NEHRU COLLEGE OF ENGINEERING AND RESEARCH CENTRE

(Accredited by NAAC, Approved by AICTE New Delhi, Affiliated to APJKTU)

Pampady, Thiruvilwamala(PO), Thrissur(DT), Kerala 680 588

DEPARTMENT OF ELECTRICAL AND ELECTRONICS ENGINEERING

COURSE MATERIALS

EE 474 ENERGY MANAGEMENT AND AUDITING

VISION OF THE INSTITUTION

To mould our youngsters into Millennium Leaders not only in Technological and Scientific Fields but also to nurture and strengthen the innate goodness and human nature in them, to equip them to face the future challenges in technological break troughs and information explosions and deliver the bounties of frontier knowledge for the benefit of humankind in general and the down-trodden and underprivileged in particular as envisaged by our great Prime Minister Pandit Jawaharlal Nehru

MISSION OF THE INSTITUTION

To build a strong Centre of Excellence in Learning and Research in Engineering and Frontier Technology, to facilitate students to learn and imbibe discipline, culture and spirituality, besides encouraging them to assimilate the latest technological knowhow and to render a helping hand to the under privileged, thereby acquiring happiness and imparting the same to others without any reservation whatsoever and to facilitate the College to emerge into a magnificent and mighty launching pad to turn out technological giants, dedicated research scientists and intellectual leaders of the society who could prepare the country for a quantum jump in all fields of Science and Technology

ABOUT DEPARTMENT

- Course offered: B.Tech Electrical and Electronics Engineering
- Approved by AICTE New Delhi and Accredited by NAAC
- Affiliated to the University of Dr. A P J Abdul Kalam Technological University.
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DEPARTMENT VISION

To excel in technical education and research in the field of Electrical & Electronics Engineering by imparting innovative engineering theories, concepts and practices to improve the production and utilization of power and energy for the betterment of the Nation.

DEPARTMENT MISSION

- To offer quality education in Electrical and Electronics Engineering and prepare the students for professional career and higher studies.
- To create research collaboration with industries for gaining knowledge about real-time problems.
- To prepare students with sound technical knowledge.
- To make students socially responsible.

Course code	Course Name	L-T-P - Credits	Year of Introduction
EE474	**ENERGY MANAGEMENT AND AUDITING**	**3-0-0-3**	**2016**

Prerequisite : Nil

Course Objectives

- To enable the students to understand the concept of energy management and energy management opportunities
- To understand the different methods used to control peak demand
- To know energy auditing procedure
- To understand the different methods used for the economic analysis of energy projects.

Syllabus

General principles of Energy management and Energy management planning - Peak Demand controls - Energy management opportunities in electrical systems and HVAC systems – Reactive power management – Energy audit – cogeneration system – Economic analysis of energy projects

Expected outcome .

- The students will be able to understand the different methods used to reduce energy consumption

Data Book (Approved for use in the examination):

References:

1. Albert Thumann, William J. Younger, Handbook of Energy Audits, CRC Press, 2003.
2. Charles M. Gottschalk, Industrial energy conservation, John Wiley & Sons, 1996.
3. Craig B. Smith, Energy management principles, Pergamon Press.
4. D. Yogi Goswami, Frank Kreith, Energy Management and Conservation Handbook, CRC Press, 2007
5. G.G. Rajan, Optimizing energy efficiencies in industry -, Tata McGraw Hill, Pub. Co., 2001.
6. IEEE recommended practice for energy management in industrial and commercial facilities,
7. IEEE std 739 - 1995 (Bronze book).
8. M Jayaraju and Premlet, Introduction to Energy Conservation And Management, Phasor Books, 2008
9. Paul O'Callaghan, Energy management, McGraw Hill Book Co.
10. Wayne C. Turner, Energy management Hand Book - - The Fairmount Press, Inc., 1997.

Course Plan

Module	Contents	Hours	Sem. Exam Marks
I	General principles of Energy management and Energy management planning. Peak Demand controls, Methodologies, Types of Industrial Loads, Optimal Load scheduling-Case studies.	6	15%
II	Energy management opportunities in Lighting and Motors. Electrolytic Process and Electric heating, Case studies.	8	15%
FIRST INTERNAL EXAMINATION			
III	Types of boilers, Combustion in boilers, Performances evaluation, Feed water treatment, Blow down, Energy conservation opportunities in boiler.		

	Properties of steam, Assessment of steam distribution losses, Steam leakages, Steam trapping, Condensate and flash steam recovery system, Identifying opportunities for energy savings. Classification, General fuel economy measures in furnaces, Excess air, Heat Distribution, Temperature control, Draft control, Waste heat recovery.	8	15%
IV	HVAC system: Coefficient of performance, Capacity, Factors affecting Refrigeration and Air conditioning system performance and savings opportunities. Classification and Advantages of Waste Heat Recovery system, analysis of waste heat recovery for Energy saving opportunities	7	15%
	SECOND INTERNAL EXAMINATION		
V	Energy audit -Definition, Need, Types of energy audit, Energy audit Instruments. Cogeneration-Types and Schemes, Optimal operation of cogeneration plants- Case study. Computer aided energy management.	7	20%
VI	Economic analysis methods-cash flow model, time value of money, evaluation of proposals, pay-back method, average rate of return method, internal rate of return method, present value method, life cycle costing approach, Case studies.	6	20%
	END SEMESTER EXAM		

QUESTION PAPER PATTERN:

Maximum Marks: 100 Exam Duration: 3Hourrs.

Part A: 8 compulsory questions.

One question from each module of Modules I - IV; and two each from Module V & VI.

Student has to answer all questions. (8 x5)=40

Part B: 3 questions uniformly covering Modules I & II. Student has to answer any 2 from the 3 questions: (2 x 10) =20. Each question can have maximum of 4 sub questions (a,b,c,d), if needed.

Part C: 3 questions uniformly covering Modules III & IV. Student has to answer any 2 from the 3 questions: (2 x 10) =20. Each question can have maximum of 4 sub questions (a,b,c,d), if needed.

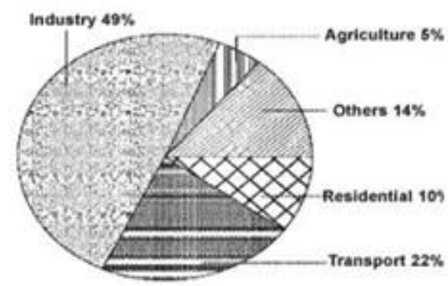
Part D: 3 questions uniformly covering Modules V & VI. Student has to answer any 2 from the 3 questions: (2 x 10) =20. Each question can have maximum of 4 sub questions (a,b,c,d), if needed.

Module 1

Lecture 1: Introduction to energy management and general principles of energy management

Energy is an integral part of today's modern life. It has become the blood of our day to day life. But it is not free. It comes at a monetary price but more than that it comes at environment cost too. It is very difficult to think about our modern life without energy. But the generation of energy requires natural resources which are depleting day by day. On the other side, use of energy is increasing exponentially. In developing nation like India, about 49% of total commercial energy is consumed in industries and utilities like Compressed Air, Air Conditioning, Steam, Hot water, Electrical systems, fuel, water system consumes substantial part of total energy in these industries.. Figure Number 1.1 shows, sector wise energy consumption for the year 1999-2000.

Figure No 1.1: Sector wise Energy Consumption (1999-2000)



Thus the need to improve and maintain energy efficiency in industrial utilities is strongly felt to survive in present scenario of rising energy costs.

Energy management is the systematic use of management and technology to improve an organisation's energy performance. It needs to be integrated, proactive, and incorporate energy procurement, energy efficiency and renewable energy to be fully effective. Energy management is all about reducing the cost of energy used by the organization, now with the added spin of minimizing carbon emissions as well. Certain principles of energy management helps to provide an initial approach to the problem of effective management of the energy in a particular sector.

In table below some of the general principles that are applicable to wide variety of situation is shown. The table also provides an approximate highly qualitative assessment of relative cost, implementation time, complexity, and benefits based on experiences.

Principle	Relative cost	Relative time to implement	Relative complexity	Relative benefit (Typical)
1. Review of historical data	Low	1 year	Low	5–10%
2. Energy audits (review of current practices)	Low	1 year	Low	5–10%
3. Operation and maintenance ("housekeeping")	Low	1 year	Low	5–15%
4. Analysis of energy use (engineering analysis, building simulation, system modeling, availability studies)	Low to moderate	1–2 years	Moderate to high	10–20%
5. Economic evaluation (cost/benefit, rate of return, life-cycle costing)	Low	1 year	Low	5–15%
6. More efficient equipment	Moderate to high	years	Moderate to high	10–30%
7. More efficient processes	Moderate to high	years	Moderate to high	10–30%
8. Energy containment (heat recovery, waste reduction)	Moderate to high	years	Moderate to high	10–50%
9. Material economy (scrap recovery, salvage, recycle)	Low	1–2 years	Low to high	10–50%
10. Substitute material	Low to moderate	1 year	Low	10–20%
11. Material quality (purity and properties)	Low	1 year	Low	5–10%
12. Aggregation of energy uses	Moderate to high	years	Moderate to high	20–50%
13. Cascade of energy uses	Moderate to high	years	Moderate to high	20–50%

Principle	Relative cost	Relative time to implement	Relative complexity	Relative benefit (Typical)
14. Alternative energy sources (substitute fuel or energy form)	Moderate to high	years	Moderate to high	10–30%
15. Energy conversion	Moderate to high	years	Moderate	10–30%
16. Energy storage	Moderate to high	years	Moderate to high	10–30%

Review Historical Data

The first principle is to *review historical energy use*. It helps establish typical seasonal, monthly, and even daily energy use patterns and facilitates identification of anomalies such as unexpected spikes or dips in usage, energy use during non-business periods, or even gradual energy increases over time that may signal degradation of equipment. Sometimes seasonal variations or scheduling discontinuities are present but unrecognized; the review process brings them to light and may suggest ways of combining operations, reducing demand charges, or otherwise affecting savings. For example, a plant may experience a surge of manufacturing during a certain season, yet maintain space conditioning all year-round. Often the question "why do we do this?" and the answer "that's the way we've always done it" flag an area for immediate savings.

Energy Audits

An **energy audit** is an inspection, survey and analysis of energy flows, for energy conservation in a building, process or system to reduce the amount of energy input into the system without negatively affecting the outputs. Energy audit is an activity that serves the purposes of assessing energy use pattern of a factory or energy consuming equipment and identifying energy saving opportunities.

In commercial and industrial real estate, an energy audit is the first step in identifying opportunities to reduce energy expense and carbon footprints. An energy audit identifies where energy is being consumed and assesses energy saving opportunities

Operation and Maintenance

Improving *operation and maintenance* in the plant will generally save energy. Well-lubricated equipment has reduced frictional losses. Cleaned light fixtures transmit more light. Changing filters reduces pressure drop. Repairing steam leaks prevents waste of high quality energy. Operation and maintenance practices are applicable to all types of end uses.

Analysis

Analysis goes hand-in-hand with the energy audit to determine how efficient equipment is, to establish what happens if a parameter changes (reduce flow by 50%), or to simulate operation (computer models of building or process energy use).

Economic Evaluation

Economic evaluation is an essential tool of energy management. New equipment, processes, or options must be studied to determine costs and returns. The analysis must include operating costs, investment tax credits, taxes, depreciation, and the cost of capital for a realistic picture, particularly when considering escalation of energy prices.

More Efficient Equipment

More efficient equipment can often be substituted to fulfill the same function (e.g., LED or high output T5 fluorescent lamps rather than T12 or even T8 fluorescent lamps for area lighting, or premium efficiency motors instead of standard or high efficiency motors). Most types of industrial, commercial, and residential equipment are now rated or labeled in terms of their efficiency; there are wide variations among different manufacturers depending on size, quality, capacity, and initial cost, but there are many online resources for comparing the different technologies.

More Efficient Processes

More efficient processes can often be substituted without detrimental effect and often yield improved product quality. A classic example is a continuous steel rolling mill, which uses a continuous process to produce steel products, avoiding energy loss involved in cooling and reheating in batch production. Another example is powder metallurgy rather than machining to reduce process energy; still another is a dry papermaking process which reduces energy expended to remove water from the finished product. Inert atmosphere ovens can reduce energy used for drying solvent-based paints, compared to ultraviolet bake ovens. Membrane separation in food processing can result in better tasting products than heat treatment technologies.[1] Drying with microwave or radio-frequency radiation increase drying rates and minimizes surface drying and cracking relative to conventional drying processes. For example, an energy management team conducted a study to find a replacement for gas-fired drying oven used in the processing of agricultural feed additives. The study tested a microwave oven, electric resistance heating, and a solar oven. The relative drying time using these three technologies was in the approximate ratio of 1:10:100. Not only was the microwave process the fastest, but it reduced waste heat losses and improved product quality.

Energy Containment

Energy containment seeks to confine energy, reduce losses, and recover energy. Examples include repair of steam and compressed air leaks, better insulation on boilers or piping, air sealing of building envelopes, and installation of heat exchangers or power recovery devices. For example, the flue gases from boilers and furnaces and other systems that depend on combustion provide excellent opportunities for heat recovery. Depending on flue gas temperatures, the exhaust heat can be used to raise steam or to preheat the air to the boiler. Figure 3.1 shows an example of such a system, where an ammonia reformer heater is designed to conserve fuel by using a steam generator and air preheater to recover heat from the stack gas.[2]

There is overlap between this energy management principle and the operation and maintenance principle discussed above (Principle 3) and the energy cascading principle discussed below (Principle 13).

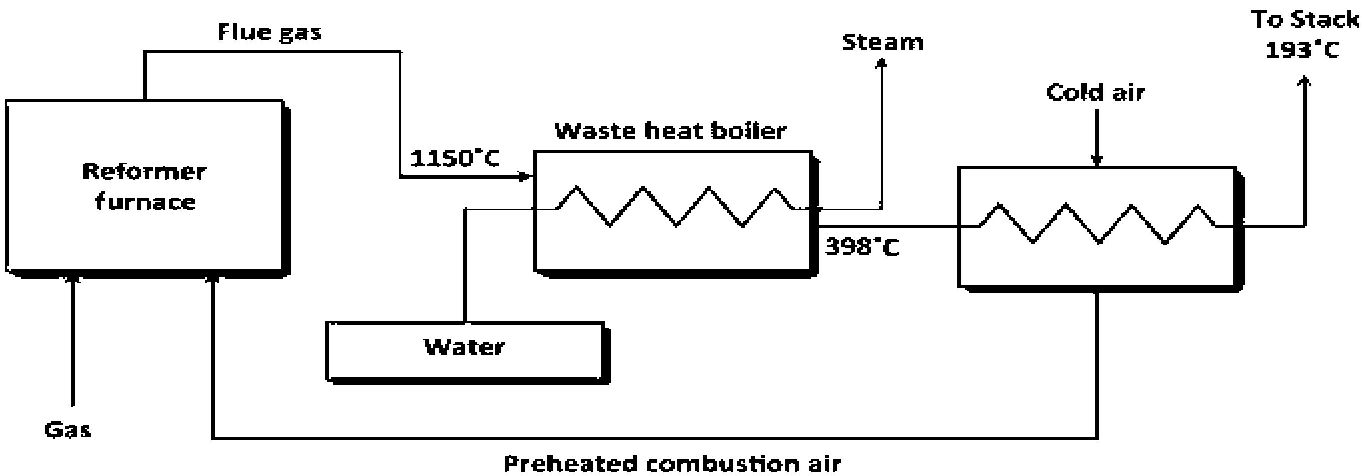


Figure 3.1 Heat recovery using an air preheater.

Material Economy

Material economy implies recovery of scrap, reduction of waste, and "design for salvage." The powder metallurgy example cited above also illustrates this principle. Product design that permits salvage or recovery of reusable parts, motors, and components is another example. Structures, in fact, can be designed for reuse and relocation.

Material Quality Selection

Material quality selection is extremely important, since unnecessary quality almost always means higher costs and often means greater energy use. For example, is distilled water needed, or is deionized sufficient? Purity of chemicals and process streams has an important impact on energy expense; trace impurities may not be important for many applications.

Substitute Materials

Substitute materials can sometimes be used to advantage. For example, in low-temperature applications, low melting point alloys can substitute high-temperature materials. A material that is easier to machine, or that involves less energy to manufacture, can replace an energy-intensive material. Water-based paints can be used without baking in certain applications. An emerging technology for primary aluminum production that uses wetted cathodes and inert anodes instead of carbon anodes promises to reduce energy use and lower greenhouse gas emission while increasing productivity and lowering costs over the conventional Hall–Héroult process; these savings are due largely to the fact that current carbon anodes are consumed during the process whereas the inert anodes do not corrode or release carbon dioxide emissions.[3]

Aggregation of Energy Uses

Aggregation of energy uses permits greater efficiency to be achieved in certain situations. For example, in a manufacturing plant it is possible to physically locate certain process steps in adjacent areas to minimize the energy use for transportation of materials. Proper time sequencing of operations can also reduce energy use, for example, by using temperatures generated by one step of the process to provide preheating needed by another step.

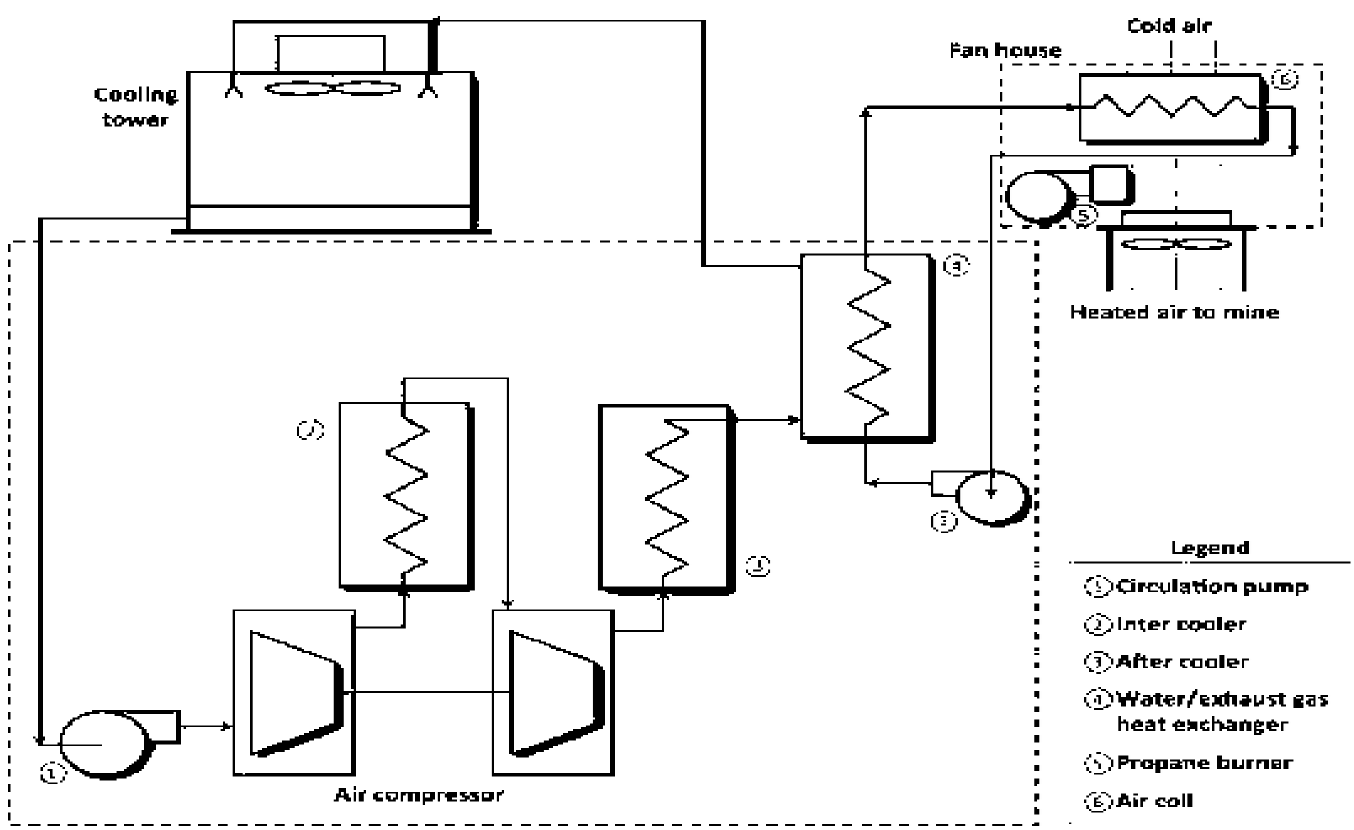


Figure 3.2 Flow diagram of mine air heating and compressor cooling cycle.

Cascade of Energy Uses

Heat recovery is an example of *cascading energy use*, whereby high temperature heat is used for one purpose and the waste heat from that process applied to another process step, and so on. There are many sources of waste heat in commercial and industrial facilities. Figure 3.1 showed an example of recovering heat from a gas-fired reformer furnace. Energy in the form of heat is also available at a variety of noncombustion sources such as electric motors, crushing and grinding operations, air compressors, and air thickening and drying processes. These units require cooling in order to maintain proper operation. The heat from these systems can be collected and transferred to some appropriate use such as space heating. An example of this type of heat recovery is shown in Figure 3.2.[4] All the energy supplied to the motor in electrical form is ultimately transformed into heat and nearly all of it is available to heat buildings or for domestic water or mine air heating.

As the temperature of waste heat decreases, the opportunities for applying it to other processes diminish; however, in some cases industrial heat pumps may be a viable and efficient option for accepting the low temperature waste heat and delivering it at a higher temperature for applications requiring higher quality energy.[5]

Energy Conversion and Energy Storage

Careful consideration of the energy source and form can lead to improved efficiency, environmental benefits and costs savings. Consider whether an *alternative energy* source, different *energy conversion* process, or *energy storage* is applicable. For example, onsite solar photovoltaic panels for electricity production are becoming more cost effective as the technology matures. In addition, solar thermal technology is an effective means for water heating. Also, thermal energy storage using ice banks or eutectic salts is a useful means to shift cooling loads to off-peak periods and battery technology is rapidly advancing, which will make onsite storage of electric energy increasingly viable in the future.

Lecture 2: Energy management planning

The stimulus to start an energy management program must come from somewhere. It could originate from a variety of potential sources, including a concerned individual who has noticed excessive compressed air leaks in the production area, a facility maintenance manager discouraged by the increasing time requirement for repairing old equipment, a company president who is suddenly made aware of rising energy costs, a corporate (or government) mandate to reduce carbon footprint, a utility account manager who notifies the company of an opportunity for great incentives, or the more extreme case of a local utility announcing it is going to curtail the factory's fuel supply.

Reducing energy costs or complying with regulations of one sort or another are usually the motivation. However, even companies that do not face high energy costs find that an energy management program pays for itself by eliminating waste and reducing costs; it may also offer the company a marketing advantage or improved public image because they can potentially tout themselves as a green business. For example, in a group of California hospitals, the Hospital Association correctly recognized that an energy management program could reduce operating costs. Perhaps more importantly, the association realized that such a program would be visible evidence that the hospitals were attempting to control costs, and therefore had important political implications, even though energy costs were small fraction of total operating costs. In many cases, there are several simultaneous motivating factors for establishing an energy management program due to the myriad drivers and benefits.

Where does one begin? An energy management program can be organized in many ways, but we suggest organizing it in three primary phases:

1. Initiation and planning.
2. Audit and analysis.
3. Implementation and continuous assessment.

Table 4.1 outlines the planning steps necessary to establish the program.
Being proactive and following this systematic process, rather than just reactively implementing projects when energy efficiency problems can no longer be ignored, greatly increases the likelihood of on-going Success and continuous energy improvement.

Table 4.1 Planning an energy management program

Initiation and planning phase
1. Commitment by management to an energy management program. 2. Assignment of an energy manager. 3. Creation of an energy management committee of major plant and department representatives.
Audit and analysis phase
1. Review of historical patterns of fuel and energy use, production, weather, occupancy, operating hours, and other relevant variables. 2. Facility walk-through survey. 3. Preliminary analyses, review of drawings, data sheets, equipment specifications. 4. Development of energy audit plans. 5. Energy audit covering (i) processes and (ii) facilities and equipment. 6. Calculation of projected annual energy use based on audit results and expected weather, operation, and/or production. 7. Comparison with historical energy records. 8. Analysis and simulation (engineering calculations, heat and mass balances, theoretical efficiency calculations, computer analysis and simulation) to evaluate energy management options. 9. Economic analysis of selected energy management options (lifecycle costs, rate of return, benefit-cost ratio).

Implementation and continuous assessment phase
1. Establishment of energy effectiveness goals for the organization and individual plants. 2. Determination of capital investment requirements and priorities. 3. Implementation of projects. 4. Promotion of continuing awareness and involvement of personnel. 5. Formation of measurement and verification procedures. Installation of monitoring and recording instruments as required. 6. Institution of reporting procedures ("energy tracking" charts) for managers and publicize results. 7. Provision for periodic reviews and evaluation of overall energy management program.

INITIATION AND PLANNING PHASE

Importance of Management Commitment

Regardless of the motivation for the program, it will not succeed without a commitment from the firm's top management. For this reason, Table 4.1 lists this as a first step in the initiation and planning phase. Management must be convinced of two key things, first, the need, and secondly, the potential economic returns that will result from investing time and money in the program. Obtaining management commitment often requires the presentation of facts, figures, and costs concerning current energy usage, along with estimates for the future and projected savings. Therefore, it may be necessary for the person responsible for encouraging program development to do some degree of historical review prior to the audit and analysis phase to help sell the concept to management, unless, of course, management is the stimulus for the program.

Energy Champions

Once management commits to the program, the next step is to name one individual the energy manager. The energy manager may be a member of the engineering staff in a large firm, or a maintenance supervisor, electrician, or foreman. The energy manager's core responsibilities are to ensure the energy management program is accepted by staff and operates effectively. This is not an easy task without the support of management and other energy champions.

Therefore, the energy manager's first step might be to formulate an energy management committee with representatives from each key department or division using energy, depending on the size and complexity of the firm. A representative from the accounting department would be another good addition. Next, the energy manager should explain to the department heads and line supervisors the need for the program, taking into consideration the economic and other motivating factors driving the program. Collectively, the committee's main responsibilities will be to ensure the program has reasonable targets and that goals are successfully met from the "ground up." Therefore, the committee should take steps to inform all personnel—from office staff to the production line—of the need, emphasizing that efforts will be placed on reducing waste and improving productivity and profitability. The energy manager and committee could even devise an incentive system whereby personnel are awarded for identifying energy management improvements.

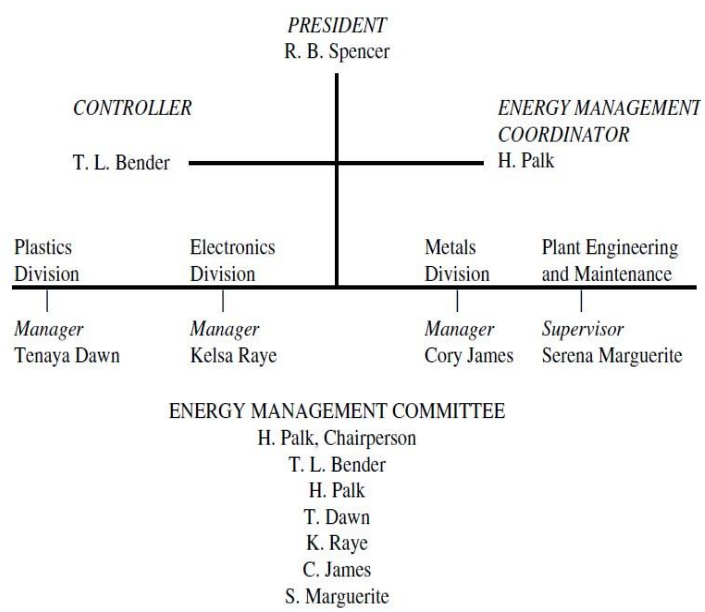


Figure 4.1 Energy management organization chart.

Figure 4.1 shows an example of an energy management organization chart for an industry with three principal divisions. The president established an energy management committee consisting of an energy manager (appointed by the president) and representatives of each of the three manufacturing divisions, plant engineering and maintenance, and the central power plant. The purpose of this committee is to coordinate plans, bring in new ideas and perspectives, and to ensure that actions taken in one part of the plant do not have an unfavorable effect on another part. A similar approach can be taken by a city. For example, following the 1973 oil embargo, Los Angeles experienced serious shortages of fuel oil and was forced to implement a mandatory program of electricity cutbacks in the residential, commercial, and industrial sectors. As the city struggled with the problems caused by these changes, the mayor created an interdepartmental energy conservation committee (Figure 4.2). This committee met periodically, reviewed or proposed new rules and regulations, initiated a system of energy reporting for the various city departments, initiated energy audits in public buildings, and provided liaison for a series of other energy management initiatives.

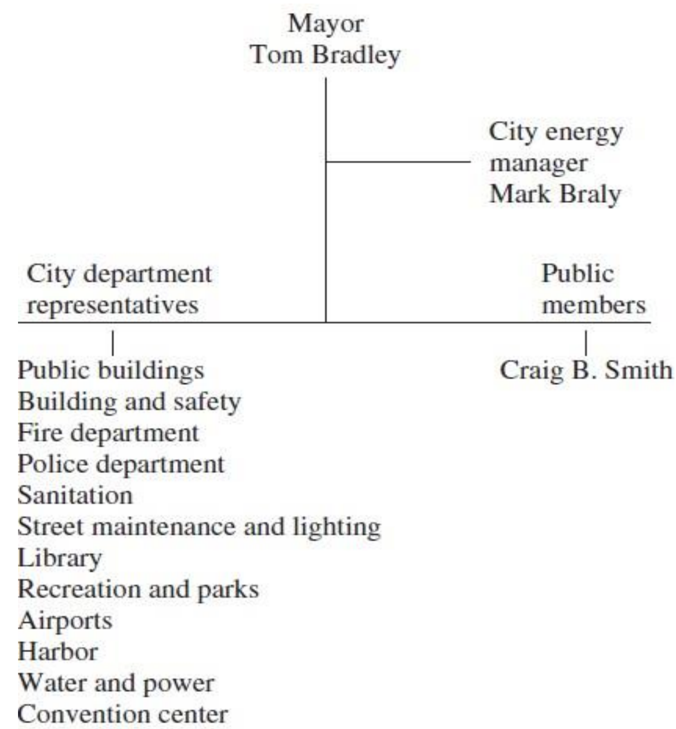


Figure 4.2 Interdepartmental energy conservation committee, city of Los Angeles.

Addressing Institutional Barriers

There are often instances where efficient energy use is discouraged by other factors. The energy manager should be aware of these barriers and should understand how to deal with them when confronted. They fall in several broad categories:

• **Economic**: Rate of return is too low, or lower than alternative investments; capital is not available; unwillingness to make short-term investments for long-term returns. This is one of the most prevalent challenges faced by energy managers and energy champions. However, there are funding opportunities that can help address this barrier. Most utility companies—gas and electric—offer a wide variety of programs that provide services or financial incentives to encourage efficient energy use. Exploring utility program opportunities is an important first step for energy managers. Additionally, some energy service companies (ESCOs) offer financing support or energy performance contracts to firms whereby the ESCO pays the capital costs and the firm repays the debt out of money saved on their energy bills; these contracts typically involve performance guarantees so that the firm only pays if the energy savings were actually realized.

• **Ownership**: Unwillingness to make investments in leased buildings or equipment. A classic example is a tenant in a leased building refusing to make investments to improve the inefficient air-conditioning system on the grounds that "it would only benefit the owner." This decision could be the correct one. On the other hand, if the investment would pay back in less time than the term of the lease, if might be justified by the operational savings alone. Ideally the landlord could be enticed to participate and provide some cost-sharing, especially since the energy upgrades would help attract future tenants.

• **Tradition, precedent**: "This is the way we've always done it"; "we'd rather invest in expanded production capacity"; "we'd have to hire new maintenance personnel or train existing staff on how to use the more sophisticated systems and controls"; "it's easier to patch problems as they occur instead of taking the time to make the case to management for new equipment." These are all real issues, but some of the easier issues to overcome with a little education and training. Even the desire to invest in expanded production capacity can be addressed at least partly by efficiency improvements that inherently increase productivity.

• **Priorities: Energy** is a low cost item, a small part of value added in manufacturing, or not a core business focus; "we have to worry about more important things." We have heard these arguments from many of the businesses we have talked to over the years. The staff is extremely busy and so focused on the core business function that they simply do not have time to explore energy management improvements. In this case, the impetus for a program may actually come, at least in part, from an external party such as a utility account representative. Some utilities, such as BC Hydro, even have programs that provide energy managers and energy management training for their customers.

The energy manager will have to explore each situation on a case-by-case basis to find appropriate solutions.

AUDIT AND ANALYSIS PHASE

After the program initiation and planning phase, the audit and analysis phase begins. This phase consists of a detailed review of historical data, energy audits, identification of energy management opportunities, energy analysis, and economic evaluation. It involves determining where and how energy is being used and identifying opportunities for using energy more effectively.

Historical Review

First consider the methods and objectives of the historical review. Data for the historical analysis can be compiled from utility bills, facility records of operating schedules and shifts, equipment inventories, production statistics, or any other available source of data. The objective is to understand both near- and long-term trends in energy usage. For example, what is the reference base, or baseline, of energy use that the energy management program will attempt to modify? Also, what are the past patterns of energy use and what do they signify for the energy management program?

Insight into the following types of trends can be useful to the energy manager:

• Is historical energy use increasing or decreasing? (Consider the past 2_5 years.)
• Are there seasonal variations in energy use? (Summer or winter peaks?)
• How complete is the database? (Energy use for the whole plant, for each division, etc.)
• What have been past trends in energy costs? (10% annual escalation or what?)
• Are there temporal variations in energy use? (Off-shift versus on-shift; weekend versus weekday, etc.)

Energy Audit

In the energy audit, the auditor or audit team collects detailed information for each piece of equipment, lighting systems, Heating, ventilating, and air conditioning (HVAC) systems, and processes, and sometimes information on the building construction. The energy manager and energy committee then use results of the audit to delineate major areas of energy use and to formulate the next steps in the energy management plan. The audit can be done on a process-by-process basis or on a building or facility basis, depending on the scope defined during the planning and initiation stage. Auditors may include members of the firm's maintenance or technical staff or outside energy specialists could be brought in to conduct the audit. Ideally, the audit team will have a combination of experienced energy engineers who know how to identify issues and opportunities and facility personnel who are intimately familiar with the facility's systems and operations.

To obtain detailed system data, the auditor may choose to measure loads and equipment operating hours (in hours per day, week, or month) using metering equipment, or he or she may use equipment nameplate specifications and knowledge of the typical loads and operating hours to estimate energy and demand. If weather-sensitive loads like space conditioning equipment represent the largest end-use in the facility, the auditor may decide to develop a model of the building and then simulate energy usage based on different weather scenarios. After accounting for and calculating energy use for all of the major loads, auditors can compare the findings with historical records. Agreement does not have to be perfect— and it most likely will not be—but significant discrepancies should be investigated to determine the source and to verify that major items have not been overlooked or usage overestimated.

Since the audit includes inspection and analysis of all equipment and systems within the scope of the program plan, it is one of the major ways to identify and flag options for more efficient energy use.

Energy and Economic Analyses

The next step is to investigate more thoroughly the options discovered during the audit along with any other potential opportunities under consideration. This investigation involves energy and economic analyses for each energy management opportunity. The analysis results help the energy management committee define goals and select promising projects to implement based on the organization's priorities. Energy and economic analyses of potential projects represent the most technically challenging portion of the energy management program

IMPLEMENTATION AND CONTINUOUS ASSESSMENT PHASE

The final phase in the energy management program is really an on-going process. It comprises establishing energy usage goals; prioritizing and implementing projects; defining measurement, verification, and reporting procedures; promoting on-going awareness and involvement of personnel; and continually assessing program goals and achievements.

Establishing Goals

After the audit and analysis phase, the energy management committee has all the necessary information for establishing meaningful energy management goals and realistic energy usage targets at the system, process, building, plant, or organization level. In the case of large organizations or multinational corporations, some goals may actually have been set prior to initiating the energy management program.

Prioritizing and Implementing Projects

Prioritizing and implementing projects identified thus far is one of the most critical aspect of the entire program, since taking action to realize improvements is the central goal of an energy management effort. Project ranking will depend somewhat on the specific priorities of the organization, such as expected economic return, meeting regulations, carbon footprint, fuel availability, production requirements, etc.

Obviously, one requirement of the implementation phase is that the organization or firm be prepared to make the investments necessary to begin saving energy. It is generally useful to categorize the energy management opportunities identified into three groups:

- Operations and maintenance ("housekeeping") options.
- Retrofit and modification options.
- New design or major construction options.

These groups call for an increasing scale of capital investment, ranging from zero to minimal for housekeeping changes, to extensive for options requiring new construction.

Inform, Train, and Motivate Personnel

The implementation and continuous assessment phase also includes actions to inform, train, and motivate personnel so that the organization fosters a strong sense of involvement and ownership of the energy management program by everyone from the factory worker or office employee to the maintenance personnel and all the way up to top management. This point deserves emphasis since it is ultimately human beings that are entrusted with these marvels of engineering that are supposed to save all this energy and money. Experience indicates that more efficient equipment and improved processes are only "half the battle." Obviously, it makes little difference how efficient the plant and equipment are if any of the following are true:

• Operating personnel do not understand the need for efficiency.
• They do not believe in the need.
• They do not know how to operate their new, improved equipment.
The human element is vital, and is all-too-often ignored.

Measure, Verify, and Report Performance

A very important element of this phase is to take measurements, monitor equipment, and verify that systems are operating as expected and energy use and performance targets and goals are being met. These actions reflect the fundamental management concept that people are only able to operate effectively if two conditions are in play:

• They know what they are supposed to accomplish.
• They receive feedback that tells them how well they are doing.

For long-term success and to prevent inefficient habits from returning, it is essential for this assessment to take place on an on-going basis.

Continuous Program Assessment

Finally, the program must succeed. It must be reviewed periodically to determine its strengths and weaknesses. It should be flexible, capable of responding to changing economic conditions (energy prices, cost of goods and services), new regulations (equipment, building, environmental), corporate mandates (energy indices, carbon footprint, other priorities), and to evolving program needs (a new process or building is added, an old one is shut down). Continuous assessment also permits a review of the success of implemented projects and provides a basis for revaluating other projects that failed to pass the first screening during the original implementation plan.

An effective energy management program must begin with management commitment. The next step is to evolve a plan for subsequent actions. A review of historical patterns of energy use provides the foundation for energy audits and further engineering studies and analysis. Early in the program, suitable criteria must be established for evaluating possible energy management projects. Training, personal awareness, and information programs are vital. The success of any program depends as much on human motivation as it does on technology.

Lecture 3: Types of loads in power systems

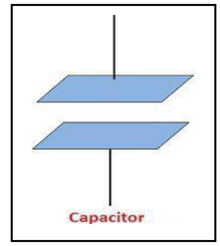
A device which taps electrical energy from the electric power system is called a load on the system. Electrical loads can be classified according to their nature as Resistive, Capacitive, Inductive and combinations of these.

Resistive Load

The resistive load obstructs the flow of electrical energy in the circuit and converts it into thermal energy, due to which the energy dropout occurs in the circuit. The lamp and the heater are the examples of the resistive load. The resistive loads take power in such a way so that the current and the voltage wave remain in the same phase. Thus the power factor of the resistive load remains in unity.

Inductive Load

The inductive loads use the magnetic field for doing the work. The transformers, generators, motor are the examples of the load. The inductive load has a coil which stores magnetic energy when the current pass through it. The current wave of the inductive load is lagging behind the voltage wave, and the power factor of the inductive load is also lagging.



Capacitive Load

In the capacitive load, the voltage wave is lagging the current wave. The examples of capacitive loads are capacitor bank, three phase induction motor starting circuit, etc. The power factor of such type of loads is leading.

Combination Loads

Most of the loads are not purely resistive or purely capacitive or purely inductive. Many practical loads make use of various combinations of resistors, capacitors and inductors. Power factor of such loads is less than unity and either lagging or leading

Examples: Single phase motors often use capacitors to aid the motor during starting and running, tuning circuits or filter circuits etc.

The load may be resistive (e.g., electric lamp), inductive (e.g., induction motor), capacitive or some combination of them. The various types of loads on the power system are:

1. **Domestic load.** Domestic load consists of lights, fans, refrigerators, heaters, television, small motors for pumping water etc. Most of the residential load occurs only for some hours during the day (i.e., 24 hours) e.g., lighting load occurs during night time and domestic appliance load occurs for only a few hours. For this reason, the load factor is low (10% to 12%).
2. **Commercial load.** Commercial load consists of lighting for shops, fans and electric appliances used in restaurants etc. This class of load occurs for more hours during the day as compared to the domestic load. The commercial load has seasonal variations due to the extensive use of air conditioners and space heaters.
3. **Municipal load**. Municipal load consists of street lighting, power required for water supply and drainage purposes. Street lighting load is practically constant throughout the hours of the night. For water supply, water is pumped to overhead tanks by pumps driven by electric motors. Pumping is carried out during the off-peak period, usually occurring during the night. This helps to improve the load factor of the power system.
4. **Irrigation load.** This type of load is the electric power needed for pumps driven by motors to supply water to fields. Generally this type of load is supplied for 12 hours during night.
5. **Traction load.** This type of load includes tram cars, trolley buses, railways etc. This class of load has wide variation. During the morning hour, it reaches peak value because people have to go to their work place. After morning hours, the load starts decreasing and again rises during evening since the people start coming to their homes.
6. **Industrial load.** Industrial load consists of load demand by industries. The magnitude of industrial load depends upon the type of industry. Thus small scale industry requires load up to 25 kW, medium scale industry between 25kW and 100 kW and large-scale industry requires load above 500 kW. Industrial loads are generally not weather dependent.

Some Other Classifications of Electrical Loads

According To Load Nature

- Linear loads
- Non-linear loads

According To Phases

- Single phase loads
- Three phase loads

According to Importance

1. Vital electrical loads (e.g. required for life safety)
2. Essential electric loads
3. Non-essential / normal electric loads.

Lecture 4: Electrical Load Management and Maximum Demand Control

Need for Electrical Load Management

In a macro perspective, the growth in the electricity use and diversity of end use segments in time of use has led to shortfalls in capacity to meet demand. As capacity addition is costly and only a long time prospect, better load management at user end helps to minimize peak demands on the utility infrastructure as well as better utilization of power plant capacities. The utilities (State Electricity Boards) use power tariff structure to influence end user in better load management through measures like time of use tariffs, penalties on exceeding allowed maximum demand, night tariff concessions etc. Load management is a powerful means of efficiency improvement both for end user as well as utility. As the demand charges constitute a considerable portion of the electricity bill, from user angle too there is a need for integrated load management to effectively control the maximum demand.

Step By Step Approach for Maximum Demand Control

1. Load Curve Generation

Presenting the load demand of a consumer against time of the day is known as a 'load curve'. If it is plotted for the 24 hours of a single day, it is known as an 'hourly load curve' and if daily demands plotted over a month, it is called daily load curves. A typical hourly load curve for an engineering industry is shown in Figure 1.5. These types of curves are useful in predicting patterns of drawl, peaks and valleys and energy use trend in a section or in an industry or in a distribution network as the case may be.

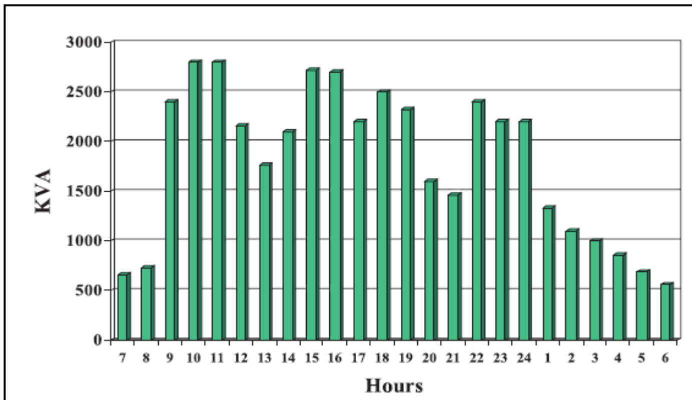


Figure 1.5 Maximum Demand (Daily Load Curve, Hourly kVA)

2. Rescheduling of Loads

Rescheduling of large electric loads and equipment operations, in different shifts can be planned and implemented to minimize the simultaneous maximum demand. For this purpose, it is advisable to prepare an operation flow chart and a process chart. Analyzing these charts and with an integrated approach, it would be possible to reschedule the operations and running equipment in such a way as to improve the load factor which in turn reduces the maximum demand.

3. Storage of Products/in process material/ process utilities like refrigeration

It is possible to reduce the maximum demand by building up storage capacity of products/ materials, water, chilled water / hot water, using electricity during off peak periods. Off peak hour operations also help to save energy due to favorable conditions such as lower ambient temperature etc. Example: Ice bank system is used in milk & dairy industry. Ice is made in lean period and used in peak load period and thus maximum demand is reduced.

4. Shedding of Non-Essential Loads

When the maximum demand tends to reach preset limit, shedding some of non-essential loads temporarily can help to reduce it. It is possible to install direct demand monitoring systems, which will switch off non-essential loads when a preset demand is reached. Simple systems give an alarm, and the loads are shed manually. Sophisticated microprocessor controlled systems are also available, which provide a wide variety of control options like:

- Accurate prediction of demand
- Graphical display of present load, available load, demand limit
- Visual and audible alarm
- Automatic load shedding in a predetermined sequence

- Automatic restoration of load
- Recording and metering

5. Operation of Captive Generation and Diesel Generation Sets

When diesel generation sets are used to supplement the power supplied by the electric utilities, it is advisable to connect the D.G. sets for durations when demand reaches the peak value. This would reduce the load demand to a considerable extent and minimize the demand charges.

6. Reactive Power Compensation

The maximum demand can also be reduced at the plant level by using capacitor banks and maintaining the optimum power factor. Capacitor banks are available with microprocessor based control systems. These systems switch on and off the capacitor banks to maintain the desired Power factor of system and optimize maximum demand thereby.

Lecture 5: Optimal load scheduling and case studies

The electrical load scheduling is the process of estimating the instantaneous loads operating in an installation. The load schedule provides the load for the particular installation in terms of apparent, reactive and active power (kVA, kVAR and kW). The load schedule preparation should ideally be the first task to perform during the electrical system design stage since it relates to the equipment sizes and other power system requirements. In particular, it provides information about the equipment ratings during normal and peak operations, thereby guiding the electrician in determining the conductor sizes.

Load scheduling is one form of load management action that allows companies to save energy by minimizing their demand. In order to have an efficient load schedule operation, the energy manager or business should conduct power logging and record all sessions so as to measure the usage of energy over a specific time. This enables the consumer to identify large loads that may be operating concurrently.

There is no standard methodology and varying methods can be used based on type of installation and person carrying out the load scheduling exercise. One of the methodology is the economic load dispatch.

The economic load dispatch means the real and reactive power of the generator vary within the certain limits and fulfils the load demand with less fuel cost. The sizes of the electric power system are increasing rapidly to meet the energy requirement. So the number of power plants is connected in parallel to supply the system load by an interconnection of the power system. In the grid system, it becomes necessary to operate the plant units more economically.

The economic scheduling of the generators aims to guarantee at all time the optimum combination of the generator connected to the system to supply the load demand. The economic load dispatch problem involves two separate steps. These are the online load dispatch and the unit commitment.

The unit commitment selects that unit which will anticipate load of the system over the required period at minimum cost. The online load dispatch distributes the load among the generating unit which is parallel to the system in such a manner as to reduce the total cost of supplying. It also fulfils the minute to the minute requirement of the system.

Module 2

INTRODUCTION

Electrical energy is becoming increasingly important to industry due to the more prevalent use of improved electric process systems and the development of new electro technologies. As a result, the potential for reduced energy use through the implementation of electrical-efficiency improvements is substantial The world consumption of primary energy increased from 3.65×10^{11} GJ (3.46×10^{11} MBtu) in 1990 to 4.01×10^{11} GJ (3.80×10^{11} MBtu) in 1999. This equates to an average annual increase of ~1%.

Industry continues to be the leading end-use sector for energy consumption. Energy use has since increased and surpassed its mid-1970s high. However, productivity has also significantly increased. As a result, there has been an appreciable reduction in the energy consumed per unit of output.

Lecture 1: Energy Management Opportunities in lighting system

In today's cost-competitive, market-driven economy, everyone is seeking technologies or methods to reduce energy expenses and environmental impact. Because nearly all buildings have lights, lighting retrofits are very common and generally offer an attractive return on investment. Electricity used to operate lighting systems represents a significant portion of total electricity consumed mainly in commercial buildings as shown in the figure 1.1.

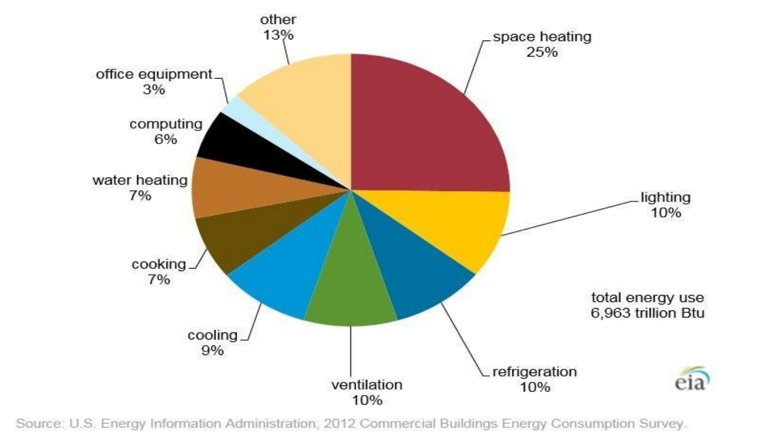


Fig: 1.1: Overall Electrical energy consumption in commercial buildings in 2012

Electric lighting is a major energy consumer. Enormous energy savings are possible using energy efficient equipment, effective controls, and careful design. Using less electric lighting reduces heat gain, thus saving air-conditioning energy and improving thermal comfort. Electric lighting design also strongly affects visual performance and visual comfort by aiming to maintain adequate and appropriate illumination while controlling reflection and glare.

