BEE CODE

COGENERATION

Prepared for

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1. OBJECTIVE AND SCOPE

1.1 Objective

1.1.1 The basic objective of this BEE Code is to establish procedures, guidelines and rules for conducting the performance tests on different types of cogeneration Systems at site operating conditions. The code also provides, to the extent feasible, ways and means for improvement of performance.

1.1.2 The performance of cogeneration system is widely understood in terms of ***Efficiency*** and ***Heat Rate.*** The objective of this code is to determine the ***Efficiency*** and ***Heat Rate*** for the cogeneration System operating at specific operating conditions prevailing at that site.

1.2 Scope

1.2.1 This code deals with the following types of cogeneration systems, which are further divided on the basis of different types of main plant equipment installed and various types of fuels fired.

	Based on fuel	**Based on equipment configuration**
i.	**Steam turbine based cogeneration system**	
	Coal/Lignite fired plant	Back-pressure steam turbine
	Liquid Fuel fired plant	Extraction & condensing steam turbine
	Natural gas fired plant	Extraction & back-pressure steam turbine
	Bagasse/Husk fired plant	Single/double extraction & condensing
ii.	**Gas turbine based cogeneration system**	
	Natural gas fired plant	Gas turbine with unfired Waste Heat Recovery Boiler (WHRB)
	Liquid fuel fired plant	Gas turbine with supplementary fired WHRB
		Gas turbine with fully fired WHRB
		Gas turbine with WHRB & steam turbine [Cogeneration-cum-combined cycle]
iii.	**Reciprocating engine based cogeneration system**	
	Liquid fuel fired plant	Reciprocating engine with unfired WHRB
	Natural gas fired plant	Reciprocating engine with supplementary fired WHRB
		Reciprocating engine with fully fired WHRB
		Reciprocating engine with absorption chiller

1.2.2 Following Codes and Standards are widely used as reference while preparing the code, as these are widely used for conducting performance testing at manufacturers' test facilities and at operating site.

Steam Turbines

DIN 1943	Thermal acceptance tests for steam turbines
BN EN 60953	Rules for steam turbine's thermal acceptance tests
ASME PTC 6	Steam turbine performance test code
IEC 953	Rules for steam turbine's thermal acceptance tests

Gas Turbines

DIN 4341	Acceptance rules for gas turbines
BS 3135	Specification for gas turbine acceptance test
ASME PTC 22	Gas turbine power plants – Power test code
ISO 2314	Gas turbines - Acceptance tests
ISO 2314	Acceptance tests for combined cycle power plants, Amendment 1

Reciprocating Engines

IS:10000	Part IV – 1980: Method of tests for Internal combustion engines Declaration of power, efficiency, fuel consumption and lubricating oil consumption
IS:10000	Part VIII – 1980: Method of tests for Internal combustion engines Performance tests

Steam Boilers

ASME PTC 4.1	Steam generating units performance test code
ASME PTC 4.4	Gas turbine heat recovery steam generators performance test code
DIN 1942	Acceptance Test for Steam Generators

The performance of fired steam generating plant can be determined in accordance with the method provided in the respective Codes for Boilers and the performance parameters so derived can be used to determine overall performance of the cogeneration plant.

2. DEFINITIONS AND DESCRIPTION OF TERMS

2.1 Symbols

2.1.1 The following symbols are used unless otherwise defined in the text.

Symbol	Description		SI Units
A	Area		m^2
f	Force		Newton
g	Local value of acceleration due to gravity		m/s^2
g_o	Standard value of acceleration due to gravity (in SI units 9.80665 m/s^2)		m/s^2
h	Enthalpy		kJ/kg
H	Theoretical enthalpy		kJ/kg
M	Moisture fraction = 1 - (x/100)		Ratio
m	Mass		kg
N	Rotational speed RPM		rps
P	Power		kW
P	Pressure		kPa kg/cm^2
S	Entropy		kJ/kgK
t	Temperature		^0C
T	Temperature, absolute		^0K
V	Velocity		m/s
v	Specific volume		m^3/kg
W	Rate of flow	For steam/liquids	kg/hr
		For gases	Nm^3/hr
x	Quality of steam, percent of dryness		percent
η	Efficiency		percent
ρ	Density		kg/m^3
γ	Specific weight		N/m^3
Q	Calorific value of fuel	For liquid/solid fuels	kJ/kg
For gas fuels			kJ/Nm^3 or Sm^3
q	Heat rate		kJ/kWh

2.2 Abbreviations

2.2.1 The following abbreviations are used unless otherwise defined in the text.

Symbol	Description
HR	Heat rate
SR	Steam rate
HP	High Pressure
LP	Low Pressure
FW	Feed Water
SH	Superheater
COMB	Combined
Diff.	Differential
Temp.	Temperature
ECON	Economizer

2.3 Subscripts

2.3.1 The following subscripts are used unless otherwise defined in the text.

Subscript	Description
G	Generator
r	Rated condition
c	Corrected
stg	Steam turbine
gt	*Gas turbine*
en	Reciprocating engine
blr	Boiler, waste heat recovery
f	fuel
steam	Steam
ng	Natural gas fuel
lq	Liquid fuel
wtr	Water
s	Specified operating condition, if other than rated
t	Test operating condition
1	Conditions measured at the steam turbine inlet stop valves and steam strainers
2	For turbines using superheated steam: condition at 1st extraction
3	For turbines using superheated steam: condition at 2nd extraction
4	Condition at turbine exhaust connection
5	Condition at condenser-condensate discharge
6	Condition at condensate pump discharge
7	Condition at feed-water pump or feed-water booster pump inlet
8	Condition at feed-water pump discharge
9	Condition at the discharge of the final feed-water heater
*a*1	Superheater-desuperheating water
*a*2	First reheater desuperheating water
*a*3	Second reheater desuperheating water
E	Extraction steam.
e	Make-up water admitted to the condensate system
hhv	Higher heating value
lhv	Lower heating value
*p*L	Packing leak-off (shaft or valve stems)
i, ii…*n*	Sequence

2.4 Definitions

Approach Point — It is difference between the saturation temperature and the water temperature entering the evaporator.

Auxiliary power/energy — All electricity consumed internally within the boundary of a cogeneration plant to run the plant.

Calorific value, gross — Gross calorific value of fuel in kJ/kg. Heat evolved per kg of fuel (for solid and liquid fuels) and per Nm^3 (normal cubic meter)/Sm^3 (standard cubic meter) of fuel (for gas fuels) in its complete combustion under constant pressure at temperature of 25^{0}C when all the water initially present as liquid in the fuel and that present in the combustion products condensed to the liquid state.

Calorific value, net — Net calorific value of fuel in kJ/kg. Heat evolved per kg of fuel (for solid and liquid fuels) and per Nm^3 (normal cubic meter)/Sm^3 (standard cubic meter) of fuel (for gas fuels) in its complete combustion under constant pressure at temperature of 25^0C when all the water initially present as liquid in the fuel and that present in the combustion products in the vapour state. (The number of heat units liberated per unit quantity of fuel burned in oxygen under standard conditions).

Capacity

Useful output produced by generator driven by steam turbine, gas turbine or engine expressed in terms of the functional output in terms of horsepower, kilowatt; also referred to as maximum continuous rating (MCR).

Capacity factor

Total energy produced for a specified period relative to the total possible amount of energy that could have been produced for the same period.

$$\frac{\text{Total energy generated in that period (kWh) x 100\%}}{\text{Total installed capacity (kW) x Period hours}}$$

Carbon (C)

Carbon in fuel, expressed as mass % as-received, as-sampled or as-fired (C_{as}); and for coal, mass % dry ash-free (C_{daf}).

Cogeneration/combined heat and power (CHP)

Simultaneous production of useful energy in different forms (heat, typically as steam) and electrical energy.

Combustion, Rate of

Rate of combustion is defined as follows.

(a) All fuels: Heat value of fuel as fired per unit of furnace volume per unit time, $J/(m^3*s)$

(b) Mass burning of solid fuels: Mass of fuel as fired per unit area grate surface per unit time, $kg/(m^2*s)$

(c) Gaseous fuels: Volume of gas fired per unit of furnace volume per unit time, m^3*s.

Combustor

A heat source in which fuel burns and produces hot flue gases to feed in turbine or otherwise reacts with the working fluid to increase the temperature.

Efficiency, Ideal Cycle

Ideal cycle efficiency is defined as the ratio of the work of the ideal cycle to the heat input. This efficiency of an ideal cycle is often referred to as the efficiency of an ideal engine.

Efficiency, Engine

The engine efficiency is defined as the ratio of actual work of a system divided by the work of a corresponding ideal system. Since indicated, brake, or combined actual work may be involved, it is possible to have three engine efficiencies.

Efficiency, Thermal

The thermal efficiency is defined as the ratio of energy output to energy input or work done divided by the heat supplied. It is directly related to heat rate.

Indicated thermal efficiency = AW_i / Q
Brake thermal efficiency = AW_b / Q
Combined thermal efficiency = BW_k / Q

Where,

A = 1 J/(W*s)
B = 1 J/(W*s)
Q = heat added, J/sec
W_i = indicated net work, J
W_b = brake net work, J
W_k = combined net work, J

The thermal efficiency of a complete plant will be expressed in the same manner as that for a turbine or engine.

Efficiency, Volumetric

Volumetric efficiency is derived only for reciprocating engines.

$$\eta_v = \frac{\text{Actual delivery}}{\text{Displacement x 100}}$$

Efficiency, Isentropic Compression

The isentropic compression efficiency is defined as ratio of theoretical isentropic power to the fluid power developed.

Efficiency, Mechanical

Mechanical efficiency is defined as the ratio of actual work to indicated internal work.

Efficiency, Overall, Compressor

Overall compressor efficiency is defined as ratio of isentropic power to the actual power supplied.

Energy of a Substance, Thermal

Internal energy of a substance is a "Point" function

Enthalpy

Enthalpy of water or steam is the amount of heat that must be added to bring it from a liquid at 0^0C to its present temperature, pressure and condition. It is expressed in terms of kJ/kg_m.

Enthalpy is defined as: $h = u + \frac{Pv}{J}$ kJ/kg

Where,

h = enthalpy, kJ/kg
u = internal energy, kJ/kg
P = pressure of fluid, kPa
v = specific volume of fluid, m^3/kg
J = mechanical equivalent of heat, 1 kJ/1000J

Enthalpy drop

The difference in enthalpy between steam at the steam turbine inlet conditions and at steam turbine outlet conditions.

Entropy

It is ratio of the heat added to a substance to the absolute temperature at which it was added.

Fossil fuels

Energy-rich substances created from the partial decomposition of prehistoric organisms over long periods of time. Examples are coal, coal seam methane, natural gas, and oil.

Fuel rate

The fuel rate of solid and liquid fuels is defined as mass of fuel fired per unit of output. For gaseous fuels, it is defined as m3 of gas at 150C and 101.325 kPa pressure per hour. Fuel rate should be qualified by reference to the unit output.

Heat Rate

Heat rate is the amount of energy input required to produce a given unit output, usually expressed as kJ/kWh, Heat rate is a measure of generating station heat efficiency.

This is the total fuel heat input expressed in kJ divided by the energy produced by the power plant expressed in kWh. It is related to thermal efficiency by the following expression (%).

$$\text{HR} = \frac{3600}{\text{Thermal efficiency}} \text{ x } 100\% \text{ given in units of kWh}$$

Higher heating value (HHV)	This is synonymous with gross calorific value.
Lower heating value (LHV)	This is synonymous with net calorific value.
Non-recoverable degradation (NRD)	The component of degradation in the sent-out thermal efficiency of a power plant due to ageing that is not recoverable through normal maintenance practices. Note that this degradation is normally measured as an increase in heat rate.
Output factor (or load factor)	Total energy produced for a specified period relative to the total possible amount of energy that could have been produced for the service hours during the same period. $$\frac{\text{Total energy generated in that period (kWh)) x 100}}{\text{Total installed capacity (kW) x service hours}} \%$$ The term output factor is intended to apply to electricity generators and may not be directly applicable to some cogeneration plants.
Period hours	Period hours are the number of hours the unit was in an active state.
Pinch Point	It is difference between the flue gas temperature leaving the evaporator and saturation temperature in waste heat boiler.
Power output, gross	The gross power output of a generator unit is total electrical energy generated during that specific duration of operation of unit.
Power output, net	The net power output of a generator unit is defined by following formulae. $$\text{Net output, kW} = \left\langle \begin{matrix}\text{Electrical power}\\ \text{output of generator}\end{matrix} \right\rangle - \left\langle \begin{matrix}\text{Auxiliary power}\\ \text{supplied}\end{matrix} \right\rangle$$ Auxiliary power supplied is that external power which is necessary for the unit's operation inclusive of, but not limited to excitation power, power for separately driven lube-oil pumps, boiler pumps, cooling water pumps, fuel pumps, fans, etc.
Service hours	Total number of hours a unit was electrically connected to the transmission system. For a twelve month reporting period, the service hours correspond to the period for which electricity was metered; i.e., corresponding to the kWhs for the period.
Steam rate	Steam consumption per hour per unit output, in which the steam turbine is charged with the net steam quantity supplied, usually expressed in kg_m/kWh.

Thermal Efficiency Generated η_{GEN}	$\dfrac{\text{Total energy generated (kWh) x 3600 x 100}}{\text{Quantity of fuel x gross calorific value of fuel consumed}}\,\%$
Thermal Efficiency Sentout, η_{SO}	$\dfrac{\text{Total energy sent out (kWh) x 3600 x 100}}{\text{Quantity of fuel x gross calorific value of fuel consumed}}\,\%$
Total installed capacity	Total installed capacity is the sum of the capacity for each unit making up the power plant, where capacity is as defined above. Also see definition of “service hours”.
Turbine	A mechanical expander device in which the working fluid produces work kinetic action on a rotating element.

2.5 Constants and conversions

2.5.1 Following conversion factors can be used in calculations.

g_0	=	Standard value of acceleration due to gravity; = in SI units 9.80665 metres per sec. per sec. This is an internationally agreed value.
J	=	Mechanical equivalent of heat; 1 kJ = 0.102 N.
One hp (Electric)	=	0.746 kW.
One kCal	=	4.19 kJ

3. GUIDING PRINCIPLES

3.1 Introduction

3.1.1 To carry out the onsite performance in correct and satisfactory manner, careful planning and proper execution are essential at every stage of the test. In this section, various requirements before, during and after conducting of equipment performance test are discussed.

3.2 Estimation of performance

3.2.1 The performance of Cogeneration System is widely understood in terms of ***Efficiency*** and ***Heat Rate***. Heat rate is the heat input required per unit of power generated (kJ/kWh), for specific fuel being fired and specific site conditions.

