Module 4

ENERGY PERFORMANCE ASSESSMENT FOR EQUIPMENT AND UTILITY SYSTEMS

SREDA
Sustainable and Renewable Energy Development Authority

Sustainable and Renewable Energy Development Authority
Power Division

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Preamble

In order to ensure energy efficiency and conservation and to determine the future course of action, Sustainable and Renewable Energy Development Authority (SREDA) has developed the Energy Efficiency & Conservation Master Plan up to 2030 in 2016. According to this plan, the target of energy saving has been set 20% per GDP by 2030 which will be achieved by the use of energy efficient machinery and equipment as well as by improving energy management system in the demand side.

In order to achieve the above mentioned target & to ensure the energy efficiency and conservation in industrial & commercial sector, SREDA has formulated the Energy Audit Regulation’2018. Based on this regulation, SREDA will conduct the Energy Auditor Certification Examination to create energy auditors and energy managers in Bangladesh.

SREDA has prepared the following modules as reading material for four paper examinations in cooperation with various National and Foreign partner organizations.

Module No	Examination Paper	Subject
Module 01	Paper 01	Fundamentals of Energy Management and Energy Audit
Module 02	Paper 02	Energy Efficiency in Thermal Systems
Module 03	Paper 03	Energy Efficiency in Electrical Systems
Module 04	Paper 04	Energy Performance Assessment for Equipment and Utility Systems

This module 04 on Energy Performance Assessment for Equipment and Utility Systems is the reading material for the preparation of Paper 04 Examination for prospective candidates.

We hope that these modules will also act as valuable resource for practicing engineers in comprehending and implementing energy efficiency measures in the facilities.

Since it is the first iteration of these modules, in some areas there might be a lack of information. Up-gradation of these modules is an ongoing process. Any suggestion and comments (please email to ad.eaa@sreda.gov.bd) on the contents of those modules will be highly appreciated.

Table of Contents

1. COMPRESSED AIR SYSTEM

1.1 Introduction

The compressed air system is not only an energy intensive utility but also one of the least energy efficient. Over a period of time, both performance of compressors and compressed air system reduces drastically due to reasons such as poor maintenance, wear and tear etc. These may lead to installing additional compressors causing more inefficiency. A periodic performance assessment of compressor is essential to minimize the cost of compressed air.

1.2 Purpose of the Performance Test

To find out:

- Actual Free Air Delivery (FAD) of the compressor
- Specific power requirement

The actual performance of the plant is to be compared with design/standard values for assessing the plant energy efficiency.

1.3 Performance Terms and Definitions

Free Air Delivery (FAD)	Volume of air delivered under the conditions of temperature and pressure at the compressor suction
Specific Energy Consumption	The ratio of power consumption (in kW) to the volume delivered at ambient conditions

1.4 Field Testing

1.4.1 Measurement of free air by pump up test

Isolate the compressor along with its individual receiver from the main compressed air system by tightly closing the isolation valve, thus closing the receiver outlet.

Open drain valve at the receiver to let out water and empty the receiver. Close the valve tightly to start the test. Start the compressor and activate the stopwatch. Note the time taken to attain the normal operational pressure P_2 (in the receiver) from initial pressure P_1.

Calculate the capacity as per the following formula:

Actual Free air discharge

Free Air Delivery in m^3/min is given by:

$$Q = \frac{P_2 - P_1}{P_0} X \frac{V}{T} \; Nm^3/minute$$

Where

P_2	=	Final pressure after filling (kg/cm^2 abs.)
P_1	=	Initial pressure (kg/cm^2abs.) after bleeding
P_0	=	Atmospheric Pressure (kg/cm^2 abs.)
V	=	Storage volume in m^3 which includes receiver, after cooler, and delivery piping
T	=	Time taken to build up pressure to P_2 in minutes

The above equation is relevant where the compressed air temperature is same as the ambient air temperature, i.e., perfect isothermal compression.

In case the actual compressed air temperature at discharge, say $t_2{}^0C$ is higher than ambient air temperature say $t_1{}^0C$ (as is usual case),the FAD is to be corrected by a factor $(273 + t_1) / (273 + t_2)$.

1.4.2 Performance Assessment

Example 1.1

A plant has a compressor of rated capacity 1680 m^3/hr. Free air delivery of the compressor is carried out by filling the receiver.

The test data are as follows:

Receiver capacity	: 10 m^3
Interconnecting pipe	: 1 m^3
Initial pressure in receiver	: 1.0 kg/cm^2a
Inlet air pressure to compressor	: 1.0 kg/cm^2a
Final pressure	: 8.25 kg/cm^2a
Time taken to fill the receiver	: 3 minutes (180 seconds)
Inlet air temperature	: 30°C
Air temperature in the receiver	: 40°C
Average duration of loading	: 40 minutes in an hour
Average duration of unloading	: 20 minutes in an hour
Power consumption during loading	: 150 kW
Power consumption during unloading	: 25 kW

(a) Free Air Delivery in m^3/min is given by:

$$\frac{\mathbf{(8.25 - 1)\ X\ 11}}{\mathbf{1\ X\ 3}}\ \boldsymbol{X}\ \frac{\mathbf{(273 + 30)}}{\mathbf{(273 + 40)}}$$

: 25.73 m^3/min
: 1545 m^3/h
: 914 CFM

(b) % output when compared to rated capacity
: 1545/1680 x 100
: 92%

(c) Average Hourly air consumption:

Average duration of loading	: 40 minutes in an hour
Average duration of unloading	: 20 minutes in an hour
% loading of the compressor	: 40 x 100/ (40+20)
	: 66.7% loading
Hourly consumption of air is given by	: % loading x actual output
	: 0.667 x 1545
	: 1030 m^3/h
	: 609 CFM

(d) Energy consumption:

% loading of the compressor	: 66.7 %
% unloading of the compressor	: 33.3 %

Hourly energy consumption is given by:
: (% loading x load power) + (% unloading x unload power)

: (0.667 x 150) + (0.333 x 25)
: 108.375 kWh
Daily energy consumption : 108.375 x 24
: 2601 kWh

(e) Overall Specific energy consumption (CFM/kW):

$$: \frac{\text{Actual hourly air consumption in CFM}}{\text{Hourly energy consumption}}$$

: 609/108.375
: 5.67 CFM/kW

Example 1.2

A free air delivery test was carried out before conducting a leakage test on a reciprocating air compressor in an engineering industry and following were the observations:

Receiver capacity	:	8.0 m^3
Initial pressure	:	0.1 kg / cm^2 gauge
Final pressure	:	7.0 kg / cm^2 gauge
Additional hold-up volume	:	0.3 m^3
Atmospheric pressure	:	1.026 kg / cm^2 abs.
Compressor pump-up time	:	3.5 minutes

Further the following observations were made during the conduct of leakage test during the lunch time when no pneumatic equipment/ control valves were in operation:

a) Compressor on load time is 24 seconds and unloading pressure is 7 kg/cm^2gauage
b) Average power drawn by the compressor during loading is 92 kW
c) Compressor unload time and loading pressure are 79 seconds and 6.6kg/cm^2 gauage respectively.

Find out the following:

(i) Compressor output in m^3/hr (neglect temperature correction)
(ii) Specific Power Consumption, kW/ m^3/hr
(iii) % air leakage in the system
(iv) Leakage quantity in m^3/hr
(v) Power lost due to leakage

(i) Compresser output m^3/minute : $\dfrac{(P_2 - P_1) \times \text{Total Volume}}{\text{Atm. Pressure} \times \text{Pumpup time}}$

: $\dfrac{(8.026 - 1.126) \times 8.3}{1.026 \times 3.5}$ = 15.948 m^3/minute

: 956.89 m^3/hr

(ii) Output : 956.89 m^3/hr

Power consumption : 92 kW

Specific power consumption : 92/956.89 = 0.09614 kW/m^3/hr

(iii) % Leakage in the system

Load time (T) : 24 s

Unload time (t) : 79 s

% leakage in the system : $\dfrac{T}{(T+t)}$x100

	:	$\frac{24}{(24+79)} x100$
	:	23.3%
iv) Leakage quantity	:	0.233x956.89
	:	222.955 m^3/hr
v) Power lost due to leakage	:	Leakage quantity x specific power consumption
	:	222.955 x 0.09614
	:	21.43 kW

Example 1.3

An instrument air compressor capacity test gave the following results (assume the final compressed air temperature is same as the ambient temperature) — Comment?

Solution:

Piston displacement	:	16.88 m^3/minute
Theoretical compressor capacity	:	14.75 m^3/minute @ 7 kg/cm^2
Compressor rated rpm 750	:	Motor rated rpm : 1445
Receiver Volume	:	7.79 m^3
Additional hold up volume, i.e., pipe / water cooler, etc., is	:	0.4974 m^3
Total volume	:	8.322 m^3
Initial pressure P_1	:	0.5 kg/cm^2
Final pressure P_2	:	7.03 kg/cm^2
Atmospheric pressure P_0	:	1.026 kg/cm^2 a
Compressor output m^3/minute	:	$\frac{(P_2 - P_1) \times \text{Total Volume}}{\text{Atm. Pressure} \times \text{Pumpup time}}$
	:	$\frac{(7.03-0.5)\times 8.322}{1.026 \times 4.021} = 13.17$ m^3/minute

Capacity shortfall with respect to 14.75 m^3/minute rating is 1.577 m^3/minute i.e., 10.69 %, which indicates compressor performance needs to be investigated further.

Example 1.4

In a medium sized engineering industry a 340 m3/hr reciprocating compressor is operated to meet compressed air requirement at 7 bar. The compressor is in loaded condition for 80% of the time. The compressor draws 32 kW during load and 7 kW during unload cycle.

After arresting the system leakages the loading time of the compressor came down to 60%. Calculate the annual energy savings at 6000 hours of operation per year.

Solution:
Average power consumption with 80% loading = [0.8 x 32 + 0.2 x 7] = 27 kW
Average power consumption with 60% loading after leakage reduction = [0.6 x 32 + 0.4 x 7] = 22 kW saving in electrical power = 5 KW
Yearly savings = 5 x 6000 = 30,000 kWH

2. LIGHTING SYSTEM

2.1 Introduction

Lighting is provided in industries, commercial buildings, indoor and outdoor for providing comfortable working environment. The primary objective is to provide the required lighting level at lowest power consumption.

2.2 Purpose of the Performance Test

Most interior lighting requirements are for meeting average illuminance on a horizontal plane, either throughout the interior, or in specific areas within the interior combined with general lighting of lower illuminance.

The purpose of performance test is to calculate the installed efficacy in terms of lux/watt/m^2 (existing or design) for general lighting installation. The calculated value can be compared with the norms for specific types of interior installations for assessing improvement options. The installed load efficacy of an existing (or design) lighting installation can be assessed by carrying out a survey as indicated in the following sections.

2.3 Terms and Definitions

Lumen is a unit of light flow or luminous flux. The lumen rating of a lamp is a measure of the total light output of the lamp. The most common measurement of light output (or luminous flux) is the lumen. Light sources are labeled with an output rating in lumens.

Lux is the metric unit of measure for illuminance of a surface. One lux is equal to one lumen per square meter.

Circuit Watts is the total power drawn by lamps and ballasts in a lighting circuit being assessed.

Installed Load Efficacy is the average maintained illuminance on a horizontal working plane per circuit watt with general lighting of an interior. Unit: lux per watt per square metre (lux/W/m^2).

Lamp Circuit Efficacy is the amount of light (lumens) emitted by a lamp for each watt of power consumed by the lamp circuit, i.e. including control gear losses. This is a more meaningful measure for those lamps that require control gear. Unit: lumens per circuit watt (lm/W).

Average maintained illuminance is the average of lux levels measured at various points in a defined area.

Color Rendering Index (CRI) is a measure of the effect of light on the perceived color of objects. To determine the CRI of a lamp, the color appearances of a set of standard color chips are measured with special equipment under a reference light source with the same correlated color temperature as the lamp being evaluated. If the lamp renders the color of the chips identical to the reference light source, its CRI is 100. If the color rendering differs from the reference light source, the CRI is less than 100. A low CRI indicates that some colors may appear unnatural when illuminated by the lamp.

Lighting Power Density (LPD) is defined as the ratio of total operating lighting load (W) for a specified region of the building to the built up area (m^2) of that specified region. LPD for a typical building is assessed and given in the table 2.1.

Table 2.1: Lighting Power Density

Floor reference	Number of lamps	Wattage of Lamp	Types of lamp	Total Lighting Load in kW	Total Area in m^2	Lighting power density in W / m^2
Floor- 1	165	36	CFL	17.80	2120	8.40
Floor - 2	212	36	CFL	22.86	2722	8.40
Floor – 3	568	36	CFL	61.32	4247	14.44
Admin	83	36	CFL	5.98	2132	2.80
Amenities & Cafeteria	260	36	CFL	9.36	3549	2.64

2.4 Preparation (before Measurements)

Before starting the measurements, the following care should be taken:

All lamps should be operating and no luminaires should be dirty or stained.
Flow of light should not be blocked throughout the interior, especially at the measuring points.
Accuracies of readings should be ensured by

- Using accurate illuminance meters for measurements
- Sufficient number and arrangement of measurement points within the interior
- Proper positioning of illuminance meter

The interior should be divided into a number of equal areas, which should be as square as possible. The illuminance at the centre of each area is measured and the mean value calculated. This gives an estimate of the average illuminance on the horizontal working plane in the interior.

2.5 Procedure of Assessment

2.5.1 Determine the Minimum Number and Positions of Measurement Points

Calculate the Room Index (RI):$RI = \frac{L \text{ X } W}{H_M \text{ X } (L+W)}$
Where

L = length of interior
W = Width of interior
H_m = Mounting height, (The height of the lighting fittings above the horizontal working plane.

The working plane is usually assumed to be 0.75m above the floor in offices and at 0.85m above floor level in manufacturing areas.)

The minimum number of measurement points can be determined from Table 2.2.

Table 2.2: Determination of measurement points

Room Index	*Minimum number of measurement points*
Below 1	***9***
1 and below 2	***16***
2 and below 3	***25***
3 and above	***36***

For example, the dimensions of an interior are:

Length = 9m,
Width = 5m,
Height of luminaires above working plane (H_m) = 2m
RI= 9 x 5 / (2 x (9+5)) =1.607

From Table 2.2 the minimum number of measurement points is 16

As it is not possible to approximate a "square array" of 16 points within such a rectangle it is necessary to increase the number of points to say 18, i.e. 6 x 3.

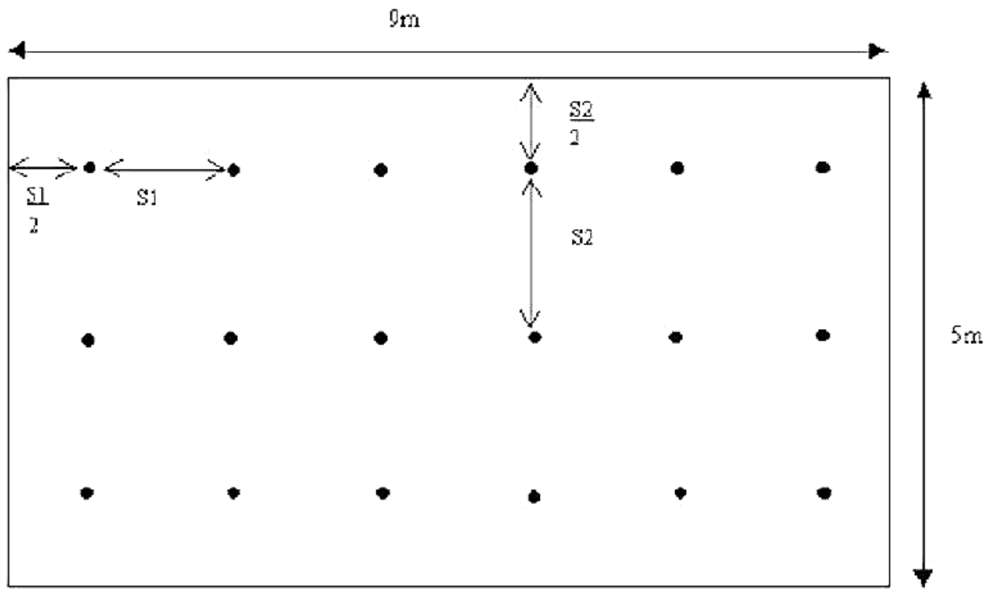


Figure 2.1: Array of measuring points

Therefore in this example the spacing between points along rows along the length of the interior = 9 ÷ 6 = 1.5m and the distance of the 'end' points from the wall = 1.5 ÷ 2 = 0.75m.

Similarly the distance between points across the width of the interior = 5 ÷ 3 = 1.67m with half this value, 0.83m, between the 'end' points and the walls.

If the grid of the measurement points coincides with that of the lighting fittings, large errors are possible and the number of measurement points should be increased to avoid such an occurrence.

2.5.2 Calculation of the Installed Load Efficacy and Installed Load Efficacy Ratio of a General Lighting Installation in an Interior

STEP 1	Measure the floor area of the interior:	Area = m^2
STEP 2	Calculate the Room Index:	RI =
STEP 3	Determine the total circuit watts of the installation by a power meter if a separate feeder for lighting is available: (If the actual value is not known a reasonable approximation can be obtained by totaling up the lamp wattages including the ballasts)	Total circuit watts =
STEP 4	Calculate Watts per square metre: (Value of step 3 ÷ value of step 1)	W/m^2 =
STEP 5	Ascertain the average maintained illuminance by using lux meter, Eav. Maintained:	E_{av}.maint. =
STEP 6	Divide 5 by 4 to calculate lux per watt per square Metre:	Lux/W/m^2 =
STEP 7	Obtain target Lux/W/m^2 for type of the interior/application and RI (2):	Target Lux/W/m^2 =
STEP 8	Calculate Installed Load Efficacy Ratio (ILER) (6÷ 7):	ILER =

Table 2.3: Target Values for Maintained illuminance on Horizontal Plane

Room Index	*Commercial lighting. (Offices, Retail stores etc.) & very clean industrial applications. Standard or good colour rendering. Ra: 40-85*	*Industrial lighting (Manufacturing areas, Workshops, Warehousing etc.) Standard or good colour rendering. Ra: 40-85*	*Industrial lighting installations where standard or good colour rendering is not essential but some colour discrimination is required. Ra: 20-40*
5	53 (1.89)	49 (2.04)	67 (1.49)
4	52 (1.92)	48 (2.08)	66 (1.52)
3	50 (2.00)	46 (2.17)	65 (1.54)
2.5	48 (2.08)	44 (2.27)	64 (1.56)
2	46 (2.17)	42 (2.38)	61 (1.64)
1.5	43 (2.33)	39 (2.56)	58 (1.72)
1.25	40 (2.50)	36 (2.78)	55 (1.82)
1	36 (2.78)	33 (3.03)	52 (1.92)

The principal difference between the targets for Commercial and Industrial Ra: 40-85 (Cols.2 & 3) of Table 2.3 is the provision for a slightly lower maintenance factor for the latter. The targets for very clean industrial applications, with Ra: of 40 - 85, are as column2.

2.5.3 ILER Assessment

Compare the calculated ILER with the information in Table 2.4.

Table 2.4: Indicators of Performance

ILER	Assessment
0.75 and above	Satisfactory to Good
0.51 – 0.74	Review suggested
0.5 or less	Urgent action required

ILER ratios of 0.75 and above are considered to be satisfactory. ILER ratios of 0.51 - 0.74 need investigation to assess if improvements are possible. There may be reasons for a low ratio, such as use of lower efficacy lamps or less efficient luminaires to achieve the required lighting effects. In such cases, more efficient alternatives can be suggested. ILER ratio of 0.5 or less certainly suggests scope for installation of more efficient lighting equipment.

After determining the ILER for the existing lighting installation, the difference between the actual ILER and the best possible (1.0) can be calculated to estimate the energy wastage.

Annual Energy Wastage (in kWh) = (1.0 - ILER) x Total load (kW) x annual operating hours (h)

2.5.4 Sample Calculations

STEP 1	Measure the floor area of the interior: Area = 45 m^2
STEP 2	Calculate the Room Index RI = 1.93
STEP 3	Determine the total circuit watts of the installation by a power meter if a separate feeder for lighting is available. If the actual value is not known a reasonable approximation can be obtained by totaling up the lamp wattages including the ballasts: Total circuit watts = 990 W
STEP 4	Calculate Watts per square metre, 3 ÷1 : W/m^2 = 22
STEP 5	Ascertain the average maintained illuminance, Eav. Maintained (average lux levels measured at 18 points) Eav.maint. = 700
STEP 6	Divide 5 by 4 to calculate the actual lux per watt per square Metre Lux/W/m^2 = 31.8
STEP 7	Obtain target Lux/W/$m^2$for the type of interior/ application and RI (2):(Refer Table 3) Target Lux/W/m^2 = 46
STEP 8	Calculate Installed Load Efficacy Ratio (ILER) (6÷ 7). = 0.7

ILER of 0.7 means that there is scope for review of the lighting system as per Table 2.4.

Annual energy loss = (1 - ILER) x watts x no. of operating hours
= (1 - 0.7) x 990 x 8 hrs/day x 300 days = 712 kWh/annum

2.5.5 Areas of Improvement

- Identify natural lighting opportunities such as windows and other openings
- For industrial lighting, explore the scope for introducing translucent sheets
- Assess scope for more energy efficient lamps and luminaries
- Assess scope for rearrangement of lighting fixtures

3. FANS AND BLOWERS

3.1 Introduction

This section describes the method of testing a fan installed on site in order to determine the performance of the fan in conjunction with the system to which it is connected.

3.2 Purpose of the Performance Test

The purposes of such a test are to determine, under actual operating conditions, the flow rate, the power input to the fan and the static pressure rise across the fan. These test results can be compared with the value specified by supplier.

3.3 Performance Terms and Definitions

Static Pressure (P_S): Static pressure is the amount of resistance measured in millimeter of water column (mm WC).when air moves through a duct. It is the pressure exerted on the duct walls.

Velocity Pressure (P_V): Velocity pressure is the pressure caused by air in motion. It is the kinetic energy of a unit of air flow in an air stream. It is a function of air density and velocity and it is used for determining air velocity in the duct.

Total Pressure **(P_T):** The sum of static pressures and velocity pressures at a point.

Relationship between Velocity, total and Static Pressures

$P_V = P_T - P_S$

Where,

P_V = Velocity Pressure

P_T = Total Pressure

P_S = Static Pressure

If velocity pressure is measured, velocity can be calculated and air flow can be determined.

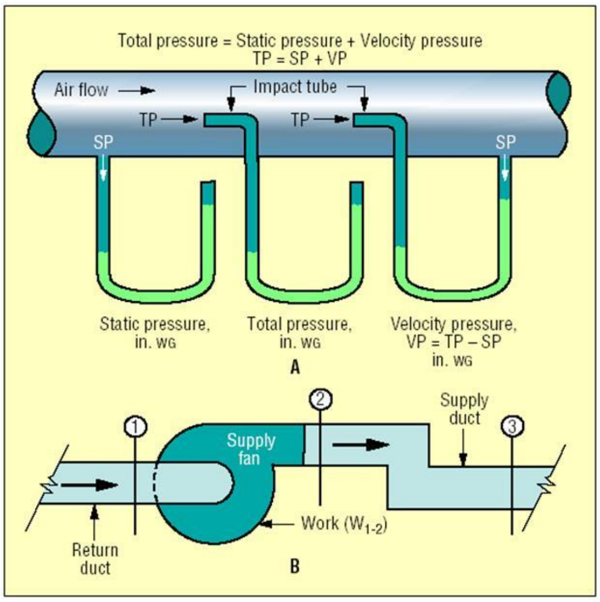


Figure 3.1

Fan Shaft Power: It is the mechanical power supplied to the fan shaft, also called as BHP.

Motor Input Power: The electrical power supplied to the terminals of an electric motor drive.

Fan Static Efficiency:

$$\eta_{Static}, \% = \frac{\text{Airflow in m}^3\text{/s x } \Delta P \text{ (Static Pressure) in mmWC}}{\text{102 x Fan Shaft Power in kW}}$$

3.4 Field Testing

Instruction

Before site tests are carried out, it should be ensured that:

- Fan and its associated equipment are functioning properly: no leakage
- Operations are stable: steady temperature, static pressures, rated speed etc.

Measurement Locations

The flow measurement plane shall be located in any suitable straight length, (preferably on the inlet side of the fan) where the airflow conditions are substantially axial, symmetrical and free from turbulence.

The part of the duct where flow measurement plane is located should be straight, of uniform cross-section and free from any obstructions which may modify the airflow.

For the purpose of determining the static pressure rise across the fan, the static pressure shall be measured at planes on the inlet and outlet side of the fan sufficiently close to it.

Equivalent diameter (D_e).For rectangular duct, equivalent diameter, D_e is given by LW/ (L + W) where L, W is the length and width of the duct. For circular ducts D_e is the same as diameter of the duct.

Measurement of Air Velocity on Site

Velocity pressure is measured by pitot tube equipped with micro manometer (Figure 3.2). To ensure accurate velocity pressure readings, the pitot tube tip must be pointed directly into (parallel with) the air stream (Figure 3.3).

Pitot tube senses total and static pressure. Manometer measures velocity pressure (Difference between total and static pressures) as shown in Figure 3.4.

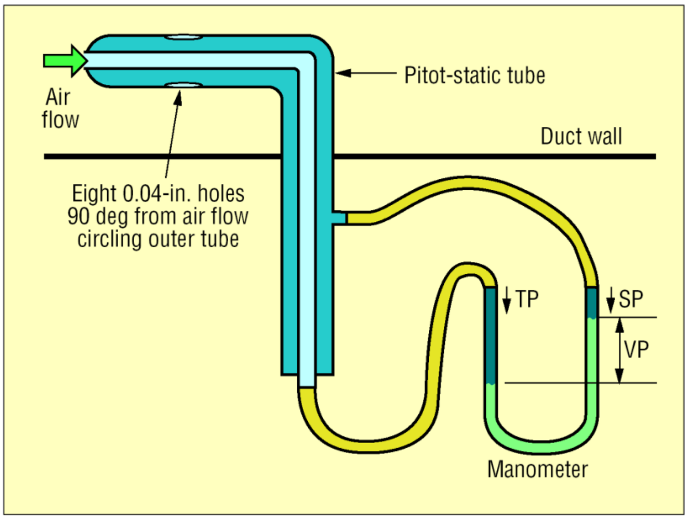


Figure 3.2: Pitot tube

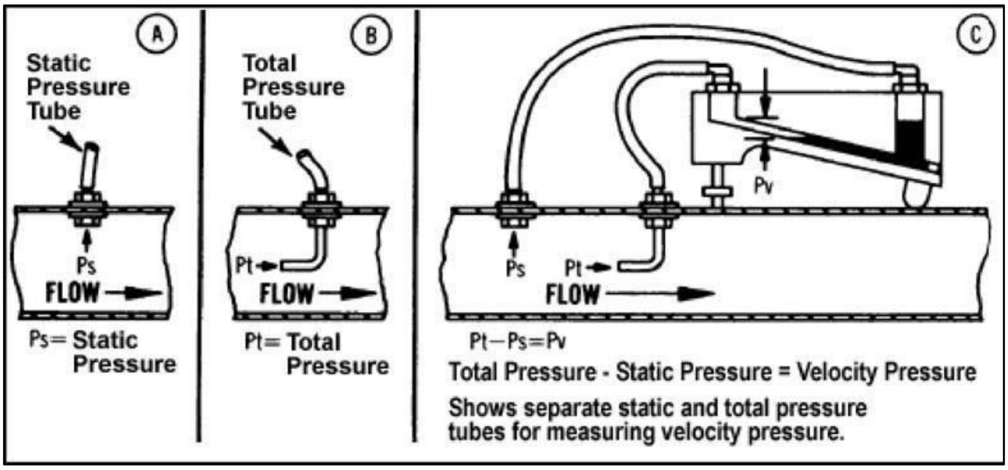


Figure 3.3: Types of Pressure Measurement

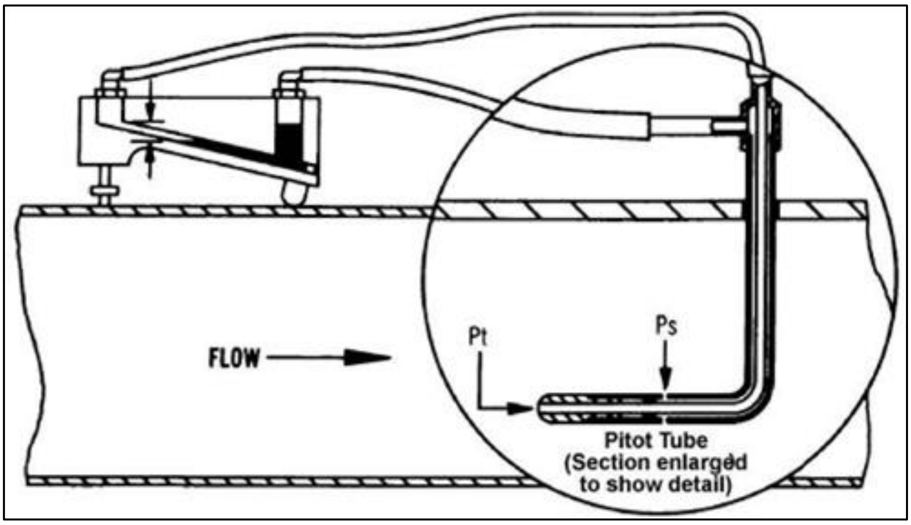


Figure 3.4: Pitot tube with Micromanometer

Traverse readings: The velocity of the air stream is not uniform across the cross section of a duct. Friction slows the air moving close to the walls, so the velocity is greater in the center of the duct.

To obtain the average velocity in ducts of 100mm diameter or larger, a series of velocity pressure readings must be taken at points of equal area. A formal pattern of sensing points across the duct cross section is recommended. These are known as traverse readings. Traverse point location for circular duct is shown in Figure 3.5.

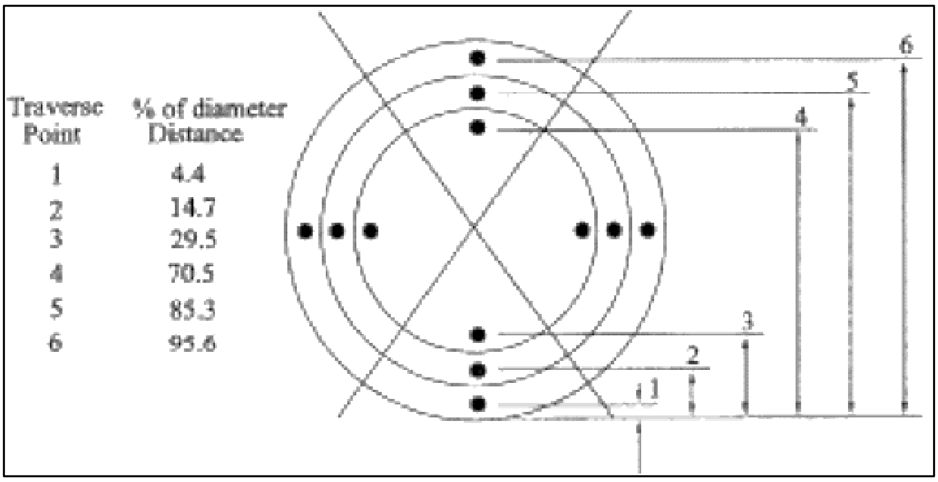


Figure 3.5 Traverse Points Location

Figure 3.6 shows recommended Pitot tube traverse point locations for traversing round and rectangular ducts. In round ducts, velocity pressure readings should be taken at centers of equal concentric areas.

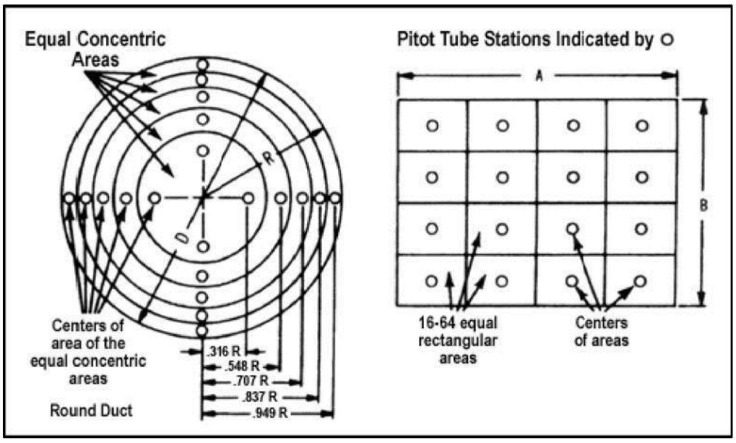


Figure 3.6: Pitot tube Traverse Point Location

The number of traverse points to be chosen depends upon the diameter in case of circular duct and equivalent diameter in case of rectangular duct.

Example 3.1 Traverse point determination for round duct

Round duct:

Let us calculate various traverse points for a duct of 1 m diameter. From Figure 3.6, for round duct of 1 m (1000 mm) diameter (D) and radius, R 0.5 m, 10 traverse points are chosen as follows:

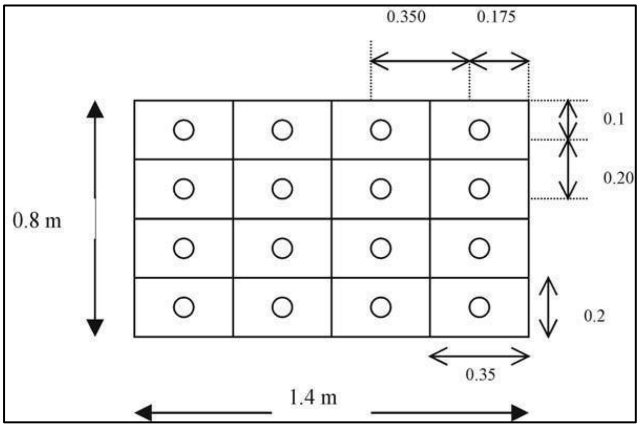
The various points from the port holes are given as follows:

0.5 – 0.949 x 0.5	***0.0255***
0.5 – 0.837 x 0.5	***0.0815***
0.5 – 0.707 x 0.5	***0.1465***
0.5 – 0.548 x 0.5	***0.226***
0.5 – 0.316 x 0.5	***0.342***
0.5 + 0.316 x 0.5	***0.658***
0.5 + 0.548 x 0.5	***0.774***
0.5 + 0.707 x 0.5	***0.8535***
0.5 + 0.837 x 0.5	***0.9185***
0.5 + 0.949 x 0.5	***0.9745***

Traverse point determination for rectangular duct (Sample Calculations)

Rectangular duct: For 1.4 m x 0.8 m rectangular duct, let us calculate the traverse points. 16 points are to be measured.

Dividing the area 1.4 x 0.8 = 1.12 m^2 into 16 equal areas, each area is 0.07 m^2. Taking dimensions of 0.35m x 0.20m per area, we can now mark the various points in the rectangular duct as follows:



In very small ducts or where traverse operations are otherwise impossible, measurement can be taken by placing Pitot tube in the centre of the duct.

Calculation of Velocity: After taking velocity pressures readings, at various traverse points, the velocity corresponding to each point is calculated using the following expression.

$$\text{Velocity (m/s)} = C_p \times \sqrt{\frac{2 \times 9.81 \times \Delta p_v}{\gamma}}$$

Where,

C_p	The pitot tube coefficient (take manufacturer's value or assume 0.85)
ΔP_v	The velocity pressure measured using pitot tube and inclined manometer at each point (traverse point) over the entire cross-section of the duct, mm water column
γ	Gas density at flow conditions, kg/m^3, corrected to normal temperature

Calculation of Density:

$$Density\ (\gamma), kg/m^3 = \frac{P \times M}{R \times T}$$

Where,

P – Absolute gas pressure, mmWC
M – Molecular weight of the gas, kg/kg mole (in the case of air M = 28.92 kg/kg mole)
R – Gas constant, 847.84 mmWC m^3/kg mole K
T – Gas temperature, K

Calculation of Velocity and Flow rate:

Average velocity = $\frac{V_1 + V_2 + \ldots V_N}{\text{Total number of traverse points (N)}}$

Where V_N is the velocity at the N^{th} traverse point

Once the cross-sectional area of the duct is measured, the flow can be calculated as follows:

Airflow (Q), m^3/s = Average velocity, V (m/s) x Fan duct area (m^2)

Anemometer: The indicated velocity shall be measured at each traverse point in the cross section by holding the anemometer stationary at each point for a period of time of not less than 1 minute. Each reading shall be converted to velocity in m/s and individually corrected in accordance with the anemometer calibration. The arithmetic mean of the corrected point velocities gives the average velocity in the air duct and the volume flow rate is obtained by multiplying the area of the air duct by the average velocity.

Measurement of Static Pressure

The static pressure is measured at the inlet and outlet sides of the fan are taken relative to the atmosphere pressure. This shall be done by using a U tube manometer or micro manometer in conjunction with the static pressure connection of a pitot tube.

Determination of Power Input

Power Measurement: The power measurements can be best done using a suitable clamp- on power meter.

Alternatively, if power meter is not available, by measuring the amps, voltage and assuming a power factor of 0.9 the power can be calculated as follows:

$$P = \sqrt{3}\ \text{x V x I x}\ \cos\Phi$$

Transmission system between motor and fan involves losses. The following values shall be used as a basis for transmission efficiency:

Properly lubricated precision spur gears 98% for each step Flat belt drive 97%
V-belt drive 95%

If fan is driven by non-electric prime mover other than motor, fuel consumption (oil, steam, compressed air etc.) should be specified and used in place of the motor power input.

$$\text{Fan shaft power} = \text{Power input to the motor x } \eta \text{ of motor at the corresponding loading x } \eta \text{ of transmission system}$$

$$\text{Fan static efficiency} = \frac{\text{Volume in } \frac{m^3}{s} \text{ x Static pressure ascross the fan in mmWC}}{102 \text{ x fan shaft power}}$$

Example 3.2

An energy audit of a fan was carried out. It was observed that the fan was delivering 18,500 Nm^3/hr of air with static pressure rise of 45 mm WC. The power measurement of the motor coupled with the fan recorded 8.7 kW. The motor operating efficiency was taken as 88%from the motor performance curves. Assess the fan static efficiency.

Q	= 18,500 Nm^3/hr
	= 5.13888 m^3/sec
Static pressure rise across the fan, ΔP_{st}	= 45 mmWC
Power input to motor	= 8.7 kW
	=8.7 kW
Power input to fan shaft	=8.7 x0.88=7.656 kW
Fan static	= Volume in m^3/sec x ΔP_{st} in mmWc
	102 x Power input to shaft
	= 5.13888 x 45
	102 x 7.656
	= 0.296
	= 29.6%

3.4 Factors that Could Affect Fan System Performance

- Leakage, re-circulation or other defects in the system
- Excessive loss in a system component located too close to the fan outlet
- Disturbance of the fan performance due to a bender other system component located too close to the fan inlet

Example 3.3

A fan handles 50,000 m^3/hr of air at 90ºC at static pressure difference of 70 mm WC. If the fan static efficiency is 55%, find out the shaft power of the fan.

The plant proposes to cool the air from 90ºC to 45ºC before it enters the fan at an envisaged static pressure difference of 60mmWC. What will be the power consumption of the fan after cooling?

(a)

Q1	=	50,000 m^3/hr,
ΔP (static)	=	70 mmWC
Fan Static Efficiency	=	55%

Fan Power P_{f1}	=	?
Q1	=	50,000/3600

= 13.88 m^3/sec

Fan Static Efficiency = Volume in m^3 x ΔP (static) in mm WC

102 x Power input to shaft in kW

0.55 = $(13.88 \times 70) / 102 \times P_{f1}$

Shaft power drawn = 17.3 kW

(b)

Q1 = 50,000 m^3/hr,

$\Delta P_{2\ (static)}$ = 60 mmWC,

Fan Static Efficiency = 55%

Fan Power P_{f2} = ?

Q2 = 50,000 x {(45 +273) / (90 +273)}

= 43,802 m^3 / hr

= 43,802/3600 = 12.2 m^3/sec

Fan Static Efficiency = Volume in m3 x $\Delta P_{(static)}$ in mm WC

102 x Power input to shaft in kW

0.55 = $12.2 \times 60 / 102 \times P_{f2}$

Shaft power drawn = 13 kW

Example 3.4

A V-belt centrifugal fan is supplying air to a process plant. The performance test on the fan gave the following parameters.

Density of air at 0°C	1.293 kg/m^3
Ambient air temperature	40 °C
Diameter of the discharge air duct	0.8 m
Velocity pressure measured by Pitot tube in discharge duct	45 mmWC
Pitot tube coefficient	0.9
Static pressure at fan inlet	- 20 mmWC
Static pressure at fan outlet	185 mmWC
Power drawn by the motor coupled with the fan	75 kW
Belt transmission efficiency	97 %
Motor efficiency at the operating load	93 %

Find out the static fan efficiency.

Air temperature	40 °C
Diameter of the discharge air duct	0.8 m
Velocity pressure measured by Pitot tube	45 mmWC
Static pressure at fan inlet	- 20 mmWC
Static pressure at fan outlet	185 mmWC
Power drawn by the motor	75 kW
Transmission efficiency	97%
Motor efficiency	93 %
Area of the discharge duct	3.14 x 0.8 x 0.8 x 1/4

	$0.5024\ m^2$
Pitot tube coefficient	0.9
Corrected gas density	(273 x 1.293) / (273 + 40) = 1.1277
Volume	C_px A √ (2 x 9.81 x △ p x γ) γ
	0.9x0.5024x√(2 x 9.81 x 45 x 1.1277) 1.1277
	$12.65\ m^3/s$
Power input to the shaft	75 x 0.97 x 0.93
	67.65 kW
$\text{Static fan efficiency} = \dfrac{Volume\ in \frac{m^3}{s}\ x\ total\ static\ prssure\ rise\ in\ mmwc}{102\ x\ Power\ input\ to\ the\ fan\ shaft\ in\ kW}$	
Fan static Efficiency	12.65 x (185 – (–20) 102 x 67.65
	37.58 %

4. MOTORS AND VARIABLE SPEED DRIVES

4.1 Introduction

The two parameters of importance in a motor are efficiency and power factor. The efficiencies of induction motors remain almost constant between 50 to 100% loading (refer Figure 4.1). When a motor has a higher rating than that required by the equipment, motor operates at part load and the efficiency of the motor is reduced. Replacement of under loaded motors with smaller motors will allow a fully loaded smaller motor to operate at a higher efficiency. This arrangement is generally most economical for larger motors, and only when they are operating at less than one-third to one-half capacity.