Lighting is not just a high priority when considering hotel design; it is also a high return, low-risk investment. By installing new lighting technologies, hotels can reduce the amount of electricity consumed and energy costs associated with lighting. There are several types of energy efficient lighting and affordable lighting technology. The following are a few examples of energy-saving opportunities with efficient lighting.

1. Installation of compact fluorescent lamps (CFLs) in place of incandescent lamps.
2. Installation of energy-efficient fluorescent lamps in place of "conventional" fluorescent lamps.
3. Installation of occupancy/motion sensors to turn lights on and off where appropriate.
4. Use an automated device, such as a key tag system, to regulate the electric power in a room.
5. Offer nightlights to prevent the bathroom lights from being left on all night.
6. Replace all exit signs with light emitting diode (led) exit signs.
7. Use high efficiency (hid) exterior lighting
8. Add lighting controls such as photo sensors or time clocks

1. Installation of compact fluorescent lamps (CFLs) in place of incandescent lamps

Minimum light output (lumens)	Electrical power consumption (watts)		
	Incandescent	Compact fluorescent	LED
450	40	9–11	6–8
800	60	13–15	9–12
1,100	75	18–20	13–16
1,600	100	23–28	15–22
2,400	150	30–52	24–28
3,100	200	49–75	30
4,000	300	75–100	38

Compact Fluorescent Lamps use a different, more advanced technology than incandescent light bulbs and come in a range of styles and sizes based on brand and purpose. They can replace regular, incandescent bulbs in almost any light fixture including globe lamps for the bathroom vanity, lamps for recessed lighting, dimming, and 3-way functionality lights. CFLs use about 2/3 less energy than standard incandescent bulbs, give the same amount of light, and can last 6 to 10 times longer. CFL prices range from $4 to $15 depending on the bulb, but you save about $25 to $30 per bulb on energy during the lifetime of the bulb.

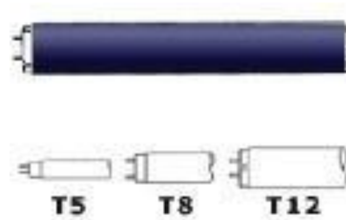
When looking to purchase CFLs in place of incandescent bulbs, compare the **light output**, or **Lumens**, and not the watts. Watts refers to the amount of energy used, not the amount of light. In other words, if the incandescent bulb you wish to replace is 60 Watts, this is equal to 800 Lumens

To get the same amount of light in a CFL, you should look to find a CFL that provides 800 Lumens or more (equal to about a 13 watt fluorescent bulb).

2. Installation of energy-efficient fluorescent lamps in place of "Conventional" fluorescent lamps.

Many lodging facilities may already use fluorescent lighting in their high traffic areas such as the lobby or office area. However, not all fluorescent lamps are energy efficient and cost effective. There are several types of fluorescent lamps that vary depending on the duration of their lamp life, energy efficiency, regulated power, and the quality of color it transmits.

There are a few styles worth noting; these models are simply labeled as "T-12", "T-8", or "T-5". The names come from the size of their diameter per eighth inch. For example, a T-12 lamp is 12/8 inch in diameter (or 1 1/2 inch); a T-8 lamp is 8/8 inch in diameter (or 1 inch); a T-5 lamp is 5/8 inch in diameter. This is a simple way to identify the type of fluorescent lamps your facility is using.



Fluorescent lamps are categorized according to their diameter.

The recommended style of fluorescent lighting is a T-8. T-8 lights are the most cost-effective. They usually cost about $0.99 a bulb and are 30% to 40% more efficient than standard T-12 fluorescent lamps, which have poor color rendition and cause eye strain. T-8 lamps provide more illumination, better color, and don't *flicker* (often exhibited by standard fluorescent fixtures). T-5 lamps are the most energy efficient and also tend to transmit the best color; however, they usually cost about $5.00 per bulb.

3. Installation of occupancy/motion sensors to turn lights on and off where appropriate.

Ultra-sonic sensor (celling mount)

Lighting can be controlled by occupancy sensors to allow operation whenever someone is within the area being scanned. When motion can no longer be detected, the lights shut off. *Passive infrared* sensors react to changes in motion. The controller must have an unobstructed view of the building area being scanned. Doors, partitions, stairways, etc. will block motion detection and reduce its effectiveness. The best applications for passive infrared occupancy sensors are open spaces with a clear view of the area being scanned.

Ultrasonic sensors transmit sound above the range of human hearing and monitor the time it takes for the sound waves to return. A break in the pattern caused by any motion in the area triggers the control.

Ultrasonic sensors can see around obstructions and are best for areas with cabinets and shelving, restrooms, and open areas requiring 360-degree coverage. Some occupancy sensors utilize *both* passive infrared and ultrasonic technology, but are usually more expensive. They can be used to control one lamp, one fixture or many fixtures. It can work in 3 modes: Time out, sensor mode and motion sensitivity settings The table below provides typical savings achievable for specific building areas, by the implementation of motion sensors.

Application	Potential Energy Cost Savings
Offices (private)	25-50%
Offices (open areas)	20-25%
Restrooms	30-75%
Corridors	30-40%
Storage areas	45-65%
Meeting rooms	45-65%
Conference rooms	45-65%
Warehouses	50-75%

4. Use an automated device, such as a key tag system, to regulate the electric power in a room.

The key tag system uses a master switch at the entrance of each guest room, requiring the use of a room key-card to activate them. Using this technique, only occupied rooms consume energy because most electrical appliances are switched off when the keycard is removed (when the guest leaves the room). The key tag system uses a master switch at the entrance of each guest room, requiring the use of a room key-card to activate them. Using this technique, only occupied rooms consume energy because most electrical appliances are switched off when the keycard is removed (when the guest leaves the room). Along with lighting, the heating, air conditioning, radio and television may also be connected to the master switch. This innovation has a potential savings of about $105.00 per room per year.

5. Offer nightlights to prevent the bathroom lights from being left on all night

Many guests opt to have a light on while they sleep. By turning the bathroom light on and leaving the bathroom door cracked open, guests are able to find their way through an unknown room in the middle of the night. Those who are accompanied by children may often do the same to comfort their child. By offering a nightlight, the energy used to power a bathroom light during the nighttime can be avoided and guests will still be able to feel comfortable in unfamiliar territory.

One particular model uses six **Light Emitting Diodes (LEDs)** in the panel of a light switch to provide light for guests. LEDs are just tiny light bulbs that fit easily into an electrical circuit. They are different from ordinary incandescent bulbs because they don't burn out or get really hot. They are often used in digital clocks or remote controls.

6. Replace all exit signs with light emitting diode (LED) exit signs.

The development of light emitting diodes (LEDs) has allowed the replacement of exit sign lighting with a more energy efficient alternative. Multiple LEDs, properly configured, produce equivalent lighting and consume 95% less electricity than incandescent bulbs and compact fluorescent lamps is 75% less energy-efficient than LED.
A major benefit is the 20-year life cycle rating of LEDs; they virtually *eliminate* maintenance. Of the three different styles of exit signs, incandescent signs are the least expensive, but are inefficient and use energy releasing heat instead of light. Fluorescent signs are also inexpensive and have an expected life of about 10,000 hours.
LED exit signs are the most expensive, but are also the most efficient exit signs available. Their payback time is usually about four years. The table on the following page offers an easy comparison of the three models of exit signs.

	Incandescent	Fluorescent	LED
Input Power (watts)	40	11	2
Yearly energy (kWh)	350	96	18
Lamp life (years)	0.25-0.5	1-2	10+
Estimated energy cost/ year ($0.06/kWh)	$21.00	$5.75	$1.10

7. Use high efficiency (hid) exterior lighting

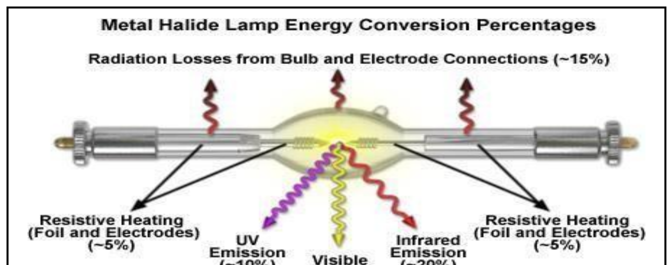


Figure 4

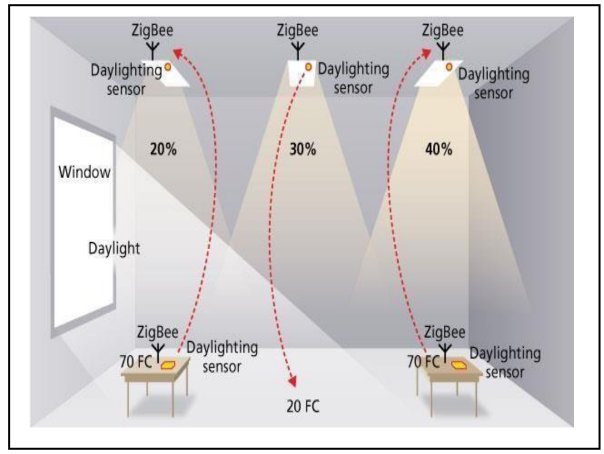
High intensity discharge (HID) lighting is much more efficient and preferable to incandescent, quartz-halogen and most fluorescent light fixtures. HID types (from least to most efficient) include mercury vapor, metal halide and high pressure sodium. Mercury vapor is seldom used anymore.

Both metal halide and high pressure sodium are excellent outdoor lighting systems. High pressure sodium has a pink-orange glow and is used when good color rendition isn't critical. Metal halide, though less efficient, provides clean white light and good color rendition. HID lighting is mostly utilized in floodlight, wall pack, canopy and area fixtures outdoors. The best type for any application depends on the area being lit and mounting options.

8. Add lighting controls such as photo sensors or time clocks

Photo sensor controls monitor daylight conditions and allow fixtures to operate only when needed. Photo sensors detect the quantity of light and send a signal to a main controller to adjust the lighting. Photo sensors are commonly used with outdoor lighting to automatically turn lights on at dusk and off at dawn, a very cost-effective control device. This helps to lower energy costs by ensuring that unnecessary lighting is not left on during daytime hours.

Photo sensors can be used indoors, as well. Building areas with lots of windows may not require lights to be on all of the time. Photocells can be used to ensure fixtures operate only when the natural light is inadequate by either controlling one light fixture, or a group of lights.



The table below demonstrates the cost savings from day light controls.

Potential Annual Lighting Energy Cost Savings with Day lighting Controls

Day lighting Strategy	Control Type	Potential Annual Energy Savings
Window sidelighting	On/off	32%
	Stepped	44%
	Continuous dimming	56%
Skylighting	On/off	52%
	Stepped	57%
	Continuous dimming	62%

Source: Lawrence Berkeley Laboratory

Time controls save energy by reducing lighting time of use through preprogrammed scheduling. Time clock equipment ranges from simple devices designed to control a single electrical load to sophisticated systems that control several lighting zones. They are one of the simplest, least expensive, and most efficient energy management devices available.

Time controls could include:

- **Simple time switches**: automatically turn lights, fans or other electronic devices off after a pre-set time.
- **Multi-channel time controls**: have the ability to control from 4 to 16 duties.
- **Special-purpose time controls**: include cycle timers for repetitive short duration cycling of equipment or outdoor lighting time controls that combine time clock and photo sensor technologies.

Lecture 2: Energy Management Opportunities in electric motors

Motors convert electrical energy into mechanical energy by the interaction between the magnetic fields set up in the stator and rotor windings. Industrial electric motors can be broadly classified as induction motors, direct current motors or synchronous motors. All motor types have the same four operating components: stator (stationary windings), rotor (rotating windings), bearings, and frame (enclosure).

Two important attributes relating to efficiency of electricity use by A.C. Induction motors are efficiency (η), defined as the ratio of the mechanical energy delivered at the rotating shaft to the electrical energy input at its terminals, and power factor (PF). Motors, like other inductive loads, are characterized by power factors less than one. As a result, the total current draw needed to deliver the same real power is higher than for a load characterized by a higher PF. An important effect of operating with a PF less than one is that resistance losses in wiring upstream of the motor will be higher, since these are proportional to the square of the current. Thus, both a high value for η and a PF close to unity are desired for efficient overall operation in a plant.

Squirrel cage motors are normally more efficient than slip-ring motors, and higher-speed motors are normally more efficient than lower-speed motors. Efficiency is also a function of motor temperature. Totally-enclosed, fan-cooled (TEFC) motors are more efficient than screen protected, drip-proof (SPDP) motors. Also, as with most equipment, motor efficiency increases with the rated capacity. The efficiency of a motor is determined by intrinsic losses that can be reduced only by changes in motor design. Intrinsic losses are of two types: fixed losses - independent of motor load, and variable losses - dependent on load.

Energy-Efficient Motors

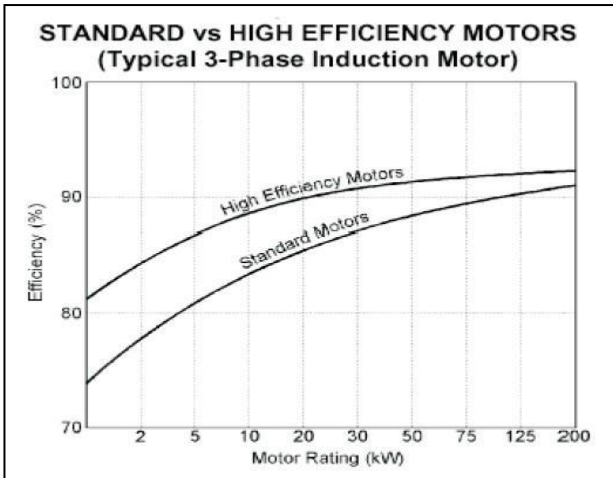


Figure 2.3 Standard vs High Efficiency Motors

Energy-efficient motors (EEM) are the ones in which, design improvements are incorporated specifically to increase operating efficiency over motors of standard design (see Figure 2.3). Design improvements focus on reducing intrinsic motor losses. Improvements include the use of lower-loss silicon steel, a longer core (to increase active material), thicker wires (to reduce resistance), thinner laminations, smaller air gap between stator and rotor, copper instead of aluminum bars in the rotor, superior bearings and a smaller fan, etc.

Energy-efficient motors now available in India operate with efficiencies that are typically 3 to 4 percentage points higher than standard motors. In keeping with the stipulations of the BIS, energy-efficient motors are designed to operate without loss in efficiency at loads between 75 % and 100 % of rated capacity. This may result in major benefits in varying load applications. The power factor is about the same or may be higher than for standard motors. Furthermore, energy efficient motors have lower operating temperatures and noise levels, greater ability to accelerate higher-inertia loads, and are less affected by supply voltage fluctuations. Measures adopted for energy efficiency to address each loss specifically as under:

Stator and Rotor I_2R Losses

These losses are major losses and typically account for 55% to 60% of the total losses. I^2R losses are heating losses resulting from current passing through stator and rotor conductors. I^2R losses are the function of a conductor resistance, the square of current. Resistance of conductor is a function of conductor material, length and cross sectional area. The suitable selection of copper conductor size will reduce the resistance. Reducing the motor current is most readily accomplished by decreasing the magnetizing component of current. This involves lowering the operating flux density and possible shortening of air gap. Rotor I^2R losses are a function of the rotor conductors (usually aluminum) and the rotor slip. Utilization of copper conductors will reduce the winding resistance. Motor operation closer to synchronous speed will also reduce rotor I^2R losses.

Core Losses

Core losses are those found in the stator-rotor magnetic steel and are due to hysteresis effect and eddy current effect during 50 Hz magnetization of the core material. These losses are independent of load and account for 20 – 25 % of the total losses. The hysteresis losses which are a function of flux density, are be reduced by utilizing low loss grade of silicon steel laminations. The reduction of flux density is achieved by suitable increase in the core length of stator and rotor. Eddy current losses are generated by circulating current within the core steel laminations. These are reduced by using thinner laminations.

Friction and Windage Losses

Friction and windage losses results from bearing friction, windage and circulating air through the motor and account for 8 – 12 % of total losses. These losses are independent of load. The reduction in heat generated by stator and rotor losses permit the use of smaller fan. The windage losses also reduce with the diameter of fan leading to reduction in windage losses.

Stray Load-Losses

These losses vary according to square of the load current and are caused by leakage flux induced by load currents in the laminations and account for 4 to 5 % of total losses. These losses are reduced by careful selection of slot numbers, tooth/slot geometry and air gap.

Energy efficient motors cover a wide range of ratings and the full load efficiencies are higher by 3 to 7 %. The mounting dimensions are also maintained as per IS1231 to enable easy replacement.

As a result of the modifications to improve performance, the costs of energy-efficient motors are higher than those of standard motors. The higher cost will often be paid back rapidly in saved operating costs, particularly in new applications or end-of-life motor replacements. In cases where existing motors have not reached the end of their useful life, the economics will be less clearly positive. Because the favorable economics of energy-efficient motors are based on savings in operating costs, there may be certain cases which are generally economically ill-suited to energy efficient motors. These include highly intermittent duty or special torque applications such as hoists and cranes, traction drives, punch presses, machine tools, and centrifuges. In addition, energy, efficient designs of multi-speed motors are generally not available. Furthermore, energy- efficient motors are not yet available for many special applications, e.g. for flame-proof operation in oil-field or fire pumps or for very low speed applications (below 750 rpm). Also, most energy-efficient motors produced today are designed only for continuous duty cycle operation.

Given the tendency of over sizing on the one hand and ground realities like ; voltage, frequency variations, efficacy of rewinding in case of a burnout, on the other hand, benefits of EEM's can be achieved only by careful selection, implementation, operation and maintenance efforts of energy managers. A summary of energy efficiency improvements in EEMs is given in the Table 2.2

TABLE 2.2 ENERGY EFFICIENT MOTORS

Power Loss Area	Efficiency Improvement
1. Iron	Use of thinner gauge, lower loss core steel reduces eddy current losses. Longer core adds more steel to the design, which reduces losses due to lower operating flux densities.
2. Stator I^2R	Use of more copper and larger conductors increases cross sectional area of stator windings. This lowers resistance (R) of the windings and reduces losses due to current flow (I).
3. Rotor I^2R	Use of larger rotor conductor bars increases size of cross section, lowering conductor resistance (R) and losses due to current flow (I).
4. Friction & Windage	Use of low loss fan design reduces losses due to air movement.
5. Stray Load Loss	Use of optimized design and strict quality control procedures minimizes stray load losses.

Factors Affecting Energy Efficiency & Minimizing Motor Losses in Operation

Power Supply Quality

Motor performance is affected considerably by the quality of input power, that is the actual volts and frequency available at motor terminals vis-à-vis rated values as well as voltage and frequency variations and voltage unbalance across the three phases. Motors in India must comply with standards set by the Bureau of Indian Standards (BIS) for tolerance to variations in input power quality. The BIS standards specify that a motor should be capable of delivering its rated output with a voltage variation of +/- 6 % and frequency variation of +/- 3 %. Fluctuations much larger than these are quite common in utility-supplied electricity in India. Voltage fluctuations can have detrimental impacts on motor performance.

Voltage unbalance, the condition where the voltages in the three phases are not equal, can be still more detrimental to motor performance and motor life. Unbalance typically occurs as a result of supplying single-phase loads disproportionately from one of the phases. It can also result from the use of different sizes of cables in the distribution system.

The options that can be exercised to minimize voltage unbalance include:

i) Balancing any single phase loads equally among all the three phases
ii) Segregating any single phase loads which disturb the load balance and feed them from a separate line / transformer

Power Factor Correction

As noted earlier, induction motors are characterized by power factors less than unity, leading to lower overall efficiency (and higher overall operating cost) associated with a plant's electrical system. Capacitors connected in parallel (shunted) with the motor are typically used to improve the power factor. The impacts of PF correction include reduced kVA demand (and hence reduced utility demand charges), reduced I2R losses in cables upstream of the capacitor (and hence reduced energy charges), reduced voltage drop in the cables (leading to improved voltage regulation), and an increase in the overall efficiency of the plant electrical system.

It should be noted that PF capacitor improves power factor from the point of installation back to the generating side. It means that, if a PF capacitor is installed at the starter terminals of the motor, it won't improve the operating PF of the motor, but the PF from starter terminals to the power generating side will improve, i.e., the benefits of PF would be only on upstream side.

The size of capacitor required for a particular motor depends upon the no-load reactive kVA (kVAR) drawn by the motor, which can be determined only from no-load testing of the motor. In general, the capacitor is then selected to not exceed 90 % of the no-load kVAR of the motor. (Higher capacitors could result in over-voltages and motor burn-outs). Alternatively, typical power factors of standard motors can provide the basis for conservative estimates of capacitor ratings to use for different size motors. The capacitor rating for power connection by direct connection to induction motors is shown in Table 2.5.

TABLE 2.5 CAPACITOR RATINGS FOR POWER FACTOR CORRECTION BY DIRECT CONNECTION TO INDUCTION MOTORS

Motor Rating (HP)	Capacitor rating (kVAr) for Motor Speed					
	3000	1500	1000	750	600	500
5	2	2	2	3	3	3
7.5	2	2	3	3	4	4
10	3	3	4	5	5	6
15	3	4	5	7	7	7
20	5	6	7	8	9	10
25	6	7	8	9	9	12
30	7	8	9	10	10	15
40	9	10	12	15	16	20
50	10	12	15	18	20	22
60	12	14	15	20	22	25

From the above table, it may be noted that required capacitive kVAr increases with decrease in speed of the motor, as the magnetizing current requirement of a low speed motor is more in comparison to the high speed motor for the same HP of the motor.

Maintenance

Inadequate maintenance of motors can significantly increase losses and lead to unreliable operation. For example, improper lubrication can cause increased friction in both the motor and associated drive transmission equipment. Resistance losses in the motor, which rise with temperature, would increase. Providing adequate ventilation and keeping motor cooling ducts clean can help dissipate heat to reduce excessive losses. The life of the insulation in the motor would also be longer: for every 10°C increase in motor operating temperature over the recommended peak, the time before rewinding would be needed is estimated to be halved

A checklist of good maintenance practices to help insure proper motor operation would include:

- Inspecting motors regularly for wear in bearings and housings (to reduce frictional losses) and for dirt/dust in motor ventilating ducts (to ensure proper heat dissipation).
- Checking load conditions to ensure that the motor is not over or under loaded. A change in motor load from the last test indicates a change in the driven load, the cause of which should be understood.
- Lubricating appropriately. Manufacturers generally give recommendations for how and when to lubricate their motors. Inadequate lubrication can cause problems, as noted above. Over lubrication can also create problems, e.g. excess oil or grease from the motor bearings can enter the motor and saturate the motor insulation, causing premature failure or creating a fire risk.
- Checking periodically for proper alignment of the motor and the driven equipment. Improper alignment can cause shafts and bearings to wear quickly, resulting in damage to both the motor and the driven equipment.
- Ensuring that supply wiring and terminal box are properly sized and installed. Inspect regularly the connections at the motor and starter to be sure that they are clean and tight.

Age

Most motor cores in India are manufactured from silicon steel or de-carbonized cold-rolled steel, the electrical properties of which do not change measurably with age. However, poor maintenance (inadequate lubrication of bearings, insufficient cleaning of air cooling passages, etc.) can cause a deterioration in motor efficiency over time. Ambient conditions can also have a detrimental effect on motor performance. For example, excessively high temperatures, high dust loading, corrosive atmosphere, and humidity can impair insulation properties; mechanical stresses due to load cycling can lead to misalignment. However, with adequate care, motor performance can be maintained.

Example2.1:

A three phase,10 kW motor has the name plate details as 415 V, 18.2 amps and 0.9 PF. Actual input measurement shows 415 V, 12 amps and 0.7 PF which was measured with power analyzer during motor running. Determine the motor loading?

Rated output at full load = 10 kW

Rated input at full load = $\boldsymbol{\sqrt{3} \times V \times I \times \cos\Phi}$ = 1.732 x 0.415 x 18.2 x 0.9 = 11.8 kW

The rated efficiency of motor at full load = (10 x 100) / 11.8 = 85%

Measured (Actual) input power = 1.732x 0.415 x 12x 0.7 = 6.0 kW

$$Motor\ loading\ \% = \frac{Measured\ kW}{Rated\ kW}\ x\ 100 = \frac{6.0}{11.8}\ x\ 100 = 51.2\%$$

Example 2.2:

A 400 Watt mercury vapor lamp was switched on for 10 hours per day. The supply volt is 230 V. Find the power consumption per day? (Volt = 230 V, Current = 2 amps, PF = 0.8)

Electricity consumption (kWh) = V x I x CosΦ x No of Hours

= 0.230 x 2 x 0.8 x 10 = 3.7 kWh or Units

Example 2.3:

An electric heater of 230 V, 5 kW rating is used for hot water generation in an industry. Find electricity consumption per hour (a) at the rated voltage (b) at 200 V.

(a) Electricity consumption (kWh) at rated voltage = 5 kW x 1 hour = 5 kWh.

(b) Electricity consumption at 200 V (kWh) = (200 / 230)2 x 5 kW x 1 hour = 3.78 kWh.

Example2.4 :

The utility bill shows an average power factor of 0.72 with an average KW of 627. How much kVAr is required to improve the power factor to .95 ?

Using formula

Cos Φ 1 = 0.72 , tan Φ 1 = 0.963

Cos Φ 2 = 0.95 , tan Φ 2 = 0.329

kVAr required = P (tan Φ 1 - tan Φ 2)

= 627 (0.964 – 0.329)

= 398 kVAr

Lecture 3: Energy Management Opportunities in Electrolytic process

An electrolytic process is the use of electrolysis industrially to refine metals or compounds at a high purity and low cost. Some examples are the Hall- Héroult process used for aluminum, the production of hydrogen from water, production of chlorine and caustic soda etc. Electrolysis is usually done in bulk using hundreds of sheets of metal connected to an electric power source. Electrolysis process uses an electric current to drive a chemical reaction which otherwise would not occur spontaneously.

Electrolytic hydrogen production has been scientifically studied for more than a century. According to the literature, hydrogen has been used by for military, industrial and commercial purposes since late 19th century. Nowadays, electrolytic hydrogen has a share of only 4% in the global production of the most abundant element of the universe. Electricity expense constitutes the largest fraction of hydrogen production costs. High hydrogen production expenses count as the main deficiency of commercial and industrial electrolyzers. Hence electrolytic methods are usually outperformed by other approaches such as steam methane reformation. An electrolyzer is usually subjected to massive current values in order to break the water molecules into oxygen and hydrogen.

Factors to improve electrical efficiency in electrolytic hydrogen production process

1. Electrolyte quality
2. Temperature
3. Pressure
4. Electrical resistance of the electrolyte
   a. Space between electrodes
   b. Size and alignment of the electrodes
5. Electrode material
6. Separator material
7. Applied voltage waveform

Electrolytic systems

Electrolysis involves movement of positively- or negatively-charged ions within an electrolyte between an anode (positively-charged electrode) and a cathode (negatively-charged electrode). These familiar processes involve electrolysis:
• Storage batteries.
• Welding.
• Corrosion.
• Electrowinning (refining of metals such as aluminum).
• Plating and anodizing.
• Electroforming, electrochemical machining, and etching.
• Fuel cells.

Corrosion

Corrosion occurs as a result of oxidation-reduction reactions between a metal or alloy and a corroding agent. Corrosion can occur as a result of chemical reactions, which usually require high temperatures and a corrosive environment, or due to electrochemical reactions, which are more common. Note that corrosion is an important indirect use of energy.
The electrochemical reactions resemble the processes that take place in a battery. They can arise when dissimilar metals occur in the presence of an electrolyte or in the presence of external electric currents. A common electrolyte is water with trace amounts of dissolved salts, acids, or alkalis. The rates of corrosion reactions are dependent on the concentration of salts, acids, or alkalis in the electrolyte, and on the surface, temperature, and chemical constituents of the corroding metal.

Welding

Where possible, AC welders are preferred as they offer a better power factor and more economical operation. Automated systems reduce standby power losses compared to manual welding because they place the weld bead more consistently (less start/stop).

Electrowinning

An important use of electrolysis is the refining of metals such as aluminum. Basically the original process involved the electrolysis of a solution of aluminum oxide in molten cryolite, using carbon anodes and electrodes. In the electrolyte solution, aluminum oxide disassociates into aluminum and oxygen ions. As currents on the order of 105 amperes pass through the cells (at potentials of 5.0_5.4 V), the aluminum ions migrate to the cell lining (cathode) where they are reduced to metallic aluminum. This process required 15_20 kWh per kg of electricity. New processes have been developed that reduce the amount of electricity required.

Plating and Anodizing

An electric current flows in a tank where the object to be plated or anodized serves as one of the electrodes. In plating, the plated object serves as the cathode and the anode has the material to be electrodeposited. Alternatively, the anode may be nonconsumable carbon and the plating material may be drawn from the bath. In anodizing (typical for aluminum), the object to be anodized is the anode and a direct current produces a buildup of aluminum oxide on the surface. By use of various organic acids, colored finishes can be produced.

Electroforming, Electrochemical Machining

Electroforming is a process whereby a thin layer of metal is deposited on an object to be coated or on a mold that is later removed. The classic example is copper plated baby shoes! Electrochemical machining is the reverse of plating; a high current is passed between an electrolyte and the part, removing metal. This process is used for fine, intricate parts or hard, difficult-to-machine metals.

EMOs in Electrolytic Processes

Table 2.6 summarizes typical energy management possibilities for electrolytic processes. The greatest users of energy in this field (aside from the large indirect use caused by corrosion) are in primary metals production, particularly aluminum and magnesium.

Table 2.6 EMOs in electrolysis

Corrosion protection
• Use protective films, paints, epoxy • Provide cathodic protection (sacrificial anodes) • Cathodic protection with an applied voltage • Electroplating and anodizing • Use chemical water treatment (corrosion inhibitors) • Avoid contact of dissimilar materials (dielectric unions)
Storage batteries
• Provide adequate maintenance (replace electrolytes, clean terminals, etc.) • Use efficient charging techniques, charge at proper rates • Avoid overheating, provide adequate ventilation
Electrolytic processes

- Insulate plating tanks
- Provide proper maintenance of electrodes and rectifiers
- Recover waste heat
- Use more efficient rectifiers (semiconductor vs. mercury arc)
- Use more efficient controls
- Develop improved electrode design and materials to increase efficiency

Lecture 4: Energy Management Opportunities in Electric heating

Electric Heat Applications

Due to its relatively higher cost, electricity is not used extensively for process heat. However, there are some types of applications where electricity offers advantages for heating. Electric heat can take several forms:

- Resistance heating.
- Induction heating.
- Dielectric heating.
- Electric arc heating.
- Microwave heating.
- Infrared heating.
- Heat pumps.

Resistance heating: Resistance heating makes use of the i2R law; i.e., power dissipated is proportional to the square of the current times resistance. An example of this is a conventional residential electric waterheater, which has two resistance heating elements, nominally rated at 3800 W and 240 V, single phase. This form of resistance heating has ahigh first law efficiency because all the heat is transferred to the material being heated; i.e., the water. Losses result from conduction through the tank walls and distribution piping.

Induction heating: Induction heating is similar to resistance heating in that the actual heating is caused by current flowing through resistance. However, in the induction heater, the heating current is induced in the work piece. An example is the heating of transformers, cores, and motor windings. Even though they are laminated to produce high resistance to the flow of such currents, transformers are in effect inductance heaters.

In an induction furnace, a coil surrounds the work piece, which must be a conductor. A variable frequency power source (oscillator) is connected to this coil, inducing eddy currents that in turn heat the work piece. The eddy currents exhibit a “screening” effect; i.e., the current density at the surface of the work piece is maximum and decreases exponentially with depth. A “penetration” depth can be defined, wherein the current has decreased to about 37% of the surface value. Approximately 90% of the heating occurs within the penetration depth. Since the penetration depth is inversely proportional to frequency, a low frequency would be used for heating a large piece and a high frequency for a smaller size.

Example. A forge heater. Billets of steel are brought by a conveying system into a water-cooled copper coil. The frequency is in the range of 1_10 kHz; specific power is about 300 kWh/ton. Advantages of induction heating include excellent temperature control and no surface decarburization. The disadvantage is a low power factor (typically 0.1_0.5), which can be corrected with capacitors.

Dielectric heating: Dielectric heating refers to the heating of nonconducting materials by an electric field. Basically, this is similar to the heating that occurs in the dielectric of a capacitor on which a high-frequency voltage is impressed. The electromagnetic fields excite the molecular makeup of material, thereby generating heat within the material. As a result, the heat is distributed uniformly throughout the work piece. Dielectric heating can be applied to wood, paper, food, ceramics, rubber, glues, and resins. The heating effect is proportional to the dielectric loss factor, the applied frequency, and the electric field strength.

Dielectric systems can be divided into two types: RF (radio frequency) and microwave. RF systems operate in the 1_100 MHz range, and microwave systems operate in the 100_10,000 MHz range. RF systems are less expensive and are capable of larger penetration depths because of their lower frequencies and longer wavelengths than microwave systems, but they are not as well suited for materials or products with irregular shapes.

Electric arc furnace:. The electric arc furnace has three electrodes connected to the secondary windings of a three-phase transformer. The principle is the same as in electric arc welding. When an arc is struck, the nearby gas is raised to such a high temperature (in excess of 5000°C) that it becomes highly ionized. In this state, it is a sufficiently good conductor to be maintained at high temperature by the resistive heating produced by the current. The high temperature of the plasma permits very efficient heat transfer. Arc furnaces with capacities in the range of a few tons to hundreds of tons are in use. The primary application of electric arc furnaces is for melting and processing recycled steel.

Microwave heating: Microwave heating (a form of dielectric heating) is a highly efficient technique for heating by high-frequency electromagnetic radiation. Typically, frequency bands are 896 or 915 MHz and 2450 MHz, corresponding to wavelengths of about 0.33 and 0.12 m. Energy is deposited in the work piece according to the same principles as the dielectric heater described above.

Furnaces can be designed to be resonant or nonresonant. The microwave oven found in many homes is an example of a resonant cavity device. Resonant systems have efficiencies generally in excess of 50%. Again, because the heat is deposited in the work piece, losses are minimized.

Infrared heating: Infrared heating is generated by i2R losses in heating lamps or devices, and this is a special case of resistance heating. The difference, however, is that infrared energy can be generated in a narrow bandwidth. This can be applied more efficiently in some cases than combustion energy that spans a broader bandwidth. To be most efficient, infrared heaters should concentrate their output at the peak of the absorption spectrum for the material being heated. For water, this corresponds to a wavelength of about $2.8X10^{26}$ m. There are applications in papermaking, drying paints and enamels, and production of chemicals and drugs.

Heat pump: The heat pump is basically a refrigerator operating in reverse. An evaporator receives heat from a low temperature heat source (the air, waste heat, ground, water, etc.). This causes evaporation of the working fluid; the vapor is then compressed by the compressor. In the condenser, it gives up the heat collected at the evaporator as well as the heat of compression. As this heat is delivered, the vapor condenses, and the hot condensate passes through the expansion valve. Heat pumps fall into the several categories, depending on the type of heating and the purpose. Those used for residential HVAC and water heating are primarily air-source or ground-source heat pumps, meaning they extract heat either from the air or from underground pipes. Therefore they use air-to-air or liquid-to-air heat transfer. Larger units for commercial and industrial applications employ liquid-to-liquid heat transfer.

Energy Management Opportunities in Electric heating can be divided into three categories

1. Reduce heat losses
2. Use more efficient processes or equipment
3. Recover heat

Reduce heat losses
• Insulate furnace walls, ducts, piping • Put covers over open tanks or vats • Reduce time doors are open • Avoid cooling time for heated products • Shutdown heating systems on tanks and ovens when not in use, or at least lower temperatures (reduce standby losses)
More efficient equipment or processes
• Use alternative processes (microwave, dielectric rather than fuel-fired) • Employ recuperators, regenerators, or preheaters • Use direct-fired rather than indirect-fired systems • Use less energy-intensive materials and processes • Use heat pumps for low temperature process heat • Reduce moisture content mechanically in materials used in drying processes • Use lower temperature processes (cold rinses, etc.)
Recover heat
• There are multiple sources: stacks, processes, building exhaust streams, cooling towers, compressors, etc. • Recovered heat can be used for space heating, water heating, process preheating, cogeneration, etc. • Many types of heat recovery systems are commercially available (heat wheels, run-around systems, heat pipes, heat exchangers, heat pumps, etc.)

Module 3

A **boiler** is an enclosed vessel that provides a means for combustion heat to be transferred into water until it becomes heated water or steam. The hot water or steam under pressure is then usable for transferring the heat to a process. Water is a useful and cheap medium for transferring heat to a process. When water is boiled into steam its volume increases about 1,600 times, producing a force that is almost as explosive as gunpowder. This causes the boiler to be extremely dangerous equipment that must be treated with utmost care.
The process of heating a liquid until it reaches its gaseous state is called evaporation. Heat is transferred from one body to another by means of (1) radiation, which is the transfer of heat from a hot body to a cold body without a conveying medium, (2) convection, the transfer of heat by a conveying medium, such as air or water and (3) conduction, transfer of heat by actual physical contact, molecule to molecule.

Boiler Specification
Typical Boiler Specification :
Boiler Make & Year : XYZ & 2003

MCR(Maximum Continuous Rating) :10TPH (F & A 100^{O}C)

Rated Working Pressure : 10.54 kg/cm^2(g)
Type of Boiler : 3 Pass Fire tube
Fuel Fired : Fuel Oil

The heating surface is any part of the boiler metal that has hot gases of combustion on one side and water on the other. Any part of the boiler metal that actually contributes to making steam is heating surface. The amount of heating surface of a boiler is expressed in square meters. The larger the heating surface a boiler has, the more efficient it becomes. The quantity of the steam produced is indicated in tons of water evaporated to steam per hour. Maximum continuous rating is the hourly evaporation that can be maintained for 24 hours. F & A means the amount of steam generated from water at 100^{O}C to saturated steam at 100 ^{O}C.

Indian Boiler Regulation

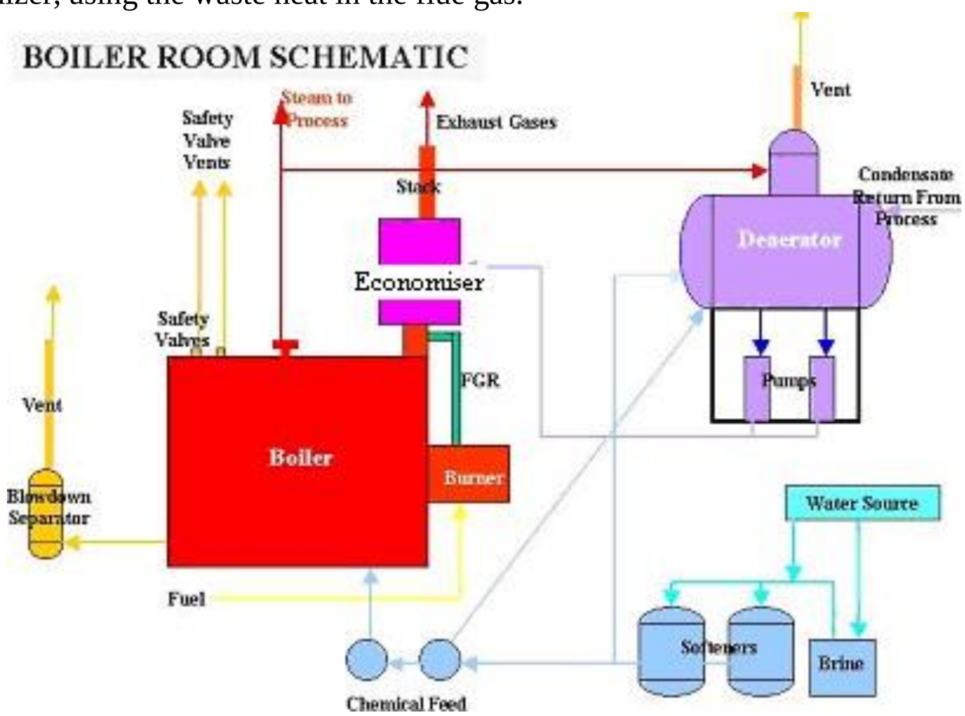
The Indian Boilers Act was enacted to consolidate and amend the law relating to steam boilers. Indian Boilers Regulation (IBR) was created in exercise of the powers conferred by section 28 & 29 of the Indian Boilers Act.

IBR Steam Boilers means any closed vessel exceeding 22.75 liters in capacity and which is used expressively for generating steam under pressure and includes any mounting or other fitting attached to such vessel, which is wholly, or partly under pressure when the steam is shut off.

IBR Steam Pipe means any pipe through which steam passes from a boiler to a prime mover or other user or both, if pressure at which steam passes through such pipes exceeds 3.5 kg/cm^2 above atmospheric pressure or such pipe exceeds 254 mm in internal diameter and includes in either case any connected fitting of a steam pipe.

Boiler Systems
The boiler system comprises of: feed water system, steam system and fuel system. The **feed water system** provides water to the boiler and regulates it automatically to meet the steam demand. Various valves provide access for maintenance and repair. The **steam system** collects

and controls the steam produced in the boiler. Steam is directed through a piping system to the point of use. Throughout the system, steam pressure is regulated using valves and checked with steam pressure gauges. The **fuel system** includes all equipment used to provide fuel to generate the necessary heat. The equipment required in the fuel system depends on the type of fuel used in the system. The water supplied to the boiler that is converted into steam is called **feed water**. The two sources of feed water are: (1) **Condensate** or condensed steam returned from the processes and (2) **Makeup water** (treated raw water) which must come from outside the boiler room and plant processes. For higher boiler efficiencies, the feed water is preheated by economizer, using the waste heat in the flue gas.



The water supplied to the boiler that is converted into steam is called **feed water**. The two sources of feed water are: (1) **Condensate** or condensed steam returned from the processes and (2) **Makeup water** (treated raw water) which must come from outside the boiler room and plant processes. For higher boiler efficiencies, the feed water is preheated by economizer, using the waste heat in the flue gas.

Boilers Classification:

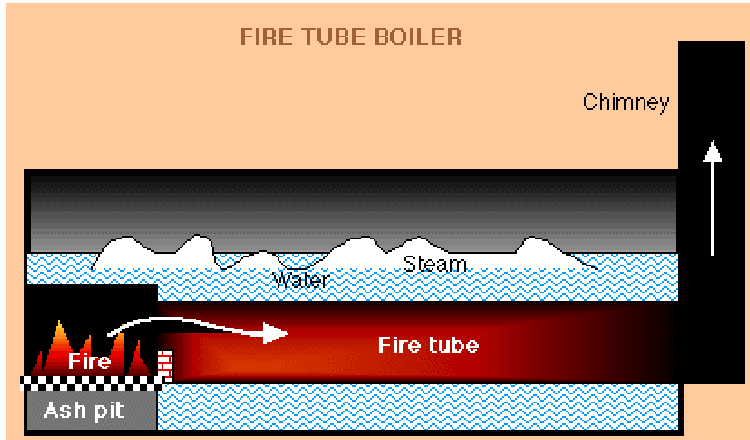
There are a large number of boiler designs, but boilers can be classified according to the following criteria:

1. According to Relative Passage of water and hot gases:

1. Water tube.
2. Fire tube.

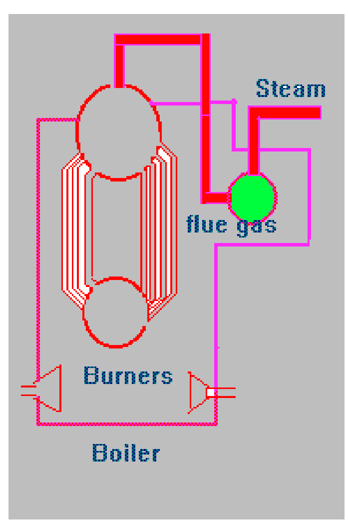
Fire tube or "fire in tube" boilers; contain long steel tubes through which the hot gasses from a furnace pass and around which the water to be converted to steam circulates. Fire tube boilers, typically have a lower initial cost, are more fuel efficient and easier to operate, but they are limited generally to capacities of 25 tons/hr and pressures of 17.5 kg/cm^2.

e.g., Lancashire, Cochran, locomotive boilers, etc.



Fire-tube boilers are:
Relatively inexpensive, Easy to clean, Compact in size, Available in sizes from 600,000 btu/hr to 50,000,000 btu/hr, Easy to replace tubes, Well suited for space heating and industrial process applications
Disadvantages of fire-tube boilers include:
Not suitable for high pressure application, Limitation for high capacity steam generation

Water tube or "water in tube" boilers in which the conditions are reversed with the water passing through the tubes and the hot gasses passing outside the tubes. These boilers can be of single- or multiple-drum type. These boilers can be built to any steam capacities and pressures, and have higher efficiencies than fire tube boilers.



The boilers can be classified according to the following criteria. In water tube boilers, water circulates through the tubes and hot products of combustion flow over these tubes. In fire tube boiler the hot products of combustion pass through the tubes, which are surrounded, by water. Fire tube boilers have low initial cost, and are more compacts. But they are more likely to explosion, water volume is large and due to poor circulation they cannot meet quickly the change in steam demand. For the same output the outer shell of fire tube boilers is much larger than the shell of water-tube boiler. Water tube boilers require less weight of metal for a given size, are less liable to explosion, produce higher pressure, are accessible and can response quickly to change in steam demand. Tubes and drums of water-tube boilers are smaller than that of fire-tube boilers and due to smaller size of drum higher pressure can be used easily. Water-tube boilers require lesser floor space. The efficiency of water-tube boilers is more. e.g., Babcock and Wilcox, Stirling, Benson boilers, etc.

6.3. COMPARISON BETWEEN 'FIRE-TUBE AND WATER-TUBE' BOILERS

S. No.	Particulars	Fire-tube boilers	Water-tube boilers
1.	*Position of water and hot gases*	Hot gases inside the tubes and water outside the tubes.	Water inside the tubes and hot gases outside the tubes.
2.	*Mode of firing*	Generally internally fired.	Externally fired.
3.	*Operating pressure*	Operating pressure limited to 16 bar.	Can work under as high pressure as 100 bar.
4.	*Rate of steam production*	Lower	Higher.
5.	*Suitability*	Not suitable for large power	Suitable for large power plants.
6.	*Risk on bursting*	Involves lesser risk on explosion due to lower pressure.	Involves more risk on bursting due to high pressure.
7.	*Floor area*	For a given power it occupies more floor area.	For a given power it occupies less floor-area.
8.	*Construction*	Difficult	Simple
9.	*Transportation*	Difficult	Simple
10.	*Shell diameter*	Large for same power	Small for same power
11.	*Chances of explosion*	Less	More
12.	Treatment of water	Not so necessary	More necessary
13.	*Accessibility of various parts*	Various parts not so easily accessible for cleaning, repair and inspection.	Various parts are more accessible.
14.	*Requirement of skill*	Require less skill for efficient and economic working.	Require more skill and careful attention.

Water-tube boilers: Are available in sizes far greater than a fire-tube design, up to several million pounds-per-hour of steam, are able to handle higher pressures up to 5,000 psig, recover faster than their fire-tube cousin, have the ability to reach very high temperatures.

Disadvantages of the water-tube design include:

High initial capital cost, cleaning is more difficult due to the design, No commonality between tubes, Physical size may be an issue

2. According to Water Circulation Arrangement:

Natural Circulation: Water circulates in the boiler due to density difference of hot and water, e.g., Babcock and Wilcox boilers, Lancashire boilers, Cochran, locomotive boilers, etc.

Forced Circulation: A water pump forces the water along its path, therefore, the steam generation rate increases, Eg: Benson, La Mont, Velox boilers, etc.

3. According to the Use:

Stationary Boiler: These boilers are used for power plants or processes steam in plants.

Portable Boiler: These are small units of mobile and are used for temporary uses at the sites.
Locomotive: These are specially designed boilers. They produce steam to drive railway engines.
Marine Boiler: These are used on ships.

4. According to Position of the Boilers:

Horizontal, inclined or vertical boilers

5. According to the Position of Furnace

Internally fired: The furnace is located inside the shell, e.g., Cochran, Lancashire boilers, etc.
Externally fired: The furnace is located outside the boiler shell, e.g., Babcock and Wilcox, Stirling boilers, etc.

6. According to Pressure of steam generated

Low-pressure boiler: a boiler which produces steam at a pressure of 15-20 bar is called a low-pressure boiler. This steam is used for process heating.
Medium-pressure boiler: It has a working pressure of steam from 20 bars to 80 bars and is used for power generation or combined use of power generation and process heating.
High-pressure boiler: It produces steam at a pressure of more than 80 bars.
Sub-critical boiler: If a boiler produces steam at a pressure which is less than the critical pressure, it is called as a subcritical boiler.
Supercritical boiler: These boilers provide steam at a pressure greater than the critical pressure. These boilers do not have an evaporator and the water directly flashes into steam, and thus they are called once through boilers.

7. According to charge in the furnace.

Pulverized fuel,
Supercharged fuel and
Fluidized bed combustion boilers.