3.2.3 Performance testing of Cogeneration system defined in this code include the following.

- Measurement and estimation of **Power Generation** from the cogeneration plant at the site operating parameters of ambient air temperature, pressure and relative humidity, site altitude, fuel being fired and its characteristics.
- Measurement and estimation of **Steam Generation** from the cogeneration plant from waste heat recovery in gas turbine based plants and reciprocating engine based plants.
- Estimation of **Cogeneration Heat Rate or Heat Input per unit** and **Cogeneration Efficiency** at the site operating parameters of ambient air temperature, pressure and relative humidity, site altitude, fuel being fired and its characteristics.
- Measurement and estimation of **Auxiliary Power Consumption** at the site operating parameters.

3.3 Pre test requirements

3.3.1 Before performance evaluation test can be undertaken, it is important to conduct careful review of the required documents inclusive of the Process and Instrumentation Diagrams (P & IDs) for the plant and system. It is also suggested to prepare a test-protocol on the following lines.

- Name of equipment to be subjected to test.
- Performance maps and performance guarantee values at installation.
- Understanding of the test procedures to be followed as defined in this code including explicitly stated exceptions, if any.
- Test Data to be collected including methods of measurements, instruments to be used for critical parameters.
- Performance analysis procedure to be adopted as per code.
- Present operating conditions of equipment and operating hours logged.
- Check for calibration of on site & on line instruments to be used for measurement of critical parameters.
- Typical test data logged automatically in in-built control system or DCS.
- Time duration for test and minimum number of tests.
- Operating parameters under which the performance needs to be evaluated for each equipment in the system.

3.3.2 Once the test-protocol on above mentioned lines has been defined and agreed upon, a final test procedure conforming to this code including required test-data sheets is prepared. At this stage, it may be necessary to give special instructions to the plant operating personnel such as off-line washing of the gas turbine prior to undertaking the test.

3.3.3 A plan for instrumentation required for the test of system and system heat cycle can be drawn out prior to test. This plan should take into account the instruments installed as part of cogeneration system and to be installed for the purpose of test.
Adequate provision for physical location, installation and number of test instruments needed to achieve test results with good repeatability should be made. Some of the items to be considered are:

(a) Location and installation of a calibrated primary flow metering section.

(b) Provision for the accurate measurement of output.

(c) Location and installation of test connections for primary pressure and temperature measurements.

(d) Provision for measurement of secondary leak-off and bypass flows, which may affect the primary flow measurement or have a significant effect in calculation of the test performance.

(e) Selection of test instruments capable of the repeatability required for consistent test results.

(f) Location of test instruments in groups to facilitate calibration and use, and minimize the number of observations required.

3.3.4 The performance parameters, commonly considered for performance guarantee and specific for onsite performance testing, are given in Table 3.1 for main components or equipment installed in cogeneration plant. The cogeneration plant configuration can be based on the combination of different systems given in the table.

3.4 Performance parameters in cogeneration plant

3.4.1 Estimation of following parameters need to be carried out in performance testing in cogeneration plant.

Table 3-1: Performance parameters for various equipment in cogeneration plant

Equipment	Performance parameter	Associated parameter
Gas turbine generator system	• Electric Power Output • Heat Rate • Exhaust Gas Temperature	• Compressor Inlet Temperature • Ambient Pressure • Compressor Inlet Relative Humidity • DeNOx Steam Flow Conditions (pressure, temperature, flow rate)
Steam turbine generator system	• Electrical Power Output • Heat Rate	• Steam Turbine Throttle Flow Conditions (temperature, pressure, flow rate) • DeNOx Steam Flow Conditions (temperature, pressure, flow rate) • Process Steam Flow Conditions (temperature, pressure, flow rate)
Reciprocating engine generator system	• Electric Power Output • Heat Rate • Exhaust Gas Temperature	• Engine Inlet Temperature • Ambient Pressure • Engine Inlet Relative Humidity
Waste heat recovery boiler	• HP Steam Flow Rate • Overall Effectiveness of System • Combined Economizer Feed water flow	• Gas temperature in HRSG inlet • Exhaust Gas Flow • Supplementary Firing Conditions • Exhaust Gas Composition at HRSG inlet

Note: Above listed parameters are based on assumption of single pressure HRSG system. In case of dual pressure HRSG system, there can be HP as well as LP steam flow rate and other conditions can be taken as the case may be.

3.5 Manufacturer's performance and correction curves and data required

3.5.1 It is essential to obtain the performance and correction curves and data, generally supplied by the respective equipment manufacturer to the plant operating personnel. Generally, following listed documents would be required as reference when doing the performance calculations.

Steam turbine

- Throttle flow versus generator output as a function of controlled extraction flow
- Steam turbine heat rate or steam rate correction factors to adjust the test rate to standard conditions defined by the heat / steam formulae.
- Turbine load corrections to adjust the test output to standard conditions defined by the heat / steam rate formulae

Gas turbine

- Heat rate versus air temperature at compressor inlet
- Gas turbine generator power output and heat rate correction as a result of steam injection
- Effect of steam injection on generator power output as a function of compressor inlet temperature
- Effect of steam injection on heat rate as a function of compressor inlet temperature
- Ambient pressure and site altitude correction curve

Reciprocating engine

- Engine inlet pipeline pressure drop versus air flow rate
- Generator output versus engine inlet temperature
- Heat rate versus engine inlet temperature
- Ambient pressure and site altitude correction curve

Power generator

- Generator output versus compressor (Gas turbine)/engine inlet temperature
- Specific humidity corrections to generator output and heat rate
- Power factor versus kVA loading correction
- Electrical losses relative to generator power factor
- Electrical losses relative to generator power factor and hydrogen pressure (for hydrogen cooled generator) to adjust the generator to rated conditions.

Waste heat recovery boiler/Dual Pressure Level)

- Gas turbine / Engine exhaust flow versus HP steam flow as a function of gas turbine exhaust temperature
- Gas turbine / Engine exhaust flow versus LP steam flow as a function of gas turbine exhaust temperature
- Gas turbine / Engine exhaust flow versus HP superheater steam temperature as a function of gas turbine exhaust temperature

3.6 Requirements during the test

3.6.1 It is of utmost importance that the operating conditions agreed upon in the test-protocol are maintained constant during the test duration, though within practical limits. In the event of observance of a significant change in one of the critical operating parameters, the entire test need to be conducted again for the duration agreed upon.

3.6.2 The steady state operating conditions can be verified by monitoring certain important test parameters out of listed one for a period of at least thirty minutes. The steady state operating conditions are assumed to exist if variation of parameters during the steady state test is within the permissible limits.

3.6.3 Moreover, in a given test-set, it is necessary to ascertain that the variation in values of different measured parameters compared to their respective test average have not exceeded the permissible limits provided under the applicable test codes or standards.

3.6.4 As it is feasible to install different combinations of power and steam generation equipment in cogeneration plant, the test procedure for each cogeneration plant can be developed individually based on the plant configuration, instrumentation and plant operating conditions.

4. INSTRUMENTS AND METHODS OF MEASUREMENTS

4.1 Performance Parameters in Cogeneration Plant

4.1.1 Measurement of some or all of the following parameters can be carried out for performance testing in cogeneration plant.

4.1.2 For the performance evaluation of cogeneration system, following test data can be generally collected.

a. **Gas turbine generator System**

1 Ambient Pressure	4 Electrical Power output	7 Diff. Pressure-Inlet Air Filter
2 Dry Bulb Temp.	5 Fuel Flow Rate	8 Exhaust Gas Temp
3 Wet Bulb Temp.	6 Fuel Gas Temp.	9 Auxiliary Power

b. **Steam turbine generator system**

1 Throttle Steam-flow, Pressure & Temp.	3 Exhaust Steam Pressure, & Temp.	6 Auxiliary Steam Flow
2 Extraction Steam-flow, Pressure & Temp.	4 Electrical Power output	
	5 Auxiliary Power	

c. **Reciprocating engine generator system**

1 Ambient Pressure	5 Electrical Power output	8 Diff. Pressure-Inlet Air Filter
2 Dry Bulb Temp.	6 Fuel Flow Rate	9 Exhaust Gas Temp
3 Wet Bulb Temp.	7 Fuel Gas Temp.	10 Auxiliary Power
4 Jacket Water Temp.		

d. **Waste Heat Recovery Boiler (WHRB)**

1 Exhaust Gas Temp. inlet HP SH	8 HP FW-Flow, Pressure & Temp.	15 HP SH Exit Temp.
2 Exhaust Gas Temp. inlet HP EVAP	9 LP Drum Pressure	16 HP SH Exit Pressure
3 Exhaust Gas Temp. inlet HP ECON	10 HP Drum Pressure	17 COMB ECON HP FW Inlet Temp.
4 Exhaust Gas Temp. inlet COMB ECON	11 LP HRSG Steam Flow, Pressure & Temp.	18 COMB ECON HP FW Exit Temp.
5 Exhaust Gas Temp. exit WHRB flow	12 HP WHRB Steam Flow, Pressure & Temp.	19 LP WHRB Blowdown
6 Exhaust Gas Diff. Pressure WHRB	13 COMB ECON LP FW Inlet Temp.	20 HP WHRB Blowdown
7 LP FW Flow, Pressure & Temp. COMB ECON	14 COMB ECON LP FW Exit Temp.	21 Flue Gas Analysis at Inlet WHRB

4.2 Measurements

4.2.1 Measurement and estimation of the following listed parameters need to be done during the test run in accordance with the type of the cogeneration plant.

(a) *Generator power output, power factor, voltage, current, reactive load*
(b) *Feed water flow, temperature*
(c) *Condensate flow, temperature*
(d) *Steam flow, pressure, temperature*
(e) *Cooling water flow, temperature*
(f) *Fuel flow & total consumption*
(g) *Fuel pressure*
(h) *Fuel temperature*
(j) *Atmospheric (Ambient) conditions, pressure, temperature, humidity, flow*

(k) *Shaft speed*
(l) *Exhaust gas (flue gas flow)* – for gas turbines and reciprocating engines
(m) *Flue gas analysis*
(n) Fuel analysis

4.3 Test instrument accuracy

4.3.1 Instruments to be used during test is recommended to have following accuracy tolerances.

Instrument	Accuracy
Inlet air RTD, Thermocouples (chrome alumel)	0 – 1000C, ± 0.35%
Exhaust air/flue gas RTD	0 – 1000C, ± 0.35%
Speed indication	± 1 rev/min, digital counter
Fuel weighing measurement	± 1 %
Fuel flow meter measurement	± 1 % (gas and liquid fuels)
Water flow meter measurement	± 1 %
Pressure instruments	± 1 %
Temperature instruments	± 1 %
Power measurement	± 0.5 %
Current transformer accuracy class	0.5
Voltage transformer accuracy class	0.5

4.3.2 The calibration of the test instruments should be established prior to the test run. The valid calibration certificate, not more than six months old, conforming to ISO Quality Standards, for all the instruments installed in the field and used as portable along with the traceability should be available for verification prior to test.

4.4 Measurement of generator power output

4.4.1 Electrical measurements can be carried out by any one of the following methods.

(a) Calibrated portable power analyzer used with integrated clamp on current transformers and voltage input from system potential transformers (for HT voltage). This instrument is preferred for site testing. Power analyser need to be calibrated in the power factor ranging from 0.5 to 1.0.

(b) Calibrated three-element test watt-hour meter, used with separate potential and current transformers, transformers to be calibrated with equivalent meter burden with no additional burden in the metering circuit.

(c) Same as (b), but with two-element watt-hour meter instead of three element watt-hour meter.

4.4.2 Instruments can be located so that the total generator output is measured. In case of existence of any external tap between the generator and the point of measurement, supplementary metering of equivalent accuracy may be provided to determine the total generator output.

4.4.3 For measurement of auxiliary power supplied to drive support equipment within the battery limit of the cogeneration plant, the method of measurement of auxiliary power can be identical to the one of (a), (b) or (c).

4.5 Measurement of feed water, condensate, steam and cooling water flow

4.5.1 Feed water flow and Condensate flow – It is recommended to use measured feed water flow as the basis for the accurate determination of the primary flow to the turbine.

The primary element for water flow measurement can be an orifice/venture/ vortex flow meter designed meeting the specification of fluid and system and installed in a specially designed flow metering pipe section.

4.5.2 Steam flow – It is recommended to use orifice/vortex based flow measurement system similar to the one to be used for feed water flow measurement with some exceptions and additions considering the requirement of measuring the flow similar to gaseous flow. Because of the inherent difficulties in installation and calibration of flow measuring stations to be used for measuring primary steam flow at high pressure and temperature steam turbines, the use of a flow measuring device in the low temperature portion of the water cycle may also be considered to determine primary steam flow to the turbine. **For measuring flow of very high pressure steam, steam flow nozzles may be used.**

4.5.3 Cooling water flow –In the absense of in-line flow meters, use the portable ultrasonic flow measurement instrument can be considered. The V-notch or weir type of metering station can also be considered. Wherever, specific accuracy is required, the method mentioned in 4.5.1 may be used.

4.6 Measurement of fuel flow

It is essential that highly accurate, reliable and calibrated metering system is available to obtain the quantity of fuel supplied to the cogeneration plant during the the performance testing. Fuel being the primary source of energy, any minor deviation in accuracy of quantity of fuel greatly affects the performance of cogeneration plant.

4.6.1 **Measurement of fuel quantity**

4.6.1(a) Gaseous fuels

For measurement of flow and quantity of gaseous fuel during the performance test, one of the following methods depending on its availability can be considered.

At most of the site locations of cogeneration plants, a microprocessor based latest online gas fuel flow and quantity measurement system, installed by the fuel supplying agency, is generally be available. Such systems are generally calibrated every three months due to requirement of accurate billing for the gas supplied. The data available through such instrumentation system can be used for the performance derivation of the cogeneration plant. However, it should be ensured that the quantity of gas received is supplied in totality to cogeneration plant. If gas is supplied to other area, then the proposed arrangement to obtain data for gas flow and quantity can not work.

Besides the fuel supplying agency's metering system, normally, a microprocessor based online gas fuel flow and quantity measurement system is generally available, integrated with the control and instrumentation system of individual gas turbine unit or reciprocating engine unit, with continuous display of instantaneous gas flow and flow totalisers. It should be ensured that the instruments forming the part of the system are calibrated within the six month period prior to the date of performance test. In case there are multiple units with a common fuel metering system, another method have to be adopted for obtaining the data of fuel flow and quantity for individual unit.

Calculation of gas volume at standard conditions from measured gas volume using following relation.

$$\mathrm{Vs} = \mathrm{Vm} \text{ x } \frac{(P\mathrm{m} - P\mathrm{w}) \text{ x } 288}{101.325 \text{ x } (T\mathrm{m} + 273) \text{ x Z}}$$

Where,

Vs = total gaseous fuel volume in standard m^3
Vm = measured or calculated volume at test conditions, m^3
*P*m = measured gas pressure, mm Hg
*P*w = water vapour pressure mm Hg, (zero for dry gas)

Tm = measured gas temperature, ^0C
Z = compressibility factor for gas at following temperature/pressure

4.6.1(b). Liquid fuels

For liquid fuel flow and consumption, either of following suggested metering system can be used.