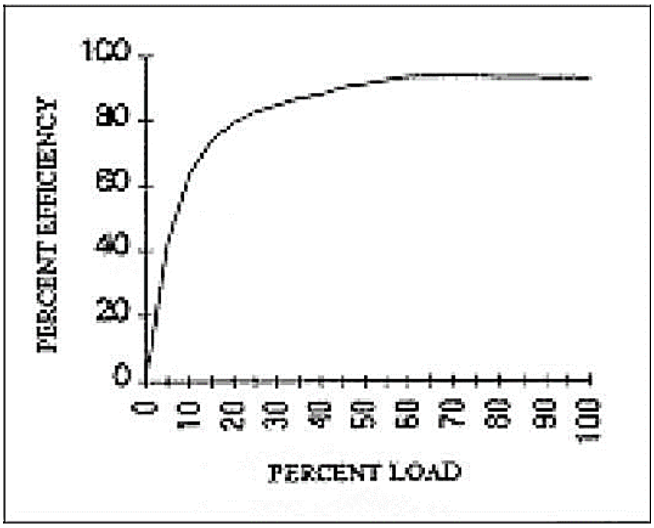


Figure 4.1

4.2 Terms and Definitions

Efficiency: The efficiency of the motor is given by

$$\eta = \frac{P_{out}}{P_{in}} = 1 - \frac{P_{Loss}}{P_{in}}$$

Where

P_{out} – Output power of the motor

P_{in} – Input power of the motor

P_{Loss} – Losses occurring in motor

Motor Loading: The motor loading, % is given by

$$\frac{\text{Actual operating load of the motor}}{\text{Rated capacity of the motor}} \text{ X } 100$$

4.2.1 Efficiency Testing

While input power measurements are fairly simple, measurement of output or losses need laborious exercise with extensive testing facilities. The following are the testing standards widely used.

Europe: IEC 60034-2, and the new IEC 61972
US: IEEE 112 - Method B
Japan: JEC 37

Even among these standards the difference in efficiency value is up to 3%.

For simplicity nameplate efficiency rating may be used for calculations if the motor load is in the range of 50 -100 %.

Field Tests for Determining Efficiency

No Load Test:

The motor is run at rated voltage and frequency without any shaft load. Input power, current frequency and voltage are noted. The no load power factor (PF) is quite low and hence low PF wattmeter's are required.

From the input power, stator I^2R losses under no load are subtracted to give the sum of friction, windage and core losses. To separate core and F & W losses, test is repeated at variable voltages and no-load input kW versus voltage is plotted, the intercept is Friction & windage (F&W) loss component.

F&W and core losses = No load power (watts) – (No load current)^2 x Stator resistance

Stator and Rotor I^2R Losses:

The stator winding resistance is directly measured by a bridge or volt amp method. The resistance must be corrected to the operating temperature. For modern motors, the operating temperature is likely to be in the range of 100^0C to 120^0C and necessary correction should be made. Correction to 75^0C may be inaccurate. The correction factor is given as follows:

$$\frac{R_2}{R_1} = \frac{235 + t_2}{235 + t_1}$$

Where, t_1 and t_2 are ambient and operating temperature in °C respectively.

The rotor resistance can be determined from locked rotor test at reduced frequency, but rotor I^2R losses are measured from measurement of rotor slip.
Rotor I^2R losses = Slip × (Stator Input – Stator I^2R Losses – Core Loss)
Accurate measurement of slip is possible by stroboscope or non-contact type tachometer. Slip also must be corrected to operating temperature.

Stray Load Losses:

These losses are difficult to measure with any accuracy. IEEE Standard 112 gives a complicated method, which is rarely used on shop floor. IS and IEC standards take a fixed value as 0.5% of output. It must be remarked that actual value of stray losses is likely to be more. IEEE – 112 specifies values from 0.9 % to 1.8%.

Table 4.2

Motor Rating	Stray Losses
1 – 125 HP	1.8 %
125 – 500 HP	1.5 %
501 – 2499 HP	1.2 %
2500 and above	0.9 %

Guidance for Users:

It must be clear that accurate determination of efficiency is very difficult. The same motor tested by different methods and by same methods by different manufacturers can give a difference of 2 %. In view of this, for selecting high efficiency motors, the following can be done:

- When purchasing large number of small motors or a large motor, ask for a detailed test certificate. If possible, try to remain present during the tests. This will entail extra costs.
- See that efficiency values are specified without any tolerance
- Check the actual input current and kW, if replacement is done
- For new motors, keep a record of no load input and current
- Use values of efficiency for comparison and for confirming, rely on measured inputs for all calculations.

Estimation of efficiency in the field can be done as follows:

- Measure stator resistance and correct to operating temperature. From rated current value, I^2R losses are calculated.
- From rated speed and output, rotor I^2R losses are calculated
- From no load test, core and F & W losses are determined for stray loss

The method is illustrated by the following example:

Example 4.1

Motor Specifications		
Rated power	=	34 kW/45 HP
Voltage	=	415 Volt

Current	=	57 Amps
Speed	=	1475 rpm
Insulation class	=	F
Frame	=	LD 200 L
Connection	=	Delta
No load test Data		

Voltage, V	=	415 Volts
Current, I	=	16.1 Amps
Frequency, F	=	50 Hz
Stator phase resistance at 30^0C	=	0.264 Ohms
No load power, P_{nl}	=	1063.74 Watts

Calculate iron plus friction and wind age losses

Calculate stator resistance at120^0C

$$\frac{R_2}{R_1} = \frac{235 + t_2}{235 + t_1}$$

Calculate stator copper losses at operating temperature of resistance at 120^0C
Calculate full load slip(s) and rotor input assuming rotor losses are slip times rotor input.
Determine the motor input assuming that stray losses are 0.5 % of the motor rated power
Calculate motor full load efficiency and full load power factor

Solution

Iron plus friction and windage loss, $P_i = f_w$

P_{nl} = 1063.74Watts
Stator Copper loss, Pst-30^0C = 3 x $(16.2/\sqrt{3})^2 \times 0.264$ = 68.43 Watts
P_i+f_w =P_{nl} –P_{st} –Cu =1063.74 – 68.43 = 995.3 Watts

Stator Resistance at120^0C,

R120^0C = 0.264 × (120 + 235/ 30+235) = 0.354 ohms

Stator copper losses at full load,

P_{st} - Cu-120^0C =3×(57/√3)2 ×0.354 = 1150.1 Watts

Full load slip

$S = (1500 – 1475) / 1500 \quad = 0.0167$
Rotor input, $P_r = P_{output}/(1\text{-}S) = 34000 / (1\text{-} 0.0167) = 34577.4$ Watts

Motor full load input power, P_{input}

$= P_r + P_{st} – Cu – 120^0C + Pi + f_w + P_{stray} = 34577.4 + 1150.1 + 995.3 + (0.005 \times 34000)$

= 36892.8 Watts

Motor efficiency at full load

$$\text{Efficiency} = \frac{P_{output}}{P_{input}} \times 100$$

$$= \frac{34000}{36892.8} \times 100$$

$$= 92.2\ \%$$

$$\text{Full Load PF} = \frac{P_{input}}{\sqrt{3} \times V \times I_r}$$

$$= \frac{36892.8}{\sqrt{3} \times 415 \times 57}$$

$$= 0.90$$

Comments:

a) The measurement of stray load losses is very difficult and not practical even on test beds.
b) The actual value of stray loss of motors up to 200 HP is likely to be 1 % to 3 % compared to 0.5 % assumed by standards.
c) The value of full load slip taken from the nameplate data is not accurate. Actual measurement under full load conditions will give better results.
d) The friction and windage losses really are part of the shaft output; however, in the above calculation, it is not added to the rated shaft output, before calculating the rotor input power. The error however is minor.
e) When a motor is rewound, there is a fair chance that the resistance per phase would increase due to winding material quality and the losses would be higher. It would be interesting to assess the effect of a nominal 10 % increase in resistance per phase.

4.3 Determining Motor Loading

4.3.1 Input Power Measurements

- First measure input power P_i with a hand held or in-line power meter Pi = Three-phase power in kW
- Note the rated kW and efficiency from the motor name plate
- The figures of kW mentioned in the name plate are for output conditions. So corresponding input power at full-rated load

$$P_{ir} = \frac{\text{Name plate full rated kW}}{\eta_{fl}}$$

Where,
η_{fl}= Efficiency at full-rated load
P_{ir}= Input power at full-rated load in kW

- The percentage loading can now be calculated as follows

$$\%\ \boldsymbol{Loading} = \frac{\boldsymbol{P_i}}{\boldsymbol{P_{Ir}}} \boldsymbol{X\ 100\%}$$

Example 4.2

The name plate details of a motor are given as power = 15 kW, efficiency, η = 0.9. Using a power meter the actual three phase power drawn is found to be 8 kW. Find out the loading of the motor.

Input power at full-rated power in kW, P_{ir}	= 15 /0.9	= 16.7 kW
Percentage loading	= 8/16.7	= 48%

4.3.2 Line Current Measurements

The line current load estimation method is used when input power cannot be measured and only amperage measurements are possible. The amperage draw of a motor varies approximately linearly with respect to load, down to about 75% of full load. Below the 75% load point, power factor degrades and the amperage curve becomes increasingly non-linear.

In the low load region, current measurements are not a useful indicator of load. However, this method may be used only as a preliminary method just for the purpose of identification of oversized motors.

$$\%\ \text{Load} = \frac{\text{Input load current}}{\text{Input rated current}} \text{ x 100 (valid up to 75\% loading)}$$

4.3.3 Slip Method

In the absence of a power meter, the slip method can be used which requires a tachometer. This method also does not give the exact loading on the motors.

$$\text{Load} = \frac{\text{Slip}}{S_S - S_r} \text{ x } 100\%$$

Where:

Load = Output power as a % of rated power
Slip = Synchronous speed - Measured speed in rpm
Ss = Synchronous speed in rpm at the operating frequency
Sr = Nameplate full-load speed

Example 4.3 Slip Load Calculation

Given: Synchronous speed in rpm = 1500 at 50 HZ operating frequency.
(Synchronous speed = 120f/P) ; f: frequency, P: Number of poles
Nameplate full load speed = 1450
Measured speed in rpm = 1480
Nameplate rated power = 7.5 kW

Determine actual output power. $Load = \frac{1500-1480}{1500-1450} * 100\% = 40\%$

From the above equation, actual output power would be 40% *x 7.5* kW = 3 kW

Slip also varies inversely with respect to the motor terminal voltage squared. A voltage correction factor can, also, be inserted into the slip load equation. The voltage compensated load can be calculated as shown

$$\text{Load} = \frac{\text{Slip}}{(S_S - S_r) \text{ x } (V_r/V)^2} \text{ x } 100\%$$

Where:

Load = Output power as a % of rated power
Slip = Synchronous speed - Measured speed in rpm
S_s = Synchronous speed in rpm
S_r = Nameplate full-load speed
V = RMS voltage, mean line to line of 3 phases
V_r= Nameplate rated voltage

4.4 Performance Evaluation of Rewound Motors

Ideally, a comparison should be made of the efficiency before and after a rewinding. A relatively simple procedure for evaluating rewind quality is to keep a log of no-load input current for each motor in the population. This figure increases with poor quality rewinds. A review of the rewind shop's procedure should also provide some indication of the quality of work. When rewinding a motor, if smaller diameter wire is used, the resistance and theI^2R losses will increase.

The motor loading survey can be performed using the format given below:

Table 4.3: Motor Field Measurement Format

Company ____________________

Date ________

General Data

Driven Equipment ____________

Motor Name Plate Data

Manufacturer ____________________

Model ____________________

Serial Number ____________________

Type :Squirrel cage/Slip ring ____________

Size (hp/kW) ____________________

Synchronous Speed (RPM) ____________

Full-Load Speed (RPM) ____________

Voltage Rating ____________________

Full-Load Amperage ____________

Full-Load Power Factor (%) ____________

Full-Load Efficiency (%) ____________

Temperature Rise ____________________

Insulation Class ____________________

From Test Certificate

Load	100%	75%	25%	No Load
Current				
PF				
Efficiency				

Stator resistance per phase =

Rewound ☐ Yes ,if yes How many times rewound ?--

☐ No

Motor Loading % ____________

Location ____________________

Process ____________________

Department ____________________

Motor Operating Profile:

No of hours of operation

I Shift ________

II Shift ________

III Shift ________

Annual Operating Time _____ hours/year

Type of load

1.Load is quite steady, motor "On" during shift ☐

2.Load starts, stops, but is constant when "On" ☐

3.Load starts, stops, and fluctuates when "On" ☐

Measured Data

Supply Voltage

By Voltmeter

V_{RY} ______

V_{YB} ______ V avg _____

V_{BR} ______

Input Amps

By Ammeter

A a ______

A b ______ A avg _____

A c ______

Power Factor (PF) ____________

Input Power (kW) ____________

Motor Operating Speed ________ RPM

At frequency of ______

Driven Equipment Operating Speed

________ RPM

Type of Transmission (Direct/Gear/Fluid coupling)

The monitoring format for rewound motor is given below:

Table 4.4: Monitoring format for rewound motor

Section	Equipment Code	Motor Code	Motor Type		No Load Current				Starter Resistance/phase		No load loss	
			Sq.Cage	Slip Ring	New Motor		After Rewinding		New	Rewound	New	Rewound
					A	V	A	V			Watts	Watts

4.5 Application of Variable Speed Drives (VSD)

Although there are many methods of varying the speeds of the driven equipment such as hydraulic coupling, gearbox, variable pulley etc., the most possible method is varying the motor speed by varying the frequency and voltage by using a variable frequency drive.

RPM = (f x 120) / p

Where f is the frequency in Hz, and p is the number of poles in any multiple of 2.

Therefore, if the frequency applied to the motor is changed, the motor speed changes in direct proportion to the frequency change. The control of frequency applied to the motor is the job given to the VSD.

The VSD's basic principle of operation is to convert the electrical system frequency and voltage to the frequency and voltage required to drive a motor at a speed other than its rated speed. The two most basic functions of a VSD are to provide power conversion from one frequency to another, and to enable control of the output frequency.

VFD Power Conversion

As illustrated by Figure 4.3, there are two basic components, a rectifier and an inverter for power conversion. The rectifier receives the 50-HzAC voltage and converts it to direct current (DC) voltage. A DC bus inside the VSD functions as a "parking lot "for the DC voltage. The DC bus energizes the inverter, which converts it back to AC voltage again. The inverter can be controlled to produce an output frequency of the proper value for the desired motor shaft speed.

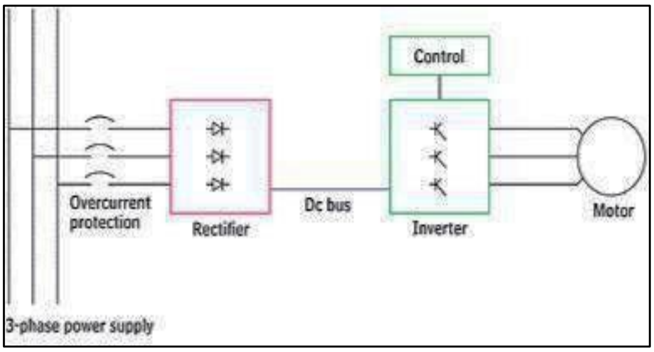


Figure 4.2: VFD Power Converter

4.5.1 Factors for Successful Implementation of Variable Speed Drives

Load Type for Variable Frequency Drives

The main consideration is whether the variable frequency drive application requires a variable torque or constant torque drive.

If the equipment being driven is centrifugal, such as a fan or pump, then a variable torque drive will be more appropriate. A fan needs less torque when running at 50% speed than it does when running at full speed. Variable torque operation allows the motor to apply only the torque needed, which results in significant reduction in energy consumption.

Conveyors, positive displacement pumps, punch presses, extruders, and other similar type applications require constant level of torque at all speeds. In which case, constant torque variable frequency drives would be more appropriate for the job. A constant torque drive should have an overload current capacity of 150% or more for one minute. Variable torque variable frequency drives need only an overload current capacity of 120% for one minute since centrifugal applications rarely exceed the rated current.

If tight process control is needed, then you may need to utilize a sensor less vector, or flux vector variable frequency drive, which allow a high level of accuracy in controlling speed, torque, and positioning.

Motor Information

The following motor information will be needed to select the proper variable frequency drive:

Full Load Amperage Rating: Using a motor's horse power is an inaccurate way to size variable frequency drive.

Speed Range: Generally, a motor should not be run at any speed less than 20% of its specified maximum speed allowed. If it is run at a speed less than this without auxiliary motor cooling, the motor will over heat. Auxiliary motor cooling should be used if the motor must be operated at very slow speeds.

Multiple Motors: To size a variable frequency drive that will control more than one motor, add together the full-load amp ratings of each of the motors. All motors controlled by a single drive must have an equal voltage rating.

Efficiency and Power Factor

The variable frequency drive should have an efficiency rating of 95% or better at full load. Variable frequency drives should also offer a true system power factor of 0.95 or better across the operational speed range, to save on demand charges, and to protect the equipment (especially motors).

Protection and Power Quality
Motor overload Protection for instantaneous trip and motor over current.

Additional Protection: Over and under voltage, over temperature, ground fault, and control or microprocessor fault. These protective circuits should provide an orderly shutdown of the VFD, provide indication of the fault condition, and require a manual reset (except under voltage) before restart. Under voltage from a power loss shall be set to automatically restart after return to normal. The history of the previous three faults shall remain in memory for future review.

If a built-up system is required, there should also be externally-operated short circuit protection, door-interlocked fused disconnect and circuit breaker or motor circuit protector (MCP)

To determine if the equipment under consideration is the right choice for a variable speed drive application:

The load patterns should be thoroughly studied before exercising the option of VSD. In effect the load should be of a varying nature to demand a VSD (refer Figures 4.3 and 4.4).

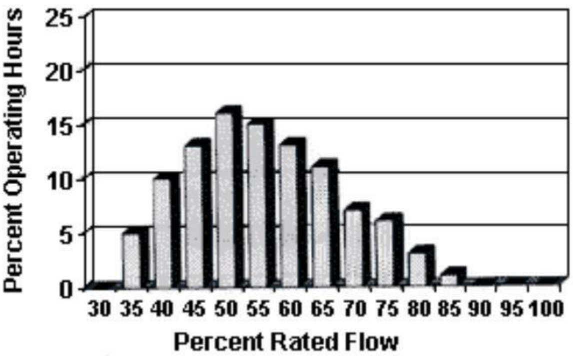


Figure 4.3: Load pattern

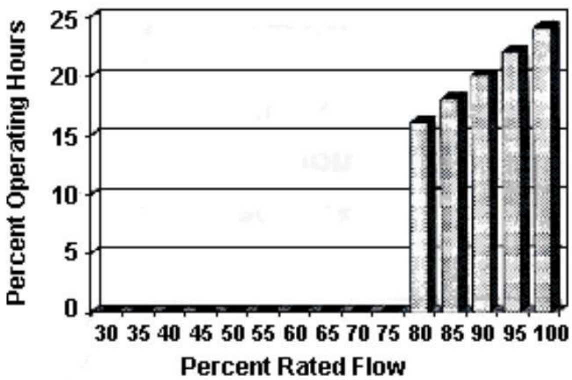


Figure 4.4: Load pattern

The first step is to identify the number of operating hours of the equipment at various load conditions. This can be done by using a Power analyzer with continuous data storage or by a simple energy meter with periodic reading being taken.

Example 4.4

Operating boiler load and associated induced draft fan-power consumption of a boiler is given as follows:

Boiler loading (%)	Damper position	Operating hours/day	Fan-motor power with damper operation (kW)
100	Full open	-	35
80	Position #1	4	31
70	Position #2	12	29
60	Position #3	8	26

Estimate the daily energy savings that can be achieved if the damper is replaced by a VFD for induced draft fan to meet the desired requirements. Assume that the air requirement is proportional to boiler loading.

Fan flow (proportional to boiler loading)	Operating hrs/day	Fan-motor power with damper (kW)	Fan-motor with VFD (kW)	Power savings (kW)	Energy savings (kWh)
A	B	C	$D = A^3 \times 35$	E=C–D	F=B x E
80	4	31	$0.8^3 \times 35 = 17.9$	13.1	52.32
70	12	29	$0.7^3 \times 35 = 12$	17	203.94
60	8	26	$0.6^3 \times 35 = 7.6$	18.4	147.52
Total daily energy savings					403.78

4.5.2 Information needed to Evaluate Energy Savings for Variable Speed Application

Method of flow control to which adjustable speed is compared:

- output throttling (pump) or dampers (fan)
- recirculation (pump) or unrestrained flow (fan)
- adjustable-speed coupling (eddy current coupling)
- inlet guide vanes or inlet dampers (fan only)
- two-speed motor.

Pump or fan data:

- head v's flow curve for every different type of liquid (pump) or gas (fan) that is handled
- Pump efficiency curves.

Process information:

- specific gravity (for pumps) or specific density of products (for fans)
- system resistance head/flow curve
- equipment duty cycle, i.e. flow levels and time duration.

Efficiency information on all relevant electrical system apparatus:

- motors, constant and variable speed
- variable speed drives
- gears
- transformers.

If we do not have precise information for all of the above, we can make reasonable assumptions for points 2 and 4.

Example 4.5

a) In a 75 kW four pole induction motor operating at 49.8 Hz and rated for 415 V and 1440 RPM, the actual measured speed is 1470 RPM. Find out the percentage loading of the motor if the voltage applied is 428 V.

b) A 6 pole, 415 volt, 3 ø, 50 Hz induction motor delivers 22 kW power at rotor shaft at a speed of 950 rpm with PF of 0.88. The total loss in the stator including core, copper and other losses is 2 kW. Calculate the following. i) Slip ii) Rotor Copper Loss iii) Total Input to motor iv) Line current at 415 V and motor pi of 0.88 v) Motor operating efficiency

Solution:

a)

$$\% \text{ Loading} = \frac{\text{Slip}}{(Ss - Sr) \times (Vr / V)^2} \times 100\%$$

Synchronous speed = 120 x 49.8 / 4 = 1494 rpm

Slip = Synchronous Speed – Measured speed in rpm.
= 1494 – 1470 = 24 rpm.

$$\% \text{ Loading} = \frac{24}{(1494 - 1440) \times (415/428)^2} \times 100\% = 47.27\%$$

b)

Synchronous Speed = (120 x 50 / 6) = 1000 rpm

Motor Speed = 950 rpm

(i) Slip = (1000 – 950) / 1000 = **5 %**

Power input to rotor = {(22 / (1 – 0.05)} = 23.16 kW

(ii) Rotor Copper Loss = (0.05 x 23.16) = 1.158 kW

Or = 23.16 - 22 = **1.16 kW**

(iii) Total Input to motor = (23.16 + 2) = **25.16 kW**

(iv) Line Current = (25.16 x 1000) /(√3 x 415 x0.88)

= **39.75 Amps**

Motor Efficiency = (22 / 25.16) = **87.44 %**

5. HVAC SYSTEM

5.1 Introduction

Air conditioning and refrigeration consume significant amount of energy in buildings and in process industries. The energy consumed in air conditioning and refrigeration systems depends on load changes, seasonal variations, operation and maintenance, ambient conditions etc. Hence the performance evaluation will have to take into account to the extent possible all these factors.

5.2 Purpose of performance test

The purpose of performance assessment is to verify the performance of a refrigeration system by using field measurements. The test will measure net cooling capacity (tons of refrigeration) and energy requirements, at the actual operating conditions. The objective of the test is to estimate the energy consumption at actual load as against design conditions.

5.3 Terms and Definitions

Refrigeration Capacity: Refrigeration Capacity is stated in terms of Tons of Refrigeration (TR). One TR is the amount of heat to be removed (3024 kcal/hr) from the atmosphere to melt one metric (short) ton of pure ice at 0 °C in 24 hours.

1 TR = 3024 kCal/h = 12000 Btu/h = 3.517 kW

Specific Power Consumption (kW/TR): It is the ratio of power input to compressor motor (kW) over tons of refrigeration (TR) produced. Lower kW/TR indicates higher efficiency.

Coefficient of Performance (COP): It is the ratio of refrigeration capacity (cooling capacity) and input power (kW) to chiller compressor. Higher COP indicates better performance.

Energy Efficiency Ratio (EER): Performance of smaller chillers and rooftop units is frequently stated as EER rather than kW/TR.EER is calculated by dividing the chiller cooling capacity (in Btu/h) by its power input (in watts) at full-load conditions. The higher the EER, the more efficient is the unit.

5.4 Preparation for Measurements

The reading should be taken after steady-state conditions are established. To minimize the effects of transient conditions, test readings should be taken simultaneously as possible. Minimum of three sets of data shall be taken, at a minimum of five-minute intervals.

5.5 Procedure

5.5.1 Performance evaluation of chilled water system

Net refrigeration capacity

The test shall include a measurement of the net heat removed from the water as it passes through the evaporator by measuring the following:

- Chilled water flow rates
- Temperature of chilled water entering the evaporator
- Temperature of chilled water leaving the evaporator
- Evaporator water pressure drop (across inlet and outlet)

All instruments, including gauges and thermometers shall be calibrated over the range of test readings for the measurement of following parameters.

Methods of measuring the chilled water flow rate

In the absence of an on-line flow meter, the chilled water flow can be measured by the following methods

- In case where hot well and cold well are available, the flow can be measured from the tank level fall (dip) or rise by switching off the secondary pump.
- Non-invasive method would require a well calibrated ultrasonic flow meter using which the flow can be measured without disturbing the system
- If the waterside pressure drop is close to the design values, it can be assumed that the water flow of pump is same as the design rated flow.

Net refrigeration capacity (Refrigeration capacity in tons of refrigeration, TR) is determined by calculating the product of the chilled water flow rate, the chilled water temperature difference across the evaporator, and the specific heat of the water.

$$\text{Net Refigeration Capacity, TR} = \frac{Q_{CH} \text{ x } d_W \text{ x } C_P \text{ x } (T_i - T_O)}{3024}$$

Where,

Q_{CH} - Flow rate of chilled water in m^3/hr
d_W - Density of water, kg/m^3
C_P - Specific heat of water in kcal/kg ^oC
T_I - Inlet (supply) temperature of chilled water to evaporator in ^oC
T_O - Outlet (return) temperature of chilled water from evaporator (chiller) in ^oC

The same equation can be used if any other liquid is used instead of chilled water, only density of the liquid should be known. The temperature measurement should be accurate and least count should be at least one decimal should be ensured.

Measurement of compressor power

The compressor input power can be measured by a portable power analyser which would give reading directly in kW.

Alternatively, the ampere can be measured by the available on-line ammeter or by using a tong tester. The power can then be calculated by assuming a power factor of 0.9.

Input power (kW) = $\sqrt{3}$ x V x I x CosΦ

To determine the heat rejected at the condenser

Heat rejected at condenser = Cooling load + Work done by compressor

$$\text{Heat Rejected (TR)} = (\text{Evaporator TR}) + \frac{\text{kW}}{3.516}$$

The shaft power kW absorbed (work done) by the compressor can be derived by measuring the motor input power multiplied by motor operating efficiency.

Heat rejected at the condenser can be measured as under:

Water cooled condenser:

a. Measure the water quantity flowing through the condenser using flow meter.
b. Measure the inlet and outlet temperature of water in the condenser using digital thermometer.

$$\text{Heat rejected (TR)} = \frac{\text{Mc x } C_p \times (t_{wo} - t_{wi})}{3024}$$

M_c - Mass flow rate of cooling water, kg/h
C_p - Specific heat of water, kcal/kg°C
t_{wi} - Cooling water temperature at condenser inlet, °C
t_{wo} - Cooling water temperature at condenser outlet, °C

Air cooled condenser:

a. Measure the air quantity flowing across condenser coil.
b. Measure the inlet and outlet temperatures of air using digital thermometer.

Since this process is normally a sensible heating, the capacity can be established by calculating only sensible heat gain.

$$\text{Heat rejected (TR)} = \frac{\text{Ma} \times C_{pa} \times (t_{ao} - t_{ai})}{3024}$$

Where,

Ma - Mass flow rate of air, kg/h
Cpa - Specific heat of air, kcal/kg°C
t_a i- Temperature of cooling air at condenser inlet °C tx,
t_{ao} - Temperature of cooling air at condenser outlet °C

Measurement of air flow

Air flow may be measured with any of the following instruments:

a) Vane Anemometer
b) Hot wire anemometer

The measuring instruments should be duly calibrated. The least count for anemometers should be 0.1 m/s. Air flow rate is calculated as the multiplication product of the average air velocity in the plane of measurement and the flow area.

Performance calculations

The energy efficiency of a chiller is expressed as following:

$$\text{Coefficient of Performance (COP)} = \frac{\text{Net Refrigeration Effect (TR)}}{\text{kW input}}$$

Another related and useful term used for benchmarking is Specific Power Consumption (kW/TR). Lower specific power consumption implies better efficiency.

$$\boldsymbol{Specific\ Power\ Consumption = \frac{Input\ Power\ to\ Compressor}{Refrigeration\ effect\ (TR)}}$$

The relation between specific power consumption and COP is as follows:

KW/TR = 3.516/COP

COP = 3.516/ (kW/TR)

Well designed, well maintained, vapour compression systems, using reciprocating, screw or scroll compressors, for chilled water at about 8°C have COP of 4 to 5.8, or Specific Power Consumption in the range of 0.61 to 0.87 kW/TR.

The COP of systems with air cooled condensers is generally about 20-40% higher. The COP of well-designed small machines like window air conditioners and split air conditioning units are around 2.5. The COP is poor due to the required compactness of the machine which limits heat transfer area and the limitation of air cooled condenser.

Chiller efficiency varies with loading; it is usually rated at full-load (100% of rated capacity) and part-load (90, 80, 70, and so on.). This information provided by chiller manufacturers is useful in selecting chiller for different applications.

Reciprocating chillers have a peak load power requirement of 1.0–1.3 kW/TR, depending on capacity and ambient air temperature.

Scroll compressors are replacement for reciprocating compressor in the range 1–50 TR.

Screw chillers have a peak load power requirement of 0.5–0.7 kW/TR.

Centrifugal chillers are generally used for cooling loads above 150 TR. These compressors are most efficient at full load, where they consume the least power (kW/TR). Typical COP is about 6 and specific power consumption is about 0.59 kW/TR.

At Air-Conditioning, Heating, and Refrigeration Institute (AHRI) standard rating condition centrifugal chiller's performance at full design capacity ranges from 0.53 kW/TR for capacity exceeding 300 tons and between 0.6–0.7 kW/TR for capacity up to 300 TR.

Evaluation of fans / blowers

The following readings can be taken for evaluation.
a) Air flow rate
b) Static pressure developed by the fan pitot tube and manometer can be used for measuring the differential head.
c) RPM of the fan using tachometer / stroboscope.
d) Current (amps), Voltage, power factor and power consumed (kW) by the fan motor using power analyzer.
The above readings establish the fan performance and can be compared with the design parameter.

Evaluation of primary and secondary water pumps

The following readings can be taken for evaluation.

a) Water flow rate
b) Head pressure developed. (measured with the help of suction and discharge pressure gauge)
c) RPM d) Current (amps), Voltage, Power drawn (kW) by the motor.

The above readings can be compared with the performance chart or design parameter.

Example 5.1

In a chemical plant, salt brine flowing at the rate of 20 m^3/hr is cooled down from 14 ^oC to 8^oC using chilled water. The chiller unit compressor motor draws 44.4 kW at a motor operating efficiency of 90%. The power drawn by the allied auxiliaries is 20 kW. The salt brine density is 1.2 kg/litre and specific heat capacity is 0.97 kcal/kg^oC

a) What is the refrigeration load (TR) imposed by the brine cooling?
b) What is the COP of refrigeration compressor?

c) What is the overall specific power consumption in kW/TR?

a) The refrigeration load in TR = Q. C_p. (T_i – T_o) /3024

Where,

Q	= mass flow rate of brine in kg/hr
C_p	= specific heat capacity of brine in kCal/ kg deg.C
T_i	= Inlet brine temperature
T_o	= Outlet brine temperature

Refrigeration load imposed by the brine TR:

TR = {20,000 x 1.2 x 0.97 (14-8)}/3024
= 46 TR

b) COP of refrigeration compressor = $\frac{3.516 \text{ x TR}}{\text{Power input to the compressor (kW)}}$

= 3.516 * 46 / (44.4 x 0.9)
= 4.04

5.5.2 Performance evaluation of air conditioning systems

For centralized air conditioning systems, the air flow at the air handling unit (AHU) can be measured with an anemometer. The dry bulb and wet bulb temperatures can be measured at the AHU inlet and outlet. The data can be used along with a psychrometric chart to determine the enthalpy (heat content of air at the AHU inlet, h_{IN} and AHU outlet, h_{OUT}).

The following equation can be used to determine chiller cooling capacity.

$$\boldsymbol{Cooling\ capacity\ (TR) = \frac{Q_A\ x\ d_A\ \ x\ (h_{IN} - h_{OUT})\ x\ 3.6}{3024}}$$

Where,

Q_A - Airflow (L/s) at evaporator (Fan Coil Units (FCU) or Air Handling Units (AHU))
d_A - Air density (kg/m^3)

Based on dry bulb and wet bulb temperatures and using psychrometric chart
h_{IN} – Enthalpy (kcal/kg) of air at AHU inlet
h_{OUT} – Enthalpy (kcal/kg) of air at AHU outlet

Example 5.2

In an air-handling unit (AHU), the filter area is 1.5 m^2 while air velocity is 2.2 m/s. The inlet air has an enthalpy of 77 kJ/kg. At the outlet of AHU, air has an enthalpy of 59 kJ/kg. The density of air of 1.3 kg/m^3. TR of the air-handling unit is assessed as follows:

TR of AHU = (Enthalpy difference x density x area x velocity x 3600) / (4.187 x 3024)

= (77-59) x 1.3 x 1.5 x 2.2 x 3600 / (4.187x 3024)
= 21.96 TR

Indicative TR profile (for Air conditioning)

- Small office cabins: 0.1 TR/m^2
- Medium size office (10–30 people occupancy) with central A/C: 0.06 TR/m^2
- Large multistoried office complexes with central A/C: 0.04 TR/m^2

Heat load can also be calculated theoretically by estimating the various heat loads, both sensible and latent, in the air – conditioned room (refer standard air conditioning hand books). The difference between these two indicates the losses by way of leakages, unwanted loads, heat ingress etc.

Example 5.3

The measured values of a 20 TR package air conditioning plant are as follows:

Average air velocity across suction side filter: 2.5 m/s
Cross Sectional area of suction: 1.2 m^2

Inlet air
Dry Bulb temperature :20^{o}C,
Wet Bulb temperature : 14^{o}C,
Enthalpy : 9.37 kcal/kg

Outlet air
Dry Bulb temperature : 12.7^{o}C,
Wet Bulb temperature : 11.3 ^{o}C;
Enthalpy : 7.45 kcal/kg
Specific volume of air : 0.85 m^3/kg

Power Measurements
Compressor: 10.69 kW
Pump: 4.86 kW
Cooling tower fan: 0.87 kW

Air flow rate = 2.5 x 1.2 = 3 m^3/sec = 10800 m^3/hr
Cooling effect delivered = [(9.37-7.45) x10800]/ (0.85 x 3024) = 8.07 TR = 28.32 kW
Compressor kW/TR = 10.69/8.07 = 1.32
Overall kW/TR = (10.69+4.86+0.87)/8.07 = 2.04
Energy Efficiency Ratio (EER) in kW/kW = 28.32/10.69 = 2.65

Example 5.4

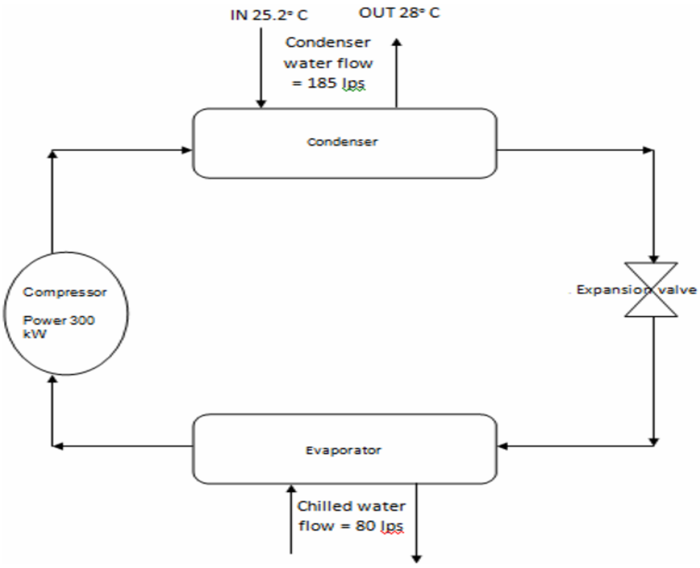


Figure 5.1: Parameters of a centrifugal chiller

Evaluate the CoP of centrifugal chiller.

Find the ratio of evaporator refrigeration load (TR) to condenser heat rejection load (TR)

Refrigeration load (TR) : $(m \times C_p \times \Delta T)/3024$

: 80 x 3600 x 1 x (13-8)/3024

: 476 TR

Coefficient of performance (COP) : Cooling effect (kW)

Power input to compressor (kW)

: (476TRx3024/860) / 300= 5.579

Evaporator cooling load (TR) : 476 TR

Condenser heat rejection load (TR) : 185 x 3600 x (28 – 25.2)/3024

: 616 TR

Ratio : $\frac{\text{Evaporator}}{\text{Condenser}} = \frac{476}{616} = 0.77$

Example 5.5

Details of centrifugal chiller and vapour absorption chiller (VAM) are given in the following Table:

Sl. No.	Parameter	Centrifugal Chiller	VAM
1	Chilled water flow (m^3/h)	192	183

2	Condenser water flow (m^3/h)	245	360
3	Chiller inlet water temperature (^0C)	13	14.5
4	Condenser water inlet temperature (^0C)	28	32
5	Chiller outlet water temperature (^0C)	7.8	9.2
6	Condenser water outlet temperature (^0C)	36.2	40.7
7	Chilled water pump consumption (kW)	32	31
8	Condenser water pump consumption (kW)	38	52
9	Cooling tower fan consumption (kW)	9	22

If the compressor of centrifugal chiller consumes 205 kW, the steam consumption for VAM is 1620 kg/Hr. Calculate the following:

1. Refrigeration load delivered (TR) for both systems?
2. Condenser Heat load (TR) for both systems?
3. Compare auxiliary power consumption for both systems, give reason?

Solution:
Compression Chiller vs. VAM

Sl. No.	Parameter	Centrifugal Chiller	VAM
1	Refrigeration load delivered (TR) = Mass of Chilled water flow x Specific heat x Delta T of Chilled water = 192 m^3/hr * 1000kg/m^3 *1 kcal/kg ^0C * (Sl. No. 3. – Sl. No. 5) / 3024	330.16	320.73
2	Condenser heat load delivered (TR) = Mass of condenser water flow x Specific heat * Delta T of condenser water = Sl. No.2 m^3/hr * 1000kg/m^3*1 kcal/kg^0C * (Sl. No. 6 – Sl. No. 4) / 3024	664.35	1035.71
3	Auxiliary Power Consumption (kW) = (Sl. No. 7 + Sl. No. 8 + Sl. No. 9)	79	105
	The auxiliary power consumption in case of VAM system is higher because heat rejection in VAM condenser is comparatively higher than centrifugal chiller with approximate similar cooling load.		
4	Total Energy Consumption:	284 kW (Auxiliary Power of 79kW and Chiller consumption of 205	Auxiliary Power of 105 kW and Steam consumption of 1620 kg/hr

Example 5.6

The operating parameters of a Vapor Compression Refrigeration system are indicated below.

Parameter	Chiller side	Condenser side
Water Flow (m^3/hr)	89	87
Inlet Temperature (^oC)	10.1	32.3
Outlet Temperature (^oC)	6.8	36.6
Density (kg/m^3)	1000	990

Find the COP of the Refrigeration system ignoring heat losses.

Refrigeration Effect = 89 x 1000 x (10.1 – 6.8) = 293700 kcal/hr

Condenser load = 87 x 990 x (36.6 – 32.3) = 370359 kcal/hr

Compressor work = Condenser load – Refrigeration effect
= 370359 – 293700
= 76659 kCal/hr

COP. = Refrigeration Effect/ Compressor work
= 293700/76659
= 3.83

Example 5.7

A pharmaceutical unit had installed a centralized refrigeration system of 120 TR Capacity several years ago. The refrigeration system operates 24 hours a day, 200 days per annum and the average electricity cost is BDT. 4.5/ kWh. The following are the key operational parameters.

- Compressor operating current and power factor : 153 amps. 0.9 pf
- Condenser pump operating current and power factor: 43 amps, 0.88 pf
- Chiller pump operating current and power factor : 25 amps, 0.9 pf
- CT fan operating current and power factor : 20 amps. 0.65 pf
- ΔT across the chiller (evaporator) : 3.5^{O}C
- Chilled water flow : 23 Lit / Sec
- Total head developed by chiller pump : 35 mtrs.
- Condenser water flow : 41 Lit / Sec
- Total head developed by condenser pump : 30 mtrs.

