BRITISH STANDARD

BS ISO 2314:2009

Gas turbines — Acceptance tests

ICS 27.040

British Standards

National foreword

This British Standard is the UK implementation of ISO 2314:2009. It supersedes BS 3135:1989 which is withdrawn.

The UK participation in its preparation was entrusted to Technical Committee MCE/16, Gas turbines.

A list of organizations represented on this committee can be obtained on request to its secretary.

This publication does not purport to include all the necessary provisions of a contract. Users are responsible for its correct application.

Compliance with a British Standard cannot confer immunity from legal obligations.

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Gas turbines — Acceptance tests

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

ISO 2314 was prepared by Technical Committee ISO/TC 192, *Gas turbines*.

This third edition cancels and replaces the second edition (ISO 2314:1989), which has been technically revised. It also incorporates the Amendment ISO 2314:1989/Amd.1:1997 and the Technical Corrigendum ISO 2314:1989/Cor.1:1997.

Introduction

This International Standard specifies guidelines and procedures for preparing, conducting and reporting thermal-acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of gas-turbine power plants and gas turbine engines, in this International Standard referred to as “gas turbines”. It is necessary that such performance test results be determined with a high level of accuracy using best engineering knowledge and industry practice in measurement technique and method.

It is necessary that a detailed, project-specific or test-equipment-specific test procedure be prepared by the party executing the performance test, based on the recommendations and guidelines given in this International Standard as well as considering contractual obligations. It is necessary that any deviations from this International Standard be mutually agreed upon by the involved parties prior to the start of the test.

Gas turbines — Acceptance tests

1 Scope

This International Standard applies to open-cycle gas-turbine power plants using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi-closed-cycle gas-turbine power plants. It can also be applied to gas turbines in combined cycle power plants or in connection with other heat-recovery systems.

In cases of gas turbines using free-piston gas generators or special heat sources (for example synthetic gas of chemical processes, blast furnace gas), this International Standard can be used as a basis but suitable modifications are necessary.

Acceptance tests of gas turbines with emission control and/or power augmentation devices that are based on fluid injection and/or inlet air treatment are also covered by this International Standard and it is necessary that they be considered in the test procedure, provided that such systems are included in the contractual scope of the supply subject to testing.

Comparative testing can be subject to many different scenarios, depending on the purpose of the conducted measures. This International Standard can also be applied to comparative tests designed to verify performance differentials of the gas turbine, primarily for testing before and after modifications, upgrades or overhaul, although no special reference is made to these topics.

This International Standard also includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters:

a) electrical or mechanical power output (gas power, if only gas is supplied);

b) thermal efficiency or heat rate;

c) turbine exhaust energy (optionally exhaust temperature and flow).

It is necessary that any other performance parameters defined in the contract between equipment supplier and purchaser be considered accordingly in the specific test procedure as well as in the supplier's standard manufacturing test procedure.

This International Standard describes measurement methods and corresponding instruments employed and their calibration arrangement and handling. It includes provisions for preparing and conducting a performance test, defines operating conditions of the gas turbine, boundary conditions and their limits as well as standard conditions (3.9) that should be used as a reference if no other conditions are agreed at the time of purchase. Furthermore, it contains provisions for the measurement data recording and handling, methods for the calculation and correction of the test results as well as the development of the uncertainty thereof.

Test tolerance is not addressed in this International Standard, because it is considered a commercial term not based on statistical analysis of measurement results. It is necessary that the methodology on how to apply tolerances for the demonstration of compliance with the guaranteed values be defined in the contract.

For the optional test to determine exhaust energy and/or flow, these values are determined from an energy balance around the gas turbine. Uncertainty values can be minimized by achieving the limits defined in this International Standard for the key parameters in the energy balance.

This International Standard does not apply to the following:

a) emission testing;

b) noise testing;

c) vibration testing;

d) performance of specific components of the gas turbine;

e) performance of power augmentation devices and auxiliary systems, such as air inlet cooling devices, fuel gas compressors, etc.;

f) conduct test work aiming at development and research;

g) adequacy of essential protective devices;

h) performance of the governing system and protective systems;

i) operating characteristics (starting characteristics, reliability testing, etc.).

2 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 2533, *Standard atmosphere*

ISO 3733, *Petroleum products and bituminous materials — Determination of water — Distillation method*

ISO 5167 (all parts), *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full*

ISO 6245, *Petroleum products — Determination of ash*

ISO 6974-1, *Natural gas — Determination of composition with defined uncertainty by gas chromatography — Part 1: Guidelines for tailored analysis*

ISO 6975, *Natural gas — Extended analysis — Gas-chromatographic method*

ISO 6976 *Natural gas — Calculation of calorific values, density, relative density and Wobbe index from composition*

ISO 9951, *Measurement of gas flow in closed conduits — Turbine meters*

ISO 10715, *Natural gas — Sampling guidelines*

ISO 12213-2, *Natural gas — Calculation of compression factor — Part 2: Calculation using molar-composition analysis*

ISO 14596, *Petroleum products — Determination of sulfur content — Wavelength-dispersive X-ray fluorescence spectrometry*

ISO 20846, *Petroleum products — Determination of sulfur content of automotive fuels — Ultraviolet fluorescence method*

ASTM D4629 *Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection*

ASTM D5291, *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*

DIN 51451, *Testing of petroleum products and related products — Analysis by infrared spectrometry — General working principles*

3 Terms and definitions

For the purpose of this document, the following terms and definitions apply.

3.1
degradation
loss of performance of a gas turbine due to wear and tear experienced in normal operation which is not recoverable by compressor cleaning, turbine cleaning, filter cleaning, etc.

NOTE 1 This can also be referred to as ageing.

NOTE 2 Adapted from ISO 3977-9:1999, 4.1.7.

3.2
equivalent operating hours
weighted operating events affecting the life of the gas turbine forming an equivalent operating time to determine inspection intervals of life expectancy

NOTE Adapted from ISO 3977-9:1999, 4.1.2.2.

3.3
gas generator
assembly of gas turbine components that produces heated, pressurized gas and provides it to a process or to a power turbine

NOTE Adapted from ISO 3977-1:1997, 2.14.

3.4
gas turbine
machine that converts thermal energy into mechanical work

NOTE 1 It consists of one or several rotating compressors, thermal device(s) that heat the working fluid, one or several turbines, a control system and essential auxiliary equipment. Any heat exchangers (excluding waste exhaust heat recovery exchangers) in the main working fluid circuit are considered as part of the gas turbine.

NOTE 2 Adapted from ISO 3977-1:1997, 2.1.

3.5
heating value
calorific value
specific energy
amount of heat released by the complete combustion in air of a specific quantity of gas or liquid fuel when the reaction takes place at constant pressure

NOTE If the combustion products accounted for are only in the gaseous state, the value is called lower heating value, LHV, or inferior calorific value or net heating value. If the combustion products are gaseous with the exception of water, which is in liquid state, the value is called higher heating value, HHV, or superior calorific value or gross heating value at 15 °C for natural gas fuel.

See ISO 6976.

3.6
power
quantity that may be expressed in terms of mechanical shaft power at the turbine coupling, electrical power of the turbine-generator or gas power in the case of a gas turbine or gas generator producing gas or compressed air

3.7
random error
result of a measurement minus the mean that would result from an infinite number of measurements of the same measurand carried out under repeatability conditions

See ISO/IEC Guide 99:2007, 2.19.

3.8
reference standard
standard, generally having the highest metrological quality available at a given location or in a given organization, from which measurements are derived

See ISO/IEC Guide 99:2007, 5.6.

3.9
standard reference conditions
conditions as defined in ISO 2533, equal to the following:

a) for the ambient air or intake air at the compressor flange (alternatively, the compressor intake flare):

- absolute pressure of 101,325 kPa (1,013 25 bar; 760 mm Hg),
- temperature of 15 °C,
- relative humidity of 60 %;

b) for the exhaust at turbine exhaust recuperator outlet, if a recuperator cycle is used:

- static pressure of 101,325 kPa

NOTE 1 In the case of the closed cycle, the standard conditions for the air heater are 15 °C and 101,325 kPa for the ambient atmospheric air.

NOTE 2 An inlet water temperature of 15 °C applies if cooling of the working fluid is used.

3.10
systematic error
bias
mean that would result from an infinite number of measurements of the same measurand carried out under repeatability conditions minus a true value of the measurand

See ISO/IEC Guide 99:2007, 2.17.

3.11
thermal efficiency
ratio of the power output to the heat consumption based on the lower heating value, LHV, or net heating value of the fuel

NOTE Adapted from ISO 3977-1:1997, 2.3.4.

3.12
heat rate
ratio of the fuel energy supplied per unit time to the power produced

NOTE 1 The heat rate is expressed in units of kilojoules per kilowatt hour.

NOTE 2 It is widely used in the power generation industry.

See ISO 11086.

3.13
tolerance
allowed deviation from a specific requirement

3.14
traceability
property of the result of a measurement or the value of the standard whereby it can be related to stated references, usually national or international standards, through an unbroken chain of comparisons all having stated uncertainties

NOTE Adapted from ISO/IEC Guide 99:2007, 2.41.

3.15
turbine inlet temperature
TIT
defined arbitrarily as a theoretical flow-weighted mean temperature before the first-stage stationary blades calculated from an overall heat balance of the combustion chamber with the gas mass flow from combustion mixed with the turbine cooling air mass flows prior to entering the first stage stationary blades

3.16
turbine outlet temperature
TOT
temperature of the hot gas leaving the turbine

3.17
type A evaluation
⟨of uncertainty⟩ method of evaluation of uncertainty by the statistical analysis of series of observations

See ISO/IEC Guide 98-3.

3.18
type B evaluation
⟨of uncertainty⟩ method of evaluation of uncertainty by means other than the statistical analysis of series of observations

See ISO/IEC Guide 98-3.

3.19
uncertainty
⟨of measurement⟩ shortened form of “uncertainty of measurement”, a parameter associated with the result of a measurement, that characterizes the dispersion of the values that can reasonably be attributed to the measurand

NOTE 1 The determination of the quality of a measurement that can be expressed with the uncertainty of the test result is of fundamental importance in any field of measuring and testing. A measure to quantify such quality is the uncertainty of measurement. The shortened term “uncertainty” is used for simplicity in this International Standard.

NOTE 2 The expression “accuracy of measurement” (closeness of the agreement between the result of a measurement and the value of the measurand), commonly abbreviated as “accuracy,” is not associated with numbers and is not used as a quantitative term.

See ISO/IEC Guide 99:2007, 2.26.

3.20
working standard
standard that is used routinely to calibrate or check material measures, measuring instruments or reference materials

See ISO/IEC Guide 99:2007, 5.7.

4 Test boundary

The test boundary concept encompasses the hardware scope of the gas turbine subject to performance testing considering the reference conditions for the given guaranties. It provides the basis for the definition and layout of instrument number, range and location required to determine the energy streams crossing the test boundary as well as to determine the actual conditions during testing for correcting the test results to reference conditions.

Figure 1 shows a typical test boundary for the scope of an open cycle gas turbine for electrical output application with the measurement stations needed for the performance determination. The measurement stations within the test boundary may be used for energy balance calculation as demonstrated in Chapter 8.

The given nomenclature is used for the example calculations in this International Standard.

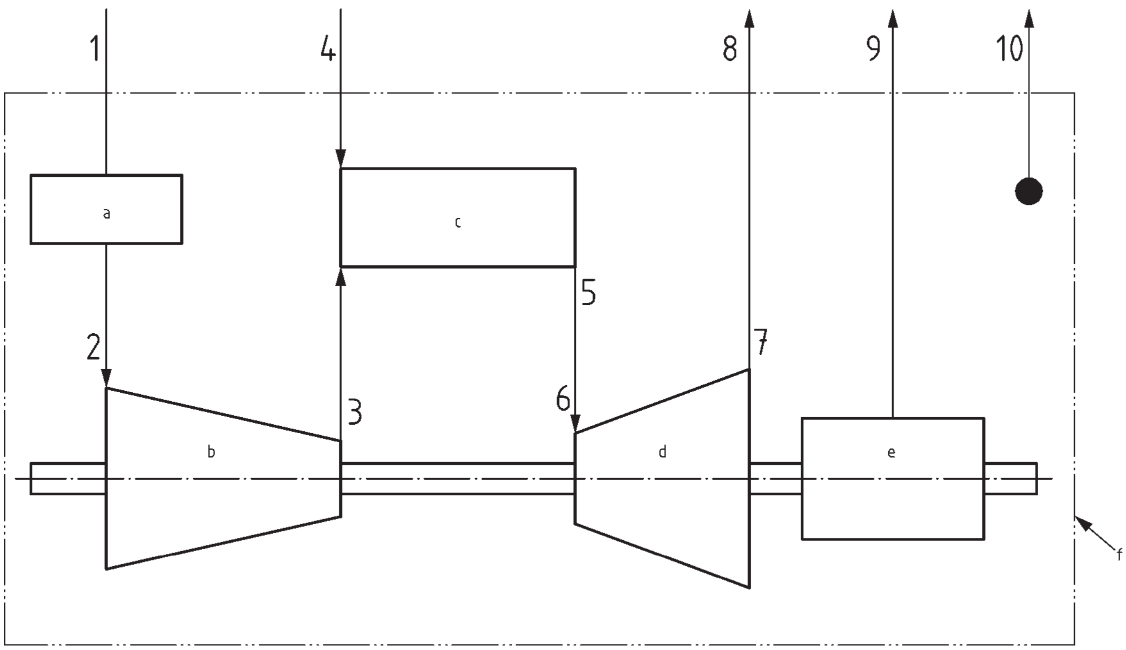


Figure 1 – Test Boundary for Generator Application

a	Air filter	d	Turbine(s)
b	Compressor(s)	e	Generator
c	Combustor(s)	f	Test boundary for generator application

The typical test boundary for mechanical drives is shown in Figure 2.

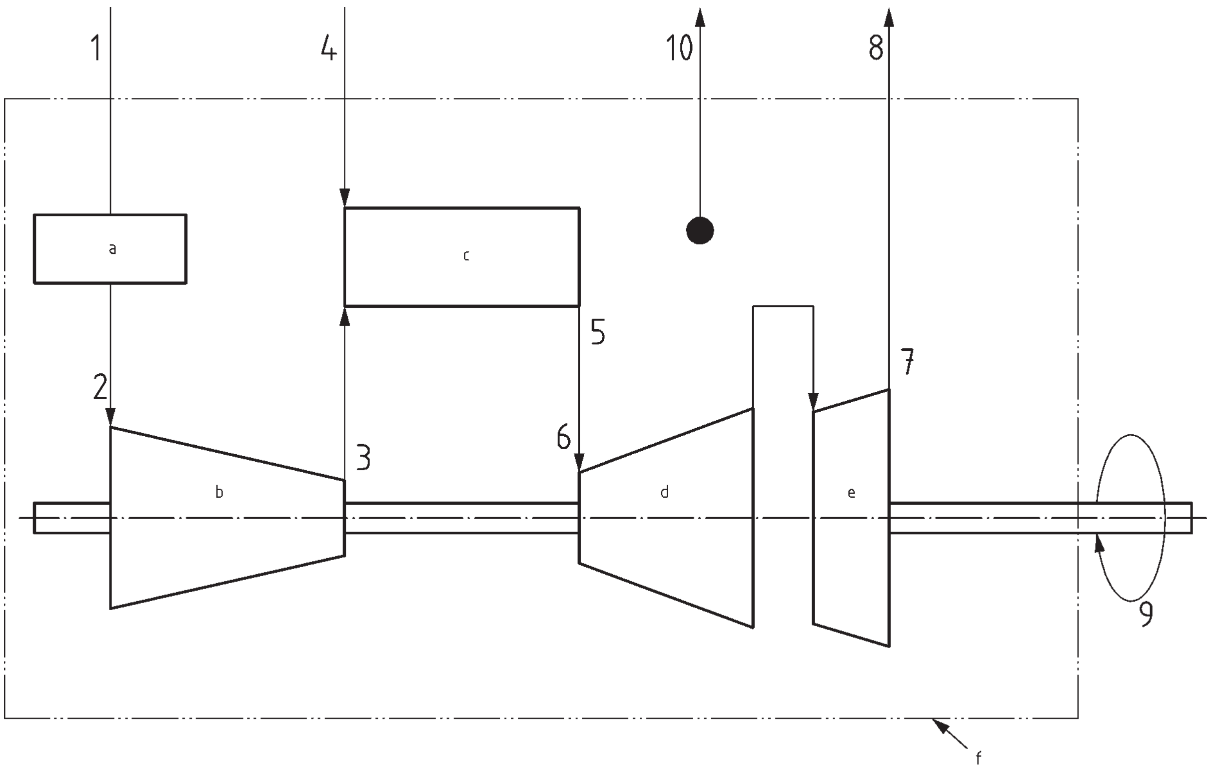


Figure 2 – Test Boundary for Mechanical Drive Application

a	Air filter	d	Turbine(s)
b	Compressor(s)	e	Power Turbine
c	Combustor(s)	f	Test boundary for mechanical drive application

Station names are given in Table 1

Table 1 – Station identification nomenclature

Station		Measurands
1	Ambient air	Temperature, pressure, humidity
2	Compressor inlet	Temperature, pressure
3	Compressor outlet	Temperature, pressure
4	Fuel + injection fluid	Flow, temperature, pressure, fuel properties
5	Combustor outlet	N/A
6	Turbine inlet	N/A
7	Turbine exhaust	Temperature, pressure
8	Stack exhaust	Temperature
9	Electrical power	Active power, power factor, frequency, voltage, current
	Shaft power	Torque, rotor speed
10	Losses	Thermal, mechanical, electrical

Note Any additional streams crossing the test boundary should be accounted for.

The losses are needed for the determination of the gas turbine exhaust energy and include all energy fluxes leaving the test boundary. Such losses are typically radiation losses, bearing and gear losses, generator losses and thermal losses. An example for the latter is heat dissipation from compressor air cooling systems in combination with a heat recovery boiler of a combined cycle plant.

Generally the losses have a small influence on the calculated gas turbine exhaust energy and therefore are often taken as constant design value rather than measured. An exception is the heat extracted from cooling systems, which may be determined based on measured flow, temperature and pressure.

5 Symbols

The symbols and nomenclature used in this International Standard are given in Table 2, together with the physical unit.

Table 2 – Symbols

Symbol	Definition	Unit
$C_{P,i}$	Correction factor for power output	-
$C_{P,i,a}$	Correction factor for power output, from measured to standard reference conditions	-
$C_{P,i,b}$	Correction factor for power output, from specified to standard reference conditions	-
$C\eta,i$	Correction factor for thermal efficiency	-
$C\eta,i,a$	Correction factor for thermal efficiency, from measured to standard reference conditions	-
$C\eta,i,b$	Correction factor for thermal efficiency, from specified to standard reference conditions	-
$\cos\varphi$	Generator power factor	-
$c_{p,a1}$	Specific heat (heat capacity) at constant pressure of air	kJ / (kg · K)

Table 2 (*continued*)

Symbol	Definition	Unit
$c_{p,i}$	Specific heat (heat capacity) of gases at constant pressure	kJ / (kg ⋅ K)
$c_{P,g7}$	Specific heat (heat capacity) at constant pressure of exhaust gases	kJ / (kg ⋅ K)
h_{a1}	Specific enthalpy of air at temperature T_{a1} entering the compressor	kJ / kg
h_{a3}	Specific enthalpy of air at compressor discharge temperature T_{a3}	kJ / kg
h_{ae}	Specific enthalpy of air at temperature T_{ae} leaking from the control volume	kJ / kg
$h_{ct3.2}$	Specific enthalpy of the air flow from the external cooler at temperature $T_{ct3.2}$ entering the control volume	kJ / kg
$h_{ex,i}$	Specific enthalpy of air at temperature $T_{ex,i}$ extracted from the compressor extraction *i*	kJ / kg
h_{f4}	Specific enthalpy of fuel at temperature T_{f4} entering the heat source (combustion chamber)	kJ / kg
h_{g6}	Mean specific enthalpy of gases at temperature T_{g6} entering the turbine	kJ / kg
h_{g7}	Specific enthalpy of exhaust gases at temperature T_{g7}	kJ / kg
h_{g8}	Specific enthalpy of exhaust gases at temperature T_{g8}	kJ / kg
HR	Heat rate of the gas turbine, based on low heating value (LHV) of the fuel and electrical power output	kJ / kWh
HR_c	Corrected heat rate of the gas turbine	kJ / kWh
HR_m	Calculated from measured data heat rate of the gas turbine	kJ / kWh
h_{w4}	Specific enthalpy of the injected water or steam mass flow at temperature T_{w4} entering the control volume	kJ / kg
h_0	Specific enthalpy of the fuel at reference temperature T_{f0}=15 °C	kJ / kg
I_S	Secondary current at instrument transformer	A
K_I	Ratio of current transformer	-
K_U	Ratio of voltage transformer	-
$\dot{m}_{a1}$	Compressor inlet air mass flow	kg / s
$\dot{m}_{a3}$	Compressor discharge air mass flow	kg / s
$\dot{m}_{ae}$	Mass flow of sealing and/or leakage air leaving the control volume	kg / s
$\dot{m}_{CA,T}$	Total turbine cooling air mass flow	kg / s

Table 2 (*continued*)

Symbol	Definition	Unit
$\dot{m}_{CA,CC}$	Combustion chamber cooling air mass flow	kg / s
$\dot{m}_{CA,1stV}$	Cooling air mass flow for 1st turbine vane row	kg / s
$\dot{m}_{e3}$	Mass flow of extracted compressor discharge air	kg / s
$\dot{m}_{ct3}$	Air mass flow to the external cooler leaving and entering the control volume	kg / s
$\dot{m}_{d}$	Relative difference in inlet mass flow between the equivalent and the actual compressor (that is, equivalent reduction flow of actual compressor inlet air flow)	%
$\dot{m}_{eq}$	Air inlet mass flow of an equivalent compressor without cooling air extraction lines, but with the same power consumption as the actual compressor	kg / s
$\dot{m}_{ex,i}$	Extraction air mass flow at the compressor extraction line i	kg / s
$\dot{m}_{f4}$	Fuel mass flow entering the control volume	kg / s
$\dot{m}_{g6}$	Gas mass flow entering the turbine	kg / s
$\dot{m}_{g7}$	Mass flow of the turbine exhaust gases	kg / s
$\dot{m}_{g7c}$	Corrected mass flow of the turbine exhaust gases	kg / s
$\dot{m}_{g8}$	Mass flow of the turbine exhaust gases	kg / s
$\dot{m}_{w4}$	Injected water or steam mass flow entering the control volume	kg / s
n_c	Reference speed of the output shaft	1/s
n_m	Specified speed of the output shaft during the test	1/s
N	Number of correction factors	-
Pb	Cooling air booster power consumption	kW
P_c	Net shaft power output at reference conditions	kW
P_{COMP}	Compressor shaft power consumption	kW
P_{e9}	Electrical power output at generator terminals	kW
P_{e9c}	Corrected electrical power output at generator terminals	kW
P_{LL}	Transformer load losses	kW
P_{NLL}	Transformer no-load losses	kW
P_S	Net shaft gas turbine shaft power output during the test	kW
P_{TRL}	Transformer losses	kW
Q_G	Generator losses	kW
$Q_{G,d}$	Generator losses from design	kW
Q_{GB}	Gearbox losses	kW
Q_{a1}	Energy stream of compressor inlet air flow, at spec. enthalpy h_{a1}	kJ / s
Q_{a3}	Energy stream of air flow at combustion chamber inlet, at spec. enthalpy h_{a3}	kJ / s
Q_{ae}	Energy stream of sealing and/or leakage air flow leaving the control volume, at spec. enthalpy h_{ae}	kJ / s
$Q_{ct3.1}$	Energy stream of cooling air flow to cooler inlet, at spec. enthalpy h_{a3}	kJ / s
$Q_{ct3.2}$	Energy stream of cooling air flow from cooler outlet, at spec. enthalpy $h_{ct3,2}$	kJ / s
Q_{e3}	Energy stream of external air extraction flow, at spec. enthalpy h_{a3}	kJ / s
Q_{ex}	Energy stream of cooling air extraction equivalent flow expressed as $\dot{m}_d$, at spec. enthalpy h_{a1}	kJ / s

Table 2 (*continued*)

Symbol	Definition	Unit
Q_{f4}	Energy stream of fuel entering the combustion chamber, based on fuel low heating value (LHV)	kJ / s
Q_{g6}	Energy stream of turbine inlet flow, at spec. enthalpy h_{g6}	kJ / s
Q_{g7}	Energy stream of exhaust flow at turbine at spec. enthalpy h_{g7}	kJ / s
Q_{g8}	Energy stream of turbine exhaust flow at,spec. enthalpy h_{g8}	kJ / s
Q_{7Ta1}	Energy of turbine exhaust flow, with the reference temperature of its spec. enthalpy indexed to the reference ambient air temperature T_{a1}	kJ / s
Q_{7cTa1}	Corrected energy stream of turbine exhaust flow, with the reference temperature of its spec. enthalpy indexed to the reference ambient air temperature T_{a1}	kJ / s
Q_{7cT0}	Corrected energy stream of turbine exhaust flow, with the reference temperature of its spec. enthalpy indexed to the reference temperature T_0	kJ / s
Q_{lo}	Low heating value (LHV)(lower heating value) of the fuel at 15 °C and constant pressure	kJ / kg
Q_m	Gas turbine mechanical losses	kW
$Q_{m,d}$	Gas turbine mechanical losses from design	kW
Q_r	Radiation and convection heat losses of the whole surface	kW
Q_{th}	Thermal heat losses(for example: heat extracted from compressor air cooling system)	kW
$Q_{th,m(d)}$	Thermal heat losses, measured or from design	kW
Q_{w4}	Energy of injected steam/water flow, at spec. enthalpy h_{w4}	kJ / s
$Q_{w4,mc}$	Measured energy of injected steam/water flow, corrected to design if applicable	kJ / s
Q_{10}	Sum of engine losses *(Q_m+Q_G+Q_r+Q_{th} +Q_{GB})*	kW
$SH = h_{f4} - h_0$	Sensible heat of the fuel	kJ / kg
S_m	Measured apparent power which is the product of measured (rms) voltage and (rms) current	kVA
S_r	Rated apparent power which is the product of rated (rms) voltage and (rms) current	kVA
T_0	Standard reference temperature for specific enthalpy of air and gases	K
T_{f0}	Reference temperature(=15°C) for specific enthalpy of fuel	°C
T_{a1}	Ambient air temperature	°C
T_{a3}	Air temperature at compressor discharge	°C
T_{ae}	Temperature of sealing and/or leakage air flow leaving the control volume	°C
T_c	Control temperature at reference conditions	°C
$T_{ct3.2}$	Temperature of the air flow from the external cooler entering the control volume	°C
$T_{ex,i}$	Extraction air temperature at the compressor extraction line *i*	°C
T_{f4}	Temperature of fuel entering the heat source (combustion chamber)	°C
T_{g6}	Temperature of gases entering the turbine	°C
T_{g7}	Average temperature of exhaust gases	°C
T_{g7c}	Corrected average temperature of exhaust gases	°C
T_{g7m}	Measured average temperature of exhaust gases	°C
T_{g8}	Mass flow average temperature of exhaust gases at the stack (simple cycle applications)	°C

Table 2 (*continued*)

Symbol	Definition	Unit
T_m	Control temperature during the test	°C
T_{w4}	Temperature of injected water or steam entering the control volume	°C
U_S	Secondary voltage at instrument transformer	V
η	Thermal efficiency of the gas turbine based on electrical power output and fuel lower heating value	-
η_C	Corrected thermal efficiency of the gas turbine	-
η_m	Measured/calculated thermal efficiency of the gas turbine	-
η_{tc}	Combustion chamber efficiency from design, taken into account the total radiation and convention heat losses	-
$\Delta_{TOT,i}$	Additive correction factor i for turbine outlet temperature	K
$\Delta_{TOT,i,a}$	Additive correction factor i for turbine outlet temperature, from measured to standard reference conditions	K
$\Delta_{TOT,i,b}$	Additive correction factor i for turbine outlet temperature, from specified to standard reference conditions	K
θ	Ratio of the absolute gas turbine compressor inlet air temperatures at test (measured), and at reference conditions	-
δ	Ratio of the ambient absolute pressure to the reference ambient absolute pressure	-

Note:
1. Air or gas temperatures are assumed to be total temperature unless otherwise agreed
2. The general equation of specific enthalpy of ideal gases is $h = h_T - h_{T0} \approx c_p(T-T_0)$

where

h_{T0} is the gas specific enthalpy at the standard reference temperature T_0 of the enthalpy and

T is the actual gas temperature.

