SECOND EDITION

Boiler Operation Engineering

Questions and Answers

P. Chattopadhyay

Boiler Operation Engineering

Questions and Answers

Second Edition

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To
my revered parents,
my beloved frau, Honey
& our son, Rahul

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Preface to the Second Edition

Thanks to the reviewer nominated by the editorial board of the POWER magazine (McGraw-Hill, Inc., NY 10011, USA) for reviewing the first edition of the book: *Boiler Operation Engineering: Questions and Answers*. Based on his valuable suggestions, I have incorporated a number of 'addendums' in this second edition of the book and the obsolete portions have been deleted.

The book has been expanded to accommodate six more chapters:

- **Upgrading PC-Fired Boilers**
- **Low NO_x Burners**
- **Emissions Control**
- **Cooling Water Treatment and Cooling Towers**
- **Reverse Osmosis**
- **NDE and Condition Monitoring**

There have been addendums to almost all chapters. The important ones are latest plant operation data, illustrations and photographs on Fluidized Bed Boilers, Fluidized Bed Boiler Design, Steam Turbines, Water Treatment and Demineralization, Ion-Exchange Resins, Cooling Tower Designs, LNBs, CASE STUDIES and many others.

Many new topics added in the APPENDIX such as Zero Liquid Discharge, NDT of Rotating Equipment, BFW Pump Availability, Boiler Refractories and their Installation, Control Valves and their Sizing, Steam Traps, Reverse Osmosis, Ion Exchange Resins Handling, Filling, Operation and Maintenance, Protection, and many others have expanded the scope of the relevant topics discussed in the mainframe text.

This edition will be very helpful to engineers and operator directly in charge of boilers, candidates appearing for first and second class Boiler Certificate Examination and Boiler Operation Engineering examinations, power plant personnel and students of power plant engineering.

Assistance, in any form from any corner, for the improvement of the book is most cordially welcome and will duly be appreciated.

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Preface to the First Edition

The production of steam and its utilization have undergone a radical change over the years as an outcome of the pioneering efforts of scientists and engineers in the field of fuel and combustion technology, boiler operation, and power generation.

Though there are many excellent texts dealing separately with these subjects, engineers and operators in charge of boiler operation may find it difficult to obtain a single book covering the various aspects of boiler operation technology. I hope this book will fulfil their requirements and also be advantageous to students undergoing courses in power plant engineering and fuel combustion technology.

The book is based on four interrelated disciplines in the production and utilization of steam:

- Water treatment and water conditioning
- Combustion of fuels and the physico-chemical principles involved
- Boilers and steam generation
- Utilization of steam for power generation

The subject matter is presented in a question-answer form. Real-life problems have been supplemented with study matter pertaining to the basic concepts, and numerical calculations, wherever necessary, have been incorporated for better understanding of the subject.

However, with the growing concept of efficient combustion of fuel, utilization of low calorie fuels, and better pollution control measures, the methods of production and utilization of steam are becoming more and more complex: the old ones phasing out to give way to the new. Therefore, in a sense the book is incomplete. And I will be grateful to those who will lend it completeness by giving constructive criticism and suggestions for further improvement of the book.

I sincerely acknowledge my indebtedness to Mr Debu Roy, my friend and colleague for checking the numerical calculations in the manuscript. I am grateful to my wife, Honey, for ferreting out a good many typographical mistakes and omissions from the typescript.

P CHATTOPADHYAY

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Nomenclature

AFS	Axial Flame Staged
AMP	Aminomethylene Phosphonate
Anex	Anion Exchange
AOFA	Advanced Over Fire Air
AS	Ammonium Sulphate
ASR	Axial Staged Return flow
ATM	Atmosphere
AVT	All Volatile Treatment
BBF	Biased Burner Firing
BCDMH	1-Bromo-3-Chloro-5, 5-dimethylhydantoin
BD	Blowdown
BFW	Boiler Feed Water
BOD	Biological Oxygen Demand
BOOS	Burner Out of Service
BPE	Boiling Point Elevation
BW	Boiler Water
BWR	Boiling Water Reactor
CA	Cellulose Acetate
CAA	Clean Air Act
CAAA	Clean Air Act Ammendments (of 1990)
Catex	Cation Exchange
CBD	Continuous Blow Down
CCR	Countercurrent Regeneration
CCSEM	Computer Controlled Scanning Electron Microscopy
CDI	Continuous Deionization
CF	Controlled Flow
CFR	Coflow Regeneration
CETF	Combustion & Environment Test Facility
CHF	Critical Heat Flux
COD	Chemical Oxygen Demand
c/o	Carryover
C/Over	Carryover
CS	Carbon Steel
CT	Cooling Tower
C/T	Cooling Tower
C/W	Cooling Water
CTA	Cellulose Triacetate
CTBD	Cooling Tower Blowdown
CVCS	Chemical & Volume Control System
DAF	Distributed Air Flow
DBMPA	Dibromo-nitrilo-propionamide
DEP	Department of Environmental Protection
DMH	Dimethylhydantoin
DMP	Demineralization Plant
DO	Dissolved Oxygen
DPT	Dew Point Temperature
EBD	Emergency Blowdown
E/C	Erosion / Corrosion
EDR	Electrodialysis Reversal
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FAC	Free Available Chlorine
FC	Fixed Carbon
FD	Flash Drum
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FMA	Free Mineral Acidity
FW	Feed Water
FWEC	Foster Wheeler Energy Corporation
GRT	Gamma Ray Tomography
GT	Gas Turbine
HE	Heat Exchanger

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HEDP	Hydroxy-ethylidine-diphosphonate
HPPAH	Heat Pipe Primary Air Heater
HRSG	Heat Recovery Steam Generator
ICGCC	Integrated Coal Gasification Combined Cycle
IEx	Ion Exchange
IFS	Internal Fuel Staged
i/l	in line
IRZ	Internal Recirculation Zone
ISSS	Integral Separator Startup System
LEA	Low Excess Air
LNB	Low NO_x Burner
LNO_x	Low NO_x
LRCA	Level Regulator Control & Alarm
L/up	Lined up
LWR	Light Water Reactor
MEH	Methylhydantoin
MOC	Materials of Construction
MSW	Municipal Solid Waste
ND	Natural Draft
NDE	Non-Destructive Examination
NDT	Non-Destructive Testing
Op	Operating
OEM	Original Equipment Manufacturer
OFA	Overfire Air
O & M	Operation & Maintenance
OSC	Off-Stoichiometric Combustion
OSHA	Occupational Safety & Health Act
OTU	Once Thru Unit
PA	Primary Air; Pulverizer Air
PAH	Primary Air Heater
PB/RF	Packed Bed / Reverse Flow
PBTC	Phosphono-Butane-Tricarboxylate
PC	Pulverized Coal
press.	Pressure
PSI	Practical (or Puckorius) Scaling Index
qty	Quantity
RAPH	Reduced Air Preheat
RF	Reverse Flow
RO	Reverse Osmosis
RO/MB	Reverse Osmosis & Mixed Bed in tandem
SAC	Strong Acid Cation Exchange Resin
SAS	Secondary Air Staging
SBA	Strong Base Anion Exchange Resin
SDI	Silt Density Index
s/d	Shutdown
SEMPC	Scanning Electron Mircoscopy Point Count
SF	Split Flame
SGP	Steam Generation Plant
SH	Superheated
SHMP	Sodium Hexa Meta Phosphate
SNCR	Selective Non-Catalytic Reduction
S-OFA	Standard Over Fire Air
SRV	Safety Relief Value
SS	Stainless Steel
ST	Steam Turbine
STS	Swirl Tertiary Staged
SV	Safety Value
TA	Turboalternator
TCS	Temperature Coefficient of Solubility
TD	Turndown
TDS	Total Dissolved Solids
temp.	Temperature
TG	Turbogenerator
THM	Trihalomethane
TLN	Tangential fired Low NO_x
TMA	Theoretical Mineral Acidity
TOC	Total Organic Carbon
TPS	Thermal Power Station
TSP	Trisodium Phosphate
TSS	Total Suspended Solids
UPS	Uniform Particle Size
VCE	Vapor Compression Evaporator
VM	Volatile Matter
VR	Velocity Recovery
WAC	Weak Acid Cation Exchange Resin
WBA	Weak Base Anion Exchange Resin
WSI	Water / Steam Injections
XAFS	X-ray Absorption & Fine Structure
ZLD	Zero Liquid Discharge

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1

BOILERS

Q. *What is a boiler?*

Ans. Broadly speaking, a boiler is a device used for generating, (a) **steam** for power generation, process use or heating purposes, and (b) **hot water** for heating purposes.

However, according to the Indian Boiler Act, 1923, a boiler is a closed pressure vessel with capacity exceeding 22.75 litres used for generating steam under pressure. It includes all the mountings fitted to such vessels which remain wholly or partly under pressure when steam is shut-off.

Q. *What is the difference between a steam boiler and a steam generator?*

Ans. Technically speaking, a steam boiler consists of the containing vessel and convection heating surfaces only, whereas a steam generator covers the whole unit, encompassing waterwall tubes, superheaters, air heaters and economizers.

Q. *How are boilers classified?*

Ans. Boilers are classified on the basis of:

1. Mode of circulation of working fluid
2. Type of fuel
3. Mode of firing
4. Nature of heat source
5. Nature of working fluid
6. Position of the furnace
7. Type of furnace
8. Boiler size
9. Materials of construction
10. Shape of tubes and their spatial position
11. Content of the tubes
12. Steam pressure
13. Specific purpose of utilization
14. General shape
15. Manufacturer's trade name
16. Special features.

Q. *What is circulation?*

Ans. It is the motion of the working fluid in the evaporating tubes. This motion is effected by head or pressure difference in the working fluid between the downcomer and uptake (riser) tubes.

The circulation may be natural or forced and the circulation circuit formed by the heated and unheated tubes may be a closed or open hydraulic system.

In natural (Fig. 1.1) and forced multiple circulation boilers (Fig. 1.2), the circulation circuit is a closed hydraulic system. While a once-through boiler represents an open-hydraulic system (Fig. 1.3). In combined-circulation (Fig. 1.4) boilers, the plant operates on closed hydraulic system at the start-up and is switched over to an open hydraulic system after attaining the specified load.

Q. *How are boilers classified on the basis of mode of circulation of working fluid?*

Ans. On the basis of mode of circulation of working fluid, boilers are classified into

1. Natural circulation boiler
2. Forced (i.e. positive) circulation boiler

Q. *What is natural circulation?*

Ans. The natural convection of water set up in the closed hydraulic system of heated and unheated tubes of the waterwall.

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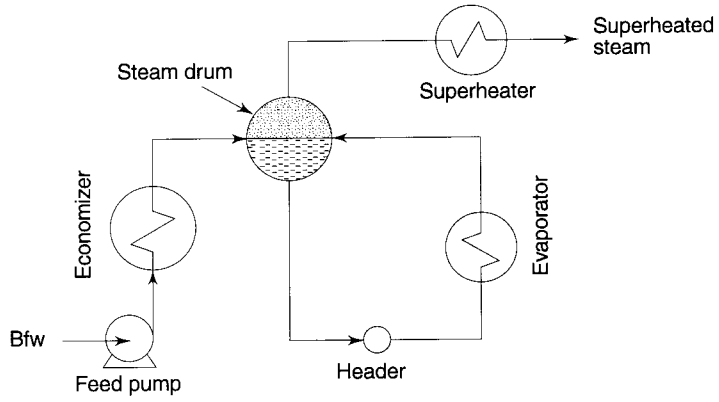

Fig. 1.1 *Natural circulation. It is a closed circuit in which the working fluid circulates by virtue of its density difference*

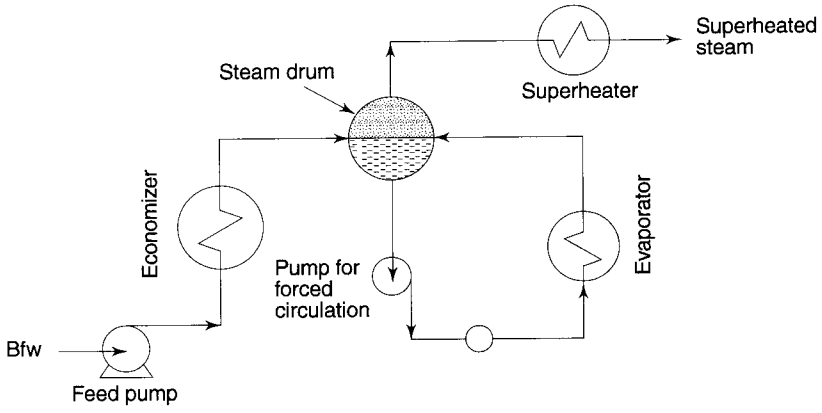

Fig. 1.2 *Multiple forced circulation. It is a closed hydraulic system in which the working fluid is circulated by forced circulation pump*

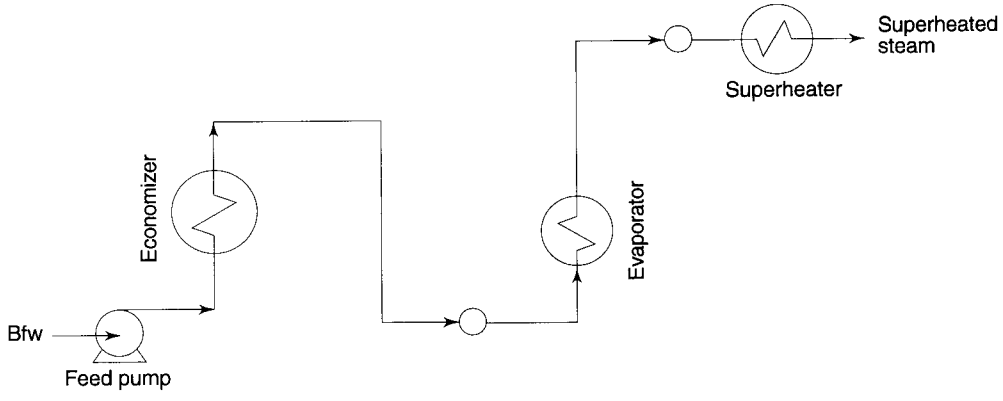

Fig. 1.3 *Open-hydraulic circuit. This system is adopted for once-through boilers*

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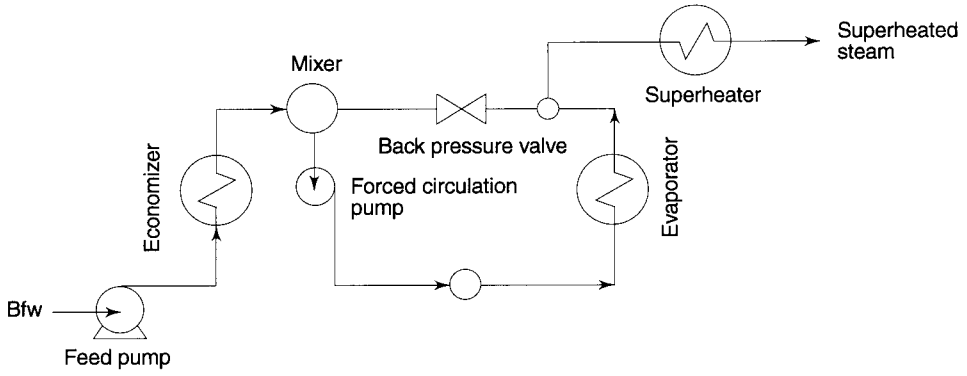

Fig. 1.4 *Combined circulation. It operates on closed hydraulic system at low load and open hydraulic systems beyond specified load*

Q. *How is natural circulation accomplished?*

Ans. The natural convection current is induced to water due to a difference in density resulting from difference in temperature.

The baffle separates out the heated riser from the unheated downcomer and therefore creates a temperature difference between the two tube systems.

Saturated water flows down the unheated downcomer and receives heat in the riser whereupon a part of it gets converted into steam. The difference in densities of saturated water in the downcomer and the steam-water mixer in the riser brings about natural circulation. (Fig. 1.5)

Q. *What is the limitation of natural circulation ?*

Ans. It is applicable to all subcritical boilers, i.e. all those which are operating at a pressure less than critical pressure.

Q. *What is forced circulation?*

Ans. If the working fluid is forced through the boiler circuits by an external pump, the ensuing circulation is called positive or forced circulation.

Q. *What are the advantages of forced circulation over natural circulation?*

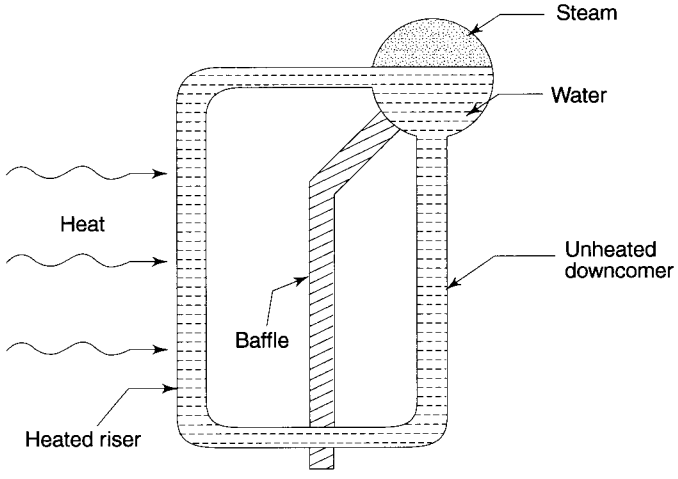

Fig. 1.5 *Natural circulation mechanism*

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Ans.

1. Steam generation rate is higher
2. Greater capacity to meet load variation
3. Quicker start-up quality from cold
4. Lower scaling problem due to high circulation velocity
5. More uniform heating of all parts reduces the danger of overheating and thermal stresses
6. Smaller tube diameter and hence lighter tubes
7. Greater freedom in arrangement of furnace, boiler component and tube layout
8. Operating temperature and pressure can be made to deviate from the designed values.

Q. *What is circulation ratio?*

Ans. It is the ratio of the mass flow rate of circulating water (G_{fw} *t/h*) to the rate of steam generation (G_s *t/h*)

$$k = G_{fw}/G_s$$

Q. *What is the value of circulation ratio for natural circulation?*

Ans. It usually ranges from 4 to 30.

Q. *What is the value of circulation ratio for forced circulation?*

Ans. It ranges from 3 to 10.

Q. *What is the value of circulation ratio for once-through steam boilers?*

Ans. Unity.

Q. *Why is the value of circulation ratio for once-through boilers unity?*

Ans. In such units, (Figs 1.6 and 1.7) the entire feed-water is continuously converted to steam as it passes through the evaporating surfaces, i.e.

$$G_{fw} = G_s$$

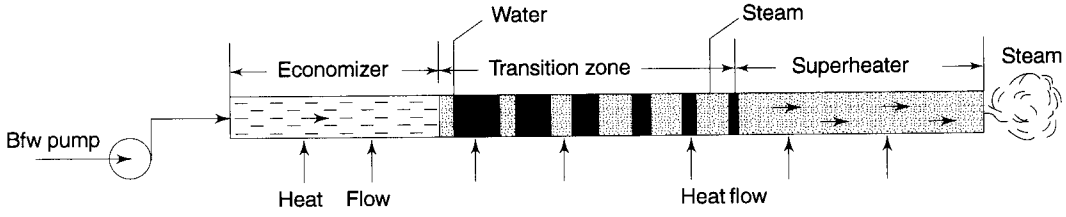

Fig. 1.6 *Transformation of BFW to steam in once-through boiler*

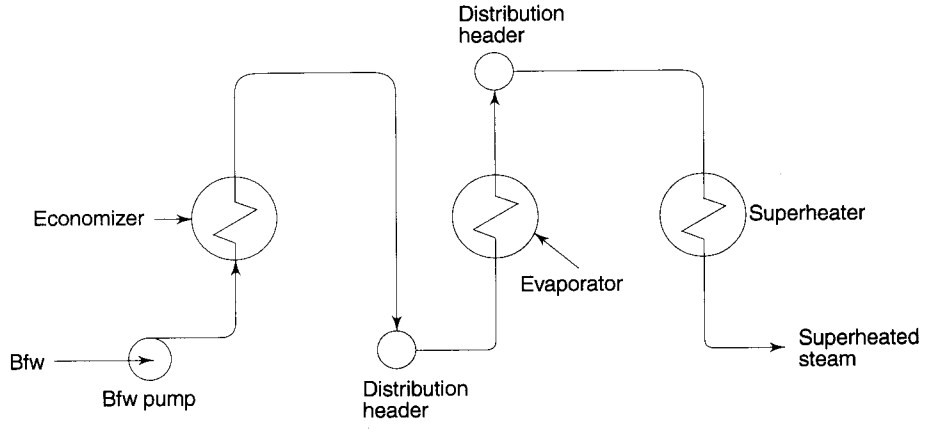

Fig. 1.7 *Once-through circuit*

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Q. *Can once-through boilers operate at subcritical as well as supercritical pressures?*

Ans. Yes.

Q. *What is the difference between a closed hydraulic system and an open hydraulic system?*

Ans. The former features a drum that acts both as a reservoir to provide working fluid circulation and separator to separate water from steam, while the latter has no drum and the working fluid passes through the evaporating tubes only once.

Q. *How can boilers be classified on the basis of tube shape and position?*

Ans. Depending on the form of tubular heating surface, boilers may be classified as

1. Straight tube boilers
2. Bent tube boilers.

Depending on the inclination of tubular heating surface, boilers may be classified as

1. Horizontal Boilers (Fig. 1.9)
2. Vertical Boilers (Fig. 1.8)
3. Inclined Boilers.

Q. *What is the difference between a horizontal boiler and a vertical boiler?*

Ans. The difference basically lies in the geometric position of the boilers.

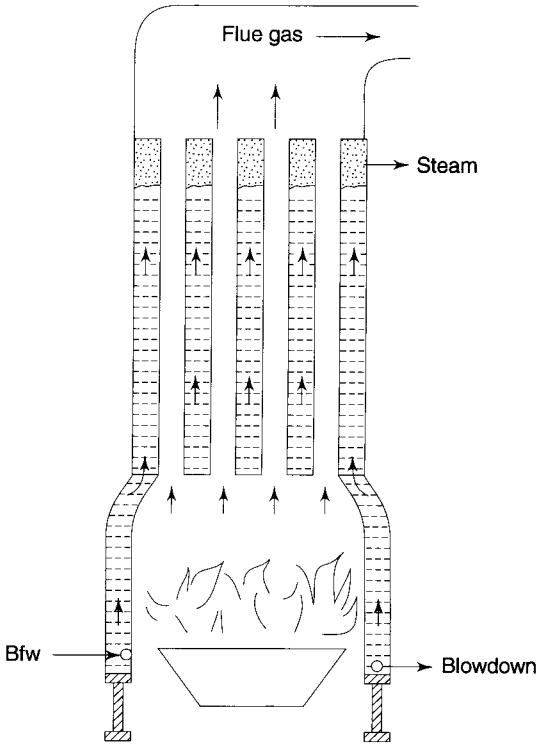

Fig. 1.8 *Vertical boiler*

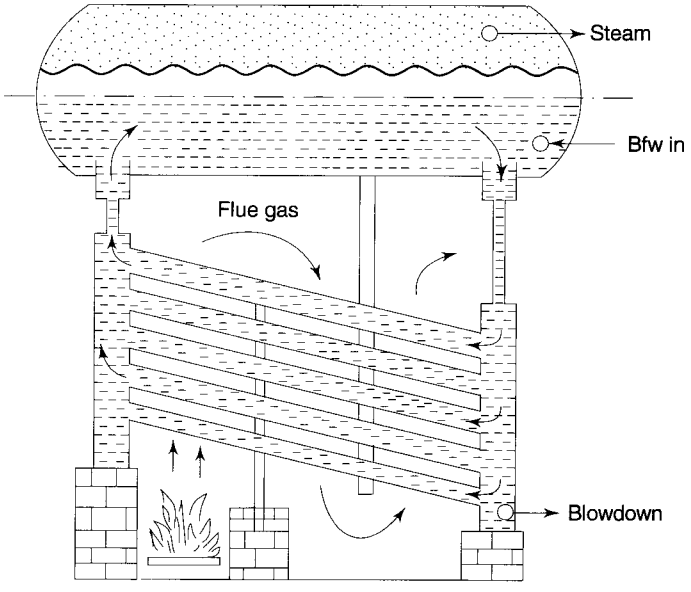

Fig. 1.9 *Horizontal boiler*

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A horizontal boiler has its principal axis horizontal or slightly inclined while that of a vertical boiler is perpendicular to the horizontal plane.

Q. *What is a single tube boiler?*

Ans. A boiler having only one firetube is called a single tube boiler. (CORNISH or simple vertical boiler).

Q. *What is a multitube boiler?*

Ans. A boiler having two or more fire or watertubes is called a multitube coiler.

Q. *How can boilers be classified on the basis of use?*

Ans. This is done on the basis of the nature of service they perform. Customarily boilers are called

(a) **stationary:** these are land based boilers.
(b) **mobile:** these are mounted on marine vessels and steam locomotives.

Q. *What is a stationary boiler?*

Ans. This boiler, as its name implies, is not required to be transported from one place to another.

Q. *What are mobile boilers?*

Ans. Locomotive and marine boilers, which are moved from place to place, are mobile boilers.

Q. *How may stationary boilers be classified further?*

Ans. They can be classified further depending on the specific service they meet:

1. Stationary boilers for central station (district) heating
2. Stationary boilers for process steam generation
3. Stationary boilers for power generation.

Stationary boilers used for heating are often classified as:

1. Residential boilers
2. Commercial boilers.

Q. *How can boilers be classified on the basis of furnace position?*

Ans. Depending on the relative location of the furnace to the boiler, the boiler classification can be made by:

1. Externally fired furnace
2. Internally fired furnace.

Q. *What is the difference between externally fired and internally fired boilers?*

Ans. In the case of externally fired boilers, the combustion of fuel takes place in a chamber outside the boiler shell while in the case of internally fired boilers, the combustion chamber is provided inside the boiler shell.

Q. *How can boilers be classified on the basis of tube contents?*

Ans. Depending on whether the flue gas or water is in the tube side, boilers can be classified as:

1. Firetube boilers
2. Watertube boilers.

Q. *Give some examples of firetube boilers.*

Ans.
1. Locomotive boiler (Fig. 1.10)
2. Cochran boiler
3. Cornish boiler.

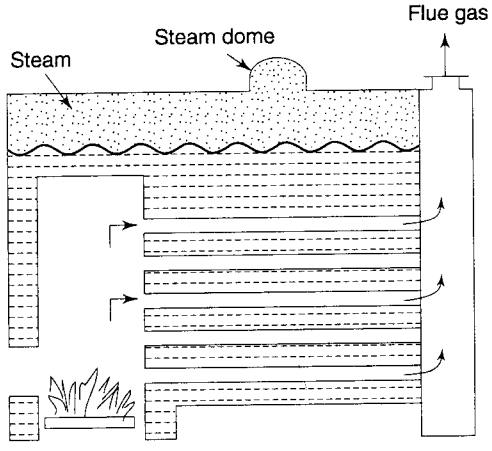

Fig. 1.10(a) *Locomotive boiler: gas flow circuit*

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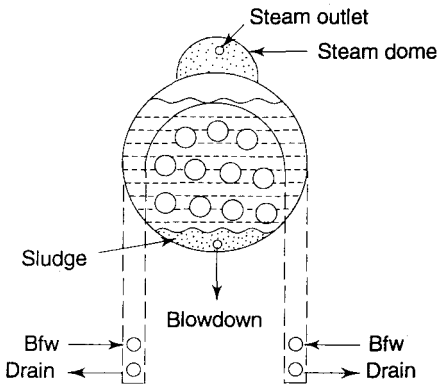

Fig. 1.10 (b) *Locomotive boiler: water circulating system*

These have hot flue gas in the tube side and BFW in the shell side.

Q. *Cite some examples of watertube boilers.*

Ans. 1. Babcock and Wilcox boiler
2. Stirling boiler
3. La Mont boiler
4. Yarrow boiler.

All these have BFW in the tube side and hot flue gas in the shell side.

Q. *What are the comparative advantages and disadvantages of firetube and watertube boilers?*

Ans.

Parameters	Firetube boilers	Watertube boilers
1. Rate of steam generation	Less rapid	More rapid
2. Suitability for power plants	Unsuitable	Suitable. All major power plants are based on these.
3. Operating steam pressure	Limited to 25 kgf/cm^2	Can well exceed 125 kgf/cm^2
4. Chances of explosion	Less	More
5. Risk of damage due to explosion	Much more	Much less
6. Water treatment	Not very necessary as minor scaling would not go far enough to cause overheating and tube-bursting	Required as scaling will lead to tube-bursting
7. Floor space requirement	Much	Less
8. Cost and construction problem	Higher	Much less
9. Transportation	Inconvenient due to large size of the shell	Comparatively easier
10. Skill required for efficient operation	Less	More

Q. *How many types of watertube boilers are there?*

Ans. Two. Straight tube and bent tube boilers.

Q. *On what grounds are bent tube boilers more favourable than straight tube boilers?*

Ans. 1. Bent tube boilers lend greater economy in fabrication and operation than straight tube boilers. These are due to the use of welding, improved quality steel, waterwall construction and new manufacturing techniques.
2. Bent tube boilers afford greater accessibility for inspection, cleaning and maintenance due to more spacious lay-out of tubes.
3. They have a higher steam generation rate than straight tube boilers
4. They produce drier steam than straight tube boilers.

Q. *What are the essential qualities of a good boiler?*

Ans. 1. It should be capable of quick start-up

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2. Should meet large load fluctuations
3. Occupy less floor space
4. Should afford easy maintenance and inspection
5. Should essentially possess the capacity of producing maximum steam with minimum fuel consumption
6. Light and simple in construction
7. Various joints should be accessible for inspection and should be away from direct flame impact
8. Tubes should be sufficiently strong to resist wear and corrosion
9. Mud and other deposits should not collect on heated plates
10. The velocity of water and that of flue gas should be a minimum.

Q. *What basic factors will you consider in selecting a boiler?*

Ans. 1. Power required to be generated
2. Operating pressure
3. Fuel-quality and type
4. Water availability and its quality
5. Probable load factor
6. Location of the power house or process plants
7. Cost of operation and maintenance
8. Cost of installation and erection
9. Availability of floor space.

Q. *How can boilers be classified on the basis of pressure?*

Ans. According to the American Society of Mechanical Engineers' "Boilers and Pressure Vessel Code" known as ASME Boiler Code, boilers may be differentiated as

1. **Low pressure boilers**—operating steam pressure not exceeding 1.021 atm* (103.427 kN/m^2) and operating pressures of hot water boiler not exceeding 10.893 atm* (1.10 MN/m^2) and temperature 394°K*.
2. **Power boilers**—all boilers with operating pressure and temperature exceeding those of LP boilers stated above
3. **Miniature boilers**—include all fired pressure vessel having the following parameters
   (a) ID of shell $\not>$ 406.4 mm*
   (b) Gross volume (casing and insulation included) $\not>$ 0.14158 m^{3*}
   (c) Water heating surface $\not>$ 1.858 m^{2*}
   (d) Allowable working pressure $\not>$ 6.8 atm (689.7 kN/m^{2*}).

(*Note* *refers to converted unit)

Q. *How can classification of boilers be effected on the basis of materials of construction?*

Ans. According to ASME Boiler Code Material Specifications
(a) Low Pressure Heating Boilers can be constructed of cast iron or steel
(b) Miniature Boilers may be constructed of copper, stainless steel, etc.
(c) Power Boilers are constructed of special steels.

Q. *How are boilers classified on the basis of size?*

Ans. Based on their size and rating, the Steel Boiler Institute (USA) has classified boilers into three categories:

Category (I): These are commercial boilers. Twenty two sizes have been standardized. Their:

Heating surface = 11.98 – 331.756 m^{2*}

Gross heat output = (45333 – 1260) kcal/s^{2*}

= (10827 – 300) kJ/s*

Category (II): These are residential boilers. Seventeen sizes.

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Heating Surface = 1.486–27.313 m^{2*}

Gross heat output = upto 126 kcal/s (30 kJ/s)*

Category (III): Oil fired boilers. Fourteen sizes. Gross heat output range is of up to 30 kJ/s*

For low-pressure cast-iron heating boilers, the Institute of Boiler and Radiator Manufacturers (USA), standardized cast-iron boilers into 33 sizes. Their steam generation rate is upto 3143.44 kg/h*.

(*Note* * refers to converted unit)

Q. *How may boilers be classified on the basis of firing?*

Ans. 1. **Fired boilers** in which supplied heat comes from the combustion of fuel.
2. **Non-fired boilers** receive heat other than that produced by the burning of fuel.

Q. *How can classification of boilers be done depending on the heat source?*

Ans. Depending on the nature of heat source, boilers can be classified into

1. **Fuel fired boiler**—these derive their heat energy by combustion of fuel which may be solid, liquid or gaseous.
2. **Waste heat boilers**—recover heat from the hot waste gases of other chemical reactions.
3. **Electrical powered boilers**—generate steam by the application of electrical energy.
4. **Nuclear powered boilers**—utilize the energy of controlled thermonuclear fission reactions to generate steam.

Q. *How can boilers be designated on the basis of the nature of fuel used?*

Ans. 1. **Coal fired**
   (a) Pulverized coal fired
   (b) Stoker fired
   (c) Hand fired
2. **Gas fired**
3. **Oil fired**
4. **Wood fired**
5. **Bagasse fired** (Fluidized bed bagasse fired furnace for boilers have recently been developed).

Q. *How can boilers be described in terms of the type of furnace?*

Ans. 1. Dutch oven boiler
2. Open boiler
3. Scotch boiler
4. Screened boiler
5. Twin boiler.

Q. *How is the general shape factor harnessed to classify a boiler?*

Ans. Depending on their shapes and design features, boilers can be classified as follows:

(A) Watertube boilers

1. Horizontal straight tube:
   (a) boxed header type
   (b) sectional header type
2. Bent tube boilers:
   (a) mono-drum type
   (b) bidrum type
   (c) tridrum type
   (d) quadridrum type.

If the drum is parallel to the tubes, it is called longitudinal *drum type boiler;* if across the tubes, it is called a *cross-drum type.*

(B) Firetube boilers

(a) short fire box type
(b) compact
(c) vertical tube type
(d) horizontal type
(e) locomotive
(f) Scotch type.

Q. *How can the boiler type be indicated by the manufacturer's trade name?*

Ans. Many a manufacturer applies his trade name to the particular type of boiler he designs, e.g.,

1. Benson boiler (Fig. 1.11)
2. Sulzer boiler (Fig. 1.12)
3. La Mont boiler (Fig. 1.13)

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4. Velox boiler
5. Loeffler boiler (Fig. 1.14)
6. Babcock boiler
7. Wilcox boiler
8. Yarrow boiler
9. Manning boiler
10. Thornycraft boiler

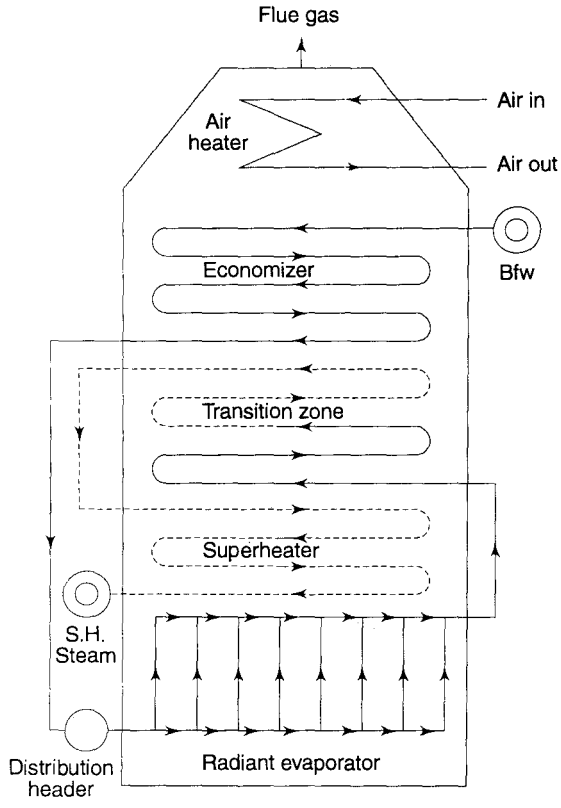

Fig. 1.11 *Benson Boiler*

Q. *Sometimes special features of boilers are used to classify them. How is this done?*

Ans. Depending upon the placement and firing operation of burners, boilers may be classified as:

(a) Differential fired type
(b) Tangential fired type.

Similarly there is the anthratube boiler, which is a completely self-contained anthracite burning unit.

Different variations exist, such as tube-in-tube boiler, top-fired boiler, and so on.

There are also:
(a) Dual circulation boiler,
(b) Boiler with gas recirculation
(c) Pressurized and supercharged boilers.

Q. *How are boilers generally categorized?*

Ans. They may be categorized into four general types:

1. **Steel boilers:**
   (a) Firetube type
   (b) Watertube type
   (c) Shell type
2. **Cast-iron boilers**
3. **Special design boilers**
4. **Nuclear powered boilers.**

Watertube boilers may be further subdivided into:

1. Horizontal straight tube type
2. Bent tube type:
   (a) Natural circulation type
   (b) Forced circulation type.

Q. *What are the inherent advantages of horizontal straight tube boilers if the tube sizes are small?*

Ans. 1. Tube replacement is easier
2. Draught (draft) loss is low
3. Better end-to-end visibility through tubes before and after cleaning
4. Greater accessibility to all components for inspection and cleaning
5. Low head room.

Q. *Smaller straight tube horizontal boilers are associated with certain disadvantages. What are they?*

Ans. 1. Access to internal components uses more time and labour. Inadequacy in design adds to the grievance of the operators

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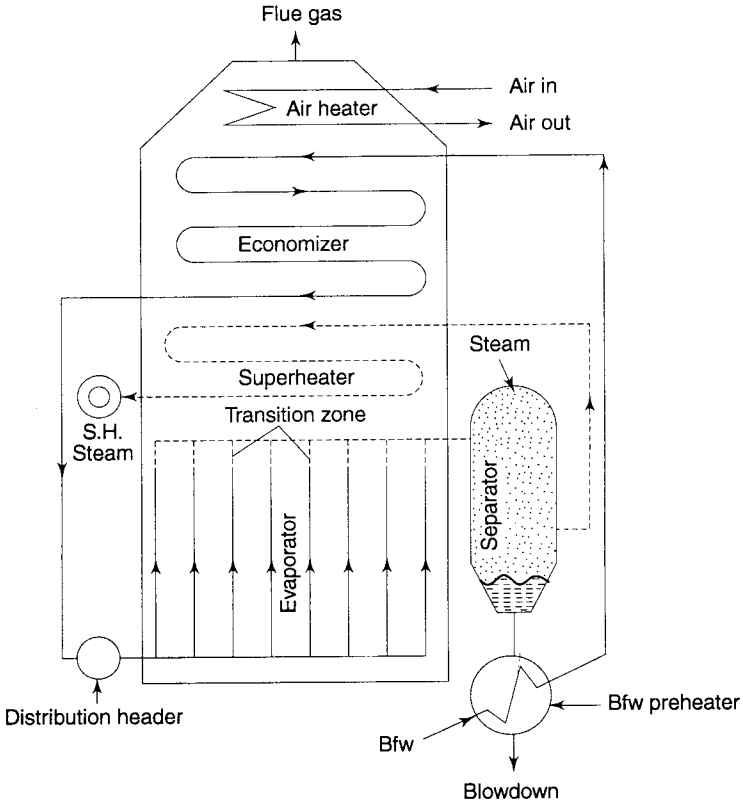

Fig. 1.12 *Sulzer boiler*

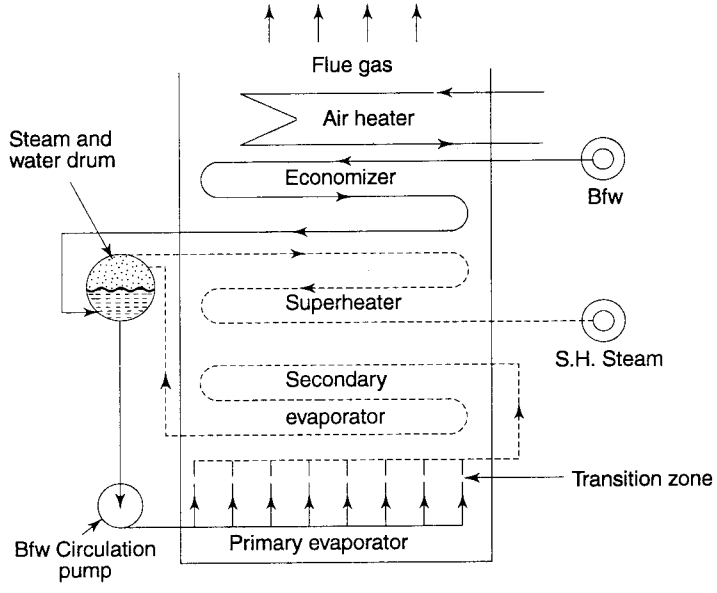

Fig. 1.13 *La Mont boiler*

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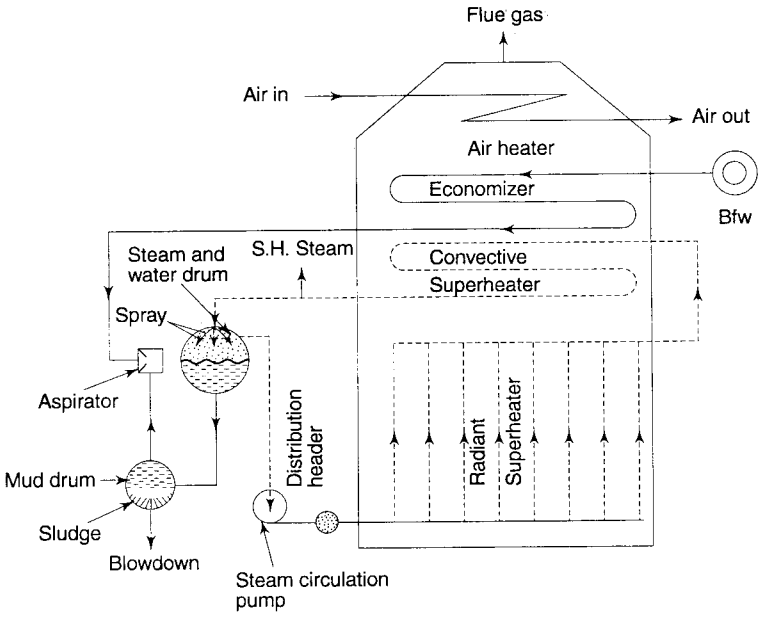

Fig. 1.14 *Loeffler Boiler*

2. Because of relatively low circulation rates and poor circulatory distribution, the steam generation rate is sharply impaired
3. If steaming rate is raised, the separation of steam from water in the steam drum becomes inadequate because a limited surface area is available for disengagement.

Q. *Briefly describe the horizontal straight tube boiler.*

Ans. These boilers are made up of banks of straight tubes laid out in a staggered arrangement at an angle 5° to 15° to the horizontal, which are expanded into headers at the ends. The tubes are 75–100 mm in diameter with length not exceeding 600 cm. Smaller diameter tubes are selected when greater tube spacing is required to meet steam demand at higher pressure. Providing flat surfaces for these tube connections, the header may be a box or sectional type connected to the drum by means of circulation tubes—downtakes and uptakes. The drum may be of the longitudinal or cross type.

These boilers may be oil, gas, coal, bagasse or wood fired. Pulverized coal, firing can also be incorporated.

When the boiler is fired, steam and water rise along the inclined tubes to the front headers and then pass to the drum through circulation tubes (uptakes). The water then circulates down through downtakes to the rear header and finally to the tubes to complete the cycle.

Q. *Why are the tubes, in horizontal straight tube boilers, inclined at an angle of 5 – 15° to the horizontal?*

Ans. To ensure better circulation.

Q. *Briefly describe a bent tube boiler.*

Ans. These are multidrum watertube boilers fitted with two, three or four drums, and usually having one lower drum called mud drum that serves as a blow-down for removal of sludge and concentrations of salts. The remaining drums placed at the top of the boiler are called steam and water drums.

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The tubes may be inclined or vertical, arranged in banks, or forming waterwalls backed with furnace wall refractories.

Baffles are placed in the gas path to ensure even heating of watertubes. The drums are protected from the radiant heat of fire.

The mode of steam-water circulation is as shown in Fig. 1.15.

The boilers lend themselves to a wide range of fuel burning. They can be fired with oil, gas, coal, bagasse or wood. For higher capacity of steam generation (45*t/h*) pulverized coal or crushed coal (cyclone furnace) firing is adopted.

Bent tube boilers have high stream generation rate and are quick to respond to fluctuating loads.

Q. *What are the advantages of bent tube boilers over straight tube boilers?*

Ans. 1. Steaming rate is higher
2. Deliver drier steam
3. More responsive to load fluctuations

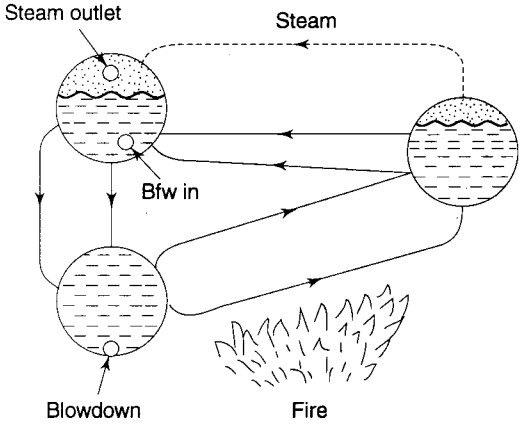

Fig. 1.15(a) *Inclined bent-tube boiler*

4. Lend greater economy in fabrication and operation
5. Afford greater accessibility for inspection, cleaning and maintenance
6. Greater design flexibility as the tubes enter the drum radially
7. The bent tubes allow free expansion and contraction
8. Boiler capacity can be increased without increasing the drum diameters.

Q. *Why do bent tube boilers have a quicker response to load fluctuation?*

Ans. They have very good evaporating flexibility because of the relatively small water volume for the steam generating capacity.

Q. *When are vertical tubes preferred to inclined tubes in designing bent tube boilers?*

Ans. This is given primary design consideration when bent tube boilers are fired with coal having low-melting ash or particularly abrasive ash.

Q. *What is a waste heat boiler?*

Ans. It is a special purpose boiler designed to generate steam by

(a) removing the generated heat, as called for, by the chemical processes involving exothermic reactions viz, the partial gasification of fuel oil; synthesis of ammonia $N_2 + 3H_2 \rightarrow 2NH_3 + 22$ kcal); oxidation

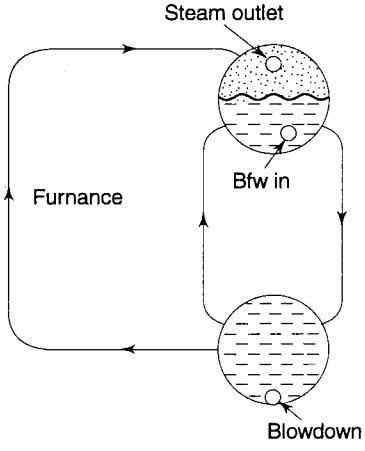

Fig. 1.15(b) *Vertical bent-tube boiler*

of sulphur dioxide to troxide ($2SO_2 + O_2 \rightarrow 2SO_3 + 45$ kcal); conversion of ammonia to nitric oxide ($4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O + 3O_2$ kcal)

(b) recovering heat that is
  (i) evolved as an integral part of the process and would otherwise go waste, such as from an open-hearth furnace

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(ii) a by-product of chemical process, e.g. black liquor recovery
(iii) made available by burning waste, e.g. wood scraps.

Q. *Does a waste heat boiler serve any purpose in addition to producing useful steam?*

Ans. 1. It reduces air and water pollution
2. It lowers the flue gas temperature, reducing the maintenance of flues, fans, and stacks.

Q. *How may waste heat boilers be classified?*

Ans. They can be classified as:
1. Watertube boiler
2. Gastube boiler
3. Bent tube boiler
4. Positive circulation boiler
5. Supercharged boiler
6. Three-drum-low-head boiler
7. Waterwall bidrum type boiler

Q. *Where are waste heat boilers generally employed?*

Ans.

Waste Heat Boiler Type	Application
1. Watertube	For clean or dust laden flue gas
2. Gastube	For relatively clean flue gases
3. Bent tube	Handles heavily dust laden gases
4. Positive circulation	For clean, low-temperature gases
5. Supercharged	Gas turbine exhaust
6. Three-drum-low-head boiler	Suitable for light dust loadings
7. Waterwall bidrum type	For gases with suspended sticky particles.

Q. *What should be the design considerations in the selection of a waste heat boiler?*

Ans. 1. Heat load and temperature of the gases available for waste heat recovery for steam generation
2. Chemical nature and corrosiveness of the gases
3. Available draught (draft)
4. Dust load and its nature in the gases
5. Whether the gases are under pressure or suction
6. Available space
7. Requirement for a start-up furnace, gas preheating emergency use or added capacity, etc.
8. Location for the outlet in the case of flue gases.

Q. *In case of lower gas temperature what modifications should be made in designing a waste heat boiler?*

Ans. This drawback is offset by
(a) providing high gas velocity
(b) reducing the diameter of the heat exchanger tubes
(c) increasing the number of such tubes to increase the magnitude of convective heat transfer.

Q. *What is the usual mass flowrate in the WHB (Waste Heat Boiler) of flue gases being discharged to the atmosphere after waste heat recovery?*

Ans. 29 000–39 000 kg/h. m^2.

Q. *In some cases a large quantum of dust particles is found laden in the waste gases available for steam generation. What problems are associated with dust load?*

Ans. Dust laden waste gases, if they contain abrasive dust particles, may cause severe damage to boiler tubes by erosion. Therefore, waste gases loaded with such particles require low gas velocities and that decreases the heat transfer rate in the WHB.

If the gases contain sticky or tacky particles they will deposit on heat transfer tubes, impair the heat exchange process and reduce the efficiency of the WHB.

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Q. *How can the dust load in waste gases be controlled?*

Ans. By
(a) installing dust collectors
(b) preventing by-passing of tubes with baffles
(c) providing abrupt change in the direction of gas flow path to settle dust
(d) minimizing bridging between tubes by adequate spacing.

Q. *What is a gastube WHB?*

Ans. Such boilers are shell-and-tube type boilers with hot gases flowing in the tube-side and BFW in the shell-side.

They are usually single-pass in arrangement and absorb only convection heat from the hot gases.

They have a high weight-to-heat output ratio.

They are usually found in applications for gas pressure 27-35 atm. and temperature up to 1255°K (982°C).

The external surface of the boiler is hot insulated.

The boiler tubes are of smaller diameter and more closely spaced than direct-fired waste heat boilers.

Soot blowers with nozzles directed towards the tube ends are used to clean the deposits.

Gastube boilers are used in the case of gases with light dust loadings, for obvious reasons.

Q. *How many types of gastube WHBs are there?*

Ans. Two types: Horizontal and Vertical.

Q. *Horizontal gastube waste heat boilers are set at an angle of 15° to the horizontal. Why?*

Ans. This is to
(a) ensure steam collection at the high point
(b) allow suspended solids in the water to settle down by gravity to the lowest point
(c) enhance circulation.

Q. *In which case is a vertical gastube WHB preferred to its horizontal counterpart?*

Ans. It is preferred when it is a prime necessity to save floor space.

Q. *A vertical gastube WHB with a shell diameter of 2.5 m is rarely found. What is the cause of such a limitation?*

Ans. This is due to limitations inherent in transportation and drum attachments.

Q. *Why are watertube boilers most frequently used for waste heat recovery?*

Ans. 1. They can work successfully at higher pressures
2. Since water is circulated in the tube-side which can be readily cleaned, watertube WHBs are not so susceptible to damage from poor feedwater quality
3. Better capacity to withstand the shock due to fluctuation of gas temperature
4. The furnace wall can be adequately cooled by applying water-wall tubes. This imparts a long life to the refractory lined WHB interior wall
5. The slagging and erosion problems can be minimized by varying the tube size and spacing.
6. Dust particles may be recovered
7. Lends itself to a more economic arrangement.

Q. *What are the primary considerations in designing a watertube WHB?*

Ans. The design considerations should primarily focus on two major problems. These are:
(a) problems due to sticky dust particles
(b) problems due to heavy dust loadings

The cooling and subsequent elimination of sticky particles is necessary before their entry into the convection shaft to the WHB, otherwise they will deposit on the external surfaces of watertubes and impair the heat transfer characteristics.

Hot gases heavily laden with dust particles may entail erosion problems for tubes as well as reduced heat transfer due to surface deposition of dust particles on watertubes.

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Q. *What are the reasons that led to the application of bent tube boilers for waste heat recovery?*

Ans. 1. These boilers can tolerate heavy dust loadings. The vertical tubes collect less dust
2. Greater flexibility in tube size, spacing and arrangement
3. Tube damage problem is minimised by more positive circulation
4. Allows pendant superheater installation
5. Less space is required for tube removal.

Q. *What is the chief advantage of a positive circulation waste heat boiler?*

Ans. The unit is more compact and light as extremely small diameter tubes (30–40 mm) are used, which can be arranged without regard to natural circulation requirements.

Q. *Name a positive circulation waste heat boiler.*

Ans. Positive circulation La Mont Waste Heat Boiler.

Q. *What are the applications of waste heat boilers?*

Ans. A waste heat boiler finds its application in:

1. **Steel mills**—use all types of small boilers:
   (a) horizontal and vertical gastube WHB
   (b) horizontal straight tubular WHB
   (c) bent watertube type boilers.

Waste heat boilers are fitted to open-hearth, forge and continuous heating furnaces.

Coke oven and blast furnace gases being heavily dust laden need special handling in the burner.

2. **Cement kilns**—need a WHB that must be specially designed to handle extremely dust laden gas. Hoppers are provided under the boiler and economizer to remove dust continuously.

As much as 20–40 tons of cement dust is recovered per day from a single kiln.

Two-drum and three-drum WHBs are particularly used.These are fitted with economizers, superheaters and soot blowers.

3. **Ore roaster**—A typical WHB for recovering waste heat from ore roasters is a three-drum, low-head boiler fitted with hoppers under the sections of gas path to collect gas-borne ore particles as they settle when the gases make low-velocity turns around the baffles.
4. **Lead and Zinc smelters**—These need a WHB capable of handling a gas whose temperature is as high as 1450-1480°K and which is laden with solids in a semimolten or sticky form. Usually a vertical watertube WHB is used, which must cool the gas down to 1000-1030° K in the radiant chamber to condense out the metal (Zn, Pb) vapour from the hot gas before its entry to the superheater and convection shaft.
5. **Paper making**—uses a WHB to
   (a) generate process steam by burning the waste liquor
   (b) recover the salt cake
   (c) eliminate stream pollution.

The waste liquor is dehydrated to produce char which is burnt in a large heap in a reducing atmosphere in the recovery furnace. The furnace temperature is as high as 1500-1530° K. Gas velocities are kept low to avoid fouling of the heat absorbing surfaces which comprise waterwall tubes laid on the refractory lined boiler furnace. The flue gases after passing through the economizer go through the evaporator to concentrate the black liquor.

Q. *How are marine boilers classified?*

Ans. 1. **Sectional header boiler**—either horizontal straight tube type or the sectional express type
2. **Drum type**—these are bent tube boilers having a double furnace or simple furnace
3. **Positive circulation boiler**
4. **Thermonuclear steam generator**

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Q. *How are marine boilers typified?*

Ans. Depending upon the specific usage of steam they produce, the marine boilers are divided into:

1. **Main boilers**—used for ship propulsion
2. **Auxiliary boilers**—used for running the auxiliary systems abroad the ship.

Q. *What are these auxiliary systems?*

Ans. 1. Turbogenerators for electric power generation
2. Water distillation
3. Fuel oil heating
4. Space heating
5. Cooking
6. BFW turbines

Q. *What factors must be considered in designing a marine boiler?*

Ans. 1. The boiler must be compact in size and minimum in weight
2. Maximum operating efficiency to be imparted by ensuring
   (a) proper combustion and its control
   (b) efficient heat recovery
   (c) adequate insulation
   (d) higher operating steam pressure and temperature.
3. Special design features must be effected to
   (a) outweigh the effect of the ships's rolling, pitching and vibration on steam generation
   (b) eliminate gas leakage in the fireroom
   (c) minimise heat loss to the fireroom
4. Operation reliability is to be attained by
   (a) correct designing and construction of boiler
   (b) proper installation of boiler unit, super-heater and auxiliaries
5. Simplicity in design and operation
6. Complete accessibility to boiler internals for inspection, cleaning and repairing must be ensured to minimize outage time
7. Flexible enough to maintain a constant steam temperature and pressure over a wide range of steam loads

   This necessitates:
   (a) large steam drum
   (b) large ratio of heat generating to contained water volume.
8. Fuel and its efficient utilisation.
   Pulverized coal is seldom used because of space limitation.
   Almost all oceanliners use oil fired boilers as
   (a) oil burns more cleanly than coal
   (b) oil leaves no ash
   (c) oil needs 55% of the storage capacity needed for coal
   (d) oil burning devices require less space.

Q. *What is called an 'M' boiler?*

Ans. Because of its shape, the double-furnace-single-uptake unit is referred to as an '*M*' boiler. It is fitted with a separately fired superheater and extended surface economizer.

Q. *What is the range of steam generation capacity of the 'M' boiler?*

Ans. 45 to 115 *t/h.*

Q. *What are the advantages of an 'M' boiler?*

Ans. 1. Close control over superheater temperature ensures greater efficiency
2. Generation of steam at almost any desired temperature and pressure condition can be effected at any load condition by varying the rate of combustion in the twin furnaces.
3. Desuperheater is not required
4. Requires less maintenance
5. Ensures good fuel economy at high efficiency under normal conditions
6. Compact. Less floor space is required.

Q. *What are the main drawbacks of an 'M' boiler?*

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Ans. 1. Unequal distribution of heating surfaces
2. Unbalanced combustion characteristics
3. Complicated in operation in earlier design
4. It is difficult to light off the superheater fire due to the high furnace pressure and this becomes particularly dangerous when the boiler load is considerable.
5. Since the saturated auxiliary steam is taken directly from the steam drum, under conditions of low evaporation rate the superheater may receive insufficient steam, causing superheater starvation.

Q. *What is a 'D' boiler?*

Ans. It is a single-furnace, single-uptake marine boiler having two drums. The water-cooled furnace is shaped in the form of a '*D*' and hence its name.

Q. *What are the advantages of a 'D' boiler over an 'M' boiler?*

Ans. 1. More compact and light for a given steam output
2. More reliable in operation
3. Higher steam generation efficiency
4. More economical at normal load
5. Operation is more simplified. Maintenance is much less and outage time is low
6. Superheated steam temperature can be better controlled by varying
   (a) the number of burners in line
   (b) feedwater temperature
   (c) the amount of excess air.

Q. *What are the disadvantages of a 'D' boiler?*

Ans. 1. Requires greater care during cold start-up
2. Efficiency goes down at higher steam generation rate.

Q. *Naval boilers have been found to install all tubes straight. What are its advantages?*

Ans. Straight tubes:
(a) lend themselves to greater ease of inspection, cleaning and replacement if necessary
(b) require a small number of spares.

Q. *What are the disadvantages associated with an all-tubes-straight installation?*

Ans. 1. It weakens the drum structure
2. It delimits the number of tubes that can be installed for a specified drum diameter and length.

Q. *Modern high pressure naval steam boilers are designed with all tubes bent to an arc of a circle. What are the advantages of this design?*

Ans. 1. Maximum number of tubes can be provided for a given drum length and diameter
2. Drilling holes for tube fitting on the drum is easy
3. Ease of fitting tubes to the drum.
4. Permits operation at higher boiler pressure.

Q. *The bent tube design has certain disadvantages. What are they?*

Ans. 1. Tube cleaning becomes more difficult and time consuming
2. Tube replacement is troublesome
3. Because of variation in length, size and curvature, a large number of spare tubes must always be kept ready.

Q. *What are the usual methods of installing tubes in marine boilers?*

Ans. 1. Straight tube design, known as Yarrow design. All tubes are straight
2. Foster design, in which all tubes are bent to an arc of a circle at their entry to the drum
3. Bent tube design, in which all tubes are bent at right angles to the drum surface at their entry to the drum.

Q. *What types of superheaters are generally used in marine boilers?*

Ans. Convective type superheaters.

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Q. *Why are radiant or radiant-convective superheaters not generally used in a marine boilers?*

Ans. Marine boilers have a low steam generation rate. At a low steaming rate, the radiant and radiant-convective types of superheaters will not operate satisfactorily.

Q. *A marine boiler's superheaters are plagued with excessive slagging requiring modification in superheater design to carry-out the deslagging operation. How does this problem arise, if almost all marine boilers are oil fired?*

Ans. As the fuel oil tanks, during the operation of the marine boiler, get gradually depleted, sea water is pumped into the tanks for ballast. As a result of this, the sea water salinity is imparted to the fuel oil whose sulphur and vanadium contents combine with sodium chloride during combustion to form slag which deposits on superheater tubes.

Q. *What constitutes the furnace wall of a marine boiler?*

Ans. It is constructed of a refractory wall cooled by waterwall tubes facing the furnace core. The refractory wall is backed up with insulating material and then a metal casing.

Q. *Is any draught (draft) installed in a marine boiler?*

Ans. Yes. Both forced and induced draught (draft) find their way into all marine boilers. Either F.D. or I.D. is used.

Q. *Which type of draught (draft) is more prevalent in marine boilers?*

Ans. Forced draught (draft).

Q. *Why is forced draught (draft) more prevalent in marine boilers?*

Ans. F.D. fans are smaller in size and hence fit comfortably in the limited space available for marine installation.

Q. *Why is I.D. less favoured in marine boilers?*

Ans. I.D. Fans occupy more vertical space, which is at a premium in marine installations.

Q. *In which cases are both forced and induced draughts (drafts) used in marine boilers?*

Ans. In cases of coal-fired marine boilers.

Q. *Why is the use of a desuperheater in marine boilers not favoured?*

Ans. To eliminate the complications in installation arising out of the fittings, valves and pipings are necessary.

Q. *Is any reheater installed in marine boiler units?*

Ans. Reheaters are rarely installed in marine boilers.

Q. *Why are reheaters installed rarely in marine boilers?*

Ans. 1. It adds to the weight and size of the boiler unit
2. It imparts operational complexities.

Q. *What are the primary advantages of steam reheating?*

Ans. When the reheat cycle is incorporated, the overall plant efficiency increases. The superheated steam may become wet after being expanded through turbine stages which tells upon the body of the turbine blades by eroding its surface and thereby reducing its power output. To avoid this problem, steam, after its partial expansion in the turbine, is reheated to superheated steam and is again delivered to the turbine.

Q. *When is it more economical to adopt a reheat cycle?*

Ans. Reheat cycle becomes more economical to generate high pressure superheated steam for its expansion in the turboalternator for the generation of electric power.

Q. *Why is H.P. steam favoured?*

Ans. H.P. steam possesses higher enthalpy content than MP or saturated steam and hence a higher quantum of heat drop, during expansion

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over turbine blades, is available from HP steam before it becomes wet.

Q. *What do you mean by utility boilers?*

Ans. These are boilers that burn coal, oil and natural gas to provide steam to generate electricity.

Q. *What are the primary design criteria for central station steam generators and auxiliaries?*

Ans. There are three main factors—efficiency, reliability and cost. At present, preference is given to equipment reliability to improve station availability.

Q. *The present day trend is to reduce the size of utility boilers, i.e., to limit the average size of the units between 300 and 400 MW or even 150 to 250 MW. Why?*

Ans. 1. These smaller sized units require less floor space. They can be fitted comfortably to the available space of existing utility central stations.
2. They require less erection time. A 300 MW unit will take about 6—12 months less erection time than a unit twice the size.
3. Economies of scale do not favour large units.
4. Financial risk is limited.

Q. *Why are supercritical once-through units preferred to subcritical drum-type units for large units—800 MW and above?*

Ans. For very large sizes (Fig. 1.16), the supercritical once-through units are more efficient (i.e. more fuel efficient) than subcritical drum-type boiler units, for the same amount of heat input. Hence supercritical boilers are favoured in those countries (viz. Japan) where the import fuel bill is high and efficient heat utilization overwhelms the higher construction cost of these units.

Q. *Why is the present trend to prefer once-through boilers to drum-type boilers for 500 MW and higher capacity monobloc power units?*

Ans. Monobloc units with drum-type boiler for large capacity (500 MW) power plants need a high-capacity, high-pressure boiler drum. These giant boiler drums (boiler drum of a 500 MW boiler unit may weigh as much as 200 ton) are considerably larger in dimension and have much thicker wall cross-sections.

The operating experience of these high-capacity, high-pressure drum-type boilers reveals that at varying operating modes (load conditions) in which the unit is shutdown and started up too frequently, non-uniform temperature fields appear in the wall cross-section, producing high thermal stresses that bring about cracks of corrosion fatigue in the boiler drum.

However, in once-through boilers there are no such heavy metal elements as the drum. They are much lighter in weight and can be shutdown and started up more rapidly. For these reasons, once-through boilers are recommended for units with the duty of supplying semi-peak and peak loads.

Q. *Why is the furnace of single-housing boilers for 300 MW monobloc powerplants made of prismatic (open) shape without constriction?*

Ans. The purpose is to bring down the average heating intensity of waterwalls in the flame core zone to a safe level.

Q. *Is this the only way to reduce the average heating intensity of waterwalls in the flame core zone to a safe level?*

Ans. No. Recirculation of combustion products drawn at relatively low temperature, i.e., from the convective gas duct (usually downstream of economizer) and reintroducing the same, with the aid of fan, into the furnace will decrease the heat absorption in the lower radiation zone and stabilize temperature conditions of waterwalls. Therefore, the average heating intensity of waterwalls in the flame core zone is reduced, whereupon the possibility of high-temperature corrosion is minimized.

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Q. *Of late, steam boilers with gas-tight enclosures are gaining ground. Why?*

Ans. 1. Gas tight waterwalls ensure a substantial increase in economic efficiency
2. It extends the reliability of the boiler units
3. Heat losses to waste gases are reduced as there is no air in-leakage in the furnace and the ducts
4. Low auxiliary power consumption in the supply of air and discharge of combustion products
5. Combustion under optimal conditions with least excess air ratio is possible. This eliminates low-temperature corrosion and fouling of heat-transfer surfaces
6. Heavy refractory lining is replaced by light heat insulation as a result of which
   (a) the mass of boiler structure and foundation is curtailed
   (b) loss of heat decreases
   (c) quicker start-up/shutdown.
7. Easier removal of slag and soot from the furnace by water without the risk of damaging the lining.

Q. *Why is the load-carrying boiler structure predominantly combined with the building structure in modern high-capacity boiler design?*

Ans. To achieve a considerable saving in metal. For example, such a design of an 800 MW monobloc unit (Fig. 1.16) results in the saving of 1500 ton of metal.

Q. *Briefly describe the boiler of a superthermal power station.*

Ans. One typical example is the TGMP-1202 boiler of suspended design (Russian) for a 1200 MW monobloc unit.

It is a supercharged boiler where the mass flowrate of working fluid flowing by single-pass mode in the furnace waterwalls is as high as 2000 kg/m^{2}s.

It is a gas and fuel oil fired supercritical pressure unit where the burners are laid out in two fronts and two tiers (see Fig. 1.17) and FO burners are used for startup.

The furnace carries membrane sections of unified width and has large depths so that flames do not lick the waterwalls which are of all-welded type. The reliability of the waterwalls is enhanced by providing the boiler with a water recirculating system which operates when the load is less than 40-50% of the designed load.

In the horizontal convective duct is laid a supercritical pressure superheater which combines platen sections and two convective stages.

Q. *Why are fluidized-bed boilers gaining ground for utility power and cogeneration industries?*

Ans.

1. ***Fuel flexibility***—A variety of solid fuels right from low cost solid fuels to conventional fossil fuels can be burned. Fuels burned include many types of coals, biomass, petroleum cokes and other wastes, viz. anthracite mining waste (culm), oil shale, spent shale, tar sands, coal slurries and agricultural wastes using a variety of limestone sorbents. This means flexible, reactive capabilities of fuel market fluctuation.
2. ***Lower installation cost***—Modular design allows for lower cost on-site installation. Also modular designs accommodate specific modifications without major redesign cost.
3. ***Low emissions***—NO_x production is minimum and they have the added capability of removing SO_2 from flue gas during combustion. These units are known to operate at the lowest emission profile obtained by solid fuel combustor low particulate emission.
4. ***High combustion efficiency***—Simple design and fuel flexibility allow users to

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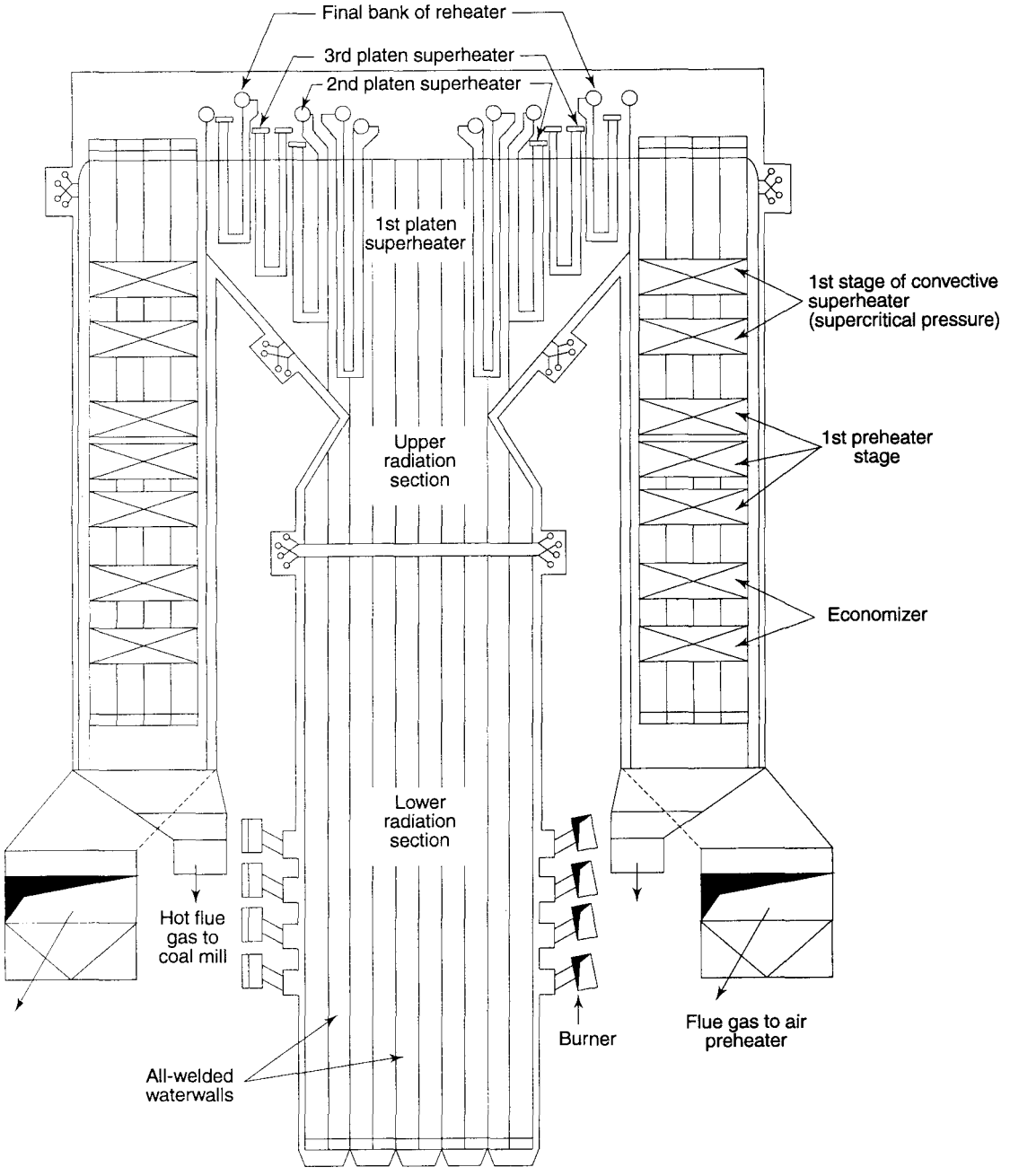

Fig. 1.16 *800 MW Monobloc Unit*
Steam generating cap. 2650 t/h
Steam temperature: 545°C/545°C
Steam pressure: 25.5 MN/m²
T-Shaped in layout, it has its boiler structure suspended from boiler room

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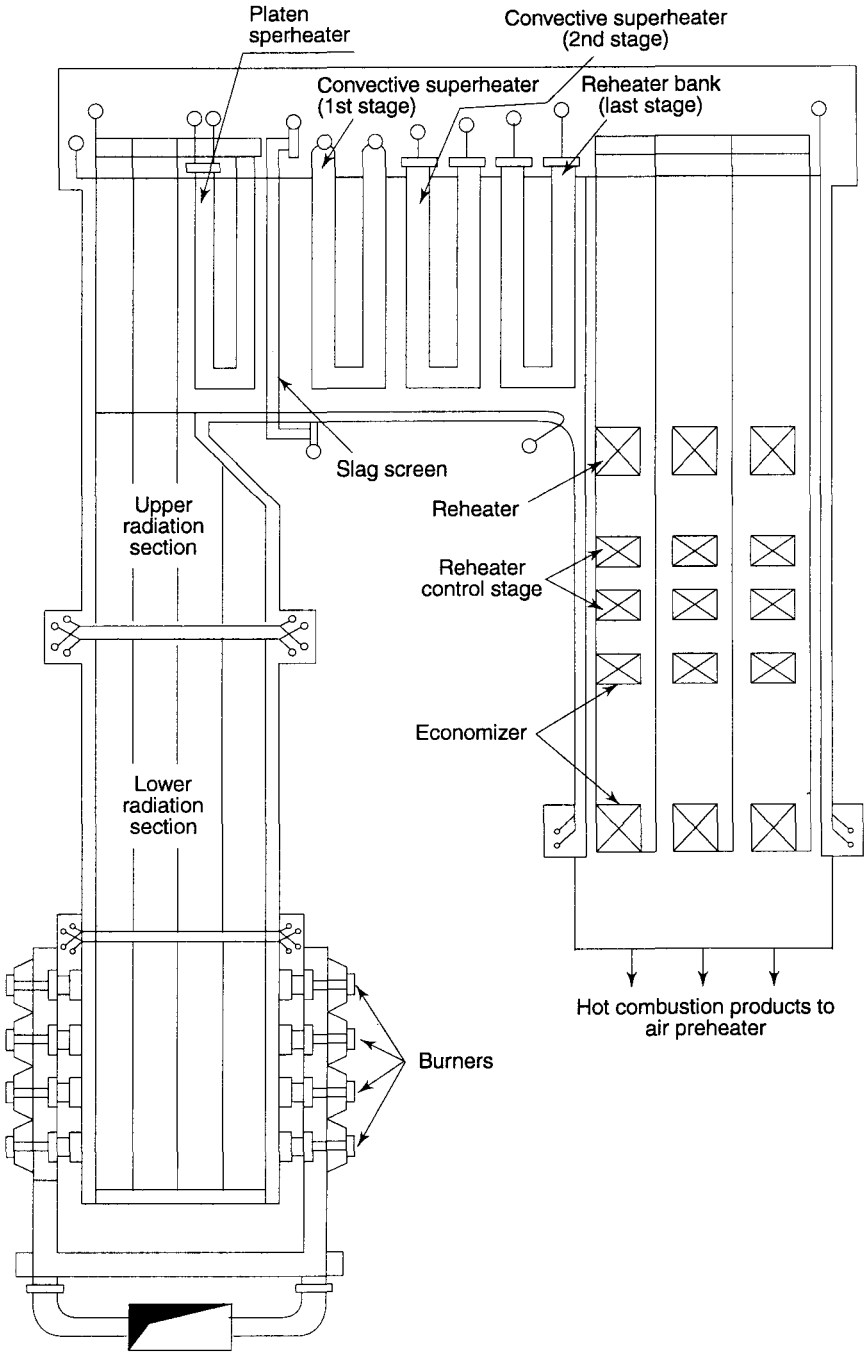

Fig. 1.17 *1200 MW Monobloc Unit TGMP-1202*
Gas and fuel oil fired boiler of suspended design generates 3950 ton/h of supercritical-pressure superheated steam

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achieve excellent combustion efficiencies, as high as 98%.

5. ***High availabilities***—in excess of 95% is possible.
6. ***High turndown ratio***
7. ***Combined cycle***—Pressurized Fluidized Bed (PFB) combustion technology affords highly efficient gas-turbine-based combine cycle
8. ***Minimum building volume***
9. ***Advanced control system***—Allows accurate control of temperature of combustion products in the furnace, minimizing NO_x production, particulate formation and complete combustion of fuels.
10. ***Burning hazardous wastes***—Fluidized bed combustion techniques are particularly useful for firing hazardous wastes. Their flexibility permits simultaneous combustion of solids, sludges, slurries and gases in the same unit. These units can attain higher destruction efficiencies at lower temperatures for a wider range of waste materials than most other thermal oxidation systems. Destruction efficiency as high as 99.99% has been reported for fuels containing organic hazards.
11. ***Cofiring***—With refuse derived fuel (RDF) as well as conventional pulverized coal, fuel oils and gas is possible. This is an added bonanza of fluidized combustion systems using low-cost fuels to meet higher load demands.
12. ***Low operating cost***
13. ***Short construction time***
14. ***Low cost of electricity***
15. ***Better ash quality***—Ash produced is non-toxic

Q. *What are the disadvantages of fluidized-bed boilers as compared to pulverized coal fired boilers?*

Ans.

1. The feed stream of solid fuels must be closely monitored and sized properly.
2. Combustion efficiency is usually poor at low loads.
3. When burning low grade fuels, particularly those containing salts, care must be taken to maintain accurate bed temperature over AFT. Otherwise the salts may melt at the bed temperatures or may produce eutectics in the bed causing bed seizure and loss of fluidization.
4. Inbed tube erosion is higher.
5. For utility units above 200 MW, any economy of scale disappears for bubbling-bed boilers owing to the fact that bed plan area requirements exceed the practical limits.

   CFB is handicapped by the same problem. It is height-limited as unit output increases due to the large amount of solids that must be circulated through the furnace. After this height-limit is reached, the designer must increase the bed plan area to accommodate greater heat-transfer surface requirements. And from a practical point of view this is not affordable.
6. Pulverized coal-fired conventional boilers register higher efficiency than fluidized-bed boilers of units above 200 MW. The efficiency gain is about $1\frac{1}{2}\%$.
7. P.C. fired boilers require at least half the limestone requirement of fluidized bed boilers for equivalent sulphur arrest.
8. The most nagging drawback with fluidized bed boilers is that they produce a substantial quantity of solid waste (ash) that must be safely disposed of. Some experts believe that the quantity is even greater than that form a conventional pulverized-coal-fired-boiler befitted with a wet limestone scrubber at equivalent conditions.

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Q. *Why is the quantity of ash produced by a FBC unit greater than a conventional pulverized-coal-fired boiler fitted with wet-limestone-scrubber at equivalent conditions?*

Ans. This is mainly due to the fact that whereas a wet scrubber can operate at a calcium-to-sulphur ratio close to 1.0, an FBC unit may require anywhere from 1.5 to 3.0.

Q. *How can fluidized-bed boilers be classified?*

Ans. All fluidized-bed boilers can be categorized into two main groups, depending on the mode of operation of the fluidized bed.

These are:

1. Atmospheric Fluidized Bed (AFB) boilers
2. Pressurized Fluidized Bed (PFB) boilers

Atmospheric Fluidized Bed boilers can be of two types:

1. Atmospheric Bubbling Bed boilers (Fig. 1.18)
2. Atmospheric Circulating-Bed boilers (CFB) (Fig. 1.19)

AFB boilers can be subdivided into

(a) Bubbling-Bed with inbed tubes
(b) Bubbling-Bed without inbed tubes
(c) Circulating-Fluidized-Bed with external heat exchangers
(d) Circulating-Fluidized-Bed without external heat exchangers.

A distinction can also be made on the basis of fluidizing velocity of air, which is the fundamental distinguishing feature of fluidized-bed-combustion units. (Fig. 1.20)

Bubbling-beds have lower fluidization velocities (1.2–3.6 m/s) so that particles do not escape from the bed (elutriation) into the convective passes. CFBs apply higher velocities (3.6-9 m/s) and in fact promote solids elutriation.

Q. *What are the principal attributes of atmospheric-fluidized-bed (AFB) units?*

Ans.

1. In a typical AFB combustion unit, solid, liquid or gaseous fuels (particularly coal plus solid waste fuels, viz. culm, municipal wastes, etc.), together with inert

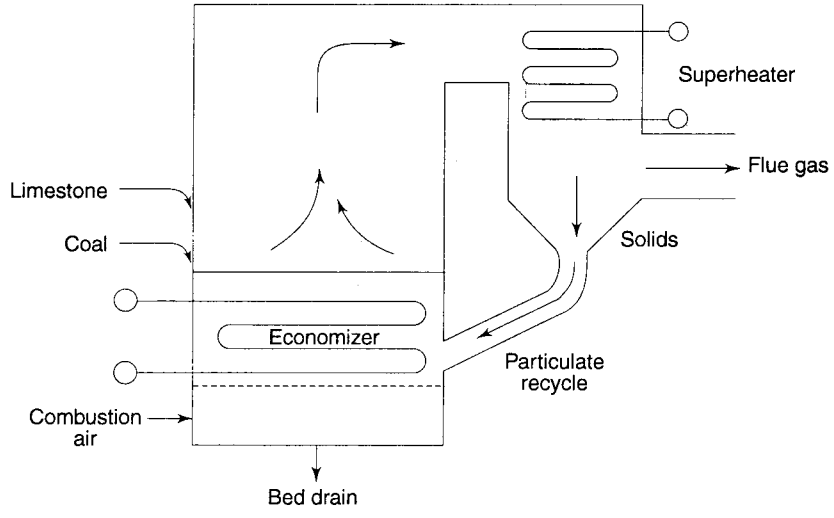

Fig. 1.18 *Bubbling-bed boiler. It has inbed evaporator tubes and superheater tubes in the convective shaft*

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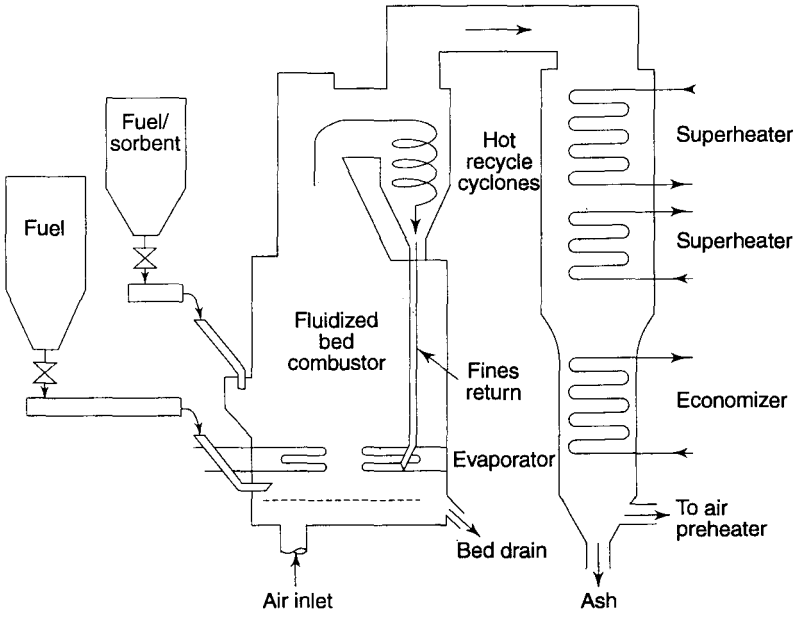

Fig. 1.19 *Circulating fluidized bed. Modular design for cost effective field installation and advanced emission control is possible*

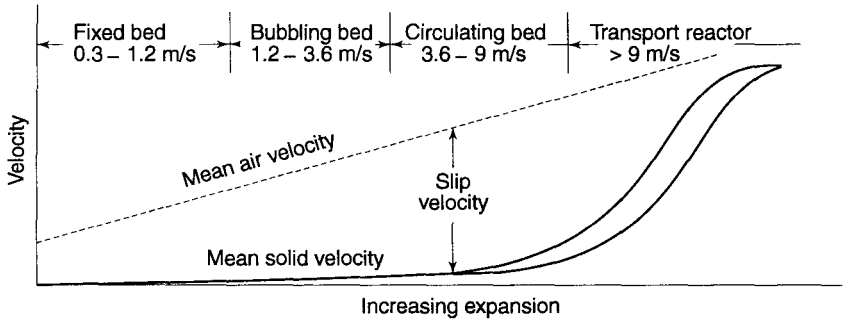

Fig. 1.20 *Fluidizing velocity of air is the fundamental distinguishing feature of fluidized bed combustion units. Bubbling beds have low air velocity while the CFBS have higher*

material—viz. silica, alumina or ash—and/or a sorbant such as limestone are kept suspended in the combustion chamber by primary air distributed below the combustor floor.

2. Turbulence is promoted by fluidization that turns the entire mass of solids into something like a liquid. Owing to improved mixing, heat is generated at a substantially lower and more uniformly distributed temperature—typically 810°–870°C than a stoker fired units or a pulverized coal fired boiler. Thus given the properly sized combustion chamber, the heat release rate will be at a level comparable to a conventional boiler, but at a

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lower temperature and theoretically without any loss of efficiency.

3. The operating temperature (810°–870°C) of an FBC unit is well below the formation of thermal NO_x
4. Staged combustion can be applied to minimize the formation of fuel-bound NO_x as well
5. The operating temperature range is such that the reactions of SO_2 with a suitable sorbent, commonly limestone, are thermally balanced
6. The fluidization mechanism leads to less volatilization of alkali compounds
7. Added turbulence minimizes the chances of a hot spot on the boiler and shell surfaces
8. Less sensitivity to quantity and nature of ash
9. Smaller furnace volume.

Q. *What is the layout of evaporator tubes in AFB units?*

Ans. The evaporator tubes serve as a suitable heat sink in the combustion area to control temperature. They are laid out in the traditional pattern of waterwall enclosures. There may be different designs as, for instance, where the boiler tubes are located within the bed itself.

Q. *Does this mean that only the watertube design is possible?*

Ans. No; both watertube and firetube designs are possible. Firetube boilers are more popular for larger sizes.

Q. *How is steaming rate controlled in AFB units?*

Ans. This is effected by manipulating the primary bed parameters, i.e.

(a) bed height
(b) bed temperature
(c) inventory

plus controlling the superficial gas velocity. Indeed the manipulation of gas velocity accomplishes most of the control.

Q. *Why are the bubbling fluidized bed boilers so called?*

Ans. The combustors of such boilers are provided with a grid upon which is supported a dense bed of fuel and limestone. The bed is maintained in a fluid-like state by air blown up through the grid and the bed from the bottom of gridholes. As the air flows upwards it mixes the limestone and fuel and at the same time keeps the bed in suspension. The action of air creates extreme turbulence in the bed material and produces the effect of a bubbling fluid.

Q. *Can't bubbling fluidized bed boilers be made amenable to limited load fluctuation?*

Ans. Yes; limited load fluctuation can be made possible.

Q. *How can bubbling fluidized bed boilers be made amenable to limited load fluctuation?*

Ans. By lessening the amount of air passing through the bed.

Q. *Why?*

Ans. This lowers the bed depth and retards combustion.

Q. *What is bed-slumping?*

Ans. Reducing bed depth is sometimes called bedslumping.

Q. *Why must the velocity of air through the bed be kept always above the minimum fluidizing velocity?*

Ans. To avoid incomplete combustion which results in smoking. If the velocity of air through the bed is below the minimum fluidizing velocity, it will affect the removal of sulphur dioxide.

Q. *How many types of bubbling-bed boilers are there?*

Ans. Two:

(a) single-stage bubbling-bed units
(b) two-stage bubbling-bed units

Q. *What is the concept behind two-stage bubbling-bed units?*

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Ans. The basic idea is to separate the combustion process from the absorption process so that each can be optimized without the design compromises inherent in the single-bed unit. For instance, a higher combustion temperature can be attained in a lower bed since absorption is no longer a limiting factor.

Q. *What is the world's largest bubbling-bed boiler?*

Ans. It is the 160 MW bubbling-bed boiler of Tennessee Valley Authority. Till date (1989) it is the largest AFB bubbling-bed unit.

Q. *What are the important features of this largest bubbling-bed unit?*

Ans.

1. It supports a single-level bed divided into 12 compartments
2. It has under-bed feed system
3. Its primary superheater and evaporator are fitted in the bed
4. Its finishing superheater and reheater are fitted in a split convection pass
5. Main-steam temperature control by spray water
6. Reheat-steam temperature control by gas-flow dampers

Q. *What is the world's largest circulating fluidized bed (CFB) unit?*

Ans. It is the 150 MW unit of the Texas-New Mexico Power Company.

Q. *What is the fuel of this largest circulating fluidized bed unit?*

Ans. Texas lignite

Q. *What are the important features of this largest circulating fluidized bed unit?*

Ans.

1. Dense-phase fuel injection in the combustor
2. Single combustor system fitted with water-cooled walls, grate and plenum
3. Four refractory-lined cyclones for recirculation of unburnt fuel
4. Two numbers of external fluidized-bed heat exchangers (FBHE) each with watercooled walls
5. One FBHE sports a superheater and evaporator while the other has one reheater and superheater

Q. *What are the advantages of CFB units over bubbling-bed systems?*

Ans.

1. Larger residence time of fuel that enhances combustion efficiency
2. Greater amount of absorption of SO_2 and other acid gases because of longer residence time
3. Use can be made of less-prepared fuel and sorbent
4. Free from many problems associated with underbed and/or overbed feeding of the fuel as encountered in bubbling-bed combustion system.

Q. *What is the common disadvantage of a CFB unit?*

Ans. Higher electricity bill because of greater fan power is required to maintain the higher velocity through bed.

Q. *What is PFBC?*

Ans. It means Pressurized Fluidized Bed Combustion

Q. *What are the two key features that distinguish PFBC units from AFB units?*

Ans.

1. Combustion takes place at pressures higher than the atmospheric
2. It couples two cycles—conventional steam turbine cycle with the gas-turbine cycle.

Q. *How does PFBC work?*

Ans. Fluidized bed combustion takes place at elevated pressures.

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It incorporates a gas turbine that drives an air compressor which supplies combustion air at high pressure to the fluidized bed combustor. The resulting flue gas, also at high pressure, is cleaned of suspended solids and directed to drive the gas turbine. (Fig. 1.21)

Evaporator tubes laid out in the fluidized-bed-combustor abstract the heat generated, producing steam which drives a steam turbine to produce 80% of the units' power.

Q. *What is the paramount advantage of a PFBC unit over conventional and atmospheric fluidized-bed boilers?*

Ans. PFBC units offer higher efficiency than conventional and AFB units.

Q. *What is the operational efficiency of a PFBC unit?*

Ans. PFBC can operate at 40–42% efficiency.

The designed efficiency of the 80 MW PFBC unit of the Tidd Power Station, USA is 40%. Another 320 MW PFBC unit with 42% efficiency is planned. Other commercial units that will come to life in future will have still greater efficiencies.

Q. *Show that the combined cycle efficiency of PFBC is always greater than the equivalent steam cycle plant efficiency.*

Ans. PFBC system operates with steam and gas turbines in tandem. Since some portion of the input energy is extracted by the GT at a higher temperature than that recovered by the ST, the overall efficiency of the combined cycle is about 40–41% compared to about 38% for a basic steam cycle.

Consider the simplified diagram of supercharged PFBC system (Fig. 1.22).

Overall energy balance yields

$$Q_i = Q_s + x \cdot \eta_{GT} \cdot Q_i + Q_o \qquad (1)$$

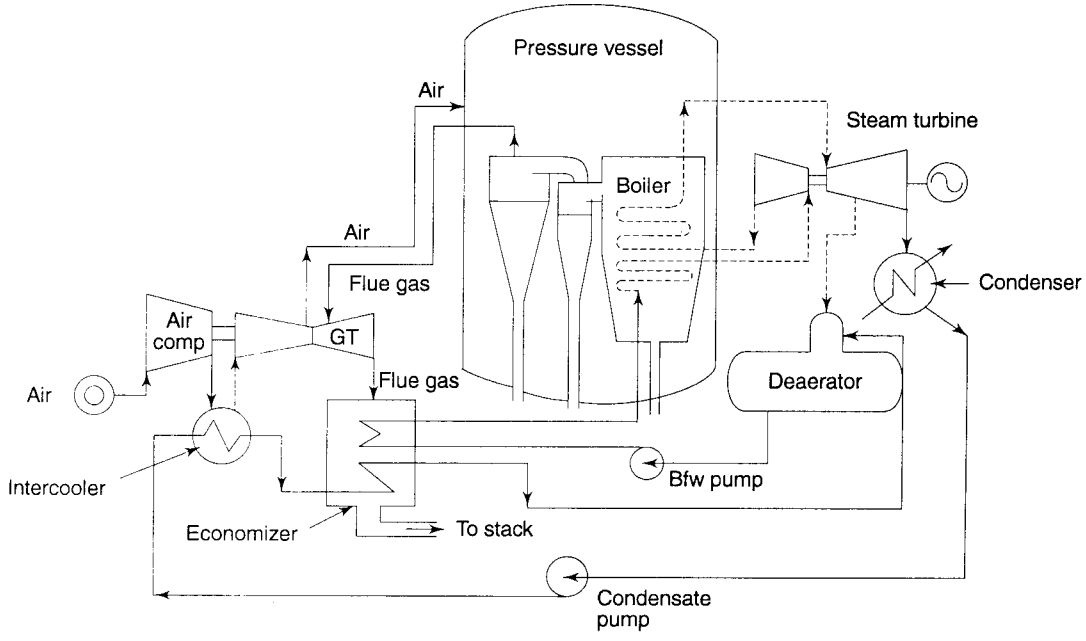

Fig. 1.21 *Pressurized fluidized bed boiler. It operates on steam turbine and gas turbine cycle combined to achieve high overall efficiency*

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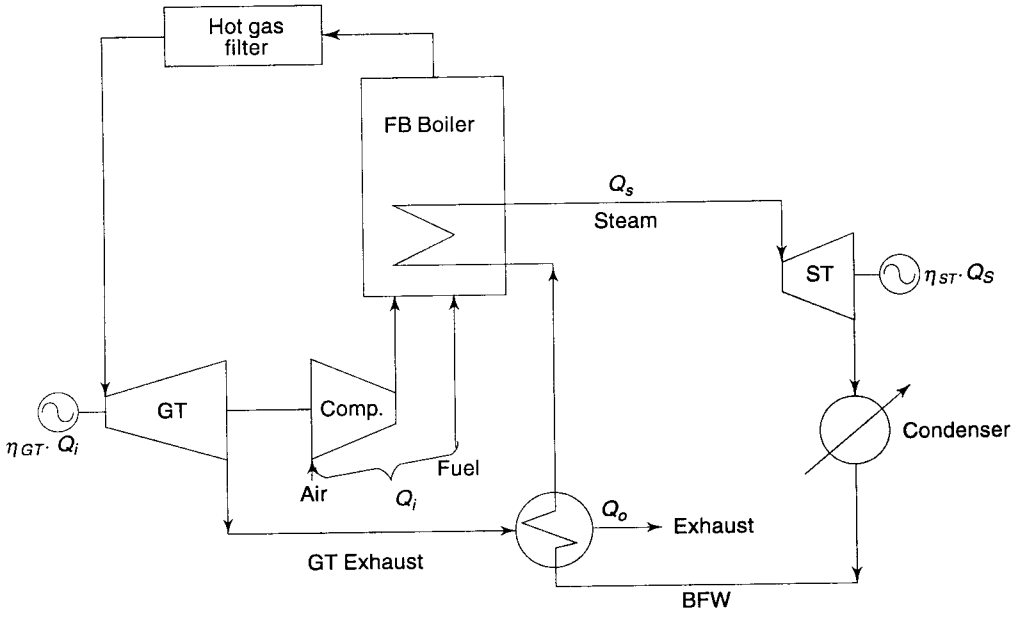

Fig. 1.22 *Schematic representation of PFBC supercharged cycle*

Power generated by *ST*

$$p_{ST} = \eta_{ST} \cdot Q_s \qquad (2)$$

Power generated by GT

$$p_{GT} = x \cdot \eta_{GT} \cdot Q_i \qquad (3)$$

Efficiency of the combined cycle

$$\eta_{cc} = \frac{p_{ST} + p_{GT}}{Q_i} \qquad (4)$$

Boiler efficiency

$$\eta_b = \frac{Q_i - Q_o}{Q_i} \qquad (5)$$

Plant efficiency

$$\eta_p = \eta_b \cdot \eta_{ST} \qquad (6)$$

where, Q_i = total thermal input, W

Q_o = heat rejection to the atmosphere, W

Q_s = heat absorbed by steam, W

p_{ST} = power generated by steam turbine, W

p_{GT} = power generated by gas turbine, W

x = fraction of total thermal input entering *GT*

η_{GT} = efficiency of *GT*

η_{ST} = efficiency of *ST*

η_b = efficiency of boiler

η_p = efficiency of steam cycle plant

From Eqn. (4)

$$\eta_{cc} = \frac{p_{ST}}{Q_i} + \frac{p_{GT}}{Q_i}$$

$$= \eta_{ST} \frac{Q_s}{Q_i} + \frac{x \cdot \eta_{GT} \cdot Q_i}{Q_i} \quad \text{Eqns. 2 and 3}$$

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$$= \eta_{ST} \frac{Q_i - x \cdot \eta_{GT} \cdot Q_i - Q_o}{Q_i} + x \cdot \eta_{GT}$$

Eqn. 1

$$= \eta_{ST} \left(1 - x \cdot \eta_{GT} - \frac{Q_o}{Q_i}\right) + x \cdot \eta_{GT}$$

$$= \eta_{ST} (\eta_b - x \cdot \eta_{GT}) + x \cdot \eta_{GT} \quad \text{Eqn. 5}$$

$$= \eta_p + x \cdot \eta_{GT} (1 - \eta_{ST}) \quad \text{Eqn. 6}$$

Since x, η_{GT} and $(1 - \eta_{ST})$ are always positive, the combined cycle efficiency is always greater than the equivalent steam cycle plant efficiency, η_p.

Q. *What are the principal factors that influence combustion efficiency of a FB boiler?*

Ans.

1. Combustion temperature
2. Excess air level
3. Superficial gas residence time.

Q. *What is the combustion efficiency of PFBC boilers?*

Ans. 99% or greater.

Q. *Why is the combustion efficiency of PFBC boilers so high?*

Ans. This is because of large superficial gas residence time in commercial designs and the use of large amount of excess air. Plus the better gas-solids contacting (smaller bubbles) brought about by pressure and the closely-spaced tubebanks restricting the growth of bubbles in the deep beds assist in attaining these high efficiencies.

Q. *What is the mode of combustion in PFBC systems?*

Ans. Practically all combustion takes place within the bed i.e. freeboard combustion is negligible.

Q. *Does it beget any specific advantage?*

Ans. Yes. It is fortuitous that in PFBC units fuels burnout in inbed combustion so far as GT operation is concerned. It is doubtful whether flue gas temperature inlet to the GT could be adequately controlled if freeboard combustion were significant. Plus any extension of freeboard combustion into the gas-cleaning cyclones would, sooner or latter, lead to sintering of the dust and problems of dust removal.

Q. *What is the advantage of PFBC units over the AFB units in the context of heat transfer?*

Ans. PFBC units register considerably higher heat transfer coefficients than AFB units because of lower fluidizing velocities (and consequently smaller bed particle sizes) in pressurized fluidized bed combustion system. For instance, at 1 m/s and 1125 °K, the heat transfer coefficient is about 350 W/(m^2 °K) in pressurized units as against 270 W/(m^2 °K) at 2.5 m/s in atmospheric units.

Q. *Sulfur retention in fluidized bed combustors is a function of pressure and temperature as is evident from the Fig. 1.23.*

While dolomite in AFB units exhibits higher sulfur retention than limestone, PFBC systems find dolomite superbly more efficient than limestone in sulfur arresting. Why?

Ans. Sulphur retention is functionally dependent on the porosity of the sorbent particles and pressurized operation brings about a radical change to this physcial characteristic.

With limestones, porosity is developed by calcination, and this occurs readily at atmospheric pressure, but only with greater difficulty and at elevated temperatures in pressurized units.

Calcination is endothermic

$$CaCO_3 \rightleftharpoons CaO + CO_2 - 183 \text{ kJ/g mol}$$

and the reaction is thermodynamically controlled such that the equilibrium partial pressure (p_e) is related to the absolute temperature T (°K) by the Arrhenius relationship:

$$p_e = 1.2 \times 10^7 \exp. [-E/RT]$$

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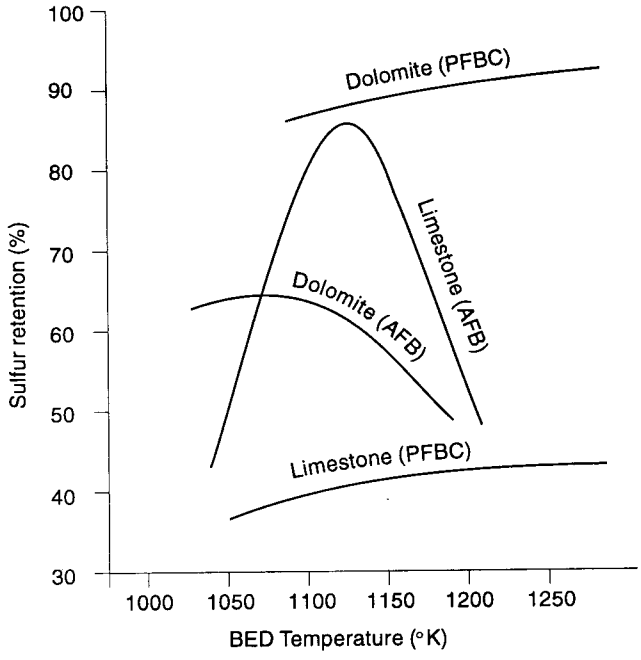

Fig. 1.23 *Effects of temperature and press on sulphur retention. Reactive limestone and dolomites sized to 0–1600 μm, normalized to Ca: S = 2 and superficial gas residence time = 0.5s.*

where, p_e is in bar

E = activation energy of $CaCO_3$ decomposition = 159 kJ/g mol

R = gas constant

The forward reaction i.e. decomposition of $CaCO_3$ will occur only if the partial pressure of carbon dioxide (which is dependent on the total pressure and excess air level) is less than p_e. The dependence of calcination temperature of $CaCO_3$ on these two variables is shown in Fig. 1.24.

Because of the difficulty in achieving clacination of calcium carbonate at high pressure, the effectiveness of limestones is reduced.

Dolomites, on the other hand, undergo two stages of calcination:

$$CaCO_3 \cdot MgCO_3 \xrightarrow[\text{Calcination}]{\text{Half}} (CaCO_3 + MgO) + CO_2$$

$$[CaCO_3 + MgO] \xrightarrow[\text{Calcination}]{\text{full}} [CaO + MgO] + CO_2$$

The half-calcination reaction occurs rapidly at all temperatures above about 875 °K in both *AFBC* and *PFBC* and results in the development of considerable porosity in the dolomite particle. However, at low pressure operation (AFB units) evolution of CO_2 is enhanced by full calcination (calcination of calcium carbonate). This rapid evolution of carbon dioxide can cause severe decrepitation of the calcined particles [CaO·MgO], forming fines that are elutriated from the combustor before absorbing much SO_2. On the other hand, op-

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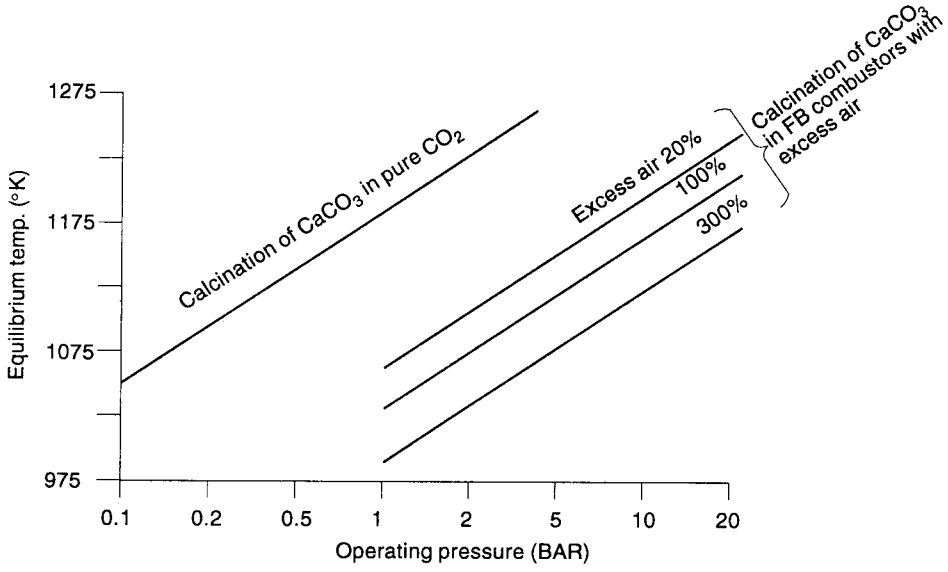

Fig. 1.24 *Dependence of calcination equilibrium temperature on operating pressure and excess air level.*

eration at high pressures severely restricts decrepitation yielding abundant porosity development by half-calcination with the effect that high-gain in sorbent utilization is achieved even under conditions preventing calcination of the calcium carbonate component. This explains the reversal of the relative effectiveness of limestone and dolomite.

Q. *What is the advantage of PFBC units over AFBC units as regards to NO_x emission?*

Ans. *PFBC* units give rise to much lower NO_x emissions than *AFBC* units. And the NO_x emission reduces, approximately in proportion to the square root of pressure, as the experimental data reveal.

Q. *Why does this happen?*

Ans. This is not known yet.

Q. *What are the NO_x gases that leave the combustor of a FB boiler?*

Ans. Almost entirely NO.

Q. *Is it true that low NO_x emission in FB combustion is due to low temperature operation?*

Ans. Not at all. The low temperature of fluidized bed combustion does not guarantee low NO_x emissions and that's why it will be incorrect to attribute low emissions, when they do occur, to the low temperature.

Q. *Where does this NO_x come from?*

Ans. In some cases virtually all the NO_x comes from the 'fuel-nitrogen' i.e. the nitrogen that was chemically combined in the fuel. And in all other cases, NO_x originates from the combustion air.

Q. *What factors exert influence on NO_x emission in fluidized bed combustors?*

Ans.

1. Operating pressure
2. Bed temperature
3. Excess air level
4. Configuration of the combustor
5. Bed material—its composition and particle size
6. Materials of construction
7. Coal particle size

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8. Coal type and the production and chemical nature of combined nitrogen
9. Combustion fundamentals.

Q. *Why is considerable importance laid on alkali emissions during fluidized bed combustion?*

Ans. They influence high-temperature corrosion of gas turbine blades.

Q. *How is this type of attack initiated?*

Ans. Alkali salts react with fuel-sulphur and oxygen of combustion air to form volatile alkali sulphates which are transported through the system as fine particulates and as vapour species which are in equilibrium with solid alkali metal species in the bed or in suspension. These elutriated fines deposit on the hot blade surfaces and corrode the host.

Q. *Which factors chiefly determine the alkali metal carryover?*

Ans.

1. Bed temperature
2. Chlorine content of coal.

Q. *Experimental results show that the alkali content of the gas phase is, in itself, not a sufficient measure of the tendency to condense alkali sulphate in the gas turbine. Why?*

Ans.

1. The chlorine/alkali metal ratio in the PFBC efflux is higher than with oil products. This might be expected to suppress condensate [cf. Na/K-chlorides are more volatile than Na/K-sulphates].
2. The alumino-silicates of coal-ash (called gettering) tie up some of the alkali metal in a harmless form.

Q. *Can this gettering prevent sulphate deposition on GT blades?*

Ans. No. Thermochemical calculations as presented in Report No. CS-1469 of EPRI by the General Electric Company indicate that with typical chlorine alkali metal ratios, the alkali metal sulphate condensation on turbine blades will far outstrip a conventional liquid fuel-fired GT even with 90% gettering.

Q. *How much of the input alkali is vaporized from a PFBC?*

Ans. About 1 to 2%.

Q. *Is such a minor extent of alkali emission harmful?*

Ans. Yes ; the efflux is considered to be potentially corrosive.

Q. *Which factors control the potential of alkali attack on blades?*

Ans.

1. Blade temperature
2. Corrosion resistance of blade material.

Q. *What is the maximum permissible limit of blade temperature in the context of alkali attack?*

Ans. If the metal temperature is not higher than about 1075°K, the existing turbine alloys with existing corrosion-resistant coatings should give adequate life.

Q. *What primary factors are being considered in the selection of industrial boilers today?*

Ans.

1. Fuel flexibility over the life of the boiler unit
2. Capability to burn low-quality fuels or derived fuels
3. Possible hook-up for cogeneration facility
4. Capability to fulfill ever-increasing emission standards
5. Optimizing the existing equipment regarding the efficiency, performance and service life
6. Turndown and part-load capability

Q. *How are industrial boilers classified?*

Ans.

1. Watertube boiler
2. Firetube boiler
3. Heat recovery boiler
4. Electrode boiler

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5. Packaged boiler
6. Field erected boiler
7. Fluidized-bed boiler
8. Refuse-fired boiler
9. Unfired boiler

Q. *Briefly describe watertube boilers used for industrial purposes?*

Ans. Only a few years ago all industrial watertube boilers would generate most of the steam in the convective bank of waterwall tubes. With the growth of demand of steam at higher pressure and temperature, and to meet the industry's need for higher capacity and higher efficiency, most of the steam is now-a-days generated in the radiant section of the waterwall tubes where heat transfer occurs principally through radiation. The design features of these radiant boilers are basically the same as those used in utility central stations.

Fuels burned range from conventional fossil fuels to a wide range of waste and low-grade energy sources. These include:

(a) Industrial and municipal sludges
(b) Woodwaste
(c) Petroleum coke
(d) Coal-mining waste
(e) Liquid industrial wastes
(f) Blast furnace gas
(g) Gas from sewage-sludge digesters

Q. *In which cases are packaged boilers used?*

Ans. Packaged boilers suit those industries where the steam requirement is modest. (Fig. 1.25)

Q. *What fuels are used for packaged boilers?*

Ans. Packaged boilers are almost exclusively designed for liquid and gaseous fuels.

Also, pulverized solid fuel can be used to generate steam to the highest practical limit of 45 t/h if the solid fuel has high calorific value and the fuel is pulverized to ultra-fine particles.

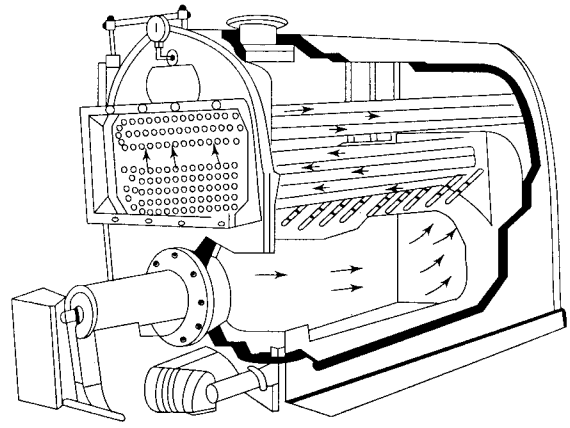

Fig. 1.25 *A typical two-pass packaged boiler. It is a fire-tube boiler that burns liquid fossil fuels*

Q. *Is the practical limit of a packaged boiler 45 t/h steam?*

Ans. Yes; because of the size that is commensurate with higher steam demand.

Though packaged units of capabilities upto 272 t/h are available, boilers larger than 112 t/h cannot be supplied by rail.

Note: Packaged boilers are shop-assembled units.

Q. *What are the basic design characteristics of packaged boilers?*

Ans.

1. Maximum use of vertical or near-vertical waterwall tubes in the radiant as well as convective zone of the furnace
2. Use of economizer to hike up overall efficiency
3. Maximum use of natural circulation of working fluid to increase heat absorption

Q. *What are the usual structural configurations of packaged boilers?*

Ans. Most of the packaged boiler units come in the form of *A*, *O* and *D* type configurations.

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Q. *What are the distinguishing features of each such type of packaged unit?*

Ans. The *D*-type boiler is the most flexible among the three. It has

(a) only two drums
(b) large volume of combustion space to fit a superheater or economizer into it

The *O*-type boiler is a symmetrical unit. It exposes the least amount of heat to the radiant surfaces.

The *A*-type packaged boiler is a tridrum type unit. It has two small lower drums plus one large upper drum where separation of steam from water takes place.

Q. *What are the ranges of temperature and pressure in which the packaged boilers, in general, operate?*

Ans. Operating pressure: 8.5–68 atm.

Operating temperature: 510°C (maxm.)

Q. *Can packaged boiler units be hooked up for cogeneration purposes?*

Ans. Yes; only the largest units can lend themselves for cogeneration facilities.

Q. *Why does this limitation exist?*

Ans. Low superheat temperature is available due to space limitation.

Q. *Is water carryover into the steam a problem with packaged units?*

Ans. Yes.

Q. *What measures are taken to counter it?*

Ans. Steam separators are installed in the steam drum.

Q. *What type of separators are used?*

Ans. Right from the simplest ones (e.g., baffle and chevron types) to highly sophisticated centrifugal types are used.

The simplest types are used for separating low pressure saturated steam while for high pressure steams (to be used in steam turbines where water droplet carryover in steam is detrimental) centrifugal separators are used.

Q. *What types of superheaters are used in packaged boilers?*

Ans.

1. Radiant type
2. Radiant-convective type

Q. *What is the important difference between the working characteristics of a radiant type and a radiant-convective type superheater?*

Ans. Radiant type superheater superheats the steam to higher-than-design temperatures at low loads.

Radiant-convective superheater maintains a relatively steady superheat temperature over the entire load range.

Q. *What are field erected boilers?*

Ans. These are predominantly watertube boilers erected in the field.

