heat rate determined by the test. Examples of this test goal are valve-point testing on a steam cycle plant (including maximum capability testing) and base-load testing on a combined cycle plant with or without duct firing.

specified net power test: a test run at a specified net power regardless of ambient or other external conditions. An example of this test goal is acceptance test on a duct fired combined cycle plant with an output guarantee over a range of ambient temperatures

test boundary: identifies the energy streams required to calculate corrected results

uncertainty: an estimate of the error. Refer to PTC 19.1.

SECTION 3 — GUIDING PRINCIPLES

3.1 INTRODUCTION

This Section provides guidance on the conduct of overall plant testing, and outlines the steps required to plan, conduct, and evaluate a Code test of overall plant performance. The Subsections discuss the following:

- test plan (Subsection 3.2)
- test preparations (Subsection 3.3)
- conduct of test (Subsection 3.4)
- calculation and reporting of results (Subsection 3.5)

The Code recognizes that different types of plants and even different types of tests will have a unique test goal and operating mode. The following illustrate the different test goals considered by the Code and includes examples.

(a) The test can be run at a specified disposition with both load and heat rate determined by the test. An example of this test goal would be valve-point testing on a steam cycle plant (including maximum capability testing) or base-load testing on a combined cycle plant with or without duct firing.

(b) The test can be run at a specified corrected net power that is near to the design value of interest. Examples of this test would be an acceptance test of a steam cycle plant where heat rate is guaranteed at a specific load, or partial-load tests for development of heat rate curves.

(c) The test can be run at a specified net power regardless of ambient or other external conditions. An example of this test goal is an acceptance test on a duct-fired combined cycle plant with an output guarantee over a range of ambient temperatures.

Regardless of the test goal, the results of a Code test will be corrected net power and either corrected heat rate or corrected heat input. The test must be designed with the appropriate goal in mind to ensure proper procedures are developed, the appropriate operating mode during the test is followed, and the correct performance equations are applied. Section 5 provides information on the general performance equation and variations of the equation to support specific test goals.

3.1.1 Test Boundary and Required Measurements. The test boundary identifies the energy streams which must be measured to calculate corrected results. The test boundary is an accounting concept used to define the streams that must be measured to determine performance. All input and output energy streams required for test calculations must be determined with reference to the point at which they cross the boundary. Energy streams within the boundary need not be determined unless they verify base operating conditions or unless they relate functionally to conditions outside the boundary.

The methods and procedures of this Code have been developed to provide flexibility in defining the test boundary for a test. In most cases, the test boundary encompasses all equipment and systems on the plant site. However, specific test objectives may mandate a different test boundary. For example, an acceptance test may be required for a bottoming cycle that is added in the repowering portion of an upgrade.

For this Code to apply, the test boundary must encompass a discrete electric-power-producing heat cycle. This means that the following energy streams must cross the boundary:

- all heat inputs
- net electrical output and any secondary outputs

For a particular test, the specific test boundary must be established by the parties to the test. Some or all of the typical streams required for common plant cycles are shown in Fig. 3.1.

Solid lines indicate some or all of mass flow rate, thermodynamic conditions, and chemical analysis of streams crossing the test boundary, which have to be determined to calculate the results of an overall plant performance test.

The properties of streams indicated by dashed lines may be required for an energy and mass balance, but may not have to be determined to calculate test results.

Typical test boundaries for the two most common applications — steam power plants and combined cycle power plants — are shown in Figs. 3.2 and 3.3, respectively. If these plants were cogeneration

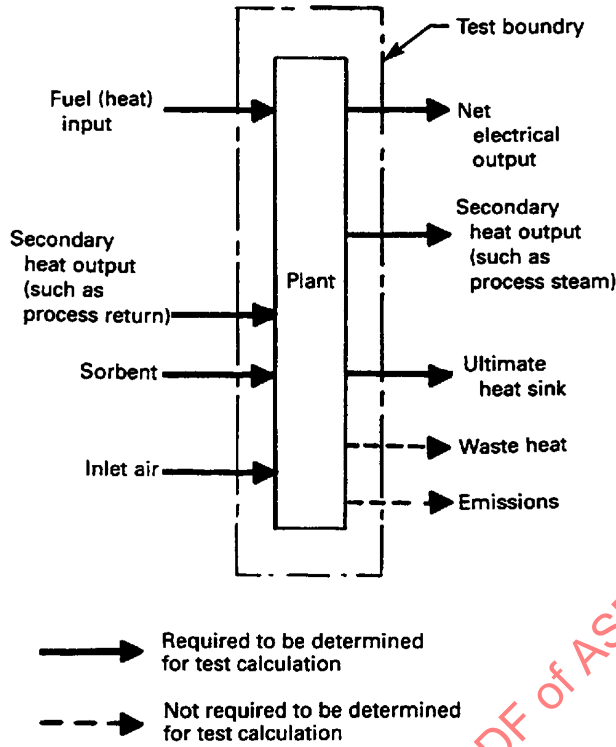


FIG. 3.1 GENERIC TEST BOUNDARY

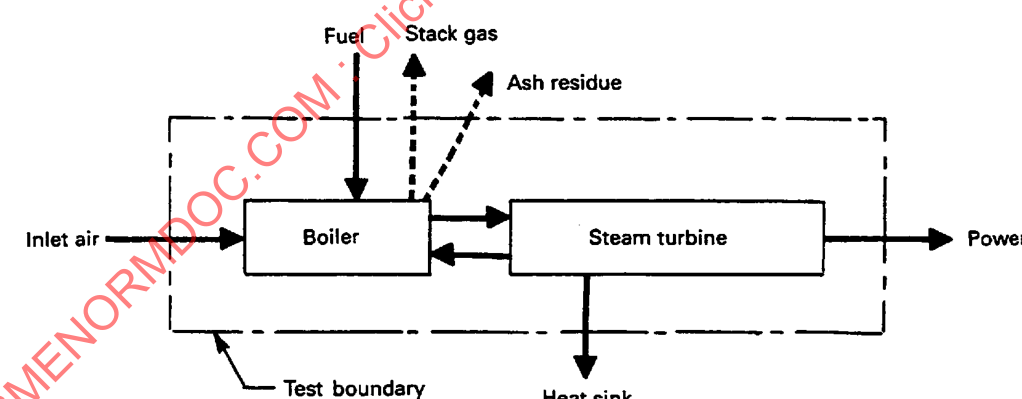


FIG. 3.2 TYPICAL STEAM PLANT TEST BOUNDARY

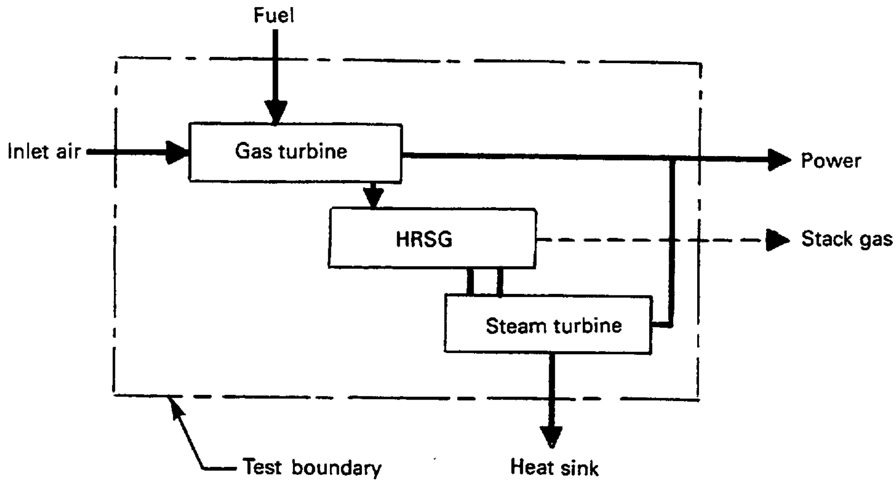


FIG. 3.3 TYPICAL COMBINED CYCLE PLANT TEST BOUNDARY

plants, secondary process input and output streams would also be shown crossing the test boundary.

More definitive test boundaries for specific representative cycles are shown in Figs. 5.1, 5.2, 5.3, and in the appendices describing sample calculations.

3.1.2 Required Measurements. Some flexibility is required by this Code in defining the test boundary, since it is somewhat dependent on a particular plant design. In general, measurements or determinations are required for the following streams.

3.1.2.1 Primary Heat Input. Measure or calculate fuel mass flow and heating value at the point at which they cross the test boundary. The test boundary would typically be where the fuel enters the plant equipment; however, the actual measurement may be upstream or downstream of that point if a better measuring location is available and if the flow and fuel constituents at the metering point are equivalent to or can be accurately corrected to the conditions at the test boundary.

For gas and liquid fuels, the method of primary heat input determination depends on the particular fuel and plant type. In most cases, it is determined by the product of the measured fuel flow and the average fuel heating value. If the plant is a steam turbine plant fired by gas or liquid fuels, primary heat input is sometimes determined by the product of the heat input to the steam and the inverse of the steam generator efficiency determined by the energy balance method (also called the heat loss method).

For solid fuels of consistent constituency, the energy balance method is required.

The use of higher heating value is preferred, but lower heating value may also be used. For solid fuel plants, the use of higher heating value requires that latent heat losses be accounted for in the energy balance method of evaluating plant thermal input.

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

3.1.2.2 Secondary Heat Inputs. Secondary heat inputs to the cycle may include process energy return; make-up, and low energy external heat recovery. Measurements to determine the mass flow and energy level are required for correction to the base reference conditions.

3.1.2.3 Inlet Air For Combustion. The total pressure, the dry bulb temperature, and the specific humidity are required for combustion air where the air enters the plant equipment. Measurement of inlet air conditions is discussed in Appendix G.

3.1.2.4 Sorbents. The quality, analysis, and quantity of sulfur sorbent or other chemical additives which affect the corrected heat rate or corrected net power must be measured for correction to the design conditions. Corrections for sorbent injection rate are limited to variations attributable to differences between test and design fuel or sorbent characteristics, or due to variations attributable to ambient conditions.

3.1.2.5 Electric Power. The electric power output from the plant is the net plant output at the test boundary, which is generally on the load side of a step-up transformer. The specific point of measurement may be at that location, or may be made by measuring the generator outputs and the auxiliary loads with corrections for step-up transformer losses based on transformer efficiency tests. The criteria for selection of the specific measurement points is based on a determination of the lowest achievable uncertainty.

3.1.2.6 Secondary Outputs. Nonelectrical energy outputs must be determined to calculate the results.

3.1.2.7 Emissions. Emissions are any discharge across the test boundary which must be limited to meet regulatory or other licensing requirements. These may include gaseous, particulate, thermal, or noise discharges to the ambient air, waterways, or the ground. Determinations of emissions are outside the scope of this Code, and as such, no emission limitations or required measurements are specified. However, since emissions limits may have an effect on results, the test plan must specify emission levels or limits, as required operation conditions for the test.

3.1.2.8 Heat Sink Conditions. Corrections to the plant output are required for differences between the design and test heat sink conditions. The parameters of interest depend on the type of heat sink used. For open cycle cooling, it is the temperature of the circulating water where it crosses the test boundary. For an evaporative cooling tower, it is the barometric pressure and the ambient air wet-bulb temperature. For a dry air cooling system, it is the ambient air barometric pressure and dry-bulb temperature. When the test boundary excludes the heat rejection system, the correction is based on the steam turbine exhaust pressure.

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

3.1.2.10 Specific Required Measurements. The specific measurements required for a test depend on the particular plant design and the test boundary required to meet the specific test intent.

3.1.3 Application of Corrections. The calculation of results for any plant or thermal island described by this Code requires adjusting the test-determined values of thermal input and power by the application of additive and multiplicative correction factors. The general forms of these equations are:

$$P_{corr} = (P_{meas} + \text{additive "}P\text{" corrections}) \times (\text{multiplicative "}P\text{" corrections})$$

$$HR_{corr} = \frac{Q_{meas} + \text{additive "}Q\text{" corrections}}{P_{meas} + \text{additive "}P\text{" corrections}} \times (\text{multiplicative "}HR\text{" corrections})$$

An alternate definition of corrected heat rate is:

$$HR_{corr} = Q_{corr}/P_{corr}$$

where

$$Q_{corr} = (Q_{meas} + \text{additive "}Q\text{" corrections}) \times (\text{multiplicative "}Q\text{" corrections})$$

The format of the general equations identify and represent the various corrections to measured performance and to mathematically decouple them so that they can be applied separately. The correction factors are also identified as being necessary due to operational effects for which corrections are allowable, such as those caused by changes in cogeneration plant process flows, and as those necessary due to uncontrollable external effects, such as inlet air temperature to the equipment.

Also, Section 5 permits the Code user to utilize a heat balance computer program with the appropriate test data input following a test run, so that the corrected performance can be calculated from data with only one heat balance run necessary.

While these correction factors are intended to account for all variations from base reference conditions, it is possible that plant performance could be affected by processes or conditions that were not foreseen at the time this Code was written. In this case, additional correction factors, either additive or multiplicative, would be required.

All correction factors must result in a zero correction if all test conditions are equal to the base reference conditions.

3.1.4 Design, Construction, and Start-up Considerations. During the design phase of the plant, consideration should be given to accurately conducting acceptance testing for overall performance for the specific type of plant.

Consideration should also be given to the requirements of instrumentation accuracy, calibration, recalibration documentation requirements, and location of permanent plant instrumentation to be used for testing. Adequate provisions for installation of temporary instrumentation where plant instrumentation is not adequate to meet the requirements of this Code must also be considered during the design stages. For example, all potential transformers (PTs) and current transformers (CTs) used for power measurement should be calibrated.

If the steam or electrical hosts are unable to accept electricity or process steam, make other provisions to maintain the test values within the appropriate "Permissible Deviations from Design" values in Table 3.2.

Table 3.1 lists the items to consider during the specific plant design, construction, and start-up.

3.2 TEST PLAN

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

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

3.2.1 Schedule of Test Activities. A test schedule should be prepared which should include the sequence of events and anticipated time of test, notification of the parties to the test, test plan preparations, test preparation and conduct, and preparation of the report of results.

3.2.2 Responsibilities of Parties. The parties to the test should agree on individual responsibilities required to prepare, conduct, analyze, and report the test in accordance with this Code. This includes agreement on the organization of test personnel and designation of a test coordinator who will be responsible for the execution of the test in accordance with the test requirements and will coordinate the setting of required operating conditions with the plant operations staff.

Representatives from each of the parties to the test should be designated who will observe the test and confirm that it was conducted in accordance with the test requirements. They should also have the authority, if necessary, to approve any agreed upon revisions to the test requirements during the test.

3.2.3 Test Procedures. The test plan should include test procedures that provide details for the conduct of the test. The following are included in the test procedures:

(a) objective of test and method of operation

(b) test acceptance criteria for test completion

(c) base reference conditions

(d) defined test boundaries identifying inputs and outputs and measurements locations

(e) the intent of any contract or specification as to operating conditions, performance guarantees, and environmental compliance

(f) complete pretest uncertainty analysis, with bias uncertainties established for each measurement

(g) specific type, location, and calibration requirements for all instrumentation and measurement systems and frequency of data acquisition

(h) measurement requirements for applicable emissions, including measurement location, instrumentation, and frequency and method of recording

(i) sample, collection, handling, and analysis method and frequency for fuel, sorbent, ash, etc.

(j) method of plant operation

(k) identification of testing laboratories to be used for fuel, sorbent, and ash analyses

(l) required operating disposition or accounting for all internal thermal energy and auxiliary power consumers having a material effect on test results

(m) required levels of equipment cleanliness and inspection procedures

(n) procedures to account for performance degradation, if applicable

(o) valve line-up requirements

(p) preliminary testing requirements

(q) pretest stabilization criteria

(r) required steadiness criteria and methods of maintaining operating conditions within these limits

TABLE 3.1
DESIGN, CONSTRUCTION, AND START-UP CONSIDERATIONS

No.	Item	Elect	Flow	Press.	Temp.
1	Permanent plant instrumentation used for test measurements	X	X	X	X
2	Connections and spool sections	X	X	X	X
3	Changes in location		X	X	X
4	Changes in loop routing		X	X	X
5	Applicability	X	X	X	X
6	Access	X	X	X	X
7	Environment effects	X	X	X	X
8	Quantity			X	X
9	Layout	X	X	X	
10	Ability to duplicate measurement	X	X	X	X
11	Installation timing		X		
12	Up & down stream straight lengths		X		
13	Water leg correction		X	X	
14	Water leg inspection		X	X	
15	Condensate pots		X	X	
16	Heat tracing		X	X	

NOTES:

(1) Permanent Plant Instrumentation Used for Test Measurements. It must be considered in the plant design if it is desired to use some permanent plant instrumentation for primary measurements. Such permanent plant instrumentation must meet the Class 1 requirements of Section 4 if it must be considered Code quality Class 1 instrumentation, or the Class 2 requirements of Section 4 if lesser accuracy is acceptable. This includes obtaining appropriate laboratory calibrations and submitting all laboratory calibration reports, certifications or calibration results for all permanent plant instrumentation used for the test, as applicable. The ability to do post-test recalibrations or verifications is required as described in this Code. Many times, after considering such requirements, it may be decided to use temporary instrumentation in some areas where permanent instrumentation was initially desired to be used. Similarly, it might also be determined to use alternate permanent instrumentation. These decisions are best taken care of in the design stages.

(2) Connections and spool sections required for temporary test instrumentation which will be used for primary measurements. Pressure connections, thermowells, spool sections for flow meters, and electrical metering tie-ins for temporary test instrumentation needed to meet the Class 1 requirements of Section 4 should be incorporated into the plant design.

(3) Changes in Location. Documentation that records the relocation of items in the process variable loop routing during the design and/or the construction phase of the plant. Any impact on test uncertainty should be identified and reviewed with consideration to contractual and code limitations. An example is the relocation of a flow meter within a process line.

(4) Changes in Loop Routing. An example is the rerouting of condensate legs.

(5) Applicability. The proximity to the desired test process value measured. Note whether the recorded value is an instantaneous or average value. Note also the historical logging capabilities necessary for the testing.

(6) Access is required for inspection, calibration, and any temporary instrument installation and removal.

(7) Minimize EMF effects, vibration and pulsation to instruments, and instrument loops. Ensure proper grounding for instrument circuits and digital systems.

(8) Quantity of devices and instrument ports available at one location to reduce uncertainty and provide contingency data acquisition. An example is using two (2) or dual element thermocouples to measure critical temperatures.

(9) Layout of instrument loops to minimize measurement error. Precautions are listed in Section 4 of this Code. If instrument transformers are used, adequate wire size should be used to reduce voltage drops and a neutral cable should be provided to enable accurate 3-phase watt metering.

(10) Ability to duplicate measurements. This allows a validation of process value and includes a contingency plan for test measurements. A separate device should be identified to collaborate and backup a test measurement.

(11) Timing of flow elements installation with respect to acid cleaning and/or steam blows. For instance, a calibrated flow measuring device should not be installed prior to acid cleaning or steam blows.

(12) Up and down stream straight lengths for flow elements to minimize uncertainty. The upstream and downstream lengths impact the flow measurement uncertainty, and therefore should be maximized.

(13) Water leg correction necessary for accurate process variable measurement. A difference in flow measurement tap elevation will alter the differential pressure measured at a zero flow condition. Flow measurement devices should be installed in horizontal pipe runs.

(14) Ability to inspect water legs to validate water leg height.

(15) Accessible condensate pots to check or refill condensate lines to transmitter.

(16) Validate the installation of heat tracing. A check should be made to validate that heat tracing done on water legs is in accordance with manufacturer's instructions to prevent boiling of condensate.

(s) allowable variations from base reference conditions and methods of setting and maintaining operating conditions within these limits

(t) number of test runs and durations of each run

(u) test start and stop requirements

(v) data acceptance and rejection criteria

(w) allowable range of fuel conditions, including constituents and heating value

(x) correction curves or algorithms

(y) sample calculations or detailed procedures specifying test run data reduction and calculation and correction of test results to base reference condition

(z) the method for combining test runs to calculate the final test results

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

(bb) test report format, contents, inclusions, and index

3.3 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, or documentation. Updated information should be provided as it becomes known.

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

Personnel and instrumentation involved in the test should be considered. For example, provision of safe access to test point locations, availability of suitable utilities and safe work areas for personnel as well as potential damage to instrumentation or calibration shifting because of extreme ambient conditions such as temperature or vibration.

Documentation must 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.

The remainder of this Subsection describes preparations relating to:

- test apparatus (3.3.1)
- test personnel (3.3.2)
- equipment inspection and cleanliness (3.3.3)
- preliminary testing (3.3.4)

3.3.1 Test Apparatus. Test instruments are classified as described in para. 4.1.2.1. Instrumentation used for data collection must be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can either be permanent plant instrumentation or temporary test instrumentation.

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 30 readings 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 prior to and after the test must be carried out, and those records and calibration reports must be made available. Following the test, recalibration or adequate reconfirmation or verification is required.

The continuous emissions monitoring system should be in normal operation throughout the test time frame unless the parties to the test mutually agree to the contrary.

3.3.2 Test Personnel. Test personnel are required in sufficient number and expertise to support the execution of the test. (See para. 3.2.2, "Responsibilities of Parties.") Operations personnel must be familiar with the test operating requirements in order to operate the equipment accordingly.

3.3.3 Equipment Inspection and Cleanliness. Since a PTC 46 test is not intended to provide detailed information on individual components, this Code does not provide corrections for the effect of any equipment that is not in a clean and functional state.

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

All parties to the test shall have reasonable opportunity to examine the plant and agree that it is ready to test. The plant should be checked to ensure that equipment and subsystems are installed and operating in accordance with their design parameters.

3.3.4 Preliminary Testing. Preliminary testing can and should be conducted sufficiently in advance of the start of the overall performance test to allow time to calculate preliminary results, make final adjustments, and modify the test requirements and/or test equipment. Results from the preliminary testing should be calculated and reviewed to identify any problems with the quantity and quality of measured data. The parties shall mutually agree before the test to any test modifications so determined.

Some reasons for a preliminary run are:

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

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

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

(d) to ensure that the target uncertainty can be obtained by checking the complete system

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

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

(g) to ensure that process boundary inputs and outputs are not constrained other than those 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

3.4 CONDUCT OF TEST

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

- starting and stopping tests and test runs (3.4.1)
- methods of operation prior to and during tests (3.4.2)
- adjustments prior to and during tests (3.4.3)
- duration and number of tests and number of readings (3.4.4)
- constancy of test conditions (3.4.5)

In addition, this Subsection contains the following tables:

- Table 3.2 Guidance for Establishing Permissible Deviations from Design
- Table 3.3 Typical Pretest Stabilization Periods
- Table 3.4 Minimum Test Durations

3.4.1 Starting and Stopping Tests and Test Runs. The test coordinator is responsible for ensuring that all data collection begins at the agreed-upon start of the test, and that all parties to the test are informed of the starting time.

3.4.1.1 Starting Criteria. Prior to starting each performance test, the following conditions must be satisfied:

(a) operation, configuration, and disposition for testing has been reached in accordance with the agreed upon test requirements, including:

(1) equipment operation and method of control

(2) unit configuration, including required process efflux flow

(3) valve line-up

(4) availability of consistent fuel and fuel supplements within the allowable limits of the fuel analysis for the test (by analysis as soon as practicable preceding the test)

(5) plant operation within the bounds of the performance correction curves, algorithms or programs

(6) equipment operation within allowable limits

(7) for a series of test runs, completion of internal adjustments required for repeatability

(b) Stabilization. Prior to starting test, the plant must be operated for a sufficient period of time at test load to demonstrate and verify stability in accordance with para. 3.4.2 criteria.

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

3.4.1.2 Stopping Criteria. Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied. (See paras. 3.4.4 and 3.4.5.) The test coordinator should verify that methods of operation during test, specified in para. 3.3.2, 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. After all test runs are completed, secure equipment operating for purposes of test only (such as vent steam). Return operation control to normal dispatch functions, if appropriate.

3.4.2 Methods of Operation Prior To and 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.

Typical but nonexhaustive examples of operating equipment for consideration include fuel handling equipment, soot blowers, ash handling systems, gas turbine compressor inlet chillers or evaporative coolers, gas compressors, water treatment equipment, and blowdown. Any environmental control system must be operating and within normal ranges, including percent solids, gas flow, inlet and outlet emission concentrations, pH, and solid and liquid concentrations.

3.4.2.1 Operating Mode. The operating mode of the plant during the test should be consistent with the goal of the test. The corrections utilized in the general performance equation and the development of correction curves will be affected by the operating mode of the plant. If a specified corrected or measured load is desired, the plant control system should be configured to maintain the load during the test. If a specified disposition is required, the control system should maintain the disposition and not make changes to the parameters which should be fixed, such as valve position.

The plant equipment should be operated in a manner consistent with the basis of design or guarantee, and in a manner that will permit correction from test operating conditions to base reference conditions.

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

3.4.2.2 Valve Line-up/Cycle Isolation. A cycle isolation checklist should be developed to the satisfaction of all parties to the test. The checklist should be divided into three categories: manual valve isolation checklist, automatic valve isolation checklist, and test valve isolation checklist.

(a) The manual valve isolation checklist should be an exhaustive list of all the valves that should be closed during normal operation. These are the valves that affect the accuracy or results of the test if they are not secured. These valve positions should be checked before and after the test.

(b) The automatic valve isolation checklist is a list of valves that should be closed during normal operation but may from time to time cycle open (such as feedwater heater emergency dump valves). 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 available from the plant control system, these valve positions should be continually monitored during the test.)

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

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

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

Effort should be made to confirm zero flow through valves that are required to be closed during the test.

3.4.2.3 Equipment Operation. Plant equipment required for normal plant operation should be operating as defined by the respective equipment suppliers' instructions (to support the overall objectives of the plant test), unless otherwise agreed to by the parties to the test. Equipment that is necessary for plant operation or that would normally be required for the plant to operate at base reference conditions must be operating or accounted for in determining auxiliary power loads.

At least 99.9% of nonelectric internal energy consumption should be accounted for and specified operating disposition tabulated. At least 99% of electrical auxiliaries should be accounted for and specified operating disposition tabulated. Any changes in equipment operation that affect plant corrected heat rate or corrected performance by more than 0.25 (or mutually agreed) percent will invalidate a test run. A switch-over to redundant equipment, such as a standby pump, is permissible. Intermittent nonelectrical internal energy consumption and electrical auxiliary loads, such as prorating, or proportioning, must 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 water treatment regeneration, well pump, material handling, soot blowing, blowdown, heat tracing, and air preheating.

3.4.2.4 Proximity to Design Conditions. It is desirable to operate the plant during the test as closely as possible to the base reference performance conditions, and within the allowable design range of the plant and its equipment so as to limit the magnitude of corrections to net electrical output and heat rate. Table 3.2 was developed based on achieving the overall test uncertainties described in Table 1.1. Excessive corrections to plant performance parameters can adversely affect overall test uncertainty. To maintain compliance with test code requirements, the actual test should be conducted within the criteria given in Tables 3.2 and 3.3 or other mutually agreed operating criteria that result in overall test uncertainty compatible with Table 1.1.

3.4.2.5 Stabilization. Agreement must be reached on the necessary stable conditions before starting the test. The length of operating time necessary to achieve the required steady state will depend on previous operations, using Table 3.2 as a guide.

3.4.2.6 Plant Output. A test may be conducted at any load condition, as required to satisfy the goals of the test. For those tests which require a specified corrected or measured load, the test run electrical output should be set so that the estimated test result of net electrical power is within one (1) percent of the applicable design value. For those tests which require a specified disposition of the plant, the test electrical output will be dependent on the performance of the plant itself and will not be controlled. At no time should the actual test conditions exceed any equipment ratings provided by the manufacturer.

3.4.2.7 Plant Thermal Energy. Cogeneration plant thermal energy export shall be set at levels specified or as mutually agreed by parties to the test. If automatic control of export energy does not provide sufficient stability and proximity to design conditions, manual control or venting of export energy may be required.

3.4.2.8 Fuel and Fuel Supplements. Consumption and properties of fuel and fuel supplements (such as limestone) should be maintained as constant as practicable for the duration of the preliminary test and actual test. Permissible deviations in fuel properties for various fuels and components are specified in Table 3.2.

3.4.2.9 Emissions. Throughout the tests, the plant shall be operated in accordance with the emissions limits outlined in the test plan. Emissions should be monitored with approved equipment. However, this Code does not require that emissions tests be conducted as part of the overall performance test. Emissions can be monitored with normal monitoring equipment, not necessarily compliance testing equipment.

3.4.2.10 On-line Cleaning. On-line cleaning of boiler heat transfer surfaces and gas turbine compressors should be addressed.

3.4.3 Adjustments Prior to and During Tests. This Subsection describes the following three types of adjustments related to the test:

- permissible adjustments during stabilization periods or between test runs
- permissible adjustments during test runs
- non-permissible adjustments

3.4.3.1 Permissible Adjustments During Stabilization Periods Between Test Runs. Agreement should be reached before the test on acceptable adjustments prior to the test. Basically, any adjustments may be made to the equipment and/or operating conditions, but the requirements for determination of stable operation (see para. 3.4.2.5) still apply. For example, if the fuel distribution on a stoker is altered, sufficient stable operating time must be allowed for a complete change of the ash on the grates. Similarly, a change in fluidized bed combustor ash reinjection must permit restabilization of the bed. Changes in nonprimary measurements, such as steam temperature, may be made so long as the requirement for stability of primary measurements still hold.

Typical adjustments prior to tests 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 are permissible. Tuning and/or optimization of component or plant performance is permissible. Adjustments to avoid corrections or to minimize the magnitude of performance corrections are permissible.

3.4.3.2 Permissible Adjustments During Test Runs. Permissible adjustments during tests are those required to correct malfunctioning controls, maintain equipment in safe operation, or to 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.

3.4.3.3 Nonpermissible Adjustments. Any adjustments that would result in equipment being operated beyond manufacturer's operating, design, or safety limits and/or specified operating limits are not permitted. Adjustments or recalibrations which would adversely affect the stability of a primary measurement during a test are also not permitted.

TABLE 3.2
GUIDANCE FOR ESTABLISHING PERMISSIBLE DEVIATIONS FROM DESIGN (ALL ± VALUES)

	Combined Cycle Plant	Gas Turbine with HRSG for Steam Generation	Steam Turbine Cycle Plant Primary Heat Input Measured Directly	Steam Turbine Cycle Plant Primary Heat Input Measured by Heat Loss Method
INLET AIR conditions to equipment	Gas turbine maximum allowable deviation in required mode, such as base loaded. Varies by gas turbine.	Gas turbine maximum allowable deviation in required mode, such as base loaded. Varies by gas turbine.	25°F (14°C) wet bulb or 30°F (17°C) dry bulb if the air-cooled heat sink (cooling tower or air-cooled condenser) is included in test boundary.	More stringent of the allowable deviation for a steam cycle plant with primary heat input measured directly, or of the boiler limits on inlet air temperature.
HEAT SINK Conditions: air cooling in the test boundary	See "Inlet Air"	See "Inlet Air"	See "Inlet Air"	See "Inlet Air"
HEAT SINK Conditions: *(a)* circ water cooling or *(b)* condenser pressure at the test boundary	Equivalent to limits of calculable steam turbine output variation with condenser pressure. Varies by steam turbine.	N/A	Equivalent to limits of calculable steam turbine output variation with condenser pressure. Varies by steam turbine.	Equivalent to limits of calculable steam turbine output variation with condenser pressure. Varies by steam turbine.
THERMAL EFFLUX: minimum process efflux *F(min)*, as a function of base reference process efflux [Notes (1) and (2)]	If Rb is 0.30 or less: $F(min) = 0.30 \times Fb \times (Pps/Pms)$ If Rb exceeds 0.30: $F(min) = Rb \times Fb \times (Pps/Pms)$ [Note (1)]	If Rb is 0.30 or less: $F(min) = 0.30 \times Fb \times (Pps/Pms)$ If Rb exceeds 0.30: $F(min) = Rb \times Fb \times (Pps/Pms)$ [Notes (1) and (2)]	If Rb is 0.30 or less: $F(min) = 0.75 \times Fb \times (Pps/Pms)$ If Rb exceeds 0.30: $F(min) = [0.75 + (Rb - 0.30)/0.70 \times 0.25] \times Fb \times (Pps/Pms)$ [Notes (1) and (2)]	If Rb is 0.30 or less: $F(min) = 0.75 \times Fb \times (Pps/Pms)$ If Rb exceeds 0.30: $F(min) = [0.75 + (Rb - 0.30)/0.70 \times 0.25] \times Fb \times (Pps/Pms)$ [Notes (1) and (2)]
THERMAL EFFLUX: process steam enthalpy, referenced to ISO or absolute temperature	Equivalent to 10% of enthalpy downstream of attemperation, if applicable.	Equivalent to 10% of enthalpy downstream of attemperation, if applicable.	Equivalent to 10% of enthalpy downstream of attemperation, if applicable.	Equivalent to 10% of enthalpy downstream of attemperation, if applicable.
GAS, LIQUID FUEL: fuel analysis (heating value, constituents)	Allowable deviation permitted for the gas turbine. Varies with turbine.	Allowable deviation permitted for the gas turbine. Varies with turbine.	Contract fuel specification limits.	Contract fuel specification limits.

TABLE 3.2 (CONT'D)

SOLID FUEL: fuel analysis (heating value, constituents)	Contract fuel specification limits.	Contract fuel specification limits.	Contract fuel specification limits.	Contract fuel specification limits.
ELECTRICAL PARAMETERS: power factor kW frequency	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.

NOTE

(1)
Fb = base reference process efflux, lbm/h, kg/h, Btu/h, or kW(t)
F(min) = minimum process efflux flow during test, units consistent with *Fb*
NP = plant net power output from base heat balance, kW(e)
PE = mechanical equivalent of the process efflux from base heat balance, kW(t)
Pms = main steam pressure, psia or kPa
Pps = process steam pressure, psia or kPa
Rb = ratio of PE/(NP + PE), dimensionless

(2) Smaller values may be used for the minimum required process efflux only if steam cycle characteristics (such as steam turbine flow factors) needed for heat balance calculations can be confirmed with data.

TABLE 3.3
TYPICAL PRETEST STABILIZATION PERIODS

Type of Plant	Stabilization
Gas fired boiler	1 hr
Oil fired boiler	1 hr
Pulverized coal-fired boiler	1 hr
Fluidized bed combustor	24 hr [1]
Simple cycle with heat recovery	1 hr
Combined cycle	1 hr
Reciprocating engines	1 hr
Stoker and cyclone	4 hr

NOTE:
[1] If chemical stability has been satisfied, then testing may commence one (1) hour following achievement.

TABLE 3.4
RECOMMENDED MINIMUM TEST RUN DURATIONS

Type of Plant	Test Run
Gas fired boiler	2 hr
Oil fired boiler	2 hr
Pulverized coal-fired boiler	2 hr
Fluidized bed combustor	4 hr
Simple cycle with heat recovery	1 hr
Combined cycle	1 hr
Stoker and cyclone	4 hr

3.4.4 Duration of Runs, Number of Test Runs, and Number of Readings

3.4.4.1 Duration of Runs. The duration of a test run shall be of sufficient length that the data reflects the average efficiency and/or performance of the plant. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical plant operating characteristics. The recommended test durations are tabulated in Table 3.4.

The test coordinator and the parties to the test may determine that a longer test period is required. The recommended times shown in Table 3.4 are generally based upon continuous data acquisition. Depending upon the personnel available and the method of data acquisition, it may be necessary to increase the length of a test in order to obtain a sufficient number of samples of the measured parameters to attain the required test uncertainty. When point-by-point traverses are required, the test run should be long enough to complete two full traverses. Test runs using blended or waste fuels may also require longer durations if variations in the fuel are significant. Test run duration should consider transit times of samples.

3.4.4.2 Number of Test Runs. A run is a complete set of observations with the unit at stable operating conditions. A test is a single run or the average of a series of runs.

While not requiring multiple runs, the advantages of multiple runs should be recognized. Conducting more than one run will:

- provide a valid method of rejecting bad test runs
- allow the parties to the test to examine the validity of the results
- 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 completing the first test run that meets the criteria for an acceptable test run (which may be the preliminary test run), the data should be consolidated and preliminary results calculated and exam-

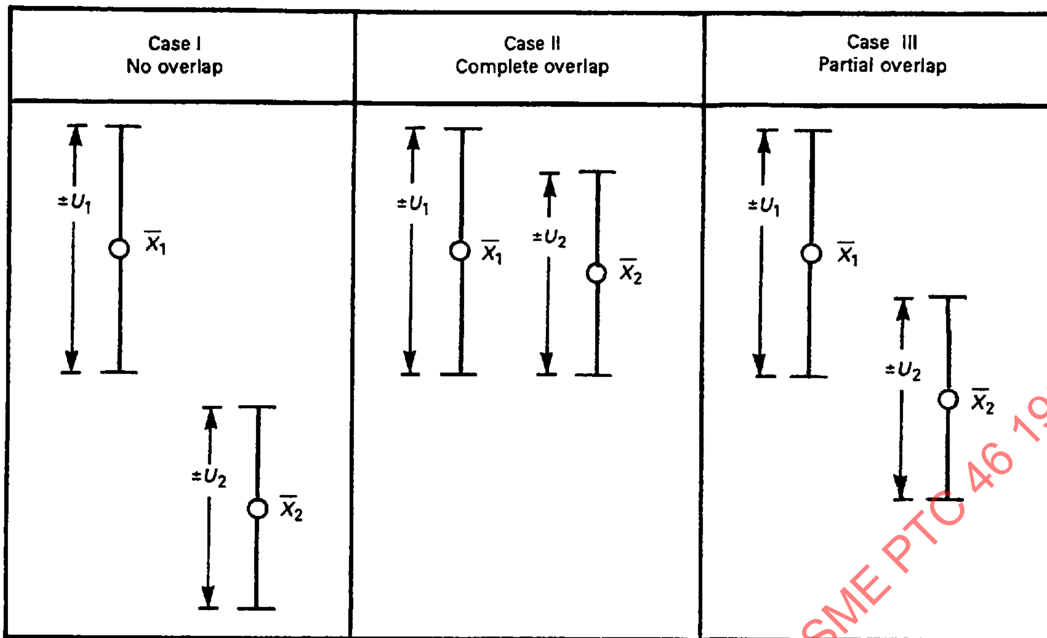


FIG. 3.4 THREE POST-TEST CASES

ined to ensure that the results are reasonable. If the parties to the test agree, the test may be concluded at the end of any test run.

3.4.4.3 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 Fig. 3.4 should be considered.

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.

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 interval, $X_2 \pm U_1$.

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 1 or case 3, the results from all of the runs should be reviewed in an attempt to explain the reason for excessive variation. Should no reason become obvious, the parties to the test can either increase the uncertainty band to encompass the runs and therefore make them repeatable, or they can conduct more runs, which will allow them to calculate the precision component of uncertainty directly from the test results.

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

3.4.4.4 Number of Readings. Sufficient readings must be taken within the test duration to yield total uncertainty consistent with Table 1. Ideally at least 30 sets of data should be recorded for all nonintegrated measurements of primary variables. There are no specific requirements for the number of integrated readings or for measurements of secondary variables for each test run.

3.4.5 Constancy of Test Conditions. The primary criteria for steady state test conditions is that the average of the data reflects equilibrium between energy input from fuel and energy output to thermal and/or electrical generation. The primary uncontrollable parameters affecting the steady state conditions of a test are typically the ambient conditions. Testing durations and schedules must be such that changes in ambient conditions are minimized. See para. 3.4.2.5.

3.5 CALCULATION AND REPORTING OF RESULTS

The data taken during the test should be reviewed and rejected in part or in whole if not in compliance with the requirements for the constancy of test conditions. See para. 3.4.5.

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 plant being tested.

3.5.1 Causes for Rejection of Readings. Upon completion of 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 PTC 19-1 and ANSI/ASME MFC-2M (Appendix C) for data rejection criteria. A test log should be kept. Any plant upsets which cause test data to violate the requirements of Table 3.2 shall be rejected. A minimum of 10 minutes following the recovery of these criteria shall also be rejected to allow for restabilization.

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

During the test, should any control system set points be modified that effects stability of operation beyond code allowable limits as defined in Table 3.2, test data shall be considered for rejection from the calculations of test results. The period rejected shall start immediately prior to the change and end no less than 10 minutes following the recovery of the criteria found in Table 3.2.

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

3.5.2 Uncertainty. 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 PTC 19.1, "Measurement Uncertainty." PTC 19.1 specifies procedures for evaluating measurement uncertainties from both random and fixed errors, and the effects of these errors on the uncertainty of a test result.

This Code addresses test uncertainty in the following four sections.

- Section 1 defines expected test uncertainties.
- Section 3 defines the requirements for pretest and post-test uncertainty analyses, and how they are used in the test. These uncertainty analyses and limits of error are defined and discussed in para. 3.5.2.1.
- Section 4 describes the bias uncertainty required for each test measurement.
- Section 5 and Appendix F provide applicable guidance for determining pretest and post-test uncertainty analysis results.

3.5.2.1 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 bias and precision error for each of the proposed test measurements should be used to help determine the number and quality of test instruments required for compliance with code or contract specifications.

The pretest uncertainty analysis must include an analysis of precision uncertainties to establish permissible fluctuations of key parameters in order to attain expected uncertainties.

In addition, a pretest uncertainty analysis can be used to determine the correction factors which are significant to the corrected test. For simplicity, this Code allows elimination of those corrections which do not change the test results by 0.05 percent. Also, pretest uncertainty analysis should be used to determine the level of accuracy 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 expected test uncertainty described in Section 1 has been realized.

3.5.3 Data Distribution and Test Report. Parties to the test have the right to have copies of all data at the conclusion of the test. Data will be distributed by the test coordinator and approved in a manner agreed to prior to testing.

A test report is written in accordance with Section 6 of this Code by the test coordinator and distributed within a time frame agreed to by all parties. A preliminary report incorporating calculations and results may be required before the final test report is submitted for approval.

SECTION 4 — INSTRUMENTS AND METHODS OF MEASUREMENT

4.1 GENERAL REQUIREMENTS

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

U.S. Customary units are shown in all equations in this Section. However, any other consistent set of units may be used.

4.1.2 Instrumentation Classification. The instrumentation employed to measure a variable will have different required type, accuracy, redundancy, and handling depending upon the use of the measured variable and depending on how the measured variable affects the final result. For purposes of this discussion, variables at a given location are temperature, pressure, flow, velocity, voltage, current, stream constituency, and humidity. Measurements are classified as either primary or secondary variables.

4.1.2.1 Primary Variables. Variables that are used in calculations of test results are considered primary variables. Primary variables are further classified as Class 1 primary variables or Class 2 primary variables. Class 1 primary variables are those which have a relative sensitivity coefficient of 0.2 percent or greater. These variables will require higher-accuracy instruments with more redundancy than Class 2 primary variables which have a relative sensitivity coefficient of less than 0.2 percent.

4.1.2.2 Secondary Variables. Variables that are measured but do not enter into the calculation of the results are secondary variables. These variables are measured throughout a test period to ensure that the required test condition was not violated. An example of these variables are gas turbine exhaust temperature or steam turbine inlet pressure and temperature. These example variables verify that the unit was not over- or under-"fired" during the test period.

This Code does not require high accuracy instrumentation for secondary variables. The instruments that measure these variables may be permanently installed plant instrumentation. The code does require verification of instrument output prior to the test period. This verification can be by calibration or by comparison against two or more independent measurements of the variable referenced to the same location. The instruments should also have redundant or other independent instruments that can verify the integrity during the test period.

4.1.3 Instrument Calibration

4.1.3.1 Definition of Calibration. Calibration of an instrument is the act of applying process conditions to the candidate instrument and to a reference standard in parallel. Readings are taken from both the candidate instrument and the reference standard. The output of the instrument then may be adjusted to the standard reading. As an alternative, the difference between the instrument and the reference standard may be recorded and applied to the instrument reading. This alternative method is mandatory in the case of thermocouple or Resistance Temperature Devices (RTDs) because their output cannot be easily altered.

4.1.3.2 Reference Standards. In general all test instrumentation used to measure primary (Class 1 and Class 2) variables should be calibrated against reference standards traceable to the National Institute of Standards and Technology (NIST), other recognized international standard organization, or recognized physical constants. All reference standards should be calibrated as specified by the manufacturer or other frequency as the user has data to support extension of the calibration period. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The reference standards should have an uncertainty at least 4 times less than the test instrument to be calibrated. A reference standard with a lower uncertainty may be employed if the uncertainty of the standard combined with the precision uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument.

Instrumentation used to measure secondary variables need not be calibrated against a reference standard. These instruments may be calibrated against a calibrated instrument.

4.1.3.3 Ambient Conditions. Calibration of instruments used to measure primary variables (Class 1 or Class 2) should be performed in a manner that replicates the condition under which the instrument will be used to make the test measurements. Consideration must be given to all process and ambient conditions which may affect the measurement including temperature, pressure, humidity, electromagnetic interference, radiation, or etc.

4.1.3.4 Instrument Ranges and Calibration Points. The number of calibration points depends upon the classification of the variable the instrument will measure. The classifications are discussed in para. 4.1.2. The calibration should bracket the expected measurement range as closely as possible.

(a) Class 1 Primary Variables

The instruments measuring Class 1 primary variables should be calibrated at two (2) points more than the order of the calibration curve fit.

Each instrument should also be calibrated such that the measuring point is approached in an increasing and decreasing manner. This exercise minimizes any hysteresis effects.

Some instruments are built with a mechanism to alter the range once the instrument is installed. In this case, the instrument must be calibrated at each range to be used during the test period.

Some devices cannot practically be calibrated over the entire operating range. An example of this is the calibration of a flow measuring device. These devices are calibrated often at flows lower than the operating range and the calibration data is extrapolated. This extrapolation is described in Subsection 4.4.

(b) Class 2 Primary Variables

Instruments measuring Class 2 primary variables should be calibrated at 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).

(c) Secondary Variables

Instruments used to measure secondary variables can be checked in place with two or more instruments measuring the variable with respect to the same location or can be calibrated against a previously calibrated instrument.

Should the instrument be calibrated, it need only be calibrated at one point in the expected operating range.

4.1.3.5 Timing of Calibration. All test instrumentation used to measure primary (Class 1 and Class 2) variables will be calibrated prior to and calibrated or checked following the tests. No mandate is made regarding quantity of time between the initial calibration, the test period, and the recalibration. The quantity of time between initial and recalibration should however be kept to a minimum to obtain an acceptable calibration drift.

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

Post-test calibration of current and potential transformers is not required.

4.1.3.6 Calibration Drift. Calibration drift is defined as the difference in the calibration correction as a percent of reading. When the post-test calibration indicates the drift is less than the instrument bias uncertainty, the drift is considered acceptable and the pretest calibration is used as the bias for determining the test results. Occasionally the instrument calibration drift is unacceptable. Should the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable.

Calibration drift can result from instrument malfunction, transportation, installation, or removal of the test instrumentation. Should unacceptable calibration drift occur, engineering judgment must be used to determine whether the initial or recalibration is correct. Below are some 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. An example of this check is vented pressure transmitters, no load on watt meters, and ice point temperature instrument check.

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

4.1.3.7 Loop Calibration. All instruments used to measure primary variables (Class 1 or Class 2) should be loop-calibrated. Loop calibration involves the calibration of the instrument through the signal conditioning equipment. This may be accomplished by calibrating instrumentation employing the test signal conditioning equipment either in a laboratory or on site during test setup before the instrument is connected to process. Alternatively, the 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 must be performed to ensure that the combined uncertainty of the measurement system meets the accuracy requirements described herein.

4.1.3.8 Quality Assurance Program. Each calibration laboratory must have in place a quality assurance program. This program is a method of documentation where the following information can be found:

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

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

All parties to the test should be allowed access to the calibration facility as the instruments are calibrated. The quality assurance program should also be made available during such a visit.

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

4.1.5 Redundant Instrumentation. Redundant instruments are two or more devices measuring the same parameter with respect to the same location. Redundant instruments should be used to measure all primary (Class 1 or Class 2) variables with the following exceptions. Redundant flow elements and redundant electrical metering devices are not required because of the large increase in costs, but should be considered when developing a test plan.

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

4.2 PRESSURE MEASUREMENT

4.2.1 Introduction. This Subsection presents requirements and guidance regarding the measurement of pressure. Due to the state of the art and general practice, it is recommended that for primary measurements electronic pressure measurement equipment be used. Dead weight gages, manometers, and other measurement devices may in some cases be as accurate and may be used.

All signal cables must have a grounded shield to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from EMF producing devices such as motors, generators, electrical conduit, and electrical service panels.

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

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

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

4.2.2 Pressure Transmitter Accuracy

4.2.2.1 Introduction. The required pressure transmitter accuracy will depend upon the type of variables being measured. Refer to para. 4.1.2 for discussion on primary and secondary variables.

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

Class 2 primary variables should be measured with 0.25% accuracy class pressure transmitters that have a total uncertainty of 0.50% or better of calibrated span. These pressure transmitters do not need to be temperature compensated.

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

4.2.3 Pressure Transmitter Types

Three types of pressure transmitters are described below.

- absolute pressure transmitters
- gage pressure transmitters
- differential pressure transmitters

4.2.3.1 Absolute Pressure Transmitters

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

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

The second method calibrates by developing and holding a constant vacuum in a chamber using a suction and bleed control mechanism. The test instrument and the calibration standard are both connected to the chamber. The chamber must be maintained at constant vacuum during the calibration of the instrument.

4.2.3.2 Gage Pressure Transmitters

Application: Gage pressure transmitters measure pressure referenced to atmospheric pressure. To obtain absolute pressure, the test site atmospheric pressure must be added to the gage pressure. This test site atmospheric pressure should be measured by an absolute pressure transmitter. Gage pressure transmitters may only be used on measurement locations with pressures higher than atmospheric. Gage pressure transmitters are preferred over absolute pressure transmitters in measurement locations above atmospheric pressure because they are easier to calibrate.

Calibration: Gage pressure transmitters can be calibrated by an accurate deadweight gage. The pressure generated by the dead weight gage must be corrected for local gravity, air buoyancy, piston surface tension, piston area deflection, actual mass of weights, actual piston area, and working medium temperature. If the above corrections are not used, the pressure generated by the dead weight gage may be inaccurate. The actual piston area and mass of weights is determined each time the dead weight gage is calibrated.

4.2.3.3 Differential Pressure Transmitters

Application: Differential pressure transmitters are used where flow is determined by a differential pressure meter.

Calibration: Differential pressure transducers used to measure Class 1 primary variables must be calibrated at line static pressure unless data is available showing that the effect of high line static pressure is within the instrument accuracy. Calibrations at line static pressure are performed by applying the actual expected process pressure to the instrument as it is being calibrated.

Calibrations at line static pressure can be accomplished by one of three methods:

(a) two highly accurate dead weight gages;
(b) a dead weight gage and divider combination; or
(c) one dead weight gage and one differential pressure standard.

Differential pressure transmitters used to measure Class 2 primary variables or secondary variables do not require calibration at line static pressure and can be calibrated using one accurate dead weight gage connected to the "high" side of the instrument. If line static pressure is not used, the span must be corrected for high line static pressure shift unless the instrument is internally compensated for the effect.

Once the instrument is installed in the field, the differential pressure from the source should be equalized and a zero value read. This zero bias must be subtracted from the test-measured differential pressure.

4.2.4 Vacuum Measurements

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

Atmospheric pressure measurements must be measured with absolute pressure transmitters.

4.2.4.2 Installation. All vacuum measurement sensing lines must slope upward from the source to the instrument. All sensing lines in steam or water service must be purged with a minute amount of air or nitrogen to deter water legs from forming. The Code recommends that a purge system be used that isolates the purge gas during measurement of the process. A continuous purge system may be used; however it must be regulated to have no influence on the reading. Prior to the test period, readings from all purged instrumentation should be taken successively with the purge on and with the purge off to prove that the purge air has no influence.

Once transmitters are connected to process, a leak check must be conducted. The leak check is performed by isolating first the purge system and then the source. If the sensing line has no leaks, the instrument reading will not change.

Atmospheric pressure transmitters should be installed in the same general area and elevation of the gage pressure transmitters and should be protected from air currents that could influence the measurements.

4.2.5 Gage Pressure Measurements

4.2.5.1 Introduction. Gage pressure measurement variables are those at or above atmospheric pressure. These measurements may be made with gage or absolute pressure transmitters. Gage pressure transmitters are recommended since they are easier to calibrate and to check once on site.

Caution must be used with low pressure variables because they may enter the vacuum region at part load operation.

4.2.5.2 Installation. Gage pressure transmitters used in gas service should be installed with the sensing line sloping continuously upward to the instrument. This method alleviates inaccuracies from possible condensed liquid in the sensing line.

Pressure transmitters used in steam or water service should be installed with the sensing line sloping continuously downward to the instrument. This ensures that the sensing line will be full of water. 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 or water in the sensing line. This liquid causes a static pressure head to develop in the sensing line. This static head must be subtracted from the pressure measurement. The static head is calculated by multiplying the sensing line vertical height by gravity and the density of the liquid in the sensing line.