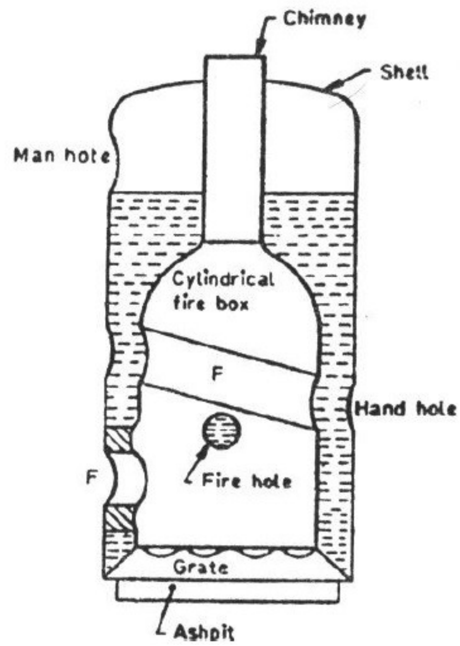
1.Simple vertical boiler:

Cylindrical shell: The shell is vertical and it attached to the bottom of the furnace. Greater portion of the shell is full of water which surrounds the furnace also. Remaining portion is steam space. The shell may be of about 1.25 metres diameter and 2.0 meters height.
Cross-tubes: One or more cross tubes are either riveted or flanged to the furnace to increase the heating surface and to improve the water circulation.
Furnace (or fire box): Combustion of coal takes place in the furnace (fire box).
Grate: It is placed at the bottom of fire box and coal is fed on it for burning.
Fire door: Coal is fed to the grate through the fire door.
Chimney (or stack): The chimney (stack) passes from the top of the firebox through the top of the shell.
Manhole: It is provided on the top of the shell to enable a man to enter into it and inspect and repair the boiler from inside it. It is also, meant for cleaning the interior of the boiler shell and exterior of the combustion chamber and stack (chimney).
Hand holes: These are provided in the shell opposite to the ends of each cross tube for cleaning the cross tube.
Ashpit: It is provide for collecting the ash deposit, which can be removed away at intervals.

Working:

The fuel (coal) is fed into the grate through the fire hole and is burnt. The ashpit placed below the grate collect the ashes of the burning fuel. The combustion gas flows from the furnace, passes around the cross tubes and escapes to the atmosphere through the chimney. Water goes by natural circulation due to convection currents, from the lower end of the cross tube and comes out from the higher end. The working pressure of the simple vertical boiler does not exceed 70 N/cm^2.

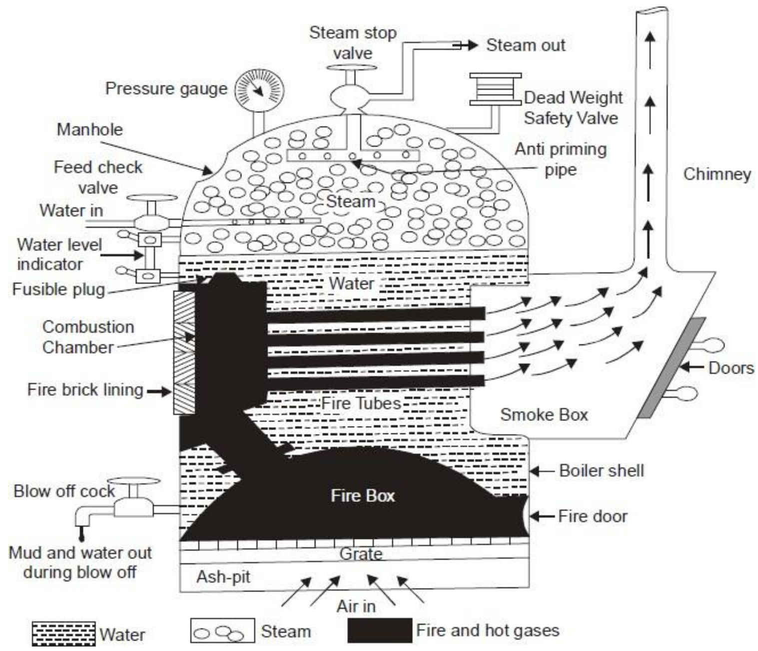
The following mountings are fitted in the boiler:
Pressure gauge: it indicates the pressure of the steam inside the boiler.
Water gauge (water level indicator): this indicates the water level in the boiler.
Safety valve: it prevents an increase of steam pressure in the boiler above its design pressure.
Steam stop valve: it regulates the flow of steam supply to requirements.



2. Cochran boiler

Cochran boiler is a vertical, coal or oil fired, fire-tube boiler. It is the modification of a simple vertical boiler with increase in surface area.

Cochran boiler consists of a cylindrical shell with its top in a spherical shape. The furnace of the Cochran boiler is in hemispherical shape. The grate is placed at the bottom of the furnace and the ash-pit is located below the grate. The coal is fed into the grate through the fire door and ash formed is collected in the ash-pit and coal is removed manually. The furnace and the combustion chamber are connected through a pipe. The back of the combustion chamber is lined with fire bricks. The hot gases from the combustion chamber flow through the nest of horizontal fire tubes. The passing through the fire tubes transfers a large amount of the heat to the water through convection. The flue gases exhausting out by fire tubes to the atmosphere through chimney.



Coal or oil can be used as a fuel in Cochran boiler. If oil is selected as fuel, no grate is required but the bottom of the furnace is lined with fire bricks. Oil burners are fitted at a suitable location below the fire door. A manhole near the top of the spherical shell is made for cleaning of boiler. Also a number of hand-holes are provided around the outer shell for cleaning purposes. The smoke box in is provided inside the boiler with doors for cleaning inside the fire tubes.

Boiler is provided with all required mountings.

Pressure Gauge: Pressure gauge indicates the pressure of the steam in the boiler.

Water Level Indicator: Water level indicator is used to indicate the water level in the boiler. The water level in the boiler should not fall below a critical level otherwise the boiler will be overheated and the tubes may damage.

Safety Valve: The function of the safety valve is used to prevent the increase of steam pressure in the holler above its design pressure. When the pressure increases above design pressure, the valve opens and discharges the steam to the atmosphere. When this pressure falls just below design pressure, the valve closes automatically.

Blow-off Cock: The water supplied to the boiler always has impurities like mud, sand and, salt. Due to heating of water, they get deposited at the bottom of the boiler and if they are not removed, they are accumulated at the bottom of the boiler and reduces its capacity and heat transfer rates. Also the salt content in water can goes on increasing as a result of evaporation of water. These deposited salts are removed with the blow-off cock mounting. The blow-off cock is usually operated for few minutes after every 5 to 6 hours of boiler working. Blow-off cock helps to keep the boiler clean.

Steam Stop Valve: Steam step stop valve regulates the flow of steam supply outside. The steam from the boiler first enters into an ant-priming pipe where most of the water particles associated with steam are removed.

Feed Check Valve: The high pressure feed water is supplied to the boiler through this valve. Feed check valve opens towards the boiler only and feeds the water to the boiler. If the feed water pressure is less than the boiler steam pressure then this valve remains closed and prevents the back flow of steam through the valve.

The outstanding features of Cochran boiler are listed below:
In Cochran boiler any type of fuel can be used.
It is best suitable for small capacity requirements.
It gives about 70% thermal efficiency with coal firing and about 75% thermal efficiency with oil firing.
The ratio of grate area to the heating surface area varies from 10: 1 to 25: 1.

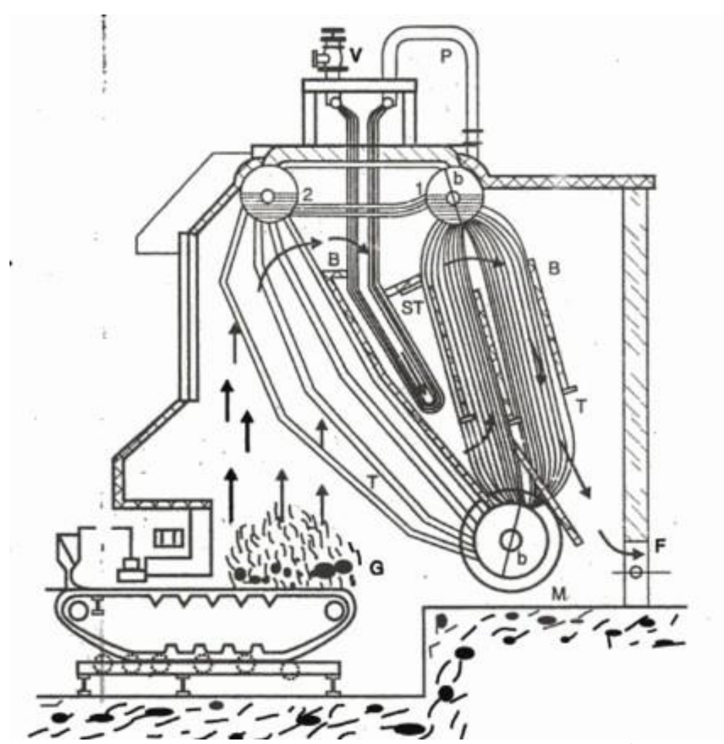
Advantages of Cochran Boiler:
Cochran boiler is very compact and requires minimum floor space.
Construction cost is low.
It is semi-portable and hence easy to install and transport.
Because of self contained furnace no brick work setting is necessary.

Disadvantages of Cochran Boiler:
It requires high head room space.
The capacity is less due to its vertical design.
Due to its vertical design, it often presents difficulty in cleaning and inspection.

3. Stirling boiler

Stirling boilers are one of the larger arrangements for a water-tube boiler: acceptable for stationary use, but impractical for mobile use, except for large ships with modest power requirements. They consist of a large brick-built chamber with a sinuous gas path through it, passing over near-vertical water-tubes that zig-zag between multiple steam drums and water drums.

ST = Superheater tubes
T = Water tubes
G = Grate
M = Mud drum
V = Stop valve
P = Steam pipe
b = Water baffle
B = Baffle wall
F = Furnace



Stirling Boiler is one of the most basic variety of bent tube boiler. In most of the modern thermal power generating plants we use bent tube boiler. Stirling Boiler is one of the largest capacity boiler. A Stirling Boiler can generate as high as 50,000 kg steam per hour and can produce pressure as high as 60 kg per cm^2. Because of the huge capacity we can use this boiler in central power stations. In Stirling Boiler there are two steam drums and one mud drum. Two steam drums are placed on the top portion of the boiler system structure and one mud drum is placed on bottom of the structure. The top steam drums are connected to the bottom mud drum with banks of bent tubes. Since the tubes are bent, the mechanical stresses due to expansion of the pipes during heating cannot effect the system much.

The steam drums, mud drum and bent tubes are made of steel. Also still structure is used to support the entire system.

The entire system is enclosed by a brickwork. Here the brick enclosure is used to prevent the heat dissipation to the surroundings. The fire door is constructed at the bottom side of the brick enclosure wall. The damper is provided on the other side of the brick enclosure wall to take out the combustion gas as when required. The fire brick arch is provided above the furnace. Three baffles are provided in the boiler system to allow the combustion gas to flow in zigzag way. There is one water circulating tubes connecting the mud drums. Also there are steam circulating tubes connecting middle steam drums to outer steam drums. There is also a group of hot water circulating tube from front steam drum to middle steam drum. A safety value is provided on the back steam drum. Finally the steam is collected from middle steam drum. The steam compartment is constructed inside the middle steam drum. The super heater is connected to steam compartment through a steel pipe.

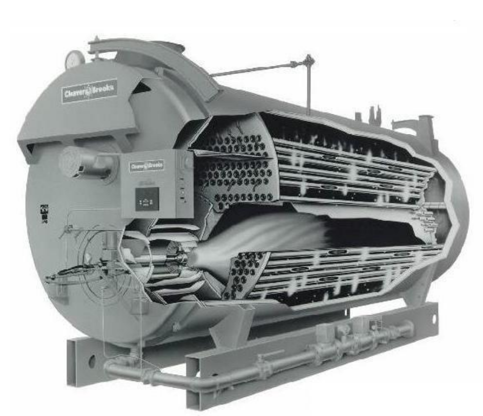
Packaged Boiler:

The packaged boiler is so called because it comes as a complete package. Once delivered to site, it requires only the steam, water pipe work, fuel supply and electrical connections to be made for it to become operational. Package boilers are generally of shell type with fire tube design so as to achieve high heat transfer rates by both radiation and convection.

The features of package boilers are:

- Small combustion space and high heat release rate resulting in faster evaporation.
- Large number of small diameter tubes leading to good convective heat transfer.
- Forced or induced draft systems resulting in good combustion efficiency.
- Number of passes resulting in better overall heat transfer.
- Higher thermal efficiency levels compared with other boilers.

These boilers are classified based on the number of passes - the number of times the hot combustion gases pass through the boiler. The combustion chamber is taken, as the first pass after which there may be one, two or three sets of fire-tubes. The most common boiler of this class is a three-pass unit with two sets of fire-tubes and with the exhaust gases exiting through the rear of the boiler.



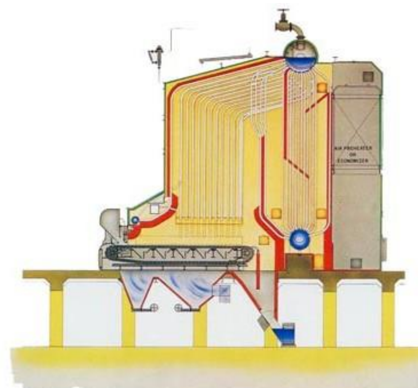
Stoker Fired Boiler:

Stokers are classified according to the method of feeding fuel to the furnace and by the type of grate. The main classifications are:

1. Chain-grate or traveling-grate stoker

2. Spreader stoker

Chain-Grate or Traveling-Grate Stoker Boiler



Coal is fed onto one end of a moving steel chain grate. As grate moves along the length of the furnace, the coal burns before dropping off at the end as ash. Some degree of skill is required, particularly when setting up the grate, air dampers and baffles, to ensure clean combustion leaving minimum of unburnt carbon in the ash. The coal-feed hopper runs along the entire coal-feed end of the furnace. A coal grate is used to control the rate at which coal is fed into the furnace, and to control the thickness of the coal bed and speed of the grate. Coal must be uniform in size, as large lumps will not burn out completely by the time they reach the end of the grate. As the bed thickness decreases from coal-feed end to rear end, different amounts of air are required- more quantity at coal-feed end and less at rear end.

Spreader Stoker Boiler

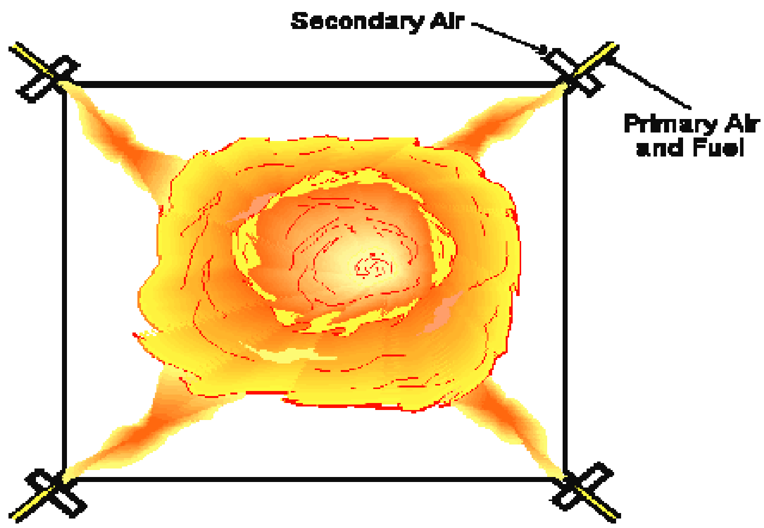
Spreader stokers utilize a combination of suspension burning and grate burning. The coal is continually fed into the furnace above a burning bed of coal. The coal fines are burned in suspension; the larger particles fall to the grate, where they are burned in a thin, fast-burning coal bed. This method of firing provides good flexibility to meet load fluctuations, since ignition is almost instantaneous when firing rate is increased. Hence, the spreader stoker is favored over other types of stokers in many industrial applications.

Pulverized Fuel Boiler

Most coal-fired power station boilers use pulverized coal, and many of the larger industrial water-tube boilers also use this pulverized fuel. This technology is well developed, and there are thousands of units around the world, accounting for well over 90% of coal-fired capacity.

The coal is ground (pulverised) to a fine powder, so that less than 2% is +300 micro metre (μm) and 70-75% is below 75 microns, for a bituminous coal. It should be noted that too fine a powder is wasteful of grinding mill power. On the other hand, too coarse a powder does not burn completely in the combustion chamber and results in higher unburnt losses.

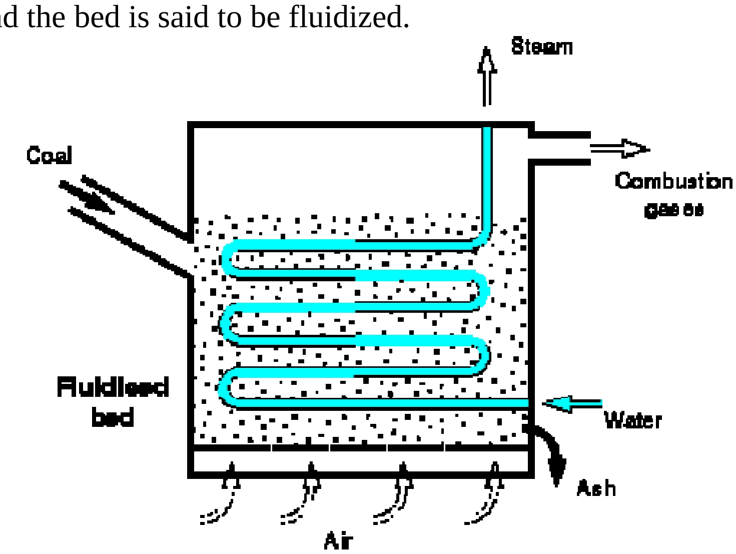
The pulverised coal is blown with part of the combustion air into the boiler plant through a series of burner nozzles. Secondary and tertiary air may also be added. Combustion takes place at temperatures from 1300-1700°C, depending largely on coal grade. Particle residence time in the boiler is typically 2 to 5 seconds, and the particles must be small enough for complete combustion to have taken place during this time.



This system has many advantages such as ability to fire varying quality of coal, quick responses to changes in load, use of high pre-heat air temperatures etc.One of the most popular systems for firing pulverized coal is the tangential firing using four burners corner to corner to create a fireball at the center of the furnace

FBC Boiler

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream. Further, increase in velocity gives rise to bubble formation, vigorous turbulence and rapid mixing and the bed is said to be fluidized.



If the sand in a fluidized state is heated to the ignition temperature of the coal and the coal is injected continuously in to the bed, the coal will burn rapidly, and the bed attains a uniform temperature due to effective mixing. Proper air distribution is vital for maintaining uniform fluidisation across the bed.). Ash is disposed by dry and wet ash disposal systems. Fluidised bed combustion has significant advantages over conventional firing systems and offers multiple benefits namely fuel flexibility, reduced emission of noxious pollutants such as SOx and NOx, compact boiler design and higher combustion efficiency.

Performance Evaluation of Boilers

The performance parameters of boiler, like efficiency and evaporation ratio reduces with time due to poor combustion, heat transfer surface fouling and poor operation and maintenance. Even for a new boiler, reasons such as deteriorating fuel quality, water quality etc. can result in poor boiler performance. Boiler efficiency tests help us to find out the deviation of boiler efficiency from the best efficiency and target problem area for corrective action.

Boiler Efficiency

Thermal efficiency of boiler is defined as the percentage of heat input that is effectively utilised to generate steam. There are two methods of assessing boiler efficiency.

1) The Direct Method: Where the energy gain of the working fluid (water and steam) is compared with the energy content of the boiler fuel.

2) The Indirect Method: Where the efficiency is the difference between the losses and the energy input.

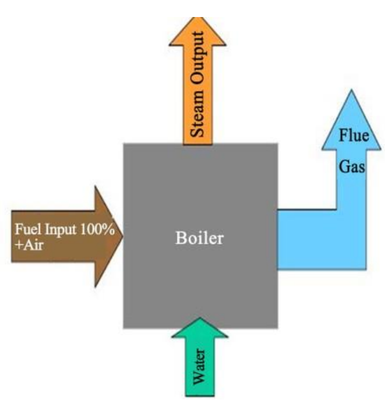
a. Direct Method

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

$$Boiler\ Efficiency = \frac{Output\ Heat}{InputHeat} \times 100$$

Parameters to be monitored for the calculation of boiler efficiency by direct method are

• Quantity of steam generated per hour (Q) in kg/hr.
• Quantity of fuel used per hour (q) in kg/hr.
• The working pressure (in kg/cm^2(g)) and superheat temperature (^{o}C), if any
• The temperature of feed water (^{o}C)
• Type of fuel and gross calorific value of the fuel (GCV) in kcal/kg of fuel



$$Boiler\ Efficiency = \frac{Q(hg - h_f)}{q \times GCV} \times 100$$

Where, h_g – Enthalpy of saturated steam in kcal/kg of steam, h_f - Enthalpy of feed water in kcal/kg of water

Advantages of direct method:

Plant people can evaluate quickly the efficiency of boilers

Requires few parameters for computation

Needs few instruments for monitoring

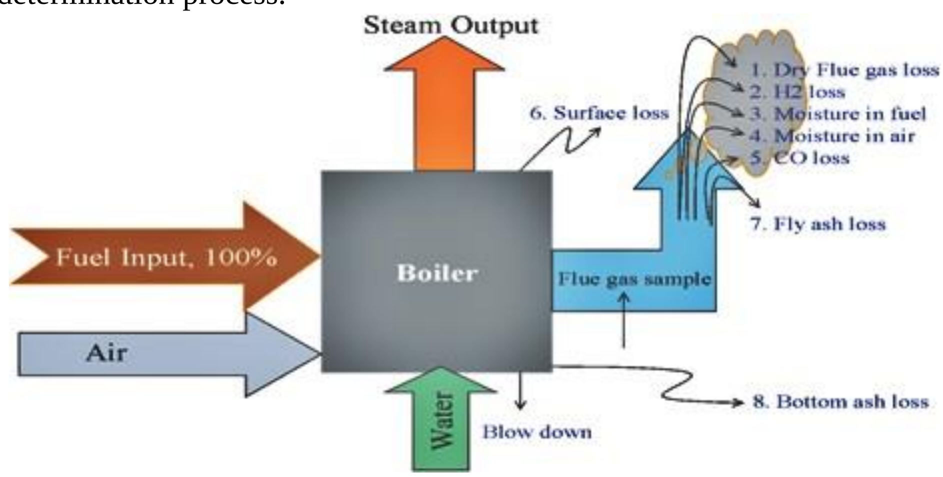
Disadvantages of direct method:

Does not give clues to the operator as to why efficiency of system is lower

Does not calculate various losses accountable for various efficiency levels

b. Indirect Method

Indirect method is also called as heat loss method. The efficiency can be arrived at, by subtracting the heat loss fractions from 100. The standards do not include blow down loss in the efficiency determination process.



The principle losses that occur in a boiler are:

• Loss of heat due to dry flue gas
• Loss of heat due to moisture in fuel and combustion air
• Loss of heat due to combustion of hydrogen
• Loss of heat due to radiation
• Loss of heat due to unburnt

Steps to calculate efficiency using indirect method

a.Theoretical air requirement $[(11.6\times C)+\{34.8\times(H_2-O_2/8)\} +4.35\times S)]/100$ kg/kg of fuel

b. Excess Air supplied (EA) = $\dfrac{O_2}{(21-O_2)}\times 100$

c. Actual mass of air supplied/ kg of fuel (AAS) = {1 + EA/100} x theoretical air

i. Percentage heat loss due to dry flue gas = $\dfrac{m\times C_P\times(T_f-T_a)}{GCV\ of\ fuel}\times 100$

m = mass of dry flue gas in kg/kg of fuel

m = Combustion products from fuel: CO_2 + SO_2 + Nitrogen in fuel + Nitrogen in the actual mass of air supplied + O2 in flue gas. (H2O/Water vapour in the flue gas should not be considered)

Cp = Specific heat of flue gas (0.23 kcal/kg ^{0}C)

ii. Percentage heat loss due to evaporation of water formed due to H_2 in fuel

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

Where, H_2 – kg of H_2 in 1 kg of fuel
C_p – Specific heat of superheated steam (0.45 kcal/kg ^{0}C)

iii. Percentage heat loss due to evaporation of moisture present in fuel

$$= \frac{M \times \{584 + C_p(T_f - T_a)\}}{GCV\ of\ fuel} \times 100$$

Where, H_2 – kg of H_2 in 1 kg of fuel
C_p – Specific heat of superheated steam (0.45 kcal/kg ^{0}C)
584 is the latent heat corresponding to the partial pressure of water vapour.

iv. Percentage heat loss due to moisture present in air

$$= \frac{AAS \times humidity\ facto \times C_p(T_f - T_a)\}}{GCV\ of\ fuel} \times 100$$

C_p – Specific heat of superheated steam (0.45 kcal/kg ^{0}C)

v. Percentage heat loss due to unburnt in fly ash

$$¿ \frac{Total \frac{ashcollecte}{kgof\ fuelburnt} \times GCV\ of\ fly\ ash}{GCV\ of\ fuel} \times 100$$

vi Percentage heat loss due to unburnt in bottom ash

$$¿ \frac{Total \frac{ashcollecte}{kgof\ fuelburnt} \times GCV\ of\ bottom\ ash}{GCV\ of\ fuel} \times 100$$

vii Percentage heat loss due to radiation and other unaccounted loss
The actual radiation and convection losses are difficult to assess because of particular emissivity of various surfaces, its inclination, air flow pattern etc. In a relatively small boiler, with a capacity of 10 MW, the radiation and unaccounted losses could amount to between 1% and 2% of the gross calorific value of the fuel, while in a 500 MW boiler, values between 0.2% to 1% are typical. The loss may be assumed appropriately depending on the surface condition.
Radiation and other unaccounted loss =
0.548 x [$(Ts / 55.55)^4$ – $(Ta / 55.55)^4$] + 1.957 x $(Ts – Ta)^{1.25}$ x sq.rt of [(196.85 Vm + 68.9) / 68.9]
where
Vm = Wind velocity in m/s
Ts = Surface temperature (K)
Ta = Ambient temperature (K)

Efficiency of boiler (η) = 100 – (i + ii + iii + iv + v + vi + vii)

Boiler Blow-down
When water is boiled and steam is generated, any dissolved solids contained in the water remain in the boiler. If more solids are put in with the feed water, they will concentrate and may eventually reach a level where their solubility in the water is exceeded and they deposit from the solution. Above a certain level of concentration, these solids encourage foaming and cause

carryover of water into the steam. The deposits also lead to scale formation inside the boiler, resulting in localized overheating and finally causing boiler tube failure.

It is, therefore, necessary to control the level of concentration of the solids and this is achieved by the process of blowing down, where a certain volume of water is blown off and is automatically replaced by feed water - thus maintaining the optimum level of total dissolved solids (TDS) in the boiler water. Blow down is necessary to protect the surfaces of the heat exchanger in the boiler. However, blow down can be a significant source of heat loss, if improperly carried out. The maximum amount of total dissolved solids (TDS) concentration permissible in various types of boilers is given.

Note: Refer guidelines specified by manufacturer for more details *parts per million

TABLE 2.1 RECOMMENDED TDS LEVELS FOR VARIOUS INDUSTRIAL PROCESS BOILERS

Boiler Type		Maximum TDS (ppm)*
1.	Lancashire	10,000 ppm
2.	Smoke and water tube boilers (12 kg/cm^2)	5,000 ppm
3.	Low pressure Water tube boiler	2000-3000
4.	High Pressure Water tube boiler with superheater etc.	3,000 - 3,500 ppm
5.	Package and economic boilers	3,000 ppm
6.	Coil boilers and steam generators	2000 (in the feed water)

Conductivity as Indicator of Boiler Water Quality

Since it is tedious and time consuming to measure total dissolved solids (TDS) in boiler water system, conductivity measurement is used for monitoring the overall TDS present in the boiler. A rise in conductivity indicates a rise in the "contamination" of the boiler water.

Conventional methods for blowing down the boiler depend on two kinds of blowdown - intermittent and continuous.

Intermittent Blowdown

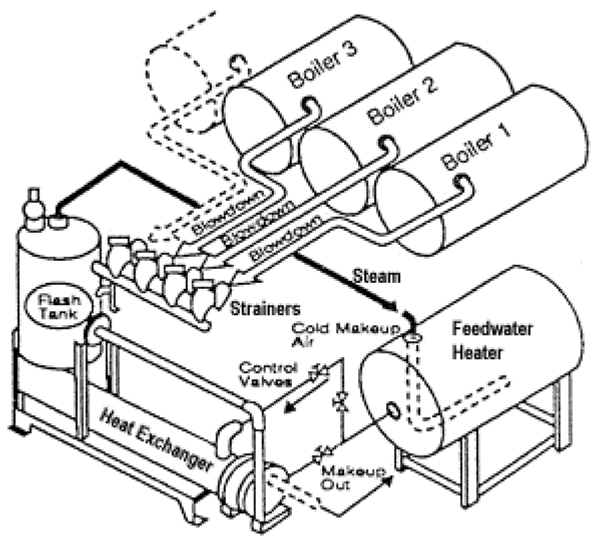
The intermittent blown down is given by manually operating a valve fitted to discharge pipe at the lowest point of boiler shell to reduce parameters (TDS or conductivity, pH, Silica and Phosphates concentration) within prescribed limits so that steam quality is not likely to be affected. In intermittent blowdown, a large diameter line is opened for a short period of time, the time being based on a thumb rule such as “once in a shift for 2 minutes”.

Intermittent blowdown requires l*arge* short-term increases in the amount of feed water put into the boiler, and hence may necessitate larger feed water pumps than if continuous blow down is used. Also, TDS level will be varying, thereby causing fluctuations of the water level in the boiler due to changes in steam bubble size and distribution which accompany changes in concentration of solids. Also substantial amount of heat energy is lost with intermittent blowdown.

Continuous Blowdown

There is a steady and constant dispatch of small stream of concentrated boiler water, and replacement by steady and constant inflow of feed water. This ensures constant TDS and steam

purity at given steam load. Once blow down valve is set for a given conditions, there is no need for regular operator intervention.
Even though large quantities of heat are wasted, opportunity exists for recovering this heat by blowing into a flash tank and generating flash steam. This flash steam can be used for pre-heating boiler feed water or for any other purpose (see Figure 2.8 for blow down heat recovery system). This type of blow down is common in high-pressure boilers.



Blowdown Heat Recovery System

Blowdown calculations
The quantity of blowdown required to control boiler water solids concentration is calculated by using the following formula:

$$Blow\ down(\ )=\frac{Feed\ water\ TDS\ x\ \ Make\ upwater}{Maximum\ Permissible\ TDS \in Boiler\ \ water}$$

Benefits of Blowdown
Good boiler blow down control can significantly reduce treatment and operational costs that include:
− Lower pretreatment costs
− Less make-up water consumption
− Reduced maintenance downtime
− Increased boiler life
− Lower consumption of treatment chemicals

Boiler Water Treatment
Producing quality steam on demand depends on properly managed water treatment to control steam purity, deposits and corrosion. A boiler is the sump of the boiler system. It ultimately receives all of the pre-boiler contaminants. Boiler performance, efficiency, and service life are direct products of selecting and controlling feed water used in the boiler.
When feed water enters the boiler, the elevated temperatures and pressures cause the components of water to behave differently. Most of the components in the feed water are soluble. However, under heat and pressure most of the soluble components come out of solution as particulate solids, sometimes in crystallized forms and other times as amorphous particles. When solubility

of a specific component in water is exceeded, scale or deposits develop. The boiler water must be sufficiently free of deposit forming solids to allow rapid and efficient heat transfer and it must not be corrosive to the boiler metal.

Deposit Control

Deposits in boilers may result from hardness contamination of feed water and corrosion products from the condensate and feed water system. Hardness contamination of the feed water may arise due to deficient softener system.

Deposits and corrosion result in efficiency losses and may result in boiler tube failures and inability to produce steam. Deposits act as insulators and slows heat transfer. Large amounts of deposits throughout the boiler could reduce the heat transfer enough to reduce the boiler efficiency significantly. Different type of deposits affects the boiler efficiency differently. Thus it may be useful to analyze the deposits for its characteristics. The insulating effect of deposits causes the boiler metal temperature to rise and may lead to tube-failure by overheating.

Impurities causing deposits

The most important chemicals contained in water that influences the formation of deposits in the boilers are the salts of calcium and magnesium, which are known as hardness salts.

Calcium and magnesium bicarbonate dissolve in water to form an alkaline solution and these salts are known as alkaline hardness. They decompose upon heating, releasing carbon dioxide and forming a soft sludge, which settles out. These are called temporary hardness-hardness that can be removed by boiling.

Calcium and magnesium sulphates, chlorides and nitrates, etc. when dissolved in water are chemically neutral and are known as non-alkaline hardness. These are called permanent hardness and form hard scales on boiler surfaces, which are difficult to remove. Non-alkalinity hardness chemicals fall out the solution due to reduction in solubility as the temperature rises, by concentration due to evaporation which takes place within the boiler, or by chemical change to a less soluble compound.

Silica

The presence of silica in boiler water can rise to formation of hard silicate scales. It can also associate with calcium and magnesium salts, forming calcium and magnesium silicates of very low thermal conductivity. Silica can give rise to deposits on steam turbine blades, after been carried over either in droplets of water in steam, or in volatile form in steam at higher pressures.

Two major types of boiler water treatment are: Internal water treatment and External water treatment.

Internal Water Treatment

Internal treatment is carried out by adding chemicals to boiler to prevent the formation of scale by converting the scale-forming compounds to free-flowing sludges, which can be removed by blowdown. This method is limited to boilers, where feed water is low in hardness salts, to low pressures- high TDS content in boiler water is tolerated, and when only small quantity of water is required to be treated. If these conditions are not applied, then high rates of blowdown are required to dispose off the sludge. They become uneconomical from heat and water loss consideration.

Different waters require different chemicals. Sodium carbonate, sodium aluminate, sodium phosphate, sodium sulphite and compounds of vegetable or inorganic origin are all used for this purpose. Proprietary chemicals are available to suit various water conditions. The specialist must be consulted to determine the most suitable chemicals to use in each case. Internal treatment alone is not recommended.

External Water Treatment

External treatment is used to remove suspended solids, dissolved solids (particularly the calcium and magnesium ions which are a major cause of scale formation) and dissolved gases (oxygen and carbon dioxide).

The external treatment processes available are**: ion exchange; demineralization; reverse osmosis and de-aeration.** Before any of these are used, it is necessary to remove suspended solids and colour from the raw water, because these may foul the resins used in the subsequent treatment sections.

Methods of **pre-treatment include simple sedimentation in settling tanks or settling in clarifiers with aid of coagulants and flocculants. Pressure sand filters, with spray aeration to remove carbon dioxide and iron, may be used to remove metal salts from bore well water.**

The first stage of treatment is to remove hardness salt and possibly non-hardness salts. Removal of only hardness salts is called softening, while total removal of salts from solution is called demineralization.

The processes are:

Ion-exchange process (Softener Plant)

In ion-exchange process, the hardness is removed as the water passes through bed of natural zeolite or synthetic resin and without the formation of any precipitate. The simplest type is 'base exchange' in which calcium and magnesium ions are exchanged for sodium ions. After saturation regeneration is done with sodium chloride. The sodium salts being soluble, do not form scales in boilers. Since base exchanger only replaces the calcium and magnesium with sodium, it does not reduce the TDS content, and blowdown quantity. It also does not reduce the alkalinity.

Demineralization is the complete removal of all salts. This is achieved by using a "cation" resin, which exchanges the cations in the raw water with hydrogen ions, producing hydrochloric, sulphuric and carbonic acid. Carbonic acid is removed in degassing tower in which air is blown through the acid water. Following this, the water passes through an "anion" resin which exchanges anions with the mineral acid (e.g. sulphuric acid) and forms water. Regeneration of cations and anions is necessary at intervals using, typically, mineral acid and caustic soda respectively. The complete removal of silica can be achieved by correct choice of anion resin.

Ion exchange processes can be used for almost total demineralization if required, as is the case in large electric power plant boilers

De-aeration

In de-aeration, dissolved gases, such as oxygen and carbon dioxide, are expelled by preheating the feed water before it enters the boiler. All natural waters contain dissolved gases in solution. Certain gases, such as carbon dioxide and oxygen, greatly increase corrosion. When heated in boiler systems, carbon dioxide (CO_2) and oxygen (O_2) are released as gases and combine with water (H_2O) to form carbonic acid, (H_2CO_3). Removal of oxygen, carbon dioxide and other non-condensable gases from boiler feed water is vital to boiler equipment longevity as well as safety of operation. Carbonic acid corrodes metal reducing the life of equipment and piping. It also dissolves iron (Fe) which when returned to the boiler precipitates and causes scaling on the boiler and tubes. This scale not only contributes to reducing the life of the equipment but also increases the amount of energy needed to achieve heat transfer.

De-aeration can be done by mechanical de-aeration, by chemical de-deration or by both together.

Mechanical de-aeration

Mechanical de-aeration for the removal of these dissolved gases is typically utilized prior to the addition of chemical oxygen scavengers. Mechanical de-aeration is based on Charles' and Henry's laws of physics. These laws state that removal of oxygen and carbon dioxide can be accomplished by heating the boiler feed water, which reduces the concentration of oxygen and carbon dioxide in the atmosphere surrounding the feed water. Mechanical de-aeration can be the most economical. They operate at the boiling point of water at the pressure in the de-aerator. They can be of vacuum or pressure type.

The vacuum type of de-aerator operates below atmospheric pressure, at about 82°C, can reduce the oxygen content in water to less than 0.02 mg/litre. Vacuum pumps or steam ejectors are required to maintain the vacuum.

The pressure-type de-aerators operates by allowing steam into the feed water through a pressure control valve to maintain the desired operating pressure, and hence temperature at a minimum of 105°C. The steam raises the water temperature causing the release of O_2 and CO_2 gases that are then vented from the system. This type can reduce the oxygen content to 0.005 mg/litre.

Where excess low-pressure steam is available, the operating pressure can be selected to make use of this steam and hence improve fuel economy. In boiler systems, steam is preferred for de-aeration because:

− Steam is essentially free from O_2 and CO_2,
− Steam is readily available
− Steam adds the heat required to complete the reaction.

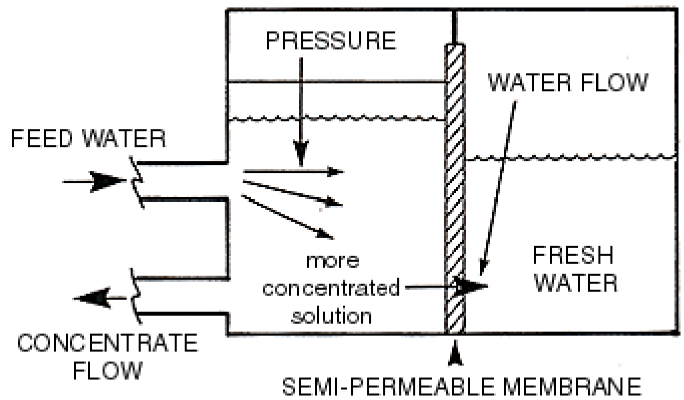
Chemical de-aeration

While the most efficient mechanical deaerators reduce oxygen to very low levels (0.005 mg/litre), even trace amounts of oxygen may cause corrosion damage to a system. Consequently, good operating practice requires removal of that trace oxygen with a chemical oxygen scavenger such as sodium sulfite or hydrazine. Sodium sulphite reacts with oxygen to form sodium sulphate, which increases the TDS in the boiler water and hence increases the blowdown requirements and make-up water quality. Hydrazine reacts with oxygen to form nitrogen and water. It is invariably used in high pressures boilers when low boiler water solids are necessary, as it does not increase the TDS of the boiler water.

Reverse Osmosis

Reverse osmosis uses the fact that when solutions of differing concentrations are separated by a semi-permeable membrane, water from less concentrated solution passes through the membrane to dilute the liquid of high concentration. If the solution of high concentration is pressurized, the process is reversed and the water from the solution of high concentration flows to the weaker solution. This is known as reverse osmosis. The semipermeable nature of the membrane allows the water to pass much more readily than the dissolved minerals. Since the water in the less concentrated solution seeks to dilute the more concentrated solution, the water passage through the membrane generates a noticeable head difference between the two solutions. This head difference is a measure of the concentration difference of the two solutions and is referred to as the osmotic pressure difference. When a pressure is applied to the concentrated solution which is great that the osmotic pressure difference, the direction of water passage through the membrane is reversed and the process that we refer to as reverse osmosis is established. That is, the membrane's ability to selectively pass water is unchanged, only the direction of the water flow is changed.

The quality of water produced depends upon the concentration of the solution on the high-pressure side and pressure differential across the membrane. This process is suitable for waters with very high TDS, such as sea water



Energy Conservation Opportunities
The various energy efficiency opportunities in boiler system can be related to combustion, heat transfer, avoidable losses, high auxiliary power consumption, water quality and blowdown.
Examining the following factors can indicate if a boiler is being run to maximize its efficiency:
1. Stack Temperature
The stack temperature should be as low as possible. However, it should not be so low that water vapor in the exhaust condenses on the stack walls. This is important in fuels containing signficant sulphur as low temperature can lead to sulphur dew point corrosion. Stack temperatures greater than 200°C indicates potential for recovery of waste heat. It also indicate the scaling of heat transfer/recovery equipment and hence the urgency of taking an early shut down for water / flue side cleaning.
2. Feed Water Preheating using Economiser
Typically, the flue gases leaving a modern 3-pass shell boiler are at temperatures of 200 to 300 ^oC. Thus, there is a potential to recover heat from these gases. The flue gas exit temperature from a boiler is usually maintained at a minimum of 200 ^oC, so that the sulphur oxides in the flue gas do not condense and cause corrosion in heat transfer surfaces. When a clean fuel such as natural gas, LPG or gas oil is used, the economy of heat recovery must be worked out, as the flue gas temperature may be well below 200^oC.
The potential for energy saving depends on the type of boiler installed and the fuel used. For a typically older model shell boiler, with a flue gas exit temperature of 260^oC, an economizer could be used to reduce it to 200^oC, increasing the feed water temperature by 15^oC. Increase in overall thermal efficiency would be in the order of 3%. For a modern 3-pass shell boiler firing natural gas with a flue gas exit temperature of 140^oC a condensing economizer would reduce the exit temperature to 65^oC increasing thermal efficiency by 5%.
3. Combustion Air Preheat
Combustion air preheating is an alternative to feedwater heating. In order to improve thermal efficiency by 1%, the combustion air temperature must be raised by 20 ^oC. Most gas and oil burners used in a boiler plant are not designed for high air preheat temperatures.
Modern burners can withstand much higher combustion air preheat, so it is possible to consider such units as heat exchangers in the exit flue as an alternative to an economizer, when either space or a high feed water return temperature make it viable.
4. Incomplete Combustion
Incomplete combustion can arise from a shortage of air or surplus of fuel or poor distribution of fuel. It is usually obvious from the colour or smoke, and must be corrected immediately.

In the case of oil and gas fired systems, CO or smoke (for oil fired systems only) with normal or high excess air indicates burner system problems. A more frequent cause of incomplete combustion is the poor mixing of fuel and air at the burner. Poor oil fires can result from improper viscosity, worn tips, carbonization on tips and deterioration of diffusers or spinner plates.

With coal firing, unburned carbon can comprise a big loss. It occurs as grit carry-over or carbon-in-ash and may amount to more than 2% of the heat supplied to the boiler. Non uniform fuel size could be one of the reasons for incomplete combustion. In chain grate stokers, large lumps will not burn out completely, while small pieces and fines may block the air passage, thus causing poor air distribution. In sprinkler stokers, stoker grate condition, fuel distributors, wind box air regulation and over-fire systems can affect carbon loss. Increase in the fines in pulverized coal also increases carbon loss.

5. Excess Air Control

Excess air is required in all practical cases to ensure complete combustion, to allow for the normal variations in combustion and to ensure satisfactory stack conditions for some fuels. The optimum excess air level for maximum boiler efficiency occurs when the sum of the losses due to incomplete combustion and loss due to heat in flue gases is minimum. This level varies with furnace design, type of burner, fuel and process variables. It can be determined by conducting tests with different air fuel ratios.

6. Radiation and Convection Heat Loss

The external surfaces of a shell boiler are hotter than the surroundings. The surfaces thus lose heat to the surroundings depending on the surface area and the difference in temperature between the surface and the surroundings.

The heat loss from the boiler shell is normally a fixed energy loss, irrespective of the boiler output. With modern boiler designs, this may represent only 1.5% on the gross calorific value at full rating, but will increase to around 6%, if the boiler operates at only 25 percent output.

Repairing or augmenting insulation can reduce heat loss through boiler walls and piping.

7. Automatic Blowdown Control

Uncontrolled continuous blowdown is very wasteful. Automatic blowdown controls can be installed that sense and respond to boiler water conductivity and pH. A 10% blow down in a 15 kg/cm^2 boiler results in 3% efficiency loss.

8. Reduction of Scaling and Soot Losses

In oil and coal-fired boilers, soot buildup on tubes acts as an insulator against heat transfer. Any such deposits should be removed on a regular basis. Elevated stack temperatures may indicate excessive soot buildup. Also same result will occur due to scaling on the water side. High exit gas temperatures at normal excess air indicate poor heat transfer performance. This condition can result from a gradual build-up of gas-side or waterside deposits. Waterside deposits require a review of water treatment procedures and tube cleaning to remove deposits. An estimated 1% efficiency loss occurs with every 22^oC increase in stack temperature. Stack temperature should be checked and recorded regularly as an indicator of soot deposits. When the flue gas temperature rises about 20^oC above the temperature for a newly cleaned boiler, it is time to remove the soot deposits. It is, therefore, recommended to install a dial type thermometer at the base of the stack to monitor the exhaust flue gas temperature.

It is estimated that 3 mm of soot can cause an increase in fuel consumption by 2.5% due to increased flue gas temperatures. Periodic off-line cleaning of radiant furnace surfaces, boiler tube banks, economizers and air heaters may be necessary to remove stubborn deposits.

9. Reduction of Boiler Steam Pressure

This is an effective means of reducing fuel consumption, if permissible, by as much as 1 to 2%. Lower steam pressure gives a lower saturated steam temperature and without stack heat recovery, a similar reduction in the temperature of the flue gas temperature results. Steam is generated at pressures normally dictated by the highest pressure / temperature requirements for a particular process. In some cases, the process does not operate all the time, and there are periods when the boiler pressure could be reduced. The energy manager should consider pressure reduction carefully, before recommending it. Adverse effects, such as an increase in water carryover from the boiler owing to pressure reduction, may negate any potential saving. Pressure should be reduced in stages, and no more than a 20 percent reduction should be considered.

10. Variable Speed Control for Fans, Blowers and Pumps

Variable speed control is an important means of achieving energy savings. Generally, combustion air control is effected by throttling dampers fitted at forced and induced draft fans. Though dampers are simple means of control, they lack accuracy, giving poor control characteristics at the top and bottom of the operating range. In general, if the load characteristic of the boiler is variable, the possibility of replacing the dampers by a VSD should be evaluated.

11. Effect of Boiler Loading on Efficiency

The maximum efficiency of the boiler does not occur at full load, but at about two-thirds of the full load. If the load on the boiler decreases further, efficiency also tends to decrease. The factors affecting boiler efficiency are :

• As the load falls, so does the value of the mass flow rate of the flue gases through the tubes. This reduction in flow rate for the same heat transfer area, reduced the exit flue gas temperatures by a small extent, reducing the sensible heat loss.

• Below half load, most combustion appliances need more excess air to burn the fuel completely. This increases the sensible heat loss.

In general, efficiency of the boiler reduces significantly below 25% of the rated load and as far as possible, operation of boilers below this level should be avoided.

12. Proper Boiler Scheduling

Since, the optimum efficiency of boilers occurs at 65-85% of full load, it is usually more efficient, on the whole, to operate a fewer number of boilers at higher loads, than to operate a large number at low loads.

13. Boiler Replacement

The potential savings from replacing a boiler depend on the anticipated change in overall efficiency. A change in a boiler can be financially attractive if the existing boiler is

old and inefficient

not capable of firing cheaper substitution fuel

over or under-sized for present requirements

not designed for ideal loading conditions

The feasibility study should examine all implications of long-term fuel availability and company growth plans. All financial and engineering factors should be considered. Since boiler plants traditionally have a useful life of well over 25 years, replacement must be carefully studied.

Steam System

Steam has been a popular mode of conveying energy since the industrial revolution. Steam is used for generating power and also used in process industries such as sugar, paper, fertilizer, refineries, petrochemicals, chemical, food, synthetic fibre and textiles. The following characteristics of steam make it so popular and useful to the industry:

Highest specific heat and latent heat
Highest heat transfer coefficient
Easy to control and distribute
Cheap and inert

Properties of Steam

Water can exist in the form of solid, liquid and gas as ice, water and steam respectively. If heat energy is added to water, its temperature rises until a value is reached at which the water can no longer exist as a liquid. We call this the "saturation" point and with any further addition of energy, some of the water will boil off as steam. This evaporation requires relatively large amounts of energy, and while it is being added, the water and the steam released are both at the same temperature. Equally, if steam is made to release the energy that was added to evaporate it, then the steam will condense and water at same temperature will be formed.

1. Liquid Enthalpy

Liquid enthalpy is the "Enthalpy" (heat energy) in the water when it has been raised to its boiling point to produce steam, and is measured in kCal/kg, its symbol is h_f. (also known as "Sensible Heat")

2. Enthalpy of Evaporation (Heat Content of Steam)

The Enthalpy of evaporation is the heat energy to be added to the water (when it has been raised to its boiling point) in order to change it into steam. There is no change in temperature, the steam produced is at the same temperature as the water from which it is produced, but the heat energy added to the water changes its state from water into steam at the same temperature.