Fuels used range from coal, solid waste (woodwaste, municipal waste and industrial waste) to oil, gas and gaseous or liquid wastes. (fig. 1.26)

When coal and solid biomass fuels are used, stoker firing is the dominant choice.

The mode of firing may be of the suspension type if pulverized coal or biomass fuel in the form of dry fines, e.g., sawdust, sanderdust and rice hulls are available. Suspension firing and fluidized bed combustion are usually the choices for the larger units.

Q. *In which case are fluidized-bed field erected boilers preferred to suspension fired boilers?*

Ans. Though for larger units, fluidized-bed boilers are too expensive, they are preferred when stringent restrictions on the emission of NO_x, SO_x and particulates are imposed.

Q. *What are the usual operating temperatures pressures and capacities of field erected boilers?*

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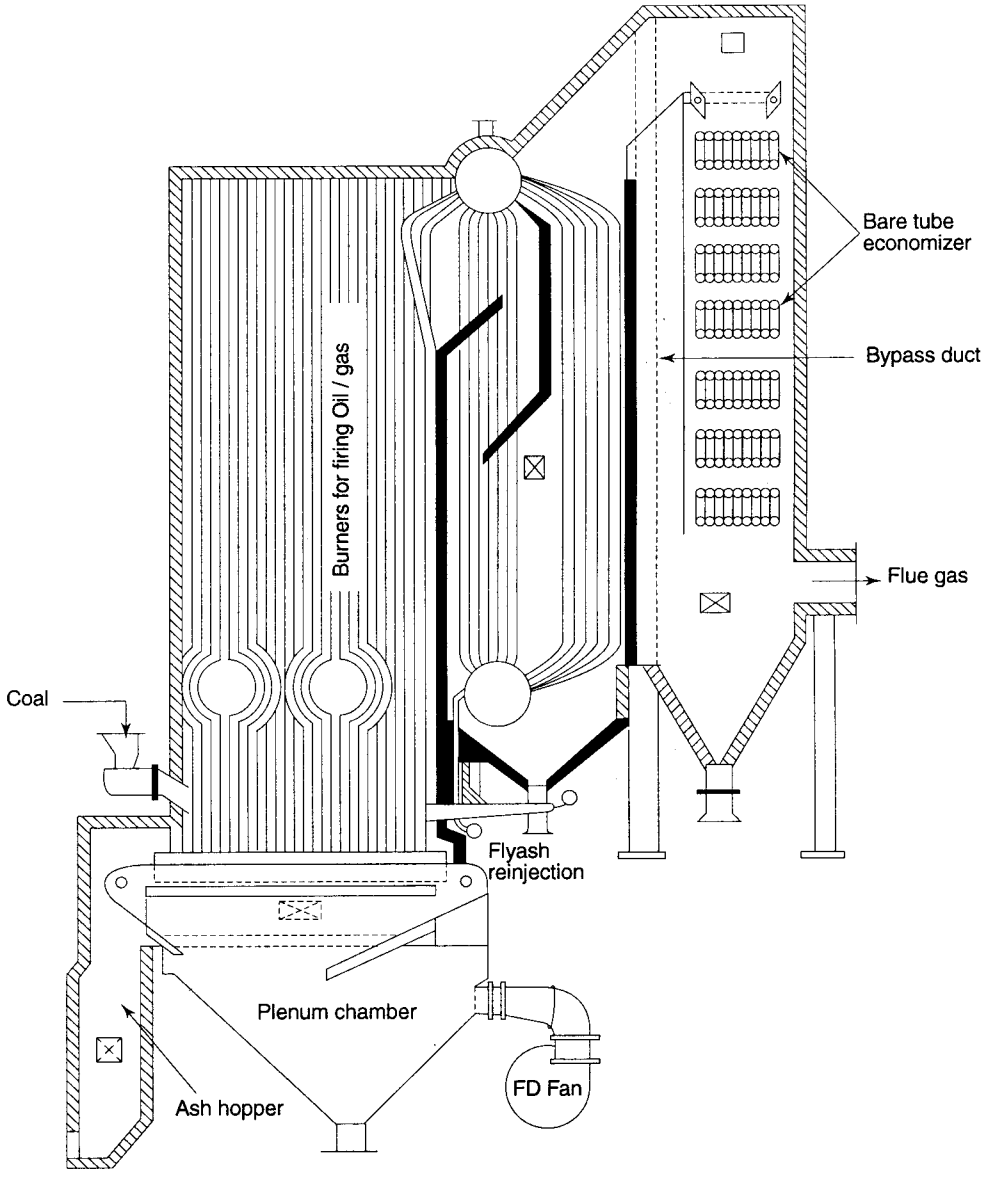

Fig. 1.26 *Field-erected spreader stoker boiler unit*
It burns a wide variety of coal and solid wastes in addition to gas and liquid fuels. Unit capacity is 115 ton/hr

Ans. Steam generating capacity 20 t/h to 180 t/h
Operating (Steam) temperature 450–500°C
Operating Steam pressure 61–102 atm.

Q. *Why is close control of furnace-exit gas temperature necessary in the case of refuse-fired boilers?*

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Ans. This temperature monitoring and control is imperative to minimize slag and flyash depositions.

Q. *What types of fluidized-bed boilers are used as industrial units?*

Ans.

1. Bubbling-bed boilers
2. Circulating fluidized-bed boilers

are the fluidized-bed units mostly used to meet the demands of industries. They are all watertube boilers.

Q. *What are the basic design features of bubbling-bed steam generators?*

Ans.

(a) Natural or forced-circulation, water tube fluidized bed steam generator designs are used for industrial and utility applications.

(b) The combustor can be single or multiple-cell, partitioned by waterwalls. Shown in Fig. 1.27 is the Foster Wheeler's bubbling-bed boiler.

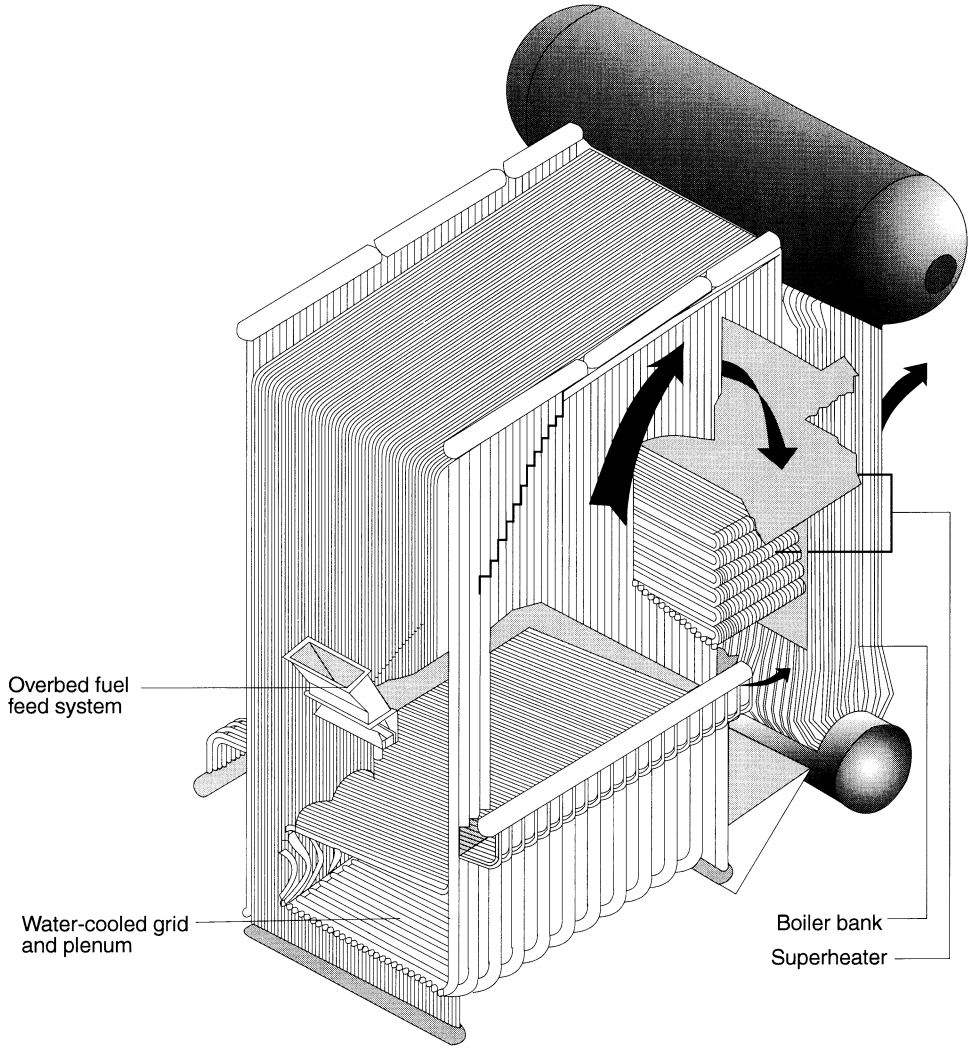

Fig. 1.27 *A bubbling bed boiler*
Source: SP87-4R94 (Tech. Paper/FW) Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

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(c) Air plenum chamber installed beneath each cell supplies the fluidizing air that also supplies oxygen to sustain combustion.
(d) The part and parcel of the boiler circuitry is a water-cooled air distributor that includes directional air nozzles which assist in directing any large ash or non-combustible tramp materials towards the bed-drain.
(e) A flyash reinjection system is normally embodied to optimize the unit's combustion efficiency by recycling unburned C-particles to the fluidized bed.
(f) Fuel is typically fed to the boiler using mechanical spreaders to distribute the fuel all over the bed surface.
(g) Limestone is used for sulphur dioxide emission control. It is either introduced as the primary bed material or fed with the fuel as needed.

Source: SP87-4R94 (Brochure/Foster Wheeler Corpn, NJ 08809-4000, USA)

Q. *How are the waterwalls arranged in the bubbling-bed boiler?*

Ans. The waterwall tubes are oriented either horizontally or vertically within the bed.

Q. *What is the chief advantage of vertically laid waterwall tubes over horizontally laid tubes?*

Ans. Horizontal steam-generating tubes are associated with more erosion problems than the tubes disposed vertically.

Q. *What measures are adopted to minimize erosion of in-bed tubes?*

Ans. Tubes are
(a) fitted with studs or fins
(b) coated with protective metal coating
(c) chromized to combat erosion.

Q. *Thermal-spray coating tames CFB erosion. How has this been made possible?*

Ans. With the advent of new spray processes, such as electric-arc wire and high-velocity oxygen fuel (HVOF), and improved coating materials, it has been possible to battle out corrosion in the most aggressive environment of CFB.

Q. *What are the advantages of thermal-spray coatings?*

Ans. Thermal-spray coatings have demonstrated their ability to
(a) increase component life
(b) reduce forced-outage rates
(c) extend the interval between scheduled shutdowns.

In CFB's they have the following advantages:
(a) negligible loss of heat transfer
(b) during spraying process no heat is applied to the tubing—tube temperature remains below 395°K
(c) application cost is 30–40% lower
(d) application time is significantly less
(e) wide choice of coating materials.

Q. *Cite two examples of coating materials.*
1. Iron-based alloy containing 30% Cr.
2. Low-carbon steel similar to chemistry and hardness to the material in the existing weld overlay.

Q. *How is this thermal-spray coating applied?*

Ans. One widely used technique is the electric-arc wire process. It is the easiest spray process to use. Electric-arc wire is portable and involves little in-boiler equipment. It uses compressed air instead of inert or combustible gases. It is quieter and logs higher material deposition rate than other spray processes.

Q. *What parameters are manipulated to control the steaming rate?*

Ans.
1. Bed height
2. Bed temperature
3. Solids inventory
4. Superficial gas velocity

Q. *What are the basic characteristics of circulating fluidized-bed boilers?*

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Ans.

1. They generally do not have in-bed tubes
2. They use hot-solids separation device (cyclones) to minimize erosion of heat absorption surfaces
3. Many CFBs have an external heat exchanger (EHE) (Fig. 1.28)

Some CFBs do not have EHE. The superheater is placed in the dense-phase flow at the top of the furnace (Fig. 1.29) or in the convective shaft downstream of the particle separator.

Q. *What is EHE?*

Ans. It is refractory lined box into which are arranged tube bundles.

Q. *What is the purpose of fitting an EHE?*

Ans. It cools the solids returning from cyclone separator. Changes in load conditions and fuel properties alter the heat absorption rate in the furnace. The EHE helps to compensate for variations in the rate of heat-absorption.

Heat transfer in the EHE increases when absorption in the combustor decreases and vice-versa.

Q. *Are the CFBs provided with sootblowers?*

Ans. Though the requirements of sootblowing for CFBs are much less than for other solid-fuels fired boilers, such units are provided with sootblowers.

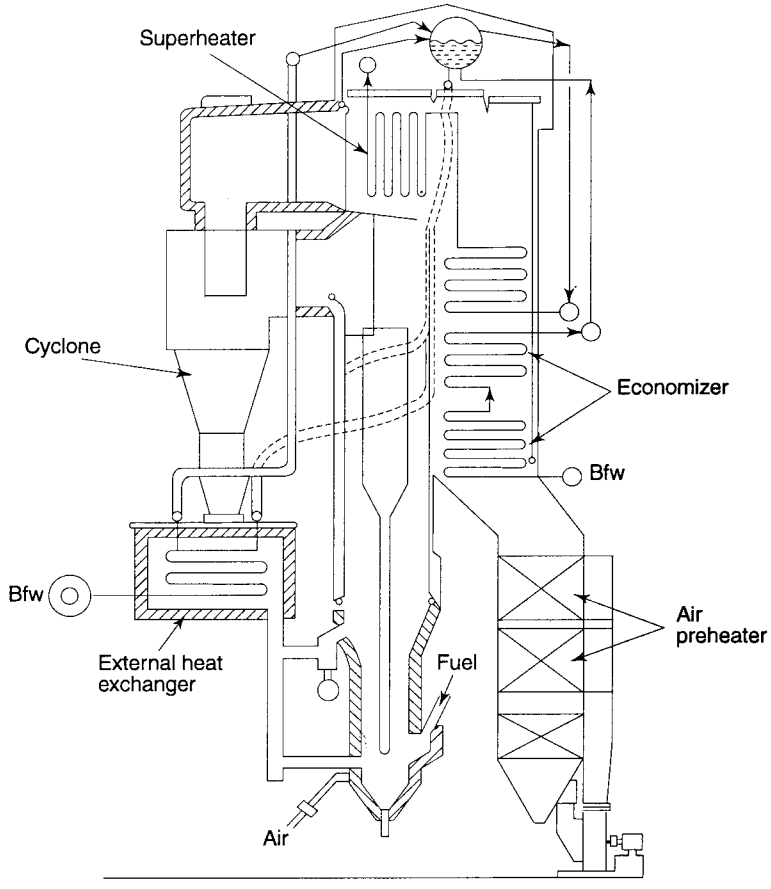

Fig. 1.28 *CFB fitted with external heat exchanger.*

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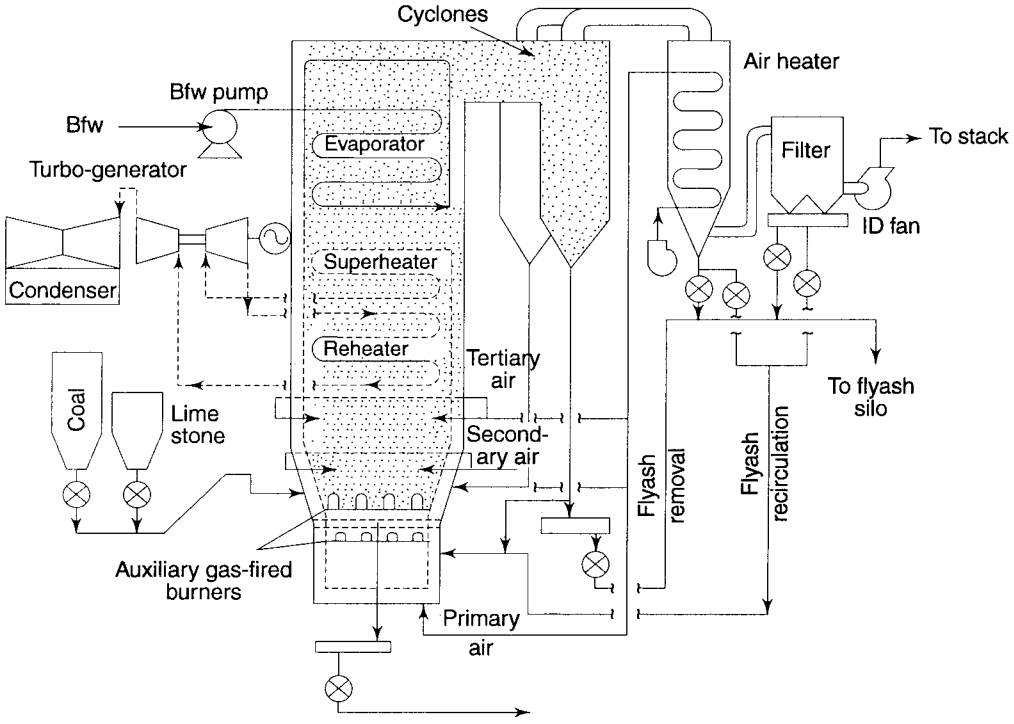

Fig. 1.29 *Circulating fluidized bed-boiler. It has no EHE. Its superheater is placed in the dense phase flow.*

Q. *CFBs offer fuel diversity and cost reduction. What fuels do they burn and how cost effective are they?*

Ans. CFB (Circulating Fluidized-Bed) boilers burn virtually all types of low-grade solid and solid-waste fuels:

(a) municipal refuse
(b) peat
(c) industrial waste
(d) coal-water slurries
(e) sewage sludge
(f) petroleum coke
(g) oil shale
(h) coal mining wastes
(i) manure
(j) wood
(k) biomass

The degree of variation in these fuels is striking (Tables 1.1 and 1.2)

Two existing natural-gas-fired boilers of a large independent-power/cogeneration site in North America were revamped and replaced with two CFB units producing 100 MW of electricity each and 36 t/h of steam for process use. The units were brought into operation in 1992 and are designed to use 100% petroleum coke. This coke comes from two local refineries who are the recipients of some of the electricity generated by the plant.

Switching to petroleum coke reduced fuel cost by almost 90%—including the cost of limestone, fuel transportation and ash disposal. Water treatment systems, deaerators, condensers, BFW preheaters & BFW-pumps were all salvaged from the erstwhile utility units.

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Table 1.1 ***Characteristics of some waste and alternative fuels fired in CFB boilers***

TYPE	SOURCE	DESCRIPTION
Waste coal	Bituminous coal mines in North America	Acidic, 65% ash, 1.8% sulphur, 6-10.5% moisture, 13 514 kJ/kg
Culm	Anthracite mining byproduct	High in ash containing high levels of potassium and illite, low heating value
Biomass	Agricultural waste, forestry byproducts, urban woodwaste, etc	Leafy or green residues-high alkali levels; great size variability, 10-60% moisture; 6990-22 135 kJ/kg, blending necessary to maintain some consistency
Peat	Peat bogs	40-70% moisture; 8000-21 840 kJ/kg, 65-70% volatiles, 4-7% ash
Petroleum coke	Petroleum refining	High heating value; low volatile, high sulfur content difficult to use in conventional boilers
Lignite	Mae Moh mines in Thailand	25-50% moisture; 7-35% ash; 8400-13 020 kJ/kg; 0.9-3.2% sulphur

Table 1.2 ***Comparison of typical waste-fuel analyses***

Component	Bituminous coal waste	Petroleum coke	80% coke+ 20% TDF	Anthracite coal waste	Tire-derived fuel (TDF)
Fixed carbon, %	16.8	83.93	73.91	22.02	22.0
Volatile matter, %	15.2	9.83	17.66	6.84	63.1
Ash, %	61.3	0.67	1.75	70.05	12.3
H_2O, %	6.5	5.58	6.69	1.09	2.6
HHV, kJ/kg	14 698	33 086	32 853	7573	32 620
Sulphur, %	0.8	5.52	4.57	0.34	1.3

Source: Electric Power International (Sept. 1994)
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Q. *The Pyroflow CFB boiler located at Kuk Dong Oil refinery in Seosan, Korea fires 100% pet coke. Boiler performance has been excellent, easily meeting all performance guaranties. The boiler efficiency exceeds 90%. What is the reason of high boiler efficiency?*

Ans. This is primarily the result of the low ash content and high combustion efficiency. The combustion efficiency has been greater than 98%.

Q. *The Kuk Dong plant does not utilise flyash reinjection. What would have been the outcome if this flyash were reintroduced to the CFB combustor?*

Ans. It would improve combustion efficiency even more.

Q. *What are the advantages of petroleum coke combustion in CFB firing over more traditional firing?*

Ans.

1. Superior ignition and flame stability
2. Excellent combustion efficiency, in the range of 96-99.5%
3. Low flue gas emissions without backend gas cleanup. NO_x emissions are as low as 0.0215–0.0859 kg/MMKJ without ammo-

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nia injection and less than 0.03 kg/MMKJ with ammonia injection.

4. Relative insensitivity to low melting vanadium compounds
5. Ability to easily handle varying fuel quality
6. Sulphur removal of 90% and greater, by infurnace lime injection.

Q. *How do CFBs make fuel flexibility compatible with low emissions?*

Ans. CFB boilers inherently produce low NO_x emissions than other boiler designs, while SO_2 and other acid gases are absorbed during combustion by adding a suitable sorbent.

CFB combustors burn fuel in a turbulent atmosphere under relatively uniform mixing conditions to achieve efficient combustion with low NO_x and CO emissions. Inasmuch as they operate at lower average furnace temperatures (1090° — 1200°K) compared to stoker-and PC-fired units, they lend for ammonia and urea injection in a better way in case additional NO_x control is required.

CFB boilers keep SO_2 emissions at bay, since the combustion temperature is within the range where the reaction of limestone with SO_2 liberated during combustion is ideal. According to one recent report, 90% SO_2 removal is routinely achieved with Ca:S ratio of 2:1 in CFB combustors.

A survey of several operating units reveals that they all achieve very low levels of SO_2, NO_2, and flyash emissions— generally well below permitted values—with little difficulty (Table 1.3).

One of the world's largest peat-fired CFB boiler is operating in Seinäjoki, Finland at a papermill. Designed to fire a mixture of peat, woodwaste, coal and papermill-sludge, it is one of the largest, clean CFB units designed todate, thanks to inherently low NO_x emission capability of circulating fluidized bed combustors while burning fuels of varied characteristics.

Table 1.3 ***Emissions performance for several CFB units***

	NO_x		SO_2		CO		Flyash	
	Permit	Actual	Permit	Actual	Permit	Actual	Permit	Actual
100-MW unit firing low-sulphur coal[1], kg/million kcal	0.055	0.018	0.05	0.009	0.16	0.031		
85-MW unit firing bituminous coal-mining waste, kg/h	152	45	360	70			7.6	2.3
Two 38.6-t/h units firing high-sulphur coal, kg/million kcal	0.22	0.13	0.55	< 0.55	200 ppm	39 ppm	0.019	0.012
Two 160-MW units firing lignite, kg/million kcal		0.09		0.22				5.6% opacity
26.4-MW unit firing low-sulphur coal[1,2], kg/million kcal	0.019	0.013	0.019	0.01	0.043	0.01	0.011	0.002
102.5-t/h unit firing high-sulphur coal, kg/million kcal		≤ 0.066		≤0.44		≤100 ppm		
211-t/h unit firing bituminous coal waste, kg/million kcal		<0.033		<0.33[3]		<0.11		

[1] Includes ammonia injection system for NO_x control [2] Unit is described as a hybrid bubbling bed/CFB [3] Calcium-to-sulphur ratio is 1.8 to 2.1

Source: Electric Power International (SEPT. '94)

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Q. *Do tne CFB combustors burn only solid fuels?*

Ans. NO. Solid, liquid, or gaseous fuel or fuels, are burnt together with inert materials like sand, silica, alumina or ash and/or a sorbent, such as a limestone.

Q. *How is this process realised?*

Ans. The charge of fuel, sorbent plus inerts are kept suspended in furnace thru the action of the primary air distributed below the combustor floor. Secondary air may be introduced into the combustor to provide a staged-combustion effect. As the combustion takes place, the generated heat is transferred from the hot bed material to the membrane waterwall.

Q. *What make CFB technology an attractive proposition in comparison to other firing techniques?*

Ans. This is ascribed to the three Ts of combustion:

(a) time (b) turbulence (c) temperature.

Fluidization promotes intensive turbulence and the entire mass of solids behaves much like a liquid.

Improved mixing generates heat at substantially lower temperatures (1080°K—1175°K) and gives rise to more uniform temp. distribution in the furnace space than a stoker-fired unit or a PC-unit. Therefore a properly sized combustion chamber will release heat at an equivalent level of a conventional boiler, but at a lower temperature and theoretically without any loss in efficiency.

The added turbulence begets several advantages:

1. less volatilization of alkali compounds
2. reduced chance of hot spots on boiler and shell surfaces
3. less sensitivity of the fuel
4. a smaller furnace volume.

Extra volume is not required to allow the ash to cool before flowing thru the convective passes.

Low combustion temperatures offer advantages for emissions control

1. operating temps. are well below the formation point of thermal NO_x
2. stagged-combustion is feasible, by introducing secondary air, to minimize fuel-bound NO_x formation
3. addition of a suitable sorbent eliminates or at least minimizes the need for downstream control
4. sulphur-absorption reactions are thermally balanced by the operating-temp. range of CFB units

Thus, there tends to be design trade-offs involved in maintaining high SO_2 removal efficiency together with high combustion efficiency.

Another major advantage of lower combustion temp., particularly when firing coal, is realized through minimum staging and fouling and other problems associated with PC-fired and stoker-fired units.

Q. SO_2 *removal by sorbent absorption*

$$CaO + SO_2 + 1/2\ O_2 \longrightarrow CaSO_4$$

is thermally balanced over the operating-temperature range of CFB combustors. How is the optimum absorption of sulphur influenced by the CFB combustion temperature?

— Sulphur dioxide is absorbed by lime by a reversible reaction:

$$CaO + SO_2 + 1/2\ O_2 \rightleftharpoons CaSO_4 + 486\ kJ/g\ mol$$

which becomes counter-operative as the temperature increases. However, optimum absorption of sulphur dioxide is achievable at higher CFB combustor temperatures provided higher sorbent injection is made i.e. at higher calcium-to-sulphur (Ca:S) ratio (Fig. 1.30).

Q. *How is steaming rate controlled in CFB units?*

Ans. Steaming rate is controlled by manipulating four primary bed parameters:

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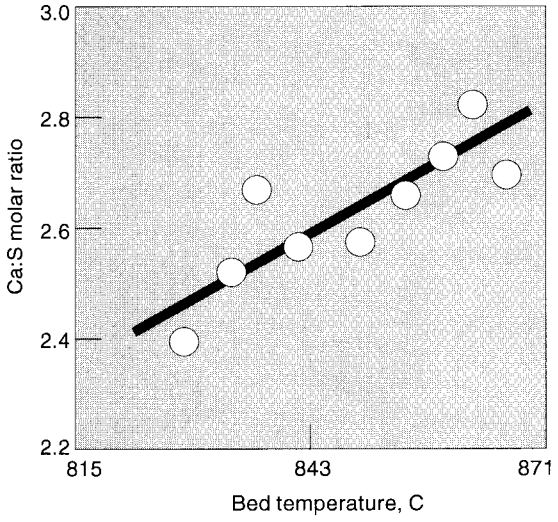

Fig. 1.30 *Optimum absorption of sulphur by calcium is achieved at normal CFB combustion temperature.*

Source: Electric Power International (Sep. '94) Reproduced with kind permission of AHLSTROM PYROPOWER INC./San Diego/CA 92121/USA

1. bed height
2. bed temperature
3. solids inventory
4. superficial gas velocity.

Velocity changes accomplish most of the control. For instance, reducing the fluidization velocity, less heat-transfer surface is exposed to the bed. When airflow is shut-off completely, heat transfer drops practically to zero, offering quick turndown capability.

Trundown and steam-rate control can also be effected by reducing the quantum of bed inventory i.e. bed material or by regulating fuel feed, as with other firing systems.

Q. *What is PYROFLOW® CFB technology?*

Ans. PYROFLOW® is the patented trademark of famous Finnish Co. AHLSTROM PYROPOWER recognized worldwide as the leader in the supply of fluidized-bed combustion systems.

Note 'PYR' is the Greek word for fire and 'FLOW' means movement or circulation. Hence PYROFLOW system is a true representative of circulating fluidized bed (CFB) combustion.

Q. *How does the PYROFLOW system work?*

Ans. The Pyroflow CFB combustion system operates on the circulating bed concept. Fuel and limestone (for sulfur capture) are fed into the lower portion of the combustion chamber in the presence of fluidizing air. The turbulent environment mixes the fuel and limestone quickly and uniformly with the bed material. Fluidizing air causes the fuel, limestone and bed material to circulate and rise thruout the combustion chamber and enter the hot cyclone separator (Fig. 1.31). The captured solids, including any unburned fuel, are then reinjected into the combustion chamber through the non-mechanical loopseal.

Continuous circulation of solids through the PYROFLOW system provides longer fuel residence time, resulting in very efficient fuel combustion. The limestone in the fuel mixture reacts with the sulphur dioxide (SO_2) and other sulphur compounds in the flue gas and is removed with the ash as an inert dry solid, calcium sulphate or gypsum ($CaSO_4$). The relatively low combustion temperature (1075—1175°K) and the introduction of secondary air at various levels above the grid provides for staged combustion, limiting the formation of oxides of nitrogen (NO_x). From the convection zone, flue gases pass through a particulate collection system to the stack via induced draft fans.

Source: AHLSTROM Brochure: PYROFLOW CFB technology

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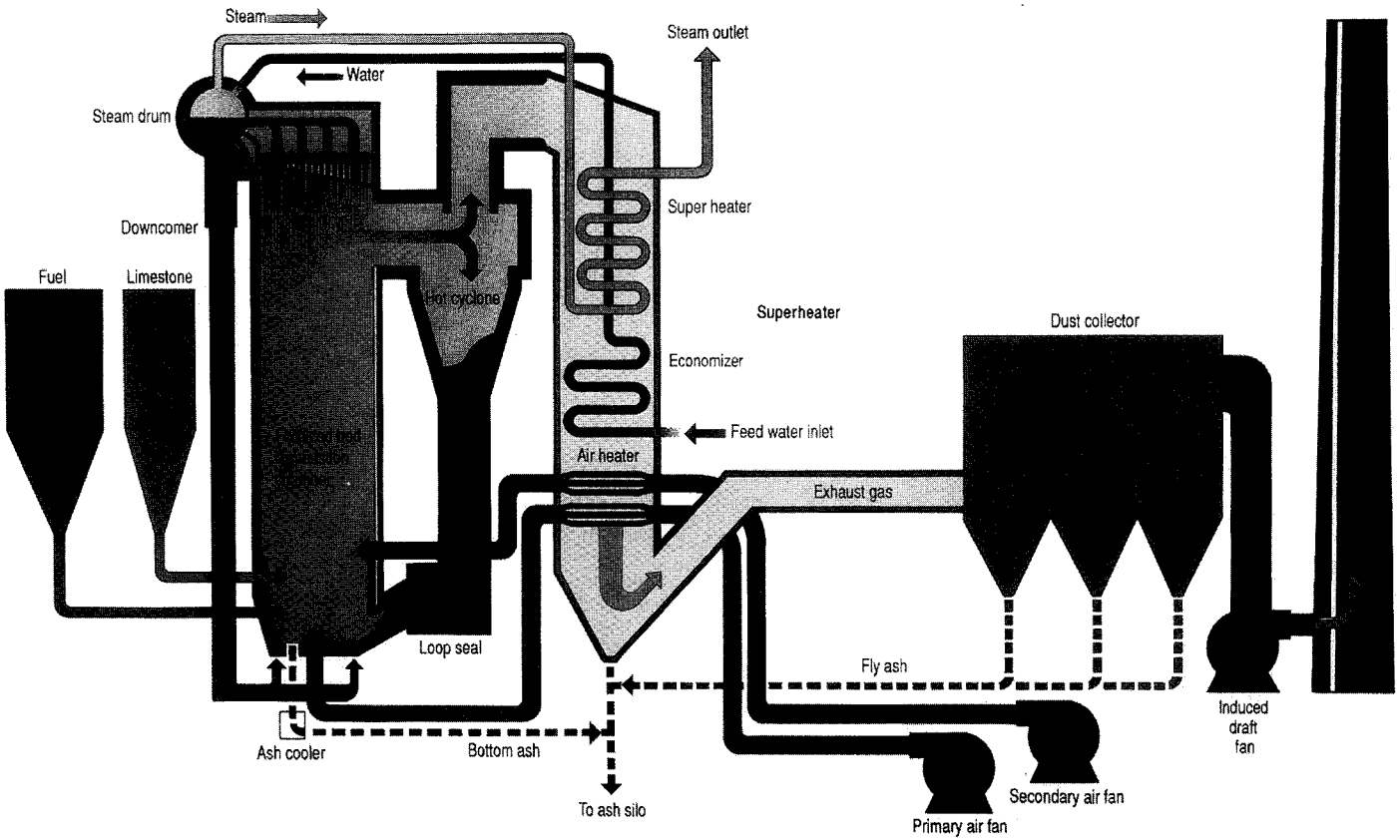

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Fig. 1.31 *Ahlstrom pyroflow CFB system.*

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Q. *What are the major components of CFB units?*

Ans.

1. A refractory-lined lower combustor section with fluidizing air inlet nozzles located on the floor above the windbox
2. An upper-combustor section lined with waterwall
3. A transition piece—including a hot-solids separator and re-entry downcomer—that may be either entirely or partially lined with refractory
4. A convective boiler section which is similar to that for a conventional boiler in most cases
5. A loopseal, also called a '*J*-valve' or '*L*-valve', to provide a simple non-mechanical hydraulic barometric seal against the combustor shell.

Primary air is supplied as the fluidizing medium while secondary air is supplied a few metres above the combustor floor to effect staged combustion.

Q. *In several designs of convective passes for most CFBs, the superheater is located in the combustor ahead of the cyclone. Why is this arrangement made?*

Ans.

1. To take advantage of high heat-transfer rates in the region
2. To lower the temperature of flue gas entering the cyclone so that lower temperature refractory materials may be used.

Q. *The design of loopseal (also called a 'J-valve' or 'L-valve') plays an important role in determining the sulphur capture efficiency of the bed. How is this true?*

Ans. The loopseals are large-diameter, refractory-lined pipes to recycle elutriated bed particles. They are void of any internals but may be equipped with nozzles for admitting compressed air to keep material flowing. The solids-recycle-stream may or may not be controlled to help maintain a constant bed temperature which affects sulphur retention efficiency.

Q. *From the process perspective it is said that cyclone is the 'linchpin' of the CFB process. Why?*

Ans. The cyclone separates the entrained particles from the flue gas leaving the combustor and feeds back hot solids to the combustor. The higher the solids recycle rate, the higher is the efficiency of the process in ensuring uniform temperature in the combustor. The efficiency of the cyclone determines the capture rate of the fines fraction of the solids entering the cyclone. This, in turn, affects limestone utilization and carbon burnout. That is, the cyclone plays the dual-role maintaining the high combustion efficiency of the combustor as well as delivering clean flue gas to ensure better heat-transfer efficiency in the convective shaft of the system resulting in high overall plant efficiency of the CFB unit.

Q. *How is the cyclone efficiency related to cyclone size?*

Ans. The basic cyclone theory suggests that as the cyclone size increases, the collection efficiency decrease.

Q. *Why does collection efficiency decrease with increase in cyclone size?*

Ans. Because of reduction in the centrifugal force separating the solids:

$$\text{Centrifugal force} = m\frac{v^2}{r}$$

where, m = mass of the flue-gas-borne particle, kg

v = tangential velocity of the particle whirling in the cyclone, m/s

r = radius of whirl, m

Q. *Why do large CFB units employ multiple-cyclone arrangements?*

Ans. As the cyclone size increases, the collection efficiency decreases with the effect that a point,

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in scaling up, will be reached ultimately where cyclone size gets so large that limestone utilization and carbon burnout decrease. So large single units employ multiple cyclone arrangements.

Q. *How can the cyclone design be optimized?*

Ans. This can be done by determining the relationship among fuel and limestone particle size and residence time for which the CFB combustor operates best. Then the cyclone design can be modified to arrive at and maintain those conditions.

Q. *What do you mean by "d50" related to the grade efficiency curve of a cyclone?*

Ans. It is the basic cyclone design parameter that describes the particle size for which 50% removal is theoretically obtained.

Q. *How can an optimum limestone particle size be determined for a given combustor?*

Ans. This requires understanding the relationships of concentrations of sulphur and lime as a function of particle size. For this, a comprehensive evaluation of parameters viz. average particle size, density, elemental analysis, loss-on-ignition, free carbon content and free limestone concentration is necessary by studying fly-ash and bottom-ash samples from an operating CFB boiler.

Research work conducted so far has revealed that distributions of free carbon, free lime, and sulphur are widely non-uniform. Very little unburnt carbon has been found present in the intermediate-sized ash particles while concentrations substantially higher than average have been found in both small and large particle fractions. By considering the relationship of fuel-sulphur and free lime concentrations as a function of particle size, an optimum limestone particle size, or at least a narrow size range, can be estimated for a given combustor.

Q. *Why is a steam-cooled or water-cooled cyclone designed?*

Ans. A steam-cooled cyclone can provide the Ist pass of the superheater surface once steam leaves the drum while the water-cooled cyclone can act as an extension of the boiler's natural-circulation system.

Both act as a heat-sink to

(a) avoid any afterburning of elutriated carbon particle (this may lead to high cyclone temperature)

(b) subsequently reduce refractory needs in this critical area, leading to lower weight and reduced structural components

(c) provide faster start-up inasmuch as the drum limits the warmup rate, not the thick refractory in the cyclone.

Q. *What are the basic design featurs of a steam-cooled cyclone?*

Ans. Shown in Fig. 1.32 is a unique cyclone design developed by Foster Wheeler Corporation, USA to give optimum performance and wear resistance.

The entire cyclone enclosure (inlet duct, roof, barrel, and hopper) is steam cooled. The cyclone steam circuitry is the first pass of superheat for steam leaving the steam drum. Steam flow through the cyclone is in a series or parallel arrangement. Wear resistance is ensured by a thin layer of high conductivity, high alumina, phosphate-bonded refractory mounted on a high-density stud pattern.

Q. *What advantages do these unique features of steam-cooled cyclone beget?*

Ans.

1. Fabricated from pressure parts, the cyclone is simply an extension of the furnace that allows it to be top-supported and to expand downward along with the furnace minimizing differential thermal expansion simplifying the mechanical design of the furnace/cyclone and cyclone-HRA interfaces.
2. The absorbed heat goes to superheat the stream and to provide a heat-sink to quench after-burning in the cyclone that might occur when difficult-to-burn fuels such as anthracite culm, woodwaste, pet coke and refuse derived fuel (RDF) are fired

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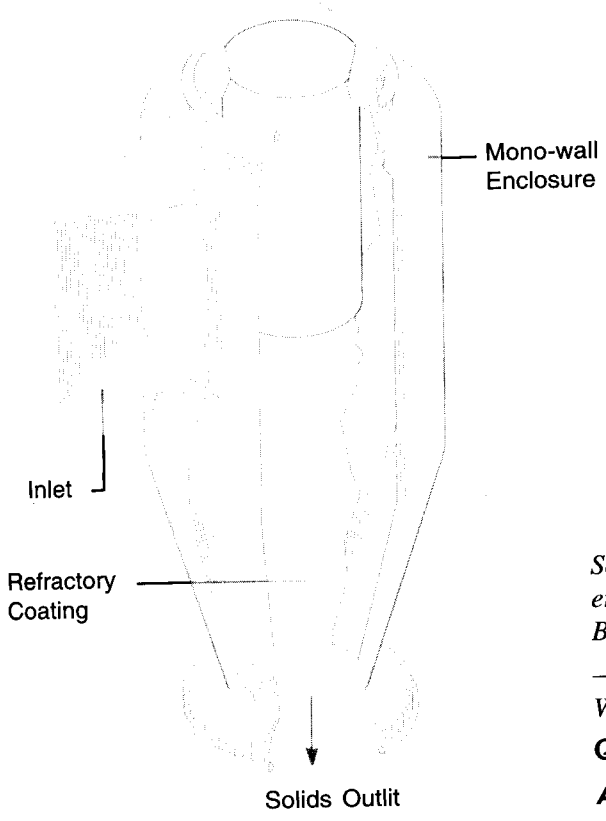

Fig. 1.32 *The steam-cooled cyclone designed by Foster Wheeler for its CFB boilers. Steam-cooled monowall forms the cyclone enclosure. The cyclone is intergrated with the boiler circuitry for structural thermal compatibility.*

Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

3. Standard insulation and lagging can be applied to provide a nominal outside temperature 333°K as compared to the 394°K on an uncooled casing type design. The lower face temperature significantly curtails the radiant heat loss from the unit (Fig. 1.33) and enhances personal safety.
4. The thin refractory layer (25mm as compared to 305-406 mm on a casing type design) significantly reduces the cyclone weight and therefore, structural steel weight.
5. The refractory is never a limiting factor to the startup rate which can be as fast as 4 to 6 hrs to bring the unit from cold conditions to full load with the steam drum. Uncooled casing type cyclones with 305-406 mm refractory thickness require 12 to 16 hrs for startup.
6. Shop fabrication in quadrants with shop installed and cured refractory greatly simplifies field erection job and considerably improves quality control that invites low maintenance and repair, and high availability.

Source: Update of Waste Fuel Firing Experience in Foster Wheeler Circulating Fluidized Bed Boilers

—I.F. Abdulally; R. Navazo (SP93-16/FOSTER WHEELER)

Q. *What is backpass?*

Ans. It is the convective shaft of the CFB boiler.

Q. *What does backpass include?*

Ans.

1. Reheater
2. Superheater
3. Economizer
4. Air preheater (Fig. 1.34)

The heating surface tube bundles are arranged in a way similar to PC-fired units.

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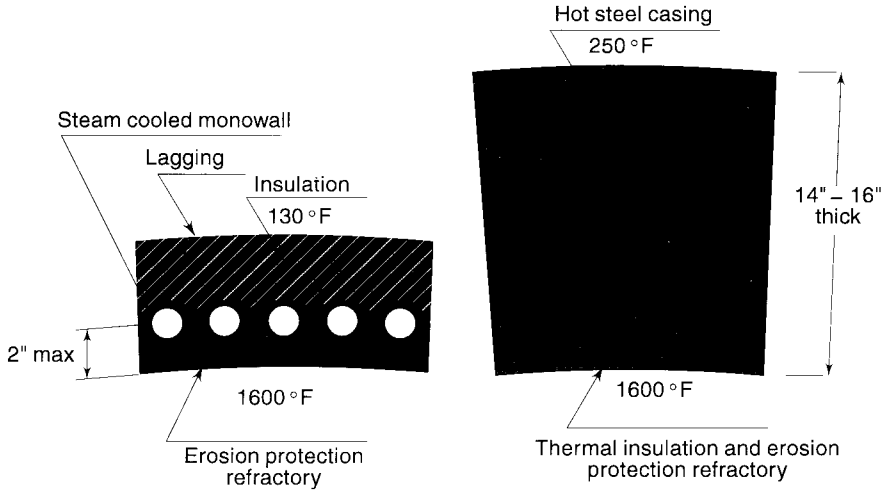

Fig. 1.33 *Cyclone refractory comparison*
Courtesy: Foster Wheeler Corprn./NJ 08809-4000/USA

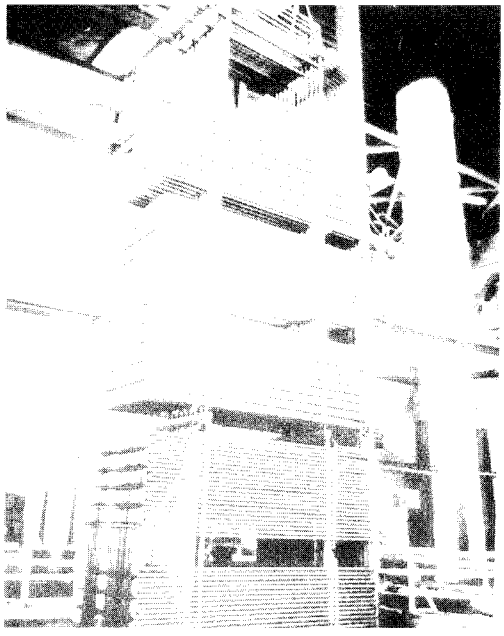

Fig. 1.34 *The CFB backpass consists of superheater, reheater, economizer and air preheater. Arrangement is similar to PC-fired units.*

Source: Electric Power International (Sep. 1994)
Courtesy: AHLSTROM PYROPOWER/San Diego/ CA 92121/USA

Q. *What is the type of economizer used in a CFB backpass?*

Ans. CFB designers use either an inline spiral fin or bare-fin economizer.

Q. *When are the reheaters installed?*

Ans. For large utilities (> 100 MW_e), the primary emphasis is laid on more efficient plant operation and high pressure steam generation using large boilers. These units include reheat cycles.

Q. *As the CFBs increase in size and reheat cycles are incorporated some manufacturers add fluidized-bed heat exchangers (FBHE). Why?*

Ans. To enhance steamside heat pickup. As CFBs grow larger in size, the surface-to-volume ratio of the combustor decreases whereupon the furnace waterwalls cannot meet the required evaporator duty. Under these circumstances, FBHEs allow incremental evaporative duty by passing a sufficient amount of recycle solids into the bundles.

Q. *Is this the only ground to favour FBHE?*

Ans. Besides performing the reheat duty, FBHE has another plus point i.e. these heat exchangers work at very low superficial velocities, around

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30 cm/s, and some designers believe that they are less prone to erosion than are in-combustor evaporative panels.

Q. *What are other reheat options for CFBs?*

Ans.

1. Steam-cooled cyclones
2. External heat exchangers (EHE)
3. Tube bundles in the backpass shaft
4. Omega panels
5. Wingwalls in the upper section of the combustor.

Q. *Foster Wheeler has designed, erected and operated several Circulating Fluidized Bed (CFB) units in the continental United States firing a variety of waste fuels including anthracite culm, petroleum coke and tire-derived-fuel in addition to normal coals. These units have accumulated many years of operation with high availability and low maintenance. What are the main design features and components of FW CFB units?*

Ans.

1. Balanced draft system
2. 100% natural circulation
3. High heat input start-up burner located in the primary duct
4. Fully water-cooled air plenum, grid and furnace
5. Directional air grid
6. Fludized-bed stripper-cooler for handling bottom ash
7. Air swept fuel feeders
8. Steam-cooled cyclone and inlet channel integral with the furnace
9. Non-mechanical '*J*-valve' (loopseal) in the recycle system
10. Conventional series or parallel pass HRA: Heat Recovery Area
11. Tubular airheater.

Q. *What are the distinctive features of FW CFB process?*

1. Presence of a pronounced bed with bed-depth of 0.5—1m and relatively solids lean freeboard above it (Fig. 1.35)

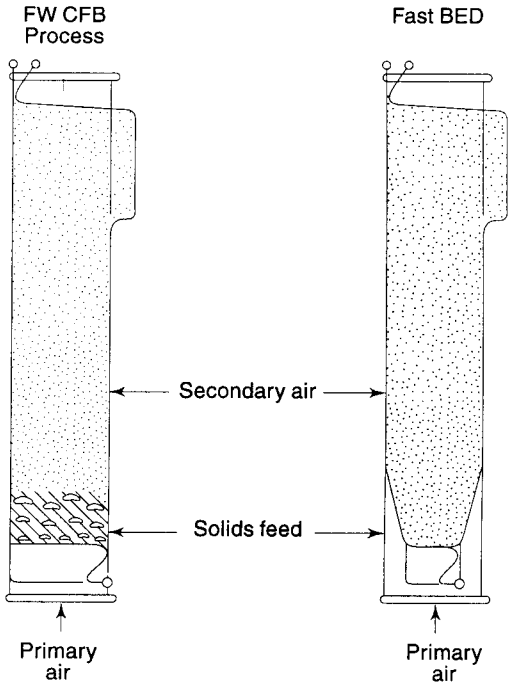

Fig. 1.35 *Comparison of fluidized regimes. FW CFB restricts fuel combustion within a bed depth of about a meter and thereby minimizing afterburning in the cyclone.*

Courtesy: Foster Wheeler Corpn./N J 08809-4000/ USA

2. Distinct bed fluidizing regime is achieved by using relatively coarse fuel and sorbent size distributions and a relatively low primary furnace zone velocity. Therefore, the bed does not require an additional coarse inert material such as rock or pebbles.This begets the advantage of firing waste fuels with either high ash viz. anthracite culm or very low ash such as petroleum coke.
3. Higher solids residence time.
4. Lower solids loading through the HRA and downstream equipment.
5. Low erosion potential in the furnace and cyclone inlet
6. Predictable thermal performance
7. Simple controls.

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Q. *What are the benefits of these conditions?*

Ans.

1. Predictable operating conditions
2. High fuel burnup efficiencies
3. High limestone utilization
4. Low SO_2, NO_x, and CO emissions
5. Low maintenance
6. Low prediction cost.

Q. *What is a directional water-cooled air distributor?*

Ans. Developed by Foster Wheeler for bubbling fluidized beds (BFBs) in the early 1980's, the water-cooled directional air distributor is formed of single outlet nozzles oriented in a specific pattern to direct coarse material toward the drain. The directional air nozzles are bolted to the integrally welded fins of the distributor floor (Fig. 1.36).

The distributor floor and air plenum floor are formed by using the furnace front or rear wall tubes. Since the furnace and air plenum share the side waterwalls, there is no need to install high temperature expansion joint and thick refractory layer.

Q. *How does the water cooled air distributor operate?*

Ans. The directional air distributor is formed of single outlet nozzles oriented in a specific pattern to direct coarse material toward the bed outlet drain. The pattern of the nozzle arrangement is varied depending on the nature of the fuel. For example, a fuel consisting of rocks or other tramp material will have a pattern that will give rise to least residence time for such substances. Conversely, a fuel which is either coarse or possesses low reactivity will require a pattern of nozzle arrangement that begets the greatest residence time. The outlet of the nozzles are large, i.e. approximately 13 to 25 mm in diameter.

The outlet branch of the nozzle discharges a large, almost horizontally jet of air which effectively dislodges even large particles in its path. Any large or heavy material, small clinkers or agglomerates sink to the bottom of the fluidized bed. These particles are forcibly conveyed to the bed-drain along a path dictated by the nozzle pattern before they accumulate, defluidize, overheat and/or fuse as large masses.

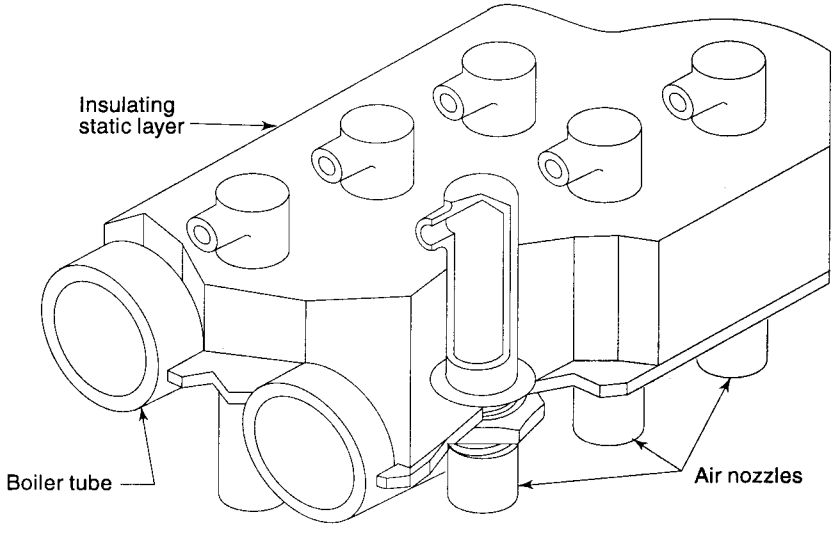

Fig. 1.36 *Directional water-cooled air distributor.*
Courtesy: Foster Wheeler Corpn./NJ 08809-4000 /USA

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Q. *Why are nozzles with large single outlet are preferred to nozzles with multiple small openings?*

Ans. Large dia nozzles are not prone to pluggage as are nozzles with small openings.

Q. *Where is the directional air distributor installed and what is its utility?*

Ans. The directional air distributor is provided in the furnace as well as in the bottom ash fluidized bed stripper-cooler.

The unique directional distributor design continually removes over-sized particles from the furnace into the ash disposal system and thereby insures uninterrupted operation. This feature is particularly important for a large capacity ACFB unit that has a large plan area.

Q. *Is there any specific example attesting to the advantage of using directional air distributor in CFBs burning waste or non-conventional fuels?*

Ans. The 20MW_e ACFB boiler at the Manitowoc Public Utilities (MPU), Manitowoc, Wisconsin (USA) burns a combination of petroleum coke, Tire-Derived-Fuel (TDF) and bituminous coal. Accumulation and nesting of wire from the TDF has not been experienced. Wires accumulate to a maximum level which is below the nozzle discharge. Additionally, wire pieces are found in the spent bed material leaving the bed-ash-stripper-cooler. Therefore, directional nozzles are decidedly effective in removing the wires originating from TDF.

Similarly, after several months of operation the NISCO ACFB unit (2 × 110 MW), Westlake, Los Angeles (USA) has not experienced any fluidization problems in the furnace or the stripper-cooler despite the high vanadium content in the delayed coke. This is attributed to the effectiveness of the directional distributors to dislodge any agglomerates that might have begun to form in the unit.

Q. *The screw-coolers of the 1980's are no longer favoured today; instead, fluidized stripper-coolers are preferred. What are the main disadvantages of screw-coolers?*

Ans.

1. High equipment capital cost
2. Lower limestone utilization and fuel burn-up efficiency. These two increase the plant operating cost.
3. Large cooling water requirement
4. Unrecoverable solids heat loss lowering boiler efficiency
5. Numerous mechanical and operational problems that invited unacceptable down-time and maintenance

Q. *How did the stripper-cooler overcome the drawbacks of screw-coolers?*

Ans. The stripper-cooler was developed to tide over these disadvantages of screw-coolers and to provide a system complimenting the ACFB process. The fluidized-bed stripper-cooler (Fig. 1.37) performs the following functions:

(a) Selectively removing coarse spent bed material to control the solids inventory in the lower dense bed region of the furnace

(b) Selectively sorting out and removing over-sized bed material from the furnace

(c) Classifying and reinjecting the fine unreacted limestone and fuel particles from the bed material extracted from the furnace.

(d) Cooling the spent bed material down to an acceptable temp. before discharging it into the disposal system

(e) Recycling the stripping and cooling air to the furnace and thereby making a recovery of heat from the spent bed material

(f) Insures almost total burnout of char and thereby minimizing drainage of coal in the spent bed-ash.

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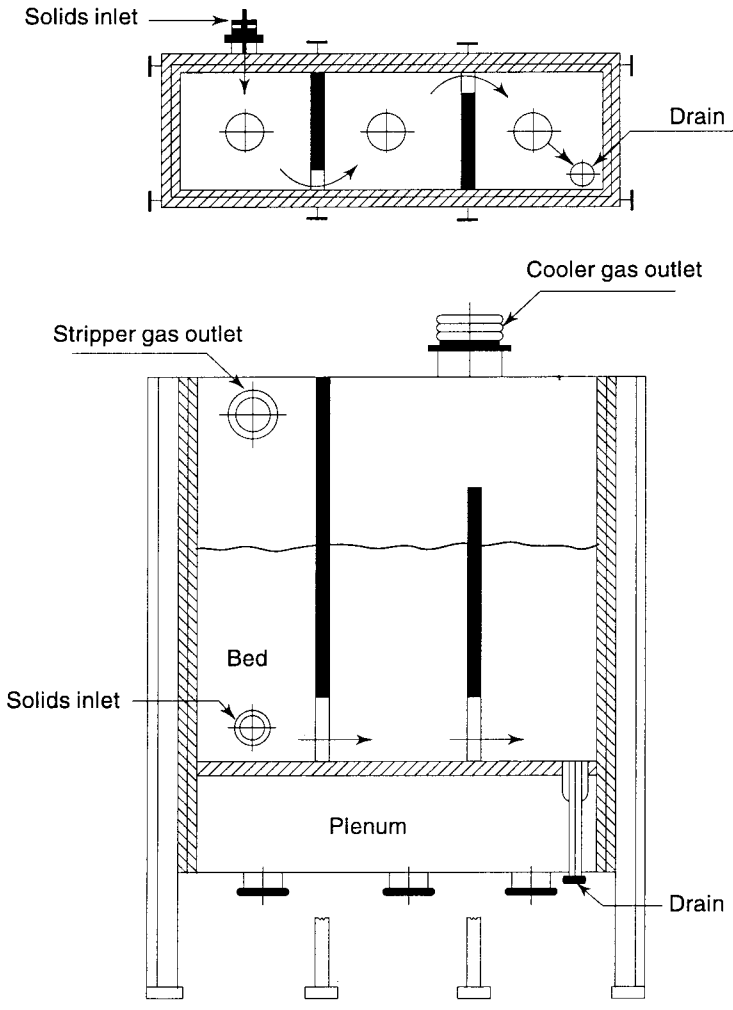

Fig. 1.37 *Stripper Cooler*
Courtesy: Foster Wheeler Corp./NJ08809-4000/USA

Q. *What is a stripper-cooler and how does it operate?*

Ans. The stripper-cooler is simply a refractory lined box with typically three fluidized compartments

(a) one stripper zone
(b) two cooling zones

Cold primary air that is bypassed around the primary air heater is used to fluidize the material in each zone. The air flowrate to the stripper zone is independently controlled to provide a sufficiently high fluidizing velocity to entrain fine material so that it can be reinjected back into the furnace alongwith the fluidizing air that then becomes part of the secondary air for combustion. The air flowrate to the cooling zones is controlled to the level required to adequately cool the solids and maintain the fluidizing velocity above a minimum level for good mixing. The stripper and cooler zones have separate ducts to return

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the fluidizing air to the furnace. The cooling zones use a common duct.

Source: SP90 - 8 (FW Tech. Paper)

Q. *Why is the fluidized bed stripper-cooler divided into multiple compartments?*

Ans. To simulate a counterflow heat exchanger from a temperature differential standpoint.

Q. *The risks of firing coal are relatively low. Until recently, the primary fuel considered in commercial projects utilizing a CFB boiler was usually low grade bituminous containing high levels of sulphur and/or ash and moisture. However, today's utilities are bent on burning waste and alternative fuels such as pet coke and anthracite culm than coal in CFB units. Why?*

Ans. The economic advantages of firing waste and alternative fuels are

1. Low delivered cost (in most cases less than $10/ton)
2. Very low ash and moisture content, therefore reduced cost of transportation and flyash disposal
3. Minimal feedsize reduction required
4. Very high heating value
5. Coarser, cheaper limestone is utilized.

These advantages reward a 30–40% reduction in steam production coast compared to CFB coal.

Q. *How far does the CFB boiler lend itself to the electric utility system?*

Ans. A power generating station requires its boilers to operate steadily on base load supplemented by the capacity to meet rapid load fluctuation as and when required.

The design of stoker fired boiler renders it inherently cumbersome to perform sharp increases or decreases in load. Hence it is lucrative and rather a practical proposition to base load them whenever possible. And then integrate the system with a CFB boiler to add new flexibility into the utility's operation.

The CFB boiler has demonstrated very fast load increase and shedding capabilities on automatic control. Also, the CFB unit can be 'hot slumped' and kept 'bottled up' in a hot condition for periods exceeding even 14 hrs. This enables the unit to be brought back into full load in a very short time without taking recourse to start-up gas burners.

Q. *Can the cycling operation of CFB be cost effective?*

Ans. Yes.

The 20 MW_e ACFB boiler of MPU has been routinely cycled since Dec. 1991. A normal operating pattern is to 'hot slump' the unit at about 10 o'clock at night and hot restart the unit at 5 o'clock the next morning. During this time, the MPU buys the low cost electric power to supply to the City of Manitowoc at the lowest cost.

Note: Despite this cycling operation coupled with many hours of firing different fuels, the MPU unit has demonstrated high availability (~ 100%).

Source: Update of Waste Fuel Firing Experience in Foster Wheeler Circulating Fluidized Bed Boilers—I.F. Abdulally & R. Navazo (SP93-16/FW)

Q. *How do fuel feeders in a CFB furnace work?*

Ans. These fuel feeders must be uniformly injected into a circulating mass of solids. The fuel flow must be uninterrupted and coking must not occur. An air swept fuel feeder developed by Foster Wheeler is illustrated in Fig. 1.38.

Q. *What is INTREX?*

Ans. INTREX is Integrated Recycle Heat Exchanger—a patented design developed by Foster Wheeler for reheat steam generator design. In fact it is a bubbling bed that forms an extension of the furnace at the point where flyash is returned to the furnace from the cyclone (Fig. 1.39).

Q. *How was the concept of INTREX born?*

Ans. In order to accommodate the reheat steam cycle, the CFB steam generator must be configured for optimum heat transfer for feedwater heating, steam generation, main steam superheating and reheating.

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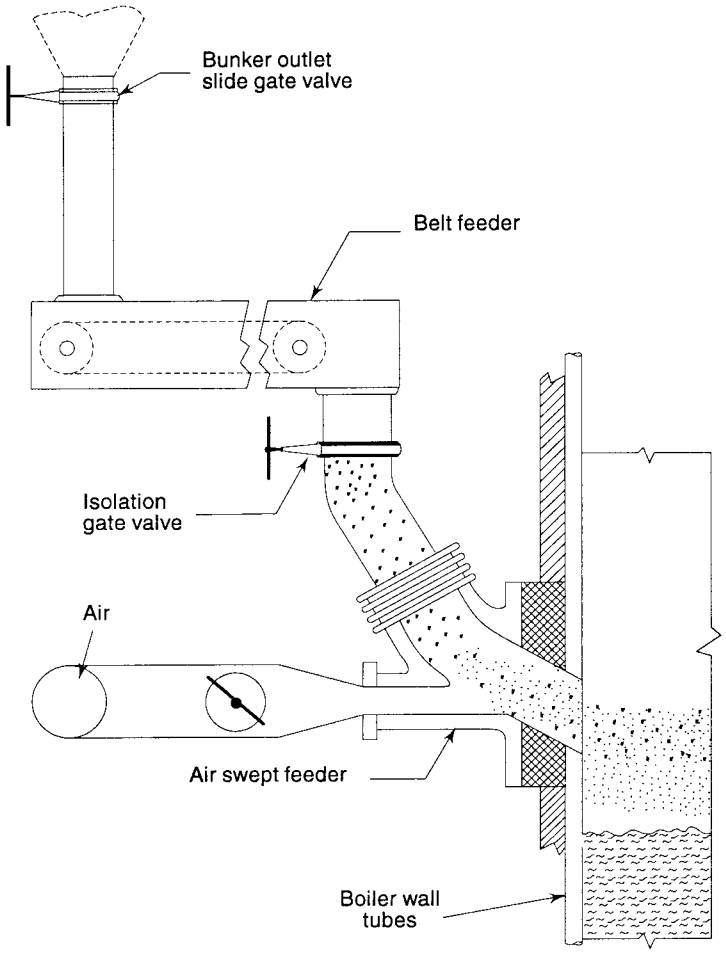

Fig. 1.38 *An air-swept fuel feeder.*
Source: SP90-8/FW Tech. Paper
Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

Because of the low operating temperature range (1115°—1170°K)* of the CFB, the split between furnace and heat recovery area (HRA) heat absorption gets defined. As a consequence, there is not much leftover heat in the flue gas entering the HRA to accomplish all superheat and reheat. Therefore, it requires some sort of superheating/reheating in the furnace solids circulation loop. This concept was translated by Foster Wheeler Corporation into reality in the shape of INTREX to provide a means to transfer a part of the furnace heat absorption duty into a bubbling-bed heat exchanger (the INTREX) eliminating the need for an excessively tall furnace or the need to install furnace panels that may experience excessive erosion.

* which permits combustion to occur below the ash fusion point while ensuring optimum temperature for limestone sulphur capture and reduced NO_x formation, and staged combustion that further reduces NO_x emissions.

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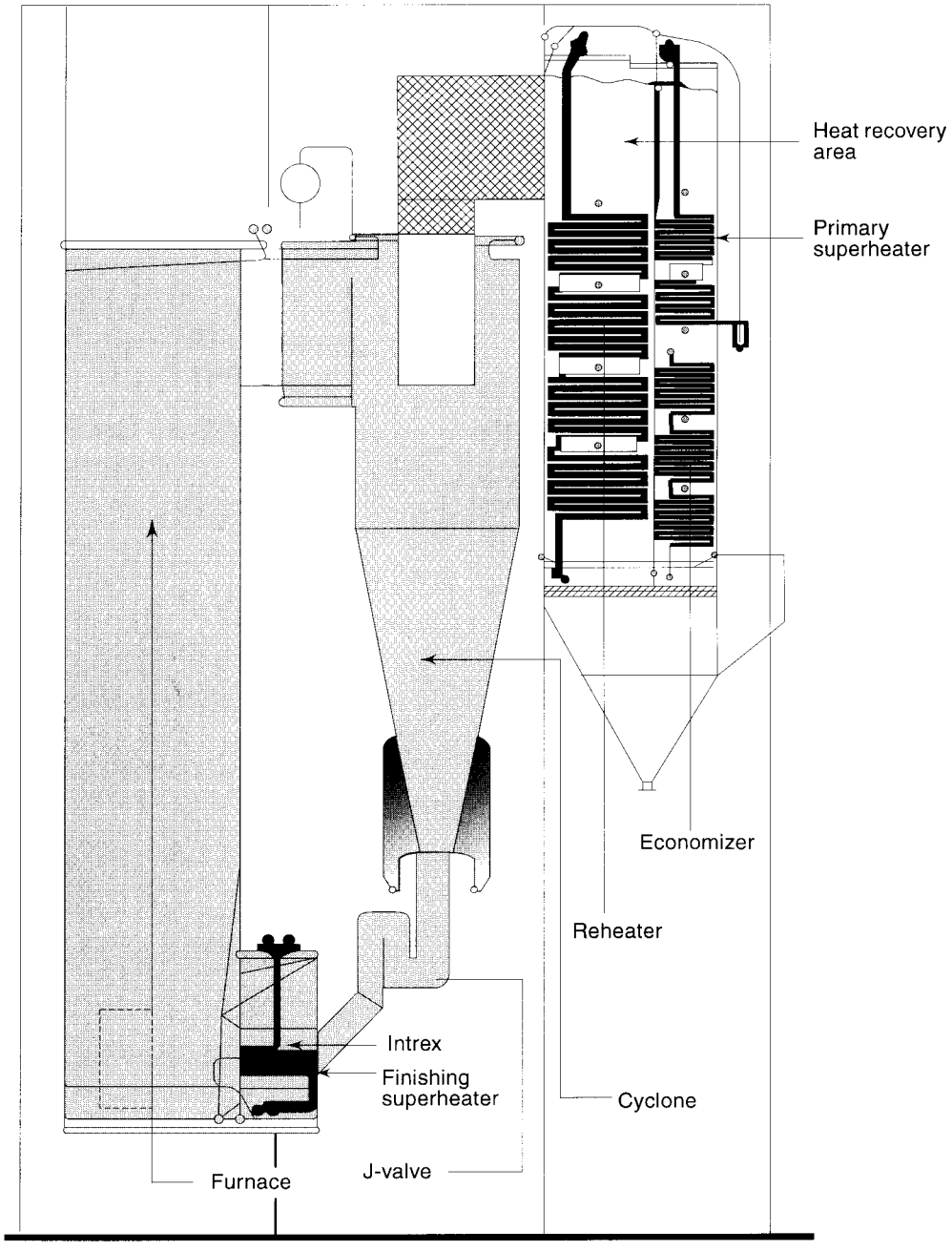

Fig. 1.39 *Foster Wheeler's CFB utility steam generator with INTREX. The intrex is simply an unfired fluidized bed heat exchanger with a non-mechanical means for diverting solids.*

Source: SP87-4R94 (FW)
Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

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Q. *How does the INTREX system work?*

Ans. Solids entrained in the flue gas leaving the CFB combustor are collected by the cyclone separators and drop into the J-valves (Fig. 1.40).

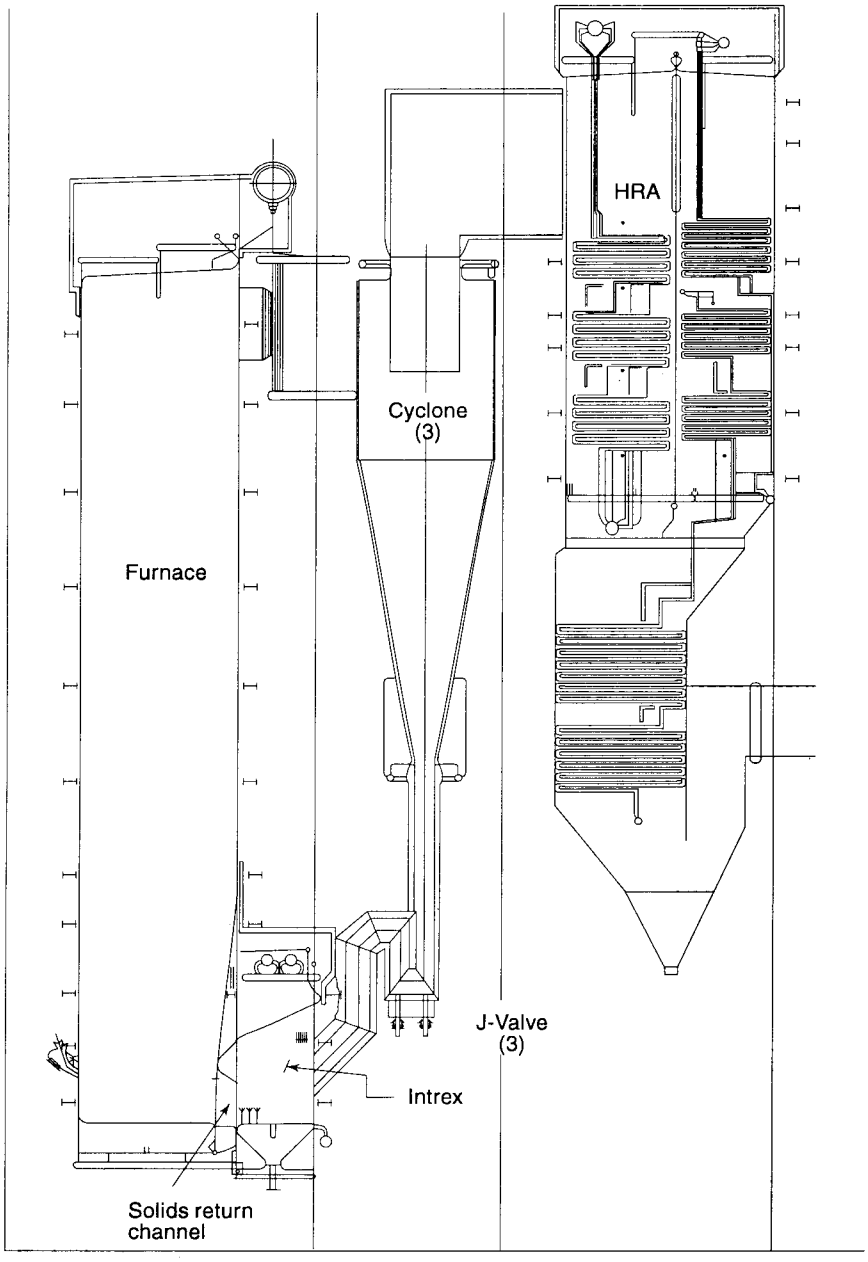

Fig. 1.40 *Reheat CFB Steam Generator*
Source: SP90-8 (Tech. Paper/FW)
Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

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From the *J*-valves, the solids flow into the INTREX inlet channels which have screen openings at the bottom of the partition walls that separate the inlet channels from the main steam-cooled INTREX cells (Fig. 1.41).

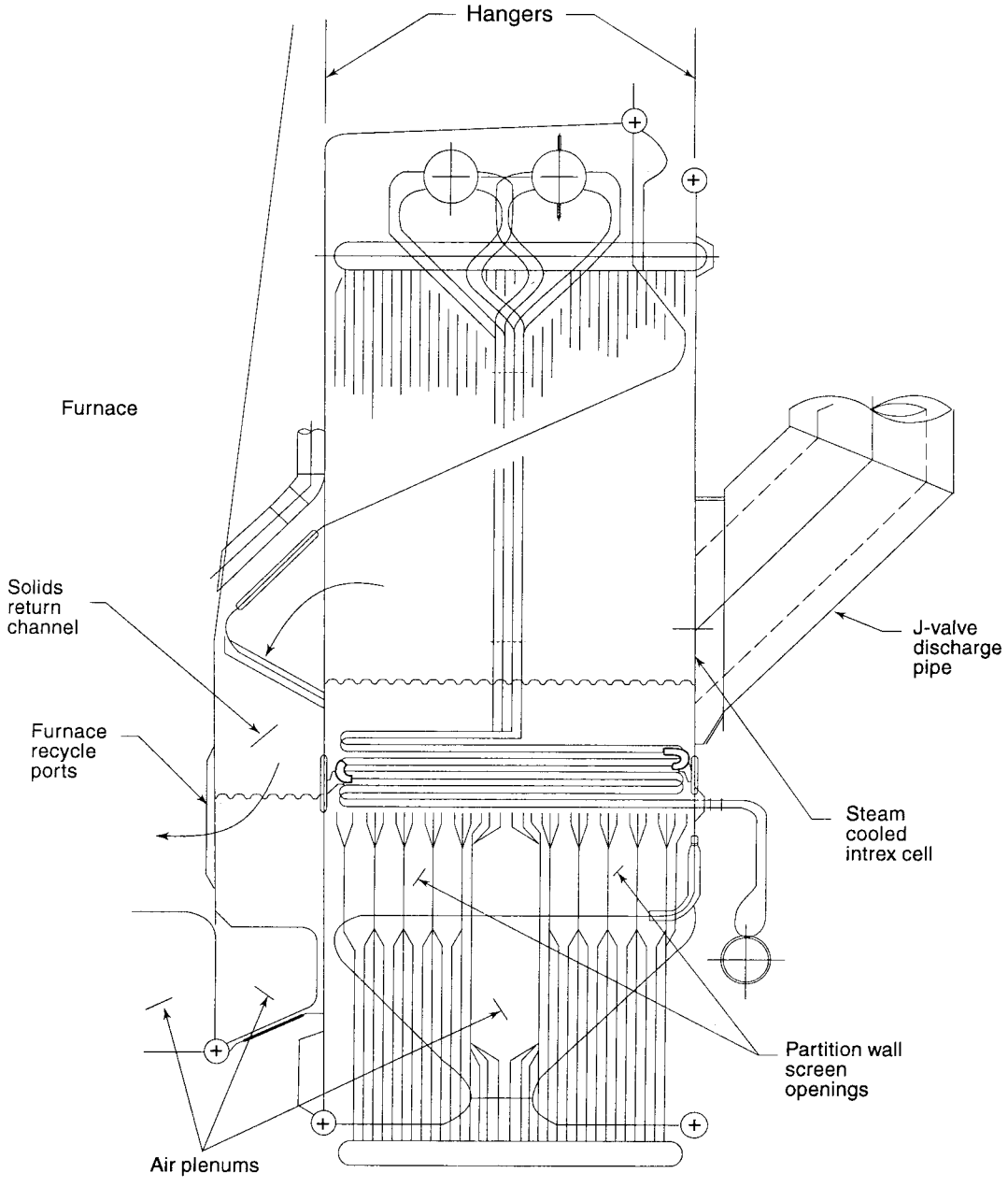

Fig. 1.41 (A)

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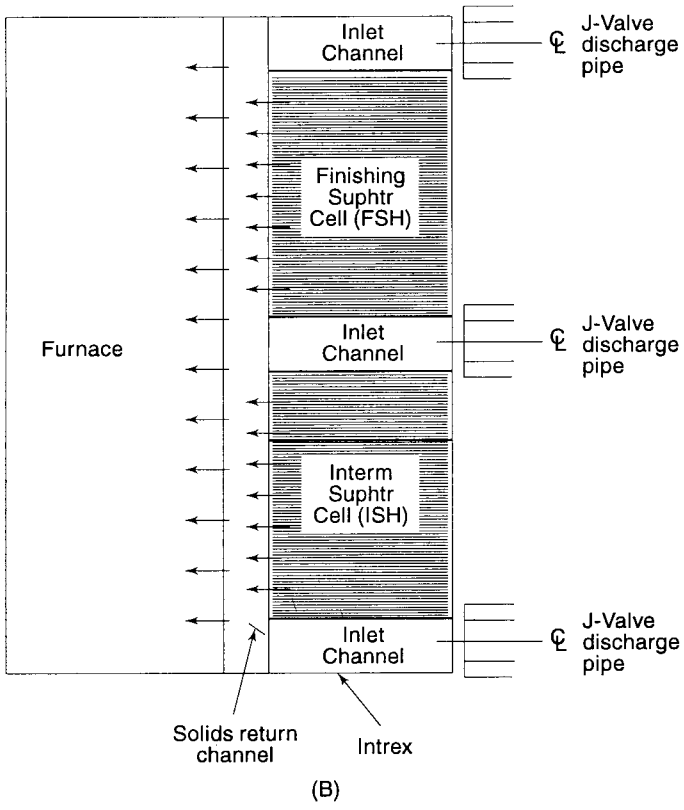

Fig. 1.41 *(A) Intrex side elevation*
(B) Intrex plan elevation
Source: SP90-8(Tech. Paper/FW)
Courtesy: Foster Wheeler Corpn/NJ 08809-4000/USA

During normal operation, the solids flow through the partition wall openings, under and then up through the tube coils transferring in the process, some of the sensible heat of the solids into the superheater coils and into the waterwalls forming the enclosure of the INTREX.

The solids thereafter spill through screen openings in the INTREX frontwall that forms the SRC in combination with the furnace rearwall and sidewalls. SRC uniformly returns 'cooled' solids to the furnace. The recycled solids fluidized by air in the INTREX flow into the combustor from the SRC through multiple openings distributed along the furnace rearwall.

The solids cooled in the INTREX and transported back to the combustor, and the heat absorbed in the water-cooled furnace enclosure walls and the steam-cooled cyclones, maintain the furnace at relatively isothermal conditions for optimum carbon burn-up and emissions control. The main steam temperature is controlled by spray water attemperators upstream of each INTREX superheater.

Q. *What are the utilities of INTREX?*

Ans.

1. It takes the advantage of the excellent heat transfer coefficient in a bubbling bed

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2. Because of the low wear potential of the fine solids (about 200 μm), uniformly sized flyash and low fluidizing velocities (0.15–0.45 m/s) tube wear is not a concern.
3. Hooking up an INTREX with a CFB enables the designer to size the furnace for complete combustion of feed fuels while keeping all H.E. coils out of highly erosive environment.
4. It also serves to maintain a consistent solids temperature throughout the cycle.

Q. *Why is special armoured protection or tube treatment (chromizing) required to protect the inbed tubes in a bubbling fluidized bed (BFB) but not in he case of CFBs with INTREX system?*

Ans. BFBs operate with coarse (30 mm) fuel feed, high fluidizing velocities (2.5—3 m/s) that subject the inbed heat exchanger tubes to a highly erosive atmosphere. Therefore, these tubes need special protection while the INTREX tubes working under the low wear potential of fines require no such protection.

Q. *What are the basic design features of INTREX?*

Ans.

1. Integrated Water-Cooled Configuration
2. Nonmechanical Means for Diverting Solids
3. Solids Return Channel
4. Passive design.

Q. *What do you mean by 'integrated water-cooled configuration' of INTREX? How does it differ from conventional EHEs?*

Ans. While the conventional external heat exchangers are typically large refractory layered boxes located at a distance from the furnace, the INTREX is formed by the same water-cooled membrane construction (MONOWALL) used for the furnace. It is positioned so that the furnace rearwall is inline with the INTREX frontwall. That is the INTREX is inducted as a basic component of the lower part of the combustor.

Q. *How does this design beget advantages with respect to conventional EHEs?*

Ans. EHEs are located outside and positioned at a distance from the furnace. These large, heavy weight refractory-lined boxes must be supported from the bottom. Also they require large refractory-lined ducts for return of solids to the furnace, and require a hanger arrangement for tube support. While the furnace and cyclone are top supported and growing downward, the bottom supported EHEs grow upward. These features inherently require significant flexibility in design to accommodate large refractory lines that extend from the heat exchanger.

As against this, the INTREX is top supported and grows downward at the same rate as all the other water-cooled pressure parts. Load is picked up from the furnace rearwall, and the downcomers and risers that service the INTREX from the steam drum.

Q. *What is the principle of providing non-mechanical means for diverting solids to the INTREX?*

Ans. It is a safety system to protect the INTREX superheater tubes during start-up and emergency trip. For this, the technique of differential fluidization and a simple pressure balance between adjacent fluidized beds can be harnessed* directly back to the furnace bypassing the main steam-cooled INTREX beds.

Q. *How is this accomplished?*

Ans. Under normal operating conditions, all solids collected by the cyclones are passed through the steam-cooled INTREX beds by fluidizing the main cells at a higher superficial velocity than the inlet channels and directing the flow of solids through the screen openings in the bottom area of the partition.

* instead of installing a high temperature mechanical valve walls, under and up

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through the supperheater coils, spill through the weir ports formed by screen tube openings and fall into the solids return channel.

By means of differential fluidization and a simple pressure balance between the adjacent fluidizied beds, entire solids settling in the cyclone can be directed through the INTREX cells.

However, during emergency shutdown conditions or during start-up the solids collected in the cyclones are passed directly into the solids return channel, bypassing the main steam-cooled INTREX beds. This is accomplished by activating the tall fluidization nozzles that extend above the screen openings in the bottom of each partition wall, while the lower nozzles in the inlet channels are kept shut. As a consequence, a defluidized zone is generated that deters solids from flowing into the main cells. The solids entering the inlet channels then expand up to the inlet weir ports and drop into the solids return channels.

Note: The high and low nozzles, in essence, act as a fluid switch that puts the INTREX into a bypass mode of operation thereby eliminating the need for high temperature mechanical valves.

Q. *What is SRC?*

Ans. It stands for Solids Return Channel.

The SRC is a single fluidized bed that is common to all INTREX.

Q. *What is the primary function of SRC?*

Ans. The primary function of SRC is to provide a means to uniformly return the recycled solids to the furnace.

Q. *What is the utility of SRC?*

Ans.

1. In case flow unbalance occurs between the cyclones or INTREX cells, aeration of the SRC will uniformly distribute the solids through each of the ports provided in the furnace rearwall.
2. It provides a buffer zone between the INTREX and the furnace to prevent coarse particles spit-back into the INTREX beds.

Q. *How is the backflow of furnace materials into the SRC prevented?*

Ans. With the INTREX fluidizing air and recycled solids returning to the furnace via the same ports, the bed level in the SRC is kept at a minimum height and a positive momentum is maintained into the furnace that prevents the backflow of furnace material.

Q. *How is the CFB furnace given refractory protection?*

Ans. In areas of high solids concentration, substoichiometric atmosphere, or direct solids impingement (these areas include the lower furnace enclosure walls, roof, and peripheral area around each cyclone inlet), refractory protection is given to the heat exchange surfaces. Foster Wheeler Corporation applies a thin layer (13mm) of phosphate bonded, high alumina refractory with stainless steel reinforcing fibres on a high density stud pattern (Fig. 1.42).

This configuration is claimed to beget maximum wear resistance with high thermal conductivity for heat transfer.

Source: The Foster Wheeler Approach to CFB Technology

—S.J. Goidich & M. Seshamani (SP 90-8/Foster Wheeler)

Q. *"Pressurized circulating fluidized bed (PCFB) technology may be the most promising for meeting the objectives of future coal-firing applications."*

Why?

Ans. PCFB is one of the clean coal technologies that offer the greatest potential to maximize the competitiveness of coal-fired power generation due to high plant efficiency, low environmental emissions, low capital costs, low operating costs, and ultimately, a low net cost of electricity.

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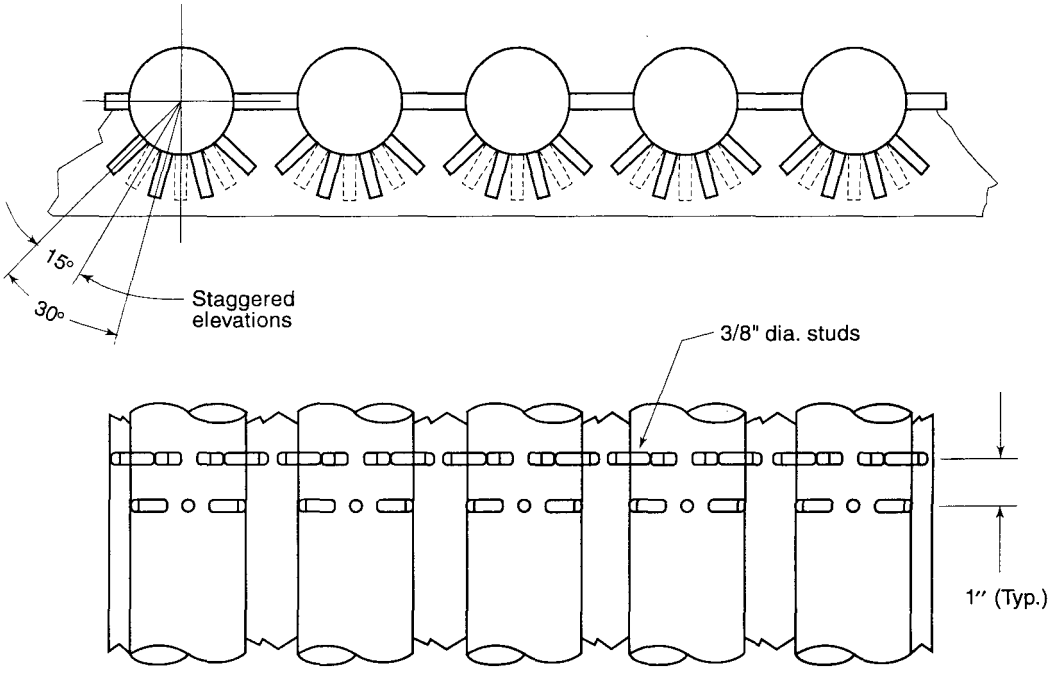

Fig. 1.42 *Refractory Anchoring Method*
Source: SP90-8 (Tech. Paper/FW)
Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

When compared to conventional pulverized coal/scrubber technology, the PCFB can produce a 10—15% higher net plant efficiency at a lower cost, while satisfying the strictest emissions requirements. Over and above, the PCFB technology is eminently suitable for supercritical steam conditions that will allow achievement of even higher net plant efficiencies. Like other clean coal technologies such as pressurized bubbling fluidized bed (PBFB) or integrated gasification-combined cycle (IGCC), the PCFB will have very high efficiency and very low emissions. Because of process simplicity and the capability to operate the system at very low excess air levels, the PCFB technology is expected to have much lower capital cost, operating cost, and resulting cost of electricity.

Q. *How does the PCFB technology work?*

Ans. Pressurized circulating fluidized bed (PCFB) technology utilizes a circulating fluidized bed (CFB) boiler operating at 1.2—1.6MPa, in combination with a high temperature particulate removal system (ceramic filter). The hot, pressurized gas produced in the combustion process generates high quality steam in the combustor for expansion in a ST and is then expanded in a GT to efficiently generate power in a combined cycle system (Fig. 1.43).

In the PCFB cycle, compressed air from a GT-driven-air compressor flows through the pressure vessel to the PCFB combustor. The coal mixed up with water and limestone is fed as a paste to the combustor where combustion occurs at about 1145°K at elevated pressure. Inasmuch as the combustion takes place at elevated pressures, the combustion efficiency is almost 100%, even at

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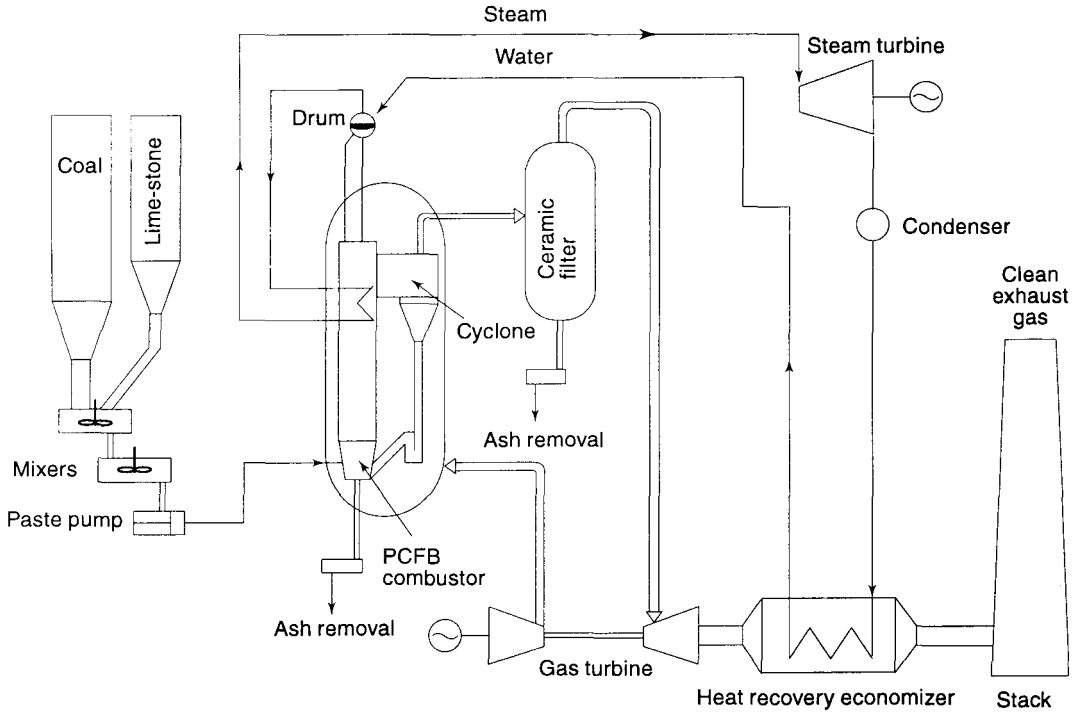

Fig. 1.43 *PCFB technology flow diagram. Ahlstrom Pyroflow PCFB system.*
Source: *PTP-71 (Tech. Paper/Ahlstrom Pyropower)*
Courtesy: *Ahlstrom Pyropower Inc./San Diego/Ca 92121/USA*

very low levels of excess air. Heat transfer surfaces located in the combustor control the combustion temperature and allow the generation of HP steam. The high pressure superheated steam from the PCFB goes to the steam header and into the steam turbine cycle to generate the lion's share (i.e. about 80%) of the plant electrical power.

The high pressure combustion gas from the PCFB combustor is passed ceramic filters to arrest the gas-borne particulates. The resulting clean gas is then directed to a conventional single-shaft gas turbine. The most significant feature of the gas turbine's adaptation for the PCFB application is that, for some GTs, the casing of the GT is modified to allow for return of hot, clean, pressurized flue gas to the expander. Gas turbines that are already configured with external (silo type) combustors will not require this adaptation. Flue gas flows through the GT expander to drive the compressor and to provide the remaining 20% of the station output to complement the power from the steam turbine. The heat in the GT exhaust is utilized for feedwater heating.

The plant load is controlled by varying the fuel and air flow-rates to the combustor. Unlike bubbling bed PFBs, the PCFB requires no bed material inventory adjustment. Sulfur dioxide (SO_2) removal is accomplished within the combustor by reaction with the limestone fed with the coal paste. Capability has been demonstrated to effectively control SO_2 under pressure at significantly lower Ca : S ratios than are typically required ACFBs. Over and above, NO_x emissions from the process gets minimized due to staged combustion, and can be further reduced, if necessary, by injection of ammonia into the process.

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Q. *Pilot plant test* results show that the PCFB can utilize 10% excess air while still maintaining a combustion efficiency of nearly 100%. Why is this high combustion efficiency achieved even at low excess air?*

Ans. This high combustion efficiency is ascribed to the effects of pressure on gas diffusion and the excellent lateral mixing or particles and gas in the relatively small pressurized combustion chamber. For all types of coals, carbon conversion efficiencies in the range of 99.8% to over 99.9% have been consistently achieved.

Q. *Why are the high combustion efficiency and low excess air level important parameters in PCFB systems?*

Ans. High combustion efficiency has two important advantages:

1. Efficient utilization of coal. This higher fuel utilization rewards higher overall net plant efficiency.
2. Low residual carbon in ash due to high burnup. This improves the disposal properties and the potential for commercial utilization of the solid waste products.

Low excess air is important for the following reasons:

1. Since the temperature in a CFB is primarily controlled by the generation and superheating of steam in the combustion, high excess air levels are not necessary to control combustor temperature.
   This is not true for IGCC technologies where an adiabatic combustor is used to directly fire the GT. The temperature of this combustor must be controlled by firing with high levels of excess air, typically in the range of 250 to over 300%.
   The net result is that for a given GT, more air provided by the gas turbine's compressor is available for combustion rather than temperature control and so more fuel can be fired. More heat input results in greater power output. Ultimately, the result is a significantly lower capital cost.
2. As excess air levels are reduced, less NO_x emissions are produced, allowing very low NO_x levels without additional controls.

Q. *How much is the sulphur capture in PCFB?*

Ans. Typical pilot plant data for sulphur capture in the PCFB at Karhula, Finland is shown in Fig. 1.44.

The sulphur content of the coals tested have varied from 0.43% to 3.5% (on a dry basis). For high sulphur coals, as much as 90% sulphur capture has been typically achieved while using a calcium-to-sulphur molar ratio in the range of 1.15. Sulphur capture to the extent of 95% has been typically achieved with Ca:S ratio in the range of 1.4—1.5. In many tests, sulphur removal efficiencies as high as 98% and even exceeding 99% have been achieved.

Q. *Is the mechanism of sulphur capture in a PCFB same as that in ACFB?*

Ans. No.

The mechanism of sulphur capture with limestone under pressurized conditions is different than the mechanism under atmospheric conditions.

Q. *Why?*

Ans. This is because limestone ($CaCO_3$) does not calcine at the high CO_2 partial pressure conditions present in the PCFB. The result is that SO_2 in the flue gas reacts straightway with $CaCO_3$, releasing CO_2 during the absorption process

$$CaCO_3 + SO_2 + \frac{1}{2}O_2 \longrightarrow CaSO_4 + CO_2$$

It is believed that this release of CO_2 continuously exposes new reaction sites on the surface of limestone particles, allowing more complete utilization of the limestone.

* AHLSTROM PYROPOWER'S 10 MW_e PCFB pilot plant in Karhula, Finland has logged, since it's start-up in 1989, more than 6000 hrs of successful operation with various coals and sorbents.

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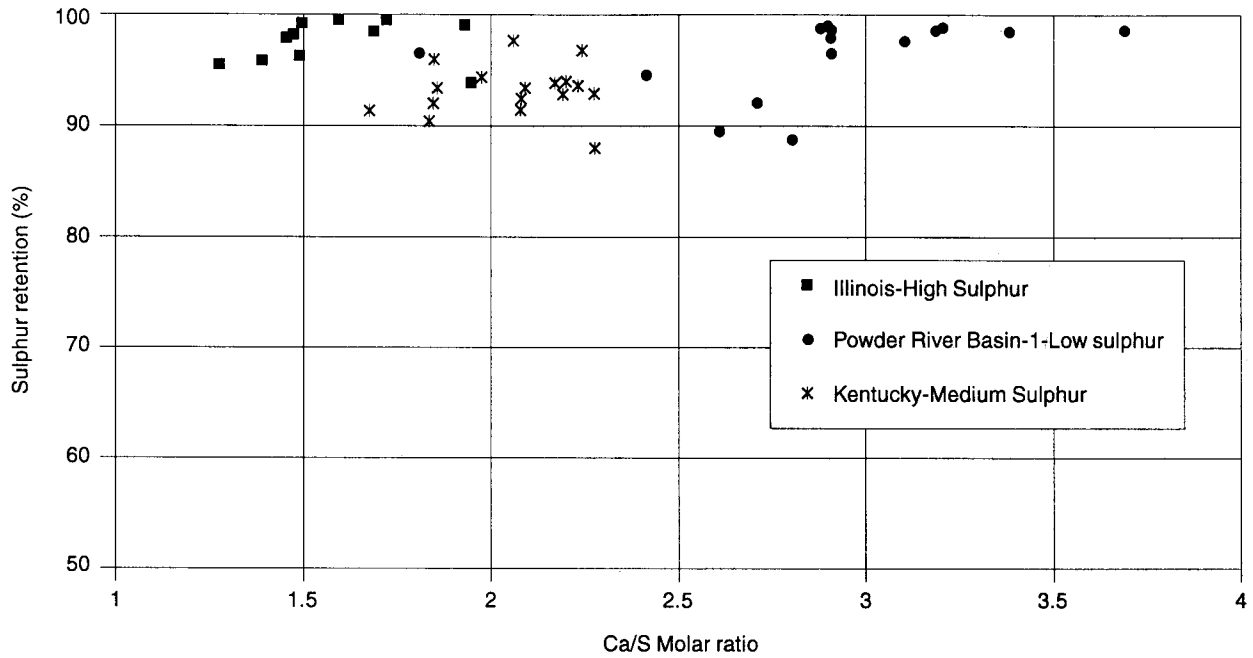

Fig. 1.44 *Sulphur retention for low, medium and high sulphur coals.*
Source: PTP-99 (Tech. Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower INC/San Diego/CA 92121/USA

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Q. *What is the level of NO_x emissions in PCFB combustion?*

Ans. 100 ppmvd (0.086—0.129 kg/MMKJ) or below can be achieved. Figures 1.45 and 1.46 show typical pilotplant data on NO_x emissions.

Q. *What is the reason for such low levels of NO_x emissions from PCFB units?*

Ans. Thermal NO_x production during any fuel combustion is dependent on the combustion temperature, the excess air level, and the distribution of primary and secondary air (combustion air staging) in the combustor. The capability to operate at low levels of excess air, the relatively low combustion temperature in the PCFB (1115—1200°K), and optimal combustion air staging, minimize the production of NO_x in the PCFB.

Q. *Can the NO_x-emission levels be further reduced?*

Ans. Yes; it can be further reduced by 60%—90%, by injecting ammonia at selected locations in the process (non-catalytic reduction of NO_x)

$$NO + NO_2 + 2\ NH_3 \longrightarrow N_2 + 3\ H_2O$$

Q. *Will reducing NO_x emission level not invite 'ammonia slip', another environmental concern?*

Ans. Yes; but the measured levels of ammonia slip have been observed to lie below those observed in conventional technologies.

Q. *What are the other clean coal technologies that compete with the PCFB?*

Ans.

1. Pulverized Coal/Scrubber (PC/Scrubber) technology
2. Pressurized Bubbling Fluidized Bed (PBFB) technology
3. Integrated Gasification/Gasification Cycle (IGCC) technology

Q. *How does the PC/Scrubber clean coal technology operate?*

Ans. This is a conventional coal-burning technology with a radiant, balanced-draft, direct-fired pulverized coal (PC) fired boiler typically fitted with a regenerative air heater, a selective catalytic reduction (SCR) reactor for NO_x control, a wet limestone, forced oxidation spray tower flue gas desulphurization (FGD) for SO_2 control, and a baghouse for particulate control.

One such process is schematically presented in Fig. 1.47.

All of the coal fired is used to generate steam which is utilized in a conventional Rankine steam turbine cycle.

Q. *How does the PBFB system operate?*

Ans. The pressurized bubbling fliuidized bed (PBFB) technology utilizes a bubbling fluidized bed boiler operating at 1.2—1.6 MPa inside a pressure vessel in conjunction with a gas turbine combined cycle (Fig. 1.48).

Combustion air is compressed in a twin-shaft, intercooled GT-driven-air-compressor and flows to the PBFB combustor. Coal is fed as coal-water paste to the combustors. A part of the combustion-heat is used to generate steam in the inbed heat transfer surface. The steam then flows to the steam turbine which generates approximately 80% of the plant power output.

In some PBFB designs, primary and secondary cyclones are utilized to remove some of the particulate from the flue gas upstream of GT. Of course, the blading for the PBFB-GT expander is extra ruggedized to accommodate a certain level of erosion by the particulate in the flue gas. The remaining particulates from the PBFB flue gas are then removed in baghouse filter before letting it out to the atmosphere. In other PBFB designs, a hot gas filter is used to remove all the particulates before the gas enters the gas turbine and no gas cleaning downstream is required.

Q. *How does the IGCC system work?*

Ans. Integrated Gasification-Combined Cycle (IGCC) technology operates on an entrained bed slagging, oxygen blown coal gasification process, with "cold gas" clean up technology for conversion of COS to H_2S and for the removal

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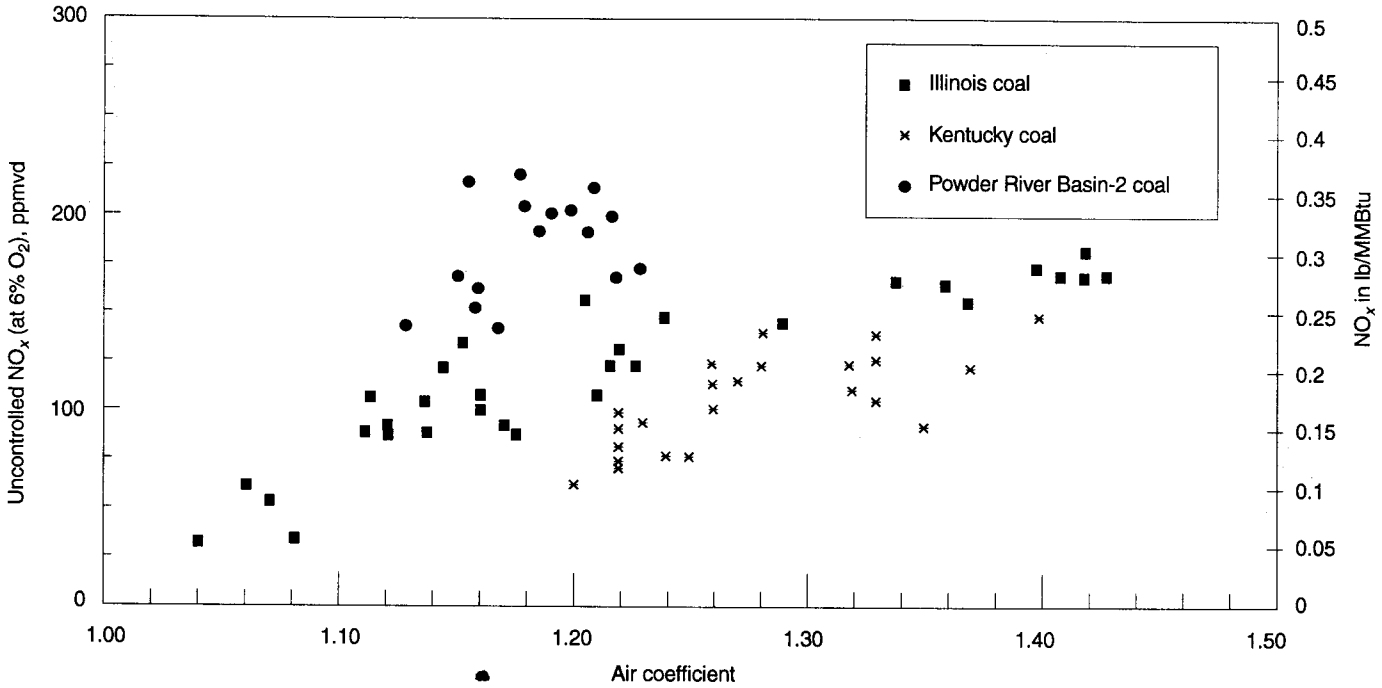

Fig. 1.45 *NO_x emission vs excess air w/o ammonia injection*

Source: PTP-99 (Tech. Paper/Ahlstrom Pyropower)

Courtesy: Ahlstrom Pyropower INC/San Diego/AC 92121/USA

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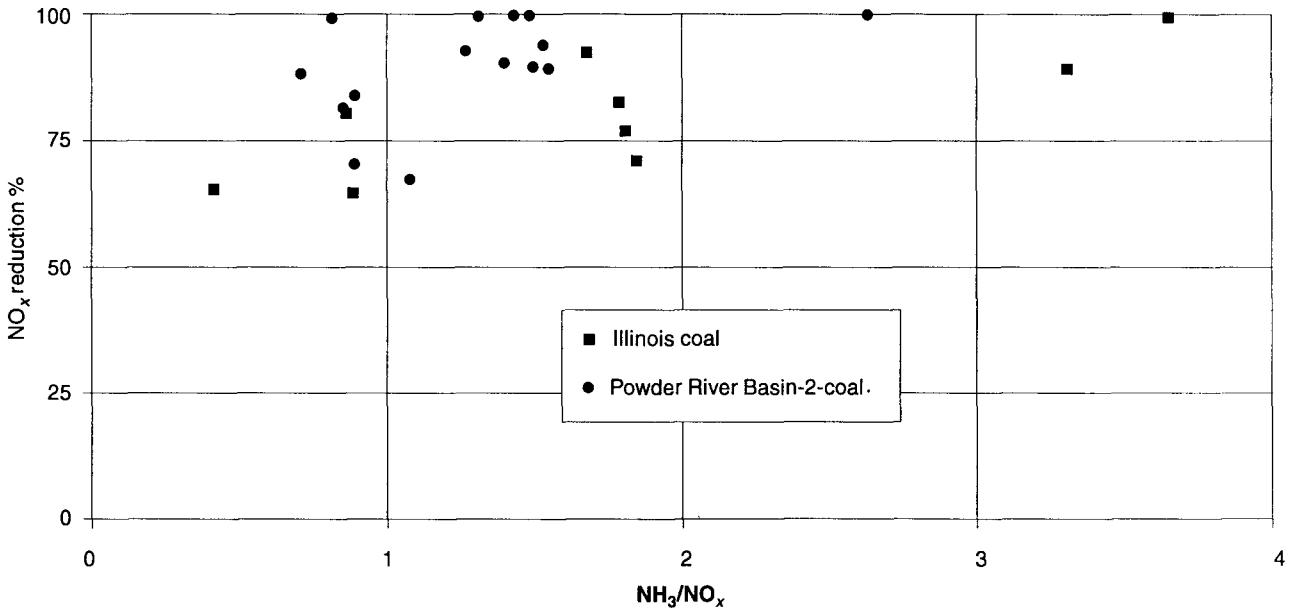

Fig. 1.46 *NO_x Reduction by Ammonia Injection*
Source: PTP-99 (Tech. Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower INC/San Diego/AC 92121/USA

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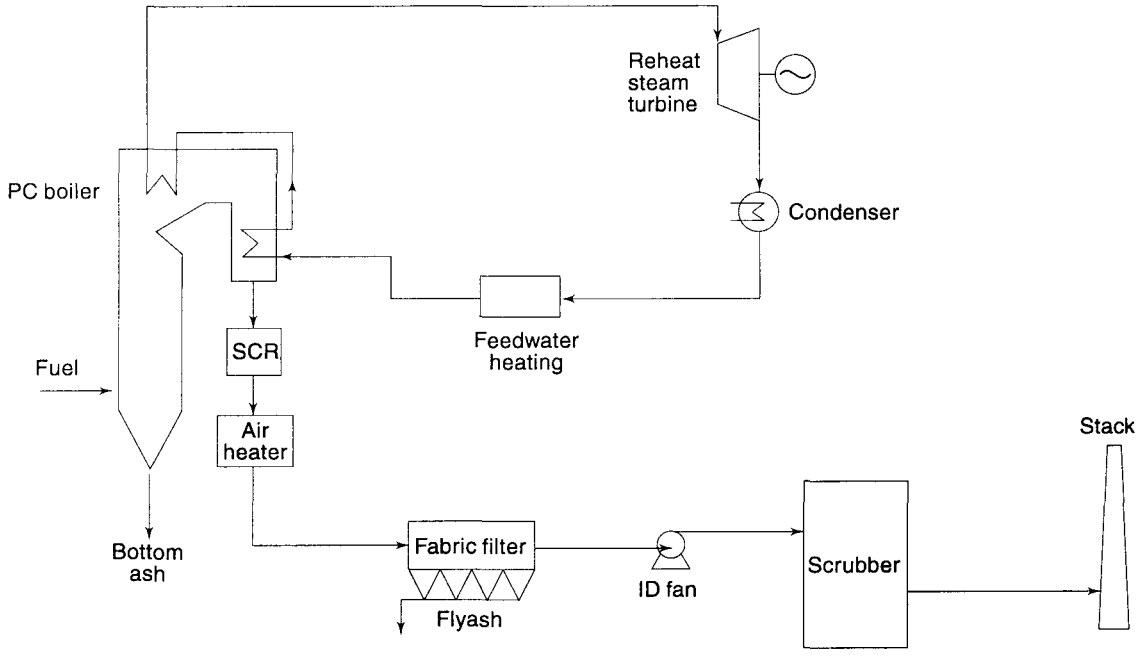

Fig. 1.47 *Pulverized coal boiler with wet scrubber*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc/San Diego/CA 92121/USA

of H_2S, NH_3, HCN and soot etc. The treated syngas is fired in a gas turbine combined power-plant keeping air level as high as 250—300% (15% O_2). The GT produces about two-thirds of x the plant electrical power output.

The hot flue gas exiting GT is utilized to generate steam in a HRSG. The superheated steam flows to the steam turbine cycle where the remaining electrical power is generated (Fig. 1.49).

The IGCC system requires an air separation unit (ASU) separating the air stream into elemental O_2 and N_2. In a medium integration IGCC (Fig. 1.49), atmospheric air is compressed and separated in the ASU. The fractionated O_2 is charged to the gasifier as the gasification agent while a part of the N_2 fraction is used for coal conveying and most of the N_2 is vented to the atmosphere.

In the more efficient, high integration IGCC (Fig. 1.50), the air to the ASU is obtained from the GT-driven air compressor. The O_2, as usual, is fed to the gasifier, some of N_2 is used for coal transporting and the remaining N_2 is mixed with the syngas to increase the mass flow of the GT and, hence, the gas turbine power output, and also to aid to the reduction of NO_x in the GT. Feedwater and steam superheating circuitry is also integrated between the ASU, gasification plant, and combined cycle plant to make optimum use of low level heat.

Q. *What is the plant performance of PCFB with respect to comparable IGCC unit?*

Ans. Performance for a PCFB utilizing a 16.5 MPa/810°K/810°K steam cycle/62.5mm Hg condenser pressure, 406°K stack gas temperature and firing Illinois 6 coal is shown in Table 1.4.

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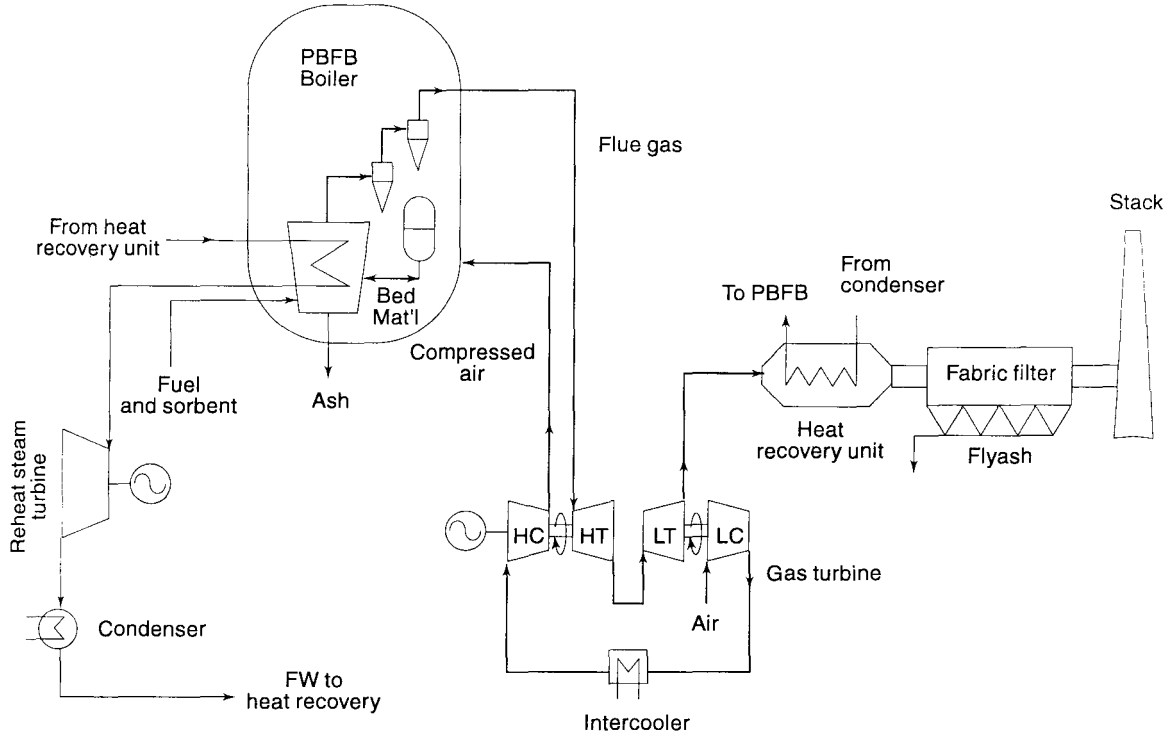

Fig. 1.48 *Pressurized Bubbling Fluidized Bed (PBFB) cycle*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA92121/USA

Table 1.4 *Comparison of PCFB to IGCC*

Process		PCFB	IGCC (High Int.)
Excess air	%	10%	300%
O_2 in flue gas	%	2%	15%
Air to cooling GT blading	%	9%	20%
Gas Turbine Output	MW_e	75	175
Steam Turbine Output	MW_e	303	110
Station Power	MW_e	15	30
Net Power Output (with equiv. GT)	MW_e	363	255
Plant Cost	million	$398.5	$424.1
Capital Cost	$/kW	1095	1663
Heat Rate (HHV)	Btu/kW-hr	8,558.	8,460
Levelized COE	¢/kWh	5.1	6.3

* PCFB heat rate can be improved by 300+ Btu/kwh using supercritical steam conditions.

Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA92121/USA

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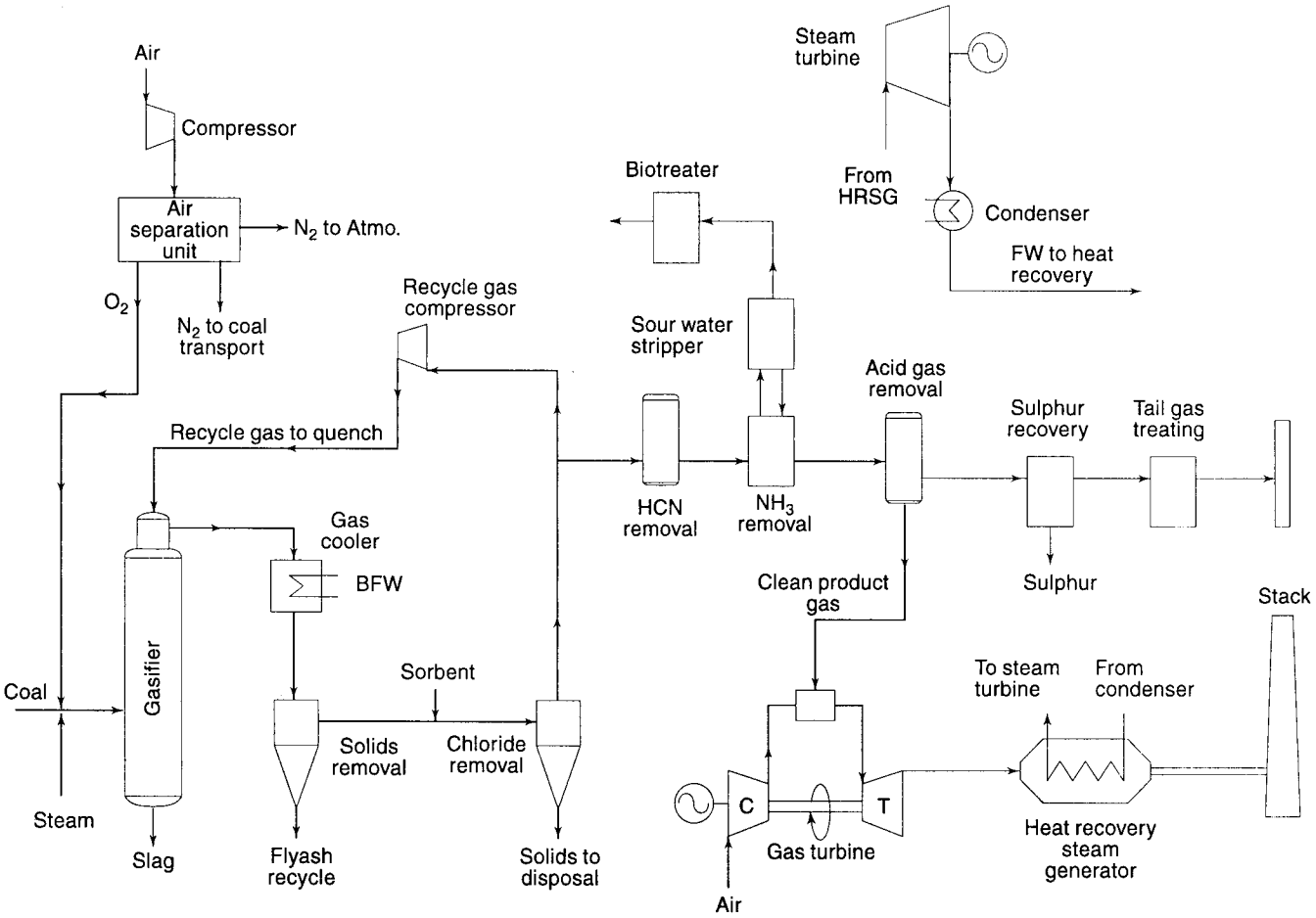

Fig. 1.49 *Medium Integration Gasification Combined (IGCC) Cycle.*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA 92121/USA

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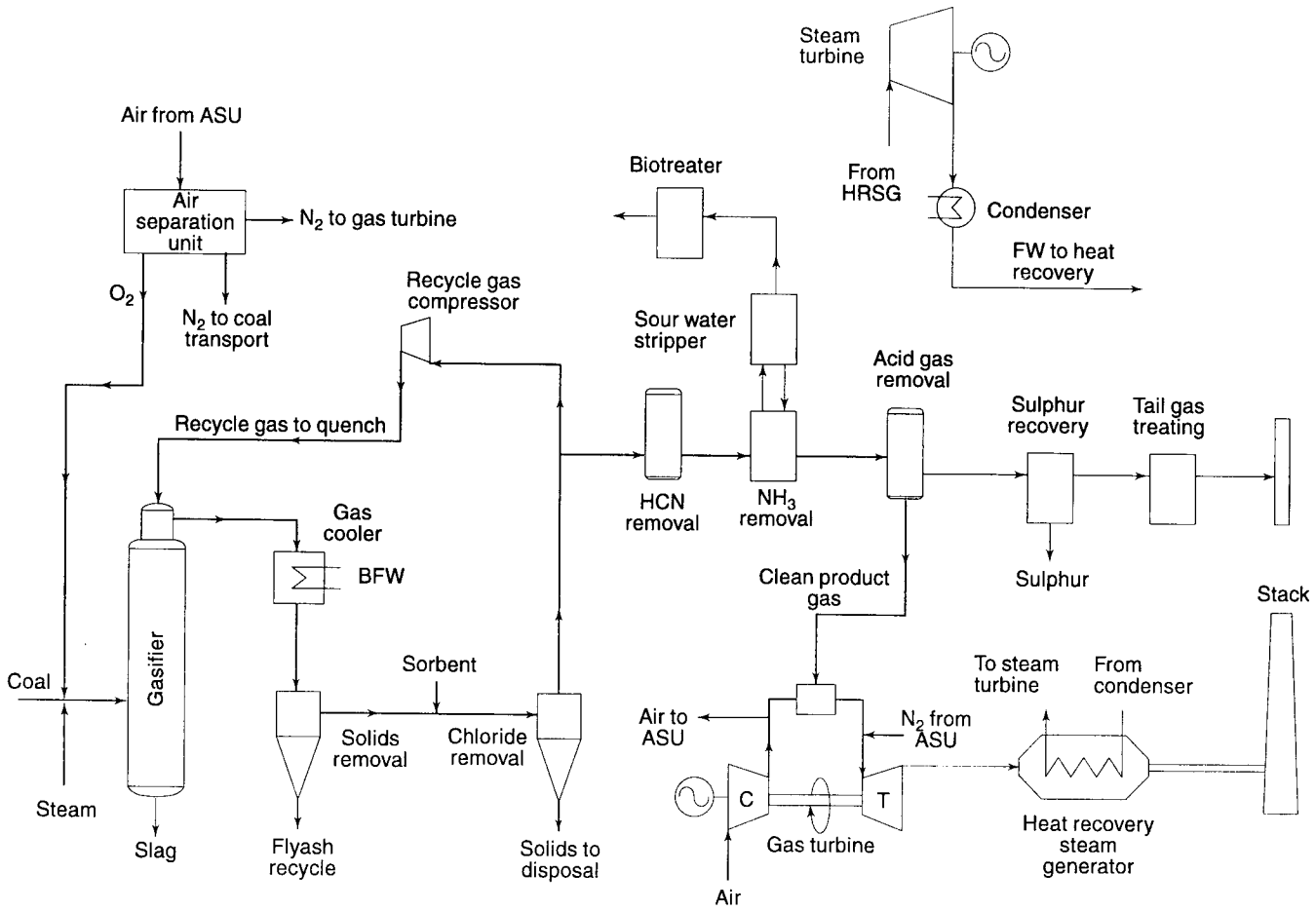

Fig. 1.50 *High Integration Gasification Combined Cycle (IGCC).*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA 92121/USA

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The IGCC used for comparison operates on 10 MPa/810°K/62. 5mm Hg non-reheat cycle with stack gas temperature of 408°K.

Q. *How can the PCFB be compared with other clean coal technologies?*

Ans. Fig. 1.51 shows a heat rate comparison of the clean coal technologies.

PC/SCRUBBER Unit : a radiant, balanced draft direct-fired pulverized coal (Illinois #6 coal) fired boiler operating on 16.5 MPa/810°K/810°K/62. 5mm Hg steam cycle, 405°K stack temperature.

PBFB Unit: 16.5 MPa/810°K/810°K steam cycle/62.5mm Hg condenser pressure/405°K stack temperature.

PCFB Unit: 16.5 MPa/810°K/810°K steam cycle/62.5 mm Hg condenser pressure 405°K stack temperature.

IGCC Unit: 10 MPa/810°K/62.5mm Hg non-reheat cycle with stack temperature of 408°K

Fig. 1.52 shows a comparison of plant capital costs of different clean coal technologies.

The PCFB shows a lower cost/kW than all of the other technologies.

Fig. 1.53 shows a comparison of the levelized cost of electricity for the clean coal technologies.

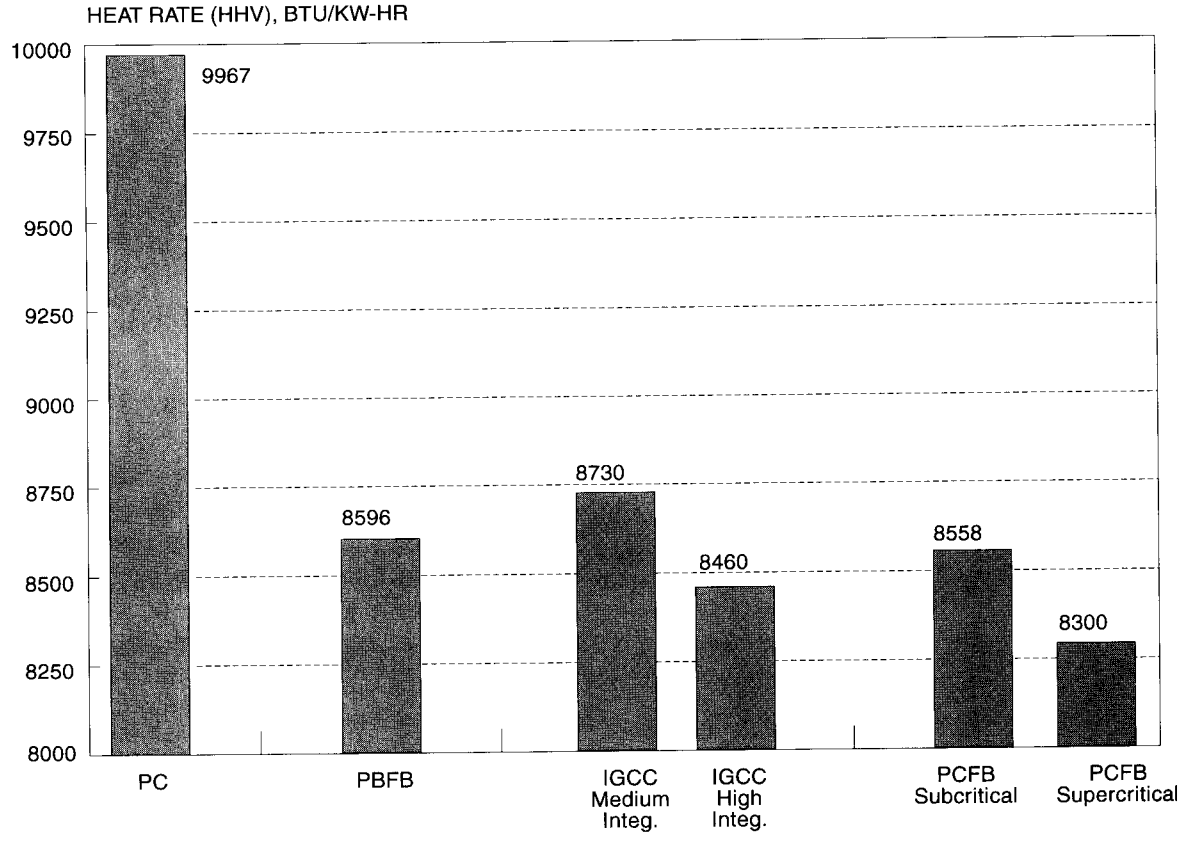

Fig. 1.51 *Net heat rate.*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA 92121/USA

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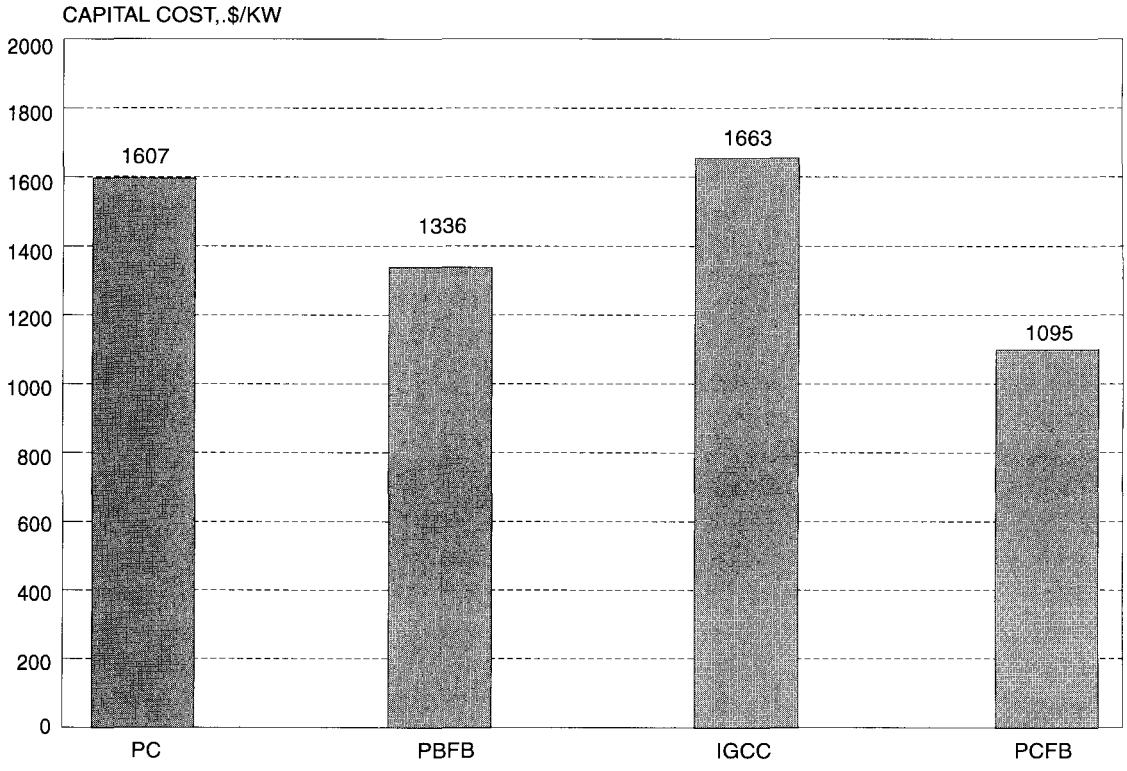

Fig. 1.52 *Plant capital cost*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA 92121/USA

As shown in Fig. 1.53, the PCFB has the lowest levelized cost of electricity. This is due largely to its high efficiency and low capital cost requirements.

While the high integration IGCC has a slightly better heat rate and, hence, a slightly lower fuel cost than the PCFB, the capital and *O & M* costs of IGCC are considerably higher, which results in a significantly higher cost of electricity for the IGCC.

Q. *What are the basic reasons that contribute to lower projected cost of the PCFB with respect to pulverized coal/scrubber systems?*

Ans.

1. Smaller space requirement
2. Smaller components and less steel
3. No need for external sulphur removal, NO_x-control, or backend particulate removal systems
4. Relatively lower cost of PCFB boiler than PC/Scrubber system
5. PCBF combined cycle system begets higher net power output.

Q. *What factors are responsible for lower projected cost of PCFB as against PBFB?*

Ans.

1. Much smaller and lighter-weight pressure vessel
2. Simpler fuel feed system
3. Less refractory
4. No need for a baghouse
5. No ash storage vessel
6. No nitrogen inerting system

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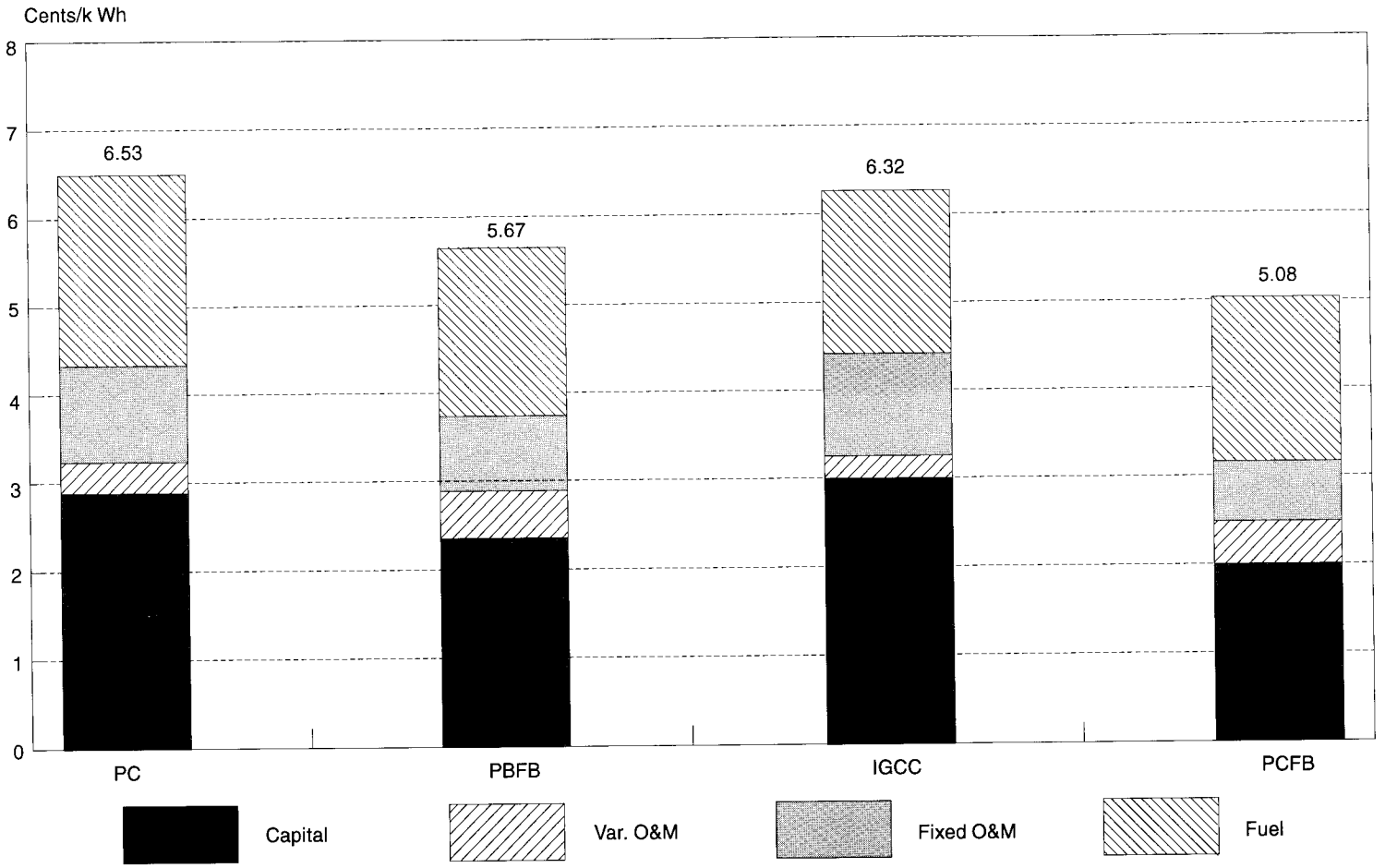

Fig. 1.53 *Levelized cost of electricity.*
Source: PTP-99 (Technical Paper/Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower Inc./San Diego/CA 92121/USA

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Q. *What are the significant reasons for the lower projected cost of the PCFB with respect to IGCC system?*

Ans.

1. Lower excess air at elevated pressures resulting in almost 100% combustion efficiency and greater power output
2. Less cooling of GT blades due to lower turbine inlet temp., again allowing more of the air available for the GT to be used to produce power
3. A much simpler system with far fewer components
   (a) no larger auxiliary air compressors
   (b) no oxygen plant
   (c) no hydrolysis unit
   (d) no ammonia scrubbing
   (e) no absorbers or strippers
   (h) no sulphur plant
   (g) no tail gas treating
   (h) no wastewater biotreating.

Q. *PCFB technology makes better use of air for combustion than other coal utilization technologies. This is a major advantage. How is this advantage realised?*

Ans. The extremely effective combustion efficiency, coupled with the capability to absorb heat in the combustor to control the combustion temp., makes PCFB process finely tuned to the operation at very low excess air which is typically 10% over the stoichiometric requirements.

In contrast IGCC cycles operate at much higher excess air, typically ranging from 250—300%. In fact the system itself requires so. IGCC system harnesses directly fired gas turbines and hence the temp. of combustion in these processes is controlled adiabatically using high excess air.

In other words, the temperature at the inlet to the GT in PCFB is controlled by transferring much of the heat of combustion to steam, while the temp. at the inlet to the gas turbine in an IGCC system is controlled by firing at high levels of excess air No heat is removed during the combustion process.

Source: Performance, Emissions and Cost of Ahlstrom Pyroflow R Pressurized CFB Technology

— Steve J. Provol and Tom W. Lamar

(Technical Paper PTP-99/Ahlstrom Pyropower Inc.)

Q. *What is APFBC?*

Ans. Advanced Pressurized Fluidized Bed Combustion.

Q. *How does APFBC system work?*

Ans. It integrates the PFBC technology with the coal carbonization system.

Coal is fed to a pressurized carbonizer, where it is converted to a low-calorie fuel gas and char (Fig 1.54).

The char is transferred to a PCFB combustor, where it is burned and the flue gas is filtered hot to remove particulates.

The fuel gas produced in the carbonizer is cleaned of particulates in a ceramic filter and is fired together with cleaned PCFB-exit flue gas in a specially designed combustor. The excess air supplied to PCFB battery acts as oxidizer to complete the fuel gas burnup.

The hot gaseous products exiting the topping combustor under pressure is allowed to expand in the GT at 1560°K increasing the PFBC plant to about 45 per cent (HHV basis).

A part of the heat generated in the PCFB unit is extracted in FBHE to generate superheated steam which is used to drive steam turbine.

Using high-pressure steam systems and advanced GT technology, the PFBC plant efficiency can be raised to 49 per cent.

Q. *Is there any such plant in operation?*

Ans. A 7MW_e plant designed by Foster Wheeler to test system components and to evaluate turbine system configurations went into operation in January 1995.

Q. *How does the APFBC module design work?*

Ans. The process flow diagram for the APFBC is shown in Fig. 1.55.

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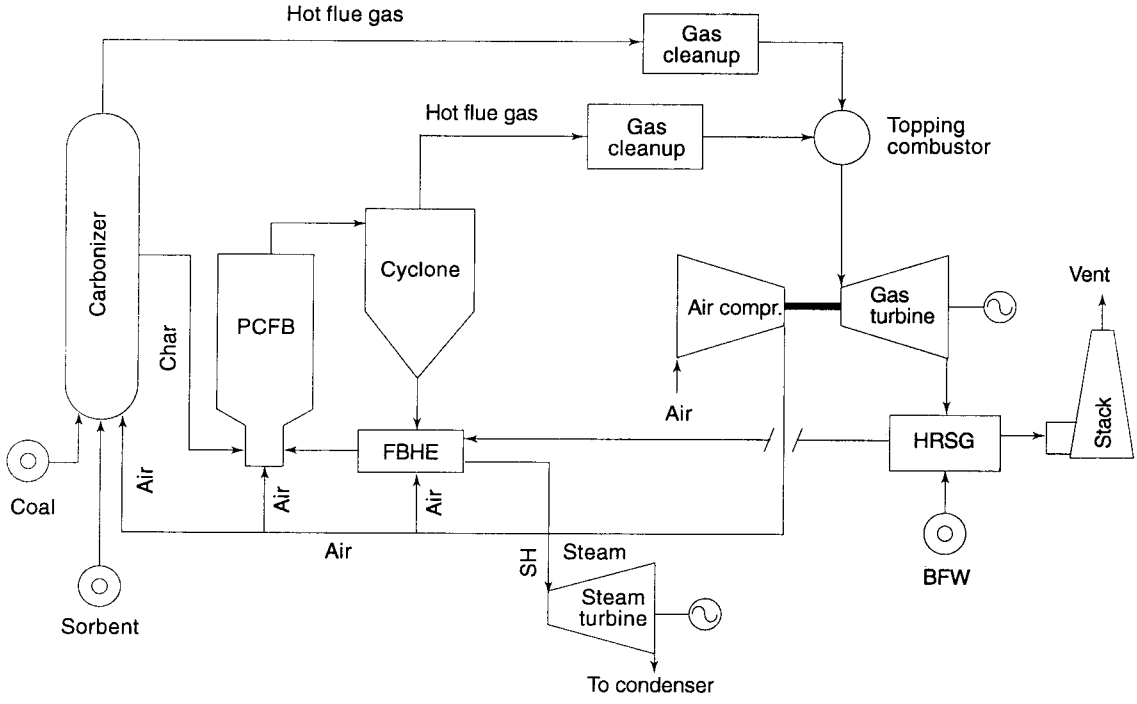

Fig. 1.54 *APFBC system.*

Coal is fed to the carbonizer either as a paste or in dry form. Sorbent is pneumatically introduced to the carbonizer dry.

The fuel gas from the carbonizer is freed from particulates and alkali in a cyclone, ceramic filter, and alkali getter. The char produced in the carbonizer is conveyed to the PCFB that also receives solids collected in the carbonizer cyclone and ceramic filter. The char-sorbent mixture burns in the PCFB combustor and the resulting flue gas is cleaned of particulates and alkali in a ceramic filter and alkali getter.

The 'cleaned' carbonizer fuel gas is burned in the topping combustor, utilizing the 'cleaned' PCFB flue gas (vitiated air) as the oxidant. The hot topping combustor exhaust under pressure is allowed to expand in the gas turbine driving the air compressor and generator.

The ash from the PCFB is cooled, depressurized, and pneumatically transported to a silo.

The unit burns Illinois #6 coal. Longview limestone is used as sorbent while Eagle Butte subbituminous coal is used as an alternative fuel.

The APCFB module is designed for a dry coal feed of about 0.69 kg/s and a sorbent feed of about 0.13 kg/s.

Q. *What are the basic design features of the carbonizers?*

Ans. The carbonizer is a fluidized (spouting) bed void of any heat-transfer surface.

The carbonizer is a vertical, refractory-lined vessel 14.6m high with a 914mm dia (ID) bed section (lower part) and a 1219 mm dia (ID) disengagement section (upper part).

Operating press. : 1.21 MPa abs.

Operating temp. : 1200°K

Bed temperature is controlled by air-to-coal ratio.

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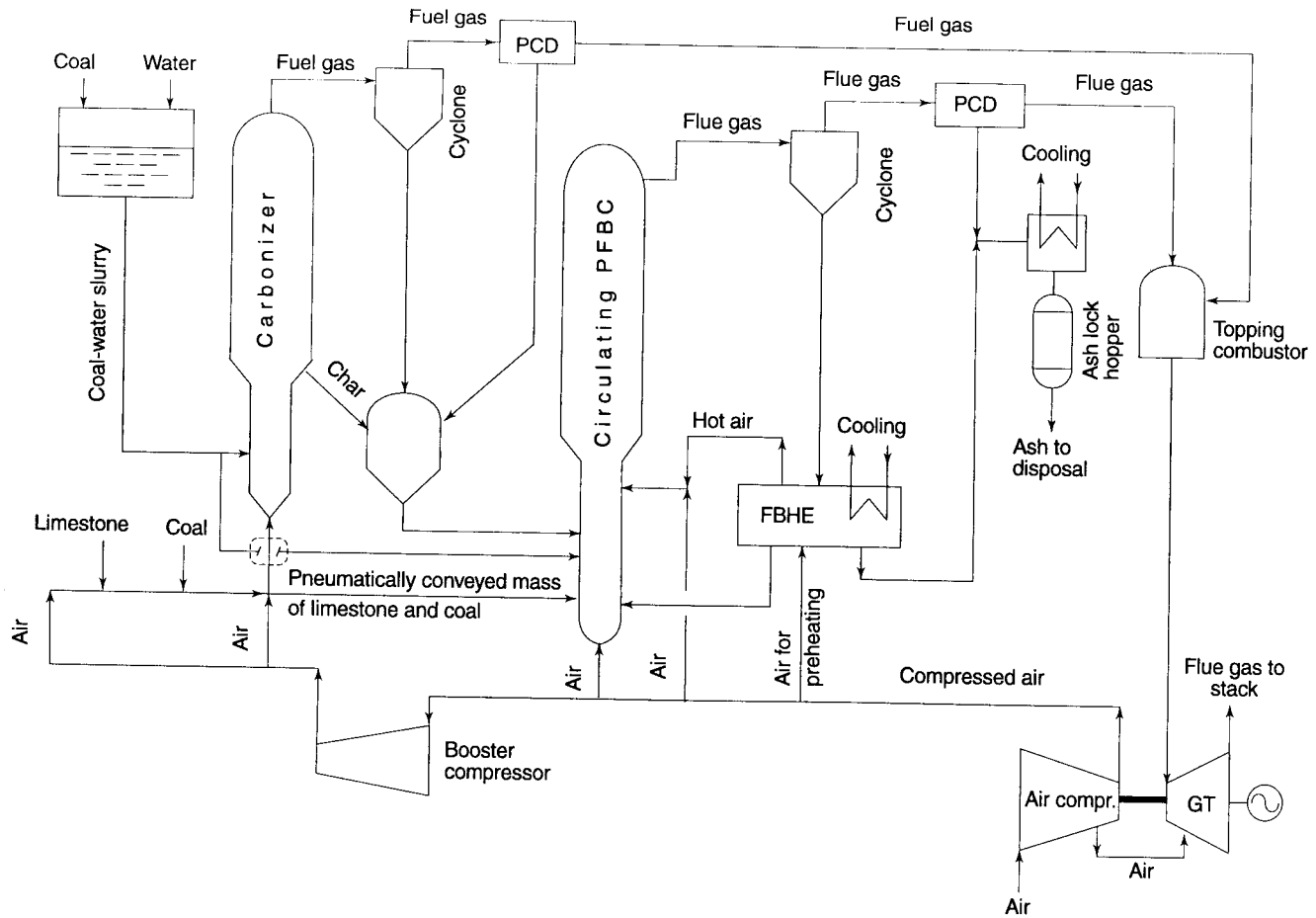

Fig. 1.55 *APFBC system process flow diagram.*
Source : Design Update for an APFBC Facility at Wilsonville, AL—J.D. McClung et. al.
Courtesy: Foster Wheeler Corpn./NJ08809-4000/USA

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The coal paste and limestone sorbent enter the carbonizer axially thru the bottom. The vessel is provided with extra nozzles to permit alternately feeding coal and limestone radially at varied inbed and above-bed elevations. Provision has also been made in the design to charge coal pneumatically.

With the design sorbent, Longview limestone, a Ca : S molar ratio of 2 has been chosen to ensure 95% sulphur removal from the design coal (Illinois # 6 coal). A 5-second bed-residence time has been selected to achieve the maximum sulphur capture in the carbonizer. Of course, the freeboard disengagement section further increases the residence time in the carbonizer.

Q. *What are the main functions of the PCFB combustor?*

Ans. The three main functions of the PCFB combustor are

1. char combustion
2. conversion of CaS in the char to $CaSO_4$
3. 95+% sulphur removal and reducing NO_x emission through staged combustion.

Q. *What are the major operating parameters controlling these functions?*

Ans.

1. ***Residence Time***—A 9-second bed-residence time has been selected to accomplish high carbon conversion, CaS $\longrightarrow$ $CaSO_4$ conversion and sulphur capture (95 + per cent).
2. ***Bed Temperature***—Based on PBFB technology to derive high bed-to-inbed surface heat transfer coefficients, bed temperature is restricted to 1145°K. Of course, a higher bed temperature could be selected to improve carbon conversion, but it would give rise to higher alkali release increasing the potential of bed agglomeration and corrosion of downstream components.
3. ***Ca/S Mole Ratio***—A Ca/S molar ratio of 2 is selected to attain 95^+ % sulphur capture with Illinois # 6 coal and longview limestone.
4. ***Bed Stoichiometry***—Of course, the combustion process is staged. The objective is to control NO_x formation. The lower part of the combustor operates in a reducing mode with approximately 70% stoichiometry. The upper portion operates in an oxidizing mode.

Q. *What are the basic design features of the PCFB combustor?*

Ans. The PCFB, shown in Fig. 1.56, is a refractory-lined vessel having the following dimensions

Overall height : 34.6 m

ID of upper section : 838 mm

The vessel is lined with a doubler-layer refractory—a 101mm of light castable refractory (inner layer) and a 122mm of hard-face refractory (outer layer) for erosion resistance.

Primary air is fed into the combustor from the plenum thru the grid floor which sports air inlet nozzles to distribute the airflow evenly across the grid cross-section for optimum mixing in the combustor.

Ports for secondary air inlet are also provided above the grid floor at four different elevations.

The hot flue gas exits at the top of the vessel.

Q. *What is HTGC?*

Ans. High Temperature Gas Cleaning.

Q. *How does it function?*

Ans. It consists of three cleaning stages in series

(a) Cyclone

(b) Particulate Control Device (PCD)

(c) Alkali-Removal System

to control particulates and alkalis.

The cyclone removes the bulk of the relatively coarse particles. The PCD that follows ensures the final degree of particle removal. The last stage—alkali removal—captures sodium and potassium vapour-phase pieces.

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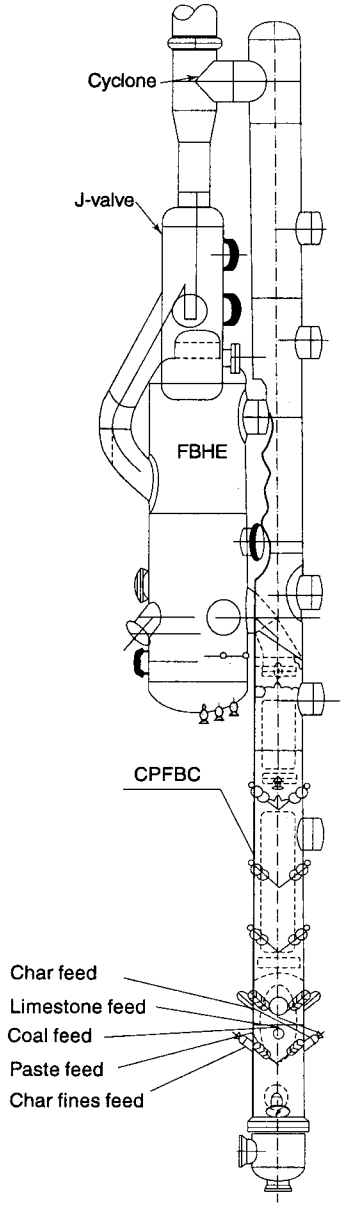

Fig. 1.56 *The second-generation pressurized circulating fluidizing bed combustor designed by Foster Wheeler Corpn. In an effort to produce the most efficient clean coal technology in the power sector.*

Source: Design Update for an APFBC facility at Wilsonville, AL—J.D. McClung et. al.

Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

Q. *For what purpose is HTGC installed?*

Ans. The HTGC systems are designed and installed to achieve sufficient levels of particle and alkali removal to safeguard the gas turbine blades from erosion, deposition and corrosion damage as well as to satisfy plant emissions standards.

Q. *What are the performance requirements of the HTGC systems?*

Ans. HTGC systems are provided to perform the following duties

1. Reduce outlet particulate loadings less than 20ppm (w) with no more than 1 wt% particles exceeding 0.01 mm (10 μm) and no more than 10 per cent exceeding 0.005 mm (5 μm).
2. Control alkali content (total Na + K-vapour) to less than 50 ppb (w)
3. Limit the maximum pressure drop across each HTGC train to 68.9 kPa.
4. Limit the temperature drop to less than 56°K across the carbonizer HTGC train and to less than 6°K across the PCFB train.

Q. *What are alkali-removal systems and how do they operate?*

Ans. These are simply packed beds of emathlite pellets contained in vertical, refractory-lined pressure vessels. The emathlite is a clay-material that reacts irreversibly with sodium and potassium vap-phase compounds at high temp. Nozzles are provided for gas inlet and outlet at the top and bottom of the vessels respectively, as well as for pellet loading and unloading. Although the expected alkali content in the hot flue gas is lower than the turbine tolerance, an alkali getter is installed in the hot flue gas stream as a safety measure.

Q. *What is the PCD used?*

Ans. Usually, the low-density candle design made of aluminosilicate is used as PCD service for the carbonizer while ceramic candle barrier filter is used as PCD for PCFB system.

In one such typical design (Foster Wheeler Corporation), the filter vessel (ID = 1370 mm)

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downstream of the carbonizer is fitted with 78 candles arranged in size groups of 13 each for jet pulse cleaning. The 60 mm OD × 40 mm ID × 1.5m long candles are of an aluminosilicate fibre construction using silica and alumina as binders. The monolithic flared flange and end cap of the candle are of densified ceramic fibre construction, as are the tubesheet and the candle retainer plate.

The PCD service downstream of PCFB is ceramic candle barrier filter. One such typical design consists of a refractory-lined coded pressure vessel containing six arrays, or 'clusters' of 270 coors 60 mm OD × 1.5 m long candle elements. The individual clusters are supported from a common high-alloy tubesheet and expansion assembly spanning the 3100 mm OD press. vessel. The arrays are formed by attaching individual filter elements to a common plenum and discharge pipe. (See Fig. 1.57)

Q. *What is the topping combustor?*

Ans. It is a gas burner designed to burn the fuel gas from the carbonizer in the high-temp. vitiated air from PCFB combustor. Thick layers of hot air effectively cools the walls of the burner. Thick layers of cooling air at the leading edge of each inlet section are created by concentric annular passages. That is why this gas burner is appropriately called a multiannular swirl burner (MASB).

Q. *What are the basic design features of MASB?*

Ans. Shown in Fig. 1.58 is the topping combustor assembly. Each of the carbon steel spools is a pressure vessel. A concentric stainless steel cyclinder inside each piece serves as the high temperature

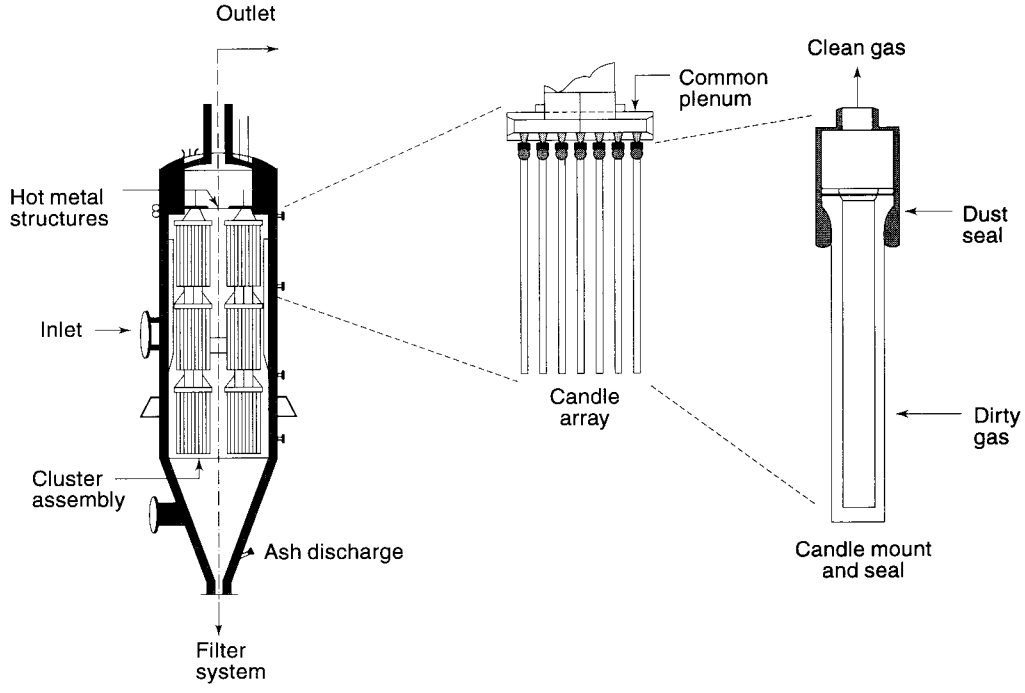

Fig. 1.57 *Hot Gas Ceramic Candle Filter.*
Source: Design Update for an APFBC facility at Wilsonville—J.D. McClung et. al.
Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

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boundary. A layer of insulation fills the void between the concentric cylinders. The exhaust diffuser is a double-wall steel piece designed to accommodate CW for this region of MASB. The inner liner of this piece is a Hastelloy alloy. The topping combustor itself is an Inconel or Hastelloy-type alloy with a diameter of about 457 mm.

Q. *How does MASB operate?*

Ans. About 9.58 kg/s of vitiated air (PCFB exit) enters the combustor at 1.03 MPa abs./1035°K and supports the combustion of about 1.46 kg/s of carbonizer fuel gas at 1175°K producing an exhaust gas temperature of 1560°K—the optimum firing temperature for a utility-size plant.

Source: Design Update for an Advanced Pressurized Fluidized Bed Combustion Facility at Wilsonville, Alabama—J.D. McClung, R.E. Froehlich and M.T. Quandt

Courtesy: Foster Wheeler Corpn./NJ 08809-4000/USA

Q. *What do you mean by the heating surface of a boiler?*

Ans. It is the surface area of boiler tubes exposed to the hot gases of combustion in the furnace space in order to transfer heat to the working fluid to generate steam.

Q. *How many types of heating surface may a boiler have?*

Ans.

1. *Radiant Heating Surface*—Waterwalls receiving direct radiant flame heat
2. *Convective Heating Surface*—located in the convective shaft of the furnace and receives heat entirely by convection
3. *Radiant-Convective Heating Surface*—heated partly by radiant heat and partly by convective heat

Q. *In which type of boiler—watertube or firetube—is the heating surface more for tubes with the same specifications?*

Ans. Watertube boilers.

Q. *Why?*

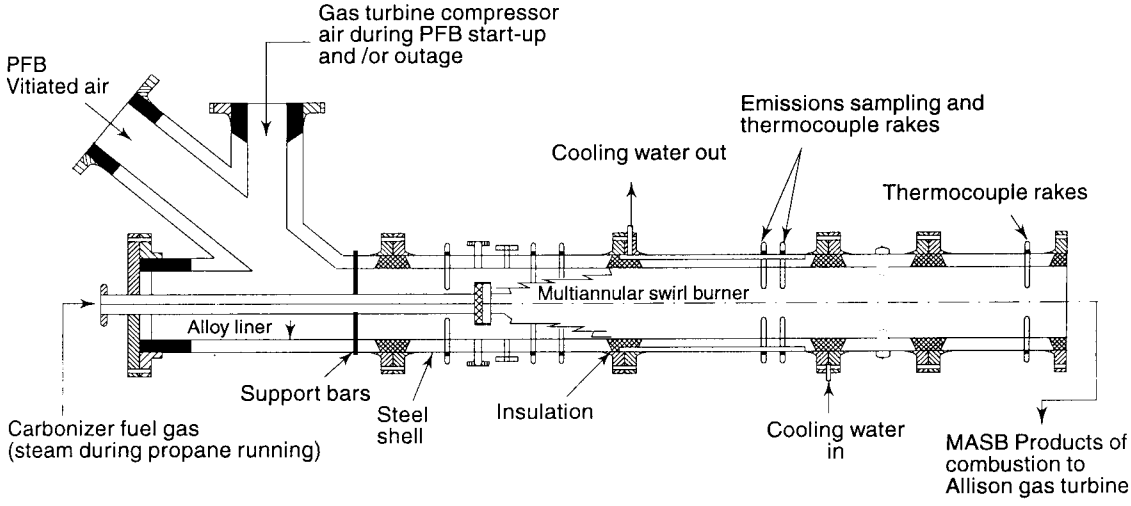

Fig. 1.58 *Topping combustor assembly.*
Source: Design Update for an APFBC Facility at Wilsonville, AL—J.D. McClung et. al.
Courtesy: Foster Wheeler Corpn./NJ 08890-4000/USA

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Ans. The effective heating surface of watertube boilers is the external surface area of the tubes exposed to furnace gases while the heating surface of firetube boilers is the internal surface area of the tubes. For tubes having the same dimension, the internal surface area of the tube is less than its external surface area. Therefore, watertube boilers will have greater heating surface than firetube boilers.

Q. *Why is a safety relief valve installed close to a pressure reduction valve in a steam line?*

Ans. It is an added safety to the steam line to avoid sudden steam pressure development in the steam main in case the pressure reducing valve fails to operate properly, i.e. the valve may get stuck-up in the open position, impairing the downstream pressure of steam (L.P.). The safety valve fitted closely to the PRV is set at a pressure slightly greater than L.P. steam pressure and it goes off if there is an accidental pressure development in the low pressure side.

Q. *What are boiler baffles?*

Ans. The flow of hot combustion gas over the banks of boiler tubes is controlled by what are called baffles. (Fig. 1.59)

Q. *Why are baffles placed in the path of hot flue gases in the convective shaft of watertube boilers?*

Ans. To put into effect a more even distribution and transfer to convective heat from hot combustion gases to the convective heating surfaces of the boiler unit.

Moreover, they maintain proper gas velocity, facilitate flyash and soot deposition and reduce draft loss.

Q. *Upon what factors does baffle arrangement depend?*

Ans.

1. Allowable draft (draught) loss
2. The layout of boiler heating surface and its dimension
3. Gas outlet position

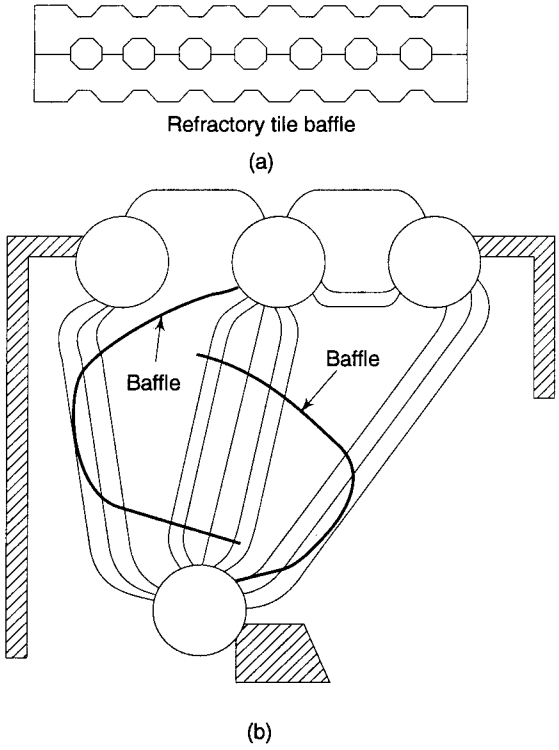

Fig. 1.59 *(a) Refractory tile*
(b) Baffle arrangement in a bent-tube boiler

4. Fuel
5. Fuel burning equipment and operating parameters
6. Baffle supporting device

Q. *What factors should be considered in designing a baffle?*

Ans. The baffle design should be such that it

(a) ensures best distribution of heating surface with respect to the gaseous products of combustion
(b) ensures proper flue gas velocity
(c) maintains cross-flow of flue gas past the boiler tubes
(d) deposits flyash and dust where it is accessible for easy removal
(e) eliminates dead pockets
(f) avoids high draught (draft) loss

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Q. *When may the furnace baffles open out?*

Ans. Due to crack or formation of patch holes.

Q. *What will happen in the case of baffle failure?*

Ans. Combustion gases will be short circuited when baffles open out. A modified heat redistribution will take place. Some parts will get more overheated than the others. Tubes may fail. Excessive flue gas temperature at the stack outlet will occur and this will bring down the overall thermal efficiency of the boiler.

Q. *Why is a slag screen installed?*

Ans. The slag screen, as its name implies, is installed to overcome clogging of boiler tubes as a result of cooling and adhering of molten slag on the tube surface.

Q. *Where is the slag screen installed?*

Ans. At the entry to the convective shaft of the boiler furnace.

Q. *Why are slag screens installed at the entry to the convective shaft?*

Ans. It is required that hot flue gases and molten slag, before their entry to the convective shaft of the furnace, should be cooled to a point at which they will not stick to the boiler tube surfaces. To avoid clogging, the watertube boilers are given the facility of slag screens installed at the entry.

Q. *What are the drawbacks of a slag screen?*

Ans. A slag screen

1. limits the maximum distance for effective tube cleaning by soot blowing. This imposes restrictions on tube bank design.
2. reduces the accessibility for the repairing or replacement of faulty boiler tubes.

Q. *In what pattern can a slag screen be arranged?*

Ans. Two:

1. in-line arrangement
2. staggered arrangement. [Fig. 1.60]

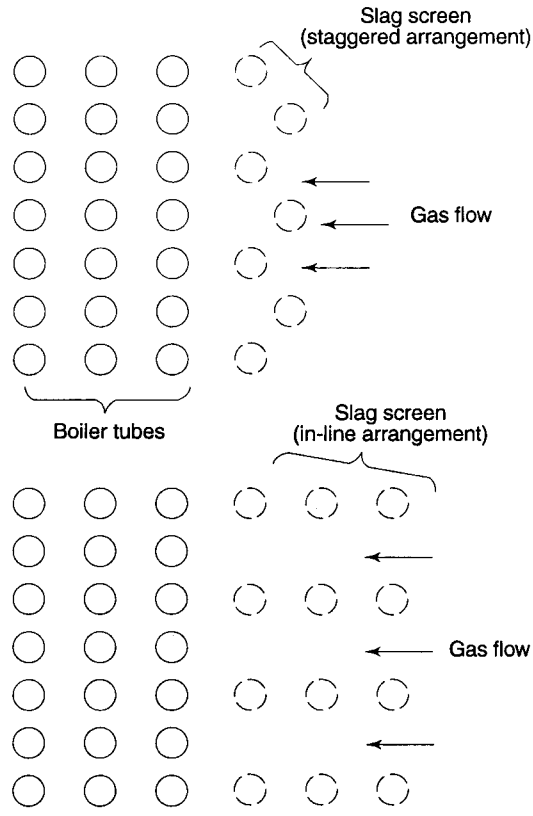

Fig. 1.60 *Slag screen is installed upstream of boiler tubes.*

Q. *Which one is better?*

Ans. In-line arrangement.

Q. *Why is in-line arrangement better?*

Ans. In-line arrangement has wider tube spacings. It reduces slagging. The wider tube spacing facilitates manual cleaning, washing and replacement of boiler tubes.

Q. *Why is the steam drum provided?*

Ans. It is provided to carry out the process of separation and steam purification at higher pressures with the aid to baffles and other devices called steam internals as well as to provide an adequate amount of steam storage.

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Q. *What are drum internals?*

Ans. It includes all apparatus within a steam drum, viz. baffles and various devices to effect the separation of steam from steam-water mixture, the various chemical and feedwater admission pipelines and blowdown lines.

Q. *What should be the basic qualities of drum internals?*

Ans. They should

1. provide highly pure steam to prevent superheater tubes from burn-outs and the steam turbine from fall-out of the nominal capacity
2. maintain purity of steam at a steady rate despite the fluctuation of boiler water concentrations over a wide range
3. maintain steam purity despite the fluctuations of water level occurring during normal operation
4. ensure steam-free water to the downcomer tubes for maximum circulation
5. ensure minimum pressure drop through the separators
6. provide maximum accessibility for inspection of the drum
7. be basically simple in design to minimize the installation and removal time.

Q. *What fundamental steps are involved during the process of steam separation and purification in the steam drum?*

Ans. The process involves three steps

1. separation
2. steam washing
3. steam scrubbing

Separation is the primary step while steam washing and steam scrubbing are secondary.

Q. *What is steam separation?*

Ans. It is the process of eliminating bulk masses of water droplets from steam.

Q. *How can steam separation be achieved?*

Ans. This can be effected by any of the following three methods

1. gravity separation
2. abrupt change in direction of flow pattern
3. centrifugal separation
4. using baffles
5. impact against a plate

Q. *What is a dry pipe?*

Ans. It is a perforated or slotted pipe placed in the highest part of the boiler to provide commercially dry (97% dry) steam. It is a capped pipe fitted with a drain to prevent accumulation of water and perforated openings at the top that allow the entry of steam but discourage the entry of water. The openings are drilled holes (20 mm) dia or slots (7.5 mm) wide. (Fig. 1.61)

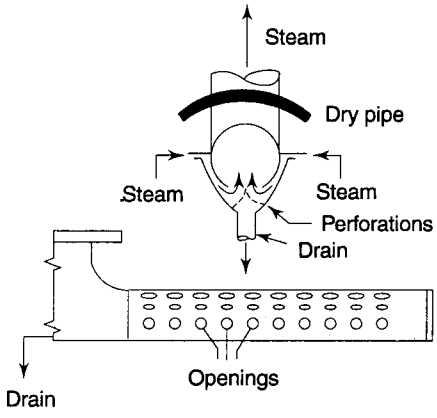

Fig. 1.61 *Dry pipe.*

Q. *What are baffles?*

Ans. Baffles are steam drum internals that break up steam-water jets entering the drum.

Q. *How many types of baffles are in use?*

Ans.

1. Deflector-plate baffle (Fig. 1.62)
2. Offset deflector-plate baffle (Fig. 1.63)
3. Slotted deflector-plate baffle (Fig. 1.64)
4. V-baffle (Fig. 1.65)
5. Perforated plate and V-baffle (Fig. 1.66)
6. Angle-iron deflector baffle (Fig. 1.67)
7. Hydraulic barrage baffle (Fig. 1.68)
8. Compartment baffle (Fig. 1.69)

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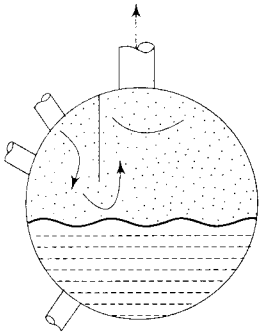

Fig. 1.62

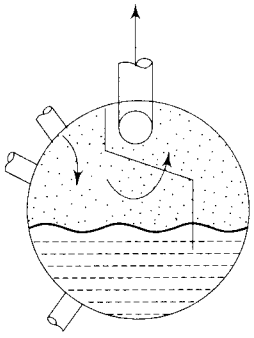

Fig. 1.63

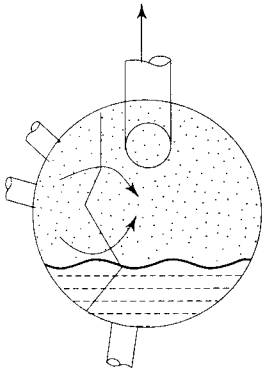

Fig. 1.64

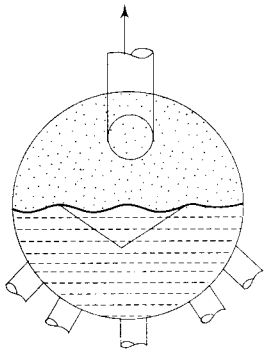

Fig. 1.65

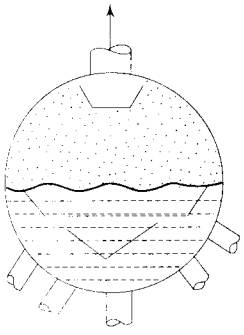

Fig. 1.66

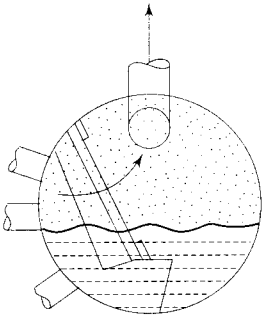

Fig. 1.67

Q. *Why are deflectors or compartment baffles necessary?*

Ans. For low steam release rates a V-baffle or single vertical baffle is adequate, but for higher release rates deflectors or compartment baffles are necessary for separation.

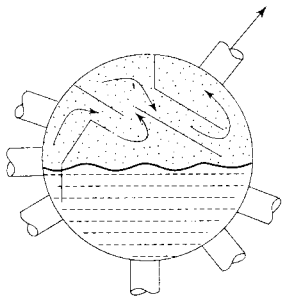

Fig. 1.68

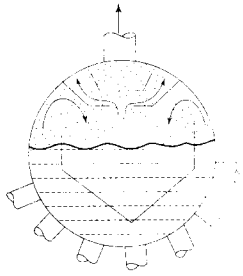

Fig. 1.69

Q. *When is a hydraulic barrage installed?*

Ans. These types of baffles are installed to control excessive foam or spray formation.

Q. *How does it perform this job?*

Ans. It creates a successful high velocity screen or curtain through which steam must pass in order to exit. As a result, the water particles losing their kinetic energy by successive impacts with the 'curtains' fall off, and steam escapes dry.

Q. *What is a cyclone separator?*

Ans. This is an effective device to harness steam-water separation by utilizing centrifugal forces. [Fig. 1.70]

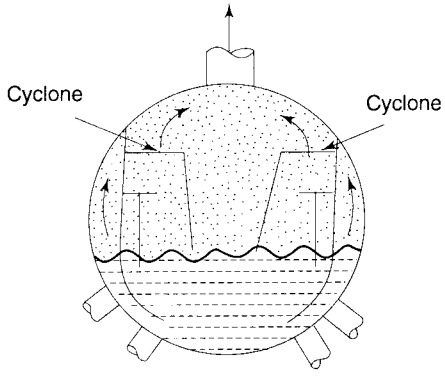

Fig. 1.70 *Cyclone separator.*

Q. *How does it do so?*

Ans. It imparts to the steam-water mixture, as it enters the drum, a rotary motion which develops a centrifugal force that destroys the foam bubble, eliminates spray and separates out solid particles.

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Q. *What is steam washing?*

Ans. It is the process of rinsing the separated steam with steam condensate or fresh, relatively clean feedwater.

Q. *What is the purpose of steam washing?*

Ans. Its purpose is to condense out the dissolved silica from steam as well as to wash out impurities carried over by steam.

Q. *How much of the silica carryover by steam can be eliminated by the process of steam washing?*

Ans. As much as 90% with a proper washer.

Q. *What are the ways to reduce the silica content of steam leaving the washer.*

Ans.

1. Increasing the stage efficiency of the washer
2. Adding more washer stages in series
3. Increasing the ratio (by weight) of wash water to steam
4. Washing the steam with water with lower silica content
5. Reducing the silica content of steam entering the washer

Q. *How many types of steam washers are in vogue?*

Ans.

1. Condensing type (Fig. 1.71)
2. Wire-mesh type (Fig. 1.72)
3. Spray-type (Fig. 1.73)
4. Wetted scrubber type (Fig. 1.74)
5. Hood type (Fig. 1.75)

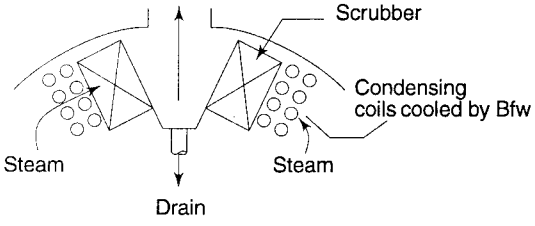

Fig. 1.71

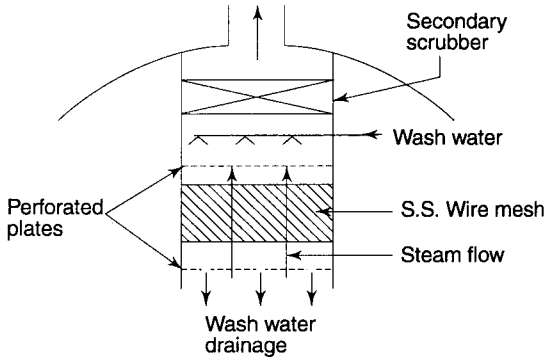

Fig. 1.72

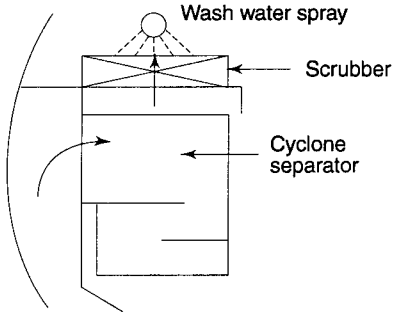

Fig. 1.73

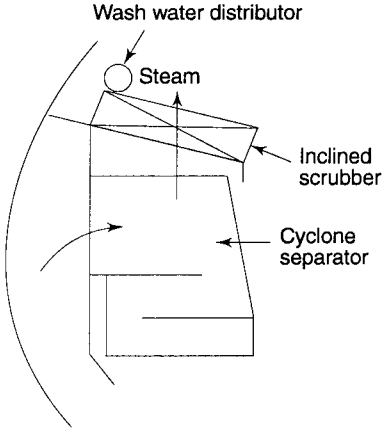

Fig. 1.74

Q. *How does the condensing type steam washer function?*

Ans. In this device steam is passed over condensing coils cooled by feewater flowing through them. Upon contact with the relatively cold metal sur-

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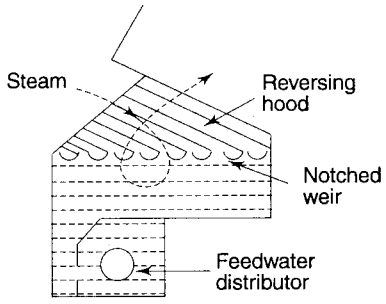

Fig. 1.75

face of the coil, a portion of the steam is condensed and this condensate provides a washing liquid for the rest of the saturated steam. This steam condensate is of higher quality than feedwater and hence possesses a higher affinity for silica. Thus this kind of steam washer is quite effective for removing vapourized silica as well as the solids carried in the moisture and other impurities.

Q. *What are the basic features to be kept in mind while designing steam washers?*

Ans.

1. They must provide for intimate mixing of washing liquid (feedwater/condensate) with steam
2. They must be effective at partial load
3. They should have a minimal tendency to adhere to sludge
4. Multistage washing for higher efficiency

Q. *What is steam scrubbing?*

Ans. It is analogous to filtration. The wet steam is passed between closely spaced corrugated plates or screens that collect the water droplets carried by steam. The mass of water collected on the screens is dripped by gravity to the water below in the boiler drum. (Fig. 1.76)

The scrubber eliminates most of the water droplets added to steam from spray and splatter. Also, it breaks up and eliminates dry foam.

Q. *How much water carryover by steam can be arrested by the scrubber?*

Ans. It can slash the water carry over by steam & down to 1/30th of the 1% moisture at full load.

Q. *On which factors does the efficiency of a steam scrubber depend?*

Ans. It depends upon such variables as

1. the surface area of the scrubber
2. time of contact

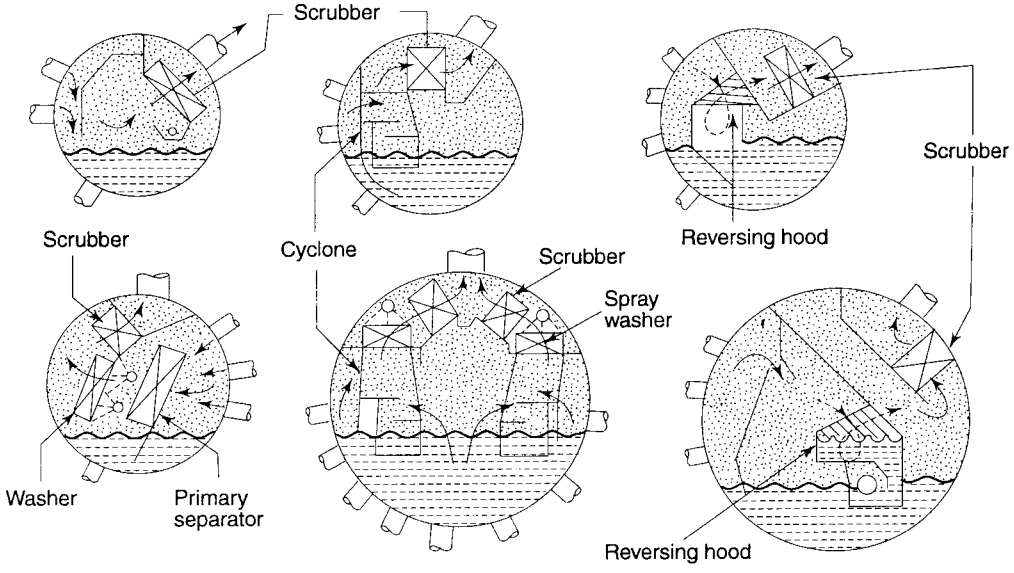

Fig. 1.76 *Various arrangements of steam scrubbers.*

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3. velocity and pressure of steam
4. the shape of steam passage (sinuous passage)

Q. *What should be the velocity of steam at low pressure?*

Ans. 2.45–3 m/s.

Q. *What should be the steam velocity at high pressure?*

Ans. 0.6 m/s

Q. *The scrubber is not highly effective in removing small quantities of fine mists suspended in steam as more efficient scrubbers are impractical. Why?*

Ans. More efficient scrubbers cannot be designed because of the limitations imposed by such factors as plugging, corrosion and pressure drop. A scrubber covered with a heavy accumulation of wet foam may break and give rise to a high degree of carryover.

Q. *A scrubber fitted together with a washer is more efficient. Why?*

Ans. As the steam passes through the washer, the moisture droplets suspended in the steam get enlarged lending themselves more amenable to fall-out upon contact with the metal surfaces as the steam moves through the scrubber. This increases the effectiveness of the scrubber and helps reduce the carryover.

Q. *What is a dry drum?*

Ans. It is an additional drum fitted occasionally above the boiler drum proper as an extra safeguard from carryover. As no boiler water is held up within its space, it is called a dry drum. (Fig. 1.77)

Q. *For what purpose is a dry drum set up?*

Ans. A dry drum, sufficiently large and provided with adequate drainage facility is a good protection against priming and foamover.

Q. *What are the basic elements of consideration in designing a boiler drum?*

Ans.

1. Limitations of space
2. Even distribution of steam
3. Pressure drop across the unit
4. Drainage facility
5. Problem of corrosion
6. Accessibility to drum internals
7. Problem of dirt deposition
8. Cleaning

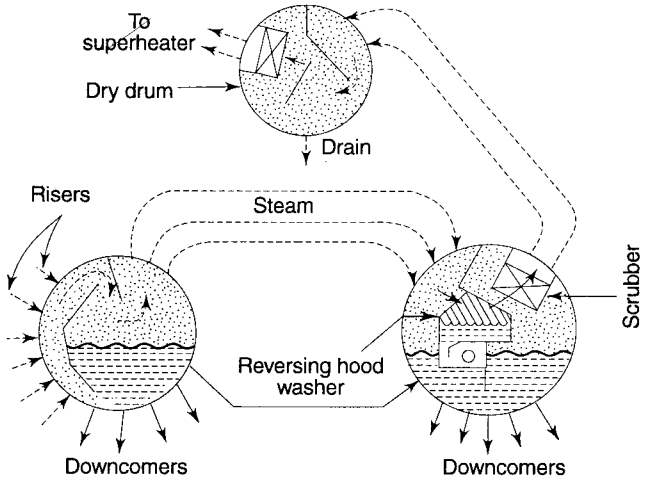

Fig. 1.77 *Dry drum arrangement.*

9. Weight
10. Strength
11. Method of installation.

Q. *Why is feedwater treatment added to the boiler rather than to the feedwater itself?*

Ans. This is to eliminate the problem of plugging of washer by sludge resulting from chemical reactions.

Q. *In some marine boilers, water baffles—called swash plates—are installed in the lower half of athwartship (across-ship) steam drums. Why?*

Ans. These plates reduce the surging of boiler water from end to end in the drum as the ship rolls in choppy seas.

Q. *Why is a dual circulation boiler installed?*

Ans. For boilers operating at pressures above 4137 kN/m^2 (40.96 atm.), the solubility of silica in steam becomes considerable and may cause blade deposition in the steam turbines. The dual circulation boiler is designed to eliminate this silica carryover in particular.

Q. *How does it work?*

Ans. It works on the principle of stage evaporation. It has two separate heat absorbing sections—the heavy duty primary section is composed of furnace waterwall tubes and furnace circulatory system while the low duty secondary section is constituted of a boiler convection tubes bank which is moderately heated.

These two separate sections, each having its own independent circulating system, are functionally identical to two separate boilers mounted in one setting.

BFW is delivered to the primary section while continuous blowdown from this section serves as feedwater to the secondary section. (Fig. 1.78)

In comparison to the steam output of the unit, the blowdown from the primary section is considerable, rendering a low-silica-feedwater maintained in the primary section while a much higher concentration of silica is maintained in the secondary section where the steam generation rate being comparatively low, the possibility of foam-

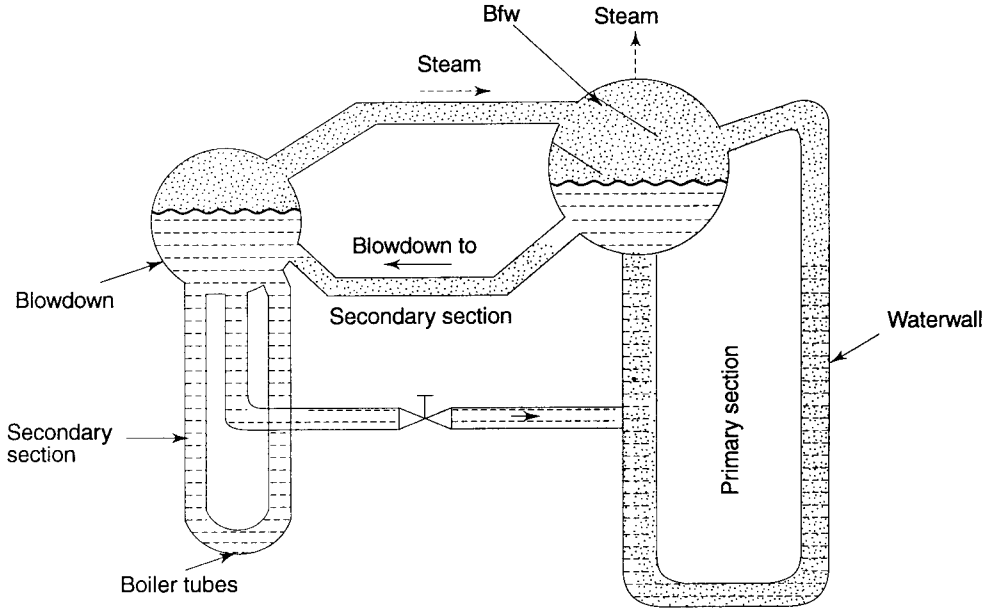

Fig. 1.78 *Dual circulation boiler.*

ing and excessive carryover is precluded. Since the primary section contributes to the lion's share of overall steam output, a low concentration of silica in the boiler water of this section reduces the carryover of silica by steam. Moreover, the generated steam in the secondary section being scrubbed by feedwater, a part of it gets condensed and the silica contamination in steam leaving this section is greatly reduced.

The drum internals of these two sections are totally segregated by a baffle arrangement that does not allow the feedwater and condensate to dilute the feed to the secondary section or the high-silica water of the secondary section to contaminate the feedwater in the primary section.

Q. *What are the distinct advantages of a dual circulation steam generation unit?*

Ans.

1. Marked reduction in carryover of silica as well as total dissolved solids in steam
2. Permits higher impurity level in the intake feed
3. Low blowdown as high concentrations are maintained in the secondary section. This also minimizes heat loss and feedwater make-up
4. Lower concentration of silica and TDS in BFW in the high duty furnace section greatly reduces the danger of scaling
5. Permits higher heat absorption rate over a prolonged period
6. Outage time and maintenance cost are minimal
7. Needs smaller economizer
8. Reduces treatment chemical cost

Q. *What are the upper pressure limitations of boilers?*

Ans.

Steel Firetube Boiler	10-17 atm
Steel Watertube Boiler	No effective limitations. Boilers for operation at 340 atm have been built
Cast-Iron Boiler	1 atm steam 2 atm hot water (although hot water heaters may operate at 11 atm if the temperature does not exceed 120°C)

Q. *What are the effects of expansion and contraction?*

Ans. When heated boilers expand. When cooled they contract. The magnitude of expansion depends on the source of the heating effect, i.e. whether the heat source is a radiant flame or relatively cooler flue gases. The heating and cooling is not uniform and may give rise to hot spots within the boiler. Hence, a boiler designer should give necessary consideration to expansions.

Q. *What about the expansion problem in a steel boiler?*

Ans. Properly designed steel boilers present little expansion difficulty and is relatively free from stresses due to expansion and contraction. The connecting pipelines should be adequately provided for expansion and movement.

Q. *What is the effect of expansion or contraction stresses on tubes?*

Ans. Leakage develops where the tubes are bent into the drum or tubesheet.

Q. *What about the expansion and contraction problem in a cast-iron boiler?*

Ans. Thermal stresses induced due to expansion or contraction will warp sections of the cast-iron boiler. And deformed sections take a permanent shape. Replacement may be difficult.

Q. *How does flame impingement affect the boiler?*

Ans. As the flame impinges on waterwalls, it becomes cooled and the flame temperature drops which in turn may result in incomplete combustion and soot formation.

Q. *Does a draft affect boiler operation?*

Ans. The draft problems that are encountered when a chimney alone is used are eliminated if draft fans are installed. Practical experiences show

that a draft fan is far more economical than a chimney of adequate height in all cases except those of small installations.

Q. *Can chimney be eliminated if draft fans are installed?*

Ans. No. Some kind of chimney or stack is necessary despite the installation and operation of draft fans. This is because a chimeny/stack of appropriate height will permit discharge of flue gases to such a level that the dilution of obnoxious gases (air pollutants) by the atmospheric air will be within acceptable limits.

Q. *What is the need for a large water capacity?*

Ans. If a boiler has large water capacity, it will function smoothly and better against a relatively steady load or slowly varying load.

Q. *For sudden load changing conditions, what effect will the boiler water capacity have?*

Ans. If sudden load-changes are prevalent, boilers having less or a small water capacity will be more responsive to quicker load fluctuations.

Q. *Compare watertube and firetube boilers in the light of water capacity*

Ans. Watertube boilers have a smaller water capacity than firetube boilers. Therefore watertube boilers are more responsive to a rapid load change.

The larger water capacity of firetube boilers imparts stability but does not permit rapid load fluctuation.

Q. *How does water circulation affect a boiler?*

Ans. Good circulation is a desirable feature for all boilers. Inadequate circulation of working fluid will reduce its heat removal rate efficiency, causing higher metal temperature.

Firetube boilers usually have poor circulation compared to watertube boilers. If properly designed, watertube boilers have good circulating characteristics that ensure higher heat removal efficiency.

Q. *What are the steaming characteristics of a firetube boiler?*

Ans. Firetube boilers in general, are not fast steamers. The steaming rate of a firebox type boiler is much faster than that of externally fired boilers.

However, the steaming characteristics of a firetube boiler vary with differing design and with the ratio of heating surface to water volume.

Q. *What are the steaming characteristics of a packaged boiler?*

Ans. Packaged boilers have quicker steaming rate than firetube boilers because of a large heating surface with smaller water volume.

Q. *What are the steaming characteristics of watertube boilers?*

Ans. Fast.

Q. *What are the steaming characteristics of cast iron boilers?*

Ans. Slow steaming rate, except those having smaller water volume. This is because a large quantity of metal is involved in a cast-iron boiler.

At the start-up, the steaming rate is low but thereafter such boilers have relatively stable steaming characteristics.

Q. *What are the effects of low-water in the case of a steel boiler?*

Ans. Replacement of exposed tubes or crown sheets is required. This means a considerable downtime loss as the boiler is shutdown and kept out of service till the repair jobs are completed.

Q. *What are the effects of low-water operation in the case of cast-iron boilers?*

Ans. It occasionally results in cracked sections.

Though little difficulty is encountered in disconnecting or replacing the cracked sections of an external header type boiler, total shutdown of a push-nipple type boiler must be taken until a replacement section is obtained. Warpage may sometime invite replacement of the boiler.

Q. *How can sludge be removed from the boiler?*

Ans. Periodic blowdown is the method most practised to remove sludge deposited on the mud drum or mud ring.

If it has become solid cake, a high-pressure water hose is harnessed to dislodge the cake during shut-down periods. If it still remains, it is chipped out.

Due to lack of adequate clearance, it is usually difficult to remove sludge from the bottom of Scotch type boilers.

Q. *How can the boiler tube scales be removed?*

Ans. Incrustation of scales on the outside surface of a boiler tube is removed as follows

1. The boiler is emptied
2. The boiler is then carefully heated
3. Cold water is sprayed on the tubes to induce thermal stress in the solidified scale and remove the ruptured scales.

Scales inside a boiler tube are turbined (reamed) out carefully with special equipment.

Q. *Why does soot deposit in the boiler flue passes?*

Ans. Improper combustion is the cause of soot formation in the boiler furnace. Combustion-gas-borne soot gets deposited in the boiler flue passes.

Q. *What is the effect of soot deposition in the flue gas passage of a boiler?*

Ans. It impairs heat transfer characteristics and thereby reduces the overall efficiency of the boiler. Tests conducted at the Bureau of Standards have confirmed that reduction of boiler efficiency by 8% over an 8-day operating period was principally due to the rapid buildup of soot deposits.

Q. *Compare the soot blowing characteristics of a steel firetube boiler and a steel watertube boiler.*

Ans. Annual or biannual soot blowing may be adequate for steel firetube boilers because they have large tubes and ample furnace volume. However such infrequent soot cleaning is not recommended.

Steel watertube boilers should be cleaned regularly. Large installations have soot blowers.

Q. *What is the effect of soot on cast-iron boilers?*

Ans. Initially there is some soot build-up and with that there occurs initial efficiency reduction. After that there is little additional soot development because of the large size of passageways. And so no further efficiency drop takes place.

Annual soot cleaning may be adequate.

Q. *What about the relative ease of servicing of cast-iron boiler, steel boiler and packaged boiler?*

Ans. For cast-iron boilers, the waterside is inaccessible whereas the fireside is accessible for inspection and maintenance by simply opening the doors. The flue ducts are large and lend themselves to easy cleaning.

The waterside of watertube steel boilers and packaged units is accessible for inspection and maintenance jobs through manholes, handholes or washout plugs. The mere opening of doors makes the fireside accessible to inspection and maintenance.

Accessibility to tubes for firetube boilers is gained through hinged, front flue doors. Soot cleaning is accomplished through the doors set in the rear smoke box.

If the firetube boilers are fitted with smaller steel tubes they present more difficulty in cleaning than cast-iron boilers because the latter provide ample cleaning space.

Watertube boilers of power plants have handholes for tube rolling.

The waterside of a packaged firetube unit is accessible for inspection through manholes. The rear wall is to be unbolted and removed to get access to the fireside. Hence firetube packaged boilers are not generally considered easily accessible for maintenance and cleaning.

Q. *Why do the present day boiler designers not recommend maximum flue gas velocities in boilers?*

Ans. It is due to deteriorating fuel quality. With the degraded variety of fuel burned in the combustion chamber, the metal loss in the convection pass caused by flyash mounts. This erosion problem being proportional to an exponential function of flue-gas velocity, the latter is a major consideration in boiler design.

Q. *Why is chromizing of waterwall, superheater and reheater tubes done?*

Ans. This strengthens the tubes in combating flyash erosion problems.

Q. *How does it work?*

Ans. Chromium, a powerful corrosion resistant metal, diffuses into the base metal of the tubes of the heat exchangers, viz. evaporators, superheaters, etc., thereby protecting against fireside grooving and corrosion, with the effect that tube life is extended dramatically.

Q. *Why are internally ribbed tubes laid out in the high-heat-absorption zones of natural circulation drum-type boilers operating at high supercritical pressures?*

Ans. It ensures high availability of the boilers.

Q. *How?*

Ans. When internally ribbed tubes are arranged in the high-heat-absorption zones of the combustion chamber, they provide a far greater margin of safety against tube failure from departure from nucleate boiling (DNB) conditions. They impart a centrifugal action to the working fluid that forces water droplets towards the waterwall tube surface and inhibits the formation of a steam film.

Q. *Is it true then that the DNB is more possible with smooth tubes than with internally ribbed tubes?*

Ans. Yes.

Q. *What do you mean by cycling service?*

Ans. It means boilers must be designed to cycle on and off. For example, a typical requirement may be nightly or weekend shutdowns.

Q. *In what way does a boiler designed for cycling service differ from one designed for base-load duty?*

Ans. They differ in the arrangement of superheater and reheater surfaces. This change is required to permit operation at rated steam temperatures at all loads.

Q. *How is the start-up system for cycling units designed to allow quicker matching of final steam-to-turbine temperature?*

Ans. The arrangement is as shown. [Fig. 1.79]

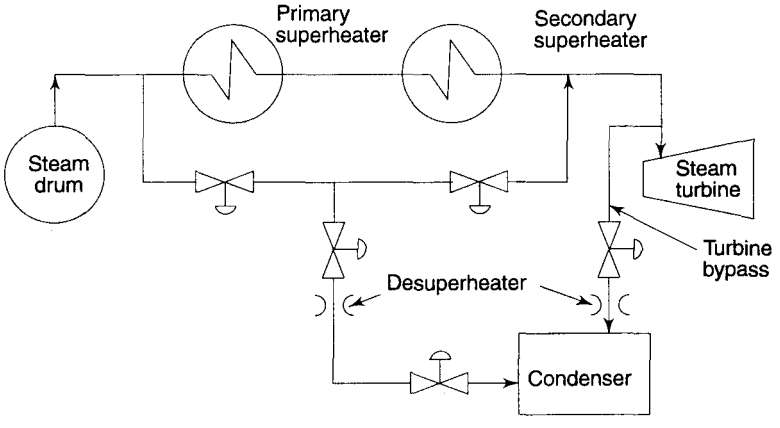

Fig. 1.79

A part of the steam from the steam drum flows straight to the condenser via the desuperheater while the remaining steam passes through the superheaters and becomes superheated at a temperature higher than that which would result if the entire steam were passed through the superheater. This allows more rapid final steam-to-turbine temperature matching than is experienced by a boiler without this system.

Q. *Why do the spray systems of some superheaters and reheaters on some cycling boilers have twice as much capacity as those of non-cycling boiler designs?*

Ans. This extra spray capability endows the cycling system with a greater control flexibility for maintaining the boilertube metal temperature within recommended limits.

Q. *What is the European by-pass system?*

Ans. It is the full by-pass system. [Fig.1.80]

Q. *What are the advantages of this full-bypass system?*

Ans. This system bestows

1. virtually unlimited turbine temperature matching capabilities
2. positive reheater cooling protection at all loads
3. allows the boiler to operate continuously from 60% to 100% (depending on boiler size) of Maximum Continuous Rating (MCR) after the turbine trips.

Q. *What factors affect the combustion efficiency of boilers?*

Ans. There are three factors that affect combustion efficiency

1. **Sensible Heat Losses:** it is the total heat carried away by hot dry flue gases.
2. **Hydrogen Losses:** it is the heat lost in vaporizing the moisture present in the fuel and flue gases.
3. **Combustible Losses:** it is the heat lost due to incompletely burnt products of combustion.

Q. *What parameters are to be monitored to calculate the foregoing three factors determining the combustion efficiency?*

Ans.

1. Net stack temperature
2. All the flue gas components

Q. *Why is the monitoring of net stack temperature required?*

Ans. The importance of monitoring net stack temperature can be realized from the fact that if it is high, it indicates that a large amount of heat is being wasted to the atmosphere. If, on the other hand, stack temperature is kept too low, it may result in cold end corrosion.

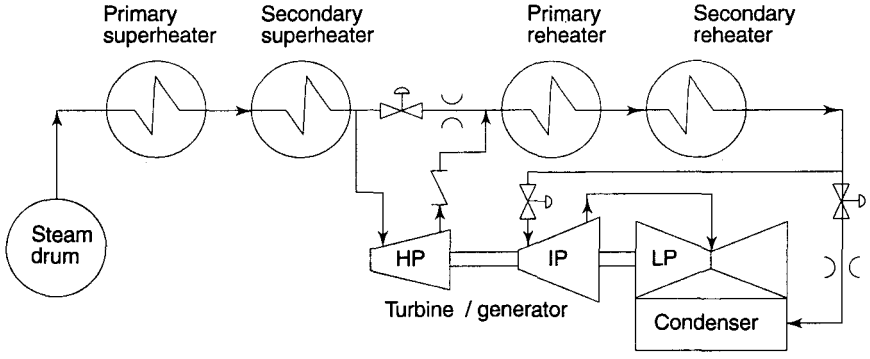

Fig. 1.80 *European bypass system.*

Q. *What components will you get in flue gas analysis?*

Ans. Oxygen, carbon dioxide, water vapour, sulphur dioxide, sulphur trioxide, oxides of nitrogen, and unburnt combustibles, viz. CO, H_2 and hydrocarbons.

Q. *What is the fundamental indicator of good combustion?*

Ans. The presence of minimum O_2, maximum CO_2 and nil combustibles in the flue gas.

Q. *What is the disadvantage of using excess air to reduce the combustibles content in flue gas to zero?*

Ans. It will

1. lower the furnace temperature
2. tax excess fan horsepower
3. result in heat loss due to heating of the induced air that does not enter into the combustion process.

Q. *Why is the measurement of draft essential?*

Ans. It assists in setting the damper correctly for various loads.

Excessive draft can result in increase of net stack temperature and lower the percentage of CO_2 in the flue gas.

If, on the other hand, the draft is inadequate, it will result in insufficient combustion air and smoky operation.

Q. *What is the conventional practice to determine the correct draft for introducing minimum excess air required for smokeless operation?*

Ans. This is obtained by a trial and error method, as the precise relationship between damper position and the amount of draft is not known. So the correct draft for minimum excess air compatible with smokeless combustion is determined for various loads by a trial method using a flue gas analyzer to monitor the levels of excess air, as dictated by the damper position and the amount of draft.

Q. *Though close monitoring of net stack temperature, oxygen and total combustibles in the flue gas is essential to control the combustion efficiency, yet more emphasis is given to monitor the combustibles at very close levels. Why?*

Ans. The combustion efficiency curve shows that the rate of energy loss in case of excess fuel, i.e. higher combustibles is much greater than in the case of excess air, i.e., high percentage of oxygen. [Fig. 1.81]

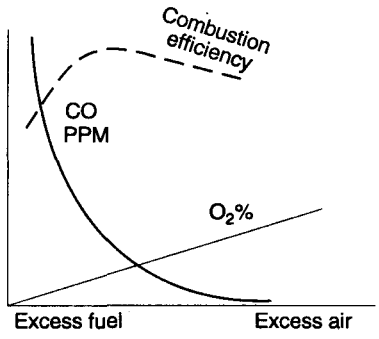

Fig. 1.81 *Effect of excess fuel and excess air on combustion efficiency.*

The rate of energy loss in the former case is about six times the rate of energy loss due to higher oxygen level.

Q. *Why it is required that fuel firing equipment operate under optimal combustion conditions?*

Ans. It will ensure

1. better heat transfer rate
2. increase in combustion efficiency
3. decrease in fan power loss
4. decrease in air pollution
5. reduction in downtime, e.g. reduction in soot blowing.

Q. *What are the disadvantages in monitoring the flue gas with Orsat Apparatus?*

Ans. The apparatus is cumbersome. The monitoring of flue gas with it is a time consuming process. It also suffers from inaccuracies. It calls for special skills of the personnel to minimize human error.

Q. *Do you recommend the use of stand-alone analyzers for monitoring flue gases?*

Ans. No.

Q. *Why?*

Ans. These stand-alone systems may sometimes prove their worth under specific circumstances, yet their use for monitoring total combustion efficiency suffers from certain specific limitations.

Q. *What are these specific limitations?*

Ans. **Take the case of CO_2-Analyzer.** It needs

1. higher maintenance
2. greater precision of measurements.

Moreover, the readings it produces are a function of the carbon/hydrogen ratio of the fuel burnt. These factors in combination make CO_2 monitoring difficult.

Take the case of On-line CO-Analyzer.

It uses infrared techniques that suffer from interference problems at elevated temperatures. Also, the presence of particulate solids in the flue gases impart inaccuracy. They interfere with the reading by blocking the light source. Besides, analyzers measuring CO only do not indicate the magnitude of fuel wastage due to the presence of other combustibles.

Oxygen-Analyzers by themselves cannot measure the combustion efficiency.

Q. *Then what instrument do you recommend for flue gas monitoring?*

Ans. Portable, multivariable combustion analyzer.

Q. *Any specific example?*

Ans. Model ENERAC-2000. It is manufactured and marketed by Energy Efficiency Systems, Inc. USA.

Q. *What are the important and striking features of a good portable combustion analyzer?*

Ans. A good portable analyzer should have the following features:

It should monitor

1. net stack temperature
2. excess oxygen
3. total combustibles.

Besides, some comprehensive analyzers have some striking features, such as:

1. draft measurement and excess air calculation
2. data logging and storing capability
3. autocalibration facilities
4. direct calculation of energy savings from computer programs by virtue of its interfacing capabilities with computer input data
5. add-on modules with NO_x SO_x measurement (This enables pollution control)
6. quicker flue gas analysis. What Orsat apparatus completes in hours, Enerac-2000 finishes within minutes
7. multifuel switches are provided to determine the combustion efficiency of as many as 15 different fuels
8. can be lined up with any fuel firing equipment.

Q. *What are the viable techniques, that if implemented, may result in a 5-10% savings of coal in a coal fired boiler?*

Ans.

1. Control of excess air
   It has been observed that for every 20-30% excess air, the boiler efficiency drops by 0.7%
2. Soot Blowing
   Fouling of heat exchanger surfaces by soot will bring about a rise in flue gas temperature. And a 4.5°C rise in flue gas temperature will cut down boiler efficiency by 0.2%.
3. Using of high pressure BFW heaters
4. Ensuring proper fuel/air distribution in the burners
5. Avoiding low combustion air temperature
6. Avoiding low primary air velocity

7. Ensuring adequate fuel/air mixing
8. Minimizing unburnt loss by increasing fineness of coal
9. Controlling Blowdown Loss. 16% of blowdown means a total heat loss of 0.42%, making it imperative to maintain blowdown as per the optimum requirement.
10. Reduction of unburnt gases in the flue gas
11. Minimizing condenser losses
12. Efficient Steam Management. This means maintaining rated steam parameters at the turbine inlet and the back pressure of the turbine exhaust.
13. Prevention of spontaneous coal combustion
14. Prevention of coal loss by natural forces like air/wind, rain, etc. during transportation and storage
15. Proper use and application of bowl mills for accurate sizing of coal.

Q. *What may be the cause of a fall in condenser vacuum in the surface condenser?*

Ans.

1. Deposition of foulants on the surface condenser's tubes
2. Low circulation flow
3. High air ingress in the condenser
4. High cooling water inlet temperature.

Q. *If a thermal powerplant burns inferior coal of a quality different from the designed coal specification of the boilers, what harm will it cause?*

Ans. Use of inferior quality of coal in boilers may lead to

1. operational problems
2. excessive use of coal
3. malfunctioning of coal handling plants
4. chocking of chutes
5. poor functioning of dust extraction plants
6. drastic cut in the availability of plant
7. reduction in plant load factor (PLF)

Q. *What factors may lead to excessive fuel oil consumption in coal fired boilers of thermal power stations?*

Ans.

1. Burning of inferior quality coal
2. Operating the plant at part load
3. Maloperation of the equipment
4. Frequent shutdown/start-up of the plant
5. Problems in stablization as well as full-load operation of new units.

Q. *What is the drawback of operating a boiler at part load condition?*

Ans. Despite being under part load of steam generation, the running equipment consume almost the same amount of energy as in a full load condition.

Q. *How can start-up and shutdown losses be cut down?*

Ans. A fast start-up is highly desirable, as it cuts down the energy consumption during this period.

A few thermal powerplants follow an open valve boiler start-up. This saves half of coal start-up costs.

Q. *What is the turn-down ratio of a steam control valve?*

Ans. It is the ratio of normal design flow to minimum controllable flow.

T = Normal design flow/Minimum controllable flow

Q. *What is the rangeability ratio of a steam control valve?*

Ans. It is the ratio of maximum controllable flow to minimum controllable flow.

R = Maximum controllable flow/Minimum controllable flow

Note: The above definitions hold good for gun and nozzle also.

Generally, $T \approx 70\%\ R$

2

HIGH PRESSURE BOILERS

Q. *Why is high pressure steam in growing demand in power plants?*

Ans. To increase the efficiency of the plant and reduce the cost of production of electricity.

Q. *How does high pressure steam increase the efficiency of power plants?*

Ans. Higher the temperature and pressure of the steam, higher is its heat content and therefore, greater the enthalpy drop available in the expansion turbine. This means the efficiency of the power plant will be higher.

In high pressure steam generation plants greater economy in the production of electricity is obtained by making use of high temperature flue gases.

Q. *What are the unique features of high pressure boilers?*

Ans. **1. Method of Water Circulation:** Can be both natural as well forced circulation types. The use of natural circulation is limited to subcritical boilers with operating pressure upto 140 kgf/cm^2, while for critical (steam pressure 218 atm) and supercritical boilers forced circulation is used.

2. Type of Tubing: Most of the high pressure boilers are of the water-tube type in which water is circulated through tubes arranged parallel to each other.

3. Improved Method of Heating: Greater heat transfer is achieved by improved methods of heating:

(a) by evaporating water at pressure higher than the critical pressure of steam thus saving the latent heat

(b) by heating of water by mixing the superheated steam to obtain the highest heat transfer coefficient

(c) by increasing the velocity of water through the tubes and raising the flue gas velocity above sonic level, with the effect that the overall heat transfer coefficient is enhanced.

Q. *Why is natural circulation limited to subcritical boilers?*

Ans. Natural circulation works on the basis of density difference between steam and water.

At critical pressure (218 atm) and saturation temperature (374°C) of steam, the density difference of steam and water is zero and so natural circulation ceases. Hence natural circulation is operative in the case of subcritical boilers.

Q. *Why are the water tubes arranged in parallel?*

Ans. To reduce the pressure loss and to get better control over the quality of the steam.

Note: There would have been a large pressure drop due to friction if the water flow were to take place through one continuous tube.

Q. *What are the advantages of high pressure boilers?*

Ans. 1. Chances of scale formation on tube walls are very low due to high velocity of feedwater.

2. Quick start-up from cold is possible if power from an external source is available.
3. Increased efficiency (40-42%) of the plant due to higher enthalpy of steam output. As a result, more work output is available from the expansion turbine. (Fig. 2.1)
4. Fit for meeting variable load quickly, as steam can be raised quickly.
5. Light-weight tubes with better heating characteristics can be used to reduce the cost, erection time and space requirement for tube layout.
6. When forced circulation is adopted, there is a greater degree of freedom in the lay-out of the furnace, tubes and boiler compartments.
7. Danger of overheating and thermal shock is minimized due to all parts being uniformly heated.

Q. *Who introduced the forced circulation boiler?*

Ans. Credit goes to La Mont for introducing the forced circulation boiler for the first time (1925).

Q. *Briefly describe a La Mont boiler.*

Ans. It consists primarily of three circuits (Fig. 2.2)

(a) **Air circuit:** Cold air is blown by a blower through the air preheater where it gets heated up in the process of heat exchange with flue gases. Hot air is then directed to the combustion chamber to be used as combustion air.

(b) **Water circuit:** Deaerated BFW is pumped through the economizer—a coil type heater—by a BFW pump and fed to the steam separating drum from which it is forced through the tubes of radiant evaporators and convective evaporator by a circulating pump. Together with steam

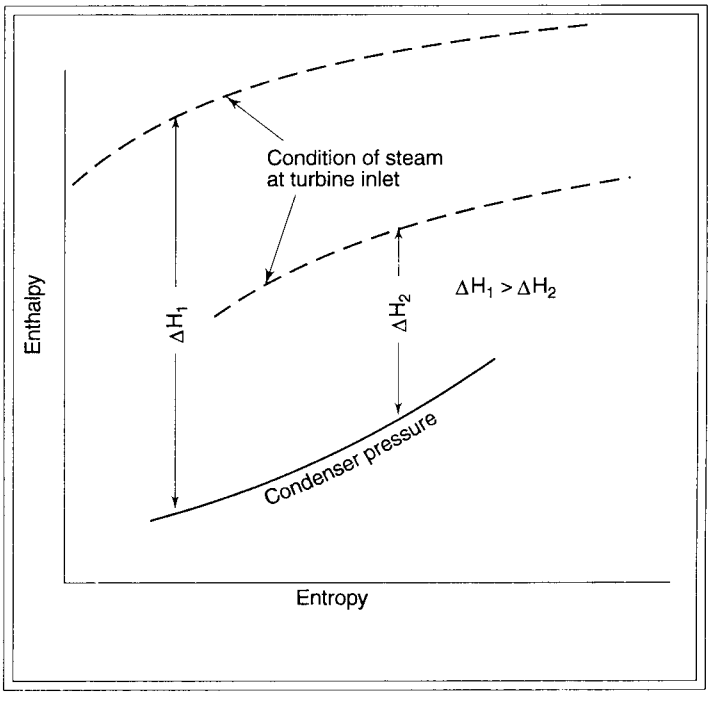

Fig. 2.1 *High enthalpy drop is available from steam of higher pressure.*

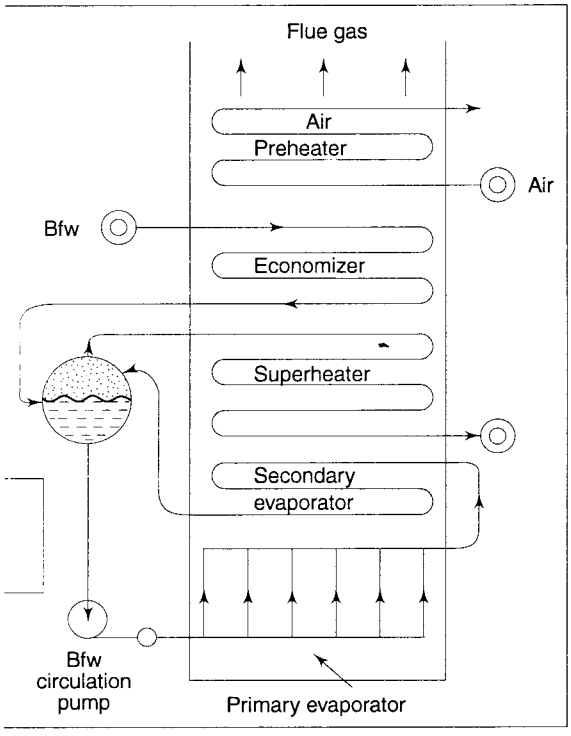

Fig. 2.2 *La Mont Boiler—a schematic representation.*

it returns to the steam drum to complete the cycle.

(c) **Steam circuit**—The steam separated in the steam drum is saturated steam. It is superheated in the superheater coil and fed to the expansion turbine to generate power or drive compressors.

Note: This boiler is adaptable for all pressures from subcritical to supercritical; capacity exceeding 50 t/h.

Q. *What is the ratio of BFW circulation to the tonnage of steam produced?*

Ans. Water circulation is 8 to 10 times the weight of the steam produced.

Q. *Why is such a high circulation ratio maintained?*

Ans. To prevent the evaporator tubes from overheating.

Q. *What is the main drawback of a La Mont boiler?*

Ans. The main drawback of a La Mant boiler is reduced heat transfer coefficient due to formation and attachment of steam bubbles on the inner surface of watertubes.

Q. *How can this be eliminated?*

Ans. By operating the boiler at critical pressure (218 atm).

Q. *Why?*

Ans. At this pressure the density of water is equal to that of steam. Hence no bubble will form.

Q. *What is the minimum steam generating pressure of a Benson boiler?*

Ans. 225 atm.

Q. *When did such a boiler go into operation first?*

Ans. In the year 1927 in Germany by Siemens-Schuckert-Merke.

Note: It was first built in England (1923) by Mark Benson, a Czechoslovakian.

Q. *Briefly describe a Benson boiler.*

Ans. It consists mainly of two circuits (Fig. 2.3)

(a) **Air circuit**: Cold air blown by the blower is heated up in the air preheater by hot flue gas by indirect contact heat transfer.

The resulting hot air is directed to the combustion chamber to be used as combustion air.

(b) **Water-steam circuit:** Forced circulation is introduced to generate superheated steam in this open hydraulic system.

A high pressure feed pump feeds BFW (Boiler Feed Water) to the economizer, radiant evaporator, convective evaporator and superheater, thus converting feedwater into superheated steam in a once-through cycle.

Q. *What is the major problem associated with a Benson boiler?*

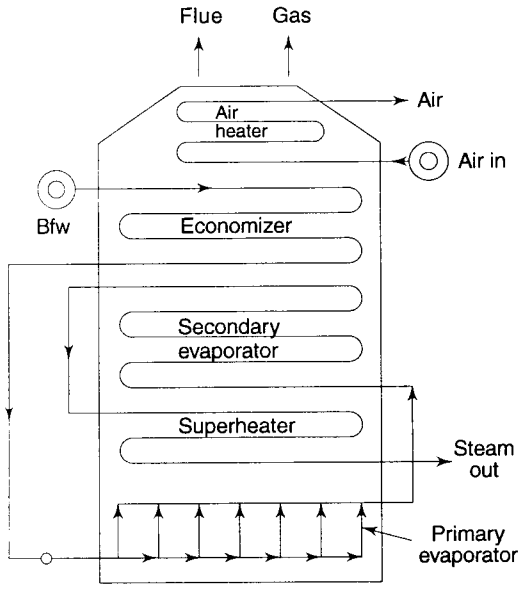

Fig. 2.3 *Benson boiler—a schematic representation.*

Ans. Salt deposition in the transformation zone where all remaining water is converted into steam.

Q. *How can this be avoided?*

Ans. By flushing out the boiler after every 4000 working hours.

Q. *What are the maximum operating temperature and pressure achieved so far in a commercial Benson boiler?*

Ans. Temperature : 650°C; Pressure : 500 atm

Q. *What are the advantages of a Benson boiler?*

Ans.

1. There is no boiler drum, which means a reduction in the overall weight of the boiler and a cut in capital investment.
2. There is no expansion joint as the boiler is of the forced circulation type. Since all parts are welded at their sites, it is easier and quicker to erect a Benson boiler.
3. Start-up is quicker because of welded joints
4. Needs comparatively less floor-space than other boilers of the same capacity
5. Better and more efficient protection of furnace walls as the high pressure boiler tubes have smaller diameters and are closely spaced
6. Economic operation at partial load or over load is possible
7. Inherently free from the problem of bubble formation which occurs in the case of natural circulation as the load drops abruptly

   This feature makes Benson boilers very suitable for grid power stations
8. Blowdown loss is less, hardly 4% of natural circulation boilers of the same capacity.
9. Minimum explosion hazard as tubes are of small diameter with very little storage capacity.

Q. *Briefly describe the water-steam circuit of a Schmidt-Hartmann boiler.*

Ans. The water-steam system of this type of boiler comprises two circuits—primary circuit and secondary circuit. (Fig. 2.4)

High pressure (100 atm) steam produced from distilled water in the primary evaporator of the primary circuit is allowed to exchange its heat with impure water in the evaporator and BFW preheater in the secondary circuit to generate steam (60 atm) which is passed through the superheater to produce superheated steam.

Q. *What is the nature of circulation in the primary circuit of a Schmidt-Hartmann boiler?*

Ans. Natural circulation.

Q. *Will it be sufficient to effect the necessary rate of heat transfer as to overcome the thermo-siphon head of about 2 to 10 m of water column?*

Ans. Yes.

Q. *What is the rate of heat transfer from the primary circuit to the secondary circuit?*

Ans. About 10000–12000 kJ/m^2 h°C

Q. *What are the advantages of Schmidt-Hartmann boilers?*

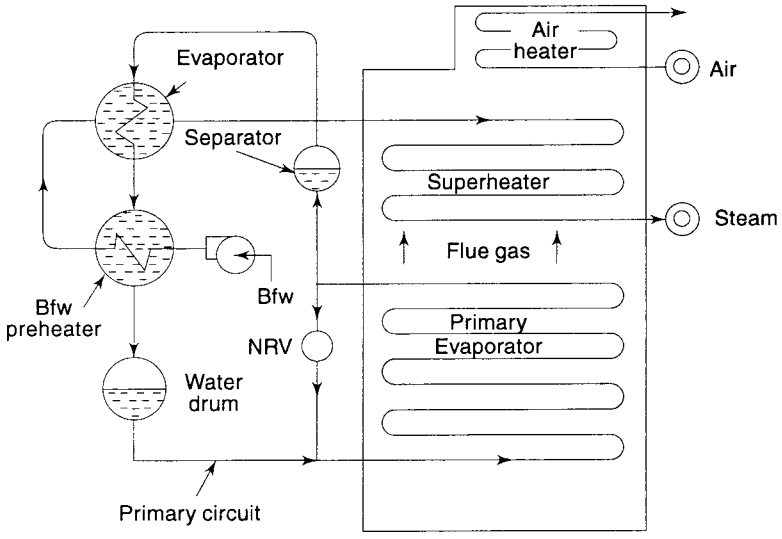

Fig. 2.4 *Air and steam-water circuits of a Schmidt-Hartmann boiler.*

Ans.

1. Chances of overheating are minimal as the highly heated components carry pure water with no risk of salt deposition at all
2. Accepts wide load fluctuations without undue priming or abnormal increase of pressure in the primary circuit
3. Evaporation proceeds without priming
4. Salt deposition due to evaporation of impure water in the evaporation drum can be quickly and easily brushed off.

Q. *What is the speciality of a Velox boiler?*

Ans. Here the steam generation is based on the principle that the rate of heat transfer from hot flue gas to water is much higher at supersonic velocity than at subsonic velocity of the flue gas. Hence compressed air (2.5 atm) is used to produce flue gas at supersonic velocity (200 to 250 m/s).

Q. *What is the degree of heat release in the combustion chamber of a Velox boiler?*

Ans. (30–42) $\times$ 10^6 kJ/m^3 of the combustion chamber.

Q. *Briefly describe the Velox boiler.*

Ans. Air is compressed to 2.5 atm by an air compressor driven by a gas turbine to produce flue gas at supersonic velocity in the combustion chamber. The gas turbine is driven by hot (500°C) flue gas from the superheater exit. (Fig. 2.5)

The combustion chamber is vertical and cylindrical, lined with tubes of 10 cm dia.

Inside each tube is another concentric tube of 2.5 cm dia through which hot flue gas passes at supersonic velocity while BFW flows through the annulus between the two tubes.

The mixture of water and steam produced passes through a separator that separates steam which is fed to the superheater heated by hot flue gas to produce superheated steam.

The flue gas (500°C) from the superheater is allowed to expand in the gas turbine to drive the air compressor. The turbine exhaust gas is passed countercurrently through the economizer to preheat the BFW and then finally discharged at 90°C and 120 m/s to atmosphere.

Q. *What is the basic factor that limits the capacity of a Velox boiler?*

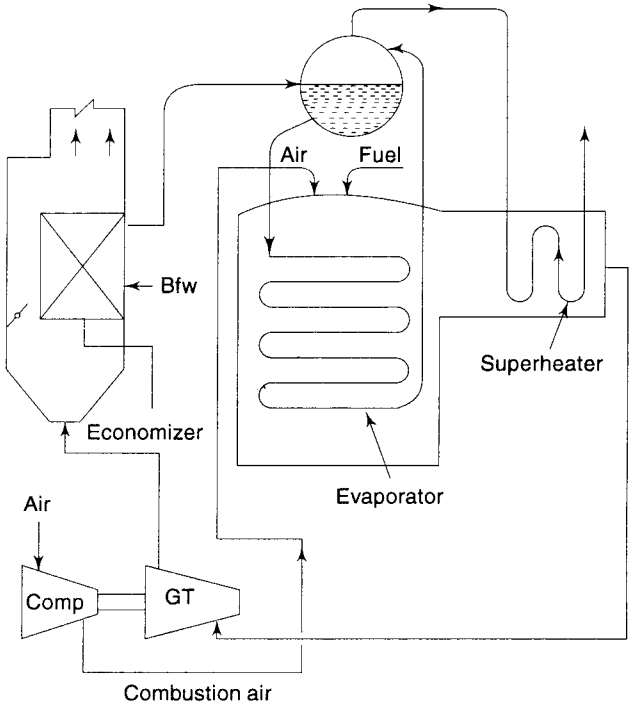

Fig. 2.5 *Schematic representation of Velox boiler.*

Ans. With increase in the capacity of Velox boilers, greater is the power requirement of the air compressor, so as to deliver more combustion air at supersonic velocity. Since a gas turbine alone may not be able to cope with this power demand of the air compressor, power from an external source needs to be supplied.

That is why the size of the Velox boiler is limited to 100 t/h and the power requirement of the air compressor at this velocity is 450 kW.

Q. *What is a supercritical boiler?*

Ans. A boiler producing steam above critical pressure, i.e. above 218 atm is called a supercritical boiler.

Q. *What is the basic difference between subcritical and supercritical boilers?*

Ans. Subcritical boilers operate at pressures below 218 atm while supercritical boilers operate at pressures above 218 atm.

A subcritical boiler has three distinct sections—economizer, evaporator and superheater while a supercritical boiler has only an economizer and a superheater.

Q. *What are the advantages of supercritical boilers over subcritical ones?*

Ans.

1. Higher heat transfer rate
2. More flexible in accepting load variation
3. Greater ease of operation
4. Higher thermal efficiency (40-42%) of power generating stations can be achieved by using supercritical steam
5. The absence of two-phase mixture in supercritical boilers minimizes the problem of erosion and corrosion
6. Steadier pressure level.

Q. *What is a supercharged boiler?*

Ans. A boiler where combustion is carried out under pressure in the combustion chamber by supplying compressed air. (Fig. 2.6)

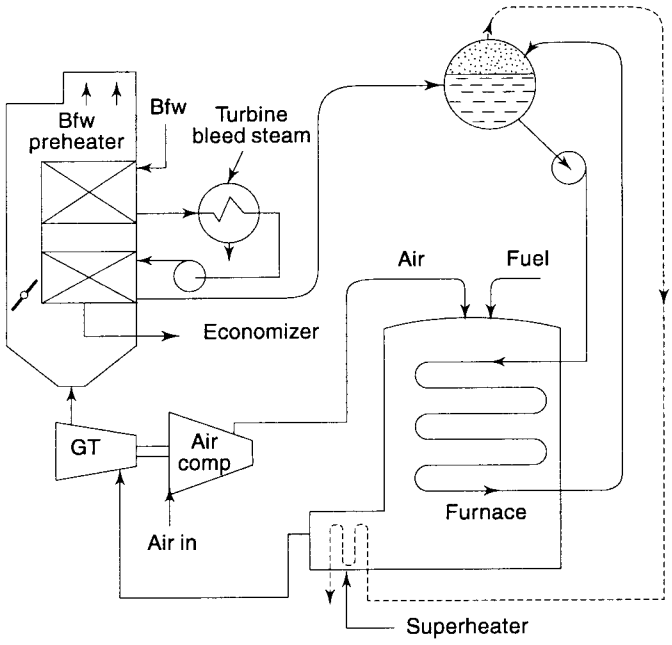

Fig. 2.6 *Schematic diagram of a Supercharged boiler.*

Q. *What are the direct utilities of combustion under pressure?*

Ans. The flue gas is also under pressure (about 5 atm) which is utilized to drive the gas turbine to run the air compressor coupled with it to supply the compressed air for combustion.

Due to pressurized combustion, the overall heat transfer coefficient is very high.

Q. *What are the specific advantages of supercharged boilers over other conventional boilers?*

Ans.

1. Much higher overall heat transfer coefficient
2. The heat transfer surface of supercharged boiler is barely 25–30% of the heat transfer surface of a conventional boiler. And that means a drastic saving in the material cost
3. Quicker start-up possible. A 150 t/h supercharged boiler can be brought to full load in less than half an hour
4. Better response to control
5. The power available from the gas turbine can be utilized to run the auxiliaries

Q. *What is the main drawback of such a pressurized combustion system?*

Ans. The entire gas passage should be carefully made leak-proof.

Q. *Draw the pressure distribution in the gas-air path of a boiler with balanced draft and one with a supercharged furnace.*

Ans. See Fig. 2.7

Q. *How many heat zones are there in most commonly used pulverized coal fired boilers?*

Ans. Three.

Q. *What are the three heat zones in commonly used pulverized coal fired boilers?*

Ans. One radiation zone (Zone I) and two convection zones (Zones II and III). (Fig. 2.8).