Usually T_0=0°C : in this case $h_{T0} = 0$ and $h = hT \approx c_{pT}$; but it can be assumed equal to the ambient air temperature, or to any other temperature.

6 Preparation for tests

6.1 General

Performance Testing requires complex and detailed preparations. Since the purpose of such tests may vary, it is important to establish upfront the test objectives, identify the participating parties and their role in the process. A clear determination of the equipment boundaries and associated instrumentation shall avoid any potential disagreements after the test. A detailed test procedure specific to the test site/supplier's test facility and conditions shall be agreed by all parties involved.

6.1.1 Agreements before the test

Many factors influence significantly the results of acceptance tests. Therefore tests shall always be carefully programmed, organized and conducted so that the results are of the highest practical accuracy.

6.1.2 Test objectives

The objective of any tests is to determine performance characteristics of the gas turbine in accordance to any previously drawn up agreements such as the Purchase Agreements, Test Criteria Documents, EPC requirements, Power Purchase Agreements, Contractual Services Agreement etc. A detailed procedure for conducting the tests and evaluating the results shall be issued and agreed upon prior to conducting the tests. This test procedure shall provide full details of the method of measurement and about method used for correcting the results from test conditions to the reference conditions or the criteria set out in the pertinent documents. This test standard does not deal with tests needed to determine the environmental emissions, noise and vibration, that generally form part of other test procedures. However, these tests can be carried out concurrently with acceptance tests as per the purchase contracts or other related documents.

6.1.3 Performance degradation

The performance degradation of gas turbine during operation is an existing phenomenon. The degradation on the gas turbine is caused primarily by fouling and erosion of the gas flow path, and also by wear and tear. The agreement to apply degradation corrections to the performance test results is strictly a commercial issue between the parties and beyond the scope of this standard.

In most cases, the gas turbine performance guarantees are made based on equipment “new and clean” condition. The contractual agreements between the parties should define the period when the equipment is considered as new and clean and state if performance corrections are permitted, when equipment is tested beyond this period.

The detailed methodology on how to apply degradation correction may be derived from Comparative Tests, fleet performance of similar units, predictive degradation curves, or other methods. It should be also noted that actual measurement of degradation through Comparative Testing over short time periods is difficult because the rate of deterioration and measurement uncertainty have similar magnitudes and by the fact that during commissioning the control parameters could be changed. The degradation correction may be additive or multiplicative and could be applied to the test results or the guarantees made to the gas turbine as indicated in 8.2.2.5.

6.1.4 Design, Construction and start up considerations

The following recommendations should be considered when establishing the requirements for instrumentation accuracy, calibration, documentation and location of permanent and temporary instrumentation to be used during the test.

1. If permanent installed instrumentation will be used during the test, the requirements of 6.4 should be implemented if possible at early stages of the design. The ability to conduct post test calibrations or to substitute with temporary instrumentation also should be considered.

2. For temporary instrumentation, the design should cater to allow connections and spools sections, pressure connections, thermo wells and electrical tie-ins. To meet the required flow meters measurement uncertainty limits, use of flow straighteners is recommended.

3. The instrumentation layout shall be as given in this scope for measurement uncertainty and if possible allow the ability to validate critical test measurements. (e.g. pressure, temperature, fuel flow, power output)

6.2 Test procedure

The performance test shall be conducted based on a test procedure, which was developed to provide detailed guidance on the test execution. This document supplements the contract obligations and clarifies particulars of contract issues. It shall provide the course of action for performing the test. . Prior to the execution, the test procedure shall be agreed upon, by authorized signatures of all parties to the test. The following topics should be included within the test procedure:

a) Base reference conditions and guarantees

b) The criteria for acceptance at the test completion.

c) Test control borders and the locations of the measuring sensors

d) Details about instrumentation including : type, location and calibration requirements

e) The requirements for the stabilization period prior to the test commencement.

f) The details concerning fuel handling, including a procedure for fuel samples collection, handling, method of analysis, frequency of sampling, as well as the distribution of duplicate fuel samples for each party, including a set of samples to be kept in case of additional analysis

g) Allowable range of fuel conditions, including constituents and heating value

h) Required operating conditions, e.g. test load, rotating speed, isolation list (see also Table 9)

i) Required levels of equipment cleanliness and inspections prior to test

j) Procedure to account for performance degradation

k) Recording of test readings and observations

l) Number of test runs and duration of each run

m) Frequency of data acquisition, data acceptance and rejection criteria

n) Method of combining test runs to calculate the final test result

o) Numerical values, curves or algorithms for correction under conditions differing from the specified conditions

p) Requirements for data storage, document retention, data and test report distribution

q) Method for agreeing and documenting any modification to test procedure

r) Method for documenting the specific gas turbine control parameters pre-test and post-test.

6.3 Test preparation

The equipment shall be capable of reliable operation at full load before any test at the suppliers test facility or on site test commences. Where on site testing is to be undertaken, the tests should be carried out very shortly after the commissioning process has been completed. For the plants that are already in commercial operation the tests shall be carried out in clean and undamaged condition. Appropriate degradation allowance may be applied as agreed in commercial contracts

A test director shall be appointed by the test conducting party. The appointed test director shall be responsible for seeing that all tests are conducted in professional manners and this test standard used as a guideline for the execution of the tests. The previously agreed test procedure shall be the basis for conducting the tests.

Prior to the tests, all parties involved in the testing shall be in agreement with the procedures for at least the following items:

a) Conduct a survey of all plant identifying any deficiencies in equipment and for procedures, which might affect the performance test.

b) inspection of the fuel flow measuring system

c) The gas turbine compressor blades should be visually inspected and cleaned (off line washing with previous hand washing if necessary) unless only limited running, from a known clean condition, has been undertaken before the test and all the components are clean and ready for test.

d) Gas turbine compressor inlet guide vane angle has been verified by measurement and adjusted to control specifications if necessary.

e) Gas turbine TIT (turbine inlet temperature) control parameters based on the exhaust temperature and other relevant factors.

f) Calibration of all temporary instruments before shipment to site and valid certificates to be less than 12 months, traceable to national or international laboratories.

g) Location and proper installation of all temporary and unit (if applicable) instruments and crosschecked with the calibration certificates and serial numbers.

h) Electrical power output measurement including power factor (gross and/or net if applicable).

i) Data acquisition system for monitoring all relevant parameters and the frequency of data collection.

j) Data that is required manually and the frequency of data collection.

k) Use of operating screen prints for additional information which may include plant emission readings and any alarms that may affect the running of the acceptance tests.

l) Detailed schedule of all the tests including the duration of all tests.

m) Operation modes and settings of the gas turbine (e.g. bypass or boiler, anti-icing, compressor bleed, etc.).

n) A preliminary and recent fuel analysis (with fuel density and calorific value) is available to ensure that the fuel is substantially as intended.

o) Sampling methodology and the frequency of sampling of the primary fuel. The number of samples to be retained by the operator, the conducting test team and spare sample shall be agreed prior to the test. Identification of the names of the laboratories for fuel analyses. Portable gas analysis equipment may be selected for this use, if it meets the accuracy requirements of this standard.

p) A proper number of personnel, of suitable skill, is available for the correct use of the instruments and for collecting the test data.

q) An effective indication and intercom system is available to indicate the starting and the end of the tests and the various pauses wherein the readings of the different instruments shall to be taken.

6.3.1 Equipment preparation

Proper preparation of the gas turbine test is essential. Where a site test is to be undertaken this preparation is not considered part of normal commissioning activity of the plant that is being acceptance tested from new. For on site tests it is normal practice that the supplier of the equipment inspects the plant to be tested and provide instructions as to the restorative action that is required prior to conducting the tests. In any case, before the tests, the machine shall be placed at the disposal of the supplier for examination and cleaning. A pre-test readiness report that demonstrates the equipment has been properly prepared shall be issued to all the parties concerned by the tester of the plant prior to conducting the tests.

6.3.2 Test deviation agreements

Any test deviation outside the performance test procedure or this test standard shall be agreed prior to the test completion and shall be handed over in writing to all parties involved.

A meeting shall be held with all parties involved to agree if the preceding tests were conducted in accordance with performance test procedure and the guidelines given in the test standard. It shall also be agreed whether the collected data are acceptable to all parties involved in the tests. Once this has been agreed, the test shall be designated as an official test.

6.3.3 Schedule and location of test activities

A test schedule should be prepared to include at least the sequence of events, anticipated time of test and requirements to notify of the parties. Other activities such as preparations to the test, conduct of the test and completion of the report results should also be provided. The location shall be designated at the actual plant site or other test facilities, where working conditioned could be acceptable to all parties.

6.3.4 Preliminary to tests

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.

6.3.5 Pre test records

Dimensions and physical conditions of parts (pipe length, orifice diameters) of the gas turbine required for calculations or other test purposes shall be determined and recorded before the test. Serial numbers and data from nameplates should be recorded to identify the gas turbine and auxiliary equipment tested. All instrumentation should be identified and model and serial numbers recorded. Documentation shall be developed or be made available for calculated or adjusted data to provide independent verification of algorithms, constants, scaling, calibration corrections, offsets, base points, and conversions.

6.4 Instruments and measuring methods

6.4.1 General requirements

This section describes the instruments, methods and precautions to be employed in testing gas turbines and components in accordance with this International Standard. Where there is no specification in this clause concerning the instruments and the measurement method used, these shall be subject to agreement by the parties to the test.

The use of advanced electronic instruments and devices together with a computer controlled data recording and processing system is preferred in respect of achieving test data and results with the highest level of accuracy. However manual recording of analogue instruments is allowed in cases where non-electronic instrumentations are used.

The instruments and measuring methods mentioned and described hereafter are state of the art and commonly employed at the time this International Standard is published, however, new technology and methods of measurement may be adopted for performance testing as they are available provided they comply with the requirements for the maximum uncertainties specified herein.

Instruments, devices and measurements shall be employed in accordance with relevant International Standards, unless otherwise agreed.

Users of this standard shall develop a site and equipment specific uncertainty calculation based on the implicit understanding that all parties to a performance test are interested in test results with lowest practical uncertainty.

The final uncertainty of a test result will be unique for each test because of the differences in the scope of supply, fuel used, turbine sensitivity coefficients, instrumentation and driven equipment characteristics. Therefore, it is not the intention of this standard to define limits for the overall uncertainty of a test.

To ensure reliable and accurate test results, limits for the uncertainty of required measurements and also for the permissible variations of the operating parameters during a test are established in this standard.

For comparative testing, unlike absolute level of testing, the determination of uncertainty is different, since the desired result is the difference in power or efficiency rather than the absolute level. The viability of the test is based on selecting the appropriate instrumentation and defining the sensitivities in such a way that the uncertainty will be only a relative small percentage of the expected differential.

6.4.1.1 Measurement uncertainty

In general, no measurement or test is perfect and imperfections give rise to error of measurements in the result. Consequently, the result of a measurement is only an approximation to the value of measurand, i.e. the specific quantity subject to measurement. When applied to gas turbine testing, the general term measurand may cover many different quantities, e.g. gas turbine heat rate, plant efficiency, electrical or mechanical power, the mass flow of water or steam, temperature and pressure of fluids. A detailed way to conduct a measurement uncertainty is given in Annex A. The application of uncertainty analysis to a test has the following objectives:

a) enables to quantify the quality of a test result ;

b) identifies the contribution of each measurement to the overall test uncertainty;

c) provides a mechanism for improving the quality of the test.

If the instruments for a performance test are qualified with an uncertainty equal to or better than the maximum uncertainties as specified in Table 3 then the test results will follow with an inherently high level of accuracy. In such cases the determination of the overall test uncertainty is not mandatory.

However, where one or more test instruments are not in conformance with the uncertainty levels of Table 3 the following procedure may be applied:

A pre-test uncertainty analysis shall be performed by using the limit for each measurement specified in Table 3 along with the appropriate sensitivity factors for the turbine being tested. This shall provide a benchmark for the overall test uncertainty.

Then the number and type of instrument(s) for each parameter shall be selected so that the result of the overall uncertainty is equal to or less than the previously calculated benchmark.

The application and the use of overall uncertainty figures to the final performance test results are outside the scope of this standard, as these are primarily contractual and its rationalisation should be agreed prior to the acceptance tests. However, when uncertainty of measured of relative performance levels is to be calculated it is essential that for all instrument readings the random and systematic error associated with the readings are known.

6.4.1.2 Maximum allowable uncertainties

To achieve test results with highest possible accuracy it is mandatory to establish the maximum permissible uncertainties of measuring instruments, devices or parameters.

During preparation of a performance test the measurement methods shall be carefully evaluated and the instruments and apparatus calibrated to prove that they are in compliance with the uncertainties summarized in Table 3 for units generating electrical power.

Table 3 – Maximum permissible uncertainties

Individual instrument or parameter	Max. uncertainty	Remarks
Barometric pressure	± 0.05 %	Instrument uncertainty
Air inlet temperature	± 0.2 K	Instrument uncertainty
Relative humidity	± 2 %	Instrument uncertainty
Electrical power metering	± 0.2 %	Instrument uncertainty
Current transformer	± 0.2 %	Equivalent to accuracy class 0.2S
Voltage transformer	± 0.2 %	Equivalent to accuracy class 0.2S
Mechanical power (torque)	± 1.0 %	Instrument uncertainty
Frequency / Shaft speed	± 0.25 %	Instrument uncertainty
Gas fuel pressure	± 0.25 %	Instrument uncertainty
Gas fuel temperature	± 0.2 K	Instrument uncertainty
Gas fuel heating value	± 0.5 %	Combined uncertainty of gas composition
Gas fuel mass flow	± 0.5 %	Combined uncertainty of temperature, pressure, volumetric flow and gas composition
Oil fuel temperature	± 0.2 K	Instrument uncertainty
Oil fuel heating value	± 1.0 %	Combined uncertainty of laboratory analysis
Oil fuel mass flow	± 0.5 %	Combined uncertainty of volumetric flow and temperature
Turbine exhaust temperature	± 3 K	Instrument uncertainty
Inlet pressure loss	± 50 Pa	Instrument uncertainty
Exhaust pressure loss	± 50 Pa	Instrument uncertainty

6.4.1.3 Calibration

The calibration, defined as set of operations that establish, under specified conditions, the relationship between values of quantities indicated by a measuring instrument of measuring system, or values represented by a material measure of a reference material, and the corresponding values realized by standards (ISO/IEC Guide 99), is providing the input quantity for the correction or compensation of the recognized error arising from a systematic effect as well as the quantity of the remaining uncertainty (Type B standard uncertainty, ISO/IEC Guide 98-3) which is required for the determination of the combined standard uncertainty of the final test result.

The instruments and devices required for the determination of the performance as defined in the test procedure shall be properly calibrated versus reference standards to allow elimination of the systematic effect of the candidates, where applicable, and to verify that their uncertainties are in compliance with the maximum uncertainties given in Table 3.

The calibration shall include sufficient points covering the operation range expected for the performance test as well as considering hysteresis effects. If on-site plant instruments and devices are used for performance testing, the required calibration may be accomplished with working standards. Likewise, on-site calibration checks of temporary test equipment can be done using working standards.

Each instrument shall be provided with a calibration certificate proving the traceability of the calibration procedure to national or international standards and shall be reported as recommended by EA (European co-operation for Accreditation) in the publication Expression of Uncertainty of Measurement in Calibration (EA-04/02) or other recognized organizations. Certificates of calibration shall meet the requirement stated in Section 6.3 item f.

The adjustment of the measuring instrument or system for systematic error from calibration can either be done by compensating the systematic effect with an algebraically added correction or a numerical correction factor applied to the measurement result. Where electronic data collection systems are used for performance testing, the adjustment of the systematic type of deviation by means of correction can be replaced by using polynomial regression curves generated with the method of least square fitting based on the calibration data of the reference standard and the relating electronic signal of the measuring instrument.

The need for re-calibration of various sensors will be determined based on the sensor manufacturer recommendations for specific applications.

6.4.2 Pressure measurement

Preferably calibrated electronic pressure transducers based on sensing technology such as piezo, capacitive etc. with temperature compensation shall be used to assure highest level of measurement accuracy. However instruments like manometers (U-tube or single leg type), dead-weight gauges Bourdon or other elastic type gauges may also be used where applicable.

The methodology, number and type of instruments used for the measurement of a pressure shall be carefully evaluated considering magnitude and range of parameter, accuracy requirement as well as specific flow dynamics and design of equipment.

Attention shall be paid to location and installation of pressure instruments in a manner that no additional errors induced by environmental conditions such as radiation, vibration, etc. or leakage of pipe and fitting increase the uncertainty of the reading.

6.4.2.1 Barometric pressure

The absolute atmospheric pressure shall be measured with a barometric pressure transmitter calibrated with a maximum uncertainty of 0.05%. The instrument shall be located outside of any closed containment in a stable and protected environment at an elevation equal to the centreline of the gas turbine shaft.

Barometric pressures from local weather stations shall not be used.

6.4.2.2 Compressor inlet pressure

Compressor inlet pressure is defined as the total pressure prevailing at the compressor inlet. It is an absolute pressure based on the algebraic sum of the barometric pressure, the gauge static pressure and the dynamic pressure, when the quantities are measured and evaluated separately.

The dynamic pressure is usually calculated using the mean velocity and air density in the section where static pressures are measured. This mean velocity is computed from the area of this section and the rated flow.

If no inlet duct, silencer or filter is used; inlet pressure shall be taken as barometric pressure.

Where the mean velocity at the compressor flange or in the vicinity of the compressor inlet flare is below 20 m/s, static pressure may be measured at one station only. In the event of the velocity being higher than 20 m/s, static pressure shall be taken as the average of three stations, placed as near symmetrically as possible in a place normal to the mean flow.

For closed cycle installations, the procedure for measuring compressor inlet pressure shall be the same as that specified for compressor outlet pressure

6.4.2.3 Turbine outlet pressure

Turbine outlet pressure is defined as the static pressure prevailing at the turbine exhaust flange (or regenerator outlet flange, if a regenerative cycle is used), and is obtained in the same manner as for the compressor inlet pressure. The static pressure shall be taken as the arithmetic average of the measurements at three stations placed as nearly symmetrically as possible in the section.

If no outlet duct is used, outlet static pressure shall be taken as barometric pressure.

Where conditions of high velocity and pressure gradients exist at the chosen location, measurement methods shall be agreed to ensure that the value obtained is representative of the mean weighted pressure. Alternatively, a calculated exhaust pressure relative to ambient may be considered.

6.4.2.4 Compressor outlet pressure and turbine inlet pressure

If turbine inlet temperature is determined by indirect means, it may be necessary to measure the compressor outlet pressure or, if practicable, the turbine inlet pressure.

Static pressure shall be measured by one or more probes as applicable. In case of multiple probes, the pressure value will be the arithmetic average of the measurements. Dynamic pressure shall be computed from the estimated mean velocity in the relevant section.

6.4.2.5 Fuel gas pressure

For the determination of the fuel gas density at line conditions the fuel gas pressure shall be measured in conjunction with the fuel gas temperature installed as close as possible to the fuel meter.

6.4.3 Temperature measurement

Recommended instruments for measuring temperatures are:

a) resistance thermometers (IEC 60751, Industrial platinum resistance thermometer sensors)

b) thermocouples [IEC 60584 (all parts)]

Other temperature measuring devices such as thermistors and liquid in-glass thermometers may also be used provided they are properly calibrated with uncertainty in compliance with the limits given in this standard.

Each instrument used for testing shall be calibrated or compared with an instrument certified by a recognized authority to verify that they are within the maximum uncertainty limits.

Where the temperature of a fluid stream is measured with the dynamic component of temperature exceeding 0.5K, a stagnation (total temperature) type thermometer shall be used, or alternatively the appropriate correction shall be applied to the measurement made with a standard probe.

6.4.3.1 Air inlet temperature

Depending on the test boundary definition the air inlet temperature is equal either to the ambient air temperature or the compressor inlet temperature.

6.4.3.2 Ambient air temperature

Instruments required for the measurement of the ambient air temperature shall be installed at the location where the air stream is crossing the specified test boundary, typically at the filter house of the air inlet duct. Special care is required for the protection and shielding of the temperature probes from solar and other radiation sources as well as from high (> 10 m/s) air flow across the sensing element.

In case of multiple gas turbine units, installed in one or more rows or staggered, with or without evaporative cooling systems (within the inlet air system) every effort shall be taken to find the most representative and accurate location(s) for the determination of the weighted average of the ambient air temperature and humidity, where the test boundary is entered.

The number of instruments shall depend on the shape and the size of the air filter system inlet area.The temperature shall be measured with four instruments uniformly distributed over the cross sectional area of the inlet. It is recommended to locate one sensor for each 10 m^2 of inlet area. In case where inhomogeneous temperature profile exists over the inlet section, the number of probes shall be increased accordingly. If the difference of the maximum and minimum temperature is larger than 5 K, such as in case of nearby plant equipment producing hot streams directed towards the air inlet duct, the root cause shall be investigated and where possible eliminated.

6.4.3.3 Compressor inlet temperature

The air temperature at the compressor inlet may be used for energy balance calculation. It shall be measured with instruments having a maximum uncertainty of 0.2°K. At least two sensors shall be used and readings taken simultaneously to calculate the mean value. If the temperature is measured at a location where the air velocity is higher than 20 m/s, the measured temperature shall be corrected with the computed dynamic portion of the total temperature using the calculated air velocity.

In case of evaporative cooling or other fogging systems in operation care should be taken for the selection of the measurement location(s) in order to prevent sub-cooling of the temperature element(s) by water droplet impingement.

6.4.3.4 Turbine inlet temperature TIT

Operation of the gas turbine at the specified temperature setting during testing is fundamental to the determination of thermal performances. Generally, gas turbines are designed on the basis of turbine inlet temperature, which is, except for special cases such as closed cycle gas turbines, virtually impossible to measure. Therefore the turbine inlet temperature can only be determined by indirect means based on heat balance calculations. The procedure for the calculation of the ISO turbine inlet temperature is defined in 8.3.5.2.

For the measurement of the turbine inlet temperature of closed cycle turbines, two sensors may be sufficient.

6.4.3.5 Turbine outlet (exhaust) temperature

Typically the scope of a gas turbine includes the measurement devices for the turbine outlet temperature because it is used in the gas turbine operation, control and protection system as primary input parameter. Gas turbine manufacturers, through development and experience, are determining the number and location of the temperature measurement probes in the exhaust plenum or in the inter-stage area (on multiple shaft or reheat gas turbines), accounting for non-uniform temperature and flow velocity profiles as well as thermal radiation and conduction effects.

If temporary test instrumentation is used for the measurement of the turbine outlet temperature, a minimum of four sensors or appropriate traverse probes shall be located at centres of equal cross sectional areas considering spatial temperature and flow velocity gradients. If, for practical reasons, it is necessary to place the sensors close to, or at, the turbine exhaust flange, more than four sensors may be required to assure adequate accuracy. For closed cycle turbines, two temperature probes may be sufficient. The casing and the duct between the turbine exhaust flange and the measuring station shall be properly insulated.

The exhaust gas temperature shall be measured near the test boundary, which is often the interface plane between the gas turbine and Heat Recovery Steam Generator or the gas turbine exhaust stack. The exhaust gas from a gas turbine usually has a non-uniform temperature and velocity profile. Therefore, the individual measured exhaust gas temperatures may be averaged. The method shall be defined by the manufacturer. The preferred method is for the manufacturer to provide a calculation method based on either field test data from other similar units, or from analytical means such as CFD modelling.

6.4.3.6 Combustion chamber air inlet temperature

It may be necessary (see 8.3.4) to determine the mean total temperature at the inlet to the combustion chamber and estimate the temperature rise therein. Methods for measurement of the mean total temperature at the entry to the combustion chamber will vary according to the detailed design of the machine. Necessary precautions shall be taken into account against radiation

6.4.3.7 Fuel temperature

Fuel temperature may need to be measured at two different locations, close to the flow meter for the calculation of the fuel supply and, if applicable, for liquid fuel return and at the test boundary for the determination of the sensible heat.

6.4.4 Fuel measurements

6.4.4.1 Gaseous fuel

Since each energy stream shall be determined with reference to the point at which they cross the test boundary, the choice of the test boundary can have a significant impact on the test results. It may be at a different location depending on what parameter is being determined (i.e. gas turbine efficiency vs. exhaust gas energy via heat balance). An example might be the use of a fuel pre-heater, which requires the use of different temperature values for efficiency and exhaust energy.

6.4.4.1.1 Gas fuel characteristics

Gaseous fuel characteristics shall include the determination of

a) density

b) heating value

c) composition

d) temperature

e) pressure

f) flow

Upon agreement between the parties to the test, heating value and density may be calculated or taken from records of the gas supplier, provided the dates and times of the records are concurrent with test dates and times, and the bases of the values selected are completely described in the test reports. In addition the calibration data of the reference measurement instrumentation shall be traceable to International Standards with the uncertainty in compliance with the limits given in these Standards.

For blast furnace or refinery gas and other gases, the composition of which varies continuously, sampling shall be carried out with such frequency during the period of the test that a fair and representative heating value of the gas is obtained by averaging the results. When possible, it is recommended that a gas chromatograph be used during the test.

6.4.4.1.2 Gas fuel density

The gas density and compressibility at test conditions shall be calculated with the methods specified in ISO 6976 and ISO 12213-2 respectively, based on fuel gas pressure and temperature measured at the flow meter. Both, density and compressibility shall be determined with the actual molar fuel gas composition.

For gas mixtures not covered by the referenced standards parties shall agree on the method to be used to calculate the density.

6.4.4.1.3 Heating value

The lower heating value (LHV), called also net heating value of gaseous fuel shall be determined by computation according to ISO 6976, using the specific heating values at constant pressure of the component gases and their normalized proportions in the fuel and based on a combustion reference temperature of 15°C.

Alternatively any other type of calorimeter may be used, if the uncertainty values required by the standard are met. The method to be applied shall be previously agreed upon by all parties to the test.

In any case, adjustment shall be made for sensible heat of the fuel where the actual temperature at test conditions is above or below 15 °C.

6.4.4.1.4 Fuel gas composition

The molar fuel gas fractions shall be determined by a certified laboratory in accordance with the chromatographic method for hydrocarbons up to C8 as described in ISO 6974-1, also called “Tailored Analysis”. If gas analysis is required for higher hydrocarbons up to hexadecane (C16), ISO 6975 shall be applicable (Extended Analysis).

Gas analysis data of online gas chromatographs may be acceptable by mutual agreement of the parties to the test and provided that the chromatographs are properly calibrated, traceable to international standards. Alternatively, for the verification of the online chromatograph, gas fuel samples may be analyzed by a certified laboratory and compared with the online results taken simultaneously with the samples.

The moisture fraction in industrial natural gas is usually of a small magnitude having a negligible effect on the heating value of the gas. Therefore the determination of the moisture content is not required. However, where indications reveal that the gas contains moisture above common standard, the fraction thereof shall be analyzed by either laboratory analysis or dew point measurement method.

In certain gaseous fuels such as blast furnace gas, the fraction of dust in the fuel is of importance and shall be measured. Dust may have an impact on the accuracy of the measurements of gas mass flow, due to possible erosion or other mechanical effects on the flowmeter. However, owing to the wide range of dust characteristics, loadings, etc., the parties shall agree previously on the procedure to be used by qualified personnel with experience in this class of fuels.

6.4.4.1.5 Fuel gas sampling

Fuel gas samples shall be taken in accordance with in ISO 10715 using special sample containers. It is recommended to take at least two sets of samples, one at the beginning and one at the end of a test run. Additional sets of samples may be taken within the test period where the gas composition is fluctuating.

A minimum of three samples per set shall be taken, one for the laboratory analysis plus an additional spare sample. The spare samples shall be retained until laboratory results are released and considered to be acceptable. The fuel characteristics used for test run analysis shall be determined from the average of the characteristics from the individual fuel samples taken at the beginning and completion of each test run.