To measure liquid fuel flow in pipelines, it is recommended to use digital readout on a control panel of equipment being fired with liquid fuel. The method of measurement is similar to 4.6.1

If the system mentioned at 4.6.1 (a) is not installed, and if the liquid fuel is clear such as Kerosene, Light diesel oil or High speed diesel, the portable ultrasonic flow measurement unit may be used.

4.7 Measurement of pressure

4.7.1 Following instruments can be used for measuring pressure.

(a) For measuring the steam pressure at various points on the steam circuit, fuel gas pressure and other relevant pressures, the Bourdon gauges of required ranges can be used, which should be calibrated against standard dead weight gauge or a master gauge. The graduations should permit readings within ± 1% percent of the expected pressure measurement. In place of Bourdon gauges, digital pressure gauge with accuracy of 0.25% percent can also be used.

(b) The pressures can also be taken for certain parameters from the digital readout on the control panel, which will generally be getting signals from the online precision pressure instrumentation such as pressure transmitters.

(c) For measurement of low pressures of less than 0.2 MPa (absolute), manometers can be used.

4.8 Measurement of temperature

4.8.1 Following instruments can be used for measuring temperature.

(a) For measuring the temperature of steam at various points on the entire steam circuit, the calibrated thermocouples or resistance temperature detectors (RTDs) installed online or on equipment can be used. Wherever, the provision of thermo-well is made, calibrated mercury-in-glass thermometers can also be used.

(b) The temperatures can also be taken for certain parameters from the digital readout on the control panel, which will generally be getting signals from the online precision temperature instrumentation such as thermocouple or RTD based temperature transmitters.

(c) The instrument for temperature measurement can be so chosen that it can read with an accuracy of ± 1% percent of the absolute temperature. Absolute value of full-scale error can not exceed 1^0C.

Special attention need to be paid in location of points for pressure and temperature measurements, where these readings are used to determine steam enthalpy in the steam circuit. Pressure taps need to be located as close as possible to the point of corresponding temperature measurement.

4.9 Measurement of atmospheric conditions

4.10.1 Atmospheric pressure can be measured using either a barometer or can be obtained from standard meteorological data. The temperature can be measured using a calibrated mercury-in-glass thermometer installed at prominent location. Standard dry and wet bulb thermometers can also be used for measuring temperature and to determine humidity level for correcting the calculations.

4.10 Measurement of shaft speed

4.11.1 The shaft speed can be taken from the digital readout on the control panel visual display unit and data logger fed with signal from magnetic induction pick-up installed on the turbine or engine as the case may be.

4.11 Measurement of Air Flow and Exhaust Flue Gas Flow

4.12.1 For testing purposes, pitot tube/manometer can be used for measurement of air flow. Pitot tube is recommended to be suitable for velocities more than 3 m/s and for temperature up to 700^0C. For lower air velocities, anemometer can be used. Both instruments have limitations as follows.

(a) Pitot tube: This instrument can only be used in powder free clean air systems after the cyclone/bag filter. The point of measurement should ideally have six diameters of straight duct length before the measurement point. Also, the use of pitot tube should not be attempted at positions closer than one duct diameter to any upstream bend or damper. The static holes of the pitot must be free from burrs, clean and without having any dents. While, measuring, the angle of deviation of the pitot from the air stream must be zero, otherwise with 10^0 misalignment, the deviation from true reading can be up to 5%.

(b) Anemometer: The anemometer is not suitable for hot powder laden airflow or ducts handling corrosive/explosive air-gas mixtures. Anemometer can have ± 1% accuracy.

(c) The pitot tube/anemometer measurements can be carried out to determine velocity profile over the duct as discussed hereunder as per Log Tchebycheff method and average velocity can be determined from the readings. Volumetric flow is derived from cross sectional area and mass flow is calculated from the humid volume of the air-water mixture.

(d) Exhaust gas flow can also be estimated from measured CO_2 in flue gases and flue gas temperature, based on ultimate analysis of fuel. A sample calculation of exhaust flue gas flow rate for a gas turbine system is given in Annexure-1.

4.12.2 Log Tchebycheff method for rectangular ducts

Refer to Fig. 4.1. The intersection points of vertical and horizontal line are the points where the airflow measurement is required. For width H and height V, the location of points is indicated in the figure. Airflow is obtained by multiplying average velocity measured at all points with area.

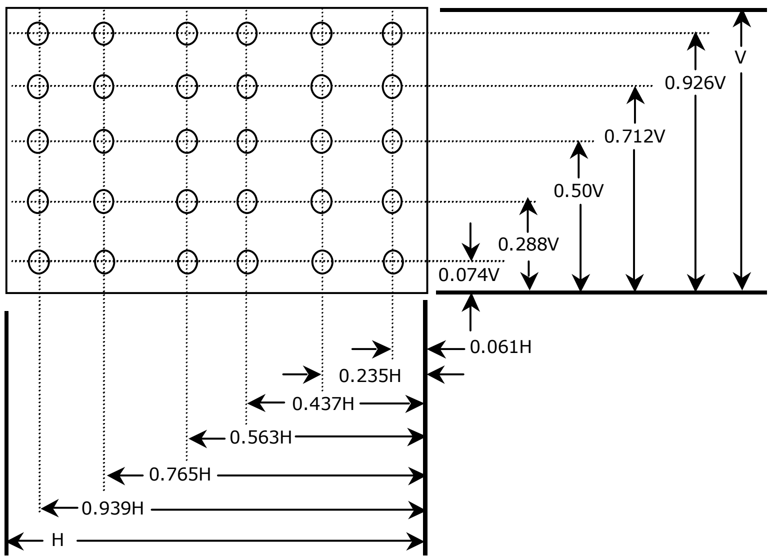

Figure 4-1: Log Tchebycheff method for rectangular ducts

Table is provided hereunder, which indicates location of measurement for rectangular ducts.

Table 4-1: Measurement point location

Nos. of transverse lines		
5 (for H<39")	**6 (for 36">H>30")**	**7 (for H>36")**
0.074	0.061	0.053
0.288	0.235	0.203
0.500	0.437	0.366
0.712	0.563	0.500
0.926	0.765	0.634
	0.939	0.797
		0.947

4.12.2 Log Tchebycheff method for circular ducts

Refer to Fig. 4.2. The duct is divided into concentric circles, applying multiplication factors to the diameter. An equal number of readings are taken from each circular area, thus obtaining the best average. Airflow is obtained by multiplying average velocities measured at all points within the area.

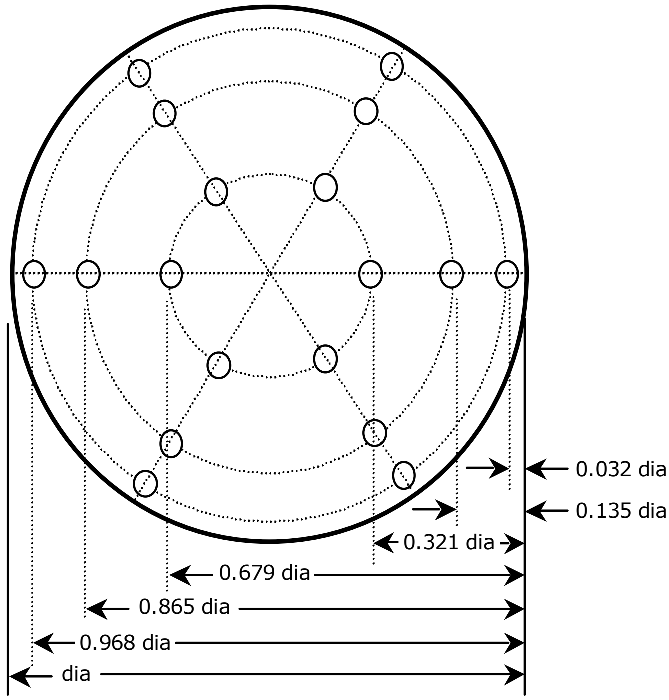

Figure 4-2: Log Tchebycheff method for circular ducts

4.12 Measurement of flue gas composition

4.13.1 The flue gas analyzer having facility for Oxygen analysis using Zirconium probe is recommended to be used online to measure flue gas components at sampling provided.

4.13 Fuel heating value calculations

The heating value gaseous fuels and liquid fuels can be obtained either from the fuel supplying agency or sample can be collected during the test run and given for testing to recognized laboratory / institution and the results so provided for higher and lower heating values are to be used in the calculations. For testing of fuel, the laboratory should carry out the testing in accordance with the test methods for such property prescribed under the relevant Indian or International Standards.

4.14 Measurement of Time

4.14.1 The measurement of time of test durations and other observations can be determined by observations of synchronized stop watches by the individual observers. Watches and clocks can be synchronized at the start of the test.

4.15 Maximum permissible variations in test conditions

	Variable parameter	Variation of observed reading from reported average test condition
i.	Power output (for rated output or part loads)	± 2 %
ii.	Power factor	± 2 %
iii.	Rotating speed	± 1 % in gas turbine ± 5 % in steam turbine
iv.	Pressure, gas fuel supplied to gas turbine/engine	± 2 % of absolute equivalent of average pressure
v.	Cooling water temperature, outlet	± 5°C
vi.	Turbine exhaust temperature, in gas turbine	± 5°C
vii.	Fuel consumption	± 2 %
viii.	Steam pressure at steam turbine inlet	± 3 % of absolute pressure
xiv.	Steam pressure at extraction	± 5 %
x.	Steam flow at extraction	± 5 %
xi.	Feed water temperature, final	± 5°C
xii.	Aggregate isentropic enthalpy drop of any one of the sections of steam turbine	± 10 %
xiii.	Exhaust back-pressure at gas turbine/engine	± 1% of absolute equivalent of average pressure

5. PERFORMANCE CALCULATION PROCEDURE

5.1 Calculation procedures

5.1.1 In view of feasibility of number of combinations of power and steam generation equipment in cogeneration system, the calculation procedure for each cogeneration plant can be developed individually based on the plant configuration, instrumentation and plant operating conditions. Few methods are outlined in this section for the determination of performance parameters based on test.

5.2 Extraction-cum-condensing steam turbine based cogeneration plant

5.2.1 Basic formulae used in procedure

(a) Steam turbine cycle heat rate is defined as ratio of the heat supplied to the steam and water in the boiler to output from the turbine. The quantity of heat is calculated from the measurement of the total heat supplied to the boiler and of boiler efficiency by the loss method.

$$\text{Turbine cycle heat rate} = \frac{\text{Heat input to steam and water}}{\text{power output}}$$

$$= \frac{\text{Total heat input to boiler} - \text{boiler losses}}{\text{power output}}$$

$$\text{Boiler Efficiency} = \frac{\text{Total heat input to boiler} - \text{boiler losses}}{\text{Total heat input to boiler}} \text{ x } 100\ \%$$

$$\text{Turbine cycle heat rate} = \frac{\text{Total heat input to boiler x boiler efficiency}}{\text{power output}}$$

(b) The definition does not consider heat additions and removals in boiler feed pumps, jet air ejectors, etc.

(c) The waste heat recovery boiler losses and credits considered under this procedure are as follows.

Losses

(1) Dry flue gas
(2) Moisture from burning of hydrogen
(3) Moisture in air
(4) Surface radiation and convection losses

Credits

(1) Heat supplied through fuel, if fired in WHRB

5.2.2 Instrumentation requirements

(a) Typical diagram showing location of instruments for measuring various variables is given in Fig. 5.1. Some of the variables can be estimated from the manufacturer's data as indicated on the figure.

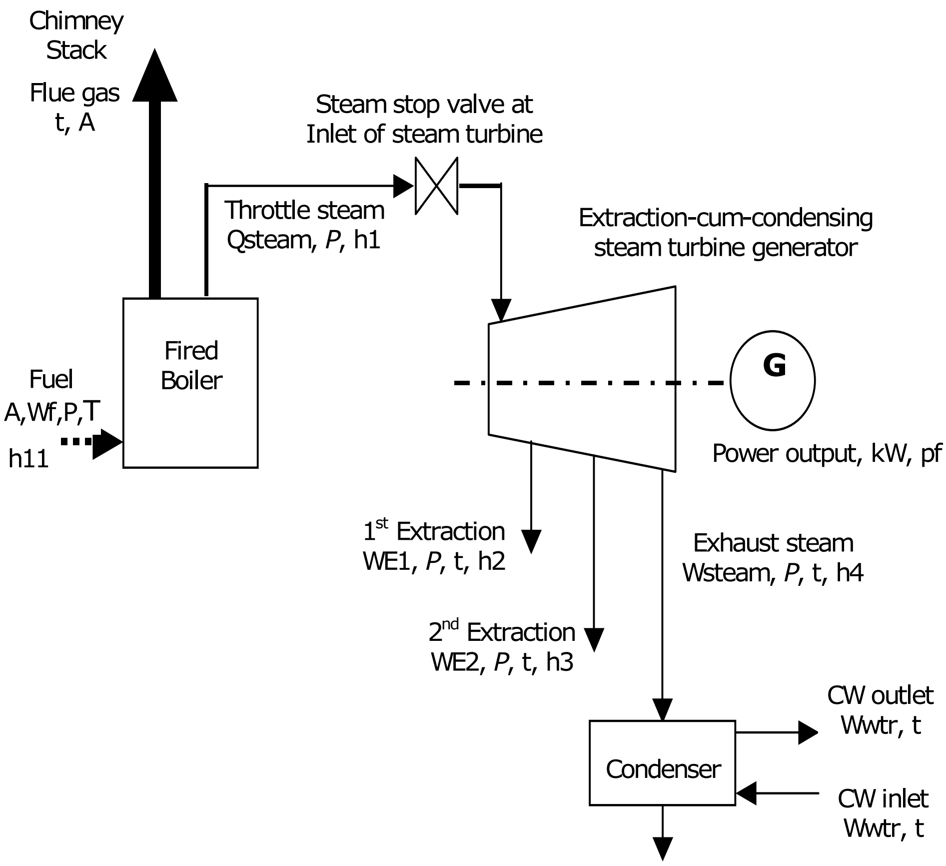

Figure 5-1: Steam turbine process flow with instrument locations

W*f*:	Fuel flow
P :	Pressure
t :	Temperature
Qsteam:	Estimated flow
WE1 :	1st extraction
Wsteam:	Exhaust steam flow of throttle steam
WE2 :	2nd extraction
Wwtr :	Cooling water flow
A :	Analysis required
kW :	Kilowatts
pf :	Power factor

(b) Requirement of instrumentation to be deployed can vary marginally with the type of cycle being tested. The scheme shown above represents a double extraction-cum-condensing cycle with required measurements as follows.