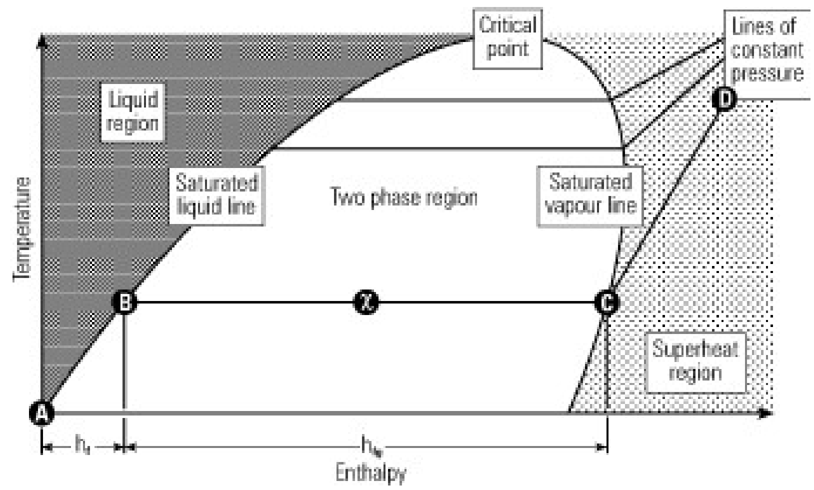
When the steam condenses back into water, it gives up its enthalpy of evaporation, which it had acquired on changing from water to steam. The enthalpy of evaporation is measured in kCal/kg. Its symbol is h_{fg}. Enthalpy of evaporation is also known as latent heat.

The temperature at which water boils, also called as boiling point or **saturation temperature,** it increases as the pressure increases. When water under pressure is heated its saturation temperature rises above 100 ^{o}C. From this it is evident that as the steam pressure increases, the usable heat energy in the steam (enthalpy of evaporation), which is given up when the steam condenses, actually decreases. The total heat of dry saturated steam or enthalpy of saturated steam is given by sum of the two enthalpies $h_f + h_{fg.}$. When the steam contains moisture the total heat of steam will be $h_g = h_f + h_{fg}$ where is the dryness fraction. The temperature of saturated steam is the same as the water from which it is generated, and corresponds to a fixed and known pressure. **Superheat** is the addition of heat to dry saturated steam without increase in pressure. The temperature of superheated steam, expressed as degrees above saturation corresponding to the pressure, is referred to as the degrees of **superheat**.

3.The steam phase diagram

The relationship between the enthalpy and the temperature at various different pressures, and is known as a phase diagram.

As water is heated from 0°C to its saturation temperature, its condition follows the saturated liquid line until it has received all of its liquid enthalpy, h_f, (**A** - **B**). If further heat continues to be added, it then changes phase to saturated steam and continues to increase in enthalpy while remaining at saturation temperature, h_{fg}, (**B** - **C**). As the steam/water

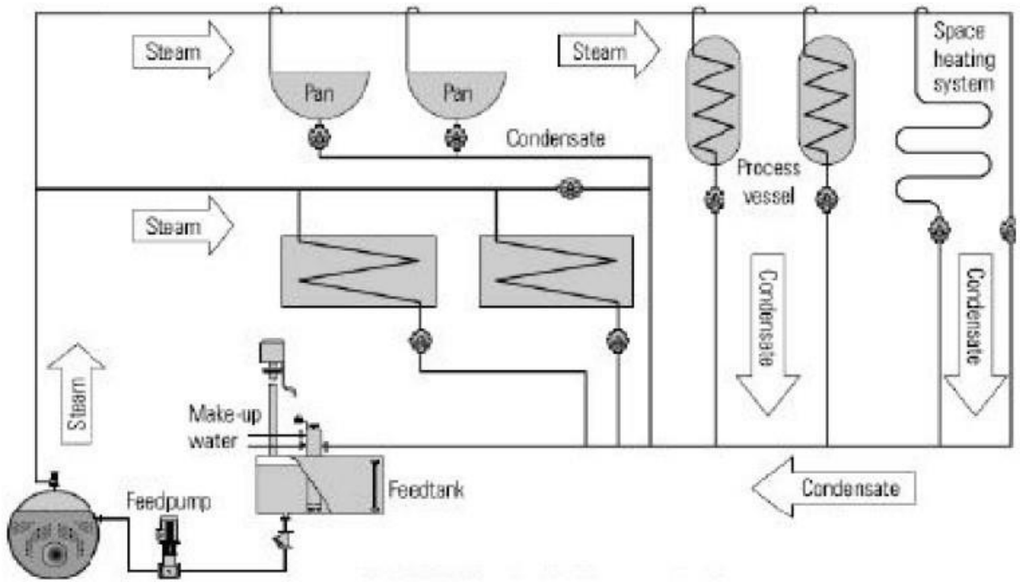


mixture increases in dryness, its condition moves from the saturated liquid line to the saturated vapour line. Therefore at a point exactly halfway between these two states, the dryness fraction χ is 0.5. Similarly, on the saturated vapour line the steam is 100% dry. Once it has received all of its enthalpy of evaporation, it reaches the saturated vapour line. If it continues to be heated after this point, the temperature of the steam will begin to rise as superheat is imparted (**C** - **D**).

The saturated liquid and saturated vapour lines enclose a region in which a steam/water mixture exists - wet steam. In the region to the left of the saturated liquid line only water exists, and in the region to the right of the saturated vapour line only superheated steam exists. The point at which the saturated liquid and saturated vapour lines meet is known as the **critical point**. As the pressure increases towards the critical point the enthalpy of evaporation decreases, until it becomes zero at the critical point. This suggests that water changes directly into saturated steam at the critical point. Above the critical point only gas may exist. The gaseous state is the most diffuse state in which the molecules have an almost unrestricted motion, and the volume increases without limit as the pressure is reduced. The critical point is the highest temperature at which liquid can exist. Any compression at constant temperature above the critical point will not produce a phase change. Compression at constant temperature below the critical point however, will result in liquefaction of the vapour as it passes from the superheated region into the wet steam region. The critical point occurs at 374.15°C and 221.2 bar for steam. Above this pressure the steam is termed supercritical and no well-defined boiling point applies.

Steam Distribution

The steam distribution system is the essential link between the steam generator and the steam user. Whatever the source, an efficient steam distribution system is essential if steam of the right quality and pressure is to be supplied, in the right quantity, to the steam using equipment. Installation and maintenance of the steam system are important issues, and must be considered at the design stage.



As steam condenses in a process, flow is induced in the supply pipe. Condensate has a very small volume compared to the steam, and this causes a pressure drop, which causes the steam to flow through the pipes. The steam generated in the boiler must be conveyed through pipework to the point where its heat energy is required. Initially there will be one or more main pipes, or ‘steam mains’, which carry steam from the boiler in the general direction of the steam using plant. Smaller branch pipes can then carry the steam to the individual pieces of equipment.

The working pressure

The distribution pressure of steam is influenced by a number of factors, but is limited by:

- The maximum safe working pressure of the boiler,
- The minimum pressure required at the plant

As steam passes through the distribution pipework, it will inevitably lose pressure due to:

- Frictional resistance within the pipework
- Condensation within the pipework as heat is transferred to the environment.

Therefore allowance should be made for this pressure loss when deciding upon the initial distribution pressure.

Features of Steam Piping

General layout and location of steam consuming equipment is of great importance in efficient distribution of steam. Steam pipes should be laid by the shortest possible distance rather than to follow a building layout or road etc. However, this may come in the way of aesthetic design and architect’s plans and a compromise may be necessary while laying new pipes.

Apart from proper sizing of pipe lines, provision must be made for proper draining of condensate which is bound to form as steam travels along the pipe. There should also be large pockets in the pipes to enable water to collect otherwise water will be carried along with steam. These drain pockets should be provided at every 30 to 50 meters and at any low point in the pipe network. The pocket should be fitted with a trap to discharge the condensate. Necessary expansion loops are required to take care of the expansion of pipes when they get heated up. Automatic air vents should be fixed at the dead end of steam mains, which will allow removal of air which will tend to accumulate.

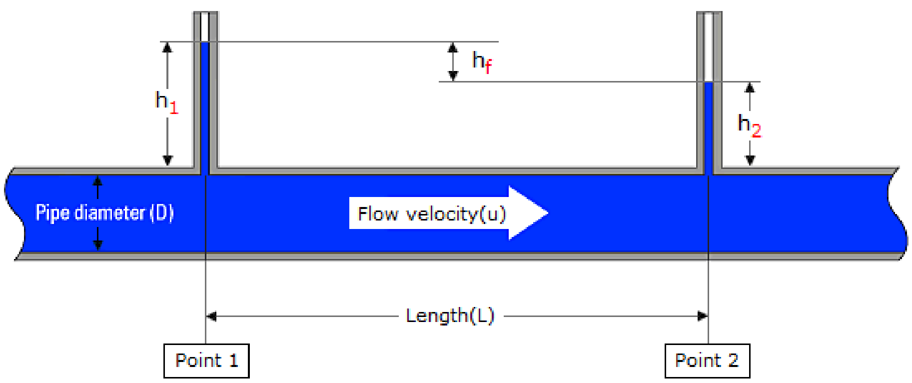
Steam Pipe Sizing and Design

Any modification and alteration in the existing steam piping, for supplying higher quality steam at right pressure and quantity must consider the following points:

Pipe Sizing

The objective of the steam distribution system is to supply steam at the correct pressure to the point of use. It follows, therefore, that pressure drop through the distribution system is an important feature

Proper sizing of steam pipelines help in minimizing pressure drop. The velocities for various types of steam are:
Superheated 50-70 m/sec
Saturated 30-40 m/sec
Wet or Exhaust 20-30 m/sec



For fluid flow to occur, there must be more energy at Point 1 than Point 2. The difference in energy is used to overcome frictional resistance between the pipe and the flowing fluid.

This is illustrated by the equation $h_f = \dfrac{4\,fLU^2}{2\,gD}$

Where: h_f = Head loss to friction (m) f = Friction factor (dimensionless) L = Length (m) u = Flow velocity (m/s) g = Gravitational constant (9.81 m/s²) D = Pipe diameter (m)..

Pipe Redundancy

All redundant (piping which are no longer needed) pipelines must be eliminated, which could be, at times, upto 10-15 % of total length. This could reduce steam distribution losses significantly. The pipe routing shall be made for transmission of steam in the shortest possible way, so as to reduce the pressure drop in the system, thus saving the energy.

Proper Selection, Operation and Maintenance of Steam Traps

The purpose of installing the steam traps is to obtain fast heating of the product and equipment by keeping the steam lines and equipment free of condensate, air and non-condensable gases. A steam trap is a valve device that discharges condensate and air from the line or piece of equipment without discharging the steam.

Functions of Steam Traps

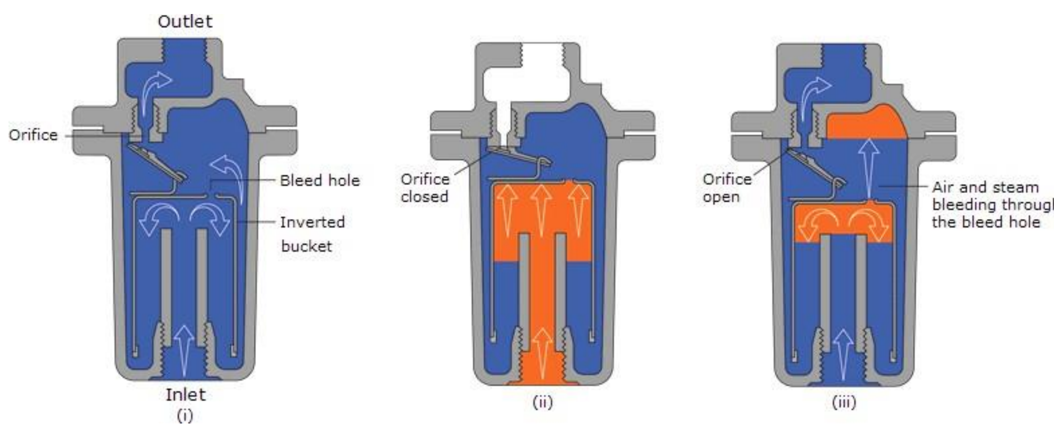
The three important functions of steam traps are:

- To discharge condensate as soon as it is formed
- Not to allow steam to escape.
- To be capable of discharging air and other incondensible gases.

Types of Steam Traps
There are three basic types of steam trap- mechanical (operates due to change in fluid density), thermostatic(operates due to change in temperature) and thermodynamic(operates due to change in fluid dynamics)

Inverted Bucket (mechanical)

The inverted bucket steam trap is shown in Figure. As its name implies, the mechanism consists of an inverted bucket which is attached by a lever to a valve. An essential part of the trap is the small air vent hole in the top of the bucket. In fig. (i) the bucket hangs down, pulling the valve off its seat. Condensate flows under the bottom of the bucket filling the body and flowing away through the outlet. In (ii) the arrival of steam causes the bucket to become buoyant, it then rises and shuts the outlet. In (iii) the trap remains shut until the steam in the bucket has condensed or bubbled through the vent hole to the top of the trap body. It will then sink, pulling the main valve off its seat. Accumulated condensate is released and the cycle is repeated.
In (ii), air reaching the trap at start-up will also give the bucket buoyancy and close the valve. The bucket vent hole is essential to allow air to escape into the top of the trap for eventual discharge through the main valve seat. The hole, and the pressure differential, are small so the trap is relatively slow at venting air. At the same time it must pass (and therefore waste) a certain amount of steam for the trap to operate once the air has cleared. A parallel air vent fitted outside the trap will reduce start-up times.



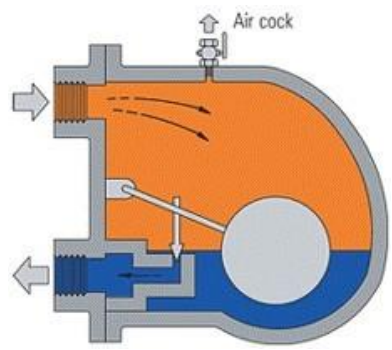
Advantages of the inverted bucket steam trap
The inverted bucket steam trap can be made to withstand high pressures.
Like a float-thermostatic steam trap, it has a good tolerance to water hammer conditions.
Can be used on superheated steam lines with the addition of a check valve on the inlet.
Failure mode is usually open, so it's safer on those applications that require this feature, for example turbine drains.

Disadvantages of the inverted bucket steam trap
The small size of the hole in the top of the bucket means that this type of trap can only discharge air very slowly. The hole cannot be enlarged, as steam would pass through too quickly during normal operation.
There should always be enough water in the trap body to act as a seal around the lip of the bucket. If the trap loses this water seal, steam can be wasted through the outlet valve. This can often happen on applications where there is a sudden drop in steam pressure, causing some of the condensate in the trap body to 'flash' into steam. The bucket loses its buoyancy and sinks,

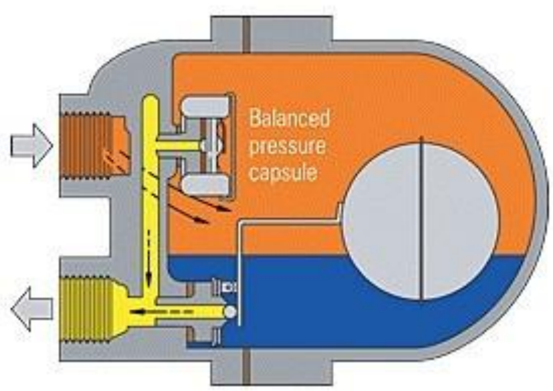
allowing live steam to pass through the trap orifice. Only if sufficient condensate reaches the trap will the water seal form again, and prevent steam wastage.

Float and Thermostatic

The ball float type trap operates by sensing the difference in density between steam and condensate. Condensate reaching the trap will cause the ball float to rise, lifting the valve off its seat and releasing condensate. As can be seen, the valve is always flooded and neither steam nor air will pass through it, so early traps of this kind were vented using a manually operated cock at the top of the body.



Modern traps use a thermostatic air vent. This allows the initial air to pass whilst the trap is also handling condensate.



The automatic air vent uses the same balanced pressure capsule element as a thermostatic steam trap, and is located in the steam space above the condensate level. After releasing the initial air, it remains closed until air or other non-condensable gases accumulate during normal running and cause it to open by reducing the temperature of the air/steam mixture. The thermostatic air vent offers the added benefit of significantly increasing condensate capacity on cold start-up.

In the past, the thermostatic air vent was a point of weakness if water hammer was present in the system. Even the ball could be damaged if the water hammer was severe. However, in modern float traps the air vent is a compact, very robust, all stainless steel capsule, and the modern welding techniques used on the ball makes the complete float-thermostatic steam trap very robust and reliable in water hammer situations.

In many ways the float-thermostatic trap is the closest to an ideal steam trap. It will discharge condensate as soon as it is formed, regardless of changes in steam pressure.

Advantages of the float-thermostatic steam trap

1. The trap continuously discharges condensate at steam temperature. This makes it the first choice for applications where the rate of heat transfer is high for the area of heating surface available.
2. It is able to handle heavy or light condensate loads equally well and is not affected by wide and sudden fluctuations of pressure or flow rate.
3. As long as an automatic air vent is fitted, the trap is able to discharge air freely.
4. It has a large capacity for its size.
5. The versions which have a steam lock release valve are the only type of trap entirely suitable for use where steam locking can occur.
6. It is resistant to water hammer.

Disadvantages of the float-thermostatic steam trap

Although less susceptible than the inverted bucket trap, the float type trap can be damaged by severe freezing and the body should be well lagged, and / or complemented with a small supplementary thermostatic drain trap, if it is to be fitted in an exposed position.

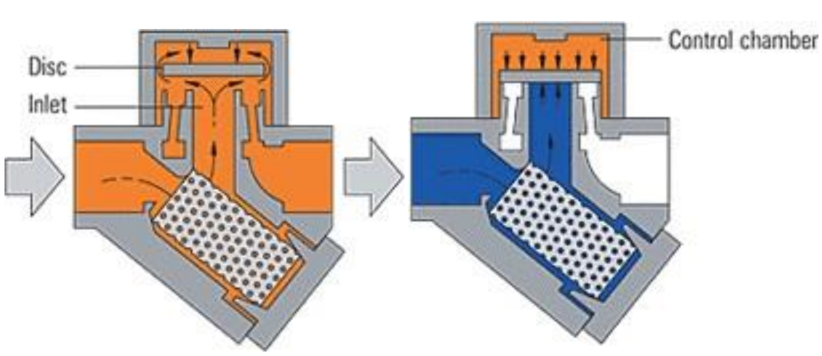
As with all mechanical type traps, different internals are required to allow operation over varying pressure ranges. Traps operating on higher differential pressures have smaller orifices to balance the bouyancy of the float.

Thermodynamic

The thermodynamic trap is an extremely robust steam trap with a simple mode of operation. The trap operates by means of the dynamic effect of flash steam as it passes through the trap. The only moving part is the disc above the flat face inside the control chamber or cap.

On start-up, incoming pressure raises the disc, and cool condensate plus air is immediately discharged from the inner ring, under the disc, and out through three peripheral outlets (only 2 shown). Hot condensate flowing through the inlet passage into the chamber under the disc drops in pressure and releases flash steam moving at high velocity. This high velocity creates a low pressure area under the disc, drawing it towards its seat.

At the same time, the flash steam pressure builds up inside the chamber above the disc, forcing it down against the incoming condensate until it seats on the inner and outer rings. At this point, the flash steam is trapped in the upper chamber, and the pressure above the disc equals the pressure being applied to the underside of the disc from the inner ring. However, the top of the disc is subject to a greater force than the underside, as it has a greater surface area. Eventually the trapped pressure in the upper chamber falls as the flash steam condenses. The disc is raised by the now higher condensate pressure and the cycle repeats



Bimetallic Type

Bimetallic steam traps operate on the same principle as a heating thermostat. A bimetallic strip or wafer connected to a valve bends or distorts when subjected to a change in temperature. When properly calibrated, the valve closes off against a seat when steam is present, and opens when condensate, air, and other noncondensable gases are present.

Advantages of the bimetallic steam trap
relatively small size for the condensate loads they handle
resistance to damage from water hammer

Thermostatic traps are often considered a universal steam trap; however, they are normally not recommended for extremely high condensate requirements (over 7000 kg/hr). For light-to-moderately high condensate loads, thermostatic steam traps offer advantages in terms of **initial cost, long-term energy conservation, reduced inventory, and ease in application and maintenance.**

A **disadvantage** is that they must be set, generally at the plant, for a particular steam operating pressure. If the trap is used for a lower pressure, it may discharge live steam. If used at a higher steam pressure, it can back up condensate into the system.

Installation of Steam Traps

In most cases, trapping problems are caused by bad installation rather than by the choice of the wrong type or faulty manufacture. To ensure a trouble-free installation, careful consideration should be given to the drain point, pipe sizing, air venting, steam locking, group trapping vs. individual trapping, dirt, water hammer, lifting of the condensate, etc.

1) Drain Point

The drain point should be so arranged that the condensate can easily flow into the trap. This is not always appreciated. For example, it is useless to provide a 15mm drain hole in the bottom of a 150 mm steam main, because most of the condensate will be carried away by the steam velocity. A proper pocket at the lowest part of the pipe line into which the condensate can drop of at least 100mm diameter is needed in such cases.

2) Pipe Sizing

The pipes leading to and from steam traps should be of adequate size. This is particularly important in the case of thermodynamic traps, because their correct operation can be disturbed by excessive resistance to flow in the condensate pipe work. Pipe fittings such as valves, bends and tees close to the trap will also set up excessive backpressures in certain circumstances.

3) Air Binding

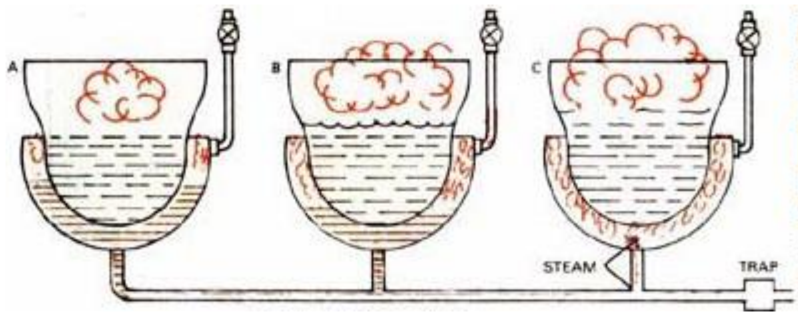
When air is pumped into the trap space by the steam, the trap function ceases. Unless adequate provision is made for removing air either by way of the steam trap or a separate air vent, the plant may take a long time in warming up and may never give its full output.

4) Steam Locking

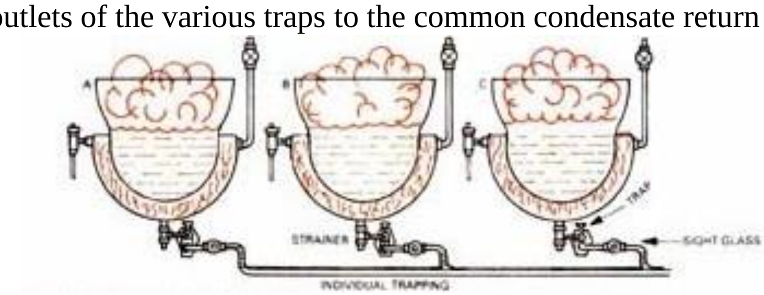
This is similar to air binding except that the trap is locked shut by steam instead of air. The typical example is a drying cylinder. It is always advisable to use a float trap provided with a steam lock release arrangement.

5) Group Trapping vs. Individual Trapping

It is tempting to try and save money by connecting several units to a common steam trap as shown in Figure. This is known as group trapping. However, it is rarely successful, since it normally causes water-logging and loss of output.



The steam consumption of a number of units is never the same at a moment of time and therefore, the pressure in the various steam spaces will also be different. It follows that the pressure at the drain outlet of a heavily loaded unit will be less than in the case of one that is lightly or properly loaded. Now, if all these units are connected to a common steam trap, the condensate from the heavily loaded and therefore lower pressure steam space finds it difficult to reach the trap as against the higher pressure condensate produced by lightly or partly loaded unit. The only satisfactory arrangement, thus would be to drain each steam space with own trap and then connect the outlets of the various traps to the common condensate return main as in figure.



6) Dirt

Dirt is the common enemy of steam traps and the causes of many failures. New steam systems contain scale, castings, weld metal, piece of packing and jointing materials, etc. When the system has been in use for a while, the inside of the pipe work and fittings, which is exposed to corrosive condensate can get rusted. Thus, rust in the form of a fine brown powder is also likely to be present. All this dirt will be carried through the system by the steam and condensate until it reaches the steam trap. Some of it may pass through the trap into the condensate system without doing any harm, but some dirt will eventually jam the trap mechanism. It is advisable to use a strainer positioned before the steam trap to prevent dirt from passing into the system.

7) Water Hammer

A water hammer in a steam system is caused by condensate collection in the plant or pipe work picked up by the fast moving steam and carried along with it. When this collection hits obstructions such as bends, valves, steam traps or some other pipe fittings, it is likely to cause severe damage to fittings and equipment and result in leaking pipe joints. The problem of water hammer can be eliminated by positioning the pipes so that there is a continuous slope in the direction of flow. A slope of at least 12mm in every 3 metres is necessary, as also an adequate number of drain points every 30 to 50 metres.

8) Lifting the condensate

It is sometimes necessary to lift condensate from a steam trap to a higher level condensate return line. The condensate will rise up the lifting pipework when the steam pressure upstream of the trap is higher than the pressure downstream of the trap. The pressure downstream of the trap is generally called backpressure, and is made up of any pressure existing in the condensate line plus the static lift caused by condensate in the rising pipework. The upstream pressure will vary between start-up conditions, when it is at its lowest, and running conditions, when it is at its highest.

Energy Saving Opportunities

1. Monitoring Steam Traps

For testing a steam trap, there should be an isolating valve provided in the downstream of the trap and a test valve shall be provided in the trap discharge. When the test valve is opened, the following points have to be observed :

Condensate discharge-Inverted bucket and thermodynamic disc traps should have intermittent condensate discharge. Float and thermostatic traps should have a continuous condensate discharge. Thermostatic traps can have either continuous or intermittent discharge depending upon the load. If inverted bucket traps are used for extremely small load, it will have a continuous condensate discharge. 3. Steam System

Flash steam-This shall not be mistaken for a steam leak through the trap. The users sometimes get confused between a flash steam and leaking steam. The flash steam and the leaking steam can be approximately identified as follows

If steam blows out continuously in a blue stream, it is a leaking steam.

If a steam floats out intermittently in a whitish cloud, it is a flash steam.

2. Continuous steam blow and no flow indicate, there is a problem in the trap.

Whenever a trap fails to operate and the reasons are not readily apparent, the discharge from the trap should be observed. A step-by-step analysis has to be carried out mainly with reference to lack of discharge from the trap, steam loss, continuous flow, sluggish heating, to find out whether it is a system problem or the mechanical problem in the steam trap.

3. Avoiding Steam Leakages

Steam leakage is a visible indicator of waste and must be avoided. It has been estimated that a 3 mm diameter hole on a pipeline carrying 7kg/cm^2 steam would waste 33 KL of fuel oil per year. Steam leaks on high-pressure mains are prohibitively costlier than on low pressure mains. Any steam leakage must be quickly attended to. In fact, the plant should consider a regular surveillance programme for identifying leaks at pipelines, valves, flanges and joints. Indeed, by plugging all leakages, one may be surprised at the extent of fuel savings, which may reach up to 5% of the steam consumption in a small or medium scale industry or even higher in installations having several process departments.

4. Providing Dry Steam for Process

The best steam for industrial process heating is the dry saturated steam. Wet steam reduces total heat in the steam. Also water forms a wet film on heat transfer and overloads traps and condensate equipment. Superheated steam is not desirable for process heating because it gives up heat at a rate slower than the condensation heat transfer of saturated steam.

It must be remembered that a boiler without a super heater cannot deliver perfectly dry saturated steam. At best, it can deliver only 95% dry steam. The dryness fraction of steam depends on various factors, such as the level of water to be a part of the steam.

As steam flows through the pipelines, it undergoes progressive condensation due to the loss of heat to the colder surroundings, the extent of the condensation depends on the effectiveness of the lagging. Since dry saturated steam is required for process equipment, due attention must be paid to the boiler operation and lagging of the pipelines.

Wet steam can reduce plant productivity and product quality, and can cause damage to most items of plant and equipment. Whilst careful drainage and trapping can remove most of the water, it will not deal with the water droplets suspended in the steam. To remove these suspended water droplets, separators are installed in steam pipelines.

The steam produced in a boiler designed to generate saturated steam is wet. Although the dryness fraction will vary according to the type of boiler, most shell type steam boilers will produce steam with a dryness fraction of between 95 and 98%. The water content of the steam produced by the boiler is further increased if priming and carryover occur.

5. Utilising Steam at the Lowest Acceptable Pressure for the Process

A study of the steam tables would indicate that the latent heat in steam reduces as the steam pressure increases. It is only the latent heat of steam, which takes part in the heating process when applied to an indirect heating system. Thus, it is important that its value be kept as high as possible. This can only be achieved if we go in for lower steam pressures. As a guide, the steam should always be generated and distributed at the highest possible pressure, but utilized at as low a pressure as possible since it then has higher latent heat. Since temperature is the driving force for the transfer of heat at lower steam pressures, the rate of heat transfer will be slower and the processing time greater. Depending on the equipment design, the lowest possible steam pressure with which the equipment can work should be selected without sacrificing either on production time or on steam consumption.

6. Proper Utilization of Directly Injected Steam

The heating of a liquid by direct injection of steam is often desirable. The equipment required is relatively simple, cheap and easy to maintain. No condensate recovery system is necessary. The heating is quick, and the sensible heat of the steam is also used up along with the latent heat, making the process thermally efficient. In processes where dilution is not a problem, heating is done by blowing steam into the liquid (i.e) direct steam injection is applied. If the dilution of the tank contents and agitation are not acceptable in the process (i.e)direct steam agitation are not acceptable, indirect steam heating is the only answer.

Ideally, the injected steam should be condensed completely as the bubbles rise through the liquid. This is possible only if the inlet steam pressures are kept very low—around 0.5kg/cm^2 –and certainly not exceeding 1 kg/cm^2. If pressures are high, the velocity of the steam bubbles will also be high and they will not get sufficient time to condense before they reach the surface.

7. Minimising Heat Transfer Barriers

The metal wall may not be the only barrier in a heat transfer process. There is likely to be a film of air, condensate and scale on the steam side. On the product side there may also be baked-on product or scale, and a stagnant film of product.

Agitation of the product may eliminate the effect of the stagnant film, whilst regular cleaning on the product side should reduce the scale. Regular cleaning of the surface on the steam side may also increase the rate of heat transfer by reducing the thickness of any layer of scale, however, this may not always be possible. This layer may also be reduced by careful attention to the correct operation of the boiler, and the removal of water droplets carrying impurities from the boiler

8. Proper Air Venting

When steam is first admitted to a pipe after a period of shutdown, the pipe is full of air. Further amounts of air and other non-condensable gases will enter with the steam, although the proportions of these gases are normally very small compared with the steam. When the steam condenses, these gases will accumulate in pipes and heat exchangers. Precautions should be taken to discharge them. The consequence of not removing air is a lengthy warming up period, and a reduction in plant efficiency and process performance. Air in a steam system will also affect the system temperature. Air will exert its own pressure within the system, and will be added to the pressure of the steam to give a total pressure. Therefore, the actual steam pressure and temperature of the steam/air mixture will be lower than that suggested by a pressure gauge.

Automatic air vents for steam systems (which operate on the same principle as thermostatic steam traps) should be fitted above the condensate level so that only air or steam/air mixtures can reach them.

9. Condensate Recovery

The steam condenses after giving off its latent heat in the heating coil or the jacket of the process equipment. A sizable portion (about 25%) of the total heat in the steam leaves the process equipment as hot water. Figure 3.23 compares the amount of energy in a kilogram of steam and condensate at the same pressure. The percentage of energy in condensate to that in steam can vary from 18% at 1 bar g to 30% at 14 bar g; clearly the liquid condensate is worth reclaiming.

If this water is returned to the boiler house, it will reduce the fuel requirements of the boiler. For every 6^0C rise in the feed water temperature, there will be approximately 1% saving of fuel in the boiler.

Benefits of condensate recovery

Financial reasons

Condensate is a valuable resource and even the recovery of small quantities is often economically justifiable. The discharge from a single steam trap is often worth recovering. Un-recovered condensate must be replaced in the boiler house by cold make-up water with additional costs of water treatment and fuel to heat the water from a lower temperature.

Water charges (are reduced)

Any condensate not returned needs to be replaced by make-up water, incurring further water charges from the local water supplier.

Effluent restrictions (Effluent charges and possible cooling costs are reduced)

High temperature of effluent is detrimental to the environment and may damage to pipes. Condensate above this temperature must be cooled before it is discharged, which may incur extra energy costs.

Maximising boiler output

Colder boiler feed water will reduce the steaming rate of the boiler. The lower the feed water temperature, the more heat, and thus fuel needed to heat the water.

Boiler feed water quality

Condensate is distilled water, which contains almost no total dissolved solids (TDS). Boilers need to be blown down to reduce their concentration of dissolved solids in the boiler water. Returning more condensate to the feed tank reduces the need for blow down and thus reduces the energy lost from the boiler.

10. Insulation of Steam Pipelines and Hot Process Equipment

Heat can be lost due to radiation from steam pipes. As an example while lagging steam pipes, it is common to see leaving flanges uncovered. An uncovered flange is equivalent to leaving 0.6 metre of pipe line unlagged. If a 0.15m steam pipe diameter has 5 uncovered flanges, there would be a loss of heat equivalent to wasting 5 tons of coal or 3000 litres of oil a year. This is usually done to facilitate checking the condition of flange but at the cost of considerable heat loss. The remedy is to provide easily detachable insulation covers, which can be easily removed when necessary. The various insulating materials used are cork, Glass wool, Rock wool and Asbestos

11. Flash Steam Recovery

Flash steam is produced when condensate at a high pressure is released to a lower pressure and can be used for low pressure heating. The higher the steam pressure and lower the flash steam pressure the greater the quantity of flash steam that can be generated. In many cases, flash steam from high pressure equipments is made use of directly on the low pressure equipment to reduce use of steam through pressure reducing valves.

Flash steam available % ¿ $\frac{S_1 - S_2}{L_2}$

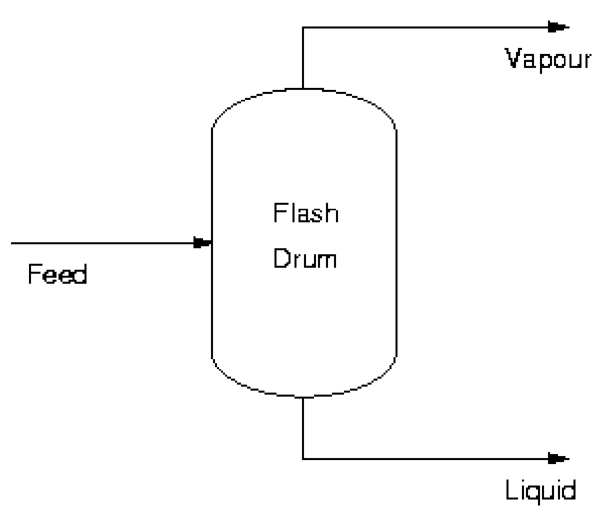
Where: S_1 is the sensible heat of higher pressure condensate.

S_2 is the sensible heat of the steam at lower pressure (at which it has been flashed).

L_2 is the latent heat of flash steam (at lower pressure).

Flash steam can be used on low pressure applications like direct injection and can replace an equal quantity of live steam that would be otherwise required. The demand for flash steam should exceed its supply, so that there is no build-up of pressure in the flash vessel and the consequent loss of steam through the safety valve. Generally, the simplest method of using flash steam is to flash from a machine/equipment at a higher pressure to a machine/equipment at a lower pressure, thereby augmenting steam supply to the low pressure equipment. In general, a flash system should run at the lowest possible pressure so that the maximum amount of flash is available and the backpressure on the high pressure systems is kept as low as possible.

Flash steam from the condensate can be separated in an equipment called the ‘flash vessel’. This is a vertical vessel as shown in the Figure.



The diameter of the vessel is such that a considerable drop in velocity allows the condensate to fall to the bottom of the vessel from where it is drained out by a steam trap preferably a float trap. Flash steam itself rises to leave the vessel at the top. The height of the vessel should be sufficient enough to avoid water being carried over in the flash steam. The condensate from the traps (A) along with some flash steam generated passes through vessel (B). The flash steam is let out through (C) and the residual condensate from (B) goes out through the steam trap (D). The flash vessel is usually fitted with a 'pressure gauge' to know the quality of flash steam leaving the vessel. A 'safety valve' is also provided to vent out the steam in case of high pressure build up in the vessel.

Furnaces

A furnace is an equipment to melt metals for casting or heat materials for change of shape (rolling, forging etc) or change of properties (heat treatment).

Characteristics of an Efficient Furnace

Furnace should be designed so that in a given time, as much of material as possible can be heated to an uniform temperature as possible with the least possible fuel and labour. To achieve this end, the following parameters can be considered.

- Determination of the quantity of heat to be imparted to the material or charge.
- Liberation of sufficient heat within the furnace to heat the stock and overcome all heat losses.
- Transfer of available part of that heat from the furnace gases to the surface of the heating stock.
- Equalisation of the temperature within the stock.
- Reduction of heat losses from the furnace to the minimum possible extent.

Furnace Energy Supply

Since the products of flue gases directly contact the stock, type of fuel chosen is of importance. For example, some materials will not tolerate sulphur in the fuel. Also use of solid fuels will generate particulate matter, which will interfere the stock place inside the furnace. Hence, vast majority of the furnaces use liquid fuel, gaseous fuel or electricity as energy input.

Melting furnaces for steel, cast iron use electricity in induction and arc furnaces. Non-ferrous melting utilizes oil as fuel.

Oil Fired Furnace

Furnace oil is the major fuel used in oil fired furnaces, especially for reheating and heat treatment of materials. LDO is used in furnaces where presence of sulphur is undesirable. The key to efficient furnace operation lies in complete combustion of fuel with minimum excess air.

Furnaces operate with efficiencies as low as 7% as against upto 90% achievable in other combustion equipment such as boiler. This is because of the high temperature at which the furnaces have to operate to meet the required demand. For example, a furnace heating the stock to 1200^{o}C will have its exhaust gases leaving atleast at 1200^{o}C resulting in a huge heat loss through the stack. However, improvements in efficiencies have been brought about by methods such as preheating of stock, preheating of combustion air and other waste heat recovery systems.

Types and Classification of Different Furnaces

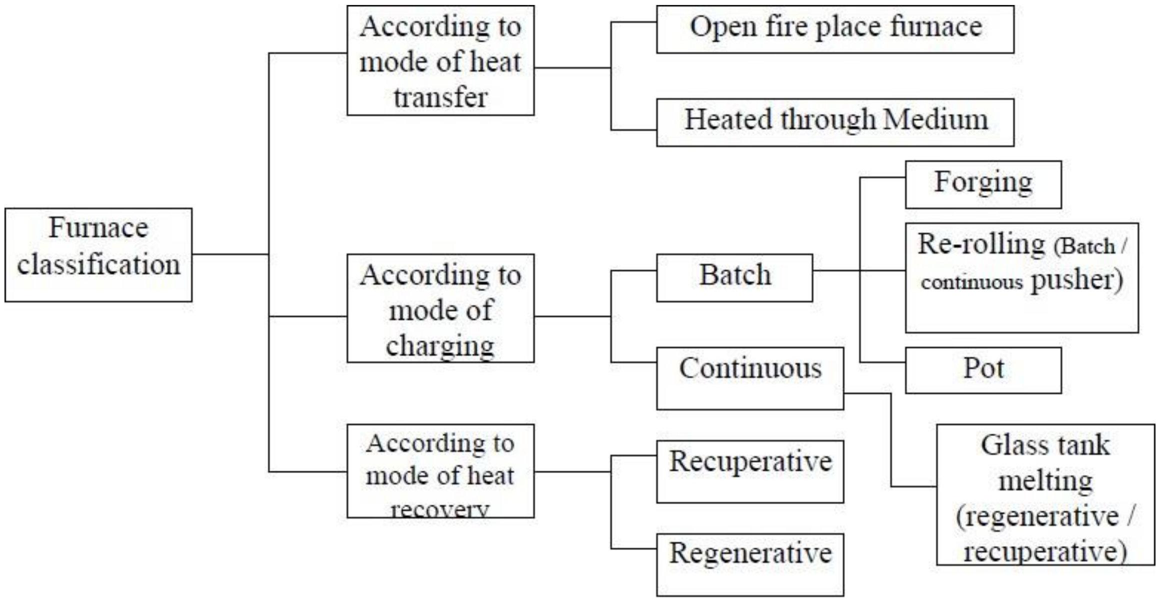


Figure 4.1 : Furnace Classification

Typical Furnace System

i) Forging Furnaces

The forging furnace is used for preheating billets and ingots to attain a 'forge' temperature. The furnace temperature is maintained at around 1200 to 1250^{O}C. Forging furnaces, use an open fireplace system and most of the heat is transmitted by radiation. The typical loading in a forging furnace is 5 to 6 tonnes with the furnace operating for 16 to 18 hours daily. The total operating cycle can be divided into (i) heat-up time (ii) soaking time and (iii) forging time. Specific fuel consumption depends upon the type of material and number of 'reheats' required.

ii) Rerolling Mill Furnace

a) Batch type

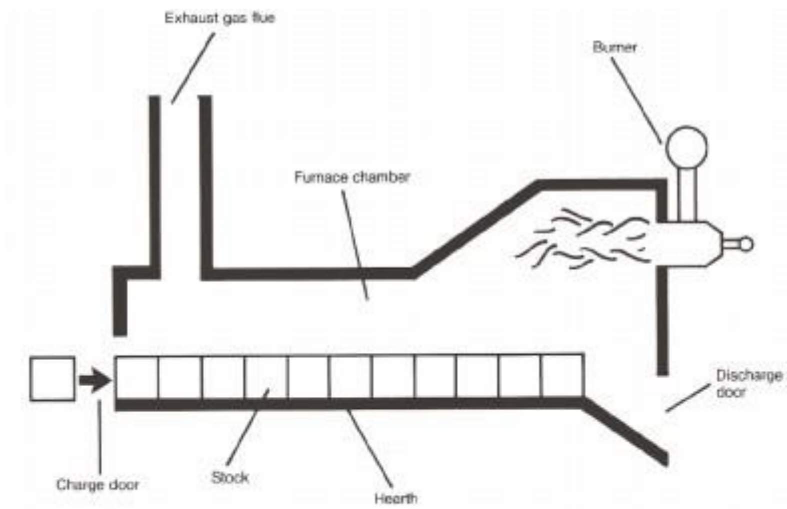
A box type furnace is employed for batch type rerolling mill. The furnace is basically used for heating up scrap, small ingots and billets weighing 2 to 20 kg. for rerolling. The charging and discharging of the 'material' is done manually and the final product is in the form of rods, strips etc. The operating temperature is about 1200 ^{O}C. The total cycle time can be further categorized into heat-up time and rerolling time. During heat-up time the material gets heated upto the required temperature and is removed manually for rerolling. The average output from these furnaces varies from 10 to 15 tonnes / day and the specific fuel consumption varies from 180 to 280 kg. of coal / tonne of heated material.

b) Continuous Pusher Type:

The process flow and operating cycles of a continuous pusher type is the same as that of the batch furnace. The operating temperature is about 1250 ^{O}C. Generally, these furnaces operate 8 to 10 hours with an output of 20 to 25 tonnes per day. The material or stock recovers a part of the heat in flue gases as it moves down the length of the furnace. Heat absorption by the material in the furnace is slow, steady and uniform throughout the cross-section compared with batch type.

iii) Continuous Steel Reheating Furnaces

The main function of a reheating furnace is to raise the temperature of a piece of steel, typically to between 900°C and 1250^{O}C, until it is plastic enough to be pressed or rolled to the desired section, size or shape, The furnace must also meet specific requirements and objectives in terms of stock heating rates for metallurgical and productivity reasons. In continuous reheating, the steel stock forms a continuous flow of material and is heated to the desired temperature as it travels through the furnace.



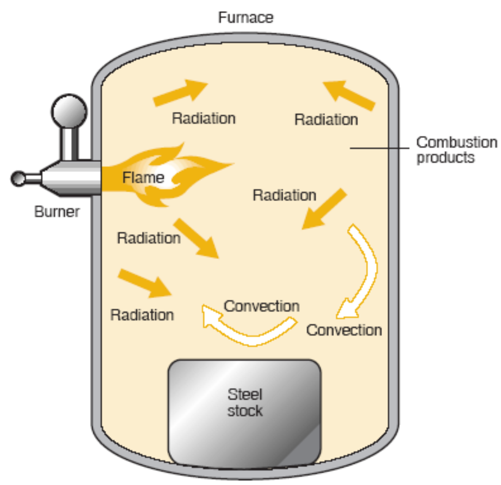
All furnaces possess the features

A refractory chamber constructed of insulating materials for retaining heat at the high operating temperatures. A hearth to support or carry the steel. This can consist of refractory materials or an arrangement of metallic supports that may be water-cooled. Burners that use liquid or gaseous fuels to raise and maintain the temperature in the chamber. Coal or electricity can be used for reheating. A method of removing the combustion exhaust gases from the chamber. A method of introducing and removing the steel from the chamber. These facilities depend on the size and type of furnace, the shape and size of the steel being processed, and the general layout of the rolling mill. Common systems include roller tables, conveyors, charging machines and furnace pushers.

Heat Transfer in Furnaces

In simple terms, heat is transferred to the stock by:

1. Radiation from the flame, hot combustion products and the furnace walls and roof;
2. Convection due to the movement of hot gases over the stock surface.



At the high temperatures employed in reheating furnaces, the dominant mode of heat transfer is wall radiation. Heat transfer by gas radiation is dependent on the gas composition (mainly the carbon dioxide and water vapour concentrations), the temperature and the geometry of the furnace.

Types of Continuous Reheating Furnace

Continuous reheating furnaces are primarily categorised by the method by which stock is transported through the furnace. There are two basic methods:

• Stock is butted together to form a stream of material that is pushed through the furnace. Such furnaces are called pusher type furnaces.

• Stock is placed on a moving hearth or supporting structure which transports the steel through the furnace. Such types include walking beam, walking hearth, rotary hearth and continuous recirculating bogie furnaces.

i) Pusher Type Furnaces

The pusher type furnace is popular in steel industry. It has relatively low installation and maintenance costs compared to moving hearth furnaces. The furnace may have a solid hearth, but it is also possible to push the stock along skids with water-cooled supports that allow both the top and bottom faces of the stock to be heated. The design of a typical pusher furnace design is shown schematically in Figure.

Disadvantages:

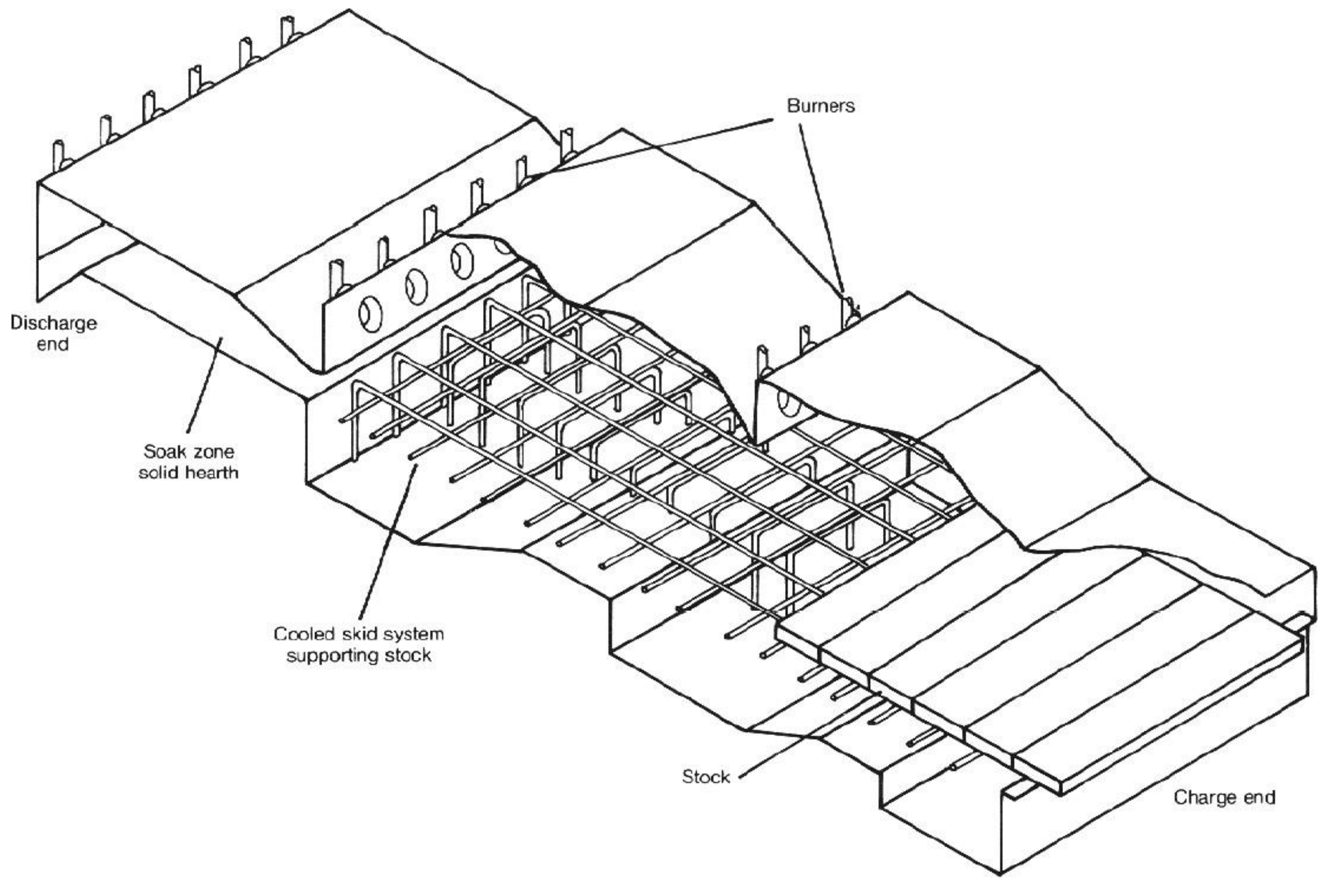
Frequent damage of refractory hearth and skid marks on material

Water cooling energy losses from the skids and stock supporting structure in top and bottom fired furnaces have a detrimental effect on energy use;

Discharge must be accompanied by charge:

Stock sizes and weights and furnace length are limited by friction and the possibility of stock pile-ups.