6.4.4.1.6 Gaseous fuel flow measurement

The actual volume of flow per unit of time (flow rate) of gaseous fuels shall preferably be determined by means of either a turbine type flow meter in accordance with ISO 9951, a positive displacement volumetric flow meter, an orifice metering run or a coriolis meter meeting the applicable requirements of a recognised international or national standard.

In the event of such a method not being practicable, gas consumption may be determined from flow measurement by means of nozzles, orifices or venturi meters, which shall be designed, arranged and instrumented in accordance with ISO 5167 (all parts).

The computation of the actual fuel mass flows at test conditions is based on the equations outlined in ISO 9951 and ISO 5167 (all parts) respectively and in conjunction with ISO 6976 for the determination of the gas density.

Ultrasonic flow meters or others shall also be permitted provided the devices are individually calibrated and comply with the uncertainty requirements given in this International Standard.

Fuel meters used for performance testing shall be individually calibrated to reduce the maximum uncertainty of fuel mass flow to 0,5%.

6.4.4.2 Liquid fuel measurement

6.4.4.2.1 Liquid fuel characteristics

Parties to the test shall agree upon the fuel sampling method. Fuel characteristics shall include the determination of:

a) density

b) heating value

c) viscosity where applicable

d) temperature

e) composition

f) flow

6.4.4.2.2 Density

Density of crude or liquid petroleum fuel may be obtained by hydrometer method as described in ISO 3675 or other equivalent standard. The actual density at test conditions shall be determined by interpolating between the analysis results using the measured fuel temperature.

6.4.4.2.3 Heating value

The higher heating value (HHV) (gross heating value) at constant volume and a reference temperature of 15°C shall be determined by means of a bomb calorimeter method. Then the lower heating value (LHV) (net heating value) at constant volume is found by calculation deducting the latent heat of the calculated amount of water vapour produced from the measured hydrogen content of the fuel.

The foregoing determination should be carried out in accordance with DIN 51900-1 or equivalent standard by a physical or chemical laboratory agreed upon by the parties. Continuous flow calorimeter or other ISO approved instrumentation may also be used.

In each case, adjustment shall be made for sensible heat of the fuel with a test temperature different than 15°C. The specific heat may be taken from the Table 4.

Table 4 – Liquid fuel properties

Fuel	Viscosity	Specific heat
Gas oil	< 9,5 x 10^{-6} m^2/s at 20 °C	1,88 kJ/kg/K
Light fuel oil	< 49 x 10^{-6} m^2/s at 20 °C	1,76 kJ/kg/K
Medium fuel oil	< 110 x 10^{-6} m^2/s at 50 °C	1,63 kJ/kg/K
Heavy or extra heavy fuel oil	< 380 x 10^{-6} m^2/s at 50 °C	1,59 kJ/kg/K

6.4.4.2.4 Liquid fuel composition

The liquid fuel mass fractions (C, H, N, O, S) shall be determined by the following codes: for Carbon, Hydrogen and Nitrogen ASTM D5291, Trace Nitrogen by ASTM D4629, Sulphur by ISO 14596 or ISO 20846 and Oxygen by DIN 51451. In addition the determination of water shall be done by ISO 3733 and for ash by ISO 6245 respectively. With the results of the fuel analysis the specific heat and enthalpy for the fuel and the exhaust gas can be established. Also the exhaust gas composition can then be determined.

6.4.4.2.5 Liquid fuel sampling

A fuel sampling location shall be identified and agreed upon prior to the test. The sampling shall be selected as close as possible to the test boundary, upstream of the metering station, such that the liquid fuel sample represents the characteristics of the fuel flowing through the metering device. Special care should be taken to ensure that the sampling location is not influenced by all the processes outside of the test boundary that may change the composition of the fuel (strainers, filters etc).

Sets of at least three liquid fuel samples should be taken at the beginning and completion of a test. If unsteady fuel supplies are suspected, samples may be taken more often. One sample from each set shall be sent to a qualified laboratory. One sample should be provided to the owner and the third should be retained until all fuel analysis is completed and the results are accepted by all parties. The fuel characteristics used for test analysis shall be determined from the average of the characteristics from individual fuel samples taken before and after each test.

6.4.4.2.6 Liquid fuel flow measurement

Where the liquid fuel flow is measured with a nozzle, orifice or venturi flow section, such meter shall be designed, arranged and instrumented in accordance with a recognized standard, for example ISO 5167 (all parts). Other flow devices such as positive displacement volumetric, vortex, coriolis or ultrasonic flow meters shall also be permitted. In any case, the fuel flow measuring device shall be suitably calibrated to ensure that the maximum uncertainty is less than 0,5 %

Calibrated volumetric measuring tanks may also be used provided that the required uncertainty of measurement can be demonstrated.

A weigh tank system shall be free upon its pivot and unconstrained by any external force such as might be applied by unsuitably designed or unsuitably placed pipe connections. It shall be calibrated before the test with an overall maximum uncertainty of measurement not exceeding 0,5% of the measured quantity.

Any spill or leakage from control valves or burners shall either be reintroduced into the fuel system downstream of the fuel flow meter or its quantity shall be separately measured and deducted from the total measured flow.

6.4.5 Power measurement

6.4.5.1 Electrical power measurement

These tests shall be performed using electrical measurement equipment in accordance with the standards of IEC (International Electro-technical Commission) or other recognized standards.

The definition of electrical power output to be verified may be given at different stations as indicated in Figure 3 depending on the test boundary stipulated by contractual scope or guarantee definition etc. The power may be measured at any station if properly equipped with adequate transformers and in conformance with the requirements of this International Standard.

It is to be noted that design and nomenclature may be different to the terms used by gas turbine manufacturers.

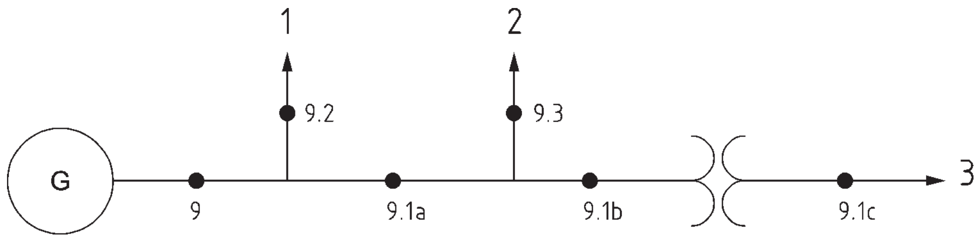


Figure 3 – Stations definition of electrical power

1 Excitation

2 Auxiliary

3 to grid

Table 5 – Station definitions for electric power measurement

Station	Description of measurement
9	Gross electrical power at generator terminals. In case of dynamic excitation of the generator this power corresponds with the power at station 9.1a.
9.1a	Net electrical power of generator = gross electrical power at generator terminals minus excitation power
9.1b	Net electrical power low voltage = net electrical power of generator minus equipment or plant auxiliary
9.1c	Net electrical power high voltage = net electrical power low voltage minus step-up transformer losses
9.2	Excitation power (static excitation)
9.3	Equipment or plant auxiliary

The metering method of the electrical power, the two-watt meter or preferably three-wattmeter method, is depending on the various types of the power generating and distributing arrangements, which typically are three-phase systems with Star or Delta generator connection in three- or four-wire configuration.

In order to select the appropriate metering equipment and define the corresponding instrument transformer connection the particular site configuration shall be reviewed during planning and preparation of the test.

6.4.5.1.1 Electrical power metering

For the measurement of the active power single-phase or poly-phase precision Watt- or Watthour-meters of an accuracy class of not more than 0,2% shall be used. If the power meter is not equipped with an integrated feature to measure the power factor, the instantaneous reactive power shall be recorded with a Var-or Var-hour meter of an accuracy class of 0,5% or less.

In cases where excitation and/or auxiliary power, branched off the main generator bus line, is metered to determine the net electrical output based on gross power measurement, the accuracy of the corresponding Watt- or Watthour-meter shall be of a magnitude that the contribution to the uncertainty of the net output is less than 0.03%.

The recording time for Watthour-meters shall be measured with such a precision that the contribution to the uncertainty of the power to be determined is less than 0,03%.

Power metering equipment used for testing shall be calibrated against reference standards traceable to recognized international standards. The calibrations shall be made in such a manner that the expected test load, voltage and frequency conditions are covered.

Preferably portable test instruments, properly calibrated in a laboratory, shall be used. However switchboard instruments may be used by mutual consent of the parties and provided that the requirements given in this International Standard are fulfilled.

Metering systems, such as poly-phase meters, which cannot be verified and calibrated by separate single-phases, shall not be used.

6.4.5.1.2 Instrument transformers

Correctly rated and calibrated voltage and current transformers of at least 0.2% accuracy class or better shall be used. The instrument transformers shall be designed solely for metering purpose with no unknown burden other than that of test instrument and leads i.e. protective relay or voltage regulator devices shall not be connected to the transformers.

The calibrations shall cover the expected field test conditions such as turn ratio, phase angle and rated burden.

The connecting leads between meter and instrument transformer shall be arranged so that effects such as inductance, voltage drop or any other cause are minimized. Twisted and shielded pairs for current leads are reducing the impact of inductance and voltage drop may be minimized by choosing appropriate wire gauge and resistance considering wire length and load of voltage transformer.

6.4.5.2 Mechanical power determination

6.4.5.2.1 Torque measurement

Either of the types of apparatus described in the following sections may be applied to measure torques used in the derivation of the mechanical outputs of gas turbines.

6.4.5.2.2 Absorption dynamometers (mechanical, or any fluid types, or a combination of any of these)

The dynamometer selected shall be chosen so that the minimum measured torque at any speed is at least 20 % of its normal maximum rated torque. Absorption dynamometers shall be constructed so that the cooling fluid enters and leaves in a plane through the axis so as to avoid tangential velocity components. Similar precautions shall also be taken regarding external windage. Hose connections, if used, shall impose no sensible tangential restraint. Dashpots, if used for damping oscillations, shall be demonstrated to impose equal resistance to motion in either direction. Effective radius arms of dynamometers shall be measured with an uncertainty not exceeding 0,1%. A manufacturer's certificate may be accepted as evidence for the accuracy.

The force-measuring device shall be checked against certified weights in the directions of both increasing and decreasing load. The positive or negative error of the force-measuring device shall not exceed 0,1% of the maximum load to be read in the test. The average of increasing and decreasing loadings shall be accepted as the calibration only if the difference remains within 0,3% of the maximum test load.

Tests shall be considered unsatisfactory should there be irregularities in the operation of the dynamometer, for example a period surging of load, such as might be due to the action of water in the dynamometer, or some resonant condition that produces pulsations of indicated torque in excess of ± 2%.

6.4.5.2.3 Shaft torque meter

The calibration certificate for the shaft torque meter shall be verified before the test series current in accordance with the manufacturers recommendations for the specific application. If the system is affected by temperature, it shall be recalibrated after the test at the temperature experienced during the test. Calibration shall be performed with the torsion-indicating means undisturbed from pre-test to the end of the post-test determination. In any case, observations shall be taken with a series of increasing loadings to a value above maximum test readings, followed by a series of decreasing loads. Loading shall always progress in one direction except at maximum value. The average of increasing and decreasing loads shall be accepted as the calibration only if the difference is within 1% of the maximum test load.

Readings shall be taken with sufficient frequency and averaged with sufficient data in order not to be influenced by the oscillation of the shaft torque.

6.4.5.3 Power determination, gas generator

The power of a gas generator can be determined by replacing the power turbine by a nozzle or equivalent opening restrictor at full load. The power is defined as that produced by an isentropic expansion from measured conditions at generator outlet (total pressure and temperature) to the ambient atmospheric pressure.

6.4.5.4 Power determination, other cases

Where output is in a form which is not electrical and when it is not practicable to measure the output on the shaft itself (for example pumps, compressors, etc.), reference shall be made to the appropriate standard for testing the driven machine. Such standards may be used only after mutual agreement by the parties involved.

6.4.6 Speed measurement

An instrument of the speed-indicating type may be used for initial setting of the test speed and for checking constancy of speed during test periods. Each shaft of a multi-shaft engine shall be equipped with a speed-indicating device.

For checking constancy of speed during test periods, electronic pulse counter type speed indicators are recommended for visual readout as well as recording.

Either positively driven or no-contact type tachometers shall be used for all speeds. Hand-held tachometers are not recommended, because of the possibility of slip.

When mean rotational speed influences test results, an integrating type revolution counter, positively driven from the shaft, shall be used. Counting and time accuracy shall be such that uncertainty of mean speed does not exceed 0,25 %. Whenever electronic type pulse counters are used for power and efficiency determinations, readings shall be taken with sufficient frequency that the average of all readings will not differ from the average of alternate readings by more than 0,25 %.

6.4.7 Other measurements

6.4.7.1 Humidity

When the moisture content of the air entering the test boundary shall be measured, an instrument with the capability of determining relative humidity within an uncertainty of 2% points shall be used.

The number of instruments shall depend on the shape and the size of the air filter system inlet area .

In case of multiple gas turbine units, installed in one or more rows or staggered, with or without evaporative cooling systems (within the inlet air system) every effort shall be taken to find the most representative and accurate location(s) for the determination of the weighted average of the ambient air temperature and humidity, where the test boundary is entered.

The humidity may be determined with direct measurement using a hygrometer or with measurement of wet and dry bulb temperature, barometric pressure and calculating the relative humidity by means of psychrometric charts, tables or algorithms.

6.4.7.2 Secondary heat input/extraction

Where the performance test requires measurement of secondary heat input such as injection flow or heat extracted by the lubricant coolers, intercoolers and vents, as in the case of indirect measurements of mechanical power, the accurate temperature, pressure and flow measurements shall permit determination of the heat with a maximum uncertainty no bigger than 10%.

6.4.7.3 Data recording system

The use of an electronic data recording system in favour of manual recording is recommended for two reasons, one is the avoidance of personal bias in reading analog instruments and the other is the higher sampling rate which allows a reduction of the uncertainty component caused by random effects.

The recording system shall have the ability to store the data of the primary electronic (typically analogue) signal generated by the instrument as well as the data of the corresponding signal transformed into engineering units to allow post test data verification or correction.

Data acquisition systems converting primary analogue signals into digital signals using A-D converters shall have a resolution of 14 bit (equal to 0,006% of range) or better.

7 Conductance of test

7.1 Specified reference conditions

The reference conditions shall be defined by the guarantees or the object of the test and they form the base line for corrections. Every effort should be made to run the test under the specified conditions or as close as possible to the specified conditions, in order to minimize the effect of corrections. The guaranteed performance data, as written in the Contract documents, refer to the GT Generator Unit operating at specified reference conditions and specified fuel. Typical reference conditions are mentioned in Table 6.

Table 6 – Specified reference conditions 1)

Ambient pressure	Pa
Ambient temperature	°C
Ambient relative humidity	%
Frequency	Hz
Power factor (cos φ)	-
GT-generator unit speed of rotation	rpm
Compressor inlet total pressure drop, @ specified site conditions (1)	Pa
Turbine exhaust static pressure drop, @ specified site conditions (1)	Pa
Normal sulfur content as hydrogen sulfide	ppm_v
Calorific value of fuel @ specified conditions	kJ/kg
C / H ratio(2) H / C ratio	mol % / mol % mass % / mass %
Mean temperature at gas turbine fuel manifold inlet	°C
Pressure at gas turbine fuel manifold inlet (for information only)	Pa

Notes:

1. Alternatively, at ISO conditions (101.325 kPa, 15°C, 60% RH, Δp_{INLET}=0 Pa, Δp_{OUTLET}=0 Pa)

2. a) H/C atom ratio base on mole percentages without CO_2
   b) C/H mass percentage ratio without CO_2

7.1.1 Specified gaseous fuels

In case of natural gas, a typical list of fuel gas components is shown here below. The mol% of the individual gas components shall be the same as specified in the Contract documents. For special gaseous fuels other than natural gas (for example: synthetic gas), the proper gas composition shall be specified.

Table 7 – Typical list of fuel gas components

Methane	CH_4
Ethane	C_2H_6
Propane	C_3H_8
iso-Butane	$i\text{-}C_4H_{10}$
n-Butane	$n\text{-}C_4H_{10}$
iso-Pentane	$i\text{-}C_5H_{12}$
n-Pentane	$n\text{-}C_5H_{12}$
Hexane	C_6H_{14}
Heptane	C_7H_{16}
Octane	C_8H_{18}
Nitrogen	N_2
Argon	Ar
Oxygen	O_2
Carbon dioxide	CO_2
Carbon monoxide	CO
Moist	H_2O
Hydrogen	H_2
Helium	He

The fuel temperatures at the boundary scope of supply and at fuel control valve need also to be specified from the contract document. Other values such as calorific value, C/H ratio shall be calculated based on the composition given above.

7.1.2 Specified liquid fuels

Typical characteristics of a fuel distillate oil, which shall be the same as written in the Contract documents:

Table 8 – Typical characteristics of liquid fuels

Calorific value of fuel @ 15°C	kJ / kg
Density @ 15°C	kg/m^3
Specific gravity @ 15°C	-
Kinematic viscosity @ 50°C (for information only)	mm^2/sec
Sulfur, total	mass %
Carbon, total	mass %
Hydrogen	mass %
Nitrogen	mass %
Oxygen	mass %
C/H ratio	mass %/mass %

7.2 Preliminary checks

In addition to the test preparations as described in Section 6.3, immediately prior to start the tests, the gas turbine operation shall be visually checked for cleanliness and possible fluid leaks. Particularly, the following shall be checked:

- All mechanical and electric equipment are in normal operating conditions, complying with the agreed list of consumers, part of test procedure.

- On line compressor wash is off (dependent on operating regime).

- Check of operating modes of the gas turbine

- The gas turbine should be thermally stable and operating to control specifications prior to start recording the test readings. Guidelines for operating conditions to achieve thermal stability shall be given by the manufacturer. Any variations of important instruments should be inside the permissible values given in the standard.

7.3 Starting and stopping of tests

The test director is responsible for ensuring that all starting criteria for the test are fulfilled. All parties to the test shall be informed of the starting time of the test by the test director. The test director is responsible for the check of the fulfilment of all stopping criteria and to achieve agreement of all parties to the test on stopping the test or test run. The test director may extend or terminate the test if the requirements are not met.

7.3.1 Starting criteria

Prior to starting the performance test, the following criteria have to be satisfied:

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

  - equipment operation and method of control

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

- gas turbine operation within the bounds of the correction curves, algorithms or programs

- equipment operation within the allowable limits

b) Stabilization - Before starting a test run, the plant shall be operated as long as necessary to establish steady state conditions. Steady state is achieved when the key parameters associated with the test objectives have been stabilized. Stability will be achieved when, prior to the test run, each observation of an operating condition shall not vary from the reported average, by more than the amount specified in Table 9.

c) Data collection – Data acquisition system(s) functioning, and test personnel in place and ready to collect enough data to achieve random errors as low as possible.

7.3.2 Stopping criteria

Prior to stopping the performance test, the following information should be confirmed:

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

- equipment operation and method of control

- gas turbine operation within the limits of the correction curves, algorithms or programs (the handling of exceeding of these bounds has to be agreed on by all parties to the test)

b) Steady state - Key parameters associated with the test objectives have not exceeded the steady state criteria from the reported average, by more than the amount specified in Table 9.

c) Data collection – Data acquisition system(s) collected sufficient information as specified in the test procedures.

7.4 Operation prior and during test

7.4.1 Operating mode

The operating mode of the gas turbine during the test should be consistent with the objectives of the test. The corrections utilized in the development of correction curves will be affected by the operating mode. If a specified, corrected or measured load condition is desired the control system should be configured to maintain the condition during the test.

7.4.1.1 Variable speed turbine

Test conditions (temperature and pressure at the gas turbine compressor inlet, etc.) will in most cases be different from the defined reference conditions. Therefore, test results will have to be corrected to reference conditions, as described in section 8.2.

In the case of an installation involving variable speed characteristics, such as mechanical drive, it may be possible to operate the gas turbine at a condition which is aerodynamically similar to the reference conditions. This approach, if adopted in the test procedure and accounted for in the test result correction method, can lead to increased accuracy of the corrected test results.

Aerodynamic similarity is given if the relationship between operating parameters at test conditions and reference conditions is as follows:

a) Output shaft speed:

$$n_m = n_c \sqrt{\theta}$$

where

n_m is the specified speed of the output shaft during the test in 1/s

n_c is the reference speed of the output shaft in 1/s

θ is the ratio of the absolute gas turbine compressor inlet air temperatures at test (measured), and at reference conditions $(T_{a2,m} + 273.15)/(T_{a2,c} + 273.15)$.

b) Shaft power output:

$$P_S = P_c \delta \sqrt{\theta} \text{ or } P_c = \frac{P_S}{\delta \sqrt{\theta}}$$

where

P_S is the net shaft power output during the test (specified or at control temperature limit) in kW

P_c is the net shaft power output at reference conditions in kW

δ is the ratio of the ambient absolute pressure to the reference ambient absolute pressure

c) Control temperature (e.g. turbine inlet, turbine intermediate or exhaust)

$$T_m = T_c \theta \text{ or } T_c = \frac{T_m}{\theta}$$

where

T_m is the control temperature during the test in K

T_c is the control temperature at reference conditions in K

The gas turbine efficiency calculated based on data taken at that test point will correspond to the efficiency at reference conditions, but may need to be corrected if other parameters, e.g. pressure losses, differ between test and reference conditions.

7.4.2 Auxiliary equipment operation

All the auxiliary equipment that is necessary for normal operation of the gas turbine at specified reference conditions, has to be accounted in determining auxiliary power loads (for example, heat tracing). Intermittent auxiliary loads also have to be accounted for in an equitable manner and applied to the power consumption in a manner agreeable to all parties.

7.4.3 Inlet air treatment (evaporative coolers, chillers, foggers, heaters)

Due to the increase in the test uncertainty in determining the effectiveness of inlet air treatment devices, it is recommended that the gas turbine test be conducted without these devices in operation. The acceptance test results can then be adjusted using the appropriate design correction curves for the inlet air treatment equipment that is out of operation. If inlet air treatment operation is specified as part of the scope of the acceptance test, the gas turbines shall be tested with the inlet air treatment in operation (if weather conditions permit), and the acceptance test results adjusted using the appropriate correction curves. No correction for the sensible heat of water added or removed (blow down) is necessary for testing with coolers.

7.4.4 Adjustments

Prior to the start of the official Acceptance test runs, the contractor shall be permitted to do adjustments and run preliminary tests. The purpose of preliminary tests is:

a) Determining whether the Gas Turbine and associated plants are in a condition suitable for conducting an Acceptance Test.

b) Checking instrumentation, Data Acquisition System and equipment status

c) Instructing personnel involved with the test and plant isolation; familiarization with test procedure

d) The Gas Turbine final setting shall be established according to the results of the preliminary tests.

After preliminary tests are concluded the test director may declare the beginning of the official test.

Once an official test run has started, no adjustments shall be permitted except by agreement of all parties to the test.

7.5 Duration of tests

The duration of a test run and the frequency of the readings shall be selected to provide reliable average of the readings. A 30 minute test run is recommended to be in compliance with Table 9 and to meet the test uncertainty requirements. If it is not possible to fulfill all the requirements of Table 9, then evaluation of power and efficiency shall be carried out three times consecutively. In this case the duration of each test being not less than 5 minutes and not longer than 20 minutes (i.e. a total period of not less than 15 minutes and no longer than 60 minutes). The results of the three test runs shall be averaged. For optional tests the adequate duration of any test is to be mutually agreed on by the parties prior to the test.

7.6 Maximum permissible variations in operating conditions

Each observation of an operating condition shall not vary from the reported test average, by more than the amount specified in the following table. Although the listed parameters are not independent, no single figure of table 9 shall be exceeded during a test run.

Table 9 – Maximum permissible variations in operating conditions

	Variable	Variation of any observation from reported average operating conditions during a test run
1	Electric output at generator terminals	± 1%
2	Shaft power output (mechanical drive)	± 2%
3	Power factor	± 2%
4	GT-Generator unit speed of rotation, if applicable	± 1%
5	Temperature of gaseous fuel[(1)], as supplied to the plant	± 3K
6	Temperature of liquid fuel, as supplied to the plant	± 3 K
7	Gaseous fuel pressure	± 1%
8	Ambient temperature	± 2K
9	Barometric pressure	± 0,5%
10	Flue gas exhaust absolute pressure	± 1%
11	Turbine exhaust temperature	± 2K
[(1)] For gaseous fuels other than natural gas, the allowable variation shall be specified by prior agreement		

In case that, during the test run, some observations of an operating condition will vary beyond the permissible limits prescribed in the Table 9, the test run can be rejected. However, if the fluctuation is limited in time and amplitude, it can be agreed between the parties to discard those readings showing excessive deviations, and to accept the test.

7.7 Test records

To the extent possible, test readings shall be recorded on a data acquisition system. The measured values of test parameters, as well as settings and other significant observations during the test, shall be entered on carefully prepared forms, which constitute original log-sheets to be authenticated by the observer's signature.

The observations shall include the date and time of day, ambient conditions (temperature, pressure and relative humidity) and the required measurements. They shall be the actual readings without application of any instrument corrections. The position of each measurement shall be clearly marked on a flow sheet, using the nomenclature presented in the project specific acceptance test procedure.

For the acceptance test, a complete set of unaltered log-sheets and recorded charts shall become the property of the parties to the test. The log-sheets and any recorded charts shall constitute a complete record.

The original sheets and recorded charts shall be such as to permit facsimile reproduction as, for example, by photocopying process. Copies of documents in handwriting are not permissible.

Immediately after completion of each test run all relevant electronically taken data shall be given to the each party involved. All original measurement data taken manually shall be countersigned and set of data handed over to the parties involved.

A meeting shall be held with all parties involved to agree if the preceding tests were conducted in accordance with performance test procedure and the guidelines given in the test standard. It shall also be agreed whether the collated data are acceptable to all parties involved in the tests. Once this has been agreed, the test shall be designated as an official test.

7.8 Test validity

Validation of test runs shall be mutually agreed to by the Contractor and the Customer (or Employer) representatives.

If, during the conduction of the test or the subsequent analysis of the observed data, an inconsistency is found which affects the validity of the results, the parties should make every reasonable effort to adjust or eliminate the inconsistency by mutual agreement.

Test validation shall be based upon any condition invalidating test data, including as the minimum:

a) GT - Generator Unit load rejection, originated by external / internal causes.

b) Failure of test equipment without redundancy.

c) Variation of variables beyond the limits prescribed in Table 9, unless by a written agreement among the parties such variations are permitted

d) GT running under load limiter

e) Anti-icing in operation, unless by a written agreement among the parties such variations are permitted

8 Computation of results

In computing results of tests for power and thermal efficiency, the determination may be made with averaged or integrated values of observations made during a single test run, after applying corrections for instruments, etc., as presented in this International Standard.

8.1 Performance test results

8.1.1 General

The calculated examples in this section are based on generator drive applications, however, these examples can easily be converted into mechanical drive applications.

8.1.2 Power

If the power output is measured at a station, which is identical with the contractually defined reference or guaranteed power output, the measurement result can directly be used for correction to reference conditions as per equation (12).

For generator application the active power P_{e9}, measured at the secondary side of the instrument transformers with single-phase watt meter method, can be expressed with the following equation:

$$P_{e9} = \sum_{i=1}^{n} \left[\left(U_S \cdot K_U \right) \cdot \left(I_S \cdot K_I \right) \cdot \cos\varphi \right]_i \qquad \text{...(1)}$$

where

U_S is the secondary voltage at the instrument transformer

I_S is the secondary current at the instrument transformer

K_U is the ratio of the voltage transformer

K_I is the ratio of the current transformer

$cos\varphi$ is the generator power factor

n is the number of phases, normally n = 3

Where the power loss of the step-up transformer is considered for the determination of the active power between station 9.1b and 9.1c of Figure 3, the power loss at actual test conditions shall be calculated based on transformer factory test data as follows:

$$P_{TRL} = P_{NLL} \cdot \left(\frac{U_m}{U_r} \right)^2 + P_{LL} \cdot \left(\frac{S_m}{S_r} \right)^2 \qquad \text{...(2)}$$

where

P_{TRL} are the actual transformer losses

P_{NLL} are the no-load losses of the transformer from factory test report

U_m is the measured generator voltage at test conditions

U_r is the rated generator voltage

P_{LL} are the load losses of the transformer from factory test report

S_m is the measured apparent power at test conditions

S_r is the rated apparent power

Mechanical power is determined by torque meter or heat balance of load equipment.