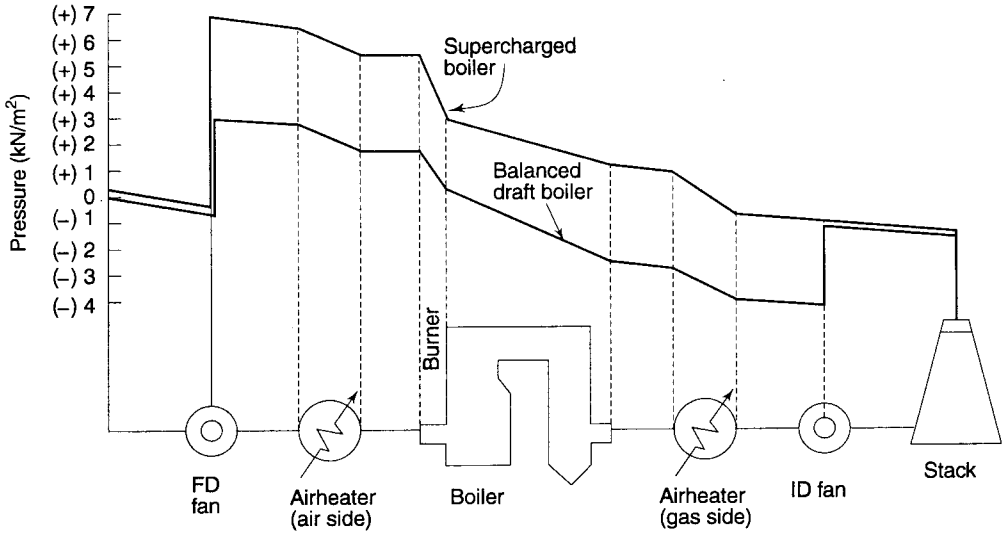

Fig. 2.7 *Pressure distribution in the gas-air path of balanced draft and Supercharged boilers.*

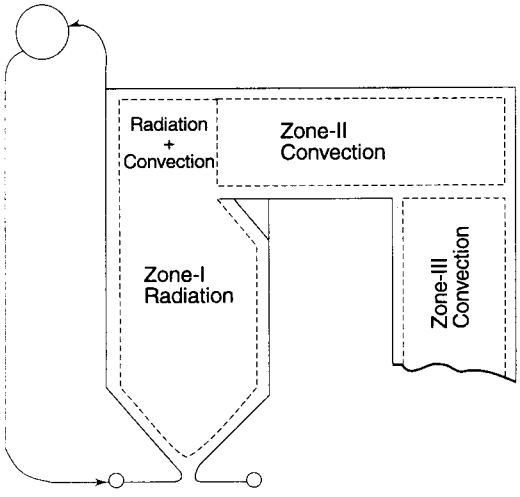

Fig. 2.8 *Different zones of pulverized coal fired boilers.*

In the bottom and middle portion of Zone I, most of the heat transfer takes place by radiation from the yellow flames. Hence this zone is called the radiation zone. This effect of radiation is reduced in the top portion of Zone I where secondary air is introduced, with the effect that a considerable amount of heat transfer is contributed by convection. Here heat transfer takes place due to both radiation and convection.

Heat transfer in zones II and III takes place predominantly by convection. The former is called the high temperature zone and the latter is called the low temperature zone.

Q. *Why should the flue gas temperature in zones II and III be lower than the ash fusion temperature (AFT)?*

Ans. If the flue gas temperatures in the zones II and III are higher than the AFT (Ash Fusion Temperature), then the convective mode of heat transfer will bring about slag deposition on metal tube surfaces carrying water or steam, as the surface temperature of the tubes is always less than AFT.

Q. *How much of the total heat generated is absorbed in Zone I?*

Ans. About half of the total heat.

Q. *How can this be increased?*

Ans. By firing pulverized coal with low AFT and by reducing the excess air supply.

Q. *Why can more heat transfer by radiation be effected using low AFT coal?*

Ans. Firing pulverized coal with low AFT will not deposit slag on the water-tube surfaces in this zone and as a result more heat transfer will be effected through the clean heat transfer surface.

Q. *Why is more heat transfer by radiation essential when using low AFT coal?*

Ans. Firing pulverized coal with low AFT in hot turbulent air coupled with low excess air produces a very high flame temperature at which the ash always remains in a molten state. The evaporator tube surface temperatures are always less than this AFT and that entails the risk of solidification of molten ash on the surface of the evaporator tubes. In order to avoid slagging of evaporator tubes, the use of convection heat transfer should be avoided as long as the gas temperature is higher than AFT. And therefore, heat transfer by radiation is essential. Even though the radiant surface is more expensive for the same degree of heat transfer, the heat transfer must be by radiation.

Q. *If there is a fall in excess air supply, why does heat transfer in ZONE I increase?*

Ans. In this zone, heat transfer occurs predominantly by radiation. Introduction of excess air will entail a convection current, flame temperature will drop and that will reduce the amount of heat transfer by radiation. Conversely with the supply of less excess air, the heat transfer by radiation in zone I will increase.

Q. *Why is the evaporator, not the superheater located in ZONE I?*

Ans. Reduction in furnace size demands the lowest possible surface temperature of tube metals. The evaporator tubes always offer lower surface temperature than superheater tubes carrying superheated steam. Hence the evaporator, not the superheater, is the most suitable component to be located in ZONE I.

Q. *Why is the superheater located in ZONE II?*

Ans. For a medium pressure boiler (40–60 atm and 440–460°C), the heat absorbed by the superheater does not exceed one-fifth of the total heat absorption of the boiler and the evaporator tubes occupy the entire surface of the furnace. The superheater is of the convective type. Hence zone II is the most preferred location for the superheater, as the heat transfer in this zone is mainly of the convective type.

For high pressure boilers (100 atm/540°C), the superheater is partly convective and partly radiative. The convective part is placed in zone II while the radiant platen section is suspended in the top portion (radiant + convection) of zone I. These two super-heaters are joined in series.

3

BOILER AUXILIARIES

Q. *What do you mean by boiler auxiliaries?*

Ans. These are the devices incorporated in the boiler circuit to boost up the efficiency and performance of the steam generation plant and assist in the systematic and adequate operation of the boiler unit for prolonged periods.

Q. *What are they?*

Ans. Usually a boiler is fitted with the following auxiliaries (accessories):

1. Air preheater
2. Economizer
3. Superheater
4. Desuperheater
5. Boiler feed pumps
6. Forced draft and induced draft fans
7. Mechanical separator
8. Equipment tanks
   (a) Feedwater tank
   (b) Deaerator
   (c) Continuous blowdown expander
   (d) Drainage expander
9. Chemical dosing system
10. Soot blowers and wall blowers
11. Pressure reduction valve
12. Pulverizers and fuel firing system
13. Ash handling system.

Q. *What is a boiler feed pump?*

Ans. A pump that feeds boiler water (polished water) to the steam drum via the economizer (for perheating).

Q. *What are the two most important criteria of a boiler feed pump?*

Ans. It must be absolutely positive and reliable under all variable operating conditions.

Q. *What kind of pump should a boiler feed pump be?*

Ans. It may be

(a) a direct acting pump driven by its own cylinders

(b) a reciprocating pump driven by a motor or belted to the machinery

(c) a centrifugal pump—turbo-driven or electrically driven by motor

Q. *How are direct acting pumps classified?*

Ans. They may be classified as simplex, duplex and triplex pumps.

Q. *What is the basic difference between these three?*

Ans. The simplex pump has one pump cylinder and one engine cylinder.

In duplex and triplex pumps there are two and three pump cylinders respectively.

Q. *What kinds of reciprocating pumps can be used?*

Ans. Both plunger driven and piston driven.

Q. *Among the three kinds of pumps—direct acting, reciprocating and centrifugal—which one will you prefer as a boiler feedwater pump?*

Ans. Centrifugal pump.

Q. *Why?*

Ans. A centrifugal pump is capable of

1. delivering steady flow of BFW
2. supplying the largest quantity of BFW under a given head
3. accepting load variations most easily
4. trouble free and smooth operation; less floor space is required and maintenance cost is low.

Q. *Why are both turbo-driven and motor-driven centrifugal BFW pumps installed?*

Ans. During start-up, the motor driven pumps are lined up to establish circulation.

When the unit is in full operation and steam is available, one or two turbo-driven pumps may be lined up to spare corresponding number (s) of motor-driven pumps for reserve, rest, repairing or saving of electricity, which is costlier than steam. Motor driven pumps will continue to circulate BFW through the boiler unit when the latter trips.

Q. *Suppose both steam and electricity are available. Which centrifugal pump would you prefer to switch on?*

Ans. Turbo-driven.

Q. *Why?*

Ans. Steam is cheaper than electricity?

Q. *In recent years the cycling operation of powerplants has become a standard requirement of the utility industry. Because of this development the suitability of every component in the power generating system must be carefully assessed in great detail against the operational requirement it faces.*

In this context what are the essential requirements of BFW pumps?

Ans.

(a) Rapid rate of boiler load reduction e.g. 0.75% per s down to about 25% load

(b) Boiler load reduction following a turbine trip e.g. 1% per s with pumps on hot standby

(c) Boiler load increase with pumps on standby (e.g. pump startup from cold standby)

CASE STUDY

Problems crop up due to changing boundary conditions around the boiler feed pumps (deaerator/ feedwater tank, suction pipe, operating transients etc.).

Shown in Fig. 3.1 is the general layout of the BFW pump circuit.

Case-I The boiler is operating at constant load with pump on standby.

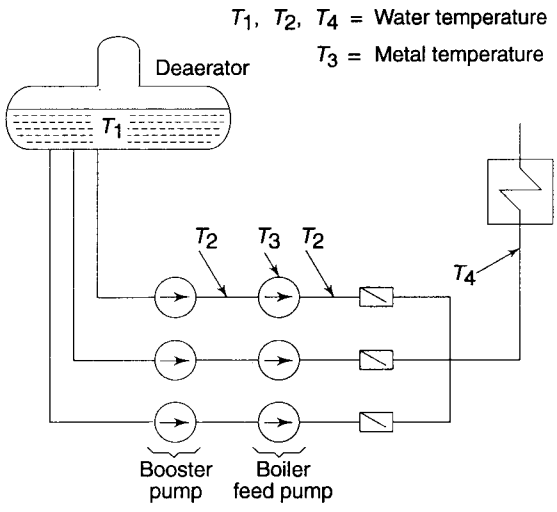

Fig. 3.1 *Simplified BFW pump circuit.*
Source: Cycling Effects on Boiler Feed Pumps— A Simon et. al.
Brochure: 27.58.04.40 (Sulzer Brothers Ltd.)

At $T_1 = 453°K$, one pump is switched off. The temperature in the deaerator is maintained at the same temperature T_1, while the idle feedpump and its suction pipe cool due to heat transfer by radiation and convection. At least one feed pump is still running. Therefore, after a certain time, the following conditions prevail:

$$T_1 = T_4$$

$$T_2 < T_1$$

$$T_2 < T_3$$

as the heat storage of the pump is much bigger than that of the pipe due to its large mass. Of course, after an indefinite time T_2 will equal T_3.

Q. *If the idle pump is switched on again, what problems will generate?*

Ans.

1. There will be a thermal shock (thermoshock) in the pump casing when the first plug of cold water from the pipe flows into the hot pump.
2. When the first plug of cold water gushes into the high pressure BFW preheater, it can inflict a thermoshock or even "condensation shock" (water hammer) in the preheater. This effect is even worse when only one pump is in operation, which prevents mixing of the feedwater prior to the HP pre-heater inlet.

Q. *What may be the outcome of thermoshock generated in the pump casing?*

Ans. It generates large stresses that can even lead to permanent deformations.

Q. *How can this problem be overcome?*

Ans. Analyze the problem on the basis of

(a) temperature distribution in the pump
(b) forces created by thermoshock and condensation.

Go for appropriate material selection and design measures.

Case-II Boiler load reduction with pump on standby.

At $T_1 = 453°K$, one pump is switched off.

The deaerator pressure drops bringing about a consequential decrease in deaerator temperature, within an hour, down to 393°K (saturation pressure = 0.2 MPa).

Due to this relatively rapid pressure drop, the water in the suction pipe undergoes partial flashing into steam and gets expelled (steam out). This effect is enhanced by the heat stored in the suction pipe and the pump.

Refer to Fig. 3.1. With at least one feedpump still i/1, the following temperature conditions prevail:

$$T_1 = T_4$$

$$T_2 \simeq T_1$$

$$T_3 > T_2$$

Q. *If the idle pump is switched on again what problems will occur?*

Ans. Depending on the specific volume of the content*, the following problems will arise to some extent:

(a) Cavitation
(b) Hydraulic unbalance
(c) Condensation shock (water hammer)

Thermoshock will also occur.

* This content comprises a z-phase flow i.e. a steam-water mixture which both the booster pump and feed pump are forced to pump.

Q. *The hydraulic unbalance of rotor occurs due to 2-phase flow in the impellers. What is the effect of this on BFW pumps?*

Ans. The radial static and dynamic forces can become so great that the rotor touches the stator (fouling). As expected, this will bring about premature wear and damage and even seizure of the rotor if the selected materials are not appropriate. Compared with normal operating conditions, the steam and water mixture has very low cooling and lubricating effect which increases the risk of a rotor seizure.

Q. *How does condensation shock arise and what is its effect?*

Ans. There are reported cases in which steam that had been formed in the suction system collapsed in zones of higher pressure within the pump, after the pump had been restarted. The mechanical stress induced due to this is called condensation shock or water hammer.

This condensation shock leads to considerable forces and thus to permanent deformation of pump parts.

Case-III Boiler load is increased with pumps on standby.

At $T_1 = 393°K$ one pump is switched off.

The deaerator pressure increases and therefore, the temperature T_1 in the deaerator also rises to say 453°K.

As the pump is taken off the line, the suction pipe and the pump itself begin to cool due to heat transfer by radiation and convection to the surroundings. The heat transfer from the deaerator through the water and metal is too small to maintain temperature of 393°K or even heat the suction pipe (this might be possible only in the zone where the suction pipe leaves the deaerator).

Refer to Fig. 3.1. With at least one feedpump still *i*/1, the following temperature conditions prevail:

$T_1 = T_4$

$T_2 < T_1$ (T_2 becomes relatively lower the longer the pump has been switched off)

$T_2 < T_3$ (The heat storage of the pump is much larger than that of the pipe due to the large mass of the former)

Q. *Now if the idle pump is switched on again, what problems will occur?*

Ans.

(a) Thermoshock in the pump

(b) Thermoshock and water hammer in the BFW preheater.

Q. *How does a HP-bypass (High Pressure Turbine Bypass) exert influence on the available NPSH-safety margins?*

Ans. With a 100% HP-bypass, the boiler load must not be reduced following a turbine trip. Thus the boiler feed pumps can continue to run at their normal operating point at the time of turbine trip. If a smaller HP-bypass is installed, e.g. one with a 50% capacity, the boiler, and consequently the pumps, will be forced to reduce the load to 50% following a turbine trip. The transient pressure decay v_p in the deaerator can be established for such load reduction and compared with the maximum allowable transient pressure decay v_{pma}, in order to obtain the available NPSH safety margin at various loads for different load reduction gradients.

Note that for a load reduction of, say 0.75%/s, the smallest safety margin does not occur at the maximum of the respective curve v_p (Q), which lies at about 60% load.

This example demonstrates that a turbine trip with a subsequent boiler load reduction can be more critical than a turbine trip without a subsequent boiler load reduction, depending on the load-reduction transient and the final load at the end of the load reduction.

Source: Cycling Effect on Boiler Feed Pumps

— A. Simon; G. Eichhorn (Sulzer Brothers Ltd, Switzerland)

R. Vach (Sulzer Brothers, South Africa)

S. Pace (Electric Power Research Institute, USA)

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Q. *What is the normal operating speed range of BFW pumps?*

Ans. 2500—9000 rpm

Q. *At what temperature range do BFW pumps deliver hot water?*

Ans. 400°—495°K

Q. *A BFW pump delivers water at 425°K while operating at 3200 rpm. If this pump is switched off what thermo-hydraulic phenomenon will occur inside the pump?*

Ans. As soon as the pump is switched off, the fluid trapped inside the pump begins to cool. The cooler portion of the fluid inside the pump casing sinks to the bottom because of its higher density, and the warmer fluid rises up towards the top. As a consequence, a thermo-siphon circulation sets in inside the pump.

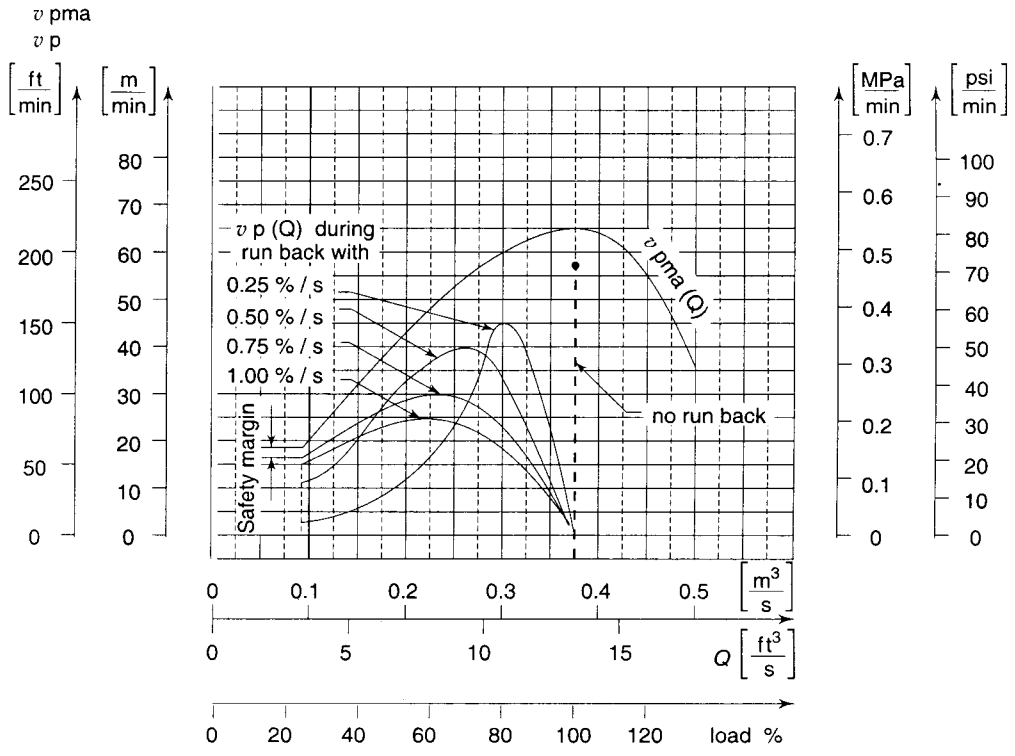

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Fig. 3.2 *Comparison of maximum allowable transient pressure decay v_{pma} with the maximum transient pressure decay v_p after a turbine trip with a subsequent boiler load reduction.*

Q. *If the BFW pump is a barrel-type one, how many such thermo-siphon circuits will arise in case of pump stoppage?*

Ans. Two—one between the barrel casing and stator and the other between stator and rotor (Fig. 3.3)

Q. *What are the effects of such double thermo-siphon phenomena in a barrel-type pump?*

Ans. The two thermo-siphon circuits establish two different temperature differentials; one between the top and bottom of the barrel casing and a second between the top and bottom of the inner pump body. Such temperature differentials can exceed 80°K within 2 hours.

The pump casing deforms even under normal operating conditions if the temperature differential between the top and the bottom of the casing rises up to 15°K.

Therefore, the large temperature differentials cause the upper (warmer) portions of both the barrel casing and the inner pump body to become longer than the lower (cooler) portions. These expansions warp both the casings—this phenomenon is called *distortion or hogging* that pushes the bearings downwards (Fig. 3.4 and 3.5).

In addition to distortion of the casing, the rotor also begins to deform similar to the casing as soon as the hot pump is brought to a stop. This

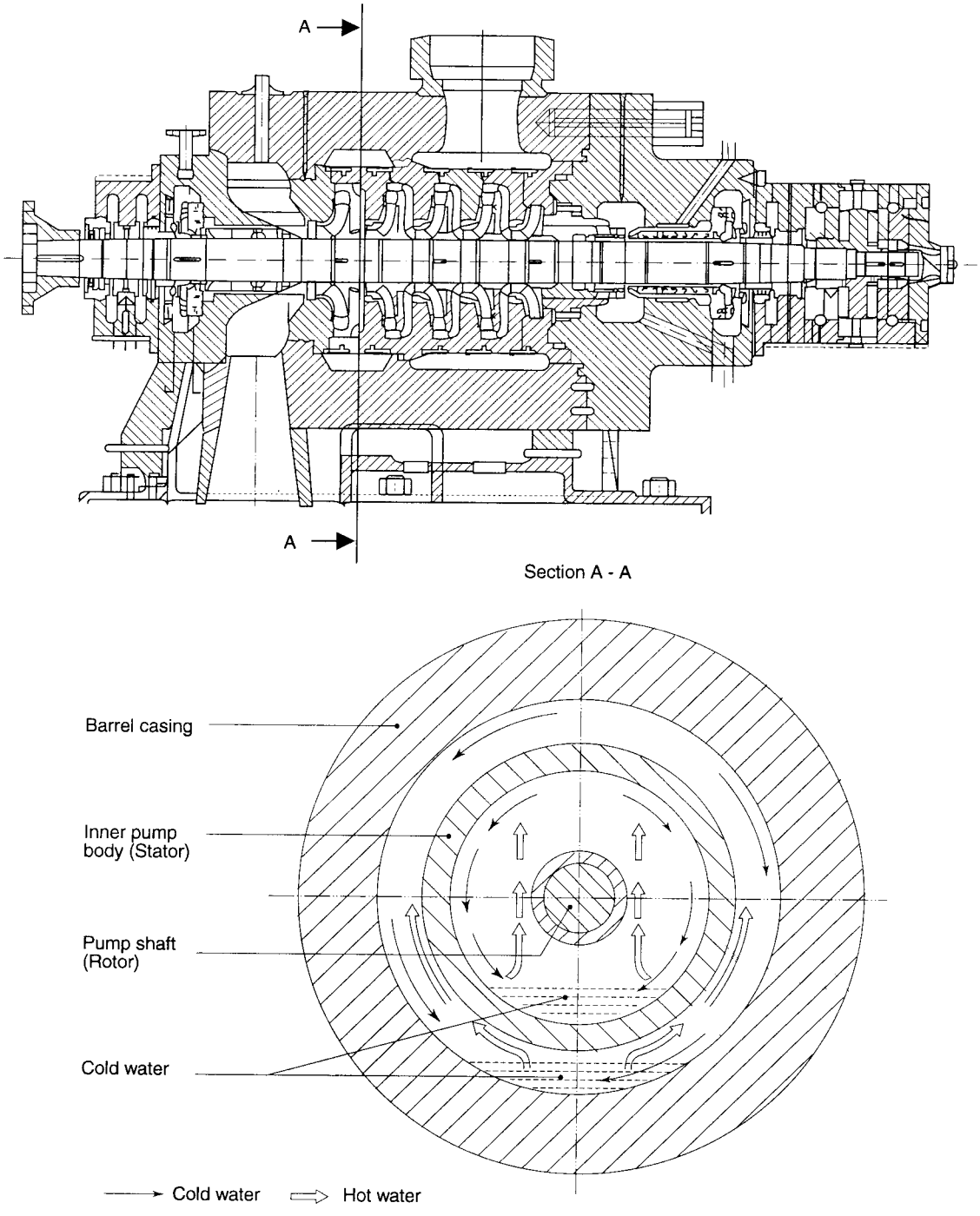

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Fig. 3.3 *Thermo-siphon circuit in a barrel-type pump.*

Source: *Cycling Effects on Boiler Feed Pumps—A. Simon et. al./Brochure 27.58.04.40 (Sulzer Brothers Ltd.)*

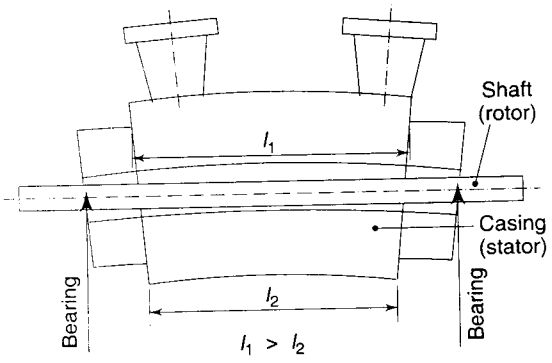

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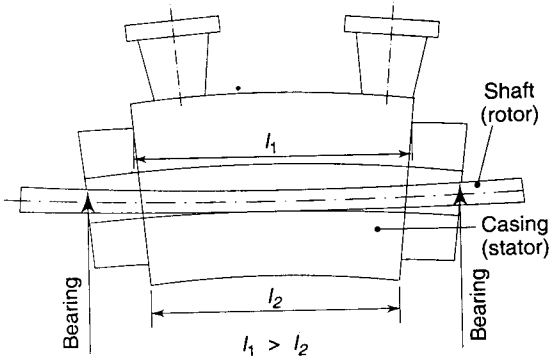
Fig. 3.4 *Thermal deformation of pump parts under normal operating conditions (Hot Running) and at shutdown, due to temperature differential between casing top and bottom.*

Source: Cycling Effect on Boiler Feed Pumps—A. Simon et. al.

Brochure 27.58.04.40 (Sulzer Brothers Ltd.)



$(l_1 - l_2)$ > $(l_1 - l_2)$
Fig. 3.3 Fig. 3.2

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Fig. 3.5 *Thermal deformation of pump parts after a hot pump has been stopped for a certain time (in the figure the shaft is shown turned by half a revolution).*

Source Cycling Effects on Boiler Feed Pumps—A. Simon et. al.

Brochure 27.58.04.40 (Sulzer Brothers Ltd.)

rotor distortion is brought about mainly by the effect of cooling caused by the shaft seals (thermo-siphon effect round the shaft) and partly by natural stratification of the trapped water.

The deformation of rotor is normally greater than that of the casing. As long as the rotor is not turned, it may not foul with the casing. After it rotates by half a revolution, however, the worst case results as the rotor and the casing is distorted in opposite direction (Fig. 3.5).

Q. *Which other factors influence the above deformations arising from the thermo-siphon effect?*

Ans. The warpage of pump casing is greatly influenced by the location of

(a) suction pipe
(b) discharge pipe
(c) balancing water pipe
(d) C/W pipe
(e) injection water pipe

For instance, the seal injection flow that circulates through the stator cools that part of the pump. The degree of cooling is a function of the mass flow and temperature of the injected water and of the flow cross-section and surface.

The thermo-siphon effect round the shaft is influenced by the type of shaft seal; in particular, the effect depends on control of the injection and cooling water.

Q. *What are the consequences of distortion induced by thermo-siphon effect in the BFW pump?*

Ans. As a result of the distortion, some parts of the rotor will touch parts of the casing the region of the sealing gaps. In some cases, portions of the rotor are pressed against the casing so firmly that it becomes practically impossible to rotate the shaft without applying a large torque.

Note: It may take six or more hours before the rotor is completely free again.

Q. *Are these effects measurable?*

Ans. Yes; in certain cases these are measurable.

Q. *Within what stipulated time can such effects be measured?*

Ans. They become measurable within a few minutes of switching off a pump.

Q. *If the pump is started frequently before the rotor is completely free again, what will happen?*

Ans. Under these circumstances, the abnormally high frequency between the stationary and rotating components will inflict premature wear and a corresponding premature increase in the sealing gaps at the very least. In some cases this can even result in seizure of the rotor.

Over and above, the distortion can induce higher shaft vibrations immediately after restart from hot standby condition. However, this higher vibration level rapidly drops to the normal level with increasing pump speed.

Q. *What measures can be adopted to overcome thermal deformation problems of centrifugal BFW pumps?*

Ans.

(a) Improving shaft seals
(b) Turning of rotor
(c) Prewarming of pump

Q. *How can the shaft sealing within a BFW pump be effected?*

Ans. This can be effected alternately by means of

(a) mechanical seals
(b) fixed throttling bushing seals
(c) floating ring seals.

Q. *How does rotor deformation arise from the mechanical seal system of BFW pumps?*

Ans. Tests and field measurements have shown that the cooling system of the mechanical seal exercises a great influence mainly on rotor deformation.

Internal cooling circuit is an integral part of the mechanical sealing system of the pump assembly. It takes care of the heat dissipated through the seal. This heat is the combined heat produced by the seal and part of the heat due to heat-flow from the pump.

The internal cooling circuit is very often assisted by a so-called cooling jacket, which reduces the heat-flow from the pump towards the seal and is fed with separate C/W (Fig. 3.6).

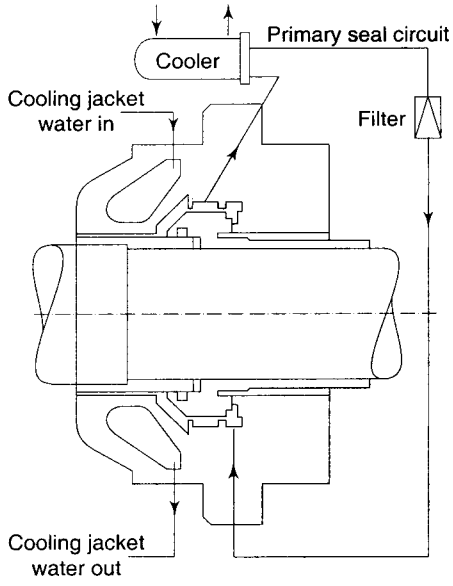

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Fig. 3.6 *Typical mechanical seal cooling system of a centrifugal pump.*

Source: Cycling Effects on Boiler Feed Pumps—A. Simon et. al. Brochure 27.58.04.40 (Sulzer Brothers LTD/ Winterthur/Switzerland)

With auxiliary piping correctly laid, this cooling system will cause neither rotor nor stator distortion during normal operation. However, as soon as the pump is stopped, a very strong internal thermo-siphon effect sets up immediately in the small gaps around the rotor in the vicinity of the shaft seal. The result is a great temperature difference (up to 90°K) between top and bottom of the rotor in this zone, which naturally causes bending of the rotor. Over and above, the cooling effect from the seal area promotes thermal stratification in the pump casing, thus enhancing stator deformation.

Q. *Why on hot standby or just after stopping the pump, is it not advisable to switch off the two cooling circuits of the mechanical seal?*

Ans. Mechanical seals are never completely tight. Therefore, the temperature must be kept well below 373°K to avoid flashing within the seal and vapour influx into the bearings. Therefore, injection of cold condensate into the seals must be maintained and hence the two cooling circuits must not be switched off when the pump is kept on hot standby or just stopped.

Q. *How is the injection of cold condensate into the seals maintained?*

Ans. Two injection control systems are known to achieve this goal.

1. **ΔP-Control** This method works on the principle of injecting cold condensate at a slightly higher pressure than the water in the pump. As a result a certain quantity of cold water flows into the pump casing.
2. **$\Delta t/t$-Control** In this case the injected cold water mixes with the shaft seal leakage in such a way that the outflowing water is kept sufficiently below 373°K to avoid vaporization. No cold water flows into the pump.

Q. *What is the drawback of ΔP-Control?*

Ans. The inflow of cold condensate into the pump casing does not follow a completely uniform flow pattern around the shaft due to gravity effects and a possible eccentricity between the shaft and sleeves. This gives rise to a temperature gradient within the shaft from top to bottom with a consequential distortion of the rotor in this area. The added effect of cold water flow into the lower cavities of the pump casing enhances the stator distortion.

Q. *What is the drawback of $\Delta t/t$-Control?*

Ans. This control system is more complicated than ΔP-Control system. The outward bound flow mixture does not follow an absolutely uniform flow pattern around the rotor with the effect that it enhances some rotor distortion.

Q. *How does turning of the rotor prevent distortion of the pump shaft arising from the thermo-siphon effect?*

Ans. The simplest and easiest way to avoid shaft deformation is to turn the rotor immediately after the hot pump goes on standby. However, the turning speed must be high enough to ensure an oil film in the journal bearings.

Typical speed is 25 to 50 rpm. If the turning speed is too low, the bearings must be provided with a hydraulic jacking device. At low rotational speed, say about 40 rpm for a medium size pump, the water circulation becomes too insufficient to prevent stratification of the water in the pump.

Q. *What is imperative when such a BFW pump trips?*

Ans. The barring gear (turning gear) must be automatically engaged (i.e. locked) on pump run down, without allowing the pump ever to come a standstill.

Q. *What is the advantage of this system?*

Ans. For a turbo-driven pump, in most cases no additional equipment is necessary. This is because, the turbine usually comes fitted with a barring gear to avoid the risk of rotor distortion. Therefore, the pump can be driven together with the turbine at no additional cost.

Q. *What are the disadvantages of barring gear mechanism?*

Ans.

1. Barring gear turns the rotor at low rpm and this solves only the problem of shaft distortion which is, however, just one of several thermo-siphonic problems.
2. Where a pump is not turbo-driven, an additional turning gear must be installed. This is costly.
3. Depending on the drive system, turning of the rotor is not always easy to achieve.

Q. *Does this barring system exert any adverse effect on pump-drive?*

Ans. Yes, if the pump-drive is a converter-fed synchronous motor. In this case though it would be possible (at least theoretically) to reduce the speed to about 50 rpm, however in practice this is not advisable because of torsional vibrations of the motor at low speed. Over and above, the power drainage of the converter may be excessive and hardly economical since the converter would operate at less than 1% load for rotor turning.

Q. *How does pump prewarming avert thermosiphonic problems?*

Ans. It works on the principle of temperature equalising. The aim of any prewarming system is to equalise the temperature of the pump and to bring the temperature of the pump and the trapped water in the suction header as close as possible to the water temperature in the deaerator.

Shown in Fig. 3.7 is such a prewarming system that is very suitable for cycling operation.

Q. *What are the advantages of prewarming?*

Ans.

1. The entire suction line, including the booster pump and the main pump is prewarmed
2. As the prewarming pump is to overcome only the friction loss, here is only small auxiliary power consumption
3. No motorized valves are required
4. The additional circulation pump assures that a water circulation can be maintained to prevent flashing even during plant shutdown.

Q. *What are the disadvantages of prewarming?*

Ans.

1. Prewarming needs installation of circulation pumps. Although only a small pump is required, the approach is nevertheless costly.
2. The prewarming flow through the pump suction and discharge nozzle must be defined by orifices.

Q. *Why is the FD fan installed before the air preheater and not after?*

Ans. This reduces the volume of air handled by the FD fan. The volume of air increases considerably after the air preheater.

Q. *The size of the ID fan is always larger than the FD fan. Why?*

Ans. ID fan is to handle a fluid (flue gas) with higher specific volume than the fluid (air) handled by the FD fan. Greater the specific volume of the gas handled, larger will be the size of the fan.

Q. *Why are FD fans installed with impellers having blades inclined backwards?*

Ans.

1. Backward curved blades endow the fan with greatest efficiency
2. Air handled by FD fans is clean, i.e., free from grit, soot, etc., which might otherwise impair the performance of an FD fan fitted with backward curved blades.

Q. *The efficiency of the backward curved blades is higher than forward curved blades. Why?*

Ans. The former offer minimum resistance to the rotation of the impeller.

Q. *Why are backward curved blades with radial tips used in ID fans?*

Ans. ID fans handle flue gas containing soot and grit. The radial tips make the wheel self-cleaning and prevent dust from clogging the blades.

Q. *Economizers are so designed that the water temperature is not raised within 30°C of the boiler temperature. Why?*

Ans. This is to avoid water hammer due to sudden condensation of pockets of steam.

Q. *BFW should not enter the economizer below a certain temperature. Why?*

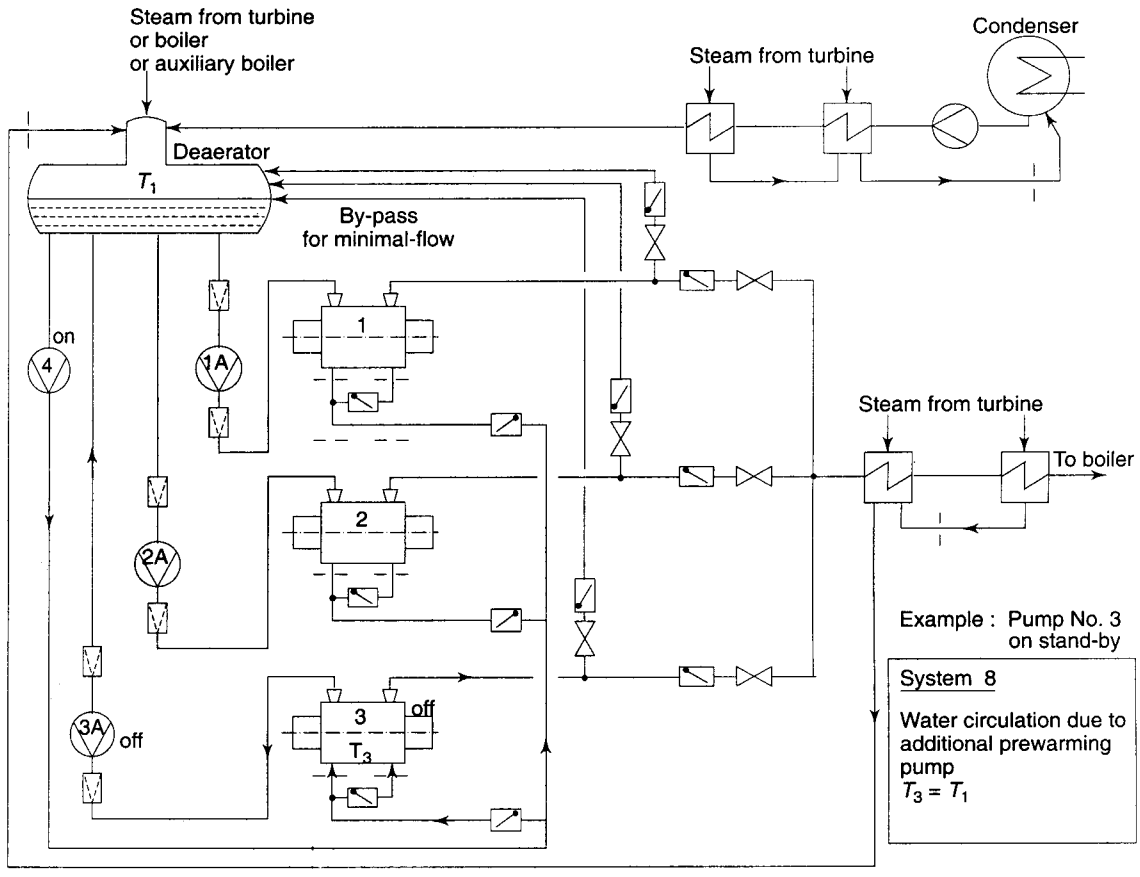

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Fig. 3.7 *Prewarming system.*

The additional circulation pump (No. 4) inducted into the circuit takes water from the deaerator, forcing it through the BFW pump, back through the suction line and into the deaerator. The minimum-feedwater-flowline of the idle pump remaining open, a part of the flow passes through it on its way back to the deaerator.

Source: *Cycling Effects on Boiler Feed Pumps—A. Simon et. al.*

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Ans. Before being delivered to the boiler drum, BFW is preheated in the economizer, by indirect heat exchange with the flue gas,—either in crossflow or counterflow with the BFW. However, BFW is not allowed to enter the economizer below a minimum temperature, for, this may cause a sharp drop in the temperature of the flue gas. If the flue gas temperature drops to its dew point

(140-150°C), it will give rise to condensation of sulphuric acid resulting from the reaction of oxides of sulphur with water vapour produced due to fuel burning. Acid mist condensing on the economizer and air preheater tubes will cause severe corrosion of the metal and even lead to tube failure.

Q. *Why were earlier economizer tubes made of cast iron?*

Ans. Earlier economizer tubes of low pressure boilers were made from cast iron which exhibits good resistance to acid corrosion as inflicted by SO_2/SO_3 + water vapour. Hence the chances of attack on cast iron by acid mist near dew point were narrow.

Q. *Why may a sub-economizer be a necessity?*

Ans. The one economizer may be by-passed for desludging (blowdown) without putting the boiler off operation.

Q. *Why are fins used all over the economizer tubes?*

Ans. A bare tube economizer is beset with the disadvantage that there are always some dead spaces behind the tube in the gas flow direction. To avoid this problem, fins are planted. Due to increased surface area, overall heat-transfer increases.

[*Finned economizer tubes are called gilled tubes.*]

Q. *What should be the ideal design of an economizer?*

Ans. Flue gas will pass vertically downwards in countercurrent flow with the boiler feedwater moving upwards for highest thermal efficiency.

Q. *What kind of heat exchanger is the superheater?*

Ans. It is a surface heat exchanger.

Q. *What kind of function does it accomplish?*

Ans. It produces superheated steam by first bringing wet steam to saturation point and then raising its temperature to the degree of superheat according to design.

Q. *Why is a higher degree of superheat a necessity?*

Ans. Since the work done per kg of superheated steam in expanding in the turboalternator is proportional to the adiabatic heat drop, greater the degree of superheat, the greater is the enthalpy drop available from the superheated steam without being wet, thereby increasing the life and efficiency of the turboalternator.

Q. *Why is forced circulation a necessity?*

Ans. At higher pressures beyond 140 atm ($14MN/m^2$), the density of steam, at saturation temperature, approaches that of water and as such natural circulation, which is based on the density difference between BFW and steam increasingly becomes inoperative. And that makes it imperative to install, in the steam-water circuit, a circulation pump to force water through the evaporating tubes of the boiler.

Q. *Why are extra precautions necessary to bring a vertical-coil superheater in line?*

Ans. Vertical coils are non-drainable and hence extra precautions are required during boiler start-up, to drive away any entrapped condensate.

Q. *What should be the temperature difference between the gas-side and steam-side of superheaters?*

Ans. 140°C for effective heat transmission which primarily depends on mass velocity and temperature difference.

Q. *Which will influence the effective heat transfer more—a slight rise in mass velocity or a slight rise in gas temperature?*

Ans. A slight rise in mass velocity.

Run	ΔM	$\Delta\Theta$	Product ($\Delta M\ \Delta\Theta$)
1st	2	3	6
2nd	(2 + 1)	3	9
3rd	2	(3 + 1)	8

Q. *Why must expansion loops be provided in the supply piping?*

Ans. To avoid thermal strain due to differential expansion between equipment piping and the boiler.

Q. *Why is it imperative to carry out the soot blowing operation when the boiler is operating at a stable rate?*

Ans. This is done so as to prevent any fire from being blown out as the soot blowing is going on.

(Soot blowing at 30-40% of the rated load of a boiler is sufficient for purging; best result: 75% load of boiler.)

Q. *Why is it not recommended to carry out the soot blowing when any boiler is out of service?*

Ans. To avoid the risk of explosion due to leftover unburnt combustibles in the passages.

Q. *How many safety valves, at least, are required for a boiler?*

Ans. Two.

Q. *Why is a minimum of two safety valves required for a boiler?*

Ans. If one gets out of order (i.e. stuck up), the other will save the boiler by blowing the excess steam.

Q. *What should be the total capacity of the safety valves?*

Ans. It should be equal to the design steam flow of the boiler.

Q. *What is the critical pressure of steam?*

Ans. It is 218 atm or 225 kgf/cm^2, at which the volume of steam is equal to the volume of water.

Q. *What is wire drawing?*

Ans. It refers to the process of expansion of steam when no energy is expended. Steam, as it expands through any orifice or valve, does not perform any external work and as such does not undergo any loss of its heat energy.

Q. *Why does dry, saturated steam get superheated after wire drawing?*

Ans. The total heat content of steam during wire drawing is constant:

Total heat before wire drawing = Total heat after wire drawing.

Due to expansion through the orifice, the steam pressure falls but not its ΔH. As such the dry, saturated steam gets superheated.

Q. *In a boiler where coal is fired on grates, slightly negative pressure is maintained over the grate and slightly positive pressure (5-7.5 cm of water) below it. Why?*

Ans. To avoid leakage of furnace gases to the surroundings. Positive pressure below the grate will force the entire combustion air up through the coal bed on the grate to ensure better and more efficient combustion of the fuel while the negative pressure above the grate will augment the flow of combustion air through the coal bed and eliminate the risk of positive pressure build-up above the coal bed, thus reducing the chances of flue gas leakage to the surroundings.

Q. *Why does the fuel bed have to be maintained in such a way that the bed-resistance remains uniform throughout?*

Ans. Otherwise there will be a channeling of combustion air leading to incomplete combustion. Combustion air will follow the path of less resistance across the coal bed and therefore, the fuel-air mixture will not be uniform throughout, leading to uneven combustion.

Q. *What is a clinker?*

Ans. It is a solidified mass of fused ash.

Q. *Why is a clinker unwanted in a stoker furnace?*

Ans. It obstructs the flow of combustion through the coal bed.

Q. *What is the temperature inside the bowl mill of the pulverizer unit?*

Ans. 75°–90°C.

Q. *If it is raised above this range what will happen?*

Ans. Volatile matter of pulverized coal will quickly evaporate and there is a good chance of an explosion.

Q. *What determines this temperature range?*

Ans. Coal's volatile matter.

Q. *If the ash content of the coal is high, will you increase or decrease the temperature?*

Ans. Temperature should be raised.

Q. *Which bearing—motor bearing or exhauster bearing of the bowl mill—is likely to be damaged first?*

Ans. Exhauster bearing.

Q. *Why?*

Ans. Coal particles erode into the fan blades causing a defective balancing which will entail vibration of the journal, impairing the bearing.

Q. *One bowl mill feeds four burners placed at different locations in the boiler unit of SGP of a powerplant. How is the same flowrate maintained all through?*

Ans. By placing orifices in each tube feeding pulverized coal to the burner, the flow through all tubes is made nearly constant. Flow is restricted most in the case of the shortest tube.

CASE STUDY Dewpoint Corrosion of ID Fans

Two PC-fired boilers of a steam generation plant had been burning high-sulphur FO for several years. It used to maintain FG temperature well above the dew point to avoid corrosion of ID fan blades.

Recently, it has switched over to low-sulphur oil to meet emission requirements. This fuel-switch has taxed the company to run at a higher operating cost. In order to reduce the cost through gain in efficiency, the plant wants to decrease the FG exit temperature down as close to the dew point as possible, even at a risk of passing below it on occasional low loads.

However, the plant engineers are concerned more about possible corrosion effect on the induced-draft fans than on the air heaters. Under their consideration are the coatings of plastics and metals but they're not sure of the benefits or longevity of these coatings.

Will these metal overlays ensure good results or have cracks in the base metal?

The ID fans are not too well mounted. Vibration problems are to be avoided at all costs. Therefore, fan unbalance due to all blade corrosion is not acceptable at all.

Q. *How will the plastic coating stand up? What care is needed in applying them to fan rotors?*

Ans. Coating is not at all an economical solution to the problem of corrosion considering the enormous size of the duct and the ID fan itself. Thick coating is suitable for ducting and breeching, but not for high-speed fans, where a defect in the coating degenerates to a crack and chips off the coating overlay exposing the base metal to corrosion.

Some coatings have been reported to build up with deposits more than the original metal and so the fan can get slowly become unbalanced.

Nevertheless, many methods have been attempted to deter dewpoint corrosion in ID-fans and air heater. Plastic coatings tend to crack and are difficult to apply.

Pinholes lead to serious corrosion below the coating. Hence care must be taken in application of coating on ID-fan blades. Contaminants must be carefully removed before coating is deposited. These contaminants are of two kinds—*visible* and *invisible*. Visible contaminants such as oils, grease, dirt cause much less trouble than invisible ones such as alkalis, salts, acids and finger marks, which when present under a plastic coating, accelerate corrosion and blistering. Before the coating is applied to the blades, they must be

rinsed with a solution at $pH < 5$ maintained by a mixture of chormic and phosphoric acid.

Painting the rotor with a good enamel is also a method of protection.

Another protection against SO_3 attack is the use of an alkaline powder, such as dolomite, magnesite, or lime, fired with the fuel and equal in amount to the ash of the fuel. The alkaline powder helps neutralize H_2SO_4 and stops corrosion, in addition to reducing deposits of particles.

MgO-slurry additives in the FO can reduce SO_3 corrosion only if excess air is below the 3-5% range. With higher excess air, the SO_3-content in FG increases.

Glass tubular air heaters are decidedly expensive and can crack as can the ceramic on some tubes.

For these reasons, probably the old remedy of keeping the fan inlet temperature 12—27°K above the dewpoint is the best. As such a hot air-recirculation technique seems to be attractive:

Install a recirculation fan to draw hot air at air-heater hotend and reintroduce it to the FD fan discharge.

CASE STUDY ID-Fan Failure

An ID-fan of a PC-fired unit (firing 227 t of coal fines per *h*) flew apart without warning, wrecking the housing, ductwork on an adjacent boiler breeching plus inflicting some damage to the bearings of the drive motor.

The fan supplier explained that imbalance resulting from deposits was partly responsible for this type of failure—the sort that happens once in a while.

The company got a replacement and installed vibration-indicating gauges instead of online instrumentation.

Q. (1) *What are the possible cause that brought about the boiler-fan disaster?*

(2) *Do you think the vibration equipment adequate?*

(3) *What steps do you suggest to prevent occurance of such a fan failure?*

(4) *Do you specify better fans?*

Ans. The likely causes of fan-blade failures are:

(a) dirt & ash accumulation on fan blades
(b) corrosion from ash abrasiveness
(c) shaft corrosion because of 'dewing'* of FG condensibles.

These factors might have interacted giving rise to rotor imbalance. Usually the dirt and ash particles deposit equally on all blades. However, minor differences in the deposit component or blade surface cause clumps of material to fly off and increase both vibration and metal stress until the blades fracture.

Also there could have been the following causes that could render fans to fly into pieces:

(1) excessive oil clearance causing oil swirl
(2) inadequate oil clearance causing high temperatures
(3) drive-coupling misalignment (assuming babbitt sleeve bearings)

Installation of a vibration-indicating equipment (vibration monitor) is a good idea but not a good solution, for mere indication of vibration will not prevent damage. One good option is to integrate a vibration guage with a motor cut-off switch actuated by severe vibration. It will automatically trip the fan-motor when the preset vibration limit is exceeded, thus thawrting unwarranted fan failure. A better option is to harness proximity probe monitors. These low-to moderate-cost devices give easily interpreted and continuous monitoring of the ID fan. They can issue warning alarms and trip at critical levels.

Preventive Measures

1. Mandatory dye-penetration test every 3 to 5 years to check fan blade welds
2. Periodic vibration monitoring by using handheld vibration monitor on horizontal, vertical and axial motion of fan and motor

3. Periodic checking with accelerometer pickups to get data on acceleration, peak frequencies & amplitudes over a spectrum. Reproduction of the data in the form of graphs for visual display of vibration history of fan and motor for later comparison.
4. Recording of bearing temperature in every shift & periodic inspection of fan rotor for deposits and corrosion
5. Weekly inspection of oil-slinger rings.

Better Fan System

It might be better to specify a backward/radial-plate-type double inlet centrifugal fan instead of a more efficient airfoil-blade type one. This will render onsite repair, with welding and static balancing much easier. A variable-speed ID-fan inlet-vane-angle control could be a better choice to fit into erosive coal-fired service.

CASE STUDY Erosion of BFW Pump Casing Flange

Two BFW pumps (4-stage, horizontal, split-case centrifugal) operate at 59 Hz and deliver 68 m^3/h of BFW at 510m head. One is six years older than the other but both are afflicted with identical problems. After two or three months of service their capacity has dropped to as low as 45 m^3/h for one. Examination has revealed severe water washing at the casing flange in the HP-stage area, but nowhere else.

Both pumps have been repeatedly repaired, but the problem has recurred.

The following conditions are applicable:
(1) Water used is DMW
(2) Pump casings are made of iron.
(3) NPSH at the pump inlet is adequate.

Q. *What repair or charges do you deem effective?*

Q. *Should the company try a new pump type or change some materials?*

Ans. An excess interstage pressure differential is the likely cause of the trouble. The high ΔP between the stages coupled with a poor-fitting gasket gives rise to a small leak that erodes away the gasket. The resulting backflow to the previous stage erodes the casing metal. High-pressure heated water flashes to steam on release of pressure, and this causes gradual erosion of the pump casing flange (Fig. 3.8).

The section with highest ΔP is most susceptible to this damage.

Possible Causes

(a) Perhaps the gasket material has been changed from the original
(b) Perhaps the gasket was not installed properly
(c) Perhaps the BFW regulating valve is sized too small, causing a pressure backup at the pump. An oversize pump, too, can develop an over pressure at the final stage.

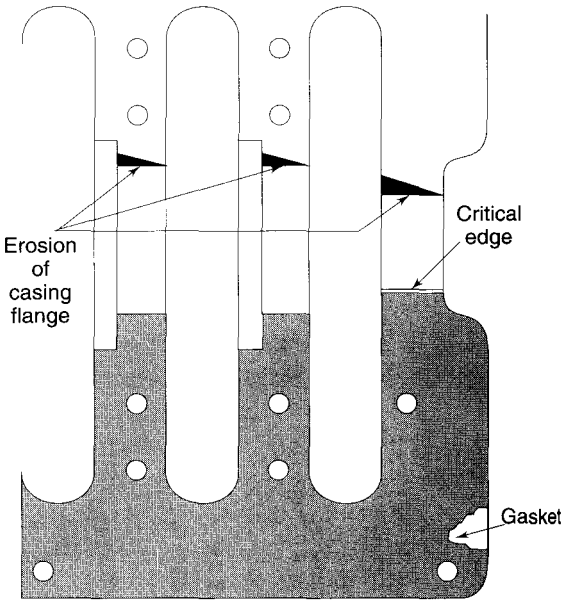


Fig. 3.8 *High interstage ΔP coupled with poorly fitted gasket initiate a small leak that erodes away the gasket and pump-casing flange afterwards.*

Remedial measures

(a) The original pump manufacturer should be called in to offer an explanation and remedy for the problem
(b) Use is to be made of a gasket slightly oversized at these corners; this makes sure that the corner is tightly filled by the gasket
(c) Use of a high-temperature sealant
(d) Proper deaeration of BFW
(e) The horizontal joint between casing halves should be as flat as possible.
(f) Casing gasket must be of proper thickness
(g) When the rotor is installed, the upper casing should be torqued down to squeeze the casing rings slightly and eliminate seepage and cavitation
(h) Bore for the rings should be checked for ellipticity when casing halves are bolted together with the gasket in place. Cast iron is a good material, but steel would be more appropriate in this high pressure service.

4

BOILER MOUNTINGS AND ACCESSORIES

Q. *What do you mean by boiler mountings?*

Ans. These are fittings primarily intended for the safety of the boiler and control of the steam generation process completely.

Q. *What are they?*

Ans. According to the Indian Boilers Act, 1923, they are

1. Pressure gauge
2. Safety valves (2 Nos.)
3. Water level indicators (2 Nos.)
4. Feed check valve
5. Steam stop valve
6. Fusible plug
7. Blow-off cock
8. Manholes and mudholes.

Q. *What is a pressure gauge?*

Ans. It is a device fitted to indicate the pressure of a fluid.

Q. *How does it work in a steam boiler?*

Ans. The steam enters a hollow tube of elliptical cross-section that gets circular under steam pressure. This results in a slight movement of the other end of the tube which is attached to a rack and pinion system via rod and a lever. The pinion greatly magnifies the movement and a pointer fitted to the pinion moves on a scale to indicate the pressure applied.

Q. *What is a valve?*

Ans. It is a flow control device.

Note: Other flow control devices are

1. orifices
2. variable speed pumps

Q. *What are the principal purposes of valves used in thermal and nuclear powerplants?*

Ans.

1. Shut-off or blocking
2. Throttling
3. Draining and venting
4. Relief of excess header pressure

Q. *What are the basic constructional features of a valve?*

Ans. The valve body is a cast, forged or machined element to house valve mechanism. It must be sufficiently strong to resist internal pressure and loads from piping and actuator. It should have sufficient volume to accommodate flow and must have suitable shape for connection to piping and attachment of the actuating or operating mechanism.

The closing element is a disc, plug or ball that must fit leak-tight against the valve seat which is an orifice or a diaphragm across the valve cavity.

The motion of the closing element is controlled from outside by means of either a sliding stem or rotating stem attached to the closing element.

Packing is used to prevent gland leakage. Sometimes bellows seal is used for the purpose. Packing allows the stem to slide and rotate while bellows seal allows only sliding.

Considerable pressure is required to open and close large valves. The pressure retaining part of a valve is called bonnet which guides the stem and contains the component for stem sealing. It may also provide the opening to the body cavity for assembly of internal parts. The bonnet may also be used to attach the actuator to the valve body.

Q. *How are valves attached to the piping?*

Ans.

1. Valves with pipe threads are screwed into position
2. Valves equipped with flanges are bolted in position
3. Valves are also welded into position (HP boilers)

Q. *What is a gate valve and how does it work?*

Ans. It consists of a gate (disc) that can be raised or lowered into a passageway which is a straight-through opening in the body. The gate is at right angles to the flow and moves up and down in between slots (valve seats) that hold it in the correct vertical position.

The method of achieving tight, leakproof seating varies. The one-piece gate is usually wedge-shaped and it tightens against the two facing slanting seats when forced down to a shut-off position.

The gate valve with parallel seats and the two-piece disc sliding down between them is more versatile. The downstream half seats tightly by upstream pressure. A spring between the halves keeps the valve closed when pressure is low or off.

In the gate valve, the diaphragm is virtually non-existent because the seat bores are so large.

The bonnet closure is by a high-pressure seal that becomes tighter the higher the internal pressure.

Q. *Where is the gate valve chiefly used?*

Ans. These valves are used chiefly where they are to be operated either wide open or closed. They are employed in steam and water pipelines of 100—600 mm dia.

Q. *What are the advantages of these valves?*

Ans.

1. The gate valve can handle all fluids
2. When wide open it offers very little resistance to flow and consequently the ΔP through the valve is minimized.

Q. *What are the disadvantages of gate valves?*

Ans.

1. Larger valves require considerable force to operate (the down-stream gate is pressed very tightly against the guide by upstream pressure)
2. Very difficult to repair once the valve seats have been damaged
3. For one-piece disc wedging between inclined seats, jamming is a problem. Also wedging causes damage to the seats and even the body
4. Mismatch of seat and disc is another peril.

Q. *Why is a bypass valve fitted to a gate valve fitted to a MP/HP steam header?*

Ans. This bypass valve is called an ***equalizer valve*** as it equalizes the system pressure on either side of the gate when it is opened and thereby relieving the downstream gate from pressing tightly against the valve seat. And as a consequence, it becomes easier then to open the gate valve.

Note: The same philosophy applies to GLOBE valves fitted to HP lines. (see Fig. 4.1)

Q. *What is a globe valve and how does it work?*

Ans. It is a linearly operated valve using a disc or plug-like closure member which is forced into a tapered hole called a seat. The name is derived from a globular cavity around the port region. The angle used on the taper of the seat and disc varies with the valve size and the kind of service to which the valve will be subjected.

The valve leakage can be minimized through proper design of the disc and seat and selection of materials.

The closure element is fitted to the valve stem which extends through the bonnet and is threaded and fitted with a handwheel. Turning the handwheel moves the stem in or out thus closing or opening the valve. When opening the valve, the closure member moves perpendicularly away from the seat and orifice. To prevent leakage around the valve stem, the bonnet is provided with a packing gland.

Due to many possibilities of modifying the trim design for different throttling purposes, linear globe valves are the traditional standard solution for control applications.

Q. *For what kind of service are globe valves mainly used?*

Ans. Globe valves are used mainly where the flow is to be throttled or modulated.

Q. *What are the basic advantages of a globe valve over a gate valve?*

Ans.

1. Globe valves, unlike gate vales, can readily throttle or modulate flow over long periods without serious damage.
2. Globe valve can act as stop/check valve
3. Valve parts are easy to repair and replace.

Q. *Why are the globe valves better than gate valves in throttling service?*

Ans. The seats and discs on the globe valve are not cut by the throttling action as readily as with gate valves.

The globe valve lends itself for many designs that make throttling through stages possible. For example, consider a boiler blowdown valve that releases hot, dirty water from boiler drum. The valve is provided with staged plug that breaks down the pressure of the inlet fluid in stages with the effect that blowdown water is released without excessive flashing and damage due to cavitation is prevented as a consequence.

Q. *What are the main disadvantages of a globe valve?*

Ans.

1. Increased resistance to flow i.e. higher ΔP across the valve
2. More force is required to close the valve as the disc is acted upon by great pressure underneath.
3. Susceptible to plugging due to ingress of foreign matter.

Q. *How can the globe valve act as a check valve?*

Ans. The valve disc is capable of sliding freely up to some distance on the stem-end. Therefore, the valve can act as a check valve to prevent backflow from a common header into an idle boiler or boiler at reduced pressure. That's how an ordinary globe valve plays a stop/check valve.

Q. *What is a stem-guided valve?*

Ans. A type of globe control valves where the plug (closing member) is guided by a bushing facility surrounding the plug or the stem.

Q. *What is a control valve?*

Ans. It is a power-actuated valve capable of throttling or modulating the flow. It is the final control element in a control loop.

These valves operate automatically, receiving signals from an external controller. Rotary and globe-type valves are most commonly used for this purpose.

Q. *What is a rotary valve?*

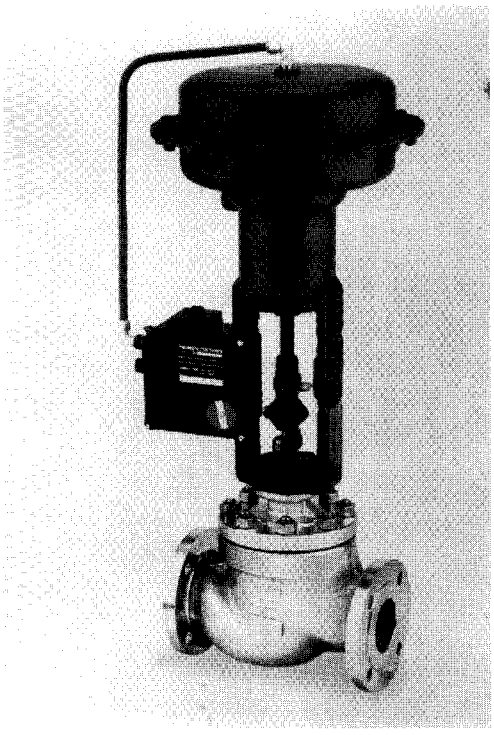
Ans. It represents a category of valves where the closure member rotates instead of moving linearly. Belonged to this family of rotary valves are ball and butterfly valves. The rotation is normally 90°.

Q. *What is a butterfly valve?*

Ans. It is a rotary valve that uses a disc as the closure member.

These valves are normally of wafer design fitting directly between pipeline flanges.

Butterfly valves can be symmetric or eccentric (i.e. offset), the latter referring to the disc stem being displaced from the centre of the disc (Fig. 4.2).



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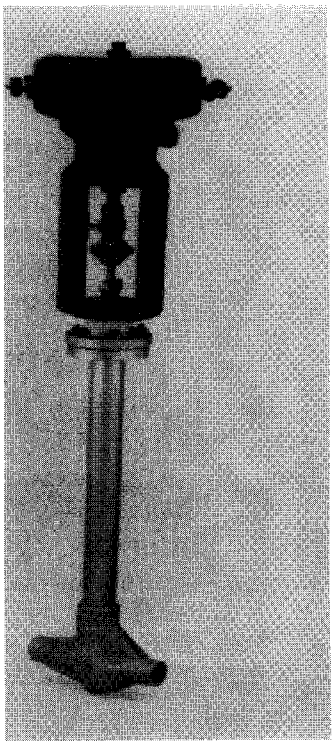

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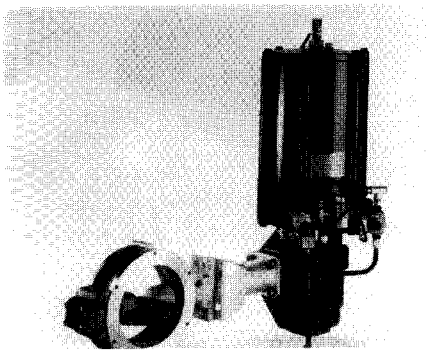
Fig. 4.1 *Globe control valves with reversible seat rings to maximize trim life and minimize maintenance.*

Source: The Valve Book (Neles-Jamesbury Publ.)



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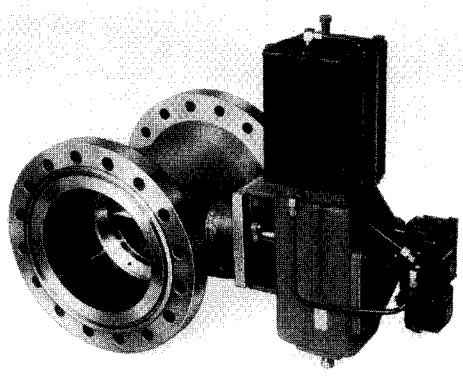

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Fig. 4.2 *Neldisc® butterfly valves with patented seating principle consist of a double eccentric disc and a floating seat. They harness metal-to-metal seating for ensuring long-lasting tightness in demanding control applications involving high temperatures.*

Source: The Valve Book (Neles-Jamesbury Publications)

Q. *What are S-disc valves?*

Ans. They are Neles-Jamesbury series of butterfly control valves equipped with a flow balancing trim on the downstream side of the valve body. The trim, a perforated plate partially covering the valve outlet, reduces noise and cavitation, stabilizes the flow pattern and reduces dynamic torque on the disc (Fig. 4.3).

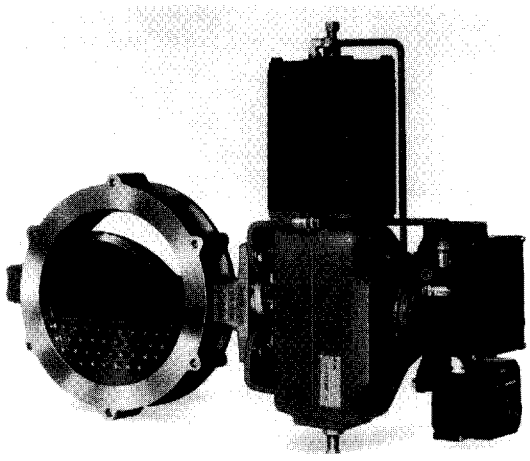

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Fig. 4.3 *S-disc butterfly control valves are metal-seated Neldisc butterfly valves equipped with a flow balancing trim at the valve outlet for better control performance, less noise and less cavitation.*

Source: The Valve Book (Neles-Jamesbury Publication)

Q. *What are Wafer-Sphere valves?*

Ans. These are Neles-Jamesbury series of high-performance, soft-seated butterfly valves for control-services. the seating principle is a single-piece, flexible polymeric seat that is pressurized to assure positive shut-off in both directions (Fig. 4.4).

Q. *What is a ball valve?*

Ans. A rotary valve using a spherical ball between two seats as the closure member. The flow opening on conventional ball valves may be full bore (Fig. 4.5) or reduced bore.

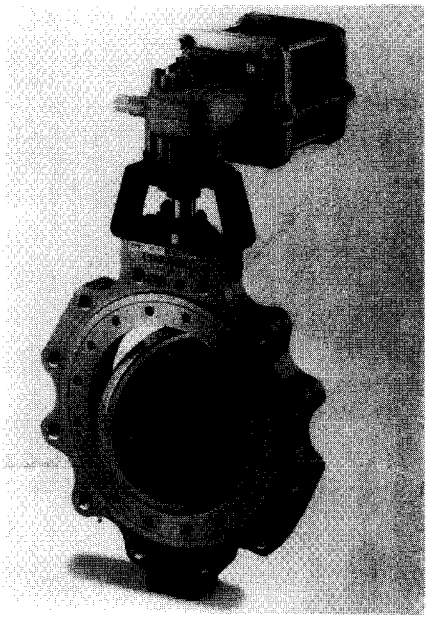

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Fig. 4.4 *Wafer-Sphere® butterfly valves are soft-seated, double eccentric control valves with a single-piece flexible polymeric seat that is pressure-energized to assure positive shut-off in both directions.*

Source: The Valve Book (Neles-Jamesbury Publication)

Heavy duty metal-seated ball control valves are designed for the most demanding applications (Fig. 4.6).

For demanding control applications new types of ball valves have been developed with different designs of the flow opening. The *R*-series segment control valves and *Q*-Ball valves—both of Neles-Jamesbury—are the two good examples of advanced design using multistage throttling passages for low pressure recovery (Fig. 4.7 & 4.8)

Q. *What is trim?*

Ans. It represents the combination of flow control elements inside a valve. Included into it are the throttling member (ball, disc, plug etc) and its stem, the seat as well as any other parts affecting control of the flow.

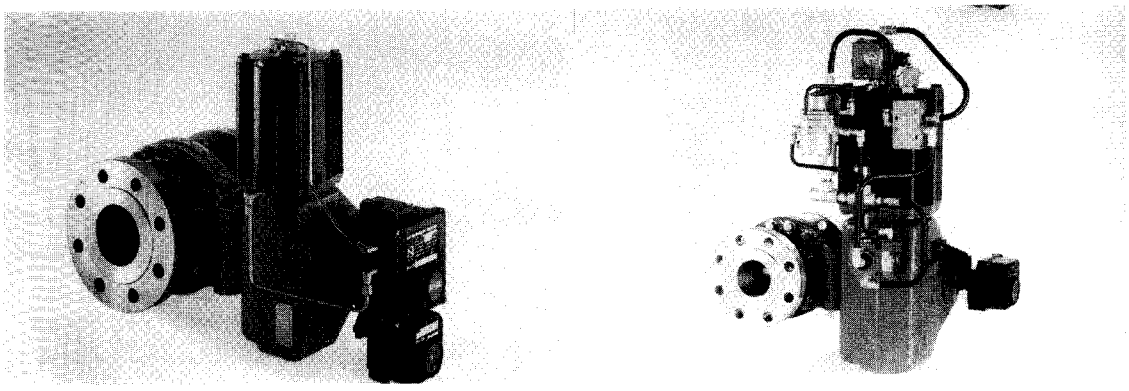

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Fig. 4.5 *Metal-seated full bore ball valves with equal percentage flow characteristic. These Stem-Ball® ball valves are provided with ball and stem cast into one piece for hysteresis-free operation.*

Source : The Valve Book (Neles-Jamesbury Publication)

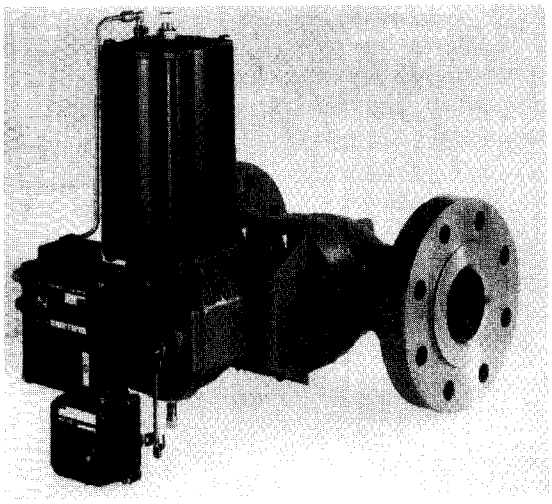

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Fig. 4.6 *Heavy-duty metal seated ball valve. Top entry, trunnion mounted design.*

Source: The Valve Book (Neles-Jamesbury Publication)

Q. *What is the difference between a seat-supported ball valve and a trunnion-mounted ball valve?*

Ans. The seat-supported valve features a construction where the ball is supported by seat rings, one around each body outlet. Tightness is normally provided by the downstream seat.

In turnnion mounting construction the trim is supported with bearings. The upstream spring-loaded seat acts as the primary seat.

Q. *Why is top entry design almost always preferred in weldend valve installations?*

Ans. The valve with the top entry construction can be assembled and disassembled thru the top of the valve. This permits servicing of the valve without disconnecting the valve body from the pipeline. This design feature makes the valve ideal for weldend installations.

Q. *What is Stem-Ball® valve?*

Ans. As the name implies, these valves have their ball and the stem integrally cast into one piece, thus eliminating the dead band between ball and stem.

Q. *What is dead band?*

Ans. It refers to the range through which an input signal to the valve can be varied without initiating a response in output. (See Fig. 4.9)

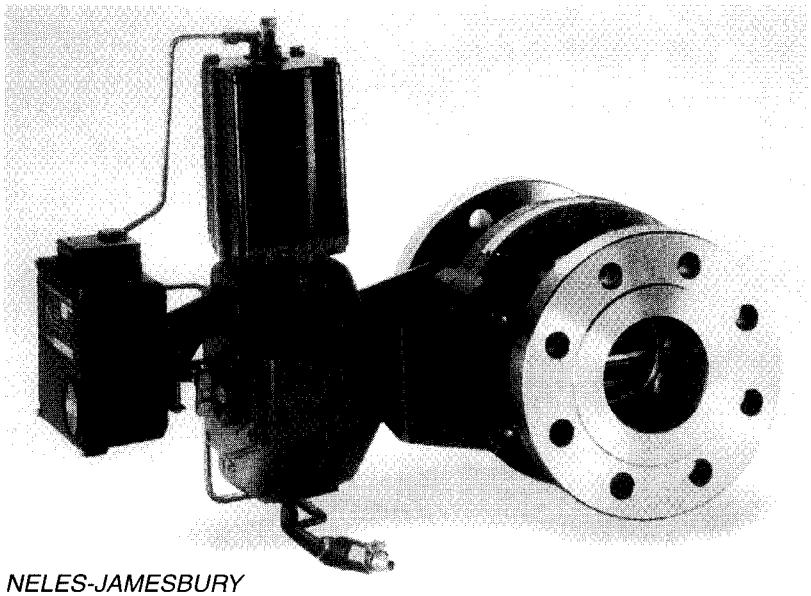

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Fig. 4.7 *Q-Ball® valve.*

The low-noise control valves are for demanding applications. Parallel perforated attenuator plates in the ball flow opening or with multiple holes thru the ball give rise to multistage throttling permitting low pressure recovery and reduce velocities, noise, cavitation and vibration. These high capacity units are self-cleaning, sport non-clogging feature and have wide rangeability.

Source: The Valve Book (Neles-Jamesbury Publications)

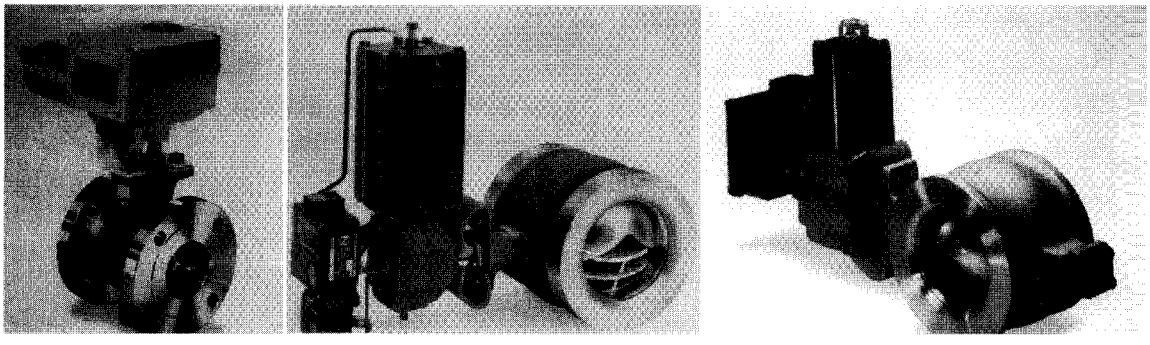

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Fig. 4.8 *Segment valves (R-series of Neles-Jamesbury)*

A special category of metal seated rotary control valves, they come fitted with a concentric V-shaped trim on the side of the rotary ball segment for general purpose control with equal percentage flow characteristic. Compact, light-weight & of high capacity, they are essentially maintenance-free control units.

Source: The Valve Book (Neles-Jamesbury Publications)

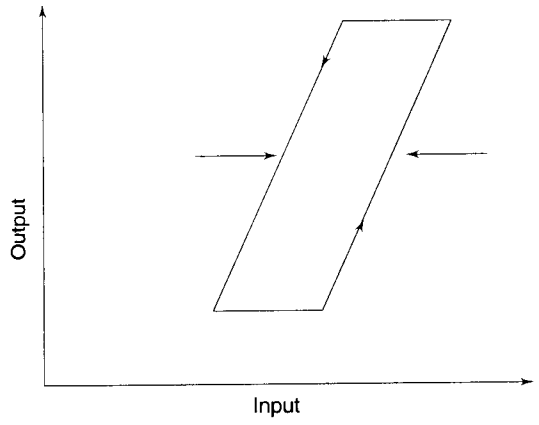

Fig. 4.9

Q. *What is the difference between soft-seating and metal(-to-metal) seating?*

Ans. The general methods of valve seating are

(a) soft seating
(b) metal seating

Soft seating utilizes elastomer seats usually against a metal closure member (disc, ball etc,). As opposed to soft-seating, metal-to-metal seating utilizes metal on the seats as well as on the closure member.

Q. *What are comparative advantages of soft-seating and metal-to-metal seating?*

—Soft-seating is ideal for completely drop-tight sealing in on-off applications, as well as for control applications involving toxic and corrosive fluids. However, their range of application is limited over the temperature range which the elastomer can withstand.

Metal-seating is ideal for long-lasting. They are successfully used in control valves in demanding control applications involving high temperatures and abrasive fluids. The temperature range is not limited by elastomer materials.

Q. *What do you mean by bidirectionality?*

Ans. It refers to the capability of a valve to throttle or shut-off flow in both directions.

Q. *Control valves are vital in boiler service. What is the main purpose for which the control valves are chiefly used?*

Ans. For accurate throttling of flow in response to rapidly changing system-needs over a long period.

Q. *How is this flow-control achieved?*

Ans. One way to control the flow of fluid is by varying the throughput section area of the valve as the control member moves translationally.

By another method, the control member rotates inside a sleeve with a port mounted in the valve housing.

Q. *What should be the pipe layout on which the control valve is to be fitted?*

Ans. All control valves and valves with throttling service are mostly installed in the horizontal portions of pipelines.

Q. *How will you judge the suitability of a control valve for a service?*

Ans. By two factors

1. the ability of the control valve to control flow accurately and without fluctuation at low flow
2. the per cent of maximum flow variations with settings of the disc or plug.

Q. *How is the selection of a control valve made?*

— The selection of a control valve is divided into two parts. First, the mechanical selection in which suitable valve style, materials and pressure rating are picked to guarantee safe and reliable performance according to good engineering practices, local laws and regulations etc. This selection should be made using bulletins and technical informations specific for each valve type. Secondly, the sizing of a selected valve, in which the size of the given valve type is determined, while trying to prevent unwanted phenomena like excessive noise or liquid cavitation. After the valve size has been determined, the installed performance of the valve to phase out poor control perform-

ance like hunting, excessive slow or fast response and poor accuracy is further predicted.

Source: Flow Control Manual—Neles-Jamesbury/ P-20.

Q. *Because of its complexity and demanding functions, a valve is particularly prone to corrosion. What types of corrosion attack a valve?*

Ans.

1. Uniform corrosion
2. Pitting and crevice corrosion
3. Bimetallic corrosion
4. Selective corrosion
5. Stress corrosion cracking
6. Erosion, cavitation and impingment corrosion.

Q. *How does uniform corrosion attack a valve?*

Ans. It is a slow corrosion that spreads uniformly over a wide surface. However, valve ports, in most cases, remain unaffected. Its symptoms are leaks and seizures. It is intolerable on sealing and sliding surfaces.

Q. *How does pitting corrosion attack a valve?*

Ans. Pitting corrosion is realized through the formation of innumerable pits, mainly due to chloride attack. Such type of corrosion quickly penetrates through stainless alloys exposed to stagnant fluids in a closed valve. Even small concentrations of chloride can pierce a stainless steel wall.

Q. *How does the crevice corrosion attack a valve?*

Ans. Almost all valve types have crevices where the fluid stands even when the valve is fully open and the flow is rapid i.e. crevice corrosion occurs under stagnant fluid film trapped in the crevice/fissure on the surface of valve interior. Crevice corrosion is often very rapid and autocatalytical i.e. it accelerates penetration of crevice or fissure inwardly causing more extensive damage than pitting.

Q. *What is bimetallic corrosion?*

Ans. In this type of corrosion, a noble metal escalates the rate of corrosion of a base metal.

Q. *How does selective corrosion occur in the valves?*

Ans. Valve components are made from a wide range of alloys having different constituent parts or phases. In corrosive environment they respond differentially. For instance, the zinc-dominant phases of some brass types corrode quickly in water containing Cl^- ions. Such type of corrosion can penetrate through the valve body.

Q. *How do valves get affected by stress-corrosion cracking?*

Ans. The stress-corrosion cracking, occurring in certain media when the component under tensile stress is in a certain temperature range, can break valve components without any forewarning.

Q. *How do erosion, cavitation and impingement corrosion affect a valve?*

Ans. These three forms of corrosion are closely interlinked where corrosion weds mechanical wear. They occur mostly in those valves which are exposed to high flowrates or liquids containing a load of abrasive suspended solids or gas bubbles that break the oxide/hydroxide film protecting the stainless alloy. Even cavitation bubble caused by pressure changes may locally destroy this passivating layer. A new film is formed wearing the alloy and the film breaks again to repeat the cycle all over again. As the process continues, damage may go many millimetres deep.

Q. *How can the corrosion of valves be controlled?*

Ans. In five different ways

1. Modification of the material
2. Modification of the component structure
3. Plating and surface treatment
4. Modification of the environment
5. Cathodic or anodic protection.

Q. *How is the modification of MOC of valve components made?*

Ans. Heavy alloying of steel with chromium, nickel and molybdenum is a good example of material modification.

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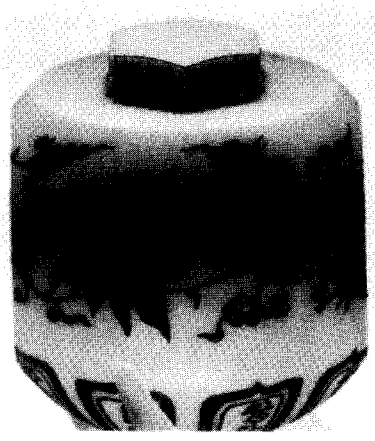

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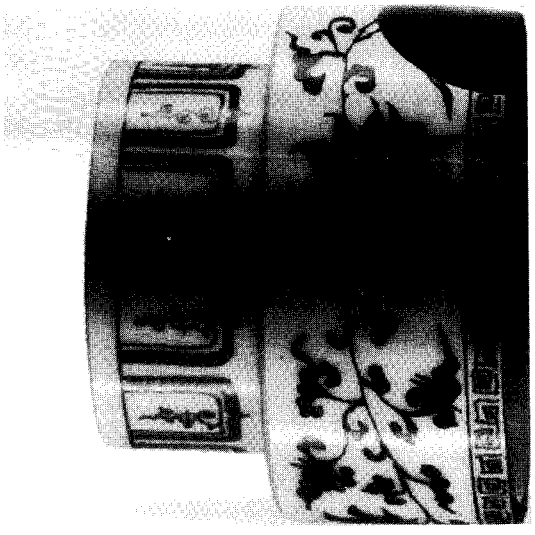

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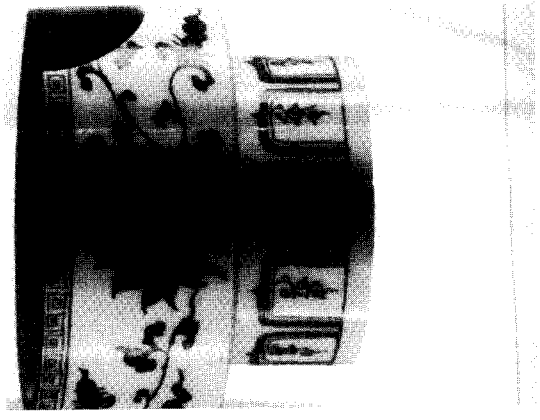

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Fig. 4.10

Also selection is made from different types of steel, stainless steels, super alloys, titanium etc.

The ceramic coated valves (Fig. 4.10) are eminently suitable for controlling erosive and abrasive slurries and also equally suitable for lime mud and carbonate handling.

The valve body can be made of titanium, Hastelloy ®, depending on the customer's needs, instead of standard stainless steel.

Materials selection is always accompanied by selection of the manufacturing method. For instance, machined seat of Incoloy 825 cannot withstand the stresses, because of its moderate yield strength, produced when the valve closes or the pressure differences over the valve. However, this problem can be solved by roll-forming which improves the strength of Incoloy 825—a superalloy which is extremely resistant to corrosion.

Q. *What ceramic materials are used?*

Ans. A number of ceramic materials are available. One of the notables being PSZ—zirconia oxide partly stabilized with magnesia.

Q. *What is the advantage of using PSZ?*

Ans. This material gives the high tensile strength and thermal shock resistance.

Q. *Ceramic valves are very costly. So how can its application be justified?*

Ans. A ceramic Ball Valve certainly costs far more than a traditional steel valve. But then, its expected life-time in the application is far, far longer, giving the lowest cost per year.

Q. *Cobalt-based alloys have been traditionally used in most valve applications. Why?*

Ans. Metals and alloys that find their way to the fabrication of valve must meet two basic requirements

1. high resistance to sliding and galling wear
2. low friction.

Cobalt-based alloys have long been the champion to these requirements. Over and above, cobalt hardfacings offer good weldability and thermal expansion properties, essential to valve surfaces subject to servere service. Stellite® 6, a long-time favourite cobalt-based alloy, is an ideal choice for such duty.

Q. *Cobalt-based alloys are extensively used in valves in nuclear powerplants. Why?*

Ans. Cobalt-based alloys display outstanding resistance to wear and corrosion. Hence they're extensively used even in the demanding conditions (561°K/40 bar) of primary circuit of nuclear powerplants.

Q. *Is there any hazard arising out of using cobalt in the circuit of nuclear powerplants?*

Ans. There is no metal or alloy in the world, which is absolutely free from wear. Hence in certain cases the wear of parts coated with hardfacing alloys containing cobalt has been reported to cause problems. Cobalt particles may enter the cooling water or reactor cleanup-system-water and thereby pass through the reactor core region. Once into the reactor core, they come under neutron bombardment whereupon Co-59 transmutes to radioisotope Co-60 which is gamma active nuclide

Lifetime Comparison Table

Valve Type	Life Time	Valves/Year	Cost/Unit	Cost/Year
Ceramic ball valve, PSZ	1—3 years	0.5	42 000	21 000
Stainless steel segment valve with Stellite® flowports	3—6 months	2.5	15 000	37 500
Stainless steel segment valve	1—2 months	8	12 000	96 000

Source: CURRENT (# 3, 1993), Neles-Jamesbury Publication

$$\text{Co–59} + {}^{1}_{0}\text{n} \longrightarrow \text{Co–60} \rightsquigarrow \gamma$$

This increases radiation level through the circuit. As a result there is constant build up of deadly radioactivity in the reactor's primary circuit.

Q. *How much of total radiation hazard is attributed to Co–60?*

Ans. In a LWR (Light Water Reactor), the amount of release can amount to a few hundred grams of cobalt annually with the effect that after a number of years the gamma scan values emitted by Co–60 overwhelms gamma radiation from all other sources. In Sweden, it has been estimated that about half of all unwanted radiation in nuclear powerplants has originated from cobalt-based hardfacing alloys.

Q. *How dangerous is Co–60?*

Ans. If an operator/maintenance personnel stands 1m away from one milligram of radioactive stellite, he will receive the annual permitted dose of gamma radiation within just two hours.

Q. *How can this problem be solved?*

Ans. One way to assure full safety to maintenance personnel so that they don't get exposed to unsafe radiation levels as they work on irradiated piping or area contaminated by radioactive Stellite, they must be rotated in and out of these areas after brief periods.

Another alternative is to replace the cobalt alloys with cobalt-free alloys with wear resistance as good or better than Stellite 6. Around the world, investigations have made a steady headway to replace cobalt alloys as a way to reduce the radiation exposure of maintenance personnel working in PWRs and BWRs.

Q. *What are the disadvantages of the 1st option?*

Ans. It needs more manning and hence raises the costs of reactor operation.

Frequent rotation of maintenance staff complicates the work and the job gets hampered and delayed.

Q. *Name some typical alloys which are suitable candidates for replacing cobalt alloys in nuclear power industry.*

Ans.

1. NOREM A—an iron based alloy developed by Amax Materials Research Centre, Michigan (USA). Better antigalling characteristics than Stellite 6.
2. NELSIT—A Neles-Jamesbury product. Essentially a mixture of stainless steel with extra silicon having better antigalling behaviour than Stellite 6.
3. ELMAX—developed by Uddeholm AB of Goteborg, Sweden, is a high chromium-vanadium-molybdenum steel. Demonstrates outstanding galling resistance.
4. EVERIT 50 SO—a trade name of Thyssen Edelstahlwerke, Germany, an Fe-C-Cr-Si-Mo-Mn alloy showing significantly better antigalling behaviour than Stellite 6.
5. APM 2311—exhibits outstanding galling resistance & higher friction coefficients than Stellite® 6. It has been developed by ABB Stal of Sweden.

Q. *What is galling?*

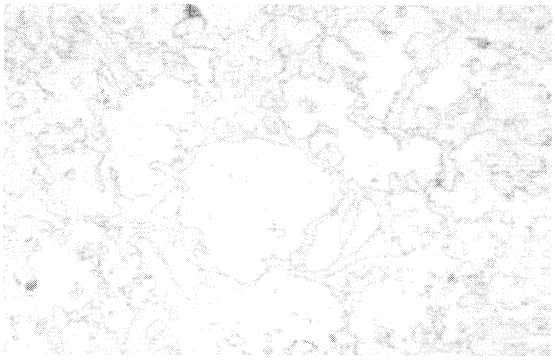
Ans. It means severe scuffing. It is used to describe what happens to two contacting surfaces when they're rubbed against each other under high pressure without lubrication. It results in gross damage to the mating surfaces and even metal failure.

Q. *Why is galling resistance a critical property in nuclear hardfacing materials?*

Ans. Hardfacing materials are extensively used in most valve applications. However, galling can be fatal in valve seating as it results in gross damage to surface or metal failure. The two mating surfaces no longer contact properly and the seal is lost. Thus resistance to galling is counted upon as the top performance criterion, especially in nuclear powerplants.

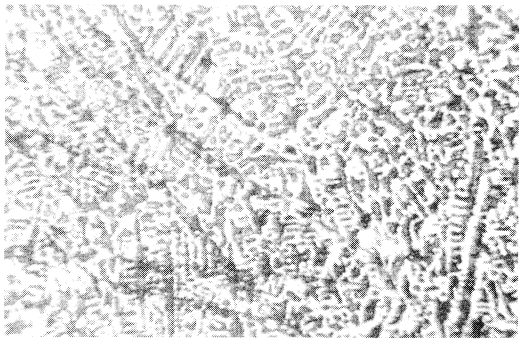
Q. *Ni-Fe based alloys are more popular in boiler feedwater service than cobalt-based alloys. Why?*

Ans. Cobalt-based alloys suffer from erosion/corrosion due to hydrazine added in the water.



Cobalt-free ball valve seat hardfacing alloy suitable for nuclear power plants

Nickel-based valve ball hardfacing alloy used in high-temperature, high-abrasion service



Cobalt-based hardfacing alloy used extensively in control-valve trims

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Fig. 4.11

Q. *As valve materials APM 2311 and Everit 50 alloys are very promising. Why?*

Ans. They demonstrate good galling resistance.

Over and above they display higher friction coefficients than Stellite® 6. Ni-Fe alloy combination provides low friction even at high temperatures and under dry conditions.

Q. *Why is the inspecting of valve stems and valve-stem packing critical?*

Ans. To avoid stem seal leakage.

Q. *Why?*

Ans. Traditionally, seal materials has been soft, requiring frequent adjustment (tightening) to effect a proper seal. Though more resistant PTFE-type packings come to the rescue by minimizing the necessary adjustment, but they generate other problems such as improper alignment causing premature failure.

Efforts to eliminate leaks will not be successful unless the packing is uniformly loaded and not overloaded. Overloading of packing will invite premature packing failure due either to extrusion or accelerated wear.

Q. *When will you go for repacking valve stems?*

Ans. If adjustment fails to eliminate leakage.

Q. *What basic guidelines are to be considered for repacking of valve stems?*

Ans.

1. Old asbestos packing is often found during the repacking process. However, the stem

gland clearances acceptable for asbestos may allow migration of asbestos replacements out of the packing box and result in leakage. Therefore, a manu-facturer who can recommend a special header and follower rings to effectively hold the new packing material is to be consulted.

2. The packing follower (gland) bolts must be tightened to the extent to generate enough stress to compress the packing. In case the gland-bolts are not capable of doing so, ask the valve manufacturer whether this could be the source of continuous leakage.
3. In the case of multiple ring packing boxes, it may be necessary to preload each ring before assembly. This is because the coefficient of friction of many asbestos replacement materials prevents normal packing in multiple ring packing-boxes from stressing the lower rings to the level required for sealing.

Q. *Is there any real harm in oversizing valves, besides, perhaps having to pay a bit more?*

Ans. Definitely.

Control valves oversizing increases valve error and control loop dead time. From the physical stand point, control valve error is the gain multiplied by the valve position error. In other words, when the gain of the oversized valve is high, the error at flow will be high as well. On the other hand, if the control valve gain is high, then the controller gain must be reduced to prevent control loop instability. This means that control signal changes coming from the controller are smaller, which leads to a significant increase in control valve dead time*.

Source: CURRENT (# 1, 1994/P-11), Neles-Jamesbury Publ.

* *Dead Time* *The interval of time between input changes and the start of output response.*

Q. *What is terminal pressure drop, and what does it have to do with cavitation?*

Ans. Terminal pressure drop is used to describe the pressure drop of choked liquid flow, after which further increase in the pressure drop will no longer produce a higher flowrate at a given valve travel and constant upstream pressure. There will be a very high cavitation level in a valve, when the actual pressure drop is at or above the terminal pressure drop and all available means must be used to prevent cavitation damage.

Source: CURRENT (# 1, 1994/P-11), Neles-Jamesbury Publication.

Q. *We need a top-entry control valve for steam duty at 425°C and dP 45 bar. What materials and coatings would you recommend?*

Ans. You may be surprised by this answer. Instead of WCB which is not strong enough, we would go with a WC6 low-alloy steel body. The ball material should be made of martensitic stainless steel, preferably type CA6NM. Again, you would expect a CH8M ball, but in this case we need the higher strength to handle the torque.

Suitable ball coatings for high-temperature steam are thermally sprayed nickel-boron or tungsten carbide. We would probably go with the tungsten carbide in this case, because spray-and-fuse nickel-boron coats are mostly applicable for austenitic steels such as CF8M and not for martensitic steels such as CA6NM. Tungsten carbide is applied using a high velocity spray technique and will not be fused so we can use it on almost any base material. The seat coating would be treated in the same manner.

Source: CURRENT (# 1/1994 /P-11), Neles-Jamesbury Publication

Q. *What is ISMO?*

Ans. It stands for Intelligent Signal Modifier introduced by the Neles-Jamesbury technologist in early 1994.

Q. *What is the purpose of ISMO?*

Ans. It was designed to give operators the possibility to optimize valve performance through a

fine improvement in valve actuator performance than commonly realized.

This state-of-the-art device provides online valve diagnostics and boosts up valve performance through increasing the precision of valve positioning.

Q. *Where does the deficiency of standard control valves lie that calls for the installation of ISMO Units?*

Ans. It is well-known that the inherent performance of a standard control valve depends, by and large, on the friction characteristics of valve/actuator package, the actuator output/valve torque and the mechanical feedback/lever mechanisms inside the positioner. These factors largely determine the response time, dead times, positioning accuracy, and specific flow characteristics.

For example, take the case of a valve package with a standard electro-pneumatic positioner. There is normally a time gap (dead time) between the signal change and the actuator/valve movement as input pressure builds to the point it overcomes the combined friction of the valve, actuator packing, bearings, seat, etc. Actuator speed is then determined by the positioner beam and feedback mechanisms.

Because of delay, the feedback mechanism fails to slow the valve sufficiently as the correct position is reached with the effect that there is a minor deviation from setpoint or overshoot.

Q. *How does the ISMO system overcome this 'deficiency'?*

Ans. The ISMO unit contains a position transmitter, position display and diagnostic module. Instead of connecting the input signal to the positioner, it is routed through the ISMO unit installed directly on the top of the control valve positioner. The resulting data stream is collected and analyzed on a PC with an easy-to-use Windows®—based interface program called NELDIAG (Fig. 4.12).

The control algorithm in the unit senses the signalled position change and instantly activates the actuator to start moving. Valve position change is therefore synchronous with signal change and the setpoint is reached without the slightest overshoot. As a consequence, all dead times are eliminated and there is far greater control quality through out the loop.

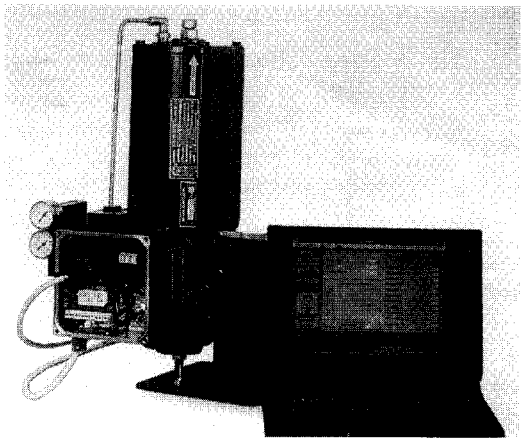

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Fig. 4.12 *ISMO system improves online valve performance. The unit is provided with an MS Windows®-based NELDIAG user inerface program to enable the user to freely modify valve characteristics and gain, run online and offline diagnostic, maintain a valve travel logbook and perform test routines.*

Source: Current, # 1, 1994, P-11 (Neles-Jamesbury Publication)

CASE STUDY

Detroit's resource recovery facility burns about 3000t refuse per day producing 250 t/h of steam which is piped 5.5 km to Detroit Edison customers and the utility's Beacon Heating Plant where it is tied to the utility's steam distribution system.

The steam arrives at the Beacon Plant through a 350 mm line and a 500mm line at 15 bar. This pressure has to be reduced to the usual manifold pressure of the Beacon Plant, about 9 bar, before it is sent by existing underground feeders to downtown Detroit.

The Beacon Plant has an additional operating condition as well. Between October and April,

the Beacon Plant supplies steam to the customers on the tie line between the resource recovery facility and the plant by backfeeding through the control valves. Whatever steam is produced by the resource recovery facility during this period is sent directly to the north end of the utility's distribution system.

The Beacon Plant needed control valves on these lines to reduce the pressure of the steam generated and supplied by the resource recovery facility.

Besides, the control valve would also have the capability to reduce the noise level, inasmuch as high volume of steam was going through the lines.

In order to accommodate the special requirements of the line, Neles-Jamesbury 300mm *Q*-Ball® rotary control valves were installed. They are actuated by Neles-Jamesbury BJ 32 spring return pneumatic actuators combined with NE600 electropneumatic positioners. The whole system is controlled by a Moore Products Mycro 352 single loop digital controller programmed to maintain suitable manifold pressure.

Source: Current # 3, 1994, Neles-Jamesbury Publication

The system has helped the utility improve operating conditions.

Q. *How was the precise control of pressure and noise reductions achieved?*

Ans. The *Q*-Ball® valve sports a series of parallel perforated attenuator plates (Fig. 4.13) that set up stages of pressure reduction at high pressure drop, low flow, and low opening angles. This gradual pressure reduction reduces velocities of flow, brings down noise level and minimizes erosion.

Note: When high flowrate, large opening angle, and minimal pressure reduction are required, the plates align themselves with the flow providing a higher capacity than traditional globe valve.

Q. *What is the noise control mechanism in Q-Ball valve?*

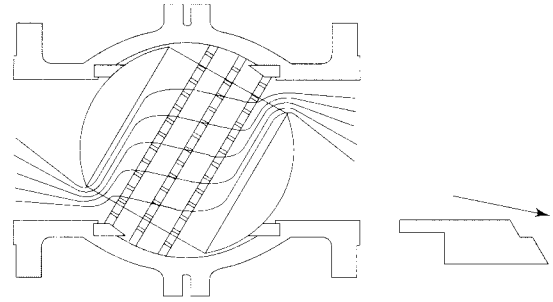

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Fig. 4.13 *The construction of a Q-Ball valve Source: The Valve Book (Neles-Jamesbury Publication)*

Ans. The attenuator plates in the flowpart of the valve divide the flow into a number of small streams and create the drop in pressure in several successive stages (Fig. 4.14).

Subdivision of flow into multiple streams attenuates the noise following the principle of acoustic control. This is an example of source treatment.

Q. *How do customers on the tie line receive steam from Beacon Plant during winter months?*

Ans. Before installation of Q-Ball control valves, the Beacon Plant sometimes had to l/up another standby steam plant in the winter to maintain the header pressure in the northend. Now the steam goes to the customers on the tie line between the resource recovery facility and the plant by backfeeding through the control valves i.e. supplying the customers on the tieline through reverse flow (because of bidirectional characteristics of the Q-Ball valve).

Q. *What is an actuator?*

Ans. It is a device supplying force and motion to the valve-closure member : ball, disc or plug.

It may be anything from a simple lever to a handwheel to a highly engineered electrohydraulic system that moves the internal closure elements for blocking or throttling.

Simple levers and handwheels are not enough to operate a large valve or a remote-control valve.

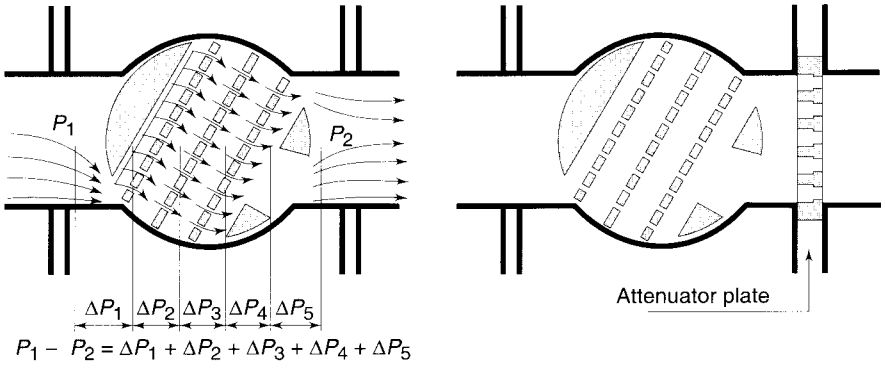

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Fig. 4.14 *The noise control trim breaks the flow into multiple streams and thereby controls the noise following the principles of acoustic control.*

Source: Flow Control Manual (Neles-Jamesbury Publication)

Considerable torque is necessary to open or to close large valves. Therefore, a gear-box is mounted to allow manual-actuation of large valves.

Powered actuators replace manual actuation and they chiefly rely on electricity and compressed air and in some cases, oil hydraulic systems as well.

Electric motor actuators are frequently employed to operate remote-control valves in blocking and full-fledged throttling control services as well.

Q. *What types of valve-actuators are most frequently used in steam boilers?*

Ans. 1. Cylindrical actuator
2. Diaphragm actuator
3. Vane actuator

Q. *How does the cylinder actuator operate?*

Ans. It is operated either pneumatically or hydraulically. A piston moves inside a cylinder by pneumatic or hydraulic pressure. (See Figs 4.15 and 4.16)

They can be

(a) single-acting i.e. equipped with a return spring, or

(b) double-acting using air or oil pressure for movement in both directions.

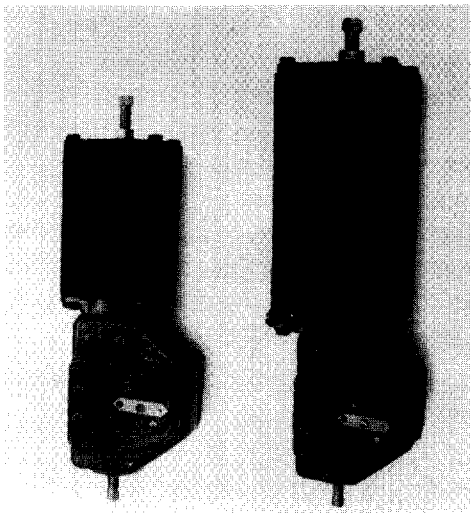

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Fig. 4.15 *Cylinder actuators. Shown here are Neles-Jamesbury units rugged and simple in design with all parts fully enclosed to offer highest degree of safety.*

Source: The Valve Book (Neles-Jamesbury Publication)

When used with rotary valves, a linkage system is needed to convert the linear motion of the piston rod into 90° rotary motion.

Q. *What is a diaphragm actuator and how does it operate?*

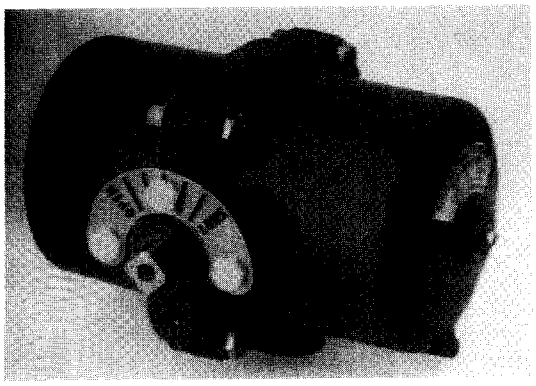

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Fig. 4.16 *Double-acting cylinder actuator. They are of plastic/stainless steel construction for excellent corrosion resistance.*

Source: The Valve Book (Neles-Jamesbury Publication)

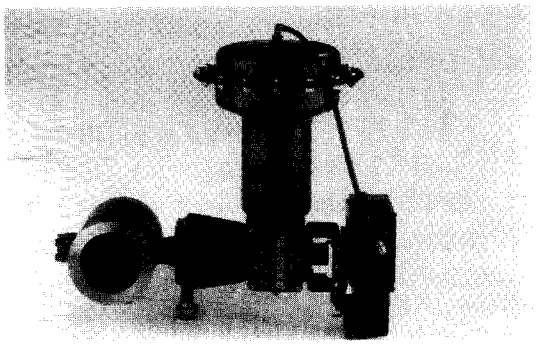

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Fig. 4.17 *Diaphragm actuator for rotary valves (Quadra-Power® unit of Neles-Jamesbury)*

Source: The Valve Book (Neles-Jamesbury Publication)

Ans. It is a pneumatically operated actuator that consists of

(a) a diaphragm fitted within a pressure case (air chamber)
(b) an actuator stem
(c) a return spring
(d) a seal system. (See Figs. 4.17 and 4.18)

The air chamber is sealed by the flexible diaphragm with most of its flat area supported by a plate at the end of the actuator stem.

Variable air pressure flexes the diaphragm and positions the stem with the aid of a return spring.

The system adapts well to small-to-medium control valves.

The spring ensures a fail-safe seating or opening force. Also it helps in relating a given valve opening percentage to a given air pressure.

Q. *What is a vane actuator and how does it operate?*

Ans. It is a pneumatically operated actuator used with rotary valves.

The actuator sports a paddle-shape vane housed in a sector-shaped pressure casing giving a 90° rotary motion to the vane shaft connected to the valve stem.

Vane actuators can be

1. single-acting fitted with a return spring
2. double-acting i.e. operated in both directions by air pressure. (Fig. 4.19)

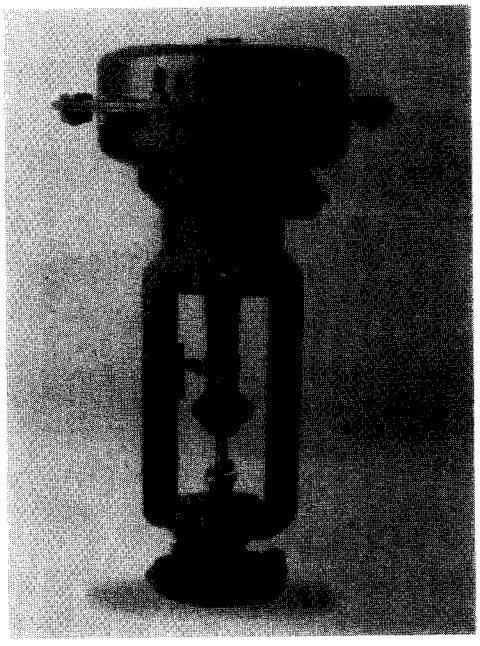

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Fig. 4.18 *Diaphragm actuator for linear globe valves (D/R series of Neles-Jamesbury).*

Source: The Valve Book (Neles-Jamesbury Publication)

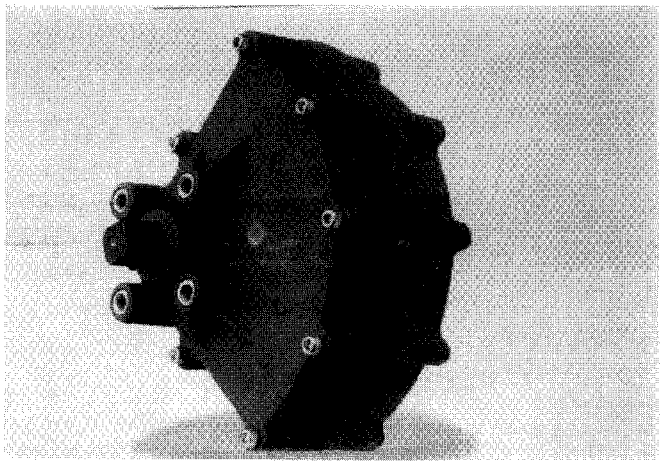

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Fig. 4.19 *Vane Actuator.*
Shown here is the V-series model of Neles-Jamesbury. Its thermoplastic polyester construction gives it very good corrosion-protection.
Source: The Valve Book (Neles-Jamesbury Publication)

Q. *Why is actuator alignment of control valves so vital?*

Ans. Defective or incorrectly specified actuators can lead to severe valve leakage problems. They can subject valve components to undue stress, jam a valve open or shut, short stroke or fail to stroke when required.

Q. *Actuator mounting is one of the most critical aspects of valve installation. In the past few years, there has been a growing trend towards field mounting of actuators.*

What are the specific guidelines that should be given particular attention when installing actuators in the field?

Ans. Always follow the manufacturer's instructions when installing actuators in the field and apply common sense.

1. Check whether the actuator output shaft and stem aligned. Are they parallel?

If the actuator fails to meet these criteria, be sure the actuator will put a side load on the valve stem and cause the packing to wallow during cycling. Obviously, this will cut short packing life.

2. Look out for antivibration hardware supplied by the valve manufacturer in their linkage kit. If this hardware gets overlooked and the valve manufacturer's kit is not used, be sure it will culminate in the loosening of the packing follower system during cycling.

Examine the valve design and apply common sense engineering. It may reveal the need for such locking hardware.

3. Verify the rigidity of the linkage package by observing its behaviour during bench testing. If the mounting kit flexes elastically or plastically to the extent that shaft misaligns during the stroking process, all the efforts to align shafts and to avoid the loosening of the fasteners will go in vain.

Q. *What is a positioner?*

Ans. It is a device for varying and keeping the actuator position in control valve applications. The duty of the positioner is to compare actual actuator position to the desired actuator position and thereafter to adjust the pressure applied on the actuator until the desired position is attained. (See Figs 4.20 and 4.21)

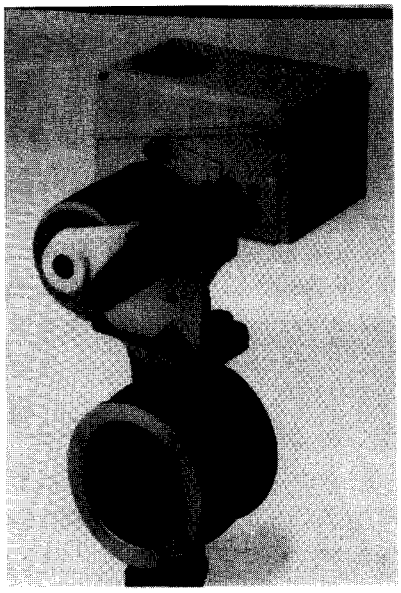

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Fig. 4.20 *NELPAC® Integrated Compact Control unit containing the cylinder actuator, the positioner and the limit switch.*

Source: The Valve Book (Neles-Jamesbury Publication)

They can be pneumatic or electro-pneumatic and single-or double-acting.

Q. *What is QUADRA-POWR® II?*

Ans. It is a versatile spring diaphragm actuator (Neles-Jamesbury product) designed exclusively for on-off and control applications of quarter-turn rotary valves. Fig. 4.22.

Q. *What are the advantages of Quadra-Powr® II actuators?*

Ans.

1. Completely field-reversible by simply inverting it. Fail to open or fail to close operation can be quickly changed in the field without disassembly
2. Can operate in a wide range of supply pressures (1.4 to 6 bar g)
3. Ensure safe and reliable operation even with minimal supply pressure

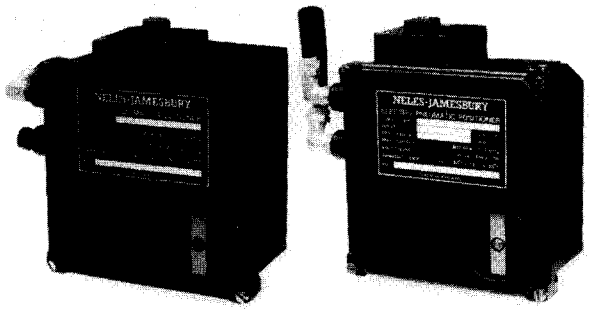

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Fig. 4.21 *Pneumatic positioner (left) and electro-pneumatic positioner (right).*

Source : The Valve Book (Neles-Jamesbury Publication)

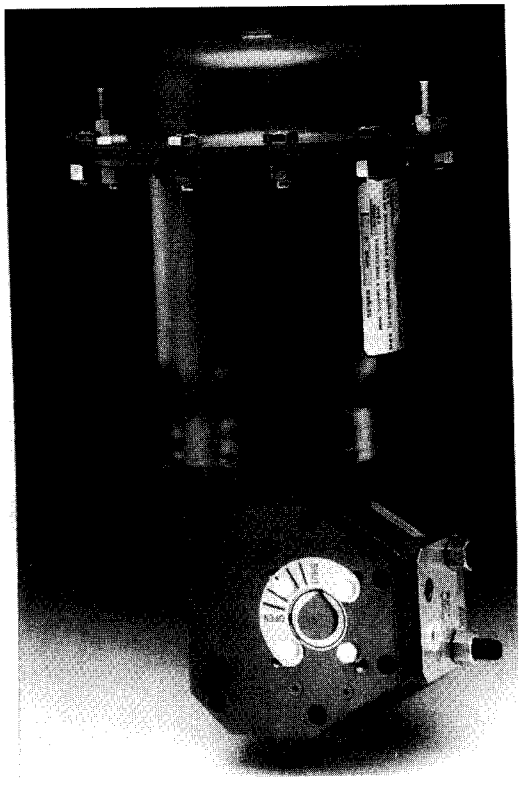

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Fig. 4.22 *Quadra-Powr® II Actuator*

Source: Current,® #3, 1993

4. Two-stage epoxy coating (outside and inside) begets extended protection in corrosive environment.

Q. *What are the special features of Quadra-Powr® II?*

Ans. These actuators combine the extremely precise flow control typical of spring-rolling-diaphragm designs with the torque capabilities of piston actuators. The combination makes the Quadra-Powr II extremely suitable for virtually any process control application.

The diaphragm plate support system makes it impossible for the diaphragm to pinch on itself, eliminating the need for diaphragm change.

Q. *What is acoustic control?*

Ans. Acoustic control affects the noise level by virtue of acoustics. This can be achieved by either dividing the flow into multiple streams or by modification of the acoustic field.