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

4.2.6 Differential Pressure Measurements

4.2.6.1 Introduction. Differential pressure measurements are used to measure flow of a gas or liquid over or through a flow element. The fluid flow over or through this type of device produces a drop in pressure. The differential pressure transmitter measures this pressure difference or pressure drop that is used to calculate the fluid flow.

4.2.6.2 Installation. Differential pressure transmitters should be installed utilizing a five-way manifold shown in Fig. 4.1. This manifold is required rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve.

If the instrument is used in gas service, the sensing lines should slope upward to the instrument. This

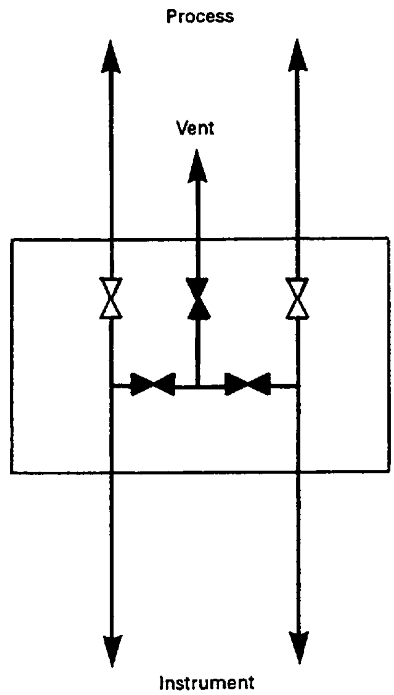


FIG. 4.1 FIVE-WAY MANIFOLD

eliminates the possibility of error due to moisture condensing in the sensing lines.

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

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

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

where:

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

4.3 TEMPERATURE MEASUREMENT

4.3.1 Introduction. This Section presents requirements and guidance regarding the measurement of temperature. It also discusses applicable temperature measurement devices, calibration of temperature measurement devices, and application of temperature devices.

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

All temperature instrumentation signal wires should have a grounded shield to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from EMF-producing devices such as motors, generators, electrical conduit, and electrical service panels.

4.3.2 Required Uncertainty. All instruments used to measure Class 1 primary variables must have a bias uncertainty of no more than 0.50°F for temperatures less than 200°F and no more than 1°F for temperatures more than 200°F. Instruments used to measure Class 2 primary variables must have a bias uncertainty of no more than 3°F. Instruments used to measure secondary variables shall have a bias uncertainty of no more than 5°F. Primary and secondary variables are described in para. 4.1.2

4.3.3 Acceptable Temperature Measurement Devices

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

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

4.3.3.2 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 200°F. The maximum temperature is dependent on the type of thermocouple and sheath material used.

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

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

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

For temperatures above 1400°F to 2450°F type "K" (Chromel Alumel) thermocouples have the highest EMF per degree.

Thermocouples used to measure Class 1 primary variables must be continuous lead from the measurement's tip to the connection on the cold junction. These high accuracy thermocouples must have a cold junction reference of 32°F or ambient if the junction is well-insulated and reference measuring device is calibrated. The ice point reference can either be a stirred ice bath or a calibrated electronic ice bath.

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

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

Thermocouples used to measure Class 2 primary variables can have junctions in the sensing wire. The junction of the two sensing wires must be maintained at the same temperature. The cold junction may be at ambient temperature for these less accurate thermocouples provided that the ambient is measured and the measurement is compensated for changes in cold junction temperature.

Thermocouples should be constructed according to PTC 19.3, Temperature Measurement.

Thermocouples can effectively be used in high vibration areas such as main or high pressure inlet steam to the steam turbine. High vibration measurement locations may not be conducive to other measurement devices.

4.3.3.3 Resistance Temperature Devices (RTD). The Resistance Temperature Device (RTD) may be used in testing from any low temperature to the highest temperature recommended by the RTD manufacturer. Typically RTDs can measure in excess of 1200°F.

Temperature measurements of Class 1 primary variables are best measured by a four-wire type and made of platinum as presented in Fig. 4.2. Three-

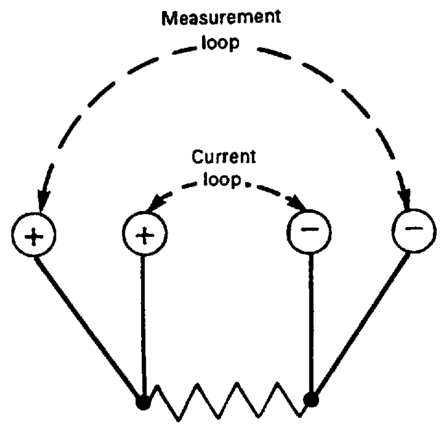


FIG. 4.2 FOUR-WIRE RTDs

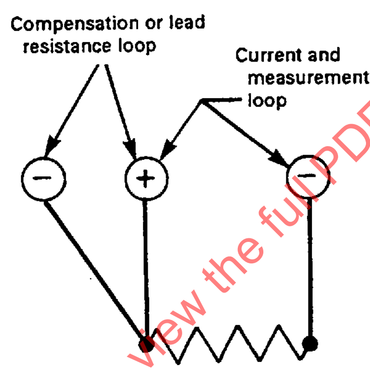


FIG. 4.3 THREE-WIRE RTDs

wire RTDs as shown in Fig. 4.3 and described in the following paragraph may be used for Class 1 primary variables if they can be shown to have the accuracy as required herein. They must however be made of platinum.

Temperature measurements of Class 2 primary variables can be made accurately with either four-wire or three-wire devices and do not necessarily need to be made of platinum.

The calculation of temperature from the resistance should be done according to equations in IPTS 68 as given in NIST monograph 126, section 6.1. RTDs should be constructed in accordance with PTC 19.3.

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

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

4.3.4 Calibration of Primary Variables Temperature Measurement Devices. The calibration of temperature measurement devices is accomplished by inserting the candidate temperature measurement device into a calibration medium along with a temperature standard. The temperature of the calibration medium is then set to the calibration temperature setpoint. The temperature of the calibration medium is allowed to stabilize until the temperature of the standard is fluctuating less than the accuracy of the standard. The signal or reading from the standard and the candidate temperature device are sampled to determine the bias of the candidate temperature device. See PTC 19.3 for a more detailed discussion of calibration methods.

4.3.5 Typical Applications

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

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

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

The thermowell should be installed so that the tip protrudes through the boundary layer of the fluid to be measured. The thermowell should be located in an area where the fluid is well-mixed and has no potential gradients. If 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 it should be installed on the opposite side of the pipe and not directly downstream of another thermowell.

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

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

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

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

The temperature measurement device can be installed directly into the fluid using a bored-through-type compression fitting. The fitting should be of proper size to clamp onto the device. A plastic or Teflon-type ferrule is recommended so that the device can be removed easily and used elsewhere. The device must protrude through the boundary layer of the fluid. Care must be used so that the device does not protrude into the fluid enough to cause vibration of the device from the flowing fluid. If the fluid is a hazardous gas such as natural gas or propane the fitting should be checked for leaks.

A "flow-through well" is shown in Fig. 4.4. This arrangement is only applicable for water in a cooling system where the fluid is not hazardous and the fluid can be disposed without great cost. The principle is to allow the fluid to flow out of the pipe or vessel, over the tip of the temperature measurement device.

4.3.5.3 Temperature Measurement of Products of Combustion in a Duct. Measurement of the fluid temperature in a duct requires several measurement points to minimize the uncertainty effects of temperature gradients. Typically, the duct pressures are low or negative so that thermowells are not needed. A long sheathed thermocouple or an unsheathed thermocouple attached to a rod will suffice.

The number of measurement points necessary to be used is determined experimentally or by experience from the magnitude of the temperature variations at the desired measurement cross-section and the required maximum uncertainty of the value of the average temperature. The total uncertainty of the average temperature is affected by the uncertainty of the individual measurements, the number of points used in the averaging process, the temperature gradients, and the time variation of the readings. The parties to the test should locate the measurement plane at a point of uniform temperatures and velocities to the extent practical. The recommended number of points are:

- located every nine (9) ft^2
- a minimum of four (4) points
- a maximum of 36 points

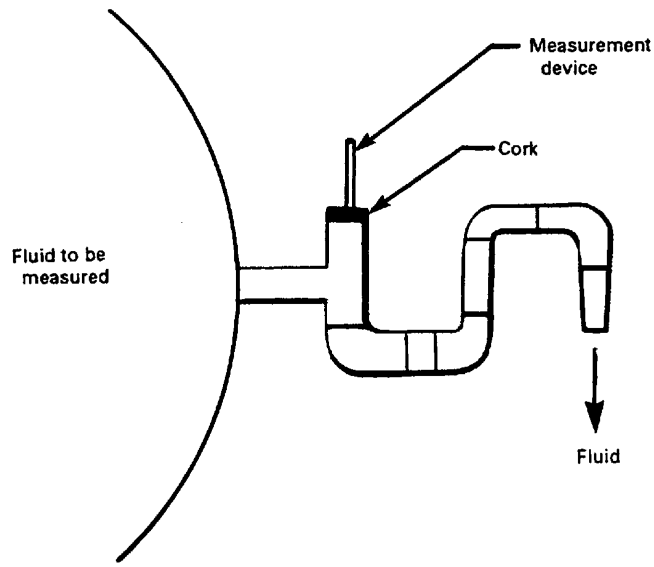


FIG. 4.4 FLOW-THROUGH WELL

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

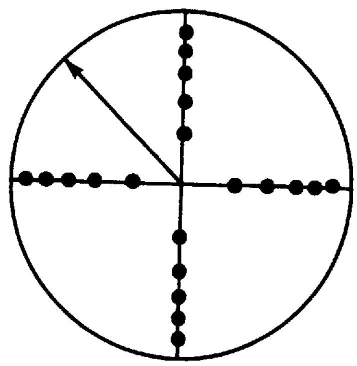
For round ducts the points may be installed in two (2) diameters 90 deg. from each other as shown in Fig. 4.5, which also shows the method of calculating the measurement point spacing. The point spacing is based on locating the measurement points at the centroids of equal areas.

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

4.3.5.4 Inlet Dry Bulb Air Temperature. The dry bulb temperature is the static temperature at the inlet to the plant equipment. The temperature sensor must be shielded from solar and other sources of radiation and must have a constant air flow across the sensing element. Although not required, a mechanically aspired psychrometer, as described below, may be used. If a psychrometer is used, a wick should not be placed over the sensor (as is required for measurement of wet bulb temperature). If the air velocity across the sensing element is greater than 1,500 feet per minute, shielding of the sensing element is required to minimize stagnation effects.

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

(a) Wet Bulb Temperature. The thermodynamic wet bulb temperature is the air temperature that results when air is adiabatically cooled to saturation. Wet bulb temperature can be inferred by a properly designed mechanically aspired psychrometer. The process by which a psychrometer operates is not adiabatic saturation, but one of simultaneous heat and mass transfer from the wet bulb sensing element. The resulting temperature achieved by a psychrometer is sufficiently close to the thermodynamic wet bulb temperature over most range of conditions. However, a psychrometer should not be used for temperatures below 40°F or when the relative humidity is less than 15 percent. Within the allowable range of use, a properly designed psychrometer can provide a determination of wet bulb temperature with an uncertainty of



Cross Section of Circular Gas Passage

NOTE: indicates location of sample point

$$r_n = R\sqrt{\frac{2N_a \cdot 1}{N_T}}$$

r_n = distance from sampling point to center of pipe
R = radius of pipe
N_a = no. of sampling points counted from center as zero
N_T = total no. of sampling points on A diameter

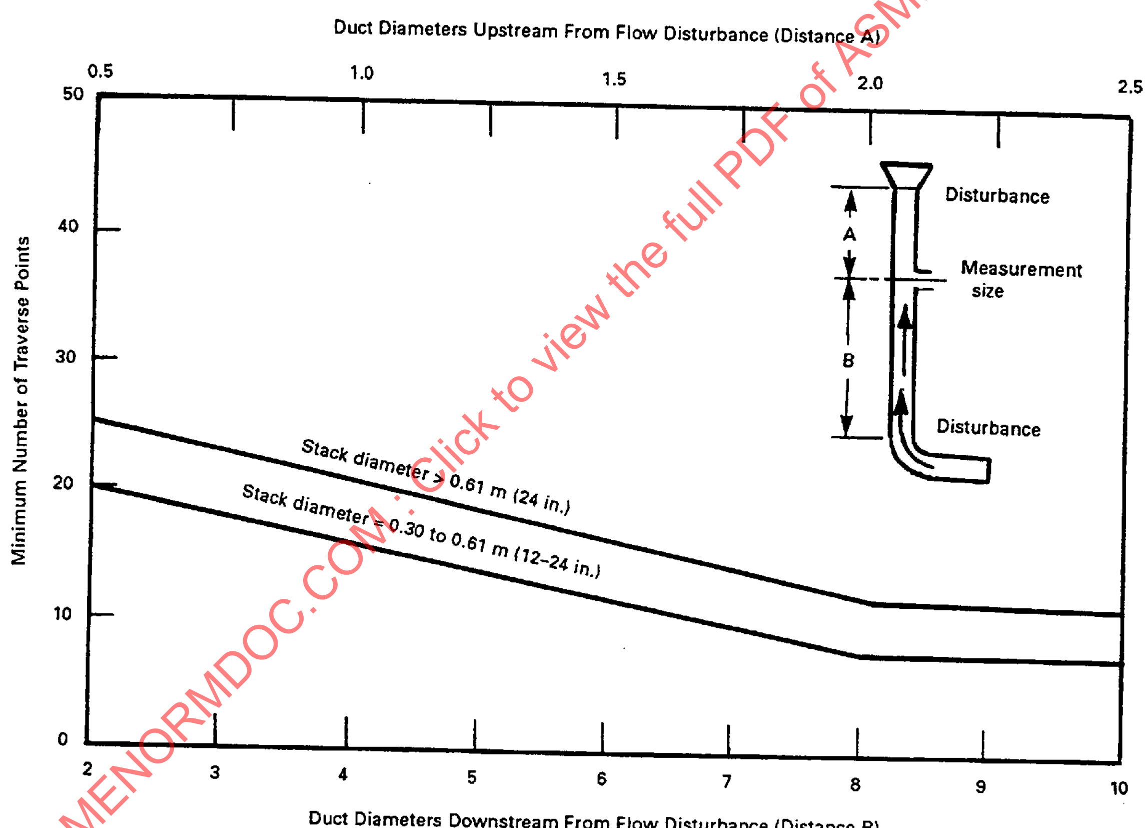


FIG. 4.5 DUCT MEASUREMENT POINTS

approximately ± 0.25°F (based on a temperature sensor uncertainty of ± 0.15°F).

The mechanically aspirated psychrometer should incorporate the following features:

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

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

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

(4) The air velocity across the sensing element is maintained constant in the range of 800 to 1,200 feet per minute.

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

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

(b) Cooled Mirror Dew Point Hygrometer. The dew point temperature is the temperature of moist air when it is saturated at the same ambient pressure and with the same specific humidity. A cooled mirror dew point hygrometer uses a cooled mirror to detect the dew point. Air is drawn across a mirror which is cooled to the temperature at which vapor begins to form on the mirror. A temperature sensor mounted in the mirror measures the surface temperature. Manual devices are available. There are also commercially available instruments that automatically control the mirror temperature, detect the inception of condensation, and provide a temperature readout. Commercially available cooled mirror dew point hygrometers measure the dew point temperature with an uncertainty of approximately 0.5°F.

The advantages of using dew point hygrometers include:

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

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

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

The advantages of relative humidity hygrometers include:

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

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

4.4 FLOW MEASUREMENT

4.4.1 Water and Steam

4.4.1.1 Water flows can be measured more accurately than steam flows. Whenever possible it is best to configure the tests so that water flows are measured and used to calculate steam flows. The usual method of determining flow is with a differential pressure meter, using two independent differential pressure instruments.

4.4.1.2 The flow section with a throat tap nozzle described in PTC 6 is recommended for the Class 1 primary flow measurements when the test Reynolds numbers are greater than the maximum calibrated Reynolds number.

4.4.1.3 Other Flow Measuring Devices. Information relative to the construction, calibration, and installation of other flow measuring devices appears in ASME MFC-3M. These devices can be used for Class 2 flow measurements and for secondary flow measurements. They can also be used for Class 1 primary flow measurement when Reynolds number extrapolation is not required.

- The beta-ratio should be limited to the range of 0.25 to 0.50 for wall-tap nozzles and venturis and 0.30 to 0.60 for orifices.
- Class 1 primary flow measurement requires calibration.
- For Class 2 primary and secondary flows, the appropriate reference coefficient for the actual device given in ASME MFC-3M may be used.

4.4.1.4 Water Flow Characteristics. Flow measurements shall not be undertaken unless the flow is steady or fluctuates only slightly with time. Fluctuations in the flow shall be suppressed before the beginning of a test by very careful adjustment of flow and level controls or by introducing a combination of conductance, such as pump recirculation, and resistance, such as throttling the pump discharge, in the line between the pulsation sources and the flow measuring device. Hydraulic damping devices on instruments do not eliminate errors due to pulsations and, therefore, should not be used.

In passing through the flow measuring device, the water should not flash into steam. The minimum throat static pressure shall be higher than the saturation pressure corresponding to the temperature of the flowing water by at least 20 percent of the throat velocity head, as required per para. 4.5.1.7 to avoid cavitation.

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

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

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

4.4.1.7 Additional Flow Measurements

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

(b) Two-Phase Steam-Water Mixtures. There are instances when it is desirable to measure the flow rate of a two-phase mixture. PTC 12.4 describes methods for measurement of two-phase flow.

4.4.2 Liquid Fuel. Liquid fuel flows shall be measured using flowmeters that are calibrated throughout their Reynolds number range expected during the test using the actual flow. For volume flow meters the temperature of the fuel also must be accurately measured to correctly calculate the flow. Other flow meters are permitted if a measurement error of 0.7% or less can be achieved.

4.4.2.1 Positive Displacement Oil Flow Meter. Use of oil flow 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.

$$q_{mh} = (8.337)\,(60)\,q_v\,(sg) \qquad (4.4.1)$$

where

q_{mh} = mass flow, lbm/h
q_v = volume flow, gal/m
sg = specific gravity at flowing temperature, dimensionless
8.337 = density of water at 60°F, lb/gal
60 = minutes per hour, m/h

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 to the correct temperature.

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

ASME MFC-3M-1989 details the calculation of the uncertainty of an orifice metering run manufactured and installed correctly. The manufacturer requirement is to demonstrate that the meter was manufactured in accordance with the appropriate references, shown in para. 4.4.3.1.

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

4.4.3.1 Calculation of Natural Gas Fuel Flow Using an Orifice. The following procedure is shown for calculation of natural gas fuel flow using measurements from a flange-tapped orifice meter. The orifice metering run must meet the straight length requirements of ISO-5167, and the manufacturing and other installation requirements of ASME MFC-3M-1989. These include circularity and diameter determination of orifice and pipe, pipe surface smoothness, orifice edge sharpness, plate and edge thickness, and other requirements, detailed in ASME MFC-3M-1989. The calculations are also done in strict accordance with ASME MFC 3M-1989, with an example shown below.

Mass Fuel Flow

The following equation is used to develop the mass fuel flow, in lb/s.

$$q_{ms} = 0.09970190\ C\ Y_1\ d^2 \sqrt{\frac{h_w\ \rho_{fl}}{1-\beta^4}} \qquad (4.4.2)$$

where

q_{ms} = gas mass flow, lb/s
0.09970190 = units conversion constant
C = discharge coefficient, dimensionless
Y_1 = expansion factor, dimensionless
d = diameter of orifice, in.
D = inside diameter of pipe, in.
h_w = differential pressure, in. of H_2O at 60°F
ρ_{fl} = density of flowing gas upstream of orifice, lbm/ft^3
β = beta ratio (d/D), dimensionless

Note: Any other consistent set of units is acceptable with the use of the appropriate units conversion constant.

Orifice and Pipe Dimension Correction to Flowing Temperature

The dimesions of the orifice and pipe may be measured at conditions that vary from their in-service conditions. The following equations compensate for the dimensional changes to the components due to temperature variations.

$$d = [1 + \alpha_{PE}\,(t_f - t_{meas})]\ d_{meas} \qquad (4.4.3)$$

$$D = [1 + \alpha_P\,(t_f - t_{meas})]\ D_{meas} \qquad (4.4.4)$$

where

d_{meas} = measured diameter of orifice, in.
D_{meas} = measured diameter of pipe, in.
α_{PE} = coefficient of thermal expansion for orifice, in./in./°F
α_P = coefficient of thermal expansion for pipe in./in./°F
t_f = temperature of flowing fluid, °F
t_{meas} = metal temperature when components were measured, °F

Calculation of Flow Density

Calculation of the density of the flowing gas (ρ_{fl}) can be derived from the ideal gas laws.

$$\rho_{fl} = \frac{P_f\, Mr_{air}\, sg_i}{Z_f\, R\, T_f} \qquad (4.4.5)$$

where

P_f = pressure of gas, PSIA
Mr_{air} = molecular weight of standard air, 28.9625 lb/lbmole
sg_i = gas ideal specific gravity, dimensionless
Z_f = natural gas compressibility factor, dimensionless (developed from AGA Transmission Measurement Committee Report No. 8)
R = Universal Gas Constant, 10.7316 $\frac{\text{PSIA ft}^3}{\text{lb mole °R}}$
T_f = absolute temperature of gas, °R

Expansion Factor

The expansion factor compensates for the change in gas density due to the increase in pressure when flowing through the orifice.

$$Y_1 = 1 - (0.41 + 0.35\beta^4)\frac{h_w}{27.73\ \kappa\ P_f} \qquad (4.4.6)$$

where

κ = isentropic coefficient, 1.3

27.73 = units conversion factor, in. H_2O/PSI

Coefficient of Discharge

The coefficient of discharge relates actual test data to theoretically determined flows.

For $D \geq 2.3$ in.

$$C = 0.5959 + 0.0312\beta^{2.1} - 0.1840\beta^8 + 0.09D^{-1}\ \beta^4\ (1 - \beta^4)^{-1} - 0.0337D^{-1}\beta^3 + 91.71\beta^{2.5}\ R_D{}^{-0.75} \qquad (4.4.7)$$

for 2 in. < D < 2.3 in., see MFC-3M-1989

R_D = Reynolds number with respect to the pipe diameter, dimensionless

Reynolds Number

$$R_D = \frac{22738\ q_{ms}}{\mu D} \qquad (4.4.8)$$

where

q_{ms} = mass gas flow, lb/sec

μ = absolute viscosity of the fluid, 6.9 x 10^6 lbm/ft sec

4.4.3.2 Turbine Meters for Natural Gas Fuel Flow Measurement. Use of turbine meters is one alternative to orifice gas flow measurement. The turbine meter measures actual volume flow. The turbine meter rotates a shaft connected to a display. Through a series of gears the rotational shaft speed is adjusted so that the counter displays in actual volume units per unit time, e.g., actual cubic feet per minute. This value must be adjusted to mass flow units, lb/h.

$$q_{ms} = 60\ q_v\ \rho_f \qquad (4.4.9)$$

where

q_{ms} = mass flow, lb/h

q_v = actual volume flow, acf/m

ρ_f = density at flowing conditions, lb/acf

60 = minutes per hour, m/h

$$\rho_f = \frac{P_f\ Mr_{air}\ sg_i}{Z_f\ R\ T_f} \qquad (4.4.10)$$

where

P_f = pressure of gas, PSIA

Mr_{air} = molecular weight of standard air, 28.9625 lb/lb mole

sg_i = gas ideal specific gravity, dimensionless

Z_f = natural gas compressibility factor, dimensionless (developed from AGA Transmission Measurement Committee Report No. 8)

R = Universal Gas Constant, 10.7316 $\frac{\text{PSIA ft}^3}{\text{lb mole °R}}$

T_f = absolute temperature of gas, °R

4.4.3.3 Digital Computation of Fuel Flow Rate. Mass flow rate as shown by computer print-out or flow computer is not acceptable without showing intermediate results and the data used for the calculations. Intermediate results for an orifice would include the discharge coefficient, corrected diameter for thermal expansion, expansion factor, etc. Raw data includes static and differential pressures, and temperature. For a turbine meter, intermediate results include the turbine meter constant(s) used in the calculation, and how it is determined from the calibration curve of the meter. Data includes frequency, temperature, and pressure. For both devices, fuel analysis and the intermediate results used in the calculation of density is required.

4.5 PRIMARY HEAT INPUT MEASUREMENT

4.5.1 Consistent Solid Fuels. Consistent solid fuels are defined as those with a heating value that varies less than 2.0% over the course of a performance test. The heat input to the plant by consistent solid fuel flow must be measured and calculated by indirect methods since solid fuel flow cannot be accurately measured using direct methods. The approach requires dividing the heat added to the working fluid by the boiler fuel efficiency as follows:

$$\textit{facility heat input} = \frac{\text{boiler energy output}}{b.e.}$$

where

facility heat input = the energy added to the facility by the consistent fuel, Btu/lb *boiler energy output* = heat added to the working fluid (including blowdown) by the boiler, Btu/lb

b.e. = boiler fuel efficiency

$$= 1 - \frac{\Sigma \text{ losses} + \Sigma \text{ credits}}{\text{heating value}}$$

The boiler fuel efficiency (b.e.) shall be calculated using the energy balance method per PTC 4, Fired Steam Generators.[1]

The boiler energy output is the energy added to the boiler feedwater as it becomes superheated steam and as steam is reheated if applicable. The boiler energy output is calculated by drawing a mass and energy control volume around the boiler. Then the product of the flow and enthalpy of each water and steam stream crossing the volume are summed. Flows entering the volume are negative and the flows leaving are positive. All steam or water flows into or out of the boiler will be included. These flows include feedwater, superheat spray, blowdown, sootblower steam, and steam flows.

The following is some guidance as to when flow should be included and how to make measurements. Superheat spray/attemperator flow generally originates at the boiler feedpump discharge. However, occasionally it originates from the feedwater line downstream of any feedwater heaters and downstream of the feedwater measurement. Should the latter be the case, do not include the superheat spray flow in the calculation.

Boiler blowdown most often leaves the cycle and should be counted as one of the leaving streams. The enthalpy of this stream is saturated liquid at the boiler drum pressure. This Code recommends that the boiler blowdown be isolated since it is difficult to measure a saturated liquid flow.

Sootblowing steam should be counted as a leaving flow stream if it originates within the boiler. Often this steam originates upstream of one of the superheat sections. If sootblowing steam cannot be measured it should be isolated during the test. If the sootblowing steam originates downstream of the main steam it should not be included in the calculation.

The main steam flow is typically calculated by subtracting blowdown and other possible extraneous flow like sootblowing steam from the feedwater flow.

[1] PTC 4 is scheduled for publication in 1998, and will replace PTC 4.1, "Steam Generating Units." Until then, the parties to the test must agree on a methodology for calculating the boiler fuel efficiency. Nonmandatory guidance for the determination of boiler fuel efficiency is provided in Appendix H, which can be used by mutual agreement of the parties to a test until PTC 4 is available.

The reheat steam flow to the boiler is determined by subtracting from the main steam flow any leakages and extractions that leave the main steam before it returns to the boiler as reheat steam. Leakages shall be either measured directly, calculated using vendor pressure for flow relationships, or determined by methods acceptable to all parties. Extraction flows shall either be measured directly or calculated by heat balance around the heater if the extraction is serving a heater.

Reheat spray flow must also be included as one of the flow streams into the boiler. The reheat return flow is the summation of the reheat steam flow to the boiler and the cold reheat spray.

4.5.2 Consistent Liquid or Gaseous Fuels. Consistent liquid or gaseous fuels are those with heating values that vary less than 1.0% over the course of a performance test. Since liquid and gas flows and heating values can be determined with high accuracy, the heat input from these type fuels is usually determined by direct measurement of fuel flow and the laboratory or on-line chromatograph-determined heating value. Consistent liquid or gaseous fuels heat input can also be determined by calculation as with solid fuels.

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

Subsection 4.4 includes a discussion of the measurement of liquid and gaseous fuel flow. Should the direct method be employed, the flow is multiplied by the heating value of the stream to obtain the facility heat input to the cycle. The heating value can be measured by an on-line chromatograph or by sampling the stream periodically (at least three samples per test) and analyzing each sample individually for heating value. The analysis of gas, either by on-line chromatography or from laboratory samples, in accordance with ASTM D D1945 results in the amount and kind of gas constituents, from which heating value is calculated. Liquid fuel heating value may be determined by calorimeter in accordance with ASTM D4809.

4.5.3 Solid Fuel and Ash Sampling. Refer to PTC 4, Fired Steam Generators, for sampling requirements and procedures.[2]

[2] PTC 4 is scheduled for publication in 1998, and will replace PTC 4.1, "Steam Generating Units." Until then, the parties to the test must agree on a methodology for calculating solid fuel and ash sampling. Nonmandatory guidance for solid fuel and

4.6 ELECTRICAL GENERATION MEASUREMENT

4.6.1 Introduction. This Subsection presents requirements and guidance regarding the measurement of electrical generation. The scope of this Subsection includes the measurement of polyphase (three phase) real and reactive power measurements. Typically the polyphase measurement will be net or overall plant generation, the direct measurement of generator output (gross generation), or power consumption of large plant auxiliary equipment (such as a boiler feedpump drives).

ANSI/IEEE Standard 120-1989, "IEEE Master Test Guide for Electrical Measurements in Power Circuits" is referenced for measurement requirements not included in this Subsection or for any additionally required instruction.

4.6.2 Electrical Measurement System Connections. Polyphase power systems will be three-wire or four-wire type systems. Below is a description of where each of these systems are found and how the measurements are made.

4.6.2.1 Three Wire Power Systems. Three wire power systems are used for several types of power systems as shown in Fig. 4.6. Descriptions of various three wire power systems are as follow:

(a) Where generator output (gross generation) is desired from an "Open Delta" connected generator. In this case no neutral or fourth wire is available.

(b) Where generator output is desired from a "wye" connected generator with a high impedance neutral grounding device. In this case the generator is connected directly to a transformer with a delta primary winding and load distribution is made on the secondary, grounded-wye, side of the transformer. Any load unbalance on the load distribution side of the generator transformer are seen as neutral current in the grounded wye connection. On the generator side of the transformer, the neutral current is effectively filtered out due to the delta winding, and a neutral conductor is not required.

(c) Where generator output is desired from a wye connected generator with a low impedance neutral grounding resistor. In this case the generator is connected to a three-wire load distribution bus and the loads are connected either phase to phase, single phase, or three phase delta. The grounding resistor is sized to carry 400 to 2000 amperes of fault current.

(d) A less common fourth example of a three-wire power system is where generator output is desired from an ungrounded wye generator used with a delta-wye grounded transformer.

Three-wire power systems can be measured using two "Open Delta Connected" potential transformers (PTs) and two current transformers (CTs). The Open Delta metering system is shown in Fig. 4.6. These instrument transformers are connected to either two watt meters, two watt-hour meters, or a two-element watt-hour meter. A var type meter is the recommended method to measure reactive power to establish the power factor. Power factor is then determined as follows:

$$PF = \frac{Watts_t}{[Watts_t^2 + Vars_t^2]^{0.5}}$$

where

PF = power factor
$Watts_t$ = total watts
$Vars_t$ = total vars

Alternatively, for balanced three-phase sinusoidal circuits, power factor may be calculated from the phase-to-phase power measurement as follows:

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

where

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

4.6.2.2 Four-Wire Power Systems. There are two types of four-wire power systems as shown in Fig. 4.7. Descriptions of various three-wire power systems are as follow:

(a) Where generator output is desired from a wye connected generator with a solid or impedance ground where current can flow through this fourth wire.

(b) Where net plant generation is measured somewhere other than at the generator such as the high side of the step-up transformer. In this case the neutral is simulated by a ground.

In addition, with the exception of the "Open Delta" generator connection, all of the three-wire systems described in para. 4.6.2.1 can also be mea-

ash sampling is provided in Appendix I, which can be used by mutual agreement of the parties to a test until PTC 4 is available.

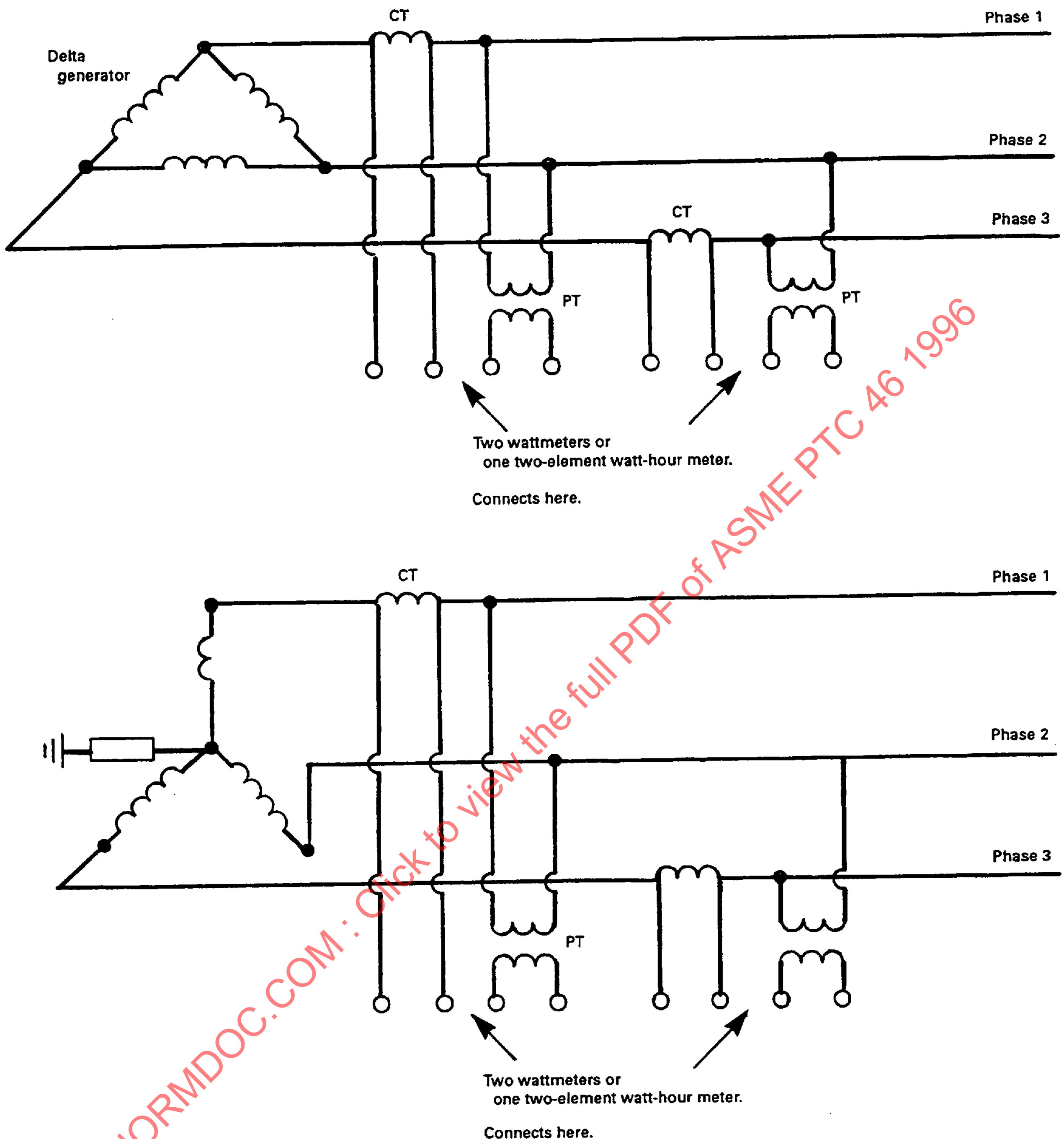


FIG. 4.6 THREE-WIRE OPEN DELTA CONNECTED METERING SYSTEM

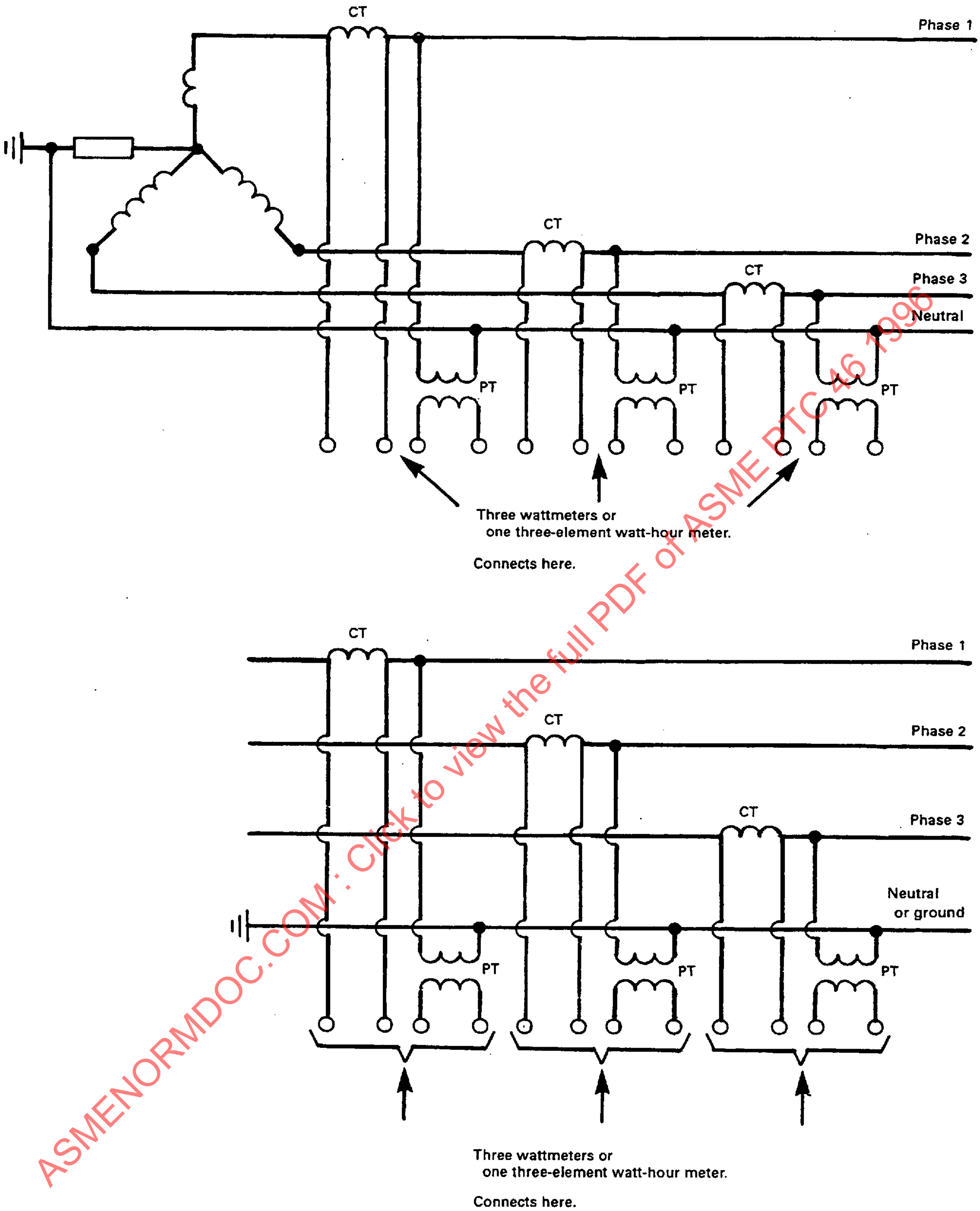


FIG. 4.7 FOUR-WIRE METERING SYSTEM

sured using the four-wire measurement system described in this Section.

The measurement of a four-wire power systems made using three PTs and three CTs as shown in Fig. 4.7. These instrument transformers are connected to either three watt/var meters, three watt-hour/var-hour meters, or a three element watt-hour/var-hour meter. The var meters are necessary to establish the power factor as follows:

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

where

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

Alternatively, power factor may be determined by measuring each phase current and voltage, with the following equation:

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

where

PF = power factor
V_i = phase voltage for each of the three phases
I_i = phase current for each of the three phases

4.6.3 Electrical Metering Equipment. There are four types of electrical metering equipment that may be used to measure electrical energy: 1) watt meters, 2) watt-hour meters, 3) var meters, and 4) var-hour meters. Single or polyphase metering equipment may be used. However, if polyphase equipment is used the output from each phase must be available or the meter must be calibrated three phase. These meters are described below.

4.6.3.1 Watt Meters. Watt meters measure instantaneous active power. The instantaneous active power must be measured frequently during a test run and averaged over the test run period to determine average power (kilowatts) during the test. Should the total active electrical energy (kilowatt-hours) be desired, the average power must be multiplied by the test duration in hours.

Watt meters measuring a Class 1 primary variable such as net or gross active generation must have a bias uncertainty equal to or less than 0.2 percent of reading. Metering with an uncertainty equal to or less than 0.5 percent of reading may be used for the measurement of Class 2 primary variables. There is no metering accuracy requirements for measurement of secondary variables. The output from the watt meters must be sampled with a frequency high enough to attain an acceptable precision. This is a function of the variation of the power measured. A general guideline is a frequency of not less than once each minute.

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

Watt-hour meters measuring a Class 1 primary variable such as net or gross active generation must have an uncertainty equal to or less than 0.2 percent of reading. Metering with an uncertainty equal to or less than 0.5 percent of reading may be used for measurement of Class 2 primary variables. There are no metering accuracy requirements for measurement of secondary variables.

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

4.6.3.3 Var Meters. Var meters measure instantaneous reactive power. The var measurements are typically used on four wire systems to calculate power factor as discussed in para. 4.6.2.2. The instantaneous reactive power must be measured frequently during a test run and averaged over the test run period to determine average reactive power (kilovars) during the test. Should the total reactive electrical energy (kilovar-hours) be desired, the average power must be multiplied by the test duration in hours.

Var meters measuring a Class 1 or Class 2 primary variable must have an uncertainty equal to or less than 0.5 percent of reading. There is no metering accuracy requirements for measurement of secondary variables. The output from the var meters must be sampled with a frequency high enough to attain an acceptable precision. This is a function of the variation of the power measured. A general guideline is a frequency of not less than once each minute.

4.6.3.4 Var-hour Meters. Var-hour meters measure reactive energy (kilovar-hours) during a test period. The measurement of var-hours must be divided by the test duration in hours to determine average active power (kilovars) during the test period.

Var-hour meters measuring a Class 1 or Class 2 primary variable must have an uncertainty equal to or less than 0.5 percent of reading. There is no metering accuracy requirements for measurement of secondary variables.

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

4.6.3.5 Watt and Watt-hour Meter Calibration. Watt and watt-hour meters, collectively referred to as power meters, are calibrated by applying power through the test power meter and a watt meter or watt-hour meter standard simultaneously. This comparison should be conducted at several power levels (at least five) across the expected power range. The difference between the test and standard instruments for each power level should be calculated and applied to the power measurement data from the test. For test points between the calibration power levels, a curve fit or linear interpolation should be used. The selected power levels should be approached in an increasing and decreasing manner. The calibration data at each power level should be averaged to minimize any hysteresis effect.

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

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

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

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

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

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

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

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

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

4.6.4 Instrument Transformers. Instrument transformers include potential transformers and current transformers. The potential transformers measure voltage from a conductor to a reference and the current transformers measure current in a conductor.

4.6.4.1 Potential Transformers. Potential transformers measure either phase to phase voltage or phase to neutral voltage. The potential transformers

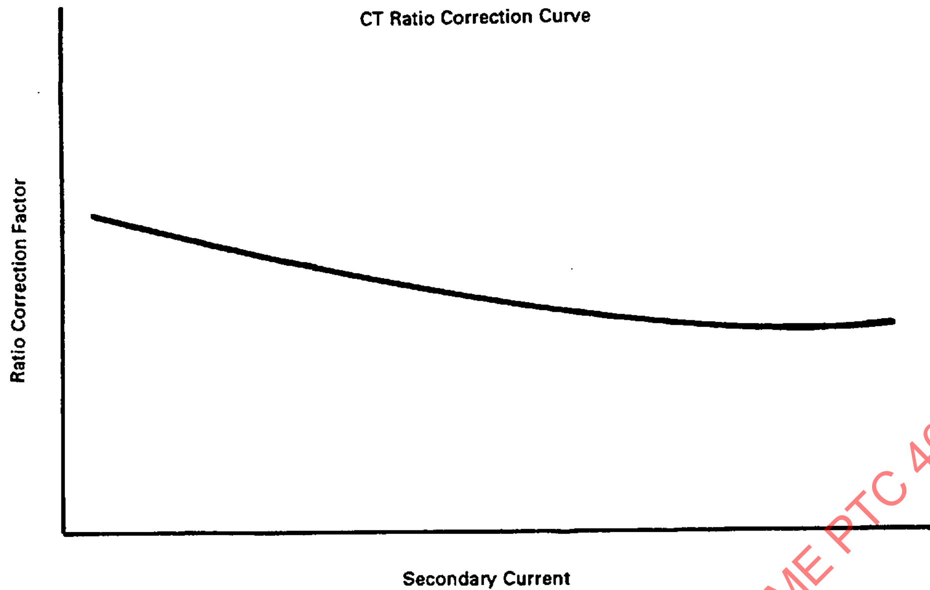


FIG. 4.8 TYPICAL CORRECTION CURVE

serve to convert the line or primary voltage (typically very high in voltage) to a lower or secondary voltage safe for metering (typically 120 volts for phase to phase systems and 69 volts for phase to neutral systems). For this reason the secondary voltage measured by the potential transformer must be multiplied by a turns ratio to calculate the primary voltage.

Potential transformers are available in several metering accuracy classes. For the measurement of Class 1 or Class 2 primary variables or secondary variables, 0.3 percent bias uncertainty class potential transformers shall be used. In the case of Class 1 primary variable measurement, potential transformers must be calibrated for turns ratio and phase angle and operated within their rated burden range.

4.6.4.2 Current Transformers. Current transformers measure current in a given phase. Current transformers serve to convert line or primary current (typically very high) to lower or secondary metering current. For this reason the secondary current measured by the current transformer must be multiplied by a turns ratio to calculate the primary current.

Current transformers are available in several metering accuracy classes. For the measurement of Class 1 or Class 2 primary variables or secondary variables, 0.3 percent bias uncertainty class current transformers shall be used. In the case of Class 1 primary variable measurement, current transformers must be calibrated for turns ratio and phase angle and operated within their rated burden range.

4.6.5 Calculation of Corrected Average Power or Corrected Total Energy. The calculation method for average power or total energy should be performed in accordance with ANSI/IEEE Standard 120 for the specific type of measuring system used. For Class 1 primary variable, power measurements must be corrected for actual instrument transformer ratio and for phase-angle errors in accordance with the procedures of ANSI/IEEE Standard 120.

4.7 DATA COLLECTION AND HANDLING

4.7.1 Data Collection and Calculation Systems

4.7.1.1 Data Collection Systems. A data collection system should be designed to accept multiple instrument inputs and be able to sample data from all of the instruments within two to three minutes to obtain all necessary data with the plant at the same condition. The system should be able to collect data and store data and results within three minutes.

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

4.7.2 Data Management

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

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

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

4.7.3 Construction of Data Collection Systems

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

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

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

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

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

4.7.3.3 Usage of Existing Plant Measurement and Control System. The Code does not prohibit the use of the plant measurement and control system for code testing. However, this system must meet the requirements of this Section. Below are some caution areas.

Typically plant measurement and control systems do not calculate flows in a rigorous manner. Often the flow is based on a ratio relationship with compensation factors. Calculation of flow should follow Subsection 4.4.

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

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

Distributed control systems typically only report changes in a variable which exceed a set threshold value. The threshold value must be low enough so that all data signals sent to the distributed control system during a test are reported and stored.

SECTION 5 — CALCULATIONS AND RESULTS

5.1 FUNDAMENTAL EQUATIONS

The fundamental performance Eqs., (5.1.1), (5.1.2), and (5.1.3a,b) are applicable to any of the types of power plants covered by this Code.

Corrected net power is expressed as:

$$P_{corr} = \left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{5} \alpha_j \qquad (5.1.1)$$

Corrected heat input is expressed as:

$$Q_{corr} = \left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right) \prod_{j=1}^{5} \beta_j \qquad (5.1.2)$$

Corrected heat rate is expressed as:

$$HR_{corr} = \frac{\left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right) \prod_{j=1}^{5} \beta_j}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{5} \alpha_j} \qquad (5.1.3a)$$

or

$$HR_{corr} = \frac{\left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right)}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right)} \prod_{i=1}^{5} f_i \qquad (5.1.3b)$$

Additive corrections factors Δ_i and ω_i, and multiplicative correction factors α_j, β_j and f_j, are used to correct measured results back to the design-unique set of base reference conditions. Tables 5.1 and 5.2 summarize the correction factors used in the fundamental performance equations.

The correction factors which are not applicable to the specific type of plant being tested, or to the test objectives, are simply set equal to unity or zero, depending on whether they are multiplicative correction factors or additive correction factors, respectively.

Some correction factors may be significant only for unusually large deviations from design conditions, or not at all, in which case they can also be ignored. An example of this is some secondary heat inputs, such as process return temperature in a cogenerator. If the pre-test uncertainty analysis shows a correction to be insignificant, these corrections can be ignored, or may be measured.

The fundamental performance equations, which are generalized, can then be simplified to be specific to the particular plant type and test program objectives.

5.2 MEASURED NET PLANT POWER AND HEAT INPUT TERMS IN THE FUNDAMENTAL EQUATIONS

Measured net plant power for a power plant with multiple prime movers is expressed as:

$$P_{meas} = \left(\sum_{n=1}^{k} P_{\substack{measured,\\ generator_n}}\right) - P_{\substack{measured,\\ aux}} - P_{\substack{transformer\\ losses}} - P_{\substack{line\\ losses}} \qquad (5.2.1)$$

where

n = an individual generator

k = the total number of generators

Equation (5.2.1) represents net plant power as measured in the switchyard. Line losses may be negligible or outside of the test boundary, but are included in Eq. (5.2.1) for those cases when it is necessary to consider them.

Any of the loss terms can be excluded from Eq. (5.2.1) if the test boundary dictates.

Heat input which can be calculated from measured fuel flow and heating value is expressed as:

$$Q_{meas} = [(HV)(q_m)]_{fuel} \qquad (5.2.2)$$

If the fuel flow cannot be directly measured, Q_{meas} is determined from results of heat input computations based on heat output and steam generator corrected fuel energy efficiency. Steam generator corrected fuel energy efficiency would be determined by the energy balance method per ASME PTC 4. Heat

TABLE 5.1
SUMMARY OF ADDITIVE CORRECTION FACTORS IN FUNDAMENTAL PERFORMANCE EQUATIONS

Additive Correction to Thermal Heat Input	Additive Correction to Power [Notes (1) and (2)]	Operating Condition or Uncontrollable External Condition Requiring Correction	Comments
ω_1	Δ_1	Thermal efflux (Operating)	Calculated from efflux flow rate and energy level, such as process steam flow and enthalpy
ω_2	Δ_2	Generator(s) power factor(s) (Operating)	Corrected for each generator and combined
ω_3	Δ_3	Steam generator(s) blowdown different than design (Operating)	*BD* is sometimes isolated so that performance may then be exactly corrected to design *BD* flow rate
ω_4	Δ_4	Secondary heat inputs (External)	Process return or make-up temperature is typical
ω_{5A}	Δ_{5A}	Ambient conditions, cooling tower or air-cooled heat exchanger air inlet (External)	For some combined cycles, may be based on the conditions at the combustion turbine inlets
ω_{5B}	Δ_{5B}	Circ water temperature different than design (External)	To be used if there is no cooling tower or air-cooled condenser in the test boundary
ω_{5C}	Δ_{5C}	Condenser Pressure (External)	If the entire heat rejection system is outside the test boundary
ω_6	Δ_6	Auxiliary Loads, thermal and electrical (Operating)	(a) To account for auxiliary loads when the multiplicative corrections are based on gross generation, usually only for steam turbine plants (b) To compensate for irregular or off design auxiliary loads
ω_7	Δ_7	Measured power different than specified if test goal is to operate at a predetermined power, or operating disposition slightly different than required if a specified disposition test (Operating)	To account for (a) the small difference in measured versus desired power for a test run to be conducted at a specified measured or corrected power level, or (b) small differences between required and actual unit operating disposition such as valve point operation of a steam turbine plant

NOTES:
(1) For additive corrections 1–6, for a given correction *i*, usually either ω_i or Δ_i will be used for combined cycle plants, but not both. Use of both usually means that a correction is being made twice for a given condition. For steam turbine plants, it is sometimes necessary to use ω_i and Δ_i corrections with the same subscript, as shown in the sample calculations.
(2) Additive correction factors with subscript 7 must always be used together. The correction ω_7 is the correction to heat input that corresponds to Δ_7.