PS: all the motors operate at 415 Volts and efficiency of 90%

Calculate:

- The power consumed by the compressor, condenser pump, chiller pump and CT fan.
- TR developed by the system
- Specific power consumption i.e. overall kW/TR and COP and Energy Efficiency ratio

(EER)

- Combined efficiency (motor and pump) of condenser and chiller pumps

The unit proposes to replace the existing condenser and chilled water pumps with efficient pumps having a combined efficiency of 65%. Also the unit goes in for condenser cleaning by which the power consumption of compressor has reduced by 10%.

Calculate:

- The envisaged power consumption of the compressor, condenser and chiller pump
- Hourly energy savings (compressor, condenser and chilled water pump)
- Annual energy and equivalent monetary savings (compressor, condenser and chilled water pump)
- Specific power consumption i.e. overall kW/ TR and COP and Energy Efficiency ratio (EER)

Solution

Present Condition:

Compressor Motor Power	:	99 kW
Condenser Pump Motor Power	:	27.2 kW
Chiller Pump Motor Power	:	16.2 kW
CT Fan	:	9.4 kW
Total Power	:	151.8 kW
TR Devp	:	(23 * 3600 * 3.5 / 3024) = 95.83
Sp. Power	:	1.58 kW/ TR
Compressor kW/TR	:	99/95.83
	:	1.03 kW/tR
COP	:	3.516/kW/TR = 3.41
EER	:	12/kW/TR
: 11.65		
Condenser pump efficiency	:	44.4%
Chiller pump efficiency	:	48.8%

Proposed condition:

Compressor Motor Power	:	89 kW
Condenser Pump Motor Power	:	18.6 KW
Chiller Pump Motor Power	:	12.2 kW
CT Fan	:	9.4 kW
Total Power	:	129.2 kW
TR Devp	:	95.83 TR i.e. (23 LPS * 3600 Sec * 3.5 / 3024)
Sp. Power	:	1.35 kW/ TR
Compressor kW/TR	:	89/95.83 = 0.93 kW/TR
COP	:	3.516 / 0.93 = 3.78
EER	:	12 / 0.93 = 12.90

	Compressor	Condenser Pump	Chiller Pump
Hourly energy savings – kWh	(99-89) = 10	(27.2-18.6) = 8.6	(16.2–12.2) = 4.0
Annual energy savings – kWh (4800 hrs)	48000	41280	19200

5.5.3 Procedure for Performance Evaluation of Vapour Absorption Refrigeration (VAR) System

It should be ensured that the evaporator, condenser and generator are nearly at same operating conditions throughout the duration of the test. The vapour absorption system auxiliaries include chiller water pumps, condenser water pumps, cooling tower fans and performance assessment of these auxiliaries can be carried out in the same manner as applicable to vapour compression refrigeration system auxiliaries.

5.5.4 Estimation of performance at evaporator side

The performance evaluation involves the measurement of following parameters.

Refrigeration effect (QC)

- Chilled water flow rate in the evaporator.
- Chilled water temperatures at the evaporator inlet and outlet.

Thermal power input (Qin)

- Steam mass flow rate in case of steam heated vapour absorption chilling package.
- Fuel flow rate in case of direct fuel fired vapour absorption package.

Measuring instruments:

- The measuring instruments should be duly calibrated.
- Direct reading thermometers can be used for measuring temperature. The least count for temperature indicating instruments should be 0. 1°C.
- The method mentioned in VCR system can be used for water flow rate measurement.
- For steam heated vapour absorption chilling package, the thermal power consumption may be measured with any of the following instruments:

  a) Calibrated in-line steam flow meter.
  b) Collection of condensate in calibrated volume (container) for a defined time period. The time period should be measured with a digital chronometer (stop-watch) with least count of 1/100 second. The condensate may be cooled to reduce the flash steam losses.

- For fuel fired vapour absorption systems, the thermal power may be measured with any of the following instruments:

a) Calibrated In—line fuel flow meter.
b) Fuel level difference (for liquid fiiels) for a defined time period in a calibrated day tank. The time period should be measured with a digital chronometer (stop-watch) with least count of l/100 second.

Performance calculations:

Coefficient of performance, COP at evaporator side

$$COP = \frac{Net\ refrigeration\ effect, Q_e}{Thermal\ power\ input, Q_{in}}$$

$$= \frac{M_e \times C_p \times (t_{in} - t_{out})}{3600 \times Q_{in}}$$

For Steam heated Vapour Absorption Chilling Packages,

$$Q_{in} = \frac{M_{st} \times (h_{st} - h_{cond})}{3600}$$

For Direct Fuel-Fired Vapour Absorption Chilling Packages,

$$Q_{in} = \frac{M_f \times GCV}{3600}$$

Where,

Q_{in}	=	Thermal energy input in kW
Q_e	=	Refrigeration effect in kW
M_e	=	Chilled water flow rate in the evaporator, kg/h
Cp	=	Specific heat ofwater, kJ/kg-K
t_{in}	=	Chilled water temperature at evaporator inlet, K
t_{out}	=	Chilled water temperature at evaporator outlet, K
M_{st}	=	Steam consumption rate, kg/hr
h_{st}	=	Enthalpy of steam at operating pressure, kJ/kg
hcond	=	Enthalpy of condensate, kJ/kg
Mf	=	Fuel consumption rate, kg/hr
GCV	=	Gross calorific value of fuel, kJ/kg

5.5.5 Estimation of performance at condenser side (water cooled condenser)

The performance evaluation involves the measurement of following parameters.

Heat rejected at the condenser (QC)

- Cooling water flow rate in the condenser.
- Cooling water temperatures at absorber inlet and the condenser outlet.

Thermal energy input (Qin)

- Steam mass flow rate in case of steam heated vapor absorption chilling package.
- Fuel flow rate in case of direct fuel fired vapor absorption package.

Determination of refrigeration effect and COP:

i. The refrigeration effect and COP can be determined from the overall heat balance of the condenser and VAR system.

ii. Heat rejected at the condenser (Q) is equal to refrigeration effect heat (QC) plus thermal energy input (absorbed) by the system (Qin)

Performance calculations:

a) COP at condenser side for steam heated vapour absorption package

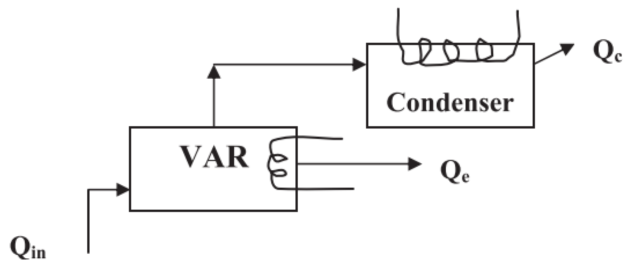


Figure 5.2

At condenser,

Refrigeration effect heat = Heat rejected in the condenser — Thermal energy input

$Q_e = Q_c — Q_{in}$

$$COP = \frac{\text{Net refrigeration effect, } Q_e}{\text{Thermal energy input, } Q_{in}}$$

$$COP = \frac{Q_c - Q_{in}}{Q_{in}} = \frac{Q_c}{Q_{in}} - \frac{Q_{in}}{Q_{in}} = \frac{Q_c}{Q_{in}} - 1$$

Therefore,

$$COP = \frac{\text{Heat rejected at condenser, } Q_c}{\text{Thermal energy input, } Q_{in}} - 1$$

$$= \frac{Mc \times Cp \times (t_{wo} - t_{wi})}{3600 \times Q_{in}} - 1$$

$$Q_{in} = \frac{M_{st} \times (h_{st} - h_{cond})}{3600}$$

b) COP at condenser side for direct fuel fired vapour absorption packages

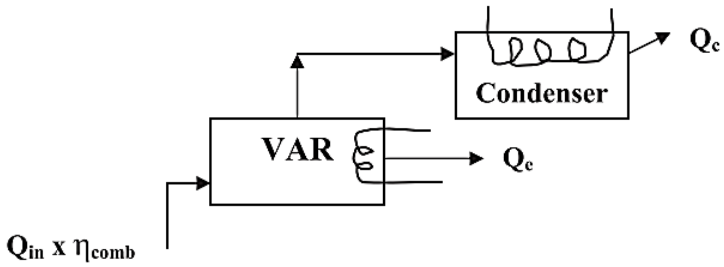


Figure 5.3

At condenser,
Refrigeration effect heat = Heat rejected in the condenser — Heat input

$$Q_e = Q_c - Q_{in}\ \eta_{comb}$$

$$COP = \frac{Q_e}{Q_{in}}$$

$$COP = \frac{Q_c - Q_{in} \times \eta_{comb}}{Q_{in}} = \frac{Q_c}{Q_{in}} - \frac{Q_{in} \times \eta_{comb}}{Q_{in}} = \frac{Q_c}{Q_{in}} - \eta_{comb}$$

Therefore,

$$COP = \frac{\text{Heat rejected at condenser, } Q_c}{\text{Thermal energy input, } Q_{in}} - (\eta_{comb})$$

$$= \frac{M_c \times C_p \times (t_{wo} - t_{wi})}{3600 \times Q_{in}} - (\eta_{comb})$$

$$Q_{in} = \frac{M_f \times GCV}{3600}$$

Where,

M_c = Cooling water flow rate in the condenser, kg/h
t_{wi} = Cooling water temperature at absorber inlet, K for VAR chiller
t_{Wo} = Cooling water temperature at condenser outlet, K

η_{comb}= Combustion efficiency

Combustion Efficiency Calculations:

The method described below can be used for estimating combustion efficiency of a direct fuel fired absorption chilling unit. The methodology is the "Indirect Method" to estimate combustion efficiency (η_{comb}), wherein the losses are estimated from flue gas analysis to estimate efficiency.

Observations:

Flue gas analysis:

a) Average % O2 (V/V)
b) Flue / stack gas temperature, Tf (°C)
c) Average ambient air temperature, Ta (°C)

Fuel analysis:

a) % Moisture (W/W), M
b) % Carbon (W/W), C
c) % Hydrogen (W/W), H_2
d) % Oxygen (w/W), O_2
e) % Nitrogen (w/w), N2
f) % Sulphur (W/W), S
g) Gross calorific valve, GCV (kcal/kg)

Calculations:

Theoretical air required for combustion	=	[(11.6 x C) + {34.8 x (H_2-O_2 /8)}+(4.35 x S)]/100 kg/kg of fuel. [from fuel analysis] Where C, H_2, O_2 and S are the percentage of carbon, hydrogen, oxygen and sulphur present in the fuel.
% Excess air supplied	=	$\frac{O_2\%}{21 - O_{2\%}} x100$ [from fuel analysis]
Actual mass of air supplied	=	{1 + EA/ 100} X Theoretical air

% Dry gas loss (D.G.L.):

D.G.L.	=	$\frac{mf\ x\ C_{pf}\ x(T_f - T_a)}{GCV\ of\ fuel}\ x\ 100$
Where,		
mf	=	Mass of dry flue gas in kg/kg of fuel
Total mass of dry flue gas /kg of fuel = Actual mass of air supplied/kg of fuel +1 kg of fuel — (9H2 + M)		
Cpf	=	Specific heat of flue gas in kcal/kg

e) % Wet gas loss (W.G.L.): = $\frac{(9\ x\ H_2 + M)\ x\ \{584 + 0.45\ (T_f\ \text{-}\ T_a\ )\}}{GCV\ of\ fuel}\ x\ 100$

Where, 584 = Latent heat corresponding to partial pressure of water vapor
0.45 = Specific heat of water vapor / superheated steam in kcal/kg°C

f) Total stack loss or flue gas loss (%) = D.G.L. + W.G.L.

g) Combustion efficiency by indirect method, ncomb = (100 - % Total flue gas losses) = Heat absorbed by the generator of VAR system.

Note: In this method only the major combustion losses namely, dry and wet flue gas losses are considered. All other losses are considered insignificant and hence ignored.

5.5.6 Performance assessment of Vapor Absorption Refrigeration (VAR) system:

Example 5.8

This is a sample calculation for a Vapor Absorption Chilling Package. Measurements are shown along with equations and estimation of results.

Equipment Specification for VAR system

Parameter	Unit	Quantity
Rated Generator temperature (in case of VAR chilling package)		165
Rated Capacity at Full Load	TR	1180
Fluid being cooled in the evaporator		Water
Rated Evaporator Fluid Flow Rate, Me	m3/h	713
Rated Evaporator inlet temperature, tin	◦C	12
Rated Evaporator outlet temperature, tout	◦C	7
Rated Condenser Water Flow Rate, Mc	m3/h	1427
Rated Condenser inlet temperature, twi	◦C	27
Rated Condenser outlet temperature, tWO	◦C	32

Method 1: Evaporator side

Estimation of performance from refrigeration effect in evaporator for steam heated vapor chilling packages (Chilling water)

Parameter	Unit	Value
Ambient dry bulb temperature	^{0}C	38
Ambient wet bulb temperature	^{0}C	25
Chilled water flow, Me	m 3/h	620
Chilled water density, p	kg/ m3	1000
Specific heat of chilled water, CD	kJ/kg/K	4_18
Chilled water temperature at evaporator inlet, tin	^{0}C	88
Chilled water temperature at evaporator outlet, tout	^{0}C	6.8
Cooling Water flow, Mc	m3/h	954
Cooling water inlet temperature, twi	^{0}C	26.6
Cooling water outlet temperature, tWO	^{0}C	299
Refrigeration Effect, Qe		$M_e \times \rho \times C_p (t_{in} - t_{out})$

	kJ/h	5 1 83200
Refrigeration Effect, R		Qe / (3.516 x 3600)
	TR	410
Generator temperature	^{0}C	120
Steam Pressure	kPa	300
Enthalpy of steam, hst	kJ/kg	2734
Steam consumption rate, Mst	kg/h	3443
Condensate temperature	^{0}C	100
Enthalpy of condensate, hcond	kJ/kg	418
Estimated Thermal energy Input, Qin	kJ/h	M_{st} X ($h_{st} - h_{cond}$)
	kJ/h	7974332
Coefficient of Performance, COP	kW/kW	QP/ Qin
		0.65
Specific Energy consumption, SEC	kJ/TR	M_{st}X (h_{st}-h_{cond})/R
	kJ/TR	3443 X (2734 — 418) / 410
	kJ/TR	19449
	kcal/TR	4645

Method 2: Condenser side

Estimation of performance from heat rejection in Water Cooled Condenser for steam heated vapor absorption chilling packages (Cooling water)

Parameter	Formula	Unit	Value
Heat Rejection, Qc	M_c x ρ x Cp x ($t_{wo} - t_{wi}$)	kJ/h	13159476
Refrigeration Effect, Qe	$Q_c - Q_{in}$	kJ/h	5185144
Refrigeration Effect, R	Q_e/ (3.516 x 3600)	TR	410
Coefficient of Performance, COP	Q_e / Q_{in}	kW/kW	0.65

Inference: The performance parameters estimated above show a deviation from the actual design values. This may due to operation of the chiller at less than 50% load.

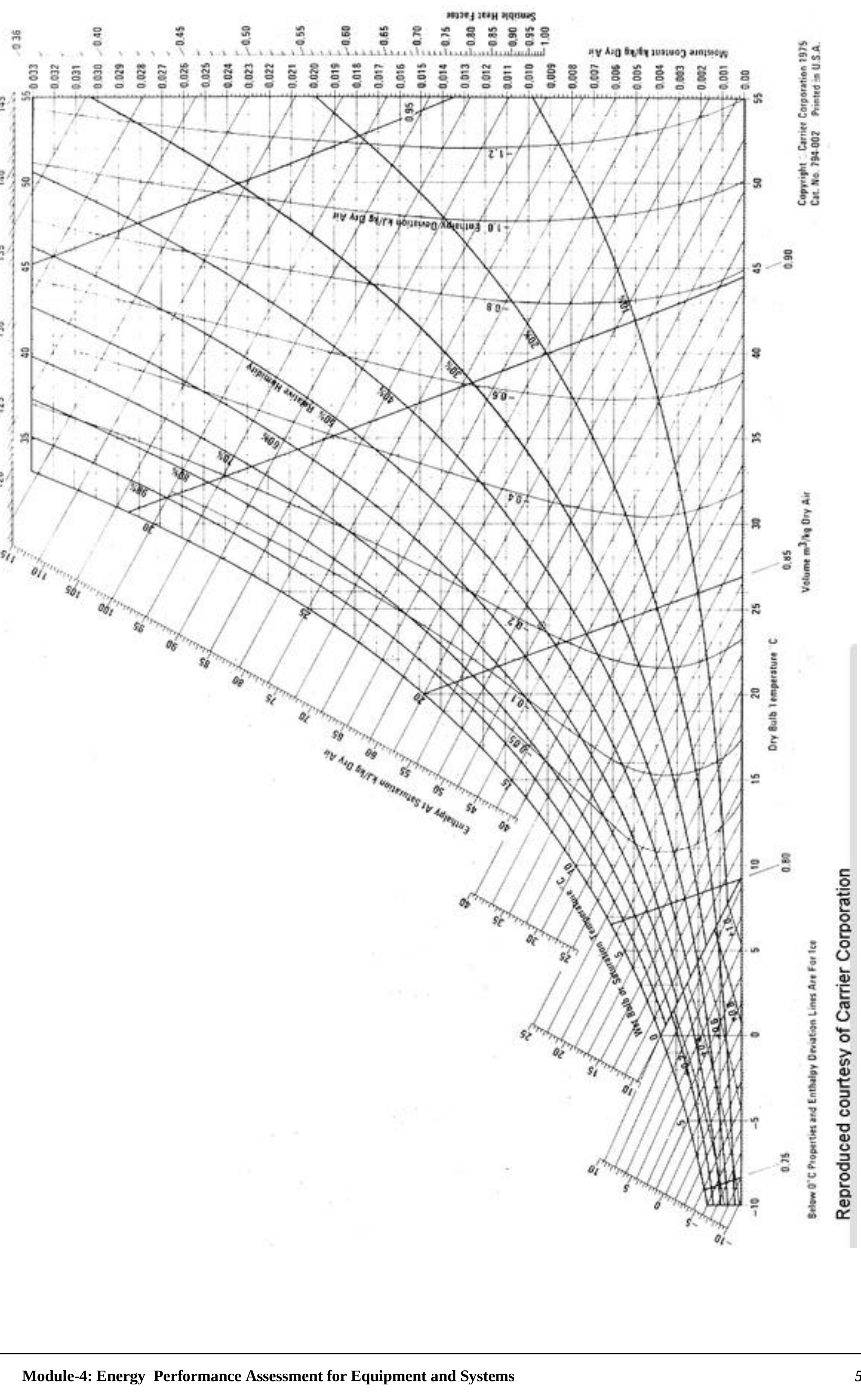


Figure 5.4: Psychrometric chart

Example 5.9

In an air conditioning system of a food processing industry, the cold air flow rate is 20,000 m3/hr at a density of 1.2 kg/m3 .The inlet and outlet enthalpy of the air are 105 kJ/kg and 80 kJ/kg. The COP of the existing vapor compression system is 3.75. The efficiency of the motor coupled with the compressor is 90%.

The management wants to install a Vapor Absorption System (VAR).The saturated steam for VAR will be supplied either from a new waste heat boiler to be installed with the existing DG sets or from the existing FO fuel fired boiler. The plant is operating for 8000 hr/annum. The investment of VAR system is BDT. 20 lakhs. The investment for waste heat boiler is BDT. 6 lakhs. The power cost is BDT. 6/kWh.

As an energy auditor which one of the following options will you recommend to the management?

Option-1: Supply steam from the existing FO fuel fired boiler to VAR system and avoid the investment of waste heat boiler

Option-2: Supply steam from the waste heat boiler, which needs an investment in addition to VAR system

The steam consumption per TR will be 5.5 kg/TR. The cost ofF0 is BDT. 32,000/ ton. The evaporation ratio of the existing FO fired boiler is 14. Neglect losses in transmission of steam and chilled water.

Solution:

Existing Base Case VCR System	
TR Rating	$= \dfrac{(20{,}000\ m^3/hr \times 1.2\ kg/m^3)\ (105-80)\ kJ/kg}{3024 \times 4.187}$
	= 47.38 TR
COP	= 3.75
COP	$= \dfrac{\text{Refrigeration effect, kcal/hr}}{\text{Power Input, kcal/hr}}$
Compressor power input	$= \dfrac{47.38 \times 3024\ kcal}{3.75 \times 860}$
	= 44.43 kW
Motor input power	= 44.43/0.9 = 49.37 kW
Annual Energy Consumption	= 49.37 x 8000 = 3.95 Lakhs kWh
Annual cost in VCR system (Base Case)	=3.95 X 6 = BDT. 23.7 Lakhs

Option — 1 : VAR System with Steam Supply from Existing Boiler	
Steam Consumption /TR	= 5.5 kg/TR
Steam Consumption per hr	= 5.5 x 47.38 = 261kg/hr
Evaporation Ratio IN THE EXISTING BOILER	= 14
1 ton of steam cost	= BDT 32000/14 = BDT 2.29/ kg of steam
Investment for VAR system	= BDT.20.00 Lakhs
Electricity cost saving per hr	= 49.37 X 6 =BDT. 296.22
Steam cost per hr	= 261 x 2.29 = BDT. 598
Since the steam cost per hour is higher than electricity cost this option is not feasible	
Option-2: With VAR & steam supply from WHR steam boiler of DG set	
Total Investment	= BDT. 20.00 + 6.00 = 26.00 Lakhs
Annual Savings	= BDT.23.7 lakhs
Simple Payback period	= 26/23.7 = 1.09 years.

Solution

Option 2 should be selected

6. BOILER PERFORMANCE ASSESSMENT

6.1 Introduction

The key performance parameters of boilers such as efficiency and evaporation ratio, reduces with time, due to poor combustion, heat transfer fouling and poor operation and maintenance. Deterioration of fuel quality and water quality also leads to poor performance of boiler. Periodic efficiency testing of boiler helps us to find out how far the boiler efficiency drifts away from the best efficiency. Any observed abnormal deviations could be investigated to identify problem areas for necessary corrective action. Assessing the current level of efficiency and performance of boiler is the first step for energy conservation activity.

6.2 Purpose of the Performance Test

- To find out the efficiency of the boiler
- To find out the Evaporation Ratio

The purpose of the performance test is to determine actual performance and efficiency of the boiler and compare it with design values or norms. The performance parameters can be used for tracking variations and initiating corrective actions.

The procedures for boiler efficiency testing for both oil-fired and gas-fired fired boilers are outlined.

6.3 Performance Terms and Definitions

6.3.1 Direct method of testing

This is also known as 'input-output method' due to the fact that it needs only the useful output (steam) and the heat input (i.e. fuel) for evaluating the efficiency. This efficiency can be evaluated using the formula:

$$B\text{oiler Efficiency}, \eta = \frac{\text{Heat output}}{\text{Heat input}} \text{ X } 100$$

$$\boldsymbol{Boiler\ Efficiency}, \eta = \frac{\boldsymbol{Heat\ in\ steam\ output\ (kCal)}}{\boldsymbol{Heat\ in\ fuel\ input\ (kCal)}}\ \boldsymbol{X\ 100}$$

$$\text{Evaporation ratio} = \frac{\text{Quantity of steam generation}}{\text{Quantity of fuel consumption}}$$

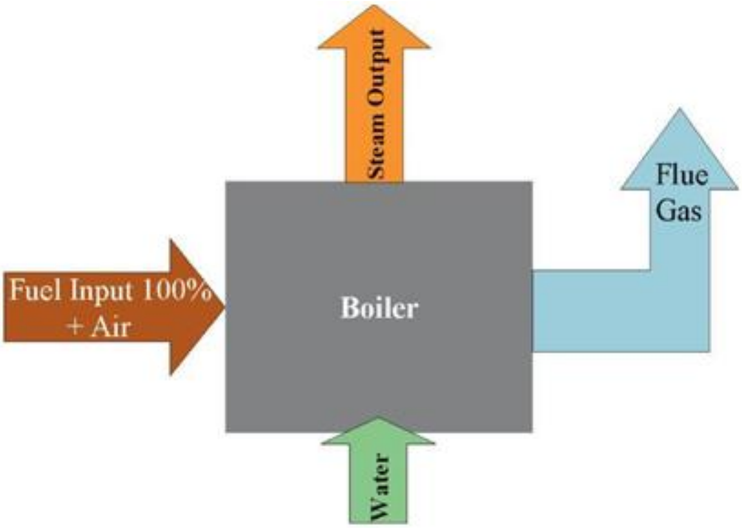


Figure 6.1

$$\boldsymbol{Boiler\ efficiency = \frac{Flow\ rate\ of\ steam\ x\ (Steam\ enthalpy - Feed\ water\ enthalpy}{Fuel\ firing\ rate\ x\ Calorific\ value}\ X\ 100}$$

6.3.2 Measurements Required for Direct Method Testing

Heat input

Both heat input and heat output must be measured. The measurement of heat input requires knowledge of the calorific value of the fuel and its flow rate in terms of mass or volume, according to the type of the fuel.

For gaseous fuel: A gas meter of the approved type can be used and the measured volume should be corrected for temperature and pressure. A sample of gas can be collected for calorific value determination, but it is acceptable to use declared calorific value of gas suppliers.

For liquid fuel: Heavy fuel oil is very viscous, and this property varies sharply with temperature. The meter, which is usually installed on the combustion appliance, should be regarded as a rough indicator only and, for test purposes, a meter calibrated for the particular oil is to be used. The best is the use of an accurately calibrated day tank.

Heat output

There are several methods, which can be used for measuring heat output. With steam boilers, an installed steam meter can be used to measure flow rate, but this must be corrected for temperature and pressure. Modern flow meters of the variable-orifice or vortex shedding types are recommended.

The alternative to measuring steam in small boilers is to measure feed water entering the boiler. This can be done by previously calibrating the feed tank and noting down the levels of water at the beginning and end of the trial. Care should be taken not to pump water during this period. Heat addition for conversion of feed water (at inlet temperature) to steam, is considered for heat output.

Intermittent blow down, if deployed in the boiler, should be avoided during the trial period. In case of boilers with continuous blow down, the heat loss due to blow down should be calculated and added to the heat in steam.

6.3.3 Boiler Efficiency by Direct Method: Calculation and Example

Test Data and Calculation

Water consumption and coal consumption are to be measured in a coal-fired boiler at hourly intervals. Weighed quantities of coal are fed to the boiler during the trial period. Simultaneously water level difference was noted to calculate steam generation during the trial period. Blow down was avoided during the test. The measured data and calculations are as follows:

Direct Method (sample calculations)

Type of boiler: Coal-fired boiler

Table 6.1

Heat input data	Heat output data
Quantity of coal fired: 1.6 TPH GCV of coal: 4000 kCal/kg	Quantity of steam generated: 8 TPH Steam pressure/ temperature: 10 kg/cm^2 (g)/180^{o}C Enthalpy of steam (dry and saturated) : 665 kCal/kg Feed water temperature: 85^{o}C Enthalpy of feed water: 85 kCal/kg
Boiler efficiency (η) = <u>Q x (H-h) x 100</u> (q x GCV) Where, Q = Quantity of steam generated per hour (kg/hr) Q = Quantity of fuel used per hour (kg/hr) GCV = Gross calorific value of fuel (kCal/kg) H = Enthalpy of steam (kCal/kg) H = Enthalpy of feed water (kCal/kg) Boiler efficiency (η) = 8 TPH x 1000 kg/T x (665-85) x 100 1.6 TPH x 1000 kg/T x 4000 kCal/kg = 72.5 % Evaporation Ratio = 8 tonne of steam/1.6 tonne of coal = 5	

Merits and Demerits of Direct Method

Merits

- Plant people can quickly evaluate the efficiency of boilers
- Only few parameters required for computation
- Only few instruments for monitoring

Demerits

- Does not give indicate why efficiency of boiler is lower
- Does not account various losses
- High (erroneous) Evaporation ratio and efficiency of steam is wet due to water carryover

Determination of Evaporation ratio

The simplest way to calculate fuel-to-steam efficiency is using steam generation and fuel consumption data from operating log book. Steam-Fuel consumption ratio, which is commonly called Evaporation Ratio, is given by the relation:

$$\text{Evaporation Ratio} = \frac{\text{Feed water consumption (kg/hr)}}{\text{Fuel consumption (kg/hr)}}$$

The two metering devices, fuel consumption meter and feed water flow meter, are needed for determining Evaporation Ratio. These two values should be recorded in the log sheet. For calculating steam rate, blow down rate is deducted. Typical Evaporation ratios of boilers for various fuels are as follows:

Table 6.2: Typical Evaporation Ratio

Type of fuel	Typical Evaporation Ratio
Fuel oil Solid fuel Gaseous fuel	~ 13–14 kg steam/kg fuel oil ~ 4–5 kg steam/kg solid fuel ~ 13 kg steam/Nm^3 gaseous fuel

If the Evaporation Ratio is lower than the typical value, it means boiler efficiency is deteriorating. Evaporation Ratio after commissioning or annual boiler overhaul can be considered as the benchmark value. For every one unit reduction in Evaporation Ratio, the boiler efficiency reduces by 1%.

6.3.4 The Indirect Method Testing

Description

All the losses occurring in the boiler are measured. The efficiency can then be arrived at, by subtracting the heat loss fractions from100. An important advantage of this method is that the errors in measurement do not make significant change in efficiency.

Most performance tests in industrial boilers are carried out using indirect method. The reference standards for Boiler Testing at a site for the indirect method are the British Standard, BS

845:1987 and the USA Standard ASME PTC-4-1 Power Test Code Steam Generating Units.

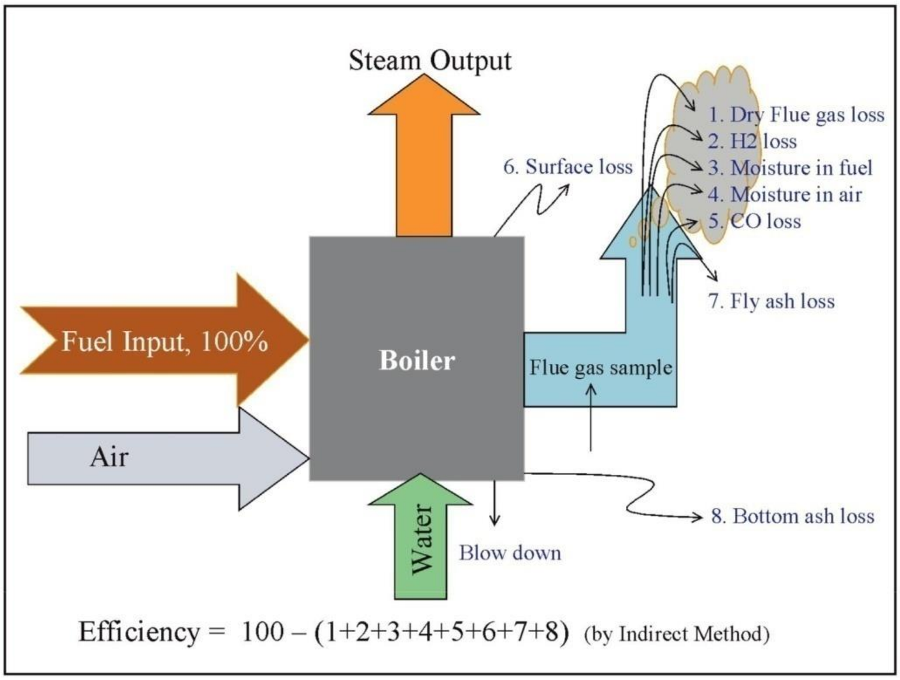


Figure 6.2

The following losses are applicable to liquid, gas and solid fired boiler

L1 – Loss due to dry flue gas (sensible heat)
L2 – Loss due to hydrogen in fuel (H_2)
L3 – Loss due to moisture in fuel (H_2O)
L4 – Loss due to moisture in air (H_2O)
L5 – Loss due to carbon monoxide (CO)
L6 – Loss due to surface radiation, convection and other unaccounted losses*
*Losses which are insignificant and are difficult to measure.

The following losses are applicable to solid fuel fired boiler in addition to above.

L7 - Unburnt losses in fly ash (carbon)
L8 - Unburnt losses in bottom ash (carbon)

Boiler Efficiency by indirect method = 100 – (L1 + L2 + L3 + L4 + L5 + L6 + L7 + L8)

Measurements Required for Performance Assessment Testing

The following parameters need to be measured, as applicable for the computation of boiler efficiency and performance:

a) Flue gas analysis
   Percentage of CO_2 or O_2 in flue gas
   Percentage of CO in flue gas
   Temperature of flue gas

b) Flow meter measurements for

Fuel
Steam
Feed water
Condensate water
Combustion air

c) Temperature measurements for
Flue gas

Steam
Makeup water
Condensate return
Combustion air
Fuel
Boiler feed water

d) Pressure measurements for

Steam
Fuel
Combustion air, both primary and secondary
Draft

e) Water condition

Total dissolved solids (TDS)
pH
Blow down rate and quantity

Table 6.3: Typical instruments used for boiler performance assessment

Instrument	Type	Measurements
Flue gas analyzer	Portable or fixed	% CO_2 , O_2 and CO
Temperature indicator	Thermocouple, liquid in glass	Fuel temperature, flue gas temperature, combustion air temperature, boiler surface temperature, steam temperature
Draft gauge	Manometer, differential pressure	Amount of draft used or available
TDS meter	Conductivity	Boiler water TDS, feed water TDS, make-up waterTDS.
Flow meter	As applicable	Steam flow, water flow, fuel flow, air flow

Test Conditions and Precautions for Indirect Method Testing

a) The efficiency test does not account for the following:

Standby losses. Efficiency test is to be carried out, when the boiler is operating under a steady load. Therefore, the efficiency test does not reveal standby losses, which occur between firing intervals.

Blow down loss. The amount of energy wasted by blow down varies over a wide range.

Soot blower steam. The amount of steam used by soot blowers is variable and depends on the type of fuel.

Auxiliary equipment energy consumption. The efficiency test does not account for the energy usage by auxiliary equipment, such as burners, fans, and pumps.

b) Preparations and pre conditions for testing:

- Burn the specified fuel at the required rate.
- Conduct the tests while the boiler under steady load conditions. Avoid testing during warming up of boilers from a cold condition
- Obtain the relevant charts /tables (e.g. Steam chart) for the additional data.
- Determine general method of operation, sampling and analysis of fuel and ash.
- Ensure accuracy of fuel and ash analysis in the laboratory.
- Check the type of blow down and method of measurement
- Ensure proper operation of all instruments.
- Inspect for any air infiltration in the combustion zone.

c) Flue gas sampling location

Flue gas sampling point for temperature and gas analysis is ideally carried out at zone of maximum gas flow which normally coincides with zone of maximum temperature.

d) Options of flue gas analysis

Check the Oxygen Test with the Carbon Dioxide Test

If continuous-reading oxygen meter or equipment is installed in boiler plant, use oxygen reading. Occasionally use portable test equipment that checks for both oxygen and carbon dioxide.

If the carbon dioxide test does not give the same results as the oxygen test, something is wrong. One (or both) of the tests could be wrong, perhaps because of stale chemicals or drifting instrument calibration. Another possible reason could be that outside air is being picked up along with the flue gas. This occurs if the combustion gas area operates under negative pressure and there are leakages in the boiler casing.

Carbon Monoxide Test

The carbon monoxide content of flue gas is a good indicator of incomplete combustion with all types of fuels, as long as they contain carbon. Normally, carbon monoxide in the flue gas is minimal with ordinary amounts of excess air in the flue gas, but sharply rises as soon as fuel combustion starts to become incomplete.

e) Planning for the testing:

- The testing is to be conducted for duration of 4 to 8 hours in a normal production day.
- Resources such as manpower, fuel, water and instrument check should be planned and the same has to be communicated to the boiler Supervisor and Production Department.
- Sufficient quantity of fuel stock and water storage required for the test duration should be arranged so that a test is not disrupted due to non-availability of fuel and water.
- Necessary sampling point and instruments are to be made available.
- Lab Analysis should be carried out for fuel, flue gas and water in coordination with lab personnel.
- The steam table, psychrometric chart, calculator are to be arranged for computation of boiler efficiency.

6.3.5 Boiler Efficiency by Indirect Method: Calculation Procedure and Formula

In order to calculate the boiler efficiency by indirect method, all the losses that occur in the boiler must be established. These losses are conveniently related to the amount of fuel burnt.

Theoretical (stoichiometric) air–fuel ratio and excess air supplied are to be determined first for computing the boiler losses. The formulae areas follows:

Table 6.4

Theoretical air required for combustion	=	{(11.6 x C) +{34.8 x (H_2–O_2/8)} + (4.35 x S)}/100 kg/kg of fuel (from fuel analysis) Where C, H_2, O_2 and S are the percentage of carbon, hydrogen, oxygen and sulphur present in the fuel
Excess air supplied (EA)	=	$\frac{O_2\,\%}{21-O_2\%}\ X\ 100$ { from flue gas analysis}
		O_2 measurement is recommended. If O_2 is not possible, CO_2 is used
		$\frac{7900 \text{ x } [(CO_2\%)_t - [(CO_2\%)_a]}{[(CO_2\%)_a \text{ x } [100 - [(CO_2\%)_t]}$ [from flue gas analysis]
Where, $CO2_t$		Theoretical $CO2_t$
$CO2_a$		Actual $CO2_a$ measured
$CO2_t$		$\frac{\text{Moles of C}}{\text{Moles of } N_2 + \text{Moles of C}}$
Moles of N_2		$\frac{\text{Weight of } N_2 \text{ in theoretical air}}{\text{Molecular weight of } N_2} + \frac{\text{Weight of } N_2 \text{ in fuel}}{\text{Molecular weight of } N_2}$
Moles of C		$\frac{\text{Weight of C in fuel}}{\text{Molecular weight of C}}$
Actual mass of air supplied		{1 + EA/100} x theoretical air

L1 Heat loss due to dry flue gas

The various losses associated with the operation of a boiler are discussed with required formula:

L1 Heat loss due to dry flue gas

$$L1 \quad = \quad \frac{\text{m X C}_\text{P}\text{ X (T}_\text{f} - \text{T}_\text{a}\text{)}}{\text{GCV of fuel}} \text{X 100}$$

L1 = % heat loss due to dry flue gas
m = Mass of dry flue gas in kg/kg of fuel
= Combustion products from fuel: CO_2 +SO_2 +Nitrogen in fuel+ Nitrogen in the Actual mass of air supplied + O_2 in flue gas
(H_2O/water vapour in the flue gas should not be considered on dry basis)
C_p = Specific heat of flue gas kCal/kg^{o}C
T_f = Flue gas temperature in ^{o}C
T_a = Ambient temperature in ^{o}C

Note 1: For Quick and simple calculation of boiler efficiency use the following.

A: Simple method can be used for determining the dry flue gas loss as follows:

$$\boldsymbol{Percentage\ of\ heat\ loss\ due\ to\ flue\ gas = \frac{m\ X\ C_P\ X\ (\ T_f - T_a\ )}{GCV\ of\ fuel} X\ 100}$$

Total mass of flue gas (m)/kg of fuel = mass of actual air supplied/kg of fuel + 1 kg of fuel

Note 2: Water vapour is produced from hydrogen in fuel, moisture present in fuel and atmospheric air during the combustion. The losses due to these components have not been included in the dry flue gas loss since each loss is separately calculated as part of wet flue gas loss.

L2 Heat loss due to evaporation of water formed due to H_2 in fuel(%)

The combustion of hydrogen causes a heat loss be cause the product of combustion is water and this water is converted to steam carrying away heat in the form of its latent heat.

$$L2 \quad = 9 \text{ x } H_2 \text{ x } \frac{\{584 + C_p(T_f - T_a)\}}{\text{GCV of fuel}} \text{x } 100$$

Where,

H_2 = kg of hydrogen present in fuel on 1 kg basis
C_p = Specific heat of superheated steam in kCal/kg ^{o}C
T_f = Flue gas temperature in ^{o}C
T_a = Ambient temperature in ^{o}C
584 = Latent heat corresponding to partial pressure of water vapour

L3 Heat loss due to moisture present infuel

Moisture entering the boiler with the fuel leaves as a superheated vapour. This moisture loss is made up of the sensible heat to bring the moisture to boiling point, the latent heat of evaporation of the moisture, and the superheat required to bring this evaporated moisture (steam) to the temperature of the exhaust gas. This loss can be calculated with the following formula:

$$L3 \quad = M \text{ x } \frac{\{584 + C_p(T_f - T_a)\}}{\text{GCV of fuel}} \text{x } 100$$

Where,

M = kg moisture in fuel on 1 kg basis

C_p = Specific heat of superheated steam in kCal/kg °C

T_f = Flue gas temperature in °C

T_a = Ambient temperature in °C

584 = Latent heat corresponding to partial pressure of water vapour

L4 Heat loss due to moisture present in air

Vapour in the form of humidity in the incoming combustion air is superheated as it passes through the boiler. Since this heat passes up the stack, it must be included as a boiler loss.

To relate this loss, the moisture content of the combustion air and the amount of air supplied per unit mass of fuel burned must be known. The mass of vapour that air contains can be obtained from psychrometric charts and typical values are as follows:

Table 6.5

Dry-Bulb Temperature	Wet Bulb Temperature	Relative Humidity	Kilogram waterper Kilogram dry air (Humidity Factor)
°C	°C	(%)	
20	20	10	0.016
20	14	50	0.008
30	22	50	0.014
40	30	50	0.024

$$L4 = \frac{\text{AAS x Humidity factor x } C_p \text{ x } (T_f - T_a) \text{ x } 100}{\text{GCV of fuel}}$$

Where,

AAS = Actual mass of air supplied

Humidity factor = kg of water per kg of dry air

Cp = Specific heat of superheated steam in kCal/kg °C

T_f = Flue gas temperature in °C

T_a = Ambient temperature in °C

L5 Heat loss due to incomplete combustion (CO):

Products formed by incomplete combustion could be mixed with oxygen and burned again with a further release of energy. Such products include CO, H_2, and various hydrocarbons and are generally found in the flue gas of the boilers. Carbon monoxide is the only gas whose concentration can be determined conveniently in a boiler plant test.

$$L5 = \frac{\%\text{CO x C}}{\%\text{ CO} + \%\text{CO}_2} \text{ x } \frac{5654}{\text{GCV of fuel}} \text{ x } 100$$

Where,

L5 = % heat loss due to partial conversion of C to CO
(1% = 10000 PPM)

CO = Volume of CO in flue gas leaving economizer (%)
CO_2 = Actual volume of CO_2 in flue gas (%)
C = Carbon content kg/kg of fuel
*5654 kCal/kg - Heat loss due to partial combustion of carbon

L6 Heat loss due to radiation and convection:

The other heat losses from a boiler consist of the loss of heat by radiation and convection from the boiler casing into the surrounding boiler house.