Control valve aerodynamic noise is mainly caused by dipole sources when the flow velocity is subsonic. An aerodynamic dipole consists of two monopoles pulsing 180° out of phase near a solid boundary. In this case the acoustic intensity is given by

$$I \simeq \rho^2 \cdot \frac{v^6 \cdot D_j^2}{r^2} \qquad (1)$$

where, I = acoustic intensity

ρ = density of jet

v = velocity of jet

D_j = diameter of jet

r = distance from source

Note, the noise intensity is proportional to the sixth power of jet velocity.

High speed jet noise is generated by aerodynamic quadropoles which consists of two dipoles pulsing in opposing pairs. The noise intensity in this case is given by

$$I \simeq \rho^2 \cdot \frac{v^8 \cdot D_j}{r^2} \qquad (2)$$

The noise intensity here is proportional to the eighth power of the velocity.

Thus the division of flow into multiple streams is very effective in reducing the intensity of noise. This is due to the fact that noise intensity generated by a single orifice decreases rapidly when the hole diameter is decreased.

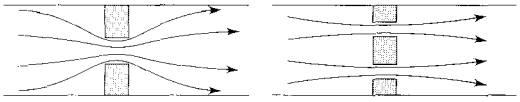

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Fig. 4.23 *Effect of increasing number of holes on noise level .*

Source: Flow Control Manual (Neles-Jamesbury Publication)

Thus a number of small holes attenuates noise more effectively than big hole. A rule of thumb is that each doubling of the number of holes reduces noise by 3dB (See Fig. 4.23).

Source: Flow Control Manual, 1994/P-69, 70, 77 (Neles-Jamesbury Publication)

Q. *In order to close the feed of natural gas to boilers in case of emergency, ESD (Emergency Shut Down) valves are installed. What are the basic requirements of an ESD valve?*

Ans. The most important requirement for an ESD valve is that it must close with complete reliability thru remote control in an emergency. The closing energy must be stored in the valve actuator, basically in the form of an energized mechanical spring. "Spring to close" is the most commonly used actuator mechanism.

The second requirement is the firesafe construction of both valve and actuator. The actuator must close the valve before its seats, bearings and solenoid valves are destroyed. The valve must be tight at the temperature caused by fire. This is a measure to ensure that no gas leak to the fire.

The third important requirement is very quick closing time, usually 2—3s.

Q. *Why are ball and butterfly valves the most suitable candidates for ESD applications than gate or globe valves?*

Ans. ESD valves must be very quick acting. During quick operation rotary valves require smaller inertial forces than gate or globe valves. In ball and butterfly valves this advantage is greater the larger the nominal size and the higher pressure class of the valve. To ensure an economical and quick-acting actuation, these valves are equipped with pneumatic or pneumatic spring-return actuator so that the operating energy is stored in compressed air or in a mechanical spring. Rotary valves and spring-return actuators permit a very short closing time to be reached.

Q. *Which one, between ball and butterfly valves, is more economical for ESD applications?*

Ans. Butterfly valves.

Q. *Why?*

Ans. They are generally lighter and require less torque, making for economical ESD valves.

Q. *Under what operating conditions, are butterfly valves mostly used in ESD services?*

Ans. They are used chiefly in low and medium-pressure services in medium and large-dia piping. At high temperatures, metal seats are required.

Q. *When is a ball valve the best solution?*

Ans. For more demanding applications.

In the most demanding ESD applications of high temperature and higher differential pressure, fully metal-seated turnnion-mounted ball valve is recommended.

Note: Stem-Ball® valve of Neles-Jamesbury is an outstanding example for ESD application under demanding environment of extreme temperatures and higher differential pressure.

CASE STUDY

The INDIAN POINT 3 nuclear powerplant started operating in 1976 and rubber-lined butterfly valves were installed for isolation and flow control in the plant's service water system. The plant uses brackish Hudson River water.

Problems cropped up shortly afterwards. Research proved conclusively that the plant was denied of optimum servicelife from these valves, primarily because of their design.

Beginning in 1981, the New York Power Authority replaced 100 rubberlined butterfly valves with double-offset, PTFE-seated butterfly valves. The original valves were single-offset configuration.

Since the replacement program started, none of the new valves have required more than routine maintenance.

Source: The Valve Book (Neles-Jamesbury Publication)/P-289

Q. *Why were the rubberlined butterfly valves replaced with PTFE-seated butterfly valves?*

Ans. Since the valves were to handle brackish Hudson River water, salt & silt in the water inflicted valve erosion. The rubber lining and the valve's design allowed the service water, which cooled the powerplant's heat exchangers and other components, to degrade the whole valve.

Hence 100 Nos. of rubberlined butterfly valves were replaced.

Q. *Why were PTFE-seating butterfly valves selected?*

Ans. PTFE-seating in butterfly valves with double-offset design offers optimum valve life. This design Wafer-Sphere® valves is able to withstand greater pressure differential, up to 2MPa. They give more reliable and positive shut-off.

CASE STUDY

The 775MW nuclear power station located in Surrey, Virginia (USA) went on line in the early

1970s and has been operating continuously for the last 20 years.

Program was underway to replace the rubberlined metal-seated butterfly valves in the service water system with Neles-Jamesbury's Wafer-Sphere® high performance butterfly valves with a nickel-aluminium-bronze body. The project completed in 1994.

The service water system valves play an important role to the safety of the power station. The valves isolate the heat exchanger system and must serve as an effective pressure boundary for the James River water, by maintaining a positive shutoff.

In the containment building, the reactor coolant feedwater pipe system carries fluid at 155 bar and about 575°K. A leak in the reactor coolant pipe could release this high pressure and heat into the concrete reactor containment, causing an emergency situation. In case of a coolant pipe leak, the valves would open automatically, allowing the river water to flow into the heat exchangers to relieve that heat and keep the pressure inside the containment below the designed limit of 3 bar.

Except during regularly scheduled system test to check the operation of the valves, the H.E. pipes are always dry.

The brackish river water is admittedly silty and the 16 existing valves in the system were replaced with Neles-Jamesbury 600 mm Wafer-Sphere high performance butterfly valves.

Source: Current, # 2, 1993 (Neles-Jamesbury Publication),/P-7.

Q. *Why are the heat exchanger pipes always kept clean and dry?*

Ans. The purpose is to retain the proper heat transfer coefficient during the first stages of a coolant system emergency—the most critical stage.

Q. *Why is greater stress laid on maintaining a positive shut-off of the servicewater valves?*

Ans. If river water seeps into the system and is allowed to stand, marine organisms will grow in abundance. This could dramatically change the heat transfer capabilities of the system. Silting on the tubes and the growth of marine organisms anchoring at the tubewalls will adversely affect the overall heat transfer coefficient to the direct detriment of the safety of the reactor housing. Also they jam the valve assembly and offset and reactor safety.

Q. *Why were the butterfly valves with nickel-aluminium-bronze body selected to replace the existing ones?*

Ans. Nickel-aluminium-bronze alloy has been selected for its superior resistance to brackish water.

Q. *Why were the 16 existing butterfly valves replaced by 600 mm Wafer-Sphere butterfly valves of Neles-Jamesbury?*

Ans. These are high performance butterfly valves. They are rated ANSI Class 150, and are manufactured to Nuclear Code Class III specifications.

Q. *Why has the Wafer-Sphere design been selected?*

Ans. This is because of Wafer-Sphere's high reliability and high performance characteristics resulting from its single piece flexible polymeric seat, pressure energized to assure positive shutoff over thousands of cycles. The special seat arrangement compensates for pressure and temperature changes, as well as wear, to allow operation with the lowest possible torque. (See Figs 4.24 and 4.25)

Q. *What are the added benefits of using Wafer-Sphere valve?*

Ans. These valves feature an offset shaft and eccentric disc design that exercises a camming effect on the disc. This causes the disc to swing completely out of contact with the seat upon opening, eliminating wear points at the top and bottom of the seat. On closing, the disc moves tightly

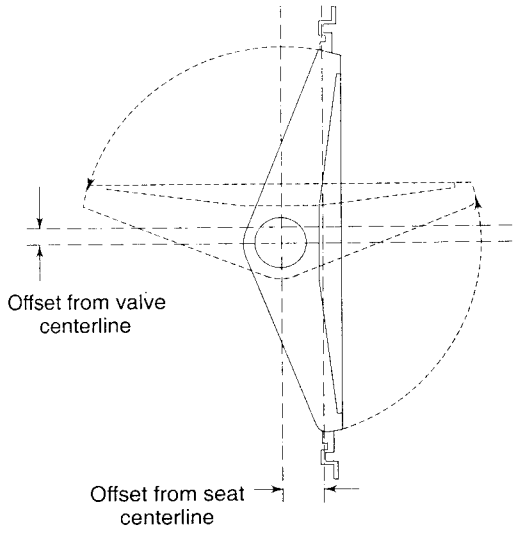

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Fig. 4.24 *The flexible seat of a WAFER-SPHERE valve is pressure energized with polymeric element being increasingly forced against the disc as system pressure rises.*

Source: The Valve Book (Neles-Jamesbury Publication), P-221

into the flexible lip for reliable sealing around the seat. This sealing design is more effective than the squeezee type of seal used in conventional butterfly valves, where the disc is literally squeezed into the rubber or PTFE liner.

Should the seat need to be replaced, only the body insert needs to be removed. No shaft or disc disassembly is necessary.

Source: Current, # 2, 1993 (Neles-Jamesbury Publ.), P-7.

Wafer-Sphere valves have high flow capacity coefficient. As a result, less energy is required to move fluids through the system.

They sport special features that increase plant safety. For instance, they are quick closing. A quarter turn rotates the disc from wide open to completely closed. The movement is readily adaptable to either manual or automatic mechanical operation.

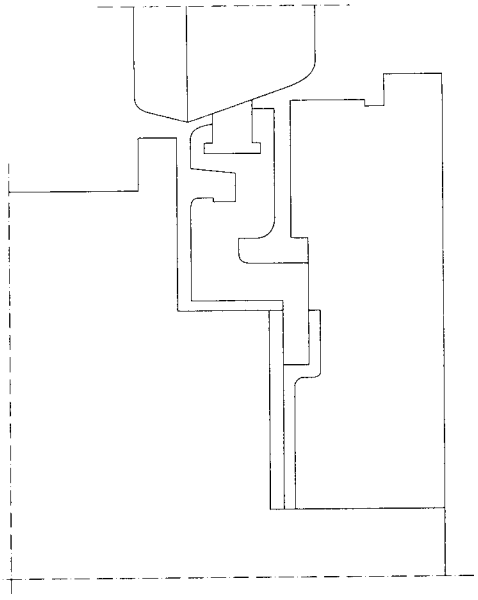

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Fig. 4.25 *The eccentric disc and offset shaft of a WAFER-SPHERE valve allows full circle sealing of the disc against the inside diameter of the seat.*

Source: The Valve Book (Neles-Jamesbury Publication), P-223

CASE STUDY

A Finnish pulp mill had been using a conventional globe valve in its soda recovery boiler feedwater circuit to control boiler drum level. It has a conventional rising-stem device that developed serious operational problems including excessive leakage in the control of small flows and erosion thru cavitation.

As far back as late 1985, Neles-Jamesbury supplied a Q-Ball valve PN 250 (ANSI Class 1500) to eliminate these problems. And with the Q-Ball the problems got eliminated.

Q. *Why was the Q-Ball valve selected?*

Ans.

1. Q-Ball® is a low noise, anticavitation valve featuring tight metal-to-metal seating

2. Q-Ball valve is more acceptable for a wide range of control applications
3. It features larger capacity and higher mechanical stability over the conventional control valves
4. No wear on seat or trim through erosion
5. Small external size.

Q. *How did Q-Ball valve solve the problem?*

Ans. The Q-Ball valve works on the principle of 'divide-and-control': division of total pressure drop into multiple stages and of flow into smaller streams.

This design feature changes the high recovery character of a rotary valve to a low-recovery character. Thus the Q-Ball valve can be applied to demanding applications.

Filling and pressurization of a boiler makes it necessary to control low flowrates under very high differential pressure. The Q-Ball construction installed as a BFW valve was quite able to handle small flows under high differential pressure conditions. see Fig. 4.26

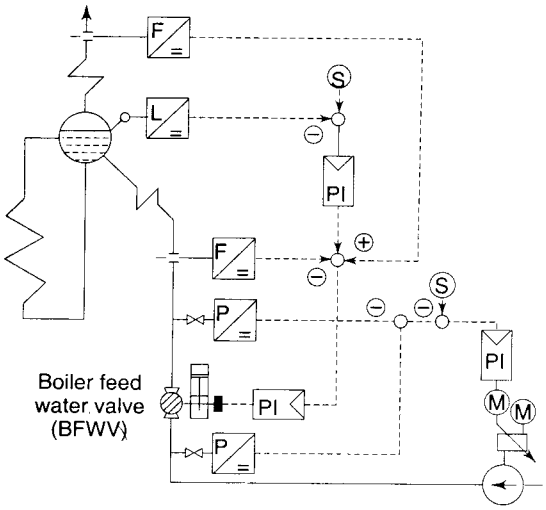


Fig. 4.26 *A typical feedwater level control system using a Q-Ball valve to control BFW flow to boiler drum.*

Source: *The Valve Book (Neles-Jamesbury Publication), p-286*

Q. *What added benefits did the Finnish Plant obtain from the Q-Ball valve?*

Ans. 1. Because of the smallest controllable pressure drop over the valve at normal and maximum flowrates, the pump power consumption could be minimized due to very high thruput capacity of Q-Ball valve.

2. The Q-Ball construction offered a cost-effective solution, reducing both initial and plant operating costs through diminished maintenance, improved operating reliability and extended service life.

Q. *What is a safety valve?*

Ans. It is a device that lets out the excess steam when the steam pressure in the boiler, steam header or pipeline exceeds the working pressure.

Q. *How does a safety valve work?*

Ans. It works automatically. When the steam pressure exceeds the working pressure, it automatically vents some steam from the system with the effect that the system pressure returns to the normal working limit.

Q. *In general, how many types of safety valves are used in practice?*

Ans. Four types.

Q. *What are they?*

Ans.

1. Spring loaded safety valve
2. Lever safety valve
3. Dead weight safety valve
4. High steam and low water safety valve.

Q. *What is a Ramsbottom safety valve?*

Ans. It is a spring loaded safety valve.

Q. *How does it work?*

Ans. The valve is loaded with a helical spring (Fig. 4.27) that pulls two valves to press upon the respective valve seats. It is the compressive strength of the spring that holds the valves tightly upon the valve-seats. When the steam pressure exceeds the normal working limit, the force of

the steam acting on the valve seats exceeds the compressive force of the spring, the valves get lifted from their seats and release the excess steam till the pressure falls below the preset limit, after which the valves again rest on their seats.

Q. *What is the limitation of a Ramsbottom safety valve?*

Ans. The spring may get stuck-up.

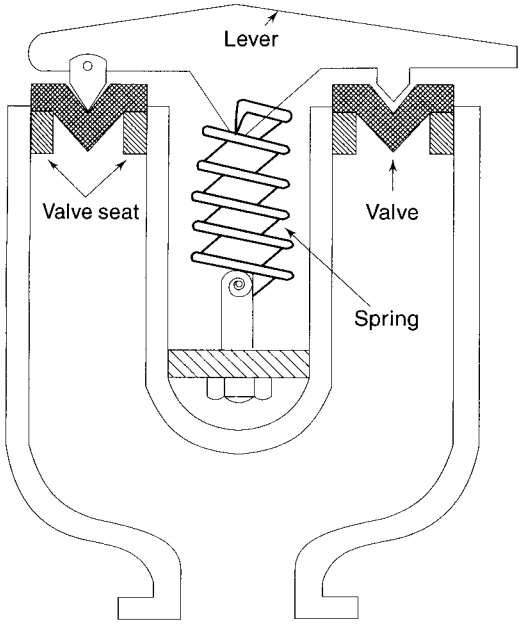


Fig. 4.27 *Ramsbottom safety valve.*

Q. *What is a dead-weight safety valve?*

Ans. It is a safety valve that uses a weight sufficiently heavy to keep the valve on its seat below the allowable pressure limit. [Fig. 4.28]

Q. *How does it operate?*

Ans. The weight exerted upon the valve is enough to press it tightly upon the valve seat against the normal steam pressure.

When the steam pressure exceeds the normal limit, it lifts the valve up together with its weight, allowing excess steam to escape and bringing the pressure down to its normal value.

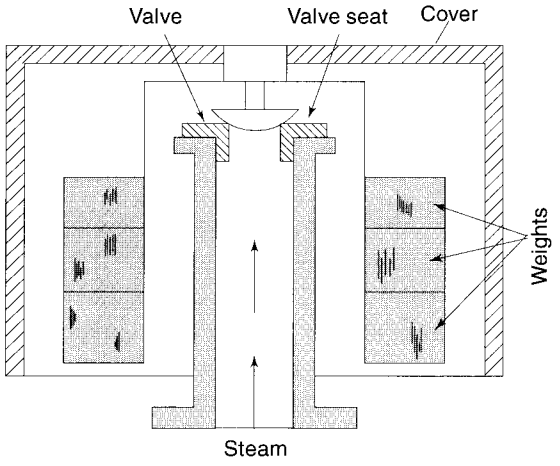


Fig. 4.28 *Dead-weight safety valve.*

Q. *Can you prescribe this type of safety valve for high pressure boilers?*

Ans. No.

Q. *Why?*

Ans. Large amounts of weights will be required to balance the steam pressure.

Q. *What are the common linkages between a check valve and a safety valve?*

Ans. Both, by design, are self-contained and operate automatically.

Q. *What are the worst defects of a check valve?*

Ans.

1. Sticking open
2. Late closing
3. Flutter and vibration.

Q. *What are the outcomes of 'late closing'?*

Ans. Water hammer and system damage

Q. *What may be the result of 'flutter and vibration'?*

Ans. Premature valve failure.

Q. *What is the primary mission of a pop safety valve installed on a steam header?*

Ans. Its mission is to remain tightly shut-off at all steam pressures below a selected preset value

and, at precisely that pressure, to open wide instantly and to vent a rated flow of steam until the header pressure drops a few per cent below the set pressure.

Q. *What are the two important types of safety-relief-valves?*

Ans. SRVs are of two main types
(a) Spring-loaded safety-relief-valves
(b) Pilot-operated safety-relief-valves.

Q. *What are the benefits of pilot operated S.V. compared to the spring loaded S.V.?*

Ans.
1. ON/OFF opening, no chatter and erosion of seating surfaces
2. Leak tightness is maintained right up to the exact set pressure
3. The maximum working pressure can be raised up to 98% of set-pressure
4. The set-pressure is not API-RP-526 limited, even with large orifice area
5. There is no pressure limit, even when orifices are large
6. Perfect operating irrespective of the type of fluid : steam, gas, vapour or liquid
7. Completely suitable for two-phase flow
8. Variable backpressures acceptable up to 95% of set-pressure
9. High number of opening at right set-pressure without loosing leaktightness
10. Adjustable and small blowdown
11. Can be mounted in any position
12. Dimensions and weights are much reduced
13. Can be operated by remote control with a solenoid valve
14. Control of operation by another parameter (time, pressure gradient etc.) while maintaining the valve safety function
15. Control of operation while in service by performing a field test (set pressure), without loosing the SRV's initial protection function
16. Variation of the set-pressure as a function of plant operational stages.

Source: *Pilot Operated Safety Relief Valves (Product Bulletin of SEBIM Group, France)*

Q. *It is said: 'A safety valve is not just another valve'. What is the significance of this message?*

Ans. Safety valves (SVs) must come up with 100% repeatability as well as reliability. This is because it is impossible to predict when overpressure will set in. And therefore, safety valves must remain operable at all times because in times of emergency a valve jamming may be disastrous.

Q. *Safety valves are the part and parcel of a boiler system. They must be capable and available to perform their duties at all times.*

How is their importance realized in a steam generation plant?

Ans. 1. Safety valve is a 'body-guard' to any pressurized system. This overpressure protection equipment is critical in safeguarding lives and property. In a boiler system, PRVs installed on various parts of the system accomplish the task.

2. Over and above its critical safety function, a PRV must perform properly within the pressure limits that let it open and reseat it while maintaining seat integrity so that no leakage occurs. These operating characteristics are imperative in keeping the valve workable and boiler in service even after an overpressurization event.

Q. *Safety valves are the most critical equipment to any pressurized system. Therefore, special measure must be adopted in the design and manufacture of a safety valve. What is the standard basic procedure?*

Ans. Pressure-relief valves (PRVs) are designed and fabricated in accordance to internationally acclaimed STANDARDS that provide the specific construction guidelines dictating product features and support services in order to get specified performance.

Q. *What are the 'standards' for safety valves?*

Ans. There are four major standards most widely practised worldwide:

1. ASME (US)
2. ISO (International)
3. BSI (British)
4. TRD (German)

Q. *Reliability is vital in overpressure protection programs. How does the valve design affect the reliability factor?*

Ans. Larger the number of components of a safety-relief valve, higher is the probability of its failure.

For instance, a simple spring-loaded safety valve contains about 18 major components. A high-performance spring-loaded valve, for more demanding services, has about 28 major components. An auxiliary-assisted SV may sport as many as 80 major components.

When these three valves are put to comparison, the an important point to note is that the auxiliary-assisted valve will perform quite differently in case any element of the auxiliary support system fails. The valve then will not perform within specified limits except to always fail in full-open position.

Now, if each component in all the above three valve designs are 99.8% reliable, the probability of failure of the auxiliary-assisted design is much higher than the other two designs, because of the larger number of components.

Q. *What is the functional difference between the spring-loaded safety valve and the auxiliary-assisted SV?*

Ans. The spring-loaded safety valve performs independently. It does not need any power source to operate.

The auxiliary-assisted design needs external power source to operate and as such there must be redundant power sources to endow it comparative reliability.

Q. *In general, only about 50% of all installed safety valves are capable of performing as per their initial specs—a fact that has been revealed in a recent industrial survey. So, half of the installed population can have problems in varying degrees that may lead to valve failure.*

What are these problems that may invite valve failure?

Ans.

1. Poor installation practices and/or improper operating conditions
2. Inadequate repair tools or lack of proper tools or equipment available on-site
3. Shortage of spare parts on-site
4. Spare parts not procured from the original valve manufacturer or any renowned company
5. Improperly trained technician
6. Lack of proper test facilities or techniques.

Q. *How can we guard against poor installation?*

Ans. Poor installation is usually detectable during start-up and testing. It is always advised to follow the guidelines provided by the reputed valve suppliers to assure proper installation.

Q. *What operating conditions can impair the safety valve operation?*

Ans.

1. Operating pressures too close to valve set pressure
2. Mechanical vibrations
3. Sonic vibrations

Q. *What is the usual effect of these adverse operating conditions?*

Ans.

1. Valve leakage
2. Premature valve-opening

Q. *How can you solve the lack of proper repair equipment on-site?*

Ans. The easiest and safest way is to procure from the valve suppliers all equipment and tooling necessary for servicing their products.

An alternative is to make them available from another source.

Q. *What should be the common philosophy in the management of service and repair of safety valves in powerplants?*

Ans. The powerplant should

1. maintain the list of critical components identified by the valve suppliers
2. maintain an inventory of these critical parts necessary to keep their products in service
3. review need for additional components as planning for future scheduled outage proceeds.

Q. *Suppose a powerplant finds the order-delivery lead time for safety valve spare parts is too long. What are the alternatives left?*

Ans. The powerplant has two alternatives either the plant will attempt to rework the existing parts or it will try to have new parts fabricated locally.

Q. *Which one you deem preferable?*

Ans. None.

Q. *Why?*

Ans. Neither alternative is acceptable.

Q. *Do you think fabricating new parts locally is bad?*

Ans. Yes.

Q. *Why?*

Ans. Manufacturing a part locally by copying the original equipment manufacturer's (OEM's) part invites the highest risk.

Q. *How?*

Ans. Most people do not have adequate depth in the technology associated with a good safety valve design. If improperly designed, a part may fail and that can lead to loss of overpressure protection.

Wrong Materials of Construction—Material selection is not an arbitrary process. Highly specialized materials are necessary to carry seat loads, withstand impact loads, and take lapping to reduce leak paths.

Corrosion resistant steels are frequently used. But they must be heat treated to exact specifications to attain proper hardness.

Wrong Guide Material bodes disaster. It can result in improper clearances. Under demanding service condition, thermal expansion may prevent the disc holder from sliding within the guide with the effect that valve lift is restricted and its capacity is reduced. Or the worst, the disc holder may get jammed inside the guide arresting valve lift altogether during overpressure emergency.

Poor Dimensioning—If the parts are not manufactured to exact dimensions, proper assembly of components is simply impossible. At higher service temperatures, this proper fit becomes the most vital criteria forasmuch as the valve components expand. Poor dimensioning of the parts may lead to either valve leakage or stuck up of disc holder in the guide. Poor SV performance, because of use of parts not of OEM quality, entails possible loss of plant safety.

Q. *Why is the quality of personnel training a no less important factor in determining the safety valves performance?*

Ans. Improperly trained personnel will end up with improper installation of the parts, even if the quality parts are on hand. Defective installation degrades valve performance and tells upon safety.

The valve will start leaking at the very start-up and if during the installation of the parts, the proper sequence is not maintained allowances for movement of parts could be incorrect, leading to binding.

Q. *After the installation of the proper parts, the SV is subjected to testing. How will you be assured of correct alignment of component parts in the valve?*

Ans. The valve set pressure, if the component alignments are OK, will be stable and repeatable.

Q. *What is the purpose of seat-tightness test?*

Ans. To get sure that the seat conditioning is successful and that the valve can remain leaktight while normally closed.

Q. *During valve testing, determination of the valve's full lift and closing pressures is very difficult. Why?*

Ans. This is because the valves are tested on test facilities that produce only a small percentage of valve rated relieving capacity.

Q. *What should be done to determine the valves full lift and closing pressure?*

Ans. The valves must be mounted on the boiler and put to overpressure test. This system is preferable and rather more practical as it will allow a check on all performance parameters.

Q. *If the overpressure on the boiler is not allowed, how will overpressure testing be done?*

Ans. Overpressure only the drum and superheater (assuming that this is permissible)

An auxiliary setting device serves for the reheater, permitting verification of set pressure and leak tightness.

If overpressure of the drum and superheater is not allowed, the auxiliary setting device can also test the drum and superheaters SRVs.

The valve should be actuated three times, recording data in each time. This way one can assure stable set pressure.

At the test end, a final leak pressure test is to be conducted, with no leakage permitted.

When the boiler is back in service and operating under stable condition, the SV set pressures are again to be tested by the auxiliary setting device. This check assures correct valve opening pressure.

Q. *Increasing safety requirements in the nuclear industry have led to the use of highly qualified valves and pilot actuation systems.*

What are the essential requirements of the valve system installed in the primary coolant circuit of a Pressurized Water Reactor (PWR)?

Ans.

1. The valve system has to provide the operator controllable overpressure relief by manual relief valve actuation
2. It must ensure isolation or blocking of the relief line, by manual or automatic actuation, in case the relief valve leaks or fails open
3. The most important of all, it must guarantee a stand-alone automatic safety overpressure prevention function to prevent overstressing of the primary circuit components in the absence of operator intervention.

Note: The catastrophe of Three Mile Island Unit II in 1979 was the outcome of the failure of the valve system to ensure overpressure protection of the primary coolant circuit of the Unit's PWR.

Q. *What is the basic difference in the design of safety valve of a conventional powerplant and that of a PWR electricity generating plant?*

Ans. In conventional powerplants it is essential that the safety valve opens at the correct pressure.

Whereas in PWR powerplants the S.V. must open at correct pressure and close at the correct pressure—both are essential. Thus the set points of the valves, lift pressure and blowdown must be reliable.

Q. *If the S.V. of a PWR fails to close at the correct pressure, what will happen?*

Ans. If the pressure falls below the saturation curve then nuclear boiling may occur resulting in a net loss of good heat transfer between the nuclear fuel and the primary coolant water.

Q. *What are the extra strains that a safety valve installed in the primary circuit of a PWR unit has to bear?*

Ans. The safety valve meant for primary circuit of PWR must sustain its good reliability in presence of a variety of discharge fluids—steam, water, steam-water mixture, water followed by steam followed by water. It will also have to take load of hydrogen used to absorb oxygen in the primary coolant fluid.

Q. *What if spring-loaded safety valves were installed in the primary circuit of PWR?*

Ans. The spring-loaded safety valve in the primary circuit of PWR of TMI Unit II, USA stuck up and invited disastrous consequences in 1979.

In France, the EDF GRAVELINES PWR lost pressure in its Residual Heat Removal Circuit when a spring-loaded safety valve (SLV), vibrated and stuck open whilst discharging water.

In 1980, a SLV at the Saint Laurent Plant, France, vibrated and stuck closed during a water test. In real-time urgency this could mean another disaster.

These incidents and similar others ingrain the truth the SLVs are unfit in the primary circuit of PWR units.

Q. *What is the alternative?*

Ans. Inducting POSRV in to the circuit.

Q. *What is POSRV?*

Ans. It is Pilot Operated Safety Relief Valve.

It was invented, as far back as 1965, by a French genius M. Francois Gemignani.

Note: The POSRV was installed in French Naval ships in 1968 to control boiler pressure during non-steady propeller loads. And in 1972 it was installed in conventional powerplants, in 1974 in US Navy ships, in 1975 in petrochemical and conventional powerplants.

From 1979 onwards it got its way down to nuclear powerplants to function as reliable, stand-alone relief valve under critical conditions.

Q. *What is the basic operating principle of POSRV?*

Ans. The valve is medium operated i.e. the main valve actuation force is derived from the system pressure. This arrangement is made by extending the area of the piston to the extent of 50% greater than the area of the valve disc. Therefore, applying the same pressure to the piston and the disc results in the valve remaining closed.

The action of the valve is bistable with a closed neutral transient. The main valve is either fully open or fully shut. As the system pressure rises, the pilot piston P compresses the spring S and the operating cam C moves downwards. This action closes the pilot valve R_1 and isolates the main valve piston from the system pressure (Fig. 4.29). If the system pressure rises still further the pilot valve R_2 opens and drains the fluid above the main piston thus allowing the main valve to open.

Reducing the system pressure causes R_2 and R_1 to go through the reverse procedure; first R_2 isolates the drain then R_1 reinstates the pressure to the main valve piston and the main valve closes. Therefore, the blowdown, defined as the difference between the lift pressure and the reseat pressure, is controlled by the thickness of the operating cam C between R_1 and R_2.

Source: Development and Application of a Pilot Operated Safety Relief Tandem Valve for Nuclear Powerplant—D.R. Airey and A. Gemignani et. al. (PVP-Vol. 236 Reprint, ASME Publ., Book NO. G00671-1992). Reproduced with kind permission of Andre Gemignani, G.M. of SEBIM.

Q. *What significant advantages do these operational characteristics over the conventional SLV?*

Ans.

1. The seating stress—the feature that minimizes valve leakage—is a maximum at the system pressure immediately prior to lift. This allows leak-free operation at system pressures up to 95% of the lift pressure.
2. The valve controlling mechanism is removed away from the region of transient flow and inherent instability, to a stable sensing region in the pressure vessel to be protected. As a consequence, the damag-

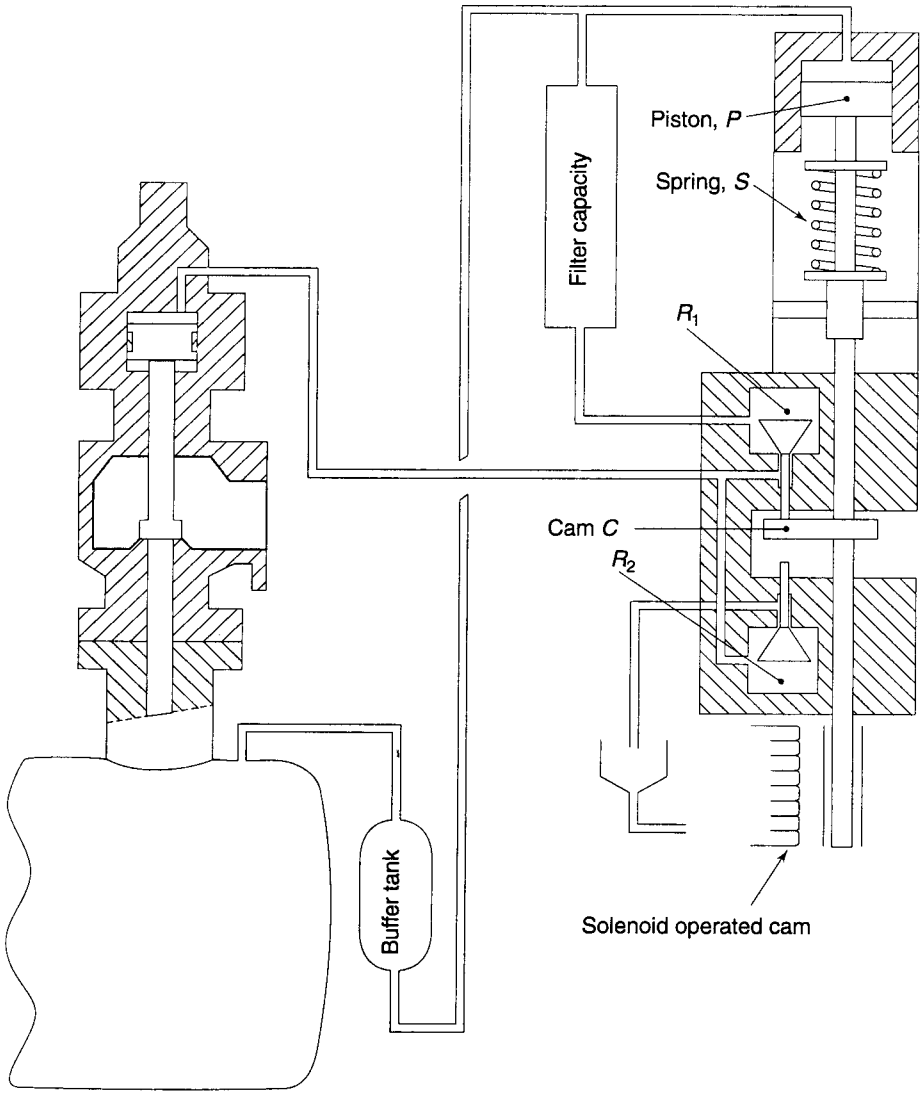


Fig. 4.29 *Pilot system for a single valve.*
Source: PVP-Vol. 236 (PERPINT)/ASME Publ./P-49 to 60 (Reproduced with kind permission of Andre Gemignani, General Manager of SEBIM

ing oscillations due to the discharge of incompressible fluids are inhibited.

3. The installation of a 3-way solenoid valve or the solenoid operated cam depicted in Fig. 4.29 permits the valve to be opened remotely be electrical signal and thus provides a relief function.

Q. *What is POSR tandem valve?*

Ans. It means two POSRVs operating in series.

The upstream valve is the safety valve (SV) set at the system overpressure protection level. The second, downstream valve is the redundant safety valve (RSV). (see Fig. 4.30)

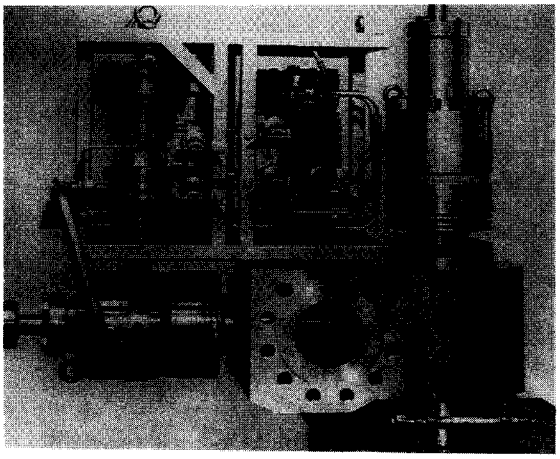


Fig. 4.30 *High temperature tandem valve and pilot.*
Source: *PVP-Vol. 236, ASME Publ. (Reprint)/ P-59*
Courtesy: *SEBIM*

Q. *Why is such a tandem valve installed in PWRs?*

Ans. The objective is to enforce extra safety. If the upstream valve fails to close then the system pressure would fall and, at a pressure above that at which nuclear boiling occurs, the downstream valve will close. The possibility of either valve failing to open when called upon to do so is guarded against by having three parallel discharge lines each fitted with a tandem valve set at sequential opening/closing pressures. see Fig. 4.31

The second valve acts as the Back-up Safety Valve.

Q. *What are the basic constructional features of the main valve in the circuit shown in Fig. 4.29?*

Ans. The piston of the main valve is constructed of stainless steel and sports graphite and elastomer piston sealing rings.

A weak spring maintains contact between the piston operating rod and the valve disc and holds the disc on the seat at low system pressures. The system lift pressure on the safety valve (SV) with zero piston pressure is about 7 bar. The cyclinder is fitted with an extensive array of cooling fins and thermal barriers are interposed between the cylinder and the valve body.

The bellow is an integral part of the disc assembly and isolates the working fluid from atmosphere.

Q. *What are the constructional features of pilot valves R_1 and R_2?*

Ans. Basically they are spring- loaded autoclave ball valves in which the seat moves under the action of the operating cam.

Q. *What are the potential discharge duties that the SV of the primary circuit of a PWR has to perform following a primary circuit overpressure incident?*

Ans.

1. Water followed by steam discharge
2. Water discharge
3. Steam followed by water discharge
4. Hydrogen effects
5. Post-accident pressure relief.

Q. *What is the effect of 'water followed by steam discharge'?*

Ans. If it is necessary to fit a hydrogen loop seal then at each first lift of the SV piston, about 10 litres of cold condensate from the loop seal will be discharged followed by saturated steam. Thus the complete valve suffers a thermal shock and at each change of direction of the fluid inside the valve, transient mechanical shocks are experienced by each component in the flowpath.

Source: *Development and Application of Pilot Operated Safety Relief Tandem Valve for Nuclear Powerplant—D.R. Airey and A. Gemignani et. al. (PVP-Vol. 236 (Reprint), ASME Publ.*

Courtesy: SEBIM

Q. *What is hydrogen effect?*

Ans. If significant excess quantities of hydrogen are present in the pressurizer, then the hydrogen may stratify above the steam under the action of

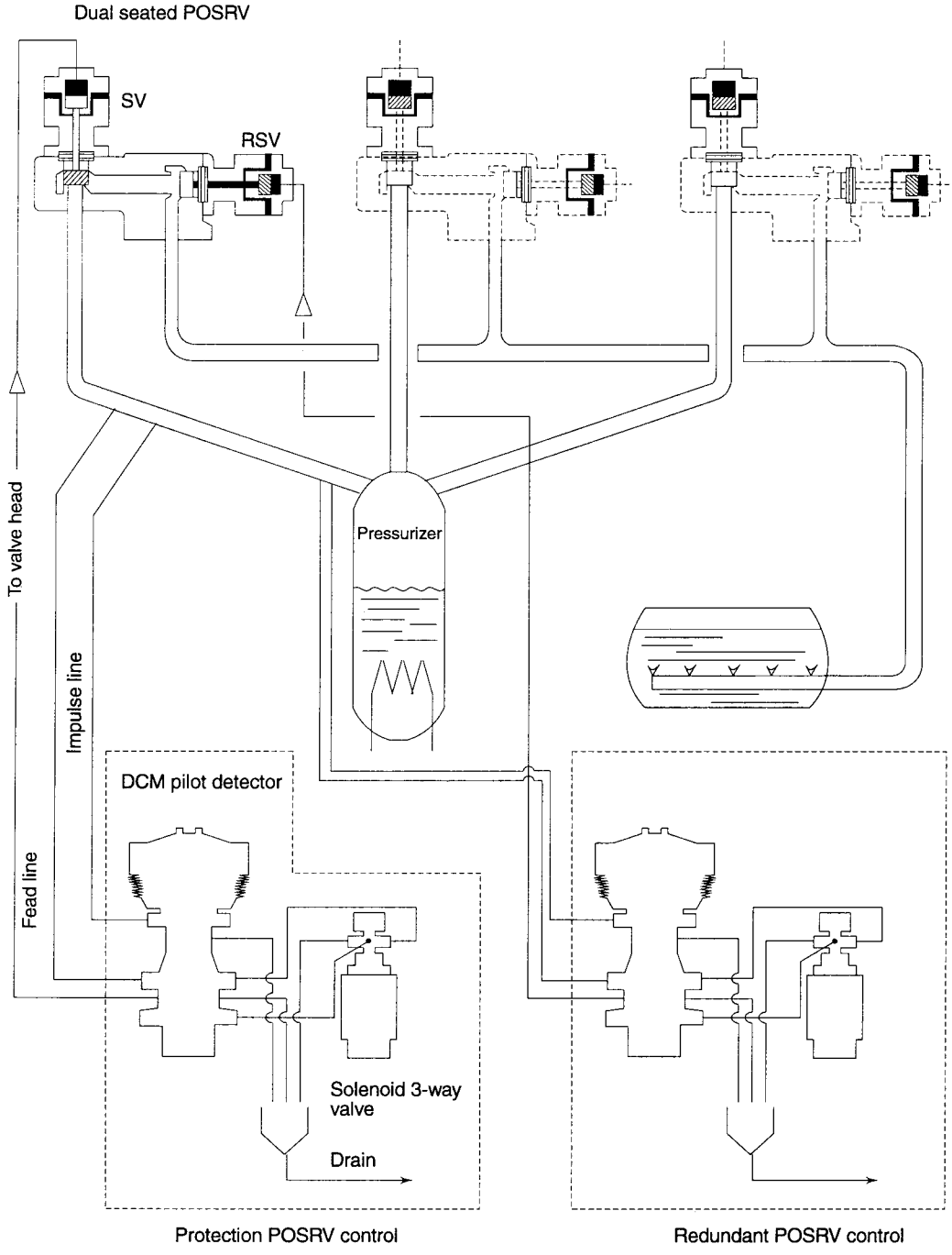


Fig. 4.31 *POSRV tandem installation with DCM pilot.*
Source: *PVP-Vol. 236, ASME Publ. (Reprint)*
Courtesy: *SEBIM*

bouyancy forces. Thus the valve may experience a sequence of discharge phases:

first incompressible cold water
second high velocity hydrogen
third lower velocity steam

Since the internal valve components downstream of the SV are initially exposed to the conditions in the reactor coolant drain tank, low pressure incondensible gas and water vapor, then the valve as a whole can experience three thermal and mechanical transitions during a single lift.

Source: PVP-Vol. 236

Courtesy: SEBIM

Q. *How can the problem be overcome?*

Ans. It requires modifications of the pilot detector assembly as well as the main valve.

Q. *What are the modifications of pilot detectors carried out?*

Ans. The SEBIM Group, France, replaced their erstwhile pilot detector with a DCM pilot detector (Fig. 4.32) that embodies the following modification features

1. The helical spring in the earlier design is replaced by a Bellville diaphragm spring
2. The pilot piston and its elastomer seal are replaced by a flexible metal bellows
3. R_1 and R_2 valves are combined in a seat/ball/tube arrangement
4. At the bottom of the assembly a further metal bellows piston, disc and seat (secondary pilot), are added to ensure large pilot flowrates for large valves.

Q. *How does this DCM pilot detector operate?*

Ans. As the system pressure increases, it forces the upper piston up against the Bellville spring and eventually it overcomes the spring force and allows the tube and ball to move upwards.

When the ball reaches the seat, it becomes equivalent to closing R_1—the isolation pilot in the erstwhile design (see above). With further increase of pressure the tube separates from the ball (equivalent to opening of R_2 of the erstwhile pilot) and the fluid above the piston then escapes to the drain. The lower piston moves downwards and isolates the supply and drains the fluid above the main valve piston. A further method of operating the lower piston is to actuate the 3-way solenoid valve (Fig. 4.32).

Q. *What advantages does this DCM design have as regard to over-pressure incident in the primary circuit of PWR?*

Ans. The erstwhile pilot operated safety valve suffered from four main bottlenecks in case of nuclear incident

1. Upper temperature limit was restricted to 423°K by the pilot components and the main valve piston seals.
2. The pilot was not capable of accommodating higher flowrate.
3. The number of components in the complete valve and the pilot were too many.
4. The main valve mass flowrate must be enhanced to meet the safety requirements of higher capacity PWRs.

Using metal bellows pistons and static C-ring or moving graphite seals, the upper pressure limit of the DCM pilot is staggeringly 180 bar with an ultimate temp. limit of 832°K. This allows operation on steam or other high temperature fluids.

The number of components has been significantly reduced (by 67%) compared to the erstwhile design and short rigid pipes now connect the pilot unit to the valve body.

Large medium operated valves have large swept volumes and this together with small orifice pilots leads to unacceptably long operating times. The provision of a secondary high flowrate pilot has overcome this difficulty.

Q. *What are the principal modifications that have been carried out on the main valve?*

Ans.

1. Provision of increased nozzle diameters

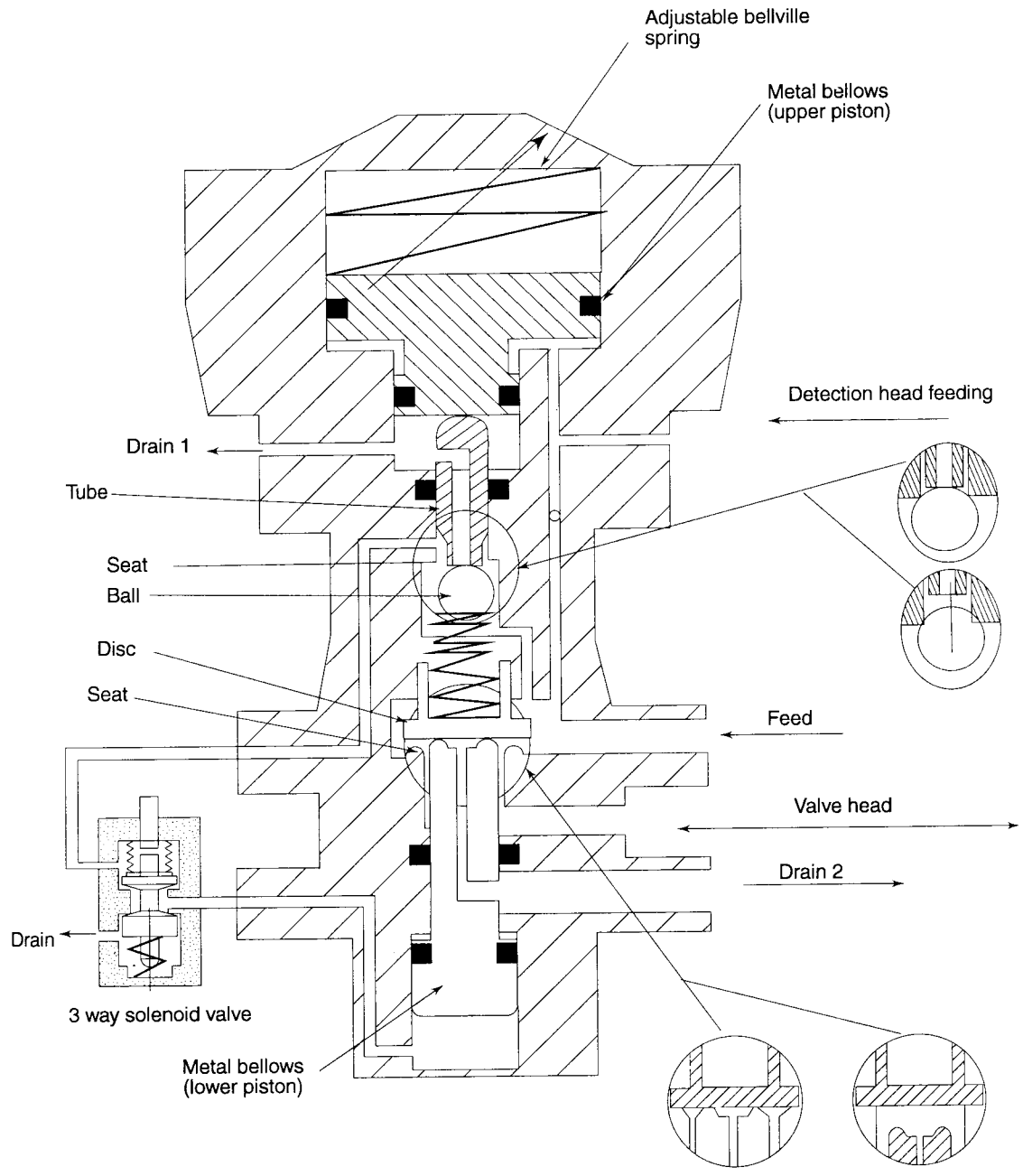


Fig. 4.32 *DCM Pilot Detector.*

Source: PVP-Vol. 236 (ASME Publ.)

Courtesy : SEBIM

2. Improved hydraulic flowpaths
3. Optional double exhaust ports
4. A flexible disc seal replacing the seal of the earlier design.

Q. *What are the effects of such modifications?*

Ans. The first three modifications have increased the mass flowrate by 30% over the earlier design.

The last one has made the valve capable of continuous operation at temperatures 823°K.

Q. *What is the operating principle of the Pilot Operated Safety Relief Valve (POSRV)?*

Ans. Shown in Fig. 4.33 is the series DC pilot detector of SEBIM Group.

It operates three basic functions needed to operate a pilot-operated safety relief valve.

Function A: Pressure detection head (DT) detects and compares with set-pressure the fluctuations of pressure inside the equipment being protected.

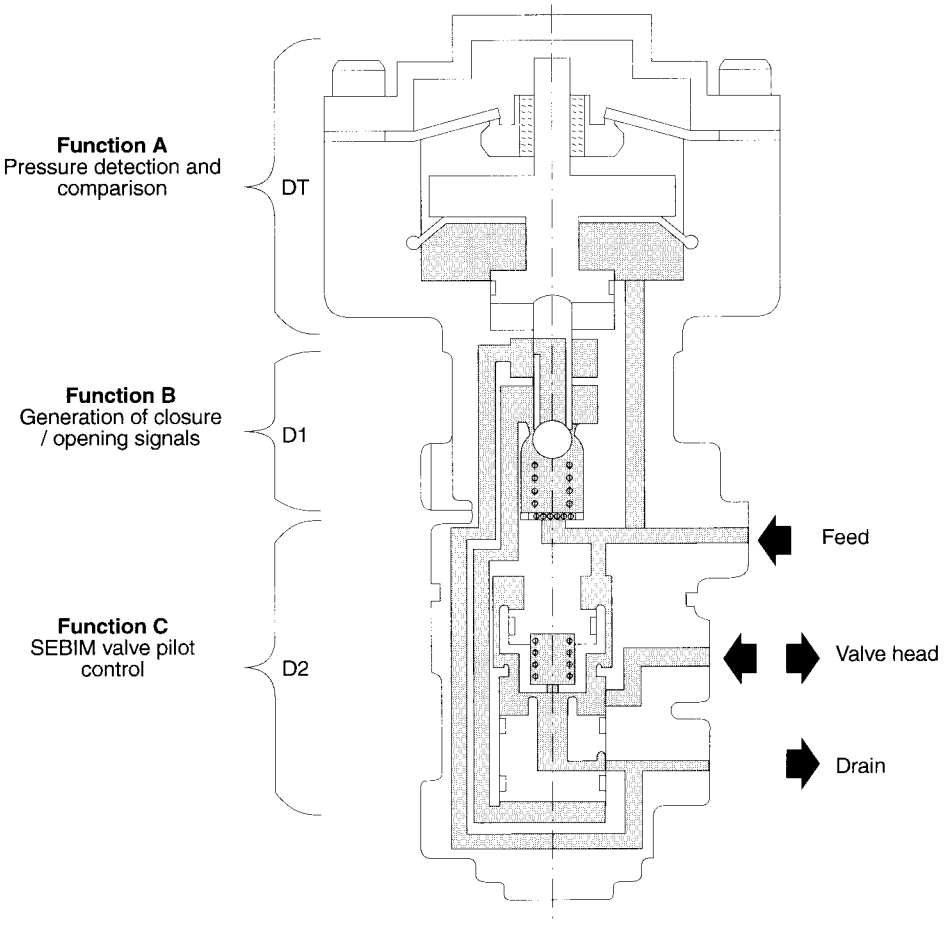


Fig. 4.33 *Pilot detector (DC series of SEBIM).*
Courtesy: SEBIM
Source: D.2.85.11 (SEBIM Bulletin)

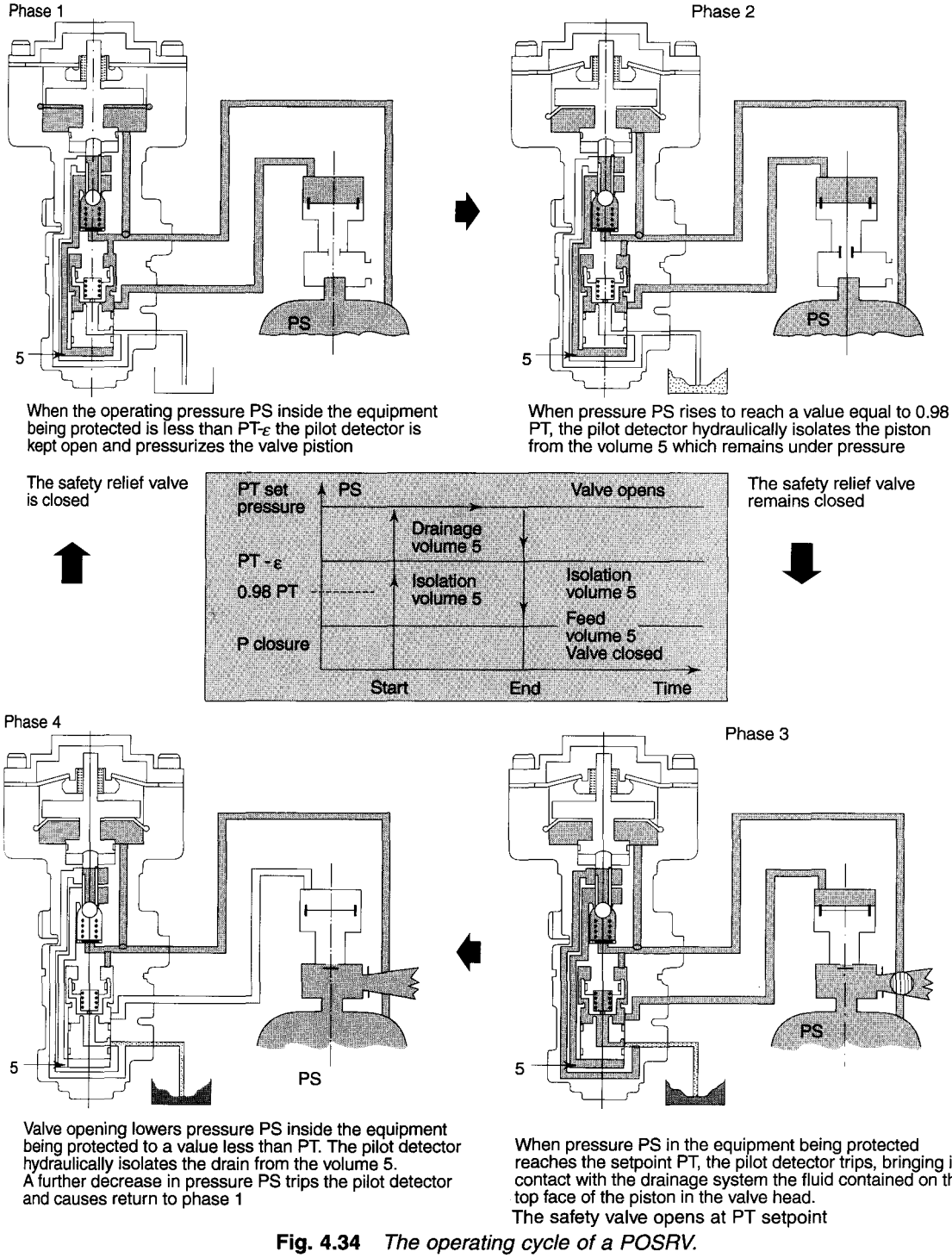


Fig. 4.34 *The operating cycle of a POSRV.*
Source: Pilot Detectors (D.2.85.11)
Courtesy: SEBIM

Function B: Control distributor (D1) generates OPEN/CLOSE signals based on the pressure level inside the equipment being protected

Function C: Power distributor (D2) distributes to the safety relief valve the motive fluid necessary to keep it in the CLOSED position and removes the fluid to keep it in the OPEN position.

Q. *What is the operating cycle of such a POSRV?*

Ans. The operating cycle completes in 4 stages as presented in Fig. 4.34.

Q. *How are these pilot detectors commercially codified?*

Ans. The standard of condition of an internationally renowned company (SEBIM, Chateauneuf-less-Martigues, France) manufacturing pilot detectors and SRVs is given below:

Q. *What is DCS?*

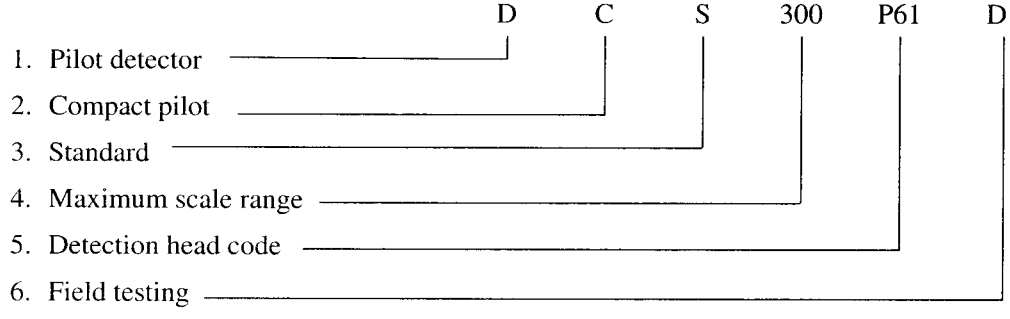
Ans. It is standard compact pip action and non-flowing pilot (Fig. 4.35).

Q. *What are the characteristics of DCS pop action pilot?*

PILOT DETECTOR COMMERCIAL CODIFICATION

1. **Category of equipment**
   D Pilot detectors
2. **Type of equipment**
   C Compact pilot
   M French Navy pilot
   N Nuclear pilot
3. **Construction**
   S Standard temp. < 200°C
4. **Maximum Scales**
   15 (3 to 15 bar)
   300 (15 to 300 bar)
   Example of codification
5. **Detection head code**
6. **Accessories**
   A No accessory
   B Manual Control pushbutton
   D Field testing
   E Electrical control*
   F Valve head filter
   T Buffer tank
   M temp. > 200°C
   V Gag
   Z Other accessories

* For this option, voltage type of current and switching specifications must be clearly given.



Source: Pilot Detectors (D.2.85.11)
Courtesy: SEBIM

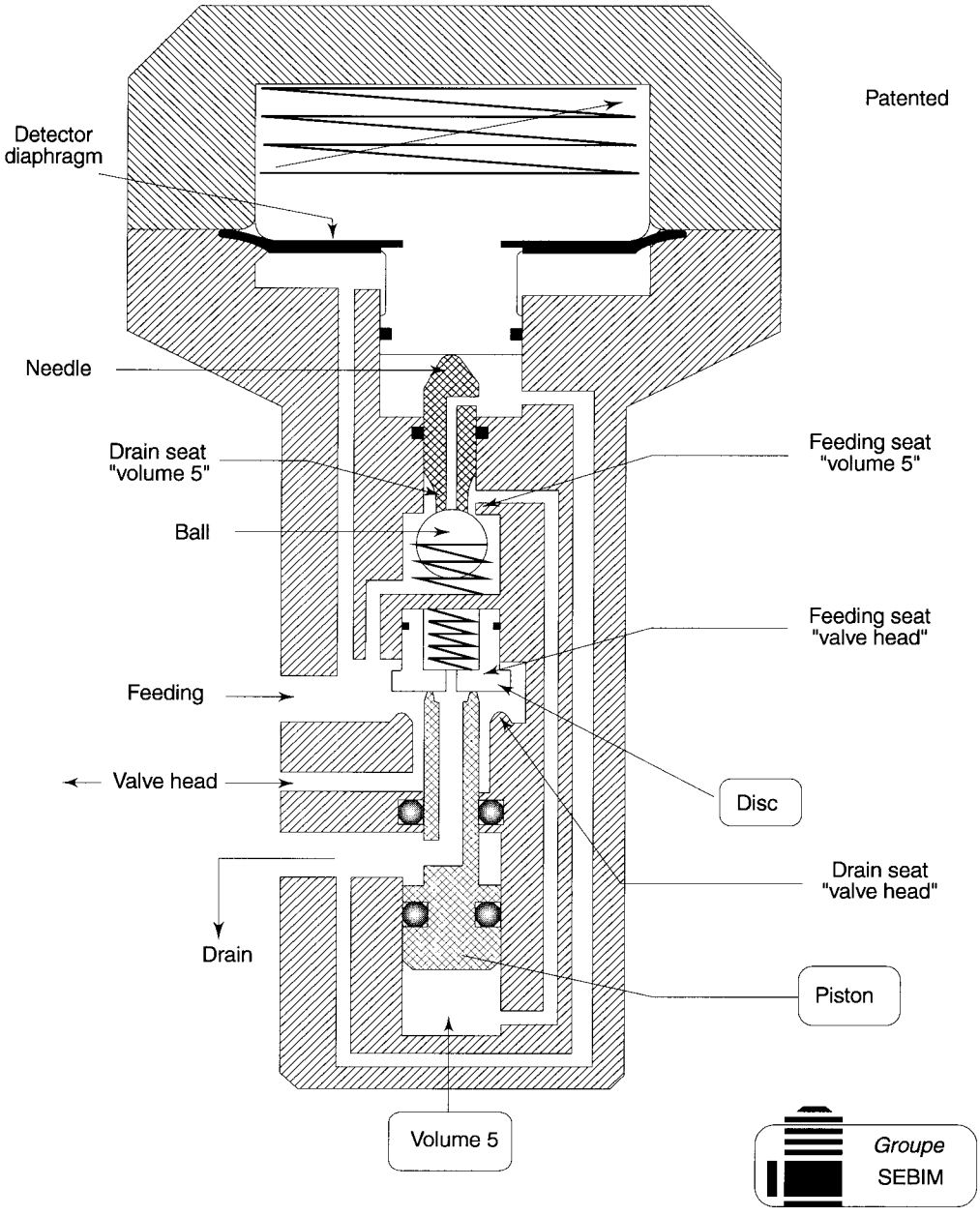


Fig. 4.35 *Pop action pilot DCS.*

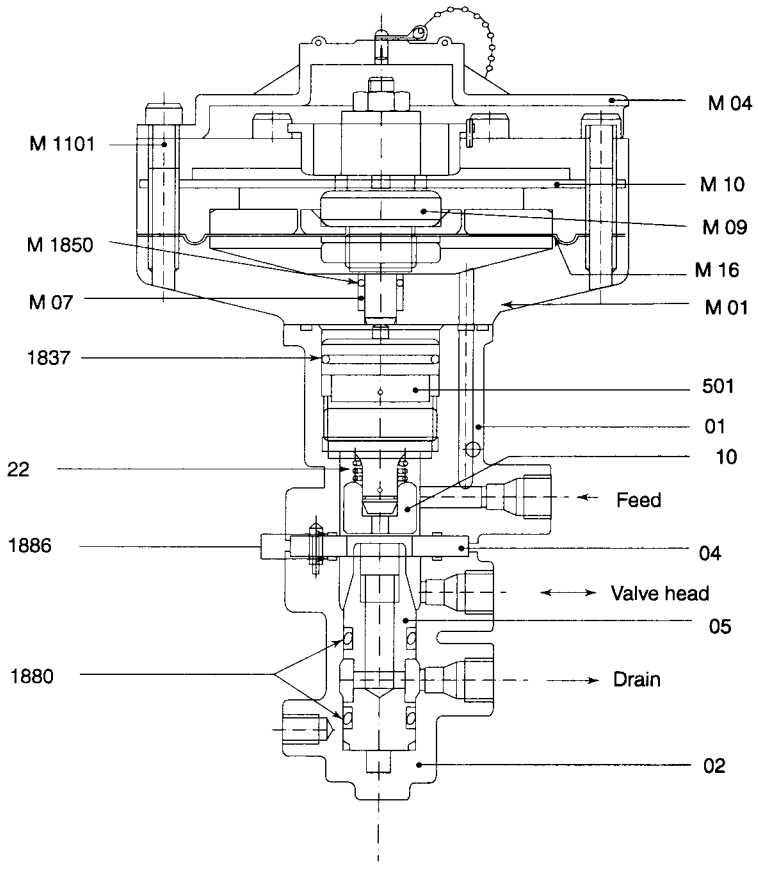
Source: Pilot Operated Safety Relief Valve (RSBD/18108 Vierzon/France)

Courtesy: SEBIM

It comes in two popular models:

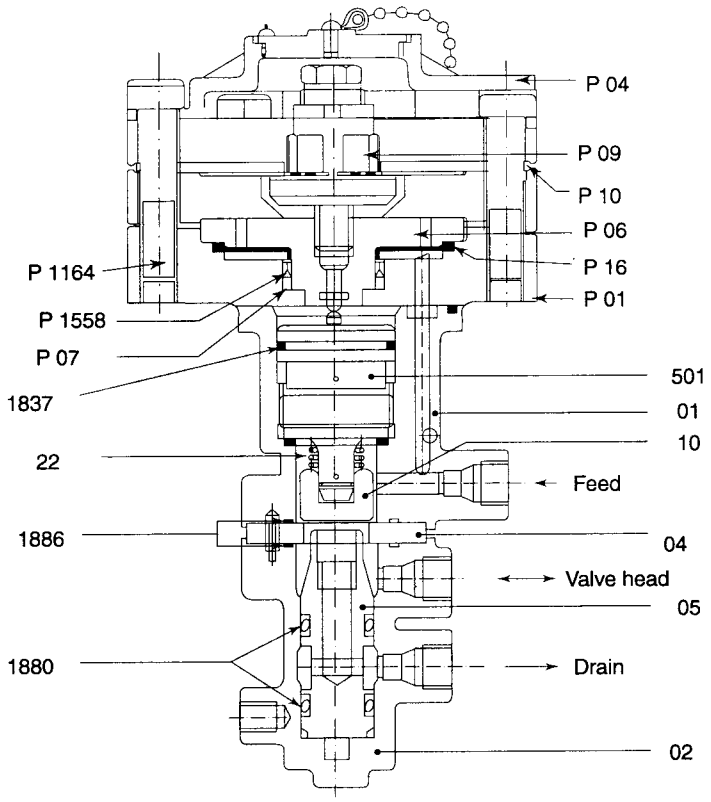
DCS 15 (Fig. 4.36)

DCS 300 (Fig. 4.37)



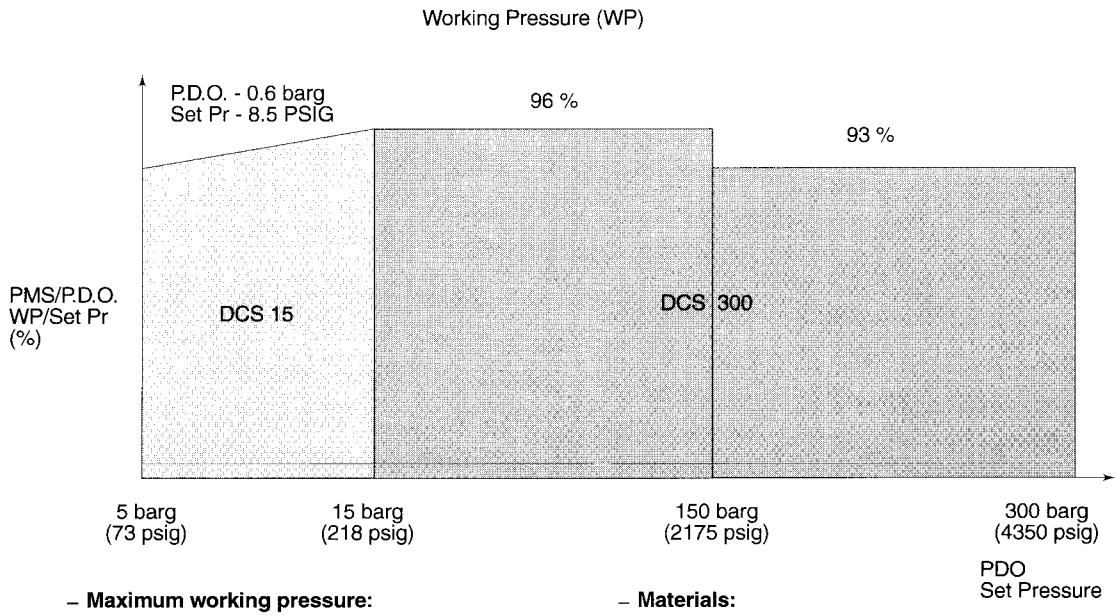
Item NO.	Part	Standard materials grade	UNS or ASTM	NACE MR 01-75	UNS or ASTM
01	Upper body	Z3. CND. 19-10 M		Z3. CND. 19-10 M	
02	Lower body	Z3. CND. 19-10 M		Z3. CND. 19-10 M	
04	Seat	Z6. CND. 17-04		Z6. CND. 17-04	
05	Piston	Z6. CND. 17-04		Z6. CND. 17-04	
10	Disc	NC 19 Fe Nb	UNS. NO7.718	NC. 19 Fe.Nb.	
22	Spring	Z10. CN.18-09	302	Inconel 600	
501	3-way cartridge	Stainless steel	Stainless steel	Stainless steel	Stainless steel
1837	"O" ring	60 C7.372 AC	FPM	60 C7.372.AC	FPM
1880	"O" ring	60 C7.372 AC	FPM	60 C7.372.AC	FPM
1886	"O" ring	60 C7.372 AC	FPM	60 C7.372.AC	FPM
M 01	Detection head	Z3. CND.19-10 M	"	Z3.CND. 19-10 M	"
M 09	Setting nut	Z6.CND.17-04		Z6.CND. 17-04	
M 07	Piston ring	JP 991		JP. 991	
M 04	Protective cover	Z3.CND. 19-10 M		Z3.CND. 19-10 M	
M 10	Spring washer	45.SCD.6	A 401.77	1.725	
M 16	Membrane	60 C7. 372 AC	FPM	60 C7.372 AC	FPM
M 1101	Screw	Z6. CN 18-10	304	Z6.CN.18-10	304
M 1850	"O" ring	60.C7.372 AC	FPM	60.C7.372 AC	FPM

Fig. 4.36 *DCS 15 model.*
Source: Pilot detectors (D.2.85.11)
Courtesy: SEBIM



Item NO.	Part	Standard materials grade	UNS or ASTM	NACE MR 01-75	UNS or ASTM
01	Upper body	Z3. CND. 19-10 M		Z3. CND. 19-10 M	
02	Lower body	Z3. CND. 19-10 M		Z3. CND. 19-10 M	
04	Seat	Z6. CND. 17-04		Z6. CND. 17-04	
05	Piston	Z6. CND. 17-04		Z6. CND. 17-04	
10	Disc	NC 19 Fe Nb	UNS. NO7.718	NC. 19 Fe. Nb.	UNS. No7. 718
22	Spring	Z10. CN. 18-09	302	Inconel 600	
501	3-way cartridge	Stainless steel	Stainless steel	Stainless steel	Stainless steel
1837	"O" ring	60 C7. 372 AC	FPM	60 C7. 372 AC	FPM
1886	"O" ring	60 C7. 372 AC	FPM	60 C7. 372 AC	FPM
1880	"O" ring	60 C7. 372 AC	FPM	60 C7. 372 AC	FPM
P 01	Detection head	Z3. CND. 19-10 M		Z3. CND. 19-10 M	
P 04	Protective cover	Z3. CND. 19-10 M		Z3. CND. 19-10 M	
P 07	Piston ring	JP 991		JP. 991	
P 09	Setting nut	Z6. CND. 17-04		Z6. CND. 17-04	
P 10	Spring washer	45. SCD. 6	A. 401. 77	1.725	
P 16	Membrane	60 C7.372 AC	FPM	60 C7.372 AC	FPM
P 1164	Screw	Z6. CN 18-10	304	Z6. CN. 18-10	304
P 1558	Seal	PTFE	PTFE	PTFE	PTFE

Fig. 4.37 *DCS 300 model.*
Source: Pilot detectors (D.2.85.11)
Courtesy: SEBIM



- **Maximum working pressure:**
  - 98% of the set pressure
- **Blowdown:**
  - Following pressure range:
    - 8.5 PSIG from 73 to 218 PSIG
    - 4 % from 218 to 2175 PSIG
    - 7% from 2180 to 4350 PSIG
- **Overpressure:**
  - Pop action
- **Materials:**
  - All stainless steel
  - Standard Gaskets in VITON
- **Temperature:**
- From –20°C to 180°C (–4°F to 356°F)

Remarks:
- Non flowing POP ACTION
- Pilot for GAS and LIQUID

Fig. 4.38 *Characteristics of DCS Pop action pilot.*
Source: Pilot Operated Safety Relief Valve (RSBD Manual)
Courtesy: SEBIM

Q. *What are the main valves to which DCS pilot detectors are adaptable?*

Ans.

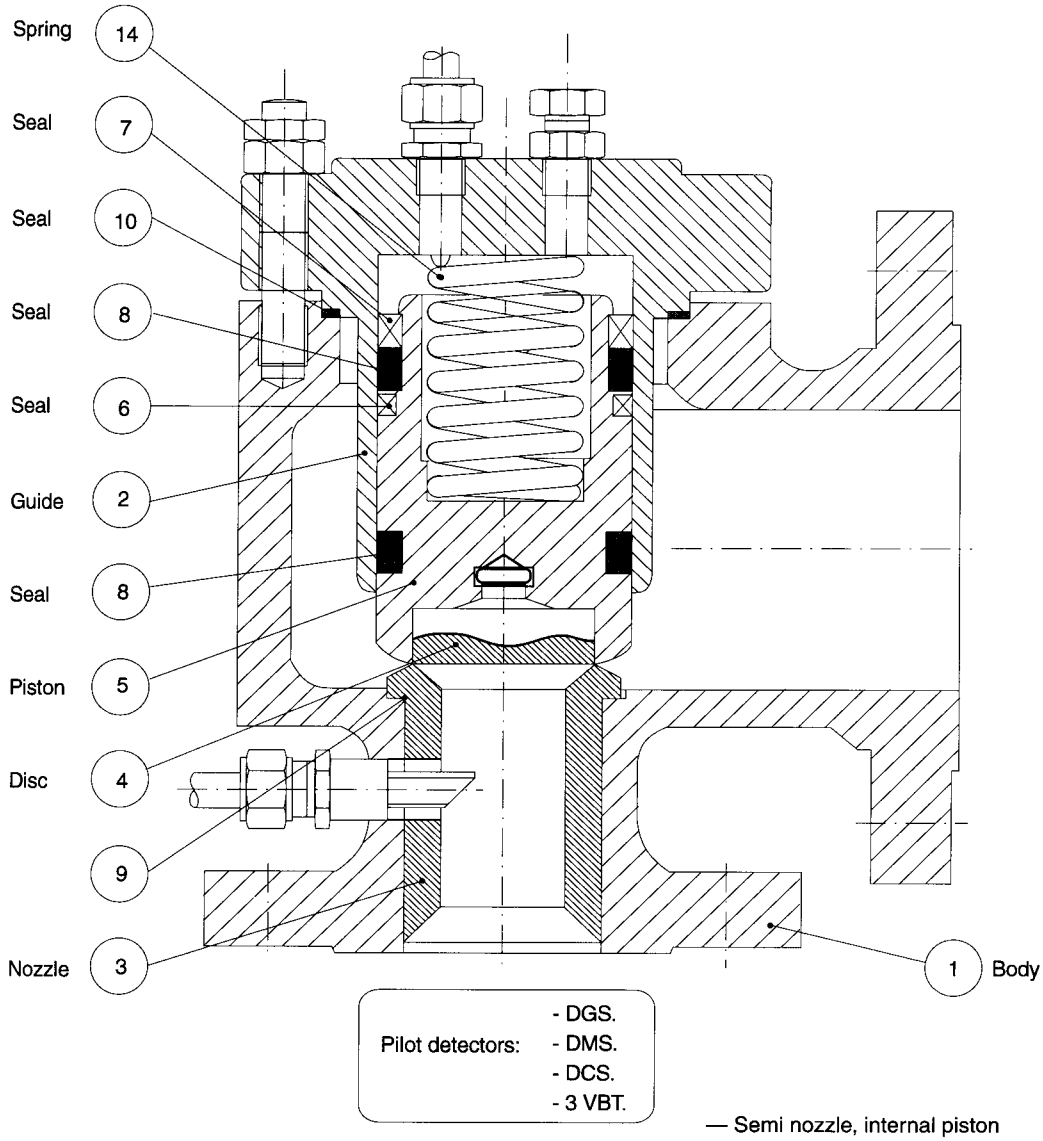
1. Semi nozzle, internal piston type valve of series 75 (Fig. 4.39)
2. Full nozzle, internal piston type valve of series 76 (Fig. 4.40)
3. Full nozzle, bellows piston type valve of series 86 (Fig. 4.41)
4. Full nozzle + flange, bellows piston type valve of series MGD. (Fig. 4.42)

Q. *What is the function of a water-level indicator?*

Ans. To indicate the level of water in the boiler.

Q. *How does it work?*

Ans. It is a vertical hard glass tube (Fig. 4.43) whose upper and lower ends are connected to steam space and water space respectively, with brass tubes. Therefore, the same pressure of steam acts upon the water in the boiler and the water in the gauge glass, which therefore indicates the same level of water as that in the boiler.



— Semi nozzle, internal piston
— Normalized or calibrated orifice area.
— Gas, liquid or steam.
— Temperature: up to 250*C
— Flanges: PN or ANSI.
— Sizes: 1 1/2" × 2" up to 8" × 10"
— Rating: up to 900# dependent on DN.
— Pressure: up to 150 bar.
— Body: Carbon or stainless steel.

Fig. 4.39 *The main valve of Pilot Operated SRV: SERIES 75 (SEBIM).*
Source: Pilot Operated Safety Relief Valve (RSBD Manual)
Courtesy: SEBIM

- Full nozzle, internal piston
- Normalized orifice area (D to T) + extension (B, U, V, W, X)
- Gas, liquid or steam.
- Temperature: up to 250 °C
- Flanges: PN or ANSI.
- Pressure: up to 300 bar
- Sizes, Rating & dimensions:
- Temperature: up to 250 °C in accordance with API-RP-526
- Body: Carbon or stainless steel

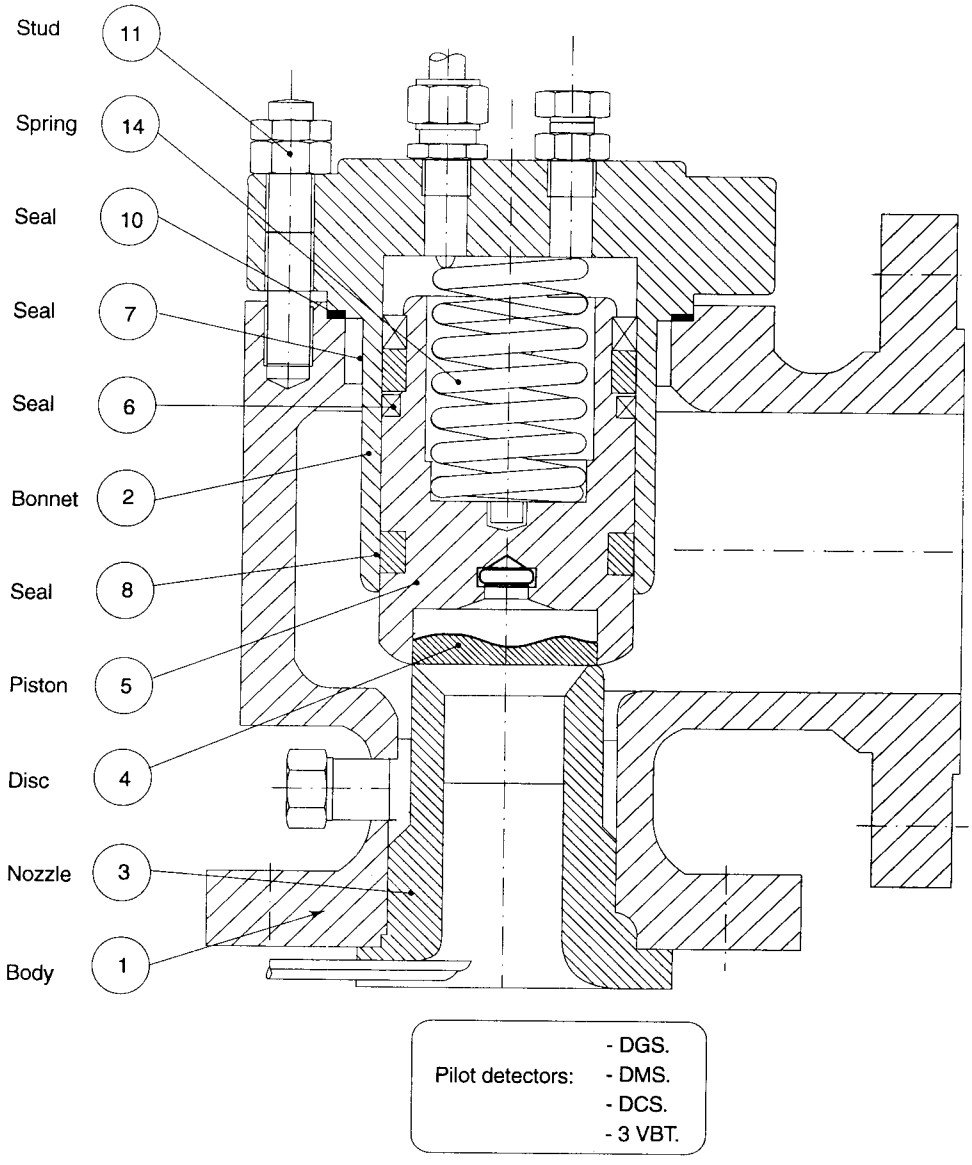
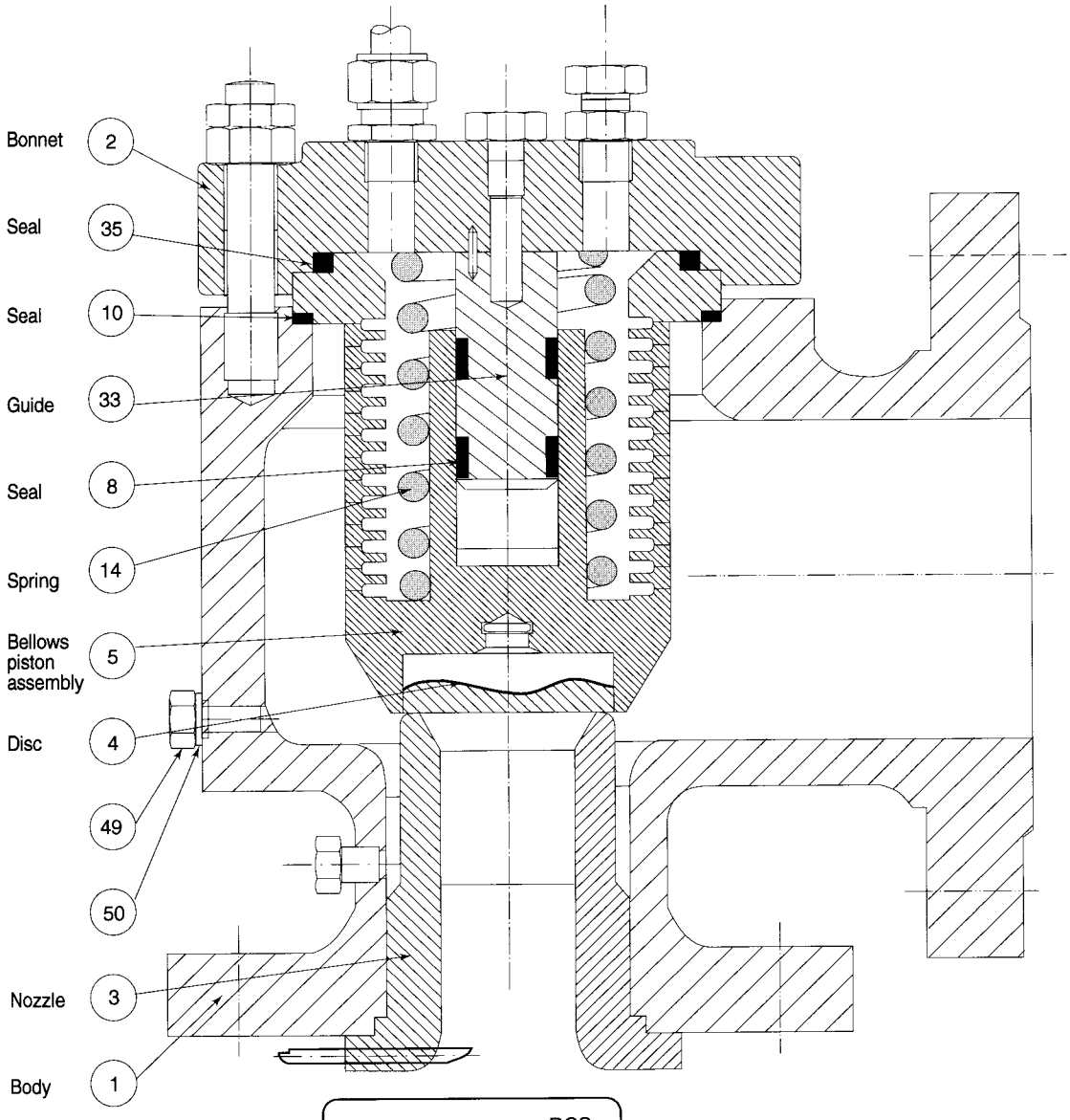


Fig. 4.40 *The main valve of Pilot Operated SRV: SERIES 76 (SEBIM).*
Source: POSRV (RSBD Manual)
Courtesy: SEBIM



Main Valve
- Full nozzle, bellows piston.
- Normalized orifice area (D to T).
- Gas, liquid or steam.
- Temperature: up to 550°C.
- Flanges: PN or ANSI.
- Pressure: up to 300 bar.
- Sizes, Rating & Dimensions: in accordance with API-RP-526.
- Body: Carbon/Stain. st./Cr-Mo.

Fig. 4.41 *The main valve of Pilot Operated SRV: Series 86 (SEBIM).*
Source: POSRV (RSBD Manual)
Courtesy: SEBIM

- Full nozzle + flange, bellows
- Calibrated orifice area.
- Gas or steam
- Temperature: up to 550 °C
- Flanges: PN or ANSI (inlet B.W. possible).
- Pressure: up to 300 bar
- Sizes: 2" × 3" up to 6" × 8"
- Body A217-WC9

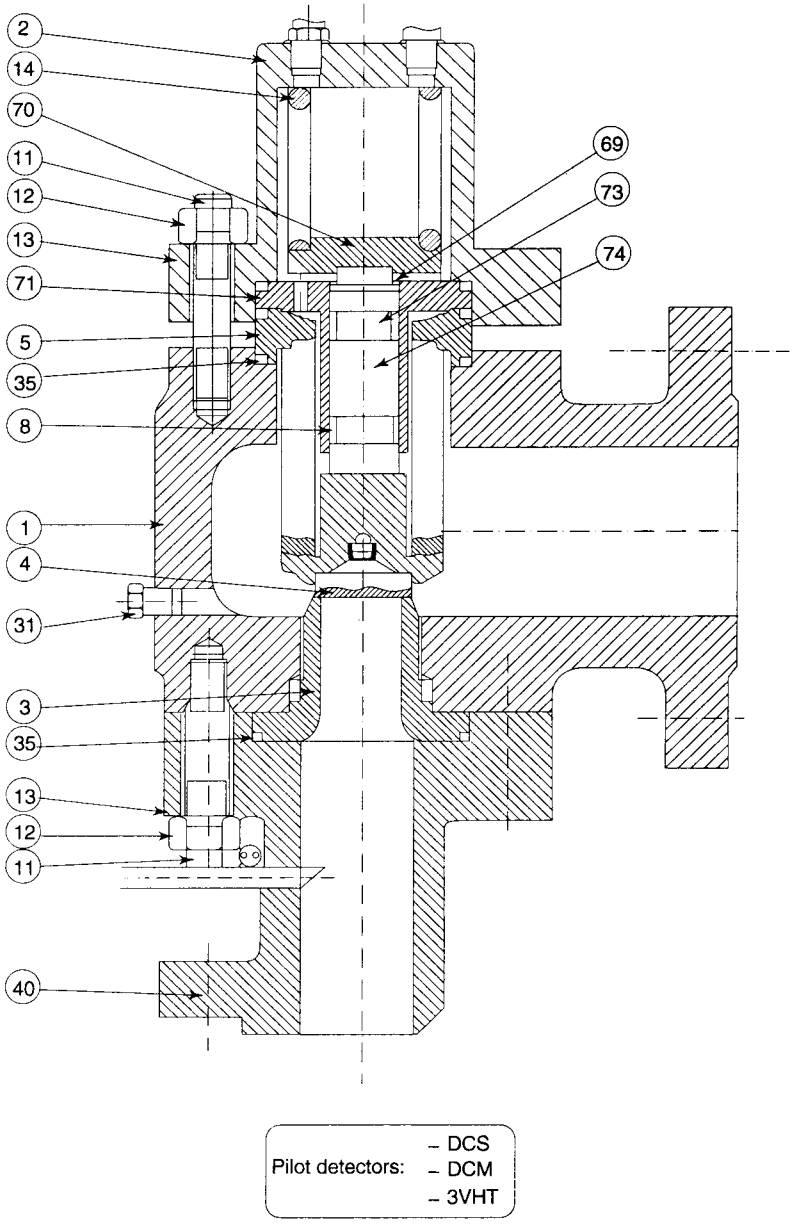


Fig. 4.42 *The main valve of Pilot Operated SRV: Series MGD (SEBIM).*
Source: POSRV (RSBD Manual)
Courtesy: SEBIM

Q. *If the water cock, during operation, is kept open and the steam cock closed, what will happen?*

Ans. Water from the boiler will channel into the gauge glass and fill it indicating a false, high water level in the boiler.

Q. *Why?*

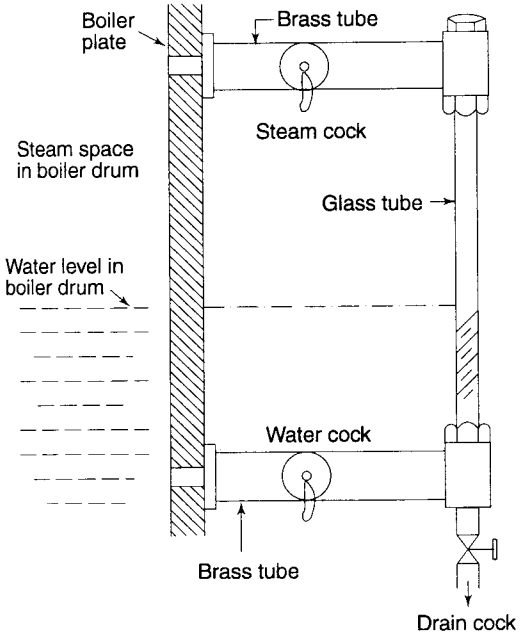


Fig. 4.43 *Water-level indicator.*

Ans. Since there is no steam inlet to the gauge glass, a differential pressure is set up between the water in the boiler and that in the gauge glass. Boiler water pressure being higher, it will force its way up the gauge glass.

Q. *During the line-up of a gauge glass, what will you do?*

Ans. The following sequence of operations is performed

1. Drain cock is opened
2. Water cock is crack opened
3. Steam cock is crack opened
4. Drain cock is fully closed
5. Steam cock and water cock are fully opened.

Q. *What will happen in case of breakage of the gauge glass?*

Ans. The gauge glass is provided with valves which are arranged with steel balls inside such that in the event of any accidental breakage of gauge glass, steam and water will gush forth abruptly and in that process they will position the ball in such a way that flow of steam and water ceases automatically.

Q. *Why is a boiler normally provided with two dependable gauge glasses to work on?*

Ans. If one fails due to accidental breakage, the other one will continue to be in-line and will show the water level.

Q. *Why should the steam connection of the gauge glass from the steam drum not be lagged whereas the water connection of the gauge glass should be lagged?*

Ans. This will keep an all time small flow of condensate through the gauge glass with the effect that the gauge glass will remain active all the time.

Q. *What is the function of a feed check valve?*

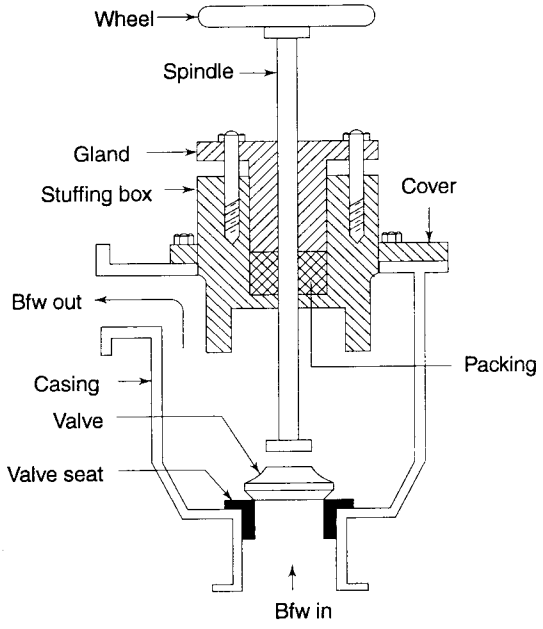


Fig. 4.44 *Feed check valve.*

Ans. To control the flow of BFW from the feed pump to the boiler and to prevent the backflow of water from the boiler to the pump when it is not working or its pressure is less than boiler pressure.

Q. *Where is it fitted?*

Ans. It is placed downstream of the BFW pump and near the boiler end of the discharge pipe.

Q. *How does it work?*

Ans. During normal operation, the valve (Fig. 4.44) is lifted off the valve seat due to the discharge pressure of the water from the pump and that allows water to pass into the boiler. When the pump is stopped, the boiler water at high pressure will rush back and press the valve tightly upon its seat.

Also, the flow can be controlled with the aid of a handwheel that can regulate the lift of the valve by means of a spindle connected to it.

Q. *What is the function of a steam stop valve?*

Ans. To stop or allow the flow of steam from the boiler to the steam pipe.

Q. *What is a junction valve?*

Ans. It is a steam stop valve (Fig. 4.45) mounted on the boiler, at the junction of the boiler and steam pipe, to control the flow of steam from the boiler.

Q. *What is the function of the fusible plug?*

Ans. To prevent the boiler from being damaged due to overheating when the water level falls below the lowest permissible limit in the boiler.

Q. *How does it work?*

Ans. A bronze plug tapered within, it is stuffed with an easily fusible alloy and is mounted on the head plate of the boiler. (Fig. 4.46)

Under normal operating conditions, the upper end of the plug is submerged in water while its bottom remains exposed to the boiler furnace located immediately below the plug. If the water level falls to expose dry the top surface of the plug, the fusible material will melt due to high temperature and steam will gush out of the plug hole into the boiler to extinguish the fire, or will let out a sound of warning to the boiler attendant to expedite action.

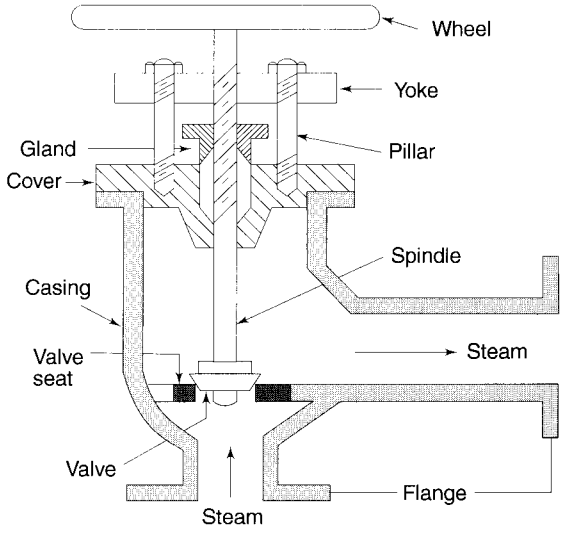


Fig. 4.45 *Junction valve.*

Q. *For what purpose is a blow-off cock fitted?*

Ans. It is imperative to empty the boiler periodically for cleaning and inspection. It is for this purpose that a blow-off cock (Fig. 4.47) is fitted. It will let out any sediment along with a portion of BFW when it is opened.

Q. *Where is it fitted?*

Ans. It is fitted directly to the boiler shell or to a pipe connected with the boiler.

Q. *What is the utility of a fusible plug?*

Ans. It is a safety device installed in almost all firetube boilers at the lowest safe water level in the boiler drum. If the boiler water level goes below this level, the fusible plug of tin will melt (at 560°K) and allow steam to pass through making a warning noise for low water level.

Q. *Why are all-welded boilers now preferred to rivetted boilers?*

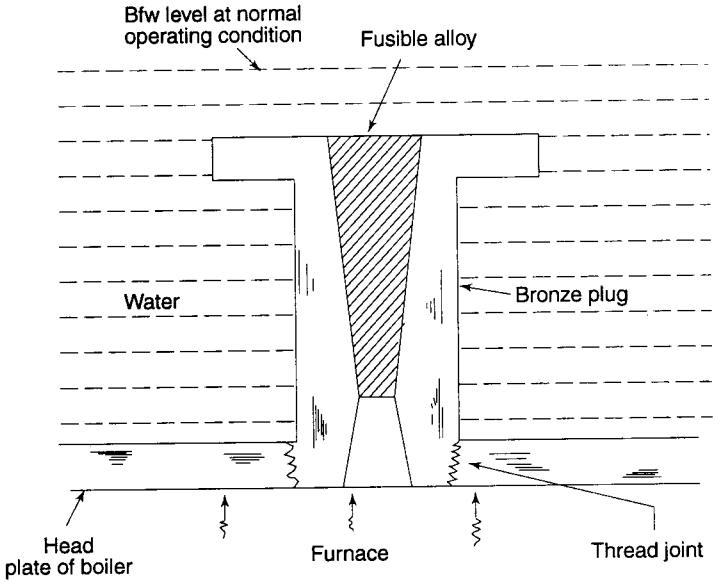


Fig. 4.46 *Fusible plug.*

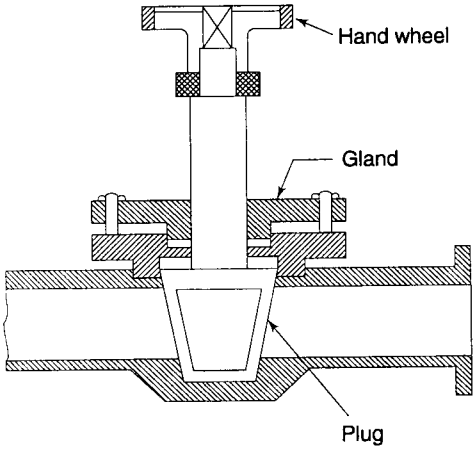


Fig. 4.47 *Blow-off cock.*

Ans. Because of the limitation posed by the ligament—a section of solid plate between rivet/tube holes—rivetted boilers are less favoured. Though ligament efficiency as high as 85% can be achieved in the case of rivetted boilers, welded construction parts have better joint efficiency imparted by improved welding technology and high quality weld rods.

5

BOILER OPERATION INSPECTION AND MAINTENANCE

Q. *What principal characteristics are taken into consideration in describing the operating conditions of boilers?*

Ans. 1. Average efficiency of a boiler for a particular operating period
2. Net efficiency of the boiler at rated load
3. Availability factor, i.e. the ratio of operation time and reserve time to the calendar time
4. Operation factor, i.e., the actual operating time of the boiler to the length of the calendar time (month, year) considered
5. Capacity factor which is the ratio of the total steam generated during operation time to the probable steam generation during calendar time at the rated steam generation capacity
6. Average and maximum time of a campaign (i.e. the operating time to failure)

Q. *What do you mean by boiler failure?*

Ans. It refers to any incident that disturbs the operating ability of a boiler.

Q. *When is the boiler expected to have the highest values of the indicated characteristics?*

Ans. Boiler operating in base regime.

Q. *What do you mean by a monobloc unit?*

Ans. The boiler and the steam turbine taken as a whole are called a monobloc unit.

Q. *What do you mean by manoeuvrability of monobloc units?*

Ans. This concept includes
1. start-up and shutdown characteristics
2. operating load range
3. the dynamic properties
4. the characteristics at sudden surging of load and load-sheddings.

Q. *What do you mean by load control range?*

Ans. It is the load range in which the automatic control system of the boiler responds quickly to the load variations without the interference of the operating personnel.

In this range, the number of burners in line is not changed nor is any adjustment made of automatic regulators, and the composition of the automatic auxiliary equipment remains the same.

Q. *What is the allowable load range?*

Ans. It includes loads right from the lowest load at which the boiler can function steadily to the load at the lower limit of control range.

Q. *How does the load vary in this range?*

Ans. It varies slowly.

Q. *What changes are effected during load variation in the allowable load range?*

Ans. 1. Change of composition of the auxiliary equipment

2. Change in the number of burners in line
3. Some automatic regulators are switched off.

Q. *What is the steady regime of boiler operation?*

Ans. In this region the steam parameters vary insignificantly at any load.

Q. *What is the unsteady regime of boiler operation?*

Ans. In this region load variation and fluctuation of steam parameters occur due to internal or external disturbances.

Q. *Which factors are responsible for internal disturbances?*

Ans. Variation in

1. flowrate of BFW
2. temperature of BFW
3. fuel consumption rate
4. combustion air flowrate, etc.

Q. *Which factors cause external disturbances?*

Ans. Variation in

1. steam pressure in the steam main
2. load of the turbo-alternator
3. the degree of opening of start-up & shut-down device.

Q. *What do you mean by the acceleration characteristic of a boiler?*

Ans. It is a characteristic by virtue of which the boiler is able to change its load quickly.

Q. *What are the principal types of boiler shutdown?*

Ans.1. Emergency shutdown
2. Shutdown for repairing jobs with cooling of the whole or part of the boiler unit
3. Shutdown for repairing jobs or to reserve without cooling of the boiler and steam pipelines.

Q. *In which cases must a boiler be shutdown immediately?*

Ans.1. Explosion in the furnace damaging the brickwork or pressure parts
2. Flame extinction in the furnace
3. Deformation of pressure parts that might invite explosion and endanger the operating personnel
4. Failure to ensure reliable boiler operation because of bad visibility, fire and danger of explosion
5. Non-permissible rise of superheated steam temperature
6. Failure of feed pumps
7. Failure of both water-level gauges for drum type boilers and feedwater flowmeters for once-through boilers.
8. When the water level in the drum drops below the safety mark or in the case of once-through boilers, the supply of feedwater is interrupted for more than 30s
9. Rupture of tubes in the water-steam path
10. Fuel burning on the heat recovery zone. This is accompanied by abnormal rise of temperature of the flue gases
11. Inadmissible pressure drop of gas or fuel oil behind the control valve
12. When there is no steam flow through the steam reheater.

Q. *What do you mean by normal shutdown to hot standby?*

Ans. It is the normal shutdown for a relatively short spell of time while maintaining the existing pressure and temperature conditions substantially.

Q. *What procedure is adopted, over and above the normal shutdown, for this purpose, in the case of pulverized fuel fired drum type boilers?*

Ans. The normal shutdown procedure is followed, except for the following

1. Drum pressure should not be reduced in line with unit load reduction
2. Water level should be kept in sight in the gauge glass. Whenever water-level drops out of sight fresh make-up is to be taken to restore the water level in the gauge glass

3. Hot air shut-off gate valve should be closed as each pulverizer is taken out of service. When the coal-air temperature drops to 45°C, the pulverized coal feeder is stopped. The pulverizer is to be run until empty and then stopped.
4. ID and FD fans are to be kept in line at least five minutes at 30% air flow, after all fires are out, to purge the unit
5. All gas ducts, secondary air duct and windobox dampers are to be closed

Q. *What procedures are adopted in the case of a pulverized coal fired drum type boiler for normal shutdown to cold?*

Ans. 1. Load on the unit is gradually reduced and so is the firing rate
2. Steam temperature control, combustion control and feedwater control are put on auto till a point is reached when these are switched over to 'manual' for better control
3. When the feeder rating on pulverizers is dropped below 50%, stabilizing fuel oil guns are put in line
4. The pulverizers are taken out of service when the minimum rating is reached. The pulverizers are run for two minutes to get totally empty.
5. The second pulverizer is taken out of service when the feeder rating on this pulverizer reaches 40%
6. Soot blowers are put in line
7. Along with fuel reduction air flow is reduced to and maintained at 30% of the maximum
8. As the load is being reduced, expansion movement of the unit is checked
9. When the last pulverizer is taken shutdown, fuel oil guns are removed from service
10. As the unit goes off line, the superheater outlet vents and drains are wide opened
11. Desuperheating isolating valves are closed
12. ID and FD fans are kept in line for five minutes at 30% air flow to purge the unit after the fires are extinguished.

Q. *What steps should be taken in case an emergency fuel trip occurs in the pulverized coal fired boiler?*

Ans. 1. The system should be purged with air for five minutes with air flowrate at pre-trip value
2. If during the fuel-trip, the oil guns were in line, they should be checked to ensure complete closure of individual nozzle shut-off valve.
   The oil guns are retracted, removed, cleaned and reinstalled.
3. If pulverizers were in line during the fuel-trip, all pulverizers are to be emptied of coal.

Q. *In which cases does the water level fall out of sight of the water gauge?*

Ans. 1. Failure of the BFW supply.
2. Momentary fluctuations due to extraordinary changes in load.
3. Neglect of the operator.

Q. *What may happen due to low water in the boiler?*

Ans. It may be anything from leakage to explosion. Of course, it depends greatly upon the type of boiler, the rate of combustion and just how low the water level is.

Q. *If you find the water level cannot be restored immediately, what will you do?*

Ans. 1. All fuel supply should be cut off immediately
2. All steam being discharged from the unit should be shut off
3. High air flowrate is to be maintained to cool down the furnace quickly
4. Steam pressure is to be reduced gradually, if pressure parts damage is suspected, by opening the superheater start-up drains

5. Inspection and repairing of leaks after draining of the boiler, are to be carried out.

Q. *In the case of high water level what will happen?*

Ans. It may lead to carryover of BFW and cause priming.

Q. *What necessary steps will you take in the case of high water level?*

Ans.
1. Water level is to be brought down immediately by opening the drain valves of the water-wall system
2. Steam generation rate is to be reduced.

Q. *How will you detect priming?*

Ans. It is indicated by rapid fluctuations in the outlet steam temperature.

Q. *What will you do when there are rapid fluctuations in the outlet steam temperature?*

Ans.
1. Rate of steam generation is to be reduced
2. Water level, if abnormally high, is to be reduced
3. Alkalinity and TDS of BFW are to be checked
4. Investigation of the condition of the drum internals, when opportunity comes, is to be carried out.

Q. *How will you detect tube failure in a boiler?*

Ans. Tube leakages, if minor, can be detected by the loss of working fluid from the system.

It can be detected by the noise produced by the leak.

It can also be suspected in case of loss of boiler water chemicals.

Q. *What procedures will you adopt in case a leakage has been detected?*

Ans.
1. Boiler is to be shutdown and cooled
2. Boiler drum is to be drained
3. Inspection and detection of leakages are to be carried out
4. Leaks are to be repaired and leaky tubes may be replaced.

Q. *Why steps are to be taken in case an economizer fails?*

Ans. Boilers having no economizer by-pass are to be shutdown immediately.

For boilers befitted with an economizer by-pass, the by-pass should be taken in line and economizer taken out of service for repairing.

Q. *During steam raising what precautions should be taken for non-drainable superheaters?*

Ans.
1. Temperature of the superheater tubes should not be allowed to exceed the higher allowable limit
2. No abnormal temperature difference between any two parts should be allowed
3. During start-up, the tube metal temperature is kept below the temperature which the tubes attain at maximum designed capacity
4. The firing rate should be controlled to avoid accumulation of condensate in the superheater coils.

Q. *Why is the safety valve of superheater set at a lower pressure than the safety valve of the boiler drum?*

Ans. It is a safety measure to protect the superheater from starvation.

If the safety valve of the boiler drum is set at a pressure lower than that of the superheater, then in case the boiler safety valve blows there will not be adequate steam flow to the superheater. Therefore, the superheater coils will starve.

Q. *What will happen to the superheater in the case of starvation?*

Ans. The superheater coils will get overheated and this may result in warping of tubes or in extreme cases, tube failure.

Q. *What do you mean by boiler load?*

Ans. If refers to the total demand (including radiation) imposed upon the boiler by the equipment and its connecting piping system when there is the greatest requirement (usually at the time of start-up).

Q. *What is net load?*

Ans. This means total load plus other such loads as hot water. This is also inclusive of radiation at design temperature.

Q. *What is design load?*

Ans. It is the net load together with the piping tax.

Q. *What is gross load?*

Ans. It refers to the design load and pickup allowance combined.

Q. *What do you mean by boiler rating?*

Ans. It refers to the manufacturer's stated capacity of a boiler capable of handling the boiler load.

Boilers are rated on the basis of catalog heating surface area or by performance test or by both.

Power boilers are rated on the basis of boiler horse power together with a suggested overfiring rate. It is important to note that the catalog heating surface forms the very basis of boiler horse power.

Q. *In which units may ratings be expressed?*

Ans. 1. Equivalent evaporation (i.e. kg of steam generated per hr from and at 100°C)
2. Kg of steam per hour for specified pressure and temperature
3. For utility plants by their turbine capability in kilowatts or megawatts
4. Rate of heat generation (kcal/hr) in the furnace.

Q. *What do you mean by gross boiler output?*

Ans. It is the heat (steam or hot water) available from a boiler working under the limiting conditions specified by the rating code.

Q. *What do you mean by the 'heat available from a boiler?*

Ans. It is the heat output of the boiler, i.e. the total load the boiler will carry.

Q. *Is it the same as the maximum boiler nozzle output?*

Ans. Not necessarily.

Q. *Why?*

Ans. Usually a boiler is capable of greater capacity, which may exceed some of the limiting conditions as imposed by the rating code.

That is why gross boiler output should never be equated to a rating.

Q. *What do you mean by maximum boiler output?*

Ans. This refers to the greatest amount of heat that can be developed at the boiler nozzle for a brief spell. It has no connection to normal operating limitations.

Q. *What is nominal rating?*

Ans. It is the theoretical heating load a boiler is designed to handle. Of course, it does not necessarily indicate the correct boiler rating.

Q. *What is net boiler rating?*

Ans. It is the actual heating load the boiler is capable of handling.

Q. *What parameters are included in this 'actual heating load' that a boiler is capable of handling?*

Ans. 1. All radiation at design temperature.
2. Estimated amount of maximum heat requirement of a connected water heater or other connected apparatus.

Q. *What is piping tax?*

Ans. It is an arbitrary allowance to compensate for the heat losses by a normal amount of insulated piping.

Q. *What is pickup allowance?*

Ans. It is an arbitrary allowance to compensate for the extra load imposed during warming-up periods. That is why it is also called warming-up allowance. For instance, if during the warming-up period, the air inlet temperature is 10°C, then radiation at this temperature has approximately 17.5% greater output than at 18°C.

Q. *What is piping and pickup?*

Ans. This corresponds to the total amount of heat allowed, apart from net load, to provide for piping, pickup and contingencies.

(This is also an arbitrary allowance to compensate for piping, pickup and contingencies, in addition to the net load.)

Q. *How much of the net boiler rating is maintained as piping and pickup allowance?*

Ans. Steel Boiler Institute as well as Mechanical Contractors Association of America have established

Pickup and Piping Allowance

Mechanically fired boilers	➤ 33.33% of net boiler rating
Hand fired boilers	➤ 50% of net boiler rating

Q. *What are ECR and MCR of a boiler?*

Ans. ECR stands for Economic Continuous Rating, i.e. it is the boiler load at which the boiler runs with optimum efficiency.

MCR stands for Maximum Continuous Rating, i.e. it is the maximum boiler load at which the boiler can run without any problem.

Q. *What is the value of ECR in terms of MCR?*

Ans. Generally ECR of a boiler is 75-80% of its MCR.

Q. *In which case—MCR or ECR—the will boiler run with higher efficiency?*

Ans. ECR.

CASE STUDY Boiler Derating

A utility wants to retire its oil-fired D-type water tube boiler [1 MPa; 37.5 t/h] temporarily. It needs a part of the steam capacity now for heating, but would like to drop down to a lower pressure, first to 0.3 MPa, to be on the safe side with this piece of equipment which has some tube corrosion. However, the manufacturer advised against this as the reduced circulation might upset the heat distribution in the boiler causing tube overheating and scaling. Boiler inspectors, too, advised the utility not to go for a pressure conversion.

Nevertheless, the utility wants to derate the boiler down to 0.1 MPa whereupon it will no longer have to be concerned with inspection. Obviously, the volume of steam flow will increase, however, the utility thinks that its steam lines can handle the larger volume flow. It dose not want to buy new boiler capacity now for heating load in case this old boiler can be used.

Q. *What problems will the utility face in case they derate the boiler from 1 MPa down to 0.1 MPa? The boiler is a natural-circulation type. Will forced circulation assist in this switchover?*

Ans. The oil-fired boiler being a natural-circulation watertube type, it sports well-defined water circulation path within the many parallel circuits of the tubes. Since the driving force, in such thermo-siphonic systems, comes from the relative difference in density of the working fluids between the warmer and cooler sections of the boiler, it is this density difference that tends to work against circulation at low pressures. Circulation rate will obviously differ at 0.1 MPa. A pump to assist circulation or an addition of external downcomers would be impractical on the existing set-up.

If the operating pressure is lowered drastically, the following problems may arise

1. The steam volume will become so large that it may choke flow inside the tubes. Chocking results in overheating of tubes which may eventually fail. Even at 0.1 MPa, a sudden tube failure would be serious
2. The boiler will be more likely to prime
3. The superheater may give trouble also in a lowered-pressure situation, because the steam may not divide equally among the elements

4. The safety valve will need a much larger operating area to accommodate the larger volume of steam generated
5. With the same furnace volume and burner-management system, a modulating or 'start-stop' pattern may develop
6. The temperature excursion will tend to accelerate tube scaling and corrosion, especially with reduced circulation
7. Ability to take sudden load swings will be lower at 0.1 MPa than at 1 MPa.