TABLE 5.2
SUMMARY OF MULTIPLICATIVE CORRECTION FACTORS IN FUNDAMENTAL PERFORMANCE EQUATIONS

Multiplicative Correction to Thermal Heat Input	Multiplicative Correction to Power	Multiplicative Correction to Heat Rate $f_i = \frac{\beta_i}{\alpha_i}$	Operating Condition or Uncontrollable External Condition Requiring Correction	Comments
β_1	α_1	f_1	Inlet temperature correction (external)	Measured at the test boundary at the inlet to the equipment
β_2	α_2	f_2	Ambient pressure correction (external)	As per β_1, α_1, f_1
β_3	α_3	f_3	Ambient humidity (external)	As per β_1, α_1, f_1
β_4	α_4	f_4	Fuel supply temperature correction (external)	
β_5	α_5	f_5	Correction due to fuel analysis different than design (external)	

GENERAL NOTE:
Inlet ambients and fuel/sorbent chemical analysis deviations from base reference conditions are part of the corrections for the heat loss method for coal or solid fuel plant when that method is used to determine thermal heat input. In those circumstances, they are not part of the overall plant performance test corrections per se.

output is determined by steam generator water/steam side measurements.

5.3 PARTICULARIZING FUNDAMENTAL PERFORMANCE EQUATIONS TO SPECIFIC CYCLES AND TEST OBJECTIVES

5.3.1 General. The applicable corrections to use in the fundamental performance equations for a particular test depend on the type of plant or cycle being tested, and the goal of the test.

5.3.2 Specified Disposition Test Goal. If the goal of the test is to determine net plant power and heat rate under a specified unit operating disposition without setting output to a predetermined numerical power, then Eqs. (5.1.1) and (5.1.3) are simplified differently depending on the type of power plant.

(a) Combined Cycle Plants — Specified Unit Disposition

For combined cycle plants without duct firing, or duct firing out of service, and the specified operating disposition being the base loading of the gas turbines, the Δ correction factors are the only additive corrections which are used. Use of both types of additive corrections would be double-accounting for the same correction. Note that all the Δ corrections through subscript 5 are steam turbine cycle power related except for the gas turbine generator power factor correction. For a combined cycle plant, Eqs. (5.1.1) and (5.1.3b) reduce to:

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_6)\alpha_1\alpha_2\alpha_3\alpha_4\alpha_5 \quad (5.3.1)$$

$$HR_{corr} = \frac{(Q_{meas})\,(f_1 f_2 f_3 f_4 f_5)}{(P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_6)} \quad (5.3.2)$$

From the format of Eq. (5.3.2), it is seen that once the steam turbine cycle output is corrected to reference conditions by use of the additive correction factors, and the other additive corrections are incorporated, then the more global corrections for inlet conditions and fuel analysis are applied.

Examples of applications of Eqs. (5.3.1) and (5.3.2) are shown in Appendix 1 and Appendix 3.

(b) Steam Turbine Plants — Specified Unit Disposition

For steam turbine plants, if the test goal is tied to a specified disposition, it is usually based on either a valve point operating mode, or on the throttle flow rate. For a steam turbine plant, the steam generator calculations are first done separately from the overall plant calculations in order to calculate PTC 46-measured thermal input. As such, the two additive corrections to overall plant reference conditions which always relate to steam flows affect the corrected thermal input as well as the corrected power of the plant. These are the additive correction with subscripts "1" and "3," for blowdown and process steam.

The multiplicative correction factors for inlet air conditions and fuel analysis and conditions are embedded in the steam generator data analysis. Q_{meas} for the overall plant test is the corrected thermal input as determined from an ASME PTC 4 test.

Hence, the correction factors for the air inlet conditions and the other multiplicative correction factors are all unity in the overall plant performance equations, and some of the additive correction factors with the same subscript are used.

The fundamental performance equation for power, Eq. (5.1.1) becomes:

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_7) \qquad (5.3.3)$$

For heat rate, Eq. (5.1.3a) then becomes

$$HR_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_3 + \omega_7)}{(P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_7)} \qquad (5.3.4)$$

In Eq. (5.3.4), Q_{meas} is thus equal to the steam generator tested output as defined in ASME PTC 4, including blowdown energy if applicable, divided by the steam generator corrected fuel energy efficiency calculated per ASME PTC 4 (see Subsection 5.2).

The ω factors are then used to correct the thus calculated measured thermal input to the plant reference conditions, such as reference process efflux, blowdown, and required operating disposition.

The ω correction curves are calculated by heat balance using base reference steam generator corrected fuel energy efficiency. If the tested corrected efficiency deviates significantly from reference, then recalculation of the ω corrections simply by multiplying each one by the ratio of base reference fuel energy efficiency to the test corrected efficiency can be done if the difference affects the results significantly.

An example of application of Eqs. (5.3.3) and (5.3.4) are in Appendix E for the unit required disposition of fixed throttle flow. Required unit disposition at valve point operation would be similarly calculated.

Note that Eq. (5.3.4) is in the format:

$$HR_{corr} = \frac{Q_{corr}}{P_{corr}} \qquad (5.3.5)$$

5.3.3 Specified Corrected Net Power

Specified corrected net power tests are conducted for steam turbine plants.

For a steam turbine plant for which a test is run with the goal that heat rate is determined at a specific corrected net power, the unit operating net power, *after* being corrected to the base reference conditions, is adjusted for the test, to be as close as possible to the design value of interest. Δ_7 and ω_7 are applied to adjust for the small difference between the actual adjusted power and the desired adjusted power.

As shown in Appendix E, the applicable equations are identical to a steam power plant when the goal is to test at a fixed operating disposition.

5.3.4 Specified Measured Net Power

The other test whose required unit operating disposition dictates adjustment of power to a predetermined value for testing is a specified measured net power test. This test is conducted for a combined cycle power plant with duct firing or other form of power augmentation, such as steam or water injection when used for that purpose.

For this test, the net power is set as closely as possible to a specified amount regardless of air inlet conditions.

The ω additive corrections are applicable (but not the Δ corrections except Δ_7).

Δ_7 and ω_7 are applied to adjust for the small difference between the actual adjusted power and the desired adjusted power.

In this case, the fundamental performance equation for corrected net power simplifies to:

$$P_{corr} = P_{base\ reference} \doteq (P_{meas} + \Delta_7) \qquad (5.3.6)$$

The fundamental equation for corrected heat rate simplifies to:

$$HR_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_2 + \omega_3 + \omega_4 + \omega_5 + \omega_6 + \omega_7)\,(f_1 f_2 f_3 f_4 f_5)}{(P_{meas} + \Delta_7)} \qquad (5.3.7)$$

Note that Eq. (5.3.7) is also in the format of Eq. (5.3.5). Because $\alpha_j = 2$, then $\beta_j = f_j$.

Table 5.3 summarizes the format of the general performance equations to use for various types of power plants or thermal islands, and test objectives discussed in this Section. There may be other applications for which different combinations of the correc-

TABLE 5.3
EXAMPLES OF TYPICAL CYCLES AND TEST OBJECTIVES — CORRESPONDING SPECIFIC PERFORMANCE EQUATIONS

Type of Plant or Thermal Island	Test Objective	Applicable Performance Test Equations	Test Objective Type
Combined cycle (steam turbine/ combustion turbine), no heat recovery steam generator duct firing.	Unit disposition is to be operating base loaded for the test.	Net Power, Eq. (5.3.1) Heat Rate, Eq. (5.3.2)	Specified disposition
Combined cycle (steam turbine/ combustion turbine), heat recovery steam generator duct firing.	Operate base loaded and fire external duct firing to the same required plant power level regardless of inlet air temperature.	Net Power, Eq. (5.3.6) Heat Rate, Eq. (5.3.7)	Specified measured net power
Steam turbine plant (Rankine cycle)	Fire until the design power level for the heat sink and air inlet conditions at the time of the test is reached.	Net Power, Eq. (5.3.3) Heat Rate, Eq. (5.3.4)	Specified corrected net power
Steam turbine plant (Rankine cycle)	Operate at required valve point disposition.	Net Power, Eq. (5.3.3) Heat Rate, Eq. (5.3.4)	Specified disposition
Steam turbine plant (Rankine cycle)	Operate at required throttle flow rate.	Net Power, Eq. (5.3.3) Heat Rate, Eq. (5.3.4)	Specified disposition

tion factors are used, but the general performance equations should always apply.

5.3.5 Alternate to Δ_7 and ω_7 Correction Factors. During a test run for which the test objective requires setting the power level, power will not be precisely at the required level because (1) adjustments are made utilizing readings of most operating conditions from the control room, (2) there are normal fluctuations during the test run after the unit is set for testing, and (3) desired power level might be dependent on final fuel analysis, which has to be assumed for the test.

Similarly, during a specified disposition test of a steam turbine plant, the unit may be found to have been operating in a slightly different disposition than required for the same reasons.

There are two ways to handle these situations. The preferred method is to incorporate the Δ_7 and ω_7 correction factors.

The second and alternate technique is to interpolate through the results of several test runs to determine where the results are at the desired power level or desired disposition. If the alternate method is used, then Δ_7 and ω_7 are not applicable and can be eliminated from the performance equations. However, the measured power levels or disposition of the test runs should have enough of a spread given the test uncertainty for reasonable results to be achieved this way.

This is shown in the example in Appendix E for a fixed corrected power test. In lieu of the additive corrections Δ_7 and ω_7, three tests were conducted and the result was interpolated.

Usually power levels can be set close enough to desired such that the alternate method is not necessary. And for steam turbine plants in particular, heat rate versus power at full loads is a relatively flat curve.

5.3.6 Different Test Goals for the Same Cycle. Tests with different objectives can be conducted at the same power plant, in which case care must be taken to ensure that appropriate sets of correction factors are calculated based on the test goal. In most cases, a single test objective is selected for a particular site.

5.4 DISCUSSION OF APPLICATION OF CORRECTION FACTORS

The format of the fundamental equations allows decoupling of the appropriate correction effects (process efflux, ambient conditions, etc.) relative to the measured prime parameters of heat rate and power, so that measured performance can be corrected to the reference conditions. Corrections are calculated for parameters at the test boundary different than base reference conditions which affect measured performance results. Tables 5.1 and 5.2 indicate whether each correction is considered due to uncontrollable external conditions, or to operating conditions.

Correction curves applied to measured performance are calculated by a heat balance model of the thermally integrated systems contained within the test boundary. The heat balance model represents the mathematical definition of the expected performance of the energy conversion facility. Each correction factor is calculated by running the heat balance model with a variance in only the parameter to be corrected for over the possible range of deviation from the reference condition. Correction curves are thus developed to be incorporated into the specific plant test procedure document. The model is finalized following purchase of all major equipment and receipt of performance information from all vendors.

Some of the correction factors are summations of smaller corrections or require a family of curves. For example, the correction for power factor is the summation of power factor corrections for each generator.

It is noted that for convenience, identical subscripts for all additive correction factors, and similarly for all multiplicative correction factors, represent the same variable to be corrected for, but the symbols are different depending on the result being corrected.

In lieu of application of the equations in Subsection 5.3, a heat balance computer model may be applied after the test using the appropriate test data and boundary conditions so that all the corrections for the particular test run are calculated simultaneously. Heat balance studies of different cycles using the performance equations in the above format have demonstrated that interactivity between correction factors usually results in differences of less than 0.2% compared to calculation of the complete heat balance post-test with the test data. An advantage of this post-test heat balance calculation is a reduction or elimination in required heat balance calculations required to generate all the heat balance correction curves.

5.4.1 Additive Correction Factors — Δ and ω. The additive corrections are discussed below in paras. 5.4.1.1–5.4.1.7.

5.4.1.1 Correction Due to Thermal Efflux Different Than Design — Δ_1 or ω_1. For a cogeneration power plant, the design net power and heat rate is specified at a design thermal efflux, or secondary output. These are the corrections for deviations from design reference thermal efflux during the performance test run, when applicable.

If thermal efflux is in the form of process steam, which is the most common, then the design net thermal efflux for each process may be defined as:

$$Q_{\substack{\text{thermal efflux,}\\ \text{design}}} = \left[(mh)_{\substack{\text{process}\\ \text{steam}}} - (mh)_{\substack{\text{process}\\ \text{return}}} - \left(m_{\substack{\text{process}\\ \text{steam}}} - m_{\substack{\text{process}\\ \text{return}}} \right) h_{\substack{\text{make}\\ \text{up}}} \right]_{\text{design}} \tag{5.4.1}$$

If the design process return flow is equal to design process steam flow, and Eq. (5.4.1) simplifies to:

$$Q_{\substack{\text{thermal efflux,}\\ \text{design}}} = \left[\left(m_{\substack{\text{process}\\ \text{steam}}} \right) \left(h_{\substack{\text{process}\\ \text{steam}}} - h_{\substack{\text{process}\\ \text{return}}} \right) \right]_{\text{design}} \tag{5.4.2}$$

Test results are corrected for deviations from design values of each term in Eq. (5.4.2). The sum of the corrections equals Δ_1 (or ω_1).

It is also permissible to include the process return energy correction as part of the correction Δ_4, (or ω_4), which is for secondary heat inputs into the cycle (see below), if more convenient. If that option is selected, then process return is not considered as part of the Δ_1 (or ω_1) correction.

5.4.1.2 Generator Power Factor Correction — Δ_2 or ω_2. The output of each generator is corrected to its design power factor rating from measurements of MVARS and MW. The sum of all the corrections to each generator comprise Δ_2 (or ω_2).

5.4.1.3 Steam Generator Blowdown Correction — Δ_3 or ω_3. To compare test results to design reference heat balance values, it is recommended to isolate blowdown if possible and to correct to the design blowdown flow rate. This simplifies the test because of the difficulty in determining actual blowdown flow rates.

5.4.1.4 Secondary Heat Input — Δ_4 or ω_4. Secondary heat inputs are all heat inputs to the test boundary other than primary fuel. Examples are make-up water and low level external heat recovery. The process steam return portion for a cogeneration unit can be considered in this correction term, or as part of Δ_1 (or ω_1).

Effects of differences in make-up temperature or flow from design should be considered for those cases where it has impact. The same holds true for process steam returned as water.

If any of the return is stored in a tank and then added to the cycle, as opposed to direct return to the cycle, the conditions prior to entering the cycle are corrected to reference conditions.

5.4.1.5 Heat Sink — Δ_5 Factors. Only one of the correction factors Δ_{5A}, Δ_{5B}, or Δ_{5C} (or ω_{5A}, ω_{5B}, or ω_{5C}) is applied, depending on the cycle test boundary, or cycle configuration of the plant or thermal island. Figures 5.1, 5.2, and 5.3 show configurations where these corrections are respectively applicable for a combined cycle power plant.

(a) Ambient conditions at the cooling tower air inlet — Δ_{5A}, or ω_{5A}

If cooling tower(s) or air-cooled condenser(s) exist within the test boundary, then a correction is made for cooling tower/air-cooled condenser atmospheric inlet conditions. For a wet cooling tower, applicable ambients are wet bulb temperature and barometric pressure. Humidity and dry bulb temperature may be used in lieu of wet bulb temperature. Typically, for a dry cooling tower, or air cooled condenser, dry bulb temperature and barometric pressure are the required applicable ambient conditions. The barometric pressure component of this correction can be incorporated into the subscripted "2" multiplicative correction factors.

It may be acceptable to assume that cooling tower inlet conditions are identical to those measured at the combustion turbine inlets in a combined cycle, if they are measured at the combustion turbine inlet(s).

(b) Circulating water temperature — Δ_{5B}, or ω_{5B}

If there is no cooling tower(s) or air-cooled condenser(s) within the test boundary, then the heat sink correction is made based on measured circulating water conditions.

(c) Condenser pressure — Δ_{5C}, or ω_{5C}

If the condenser is not part of the test boundary, a correction is made to the steam turbine cycle based on the measured condenser pressure.

5.4.1.6 Thermal and Electrical Auxiliary Loads — Δ_6 or ω_6. These corrections are for off-design auxiliary load line-up at the tested conditions. Care must be taken to assure that no overlap exists between corrections taken here as well as for inlet temperature and other external condition corrections

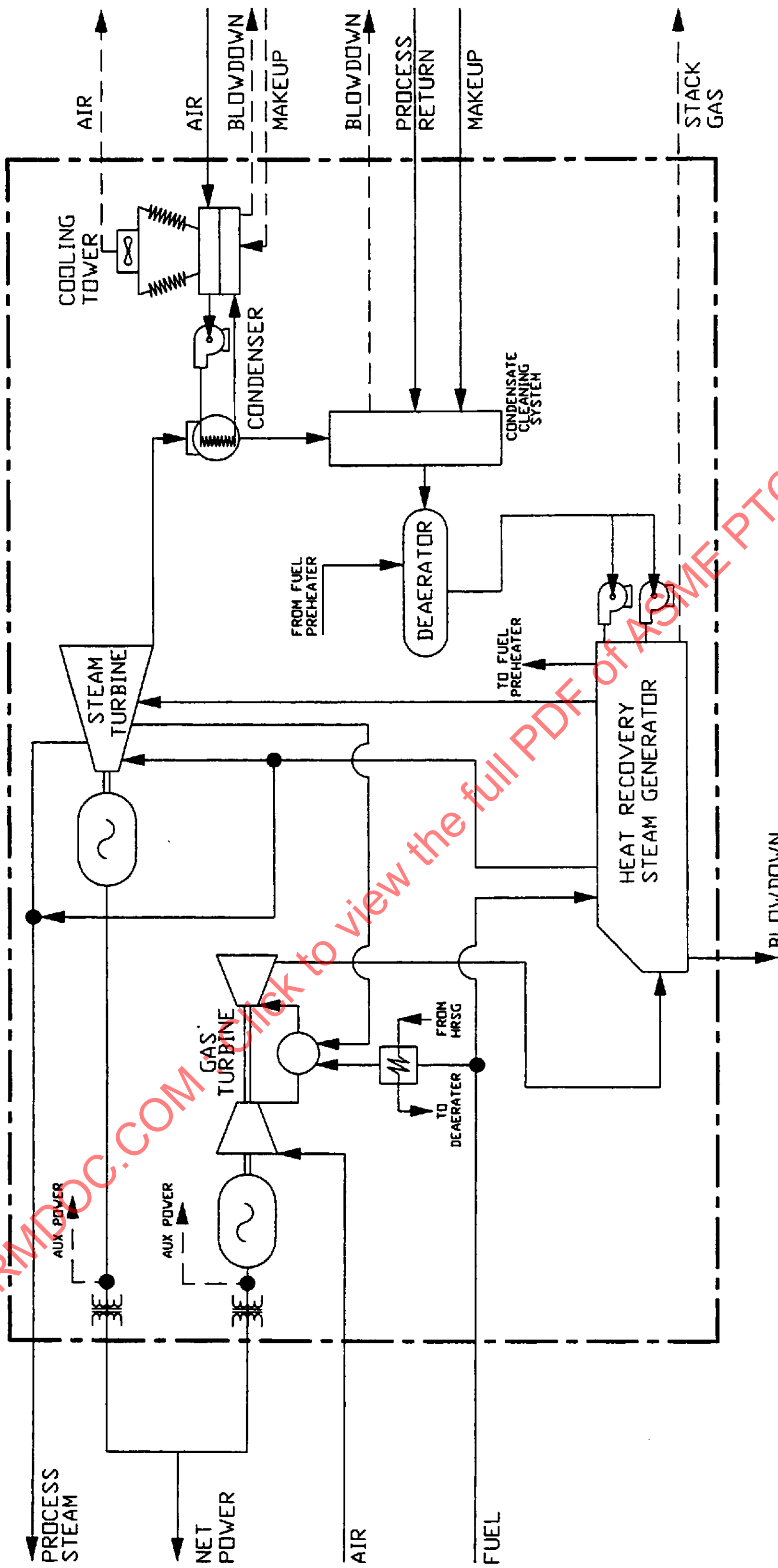


FIG. 5.1 TYPICAL TEST BOUNDARY FOR A POWER PLANT REQUIRING APPLICATION OF HEAT SINK CORRECTION FACTOR Δ_{5A} OR ω_{5A}

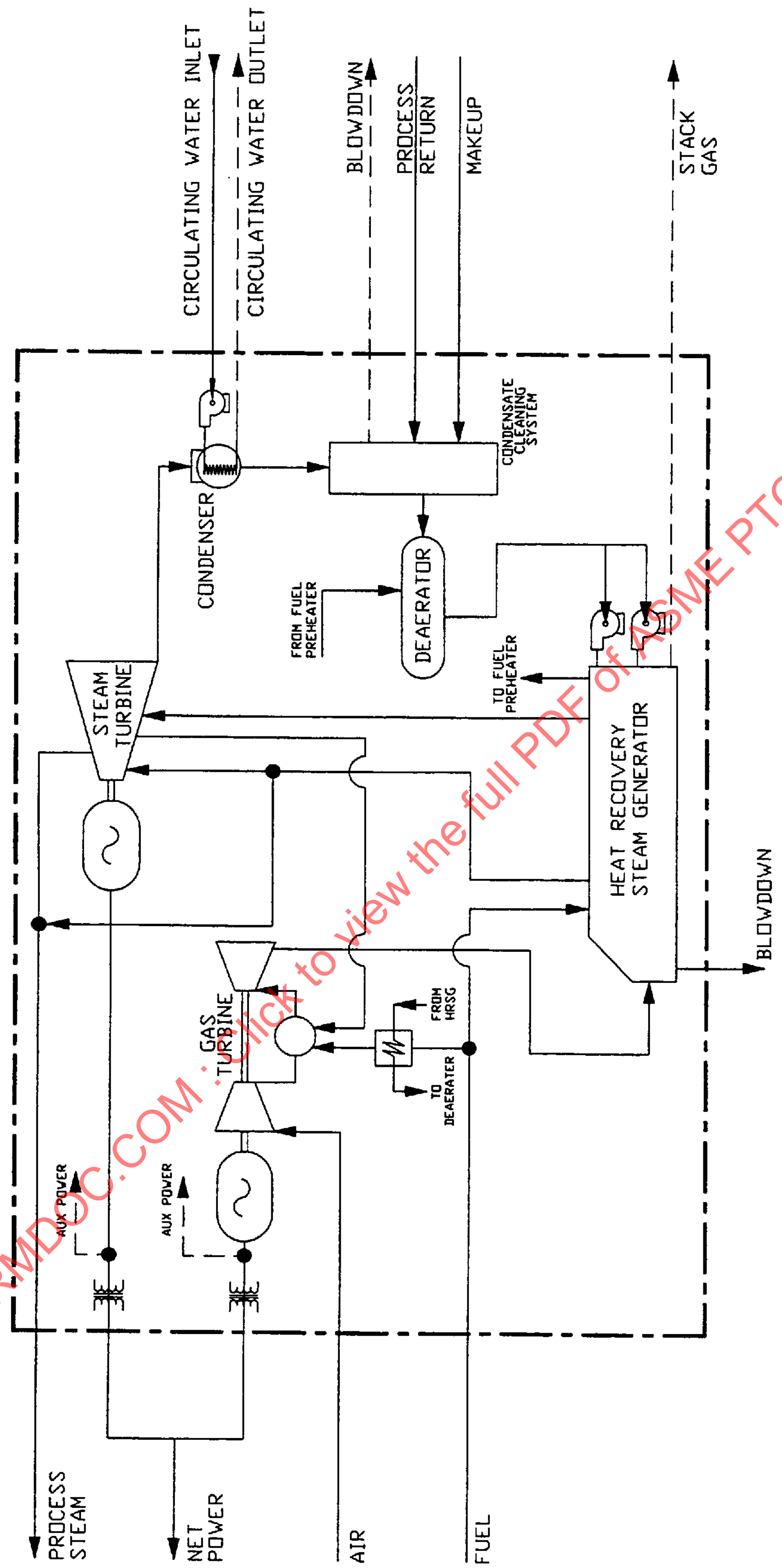


FIG. 5.2 TYPICAL TEST BOUNDARY FOR A POWER PLANT REQUIRING APPLICATION OF HEAT SINK CORRECTION FACTOR Δ_{5B} OR ω_{5B}

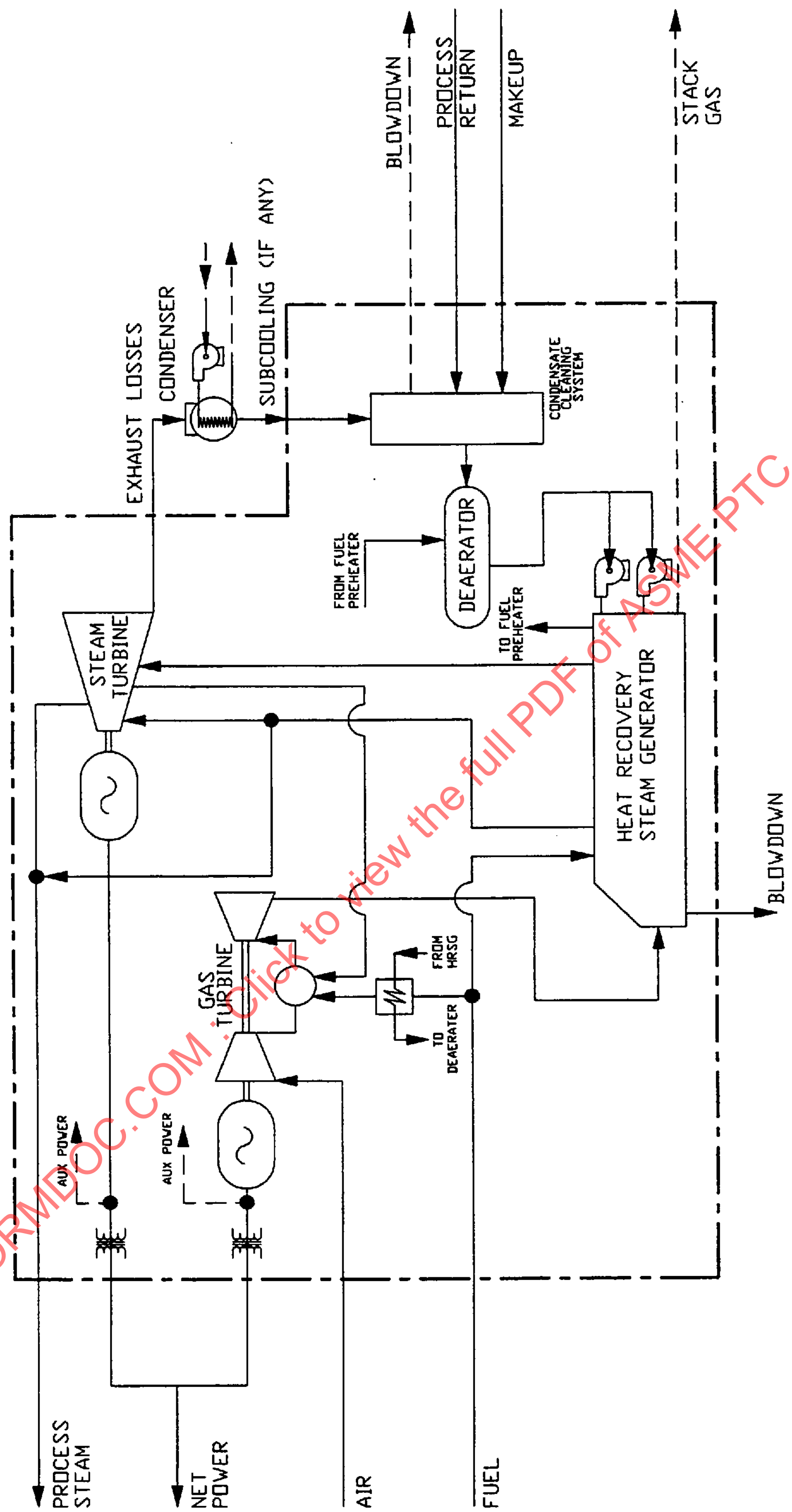


FIG. 5.3 TYPICAL TEST BOUNDARY FOR A POWER PLANT OR THERMAL ISLAND REQUIRING APPLICATION OF HEAT SINK CORRECTION FACTOR Δ_{5C} OR ω_{5C}

in which normal auxiliary load variations with varying external conditions have already been considered.

5.4.1.7 Small Difference in Measured Power from Target Power, or Actual Unit Disposition from Operating Disposition — Δ_7 or ω_7. For specified measured net power and specified corrected net power tests, in which the power during the test is set, these are used to correct for the fact that measured power will never equal precisely the desired power for the practical reasons tabulated in para. 5.3.5. These corrections must always both be used together. Once measured power is corrected to the precise value it should have been exactly set to, then the concomitant change in thermal heat input must be considered.

For the same reasons, these corrections are used when the required unit operating disposition is slightly different than required for a steam turbine plant.

5.4.2 Multiplicative Correction Factors — α, f, and β. For a steam turbine cycle, multiplicative corrections usually do not apply.

For combined cycles, once the steam turbine portion of the cycle has been corrected to design reference conditions by the additive corrections, then the plant performance can be corrected based on ambients and other external quantities using the multiplicative correction factors as described below.

α multiplicative corrective factors are used to correct measured net power, and *either* f *or* β is used to correct heat rate or measured thermal heat input, respectively. It is preferred to use f.

The multiplicative correction factors are discussed below in paras. 5.4.2.1–5.4.2.4.

5.4.2.1 Inlet Temperature, Pressure, and Humidity Corrections α_1, α_2, α_3 and f_1, f_2, and f_3, or β_1, β_2, and β_3. Correction is made to plant performance based on the inlet temperature (α_1 and f_1, or β_1), inlet pressure (α_2 and f_2, or β_2), and inlet humidity (α_3 and f_3, or β_3).

Inlet temperature of the air crossing the test boundary at gas turbine compressor inlet(s) is preferably measured inside the air inlet duct because of better mixing to attain true bulk ambient temperature.

Inlet pressure and humidity of air crossing the test boundary at gas turbine compressor inlet(s) should be measured in the vicinity of the gas turbine compressor inlet ducts, but can be measured outdoors.

5.4.2.2 Fuel Supply Temperature Correction — α_4 and f_4, or β_4. Fuel supply temperature upstream of any conditioning device such as preheating which is different than base reference affect performance. Provision is made for correction in the performance equations for this.

5.4.2.3 Fuel Analysis Correction — α_5 and f_5, or β_5. Differences in fuel properties between the design fuel and the performance test fuel can lead to variance from design performance. This corrects for difference in fuel properties.

5.5 SPECIAL CONSIDERATIONS OF PERFORMANCE EQUATIONS AS APPLIED TO COMBINED CYCLES

5.5.1 Multiple Locations of Air Inlet. Corrected performance by utilizing the fundamental performance equations in the formats for combined cycles shown in Subsection 5.3 assumes that the air at each gas turbine inlet is equivalent. The equations also allow for accommodating the combined cycle calculations if significantly different air inlet conditions exist at the cooling tower(s) or air-cooled condenser(s) than at the gas turbine(s).

For facilities with more than one gas turbine, it is almost always acceptable to average the ambient measurements at all gas turbine compressor inlets and use the average for the determination of inlet corrections, provided the gas turbines are identical models, which is usually the case. Slight differences between conditions at each inlet will not impact the calculated results if the machines are all the same model and fulfill the base loading requirement of unit disposition.

A correction for inlet conditions at the cooling towers different than at the compressor inlets can be developed and used (Δ_{5A} or ω_{5A}).

Ambient pressure and humidity can be assumed uniform for the entire site if measured in the vicinity of the gas turbine compressor inlets.

If necessary, expansion of Eq. (5.3.1) for a cycle mandating a test goal of constant unit disposition is written as

$$P_{corr} = \sum_{m=GT_1}^{\substack{\text{Total \# of}\\ \text{gas turbines}}} \left[\left(P_{meas,gross_{GT_m}} + \Delta_{2_{GT_m}}\right) \prod_{n=1}^{5} \alpha_{n_{GT_m}} \right]$$

$$+ \sum_{j=1}^{\substack{\text{Total \# of}\\ \text{steam}\\ \text{turbines}}} \left[\left(P_{meas,gross_{ST_j}} + \sum_{k=1}^{5} \Delta_{k_{ST_j}}\right) \prod_{n=1}^{5} \alpha_{n_{ST_j}} \right]$$

$$- P_{aux} \prod_{n=1}^{5} \lambda_n - P_{\substack{\text{transformer}\\ \text{loss}}} - P_{\substack{\text{line}\\ \text{loss}}} \tag{5.5.1}$$

if it is more prudent not to average conditions at each gas turbine inlet.

The subscripts for the new multiplicative correction factors, λ_n, refer to the same parameters to be corrected for as in the other multiplicative corrections. Care is taken in calculating heat balances to determine correction factors for the format of Eq. (5.5.1) to base the α_n correction factors on gross power. Heat balance calculations to determine corrections to ambients utilizing the format of Eq. (5.2.3) include auxiliary load effects in that equation's respective α's.

Note that the α corrections for the steam turbines in Eq. (5.5.1) will not be unity even if the cooling tower is outside the test boundary, due to the ambient effect at the combustion turbine inlet on steam production.

Similarly, for the test goal of a specified unit disposition without setting output to a predetermined level (para. 5.3.2), the corrected heat rate equation may be expanded into the following format if Eq. (5.5.1) is used in lieu of Eq. (5.3.1):

$$HR_{corr} = \frac{\sum_{m=1}^{\substack{\text{total \# of}\\ \text{fuel inputs}}} \left[\left(Q_{meas_m}\right) \prod_{n=1}^{5} \beta_{n_m} \right]}{P_{corr} \text{ per Eq. (5.5.1)}} \tag{5.5.2}$$

Similar formulations can be developed for specified measured net power tests for combined cycles in which there is duct firing, if necessary.

It is also usually valid, in combined cycles, if there is no inlet cooling during the test, or inlet chilling, to assume that the air inlet temperature is equivalent at the gas turbine compressor inlet(s) and the cooling tower air inlet(s), provided it is measured at the point of greatest influence, which is overwhelmingly the gas turbine compressor(s). During the test planning stages, calculations are performed to determine sensitivity coefficients for cycle affects due to deviation of inlet conditions from design at the compressor inlet(s) and the cooling tower(s) to verify the validity of this assumption. Effects of real temperature differences between cooling tower and combustion turbine compressor inlets, are compared. (When doing the sensitivity studies, note that measurement of inlet temperature at the cooling tower inlets is a high uncertainty measurement, whereas the mixing of air inside the gas turbine compressor inlet ducts improves the accuracy of bulk ambient temperature measurement.) Δ_{5A} (or ω_{5A}) is calculated if measureable differences affect the results by more than 0.1%.

5.5.2 Special Case of Inlet Air Evaporative Cooler(s). Experience shows that testing with evaporative coolers in-service can lead to erroneous, non-repeatable results. The major reason why testing with the cooler(s) in service and using upstream air inlet conditions to determine the appropriate corrections to plant performance can lead to unacceptably large errors is because the thermal performance of the plant varies strongly with the temperature condition at the compressor inlet. It is, in fact, the steepest correction to the plant output. If the evaporative cooler produces a downstream temperature which is — or is measured as — slightly greater than 1°F different than the design number, results can typically be affected by 0.5%.

An alternate and more practical approach is to test the unit performance with the evaporative cooler(s) out of service, if possible, correct performance to a base condition, and then correct the calculated base condition performance based on the verification of evaporative cooler performance from a separate test.

A further complication is that large changes in evaporator cooler performance, as measured by effectiveness, produce only relatively small changes in downstream temperature. Precise determination of effectiveness within a meaningful uncertainty relative to the effect on plant performance is almost always not possible.

The effectiveness of the evaporative cooler is defined by:

$$eff = \frac{T_{i,db} - T_{e,db}}{T_{i,db} - T_{i,wb}} \tag{5.5.3}$$

where

T = temperature

Subscripts:

db: dry bulb

e: exit, or downstream (D/S)

TABLE 5.4
CHANGE IN COMPRESSOR INLET TEMPERATURE OVER A 30% RANGE IN EVAPORATOR COOLER EFFECTIVENESS ON AN 80°F DAY, WITH 80% RELATIVE HUMIDITY

Effectiveness	Upstream Dry Bulb Temp.	Upstream Relative Humidity	Downstream Dry Bulb Temp.	Downstream Relative Humidity	Downstream Wet Bulb Temp.
0.70	80°F	80%	76.6	94%	75.1°F
0.75	80°F	80%	76.3°F	95%	75.1°F
0.85	80°F	80%	75.8°F	97%	75.1°F
0.95	80°F	80%	75.4°F	99%	75.1°F
1.00	80°F	80%	75.1°F	100%	75.1°F

i: inlet, or upstream (U/S)
wb: wet bulb

Very small errors in temperature measurement cause large variations in the calculation of effectiveness, as shown in Table 5.4. Table 5.4 assumes an 80°F day at 80% relative humidity.

Note that a 30% change in effectiveness corresponds to only a change of 1.5°F downstream temperature.

New correction factors are developed for the special case of a plant with evaporative air cooler(s).

The plant is tested with the evaporative cooler(s) out of service. Then, for comparison with the design heat balance plant performance:

$$P_{\substack{corr,\\ \text{evap cooler I/S}}} = P_{\substack{corr,\\ \text{evap cooler O/S}}} \times K_{P_{\substack{evap\\ cooler}}} \quad (5.5.4)$$

Where $P_{\substack{corr,\\ \text{evap cooler O/S}}}$ is the corrected power as determined by Eqs. (5.1.1) or (5.5.1), with the corrections being performed to the base reference cooler(s) *inlet* temperature and humidity. $K_{p_{\substack{evap\\ cooler}}}$ is the power correction factor used to correct the tested plant performance with the evaporative cooler(s) out of service to the performance it would have been with the cooler(s) in service at the base reference inlet temperature and humidity.

Similarly,

$$HR_{\substack{corr,\\ \text{evap cooler I/S}}} = HR_{\substack{corr,\\ \text{evap cooler O/S}}} \times K_{HR_{\substack{evap\\ cooler}}} \quad (5.5.5)$$

or

$$Q_{\substack{corr,\\ \text{evap cooler I/S}}} = Q_{\substack{corr,\\ \text{evap cooler O/S}}} \times K_{Q_{\substack{evap\\ cooler}}} \quad (5.5.6)$$

where the left hand terms represent the corrected heat rate and corrected heat input, respectively, to what they would have been with the evaporative cooler(s) in service during the plant test. The first terms on the right side of the equations represent corrected heat rate or corrected thermal input with the evaporator cooler out of service per the appropriate equations in Subsection (5.3), and corrected to base reference conditions at the *inlet* of the cooler(s). The *K* terms are the correction factors to correct the tested plant performance with the evaporative cooler(s) out of service to the performance it would have been with the coolers in service.

Because measurement error will probably be larger than the requirements to determine effectiveness within a small range of performance, experience dictates that the best that can be achieved is to assume that performance of the evaporator has been verified if the design effectiveness is calculated from the test data within test uncertainty, and to use the corrections to plant performance based on the base reference effectiveness.

5.5.3 Staged Testing of Combined Cycle Plants for Phased Construction Situations. This subsection details the methodology to test for new and clean net power and heat rate of a combined cycle plant when it is constructed in phases. The gas turbines of the plant usually operate for several months in simple cycle mode while the steam portion of the combined cycle plant is being constructed.

In order to determine the combined cycle new and clean performance, it is necessary to test the gas turbines when they are new and clean (Phase 1 test series), and combine those results with new and clean steam turbine cycle performance data (Phase 2 test series).

This protocol requires corrections in addition to the standard corrections tabulated in Tables 5.1 and 5.2. These are:

(a) air flow rate deterioration of the gas turbines

(b) the change in gas turbine exhaust gas pressure drop to atmosphere based on the different back end geometry of the ductwork and equipment downstream of the combustion turbines

(c) combined cycle mode fuel heating not available in simple cycle mode

Determination of the first two items requires gas turbine test data taken with the steam cycle by-passed during the Phase 2 test series. If the plant does not include a by-pass, the simple cycle Phase 2 test must be conducted just prior to shut down for the HRSG tie-in.

The simple cycle tests during Phase 2 are called Phase 2A tests, while the final combined cycle operation tests are considered as Phase 2B tests.

Nomenclature for the unique correction factors to this protocol are:

Corrections due to physical changes between Phase 1 and Phase 2:

C_f: Correction to steam cycle gross power output at design reference conditions to new and clean air flow rate of the gas turbines

C_{x_i}: Correction to Phase (2A) gas turbine "i" gross power output at design reference conditions to account for exhaust gas pressure change between test phases

C_h: Correction to Phase (1) simple cycle thermal heat input at design reference conditions to account if fuel preheating is available during Phase (2B) and not during Phase (1)

Table 5.5 summarizes the reasons for each test series.

Note that there is usually an air flow reduction and back pressure change in the simple cycle mode after extended operation, which is why the second phase of testing must be done in two parts.

5.5.3.1 Special Performance Equations — Phased Construction. The corrected total gross power output of the gas turbines used for the combined cycle plant performance evaluation is:

$$\sum_{i=1}^{\text{number of gas turbines}} P_{\text{corr}_{GT_i}} = \sum_{i=1}^{\text{number of gas turbines}} \left\{ \left[\left(P_{\text{corr}_{GT_i}} \right)_{\text{PHASE 1}} + \left(P_{\text{corr}_{GT_i}} \right)_{\text{PHASE 2A}} \left(C_{x_i} - 1 \right) \right] \right\} \qquad (5.5.7)$$

Equation (5.5.7) expresses the total gross power output of the gas turbines as corrected to reference conditions, and in new and clean condition, by means of application of the Phase 1 simple cycle test results. It also corrects new and clean gas turbine power output at reference conditions for operation in combined cycle mode for the change in exhaust pressure between simple cycle and combined cycle operation. Note that the corrected gas turbine power, identified by subscript "corr," is based on ASME PTC 22 tests and corrections.

The corrected total gross output of the steam turbine used for the combined cycle plant performance evaluation is:

$$P_{\text{corr}_{ST}} = \sum_{j=1}^{\text{Total \# of steam turbines}} \left[\left(P_{\text{meas,gross}_{ST_j}} + \sum_{k=1}^{7} \Delta_{k_{ST_j}} \right) \prod_{n=1}^{5} \alpha_{n_{ST_j}} \right] (C_f) \qquad (5.5.8)$$

Equation (5.5.8) corrects the measured steam turbine cycle power output to design reference conditions, and also to combustion turbine new and clean condition by application of C_f.

C_f is determined by comparison of the Phase 1 and the Phase 2A simple cycle test series results by ratio of the airflow references measured during those respective test series for each gas turbine. The references are based on the total pressure drop across the compressor scroll corrected to base reference operating conditions.

The total plant gross power in combined cycle mode at reference conditions, and at new and clean conditions, is therefore expressed as:

$$P_{\text{corr, gross}} = \sum_{i=1}^{\text{number of gas turbines}} P_{\text{corr}_{GT_i}} + \sum_{i=1}^{\text{number of steam turbines}} P_{\text{corr}_{ST_i}} \qquad (5.5.9)$$

The corrected thermal heat input from the fuel used for the combined cycle plant performance evaluation is:

$$Q_{\text{PHASE 2B}} = (Q_{\text{PHASE 1}})\,(C_h), \qquad (5.5.10)$$

where $Q_{\text{PHASE 1}}$ is calculated from the power and heat results of Phase 1 tests by:

TABLE 5.5
REQUIRED TEST SERIES FOR PHASED CONSTRUCTION COMBINED CYCLE PLANTS

Test Phase	Reasons for Tests	Operating Mode
Phase 1	New and clean gas turbine performance	Simple cycle operation after initial simple cycle start-up
Phase 2A	Gas turbine performance to determine degradation effect on exhaust gas flow rate, and gas turbine back pressure changes	Simple cycle operation (see para. 5.5.3)
Phase 2B	Steam cycle performance for determination of combined cycle plant performance in new and clean condition. This is accomplished by combining gas turbine data from Phase 1 with the steam cycle performance data, with appropriate corrections based on Phase 2A tests.	Full combined cycle operation

$$Q_{PHASE\ 1} = \sum_{i=1}^{i=\text{number of gas turbines}} \left(P_{GT_i}\right)_{PHASE\ 1} * HR_{PHASE\ 1} \quad (5.5.11)$$

Equation (5.5.10) expresses the total thermal heat input from the fuel as corrected to reference conditions, and in new and clean condition, by means of application of the corrected power and corrected efficiency Phase 1 test results from equation (5.5.11). It also corrects new and clean total thermal heat input at reference conditions for operation in combined cycle mode due to the operation of fuel preheating by application of C_h.

The total plant gross heat rate in new and clean conditions, combined cycle mode, and at contract operating conditions, is therefore expressed as:

$$HR = \frac{Q_{PHASE\ 2B}}{P_{corr\ gross}} \quad (5.5.12)$$

Net power and heat rate is found by subtracting corrected auxiliary loads from the plant gross power, and subtracting transformer losses, if applicable, and line losses, if applicable.

5.6 SPECIAL CONSIDERATIONS AS APPLIED TO STEAM TURBINE PLANTS

Steam turbine based power plants do not usually have a defined base load rating as do gas turbine or combined cycle power plants. There are two possible equivalent definitions of base load rating for a steam plant. The first is defined at a specified amount of main steam flow from the steam generator at rated steam conditions such as maximum continuous rating, provided other plant components do not have to be operated above their continuous design ratings. The other possible required disposition of a steam turbine plant during a test might be with operation at a particular control valve operating point.

Performance correction to a reference condition requires knowledge or estimation of how the corrected plant net electrical output varies with corrected fuel energy input. Figure 5.4 illustrates how gross output of a steam turbine based plant varies with steam turbine throttle flow.

The scallops in the output vs throttle flow curve are due to the control action of the steam turbine throttle valves. The straight line curve labeled valve best point performance shows how the plant output would vary if calculated on a valve best point basis. This performance is not realizable but is synthesized by passing a straight line through the steam turbine valve points. In practice, the actual performance varies from the valve best point performance by a maximum of about 0.35% for a six valve reheat machine to 0.7% or more for a non-reheat machine.

A steam turbine plant for which required operating disposition is based on operation at valve point must be tested at that valve point.

If the specified disposition is a throttle flow rate, refer to para. 5.3.5. The plant may be tested over a range of steam turbine throttle flows sufficient to encompass the corrected performance point of

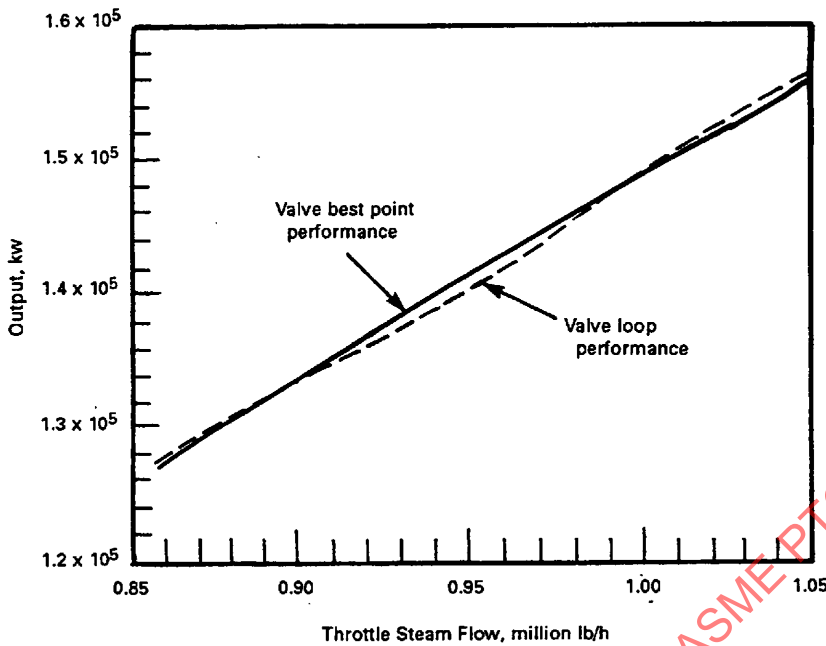


FIG. 5.4 OUTPUT VERSUS THROTTLE STEAM FLOW

interest. The applicable performance equations in this scenario are thus for a fixed unit disposition, with the corrected power floating. A corrected output versus corrected input curve is developed from the test data. The curve is entered at the net corrected output to determine the net corrected fuel energy input. Another procedure for this specified disposition, which is preferred, would simply be to apply the Δ_7 and ω_7 corrections.

The performance characteristics of a steam turbine operating in a combined cycle plant is normally different than shown here. What is discussed here is not applicable to such a plant, or to a large sliding pressure mode steam turbine plant.

Figure 5.5 shows a typical test boundary for a non-reheat steam cycle that may be used in straight power generation or cogeneration applications.

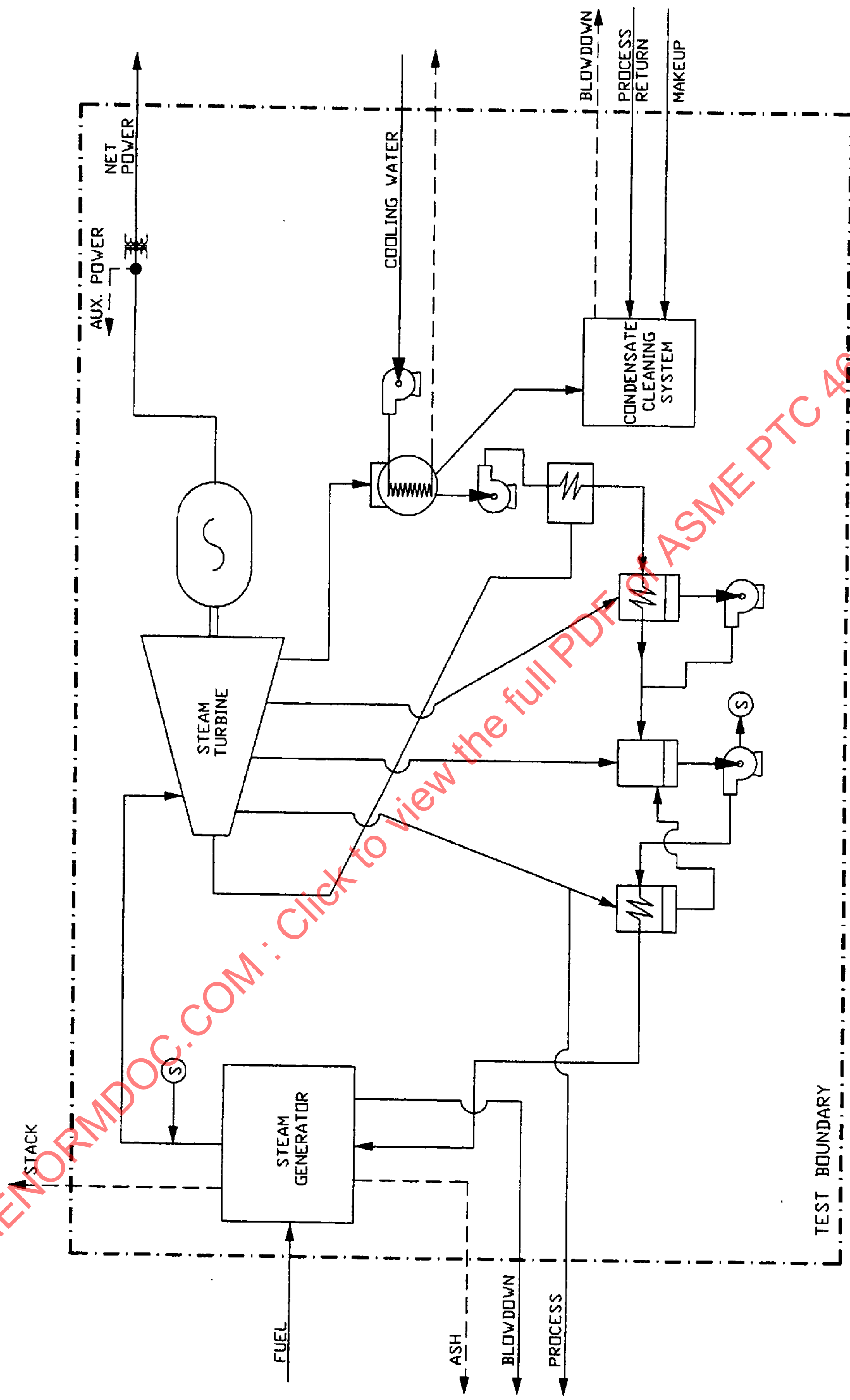


FIG. 5.5 STEAM TURBINE PLANT TEST BOUNDARY

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) Calculation 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 contains the following.

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

(b) date and time of the test

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

(d) comparison with the contract guarantee

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

6.3 INTRODUCTION

This section of the test report includes the following.

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

(1) an historical perspective, if appropriate

(2) a cycle diagram showing the test boundary (refer to the figures in the appendices for examples of test boundary diagrams for specific plant type or test goal)

(b) a listing of the representatives of the parties to the test

(c) any pre-test agreements which were not tabulated in the executive summary

(d) the organization of the test personnel

(e) test goal per Sections 3 and 5 of this Code

6.4 CALCULATIONS AND RESULTS

The following should be included in detail:

(a) 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.)