Normally surface loss and other unaccounted losses is assumed based on the type and size of the boiler as given below

For industrial fire tube / packaged boiler = 1.5 to 2.5%
For industrial water tube boiler = 2 to 3%
For power station boiler = 0.4 to 1%

It can be calculated if the surface area of boiler and its surface temperature are measured and using the following formula:

$$L6 = 0.548 \text{ x } [\left(\frac{T_s}{55.55}\right)^4 - \left(\frac{T_a}{55.55}\right)^4] + 1.957 \text{ x } (T_s - T_a)^{1.25} \text{ x sq. rt. of } [\frac{(196.85\ V_m + 68.9)}{68.9}]$$

Where,

L6 = Radiation loss in W/m^2
V_m = Wind velocity in m/s
T_s = Surface temperature (K)
T_a = Ambient temperature (K)

Heat loss due to unburned carbon in fly ash and bottom ash:

Small amounts of carbon will be left in the as hand this constitutes a loss of potential heat in the fuel. To assess these heat losses, samples of ash must be analyzed for carbon content. The quantity of ash produced per unit of fuel must also be known.

L7 Heat loss due to unburnt in fly ash (%)

$= \mathit{Total\ ash\ collected/kg\ of\ fuel\ burnt} \times \mathit{G.C.V\ of\ fly\ ash}$ ×100 GCV of fuel

L8 Heat loss due to unburnt in bottom ash (%)

$=\mathit{Total\ ash\ collected\ /kgoffuelburnt} \times \mathit{G.C.Vofbottomash}$×100 GCV of fuel

Heat Balance:

Having established the magnitude of all the losses mentioned above, a simple heat balance would give the efficiency of the boiler. The efficiency is the difference between the energy input to the boiler and the heat losses calculated.

Boiler Heat Balance:

Input/output parameter		kCal / kg of fuel	%
Heat Input in fuel	=		100
Various Heat losses in boiler			
1. Dry flue gas loss	=		
2. Loss due to hydrogen in fuel	=		
3. Loss due to moisture in fuel	=		
4. Loss due to moisture in air	=		
5. Partial combustion of C to CO	=		
6. Surface heat losses	=		
7. Loss due to Unburnt in fly ash	=		
8. Loss due to Unburnt in bottom ash	=		
Total Losses	=		
Boiler efficiency = 100 - (1+2+3+4+5+6+7+8)			

6.4 Efficiency for an oil fired boiler (Sample calculations)

Example 6.1

The following are the data collected for a boiler using furnace oil as the fuel. Find out the boiler efficiency by indirect method.

Ultimate analysis (%)		
Carbon	=	84
Hydrogen	=	12
Nitrogen	=	0.5
Oxygen	=	1.5
Sulphur	=	1.5
Moisture	=	0.5
GCV of fuel	=	10000 kCal/kg
Fuel firing rate	=	2648.125 kg/hr
Surface Temperature of boiler	=	80 °C
Surface area of boiler	=	90 m^2
Humidity	=	0.025 kg/kg of dry air
Wind speed	=	3.8 m/s
Flue gas analysis (%)		
Flue gas temperature	=	190°C
Ambient temperature	=	30°C
Co_2% in flue gas by volume	=	10.8
O_2% in flue gas by volume	=	7.4

a) Theoretical air required	=	$[(11.6 \times C) + [\{34.8 \times (H_2 - O_2/8)\} + (4.35 \times S)] /100$ kg/kg of fuel. [from fuel analysis]
	=	$[(11.6 \times 84) + [\{34.8 \times (12 - 1.5/8)\} + (4.35 \times 1.5)] / 100$
	=	**13.92 kg/kg of oil**
b) Excess Air supplied (EA)	=	$(O_2 \times 100) / (21 - O_2)$
	=	$(7.4 \times 100) / (21 - 7.4)$
	=	**54.4 %**
c) Actual mass of air supplied/ kg of fuel (AAS)	=	{1 + EA/100} x theoretical air
	=	{1 + 54.4/100} x 13.92
	=	21.49 kg / kg of fuel
Mass of dry flue gas	=	Mass of $(CO_2 + SO_2 + N_2 + O_2)$ in flue gas + N_2 in air we are supplying
	=	$\frac{0.84 \times 44}{12} + \frac{0.015 \times 64}{32} + 0.005 + \frac{7.4 \times 23}{100} + \frac{21.49 \times 77}{100}$
	=	**21.36 kg / kg of oil**

$$\% \text{ Heat loss in dry flue gas} = \frac{m \times C_p \times (T_f - T_a)}{\text{GCV of fuel}} \times 100$$

$$= \frac{21.36 \times 0.23 \times (190 - 30)}{10000} \times 100$$

$$L_1 = \mathbf{7.86\ \%}$$

$$\text{Heat loss due to evaporation of water due to } H_2 \text{ in fuel } (\%) = \frac{9 \times H_2 \times \{584 + C_p (T_f - T_a)\}}{\text{GCV of fuel}} \times 100$$

$$= \frac{9 \times 0.12 \times \{584 + 0.45\ (190 - 30)\}}{10000} \times 100$$

$$L_2 = \mathbf{7.08\ \%}$$

$$\% \text{ Heat loss due to moisture in fuel} = \frac{M \times \{584 + C_p (T_f - T_a)\}}{\text{GCV of fuel}} \text{ X } 100$$

$$= \frac{0.005 \times \{584 + 0.45\ (190 - 30)\}}{10000} \times 100$$

$$L_3 = \mathbf{0.033\%}$$

$$\% \text{ Heat loss due to moisture in air} = \frac{\text{AAS} \times \text{humidity} \times C_p \times (T_f - T_a) \times 100}{\text{GCV of fuel}}$$

$$= \frac{21.36 \times 0.025 \times 0.45 \times (190 - 30) \times 100}{10000}$$

$$L_4 = \mathbf{0.38\ \%}$$

Radiation and convection loss = (L_6)		$0.548 \times [(T_s / 55.55)^4 - (T_a / 55.55)^4] + 1.957 \times (T_s - T_a)^{1.25} \times \text{sq.rt of } [(196.85\ V_m + 68.9) / 68.9]$
	=	$0.548 \times [(353 / 55.55)^4 - (303 / 55.55)^4] + 1.957 \times (353 - 303)^{1.25} \times \text{sq.rt of } [(196.85 \times 3.8 + 68.9)/ 68.9]$
	=	1303 W/m^2
	=	1303 x 0.86
	=	1120.58 kCal / m^2
Total radiation and convection loss per hour	=	1120 .58 x 90 m^2 = 100852.2 kCal
% Radiation and convection loss	=	$\frac{100852.2 \times 100}{10000 \times 2648.125}$
L_6	=	**0.38 %** Normally it is assumed as 0.5 to 1 % for simplicity

Boiler efficiency by indirect method	=	$100 - (L_1 + L_2 + L_3 + L_4 + L_6)$
	=	100 – (7.86 + 7.08 + 0.033 + 0.38 + 0.38)
	=	100 – 15.73
	=	**84.27 %**

Summary of Heat Balance for the Boiler Using Furnace Oil

Input/Output Parameter		kCal / kg of furnace oil	%Loss
Heat Input	=	10000	100
Losses in boiler :			
1. Dry flue gas, L_1	=	786	7.86
2. Loss due to hydrogen in fuel, L_2	=	708	7.08
3. Loss due to Moisture in fuel, L_3	=	3.3	0.033
4. Loss due to Moisture in air, L_4	=	38	0.38
5. Partial combustion of C to CO, L_5	=	0	0
6. Surface heat losses, L_6	=	38	0.38
Boiler Efficiency = 100 - ($L_1 + L_2 + L_3 + L_4 + L_6$) = 84.27 %			

Note: For quick and simple calculation of boiler efficiency use the following.

Simple method can be used for determining the dry flue gas loss as follows:

$$\boldsymbol{Percentage\ of\ heat\ loss\ due\ to\ flue\ gas = \frac{m\ X\ C_P\ X\ (\ T_f - T_a\ )}{GCV\ of\ fuel} X\ 100}$$

Total mass of flue gas (m)/kg of fuel =

Mass of actual air supplied/kg of fuel + 1 kg of fuel– (9 H_2 + M) = 21.49 + 1 – 1.085=21.405
Dry flue gas loss in %= 21.405 x 0.23 x (190 – 30) x 100 /10000 = 7.86 %

Example 6.2 Efficiency for a cool fired boiler

The following are the data collected for a boiler using coal as the fuel. Find out the boiler efficiency by indirect method.

Fuel firing rate	=	5600 kg/hr
Steam generation rate	=	21940 kg/hr
Steam pressure	=	43 kg/cm^2 (g)
Steam temperature	=	377 ^oC
Feed water temperature	=	96 ^oC
%CO_2 in Flue gas	=	14
%CO in flue gas	=	0.55
Average flue gas temperature	=	190 ^oC
Ambient temperature	=	31 ^oC
Humidity in ambient air	=	0.0204 kg / kg dry air
Surface temperature of boiler	=	70 ^oC
Wind velocity around the boiler	=	3.5 m/s
Total surface area of boiler	=	90 m^2
GCV of Bottom ash	=	800 kcal/kg
GCV of fly ash	=	450 kcal/kg
Ratio of bottom ash to fly ash	=	90:10

Fuel Analysis (in %)		
Ash	=	48
Moisture	=	4.4
Carbon	=	36
Hydrogen	=	2.6
Nitrogen	=	1.1
Oxygen	=	7.3
Sulphur	=	0.6
GCV	=	3501 kcal/kg

Boiler efficiency by indirect method		
Step – 1 Find theoretical air requirement Theoretical air required for complete combustion	=	$[(11.6\,x\,C)+\{34.8\,x\,(H_2-O_2/8)\}+(4.35\,x\,S)]/100$ kg/kg of coal
	=	[(11.6 x36) + {34.8 x (2.6 – 7.3/8)} + (4.35 x 0.6)] / 100
	=	**4.79 kg / kg of coal**

Step – 2 Find theoretical CO_2 %

% CO_2 at theoretical condition $(CO_2)_t$ = $\dfrac{Moles\ of\ C}{Moles\ of\ N_2 + Moles\ of\ C + Moles\ of\ S}$

Where,
Moles of N_2 = $\dfrac{Wt\ of\ N_2\ in\ theoritical\ air}{Mol.wt\ of\ N_2} + \dfrac{Wt\ of\ N_2\ in\ fuel}{Mol.Wt\ of\ N_2}$

Moles of N_2 = $\dfrac{4.79\,x\,77/100}{28} + \dfrac{0.011}{28} = 0.1321$

Moles of C = 0.36/12 = 0.03

Moles of S = 0.006/32 = 0.0001875

$$(CO_2)_t = \frac{0.03}{0.03 + 0.1321 + 0.0001875}$$

$$(CO_2)_t = 18.48\ \%$$

Step – 3 To find Excess air supplied

Actual CO_2 measured in flue gas = 14.0%

% Excess air supplied (EA) = $\dfrac{7900\,x[(CO_2\%)_t - (CO_2\%)_a]}{(CO_2)_a\%\ x\ [100-(CO_2\%)_t]}$

$$= \frac{7900\,x[18.48-14]}{14\ x\ [100-18.48]}$$

= 31 %

Step – 4 To find actual mass of air supplied

Actual mass of air supplied = {1 + EA/100} x theoretical air

= {1 + 31/100} x 4.79

= **6.27 kg/kg of coal**

Step –5 To find actual mass of dry flue gas

Mass of dry flue gas = Mass of CO_2 in flue gas +Mass of N_2 content in the fuel+ Mass of N_2 in the combustion air supplied + Mass of oxygen in flue gas + Mass of SO_2 in flue gas

Mass of dry flue gas = $\dfrac{0.36\,x\,44}{12} + 0.011 + \dfrac{6.27\,x\,77}{100} + \dfrac{(6.27-4.79)\,x\,23}{100} + \dfrac{0.006\,x\,64}{32}$

= **6.51 kg / kg of coal**

Step – 6 To find all losses

1. % Heat loss in dry flue gas (L_1) $= \dfrac{m \, x \, C_p \, x (T_f - T_a)}{GCV \; of \; fuel} \, x \, 100$

$= \dfrac{6.51 \, x \, 0.24 \, x (190 - 31)}{3501} \, x \, 100$

L_1 = **7.1 %**

2. % Heat loss due to formation of water from H_2 in fuel (L_2) $= \dfrac{9 \text{ x } H_2 \text{ x } \{584 + C_p \, (T_f - T_a)\}}{\text{GCV of fuel}} \, x \, 100$

$= \dfrac{9 \text{ x } H_2 \text{ x } \{584 + C_p \, (T_f - T_a)\}}{\text{GCV of fuel}} \, x \, 100$

L_2 = **4.36 %**

3. % Heat loss due to moisture in fuel (L_3) $= \dfrac{\text{M x } \{584 + C_p \, (T_f - T_a)\}}{\text{GCV of fuel}} \, x \, 100$

$= \dfrac{0.044 \text{ x } \{584 + 0.43 \, (190-31)\}}{3501} \, x \, 100$

L_3 = **0.82 %**

4. % Heat loss due to moisture in air (L_4) $= \dfrac{AAS \, x \, humidity \, x \, C_p \, x (T_f - T_a)}{GCV \; of \; fuel} \, x \, 100$

$= \dfrac{6.27 \, x \, 0.0204 \, x \, 0.43 \, x (190 - 31)}{3501} \, x \, 100$

L_4 = **0.25 %**

5. % Heat loss due to partial conversion of C to CO (L_5) $= \dfrac{\%CO \; x \; C}{\%CO + \%CO_2} \; x \; \dfrac{5654}{GCV \; of \; fuel} \, x \, 100$

$= \dfrac{0.55 \; x \; 0.36}{0.55 + 14} \; x \; \dfrac{5654}{3501} \, x \, 100$

L_5 = **2.2 %**

6. Heat loss due to radiation and convection (L_6)	=	0.548 x [$(343/55.55)^4$ – $(304/55.55)^4$] + 1.957 x $(343 - 304)^{1.25}$ x sq.rt of [(196.85 x 3.5 + 68.9) / 68.9]
	=	937.62 w/m^2
	=	937.62 x 0.86
	=	806.35 kcal / m^2
Total radiation and convection loss per hour	=	806.35 x 90
	=	72571.6 kcal/hr
% radiation and convection loss	=	$\frac{72571.6 \times 100}{3501 \times 5600}$
L_6	=	**0.37 %**

7. % Heat loss due to unburnt in fly ash		
% Ash in coal	=	48
Ratio of bottom ash to fly ash	=	90:10
GCV of fly ash	=	450 kcal/kg
Amount of fly ash in 1 kg of coal	=	0.1 x 0.48
	=	0.048 kg
Heat loss in fly ash	=	0.048 x 450
	=	21.6 kcal / kg of coal
% heat loss in fly ash	=	21.6 x 100 / 3501
L_7	=	**0.62 %**

8. % Heat loss due to unburnt in bottom ash		
GCV of bottom ash	=	800 kcal/kg
Amount of bottom ash in 1 kg of coal	=	0.9 x 0.48
	=	0.432 kg
Heat loss in bottom ash	=	0.432 x 800
	=	345.6 kcal/kg of coal
% Heat loss in bottom ash	=	345.6 x 100 / 3501
L_8	=	**9.87 %**

Boiler efficiency by indirect method	=	100 – (L_1+ L_2+ L_3+ L_4+ L_5+ L_6+ L_7+ L_8)
	=	100-(7.1 + 4.36 + 0.82 + 0.25 + 2.2 + 0.37 + 0.62 + 9.87)
	=	100-25.59
	=	**74.41 %**

Summary of Heat Balance for Coal Fired Boiler

Input/Output Parameter		kcal / kg of coal	% loss
Heat Input		3501	100
Losses in boiler			
1. Dry flue gas	L_1	248.6	7.1
2. Loss due to hydrogen in fuel	L_2	152.6	4.36
3. Loss due to moisture in fuel	L_3	28.7	0.82
4. Loss due to moisture in air	L_4	8.7	0.25
5. Partial combustion of C to CO	L_5	77.0	2.2
6. Surface heat losses	L_6	13.0	0.37
7. Loss due to Unburnt in fly ash	L_7	21.7	0.62
8. Loss due to Unburnt in bottom ash	L_8	345.5	9.87
Boiler Efficiency = 100 – ($L_1 + L_2 + L_3 + L_4 + L_5 + L_6 + L_7 + L_8$) = 74.41 %			

6.5 Factors Affecting Boiler Performance

The various factors affecting the boiler performance are as follows:

- Periodical cleaning of boilers
- Periodical soot blowing
- Proper water treatment programme and blow down control
- Draft control
- Excess air control
- Percentage loading of boiler
- Steam generation pressure and temperature
- Boiler insulation
- Quality of fuel

All these factors individually/combined, contribute to the performance of the boiler and reflected either in boiler efficiency or evaporation ratio. Based on the results obtained from the testing, further improvements have to be carried out for maximizing the performance. The test can be repeated after modification or rectification of the problems and compared with standard norms. Energy auditor should carry out this test periodically once in six months and report to the management for necessary action.

6.6 Data Collection Format for Boiler Performance Assessment

Sheet 1: Technical specification of boiler
Boiler ID code and Make Year of Make Boiler capacity rating Type of Boiler Type of fuel used Maximum fuel flow rate Efficiency by GCV Steam generation pressure & super heat temperature Heat transfer area in m^2

Is there any waste heat recovery device installed Type of draft Chimney height in metre
Sheet 2: Fuel analysis details
Fuel fired GCV of fuel Specific gravity of fuel (Liquid) Bulk density of fuel (Solid)

Proximate analysis	Date of test	%
Fixed carbon Volatile matter Ash Moisture		
Ultimate analysis	Date of test	%
Carbon Hydrogen Sulphur Nitrogen Ash Moisture Oxygen		
Water analysis	Date of test	%
1 Feed water TDS 2 Blow down TDS 3 PH of feed water 4 PH of blow down		
Flue gas Analysis	Date of test	%
CO_2 O_2 CO Flue gas temperature		 °C

Sheet 3: Format sheet for boiler efficiency testing															
S. No.	Time	Ambient air		Fuel		Feed water		Steam			Flue gas analysis				Surface temperature of boiler, °C
		Dry bulb Temp. °C	Wet Bulb Temp, °C	Flow rate kg/hr	Temp, °C	Flow rate m^3/hr	Temp. °C	Flow rate m^3/hr	Temp. °C	Pressure kg/cm^2	O_2	CO_2	CO	Temp. °C	
1.															
2.															
3.															

6.6 Boiler Terminology

MCR: Steam boilers rated output is usually defined as MCR (Maximum Continuous Rating). This is the maximum evaporation rate that can be sustained for 24 hours and may be less than a shorter duration maximum rating.

a. Boiler Rating

Conventionally, boilers are specified by their capacity to hold water and the steam generation rate. Often, the capacity to generate steam is specified in terms of equivalent evaporation (kg of steam / hour at 100 ^{0}C). Equivalent evaporation- "from and at" 100 ^{0}C.Theequivalent of the evaporation of 1 kg of water at 100 ^{0}C to steam at 100 ^{0}C.

Efficiency: In the boiler industry there are four common definitions of efficiency:

b. Combustion efficiency

Combustion efficiency is the effectiveness of the burner only and relates to its ability to completely burn the fuel. The boiler has little bearing on combustion efficiency. A well-designed burner will operate with as little as 15 to 20% excess air, while converting all combustibles in the fuel to useful energy.

c. Thermal efficiency

Thermal efficiency is the effectiveness of the heat transfer in a boiler. It does not take into account boiler radiation and convection losses - for example from the boiler shell water column piping etc.

d. Boiler efficiency

The term boiler efficiency is often substituted for combustion or thermal efficiency. True boiler efficiency is the measure of fuel to steam efficiency.

e. Fuel to steam efficiency

Fuel to steam efficiency is calculated using either of the two methods as prescribed by the ASME (American Society for Mechanical Engineers) power test code, PTC 4.1. The first method is input output method. The second method is heat loss method.

f. Boiler turndown

Boiler turndown is the ratio between full boiler output and the boiler output when operating at low fire. Typical boiler turndown is 4:1. The ability of the boiler to turndown reduces frequent on and off cycling. Fully modulating burners are typically designed to operate down to 25% of rated capacity. At a 20% of the load capacity, the boiler will turn off and cycle frequently.

A boiler operating at low load conditions can cycle as frequently as12 times per hour or 288 times per day. With each cycle, pre and post purge air flow removes heat from the boiler and sends it out the stack .Keeping the boiler on at low firing rates can eliminate the energy loss. Every time the boiler cycles off, it must go through a specific start-up sequence for safety assurance. It requires about a minute or two to place the boiler back on line. And if there is a sudden load demand, the startup sequence cannot be accelerated. Keeping the boiler on line assures the quickest response to load changes. Frequent cycling also accelerates wear of boiler components. Maintenance increases and more importantly, the chance of component failure increases.

Boiler(s) capacity requirement is determined by much different type of load variations in the system. Boiler over sizing occurs when future expansion and safety factors are added to assure that the boiler is large enough for the application. If the boiler is oversized the ability of the boiler to handle minimum loads without cycling is reduced. Therefore capacity and turndown should be considered together for proper boiler selection to meet overall system load requirements.

Primary air: That part of the air supply to a combustion system which the fuel first encounters.

Secondary air: The second stage of admission of air to a combustion system, generally to complete combustion initiated by the primary air. It can be injected into the furnace of a boiler under relatively high pressure when firing solid fuels in order to create turbulence above the burning fuel to ensure good mixing with the gases produced in the combustion process and thereby complete combustion

Tertiary air: A third stage of admission of air to a combustion system, the reactions of which have largely been completed by secondary air. Tertiary air is rarely needed.

Stoichiometric: In combustion technology, stoichiometric air is that quantity of air, and no more, which is theoretically needed to burn completely a unit quantity of fuel. 'Sub-stoichiometric' refers to the partial combustion of fuel in a deficiency of air

Balanced draught: The condition achieved when the pressure of the gas in a furnace is the same as or slightly below that of the atmosphere in the enclosure or building housing it.

Gross calorific value (GCV): The amount of heat liberated by the complete combustion, under specified conditions, by a unit volume of a gas or of a unit mass of a solid or liquid fuel, in the determination of which the water produced by combustion of the fuel is assumed to be completely condensed and its latent and sensible heat made available.

Net calorific value (NCV): The amount of heat generated by the complete combustion, under specified conditions, by a unit volume of a gas or of a unit mass of a solid or liquid fuel, in the determination of which the water produced by the combustion of the fuel is assumed to remain as vapour.

Absolute pressure The sum of the gauge and the atmospheric pressure. For instance, if the steam gauge on the boiler shows 9 kg/cm^{2}g the absolute pressure of the steam is 10 kg/cm^2(a).

Atmospheric pressure The pressure due to the weight of the atmosphere. It is expressed in pounds per sq. in. or inches of mercury column or kg/cm^2. Atmospheric pressure at sea level is 14.7 lbs./ sq. inch. or 30 inch mercury column or 760mm of mercury (mm Hg) or
101.325 kilo Pascal (kPa).

Carbon monoxide (CO): Produced from any source that burns fuel with incomplete combustion, causes chest pain in heart patients, headaches and reduced mental alertness.

Blow down: The removal of some quantity of water from the boiler in order to achieve an acceptable concentration of dissolved and suspended solids in the boiler water.

Complete combustion: The complete oxidation of the fuel, regardless of whether it is accomplished with an excess amount of oxygen or air, or just the theoretical amount required for perfect combustion.

Perfect combustion: The complete oxidation of the fuel, with the exact theoretical (stoichiometric) amount of oxygen (air) required.

Saturated steam: It is the steam, whose temperature is equal to the boiling point corresponding to that pressure.

Wet Steam Saturated steam which contains moisture

Dry Steam Either saturated or superheated steam containing no moisture.

Super heated Steam Steam heated to a temperature above the boiling point or saturation temperature corresponding to its pressure.

Example 6.3

A Process industry is operating a natural gas fired boiler of 10 tonnes/hr to cater to a steam load of 8 tonnes/hr at 10.5 kg/cm^2 (g). The O_2 in the flue gas is 4% and the exit flue gas temperature is180^{o}C. Due to increased cost of natural gas, the management has decided to revert to operating the furnace oil fired boiler, having an efficiency of 84% on G.C.V. for meeting the above load.

In keeping with its sustainability policy the management proposes to offset the additional CO_2 emissions due to the use of furnace oil by sourcing a part of its total electrical energy consumption from green power (wind source).

The following are the additional data.

Composition of Fuels (% by Weight)

Constituents	Natural gas	Furnace oil
Carbon	73	84
Hydrogen	23	11
Nitrogen	3	0.5
Oxygen	1	0.5
Sulphur	-	4

- G.C.V. of natural gas -13000 kCal/kg
- Enthalpy of steam at 10.5 kg/cm^2(g) -665 kCal/kg.

- Inlet feed water temperature -90^{O}C
- Heat loss due to Radiation and moisture in air -1.2%
- Specific heat of flue gases -0.29 kCal/kg^{O}C
- Specific heat of super heated water vapour -0.45 kCal/kg^{O}C
- G.C.V. of furnace oil - 10,000 kCal/kg
- Ambient temperature -30^{O}C

Substitution by 1 kWh of green electrical energy in place of grid electricity reduces 0.80 kg of CO_2.

Determine the monthly amount of green electrical energy from wind, (for 720 hours operation) required to be purchased to maintain the existing level of CO_2 emissions.

Theoretical air required	11.6 C+ [34.8 (H_2 – O_2/8)] + 4.35 S
	11.6x0.73 + [34.8 (0.23 – 0.01/8)]
	16.43 kg. air / kg. gas
Excess Air %	[% O_2 /(21 - % O_2)]x100 [(4) / (21 – 4)] x100 = 23.5%
Actual Air Supplied (AAS)	(1 + 0.235) x 16.43
	20.29 kg.air / kg.gas
Mass of dry flue gas, m_{dfg}=	Mass of combustion gases due to Presence of C,S + mass of N_2 in the fuel + mass of nitrogen in air supplied + mass of excess O_2 in flue gas
	(0.73 x 44/12) + 0.03 + (20.29 x 0.77) + (20.29–16.43) x 0.23 = 19.22 kg. dry flue gas / kg. gas
	(M_{air}+M_{fuel}) i.e., (20.29+1) – (9H_2 + M) = 21.29 – 9x0.23 + 0 = 19.22 may also be considered.
L1	=% heat loss due to dry flue gases
	M_{dfg}xC_px (T_f– T_a)x 100 GCV of fuel(NG)
	19.22 X 0.29 X (180 – 30)x 100 13000
	6.43%
L2	% Loss due to water vapour from hydrogen
	9 H [584 + Cps (T_f – Ta)] x100 13000
	[9x0.23x[584+0.45x(180-30)]x100

	13000
	10.37%
Heat loss due to Radiation and moisture in air	1.2% (given)
Efficiency of natural gas boiler on GCV	100 – [6.43 + 10.37 + 1.2]
	82%
Steam Load	8 tonnes /hr.
Amount of Gas required	$\frac{8000\ (665 - 90)}{0.82 \times 13000}$ = 431.52 kg/hr
Amount of CO_2 emission with natural gas	(431.52 X 0.73 X 3.67) = 1156.1 Kg/hr
Amount of furnace oil required for the same steam load	8000 (665 – 90) 0.84 X 10000
	547.62 kg/hr
Amount of CO_2 emission with F.O	(547.62 X 0.84 X 3.67)
	1688.2kg CO_2/hr
(Note: 1 Kg. Carbon Combustion emits 3.67 Kg. CO2) Increase in CO_2 emission due to switching from natural gas to furnace oil	(1688.2 – 1156.1) = 532.1 kg. CO_2/hr.
[Substituting 1 kWh grid (Thermal) electrical energy by green electrical energy reduces 0.80 Kg. of CO2)] Green energy to be purchased to offset higher CO_2 emissions per month	[(532.1x 720)/ 0.8] =**4,78,890 kWh**

7. COGENERATION AND TURBINES (GAS, STEAM)

7.1 Introduction

Cogeneration systems can be broadly classified as those using steam turbines, gas turbines and diesel generator (DG) sets.

Steam turbine cogeneration systems involve different types of configurations with respect to mode of power generation such as extraction, back pressure or a combination of back-pressure, extraction and condensing.

Gas turbines with heat recovery steam generators are another mode of cogeneration. Depending on power and steam load variations in the plant, the entire system performance is dynamic. A performance assessment would yield valuable insights into cogeneration system performance and scope for further optimisation.

7.2 Purpose of the Performance Test

The main purpose of the cogeneration plant performance test is to determine the power output and plant heat rate. The plant performance will be compared with the baseline values for assessing plant operating conditions.

The other purpose of the performance test is to show the maintenance accomplishment after a major overhaul. In certain cases, the efficiency of individual components like steam turbine is addressed specifically where performance deterioration is suspected. The purpose of evaluation could even be for a total plant revamp.

7.3 Field Testing Procedure

The test procedure for each cogeneration plant will be developed considering plant configuration, instrumentation and plant operating conditions. A method is outlined in the following section for the measurement of heat rate and efficiency of a co-generation plant.

7.3.1 Test Duration

The test duration is site specific and in a continuous process industry,8-hourtest data should give reasonably reliable data. In case of an industry with fluctuating electrical/steam load profile, a set 24-hour test data sampling is recommended.

7.4 Measurements and Data Collection

The following instrumentation (online / field) for the performance measurement is recommended:

Table 7.1: Instrumentation for performance measurement

Steam flow measurement	Orifice flow meters
Fuel flow measurements	Volumetric measurements / Mass flow meters
Air flow / Flue gas flow	Pitot tube with manometer/micro manometer / Venturi / Orifice flow meter

Flue gas Analysis	Zirconium Probe Oxygen analyser
Unburnt Analysis	Gravimetric Analysis
Temperature	Thermocouple
Cooling water flow	Orifice flow meter / non-contact flow meter. weir /channel flow
Pressure	Bourdon Pressure Gauges
Power	Trivector meter / Energy meter
Condensate	Orifice flow meter

Data should be collected during steady state plant running conditions. Among others the following are essential details to be collected for cogeneration plant performance evaluation.

7.4.1 Thermal Energy

		Flow	Pressure	Temperature
1.	Steam inlet to turbine	✓	✓	✓
2.	Fuel input to boiler/gas turbine	✓	-	-
3.	Combustion air	✓	✓	✓
4.	Extraction steam to process	✓	✓	✓
5.	Back pressure steam to process	✓	✓	✓
6.	Condensing steam	✓	✓	✓
7.	Condensate from turbine	✓	-	✓
8.	Turbine bypass steam	✓	-	-
9.	Flue gas to HRSG	-	✓	✓
10.	Exit flue gas	✓	-	+ Composition
11.	Cooling water to condenser	✓	✓	✓

7.4.2 Electrical Energy

- Total power generation during the trial period from individual turbines.
- Hourly average power generation
- Quantity of power imported from the grid
- Auxiliary power consumption

7.5 Performance Terms and Conditions

Overall Plant Performance

$$Overall\ plant\ fuel\,rate, kg/kWh\,(or)\,Sm^3/kWh = \frac{Fuel\ consumption, kg/hr\ or\ Sm^3/hr}{Power\ output, kW}$$

$$Energy\ Utilisation\ Factor, EUF = \frac{Electrical\ output, Q_e + Thermal\ ouput, Q_{th}}{Fuel\ heat\ input, Q_f}$$

Steam Turbine Performance

Turbine stage (isentropic) efficiency,%

$$= \frac{Actual\ enthalpy\ drop\ across\ the\ turbine, kCal/kg}{Stage\ (Isentropic)\ enthalpy\ drop\ across\ the\ turbine, kCal/kg} \times 100$$

Gas Turbine and Heat Recovery Steam Generator Performance

$$\text{Overall plant heat rate, kCal/kWh} = \text{Overall plant fuel rate, kg/kWh} \times \text{GCV of fuel, kCal/kg}$$

$$\text{Overall plant heat rate, kCal/kWh}$$

$$= \text{Overall plant fuel rate, Sm}^3/\text{kWh} \times \text{NCV of gas, kCal/Sm}^3$$

$$\eta_{HRSG} = \frac{\text{Steam flowrate} \times (\text{Enthalpy of steam} - \text{Enthalpy of feed water}) \times 100}{(\text{Exhaust gas flowrate} \times \text{I/L enthalpy}) + (\text{Auxiliary fuel} \times \text{GCV})}$$

7.6 Calculations for Steam Turbine Cogeneration System

Step 1:

Calculate the actual heat extraction in turbine at each stage,

Steam Enthalpy at turbine inlet	H_1 kcal / kg
Steam Enthalpy at 1st extraction	H_2 kcal / kg
Steam Enthalpy at Condenser	H_3 kcal / kg
Heat extraction from inlet to extraction	$H_1 - H_2$ kcal / kg
Heat extraction from extraction to condenser	$H_2 - H_3$ kcal / kg

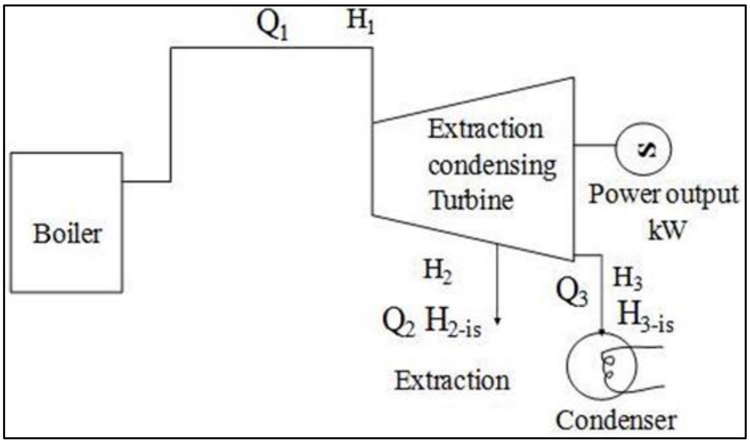
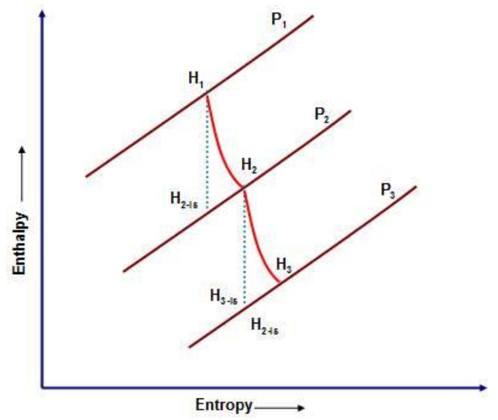


Figure 7.1: Process Flow Diagram for Cogeneration Plant

Step 2:

From Mollier diagram (H−ϕ) Diagram) estimate the theoretical heat extraction for the conditions mentioned in Step 1. Towards this: Plot the turbine inlet condition point (H_1) in the Mollier chart – corresponding to steam pressure (P_1) and temperature. Since expansion in turbine is an adiabatic process, the entropy is constant. Hence draw a vertical line from inlet point (parallel to y-axis) upto the extraction pressure (P_2). Read the corresponding enthalpy H_2-is. Plot the extraction condition point (H_2) in the Mollier chart – corresponding to steam pressure (P_2) and temperature. Draw a vertical line from extraction point (parallel to y-axis) upto the condensing pressure (P_3). Read the corresponding enthalpy H_3-is. Compute the theoretical heat drop for different stages of expansion.	 ***Figure 7.2: Mollier Chart***

Step-3:

Compute turbine stage (isentropic) efficiency)

$$\boldsymbol{Efficiency\ of\ extraction\ stage = \frac{Heat\ extraction\ actual}{Heat\ extraction\ theoretical}}$$

$$\boldsymbol{= \frac{H_1 - H_2}{H_1 - H_{2-IS}}}$$

$$\boldsymbol{Efficiency\ of\ condensing\ stage = \frac{Heat\ extraction\ actual}{Heat\ extraction\ theoretical}}$$

$$\boldsymbol{= \frac{H_2 - H_3}{H_2 - H_{3-IS}}}$$

Step-4:

Calculate the turbine output (P_t)

$$\textit{Turbine power output } (P_t), MW = \frac{Q_1 \ x \ (H_1 - H_2) + Q3 \ x \ (H_2 - H_3)}{860 \ x \ 1000}$$

Where,

Q1, Q2, Q3 – Steam flow rate in kg/hr
H– Enthalpy in kCal/kg

Step 5:

Calculate the generator output (P_g)

Generator output (P_g), MW = Pt x η_m x η_{gear} x η_{gen}

Where,

η_m Mechanical efficiency of turbine in %
η_{gear} Efficiency of gear box in %
η_{gen} Efficiency of generator in %

Example 7.1

For the data given for extraction condensing turbine, stage-wise (isentropic) turbine efficiency is calculated as follows:

Parameters	Units	Data
Main steam		
Steam pressure	Kg/cm^2	68
Steam temperature	^{o}C	485
Steam flow, Tons per hour	TPH	19.2
Steam enthalpy	kCal/kg	807.9
First extraction		
Steam pressure	Kg/cm^2	9
Steam temperature	^{o}C	280
Steam flow	TPH	8
Enthalpy (actual)	kcal/kg	719.9
Enthalpy (isentropic)	kcal/kg	648.2

Parameters	Units	Data
Condenser		
Condenser vacuum	Kg/cm^2 (g)	-0.9
Condensate temperature	^{o}C	45.4
Condensate flow	TPH	11.2
Enthalpy (actual)	kcal/kg	561
Enthalpy (isentropic)	kcal/kg	534.2

Turbine stage isentropic efficiency, % = Actual enthalpy drop across the turbine, kCal/kg x 100
Stage (Isentropic) enthalpy drop across the turbine, kCal/kg

Extraction stage (Isentropic) efficiency, % = (807.9 – 719.9) / (807.9 – 648.2)
= 71.14%

Condensing stage (Isentropic) efficiency, % = (719.9 – 534.2) / (719.9 – 534.2)
= 85.57%

Extraction stage power output = 19200 x (807.9 – 719.9)/860
= 1944 kW

Condensing stage power output = 11200 x (719.9–561)/860
= 2069.4 kW

Total power output = 4013 kW

Example 7.2

The performance trial of gas turbine indicated the following values:

Description		
Parameter	Unit	Value
Test duration	hours	4
Gas turbine data		
Compressor inlet parameters		
Air temperature	°C	37
Air pressure (atmospheric)	kg/cm^2(g)	1.0332
Dry bulb temperature	°C	36.5
Wet bulb temperature	°C	28

Fuel data		
Fuel fired	Natural gas	
Fuel flow rate	Sm^3/hr	1312
Lower heating value of natural gas	$kCal/sm^3$	9465
Auxiliary fuel for Heat Recovery Steam Generator (HRSG)		
Exhaust flue gas conditions		
Flow	Kg/s	14.32
Temperature	°C	548
Specific heat of flue gas	kCal/kg °C	0.25
Generator data		
Average power output	kW	3994.5
Power factor		0.875
Waste Heat Recovery Boiler (WHRB)		
Exhaust gas temperature at inlet to boiler	°C	542
Exhaust gas temperature at boiler exit	°C	131.4
Steam parameters at WHRB exit		
Flow	TPH	9.145
Temperature	°C	195.5
Enthalpy	kcal/kg °C	678.4
Feed water inlet parameters		
Flow	kg/h	9605
Temperature at drum inlet	°C	105

	Enthalpy at drum inlet	kCal/kg	105	

Overall fuel rate:

Fuel consumption : 1312 sm^3/hr
Electrical output : 3994.5 kW
Overall plant fuel rate : 1312/3994.5 sm^3/hr/kW
: 0.32844 Sm^3/kWh

Overall plant heat rate:

Overall plant heat rate, kCal/kWh : Overall plant fuel rate, sm^3/hr x LHV of fuel, kCal/Sm^3
: 0.32844 X 9465 = 3109 kCal/kWh

Thermal efficiency of HRSG : Steam flow rate x (Enthalpy of steam – Enthalpy of feed water) x 100
(Exhaust gas flow rate x Specific heat x Temperature) + Aux. fuel x LHV

$$\eta_{HRSG} : \frac{9145 \times (678.4 - 105)}{14.32 \times 3600 \times 0.25 \times 542} \times 100 = 75\%$$

Energy Utilization factor:

$$EUF : \frac{P_E + Q_{TH}}{Q_f}$$

$$: \frac{(3994.5 \times 860) + 9145 \times (678.4 - 105) \times 100}{1312 \times 9465}$$

: 70%

Example 7.3

A gas turbine generator is delivering an output of 20 MW in an open cycle with a heat rate of 3440 kcal/kWh. It is converted to combined cycle plant by adding heat recovery steam generator and a steam turbine raising the power generation output to 28 MW. However, with this retrofitting and increased auxiliary consumption, the fuel consumption increases by 5% in the gas turbine.

Calculate the combined cycle gross heat rate and efficiency.