The most practical and economic solution will be to operate the boiler at 1 MPa coupled with a turbine that will act as a pressure reducing valve while lending itself as a prime mover for a fan, pump or compressor.

Another sound alternative, in case the boiler is found or made reasonably sound, is to operate the boiler at 7-8 MPa and use the steam in a heat exchanger to heat up the condensate going back to the boiler. Little makeup and water treatment is necessary.

Q. *What is the peak load of a boiler?*

Ans. It is the maximum load at which the boiler can run for a short period, normally a couple of hours, in a day's service without problems.

Q. *Why has a provision been made for it?*

Ans. To accommodate a sudden increase in load demand over a brief period of time.

Q. *What is overloading of a boiler?*

Ans. It is the running of a boiler at a load higher than its MCR value for a considerable length of time.

Q. *What do you mean by system load?*

Ans. It is the total power produced, at any particular instant, by all the plants of a power generating system.

Q. *What type of units are suitable for base load supply?*

Ans. Large monobloc units operating on supercritical steam parameters usually supply a base load.

Q. *What type of units are suitable for semi-peak and peak-load supply?*

Ans. Subcritical-pressure plants are particularly suitable for this duty.

Q. *Why are subcritical-pressure plants suitable for semi-peak and peak load supply?*

Ans.1. They are well suited for load variations
2. They have faster start-up
3. They require less time to attain the installed load.

Q. *Why are the monobloc units of supercritical pressure not assigned to supply semi-peak and peak loads?*

Ans.1. These steam generating giants have large boilers and heavy metal parts. Therefore, they require a longer time for boiler firing and heating up of pipelines.
2. They consume a greater amount of heat during startup. So it is uneconomical to resort to frequent start-up and shutdown of these units.
3. They are less convenient for control.
4. Since they are high-pressure boilers, their valves and fittings are prone to wear due to frequent load fluctuations and frequent start-ups.
5. These high-pressure boilers have thicker tubes that are more liable to develop high thermal stresses (causing corrosion fatigue) owing to frequent load variations.

Q. *What is the lower limit of the load control range?*

Ans. Operating experience has established the following lower limits of the load control range

Fuel Burned/Boiler Type	*Lower Limit of Load Control Range*
Fuel oil/Gas/High-volatile coal	40–50% of rated load
Lean coal	50–60% of rated load
Slag-bottom boiler	60–75% of rated load

Q. *What is the lowest load for stable operation of a boiler?*

Ans. It is usually 30–40% of the rated load.

Q. *Why is it advisible to select initial steam pressure equal to 13 MN/m^2 instead of 16 MN/m^2, for the operation of a steam turbine?*

Ans. It has been established from past experience that approximately the same economic efficiency characteristics are obtained irrespective of whether the initial steam pressure is 13 MN/m^2 or 16 MN/m^2.

Moroever, the manoeuvrability of the power plants at these steam pressures is roughly the same.

Past experience shows positive results in the operation of steam-turbine plant at a pressure of 13 MN/m^2.

Hence for a manoeuvring power plant it is advisable to select initial steam pressure equal to 13 MN/m^2 instead of 16 MN/m^2.

Q. *For boiler plants operating at semi-peak and peak load conditions the temperature of live and reheated steam is kept in the region of 530–535°C. Why?*

Ans. The tubes for boilers for semi-peak and peak load duty are made of pearlitic steel. For reliable operation under variable load, the temperature of live and reheated steam is kept at 530–535°C.

Q. *Why are austenitic steels not used to enable the tubes to operate a higher temperatures?*

Ans. Austenitic steels are much more expensive (five to eight times) then pearlitic steels. If austenitic steels are used, it will greatly enhance the capital expenditure.

Q. *Why is the lower limit of superheated steam temperature kept at 480-500°C in a thermal powerplant?*

Ans. This is to protect the final stages of the turbine from erosion damage. These stages of the turbine tend to be operated in the wet region of steam expanding through the blades of the previous stages. Water particles striking on the blade profile can cause impingement, corrosion/erosion.

Q. *Should a manoeuvrable boiler unit be compact?*

Ans. A manoeuvrable boiler unit should be compact so that it contains a small mass of metal. With a lower mass of metal, less time is required for start-up and changeover from one thermal mode to another.

Q. *Why are manoeuvrable boiler units usually fuel-oil fired?*

Ans. A manoeuvrable boiler unit should essentially possess the capacity of rapid changeover from one thermal state to another. In the case of fuel-oil fired boilers this basic condition is easily met, as the fuel oil combustion is efficient as well as stable over a wide range of operating loads.

Q. *Why are the convective elements of manoeuvrable boilers made with a horizontal arrangement of tubes?*

Ans. A manoeuvring boiler unit should be drainable for maintenance convenience. This being the case, the tubes the arranged horizontally in the convective heat transfer elements.

Q. *Why is the working fluid in a manoeuvring once-through boiler circulated at high mass velocity?*

Ans. To ensure

1. proper cooling over a wider range of loads
2. reliable operation of a boiler at low loads.

Q. *It is true that the efficiency of a monobloc unit and a thermal power station is a function of the initial steam parameters. What technical difficulties inhibit the possibility of increasing the temperature and pressure of the steam infinitely?*

Ans. 1. The first deterring factor is the availability and cost of the special steels that will operate reliably at higher parameters of superheated steam for prolonged periods.

2. The cost of metal in the superheater and pipelines increases sharply with increase in temperature.
3. For generating subcritical-pressure steam, natural circulation drum type boilers are usually employed. And with the increase of pressure, the driving circulation head decrease so that the highest pressure in the drum is established at 17 MN/m^2 so as to ensure reliable circulation. Therefore, a higher pressure may tell upon reliability.
4. The most deterrent factor in selecting higher steam pressure is the cost of the boiler drum. For a high-capacity drum-type boiler, higher steam pressure means a drum of larger dimension and wall thickness. With the addition of more metal, the cost of the drum mounts. It becomes very heavy and bulky, which presents considerable difficulties in mounting and operating the boiler.

Q. *What are the consequences of overloading a boiler?*

Ans. It will

1. affect the design circulation velocity
2. result in higher flue gas temperature
3. bring about higher superheated steam temperature, that may lead to superheater coil failure by bulging or overheating.

A boiler is never guaranteed for running at overload.

Q. *Why is it not advisable to run a boiler at part load?*

Ans. Constant running of a boiler at part load will cut short its life due to rapid wear and tear.

Q. *What are the effects of running a monobloc unit at derated pressure?*

Ans. If the boiler of a monobloc unit having turbo-alternator in line runs at a derated pressure

1. the pressure of the steam inlet to turbine will be low and that will consequently reduce the output of the turbine. Of course, a steam pressure drop of 5 to 10% will not affect the TA output much
2. the specific volume of steam will increase, but as the boiler and piping design are constant, the rate of steam generation will drop and steam supply will be lower
3. the overall thermal efficiency of the monobloc unit will be less.

Q. *Why is CO_2% in the flue gases measured?*

Ans. To detect whether the fuel combustion within the furnace is complete or not.

Q. *What are the reasons for black smoke emission through the chimney of a spreader stoker?*

Ans. 1. Incomplete combustion of fuel in the furnace and disintegrated carbon particles being released without being completely burned in the furnace.
2. Carryover of coal fines due to excess of its percentage in the coal-feed.
3. Low supply of secondary air that would otherwise complete the combustion.

Q. *Where is the problem of coal segregation encountered?*

Ans. In a stoker fired furnace.

Q. *What is it?*

Ans. Clogging of coal feeder or chain grate due to large size of coal (in the former case) or higher percentage of coal fines in the feed (later case).

Q. *Why does coal segregation occurs?*

Ans. Segregation will occur if

1. coal contains a higher percentage of fines
2. the design of the coal bunker is not proper and the bunker sides are not slopped to 40°–60° for proper rolling of coal-feed
3. the coal size is more than 23 cm.

Q. *Where is the fire slippage encountered?*

Ans. In a stoker fired furnace

Q. *Why?*

Ans. If the quality of coal is poor or if the stoker runs at a higher speed due to overloading of the boiler, the proper combustion of coal may be impaired. Therefore, the arch may get cooled and have less radiant heat, with the effect that the fire gradually advances.

Q. *How will you operate a blow-off valve hooked up in series with a quick opening valve?*

Ans. The quick opening valve should be opened first followed by the blow-off valve.

During closing, the blow-off valve is to be closed first and then the quick opening valve.

Q. *What do you mean by the firing regime of a boiler?*

Ans. Heating the water-steam and gas-air paths, whereupon the process of steam generation sets in and the temperature and pressure of the steam is gradually raised to the specified value. The firing regime is completed when steam is generated at the rated capacity and the steam parameters attain the specified values.

This is also called the start-up regime.

Q. *Does the boiler start-up depend on the normal state of the equipment?*

Ans. Yes.

Q. *How many kinds of start-up are there?*

Ans. 1. Hot start-up
2. Warm start-up
3. Cold start-up

Q. *How are these distinguished?*

Ans. These are distinguished by the length of idle time preceding start-up.

For a monobloc unit

Mode Of Start-Up	*Preceding Idle Time*
Hot	6–10 h
Warm	6–10 h to 70–90 h
Cold	70–90 h

For conventional boilers, the difference between hot and warm start-ups is determined by the preceding idle time of 6–10 h or more, while the difference between warm and cold start-ups is by the loss of gauge pressure in the boiler and the temperature drop of the hottest elements down to 150°C.

Q. *How can the load of pulverized coal fired drum type boiler unit be decreased?*

Ans. 1. Load is gradually reduced on the unit and the firing rate is reduced.
2. If the unit load decreases to a point when the feeder rating on the pulverizers is reduced to below 50% of the maximum, stabilizing fuel oil firing is introduced and one pulverizer is taken out of service as follows:
   (a) The pulverizer coal feeder rating of the selected pulverizer is gradually reduced to a minimum.
   (b) When the minimum rating (approximately 25%) is reached, the hot air shut-off gate valve is closed.
   (c) When the pulverizer coal-air temperature drops to 45°C the coal feeder is taken out of service.
   (d) The pulverizer is run for about two minutes to make it completely empty and then stopped.

Q. *How can the load on the above boiler unit be raised?*

Ans. 1. The load is increased gradually and the firing rate is raised.
2. If the unit load is increased to a point where the feeder rating of the pulverizers in line exceeds 80% of the maximum, then the second pulverizer is taken in line, as follows
   (a) Pulverizer is brought to operating temperature by opening the hot air shut-off gate valve
   (c) Pulverizer coal-feeder is started at minimum feeder rating
   (d) After the coal ignition has been established, feeder rating is increased

until the pulverizer loading equals the other pulverizers in line

Q. *How can the load control of a fluidized bed boiler with inbed tubes be achieved?*

Ans. The air supply and coal feedrate are changed to vary boiler output. Since these two variables define the heat flux to the inbed heat transfer surfaces

$$Q_t = h \cdot A \cdot (T_b - T_t) + \varepsilon \cdot \sigma \cdot A \cdot (T^4_b - T^4_t)$$

it requires that the heat flux, Q_t/A, to the boiler tubes must be varied approximately in proportion to the output

where Q_t = heat transfer to the tubes, W

h = convective bed-to-surface (tube) heat transfer coefficient, W/(m$^2 \cdot$ °K)

A = surface area of tubes in contact with the bed, m^2

T_b = bed temperature, °K

T_t = tube surface temperature, °K

ε = emissivity of tubes

σ = Stefan-Boltzmann constant = 5.667 $\times 10^{-8}$ W/m$^2 \cdot$°K^4

However, for fluidized bed boilers it is essential to maintain the excess air level approximately constant to ensure optimum efficiency throughout the turndown range of the boiler. Therefore, it is evident from the above equation that it would have been particularly convenient if the heat transfer coefficient were to reduce in proportion to decrease in fluidizing velocity. However, h is independent of velocity for the particle sizes used.

Forasmuch as the temperature of the tube metal (T_t) in the bed is usually constant (close to the steam saturation temperature at boiler pressure), it is clear from the above equation that the only means of implementing the require variation in heat flux are

1. Varying the bed temperature within its restricted operating range
2. Varying the area of heat transfer surface in the bed.

Q. *How does the variation of bed temperature ensure load control of a fluidized bed boiler?*

Ans. As stated above, the boiler output can be varied by changing the heat flux to the immersed tubes and this heat flux, Q_t/A, can be altered by changing the bed temperature. For instance it is possible to slash down heat flux by

(a) 50% for superheater tubes at 825°K
(b) 27% for evaporator tubes at 475°K
(c) 23% for LP hot water boiler tubes at 355°K

by varying the bed temperature.

Therefore, the Ist stage of turndown from maximum output is to reduce the air and coal feedrates in proportion, keeping the excess air level constant (to maintain optimum efficiency throughout) and allowing the bed temperature to fall to its minimum value (Fig. 5.1).

This will enable the boiler output to be reduced approximately in proportion to the heat flux to the tube i.e. by about 27% for a boiler with inbed evaporator tubes at 475°K. Obviously, the percentage reduction in boiler output is not exactly the same as that of the heat flux to tubes. This is because the enthalpy of off-gas is also reduced at a lower bed temperature.

The necessity for maintaining a constant excess air level in the combustor puts a lower limit up to which the air supply rate (i.e. fluidizing velocity) can be reduced. This also fixes the minimum acceptable bed temperature below which the bed will subscribe to inefficient combustion and smoke emission. Again if the fuel contains sulphur, the bed is fluidized with the addition of additives [$CaCO_3$; $CaCO_3 \cdot MgCO_3$] to arrest sulphur. This sulphur retention

$$CaO + SO_2 + 1/2\ O_2 \longrightarrow CaSO_4$$

again restricts the bed temperature to between 1075°K and 1125°K. That is, the boiler's maxi-

mum turndown attainable is restricted by the minimum air supply rate and sulphur retention temperature.

Q. *However the measure to attain the maximum turndown by lowering the bed temperature commensurating with the reduction of air and coal feedrates is insufficient for most commercial applications of FB boilers. What is the design modification adopted to out-weigh this deficiency?*

Ans. In order to translate the concept of load variation with bed temperature into practice, the turndown is extended by subdividing the bed into a number of compartments and operating the appropriate number of compartments so as to get a bed temperature within the operating range.

It is not necessary that the compartments should be of equal area. If 73% turndown can be achieved, through bed-temperature variation, in a single compartment (Fig. 5.1) the output range 100 to 73% is achieved with all of the bed area, 73 to 53% MCR with 73% of the bed area, and 53 to 39% MCR with 53% of the area.

Q. *What is the major disadvantage of achieving turndown by varying bed temperature with multiple compartments?*

Ans. The dynamic response of the system is slow. This is due to thermal inertia of the beds. This is particularly more pronounced in the case with deep beds necessary if limestone is used to retain sulphur.

Note: Control techniques are being developed to get acceptable boiler response when using crushed coal to provide rapid combustion response.

Q. *Is there any other important drawback of achieving turndown by varying bed temperature with a multiple compartment system?*

Ans. When reducing the number of compartments in operation there arises the simultaneous need to increase the temperature of the beds remaining in operation from minimum to maximum in order to ensure stable boiler operation. The reverse situation arises when restarting a compartment. However restart-up of a compartment from shutdown-to-hot is relatively easy provided the bed temperature of the compartment has not gone below 975°K since it is possible to simply refluidize and commence coal firing. In case the bed has cooled below 975°K, it becomes necessary to light up the auxiliary burner to reheat the bed to threshold temperature for sustained combustion. This

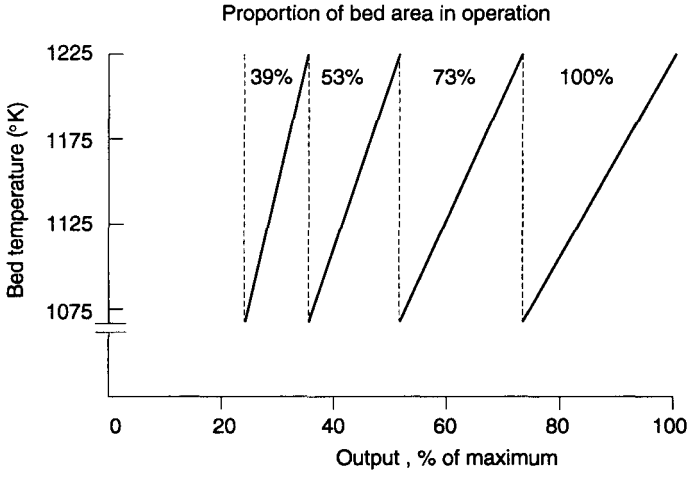


Fig. 5.1 *Turndown with fully immersed tubes at 475°K.*

process takes a certain time, with a consequent delay in increasing output.

Q. *What should be the type and service of the FB boiler to be most suitable for turndown by varying bed temperature with multiple compartments?*

Ans. Boiler load control by varying bed temperature with multiple compartments is most appropriate for boilers which are to be operated for long periods at a steady output. That is the boilers operating on base load duty are the fittest candidates for turndown by altering bed temperature with multiple compartments. These large boilers also lend themselves to compartmentalizing the bed to facilitate fabrication by assembling factory-built modules.

Q. *How can load control be achieved by varying the heat transfer surface in the bed?*

Ans. This is an alternative approach to load control realized through varying the areas of the heat transfer surface in the fluidized bed so that heat transfer to tubes can be modulated while maintaining a near-constant bed temperature.

Variation in the effective heat transfer area can be readily achieved by positioning the banks of heat transfer tubes such that the surface area immersed in the bed can be altered by varying the bed level (Fig. 5.2).

Obviously, some amount of bed expansion occurs as the fluidizing velocity is increased. Therefore, the combustor is so designed and the arrangement of tubebanks is so made that at a given velocity the bed is expanded to submerge sufficient heat transfer surface to extract the required heat flux.

Q. *What are the disadvantages of load control by varying the inbed heat-transfer-surface?*

Ans. This concept has two basic disadvantages

1. Particle splashing
2. Higher fan power requirement

Particle splashing is unavoidable and it increases with the fluidizing velocity. As this process occurs some heat is transferred to the tubes above the nominal bed level. Because of this it is not possible to fully immerse all of the tubes at maximum output and this makes it essential to install an additional number of tubings than in designs in which the tubes are fully immersed.

Secondly, for combustors designed to operate at high velocities the tubebank required to extract the heat might be up to 500 mm in height and to achieve this variation in bed level within the operating fluidizing velocity range inherently requires the use of a relatively deep bed. Higher bed-depth extorts more tax on fan power.

Q. *How is the start-up of a FBC boiler made?*

Ans. Preheating of the inert bed materials to about 875°K is a prerequisite to the start-up of a fluidized bed boiler. This preheating carried out by using an auxiliary heating system is all but essential to sustain fuel combustion in the fluidized bed.

Bed preheating is carried out by either of two processes

1. Above-bed combustion of auxiliary fuel using cold air to fluidize the bed inerts
2. Bubbling hot gas through the bed (Hot-gas start-up).

Thereafter, fuel is charged to the bed. In the case of a coal-fired unit, coal-feeding commences at a temperature of about 775°K.

Q. *What is the most critical problem that a coal-fired FB unit germinates during start-up?*

Ans. It is the problem of clinkering.

When coal is charged to the fluidized bed at 775°K, its volatiles burnout above the bed while enriching the char concentration within the bed. This is because, at this temperature the rate of combustion of residual char particles is rather too slow with the effect that the char accumulates to a high concentration in the bed.

As the volatiles burn, the bed temperature rises and with that the char combustion rate increases

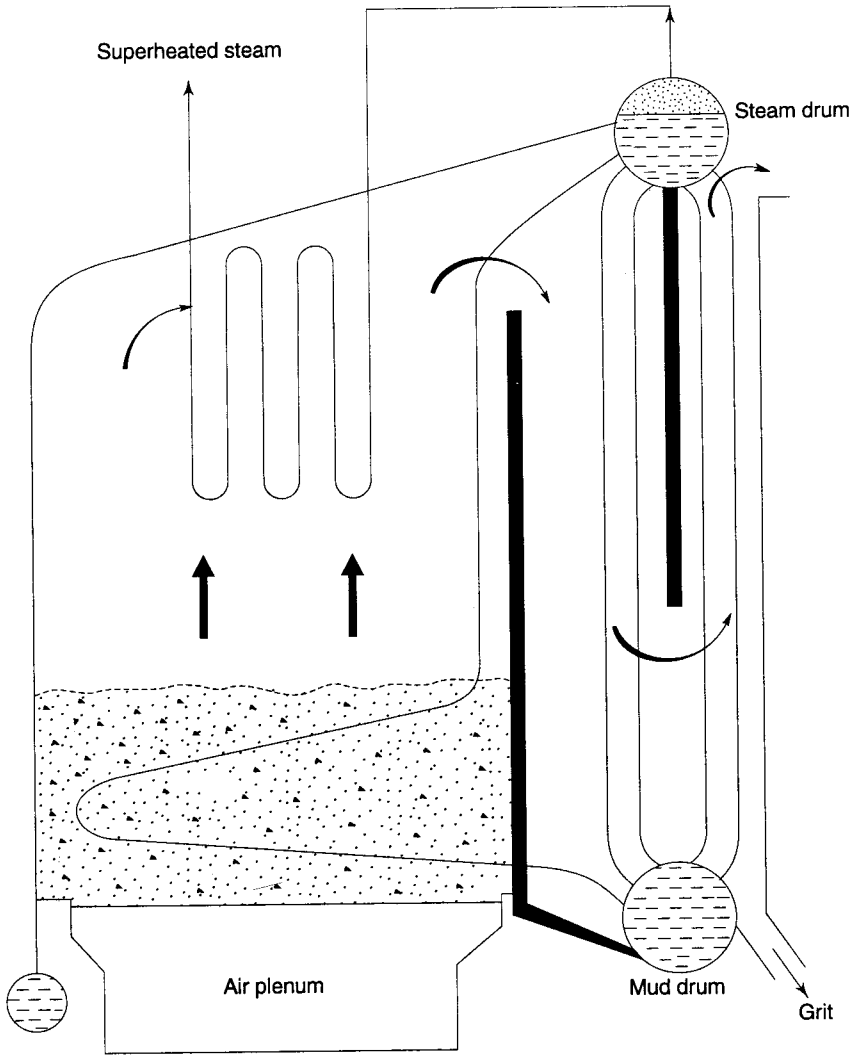


Fig. 5.2 *The surface area of tubes for inbed heat transfer can be varied by changing fluidizing velocity.*

and the char : carbon equilibrium concentration decreases towards the operating level.

Now if char accumulates to a level exceeding the equilibrium concentration when the bed temperature has already reached the operating level, all of the oxygen in the air will be used up for combustion, rather than 80% (for combustion with 25% excess air) and the heat release rate will shoot up beyond the design value. This will bring about a consequential rise in bed temperature mounting the risk of bed clinkering.

Q. *What should be done to avoid clinkering?*

Ans. It is imperative to exercise a careful control of coal feedrate during start-up to avoid excessive accumulation of char.

Q. *How is the above-bed combustion of auxiliary fuel during start-up of a FB boiler unit achieved?*

Ans. The simplest above-bed start-up combustion for bed preheating is carried out by an oil or gas burner directed at the surface of the bed while cold air is used to fluidize the bed.

Q. *What is the advantage of this method?*

Ans. Relatively low capital cost.

Q. *What is the drawback of this system?*

Ans. It is somewhat inefficient. This is because only a part of the heat released is transferred to the bed.

Q. *How can the efficiency of bed preheating system using auxiliary oil/gas burner be improved?*

Ans. By premixing the gas with fluidizing air.

The gas burns as a flame above the bed surface until the bed temperature rises to about 925°K. Thereafter, the combustion proceeds through out the bed raising the bed temperature further. By 1075°K there is no longer a above-bed flame.

Q. *How is the hot-gas start-up made?*

Ans. By passing hot gas through the bed.

In most commercial units it is a two-stage process:

During the 1st phase of bed heating, the bed is held static and hot gas at about 1175°K is supplied to the cold bed at about 50% maximum fan rating. [Please note that the gas mass flowrate which can be passed through the cold bed without fluidizing is typically about 6 times that for a hot bed.] Therefore, the bed does not fluidize immediately and a hot zone at 1175°K forms at the bottom.

This hot zone gradually extends throughout the bed. But for the refraining action of the cold bed above, the gas flowrate would be sufficient to fluidize the hot zone. As the hot zone extends upwards (2nd phase of bed heating), a point is eventually reached when the bed-depth of the cold bed is just insufficient to restrain the upwelling surge of the hot zone below. And the bed then suddenly fluidizes.

The hot gas flowrate is usually selected such that this hot-gas fluidization occurs at a mean temperature at which coal feeding can be ensued, typically 775°K.

Q. *What is the chief advantage of hot-gas start-up system?*

Ans. There is no above-bed flame. So this system is inherently free from the inefficiency of above-bed combustion system using auxiliary fuel for bed start up.

Q. *What is the chief disadvantage of hot-gas start-up?*

Ans. It requires

1. the hot-gas duct to be refractory lined
2. the distributor must be made from expensive heat-resistant alloys with allowance for thermal expansion
3. the distributor to be cooled by air or water.

Q. *Why is hot-gas start-up initiated through heating of the static bed, not the fluidized bed?*

Ans. If the bed is fluidized, a large amount of input heat escapes with the gas leaving at bed temperature while the remaining portion is lost to heat up the inbed tubes. In order to minimize these losses, static bed heating is initiated by taking advantage of the gas mass flowrate required to fluidize a coldbed than a hotbed. Therefore, the heating gas entering a static bed enjoys much extended residence time than a fluidized bed and accordingly the static bed gives rise to more intense and quick bed heating.

Q. *What complications arise during load changing in PFBC units?*

Ans. The combination of a PFBC and a gas turbine leads to following complications

1. When the generator trips, it becomes necessary to disconnect the PFBC from the turbine in a fraction of a second to prevent overspeeding of GT
2. The steam turbine in the supercharged boiler circuit germinates added complicacy

since it becomes necessary to reduce steam simultaneously as the gas turbine load is reduced.

Q. *Why does the first problem arise?*

Ans. Gas turbine is a quick acting device whereas PFBC plant is a 'slow coach' i.e. having a relatively slow response rate. Over and above, PFBC unit constitutes a storehouse of enormous energy compared to a conventional gas turbine. Therefore, it becomes a must to disconnect the inflow of energy from PFBC to GT system when the generator trips. This requires venting of combustion gases (PFBC efflux). Large, quick-acting, valves for combustor exhaust steam are yet to be developed.

Q. *Is there any ingenuous way to address the problem of turbine overspeeding?*

Ans. By coupling the generator, turbine and air compressor through a single-shaft. This is advantageous: the compressor acts as a brake in the event of generator trip.

Q. *How can the second problem be tackled?*

Ans. The first step is to reduce the gas turbine output and the pressure in the system. This can be accomplished by reducing the bed temperature and bypassing some of the compressor air directly to the turbine. The bed temperature can be reduced to a minimum of 1025°K before combustion efficiency becomes unacceptably low. This coupled with compressor air bypassing can bring gas turbine output down to almost idling.

With the reduction of bed temperature the output of steam cycle gets reduced because of the fall of temperature differential across the tubes. However, the turbine load can be reduced only to about two-thirds of the full power output (Δ temperature between the bed and the tubes at full load is 350°K which drops to 200—250°K at minimum bed temperature).

Q. *How can the steam turbine output be further reduced?*

Ans. This can be done by either of two methods:

1. Lowering the bed-depth by transferring the bed inventory to a separate container and thus reducing the amount of tube surface which is immersed in the bed. This method takes advantage of the fact that the heat transfer coefficients to tubes above the bed are much lower than bed-to-surface heat transfer coefficient for inbed tubes.
2. Arranging the boilers into a number of identical modules (say two modules per GT) and two, three or four gas turbines per steam turbine. When minimum bed temperature (and/or maximum bypass) has been reached, further load reduction is accomplished by shutting down a GT and slumping the associated bed modules with the effect that steam output in these beds is reduced almost to zero.

Q. *What are the problems encountered with the operation of CFB units and how have they been addressed?*

Ans.

Problem 1 **NO_x emissions at low loads. Ammonia injection is ineffective at the combustion temperature less than 1035°K experienced at low loads.**

Solution

This problem was encountered at the 180MW_e AES Barbers Point facility, Oahu, Hawaii as the air permit included no provision for allowable NO_x emission levels at low loads, making it difficult to meet the NO_x permit at low loads less than 50%.

AES working with Pyropower, resolved this problem by biasing air and coal flow, optimizing flyash reinjection, decreasing limestone feed in anticipation of lower boiler load, and increasing ammonia flow to reduce the rolling average of NO_x emission.

Problem 2 **High ammonia consumption and ammonia slip.**

Solution

The 180MW_e CFB unit of AES Barbers Point, Oahu, Hawaii experienced this problem at low loads and it was exacerbated by excess limestone in the bed at low loads. This problem was addressed by changing the operating procedure so that greater turndown of limestone feed could be accomplished.

Problem 3 **The Pyroflow CFB boiler (bituminous coal fired) located at Niagara Falls, NY made a smooth start-up. The facility with nominal electric export of 45MW and process steam to chemical plant met all capacity and emissions guarantee. It took just 2 months from 1st coal firing to first full load operation. 80% of boiler load was achieved one week after coal firing, but could not be exceeded.**

Solution

The cause of boiler load limitation was due to limestone size distribution being out of specification and the flyash reinjection system was out of service, which did not allow SO_2 compliance above 80% load.

Problem 4 **The original design of the vortex finders in the hot cyclones of the above the Pyroflow CFB unit of Niagara Falls, New York got warped during operation which restricted gas flow through the cyclone.**

Solution

The original design was modified to a new design harnessing stiffener rings to eliminate warping

Problem 5 **Two 80MW_e Bayard Plant, West Virginia, USA went into commercial operation in 1991. Two CFB Pyroflow boilers (179 t/h) burning waste coal (bituminous GOB) and using pneumatic limestone injection for SO_2 reduction developed following problems**

I. **Accumulation of fuel on the rails**
II. **Variations in the limestone particle size distribution**

Solution

The drag chain conveyor, which conveys the fuel to the loopseal feedpoints, was fitted with a scraper bar made of keystock to prevent fuel accumulation.

To accommodate variations in limestone particle size distribution, modifications were made to the configuration of the pneumatic transport piping to reduce piping pressure drop. Also the limestone feeders were changed from screw type to rotary valve type in order to function properly after fluidization air was required within the limestone silo for proper flow for solids.

Problem 6 **The two CFB Pyroflow boilers (181 t/h each) of American Bituminous Power Project's Grant Town electric unit (80 MW) went commercial in 1992. They burn coal waste (bituminous GOB) and harness pneumatic limestone injection for sulfur retention. The start-up of the boilers proceeded very well and all capacity and emissions guarantees were met.**

However, problems cropped up in the form of ash accumulation on the superheater and economizer tubes.

Solution

To reduce the temperature of the flue gas at the airheater outlet, two of the rotary type sootblowers were changed to retractable type sootblowers. This was done on both boilers to provide better cleaning of the ash accumulation on the superheater and economizer tubes.

Problem 7 **The Pyroflow boiler located at the Kuk Dong Oil refinery was started up in the spring of 1989. The boiler was designed by Ahlstrom Pyropower Inc. to fire 100% delayed petroleum coke, up to 100% MCR. It is rated at 109 t/h steam at 11 MPa and 795°K. Steam is used in the refinery process and to generate power for the refinery. Limestone crushed to 1 mm size onsite by a roller mill is transported by two pneumatic transport lines, using primary air, and fed to the furnace.**

Start-up and initial operation, went smoothly, with the exception of several cyclone blockages at higher boiler loads, which limited continuous high load operation during the first year of operation.

Solution

These blockages were characterized by loose circulating ash bridged in the cyclone cone or downcomer. The loopseal was typically empty. The looseness of the ash indicated that sintering was not the cause of the blockages.

The lab analysis of the ash showed that it was very fine, with 100% of the particles having a diameter smaller than 125 μm. The ash was very difficult to fluidize.

The circulating ash in the Kuk Dong Oil boiler was too fine to circulate reliably through the cyclones and loopseals, resulting in cyclone blockages.

Forasmuch as the pet coke is essentially free from ash, the circulating ash is primarily limestone products (CaO and $CaSO_4$). Thus the too fine circulating ash was a result of very fine limestone. The limestone size was increased to Ahlstrom Pyropower's standard size, in mid-1990, through a combination of minor modifications to the limestone roller mill and a change in the limestone source. While using the coarse limestone, there have been no further cyclone blockages.

Problem 8 **Two 80 MW_e Ahlstrom Pyroflow CFB boilers for Gilberton Power Company were designed to burn low grade anthracite culm. The boilers begun operation in December 1987. These units produce steam for a coal drying facility and generate electricity for sale to Pensylvania Power and Light.**

Start-up philosophy was to bring one boiler full load on solid fuel and finetune its operation. The plant sustained full load in Sept. 1988.

However, the plant encountered, during operation, the following problems

I. The selection of culm at Gilberton brought about some unanticipated problems. When wet, culm is extremely sticky, which caused the boiler feed system to clog on numerous occassions. The problem was more prominent in the boiler's frontwall feeders than in the rearwall feeders.

II. Particulate emission limits were a challange. When the plant was near full load in May 1988, the fiberglass filter bags could not meet the emissions limits because the grain loading in the flue gas was higher than anticipated. The plant was forced to operate at reduced capacity to stay with emission limits.

III. The refractory in the cyclones faced failures. The cyclone roof got eroded severely. The refractory in the scroll area has shown loss of material.

IV. For bottom ash removal the side coolers have water cooled walls and use recirculated flue gas as the fluidizing medium. The coolers are equipped with classifying velocity control.
The fuel ash split changed dramatically from that experienced in the pilot plant tests, resulting in 50-60% bottom ash compared to the 30% observed in the pilot tests. The result of higher bottom ash flowrate was that the cooler's design cooling capabilities were overtaxed.

Solution

I. To stop the clogging, frontwall screw feeders were extended to the face of the boiler wall, rather than stopping 1.8m from the boiler. The rearwall feeder chutes were modified by increasing the diameter from top to bottom instead of the constant diameter.

II. Tests were performed on various filter-bag materials and one type was found more suitable for this application. Subsequently, all the fibrebags in the fabric filter were replaced with NOMEX bags.

III. The cause of these failures has not been finally determined, but it is guessed that alkali attack of refractory material associated with occasional high cyclone operating temp. is at least partly to blame. Investigations are still underway to determine the cause.

IV. The cooling capacity was increased by the addition of water sprays.

Problem 9 **The Southest Paper (SEP) manufacturing facility in Dublin, Georgia utilizes a 181 t/h CFB boiler with main steam conditions of 8.79 MPa, 785°K. Capable of burning #2 oil, coal and deinking sludge, the boiler has been in operation since October 1989.**

The SEP unit was designed with two coal mills supplying fuel pneumatically to the boiler similar to a pulverized coal design. Each mill has two coal pipes carrying fuel to the furnace, one pipe feeding each of four furnace walls. Loss of coal mill is similar in effect on the boiler to loss of a feeder.

Solution

The loss of a mill is usually due to wet coal causing a pluggage either in the downspout to the mill or to the feeder.Therefore, if one mill plugs it is possible that the other may plug, so burners are started in the event that the other mill were to trip. During this period the sludge flow may be backed down to maintain bed temperatures, it can then be returned to previous flowrate typically within 15–20 minutes when the bed temperature has settled out from the effects of the fuel interruption. The unit can run indefinitely in this mode and still maintain emissions easily.

Problem 10 **The Boise Cascade Coated Paper Mill in Rumford, Maine utilizes two 188 t/h CFBs with the same main steam conditions as the SEP units. These units are capable of burning # 6 oil, coal and biomass derived from a debarking operation. The boilers have been in service since May 1990.**

The Rumford units employ feeders dropping coal directly into the boilers through rotary valves. Like the SEP unit, they suffer from a loss of a coal mill or feeder. Though the control system is designed to ramp the remaining fuel feeder or mill to make up for the loss of the other feeder or mill the operators prefer to utilize the oil-fired start-up burners to make up for the loss.

Solution

It is not desirable to operate at full load on one feeder due to the stratification of excess oxygen produced in the furnace with this arrangement so a burner is started on the side which lost a feeder to help balance the excess oxygen across the furnace and to maintain load.

Problem 11 **If the sludge is lost at the SEP plant due to processing plant problems and if the ceasation of flow lasts longer than 30 minutes, bed temperatures shoot up very high.**

Solution

The combustion gas recirculation fan is started to supply gas to the combustion chamber. This keeps bed temperatures from rising too high, compensating for the loss of gas volume that the moisture in the sludge was providing. Emissions can still be met in this operating mode.

Problem 12 **The SEP/Rumford boiler operates by burning oil, coal and waste fuel. The boiler trips even when it is in normal operation fulfilling steam and waste fuel consumption demands.**

Solution

A boiler trip from this condition results in a hot restart, assuming that the boiler is to be restarted.

After the trip occurs the actions taken depend upon whether the fans have tripped or not. In case the fans have not tripped, then the cause of trip is determined, the trip is reset, and solid fuel feed restarted as long as bed temperature has not dropped below 1035°K. If the temperature drops below 1035°K, then an oil burner is taken *i*/1 following a boiler purge and the solid fuel added.

In this situation the boiler can normally be back to full load with 5–30 minutes following the trip depending upon whether start-up burners were required.

If fans trip due to a need to protect the furnace from either overpressure or overheating potential then the restart takes longer due to the need to get the fans running and to reset airflows. If this is done before the bed temperature drops below 1035°K it will be possible to simply restart solid fuel again. If the bed temperature drops below this point then the boiler is purged, a burner is started, and solid fuel introduced immediately thereafter. In this situation the boiler is usually back to full load within 1–2 hours.

Waste fuel firing can be restarted as soon as solid fuel is reestablished and the bed temperature is above 1035°K.

Problem 13 **The Point Aconi Generating Station at Cape Breton, Nova Scotia receives coal from Prince Mine. The fuel is a high sulphur (3—5%), medium ash (12—20%) subbituminous coal.**

The boiler is a Pyroflow CFB unit having a design main steam flow of 146.5 kg/s at 814°K, 12.78MPa, and a reheat steam flow of 129.1 kg/s at 813°K and 3.29 MPa. The boiler includes a water cooled combustor, bricklined cyclone and a conventional rear pass containing Superheater III, and Reheater I and Reheater II, in a steam cooled convection cage, plus an economizer and air heater (Fig. 5.3).

A number of problems have occurred early in its life

I. ***Erosion on Omega tubes***

During the initial attempt of 120h reliability run, a leak sprang up on a leading Omega tube on one side of the lower platens in SH I. An inspection during the outage showed that the lead tube on all Omega tube platens showed extensive erosion in an area adjacent to and up to 5m out from the rearwall.

Solution

This problem was addressed with a squared-off rectangular tube shield as shown in Fig. 5.4.

These shields were installed on all lead tubes of each upper and lower Omega tube section. An inspection two months later has shown no erosion with all shields intact and in good condition.

II. ***High reheat metal temperature***

Shortly after first the coal fire, and as the plant approached full-load operation a flow imbalance was observed in the second stage of the reheater (RH II)

Solution

Initial monitoring identified this as a flow imbalance resulting from the configuration of the crossover piping from RH I to RH II. During shutdown a modification to this piping was carried out. Observations a week after have revealed that the imbalance is gone and reheat metal temperatures are now running in a safe range.

III. ***Fouling in backpass***

During the scheduled turbine screen outage in Dec. 1993, an inspection of the backpass showed severe fouling in the backpass. The Superheater III and Reheater I and Reheater II circuits were severely fouled with a hard ash deposit. The ash buildup in the economizer and airheater was a loose powder that was easily cleared. The fouling throughout the unit was evenly distributed with no indication of uneven gas flow.

Some slight signs of corrosion have been seen, especially in the lead tubes of SH III.

Solution

A detailed ash analysis has not revealed a positive chemical mechanism that triggered the fouling process.

Pyropower, on reviewing the fouling conditions on the unit, installed in the April '94 shutdown 4

Nos. of addition a DIAMOND I-K retractable shootblowers to aide in cleaning the SH III surface. Tubes along the sootblower path have been fully shielded and fouling conditions are being monitored with some improvement noted. In addition, sonic blowers have been installed in the economizer section.

IV. ***High furnace Temperature***

The most difficult problem todate at Point Aconi has been dealing with high furnace temperatures and the associated higher than design Calcium/Sulphur ratios.

Solution

Considerable attention has been given to the coal and limestone preparation plants and the effect of their product on bed quality.

Coal and limestone sizing as fuel to the boiler lie outside the prescribed limit for Pyropower CFB boilers. Hence it is intended to modify both the coal crushers to produce 6 mm minus product and to modify the limestone pulverizers to produce a product more in line with the Pyro curve.

V. ***Ash handling problem***

Nova Scotia Power is having significant problems handling the ash produced at Pt. Aconi. The ash is discharged from the silos by paddle wheel mixers and then trucked to an adjacent landfill site (Fig. 5.5).

Earlier it was decided to handle the ash in a two stage conditioning process with primary hydration taking place at the silo and secondary hydration at the ash-site. In order to carryout primary hydration, 40% water by weight had to be added at the silo. This has proven to be very troublesome with excess steaming in trucks.

This had resulted in ash spillage out of the trucks and a safety problem for the operators.

Solution

In order to address this problem, pyropower has recently reduced the amount of water being added at the silo to 15% by weight.

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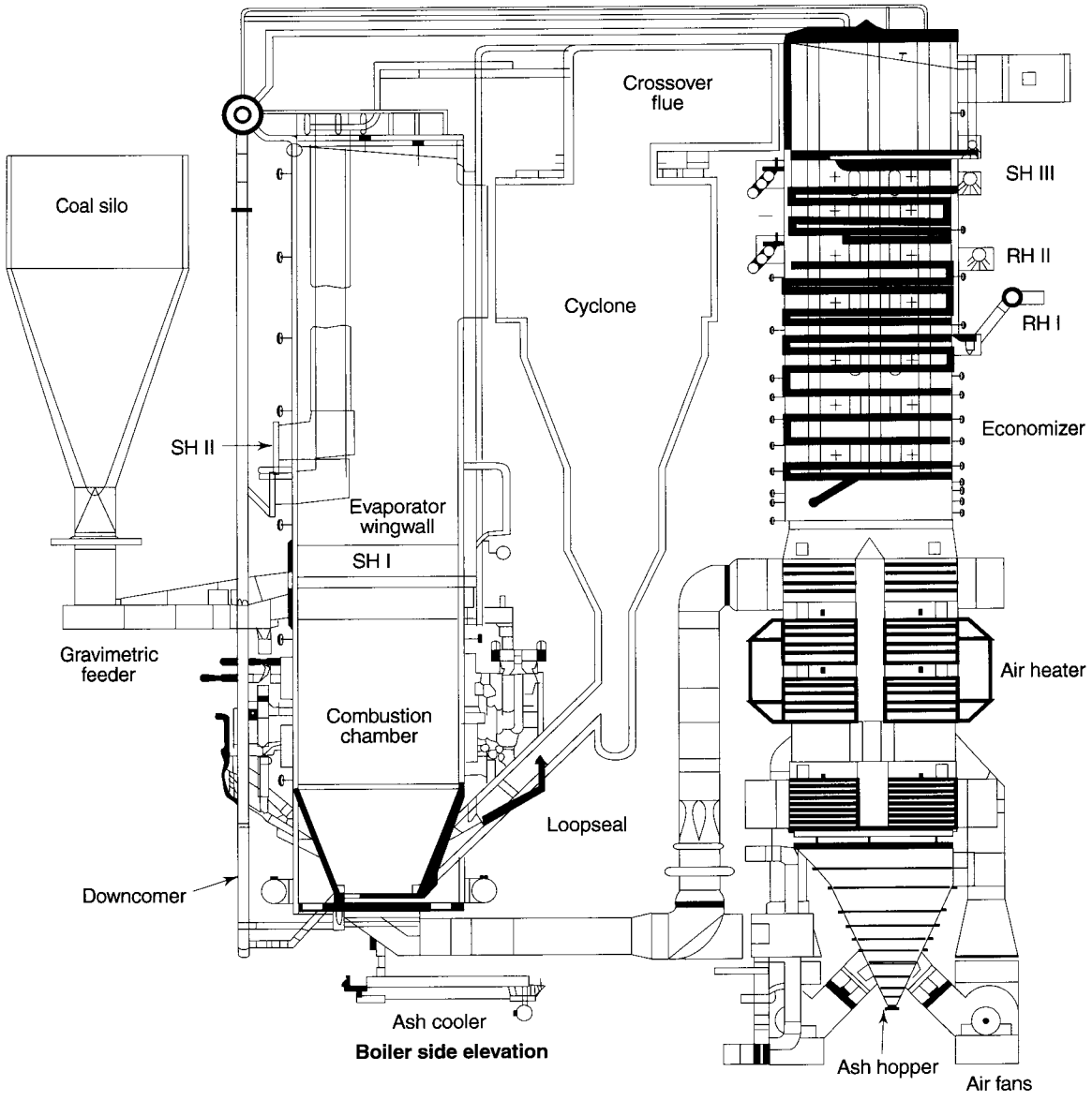


Fig. 5.3 *The Pyroflow CFB boiler of the POINT ACONI UNIT sports a combustor having a grid size of 3.35 m × 17.6 m and a total height of 35.18m (approx).*

Source : *TECHNICAL PAPER PTP-98 (AHLSTROM PYROPOWER)*

COURTESY : *AHLSTROM PYROPOWER, Inc./San Diego/CA 92186-5480/USA*

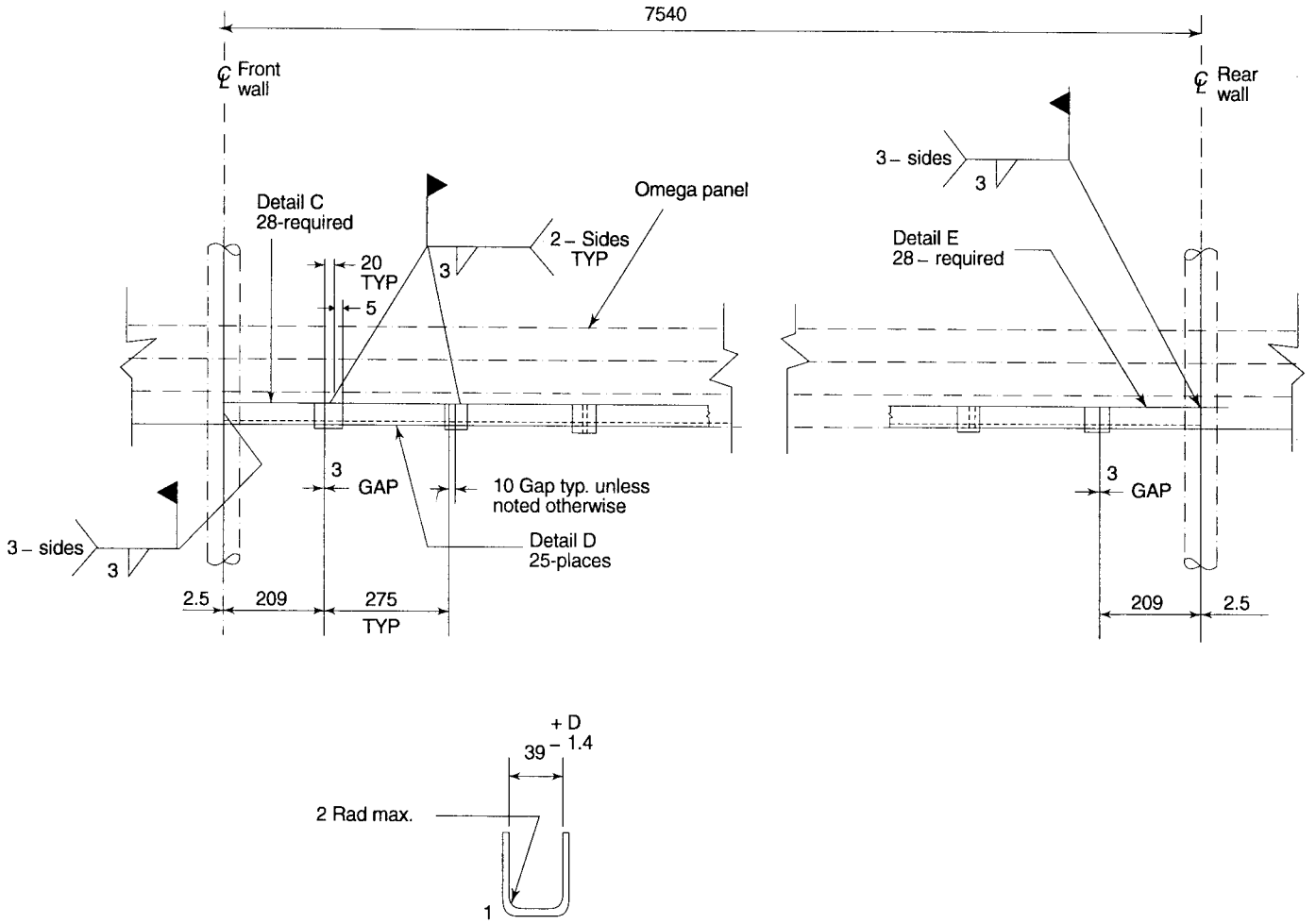


Fig. 5.4 *The Pyropower engineers successfully came up with a squared-off rectangular tube shield installed on all lead tubes of each upper & lower OMEGA tube sections to fight erosion on OMEGA tubes.*

Source : *Tech. Paper PTP-98 (Ahlstrom Pyropower)*

Courtesy : *AHLSTROM PYROPOWER, Inc./San Diego/CA 92186-5480/USA*

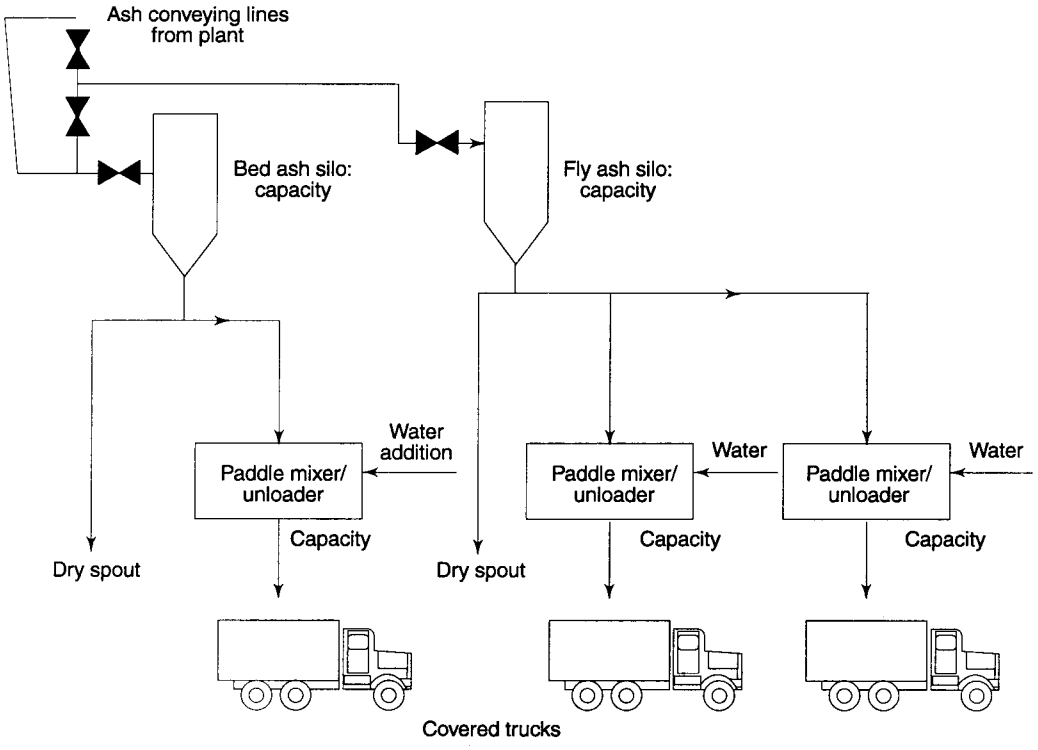


Fig. 5.5 *The bottom ash silo is equipped with both a dry unloader and a wet paddlewheel unloader for discharge into trucks.*

Source : Technical Paper PTP-98 (AHLSTROM PYROPOWER)

Courtesy : Ahlstrom Pyropower, Inc./San Diego/CA 92186-5480/USA

Problem 14 **Foster Wheeler Mt. Carmel, Inc. owns and operates the 40 MW CFB steam generator which is designed to burn anthracite culm (a waste byproduct of the anthracite coal mining industry). The culm is hard-to-burn, low reactivity, low volatile, high ash (64%) fuel that imposes special requirements to the steam generator and auxiliary system designs. The steam generator, which is of non-reheat design, has the nominal capacity of producing 174 t/h of superheated steam at 761°K/6.37MPa.**

During initial start-up, the following problems were encountered

I. ***Fuel feed system capacity limitations***
A coarser than specified culm size distribution was produced when the crushing system was operated at the capacity required to meet full load steam conditions. As a consequence, the crushing system had to be operated at a lower capacity to achieve the desired culm size distribution for efficient, troublefree and stable boiler operation.

Solution

The mills are being modified to give acceptable capacity, feedsize distribution and specified ability to achieve full operation with a crusher out service.

II. ***Ash disposal system capacity limitation***
During the initial full-load operation of the boiler, it became apparent that the actual capacity of the pneumatic-

Courtesy : AHLSTROM PYROPOWER, Inc./San Diego/CA 92186-5480/USA

vacuum type ash disposal system was less than the specified design capacity. This was evident from the inability of the A-D system to extract sufficient spent up bed material to maintain the desired solids inventory in the furnace at full load.

Solution In order to fulfil the design capacity requirements of the ash disposal system, it is intended to install separate additional pressurized pneumatic systems for the removal of bed-ash from each of the stripper-cooler.

Problem 15 **The 20MW$_e$ ACFB boiler went into service in April 1991 at Manitowoc Public Utilities (MPU) facility located near Lake Michigan, Wisconsin. The unit designed by FW to generate 91 t/h of steam at 6.77MPa and 758°K burns bituminous coal, pet coke and TDF.**

I. Initial operation with pet coke and the limestone size used with coal proved to be difficult because bed temperatures were lower than expected.

Solution

Switching to a coarser grind of limestone solved this problem.

II. Because of the differences in solids chemistry and density, the operation of the J-valve proved to be erratic leading to pluggage.

Solution

A J-valve optimization program was undertaken to tackle this problem. Additional aeration nozzles were provided and the aeration rates at each J-valve location were varied to produce a smooth operation of the J-valve as indicated by a steady seal height differential pressure. This procedure was repeated at several load points. The optimization produced function generator curves that were programmed into DCS control system. These curves control aeration quantities at each location, based on boiler load and J-valve operating temp. The end result was smooth J-valve operation.

Problem 16 **The NISCO CFB Unit No.1 and No.2 firing 100% pet coke went into service in July 31, 1992 and Sept. 19, 1992 respectively. The two 110MW RH Units located at Westlake, Los Angeles were designed by FW Corpn.**

I. The formation of small deposits has occurred on surfaces which run cooler than combustion temperatures such as nozzles, secondary air openings, and limestone openings.

Solution

During the first inspection, tube polishing was present on the rearwall of the furnace. Polishing was located in an area where the furnace rearwall tubes are bent inward to form the smaller furnace size. A thin layer of refractory was added in this area.

II. Bypass nozzles within the INTREX^{TM} heat exchanger inlet cells were bent over and in many cases broken off.

Solution

These were modified by shortening the undamaged end and returning them to their original location.

III. Plugging of the J-valve though the J-valve had the same modified aeration as that on the MPU unit.

Solution

This plugging is attributed to the higher quantity of vandium in the fuel. The amount of aeration nozzles have subsequently been increased and replaced with special directional nozzles to overcome this concern. The J-valve seal high is lower by 250mm WC since the modifications indicating that the new nozzles are effective. The J-valve operation todate has been quite satisfactory with the absence of any previous operational difficulties.

Q. *A boiler is designated by*

$$\text{TT}\ \frac{6}{6.5}\ \text{VU}\ 40\ \frac{137}{91}\cdot\frac{1}{5}\cdot\frac{40}{48}\cdot\frac{7}{18}$$

What does each symbol or numeral mean?

Ans. TT stands for Tilting Tangential type burners (for corner firing)

5 represents	furnace width in metre
6.5 represents	furnace depth in metre
VU 40 represents	type of boiler series
137 represents	internal dia (in cm) or steam drum
91 represents	internal dia (in cm) of water drum
5 represents	size of boiler bank tubes (in cm)
40 represents	number of rows wide boiler bank tubes
18 represents	number of rows deep boiler bank tubes
7 represents	distance between the centres of steam drum and water drum (in m)
18 represents	distance between waterwall system bottom ring header and water drum centres (in m).

Q. *How can a bidrum type pulverized fuel fired balance draft boiler be grouped into parts?*

Ans. All the important parts can be grouped under three heads

1. **Pressure parts**	steam drum; water drum; evaporator, superheater, desuperheater, boiler banks, economizer, boiler valves and fittings and integral parts
2. **Non-pressure parts**	air heater, gas duct, dust collectors, boiler support, fuel firing system, insulation and refractory materials
3. **Rotating parts**	pulverizers, exhausters, feeder, F.D. and I.D. fans, soot blowers

Q. *What is the function of an exhauster?*

Ans. It sucks in a pulverized coal and air mixture from the coal mill and delivers it to the burners.

Q. *Why is inspection of boilers and their auxiliaries to be carried out on a regular basis?*

Ans. The inspection of boilers is carried out according to preplanned schedules and on a regular basis to detect defects, locate deterioration of material, abnormal wear, etc. so that these can be rectified to avoid serious damage.

Q. *When is such inspection carried out?*

Ans. Both during operation and shutdown.

Q. *At what intervals should the boiler maintenance engineer carry out a check of the boiler during operation, in case the boiler is being put into operation after a long period of repair, adjustments, reserve or overhaul, etc.?*

Ans. At least once in a quarter.

Q. *How should he carry out this check?*

Ans. He should inspect, during the loading of the boiler, to ascertain the following

(a) feed system, signals, interlocks, regulating devices, instruments, auxiliaries, furnaces and boilers functioning properly and satisfactorily
(b) the boiler operation is in conformity with the instructions specified by the boiler suppliers, Govt. regulations, safety rules, etc. with respect to working parameters, viz. steam temperature, pressure, water level, draft losses, etc.
(c) equipment is kept clean, tidy and in workable condition, i.e. floors and passages are clean, adequate provision of fire-fighting equipment exists.
(d) skilled and well-informed operators are manning the boiler.

Q. *Why is it essential to examine thoroughly the pressure parts of a boiler?*

Ans. This thorough examination is done to detect the presence of scales, deposits, corrosion and pitting, etc. on the surfaces of the pressure parts. It is carried out both internally and externally.

Q. *At what intervals, is internal inspection of a boiler normally carried out?*

Ans. Once a year.

Q. *What steps precede internal inspection of a boilers?*

Ans. 1. The boiler is to be shutdown and cooled carefully.
2. ID and FD fans should be run to complete thorough ventilation of the boiler.
3. The boiler is then to be drained through waterwall drain valve.
4. Feedlines, steam lines and drainage expanders are to be disconnected from the boiler to avoid ingestion of hot water or steam in the boiler.
5. All furnace inspection doors and manholes are to be kept open.
6. All manholes on drum and heater should be kept open.

Q. *How is internal inspection carried out?*

Ans. 1. Checking the presence of deposits on the tube outer surfaces inside the drum and the exposed portions of the waterwall tubes, steam lines, headers, feedlines, etc.
2. Collecting the samples of these deposits and getting them analyzed in the lab.
3. Arranging for cleaning of the boiler:
   (a) The external surfaces of tubes, drum and waterwall tube are cleaned by using powerful water-jets.
   (b) Deposits which are hard to dislodge are brushed off.

Components	*Look for*
1. Drum inner surface	Presence of development of cracks, corrosion, pitting, thinning of sections. Cleanliness of waterwalls
2. Tubes and headers	Blockage, thinning out, deposits, etc.
3. Other surfaces of waterwall, superheater, economizer tubes	Deformation, increase of dia, bulging out due to corrosion, thinning out due to erosion, obstruction to free thermal expansion due to deposits in expansion gaps.

Q. *Why is boiler preservation a necessity?*

Ans. The internal surfaces of boilers are prone to corrosion by leftover water after operation or by atmospheric oxygen when they are out of service. Hence boiler preservation is required to protect the internal surfaces from corrosion.

Q. *How many methods are there for the preservation of boilers?*

Ans. There are two methods
1. preservation by wet method
2. preservation by dry method

Q. *For which categories of boilers, is preservation by wet method recommended?*

Ans. Boilers which are kept ready for stand-by service and may be required for sudden demands of operation are preserved by the wet method.

The wet method is also recommended for large boiler units with multiple circuits that are very difficult to drain and dry out thoroughly.

Q. *Why are boilers for stand-by service preserved by the wet method?*

Ans. This renders them available and ready for service quickly. Also this is a more practical method.

Q. *For which category of boilers, is the dry method of preservation recommended?*

Ans. This method is recommended for boilers which are scheduled to be kept out-of-service for a long period and are not expected to be put into operation at short notice.

Q. *Why?*

Ans. As sufficient time allowance can be made for the preparation of the boiler prior to placing it in service.

Q. *Is the wet method also followed for this category of boilers?*

Ans. Yes.

Q. *What is the procedure for the preservation of external surfaces?*

Ans. The boiler should be drained completely.

Obeying the relevant cleaning standards, the external as well as internal surfaces of all pressure parts and metallic surface should be cleaned thoroughly.

Using alkaline water, the whole boiler pressure parts surfaces as well as the gas side surfaces of the air heater should be thoroughly washed. BFW is recommended for this purpose.

Next, the boiler is to be filled with deaerated polish water and the unit fired to raise about 7 kg/cm^2 pressure. This pressure should be maintained till the setting is completely dry, which may require intermittent firing.

The setting, inclusive of the stack should be isolated, i.e. closed to prevent, as far as possible, the infiltration of air from outside.

Periodic inspection is to be followed to guard against condensate on and corrosion of external surfaces of pressure parts. This is particularly important when the wet method is used.

Finally, the safety valve escape piping should be sealed off (closed) so that no rainwater can ingress into the system.

Q. *Why is alkaline water used to wash the pressure parts as well as the gas side surfaces of the air heater?*

Ans. To remove sulphur bearing flue dust, since sulphur is soluble in caustic alkali.

Q. *How is the preservation of boilers by wet method carried out?*

Ans. 1. The boiler should be filled with feedwater to the normal water level through the condenser. The pH of water should be 10.5–11.
2. Hydrazine to the extent of 200 ppm is to be dosed with the water. The unit is to be steamed in service to ensure uniform concentration of boiler water throughout the unit and to eliminate dissolved oxygen from water.
3. The boiler pressure should be stepped down gradually and the water level raised as high as is permissible for same operation while delivering some steam to the line.

   But before a vacuum, due to cooling off is produced, the boiler should be filled with deaerated water until the water spills over and fills the superheater.
4. If the superheater is non-drainable, it must be backfilled with deaerated water from the outlet drain prior to filling the drum to overflowing into the superheater.
5. Boiler connections should be checked for leakage.
6. Analysis of boiler water should be carried out frequently. If the hydrazine concentration in water happens to drop below 50 ppm, the water in the drum should be lowered to the normal operating level and an appropriate quantity of chemicals should be dosed to bring back 200 ppm of N_2H_4 or 300–400 ppm Na_2SO_3. The boiler should be steamed to circulate chemicals to uniform concentration.

Q. *If hydrazine is not available to dose in the filling water, what should be done?*

Ans. Sodium sulphite (Na_2SO_3) is another good alternative. This chemical should be added to the filling water to raise the sulphite concentration to 300–400 ppm. It acts as a deoxygenator.

Q. *What precautions should be taken for wet preservation?*

Ans. 1. Fully demineralized and deoxygenated water should be taken.
2. Wet preservation should obviously be avoided if there is any possibility of the ambient temperature dropping to freezing point.
3. The drum aircock should be connected to the surge tank (capacity $\approx$ 0.45–0.5 m^3) located 300 to 450 cm above the drum. This will ensure positive pressure

within the boiler, thus barring the entry of oxygen from outside. This surge tank should be covered and closed with hydrazine.

4. Water should be regularly circulated, i.e. once a week by
   (a) using circulating pumps
   (b) steaming the boiler by providing connections on the feeding
5. Boilers meant for stand-by service should be emptied after every two or three weeks down to the bottom of the steam drum. The drum should be inspected for any signs of deterioration and then the boiler refilled to the normal operating level, steamed and dosed with hydrazine or sodium sulphite in appropriate amounts.

   Boilers to be preserved for a prolonged period should be completely emptied after every eight weeks for similar inspection.
6. Nitrogen blanket in the steam space should be maintained by opening the nitrogen supply so that positive nitrogen pressure is always kept on the steam space.

Q. *Why is the periodic circulation of preserving liquid required at regular intervals during the wet persevation of boilers?*

Ans. It has been found from experience that if the preservation liquid is kept static, it does not prevent corrosion after two months or so.

Q. *What type of active corrosion is usually formed in case of static storage over two months?*

Ans. Active pitting corrosion is usually found.

Q. *How is the preservation of the internal surfaces of a boiler carried out by the dry method?*

Ans. 1. The boiler should be filled with deaerated polish water and fired to raise the pressure to 7 kg/cm^2.

   After that firing is discontinued and the boiler pressure is allowed to drop to 2–3 kg/cm^2.

   The water is to be drained out of the unit.
2. The drum blowdown, air cocks, gauge glass and waterwall box drains, excluding superheater box drains should be opened.
3. All drum manhole doors and all superheater drains should be opened and hot air from portable blowers should be directed into the boxes to complete the drying of internal surfaces.
4. After thorough drying, trays containing silica gel on activated alumina (1.3 kg/m^3 or 0.25 kg/m^2 of heating surface) should be placed inside the drum. Alternatively, anhydrous calcium chloride or unslaked lime (5.1 kg/m^3 or 0.098 kg/m^2 of heating surface) may be used as a dessicant.
5. Pressure parts are then to be closed airtight so that no moisture/air leaks in. Any line through which moisture can ingress into the unit should be disconnected.
6. Inspection should be carried out once a month and the dessicant trays replenished as necessary.
7. Alternatively, nitrogen can be used for dry storage. This nitrogen must be as pure as is practically possible.

Before injecting the nitrogen, the boiler should be freed from as much water as possible. The boiler should be purged with nitrogen by connecting the lower header drains to the nitrogen supply line. Thereafter, a positive pressure of nitrogen should be maintained in the boiler.

Q. *When anhydrous calcium chloride is used as a dessicant, what portion of the tray should be filled, before placing it in the boiler drum?*

Ans. Less than 3/4th of the tray.

Q. *Why?*

Ans. Anhydrous calcium chloride is a dessicant and upon absorbing water it gradually dissolves in it, swells in volume and thereby entails the risk of spillover. The liquid is corrosive.

Q. *How much pure nitrogen is preferred when dry preservation using nitrogen is recommended?*

Ans. The oxygen impurity in it should not exceed 200 ppm.

Q. *Why?*

Ans. Traces of oxygen together with isolated pockets of water on the internal surfaces of boilers can lead to severe pitting corrosion.

Q. *What precautions should be taken during dry preservation?*

Ans. 1. Inspection personnel going inside the drum must wear an oxygen mask to prevent suffocation.
2. The steam drum should always be kept under positive nitrogen pressure when nitrogen is used as preserving agent.
3. The drum should be inspected regularly at least once every month.
4. Dessicants should be replenished as required.
5. The superheater box drain should be kept closed.

6

BOILER CALCULATIONS

Q. *What is equivalent evaporation?*

Ans. It is the quantity of water evaporated from and at 100°C to produce dry saturated steam at 100°C by absorbing the same amount of heat as used in the boiler under actual operating conditions.

$$M_{eq} = M_{act}\,(H - H_{w_1})/539$$

where M_{eq} = equivalent evaporation

M_{act} = actual mass of steam generated per unit mass of fuel burnt

H = total specific enthalpy of steam under operating conditions, kcal/kg

H_{w_1} = specific enthalpy of feedwater, kcal/kg

Latent heat of dry, saturated steam at 100°C is 539 kcal/kg.

Q. *What is the factor of evaporation?*

Ans. It is the factor to be multiplied with the quantity of steam generated under working conditions to get the equivalent evaporation.

Equivalent evaporation = Actual evaporation $\times (f)$

or $M_{eq} = M_{act}\,(f)$

or $M_{act}\,(H - H_{w_1})/539 = M_{act}\,f$

$\therefore \quad f = (H - H_{w_1})/539$

Q. *What is boiler efficiency?*

Ans. It is the ratio of the heat load of the generated steam to the heat supplied by the fuel over the same period.

Heat load of generated steam

$$= G_s\,(H - H_{w_1})\text{kcal/s}$$

where G_s = rate of steam generation, kg/s

Rate of heat supplied by fuel = $G_f \times (\text{CV})_f$ kcal/s where G_f = rate of fuel burning, kg/s

$$\eta_{boiler} = \frac{G_s}{G_f}\,\frac{(H - H_{w_1})}{(\text{CV})_f}$$

$$= M_{act}\,(H - H_{w_1})/(\text{CV})_f$$

where G_s/G_f = actual evaporation = M_{act}

Q. *What is economizer efficiency?*

Ans. It is defined as the ratio of the heat absorbed by the BFW in the economizer to the heat supplied by the flue gases in the economizer, the temperature of flue gases being reckoned above the temperature of the air supplied to the boiler.

$$\eta_{econ} = \frac{M_{act}\Delta\Theta}{M_{f_1} C_p (\Theta_f - \Theta_{air})}$$

where $\Delta\,\Theta$ = rise in BFW temperature in the economizer

M_{f_1} = mass of flue gases per unit mass of fuel

C_p = specific heat of flue gases

Θ_f = flue gas temperature at inlet to economizer

Θ_{air} = temperature of air delivered to the boiler

Problem 6.1 A boiler generates 4.5 t of superheated steam (500°C, 90 kgf/cm^2 abs.) per ton of coal feed.

The BFW temperature = 45°C

What is the equivalent evaporation from and at 100°C per ton of coal?

Solution

STEAM
90 kgf/cm^2 abs.
500°C
—— Specific Enthalpy = 809 kcal/kg

Sensible heat of feedwater at 45°C = 45 kcal/kg

Heat required to produce 4.5 t steam (90 kgf/cm^2 abs., 500°C)

$$= 4.5 \times 10^3 \times (809 - 45)$$

$$= 3438 \times 10^3 \text{ kcal}$$

Latent heat of dry, saturated steam at 100°C

$$= 539 \text{ kcal/kg} = 539 \times 10^3 \text{ kcal/t}$$

Therefore, equivalent evaporation from and at 100°C

$$= \frac{3438 \times 10^3}{539 \times 10^3} \frac{\text{kcal}}{\text{kcal/t}} = 6.378 \text{ t per ton of coal.}$$

Ans

Problem 6.2 A steam boiler generates 7.5 tons of steam per ton of coal burned. Calculate the equivalent evaporation from and at 100°C per ton of coal from the following data:

Steam pressure = 10 kgf/cm^2.abs.

Dryness fraction = 0.95

Feedwater temperature = 50°C

Solution Working formula

$$M_{eq} = \frac{M_{act}\,(H - H_{w_1})}{539}$$

M_{act} = 7.5 t/t of coal

H_{w_1} = 50 kcal/kg = 50 × 10^3 kcal/t

H_2 = 181.3 × 10^3 kcal/t

x = 0.95

L = 483 × 10^3 kcal/t

$H = H_w + xL = [181.3 + 0.95\ (483)] \times 10^3$

$= 640 \times 10^3$ kcal/t

$M_{eq} = 7.5\ (640.15 - 50) \times 10^3/539$

= 8.211 t of steam/t of coal ***Ans***

Problem 6.3 A boiler is working at 14 bar and evaporates 8.5 kg of water per kg of coal fired from the BFW entering at 39°C. Determine the equivalent evaporation from and at 100°C if the steam is 0.96 dry at the stop valve.

Solution The equivalent evaporation from and at 100°C is

$$M_{eq} = M_{act}\,(H - H_{w_1})/L_{100}$$

Now

M_{act} = 8.5 kg steam per kg of coal

H_{w_1} = 163.4 kJ/kg

H_w = 830 kJ/kg (at 14 bar)

x = 0.96

L = 1957.7 kJ/kg (at 14 bar)

$H = H_w + x_L$

= 830 + 0.96 (1957.7)

= 2709.39 kJ/kg

L_{100} = 2257 kJ/kg

M_{eq} = 8.5 (2709.39 − 163.4)/2257

= 9.588 kg steam/kg of coal

= 9.59 kg steam/kg of coal **Ans**

Problem 6.4 A boiler produces 220 t of dry saturated steam per hour at a pressure 60 kgf/cm^2, abs. from feedwater at a temperature of 120°C.

Coal consumption = 1200 t/day

Calorific value of coal = 4200 kcal/kg

1% of coal escapes unburnt.

Determine

(a) the equivalent evaporation per ton of coal fired
(b) the efficiency of the boiler
(c) the overall efficiency of the boiler

Solution

Step (I) Heat Load of Steam/Ton

Enthalpy of dry, saturated steam at 60 kgf/cm^2 abs. = 665.4 kcal/kg

Enthalpy of water at 120°C = 120 kcal/kg

Therefore, heat required to raise 1 ton of steam $= 10^3 (665.4 - 120) = 545.4 \times 10^3$ kcal

Step (II) Equivalent Evaporation

Coal consumption = 1200 t/day = 50 t/h

Steam generated per ton of coal fired

= 220/50 = 4.4 t

Therefore, equivalent evaporation

$$= \frac{4.4(545.4 \times 10^3)}{539 \times 10^3}$$

= 4.452 ton of steam/t of coal

Step (III) Boiler Efficiency

Energy output = 220 (545.4×10^3) kcal/h

Coal charged to the boiler = 50 t/h

Actual coal burnt = 50 (1 – 1/100) = 49.5 t/h

Therefore, energy input

$= 49.5 \times 10^3$ (4200) kcal/h

$$\eta_{boiler} = \frac{220(545.4 \times 10^3)}{49.5 \times 10^3 \times 4200}$$

= 0.577 i.e. 57.7% **Ans**

Step (IV) Overall Efficiency of the Boiler

$$[\eta_{boiler}]_0 = \frac{220(545.4 \times 10^3)}{50 \times 10^3 \times 4200}$$

= 0.5713

= 57.13% ***Ans.***

Problem 6.5 A boiler consumes 224 tons of coal to produce 1864 tons of steam per day. The steam is dry, saturated at 90 atm. absolute. Calculate the boiler thermal efficiency, and the equivalent evaporation per ton of coal if the calorific value of coal is 5400 kcal/kg of coal, the specific enthalpy of feedwater being 425.036 kJ/kg of water.

Solution

Step (I) Rate of Evaporation

Mass of steam produced = 1864 ton

Mass of coal consumed = 224 ton

Actual evaporation capacity = 1864/224

= 8.321 t/t of coal

Step (II) Equivalent Evaporation

Evaporation capacity, M_a = 8.321 t/t of coal

Sp. enthalpy of dry, satd. steam (90 atm. abs.),

H = 2705 kJ/kg

$= 2705 \times 10^3$ kJ/t

Sp. enthalpy of BFW, H_W = 425.036 kJ/kg

$= 425.036 \times 10^3$ kJ/t

Equivalent evaporation, $M_e = M_a (H - H_w)/L$

$= 8.321 (2705 - 425.036) \times 10^3/(2257 \times 10^3)$

= 8.405 ton steam/ton of coal ***Ans.***

Step (III) Boiler Thermal Efficiency

Working Formula: Boiler thermal efficiency

= energy to steam/energy from fuel

Energy to steam

$= 8.321 (2705 - 425.036) \times 10^3$ kJ

Energy from fuel

$= 5400 \times 10^3$ kcal/t of coal

$= 5400 \times 4.1868 \times 10^3$ kJ/t of coal

Boiler thermal efficiency

$$= \frac{8.321(2705 - 425.036) \times 10^3}{5400 \times 4.1868 \times 10^3}$$

$= 0.8391$

$= 83.91\%$

$\approx 84\%$ ***Ans.***

Problem 6.6 A boiler generates 7.5 tons of steam per hour at 18 bar (1 bar = 10^5 N/m^2). The steam temperature is 598 K and the feedwater temperature is 328 K.

When fired with oil of calorific value 47250 kJ/kg, the boiler plant achieves an efficiency of 85%.

The generated steam is fed to drive a turbine which develops 0.75 MW and exhausts at 1.8 bar, the dryness fraction of the steam being 0.97.

Determine the rate of fuel consumption and the fraction of enthalpy drop, through turbine, converted to useful work.

If the turbine exhaust is directed for process heating, estimate the heat transfer available per ton of exhaust steam above 322.4 K.

Solution

Step (I) Energy to Raise Steam

Specific enthalpy of generated steam

$= 3106 - 0.84(3106 - 3083)$

$= 3086.6$ kJ/kg (by interpolation)

Specific enthalpy of BFW at 328 K

$= 230.274$ kJ/kg

Specific energy to raise steam

$= 3086.68 - 230.274$

$= 2856.4$ kJ/kg.

Step (II) Rate of Fuel Oil Consumption

Rate of steam generation = 7.5 t/h = 7500 kg/h

Specific energy to raise steam = 2856.4 kJ/kg

Energy input to steam/h = 7500 (2856.4)kJ

$$\text{Boiler efficiency} = \frac{\text{Energy to steam/h}}{\text{Energy from fuel/h}}$$

$= 85\%$

$= 0.85$

Rate of fuel consumption (Energy from oil/h)

$= 7500\ (2856.4)/(0.85)\ (47250)$

$= 533.408$ kg ***Ans.***

Step (III) Rate of Specific Enthalpy Drop in Turbine

Specific enthalpy of exhaust steam,

$H_2 = H_w + x \cdot L$

$= 490.7 + 0.97\ (2211)$

$= 2635.37$ kJ/kg

Specific enthalpy of inlet steam,

$H_1 = 3086.68$ kJ/kg

Specific enthalpy drop in turbine,

$\Delta H = H_1 - H_2$

$= 3086.68 - 2635.37$

$= 451.31$ kJ/kg of steam

Steam feed = 7.5 t/h = 7500/3600 kg/s

Rate of specific enthalpy drop in turbine

$= 451.31\ (7\ 500/3\ 600)$ kJ/s

$= 940.229$ kJ/s

Step (IV) Fraction of Enthalpy Converted to Useful Work

Energy output from turbine

$= 0.75$ MW

$= 0.75 \times 10^3$ kW

$= 0.75 \times 10^3$ kJ/s

Rate of enthalpy drop in turbine = 940.229 kJ/s

Fraction of enthalpy drop converted to useful work

$= 0.75 \times 10^3/940.229$

$= 0.7976 \approx 0.8$

Step (V) Heat Transfer Available in Exhaust Steam Above 322.4 K

Specific enthalpy of exhaust steam = 2635.37 kJ/kg

Specific enthalpy of water at 322.4 K = 207 kJ/kg

Heat transfer available in exhaust steam above 322.4 K $= 2635.37 - 207$

$= 2428.37$ kJ/kg ***Ans.***

Problem 6.7 The following observations were made in the case of a boiler fitted with an economizer

Rate of steam generation = 5 t/t of coal

Equivalent evaporation from and at 100°C

= 5.5 t/t of coal

Boiler feedwater temperature inlet to economizer

= 100°C

Temperature of BFW inlet to boiler = 180°C

Temperature of air supplied to the boiler = 30°C

Temperature of flue gases entering the economizer = 400°C

Weight of flue gases produced per ton of dry coal

= 15 t

Mean specific heat of flue gases = 0.20 kcal/kg °C

Calorific value of coal = 5400 kcal/kg

Determine

(a) the boiler efficiency
(b) the economizer efficiency
(c) the combined efficiency of the whole plant

Solution

Step (I) Heat Output

Steam generated from and at 100°C = 5.5 t/t of coal burnt

Therefore, heat output $= 5.5 \times 10^3$ (539) kcal/t of coal burnt

Step (II) Heat Input

Calorific value of coal = 5400 kcal/kg

Therefore, heat input $= 5400 \times 10^3$ kcal/t of coal burnt

Step (III) Boiler Efficiency

$$\eta_{\text{boiler}} = \frac{\text{Heat Output}}{\text{Heat input}} = \frac{5.5 \times 10^3 (539)}{5400 \times 10^3}$$

$= 0.5489$ i.e. 55% (approx) ***Ans.***

Step (IV) Heat of Flue Gases

Heat of the flue gases entering the economizer

$= 15 \times 10^3$ (0.20) (400 – 30) kcal/t

$= 111 \times 10^4$ kcal/t of coal

Step (V) Heat Absorbed by BFW in the Economizer

Heat absorbed by BFW in the economizer

$= 5 \times 10^3$ (180 – 100) kcal/t of coal

$= 40 \times 10^4$ kcal/t of coal

Step (VI) Economizer Efficiency

$\eta_{\text{econ}} = (40 \times 10^4)/(111 \times 10^4)$

$= 0.3603$ i.e. 36% ***Ans.***

Step (VII) Combined Efficiency

Heat absorbed in the boiler $= 5.5 \times 10^3$ (539) kcal/t of coal

Heat absorbed in the economizer $= 40 \times 10^4$ kcal/t of coal

Total heat absorbed in boiler and economizer combined

$= 5.5 \times 10^3$ (539) $+ 40 \times 10^4$

$= 336.45 \times 10^4$ kcal/t of coal

Energy released by burning coal $= 5400 \times 10^3$ kcal/t of coal

$$\eta_{\text{comb}} = \frac{336.45 \times 10^4}{5400 \times 10^3} = 0.623 \text{ i.e. } 62.30\%$$

Ans.

Problem 6.8 A boiler produces steam at 90 kgf/cm^2 abs. at the rate 150 t/h from the feedwater at 120°C. The stam is dry, saturated. What is the boiler horse power?

Solution

STEAM, 90 kgf/cm^2 abs. Dry, saturated — Total heat = 655.7 kcal/kg

Sensible heat of BFW at 120° C = 120 kcal/kg

Equivalent evaporation from and at 100°C

$= 150 \times 10^3 (655.7 - 120)/539$

$= 149.08 \times 10^3$ kg/h

Therefore, boiler horse power = 149.08×10^3/ 15.653 = 9524.15

Boiler Horse Power is a very commonly used unit for measuring the capacity of a boiler. ASME (American Society for Mechanical Engineers) defines a unit boiler horse power as the boiler capacity to evaporate 15.653 kg of BFW per hour from and at 373 K into dry, saturated steam or equivalent in heating effect.

Boiler h.p. = Equivalent evaporation from and at 373°K per hour/15.653

Problem 6.9 A boiler generates 6.5 t of steam per ton of coal fired.

The steam is at 18 kgf/cm^2 gauge

The boiler feedwater temperature = 110°C downstream of deaerator

Boiler efficiency = 75%

Factor of evaporation = 1.15

C_p of steam = 0.55 kcal/kg °C

Determine

(a) the temperature of the steam
(b) the degree of superheat, if any
(c) the equivalent evaporation per ton of coal burnt
(d) the calorific value of coal

Solution

Step (I) Steam Parameters

STEAM, 18 kgf/cm^2.g
- Pressure = 19 kgf/cm^2 abs.
- H_w = 213.1 kcal/kg
- Latent heat L = 455.1 kcal/kg
- Saturation temp.Θ_s = 208.8°C

Step (II) Degree of Superheat

Total heat of the steam = $H_w + L + C_P \Delta\Theta$

Where, $\Delta\Theta$ = degree of superheat

Specific enthalpy of feedwater = H_{fw}

Therefore, the factor of evaporation

$$= \frac{H_w + L + C_p\Delta\Theta - H_{fw}}{539}$$

$$\text{or } 1.15 = \frac{213.1 + 455.1 + 0.55(\Delta\Theta) - 110}{539}$$

$\therefore \Delta\Theta = 112.09°C$ ***Ans.***

Step. (III) Superheated Steam Temperature

$\Delta\Theta = 112.09°C$

or, $\Theta - \Theta_s = 112.09°C$

or $\Theta = 208.8 + 112.09$

$= 320.89°C \approx 321°C$ ***Ans.***

Step (IV) Heat Output

Heat required to generate steam

$= 6.5 \times 10^3 (213.1 + 455.1 + 0.55\Delta\ \Theta - 110)$ kcal/t of coal

$= 6.5 \times 10^3 (558.2 + 0.55 \times 112.09)$ kcal/t of coal

$= 4029.021 \times 10^3$ kcal/t of coal

Step (V) Heat Input

Calorific value of coal = CV kcal/kg

Energy released per ton of coal burnt

$= 10^3 \times$ CV kcal

Step (VI) Boiler Efficiency

$$\eta_{\text{boiler}} = \frac{\text{Heat output}}{\text{Heat input}} = \frac{4029.021 \times 10^3}{10^3 \times \text{CV}}$$

or $0.75 = 4029.021/CV$;

$\therefore$ $CV = 5372$ kcal/kg of coal **Ans.**

Step (VII) Equivalent Evaporation

$$M_{eq} = \frac{6.5(213.1+455.1+0.55\times112.09-110)}{539}$$

$= 7.474$ t/t of coal burnt **Ans.**

Problem 6.10 The following observations were made during the trial run of a boiler.

Steam generation rate = 16 t/h

Feedwater temperature = 30°C

Steam quality = 0.9 dry

Steam pressure = 15 kgf/cm^2 abs.

Coal consumption = 2.5 t/h

Calorific value of coal = 6540 kcal/kg

Ash + unburnt coal collected from beneath the grates = 0.2 t/h (Calorific value = 700 kcal/kg)

Weight of flue gases = 15 t/t of coal fired

Flue gas temperature = 350°C

Average specific heat of flue gases = 0.25 kcal/kg °C

Ambient air temperature = 25°C

Calculate

(a) the boiler efficiency
(b) the percentage of heat loss of the flue gases
(c) the percentage of heat loss to the ash
(d) the percentage of heat loss unaccounted for

Solution

Step (I) Steam Parameters

STEAM, 15 kgf/cm^2 abs.
- Sensible heat, $H_w = 200.7$ kcal/kg
- Latent heat, $L = 466$ kcal/kg

Step (II) Heat Output Rate

Rate of steam generation = 16 t/h

Heat output rate $= 16 \times 10^3 (H_w + xL - H_{fw})$

$= 16 \times 10^3 (200.7 + 0.9 \times 466 - 30)$

$= 9441.6 \times 10^3$ kcal/h

Step (III) Heat Input Rate

Coal consumption = 2.5 t/h

Calorific value of coal = 6540 kcal/kg

Heat input rate $= 2.5 \times 10^3 \times 6540$ kcal/h

Step (IV) Boiler Efficiency

η_{boiler} = Heat output rate/Heat input rate

$= 9441.6 \times 10^3/(2.5 \times 10^3 \times 6540)$

$= 0.5774$ i.e. 57.74% **Ans.**

Step (V) Heat Load of Flue Gases

Flue gases generated = 15 t/t of coal

Heat load of flue gases

$= 15 \times 10^3 \times 0.25\ (350 - 25)$

$= 1218.75 \times 10^3$ kcal/t of coal

Step (VI) Heat Generated By 1 Ton of Coal

Heat produced by 1t of coal $= 10^3 \times 6540$ kcal

Step (VII) Percentage of Heat Loss of Flue Gases

$= [1218.75 \times 10^3/6540 \times 10^3]\ (100)$

$= 18.63\%$ **Ans.**

Step (VIII) Percentage of Heat Loss to Ash

Ash + unburnt coal collected = 0.2 t/h

Heat loss due to ash + unburnt coal

$= 0.2 \times 10^3 \times 700$ kcal/h

Heat generated in the furnace

$= 2.5 \times 10^3 \times 6540$ kcal/h

Therefore, percentage of heat loss to ash

$$= \frac{0.2\times10^3\times700}{2.5\times10^3\times6540}\ (100) = 0.85\%$$ **Ans.**

Step (IX) Percentage of Unaccounted Heat

Useful heat = 57.74%

Heat lost to flue gases = 18.63%

Heat lost to ash = 0.85%

Total accounted heat = 57.74 + 18.63 + 0.85

= 77.22%

$\therefore$ Unaccounted heat = 100 – 77.22 = 22.77 %

Ans.

Problem 6.11 A boiler generates 7.5 t of steam per hour at pressure 1.8 MN/m^2 and temperature 325°C from feedwater at 49.4°C. When fired with oil of calorific value 45 MJ/kg, the boiler attains an efficiency of 78%. The steam (325°C) is fed to a turbine that develops 650 kW and exhausts at 0.18 MN/m^2, the dryness fraction of steam being 0.95.

Determine

(a) the mass of oil fired per hour

(b) the fraction of the enthalpy drop through the turbine which is converted to useful work

Also determine the heat transfer available per kg of exhaust steam above 49.4°C, if the turbine exhaust is used for process heating.

Solution

Step (I) Specific Enthalpy of Generated Steam

H = 3106 – 0.84 (3106 – 3083)

= 3086.45 kJ/kg (by interpolation)

Step (II) Specific Enthalpy of BFW (49.4°C)

H_{fw} = 206.9 kJ/kg

Step (III) Heat Output

Energy required to generate steam

= 3086.45 – 206.9

= 2 879.55 kJ/kg

The rate of steam generation = 7.5 t/h

$\therefore$ Heat output = 7.5×10^3 = 2 879.55 kJ/h

Step (IV) Rate of Oil Burning

Let the mass of oil fired be $\dot{M}$ kg/h

Heat input = $\dot{M} \times 45 \times 10^3$ kJ/h

Boiler efficiency = 78%

0.78 = Heat output/Heat input

$= 7.5 \times 10^3 \times 2\ 879.55/\dot{M} \times 45 \times 10^3$

$\therefore$ M = 615 kg/h ***Ans.***

Step (V) Specific Enthalpy Drop in Turbine

Specific enthalpy of exhaust steam

$= H_w + xL = 490.7 + 0.95\ (2210.8)$

= 2590.96 kJ/kg

$\therefore$ Specific enthalpy drop in turbine

= 3086.45 – 2590.96

= 495.45 kJ/kg

Step (VI) Rate of Enthalpy Drop in Turbine

Rate of steam fed to turbine

= 7.5 t/h

= $7.5 \times 10^3/3600$ kg/s

Specific enthalpy drop in turbine = 495.45 kJ/kg

$\therefore$ Rate of enthalpy drop in turbine

= $495.45\ (7.5 \times 10^3/3600)$ kJ/s

= 1032.187 kJ/s

Step (VII) Fraction of Enthalpy Drop Converted to Useful Work

Energy output from turbine

= 650 kW

= 650 kJ/s

Energy input to turbine = 1032.187 kJ/s

$\therefore$ Fraction of enthalpy drop converted to useful work

= 650/1032.187

= 0.629 ***Ans.***

Step (VIII) Heat Transfer from Exhaust Steam

The net heat available, for process heating, from exhaust steam above 49.4°C = 2590.96 – 206.9 = 2384.06 kJ/kg ***Ans.***

Problem 6.12 A steam generation plant supplies 8500 kg of steam per hour at pressure 0.75 MN/m^2. The steam is 0.95 dry.

Feedwater temperature = 41.5°C

Coal consumption = 900 kg/h

Calorific value of coal = 32450 kJ/kg

Determine

(a) the boiler efficiency
(b) the equivalent evaporation from and at 100°C
(c) the saving in fuel consumption, if by installing an economizer it is estimated that the feedwater temperature could be raised to 100°C, assuming that other conditions remained unchanged and the efficiency of the boiler increases by 6%.

Solution

Step (I) Steam Generation Per Ton of Coal

Rate of steam generation = 8500 kg/h

Coal consumption = 900 kg/h

Therefore, steam generation per kg of coal

= 8500/900

= 9.44 kg

$\therefore$ Steam generation/ton of coal = 9440 kg

= 9.44 t

Step (II) Specific Enthalpy of Steam Raised

$H = H_w + xL = 709.3 + 0.95\ (2055.5)$

= 2662.025 kJ/kg

Step (III) Energy Required to Generate Steam

Specific enthalpy of steam raised

= 2662.025 kJ/kg

Specific enthalpy of BFW = 173.9 kJ/kg

Heat output = 2662.025 – 173.9

= 2488.125 kJ/kg of steam

Step (IV) Boiler Efficiency

$$\eta_{\text{boiler}} = \frac{\text{Heat Output/kg of coal}}{\text{Heat input/kg of coal}}$$

$$= \frac{2488.125}{32450}\ (9.44)$$

= 0.7238 i.e. 72.38% ***Ans.***

Step. (V) Equivalent Evaporation

Steam raised per kg of coal = 9.44 kg

Energy required to generate this steam

= 9.44 (2488.125) kJ/kg coal

Specific enthalpy of evaporation from and at 100°C = 2256.9 kJ/kg.

Equivalent evaporation = 9.44 (2488.125)/2256.9

= 10.40 kg/kg of coal ***Ans.***

Step (VI) Energy Required to Generate Steam Under New Conditions

Specific enthalpy of BFW at 100°C = 419.1 kJ/kg

Energy required to generate steam when economizer is incorporated

= 2662.025 – 419.1

= 2242.925 kJ/kg

Energy to steam/h

= 2242.925 × 8 500 kJ

Step (VII) Rate of Coal Consumption when Economizer is Fitted

Energy output = 2242.925 × 8500 kJ/h

Energy input = M × 32450 kJ/h

Boiler efficiency = 72.38 + 6 = 78.38%

$$\therefore\ 0.7838 = \frac{2242.925 \times 8500}{\dot{M} \times 32450}$$

$\therefore\ \dot{M}$ = 749.57 kg/h

Step (VIII) Saving in Fuel Consumption

Initial fuel consumption rate = 900 kg/h

Modified fuel consumption rate when economizer is fitted = 749.57 kg/h

Saving in fuel consumption = 900 – 749.57

= 150.43 kg coal/h ***Ans.***

Problem 6.13 The following observations were made during the trial run of a boiler.

Rate of steam generation = 5 t/h

Stam quality: dry, saturated

Steam pressure = 10 kgf/cm^2 gauge

Average specific heat of steam = 0.55 kcal/kg. °C

Feedwater temperature = 85°C

Room temperature = 25°C

Atmospheric pressure = 1 kgf/cm^2

Fuel consumption = 650 kg coal/h

Calorific value of coal = 7500 kcal/kg of coal

Moisture content of coal = 2.5 %

Fuel contains: C – 86%; H – 5%; Ash – 9%

Flue gas temperature = 300°C

Mean specific heat of flue gases = 0.25 kcal/kg °C

Analysis of dry flue gases:

CO_2 – 10%; O_2 – 8%; N_2 – 82%

Produce a complete heat balance sheet taking 1 kg dry coal as the basis.

Solution

Step (I) Energy to Steam Per kg of Dry Coal

Steam pressure = 10 kgf/cm^2 gauge

= 11 kgf/cm^2 abs.

Sensible heat of steam at 11 kgf/cm^2 absolute

= 185.7 kcal/kg

Latent heat of evaporation at 11 kgf/cm^2 absolute

= 478.4 kcal/kg

Specific enthalpy of dry, saturated steam generated

= 185.7 + 478.4

= 664.1 kcal/kg

Specific enthalpy of feedwater = 85 kcal/kg

Coal consumption

= 650 kg/h

Dry, coal consumption = 650 (100 – 2.5)/100

= 650 × 0.975 kg/h

Energy to steam/kg coal

= (664.1 – 85) (5000)/(650 × 0.975)

= 4568.836 kcal

Step (II) Flue Gas Analysis

Basis: 100 m^3 of dry flue gas

Constituent	Volume m^3	Mol. wt	Proportional Mass	Remarks
CO_2	10	44	44(10) = 440	Carbon content = 440 (12/44) = 120
O_2	8	32	32(8) = 256	
N_2	82	28	28(82) = 2296	
	100	104	2992	

Step (III) Coal Analysis

Basis: 1 kg dry coal

Constituent	Chemical Reaction during combustion	Remarks
C	$C + O_2 \rightarrow CO_2$ (12) (44)	Wt. of dry flue gas produced = (2992/104) (86/100) = 24.741 kg/kg of coal
H	$H_2 + \frac{1}{2} O_2 \rightarrow H_2O$ (2) (18)	Wt. of water vapour produced = (18/2) (5/100) = 0.45 kg/kg of dry coal

Wt. of moisture fired

= 0.025/0.975

= 0.02564 kg/kg of dry coal

Total wt. of water vapour in flue gases

= 0.45 + 0.02564

= 0.4756 kg/kg of dry coal.

Step (IV) Heat Load of Water Vapour

= 0.4756 [638.8 + 0.55 (300 – 90) – 25]

= 344.5 kcal/kg of dry coal

where 638.8 kcal/kg = total heat of water vapour at 1 kgf/cm^2 absolute to which flue gases are discharged

Step (V) Heat Load of Dry Flue Gases

Heat loss to flue gases

= 24.741 (0.25) (300 – 25)

= 1700.944 kcal/kg of dry coal

Step (VI) Heat Balance

Basis: 1 kg of dry coal

Heat Input	%	Heat Expenditure	%
Total heat supplied = 7500 kcal	100	Heat consumed in steam formation = 4568.836 kcal	60.92
		Heat lost to flue gas = 1700.944 kcal	22.70
		Heat lost to vapour = 344 kcal	4.60
		Heat unaccounted for = 886.220 kcal	11.80
7 500 kcal	100	7 500 kcal	100.00

Problem 6.14 During the trial run of a boiler the following data was recorded:

Coal consumption	83.1t
Steamp produced	606 t
Boiler:	
Steam pressure	1.461 MN/m^2 = 14.42 atm
Steam temperature	470 K
Superheater:	
Superheated steam temperature	610 K
Economizer:	
Water inlet temperature	353 K
Water outlet temperature	400 K
Air heater:	
Air inlet temperature	320 K
Air outlet temperature	380 K
Flue gas inlet temperature	503 K
Flue gas outlet temperature	405 K

Coal analysis	(by weight)	Flue gas analysis	(dry basis)
C	62.5%	CO_2	13.2% (by volume)
H	4.25%	O_2	4.85% (-do-)
O	5.11%	N_2	81.95% (-do)
N	1.2%		
S	0.85%		
Ash	9.85%		
Moisture	16.24%		
Total	100%		

Gross calorific value = 30550 kJ/kg (dry coal)

Boiler house temperature = 298 K

Enthalpy of dry, saturated steam at 1.461 MN/m^2 = 2791 kJ/kg.

Substances	Specific Heats (kJ/kg °K)
Dry flue gas	1.005
Water vapour in flue gas	2.095
Water	4.187

Determine

(a) theoretical air requirements per kg of coal
(b) actual air supplied per kg of coal fired
(c) weight of flue gas per kg of coal burned
(d) thermal efficiencies of
  (i) boiler
  (ii) superheater
  (iii) air heater
  (iv) economizer
(e) heat lost in the flue gas

Summarize the overall result on the basis of 1 kg coal burnt.

Solution

Step (I) Theoretical Air Requirements

Basis: 100 kg coal

Constituent Element	% by Weight	Molecular Weight	kmol	kmol of O_2 required for complete combustion
C	62.5	12	5.208	5.208
H	4.25	2	2.125	2.125/2 = 1.0625
O	5.11	32	0.159	(–) 0.159
N	1.2	28	0.042	
S	0.85	32	0.027	0.027
Ash	9.85			
Moisture	16.24	18		
				Σ = 6.1385

Therefore theoretical air requirement

= 6.1385 (100/21)

= 29.23 kmol/100 kg coal

= 29.23 (28.9)kg/100 kg coal

= 844.744 kg/100 kg coal

= 8.447 kg/kg of coal ***Ans.***

(*cf* The average molecular weight of air is 28.9)

Step (II) Actual Air Supplied

100 kg coal contains 5.208 kmol of C

100 kmol of dry flue gas contains 13.2 kmol of C

Therefore, the amount of flue gas produced

= 5.208 (100/13.2)

= 39.45 kmol/100 kg coal

Let x mol of air be supplied per 100 kg of coal burnt.

Therefore by nitrogen balance we get,

$$79x/100 + 0.042 = \frac{81.95}{100}\ (39.45)$$

$\therefore\ x = 40.87$ kmol/100 kg coal

Therefore, the weight of air supplied

= 40.87 (28.9)

= 1181.14 kg/100 kg coal

= 11.81 kg/kg coal ***Ans.***

Note: % excess air = (11.81 – 8.447) (100/8.447)

= 39.81%

Step (III) Weight of Flue Gas

Basis: 100 kmol

Flue Gas Constituent	kmol	Molecular Weight	Weight	Weight in 39.45 kmol of Flue Gas
CO_2	13.2	44	13.2(44)	13.2(44)(39.45/100) = 229.125
O_2	4.85	32	4.85(32)	4.85(32)(39.45/100) = 61.226
N_2	81.95	28	81.95(28)	81.95(28)(39.45/100) = 905.219
				Σ = 1195.57 kg

Water produced due to combustion of hydrogen content of coal

= 2.125 kmol = 2.125 (18) = 38.25 kg

Free moisture = 16.24 kg

Therefore, the total weight of wet flue gas

= 1195.57 + 38.25 + 16.24

= 1250.06 kg/100 kg coal

= 12.50 kg/kg coal ***Ans.***

Step (IV) Thermal Efficiencies

1. Boiler

Total heat content of steam at 1.461 MN/m^2

= 2791 kJ/kg

Total heat content of water charged to boiler

= 4.187 (400 – 273)

= 531.749 kJ/kg

Therefore, the net heat transferred to steam

= 2791 – 531.749

= 2259.251 kJ/kg

Rate of steam generation/t of coal

= 606/83.1 t/t

= 7.292 t/t of coal (or kJ/kg coal)

Therefore, the heat transferred to steam/kg of coal burned

= 7.292 (2259.251)

= 16474.458 kJ/kg coal

Gross calorific value of coal as fired

= 30550 (100 – 16.24)/100

= 25588.68 kJ/kg coal

Therefore, thermal efficiency of the boiler

= 16474.458/25588.68

= 0.6438 i.e. 64.38% ***Ans.***

2. Superheater

Net heat transferred to steam in the superheater

= 7.292 (2.095) (610 – 470)

= 2138.74 kJ/kg coal

Therefore, thermal efficiency of the superheater

= 2138.74/25588.68

= 0.0835 i.e. 8.35% ***Ans.***

3. Air Heater

Weight of air charged to the boiler

= 11.81 kJ/kg coal

Heat absorbed by air in the air heater

= 11.81 (1.005) (380 – 320)

= 712.143 kJ/kg coal

Therefore, the efficiency of the air heater

= 712.143/25588.68

= 0.0278 i.e. 2.78% ***Ans.***

4. Economizer

Heat transferred to BFW

= 7.292 (4.187) (400 – 353)

= 1434.985 kJ/kg coal

Therefore, thermal efficiency of the economizer

= 1434.985/25 588.68

= 0.0560 i.e. 5.6% ***Ans.***

Step (V) Heat Lost to the Flue Gas

Weight of the dry flue gas

= 11.95 kJ/kg coal

Enthalpy of the dry flue gas

= 11.95 (1.005) (405 – 298)

= 1285 kJ/kg coal

Water content in flue gases when 100 kg coal burnt

= 38.25 + 16.24

= 54.49 kg

Therefore, the weight of water vapour/kg of coal burnt

= 0.5449 kg

Therefore, the enthalpy of water in the flue gases

= 0.5449 [2.095 (405 – 311*) + 2411.2* + 4.187 (405 – 298)]

= 1665.29 kJ/kg coal

* [*Dew Point of Wet Flue Gas*]

Flue Gas Constituent	kmol			% Composition
CO_2	(13.2/100)	(39.45) =	5.2	12.24
O_2	(4.82/100)	(39.45) =	1.9	4.47
N_2	(81.95/100)	(39.45) =	32.33	76.13
H_2O	54.49/18	=	3.02	7.11
		= Σ	42.46	Σ = 99.95

Therefore, the vapour pressure of water vapour

= (7.11/99.95) (101.3)

= 7.20 kN/m^2

which corresponds to the dew point 311°K and latent heat of evaporation 2411.2 kJ/kg

Therefore, the total heat lost to flue gas

= 1285 + 1665.29

= 2950.29 kJ/kg coal

Hence, the percentage of heat lost to the flue gas

= (2950.29/25588.68) (100)

= 11.52%

Tabulation of Result (Basis: 1 kg coal burned)

Unit	Heat recovered (kJ)	% GCV wet coal	% Efficiency
Boiler	15762	61.59	78.34
Air Heater	712	2.78	
Superheater	2139	8.36	
Economizer	1435	5.61	
Heat to flue gas	2950	11.53	21.66
Heat unaccounted	2591	10.13	
		Σ =	100.00

Problem 6.15 A boiler generates 6000 kg steam per hour at 10 kgf/cm^2 from BFW at 40°C. The steam is 0.97 dry. The boiler is fired with coal at the rate of 700 kg/h using 16 kg of air (at 15°C) per kg of coal fired.

Assuming the boiler efficiency to be 70%, determine

(a) excess air coefficient

(b) flue gas temperature leaving the boiler

Given The coal is composed of carbon and hydrogen besides its ash content 12%.

Combustion	Heat of Combustion
$C + O_2 \longrightarrow CO_2$	8075 kcal/kg of carbon
$H_2 + O_2 \longrightarrow H_2O$	34500 kcal/kg of hydrogen

Specific heat of flue gas = 0.25 kcal/kg °C

18% of total heat generated by coal is lost to substances other than coal.

Solution

Step (I) Heat Content of Generated Steam

$H = H_w + xL - H_{fw}$

$= 181 + 0.97\ (482) - 40 = 608.54$ kcal/kg

Step (II) Calorific Value of Coal

It can be determined from the boiler efficiency relationship.

η_{boiler} = Heat output/Heat input

Now Heat Output = 6000 (608.54) kcal/h

Heat input = 700 × CV where CV = calorific value of coal

or $0.70 = 6000\ (608.54)/(700 \times CV)$

$\therefore$ CV = 7 452 kcal/kg

Step (III) Carbon and Hydrogen Content of Coal

Basis: 1 kg coal

Therefore, the coal contains (1 – 0.12), i.e. 0.88 kg of C + H per kg of coal fired.

If x be the part of C/kg of coal, then

$x\ (8075) + (0.88 - x)\ (34500) = 7452$

$\therefore\ x = 0.8669$

	Carbon	+	Hydrogen
1 kg Coal	0.8669 kg		0.0131 kg

Step (IV) Theoretical Air Requirement for Complete Combustion

Basis: 1 kg coal

Element	Combustion Reaction	Weight	O_2 Requirement
C	$C + O_2 \rightarrow CO_2$ (12) (32)	0.8669 kg	0.8669 (32/12) = 2.3117 kg
H	$2H_2 + O_2$ (4) (32) $\rightarrow 2H_2O$	0.0131 kg	0.0131 (32/4) = 0.1048 kg
			Σ = 2.4165 kg

Since air contains 23% O_2 by mass, the stoichiometric (theoretical) air requirement for complete combustion

$= 2.4165\ (100/23)$

$= 10.506$ kg

Step (V) Excess Air Coefficient

Excess air coefficient = Actual air/minimum air

$= 16/10.506$

$= 1.523$ ***Ans.***

Step (VI) Enthalpy of Flue Gas

Mass of coal + mass of air = Mass of flue gas

(1 – 0.12)kg + 16 kg = Mass of flue gas

or, Mass of flue gas = 16.88 kg.

Heat Generated (kcal/h)	Heat Received by (kcal/h)
By coal: 700(7452) = 5216400	Flue gas: 16.88(700)(0.25)(ΔΘ) = 2954 ΔΘ Steam: 6000 (608.54) = 3651240 Substances other than flue gas: 700(7452) (0.18) = 938952

By heat balancing

$2954\ (\Delta\Theta) + 3651240 + 938952 = 5216400$

$\therefore\ \Delta\Theta = 211.98°C \approx 212°C$

Hence the temperature of the flue gas at the boiler outlet

$= 212 + 15 = 227°C$ ***Ans.***

Problem 6.16 A boiler is fired with coal having following percentage composition by mass:

C—85%; H—5%; S—1%; O—2.5%; Incombustible—6.5%.

Determine the boiler efficiency from the given data:

Excess air supplied = 40%

Flue gas temperature at boiler exit = 170°C

Ambient air temperature = 25°C

Specific heat of flue gas = 0.25 kcal/kg°C

Specific heat of steam = 0.48 kcal/kg°C

Combustion	Heat of Combustion
$C + O_2 \rightarrow CO_2$	8075 kcal/kg
$S + O_2 \rightarrow SO_2$	2220 kcal/kg
$H_2 + O_2 \rightarrow H_2O$	34500 kcal/kg

Unaccounted heat loss = 18%

Solution

Step (I) Calorific Value of Coal

$CV = 8075(C) + 2220(S) + 34500(H - O/8)$

where, C, S, H & O stand for carbon, sulphur, hydrogen and oxygen percentage.

$= 8075(0.85) + 2220(0.01) + 34500(0.05 - 0.025/8)$

$= 8503$ kcal/kg

Step (II) Stoichiometric Oxygen

Basis: 1 kg fuel

Element	Combustion Reaction	Oxygen Required Per Kg of Fuel
C	$C + O_2 \rightarrow CO_2$ (12) (32)	(32/12) (0.85) = 2.2666 kg
S	$S + O_2 \rightarrow SO_2$ (32) (32)	(32/32) (0.01) = 0.01 kg
H	$2H_2 + O_2 \rightarrow 2H_2O$ (4) (32)	(32/4) (0.05) = 0.4 kg Σ = 2.6766 kg

Since the fuel contains 0.025 kg oxygen/kg of fuel, the actual mass of O_2 requirement per kg of coal burnt

$= 2.6766 - 0.025$

$= 2.6516$ kg

Step (III) Air Supplied

Theoretical mass of air requirement

$= 2.6516\ (100/23)$

$= 11.5289$ kg

40% excess air supplied.

Hence the actual air supplied

$= 1.4\ (11.5289)$

$= 16.14$ kg/kg of coal

Step (IV) Mass of Flue Gas

Mass of combustibles per kg of coal

$= 1 - 0.065$

$= 0.935$ kg

Fuel + Air = Flue Gas

0.935 kg 16.14 kg = Flue Gas

Hence the total mass of flue gas (inclusive of water vapour) produced per kg of coal burnt

$= 0.935 + 16.14$

$= 17.075$ kg

Step (V) Mass of Dry Flue Gas

$2H_2 + O_2 \longrightarrow 2H_2O$
(4) (2×18)

Mass of water produced/kg of H_2 burned

= 2 (18)/4

= 9 kg

Mass of water produced/kg of coal (H-content: 5%) burned

= 9(0.05)kg

= 0.45 kg

Mass of dry flue gas produced/kg of coal burnt

= 17.075 – 0.45

= 16.625 kg

Step (VI) Heat Balance

Basis: 1 kg coal

Heat Evolved	Heat Lost To
8 503 kcal	Flue gas (dry) = 16.625 (0.25) (170 – 25) = 602.65 kcal Steam (1 atm press.) generated from fuel burning = 0.45 $[H + C_p (\Delta\Theta) - \Theta_{air}]$ = 0.45 [639 + 0.48 (170 – 100) – 25] = 291.42 kcal Unaccounted sources = (18/100) (8 503) = 1 530.54 kcal Total = 2 424.61 kcal

Heat utilized = 8503 – 2424.61

= 6078.39 kcal/kg coal

Step (VII) Boiler Efficiency

$$\eta_{boiler} = \frac{\text{Heat utilized}}{\text{Heat generated}}$$

$$= \frac{6078.39}{8503}$$

= 0.7148 i.e. 71.48% ***Ans.***

Problem 6.17 A water tube boiler operates 8400 h/year at 80% efficiency. The unit rated at 27215 kg/h operates at 7.82 atm.

It burns natural gas for six months of the year and No. 2 fuel oil for the rest.

Average annual boiler loading is 60% with an input of 11347303 kcal/h.

Without Economizer

Natural gas consumption = 1274.25 Nm^3/h at 60% load

Fuel oil (NO. 2) consumption = 1.459 m^3/h at 60% load

After Adding An Economizer

BFW flowrate (including blowdown) at 60% load

= 17145 kg/h

Feedwater temperature at the economizer inlet

= 105°C

Feedwater temperature at the economizer outlet

= 136°C

Fluegas temperature at economizer inlet = 260°C

Fluegas temperature at economizer outlet = 149°C

Determine

(a) the fuel saving using the economizer
(b) total annual fuel cost without installing the economizer
(c) total annual saving of fuel after installing the economizer
(d) the payback months, if the economizer cost is Rs. 600,000 installed

Given Natural gas cost = Rs. 1.06 per Nm^3 of gas

Fuel oil (No. 2) cost = Rs 1 255 per m^3 of F.O.

Solution The addition of an economizer to a water-tube boiler system reduces fuel cost.

The fuel saving using the economizer is

$$S = \frac{H \times 100}{I}$$

where S = fuel saving in percent

H = heat recovered, kcal/h = $\dfrac{F \times \Delta\Theta}{B}$

$F = BFW$ flowarate, kg/h

$\Delta\Theta = \Theta_2 - \Theta_1$ = temperature difference of BFW before and after the economizer

Θ_1 = BFW temperature at economizer inlet, °C

Θ_2 = BFW temperature at the economizer outlet, °C

B = boiler efficiency

(a) $H = (17145)\ (136 - 105)/0.8$

= 664368.78 kcal/h

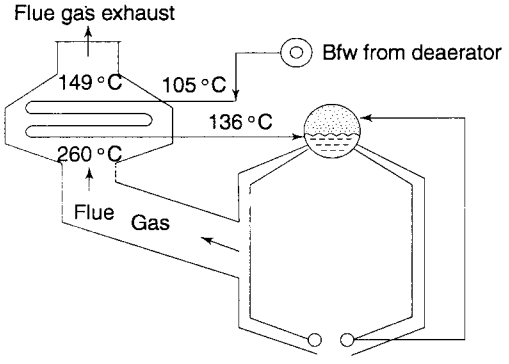


Fig. 6.1 *Figure to the Problem 6.17.*

$$\therefore S = \frac{664368.78 \times 100}{11347303} = 5.85\% \qquad \textbf{Ans.}$$

(b) Total operating period = 8400 h/year

Natural gas burned for 4200 h and F.O. burned for the remaining 4200 h over the year.