(b) tabulation of the reduced data necessary to calculate the results, summary of additional operating conditions not part of such reduced data

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

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

(e) detailed calculations of heat input from fuel from a coal-fired power plant utilizing PTC 4 and water/steam side measurements

(f) detailed calculations of fuel properties — density, heating value (Values of constituent properties, used in the detailed calculations shall be shown.) Heating value must be identified as either high or low heating value.

(g) any calculations showing elimination of data for outlier reason, of for any other reason

(h) comparison of repeatability of test runs

(i) clarity as to whether reported heat rate is base on HHV or LHV

6.5 INSTRUMENTATION

(a) tabulation of instrumentation used for the primary and secondary measurements, including make model number, etc.
(b) description of the instrumentation location
(c) means of data collection for each data point, such as temporary data acquisition system print-out, plant control computer print-out, or manual data sheet, and any identifying tag number and/or address of each
(d) identification of the instrument which was used as back-up
(e) description of data acquisition system(s) used
(f) summary of pretest and post-test calibration

6.6 CONCLUSIONS

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

6.7 APPENDIXES

Appendixes to the test report should include:
(a) the test requirements
(b) copies of original data sheets and/or data acquisition system(s) print-outs
(c) copies of operator logs or other recording of operating activity during each test
(d) copies of signed valve line-up sheets, and other documents indicating operation in the required configuration and disposition
(e) results of laboratory fuel analysis
(f) instrumentation calibration results from laboratories, certification from manufacturers

APPENDIX A — SAMPLE CALCULATIONS COMBINED CYCLE COGENERATION PLANT WITHOUT DUCT FIRING HEAT SINK: COMPLETELY INTERNAL TO THE TEST BOUNDARY TEST GOAL: SPECIFIED MEASUREMENT POWER — FIRE TO DESIRED POWER LEVEL BY DUCT FIRING

(This Appendix is not a part of ASME PTC 46-1996.)

Cycle Description

The plant to be tested is a non-reheat combined cycle cogeneration plant that is powered by two nominal 85 MW gas turbines with inlet evaporative coolers and steam injection for NOx control and power augmentation.

The gas turbine exhausts produce steam in two triple-pressure heat recovery steam generators. The high pressure, 1280 psig/900°F (89.27 bar(a)/482°C), steam feeds the throttle of an 88 MW condensing steam turbine that has an intermediate pressure extraction port at 350 psig [25.1 bar(a)] to supply thermal efflux steam and make up for shortages of gas turbine injection steam. The exhaust steam from the steam turbine is fed to an air-cooled condenser. The low pressure, 30 psig [3.1 bar(a)] saturated, steam is used only for boiler feed water deaeration. There is no supplemental firing capability in the HRSGs.

Thermal efflux is in the form of export steam, primarily extracted from the steam turbine with steam conditions controlled at 300 Psig/550°F (21.7 bar(a)/288°C).

Test Boundary Description

Basically, the entire plant is included within the test boundary, as is indicated on the process flow diagram. Air crosses the boundary at the inlets of the gas turbines and the inlet to the condenser.

Net plant electrical output is determined from measurements of the output of each generator with an allowance made for the losses of each step-up transformer. Plant auxiliary loads are supplied from the utility high voltage supply during the test.

Fuel flow rate and heating value are measured in the plant fuel supply line near where the fuel crosses the test boundary.

Export steam is measured in the steam export line where it crosses the test boundary.

Reference and Measured Conditions

Parameter	Reference Condition	Measured Condition	
Steam Export	250 (31.5)	218 (27.5)	k Lb/hr (kg/s)
Power Factor	0.85	0.975	
Ambient Temperature	70 (21)	59 (15)	°F (°C)
Ambient Pressure	14.433 (0.99512)	14.595 (1.0063)	Psia [bar(a)]
Relative Humidity	60	77	%

Measured Results

Plant Net Power	----- MW
Net Heat Rate	----- Btu/kWh HHV
Fuel Input	1,977 mm Btu/hr HHV 579.4 MJ/s HHV
Gas Turbine 1 Power	87.0 MW
Gas Turbine 2 Power	87.5 MW
Steam Turbine Power	49.5 MW
Auxiliary Load	4.5 MW

Fundamental Equations

$$P_{corr} = \left(P_{meas} + \sum_{i=1}^{7} \Delta_i \right) \prod_{j=1}^{5} \alpha_j$$

$$HR_{corr} = \frac{Q_{corr}}{P_{corr}}$$

$$Q_{corr} = \left(Q_{meas} + \sum_{i=1}^{7} \omega_i \right) \prod_{j=1}^{5} \beta_i$$

Table of Required Corrections and Correction Factors

Correction/Factor	Power	Fuel Energy
Additive Corrections		
Thermal Efflux	Δ_1	—
Gas Turbine Power Factor	Δ_{2A}	—
Steam Turbine Power Factor	Δ_{2B}	—
Multiplicative Correction Factors		
Ambient Temperature	α_1	β_1
Ambient Pressure	α_2	β_2
Relative Humidity	α_3	β_3

Corrections Not Required

The following corrections and correction factors are not required for this specific test:

Δ_3 = HRSG blow-down was closed for test and the guarantee was based on no blow-down

Δ_4 = there were no secondary heat inputs

Δ_{5A} = inlet air conditions were acceptably close to those at the inlets to the gas turbines, so an average temperature was used for the calculations

Δ_{5B} = does not apply to this condensing system

Δ_{5C} = does not apply to this condensing system

Δ_6 = there were no irregular or off-design auxiliary loads during the test

Δ_7 = the test was a constant disposition test and therefore Δ_7 was zero

α_4,β_4 = fuel supply conditions were the same as for design

α_5,β_5 = fuel analysis matched the design fuel

The above corrections may be required for calculations of an actual test of a similar plant. The fact that they were neglected in this example does not mean that they should always be neglected.

Correction Curves and Fitted Equations

These curves and equations are linear and nonlinear regressions of calculated performance deviations based on a model of a specific plant, and *should not be used generically* for any PTC 46 Test.

$\Delta_1 = -22{,}180 + 88.8 \cdot (\text{k Lb/hr})$

$\Delta_{2A} = \text{MW} \cdot 1000 \cdot 0.987 \cdot (0.01597) \cdot (\text{pf} - 0.85) - 0.012104 \cdot (\text{pf}^2 - 0.85^2) - 0.021571 \cdot (\text{pf} - 0.85) \cdot \text{MW}/135)$

$\Delta_{2B} = \text{MW} \cdot 1000 \cdot 0.9825 \cdot (0.01597 \cdot (\text{pf} - 0.85) - 0.012104 \cdot (\text{pf}^2 - 0.85^2) - 0.021571 \cdot (\text{pf} - 0.85) \cdot \text{MW}/88)$

$\alpha_1 = 0.844902 + 0.00146818(°\text{F}) + 0.000010612(°\text{F})^2$

$\alpha_2 = 2.134403 - 0.07858(\text{Psia})$

$\alpha_3 = 0.957444 + 0.078668 \cdot (\%\text{RH}/100) - 0.01301(\%\text{RH}/100)^2$

$\beta_1 = 0.852007 + 0.001696891(°\text{F}) + 5.9254\text{E-}06(°\text{F})^2$

$\beta_2 = 2.045731 - 0.07245(\text{Psia})$

$\beta_3 = 0.958413 + 0.078079 \cdot (\%\text{RH}/100) - 0.01474(\%\text{RH}/100)^2$

Discussion

Corrections are for factors affecting plant performance that are outside the control of the party running the test.

Steam export flow rate has been corrected to guarantee temperature and pressure conditions in the measurement process.

Corrections for fuel energy input have been used instead of those for heat rate based on a personal preference for this particular method of correction.

The ambient temperature used for corrections is the average dry bulb temperature at the inlets of the gas turbines. The relative humidity is the average of the inlets to the gas turbines.

To simplify the calculations, the power factors of the three generators are assumed equal during the measurement period. This is not always true.

Type	Description	Component	U.S. Customary Value	Units	SI Value	Units
basis	steam export		250	k lb/hr	31.5	kg/s
basis	power factor		0.85		0.85	
basis	ambient temperature		70	°F	21	°C
basis	atmospheric pressure		14.433	psia	0.99512	bara
basis	relative humidity		60%		60%	
test	gas turbine 1 power		87,000	kw	87,000	kw
test	gas turbine 2 power		87,500	kw	87,500	kw
test	steam turbine power		49,500	kw	49,500	kw
test	auxiliary load		4,500	kw	4,500	kw
test	fuel input-HHV		1,977.0	mm btu/hr	579.40	mj/s
test	steam export		218	k lb/hr	27.5	kg/s
test	power factor		0.975		0.975	
test	ambient temperature		59	°F	15	°C
test	atmospheric pressure		14.595	psia	1.0063	bara
test	relative humidity		77%		77%	
test	transformer losses		0.5%		0.5%	
test	gross power		224,000	kw	224,000	kw
test	auxiliary load		4,500	kw	4,500	kw
test	transformer losses		1,120	kw	1,120	kw
test	net power		219,500	kw	219,500	kw
test	Delta 1 steam export	Thermal Efflux	218	k lb/hr	27.5	kg/s
curve	correction delta 1		(2,822)	kw	(2,822)	kw
test	Delta 2A power factor	Gas Turbine Power Factor	0.975		0.975	
test	gas turbine 1 power		87,000	kw	87,000	kw
curve	GT 1 corr delta 2A		(215)	kw	(215)	kw
test	gas turbine 2 power		87,500	kw	87,500	kw
curve	GT 2 corr delta 2A		(217)	kw	(217)	kw
add	total corr delta 2A		(432)	kw	(432)	kw
test	Delta 2B power factor	Steam Turbine Power Factor	0.975		0.975	
test	steam turbine power		49,500	kw	49,500	kw
curve	corr delta 2B		(111)	kw	(111)	kw
test	Alpha 1 ambient temperature	Ambient Temperature — Power	59	°F	15	°C

Type	Description	Component	U.S. Customary Value	Units	SI Value	Units
curve	corr alpha 1		0.96846		0.96846	
	Alpha 2	Atmospheric Pressure — Power				
test	atmospheric pressure		14.595	psia	1.0063	bara
curve	corr alpha 2		0.98756		0.98756	
	Alpha 3	Relative Humidity — Power				
test	relative humidity		77.0%		77.0%	
curve	corr alpha 3		1.01030		1.01030	
	Beta 1	Ambient Temperature — Fuel				
test	ambient temperature		59	°F	15	°C
curve	corr beta 1		0.97275		0.97275	
	Beta 2	Atmospheric Pressure — Fuel				
test	atmospheric pressure		14.595	psia	1.0063	bara
curve	corr beta 2		0.98831		0.98831	
	Beta 3	Relative Humidity — Fuel				
test	relative humidity		77.0%		77.0%	
curve	corr beta 3		1.00980		1.00980	
		Corrected Power				
test	net power		219,500	kw	219,500	kw
curve	delta 1		(2,822)	kw	(2,822)	kw
curve	total delta 2A		(432)	kw	(432)	kw
curve	delta 2B		(111)	kw	(111)	kw
curve	alpha 1		0.96846		0.96846	
curve	alpha 2		0.98756		0.98756	
curve	alpha 3		1.01030		1.01030	
calc	corrected net power		208,845	kw	208,845	kw
		Corrected Fuel				
test	fuel input — HHV		1,977.0	mm btu/hr	579	mj/s
curve	beta 1		0.97275		0.97275	
curve	beta 2		0.98831		0.98831	
curve	beta 3		1.00980		1.00980	
calc	corrected fuel input — HHV		1,919.3	mm btu/hr	562.48	mj/s
		Corrected Heat Rate				
calc	corrected fuel input		1,919.3	mm btu/hr	562.48	mj/s
calc	corrected net power		208,845	kw	208,845	kw
calc	corrected heat rate		9,190	btu/kwh	9,696	kj/kwh

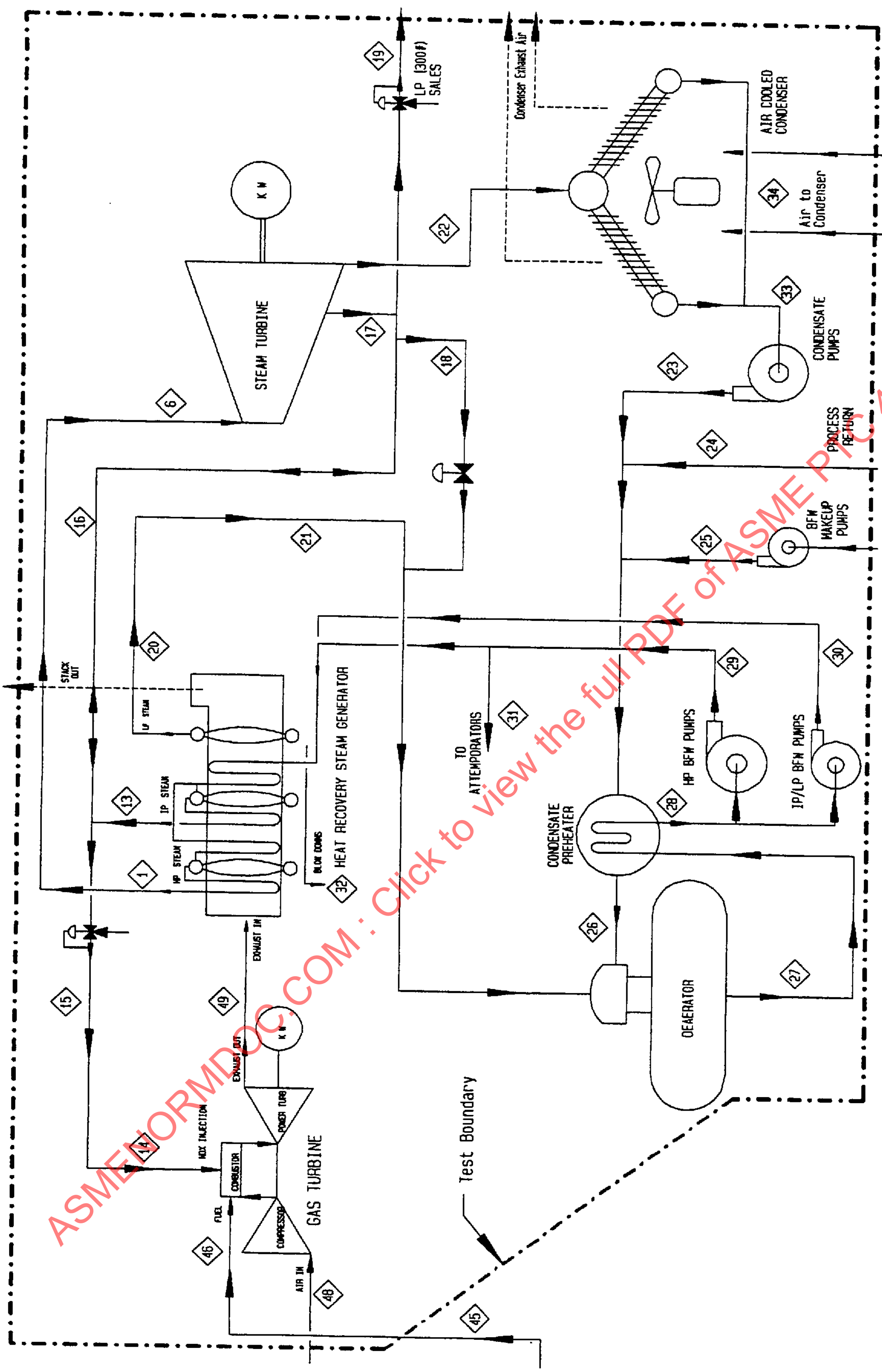


FIG. A.1 COMBINED CYCLE PLANT — DRY CONDENSER — PROCESS FLOW DIAGRAM

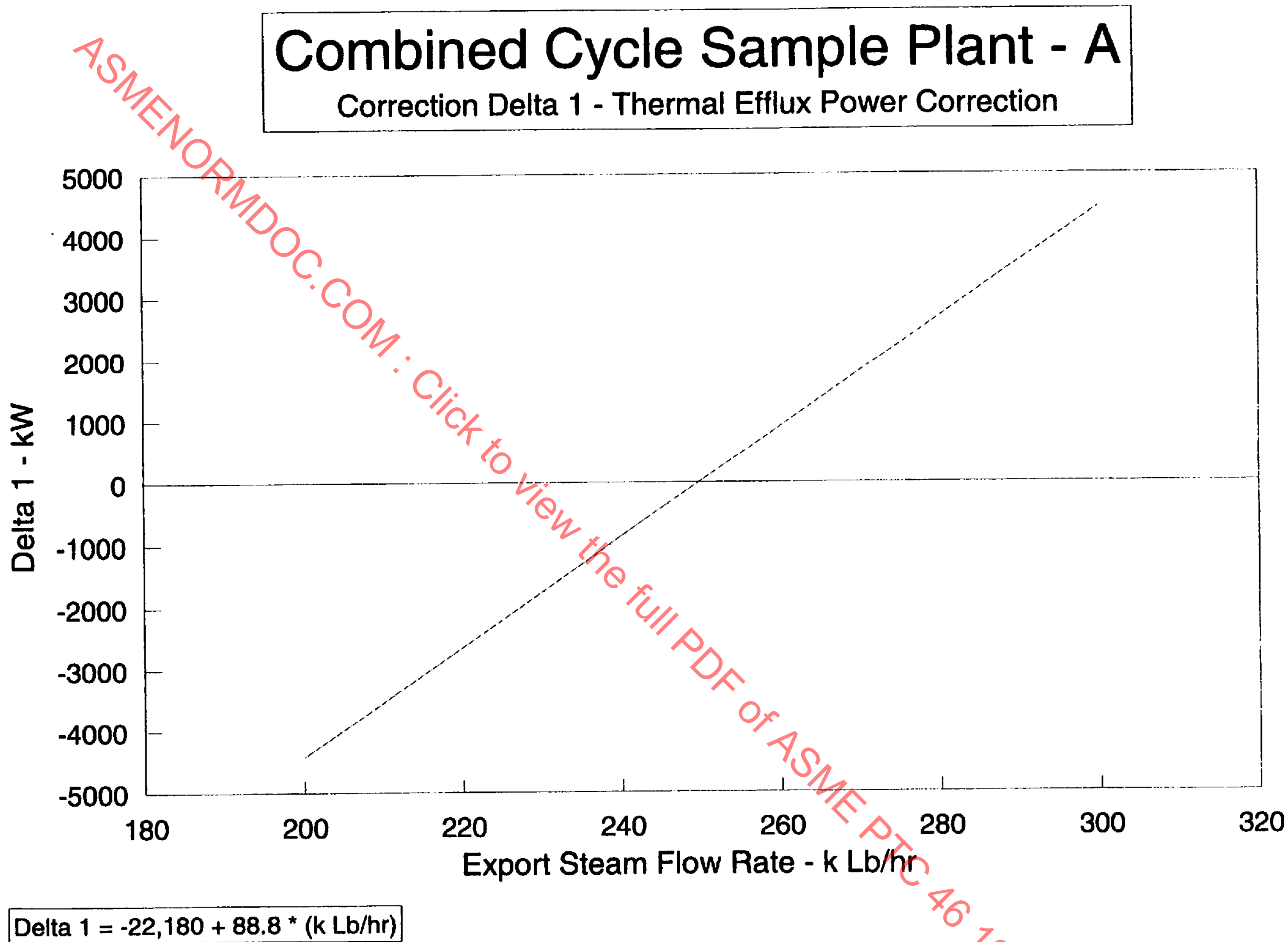
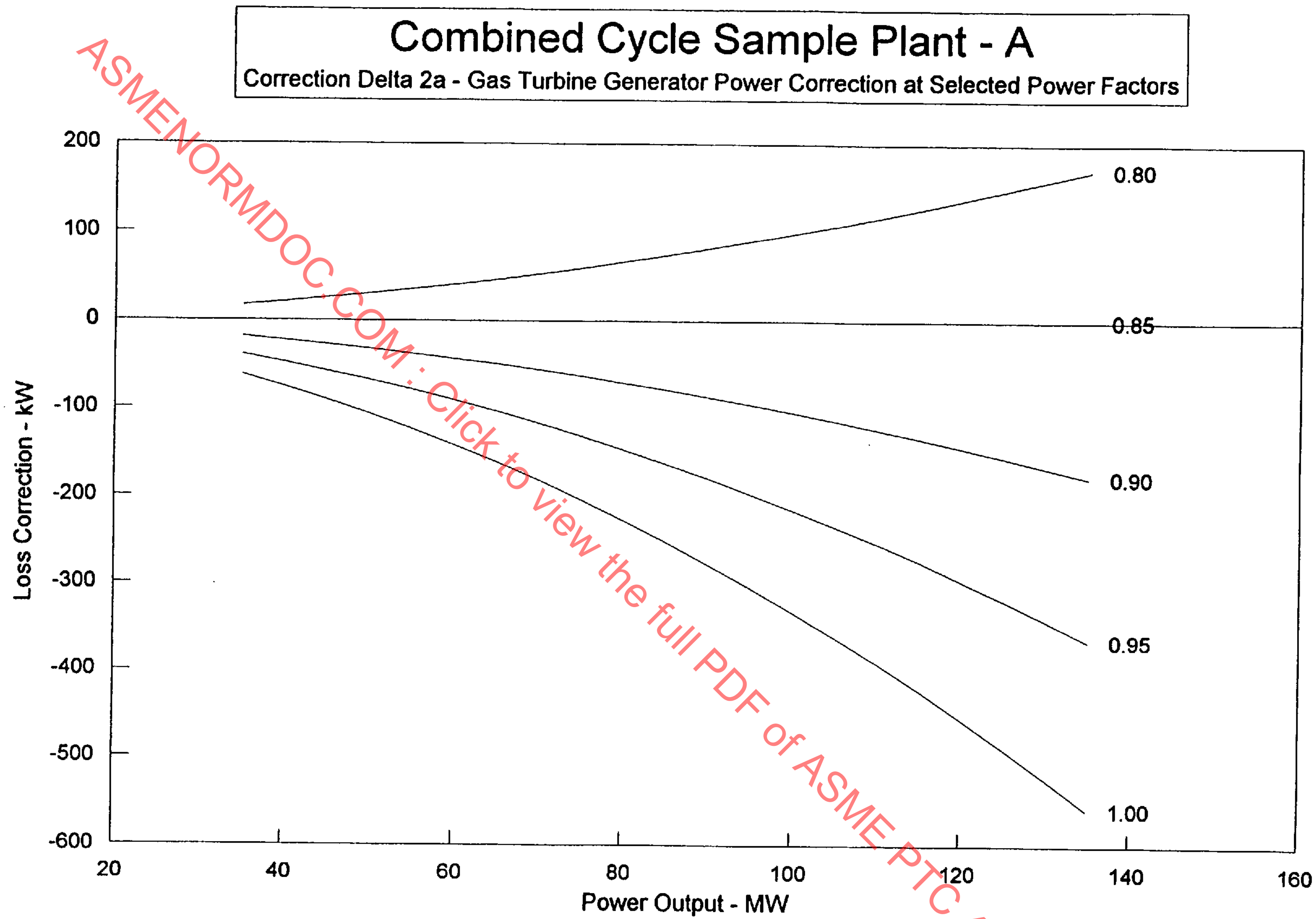


FIG. A.2 COMBINED CYCLE SAMPLE PLANT — A CORRECTION DELTA 1 — THERMAL EFFLUX POWER CORRECTION



Delta 2a = MW * 1000 * 0.987 * (0.01597 * (pf - 0.85) - 0.012104 * (pf^2 - 0.85^2) - 0.021571 * (pf - 0.85) * MW/135)

FIG. A.3 COMBINED CYCLE SAMPLE PLANT — A CORRECTION DELTA 2A — GAS TURBINE GENERATOR POWER CORRECTION AT SELECTED POWER FACTORS

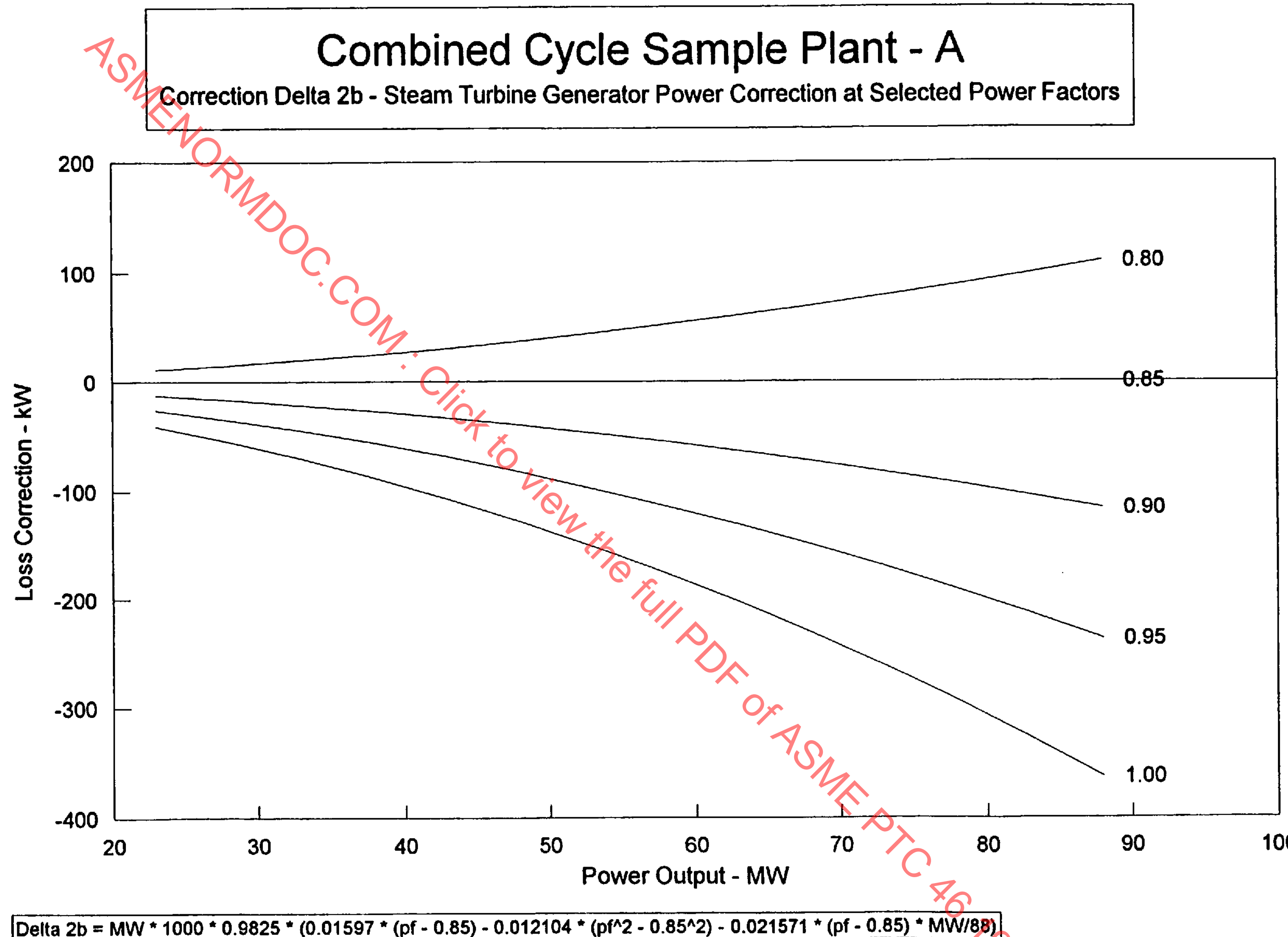


FIG. A.4 COMBINED CYCLE SAMPLE PLANT — A CORRECTION DELTA 2B — STEAM TURBINE GENERATOR POWER CORRECTION AT SELECTED POWER FACTORS

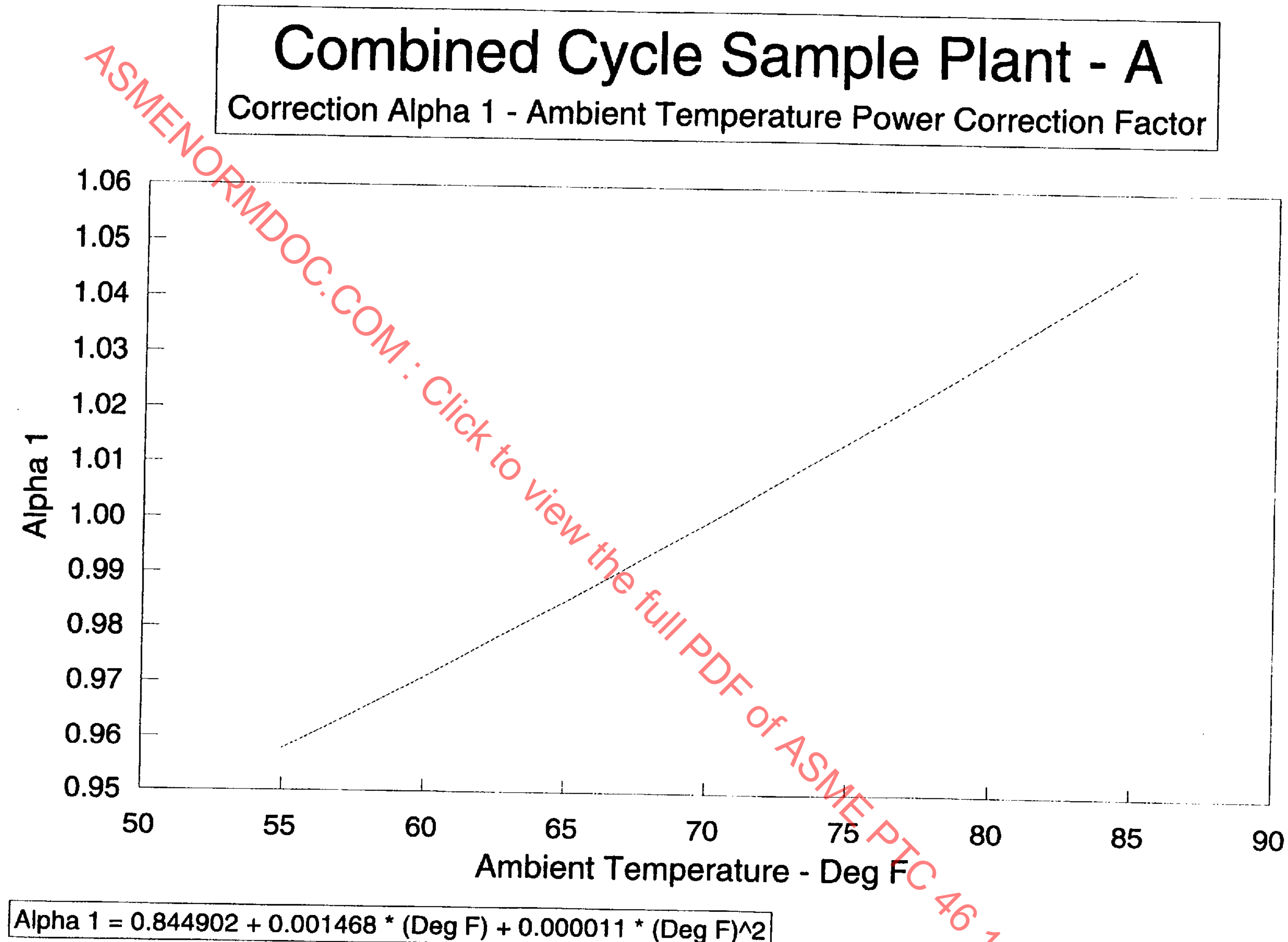


FIG. A.5 COMBINED CYCLE SAMPLE PLANT — A CORRECTION ALPHA 1 — AMBIENT TEMPERATURE POWER CORRECTION FACTOR

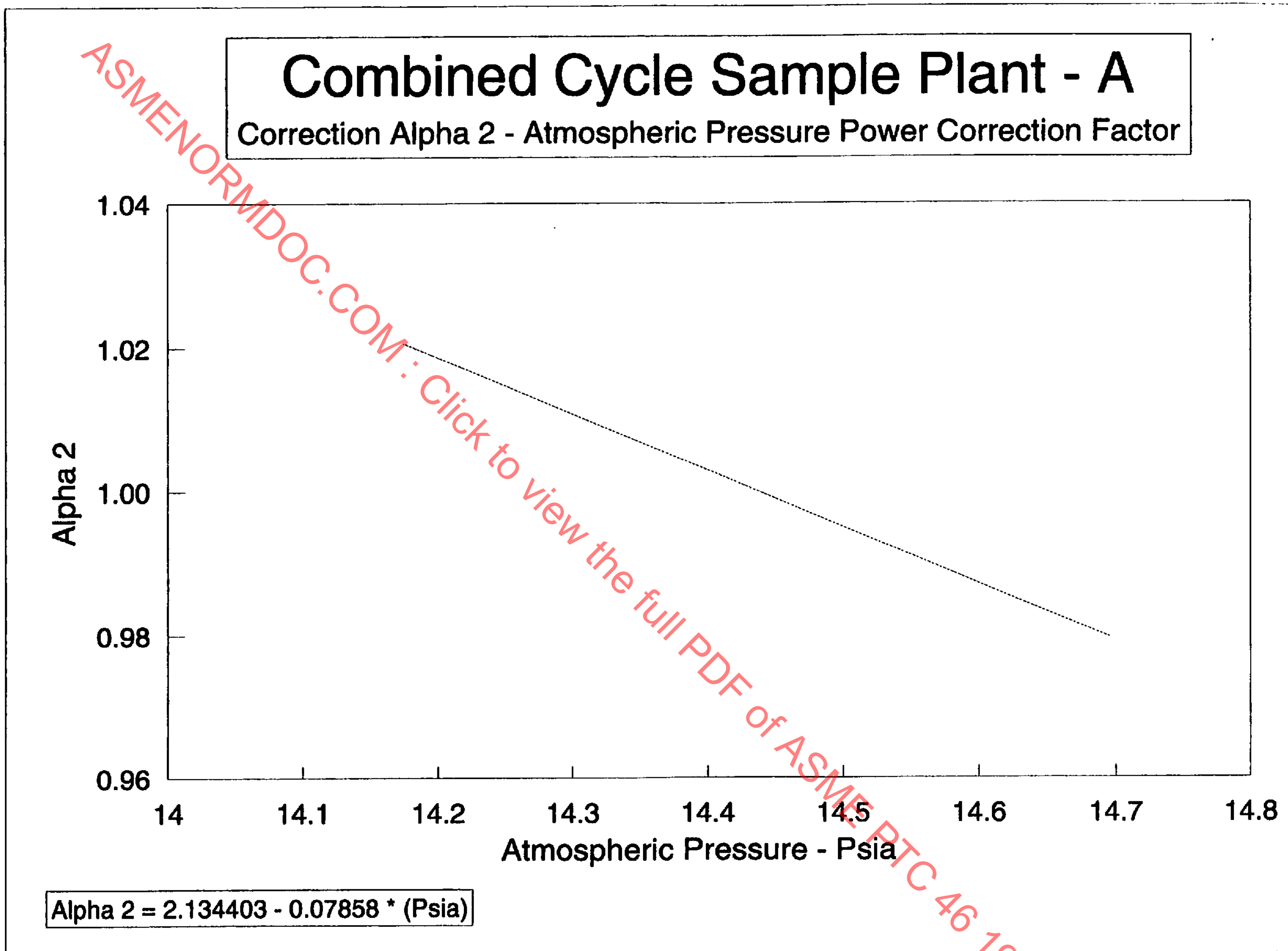


FIG. A.6 COMBINED CYCLE SAMPLE PLANT — A CORRECTION ALPHA 2 — ATMOSPHERIC PRESSURE POWER CORRECTION FACTOR

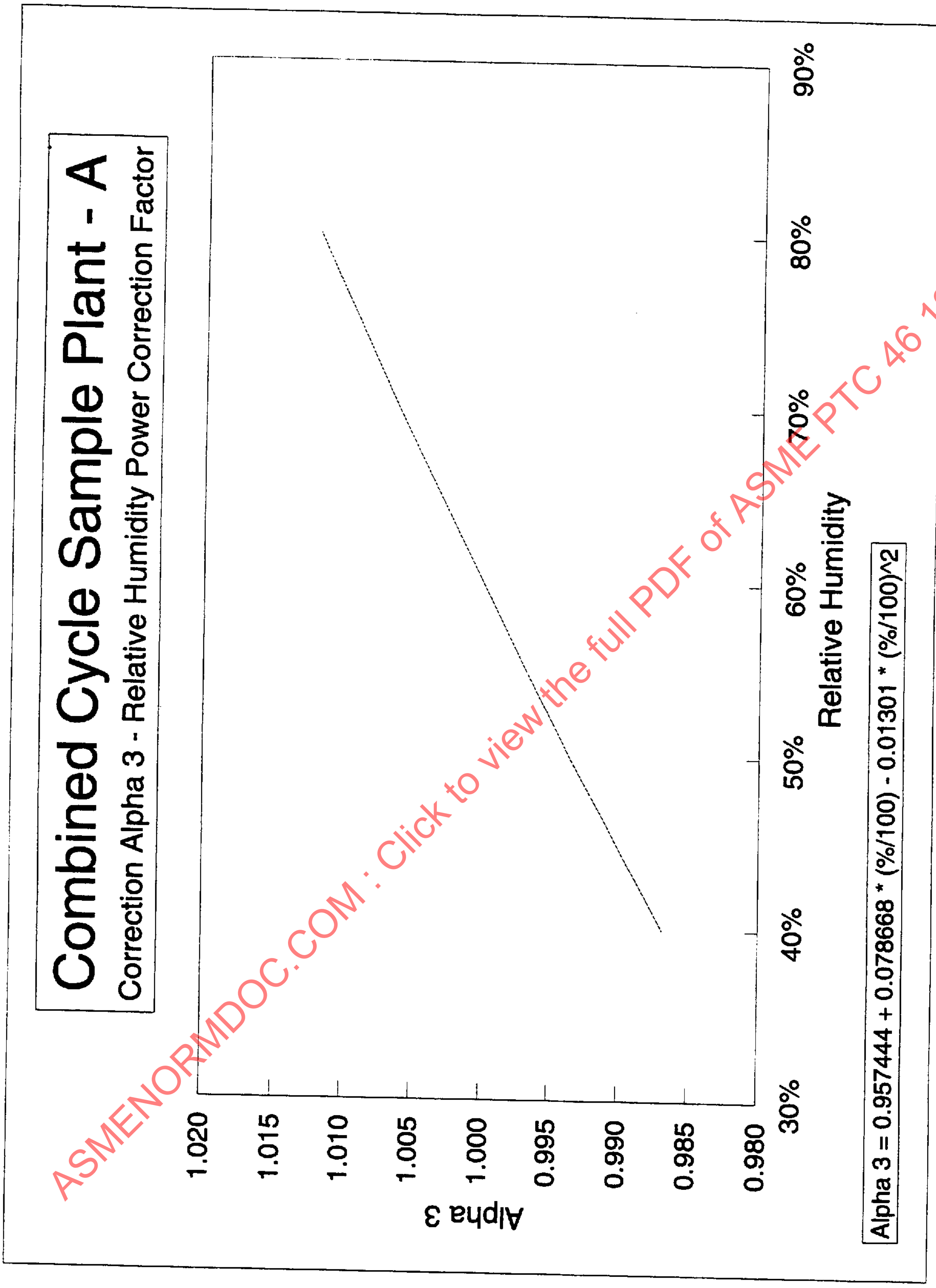


FIG. A.7 COMBINED CYCLE SAMPLE PLANT — A CORRECTION ALPHA 3 — RELATIVE HUMIDITY POWER CORRECTION FACTOR

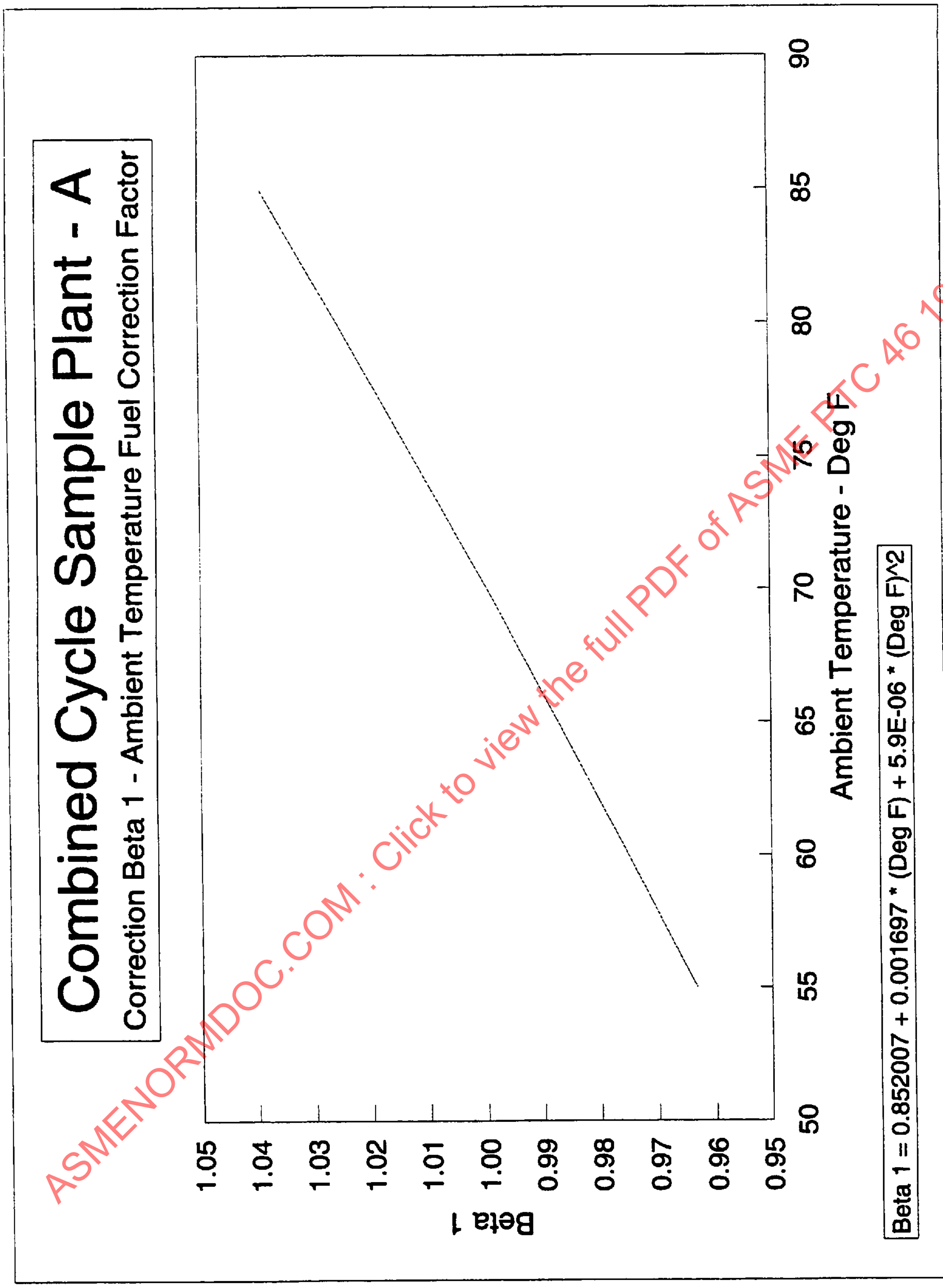


FIG. A.8 COMBINED CYCLE SAMPLE PLANT — A CORRECTION BETA 1 — AMBIENT TEMPERATURE FUEL CORRECTION FACTOR

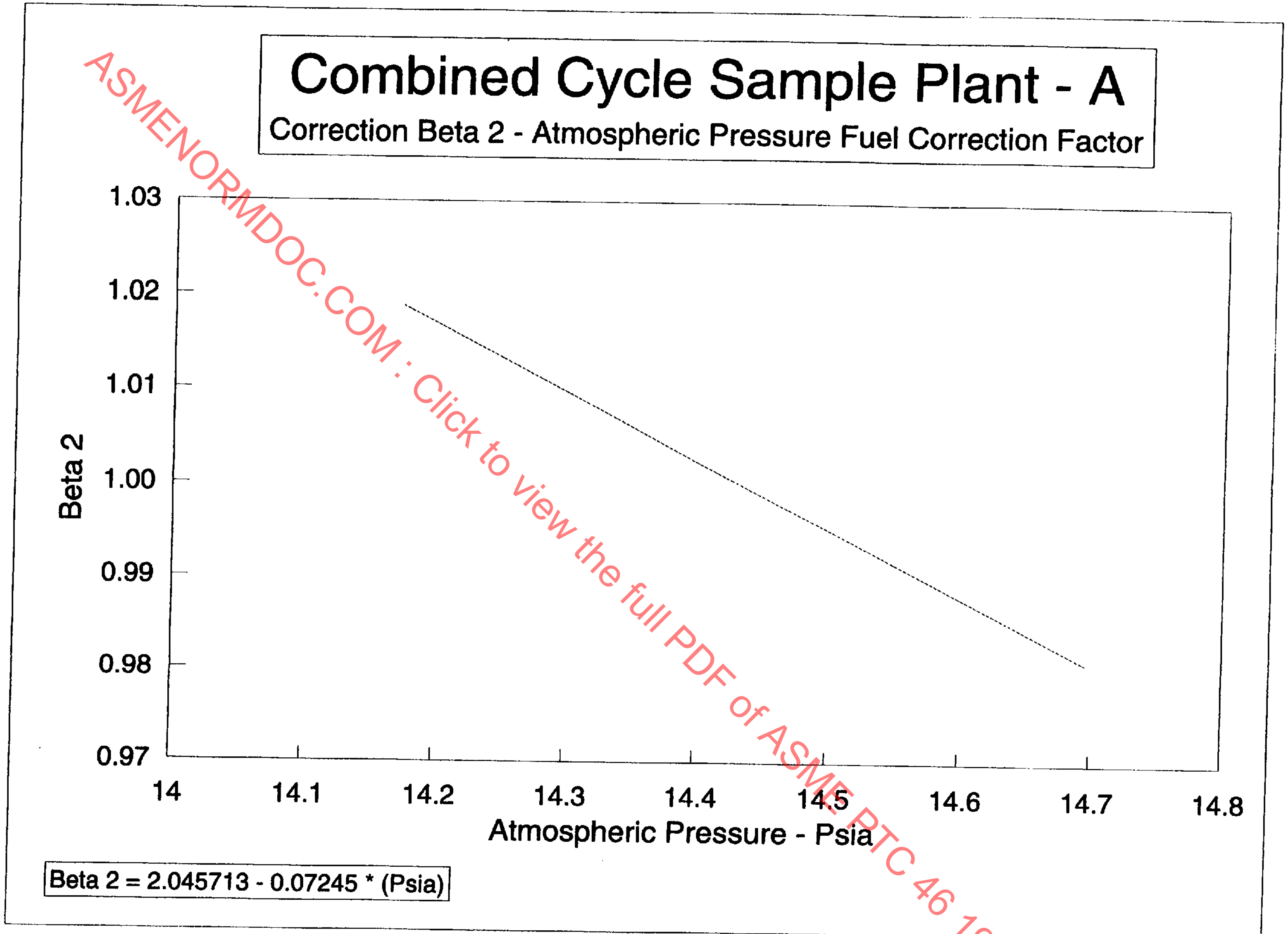


FIG. A.9 COMBINED CYCLE SAMPLE PLANT — A CORRECTION BETA 2 — ATMOSPHERIC PRESSURE FUEL CORRECTION FACTOR

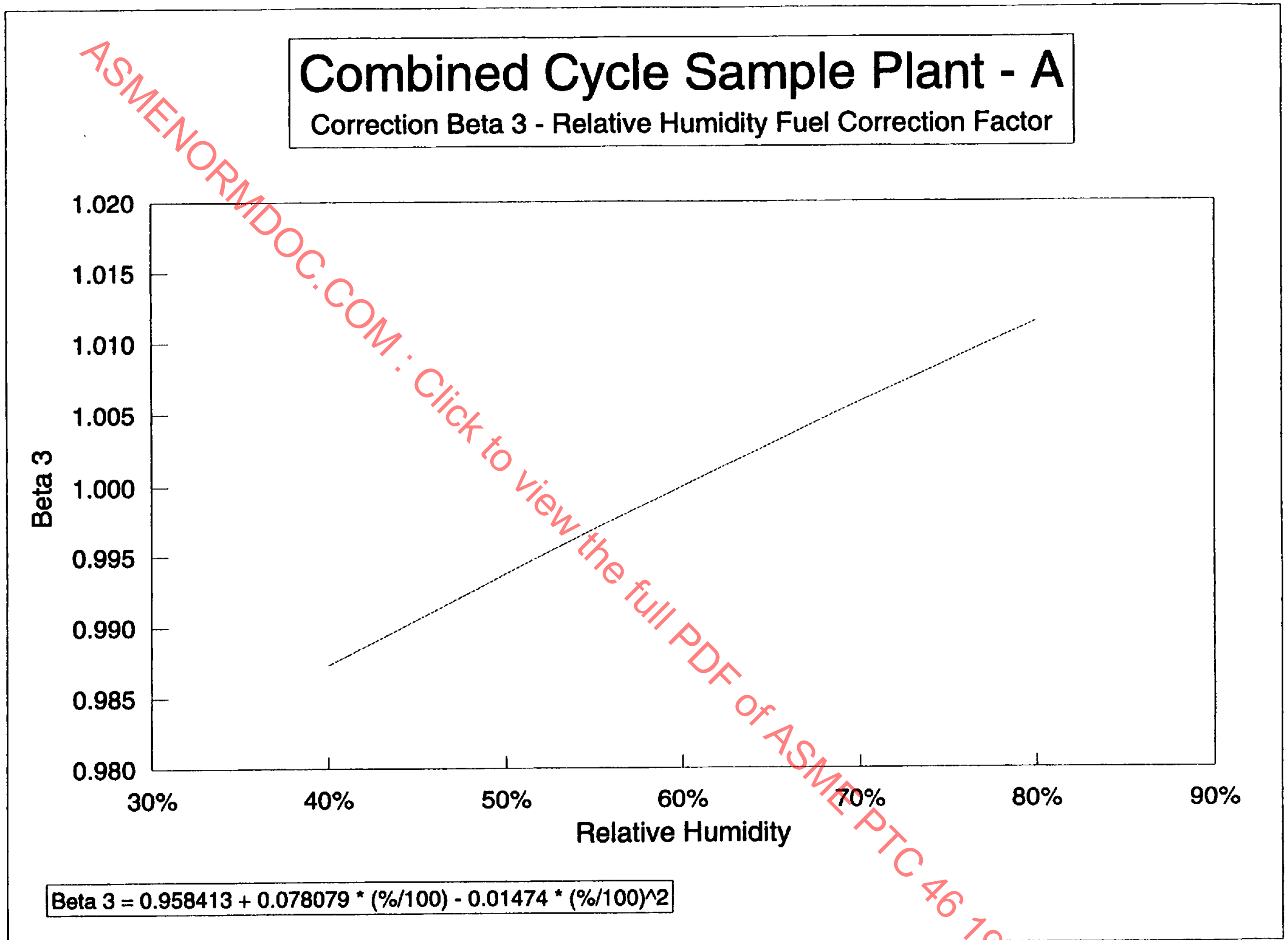


FIG. A.10 COMBINED CYCLE SAMPLE PLANT — A CORRECTION BETA 3 — RELATIVE HUMIDITY FUEL CORRECTION FACTOR

APPENDIX B — SAMPLE CALCULATIONS COMBINED CYCLE COGENERATION PLANT WITH DUCT FIRING HEAT SINK: EXTERNAL TO TEST BOUNDARY TEST GOAL: SPECIFIED MEASUREMENT POWER — FIRE TO DESIRED POWER LEVEL BY DUCT FIRING

(This Appendix is not a part of ASME PTC 46-1996.)

B.1 CYCLE DESCRIPTION AND UNIT DISPOSITION

This cycle consists of a gas turbine that exhausts to a two pressure level heat recovery steam generator with duct firing, plus a single case steam turbine that exhausts to a water cooled condenser. (Refer to the cycle diagram in Fig. B.1). HP steam from the HRSG goes to the steam turbine throttle valve. An extraction port on the steam turbine provides steam for gas turbine NOx control. The steam turbine also has an LP induction/extraction port. When little or no process steam is required, LP steam from the HRSG is inducted into the turbine. When design quantities of process steam are required, LP steam is extracted from the turbine and combined with LP steam from the HRSG. The cycle also includes a fuel preheater, a deaerator, and a chemical cleaning system.

The operating disposition of this plant is such that it allows adjustment to plant power by adjusting the rate of fuel to the duct burner. The gas turbine is base loaded and its power output is a function of ambient conditions. The steam turbine must provide the difference between the design power level and the gas turbine power output. By varying duct burner fuel flow, the necessary amount of steam in the HRSG is produced to meet the required steam turbine power output and process steam flow requirements.