Throttle steam flow, temperature, pressure
Exhaust flue gas temperature, analysis
Fuel flow, analysis
1st extraction flow, temperature, pressure
2nd extraction flow, temperature, pressure
Turbine exhaust steam flow, temperature, pressure
Generator power output, power factor

Ambient wet and dry bulb temperature

(c) The recommendations given for each category of boiler, steam turbine and generator instrumentation need to be followed and precision instrumentation shall be used for all measurements to minimize impact on the result of turbine cycle heat rate.

5.2.3 Conduct of the test

(a) Necessary arrangements are to be made to ensure consistent supply of fuel to the extent feasible.

(b) Elimination of losses associated with incomplete combustion need to be ensured from the steam generator during the test duration. Cleaning of burners shall be carried out for proper atomization. Flue gas analysis shall be resorted to verify the presence of excess O_2 and the absence of CO.

(c) The load for the test need to be established so that the turbine operates at a known governor valve point with operating conditions as close to specified operating conditions as possible and on load limit control. The unit needs to be removed from automatic load control mode, if it is in the system.

(d) A minimum of 30 min. of unit stabilization period can be permitted.

(e) Duration of such test is recommeded to be at least 8 hours to the extent possible.

(f) Specifically for fuel flow and boiler loss measurements, the following time duration for readings is recommended.

Reading	Frequency
Fuel differential pressure (Gas fuel)	30 min
Totalizer meter (Liquid fuel)	30 min
Conveyor belt weighing (For solid fuel)	30 min
Fuel temperature, pressure	30 min
Flue gas analysis	30 min
Flue gas temperature	30 min
Ambient temperature	30 min

5.2.4 Steam Turbine Calculation Procedure

Step 1: Calculate the actual heat extraction at each stage in turbine.

Steam enthalpy at steam turbine inlet	: h_1, kJ/kg
Steam enthalpy at 1st extraction	: h_2, kJ/kg
Steam enthalpy at 2nd extraction	: h_3, kJ/kg
Steam enthalpy at condenser (turbine exhaust)	: h_4, kJ/kg

Heat extraction from inlet to 1st extraction, h_5	: $h_1 – h_2$
Heat extraction from 1st – 2nd extraction, h_6	: $h_2 – h_3$
Heat extraction from 2nd extraction – exhaust, h_7	: $h_3 – h_4$

Step 2: From Mollier, H - Φ diagram, the theoretical heat extraction for the conditions mentioned in Step 1 is to be derived.

Isentropic enthalpy after 1st extraction	: H_1, kJ/kg
Isentropic enthalpy after 2nd extraction	: H_2, kJ/kg
Isentropic enthalpy at condenser conditions	: H_3, kJ/kg

Theoretical heat extraction from turbine inlet to 1st extraction, h_8	: h_1 - H_1
Theoretical heat extraction from 1st – 2nd stage extraction, h_9	: $H_1 – H_2$
Theoretical heat extraction from 2nd extraction	: $H_2 – H_3$

- condensation, h_{10}

Step 3: Determine the steam turbine efficiency.

$$\text{Efficiency of 1st stage} = h_5 / h_8$$

$$\text{Efficiency of 2nd stage} = h_6 / h_9$$

$$\text{Efficiency of conden. stage} = h_7 / h_{10}$$

Step 4: Determine the station heat rate.

$$\text{Heat rate} = \frac{m\,(h_1 - h_{11})}{P}\ \text{kJ/kWh}$$

Where, *m* : Mass flow rate of steam in kg/h
h1 : Enthalpy of inlet steam in kJ/kg
h11: Enthalpy of feed water in kJ/kg
P : Average power generated kW

The above calculations are summarised below in MS Excel format in table 5.1. Use of reliable software is recommended for enthalpy and entropy determination compared to the use of steam tables/charts. This is to improve accuracy.

Table 5-1: Format of calculations-Steam turbine

	Description	Equation to be used in column C	Value
	A	B	C
1	Mass flow rate of steam : *m* ,kg/h	Measured value	
2	Enthalpy of feed water : h_{11} kJ/kg	From steam tables	
3	Steam enthalpy at steam turbine inlet: h_1, kJ/kg	From steam tables	
4	Steam enthalpy at 1st extraction: h_2, kJ/kg	From steam tables	
5	Steam enthalpy at 2nd extraction.: h_3, kJ/kg	From steam tables	
6	Steam enthalpy at condenser (turbine exhaust): h_4, kJ/kg	From steam tables	
7	Heat extraction from inlet to 1st extraction, $h_5 : h_1 – h_2$	C3-C4	
8	Heat extraction from 1st – 2nd extraction, h_6: $h_2 – h_3$	C4-C5	
9	Heat extraction from 2nd extraction – exhaust, $h_7 : h_3 – h_4$	C5-C6	
10	Isentropic enthalpy after 1st extraction: H_1, kJ/kg	From Mollier chart	
11	Isentropic enthalpy after 2nd extraction: H_2, kJ/kg	From Mollier chart	
12	Isentropic enthalpy at condenser conditions: H_3, kJ/kg	From Mollier chart	
13	Theoretical heat extraction from turbine inlet to 1st extraction, $h_8 : h_1 - H_1$	C3-C10	
14	Theoretical heat extraction from 1st – 2nd stage extraction, h_9: $H_1 – H_2$	C10-C11	
15	Theoretical heat extraction from 2nd extraction - condensation, h_{10}: $H_2 – H_3$	C11-C12	
16	$\text{Efficiency of 1st stage} = h_5 / h_8$	C7/C13	
17	$\text{Efficiency of 2nd stage} = h_6 / h_9$	C8/C14	
18	$\text{Efficiency of conden. stage} = h_7 / h_{10}$	C9/C15	
19	Average power generated: P, kW	Measured value	
20	$\text{Heat rate} = \frac{m\,(h_1 - h_{11})}{P}\ \text{kJ/kWh}$	C1*(C3-C2)/C19	

5.3 Gas turbine based cogeneration plant

5.3.1 Basic formulae used in procedure

(a) Heat supplied to the gas turbine cycle is defined as ratio of the heat supplied to the gas turbine through fuel input to kW output from the generator driven by the turbine. The quantity of heat is arrived at from the measurement of the total heat supplied to the gas turbine and of waste heat recovery boiler (WHRB) efficiency by the input - output method.

$$\text{Gas turbine heat rate} = \frac{\text{Heat input to gas turbine, kJ [fuel input]}}{\text{power output}}$$

$$\text{WHRB Efficiency} = \frac{\text{Total output of WHRB, kJ [steam]}}{\text{Total heat input to WHRB}}$$

$$\text{Overall gas turbine cycle heat rate} = \frac{860 \text{ x } 4.19 \text{ x } 100}{\text{Overall plant efficiency}} \; kJ \,/\, kWh$$

$$\text{Thermal efficiency} = \frac{(\text{Power output x } 860 \text{ x } 4.19) + (\text{Steam generated x enthalpy})}{\text{Heat input (fuel) x LHV of fuel}} \text{ x } 100 \; \%$$

(c) The definition does not consider heat additions and removals in the boiler feed pumps, etc.

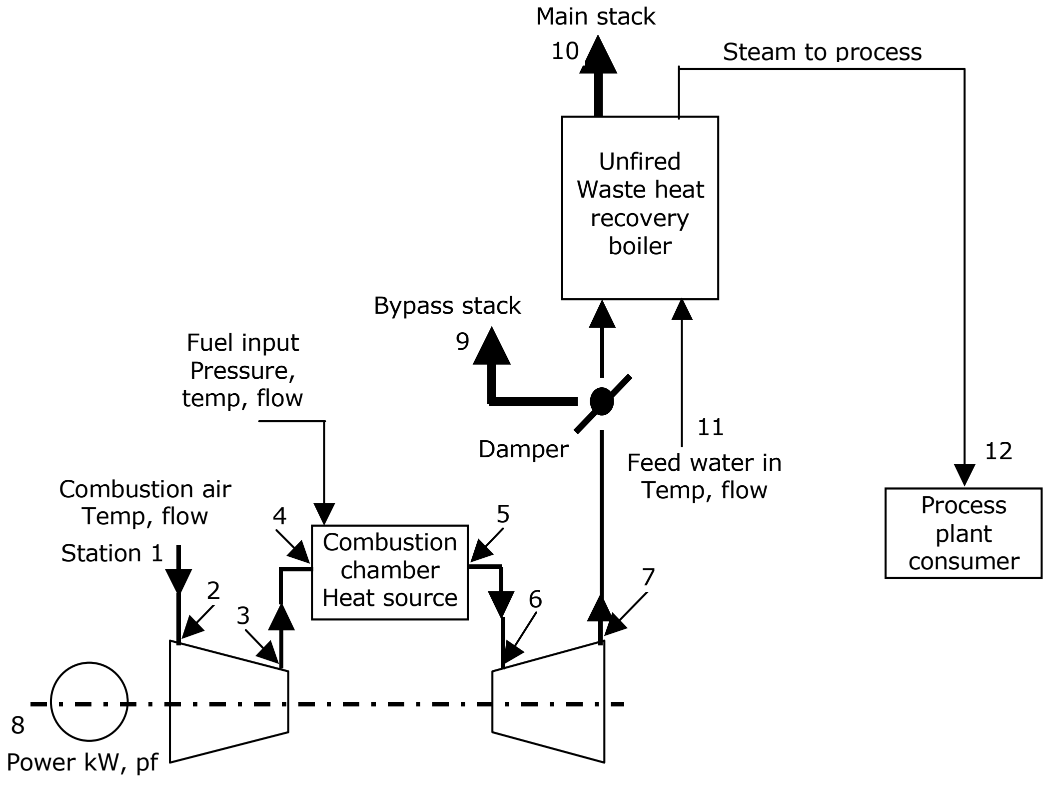

Figure 5-2: Gas turbine process flow with instrument locations

5.3.2 Instrumentation requirements

(a) Typical diagram showing the basic nomenclature used hereunder and location of instruments for measuring various variables is given in Fig. 5.2. Some of the variables need to be estimated from the manufacturer's data as indicated on the figure.

Station 1: Ambient air conditions, pressure, temperature, humidity, flow, pressure drop across the air filter bank
Station 2: Conditions of air at inlet of compressor, temperature
Station 3: Conditions of air leaving the compressor (manufacturer's data, if required)
Station 4: Fuel input to combustion chamber, flow, temperature, pressure, analysis (fuel supplier's data or analysis through third party)
Station 5: Flue gas conditions at exit of combustion chamber, temperature (manufacturer's data, if required)
Station 6: Flue gas conditions at inlet of turbine, temperature (manufacturer's data, if required)
Station 7: Exhaust flue gas conditions leaving turbine, entering WHRB, temperature, flow
Station 8: Power output, kW: Kilowatts, pf: Power factor
Station 9: Exhaust flue gas conditions leaving the bypass stack, temperature
Station 10: Exhaust flue gas conditions leaving the main stack, temperature
Station 11: Feed water input to WHRB, flow, temperature
Station 12: Steam output from WHRB, pressure, temperature, flow

Additional nomenclature used with letter designate the type of fluid in various parts of cycle:

f : Fuel	a : Air (or other working fluid)
wtr : Water	g : Gas after the combustion chamber
s : Steam	b : Bearing fluid

5.3.3 Operating conditions

(a) The test fuel for gas turbine based cogeneration and test conditions can be decided prior to the test.

(b) The test data for the system can be collected only after the steady state plant operating conditions have been established. Steady state is to be considered achieved when continuous monitoring indicates the readings have been within the maximum permissible variations.

(c) The time duration of test is to be minimum eight hours after attaining of steady state conditions.

(d) In the event of observance of inconsistency during conduct of a test, or during subsequent interpretation and analysis of the recorded data affecting the validity of results, an effort should be made to adjust or eliminate the inconsistency. In case of abnormal inconsistency, the entire test can be conducted again.

(e) Specific conditions for the testing of a waste heat recovery boiler (WHRB) can be as follows.

i. Heat input is total of the sensible heat and latent heat contents of hot flue gas entering WHRB and chemical heat combustion resulting from burning of supplementary fuel, if any.

ii. WHRB output can be determined following the procedure adopted for conventional fired boilers, i.e. heat absorbed by the working fluid. Another method can be to derive the steam flow as output from WHRB.

iii. Determination of heat content of hot flue gas entering WHRB will require measurement of temperature, weight flow of gas and analysis of gas for better accuracy of the result.

iv. Gas quantity entering the WHRB may be determined by the following methods.

   (1) calculation of amount of fuel burnt in gas turbine, analysis of fuel and composition of waste gas.

   (2) actual measurement of gas quantity.

   (3) measurement of gas quantity leaving WHRB, analysis gases entering and leaving WHRB including calculating supplementary combustion products, if supplementary fuel is fired.

v. Losses in WHRB can vary with type of input to the prime mover.

vi. For WHRB without supplementary firing, the heat losses can be as follows.

   (1) the difference between sensible heat content of exhaust flue gas at exit gas temperature and reference air temperature, usually ambient.

   (2) the difference between latent heat content of exhaust flue gas at exit gas temperature and reference air temperature.

vii. Minimum test duration can be four hours from the achieving of the steady state condition.

5.3.4 Calculation procedure

(a) **Fuel flow calculations**

Fuel flow can be measured using methods given in section 4.6.