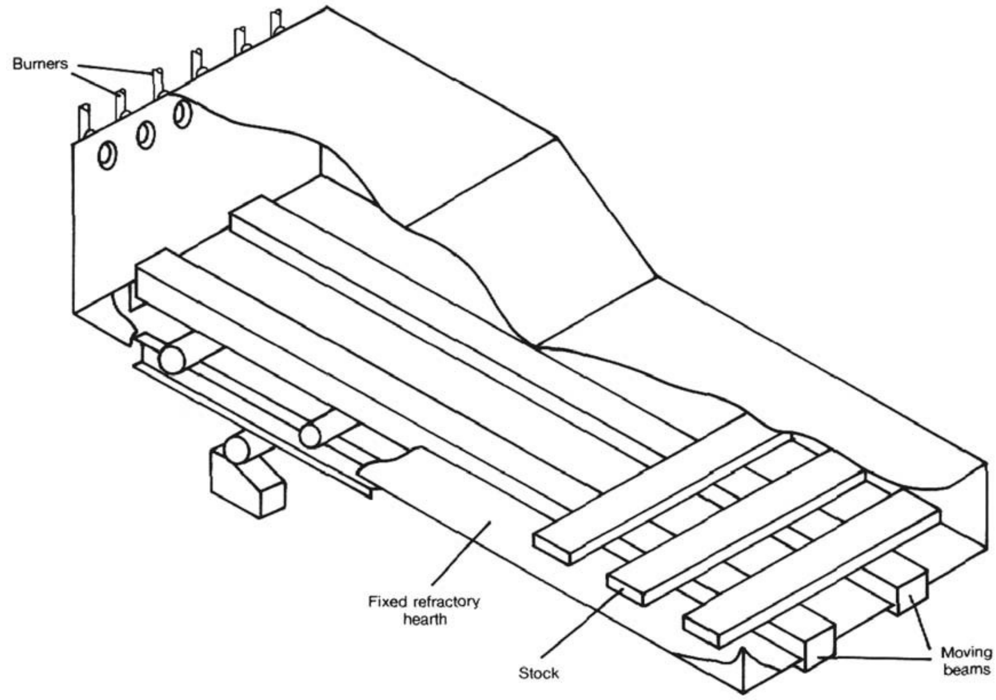
All round heating of the stock is not possible.



ii) Walking Hearth Furnaces

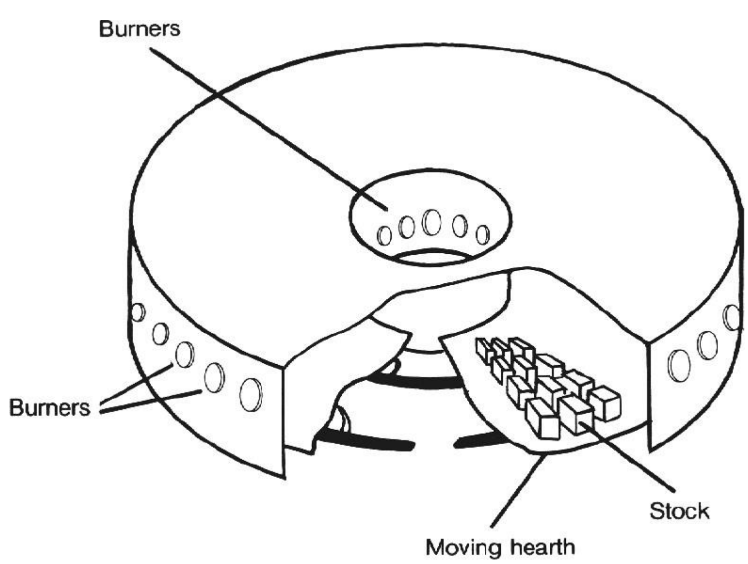
The walking hearth furnace allows the stock to be transported through the furnace in discrete steps. Such furnaces have several **attractive features** simplicity of design, ease of construction, ability to cater for different stock sizes, negligible water cooling energy losses and minimal physical marking of the stock.

The main **disadvantage** of walking hearth furnaces is that the bottom face of the stock cannot be heated. This can be alleviated to some extent by maintaining large spaces between pieces of stock. Small spaces between the individual stock pieces limits the heating of the side faces and increases the potential for unacceptable temperature differences within the stock at discharge. Consequently, the stock residence time may be long, possibly several hours; this may have an adverse effect on furnace flexibility and the yield may be affected by scaling.



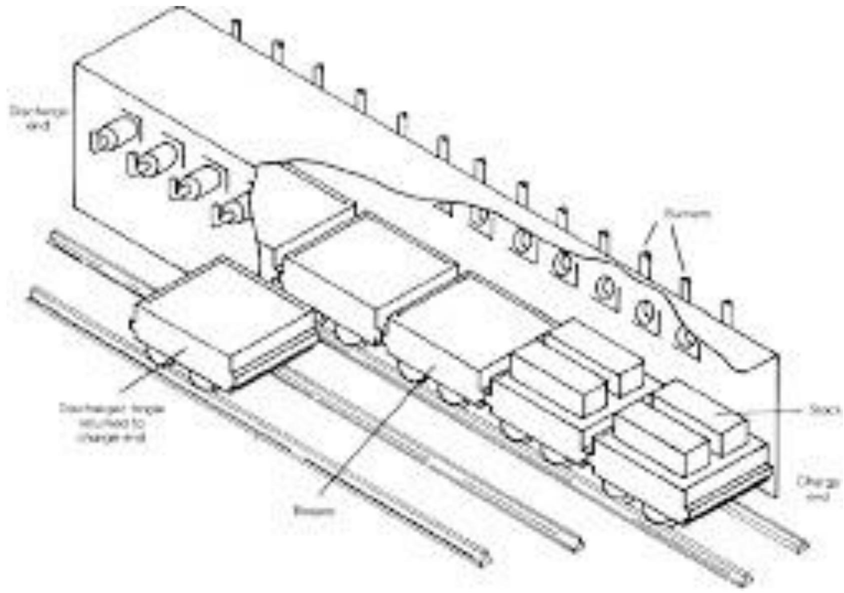
iii) Rotary hearth furnace

The rotary hearth furnace has tended to superside the recirculating bogie type. The heating and cooling effects introduced by the bogies are eliminated, so heat storage losses are less. The rotary hearth has, however a more complex design with an annular shape and revolving hearth.



iv) Continuous Recirculating Bogie type Furnaces

These types of moving hearth type furnaces tend to be used for compact stock of variable size and geometry. In bogie furnaces, the stock is placed on a bogie with a refractory hearth, which travels through the furnace with others in the form of a train. The entire furnace length is always occupied by bogies. Bogie furnaces tend to be long and narrow and to suffer from problems arising from inadequate sealing of the gap between the bogies and furnace shell, difficulties in removing scale, and difficulties in firing across a narrow hearth width.



v) Walking Beam Furnaces: The walking beam furnace (Figure 4.9) overcomes many of the problems of pusher furnaces and permits heating of the bottom face of the stock. This allows shorter stock heating times and furnace lengths and thus better control of heating rates, uniform stock discharge temperatures and operational flexibility. In common with top and bottom fired pusher furnaces, however, much of the furnace is below the level of the mill; this may be a constraint in some applications.

General Fuel Economy Measures in Furnaces

Typical energy efficiency measures for an industry with furnace are:

1) Complete combustion with minimum excess air
2) Correct heat distribution
3) Operating at the desired temperature
4) Reducing heat losses from furnace openings
5) Maintaining correct amount of furnace draft
6) Optimum capacity utilization
7) Waste heat recovery from the flue gases
8) Minimum refractory losses
9) Use of Ceramic Coatings

1. Complete Combustion with Minimum Excess Air:

The amount of heat lost in the flue gases (stack losses) depends upon amount of excess air. In the case of a furnace carrying away flue gases at 900^{o}C, % heat lost is shown in table 4.3:

TABLE 4.3 HEAT LOSS IN FLUE GAS BASED ON EXCESS AIR LEVEL

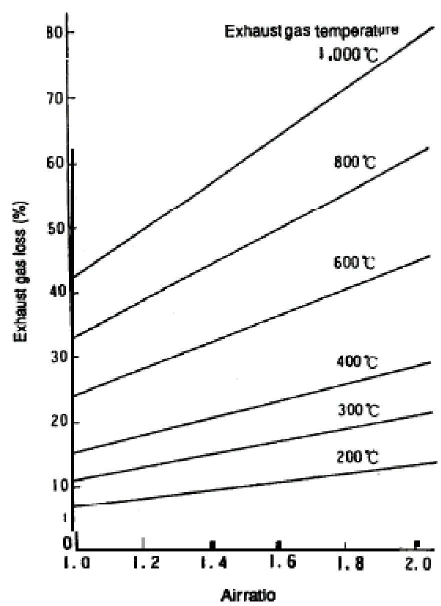
Excess Air	**% of total heat in the fuel carried away by waste gases (flue gas temp. 900^{o}C)**
25	48

50	55
75	63
100	71

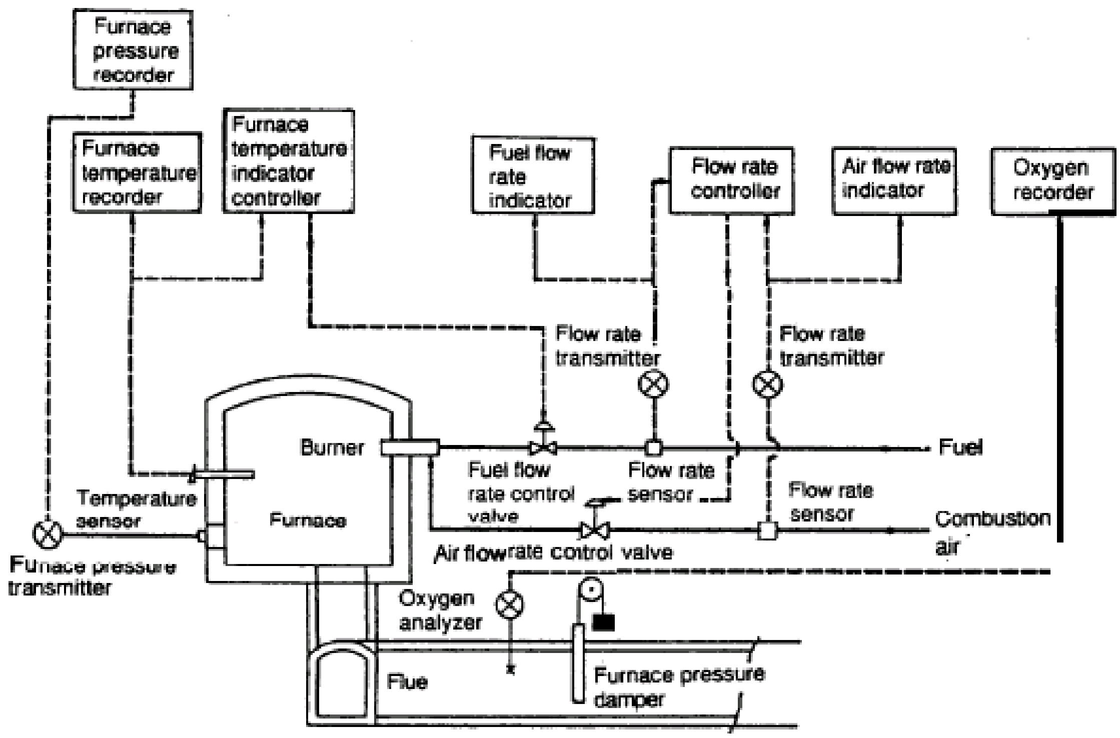
To obtain complete combustion of fuel with the minimum amount of air, it is necessary to control air infiltration, maintain pressure of combustion air,fuel quality and excess air monitoring.

Higher excess air will reduce flame temperature, furnace temperature and heating rate. On the other hand, if the excess air is less, then unburnt components in flue gases will increase and would be carried away in the flue gases through stack. The figure indicates relation between air ratio and exhaust gas loss.

The optimization of combustion air is the most attractive and economical measure for energy conservation. The impact of this measure is higher when the temperature of furnace is high. Air ratio is the value that is given by dividing the actual air amount by the theoretical combustion air amount, and it represents the extent of excess of air.



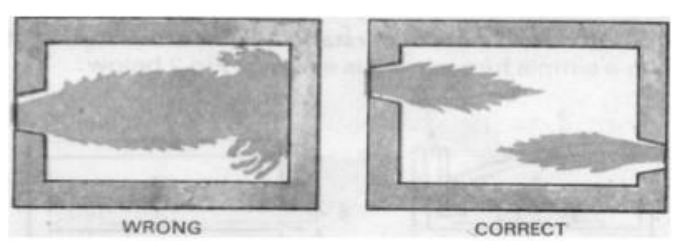
If a reheating furnace is not equipped with an automatic air/fuel ratio controller, it is necessary to periodically sample gas in the furnace and measure its oxygen contents by a gas analyzer. The Figure shows a typical example of a reheating furnace equipped with an automatic air/fuel ratio controller.



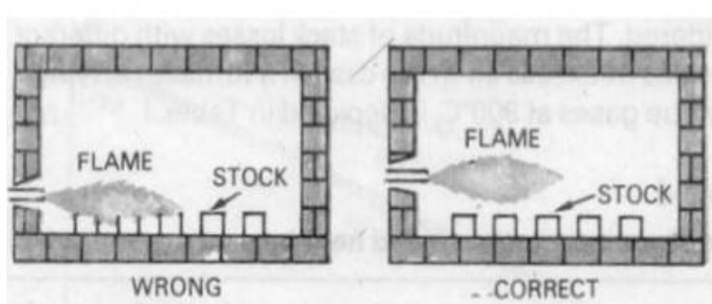
2. Proper Heat Distribution:

Furnace design should be such that in a given time, as much of the stock could be heated uniformly to a desired temperature with minimum fuel firing rate.

Following care should be taken when using burners, for proper heat distribution:



Heat distribution in furnace



i) The flame should not touch any solid object and should propagate clear of any solid object. Any
obstruction will deatomise the fuel particles thus affecting combustion and create black smoke. If
flame impinges on the stock, there would be increase in scale losses

ii) If the flames impinge on refractories, the incomplete combustion products can settle and react
with the refractory constituents at high flame temperatures.
iii) The flames of different burners in the furnace should stay clear of each other. If they intersect,
inefficient combustion would occur. It is desirable to stagger the burners on the opposite sides.
iv) The burner flame has a tendency to travel freely in the combustion space just above the
material. In small furnaces, the axis of the burner is never placed parallel to the hearth but always
at an upward angle. Flame should not hit the roof.
v) The larger burners produce a long flame, which may be difficult to contain within the furnace
walls. More burners of less capacity give better heat distribution in the furnace and also increase
furnace life.
vi) For small furnaces, it is desirable to have a long flame with golden yellow colour while firing
furnace oil for uniform heating. The flame should not be too long that it enters the chimney or
comes out through the furnace top or through doors. In such cases, major portion of additional
fuel is carried away from the furnace
.

3. Maintaining Optimum Operating Temperature of Furnace :

It is important to operate the furnace at optimum temperature. The operating temperatures of various furnaces are given in Table 4.4.

TABLE 4.4 OPERATING TEMPERATURE OF VARIOUS FURNACES	
Slab Reheating furnaces	1200^{o}C
Rolling Mill furnaces	1200^{o}C
Bar furnace for Sheet Mill	800^{o}C
Bogey type annealing furnaces	650^{o}C -750^{o}C

Operating at too high temperatures than optimum causes heat loss, excessive oxidation, de-carbonization as well as over-stressing of the refractories. These controls are normally left to operator judgment, which is not desirable. To avoid human error, on/off controls should be provided.

4. Prevention of Heat Loss through Openings

Heat loss through openings consists of the heat loss by direct radiation through openings and the heat loss caused by combustion gas that leaks through openings.

The heat loss from an opening can also be calculated using the following formula:

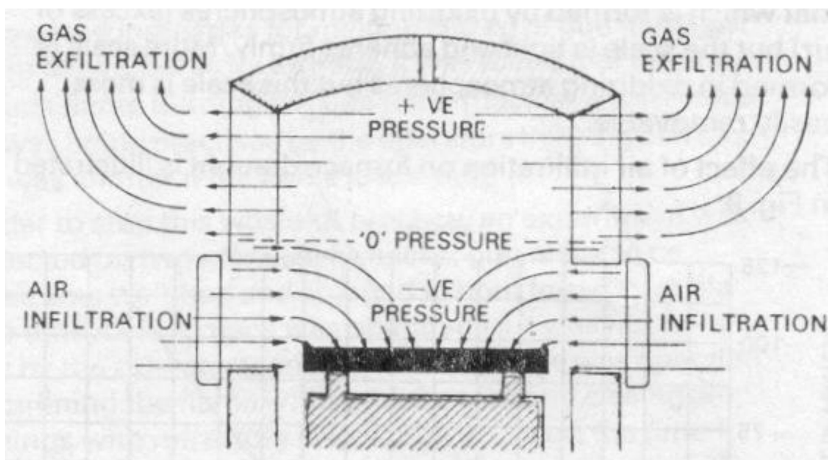
$$Q=4.88\left(\frac{T}{100}\right)^{4}\times a\times A\times H$$

where T: absolute temperature (K), a: factor for total radiation, A: area of opening, m^2 H : time (Hr)

If the furnace pressure is slightly higher than outside air pressure (as in case of reheating furnace) during its operation, the combustion gas inside may blow off through openings and heat is lost with that. But damage is more, if outside air intrudes into the furnace, making temperature distribution uneven and oxidizing billets. This heat loss is about 1% of the total quantity of heat generated in the furnace, if furnace pressure is controlled properly.

5. Control of furnace draft:

If negative pressures exist in the furnace, air infiltration is liable to occur through the cracks and openings thereby affecting air-fuel ratio control. Tests conducted on apparently airtight furnaces have shown air infiltration up to the extent of 40%. Neglecting furnaces pressure could mean problems of cold metal and non-uniform metal temperatures, which could affect subsequent operations like forging and rolling and result in increased fuel consumption. For optimum fuel consumption, slight positive pressure should be maintained in the furnace as shown in Figure.



Ex-filtration is less serious than infiltration. Some of the associated problems with ex filtration are leaping out of flames, overheating of the furnace refractories leading to reduced brick life, increased furnace maintenance, burning out of ducts and equipments attached to the furnace, etc. In addition to the proper control on furnace pressure, it is important to keep the openings as small as possible and to seal them in order to prevent the release of high temperature gas and intrusion of outside air through openings such as the charging inlet, extracting outlet and peephole on furnace walls or the ceiling.

6. Optimum Capacity Utilization:

One of the most vital factors affecting efficiency is loading. There is a particular loading at which the furnace will operate at maximum thermal efficiency. If the furnace is under loaded a smaller fraction of the available heat in the working chamber will be taken up by the load and therefore efficiency will be low.

The best method of loading is generally obtained by trial-noting the weight of material put in at each charge, the time it takes to reach temperature and the amount of fuel used. Every endeavour should be made to load a furnace at the rate associated with optimum efficiency although it must be realised that limitations to achieving this are sometimes imposed by work availability or other factors beyond control.

The loading of the charge on the furnace hearth should be arranged so that

It receives the maximum amount of radiation from the hot surfaces of the heating chambers and the flames produced.

The hot gases are efficiently circulated around the heat receiving surfaces

Stock should not be placed in the following position

- In the direct path of the burners or where flame impingement is likely to occur.
- In an area which is likely to cause a blockage or restriction of the flue system of the furnace.
- Close to any door openings where cold spots are likely to develop

The other reason for not operating the furnace at optimum loading is the mismatching of furnace dimension with respect to charge and production schedule.

In the interests of economy and work quality the materials comprising the load should only remain in the furnace for the minimum time to obtain the required physical and metallurgical requirements. When the materials attain these properties they should be removed from the furnace to avoid damage and fuel wastage. The higher the working temperature, higher is the loss per unit time. The effect on the materials by excessive residence time will be an increase in surface defects due to oxidation. The rate of oxidation is dependent upon time, temperature, as well as free oxygen content.

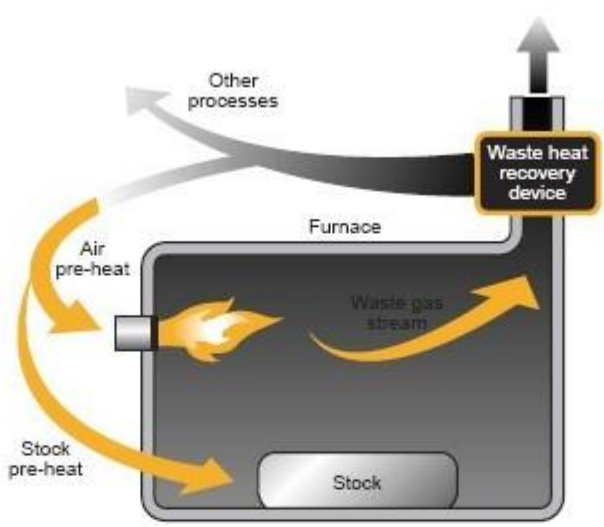
7. Waste Heat Recovery from Furnace Flue Gases:

In any industrial furnace the products of combustion leave the furnace at a temperature higher than the stock temperature. Sensible heat losses in the flue gases, while leaving the chimney, carry 35 to 55 % of the heat input to the furnace. The higher the quantum of excess air and flue gas temperature, the higher would be the waste heat availability.

Waste heat recovery should be considered after all other energy conservation measures have been taken. Minimizing the generation of waste heat should be the primary objective.

The sensible heat in flue gases can be generally recovered by the following methods.

- Charge (stock) preheating,
- Preheating of combustion air,
- Utilizing waste heat for other process (to generate steam or hot water by a waste heat boiler)



Charge Pre-heating

When raw materials are preheated by exhaust gases before being placed in a heating furnace, the amount of fuel necessary to heat them in the furnace is reduced. Since raw materials are usually at room temperature, they can be heated sufficiently using high-temperature gas to reduce fuel consumption rate.

Preheating of Combustion Air

For a long time, the preheating of combustion air using heat from exhaust gas was not used except for large boilers, metal-heating furnaces and high-temperature kilns. This method is now being employed in compact boilers and compact industrial furnaces as well. The energy contained in the exhaust gases can be recycled by using it to pre-heat the combustion air. **A** variety of equipment is available; external recuperators are common, but other techniques are now available such as self-recuperative burners.

External *Recuperators*

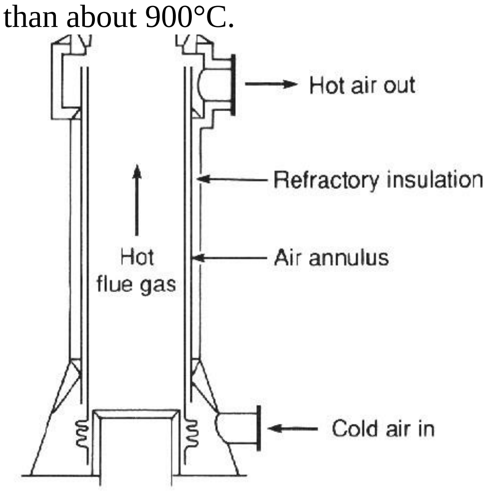
There are two main types of external recuperators:

radiation recuperators;

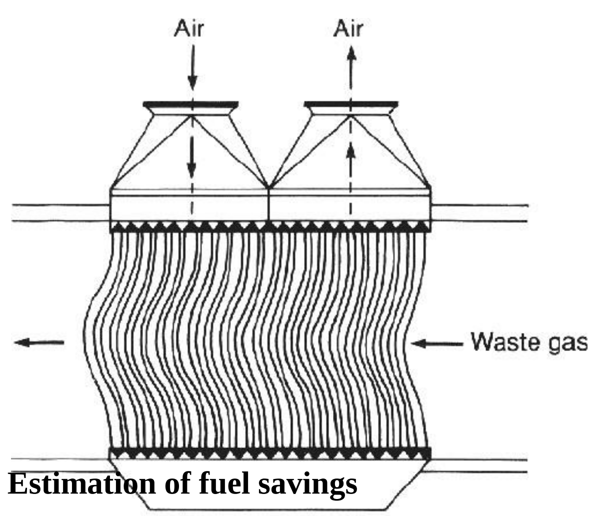
convection recuperators

Radiation recuperators generally take the form of concentric cylinders, in which the combustion air passes through the annulus and the exhaust gases from the furnace pass through the centre, see Fig The simple construction means that such recuperators are suitable for use with dirty gases, have a negligible resistance to flow, and can replace the flue or chimney if space is limited. The annulus can be replaced by a ring of vertical tubes, but this design is more difficult to install and maintain. Radiation recuperators rely on radiation from high temperature exhaust gases and should not he employed with exhaust gases at less than about 800°C.

Convection recuperators consist essentially of bundles of drawn or cast tubes, as in Fig. Internal and/or external fins can be added to assist heat transfer. The combustion air normally passes through the tubes and the exhaust gases outside the tubes, but there are some applications where this is reversed. Convection recuperators are more suitable for exhaust gas temperatures of less than about 900°C.



(a) Double Shell Radiation Recuperator



(b) Convection Recuperator

Estimation of fuel savings

By using preheated air for combustion, fuel can be saved. The fuel saving rate is given by the following formula: $S = \frac{p}{f + p - Q} \times 100$

where S: fuel saving rate, %

F: Calorific value of fuel (kCal/kg fuel)

P: quantity of heat brought in by preheated air (kCal/kg fuel)

Q**:** quantity of heat taken away by exhaust gas (kCal/kg fuel)

By this formula, fuel saving rates for heavy oil and natural gas were calculated for various temperatures of exhaust gas and preheated air.

8. Minimising Wall Losses:

About 30-40% of the fuel input to the furnace generally goes to make up for heat losses in intermittent or continuous furnaces. The appropriate choice of refractory and insulation materials goes a long way in achieving fairly high fuel savings in industrial furnaces.

The heat losses from furnace walls affect the fuel economy considerably. The extent of wall losses depend on:

- Emissivity of wall
- Thermal conductivity of refractories
- Wall thickness
- Whether furnace is operated continuously or intermittently

Heat losses can be reduced by increasing the wall thickness, or through the application of insulating bricks. Outside wall temperatures and heat losses of a composite wall of a certain thickness of firebrick and insulation brick are much lower, due to lesser conductivity of insulating brick as compared to a refractory brick of similar thickness. In the actual operation in most of the small furnaces the operating periods alternate with the idle periods. During the off period, the heat stored in the refractories during the on period is gradually dissipated, mainly through radiation and convection from the cold face. In addition, some heat is abstracted by air flowing through the furnace. Dissipation of stored heat is a loss, because the lost heat is again imparted to the refractories during the heat "on" period, thus consuming extra fuel to generate that heat. If a furnace is operated 24 hours, every third day, practically all the heat stored in the refractories is lost. But if the furnace is operated 8 hours per day all the heat stored in the refractories is not dissipated. Furnace walls built of insulating refractories and cased in a shell reduce the flow of heat to the surroundings.

9. Use of ceramic Coatings

Ceramic coatings in furnace chamber promote rapid and efficient transfer of heat, uniform heating and extended life of refractories. The emissivity of conventional refractories decreases with increase in temperature whereas for ceramic coatings it increases. This outstanding property has been exploited for use in hot face insulation.

Ceramic coatings are high emissivity coatings which when applied has a long life at temperatures up to 1350^{o}C. The coatings fall into two general categories-those used for coating metal substrates, and those used for coating refractory substrates. The coatings are non-toxic, non-flammable and water based. Applied at room temperatures, they are sprayed and air dried in less than five minutes. The coatings allow the substrate to maintain its designed metallurgical properties and mechanical strength. Installation is quick and can be completed during shut down. Energy savings of the order of 8-20% have been reported depending on the type of furnace and operating conditions.

Module 4

INTRODUCTION TO HVAC SYSTEM

HVAC stands for Heating, Ventilation, and Air Conditioning. HVAC systems control the indoor environment (temperature, humidity, air flow, and air filtering) Mechanical intervention to condition the air to a preferred temperature and relative humidity. HVAC is a basic requirement for our indoor air quality, what you breathe, temperature, humidity --in our house. So when you hear the term "HVAC" it means the entire air system of your home.

The goal of the heating, ventilating, and air conditioning (HVAC) system is to create and maintain a comfortable environment within a building. A comfortable environment, however, is broader than just temperature and humidity. Comfort requirements that are typically impacted by the HVAC system include:

□ Dry-bulb temperature (Temperature of air measured by a thermometer freely hanged)
□ Humidity
□ Air movement
□ Fresh air
□ Cleanliness of the air
□ Noise levels

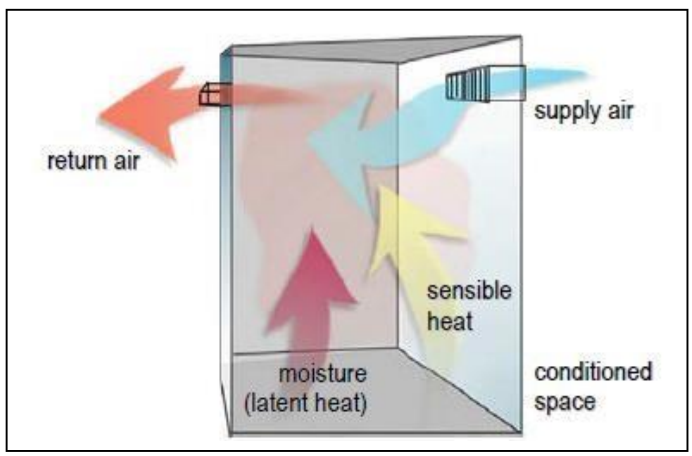
In addition, there are other factors that affect comfort but are not directly related to the HVAC system. Examples include adequate lighting, and proper furniture and work surfaces.

For generalizing the HVAC system, it can be dissected into five system loops

1. Airside loop
2. Chilled water loop
3. Refrigeration loop
4. Heat rejection loop
5. Control loop

Airside loop

The first component of this loop is the conditioned space. The first two comfort requirements mentioned were drybulb temperature and humidity. In order to maintain the dry-bulb temperature in the conditioned space, heat (referred to as sensible heat) must be added or removed at the same rate as it leaves or enters the space. In order to maintain the humidity level in the space, moisture (sometimes referred to as latent heat) must be added or removed at the same rate as it leaves or enters the space.



Most HVAC systems used today deliver conditioned (heated, cooled, humidified, or dehumidified) air to the conditioned space to add or remove sensible heat and moisture. This conditioned air is called supply air. The air that carries the heat and moisture out of the space is called return air. Imagine the conditioned supply air as a sponge. In the cooling mode, as it enters a space, this “sponge” (supply air) absorbs sensible heat and moisture. The amount of sensible heat and moisture absorbed depends on the temperature and humidity, as well as the quantity, of the supply air. Assuming a fixed quantity of air, if the supply air is colder, it can remove more sensible heat from the space. If the supply air is drier, it can remove more moisture from the space.

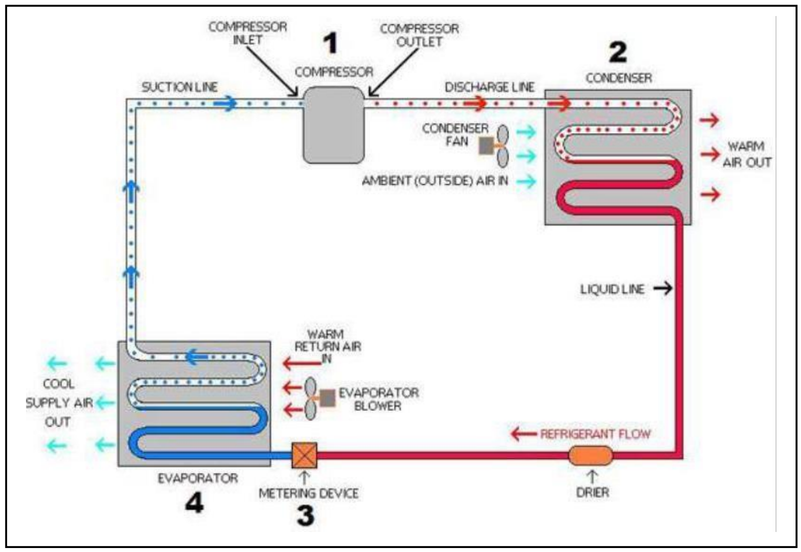
In order to determine how much supply air is needed for a given space, and how cold and dry it must be, it is necessary to determine the rate at which sensible heat and moisture (latent heat) enter, or are generated within, the conditioned space.

Chilled water loop

Chilled water systems in residential HVAC systems are extremely rare. A typical chiller uses the process of refrigeration to chill water in a chiller barrel. This water is pumped through chilled water piping throughout the building where it will pass through a coil. Air is passed over this coil and the heat exchange process takes place. The heat in the air is absorbed into the coils and then into the water. The water is pumped back to the chiller to have the heat removed. It then makes the trip back through the building and the coils all over again.

Refrigeration loop

The refrigeration system removes heat from an area that is low-pressure, low temperature (evaporator) into an area of high-pressure, high temperature (condenser). It mainly has the following components



1. Evaporator
2. Compressor
3. Condenser
4. Metering Device

Evaporator – This is the coil that is inside of the house. Warm air will pass over the coil which contains the refrigerant, then the refrigerant absorbs the heat, then the you are left with cold air which is distributed to the rooms that you are trying to cool.

Compressor – This is the life force of the refrigeration cycle, what it does is it will circulate refrigerant throughout the whole system. It will compress cold vapor into hot vapor, it also increases the low vapor pressure into high vapor pressure.

Condenser – This is the coil that is located outside on a central air conditioning system. It removes the heat that is carried through the refrigerant, forcing the hot air out.

Metering Device – Controls the flow of the refrigerant to the evaporator. There are different kinds of metering devices, some of them will have pressure limiting devices to protect the compressor from overloading, while some will control the evaporators pressure or superheat. Some common metering devices are thermostatic expansion valves, automatic expansion valves, capillary tubes, and fixed-bore.

Heat rejection loop

In the refrigeration loop, the condenser transfers heat from the hot refrigerant to air, water, or some other fluid. In a water-cooled condenser, water flows through the tubes while the hot refrigerant vapor enters the shell space surrounding the tubes. Heat is transferred from the refrigerant to the water, warming the water. The water flowing through the condenser must be colder than the hot refrigerant vapor. A heat exchanger is required to cool the water that returns from the condenser at particular temperature and back to the desired temperature of before it is pumped back to the condenser. Which is done by heat rejection loop. When a water-cooled condenser is used, this heat exchanger is typically either a cooling tower or a fluid cooler (also known as a dry cooler).

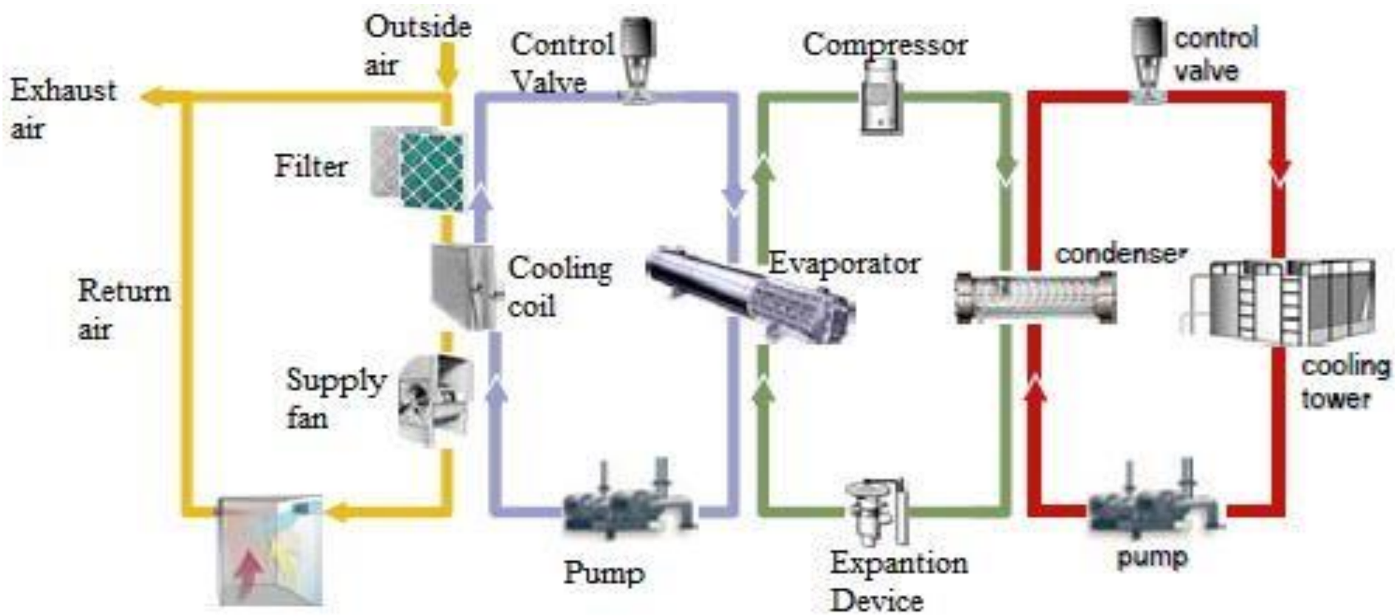
A fluid cooler is similar to an air-cooled condenser. Water flows through the tubes of a finned-tube heat exchanger and fans draw outdoor air over the surfaces of the tubes and fins. Heat is transferred from the warmer water to the cooler air. The third component of the heat-rejection loop moves the condensing media around the loop. In the case of a water cooled condenser, a pump is needed to move the water through the tubes of the condenser, the piping, the cooling tower, and any other accessories installed in the heat-rejection loop.

One method of varying the quantity of water flowing through the water-cooled condenser is to use a modulating control valve. As the heat-rejection requirement decreases, the modulating control valve directs less water through the condenser. If a three-way valve is used, the excess water bypasses the condenser and mixes downstream with the water that flows through the condenser.

Controls Loop

The fifth, and final, loop of the HVAC system is the controls loop. Each of the previous four loops contains several components. Each component must be controlled in a particular way to ensure proper operation. Typically, each piece of equipment (which may be comprised of one or more components of a loop) is equipped with a unit-level, automatic controller. In order to provide intelligent, coordinated control so that the individual pieces of equipment operate together as an efficient system, these individual unit-level controllers are often connected to a central, system-level controller. Finally, many building operators want to monitor the system, receive alarms and diagnostics at a central location, and integrate the HVAC system with other systems in the building. These are some of the functions provided by a building automation system (BAS).

The interconnection of first 4 loop in HVAC system is shown in the figure below



LECTURE 2: Coefficient of Performance

Ratio of work or useful output to the amount of work or energy input is called as coefficient of performance. It is used generally as a measure of the energy-efficiency of air conditioners, space heaters and other cooling and heating devices. COP equals heat delivered (output) in British thermal units (Btu) per hour divided by the heat equivalent of the electric energy input (one watt = 3.413 Btu/hour) or, alternatively, energy efficiency ratio divided by 3.413. Higher the COP, higher the efficiency of the equipment. Higher COPs equate to lower operating costs. The COP usually exceeds 1, especially in heat pumps, because, instead of just converting work to heat (which, if 100% efficient, would be a COP_hp of 1), it pumps additional heat from a heat source to where the heat is required. When calculating the COP for a heat pump, the heat output from the condenser (Q) is compared to the power supplied to the compressor (W).

$$\mathrm{COP} = \frac{Q}{W}$$

The COP for heating and cooling are different, because the heat reservoir of interest is different. When one is interested in how well a machine cools, the COP is the ratio of the heat removed from the cold reservoir to input work. However, for heating, the COP is the ratio of the heat removed from the cold reservoir plus the input work to the input work

$$\mathrm{COP}_{\mathrm{heating}} = \frac{|Q_H|}{W} = \frac{|Q_C| + W}{W}$$

$$\mathrm{COP}_{\mathrm{cooling}} = \frac{|Q_C|}{W}$$

where

Qc is the heat removed from the cold reservoir.

Q_H is the heat supplied to the hot reservoir.

For a better assessment of performance of refrigeration plant calculation of COP is an important factor.

The theoretical Coefficient of Performance (Carnot cycle), COP Carnot is a standard measure of refrigeration efficiency of an ideal refrigeration system- depends on two key system temperatures, namely, evaporator temperature Te and condenser temperature Tc with COP being given as:

$\mathrm{COP}_{\mathrm{Carnot}}$ = Te / (Tc - Te)

This expression also indicates that higher $\mathrm{COP}_{\mathrm{Carnot}}$ is achieved with higher evaporator temperature and lower condenser temperature. But $\mathrm{COP}_{\mathrm{Carnot}}$ is only a ratio of temperatures, and hence does not take into account the type of compressor. Hence the COP normally used in the industry is given by

$$\mathrm{COP} = \frac{\text{Cooling effect (kW)}}{\text{Power input to compressor (kW)}}$$

where the cooling effect is the difference in enthalpy across the evaporator and expressed as kW.

Difference between COP and efficiency

Both efficiency and COP are trying to give you the performance value of the system, whether it is refrigerator or engine, where it involves input and output energies. But the difference is, What types of energies are involved in. There are two types of energies namely, High Grade Energy and Low grade Energy. For efficiency, the ratios are between (1-(heat out/ heat supplied)) same form of energies. That is heat, low grade energy. So it never be grater than 1. Whereas the COP deals with the ratio between (heat removed / electricity supplied) both are different types. Electricity is a high grade energy. And hence the COP is greater than 1.

In other words the efficiency is calculated for the devices which are power producing, while in case of power absorbing devices COP is calculated because we want to check performance of device for a given power input.

LECTURE 3: Factors Affecting Performance & Energy Efficiency of Refrigeration Plants

The main factors affecting the performance and energy efficiency of refrigeration plants are the following

- Design of Process Heat Exchangers
- Maintenance of Heat Exchanger Surfaces
- Multi-Staging For Efficiency
- Matching Capacity to System Load
- Capacity Control and Energy Efficiency
- Multi-level Refrigeration for Plant Needs
- Chilled Water Storage
- System Design Features

❖ **Design of Process Heat Exchangers**

There is a tendency of the process group to operate with high safety margins which influences the compressor suction pressure / evaporator set point. For instance, a process cooling requirement of 15°C would need chilled water at a lower temperature, but the range can vary from 6°C to say 10°C. At 10°C chilled water temperature, the refrigerant side temperature has to be lower, say –5°C to +5°C. The refrigerant temperature, again sets the corresponding suction pressure of refrigerant which decides the inlet duty conditions for work of compression of the refrigerant compressor. Having the optimum / minimum driving force (temperature difference) can, thus, help to achieve highest possible suction pressure at the compressor, thereby leading to less energy requirement. This requires proper sizing of heat transfer areas of process heat exchangers and evaporators as well as rationalizing the temperature requirement to highest possible value.

TABLE 4.4 EFFECT OF VARIATION IN EVAPORATOR TEMPERATURE ON COMPRESSOR POWER CONSUMPTION

Evaporator Temperature (°C)	Refrigeration Capacity* (tons)	Specific Power Consumption	Increase in kW/ton (%)
5.0	67.58	0.81	-
0.0	56.07	0.94	16.0
-5.0	45.98	1.08	33.0
-10.0	37.20	1.25	54.0
-20.0	23.12	1.67	106.0

* *Condenser temperature 40°C*

A 1°C raise in evaporator temperature can help to save almost 3 % on power consumption. From the table 4.4 it can be identified that the power consumption of compressor can be reduced by providing proper temperature at the evaporator. As the evaporator temperature reduces the power

TABLE 4.5 EFFECT OF VARIATION IN CONDENSER TEMPERATURE ON COMPRESSOR POWER CONSUMPTION

Condensing Temperature (°C)	Refrigeration Capacity (tons)	Specific Power Consumption	Increase in (kW / TR) kW/TR (%)
26.7	31.5	1.17	-
35.0	21.4	1.27	8.5
40.0	20.0	1.41	20.5

* *Reciprocating compressor using R-22 refrigerant.*
Evaporator temperature.-10°C

consumption in compressor increases. The effect of condenser temperature on refrigeration plant energy requirements is given in Table 4.5. As condenser temperature increases the power consumption of the compressor increases. From both the table we can conclude that designing of the heat exchanger plays a good role in power consumption. Thus, with proper design of the heat exchangers used in refrigerators the power consumption of various components can be reduced.

❖ Maintenance of Heat Exchanger Surfaces

An effective maintenance holds the key to optimizing power consumption. Heat transfer can also be improved by ensuring proper separation of the lubricating oil and the refrigerant, timely defrosting of coils, and increasing the velocity of the secondary coolant (air, water, etc.). However, increased velocity results in larger pressure drops in the distribution system and higher power consumption in pumps / fans. Therefore, careful analysis is required to determine the most effective and efficient option.

TABLE 4.6 EFFECT OF POOR MAINTENANCE ON COMPRESSOR POWER CONSUMPTION

Condition	Evap. Temp (°C)	Cond. Temp (°C)	Refrigeration Capacity* (tons)	Specific Power Consumption kW/Ton	Increase in (kW/ton) (%)
Normal	7.2	40.5	17.0	0.69	-
Dirty condenser	7.2	46.1	15.6	0.84	20.4
Dirty evaporator	1.7	40.5	13.8	0.82	18.3
Dirty condenser and evaporator	1.7	46.1	12.7	0.96	38.7

* *15 ton reciprocating compressor based system. The power consumption is lower than that for systems typically available in India. However, the percentage change in power consumption is indicative of the effect of poor maintenance.*

Fouled condenser tubes force the compressor to work harder to attain the desired capacity. For example, a 0.8 mm scale build-up on condenser tubes can increase energy consumption by as much as 35 %. Similarly, fouled evaporators (due to residual lubricating oil or infiltration of air) result in increased power consumption. Equally important is proper selection, sizing, and maintenance of cooling towers. A reduction of 0.55°C temperature in water returning from the cooling tower reduces compressor power consumption by 3.0 % (see Table 4.6).

❖ Multi-Staging for Efficiency

Efficient compressor operation requires that the compression ratio be kept low, to reduce discharge pressure and temperature. For low temperature applications involving high compression ratios, and for wide temperature requirements, it is preferable (due to equipment design limitations) and often economical to employ multi-stage reciprocating machines or centrifugal / screw compressors. Multi-staging systems are of two-types: compound and cascade – and are applicable to all types of compressors. With reciprocating or rotary compressors, two-stage compressors are preferable for load temperatures from –20 to –58°C, and with centrifugal machines for temperatures around –43°C.

In multi-stage operation, a first-stage compressor, sized to meet the cooling load, feeds into the suction of a second-stage compressor after inter-cooling of the gas. A part of the high-pressure liquid from the condenser is flashed and used for liquid sub-cooling. The second compressor, therefore, has to meet the load of the evaporator and the flash gas. A single refrigerant is used in the system, and the work of compression is shared equally by the two compressors. Therefore, two compressors with low compression ratios can in combination provide a high compression ratio. For temperatures in the range of –46°C to –101°C, cascaded systems are preferable. In this system, two separate systems using different refrigerants are connected such that one provides the means of heat rejection to the other. The chief advantage of this system is that a low temperature refrigerant which has a high suction temperature and low specific volume can be selected for the low-stage to meet very low temperature requirements.

Multi stage compressors

Reciprocating/piston compressors use a cylinder to force air into a chamber, where it is compressed. The simplest compressor designs feature a single cylinder/chamber arrangement. While straightforward, this setup is limited in its efficiency and capacity for delivering high volumes of pressurized air. That's where multi-stage compressors come in. By increasing the number of cylinder stages, these machines work more effectively and can handle more tools at once.

Multi-stage compressors feature a series of cylinders, each of a different diameter. Between each compression stage, the air passes through a heat exchanger, where it is cooled. Cooling the air reduces the amount of work necessary to compress it further.

In a two-stage compressor, air is then forced into an additional chamber where it is pressurized to the required extent. In a three-stage compressor, an additional cycle of compression and cooling occurs before this.

- **Matching Capacity to System Load**

During part-load operation, the evaporator temperature rises and the condenser temperature falls, effectively increasing the COP. But at the same time, deviation from the design operation point and the fact that mechanical losses form a greater proportion of the total power negate the effect of improved COP, resulting in lower part-load efficiency. Therefore, consideration of part-load operation is important, because most refrigeration applications have varying loads. The load may vary due to variations in temperature and process cooling needs. Matching refrigeration capacity to the load is a difficult exercise, requiring knowledge of compressor performance, and variations in ambient conditions, and detailed knowledge of the cooling load.

- **Capacity Control and Energy Efficiency**

The capacity of compressors is controlled in a number of ways like on/off control, bypass or spill-back method, constant-speed step control, clearance volume control, valve control etc . Capacity control of a refrigeration plant can be defined as a system which monitors and controls the output of the plant as per the load on demand.

Capacity regulation through speed control is the most efficient option. However, when employing speed control for reciprocating compressors, it should be ensured that the lubrication system is not affected. In the case of centrifugal compressors, it is usually desirable to restrict speed control to about 50 % of the capacity to prevent surging. Below 50 %, vane control or hot gas bypass can be used for capacity modulation.