Thus, the performance test goal is to duct fire until design power is reached. The unit was designed to meet this power level on a 365 day per year basis in a temperate climate zone.

B.2 TEST BOUNDARY DESCRIPTION

The test boundary is also shown on Fig. B.1. Note that the condenser is outside the test boundary.

The streams with energy entering the system which need to be determined are:

(a) air for the gas turbine
(b) fuel to both gas turbine and the duct burner
(c) make-up flow
(d) saturated condensate from the condenser to the condensate system

The streams with energy leaving the system which need to be determined are:

(a) electrical power
(b) process steam
(c) steam turbine exhaust to condenser
(d) blowdown from the HRSG

B.3 TABLE OF REFERENCE CONDITIONS

The parameters requiring correction, and their design values, are given in Table B.1.

B.4 REQUIRED CORRECTION FACTORS

For the test, the plant is operated by adjusting the amount of duct firing until the design power level is reached. Since it is desired to minimize corrections to power, additive corrections are made to heat input using the ω corrections. Multiplicative corrections are made to heat rate using the f correction factors. There is one additive correction to

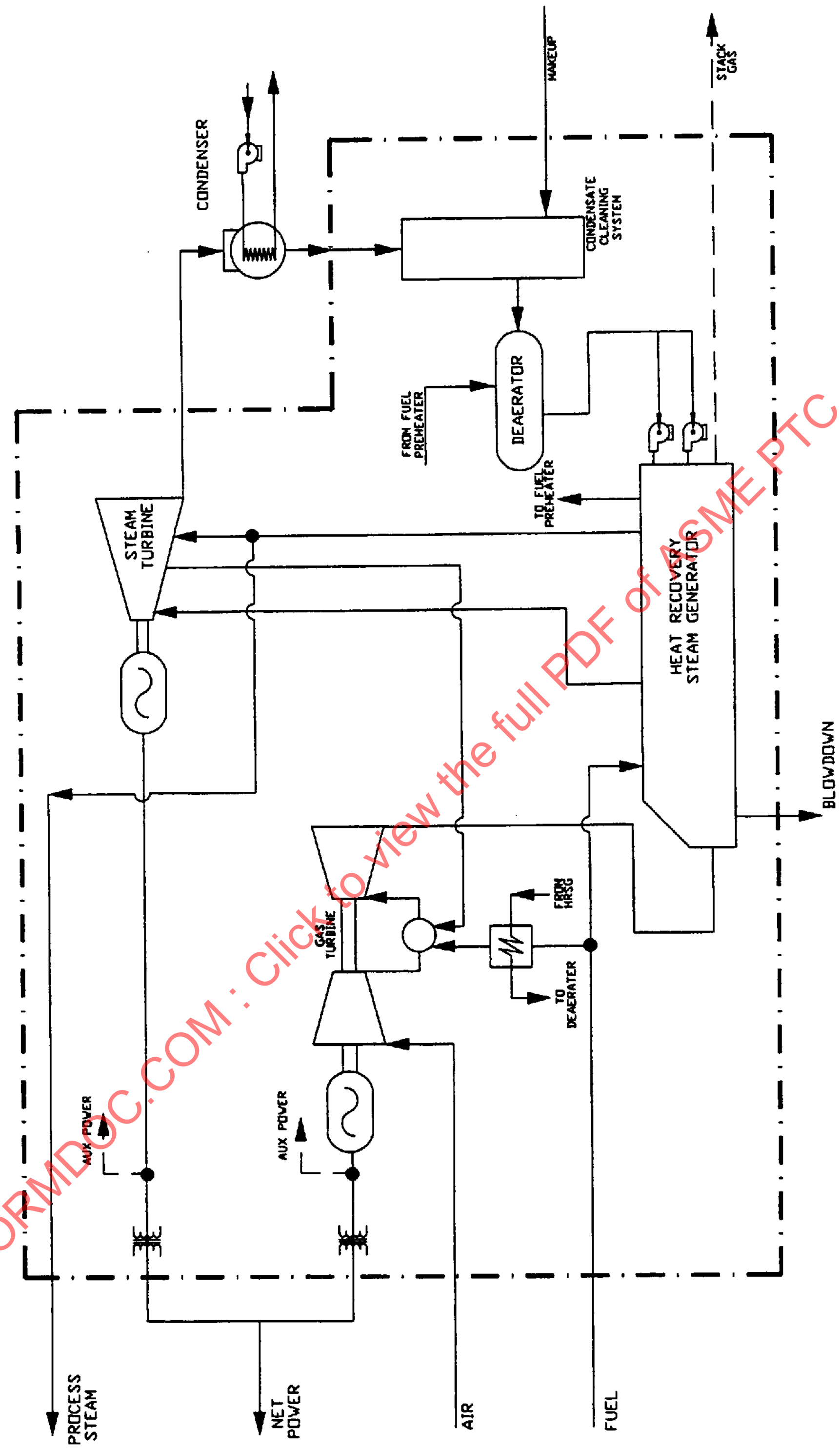


FIG. B.1 CYCLE DIAGRAM AND TEST BOUNDARY

TABLE B.1
REFERENCE CONDITIONS

Reference Condition Description	Reference Value
Gross plant power output	81,380 kW
Ambient temperature	30°F (−1.1°C)
Ambient pressure	14.68 psia (101.2 kPa)
Ambient relative humidity	60%
Gas turbine fuel temperature	350°F (177°C)
Fuel heating value, HHV	21,826 Btu/lbm (50767 kJ/kg)
Fuel carbon to hydrogen ratio	3.06
Gas turbine generator power factor	0.85
Steam turbine generator power factor	0.85
HRSG HP drum blowdown	1% Steam Flow
HRSG LP drum blowdown	1% Steam Flow
Make-up water temperature	60°F (16°C)
Excess make-up water flow*	0 lb/hr (0 kg/s)
Condenser pressure	1.50 Inches HgA (5.08 kPa)
Process steam flow	50,000 lb/hr (6.2999 kg/s)
Process steam enthalpy	1240.5 Btu/lbm (2885.4 kJ/kg)

*This is the flow in excess of that required for make-up due to NOx steam, process steam, etc. that enters the cycle.

power, Δ_7, which is used in combination with ω_7 to correct from measured power to design power.

Therefore, from the overall general heat rate equation,

$$HR_{corr} = \frac{(Q_{meas} + \sum \omega_i) \prod \beta_j}{(P_{meas} + \sum \Delta_i) \prod \alpha_j}$$

and the relationship

$$f_j = \frac{\alpha_j}{\beta_j}$$

the test equation for this specific plant and test becomes

$$HR_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_2 + \omega_3 + \omega_4 + \omega_5 + \omega_7) f_1 f_2 f_3 f_4 f_5}{(P_{meas} + \Delta_7)}$$

The individual corrections in this equation are described in Table B.2.

B.5 CORRECTION CURVES AND FITTED EQUATIONS

A series of heat balances were run in order to determine the performance test corrections. The corrections are first presented in equation form followed by a series of curves.

Correction to heat input to account for process efflux (i.e., process steam) different than design

$$\begin{aligned}\omega_1 = {} & 55082885 - 78.4074405F \\ & + 6.7583*10^{-7}F^2 - 25310.41H \\ & + 9.68613371H^2 - 0.41827648FH \\ & - 1.0758*10^{-9}F^2H - 0.00011342FH^2 \\ & + 4.2804*10^{-13}F^2H^2\end{aligned}$$

where

F = process steam flow (lb/hr)
H = process steam enthalpy (Btu/lb)

Correction to heat input to account for gas turbine generator power factor different than design.

$$\begin{aligned}\omega_{2A} = {} & 76855305.67 - 154591165PF \\ & + 75497833.33PF^2 - 3387.76765kW \\ & + 0.034160678kW^2 + 6736.6085PFkW \\ & - 3236.47PF^2kW - 0.06782565PFkW^2 \\ & + 0.032513667PF^2kW^2\end{aligned}$$

where

PF = gas turbine generator power factor
kW = gross power output measured at gas turbine generator terminals (kW)

TABLE B.2
REQUIRED CORRECTION FACTORS

Symbol	Description
ω_1	Correction to heat input to account for process efflux (i.e., process steam) different than design.
ω_2	Correction to heat input to account for generator power factor different than design. This is broken down to ω_{2A} for the GT generator and ω_{2B} for the ST generator.
ω_3	Correction to heat input to account for blowdown different than design.
ω_4	Correction to heat input to account for secondary heat inputs (ie., make-up) different than design.
ω_{5C}	Correction to heat input to account for condenser pressure different than design. (The correction would be ω_{5A} for cooling tower air inlet temperature different than design. The correction would be ω_{5B} for circulating water temperature different than design.)
ω_7	Correction to heat input to account for difference between measured power and design power.
Δ_7	Difference between design power and measured power.
f_1	Correction factor to plant heat rate to account for ambient temperature different than design.
f_2	Correction factor to plant heat rate to account for ambient pressure different than design.
f_3	Correction factor to plant heat rate to account for relative humidity different than design.
f_4	Correction factor to plant heat rate to account for fuel temperature different than design.
f_5	Correction factor to plant heat rate to account for fuel heating value different than design.

TABLE B.3
MEASURED DATA

Description	Measured Value
Gross gas turbine power output	54921 kW
Gross steam turbine output	27244 kW
Gas turbine generator power factor	0.95
Steam turbine generator power factor	0.95
Ambient temperature	47.3°F (8.50°C)
Ambient pressure	14.76 psia (101.8 kPa)
Ambient relative humidity	30%
Gas turbine fuel temperature (°F)	356°F (180°C)
Fuel heating value, HHV	22850 Btu/lbm (53149 kJ/kg)
Fuel carbon to hydrogen ratio	3.05
HRSG HP drum blowdown	Isolated
HRSG LP drum blowdown	Isolated
Make-up water temperature	64.2°F (17.9°C)
Condenser pressure	1.20 Inches HgA (4.06 kPa)
Process steam pressure	188.4 psia (1299 kPa)
Process steam temperature	463.3°F (239.6°C)
The data below is calculated from other measurements:	
Gas turbine fuel flow	25,906 lbm/hr (3.2641 kg/s)
Duct burner fuel flow	5448 lbm/hr (0.6864 kg/s)
Process steam flow	46,626 lbm/hr (5.8748 kg/s)
NOx steam flow	45,552 lbm/hr (5.7395 kg/s)
Make-up flow	92,303 lbm/hr (11.630 kg/s)
Process steam enthalpy (Btu/lb)	1249.8 Btu/lbm (2907.0 kJ/kg)

Correction to heat input to account for steam turbine generator power factor different than design

$$\omega_{2B} = 6286157 - 12273205PF + 5738500PF^2 - 443.8303\text{kW} + 0.004955327\text{kW}^2 + 914.5335714PF\text{kW} - 461.6238095PF^2\text{kW} - 0.012295PF\text{kW}^2 + 0.007606122PF^2\text{kW}^2$$

where

PF = steam turbine generator power factor

kW = gross power output measured at steam turbine generator terminals (kW)

Correction to heat input to account for blowdown different than design.

Correction from isolated to 1% HP blowdown. LP blowdown is insignificant.

$$\omega_3 = 592390.1 - 672.4T + 100.0485T^2$$

where

T = ambient temperature (°F)

Correction to heat input to account for secondary heat inputs (i.e., make-up) different than design

$$\omega_4 = -571800 - 1300.38F + 5.9631*10^{-19}F^2 + 9440T + 1.5T^2 + 0.17475FT + 6.7763*10^{-21}F^2T + 0.0002125FT^2 - 5.294*10^{-23}F^2T^2$$

where

F = excess make-up flow (lb/hr)
T = make-up temperature (°F)

Correction to heat input to account for condenser pressure different than design

$$\omega_{5C} = 11686296.56 - 8308140.313P + 344850.625P^2 + 68357.175T - 393.718125T^2 - 52424.275PT + 4568.55P^2T + 282.085625PT^2 - 13.07125P^2T^2$$

where

P = condenser pressure (inches Hg absolute)
T = ambient temperature (°F)

Correction to thermal heat input to account for difference between measured power and design power

$$\omega_7 = -2.61186*10^{-12} + 7260.752844\Delta_7 - 0.537355297\Delta_7^2 + 4.27425*10^{-14}T - 2.24607*10^{-15}T^2 + 26.6786625\Delta_7T + 0.018662119\Delta_7^2T - 0.222322188\Delta_7T^2 - 0.000155518\Delta_7^2T^2$$

where

Δ_7 = difference between design power and measured power, $P_{design} - P_{meas}$, (kW)
T = ambient temperature (°F)

Difference between design power and measured power

$$\Delta_7 = 81380 - P_{meas}$$

Correction factor to heat input to account for ambient temperature different than design

$$f_1 = 1.012975085 - 0.00043780337T + 1.766957*10^{-7}T^2$$

where

T = ambient temperature (°F)

Correction factor to heat input to account for ambient pressure different than design

$$f_2 = 1.617199959 - 0.08191305P + 0.002715903P^2$$

where

P = ambient pressure (psia)

Correction factor to heat input to account for relative humidity different than design

f_3 = 1.0 (correction is insignificant)

Correction factor to heat input to account for gas turbine fuel temperature different than design

$$f_4 = 0.99301814 + 0.000019948177T$$

where

T = fuel temperature (°F)

Correction factor to heat input to account for fuel heating value different than design

$$f_5 = 2.66107573 - 0.00010133V + 3.3266*10^{-13}V^2 - 1.06344696R + 0.17852287R^2 + 6.5632*10^{-5}VR - 2.1534*10^{-13}V^2R - 1.1011*10^{-5}VR^2 + 3.4844*10^{-14}V^2R^2$$

where

V = fuel higher heating value (Btu/lb)
R = fuel carbon to hydrogen ratio (no units)

B.6 SAMPLE CALCULATIONS AND RESULTS

The "Corrected Value" entries of Table B.4 are calculated as described below. The plant specific test equation is repeated for convenience.

$$HR_{corr} = \frac{(Q_{meas} + \omega 1 + \omega 2 + \omega 3 + \omega 4 + \omega 5 + \omega 7)\, f1 f2 f3 f4 f5}{(P_{meas} + \Delta 7)}$$

The additive correction to power is

82,165 kW − 785 kW = 81,380 kW

The additive corrections to heat input are

716,438,900 + 2,289,194 + 328,100 + 137,016 + 784,423 − 120,605 + 2,616,334 − 6,301,412 = 716,171,950 Btu/hr

(755,874,400 + 2,415,228 + 346,164 + 144,560 + 827,610 − 127,245 + 2,760,379 − 6,648,343 = 755,592,753 kJ/hr)

The multiplicative corrections are

(0.9926623)(0.9998435)(1.000000)(1.0001197)(0.9964189) = 0.989071059

The complete equation is then

$$HR_{corr} = \frac{(716{,}171{,}950)(0.989071059)}{81380}$$

$$HR_{corr} = 8704 \text{ Btu/kW-hr}$$

$$HR_{corr} = \frac{(755{,}592{,}753 \text{ kJ/hr})(0.989071)}{81380 \text{ kW}}$$

$$HR_{corr} = 9183 \text{ kJ/kW-hr}$$

TABLE B.4
PERFORMANCE CORRECTIONS

Gross Plant Design Power		81,380 kW	
Description	Measured Value	Correction	Corrected Value
GT generator gross power	54,921 kW		
ST generator gross power	27,244 kW		
Gross plant power	82,165 kW		
Difference from design power		$\Delta 7$ = −785 kW	
Corrected gross plant power			81,380 kW
Gas turbine gas flow	25,906 lbm/hr (3.2641 kg/s)		
Duct burner gas flow	5448 lbm/hr (0.6864 kg/s)		
Total gas flow	31,354 lbm/hr (3.9505 kg/s)		
Fuel heating value, HHV	22,850 Btu/lbm (53149 kJ/kg)		
Measured heat input	716,438,900 Btu/hr (755,874,400 kJ/hr)		
Process steam flow	46,626 lbm/hr (5.8748 kg/s)		
Process steam enthalpy	1249.8 Btu/lbm (2907.0 kJ/kg)		
Process efflux correction		$\omega 1$ = 2,289,194 Btu/hr ($\omega 1$ = 2,415,228 kJ/hr)	
GT generator power factor	0.95		
GT generator power factor correction		$\omega 2A$ = 328,100 Btu/hr ($\omega 2A$ = 346,164 kJ/hr)	
ST generator power factor	0.95		
ST generator power factor correction		$\omega 2B$ = 137,016 Btu/hr ($\omega 2B$ = 144,560 kJ/hr)	
HP and LP blowdown	Isolated		
Blowdown correction		$\omega 3$ = 784,423 Btu/hr ($\omega 3$ = 827,610 kJ/hr)	
Excess make-up flow	125 lbm/hr (0.0157 kg/s)		
Make-up temperature	64.2°F (17.9°C)		

TABLE B.4
PERFORMANCE CORRECTIONS (CONT'D)

Gross Plant Design Power		81,380 kW	
Description	**Measured Value**	**Correction**	**Corrected Value**
Make-up correction		$\omega4$ = −120,605 Btu/hr ($\omega4$ = −127,245 kJ/hr)	
Condenser pressure	1.20 inches HgA (4.06 kPa)		
Condenser pressure correction		$\omega5C$ = 2,616,334 Btu/hr ($\omega5C$ = 2,760,379 kJ/hr)	
Power difference (Δ7)		−785 kW	
Power difference correction		$\omega7$ = −6,301,412 Btu/hr ($\omega7$ = −6,648,343 kJ/hr)	
Ambient temperature	47.3°F (8.50°C)		
Ambient temperature correction		$f1$ = 0.9926623	
Ambient pressure	14.76 psia (101.8 kPa)		
Ambient pressure correction		$f2$ = 0.9998435	
Ambient relative humidity	30%		
Ambient relative humidity correction		$f3$ = 1.000000	
GT fuel temperature	356°F (180°C)		
GT fuel temperature correction		$f4$ = 1.0001197	
Fuel heating value, HHV	22850 Btu/lbm (53149 kJ/kg)		
Fuel carbon to hydrogen ratio	3.05		
Fuel analysis correction		$f5$ = 0.9964189	
Plant heat input after additive corrections, HHV			716,171,950 Btu/hr (755,592,753 kJ/hr)
Corrected plant heat rate, HHV			8704 Btu/kW-hr (9183 kJ/kW-hr)