(b) **Specific fuel consumption calculations**

Calculate the fuel consumption of the plant per unit time using following formulae.

$$V_{ng} = Vs / Tt \text{ for gaseous fuels} \qquad W_l = Ww / Tt \text{ for liquid fuels}$$

Where,

V_{ng} = fuel consumption per hour, for gaseous fuels, Nm^3 /hr
W_l = fuel consumption per hour, for liquid fuels, kg/hr,
Tt = time duration of test, hours
Vs = total gaseous fuel volume in Nm^3
Ww = total liquid fuel consumption, kg

Calculate the specific fuel consumption of the plant using following equation.

$$W_s = \frac{V_{ng}}{P} \text{ for gaseous fuels} \qquad W_s = \frac{W_l}{P} \text{ for liquid fuels}$$

Where,

W_S = specific fuel consumption, for gaseous fuels Nm^3
for liquid fuels kg/kWh
P = net electrical power output, kW

(c) **Heat consumption rate calculations**

Calculate the heat consumption rate of the plant using following equation.

$$q_r = V_{ng} \text{ x } Q_{lo} \text{ for gaseous fuels} \qquad q_r = W_l \text{ x } Q_{lo} \text{ for liquid fuels}$$

Where,

q_r = rate of heat consumption, kJ/hr
Q_{lo} = lower heating value of fuel, for gaseous fuels kJ/Nm^3
for liquid fuels, kJ/kg,

(d) **Heat rate calculations**

Calculate the heat rate of the plant using following equation.

$$q_s = \frac{q_r}{P}$$

Where,
q_s = heat rate, kJ/kWh
q_r = rate of heat consumption, kJ/hr
P = net electrical power output, kW

OR heat rate of the plant may also be calculated using following equation.

$$q_s = \frac{3600}{\eta_{gt}} \text{ for net electrical power, kW}$$

Where,
q_s = heat rate, kJ/kWh
η_{gt} = thermal efficiency based on net electrical power output

OR the heat rate of the plant using following equation.

$$q_s = \frac{V_{ng}\ x\ Q_{lo}}{P} \text{ for gaseous fuels} \qquad q_s = \frac{W_l\ x\ Q_{lo}}{P} \text{ for liquid fuels}$$

Where,
q_s = heat rate, kJ/kWh
Q_{lo} = lower heating value of fuel, for gaseous fuels kJ/Sm^3 or Nm^3
for liquid fuels kJ/kg,
V_{ng} = fuel consumption per hour, for gaseous fuels, Sm^3 or Nm^3/hr
W_l = fuel consumption per hour, for liquid fuels, kg/hr,
P = net electrical power output kW

(e) **Thermal efficiency calculations for gas turbine**

$$\eta_{gt} = \frac{3600 \text{ x } P \text{ x } 100}{q_r}$$

Where,
η_{gt} = thermal efficiency based on net electrical power output, percent
P = net electrical power output kW
q_r = rate of heat consumption, kJ/hr

(f) **Thermal efficiency calculations for WHRB**

$$\eta_{whrb} = \frac{W_s \text{ x } (h_{12} - h_{11}) \text{ x } 100}{W_{eg} \text{ x } C_p \text{ x } (t_e - t_{exhaust})}$$

Where,
η_{whrb} = thermal efficiency based on net steam output, percent
W_s = steam rate, kg/sec
h_{12} = steam enthalpy at boiler outlet, kJ/kg
W_{eg} = exhaust gas flow rate, kg/sec
C_p = average value of specific heat of exhaust gas, kJ/kg^{0}C
t_e = exhaust gas temperature at WHRB inlet, ^{0}C
$t_{exhaust}$ = Exhaust temperature at WHRB outlet, ^{0}C

(g) **Overall plant efficiency calculations**

$$\eta_{plant} = \frac{[(P \text{ x } 860 \text{ x } 4.19) + (W_s \text{ x } (h_{12} - h_{11}) \text{x } 3600)]}{V_{ng} \text{ or } W_l \text{ x } Q_{lo}} \text{ x } 100$$

Where,

η_{plant} = overall plant efficiency based on net power & steam output, percent
P = net electrical power output from gas turbine, kW
W_s = steam rate from WHRB, kg/sec
h_{12} = steam enthalpy at boiler outlet, kJ/kg
Q_{lo} = lower heating value of fuel, for gaseous fuels kJ/Sm^3 or Nm^3
for liquid fuels , kJ/kg,
V_{ng} = fuel consumption per hour, for gaseous fuels, Sm^3 or Nm^3/hr
W_l = fuel consumption per hour, for liquid fuels, kg/hr

(h) **Overall plant heat rate calculations**

$$q_{scogen} = \frac{860 \text{ x } 4.19 \text{ x } 100}{\eta_{plant}}$$

Where,

q_{scogen}= overall plant heat rate based on net power & steam output, kJ/kWh
η_{plant}= overall plant efficiency based on net power & steam output, percent

Calculations in the MS excel format is given in table 5.1. This table is common for gas turbine based plants and reciprocating engine based plants

5.4 Reciprocating engine based cogeneration plant

5.4.1 Basic formulae used in procedure

(a) Heat supplied to the reciprocating engine cycle is defined as ratio of the heat supplied to the engine through fuel input to power output from the generator driven by the engine. The quantity of heat is arrived at from the measurement of the total heat supplied to the engine and of waste heat recovery boiler (WHRB) efficiency by the input - output method.

(b) Heat supplied to the gas turbine cycle is defined as ratio of the heat supplied to the gas turbine through fuel input to kW output from the generator driven by the turbine. The quantity of heat is arrived at from the measurement of the total heat supplied to the gas turbine and of waste heat recovery boiler (WHRB) efficiency by the input - output method.

$$\frac{\text{Reciprocating engine cycle heat rate}}{} = \frac{\text{Heat input to reciprocating engine}}{\text{power output}}$$

$$\text{WHRB efficiency} = \frac{\text{Total output of WHRB, [Steam]}}{\text{Total heat input to WHRB}}$$

$$\text{Overall reciprocating engine cycle heat rate} = \frac{860 \times 4.19 \text{ x } 100}{\text{Overall plant efficiency}}$$

$$\text{Thermal efficiency} = \frac{(\text{Power output x } 860 \times 4.19) + (\text{Steam generated x enthalpy})}{\text{Heat input (fuel) x LHV of fuel}} \text{ x } 100\%$$

(b) The definition does not consider heat additions and removals in boiler feed pumps, or hot water pumps, etc. as the case may be.

5.4.2 Instrumentation requirements

(a) Typical diagram showing the basic nomenclature used hereunder and location of instruments for measuring various variables is given in Fig. 5.3. Some of the variables can be estimated from the manufacturer's data as indicated on the figure.

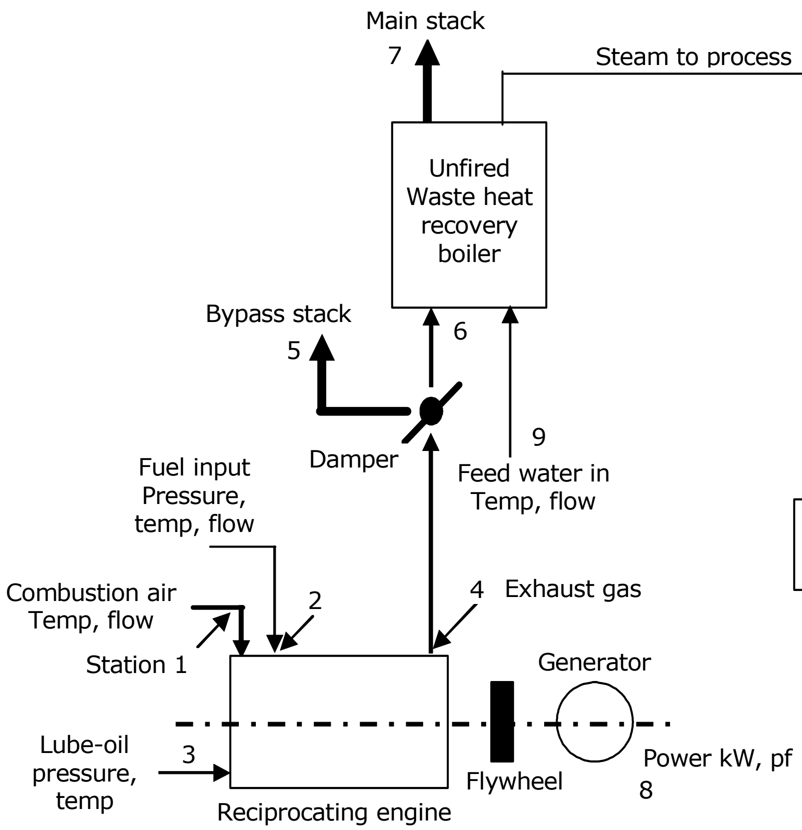

Figure 5-3: Reciprocating Engine process flow with instrument locations

Station 1 : Ambient air conditions, pressure, temperature, humidity
Station 2 : Fuel input to engine, flow, temperature, pressure, analysis
Station 3 : Conditions for lube-oil sent to engine, analysis, flow, temperature, pressure
Station 4 : Flue gas conditions at exit of engine, temperature
Station 5 : Exhaust flue gas conditions leaving the bypass stack, temperature
Station 6 : Exhaust flue gas conditions entering WHRB, temperature
Station 7 : Exhaust flue gas conditions leaving the main stack, temperature
Station 8 : Power output, kW: Kilowatts, pf: Power factor
Station 9 : Feed water input to WHRB, flow, temperature
Station 10: Steam output from WHRB, pressure, temperature, flow

Additional nomenclature used with letter designate the type of fluid in various parts of cycle:

f : Fuel	a : Air (or other working fluid)
w : Water	g : Gas after the combustion chamber
s : Steam	b : Bearing fluid

5.4.3 Operating conditions

(a) The test data for the system are to be collected only after the steady state plant operating conditions have been established. Steady state can be considered achieved when continuous monitoring indicates that the readings have been within the maximum permissible variations.

(b) The time duration of test can be minimum eight hours after attaining steady state conditions.

(c) In the event of observance of inconsistency during conduct of a test, or during subsequent interpretation and analysis of the recorded data affecting the validity of results, an effort can be made to adjust or eliminate the inconsistency. In case of abnormal inconsistency, the entire test can be conducted again.

(d) Specific conditions for the testing of a waste heat recovery boiler (WHRB) can be as provided in Para 5.3.3(g).

5.4.4 Calculation procedure

(a) **Fuel flow calculations**

i. Gaseous fuels – Method as provided in section 4.6 can be followed for determining the flow of gaseous fuel.
ii. Liquid fuels – For measurement of liquid fuel flow and quantity, the procedure at section 4.6 can be employed.

(b) **Fuel heating value calculations**

As explained in section 4.13.

(c) **Specific fuel consumption calculations**

Calculate the fuel consumption of the plant per unit time using following formulae.

W_{ng} = Vs/ Tt, for gaseous fuels W_l = Ww/ Tt, for liquid fuels,
Where,
V_{ng} = fuel consumption per hour, for gaseous fuels, Nm^3, Sm^3/hr
W_l = fuel consumption per hour, for liquid fuels, kg/hr,
Tt = time duration of test, hours
Vs = total gaseous fuel volume in standard m^3
Ww = total liquid fuel consumption, kg

Calculate the specific fuel consumption of the plant using following equation.

$$W_s = \frac{V_{ng}}{P} \text{ for gaseous fuels} \qquad W_s = \frac{W_l}{P} \text{ for liquid fuels}$$

Where,
W_S = specific fuel consumption, for gaseous fuels Nm^3 or Sm^3/kWh
for liquid fuels kg/kWh
P = net electrical power output, kW

(d) **Heat consumption rate calculations**

Calculate the heat consumption rate of the plant using following equation.

$$q_r = V_{ng} \text{ x } Q_{lo} \text{ for gaseous fuels}$$

$$q_r = W_l \text{ x } Q_{lo} \text{ for liquid fuels}$$

Where,

q_r = rate of heat consumption, kJ/hr
Q_{lo} = lower heating value of fuel, for gaseous fuels kJ/Nm^3 or Sm^3
for liquid fuels ,kJ/kg,

(e) **Heat rate calculations**

Calculate the heat rate of the plant using following equation.

$$q_s = \frac{q_r}{P}$$

Where,
q_s = heat rate, kJ/kWh
q_r = rate of heat consumption, kJ/hr
P = net electrical power output kW

OR heat rate of the plant may also be calculated using following equation.

$$q_s = \frac{3600}{\eta_{re}} \text{ for net electrical power in kW}$$

Where,
q_s = heat rate, kJ/kWh
□re = thermal efficiency based on net electrical power output

OR the heat rate of the plant using following equation.

$$q_s = \frac{V_{ng} \text{ x } Q_{l_0}}{P} \text{ for gaseous fuel} \qquad q_s = \frac{W_l \text{ x } Q_{l_0}}{P} \text{ for liquid fuel}$$

Where,
q_s = heat rate, kJ/kWh
Q_{l0} = lower heating value of fuel, for gaseous fuels kJ/Sm^3 or Nm^3
for liquid fuels kJ/kg,
V_{ng} = fuel consumption per hour, for gaseous fuels, Sm^3 or Nm^3/hr
W_l = fuel consumption per hour, for liquid fuels, kg/hr,
P = net electrical power output kW

(f) **Thermal efficiency calculations for reciprocating engine**

$$\eta_{re} = \frac{3600 \text{ x P x } 100}{q_r}$$

Where,
η_{re} = thermal efficiency based on net electrical power output, percent
P = net electrical power output kW
q_r = rate of heat consumption, kJ/hr

(g) **Thermal efficiency calculations for WHRB**

$$\eta_{whrb} = \frac{W_s \text{ x } (h_{11} - h_{10}) \text{ x } 100}{W_{eg} \text{ x } C_p \text{ x } (t_e \text{ - } t_{exhaust})}$$

Where,
η_{whrb} = thermal efficiency based on net steam output, %
W_s = steam rate, kg/sec
h_{11} = steam enthalpy at boiler outlet, kJ/kg
W_{eg} = exhaust gas flow rate, kg/sec
C_p = average value of specific heat of exhaust gas, kJ/kg^{0}C
t_e = exhaust gas temperature at WHRB inlet, ^{0}C

$t_{exhaust}$ = Exhaust temperature at WHRB outlet, ^0C

(h) **Overall plant efficiency calculations**

$$\eta_{plant} = \frac{[(P \text{ x } 860 \text{ x } 4.19) + (W_s \text{ x } (h_{11} - h_{10}) \text{ x } 3600)] \text{ x } 100}{W_{ng} \text{ or } W_l \text{ x } Q_{lo}}$$

Where,

η_{plant} = overall plant efficiency based on net power & steam output, %
P = net electrical power output from gas turbine, kW
W_s = steam rate from WHRB, kg/sec
h_{11} = steam enthalpy at boiler outlet, kJ/kg
Q_{lo} = lower heating value of fuel, for gaseous fuels – kJ/Sm^3 or Nm^3
for liquid fuels - kJ/kg,
W_{ng} = fuel consumption per hour, for gaseous fuels, Sm^3 or Nm^3/hr
W_l = fuel consumption per hour, for liquid fuels, kg/hr,

(j) **Overall plant heat rate calculations**

$$q_{scogen} = \frac{860 \text{ x } 4.19 \text{ x} 100}{\eta_{plant}}$$

Where,

q_{scogen} = overall plant heat rate based on net power & steam output, kJ/kWh
η_{plant} = overall plant efficiency based on net power & steam output, %

The following table summarises calculations for estimating overall efficiency of reciprocating engine based cogeneration plants and gas turbine based plants.