8.1.3 Thermal efficiency / heat rate

The thermal efficiency η of the engine based on electrical power output and the net heat consumption is computed from

$$\eta = \frac{P_{e9}}{Q_{f4}} \qquad \text{...(3)}$$

where

P_{e9} is the electrical power output, in kilowatt

Q_{f4} is the heat consumption of the fuel, based on lower heating value, in kilowatt

The heat rate HR in kilojoules per kilowatt hour, may be computed from

$$HR = \frac{Q_{f4}}{P_{e9}} \cdot 3600 = \frac{1}{\eta} \cdot 3600 \qquad ...(4)$$

The heat consumption Q_{f4}, in kilowatt, is determined by the equation

$$Q_{f4} = \dot{m}_{f4}(Q_{lo} + SH) \qquad ...(5)$$

with the sensible heat SH in kJ/kg

$$SH = h_{f4} - h_0 = c_{p,f4}(T_{f4} - T_{f0}) \qquad ...(6)$$

and

$\dot{m}_{f4}$ is the fuel consumption, in kilogram per second

Q_{lo} is the lower heating value (LHV) of the fuel at 15 °C and constant pressure, in kilojoules per kilogram

h_{f4} is the specific enthalpy of the fuel at temperature T_{f4} entering the test boundary, in kilojoules per kilogram

h_0 is the specific enthalpy of the fuel at reference temperature $T_{f0} = 15°C$, in kilojoules per kilogram.

$c_{p,f4}$ is the specific heat of the fuel at constant pressure, in kilojoules per kilogram Kelvin.

8.1.4 Turbine exhaust gas energy

The calculation of the turbine exhaust gas energy is based on the system energy balance for the equipment subject to performance testing with the energy streams crossing the defined test boundary as shown in Figure 1 and Figure 2:

$$Q_{a1} + Q_{f4} + Q_{w4} = Q_{g8} + P_{e9} + Q_{10} \qquad ...(7)$$

where

$Q_{a1} = \dot{m}_{a1} \cdot h_{a1}$ is the energy of ambient air with the mass flow $\dot{m}_{a1}$ and the specific enthalpy h_{a1}

$Q_{f4} = \dot{m}_{f4}(Q_{lo} + SH)$ is the energy of fuel with the mass flow $\dot{m}_{f4}$, the lower heating value Q_{lo} and the sensible heat SH (see equation 6)

$Q_{w4} = \dot{m}_{w4} \cdot h_{w4}$ is the specific enthalpy of the injected water or steam mass flow at temperature T_{w4} entering the control volume, in kilojoules per kilogram; consideration of evaporation of water can lead to negative values for specific enthalpy

Q_{g8} is the resulting energy of turbine exhaust gas assuming Q_{g8} is equal to Q_{g7}

P_{e9} is the electrical power

$Q_{10} = Q_m + Q_G + Q_{GB} + Q_r + Q_{th}$ is the sum of the losses including mechanical Q_m, generator Q_G, gear box Q_{GB}, radiation and convection loss Q_r, thermal heat losses Q_{th} that could be extracted heat from air coolers (e.g. $Q_{th} = Q_{ct3.1} - Q_{ct3.2}$, see figure 4).

Q_r is the radiation and convection heat loss commonly defined as $Q_r = (1-\eta_{tc})\dot{m}_{f4}(Q_{lo} + SH)$

where

η_{tc} is the combustion chamber efficiency.

With the general definition of the specific enthalpy $h = c_p(T - T_0)$, where c_p, assumed constant, is the heat capacity at constant pressure, T the actual "process" temperature and T_0 the reference temperature of the enthalpy (commonly 273.15 K, but can vary in the industry), the equation (7) can be rewritten as

$$\dot{m}_{a1} \cdot c_{p,a1} \cdot (T_{a1} - T_0) + \dot{m}_{f4}(Q_{lo} + SH) + Q_{w4} = Q_{g7} + P_{e9} + Q_{10} \qquad ...(8)$$

To simplify the above equation the reference temperature T_0 is set equal with the ambient air temperature $T_0 = T_{a1}$, which eliminates Q_{a1}.

Equation (8) regrouped, substituting Q_{10} with its components and resolved for Q_{g7} is then

$$Q_{g7} = \dot{m}_{f4}(Q_{lo} + SH)\eta_{tc} + Q_{w4} - P_{e9} - Q_m - Q_G - Q_{GB} - Q_{th} \qquad ...(9)$$

where

$\dot{m}_{f4}(Q_{lo} + SH)$ is the heat input Q_{f4} of the fuel, which can be set equal to the electrical power P_{e9} divided by the thermal efficiency η of the gas turbine as follows

$$Q_{f4} = \frac{P_{e9}}{\eta} \qquad ...(10)$$

Now equation (9) is simplified with equation (10) resulting in

$$Q_{g7} = P_{e9}\left(\frac{\eta_{tc}}{\eta} - 1\right) + Q_{w4} - Q_m - Q_G - Q_{GB} - Q_{th} \qquad ...(11)$$

where

Q_{g7} is the turbine exhaust gas energy with the enthalpy at the assumed reference temperature T_{a1}.

8.2 Correction of test results to reference conditions

The preferred approach in conducting acceptance tests is to run the gas turbine as close as possible at the defined reference conditions to minimize the correction of the results. It is recognized however that this may not always be possible; the tests may have to be run under some other conditions, and the results corrected to reference conditions to facilitate comparison of the measured with the guaranteed performance data.

8.2.1 Correction methodology

The fundamental performance equations for correcting calculated test values to the reference conditions are applicable to any of the gas turbine types covered by this Standard. The applicable corrections to be used for a particular test depend on the type of gas turbine being tested and the goal of the test. The format of the fundamental equations allows decoupling of the appropriate correction effects (ambient conditions, injection fluids, etc.) relative to the measured parameters of power, heat rate, exhaust flow or energy, and exhaust temperature so that measured performance can be corrected to the reference conditions.

A set of correction values is calculated by changing only one variable at a time and calculating a correction for each value of that variable within a defined range. A graphical representation for this type of correction provides a single curve as a function of the variable. If one were to determine an algebraic equation to represent that set of corrections, one would have a single equation in only one variable.

Several corrections could be bivariate, requiring the formulation to be a function of two variables. To create a bivariate formulation, several sets of correction values are created as described above by varying only one variable within a set. The second variable is changed between sets. If one were to graph this bivariate formulation, the multiple sets of corrections would make up a family of curves for which the second variable is constant along any one curve but is different between curves. For example, the correction for fuel composition may be split into two or more components to better characterize the impact of fuel composition on gas turbine performance.

To determine algebraic equations, one could either create a single equation with two variables or multiple single-variable equations with each equation giving the corrections at a different value of the second variable of graphical interpretation of correction curves, it is necessary to provide a table of the data points that reflects the response of the dependent variable to the independent variable over a defined range. It is also recommended that equations and/or graphical representations be supplied.

8.2.2 Correction factors

The measurement of electrical or mechanical power and the gas turbine fuel heat consumption is essential for the performance test. Sufficient supporting data shall be recorded to enable correction of the test results to reference conditions, as stated in the appropriate sections of the relevant contracts, so that a comparison may be made between the results from testing and rated gas turbine capability at specified operating conditions. Correction curves should be provided prior to the tests. It is vital that the test boundary or envelope, which surrounds the gas turbine is established. All streams crossing the boundary shall be identified and determined.

8.2.2.1 Correction of power

Measured and calculated test results are corrected with the following basic equation:

$$P_{9,c} = P_{9,m} \cdot \prod_{i=1}^{N} C_{P,i} \qquad \text{…(12)}$$

where

$P_{9,c}$ is the corrected power output of the gas turbine

$P_{9,m}$ is the measured/calculated power output of the gas turbine

$C_{P,i}$ is the correction factor i for power output

N is the number of correction factors

8.2.2.2 Correction of thermal efficiency and heat rate

Measured and calculated test results are corrected with the following basic equation:

$$\eta_c = \eta_m \cdot \prod_{i=1}^{N} C_{\eta,i} \qquad \text{...(13)}$$

where

η_c is the corrected thermal efficiency of the gas turbine

η_m is the measured/calculated thermal efficiency of the gas turbine

$C_{\eta,i}$ is the correction factor i for thermal efficiency

N is the number of correction factors

and the corrected heat rate is as follows:

$$HR_c = \frac{HR_m}{\prod_{i=1}^{N} C_{\eta,i}} = \frac{3600}{\eta_c} \qquad \text{...(14)}$$

where

HR_c is the corrected heat rate of the gas turbine

HR_m is the measured/calculated heat rate of the gas turbine

8.2.2.3 Correction of turbine outlet temperature

Measured and calculated test results are corrected with the following basic equation:

$$T_{g7,c} = T_{g7,m} - \sum_{i=1}^{N} \Delta TOT,i \qquad \text{...(15)}$$

where

$T_{g7,c}$ is the corrected turbine outlet temperature, in °C;

$T_{g7,m}$ is the measured turbine outlet temperature, in °C;

$\Delta TOT,i$ is the additive correction factor i for turbine outlet temperature, in K;

N is the number of correction factors

8.2.2.4 Correction of turbine exhaust gas energy

The correction of the turbine exhaust gas energy to reference conditions is inherently included while the exhaust energy, according to equation (11), is determined with equation (12), (13) and (15), which are the corrected input parameters power, thermal efficiency and turbine outlet temperature. An acceptable alternative is the correction of turbine exhaust gas mass flow and temperature.

The input parameters in equation (11) can now be substituted with the measured and corrected power $P_{e9} = P_{e9,c}$ and thermal efficiency $\eta = \eta_c$, the measured energy of the injection fluid $Q_{w4} = Q_{w4,mc}$ and thermal heat loss $Q_{th} = Q_{th,m(d)}$, whose value can also be taken from design if determination by measurement is not practicable, as well as the mechanical $Q_m = Q_{m,d}$, gear box $Q_{GB} = Q_{GB,d}$ and generator $Q_G = Q_{G,d}$ losses from design. With the assumption $T_0 = T_{a1}$ above, Q_{g7} of equation (11) becomes then the corrected turbine exhaust gas energy $Q_{g7,c,Ta1}$ with the reference temperature of its enthalpy indexed to the ambient air temperature T_{a1}, which is the temperature used as reference for the correction of power and thermal efficiency as well as of the remaining parameters taken from design as follows

$$Q_{g7,c,Ta1} = P_{e9,c}\left(\frac{\eta_{tc}}{\eta_c} - 1\right) + Q_{w4,mc} - Q_{m,d} - Q_{G,d} - Q_{GB,d} - Q_{th,m(d)} \qquad \text{...(16)}$$

where

$Q_{g7,c,Ta1}$ is the corrected turbine exhaust gas energy at reference ambient air temperature T_{a1}

$P_{e9,c}$ is the measured and corrected power according to equation (12)

η_c is the measured and corrected thermal efficiency according to equation (13)

η_{tc} is the combustion efficiency from design

$Q_{w4,mc}$ is the measured thermal energy from injection fluid, corrected to design if applicable

$Q_{m,d}$ is the mechanical loss from design

$Q_{G,d}$ is the generator loss from design

$Q_{GB,d}$ is the gear box loss from design

$Q_{th,m(d)}$ is the thermal heat loss, measured or from design

Next step is the correction of $Q_{g7,cT,a1}$ from indexed reference temperature T_{a1} to the original temperature T_0. For this, equation (16) is rewritten as follows

$$Q_{g7,c,Ta1} = \dot{m}_{g7,c} \cdot c_{p,g7}(T_{g7,c} - T_{a1}) \qquad \text{...(17)}$$

and applied for the turbine exhaust gas energy at reference temperature T_0

$$Q_{g7,c,T0} = \dot{m}_{g7,c} \cdot c_{p,g7} (T_{g7,c} - T_0) \qquad \text{…(18)}$$

Equations (17) and (18) are then combined and resolved for the corrected turbine exhaust gas energy

$Q_{g7,c,T0}$ at reference temperature T_0

$$Q_{g7,c,T0} = Q_{g7,c,Ta1} \frac{(T_{g7,c} - T_0)}{(T_{g7,c} - T_{a1})} \qquad \text{…(19)}$$

where

$Q_{g7,c,Ta1}$ is the corrected turbine exhaust gas energy at reference ambient air temperature T_{a1}, calculated with equation (16)

$T_{g7,c}$ is the corrected turbine exhaust gas temperature according to equation (15)

T_0 is the reference temperature of the specific enthalpy (commonly 273.15 K)

T_{a1} is the ambient air temperature at reference (contract or agreement) conditions

8.2.2.5 Summary of correction factors

The following table summarizes the correction factors for power output, thermal efficiency and turbine outlet temperature.

Table 10 – Overview of correction factors

Parameter of reference condition	Power	Efficiency	TOT
Barometric pressure	$C_{P,1}$	$C_{\eta,1}$	$\Delta_{TOT,1}$
Ambient air temperature	$C_{P,2}$	$C_{\eta,2}$	$\Delta_{TOT,2}$
Relative humidity	$C_{P,3}$	$C_{\eta,3}$	$\Delta_{TOT,3}$
Generator power factor	$C_{P,4}$	$C_{\eta,4}$	$\Delta_{TOT,4}$
Generator frequency or gas turbine or power turbine speed	$C_{P,5}$	$C_{\eta,5}$	$\Delta_{TOT,5}$
Inlet pressure loss	$C_{P,6}$	$C_{\eta,6}$	$\Delta_{TOT,6}$
Outlet pressure loss	$C_{P,7}$	$C_{\eta,7}$	$\Delta_{TOT,7}$
Injection fluid flow	$C_{P,8}$	$C_{\eta,8}$	$\Delta_{TOT,8}$
Fuel composition	$C_{P,9}$	$C_{\eta,9}$	$\Delta_{TOT,9}$
Heat extraction	$C_{P,10}$	$C_{\eta,10}$	$\Delta_{TOT,10}$
Degradation	$C_{P,11}$	$C_{\eta,11}$	$\Delta_{TOT,11}$

The correction factors are individually defined during preparation of a particular test procedure, depending on gas turbine configuration, scope subject to performance testing and contractual specifications. Additional correction factors shall be applied where necessary. Correction factors, which are not applicable, are set equal to unity for multiplicative and zero for additive factors.

Basically the correction factors are derived from correction curves supplied by the gas turbine manufacturer. The curves are generated by varying one parameter over the range of expected deviations from standard or specified reference conditions. Several correction curves could be bivariate. In this case the correction will be a function of two variables. To create appropriate correction curves, several sets of correction values are created by varying only on variable within a set. The second variable is changed between the sets. A graphic representation of this type of correction appears as a family of curves for which the second variable is constant along one curve but different between curves. In addition to the correction curves, polynomial equations of the curves or a list with base points for interpolation may be provided to simplify the correction procedure during evaluation of the test results and to avoid misinterpretation in reading correction curves.

Where the specified reference conditions are other than standard reference conditions (see Clause 3, 3.9) with the correction curves based on the latter, the correction factors shall be calculated as follows:

$$C_{P,i} = \frac{C_{P,i,a}}{C_{P,i,b}} \qquad \text{…(20)}$$

$$\Delta TOT_{,i} = \left(\Delta TOT_{,i,a} - \Delta TOT_{,i,b}\right) \qquad \text{…(21)}$$

where

a is the correction factor from measured to standard reference conditions

b is the correction factor from specified to standard reference conditions

Sometimes manufacturers are providing curves showing the relative change of performance versus the variable parameter. In such case, the multiplicative correction factor is equal to the inverse of the relative change of performance as show below on an example for power correction:

$$C_{P,i} = \frac{1}{\left(\dfrac{P}{P_{ref}}\right)} \qquad \text{…(22)}$$

where

P is the power as function of the variable parameter

P_{ref} is the power at specified or standard reference condition

The use of gas turbine performance simulation model provided by the manufacturer is also permitted for correction of test results. Simulation models may be employed for acceptance tests of complex gas turbine configurations or where variable parameters are not independent.

8.3 Other gas turbine performance parameters

8.3.1 General

In this section following subjects will be dealt with:

- Gas Turbine Energy Balance
- Compressor Inlet Air Mass Flow
- Combustion Chamber Energy Balance
- Turbine Inlet Gas Temperature

Due to technical developments some parameters can only be determined with help of manufacturer's data and complicated calculations. Therefore the equations underneath, referring to the last two subjects, will act as guidelines. The use of appropriate non-dimensional correction curves is permitted.

8.3.2 Gas turbine energy balance

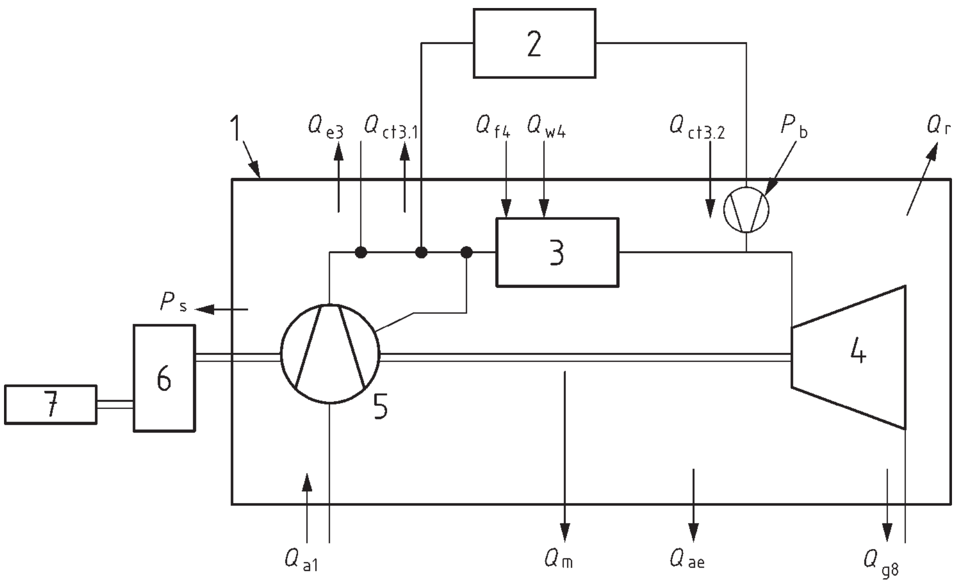


Figure 4 – Control Volume for Gas Turbine Energy Balance

1	Control volume	5	Compressor
2	Air cooler	6	Gear box
3	Heat source	7	Load
4	Turbine		

Gas turbine energy balance:

$$Q_{a1} + Q_{f4} + Q_{w4} + Q_{ct3.2} + P_b = P_s + Q_{e3} + Q_{ct3.1} + Q_r + Q_{g8} + Q_{ae} + Q_m \quad \ldots(23)$$

where

$Q_{a1} = \dot{m}_{a1} \cdot h_{a1}$	compressor air inlet
$Q_{f4} = \dot{m}_{f4} \cdot (Q_{lo} + h_{f4} - h_0)$	fuel
$Q_{w4} = \dot{m}_{w4} \cdot h_{w4}$	water / steam
$Q_{ct3.2} = \dot{m}_{ct3} \cdot h_{ct3.2}$	cooling air cooler outlet
P_b	booster power consumption
$P_s = P_{e9} + Q_{GB} + Q_G$	shaft power output
$Q_{e3} = \dot{m}_{e3} \cdot h_{a3}$	external air extraction
$Q_{ct3.1} = \dot{m}_{ct3} \cdot h_{a3}$	cooling air cooler inlet
$Q_r = (1 - \eta_{tc}) \cdot \dot{m}_{f4} \cdot \left(Q_{lo} + h_{f4} - h_0\right)$	radiation and convection heat losses
$Q_{g8} = \dot{m}_{g8} \cdot h_{g8}$	turbine exhaust gas
$Q_{ae} = \dot{m}_{ae} \cdot h_{ae}$	leakage from the control volume
Q_m	mechanical losses

where

$\dot{m}_{a1}$ is the compressor inlet mass flow, in kilograms per second;

h_{a1} is the specific enthalpy of air at temperature T_{a1} entering the compressor, in kilojoules per kilogram;

$\dot{m}_{f4}$ is the fuel mass flow entering the control volume, in kilograms per second;

Q_{lo} is the lower heating value (LHV) of the fuel at 15°C and constant pressure, in kilojoules per kilogram;

h_{f4} is the specific enthalpy of the fuel at temperature T_{f4} entering the heat source (combustion chamber), in kilojoules per kilogram;

h_0 is the specific enthalpy of the fuel at 15°C, in kilojoules per kilogram;

$\dot{m}_{w4}$ is the injected water or steam mass flow entering the control volume, in kilograms per second;

h_{w4} is the specific enthalpy of the injected water or steam mass flow at temperature T_{w4} entering the control volume, in kilojoules per kilogram; consideration of evaporation of water can lead to negative values for specific enthalpy

$\dot{m}_{ct3}$ is the air mass flow to the external cooler leaving and entering the control volume, in kilograms per second;

$h_{ct3.2}$ is the specific enthalpy of the air flow from the external cooler at temperature $T_{c3.2}$ entering the control volume, in kilojoules per kilogram;

P_b is the cooling air booster power consumption, in kilowatt;

P_s is the shaft power output of the gas turbine, in kilowatt;

Q_G are the generator losses, in kilowatt

Q_{GB} are the gear box losses, in kilowatt

P_{e9} is the electrical output at generator terminals. in kilowatt

$\dot{m}_{e3}$ is the mass flow of extracted compressor discharge air, in kilograms per second;

h_{a3} is the specific enthalpy of the air at compressor discharge temperature T_{a3}, in kilojoules per kilogram;

η_{tc} is the combustion chamber efficiency, taken into account the total radiation and convection heat losses

$\dot{m}_{g8}$ is the mass flow of the turbine exhaust gases, in kilograms per second;

h_{g8} is the specific enthalpy of exhaust gases at temperature T_{g8}, in kilojoules per kilogram.

$\dot{m}_{ae}$ is the mass flow of sealing and or leakage air leaving the control volume, in kilograms per second;

h_{ae} is the specific enthalpy of air at temperature T_{ae} leaking from the control volume, in kilojoules per kilogram.

Notes (1) Reference temperature to be stated, e. g. 0°C or 15°C.

(2) Station 1 –air inlet and Station 2 – Compressor Inlet may be interchangeable, where applicable.

(3) Station 7 –gas turbine exhaust and Station 8 –Stack exhaust may be interchangeable, where applicable.

(4) m_{ct3} can also be determined from a heat exchanger balance.

8.3.3 Compressor inlet air mass flow

The exhaust gas mass flow $\dot{m}_{g8}$ at turbine outlet is defined as:

$$\dot{m}_{g8} = \dot{m}_{a1} + \dot{m}_{f4} + \dot{m}_{w4} - \dot{m}_{e3} - \dot{m}_{ae} \qquad ...(24)$$

The Gas Turbine Energy Balance is obtained from Figure 4:

$$\dot m_{a1}\cdot h_{a1}+\dot m_{f4}\cdot\left(Q_{lo}+h_{f4}-h_{0}\right)+\dot m_{w4}\cdot h_{w4}+\dot m_{ct3}\cdot h_{ct3.2}+P_{b}= P_{s}+\dot m_{e3}\cdot h_{a3}+\dot m_{ct3}\cdot h_{a3}+\left(1-\eta_{tc}\right)\cdot\dot m_{f4}\cdot\left(Q_{lo}+h_{f4}-h_{0}\right)+\dot m_{g8}\cdot h_{g8}+\dot m_{ae}\cdot h_{ae}+Q_{m} \quad ...(25)$$

By inserting the equation (24) into the equation (25) the following equation for the calculation of the air mass flow at compressor inlet is obtained:

$$\dot m_{a1}=\frac{\dot m_{f4}\cdot\eta_{tc}\cdot\left(Q_{lo}+h_{f4}-h_{0}-\dfrac{h_{g8}}{\eta_{tc}}\right)-\dot m_{w4}\cdot\left(h_{g8}-h_{w4}\right)-\dot m_{ct3}\cdot\left(h_{a3}-h_{ct3.2}\right)+\dot m_{e3}\cdot\left(h_{g8}-h_{a3}\right)+\dot m_{ae}\left(h_{g8}-h_{ae}\right)-P_{s}+P_{b}-Q_{m}}{h_{g8}-h_{a1}} \quad ...(26)$$

With equation (24) the turbine exhaust gas flow can be determined.

Other methods for the determination of the compressor inlet air flow or the turbine exhaust gas flow can also be used, e.g. based on the energy balance of the coupled HRSG, the oxygen content measurement in the gas turbine or the HRSG stack, the direct air flow measurement at the compressor inlet venturi. The impact of the uncertainty of the result depends on the applied method.

8.3.4 Combustion chamber energy balance

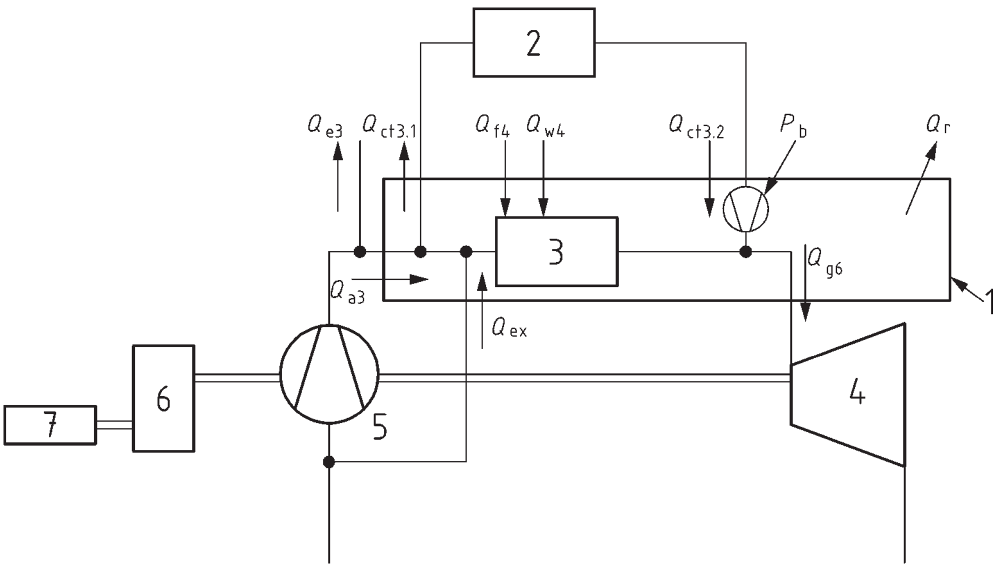


Figure 5 – Control volume for combustion chamber energy balance

1	Control volume	5	Compressor
2	Air cooler	6	Gearbox
3	Heat Source	7	Load
4	Turbine		

Combustion chamber energy balance:

$$Q_{a3} + Q_{f4} + Q_{w4} + Q_{ct3.2} + P_b + Q_{ex} = Q_{ct3.1} + Q_r + Q_{g6}$$

...(27)

where

$Q_{a3} = \left(\dot{m}_{a3} - \dot{m}_{e3}\right) \cdot h_{a3}$ compressor air outlet

$Q_{f4} = \dot{m}_{f4} \cdot (Q_{lo} + h_{f4} - h_0):$ fuel

$Q_{w4} = \dot{m}_{w4} \cdot h_{w4}$ water / steam

$Q_{ct3.2} = \dot{m}_{ct3} \cdot h_{ct3.2}$ cooling air cooler outlet

P_b cooling air booster power consumption

Q_{ex} cooling air extraction equivalent

$Q_{ct3.1} = \dot{m}_{ct3} \cdot h_{a3}$ cooling air cooler inlet

$Q_r = (1 - \eta_{tc}) \cdot \dot{m}_{f4} \cdot \left(Q_{lo} + h_{f4} - h_0\right)$ radiation and convection heat losses

$Q_{g6} = \dot{m}_{g6} \cdot h_{g6}$ turbine inlet gas

where

$\dot{m}_{a3}$ is the compressor discharge air mass flow, in kilograms per second;

h_{a3} is the specific enthalpy of air at temperature T_{a3} at compressor discharge, in kilojoules per kilogram;

$\dot{m}_{g6}$ is the gas mass flow entering the turbine, in kilograms per second;

h_{g6} is the mean specific enthalpy of gases at temperature T_{g6} entering the turbine, in kilojoules per kilogram.