The efficiency of screw compressors operating at part load is generally higher than either centrifugal compressors or reciprocating compressors, which may make them attractive in situations where part-load operation is common. Screw compressor performance can be optimized by changing the volume ratio. In some cases, this may result in higher full-load efficiencies as compared to reciprocating and centrifugal compressors. Also, the ability of screw compressors to tolerate oil and liquid refrigerant slugs makes them preferred in some situations.

- **Multi-level Refrigeration for Plant Needs**

The selection of refrigeration systems also depends on the range of temperatures required in the plant. For diverse applications requiring a wide range of temperatures, it is generally more economical to provide several packaged units (several units distributed throughout the plant) instead of one large central plant. Another advantage would be the flexibility and reliability accorded. The selection of packaged units could also be made depending on the distance at which cooling loads need to be met. Packaged units at load centers reduce distribution losses in the system. Despite the advantages of packaged units, central plants generally have lower power consumption since at reduced loads power consumption can reduce significantly due to the large condenser and evaporator surfaces. Many industries use a bank of compressors at a central location to meet the load. Usually the chillers feed into a common header from which branch lines are taken to different locations in the plant. In such situations, operation at part-load requires extreme care. For efficient operation, the cooling load, and the load on each chiller must be monitored closely. It is more efficient to operate a single chiller at full load than to operate two chillers at part-load. The distribution system should be designed such that individual chillers can feed all branch lines. Isolation valves must be provided to ensure that chilled water (or other coolant) does not flow through chillers not in operation. Valves should also be provided on branch lines to isolate sections where cooling is not required. This reduces pressure drops in the system and reduces power consumption in the pumping system. Individual compressors should be loaded to their full capacity before operating the second compressor. In some cases it is economical to provide a separate smaller capacity chiller, which can be operated on an on-off control to meet peak demands, with larger chillers meeting the base load.

Flow control is also commonly used to meet varying demands. In such cases the savings in pumping at reduced flow should be weighed against the reduced heat transfer in coils due to reduced velocity. In some cases, operation at normal flow rates, with subsequent longer periods of no-load (or shut-off) operation of the compressor, may result in larger savings.

❖ Chilled Water Storage

Depending on the nature of the load, it is economical to provide a chilled water storage facility with very good cold insulation. Also, the storage facility can be fully filled to meet the process requirements so that chillers need not be operated continuously. This system is usually economical if small variations in temperature are acceptable. This system has the added advantage of allowing the chillers to be operated at periods of low electricity demand to reduce peak demand charges - Low tariffs offered by some electric utilities for operation at night time can also be taken advantage of by using a storage facility. An added benefit is that lower ambient temperature at night lowers condenser temperature and thereby increases the COP. If temperature variations cannot be tolerated, it may not be economical to provide a storage facility since the secondary coolant would have to be stored at a temperature much lower than required to provide for heat gain. The additional cost of cooling to a lower temperature may offset the benefits. The solutions are case specific. For example, in some cases it may be possible to employ large heat exchangers, at a lower cost burden than low temperature chiller operation, to take advantage of the storage facility even when temperature variations are not acceptable. Ice bank system which store ice rather than water are often economical.

❖ System Design Features

In overall plant design, adoption of good practices improves the energy efficiency significantly. Some areas for consideration are:

_ Design of cooling towers with FRP impellers and film fills, PVC drift eliminators, etc.

_ Use of softened water for condensers in place of raw water.

_ Use of economic insulation thickness on cold lines, heat exchangers, considering cost of heat gains and adopting practices like infrared thermography for monitoring - applicable especially in large chemical / fertilizer / process industry.

_ Adoption of roof coatings / cooling systems, false ceilings / as applicable, to minimize refrigeration load.

_ Adoption of energy efficient heat recovery devices like air to air heat exchangers to pre-cool the fresh air by indirect heat exchange; control of relative humidity through indirect heat exchange rather than use of duct heaters after chilling.

_ Adopting of variable air volume systems; adopting of sun film application for heat eflection; optimizing lighting loads in the air conditioned areas; optimizing number of air changes in the air conditioned areas are few other examples.

LECTURE 4: Energy Saving Opportunities of Refrigeration Plants

a) Cold Insulation

When a cold fluid is being transported through a system exposed to the ambient air, heat is being transferred from the air into the fluid in the system and the following occurs:

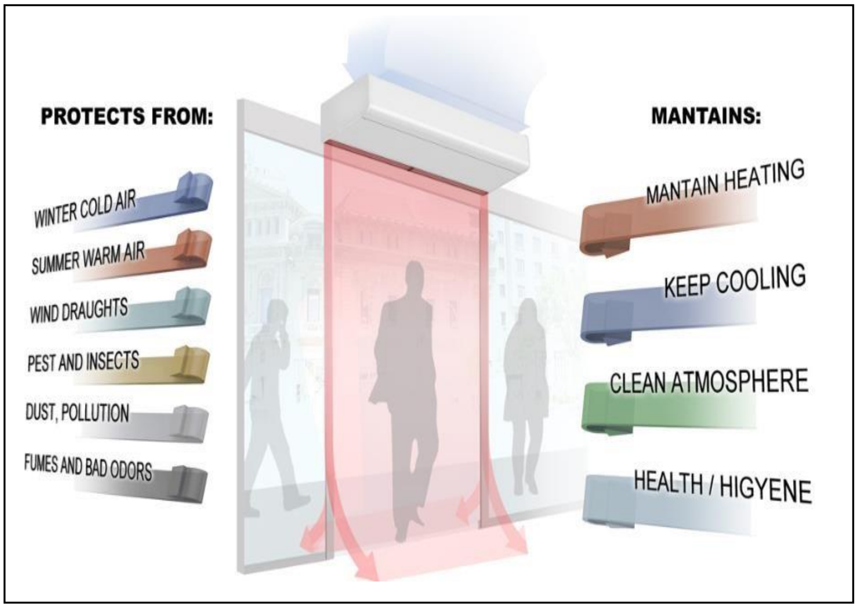
- A temperature drop across the surface air film on the jacketing material
- A further temperature drop across the insulation system
- Yet a further temperature drop across the containing material
- And finally another temperature drop across the fluid film into the fluid itself.

For avoiding all the above causes cold insulation should be done. Thus Insulate all cold lines / vessels using economic insulation thickness to minimize heat gains; and choose appropriate (correct) insulation. Two common materials used in cold insulation are:

- Polyurethane Foam: Perfect for handling low thermal conductivity and substances with below freezing temperatures. Polyurethane foam also allows for low smoke emission and low water vapor permeability.
- Rubber Foam: Rubber foam is also often recommended for condensation control as the closed cell technology is highly resistant to moisture vapor.

b) Building Envelope

A building envelope is the physical separator between the conditioned and unconditioned environment of building including the resistance to air, water, heat, light, and noise transfer. Optimize air conditioning volumes by measures such as use of false ceiling and segregation of critical areas for air conditioning by air curtains.



An air curtain is a fan-powered device that creates an invisible air barrier over the doorway to separate efficiently two different environments, without limiting the access of the people or vehicles. The energy saving air screen reduces heating and cooling costs by up to 80% while protecting the internal climate and increasing people comfort.

c) Building Heat Loads Minimization

Minimize the air conditioning loads by measures such as roof cooling, roof painting, efficient lighting, pre-cooling of fresh air by air- to-air heat exchangers, variable volume air system, optimal thermo-static setting of temperature of air conditioned spaces, sun film applications, etc.

d) Process Heat Loads Minimisation

Minimize process heat loads in terms of TR capacity as well as refrigeration level, i.e., temperature required, by way of:

i) Flow optimization
ii) Heat transfer area increase to accept higher temperature coolant
iii) Avoiding wastages like heat gains, loss of chilled water, idle flows.
iv) Frequent cleaning / de-scaling of all heat exchangers

e) At the Refrigeration A/C Plant Area

i. Ensure regular maintenance of all A/C plant components as per manufacturer guidelines.
ii. Ensure adequate quantity of chilled water and cooling water flows, avoid bypass flows by closing valves of idle equipment.
iii. Minimize part load operations by matching loads and plant capacity on line; adopt variable speed drives for varying process load.
iv. Make efforts to continuously optimize condenser and evaporator parameters for minimizing specific energy consumption and maximizing capacity.
v. Adopt VAR system where economics permit as a non-CFC solution.

LECTURE 5: Introduction to Waste Heat Recovery system

Waste heat is heat, which is generated in a process by way of fuel combustion or chemical reaction, and then “dumped” into the environment even though it could still be reused for some useful and economic purpose. The essential quality of heat is not the amount but rather its “value”. The strategy of how to recover this heat depends in part on the temperature of the waste heat gases and the economics involved.

Large quantity of hot flue gases is generated from Boilers, Kilns, Ovens and Furnaces. If some of this waste heat could be recovered, a considerable amount of primary fuel could be saved. The energy lost in waste gases cannot be fully recovered. However, much of the heat could be recovered and minimize the overall losses.

Classification of Waste heat recovery system

In considering the potential for heat recovery, it is useful to note all the possibilities, and grade the waste heat in terms of potential value as shown in the following Table 8.1

TABLE 8.1 WASTE SOURCE AND QUALITY

S.No.	Source	Quality
1.	Heat in flue gases.	The higher the temperature, the greater the potential value for heat recovery
2.	Heat in vapour streams.	As above but when condensed, latent heat also recoverable.
3.	Convective and radiant heat lost from exterior of equipment	Low grade – if collected may be used for space heating or air preheats.

4.	Heat losses in cooling water.	Low grade – useful gains if heat is exchanged with incoming fresh water
5.	Heat losses in providing chilled water or in the disposal of chilled water	a) High grade if it can be utilized to reduce demand for refrigeration. b) Low grade if refrigeration unit used as a form of heat pump.
6.	Heat stored in products leaving the process	Quality depends upon temperature.
7.	Heat in gaseous and liquid effluents leaving process.	Poor if heavily contaminated and thus requiring alloy heat exchanger.

The waste heat recovery system can be classified as:

1. High temperature heat recovery system
2. Medium temperature heat recovery system
3. Low temperature heat recovery system

High temperature heat recovery system

The following Table 8.2 gives temperatures of waste gases from industrial process equipment in the high temperature range. All of these results from direct fuel fired processes.

TABLE 8.2 TYPICAL WASTE HEAT TEMPERATURE AT HIGH TEMPERATURE RANGE FROM VARIOUS SOURCES

Types of Device	Temperature, °C
Nickel refining furnace	1370 –1650
Aluminium refining furnace	650–760
Zinc refining furnace	760–1100
Copper refining furnace	760– 815
Steel heating furnaces	925–1050
Copper reverberatory furnace	900–1100
Open hearth furnace	650–700
Cement kiln (Dry process)	620– 730
Glass melting furnace	1000–1550
Hydrogen plants	650–1000
Solid waste incinerators	650–1000
Fume incinerators	650–1450

Medium Temperature heat recovery system

The following Table 8.3 gives the temperatures of waste gases from process equipment in the medium temperature range. Most of the waste heat in this temperature range comes from the exhaust of directly fired process units.

TABLE 8.3 TYPICAL WASTE HEAT TEMPERATURE AT MEDIUM TEMPERATURE RANGE FROM VARIOUS SOURCES

Type of Device	Temperature, °C
Steam boiler exhausts	230–480
Gas turbine exhausts	370–540
Reciprocating engine exhausts	315–600
Reciprocating engine exhausts (turbo charged)	230–370
Heat treating furnaces	425–650
Drying and baking ovens	230–600
Catalytic crackers	425–650
Annealing furnace cooling systems	425–650

Low Temperature Heat Recovery

The following Table 8.4 lists some heat sources in the low temperature range. In this range it is usually not practical to extract work from the source, though steam production may not be completely excluded if there is a need for low-pressure steam. Low temperature waste heat may be useful in a supplementary way for preheating purposes.

TABLE 8.4 TYPICAL WASTE HEAT TEMPERATURE AT LOW TEMPERATURE RANGE FROM VARIOUS SOURCES

Source	Temperature, °C
Process steam condensate	55–88
Cooling water from:	
Furnace doors	32–55
Bearings	32–88
Welding machines	32–88
Injection molding machines	32–88
Annealing furnaces	66–230
Forming dies	27–88
Air compressors	27–50
Pumps	27–88
Internal combustion engines	66–120
Air conditioning and refrigeration condensers	32–43
Liquid still condensers	32–88
Drying, baking and curing ovens	93–230
Hot processed liquids	32–232
Hot processed solids	93–232

LECTURE 6: Benefits of Waste Heat Recovery

Benefits of 'waste heat recovery' can be broadly classified in two categories:

Direct Benefits:

Recovery of waste heat has a direct effect on the efficiency of the process. This is reflected by reduction in the utility consumption & costs, and process cost.

Indirect Benefits:

a) Reduction in pollution: A number of toxic combustible wastes such as carbon monoxide gas, sour gas, carbon black off gases, oil sludge, Acrylonitrile and other plastic chemicals etc, releasing to atmosphere if/when burnt in the incinerators serves dual purpose i.e. recovers heat and reduces the environmental pollution levels.

b) Reduction in equipment sizes: Waste heat recovery reduces the fuel consumption, which leads to reduction in the flue gas produced. This results in reduction in equipment sizes of all flue gas handling equipments such as fans, stacks, ducts, burners, etc.

c) Reduction in auxiliary energy consumption: Reduction in equipment sizes gives additional benefits in the form of reduction in auxiliary energy consumption like electricity for fans, pumps etc..

LECTURE 7: Analysis of waste heat recovery for Energy saving opportunities

In any heat recovery situation it is essential to know the amount of heat recoverable and also how it can be used. An example of the availability of waste heat is given below:

In a heat treatment furnace, the exhaust gases are leaving the furnace at 900 °C at the rate of 2100 m^3/hour. The total heat recoverable at 180^0C final exhaust can be calculated as

$Q = V \times \rho \times C_p \times \Delta T$

Q is the heat content in kCal

V is the flow rate of the substance in m^3/hr

ρ is density of the flue gas in kg/m^3

C_p is the specific heat of the substance in kCal/kg °C

ΔT is the temperature difference in °C

Cp (Specific heat of flue gas) = 0.24 kCal/kg/°C

Heat available (Q) = 2100 × 1.19 × 0.24 × ((900-180) = 4, 31,827 kCal/hr
By installing a recuperator, this heat can be recovered to pre-heat the combustion air. The fuel savings would be 33% (@ 1% fuel reduction for every 22 °C) reduction in temperature of flue gas.

LECTURE 8: Commercial Waste Heat Recovery Devices

Some of the common commercial waste heat recovery devices are following:

a) Recuperator
b) Radiation/Convective Hybrid Recuperator
c) Ceramic Recuperator
d) Regenerator
e) Heat Wheels
f) Heat Pipe
g) Economiser
h) Thermocompressor
i) Direct Contact Heat Exchanger

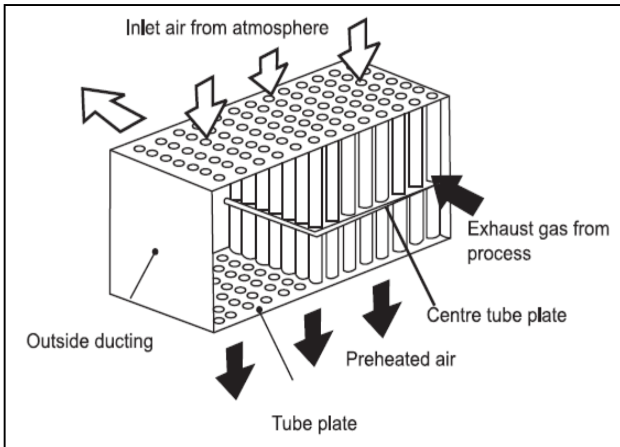


Figure 8.1 WHR using Recuperator

Recuperators

In a recuperator, heat exchange takes place between the flue gases and the air through metallic or ceramic walls. Duct or tubes carry the air for combustion to be pre-heated, the other side contains the waste heat stream. A recuperator for recovering waste heat from flue gases is shown in Figure 8.1.

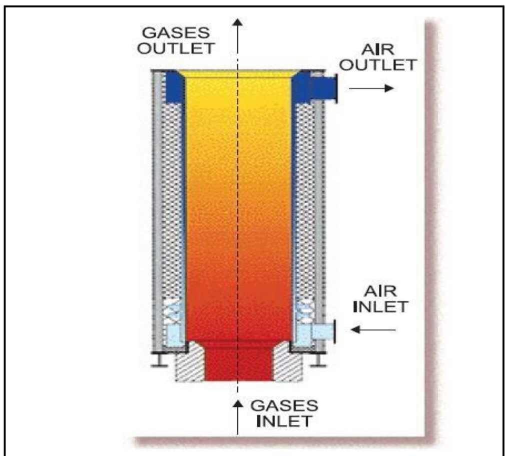


Figure 8.2 Metallic Radiation Recuperato

The simplest configuration for a recuperator is the metallic radiation recuperator, which consists of two concentric lengths of metal tubing as shown in Figure 8.2. The inner tube carries the hot exhaust gases while the external annulus carries the combustion air from the atmosphere to the air inlets of the furnace burners. The hot gases are cooled by the incoming combustion air which now carries additional energy into the combustion chamber. This is energy which does not have to be supplied by the fuel; consequently, less fuel is burned for a given furnace loading.

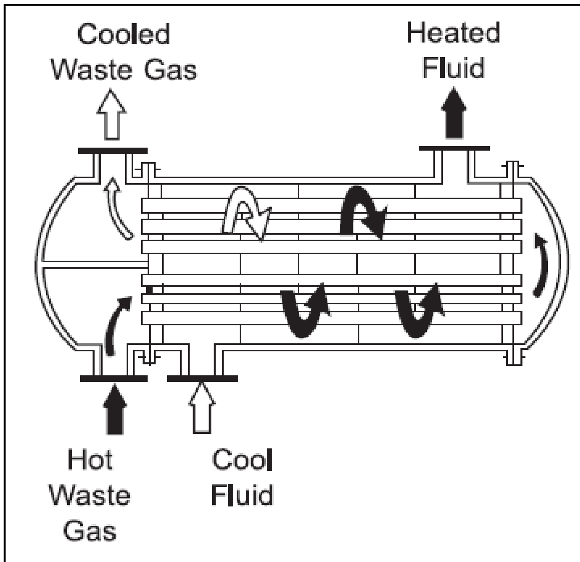


Figure 8.3 Convective Recuperator

A second common configuration for recuperators is called the tube type or convective recuperator. As seen in the figure 8.3, the hot gases are carried through a number of parallel small diameter tubes, while the incoming air to be heated enters a shell surrounding the tubes and passes over the hot tubes one or more times in a direction normal to their axes.

If the tubes are baffled to allow the gas to pass over them twice, the heat exchanger is termed a two-pass recuperator; if two baffles are used, a three-pass recuperator, etc. Although baffling increases both the cost of the exchanger and the pressure drop in the combustion air path, it increases the effectiveness of heat exchange. Shell and tube type recuperators are generally more compact and have a higher effectiveness than radiation recuperators, because of the larger heat transfer area made possible through the use of multiple tubes and multiple passes of the gases.

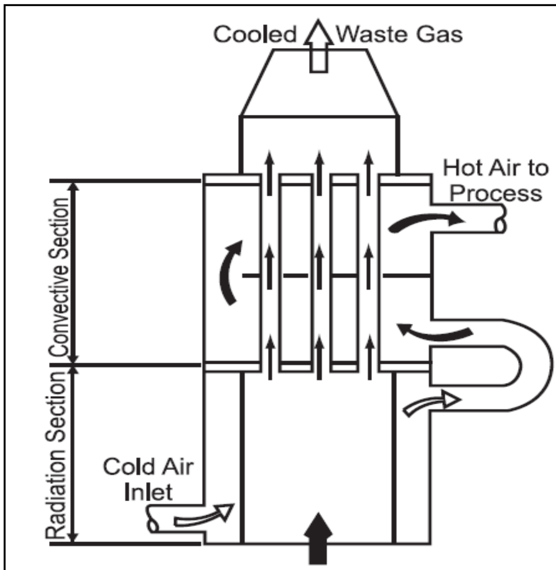


Figure 8.4 Convective Radiative Recuperator

Radiation/Convective Hybrid Recuperator:

For maximum effectiveness of heat transfer, combinations of radiation and convective designs are used, with the high-temperature radiation recuperator being first followed by convection type. These are more expensive than simple metallic radiation recuperators, but are less bulky. A Convective/radiative Hybrid recuperator is shown in Figure 8.4

Ceramic Recuperator

The principal limitation on the heat recovery of metal recuperators is the reduced life of the liner at inlet temperatures exceeding 1100°C. In order to overcome the temperature limitations of metal recuperators, ceramic tube recuperators have been developed whose materials allow operation on the gas side to 1550°C and on the preheated air side to 815°C on a more or less practical basis. Early ceramic recuperators were built of tile and joined with furnace cement, and thermal cycling caused cracking of joints and rapid deterioration of the tubes. Later developments introduced various kinds of short silicon carbide tubes which can be joined by flexible seals located in the air headers. Earlier designs had experienced leakage rates from 8 to 60 percent. The new designs are reported to last two years with air preheat temperatures as high as 700°C, with much lower leakage rates.

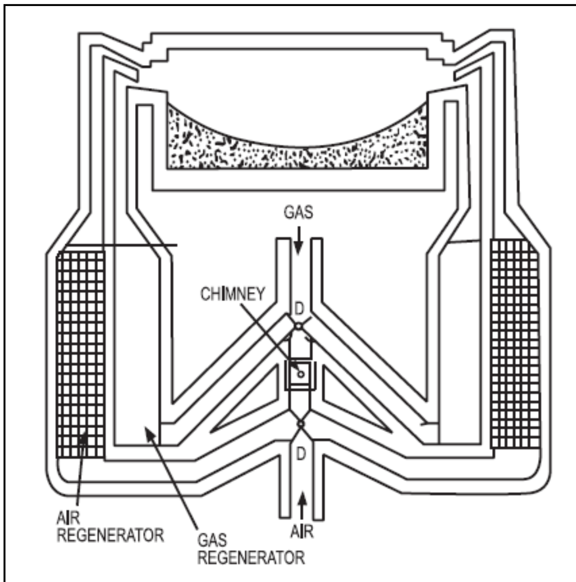


Figure 8.5 Regenerator

Regenerator

The Regeneration which is preferable for large capacities has been very widely used in glass and steel melting furnaces. Important relations exist between the size of the regenerator, time between reversals, thickness of brick, conductivity of brick and heat storage ratio of the brick. In a regenerator, the time between the reversals is an important aspect. Long periods would mean higher thermal storage and hence higher cost. Also long periods of reversal result in lower average temperature of preheat and consequently reduce fuel economy. (Refer Figure 8.5).

Accumulation of dust and slagging on the surfaces reduce efficiency of the heat transfer as the furnace becomes old. Heat losses from the walls of the regenerator and air in leaks during the gas period and out leaks during air period also reduces the heat transfer.

Heat Wheels

A heat wheel is finding increasing applications in low to medium temperature waste heat recovery systems. Figure 8.6 is a sketch illustrating the application of a heat wheel. It is a sizable porous disk, fabricated with material having a fairly high heat capacity, which rotates between two side-by-side ducts: one a cold gas duct, the other a hot gas duct. The axis of the disk is located parallel to, and on the partition between, the two ducts. As the disk slowly rotates, sensible heat (moisture that contains latent heat) is transferred to the disk by the hot air and, as the disk rotates, from the disk to the cold air.

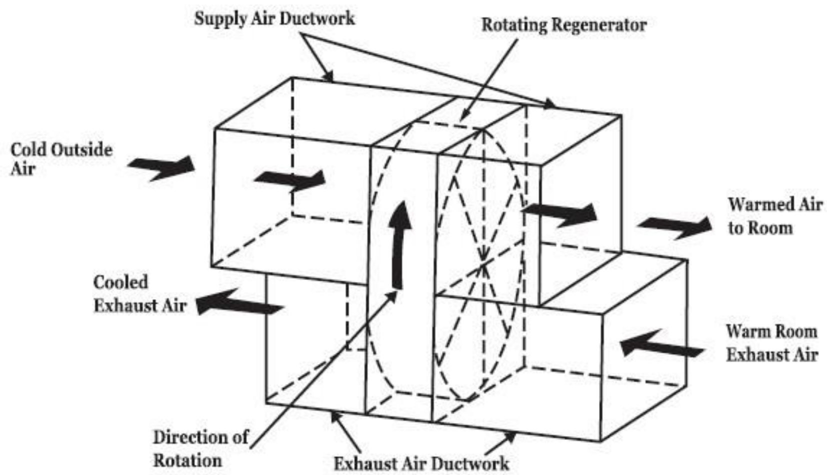


Figure 8.6 Heat Wheel

The overall efficiency of sensible heat transfer for this kind of regenerator can be as high as 85 percent. Heat wheels have been built as large as 21 metres in diameter with air capacities up to 1130 m3 / min. A variation of the Heat Wheel is the rotary regenerator where the matrix is in a cylinder rotating across the waste gas and air streams. The heat or energy recovery wheel is a rotary gas heat regenerator, which can transfer heat from exhaust to incoming gases. Its main area of application is where heat exchange between large masses of air having small temperature differences is required. Heating and ventilation systems and recovery of heat from dryer exhaust air are typical applications.

Heat Pipe

A heat pipe can transfer up to 100 times more thermal energy than copper, the best known conductor. In other words, heat pipe is a thermal energy absorbing and transferring system and have no moving parts and hence require minimum maintenance. The Heat Pipe comprises of three elements - a sealed container, a capillary wick structure and a working fluid.

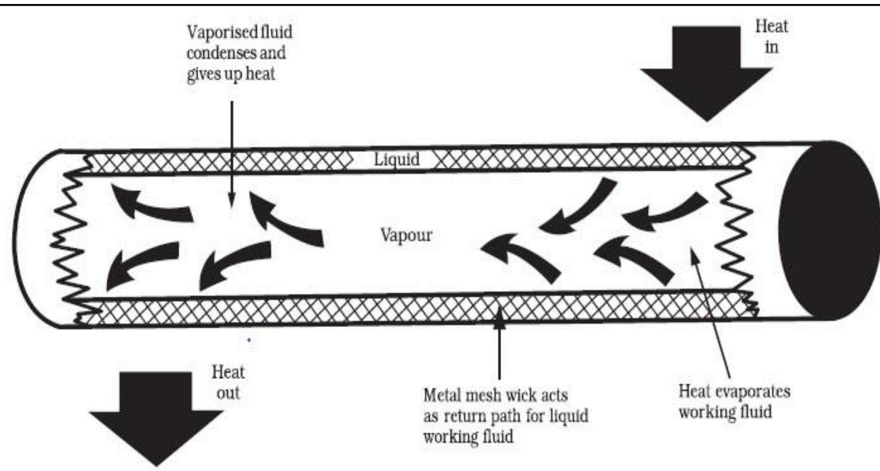


Figure 8.7 Heat Pipe

The capillary wick structure is integrally fabricated into the interior surface of the container tube and sealed under vacuum. Thermal energy applied to the external surface of the heat pipe is in equilibrium with its own vapour as the container tube is sealed under vacuum. Thermal energy applied to the external surface of the heat pipe causes the working fluid near the surface to evaporate instantaneously. Vapour thus formed absorbs the latent heat of vapourisation and this part of the heat pipe becomes an evaporator region. The vapour then travels to the other end the pipe where the thermal energy is removed causing the vapour to condense into liquid again, thereby giving up the latent heat of the condensation. This part of the heat pipe works as the condenser region. The condensed liquid then flows back to the evaporated region. A figure of Heat pipe is shown in Figure 8.7

Economiser

In case of boiler system, economizer can be provided to utilize the flue gas heat for preheating the boiler feed water. On the other hand, in an air pre-heater, the waste heat is used to heat combustion air. In both the cases, there is a corresponding reduction in the fuel requirements of the boiler. An economizer is shown in Figure 8.8. For every 22°C reduction in flue gas temperature by passing through an economiser or a pre-heater, there is 1% saving of fuel in the boiler. In other words, for every 6°C rise in feed water temperature through an economiser, or 20°C rise in combustion air temperature through an air pre-heater, there is 1% saving of fuel in the boiler.

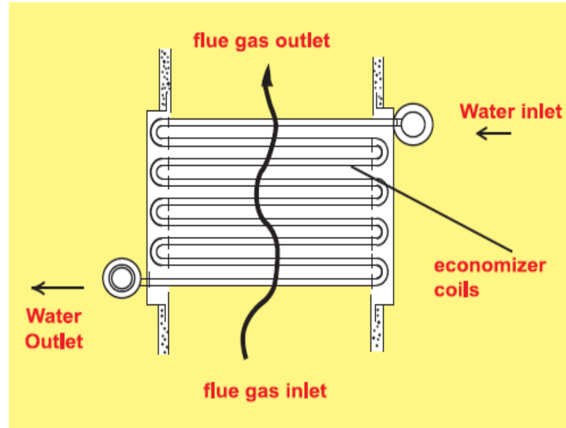


Figure 8.8 Economiser

Shell and Tube Heat Exchanger

When the medium containing waste heat is a liquid or a vapor which heats another liquid, then the shell and tube heat exchanger must be used since both paths must be sealed to contain the pressures of their respective fluids. The shell contains the tube bundle, and usually internal baffles, to direct the fluid in the shell over the tubes in multiple passes. The shell is inherently weaker than the tubes so that the higher-pressure fluid is circulated in the tubes while the lower pressure fluid flows through the shell. When a vapor contains the waste heat, it usually condenses, giving up its latent heat to the liquid being heated. In this application, the vapor is almost invariably contained within the shell. If the reverse is attempted, the condensation of vapors within small diameter parallel tubes causes flow instabilities. Tube and shell heat exchangers are available in a wide range of standard sizes with many combinations of materials for the tubes and shells. A shell and tube heat exchanger is illustrated in Figure 8.9.

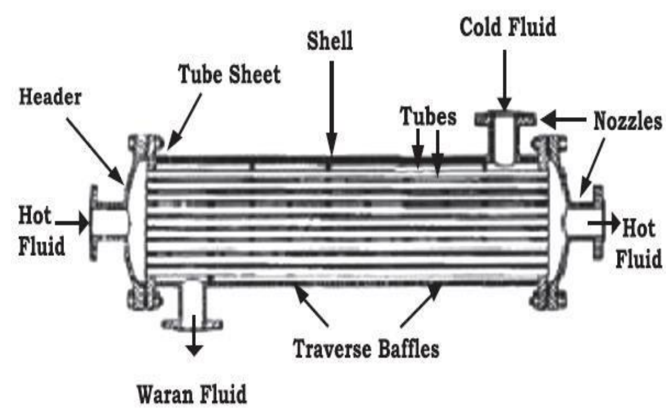


Figure 8.9 Shell & Tube Heat Exchanger

Typical applications of shell and tube heat exchangers include heating liquids with the heat contained by condensates from refrigeration and air-conditioning systems; condensate from process steam; coolants from furnace doors, grates, and pipe supports; coolants from engines, air compressors, bearings, and lubricants; and the condensates from distillation processes.

Plate heat exchanger

The cost of heat exchange surfaces is a major cost factor when the temperature differences are not large. One way of meeting this problem is the plate type heat exchanger, which consists of a series of separate parallel plates forming thin flow pass. Each plate is separated from the next by gaskets and the hot stream passes in parallel through alternative plates whilst the liquid to be heated passes in parallel between the hot plates. To improve heat transfer the plates are corrugated.

Hot liquid passing through a bottom port in the head is permitted to pass upwards between every second plate while cold liquid at the top of the head is permitted to pass downwards between the odd plates. When the directions of hot & cold fluids are opposite, the arrangement is described as counter current. A plate heat exchanger is shown in Figure 8.10.

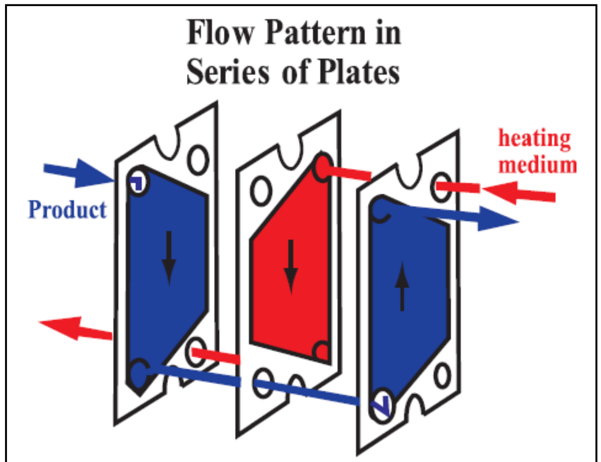


Figure 8.10 Plate Heat Exchanger

Typical industrial applications are:

– Pasteurisation section in milk packaging plant.
– Evaporation plants in food industry.

Run Around Coil Exchanger

It is quite similar in principle to the heat pipe exchanger. The heat from hot fluid is transferred to the colder fluid via an intermediate fluid known as the Heat Transfer Fluid. One coil of this closed loop is installed in the hot stream while the other is in the cold stream. Circulation of this fluid is maintained by means of circulating pump.

It is more useful when the hot land cold fluids are located far away from each other and are not easily accessible. Typical industrial applications are heat recovery from ventilation, air conditioning and low temperature heat recovery.

Waste Heat Boilers

Waste heat boilers are ordinarily water tube boilers in which the hot exhaust gases from gas turbines, incinerators, etc., pass over a number of parallel tubes containing water. The water is vaporized in the tubes and collected in a steam drum from which it is drawn off for use as heating or processing steam. Because the exhaust gases are usually in the medium temperature range and in order to conserve space, a more compact boiler can be produced if the water tubes are finned in order to increase the effective heat transfer area on the gas side. The Figure 8.11 shows a mud drum, a set of tubes over which the hot gases make a double pass, and a steam drum which collects the steam generated above the water surface. The pressure at which the steam is generated and the rate of steam production depends on the temperature of waste heat. The pressure of a pure vapor in the presence of its liquid is a function of the temperature of the liquid from which it is evaporated. The steam tables tabulate this relationship between saturation pressure and temperature.

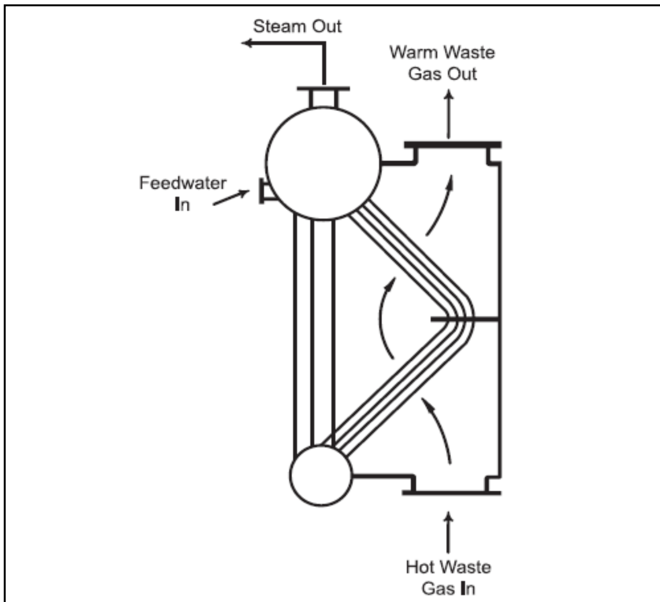


Figure 8.11 Two-Pass Water Tube Waste Heat Recovery Boiler

If the waste heat in the exhaust gases is insufficient for generating the required amount of process steam, auxiliary burners which burn fuel in the waste heat boiler or an after-burner in the exhaust gases flue are added. Waste heat boilers are built in capacities from 25 m3 almost 30,000 m3 / min. of exhaust gas.

Thermocompressor

In many cases, very low pressure steam are reused as water after condensation for lack of any better option of reuse. In many cases it becomes feasible to compress this low pressure steam by very high pressure steam and reuse it as a medium pressure steam. The major energy in steam, is in its latent heat value and thus thermocompressing would give a large improvement in waste heat recovery. The thermocompressor is a simple equipment with a nozzle where HP steam is accelerated into a high velocity fluid. This entrains the LP steam by momentum transfer and then recompresses in a divergent venturi. Afigure of thermocompressor is shown in Figure 8.13. It is typically used in evaporators where the boiling steam is recompressed and used as heatingsteam.

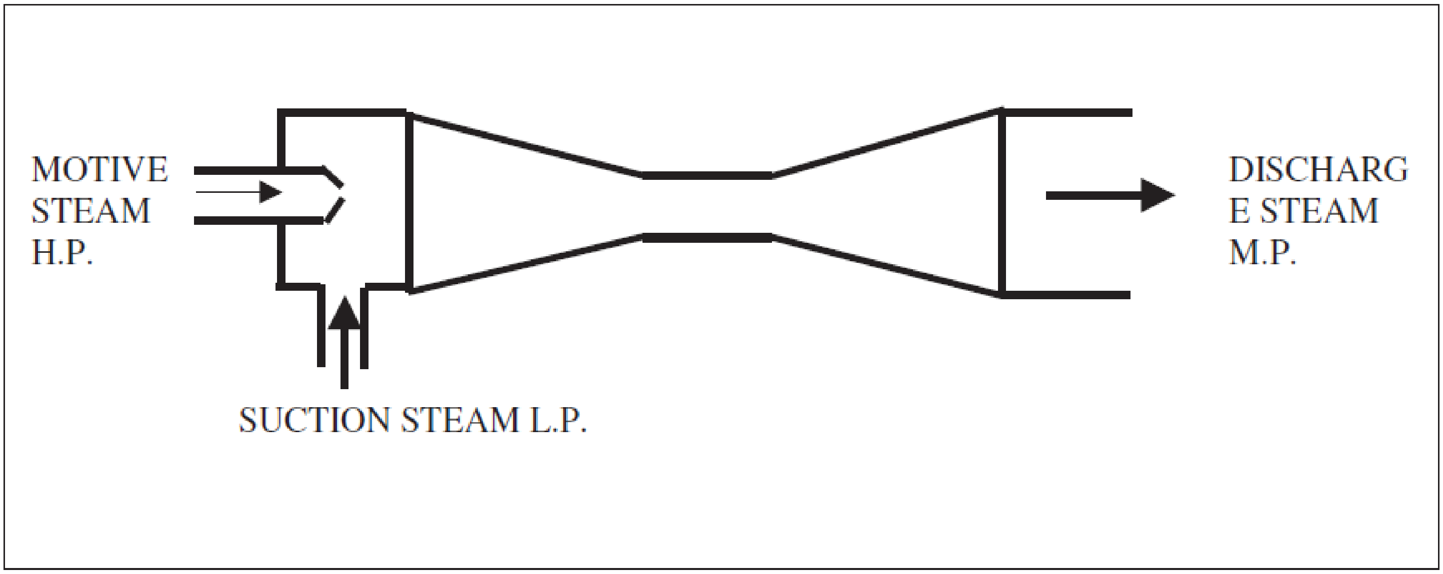


Figure 8.13 Thermocompressor

Module 5

INTRODUCTION

The fundamental goal of energy management is to produce goods and provide services with the least cost and least environmental effect.

As per the Energy Conservation Act, 2001, Energy Audit is defined as "***the verification, monitoring and analysis of use of energy including submission of technical report containing recommendations for improving energy efficiency with cost benefit analysis and an action plan to reduce energy consumption***".

The objective of Energy Management is to achieve and maintain optimum energy procurement and utilization, throughout the organization and:

• To minimize energy costs / waste without affecting production & quality
• To minimize environmental effects.

Energy Audit: Needs

In any industry, the three top operating expenses are often found to be energy (both electrical and thermal), labour and materials. If one were to relate to the manageability of the cost or potential cost savings in each of the above components, energy would invariably emerge as a top ranker, and thus energy management function constitutes a strategic area for cost reduction. Energy Audit will help to understand more about the ways energy and fuel are used in any industry, and help in identifying the areas where waste can occur and where scope for improvement exists.

The Energy Audit would give a positive orientation to the energy cost reduction, preventive maintenance and quality control programmes which are vital for production and utility activities. Such an audit programme will help to keep focus on variations which occur in the energy costs, availability and reliability of supply of energy, decide on appropriate energy mix, identify energy conservation technologies, retrofit for energy conservation equipment etc.

In general, Energy Audit is the translation of conservation ideas into realities, by lending technically feasible solutions with economic and other organizational considerations within a specified time frame.

The primary objective of Energy Audit is to determine ways to reduce energy consumption per unit of product output or to lower operating costs. Energy Audit provides a “bench-mark" (Reference point) for managing energy in the organization and also provides the basis for planning a more effective use of energy throughout the organization.

LECTURE 1: Energy Audit: Types and Methodology

Energy Audit is the key to a systematic approach for decision-making in the area of energy management. It attempts to balance the total energy inputs with its use, and serves to identify allthe energy streams in a facility. It quantifies energy usage according to its discrete functions. Industrial energy audit is an effective tool in defining and pursuing comprehensive energy management program. As per the Energy Conservation Act, 2001, Energy Audit is defined as "the verification, monitoring and analysis of use of energy including submission of technical report containing recommendations for improving energy efficiency with cost benefit analysis and an action plan toreduce energy consumption".

Type of Energy Audit

The type of Energy Audit to be performed depends on:
- Function and type of industry
- Depth to which final audit is needed, and
- Potential and magnitude of cost reduction desired

Thus Energy Audit can be classified into the following two types.

i) Preliminary Audit
ii) Targeted Audit
iii) Detailed Audit

Preliminary Energy Audit Methodology

Preliminary energy audit is a relatively quick exercise to:

- Establish energy consumption in the organization
- Estimate the scope for saving
- Identify the most likely (and the easiest areas for attention
- Identify immediate (especially no-/low-cost) improvements/ savings
- Set a 'reference point'
- Identify areas for more detailed study/measurement
- Preliminary energy audit uses existing, or easily obtained data

Targeted energy Audit

- Targeted energy audits are mostly based upon the outcome of the preliminary audit results.
- They provide data and detailed analysis on specified target projects.
- As an example, an organization may target its lighting system or boiler system or compressed air system with a view to bring about energy savings.
- Targeted audits therefore involve detailed surveys of the target subjects/areas with analysis of the energy flows and costs associated with those targets.

Detailed Energy Audit Methodology

A comprehensive audit provides a detailed energy project implementation plan for a facility, since it evaluates all major energy using systems. This type of audit offers the most accurate estimate of energy savings and cost. It considers the interactive effects of all projects, accounts for the energy use of all major equipment, and includes detailed energy cost saving calculations and project cost. In a comprehensive audit, one of the key elements is the energy balance. This is based on an inventory of energy using systems, assumptions of current operating conditions and calculations of energy use. This estimated use is then compared to utility bill charges. Detailed energy auditing is carried out in three phases: Phase I, II and III.

Phase I - Pre Audit Phase

Phase II - Audit Phase

Phase III - Post Audit Phase

Phase I -Pre Audit Phase Activities

A structured methodology to carry out an energy audit is necessary for efficient working. An initial study of the site should always be carried out, as the planning of the procedures necessary for an audit is most important.

Initial Site Visit and Preparation Required for Detailed Auditing

An initial site visit may take one day and gives the Energy Auditor/Engineer an opportunity to meet the personnel concerned, to familiarize him with the site and to assess the procedures necessary to carry out the energy audit. During the initial site visit the Energy Auditor/Engineer should carry out the following actions: -

- Discuss with the site's senior management the aims of the energy audit.
- Discuss economic guidelines associated with the recommendations of the audit.
- Analyze the major energy consumption data with the relevant personnel.
- Obtain site drawings where available - building layout, steam distribution, compressed air distribution, electricity distribution etc.
- Tour the site accompanied by engineering/production

The main aims of this visit are: -

- To finalize Energy Audit team
- To identify the main energy consuming areas/plant items to be surveyed during the audit.
- To identify any existing instrumentation/ additional metering required.
- To decide whether any meters will have to be installed prior to the audit eg. kWh, steam, oil or gas meters.
- To identify the instrumentation required for carrying out the audit.
- To plan with time frame
- To collect macro data on plant energy resources, major energy consuming centers
- To create awareness through meetings/ program

Phase II- Detailed Energy Audit Activities

Depending on the nature and complexity of the site, a comprehensive audit can take from several weeks to several months to complete. Detailed studies to establish, and investigate, energy and material balances for specific plant departments or items of process equipment are carried out. Whenever possible, checks of plant operations are carried out over extended periods of time, at nights and at weekends as well as during normal daytime working hours, to ensure that nothing is overlooked.

The audit report will include a description of energy inputs and product outputs by major department or by major processing function, and will evaluate the efficiency of each step of the manufacturing process. Means of improving these efficiencies will be listed, and at least a preliminary assessment of the cost of the improvements will be made to indicate the expected pay- back on any capital investment needed. The audit report should conclude with specific recommendations for detailed engineering studies and feasibility analyses, which must then be per- formed to justify the implementation of those conservation measures that require investments. The information to be collected during the detailed audit includes: -

1. Energy consumption by type of energy, by department, by major items of process equipment, by end-use
2. Material balance data (raw materials, intermediate and final products, recycled materials, use of scrap or waste products, production of by-products for re-use in other industries, etc.)

3. Energy cost and tariff data
4. Process and material flow diagrams
5. Generation and distribution of site services (eg. compressed air, steam).
6. Sources of energy supply (e.g. electricity from the grid or self-generation)
7. Potential for fuel substitution, process modifications, and the use of co-generation systems (combined heat and power generation).
8. Energy Management procedures and energy awareness training programs within the establishment

The ten steps for detailed energy audit

Step No	PLAN OF ACTION	PURPOSE / RESULTS
	Phase I –Pre Audit Phase	
Step 1	• Plan and organise • Walk through Audit • Informal Interview with Energy Manager, Production / Plant Manager	• Resource planning, Establish/organize a Energy audit team • Organize Instruments & time frame • Macro Data collection (suitable to type of industry.) • Familiarization of process/plant activities • First hand observation & Assessment of current level operation and practices
Step 2	• Conduct of brief meeting / awareness programme with all divisional heads and persons concerned (2-3 hrs.)	• Building up cooperation • Issue questionnaire for each department • Orientation, awareness creation
	Phase II –Audit Phase	
Step 3	• Primary data gathering, Process Flow Diagram, & Energy Utility Diagram	• Historic data analysis, Baseline data collection • Prepare process flow charts • All service utilities system diagram (Example: Single line power distribution diagram, water, compressed air & steam distribution. • Design, operating data and schedule of operation • Annual Energy Bill and energy consumption pattern (Refer manual, log sheet, name plate, interview)
Step 4	• Conduct survey and monitoring	• Measurements : Motor survey, Insulation, and Lighting survey with portable instruments for collection of more and accurate data. Confirm and compare operating data with design data.

Step 5	• Conduct of detailed trials /experiments for selected energy guzzlers	• Trials/Experiments: - 24 hours power monitoring (MD, PF, kWh etc.). - Load variations trends in pumps, fan compressors etc. - Boiler/Efficiency trials for (4 – 8 hours) - Furnace Efficiency trials Equipments Performance experiments etc
Step6	• Analysis of energy use	• Energy and Material balance & energy loss/waste analysis
Step 7	• Identification and development of Energy Conservation (ENCON) opportunities	• Identification & Consolidation ENCON measures ▪ Conceive, develop, and refine ideas ▪ Review the previous ideas suggested by unit personal ▪ Review the previous ideas suggested by energy audit if any ▪ Use brainstorming and value analysis techniques ▪ Contact vendors for new/efficient technology
Step 8	• Cost benefit analysis	• Assess technical feasibility, economic viability and prioritization of ENCON options for implementation • Select the most promising projects • Prioritise by low, medium, long term measures
Step9	• Reporting & Presentation to the Top Management	• Documentation, Report Presentation to the top Management.
	Phase III –Post Audit phase	
Step10	• Implementation and Follow-up	Assist and Implement ENCON recommendation measures and Monitor the performance • Action plan, Schedule for implementation • Follow-up and periodic review

LECTURE 2: Energy Audit Instrumentation

The EAI types included in the directory were selected as a basic audit instrument set by RMA(Resource management association)staff following discussions with Indian energy consulting firm personnel. RMA staff and a team at the Mechanical Engineering Department of Indian Institute of Technology - Madras attempted to identify all EAI manufacturers and suppliers and sent surveys to each identified manufacturer or supplier. Much of the information supplied by the firms surveyed was incomplete.

Anemometers

Anemometers are essentially fluid flow measuring instruments. As energy audit tools, they are most commonly used to measure air flow from heating, ventilation, and air conditioning (HVAC) systems. Anemometers are classified into four types:

1. **Rotating Vane**
2. **Bridled Vane**
3. **Deflecting Vane**
4. **Hot Wire**

- **Rotating Vane:** This instrument consists of a lightweight, fluid-driven vane, wheel or propeller, which is connected by a gearing system to a set of recording dials which display the amount of fluid passing through the wheel during a prescribed period. To compensate for the mechanism=s frictional drag at low fluid velocities, an A over-speeding@ gear train is often utilized. The over-speeding correction is usually additive at lower fluid velocities and subtractive at higher velocities.
- **Bridled Vane**: The velocity measurement made by this type of anemometer does not depend on a time interval. It measures the instantaneous velocity and head, then displays the velocity.
- **Deflecting Vane** : Instead of using a swinging vane to deflect the fluid flow and indicate a velocity reading, this instrument utilizes the pressure exerted on a vane. The deflecting vane is free to move in a circular tunnel and causes a pointer to indicate the velocity measurement on a scale. This type of anemometer is not dependent on fluid density because it senses pressure differentials to indicate velocities.
- **Hot Wire :** The hot-wire anemometer is employed to measure mean and turbulent velocity components. A fine wire is heated electrically and placed in the flow stream. The heat transfer rate from the wire is a function of flow velocity. In the more common constant-temperature version, the temperature of the wire is held constant through a suitable electrical circuit. Complete commercial versions of hot-wire and hot-film anemometers are available. These instruments are complex and relatively costly. In the U.S. they are commonly used for energy auditing.