Table 5-2: Calculations for estimating overall efficiency and heat rate

Sl No.	Parameter	Equation to be used in column C & Comments	Quantity
	A	B	C
1	V_g, fuel consumption rate, Sm^3/h	Measured value	
2	P, electrical power output, kW	Measured value	
3	Q_{lo}, lower heating value of fuel, kJ/ m^3	From standard data	
4	q_r, rate of heat consumption, kJ/h	C1*C3	
5	q_s , heat rate, kJ/kWh	C4/C2	
6	η_g, thermal efficiency based on net electrical power output, %	3600 X *C2* X 100 / *C5*	
7	W_{eg}, exhaust gas flow rate, kg/s	Estimated value	
8	C_p, average value of specific heat of exhaust gas, kJ/kg-^0C	From standard data	
9	t_e, exhaust gas temperature at WHRB inlet, ^0C	Measured value	
10	t_{pp}, pinch point temperature, ^0C	specified value	
11	h_{10}, feed water enthalpy at drum inlet, kJ/kg	From measured temperature & standard data	
12	h_{11}, steam enthalpy at boiler outlet, kJ/kg	From measured temperature & standard data	
13	W_s, steam rate from WHRB, kg/sec	Measured value	
14	$t_{exhaust}$, temperature at WHRB exit (chimney), ^0C	Measured value	
15	η_{whrb} thermal efficiency of WHRB based on net steam output	C13*(C12-C11)*100/(C7*C8* (C9-C14))	
16	η_{plant}overall plant efficiency based on net power & steam output, %	((C2*860*4.19)+(C13*(C12-C11)*1000)) /C4	
17	q_{scogen}overall plant heat rate based on net power & steam output, kJ/kWh	860*4.19*100/C16	

6. REPORT OF TEST RESULTS AND SAMPLE CALCULATION

6.1 Calculation procedure for gas turbine based cogeneration plant

6.1.1 The method of reporting the performance determined through the test can generally be on following lines. The proposed method is provided for gas turbine based cogeneration plant with configuration of one set of gas turbine power generator and unfired waste heat recovery boiler and other auxiliaries.

6.1.2 The formats for collecting the field test measurements, calculation procedure with sample calculation and information to be provided in the report can generally follow the specimen provided. As mentioned in foregoing discussion, the cogeneration plants are available in numerous different combinations, as such the practical formats will have to be decided at site considering the plant configuration, fuel, etc. through mutual discussion and agreement prior to the test.

6.2 Format of equipment data and field test data collection

The format for basic equipment data can be as follows.

Table 6-1: Cogeneration Power Plant Data Sheet

Parameter	Unit	Quantity	Tolerances
Gas turbine data			
Manufacturer			
Model			
Serial No.			
Fuel suitability	Natural gas, High speed diesel		
Rating at ISO conditions @ 15^{0}C, 1.033 Kg/cm^2	kW	4899 on Natural gas 4637 on HSD	
Rating at site designed conditions @ 35^{0}C, 1.033 Kg/cm^2	kW	4127 on Natural gas 3921 on HSD	
Gas turbine heat rate			
Heat rate at ISO conditions @ 15^{0}C, 1.033 Kg/cm^2	kJ/kWh	12200.3 on NG 12464.1 on HSD	± 0 % ± 0 %
Heat rate at designed site conditions @ 35^{0}C, 1.033 Kg/cm^2	kJ/kWh	12945.6 on NG 13230.3 on HSD	± 0 % ± 0 %
Gas turbine shaft speed	RPM	17745	
Exhaust flue gas conditions			
At ISO conditions, Natural gas fuel			
exhaust flue gas flow	kg/sec	19.2	
temperature	^{0}C	539	
At ISO conditions, High speed diesel fuel			
exhaust flue gas flow	kg/sec	19.25	
temperature	^{0}C	532	
At site design conditions, Natural gas fuel			
exhaust flue gas flow	kg/sec	17.5	± 3 %
temperature	^{0}C	556	± 15 ^{0}C
At site design conditions, High speed diesel fuel			
exhaust flue gas flow	kg/sec	17.6	± 3 %
temperature	^{0}C	549	± 15 ^{0}C

Cogeneration Power Plant Data Sheet			
Parameter	Unit	Quantity	Tolerances
Natural gas fuel Data			
Higher heating value	kJ/SM^3	40821.3	± 1 %
Lower heating value	kJ/SM^3	39447.6	± 1 %
High speed diesel fuel Data			
Higher heating value	kJ/kg	44589.0	± 2 %
Lower heating value	kJ/kg	42705.4	± 2 %
Generator data			
Manufacturer			
Model			
Serial No.			
Rating for apparent power	kVA	5200	
Power output at rated power factor	kW	4160	± 3 %
Generation nominal voltage	kV	11	
Full load current (at rated pf)	Amp	273.25	
Rated power factor		0.8	
Generator shaft speed	RPM	1500	
Waste heat recovery boiler data			
Manufacturer			
Model			
Serial No.			
Rated steam conditions			
MCR steam flow	kg/hour	10450	± 5 %
pressure	Kg/cm^2(g)	8.0	
temperature	^{0}C	200	
Exhaust flue gas conditions at WHRB outlet			
temperature	^{0}C	135	± 3 %
Exhaust gas pressure drop between turbine and WHRB inlet	mm Wc	100	
Exhaust gas pressure drop between WHRB inlet and chimney	mm Wc	250	

The format for presentation of collected test data for report and for using in the calculations can be as follows.

Description		
Parameter	**Unit**	**Quantity**
Test duration	hours	4
Ambient conditions (Gas turbine compressor inlet conditions)		
air temperature	^{0}C	36.5
pressure	kg/cm^2	1.0332
relative humidity	%	57.5
Gas turbine data		
Gas turbine compressor inlet conditions		
air temperature	^{0}C	37.0
pressure	kg/cm^2	1.0332
dry bulb temperature	^{0}C	36.5
wet bulb temperature	^{0}C	28.0
Diff. Pressure - Inlet air filter	mm Wc	35.8

Fuel Data		
fuel fired	Natural gas	
fuel flow rate	SM^3/hour	1311.971
lower heating value of NG	kJ/SM^3	39565.3
Exhaust flue gas conditions		
flow	Kg/sec	16.35
temperature	^0C	548
Generator data		
Average power output	kW	3994.5
Power factor		0.875
Waste heat recovery boiler data		
Pinch point temperature	^0C	182
Exhaust gas temp at inlet	^0C	542
Exhaust gas temp exit boiler	^0C	131.4
Steam parameters at WHRB exit		
flow	MT/hour	9.145
temperature	^0C	195.5
pressure	Kg/cm^2	8.05
Feed water inlet parameters		
flow	Kg/hour	9605
Temperature at drum inlet	^0C	105
pressure	Kg/cm^2	12.4
Enthalpy at drum inlet	KJ/kg	440
Exhaust flue gas composition		

Diagram showing field test data measurement points

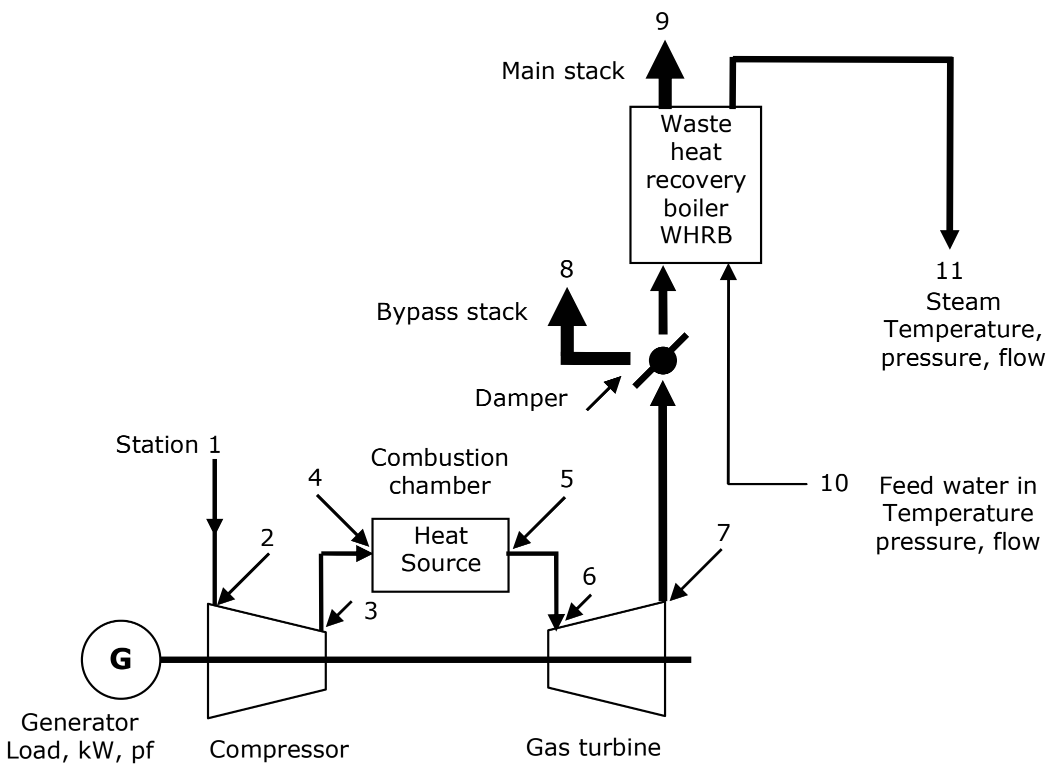

Figure 6-1: Gas turbine process flow with instrument locations

Station 1: Ambient air conditions, pressure, temperature, humidity
Station 2: Air conditions at inlet of compressor,
Station 3: Conditions for air leaving comp
Station 4: Fuel input to combustion chamber, flow, temperature, pressure, analysis
Station 5: Flue gas conditions at exit of combustion chamber, temperature
Station 6: Flue gas conditions at inlet of turbine, temperature
Station 7: Exhaust flue gas conditions leaving turbine, entering WHRB, temperature, flow
Station 8: Exhaust flue gas conditions leaving the bypass stack, temperature
Station 9: Exhaust flue gas conditions leaving the main stack, temperature
Station 10: Feed water input to WHRB, flow, temperature
Station 11: Steam output from WHRB, pressure, temperature, flow
kW: Kilowatts pf: Power factor

Additional nomenclature used with letter designate the type of fluid in various parts of cycle:

f : Fuel	a : Air (or other working fluid)
w : Water	g : Gas after the combustion chamber
s : Steam	b : Bearing fluid

6.3 Fuel flow calculations

6.4.1 The sample calculations consider firing of Natural gas fuel. It is assumed that for measuring gas fuel flow and consumption, the digital readout is available on a control panel display unit of equipment being fired with gas fuel. The readout on the control panel is available from a microprocessor, which is fed necessary signals from the flow measuring device installed in the field consisting of orifice, differential pressure transmitter and temperature transmitter (duly compensated). The gas flow and consumption at 10 min. interval is noted for the test duration and then averaged out for use in calculations.

6.4.2 The fuel higher heating value (HHV) and lower heating value (LLV) are averaged out on the basis of the report of analysis generated by testing of sample of Natural gas prior to the commencement of test and the heating values available from the supplier's bills for the last 6-12 months. The bills provide required data for considering the variations in the heating values over a period of time to determine the best feasible value for the purpose of calculations.

6.4 Determination of Efficiency and Heat rate

6.5.1 $$W_s = \frac{V_{ng}}{P} \text{ for gaseous fuel}$$

Where

V_{ng}, fuel consumption per hour = 1311.971 Sm^3/hr, for gaseous fuel
P, electrical power output kW = 3994.5 kW
W_s, specific fuel consumption = 1311.971/3994.5
= 0.32844 Sm^3/kWh

6.5.2 **Heat consumption rate calculations**

Calculate the heat consumption rate of the plant using following equation.

$$q_r = V_{ng} \text{ x } Q_{lo} \quad \text{for gaseous fuels}$$

Where,

q_r = rate of heat consumption, kJ/hr
Q_{lo}, lower heating value of fuel, for gaseous fuels = 39565.3 kJ/Sm^3
V_{ng}, fuel consumption per hour = 1311.971 Sm^3/hr, for gaseous fuel

q_r = 1311.971 X 39565.3 kJ/hr
q_r = 51.9085 million kJ/hr

6.5.3 Heat rate calculations

Calculate the heat rate of the plant using following equation.

$$q_s = \frac{q_r}{P}$$

Where,
q_s = heat rate, kJ/kWh
q_r, rate of heat consumption = 51.9085 kJ/hr
P, net electrical power output = 3994.5 kW
q_s, heat rate = 51.9085 X 10^6 / 3994.5
= 12995 kJ/kWh

6.5.4 Gas turbine thermal efficiency calculations

$$\eta_{gt} = \frac{3600\ x\ P \times 100}{q_r}$$

Where,
η_{gt} = thermal efficiency based on net electrical power output, percent
P, net electrical power output = 3994.5 kW
q_r, rate of heat consumption = 51.9085 kJ/hr
η_{gt} = 3600 X P X 100 / q_r
= 3600 X 3994.5 X 100 / 51.9085
= 27.7 %

Alternate formulae for heat rate of the plant may be used for calculating the gas turbine efficiency as per following equation.

$$\text{Gas turbine heat rate, } q_s = \frac{3600}{\eta_{gt}} \text{ for net electrical power in kW}$$

Where,
q_s, = heat rate, kJ/kWh
η_{gt}.thermal efficiency based on net electrical power output = 27.7 %
q_s, = 3600 X 100 / 27.7
heat rate = 12996 kJ/kWh

6.5.5 Steam flow from WHRB

Actual steam flow measured, average for 4 hours = 10.44 MT
= 2.9 kg/s

6.5.6 Thermal efficiency calculations for WHRB

$$\eta_{whrb} = \frac{W_s\ x\ (h_{11} - h_{12})\ x\ 100}{W_{eg}\ x\ C_p\ x\ (t_e - t_{exhaust})}$$

Where,
η_{whrb} = thermal efficiency based on net steam output, percent
W_s, steam rate = 2.9 kg/sec

$h_{11,}$ steam enthalpy at boiler outlet = 2835.6 kJ/kg
W_{eg}, exhaust gas flow rate = 16.25 kg/sec
C_p, average value of specific heat of exhaust gas = 1.1807 kJ/kg^{0}C
t_e, exhaust gas temperature from GT = 542 ^{0}C
$t_{exhaust}$, temperature at WHRB exit (chimney) = 131.4 ^{0}C

$$\eta_{whrb} = \frac{2.9 \text{ x } (2835.6 - 440) \text{ x } 100}{16.25 \text{ x } 1.1807 \text{ x } (542 - 131.4)}$$

. η_{whrb} thermal efficiency based on net steam output = 87.7% percent

6.5.7. **Overall plant efficiency calculations for gas turbine based cogeneration Plant**

$$\eta_{plant} = \frac{[(P \text{ x } 860 \times 4.19) + (W_s \text{ x } (h_{11} - h_{12}) \text{ x } 3600)]}{V_{ng} \text{ x } Q_{lo}} \text{ x } 100$$

Where,

η_{plant} = overall plant efficiency based on net power & steam output, percent
P, net electrical power output from gas turbine = 3994.5 kW
W_s, steam rate from WHRB = 2.9 kg/sec
$h_{11,}$ steam enthalpy at boiler outlet = 2835.6 kJ/kg
Q_{lo}, lower heating value of fuel, for gaseous fuels = 39565.3 kJ/Sm^3
V_{ng}, fuel consumption per hour = 1311.971 Sm^3/hr, for gaseous fuel

$$\eta_{plant} = \frac{[(3994.5 \text{ x } 860 \times 4.19) + (2.9 \text{ x } (2835.6 - 440) \text{ x } 3600)]}{1311.971 \text{ x } 39565.3} \text{ x } 100$$

. η_{plant} overall plant efficiency based on net power & steam output = 75.9%

6.5.8 **Overall cogen plant heat rate calculations for gas turbine based system**

$$q_{scogen} = \frac{860 \text{ x } 4.19 \text{ x } 100}{\eta_{plant}}$$

Where,

q_{scogen} = overall plant heat rate based on net power & steam output, kJ/kWh
η_{plant} overall plant efficiency based on net power & steam output = 75.9 %

$$q_{scogen} = \frac{860 \text{ x } 4.19 \text{ x } 100}{75.9}$$

q_{scogen} overall plant heat rate based = 4747.7 kJ/kWh on net power & steam output

The above calculations are summarized in the table given below, in MS Excel spread sheet format.