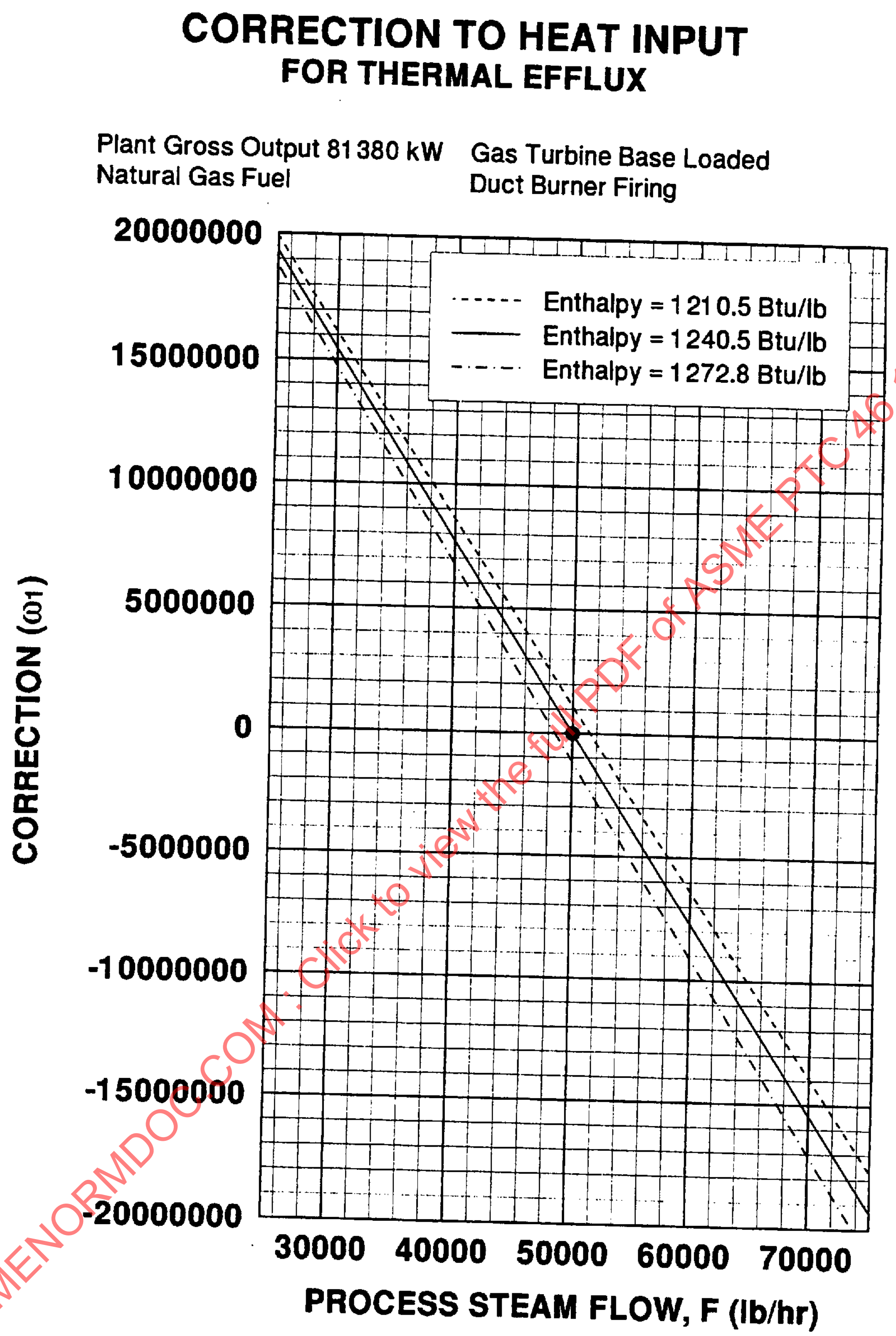


FIG. B.2 CORRECTION TO THERMAL HEAT INPUT FOR THERMAL EFFLUX

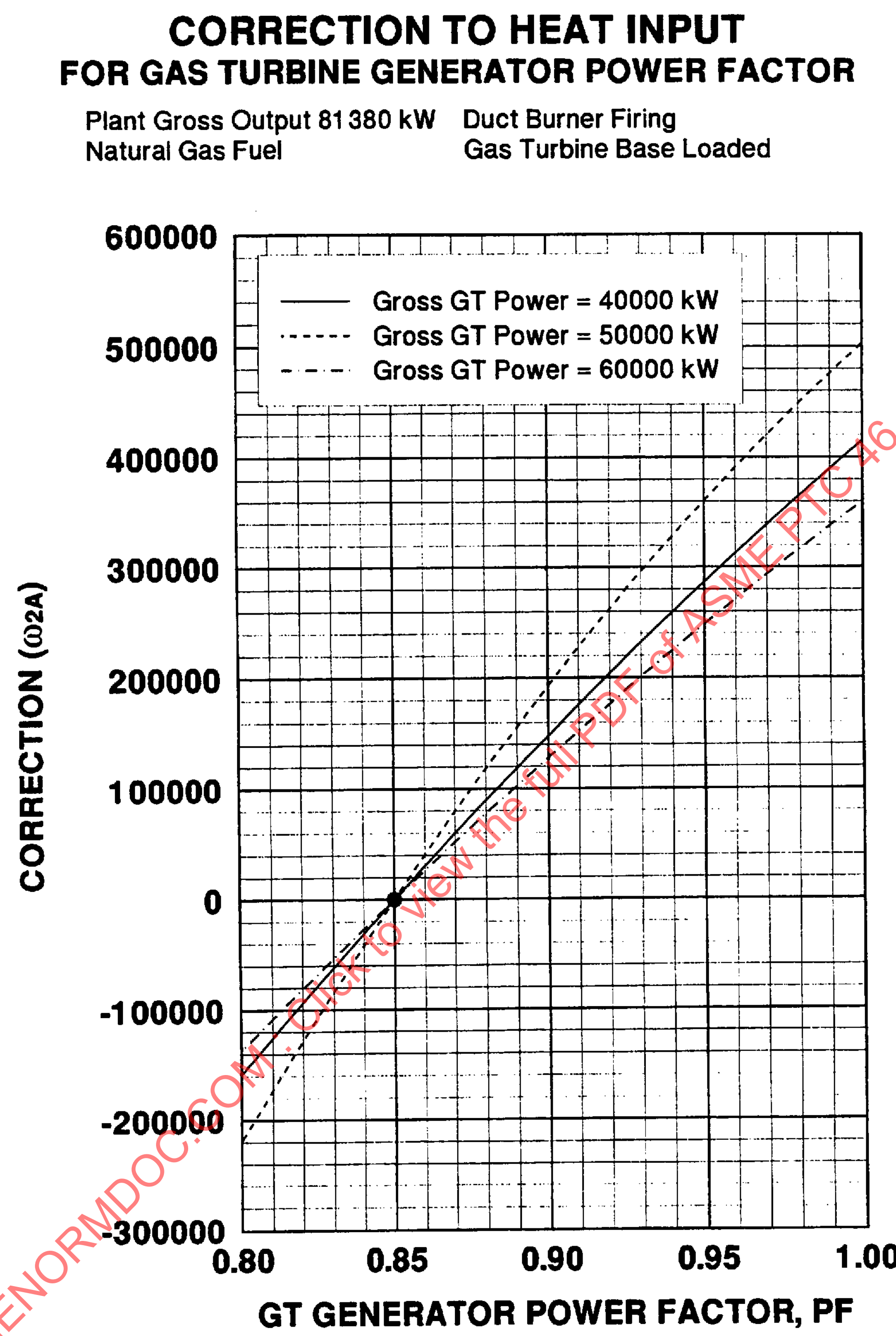


FIG. B.3 CORRECTION TO THERMAL HEAT INPUT FOR COMBUSTION TURBINE GENERATOR POWER FACTOR

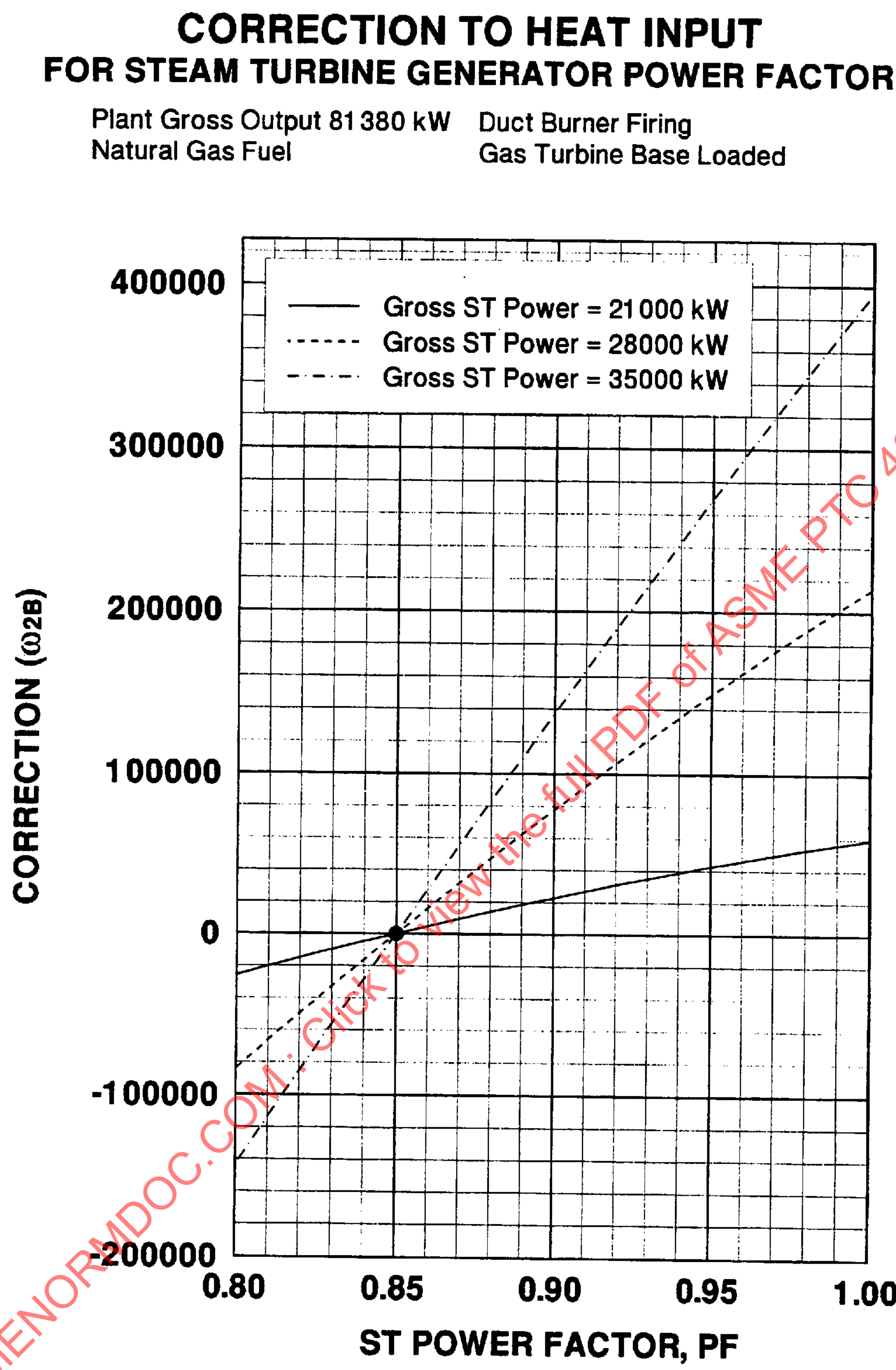


FIG. B.4 CORRECTION TO THERMAL HEAT INPUT FOR STEAM TURBINE GENERATOR POWER FACTOR

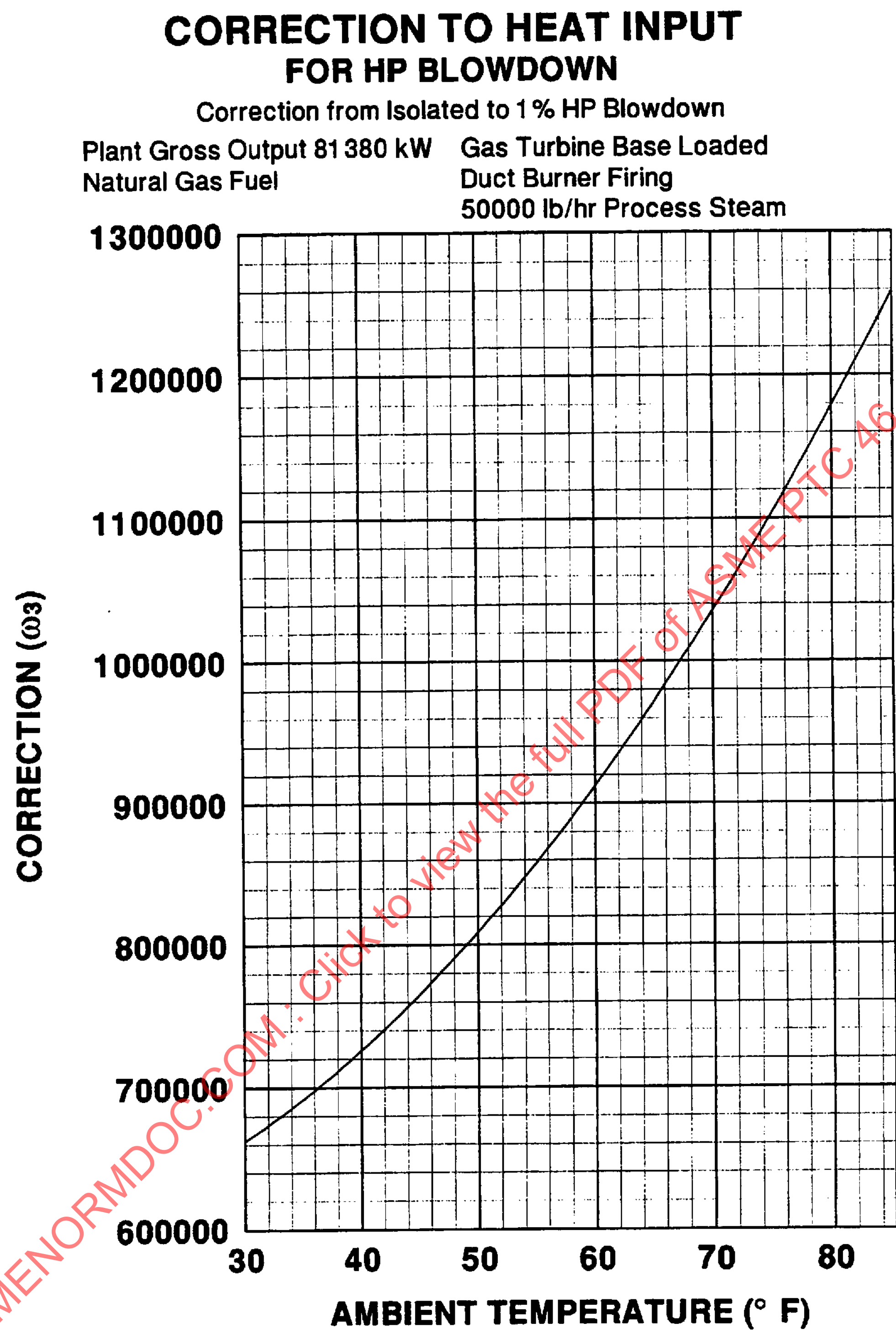


FIG. B.5 CORRECTION TO THERMAL HEAT INPUT FOR HP BLOWDOWN

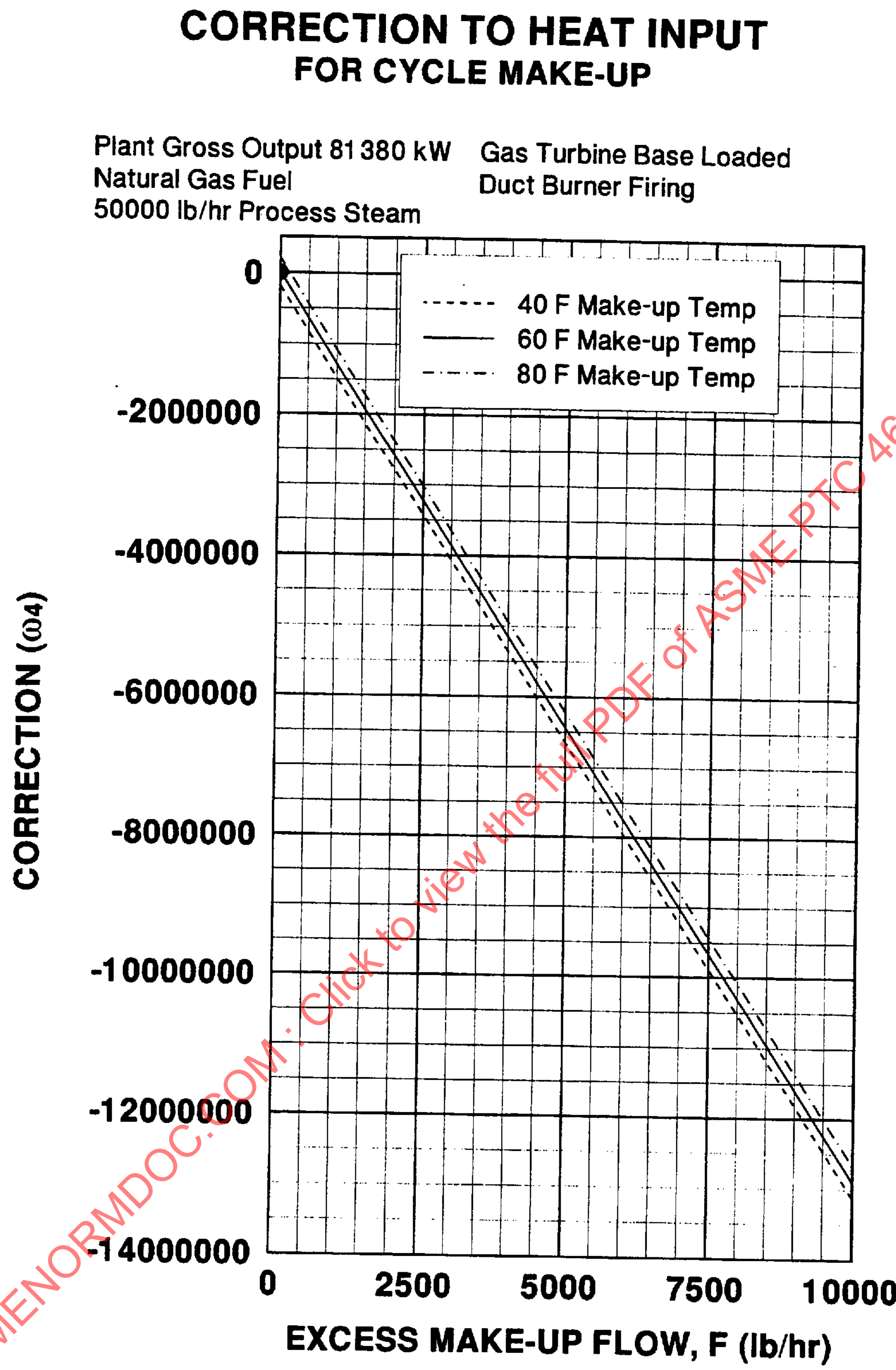


FIG. B.6 CORRECTION TO THERMAL HEAT INPUT FOR CYCLE MAKE-UP

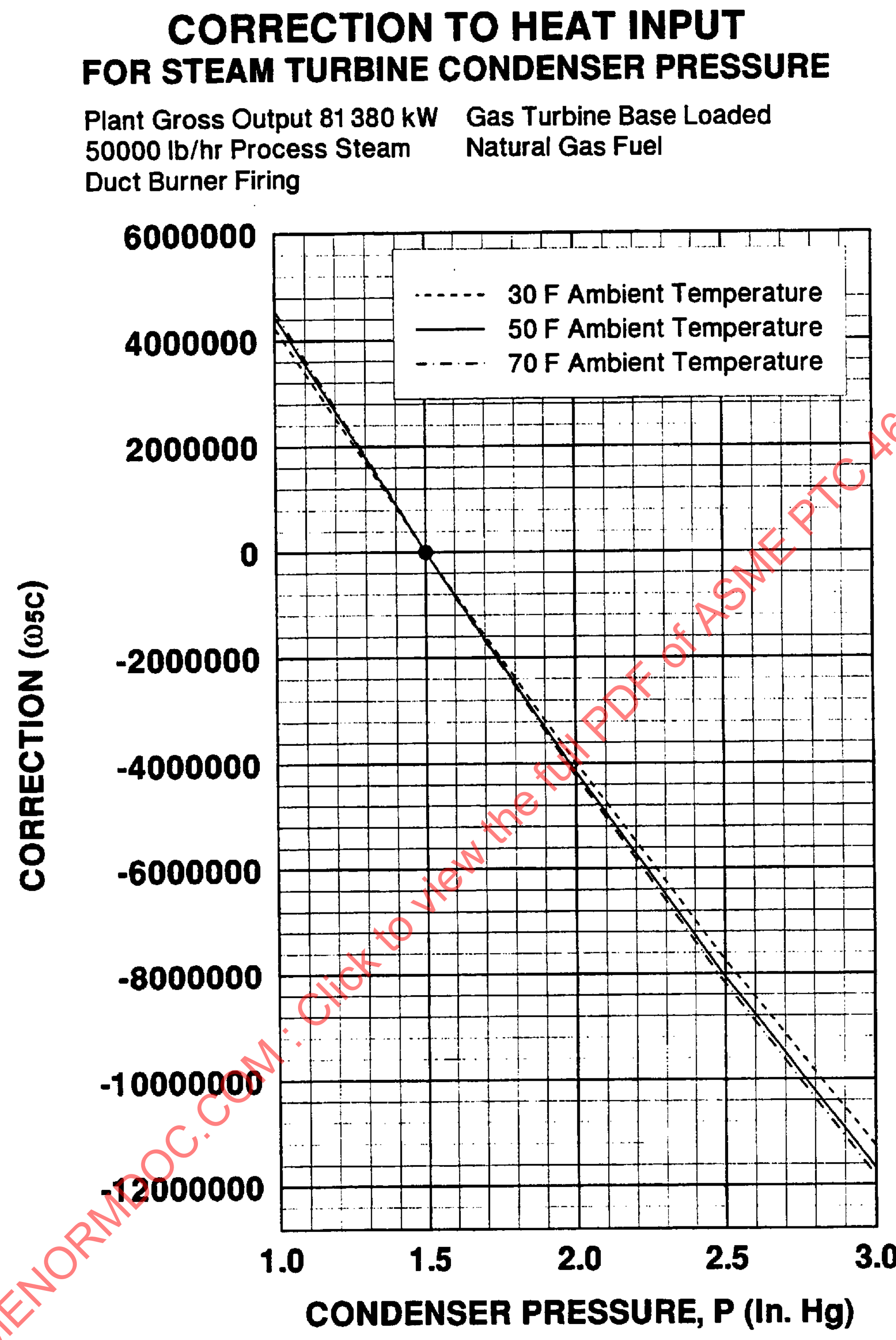


FIG. B.7 CORRECTION TO THERMAL HEAT INPUT FOR STEAM TURBINE CONDENSER PRESSURE

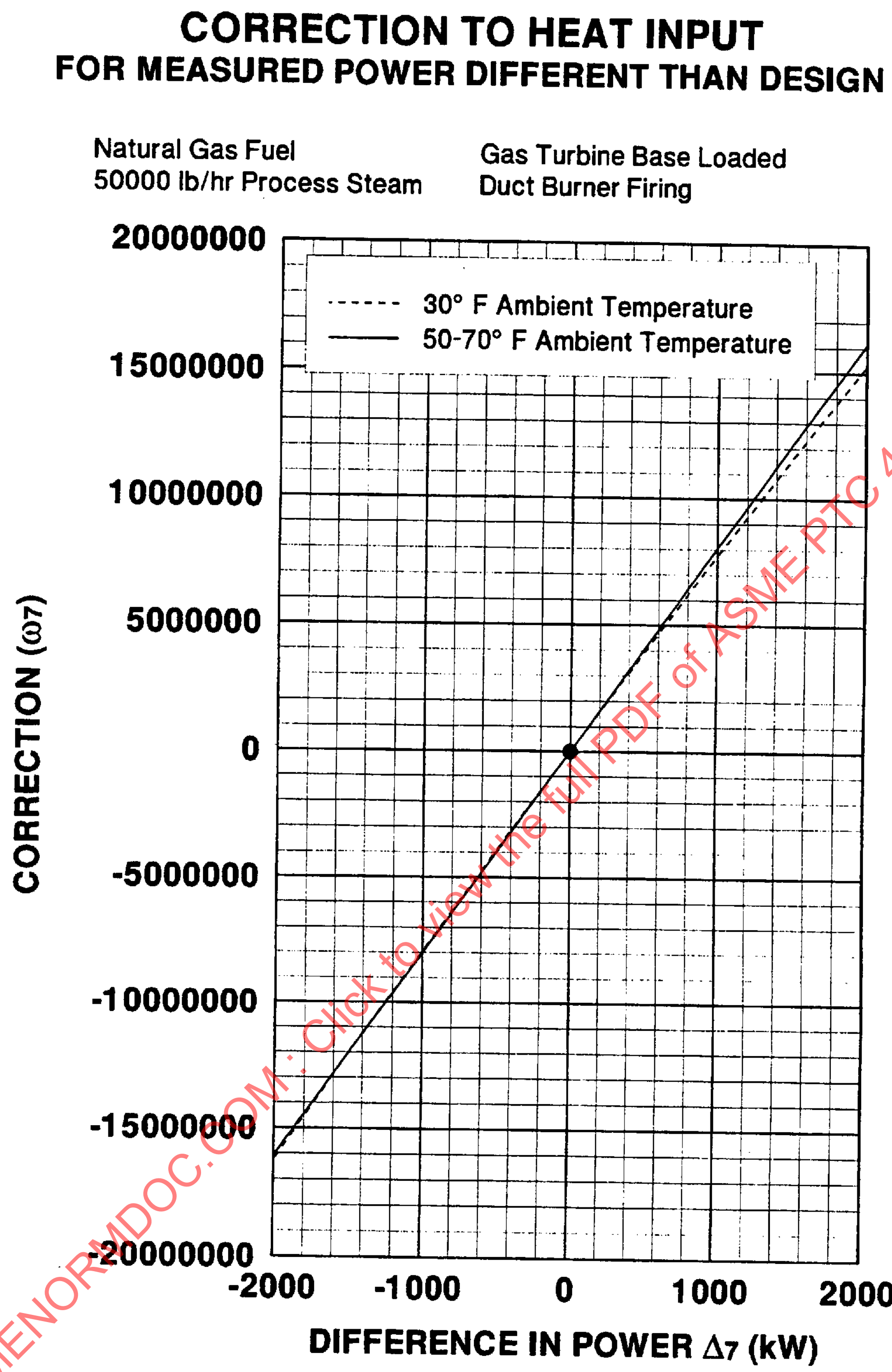


FIG. B.8 CORRECTION TO THERMAL HEAT INPUT FOR MEASURED POWER DIFFERENT THAN DESIGN

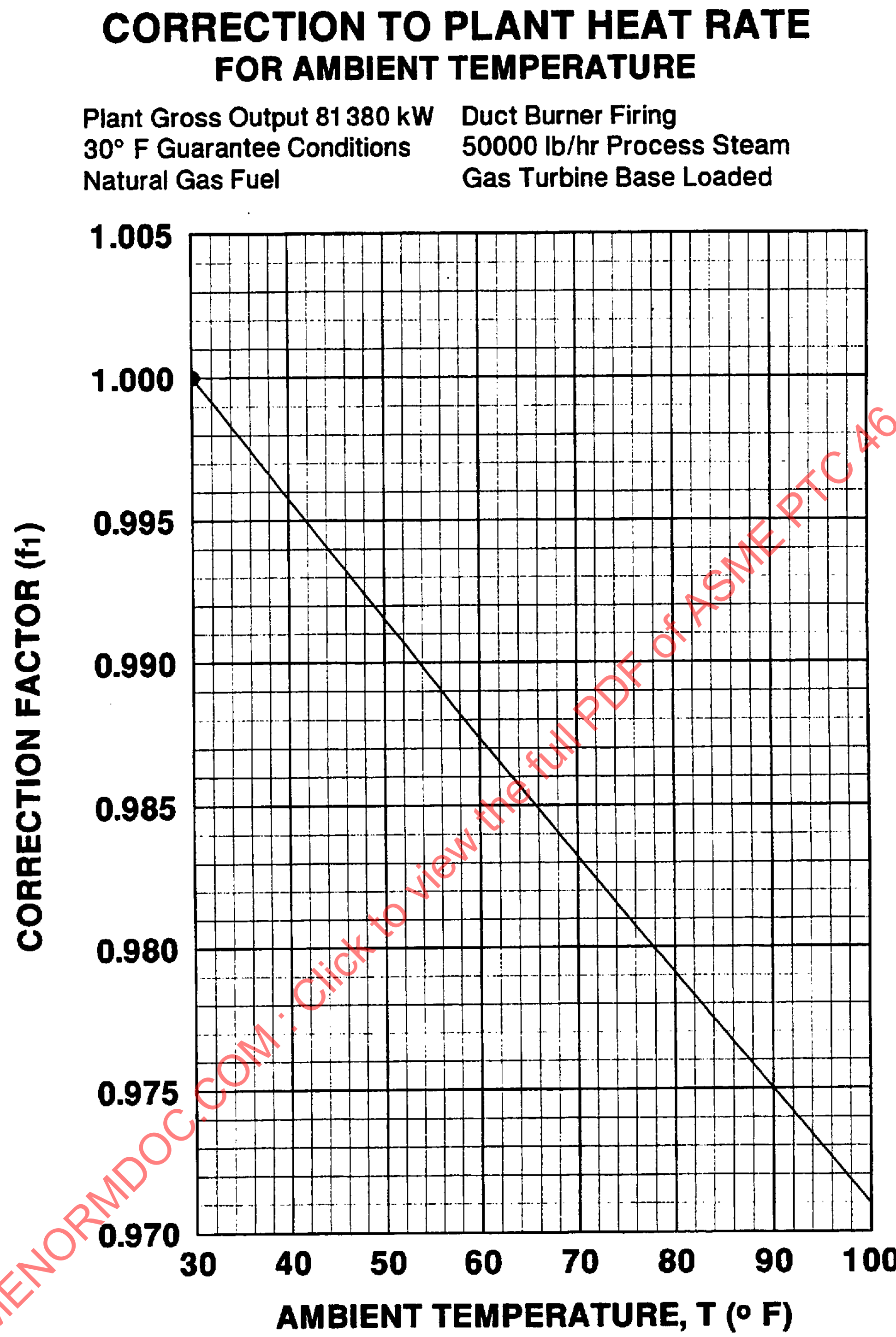


FIG. B.9 CORRECTION TO PLANT HEAT RATE FOR AMBIENT TEMPERATURE

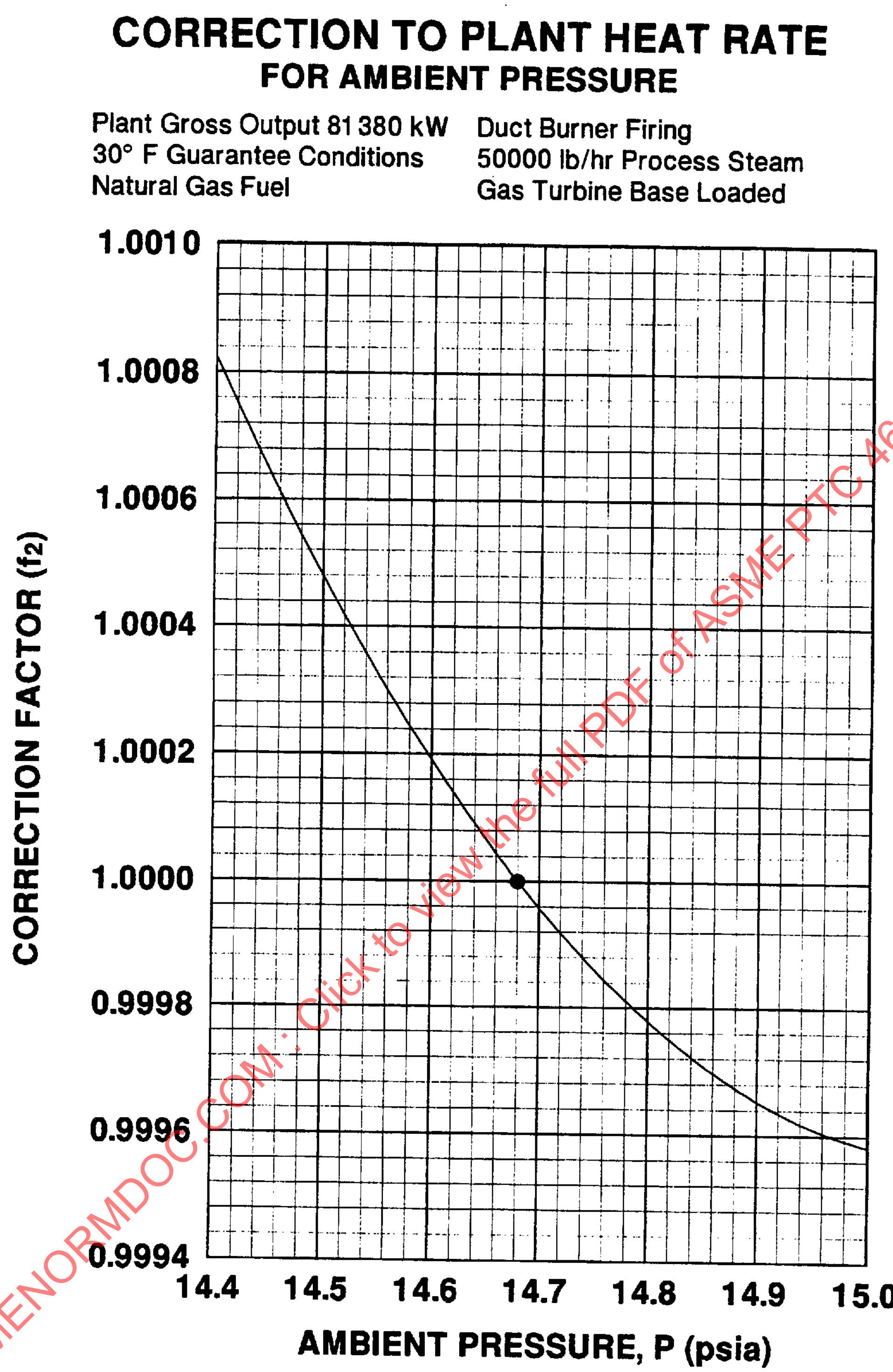


FIG. B.10 CORRECTION TO PLANT HEAT RATE FOR AMBIENT PRESSURE

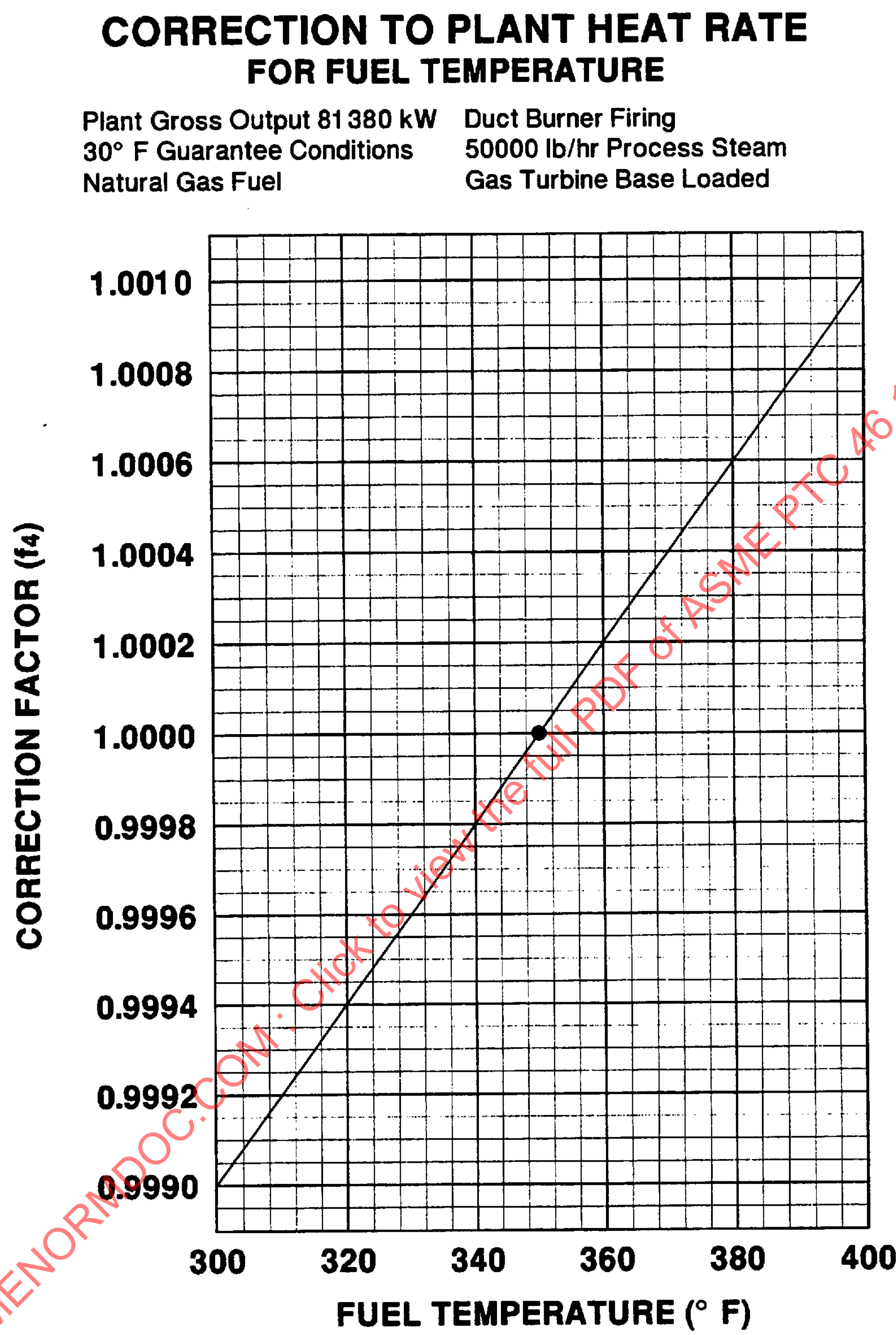


FIG. B.11 CORRECTION TO PLANT HEAT RATE FOR FUEL TEMPERATURE

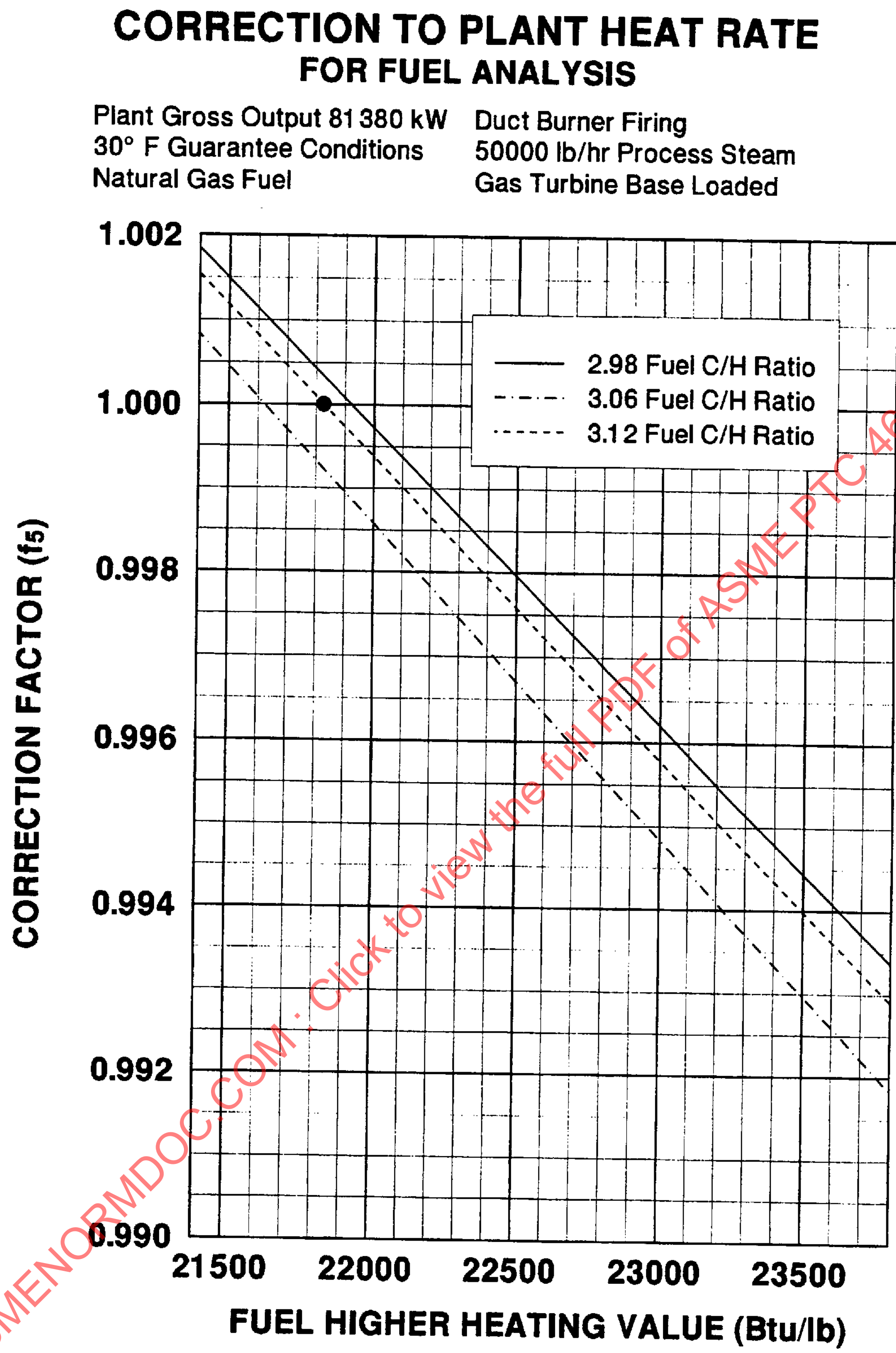


FIG. B.12 CORRECTION TO PLANT HEAT RATE FOR FUEL ANALYSIS

APPENDIX C — SAMPLE CALCULATIONS COMBINED CYCLE COGENERATION PLANT WITHOUT DUCT FIRING HEAT SINK: COOLING TOWER EXTERNAL TO THE TEST BOUNDARY TEST GOAL: SPECIFIED DISPOSITION IS GAS TURBINE BASE LOADED (POWER FLOATS)

(This Appendix is not a part of ASME PTC 46-1996.)

C.1 Introduction

The combined cycle/cogeneration plant for the sample calculation that follows is generally shown on Fig. C.1. The major equipment items are as follows:

gas turbine: 115 MW at ISO conditions (59°F (15°C), 60% RH, and sea level) with 4 inwg (12.0 mbar) inlet and 12 inwg (36 mbar) exhaust pressure drop and steam injection for NOx control to 25 ppm
heat recovery steam generator: three steam pressure levels one of which is used with an integral deaerator. The design conditions at the outlet of the HRSG are 1280 psig (88.3 barg) and 900°F (482.2°C) for the HP steam, 330 psig (22.8 barg) and 500°F (260°C) for the IP steam, and saturated 15 psig (1.03 barg) steam for the integral deaerator.
steam turbine: condensing type, 40 MW nominal rating, with an exit pressure of 2.0 in Hg (67.5 mbar) with two extraction ports at 315 psig (21.7 barg) and 165 psig (11.4 barg)
condenser: shell and tube with a cooling water inlet temperature of 80°F (26.7°C) and a 20°F (11.1°C) rise
deaerator: integral with LP drum with pegging steam from IP steam line if needed

C.2 Test Boundary

The test boundary is typically shown as Fig. C.1. The measurement points for this calculation are as follows:

(a) combined net power output from the gas and steam turbine generator excluding in-plant auxiliary power
(b) fuel input to the gas turbine (specified as LHV for reference)
(c) cogeneration steam flow to the user
(d) condensate return flow from the user
(e) ambient air conditions at the gas turbine filter house inlet
(f) condenser cooling water inlet
(g) blowdown from the HRSG
(h) make-up feedwater

C.3 Test Reference Conditions

For the sample calculation that follows, the design reference conditions are:

Ambient temperature	60°F (15.6°C)
Relative humidity	60%
Plant site elevation	0 ft/14.696 psia [0 m/1.013 bar (a)]
Process steam flow	150,000 lb/hr (18.9 kg/s)
Process steam pressure	150 psig (10.3 barg)
Process steam temperature	373°F (189°C)
Blowdown flow	14,405 lb/hr (1.81 kg/s)
Condensate return flow	75% at 180°F (82.2°C)
Cooling water inlet temperature	60°F (15.6°C)
Fuel heating value, LHV	21515 Btu/lb (50044 kJ/kg)
Net plant power output	145,540 kW
Net plant heat rate, LHV (without credit for process energy)	7966 Btu/kWh (8404.6 kJ/kWh)

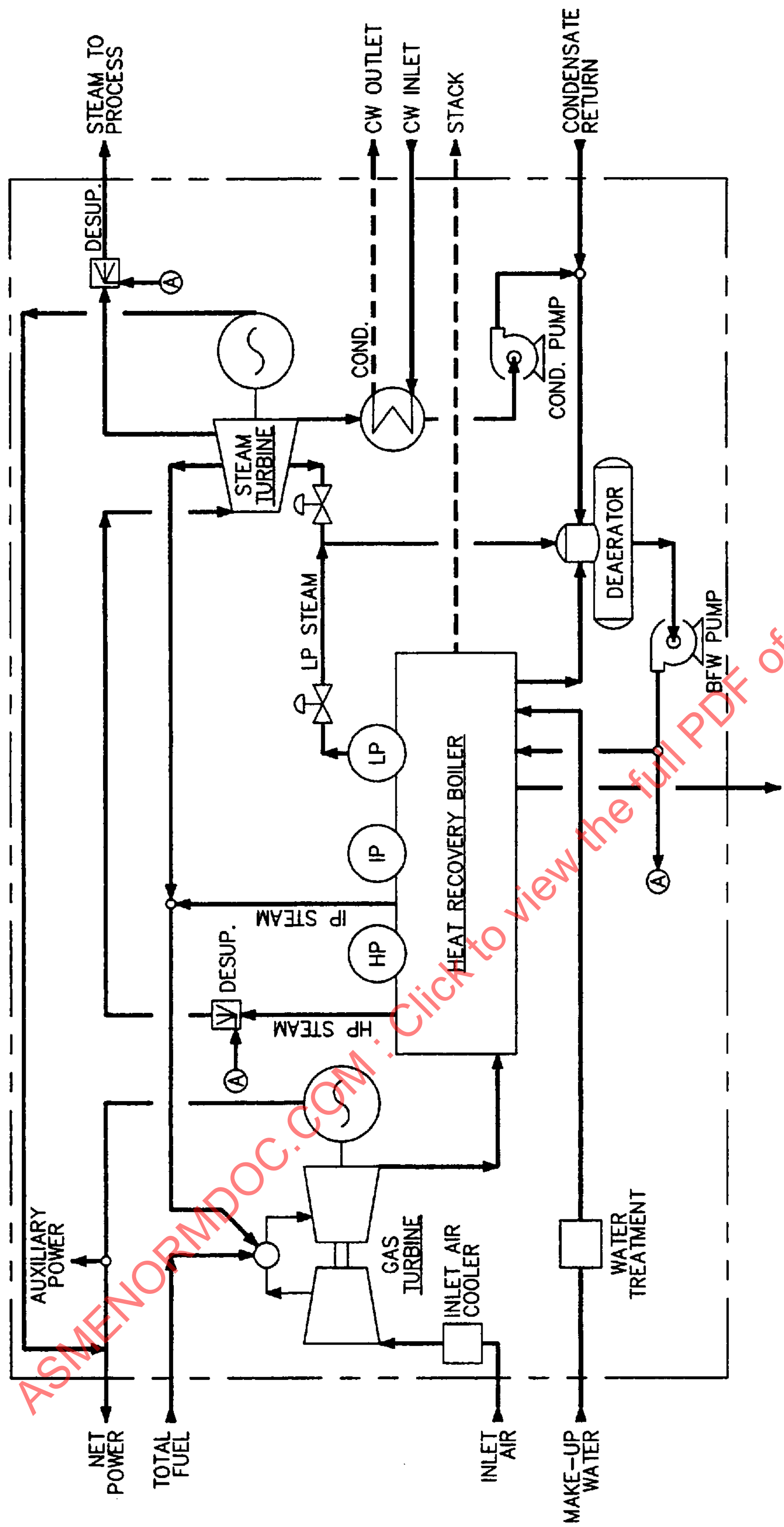


FIG. C.1 TEST BOUNDARY OF TYPICAL COMBINED CYCLE/COGENERATION PLANT WITH EXTERNAL CONDENSER COOLING

C.4 Correction Factors

The general equation for corrected power from Section 5 is

$$P_{corr} = (P_{meas} + \Sigma\Delta_i)\ \Pi\alpha_i$$

The overall general heat rate equation from Section 5 is

$$HR_{corr} = \frac{(Q_{meas} + \Sigma\omega_i)}{(P_{meas} + \Sigma\Delta_i)}\Pi f_j$$

The test requirements are based on fixed unit disposition based on base loaded gas turbines with no duct burning. For this test configuration the ω_1 through ω_7 and Δ_7 all become 0.

Other specific simplifying assumptions for this configuration are with regard to the variables found in the above equation and in Tables 5.1 and 5.2:

(a) The generator power factor is specified as a constant of 0.9 lead and will not vary, thus Δ_2 becomes 0.

(b) The auxiliary load and transformer losses are not expected to vary for design and off design conditions, and since net power is measured, Δ_6 becomes zero.

(c) For this fixed unit disposition test, the α_4 and α_5 terms become 1.

The f_5 term in the above heat rate equation is used to correct the fuel heating value that was assumed at the time of the test to that of the tested fuel sample analysis recieved after completion of the test. It is defined as

$$f_5 = \frac{\text{Fuel Analysis Value (LHV)}}{\text{21515 (LHV)}}$$

The complete list of additive and multiplicative corrections from Tables 5.1.1 and 5.1.2 that are applicable for the boundary conditions described above are listed as:

Changing Boundary Value	Parameter Correction Variable(s)
Ambient temp	α_1, f_1
Ambient pressure	α_2, f_2
Ambient relative humidity	α_3, f_3
Fuel heating value	f_5
Change in steam sales	Δ_1
HRSG blowdown flow	Δ_3
Make-up water temp	Δ_4
Condenser cooling water temp	Δ_{5B}
Condensate return	Insignificant

Reducing the general equation with these corrections the new power equation is

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta_3 + \Delta_4 + \Delta_{5B})\ \alpha_1\alpha_2\alpha_3$$

and the new heat rate equation is

$$HR_{corr} = \frac{(Q_{meas})\ f_1 f_2 f_3 f_5}{(P_{meas} + \Delta_1 + \Delta_3 + \Delta_4 + \Delta_{5B})}$$

The correction factors listed above are best determined using a computer model of the complete plant. The following pages list data sheets that display the resulting correction variables from the plant model calculations for different ranges of the parameters. For each parameter the power correction variable and/or the heat rate correction variables were curve fit (signified by a ′ symbol) using a third-order polynomial fit. Following each data sheet, a graph showing the data points and the curve fits are also presented.

Performance Test Code Data Sheet
Parameter: Ambient Temperature
Design Point: 60 °F

	Ambient Temperature	Net Plant Power	Net Plant Heat Rate	Power Corr. Variable	Heat Rate Corr. Variable	Power Corr. Curve Fit	Heat Rate Corr. Curve Fit
	°F	kW	Btu / kWh	-	-	-	-
	T	P	HR	α_1	f_1	α_1'	f_1'
	30	153,010.0	8035.9	0.951180	0.995035	0.952378	0.990581
	36	151,660.0	8016.4	0.959647	0.997455	0.959045	0.993991
	42	150,170.0	8004.3	0.969168	0.998963	0.967437	0.996366
	48	148,650.0	7992.1	0.979078	1.000488	0.977602	0.997771
	54	147,220.0	7973.4	0.988589	1.002834	0.989586	0.998268
Design Point:	60	145,540.0	7996.0	1.000000	1.000000	1.003435	0.997921
	66	142,880.0	7988.4	1.018617	1.000951	1.019196	0.996795
	72	140,190.0	8012.8	1.038162	0.997903	1.036916	0.994952
	78	137,500.0	8036.9	1.058473	0.994911	1.056641	0.992456
	84	134,900.0	8052.6	1.078873	0.992971	1.078417	0.989371
	90	132,170.0	8075.7	1.101158	0.990131	1.102292	0.985759

Regression Analysis
Order: 3rd

T	T^2	T^3	α_1	f_1
30	900	27000	0.951180	0.995035
36	1296	46656	0.959647	0.997455
42	1764	74088	0.969168	0.998963
48	2304	110592	0.979078	1.000488
54	2916	157464	0.988589	1.002834
60	3600	216000	1.000000	1.000000
66	4356	287496	1.018617	1.000951
72	5184	373248	1.038162	0.997903
78	6084	474552	1.058473	0.994911
84	7056	592704	1.078873	0.992971
90	8100	729000	1.101158	0.990131

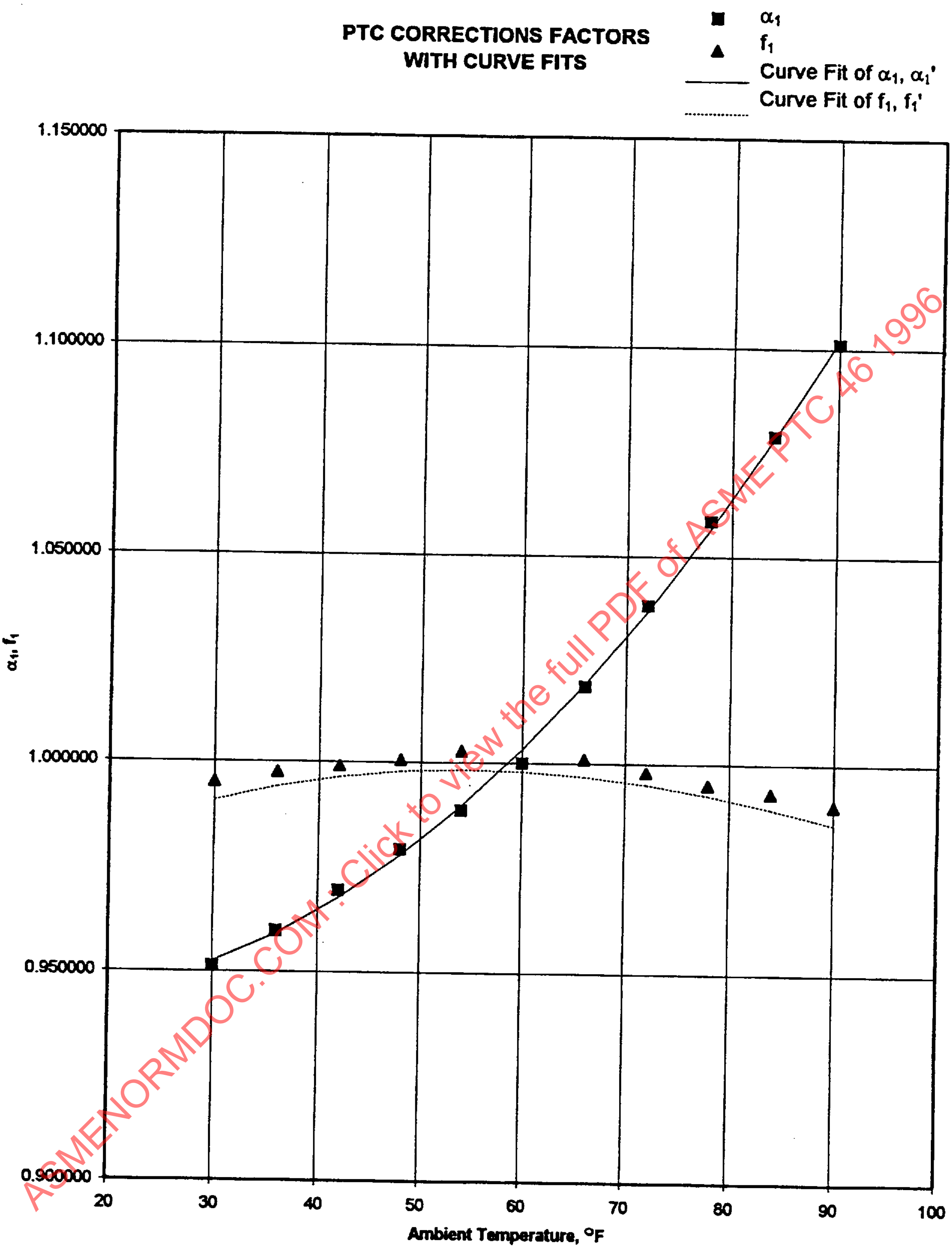
Regression Results

	Intercept	C_1	C_2	C_3	R^2
α_1'	0.943300812	-0.000332432	2.00891E-05	3.59239E-08	0.998954255
f_1'	0.955794514	0.001705298	-1.96625E-05	4.90452E-08	0.938588992

where:

α_1' = Intercept + $C_1(T)$ + $C_2(T)^2$ + $C_3(T)^3$

f_1' = Intercept + $C_1(T)$ + $C_2(T)^2$ + $C_3(T)^3$


PTC CORRECTIONS FACTORS
WITH CURVE FITS
α_1
f_1
Curve Fit of α_1, α_1'
Curve Fit of f_1, f_1'
1.150000
1.100000
1.050000
1.000000
0.950000
0.900000
α_1, f_1
20
30
40
50
60
70
80
90
100
Ambient Temperature, °F

Performance Test Code Data Sheet
Parameter: Ambient Pressure
Design Point: 14.696 psia

Design HR 7,966.0 Btu / kWh
Design Power 145,540.0 kW

Ambient Pressure	Net Plant Power	Net Plant Heat Rate	Power Corr. Variable	Heat Rate Corr. Variable	Power Corr. Curve Fit	Heat Rate Corr. Curve Fit
psia	kW	Btu / kWh	-	-	-	-
P	PWR	HR	α_2	f_2	α_2'	f_2'
13.262	128,530.0	8140.0	1.132343	0.978624	1.132317	0.978625
13.409	130,280.0	8120.1	1.117132	0.981022	1.117180	0.981018
13.557	132,030.0	8100.7	1.102325	0.983372	1.102335	0.983376
13.704	133,770.0	8081.8	1.087987	0.985672	1.087972	0.985668
13.852	135,520.0	8063.4	1.073937	0.987921	1.073882	0.987929
13.999	137,270.0	8045.4	1.060246	0.990131	1.060245	0.990128
14.146	139,020.0	8027.9	1.046900	0.992289	1.046950	0.992283
14.294	140,770.0	8010.8	1.033885	0.994408	1.033899	0.994410
14.441	142,510.0	7994.1	1.021262	0.996485	1.021256	0.996482
14.589	144,260.0	7977.8	1.008873	0.998521	1.008837	0.998529
14.736	146,010.0	7961.8	0.996781	1.000528	0.996798	1.000524

Regression Analysis
Order: 3rd

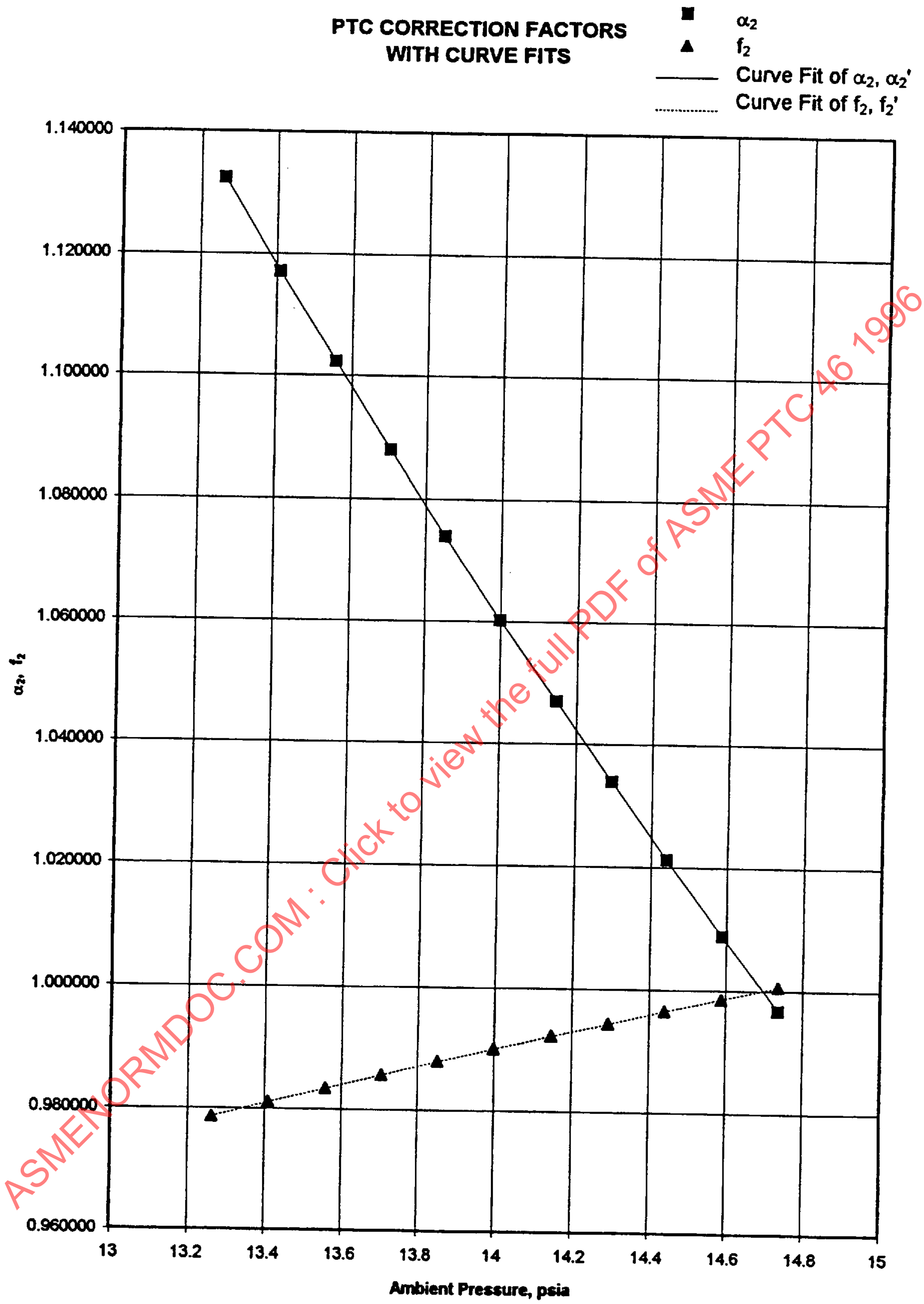
P	P^2	P^3	α_2	f_2
13.262	175.880644	2332.529101	1.132343	0.978624
13.409	179.801281	2410.955377	1.117132	0.981022
13.557	183.792249	2491.67152	1.102325	0.983372
13.704	187.799616	2573.605938	1.087987	0.985672
13.852	191.877904	2657.892726	1.073937	0.987921
13.999	195.972001	2743.412042	1.060246	0.990131
14.146	200.109316	2830.746384	1.046900	0.992289
14.294	204.318436	2920.527724	1.033885	0.994408
14.441	208.542481	3011.561968	1.021262	0.996485
14.589	212.838921	3105.107018	1.008873	0.998521
14.736	217.149696	3199.91792	0.996781	1.000528

Regression Results

	Intercept	C_1	C_2	C_3	R^2
α_2'	5.641320426	-0.687385781	0.034619369	-0.000635263	0.999999479
f_2'	0.342759195	0.094852034	-0.004698993	8.76304E-05	0.999999532

where:

α_2' = Intercept + $C_1(P)$ + $C_2(P)^2$ + $C_3(P)^3$
f_2' = Intercept + $C_1(P)$ + $C_2(P)^2$ + $C_3(P)^3$


PTC CORRECTION FACTORS
WITH CURVE FITS
α_2
f_2
Curve Fit of α_2, α_2'
Curve Fit of f_2, f_2'
1.140000
1.120000
1.100000
1.080000
1.060000
1.040000
1.020000
1.000000
0.980000
0.960000
α_2, f_2
13
13.2
13.4
13.6
13.8
14
14.2
14.4
14.6
14.8
15
Ambient Pressure, psia

Parameter: Relative Humidity
Design Point: 60 %

Ambient Relative Humidity	Net Plant Power	Net Plant Heat Rate	Power Corr. Variable	Heat Rate Corr. Variable	Power Corr. Curve Fit	Heat Rate Corr. Curve Fit
%	kW	Btu / kWh	-	-	-	-
Per	P	HR	α_3	f_3	α_3'	f_3'
10	145,619.9	7950.9	0.999451	1.001901	0.999441	1.001899
20	145,609.9	7954.0	0.999520	1.001510	0.999544	1.001517
30	145,589.9	7956.9	0.999657	1.001145	0.999653	1.001137
40	145,570.0	7960.0	0.999794	1.000754	0.999767	1.000757
50	145,560.0	7963.0	0.999863	1.000377	0.999884	1.000378
Design Point: 60	145,540.0	7966.0	1.000000	1.000000	1.000001	1.000000
70	145,520.0	7969.0	1.000137	0.999623	1.000117	0.999623
80	145,510.0	7972.0	1.000206	0.999247	1.000229	0.999246
90	145,490.1	7975.0	1.000343	0.998870	1.000335	0.998871

Regression Analysis
Order: 3rd

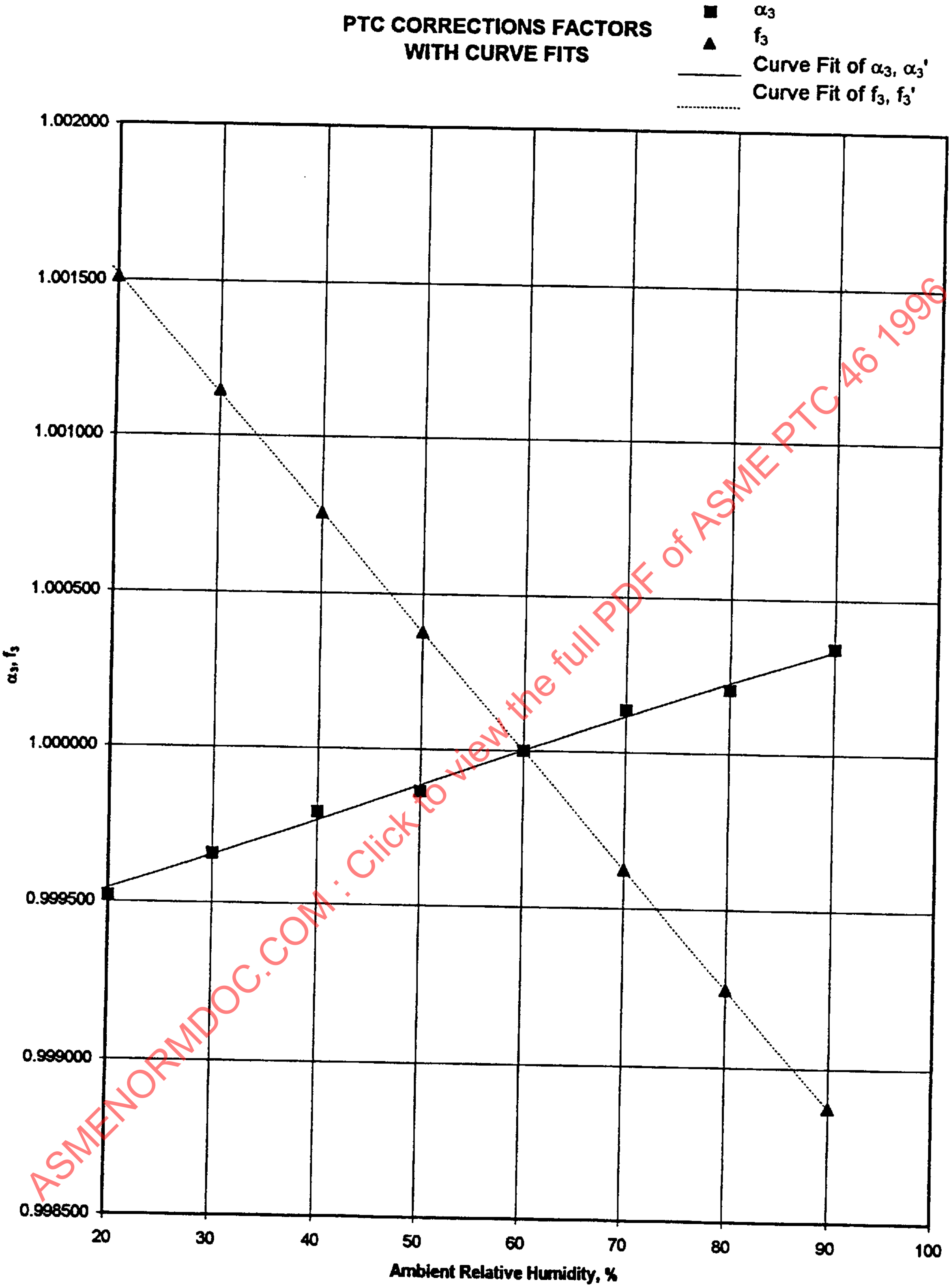
Per	Per^2	Per^3	α_3	f_3
10	100	1000	0.999451	1.001901
20	400	8000	0.999520	1.001510
30	900	27000	0.999657	1.001145
40	1600	64000	0.999794	1.000754
50	2500	125000	0.999863	1.000377
60	3600	216000	1.000000	1.000000
70	4900	343000	1.000137	0.999623
80	6400	512000	1.000206	0.999247
90	8100	729000	1.000343	0.998870

Regression Results

	Intercept	C_1	C_2	C_3	R^2
α_3'	0.999346728	8.89891E-06	5.42992E-08	-3.46311E-10	0.996278563
f_3'	1.002281715	-3.83348E-05	5.78617E-09	-1.08789E-11	0.999985041

where:

$$\alpha_3' = \text{Intercept} + C_1(Per) + C_2(Per)^2 + C_3(Per)^3$$
$$f_3' = \text{Intercept} + C_1(Per) + C_2(Per)^2 + C_3(Per)^3$$


PTC CORRECTIONS FACTORS
WITH CURVE FITS
α_3
f_3
Curve Fit of α_3, α_3'
Curve Fit of f_3, f_3'
1.002000
1.001500
1.001000
1.000500
1.000000
0.999500
0.999000
0.998500
α_3, f_3
20
30
40
50
60
70
80
90
100
Ambient Relative Humidity, %

Performance Test Code Data Sheet
Parameter: Steam Sales Flow
Design Flow: 150,000 lb/hr

Design HR 7,966.0 Btu / kWh
Design Power 145,540.0 kW

Steam Sales Flow	Net Plant Power	Power Corr. Variable	Power Corr. Curve Fit
lb/hr	kW	kW	kW
SS	PWR	Δ_1	Δ'_1
112,500	148,600.0	-3060.0	-3060.139860
120,000	147,990.0	-2450.0	-2450.699301
127,500	147,380.0	-1840.0	-1839.533800
135,000	146,770.0	-1230.0	-1226.923077
142,500	146,150.0	-610.0	-613.146853
150,000	145,540.0	0.0	1.515152
157,500	144,920.0	620.0	616.783217
165,000	144,310.0	1230.0	1232.377622
172,500	143,690.0	1850.0	1848.018648
180,000	143,080.0	2460.0	2463.426573
187,500	142,460.0	3080.0	3078.321678

Regression Analysis
Order: 3rd

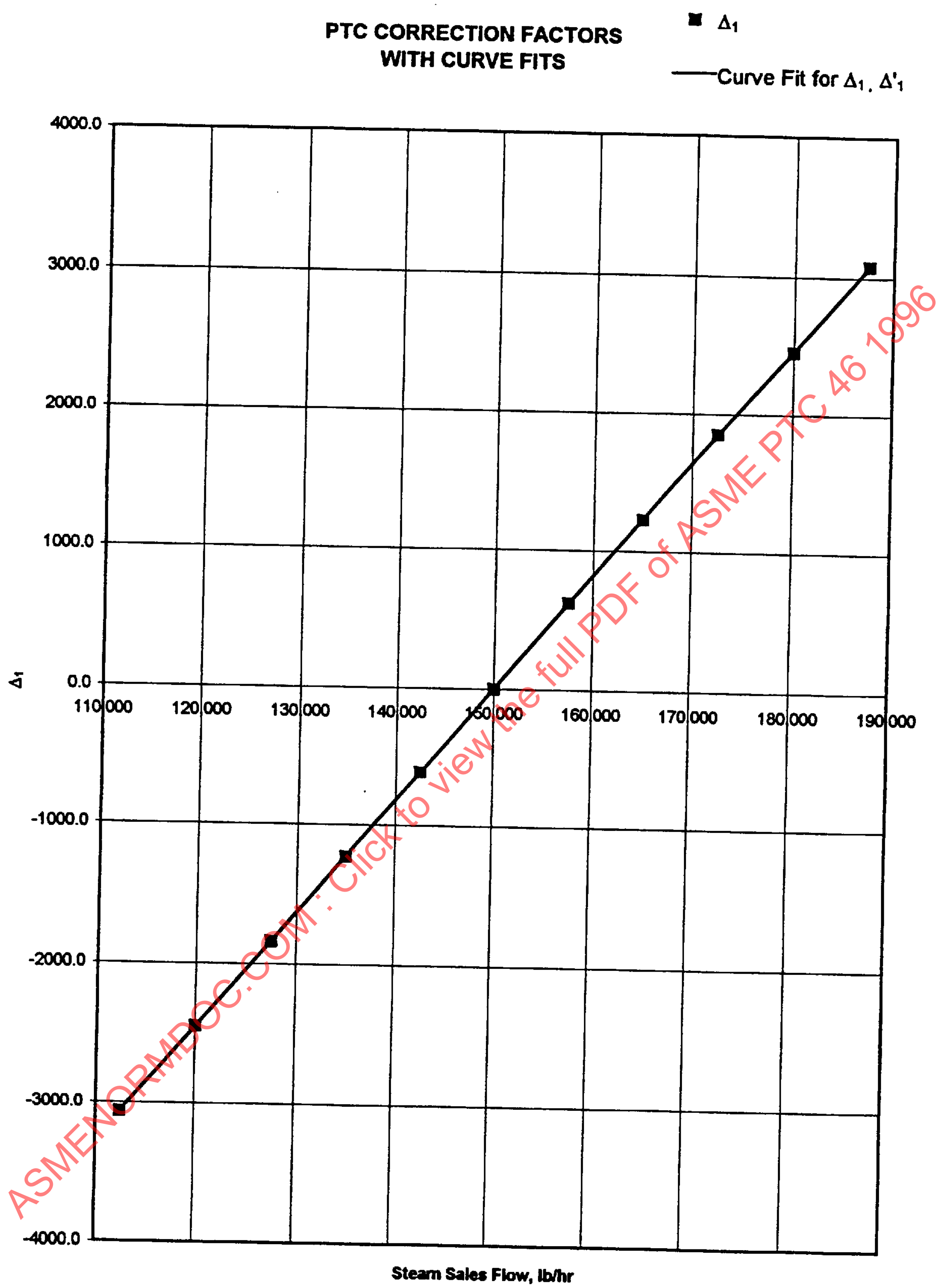
SS	SS^2	SS^3	Δ_1
112,500	1.26563E+10	1.42383E+15	-3060.000000
120,000	1.44000E+10	1.72800E+15	-2450.000000
127,500	1.62563E+10	2.07267E+15	-1840.000000
135,000	1.82250E+10	2.46038E+15	-1230.000000
142,500	2.03063E+10	2.89364E+15	-610.000000
150,000	2.25000E+10	3.37500E+15	0.000000
157,500	2.48063E+10	3.90698E+15	620.000000
165,000	2.72250E+10	4.49213E+15	1230.000000
172,500	2.97563E+10	5.13295E+15	1850.000000
180,000	3.24000E+10	5.83200E+15	2460.000000
187,500	3.51563E+10	6.59180E+15	3080.000000

Regression Results

	Intercept	C_1	C_2	C_3	R^2
Δ'_1	-11804.54545	0.072926185	5.51153E-08	-1.10507E-13	0.999998629

where:

$$\Delta'_1 = \text{Intercept} + C_1\,(SS) + C_2\,(SS)^2 + C_3\,(SS)^3$$


PTC CORRECTION FACTORS
WITH CURVE FITS
Δ1
Curve Fit for Δ1 , Δ'1
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
-2000.0
-3000.0
-4000.0
Δ1
110000
120000
130000
140000
150000
160000
170000
180000
190000
Steam Sales Flow, lb/hr

Performance Test Code Data Sheet
Parameter: Blowdown Flow
Design Point: 14,405 lb/hr

Design HR 7,966.0 Btu / kWh
Design Power 145,540.0 kW

Blowdown Flow lb/hr BD	Net Plant Power kW PWR	Power Corr. Variable kW Δ_3	Power Corr. Curve Fit kW Δ'_3
0	145,970.0	-430.0	-432.517483
2,400.8	145,910.0	-370.0	-363.916084
4,801.7	145,830.0	-290.0	-293.286713
7,202.5	145,760.0	-220.0	-221.083916
9,603.3	145,690.0	-150.0	-147.762238
12,004.2	145,610.0	-70.0	-73.776224
14,405.0	145,540.0	0.0	0.419580
16,805.8	145,470.0	70.0	74.370629
19,206.7	145,390.0	150.0	147.622378
21,607.5	145,320.0	220.0	219.720280
24,008.3	145,250.0	290.0	290.209790

Regression Analysis
Order: 3rd

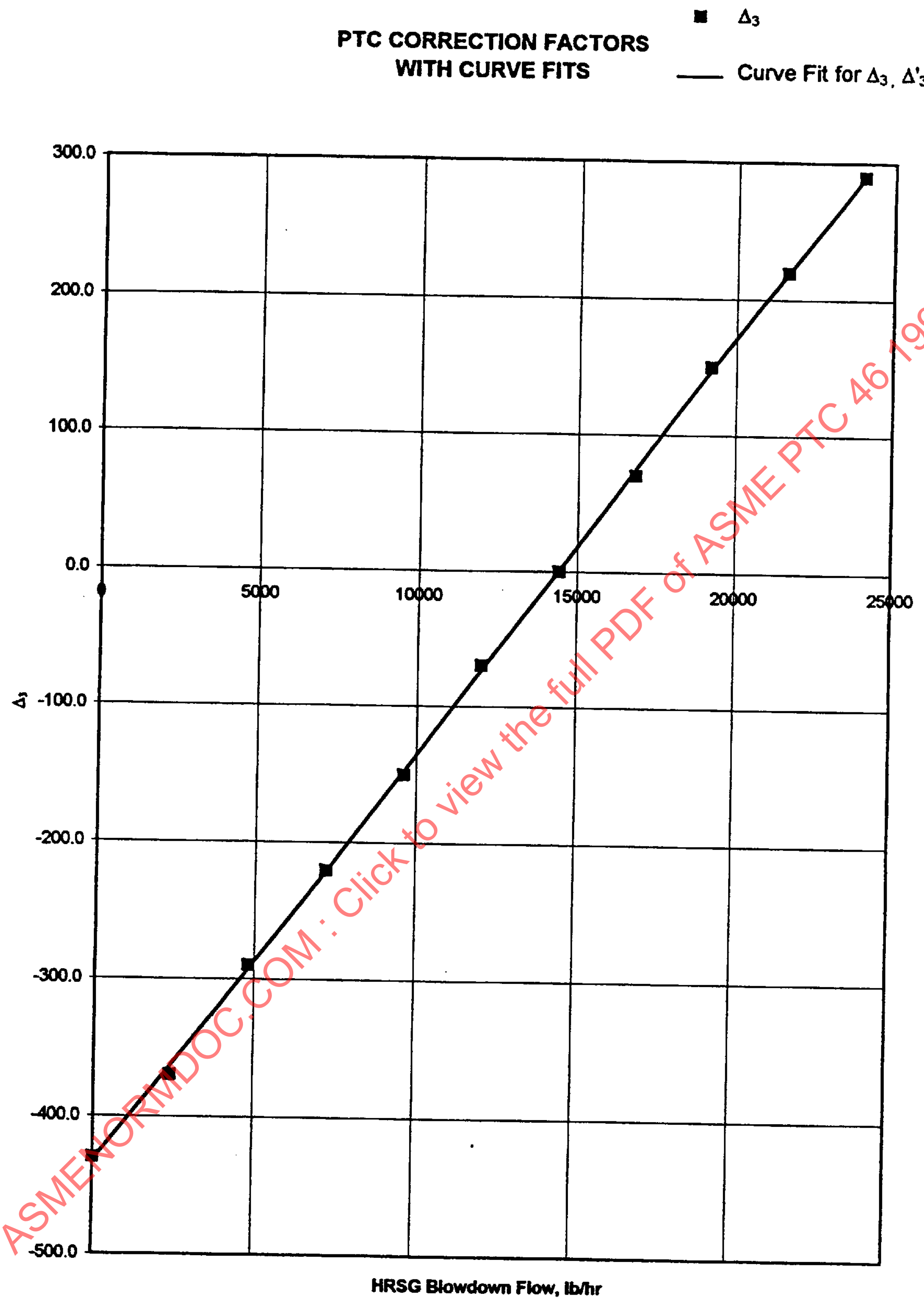
BD	BD^2	BD^3	Δ_3
0	0	0	-430.000000
2,400.8	5764000.694	13838405001	-370.000000
4,801.7	23056002.78	1.10707E+11	-290.000000
7,202.5	51876006.25	3.73637E+11	-220.000000
9,603.3	92224011.11	8.85658E+11	-150.000000
12,004.2	144100017.4	1.7298E+12	-70.000000
14,405.0	207504025	2.9891E+12	0.000000
16,805.8	282436034	4.74657E+12	70.000000
19,206.7	368896044.4	7.08526E+12	150.000000
21,607.5	466884056.3	1.00882E+13	220.000000
24,008.3	576400069.4	1.38384E+13	290.000000

Regression Results

	Intercept	C_1	C_2	C_3	R^2
Δ'_3	-432.5174825	0.028088538	2.15347E-07	-5.47444E-12	0.999829196

where:

$$\Delta'_3 = \text{Intercept} + C_1(BD) + C_2(BD)^2 + C_3(BD)^3$$


PTC CORRECTION FACTORS
WITH CURVE FITS
Δ_3
Curve Fit for Δ_3, Δ'_3
300.0
200.0
100.0
0.0
-100.0
-200.0
-300.0
-400.0
-500.0
Δ_3
5000
10000
15000
20000
25000
HRSG Blowdown Flow, lb/hr

Performance Test Code Data Sheet

Parameter: Make-up Water Temperature — Design HR 7,966.0 Btu / kWh

Design Point: 60 °F — Design Power 145,540.0 kW

Make-up Temperature	Net Plant Power	Power Corr. Variable	Power Corr. Curve Fit
°F	kW	kW	kW
MU	PWR	Δ_4	Δ'_4
40	145,500.0	40.0	41.048951
43	145,500.0	40.0	37.482517
46	145,510.0	30.0	32.727273
49	145,510.0	30.0	27.027972
52	145,520.0	20.0	20.629371
55	145,530.0	10.0	13.776224
58	145,530.0	10.0	6.713287
61	145,540.0	0.0	-0.314685
64	145,550.0	-10.0	-7.062937
67	145,550.0	-10.0	-13.286713
70	145,560.0	-20.0	-18.741259

Regression Analysis

Order: 3rd

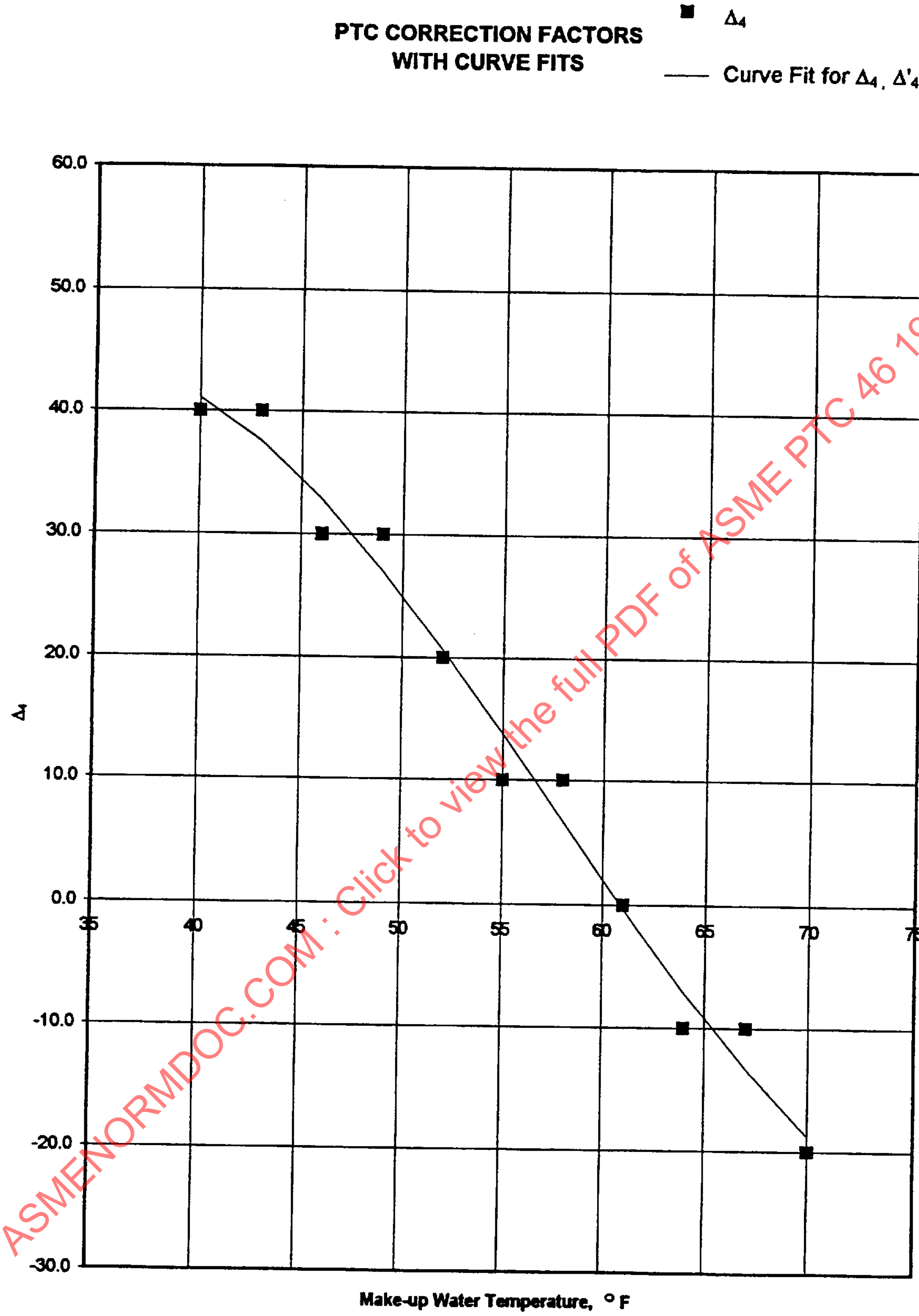
MU	MU^2	MU^3	Δ_4
40	1600	64000	40.000000
43	1849	79507	40.000000
46	2116	97336	30.000000
49	2401	117649	30.000000
52	2704	140608	20.000000
55	3025	166375	10.000000
58	3364	195112	10.000000
61	3721	226981	0.000000
64	4096	262144	-10.000000
67	4489	300763	-10.000000
70	4900	343000	-20.000000