Annual cost of natural gas

$$= 1274.25 \left(\frac{\text{Nm}^3}{\text{h}}\right) \times 4200 \left(\frac{\text{h}}{\text{year}}\right) \times 1.06 \left(\frac{\text{Rs}}{\text{Nm}^3}\right)$$

= Rs. 5672961.

Annual cost of fuel oil

$$= 1.459 \left(\frac{\text{m}^3}{\text{h}}\right) \times 4200 \left(\frac{\text{h}}{\text{year}}\right) \times 1255 \left(\frac{\text{Rs}}{\text{m}^3}\right)$$

= Rs. 7690389

$\therefore$ Total annual cost of fuel prior to installation of economizer

= Rs. 5672961 + Rs. 7690389

= Rs. 13,363,350/- **Ans.**

(c) After the installation of the economizer, a 5.85% saving in fuel results.

Annual saving in natural gas

= Rs. 5672961 × 5.85/100

= Rs. 331868/-

Annual saving in fuel oil cost

= Rs. 7690389 × 5.85/100

= Rs. 449888/-

$\therefore$ Total annual saving of fuel cost after installation of the economizer

= Rs. 331868 + Rs. 449888 = Rs. 781756/- **Ans.**

(d) The payback is

$$P = \frac{E \times 12}{A}$$

where P = payback months

E = installed economizer cost, Rs

A = annual fuel savings with economizer, Rs

$$\therefore P = \frac{\text{Rs. } 600\,000}{\text{Rs. } 781\,756} \times 12$$

= 9.21 months **Ans.**

Problem 6.18 A waste heat boiler is hooked up with a diesel generator set to produce steam from waste heat.

At 60% DG-set load, saturated steam of 10 kg/cm^2 g is produced in the waste heat boiler at the rate of 40 ton/day.

Average electric energy generated per day varies from 65 to 70 MWH.

Estimate

(a) the economics of incorporating the waste heat boiler

(b) the payback period of the waste heat boiler

Given

The cost of purchased electrical energy from the grid = Rs 1.12/KWH

Cost of generated electricity after the installation of WHB = Rs 0.95/KWH

(This includes overheads and depreciation charges)

Number of operating days per year = 270

Cost of waste heat boiler installed

= Rs 3,000 000/-

Maintenance and overhead expenses

= 12% of the cost of WHB

Rate of interest payable = 20% on the principal amount

DG Set Load	Steam Generation Rate
60%	40 t/day
100%	80 t/day

1 ton of coal generates 4.5 t of saturated steam at 10 kg/cm^2 g

Coast of coal = Rs 750 per ton

Solution

(a) Economics of Incorporating WHB

The cost of electricity purchased from the grid

= Rs 1.12/KWH

The cost of generated electricity after the installation of WHB

= Rs 0.95/KWH

Monetary savings per unit electricity generated

= Rs (1.12 – 0.95)/KWH = Rs 0.17/KWH

Average electricity generation/day

$$= \frac{65 + 70}{2} \text{ MWH} = 67.5 \text{ MWH}$$

Number of working days per year = 270

Therefore, monetary savings with respect to power purchased from the grid

$$= 0.17 \left(\frac{\text{Rs}}{\text{KWH}}\right) \times 67.5 \times 1000 \left(\frac{\text{KWH}}{\text{day}}\right)$$

$$\times 270 \left(\frac{\text{days}}{\text{year}}\right) = \text{Rs } 3{,}098\ 250/\text{- per year}$$

(b) Payback Period of WHB

Cost of waste heat boiler

= Rs 3,000,000/-

Maintenance and overheads

= 12% of capital cost of WHB

= Rs 360,000/-

Interest on principal amount

= 20% of Rs. 3,000,000/-

= Rs 600,000/-

Total steam generated on 100% load = 80 t/day

4.5t of coal generate 1 ton of steam

Amount of coal saved = 80/4.5 = 17.777 t/day

Monetary savings, on the basis of coal, per year

$$= 750 \left(\frac{\text{Rs}}{\text{ton}}\right) \times 17.777 \left(\frac{\text{ton}}{\text{day}}\right) \times 270 \left(\frac{\text{day}}{\text{year}}\right)$$

= Rs 3599842/-

WHB is an energy saving equipment. So it qualifies for 100% depreciation in the 1st year.

Approximate savings in corporate taxes @ 55%) per year

= Rs 3000000 × 0.55

= Rs 1650000/-

Net Savings per year

= Rs (3599842 – 360000 – 600000 + 1650000)

= Rs 4289842/-

$$\text{Payback period} = \frac{\text{Rs } 3000000}{\text{Rs } 4289842} \times 12 \text{ months}$$

$$= 8.39 \text{ months} \qquad \textit{Ans.}$$

Problem 6.19 Determine the

(a) rate of fuel consumption in kg/h

(b) efficiency of WHB of Problem 6.18

Given

1 lt. of fuel generates 4.025 KWH of electrical energy

Specific gravity of liquid fuel = 0.90

Exhaust gas flowrate and temperature at 68% load are 7.55 kg/s and 325°C respectively.

Flue gas temperature at WHB inlet = 320°C

Flue gas temperature at WHB outlet = 170°C

Average feedwater temperature to the boiler = 75°C

Specific heat of flue gas = 0.26 kcal/kg °C

Assume 5% radiation loss suffered by the flue gas in the WHB.

Solution The determination of efficiency of the waste heat boiler is to be made on the basis of heat balance.

(a) Rate of Fuel Consumption

Average electric energy generated per day

= 67500 KWH

∴ Average fuel consumption per day

= 67500/4.025

= 16770 lt.

∴ Mass rate of fuel consumption

$$= 16770 \left(\frac{\text{lt}}{\text{day}}\right) \times 0.9 \left(\text{kg}\frac{\text{kg}}{\text{lt}}\right) \times \frac{1}{24}\frac{1}{(\text{h/day})}$$

$$= 628.875 \text{ kg/h} \qquad \textit{Ans.}$$

(b) Flowrate of Flue Gas at 60% Load

= 7.55 × 3600 = 27180 kg/h

(c) Useful Heat of Flue Gas

Total heat rejected by hot flue gas in the WHB

$$= 27180 \left(\frac{\text{kg}}{\text{h}}\right) \times 0.26 \left(\frac{\text{kcal}}{\text{kg°C}}\right) \times (320 - 170)\ (°\text{C})$$

= 1060020 kcal/h

Heat lost to radiation

= 1060020 × 5/100 kcal/h

= 53001 kcal/h

Useful heat available for steam generation

= 1060020 − 53001

= 1007019 kcal/h

= Heat input rate

(d) Heat Output

Average steam (10 kg/cm^2 g and saturated) generation rate

= 40 t/day

= 40 × 1000/24 kg/h

= 1666.66 kg/h

Average feedwater temperature = 75°C

Heat required to generate 1666.66 kg steam (10 kg/cm^2 g and saturated)

= 1666.66 × (183 − 75) + 1666.66 × 478.4 kcal

= 977329 kcal

∴ Heat output rate = 977329 kcal/h

Heat input rate = 1007019 kcal/h

∴ Efficiency of waste heat boiler

$$= \frac{977329}{1007019} \times 100\%$$

$$= 97.05\% \qquad \textit{Ans.}$$

BOILER HEAT BALANCE CALCULATIONS

Basis: 1 kg fuel

Heat Input

(A) H_1 = Gross calorific value of fuel, kcal

(B) H_2 = Heat input of fuel

$= c \cdot (\Theta_f - \Theta_r)$ kcal

c = specific heat of fuel, kcal/kg °C

Θ_f = temperature of fuel, °C

Θ_r = reference temperature, °C

(C) H_3 = Heat input of air

$= M_a\, c_a\, (\Theta_a - \Theta_r)$, kcal

M_a = mass of input dry air/kg fuel, kg air/kg fuel

c_a = specific heat of humid air

$= 0.24 + 0.46H$, kcal/kg dry air °C

H = humidity of air, kg moisture/kg dry air

Θ_a = air temperature, °C

Total heat input, $H_i = H_1 + H_2 + H_3$, kcal

Heat Output

(A) Heat consumed in generating steam

1. Economizer $H_4 = M_w\, (h_{ew} - h_{fw})$, kcal

M_w = mass of feedwater per unit mass of fuel, kg/kg fuel

h_{ew} = enthalpy of water at economizer outlet, kcal/kg

h_{fw} = enthalpy of feedwater, kcal/kg

2. Evaporator (Boiler) $H_5 = M_s(h_s - h_{ew})$, kcal

M_s = mass of steam generation per unit mass of fuel, kg steam/kg fuel

h_s = enthalpy of steam generated, kcal/kg

3. Superheater $H_6 = M_s\, (H_{ss} - h_s)$, kcal

h_{ss} = enthalpy of superheated steam, kcal/kg

(B) Heat lost in flue gases

$H_7 = \Sigma\, n_i\, \bar{c}_{pi}\, (\Theta_{fg} - 25)$, kcal

n_i = number of moles of i-th component present in the flue gas produced due to combustion of 1 kg fuel.

$\bar{c}_{Pi}$ = the mean specific heat of i-th component at Θ_{fg}

Θ_{fg} = flue gas temperature, °C

(C) Heat loss due to evaporation

1. Moisture is formed due to combustion of hydrogen in the fuel. Loss of heat to evaporate this moisture

$H_8 = M_m\, L$, kcal

M_m = mass of moisture formed by burning of hydrogen per kg of fuel, kg H_2O/kg fuel

L = latent heat of evaporation of the moisture at the dew point of the flue gases, kcal/kg

2. Heat loss due to evaporation of moisture present in the fuel

$H_9 = M_{mf}\, L$ kcal

M_{mf} = mass of moisture present in the fuel, kg/kg fuel

(D) Heat loss due to incomplete combustion of carbon as carbon monoxide.

$$H_{10} = \left[\frac{CO}{CO + CO_2}\right] \times C \times 5\,636.7 \text{ kcal}$$

CO = % (by volume) of carbon monoxide in the flue gas

CO_2 = % (by volume) of carbon dioxide in the flue gas

C = carbon burnt per kg fuel burnt, kg/kg fuel

(E) Heat loss due to unburnt carbon

$H_{11} = M_c(7837.5)$, kcal

M_c = mass of unconsumed carbon in refuse, kg/kg fuel

(F) Heat loss due to blowdown

$H_{12} = M_{bl}\, (h_{bw} - h_{fw})$, kcal

M_{bl} = mass of blowdown water, kg/kg fuel

h_{bw} = enthalpy of boiler water, kcal/kg

(G) Unaccounted heat loss

$$H_{13} = H_i - (H_4 + H_5 + H_6 + H_7 + H_8 + H_9 + H_{10} + H_{11} + H_{12})$$

Problem 6.20 A stoker-fired watertube boiler burns coal at the rate of 4 t/h to generate steam of 30 kg/cm^2 abs and 430°C at the rate of 30 t/h. Evaluate the boiler performance from the following data:

(a) *Component* — *Proximate analysis of coal*

Ash	12.7% (by weight)
Moisture	7.9% (by weight)

(b) Gross calorific value of coal = 6 250 kcal/kg

(c) *Component* — *Flue Gas Analysis*

CO_2	12.85%
O_2	6.5%
N_2	rest

(d) Carbon present in the cinder as unburnt combustible = 2.75%

(e) The feedwater temperature = 90°C

(f) Flue gas temperature at economizer outlet = 150°C

Flue gas pressure at economizer outlet = 755 mmHg

(g) Air temperatures at burner inlet: 30°C DB and 22°C WB. Ignore the presence of sulphur and oxygen in coal.

Solution The boiler performance, i.e. the overall thermal efficiency of the boiler is to be evaluated on the basis of heat balance.

Basis: 100 kmol of dry flue gas.

1. Oxygen Supplied with Combustion Air

N_2 in the flue gases

= 100 – (12.85 + 6.5)

= 80.65 kmol

100 kmol air contains 79 kmol N_2 and 21 kmol O_2

∴ O_2 supplied for combustion

= (21/79) × 80.65 = 21.438 kmol

2. Water Vapour Produced During Combustion

$$\underset{1\text{ kmol}}{C} + \underset{1\text{ kmol}}{O_2} \rightarrow \underset{1\text{ kmol}}{CO_2}$$

1 kmol of CO_2 requires 1 kmol of O_2 for combustion.

∴ 12.85 kmol of CO_2 require 12.85 kmol of O_2 for combustion.

Therefore, the oxygen utilized for hydrogen burning of fuel

= 21.438 – (12.85 + 6.5)

= 2.088 kmol

$$\underset{2\text{ kmols}}{2H_2} + \underset{1\text{ kmol}}{O_2} \rightarrow \underset{2\text{ kmols}}{2H_2O}$$

∴ Hydrogen burnt = 2(2.088) = 4.176 kmol

∴ Water produced = 4.176 kmol

3. Unburnt Carbon for 100 kmol of Dry Flue Gas

Carbon retained in the cinder

$$= \frac{2.75}{100} \times 4 \times 1000 \text{ kg/h}$$

= 110 kg/h

(FC + VM) in coal

= 100 – (ash% + moisture%) in coal

= 100 – (12.7 + 7.9) = 79.4%

$$\therefore \frac{\text{unburnt carbon}}{(\text{FC} + \text{VM} - \text{unburnt carbon})}$$

$$= \frac{2.75}{79.4 - 2.75} = 0.0358$$

Carbon in the flue gas

= carbon in the CO_2 in the flue gas

= 12.85 kmol

= 12.85 × 12

= 154.2 kg

Hydrogen in the flue gas

= 4.176 kmol

= 4.176 × 2

= 8.352 kg

Total burnt combustible

= 154.2 + 8.352

= 162.552 kg

Carbon unburnt for 100 kmol of dry flue gas

= 0.0358 × 162.552

= 5.8193 kg

= 0.4849 kmol

4. Excess Air

$$C + O_2 \rightarrow CO_2$$

1 kmol 1 kmol 1 kmol

1 kmol of C requires 1 kmol O_2 for combustion

∴ 0.4899 kmol of C requires 0.4899 kmol of O_2 for combustion

∴ Oxygen required to burn that unburnt carbon = 0.4899 kmol

∴ Excess O_2 supplied

= 6.5 – 0.4899 = 6.0151 kmol

Total stoichiometric O_2 required

= 12.85 + 2.088 + 0.4899

= 15.4229 kmol

Therefore, excess air supplied

$$= \frac{6.0151}{15.4229} \times 100$$

= 39%.

5. Moisture Content of the Flue Gas

100 kg coal contains 7.9 kg free moisture and [100 – (12.7 + 7.9)] i.e. 79.4 kg combustibles.

Free moisture appearing with the combustion of 162.552 kg combustibles

$$= \frac{7.9}{79.4} \times 162.552$$

= 16.173 kg = 16.173/18 kmol = 0.8985 kmol

From psychrometric chart, humidity of air at 30°C DB and 22°C WB

= 13.4 gm/kg dry air

$$= \frac{13.4}{18 \times 1000} \text{ kmol } H_2O / \frac{1}{29} \text{ kmol dry air}$$

$$= \frac{0.02158 \text{ kmol water}}{\text{kmol dry air}}$$

Therefore, the total moisture entering the combustion zone

= 0.02158 × kmol of air containing 21.438 kmol O_2

$$= (0.02158) \times \left[\frac{100}{21} \times 21.438\right]$$

= 2.203 kmol

Therefore, total moisture in the flue gases

= (4.176 + 0.8985 + 2.203) kmol

= 7.2775 kmol

6. Composition of Flue Gas

Component		kmol	mol%
CO_2		12.85	11.97
O_2		6.5	6.05
N_2	$\frac{79}{21} \times 21.438$	= 80.647	75.179
H_2O		7.275	6.781
		107.272	99.980

7. Heat Input Rate

Rate of fuel burning = 4 ton coal/h

Gross clorific value of fuel = 6250 kcal/kg

Heat input rate = $4 \times 1000 \times 6250$

= 25000000 kcal/h

Ignoring the heat input of air (at 30°C), the net heat imput rate = 25000000 kcal/h

8. Heat Output Rate

[A] Heat absorbed in generating superheated steam

$H_4 + H_5 + H_6$

$= 30{,}000 \times (787.8 - 90.04)$ kcal/h

= 20932800 kcal/h

where 787.8 kcal/kg = enthalpy of steam at 30 kgf/cm^2 abs and at 430°C = h_{ss}

90.04 kcal/kg = enthalpy of water at 90°C

[B] Combustibles left in the cinder (as C)

= 110 kg/h

Calorific value of carbon (GCV = NCV)

= 94.05 kcal/mol

$$= \frac{94.05}{12} \times 1000 \text{ kcal/kg}$$

Heat lost in the combustibles

$$H_{11} = \frac{94.05}{12} \times 1000 \times 110 \text{ kcal/h}$$

= 862125 kcal/h

[C] Total free moisture evaporated from coal

$$= \frac{7.9}{79.4} \times 4000 \times \frac{79.4 - 2.75}{100}$$

= 305.055 kg/h

Now, partial pressure of water vapour in the flue gas

= 755 × mol fraction of water vapour in the flue gas

= 755 (7.275/107.272)mm Hg

= 51.20 mm Hg

Dew point of flue gases ≈ 38°C

Latent heat of water at 38°C = 575.83 kcal/kg

Heat lost due to evaporation of free moisture

= 305.055 × 575.83 = 175660 kcal/h

[D] Heat loss due to evaporation of moisture formed due to combustion of hydrogen in the coal burnt

$$H_8 = \left[\frac{4.176}{162.552}\right](4000)\left[\frac{79.4 - 2.75}{100}\right]$$

(18) (575.83) kcal/h

$$\left[\frac{\text{kmol } H_2O}{\text{kg comustibles}}\right]\left[\frac{\text{kg coal}}{\text{h}}\right]\left[\frac{\text{kg combustibles}}{\text{kg coal}}\right]$$

$$\left[\frac{\text{kg } H_2O}{\text{kmol } H_2O}\right]\left[\frac{\text{kcal}}{\text{kg}}\right] = 816408 \text{ kcal/h}$$

[E] Heat lost in flue gases (H_7) is evaluated on the basis of mean specific heat data of flue gas components:

Component	Mean Sp. Heat in the Range 25° – 150°C
CO_2	9.5 kcal/kmol °C
H_2O	8.12 kcal/kmol °C
O_2	7.12 kcal/kmol °C
N_2	7.00 kcal/kmol °C

Therefore, for 107.272 kmol of flue gas

$n_i\, c_{pi} = 12.85\ (9.5) + 7.275\ (8.12) + 6.5\ (7.12) + 80.647\ (7)$ kcal/°C

= 791.957 kcal/°C

Heat lost in flue gases = 791.957 (150 – 25)

= 99,994.62 kcal

Therefore, the rate of heat loss of flue gases

$$= 99{,}994.62\ (4{,}000/162.552)\left(\frac{79.4 - 2.75}{100}\right) \text{ kcal/h}$$

$$= 1{,}886{,}064 \frac{\text{kcal}}{\text{h}}$$

9. Heat Balance

Heat Input Rate (kcal/h)	Heat Output Rate (kcal/h)		
25,000,000	Steam generation	= 20932800	83.73%
	Heat loss due to unburnt combustibles	= 862125	3.44%
	Heat loss due to evaporation of free moisture	= 175660	0.70%
	Heat loss due to evaporation of moisture formed due to combustion of hydrogen in the fuel	= 816408	3.26%
	Heat lost to flue gases	= 1886064	7.54%
	Unaccounted heat loss (by difference)	= 326943	1.30%
		Total = 25 000 000	

10. Overall Thermal Efficiency of the Boiler

$$= \frac{\text{Heat output rate (steam generation)}}{\text{Heat input rate (fuel combustion)}}$$

$$= \frac{20932800}{25000000} \times 100 = 83.73\%$$

7

DRAUGHT

Q. *What is draught (draft)?*

Ans. The difference in pressure of the combustion products within a boiler furnace and the cold air outside is known as (draught or draft).

Draught is also the differential pressure between the air column (chimney height) outside and the hot flue gas column (chimney height) inside the chimney. See Fig. 7.1.

Equipment	*Level*	*Pressure*
Combustion chamber	Grate	$p_1 = p_a$ + pressure of cold air of column H where d_a = density of air $= p_a + H\, d_a\, g$
Chimney	Grate	$p_2 = p_a$ + pressure of hot flue gas of column H $= p_a + h\, d_f g$

Since $p_1 > p_2$, the draught produced

$$= p_1 - p_2$$
$$= (p_a + H\, d_a\, g) - (p_a + H\, d_f\, g)$$
$$= H\,(d_a - d_f)\,g \text{ kgf/cm}^2$$

Q. *Is there any other definition of draught?*

Ans. It is the difference in the weight of a cold air column of chimney height (H) and that of flue gas of the same column of chimney height.

Q. *How?*

Ans. Draught = $H\,(d_a - d_f)\,g$ kgf/cm^2

Now, if unit area of cross-section of the chimney is considered, then

$$H\, d_a\, g = \underbrace{\text{H (Area of Cross-section)}}_{\text{Volume}}\, d_a\, g$$

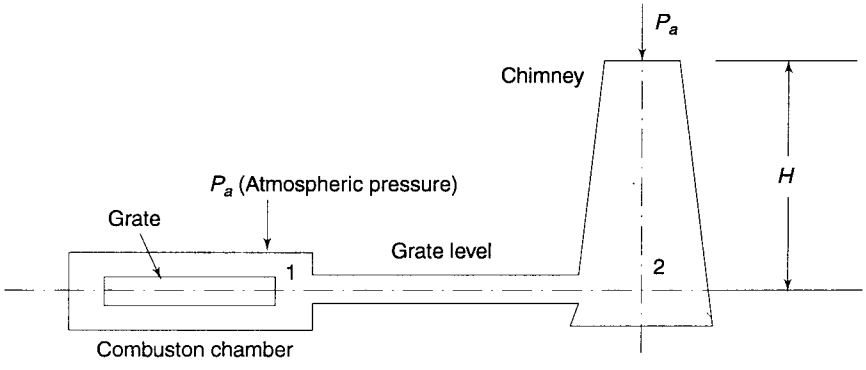


Fig. 7.1

$$= \text{wt. of air column of height } H$$

$$= W_a$$

$$H\, d_f\, g = H \text{ (Area of Cross-section) } d_f\, g$$

$$= \text{wt. of flue gas column of height } H$$

$$= W_f$$

$$\text{Draught} = (W_a - W_f) \text{ kgf}$$

Q. *Why is draught a necessity?*

Ans. 1. To force adequate air through the combustion chamber to assist in the proper combustion of fuel
2. To draw out the resulting hot flue gas from the combustion chamber
3. To vent the products of combustion to atmosphere after necessary heat recovery in superheater, economizer and air heater.

Q. *How is draught classified?*

Ans. Draught can be broadly classified into two classes—natural draught and artificial draught.

Artificial draught is of two types—steam jet draught and mechanical draught.

Steam jet draught can be of induced as well as forced draught type.

Mechanical draught can be of induced, forced and balanced draught types.

Q. *What is natural draught?*

Ans. When the draught is generated with the help of the chimney only.

Q. *What are the advantages of natural draught?*

Ans. 1. Simple in design and construction
2. Low capital investment (lower than that for artificial draught)
3. No maintenance cost
4. Needs no power input for operation
5. High dispersion of flue gas as chimney height is very high
6. Long life.

Q. *What is artificial draught?*

Ans. The draught produced by steam jet or mechanical means like fans and blowers.

Q. *Why is artificial draught required?*

Ans. It is because natural draught will not be sufficient to generate enough static draught (250 to 350 mm of water column) as is required by large steam generation plants.

Moreover, natural draught has one serious limitation i.e. variation of draught with the variation of the climatic conditions.

Q. *How does natural draught vary with the climatic conditions?*

Ans. It decreases with the increase of ambient air temperature and increases with the fall of the latter.

For maximum discharge, the draught (draft) produced (in mm of water column),

$$h_w = 176.5 \text{ H}/T_{\text{air}}$$

where T_{air} is the absolute temperature (K) of inlet air and H is the height of the chimney.

Q. *What are the specific advantages of artificial draught?*

Ans. 1. No need for a large chimney, which is both uneconomical and inconvenient to build
2. Higher operating efficiency (about 70%) than natural draught (hardly 1%)
3. Functionally independent of climatic conditions
4. Any grade of fuel—superior or inferior variety—can be economically burnt
5. Eliminates the need for high temperature of the exhaust flue gas as required in the case of natural draught. About 20% of heat released by fuel is lost to the flue gases in the natural draught
6. Draught can be regulated as per the requirement of the furnace.

Q. *What are the major disadvantages of artificial draught?*

Ans. 1. High investment
2. High operating and maintenance cost.

Q. *How many types of steam jet draught are there?*

Ans. Two—induced draught and forced draught (draft).

Q. *How is induced draught by steam produced?*

Ans. Exhaust steam is directed into the smoke box through nozzles. (Fig. 7.2) Steam emerging from these nozzles at high velocity creates a partial vacuum that drags out the air through the furnace space to chimney.

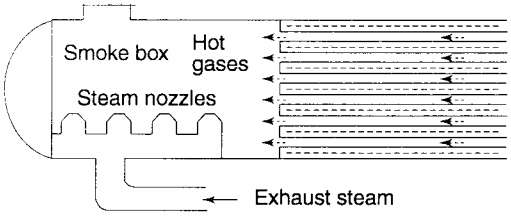


Fig. 7.2 *Induced draught produced by steam*

Q. *Where is such a system employed?*

Ans. Steam locomotive boilers.

Q. *What is the pressure of exhaust steam?*

Ans. 1.5 to 2 kgf/cm^2

Q. *What is turbine draught?*

Ans. Forced draught produced by steam is also called turbine draught.

Q. *What are the advantages of steam jet draught?*

Ans. 1. Simplicity in design and operation
2. Low installation cost
3. Has the capability of accepting low grade fuel
4. Occupies very little space.

Q. *What are the disadvantages of a steam jet draught?*

Ans. 1. Operates only when steam is available
2. Draught produced is very low (20-30 mm of water column).

Q. *How does the forced draught mechanical system operate?*

Ans. A blower or forced draught (F.D.) fan is installed upstream of the boiler and air is forced to pass through the furnace, flues, economizer, air heater and the chimney. (Fig. 7.3)

Q. *Why is it called forced draught?*

Ans. Air is forced to flow through the entire system under pressure.

Q. *Forced draught mechanical system is also called positive draught system. Why?*

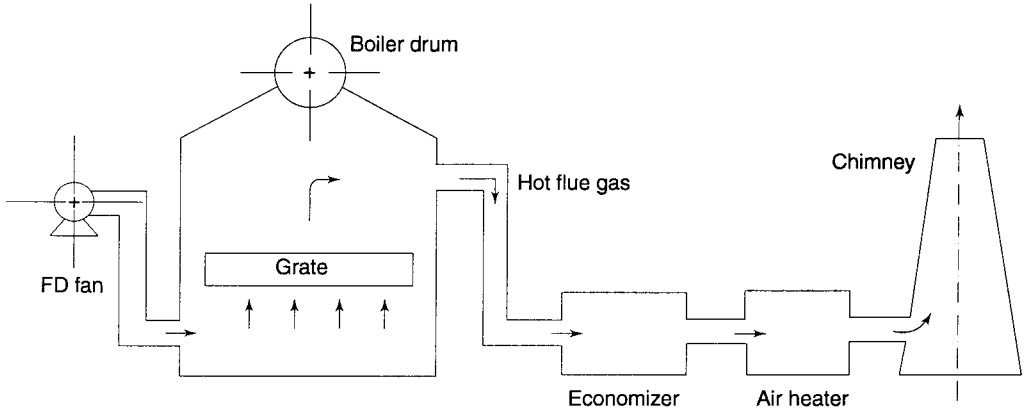


Fig. 7.3 *Forced draught (mechanical system).*

Ans. The air pressure throughout the system is positive, i.e. above the atmospheric pressure.

Q. *If the chimney is eliminated, will it affect the forced draught system?*

Ans. Not very much.

Q. *Then why is a chimney installed in a forced draught system?*

Ans. To prevent the contamination of stack gas in the ground level. Its chief function is to discharge the flue gas at higher levels.

Q. *How does an induced draught mechanical system operate?*

Ans. In this case a blower or induced draught fan is installed downstream of the air heater to suck out the air from the furnace and let it out, via economizer and air heater, to the atmosphere through the chimney. (Fig. 7.4).

Q. *What is the total draught produced by this system?*

Ans. It is the sum of the draughts produced by the I.D. (Induced Draught) fan and the chimney.

Q. *Induced draught is used, in general, when economizer and air heater are incorporated in the system. Why?*

Ans. Overall draught generated is independent of the temperature of the hot flue gas and as such the flue gas can be discharged after extracting as much heat as possible in the economizer and air heater.

Q. *What is the most suitable location of the I.D. fan?*

Ans. It should be located at a place where the flue gas temperature is lowest, i.e. downstream at the air heater.

Q. *Why should the I.D. fan be located where the flue gas temperature is lowest?*

Ans. Since the flue gas can be discharged as cold as possible, it is convenient to locate the I.D. fan where most of the heat of the flue gas has been recovered. This will also mean reduced size of the I.D. fan, as lower the gas temperature lower will be the specific volume of the gas handled.

Q. *What are the advantages of forced draught (draft) over the induced draught?*

Ans. 1. The size of the F.D. fan is smaller and its power requirement is lower than the I.D. fan since the temperature (hence the specific volume) of the fluid (air) handled by the F.D. fan is lower than that of the fluid (flue gasses) handled by the I.D. fan. The size of the I.D. fan is 1.3 times the size of the F.D. fan.

2. For I.D. fans, a separate cooling water system should be included to cool the fan

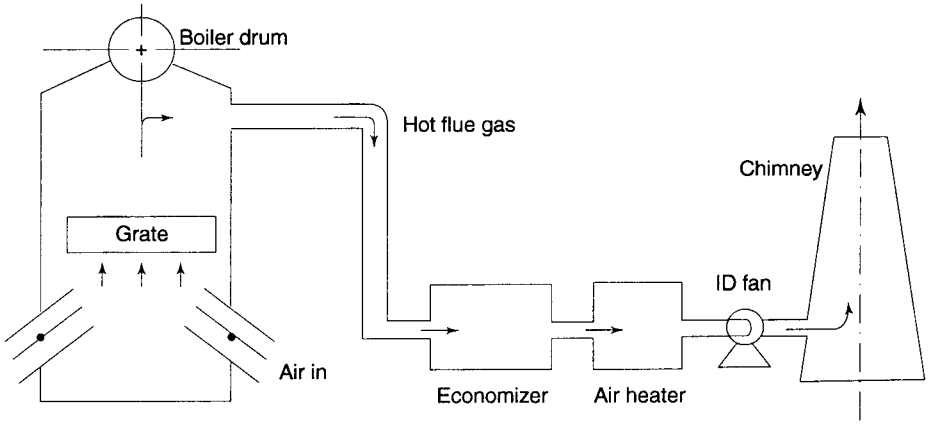


Fig. 7.4 *Induced draught (mechanical system).*

bearings as it will have to withstand the high temperature of the flue gases.

3. Since during forced draught, the furnace is always at a pressure above the atmospheric pressure, there is no chance of leakage of cold air into it. Whereas in the case of induced draught, there is always ingestion of cold air from outside into the furnace causing dilution of combustion.
4. There is more uniform and greater penetration of combustion air through the furnace grate in the case of forced draught than in the case of induced draught. Better the penetration and distribution of the air, greater is the rate of firing.
5. Whenever firing is to be done in the case of an I.D. system, there is always a rush of cold air into the furnace space as the doors are opened. This means draught loss and loss in heat transmission efficiency of the surfaces.

Q. *Then why is not an F.D. used alone?*

Ans. In this case, the furnace cannot be opened for firing or for inspection, as the high pressure air inside the furnace will try to gush out suddenly. And this may blow out the fire completely, stopping the furnace.

Q. *Then what is the solution?*

Ans. Use of balanced draught, i.e. I.D. and F.D. combined.

Q. *How will the balanced draught function?*

Ans. The forced draught fan will supply the combustion air for proper and complete combustion of fuel and will overcome the fuel bed resistance in the case of stoker grate.

The induced draught will remove the flue gas plus excess air from the furnace, maintaining the pressure inside the furnace just below the atmospheric. (Fig. 7.5)

Q. *What is the pressure distribution throughout this system?*

Ans. Fig. 7.6.

Q. *What is the pressure inside the furnace?*

Ans. It is near atmospheric and somewhat below it.

Q. *What is its effect?*

Ans. This eliminates the danger of blowing out of flames as well as the danger of inrushing of air into the furnace when the furnace doors are opened for inspection.

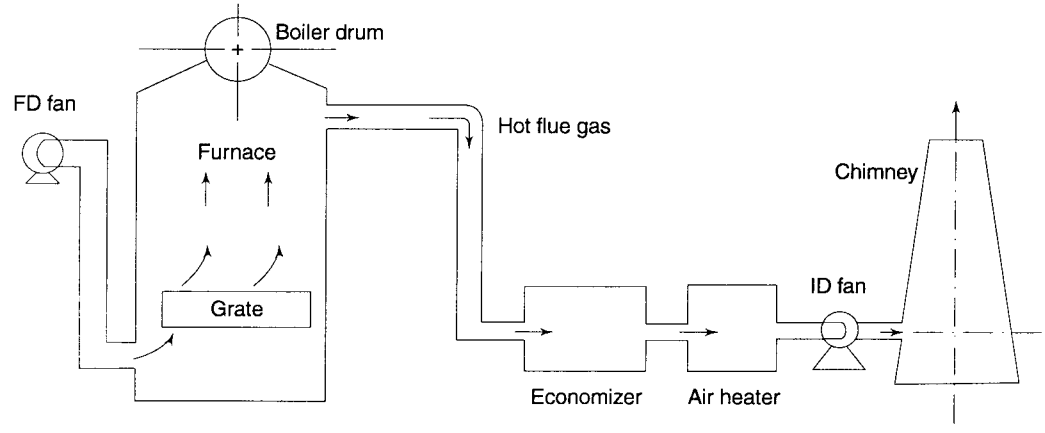


Fig. 7.5 *Balanced draught system.*

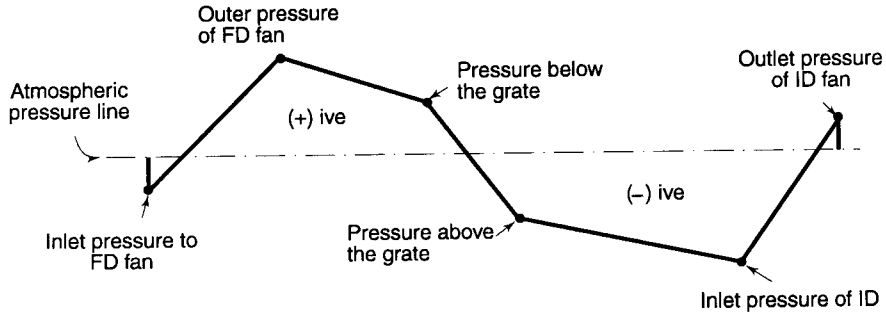


Fig. 7.6 Pressure distribution profile in a balanced draught system

Q. *What is the pressure of air below the grate?*

Ans. Above atmospheric.

Q. *Why is this necessary?*

Ans. To flush the fuel bed with adequate and uniform supply of air for proper combustion.

Q. *What is the pressure of air above the grate?*

Ans. Below atmospheric.

Q. *Why is this necessary?*

Ans. To drag out the products of combustion as quickly as possible from the zone of combustion.

Q. *How can the efficiency of the fans (ID/FD) be computed?*

Ans. If the fan generates a draught of h_w mm of water (= h_w kgf/m^2) and discharges V m^3/min of gas, then the work done by the fan

$$= h_w \text{ V, kgf} \cdot \text{m/min}$$

$$\text{H.P. of the fan} = \frac{h_w V}{4500}$$

If η_1 and η_2 be the transmission efficiency (between the prime mover and the fan) and mechanical efficiency (of the fan), then

$$\text{B.H.P. of primemover} = \frac{h_w V}{4500\, \eta_1 \eta_2}$$

This is the required relationship from which the mechanical efficiency of the fan can be computed.

Q. *How is the volumetric flowrate (V m^3/min) of ID or FD determined?*

Ans. For an F.D. fan, the gas handled is air. Hence the volume of air supplied per minute

$$V_a = \frac{W\, M_a}{\rho_a} \; m^3$$

where W = kg of coal burnt per minute

M_a = kg of air supplied per kg of coal

ρ_a = density of air at temperature T_a

Since the pressure difference between atmospheric air and discharged air of F.D. fan is small, by applying Charles' Law

$$\rho_1 T_1 = \rho_2 T_2$$

$$\text{or } 1.293\ (273) = \rho_a T_a$$

$$\therefore \qquad \rho_a = \frac{1.293\ (273)}{T_a}$$

$$\therefore \qquad V = \frac{W\, M_a\, T_a}{1.293\ (273)} = W\, M_a\, T_a/353$$

For I.D. fan by following mass balance

Fuel	+	Air	⟶	Flue Gas
W		$W \cdot M_a$		$W + W \cdot M_a$
				$= W\,(1 + M_a)$

Therefore, the volume of flue gas handled

$$V_f = \frac{W(1 + M_a)}{\rho_f}$$

where ρ_f = density of flue gas at flue gas temperature T_f, at the inlet of I.D. fan

Now during combustion,

$$C + O_2 \longrightarrow CO_2$$
$$1 \text{ vol.} \qquad 1 \text{ vol.}$$

the volume of air required for combustion is equal to the volume of flue gas produced, ignoring the reaction $2H_2 + O_2 \longrightarrow 2H_2O$ as the H-content of coal is too small.

Therefore, volume of $W(1 + M_a)$ kg of flue gas

$$= \frac{W\, M_a\, T_f}{1.293\,(273)}$$

$$\therefore \quad \rho_f = \frac{W(1 + M_a)}{\dfrac{WM_a\, T_f}{(273 \times 1.293)}} = \frac{1 + M_a}{M_a} \frac{273\,(1.293)}{T_f}$$

$$\therefore \quad V_f = \frac{W(1 + M_a)}{1} \frac{T_f}{273\,(1.293)} \cdot \frac{M_a}{1 + M_a}$$

$$\text{or} \quad V_f = \frac{W\, M_a\, T_f}{353} \; m^3$$

Q. *Show that the ratio of B.H.P. of the prime mover of an F.D. fan to the B.H.P. of the prime mover of an I.D. fan is the ratio of absolute temperature of air to flue gas, provided both fans produce the same draught (draft) and have the same efficiency.*

Ans. B.H.P. of the prime mover of F.D. Fan

$$= \frac{h_w\, V_a}{4500\, \eta_1\, \eta_2}$$

$$= \frac{h_w\, W\, M_a\, T_a}{4500\, \eta_1\, \eta_2\, 353}$$

B.H.P. of the prime mover of I.D. fan

$$= h_w\, V_f / 4500\, \eta_1\, \eta_2$$

$$= h_w\, W\, M_a\, T_f / 4500\, \eta_1\, \eta_2\, (353)$$

$$\frac{\text{B.H.P. of the prime mover of F.D. Fan}}{\text{B.H.P. of the prime mover of I.D. Fan}} = \frac{T_a}{T_f}$$

Q. *An I.D. fan requires more power, generally 50% more power, than an F.D. fan. Why?*

Ans. Generally, $T_f = 1.5\, T_a$ and as such

$$\frac{\text{B.H.P. of the prime mover of I.D. Fan}}{\text{B.H.P. of the prime mover of F.D. Fan}} = \frac{T_f}{T_a}$$

$$= \frac{1.5\, T_a}{T_a}$$

$$= 1.5$$

I.D. fan requires 1.5 times the power required by F.D. fan, i.e. an I.D. fan draws 50% more power than an F.D. fan.

Q. *Why is the control of air supply to the combustion chamber of thermal power plants necessary?*

Ans. To meet the variable load demand.

Q. *What is system resistance characteristic?*

Ans. Interpolation of various static pressures developed within the furnace at varying air flows yields a certain curve called system resistance characteristic. [Fig. 7.7]

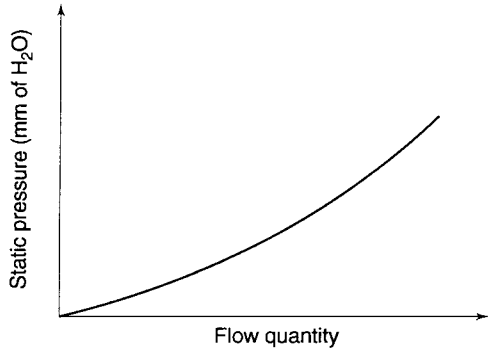


Fig. 7.7 *System resistance characteristic.*

Q. *How many resistance curves are there for a particular boiler system?*

Ans. Only one.

Q. *What is the total resistance along the boiler system?*

Ans. It is the sum of the pressure losses in fittings, filters, ducts, fuel bed, economizer, air heater and many others.

Q. *How does this total resistance vary with the velocity and quantity of airflow into the boiler system?*

Ans. The total resistance increases with the increase of velocity and quantity of air flow (Q)

$$h_1 = K\,Q^2$$

where h_1 = head loss due to total resistance

Q. *How can the supply of air be controlled to meet the variable load demand?*

Ans. Two ways

1. Damper control
2. Speed control

Q. *Show how air flow can be adjusted by damper control?*

Ans. Let (for the fan operating at speed N_1 (rpm)), point A marks the point of operation at full load whence the quantity of air supply is Q_a. [Fig. 7.8]

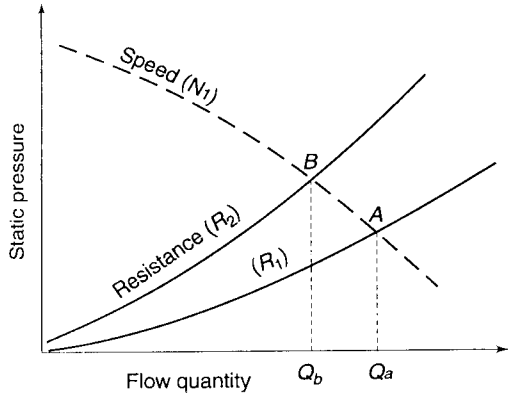


Fig. 7.8 *Damper control.*

Now, if the load is to be reduced, the flow of air is to be reduced, say to Q_b. This is determined by increasing the system resistance, i.e. by partly closing the dampers. This brings about a new resistance curve (R_2) which intersects the fan characteristic at point B. Now quantity of airflow (Q_b) corresponding to this point is the desired value.

Q. *How can the flow quantity of air be adjusted by speed control?*

Ans. This is achieved by changing the fan rpm to bring about the desired change in the fan characteristic.

If the airflow is to be reduced from Q_a to Q_b, the speed of the fan is reduced from N_1 to N_2 rpm so that the new fan characteristic intersects the resistance curve (R_1) at point B corresponding to airflow Q_b [Fig. 7.9]

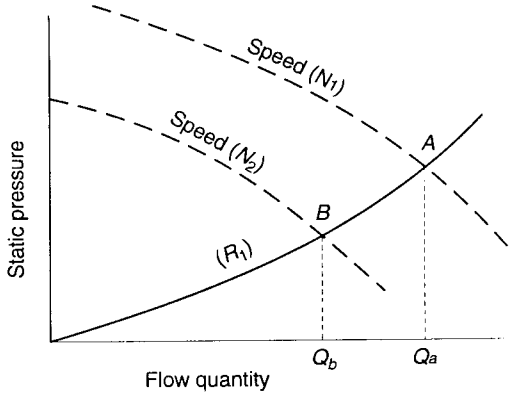


Fig. 7.9 *Speed control.*

Q. *Between damper control and speed control which is more economical?*

Ans. Speed control.

Q. *Why?*

Ans. The power (B.H.P.) requirement in the case of speed control is less than that required in the case of damper control to bring about the desired change in airflow quantity. [Fig. 7.10]

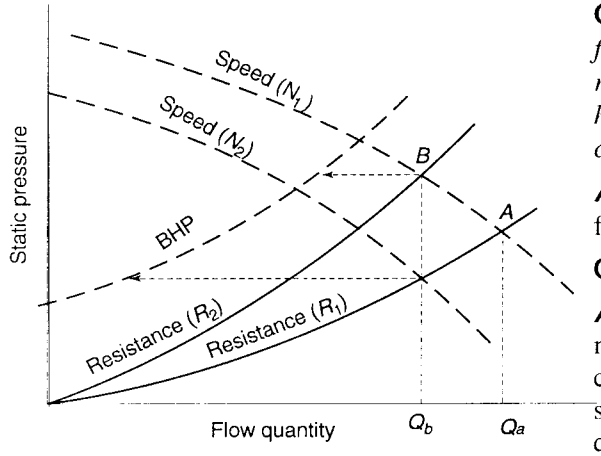


Fig. 7.10

Q. *But most of the steam generation plants use inlet louvers or discharge dampers to control airflow while keeping motor speed constant. Why?*

Ans. This is because speed control, with slip ring motors or multiple winding induction motors is too expensive to favour speed control system.

Q. *What is the total draught required to produce the desired airflow in the furnace and discharge the flue gas out of the chimney?*

Ans. It is the arithmetic sum of draught losses in the air and gas loops in the boiler unit

$$h_t = h_{fb} + h_e + h_d + h_v$$

where h_t = total draught loss (in mm of water)

h_{fb} = draught loss in fuel bed (mm of water)

h_e = draught loss in equipment (mm of water)

h_d = draught loss in ducts and chimney (mm of water)

h_v = head loss to produce the required exit velocity of the flue gas from the chimney (mm of water)

Q. *What factors influence the fuel bed resistance responsible for draught loss?*

Ans. Fuel bed thickness, size of coal and rate of combustion.

Q. *If a forced draught stoker furnace is used to fire anthracite coal and bituminous coal separately, in which case will the draught loss be higher for the same rate of combustion (kg of coal/m^2 of grate area)?*

Ans. Draught loss will be higher in the case of forced draught stoker firing anthracite coal.

Q. *Why?*

Ans. Anthracite coal contains much less volatile matter than bituminous coal. Hence it is more compact than the bituminous variety. So for the same rate of combustion, it will require greater quantity of airflow than bituminous coal.

Since the total resistance of the equipment increases with the increase in velocity and quantity of airflow, draught loss will be higher in the case of anthracite bed than its bituminous counterpart.

Q. *What is the velocity head loss?*

Ans. The velocity head loss (h_v) is given by

$$h_v = \frac{v^2}{2g}$$

where v = velocity of the flue gas at the exit of the chimney.

Q. *What factors influence it?*

Ans. Air temperature and natural air velocity at the chimney height.

Q. *What is the head loss in the ducts and chimney?*

Ans. It is the draught loss to overcome friction between air/ flue gas and gas ducts/chimney.

It is given by the Fanning equation

$$h_d = \frac{4 f L v^2}{2 g d}$$

where f = friction factor of the duct and chimney

L = length of the duct and chimney

v = velocity of air/flue gas flow

d = hydraulic diameter of the duct = $2\left[\frac{\pi r^2}{P}\right]$

P = wetted perimeter

Q. *What is a chimney?*

Ans. It is a long, vertical cylindrical construction made of steel or masonry or concrete to discharge the flue gas of a boiler sufficiently high into the atmosphere to avoid nuisance to the local people.

Q. *What are the main loads acting on the chimney?*

Ans. Its own dead weight acting through the centre of mass and wind pressure.

Q. *What is the wind pressure normally taken to design a chimney?*

Ans. It is 0.015 kgf/cm^2.

Q. *In which case is a steel chimney preferred?*

Ans. Generally preferred for short exhaust stacks.

Q. *Why?*

Ans. For economy.

Q. *How are they erected? Are they a monobloc system or otherwise?*

Ans. In general, they are made of several sections erected in the field and welded or riveted along the horizontal joints.

Q. *What is the major drawback of a steel chimney?*

Ans. Combustion of high-sulphur fuel liberates acidic oxides like SO_2 and SO_3 producing acid mist (H_2SO_3, H_2SO_4) at dew point. These acids act upon the steel surface leading to a severe corrosion problem.

Q. *How can this be prevented?*

Ans. 1. Lining the steel chimney with acid-resistant brick (silica brick)
2. Cladding the inner surface of the chimney with aluminium.

Q. *What is known as cold air inversion?*

Ans. It marks the phenomenon when the flue gas pressure inside the chimney is less than the air pressure outside the chimney.

Q. *When does cold air inversion occur?*

Ans. When several boilers working on partial load are connected to a common chimney.

Q. *Why is a steel chimney particularly favoured in the case of a gas turbine power plant?*

Ans. A gas turbine attains its full load in less than a minute and as such the chimney has to withstand a thermal shock resulting from the increase in temperature of 450–500°C (723–773 K) during this period.

The thin walled steel chimney having high thermal conductivity is best fitted for accepting such a load.

Q. *Instead of common bricks, perforated bricks are used nowadays to construct brick chimneys. Why?*

Ans. The perforations aid
(a) structural stability
(b) heat insulating properties of the construction with the effect that maximum draft performance is gained.

Q. *In which cases are reinforced concrete chimneys favoured?*

Ans. In cases where the life of the chimney is singled out as the most important and prime element of consideration and where high thermal stresses are absent.

Q. *What is the main drawback of such concrete chimneys?*

Ans. They are susceptible to spalling due to high thermal shock. Acid/water will ingress through the cracks developed due to thermal stress and cause splitting.

Q. *In which cases are glass-reinforced plastic chimneys favoured?*

Ans. Under the following operating conditions, a glass-reinforced plastic chimney is most favourable

1. low flue gas temperature
2. low thermal stress
3. highly corrosive emissions.

Q. *How can chimney height be calculated from draught (draft)?*

Ans. Draught is the difference between the pressures exerted by the air column and flue gas column of the same chimney height (H) measured from the boiler grate level, i.e.

draught = $p_{air} - p_{fg}$

[See steps I to IV on p. 240–241]

Q. *How can this equation be expressed in terms of mm of water?*

Ans. Since 1 kg/m^2 ≡ 1 mm of water column, draught measured in terms of water column comes out as

$$h = 353H\left[\frac{1}{T_1} - \frac{W+1}{W}\frac{1}{T}\right] \text{ mm}$$

of water column

Q. *How can draught be expressed in terms of the height of the column of the flue gas?*

Ans. If h_{fg} be the height of a column of hot flue gases equivalent to the draught pressure of p kgf/m^2, then

$$h_{fg} = p/\text{Density of hot flue gases}$$

$$= \frac{1.293HT_0\left[\frac{1}{T_1} - \frac{W+1}{W}\frac{1}{T}\right]}{1.293\left(\frac{W+1}{W}\right)\frac{T_0}{T}}$$

$$= H\left[\frac{W}{W+1}\cdot\frac{T}{T_1} - 1\right], \; m \;]$$

Q. *How can the chimney diameter be determined?*

Ans. Velocity of flue gases in the chimney

$$v = \sqrt{2g\,(h_{fg} - h_L)}$$

where h_L = draught loss in chimney

Step (I) *Now*

Fuel	+	Air	⟶	Flue Gas (T °K)
Mass 1 kg		W kg		$(W + 1)$ kg

Step (II)

Gas	Temperature	Volume	Remarks
Air (1 kg)	T_0K = 273°K	$\frac{RT_0}{p} = \frac{29.27(273)}{1.023\times10^4} = 0.7734$ m^3	
-do-	T_1°K (air temp. outside chimney)	$\frac{0.7734\,T_1}{T_0}$ m^3	Applying Charle's Law as pressure difference between the furnace and chimney is too low
Air (W kg)	-do-	$0.7734\,\frac{WT_1}{T_0}$ m^3	
Flue Gas [$(W + 1)$ kg]	T °K	$0.7734\,\frac{WT}{T_0}$ m^3	The volume of air required for complete combustion C + O_2 ⟶ CO_2 1 vol. 1 vol. is practically equal to the volume of the products of combustion

Step (III)

Gas	Mass	Volume	Density	Pressure
Air	W kg	$0.7734\ W(T_1/T_0)$	$W/0.7734W\,(T_1/T_0)$ $= 1.293\ (T_0/T_1)$ kg/m^3	$p_{air} = 1.293\ H\ (T_0/T_1)\ g$, kgf/m^2
Flue Gas	$(W+1)$ kg	$0.7734\ W(T/T_0)$	$(W+1)/0.7734W\ (T/T_0)$ $= 1.293\ \frac{W+1}{W}\ \frac{T_0}{T}$	$p_{fg} = 1.293\ H\ \frac{W+1}{W}\ \frac{T_0}{T}\ g$, kgf/m^2

Step (IV)

$$\text{Draught (Draft)} = p_{air} - p_{fg} = 1.293 T_0\ H \left[\frac{1}{T_1} - \frac{W+1}{W}(1/T)\right] g,\ \text{kgf/m}^2$$

$$= 353\ H \left[\frac{1}{T_1} - \frac{W+1}{W}\ \frac{1}{T}\right] g,\ \text{kgf/m}^2$$

where $T_0 = 273$ K

With the help of this equation chimney height can be calculated.

$$v = 4.43\ \sqrt{h_{fg}\ (1 - h_L/h_{fg})}$$

$$= 4.43\ \sqrt{(1 - h_L/h_{fg})}\ \sqrt{h_{fg}} = C\sqrt{h_{fg}} \quad \text{(I)}$$

where C = constant $= 4.43\ \sqrt{1 - h_L/h_{fg}}$

Again, mass flowrate of flue gases through chimney

$$\dot{M} = \text{volume flowrate} \times \text{density}$$

$$= (vA) \times \rho_{fg} = C\sqrt{h_{fg}}\ A\ \rho_{fg} \quad \text{(II)}$$

From the known values of v, ρ_{fg} and $\dot{M}$ the value of A (area of cross-section) of the chimney can be found out from equation (II). When A is known, the diameter of the chimney can be easily determined.

Q. *What is the condition for maximum discharge through a chimney?*

Ans. For maximum discharge to take place, the chimney draught expressed in terms of column of hot flue gases should be equal to the height of the chimney.

Q. *Why is it said that chimney draught is created at the cost of thermal efficiency of the boiler?*

Ans. The chimney draught is a function of the temperature

$$\text{Draught} = 353\ H \left[\frac{1}{T_1} - \frac{W+1}{W}\left(\frac{1}{T}\right)\right] g,\ \text{kgf/m}^2$$

of the hot flue gases leaving the chimney. As is evident from the above equation, higher the temperature of the flue gases, greater will be the draught.

So a sizeable portion of the heat generated in the boiler furnace goes to heat up the flue gases to the desired temperature to maintain the desired draught level. This heat could have otherwise been utilized for heating the BFW or preheating the combustion air to increase the efficiency of the boiler.

Q. *How can chimney efficiency be determined?*

Ans. This can be done with the aid of the following equation:

$$\eta_{chim} = \frac{H\ [(W/W+1)\ (T/T_1) - 1]}{4.187\ C_p\ (T - T_2)}$$

where T_2 = temperature of flue gases in artificial draught.

Q. *What is the magnitude of chimney efficiency, in general?*

Ans. It comes out to be a fraction of a per cent.

Problem 7.1 The height of a chimney of a steam generation plant is 35 m. Determine

(a) the draught produced by the chimney
(b) the available draught from the following parameters:
Flue gas temperature = 300°C,
Ambient air temperature = 25°C
Mass of air supplied = 20 kg/kg of fuel,
Available draught (draft)
= 0.82 times natural draught

Solution

Step (I) Chimney Draught Theoretical

H	T_1	T	W	$h = 353\ H \left\{ \frac{1}{T_1} - \left[\frac{W+1}{W} \right] \frac{1}{T} \right\}$, mm of H_2O
35 m	25 + 273 = 298°K	300 + 273 = 573°K	20 kg/kg of fuel	353 (35) {1/298 – (21/20) (1/573)}, mm of H_2O = 18.82 mm of H_2O ***Ans.***

Step (II) Available Draught

Available draught = 0.82 (Natural draught)

= 0.82 (18.82)mm of H_2O

= 15.43 mm of H_2O ***Ans.***

Problem 7.2 Determine the height of the chimney required to produce a static draught of 18 mm of H_2O when the mean temperature of the flue gases is 550°K and ambient air temperature is 300°K.

Barometric pressure = 76 cm of Hg

Characteristic gas constant for air = 29.27 kgf m/kg°K

Characteristic gas constant for flue gas = 27 kgf m/kg°K

Solution

Step (I) Density of Air at 300°K

$$\rho_{air} = p_{air}/R_{air}\ (300)$$

$$= \frac{1.032 \times 10^4}{29.27 \times 300}$$

$$= 1.1752\ \text{kg/m}^3$$

Step (II) Density of Flue Gases at 550°K

$$\rho_{fg} = p_{fg}/R_{fg}\ (550)$$

$$= 1.032 \times 10^4/(27)\ (550)$$

$$= 0.6949\ \text{kg/m}^3$$

Step (III) Chimney Height

Let the height and area of cross-section of the chimney be H and A respectively.

Therefore, weight of the air column of chimney height = $h\ \rho_{air}\ A$

$\therefore$ Weight of flue gas column of chimney height

$$= H\ \rho_{fg}\ A$$

$\therefore$ Draught (Draft)

$$= H\ \rho_{air}\ A - H\ \rho_{fg}\ A = HA\ (\rho_{air} - \rho_{fg})$$

or $18A = HA\ (1.1752 - 0.6949)$

$\therefore$ $H = 37.47$ m ***Ans.***

Problem 7.3 A boiler consumes 25 t coal per hour. The flue gases temperature is 575°K while the ambient air temperature is 300°K. If the draught produced by a 40 m high concrete chimney is 20 mm of H_2O, calculate

(a) the air supplied per ton of coal burnt

(b) the draught (draft) in terms of hot flue gas
(c) the flowrate of hot flue gases through the chimney
(d) the velocity of the flue gases in the chimney
(e) the diameter of the chimney at the base

Assume 0.0666 times the draught is available for producing the velocity.

Solution

Step (I) Combustion Air Requirement

T	T_1	H	h	Combustion Air Requirement
575°K	300°K	40m	20 mm of H_2O	W

Working Formula:

$$h = 353\ H\left[\frac{1}{T_1} - \frac{W+1}{W}\frac{1}{T}\right]$$

or $20 = 353\ (40)\ \{1/300 - [(W + 1)/W]\ (1/575)\}$

or $\dfrac{W+1}{W} = 1.102$

$\therefore$ $W = 9.775$ t/t of coal fired **Ans.**

Step (II) Draught (Draft) in terms of Hot Flue Gas

$$h_{fb} = H[(W/W + 1)\ (T/T_1) - 1]\ m$$
$$= 40[(9.775/10.775)\ (575/300) - 1]$$
$$= 29.55\ \text{m}$$ **Ans.**

Step (III) Mass Flowrate of Flue gases

Coal consumption = 25 t/h

Air supplied = 25 (9.775) = 244.375 t/h

Flue gas produced = 25 + 244.375 = 269.375t/h

Step (IV) Density of Flue Gases

$$\rho_{fg} = 1.293\left[\frac{W+1}{W}\right]\left[\frac{T_0}{T}\right]$$
$$= 1.293\ (10.775/9.775)\ (273/575)$$
$$= 0.676696\ \text{kg/m}^3$$
$$= 0.676696 \times 10^{-3}\ \text{t/m}^3$$

Step (V) Volumetric Flowrate of Flue Gases

Mass Flowrate	Density	Volumetric Flowrate
269.375 t/h	0.676696×10^{-3} t/m^3	$269.375/(0.676696 \times 10^{-3}) = 398.0736 \times 10^3$ m^3/h $= 398\ 074$ m^3/h

Step (VI) Draught (Draft) available for Velocity producing

$$= 29.55\ (0.0666)$$
$$= 1.968\ \text{m of hot flue gas column}$$

Step (VII) Velocity of Flue Gases in the Chimney

$$v = \sqrt{2g\ (1.968)}\ \text{m/s} = 6.21\ \text{m/s}$$ **Ans.**

Step (VIII) Chimney Diameter

Area of cross-section of chimney at the base × Velocity of flue gases = Volumetric flowrate of flue gases

$$\frac{\pi}{4}\ D^2\ v = 398\ 074 \times \frac{1}{3600}$$

or $D^2 = \dfrac{398074}{3600} \times \dfrac{4}{\pi} \times \dfrac{1}{6.21}$

$\therefore$ $D = 4.762$ m **Ans.**

Problem 7.4 Calculate the static draught that would be produced by a chimney 30 m high for the maximum discharge through the chimney. The ambient air temperature is 27°C.

Solution

Step (I) Condition for Maximum Draught

For maximum draught in a given chimney

$$\frac{T}{T_1} = 2\,\frac{W+1}{W}$$

where T = abs. temp. of flue gases in the chimney

T_1 = abs. temp. of ambient air

W = mass of air required per kg of coal burnt

Step (II) Static Draught for Maximum Discharge

The draught equation is

$$h = 353H\left[1/T_1 - \frac{W+1}{W}(1/T)\right] \text{ mm of water}$$

column

For maximum discharge,

$$h_{max} = 353\ H\left[\frac{1}{T_1} - \frac{W+1}{W}\,\frac{W}{W+1}\,\frac{1}{2T_1}\right]$$

$$= 353\ H/2T_1$$

$$= 353(30)/[(2)\ (273 + 27)]$$

$$= 17.65 \text{ mm of water column} \qquad \textbf{\textit{Ans.}}$$

Problem 7.5 The chimney of a steam generation plant is 35 m high producing a natural draught of 30 m column of hot flue gases.

Estimate

(a) the temperature of the flue gases leaving the chimney

(b) the heat lost to flue gases if the average temperature of the flue gases leaving the boiler in artificial draught system is 160°C. The mean specific heat of flue gases is 0.25 kcal/kg°C.

(c) the chimney efficiency

(d) the amount of total heat spent in producing natural draught

(e) the temperature of the flue gases in the chimney for maximum discharge.

Given

The calorific value of coal = 6500 kcal/kg

Combustion air supplied = 20 kg/kg of coal burnt

Ambient air temperature = 27°C

Solution

Step (I) Temperature of Flue Gases leaving the Chimney

This can be estimated with the help of the following equation:

$$h_{fg} = H\left[\frac{W}{W+1}\,\frac{T}{T_1} - 1\right]$$

or $\quad 30 = 35\ [(20/21)\ (T/273 + 27) - 1]$

or $\quad T = 585°K$ i.e. $312°C$ $\qquad$ ***Ans.***

Step (II) Extra Heat Loss to Flue Gases above 160°C

Extra heat carried away by 1 kg of flue gases

$$= 1\ (0.25)\ (312 - 160) \text{ kcal}$$

$$= 38 \text{ kcal} \qquad \textbf{\textit{Ans.}}$$

Step (III) Chimney Efficiency

Static heat = 30 m

Maximum energy which this static head will impart to 1 kg of flue gases = 30 × 1 = 30 kgf. m

Chimney Efficiency

$$= \frac{30}{38 \times (427)}$$

$$= 1.84 \times 10^{-3} \text{ i.e. } 0.18\% \qquad \textbf{\textit{Ans.}}$$

[where, 1 kcal = 427 kgf. m of mechanical work]

Step (IV) Amount of Heat Spent for Creating Draught

Extra heat carried away for creating draught

= wt. of flue gas × sp. heat × temperature difference

= (20 + 1) (0.25) (312 – 160)

= 798 kcal/kg of fuel

Heat produced by burning coal = 6500 kcal/kg of fuel

∴ % of heat spent in creating draught

= [798/6 500] × 100 = 12.27 % ***Ans.***

Step (V) Flue Gas Temperature for Maximum Discharge in Chimney

For maximum discharge,

$$\frac{T}{T_1} = 2\,\frac{W+1}{W}$$

or $$T = 2\left(\frac{21}{20}\right)(273 + 27)$$

= 630°K i.e. 357°C ***Ans.***

8

PRIMARY FUELS

Q. *What is fuel?*

Ans. Fuel is a substance which, upon burning in air or oxygen, liberates heat.

Q. *How are fuels classified?*

Ans. Fuels can be classified according to

(a) the physical state in which they exist in nature—solid, liquid and gaseous
(b) the mode of their procurement—natural and synthetic
(c) their calorific value

Primary Fuels	Secondary Fuels
Solid	**Solid**
1. Wood	1. Coke
2. Peat	2. Charcoal
3. Coal	3. Briquettes
4. Lignite	
5. Oil shale	
Liquid	**Liquid**
1. Petroleum	1. Gasoline
	2. Naphtha
	3. Diesel oil
	4. Kerosene
	5. Fuel oils
	6. Shale oil
	7. Coal-tar
	8. Colloidal fuel
	9. Alcohols
Gaseous	**Gaseous**
1. Natural gas	1. Coal gas
	2. Producer gas
	3. Water gas
	4. Oil-gas
	5. Hydrogen
	6. Acetylene
	7. Butane

Q. *What are primary fuels?*

Ans. These are those fuels which occur naturally, such as wood, peat, coal, lignite, petroleum and natural gas.

Q. *What are secondary fuels?*

Ans. These are fuels produced from primary fuels by some treatment processes.

Q. *What is coal?*

Ans. Coal is the stratified rock of decaying trees and vegetation that underwent morphological changes by anaerobic biodegradation through millions of years under heat and pressure of the earth crust above them.

Q. *Which conditions led to the formation of peat?*

Ans. Conditions which were not truly anaerobic.

Q. *How did the degree of alkalinity in the surrounding clay affect the quality of coal?*

Ans. The nature of alkalinity of surrounding clay was the deciding factor in determining the type of coal resulting from the decaying trees and vegetation heaped under tons of the earth's crust many millions years ago.

During anaerobic decomposition of cellulose of the wood, CO_2 and H_2O were liberated and the absorption in the surrounding clay of carbon dioxide produced led the decay to proceed further.

As the decomposition proceeded further, hydrogen and oxygen were gradually consumed from

the solid mass and eliminated with the effect that the residue became gradually enriched in carbon and depleted of H and O content in its successive stages of transformation.

Material	%C	Parts of		
		C	H	O
Cellulose	44.6	100	14	111
Wood	50	100	12	88
Peat	60	100	10	57
Lignite	62	100	7.9	54
Brown coal	69.5	100	7.8	36
Bituminous coal	78.8	100	6	21
Anthracite	91	100	4.7	5.2
Graphite	100	100	nil	nil

Therefore, with the propagation of decomposition, more and more CO_2 as well as H_2O were liberated and the quality of the coal improved. Since the absorption of carbon dioxide by the surrounding clay allowed the decay to proceed further, higher alkalinity (absorbing CO_2) led to the formation of bituminous and anthracite variety of coal while lower alkalinity led to the formation of lignite variety.

Q. *How does the volatile matter content determines the rank of coal?*

Ans. Higher the volatile matter content of the coal, lower is the rank of the coal and vice versa.

Q. *With the growth of rank, more and more oxygen is expelled from the coal and with that its calorific value increases. Why?*

Ans. The presence of oxygen in coal tends to reduce its calorific value because the oxygen is combined with hydrogen in coal as water. The heat of this chemical reaction has already been liberated and is, therefore, not available during combustion of coal.

So, as oxygen is excluded from coal, its rank gradually increases and it becomes enriched with carbon and consequently the calorific value of the resulting coal increases.

Coal	Parts of			Calorific Value
	C	H	O	
Peat	100	10	57	18670 kJ/kg
Lignite	100	7.9	54	21000 – 25600 kJ/kg
Brown coal	100	7.8	36	27250 kJ/kg
Bituminous	100	6	21	32125 kJ/kg
Anthracite	100	4.7	5.2	32550 kJ/kg
Graphite	100	–	–	32 910 kJ/kg

Q. *How was petroleum formed?*

Ans. Petroleum was formed by anaerobic decay of marine plant and animal life.

Dead plants and animals of aquatic origin deposited at the bottom of shallow seas were covered with a thick layer of silt and set to decay under near-anaerobic conditions. The steady accumulation of mud above the decaying remains of organic matter led to an increase of temperature and pressure that favoured the formation of liquid and gaseous hydrocarbons.

Q. *What is the ultimate analysis of coal?*

Ans. It is the chemical analysis of coal to determine the percentage of more important chemical elements in coal, which are basically carbon, hydrogen, nitrogen and sulphur and occasionally phosphorus and chlorine.

Q. *How are the percentages of hydrogen and carbon determined?*

Ans. By burning a fixed weight of the coal sample to a fixed weight of residue (ash) in a strongly oxidized atmosphere and determining the amounts of CO_2 and H_2O resulting form combustion.

Carbon dioxide is absorbed in a preweighed solution of KOH while water vapour is absorbed in a preweighed mass of anhydrous $CaCl_2$.

Q. *How is the sulphur content in coal determined?*

Ans. By the Eschka method. In this process a fixed weight of coal sample is strongly heated with a mixture of sodium carbonate and magne-

sium oxide. The sulphur content of the coal gets converted into sulphites and sulphides of sodium and magnesium. The residue is washed into a beaker, oxidized to sulphate by bromine water and the sulphur is then precipitated as barium sulphate. The weight of sulphur is then equal to 13.73% of the precipitated barium sulphate.

Q. *How is the nitrogen content of coal determined?*

Ans. By the Kjeldahl method. In this method, a fixed weight of coal sample is oxidized with concentrated sulphuric acid whereupon the nitrogen content of coal is converted into ammonium sulphate. This is distilled off and titrated with a quantity of standard alkali and the amount of ammonia and hence the percentage of nitrogen is obtained by back titration.

Q. *How is the moisture content of coal determined?*

Ans. Accurately weighed quantity of coal sample is heated in a clean, dry crucible placed in an oven maintained at 373–383°K (100 – 110°C) for one hour. The crucible is then allowed to cool in a desicator and reweighed. This process, i.e. heating, cooling and weighing is repeated until the final weight becomes constant.

$$\text{Therefore, \% of moisture} = \frac{\text{Loss in weight}}{\text{Weight of coal}} \times 100$$

Q. *How is the ash content of coal determined?*

Ans. Accurately weighed quantity of coal sample taken in a dry, clean, preweighed crucible is completely combusted in air at 730°C (1003°K) for about an hour so that all its combustible material is burnt off leaving the ash as residue. The ash with crucible is weighed after cooling in a desicator.

$$\therefore \text{ \% of ash} = \frac{\text{Weight of residue}}{\text{Weight of coal}} \times 100$$

Q. *How is the oxygen content of coal determined?*

Ans. It is not determined directly. It is calculated as the sum of the percentage of the elements plus moisture and ash subtracted from 100.

$$O(\%) = 100 - [C + H + N + S + H_2O + \text{Ash}]\ \%$$

Q. *Why is the oxygen content of coal called oxygen plus errors?*

Ans. This is because all the experimental errors in the determination of the percentages of all the elements (C, H, N, S) and moisture and ash get included the percentage weight of oxygen of coal.

Q. *What is the utility of ultimate analysis?*

Ans. The results of ultimate analysis are of prime importance.

The concentrations of carbon, hydrogen and oxygen are particularly required in the classification of coal as well as in combustion calculations.

The concentrations of chlorine and vanadium are vital in considering the problems of corrosion and boiler deposits.

The sulphur and phosphorus contents have significant bearing on the metallurgy of iron and steel. The presence of sulphur poses severe problems of corrosion due to formation of clinker and corrosive gases like SO_2 and SO_3.

Q. *How does the sulphur content of coal exert influence upon the metallurgy of iron and steel?*

Ans. In the metallurgy of iron and steel, coke is required as the reducing agent to reduce FeO and Fe_2O_3 to iron. This coke results from the carbonization of coal, during which 65–70% of the sulphur content of coal remains in the coke, 20% escapes as H_2S and the rest gets its way to tar and aqueous liquor. Coke thus obtained is contaminated coke unfit for metallurgical purposes.

[Coal must be washed in scrubbers and purifiers to reduce its sulphur content to 0.5 g/m^3 and then upon carbonization it will produce metallurgical grade coke containing less than 0.6% sulphur.]

Q. *The phosphorous content in coal is usually very low (0.1%). So how can this coal influence the metallurgy of iron and steel?*

Ans. Though the phosphorous content coal is very low, the coke produced from it by carbonization process should not exceed 0.01 % phosphorous for the coke being suitable for metallurgical purposes. As the phosphorous will react with iron to form hard, brittle iron phosphide.

Q. *What is the sulphur content of coal?*

Ans. It varies depending upon the nature of coal. Usually sulphur content of coal ranges from 0.5 to 3%. Sometimes it may be as high as 5-6%.

Q. *How does sulphur occur in coal?*

Ans. It occurs in three forms:

(a) as pyrites FeS_2
(b) as organic sulphur combined with carbon atoms of giant coal molecule
(c) as gypsum, $CaSO_4$

Q. *Does the presence of pyrites in coal pose any harmful effect?*

Ans. Yes. The effect may be disastrous as the resulting clinker having relatively low fusion point, forms a eutectic with the firebars (in Stoker furnace) leading to severe corrosion.

Q. *What is proximate analysis?*

Ans. It is the chemical analysis to determine the percentages of such important components of coal as moisture, volatile matter, ash and fixed carbon.

Q. *What is fixed carbon?*

Ans. It is a hypothetical term and is not a precise constituent of coal. It does not imply the existence of uncombined carbon in coal material nor does it bear any relationship with the total carbon as determined by ultimate analysis. It is obtained by subtracting from 100 the sum of the percentages of moisture, volatile matter and ash content of the coal sample.

Q. *What is the significance of proximate analysis of coal?*

Ans. Its significance lies in the classification of coal on the basis of its percentage content of volatile matter and calorific value. (Fig. 8.1)

Q. *How is moisture present in coal?*

Ans. It exists in three forms

(a) surface moisture
(b) inherent moisture
(c) combined moisture

Q. *How is surface moisture acquired by coal?*

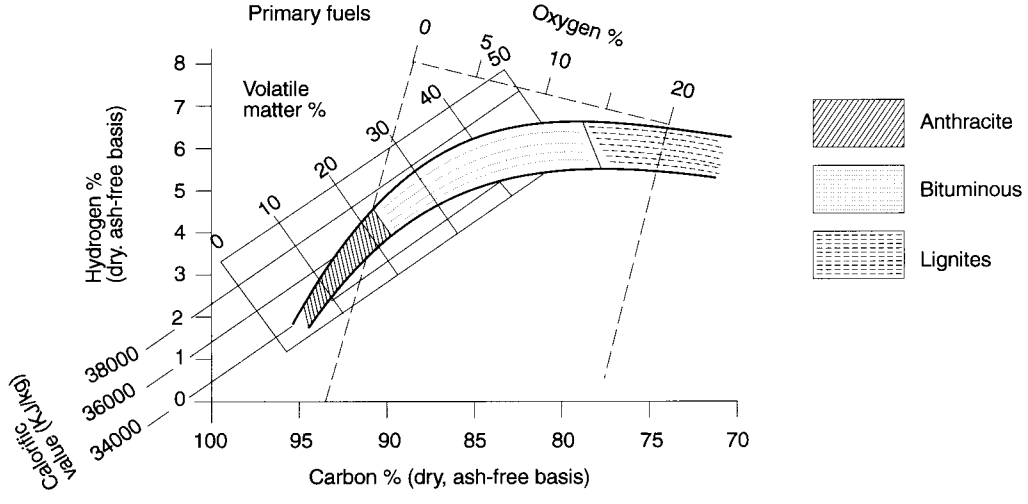


Fig. 8.1 *Coal classification on the basis of Proximate Analysis of coal.*

Ans. During washing and scrubbing of coal for storage and cleaning.

Q. *How is inherent moisture ingressed in coal?*

Ans. It is the absorbed moisture as water is absorbed through capillaries in the coal substance and makes its way throughout the body of coal.

Q. *How is combined moisture present in coal?*

Ans. In the same way as it is present in hydrates. It is held in loose combination.

Q. *How does the percentage moisture affect the quality of coal?*

Ans. The lower the rank of a coal, the higher is the moisture percentage of coal and vice versa.

Q. *The presence of moisture diminishes the gross calorific value of coal? Why?*

Ans. The oxygen content of coal is present as moisture that has consumed from coal its hydrogen content equal to the 1/8th of the weight of the oxygen content.

Hence the amount of free hydrogen available for combustion will be less than the total hydrogen content of coal. That explains why the gross calorific value or higher calorific value diminishes with the increase of moisture content in coal.

Q. *If it is so then why as much as 15% of water is added to the coal feed in large boiler plants?*

Ans. The purpose is to disperse the fine material in the combustion zone of the furnace.

Q. *What is volatile matter in coal and how is it determined?*

Ans. It is defined as the percentage loss in weight when a finely ground coal specimen is heated in a closed vessel at 1200°K for 40 minutes. After cooling and drying in a desicator the residue (coke) is weighed. From this experiment the coke percentage is determined. Moisture percentage is determined in a separate experiment.

Therefore, % volatile matter

= 100% – (coke + moisture) %

Q. *What are the basic components of volatile matter?*

Ans. There are three basic components of volatile matter

1. **Gases:** containing CO, H_2, CH_4, C_2H_6 and H_2S
2. **Tar:** a complex mixture of such hydrocarbons as benzene, toluene, naphthalene, xylene, phenols, cresols, anthracine and free carbon
3. **Ammoniacal liquor:** aqueous condensate of nitrogen and sulphur compounds plus cyanides.

Q. *Does the ammoniacal liquor result from free or inherent moisture content of coal?*

Ans. No. It results from the decomposition of combined moisture, i.e. decomposition of hydrates.

Q. *What is the effect of volatile matter in the combustion process?*

Ans. To produce smoke.

Q. *What is smoke?*

Ans. It is essentially the aerosols of tar and finely divided carbon particles.

Q. *What is the overall effect of volatile matter in coal?*

Ans. They affect the design of furnace volume and arrangement of heating surfaces.

Q. *How does it affect the combustion volume?*

Ans. Coal feed having high volatile percentage will not be suitable in a furnace with small combustion volume if the burning rate is high.

Burning of low volatile coal requires forced draught and therefore reduced combustion volume will increase the combustion efficiency.

Q. *What is the percentage of volatile matter in coal?*

Ans. It varies with the origin and rank of coal. It may range from as low as 3 % to as high as 50%.

Q. *Is coal a homogeneous substance?*

Ans. No; coal is not homogeneous. Basically coal is a heterogeneous hydrocarbon containing mineral matter and water as impurities.

Q. *How is coal classified?*

Ans. (A) Coal can be classified according to the purpose for which the varieties of coal are employed, e.g.

1. **Gas coal:** coal having high percentage of volatile matter, hydrogen, but a lesser amount of oxygen
2. **Coking coal:** coal having the property of swelling and yielding high percentage of coke upon carbonization
3. **Smithy coal:** coal having a high degree of swelling characteristics
4. **Steam coal:** coal with low swelling, low ash content, producing short flame, with high calorific value.

(B) Coal can be classified according to some visual superficial difference:

1. Dry coal 2. Lean coal 3. Fatty coal. 4. Shortflame coal 5. Long-flame coal.

(C) Solid fuels including coal can be classified according to their fixed carbon, volatile matter and oxygen content.

Fuel	Fixed Carbon (%)	Volatile (%)	Oxygen (%)
Wood			43.16
Peat	29.95	70	53.55
Lignite	47	53.12	19.61
Sub-bituminous	59.5	40.52	17.01
Bituminous	69.81	30.21	5.19
Semi-bituminous	83.22	16.81	2.65
Semi-anthracite	91	9.93	2.16
Anthracite	93.84	6.19	2.13

(D) Frazer made an attempt to classify different varieties of coal according to the ratio of fixed carbon to volatile matter. But arbitrary results were obtained.

(E) **Paar's Method of Classification:** It is a simplified method classifying American coals on the basis of calorific value of sulphur-free coal and volatile matter. [Fig. 8.2]

The calorific value of sulphur-free coal was calculated as

$$\text{C.V.} = \frac{\text{C.V. of dry coal} - (5000)\,S}{1 - [1.08\,A - 0.55\,S]}$$

and the volatile matter is

$$\text{V.M.} = 100\,\frac{\text{Fixed carbon of dry coal}}{1 - [1.08\,A - 0.55\,S]}$$

where A = ash content of the coal

S = sulphur content of the coal

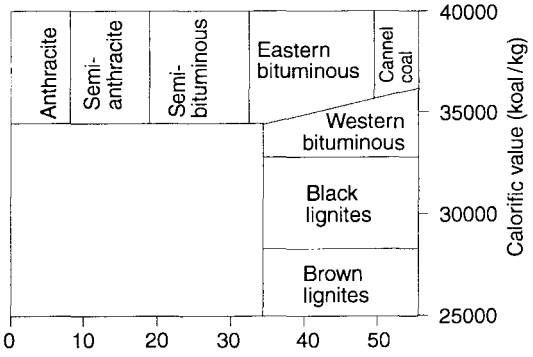


Fig. 8.2 *Parr's method of coal classification.*

(F) **Ralston's Classification:** is based on carbon-hydrogen and oxygen content of coal and on ash-moisture-sulphur-nitrogen free basis.

Plotting three parameters on a graph (Fig. 8.3) he obtained eight ellipses that belonged to:

Graphite: ellipse No. (1); **Anthracite:** ellipse No. (2); **Semi-anthracite:** ellipse No. (3); **Semi-bituminous:** ellipse No. (4); **Bituminous + Sub-bituminous:** ellipse No. (5); **Lignites:** ellipse No. (6); **Peats:** ellipse No. (7); **Wood + Plants:** ellipse No. (8)

(G) **White's Classification:** Coal is classified according to the ratio of carbon to the sum of oxygen and ash content, i.e. according to calorific values.

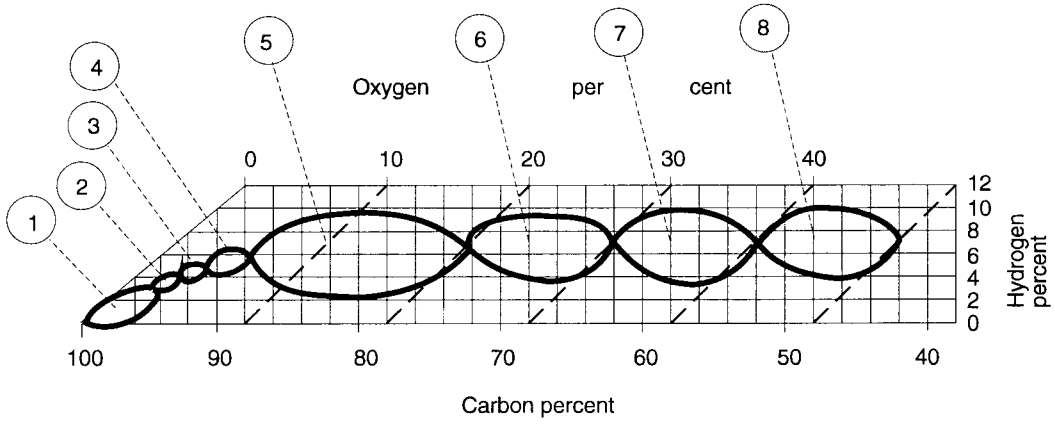


Fig. 8.3 *Ralston's method of coal classification.*

He drew his curve (Fig. 8.4) by plotting calorific value against carbon/(oxygen + ash) ratio, on the basis of the following mathematical expression

$$\text{BTU} = 16\,780 - \frac{17.23}{x + 0.98} \text{ per pound of coal}$$

where $x = \dfrac{C}{O + A}$

C = carbon %

O = oxygen %

A = ash%

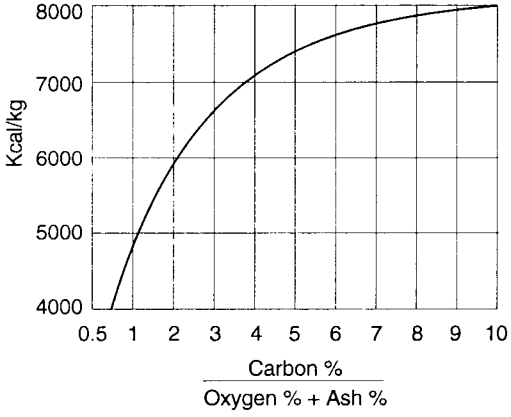


Fig. 8.4 *White's classification of coal.*

(H) **Grüner's Classification:** This classification is based on the ultimate analysis of coals on a dry-ash-free basis, according to their carbon, hydrogen and oxygen contents and is correlated against the coke-yielding capacity of coals (See table at the bottom of next page).

However, it must be borne in mind that the nature of coals is so diverse in composition, varying both geologically and geographically, that none of the above mentioned classifications is exact or universally adequate.

Q. *How are Indian coals classified?*

Ans. Coal is graded on the basis of ash and moisture content and is classified into Slack Grade-I and Slack Grade-II

Grade	Moisture + Ash	Calorific Value
Slack Grade-I	19-24%	5940-6340 kcal/kg
Slack Grade-II	24-28%	5340-5940 kcal/kg

Q. *What factors are considered in selecting coals for thermal power plants?*

Ans. Firing qualities of coal are of prime importance and influence the design of the combustion chamber, type of combustion equipment and layout of heat-transfer parts of thermal power plants.

Coals with low volatile content have slower burning characteristics but generate high fuel bed temperature. Hence forced draught is required. Therefore, grates should be so designed and fuel feed so controlled that the grate is protected by adequate ash.

Coals with high volatile content, on the other hand, have a high rate of burning and hence require a large combustion chamber for combustion of the volatiles. Such coals are very useful for thermal power plants to meet the sudden increase of load. They quickly liberate their combustible volatile gases that rapidly burn off to increase the furnace temperature to boost up steam productivity.

Also, important factors of consideration are sizing, caking characteristics of coal, grindability, resistance to degradation, ash fusion temperature and sulphur content of coal.

Q. *What is coal preparation?*

Ans. Processing run-of-mine coal to remove the inert material and moisture.

Q. *Why is coal preparation necessary?*

Ans. Run-of-mine coal is not suitable for combustion.

Q. *What are the specific steps involved in the preparation of coals?*

Ans. 1. Removal of clay and dirt
2. Drying of coal
3. Sizing of coal
4. Removal of sulphur

Q. *How is coal freed from clay and dirt?*

Ans. In two ways: dry cleaning and wet cleaning.

Q. *What is dry cleaning?*

Ans. Run-of-mine coal is screened and coal below 80 mm size is subjected to dry cleaning.

The coal is charged to vibrating screens and the mechanical energy imparted to the screens dislodges the fine clay substances adhered to the coal surface. The final condition of the coal is dictated by the degree of vibration imparted to the screens.

Q. *What is the limitation of dry cleaning?*

Ans. The only handicap is the moisture content of the coal. If it is less than 3%, then coal can be cleaned by the dry process. But unfortunately, most of the coals mined and brought to the surface are too wet to fit dry cleaning.

Q. *What is wet cleaning of coal?*

Ans. Coal is washed by sprinkling water over the bed of coal. Shale clay and coal dust are washed away with the result that the final product contains much less incombustibles.

Q. *What is the drawback of wet cleaning of coal?*

Ans. Moisture content of washed coal increases.

Grüner's Classification

Type of Coal	Coking	Coke	Flame	C	H	O+N+S	% VM at 1200°K	% Moisture
Lignite	non	—	long and smoky	60-77	5	20-36	45	20
Bituminous	non		long	75-80	5	15-20	40-45	10-20
	coking			80-85	6	10-15	30-40	5-15
	hard-coking			85-90	5-6	5-11	18-32	5
Semi-bituminous	very weakly	80-85	short smokeless	90-92	4-4.5	4-5	10-20	2-3
Semi-anthracite	non	82-90	-do-	90-93	4-4.5	3-5.5	8-15	2
Anthracite	non	95	very little flame	92-94	3-4	3-4.5	7-8	—

Q. *How can coal be dried?*

Ans. By
(a) steam heating
(b) fuel gas drying
(c) oil dehydration

Q. *How much moisture can be expelled by steam drying?*

Ans. Moisture content of coal can be reduced from 15% to 4–5%

Q. *What is the pressure of the steam generally employed?*

Ans. 30 ata.

Q. *Why is drying of coal necessary?*

Ans. 1. **For better combustion result:** as a sizeable fraction of heat of combustion is expended in evaporating the moisture content of coal (about 1.5% of the liberated heat of combustion goes to evaporate 10% moisture content)
2. **To boost up the capacity of pulverizing mill:** the capacity of pulverizer decreases by 2.5% per 1% increase of moisture content of coal
3. **To reduce the power consumption of auxiliaries:** such as I.D., F.D. fans and pulverizing mills.

Q. *What is coal sizing?*

Ans. Coal lump is broken and screened to maintain the uniformity of coal size.

Q. *Why is coal sizing necessary?*

Ans. For higher efficiency utilization.

Q. *How?*

Ans. Though a great deal of work is still required to determine precisely the relationship between the size of coal and its efficiency of utilization, since combustion is a surface reaction and accelerates with the increase of surface area exposed, as the size of the lump is reduced the rate of combustion increases.

Q. *How is sulphur removed from coal?*

Ans. Only pyritic sulphur can be removed from coal. Crushed coal with high sulphur content is washed in scrubbers to remove the pyrites.

Q. *Why can organic sulphur not be eliminated from coal?*

Ans. Organic sulphur, unlike iron pyrite (which forms a heterogeneous constituent in the coal matrix), is in the compound state with the coal hydrocarbon. Hence it is inseparable from coal and no physical process is known to eliminate it.

Q. *How much of total sulphur content in coal is distributed in pyrite and organic forms?*

Ans. Pyrite accounts for 50-80% of total sulphur load. Organic sulphur accounts for upto 40% of the total sulphur load.

Q. *How can coal be desulphurized prior to combustion?*

Ans. One novel technique is to use bacteria to desulphurize coal. The microorganisms oxidize both the inorganic and organic sulphur of coal. The process has been developed at the INEL (Idaho National Engineering Laboratory, Idaho Falls, USA).

Q. *How much coal-sulphur can be removed by this process?*

Ans. More than 95% of the pyritic (inorganic) sulphur, but less than half of the organic sulphur can be removed by this process.

Q. *What is the 'bacteria' used to desulphurize coal?*

Ans. Thiobacillus ferrooxidans

Note: Thio = sulphur

bacillus = bacteria

ferro = pyritic

oxidans = oxidizing

Q. *What is the basic mechanism of the desulphurizing process?*

Ans. Sulphur is tied to coal in insoluble pyritic form containing iron in its ferrous state. The bacteria T. ferrooxidans oxidize ferrous ions to the soluble ferric form which is removed with water.

Q. *How is the desulphurizing process carried out?*

Ans. Thiobacillus ferrooxidans is introduced to an aqueous slurry of crushed coal. The working temperature is 298°K. Bacterial treatment is slow. It takes about a week for the T.F. bacteria to achieve 95% desulphurization.

Q. *Is there any other desulphurizing bacteria?*

Ans. Sulfolobus bacteria.

This has been claimed to be more efficient; they work at 333°K—343°K.

Q. *Why is organic sulphur more difficult to remove?*

Ans. This is because organic sulphur is chemically bound to the coal structure.

Q. *In which form is organic sulphur found in coal?*

Ans. It is found in various forms. The common form being dibenzothiophene.

Note: Research with various microorganisms are underway to break the chemical bonds so that organic sulphur can be dissolved.

Source: Chemical Engineering, Nov. 23/1987, P-38

Q. *How can coal be transported from coal mines to thermal power stations?*

Ans. By four ways:

1. Transportation by rail
2. Transportation by road
3. Transportation by sea or river
4. Transportation by pipelines

Q. *Which is the speediest method?*

Ans. Transportation by pipelines.

Q. *How is this carried out?*

Ans. Coal is pulverized and made into a slurry with water. This slurry is pumped to transport coal through pipelines.

Q. *What are the drawbacks of this system?*

Ans. It requires

(a) prohibitively large capital investment
(b) huge quantity of water
(c) drying of coal before subjecting it to combustion chamber

Q. *How much of water per ton of coal is needed for transportation of coal by pipelines?*

Ans. About 1t/t of coal.

Q. *Can you mention a thermal power plant where such a system is operative?*

Ans. Mohave generating station in UK with an installed capacity of 1580 MW power generation. A 437 km pipeline transports coal to this power station.

Q. *In which cases is the transportation of coal by road economical?*

Ans. For small and medium capacity thermal power stations situated within 30 to 50 km of the coal mine belt.

Q. *Outline in brief the in-plant coal transportation system.*

Ans. Coal dumped in the coal yard by trucks/railway wagons are spread and compacted upon the vibrating screen feeder by bulldozers.

From the vibrating screen feeder, coal is fed to a belt conveyor via a hopper that feeds coal to the crusher. Crushed coal is screened in a vibrating separator. Oversized lumps are recycled to the crusher while the correct-sized coal is transported by a conveyor belt via a magnetic separator which removes the magnetic materials from coal. The iron particles cling to the belt as it travels around the magnetized pulley and the coal falls off on another conveyor belt that carries them to storage bins. [Fig. 8.5]

Q. *Apart from a belt conveyor what other similar equipment is used for the transportation of coal?*

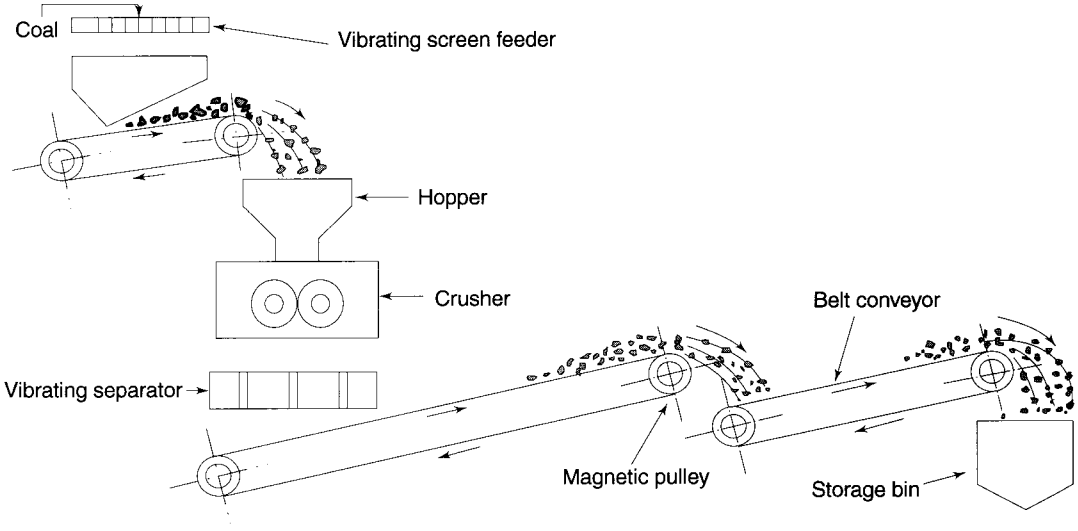


Fig. 8.5 *In-plant coal transportation system (A schematic layout).*

Ans. 1. Flight conveyor
2. Screw conveyor
3. Grab bucket conveyor
4. Bucket elevator
5. Skip hoist, etc.

Q. *What are the advantages of a belt conveyor?*

Ans. 1 Most economical system in transportation of large amount of coals. Hence most suitable for large thermal power stations.
2. Power consumption per tonnage of coal transported is less than any other type of conveyor
3. Low operating and maintenance cost
4. Load can be easily varied.

Q. *What are its disadvantages?*

Ans. 1. High capital investment
2. Unfit for shorter distance transport and at greater elevation
3. Long belt is required if coal is to be elevated at an elevation higher than 20°.

Q. *How does a screw conveyor work?*

Ans. A screw mounted on two ball bearings at two ends is rotated within a cylindrical trough, by means of a driving mechanism fitted at one end. Coal fed through a hopper into a trough at one end is carried by a screw drive at the other end. (Fig. 8.6)

Q. *What is the diameter of the screw?*

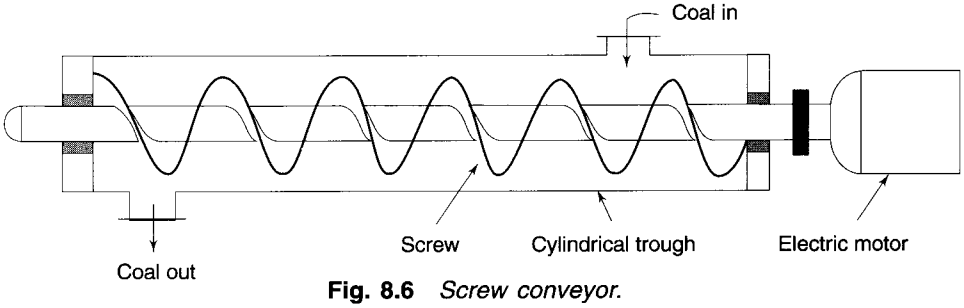


Fig. 8.6 *Screw conveyor.*

Ans. It usually varies from 15 to 50 cm.

Q. *What is the maximum capacity of a screw conveyor?*

Ans. 125 t/h

Q. *What are the advantages of a screw conveyor?*

Ans. 1. The operation is dust free
2. Simple and compact equipment
3. Requires minimum floor space
4. Investment cost is low

Q. *What are the disadvantages of a screw conveyor?*

Ans. 1. High power consumption per unit tonnage of coal transported.
2. High wear and tear
3. Length of the conveyor cannot exceed 30 m due to high torsional strain on the screw-shaft.

Q. *How does a bucket elevator function?*

Ans. Buckets fitted on infinitely long chain passing over two wheels scoop up coal from the bottom and discharge them at the top outlet as the chain moves over the wheels rotated by an electric motor. (Fig. 8.7)

Q. *What is most distinct advantage of a bucket elevator system?*

Ans. It is most advantageous for vertical lifts of solid materials and is extensively used for this purpose.

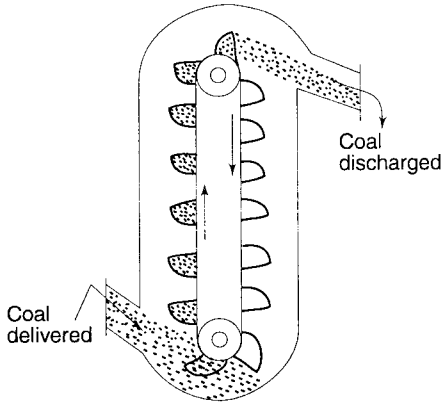


Fig. 8.7 *Bucket elevator*

Q. *What is the capacity of bucket elevators?*

Ans. Their capacity is about 60-80 t/h.

Q. *What is the speed of the chain in a bucket elevator?*

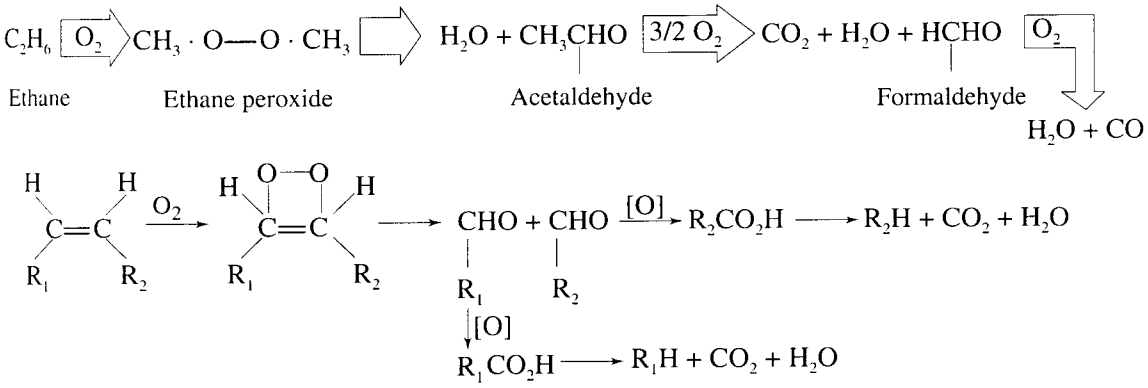
Ans. 30-75 m/min

Q. *What are the maximum height and maximum inclination of a bucket elevator?*

Ans. 30.5 m and 60° (to the horizontal)

Q. *Why is storage of coal a necessity?*

Ans. To safeguard the steam generation based plants from total shutdown in the case of failure of normal supplies of coal, i.e. to ensure a steady supply of electricity.



To meet seasonal fluctuations of market prices of coal.

Q. *What is the mechanism of spontaneous combustion of coal?*

Ans. It is thought to proceed via unstable intermediates known as peroxides, the formation of which can be exemplified through a simple example like ethane: (see P-257 bottom)

Q. *What is auto-ignition point of coal?*

Ans. It is the temperature at which coal spontaneously ignites in air.

Q. *Therefore it is desirable to store as much coal as the factory site will permit. Is it?*

Ans. Obviously not.

Q. *Why?*

Ans. There should be an optimum level of coal storage.

Q. *What is the optimum level of coal storage?*

Ans. It is roughly 10% of the total amount of the annual coal requirement of the steam generation plant.

Q. *Why should we go for an optimum level?*

Ans. Storage of coal above the optimum level is unnecessary as it would mean

1. greater risk of oxidation and spontaneous combustion
2. greater loss of volatile matter
3. deterioration of coal quality due to weathering
4. blockage of large amount of capital
5. mounting interest due to large amount of capital locked in heaps of coal
6. greater insurance charge
7. higher handling and reclamation cost

Q. *What factors influence the spontaneous combustion of coal?*

Ans. 1. large amount of coal fines
2. higher percentage of combined moisture
3. rise in ambient temperature

Q. *Why is it advantageous to store screened coal?*

Ans. It will eliminate the fine coal particles that would otherwise lead to spontaneous combustion of coal.

Q. *Does sulphur play any part in spontaneous combustion?*

Ans. No. There is no evidence to support it.

Q. *How can it be determined?*

Ans. By **Wheeler method:**

A sample of coal encased in sand-bath is steadily heated up while air is blown at a fixed rate through the coal under test. [Fig. 8.8]

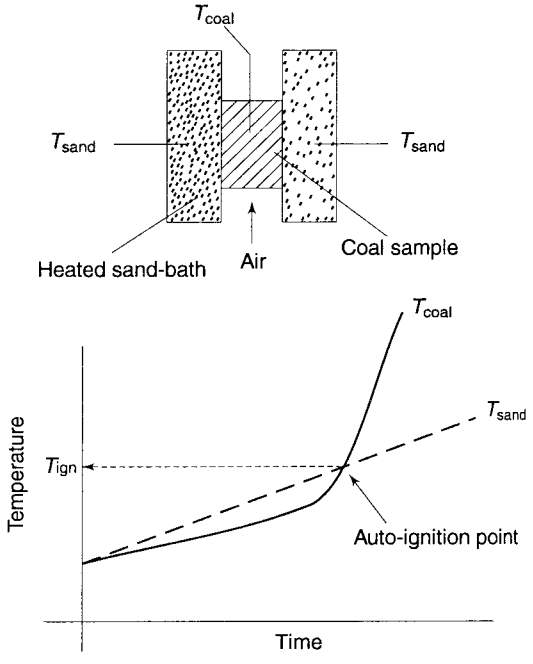


Fig. 8.8 *Temperature-time profile in coal ignition.*

The temperature of the coal sample and the sand bath are noted at periodic intervals and plotted in **Temp. vs. Time** coordinates.

The two curves intersect at a point which corresponds to the autoignition point of the coal specimen.

Q. *What is the value of autoignition for coal?*

Ans. Low ranking coals ⇒ 430–475°K

Higher ranking coals ⇒ 500–475°K

Q. *What do you mean by the term 'rational use of coal'?*

Ans. It has a dual meaning.

Firstly, it means minimizing the avoidable losses.

Secondly, it means selection of right grades of coal for right industries.

Q. *What are these avoidable losses and how can they be minimized?*

Ans. Firstly, a huge amount of coal is lost to the manufacture of soft-coke and hard coke in stack burning and beehive ovens respectively. For instance, more than 130 million litres of tar are burnt in the open every year in the Jharia coalfied belt alone. This amounts to a loss of 200,000 tons of coal-equivalent every year. This considerable loss can be avoided by adopting a low-temperature carbonization technique of coal.

Secondly, the mines burn their coking grade coal to run their installations instead of transporting coal from neighbouring mines. This is a misuse and can easily be avoided by the process of mutual exchange of coal.

Thirdly, the steam locomotives of railways use first grade coal, even coking coal, for steam generation. Whereas low grade coal, coal dust converted into briquettes, could serve the purpose well.

About 20% of the coal retrieved from mines goes to dust and probably 10% of it is retrieved for use. And this 10% is equivalent to 2.8 million tons of coal per year. This loss can be minimized by setting up coal-briquetting plants close to the coal-mines.

Finally, an appreciable quantity of coke is lost in dust during the manufacture of soft-coke. For example, if 2 million tons of soft-coke is produced annually and the formation of dust is 20%, then only 10% of the dust can feasibly be utilized and the balance dust accounts for a loss of about 360,000 tons of coke per year. This huge loss can be safely avoided by briquetting the dust.

Q. *What do you mean by scientific utilization of coal?*

Ans. Efficient utilization of coal by adopting suitable methods and apparatuses ensuring complete combustion of coal with minimum excess air, minimizing heat loss and modernizing fuel consuming installations.

Q. *How can heat loss be minimized?*

Ans. By adopting waste heat recovery system and application of better and adequate amount of insulation.

Q. *How can savings of coal be ensured?*

Ans. 1. By complete combustion of coal with minimal excess air
2. Allowing minimum heat loss, i.e. utilizing total heat liberated for useful purposes alone
3. Complete recovery of byproducts of coal carbonization processes
4. Allocation of right grade of coal for specific consumers
5. Upgradation of low ranking coal with the help of such matrix as waste molasses.

Q. *What is the primary liquid fuel occurring naturally?*

Ans. Crude petroleum.

Q. *Is it crude petroleum directly used as fuel?*

Ans. No.

Q. *Why is it called fuel then?*

Ans. Though itself a combustible material, crude petroleum is not used, as fuel straightaway for the sake of efficiency utilization. Nor is it wise to burn it that way as crude petroleum provides the source of valuable materials for petrochemical industry and manufactured products, such as synthetic fibres, plastics, drugs, paints and detergents.

It is the source of a range of gaseous and liquid fuels that distill off the fractionating column at different ranges of temperature when crude petroleum is fractionated.

Q. *How are liquid fuels classified?*

Ans. They are classified according to the mode of procurement, viz.—natural or crude oils and artificial or manufactured oils.

Q. *What are natural oils?*

Ans. Distilled natural oils are petrol, benzene, petroleum spirit, kerosene, benzol, fuel oils, diesel fuels, gas oils.

Q. *What are artificial oils?*

Ans. Distilled artificial oils are natural-gas oil, shale-oil, tar-oil, coal-tar etc.

Q. *What is the composition of crude petroleum?*

Ans. It contains such major components as

1. **Hydrocarbons**—paraffins, olefins, aromatics and cyclic compounds.
2. **Oxygen compounds**—carboxylic acids and phenols
3. **Sulphur compounds**—mercaptans, thioethers and thiophenes
4. **Inorganic compounds**—mineral matters and organometallic salts.

Q. *Give specific examples of each of these groups of compounds.*

Ans. **Paraffins:** n-octane; iso-octane; n-butane

Olefines: propylene; isobutene

Aromatics: naphthalene; pyridine

Cylic compounds: cyclopentane

Carboxylic acids: naphthenic acids

Phenols: phenols

Mercaptan: ethyl mercaptan

Thiophenes: thiophene

Q. *Does crude petroleum bear any important metal?*

Ans. Yes, It is vanadium in compound state (available in Mexican and Venezuelan crude).

Q. *What factors are considered for the gradation of petroleum?*

Ans. The following physico-chemical properties are considered:

1. Specific gravity
2. Viscosity
3. Congealing point
4. Flash point
5. Calorific value
6. Specific heat
7. Sulphur content
8. Moisture and sediment contents

Q. *What is congealing point?*

Ans. It is the temperature at which the crude becomes so pasty that it remains in place and does not flow out for one minute from a test glass inclined at 45°.

Q. *What is the specific gravity of petroleum?*

Ans. It is the ratio of the weight of a given volume of petroleum to the weight of the same volume of water at a fixed temperature.

Q. *What is the fixed temperature?*

Ans. Normally it is 288°K.

Q. *What is the most convenient method of measuring the specific gravity of liquid fuels?*

Ans. Use of hydrometer.

Q. *What is °API?*

Ans. It is the scale of measuring specific gravity introduced by the American Petroleum Industry (API).

$$°\text{API} = \frac{141.5}{\text{Sp. Gr. at } 288°\text{K}} - 131.5$$

Q. *Why is the knowledge of specific gravity of crude important?*

Ans. 1. To assess the volume of a given weight of material (or vice versa) for transportation and storage

2. To calculate the volume associated with the corresponding weight of oil from the

calorific value which is normally mentioned on a weight basis.

3. To enable a rough check on the consistency of quality in a series of batches.

Q. *Is there any relation between the calorific value of petroleum and specific gravity?*

Ans. United States Bureau of Mines gives an empirical relation between the gross calorific value of petroleum and its specific gravity as

$$HCV = 51\,916 - 8792\,\rho^2 \text{ kJ/kg}$$

where ρ = sp. gr. of oil at 288°K

Q. *Why is viscosity factor an important consideration?*

Ans. Viscosity of a liquid fuel is a measure of its resistance to flow. Its importance lies in the fact that it affects such things as the rate of flow of liquid fuels through pipelines, atomization of fuel oils at the burners and the performance and wear of diesel pumps.

Q. *What is viscosity?*

Ans. It is a specific property of a fluid and is the force required to displace one square metre of imaginary plane surface of the fluid at a rate of 1 m/s with respect to the second plane separated by a 1 m distance from the first plane and parallel to it.

Unit: N s/m^2

Q. *With which equipment, can the viscosity of liquid fuels be conveniently measured?*

Ans. By

1. Ostwald viscometer
2. Ubbelohde suspended level viscometer
3. Redwood viscometer (U.K.)
4. Saybolt-Furol viscometer (USA)
5. Engler viscometer (Continental)

Q. *What factors influence the viscosity of liquid fuels?*

Ans. Viscosity decreases with the increase of temperature and increases with the fall of temperature.

Q. *What is viscosity index scale?*

Ans. It is an arbitrary scale based on the viscosity temperature relationship of liquid fuels.

Q. *Why is a high viscosity index desirable for lube oils?*

Ans. Their service condition demands, that they to remain viscous at the operating temperature to prevent metal to metal contact between the rotating shaft and the bearings.

Q. *Why is viscosity index important for fuel oils?*

Ans. To enable us to know the temperature to which the fuel oil must be heated before it can be conveniently pumped.

Q. *What is the effect of pressure on the viscosity of oils?*

Ans. It is felt only at pressures beyond 96500 kN/m^2 (983 kgf/cm^2), such as may be encountered in a bearing.

Viscosity increases very rapidly with the increase of pressure in excess of 98,000 kN/m^2, according to the relationship

$$\log (\eta_1/\eta_2) = C(P_1 - P_2)$$

where η_1 and η_2 are dynamic viscosities of oil at pressure P_1 and P_2 respectively.

C is the constant depending on the chemical structure of the oil.

Q. *What is the flash point of a liquid fuel?*

Ans. It is the temperature at which a liquid fuel, when tested in a standard apparatus, gives off just sufficient vapour to create, in the air space above it, an explosive mixture that will flash if brought into contact with a flame.

Q. *Why is the knowledge of flash point important?*

Ans. It gives an indirect measure of volatility of the fuel and serves as an indication of the fire hazards associated with the fuel in bulk, i.e. during storage and application.

Q. *Give two examples of equipment which are used to determine the flash point of liquid fuel.*

Ans. 1. Pensky-Martin's apparatus used for liquid fuels having flash point higher than 322°K
2. Abel apparatus used for those liquid fuels whose flash point is below 322°K.

Q. *How is flash point determined?*

Ans. The liquid fuel under test is heated in a metal cup closed by a lid. At certain intervals a small test flame is introduced through an opening in the lid. The temperature of the liquid fuel at which the insertion of flame causes the vapour-air mixture above the oil in the cup to ignite is the flash point.

Q. *What is the fire point?*

Ans. If the test flame in the above case is introduced when the liquid fuel is heated above its flash point, a temperature is reached at which the bulk of the liquid fuel burns continuously. This temperature is the fire point of the liquid fuel under test.

Q. *What is the significance of the fire point?*

Ans. Uncertain.

Q. *How many types of flash points are there?*

Ans. Two. Open flash point and closed flash point.

Q. *What is open flash point?*

Ans. It is the flash point of a liquid fuel determined in an open crucible when a test flame is periodically applied above the surface.

Q. *What is closed flash point?*

Ans. It is the flash point of a liquid fuel determined in a closed crucible as mentioned earlier.

Q. *What is the difference between open and closed flashpoints?*

Ans. The open flash point of a liquid fuel is a few degrees higher than its closed flash point.

Q. *Why is the open flash point of a liquid higher than its closed flash point?*

Ans. It is because when open flash point is determined ignition takes place provided there is sufficient vapour in excess air rather than in a restricted space as with the closed flash point.

Q. *What is the octane number of a liquid fuel?*

Ans. It is an empirical rating of the antiknock quality of a liquid fuel and is a measure of its suitability for spark ignition engines.

It is the percentage of iso-octane in a mixture of iso-octane (octane value 100) and n-heptane (octane value 0) that will give the same knocking characteristics as the fuel under test in a standard spark-ignition engine.

Q. *What is knock and why does it occur in spark-ignition engines?*

Ans. Knock is the explosion occurring in the cylinder of spark-ignition engines.

It is caused by the secondary ignition of unburnt fuel after normal spark ignition, with the effect that a fast moving flame propagates along the cylinder. It gives rise to pressure waves that vibrate against the cylinder walls and we hear knocking.

Q. *How is the octane number of a liquid fuel determined if its octane number is greater than 100?*

Ans. In this case the performance of that fuel is matched to the performance of a mixture of iso-octane and tetraethyl lead.

The octane number of the fuel is then

= 100 + quantity of tetraethyl lead in the mixture.

Q. *What is the cetane number of a liquid fuel?*

Ans. It is the proportion of cetane (n-hexadecane with cetane value 100) in a mixture of *n*-hexadecane and alfa-methyl naphthalene (cetane value 0), that will give the same ignition delay after the injection of the fuel as the liquid fuel specimen in the same standard compression ignition engine.