Note: Radiation and convection heat losses for the combustion chamber (or combustion system) are assumed to be equal to the radiation and convection heat losses for the whole gas turbine system (as in section 8.3.2).

Many gas turbines use turbine cooling air that is not only extracted from compressor discharge but from different extraction stages of the compressor. In order to simplify the consideration of the compressor a cooling air extraction equivalent Q_{ex} is introduced.

$$Q_{ex} = (\dot{m}_{a1} - \dot{m}_{eq}) \cdot h_{a1} \qquad \text{...(28)}$$

$$\dot{m}_{eq} = \frac{P_{COMP}}{h_{a3} - h_{a1}} \qquad \text{...(29)}$$

$$P_{COMP} = \dot{m}_{a1} \cdot (h_{a3} - h_{a1}) - \sum_{i=1}^{n} \dot{m}_{ex,i} \cdot (h_{a3} - h_{ex,i}) \qquad ...(30)$$

where

$\dot{m}_{eq}$ is the air inlet mass flow of an equivalent compressor without cooling air extraction, but with the same power consumption as the actual compressor, in kilograms per second;

$\dot{m}_{ex,i}$ is the mass flow for air, extracted from the compressor stage *I,* in kilogram per second

$h_{ex,i}$ is the specific enthalpy of air at temperature $T_{ex,i}$ extracted from the compressor stage *i*, in kilojoules per kilogram.

The difference in inlet mass flow m_d between the equivalent and the actual compressor, as a ratio, can be defined as:

$$\dot{m}_d = \frac{\dot{m}_{a1}}{\dot{m}_{eq}} - 1 \qquad ...(31)$$

The parameter m_d can be set to zero, if the compressor extraction lines shall not be considered.

According to the definition of the ISO turbine inlet temperature (see Clause 3):

- The turbine cooling air flows shall be <u>added</u> to the control volume of the combustion chamber energy balance.
- Gas mass flow at turbine inlet equals gas mass flow at turbine outlet.

8.3.5 Turbine inlet gas temperature

8.3.5.1 General

Generally, gas turbines are designed on the basis of turbine inlet temperature. Direct measurement of the physical temperature at the turbine inlet, however, is in most cases not feasible. Thus, common method for the determination of the turbine inlet temperature is by means of heat balance calculation.

The described method yields to a virtual value of the turbine inlet temperature before the first stage stationary blades. It represents the equivalent mean temperature of an uncooled turbine with the assumption that the total turbine cooling air mass flows, including sealing air flows, is mixed with the gas mass flow from combustion prior to entering the first stage stationary blades. Thus it takes into account the relationship between the physical turbine inlet temperature (see Figure 6) and the amount of cooling air flows for the turbine. The result is a turbine inlet temperature that an uncooled turbine with the same inlet pressure and exhaust parameters would have, in order to produce the same power output as the actual turbine.

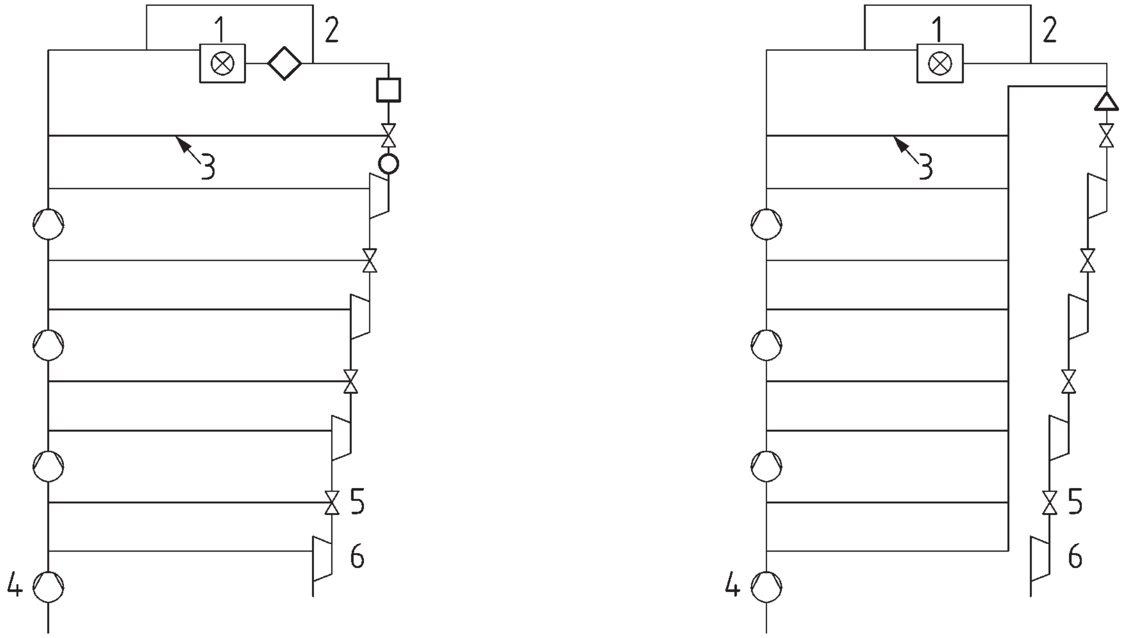


Figure 6 – Schematic showing the relationship between the turbine inlet gas temperature and cooling air flows inside the gas turbine

1 Combustion chamber

2 Combustion chamber cooling air

3 Turbine cooling & leakage air

4 Compressor stage group

5 Stationary turbine row

6 Rotating turbine row

◇ Combustion temperatur (flame temperature)

□ Turbine inlet temperature in front of 1st stationary row (TIT)

○ Firing temperature (in front of 1st rotating row (RIT)

△ Turbine inlet temperature according to this code

Table 11 – Different definitions of the turbine inlet gas temperature

General: $h_{g6} = \dfrac{\dot{m}_{a3} \bullet h_{a3} + \dot{m}_{f4} \bullet \eta_{tc} \bullet (Q_{lo} + h_{f4} - h_0)}{\dot{m}_{a3} + \dot{m}_{f4}}$			
Combustion (flame) temperature:		$\dot{m}_{a3} = \dot{m}_{a1} - \dot{m}_{CA,T} - \dot{m}_{CA,CC}$	
Temperature in front of 1st stationary row (TIT):		$\dot{m}_{a3} = \dot{m}_{a1} - \dot{m}_{CA,T}$	
(Firing) temperature in front of 1st rotating row (RIT):		$\dot{m}_{a3} = \dot{m}_{a1} - \dot{m}_{CA,T} + \dot{m}_{CA,1stV}$	
Temperature according to ISO 2314:		$\dot{m}_{a3} = \dot{m}_{a1}$	
$\dot{m}_{a1}$	compressor inlet air mass flow	$\dot{m}_{f4}$	fuel mass flow
$\dot{m}_{a3}$	combustion chamber inlet air mass flow	h_{g6}	specific enthalpy at turbine inlet
$\dot{m}_{CA,T}$	total turbine cooling air mass flow	h_{a3}	specific enthalpy at combustion chamber inlet
$\dot{m}_{CA,1stV}$	cooling air mass flow for 1st turbine vane row	Q_{lo}	net specific energy of the fuel (LHV)
$\dot{m}_{CA,CC}$	combustion chamber cooling air mass flow	h_{f4}	specific enthalpy of the fuel
η_{tc}	combustion chamber efficiency	h_0	specific enthalpy of the fuel at reference temperature

Table 11 shows the different definitions of turbine inlet gas temperature as used by the manufacturer of the gas turbines.

For this purpose the energy balances of the whole gas turbine (Figure 4) and of the combustion chamber (Figure 5) shall be used.

The selected configuration can only serve as an example. In order to enable a simple adaptation of the balances to the actual gas turbine configuration, the scheme contains special features as synonyms for certain kinds of energy and mass flows that cross the border of the control volume, e.g. an external air cooler (thermal energy), a cooling air booster (mechanical energy), air extraction or water injection (mass flow changes).

Table 11 shows all energy flows entering and leaving the chosen control volume. Additionally it is shown how the energy flows can be deducted from measured or specified values.

In a first step the energy balance of the whole gas turbine is used to determine the compressor inlet air mass flow. The result of this calculation can directly be used for the equation being derived out of the combustion chamber balance, which leads to the mean specific enthalpy at the turbine inlet. Depending on the gas composition and with the help of gas property tables the final result then is the ISO turbine inlet gas temperature.

As many gas turbines use air extractions before the compressor discharge in order to cool turbine parts, a simplification is necessary, if the balances still shall be used without knowing all necessary cooling air flows, e.g. from measurements. For this purpose a value m_d is introduced. To define it, the following assumption is made: A compressor without air extraction, but with the same power consumption as the actual compressor, would have an air inlet mass flow $\dot{m}_{eq}$. As defined in equation (31), $\dot{m}_d$ is the relative difference between actual and the equivalent compressor inlet mass flow.

8.3.5.2 ISO turbine inlet gas temperature

The combustion chamber energy balance from equation (27) can be written as follows:

$$\left(\dot{m}_{a3}-\dot{m}_{e3}\right)\cdot h_{a3}+\dot{m}_{f4}\cdot\left(Q_{lo}+h_{f4}-h_{0}\right)+\dot{m}_{w4}\cdot h_{w4}+\dot{m}_{ct3}\cdot h_{ct3.2}+P_{b}+\left(\dot{m}_{a1}-\dot{m}_{eq}\right)\cdot h_{a1}= \dot{m}_{cf}3\cdot h_{a3}+\left(1-\eta_{tc}\right)\cdot\dot{m}_{f4}\cdot\left(Q_{lo}+h_{f4}-h_{0}\right)+\dot{m}_{g6}\cdot h_{g6} \quad ...(32)$$

with

$$\dot{m}_{a3}=\dot{m}_{eq} \quad ...(33)$$

$$\dot{m}_{g6}=\dot{m}_{a1}+\dot{m}_{f4}+\dot{m}_{w4}-\dot{m}_{e3}-\dot{m}_{ae} \quad ...(34)$$

the calculation of the ISO turbine inlet gas temperature can be obtained by inserting equations (33) and (34) into equation (32):

$$h_{g6}=\frac{\dot{m}_{a1}\cdot h_{a1}+\dot{m}_{eq}\cdot\left(h_{a3}-h_{a1}\right)-\dot{m}_{e3}\cdot h_{a3}+\dot{m}_{w4}\cdot h_{w4}-\dot{m}_{ct3}\cdot\left(h_{a3}-h_{ct3.2}\right)+\dot{m}_{f4}\cdot\eta_{tc}\cdot\left(Q_{lo}+h_{f4}-h_{0}\right)+P_{b}}{\dot{m}_{a1}+\dot{m}_{f4}+\dot{m}_{w4}-\dot{m}_{e3}-\dot{m}_{ae}} \quad ...(35)$$

The temperature T_{g6} depends on h_{g6} and the composition of the exhaust gas.

In general, the specific enthalpy of the air and the combustion gases can be calculated as a function of temperature and composition, using the tables of gas property data for the pure component gases and water vapours. The most important references for the gas property data, that it is possible to found in the bibliography, are:

VDI 4670 (2003)

JANAF (1985)

NASA (1994)

ASME PTC4.4(1981)

Landolt & Börnstein (1967/1971) or later date of publishing.

The choice of the gas property data is in the responsibility of the gas turbine manufacturer and should be mentioned as a reference with the performance data.

9 Test report

The test report shall present sufficient information to demonstrate that all the objectives of the tests have been attained. The form of the reports shall follow the general outline given below. The title page shall present the following information:

a) report number or other reference;

b) date(s) of the test;

c) title of the test;

d) location of the test;

e) engine designation and unit identification

f) author(s) of report

g) date of report

The table of contents shall list the major subdivisions of the report. The summary shall present briefly the object, results and conclusions of the test. The detailed report shall include the following information:

a) object of test, guarantee and stipulated agreements;

b) special agreements made regarding any major deviation from agreed test procedure;

c) correction factors to be applied because of deviations, if any, of test conditions from those specified;

d) where applicable, detailed calculation of fuel properties and fuel flow rates;

e) detailed calculation of test results corrected to specified conditions if test operating conditions have deviated from those specified;

f) discussion of test, its results and conclusions;

g) where applicable, measurement uncertainty calculation

h) any other information the parties to the test agree to include

Information which may be omitted if already made available to all parties to the test:

a) instrumentation calibration results from laboratories, certification from manufacturers;

b) description of equipment, instruments and their location;

c) summary of relevant measurements and observations;

d) where applicable, results of fuel analyses;

e) details of calculation procedures;

f) parties / persons attending the tests

Annex A
(informative)

Uncertainty

A.1 Introduction

It is an undisputed fact that the true value of a physical quantity determined by measurement is never known, that is, regardless of the measurement method, procedure or instrumentation, all measurement include imperfections that give rise to an error in the result. Because of the lack of exact knowledge of a measured value, the result therefore can only be an approximation or estimate of the value of the measurand and thus the result is only complete when accompanied with its uncertainty.

The evaluation of the uncertainties of the gas turbine performance test results is based on the concept and the approach of expressing uncertainties as suggested in the ISO/IEC Guide 98-3 and related international standards.

A.2 General principles of measurement uncertainty analysis

Traditionally the uncertainty of the result of a measurement is viewed as having two error components, the random error, which presumably arises from unpredictable, stochastic temporal and spatial variations of the measurand, and the systematic error or bias, considered as constant in magnitude and direction for repeated observations.

This approach of categorizing errors can be ambiguous because, depending on how an error quantity appears in a mathematical model that describes the measurement process, a random component may become a systematic component and vice versa. Therefore, to avoid such ambiguity, the concept in ISO/IEC Guide 98-3 is to categorize the uncertainty components by the methods of their evaluation rather than the components themselves.

The two groups of uncertainty components are:

A: those, which are evaluated by statistical analysis of series of observations "*Type A Evaluation of Uncertainty*"

B: those, which are evaluated by means other than statistical analysis "*Type B Evaluation of Uncertainty*"

A.2.1 Type A evaluation of uncertainty

For the uncertainty calculation of a test result, the Type A uncertainty component is calculated based on a series of n sample readings of the random variable quantity q with the experimental standard deviation of the mean $s(\overline{q})$ given as

$$s(\overline{q}) = \frac{s(q_k)}{\sqrt{n}} \tag{A.1}$$

with

$s(q_k)$ as the positive square root of the variance $s(q_k)^2$ which is

$$s(q_k)^2 = \frac{1}{n-1} \sum_{k=1}^{n} \left[q_k - \overline{q} \right]^2 \tag{A.2}$$

where

q_k is the individual observation of a variable input quantity

$\bar{q}$ is the arithmetic mean or average of n observations

In this case the random variable q with $\nu = n - 1$ degrees of freedom is considered normally distributed according to the probability density function of Laplace-Gauss, also termed t-distribution or Student's distribution.

Then the standard uncertainty $u(x_i)$ of the estimate $x_i = \overline{X}_i$ of the input quantity X_i is $u(x_i) = s(\overline{X}_i)$ with $s(\overline{X}_i)^2$ calculated according to equation (A2).

A.2.2 Type B evaluation of uncertainty

The Type B component of the uncertainty calculation is based on the data provided in calibration or other certificates, such as manufacturer specifications, of the test instruments and devices.

If, for example, the numerical result of the calibration of a quantity X is reported as $X = x \pm U$, where x is the numerical value of the output estimate and U is the numerical value of the expanded uncertainty $U = k\,u_c$, equation (A6), with U determined from the combined standard uncertainty u_c of equation (A3) and the coverage factor k, then the Type B standard uncertainty $u(x_i)$ is simply the quoted value U divided by multiplier k. In case where no further information about the latter factor is provided, one may assume that normal distribution was used to calculate the uncertainty corresponding to a 95% level of confidence with a coverage factor $k = 2$.

A.2.3 Combined standard uncertainty

The combined standard uncertainty $u_c(y)$ of a measurement result is an estimated standard deviation and characterizes the dispersion of the values that could reasonably be attributed to the measurand Y. For uncorrelated input quantities it is the positive square root of the combined variance $u_c^2(y)$ obtained by *The Law of Propagation of Uncertainty,* in common parlance the RSS (root-sum-of-squares) method, calculated as follows:

$$u_c^2(y) = \sum_{i=1}^{N} \left[\frac{\partial f}{\partial x_i} \right]^2 u^2(x_i) \tag{A.3}$$

and for correlated input quantities

$$\begin{aligned} u_c^2(y) &= \sum_{i=1}^{N} \sum_{j=1}^{N} \frac{\partial f}{\partial x_i} \frac{\partial f}{\partial x_j} u(x_i, x_j) \\ &= \sum_{i=1}^{N} \left[\frac{\partial f}{\partial x_i} \right]^2 u^2(x_i) + 2 \sum_{i=1}^{N-1} \sum_{j=i+1}^{N} \frac{\partial f}{\partial x_i} \frac{\partial f}{\partial x_j} r(x_i, x_j) u(x_i) u(x_i) \end{aligned} \tag{A.4}$$

where x_i and x_j are the estimates of the measurands X_i and X_j

and

$r(x_i, x_j)$ is the correlation coefficient which characterizes the degree of correlation between x_i and x_j with $-1 \leq r(x_i, x_j) \leq +1$. For independent estimates x_i and x_j, $r(x_i, x_j) = 0$.

The combined standard uncertainty allows combining the individual standard uncertainties $u(x_i)$, whether arising from the Type A evaluation of uncertainty or Type B evaluation of uncertainty.

The partial derivatives $\partial f / \partial x_i$ of the function $y = f(x_i)$, often referred to as *sensitivity coefficients,* are either mathematically determined by derivating y for each input estimate x_i or numerically by calculating the change $(\Delta y)_i$ of the output estimate y with varying the input estimates at the expected x_i with

$$\frac{\partial f}{\partial x_i} = \frac{(\Delta y)_i}{\Delta x_i} \tag{A.5}$$

A.2.4 Determining expanded uncertainty

The expanded uncertainty U, which is a measure that defines the interval about the measurement result encompassing a large fraction of the measured values with a defined level of confidence, is obtained by multiplying the standard uncertainty $u(x_i)$ with a coverage factor k:

$$U = k \cdot u(x_i) \tag{A.6}$$

In practice, a coverage factor $k = 2$ is frequently applied for a level of confidence of 95% (exactly 95.45%) and for degrees of freedom $\nu \geq 30$.

A.3 Example of uncertainty calculation

The uncertainty calculation procedure is illustrated with the following example of a performance test on a simple gas turbine. The variables used for the determination of the uncertainties of the corrected power output, thermal efficiency and turbine exhaust gas energy shall be defined through the test boundary as shown in the following figure A.1.

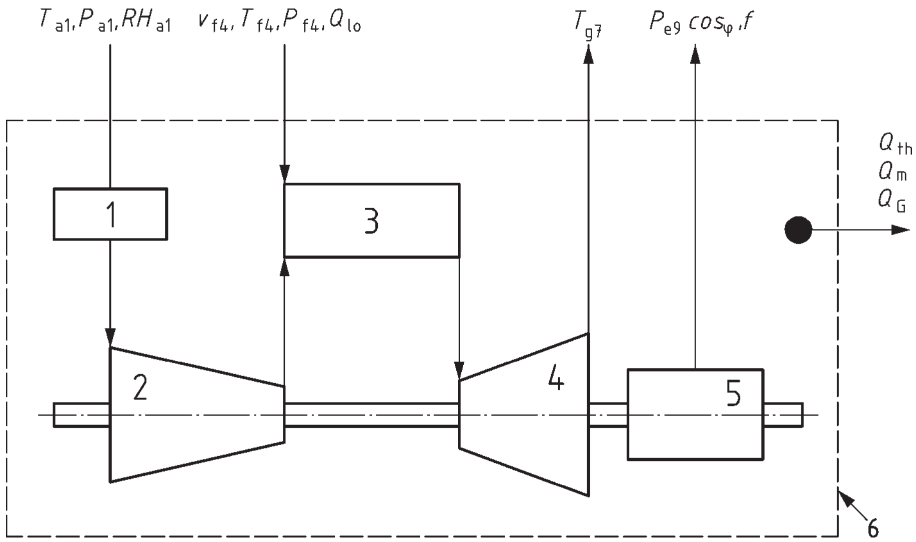


Figure A.1 – Test boundary example

1 Air filter

2 Compressor

3 Combustor

4 Turbine

5 Generator

6 Test Boundary

Table A.1 – Variables

Symbol	Measurand	Remarks
T_{a1}	Ambient air temperature	- variable for correction factors - average of at least four temperature sensors-
p_{a1}	Barometric pressure	- variable for correction factors
RH_{a1}	Ambient air relative humidity	- variable for correction factors
$\dot{v}_{f4}$	Fuel gas volume flow	- input variable for determination of fuel heat consumption - measured with turbine type flow meter
T_{f4}	Fuel gas temperature	- input variable for determination of fuel gas density and sensible heat
p_{f4}	Fuel gas pressure	- input variable for determination of fuel gas density
Q_{lo}	Lower heating value of fuel gas	- input variable for determination of fuel heat consumption - based on molar fuel composition-
T_{g7}	Turbine exhaust temperature	- variable for correction of exhaust energy
P_{e9}	Active power output	- input variable for power, thermal efficiency and exhaust energy
$\cos\ \varphi$	Generator power factor	- variable for correction factors
f	Gas turbine speed	- variable for correction factors
Q_{th}	Thermal heat losses	- input variable for determination of exhaust energy
Q_m	Mechanical losses	- input variable for determination of exhaust energy
Q_G	Generator losses	- input variable for determination of exhaust energy

The following assumptions apply for the example calculation:

Correlation of variables:

Where multiple instruments are used to measure a variable, such as the ambient temperature, those instruments are calibrated against one reference standard and therefore are correlated with correlation coefficient +1. Hence the type B uncertainty of the average temperature, calculated from the individual measured temperatures, is equal to uncertainty from calibration.

Coverage factor of type A and B uncertainty:

The type A uncertainties from statistical analysis of measured data as well as the type B uncertainties from calibration are based on a coverage factor of 2 corresponding to a level of confidence of 95 %.

A.3.1 Uncertainty of power

The corrected power output is determined with the basic equation (12) as follows:

$$P_{e9,c} = P_{e9,m} \cdot C_{P,1} \cdot C_{P,2} \cdot C_{P,3} \cdot C_{P,4} \cdot C_{P,5} \tag{A.7}$$

where

$P_{e9,m}$ is the measured power output

$C_{P,1} = f(p_{a1})$ is the power correction factor for ambient pressure

$C_{P,2} = f(T_{a1})$ is the power correction factor for ambient temperature

$C_{P,3} = f(RH_{a1})$ is the power correction factor for relative air humidity

$C_{P,4} = f(cos_{\varphi})$ is the power correction factor for generator power factor

$C_{P,5} = f(f)$ is the power correction factor for gas turbine speed

Measuring the total power of three phases at the secondary side of the instrument transformers the equation (1) can be simplified with:

$$P_{e9,m} = V_S \cdot I_S \cdot \cos_{\varphi} \cdot K_V \cdot K_I = P_{e9,ms} \cdot K_V \cdot K_I \tag{A.8}$$

where

$P_{e9,ms}$ is the measured active power output at the secondary side of the instrument transformers

Equation (A.7) can be rewritten:

$$P_{e9,c} = P_{e9,ms} \cdot K_V \cdot K_I \cdot C_{P,1} \cdot C_{P,2} \cdot C_{P,3} \cdot C_{P,4} \cdot C_{P,5} \tag{A.9}$$

The combined standard uncertainty of the measured and corrected power output is then determined based on the law of propagation of uncertainty according to equation A.4 as follows:

$$U(P_{e9,c}) = \sqrt{\begin{array}{l} \sum\limits_{j=A,B}\left[\dfrac{\partial P_{e9,c}}{\partial P_{e9,ms}} \cdot U(P_{e9,ms})_j\right]^2 + \left[\dfrac{\partial P_{e9,c}}{\partial K_V} \cdot U(K_V)\right]^2 + \left[\dfrac{\partial P_{e9,c}}{\partial K_I} \cdot U(K_I)\right]^2 + \\ \sum\limits_{i=1}^{5}\sum\limits_{j=A,B}\left[\dfrac{\partial P_{e9,c}}{\partial C_{P,i}} \cdot U(C_{P,i})_j\right]^2 \end{array}} \tag{A.10}$$

where

$U(P_{e9,ms})_j$ are the type A and B uncertainties of the measured power from measurement data and instrument calibration certificate respectively.

$U(K_V)$ is the type B uncertainty of the voltage transformer from shop test

$U(K_I)$ is the type B uncertainty of the current transformer from shop test

$U(C_{P,i})_j$ are the type A and B uncertainties of the correction variables ambient temperature, pressure, humidity, generator power factor and turbine speed and the partial derivatives or sensitivity coefficients are

$\frac{\partial P_{e9,c}}{\partial P_{e9,ms}}$ determined mathematically by deriving the power $P_{e9,c}$ for the measured power $P_{e9,ms}$

$\frac{\partial P_{e9,c}}{\partial K_{V,I}}$ determined mathematically by deriving the power $P_{e9,c}$ for the instrument transformer ratio K_V and K_I

$\frac{\partial P_{e9,c}}{\partial C_{P,i}}$ determined by numerical variation of the correction variables (the sensitivity coefficients are equal to the slope of the correction curve)

A numerical example of the uncertainty calculation for power output is given in Table A.2.

A.3.2 Uncertainty of efficiency

The corrected thermal efficiency, is according to equation (13)

$$\eta_c = \eta_m \cdot C_{\eta,2} \cdot C_{\eta,3} \cdot C_{\eta,4} \cdot C_{\eta,5} \tag{A.11}$$

where

η_m is the measured/calculated thermal efficiency

$C_{\eta,2} = f(T_{a1})$ is the efficiency correction factor for ambient temperature

$C_{\eta,3} = f(RH_{a1})$ is the efficiency correction factor for relative air humidity

$C_{\eta,4} = f(cos_{\varphi})$ is the efficiency correction factor for generator power factor

$C_{\eta,5} = f(f)$ is the efficiency correction factor for gas turbine speed

and is transformed with equation (3), (5) and (6) as follows

$$\eta_c = \frac{P_{e9,c}}{Q_{f4,c}} = \frac{P_{e9,m}}{\dot{m}_{f4,m}(Q_{lo} + c_{p,f4}(t_{f4,m} - t_{f0}))} \cdot C_{\eta,2} \cdot C_{\eta,3} \cdot C_{\eta,4} \cdot C_{\eta,5} \tag{A.12}$$

where

$\dot{m}_{f4,m}$ is the measured fuel mass flow

Q_{lo} is the lower heating value of the fuel

$c_{p,f4}$ is the specific heat capacity of the fuel

$T_{f4,m}$ is the measured fuel temperature at test boundary

T_{f0} is the reference fuel temperature at test boundary

The uncertainty of the measured and corrected thermal efficiency is as follows

$$U(\eta_c) = \sqrt{\sum_{j=A,B}\left[\frac{\partial \eta_c}{\partial P_{e9,m}} \cdot U(P_{e9,m})_j\right]^2 + \sum_{j=A,B}\left[\frac{\partial \eta_c}{\partial \dot{m}_{f4,m}} \cdot U(\dot{m}_{f4,m})_j\right]^2 + \left[\frac{\partial \eta_c}{\partial Q_{lo}} \cdot U(Q_{lo})\right]^2 + \sum_{i=1}^{5}\sum_{j=A,B}\left[\frac{\partial \eta_c}{\partial C_{\eta,i}} \cdot U(C_{\eta,i})_j\right]^2} \qquad \text{(A.13)}$$

The input variables $T_{f4,m}$ and $c_{p,f4}$ are neglected in the uncertainty analysis because their sensitivities on the thermal efficiency are less than 0.01%.