Regression Results

	Intercept	C_1	C_2	C_3	R^2
Δ'_4	-144.5333679	12.65993266	-0.260942761	0.001510835	0.984093067

where:

$$\Delta'_4 = \text{Intercept} + C_1(MU) + C_2(MU)^2 + C_3(MU)^3$$


PTC CORRECTION FACTORS
WITH CURVE FITS
Δ_4
Curve Fit for Δ_4, Δ'_4
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
-20.0
-30.0
Δ_4
35
40
45
50
55
60
65
70
75
Make-up Water Temperature, °F

Performance Test Code Data Sheet
Parameter: Condenser Cooling H_2O Temp. Design HR 7,966.0 Btu / kWh
Design Point: 60 °F Design Power 145,540.0 kW

Cond. Cooling Temperature	Net Plant Power	Power Corr. Variable	Power Corr. Curve Fit
°F	kW	kW	kW
CCT	PWR	Δ_{5s}	Δ'_{5s}
50	145,850.0	-310.0	-312.027972
53	145,830.0	-290.0	-286.083916
56	145,780.0	-240.0	-239.743590
59	145,710.0	-170.0	-173.461538
62	145,630.0	-90.0	-87.692308
65	145,520.0	20.0	17.109557
68	145,400.0	140.0	140.489510
71	145,260.0	280.0	281.993007
74	145,100.0	440.0	441.165501
77	144,920.0	620.0	617.552448
80	144,730.0	810.0	810.699301

Regression Analysis
Order: 3rd

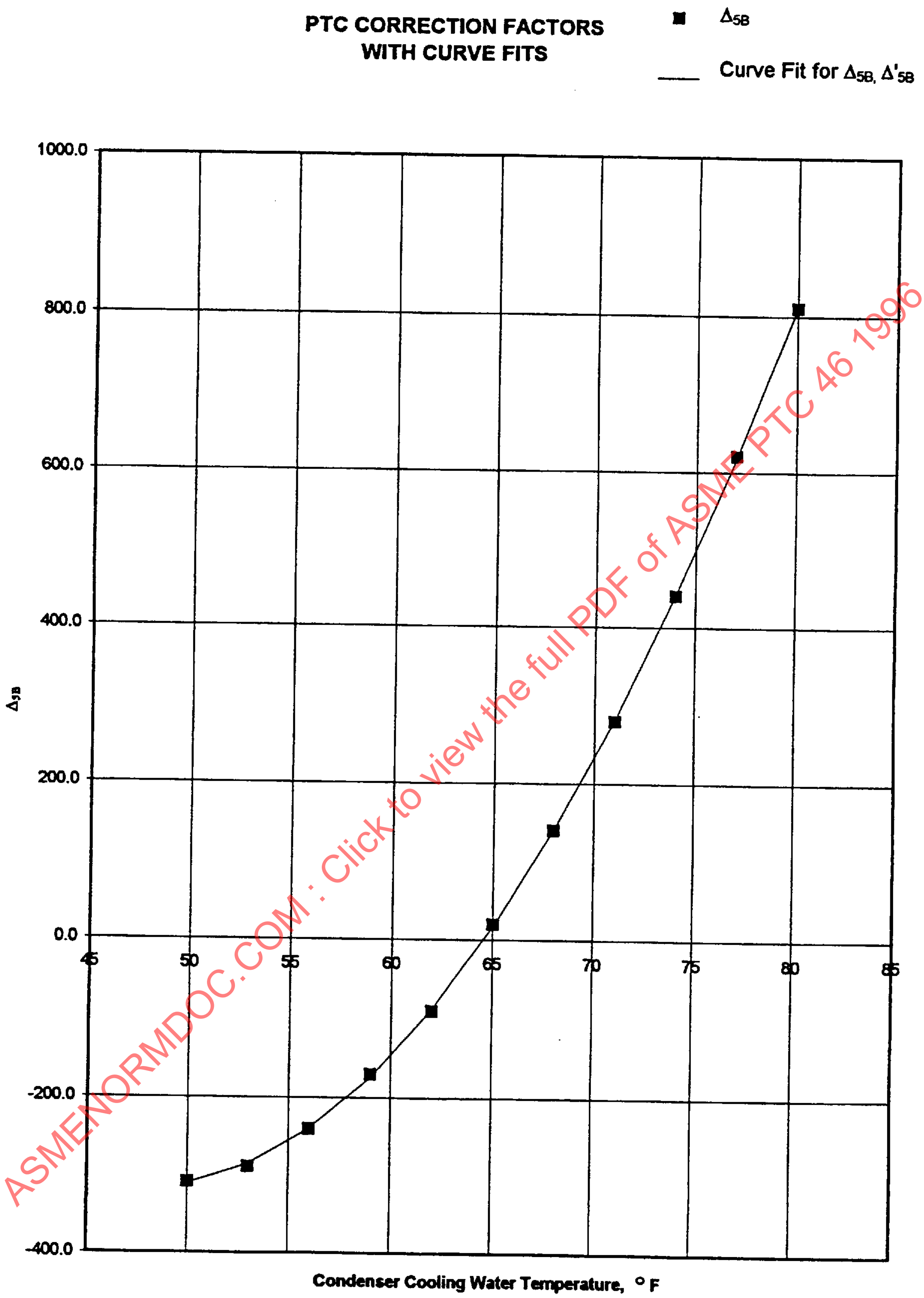
CCT	CCT^2	CCT^3	Δ_{5s}
50	2500	125000	-310.000000
53	2809	148877	-290.000000
56	3136	175616	-240.000000
59	3481	205379	-170.000000
62	3844	238328	-90.000000
65	4225	274625	20.000000
68	4624	314432	140.000000
71	5041	357911	280.000000
74	5476	405224	440.000000
77	5929	456533	620.000000
80	6400	512000	810.000000

Regression Results

	Intercept	C_1	C_2	C_3	R^2
Δ'_{5s}	2674.741432	-131.6835017	1.579254079	-0.002805836	0.999961182

where:

$$\Delta'_{5s} = \text{Intercept} + C_1\,(CCT) + C_2\,(CCT)^2 + C_3\,(CCT)^3$$


PTC CORRECTION FACTORS
WITH CURVE FITS
Δ_{5B}
Curve Fit for Δ_{5B}, Δ'_{5B}
1000.0
800.0
600.0
400.0
200.0
0.0
-200.0
-400.0
Δ_{5B}
45
50
55
60
65
70
75
80
85
Condenser Cooling Water Temperature, °F

C.5 Sample Calculation Data

The measured test data for the sample calculation is:

Ambient air temperature	80°F (26.7°C)
Relative humidity	70%
Ambient site pressure	13.8 psia (0.95 bara)
Net power output	125,910 kW
Gross gas turbine power (for checking)	100,715 kW
Gross steam turbine power (for checking)	29,329 kW
Plant auxiliary power (for checking)	3,692 kW
Transformer loss (estimated)	442 kW
Fuel consumption	47,974 lb/hr (6.04 kg/s)
Steam flow to process	165,000 lb/hr (20.8 kg/s)
Steam conditions to process	150 psig/373°F (10.34 barg/189°C)
Condensate return flow	123,750 lb/hr (15.6 kg/s)
Feedwater make-up temperature	70°F (21.1°C)
Cooling water inlet temperature	70°F (21.1°C)
HRSG blowdown setting	0 lb/hr (0 kg/s)

Fuel sample analysis shows fuel to have 21,496 Btu/lb (50,000 kJ/kg) LHV and 23,839 Btu/lb (55450 kJ/kg) HHV. For reference, fuel energy consumed and heat rate value can be multiplied by the HHV/LHV ration and the correction factor using the above equation to convert to HHV values associated with the test conditions. Finally, using the values from the sample test data above, the resulting additive and multiplicative correction values are calculated based on the curve fit equations presented previously in the data sheets. These correction values are then inserted into the appropriate equations to correct the power and the heat rate to the design values. The boundary value inputs, the resulting correction values, the corrected power, the corrected heat rate, and the variance of the corrected power and heat rate from the design point are all presented in the spreadsheet below.

PTC PERFORMANCE TEST SPREADSHEET

Equation for Corrected Net Plant Power
PTC Section 5

$$P_{corr} = (P_{meas} + \Delta'_1 + \Delta'_3 + \Delta'_4 + \Delta'_{58})\,\alpha'_1\,\alpha'_2\,\alpha'_3$$

Equation for Corrected Net Plant Heat Rate
PTC Section 5

$$HR_{corr} = \frac{Q_{meas}\,(f'_1\,f'_2\,f'_3\,f'_5)}{(P_{meas} + \Delta'_1 + \Delta'_3 + \Delta'_4 + \Delta'_{58})}$$

Design Plant Power: 145,540.0 kW
Design Plant Heat Rate: 7,966.0 Btu / kWh

Boundary Value Inputs (measured)	Units	Value
Ambient Temperature	°F	80.0
Ambient Pressure	psia	13.800
Ambient Relative Humidity	%	70.0
Steam Sales Flow	lb/hr	165,000
Blowdown Flow	lb/hr	0.0
Make-up Water Temperature	°F	70.0
Condenser Cooling Water Temperature	°F	70.0
Measured Net Plant Power:	kW	125,910
Measured Fuel Flow	lb/hr	47,974
Assumed Fuel LHV Value	Btu/lb	21,515
Fuel Analysis LHV Value	Btu/lb	21,496

	Curve Fit Equation Constants				Curve Fit Eq.
Power Correction Variables	Intercept	C_1	C_2	C_3	Result
α_1'	0.943300812	-0.000332432	2.00891E-05	3.59239E-08	1.063669
α_2'	5.641320426	-0.687385781	0.034619369	-0.000635263	1.078791
α_3'	0.999346728	8.89891E-06	5.42992E-08	-3.46311E-10	1.000117
Δ'_1	-11804.54545	0.072926185	5.51153E-08	-1.10507E-13	1232.377622
Δ'_3	-432.5174825	0.028088538	2.15347E-07	-5.47444E-12	-432.517483
Δ'_4	-144.5333679	12.65993266	-0.260942761	0.001510835	-18.741259
Δ'_{58}	2674.741432	-131.6835017	1.579254079	-0.002805836	232.839506

	Curve Fit Equation Constants				Curve Fit Eq.
Heat Rate Correction Variables	Intercept	C_1	C_2	C_3	Result
f_1'	0.955794514	0.001705298	-1.96625E-05	4.90452E-08	0.991490
f_2'	0.342759195	0.094852034	-0.004698993	8.76304E-05	0.987140
f_3'	1.002281715	-3.83348E-05	5.78617E-09	-1.08789E-11	0.999623
f_5'	0.000000	0.99912	0.000000	0.000000	0.999117

Corrected Output	Units	Value
Corrected Net Plant Power:	kW	145,659.4
Corrected Net Plant Heat Rate:	Btu / kWh	7949.2
Guarantee Net Plant Power	kW	145,540.0
Guarantee Net Plant Heat Rate	Btu / kWh	7966.0
Net Plant Power Variance:	kW	119.4
Net Plant Heat Rate Variance:	Btu / kWh	-16.8

C.6 Discussion of Results

The corrected power and heat rate are better than design.

APPENDIX D — REPRESENTATION OF CORRECTION FOR DIFFERENT HEAT SINK TEMPERATURE THAN GAS TURBINE AIR INLET TEMPERATURE (Δ_5 or ω_5) IF NECESSARY, FOR A TYPICAL COMBINED CYCLE PLANT

(This Appendix is not a part of ASME PTC 46-1996.)

The calculation of Appendix A assumed that the inlet air conditions at the gas turbine(s) compressor inlet(s) were identical to those at the cooling tower(s) air inlet(s), which is allowable per Section 5. See para. 5.5.1.

For a combined cycle power plant, for which differences in dry bulb temperatures at each location should be considered, Figs. D.1 and D.2 show typical correction curves α_i and Δ_{5A}, respectively. The intent is to show how Δ_{5A} can be represented.

Figure D.1 is based on the temperature measured at the inlet to the gas turbine compressor. Figure D.2 is the Δ_{5A} correction for the difference in temperature between the compressor inlet and the cooling tower inlet.

The plant is a typical 150 MW combined cycle. Note that, at 59°F gas turbine compressor inlet temperature, the correction to plant power is approximately 20 kW per degree difference between the gas turbine compressor inlet and the cooling tower inlet — a rather small amount considering the built-in errors in measurement of cooling tower air inlet.

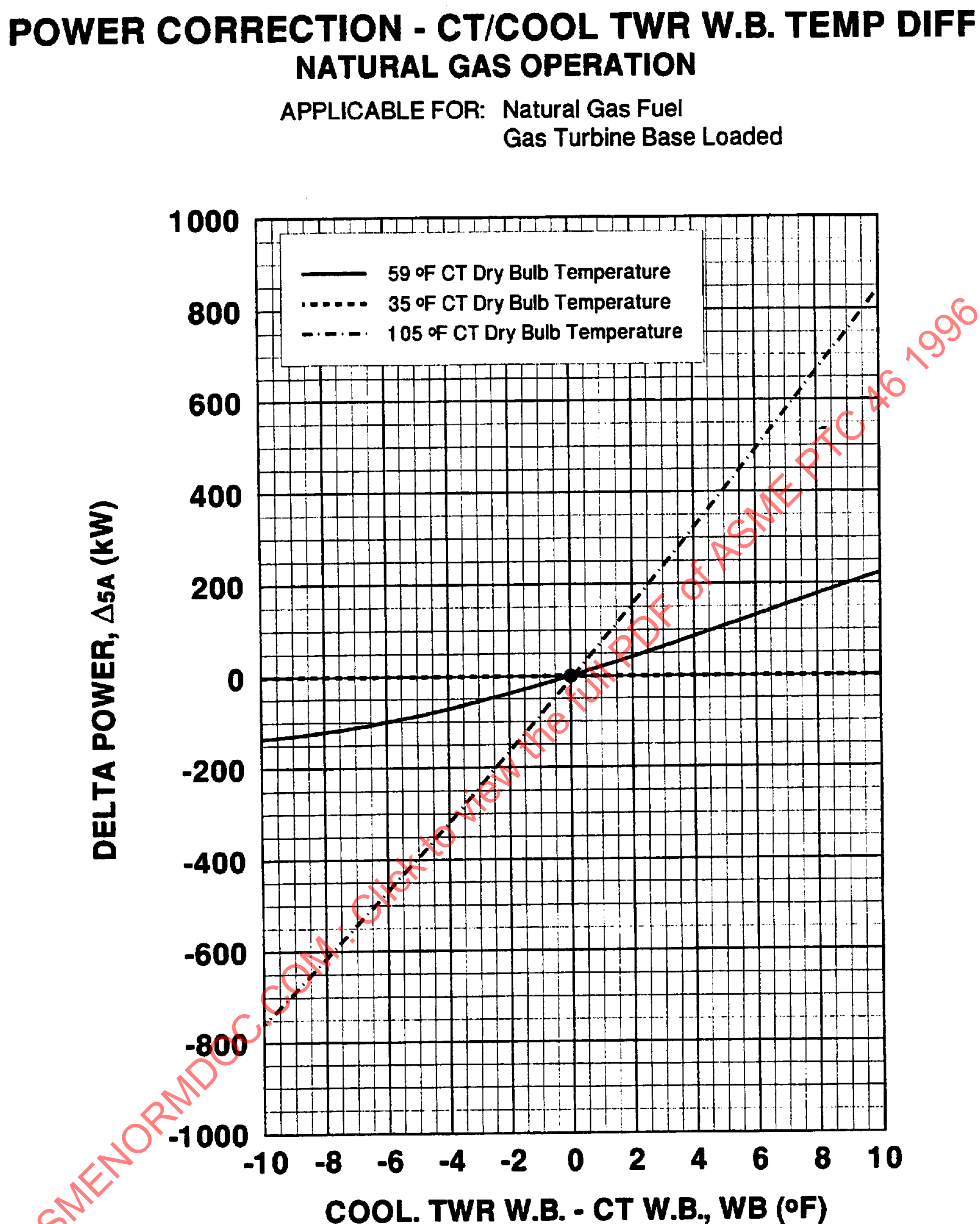


FIG. D.1 POWER CORRECTION — CT/COOL TWR W.B. TEMPERATURE DIFFERENCE

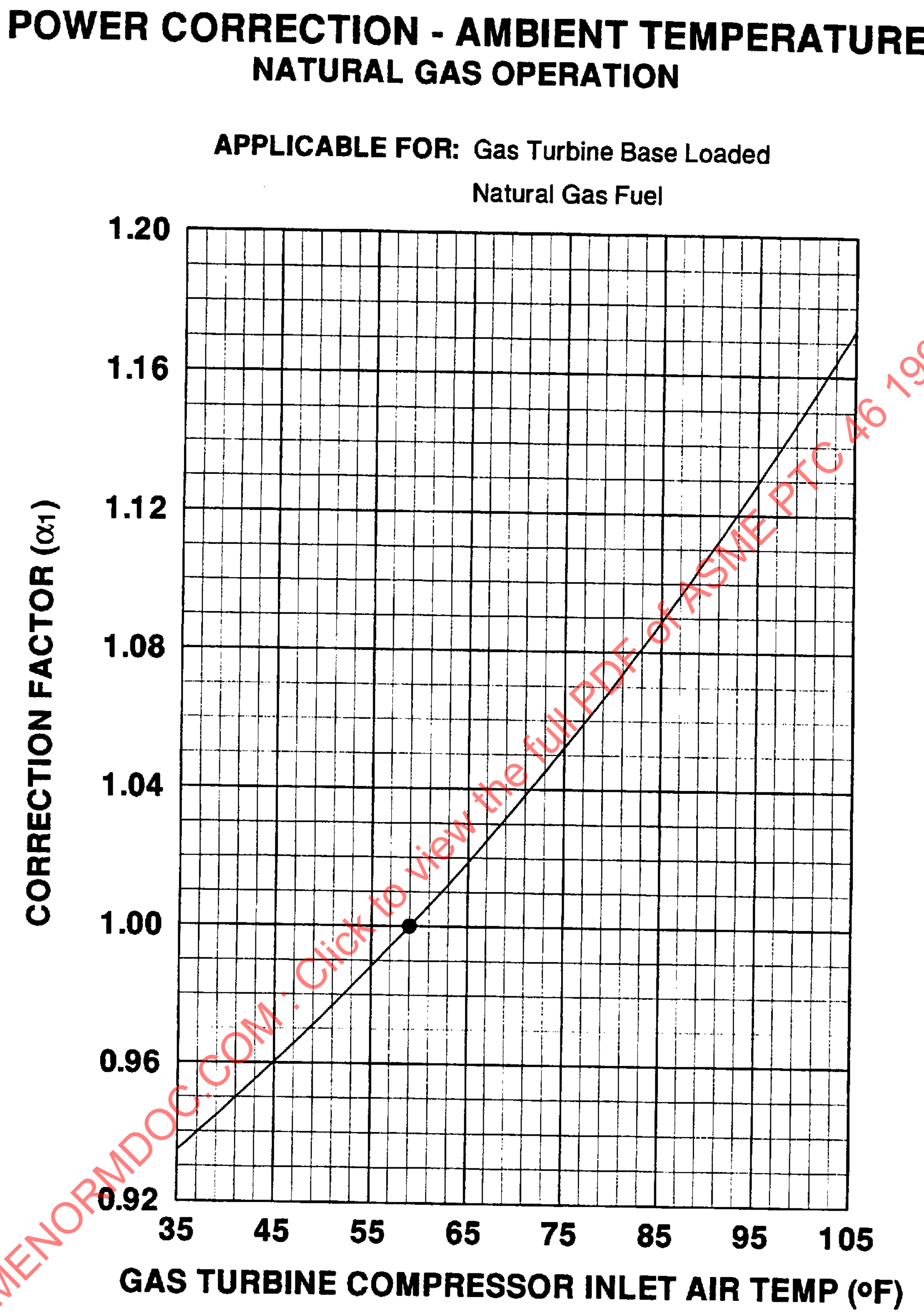


FIG. D.2 POWER CORRECTION — AMBIENT TEMPERATURE

APPENDIX E — SAMPLE CALCULATIONS STEAM POWER COGENERATION PLANT HEAT SINK: RIVER COOLING WATER FLOW WITHIN TEST BOUNDARY TEST GOAL: TWO TEST RUNS ARE MADE WITH DIFFERENT GOALS TEST RUN 1: SPECIFIED CORRECTED POWER — FIRE TO DESIRED CORRECTED POWER TEST RUN 2: SPECIFIED DISPOSITION BY FIRING TO DESIRED THROTTLE FLOW (POWER FLOATS)

(This Appendix is not a part of ASME PTC 46-1996.)

CYCLE DESCRIPTION

The PTC 46 Example Steam Plant is a simple non-reheat condensing steam turbine-based plant with three feedwater heaters and an uncontrolled extraction for process steam. Process steam condensate is returned at low temperature to the plant water treatment system. The steam generator is a circulating fluidized bed unit burning medium sulfur eastern coal with sulfur emissions controlled by limestone fed to the fluidized bed. The steam generator is equipped with a tubular air heater to preheat both primary and secondary air. The plant is equipped with a bag house to control particulate emissions. The condenser is cooled with circulating water drawn from a river. Figure E.1 is a diagram of this plant.

Nominal throttle conditions for the steam turbine are 885.0 psig and 900.0°F (6203 kPa and 482.2°C). The steam turbine is rated for continuous operation at 5% over pressure. The generator is rated at 101.2 MW to enable turbine operation at nominal conditions with no extractions. Nominal steam generator exit conditions are 931.0 psig, 903.0°F (6520 kPa and 483.9°C) and 800,000 lb/hr (100.798 kg/sec) steam flow. Maximum continuous rating of the steam generator is 975.0 psig (6824 kPa), 910.0°F (487.8°C) and 840,000 lb/hr (105.838 kg/sec). Main steam temperature to the steam turbine throttle is controlled by mixing spray flow with steam exiting the steam generator.

TEST BOUNDARY DESCRIPTION

The entire plant is located within the test boundary. Air enters the steam generators at the forced draft fan inlet. Cooling water from the river crosses the boundary. Net electrical power is delivered from the high side of the step-up transformer. Net power measurement is taken on the low side of the step-up transformer with allowance for transformer losses. Gross steam turbine power is measured at the generator terminals. Plant auxiliary power is calculated from the difference between the measured gross and net power. Process steam is measured at the plant boundary with a calibrated flow measuring section.

There are two sets of sample calculations that will be demonstrated with this example system. The first one, Test 1, is for unit heat rate at specified corrected net output. (13,115 Btu/kWh (13,837 kJ/kWh) at 83,500 kW net corrected output at the

TABLE E.1

Plant Parameter	Reference U.S. Customary Units	Reference SI Units
Ambient air temperature	80.0°F	26.7°C
Relative humidity	60%	60%
River water temperature	75.0°F	23.9°C
Steam generator blowdown	1%	
Makeup water temperature	75.0°F	23.9°C
Process condensate temperature	75.0°F	23.9°C
Process steam flow	100,000 lb/hr	12.5998 kg/sec
Process steam pressure	150.0 psig	1136 kPa
Process steam temperature	350.0°F	176.7°C
Process condensate return	100%	
Net plant output	83.5 MW	83.5 MW
Net plant heat rate	13,115 Btu/kWh	13,837 kJ/kWh

TABLE E.2

Conditional Auxiliary Power Budget	Connected Load (kW)	Duty Factor	Reference (kW)
Coal unloading	300	0.1	30
Ash transfer	100	0.2	20
Water treatment	430	0.7	301
Air compressor	600	0.5	300
HVAC	300	0.5	150
Lighting	300	0.6	180

conditions listed below.) The second sample calculation, Test 2, is for the plant tested in a fixed disposition; that is with the steam generator at maximum continuous rating of 840,000 lb/hr (105.838 kg/sec). The other reference conditions are listed in Table E.2. The net plant output and heat rate base reference conditions for Test 2 are 88,000 kW and 13,040 Btu/kWh (13,758 kJ/kWh).

Table E.2 gives an auxiliary power budget for equipment that is required to support continuous plant operation, but may not be operating at the long term expected duty factor during the performance test. These auxiliaries are to be monitored during the test and corrected to reference for purposes of comparing to guarantee.

The step-up transformer loss is 0.99% of plant net output delivered to the low side of the transformer. At the reference condition of 83500 kW net plant output (high tension side) the transformer loss is 835 kW.

The reference coal and sorbent analysis and as-tested analysis is given in Table E.3: For convenience in demonstrating the sample calculation and correction procedure, it will be assumed that the steam generator as-tested coal analysis, sorbent analysis and residue split and residue analysis are the same for each test run.

TEST 1 SAMPLE CALCULATIONS

The test strategy to demonstrate plant performance at the base reference condition of 83,500 kW corrected is to perform three test runs that span the guarantee condition. The corrected heat rate from these test runs is plotted versus corrected output or curve fit with and the test corrected heat rate read off the curve entered at the reference corrected output.

The correction procedure is designed to fit the above strategy in plant performance determination. The correction procedure produces a corrected plant operating line of heat rate versus output at the plant base reference conditions; that is the corrected operating line characterizes plant performance at reference conditions of 100,000 lb/hr (12.5998 kg/sec) of process steam, 1% boiler blowdown, 0.85 power factor, 80.0°F (26.7°C) ambient temperature and 75.0°F (23.9°C) river water temperature while

TABLE E.3

Coal Ultimate Analysis	Reference	As Tested
Carbon	69.7%	70.91%
Sulfur	1.49%	1.23%
Hydrogen	4.31%	4.40%
Moisture	5.43%	7.3%
Nitrogen	1.38%	1.34%
Oxygen	4.05%	4.61%
Ash	13.64%	10.23%
Higher heating value, Btu/lb (kJ/kg)	12,310 (28,633)	12,561 (29,217)
Sorbent Analysis	**Reference**	**As Tested**
$CaCO_3$	95%	94%
$Ca(OH)_2$	0%	0%
$MgCO_3$	4%	4.2%
Coal Ultimate Analysis	**Reference**	**As Tested**
$Mg(OH)_2$	0%	0%
H_2O	0.03%	0.03%
Inerts	0.97%	1.77%

burning the reference coal and utilizing the reference sorbent.

The following correction curves are required to correct plant performance:

- Fig E-2, Output Correction for Process Steam Flow
- Fig E-3, Output Correction for Power Factor
- Fig E-4, Output Correction for Blowdown Flow
- Fig.E-5, Output Correction for Cooling Water Temperature
- Fig E-6, Heat Consumption Correction for Process Steam Flow
- Fig E.7, Heat Consumption Correction for Blowdown Flow

The as-tested and corrected steam generator fuel energy efficiency is to be calculated according to PTC 4 using the energy balance method. The corrected energy supplied by the steam generator to the working fluid is divided by corrected efficiency to determine the corrected fuel energy input.

Table E.4 summarizes the averaged measured data of the three test runs.

Corrected Output

Corrected output for each test run is calculated using Eq. 5.3.3, repeated below. Terms in the equation are described in Section 5 of this Code.

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta 2 + \ell\ \Delta_7)$$

A summary of the corrections for the test runs is given in Table E.5.

The Δ_1 term (output additive correction for thermal efflux) is found by entering Fig. E.2 at process steam flow and determining the percentage difference in output. The percentage difference in output is multiplied by the measured gross output to give the value of Δ_1 in kW.

The Δ_2 term (output additive correction for power factor) is found by entering Fig. E.3 at the as-tested power factor and reading off the percentage difference in output. The percentage difference in output is multiplied by the as-tested gross output to give the value of Δ_2.

The Δ_3 term (output additive correction for blowdown) is found by entering Fig. E.4 at the as-tested percent blowdown and reading off the percentage difference in output. The percentage difference in output is multiplied by the as-measured gross output to give the value of Δ_3.

The Δ_{5B} term (output additive correction for cooling water temperature) is found by entering Fig. E.5 at the as-tested cooling water temperature and steam turbine throttle flow and reading off the percentage difference in output. The percentage difference in

TABLE E.4

	Test Run 1A	Test Run 1B	Test Run 1C
Turbine generator gross output, kW	92,277	93,613	94,620
Power factor	0.95	0.94	0.9
Net plant output, kW (low side SU trans)	83,540	84,526	85,391
Feedwater flow, lb/hr (kg/sec)	786,290 (99.0709)	803,823 (101.280)	817,356 (102.985)
Feedwater enthalpy, Btu/lb (kJ/kg)	256.3 (596.2)	257.1 (598.0)	257.9 (599.9)
Steam generator blowdown, %	0.80%	0.006	0.009
Blowdown enthalpy, Btu/lb (kJ/kg)	538.1 (1,252)	538.1 (1,252)	538.1 (1,252)
Main steam flow, lb/hr (kg/sec)	780,000 (98,2784)	799,000 (100.672)	810,000 (102.058)
Main steam enthalpy, SG exit Btu/lb (kJ/kg)	1,452.16 (3,777.72)	1,452.16 (3,377.72)	1,452.16 (3,377.72)
Ambient temperature, °F (°C)	70.0 (21.1)	74.0 (23.3)	80.0 (26.7)
River water temperature, °F (°C)	65.0 (18.3)	68.0 (20.0)	70.0 (21.1)
Process steam flow, lb/hr (kg/sec)	90,000 (11.340)	102,000 (12.8518)	105,000 (13.2298)
Conditional Auxiliary Power Usage (kW), Test Run Averages			
Coal unloading	0	300	30
Ash transfer	80	10	20
Water treatment	200	300	0
Air compressor	200	100	600
HVAC	50	70	200
Lighting	10	120	200
Total	540	900	1050

TABLE E.5

Output Corrections, kW	Test 1A	Test 1B	Test 1C
Δ_1, Process steam	−530.1	144.1	256.0
Δ_2, Power factor	−187.6	−172.9	−100.5
Δ_3, Blowdown	11.7	23.2	6.3
Δ_{5B}, Cooling water temperature	−87.2	−77.3	−74.8
Δ_6, Conditional auxiliary power correction	−441	−81	69
Step up transformer	−827	−836.8	−845.4
Net corrected output, kW	81478.8	83525.3	84701.6

output is multiplied by the as-measured gross output to give the value of Δ_{5B}.

The Δ_6 term is determined by subtracting the as-tested power usage of the conditional auxiliaries from the conditional auxiliary budget allowance.

Corrected Fuel Energy Input and Corrected Heat Rate

The corrected fuel energy (Q_{corr}) is calculated according to the numerator of eq. 5.3.4, where

$$Q_{corr} = Q_{meas} + \omega_1 + \omega_3 + \omega_7$$

Q_{meas} is the steam generator tested output (Q_{ro}) as defined in PTC 4, including blowdown energy, divided by corrected fuel energy efficiency calculated per PTC 4. Q_{meas} in this sense represents the test fuel energy consumption corrected to reference fuel and reference ambient temperature for the steam generator. The terms ω_1, ω_3, and ω_7 correct the fuel energy consumed to reference thermal efflux, reference blowdown and reference operating conditions if required. The ω terms are described in Table 5.1 in Section 5 of this Code.

Using relationships and terms discussed above,

$$Q_{meas} = Q_{ro}/\eta_{\text{fuel corrected}}$$

where

Q_{ro} = steam generator tested output as defined in PTC 4, including blowdown energy

TABLE E.6

	Test Run 1A	Test Run 1B	Test Run 1C
As-tested heat added to water-steam, 10^6 Btu/hr (10^6 kJ/h)	934.52 (985.97)	956.18 (1008.83)	969.36 (1022.73)
ω_1, Process steam, 10^6 Btu/hr (10^6 kJ/h)	0.526 (0.555)	−0.180 (−0.19)	−0.300 (−0.32)
ω_3, Blowdown, 10^6 Btu/hr (10^6 kJ/h)	0.021 (0.022)	0.864 (0.912)	0.193 (0.203)
Corrected heat added by steam generator, 10^6 Btu/hr (10^6 kJ/h)	935.07 (986.55)	956.87 (1009.56)	969.25 (1022.62)

$\eta_{\text{fuel corrected}}$ = steam generator corrected fuel energy efficiency calculated per PTC 4

The ω terms in this sample calculations procedure are based on a steam generator base reference efficiency of 100%. The ω corrections terms used here need to be multiplied by the ratio of reference steam generator efficiency to corrected steam generator fuel energy efficiency, i.e., $1/\eta_{\text{fuel corrected}}$.

For this example correction calculation the numerator of Eq. 5.3.4 can be expressed as

$$Q_{corr} = \frac{(Q_{ro} + \omega_1 + \omega_3 + \omega_7)}{\eta_{\text{fuel corrected}}}$$

Corrected heat rate is calculated from Eq. 5.3.4

$$HR_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_3 + \omega_7)}{(P_{meas} + \Delta_1 + \Delta_3 + \ell\ \Delta_7)} = \frac{Q_{corr}}{P_{corr}}$$

The as-tested energy added to the steam-water by the steam generator (steam generator output) is equal to the main steam flow times the enthalpy at steam generator exit plus the blowdown flow times the enthalpy of saturated water at steam generator drum pressure less feedwater flow times feedwater enthalpy. The values for the three test runs and the corrections are given in Table E.6.

The ω_1 term (heat added by steam generator additive correction for thermal efflux) is found by entering Fig. E.6 at process steam flow and determining the percentage difference in energy added. The percentage difference in energy added is multiplied by the as-tested heat added by the steam generator to give the value of ω_1 in 10^6 Btu/hr.

The ω_3 term (heat added by steam generator additive correction for blowdown) is found by entering Fig. E.7 at the as-tested percent blowdown and reading off the percentage difference in energy added. The percentage difference in energy added is multiplied by the as-tested heat added by the steam generator to give the value of ω_3 in 10^6 Btu/hr.

The design air split between primary and secondary air heater is 50% to each.

The as-tested measured parameters and analysis information is entered in the appropriate inputs of the PTC 4 spreadsheet. The as-tested steam generator fuel energy efficiency is calculated as 87.27%. (The PTC 4 calculations were modified to include blowdown steam energy as an output from the steam generator so that the modified steam generator output can be divided by fuel energy efficiency to determine fuel energy input.) The inputs and results for the as-tested steam generator efficiency are given in pages 130–132.

The ground rules for determining corrected steam generator efficiency must be agreed to by the parties to the test. For this test, since the coal and limestone analysis was not far from design, it was agreed that corrected steam generator efficiency be determined from PTC 4 calculations using:

- reference coal analysis
- reference sorbent analysis
- as-tested percent excess air
- as-tested calcium/sulfur molar ratio
- as-tested fan temperature rise for primary air, secondary air, and blower
- as-tested percent carbon burn-up
- as-tested ash split
- as-tested bed and baghouse CO_2 percentage
- as-tested primary and secondary air heater effectiveness
- as-tested sulfur capture

In addition to the as-tested fuel energy efficiency, the as-tested parameters in Table E.7 were determined. They are to be used in translating the as-tested results to corrected results.

TABLE E.7

Percent excess air	21.92%
Percent carbon burn-up	97.81%
Calcium-sulfur molar ratio	2.878
Calcination fraction of sorbent	.92
Air heater effectiveness	
Primary	48.23%
Secondary	51.84%
Fan temperature rise for primary and secondary air	
Primary	24.0°F (13.3°C)
Secondary	20.0°F (11.1°C)

TABLE E.8

Ambient temperature	70.0°F (21.1°C)
Air heater primary air inlet temperature	94.0°F (34.4°C)
Air heater secondary air inlet temperature	90.0°F (32.2°C)
Air heater flue gas inlet temperature	559.3°F (292.9°C)
Primary air heater flue gas exit temperature	360.0°F (182.2°C)
Secondary air heater flue gas exit temperature	316.0°F (157.8°C)

The as-tested ash split and ash analysis is as follows:

Ash split	Bed Ash	41.9%
	Baghouse Ash	58.1%
CO_2 in	Bed Ash	1%
	Baghouse Ash	2%
% Carbon in	Bed Ash	0%
	Baghouse Ash	12.41%

Ambient temperature and airheater temperatures are given in Table E.8.

The as-tested primary air heater effectiveness (η_p) is:

$$\eta_p = \frac{559.3 - 360}{559.3 - 94} \times 100 = 42.83\%$$

The as-tested secondary air heater effectiveness (η_s) is:

$$\eta_s = \frac{559.3 - 316}{559.3 - 90} = 51.84$$

There was no leakage around the air heater. The flue gas exit temperature from the primary (TGP_{corr}) and secondary (TGS_{corr}) air heaters, at reference condition, is calculated as follows:

$$TGP_{corr} = 559.3 - \frac{\eta_p}{100} \cdot (559.3 - 104)$$
$$= 364.3°F\ (184.6°C)$$

$$TGS_{corr} = 559.3 - \frac{\eta_s}{100} \cdot (559.3 - 100)$$
$$= 321.2°F\ (160.7°C)$$

Since the as-tested flow split between the primary and secondary was 50-50, the corrected flue gas exit temperature (TG_{corr}) is the average of the primary and secondary air heater flue gas exit temperature.

$$TG_{corr} = 342.8°F\ (172.7°C)$$

The appropriate inputs are made to the PTC 4 spreadsheet and corrected steam generator efficiency is calculated to be 87.37%. The inputs and outputs of the PTC 4 spreadsheet are given on page 00–00. The corrected heat added by the steam generator is divided by the corrected efficiency divided by 100 and the resulting fuel energy use of each test run is given in Table E.9. The corrected output and corrected heat rate results of each test run are also given.

Corrected heat rate is plotted in Fig. E.8. The corrected heat rate at 83,500 kW corrected, per Fig. E.8 is 13,112 Btu/kWh (13,834 kJ/kWh).

TEST RUN 2, DEFINED DISPOSITION TEST

Sample Calculations

The purpose of this test is to determine net plant output and heat rate at a defined disposition — in this case at steam generator MCR output of 840,000 lb/hr (105.838 kg/s) steam.

The reference condition is given in Table E.10.

It is required that this test be run at over-pressure rating of the steam turbine to pass the throttle flow at a throttle valve position that will still give good regulation. The correction curves presented for Test 1 are not valid since this test is run at over-pressure. However, for this example, the curves will be used here to demonstrate the correction required. Also, additional correction curves are required in this instance since it may not be possible to conduct the test at the exact steam generator steam flow, pressure, and temperature conditions of reference. The additional correction curves required would be those that correct for steam generator exit conditions different from reference, namely correction for steam flow, pressure, and temperatures different from reference. These correction curves are given in Figs. E.9 through E.14. These correction curves would only

TABLE E.9

	Test Run 1A	Test Run 1B	Test Run 1C
Corrected fuel energy, 10^6 Btu/hr (10^6 kJ/h)	1,070.25 (1129.18)	1,095.19 (1155.49)	1,109.37 (1170.45)
Corrected output, kW	81,478.8	83,525.3	84,701.6
Corrected heat rate, Btu/kWh (kJ/kWh)	13,135.3 (13,858.5)	13,112.1 (13,834.1)	13,097.3 (13,818.4)

TABLE E.10
TEST 2 REFERENCE CONDITIONS
Defined Disposition Test

Plant Parameter	Reference
Ambient air temperature	80.0°F (26.7°C)
Relative humidity	60%
River water temperature	75.0°F (23.9°C)
Steam generator blowdown	1%
Makeup water temperature	75.0°F (23.9°C)
Process condensate temperature °F (°C)	75.0°F (23.9°C)
Process steam flow, lb/hr (kg/s)	100,000 (12.5998)
Process steam pressure, psig (kPa)	150.0 (1,136)
Process steam temperature °F (°C)	350.0°F (176.7°C)
Process condensate return	100%
Steam generator	
Steam flow lb/hr (kg/s)	840,000 (105.838)
Temperature °F (°C)	903.2°F (484.0°C)
Pressure psig (kPa)	975.0 (6,824)
Net plant output, kW	88,000
Net plant heat rate, Btu/kWh (kJ/kWh)	13,040 (13,758)

TABLE E.11
Test 2

Turbine generator gross output (kW)	98,400
Power factor	.85
Net plant output (kW)	88,050
Feedwater flow, lb/hr (kg/s)	846,465 (106.653)
Feedwater enthalpy, Btu/lb (kJ/kg)	261.01 (607.11)
Steam generator exit flow, lb/hr (kg/s)	838,000 (105.586)
Pressure psig (kPa)	972.5 (6807)
Temperature °F (°C)	902.0 (483.3)
Enthalpy Btu/lb (kJ/kg)	1450.19 (3,373.14)
Steam generator blowdown	1%
Blowdown enthalpy Btu/lb (kJ/kg)	540.6 (1,257)
Ambient temperature °F(°C)	80.0°F (°C)
River water temperature °F(°C)	80.0°F (°C)
Process steam flow lb/hr (kg/s)	102,000 (12.8518)

TABLE E.12

Conditional Auxiliary Power Usage	kW
Coal unloading	30
Ash transfer	20
Water treatment	0
Air compressor	600
HVAC	200
Lighting	200
Total	1050

be used for small deviations from the reference point and upward corrections would not be taken if the unit could not demonstrate capability of achieving and maintaining that level of performance.

Table E.11 lists the as-tested average data.

The conditional auxiliary power usage for this test is given in Table E.12.

Note that the as-tested steam generator exit pressure, temperature, and flow were below the reference values. In this case, the unit had previously demonstrated its capability to achieve and/or maintain the desired conditions. The local utility purchasing the plant power could not take enough output to load the plant higher. There was not enough time in the window of test opportunity to adjust the control settings to achieve the desired steam generator exit conditions, so the plant supplies and plant owner agreed to correct the steam generator test values to reference. The correction for temperature and pressure would not normally be allowed according to Section 3 of this Code.

Corrected Output

Corrected output for this test is calculated using Eq. 5.3.3. Terms of the equation are described in Table 5.1.1 of this Code.

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta 2 + \ell\ \Delta_7)$$

A summary of the corrections is given in Table E.13.

The corrections Δ_1, Δ_2, Δ_3, Δ_{5B}, and Δ_6 are found in the same manner as in Test 1. Δ_{7A}, Δ_{7B}, and Δ_{7C} come from correction curves Figs. E.9, E.11, and E.13, respectively.

The corrected steam energy supplied by the steam generator is computed as was done for Test 1 with additional corrections for steam generator flow, temperature, and pressure.

Corrected Fuel Energy Input and Corrected Heat Rate

The corrected fuel energy input is calculated as was done in Test 1, but with additional corrections for steam generator flow pressure and temperature.

Again, following the development of the equations to determine Q_{corr} for the first test,

$$Q_{corr} = \frac{Q_{ro} + \omega_1 + \omega_3 + \omega_{7A} + \omega_{7B} + \omega_{7C}}{\eta_{\text{fuel corrected}}}$$

$$HR_{corr} = \frac{Q_{corr}}{P_{corr}}$$

Corrected heat rate is calculated from Eq. 5.3.4:

$$HR_{corr} = Q_{corr}/P_{corr}$$

For purposes of this example, it is assumed that the corrected steam generator efficiency is as was calculated for Test 1, namely 87.37%. The net corrected plant heat consumption is then:

$$\frac{1002.19}{.8737} = 1147.1\ 10^6 \text{ Btu/hr } (1210.3\ 10^6 \text{ kJ/h})$$

The net corrected heat rate is then:

$$\frac{1147.1 \times 10^6 \text{ Btu/hr}}{88037 \text{ kW}}$$
$$= 13{,}030 \text{ Btu/kWh } (13{,}747 \text{ kJ/kWh})$$

The values for this test run and the corrections are given in Table E.14.

The terms ω_{7A}, ω_{7B}, and ω_{7C} were determined from correction curves, Figs. E.10, E.12, and E.14, respectively.

TABLE E.13

Measured net plant output, kW	88,050
Δ_1 process steam, kW	151
Δ_2 power factor, kW	0
Δ_3 blowdown, kW	0
Δ_{5B} cooling water temperature, kW	197
Δ_6 conditional auxiliary power correction, kW	69
Δ_{7A} steam generator steam flow, kW	345
Δ_{7B} steam generator steam exit temperature, kW	69
Δ_{7C} steam generator steam exit pressure, kW	27
Step-up transformer, kW	−871
Net corrected output, kW	88,037

TABLE E.14

As tested heat supplied by steam generator, 10^6 Btu/hr (10^6 kJ/h)	998.9 (1053.9)
ω_1, process steam, Btu/hr (10^6 kJ/h)	−0.30 (−0.32)
ω_3 blowdown, Btu/hr (10^6 kJ/h)	0
ω_{7A} steam generator steam flow, Btu/hr (10^6 kJ/h)	2.25 (2.37)
ω_{7B} steam generator steam temperature, Btu/hr (10^6 kJ/h)	.57 (0.60)
ω_{7C} steam generator steam pressure, Btu/hr (10^6 kJ/h)	.77 (0.81)
corrected heat added by steam generator, 10^6 Btu/hr (10^6 kJ/h)	1002.19 (1057.37)