Application:

Anemometers are most commonly used to measure the airflow of HVAC systems, but are also used to measure other clean air flows. For example, when testing and tuning a HVAC systems it is important to insure that appropriate quantities of fresh air are delivered.

Combustion Analyzers and Other Combustion Gas Monitoring and Control Instruments

A combustion analyzer estimates the combustion efficiency of furnaces, boilers and other fossil fuel-fired devices. To estimate efficiency, the instrument measures the composition of the flue gas (typically CO2, CO and O2) and exhaust gas temperature. Oxygen levels are measured to ensure proper excess air levels. Each furnace design and fuel type has an optimal excess air level.

Two general procedures are used to determine combustion efficiency: a manual process through the Orsat procedure, or use of a (computerized) combustion analyzer. The combustion analyzer estimates efficiency by performing the concentration and temperature measurements and completing the necessary calculations to determine efficiency. The manual procedure, or Orsat method, requires the auditor to measure flue gas temperature and the concentrations of CO2 and O2, then calculate (or obtain from standard charts) the combustion efficiency.

Combustion analyzer

Combustion analyzer

The Orsat procedure provides an instantaneous measurement of the combustion products, while a combustion analyzer provides a continuous measurement of the combustion products. Continuous measurement allows for trending of combustion products as boiler load changes and as boiler adjustments and improvements are made. The Orsat procedure is relatively difficult and prone to human error.

A combustion analyzer requires a probe for stack measurements. The probe is inserted through a single stack or breathing hole to measure combustion product concentration and flue gas temperature. Combustion testing is used to gauge if the appropriate amounts of combustion air for efficient fuel combustion are being maintained in the boiler/furnace/kiln. Low CO measurements are indicative of excess air, whereas high CO concentrations are indicative of low oxygen or poor burnout conditions. Similarly, high stack temperatures (and thus high rates of heat loss) are indicative of excess air (O2).

Many of the combustion analyzers are also able to measure the concentrations of SO2, NOx , and soot, making these instruments valuable for measuring combustion air pollutant emissions. The typical range of concentration, measured by combustion analyzers in the flue gases, is 0% to 21% for O2; from 0% to 20% for CO2; and between 0% and 0.5 % for CO.

Application:

Combustion analyzers can be used for periodic combustion tuning of furnaces, boilers, and kilns and to insure optimal fuel combustion. Using a combustion analyzer to regularly maintain combustion efficiency can have a payback period of weeks to months for larger furnaces. For example, a 1% O2 reduction can result in 2% fuel savings.

<u>Ultrasonic Flow Meters</u>

Ultrasonic flow meters are used to estimate fluid flow without having to penetrate piping. Ultrasonic flow meters operate based on one of two methods. Some use the the frequency shift (i.e. Doppler Effect) experienced by an ultrasonic signal as it is reflected by bubbles or particles (i.e., discontinuities) entrained by a flowing fluid. The magnitude of the frequency shift is indicative of the velocity of the fluid. Other ultrasonic flow meters are able to estimate the velocity of a clear (i.e., free of entrained particles or bubbles) liquid. Given the inside pipe diameter, the instruments then calculate flow rate (i.e., gallons/minute or liters/minute). Ultrasonic flow meter measurements can be relatively inaccurate.

Ultra sonic flow meter

Application: Ultrasonic flow meters can be used to estimate flow rates entering or leaving a pump. For example, the instrument can be used to ensure that flow rates are maintained as efficiency improvements (i.e., reducing motor size, and re-plumbing to reducing frictional losses) are made to plumbing systems.

Humidity and Temperature Meters

Most of the humidity meters included in the directory are electrical. Electrical humidity-measuring instruments use sensors which react to varying levels of humidity by causing a physical change in a material which changes its electrical properties (often resistance). The materials electrical property is calibrated to humidity. Often thermocouples are used to measure temperatures. Thermocouples utilize materials whose resistance is indicative of temperature.

Application:

Given processes have optimal humidity and temperature conditions. For office, commercial, and residential settings, a humidity between 40% and 60% is considered optimal. Low humidity results in respiratory problems and static electricity problems which can damage delicate electric components. High humidities can cause mildew, wood warping, and poor drying.

Light Meters (Lux meter)

Light meters measure illumination or light level in units of foot-candles or lumens. Light emitted by the area of interest passes through a light-sensitive layer of cells contained in the meter. This light is converted to an electrical signal proportional to the light=s intensity. It differs from a conventional photographic light meter in that it is color- and cosine-corrected and measures lighting from a wide rather than a small field. Most lighting levels encountered during energy audits are less than 1,000 foot candles. (Note: 10.76 foot candles = 1 lux.)

Lux meter

Application:

Light meters are most commonly used to determine if interior lighting levels are appropriate, both before and after lamping upgrades are made. Lighting societies (e.g., the Illumination Engineering Society of North America) have developed guidelines for lighting levels for different work/interior areas. These guidelines were developed to minimize eye strain and maintain a safe environment, while not producing excess lumen levels and wasting energy. If lighting conditions are inappropriate, lumen levels should be adjusted.

Multimeters

Multimeters measure amps (electron flow) volts (Aelectrical pressure@) and ohms (resistance) of electrical equipment. These metering abilities can also be purchased as separate instruments: ammeters, voltmeters and ohmmeters. Ammeters are used to measure electric currents. A voltmeter measures the difference in electrical potential between two points in an electrical circuit. Multimeters, particularly the digital clamp-on designs, are considered the most versatile audit instrument. Analog instruments use a separate sensing circuit each to measure volts, amps, and ohms. Digital instruments transform the analog signals into binary signals which are counted and displayed in a digital format. The typical multimeter will measure 0 to 300 amps, 0 to 600 volts, and 0 to 1,000 ohms. The ability to measure Atrue RMS@, or root mean squared, voltage is vital when analyzing AC signals that may produce distorted wave forms.

Applications: Multimeters are commonly used to check that the proper voltage is supplied to equipment, or to determine the load on a wire or electrical device (e.g., a motor). Multimeters are also used to determine if three-phase power supply is balanced. For example, a voltage imbalance of 3% at a three-phase motor can result in a 25% motor temperature increase, which reduces motor life and motor efficiency. A high-quality multimeter (or voltmeter) is required to determine voltage balance.

pH Meters

The pH of an aqueous solution is a value expressing the solution's acidity or basicity, based on the concentration of hydrogen ions present (where 0 is strongly basic, 14 is strongly acidic, and 7 is neutral). A pH meter uses the property of certain types of electrodes to exhibit electrical potential when immersed in a solution. The electrical potential is indicative of the solution=s pH. The instrument has three elements, an electrode or cell that measures pH, a reference electrode, and a resistance thermometer. (The thermometer is used to compensate for the effect of temperature on electrical potential.) Both electrodes are typically enclosed in thin-walled glass tubes. Inside the measurement electrode, is a solution of known pH. When the measurement electrode is placed in the unknown solution a voltage is generated. The reference electrode is then inserted into the unknown solution - providing a reference voltage. The voltages are compared and displayed on a calibrated pH scale.

Application:

Accurate measurements of pH are required to properly maintain water quality in order to protect equipment and materials that are in contact with the water (e.g., boiler tubes and heat ex-changers). Serious problems (e.g., precipitation of salts and corrosion) can occur if proper Ph levels are not maintained.

Watt Meters, Power Meters, and Power Analyzers

- **Watt Meter:** The watt meter is employed to directly measure the amount of power used by a single-phase electric device. The basic watt meter consists of two voltage probes and a snap-on current coil which feeds the watt meter's movement. It measures true RMS (root mean squared) voltage, current and power factor. Based on the current and voltage measurements, a watt meter calculates and displays power (watts) consumption. Multiple measurements using a watt meter can be used to assess three-phase circuits. The typical watt meter has operating limits of 300 kW, 650 volts, and 6,000 amperes.
- **Power Meter:** Power meters measure true RMS voltage, current, and the power factor and calculate power use by single-phase and balanced or unbalanced three-phase circuits. Some meters record a time history of the measurements.
- **Three Phase Power and Disturbance Analyzer:** These meters can do everything that a power meter does and more. Power analyzers are used to determine parameters on the sine and nonlinear/distorted wave forms and harmonic distortion levels for both balance and unbalanced power systems. Many electronic devices cause harmonic distortions in both voltage and current waveforms. Because of these distortions, the measurements given by conventional power meters may be incorrect. Power analyzers compensates for harmonic distortions by using RMS methods to determine voltage and current.

Application:

These instruments are very useful for testing, measuring, servicing, and maintaining electrical equipment and facilities. For example a watt meter can be used to measure the power consumption of an individual motor to determine if it is properly sized for its application

Power disturbance information provided by power analyzers is used to diagnose problems which can reduce electronic device reliability. For example, phase sequencing problems can cause sluggish or overheated motors (which results in premature equipment failure). Managing power quality prevents overloading conductors and minimizes the risk of problems resulting from voltage irregularities.

Power Factor Meters

Power factor meters are used to measure the power factor of electrical equipment, particularly three-phase motors. Power factor is a measurement of the electrical current in a wire which is doing useful work compared to the total electrical current in the wire. The non-useful component of the current creates magnetic fields in the end-use device. These magnetic fields are not detrimental or beneficial to the end-use device. But the non-useful component of the current requires generation, transmission, and distribution capacity, thereby causing inefficiencies in power systems.

Power factor measurements indicate the phase shift between the voltage and the current. A perfect 90o phase shift has a power factor of 1.0. If the phase shift is not 90o , then a fraction of the current is not useful and the power factor is less than unity. The larger the phase shift, the lower the power factor, and the greater the power system inefficiencies. Power factor meters typically measure power factor over a range of 1.0 leading to 1.0 lagging and see Aampacities@ of up to 1,500 amperes at 600 volts.

Power factor meters can be used on single- and multi-phase electrical circuits. Multi-phase instruments simultaneously monitor all phases of voltage and current when determining power factor.

Application:

Once a power factor meter has been used to identify low power factors and the scale of the problem, capacitors can be installed to correct power factor problems by adding more capacity to the wiring network. (Power factor measurements are required to properly specify capacitor requirements.) With power factor improvement, the cost of power generation is reduced; utility power factor charges are reduced (if levied); and transmission, distribution, facility connection, and conductor size needs are reduced (as the I2R losses are reduced).

Ultrasonic Steam Trap Tester

Steam traps used in condensate return systems are typically designed to fail in the open position. In the open position, they pass high-energy-content steam directly into condensate return lines. An open steam trap is difficult to identify by visual inspection. Three types of steam trap testers have been developed to identify malfunctioning steam traps: infrared, conductive, and ultrasonic.

Ultrasonic steam trap testers are the most popular and reliable. They operate as an electronic stethoscope@. They are able to pick up the very high-pitched sound indicative of freely blowing steam (condensate draining makes a lower-pitched sound). The advantage of ultrasonic testers is that they can listen to one pipe and hear if any of the nearby steam traps have failed.

Application: Experts estimate that about 15 to 30 % of installed traps are faulty. Faulty steam traps are often the largest single source of energy losses at an industrial facility. Steam trap maintenance programs, where steam traps are regularly checked using an ultrasonic steam trap tester are typically very cost effective.

Ultrasonic detecting devices can also be used to identify any type of gas or fluid leaks (including steam, nitrogen, CFCs, compressed air, and fuel), leaking valves, line blockages, damaged motor bearings, malfunctioning compressor heads, and missing teeth on gears.

Stroboscopic Non-Contact Tachometers

A tachometer is an instrument used to measure the rotational speed of a shaft or wheel in revolutions per minute (rpm). A stroboscopic tachometer employs a variable-frequency, flashing light which makes the rotating component appear to stand still when the frequencies match. This allows the users to measure the rotational speed without contacting the object in question.

Application:

Stroboscopes are typically used to determine the mechanical loading of motors. By measuring a motor speed in rpm and electrical consumption, its efficiency can be determined. Non-contact stroboscopes are also commonly used to measure fan speeds and determine fan output (using the design fan curve).

Non-Contact Infrared Thermometers (also known as radiation pyrometers)

These thermometers rely on the electromagnetic radiation emitted by solids or fluids. The radiation is characteristic of their temperature. A lens focuses the infrared energy on the active detecting surface. The heart of the infrared thermometer is the detecting surface, which absorbs infrared energy and converts it to an electrical voltage or current. The accuracy of temperature measurements by infrared instruments depends on the absorption, reflection, and transmission characteristics of the radiative flux. These instruments typically indicate thermal variations of

0.1 ^{o}C and can cover a range of -30EC to 2,000EC (5EF-3,600EF). Corrections to apparent temperatures are made from knowledge of the emissivity of the object at the specified temperature.

Application:

Non-contact infrared thermometers, also known as heat guns, are very useful for measuring surface temperatures of steam lines, boiler surfaces, processes temperatures, etc. The primary use of infrared sensors in an energy management program is to detect building or equipment thermal losses, pinpoint insulation or weatherization needs, identify electrical hot spots, and locate unseen motor friction points

Contact Thermometers

Temperature is one of the most important properties determining the efficiency of thermal energy utilization. Several types of thermometers appropriate for energy auditing are available. The choice is usually dictated by cost, durability, range, accuracy, and application. Most HVAC applications require a thermometer with temperature of -50EC to 175EC (-50EF to 350EF). Boiler and oven stacks require thermometers able to measure up to about 500EC (1,000EF).

Contact thermometer

Thermometer types include:

- Fluid-filled instruments: These thermometers use either a fluid or solid which expands with increasing temperature. A very common design uses a simple calibrated and evacuated glass tube filled with mercury or alcohol.
- Resistance Instruments: Electronic thermometers operate on the principle that some materials change their electrical resistance as temperature changes. Typically, the sensing element consists of a long, coiled, heat-sensitive wire wound about a ceramic core and protected by a metal housing. The material=s resistance is scaled to temperature and displayed.
- Thermocouple Instruments: The operation of this class of thermometer is based on the response of two wires of dissimilar metals which, when joined together and heated, generate electricity. A very small DC voltage is produced across the ends of the wires. The resultant voltage is calibrated to temperature and displayed. Inexpensive thermocouples typically measure temperatures up to 1,100EC (2,000EF).
- Thermistor Instruments: These instruments utilize a solid-state semiconducting material which responds to temperature increases by decreasing the electrical resistance of the semiconductor. They are typically calibrated in the factory. A given current flow is indicative of a given temperature.

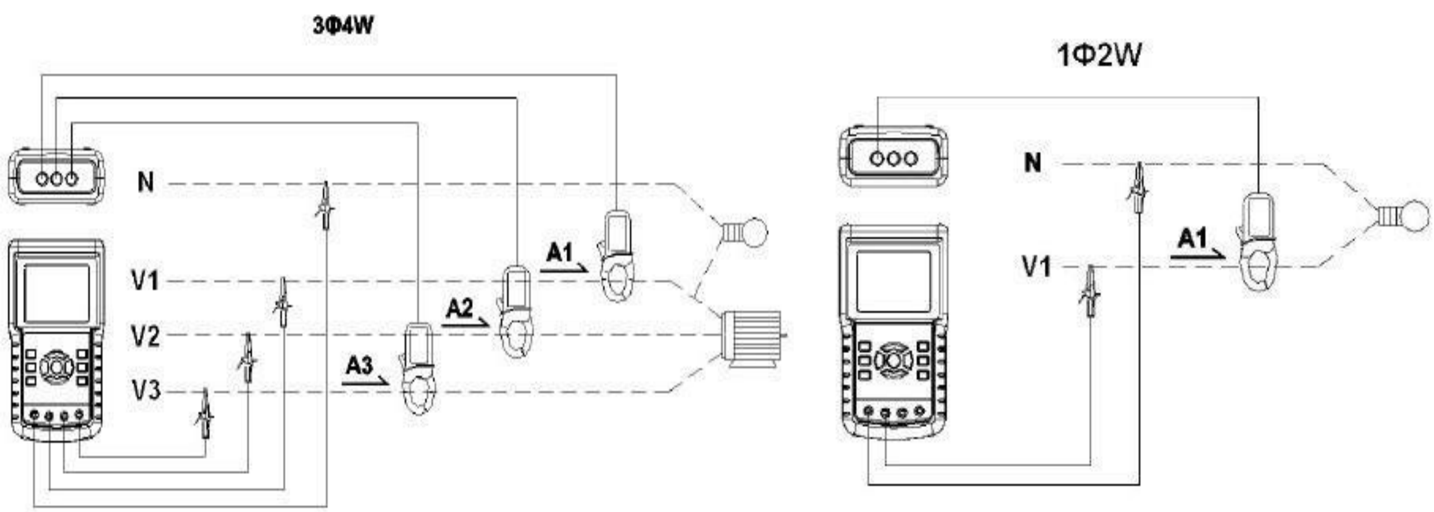
Application:

Temperature measurements are a useful method to determine process efficiencies (to assess appropriate heating levels, analyze boiler operation, and indicate building heat loss) and waste heat sources (determine the potential for waste heat recovery programs)

Power analyzer

<u>Power analyzers</u>

Electrical Measuring Instruments: These are instruments for measuring major electrical parameters such as kVA, kW, PF, Hertz, kvar, Amps and Volts. In addition some of these instruments also measure harmonics. These instruments are applied on-line i.e on running motors without any need to stop the motor. Instant measurements can be taken with hand-held meters, while more advanced ones facilitates cumulative readings with print outs at specified intervals.



Flue gas analysers

Fuel efficiency monitor: Fuel efficiency is the efficiency of a process that converts chemical potential energy contained in a carrier fuel into kinetic energy or work. This measures Oxygen and temperature of the flue gas. Calorific values of common fuels are fed into the microprocessor which calculates the combustion efficiency

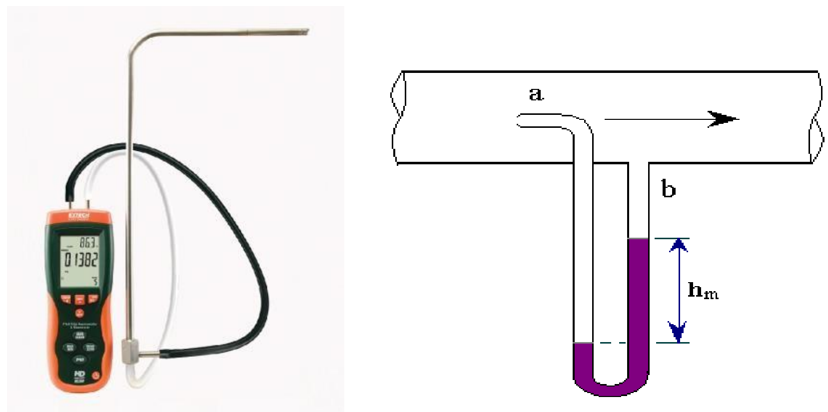
Fuel efficiency monitor


Fyrite

Fyrite: A hand bellow pump draws the flue gas sample into the solution inside the fyrite. A chemical reaction changes the liquid volume revealing the amount of gas. Percentage Oxygen or CO2 can be read from the scale.

Flow measuring instruments

Pitot Tube and manometer: Air velocity in ducts can be measured using a pitot tube and inclined manometer for further calculation of flows.



Pitot Tube and manometer

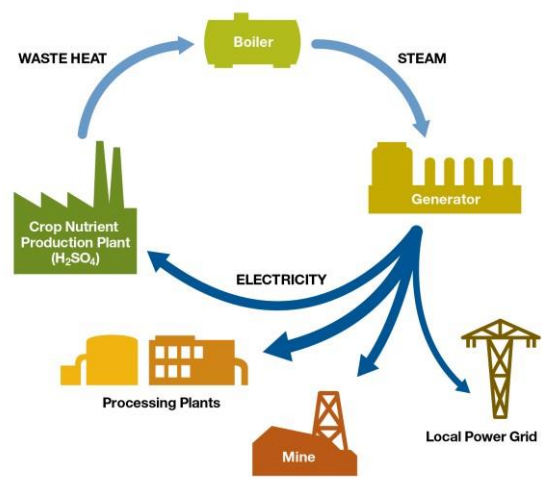
Leak Detectors:


Leak Detector

Ultrasonic instruments are available which can be used to detect leaks of compressed air and other gases which are normally not possible to detect with human abilities.

LECTURE 3: Introduction to Cogeneration and types of cogeneration

Cogeneration or Combined Heat and Power (CHP) is the combined generation of heat and power. It is not a single technology, but an integrated energy system. Cogeneration first involves producing power from a specific fuel source, such as natural gas, biomass, coal, or oil. During fuel combustion, cogeneration captures the excess heat which would have otherwise been wasted.



Combined cycle

The captured heat can be used to boil water, create steam, heat buildings, etc. For instance, in the oil sands, steam is required to produce bitumen. By using cogeneration, energy companies can simultaneously produce steam for production and electricity on site. By minimizing waste, cogeneration plants generally convert 75-80% of the fuel source into useable energy, in comparison with conventional systems which only covert about 45%.

When the heat captured is used to produce electricity, the process is referred to as combined cycle.

Cogeneration provides a wide range of technologies for application in various domains of economic activities. The overall efficiency of energy use in cogeneration mode can be up to 85 per cent and above in some cases. For example in the scheme shown in Figure 7.2, an industry requires 24 units of electrical energy and 34 units of heat energy. Through separate heat and power route the primary energy input in power plant will be 60 units (24/0.40). If a separate boiler is used for steam generation then the fuel input to boiler will be 40 units (34/0.85). If the plant had cogeneration then the fuel input will be only 68 units (24+34)/0.85 to meet both electrical and thermal energy requirements. It can be observed that the losses, which were 42 units in the case of, separate heat and power has reduced to 10 units in cogeneration mode.

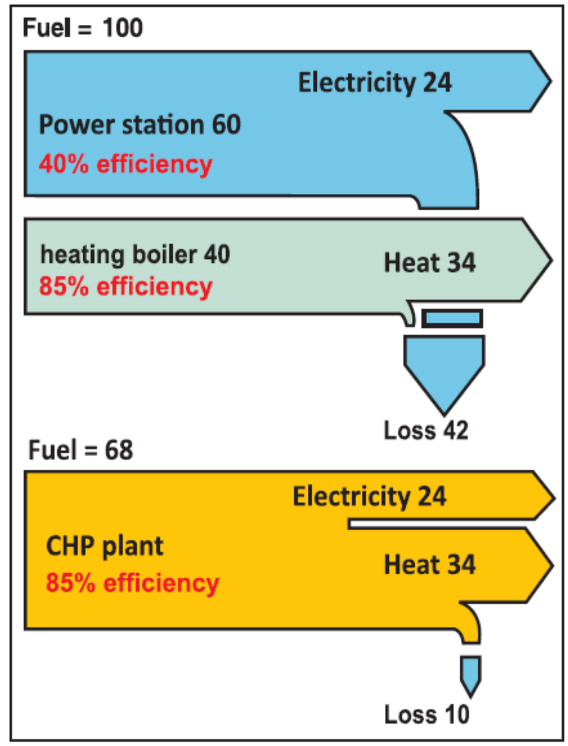


Figure 7.2 Cogeneration Advantage

Along with the saving of fossil fuels, cogeneration also allows to reduce the emission of greenhouse gases (particularly CO2 emission). The production of electricity being on-site, the burden on the utility network is reduced and the transmission line losses eliminated.

Cogeneration makes sense from both macro and micro perspectives. At the macro level, it allows a part of the financial burden of the national power utility to be shared by the private sector; in addition, indigenous energy sources are conserved. At the micro level, the overall energy bill of the users can be reduced, particularly when there is a simultaneous need for both power and heat at the site, and a rational energy tariff is practiced in the country.

Types of Cogeneration Systems (Technical Options for Cogeneration)

There are different types of cogeneration system some of them are listed below:

1. Steam Turbine Cogeneration systems
2. Gas Turbine Cogeneration Systems
3. Reciprocating Engine Cogeneration Systems

Steam Turbine Cogeneration systems

A steam generated power station is a power plant where water after its heated turns into steam and spins a steam turbine which drives an electrical generator. After it passes through the turbine, the steam is condensed and recycled back in to the same place where it was originally heated.

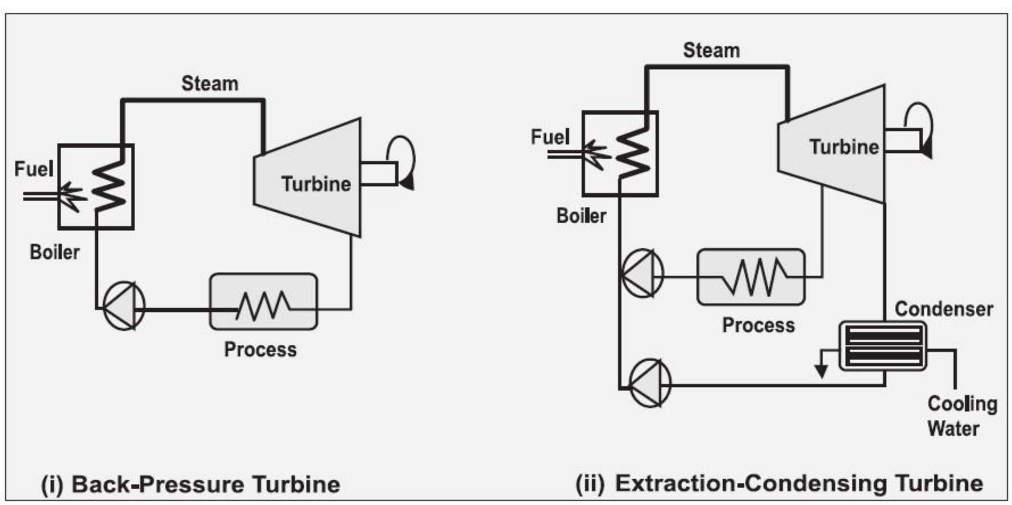


Figure 7.3 Schematic Diagrams of Steam Turbine Co-generation Systems

This cycle is known as a Rankine cycle named after the engineer William Rankine, a civil engineer who developed the theory and process.

Almost all large scale steam cogenerating power plants today still adopt this steam cycle in order to operate the turbines efficiently and provide high levels of constant electrical power generation.

The two types of steam turbines most widely used are the backpressure and the extraction-condensing types as shown in figure 7.3. The choice between the both turbines depends mainly on the quantities of power and heat and economic factors.

In a backpressure turbine, the outlet of the turbine is connected to a header that distributes steam to the various process. In a condensing turbine, outlet steam is sent to a condenser operating under vacuum. These simple backpressure or condensing turbines are typically only used in simple steam systems. In more-complex applications, multiple backpressure turbines can be combined in series to form a single turbine with multiple steam outlets. Turbines with multiple outlet ports are called extraction turbines; these are frequently used for cogeneration because they allow steam to be extracted at one or more intermediate points in the turbine casing.

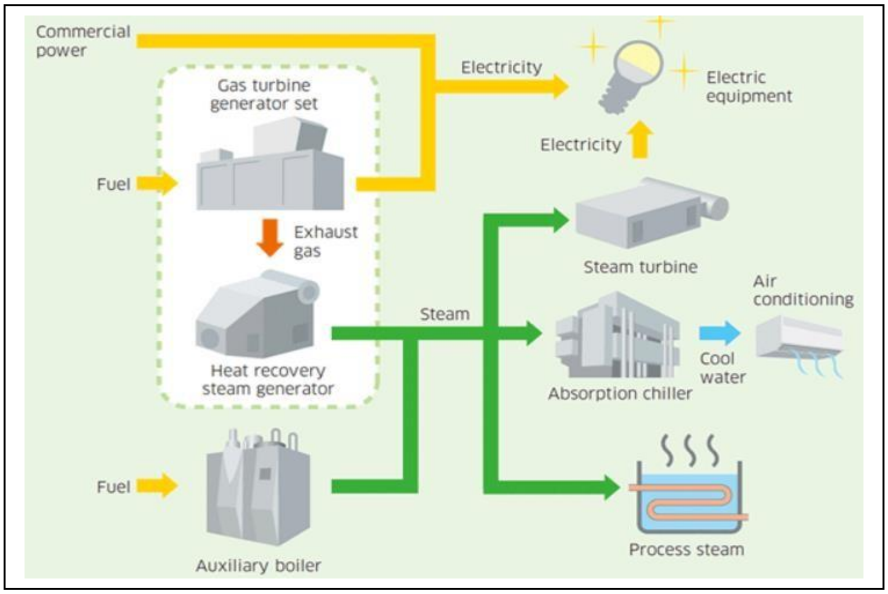
The other type of steam turbine used in CHP applications is called an extraction turbine. In these turbines, steam in extracted from the turbine at some intermediate pressure. This steam can be used to meet the facilities steam need. The remaining steam is expanded further and condensed. Extraction turbines can also act as admission turbines. In admission turbines, additional steam is added to the turbine at some intermediate point.

Another variation of the steam turbine topping cycle (In a topping cycle, the fuel supplied is used to first produce power and then thermal energy, which is the by-product of the cycle and is used to satisfy process heat or other thermal requirements. Topping cycle cogeneration is widely used and is the most popular method of cogeneration.) cogeneration system is the extraction-back pressure turbine that can be employed where the end-user needs thermal energy at two different temperature levels. The full-condensing steam turbines are usually incorporated at sites where heat rejected from the process is used to generate power. The specific advantage of using steam turbines in comparison with the other prime movers is the option for using a wide variety of conventional as well as alternative fuels such as coal, natural gas, fuel oil and biomass.

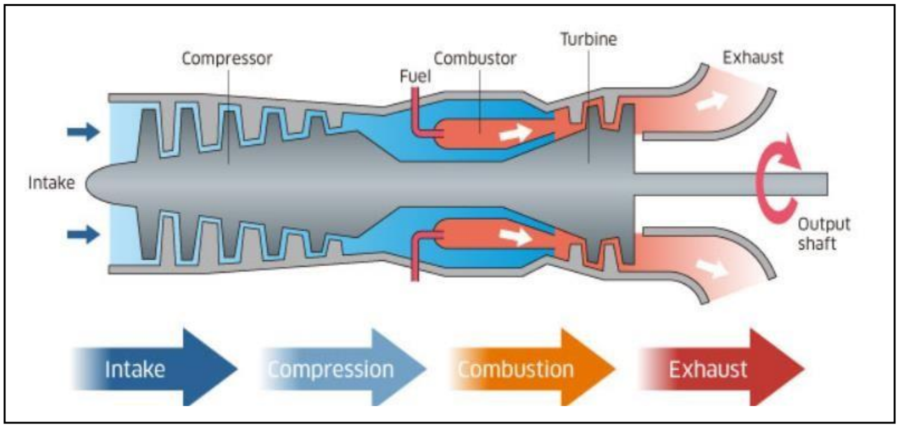
The power generation efficiency of the cycle may be sacrificed to some extent in order to optimize heat supply. In backpressure cogeneration plant there is no need for large cooling towers. Steam turbines are mostly used where the demand for electricity is greater than one MW up to a few hundreds of MW.

Gas Turbine Cogeneration Systems

A cogeneration system drives a gas turbine by using primary energy (fuel), and produces multiple types of secondary energy (e.g., electricity, steam) continuously. In a gas turbine cogeneration system, fuel is used as the primary energy, and multiple types of energy are produced in order to use energy more effectively. Furthermore, the system curbs NOx production and reduces environmental impact by using a gas turbine as the drive source.



Just like a diesel or gasoline engine, a gas turbine is a type of internal combustion engine and operates using the cycle of intake, compression, combustion (expansion) and exhaust. One major difference, however, is that the basic movement. A gas turbine is rotary movement, in contrast to the back-and-forth movement of a reciprocating engine.



The basic principle of a gas turbine is as shown in the diagram below. First, air is compressed by a compressor, and this compressed air is guided into the combustor. Here, fuel is continuously combusted to produce gas at high temperature and pressure. What a gas turbine for industry does is the gas produced in the combustor is expanded in the turbine (a vaned rotor made by attaching multiple blades to a round disk), and as the result, the rotational energy, which operates the compressor at the previous stage, is produced. The remaining energy is delivered with an output shaft.

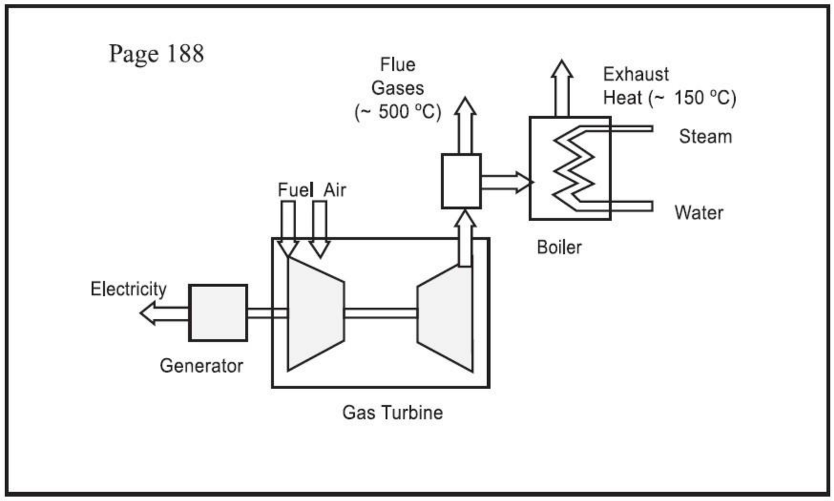


Figure 7.4 Schematic Diagram of Gas Turbine Cogeneration

Gas turbine cogeneration systems can produce all or a part of the energy requirement of the site, and the energy released at high temperature in the exhaust stack can be recovered for various heating and cooling applications (see Figure 7.4). Though natural gas is most commonly used, other fuels such as light fuel oil or diesel can also be employed. The typical range of gas turbines varies from a fraction of a MW to around 100 MW.

Gas turbine cogeneration has probably experienced the most rapid development in the recent years due to the greater availability of natural gas, rapid progress in the technology, significant reduction in installation costs, and better environmental performance. Gas turbine has a short start-up time and provides the flexibility of intermittent operation. Though it has a low heat to power conversion efficiency, more heat can be recovered at higher temperatures. If the heat output is less than that required by the user, it is possible to have supplementary natural gas firing by mixing additional fuel to the oxygen-rich exhaust gas to boost the thermal output more efficiently.

On the other hand, if more power is required at the site, it is possible to adopt a combined cycle that is a combination of gas turbine and steam turbine cogeneration. Steam generated from the exhaust gas of the gas turbine is passed through a backpressure or extraction-condensing steam turbine to generate additional power. The exhaust or the extracted steam from the steam turbine provides the required thermal energy.

Reciprocating Engine Cogeneration Systems

Also known as internal combustion (I. C.) engines, these cogeneration systems have high power generation efficiencies in comparison with other prime movers. There are two sources of heat for recovery: exhaust gas at high temperature and engine jacket cooling water system at low temperature (see Figure 5.4). As heat recovery can be quite efficient for smaller systems, these systems are more popular with smaller energy consuming facilities, particularly those having a greater need for electricity than thermal energy and where the quality of heat required is not high, e.g. low pressure steam or hot water.

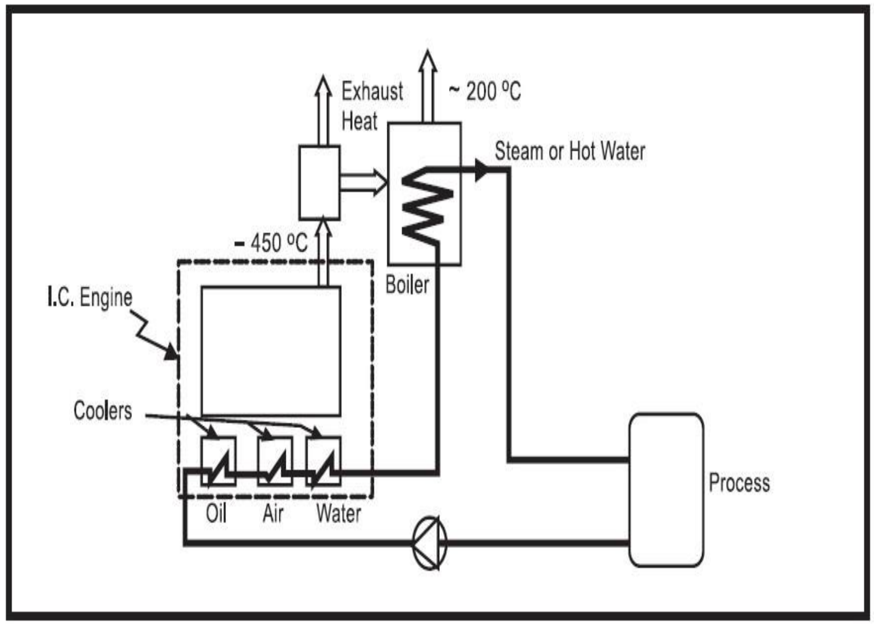


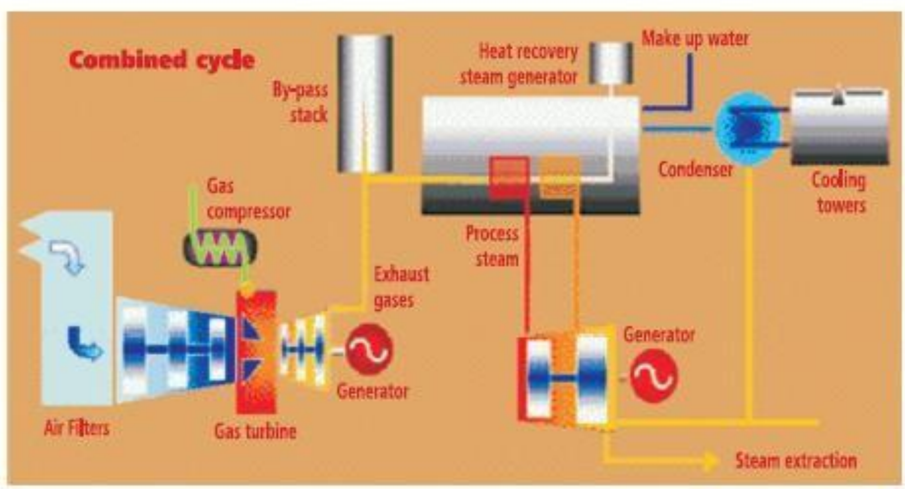
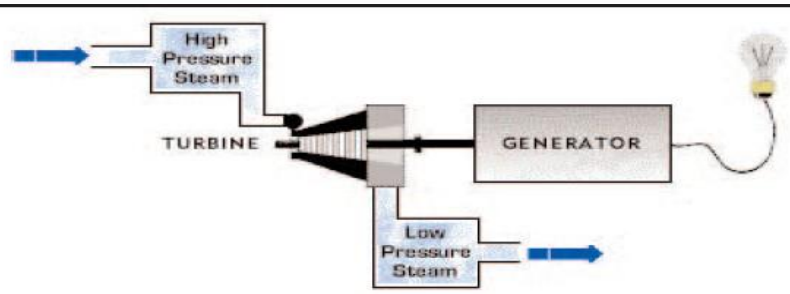
Figure 7.5 Schematic diagram of reciprocating engine cogeneration

Classification of Cogeneration Systems

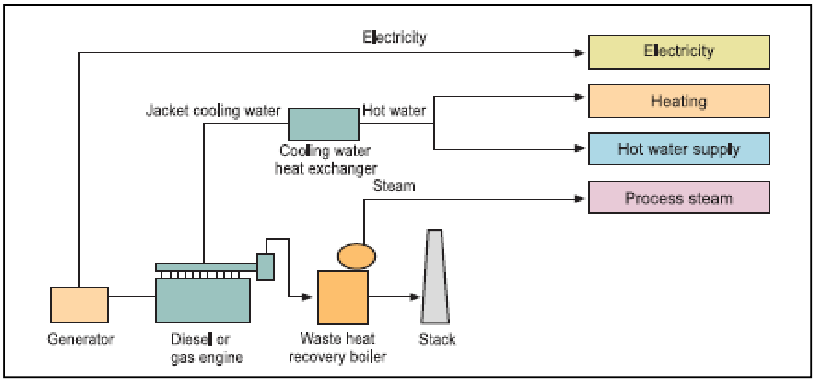
Cogeneration systems are normally classified according to the sequence of energy use and the operating schemes adopted. A cogeneration system can be classified as either a topping or a bottoming cycle on the basis of the sequence of energy use. In a topping cycle, the fuel supplied is used to first produce power and then thermal energy, which is the by-product of the cycle and is used to satisfy process heat or other thermal requirements. Topping cycle cogeneration is widely used and is the most popular method of cogeneration.

Topping Cycle

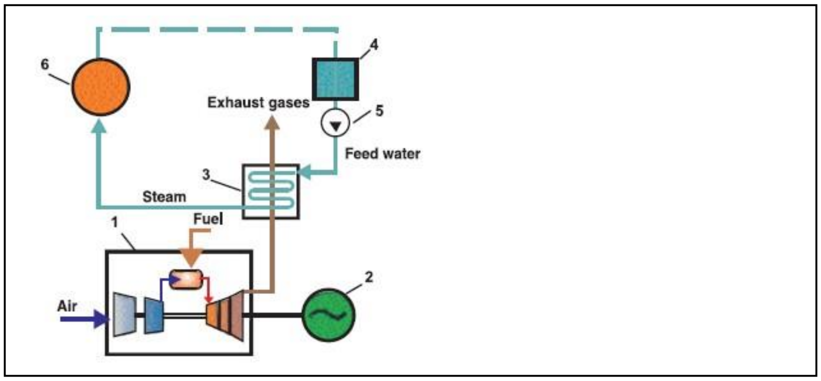
The four types of topping cycle cogeneration systems are briefly explained in Table 7.1.

Table 7.1 Types of Topping Cycles	
A gas turbine or diesel engine producing electrical or mechanical power followed by a heat recovery boiler to create steam to drive a secondary steam turbine. This is called a combined-cycle topping system.	
The second type of system burns fuel (any type) to produce high-pressure steam that then passes through a steam turbine to produce power with the exhaust provides low-pressure process steam. This is a steam-turbine topping system.	

A third type employs heat recovery from an engine exhaust and/or jacket cooling system flowing to a heat recovery boiler, where it is converted to process steam / hot water for further use.



The fourth type is a gas-turbine topping system. A natural gas turbine drives a generator. The exhaust gas goes to a heat recovery boiler that makes process steam and process heat



Bottoming Cycle

In a bottoming cycle, the primary fuel produces high temperature thermal energy and the heat rejected from the process is used to generate power through a recovery boiler and a turbine generator. Bottoming cycles are suitable for manufacturing processes that require heat at high temperature in furnaces and kilns, and reject heat at significantly high temperatures. Typical areas of application include cement, steel, ceramic, gas and petrochemical industries. Bottoming cycle plants are much less common than topping cycle plants.

The following Table 7.5 gives the advantages and disadvantages of various co-generation systems:

TABLE7.5 ADVANTAGES AND DISADVANTAGES OF VARIOUS COGENERATION SYSTEMS

Variant	Advantages	Disadvantages
Back pressure	– High fuel efficiency rating	– Little flexibility in design and operation
Steam turbine & fuel firing in boiler	– Simple plant – Well-suited to low quality fuels	– More capital investment – Low fuel efficiency rating – High cooling water demand – More impact on environment High civil const. cost due to complicated foundations
Gas turbine with waste heat recovery boiler	– Good fuel efficiency – Simple plant – Low civil const. Cost – Less delivery period – Less impact on environment – High flexibility in operation	– Moderate part load efficiency – Limited suitability for low quality fuels

Combined gas & steam turbine with waste heat recovery boiler	– Optimum fuel efficiency rating – Low relative capital cost – Less gestation period – Quick start up & stoppage – Less impact on environment – High flexibility in operation	– Average to moderate part-load efficiency – Limited suitability for low quality fuels
Diesel Engine & waste heat recovery Boiler & cooling water heat exchanger	– Low civil const. Cost due to block foundations & least no. of auxiliaries – High Power efficiency – Better suitability as stand by power source	– Low overall efficiency – Limited suitability for low quality fuels – Availability of low temperature steam – Highly maintenance prone.

LECTURE 4: Operating Schemes of Cogeneration

The operating scheme of a cogeneration system is very much site-specific and depends on several factors, as described below:

Base electrical load matching

In this configuration, the cogeneration plant is sized to meet the minimum electricity demand of the site based on the historical demand curve. The rest of the needed power is purchased from the utility grid. The thermal energy requirement of the site could be met by the cogeneration system alone or by additional boilers. If the thermal energy generated with the base electrical load exceeds the plant's demand and if the situation permits, excess thermal energy can be exported to neighboring customers.

Base Thermal Load Matching

Here, the cogeneration system is sized to supply the minimum thermal energy requirement of the site. Stand-by boilers or burners are operated during periods when the demand for heat is higher. The prime mover installed operates at full load at all times. If the electricity demand of the site exceeds that which can be provided by the prime mover, then the remaining amount can be purchased from the grid. Likewise, if local laws permit, the excess electricity can be sold to the power utility.

Electrical Load Matching

In this operating scheme, the facility is totally independent of the power utility grid. All the power requirements of the site, including the reserves needed during scheduled and unscheduled maintenance, are to be taken into account while sizing the system. This is also referred to as a "stand-alone" system. If the thermal energy demand of the site is higher than that generated by the cogeneration system, auxiliary boilers are used. On the other hand, when the thermal energy demand is low, some thermal energy is wasted. If there is a possibility, excess thermal energy can be exported to neighboring facilities.

Thermal Load Matching

The cogeneration system is designed to meet the thermal energy requirement of the site at any time. The prime movers are operated following the thermal demand. During the period when the electricity demand exceeds the generation capacity, the deficit can be compensated by power purchased from the grid. Similarly, if the local legislation permits, electricity produced in excess at any time may be sold to the utility.

Case Study

Economics of a Gas Turbine based co-generation System

Alternative I – Gas Turbine Based Co-generation

<u>Gas turbine Parameters</u>

Capacity of gas turbine generator	: 4000 kW
Plant operating hours per annum	: 8000 hrs.
Plant load factor	: 90 %
Heat rate as per standard given by gas.turbine supplier	: 3049.77 kCal / kWh
Waste heat boiler parameters – unfired steam output	: 10 TPH
Steam temperature	: 200 °C
Steam pressure	: 8.5 kg /cm2.
Steam enthalpy	: 676.44 kCal / Kg.
Fuel used	: Natural gas
Calorific value – LCV	: 9500 kCal/ sm3
Price of gas	: Rs 3000 /1000 sm3
Capital investment for total co-generation plant	: Rs. 1300 Lakhs

Cost Estimation of Power & Steam From Cogeneration Plant

1. Estimated power generation from Cogeneration plant at 90% Plant Load Factor (PLF)	: PLF × Plant Capacity × no. of operation hours = (90/100)×4000×8000 = 288.00 × 105 kWh per annum
2. Heat input to generate above units	: Units (kWh) × heat rate = 288 x 105 × 3049.77 = 878333.76 × 105 kCal
3. Natural gas quantity required per annum	: Heat input / Calorific value (LCV) of natural gas = 878333.76 x 105 / 9500 = 92.46 × 105 sm3
4. Cost of fuel per annum	: Annual gas consumption. × Price = 92.46 × 105× Rs.3000./1000 sm3 = Rs. 277.37 lakhs
5. Cost of capital and operation charges/annum	: Rs. 298.63. lakhs
6. Overall cost of power from cogeneration Plant	: Rs. 576.00.lakhs per annum
7. Cost of power	: Rs. 2.00 /kWh

Alternative-II: Electric Power from State Grid & Steam from Natural Gas Fired Boiler

Boiler Installed in Plant:

Cost of electric power from state grid – average electricity cost with demand & energy charges	: Rs. 3.00/kWh
Capital investment for 10 TPH, 8.5 kg/sq.cm.200)°C Natural gas fired fire tube boiler & all auxiliaries	: Rs. 80.00 lakh

Estimation of cost for electric power from grid & steam from direct conventional fired boiler:

1. Cost of Power from state grid for 288 lakh kWh : Rs. 864.00 lakh per annum

2. Fuel cost for steam by separate boiler

(i) Heat output in form of 10 TPH steam per annum : Steam quantity × Enthalphy × Operations/annum
$= 10 \times 1000 \times 676.44 \times 8000$
$= 541152 \times 10^5$ kCals

(ii) Heat Input required to generate 10 TPH steam :Heat output/boiler per annum @ 90% efficiency efficiency
$= 541152 \times 10^5/0.90$

Heat Input : 601280×10^5 kCal per annum

(iii) Natural Gas Quantity : Heat Input/Calorific value (LCV) of natural gas
$= 601280 \times 10^5/9500$
$= 63.29 \times 10^5$ sm^3 per annum

(iv) Cost of fuel per annum : Annual gas consumption × price
$= 63.29 \times 10^5 \times 3000 / 1000\ sm^3$
= Rs. 189.88.lakh per annum

(v) Total cost for Alternative-II : Cost of grid power + fuel cost for steam
= Rs. 864+ Rs.189.88 (lakh)
= Rs.1053.88 lakh per annum

Alternative I - Total cost : Rs. 576.00 lakh

Alternative II - Total cost : Rs. 1053.88 lakh

Differential cost : Rs. 477.88 lakh

(Note: In case of alternative-II, there will be some additional impact on cost of steam due to capital cost required for a separate boiler).
In the above case, Alternative 1 gas turbine based cogeneration system is economical compared to Alternative 2 i.e. electricity from State Grid and Steam from Natural Gas fired boiler.

LECTURE 5: Optimal Operation of Cogeneration / Combined Heat & Power Plants

Modeling of Cogeneration (CHP) Plant

Basic Diagram of Combined Heat and Power

The main characteristic of CHPs is that they reuse waste heat from prime mover during electricity generation processes to serve thermal loads, which is superior to traditional boilers. Extraction-condensing steam turbine-based CHP is very popular because the ratio between heat and electricity output could be adjusted according to various loading ratios between the two loads, providing more flexibility during peak and off-peak hours.

A typical CHP system consists of a combustion chamber, a turbine generator and a heat recovery boiler according to SIMO model of CHP can then be established, shown in Figure 5.5.