The partial derivatives or sensitivity coefficients are

$\dfrac{\partial \eta_c}{\partial P_{e9,m}}$ determined mathematically by deriving the efficiency η_C for the power $P_{e9,m}$

$\dfrac{\partial \eta_c}{\partial \dot{m}_{f4,m}}$ determined mathematically by deriving the efficiency η_C for the fuel flow $m_{f4,m}$

$\dfrac{\partial \eta_c}{\partial Q_{lo}}$ determined mathematically by deriving the efficiency η_C for the lower heating value Q_{lo}

$\dfrac{\partial \eta_c}{\partial C_{\eta,i}}$ determined by numerical variation of the correction variables (the sensitivity coefficients are equal to the slope of the correction curve) and the uncertainties of the input variables are

$U(P_{e9,m})_j$ are the type A and B uncertainties of the measured power

$U(Q_{lo})$ is the type B uncertainty of the lower heating value

$U(C_{\eta,i})_j$ are the type A and B uncertainties of the correction variables ambient temperature, humidity, generator power factor and turbine speed

$U(\dot{m}_{f4,m})_j$ are the type A and B uncertainties of the measured fuel flow. These uncertainties shall be determined individually considering the type of fuel and the flow meter. The following example calculation is based on fuel gas flow measured with a turbine type flow meter according to ISO 9951.

$$\dot{m}_{f4,m} = f\left(\dot{v}_{f4,m}, p_{f4,m}, T_{f4,m}, gas\ composition\right) = \dot{v}_{f4,m} \cdot \rho_{f4,m} \tag{A.14}$$

The above equation can be rewritten by resolving the density with the gas law for real gases

$$\dot{m}_{f4,m} = \dot{v}_{f4,m} \cdot \frac{p_{f4,m}}{Z_{f4,m} \cdot R \cdot T_{f4,m}} \cdot \sum_{i=1}^{N} x_i \cdot M_i \tag{A.15}$$

where

$\dot{v}_{f4,m}$ is the measured volume flow rate

$p_{f4,m}$ is the measured fuel gas pressure

$T_{f4,m}$ is the measured fuel gas temperature

$Z_{f4,m}$ is the compression factor

R is the molar gas constant

M is the molar mass

x is the mol fraction

The uncertainty of the mass flow rate is then determined as follows:

$$U\left(\dot{m}_{f4,m}\right) = \sqrt{\begin{aligned} &\sum_{j=A,B}\left[\frac{\partial \dot{m}_{f4,m}}{\partial \dot{v}_{f4,m}} \cdot U\left(\dot{v}_{f4,m}\right)_j\right]^2 + \sum_{j=A,B}\left[\frac{\partial \dot{m}_{f4,m}}{\partial p_{f4,m}} \cdot U\left(p_{f4,m}\right)_j\right]^2 + \\ &\sum_{j=A,B}\left[\frac{\partial \dot{m}_{f4,m}}{\partial T_{f4,m}} \cdot U\left(T_{f4,m}\right)_j\right]^2 + \left[\frac{\partial \dot{m}_{f4,m}}{\partial Z_{f4,m}} \cdot U\left(Z_{f4,m}\right)\right]^2 + \sum_{i=1}^{N}\left[\frac{\partial \dot{m}_{f4,m}}{\partial\left(x_i \cdot M_i\right)} \cdot U\left(x_i \cdot M_i\right)\right]^2 \end{aligned}} \tag{A.16}$$

The numerical calculation method is recommended for the determination of the sensitivity coefficients of above equation.

The uncertainties of the variables

$U\left(\dot{v}_{f4,m}\right)$ are the type A and B uncertainties of the measured volume flow rate

$U\left(p_{f4,m}\right)$ are the type A and B uncertainties of the measured gas pressure

$U\left(T_{f4,m}\right)$ are the type A and B uncertainties of the measured gas temperature

$U\left(Z_{f4,m}\right)$ is the type B uncertainty of the compression factor

$U\left(x_i \cdot M_i\right)$ is the type B uncertainty of the molar mass

A numerical example of the uncertainty calculation for the fuel mass flow and the thermal efficiency is given in Table A.3 and A.4 respectively.

A.3.3 Uncertainty of turbine exhaust gas energy

The equation for the corrected turbine exhaust energy, based on equation (16) and (19) is as follows:

Note In this example the thermal energy from the injection fluid (steam or water) is not included.

$$Q_{g7,c,T0} = \left(P_{e9,c} \left(\frac{\eta_{tc}}{\eta_c} - 1 \right) - Q_m - Q_G - Q_{th} \right) \cdot \frac{(T_{g7,c} - T_0)}{(T_{g7,c} - T_{a1})} \quad \text{(A.17)}$$

and with the basic equation (13) for the corrected thermal efficiency

$$\eta_c = \frac{P_{e9,c}}{Q_{f4,c}} \quad \text{(A.18)}$$

equation A.17 can be written as

$$Q_{g7,c,T0} = \left(Q_{f4,c} \cdot \eta_{tc} - P_{e9,c} - Q_m - Q_G - Q_{th} \right) \cdot \frac{(T_{g7,c} - T_0)}{(T_{g7,c} - T_{a1})} \quad \text{(A.19)}$$

with the corresponding uncertainty

$$U\left(Q_{g7,c,T0}\right) = \sqrt{\begin{array}{l} \left[\frac{\partial Q_{g7,c,T0}}{\partial Q_{f4,c}} \cdot U\left(Q_{f4,c}\right)\right]^2 + \left[\frac{\partial Q_{g7,c,T0}}{\partial \eta_{tc}} \cdot U\left(\eta_{tc}\right)\right]^2 + \left[\frac{\partial Q_{g7,c,T0}}{\partial P_{e9,c}} \cdot U\left(P_{e9,c}\right)\right]^2 + \\ \sum\limits_{j=A,B} \left[\frac{\partial Q_{g7,c,T0}}{\partial T_{g7,c}} \cdot U\left(T_{g7,c}\right)_j\right]^2 \end{array}} \quad \text{(A.20)}$$

The uncertainty terms of the input variables Q_{th}, Q_m and Q_G are neglected for the uncertainty propagation because their sensitivity coefficients are smaller than 0.01%. The remaining sensitivity coefficients in above equation A.20 are equal to 1.

The corrected fuel heat consumption $Q_{f4,c}$, from equation A.12 is

$$Q_{f4,c} = \frac{P_{e9,c}}{\eta_c} \quad \text{(A.21)}$$

and the corresponding uncertainty $U(Q_{f4,c})$ is

$$U\left(Q_{f4,c}\right) = \sqrt{\sum_{j=A,B} \left[\frac{\partial Q_{f4,c}}{\partial P_{e9,c}} \cdot U\left(P_{e9,c}\right)_j\right]^2 + \left[\frac{\partial Q_{f4,c}}{\partial \eta_c} \cdot U\left(\eta_c\right)_j\right]^2} \quad \text{(A.22)}$$

with

$U(P_{e9,c})$ from equation A.10

$U(\eta_c)$ from equation A.13

Table A.5 shows a numerical example of the uncertainty calculation for the exhaust gas energy

A.3.4 Numerical example of uncertainty calculation

Table A.2 – Uncertainty analysis of measured and corrected electrical power output

	Variable	Symbol	Type B Uncertainty U_B	Type A Uncertainty U_A	Sensitivity Coefficient SC	U_B x SC	U_A x SC	Remarks
1	Measured Power Output	$P_{e9,ms}$	± 0,20 %	± 0,018 %	1,000 %/%	± 0,200 %	± 0,018 %	
2	Voltage Transformation Ratio	K_V	± 0,20 %		1,000 %/%	± 0,200 %		
3	Current Transformation Ratio	K_I	± 0,20 %		1,000 %/%	± 0,200 %		
4	**Sub-Total U($P_{e9,m}$) of Measured Power**					**± 0,35 %**	**± 0,.02 %**	root-sum of squares (1-3)
5	Ambient Pressure Correction	$C_{P,1}$	± 0,05 %	± 0,003 %	1,000 %/%	± 0,050 %	± 0,003 %	
6	Ambient Temperature Correction	$C_{P,2}$	± 0,20 K	± 0,020 K	0,600 %/K	± 0,120 %	± 0,012 %	
7	Ambient Humidity Correction	$C_{P,3}$	± 2,00 %	± 0,060 %	0,008 %/%	± 0,016 %	± 0,000 %	
8	General Power Factor Correction	$C_{P,4}$	± 0,20 %		0,013 %/%	± 0,003 %		
9	Turbine Speed Correction	$C_{P,5}$	± 0,25 %		0,500%/%	± 0,125 %		
10	**Sub-Total U($P_{e9,c}$) of Corrected Power**					**± 0,39 %**	**± 0,02 %**	root-sum of squares (4-9)
11	**Combined Uncertainty U($P_{e9,c}$) of Corrected Power Output**					**± 0,39 %**		

Table A.3 – Uncertainty analysis of measured fuel gas mass flow

	Variable	Symbol	Type B Uncertainty U_B	Type A Uncertainty U_A	Sensitivity Coefficient SC	U_B x SC	U_A x SC	Remarks
12	Measured Volume Flow Rate	$\dot{v}_{f4,m}$	± 0,30 %	± 0,040 %	1,000 %/%	± 0,300 %	± 0,040 %	
13	Fuel Gas Pressure	$p_{f4,m}$	± 0,25 %	± 0,030 %	1,000 %/%	± 0,250 %	± 0,030 %	
14	Fuel Gas Temperature	$\dot{m}_{f4,m}$	± 0,20 K	± 0,020 K	0,350 %/K	± 0,070 %	± 0,007 %	
15	Compression Factor	$Z_{f4,m}$	± 0,10 %		1,000 %/%	± 0,100 %		
16	Molar Gas Mass	M	± 0,30 %		0,800 %/%	± 0,240 %		
17	**Sub-Total U($\dot{m}_{f4m}$) of Measured Fuel Mass Flow**					**± 0,47 %**	**± 0,05 %**	root-sum of squares (12-16)
18	**Combined Uncertainty U($\dot{m}_{f4m}$) of Measured Fuel Mass Flow**					**± 0,48 %**		

Table A.4 – Uncertainty analysis of corrected thermal efficiency

	Variable	Symbol	Type B Uncertainty U_B	Type A Uncertainty U_A	Sensitivity Coefficient SC	U_B x SC	U_A x SC	Remarks
19	Measured Power Output	$P_{e9,m}$	± 0,35 %	± 0,018 %	1,000 %/%	± 0,346 %	± 0,018 %	Sub-Total U($P_{e9,m}$) from Table A.2 (4)
20	Measured Fuel Mass Flow	$\dot{m}_{f4,m}$	± 0,47 %	± 0,050 %	1,000 %/%	± 0,474 %	± 0,050 %	Sub-Total U($m_{f4,m}$) from Table A.3 (17)
21	Lower Heating Value	Q_{lo}	± 0,50 %		1,000 %/%	± 0,500 %		
22	Ambient Temperature Correction	$C_{\eta,2}$	± 0,20 K	± 0,020 K	0,160%/K	± 0,032 %	± 0,003 %	
23	Ambient Humidity Correction	$C_{\eta,3}$	± 2,00 %	± 0,060 %	0,002 %/%	± 0,004 %	± 0,000 %	
24	Generator Power Factor Correction	$C_{\eta,4}$	± 0,20 %		0,013 %/%	± 0,003 %		
25	Turbine Speed Correction	$C_{\eta,5}$	± 0,25 %		0,100 %/%	± 0,025 %		
26	**Sub-Total U(η_c)of Corrected Thermal Efficiency**					**± 0,77 %**	**± 0,.05 %**	root-sum of squares (19-25)
27	**Combined Uncertainty U(η_c) of Corrected Thermal Efficiency**					**± 0,77 %**		

Table A.5 – Uncertainty analysis of corrected exhaust gas energy

	Variable	Symbol	Type B Uncertainty U_B	Type A Uncertainty U_A	Sensitivity Coefficient SC	U_B x SC	U_A x SC	Remarks
28	Corrected Power Output	$P_{e9,c}$	± 0,39 %	± 0,022 %	1,000 %/%	± 0,391 %	± 0,022 %	Sub-Total U($P_{e9,c}$) from Table A.2 (10)
29	Corrected Heat Input of Fuel	$Q_{f4,c}$	± 0,87 %	± 0,06 %	1,000 %/%	± 0,866 %	± 0,058 %	RSS from Table A.2 (10) and Table A.4 (26)
30	Combustion Efficiency	η_{tc}	± 0,02 %		1,000 %/%	± 0,020 %		
31	Corrected Exhaust Temperature	$T_{g7,c}$	± 5,00 K	± 0,020 K	0,010%/K	± 0,050 %	± 0,000 %	
32	**Sub-Total U($Q_{g7,c,TO}$) of Corrected Exhaust Energy**					**± 0,95 %**	**± 0,06 %**	root-sum of squares (28-31)
33	**Combined Uncertainty U($Q_{g7,c,TO}$) of Corrected Exhaust Energy**					**± 0,95 %**		

Annex B
(informative)

Example calculation of exhaust mass flow rate and turbine inlet temperature energy balance calculation

The sheet INPUT/OUTPUT is the main sheet; for most cases this is the only sheet required. Intermediate calculations are on the other worksheets.

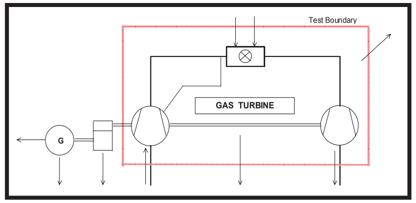
The method used for the intermediate calculation is not mandatory. It has been assumed a negligible impact of pressure on specific Enthalpy of Air, Flue gas and sensible Heat of the Fuel Gas.

The temperature effect on specific Heat of the Fuel Oil has been ignored.

This workbook could be adapted by the user to create an informal computerized analysis program.

B.1 Fuel gas fired

Single shaft gas turbine - input data - energy flow balance and duty calculation



Fuel fired : Natural gas — - No external air extraction flow and No cooling air flow to external cooler — - No gearbox

- No mass flow of sealing and or leakage air, leaving the test boundary

Ambient pressure	1,0000	bar a.
Inlet air dry bulb temperature	25,00	°C
Inlet air relative humidity	60,0	%
GT fuel gas composition	see page 75	
Water or steam injection mass flow rate -($\dot{m}_{w4}$)	0,000	kg/s
Water or steam injection temperature -(t_{w4})		°C
Water or steam injection pressure -(p_{w4})		bar a.
Flue gas temperature at turbine exhaust -(t_{g8})	594,19	°C
Air temperature at compressor discharge -(t_{a3})	424,95	
Selected ref. temperature for gas spec. enthalpy	0,00	°C
Selected ref. temperature for fuel gas spec. enthalpy	15,00	°C
Difference $\dot{m}_d$ between the actual compressor inlet air mass flow $\dot{m}_{a1}$ and the equivalent one, as a ratio to $\dot{m}_{eq}$	0,02331	

$$\dot{m}_d = \left(\frac{\dot{m}_{a1} - \dot{m}_{eq}}{\dot{m}_{eq}} \right)$$

Fuel gas mass flow rate -(m_{f4})	13,244	kg/h
Fuel gas temperature -(t_{f4})	19,57	°C
Fuel gas lower heat value -(LHV)	49151,2	kJ/kg
Fuel gas sensible heat	10,0	kJ/kg
Fuel gas total heat value ($LHV + SH_2$)	49161,2	kJ/kg
Power output at gen.terminals(P_{GT})	246596,2	kW
Generator efficiency - η_G	0,9893	
Generator losses -(P_{GEN})	2676,24	kW
Gearbox losses -(P_{GV})	0,0	kW
Comb.chamber efficiency -(η_{tc})	0,998	
Heat losses(1) -(Q_r)	1302,18	kW
GT mechanical losses -(Q_m)	807,6	kW
GT shaft power output -(Ps)	249272,4	kW

(1) Radiation and convection heat losses

INPUT DATA (shaded box)

OUTPUT (white box)

Mass flow calculation

Base equations from system energy balance and mass flow balance

$$\dot{m}_{a1} = \frac{Q_{f4} + \dot{m}_{w4} \cdot h_{w4} - h_{g8} \cdot (\dot{m}_{f4} + \dot{m}_{w4}) - P_s - Q_r - Q_m}{h_{g8} - h_{a1}}$$

Spec. enthalpy of the injected steam or water -(h_{w4})		kJ/kg
Inlet Air specific enthalpy -(h_{a1})	25,322	kJ/kg
Flue gas spec. enthalpy at turbine exhaust -(h_{g8})	658,867	kJ/kg
Energy flow of the fuel gas $Q_{f4} = m_{f4} * (LHV + SH_2)$	651091,21	kW
Air mass flow rate at compressor Inlet -($\dot{m}_{a1}$)	**617,13**	kg/s
Flue gas mass flow rate at turbine exhaust -($\dot{m}_{g8}$)	**630,38**	kg/s
Flue gas energy flow at turbine exhaust -(Q_{g8})	**415335,81**	kW

Turbine inlet temperature calculation

Base equations from combustion chamber energy balance

$$h_{g6} = \frac{\dot{m}_{a1} \cdot h_{a1} + \dot{m}_{eq} \cdot (h_{a3} - h_{a1}) + \dot{m}_{w4} \cdot h_{w4} + Q_{f4} - Q_r^{(1)}}{\dot{m}_{g6}} \qquad \dot{m}_{eq} = \left(\frac{\dot{m}_{a1}}{1 + \dot{m}_d} \right)$$

(1) It is assumed the Heat Losses of Comb. Chamber equal to the Total Heat Losses

Equivalent compressor inlet air mass flow rate -($\dot{m}_{eq}$)	603,08	kg/s
Equivalent reduction of actual compressor inlet air mass flow rate =($\dot{m}_{a1}$ - $\dot{m}_{eq}$)	14,056	kg/s
Air specific enthalpy at compressor discharge temperature -(h_{a3})	443,009	kJ/kg
Flue gas mass flow rate at turbine inlet -($\dot{m}_{g6}$ = $\dot{m}_{g8}$)	630,38	kg/s
Total energy flow entering the combustion chamber, plus fuel energy	917314,50	kW
Flue gas specific enthalpy at turbine inlet temperature -($h_{g6} = Q_{g6} / \dot{m}_{g6}$)	**1455,180**	kJ/kg
Flue gas Temperature at turbine inlet -(t_{g6})	**1230,00**	°C

DUTY SUMMARY

	Mass flow rate kg/s	Specific enthalpy kJ/kg	Energy flow kW-IN	Energy flow kW-OUT
Air at compressor inlet	617,13	25,322	15626,83	
Steam or water injection	0,000	0,00	0,00	
Fuel gas	13,244	49161,2	651091,21	
Power output at gen.terminals				246596,20
Generator losses				2676,24
Gearbox losses				0,00
Heat losses				1302,18
GT mechanical losses				807,6
Flue gas at turbine exhaust	630,38	658,867		415335,81
Sum of energy flows IN / OUT			**666718,04**	**666718,04**

Exhaust gas component	Exhaust gas mol. %	Exhaust gas mass %
CO_2	3,685	5.731
H_2O	9,088	5,768
N_2	73,852	73,114
Ar	0,866	1,222
O_2	12,510	14,147
SO_2	0,000	0,000
He	0,000	0,000

Calculation of wet air composition

Ambient pressure (p_{amb})	1,0000	bar a.
Inlet air dry bulb temperature ($t_{dry\ bulb}$)	25,00	°C
Inlet air relative humidity (φ)	60,0	%

Water vapour saturation pressure vs temperature

Based on IAPWS Industrial Formulation 1997 for the thermodynamics properties of water and steam (IAPWS-IF97)

p_{ws} = A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5 + A6 * T^6 (bar a.)

A0	A1	A2	A3	A4	A5	A6
-1,7139186035E+01	3,0961739394E-01	-2,1566592224E-03	6,7915334500E-06	-6,7999635030E-09	-1,0518480668E-11	2,1477192075E-14

T = $t_{dry\ bulb}$ + 273.15 =		298,15 K	
Water vap. saturat.pressure =	p_{ws}	0,0316975 bar a.	
Water vap. partial pressure =	$p_w = \varphi\ p_{ws}/100$	0,0190185 bar a.	
Humidity ratio =	($p_w/(p_{amb}-p_w)$)*($MW_{H2O}/MW_{dry\ air}$)=m,$_w$/m,$_{dry\ air}$	0,0120592 kg w / kg dry air	
$F_{dry\ air}$ =	$(p_{amb} - p_w)/p_{amb}$	0,9809815	
Water vapour mol. % =	100*p_w / p_{amb}	1,9018498 mol.,w% =	100*(1- $F_{dry\ air}$) 1,9018498 mol.w%
Dry air mass % =	100*1/(1+HR)	98,8084444 m, dry air%	
Water vapour mass % =	100*RH/(1+HR)	1,1915556 m, w%	

Dry air analysis

A1	A2	A3	A4	A5	A6
Component		**Molecular mass**	**Mol. %**	A3xA4 **kg/k-mol** $_{dry\ air}$	100 A5/Sum A5 **Mass%**
Carbon dioxide	CO_2	44,0098	0,033	0,0145	0,050
Water vapour	H_2O	18,0153		0,0000	0,000
Nitrogen	N_2	28,0135	78,113	21,8822	75,553
Argon	Ar	39,948	0,916	0,3659	1,263
Oxygen	O_2	31,9988	20,938	6,6999	23,133
SUM		Average molecular mass =		28,9625	100
		Dry air constant ($R_{,dry\ air}$) =		287,08 J/kg/K	

Wet air analysis

A1	A2	A7	A8	A9	A10
Component		**Molecular mass**	**Mol. %**	A7xA8 **kg/k-mol** $_{wet\ air}$	100 A9/Sum A9 **Mass%**
Carbon dioxide	CO_2	44,0098	0,032	0,0142	0,050
Water vapour	H_2O	18,0153	1,902	0,3426	1,192
Nitrogen	N_2	28,0135	76,627	21,4660	74,653
Argon	Ar	39,948	0,899	0,3590	1,248
Oxygen	O_2	31,9988	20,540	6,5725	22,857
SUM		Average molecular mass =		28,7543	100
		Wet air constant($R_{,wet\ air}$) =		289,16 J/kg/K	

Calculation of fuel gas lower heat value and elementary analysis **Molar masses and lower heat values from ISO 6976:1995/1996**

B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15
Fuel component		Molecular mass	Normalized mol.%	B3xB4 kg/k-mol$_{fuel}$	100 B5/Sum B5 mass %	LHV kJ /kg	B6xB7/100	Ar mass %	C mass %	H mass %	N mass %	He mass %	O mass %	S mass %
Methane	CH_4	16,0428	98,310	15,77167668	96,551	50035	48309,0486	0	72,28589758	24,26461426	0	0	0	0
Ethane	C_2H_6	30,07	0,530	0,159371	0,976	47520	463,6203011	0	0,779402415	0,196219798	0	0	0	0
Propane	C_3H_8	44,097	0,150	0,0661455	0,405	46340	187,643294	0	0,330878384	0,074045207	0	0	0	0
Isobutane	$i\text{-}C_4H_{10}$	58,123	0,000	0	0,000	45570	0	0	0	0	0	0	0	0
n-Butane	$n\text{-}C_4H_{10}$	58,123	0,050	0,0290615	0,178	45720	81,33939976	0	0,147057059	0,030852169	0	0	0	0
Isopentane	$i\text{-}C_5H_{12}$	72,15	0,000	0	0,000	45250	0	0	0	0	0	0	0	0
n-Pentane	$n\text{-}C_5H_{12}$	72,15	0,030	0,021645	0,133	45350	60,09129959	0	0,110292795	0,022213562	0	0	0	0
n-Hexane	$n\text{-}C_6H_{14}$	86,177	0,015	0,01292655	0,079	45110	35,69703725	0	0,066175677	0,012957911	0	0	0	0
n-Heptane	$n\text{-}C_7H_{16}$	100,204	0,005	0,0050102	0,031	44930	13,7806022	0	0,025734985	0,004936347	0	0	0	0
n-Octane	$n\text{-}C_8H_{18}$	114,231	0,000	0	0,000	44790	0	0	0	0	0	0	0	0
Nitrogen	N_2	28,0135	0,820	0,2297107	1,406	0	0	0	0	0	1,406235121	0	0	0
Argon	Ar	39,948	0,000	0	0,000	0	0	0	0	0	0	0	0	0
Helium	He	4,0026	0,000	0	0,000	0	0	0	0	0	0	0	0	0
Oxygen	O_2	31,9988	0,000	0	0,000	0	0	0	0	0	0	0	0	0
Carbon Dioxide	CO_2	44,0098	0,090	0,03960882	0,242	0	0	0	0,066175677	0	0	0	0,176300245	0
Carbon Monoxide	CO	28,01	0,000	0	0,000	10100	0	0	0	0	0	0	0	0
Water vapour	H_2O	18,0153	0,000	0	0,000	0	0	0	0	0	0	0	0	0
Hydrogen	H_2	2,0159	0,000	0	0,000	119910	0	0	0	0	0	0	0	0
Hydrogen Sulfide	H_2S	34,082	0,000	0	0,000	15200	0	0	0	0	0	0	0	0
SUM	Average molecular mass =			**16,3352**			**49151,2**	**0,000**	**73,812**	**24,606**	**1,406**	**0,000**	**0,176**	**0,000**

Fuel gas mass flow rate	13,244	kg/s
Fuel gas molar flow rate	0,81077	k-mol/s
Fuel gas lower heat value (net energy)	**49151,2**	kJ/kg
Fuel gas sensible heat	**10,0**	kJ/kg
Fuel gas total heat value	**49161,2**	kJ/kg

Fuel component atomic index

	Ar	**C**	**H**	**N**	**He**	**O**	**S**
CH_4		1	4				
C_2H_6		2	6				
C_3H_8		3	8				
i-C_4H_{10}		4	10				
n-C_4H_{10}		4	10				
i-C_5H_{12}		5	12				
n-C_5H_{12}		5	12				
n-C_6H_{14}		6	14				
n-C_7H_{16}		7	16				
n-C_8H_{18}		8	18				
N_2				2			
Ar	1						
He					1		
O_2						2	
CO_2		1				2	
CO		1				1	
H_2O			2			1	
H_2			2				
H_2S			2				1

PTC 22 sample case calculation — Fuel gas combustion calculation (stochiometric combustion - with minimum dry air)

	Molecular mass
C	12,011
H	1,00795
O	15,9994
N	14,00675
S	32,066

Fuel component		Molecul. mass	Norma-lized mol. %	kg/k-mol$_{fuel}$	k-mol N_2 / k-mol$_{fuel}$	N_2 mole change k-mol$_{fuel}$/s	k-mol O_2 / k-mol$_{fuel}$	O_2 mole change k-mol$_{fuel}$/s	k-mol CO_2/ k-mol$_{fuel}$	CO_2 mole change k-mol$_{fuel}$/s	k-mol H_2O/ k-mol$_{fuel}$	H_2O mole change k-mol$_{fuel}$/s	k-mol Ar/ k-mol$_{fuel}$	Ar mole change k-mol$_{fuel}$/s	k-mol He/ k-mol$_{fuel}$	He mole change k-mol$_{fuel}$/s	k-mol SO_2/ k-mol$_{fuel}$	SO_2 mole change k-mol$_{fuel}$/s
Methane	CH_4	16,0428	98,31	15,77167668	0	0	2	1,594129427	1	0,797064714	2	1,594129427	0	0	0	0	0	0
Ethane	C_2H_6	30,07	0,53	0,159371	0	0	3,5	0,015039722	2	0,008594127	3	0,01289119	0	0	0	0	0	0
Propane	C_3H_8	44,097	0,15	0,0661455	0	0	5	0,00608075	3	0,00364845	4	0,0048646	0	0	0	0	0	0
Isobutane	i-C_4H_{10}	58,123	0	0	0	0	6,5	0	4	0	5	0	0	0	0	0	0	0
n-Butane	n-C_4H_{10}	58,123	0,05	0,0290615	0	0	6,5	0,002634992	4	0,001621533	5	0,002026917	0	0	0	0	0	0
Isopentane	i-C_5H_{12}	72,15	0	0	0	0	8	0	5	0	6	0	0	0	0	0	0	0
n-Pentane	n-C_5H_{12}	72,15	0,03	0,021645	0	0	8	0,00194584	5	0,00121615	6	0,00145938	0	0	0	0	0	0
n-Hexane	n-C_6H_{14}	86,177	0,015	0,01292655	0	0	9,5	0,001155343	6	0,00072969	7	0,000851305	0	0	0	0	0	0
n-Heptane	n-C_7H_{16}	100,204	0,005	0,0050102	0	0	11	0,000445922	7	0,000283768	8	0,000324307	0	0	0	0	0	0
n-Octane	n-C_8H_{18}	114,231	0	0	0	0	12,5	0	8	0	9	0	0	0	0	0	0	0
Nitrogen	N_2	28,0135	0,82	0,2297107	1	0,006648287	0	0	0	0	0	0	0	0	0	0	0	0
Argon	Ar	39,948	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
Helium	He	4,0026	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
Oxygen	O_2	31,9988	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
Carbon dioxide	CO_2	44,0098	0,09	0,03960882	0	0	0	0	1	0,00072969	0	0	0	0	0	0	0	0
Carbon monoxide	CO	28,01	0	0	0	0	0,5	0	1	0	0	0	0	0	0	0	0	0
Water vapour	H_2O	18,0153	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Hydrogen	H_2	2,0159	0	0	0	0	0,5	0	0	0	1	0	0	0	0	0	0	0
Hydrogen sulfide	H_2S	34,082	0	0	0	0	1,5	0	0	0	1	0	0	0	0	0	1	0
SUM	Average molecular mass =			**16,335156**														
SUM	Molar flow change =					**0,006648287**		**1,621431995**		**0,813888122**		**1,616547126**		**0**		**0**		**0**