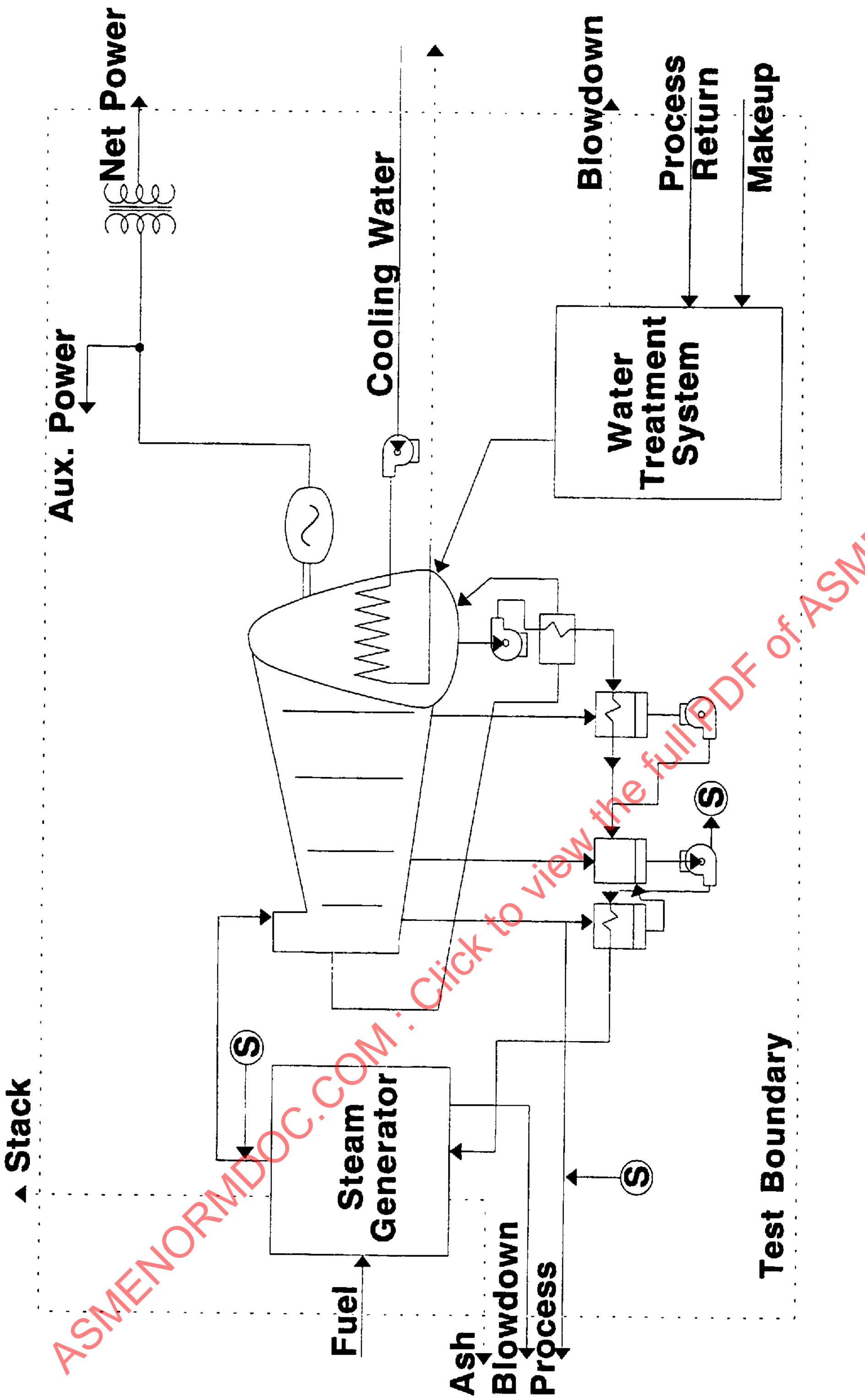


FIG. E.1 NON-REHEAT, CONDENSING, STEAM CYCLE COGENERATION PLANT

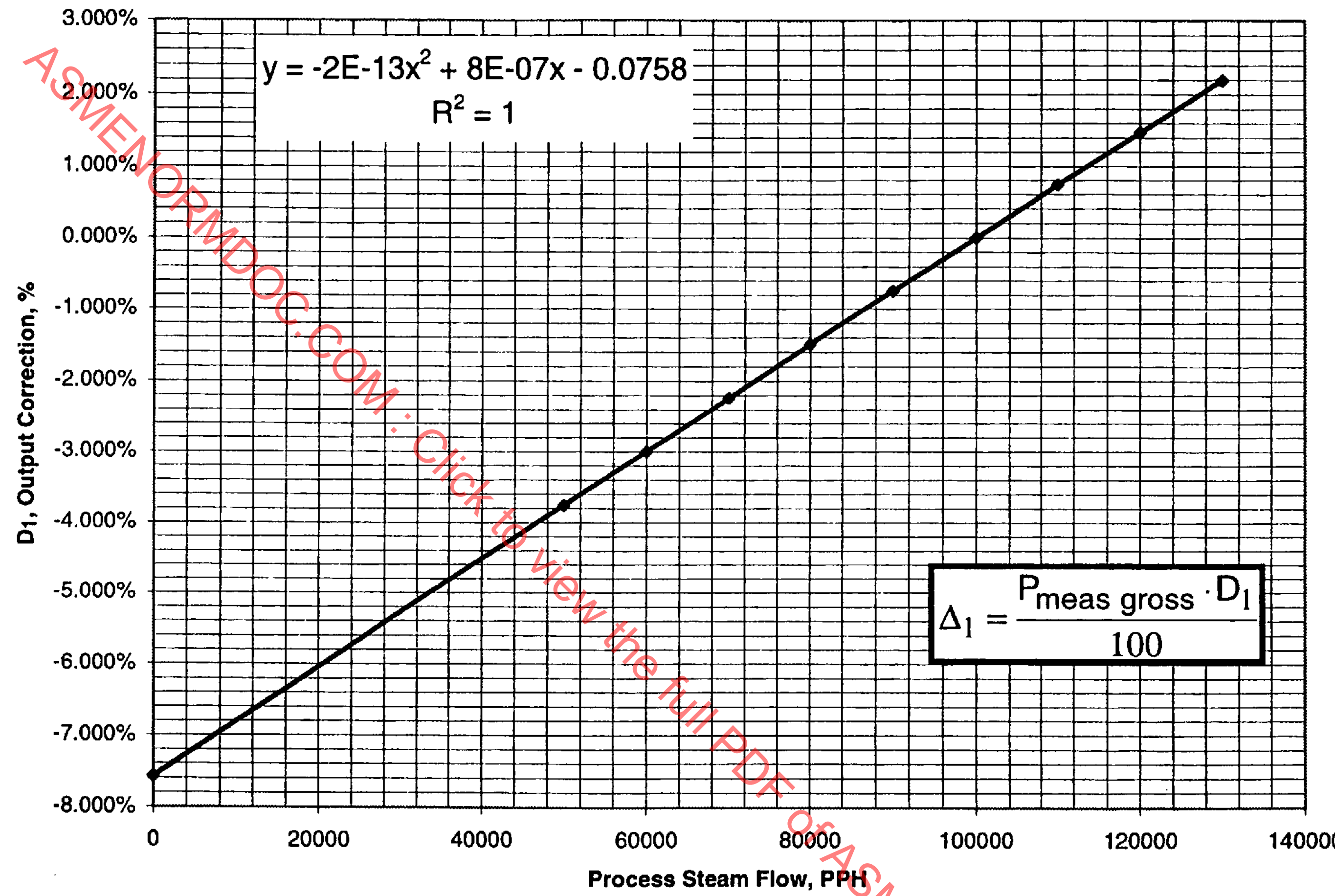


FIG. E.2 OUTPUT CORRECTION FOR PROCESS STEAM FLOW

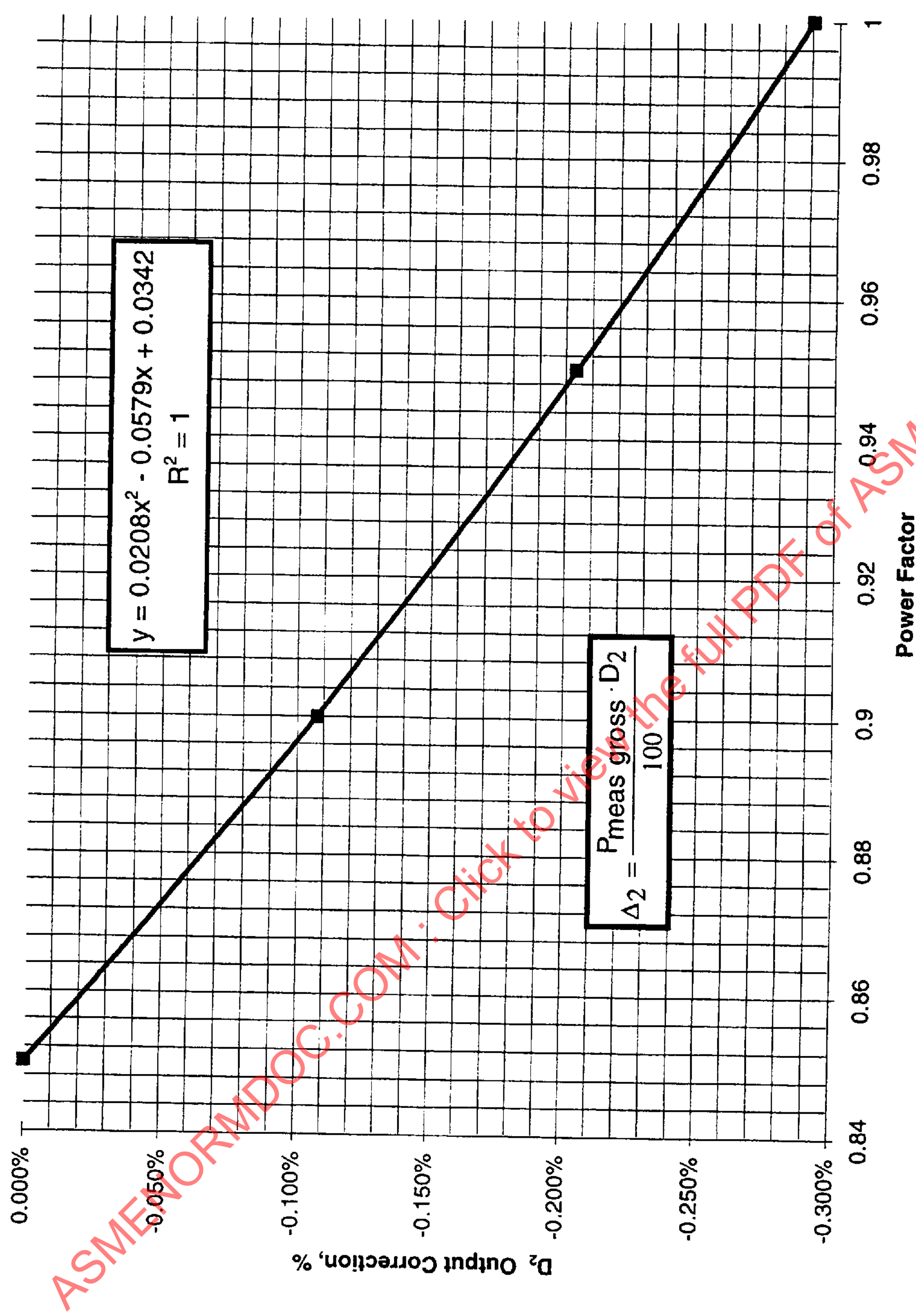


FIG. E.3 OUTPUT CORRECTION FOR POWER FACTOR

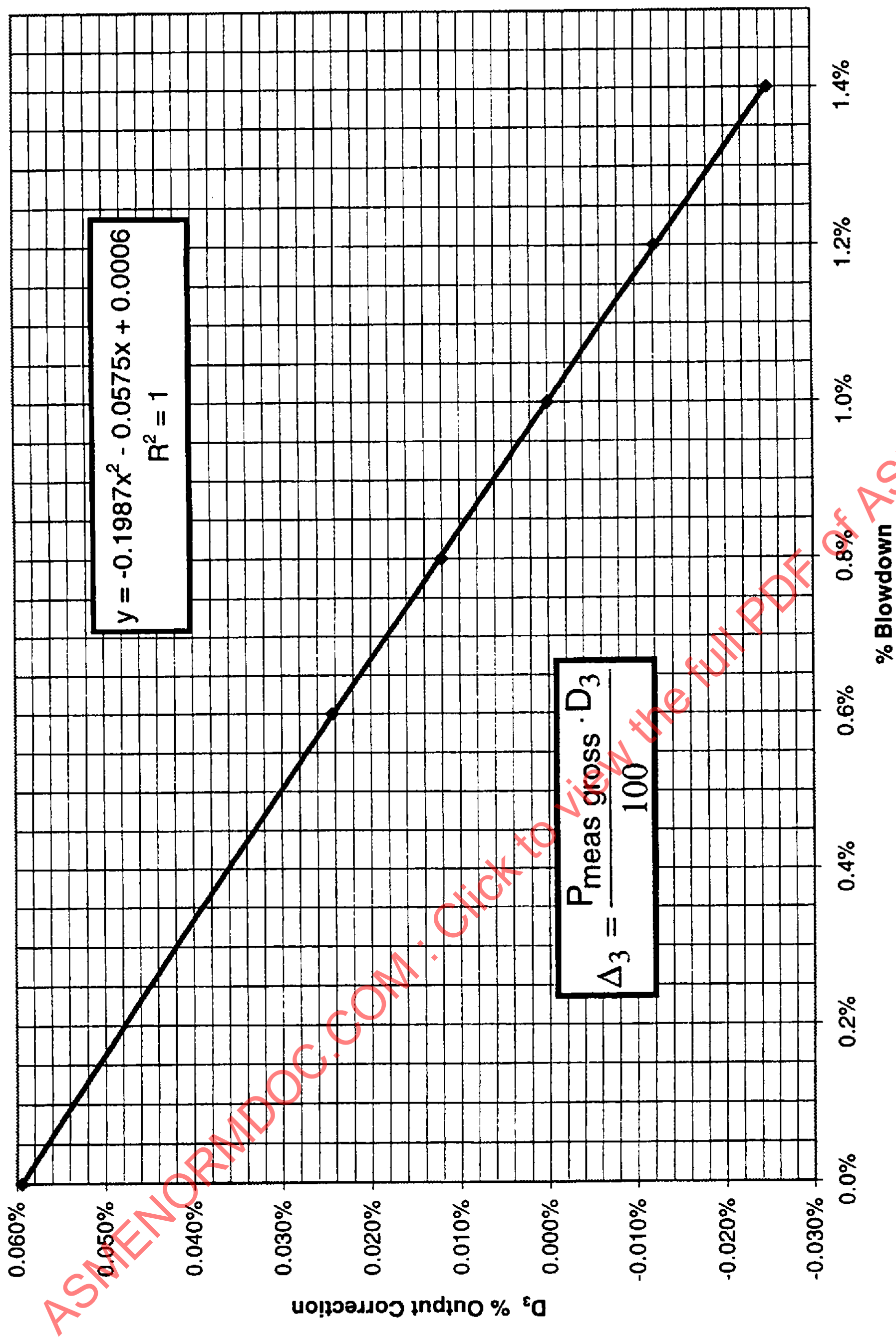


FIG. E.4 OUTPUT CORRECTION FOR BLOWDOWN

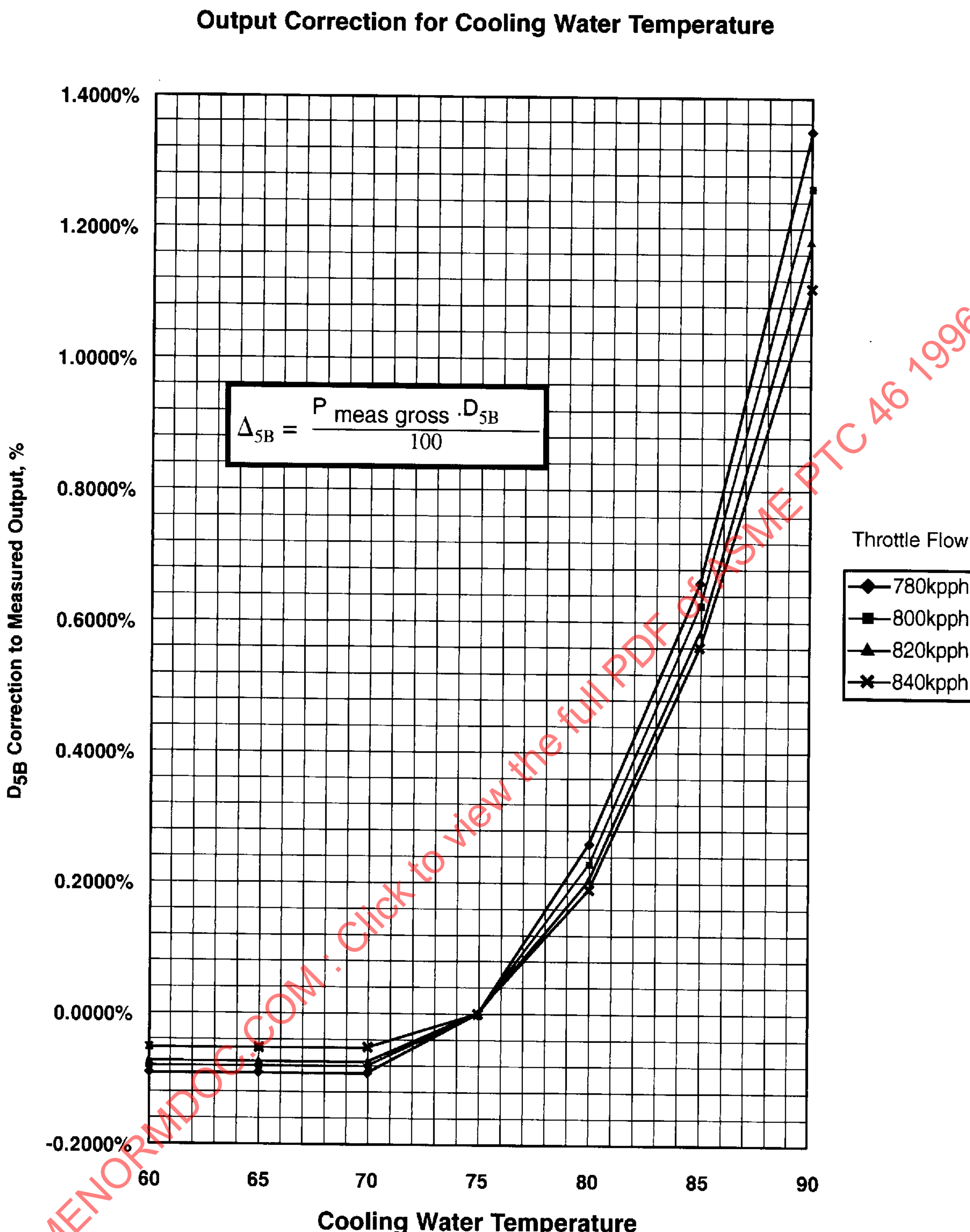


FIG. E.5 OUTPUT CORRECTION FOR COOLING WATER TEMPERATURE

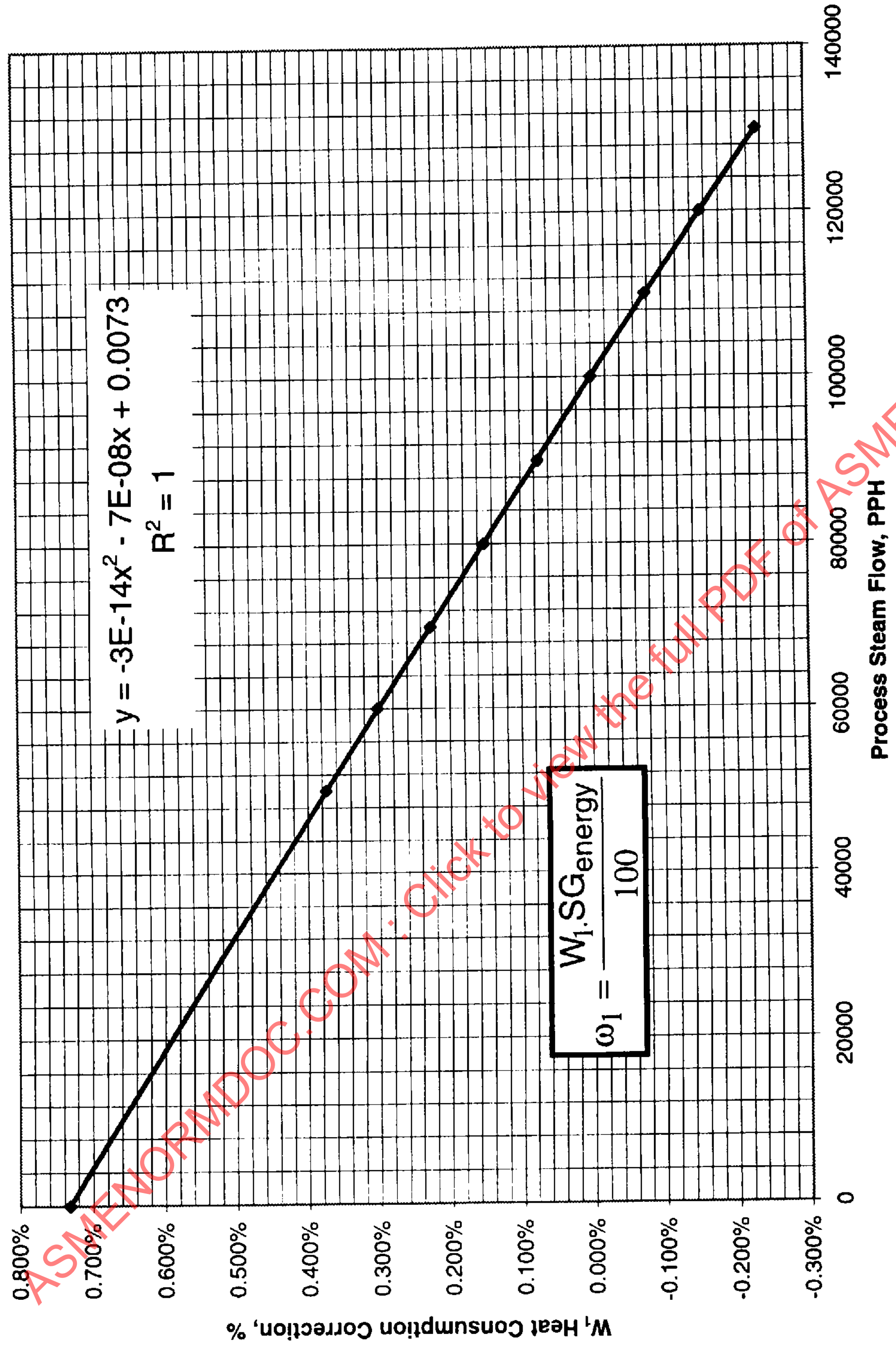


FIG. E.6 HEAT CONSUMPTION CORRECTION FOR PROCESS STEAM FLOW

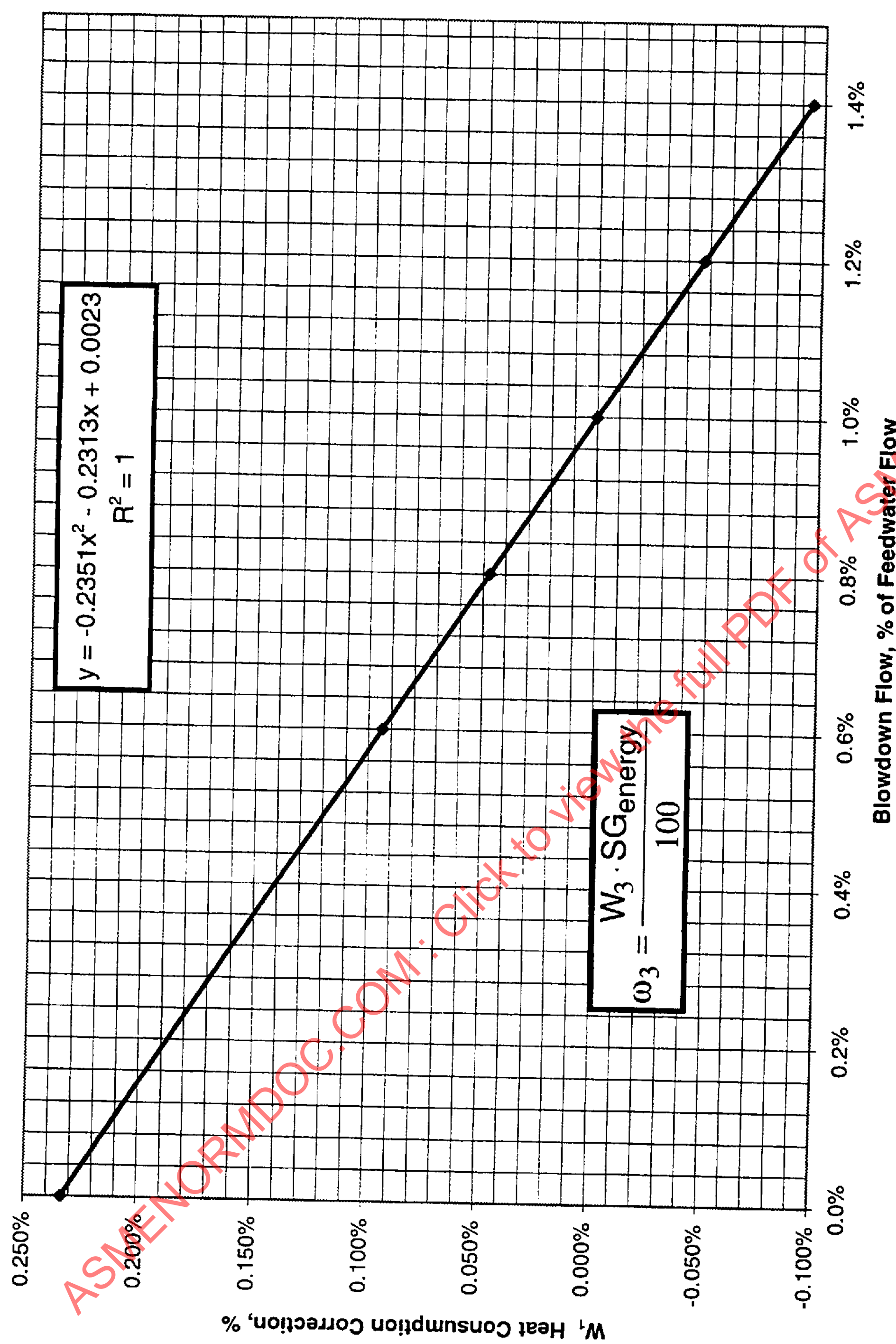


FIG. E.7 HEAT CONSUMPTION CORRECTION FOR BLOWDOWN FLOW

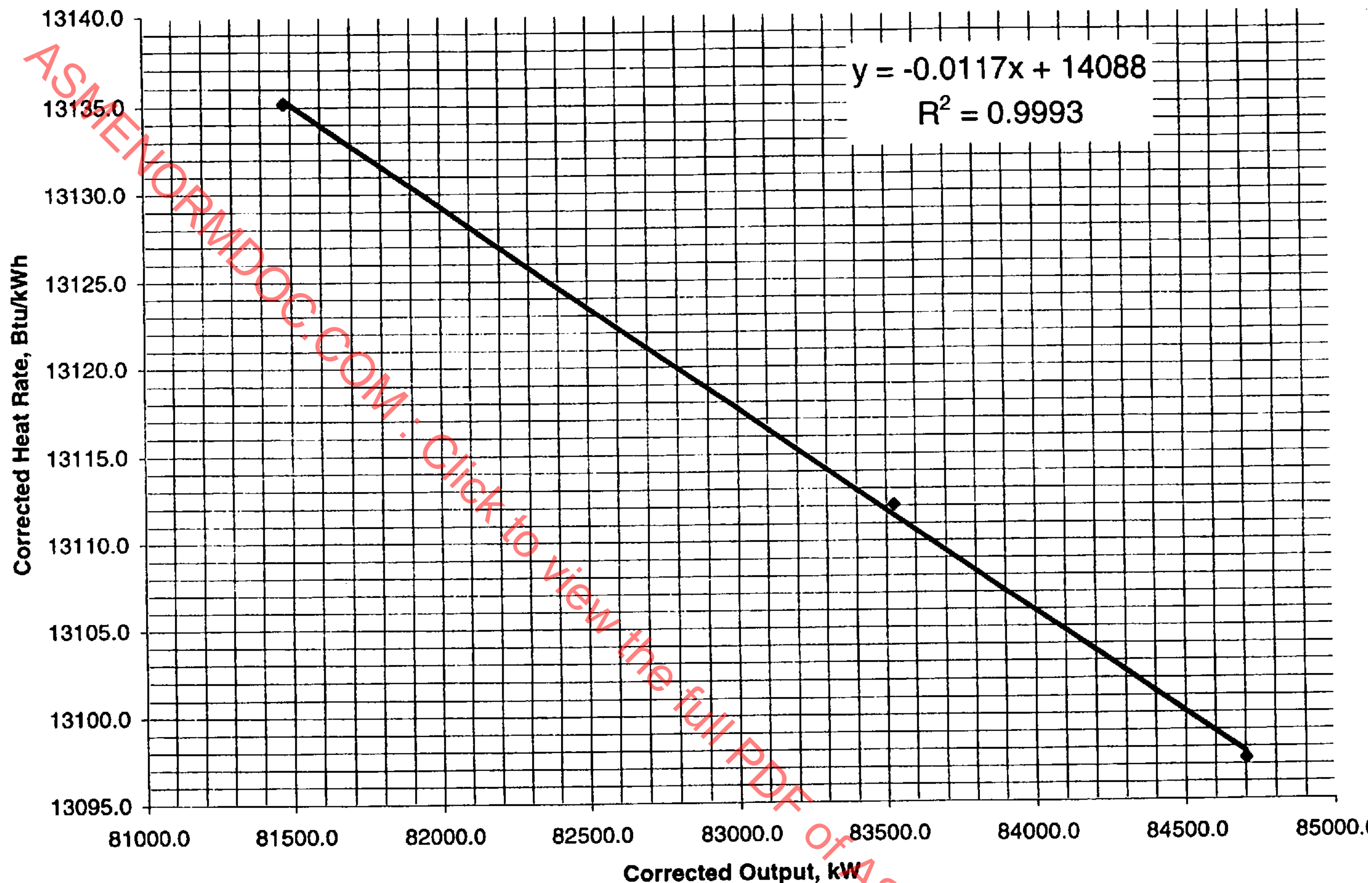


FIG. E.8 CORRECTED HEAT RATE VS CORRECTED OUTPUT

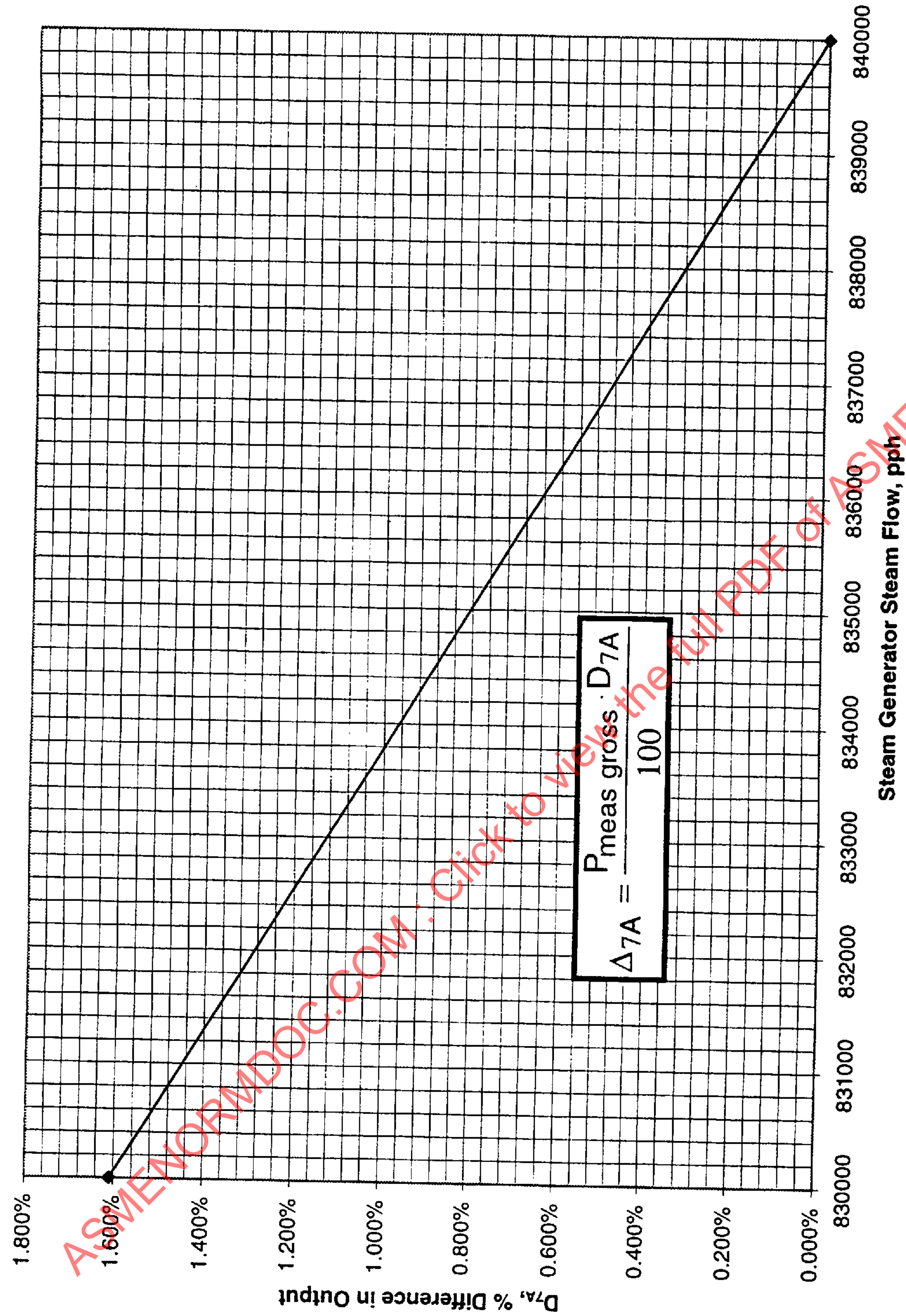


FIG. E.9 OUTPUT CORRECTION FOR STEAM GENERATOR STEAM FLOW

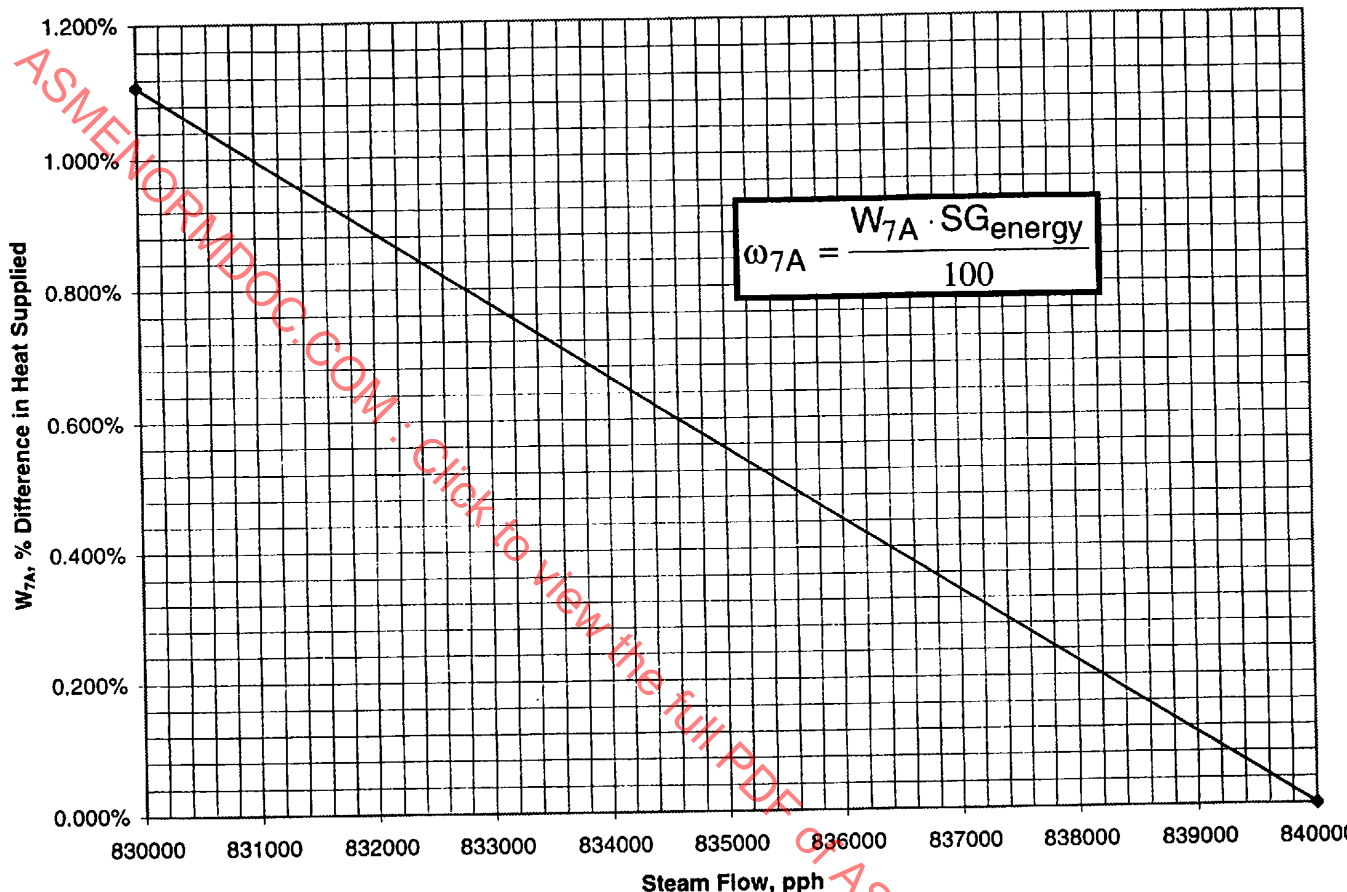


FIG. E.10 STEAM GENERATOR HEAT SUPPLIED CORRECTION FOR MAIN STEAM FLOW

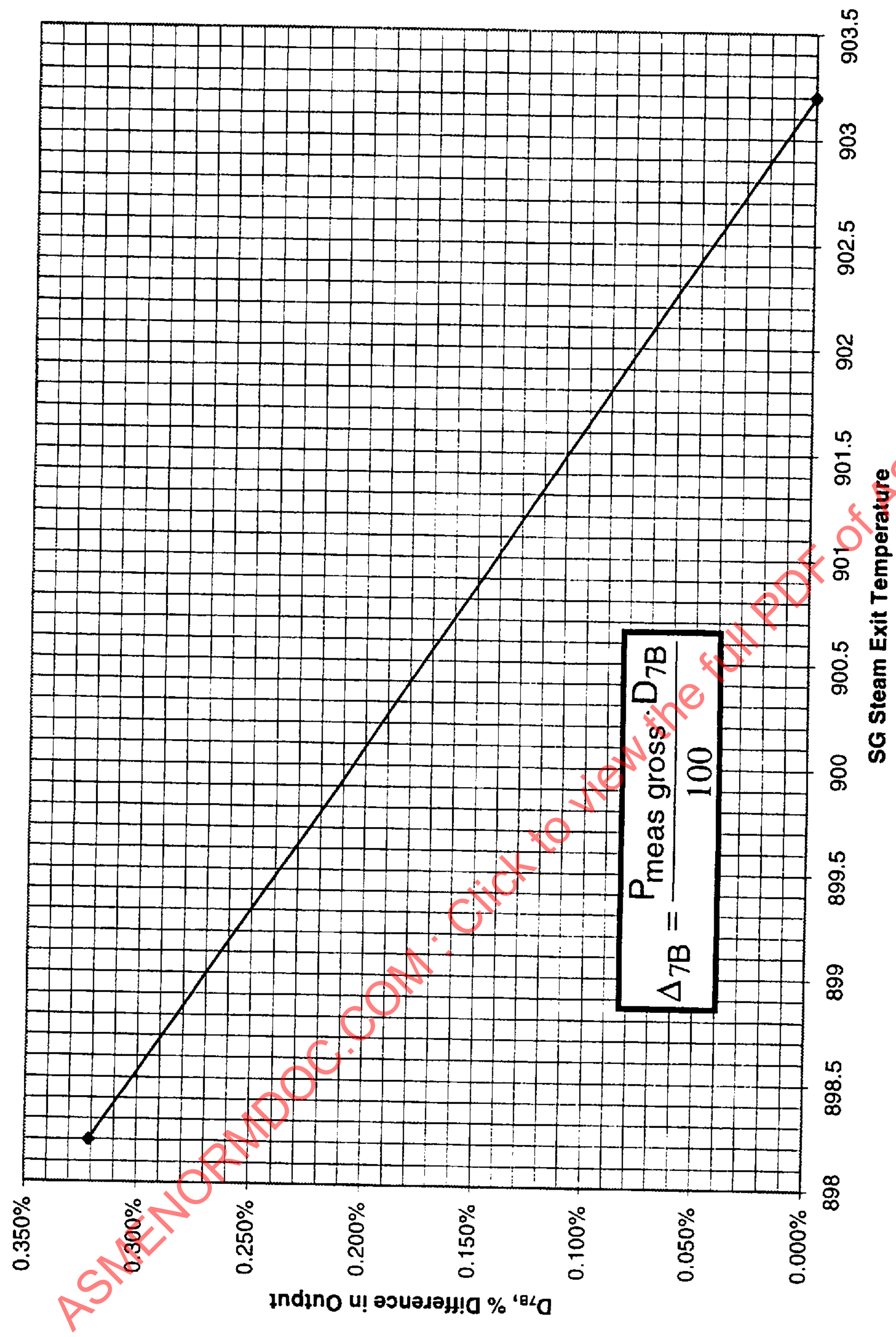


FIG. E.11 OUTPUT CORRECTION FOR SG STEAM TEMPERATURE

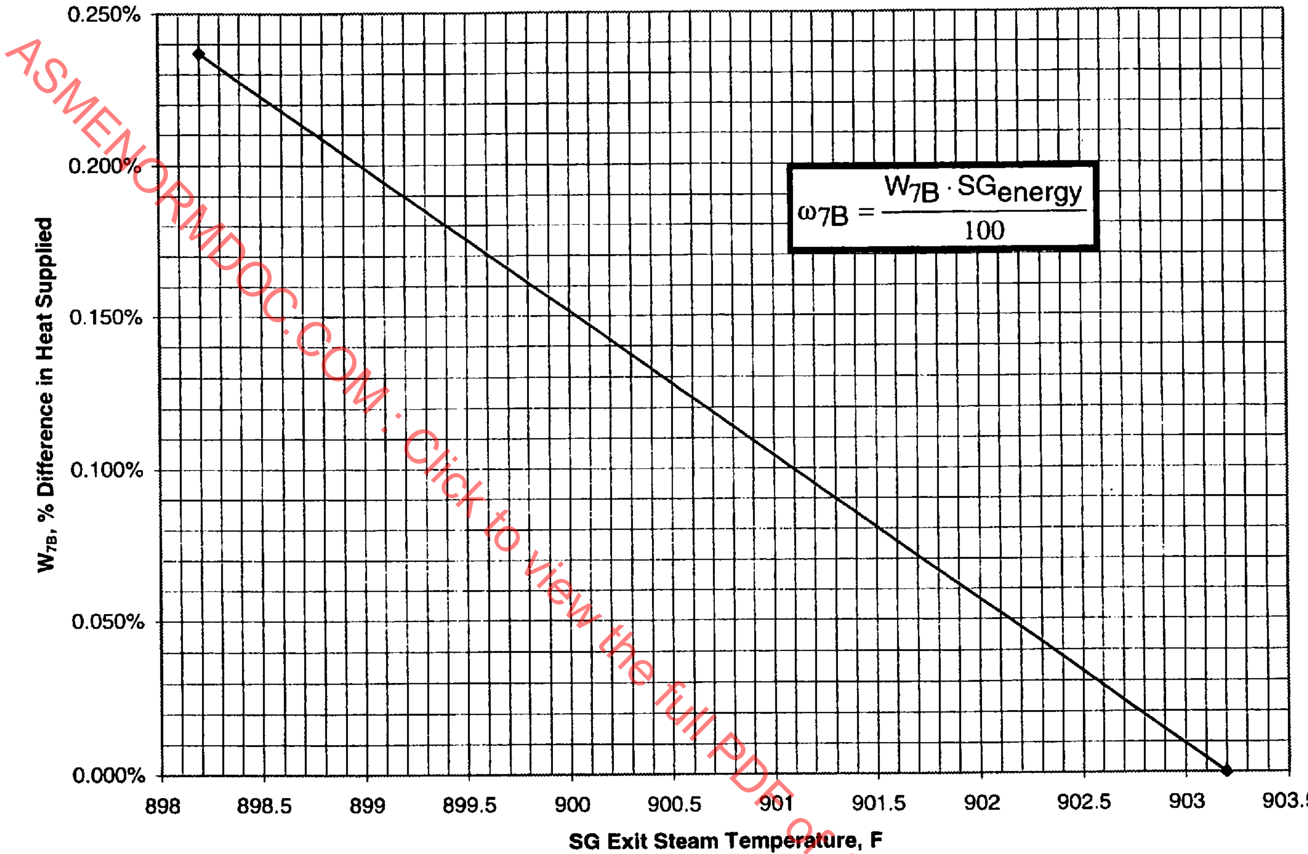


FIG. E.12 CORRECTION TO STEAM GENERATOR HEAT SUPPLIED FOR SG STEAM TEMPERATURE

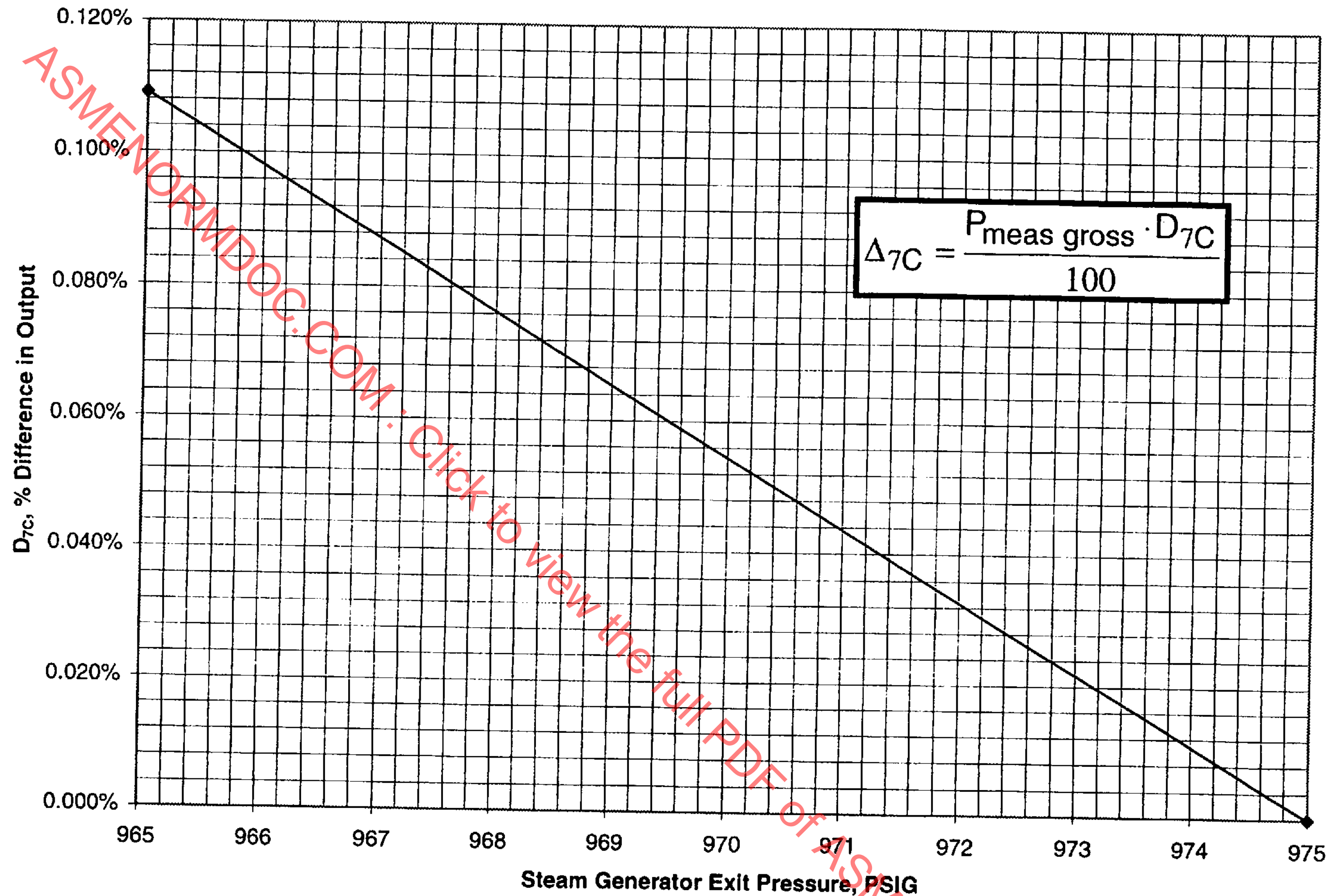


FIG. E.13 OUTPUT CORRECTION FOR SG EXIT PRESSURE

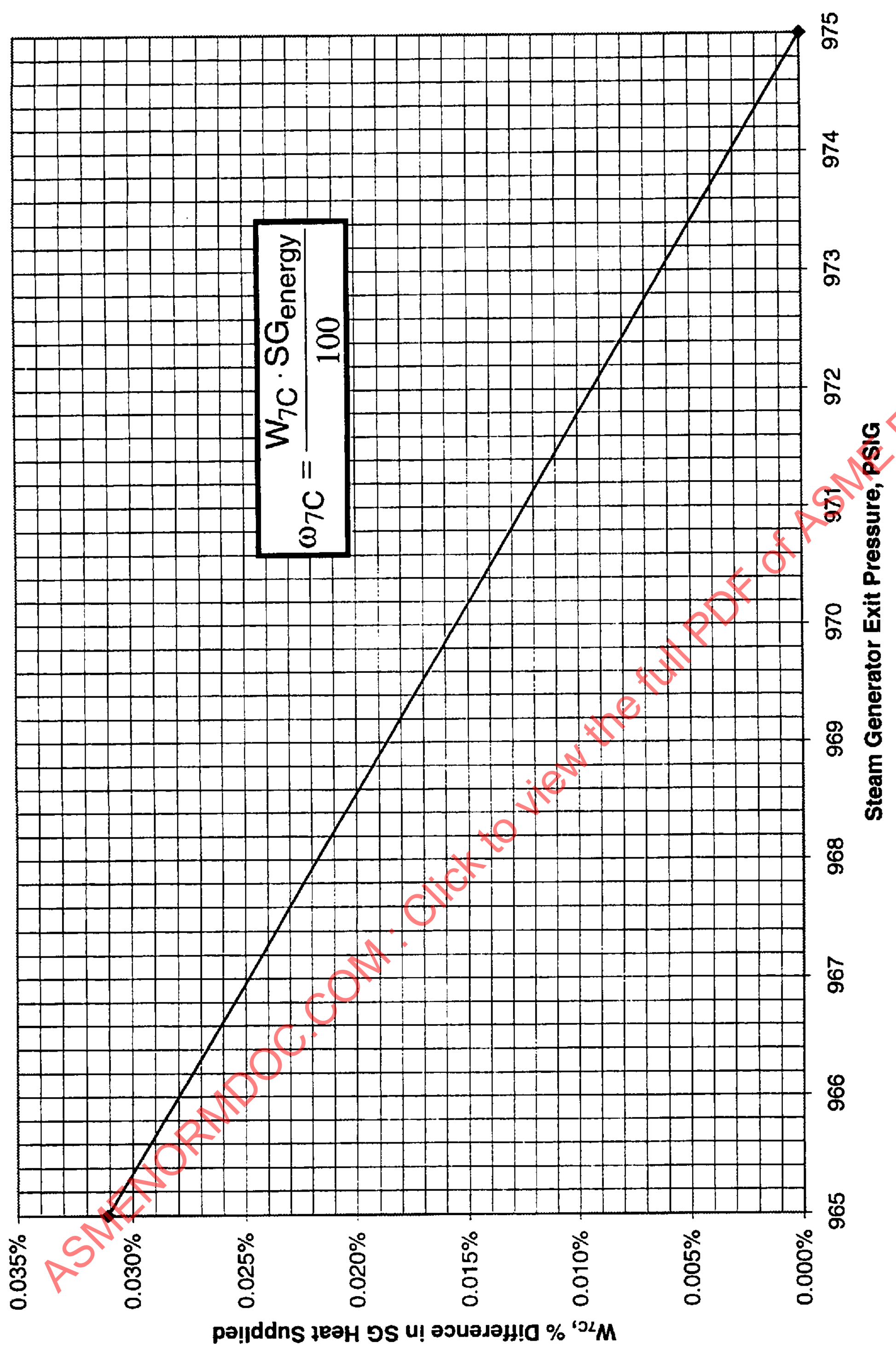


FIG. E.14 SG HEAT SUPPLIED CORRECTION FOR SG STEAM PRESSURE

INPUT DATA SHEET 1

	COMBUSTION CALCULATIONS — FORM CMBSTNa					
1	HHV — Higher Heating Value of Fuel, Btu/lbm as fired					12561.0
4	a. Measured Fuel Flow					85.0
6	Fuel Efficiency, % (estimate initially)					87.27
8	Barometric Pressure, in Hg					29.9
9	Dry Bulb Temperature, F					70.0
10	Wet Bulb Temperature, F					0.0
11	Relative Humidity, %					67.0
15	Gas Temp Lvg AH, F	Primary/Secondary or Main	15B	360.00	15A	316.00
16	Air Temp Ent AH, F	Primary/Secondary or Main	16B	94.00	16A	90.00
20	Sorbent Rate, Klbm/hr					10.00
	COMBUSTION CALCULATIONS — FORM CMBSTNb					
30	Fuel Ultimate Analysis, % Mass					
	A	Carbon				70.91
	B	Unburned Carbon in Ash				1.55
	D	Sulfur				1.23
	E	Hydrogen				4.40
	F	Moisture				7.30
	G	Moisture (Vapor for gaseous fuel)				0.00
	H	Nitrogen				1.34
	I	Oxygen				4.61
	J	Ash				10.23
	K	Volatile Matter				0.00
50	Flue Gas O2, %	Entering Air Heater				3.60
		Leaving Air Heater				3.60

NAME OF PLANT	PTC 46 Plant 1	UNIT NO.
TEST NO. Test 1A	DATE	LOAD
TIME START:	END	CALC BY
		DATE 4-28-95
		SHEET OF

INPUT DATA SHEET 2

COMBUSTION CALCULATIONS — FORM CMBSTNc					
83		Flue Gas Temperature Entering Air Heater, F			559.3
84		Air Temperature Leaving Air Heater, F			379.2
UNBURNED CARBON & RESIDUE CALCULATIONS — FORM RES					
5		Residue Mass Flow 18.2		Klbm/hr	Split, %
	A	Furnace	0.0		41.9
	B	Economizer	0.0		0.0
	C	Bag House	0.0		58.1
	D		0.0		0.0
	E		0.0		0.0
6	Carbon in Residue, %				
	A	Furnace			0.00
	B	Economizer			0.00
	C	Bag House			12.41
	D				
	E				
7	Carbon Dioxide in Residue, %				
	A	Furnace			1.04
	B	Economizer			0.00
	C	Bag House			2.10
	D				
	E				
24	Temperature of Residue, F				
	A	Furnace			1540.0
	B	Economizer			336.0
	C	Bag House			336.0
	D				
	E				

NAME OF PLANT	PTC 46 Plant 1	UNIT NO.
TEST NO. Test 1A	DATE	LOAD
TIME START:	END	CALC BY
		DATE 4-28-95
		SHEET OF

INPUT DATA SHEET 3

	SORBENT CALCULATION SHEET MEASURED C AND CO2 IN RESIDUE — FORM SRBa		
7A		SO2 in Flue Gas, ppm	92
8		O2 in Flue Gas at location where SO2 is measured, %	3.60
9		SO2 & O2 Basis, Wet [0] or Dry [1]	1
20		Sorbent Products, % Mass	
	A	CaCO3	94.00
	B	Ca(OH)2	0.00
	C	MgCO3	4.20
	D	Mg(OH)2	0.00
	E	H2O	0.03
	F	Inert	0.00
23A		Calcination Fraction	**0.93**
	SORBENT CALCULATION SHEET MEASURED C AND CO2 IN RESIDUE — FORM SRBb		
	SORBENT CALCULATION SHEET EFFICIENCY — FORM SRBc		
61		Sorbent Temperature, F	77.0
	EFFICIENCY CALCULATIONS DATA REQUIRED — FORM EFFa		
5		Gas Temperature Entering Hot Air Quality Control Equipment, F	0.0
6		Gas Temperature Leaving Hot Air Quality Control Equipment, F	0.0
	EFFICIENCY CALCULATIONS — FORM EFFb		
55		Surface Radiation and Convection, MKBtu/hr	6.4
EFFICIENCY CALCULATIONS OTHER LOSSES AND CREDITS — FORM EFFc			
Losses, %			
85A		CO in Flue Gas	0.00
85B		Pulverizer Rejects	0.00
85C		Air Infiltration	0.00
85D		Unburned Hydrogen in Flue Gas	0.00
85E		Unburned Hydrogen in Residue	0.00
85F		Unburned Hydrocarbons in Flue Gas	0.00
85G			
Losses, MKBtu/hr			
86A		Wet Ash Pit	0.000
86B		Sensible Heat in Recycle Streams — Solid	0.000
86C		Sensible Heat in Recycle Streams — Gas	0.000
86D		Additional Moisture	0.000
86E		Cooling Water	0.000
86F		Air Preheat Coil (Supplied by Unit)	0.000
86G		Boiler Circulating Pumps	0.000
86H			
Credits, %			
87A			0.00
Credits, MKBtu/hr			
88A		Heat in Additional Moisture (External to Envelope)	0.000

NAME OF PLANT	PTC 46 Plant 1	UNIT NO.
TEST NO. Test 1A	DATE	LOAD
TIME START:	END	CALC BY
		DATE 4-28-1995
		SHEET OF

INPUT DATA SHEET 4

	PARAMETER	W FLOW Klbm/hr	T TEMPERATURE, F	P PRESSURE PSIG
1	FEEDWATER	786290	285.1	1100.0
2	SH SPRAY WATER	0	260.0	1180.0
3	Ent SH-1 Attemp	0	0.0	0.0
4	Lvg SH-1 Attemp	0	0.0	0.0
6	Ent SH-2 Attemp	0	0.0	0.0
7	Lvg SH-2 Attemp	0	0.0	0.0
	INTERNAL EXTRACTION FLOWS			
9	Blowdown	6290		947.0
10	Sat Steam Extraction	0	0.0	
11	Sootblowing Steam	0	0.0	0.0
12	SH Steam Extraction 1	0	0.0	0.0
13	SH Steam Extraction 2	0	0.0	0.0
14				
	AUXILIARY EXTRACTION FLOWS			
15	Aux Steam 1	0	0.0	0.0
16	Aux Steam 2	0	0.0	0.0
17				
18	MAIN STEAM		903.0	931.0
	REHEAT UNITS			
20	REHEAT OUTLET		0.0	0.0
21	COLD REHEAT ENT ATTEMPERATOR		0.0	0.0
22	RH SPRAY WATER	0	0.0	0.0
23	COLD REHEAT EXTRACTION	0		
24	TURB SEAL FLOW & SHAFT L	0		
	FW HEATER NO. 1			
25	FW Entering	0	0.0	0.0
26	FW Leaving		0.0	0.0
27	Extraction Steam		0.0	0.0
28	Drain		0.0	0.0
	FW HEATER NO. 2			
30	FW Entering	0	0.0	0.0
31	FW Leaving		0.0	0.0
32	Extraction Steam		0.0	0.0
33	Drain		0.0	0.0

NAME OF PLANT PTC 46 Plant	UNIT NO.
TEST NO. Test 1A	LOAD
TIME START: END:	CALC BY
	DATE 4-28-95
	SHEET OF