Gas turbine output = 20 MW

Combined cycle output = 28 MW
Heat rate in GT open cycle for 20 MW = 3440 kcal/kwh
Increase in fuel consumption in combined cycle operation = 5%

Combined cycle heat rate	= (3440 X 1.05) X(20 / 28)= 2580 kCal/kwh
Combined cycle plant efficiency	= (860 / 2580) X 100= 33.33%

Example 7.4 (Trigeneration problem)

A gas engine-based trigeneration plant operates in two modes:

- Power and heating mode (10 hours per day) :
- Pel= 650 kW of electricity and 325 kg/h of steam with enthalpy addition of 530 kcal/kg of steam &EUF heat = 0.85
- Power and cooling mode (14 hours per day) :
- Pel = 650 kW of electricity and chilling load of 213 TR for absorption chillers &EU Fcool = 0.73
- Calorific value of natural gas = 8500 kcal/Sm^3
- Average operating days/year = 330
- Alternator efficiency = 0.95
- The energy loss in the flue gas and that in the cooling water is same as engine power output and other losses are negligible

a) What is the average plant energy utilization factor
b) Calculate the useful energy produced daily by the trigeneration plant in Gcal
c) Determine the daily plant natural gas requirements based on average energy utilization factor

The plant proposes to install a 60 TR hot water driven Vapour absorption chiller with a COP of 0.5 using waste heat from jacket cooling water. Check if it is feasible with supporting calculations.

1) Plant average energy utilization factor		
Plant average energy utilization factor	=	(0.85 x 10 + 0.73 x 14)/24
	=	0.78
2) The useful energy produced daily by the trigeneration plant in Gcal		
P_{Elect}	=	650 KW
Q_{Heat}	=	325 x 530
	=	172250 kcal/h
Q_{Cool}	=	213 x 3024
	=	644112 kcal/h

Total daily useful energy production of the plant	=	(650 x 860 x 24 +172250 x 10 + 644112 x 14)
	=	13416000 + 1722500 + 9017568
The useful energy produced daily	=	24156068 kcal/day
The useful energy produced in Gcal	=	24156068x 330 / 10^6
	=	7971.5 Gcal
3)The daily plant natural gas requirements		
Input heat	=	24156068 / 0.78
	=	3096931795 kcal/day
Natural gas requirements	=	3096931795 / 8500
	=	3643 Sm^3/day
4) Justification for a 60 TR Vapour Absorption chiller from waste heat of the jacket cooling water		
Heat required for operating 60 TR at COP of 0.5	= =	60 x 3024/0.5 362880 Kcal/hr
Power output of the engine	=	650 /0.95 684.2 KW
Heat in the jacket cooling water	= =	684.2 x 860 588412 kcal/hr
Since the heat requirement (362880 kcal/hr) is much less than heat available (588412 kcal/hr) the proposal is feasible.		

8. PUMPING SYSTEM

8.1 Introduction

Pumping is the process of addition of kinetic and potential energy to a liquid for the purpose of moving it from one point to another. This energy will cause the liquid to do work such as flow through a pipe or rise to a higher level. A centrifugal pump transforms mechanical energy from a rotating impeller into a kinetic and potential energy required by the system.

The most critical aspect of energy efficiency in a pumping system is matching of pump to the required load. Hence even if an energy-efficient pump is selected, but mismatched to the system, the pump will operate at very low efficiency. In addition, efficiency of a pump is expected to drop over time due to deposits in the impellers and other issues. Performance assessment of pumps would reveal the existing operating efficiencies in order to take timely corrective and preventive actions.

8.2 Purpose of the Performance Test

- Determination of the pump efficiency during operating conditions
- Determination of system resistance and the operating duty point of pump and compare the same with the design.

Performance Terms and Definitions

Pump Capacity, Q = Volume of liquid delivered by pump per unit time, m^3/hr or m^3/sec
Q is proportional to N, where N is the rotational speed of the pump (RPM)

Static Suction Head is the vertical distance in meters from the centerline of the pump to the free level of the liquid to be pumped. Suction Head exists when the source of supply is above the centerline of the pump.

Static Discharge Head is the vertical distance in feetmetres between the pump centerline and the point of free discharge or the surface of the liquid in the discharge tank.

Total Static Head is the vertical distance in metres between the free level of the source of supply and the point of free discharge or the free surface of the discharge liquid.

Friction Head is the head required to overcome the resistance to flow in the pipes, valves and fittings. It is dependent upon the size and type of pipe flow rate, and nature of the liquid and varies as a function (roughly as the square) of the capacity flow through the system.

Velocity Head is the energy of a liquid as a result of its motion at some velocity V. It is the equivalent head in metres through which the water would have to fall to acquire the same velocity, or in other words, the head necessary to accelerate the water. The velocity head is usually insignificant and can be ignored in most high head systems. However, it can be a large factor and must be considered in low head systems.

Total Head or Total Dynamic head, H **is** the difference of discharge and suction pressure. It represents the net work done on unit weights of a liquid in passing from inlet of the pump to the discharge of the pump.

System resistance is the head that is required to move liquid through a piping system at various flow rates. It is the sum of frictional head & total static head

System resistance: The sum of frictional head in resistance & total static head.

System Curve is a graphical representation of the pump head that is required to move fluid through a piping system at various flow rates. The system curve helps quantify the resistance in a system due to friction and elevation change over the range of flows. When there are no control features in the system, such as flow control valves, then the pump and system curves will intersect at the operating flow rate.

Pump Efficiency: Fluid power and useful work done by the pump divided by the power input in the pump shaft.

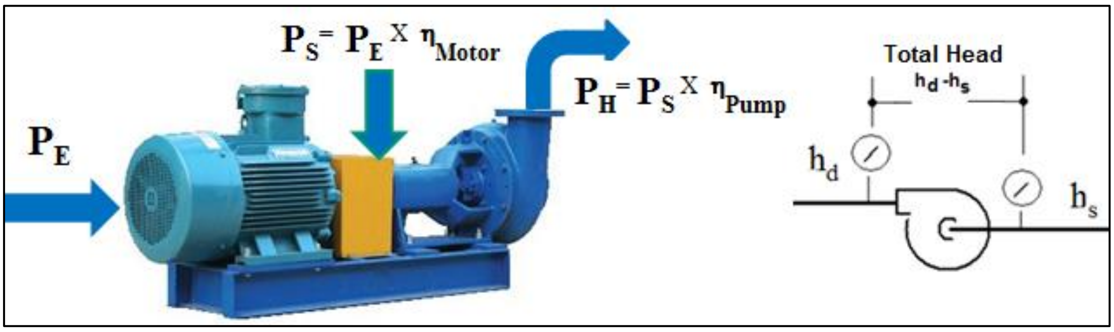


Figure 8.1

8.4 Field Testing for Determination of Pump Efficiency

To determine the pump efficiency, three key parameters are Flow, Head, and Power. Of these, flow measurement is the most challenging as normally online flow meters will not be installed in the pumping system. The following methods can be adopted to measure the flow depending on the avail ability and site conditions.

8.4.1 Flow Measurement, Q

The following are the methods for flow measurements:

- Tracer methodBS5857
- Ultrasonic flow measurement
- Tank filling method
- Installation of an on-line flow meter

Tracer Method

The Tracer method is most suitable for cooling water flow measurement. This method is based on injecting a tracer into the cooling water for a few minutes at an accurately measured constant rate. A series of samples is extracted from the system at a point where the tracer has become

completely mixed with the cooling water. The mass flow rate is calculated from the equation,
$q_{cw} = q_1 \times C_1/C_2$

where,
q_{cw} = cooling water mass flow rate, kg/s
q_1 = mass flow rate of injected tracer, kg/s
C_1= concentration of injected tracer, kg/kg
C_2 = concentration of tracer at downstream position during the 'plateau' period of constant concentration, kg/kg.
The tracer normally used is sodium chloride.

Ultrasonic Flow meter

Based on Doppler Effect principle, these meters are non-invasive i.e. measurements can be taken without disturbing the system.

Scales and rust in the pipes affect accurate measurements.

- Ensure measurements are taken in a sufficiently long length of pipe free from flow disturbance due to bends, tees and other fittings.
- The pipe section where measurement is to be taken should be hammered gently to enable scales and rusts to fallout.
- For ensuring accuracy, a section of the pipe can be replaced with new pipe for flow measurements.

Tank filing method

In open flow systems such as pumping of water to an overhead tank or into a sump, the flow can be measured by noting the difference in tank levels for a specified period during which the outlet flow from the tank is stopped. The internal tank dimensions should be taken from the design drawings, or direct measurements.

Installation of an on-line flow meter

If the application to be measured is critical and periodic, installation of on-line flow meter is recommended.

8.4.2 Determination of total head, H

Suction head (hs)

This reading is taken from the pump inlet pressure gauge and the suction pressure (value in kg/cm^2) is converted into suction head (in meters) using the conversion (1kg/cm^2 = 10 m).

If no suction pressure gauge is available, the difference of sump water level to the center line of the pump is measured. This gives the suction head in meters.

Discharge head (hd) This is taken from the pump discharge side pressure gauge. The discharge pressure (value in kg/cm^2) is converted into suction head (in metres) using the conversion (1kg/cm^2 = 10 m). Installation of pressure gauge in the discharge side is a must, if not already available.

8.4.3 Determination of Hydraulic Power (Liquid Horse power)

Hydraulic Power $P_{H,}$ kW = Q (m^3/s) x ρ (kg/m^3) x g (m/s^2) x Total head, h_d - h_s (m) / 1000

Where h_d - Discharge head,
h_s - Suction head,
ρ - Density of the liquid,
g - Acceleration due to gravity (which is 9.8)

8.4.4 Measurement of motor input power

Motor Input Power, P_E,kW = Power consumed by the motor (measured by using a portable power analyser).

8.4.5 Pump shaft power

Pump Shaft Power P_S, kW =Motor Input Power, P_E x Motor Efficiency, η_{Motor}

8.4.6 Pump Efficiency

Pump Efficiency, η_{Pump}**%** =Hydraulic Power, P_H / Pump Shaft Power, P_S

8.5 Pump Efficiency Calculation

Example 8.1

A pump in a chemical plant is supplying cooling water for process and refrigeration applications. During the performance testing the following operating parameters were measured:

Pump flow, Q	0.40 m^3/ s
Motor power consumption, P_m	325 kW Suction head (tower basin level), h_1+1 m
Delivery head, h_2	55m
Height of cooling tower	5 m
Motor efficiency	88 %
Type of drive	Direct coupled
Density of water	996 kg/ m^3

Determination of pump efficiency

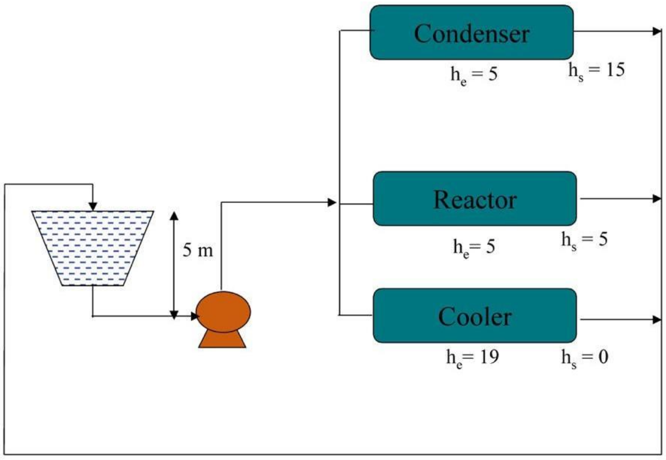
Flow delivered by the pump 0.40 m^3/s
Total head, h_2– (+h_1) 54 m (55–1)
Hydraulic power 0.40 x 54 x 996 x 9.81/1000 = 211 kW
Motor power consumption 325 kW
Pump shaft power 286 kW (325 x 0.88)

Pump efficiency 211/286 = 73.7%

8.6 Determining the System Resistance and Operating point (duty point)

Determining the system resistance curve and imposing the pump curve will indicate the operating efficiency and also change in efficiency when system curve deviates from the design/normal. An example outlining the method of constructing a system curve is illustrated as follows:

A refrigeration plant is located at +0.00 level and the process plant condensers are located at +15 m level. A cooler having a design pressure drop of 1.9 kg/cm^2 is located at the 0.00 level (ground level). Other relevant data can be taken from the earlier section. The schematic of the plant is shown in Figure 8.1.



h_s = Static Head ; h_e = Equipment pressure drop

Figure 8.2 Schematic of Refrigeration Plant pumping System

The step-by-step approach for determining system resistance curve is as follows:

Step-1: Divide system resistance into static and dynamic head
Determination of static head
Static head (condenser floor height): 15 m
Determination of dynamic head
Dynamic Head = Total Head – Static Head
Dynamic head = (54–15) = 39m
Step-2 Check maximum resistance in the different circuits

S.no.	System	Condenser loop resistance, m	Reactor loop resistance, m	Cooler loop resistance, m
1.	Supply line from the pump*	15	10	15
2.	Static head	15	5	0
3.	Equipment	5	5	19
4.	Return line from equipment*	15	10	15
5.	Tower head	0	0	5

	TOTAL	50	30	54

*data given

Cooler circuit offers the maximum resistance followed by condenser circuit.
Step 3: Draw system resistance curve

Condenser loop is chosen as it offers maximum resistance as well as has static head.

At 100% flow, Static head: 15 m and Dynamic head at full load: 39 m

Compute system resistance at different flow rates namely 75%, 50% and 25%.

S. No.	Flow (%)	Dynamic head = 39 x $(\%\text{flow})^2$	Static head, m	Total head, m
1.	100	39	15	54
2.	75	21.9	15	36.9
3.	50	9.75	15	24.75
4.	25	2.44	15	17.44

Step 4 - Plot the calculated system resistance against various flows (Figure 8.2).

If the system curve is plotted in the pump curves provided by the vendor, operating duty point can be determined and check whether pump is operating at design efficiency and deviations if any can be assessed.

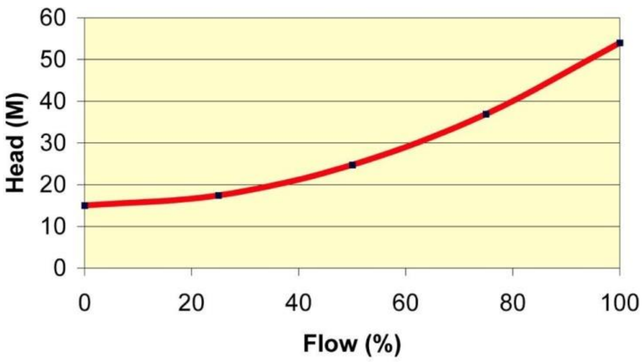


Figure 8.3 Plot of System Curve

Example 8.2

The total system resistance of a piping loop is 50 meters and the static head is 15 meters at designed water flow. System resistance offered at 75%, 50% and 25% of water flow is calculated as follows:

Total system resistance of piping loop: 50 m
Static Head: 15 m
Dynamic Head at designed water flow: 35 m

Sl. No.	Flow (%)	Dynamic Head (m) = 35 x $(\%\text{flow})^2$	Static Head (m)	Total Resistance (m)
1	75.0%	19.68	15	34.68

2	50.0%	8.75	15	23.75
3	25.0%	2.19	15	17.19

Example 8.3

A centrifugal water pump operates at 30 m^3/hr and at 1440 RPM. The pump operating efficiency is 65% and motor efficiency is 89%. The discharge pressure gauge shows 3.4 kg/cm^2. The suction is 3 m below the pump centerline. If the speed of the pump is reduced by 25 %, estimate the following:

- pump flow,
- pump head and
- motor power.

Flow = 30 m^3/hr

Head developed by the pump = 34 – (-3) = 37 m

Power drawn by the pump = (30/3600) x 37 x 1000 x 9.81/(1000 x 0.65)
= 4.65 kW

Flow at 75 % speed = 30 / Q2 = 1440/1080
= 22.5 m^3/hr

Head at 75 % speed = 37 / H2 = $(1440/1080)^2$
= 20.81 m

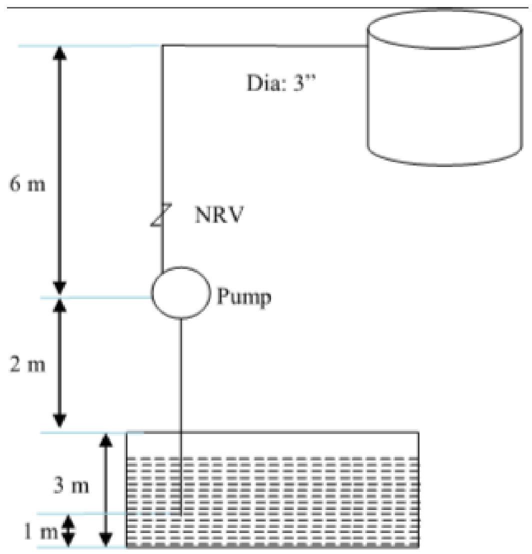
Shaft Power at 75 % speed = 4.65/kW2 = $(1440)^3$ / $(1080)^3$
= 1.96 kW

Power drawn by motor = 1.96 / 0.89
= 2.2 kW

Example 8.4

The following sketch shows the details of an installed pumping system. The rated parameters of the pump are:

Flow (Q) : 30 lps
Head (H) : 20 m
Power (P) : 10 kW
Efficiency (η) : 65%



Under normal operating conditions,

a) What will be the total head delivered by the pump if pressure drop across the NRV is 0.1 kg/cm^2
b) What will be the impact on flow rate and power consumption of this pump due to above operation condition?

c) Operating head = Discharge head (6 m) - Suction head (- 4 m) + Head loss in NRV (1m)

= 11 m.

d) Actual flow rate from the pump will be higher than the rated flow rate due to lower operating head.

e) Actual power consumption will increase due to higher flow rate.

f) Pump operating efficiency will be less than the design efficiency under actual conditions.

9. HEAT EXCHANGERS

9.1 Introduction

Heat exchangers are equipment that transfers heat from one medium to another. The proper design, operation and maintenance of heat exchangers ensure process efficiency and minimize energy losses. Heat exchanger performance can deteriorate over time, off design operations and other reasons such as fouling and scaling.

It is necessary to assess periodically the heat exchanger performance and take appropriate actions to maintain their efficiency. This section comprises certain proven techniques of monitoring the performance of heat exchangers, coolers and condensers from observed operating data.

9.2 Purpose of the Performance Test

To determine the overall heat transfer coefficient and assess the performance of the heat exchanger and find out root cause of deviation from the design heat transfer coefficient e.g. fouling.

9.3 Performance Terms and Definitions

A typical heat exchanger is shown in Figure 9.1 with following nomenclature:

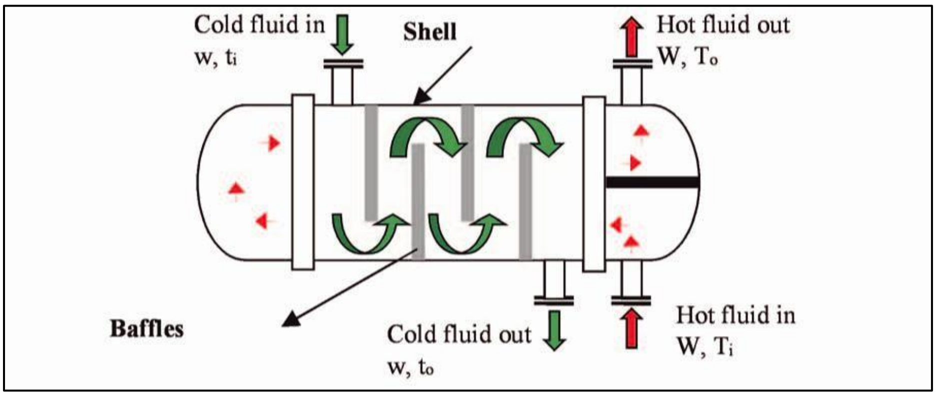


Figure 9.1 Typical Shell and Tube Heat Exchanger

9.3.1 Heat Duty

Heat duty of the exchanger can be calculated either on the hot side fluid or cold side fluid.

Heat Duty for Hot fluid, $Q_h = W \text{ x} C_{ph} \text{ x } (T_i – T_o)$

Heat Duty for Cold fluid, $Q_c = w\text{x } C_{pc} \text{ x } (t_o – t_i)$

If the operating heat duty is less than design heat duty, it may be due to heat losses, fouling in tubes, reduced flow rate (hot or cold) etc. Hence, for simple performance monitoring of exchanger, efficiency may be considered as factor of performance irrespective of other parameter. However, in industrial practice, fouling factor method is more predominantly used.

9.3.2 Overall heat transfer coefficient, U

Heat exchanger performance is normally evaluated by determining the overall heat transfer coefficient U. The overall heat transfer equation is given by the following relation:

> *Q* = U x A x LMTD
> Where,
> Q is the rate of heat transfer in kCal/hr
> A is the outside surface area of heat exchanger in m^2
> LMTD is the logarithmic mean temperature difference in ^0C
> U is the overall heat transfer coefficient kCal/hr/m^2/ ^oC)

When the hot and cold stream flows and inlet temperatures are constant, the heat transfer coefficientmaybeevaluatedusingtheaboveformula.Itmaybeobservedthattheheatpick up by the cold fluid starts reducing overtime.

9.3.3 Logarithmic Mean Temperature Difference (LMTD)

The LMTD is Logarithmic Mean Temperature Difference, used to determine the temperature driving force for heat transfer in heat exchangers. It is determined by the relationship of the fluid temperature differences at the terminals of the heat exchanger.

Table 9.1

<table>
<tr><td>T_i and T_o are the inlet and outlet temperatures of hot fluid

t_i and t_o are the inlet and outlet temperatures of cold fluid</td><td>$$LMTD = \frac{\Delta T1 - \Delta T2}{\Delta T1/\Delta T2}$$</td></tr>
<tr><td></td><td></td></tr>
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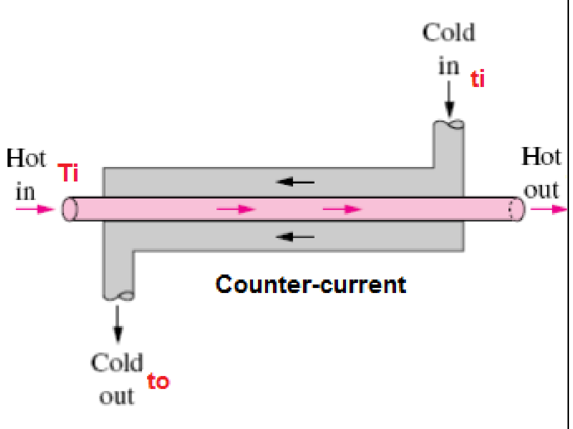

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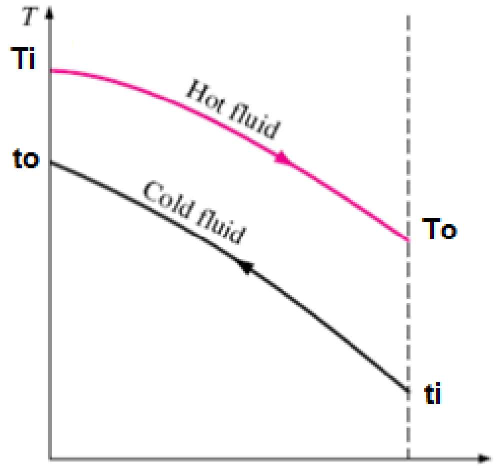

</td></tr>
<tr><td>Counter Flow Heat Exchanger</td><td>$\Delta T_1 = T_i – t_o$ and $\Delta T_2 = T_o – t_i$</td></tr>
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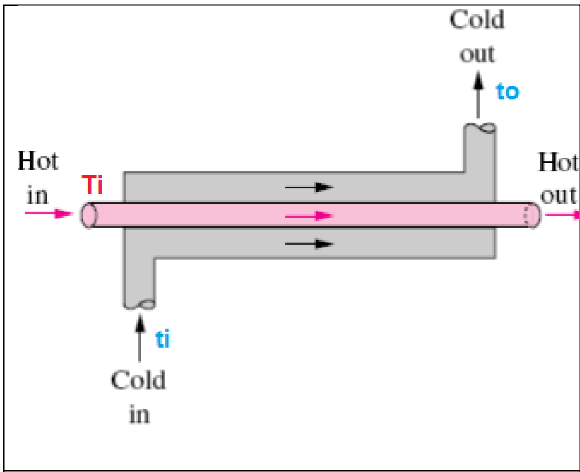
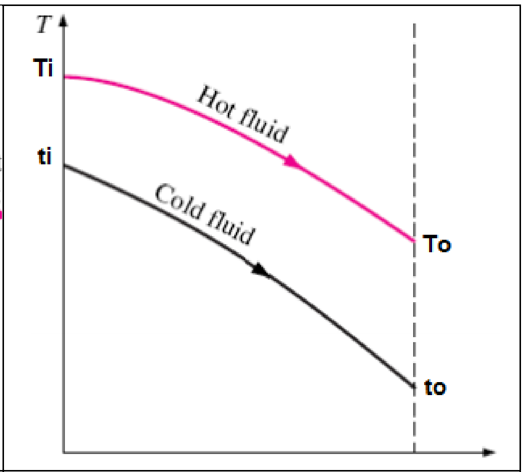




Parallel Flow Heat Exchanger	$\Delta T_1 = T_i - t_i$ and $\Delta T_2 = T_o - t_o$

9.3.4 The LMTD Correction Factor (F)

In multi-pass shell-and-tube exchangers, the flow pattern is a mixture of co-current and counter current flow, as the two streams flow through the exchanger in the same direction on some passes and in the opposite direction on others. For this reason, the mean temperature difference is not equal to the logarithmic mean. In such cases, LMTD is corrected by introducing a Correction Factor, F, which is appropriately termed as the LMTD correction factor.

9.3.5 Fouling Factor

The fouling factor represents the theoretical resistance to heat flow due to a buildup of a layer of dirt or other fouling substance on the tube surfaces of the heat exchanger. The fouling factor increases with increased fouling and causes a drop in the heat exchanger effectiveness. Common types of fouling are chemical, biological, deposition and corrosion fouling.

9.3.5 Effectiveness

The heat recovery capability of a heat exchanger is characterized by means of an index referred as the "Heat Exchanger Effectiveness".Calculating the heat exchanger effectiveness helps engineers:

- To predict how a given heat exchanger will perform a new job.
- To predict the stream outlet temperatures without a trial-and-error solution.

The heat exchanger effectiveness is defined as the ratio of actual heat transfer to the maximum possible heat transfer.

$$\epsilon = \frac{\text{Actual heat transfer rate, kcal/h}}{\text{Maximum possible heat transfer rate, kcal/h}}$$

$$= Q / Q_{max}$$

$$= Q / (C_{min} \times \Delta T_{max})$$

Where,

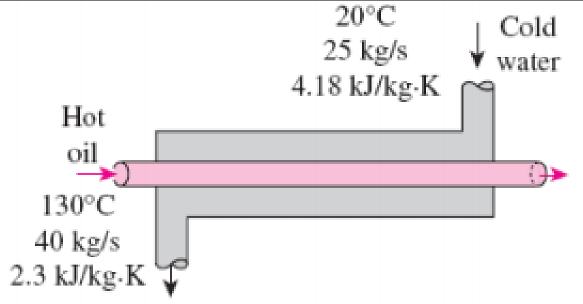
C Heat Capacity, kcal/h ^{0}C

Mass flow rate (kg/hr) x Specific heat capacity of the fluid (kcal/kg^{0}C)

C_{min} Lower of the two fluids heat capacities, kcal/h ^{0}C

ΔT_{max} Maximum temperature difference from the terminal stream temperatures, ^{0}C

Example 9.1 determination of maximum rate of heat transfer in a heat exchanger



$C_c = wc_{pc} = 104.5$ kW/K

$C_h = Wc_{ph} = 92$ kW/K

$C_{min} = 92$ kW/K

$T_{max} = T_i – t_i = 110^oC$

$Q_{max} = C_{min}\Delta T_{max} = 10{,}120$ kW

In a counter-flow exchanger one of the fluid streams will gain or lose heat until its outlet temperature equals the inlet temperature of the other stream.

The fluid that experiences this maximum temperature change is the one having the smaller value of Heat Capacity, C = mass flow rate x specific heat capacity at constant pressure, as can be seen from the energy balance equations for the two streams.

Thus, if the hot fluid has the lower value of C, we will have $T_{ho} = T_{ci}$, and

$Q_{max} = W \times C_{ph} \times (T_{hi}-T_{ci}) = C_{min} \times (T_{hi}-T_{ci})$

On the other hand, if the cold fluid has the lower value of C, then $T_{co} = T_{hi}$, and

$Q_{max} = w \times Cpc \times (Thi-Tci) = Cmin \times (Thi-Tci)$

Thus, in either case

$Q_{max} = Cmin\ (T_{hi}-T_{ci}) = C_{min} \times \Delta T_{max}$

Where, $\Delta T_{max} = (T_{hi} - T_{ci})$ is the maximum temperature difference from the terminal stream temperatures.

By definition the effectiveness, ε, is given by:

$\varepsilon = Q / Qmax = Q / (Cmin \times \Delta Tmax)$

Heat capacity ratio, r = Cmin / Cmax = (W x Cph) / w x Cpc)

9.4 Methodology of Heat Exchanger Performance Assessment

9.4.1 Procedure for determination of Overall Heat Transfer Coefficient, U atfield

This is arigorous method of monitoring the heat exchanger performance by calculating the overall heat transfer coefficient periodically. Technical records are to be maintained for all the exchangers, so that problems associated with reduced efficiency and heat transfer can be identified easily. The record comprises historical heat transfer coefficient data along with date/time of observation. A plot of heat transfer coefficient versus date/time permits rational scheduling of a heat exchanger cleaning program.

The heat transfer coefficient, kW/m^2 K is calculated by the equation
U = Q / (A x LMTD)
Where,
Q is the heat duty, kW
A is the heat transfer area of the exchanger, m^2
LMTD is temperature driving force, ^oC
The step by step procedure for determination of overall heat transfer coefficient is described as follows:
Step A
Monitoring and reading of steady state parameters of the heat exchanger under evaluation are tabulated as follows:

Table 9.2: Heat Exchanger monitoring parameters

Parameters	Units	Inlet	Outlet
Hot fluid flow, W	Kg/h		
Cold fluid flow, w	Kg/h		
Hot fluid temperature, T	^0C		
Cold fluid temperature,	^0C		
Hot fluid pressure, P	bar (g)		
Cold fluid pressure, p	bar (g)		

Step B
With monitored test data, the physical properties of the stream can be tabulated for evaluation of thermal data.

Table 9.3

Parameters	Units	Inlet	Outlet
Hot fluid density, ρ_h	Kg/m^3		
Cold fluid density, ρ_c	Kg/m^3		
Hot fluid viscosity, μ_h	MpaS		
Cold fluid viscosity, μ_c	MpaS		
Hot fluid thermal conductivity, k_h	kW/(m. K)		
Cold fluid thermal conductivity, k_c	kW/(m. K)		
Hot fluid specific heat capacity, C_{ph}	kJ/(kg. K)		
Cold fluid specific heat capacity, C_{pc}	kJ/(kg. K)		

Density and viscosity can be determined by analysis of the samples taken from the flow stream at the recorded temperature in the plant laboratory. Thermal conductivity and specific heat capacity can be referred from hand books.

Step C

Calculate the thermal parameters of heat exchanger and compare with the design data.

Table 9.4

Parameters	Units	Test data	Design data
Heat duty, Q	kW		
Hot fluid side pressure drop, ΔP_h	bar		
Cold fluid side pressure drop, ΔP_c	bar		
Temperature range hot fluid, ΔT	^0C		
Temperature range cold fluid, Δt	^0C		
Capacity Ratio, R	-		
Effectiveness, S	-		
Corrected LMTD	^0C		
Heat Transfer Coefficient, U	kW/(m^2.K)		

Step D

The following formulae are used for calculating the thermal parameters:

Heat Duty, $Q = q_S + q_L$

Where,
q_S is the sensible heat and q_L is the latent heat

For sensible heat
$q_S = W \times C_{ph} \times (T_i - T_o)/3600$ in kW
or

$q_S = W \times C_{pc} \times (t_o - t_i)/3600$ in kW

For latent heat

$q_L = W \times \lambda_h$

λ_h– Latent heat of condensation of hot condensing vapour

or

$q_L = w \times \lambda_{c,}$

λ_c– Latent heat of vapourization

Hot Fluid Pressure Drop, $\Delta P_h = P_i - P_o$

Cold Fluid Pressure Drop, $\Delta P_c = p_i - p_o$

Temperature range hot fluid, $\Delta T = T_i - T_o$

Temperature range cold fluid, $\Delta t = t_o - t_i$

Capacity ratio, $R = W \times C_{ph} / w\, C_{pc}$ (or) $(T_i - T_o) / (t_0 - t_i)$

Effectiveness, S = $(t_0 - t_i) / (T_i - t_i)$

6. LMTD

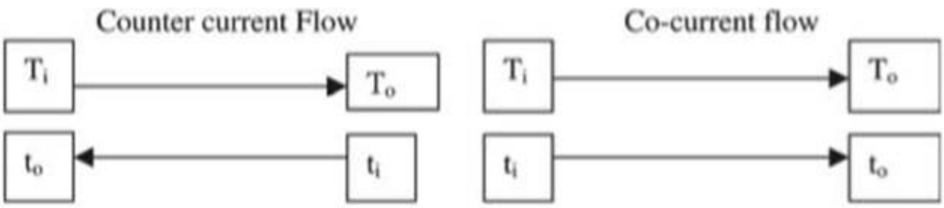


Figure 9.1: Fluid flow representation

LMTD Counter current flow = $((T_i - t_o) - (T_o - t_i)) / \ln((T_i - t_o) / (T_o - t_i))$

LMTD Co-current flow = $((T_i - t_i) - (T_o - t_o)) / \ln((T_i - t_i) / (T_o - t_o))$

7. Correction factor for LMTD to account for Cross-flow

The LMTD correction factor is a function of the temperature effectiveness and the number of tube and shell passes and is correlated as a function of two dimensionless temperature ratios. Let R and P be the two dimensionless parameters used to calculate LMTD correction factor defined by the following equations:

$R = T_a - T_b / t_b - t_a$ and $P = t_b - t_a / T_a - t_a$

Where,
T_a = inlet temperature of shell-side fluid
T_b = outlet temperature of shell-side fluid
t_a = inlet temperature of tube-side fluid
t_b = outlet temperature of tube-side fluid

Table 9.5

For R ≠ 1, compute:

$$\alpha = \left[\frac{1 - RP}{1 - P}\right]^{1/N} \qquad S = \frac{\alpha - 1}{\alpha - R} \qquad F = \frac{\sqrt{R^2+1}\,\ln\left(\dfrac{1 - S}{1 - RS}\right)}{(R - 1)\ln\left(\dfrac{2 - S(R+1 - \sqrt{R^2+1})}{2 - S(R+1 + \sqrt{R^2+1})}\right)}$$

For R = 1, compute:

$$S = \frac{P}{N - (N - 1)P} \qquad F = \frac{S\sqrt{2}}{(1 - S)\ln\left(\dfrac{2 - S(2 - \sqrt{2})}{2 - S(2 + \sqrt{2})}\right)}$$

Where,

N   Number of shell-side passes
S, α Parameters used to calculate LMTD correction factor defined by equations above.

Corrected LMTD

$$F \times LMTD$$

Overall Heat Transfer Coefficient

$$U = Q / (A \times \text{Corrected LMTD})$$

9.4.2 Example 9.1

Liquid –Liquid Heat Exchanger

A shell and tube exchanger of following configuration is considered being used for oil cooler with oil at the shell side and cooling water at the tube side.

Tube Side

460 Nos x 25.4mmOD x 2.11mm thick x 7211mm long
Pitch – 31.75mm 30^o triangular
2 Pass

Shell Side

787 mm ID
Baffle space – 787 mm
1 Pass
The monitored parameters are as below:

Parameters	Units	Inlet	Outlet
Hot fluid flow, W	kg/h	719800	719800
Cold fluid flow, w	kg/h	881150	881150
Hot fluid Temp, T_h	^OC	145	102
Cold fluid Temp, T_c	^OC	25.5	49
Hot fluid Pressure, P	bar g	4.1	2.8
Cold fluid Pressure, p	bar g	6.2	5.1
Hot fluid specific heat Capacity, C_{ph}	kJ/(kg ^OC)	2.847	
Cold fluid specific heat Capacity, C_{pc}	kJ/(kg ^OC)	4.187	

Calculation of Thermal data:
Heat Transfer Area = 264.55 m^2

1. Heat Duty: $Q = q_s + q_l$

Hot fluid, Q = 719800 x 2.847 x (145 –102) / 3600 = 24477.4 kW
Cold Fluid, Q = 881150 x 4.187 x (49 – 25.5) / 3600 = 24083.4 kW

2. Hot Fluid Pressure Drop
Pressure Drop = $P_i - P_o$ = 4.1 – 2.8 = 1.3 bar g.

3. Cold Fluid Pressure Drop
Pressure Drop = $p_i - p_o$ = 6.2 – 5.1 = 1.1 bar g.

4. Temperature range hot fluid
Temperature Range $\Delta T_h = T_{hi} - T_{ho}$ = 145 – 102 = 43 ^oC.

5. Temperature Range Cold Fluid
Temperature Range $\Delta T_c = T_{co} - T_{ci}$ = 49 – 25.5 = 23.5 ^0C.

6. LMTD
LMTD, Counter Flow = (96 – 76.5) / ln (96 / 76.5) = 85.9 ^0C.

7. LMTD Correction Factor, F, to account for Cross flow:

Computing the Parameters below:

R = (Ta-Tb) / (tb-ta) = (145-102) / (49-25.5) = 1.83

P = (tb-ta) / (Ta-ta) = (49-25.5) / (145-25.5) = 0.20

For R $\neq$ 1:

$\alpha = \{(1\text{-}RP) / (1\text{-}P)\}^{(1/N)} = \{(1\text{-} 1.83\text{x}0.2) / (1\text{-}0.2)\}^{(1/1)} = 0.793$

S = (0.793-1) / (0.793-1.83) = 0.20

$$F = \frac{\sqrt{R^2+1}\ \ln\left(\dfrac{1 - S}{1 - RS}\right)}{(R - 1)\ \ln\left(\dfrac{2 - S\,(R+1 - \sqrt{R^2+1})}{2 - S\,(R+1 + \sqrt{R^2+1})}\right)}$$

F = 0.977

8. Corrected LMTD = F x LMTD = 0.977 x 85.9 = 83.9 ^oC.

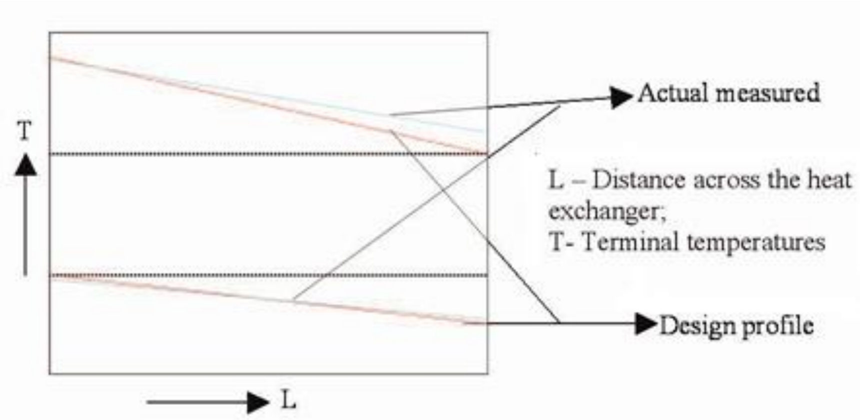
9. Overall Heat Transfer Co-efficient

$U = Q / (A \times \text{Corrected LMTD}) = 24477.4 / (264.55 \times 83.9) = 1.104\ kW/m^2.K$

Comparison of Calculated data with Design Data

Parameters	Units	Test Data	Design Data
Duty, Q	kW	24477.4	25623
Hot fluid side pressure drop, ΔP_h	Bar	1.3	1.34
Cold fluid side pressure drop, ΔP_c	Bar	1.1	0.95
Temperature Range hot fluid, ΔT_h	^{O}C	43	45
Temperature Range cold fluid, ΔT_c	^{O}C	23.5	25
Corrected LMTD, MTD	^{O}C	83.8	82.2
Heat Transfer Coefficient, U	$kW/(m^2. K)$	1.104	1.178

Inferences



Heat Duty: Actual duty differences will be practically negligible as these duty differences could be because of the specific heat capacity deviation with the temperature. Also, there could be some heat loss due to radiation from the hot shell side.

Pressure drop: Also, the pressure drop in the shell side of the hot fluid is reported normal (only slightly less than the design figure). This is attributed with the increased average bulk temperature of the hot side due to decreased performance of the exchanger.

Temperature range: As seen from the data the deviation in the temperature ranges could be due to the increased fouling in the tubes (cold stream), since a higher pressure drop is noticed.

Heat Transfer coefficient: The estimated value has decreased due to increased fouling that has resulted in minimized active area of heat transfer.

Physical properties: If available from the data or Lab analysis can be used for verification with the design data sheet as a cross check towards design considerations.

Example 9.2

(Air heater)

A finned tube exchanger of following configuration is considered being used for heating air

with steam in the tube side.
The monitored parameters are as as follows:

Parameters	Units	Inlet	Outlet
Hot fluid flow, W	kg/h	3000	3000
Cold fluid flow, w	kg/h	92300	92300
Hot fluid temperature, T	°C	150	150
Cold fluid temperature, t	°C	30	95
Hot fluid pressure, P	Bar g		
Cold fluid pressure, p	mBar g	200 mbar	180 mbar

Calculation of thermal data:

Bare tube Area = 42.8 m^2; Fined tube area = 856 m^2 .

1. Heat duty:

Hot fluid, Q = 1748 kW
Cold Fluid, Q = 1726 kW

2. Hot Fluid Pressure Drop Pressure Drop

$P_i – P_o$ =Negligible

3. Cold fluid pressure drop

$p_i – p_o$ = 200–180 = 20 mbar.

4. Temperature range hot fluid

$\Delta T = T_i – T_o$ = Not required.