Equation of ideal combustion reaction with fuel and air in ideal gas state and without water in the fuel:

CaHbSc (id) + (a+b/4+c)O2 (id) = aCO2(id) + (b/2)H2O (id o l) + cSO2(id)

Fuel gas combustion calculation - exhaust flue gas composition

Fuel gas mass flow rate	13,244	kg/s
Water or steam injection mass flow rate	0,000	kg/s
Air mass flow rate at compressor inlet	617,13	kg/s
Minimum stochiom. dry air mass flow rate	224,28	kg/s
Minimum stochiom. wet air mass flow rate	226,99	kg/s
Flue gas mass flow rate at turbine exhaust	630,38	kg/s

Minimum requirement for combustion (stochiometric combustion - dry air / wet air)

Fuel elementary component	mass %	kmol O_2 per kg/ fuel	kmol dry air / wet air per kg/fuel	kg O2 fuel per kg/fuel	kg dry air / wet air per kg/fuel	
Ar	0,000					
C	73,812	0,061453347				
H	24,606	0,061029414				
N	1,406					
He	0,000					
O	0,176	-5,50959E-05				
S	0,000	0				
SUM	99,9999892	**0,1224277**	**0,5847152**	**3,9175**	**16,9348**	**Dry Air**
		0,1224277	**0,5960512**	**3,9175**	**17,1391**	**Wet Air**

Excess air coefficient (λ) **1** **-Dry air** **HR=m,$_w$/m,$_{dry\ air}$** **0**

Combustion products (stochiometric combustion - with minimum dry air)

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12
Component		**Molecular mass**	**CO_2, H_2O, N_2, Ar from air k-mol/kg$_{fuel}$**	**O_2 from excess air k-mol/kg$_{fuel}$**	**CO_2, H_2O, SO_2 from combust. k-mol/kg$_{fuel}$**	**Water or steam inject. k-mol/kg$_{fuel}$**	**N_2, Ar, He from fuel gas k-mol/kg$_{fuel}$**	**Combust.products mole to fuel mass ratio k-mol/kg$_{fuel}$**	**Combustion products mol. %**	**Combust.products mass to fuel mass ratio kg/kg$_{fuel}$**	**Combustion products mass %**
Carbon dioxide	CO_2	44,0098	0,000192956		0,061453347			0,061646303	9,538316967	2,713041448	15,12721528
Water vapour	H_2O	18,0153	0		0,122058829	0		0,122058829	18,88573599	2,198926415	12,26064323
Nitrogen	N_2	28,0135	0,456738571				0,000501985	0,457240556	70,74723326	12,8089083	71,41914973
Argon	Ar	39,948	0,005355991				0	0,005355991	0,828713782	0,213961131	1,192991762
Oxygen	O_2	31,9988		0				0	0	0	0
Sulphur dioxide	SO_2	64,0648			0			0	0	0	0
Helium	He	4,0026					0	0	0	0	0
SUM			Combust. prod. mol. mass		**27,7499**	kg/k-mol		**0,64630**	100	**17,9348**	100
			Combust. prod. constant(R_g)		299,62	J/kg/K		Total combustion products (k-mol/kg$_{fuel}$)		Total combustion products (kg/kg$_{fuel}$)	
								8,55962	(k-mol/s)	237,53	(kg/s)

Excess air coefficient (λ) 2,7188 -Dry Air **HR=m,$_w$/m,$_{dry\ air}$ 0,0120592** **Excess air coefficient (λ) - Wet Air 2,7188**

Combustion products at turbine exhaust (real combustion - with wet air in excess)

C1	C2	C3	C13	C14	C6	C7	C8	C15	C16	C17	C18
Component		**Molecular mass**	**CO_2, H_2O, N_2, Ar from Air k-mol/kg$_{fuel}$**	**O_2 from excess air k-mol/kg$_{fuel}$**	**CO_2, H_2O, SO_2 from combust. k-mol/kg$_{fuel}$**	**Water or steam inject. k-mol/kg$_{fuel}$**	**N_2 , Ar, He from fuel gas k-mol/kg$_{fuel}$**	**Turbine exhaust gas mole to fuel mass ratio k-mol/kg$_{fuel}$**	**Turbine exhaust gas mol. %**	**Turbine exhaust gas mass to fuel mass ratio kg/kg$_{fuel}$**	**Turbine exhaust gas mass %**
Carbon dioxide	CO_2	44,0098	0,000524605		0,061453347			0,061977951	3,684519008	2,727637241	5,730654155
Water vapour	H_2O	18,0153	0,030820072		0,122058829	0		0,152878901	9,088477509	2,754159264	5,786375839
Nitrogen	N_2	28,0135	1,241771161				0,000501985	1,242273146	73,85173151	34,80041877	73,11425486
Argon	Ar	39,948	0,014561755				0	0,014561755	0,865679854	0,581712996	1,222155186
Oxygen	O_2	31,9988		0,21042608				0,21042608	12,50959212	6,733382043	14,14655996
Sulphur dioxide	SO_2	64,0648			0			0	0	0	0
Helium	He	4,0026					0	0	0	0	0
SUM			Combust. prod. mol. mass		**28,2961**	kg/k-mol		**1,68212**	100	**47,5973**	100

Combust. prod. constant(R_g) 293,84 J/kg/K

Tot. turbine exhaust gas (k-mol/kg$_{fuel}$) 22,27797 (k-mol/s)

Tot. turbine exhaust gas (kg/kg$_{fuel}$) 237,53 (kg/s)

Combustion products (stochiometric combustion - with minimum wet air)

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12
Component		**Molecular mass**	**CO_2, H_2O, N_2, Ar from air k-mol/kg$_{fuel}$**	**O_2 from excess air k-mol/kg$_{fuel}$**	**CO_2, H_2O, SO_2 from combust. k-mol/kg$_{fuel}$**	**Water or steam inject. k-mol/kg$_{fuel}$**	**N_2, Ar, He from fuel gas k-mol/kg$_{fuel}$**	**Combust.products mole to fuel mass ratio k-mol/kg$_{fuel}$**	**Combustion products mol. %**	**Combust.products mass to fuel mass ratio kg/kg$_{fuel}$**	**Combustion products mass %**
Carbon dioxide	CO_2	44,0098	0,000192956		0,061453347			0,061646303	9,373900679	2,713041448	14,95690317
Water vapour	H_2O	18,0153	0,011335998		0,122058829	0		0,133394827	20,28393928	2,403147825	13,24847041
Nitrogen	N_2	28,0135	0,456738571				0,000501985	0,457240556	69,52773117	12,8089083	70,61506614
Argon	Ar	39,948	0,005355991				0	0,005355991	0,814428867	0,213961131	1,179560279
Oxygen	O_2	31,9988		0				0	0	0	0
Sulphur dioxide	SO_2	64,0648			0			0	0	0	0
Helium	He	4,0026					0	0	0	0	0
SUM			Combust. prod. mol. mass		**27,5821**	kg/k-mol		**0,65764**	100	**18,1391**	100
			Combust. prod. constant(R_g)		301,45	J/kg/K		Total combust. products (k-mol/kg$_{fuel}$)		Total combust. products (kg/kg$_{fuel}$)	
								8,70975 (k-mol/s)		240,23 (kg/s)	

PTC 22 sample case calculation

Fuel gas molar flow rate 0,81076667 k-mol/s

	Molecular mass
C	12,011
H2	2,0159
S	32,066

Dry air analysis

Component		Molecular mass	Mol. %
Carbon dioxide	CO_2	44,0098	0,033
Water vapour	H_2O	18,0153	
Nitrogen	N_2	28,0135	78,113
Argon	Ar	39,948	0,916
Oxygen	O_2	31,9988	20,938

Wet air minimum stochiometric mass flow rate	226,9896949	kg/s
Combustion products mass flow rate, with minimum wet air	240,2336949	kg/s
Total wet air mass flow rate	617,1347792	kg/s
Wet air mass flow rate in excess	390,1450843	kg/s
Turbine exhaust gas mass flow rate	630,3787792	kg/s

Wet air analysis

Component		Molecular mass	Mol. %	kg/k-mol wet air	Mass %	Air molar flow k mol/kg wet air	Minim. stochiom. wet air molar flow k-mol/s	Wet air molar flow in excess k-mol/s
Carbon dioxide	CO_2	44,0098	0,03237239	0,014247024	0,049547385	1,125826E-05	0,002555509	0,004392355
Water vapour	H_2O	18,0153	1,901849821	0,342623951	1,191555573	6,614131E-04	0,150133962	0,258047076
Nitrogen	N_2	28,0135	76,62740805	21,46601895	74,65314222	2,664899E-02	6,049045631	10,39697162
Argon	Ar	39,948	0,898579056	0,358964361	1,248383203	3,125021E-04	0,070934746	0,12192114
Oxygen	O_2	31,9988	20,53979068	6,572486542	22,85737162	7,143197E-03	1,621431995	2,786883001
		Average molecular mass =		**28,75434083**		SUM =	**7,894101843**	13,5682152
							226,9896949	

Combustion products (stochiometric combustion - with minimum wet air)

Component		Molecular mass	Wet air molar flow k-mol/s	Combustion mole change k-mol/s	Water or steam inject. molar Flow k-mol/s	Combust.products molar flow k-mol/s	Combustion products Mol. %	Combustion products Mass %
Carbon dioxide	CO_2	44,0098	0,002555509	0,813888122	0	0,816443631	9,373900679	14,95690309
Water vapour	H_2O	18,0153	0,150133962	1,616547126	0	1,766681088	20,28393928	13,24847033
Nitrogen	N_2	28,0135	6,049045631	0,006648287	0	6,055693918	69,52773117	70,61506572
Argon	Ar	39,948	0,070934746	0	0	0,070934746	0,814428867	1,179560272
Oxygen	O_2	31,9988	1,621431995	-1,621431995	0	0	0	0
Sulphur dioxide	SO_2	64,0648	0	0	0	0	0	0
Helium	He	4,0026	0	0	0	0	0	0
					SUM =	**8,709753382**	100	99,9999994
						240,2336935		

Combustion products at turbine exhaust (real combustion - with wet air in excess)

Component		**Molecular mass**	**Wet air molar flow in excess k-mol/s**	**Turbine exhaust molar flow k-mol/s**	**Turbine exhaust gas Mol. %**	**Turbine exhaust gas mass %**
Carbon dioxide	CO_2	44,0098	0,004392355	0,820835987	3,684519008	5,730654142
Water vapour	H_2O	18,0153	0,258047076	2,024728164	9,088477509	5,786375826
Nitrogen	N_2	28,0135	10,39697162	16,45266554	73,85173151	73,11425469
Argon	Ar	39,948	0,12192114	0,192855886	0,865679854	1,222155183
Oxygen	O_2	31,9988	2,786883001	2,786883001	12,50959212	14,14655993
Sulphur dioxide	SO_2	64,0648	0	0	0	0
Helium	He	4,0026	0	0	0	0
			SUM =	**22,27796858**	100	99,99999977
				630,3787778		

Calculation of wet air specific enthalpy

Specific enthalpy of gas mixtures

h = $A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5$ (kJ/kg) Selected reference temperature for specific enthalpy 0,00 °C

Polynomial coefficients a0…a5 for computation of spec. enthalpy of gas mixtures

	D1	D2	D3	D4	D5	D6	D7	D8
i	**Component**	**Wet air mass** % A10-i	**C1-i * m-i** D2-ixD10-i	**C2-i * m-i** D2-ixD11-i	**C3-i * m-i** D2-ixD12-i	**C4-i * m-i** D2-ixD13-i	**C5-i * m-i** D2-ixD14-i	**C6-i * m-i** D2-ixD15-i
1	CO_2	0,049547385	-8,764902644E-02	2,223737168E-04	4,169121093E-07	-2,236944519E-10	6,700694181E-14	-8,345543488E-18
2	H_2O	1,191555573	-5,998924663E+00	2,207116005E-02	-1,625422405E-06	4,998116881E-09	-1,937801806E-12	2,537635648E-16
3	N_2	74,65314222	-2,156245526E+02	8,187844659E-01	-1,701523532E-04	2,615856555E-07	-1,245596636E-10	2,117587143E-14
4	Ar	1,248383203	-1,774632901E+00	6,496918260E-03	-9,596450267E-16	1,016931210E-18	-4,785423588E-22	8,237585150E-26
5	O_2	22,85737162	-5,465990706E+01	1,926952771E-01	2,382768991E-05	1,529321363E-08	-1,218576310E-11	2,327047290E-15
6	SO_2		0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
7	He		0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
SUM			-2,781456663E+02	1,040270195E+00	-1,475331736E-04	2,816532915E-07	-1,386162216E-10	2,374833674E-14
			A0	**A1**	**A2**	**A3**	**A4**	**A5**
			Σ (C1-i * m-i)	Σ (C2-i * m-i)	Σ (C3-i * m-i)	Σ (C4-i * m-i)	Σ (C5-i * m-i)	Σ (C6-i * m-i)

Inlet air temperature	25,00	°C	Compress. discharge temperature	424,95	°C
	298,15	K		698,10	K
Inlet air specific enthalpy	**25,322**	kJ/kg	Air specific enthalpy at compress. discharge temperature	**443,009**	kJ/kg

Polynomial coefficients c1…….c6-i according to Landolt-Börnstein[(1)] , for computation of specific enthalpy and specific heat capacity of individual species

	D9	D10	D11	D12	D13	D14	D15
i	**Component**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
1	CO_2	-1,768994E+00	4,488102E-03	8,414412E-06	-4,514758E-09	1,352381E-12	-1,684356E-16
2	H_2O	-5,034532E+00	1,852298E-02	-1,364118E-06	4,194615E-09	-1,626279E-12	2,129683E-16
3	N_2	-2,888352E+00	1,096785E-02	-2,279239E-06	3,504014E-09	-1,668512E-12	2,836568E-16
4	Ar	-1,421545E+00	5,204266E-03	-7,687103E-16	8,145986E-19	-3,833297E-22	6,598603E-26
5	O_2	-2,391347E+00	8,430334E-03	1,042451E-06	6,690714E-10	-5,331218E-13	1,018073E-16
6	SO_2	-1,339146E+00	3,571502E-03	5,711725E-06	-3,338909E-09	1,018544E-12	-1,249979E-16
7	He	-1,418775E+01	5,194123E-02	0,000000E+00	0,000000E+00	0,000000E+00	0,000000E+00

[(1)] "Numerical Data and Functional Relationships in Science and Technology", of Landolt-Börnstein, Springer Verlag, Berlin and Heidelberg GmbH & Co. KG (1997)

Calculation of combustion products specific enthalpy at turbine exhaust

Specific enthalpy of gas mixtures

$h = A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5$ (kJ/kg)

Selected reference temperature for specific enthalpy 0,00 °C

Polynomial coefficients a0…a5 for computation of spec. enthalpy of gas mixtures

	E1	E2	E3	E4	E5	E6	E7	E8
i	**Component**	**Combustion products mass %** C18-i	**C1-i * m-i** E2-ixE10-i	**C2-i * m-i** E2-ixE11-i	**C3-i * m-i** E2-ixE2-i	**C4-i * m-i** E2-ixE13-i	**C5-i * m-i** E2-ixE14-i	**C6-i * m-i** E2-ixE15-i
1	CO_2	5,730654155	-1,013749282E+01	2,571976037E-02	4,822008509E-05	-2,587251669E-08	7,750027796E-12	-9,652461709E-16
2	H_2O	5,786375839	-2,913169433E+01	1,071809239E-01	-7,893299437E-06	2,427161889E-08	-9,410261513E-12	1,232314626E-15
3	N_2	73,11425486	-2,111797043E+02	8,019061802E-01	-1,666448611E-04	2,561933726E-07	-1,219920116E-10	2,073935557E-14
4	Ar	1,222155186	-1,737348594E+00	6,360420682E-03	-9,394832798E-16	9,955659036E-19	-4,684883809E-22	8,064516878E-26
5	O_2	14,14655996	-3,382933372E+01	1,192602254E-01	1,474709558E-05	9,465058678E-09	-7,541839510E-12	1,440223074E-15
6	SO_2	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
7	He	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
		SUM	-2,860155737E+02	1,060427511E+00	-1,115709799E-04	2,640575335E-07	-1,311940848E-10	2,244664710E-14
			A0	**A1**	**A2**	**A3**	**A4**	**A5**
			Σ (C1-i * m-i)	**Σ (C2-i * m-i)**	**Σ (C3-i * m-i)**	**Σ (C4-i * m-i)**	**Σ (C5-i * m-i)**	**Σ (C6-i * m-i)**

Exhaust flue gas temperature 594,19 °C / 867,34 K

Turbine inlet temperature 1230,00 °C / 1503,15 K

Remark: The Turbine Inlet Temperature can be determined by iterations. Adjust the value of TIT until the difference Δh between the spec. Enthalpy resulting from the Energy flows Balance (see page 72) and the value calculated acc. to the equation above, is (abs. value) < 0.01

Exhaust flue gas specific enthalpy **658,867** kJ/kg

Flue gas specific enthalpy at turbine inlet temperature **1455,181** kJ/kg ⟶ Δh -0,00137582 kJ/kg

TRUE

Polynomial coefficients c1……c6-i according to Landolt-Börnstein[(1)] , for computation of specific enthalpy and specific heat capacity of individual species

	E9	E10	E11	E12	E13	E14	E15
i	**Component**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
1	CO_2	-1,768994E+00	4,488102E-03	8,414412E-06	-4,514758E-09	1,352381E-12	-1,684356E-16
2	H_2O	-5,034532E+00	1,852298E-02	-1,364118E-06	4,194615E-09	-1,626279E-12	2,129683E-16
3	N_2	-2,888352E+00	1,096785E-02	-2,279239E-06	3,504014E-09	-1,668512E-12	2,836568E-16
4	Ar	-1,421545E+00	5,204266E-03	-7,687103E-16	8,145986E-19	-3,833297E-22	6,598603E-26
5	O_2	-2,391347E+00	8,430334E-03	1,042451E-06	6,690714E-10	-5,331218E-13	1,018073E-16
6	SO_2	-1,339146E+00	3,571502E-03	5,711725E-06	-3,338909E-09	1,018544E-12	-1,249979E-16
7	He	-1,418775E+01	5,194123E-02	0,000000E+00	0,000000E+00	0,000000E+00	0,000000E+00

(1) “Numerical Data and Functional Relationships in Science and Technology“, of Landolt-Börnstein, Springer Verlag, Berlin and Heidelberg GmbH & Co. KG (1997)

Calculation of fuel gas sensible heat

Specific enthalpy of gas mixtures

h = A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5 (kJ/kg) Selected reference temperature for specific enthalpy 0,00 °C

Polynomial coefficients a0…a5 for computation of spec. enthalpy of gas mixtures

	F1	F2	F3	F4	F5	F6	F7	F8	F9
i	**Fuel component**		**Mass %** B6-i	**C1-i * m-i** F3-ixF12-i	**C2-i * m-i** F3-ixF13-i	**C3-i * m-i** F3-ixF14-i	**C4-i * m-i** F3-ixF15-i	**C5-i * m-i** F3-ixF16-i	**C6-i * m-i** F3-ixF17-i
1	Methane	CH_4	96,55051184	-5,319798032E+02	1,998006637E+00	-1,088201509E-03	3,951126941E-06	-2,501305145E-09	5,365418149E-13
2	Acetylene	C_2H_2		0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
3	Ethylene	C_2H_4		0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
4	Ethane	C_2H_6	0,975631947	-2,823986183E+00	4,816909560E-03	1,904862838E-05	6,291157726E-09	-7,942746511E-12	1,983128033E-15
5	Propane	C_3H_8	0,404927264	-8,845028683E-01	-1,584804324E-05	1,278185302E-05	-3,109031530E-09	-3,323922380E-13	2,362612908E-16
6	Isobutane	i-C_4H_{10}	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
7	n-Butane	n-C_4H_{10}	0,177907699	-4,036263119E-01	8,472089139E-05	5,464399378E-06	-1,289058695E-09	-2,039818508E-13	1,233414504E-16
8	Isopentane	i-C_5H_{12}	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
9	n-Pentane	n-C_5H_{12}	0,132505622	-2,849930918E-01	-6,264404690E-05	4,453676938E-06	-1,542317738E-09	2,234917999E-13	0,000000000E+00
10	n-Hexane	n-C_6H_{14}	0,079133312	-1,690061233E-01	-4,367267016E-05	2,673664567E-06	-9,493631410E-10	1,435384911E-13	0,000000000E+00
11	n-Heptane	n-C_7H_{16}	0,030671271	-6,534744387E-02	-1,719927282E-05	1,036012080E-06	-3,713398199E-10	5,668352621E-14	0,000000000E+00
12	Nitrogen	N_2	1,406235121	-4,061702024E+00	1,542337587E-02	-3,205145930E-06	4,927467550E-09	-2,346320174E-12	3,988881544E-16
13	Argon	Ar	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
14	Helium	He	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
15	Oxygen	O_2	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
16	Carbon dioxide	CO_2	0,242475922	-4,289384512E-01	1,088256670E-03	2,040292308E-06	-1,094720109E-09	3,279198299E-13	-4,084157741E-17
17	Carbon monoxide	CO	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00

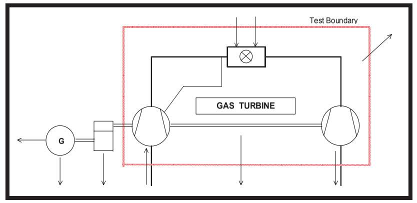
	F1	F2	F3	F4	F5	F6	F7	F8	F9
i	**Fuel component**		**Mass %** B6-i	**C1-i * m-i** F3-ixF12-i	**C2-i * m-i** F3-ixF13-i	**C3-i * m-i** F3-ixF14-i	**C4-i * m-i** F3-ixF15-i	**C5-i * m-i** F3-ixF16-i	**C6-i * m-i** F3-ixF17-i
18	Water vapour	H_2O	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
19	Hydrogen	H_2	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
20	Hydrogen sulfide	H_2S	0	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
			SUM	-5,411019057E+02	2,019280536E+00	-1,043908128E-03	3,953989735E-06	-2,511378952E-09	5,392425922E-13
				A0	**A1**	**A2**	**A3**	**A4**	**A5**
				Σ (C1-i * m-i)	Σ (C2-i * m-i)	Σ (C3-i * m-i)	Σ (C4-i * m-i)	Σ (C5-i * m-i)	Σ (C6-i * m-i)

Fuel gas temperature	19,57	°C
	292,72	K
Fuel gas specific enthalpy at process temperature	**42,435**	kJ/kg
Selected reference temperature for fuel gas specific enthalpy	15,00	°C
	288,15	K
Fuel gas specific enthalpy at reference temperature	**32,435**	kJ/kg
Fuel gas sensible heat $= SH_{Tfuel} - SH_{Tref}$	**10,00**	kJ/kg

Polynomial coefficients c1…….c6-i according to Landolt-Börnstein (1) , for computation of specific enthalpy and specific heat capacity of individual species

	F10	F11	F12	F13	F14	F15	F16	F17
i	**Fuel component**		**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
1	Methane	CH_4	-5,509860E+00	2,069390E-02	-1,127080E-05	4,092290E-08	-2,590670E-11	5,557110E-15
2	Acetylene	C_2H_2	-3,077310E+00	4,956210E-03	2,884860E-05	-2,402270E-08	1,150680E-11	-2,221340E-15
3	Ethylene	C_2H_4	-2,305520E+00	1,776950E-03	2,655630E-05	-8,035030E-09	3,740570E-13	2,794510E-16
4	Ethane	C_2H_6	-2,894520E+00	4,937220E-03	1,952440E-05	6,448290E-09	-8,141130E-12	2,032660E-15
5	Propane	C_3H_8	-2,184350E+00	-3,913800E-05	3,156580E-05	-7,678000E-09	-8,208690E-13	5,834660E-16
6	Isobutane	i-C_4H_{10}	-2,094630E+00	-7,656650E-04	3,348880E-05	-9,490040E-09	-4,357120E-13	6,358050E-16
7	n-Butane	n-C_4H_{10}	-2,268740E+00	4,762070E-04	3,071480E-05	-7,245660E-09	-1,146560E-12	6,932890E-16
8	Isopentane	i-C_5H_{12}	-1,982468E+00	-1,564796E-03	3,576854E-05	-1,330469E-08	2,212924E-12	0,000000E+00
9	n-Pentane	n-C_5H_{12}	-2,150800E+00	-4,727652E-04	3,361123E-05	-1,163964E-08	1,686659E-12	0,000000E+00
10	n-Hexane	n-C_6H_{14}	-2,135714E+00	-5,518873E-04	3,378684E-05	-1,199701E-08	1,813882E-12	0,000000E+00
11	n-Heptane	n-C_7H_{16}	-2,130575E+00	-5,607617E-04	3,377793E-05	-1,210709E-08	1,848098E-12	0,000000E+00
12	Nitrogen	N_2	-2,888352E+00	1,096785E-02	-2,279239E-06	3,504014E-09	-1,668512E-12	2,836568E-16
13	Argon	Ar	-1,421545E+00	5,204266E-03	-7,687103E-16	8,145986E-19	-3,833297E-22	6,598603E-26
14	Helium	He	-1,418775E+01	5,194123E-02	0,000000E+00	0,000000E+00	0,000000E+00	0,000000E+00
15	Oxygen	O_2	-2,391347E+00	8,430334E-03	1,042451E-06	6,690714E-10	-5,331218E-13	1,018073E-16
16	Carbon dioxide	CO_2	-1,768994E+00	4,488102E-03	8,414412E-06	-4,514758E-09	1,352381E-12	-1,684356E-16
17	Carbon monoxide	CO	-2,866840E+00	1,076430E-02	-1,683700E-06	2,911150E-09	-1,338760E-12	2,095400E-16
18	Water vapour	H_2O	-5,034532E+00	1,852298E-02	-1,364118E-06	4,194615E-09	-1,626279E-12	2,129683E-16
19	Hydrogen	H_2	-3,822340E+01	1,362380E-01	1,762750E-05	-1,758530E-08	1,008000E-11	-1,843260E-15
20	Hydrogen sulfide	H_2S	-2,640960E+00	9,562310E-03	-4,751860E-07	3,675590E-09	-1,969880E-12	3,492020E-16

(1) "Zahlenwerte und Funktionen aus Physik, Chemie, Astronomie, Geophysik und Technik", of Landolt-Börnstein, Springer Verlag, Berlin, 1967/1971



B.2 Fuel oil fired

Single shaft gas turbine - input data - energy flows balance and duty calculation

Fuel fired : Gas oil

- No external air extraction flow and No cooling air flow to external cooler
- No mass flow of sealing and or leakage air, leaving the test boundary
- No gearbox