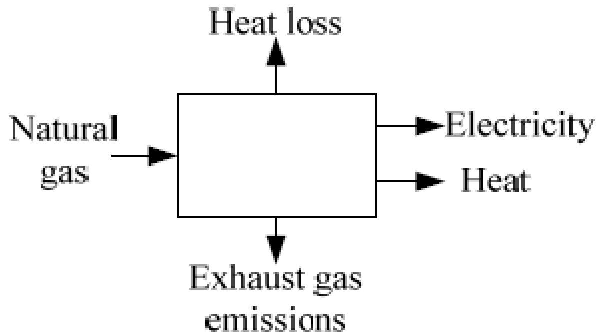


Figure 5.5 Single input and multi-output (SIMO) model of combined heat and power (CHP).

In the SIMO model of CHP, two key parameters should be determined first: overall energy conversion efficiency and Hear to power ratio (HTPR)

Overall Energy Conversion Efficiency

As shown in Figure 5.5, the output of a CHP system mainly includes four parts: electricity, heat, and unavoidable heat loss and exhaust gas emissions, while only the heat and electricity output are called useful energy. The overall energy conversion efficiency of a CHP is expressed as:.

$$\eta = \frac{Q_\Sigma}{G} \quad \text{---- 1}$$

Where η is the overall efficiency; Q_Σ is the useful energy converted from natural gas, which is also the total energy of heat and electricity, in kJ; G is the energy of natural gas, in kJ.

In most existing research, the nominal value of η is adopted. However, η is found to be changing with different loading levels and operating modes of CHPs. The overall efficiency is mainly determined and affected by the loading level and generally they are expressed as:

$$\eta = \mathrm{f}(L) \quad \text{----- 2}$$

where *L* is CHP's loading condition.

Heat to Power Ratio

Although CHPs are able to provide heat and electricity simultaneously, there is a fixed relation between the two products. To study the ratio between heat and electricity, γ_E and γ_H , are introduced.

$$E_{\text{CHP}} = \gamma_E Q_\Sigma$$
$$H_{\text{CHP}} = \gamma_H Q_\Sigma \quad \text{.......3}$$

where E_{CHP} is the energy of electricity generated by CHP, in kJ; H_{CHP} is the energy of heat generated by CHP, in kJ; γ_E and γ_H are just used to describe the energy proportion of E_{CHP} and H_{CHP}, respectively, and there is no practical significance for them.

By substituting Equation (1) into Equation (3), the output of CHP can be expressed in another form:

$$E_{\text{CHP}} = \gamma_{\text{E}} \eta G$$
$$H_{\text{CHP}} = \gamma_{\text{H}} \eta G \quad \text{.......4}$$

where γ E η is usually called electric efficiency of CHP, also denoted by ηE; and γ H η is usually called the heat efficiency of CHP, also denoted by ηH.

Apparently, γ E and γ H naturally satisfy:

$$\gamma_H + \gamma_E = 1 \quad ....5$$

The HTPR of CHPs is defined as the ratio of the heat output to the electricity output, which reflects the ability of CHPs to meet heat and electric demand. The HTPR of CHPs, denoted by ξ, expressed as:

$$\zeta = \frac{H_{CHP}}{E_{CHP}} = \frac{\gamma_H}{\gamma_E} \quad ....6$$

Optimal Operation of Cogeneration / Combined Heat & Power Plants

The optimization on CHP operation mainly concentrate on achieving economic goals (e.g., low operation cost, reduction of fuel consumption) and environmental goals (e.g., low carbon dioxide emission). The output of CHP is optimized to minimize the annual operating and maintaining costs of the whole system. When optimizing the operation strategy of CHPs to achieve maximum profits, energy prices should also be determined.

Various optimization algorithms are available to achieve real-time energy management of CHP. A discrete operation optimization model is explained here for CHPs in real-time, where the profits reach the maximum.

Discrete Optimization Model for Combined Heat and Power

In the wholesale market, electricity, heat and natural gas prices all vary at 30-min resolution, denoted by pE, pH and pG, respectively. Thus, CHPs could be operated according to the combination of the three prices to maximize benefits in the 48 dispatching steps. In the kth dispatching step, the profit is calculated by:

PRO_{CHP} (k) = I_H(k) + I_E(k) - C_G(k)   7

Where PRO is abbreviation of profit and PRO_{CHP} (k) denotes the profit in the kth step; I_H(k) and I_E(k) are the income from selling heat and electricity, respectively; C_G(k) is the cost of buying natural gas. Equation (7) can be further written as follows:

$$PRO_{CHP}(k) = H_{CHP}(k)\, p_H(k) + E_{CHP}(k)\, p_E(k) - V_G(k)\, p_G(k) \quad ......8$$

Where V_G(k) is the volume of natural gas consumed in the kth dispatching step; p_H (k), p_E (k) and p_G (k) are the prices of heat, electricity and natural gas in the kth dispatching step respectively. Usually, the energy contained in a cubic meter of natural gas is a constant, denoted by q, in kJ/m3. Thus the total energy injected into the CHP in the kth step is expressed as:

G(k) = q V_G(k)-----9

Through substituting Equation (5) into Equation (6), H and E are obtained and shown as follows:

$$\gamma_H = \frac{\zeta}{1+\zeta}$$
$$\gamma_E = \frac{1}{1+\zeta} \quad ....10$$

By substituting Equations (4), (9) and (10) into Equation (8), the objective function of CHP is obtained, given by:

$$\text{Maximize: } \mathrm{PRO}_{\mathrm{CHP}}(k)$$
$$\mathrm{PRO}_{\mathrm{CHP}}(k) = \left(\frac{\zeta}{1+\zeta} q\eta p_{\mathrm{H}}(k) + \frac{1}{1+\zeta} q\eta p_{\mathrm{E}}(k) - p_{\mathrm{G}}(k) \right) V_{\mathrm{G}}(k)$$

LECTURE 6: Computer Aided Energy Management

Computerized energy management system (EMS) is a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. The monitor and control functions are known as Supervisory Control and Data Acquisition (SCADA), followed by several on-line application functions. Energy Management Software (EMS) is a general term referring to a variety of energy-related software applications which may provide utility bill tracking, real-time metering and lighting control systems, building simulation and modeling, carbon and sustainability reporting , demand response, and/or energy audits. Managing energy can require a system of systems approach.

Objectives of EMS:

1. Maintaining the power system in a secure and stable operating state by continuously monitoring the power flowing in the lines and voltage magnitudes at the buses.

2. Maintaining the frequency within allowable limits.

3. Maintaining the tie-line power close to the scheduled values.

4. Economic Operation of the power systems through real time dispatch and Control.

5. Optimal control of the power system using both preventive and corrective control actions.

6. Real time Economic Dispatch through real power and reactive power control

7. Optimization of the power system for normal and abnormal operating scenarios.

8. Optimal control of the power system by appropriate using both preventive and corrective control actions

9. Maintenance scheduling of generation and transmission systems.

Evolution of EMS:

The evolution of EMS has a long past. It has started with control centers in 1960s to fully developed energy management systems

1960 – Termed as Control Centre’s (CC) These control centers were initially termed a load dispatch centres. The important task was to control the power generation and load demand as to match the generation with load demand. Even today, the term load dispatch centre’s are widely used in various state electricity boards as well as energy control centre’s.

1970 – Energy Control Centre’s. Here the main task was to control the energy rather than the power. Here energy monitoring is of main concern the matching of energy of power demand from that of power generation is of main concern.

1990 – Energy Management Systems (EMS) In EMS, the main task was to manage the energy through various techniques like load management (LM), demand side management (DSM), distribution management systems (DMS). EMS are computer based programs hat perform both computational tasks as well as decision making tasks so as to assist the operator for real time operation and control.

Functions and Benefits of EMS:

The important benefits of an EMS can be addresses as the following functions:

Control functions:

1. Real time monitoring and control functions.
2. Automatic Control and automation of a power system like Automated interfaces and electronic tagging
3. Efficient automatic generation control and load frequency control.
4. Optimal automatic generation control across multiple areas
5. Tie -line control.

Operating functions

1. Economic and optimal Operation of the generating system.
2. Efficient operator Decision Making Improved quality of supply

Optimization functions

1. Optimal utilization of the transmission network
2. Power scheduling interchange between areas.
3. Optimal allocation of resources
4. Immediate overview of the power generation, interchanges and reserves

Planning functions

1. Improved quality of supply and system reliability
2. Forecasting of loads and load patterns
3. Generation scheduling based on load forecast and trading schedules
4. Maintaining reserves and committed transactions
5. Calculation of fuel consumption, production costs and emissions

EMS Architecture:

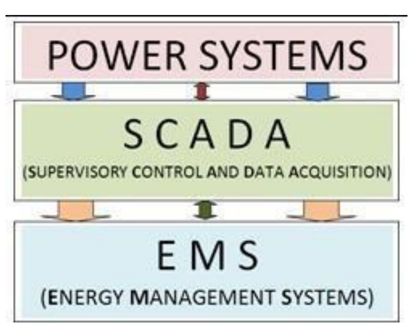


Fig 5.6 Power and Information flow between Power systems, SCADA and EMS

Figure 5.6 shows the components in EMS-SCADA. Power Systems contain generators, transformers, transmission lines, different loads to industry and consumers. SCADA consists mostly of hardware components, which measure the quantities (Voltage, current, power, etc.) from various meters. SCADA consists of collection of information from meters distributed throughout the area through Remote Terminal Units (RTUS). EMS consists of a network of computers or work stations which perform computational tasks for decision making in real time operation and control. Both On-line and Off-Line functions can be performed in an EMS. The operators in an EMS send signals to the power system through SCADA. On line functions include mainly closed loop control functions like automatic generating control (AGC), load frequency control (LFC), voltage reactive power control (volt-var control). Open loop functions like Economic Dispatch and Operator load flow, state estimation, security assessment, etc are also performed in real time as on line functions.

Practical EMS

Figure 1.4 shows the actual implementation of Power System Model, SCADA AND EMS in a laboratory environment. The power system model consists of scaled down components of three phase generators, transformers, transmission lines and loads. The SCADA modules consist essentially of hardware for measurement monitoring, control and protection of the power systems. SCADA monitors information from the power system through PT, CT, etc., collects data and sends them to the EMS. Both Analog (continuous) data and digital (discrete) information are collected by the Remote Terminal Units (RTU).

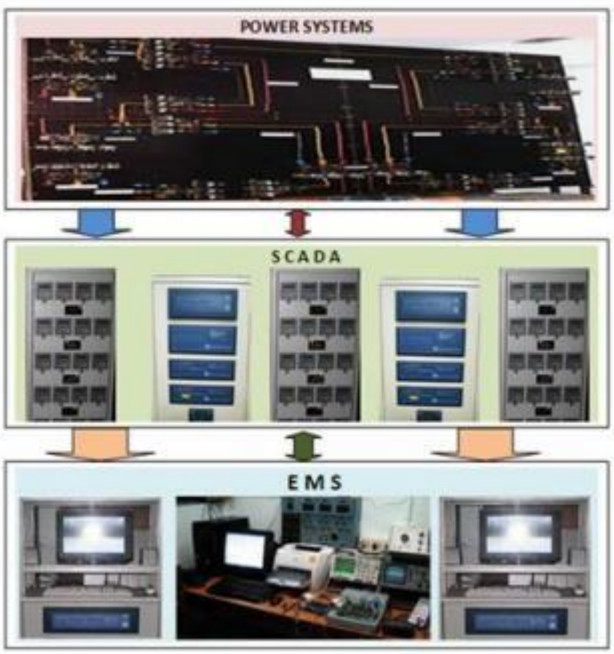


Fig 1.4.Practical EMS- SCADA System.

EMS consists of a network of computers or work stations which perform computational tasks for decision making in real time operation and control. Both On-line and Off-Line functions can be performed in an EMS. The operators in an EMS send signals to the power system through SCADA. On line functions include mainly closed loop control functions like automatic generating control (AGC), load frequency control (LFC), voltage reactive power control (volt-var control). Open loop functions like Economic Dispatch and Operator load flow, state estimation, security assessment, etc are also performed in real time as on line functions.

Working of EMS

The important working of an EMS is given below

1. Real time monitoring and control over the whole distribution network.

2. Enhanced customer service through a complete outage management package including trouble call taking, fault localization and restoration as well as outage statistics and customer notification.

3. Efficient work order handling via the built-in work management tools.

4. Better crew and resource management including support for crew scheduling and tracking, dispatching and assignments as well as follow-up and reports.

5. Optimal network utilization using the State Estimator functionality for optimal feeder reconfiguration and loss minimization in balanced networks

6. Better support for all reporting with retrieval of historical data archived in a data warehouse

Module 6

LECTURE 1: INTRODUCTION

In the process of energy management, at some stage, investment would be required for reducing the energy consumption of a process or utility. Investment would be required for modifications/retrofitting and for incorporating new technology. It would be prudent to adopt a systematic approach for merit rating of the different investment options vis-à-vis the anticipated savings.

It is essential to identify the benefits of the proposed measure with reference to not only energy savings but also other associated benefits such as increased productivity, improved product quality etc.

The cost involved in the proposed measure should be captured in totality by.

• Direct project cost
• Additional operations and maintenance cost
• Training of personnel on new technology etc.

Based on the above, the energy economics can be carried out by the energy management team. Energy manager has to identify how cost savings arising from energy management could be redeployed within his organization to the maximum effect. To do this, he 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
• Improving cost-effectiveness and/or profits
• Protecting under-funded core activities
• Enhancing the quality of service or customer care delivered
• Protecting the environment

Cash Flow Model

Cash Flow (CF) is the increase or decrease in the amount of money a business, institution, or individual has. In finance, the term is used to describe the amount of cash (currency) that is generated or consumed in a given time period. Cash flow calculations provide information on profitability, quality of earnings, liquidity, risks, capital requirements, future growth, dividends, etc. They are some of the most important tools for value investment analysis of investment opportunities.

Cash flows are classified as operating, investing, or financing activities on the statement of cash flows, depending on the nature of the transaction. Each of these three classifications is defined as follows.

 Operating activities include cash activities related to net income. For example, cash generated from the sale of goods (revenue) and cash paid for merchandise (expense) are operating activities because revenues and expenses are included in net income.

 Investing activities include cash activities related to noncurrent assets. Noncurrent assets include

(1) long-term investments
(2) property, plant, and equipment
(3) the principal amount of loans made to other entities.

For example, cash generated from the sale of land and cash paid for an investment in another company are included in this category. (Note that interest received from loans is included in operating activities.)

 Financing activities include cash activities related to noncurrent liabilities and owners' equity. Noncurrent liabilities and owners' equity items include

(1) The principal amount of long-term debt,
(2) Stock sales and repurchases, and
(3)Dividend payments. (Note that interest paid on long-term debt is included in operating activities.)

LECTURE 2: Time Value of Money

A project usually entails an investment for the initial cost of installation, called the capital cost, and a series of annual costs and/or cost savings (i.e. operating, energy, maintenance, etc.) throughout the life of the project. To assess project feasibility, all these present and future cash flows must be equated to a common basis. The problem with equating cash flows which occur at different times is that the value of money changes with time. The method by which these various cash flows are related is called discounting, or the present value concept.

For example, if money can be deposited in the bank at 10% interest, then a Rs.100 deposit will be worth Rs.110 in one year's time. Thus the Rs.110 in one year is a future value equivalent to the Rs.100 present value.

In the same manner, Rs.100 received one year from now is only worth Rs.90.91 in today's money (i.e. Rs.90.91 plus 10% interest equals Rs.100). Thus Rs.90.91 represents the present value of Rs.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:

Future Value (FV) = NPV $(1 + i)^n$ or NPV = FV / $(1+i)^n$

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

Evaluation of Proposals

Following four methods are usually used for the ***evaluation of capital investment proposals***:

1. The average rate of return method.
2. The payback period method (also known as cash payback period method).
3. The net present value method.
4. The internal rate of return method.

Method 1 and 2 are the methods that do not use the present values. Method 3 and 4 use the present values. So these methods for the evaluation of capital investment can be grouped into two categories:

Methods that Do Not Use Present Value		Methods that Use Present Value	
↓	↓	↓	↓
Average rate of return method.	Payback period method	net present value method	internal rate of return method

Methods That Ignore Present Value:

Methods that do not use the present value (average rate of return method and payback method) are easy to use. Management uses these methods initially to screen proposals. If a proposal meets the minimum standards set by management, it is subject to further analysis otherwise it is dropped from further consideration.

Methods That Use Present Value:

Methods that use present values (net present value method and internal rate of return method) in the capital investment analysis take into account the time value of money. The concept is that the money has value over time because it can be invested to earn interest income. A dollar in hand today is more valuable than a dollar to be received a year from today.

Example 1

If we invest Rs 5,000 today to earn a 10% interest per year, we will have Rs 5,500 after one year. Thus Rs 5,000 is the present value of Rs 5,500 to be received a year from today if the rate of interest is 10%.

This concept is further clarified by the calculation given by side:

Today, in hand	Rs 5,000
Rate of interest	10% p.a.
After 1 year	Rs 5,000 + (Rs 5,000 × 10/100) = Rs 5,500

Example 2

A new small cogeneration plant installation is expected to reduce a company's annual energy bill by Rs.4,86,000. If the capital cost of the new boiler installation is Rs.22,20,000 and the annual maintenance and operating costs are Rs. 42,000, the expected payback period for the project can be worked out as.

Solution

PB = 22,20,000 / (4,86,000 – 42,000) = 5.0 years

LECTURE 3: Simple Pay-Back Period

Simple Payback Period (SPP) is defined as the time (number of years) required to recovering the initial investment (First Cost), considering only the Net Annual Saving:

The payback period of a given investment or project is an important determinant of whether to undertake the position or project, as longer payback periods are typically not desirable for investment positions.

The payback period ignores the time value of money (TVM), unlike other methods of capital budgeting such as net present value (NPV), internal rate of return (IRR), and discounted cash flow.

The formula to calculate payback period of a project depends on whether the cash flow per period from the project is even or uneven. In case they are even, the formula to calculate payback period is:

$$\text{Payback Period} = \frac{\text{Initial investment}}{\text{Cash inflow per period or Annual net cost savings}}$$

Example 2: Even Cash Flows
Company C is planning to undertake a project requiring initial investment of $105 million. The project is expected to generate $25 million per year for 7 years. Calculate the payback period of the project.

Solution

Payback period=initial investment / Annual Cash flow = $105 M / $25 M = 4.2 Years

Example 3: Even Cash Flows

Project X costs $21 000 and will return a net cash inflow of $5 000 per period. What will the payback period be for this project?

Payback period=initial investment / Annual Cash flow = $21000/ $5000 = 4.2 Years

When cash inflows are uneven, we need to calculate the cumulative net cash flow for each period and then find payback period.

Example 4: Uneven Cash Flows

Project Y has an initial investment of $21 000 and will offer the following net cash inflows over the next 5 years.

Payback Period = initial investment / Net Cash Inflow

YEAR	NET CASH INFLOW	CUMULATIVE TOTAL
1	3000	3000
2	5000	8000
3	7000	15000
4	4000	19000
5	9000	28000

$21 000

Therefore, we know that it will take at least 4 years to pay the project back as the cumulative net cash inflow up to year 4 is $19 000.

That leaves us to calculate how many months it will take to get the extra $2000 from the $9 000 in Year 5.

9,000/12 = $750 per month. Thus it will take 3 months to reach $2 000. ie: $750 x 3 = $2 250 (OR $2000 / $750 = 2.666 months)

Example 5: Uneven Cash Flows

Company A have decided that they need to replace some of the machinery in their workshop. The new assets will cost $80,000. The estimated cash inflows over the next few years is listed here: find payback period?

YEAR	NET CASH INFLOW
1	15,000
2	16,000
3	10,000
4	11,000
5	16,000
6	16,000
7	19,000
8	21,000

Solution

On charting the cumulative total as shown in the figure below we know that it will take at least 5 years to pay the project back as the cumulative net cash inflow up to year 5 is $68 000.

YEAR	NET CASH INFLOW	CUMULATIVE TOTAL
1	15,000	15,000
2	16,000	31,000
3	10,000	41,000
4	11,000	52,000
5	16,000	68,000
6	16,000	84,000
7	19,000	1,03,000
8	21,000	1,24,000

$80,000

That leaves us to calculate how many months it will take to get the extra $12 000 from the $ 16 000 in Year 6.

16,000/12 = $1,333 per month. Thus it will take 9 months to reach $12 000.

ie: $1,333 x 9 = $12 200

Thus it will take 5 years and 9 months

Payback + Cost Savings

There are times when a business will look at implementing some new machinery in order to save costs and they have to decide whether it's worthwhile investing in it. There normally is a time period associated with these types of investment.

- **Example:** Raju is looking to get a new piece of machinery that will replace 5 workers who currently do the packing manually on the conveyer belt. The workers are each paid $40,000 a year and the new machinery costs $850,000. Raju has a rule that says the payback period must be 5 years of less.

Solution

- Payback Period = Initial Investment / Annual Net Cost Saving
- Payback Period = $850,000 / $200,000
- The payback period will be 4.25 years and thus would be accepted as it fits within the 5 year pattern.

Payback + Cost Savings+ Different Inflows

There are times when a business will look at implementing some new machinery in order to save costs but will also have an impact on their overall cash flows as well. There is normally a time period associated with these types of investment.

- **Example:** Raju is looking to get a new piece of machinery that will replace 5 workers who currently do the packing manually on the conveyer belt. The workers are each paid $40,000 a year and the new machinery costs $850,000. The business will have to pay additional insurance costs of $20,000 per year and repair and maintenance costs of $30,000. Raju has a rule that says the payback period must be 5 years of less.

Solution

- Payback Period = Initial Investment / Annual Net Cost Saving
- Payback Period = $850,000 / $150,000
- Savings = 200,000 - 30,000 - 20,000 = $150,000
- The payback period will be 5.66 years & thus would NOT be accepted as it fits within the 5 year criteria.

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 favours 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
- It ignores cash flows beyond the payback period.
- Does not consider profitability of economic life of project,
- Does not reflect all the relevant dimensions of profitability.

LECTURE 4: Average Rate of Return / Accounting Rate of Return (ARR)

The ARR is the percentage rate of return expected on an investment or asset as compared to the initial investment cost. ARR divides the average revenue from the asset by the initial investment to derive the ratio or return that can be expected over the lifetime of the project. ARR does not consider the time value of money or cash flows, which can be an integral part of maintaining a business.

It considers the earnings of the project of the economic life. This method is based on conventional accounting concepts. The rate of return is expressed as percentage of the earnings of the investment in a particular project. This method has been introduced to overcome the disadvantage of pay back period. The profits under this method is calculated as profit after depreciation and tax of the entire life of the project. The ARR method calculates the annual percentage return an investment provides for a business. Investment options can be compared using this method, with the investment returning the highest ARR chosen.

For example, if the ARR for Project A was 15% and for Project B was 20%, then Project B would be chosen because the ARR percentage is higher than Project A. It is known as accounting rate of return method for the reason that under this method the accounting concept of profit (net profit after tax and depreciation) is used rather than cash inflows.

The project with the higher rate of return than the minimum rate specified by the firm also known as cut off rate, is accepted and the other which gives a lower expected rate of return than the minimum rate is rejected.

Accept or Reject Criterion: Under the method, all project, having Accounting Rate of return higher than the minimum rate establishment by management will be considered and those having ARR less than the pre-determined rate will be rejected. This method ranks a Project as number one, if it has highest ARR, and lowest rank is assigned to the project with the lowest ARR.

Merits

- It is very simple to understand and use.
- It can readily be calculated by using the accounting data.
- This method takes into account saving over the entire economic life of the project. Therefore, it provides a better means of comparison of project than the pay back period.
- This method through the concept of "net earnings" ensures a compensation of expected profitability of the projects.

Demerits

- It ignores time value of money.
- It does not consider the length of life of the projects.
- It is not consistent with the firm's objective of maximizing the market value of shares.
- It ignores the fact that the profits earned can be reinvested.

This Method can be used in Several Ways such as:

- Return per unit of investment method
- Return on average investment method
- Average return on average investment method
- Average Rate of Return

1. Return per unit of investment method

This method is small variation of the average rate of return method. In this method the total profit after tax and depreciation is divided by the total investment, i.e.,

$$\text{Return per unit of investment} = \frac{\text{total profits (after dep. \& taxes)} \times 100}{\text{Net investment in the project}}$$

2. Return on average investment method

In this method the return on average investment is calculated. Using of average investment for the purpose of return on investment is preferred because the original investment is recovered over the life of the asset on account of depreciation charges.

Return on average investment$= \frac{\textit{Total profit after dep. and taxes}}{\textit{Average investment}} X\ 100$

3. Average return on average investment method

This is the most appropriate method of rate of return on investment. Under this method, average profit after depreciation and taxes is divided by the average amount of investment; thus:

$$\text{Avg. return on avg investment} = \frac{\text{average annual profit after dep. \& taxes}}{\text{Average Investment}} X\ 100$$

$$= \frac{\text{Average annual profit}}{\text{Net Investment} / 2} X\ 100$$

4. Average Rate of Return

The ARR method calculates the average annual percentage return an investment provides for a business. Investment options can be compared using this method, with the investment returning the highest ARR chosen. For example, if the ARR for Project A was 15% and for Project B was 20%, then Project B would be chosen because the ARR percentage is higher than Project A.

The technique used for calculating ARR is as follows:

- Divide the net profit generated by an investment by the number of years the project is expected to last (this is the average annual return)
- Divide the average annual return (your answer to 1.) by the initial outlay / cost of investment
- Multiply your answer by 100 to give the ARR as a percentage.

Under this method average profit after tax and depreciation is calculated and then it is divided by the total capital outlay or total investment in the project. In other words, it establishes the relationship between average annual profits to total investments.

$$\text{Average rate of return} = \frac{\text{total profits (after dep. Or taxes)}}{\text{Net investment in the project X No. of years of profit}}$$

$$= \frac{\text{Average Annual Profits}}{\text{Net Investment in the Project}} X\ 100$$

Example: Suzy owns a business manufacturing fragranced candles. Suzy is looking to expand her business and to do this she will need to buy some new machinery to help produce more fragranced candles. Suzy has searched online and found two machines that are suitable to help her achieve increased output. The cost of buying each machine and the annual estimated net profits are provided in the table below: find average rate of return of both the machines.

	Candle Wizard Cost £90 000	Wax Wonder Cost £110 000
Year 1 net profit	£20 000	£10 000
Year 2 net profit	£30 000	£20 000
Year 3 net profit	£40 000	£40 000
Year 4 net profit	£20 000	£60 000
Year 5 net profit	£20 000	£50 000
Total net profit	£130 000	£180 000

	Candle Wizard	Wax Wonder
Divide the total net profit by the number of years Annual average return	$\frac{£130\ 000}{5 \text{ years}}$ = £26 000	$\frac{£180\ 000}{5 \text{ years}}$ = £36 000
Divide the average annual return by the initial outlay / cost of investment	$\frac{£26\ 000}{£90\ 000}$ = 0.289 (3 d.p.)	$\frac{£36\ 000}{£110\ 000}$ = 0.327 (3 d.p.)
Multiply result by x 100 to give ARR %	28.9% (1 d.p.)	32.7% (1 d.p.)

LECTURE 5: Discounted cash flow methods

The payback method is a simple technique, which can easily be used to provide a quick evaluation of a proposal. However, it has a number of major weaknesses:

- ❑ The payback method does not consider savings that are accrued after the payback period has finished.
- ❑ The payback method does not consider the fact that money, which is invested, should accrue interest as time passes. In simple terms there is a 'time value' component to cash flows. Thus Rs.1000 today is more valuable than Rs.1000 in 10 years' time.

In order to overcome these weaknesses 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. The two most commonly used techniques are the 'net present value' and the 'internal rate of return' methods.

- **Net Present Value Method**

The net present value method considers the fact that a cash saving (often referred to 'cash flow') of Rs.1000 in year 1 of a project will be worth less than a cash flow of Rs.1000 in year 2. 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. If a company invested Rs.22, 20,000 in a bank with interest rate 8% annually, then the future value of this money after 5 years can be found out as following.

$$FV = D \times (1 + IR/100)^n$$

Where, FV- future value
D-Value of initial investment
IR- Interest rate
n- number of years

The future value of the investment made at present, after 5 years will be:

FV = 22,20,000 x (1 + 8/100)5 = Rs.32,61,908.4

So in 5 years the initial investment of 22,20,000 will accrue Rs.10,41,908.4 in interest and will be worth Rs.32,61,908.4. Alternatively, it could equally be said that Rs.32,61908.4 in 5 years time is worth Rs.22,20,000 now (assuming an annual interest rate of 8%).

In other words the present value of Rs.32,61,908.40 in 5 years time is Rs.22,00,000 now. The present value of an amount of money at any specified time in the future can be determined by the following equation.

$$PV = S \times (1 + IR/100)^{-n}$$

Where, PV- Present value
S-Value of cash flow in ‘n’ year times
IR- Interest rate
n- number of years

The net present value method calculates the present value of all the yearly cash flows (i.e. capital costs and net savings) incurred or accrued throughout the life of a project, and summates them. Costs are represented as a negative value and savings as a positive value. The sum of all the present values is known as the net present value (NPV). The higher the net present value, the more attractive the proposed project. The present value of a future cash flow can be determined using the equation above. 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.

$DF = (1 + IR/100)^{-n}$.

The product of a particular cash flow and the discount factor is the present value.

$PV = S \times DF$

Problem

Using the net present value analysis technique, let us evaluate the financial merits of the proposed projects shown in the Table below. Assume an annual discount rate of 8% for each project.

	Project 1	**Project 2**
Capital cost	30,000	30,000
Year	**Net Annul saving(Rs.)**	**Net Annul saving(Rs.)**
1	+6000	+6600
2	+6000	+6600
3	+6000	+6300
4	+6000	+6300
5	+6000	+6000
6	+6000	+6000
7	+6000	+5700
8	+6000	+5700
9	+6000	+5400
10	+6000	+5400
Total net saving at end of year 10	60,000	60,000

Solution

$DF = (1 + IR/100)^{-n}$.

Year	Discount Factor for 8% (a)	Project 1		Project 2	
		Net savings (Rs.) (b)	Present value (Rs.) (a x b)	Net savings (Rs.)	Present value (Rs.) (a x c) (c)
0	1.000	–30 000.00	–30 000.00	–30 000.00	–30 000.00
1	0.926	+6 000.00	+5 556.00	+6 600.00	+6 111.60
2	0.857	+6 000.00	+5 142.00	+6 600.00	+5 656.20
3	0.794	+6 000.00	+4 764.00	+6 300.00	+5 002.20
4	0.735	+6 000.00	+4 410.00	+6 300.00	+4 630.50
5	0.681	+6 000.00	+4 086.00	+6 000.00	+4 086.00
6	0.630	+6 000.00	+3 780.00	+6 000.00	+3 780.00
7	0.583	+6 000.00	+3 498.00	+5 700.00	+3323.10
8	0.540	+6 000.00	+3 240.00	+5 700.00	+3 078.00
9	0.500	+6 000.00	+3 000.00	+5 400.00	+2 700.00
10	0.463	+6 000.00	+2 778.00	+5 400.00	+2 500.20
		NPV = +10 254.00		**NPV = +10 867.80**	

It can be seen that over a 10 year life-span the *net present value* for Project 1 is Rs.10,254.00, while for Project 2 it is Rs.10,867.80. Therefore Project 2 is the preferential proposal. 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 uncertain ties in predicting future savings.

Advantages of net present value (NPV)

- It is considered to be conceptually superior to other methods.
- It does not ignore any period in the project life or any cash flows.
- It is mindful of the time value of money.
- It is easier to apply NPV than IRR(Internal rate of return).
- It prefers early cash flows compared to other methods.

Disadvantages of net present value (NPV)

- The NPV calculations unlike IRR method, expects the management to know the true cost of capital.
- NPV gives distorted comparisons between projects of unequal size or unequal economic life. In order to overcome this limitation, NPV is used with the profitability index.

Problem

It is proposed to install a heat recovery equipment in a factory. The capital cost of installing the equipment is Rs.20,000 and after 5 years its salvage value is Rs.1500. If the savings accrued by the heat recovery device are as shown below, we have to find out the net present value after 5 years. Discount rate is assumed to be 8%.

Data

Year	1	2	3	4	5
	7000	6000	6000	5000	5000

Solution

Year	Discount Factor for 8% (a)	Capital Investment (Rs.) (b)	Net Savings (Rs.) (c)	Present Value (Rs.) (a) x (b + c)
0	1,000	–20,000.00		–20,000.00
1	0.926		+7000.00	+6482.00
2	0.857		+6000.00	+5142.00
3	0.794		+6000.00	+4764.00
4	0.735		+6000.00	+3675.00
5	0.681	+1,500.00	+5000.00	+4426.50
				NPV = +4489.50

It is evident that over a 5-year life span the net present value of the project is Rs.4489.50. Had the salvage value of the equipment not been considered, the net present value of the project would have been only Rs.3468.00.

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.

$RV = S \times (1 + R/100)^{-n}$

Where RV is the real value of S realized in n years time. S is the value of cash flow in n years time and R is the 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.

$IF = (1 + R/100)^{-n}$

The product of a particular cash flow and inflation factor is the real value of the cash flow.

$RV = S \times IF$

Problem

Recalculate the net present value of the energy recovery scheme in above Example, assuming the discount rate remains at 8% and that the rate of inflation is 5%.

Solution

Because of inflation; Real interest rate = Discount rate – Rate of inflation Therefore Real interest rate = 8 – 5 = 3%

Year	Capital Investment (Rs.)	Net real Savings (Rs.)	Inflation Factor For 5%	Net real Savings (Rs.) (Considering Inflation)	Real Discount Factor For 3%	Present Value (Rs.)
0	–20,000.00		1.000	–20,000.00	1.000	–20,000.00
1		+7000.00	0.952	+6664.00	0.971	+6470.74
2		+6000.00	0.907	+5442.00	0.943	+5131.81
3		+6000.00	0.864	+5184.00	0.915	+4743.36
4		+5000.00	0.823	+4145.00	0.888	+3654.12
5	+1500.00	+5000.00	0.784	+5096.00	0.863	+4397.85
						NPV = +4397.88

The above example shows that when inflation is assumed to be 5%, the net present value of the project reduces from Rs.4489.50 to Rs.4397.88. This is to be expected, because general inflation will always erode the value of future 'profits' accrued by a project.

- **Internal rate of return Method**

In some situation if, the discount rate were reduced there would come a point when the net present value would become zero. The discount rate which achieves a net present value of zero is known as internal rate of return(IRR). Higher the internal rate the more attractive the project.

<u>Steps</u>

1. Find the discount rate and net present value at different rate of interest
2. Find one negative and positive NPV
3. Using below formula find internal rate of return

$$Internal\,rate\ of\ return = PDR + (NDR - PDR) * \frac{pos\ NPV}{pos\ NPV - neg\ NPV} * 100$$

Where,

- PDR- Discount rate which gives positive NPV
- NDR- Discount rate which gives negative NPV
- Pos NPV / neg NPV - value of +Ve and –Ve NPV

Problem

A proposed project requires an initial capital investment of Rs.20 000. The cash flows generated by the project are shown in the table Find out the internal rate of return for the project?

Year	Cash flow (Rs.)
0	–20,000.00
1	+6000.00
2	+5500.00
3	+5000.00
4	+4500.00
5	+4000.00
6	+4000.00

Solution

	Cash flow (Rs.) (Rs.)	8% discount rate		12% discount rate		16% discount rate	
		Discount factor	Present value (Rs.)	Discount factor	Present value	Discount factor (Rs.)	Present value
0	–20000	1.000	–20000	1.000	–20000	1.000	–20000
1	6000	0.926	5556	0.893	5358	0.862	5172
2	5500	0.857	4713.5	0.797	4383.5	0.743	4086.5
3	5000	0.794	3970	0.712	3560	0.641	3205
4	4500	0.735	3307.5	0.636	3862	0.552	2484
5	4000	0.681	2724	0.567	2268	0.476	1904
6	4000	0.630	2520	0.507	2028	0.410	1640
		NPV = 2791		NPV = 459.5		NPV = –1508.5	

It can clearly be seen that the discount rate which results in the net present value being zero lies somewhere between 12% and 16%. For 12% 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:

$$\text{Internal rate of return} = 0.12 + (0.16 - 0.12) \times \frac{459.5}{(459.5 - (-1508.5))} * 100$$

$$\text{Internal rate of return} = 0.12 + (0.16 - 0.12) \times \frac{459.5}{(459.5 + 1508.5)} * 100 = 12.93\%$$

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.

LECTURE 6: Life Cycle Costing

Life-cycle cost analysis is a process for evaluating the total economic worth of a usable project segment by analyzing initial costs and discounted future costs. Life cycle costing is a system that tracks and accumulates the actual costs and revenues attributable to cost object from its invention to its abandonment. Life cycle costing involves tracing cost and revenues on a product by product base over several calendar periods. Life cycle costing is defined as the **total cost** throughout its life including **planning**, **design**, **acquisition** & **support costs** & any **other costs directly attributable to owning / using the asset.**

Category of LCC Capital assets:
•Initial costs
•Operating costs
•Disposal costs

Why Use LCC?

1. Project Engineering wants to minimize capital costs as the only criteria,
2. Maintenance Engineering wants to minimize repair hours as the only criteria,
3. Production wants to maximize uptime hours as the only criteria,
4. Reliability Engineering wants to avoid failures as the only criteria,
5. Accounting wants to maximize project net present value as the only criteria, and
6. Shareholders want to increase stockholder wealth as the only criteria.

Characteristics of Life Cycle Costing:

a) Product life cycle costing involves tracing of costs and revenues of a product over several calendar periods throughout its life cycle.

b) Product life cycle costing traces research and design and development costs and total magnitude of these costs for each individual product and compared with product revenue.
c) Each phase of the product life-cycle poses different threats and opportunities that may require different strategic actions.
d) Product life cycle may be extended by finding new uses or users or by increasing the consumption of the present users.

Stages of Product Life Cycle Costing:

Following are the main stages of Product Life Cycle:

a. Market Research
b. Specification
c. Design
d. Prototype Manufacture:
e. Development:
f. Tooling
g. Manufacture
h. Selling
i. Distribution
j. Product support
k. Decommissioning

(i) Market Research: It will establish what product the customer wants, how much he is prepared to pay for it and how much he will buy.

(ii) Specification: It will give details such as required life, maximum permissible maintenance costs, manufacturing costs, required delivery date, expected performance of the product.

(iii) Design: Proper drawings and process schedules are to be defined.

(iv) Prototype Manufacture: From the drawings a small quantity of the product will be manufactured. These prototypes will be used to develop the product.

(v) Development: Testing and changing to meet requirements after the initial run. This period of testing and changing is development. When a product is made for the first time, it rarely meets the requirements of the specification and changes have to be made until it meets the requirements.

(vi) Tooling: Tooling up for production can mean building a production line, buying the necessary tools and equipment's requiring a very large initial investment.

(vii) Manufacture: The manufacture of a product involves the purchase of raw materials and components, the use of labour and manufacturing expenses to make the product

(xi) Decommissioning: When a manufacturing product comes to an end, the plant used to build the product must be sold or scrapped.

Benefits of Product Life Cycle Costing:

Following are the main benefits of product life cycle costing:

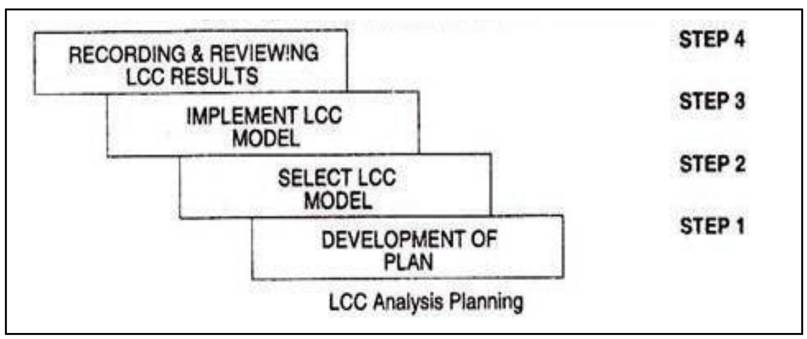
a. It results in earlier action to generate revenue or lower costs than otherwise might be considered. There are a number of factors that need to be managed in order to maximise return in a product.
b. Better decision should follow from a more accurate and realistic assessment of revenues and costs within a particular life cycle stage.
c. It can promote long term rewarding in contrast to short term rewarding.
d. It provides an overall framework for considering total incremental costs over the entire span of a product.

Life Cycle Costing Process:

Life cycle costing is a three-staged process. The first stage is life cost planning stage which includes planning LCC Analysis, Selecting and Developing LCC Model, applying LCC Model and finally recording and reviewing the LCC Results. The Second Stage is Life Cost Analysis Preparation Stage followed by third stage Implementation and Monitoring Life Cost Analysis.

Stage 1: LCC Analysis Planning:

The Life Cycle Costing process begins with development of a plan, which addresses the purpose, and scope of the analysis.



Stage 2: Life Cost Analysis Preparation:

The preparation of the Life Cost Analysis involves review and development of the LCC Model as a **"real-time"** or actual cost control mechanism. Estimates of capital costs will be replaced by the actual prices paid. Changes may also be required to the cost breakdown structure and cost elements to reflect the asset components to be monitored and the level of detail required.

Stage 3: Implementing and Monitoring:

Implementation of the Life Cost Analysis involves the continuous monitoring of the actual performance of an asset during its operation and maintenance to identify areas in which cost savings may be made and to provide feedback for future life cost planning activities.

For example, it may be better to replace an expensive building component with a more efficient solution prior to the end of its useful life than to continue with a poor initial decision.

Life Cycle Cost

LCC is the total discounted (present worth) cash flow for an investment with future costs during its economic life

LCC = K + R + M + EC - SV

Where:

K = capital cost (capital, labor, overhead)

R =Replacement cost $\{\Sigma K/(1+r)^n\}$ where r= interest rate

M= maintenance cost,

EC= energy cost

SV = Salvage Value (in year *t*)

Comparison of Alternative Energy Systems using Life Cycle Cost Analysis

Electricity is a major secondary energy carrier and is predominantly produced from fossil fuels. Challenging concerns of the fossil fuel based power generation are depletion of fossil fuels and global warming caused by greenhouse gases (GHG) from the combustion of fossil fuels. To achieve the goal of environmental sustainability in the power sector, a major action would be to reduce the high reliance on fossil fuels by resorting to the use of clean/renewable sources and efficient generation/use of electricity. In order to consider the long-term implications of power generation, a life cycle concept is adopted, which is a cradle-to- grave approach to analyze an energy system in its entire life cycle. Life cycle assessment (LCA) is an effective tool to pin point the environmental implications.

CASE STUDIES

LIFE CYCLE COST OF PV BASED PUMPING SYSTEM

Specifications

PV array rating= 500W

Pipe length=30 m

Well depth=10 m

Period of analysis= 15 m

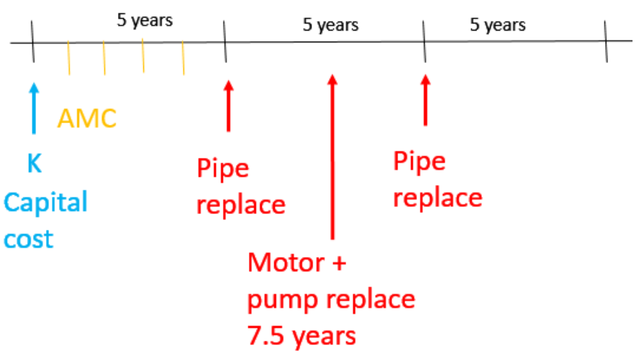
IR=10%

Annual maintenance charges (AMC) = Rs 1000 per year

- The costs are listed in the following table.

Item	Cost in Rs/KW	Life period
PV array + rest of the system	80	15years
Motor + pump	5	7.5 years
Misc.(tra nsport)	3	------
Pipe cost	100	5years
Cost of well	300 per meter	-------

➢ Draw the time line



Item	Cost in Rs/KW	Life period
PV array + rest of the system	80	15years
Motor + pump	5	7.5 years
Misc.(transport)	3	------
Pipe cost	100	5years
Cost of well	300 per meter	-------

Replacement Cost (R)

Motor + pump: $R_1 = 2500 \cdot \frac{1}{(1+i)^{7.5}} = Rs.\ 1223.2$

Pipes: $R_2 = \frac{3000}{(1+i)^5} + \frac{3000}{(1+i)^{10}}$

$= 1862.76 + 1156.63 = Rs.\ 3019.4$

$R = Rs.\ 4242.6$

Item	Cost in Rs/KW	Life period
PV array + rest of the system	80	15years
Motor + pump	5	7.5 years
Misc.(transport)	3	------
Pipe cost	100	5years
Cost of well	300 per meter	-------

Capital cost (K)

array cost = Rs. 80 × 500 W_p = Rs. 40,000/-
motor pump cost = Rs. 5 × 500 W_p = Rs. 2500/-
misc. cost = Rs. 3 × 500 W_p = Rs. 1500/-
pipe cost = Rs. 100 × 30 m = Rs. 3000/-
well cost = Rs. 300 × 10 m = Rs. 3000/-

K = Rs. 50,000/-

Maintenance Cost (M)

$M = AMC \cdot \left\{ \frac{1}{i}\left(1 - \frac{1}{(1+i)^n}\right)\right\} = 1000 \times 7.606 = Rs. 7606/-$

LCC = K + R + M

= 50,000 + 4242.6 + 7606 = Rs 61,848.67

LIFE CYCLE COST OF SOLAR THERMAL PLANT

The major components of this system to be considered in calculating life cycle cost are:

1. Heat energy Collectors
2. Boiler
3. Steam turbine
4. Electric generator

Item	Cost in Rs/KW	Life period
Heat energy collectors	25000	20years
Boiler+ steam turbine	13900	10years
Electric generator	5500	10years
Accessories, tools	1000	5years

The costs of the above mentioned components are listed in the table. Now let us say interest rate i=10% (analyze for 20 years) Then the life cycle cost per KW is calculated as follows:

Capital Cost per KW= Cost of (heat energy collectors + boiler + steam turbine + electric generator + accessories)

=25000+13900+5500+1000

=Rs.45400

$$\text{Replacement Cost} = \frac{13900}{(1+.1)^{10}} + \frac{5500}{(1+.1)^{10}} + \frac{1000}{(1+.1)^{5}} + \frac{1000}{(1+.1)^{10}} + \frac{1000}{(1+.1)^{15}}$$

= Rs.8725.4

Maintenance cost = 1% of total capital cost per year

= Rs. 3865.15

Therefore,

Life cycle cost per KW = 45400+8725.4+3865.15

=Rs.57990.55

LIFE CYCLE COST OF BIOMASS PLANT

The major components of Biogas plant are listed as follows.

1. Gassifier
2. Piping
3. Sand filter
4. Diesel engine
5. Electric Generator

Item	Cost in Rs.for 5KW plant	Life period
Biogas plant	127700	20years
Piping	8300	10years
Sand filter	4150	10years
7hp diesel engine	37700	15years
5KVA generator	78150	15years
Accessories, Tools	20750	10years
Engine room	16550	20years

The costs of different components of Biogas plant are specified in the table.

Now let us say interest rate i=10%

Then the life cycle cost is calculated as follows:

Capital Cost =127700+8300+4150+37700+78150+20750+16550

=Rs.293300

$$\text{Replacement Cost} = \frac{8300}{(1+.1)^{10}} + \frac{4150}{(1+.1)^{10}} + \frac{37700}{(1+.1)^{15}} + \frac{78150}{(1+.1)^{15}} + \frac{20750}{(1+.1)^{10}} = \text{Rs}40533.6$$

Maintenance cost = 1% 0f total capital cost per year = Rs. 24970.28

Therefore, Life cycle cost =293300+40533.6+24970.58 = Rs.358803.8

LIFE CYCLE COST OF WIND ENERGY SYSTEM

The major components of a wind energy system are:

1. Wind mill
2. Gear box
3. Controller
4. Wind turbine
5. Electric generator

The costs of the above mentioned components are listed in the following table.

Item	Cost in Rs per KW	Life period
Wind mill	25000	20years
Gearbox	2500	10years
Controller	2000	10years
Wind turbine	10500	15years
Electric generator	5500	15years
Accessories	1000	5years

Now let us say interest rate i=10%

Then the life cycle cost per KW is calculated as follows:

Capital Cost = 25000+2500+2000+10500+5500+1000 = Rs. 46500

= Rs.6811

$$\text{Replacement Cost} = \frac{2500}{(1+.1)^{10}} + \frac{2000}{(1+.1)^{10}} + \frac{10500}{(1+.1)^{15}} + \frac{5500}{(1+.1)^{15}} + \frac{1000}{(1+.1)^{5}} + \frac{1000}{(1+.1)^{10}} + \frac{1000}{(1+.1)^{15}}$$

Maintenance cost = 1% of total capital cost per year = Rs 3958.8

Therefore Life cycle cost per KW = 46500+6811+3958.8 = Rs57269.8

SOLAR PV SYSTEM

To calculate the life cycle cost per KWh the basic components of a PV system are considered as follows.

1. PV panels
2. Batteries
3. Inverters
4. Charge controllers

1	PV panel	Rs. 4 Lakhs/KW	25 Years
2	Inverter	Rs. 50000/KW	25 Years
3	Battery	Rs. 10000/KWh	5 Years

- Let us say i=10%

Capital Cost = 4Lakhs+ 50000+ 10000=Rs. 460000

$$\text{Replacement Cost} = \frac{10000}{(1+i)^5} + \frac{10000}{(1+i)^{10}} + \frac{10000}{(1+i)^{15}} + \frac{10000}{(1+i)^{20}}$$

= Rs. 13945/KWh

Maintenance Cost:As we are considering only from generating point of view maintenance cost is negligible part. Energy Cost: It does not require any external energy (because the system uses sun energy) to produce the electrical energy.