5. Temperature Range Cold Fluid

$\Delta t = t_i – t_o$ = 95 – 30 = 65 °C.

6. Capacity Ratio

Capacity ratio, R = Not significant in evaluation.

7. Effectiveness

Effectiveness, S = $(t_o – t_i) / (T_i – t_i)$ = Not significant in evaluation

8. LMTD

Calculated considering only condensing part:

a). LMTD, Counter Flow =((150 – 30)–(150–95)/ ln ((150–30)/(150–95)) = 83.3 °C.

b). Correction Factor to account for cross flow
F = 0.95

9. Corrected LMTD

MTD = F x LMTD = 0.95 x 83.3 = 79 °C.

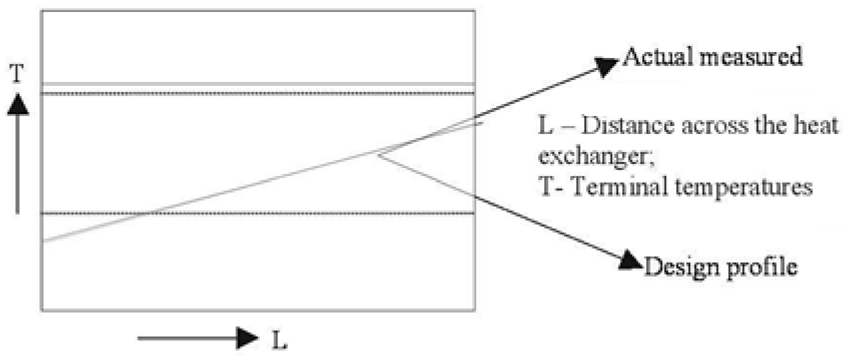
10. Overall Heat Transfer Co-efficient(HTC)

$U = Q/ A \Delta T = 1748/ (856 \times 79) = 0.026$ kW/m^2.K

Comparison of Calculated data with Design Data

Parameters	Units	Test Data	Design Data
Duty, Q	kW	1748	1800
Hot fluid side pressure drop,ΔP_h	bar	Negligible	Negligible
Cold fluid side pressure drop, Δp_c	Bar	20	15
Temperature range hot fluid, ΔT	°C		
Temperature range cold fluid, Δt	°C	65	65
Capacity ratio, R	-----		
Effectiveness, S	-----		
Corrected LMTD, MTD	°C	79	79
Heat Transfer Coefficient, U	kW/(m^2. K)	0.026	0.03

Inferences:



Heat duty: The heat exchanger is under performing.
Pressure drop: The air side pressure drop has increased even with condensation at the steam side indicating choking and blockage (dirt) on the airside.
Temperature range: No deviations.

Heat Transfer coefficient: Heat transfer coefficient decreased because of reduced fin efficiency due to choking on the air side.
Trouble shooting recommended: Pulsejet cleaning with steam / blow air on the air side is recommended and performance can be verified after cleaning. Mechanical cleaning has to be planned during down time.

9.4.3 Instruments for monitoring performance:

The test and evaluation of the performance of the heat exchanger equipment is carried out by measurement operating parameter sup stream and downstream of the exchanger. The instruments used for measurements require calibration before measurement.

Table 9.6: Instrumentation for measurement of parameters

Parameters	Units	Instruments used
Fluid flow	kg/h	Orifice flow meter, Vortex flow meter, Venturi meters, Coriollis flow meters, Magnetic flow meter
Temperature	°C	Thermo gauge for low ranges, RTD (Resistance Temperature Detector)
Pressure	bar (g)	Liquid manometers, Draft gauge, Pressure gauges Bourdon and diaphragm type, Absolute pressure transmitters.
Density	kg/m^3	Hydrometer Laboratory measurements as per ASTM standards.
Viscosity	MpaS	Viscometer Laboratory Measurements as per ASTM standards.
Specific heat capacity	J/(kg.K)	Laboratory Measurements as per ASTM standards.
Thermal conductivity	W/(m.K)	Laboratory Measurements as per ASTM standards.
Composition	%weight (or) % Volume	Laboratory Measurements as per ASTM standardsusing Chemical analysis, HPLC, GC, Spectrophotometer, etc.

9.4.4 Terminology used in Heat Exchangers

Table 9.7: Terminology used in Heat Exchangers

Terminology	Definition	Unit
Capacity ratio	Ratio of the products of mass flow rates and specific heat capacities of the cold fluid to that of the hot fluid. It can also be determined as the ratio of temperature range of the hot fluid to that of the cold fluid. Higher the ratio higher the size of the heat exchanger	
Co current flow	The fluid flows of cold and hot fluids are in same direction. Also called	

exchanger	as parallel flow.	
Counter flow exchanger	The fluid flows of cold and hot fluids are in opposite direction.	
Cross flow	The fluid flow direction of the cold and hot fluids are in cross direction	
Density	Mass per unit volume of a material	kg/m^3
Effectiveness	Ratio of the cold fluid temperature range to that of the inlet temperature difference of the hot and cold fluid. Higher the ratio lesser will be requirement of heat transfer surface	
Fouling	The formation and development of scales and deposits over the heat transfer surface diminishing the heat flux. The fouling is indicated by the increase in pressure drop.	
Fouling Factor	The reciprocal of heat transfer coefficient of the scale formed in the heat exchange process. Higher the factor lesser will be the overall heat transfer coefficient.	$(m^2.K)/W$
Heat Duty	It is the magnitude of energy or heat transferred per unit time. The capacity of the heat exchanger equipment expressed in terms of heat transfer rate.	W
Heatexchanger	Heat exchanger is designed and constructed to transmit heat (enthalpy or energy) from a high temperature hot fluid to a lower temperature cold fluid. As a result the temperature of the hot fluid decreases (or remains constant in case of losing latent heat of condensation) and temperature of the cold fluid increases (or remains constant in case of latent heat of vaporization). A heat exchanger will normally provide indirect contact heating. E.g. A cooling tower cannot be called a heat exchanger where water is cooled by direct contact with air.	
Heat Flux	The rate of heat transfer per unit surface of a heat exchanger	W/ m^2
Heat transfer surface or heat Transfer area	The surface area of the heat exchanger that provides the indirect contact between the hot and cold fluid in effecting the heat transfer. The heat transfer area is defined as the surface having both sides wetted on one side by the hot fluid and the other side by the cold fluid providing indirect contact for heat transfer	m^2
Individual Heat transfer Coefficient	The heat flux per unit temperature difference across boundary layer of the hot / cold fluid film formed at the heat transfer surface. The value of heat transfer coefficient indicates the ability of heat conductivity of the given fluid. It increases with increase indensity, velocity, specific heat, geometry of the film forming surface.	$W/(m^2.K)$
LMTD Correction factor	Calculated considering the capacity and effectiveness of a heat exchanging process. When multiplied with LMTD gives the corrected LMTD thus accounting for the temperature driving force for the cross flow pattern as applicable inside the exchanger	

Logarithmic Mean Temperature difference, LMTD	The logarithmic average of the terminal temperature approaches across a heat exchanger	°C
Overall Heat transfer Coefficient	The ratio of heat flux per unit difference in approach across a heat exchange equipment considering the individual coefficient and heat exchanger metal surface conductivity. The magnitude indicates the ability of heat transfer for a given surface. Higher the coefficient lesser will be the heat transfer surface requirement	$W/(m^2.K)$
Pressure drop	The difference in pressure between the inlet and outlet of a heat exchanger	bar
Specific heat capacity	The heat content per unit weight of any material per degree raise/fall in temperature	J/(kg.K)
Temperature Approach	The difference in the temperature between the hot and cold fluids at the inlet / outlet of the heat exchanger. The greater the difference greater will be heat transfer flux	°C
Temperature Range	The difference in the temperature between the inlet and outlet of a hot/cold fluid in a heat exchanger	°C
Thermal Conductivity	The rate of heat transfer by conduction though any substance across a distance per unit temperature difference	$W/(m^2.K)$
Terminal temperature	The temperatures at the inlet / outlet of the hot / cold fluid steams across a heat exchanger	°C
Viscosity	The force on unit volume of any material that will cause per velocity	Pa

Example 9.3

A shell-and-tube heat exchanger with 2-shell passes and 8-tube passes is used to heat ethyl alcohol (cp= 2670 J/kg·°C) in the tubes from 25°C to 70°C at a rate of 2.1 kg/s. The heating is to be done by water (C_p= 4190 J/kg·°C) that enters the shell side at 95°C and leaves at 45°C.

The LMTD correction factor for this heat exchanger is 0.82. If the overall heat transfer coefficient is 950 $W/m^2 \cdot {}^oC$, determine the flow rate of water in kg/s and surface area of the heat exchanger in m^2.

Heat duty

Cold fluid (ethyl alcohol)

Q_{cold} = 2.1 x 2670 x (70-25) J/s
= 252315 Watts
= 252.315 kW

Hot fluid (water)

$Q_{hot} = m_w$ x 4190 x (95 -45)

= mw x 209500 J/s
= (209500 m_w) Watts
= (209.5 m_w) kW
Q_{cold} = Q_{hot}

252.315 kW = (209.5 mw) kW
m_w =1.204 kg/s

LMTD = [(95-70) – (45-25)] / [ln (95-70) / (45-25)]
= 22.42°C

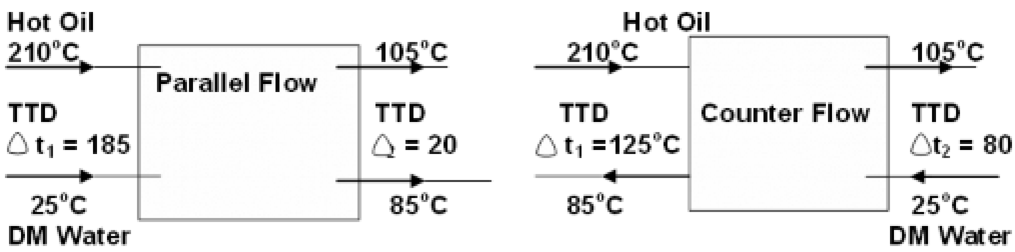
Corrected LMTD = 0.82 x 22.42
= 18.38°C

Q = U*A*LMTD
A = 252315 / (950 x 18.38)
= 14.5 m^2

Example 9.4

In an organic chemical industry 10 tonne per hour of hot oil is to be cooled from 210oC to 105oC by DM water. The DM water enters the heat exchanger at 25oC and exits at 85oC after which it is fed to the feed water storage tank of the boiler.

Depict the heat exchanger process on a schematic for the parallel and counter flow indicating the hot and cold stream temperatures along with terminal temperature difference.
Find out the LMTD for parallel and counter flow heat exchange and justify the choice of the heat exchanger.
Estimate the DM water flow rate through the heat exchanger. The specific heat of oil is 0.5 kcal/kg°C.



$$\text{LMTD parallel flow} = \frac{\Delta T_1 - \Delta T_2}{\ln (\Delta T_1 / \Delta T_2)}$$

= (185 – 20) / ln (185 / 20) = 74.19oC

LMTD Counter flow = (125 – 80) / ln (125/80) = 100.9oC

Counter flow heat exchange will yield higher LMTD and hence heat exchanger area will be

less and hence preferred.
m_c = mass flow rate of DM water
m_c x 1 x (85 – 25) = m_h x 0.5 x (210 – 105)
m_c x 1 x (85 – 25) = 10000 x 0.5 x (210 – 105)
m_c = 8750 kg/hour

10. FINANCIAL MANAGEMENT

10.1 Introduction

Businesses are increasingly realizing that prices of energy like coal, oil and natural gas are going to be expensive and there is a need to reduce energy use. Energy savings can be achieved by

- improving organizational procedures,
- adopting best operation and maintenance (O & M) practices, and/or
- Modifying or replacing existing equipment with energy efficient equipment.

In the process of implementing energy saving measures once the best operation and maintenance practice options are exhausted investment would be required for implementing the other options for modifications/retrofitting and for incorporating new technology to further reduce the energy consumption. The investment requirements for different options need to be prioritized to derive maximum benefit at least cost. The investment criteria is also governed by the level of investments required, funding options available, ease of obtaining finance, demand for their products (increasing/decreasing/static), interest & currency rate scenarios, taxation, cost of production etc.

An understanding and appreciation of project cash flows and systematic approaches to prioritize and rate the different investment options vis-à-vis the anticipated savings is essential to

- identify the benefits of the proposed measure with reference to energy savings
- identify other associated benefits such as increased productivity, improved product quality etc.

The financial approach will help energy specialist to push the business case of energy project, which is energy conservation is aligned with making money and profits.
The aim of this module is to provide understanding of

- Investment need and appraisal criteria.
- Financial analysis approach and techniques.
- Time and money relationship.
- Financial analysis techniques that apply to recurring costs and savings.
- Taxes and their effect on costs and savings.
- Rate of depreciation and its impact on investment.
- The process of borrowing money to finance an energy project and impact of costs by borrowing from different sources.
- Using excel tools for conducting financial analysis.

10.2 Investment Need and Appraisal Criteria

To consider investment in energy efficiency an organization need to be convinced that the energy project is profitable and comparable to other profit enhancement projects like increasing production. An investment proposal highlighting the following aspects should be presented to the management for active consideration of energy projects.

- The size of the energy problem it currently faces (eg. Cost of energy in terms of overall production costs, regulatory requirements etc.)
- Best operational and maintenance practices (technical and good housekeeping

measures) available to reduce energy use or improve energy efficiency at low costs (Eg. by providing appropriate training to employees).

- Proven and implemented energy saving projects that are technically and economically feasible.
- Incentives (lower tax rates, accelerated depreciation allowance, subsidies, insurance against failure, soft loans) available that make the project financially viable.
- Add on benefits from the energy project in terms of faster production, improved product quality, safety, human comfort in quantitative terms to the extent possible.
- The predicted return on investment.
- The need for investments in energy conservation can arise under following circumstances

- To retrofit existing technology& equipment and with new energy efficient one owing to
- normal replacement of equipment at end of life or
- due to substantial savings foreseen by replacing existing equipment,
- To modify or improve existing process by new technology owing to regulations or substantial savings foreseen.
- To provide staff training
- To implement or upgrade the energy information system

10.2.1 Criteria

Any investment has to be seen as an addition and not as a substitute for having effective management practices for controlling energy consumption throughout the organization. Spending money on technology or equipment for energy management cannot compensate for inadequate attention in O & M aspects to gain control over energy consumption. Therefore, before any investments are made, the first step is to ensure that:

- Organization's maintenance policy and practices tap all energy efficiency opportunities through best operation and maintenance practices and procedures.
- Energy charges are set at the lowest possible tariffs.
- Best energy forms - fuels or electricity –is used and as efficiently as possible.

Technical Appraisal criteria

The next step is to list investment opportunities. While considering these opportunities the following criteria need to be considered:

- Current energy consumption status: Compare existing energy consumption per unit of production (specific energy consumption) of a plant or process against the best benchmark figure established by peer companies or established by R &D.
- Consider availability of know-how or equipment to achieve the benchmark.
- The current state of repair and energy efficiency of the plant/building design and services, including controls
- The quality of the indoor environment like room temperatures, indoor air quality and air change rates, drafts, glare etc.
- The effect of any proposed measure on staff attitudes and behavior.

This criteria helps complete technical evaluation. Once the list of investment opportunities are shortlisted based on the above criteria the investments required and savings appraisal needs to be done.

Investment Appraisal criteria

Energy manager has to

- Identify how cost savings arising from energy management contribute to profits,
- How energy projects are comparable to other profit enhancing projects and
- How energy projects are integral to manufacturing and not standalone projects.

To do this, he/she has to work out how benefits of increased energy efficiency can be best sold to top management as:

- Reducing operating /production costs
- Increasing employee comfort and well-being and thereby scope of worker productivity.
- Improving cost-effectiveness and/or profits
- Protecting under-funded core activities
- Enhancing the quality of service or customer care delivered.
- Protecting the environment

To conduct the investment appraisal it needs to be appreciated that investment in energy efficiency is no different from any other investments. So one should apply the same criteria to energy saving investments as it applies to all its other investments.

10.3 Financial Analysis Approach and Techniques

Business's prime goal is to maximize profits. So, in assessing the financial viability of any project the proposal should answer the following questions.

- How much will the proposal cost?
- How much money will be saved by the proposal?
- Whether alternate proposals cost less and save more?

It is therefore important that the financial appraisal process allows for all these factors, with the aim of determining which investments should be undertaken, and of optimizing the benefits achieved. The appraisal process involves understanding of types of costs and their impacts on the project. This appraisal process is divided into three parts.

- The first part of this analysis will cover types of costs and their impacts.
- The second part will cover techniques for appraisal of investment.
- The third part will cover sensitivity analysis to assess risks associated in financial appraisal of projects.

10.3.1 Profit, Revenue and Costs

Business's prime goal is to maximize profits which occurs when difference between total revenue and total cost is the highest.

$$\text{Profit} = \text{Total Revenue} - \text{Total Costs}$$

Energy specialists have no control on factors impacting revenue. However, energy specialists can aid in cost minimization by

- identifying and evaluating energy conservation ways in existing systems to reduce energy consumption costs
- modifying, replacing equipment or system which involve purchasing and costs money

For proposing energy saving project the energy specialist need to explain the project's net impact on cash-flows and the net savings the project will accrue. For this an understanding of income statement and how it is prepared is essential. The following table presents a simplified structure:

$$\text{Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA)} = \text{Operating Income} - \text{Operating Expenses}$$

$$\text{Earnings before Interest and Taxes (EBIT)} = \text{EBITDA} - \text{Amortization and depreciation expenses}$$

$$\text{EBIT} = \text{Operating Revenue} - \text{Operating expenses} + \text{Non operating Income}$$

$$\text{Earnings before Taxes (EBT)} = \text{EBIT} - \text{Interest Expenses}$$

$$\text{Earnings after Taxes (EAT)} = \text{EBT} - \text{Income Tax Expenses}$$

While expenses/costs like interest, depreciation expenses, cost of energy or fuel are easy to apportion in an energy saving project, certain taxes by their income independent nature (Eg. value added tax) are neglected in financing and investment appraisals as they represent a pass-through item. However, how these taxes may affect the viability of the project needs to be appreciated by energy saving project proponents and this factor needs to be considered in sensitivity/risk analysis of the projects.
This first and second part of this module will highlight how each of these cash-flow elements effect investment choices

Example 10.1 Estimating EBIT

Sales Revenue	BDT 300,000
Cost of goods sold	BDT 5,000
Depreciation	BDT 8,000
Selling expenses	BDT 2,000
Non-operating income	BDT 500

EBIT = 300,000 − (5,000 + 8,000 + 2,000) + 500 = BDT240,500

10.3.2 Costs and Revenues

The costs and savings flow in any project can be classified as:

- Fixed costs are costs paid once like for purchasing capital equipment. Capital costs are costs associated with the design, planning, installation and commissioning of the project; and are unaffected by inflation or discount rate factors. However, instalments paid over a period of time will have time costs associated with them.
- Variable costs and savings are costs and savings paid on regular basis over a specified period of time. Variable costs include raw material costs, taxes, insurance, equipment leases, energy costs, servicing, maintenance, operating labor, and so on. Variable savings are annual savings accruing from a project that occur over the life of the project. Increases in any of these costs represent negative cash flows, whereas decreases in the costs or increase in savings represent positive cash flows.

The total cost of any project is the sum of the fixed and variable costs. Example 1 illustrates how both fixed and variable costs combine to make the total operating cost.

Example 10.2 Understanding fixed and variable costs

The capital cost of the DG set is BDT 9, 00,000, the annual output is 219 MWh, and the maintenance cost is BDT 30,000 per annum. The cost of producing each unit of electricity is 3.50 BDT/kWh. The total cost of a diesel generator operating over a 5-year period, taking into consideration both fixed and variable cost is:

Item	Type of Cost	Calculation	Cost (BDT)
Capital cost of generator	Fixed	-	9,00,000
Annual Maintenance	Fixed	30,000 x 5 (years)	1,50,000
Fuel cost	Variable	219,000 x 3.50 x 5	38,32,500
		Total Cost	48,82,500

From Example 2, it can be seen that the fixed costs represent 21.5% of the total cost. In fact, the annual electricity output of 219 MWh assumes that the plant is operating with an average output of 50 kW. If this output were increased to an average of 70 kW, then the fuel cost would become BDT 53, 65,500, with the result that the fixed costs would drop to 16.37% of the total. Thus the average unit cost of production decreases as output increases. This phenomenon is better explained using the concept of marginal analysis.

10.3.3 Marginal analysis

Marginal analysis is used to determine how much amount should be spent on energy saving projects and to compare energy projects that do not cost the same amount of money to implement.
Marginal refers to the last increment of a variable, like last LED bulb or solar panel installed in a building. The criteria applied for the project is till the marginal savings exceed the marginal cost, it is economical to add another unit. The example below illustrates the application and concept.

Example 10.3 Marginal Analysis and the proper amount of insulation

The marginal cost and cost savings of insulating a home with different thicknesses of insulation are as follows:

Amount of insulation (in inches)	Marginal cost(BDT)	
	per sq. ft of last inch	Savings per sq. ft of last inch
1	5.83	125.01
2	1.67	41.67
3	1.67	16.67
4	1.67	8.33
5	1.67	5.83

6	1.67	4.17
7	1.67	2.50
8	1.67	2.08
9	1.67	1.25

Find: the proper amount of insulation to install.

Solution: The proper amount is where marginal cost is equal to marginal cost savings. This occurs between the eighth and ninth inch of insulation. Therefore, if the home owner installs the eighth inch, the cost savings are greater than the costs. However, if the ninth inch is installed, the cost of that inch is greater than the cost savings it generates. Since insulation cannot be bought by the half-inch the least profitable inch to install in this case is the eighth inch. Therefore, eighth inches of insulation should be installed.
To achieve maximum accuracy marginal analysis should be applied to the smallest possible units. For example it is better to analyze solar collector by square foot that by 32 ft^2 collector
The concept of equating costs with savings can also be estimated using break-even analysis concept.

10.3.4 Break-even Analysis:

The concept of fixed and variable costs can be used to determine the break-even point for a proposed project. The break-even point can be determined by using the following equation.

$$\mathrm{UC_{util}} \times \mathrm{W_{av}} \times \mathrm{n} = \mathrm{FC} + (\mathrm{UC_{prod}} \times \mathrm{W_{av}} \times \mathrm{n})$$

Where,

UC_{util}	unit cost per kWh of energy bought from utility (BDT/kWh)
UC_{prod}	unit cost per kWh of produced energy(BDT/kWh)
FC	fixed costs(BDT)
W_{av}	average power output (or consumption) (kW)
n	number of hours of operation(hours)

Example 10.4 Assessing break-even point

If the electricity bought from a utility company costs an average of BDT 4.5/kWh, the breakeven point for the generator described in Example 1, when the average output is 50 kW is given by:

$$4.5 \times 50 \times \mathrm{n} = (900000 + 150000) + (3.5 \times 50 \times \mathrm{n})$$

n = 21000 hours
If the average output is 70 kW, the break-even point is given by:

$$4.5 \times 70 \times n = (9{,}00{,}000 + 1{,}50{,}000) + (3.50 \times 70 \times n)$$

n = 15000 hours
Thus, increasing the average output of the generator significantly reduces the break-even time for the project. This is because the capital investment (i.e. the generator) is being better utilized.
Having understood the broader aspect of assessing the financial viability of the project one needs to understand different elements of the cost like interest rate, taxes etc. that affect the cash flows.

Factors that need to be considered in calculating annual cash flows are:

- Interest on loan or deposits.
- Taxes, using the marginal tax rate applied to positive or negative cash flows.

- Asset depreciation, the depreciation of plant assets over their life; depreciation is a "paper expense allocation" rather than a real cash flow, and therefore is not included directly in the life cycle cost. However, depreciation is "real expense" in terms of tax calculations, and therefore does have an impact on the tax calculation noted above. For example, if a BDT 10, 00,000 asset is depreciated at 20% and the marginal tax rate is 40%, the depreciation would be BDT 200,000 and the tax cash flow would be BDT 80,000 and it is this later amount that would show up in the costing calculation.
- Intermittent cash flows occur sporadically rather than annually during the life of the project, relining a boiler once every five years would be an example.

10.4 Time Value of Money

Financial organizations like banks offer interest on money deposited and charge interest on money lent. Businesses borrow for projects if the earnings anticipated are more than the interest charged for borrowing. If businesses have enough internal resources they may invest their own funds if the interest difference between money deposited vs borrowed is high and yields net benefits. The interest charges change the value of money with time creating the problem of equating cash flows which occur at different times. To account for the time value of money and to equate cash flows it is therefore important to understand

- How interest charges are calculated.
- How to equate cash flows (single cash flow or series of uniform and non-uniform cash flows) to a common basis of time either in present or future terms (called present value or future value of money)?

10.4.1 How interest charges are calculated.

Two types of interest is normally charged namely simple interest and compound interest.
In simple interest calculation charges are calculated as a fixed percentage of the capital that is borrowed. In compound calculation interest charged is calculated on the sum of the unpaid capital and the interest charges up to that point. The equations for calculation of simple and compound interest and the concept are given in the table below.

Table 10.1: Calculation and Concept of Simple and Compound interest

<table>
<tr><td>Simple Interest</td><td>Compound interest</td></tr>
<tr><td>$\text{Simple interest (SI)} = \frac{r}{100} \times P \times n$</td><td>$\boldsymbol{Compound\ Interest\ (CI) = P \times (1 + \frac{r}{100})^{n}}$</td></tr>
<tr><td>Total Repayment value based on SI (TRV) $= \frac{P \times n \times r}{100} + P$</td><td>Total Repayment value baseed on CI (TRV) $= P \times (1 + \frac{r}{100})^{n} + P$</td></tr>
<tr><td>
<table>
<tr><td></td><td></td><td></td><td>$r_{3rd\ yr}$ = (1xr)</td></tr>
<tr><td></td><td></td><td>$r_{2nd\ yr}$ = (1xr)</td><td>$r_{2nd\ yr}$ = (1xr)</td></tr>
<tr><td></td><td>= (1xr)</td><td>$r_{1st\ yr}$ = (1xr)</td><td>$r_{1st\ yr}$ = (1xr)</td></tr>
<tr><td>P= BDT 1</td><td>BDT 1</td><td>BDT 1</td><td>BDT 1</td></tr>
<tr><td>$FV_{0th\ yr}$</td><td>$FV_{1st\ yr}$</td><td>$FV_{2nd\ yr}$</td><td>$FV_{3rd\ yr}$</td></tr>
</table>
</td><td>
<table>
<tr><td>P= BDT1</td><td>x (1 + r)</td><td>x(1+r)</td><td>x(1+r)</td></tr>
<tr><td colspan="2">Amount First Year end</td><td></td><td></td></tr>
<tr><td colspan="3">Amount Second year end</td><td></td></tr>
<tr><td colspan="4">Amount Third year end</td></tr>
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<tr><td colspan="2"><table><tr><td>= P= BDT 1</td><td>= 1 + r</td><td>= 1 + r + r</td><td>= 1 + r + r + r</td></tr></table></td><td colspan="2"></td></tr>
<tr><td rowspan="2">P</td><td rowspan="2">Principal value</td><td>n</td><td>repayment period(years)</td></tr>
<tr><td>SI</td><td>Simple interest</td></tr>
<tr><td rowspan="2">r</td><td rowspan="2">interest rate (%)</td><td>CI</td><td>Compound Interest</td></tr>
<tr><td>TRV</td><td>total repayment value which represents the future value of principal borrowed</td></tr>
</table>

The techniques involved in calculating simple and compound interest are illustrated in Example 5.

Example 10.5 Calculating Simple and Compound Interest

A company borrows BDT 3,00,00,00 to finance a new boiler installation. If the interest rate is 10% per annum and the repayment period is 5 years. Calculate the value of the total repayment and the monthly repayment value, assuming (i) simple interest and (ii) compound interest.

Assuming simple interest:

Total repayment = 30, 00,000 + (10/100 x 30, 00,000 x 5) = BDT45, 00,000
Monthly repayment = 45, 00,000 / (5x12) = BDT75, 000

Assuming compound interest

Repayment at end of year 1 = 30, 00,000 + (10/100 x 30, 00,000)
= BDT 33, 00,000
Repayment at end of year 2 = 33, 00,000 + (10/100 x 33, 00,000)
= BDT 36, 30,000
Similarly, the repayments at the end of years 3, 4 and 5 can be calculated: Repayment at end of year 3 = BDT 39, 93,000
Repayment at end of year 4 = BDT 43, 92,300
Repayment at end of year 5 = BDT 48, 31530

Alternatively, the following equation can be used to determine the compound interest repayment value.

Total repayment value = $30{,}00{,}000 \times (1 + 10 / 100)^5$ = BDT 48,31,530
Monthly repayment = 4831530/ (5 x12) = BDT80, 525

It can be seen that by using compound interest, the lender recoups an additional BDT 33, 1530. Lenders usually charge compound interest on loans.

10.4.2 How to equate cash flows?

The method by which various cash flows are related is called future, or the present value concept.

For example, if money can be deposited in the bank at 10% interest, then a BDT 100 deposit will be worth BDT 110 in one year's time. Thus the BDT 110 in one year is a future value equivalent to the BDT 100 present value.

In the same manner, BDT 100 received one year from now is only worth BDT 90.91 in today's money (i.e. BDT 90.91 plus 10% interest equals BDT 100). Thus BDT 90.91 represents the present value of BDT 100 cash flow occurring one year in the future. If the interest rate were something different than 10%, then the equivalent present value would also change.

The relationship between present and future value is determined as follows:

$$\text{Future Value} = \text{NPV}\,(1+\text{i})^{\text{n}}$$

$$\text{NPV} = \frac{\text{FV}}{(1+\text{i})^{\text{n}}}$$

Where

FV = Future value of the cash flow

NPV= Net Present Value of the cash flow

i = Interest or discount rate

n = Number of years in the future

Also, the present and future value can be determined using the Present Value Interest Factor (PVIF) and Future Value Interest Factor (FVIF) using Appendix 1 and 2.

$$\text{FV}_{\text{n}}(\text{BDT } 1) = \text{PV} \times \text{FVIF (n years, r)}$$

$$\text{PV}_{\text{n}}(\text{F}) = \text{F} \times \text{PVIF (n years, r)}$$

Example 10.6: Future Value of a Fixed Amount Greater than BDT1.

A house decides to buy two 1 m^2solar collector panels at BDT20000 each and has the option of paying BDT 20000 now or BDT 30000 5 years from now. The relevant interest rate is 10%. Let us find the payment plan that will minimize the cost the house owner must pay using future value method. The future value is calculated using any of the three methods given below.

Solution:

The future value of BDT 20000, 5 years from now, is calculated as follows

Method 1: using the formula $\text{Future Value} = \text{NPV}\,(1+\text{i})^{\text{n}}$

FV = $20000(1+0.1)^5$ = BDT 32210

Method 2: using FVIF tables (Appendix 2 given at the back of this module).

FV5 (BDT 2000) = 20000 x FVIF (5 years, 10%)

= 20000 x 1.6105

= BDT 32210

Method 3: using MS Excel.

MS Excel Formula = FV (rate, no. of periods, principal, 1)

C4 =-FV(C3,C2,,C1,1)

	A	B	C
1	Principal	BDT	20000
2	No. of years	years	5
3	Rate of interest	%	10%
4	FV(25000)	BDT	32210

FVIF (5 years, 10%) is obtained from Appendix 2. Thus, the future value of the BDT 30000 payment in 5 years is less than the BDT 20000 payment now, and the business could wait 5 years and pay BDT 30000 to minimize the cost. Instead of paying BDT2000 now, the business could put the BDT20000 in a bank account drawing 10% interest per year. After 5 years, the business would have BDT32210 in the account and could pay the BDT30000 and use the remaining BDT2210 for something else. If the BDT20000 is paid now, the business in effect loses BDT2210.

10.4.3 Cost Escalation

The price of various goods and services increases with time. To estimate the cost escalation, future value can be usefully applied. An example is illustrated below.

Example 10.7 Escalation of energy cost

The price of the natural gas is BDT 290 per Million Metric BTU as on May 2018. Let us consider this will increase 12% per year for the next 10 years. Estimate the price of natural gas after 1st, 6th and 10th years

Solution:

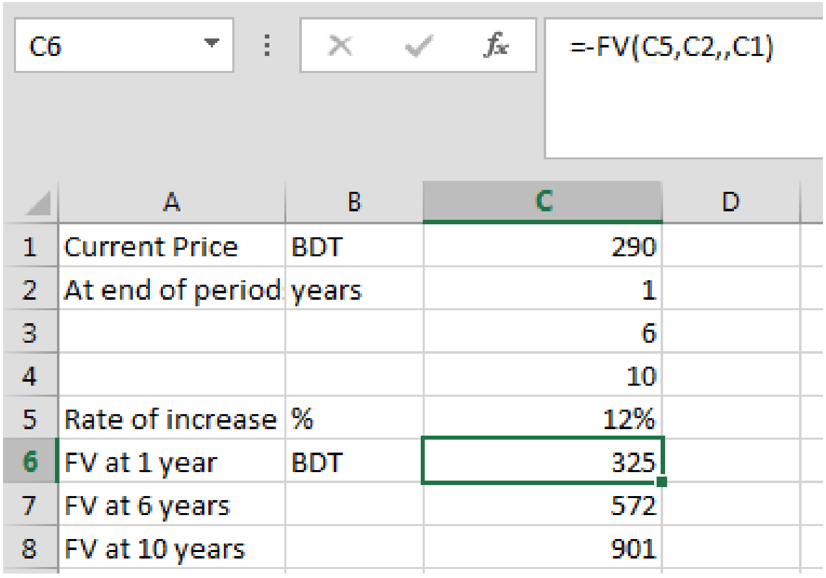
Method 1: using the formula $\text{Future Value} = \text{NPV}\,(1 + \text{i})^{\text{n}}$

FV of NG at end of	BDT
1 year	325
6 years	572
10 years	901

Method 2: Using Formula: Price of natural gas after n years = Price now x FVIF (n year, 12%)
Solution:

Price of natural gas after 1 year	= BDT 290 x 1.1200 = BDT 325
Price of natural gas after 6 years	= BDT 290 x 1.9738 = BDT 572
Price of natural gas after 10 years	= BDT 290 x 3.1058 = BDT 901

Method 3: Using MS Excel Formula: FV (rate, no. of periods, principal ,1)



C6 =-FV(C5,C2,,C1)

	A	B	C	D
1	Current Price	BDT	290	
2	At end of period	years	1	
3			6	
4			10	
5	Rate of increase	%	12%	
6	FV at 1 year	BDT	325	
7	FV at 6 years		572	
8	FV at 10 years		901	

10.4.4 Annuity

Most projects yield series of cost savings contrary to one-time amount as per the present/future value equation. These series of cash-flows are to be standardized, because savings occur at different times. The standardization can be done by assessing the present/future value of these flow of savings. This method of standardization of series of cash flows is called annuity. Annuity is a pattern of uniform/equal cash flow that is received or spent each year.
The present/future value of annuity can be calculated using the following formulas.

$$\mathrm{FVA_n(BDT\ 1)} = (1+r)^{n-1} + (1+r)^{n-2} + \cdots \ldots + (1+r)^1 + \mathrm{BDT1}$$

Where,
FVA_n(BDT 1) = Future value of an annuity of BDT 1 after paying for n time periods at ‘r’ rate of interest.

$$\mathrm{FVA_n(M)} = \mathrm{M} \times \mathrm{FVIF_a(nyears, r)}$$

Where,
FVA_n(M) = Future value (sum) of an annuity of M after paying for n time periods at ‘r’ rate of interest.
M = Amount of the annuity
$FVIF_a$(n years, r) = Future value of an annuity of BDT 1, after paying for n time periods at ‘r’ rate of interest. (This can be obtained from Appendix 4)
n = Number of years the annuity is received

Example 10.8 Sum of an annuity of more than BDT 1 per year

An intermediate raw material store room in a factory building is equipped with 300 watts (W) of fluorescent lighting, although only 30W are needed. The lights burn 24 hours per day (24 h/d), 365 days per year (d/yr).
Find: the cost savings per year resulting from the reduction in watts in the store room and the future value of these cost savings after 4 years if cost of electricity is BDT 5 per kilowatt hour (kWh), and the interest rate is 8%.

Method 1: Using formula

$$\mathrm{FVA_n(BDT\ 1)} = 11826 \times \{(1+0.08)^3 + (1+0.08)^2 + (1+0.08)^1 + 1\}$$

Method 2: Using FVIF Appendix 2:
$FVA_n(M) = M \times FVIF_a(4 \text{ years}, 8\%)$

	Units	Value
Current wattage of bulb	W	300
Replace with	W	30
Electricity usage hours per year	h/yr	8760
Electricity savings per year	Wh/yr	2365200
1 kWh	Wh	1000
Savings in electricity	kWh/yr	2365.2
Cost of electricity	BDT/kWh	5
Cost savings per year	BDT/yr	11826
Thus, the savings associated with this project form an annuity of BDT 11826 per year.		
Annuity per year	BDT/yr	11826
Interest rate	%	8
Future value at end of	years	4
Future value of annuity at end of 4 years	BDT	53289

Method 3: MS Excel Formula = FV(rate, no. of periods, M)

C14 =-FV(C12%,C13,C11)

	A	B	C	D
1			Value	units
2	Current wattage of bulb	=	300	W
3	Replace with	=	30	W
4	Electricity ussage hours per year	=	8760	h/yr
5	Electricity savings per year	=	2365200	Wh/yr
6	1 kWh	=	1000	Wh
7	Savings in electricity	=	2365.2	kWh/yr
8	Cost of electricity	=	5	BDT/kWh
9	Cost savings per year	=	11826	BDT/yr
10	Thus, the savings associated with this project form an annuuity of BDT 11826 per year.			
11	Annuity per year	=	11826	BDT/yr
12	Interest rate	=	8	%
13	Future value at end of	=	4	years
14	Future value of annuity at end of 4 years	=	53289	BDT

The present value of an annuity is the opposite of the future value (sum) of an annuity. The present value of an annuity is the BDT value that answers this question: What fixed amount today will accumulate after the given number of years to exactly the same amount as the sum (future value) of the annuity? It is given by the following formula:

$$PVA_{n_0}(\text{BDT } 1) = \text{PVIF}\,(1 \text{ year}, r) + \text{PVIF}\,(2 \text{ year}, r) + \cdots \ldots \ldots + \text{PVIF}\,(n \text{ year}, r)$$

Where,
PVA_n(BDT 1) = Present value of an annuity of BDT1 for n time periods at ‘r’ rate of interest.
PVIF = Present Value interest factor (the Present Value of BDT 1) associated with the given interest rate and year in the future.

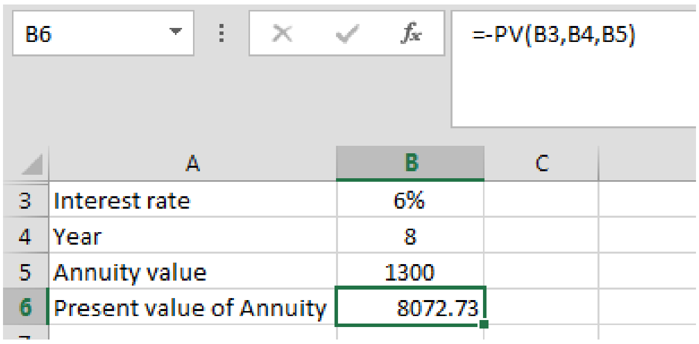
Example 10.9 The present value of an annuity

A star hotel to reduce electricity costs considered replacing CFL bulbs of a certain wattage with LED bulbs of a lower wattage in every hallway of a hotel. These bulbs have an expected life of 8 years, and will save BDT 1300 per year for the 8-year period. The interest rate is 6%.
Find: The present value of the cost savings.

Solution:
Method 1: Using PVIF Factor (Appendix 1)
The cost savings form an annuity of BDT 1300 per year for 8 years. The cost savings associated with each year will be discounted @ 6% individually back to the present, and the sum will be taken as shown in table below.

Year	Cost Savings (BDT)	PVIF	Present value (BDT)
1	1300	0.9434	1226.42
2	1300	0.8900	1157
3	1300	0.8396	1091.48
4	1300	0.7921	1029.73
5	1300	0.7473	971.49
6	1300	0.7050	916.5
7	1300	0.6651	864.63
8	1300	0.6274	815.62
Present value of Annuity			8072.87

Method 2: Using MS Excel Formula:



However, in reality costs change annually so does savings leading to non-uniform/irregular flow of cost savings. For example the cost of LED bulbs may reduce or cost of electricity may rise annually. In such cases annuity is calculated by taking the sum of the present value of the savings associated with each year.

Example 10.10 Present value of an Irregular flow cost savings

Modern retail stores prefer giving customer’s good shopping experience and offer choices to

see and feel the goods before purchasing. Accordingly a modern retail store conducting business for 310days/yr (12 h/d, Monday through Saturday) in an area of 25000 ft^2 floor space illuminated its store using400 fixtures having four 40W bulbs in each fixture. To reduce electricity costs while maintaining visual comfort the store was recommended to remove two lamps from every other light fixture in store. The cost of electricity is BDT 5 per kWh and the contract ensures the same cost for the next 5 years, after which it will increase to BDT 5.5 per kWh. The relevant interest rate is 10%.
Find: The annual cost savings associated with this project, and the present value of these savings over the next 10 years.

Solution:

	Unit	Value
Floor area of store	ft^2	25000
Business hours per year	h/yr	3720
Total no. of light fixtures at store	nos.	400
No. of bulbs in each fixture	nos.	4
Wattage of each bulb	W	40
Cost of electricity for first 5 years	BDT/kWh	5
Cost of electricity for next 5 years	BDT/kWh	5.5
No. of fixtures where change is made	nos	200
No. of lamps removed at each fixture	nos	2
Electricity saved per fixture	W	80
Watts conserved in store area	W	16000 = 16KW
Amount of energy saved per year	kWh/yr	59520
Cost savings for first 5 years	BDT/y	297600
Cost savings for next 5 years	BDT/y	327360

So, the savings of the project form an annuity of 297600/yr for first 5 years, followed by another 5 year annuity of 327360/yr. The present value of these cost savings may be determined by finding the present value of the cost savings associated with each year (a series of fixed amounts) and then taking their sum. This process is shown below.