Ambient pressure	1,0000	bar a.	Fuel oil mass flow rate -($\dot{m}_{f4}$)	14,270	kg/h
Inlet air dry bulb temperature	25,00	°C	Fuel oil temperature -(t_{f4})	32,50	°C
Inlet air relative humidity	60,0	%	Fuel oil lower heat value -(LHV)	42980,0	kJ/kg
			Fuel oil sensible heat	32,9	
GT fuel oil elementary analysis	see page 96		Fuel oil total heat value ($LHV + SH$)	43012,9	kJ/kg
Water or steam injection mass flow rate -($\dot{m}_{w4}$)	0,000	kg/s	Power output at gen.terminals(P_{GT})	229416,7	kW
Water or steam injection temperature -(t_{w4})		°C	Generator efficiency - η_G	0,9895	
Water or steam injection pressure -(p_{w4})		bar a.	Generator losses -(P_{GEN})	2442,47	kW
			Gearbox losses -(P_{GV})	0,0	kW
Flue gas temperature at turbine exhaust -(t_{g8})	576,13	°C	Comb.chamber efficiency -(η_{tc})	0,998	
Air temperature at compressor discharge -(t_{a3})	421,74		Heat losses[(1)] -(Q_r)	1227,60	kW
			GT mechanical losses -(Q_m)	807,6	kW
Selected ref. temperature for gas spec. enthalpy	0,00	°C	GT shaft power output -(Ps)	231859,1	kW
Selected ref. temperature for fuel oil spec. enthalpy	15,00	°C			
Difference $\dot{m}_d$ between the actual compressor inlet air mass flow $\dot{m}_{a1}$ and the equivalent one, as a ratio to $\dot{m}_{eq}$	0,02336				

(1) Radiation and convection heat losses

INPUT DATA (shaded boxes)

OUTPUT (open boxes)

$$\dot{m}_d = \left(\frac{\dot{m}_{a1} - \dot{m}_{eq}}{\dot{m}_{eq}} \right)$$

Mass flow calculation

Base equations from system energy balance and mass flow balance

$$\dot{m}_{a1} = \frac{Q_{f4} + \dot{m}_{w4} \cdot h_{w4} - h_{g8} \cdot \left(\dot{m}_{f4} + \dot{m}_{w4}\right) - P_s - Q_r - Q_m}{h_{g8} - h_{a1}}$$

$$\dot{m}_{g6} = \dot{m}_{a1} + \dot{m}_{f4} + \dot{m}_{w4} = \dot{m}_{g8}$$

Spec. enthalpy of the injected steam or water -(h_{w4})		kJ/kg
Inlet Air specific enthalpy -(h_{a1})	25,322	kJ/kg
Flue gas spec. enthalpy at turbine exhaust -(h_{g8})	626,397	kJ/kg
Energy flow of the fuel oil $Q_{f4} = \dot{m}_{f4} * (LHV + SH)$	613800,19	kW
Air mass flow rate at compressor Inlet -($\dot{m}_{a1}$)	617,17	kg/s
Flue gas mass flow rate at turbine exhaust -($\dot{m}_{g8}$)	631,44	kg/s
Flue gas energy flow at turbine exhaust -(Q_{g8})	395533,63	kW

Turbine inlet temperature calculation

Base equations from combustion chamber energy balance

$$h_{g6} = \frac{\dot{m}_{a1} \cdot h_{a1} + \dot{m}_{eq} \cdot \left(h_{a3} - h_{a1}\right) + \dot{m}_{w4} \cdot h_{w4} + Q_{f4} - Q_r^{(1)}}{\dot{m}_{g6}} \qquad \dot{m}_{eq} = \left(\frac{\dot{m}_{a1}}{1 + \dot{m}_d}\right)$$

(1) It is assumed the Heat Losses of Comb. Chamber equal to the Total Heat Losses

Equivalent compressor inlet air mass flow rate -($\dot{m}_{eq}$)	603,08	kg/s
Equivalent reduction of actual compressor inlet air mass flow rate =($\dot{m}_{a1}$ - $\dot{m}_{eq}$)	14,091	kg/s
Air specific enthalpy at compressor discharge temperature -(h_{a3})	439,521	kJ/kg
Flue gas mass flow rate at turbine inlet -($\dot{m}_{g6}$ = $\dot{m}_{g8}$)	631,44	kg/s
Total energy flow entering the combustion chamber, plus fuel energy	877996,07	kW
Flue gas specific enthalpy at turbine inlet temperature -($h_{g6} = Q_{g6} / \dot{m}_{g6}$)	1390,462	kJ/kg
Flue gas Temperature at turbine inlet -(t_{g6})	1200,00	°C

Duty Summary

	Mass flow rate kg/s	Specific enthalpy kJ/kg	Energy flow kW-IN	Energy flow kW-OUT
Air at compressor inlet	617,13	25,322	15627,77	
Steam or water injection	0,000	0,00	0,00	
Fuel oil	14,270	43012,9	613800,19	
Power output at gen. terminals				229416,66
Generator losses				2442,47
Gearbox losses				0,00
Heat losses				1227,60
GT mechanical losses				807,6
Flue gas at turbine exhaust	631,44	626,397		1227,60
Sum of energy flows IN / OUT			**629427,96**	**629427,96**

Exhaust gas component	Exhaust gas mol. %	Exhaust gas mass %
CO_2	4,737	7,239
H_2O	6,103	3,818
N_2	75,002	72,966
Ar	0,880	1,220
O_2	13,278	14,755
SO_2	0,000	0,001

Calculation of wet air composition

Ambient pressure (p_{amb})	1,0000	bar a.
Inlet air dry bulb temperature ($t_{dry\ bulb}$)	25,00	°C
Inlet air relative humidity (φ)	60,0	%

Water vapour saturation pressure vs temperature

Based on IAPWS Industrial Formulation 1997 for the Termodynamics properties of Water and Steam (IAPWS-IF97)

p_{ws} = $A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5 + A6 * T^6$ (bar a.)

A0	A1	A2	A3	A4	A5	A6
-1,7139186035E+01	3,0961739394E-01	-2,1566592224E-03	6,7915334500E-06	-6,7999635030E-09	-1,0518480668E-11	2,1477192075E-14

$T = t_{dry\ bulb} + 273.15$ =		298,15 K			
Water vap. saturat.pressure =	p_{ws}	0,0316975 bar a.			
Water vap. partial pressure =	$p_w = \varphi\ p_{ws}/100$	0,0190185 bar a.			
Humidity ratio =	$(p_w /(p_{amb}-p_w))*(MW_{H2O}/MW_{dry\ air})=m_{,w}/m_{,dry\ air}$	0,0120592 kg w / kg dry air			
$F_{dry\ air}$ =	$(p_{amb} - p_w)/p_{amb}$	0,9809815			
Water vapour mol. % =	$100*p_w / p_{amb}$	1,9018498 mol.,w%	=	$100*(1- F_{dry\ air})$	1,9018498 mol.w%
Dry air mass % =	100*1/(1+HR)	98,8084444 m, dry air%			
Water vapour mass % =	100*RH/(1+HR)	1,1915556 m, w%			

Dry air analysis

A1	A2	A3	A4	A5	A6
Component		**Molecular mass**	**Mol. %**	A3xA4 **kg/k-mol** $_{\text{dry air}}$	100 A5/Sum A5 **Mass %**
Carbon dioxide	CO_2	44,0098	0,033	0,0145	0,050
Water vapour	H_2O	18,0153		0,0000	0,000
Nitrogen	N_2	28,0135	78,113	21,8822	75,553
Argon	Ar	39,948	0,916	0,3659	1,263
Oxygen	O_2	31,9988	20,938	6,6999	23,133
SUM		Average molecular mass =		28,9625	100
		Dry air constant ($R_{,\text{dry air}}$) =		287,08 J/kg/K	

Wet air analysis

A1	A2	A7	A8	A9	A10
Component		**Molecular mass**	**Mol. %**	A7xA8 **kg/k-mol** $_{\text{wet air}}$	100 A9/Sum A9 **Mass %**
Carbon dioxide	CO_2	44,0098	0,032	0,0142	0,050
Water vapour	H_2O	18,0153	1,902	0,3426	1,192
Nitrogen	N_2	28,0135	76,627	21,4660	74,653
Argon	Ar	39,948	0,899	0,3590	1,248
Oxygen	O_2	31,9988	20,540	6,5725	22,857
SUM		Average molecular mass =		28,7543	100
		Wet air constant($R_{,\text{wet air}}$) =		289,16 J/kg/K	

Liquid fuel combustion calculations - exhaust flue gas composition

Fuel oil mass flow rate	14,270	kg/s
Water or steam injection mass flow rate	0,000	kg/s
Air mass flow rate at Compressor Inlet	617,13	kg/s
Minimum stochiom. dry air mass flow rate	207,06	kg/s
Minimum stochiom. wet air mass flow rate	209,56	kg/s
Flue gas mass flow rate at turbine exhaust	631,44	kg/s

Minimum requirement for combustion (Stochiometric combustion - dry air / wet air)

Fuel elementary component	Mass %	kmol O_2 per kg/ fuel	kmol dry air / wet air per kg/fuel	kg O2 fuel per kg/fuel	kg dry air / wet air per kg/fuel	
C	86,840	0,072300391				
H	13,140	0,032590902				
N	0,000					
O	0,000	0,00000E+00				
S	0,020	6,23714E-06				
SUM	100	**0,1048975**	**0,5009912**	**3,3566**	**14,5100**	**Dry air**
		0,1048975	**0,5107040**	**3,3566**	**14,6850**	**Wet air**

Excess air coefficient (λ) **1** **-Dry air** **HR=$m_{,w}/m_{,dry\ air}$** **0**

Combustion products (stochiometric combustion - with minimum dry air)

B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12
Carbon dioxide	CO_2	44,0098	0,000165327		0,072300391			0,065181805	13,58098827	3,189201773	20,56225958
Water vapour	H_2O	18,0153	0		0,065181805	0		0,122058829	12,2158911	1,174269765	7,571060551
Nitrogen	N_2	28,0135	0,391339231					0,391339231	73,34190049	10,96278155	70,6821255
Argon	Ar	39,948	0,004589079				0	0,004589079	0,860051219	0,183324532	1,181978087
Oxygen	O_2	31,9988		0				0	0	0	0
Sulphur dioxide	SO_2	64,0648			6,23714E-06			6,23714E-06	0,001168918	0,000399581	0,002576283
SUM			Combust. prod. mol. mass		**29,0677**	kg/k-mol		**0,53358**	100	**15,5100**	100
			Combust. prod. constant(R_g)		286,04	J/kg/K		Total combust. products (k-mol/kg_{fuel})		Total combust. products (kg/kg_{fuel})	
								7,61429 (k-mol/s)		221,33 (kg/s)	

Excess air coefficient (λ) **2,9451** **-Dry air** **HR=$m_{,w}/m_{,dry\ air}$** **0,0120592** **Excess air coefficient (λ) - Wet air** **2,9451**

Combustion products at turbine exhaust (real combustion - with wet air in excess)

B1	B2	B3	B13	B14	B6	B7	B8	B15	B16	B17	B18
Component		**Molecular mass**	**CO_2, H_2O, N_2, Ar from ar k-mol/kg_{fuel}**	**O_2 from excess air k-mol/kg_{fuel}**	**CO_2, H_2O, SO_2 from combust. k-mol/kg_{fuel}**	**Water or steam inject. k-mol/kg_{fuel}**	**N_2 from fuel oil k-mol/kg_{fuel}**	**Combust.products mole to fuel mass ratio k-mol/kg_{fuel}**	**Combustion products mol. %**	**Combust.products mass to fuel mass ratio kg/kg_{fuel}**	**Combustion on products mass %**
Carbon dioxide	CO_2	44,0098	0,00048691		0,072300391			0,072787301	4,736658691	3,203354559	7,239366717
Water vapour	H_2O	18,0153	0,028605522		0,065181805	0		0,093787326	6,103242565	1,689606817	3,818398223
Nitrogen	N_2	28,0135	1,15254472				0	1,15254472	75,00224479	32,28681152	72,96603121
Argon	Ar	39,948	0,013515432					0,013515432	0,879521414	0,53991449	1,220170579
Oxygen	O_2	31,9988		0,204039283				0,204039283	13,27792666	6,529012217	14,75513024
Sulphur dioxide	SO_2	64,0648			6,23714E-06			6,23714E-06	0,000405884	0,000399581	0,000903026
SUM			Combust. prod. mol. mass		**28,7953**	kg/k-mol		**1,53668**	100	**44,2491**	100
			Combust. prod. constant(R_g)		288,75	J/kg/K		Total cmbust. poducts (k-mol/kg_{fuel})		Total cmbust. pducts (kg/kg_{fuel})	
								21,92865	(k-mol/s)	221,33	(kg/s)

Combustion products (stochiometric combustion - with minimum wet air)

B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12
Component		**Molecular mass**	**CO_2, H_2O, N_2, Ar from air k-mol/kg$_{fuel}$**	**O_2 from excess Air k-mol/kg$_{fuel}$**	**CO_2, H_2O, SO_2 from combust. k-mol/kg$_{fuel}$**	**Water or steam inject. k-mol/kg$_{fuel}$**	**N_2 from fuel oil k-mol/kg$_{fuel}$**	**Combust.products mole to fuel mass ratio k-mol/kg$_{fuel}$**	**Combustion products mol. %**	**Combust.products mass to fuel mass ratio kg/kg$_{fuel}$**	**Combustion on products mass %**
Carbon dioxide	CO_2	44,0098	0,000165327		0,072300391			0,072465718	13,33819244	3,189201773	20,33286958
Water vapour	H_2O	18,0153	0,009712823		0,065181805	0		0,074894628	13,78526257	1,349249184	8,602186267
Nitrogen	N_2	28,0135	0,391339231				0	0,391339231	72,03072142	10,96278155	69,89360452
Argon	Ar	39,948	0,004589079					0,004589079	0,844675545	0,183324532	1,168792087
Oxygen	O_2	31,9988		0				0	0	0	0
Sulphur dioxide	SO_2	64,0648			6,23714E-06			6,23714E-06	0,00114802	0,000399581	0,002547542
SUM			Combust. prod. mol. mass		**28,8701**	kg/k-mol		**0,54329**	100	**15,6850**	100
			Combust. prod. constant(R_g)		288,00	J/kg/K		Total combust. products (k-mol/kg$_{fuel}$)		Total combust. products (kg/kg$_{fuel}$)	
								7,75290	(k-mol/s)	223,83	(kg/s)

PTC 22 sample case calculation **liquid fuel combustion calculation (stochiometric combustion - with minimum dry air)**

	Molecular mass
C	12,011
H2	2,0159
S	32,066
H	1,00795
O	15,9994
N	14,00675

Fuel	Element	Molecular mass	Normalized mass%	Molar flow k-mol$_{fuel}$/s	k-mol N_2 / k-mol$_{fuel}$	N_2 mole change k-mol$_{fuel}$/s	k-mol O_2 / k-mol$_{fuel}$	O_2 $_m$ole change k-mol$_{fuel}$/s	k-mol CO_2/ k-mol$_{fuel}$	CO_2 $_m$ole change k-mol$_{fuel}$/s	k-mol H_2O/ k-mol$_{fuel}$	H_2O $_m$ole change k-mol$_{fuel}$/s	k-mol SO_2/ k-mol$_{fuel}$	SO_2 mole change k-mol$_{fuel}$/s
Carbon	C	12,011	86,840	1,031736851	0	0	1	1,031736851	1	1,031736851	0	0	0	0
Hydrogen	H	1,00795	13,140	1,860307216	0	0	0,25	0,465076804	0	0	0,5	0,930153608	0	0
Nitrogen	N	14,00675	0,000	0	0,5	0	0	0	0	0	0	0	0	0
Oxygen	O	15,9994	0,000	0	0	0	0,5	0	0	0	0	0	0	0
Sulphur	S	32,066	0,020	8,90048E-05	0	0	1	8,90048E-05	0	0	0	0	1	8,90048E-05
SUM					Molar flow change =	**0**		**1,49690266**		**1,031736851**		**0,930153608**		**8,90048E-05**

Equation of ideal combustion reaction with fuel and air in ideal gas state and without water in the fuel:

CaHbSc (id) + (a+b/4+c)O2 (id) = aCO2(id) + (b/2)H2O (id o l) + cSO2(id)

Dry air analysis

Component		Molecular mass	Mol. %
Carbon dioxide	CO_2	44,0098	0,033
Water vapour	H_2O	18,0153	
Nitrogen	N_2	28,0135	78,113
Argon	Ar	39,948	0,916
Oxygen	O_2	31,9988	20,938

Wet air minim. stochiometric mass flow rate	209,5564162	kg/s
Combustion products mass flow rate, with minim. wet air	223,827	kg/s
Total wet air mass flow rate	617,1707867	kg/s
Wet air mass flow rate in excess	407,6143705	kg/s
Turbine exhaust gas mass flow rate	631,4409287	kg/s

Wet air analysis

Component		Molecular mass	Mol. %	kg/k-mol $_{wet\ air}$	Mass %	Air molar flow k mol/kg $_{wet\ air}$	Minim. stochiom. wet air molar flow k-mol/s	Wet air molar flow in excess k-mol/s
Carbon dioxide	CO_2	44,0098	0,03237239	0,014247024	0,049547385	1,125826E-05	2,359241E-03	0,004589029
Water vapour	H_2O	18,0153	1,901849821	0,342623951	1,191555573	6,614131E-04	1,386034E-01	0,269601491
Nitrogen	N_2	28,0135	76,62740805	21,46601895	74,65314222	2,664899E-02	5,584466E+00	10,86251042
Argon	Ar	39,948	0,898579056	0,358964361	1,248383203	3,125021E-04	6,548681E-02	0,127380328
Oxygen	O_2	31,9988	20,53979068	6,572486542	22,85737162	7,143197E-03	1,496903E+00	2,911669545
			Average molecular mass =	**28,75434083**		SUM =	7,287818472	
							209,5564162	

Combustion products (stochiometric combustion - with minimum wet air)

Component		Molecular mass	Wet air molar flow k-mol/s	Combustion mole change k-mol/s	Water or steam inject. molar flow k-mol/s	Combust.products molar flow k-mol/s	Combustion products Mol. %	Combustion Products mass %
Carbon dioxide	CO_2	44,0098	0,002359241	1,031736851	0	1,034096092	13,33819244	20,33286958
Water vapour	H_2O	18,0153	0,138603363	0,930153608	0	1,068756971	13,78526257	8,602186267
Nitrogen	N_2	28,0135	5,584466398	0	0	5,584466398	72,03072142	69,89360452
Argon	Ar	39,948	0,06548681	0	0	0,06548681	0,844675545	1,168792087
Oxygen	O_2	31,9988	1,49690266	-1,49690266	0	0	0	0
Sulphur dioxide	SO_2	64,0648	0	8,90048E-05	0	8,90048E-05	0,00114802	0,002547542
					SUM =	**7,752895276**	100	100
						223,8265582		

Combustion products at turbine exhaust (real combustion - with wet air in excess)

Component		Molecular mass	Wet air molar flow in excess k-mol/s	Turbine exhaust molar flow k-mol/s	Turbine exhaust gas mol. %	Turbine exhaust gas mass %
Carbon dioxide	CO_2	44,0098	0,004589029	1,038685121	4,736658691	7,239366717
Water vapour	H_2O	18,0153	0,269601491	1,338358462	6,103242565	3,818398223
Nitrogen	N_2	28,0135	10,86251042	16,44697682	75,00224479	72,96603121
Argon	Ar	39,948	0,127380328	0,192867138	0,879521414	1,220170579
Oxygen	O_2	31,9988	2,911669545	2,911669545	13,27792666	14,75513024
Sulphur dioxide	SO_2	64,0648	0	8,90048E-05	0,000405884	0,000903026
			SUM =	**21,92864609**	100	100
				631,4409287		

Calculation of wet air specific enthalpy

Specific enthalpy of gas mixtures

h = $A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5$ (kJ/kg) Selected reference temperature for specific enthalpy 0,00 °C

POLYNOMIAL COEFFICIENTS A0…A5 FOR COMPUTATION OF SPEC. ENTHALPY OF GAS MIXTURES

	C1	C2	C3	C4	C5	C6	C7	C8
i	**Component**	**Wet air mass** % A10-i	**C1-i * m-i** C2-ixC10-i	**C2-i * m-i** C2-ixC11-i	**C3-i * m-i** C2-ixC12-i	**C4-i * m-i** C2-ixC13-i	**C5-i * m-i** C2-ixC14-i	**C6-i * m-i** C2-ixC15-i
1	CO_2	0,049547385	-8,764902644E-02	2,223737168E-04	4,169121093E-07	-2,236944519E-10	6,700694181E-14	-8,345543488E-18
2	H_2O	1,191555573	-5,998924663E+00	2,207116005E-02	-1,625422405E-06	4,998116881E-09	-1,937801806E-12	2,537635648E-16
3	N_2	74,65314222	-2,156245526E+02	8,187844659E-01	-1,701523532E-04	2,615856555E-07	-1,245596636E-10	2,117587143E-14
4	Ar	1,248383203	-1,774632901E+00	6,496918260E-03	-9,596450267E-16	1,016931210E-18	-4,785423588E-22	8,237585150E-26
5	O_2	22,85737162	-5,465990706E+01	1,926952771E-01	2,382768991E-05	1,529321363E-08	-1,218576310E-11	2,327047290E-15
6	SO_2		0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
7	He		0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
SUM			-2,781456663E+02	1,040270195E+00	-1,475331736E-04	2,816532915E-07	-1,386162216E-10	2,374833674E-14
			A0	**A1**	**A2**	**A3**	**A4**	**A5**
			Σ (C1-i * m-i)	Σ (C2-i * m-i)	Σ (C3-i * m-i)	Σ (C4-i * m-i)	Σ (C5-i * m-i)	Σ (C6-i * m-i)

Inlet air temperature	25,00	°C	Compressor discharge temperature	421,74	°C
	298,15	K		694,89	K
Inlet air specific enthalpy	**25,322**	°C	Air specific enthalpy at compressor discharge temperature	**439,521**	kJ/kg

Polynomial coefficients c1…….c6-i according to Landolt-Börnstein[1] , for computation of spec. enthalpy and specific heat capacity of individual species

	C9	C10	C11	C12	C13	C14	C15
i	**Component**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
1	CO_2	-1,768994E+00	4,488102E-03	8,414412E-06	-4,514758E-09	1,352381E-12	-1,684356E-16
2	H_2O	-5,034532E+00	1,852298E-02	-1,364118E-06	4,194615E-09	-1,626279E-12	2,129683E-16
3	N_2	-2,888352E+00	1,096785E-02	-2,279239E-06	3,504014E-09	-1,668512E-12	2,836568E-16
4	Ar	-1,421545E+00	5,204266E-03	-7,687103E-16	8,145986E-19	-3,833297E-22	6,598603E-26
5	O_2	-2,391347E+00	8,430334E-03	1,042451E-06	6,690714E-10	-5,331218E-13	1,018073E-16
6	SO_2	-1,339146E+00	3,571502E-03	5,711725E-06	-3,338909E-09	1,018544E-12	-1,249979E-16
7	He	-1,418775E+01	5,194123E-02	0,000000E+00	0,000000E+00	0,000000E+00	0,000000E+00

[1] "Numerical Data and Functional Relationships in Science and Technology", of Landolt-Börnstein, Springer Verlag, Berlin and Heidelberg GmbH & Co. KG (1997)

Calculation of combustion products specific enthalpy at turbine exhaust

Specific enthalpy of gas mixtures

h = $A0 + A1 * T + A2 * T^2 + A3 * T^3 + A4 * T^4 + A5 * T^5$ (kJ/kg)

Selected reference temperature for specific enthalpy: 0,00 °C

Polynomial coefficients a0…a5 for computation of spec. enthalpy of gas mixtures

	D1	D2	D3	D4	D5	D6	D7	D8
i	**Component**	**Combustion products mass %** 18-i	**C1-i * m-i** D2-ixD10-i	**C2-i * m-i** D2-ixD11-i	**C3-i * m-i** D2-ixD2-i	**C4-i * m-i** D2-ixD13-i	**C5-i * m-i** D2-ixD14-i	**C6-i * m-i** D2-ixD15-i
1	CO_2	7,239366717	-1,280639629E+01	3,249101624E-02	6,091501418E-05	-3,268398880E-08	9,790382000E-12	-1,219367077E-15
2	H_2O	3,818398223	-1,922384804E+01	7,072811392E-02	-5,208745747E-06	1,601671046E-08	-6,209780844E-12	8,131977783E-16
3	N_2	72,96603121	-2,107515822E+02	8,002804854E-01	-1,663070240E-04	2,556739949E-07	-1,217446987E-10	2,069731092E-14
4	Ar	1,220170579	-1,734527386E+00	6,350092259E-03	-9,379576919E-16	9,939492455E-19	-4,677276221E-22	8,051421244E-26
5	O_2	14,75513024	-3,528463644E+01	1,243906762E-01	1,538150028E-05	9,872235650E-09	-7,866281595E-12	1,502179971E-15
6	SO_2	0,000903026	-1,209283638E-03	3,225159117E-06	5,157836103E-09	-3,015121594E-12	9,197717005E-16	-1,128763520E-19
7	He	0,00000000	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00	0,000000000E+00
SUM			-2,798021996E+02	1,034243609E+00	-9,521409747E-05	2,488759371E-07	-1,260294593E-10	2,179320872E-14
			A0	**A1**	**A2**	**A3**	**A4**	**A5**
			Σ (C1-i * m-i)	Σ (C2-i * m-i)	Σ (C3-i * m-i)	Σ (C4-i * m-i)	Σ (C5-i * m-i)	Σ (C6-i * m-i)

Exhaust flue gas temperature: 576,13 °C; 849,28 K

Turbine inlet temperature: 1200,00 °C; 1473,15 K

Exhaust flue gas spec. enthalpy: **626,397** kJ/kg

Flue gas specific enthalpy at turbine inlet temperature: **1390,464** kJ/kg → Δh -0,001858223 kJ/kg

TRUE

Remark: The turbine inlet temperature can be determined by iterations. Adjust the value of TIT until the difference Δh between the spec. Enthalpy resulting from the energy flows balance (see page 93) and the value calculated acc. to the equation above, is (abs. value) < 0.01

Polynomial coefficients c1…….c6-i according to Landolt-Börnstein[1], for computation of spec. enthalpy and specific heat capacity of individual species

	D9	D10	D11	D12	D13	D14	D15
i	**Component**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
1	CO_2	-1,768994E+00	4,488102E-03	8,414412E-06	-4,514758E-09	1,352381E-12	-1,684356E-16
2	H_2O	-5,034532E+00	1,852298E-02	-1,364118E-06	4,194615E-09	-1,626279E-12	2,129683E-16
3	N_2	-2,888352E+00	1,096785E-02	-2,279239E-06	3,504014E-09	-1,668512E-12	2,836568E-16
4	Ar	-1,421545E+00	5,204266E-03	-7,687103E-16	8,145986E-19	-3,833297E-22	6,598603E-26
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7	He	-1,418775E+01	5,194123E-02	0,000000E+00	0,000000E+00	0,000000E+00	0,000000E+00

(1) “Numerical Data and Functional Relationships in Science and Technology“, of Landolt-Börnstein, Springer Verlag, Berlin and Heidelberg GmbH & Co. KG (1997)

Calculation of fuel oil sensible heat

Fuel oil type	**Gas oil**	
Fuel oil temperature	32,50	°C
	305,65	K
Fuel oil specific heat	1,88	kJ/kg/K
Fuel oil specific enthalpy at process temperature	**61,100**	kJ/kg
Selected reference temp. for fuel oil spec. enthalpy	15,00	°C
	288,15	K
Fuel oil specific enthalpy at reference temperature	**28,200**	kJ/kg
Fuel oil sensible heat = $SH_{Tfuel} - SH_{Tref}$	**32,90**	kJ/kg

Fuel oil	Kinematic viscosity (10^{-6} m^2/s)	Specific heat (kJ/kg/K)
Gas oil	< 9,5 at 20°C	1,88
Light Fuel oil	< 49 at 20°C	1,76
Medium fuel oil	< 110 at 20°C	1,63
Heavy or extra heavy fuel oil	< 380 at 20°C	1,59

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