Table 6-2: Calculations for Gas Turbine Cogeneration Plant

Sl No.	Parameter	Equation to be used in column C & Comments	Quantity
	A	B	C
1	V_g, fuel consumption rate, Sm^3/h	Measured value	1311.971
2	P, electrical power output, kW	Measured value	3994.5
3	Q_{lo}, lower heating value of fuel, kJ/ m^3	From standard data	39565.3
4	q_r, rate of heat consumption, kJ/h	C1*C3	51.9085 X 10^6
5	q_s , heat rate, kJ/kWh	C4/C2	12994.999
6	$\eta_{g,}$ thermal efficiency based on net electrical power output, %	3600 X *C2* X 100 / *C5*	27.7%
7	W_{eg}, exhaust gas flow rate, kg/s	Estimated value	16.35
8	C_p, average value of specific heat of exhaust gas, kJ/kg-^{0}C	From standard data	1.1807
9	t_e, exhaust gas temperature at WHRB inlet, ^{0}C	Measured value	542
10	t_{pp}, pinch point temperature, ^{0}C	Measured value	182
11	h_{10}, feed water enthalpy at drum inlet, kJ/kg	From measured temperature & standard data	440
12	$h_{11,}$ steam enthalpy at boiler outlet, kJ/kg	From measured temperature & standard data	2835.6
13	W_s, steam rate from WHRB, kg/sec	Measured value	2.9
14	$t_{exhaust}$, temperature at WHRB exit (chimney), ^{0}C	Measured value	131.4
15	η_{whrb} thermal efficiency of WHRB based on net steam output	C13*(C12-C11)*100/(C7*C8* (C9-C14))	87.7%
16	η_{plant}overall plant efficiency based on net power & steam output, %	((C2*860*4.19)+(C13*(C12-C11)*1000)) /C4	**75.9%**
17	q_{scogen}overall plant heat rate based on net power & steam output, kJ/kWh	860*4.19*100/C16	**4747.7**

6.5.9 Correction factors

1. Gas turbine performance varies with changes in atmospheric pressure and temperature. The conditions may vary over the period of test and may differ considerably from those at which the performance is guaranteed.

2. The results can be corrected to ISO conditions based on which the gas turbine heat rate and efficiency are mentioned. The correction charts provided by the gas turbine manufacturers can be referred to get the corrected results. Correction charts for ambient conditions, speed, etc. are supplied by the manufacturers along with the equipment.

7. UNCERTAINTY ANALYSIS

7.1 Introduction

Uncertainty denotes the range of error, i.e. the region in which one guesses the error to be. The purpose of uncertainty analysis is to use information in order to quantify the amount of confidence in the result. The uncertainty analysis tells us how confident one should be in the results obtained from a test.

Guide to the Expression of Uncertainty in Measurement (or GUM as it is now often called) was published in 1993 (corrected and reprinted in 1995) by ISO. The focus of the ISO *Guide* or GUM is the establishment of "general rules for evaluating and expressing uncertainty in measurement that can be followed at various levels of accuracy ".

The following methodology is a simplified version of estimating combined uncertainty at field conditions, based on GUM.

7.2 Methodology

Uncertainty is expressed as X +/- y where X is the calculated result and y is the estimated standard deviation. As instrument accuracies are increased, y decreases thus increasing the confidence in the results.

A calculated result, r, which is a function of measured variables X_1, X_2, X_3,….., X_n can be expressed as follows:

$r = f(X_1, X_2, X_3,\ldots, X_n)$

The uncertainty for the calculated result, r, is expressed as

$$\partial_r = \left[\left(\frac{\partial r}{\partial X_1}\times\delta x_1\right)^2+\left(\frac{\partial r}{\partial X_2}\times\delta x_2\right)^2+\left(\frac{\partial r}{\partial X_3}\times\delta x_3\right)^2+\ldots\ldots\right]^{0.5} \quad \text{----(1)}$$

Where:

∂_r	= Uncertainty in the result
δxi	= Uncertainties in the measured variable X_i
$\frac{\partial r}{\partial X_i}$	= Absolute sensitivity coefficient

In order to simplify the uncertainty analysis, so that it can be done on simple spreadsheet applications, each term on RHS of the equation-(1) can be approximated by:

$$\frac{\partial r}{\partial X_1} \times \partial X_1 = r(X_1+\partial X_1) - r(X_1) \quad \text{----(2)}$$

The basic spreadsheet is set up as follows, assuming that the result r is a function of the four parameters X_1, X_2, X_3 & X_4. Enter the values of X_1, X_2, X_3 & X_4 and the formula for calculating **r** in column A of the spreadsheet. Copy column A across the following columns once for every variable in **r** (see table 7.1). It is convenient to place the values of the uncertainties $\partial(X_1)$, $\partial(X_2)$ and so on in row 1 as shown.

Table 7-1: Uncertainty evaluation sheet-1

	A	B	C	D	E
1		∂X_1	∂X_2	∂X_3	∂X_4
2					
3	X_1	X_1	X_1	X_1	X_1
4	X_2	X_2	X_2	X_2	X_2
5	X_3	X_3	X_3	X_3	X_3
6	X_4	X_4	X_4	X_4	X_4
7					
8	$y=f(X_1, X_2, X_3, X_4)$	$y=f(X_1, X_2, X_3, X_4)$	$y=f(X_1, X_2, X_3, X_4)$	$y=f(X_1, X_2, X_3, X_4)$	$y=f(X_1, X_2, X_3, X_4)$

Add ∂X_1 to X_1 in cell B3 and ∂X_2 to X_2 in cell C4 *etc.*, as in Table 7.2. On recalculating the spreadsheet, the cell B8 becomes $f(X_1+\partial X_1, X_2, X_3, X_4)$.

Table 7-2: Uncertainty evaluation sheet-2

	A	B	C	D	E
1		∂X_1	∂X_2	∂X_3	∂X_4
2					
3	X_1	$X_1+\partial X_1$	X_1	X_1	X_1
4	X_2	X_2	$X_2+\partial X_2$	X_2	X_2
5	X_3	X_3	X_3	$X_3+\partial X_3$	X_3
6	X_4	X_4	X_4	X_4	$X_4+\partial X_4$
7					
8	$r=f(X_1, X_2, X_3, X_4)$	$r=f(X_1', X_2, X_3, X_4)$	$r=f(X_1, X_2', X_3, X_4)$	$r=f(X_1, X_2, X_3', X_4)$	$r=f(X_1, X_2, X_3, X_4')$

In row 9 enter row 8 minus A8 (for example, cell B9 becomes B8-A8). This gives the values of $\partial(r, X_1)$ as shown in table 7.3.

$\partial(r, X_1)=f(X_1+\partial X_1), X_2, X_3\ldots) - f(X_1, X_2, X_3..)$ *etc.*

To obtain the standard uncertainty on *y*, these individual contributions are squared, added together and then the square root taken, by entering $\partial(r, X_1)^2$ in row 10 (Figure 7.3) and putting the square root of their sum in A10. That is, cell A10 is set to the formula, SQRT(SUM(B10+C10+D10+E10)) which gives the standard uncertainty on r, $\partial(r)$

Table 7-3: Uncertainty evaluation sheet-3

	A	B	C	D	E
1		∂X_1	∂X_2	∂X_3	∂X_4
2					
3	X_1	$X_1+\partial X_1$	X_1	X_1	X_1
4	X_2	X_2	$X_2+\partial X_2$	X_2	X_2
5	X_3	X_3	X_3	$X_3+\partial X_3$	X_3
6	X_4	X_4	X_4	X_4	$X_4+\partial X_4$
7					
8	$r=f(X_1, X_2, X_3, X_4)$	$r=f(X_1', X_2, X_3, X_4)$	$r=f(X_1, X_2', X_3, X_4)$	$r=f(X_1, X_2, X_3', X_4)$	$r=f(X_1, X_2, X_3, X_4')$
9		$\partial(r,X_1)$	$\partial(r,X_2)$	$\partial(r,X_3)$	$\partial(r,X_4)$
10	$\partial(r)$	$\partial(r,X_1)^2$	$\partial(r,X_2)^2$	$\partial(,X_3)^2$	$\partial(r,X_4)^2$

7.3 Uncertainty Evaluation of Cogeneration Plant Efficiency Testing

Based on above discussions, the methodology for estimating uncertainty in efficiency testing of cogeneration plants is explained below.

The instrument accuracy table is developed based on the accuracy of the instruments from calibration certificates. It should be noted that all instruments used in testing a cogeneration plants should be calibrated in the operating range and obtain a calibration curve. This helps in understanding errors at various points. If an instrument is tested at full scale value only, the absolute value uncertainty in measurements will increase.

For example, for a temperature indicator having 0.5% error and 1000 ºC full scale value, If calibration curve is not available, the absolute error will be based on full scale value, i.e. 1000 x 0.5% = 5ºC. Thus, uncertainty in temperature measurement is ±5 ºC. A measurement of 100ºC with this meter will be indicated as 100 ±5 ºC i.e. 5% error.

If the instrument is calibrated and assuming that error at the measured value of 500 ºC is 0.5% from the calibration curve. The absolute error at this point can be 0.005 x 500 = 2.5 ºC. Thus, uncertainty in voltage measurement is ±2.5 ºC.

In table 7.4, uncertainties in measurements are given as a % of measured value based on calibration curve for each instrument.

Table 7-4: Instrument accuracy table

	δw_g	δP	δw_{eg}	δT_e	δT_{pp}	δT_{exh}
Instrument accuracy	2%	0.5%	2.0%	0.5%	0.5%	0.5%
Absolute accuracy	26.24	20.0	0.327	2.71	0.91	0.657

The measurements and estimation of uncertainties are given in Table 7.5.

Table 7-5: Measurements and Uncertainty analysis

				δw_g	δP	δw_{eg}	δT_e	δT_{pp}	δT_{exh}
			Instrument accuracy	2%	0.5%	2.0%	0.5%	0.5%	0.5%
			Absolute accuracy	26.24	20.0	0.327	2.71	0.91	0.657
Measured Parameters	Unit	Symbol	Measurements	$w_g + \delta w_g$	$P+\delta P$	$w_{eg} + \delta w_{eg}$	$T_e + \delta T_e$	$T_{pp} + \delta T_{pp}$	$T_{exh} + \delta T_{exh}$
Fuel consumption	m^3/hr	w_g	1311.971	1338.21	1311.971	1311.971	1311.971	1311.971	1311.971
Electrical Power output	kW	P	3994.5	3994.5	4014.5	3994.5	3994.5	3994.5	3994.5
Exhaust gas flow rate at WHRB	kg/s	w_{eg}	16.35	16.35	16.35	16.677	16.35	16.35	16.35
Exhaust gas temperature at WHRB inlet	C	T_e	542	542	542	542	544.71	542	542
Pinchpoint temperature	C	T_{pp}	182	182	182	182	182	182.91	182
Temperature at WHRB exhaust	C	$T_{exhaust}$	131.4	131.4	131.4	131.4	131.4	131.4	132.057
Values taken from tables/graphs/assumptions									
Lower heating value of fuel	kJ/m^3	Q_{lo}	39565.3	39565.3	39565.3	39565.3	39565.3	39565.3	39565.3
Specific heat of exhaust gas	kJ/kg-C	C_p	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Feed water enthalpy at drum inlet	kJ/kg	h_{10}	440	440	440	440	440	440	440
Steam enthalpy at boiler outlet	kJ/kg	h_{11}	2835.6	2835.6	2835.6	2835.6	2835.6	2835.6	2835.6
Results									
Steam flow rate	kg/s	w_s	2.90	2.90	2.90	2.96	2.92	2.89	2.90
Heat consumption rate	kJ/hr	q_r	51908526.21	52946696.73	51908526.21	51908526.21	51908526.21	51908526.21	51908526.21
Heat rate	kJ/kWh	q_s	12995.00	13254.90	12930.35	12995.00	12995.00	12995.00	12995.00
Gas Turbine thermal efficiency	%	η_{GT}	26.3%	25.7%	26.4%	26.3%	26.3%	26.3%	26.3%
Thermal efficiency of WHRB	%	η_{whrb}	87.7%	87.7%	87.7%	87.7%	87.8%	87.5%	87.8%
Overall plant efficiency	%	$\eta_{overall}$	**75.9%**	**74.4%**	**76.0%**	**76.9%**	**76.3%**	**75.8%**	**75.9%**
Delta				0.0148820	-0.0013865	-0.0096338	-0.0036260	0.0012176	0.0000000
Delta^2				0.0002215	0.0000019	0.0000928	0.0000131	0.0000015	0.0000000
SQRT(sum of Delta^2)				0.01488					
Uncertainty in efficiency estimation				**2.0%**					

Measured Parameters	Unit	Symbol	Measure ments	$w_{g} + \delta w_{g}$	$P+\delta P$	$w_{eg} + \delta w_{eg}$	$T_e + \delta T_e$	$T_{pp} + \delta T_{pp}$	$T_{exh} + \delta T_{exh}$
Overall cogeneration plant heat rate	kJ/kWh	$q_{overall}$	**4747.69**	4842.644	4739.033	4688.183	4725.116	4755.319	4747.690
Delta				-94.953811	8.656970	59.507345	22.574352	-7.628771	0.000000
Delta^2				9016.22629	74.94313	3541.12406	509.60135	58.19815	0.00000
SQRT(sum of Delta^2)				94.95381					
Uncertainty in heat rate estimation				**2.0%**					

The overall plant efficiency is expressed as 75.9 ± 2.0%
Heat rate is expressed as 4747.7 ± 2% kJ/kWh

Note:

- The uncertainty in overall efficiency with 2% error in fuel flow estimation and 2% error in waste gas flow rate is estimated to be 2%. These two parameters are to be measured with high accuracy.
- The error in electrical power measurement is not very significant in the gas turbine overall efficiency calculations. The uncertainty remains at 2% even if a 2% error in electrical power measurement is assumed, instead of desired accuracy of 0.5%.