Year	Cost savings(BDT)	PVIF (Appendix 1)	Present Value(BDT)
1	297600	0.9091	270548
2	297600	0.8264	245937
3	297600	0.7513	223587
4	297600	0.6830	203261
5	297600	0.6209	184780
6	327360	0.5645	184795
7	327360	0.5132	168001
8	327360	0.4665	152713
9	327360	0.4241	138833
10	327360	0.3855	126197

These can be assessed using energy and economic efficiency and marginal analysis of cost and savings as explained below.

Method 3: Using MS Excel Formula:

I17 =-PV(I16,5,I14)

	G	H	I
14	Cost Savings for 1st five years		297600
15	Cost savings for next five years		327360
16	Rate of Interest		10%
17	Present Value of savings for first 5 years		1128138
18	Value of savings from 6th year to 10th year at		1240952
19	Present Value of savings from 6th to 10th year		770534
20	Present Value		1898672

10.5 Financial Analysis Techniques

For management to consider any energy project the overall costs of all possible alternatives should be known and the project should save at least as much as it costs. Depending on the complexity and level of investment the following techniques can be used.
The basic criteria for financial investment appraisal include:

Simple Payback- a measure of how long it will be before the investment makes money, and how long the financing term needs to be
Return on Investment (ROI) and Internal Rate of Return (IRR)- measure that allow comparison with other investment options
Net Present Value (NPV) and Cash Flow - measures that allow financial planning of the project and provide the company with all the information needed to incorporate
Energy efficiency projects into the corporate financial system.

Initially, when you can identify no or low cost investment opportunities, this principle should not be difficult to maintain. However, if your organization decides to fund a rolling program of such investments, then over time it will become increasingly difficult for you to identify opportunities, which conform to the principle. Before you'll reach this position, you need to renegotiate the basis on which investment decisions are made.
It may require particular thoroughness to ensure that all the costs and benefits arising are taken into account. As an approximate appraisal, simple payback (the total cost of the measure divided by the annual savings arising from it expressed as years required for the original investment to be returned) is a useful tool.
As the process becomes more sophisticated, financial criteria such as Discounted Cash Flow, Internal Rate of Return and Net Present Value may be used. If you do not possess sufficient financial expertise to calculate these yourself, you will need to ensure that you have access, either within your own staff or elsewhere within the organization, to people who can employ them on your behalf.
There are two quite separate grounds for arguing that, at least long after their payback periods. Such measure does not need to be written off using fast discounting rates but can be regarded as adding to the long term value of the assets. For this reason, short term payback can be an inadequate yardstick for assessing longer term benefits. To assess the real gains from investing

in saving energy, you should use investment appraisal techniques, which accurately reflect the longevity of the returns on particular types of technical measures.

10.5.1 Simple Pay Back Period

Simple Payback Period (SPP) represents, as a first approximation; the time (number of years) required to recover the initial investment (First Cost), considering only the Net Annual Saving. The annual net cost saving is the least savings achieved after all the operational costs have been met. This is the simplest technique that can be used to appraise a proposal, despite its limitations that it does not consider cash-flows after the payback period, which may be substantial. Hence It can be considered as a metric to measure a project's capital recovery and not profitability.

The simple payback period is usually calculated as follows:

$$\text{Simple payback period (years)} = \frac{\text{Capital cost of the project (in BDT)}}{\text{Net Annual Savings (in BDT)}}$$

Example 10.11 Calculating pay-back period.

A new small cogeneration plant installation is expected to reduce a company's annual energy bill by BDT 4, 86,000. If the capital cost of the new boiler installation is BDT22, 20,000 and the annual maintenance and operating costs are BDT 42,000, the expected payback period for the project can be worked out as follows.

Solution

$$\text{Payback} = \frac{22{,}20{,}000}{(4{,}86{,}000 - 42{,}000)} = 5 \text{ years}$$

According to the payback criterion, the shorter the payback period, the more desirable the project

Example 10.12 Payback Period when savings each year are equal

A SME (Small and Medium scale enterprise) considered a desktop computer with energy monitoring and management software to pursue energy conservation opportunities. The system has an original cost of BDT 3, 20,000 and will generate net after tax savings of BDT 40,000 per year.
Find: The payback period of this investment
Solution:

$$Payback\ period = \frac{BDT\ 320000}{BDT\ 40000} = 8\ years$$

If savings each year are not constant then the above equation is not applicable. In such case savings from each year are added until their sum equals the original investment. An example is shown below.

Example 10.13 Payback period when savings each year are not constant

In the above example (example 13)), suppose the annual net cost savings is BDT40,000 for the first year will increase 12% each year thereafter, whereas, the original price of the system remains at BDT 3,20,000.Find the payback period of this investment.
Solution: Consider the following table.

Year	Original Savings (first year)(BDT)	Escalation FVIP 12%	Actual savings for year(BDT)	Cumulative savings at end of year(BDT)
0	40000	Given	40000	40000
1	40000	1.12	44800	84800
2	40000	1.2544	50176	134976
3	40000	1.4049	56196	191172
4	40000	1.5735	62940	254112
5	40000	1.7623	70492	324604

Table: Payback period with an irregular flow of cost savings

The Table above shows, the total cost savings of the project become equal to its cost at the end of the fifth year. Thus, a rough estimate of the payback period if 5 years.

Advantages

A widely used investment criterion, the payback period seems to offer the following advantages:
It is simple, both in concept and application. Obviously a shorter payback generally indicates a more attractive investment. It does not use tedious calculations.
It favors projects, which generate substantial cash inflows in earlier years, and discriminates against projects, which bring substantial cash inflows in later years but not in earlier years.

Limitations

It fails to consider the time value of money. In the above example the net cost savings of 5th year are counted equally with those of the first year. This violates the most basic principle of financial analysis, which stipulates that cash flows occurring at different points of time can be added or subtracted only after suitable compounding/discounting.
The payback method does not consider savings that are accrued after the payback period has finished. This leads to discrimination against projects that generate substantial cash inflows in later years.

Example 10.14 Understanding limitation of pay-back period

To consider impact of cash flows after the payback period is over, consider the cash flows of two projects, A and B: The payback criterion prefers A, which has a payback period of 3 years, in comparison to B, which has a payback period of 4 years, even though B has very substantial cash inflows in years 5 and 6.

Investment/ Savings in Year	Cash Flow of A (BDT)	Cash Flow of B (BDT)
1	50,000	20,000

2	30,000	20,000
3	20,000	20,000
4	10,000	40,000
5	10,000	50,000
6	-	60,000

10.5.2 Return on Investment (ROI)

ROI expresses the "annual return" from the project as a percentage of capital cost. The annual return takes into account the cash flows over the project life and the discount rate by converting the total present value of ongoing cash flows to an equivalent annual amount over the life of the project, which can then be compared to the capital cost. ROI does not require similar project life or capital cost for comparison.

This is a broad indicator of the annual return expected from initial capital investment, expressed as a percentage:

$$\text{ROI} = \frac{\text{Annual Net Cash Flow}}{\text{Capital Cost}} \times 100$$

Limitations

It does not take into account the time value of money.

It does not account for the variable nature of annual net cash in flows.

Example 10.15 Calculating rate of return

A municipality replaced 1000,40 W CFL street light bulbs with 25 W LED bulbs investing BDT 30,00,000. The life of LED bulbs is 10 years. The annual electricity savings due to replacement of bulbs is 65700 kWh considering 12 hrs operation. Assuming electricity cost of BDT 5.0, annualized yearly savings are BDT 201849 considering interest rate of 10%. The return on investment would be:

$$\text{ROI} = \frac{201849}{3000000} \times 100 \ = 6.73\%$$

10.5.3 Benefit-Cost Analysis

The net cost savings of an energy project are often called the benefits of the project. If the actual net cost savings per year are identical and known, they can be used to compute the benefit-cost ratio. The formula for this ratio is as follows:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{Actual net cost savings/yr}}{\text{Net cost savings/yr needed to recover original investment}}$$

If the benefit-cost ratio is larger than one, then the net cost savings of a project (or its benefits) exceed its cost and the investment is profitable. If the ratio is less than one, then the net cost savings needed per year are greater than those actually obtained and the investment is not profitable.

10.5.4 Profitability index

Another technique, which can be used to evaluate the financial viability of projects, is the profitability index. The profitability index can be defined as:

$$\text{Profitability Index} = \frac{\text{Sum of the discounted net savings}}{\text{Capital Costs}}$$

The higher the profitability index, the more attractive the project.

Example 10.16 Calculating and comparing profitability index of two different projects

Consider two projects A and B with investment of BDT 30,000 in project A and BDT 35000 in project B. The assessment of profits indicate project A generates profit of BDT 10,254 and project B generates profit of BDT 10,867 over the life of project tenure. The profitability index can be calculated as given below.

$$\text{For Project A: Profitability index} = \frac{10{,}254}{30{,}000} = 0.342$$

$$\text{For Project B: Profitability index} = \frac{10{,}867}{33{,}000} = 0.33$$

Project A is therefore a better proposal than Project B.
This index is a quick tool to consider the better alternative among two different proposed projects.

10.6 Discounted Cash Flow Methods

In order to overcome the weakness of simple pay-back assessment method a number of discounted cash flow techniques have been developed, which are based on the fact that money invested in a bank will accrue annual interest. If a fixed amount of money or a series of equal, yearly cost savings (an-annuity) is associated with a certain time period, then an amount associated with the present – which is equal to the future amount can be calculated. The latter figure is the present value of the fixed amount, or the annuity. This process is called discounting. The two most commonly used techniques are the 'net present value' and the 'internal rate of return' methods.

10.6.1 Net Present Value

Because an amount of money in the present is worth more than the same amount at any point in the future due to time value of money, all amounts should be converted to the same period to arrive at net present value. The net present value method achieves this by quantifying the impact of time on any particular future cash flow. This is done by equating each future cash flow to its current value today, in other words determining the present value of any future cash flow. The present value (PV) is determined by using an assumed interest rate, usually referred to as a discount rate. Discounting is the opposite process to compounding. Compounding determines the future value of present cash flows, where" discounting determines the present value of future cash flows. The net present value (NPV) of a project is equal to the sum of the present values of all the cash flows associated with it. Symbolically,

$$\text{NPV} = \frac{CF_0}{(1+k)^0} + \frac{CF_1}{(1+k)^1} + \ldots . + \frac{CF_n}{(1+k)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+k)^t}$$

Where
NPV = Net Present Value
CF_t = Cash flow occurring at the end of year 't' (t=0,1,….n) n = life of the project
k = Discount rate

The discount rate (k) employed for evaluating the present value of the expected future cash flows should reflect the risk of the project.

Example 10.17 Calculating NPV

To illustrate the calculation of net present value, consider a project, which has the following cash flow stream:

Investment/Savings year-wise	Cash Flow (BDT)
1	200,000
2	200,000
3	300,000
4	300,000
5	350,000

The cost of capital, k, for the firm is 10 per cent. The net present value of the proposal is:

$$\text{NPV} = -\frac{1{,}000{,}000}{(1.10)^0} + \frac{200{,}000}{(1.10)^1} + \frac{200{,}000}{(1.10)^2} + \frac{300{,}000}{(1.10)^3} + \frac{300{,}000}{(1.10)^4} + \frac{350{,}000}{(1.10)^5} = 5{,}273$$

Example 10.18 Calculating NPV

In a cement plant, 16000 liter lubricant/yr is used to manually lubricate grinding equipment gear trains every 2 hours, using. An automatic oil-mist system was proposed by a supplier claiming that his automatic system uses only 600liters/yr without compromising on lubricating functionality. The gear lubricant costs BDT 100/liter. The expected life of the system is 5 years. The system would cost BDT 6, 00,000 to purchase and install. Maintenance costs would be BDT 37000/yr. The interest rate is 9%. Find the net present value of installing the automatic oil-mist system.

Solution:

	unit	value
Current lubricant usage	lit/yr	16000
Cost of lubricant	BDT/lit	100
Lubricant required in new oil-mist system	lit/yr	600
Life of new system	yr	5
Capital cost of new system	BDT	6,00,000
Maintenance cost of new system	BDT/yr	37000
Interest rate	%	9
Solution		
Lubricant savings due to new system	lit/yr	15400
Cost savings	BDT/yr	5,40,000
Thus, the cost savings associated with this project form an annuity of BDT 154000/yr for 5 years. The present value of this annuity is as follows:		
PV(cost savings)	BDT	59,90,063
PV(maintenance requirement)	BDT	1,43,917

Present value of the purchase of installation and maintaining new system		
PV(all costs of new system)	BDT	7,43,917
Net Present Value (NPV)	BDT	52,46,146
Since NPV > 0 the project should be implemented		
Alternate method:		
net cost savings/yr (Savings – Cost)	BDT/yr	1503000
Present value of net cost savings	Net savings/yr x PVIFa (5 years, 9%)	
	BDT	5846146
Net Present value	PVof(net cost savings - Capital cost)	
	BDT	5246146

When analyzing one particular project, the NPV methods offers no special advantage. However, the NPV methods becomes most useful when a particular function can be performed in more than one way.

Example 10.19 Comparing NPV of different options

Example: Suppose that in Examples above, 4 different oil-mist systems were available at differing costs, each system could reduce costs by a different amount, and each had a NPV greater than zero (total cost savings exceed total costs in present-value terms).

Choice among alternative Oil-mist systems

System	Capital Cost (BDT)	Maintenance cost (BDT/yr)	Cost Savings (BDT)	NPV (BDT)
1	4,00,000	60,000	10,00,000	32,56,272
2	5,00,000	55,000	12,00,000	39,53,651
3	5,50,000	45,000	15,00,000	51,09,443
4	6,00,000	25,000	15,00,000	51,37,236

In this example, System 4 would be implemented since it has the highest NPV. Once the alternative ways of achieving a goal have been determined, the NPV method can be used to choose from among the alternatives.
However, it is common practice to use a discount factor (DF) when calculating present value. The discount factor is based on an assumed discount rate (i.e. interest rate) and can be determined by using equation.

$$DF = (1 + \frac{IR}{100})^{-n}$$

The product of a particular cash flow and the discount factor is the present value.

$$PV = S \times DF$$

The values of various discount factors computed for a range of discount rates (i.e. interest rates) are shown in the annexure-1.

Example 10.20 Evaluation of financial merits using NPV

Using the net present value analysis technique evaluate the financial merits of the proposed projects shown in the table below assuming an annual discount rate of 8%.

	Project A	Project B

Capital cost in BDT	30,000	30,000
Year	Net annual savings (BDT)	Net annual savings (BDT)
1	6,000	6,600
2	6,000	6,000
3	6,000	6,300
4	6,000	6,300
5	6,000	6,000
6	6,000	6,000
7	6,000	5,700
8	6,000	5,700
9	6,000	5,400
10	6,000	5,400
Total net savings at the end of year 10	60,000	60,000

Solution

The annual cash flows should be multiplied by the annual discount factors for a rate of 8% to determine the annual present values, as shown in the table below:

Formula: $\mathrm{NPV_{Benefits}} = \mathrm{NPV_{Savings}} - \text{Capital Cost}$

Year	Discount Factor for 8% (a)	Project A		Project B	
		Net savings (BDT) (b)	Present value (BDT) (a*b)	Net savings (BDT) (b)	Present value (BDT) (a*b)
0	1.000	(30,000)	(30,000)	(30,000)	(30,000)
1	0.926	6,000	5,556.00	6,600	6,111.60
2	0.857	6,000	5,142.00	6,000	5,656.20
3	0.794	6,000	4,764.00	6,300	5,002.20
4	0.735	6,000	4,410.00	6,300	4,630.50
5	0.681	6,000	4,086.00	6,000	4,086.00
6	0.630	6,000	3,780.00	6,000	3,780.00
7	0.583	6,000	3,498.00	5,700	3,323.10
8	0.540	6,000	3,240.00	5,700	3,078.00
9	0.500	6,000	3,000.00	5,400	2,700.00
10	0.463	6,000	2,778.00	5,400	2,500.20
		NPV=10,254		NPV=10,868	

Method 2: Using MS Excel

In Excel for each year PV is calculated according to formulas explained in earlier examples. The sum of present values gives the NPV.

The net present value represents the net benefit over and above the compensation for time and risk.

It can be seen that over a 10 year life-span the net present value of Project A is BDT 10,254, while for Project B it is BDT 10,868. Therefore Project B is the preferential proposal.

Hence the decision rule associated with the net present value criterion is: "Accept the project if the net present value is positive and reject the project if the net present value is negative".
Advantages
The net present value criterion has considerable merits.
It takes into account the time value of money.
It considers the cash flow stream in its project life.

Limitations

The whole credibility of the net present value method depends on a realistic prediction of future interest rates, which can often be unpredictable. It is prudent therefore to set the discount rate slightly above the interest rate at which the capital for the project is borrowed. This will ensure that the overall analysis is slightly pessimistic, thus acting against the inherent uncertainties in predicting future savings.

10.6.2 Internal Rate of Return

This method calculates the rate of return that the investment is expected to yield. The internal rate of return (IRR) method expresses each investment alternative in terms of a rate of return. The expected rate of return is the interest rate for which total discounted benefits become just equal to total discounted costs (i.e. net present benefits or net annual benefits are equal to zero, or for which the benefit / cost ratio equals one). The criterion for selection among alternatives is to choose the investment with the highest rate of return.
The discount rate which achieves a net present value of zero is known as the internal rate of return (IRR) The higher the internal rate of return, the more attractive the project.

The rate of return is usually calculated by a process of trial and error, whereby the net cash flow is computed for various discount rates until its value is reduced to zero and is calculated using the equation given below.

$$0 = \frac{CF_0}{(1+k)^0} + \frac{CF_1}{(1+k)^1} + \cdots \dots \dots \dots + \frac{CF_n}{(1+k)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+k)^t}$$

Where,
CF_t cash flow at the end of year "t"
k discount rate
n life of the project

- CF_t is negative if expenditure> savings
- CF_t is positive if expenditure < savings.

In the net present value calculation we assume that the discount rate (cost of capital) is known and determine the net present value of the project. In the internal rate of return calculation, we set the net present value equal to zero and determine the discount rate (internal rate of return), which satisfies this condition.

Example 10.21 Evaluate internal rate of return

To illustrate the calculation of internal rate of return, consider the cash flows of a project:

Year	0	1	2	3	4
Cash Flow	(1,00,000)	30,000	30,000	40,000	45,000

The internal rate of return is the value of "K" which satisfies the following equation:

$$1{,}00{,}000 = \frac{30{,}000}{(1+k)^1} + \frac{30{,}000}{(1+k)^2} + \frac{40{,}000}{(1+k)^3} + \frac{45{,}000}{(1+k)^4}$$

The calculation of "K" involves a process of trial and error. We try different values of "K" till we find that the right-hand side of the above equation is equal to 1, 00,000. Let us, to begin with, try K-15 per cent. This makes the right-hand side equal to:

$$\frac{30{,}000}{(1.15)} + \frac{30{,}000}{(1.15)^2} + \frac{40{,}000}{(1.15)^3} + \frac{45{,}000}{(1.15)^4} = 1{,}00{,}802$$

This value is slightly higher than our target value, 100,000. So we increase the value of k from 15 per cent to 16 per cent. (In general, a higher k lowers and a smaller k increases the right-hand side value). The right-hand side becomes:

$$\frac{30{,}000}{(1.16)} + \frac{30{,}000}{(1.16)^2} + \frac{40{,}000}{(1.16)^3} + \frac{45{,}000}{(1.16)^4} = 98{,}641$$

Since this value is now less than 100,000, we conclude that the value of k lies between 15 per cent and 16 per cent. For most of the purposes this indication suffices.

Example 10.22 Calculate the internal rate of return (IRR)

The manager of a warehouse is considering the installation of an air lock at the loading door. The size of the door is 20 ft x 17.5 ft. The door is open for 10minutes -12 times a day – 5 days per week. The inside building temperature is 70°F. The heating season is October – April (30 weeks). The average outside temperature during the heating season is 38.4°F. The air flow velocity through the open door is 500 fpm. Steam, which supplies 2100 Btu/kg, is used for heating. The cost of steam is BDT 0.5/kg. The cost of the air-lock is BDT 17,70,000 installed. Assume the life of the air lock is 20 years.
Find the internal rate of return (IRR) of the purchase and installation cost of the air lock.
Use conversion factor: 0.0183 Btu = 1 ft^3-°F.

	Unit	Value
Door size	ft	20 x 17.5
Area of door	ft^2	350
Door opening time	minutes	10
No. of times it is opened in a day	nos	12
No .of days it is opened in a week	nos	5
No. of weeks heating is required	nos	30
Inside building temperature	°F	70
Outside temperature	°F	38.4
Air flow velocity	fpm	500
Heat value of steam	Btu/kg	2100
Cost of steam	BDT/kg	0.5
0.0183Btu supplied to 1 ft^3 air raises temp by 1°F	ft^3-°F	1

Cost of air lock installed	BDT	17,00,000
Life of air lock	years	20
Conversion factor	BTU ft^3 °F	0.0183
Solution:		
Air entering door	ft^3/min	175000
Temperature difference between inside and outside	°F	31.6
Heat loss	Btu/min	101199
Heating cost per min of door opening	BDT/min	24.095
Annual cost savings due to installation of air lock	BDT/yr	433710
Thus, this project yields uniform savings of BDT 433710/yr over its life.		
Proper PVIa (20 years, ?%)		3.920
From Appendix 3, for 20 year period the proper PVIa of 3.92 corresponds to 25% interest PVIa of 3.954 and26% interest PVIa of 3.808. Since the PVIa needed is equal to 3.920 the exact value of internal rate of return (i)can be interpolated as follows. i = 0.25 + (0.26-0.25) x 3.954 / (3.954 +3.808) = 0.255, or 25.5 percent		

Example 10.23 Assess project whether it will achieve desired IRR

A proposed project requires an initial capital investment of BDT 20,000. The cash flows generated by the project are shown in the table below:

Year	Cash flow (BDT)
0	(20,000)
1	6,000
2	5,500
3	5,000
4	4,500
5	4,000
6	4,000

Given the above cash flow data, let us find out the internal rate of return for the project.

Solution

Year	Cash flow (BDT)	8% discount rate		12% discount rate		16% discount rate	
		Discount factor	Present value (BDT)	Discount factor	Present value (BDT)	Discount factor	Present value (BDT)
0	(20,000)	1.000	(20,000)	1.000	(20,000)	1.000	(20,000)
1	6,000	0.926	5,560	0.893	5,358	0.862	5,172
2	5,500	0.857	4,713.5	0.797	4,383.5	0.743	4,086.5
3	5,000	0.794	3,970	0.712	3,560	0.641	3,205
4	4,500	0.735	3,307.5	0.636	2,862	0.552	2,484
5	4,000	0.681	2724	0.567	2,268	0.476	1,904
6	4,000	0.630	2520	0.507	2,028	0.410	1,640
		NPV=2791		NPV=459.5		NPV=(1,508.5)	

It can clearly be seen that the discount rate which results in the net present value being zero lies somewhere between 12% and 16%.
For12% discount rate, NPV is positive; for 16% discount rate, NPV is negative. Thus, for some discount rate between 12 and 16 percent, present value benefits are equated to present value costs. To find the value exactly, one can interpolate between the two rates as follows:

$$\text{Internal rate of return} = 0.12 \times (0.16 - 0.12) \times \frac{459.5}{\left(459 - (-1{,}508.5)\right)} \times 100$$

Internal rate of return = 12.93%
Thus, the internal rate of return for the project is 12.93 %. At first sight both the net present value and internal rate of return methods look very similar, and in some respects are. Yet there is an important difference between the two. The net present value method is essentially a comparison tool, which enables a number of projects to be compared, while the internal rate of return method is designed to assess whether or not a single project will achieve a target rate of return.

Advantages

A popular discounted cash flow method, the internal rate of return criterion has several advantages:
It takes into account the time value of money.
It considers the cash flow stream in its entirety.
It makes sense to businessmen who prefer to think in terms of rate of return and find an absolute quantity, like net present value, somewhat difficult to work with.
Limitations

A central point of criticism of the IRR Method is the implicit reinvestment assumption, which can lead to unrealistically high profitability rates. The IRR method should consequently be backed by a NPV calculation.

Example 10.24 Calculate IRR based on project savings

Calculate the internal rate of return (i) for an economizer that will cost BDT 500,000, will last 10 years, and will result in fuel savings of BDT 150,000 each year. Find the ‘i’ that will equate the following:

BDT 500,000 = 150,000 x PV (A = 10 years, i =?)
To do this,

Step I: Calculate proper PVI_a

$$\text{Proper PVIa} = \frac{\text{Cost}}{\text{Annual savings}} = \frac{500000}{150000} = 3.33$$

From PVI_a Table in Appendix 3, for 10 years period check PVIa values corresponding to proper PVI_a i.e., 3.33. As can be seen from PVIa table, the IRR falls between 27% and 28% with PVI_a of 3.364 and 3.269.

To find the rate more exactly, one can interpolate between the two rates as follows:
i = 0.27 + (0.28-0.27) x 3.364 / (3.364+3.269) = 0.275, or 27.5 percent

10.6.3 Modified Internal Rate of Return

Whenever the cost savings of an energy project are not the same each year, then the preceding techniques cannot be used to determine IRR. The present value of the net cost savings of each year should be discounted back to the present and summed, using various interest rates. That interest rate, which leads to a total present value of net cost savings that is very close to the original cost of the project, is the approximate internal rate of return.

In order to eradicate the limitation of the conventional IRR method, the modified IRR method replaces the implicit reinvestment assumption with an explicit reinvestment rate. This method requires an external project-unrelated investment opportunity rate. All positive future cash flows are discounted with this external interest rate to acquire their respective present value. Possible reinvestment rates are:

Average corporate return rate: Applicable in case the cash returns are invested in the operating activities of accompany.

Achievable interest rate in the capital market: Cash returns are invested in the capital market.

Loan interest rate: In case the cash returns are used to repay loans, the respective loan interest rate should be used.

The MIRR is calculated as follows:

$$\boldsymbol{IRR_{mod}} = \sqrt[n]{\frac{\sum_{t=1}^{n} \boldsymbol{E_t} \times (\boldsymbol{1} + \boldsymbol{r_{EXT}})^{\boldsymbol{n-t}} + \boldsymbol{R_n}}{\sum_{t=0}^{n} \boldsymbol{A_t} \times (\boldsymbol{1} + \boldsymbol{r_{EXT}})^{\boldsymbol{-t}}}} - \boldsymbol{1}$$

Where

IRR_{mod} = modified Internal Rate of Return
At = negative Cash Flows at timed
E_t = positive Cash Flows at timed
r_{EXT} = reinvestment rate
n = operating life
R_n = remaining value at timed

Table 10.2: Comparison of Project Evaluation Methods

Method	Needed Information	Result
Capital recovery factor and benefit-cost	Original cost; Life of investment; Relevant interest rate	Needed cost savings per year to recover original investment; Ratio that shows how cost savings relate to cost
Net Present value	Original cost; Life of investment; Relevant interest rate; Net cost savings per year	How much total present value of net cost savings exceeds (or less than) original cost
Internal Rate of Return	Original cost; Life of net cost savings per year	Interest rate which shows how net cost savings relate to original cost
Payback period	Original cost; Net cost savings per year	Rough estimate of time needed to recover original cost.

11. SENSITIVITY AND RISK ANALYSIS

Many of the cash flows in the project are based on assumptions that have an element of uncertainty. The present day cash flows, such as capital cost, energy cost savings, maintenance costs etc. can usually be estimated fairly accurately. Even though these costs can be predicted with some certainty, it should always be remembered that they are only estimates. Cash flows in future years normally contain inflation components which are often "guesstimates" at best. The project life itself is an estimate that can vary significantly.
Sensitivity analysis is an assessment of risk. Because of the uncertainty in assigning values to the analysis, it is recommended that a sensitivity analysis be carried out - particularly on projects where the feasibility is marginal.

- How sensitive is the project's feasibility to changes in the input parameters?
- What if one or more of the factors in the analysis is not as favorable as predicted?
- How much would it have to vary before the project becomes unviable?
- What is the probability of this happening?

Suppose, for example, that a feasible project is based on an energy cost saving that escalates at 10% per year, but a sensitivity analysis shows the break-even is at 9% (i.e. the project becomes unviable if the inflation of energy cost falls below 9%). There is a high degree of risk associated with this project - much greater than if the break-even value was at 2%.

Many of the computer spreadsheet programs have built in "what if" functions that make sensitivity analysis easy. If carried out manually, the sensitivity analysis can become laborious - reworking the analysis many times with various changes in the parameters.

Sensitivity analysis is undertaken to identify those parameters that are both uncertain and for which the project decision, taken through the NPV or IRR, is sensitive. Switching values showing the change in a variable required for the project decision to change from acceptance to rejection are presented for key variables and can be compared with post evaluation results for similar projects.

For large projects and those close to the cut-off rate, a quantitative risk analysis incorporating different ranges for key variables and the likelihood of their occurring simultaneously is recommended. Sensitivity and risk analysis should lead to improved project design, with actions mitigating against major sources of uncertainty being outlined
The various micro and macro factors that are considered for the sensitivity analysis are listed below.

Micro factors

- Operating expenses (various expenses items)
- Capital structure
- Costs of debt, equity
- Changing of the forms of finance e.g. Leasing
- Changing the project duration

Macro factors

Macro-economic variables are the variable that affects the operation of the industry of which the firm operates. They cannot be changed by the firm's management. Macro-economic variables, which affect projects, include among others:

- Changes in interest rates
- Changes in the tax rates
- Changes in the accounting standards e.g. methods of calculating depreciation
- Changes in depreciation rates
- Extension of various government subsidized projects e.g. extension of subsidies for setting up industries in under-developed regions or subsidizing renewables use etc.
- General employment trends e.g. improved employment conditions result in shortage of skilled man-power and thereby increases their hiring costs and salaries.
- Imposition of regulations on environmental and safety issues in the industry
- Energy Price change
- Technology changes

The sensitivity analysis will bring changes in various items in the analysis of financial statements or the projects, which in turn might lead to different conclusions regarding the implementation of projects.

11.1 Impact of interest rates on cash flows

In assessing likely interest out-go, it needs to be appreciated that interest rates charged may be fixed or variable. For assessment purposes long time average rates may be considered. The interest rate trend for Bangladesh is shown in figure below.

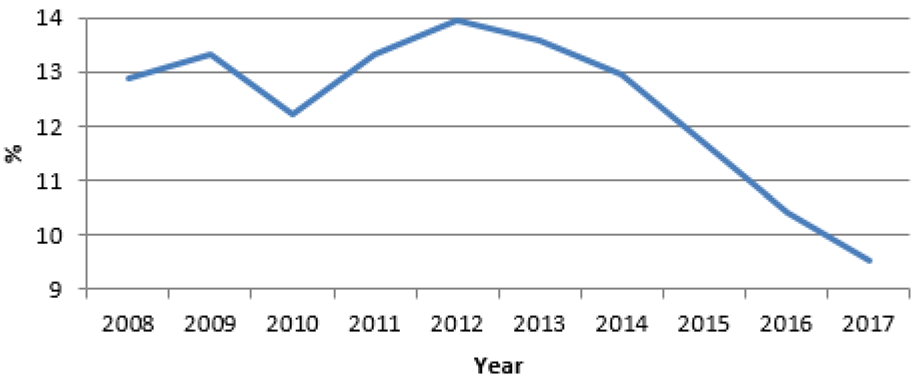


Figure 11.1: Lending Rate in Bangladesh
(Source: World Bank)

11.2 Impact of Depreciation rates on cash flows

In the above sections and examples the basic principles associated with the financial analysis of projects were considered, but they do not consider the following important issues:
The capital value of plant and equipment generally depreciates overtime.
General inflation reduces the value of savings as time progresses. For example, BDT 1000 saved in 1 years’ time will be worth more than BDT 1000 saved in 10 years’ time.

These issues are addressed by considering the income-relevant decrease of the value of the investment called depreciation or amortization. While there are various methods available, national legislations usually dictate the method to be used to determine amortization and depreciation expenses. Knowledge of legislated depreciation rates may help in minimizing tax outflows, for example accelerated depreciation is allowed for energy efficient or clean energy products or technologies. The most commonly used methods to calculate depreciation are as follows.

- Straight line method
- Reducing balance method
- Sum of years depreciation method
- Units of production depreciation method

11.2.1 Straight-line Depreciation

Straight-line depreciation is the simplest and most common type of depreciation. It is calculated by dividing the initial asset value of the investment by its operating lifetime. The depreciation amount is consequently identical for every period.

$$\text{Depreciation Amount} = \frac{\text{Initial Value of Asset}}{\text{Operating Lifetime}}$$

Example 11.1 Calculate straight-line depreciation

Consider a pump which is purchased at BDT 10,000 and has a life of 5 years. Calculate the schedule of depreciation using straight line depreciation method.

$$\text{Depreciation Amount} = \frac{10000}{5} = 2000$$

The pump depreciates by BDT 2000 every year for 5 years. The schedule of depreciation can be tabulated as follows:

Year	Depreciation Amount	Remaining Value
0	0	10,000
1	2,000	8,000
2	2,000	6,000
3	2,000	4,000
4	2,000	2,000
5	2,000	0

11.2.2 Reducing-balance Depreciation

The reducing-balance depreciation is characterized by declining depreciation amounts over the duration of an asset's operating lifetime. This is due to depreciation ensues with a constant percentage rate. Depreciation amounts are calculated as follows:

Depreciation amount= Depreciation rate * Remaining value of the previous year

Example 11.2 Calculate reducing-balance depreciation

Consider a pump which is purchased at BDT 10,000 and has a life of 5 years and depreciates at a fixed rate of 30% every year. Calculate the schedule of depreciation.

Year	Depreciation Amount (BDT) (= 0.3 x Remaining value of previous year)	Remaining Value (BDT)
0	0	10,000
1	3,000	7,000
2	2,100	4,900
3	1,470	3,430
4	1,029	2,401
5	720	1,681

This approach would never reach a remaining value of zero. Therefore, it is common to switch to straight-line depreciation by the time the depreciation amount of the reducing- balance method drops below the depreciation amount of the straight-line method.

Example 11.3 Assessing when to switch to straight-line method from reducing balance method of depreciation.

Consider a pump which is purchased at BDT 10,000 and has a life of 5 years and depreciates at a fixed rate of 30% every year. Calculate the schedule of depreciation.
Step I: Calculate depreciation value by both methods as given in Table below:

Year	Straight – Line method		Reducing balance method	
	Depreciation Amount	Remaining Value	Depreciation Amount	Remaining Value
0	0	10,000	0	10,000
1	2000	8,000	3,000	7,000
2	2000	6,000	2,100	4,900
3	2000	4,000	1,633	3,267
4	2000	2,000	1,633	1,633
5	2000	0	1,633	0

Step II: Check the year in which depreciation amount by reducing-balance method falls below the straight-line value.
As can be seen, in year 3 the depreciation amount of the straight-line method (4,900/3 =1,633) which exceeds the reducing-balance amount (1,470).
Step III: From the year in which the depreciation amount by reducing-balance method falls below the straight-line value, consider depreciation by straight-line method.
Hence, in the above example, the last three years are depreciated by straight-line method.

11.2.3 Sum of Years Depreciation

Like the previously presented depreciation method, the sum of years depreciation method results in higher depreciation amounts in the early years of an asset. A year's respective depreciation amount is calculated by dividing the total remaining years by the sum of years of operating lifetime and multiplying it with initial asset value. In year three, this would consequently be

$$\text{Depreciation amount (year 3)} = \frac{3}{1+2+3+4+5} \times \text{initial Asset Value}$$

Example 11.4 Calculate depreciation based on sum of years method

Year	Assessment Method	Depreciation Amount	Remaining Value
0	$\frac{0}{(1+2+3+4+5)} \times 10000$	0	10,000
1	$= \frac{5}{(1+2+3+4+5)} \times 10000$	3,333	6,667
2	$= \frac{4}{(1+2+3+4+5)} \times 10000$	2,667	4,000
3	$= \frac{3}{(1+2+3+4+5)} \times 10000$	2,000	2,000
4	$= \frac{2}{(1+2+3+4+5)} \times 10000$	1,333	667
5	$= \frac{1}{(1+2+3+4+5)} \times 10000$	667	0

11.2.4 Units of Production Depreciation

In this depreciation method the value of the asset is decreased according to the actual usage of the asset. In order to fully depreciate an asset, a total production output has to be presumed. The annual depreciation amounts are calculated as follows:

$$\text{Depreciation amount (year X)} = \frac{\text{Units produced (year X)}}{\text{Total production output}} \times \text{Initial Asset Value}$$

Example 5 Calculate depreciation based on rate of production

It is assumed that an asset with an initial value of 10,000 monetary units will have a total lifetime output of 24,000 units.
Step I: Consider units produced in a particular year
Step II: Calculate ratio of units produced to total lifetime output
Step II: Multiply the ratio with initial value of asset

Year	Production Units	Depreciation Amount	Remaining Value
0		0	10,000
1	6,000	2,500	7,500
2	6,000	2,500	5,000
3	5,000	2,083	2,917
4	4,000	1,667	1,250
5	3,000	1,250	0

The capital depreciation of an item of equipment can be considered in terms of its salvage value at the end of the analysis period. The Example 10.8 illustrates the point.

Example 11.6 Assessing impact of Salvage Value on NPV

It is proposed to install a heat recovery equipment in a factory. The capital cost of installing the equipment is BDT 20,000 and after 5 years its salvage value is BDT 1500. The savings accrued by the heat recovery device are as shown below. Calculate the net present value after 5 years with and without considering salvage value. Assume discount rate to be 8%.

Savings accrued

Year	1	2	3	4	5
Savings (BDT)	7000	6000	6000	5000	5000

Solution

Year	Discount Factor for 8% (a)	Capital investment (BDT) (b)	Net savings (BDT) (c)	Present value (BDT) (a)*(b+c)
0	1.000	(20,000)		(20,000)
1	0.926		7,000	6,482
2	0.857		6,000	5,142
3	0.794		6,000	4,764
4	0.735		5,000	3,675
5	0.681	1,500	5,000	4,426.5
				NPV=4489.5

It is evident that over a 5-year life span the net present value of the project is BDT 4489.50. Had the salvage value of the equipment not been considered, the net present value of the project would have been only BDT 3468.00.

11.3 Changes in inflation rates: Real value

Inflation can be defined as the rate of increase in the average price of goods and services. In some countries, inflation is expressed in terms of the retail price index (RPI), which is determined centrally and reflects average inflation over a range of commodities. Because of inflation, the real value of cash flow decreases with time. The real value of sum of money (S) realized in n years' time can be determined using the equation.

$$\mathrm{RV} = \mathrm{S} \times (1 + \frac{\mathrm{R}}{100})^{-\mathrm{n}}$$

Where

RV real value of S realized in n years' time

S value of cash flow in n years' time

R inflation rate(%)

As with the discount factor, it is common practice to use an inflation factor when assessing the impact of inflation on a project. The inflation factor can be determined using the equation.

$$\text{Inflation Factor, IF} = (1 + \frac{\mathrm{R}}{100})^{-\mathrm{n}}$$

The product of a particular cash flow and inflation factor is the real value of the cash flow.

$$\mathrm{RV} = \mathrm{S} \times \mathrm{IF}$$

The application of inflation factors is considered in Example 10.9.

Example 11.7 Calculate and assess impact of inflation on NPV of project

Recalculate the net present value of the energy recovery scheme in Example 11.3, assuming the discount rate remains at 8% and the rate of inflation is 5%.
Solution:
Because of inflation;

$$\text{Real interest rate} = \text{Discount Rate} - \text{Rate of inflation}$$

Therefore Real interest rate = 8 – 5 = 3%

Year	Capital investment (BDT)	Net savings (BDT)	Real Discount Factor for3%	Present value (BDT)
0	(20,000)		1.000	(20,000)
1		7,000	0.971	6,471
2		6,000	0.943	5,132
3		6,000	0.915	4,743
4		5,000	0.888	3,654
5	1,500	5,000	0.863	4,398
				NPV=4,398

When inflation is not considered the NPV is BDT 4489.5 (ref Example 11.3) and if inflation is considered the NPV is BDT 4,398 demonstrating the depreciation of money value due to inflation.

11.4 Considering Taxes in Financing and Investment

In making investment calculations, the previous elaboration has completely ignored tax issues. In practice, taxes influence the profitability of investments and consequently need to be considered when taking an investment decision.
From the perspective of a company, taxes represent out payments that need to be considered in the cash flows. Taxes can be income-independent and –dependent.

- Income-independent taxes: These taxes are usually property and consumer taxes. They can be easily included with the other operational out-payments. While value- added taxes are income-independent taxes as well, they are neglected in financing and investment as it represents a pass-through item.
- Income-dependent taxes: These taxes are corporate or income taxes, reducing the cash return of an investment. Essential for the determination of the level of the income-dependent taxes are not the return cash flows but the profit or loss before taxes, which has to be multiplied by the tax rate to find out the required tax payment.

In order to determine the payable income tax of an investment opportunity, taxable profits have to be estimated for every year of operating life by reducing taxable sales by taxable relevant operating expenses. The latter includes cash expenses like staff and material costs and non-cash expenses like depreciation and amortization. In case debt capital is utilized in financing an investment opportunity, interest obligations have to be considered as well.
The forecast of income-dependent payable taxes is problematic, because the respective tax rate may change over the operating life of an investment due to changes in the political framework as can be seen from the corporate tax rates shown in figure below. The effort for determining payable taxes precisely must consequently be assessed as disproportionately. Thus, investment calculation usually resorts to the simplified specification of payables taxes.