8. PRACTICES FOR OPTIMAL PERFORMANCE OF COGENERATION SYSTEMS

8.1 Steam turbine systems

Design stage:

- At the design stage of the system, the process steam demands and power demands should be integrated – either electrical power or power for mechanical drive applications in the best possible manner, in a steam turbine, keeping in view the consideration for high basic efficiency.
- Ideal solution is a back-pressure steam turbine.
- If the steam demand is such that, less power is produced than the plant requirement, a condensing portion will have to be considered along with extraction. This would result in lower efficiency, but would attain desired balance of power and steam requirements.

Best operational mode

- Power or heat operated - Depending on the total power load of the industry, number of steam turbines are arranged on one line so that one or more steam turbines can be operated according to demand of power. With such philosophy of operation, it is possible to run the turbines close to the optimal operating range.

Steam conditions

- Decentralised cogeneration power plants of low and medium output in the range of 1 to 10 MW can be considered.
- Input steam conditions may be fixed between 30 - 70 bar and live steam temperature may be fixed between 400 – 500 ^{0}C to obtain desired steam turbine performance.

Control for steam turbines

Control of the steam turbines can be achieved through the following optional facilities.

- A throttle valve in front of the steam turbine may be installed through which steam pressure of flow leading from the steam line to the individual turbines as well as their output would be controlled.
- A nozzle group control may be provided in the individual turbine, which would permit individual nozzles before the first blade wheel (control wheel) to switch in or off to control the mass flow rate of the other stages as well as to regulate the output.

Monitoring for steam turbines

- Continuous or online as well as offline monitoring of following parameters would be vital to avoid fall in the steam turbine performance. The monitoring system should be strong enough to identify all possible parameters and their small irregularity. Only difficulty in building monitoring system is its cost.
- Monitoring of conductivity of steam to ensure silica content in steam, as silica would deposit on the blades to adversely affect the output.
- Monitoring of axial differential expansion, vibrations, etc. must be carried out using suitable microprocessor based instrumentation.
- Monitoring of lube-oil circulation in bearings along with continuous cleaning of lube-oil through centrifuge is very important.

Maintenance

Generally, the periodic preventive maintenance of steam turbine is carried out as follows.

- Inspection of steam turbines and steam pipelines may be carried out from outside at least once a week for observing irregularities.
- Thorough inspection and overhauling may be generally resorted to every 5 years. However, the schedule may be decided based on data for condition of the turbine available through condition monitoring system. Hence, period of overhauling may fall between 3 to 5 years.

8.2 Gas turbine systems

Best operational mode

- Power or heat operated - Depending on the total power load of the industry, number of gas turbines are arranged on one line so that one or more gas turbines can be operated according to demand of power. With such philosophy of operation, it is possible to run the gas turbines close to the rated capacity so as to achieve optimum heat rate.
- Such method of operation would avoid running of the gas turbine at less than 80% of its rated capacity, which otherwise would result into higher heat rate.

Operating state

- Gas turbines of small capacity to large capacity are available.
- It would be better to avoid small capacity gas turbines, as they work with least electrical efficiency, unless it is possible to recover all the heat from the exhaust flue gases so that the plant could achieve optimum overall performance.

Control for gas turbines

- Control of the gas turbines can be achieved through amount of fuel injected into the combustion chamber of the gas turbine.
- The governing system for the gas turbine should be very precise and extremely reliable, and hence it is always computerised.

Monitoring for gas turbines

Continuous or online monitoring of following parameters would be vital to avoid fall in the gas turbine performance.

- Monitoring of fuel flow, pressure and temperature.
- Monitoring of flue gas temperature at turbine inlet, temperature spread around exhaust manifold at turbine outlet, exhaust gas temperature is must in order to monitor the performance.
- Monitoring of bearing vibrations must be carried out using suitable microprocessor based instrumentation. If gearbox is installed between turbine and generator, a separate monitoring of vibrations on gearbox is required.
- Monitoring of pressure and temperature of lube-oil circulated in bearings is very important. Generally, lube-oil is replaced after 8000 hours of working.
- Monitoring of inlet air temperature is important, as higher the ambient air temperature, lower would be the power output from the gas turbine or vice-versa.

Maintenance

Generally, the periodic preventive maintenance of gas turbine is carried out as follows.

- Washing of compressor, generally at an interval of one month or as specified by the manufacturer, is a must to maintain the output, as washing removes dust deposition on compressor blades occurred from ambient air drawn. Dust deposition on blades works as fowling to reduce air flow through compressor and power output.

- Thorough boroscopic inspection of turbine and compressor blades, bearings and overhauling may be resorted to every year.
- If fired with clean fuel natural gas, it may be necessary to replace the turbine blades after 25000 running hours, i.e. the life of heat resistant coating provided on the blades. Blade replacement interval may be around 20000 hours for the gas turbine fired with liquid fuels high speed diesel, kerosene oil. High ash bearing fuels like fuel oil reduces the blade life to just 10000 running hours.

Evaporative cooling of inlet ambient air

- Higher ambient air temperature reduces the power output from the gas turbine. The mechanical work done by the gas turbine is proportional to the mass of flue gases entering the gas turbine, and mass depends on quantity of ambient air supplied to the combustion chamber through compressor. High temperature reduces the density of air, i.e. mass (weight of air). Thus, at same compressor speed, less mass of air goes to the combustion chamber when the ambient air temperature is high. This results into reduction of power output due to less mechanical work done by the gas turbine.
- In order to improve or maintain the performance, ambient air is passed through evaporative type of cooling system to reduce the temperature, which makes it denser. This results into either generation of additional power or maintaining of output as near as possible to capacity.

Supplementary firing/Combustion Efficiency

- By increasing the gas turbine exhaust temperature by resorting to supplementary firing with arrangement made in the duct just before entrance to WHRB, additional steam can be generated with little increase in the plant area.
- In some applications, the burner is located between heat-transfer sections.
- If O_2 available in turbine exhaust gases is insufficient to affect complete combustion, an additional fresh air should be sent to WHRB through fresh air blower.

8.3 Reciprocating engine systems

Operating state

- The reciprocating engines of small capacity to large capacity are available. It would be better to avoid small capacity engines except for emergency standby source of power, as they offer almost no potential for heat recovery so as to operate in real cogeneration mode.
- The operating temperature of the engine should be maintained within the normal limits specified by the manufacturer. The oil temperature is normally maintained between 65 – 70^{0}C.
- Prolonged overload condition on the engine should always be avoided. Unbalance load condition should be limited so that rated current is not exceeded in any phase of the generator.
- It is desirable to provide a suitable flywheel inertia to limit the cyclic irregularity.
- It is desirable to maintain the engine speed at normal level. Sudden load imposition or shedding may abruptly change the speed and may damage some moving part.
- Do not allow the exhaust temperature to go above 430^{0}C by preventing overloading and restricting air supply to improve the fuel efficiency.
- Cooling water pH should be maintained between 7 – 8 to avoid corrosion and scaling.
- Try to run the large rated engines at more than 50% and small rated engines at 60% of their rating to have better performance.

- Monitoring of inlet air temperature and pressure is important, as higher the ambient air temperature, lower would be the power output from the reciprocating engine or vice-versa.

Maintenance

- Major point of maintenance to be attended is replacement of lubricating oil on condition basis, and not only on basis of norms of running hours prescribed by the manufacturer.
- Field oil testing kits may be used for testing to support the decision whether to change the oil.
- Avoid over lubrication to prevent deposits in the engine and on the turbo-charger blades.
- Check compression pressure regularly where such provisions are made.
- Periodic cleaning/replacement of air filers, fuel filters, etc. is very important for desired performance of the engine.
- Leakages of fuel and lube-oil, minor or major, are to be avoided at all costs, as they are largely a major factor for higher fuel and lube-oil consumption.
- The heat exchangers for lube-oil and engine jacket cooling water may be cleaned at an interval of around 500 hours depending on the water quality.

Design & installation stage

- Specific fuel consumption of engine varies with the change in ambient air (intake) temperature and pressure. Ambient air pressure changes are related to the site altitude. Hence, it is important to consider highly reliable site data as design basis to decide engine rating correctly. The data for various correction factors is available for super-charged and non-super-charged engines from engine manufacturers.
- Two stroke engines may be provided with extra long stroke for fuel economy.
- The reciprocating engines, provided with radiators and engine driven cooling fan, about 7 – 10% loss of engine bhp is found. Hence, such designs may be selected where there is a shortage of cooling water supply.
- The engine exhaust system should be designed for proper fuel and engine efficiency so that exhaust back-pressure is within permissible limits and is not exceeded. Higher than permitted back-pressure results into adverse effect on the scavenging of engine and there would be less oxygen in the cylinder during the subsequent compression stroke. The mechanical efficiency will reduce due to higher exhaust pumping losses and will increase the specific fuel consumption.
- The engine rooms heat up during running of generator sets due to heat radiation from the engine, generator, exhaust pipeline, and hot air from the radiator fans. Increase in ambient temperature results in hot air inside the room, which increases the fuel consumption due to decrease in the air:fuel ratio, as the mixture becomes richer, there is drop in the fuel efficiency. It is therefore, very essential that the engine room is provided with effective ventilation so that hot air is continuously removed by circulation with cool air. Provision of roof ventilators or wall mounted exhaust fans on upper side cane be considered.
- As much of the radiated heat is from the exhaust pipelines and manifolds, use of some type of insulation lagging on these components reduces the heat radiated into the room ambient.
- Please remember that the increase in intake air temperature from 25^0C to 40^0C results in decrease in air:fuel ratio by about 5% and the specific fuel consumption may increase in the range of 0.5 to 2% depending on the engine design.

Cooling system practices

- The engine cooling system also plays an important role in maintaining the performance. Following tips are provided to supplement the tips provided for other systems.

- Water cooled engines would work at lower specific fuel consumption with provision of separate and independent cooling water circulation system consisting of cooling towers, cooling water circulating pumps and heat exchangers.

- The cooling water system should be designed to achieve and maintain difference of 6 - 10^0C in the cooling tower inlet water and outlet water temperature, which results better fuel efficiency.

ANNEXURE-1: CALCULATION OF EXHAUST FLUE GAS FLOW

The procedure for estimation of exhaust flue gas flow rate is given below along with a sample calculation. Along with the fuel composition, the measurements required are (a) % O2 content in flue gas (b) Fuel consumption rate.

The calculations are given for a Gas turbine Exhaust flow determination.

Fuel = Natural gas
(Natural gas contains almost 99% of methane; i.e. CH_4)

Atomic weight of Carbon (C) = 12
Atomic weight of Hydrogen (H) = 1
Atomic weight of Oxygen (O) = 16
Atomic weight of Nitrogen(N) = 14

Molecular weight of Natural gas ≈ 12 + 1x4 = 16
Molecular weight of Carbon Dioxide (CO_2) = 12 +16 x 2
= 44
Molecular weight of water (H_2O) = 1 x 2 +16
= 18
Molecular weight of N_2 = 14 x 2

Carbon content in Natural gas = 75% by weight
Hydrogen content in Natural Gas = 25% by weight

CO2 generated from 1 kg of Fuel = $\dfrac{\text{Molecular weight of Carbon Dioxide (CO2)}}{\text{Atomic weight of Carbon (C) x Carbon content in Natural gas}}$
= 44/(12 x 0.75)
= 2.75 kg

Number of Moles of CO2 generated = $\dfrac{\text{CO2 generated from 1 kg of Fuel}}{\text{Molecular weight of Carbon Dioxide (CO2)}}$
= 2.75/44 = 0.0625 kilo moles

O2 required for combustion of carbon in Natural gas
= CO2 generated from 1 kg of Fuel – Carbon in 1 kg fuel
= 2.75 – 0.75
= 2.0 kg

Amount of water vapor in flue gases = 9 x Hydrogen content in Natural Gas
= 9 x 0.25
= 2.25 kg

Number of Moles of water vapor in flue gas = $\dfrac{\text{Amount of water vapor in flue gases}}{\text{Molecular weight of water (H2O)}}$
= 2.25/18
= 0.13 kilo moles

O2 required for combustion of Hydrogen in Natural gas
= water vapor generated from 1 kg of Fuel – Hydrogen in 1 kg fuel
= 2.25 – 0.25
= 2.0 kg

O2 content in Air = 23% by weight

Total air flow rate required(kg of air per kg of fuel)
= (O_2 required for combustion of carbon in Natural gas + O_2 required for combustion of Hydrogen in Natural gas)/ O_2 content in Air

= (2.0 + 2.0)/0.23
= 17.39 kg of air per kg of fuel

N_2 in flue gases (N_2 which is present in combustion air)
= Total air flow rate - (O_2 required for combustion of carbon in Natural gas + O_2 required for combustion of Hydrogen in Natural gas)
= 17.39 – (2.0+2.0)
= 13.39 kg N_2 per kg of fuel

Moles of N_2 in flue gases = $\frac{\text{N2 in flue gases}}{\text{Molecular weight of N2}}$
= 13.39/28
= 0.48 kilo moles

Total moles of flue gases = Number of Moles of CO_2 generated + Number of Moles of water vapor in flue gas + Moles of N_2 in flue gases
= 0.0625 +0.13 +0.48
= 0.67 kilo moles

Stoichiometric CO_2 (%) = Number of Moles of CO_2 generated /Total moles of flue gases
= 0.0625/0.67
= 9.4%

Measured O_2 in flue gases = 15.4%

Estimated Excess air = (Measured O_2 in flue gases)/(21- Measured O_2 in flue gases)
= 15.4/(21-15.4)
= 275%

Actual Mass of air supplied/kg of fuel = (1+ Estimated Excess air) x Total air flow rate required
= (1+2.75) x 17.39
= 65.22 kg air per kg of fuel

Total mass of flue gases per kg of fuel = 1 + Actual Mass of air supplied/kg of fuel
= 1 + 65.22
= 66.22 kg air per kg of fuel

Volume flow rate of Fuel = 1365 m3/h
Specific gravity of Natural Gas = 0.6
Mass flow rate of fuel = Volume flow rate of Fuel x Specific gravity
= 1365 x 0.6
= 819.0 kg/h

Total mass flow rate of flue gases = Mass flow rate of fuel x Total mass of flue gases per kg of fuel
= 819.0 x 66.22
= 54232 kg/h
= 15.1 kg/s

ANNEXURE-2: REFERECES

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