Figure 11.2: Corporate Tax Rate: Bangladesh
(Source: tradingeconomics.com, National Board of Revenue (NBR), Bangladesh)

While the overall corporate tax rate can be considered for preliminary assessment of tax liability there is a need for informing themselves on tax rates that may vary with type of product (Eg: Tax on revenue from renewable power could be less), the scale of industry (Eg: Micro, Small and Medium industries may be given tax preference), market segment for the product (Eg: exports or priority industrial sectors (eg: textile industries) may be taxed less owing to their capacity to earn foreign exchange or generate employment) etc. Hence, it is important to understand and assess tax liability before any investment not only to arrive at real rate of returns but maximize returns utilizing tax exemptions if allowed.
In calculating taxes normally expenses are deducted from the gross revenue earned. After deducting the applicable expenses depending on the tax rate specified for the industry/product, the taxable amount is calculated by multiplying earnings after deductible expenses with the applicable tax rate.

Example 11.8 Calculate income tax expenses

Consider a unit with an asset price of 10,000 BDT with an operating lifetime of 5 years and a corporate tax rate of 30 percent. The unit follows the straight-line depreciation method. It is assumed that the project is financing entirely with debt capital at an interest rate of 5 percent. The principal repayment is done uniformly across the life of unit. The operating income generated and expenses incurred are given in table below.

	Year 1	Year 2	Year 3	Year 4	Year 5
Operating income	8,500	9,000	9,500	10,000	10,500
Operating expenses	-1,000	-1,200	-1,400	-1,600	-1,800

Develop an income statement showing depreciation, interest and tax calculations.

$$\text{EBITDA} = \text{Operating income} - \text{Operating Expenses}$$
$$\text{Depreciation Expenses} = \frac{\text{Initial Value of Asset}}{\text{Operating Lifetime}} = \frac{10000}{5} = 2000$$
$$\text{EBIT} = \text{EBITDA} - \text{Depreciation Expenses}$$
$$\text{Interest Expenses} = \text{Remaining Assest value } \times \text{interest rate}$$
$$\text{Remaining Asset Value } = \text{Asset Value in previous year} - \text{Yearly Depreciation}$$

$$\text{EBT} = \text{EBIT} - \text{Interest Expenses}$$
$$\text{Income tax expenses} = \text{EBIT } \times \text{income tax rate}$$
$$\text{EAT} = \text{EBT} - \text{Income Tax expenses}$$

Using the above formulae, construct the income statement as given below to assess tax liabilities.

	Year 1	Year 2	Year 3	Year 4	Year 5
Operating income	8,500	9,000	9,500	10,000	10,500
Operating expenses	-1,000	-1,200	-1,400	-1,600	-1,800
EBITDA (A-B)	7,500	7,800	8,100	8,400	8,700
Depreciation expenses	-2,000	-2,000	-2,000	-2,000	-2,000
EBIT	5,500	5,800	6,100	6,400	6,700
Interest expenses	-500	-400	-300	-200	-100
EBT	5,000	5,400	5,800	6,200	6,600
Income tax expense	-1,500	-1,620	-1,740	-1,860	-1,980
EAT	3,500	3,780	4,060	4,340	4,620

11.5 Impact of taxes on cash flows

As can be seen from the above example taxes impact returns. The net impact of taxes on returns again can be assessed using the net present value concept. This is illustrated using the previous example.

Example 11.9 Assessing impact of taxes on NPV of cash flows

Year	Discount factor (10%) (a) (Appendix 6)	Cash Flow after Taxes (b) (EAT)	Net Present Value after Taxes (a*b)	Cash Flow before Taxes (c) (EBT)	Net Present Value before Taxes (a*c)
0	1.000	-10,000	-10,000	-10,000	-10,000
1	0.909	3,500	3,182	5,000	4,545
2	0.826	3,780	3,124	5,400	4,463
3	0.751	4,060	3,050	5,800	4,358
4	0.683	4,340	2,964	6,200	4,235
5	0.621	4,620	2,869	6,600	4,098
		NPV= 5,189		NPV= 11,699	

It can be seen that payable taxes have a considerable effect on the profitability of the project. In practice, the assessment of investment opportunities must be made after due consideration of income tax expenses.

11.6 Impact of Different Depreciation Methods and taxation on Cash flows

The type of depreciation method has a considerable impact on the resulting profitability of a project as well. Example 16 (Chapter 10) compares the Cash Flow after Taxes by using straight-line depreciation with the Cash Flow after Taxes by using reducing-balance (see Example 11 of Chapter 10). Due to the higher depreciation expenses in the earlier periods, the respective payable taxes are reduced and the first actual cash returns are increased by the latter method.

Thus, because of the time value of money, the project would be more profitable with reducing-balance depreciation. As a consequence, besides considering taxes, presented possible tax investment incentives have to be investigated.

Example 11.10 Impact of depreciation and income taxes on NPV of cash flows.

Year	Discount factor (10%) (a)	Cash Flow after Taxes (straight-line) (b)	Net Present Value after Taxes (a*b)	Cash Flow after Taxes (Reducing-balance) (c)	Net Present Value after Taxes (a*c)
0	1.000	-10,000	-10,000	-10,000	-10,000
1	0.909	3,500	3,182	3,800	3,455
2	0.826	3,780	3,124	3,810	3,149
3	0.751	4,060	3,050	3,950	2,968
4	0.683	4,340	2,964	4,230	2,889
5	0.621	4,620	2,869	4,510	2,800
		NPV= 5,189		NPV= 5,260	

12. FINANCING OPTIONS

Most high budget projects involve seeking external finances while smaller projects can be funded by internal revenues. While financial viability assessments methods remain the same for both external financing agencies may scrutinize the project more deeply to assess the viability. Also, external financing agencies may conduct deeper sensitivity analysis to assess risks before funding. The higher the risk normally the charges for financing will be higher. Also, as per the mandate of the financing agencies they may fund projects preferentially (Eg: Government supported or credit guaranteed projects may get preference). High risk projects may not be financed by banks but by venture funds who look for higher returns. A project proponent needs to be aware of these aspects and may include financing agencies likely to fund the proposed project in their proposals.
The various options for financing energy management projects.

For projects requiring external funding

- By obtaining a bank loan
- By raising money from stock market
- By awarding the project to Energy Service Company(ESCO)

- For projects funded from internal resources:
- From a central budget
- From a specific departmental or section budget such as engineering
- By retaining a proportion of the savings achieved.

While procedures for seeking funding from banks as loans or from stock markets as equity are well established ESCOs and performance contracting have emerged as new tools that reduces the risks of considering an energy efficiency or conservation project. Hence, implementing energy saving projects using ESCOs and performance contracting methods are only considered.

12.1 Energy Performance Contracting and Role of ESCOS

If the project is to be financed externally, one of the attractive options for many organizations is the use of energy performance contracts delivered by energy service companies, or ESCOs. ESCOs are usually companies that provide a complete energy project service, from assessment to design to construction or installation, along with engineering and project management services, and financing. In one way or another, the contract involves the capitalization of all of the services and goods purchased, and repayment out of the energy savings that result from the project.
In performance contracting, an end-user (such as an industry, institution, or utility), seeking to improve its energy efficiency, contracts with ESCO for energy efficiency services and financing.
In some contracts, the ESCOs provide a guarantee for the savings that will be realized, and absorbs the cost if real savings fall short of this level. Typically, there will be a risk management cost involved in the contract in these situations. Insurance is sometimes attached, at a cost, to protect the ESCO in the event of savings shortfall.
Energy efficiency projects generate incremental cost savings as opposed to incremental revenues from the sale of outputs. The energy cost savings can be turned into incremental cash

flows to the lender or ESCO based on the commitment of the energy user (and in some cases, a utility) to pay for the savings.

12.1.1 What are performance contracts?

Performance contracting represents one of the ways to address several of the most frequently mentioned barriers to investment. Performance contracting through an ESCO transfers the technology and management risks away from the end-user to the ESCO.

For energy users reluctant to invest in energy efficiency, a performance contract can be a powerful incentive to implement a project. Performance contracting also minimizes or eliminates the up-front cash outlay required by the end-user. Payments are made over time as the energy savings are realized.

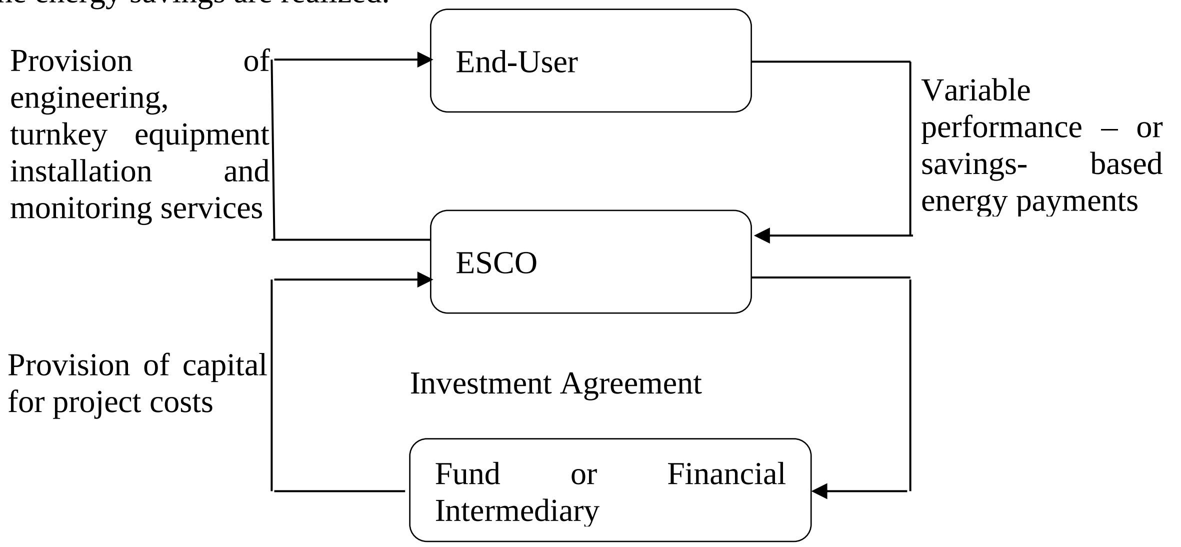


Figure 12.1

What is Performance Contracting?

The core of performance contracting is an agreement involving a comprehensive package of services provided by an ESCO, including:

- An energy efficiency opportunity analysis
- Project development
- Engineering
- Financing
- Construction/ Implementation
- Training
- Monitoring and Verification

Monitoring and verification, is key to the successful involvement of an ESCO in performance contracting where energy cost savings are being guaranteed.

ESCOs are not “bankers” in the narrow sense. Their strength is in putting together a package of services that can provide guaranteed and measurable energy savings that serve as the basis for guaranteed cost savings. But, the energy savings must be measurable. Figure above shows ESCO role.

12.2 Self-Financing Energy Management

Large and capital intensive energy savings project funding or implementation are considered based on external financing smaller or easily implementable projects are considered by internal teams. To sustain continuous improvement the teams need to be encouraged and funding mechanism for systematically assessed viable projects needs to be created.

One way to make energy management self-financing is to split savings to provide identifiable returns to each interested party. This has the following benefits:

- Assigning a proportion of energy savings to your energy management budget means you have a direct financial incentive to identify and quantify savings arising from your own activities.
- Separately identified returns will help the constituent parts of your organization understanding whether they are each getting good value for money through their support for energy management.
- If operated successfully, splitting the savings will improve motivation and commitment to energy management throughout the organization since staff at all levels will see a financial return for their effort or support.
- But the main benefit is on the independence and longevity of the energy management function.

12.3 Ensuring Continuity

After implementation of energy savings, your organization ought to be able to make considerable savings at little cost (except for the funding needed for energy management staff). The important question is what should happen to these savings?

If part of these easily achieved savings is not returned to your budget as energy manager, then your access to self-generated investments funds to support future activities will be lost. And later in the program, it is likely to be much harder for you to make savings.

However, if, an energy manager has access to a proportion of the revenue savings arising from staff's activities, then these can be reinvested in:

- Further energy efficiency measures
- Activities necessary to create the right climate for successful energy management which do not, of themselves, directly generate savings
- Maintaining or up-grading the management information system.

APPENDIX 1 Present Value Tables

Discount factors: Present value of BDT1 to be received after t years = 1/(1 + r)t.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	.990	.980	.971	.962	.952	.943	.935	.926	.917	.909	.901	.893	.885	.877	.870
2	.980	.961	.943	.925	.907	.890	.873	.857	.842	.826	.812	.797	.783	.769	.756
3	.971	.942	.915	.889	.864	.840	.816	.794	.772	.751	.731	.712	.693	.675	.658
4	.961	.924	.888	.855	.823	.792	.763	.735	.708	.683	.659	.636	.613	.592	.572
5	.951	.906	.863	.822	.784	.747	.713	.681	.650	.621	.593	.567	.543	.519	.497
6	.942	.888	.837	.790	.746	.705	.666	.630	.596	.564	.535	.507	.480	.456	.432
7	.933	.871	.813	.760	.711	.665	.623	.583	.547	.513	.482	.452	.425	.400	.376
8	.923	.853	.789	.731	.677	.627	.582	.540	.502	.467	.434	.404	.376	.351	.327
9	.914	.837	.766	.703	.645	.592	.544	.500	.460	.424	.391	.361	.333	.308	.284
10	.905	.820	.744	.676	.614	.558	.508	.463	.422	.386	.352	.322	.295	.270	.247
11	.896	.804	.722	.650	.585	.527	.475	.429	.388	.350	.317	.287	.261	.237	.215
12	.887	.788	.701	.625	.557	.497	.444	.397	.356	.319	.286	.257	.231	.208	.187
13	.879	.773	.681	.601	.530	.469	.415	.368	.326	.290	.258	.229	.204	.182	.163
14	.870	.758	.661	.577	.505	.442	.388	.340	.299	.263	.232	.205	.181	.160	.141
15	.861	.743	.642	.555	.481	.417	.362	.315	.275	.239	.209	.183	.160	.140	.123
16	.853	.728	.623	.534	.458	.394	.339	.292	.252	.218	.188	.163	.141	.123	.107
17	.844	.714	.605	.513	.436	.371	.317	.270	.231	.198	.170	.146	.125	.108	.093
18	.836	.700	.587	.494	.416	.350	.296	.250	.212	.180	.153	.130	.111	.095	.081
19	.828	.686	.570	.475	.396	.331	.277	.232	.194	.164	.138	.116	.098	.083	.070
20	.820	.673	.554	.456	.377	.312	.258	.215	.178	.149	.124	.104	.087	.073	.061

Number of Years	Interest Rate per Year														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	.862	.855	.847	.840	.833	.826	.820	.813	.806	.800	.794	.787	.781	.775	.769
2	.743	.731	.718	.706	.694	.683	.672	.661	.650	.640	.630	.620	.610	.601	.592
3	.641	.624	.609	.593	.579	.564	.551	.537	.524	.512	.500	.488	.477	.466	.455
4	.552	.534	.516	.499	.482	.467	.451	.437	.423	.410	.397	.384	.373	.361	.350
5	.476	.456	.437	.419	.402	.386	.370	.355	.341	.328	.315	.303	.291	.280	.269
6	.410	.390	.370	.352	.335	.319	.303	.289	.275	.262	.250	.238	.227	.217	.207
7	.354	.333	.314	.296	.279	.263	.249	.235	.222	.210	.198	.188	.178	.168	.159
8	.305	.285	.266	.249	.233	.218	.204	.191	.179	.168	.157	.148	.139	.130	.123
9	.263	.243	.225	.209	.194	.180	.167	.155	.144	.134	.125	.116	.108	.101	.094
10	.227	.208	.191	.176	.162	.149	.137	.126	.116	.107	.099	.092	.085	.078	.073
11	.195	.178	.162	.148	.135	.123	.112	.103	.094	.086	.079	.072	.066	.061	.056
12	.168	.152	.137	.124	.112	.102	.092	.083	.076	.069	.062	.057	.052	.047	.043
13	.145	.130	.116	.104	.093	.084	.075	.068	.061	.055	.050	.045	.040	.037	.033
14	.125	.111	.099	.088	.078	.069	.062	.055	.049	.044	.039	.035	.032	.028	.025
15	.108	.095	.084	.074	.065	.057	.051	.045	.040	.035	.031	.028	.025	.022	.020
16	.093	.081	.071	.062	.054	.047	.042	.036	.032	.028	.025	.022	.019	.017	.015
17	.080	.069	.060	.052	.045	.039	.034	.030	.026	.023	.020	.017	.015	.013	.012
18	.069	.059	.051	.044	.038	.032	.028	.024	.021	.018	.016	.014	.012	.010	.009
19	.060	.051	.043	.037	.031	.027	.023	.020	.017	.014	.012	.011	.009	.008	.007
20	.051	.043	.037	.031	.026	.022	.019	.016	.014	.012	.010	.008	.007	.006	.005

Note: For example, if the interest rate is 10% per year, the present value of BDT1 received at year 5 is BDT.621.

APPENDIX 2 Future Value Tables

Future value of BDT1 after t years = (1 + r)t.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	1.010	1.020	1.030	1.040	1.050	1.060	1.070	1.080	1.090	1.100	1.110	1.120	1.130	1.140	1.150
2	1.020	1.040	1.061	1.082	1.102	1.124	1.145	1.166	1.188	1.210	1.232	1.254	1.277	1.300	1.323
3	1.030	1.061	1.093	1.125	1.158	1.191	1.225	1.260	1.295	1.331	1.368	1.405	1.443	1.482	1.521
4	1.041	1.082	1.126	1.170	1.216	1.262	1.311	1.360	1.412	1.464	1.518	1.574	1.630	1.689	1.749
5	1.051	1.104	1.159	1.217	1.276	1.338	1.403	1.469	1.539	1.611	1.685	1.762	1.842	1.925	2.011
6	1.062	1.126	1.194	1.265	1.340	1.419	1.501	1.587	1.677	1.772	1.870	1.974	2.082	2.195	2.313
7	1.072	1.149	1.230	1.316	1.407	1.504	1.606	1.714	1.828	1.949	2.076	2.211	2.353	2.502	2.660
8	1.083	1.172	1.267	1.369	1.477	1.594	1.718	1.851	1.993	2.144	2.305	2.476	2.658	2.853	3.059
9	1.094	1.195	1.305	1.423	1.551	1.689	1.838	1.999	2.172	2.358	2.558	2.773	3.004	3.252	3.518
10	1.105	1.219	1.344	1.480	1.629	1.791	1.967	2.159	2.367	2.594	2.839	3.106	3.395	3.707	4.046
11	1.116	1.243	1.384	1.539	1.710	1.898	2.105	2.332	2.580	2.853	3.152	3.479	3.836	4.226	4.652
12	1.127	1.268	1.426	1.601	1.796	2.012	2.252	2.518	2.813	3.138	3.498	3.896	4.335	4.818	5.350
13	1.138	1.294	1.469	1.665	1.886	2.133	2.410	2.720	3.066	3.452	3.883	4.363	4.898	5.492	6.153
14	1.149	1.319	1.513	1.732	1.980	2.261	2.579	2.937	3.342	3.797	4.310	4.887	5.535	6.261	7.076
15	1.161	1.346	1.558	1.801	2.079	2.397	2.759	3.172	3.642	4.177	4.785	5.474	6.254	7.138	8.137
16	1.173	1.373	1.605	1.873	2.183	2.540	2.952	3.426	3.970	4.595	5.311	6.130	7.067	8.137	9.358
17	1.184	1.400	1.653	1.948	2.292	2.693	3.159	3.700	4.328	5.054	5.895	6.866	7.986	9.276	10.76
18	1.196	1.428	1.702	2.026	2.407	2.854	3.380	3.996	4.717	5.560	6.544	7.690	9.024	10.58	12.38
19	1.208	1.457	1.754	2.107	2.527	3.026	3.617	4.316	5.142	6.116	7.263	8.613	10.20	12.06	14.23
20	1.220	1.486	1.806	2.191	2.653	3.207	3.870	4.661	5.604	6.727	8.062	9.646	11.52	13.74	16.37

Number of Years	Interest Rate per Year														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	1.160	1.170	1.180	1.190	1.200	1.210	1.220	1.230	1.240	1.250	1.260	1.270	1.280	1.290	1.300
2	1.346	1.369	1.392	1.416	1.440	1.464	1.488	1.513	1.538	1.563	1.588	1.613	1.638	1.664	1.690
3	1.561	1.602	1.643	1.685	1.728	1.772	1.816	1.861	1.907	1.953	2.000	2.048	2.097	2.147	2.197
4	1.811	1.874	1.939	2.005	2.074	2.144	2.215	2.289	2.364	2.441	2.520	2.601	2.684	2.769	2.856
5	2.100	2.192	2.288	2.386	2.488	2.594	2.703	2.815	2.932	3.052	3.176	3.304	3.436	3.572	3.713
6	2.436	2.565	2.700	2.840	2.986	3.138	3.297	3.463	3.635	3.815	4.002	4.196	4.398	4.608	4.827
7	2.826	3.001	3.185	3.379	3.583	3.797	4.023	4.259	4.508	4.768	5.042	5.329	5.629	5.945	6.275
8	3.278	3.511	3.759	4.021	4.300	4.595	4.908	5.239	5.590	5.960	6.353	6.768	7.206	7.669	8.157
9	3.803	4.108	4.435	4.785	5.160	5.560	5.987	6.444	6.931	7.451	8.005	8.595	9.223	9.893	10.60
10	4.411	4.807	5.234	5.695	6.192	6.728	7.305	7.926	8.594	9.313	10.09	10.92	11.81	12.76	13.79
11	5.117	5.624	6.176	6.777	7.430	8.140	8.912	9.749	10.66	11.64	12.71	13.86	15.11	16.46	17.92
12	5.936	6.580	7.288	8.064	8.916	9.850	10.87	11.99	13.21	14.55	16.01	17.61	19.34	21.24	23.30
13	6.886	7.699	8.599	9.596	10.70	11.92	13.26	14.75	16.39	18.19	20.18	22.36	24.76	27.39	30.29
14	7.988	9.007	10.15	11.42	12.84	14.42	16.18	18.14	20.32	22.74	25.42	28.40	31.69	35.34	39.37
15	9.266	10.54	11.97	13.59	15.41	17.45	19.74	22.31	25.20	28.42	32.03	36.06	40.56	45.59	51.19
16	10.75	12.33	14.13	16.17	18.49	21.11	24.09	27.45	31.24	35.53	40.36	45.80	51.92	58.81	66.54
17	12.47	14.43	16.67	19.24	22.19	25.55	29.38	33.76	38.74	44.41	50.85	58.17	66.46	75.86	86.50
18	14.46	16.88	19.67	22.90	26.62	30.91	35.85	41.52	48.04	55.51	64.07	73.87	85.07	97.86	112.5
19	16.78	19.75	23.21	27.25	31.95	37.40	43.74	51.07	59.57	69.39	80.73	93.81	108.9	126.2	146.2
20	19.46	23.11	27.39	32.43	38.34	45.26	53.36	62.82	73.86	86.74	101.7	119.1	139.4	162.9	190.0

Note: For example, if the interest rate is 10% per year, the investment of BDT1 today will be worth BDT1.611 at year 5.

APPENDIX 3 Present Value Annuity Tables

Annuity table: Present value of BDT1 per year for each of t years = 1/r — 1/[r(1 + r)t].

Number of Years	Interest Rate per Year 1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	.990	.980	.971	.962	.952	.943	.935	.926	.917	.909	.901	.893	.885	.877	.870
2	1.970	1.942	1.913	1.886	1.859	1.833	1.808	1.783	1.759	1.736	1.713	1.690	1.668	1.647	1.626
3	2.941	2.884	2.829	2.775	2.723	2.673	2.624	2.577	2.531	2.487	2.444	2.402	2.361	2.322	2.283
4	3.902	3.808	3.717	3.630	3.546	3.465	3.387	3.312	3.240	3.170	3.102	3.037	2.974	2.914	2.855
5	4.853	4.713	4.580	4.452	4.329	4.212	4.100	3.993	3.890	3.791	3.696	3.605	3.517	3.433	3.352
6	5.795	5.601	5.417	5.242	5.076	4.917	4.767	4.623	4.486	4.355	4.231	4.111	3.998	3.889	3.784
7	6.728	6.472	6.230	6.002	5.786	5.582	5.389	5.206	5.033	4.868	4.712	4.564	4.423	4.288	4.160
8	7.652	7.325	7.020	6.733	6.463	6.210	5.971	5.747	5.535	5.335	5.146	4.968	4.799	4.639	4.487
9	8.566	8.162	7.786	7.435	7.108	6.802	6.515	6.247	5.995	5.759	5.537	5.328	5.132	4.946	4.772
10	9.471	8.983	8.530	8.111	7.722	7.360	7.024	6.710	6.418	6.145	5.889	5.650	5.426	5.216	5.019
11	10.37	9.787	9.253	8.760	8.306	7.887	7.499	7.139	6.805	6.495	6.207	5.938	5.687	5.453	5.234
12	11.26	10.58	9.954	9.385	8.863	8.384	7.943	7.536	7.161	6.814	6.492	6.194	5.918	5.660	5.421
13	12.13	11.35	10.63	9.986	9.394	8.853	8.358	7.904	7.487	7.103	6.750	6.424	6.122	5.842	5.583
14	13.00	12.11	11.30	10.56	9.899	9.295	8.745	8.244	7.786	7.367	6.982	6.628	6.302	6.002	5.724
15	13.87	12.85	11.94	11.12	10.38	9.712	9.108	8.559	8.061	7.606	7.191	6.811	6.462	6.142	5.847
16	14.72	13.58	12.56	11.65	10.84	10.11	9.447	8.851	8.313	7.824	7.379	6.974	6.604	6.265	5.954
17	15.56	14.29	13.17	12.17	11.27	10.48	9.763	9.122	8.544	8.022	7.549	7.120	6.729	6.373	6.047
18	16.40	14.99	13.75	12.66	11.69	10.83	10.06	9.372	8.756	8.201	7.702	7.250	6.840	6.467	6.128
19	17.23	15.68	14.32	13.13	12.09	11.16	10.34	9.604	8.950	8.365	7.839	7.366	6.938	6.550	6.198
20	18.05	16.35	14.88	13.59	12.46	11.47	10.59	9.818	9.129	8.514	7.963	7.469	7.025	6.623	6.259

Number of Years	Interest Rate per Year 16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	.862	.855	.847	.840	.833	.826	.820	.813	.806	.800	.794	.787	.781	.775	.769
2	1.605	1.585	1.566	1.547	1.528	1.509	1.492	1.474	1.457	1.440	1.424	1.407	1.392	1.376	1.361
3	2.246	2.210	2.174	2.140	2.106	2.074	2.042	2.011	1.981	1.952	1.923	1.896	1.868	1.842	1.816
4	2.798	2.743	2.690	2.639	2.589	2.540	2.494	2.448	2.404	2.362	2.320	2.280	2.241	2.203	2.166
5	3.274	3.199	3.127	3.058	2.991	2.926	2.864	2.803	2.745	2.689	2.635	2.583	2.532	2.483	2.436
6	3.685	3.589	3.498	3.410	3.326	3.245	3.167	3.092	3.020	2.951	2.885	2.821	2.759	2.700	2.643
7	4.039	3.922	3.812	3.706	3.605	3.508	3.416	3.327	3.242	3.161	3.083	3.009	2.937	2.868	2.802
8	4.344	4.207	4.078	3.954	3.837	3.726	3.619	3.518	3.421	3.329	3.241	3.156	3.076	2.999	2.925
9	4.607	4.451	4.303	4.163	4.031	3.905	3.786	3.673	3.566	3.463	3.366	3.273	3.184	3.100	3.019
10	4.833	4.659	4.494	4.339	4.192	4.054	3.923	3.799	3.682	3.571	3.465	3.364	3.269	3.178	3.092
11	5.029	4.836	4.656	4.486	4.327	4.177	4.035	3.902	3.776	3.656	3.543	3.437	3.335	3.239	3.147
12	5.197	4.988	4.793	4.611	4.439	4.278	4.127	3.985	3.851	3.725	3.606	3.493	3.387	3.286	3.190
13	5.342	5.118	4.910	4.715	4.533	4.362	4.203	4.053	3.912	3.780	3.656	3.538	3.427	3.322	3.223
14	5.468	5.229	5.008	4.802	4.611	4.432	4.265	4.108	3.962	3.824	3.695	3.573	3.459	3.351	3.249
15	5.575	5.324	5.092	4.876	4.675	4.489	4.315	4.153	4.001	3.859	3.726	3.601	3.483	3.373	3.268
16	5.668	5.405	5.162	4.938	4.730	4.536	4.357	4.189	4.033	3.887	3.751	3.623	3.503	3.390	3.283
17	5.749	5.475	5.222	4.990	4.775	4.576	4.391	4.219	4.059	3.910	3.771	3.640	3.518	3.403	3.295
18	5.818	5.534	5.273	5.033	4.812	4.608	4.419	4.243	4.080	3.928	3.786	3.654	3.529	3.413	3.304
19	5.877	5.584	5.316	5.070	4.843	4.635	4.442	4.263	4.097	3.942	3.799	3.664	3.539	3.421	3.311
20	5.929	5.628	5.353	5.101	4.870	4.657	4.460	4.279	4.110	3.954	3.808	3.673	3.546	3.427	3.316

Note: For example, if the interest rate is 10% per year, the investment of BDT1 received in each of the next 5 years is BDT3.791.

APPENDIX 4 Future Value Annuity Tables

Values of e^{rt}. Future value of BDT1 invested at a continuously compounded rate r for t years.

rt	.00	.01	.02	.03	.04	.05	.06	.07	.08	.09
.00	1.000	1.010	1.020	1.030	1.041	1.051	1.062	1.073	1.083	1.094
.10	1.105	1.116	1.127	1.139	1.150	1.162	1.174	1.185	1.197	1.209
.20	1.221	1.234	1.246	1.259	1.271	1.284	1.297	1.310	1.323	1.336
.30	1.350	1.363	1.377	1.391	1.405	1.419	1.433	1.448	1.462	1.477
.40	1.492	1.507	1.522	1.537	1.553	1.568	1.584	1.600	1.616	1.632
.50	1.649	1.665	1.682	1.699	1.716	1.733	1.751	1.768	1.786	1.804
.60	1.822	1.840	1.859	1.878	1.896	1.916	1.935	1.954	1.974	1.994
.70	2.014	2.034	2.054	2.075	2.096	2.117	2.138	2.160	2.181	2.203
.80	2.226	2.248	2.271	2.293	2.316	2.340	2.363	2.387	2.411	2.435
.90	2.460	2.484	2.509	2.535	2.560	2.586	2.612	2.638	2.664	2.691
1.00	2.718	2.746	2.773	2.801	2.829	2.858	2.886	2.915	2.945	2.974
1.10	3.004	3.034	3.065	3.096	3.127	3.158	3.190	3.222	3.254	3.287
1.20	3.320	3.353	3.387	3.421	3.456	3.490	3.525	3.561	3.597	3.633
1.30	3.669	3.706	3.743	3.781	3.819	3.857	3.896	3.935	3.975	4.015
1.40	4.055	4.096	4.137	4.179	4.221	4.263	4.306	4.349	4.393	4.437
1.50	4.482	4.527	4.572	4.618	4.665	4.711	4.759	4.807	4.855	4.904
1.60	4.953	5.003	5.053	5.104	5.155	5.207	5.259	5.312	5.366	5.419
1.70	5.474	5.529	5.585	5.641	5.697	5.755	5.812	5.871	5.930	5.989
1.80	6.050	6.110	6.172	6.234	6.297	6.360	6.424	6.488	6.553	6.619
1.90	6.686	6.753	6.821	6.890	6.959	7.029	7.099	7.171	7.243	7.316
2.00	7.389	7.463	7.538	7.614	7.691	7.768	7.846	7.925	8.004	8.085
2.10	8.166	8.248	8.331	8.415	8.499	8.585	8.671	8.758	8.846	8.935
2.20	9.025	9.116	9.207	9.300	9.393	9.488	9.583	9.679	9.777	9.875
2.30	9.974	10.07	10.18	10.28	10.38	10.49	10.59	10.70	10.80	10.91
2.40	11.02	11.13	11.25	11.36	11.47	11.59	11.70	11.82	11.94	12.06
2.50	12.18	12.30	12.43	12.55	12.68	12.81	12.94	13.07	13.20	13.33
2.60	13.46	13.60	13.74	13.87	14.01	14.15	14.30	14.44	14.59	14.73
2.70	14.88	15.03	15.18	15.33	15.49	15.64	15.80	15.96	16.12	16.28
2.80	16.44	16.61	16.78	16.95	17.12	17.29	17.46	17.64	17.81	17.99
2.90	18.17	18.36	18.54	18.73	18.92	19.11	19.30	19.49	19.69	19.89
3.00	20.09	20.29	20.49	20.70	20.91	21.12	21.33	21.54	21.76	21.98
3.10	22.20	22.42	22.65	22.87	23.10	23.34	23.57	23.81	24.05	24.29
3.20	24.53	24.78	25.03	25.28	25.53	25.79	26.05	26.31	26.58	26.84
3.30	27.11	27.39	27.66	27.94	28.22	28.50	28.79	29.08	29.37	29.67
3.40	29.96	30.27	30.57	30.88	31.19	31.50	31.82	32.14	32.46	32.79
3.50	33.12	33.45	33.78	34.12	34.47	34.81	35.16	35.52	35.87	36.23
3.60	36.60	36.97	37.34	37.71	38.09	38.47	38.86	39.25	39.65	40.04
3.70	40.45	40.85	41.26	41.68	42.10	42.52	42.95	43.38	43.82	44.26
3.80	44.70	45.15	45.60	46.06	46.53	46.99	47.47	47.94	48.42	48.91
3.90	49.40	49.90	50.40	50.91	51.42	51.94	52.46	52.98	53.52	54.05

Note: For example, if the continuously compounded interest rate is 10% per year, the investment of BDT 1 today will be worth BDT 1.105 at year 1 and BDT 1.221 at year 2.

APPENDIX 5 Present Value Annuity Tables

Present value of BDT1 per year received in a continuous stream for each of t years (discounted at an annually compounded rate r) = {1 — 1/(1 + r)t}/{ln(1 + r)}.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	.995	.990	.985	.981	.976	.971	.967	.962	.958	.954	.950	.945	.941	.937	.933
2	1.980	1.961	1.942	1.924	1.906	1.888	1.871	1.854	1.837	1.821	1.805	1.790	1.774	1.759	1.745
3	2.956	2.913	2.871	2.830	2.791	2.752	2.715	2.679	2.644	2.609	2.576	2.543	2.512	2.481	2.450
4	3.922	3.846	3.773	3.702	3.634	3.568	3.504	3.443	3.383	3.326	3.270	3.216	3.164	3.113	3.064
5	4.878	4.760	4.648	4.540	4.437	4.337	4.242	4.150	4.062	3.977	3.896	3.817	3.741	3.668	3.598
6	5.825	5.657	5.498	5.346	5.202	5.063	4.931	4.805	4.685	4.570	4.459	4.353	4.252	4.155	4.062
7	6.762	6.536	6.323	6.121	5.930	5.748	5.576	5.412	5.256	5.108	4.967	4.832	4.704	4.582	4.465
8	7.690	7.398	7.124	6.867	6.623	6.394	6.178	5.974	5.780	5.597	5.424	5.260	5.104	4.956	4.816
9	8.609	8.243	7.902	7.583	7.284	7.004	6.741	6.494	6.261	6.042	5.836	5.642	5.458	5.285	5.121
10	9.519	9.072	8.657	8.272	7.913	7.579	7.267	6.975	6.702	6.447	6.208	5.983	5.772	5.573	5.386
11	10.42	9.884	9.391	8.935	8.512	8.121	7.758	7.421	7.107	6.815	6.542	6.287	6.049	5.826	5.617
12	11.31	10.68	10.10	9.572	9.083	8.633	8.218	7.834	7.478	7.149	6.843	6.559	6.294	6.048	5.818
13	12.19	11.46	10.79	10.18	9.627	9.116	8.647	8.216	7.819	7.453	7.115	6.802	6.512	6.242	5.992
14	13.07	12.23	11.46	10.77	10.14	9.571	9.048	8.570	8.131	7.729	7.359	7.018	6.704	6.413	6.144
15	13.93	12.98	12.12	11.34	10.64	10.00	9.423	8.897	8.418	7.980	7.579	7.212	6.874	6.563	6.276
16	14.79	13.71	12.75	11.88	11.11	10.41	9.774	9.201	8.681	8.209	7.778	7.385	7.024	6.694	6.390
17	15.64	14.43	13.36	12.41	11.55	10.79	10.10	9.482	8.923	8.416	7.957	7.539	7.158	6.809	6.490
18	16.48	15.14	13.96	12.91	11.98	11.15	10.41	9.742	9.144	8.605	8.118	7.676	7.275	6.910	6.577
19	17.31	15.83	14.54	13.39	12.39	11.49	10.69	9.983	9.347	8.777	8.263	7.799	7.380	6.999	6.652
20	18.14	16.51	15.10	13.86	12.77	11.81	10.96	10.21	9.533	8.932	8.394	7.909	7.472	7.077	6.718

Number of Years	Interest Rate per Year														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	.929	.925	.922	.918	.914	.910	.907	.903	.900	.896	.893	.889	.886	.883	.880
2	1.730	1.716	1.703	1.689	1.676	1.663	1.650	1.638	1.625	1.613	1.601	1.590	1.578	1.567	1.556
3	2.421	2.392	2.365	2.337	2.311	2.285	2.259	2.235	2.211	2.187	2.164	2.141	2.119	2.098	2.077
4	3.016	2.970	2.925	2.882	2.840	2.799	2.759	2.720	2.682	2.646	2.610	2.576	2.542	2.509	2.477
5	3.530	3.464	3.401	3.340	3.281	3.223	3.168	3.115	3.063	3.013	2.964	2.917	2.872	2.828	2.785
6	3.972	3.886	3.804	3.724	3.648	3.574	3.504	3.436	3.370	3.307	3.246	3.187	3.130	3.075	3.022
7	4.354	4.247	4.145	4.048	3.954	3.865	3.779	3.696	3.617	3.542	3.469	3.399	3.331	3.266	3.204
8	4.682	4.555	4.434	4.319	4.209	4.104	4.004	3.909	3.817	3.730	3.646	3.566	3.489	3.415	3.344
9	4.966	4.819	4.680	4.547	4.422	4.302	4.189	4.081	3.978	3.880	3.786	3.697	3.612	3.530	3.452
10	5.210	5.044	4.887	4.739	4.599	4.466	4.340	4.221	4.108	4.000	3.898	3.801	3.708	3.619	3.535
11	5.421	5.237	5.063	4.900	4.747	4.602	4.465	4.335	4.213	4.096	3.986	3.882	3.783	3.689	3.599
12	5.603	5.401	5.213	5.036	4.870	4.713	4.566	4.428	4.297	4.173	4.057	3.946	3.841	3.742	3.648
13	5.759	5.542	5.339	5.150	4.972	4.806	4.650	4.503	4.365	4.235	4.112	3.997	3.887	3.784	3.686
14	5.894	5.662	5.446	5.245	5.058	4.882	4.718	4.564	4.420	4.284	4.157	4.036	3.923	3.816	3.715
15	6.010	5.765	5.537	5.326	5.129	4.945	4.774	4.614	4.464	4.324	4.192	4.068	3.951	3.841	3.737
16	6.111	5.853	5.614	5.393	5.188	4.998	4.820	4.655	4.500	4.355	4.220	4.092	3.973	3.860	3.754
17	6.197	5.928	5.679	5.450	5.238	5.041	4.858	4.687	4.529	4.381	4.242	4.112	3.990	3.875	3.767
18	6.272	5.992	5.735	5.498	5.279	5.076	4.889	4.714	4.552	4.401	4.259	4.127	4.003	3.887	3.778
19	6.336	6.047	5.781	5.538	5.313	5.106	4.914	4.736	4.571	4.417	4.273	4.139	4.014	3.896	3.785
20	6.391	6.094	5.821	5.571	5.342	5.130	4.935	4.754	4.586	4.430	4.284	4.149	4.022	3.903	3.791

Note: For example, if theinterestrateis10%peryear, a continuous cash flow of BDT1 a year for each of 5years is worth BDT3.977.A continuous flow of BDT1in year 5 only is worth BDT3.977 —— BDT 3.326= BDT.651.

APPENDIX 6 Discount Factor Table

The following formula is used to calculate a discount factor for year t and imputed rate of interest i: 1/(1+i)t

Number of years (t)	Interest Rate per year										
	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
0	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
1	1.0000	0.9901	0.9804	0.9709	0.9615	0.9524	0.9434	0.9346	0.9259	0.9174	0.9091
2	1.0000	0.9803	0.9612	0.9426	0.9246	0.9070	0.8900	0.8734	0.8573	0.8417	0.8264
3	1.0000	0.9706	0.9423	0.9151	0.8890	0.8638	0.8396	0.8163	0.7938	0.7722	0.7513
4	1.0000	0.9610	0.9238	0.8885	0.8548	0.8227	0.7921	0.7629	0.7350	0.7084	0.6830
5	1.0000	0.9515	0.9057	0.8626	0.8219	0.7835	0.7473	0.7130	0.6806	0.6499	0.6209
6	1.0000	0.9420	0.8880	0.8375	0.7903	0.7462	0.7050	0.6663	0.6302	0.5963	0.5645
7	1.0000	0.9327	0.8706	0.8131	0.7599	0.7107	0.6651	0.6227	0.5835	0.5470	0.5132
8	1.0000	0.9235	0.8535	0.7894	0.7307	0.6768	0.6274	0.5820	0.5403	0.5019	0.4665
9	1.0000	0.9143	0.8368	0.7664	0.7026	0.6446	0.5919	0.5439	0.5002	0.4604	0.4241
10	1.0000	0.9053	0.8203	0.7441	0.6756	0.6139	0.5584	0.5083	0.4632	0.4224	0.3855