Q. *For which fuels is cetane number used?*

Ans. Diesel fuels.

Q. *What is the cetane number of high-speed-diesel fuel?*

Ans. It ranges between 52 and 55.

Q. *What is diesel index?*

Ans. It is the product of the aniline point and specific gravity of the liquid fuel concerned:

Diesel Index = Aniline Point (°K) × Sp. Gr. (°API)

Q. *What is the aniline point?*

Ans. It is the temperature at which equal volumes of liquid fuel and aniline are just miscible.

Q. *What is the significance of the aniline point?*

Ans. It indicates the paraffinicity of the fuel, i.e. ignition characteristics of the fuel.

Q. *What are the advantages of liquid fuels over solid fuels?*

Ans. These are

1. Require less excess air for complete combustion
2. Higher heat generation per unit weight of fuel consumed because of higher calorific value
3. Better control of fuel consumption
4. Require no ash disposal system
5. More cleanliness of operation
6. Require less floor space for storage and handling.

Q. *Why is low sulphur content of fuel oil desirable?*

Ans. Higher sulphur content of fuel oil leads to corrosion problems. For example, fuel oil gun tip made of tungsten carbide gets quickly damaged during partial oxidation reaction in the gasifier

$$S + O_2 \rightarrow SO_2$$

(from F.O.)

$$WC + SO_2 \rightarrow WS + CO_2$$

The tungsten sulphide so produced is a brittle material and breaks off the gun-tip easily causing serious gun damage.

Q. *What is pitch?*

Ans. It is a liquid or semi-liquid residue from the distillation of crude petroleum.

Q. *Can it be used as a fuel in the boiler furnaces?*

Ans. Normally not; because of the difficulty in burning pitch in conventional oil/gas-fired boilers.

But since it contains a rich load of carbon, it can be used, at least theoretically, as fuel (Calorific Value ≃ 42 MJ/kg)

Q. *What are the difficulties encountered in burning pitch in a boiler?*

Ans. 1. The material is very sticky and difficult to handle
2. It requires considerable preheating to make it pumpable
3. It is practically incompatible with other fuels in tanks and piping
4. May contain an excessive load of moisture
5. May contain considerable amount of non-combustible particulates in suspension
6. Behaves poorly to atomization in oil burners.

Q. *What is the outcome of burning pitch in a boiler?*

Ans. Burning of pitch has more problems than benefits

1. Boiler undergoes deratings
2. Fouling of evaporator and superheater tubes becomes prevalent
3. Plugging of burner atomizers is frequent
4. Boiler components experience excessive rates of wear
5. Combustion is seldom complete. Shoot (unburned carbon) deposits
6. Stack-emission problems become a headache

7. Poor turndown
8. Combustion inefficiency.

Q. *Therefore, the use of pitch as a fuel is not rewarding. Can these problems be overcome?*

Ans. Though pitch does not lend itself as a convenient fuel it can still be burned much like an oil in the boiler.

The Sun Refining and Marketing Co's facility at Yabucoa, Puerto Rico has been successfully burning pitch in an O-type boiler (installed in 1972 and originally designed for gas firing) rated at 52 t/h of 3.1 MPa steam.

The pitch burned here is the bottoms of heavy crude feedstocks distilled in a double vacuum tower. Because of its relatively high viscosity it is preheated to 505°K before it is pumped, stored and fired. Though it is particularly high in solids and moisture contents, its heating value is quite high about 42 MJ/kg which is comparable to conventional petroleum fuels.

Q. *Though this pitch burning at Yabucoa is high in heating value, it has a substantial load of suspended solids and moisture. So does this not pose any problem during combustion?*

Ans. Yes, there were problems.

Substantial fouling led to boiler derating by 50%.

Excessive emissions of particulate solids were very common.

Burner ports got plugged up frequently with excessive carbon deposits.

Q. *How were these problems overcome?*

Ans. The above problems resulted from poor combustion of the PITCH.

A great deal of these problems were solved by replacing the conventional oil-fired burner with a custom-designed burner followed by boiler modifications.

Supplied by Voorheis Industries, Inc., Fairfield, New Jersey, the burner is absolutely unique in design because it burns pitch in a cylindrical flame, keeping it well off the evaporator tubes.

The burner sports a Bluff-Body register that prevents mushrooming of flame typical of conventional registers. High-fire combustion-air throat velocities are under 12 m/s, atomizing steam and gas-orifice velocities below 120 m/s.

The boiler modifications were carried out by Holman Boiler Works, Inc., Dallas, Texas. They laid out a refractory lining of 13 mm thick that allows the atomized pitch to absorb the maximum amount of radiant heat before the flame leaves the register (Fig. 8.9). Therefore, the atomized fuel gets completely gasified before it enters the furnace. Normally this refractory linning would not be used when the burner is switched over to conventional gas/oil firing.

So this custom-designed burner 1400 mm dia and rated at 155 million kJ/h successfully fires refinery pitch continuously in retrofitted O-type boiler.

Q. *What other special features are embodied in this new burner system to enhance combustion control and minimize fouling?*

Ans.
1. The burner sports a simplified control system with no combustion-air control required at the register.
2. It enjoys the facility of full-gun retraction to the register front-plate refractory to prevent the flame from striking the furnace wall and thereby minimizing fouling
3. Total elimination of atomizing-steam modulation and with that gone were the accompanying differential value, burner shield, diffuser, gas ring, combustion-air spin blades and specially shaped throat tiles.

Q. *What is the performance of the boiler after this retrofitting?*

Ans. The boiler now runs at its rated output achieving 85% efficiency with 25% excess air.

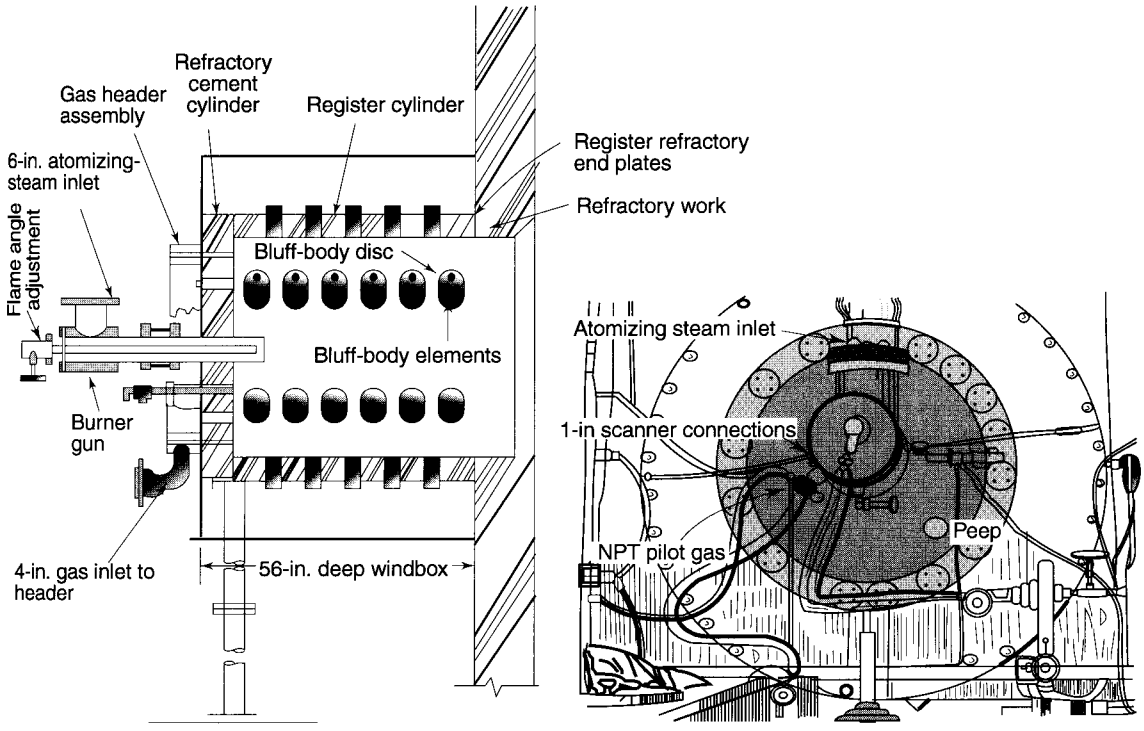


Fig. 8.9 *Custom-designed pitch burner from VOORHEIS INDUSTRIES, Inc., Fairfield, NJ. This one, 1422 mm in dia and rated at 150-million kJ/h fires refinery pitch continuously in a unique cylindrical flame.*

Source: *Power/August, 1987*

Courtesy: *Power Magazine (McGraw-Hill Publ./New York/NY 10011/USA)*

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Though it operates on base-load mode, a high turndown ratio of 5:1 is possible. Boiler inspections carried out during two scheduled shutdowns thereafter revealed no appreciable fouling anywhere in the unit. Because of staged-air effect, the NO_x level in the flue gas is anticipated to be low. Opacity of the flue gas has been drastically improved showing reduced particulate emissions.

Q. *How are gaseous fuels classified?*

Ans. They are classified into two classes

1. Natural gaseous fuel
2. Manufactured gaseous fuel.

Q. *What are natural gaseous fuels?*

Ans. The fuels belonging to this category are:

1. **Natural gas:** a colourless, odourless gas, composed of mostly methane and accumulating in the upper parts of oil of gas wells. Suitable for domestic and industrial consumption.
2. **Liquified petroleum gas:** is the primary flash distillation product of crude petroleum. Also it is produced by fractionating natural gas. It is mainly propane and butane, which are easily liquified. Used as both a domestic and industrial fuel.

3. **Refinery oil gas:** composed of some light gases obtained during processing of crude petroleum. These are light hydrocarbons with a small percentage of hydrogen and carbon monoxide. They cannot be economically converted into liquid product. Used as inplant source of fuel.

Q. *What are manufactured gaseous fuels?*

Ans. These are

1. Coal gas
2. Producer gas
3. Water gas
4. Carburetted water gas
5. Oil gas
6. Town gas
7. Blast furnace gas

Q. *What is coal gas?*

Ans. It is the gaseous product of carbonization of coal.

Q. *What are the chief constituent of coal gas?*

Ans. Methane, hydrogen and carbon monoxide.

Carbonization	Gas Composition
Low Temperature	CH_4–46%; H_2–28%; CO–12%; N_2–7%, CO_2–4%, H_2O–2%, O_2-1%
High Temperature	H_2–52%; CH_4–25%; CO–5.6%; CO_2–2.5%; C_xH_y–2.1%; N_2–12.5%; O_2–0.2%

Q. *Upon what variables does the quality of coal gas depends?*

Ans. 1. Temperature of carbonization
2. The type of plant, i.e. whether vertical retort or horizontal retort

Q. *What are the chief constituents of producer gas?*

Ans. Nitrogen, carbon monoxide and hydrogen

Q. *At what temperature is the carbonization of coal carried out?*

Ans. Low Temperature Carbonization: 775-900°K. High Temperature Carbonization: 1250-1600°K

Q. *What are the applications of coal gas?*

Ans. Used as fuel in gas fired boilers and commercial purposes.

Q. *What is producer gas?*

Ans. It is the gaseous fuel resulting from the complete gasification of the combustible material in solid fuels by air-steam mixture.

$$C + O_2 \rightarrow CO_2 \; ; \; CO_2 + C \rightleftharpoons 2CO$$

A mixture of air and steam is passed continuously through a heated bed of coke/coal for continuous generation of producer gas of uniform composition. (See table below)

Q. *Where is producer gas extensively used?*

Ans. 1. Firing open hearth furnaces in steel industry
2. Heating of retorts in coal carbonization.

Q. *What is water gas?*

Ans. It is the gaseous fuel resulting from total gasification of the combustible material in solid fuels by steam (superheated)

$$C + H_2O \rightleftharpoons CO + H_2$$

Steam is blown through a bed of incandescent coke/coal. As the above endothermic reaction proceeds, the coal bed temperature drops. When it falls to 900°C, air is blown through the bed for some time to bring the bed temperature back to the desired level (1000-1100°C)

$$C + O_2 \text{ (Air)} \rightarrow CO_2 + Q \text{ cals of heat}$$

PRODUCER GAS

Solid Fuel	Gas Composition (%)						Calorific Value
	N_2	CO	H_2	CO_2	CH_4	O_2	
Coke	56–57	26–27	10–12	5–6	0.3–0.5	—	4650–4700 kJ/m^3
Coal	46–47	28–30	15–16	3–5	2–3	0.2	6450–6500 kJ/m^3

Q. *What are its chief constituents?*

Ans. Carbon monoxide and hydrogen.

WATER GAS

Solid Fuel	Gas Composition							Calorific Value (kJ/Nm^3)
	CO	H_2	CO_2	N_2	CH_4	C_xH_y	O_2	
Coke	40–45	50–52	4–5	3–4	0.5–0.6	—	—	11200–12000
Coal	28–30	52–54	6–8	4–5	6–7	0.6–0.7	0.2	12450–13250

Q. *What are the chief usages of water gas?*

Ans. Used as

1. Industrial fuel
2. Synthesis gas in chemical processing

Q. *What are the advantages of gaseous fuels over solid fuels?*

Ans. 1. Require less excess air for complete combustion
2. Smokeless combustion is possible.
3. No ash formation
4. Higher calorific value
5. More cleanliness of operation
6. Better control of flame length and nature of flame (oxidizing or reducing)
7. Affords greater economy than coal or fuel oil at higher operating temperatures
8. Provides quicker furnace light-up
9. Better response to boiler load variations.

9

PRINCIPLES OF COMBUSTION

Q. *Does the combustion of a fuel in a furnace involve purely chemical processes?*

Ans. No. It involves a number of complex physical and chemical processes.

Q. *What physical process is most important in the study of kinetics of fuel combustion?*

Ans. It is the aerodynamic factor, i.e. the process of mixing the fuel and oxidant.

Q. *Which chemical factors are essentially required in the study of the kinetics of fuel combustion?*

Ans. Temperature and concentration of the reacting substances.

Q. *What kind of reactions are involved in fuel combustion?*

Ans. Mainly the exothermic reactions, i.e. burning of carbon, hydrogen and sulphur in the fuel

$$C + O_2 \longrightarrow CO_2 + 408.86 \text{ kJ/mol}$$

$$2H_2 + O_2 \longrightarrow 2H_2O + 286.22 \text{ kJ/mol}$$

$$S + O_2 \longrightarrow SO_2 + 292.25 \text{ kJ/mol}$$

At higher temperatures, i.e. in the flame core some endothermic reactions may occur

$$N_2 + O_2 \longrightarrow 2NO - 180 \text{ kJ/mol}$$

$$C + CO_2 \longrightarrow 2CO - 7.25 \text{ MJ/kg}$$

The last reaction takes place on the incandescent surface of the carbon particles under conditions of oxygen deficiency.

Q. *How can the rate of homogeneous and heterogeneous combustion be expressed?*

Ans. For homogeneous combustion (i.e. combustion of gaseous fuel and atomized liquid fuel), the rate of combustion at a constant temperature at any particular moment is the product of the concentrations of the reacting species

$$r = k\, C^x_{\text{fuel}}\, C^y_{O_2}$$

where k is the rate constant which depends on the temperature and chemical nature of the reagents.

C_{fuel} = concentration of fuel

C_{O_2} = concentration of oxygen

x, y are the moles of fuel and oxygen involved in the stoichimetric chemical equation.

For heterogeneous combustion, i.e. the combustion of solid fuel, the concentration of combustible substance is constant and hence the rate of this reaction is dependent only on the concentration of oxygen on the surface of the solid fuel

$$r = k\, C^s_{O_2}$$

where $C^s_{O_2}$ = concentration of oxygen on the fuel surface.

Q. *Why is the rate of formation of carbon monoxide higher than the rate of formation of carbon dioxide on the surface of burning coal?*

Ans. It is because the activation energy for the formation of CO

$$C + \frac{1}{2}O_2 \longrightarrow CO \; ; \; E_{co} = 60 \text{ kJ/mol}$$

is much less than that for the formation of CO_2

$$C + O_2 \longrightarrow CO_2 \; ; \; E_{CO_2} = 140 \text{ kJ/mol}$$

With higher activation energy the molecular bonds of the reactants break off less easily and consequently the reaction rate is lower.

Q. *What is activation energy?*

Ans. It is the minimum energy required to excite the reactant molecules to such an activated state that these molecules undergoing collisions break their old molecular bonds and rearrange themselves into molecules of new substances.

All collisions do not result in chemical reaction. Only collisions between reactant molecules excited by activation energy E result in chemical reaction. This activation energy is given by

$$k = k_o \exp\left(-\frac{E}{RT}\right)$$

Q. *Why does an excess of fuel (rich mixture) or a fuel deficiency (lean mixture) cause the rate of reaction to decrease?*

Ans. It is because of lower heat evolution per unit volume.

Since during the process of combustion, there is a steady supply of fuel and oxidant (air) in the combustion zone, the concentrations of the reagents are practically invariable in time. When these conditions prevail, the highest reaction rate is attained at a nearly stoichiometric ratio of the concentrations of the reagents. Therefore, any deviation from the stoichiometric ratio will bring about a decrease in heat evolution per unit volume.

Q. *Can combustion take place at any arbitrary concentration of fuel in the air-fuel mixture?*

Ans. No.

Q. *Why?*

Ans. There exists a lower concentration limit below which combustion is impossible and at the same time there exists an upper concentration limit when any further increase of the concentration of the fuel prevents combustion. That is, there exists a range of concentrations between these two limits at which combustion is possible. [Fig. 9.1]

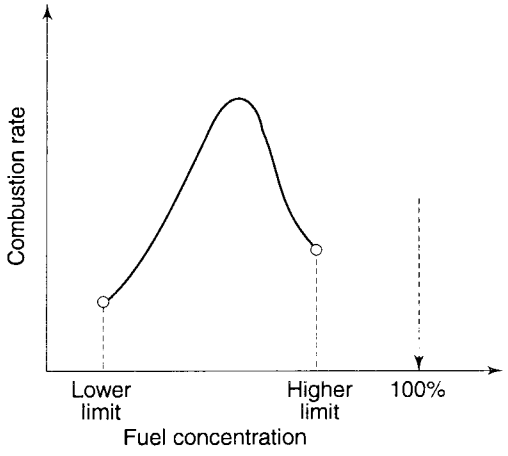

Fig. 9.1 *Combustion is possible within two defined limits of fuel concentration.*

Q. *What is explosive combustion?*

Ans. If a gaseous fuel-air mixture prepared for combustion completely fills in a particular volume, an ignition source will trigger the oxidation reaction propagating at a high rate all over the volume. This will result in a sharp increase of temperature and pressure. This type of combustion is called explosive combustion.

Q. *What do you mean by upper and lower explosive limits of gaseous fuel-air mixture?*

Ans. The fuel gas-air mixture is capable of exploding in the whole range of concentrations between these two limits.

Q. *What is ignition temperature?*

Ans. The temperature above which a self-sustained oxidation reaction between fuel and oxidant is possible is called ignition temperature.

Q. *How will you determine graphically the ignition temperature of a gaseous fuel-oxidant mixture?*

Ans. Heat generated in the initial stage of combustion can be determined with the help of the equation

$$Q_g = k_o \exp(-E/RT) C_f^x \, Vq \qquad \text{(I)}$$

where C_f = concentration of gaseous fuel

V = volume of prepared gaseous fuel-air mixture

q = thermal effect of the reaction per unit mass

And the quantity of heat removed from the reaction zone is determined by the equation

$$Q_r = \alpha A \, (T - T_s) \qquad \text{(II)}$$

where α = heat-transfer coefficient

A = surface area of surrounding walls

T = temperature of gaseous fuel-air mixture

T_s = temperature of surrounding walls

As evident from equation (I), the heat generated at the initial stage of oxidation of fuel is described by an exponential curve while the heat removal at any stage can be represented by a straight line inclined at an angle to X-axis. [Fig. 9.2]

In the beginning let the fuel-air mixture and surrounding wall temperature be T_{s_1}. Due to heat evolution in the fuel combustion, the mixture will be heated to a temperature, say, T_1. Now $T_1 > T_{s_1}$.

Initially, $Q_g > Q_r$

But at point (1), $Q_g = Q_r$ and therefore further preheating of the fuel gas-air mixture becomes impossible. This is the zone of slow oxidation.

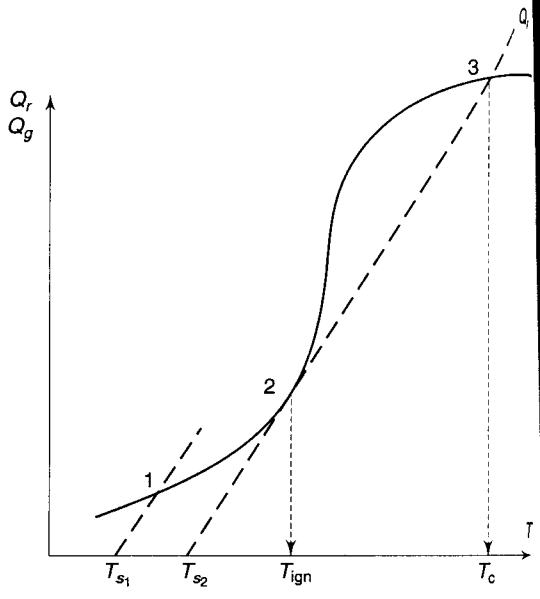

Fig. 9.2

Now, let the temperature of the surrounding walls be raised to T_{s_2}. At this point, again $Q_g > Q_r$ initially, and temperature of the mixture rises. Finally, point (2) is reached where $Q_g = Q_r$, but in contrast to point (1) this point is unstable. Only a slight increase in temperature shoots Q_g up to greater than Q_r, with the effect that heat evolution will increase more rapidly than heat removal. The temperature corresponding to this point (2) is called ignition temperature.

Q. *How can the extinction temperature be determined from such a curve.*

Ans. The point A corresponds to a state of stable combustion. If heat is extracted more forcibly, i.e. along the line LM, the combustion temperature will drop to a point B. At this point, the high temperature oxidation process interrupts for as long as Q_r becomes greater than Q_g. [Fig. 9.3]

If the temperature of the gas mixture at B is slightly decreased it will bring about a sharp drop in Q_g and since $Q_r > Q_g$ all along from B to C, combustion will cease to exist.

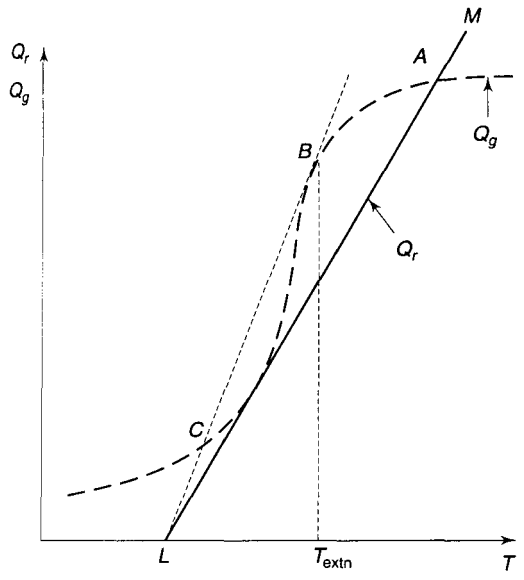

Fig. 9.3

The temperature of the fuel gas-air mixture corresponding to the point *B* is called extinction temperature.

Q. *Why is extinction temperature always higher than ignition temperature?*

Ans. It is because of the lower concentrations of gaseous fuel and air in the zone of active combustion than their initial concentration at ignition.

Q. *It has been experimentally established that the rates of combustion reaction are much higher than the rates calculated on the basis of law of mass action and Arrhenius' law. Why?*

Ans. The rates of combustion reactions, using the law of mass action and Arrhenius theory, are derived by considering the number of active molecules of the initial substances entering into oxidation reactions.

However, in fact, reactions do not occur immediately between the original molecules, i.e. combustion reaction is not a one step process but proceeds through a number of intermediate stages that involve the formation of such active molecular fragments as atoms and radicals like H, O, OH, etc. Since radicals and individual atoms can form free-valency particles, these intermediate reactions, as a result, have low levels of activation energy. Such reaction, therefore, proceed at a high rate and therefore account for the substantial high rates of combustion reactions.

Q. *What is the induction period?*

Ans. It is the time taken by the reacting molecules to generate active reaction centres in the form of charged particles and the time taken by these particles to accumulate in the medium.

These active centres are produced due to partial destruction of the original molecules due to collision with other molecules having higher energy than the atomic bond energy of the original molecules.

Q. *What is the mechanism of combustion of hydrogen?*

Ans. The combustion of hydrogen at temperatures above 500°C is an explosive chain reaction that involves the following stages

1. **Nucleation:** formation of active centres

$$H_2 + M^* \longrightarrow H + M$$

$$H_2 + O_2 \longrightarrow 2OH$$

where M^* and O_2^* are high-energy molecules

2. **Propagation:** entering of the active centres—radicals and atoms—into reactions with the surrounding molecules producing final reaction products and an even greater number of active centres

$$OH \xrightarrow{H_2} H_2O + H$$

$$H + O_2 \longrightarrow \overset{+}{O}$$

$$O \xrightarrow{H_2} OH \xrightarrow{H_2} H_2O + \overset{+}{H}$$

3. **Ceasation:** quenching of the active centres as the reaction products accumulate and the concentration of the starting material becomes lower.

$$H + H \longrightarrow H_2$$

$$OH + H \longrightarrow H_2O$$

Q. *What is the rate expression of hydrogen burning by considering the law of mass action and Arrhenius law?*

Ans. The stoichiometric equation for the combustion of hydrogen is

$$2H_2 + O_2 \longrightarrow 2H_2O$$

And accordingly, the theoretical rate expression for the combustion of hydrogen is

$$r_{H_2O} = k_o \exp(-E/RT) C_{H_2}^2 C_{O_2}$$

Q. *What is the actual reaction rate of hydrogen combustion?*

Ans. It is described by the equation

$$r_H = 10^{11} \exp(-E'/RT)\, C_H\, C_{O_2} T^{1/2}$$

where E'' = activating energy of H-atoms (reaction centres) and O_2 molecules reacting.

[Note: $E' < E$]

Q. *What are the decisive factors affecting the reaction rate of hydrogen combustion?*

Ans. Concentrations of hydrogen atoms and oxygen molecules excited by an activation energy E'.

Q. *What is the mechanism of hydrocarbon combustion?*

Ans. W. Bone suggested the following mechanism of hydroxylation

1. **Nucleation:** formation of active centres, H, OH and O

$$CH_4 \xrightarrow{\text{Heat}} CH_3 + H$$

$$H + O_2 \longrightarrow OH + O$$

2. **Propagation:** formation of intermediate hydroxylated compounds that in turn burn or disintegrate thermally

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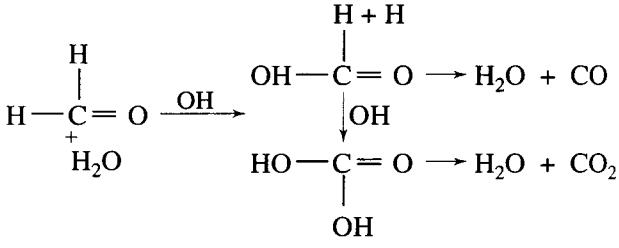
$$CH_4 + OH \longrightarrow \underset{+H}{CH_3OH} \xrightarrow{OH} \underset{+H}{CH_2(OH)_2} \longrightarrow$$

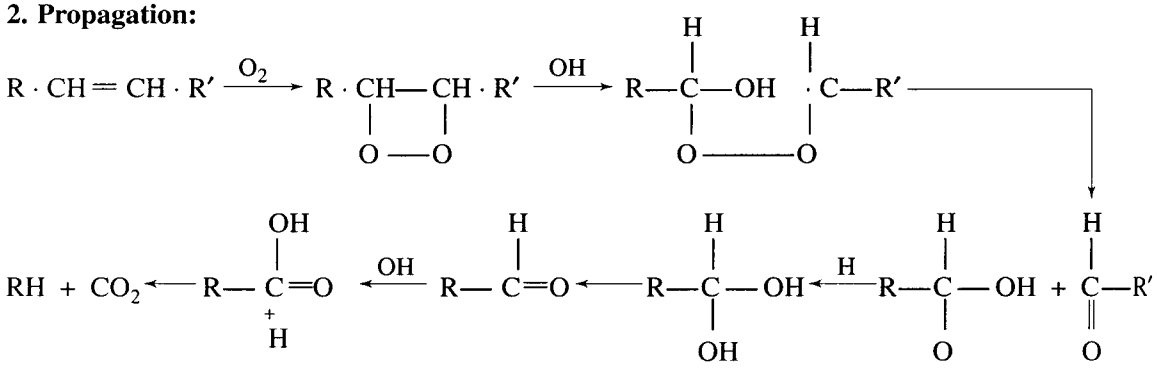


According to Bakh, combustion of hydrocarbons proceeds via unstable peroxide intermediates

1. Nucleation:

$$R \cdot CH = CH \cdot R' \xrightarrow{\text{Heat}} H \qquad H + O_2 \longrightarrow OH + O$$

2. Propagation:



Q. *How does the reaction rate of combustion of gaseous fuel change with time?*

Ans. During the induction period—a short time during which a sufficiently large number of active centres (atoms and radicals) accumulate—the reaction rate is almost unnoticeable.

Following this period, the reaction rate increases rapidly due to the propagation of a large number of parallel chain reactions over the entire volume.

Finally an equilibrium is reached between the appearance and disappearance of the active centres whereupon no more rate increase is observed. This is the maximum rate and the combustion will proceed at this rate provided there is a steady supply of combustion material and oxidant to the combustion zone.

Q. *Why is liquid fuel evaporated prior to combustion?*

Ans. So far as liquid fuel is concerned, both ignition and combustion temperatures are higher than the boiling point of the individual fuel fractions.

Hence heat is supplied to evaporate the liquid fuel, then its vapours are mixed with air, preheated to ignition temperature and ignited.

Q. *What is the mechanism and combustion characteristics of a liquid fuel droplet?*

Ans. The combustion characteristics of atomized liquid fuel (i.e. fuel droplets) in stagnant air involve a diffusion mechanism.

Step (I) Formation of vapour cloud—As soon as the liquid fuel droplet comes in contact with the air, it evaporates till the partial pressure of fuel vapour in the air is equal to the vapour pressure of the liquid at that temperature. As a result, a part of liquid from the surface of the droplet evaporates to form a vapour cloud surrounding the remaining liquid droplet. [Fig. 9.4]

Step (II) Diffusion of vapour cloud—The vapour cloud that forms around the droplet diffuses into the environment, spreading radially outward while the oxygen of the air is diffusing into the body of the vapour cloud. These two diffusions take place in the opposite direction—the fuel-vapour diffusing away from the fuel droplet and the oxygen towards the droplet.

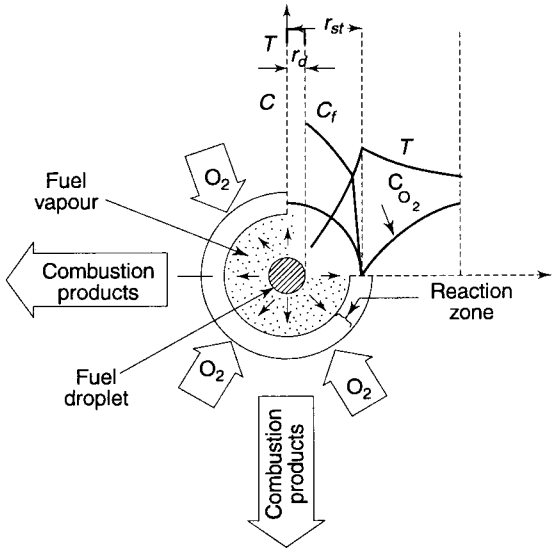


Fig. 9.4 *Mechanism of liquid fuel droplet combustion.*

Step (III) Combustion—At a certain radial distance (r_{st}) from the centre, the stoichiometric relationship between fuel vapours and oxygen is established and combustion takes place producing a spherical combustion front around the liquid droplet.

The zone with $r > r_{st}$, contains primarily combustion products mixed with oxygen while the zone with $r < r_{st}$, fuel vapours prevail, their concentration progressively increasing towards the liquid droplet.

Q. *What is the magnitude of r_{st}?*

Ans. It is 4 to 10 times of r_d—the radius of the liquid droplet.

Q. *On which factors does r_{st} depends?*

Ans. It depends primarily on the droplet size and temperature of the combustion zone.

Q. *On which factors does the rate of combustion of a liquid fuel droplet depend?*

Ans. It depends on three factors:

1. rate of evaporation of droplet from its surface
2. rate of chemical reaction (oxidation) in the combustion zone
3. rate of oxygen diffusion to the combustion zone.

Q. *Why is the rate of combustion of a liquid droplet predominantly determined by evaporation from its surface?*

Ans. The rate of combustion of a liquid droplet basically depends on the rate of oxygen diffusion to the combustion zone. Now, the quantity of oxygen diffusing through the spherical cloud of fuel vapour surrounding the liquid fuel droplet is directly proportional to the square of the sphere-diameter. Hence a slight shift in the combustion zone from the surface of the droplet, that means, the increase of the rate of evaporation from the surface of the liquid droplet will noticeably increase the mass flow rate of oxygen to the combustion zone. [Fig. 9.5]

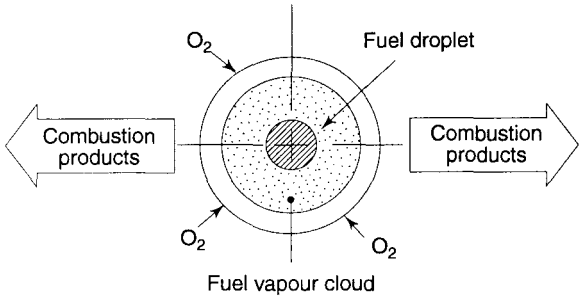


Fig. 9.5

Q. *Why is the combustion rate of liquid fuels increased by atomizing the fuel just before burning?*

Ans. Atomization of liquid fuels brings about substantial increase of the total surface available for evaporation, increasing the intensity of evaporation per unit area of their surface.

With the increase of the rate of evaporation the diameter of the vapour cloud surrounding the liquid droplets increases. Since the quantity of oxygen diffused through the vapour cloud is proportional to the square of the diameter of the cloud sphere, atomization increases the rate of oxygen diffusion through the sphere and thereby increases the combustion rate of liquid fuels.

Q. *For streamline airflow (Re < < 1) how can it be shown that the rate of heat exchange between a fuel droplet and the surrounding air increases as the size of the droplet decreases?*

Ans. For air flow at low Reynolds number Re < < 1, the heat flow through a spherical surface suspended in air is determined by λ, the conductivity of vapour film in the boundary layer.

Under these conditions, the heat transfer coefficient α is given by Sokolsh's formula

$$\text{Nu} = \frac{\alpha d}{\lambda} = 2$$

$$\therefore \qquad \alpha = \frac{2\lambda}{d} = \frac{\lambda}{r}$$

where, d = droplet diameter

From this equation it follows that with the reduction of droplet size, the rate of heat exchange between a droplet and the surrounding air increases.

Q. *What stages are involved in the combustion of pulverized solid fuel (coal)?*

Ans. **Stage (I)** THERMAL PREPARATION: Evaporation of residual moisture and separation of volatiles, as the fuel particles are heated up (400–600°C) in a few tenths of a second.

Stage (II) BURNING OF VOLATILES AND HEATING OF COKE PARTICLES: The volatiles are then ignited and they burn up within a very short period (0.2–0.5 *s*) liberating enough quantity of heat to bring coke particles to their ignition temperature.

Stage (III) COMBUSTION OF COKE PARTICLES: Coke particles, intensely heated by the

combustion of volatiles, start to burn as soon as the ignition temperature is reached. This reaction takes place at an elevated temperature (800–1000°C) and takes up 1/2 to 2/3 of the total time of combustion (1–2.5s).

Q. *What is the temperature profile of pulverized coal combustion?*

Ans. The temperature conditions of combustion of finely divided coal particles can be best represented graphically. [Fig. 9.6]

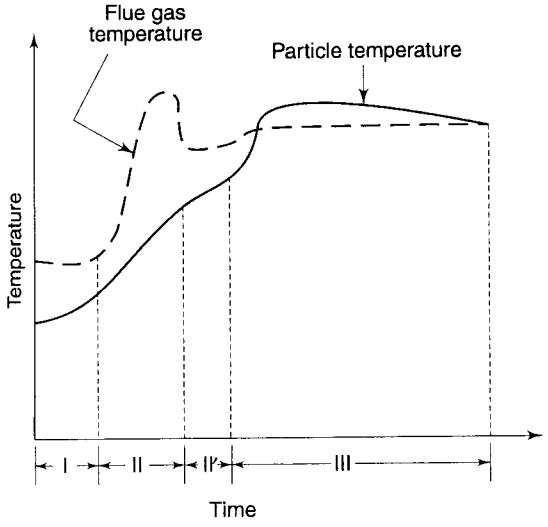


Fig. 9.6 *Temperature-time profile in pulverized coal combustion.*

Stage I representing the thermal preparation zone is accomplished at 400-600°C within a fraction of a second. All the residual moisture and volatiles are intensively evolved at this stage.

Stage II is the zone of burning volatiles as well as heating of coke particles by the heat liberated due to combustion of volatiles. If the volatile yield of coal (brown coal, oil shales, pit) is high, the liberated heat of volatile combustion will ignite the coke particles. If the yield of volatiles is low, the coke particles must be heated up externally (stage II') to ignition temperature.

The final stage is the combustion of coke particles that takes place in the temperature range 800–1000°C.

Q. *What kind of process is the final stage of pulverized coal combustion, i.e. combustion of coke?*

Ans. It is a heterogeneous process.

Q. *On which factor is its rate principally dependent?*

Ans. Supply of oxygen to the heated surface of the coke particles.

Q. *What is the mechanism of burning of coke particles?*

Ans. The probable mechanism of reaction between carbon and oxygen is as follows

1. ADSORPTION OF OXYGEN MOLECULES from the gas volume on the surface of the carbon particles to form a complex carbon-oxygen intermediate C_xO_y.
2. THERMAL DISSOCIATION of C_xO_y into CO and CO_2 whose proportions vary with reaction temperature.
   At about 1200°C, the overall reaction can be represented as

   $$4C + 3O_2 \longrightarrow 2CO + 2CO_2$$

   where the CO/CO_2 ratio is 1:1.
   But at 1700°C, the resulting reaction can be written in the form

   $$3C + 2O_2 \longrightarrow 2CO + CO_2$$

   whence CO/CO_2 is equal to 2:1.

The carbon particle is immediately surrounded by a sheath of hot gas film consisting of primary reaction products which are being continuously removed from the particle surface to the environment. [Fig. 9.7]

In this process, carbon monoxide diffusing away from the carbon particle encounters oxygen molecules diffusing in the opposite direction and reacts with it within the boundary gas-film

to produce CO_2. As a result, the concentration of oxygen across the boundary film falls off on approaching the surface of the particle.

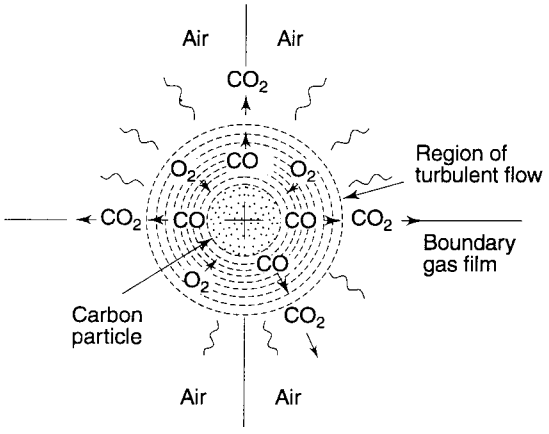


Fig. 9.7 *Mechanism of coke particle combustion.*

Q. *How does the concentration of gaseous substance at the surface of burning carbon vary?*

Ans. This can be best interpreted through graphical representation. [Fig. 9.8 and 9.9]

For carbon burning at moderate temperatures (Fig. 9.8), the oxygen concentration across the boundary gas layer decreases sharply on approaching the surface of the carbon particles, while the concentration of CO_2 increases upto a certain radial distance, as more CO is getting converted to CO_2 by diffusing O_2 and is maximum at a point when stoichiometric concentrations of O_2 and CO are attained for the reaction

$$2CO + O_2 \longrightarrow 2CO_2$$

Beyond this, the CO_2 concentration towards the carbon particle falls off because of conversion of some CO_2 to CO

$$C + CO_2 \longrightarrow 2CO$$

For high temperature combustion, (Fig. 9.9) oxygen concentration across the boundary layer decreases more sharply on approaching the carbon particles as the carbon monoxide produced consumes all the oxygen supplied. No oxygen can

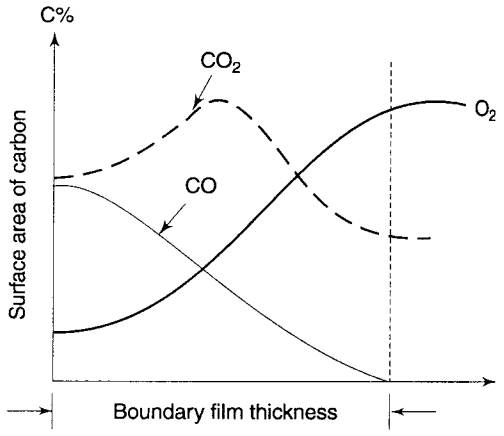


Fig. 9.8

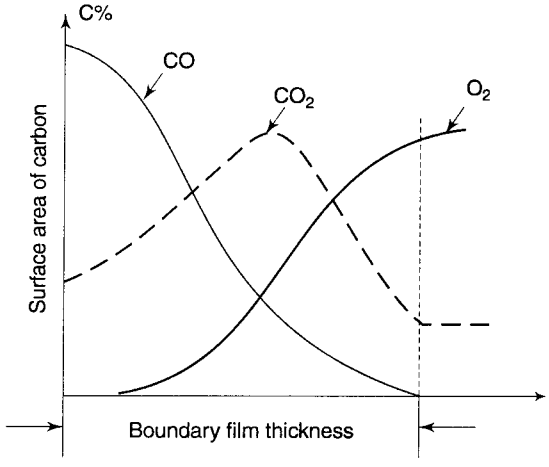


Fig. 9.9

reach the coke particles' surface. Under these conditions of oxygen deficiency, the endothermic reduction

$$CO_2 + C \longrightarrow 2CO - q$$

will occur on the surface of the coke particles increasing the carbon monoxide concentration on and adjacent to the surface of the particles.

Q. *How can the combustion of carbon particle be represented through chemical reactions?*

Ans. It involves four reactions out of which two are primary and the rest secondary.

Primary Reactions

1. $C + O_2 \longrightarrow CO_2 + Q_1$ (MJ/mol)
2. $C + \frac{1}{2}O_2 \longrightarrow CO + Q_2$ (MJ/mol)

Secondary Reactions

3. $CO + \frac{1}{2}O_2 \longrightarrow CO_2 + Q_3$ (MJ/mol)
4. $C + CO_2 \longrightarrow 2CO - Q_4$ (MJ/mol)

Q. *Is the overall reaction exothermic or endothermic?*

Ans. Exothermic. It is because $Q_4 = 0.57Q_3$ which implies that despite the endothermic reaction (reaction No. 4), the temperature of combustion is maintained at a high level due to higher heat evolution in the volume.

Q. *What process accelerates the burning-off of coke particles?*

Ans. The combustion of carbon (coke) particles proceeds via partial gasification of carbon to CO and its after-burning to CO_2

$$C \xrightarrow{O_2} CO \xrightarrow{O_2} CO_2$$

So, as more and more CO burns of into CO_2, more carbon undergoes partial gasification to produce CO shifting the foregoing chain reaction to the right and thus, in the process, accelerating the burning-off of coke particles.

Q. *Is the total rate of combustion of pulverized solid and liquid fuels determined only by the rate of chemical reactions proper?*

Ans. It is determined not only by the rate of chemical reactions proper but also by the rate of oxygen supply to the combustion zone.

Q. *How does the oxygen supply take place?*

Ans. It takes place by turbulent and gas diffusion mechanism.

Q. *What is this mechanism?*

Ans. When the carbon particle burns, it is immediately surrounded by a boundary film consisting of predominantly CO near the particle surface and predominantly O_2 and CO_2 further from the surface. (Fig. 9.10)

The CO produced due to partial gasification of carbon diffuses out from the surface towards the film boundary as more and more CO is oxidized to CO_2 when the stoichiometric ratio of CO : O_2 is reached within the boundary layer

$$C \xrightarrow{O_2} CO \xrightarrow{O_2} CO_2$$

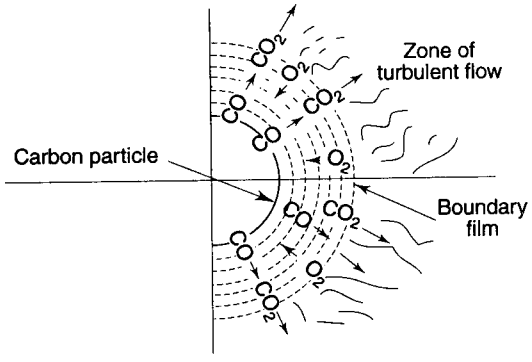


Fig. 9.10 *Carbon particle combustion (Film theory)*

Therefore, as this process continues, oxygen concentration gets constantly depleted on approaching the particle surface. Thus a concentration gradient of oxygen is established across the film—concentration of O_2 at the film surface ($C^f_{O_2}$) being greater than concentration of O_2 at the particle surface ($C^s_{O_2}$). This concentration difference is the drive for molecular diffusion of O_2 across the gas film towards the particle as long as combustion proceeds. Beyond this gas film, intensive turbulent mass transfer occurs.

Q. *How can the rate of oxygen diffusing per unit surface area of the carbon particles be determined?*

Ans. This can be determined by Fick's law:

$$K_d = \alpha_d \, [C^b_{O_2} - C^s_{O_2}] \frac{\text{kmol}}{\text{m}^2} \ \text{s}^{-1}$$

α_d = rate of mass transfer = D/δ, m/s

D = coefficient of molecular diffusion, m^2/s

δ = boundary layer thickness, m

$C^b_{O_2}$ = oxygen concentration in the bulk of main flow, $kmol/m^3$

$C^s_{O_2}$ = oxygen concentration on the surface of carbon particles, $kmol/m^3$

Q. *When will this rate of diffusion be maximum?*

Ans. For $C^s_{O_2} = 0$ whence $[K_d]_{max} = \alpha_d \, C^b_{O_2}$

Q. *If all the oxygen diffusing reacts on the particle surface, what would be the rate of reaction per unit surface area in terms of oxygen consumption?*

Ans. It will be

$$K_r = k \cdot C^s_{O_2}$$

Q. *When will this reaction rate be maximum?*

Ans. If $C^s_{O_2} = C^b_{O_2}$ whence $[K_r]_{max} = k \, C^b_{O_2}$

[Since the rate of oxygen supplied through the boundary film is equal to the rate of oxygen consumed in the surface reaction,

$$K_d = K_r = K_s \ \text{(say)}$$

Solving the two equations above,

$$K_s = \frac{\alpha_d \, k}{\alpha_d + k} C^b_{O_2} = k_r \, C^b_{O_2}$$

where $k_r = \dfrac{\alpha_d \, k}{\alpha_d + k}$]

Q. *How do K_d and K_s vary with temperature?*

Ans. This can be best represented graphically as shown in Fig. 9.11.

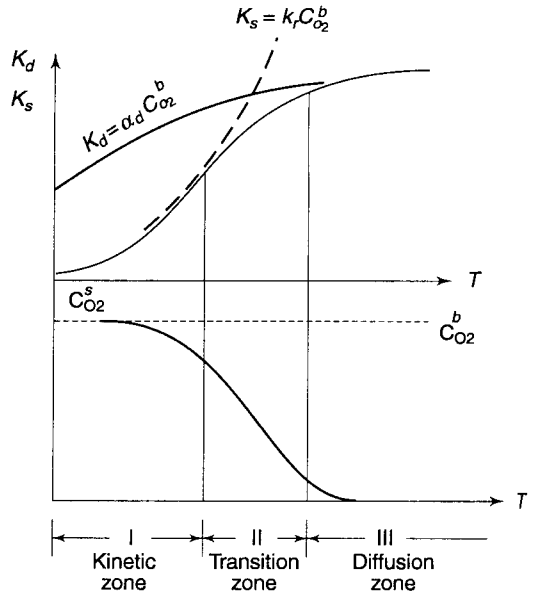


Fig. 9.11

Q. *How can these be interpreted at low and high temperatures?*

Ans. At temperatures less than 1000°C, the rate of surface reaction

$$2C + O_2 \longrightarrow 2CO$$

is rather slow. And the oxygen consumption, as a consequence, becomes a very small fraction of the total oxygen supplied to the surface, i.e.

$$k << \alpha_d$$

Under these circumstances $k_r \approx k$

and $C^b_{O_2} \approx C^s_{O_2}$

$\therefore \quad K_s = k \, C^s_{O_2}$

which implies that the total reaction rate is limited by the kinetics of the chemical reacting on the coke particle's surface.

At high temperatures (i.e. above 1400°C), the rate constant of the surface reaction shoots up rapidly and eventually exceeds the maximum rate of oxygen supply to the surface.

$$\therefore \qquad k \gg \alpha_d$$

And as such the total reaction rate is determined by the rate of oxygen supply

$$K_s = \alpha_d \, C^b_{O_2}$$

Under these conditions, the rate of the surface reaction is so high that all the oxygen reaching the coke particle surface through the diffusion mechanisms reacts instantaneously and its concentration at the surface becomes virtually equal to zero. In this zone, the surface reaction rate approaches a maxima and varies very little despite any increase of temperature.

Q. *Into how many zones, can the regions of constant-size coke particle burning be divided?*

Ans. Kinetic combustion zone
Transition combustion zone
Diffusion combustion zone

Q. *What is kinetic combustion zone?*

Ans. The temperature region (800–1000°C) for combustion of coke particles is called kinetic combustion zone.

Q. *Why is the temperature region for combustion of coke particles called the kinetic combination zone?*

Ans. During this temperature range, the total reaction rate is determined by the kinetics of the chemical reacting on the surface.

Q. *What is the diffusion combustion zone?*

Ans. The temperature range from 1400°C onwards is called the diffusion combustion zone.

Q. *Why is it so called?*

Ans. During this temperature range, the overall reaction rate is determined by the rate of oxygen diffusing to the particle surface. The reaction rate varies very little with the increase of temperature but is retarded considerably if the oxygen supply is insufficient.

Q. *What chemical reactions take place in this diffusion combustion zone in the case of coke particle burning?*

Ans. In this zone the rate of surface reaction is too high and the oxygen supplied to the surface by diffusion reacts instantaneously, with the effect that its concentration at the coke particle surface becomes nearly zero.

Due to oxygen deficiency at the surface a part of CO_2 is reduced to CO on the white hot coke surface

$$CO_2 + C \longrightarrow 2CO$$

This CO diffusing outwards meets the oncoming O_2 diffusing inwards across the boundary film and burns to produce CO_2

$$2CO + O_2 \longrightarrow 2CO_2$$

Q. *How is the reaction rate in the diffusion combustion zone affected by gas flow around the particles and particle size?*

Ans. The rate of combustion increases with the increase of gas flow around the coke particles as well as with the decreasing size of the particles.

Q. *What is the transition zone?*

Ans. The temperature range from 1000°C to 1400°C is called transition zone.

Q. *Why is it so called?*

Ans. During this temperature region, the rate of surface reaction on the coke particles is determined simultaneously by the rate of oxygen supply as well as the kinetics of the chemical reaction on the surface.

Q. *How is the transition combustion zone affected by the size of the coke particles?*

Ans. If the coke particles are large, the transition zone shifts to the lower limit of temperature while with smaller particles it appears at a higher temperature.

Q. *What is flame core zone?*

Ans. It is the zone of the furnace within which intensive combustion of fuel occurs to a burn-off intensity $\psi_f = 0.85–0.90$.

It is a zone of high temperature and the best portion of heat transfer from this zone to surrounding water-walls takes place by radiation. (Fig. 9.12)

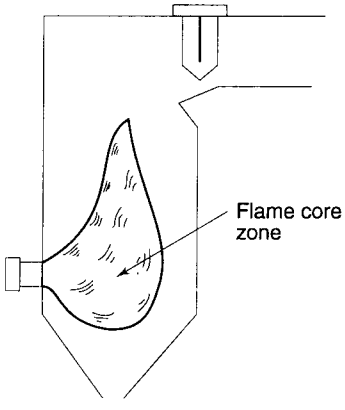


Fig. 9.12 *Flame core zone.*

Q. *What is the size of the flame core zone with respect to the furnace space?*

Ans. It occupies 20 to 33% of the furnace space volume.

Q. *What about the rest of the furnace space volume?*

Ans. The remaining portion of the furnace space volume is known as zone of fuel afterburning and gas cooling.

Q. *Why does afterburning (burn-off) take place deep in the diffusion region of the fuel afterburning and proceed slowly?*

Ans. It is because in this zone (Fig. 9.13) there is low concentration of leftover fuel and oxidant and gas flow turbulence is weak.

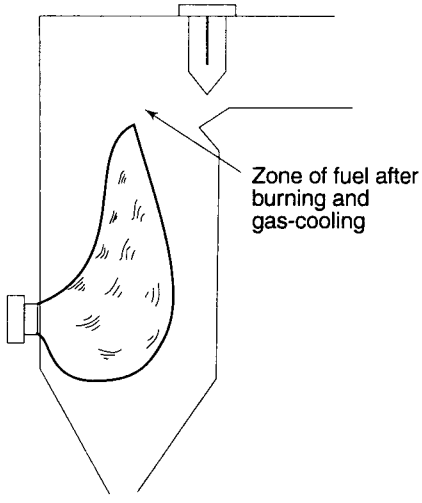


Fig. 9.13

Q. *What is resolved flame length?*

Ans. It is equal to the horizontal distance from the burner-end to the furnace axis (AB) + vertical distance from the burner level to the level of the horizontal gas duct (BC) + horizontal distance to the furnace outlet (CD)

i.e. $L_{flm} = AB + BC + CD$ [Fig. 9.14]

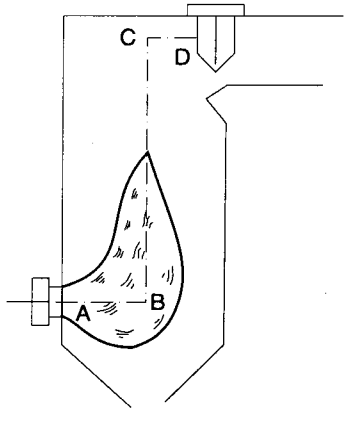


Fig. 9.14

Q. *What is the importance of resolved flame length?*

Ans. Fuel afterburning (burn-off) and temperatures in a furnace space are functionally related to the resolved flame length (L_{flm}).

Q. *How do these two parameters—burn-off degree (Ψ_f) and furnace temperature (Θ) vary with the resolved flame length?*

Ans. These can be best interpreted through curves obtained by extrapolating test results of Ψ_f and Θ at different values of relative flame length. [Fig. 9.15]

From the curves, it is evident that burn-off of anthracite coal is completed at relative flame length $L/L_{flm} = 0.35$ while that of fuel-oil is completed at $L/L_{flm} = 0.25$

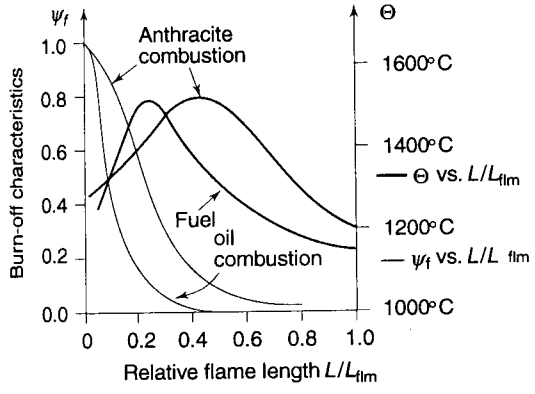


Fig. 9.15

Q. *Why is burn-off of fuel oil completed at such a small value of relative flame length?*

Ans. It is because, in this case, the flame core disappears in the initial horizontal portion (*AB* in the above figure) of the resolved flame length.

Q. *Why does the combustion of larger fractions of pulverized coal take place mainly in the diffusion region?*

Ans. When pulverized coal is used as a fuel, it consists of particles having a range of size distribution—the finest fractions get heated up quickly (within a few hundredths of a second), reach ignition point earliest and burn first. As they burn, the generated heat accelerates the heating of larger particles. But these begin burning when a large portion of oxygen has already been consumed. Therefore, the combustion of large particles, under oxygen deficiency, takes place predominantly in the diffusion region.

Q. *Why do larger fractions of pulverized coal account for the loss of fuel as the unburnt carbon in the flue gas exhaust?*

Ans. As stated above, the combustion of larger fractions of coal particles takes place when there is already a deficiency of oxygen, as the major part of the supplied oxygen has already been consumed up by the finest fractions. Therefore, only that fraction of a large carbon particle is burnt up from the surface that has received adequate oxygen penetrated through the gas film by molecular diffusion mechanism during the retention time of the particle in the furnace. This leaves a considerable portion of large size carbon particles unburnt and hence accounts for loss of fuel as unburnt carbon in the flue gas exhaust.

Q. *What factors influence the combustion of coal particles in a fluidized bed?*

Ans.
1. Bed depth
2. Fluidizing velocity
3. Particle size
4. Operating pressure
5. Nature and constituent of fuel as well as ash
6. Bed temperature
7. Fuel feeding procedure
8. Geometry of the combustors
9. Air feeding method.

Q. *How do the nature and constituent of coal and that of ash influence coal-combustion in a FB?*

Ans. Coal containing sulphur requires addition of limestone (sorbent) for sulphur-capture. Intro-

duction of these additives can influence the way a fluidized bed combustor is operated.

Coal containing higher fines percentage may lead to above-bed burning in some designs.

The volatile matter in fuel can burnout in or above the bed.

Again a coal of high ash content can led to build-up of solids in the bed, changes of bed material properties and fluidization behaviour.

The ash should have a high softening point to avoid clinkering and bed seizure. Should the ash have a low softening temperature, the bed must be operated at a low enough temperature to get rid of sintering.

Q. *How does the geometry of the combustor influence FB combustion of coal?*

Ans. The geometry of the fluidized bed influences bed-behaviour greatly. If the bed-depth to diameter ratio is less than unity, the bed goes to operate in the slugging regime whilst in a shallow bed a wide variety of bed material circulation patterns can exist.

Q. *Why is it essential that a fluidized bed combustor should operate within a restricted range of bed temperature?*

Ans. The upper temperature limit (typically 1225°K) is to avoid the risk of ash sintering while the lower limit (typically 1025°K) precludes combustion at unacceptably low efficiency.

Q. *What is the mechanism of fluidized bed coal combustion?*

Ans. When coal is burned in a fluidized bed, excess air 20—30% more than stoichiometric air is supplied to sustain combustion in a fluidized state while keeping a high temperature (typically 1125°K) throughout the bed.

During the course of combustion, the following sequence of events take place:

I. Drying: Initially the coal-moisture is driven off. As a result, surface temperature of coal particle rises.

II. Devolatilization: It follows in the wake of drying. As the fuel particles receive heat from surroundings through convection and radiation, devolatilization sets in whereupon the volatile matter tied to the fuel commence to be liberated as combustible vapors which burn as a diffusion flame surrounding the fuel particle.

The volatiles burn as a diffusion flame surrounding the fuel particle. (Fig. 9.16).

III. Char Burning: Devolatilization ends up in char—a porous mass of carbon with some ash bound in it. The degree of porosity depends upon the type of fuel.

The char sinks into the bed and starts to burn as soon as its ignition temperature is reached. However, greater time is required to burn it out than to drive off the volatiles.

The char particle moves freely in the bed only rising to the surface intermittently. The particle surface temperature exceeds the bed temperature (Fig. 9.16).

As the combustion of char proceeds, its size and mass get progressively diminished.

IV. Burnout: Eventually the char particle is reduced to its critical size whereupon it becomes small and light enough to get elutriated from the bed.

The elutriated particle continues to burn in the freeboard zone, diminishing in size further. Its temperature rises rapidly and it burns out to an ash fragment.

Q. *What is the mechanism of volatile emission?*

Ans. The mechanisms of volatile emissions from coal are extremely a complex process. The cyclic macromolecules present in coal undergo numerous thermal cracking processes. One probable cracking sequence is depicted in Fig. 9.17.

The liberated volatiles escape from the interior of the coal particle via innumerable capillaries, some of which are created by volatiles themselves to get an escape route. Initially the emis-

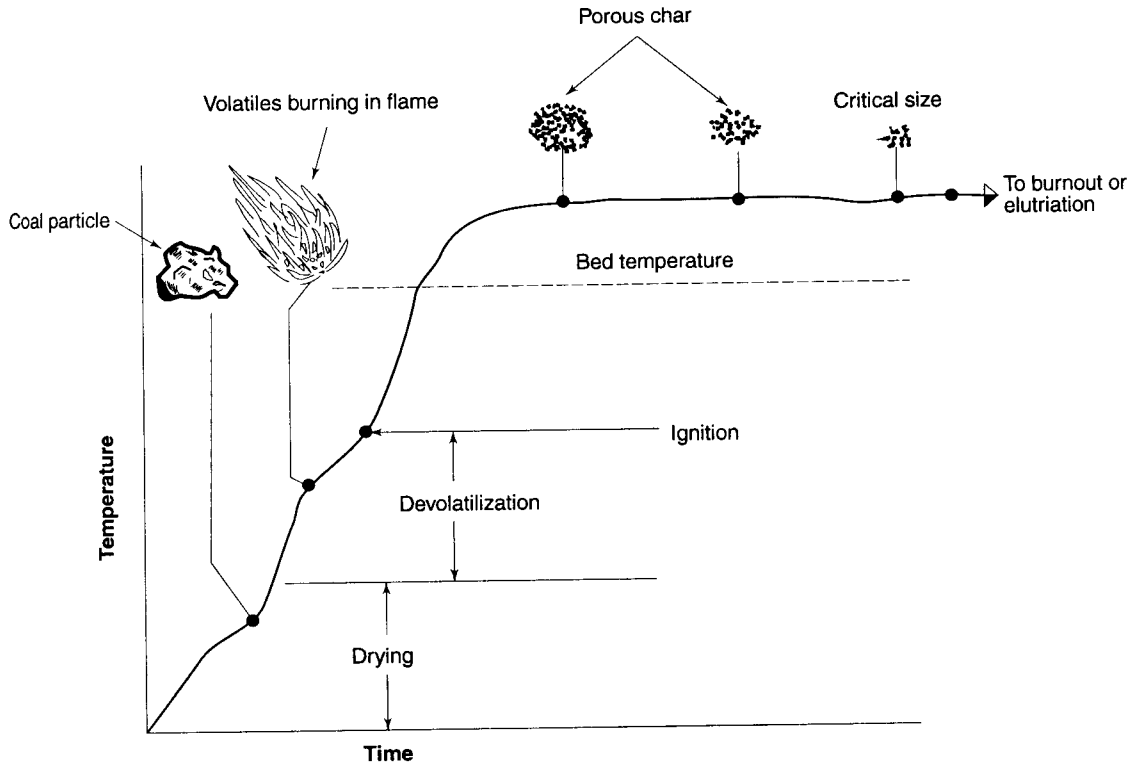


Fig. 9.16 *Temp. history of coal combustion in a fluidized bed.*

sion of volatiles proceeds via constant rate, however it lasts only over a few seconds. Soon it gives way to a falling rate mechanism realized through 1st-order decomposition reaction with respect to the mass of the volatile matter. It occupies a much longer time, although less than carbon burnout time.

Q. *How can the surface temperature of a burning coal particle be estimated?*

Ans. The surface temperature attained by a coal particle, as it enters into fluidized-bed-combustion, is determined by heat balance

Heat released by combustion reaction = Heat removed by conduction + convection + radiation

$$\therefore \quad 2\pi \cdot \mathcal{D} \cdot d_c \cdot C_0 \cdot \zeta \cdot H^c = h_c \cdot A_p \cdot (T_s - T_b)$$

where, ζ = mechanism factor = 1 to 2 depending on the CO/CO_2 formation ratio

H^c = heat of combustion of char

$$= \left[\frac{557{,}000}{\zeta} - 161{,}000 \right] \text{ kJ/kmol}$$

Thus with $\xi = 1$, for the maximum rise of surface temperature,

$$T_s = T_b + \frac{2\mathcal{D} \cdot C_0 \cdot H^c \cdot \zeta}{h_c \cdot d_c}$$

$\mathcal{D}$ = mass diffusion coefficient, m^2/s

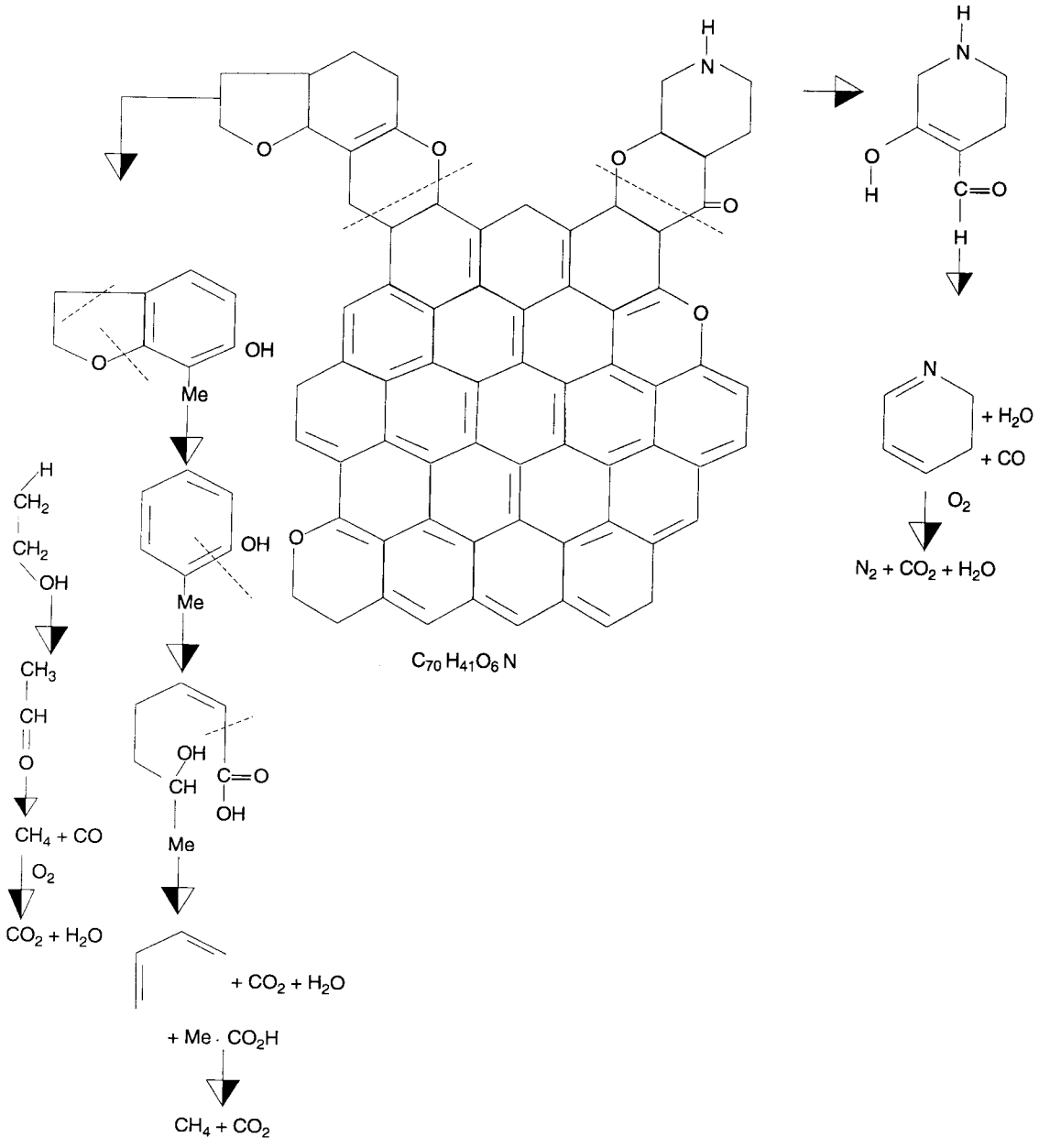


Fig. 9.17 *Devolatilization of coal proceeds via complex cracking processes.*

C_o = concentration of oxygen in inlet air, kmol/m^3

h_c = coal particle-to-bed heat transfer coefficient, W/(m^2 · °K)

For large coal particles burning in a bed of fine particles

$$h_c = \frac{0.016}{\sqrt{d_p}}, \text{ kW/(m}^2 \cdot \text{°K)}$$

where, d_p = particle size, m

For fine particles, Nu ≈ 2 (taking into account of radiation)

$$\therefore \quad h_c \cdot \frac{d_c}{k_c} = 2$$

$$\therefore \quad h_c = 2\frac{k_g}{d_c}, \text{ W/(m}^2 \cdot \text{°K)}$$

where, Nu = Nusselt No.

k_g = flue gas thermal conductivity, W/(m · °K)

d_c = char particle size, m

The equation for the full range of d_c and d_p values cannot be written in an exact form and for present purposes the two contributions can be summed up:

$$h_c = \frac{2k_g \times 10^{-3}}{d_c} + \frac{0.016}{\sqrt{d_p}}, \text{ kW/(m}^2 \cdot \text{°K)}$$

Particle-to-bed heat transfer coefficient and surface temperature

Problem 9.1 A fluidized bed boiler burns crushed coal in a bed of inert particles of 0.5 mm dia at 1225°K of bed temperature. Determine

I. heat transfer coefficient
II. maximum surface temperature of char particles of 0.1 mm, 1.0 mm and 10 mm.

Given

$\mathcal{D} = 320 \times 10^{-6}$ m^2/s
$C_o = 2.18 \times 10^{-3}$ kmol/m^3
$H^c = 396$ MJ/kmol
$k_g = 0.9$ W/(m·°K)

Solution Using Eqn

$$h_c = \frac{2k_g \times 10^{-3}}{d_c} + \frac{0.016}{\sqrt{d_p}}, \text{ kW/(m}^2 \cdot \text{°K)}$$

to determine the value of heat transfer coefficient.

$k_g = 0.9$ W/(m·°K); $d_p = 0.5$ mm $= 0.5 \times 10^{-3}$ m

For $d_c = 0.1$ mm

$$h_c = \frac{2 \times 0.9 \times 10^{-3}}{0.1 \times 10^{-3}} + \frac{0.016}{\sqrt{0.5 \times 10^{-3}}}$$
$$= 18.715 \text{ kW/(m}^2 \cdot \text{°K)}$$

For $d_c = 1$ mm

$$h = \frac{2 \times 0.9 \times 10^{-3}}{1 \times 10^{-3}} + \frac{0.016}{\sqrt{0.5 \times 10^{-3}}}$$
$$= 2.515 \text{ kW/(m}^2 \cdot \text{°K)}$$

For $d_c = 10$ mm

$$h_c = \frac{2(0.9 \times 10^{-3})}{10 \times 10^{-3}} + \frac{0.016}{\sqrt{0.5 \times 10^{-3}}}$$
$$= 0.895 \text{ kW/(m}^2 \cdot \text{°K)}$$

Surface temperature of coal particles

$$T_s = T_b + \frac{2D \cdot C_o \cdot H^c \cdot \zeta}{h_c \cdot d_c}$$

$$= 1225 + \frac{2(320 \times 10^{-6})\left[\frac{\text{m}^2}{\text{s}}\right](2.18 \times 10^{-3})\left[\frac{\text{kmol}}{\text{m}^3}\right](396000)\left[\frac{\text{kJ}}{\text{kmol}}\right] \cdot (1)}{h_c\left[\frac{\text{kW}}{\text{m}^2 \cdot \text{°K}}\right] \cdot d_c[\text{m}]} = 1225 + \frac{0.552}{h_c \cdot d_c}$$

d_c (m)	h_c (kW/m^2·°K)	T_s (°K)
0.1×10^{-3}	18.715	1520 (approx)
1×10^{-3}	2.515	1444
10×10^{-3}	0.895	1286.67

Q. *How can the burnout time of a char particle be estimated?*

Ans. During combustion of a char particle, oxygen has to diffuse to the particle and the carbon dioxide must escape from the particle. And in that process they trigger a set of reactions

$$C + O_2 \longrightarrow CO_2$$
$$C + 1/2O_2 \longrightarrow CO$$
$$CO_2 + C \longrightarrow 2CO$$
$$CO + 1/2O_2 \longrightarrow CO_2$$

Because of high diffusion rates at high particle temperatures (1270°K) or combustion in free-space, first-order reaction rate dominates. Under these conditions Arrhenius equation best fits the rate expression:

$$k_R = A_c \cdot \exp\,[-E_A/(RT_s)]$$

where, k_R = reaction rate, kmol/(m^2·s·atm)

A_c = Arrhenius constant
= 7260 kmol/(s·m^2·atm)

E_A = reaction activation energy
= 150 MJ/kmol for char burning

T_s = surface temperature of char particle, °K

R = gas constant for air
= 8.314 KJ/(kmol·°K)

The rate of the reaction is then given by

$$F_i = k_R \cdot A_p \cdot p_o$$

where, F_i = molar flowrate of gas to or from particle surface, kmol/s

A_p = surface area of the particle, m^2

p_o = partial pressure of oxygen, atm.

Forasmuch as the rate of char burning is proportional to its surface area (i.e. square of its dia), so the burnout time can be obtained by writing

$$F_i = \frac{d}{dt}\left(\frac{\rho_p}{12} \cdot \frac{\pi}{6} \cdot d_c^3\right)$$

$$= \frac{\rho_p}{12} \cdot \frac{\pi}{6} \cdot 3d_c^2 \frac{d(d_c)}{dt}$$

$$\text{cf. } V_p = \frac{\pi}{6} \cdot d_c^3$$

$$M_p = \rho_p \cdot V_p$$

$M_p/12$ = molar mass of particle

$$\therefore \quad k_R \cdot \pi d_c^2 \cdot p_o = \frac{\rho_p}{24} \cdot \pi d_c^2 \cdot \frac{d(d_c)}{dt}$$

$$\therefore \quad \frac{d}{dt}(d_c) = \frac{24}{\rho_p} k_R \cdot p_o$$

Upon integrating we get particle burnout time

$$\tau = \frac{\rho_p}{24} \cdot \frac{d_c}{k_R \cdot p_o}$$

That is the burnout time (τ, in seconds) is proportional to particle dia.

Burnout time

Problem 9.2 Calculate the burnout time for a char particle of dia 1mm for combustion at 1175°K in a fluidized bed at 1 atm. press. assuming no rise of surface temperature of particle.

Given

Density of char = 1400 kg/m^3

Combustion rate, $k_R = 1.52 \times 10^{-3}$ kmol/(m^2·s·atm.)

Also calculate the specific burning rate.

Solution The burnout time under these hypothetical conditions is given by

$$\tau = \frac{\rho_p}{24} \cdot \frac{d_c}{k_R \cdot p_o}$$

Now, p_o = partial pressure of oxygen

= Mol. fraction of O_2 × total pressure

= Vol. fraction of $O_2 \times P$

$= 0.21 \times (1)$

= 0.21 atm.

$\rho_p = 1400 \text{ kg/m}^3$

$d_c = 1 \text{ mm} = 1 \times 10^{-3} \text{ m}$

$k_R = 1.52 \times 10^{-3} \text{ kmol/(m}^2 \cdot \text{s} \cdot \text{atm.)}$

$$\therefore \quad \tau = \frac{1400(10^{-3})}{24(1.52 \times 10^{-3})\,(0.21)} = 182 \text{ s}$$

The specific burning rate

= k_R × mol. wt. of char × partial pressure of oxygen

$= (1.52 \times 10^{-3})\ (12)\ (0.21)$,

$$\left[\frac{\text{kmol}}{\text{m}^2 \cdot \text{s} \cdot \text{atm.}}\right] \times \left[\frac{\text{kg}}{\text{kmol}}\right] \times [\text{atm}]$$

$$= 3.83 \times 10^{-3} \ \frac{\text{kg}}{\text{m}^2 \cdot \text{s}}$$

$$= 3.83 \frac{\text{g}}{\text{m}^2 \cdot \text{s}} \qquad \textbf{Ans.}$$

Burnout time and specific burning rates

Problem 9.3 Calculate the burnout time for a char particle of 1 mm size with a constant surface temperature of 1373°K in the above problem. Also calculate the specific burning rate.

Solution First, we should determine the reaction rate

$A = 7260 \text{ kmol/(m}^2 \cdot \text{s} \cdot \text{atm)}$

$E_A = 150 \text{ MJ/kmol} = 150 \times 10^3 \text{ kJ/kmol}$

$R = 8.314 \text{ kJ/(kmol} \cdot \text{°K)}$

$T_s = 1373\text{°K}$

$$k_R = 7260 \exp\left(\frac{-150000}{8.314 \times 1373}\right)$$

$$= 14.259 \times 10^{-3} \ \frac{\text{kmol}}{\text{m}^2 \cdot \text{s} \cdot \text{atm}}$$

∴ Burnout time

$$\tau = \frac{1400(10^{-3})}{24(14.259 \times 10^{-3}(0.21)}$$

$$= 19.48 \text{ s} \simeq 19.5 \text{ s} \qquad \textbf{Ans.}$$

Specific burning rate

$$= (14.259 \times 10^{-3})\ (12)\ (0.21)$$

$$= 0.035932 \ \frac{\text{kg}}{\text{m}^2 \cdot \text{s}}$$

$$= 35.932 \text{ g/(m}^2 \cdot \text{s)} \qquad \textbf{Ans.}$$

Comments: With the escalation in surface temperature by 200°K (from 1175°K to 1373°K), the burnout time of the char particle gets reduced more than 9 times. This is because char combustion is kinetically controlled and so it is highly temperature sensitive.

10

THE CHEMISTRY OF COMBUSTION

Q. *What are the important reactions that take place during the combustion of fuels?*

Ans. These are:

	kcal/mol	kcal/kg	kJ/kg
1. $H_2 + 1/2\ O_2 \longrightarrow H_2O$ (vap.)	+ 57.81	28905	121 025 (of H_2)
2. $H_2 + 1/2\ O_2 \longrightarrow H_2O$ (liq.)	+ 68.36	34180	143 111 (of H_2)
3. $C + 1/2\ O_2 \longrightarrow CO$ (gas)	– 29.43	2452.5	10 268.61 (of C)
4. $CO + 1/2\ O_2 \longrightarrow CO_2$ (gas)	+ 68.22	2436.42	10201.32 (of CO)
5. $C + O_2 \longrightarrow CO_2$ (gas)	+ 97.65	8137.5	34071.71 (of C)
6. $CO_2 + C \longrightarrow 2CO$ (gas)	– 38.79	3232.5	13534.77 (of C)
7. $C + H_2O \longrightarrow CO + H_2$ (gas) (gas)	– 28.38	2365	9902.25 (of C)
8. $CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$ (gas) (liq.)	+ 192.40	12025	50348.67 (of CH_4)
9. $C_2H_2 + 2.5\ O_2 \longrightarrow 2CO_2 + H_2O$ (gas) (liq.)	+ 312.40	12015.38	50308.41 (of C_2H_2)
10. $C_2H_4 + 3O_2 \longrightarrow 2CO_2 + 2H_2O$ (gas) (liq.)	+ 345.80	12350	51709 (of C_2H_4)
11. $H_2S + 1.5\ O_2 \longrightarrow H_2O + SO_2$ (gas) (gas)	+ 124.85	3672	15375 (of H_2S)
12. $S + O_2 \longrightarrow SO_2$ (gas)	+ 69.8	2181	9133 (of S)

Problem 10.1 The composition of wood is as follows:

C—49.5%; H—6.5%; O—43%; N—0.4%; Ash—0.6%

1. What volume of air is required to burn 1 kg of wood?
2. What will be the volume of the products of combustion of 1 kg of wood?
3. Draw the material balance.
4. What will be the specific weight of the flue gas?
5. Estimate the expected calorimetric temperature.

Solution

Step (I) Composition of Wood

In Terms of % Wt.	In Terms of Mol. Volume
C = 49.5	C = 49.5/12 = 4.125
H = 6.5	H = 6.5/2 = 3.25
O = 43	O = 43/32 = 1.3437
N = 0.4	N = 0.4/28 = 0.01428
Ash = 0.6	

Step (II) Oxygen Requirement for Combustion

Now, if as per Dulong's theory, the oxygen present in a fuel would react with the hydrogen content of it in a 1:2 ratio to produce water, so 2×1.3437, i.e. 2.6874 mol. vol. of H will combine with the oxygen content of the fuel leaving 3.35 – 2.6874 = 0.5626 mol. vol. hydrogen for combustion with air.

Therefore, above data modifies to

Mol. Vol.	Oxygen Requirement for Combustion
C = 4.125	4.125 mol. vol. $\boxed{\begin{array}{l}C + O \longrightarrow CO_2 \\ 1\ mol \quad 1\ mol\end{array}}$
H = 3.25 – 2.6874 = 0.5626 O = 0.000 N = 0.01428	0.5626/2 = 0.2813 mol. vol $\boxed{\begin{array}{l}2H_2 + O_2 \longrightarrow 2H_2O \\ 2\ mol\ 1\ mol\end{array}}$
	O_2 requirement = 4.4063 mol. vol per 100 kg of wood

Step (III) Volume of Air Requirement

Air contains N_2 and O_2 in volume ratio 79:21

= 3.762

Oxygen requirement for combustion

= 4.4063 mol. vol.

Air requirement for combustion

= 4.4063 + 4.4063 (3.762)

(Oxygen) (Nitrogen)

= 20.9828 mol/100 kg of wood

Air required for combustion of 1 kg of wood

= (20.9828/100) (22.4)m^3 = 4.7 m^3 ***Ans.***

Step (IV) Volume of Combustion Products

Basis: 100 kg wood

Reactants	Chemical Reaction	Products of Combustion
C (4.125 mol)	C + O_2 ⟶ CO_2 (4.125 mol) 4.125 mol. vol.	CO_2 = 4.125 mol. vol.
H_2 (3.25 mol)	H_2 + 0.5O_2 ⟶ H_2O (3.25 mol) 3.25 mol.	H_2O = 3.25 mol. vol. N_2 = 4.4063 (3.762) + 0.01428 vol. = 16.5907 mol. vol.
		Σ Vol. = 23.9657 mol. vol. = 23.9657 (22.4) Nm^3 = 536.8316 Nm^3

Hence, volume of combustion products for 1 kg wood burnt = 5.368 Nm^3 ***Ans.***

Step (V) Material Balance

Basis: 100 kg fuel

Input			Output		
	Mol. Vol.	Weight (kg)	Flue gas	Mol. Vol.	Weight (kg)
(a) FUEL					
C	4.125	4.125(12) = 49.5	CO_2	4.125	4.125(44) = 181.5
H	0.5626	0.5626(2) = 1.1252	H_2O	3.25	3.25(18) = 58.5
H_2O	2.6874	2.6874(18) = 48.3732	N_2	16.5907	16.5907(28) = 464.53
N	0.01428	0.01428(28) = 0.399			Σ = 704.53
(b) AIR					
O	4.4063	4.4063(32) = 141.00			
N	4.4063 × 3.762 = 16.5765	16.5765(28) = 464.14			
		Σ = 704.5418			

Calculation Error = 704.5396 – 704.5418

= – 0.0022

Step (VI) Specific Weight of the Combustion Products

Flue Gas Composition		Weight
CO_2 = 4.125 mol. vol.	4.125 (44/100)	= 1.815 kg
H_2O = 3.25 mol. vol.	3.25 (18/100)	= 0.5850 kg
N_2 = 16.5907 mol. vol.	16.5907 (28/100)	= 4.6453 kg
	Total	7.0453 kg

Therefore, the sp. wt. of flue gas = 7.0453/5.368 = 1.312 kg/m^3 ***Ans.***

Step (VII) Calorific Value of Wood

Reactant	Combustion Reaction	Heat of Combustion (kcal/kg)	Heat Absorbed/ Produced (kcal/kg)
C	$C+O_2 \rightarrow CO_2$	+ 8137.5	+ 8137.5(49.5/100) = + 4028.06
H	$H_2 + 0.5O_2 \rightarrow H_2O$	+ 28905	$+ 28\,905 \frac{1.1252}{100}$ = + 325.24
			Total = + 4353.30

From this total heat developed, the quantity of heat of evaporation of 2.6874 mol. vol. of water should be subtracted.

Hence, the calorific value of wood

= 4353.30 – 2.6874(18/100) (586)

= 4069.83 kcal/kg **Ans.**

Problem 10.2 A wood specimen has the following composition in terms of per cent weight:

C – 49.7; H – 5.9; O – 43.5; N – 0.5; Ash – 0.4

1. Calculate the volume of air required to burn 1 kg of wood
2. Calculate the volume of combustion products per kg of fuel consumed
3. Draw the material balance
4. Determine the specific weight of flue gas
5. Determine the calorific value of wood
6. What will be the expected calorimetric temperature?

Step (VIII) Expected Calorimetric Temperature

This is done through a series of successive approximations.

Basis: 1 kg fuel. 1st Assumption: 2000°C

Gas	Heat Content at 2000°C	Quantity of Heat Reqd. To develop 2000°C Temp	
CO_2	562.954 kcal/kg	562.954(1.815)	= 1021.76 kcal
H_2O	1183.333 kcal/kg	1183.333(2.6874)(18/100)	= 572.41 kcal
N_2	541.785 kcal/kg	541.785(4.6453)	= 2516.75 kcal
H_2	7585 kcal/kg	7585(0.5626 × 2/100)	= 85.34 kcal
		Total	= 4196.26 kcal

This is higher than the calorific value of wood calculated (4 069.83 kcal/kg). So let's have a second trial.

2nd Assumption: 1900°C

Gas	Heat Content at 1900°C	Quantity of Heat Reqd. To develop 1900°C Temp	
CO_2	531.613 kcal/kg	531.613 (1.815)	= 964.88 kcal
H_2O	1094.833 kcal/kg	1094.833 (2.6874) (18/100)	= 529.60 kcal
N_2	511.642 kcal/kg	511.642 (4.6453)	= 2376.73 kcal
H_2	7163 kcal/kg	7163(0.5626) (2/100)	= 80.598 kcal
			Total = 3951.81 kcal

1900°C	3951.81 kcal/kg of fuel	$\frac{2000-1900}{4196.26-3951.81} = \frac{t-1900}{4069.83-3951.81}$
t°C	4069.83 kcal/kg of fuel	
2000°C	4196.26 kcal/kg of fuel	$t = 1900 + \frac{100}{244.45}(118.02) = 1948.28°C$ **Ans.**

Solution

Step (I) Composition of Wood

In Terms of % Wt.	In Terms of Mol. Vol.
C = 49.7	C = 49.7/12 = 4.141
H = 5.9	H = 5.9/2 = 2.95
O = 43.5	O = 43.5/32 = 1.359
N = 0.5	N = 0.5/28 = 0.017
Ash = 0.4	

Step (II) Oxygen Requirement for Combustion

Mol. Vol.	Combustion Reaction	O_2 Reqd. for Combustion
C = 4.141	$C + O_2 \longrightarrow CO_2$ 1 mol 1 mol 1 mol	4.141 mol. vol.
H = 2.95 – 2 (1.359) = 0.232	$H_2 + 0.5O_2 \longrightarrow H_2O$ 1 mol 0.5 mol 1 mol	$\frac{0.232}{2} = 0.116$ mol. vol.
O = 0.000		
N = 0.017		
		O_2 requirement = 4.257 mol vol. per 100 kg of wood.

Step (III) Volume of Air Requirement

Air contains 3.762 vol. N_2 per unit volume of O_2
Oxygen requirement for combustion
= 4.257 mol. vol./100 kg of wood

Air requirement for combustion
= 4.257 (Oxygen) + 4.257(3.762)(Nitrogen)
= 20.2718 mol. vol./100 kg of wood
Air requirement for combustion of 1kg wood
= 20.2718 (22.4)/100 = 4.54 Nm^3 ***Ans.***

Step (IV) Volume of Combustion Products

Basis: 100 kg wood

Reactants	Combustion Reactions	Products of Combustion
C (4.141 mol)	$C + O_2 \longrightarrow CO_2$ 4.141 (mol) 4.141 (mol)	CO_2 = 4.141. mol. vol.
H_2 (2.95 mol)	$H_2 + 0.5O_2 \longrightarrow H_2O$ 2.95 (mol) 2.95 (mol)	H_2O = 2.95 mol. vol.
		N_2 = 4.257(3.762) + 0.017 = 16.0318 mol. vol.
		Σ Volume = 23.1228 mol. vol. = 23.1228 (22.4) Nm^3 = 517.951 Nm^3

Hence the volume of combustion products for 1 kg of wood burnt = 5.179 m^3 ***Ans.***

Step (V) Material Balance

Basis: 100 kg fuel

INPUT			OUTPUT		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) Fuel					
C	4.141	49.692	CO_2	4.141	182.204
H	0.232	0.464	H_2O	2.95	53.1
H_2O	2(1.359) = 2.718	48.924			
N	0.017	0.476	N_2	16.0318	448.89
(B) Air					
O_2	4.257	136.224			
N_2	4.257 × (3.762) = 16.0148	448.415			
	Total	= 684.195		Total	= 684.194

Calculation error = 684.194 – 684.195 = – 0.001

Step (VI) Specific Weight of Combustion Products

Flue Gas Composition	Weight (kg)	
CO_2 = 4.141 mol. vol	4.141 (44/100)	= 1.822
H_2O = 2.95 mol. vol	2.95 (18/100)	= 0.531
N_2 = 16.0318 mol. vol.	16.0318 (28/100)	= 4.489
		Total = 6.842

Therefore, the specific weight of flue gas

$$= 6.842/5.179 = 1.321 \text{ kg/Nm}^3$$

Ans.

Step (VII) Calorific Value of Wood

Reactant	Combustion Reaction	Heat of Reaction	Heat Evolved/ Absorbed (kcal/kg)
C	$C + O_2 \rightarrow CO_2$	(+) 8137.5 kcal/kg	$(+)\frac{8137.5(49.7)}{100}$ = (+) 4044.34
H	$H_2 + 0.5O_2 \rightarrow H_2O$	(+) 28905 kcal/kg	$\frac{(+)28905(0.464)}{100}$ = (+) 134.12
			(+) 4178.46

From this total heat developed, the quantity of heat of evaporation of 2(1.359), i.e. 2.718 mol. vol. of water should be subtracted.

Hence the calorific value of wood

$$= 4178.46 - 2.718\ (18/100)\ (586)$$

$$= 3891.766 \text{ kcal/kg of fuel}$$ ***Ans.***

Step (VIII) Calorimetric Temperature of Combustion

1st Assumption: Let this temperature be 2000°C

Gas	Heat Content at 2000°C	Quantity of Heat Reqd. to develop 2000°C Temp.
CO_2	562.954 kcal/kg	562.954(1.822) = 1025.70 kcal
H_2O	1183.333 kcal/kg	1183.333 (2.718) (18/100) = 578.93 kcal
N_2	541.785 kcal/kg	541.785(4.49) = 2432.61 kcal
H_2	7585 kcal/kg	7585(0.232)(2/100) = 35.19 kcal
		Total = 4072.43 kcal

2nd Assumption: Temperature 1900°C

Gas	Heat Content at 1900°C	Quantity of Heat Reqd. to develop 1900°C Temp
CO_2	531.613 kcal/kg	968.598 kcal
H_2O	1094.833 kcal/kg	535.636 kcal
N_2	511.642 kcal/kg	2297.272 kcal
H_2	7163 kcal/kg	33.236 kcal
		Total = 3834.742 kcal

1900°C	3834.74 kcal/kg of fuel
t°C	3891.766 kcal/kg of fuel
2000°C	4072.43 kcal/kg of fuel

$$\frac{2000 - 1900}{4072.43 - 3834.74} = \frac{t - 1900}{3891.766 - 3834.74}$$

or t = 1900 + (5702.6/237.69) = 1923.99°C

Ans.

Problem 10.3 The percentage composition of straw in terms of weight is as given below:

C—35.5; H—5.5; O—39; N—0.5; Ash—3.75; Water—15.75

Determine:

(a) the volume of air required for complete combustion of 1 kg straw
(b) the volume of combustion products per kg of straw burnt
(c) the specific weight of flue gas
(d) the calorific value of straw
(e) the calorimetric temperature of combustion (expected value)

Also draw the material balance.

Solution

Step (I) Composition of Straw

In Terms of % Wt.	In Terms of Mol. Vol.
C = 35.5	C = 35.5/12 = 2.958
H = 5.5	H = 5.5/2 = 2.75
O = 39	O = 39/32 = 1.218
N = 0.5	N = 0.5/28 = 0.0178
Ash = 3.75	Ash = 3.75
Water = 15.75	Water = 15.75/18 = 0.875

Step (II) Oxygen Requirement for Combustion

Mol. Vol. (According to Dulong)	Combustion	O_2 Requirement for Combustion
C = 2.958	$C + O_2 \rightarrow CO_2$	2.958 mol. vol.
H = 2.75 – 2(1.218) = 0.314	$H + 1/2\ O_2 \rightarrow H_2O$	0.314/2 = 0.157 mol. vol.
O = 0.000		
N = 0.0178		
H_2O = 0.875		
		Total O_2 requirement = 3. 115 mol. vol. per 100 kg of straw

Step (III) Air Requirement for combustion

Air required

= 3.115 (Oxygen) + 3.115 (3.762) (Nitrogen)

= 14.833 mol. vol. for 100 kg of straw

Air required for 1 kg of straw

= 14.833 (22.4/100) = 3.323 Nm^3 ***Ans.***

Step (IV) Volume of Combustion Products

Basis: 100 kg of straw

Reactant	Combustion Reaction	Product of Combustion
C (2.958 mol)	$C + O_2 \rightarrow CO_2$ 2.958 mol 2.958 mol	CO_2 = 2.958 mol. vol.
H_2 (2.75 mol)	$H_2 + 0.5O_2 \rightarrow H_2O$ (2.75 mol) (2.75 mol)	H_2O = 2.75 mol. vol.
		H_2O = 0.875 mol. vol.
		N_2 = 3.115 (3.762) + 0.0178 mol. vol. = 11.736 mol. vol.

Total Volume
= 18.319 mol. vol.
= 18.319(22.4/100) Nm^3
= 4.103 Nm^3 per kg of straw burnt

Ans.

Step (V) Material Balance for Combustion

Basis: 100 kg of straw

Input			Output		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) Fuel					
C	2.958	35.496	CO_2	2.958	130.152
H	0.314	0.628	H_2O	2.75 + 0.875 = 3.625	65.25
H_2O	2(1.218) + 0.875 = 3.311	59.598	N_2	= 11.736	328.608
N	0.0178	0.499			
(B) Comb. *Air*					
O_2	3.115	99.68			
N_2	3.115 (3.762) = 11.7186	328.121			
	Total = 524.022			Total = 524.01	

Calculation error = 524.022 - 524.01 = 0.012 kg

Step (VI) Specific Weight of Combustion Products

Flue Gas Composition	Mol. Vol.	Weight
CO_2	2.958	2.958 (44/100) = 1.3015 kg
H_2O	3.625	3.625(18/100) = 0.6525 kg
N_2	11.736	11.736 (28/100) = 3.2860 kg
		Total = 5.2400 kg

Therefore, the specific weight of flue gas

$= 5.24/4.103$

$= 1.277 \text{ kg/m}^3$ ***Ans.***

Step (VII) Calorific Value of Straw

Reactant	Combustion Reaction	Heat of Reaction	Heat Produced/ Absorbed (kcal/kg)
C	$C + O_2 \longrightarrow CO_2$	(+) 8137.5 kcal/kg	$+\frac{8137.5(35.5)}{100}$ $= + 2888.812$
H	$H_2 + 0.5O_2 \longrightarrow H_2O$	(+) 28905 kcal/kg	$+\frac{28905(0.628)}{100}$ $= (+) 181.523$
			Total = (+) 3070.335

From this heat developed, according to Dulong, the quantity of heat of evaporation of 2 (1.218) + 0.875 i.e. 3.331 mol. vol. of water should be subtracted.

Hence the calorific value of water

$= 3070.335 - 3.331(18)(586)/100$

$= 2721.09$ kcal/kg ***Ans.***

Step (VIII) Calorimetric Temperature

1st Assumption: Let this temperature be 1800°C

Gas	Heat Content at 1800°C	Quantity of Heat Reqd. to develop 1800°C Temp.
CO_2	500.318 kcal/kg	500.318(1.3015) = 651.163 kcal
H_2O	1011.611 kcal/kg	1011.611(3.311) (18/100) = 602.899 kcal
N_2	481.82 kcal/kg	481.82 (3.286) = 1583.260 kcal
H_2	6745.5 kcal/kg	6745.5(0.314)(2/100) = 42.361 kcal
		Total = 2879.683 kcal

2nd Assumption: Calorimetric temperature 1700°C

Gas	Heat Content at 1700°C	Quantity of Heat Reqd. to develop 1700°C Temp.
CO_2	469.09 kcal/kg	610.528 kcal
H_2O	933.388 kcal/kg	556.281 kcal
N_2	452.321 kcal/kg	1486.328 kcal
H_2	6332.5 kcal/kg	39.768 kcal
		2692.905 kcal

Hence the calorimetric temperature lies between 1800°C and 1700°C

1800°C	2879.683	kcal/kg of fuel
t°C	2721.09	kcal/kg of fuel
1700°C	2692.90	kcal/kg of fuel

$$\frac{1800 - 1700}{2879.683 - 2692.90} = \frac{t - 1700}{2721.09 - 2692.90}$$

$\therefore\ t = 1715.09$°C ***Ans.***

Problem 10.4 Bagasse (the residue of sugarcane) has the following average composition, by weight percent, on moisture-free basis:

C—45; H—6; O—46; Ash—3

Calculate

(a) the volume of air required for complete combustion of 1 kg of bagasse
(b) the volume of combustion products per kg of bagasse burnt
(c) the specific weight of flue gas
(d) the calorific value of bagasse
(e) the calorimetric temperature

Also draw the material balance.

Solution

Step (I) Composition of Bagasse

In Terms of Weight %	In Terms of Mol. Vol.
C = 45	C = 45/12 = 3.75
H = 6	H = 6/2 = 3
O = 46	O = 46/32 = 1.4375
Ash = 3	

Step (II) Oxygen Requirement for Combustion

Mol. Vol. (according to Dulong)	Combustion Reaction	O_2 Requirement for Combustion
C = 3.75 H = 3 – 2(1.4375) = 0.125 O = 0.000	$C + O_2 \rightarrow CO_2$ $H_2 + 0.5O_2$ $\rightarrow H_2O$	3.75 mol. vol. 0.125/2 = 0.0625 mol. vol.
		Total O_2 requirement = 3.8125 mol.vol. per 100 kg of bagasse

Step (III) Air Requirement for Combustion

Air required = 3.8125 (Oxygen) + 3.8125 (3.762) (Nitrogen)

= 18.155 mol. vol. per 100 kg of Bagasse

Air required for combustion of 1 kg bagasse

= 18.155 (22.4)/100 = 4.066 Nm^3 ***Ans.***

Step (IV) Volume of Combustion Products

Basis: 100 kg of bagasse

Reactant	Combustion Reaction	Product of Combustion
C (3.75) mol	$C + O_2 \rightarrow CO_2$ (3.75) (3.75) mol mol	CO_2 = 3.75 mol. vol.
H_2 3 mol	$H_2 + 0.5O_2 \rightarrow H_2O$ 3 mol 3 mol	H_2O = 3 mol. vol.
		N_2 = 3.8125 (3.762) = 14.342 mol. vol.
	Total Volume	= 21.092 mol. vol.

Therefore, the volume of combustion products per kg of bagasse burnt

= 21.092 (22.4/100) = 4.724 Nm^3 ***Ans.***

Step (V) Material Balance for Combustion

Basis: 100 kg of bagasse

Input			Output		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) *Fuel*					
C	3.75	45	CO_2	3.75	165
H	0.125	0.25	H_2O	3	54
H_2O	2.875	51.75	N_2	14.342	401.576
(B) *Air*					
O_2	3.8125	122			
N_2	14.342	401.576			
	Total	620.576		Total	620.576

Step (VI) Specific Weight of Combustion Products

Flue Gas Composition	Weight (kg)
CO_2 = 3.75 mol. vol	165
H_2O = 3 mol. vol	54
N_2 = 14.342 mol. vol.	401.576
	Total = 620.576 per 100 kg of bagasse.

Therefore, the specific weight of flue gas

= 6.205/4.724 = 1.313 kg/Nm^3

Ans.

Step (VII) Calorific Value of Bagasse

Reactant	Combustion Reaction	Heat of Reaction (kcal/kg)	Heat Evolved/Absorbed (kcal/kg)
C	$C + O_2 \longrightarrow CO_2$	(+) 8137.5	(+) 8137.5(45/100) = (+) 3661.875
H	$H_2 + 0.5O_2 \longrightarrow H_2O$	(+) 28905	(+) 28905 (0.25/100) = (+) 72.262
			Total = (+) 3734.137

According to Dulong, the quantity of heat of evaporation of 2.875 mol. vol. of H_2O should be subtracted from this calculated value.

Hence the calorific value of bagasse

= 3734.137 – 2.875 (18) (586)/100

= 3430.882 kcal/kg.

Ans.

Step (VIII) Calorimetric Temperature

1st Assumption: Let this temperature be 1900°C

Gas	Heat Content At 1900°C	Quantity of Heat Reqd. to develop 1900°C Temp.
CO_2	531.613 kcal/kg	531.613 (1.65) = 877.161 kcal/kg of fuel
H_2O	1094.833 kcal/kg	1094.833 (51.75/100) = 566.576 kcal/kg of fuel

N_2	511.642 kcal/kg	511.642 (4.01576) = 2054.631 kcal/kg of fuel
H_2	7163 kcal/kg	7163 (0.25/100) = 17.907 kcal/kg of fuel
		Total = 3516.275 kcal/kg of fuel

2nd Assumption: Let this temperature be 1800°C

Gas	Heat Content at 1800°C	Quantity of Heat Reqd. to develop 1800°C Temp.
CO_2	500.318 kcal/kg	(+) 825.524 kcal/kg of bagasse
H_2O	1011.611 kcal/kg	(+) 523.508 kcal/kg of bagasse
N_2	481.82 kcal/kg	(+) 1934.873 kcal/kg of bagasse
H_2	6745.5 kcal/kg	(+) 16.863 kcal/kg of bagasse
		Total = 3300.768 kcal/kg of bagasse

Hence the calorimetric temperature (t°C) lies between 1900°C and 1800°C

$$\frac{1900 - 1800}{3516.275 - 3300.768} = \frac{t - 1800}{3430.882 - 3300.768}$$

$\therefore\ t = 1860.37$°C **Ans.**

Problem 10.5 The percentage composition of peat is given below in terms of weight;

C—58; H—5.45; O—33.45; N—0.75; Ash—2.35

Calculate

(a) the volume of air required for the complete combustion of 1 kg of peat
(b) the volume of flue gas per kg of peat burnt
(c) the specific weight of flue gas
(d) the calorific value of peat
(e) the calorimetric temperature of combustion

Also draw the material balance.

Solution

Step (I) Composition of Peat

In Terms of Weight %	In Terms of Mol. Vol.
C = 58	C = 58/12 = 4.833
H = 5.45	H = 5.45/2 = 2.725
O = 33.45	O = 33.45/32 = 1.045
N = 0.75	N = 0.75/28 = 0.0267

Step (II) Oxygen Requirement

Mol. Vol.	Combustion Reaction	O_2 Requirement for Combustion
C = 4.833 H = 2.725 – 2(1.045) = 0.635	$C + O_2 \longrightarrow CO_2$ $H_2 + 0.5O_2 \longrightarrow H_2O$	4.833 mol. vol. 0.635/2 = 0.3175 mol. vol.

Therefore, total oxygen requirement = 5.1505 mol. vol. per 100 kg of peat combustion.

Step (III) Air Requirement for Combustion

Air required for combustion

= 5.1505 + 5.1505 (3.762) mol. vol. per 100 kg of peat

= 24.5266 mol. vol. per 100 kg of peat

Therefore, air required for combustion of 1 kg of peat

= 24.5266 (22.4/100) Nm^3 = 5.494 Nm^3

Ans.

Step (IV) Volume of Flue Gas

Basis: 100 kg of peat

Reactant	Combustion Reaction	Product of Combustion
C 4.833 mol	$C + O_2 \longrightarrow CO_2$	= 4.833 mol. vol.
H 2.725 mol	$H_2 + 0.5O_2 \longrightarrow H_2O$	H_2O = 2.725 mol. vol.
		N_2 = 5.1505 (3.762) + 0.0267 = 19.4027 mol. vol.
		Σ Volume = 26.9607 mol. vol. per 100 kg of peat burnt

Hence the volume of flue gas/kg of peat burnt

= 26.9607 (22.4/100) = 6.0392 Nm^3 **Ans.**

Step (V) Specific Weight of Flue Gas

Flue Gas	Composition	Weight
CO_2	4.833 mol. vol.	212.652 kg
H_2O	2.725 mol. vol.	49.05 kg
N_2	19.4027 mol. vol.	543.275 kg
		Σ = 804.977 kg per 100 kg of peat

Therefore, the specific weight of flue gas

$= 8.04977/6.0392 = 1.333 \text{ kg/Nm}^3$

Ans.

Step (VI) Material Balance

Basis: 100 kg of peat

Input			Output		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. vol.	Weight (kg)
(A) *Fuel*					
C	4.833	57.996	CO_2	4.833	212.652
H	0.635	1.27	H_2O	2.725	49.05
H_2O	2.09	37.62	N_2	19.4027	543.275
N	0.0267	0.7476			
(B) *Air*					
O_2	5.1505	164.816			
N_2	19.376	542.528			
		Σ = 804.977			Σ = 804.977

Step (VII) Calorific Value of Peat

Reactant	Combustion Reaction	Heat of reaction	Heat Produced/ Absorbed
C	$C + O_2 \longrightarrow CO_2$	(+)8137.5 kcal/kg	$\frac{(+)8137.5(58)}{100}$ $= +4719.75 \frac{\text{kcal}}{\text{kg}}$
H	$H_2 + 0.5O_2 \longrightarrow H_2O$	(+)28905 kcal/kg	$\frac{(+)28905(1.27)}{100}$ $= +367.09 \frac{\text{kcal}}{\text{kg}}$
			Σ = + 5086.843 kcal per kg of peat

But according to Dulong, 2.09 (18/100) (586)

= 220.453 kcal/kg would be used up on evaporation.

Hence. the calorific value of peat

= 5086.843 – 220.453 kcal/kg

= 4866.39 kcal/kg

Step (VIII) Calorimetric Temperature

1st Assumption: Let this temperature be 2000°C

Gas	Heat Content at 2000°C	Quantity of Heat Reqd. to develop 2000°C
CO_2	562.954 kcal/kg	562.954 (2.1265) = 1197.121 kcal/kg of peat
H_2O	1183.333 kcal/kg	1183.333 (37.62/100) = 445.17 kcal/kg of peat
N_2	541.786 kcal/kg	541.786 (543.275)100 = 2943.387 kcal/kg of peat
H_2	7585 kcal/kg	7585 (1.27/100) = 96.329 kcal/kg of peat
		Σ = 4682.007 kcal/kg of peat

This value being too small, let us assume the calorimetric temperature to be 2100°C.

Gas	Heat Content at 2100°C	Quantity of Heat Reqd. to develop 2100°C Temp.
CO_2	594.25 kcal/kg	1263.672 kcal/kg of peat
H_2O	1277.722 kcal/kg	480.679 kcal/kg of peat
N_2	572.250 kcal/kg	3108.891 kcal/kg of peat
H_2	8011.50 kcal/kg	101.746 kcal/kg of peat
		Σ = 4954.988 kcal/kg of peat

2100°C	4954.988 kcal/kg of peat
t°C	4866.39 kcal/kg of peat
2000°C	4682.007 kcal/kg of peat

$$\frac{2100 - 2000}{4954.988 - 4682.007} = \frac{t - 2000}{4866.39 - 4682.007}$$

$\therefore\ t = 2067.54$°C

Ans.

Problem 10.6 The ultimate analysis of a coal sample gives the following composition on the basis of weight per cent:

C—71; H—5.5; O—3.5; N—1.25; S—1.2; Ash + Water—17.55

Determine the

1. the volume of air required for complete combustion of 1 kg coal
2. volume of flue gas per kg of coal burnt
3. specific weight of flue gas
4. calorific value of coal
5. calorimetric temperature of combustion

Also draw the material balance.

Solution

Step (I) Composition of Coal

In Terms of Weight %	In Terms of Mol. Vol.
C = 71	C= 71/12 = 5.916
H = 5.5	H = 5.5/2 = 2.75
O = 3.5	O = 3.5/32 = 0.1094
N = 1.25	N = 1.25/28 = 0.0446
S = 1.2	S = 1.2/32 = 0.0375

Step (II) Oxygen Requirement

Mol. Vol. (according to Dulong)	Combustion Reaction	Oxygen Requirement for Complete Combustion (mol. vol.)
C = 5.916	$C + O_2 \longrightarrow CO_2$	5.916
H = 2.75 − 2(0.1094) = 2.5312	$H_2 + 0.5O_2 \longrightarrow H_2O$	(2.5312)0.5 = 1.2656
N = 0.0446		
S = 0.0375	$S + O_2 \longrightarrow SO_2$	0.0375
		Σ = 7.2191 mol. vol. per 100 kg of coal

Step (III) Air Requirement for Combustion

Air required = 7.2191 + 7.2191(3.762)

(Oxygen) (Nitrogen)

= 34.3773 mol. vol. for combustion of 100 kg coal

Air required for 1 kg coal combustion

= 34.3773 (22.4/100) Nm^3

= 7.7005 Nm^3 ***Ans.***

Step (IV) Volume of Flue Gas

Basis: 100 kg of coal

Reactant	Combustion Reaction	Product of Combustion	(Mol. Vol.)
C (5.916 mol.)	$C + O_2 \longrightarrow CO_2$	CO_2	5.916
H (2.75 mol.)	$H_2 + 0.5O_2 \longrightarrow H_2O$	H_2O	2.75
S (0.0375 mol.)	$S + O_2 \longrightarrow SO_2$	SO_2	0.0375
		N_2 = 7.2191 (3.762) + 0.0446	27.2028
		Σ Volume = 35.9063 mol. vol. per 100 kg of coal burnt	

Hence the volume of flue gas per kg of coal burnt

= 35.9063 (22.4/100)

= 8.043 Nm^3

Step (V) Specific Weight of Flue Gas

Flue Gas	Composition	Weight
CO_2	5.916 mol. vol.	5.916 (44) = 260.304 kg
H_2O	2.75 mol. vol.	2.75 (18) = 49.5 kg
SO_2	0.0375 mol. vol.	0.0375 (64) = 2.4 kg
N_2	27.2028 mol. vol	27.2028 (28) = 761.678 kg
		Σ = 1073.882 kg/100 kg of coal burnt

Specific weight of flue gas

= [1073.882/100] 8.043

= 1.335 kg/Nm^3

Ans.

Step (VI) Material balance

Baiss: 100 kg of coal

Input			Output		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) *Fuel*					
C	5.916	70.99	CO_2	5.916	260.304
H	2.5312	5.062	H_2O	2.75	49.5
H_2O	0.2188	3.938	SO_2	0.0375	2.4
S	0.0375	1.2	N_2	27.2028	761.678
N	0.0446	1.25			
(B) *Air*					
O_2	7.2191	231.0112			
N_2	7.2191 (3.762) = 27.1582	760.4311			
		Σ = 1073.883			Σ = 1073.882

Step (VII) Calorific Value of Coal

Reactant	Combustion Reaction	Heat of Reaction (kcal/kg)	Heat Evolved/ Absorbed (kcal)
C	$C + O_2 \longrightarrow CO_2$	(+)8137.5	(+) 8137.5 (71/100) = + 5777.625
H	$H_2 + 0.5O_2 \longrightarrow H_2O$	(+)28905	(+) 28905 (2.5312 × 2)/ 100 = + 1463.286
S	$S + O_2 \longrightarrow SO_2$	(+)2181.25	(+) 2181.25 (0.0375) (32)/100 = 26.175
			Σ = 7267.087 kcal/kg of coal

According to Dulong, the heat of evaporation of 0.2188 mol. vol. of water should be subtracted from this calculated value.

Hence the calorific value of coal

$$= 7267.087 - \frac{0.2188(18)(586)}{100} = 7244 \text{ kcal/kg}$$

Ans.

Step (VIII) Calorimetric Temperature of Combustion

1st Assumption: Let us take it to be 2400°C

Gas	Heat Content at 2400°C	Quantity of Heat Reqd. to develop 2400°C Temp.
CO_2	688.091 kcal/kg	688.091 (2.603) = 1791.10 kcal/kg of coal
H_2O	1602 kcal/kg	1602(3.938/100) = 63.086 kcal/kg of coal
SO_2	473.062 kcal/kg	473.062 (2.4/100) = 11.353 kcal/kg of coal
H_2	9318 kcal/kg	9318 (5.062/100) = 471.677 kcal/kg of coal
N_2	665.571 kcal/kg	$\frac{665.571(761.678)}{100}$ = 5069.508 kcal/kg of coal
		Σ = 7406.726 kcal/kg of coal

This figure is too much. So we need further approximation.

2nd Assumption: 2300°C

Gas	Heat Content at 2300°C	Quantity of Heat Reqd. to develop 2300°C Temp.
CO_2	656.863 kcal/kg	1709.814 kcal/kg of coal
H_2O	1486.444 kcal/kg	58.536 kcal/kg of coal
SO_2	451.593 kcal/kg	10.838 kcal/kg of coal
H_2	8878 kcal/kg	449.404 kcal/kg of coal
N_2	634.143 kcal/kg	4830.127 kcal/kg of coal
		Σ = 7058.719 kcal/kg of coal

2400°C	7406.726 kcal/kg of coal
t°C	7244 kcal/kg of coal
2300°C	7058.719 kcal/kg of coal

$$\frac{2400 - 2300}{7406.726 - 7058.719} = \frac{t - 2300}{7244 - 7058.719}$$

$\therefore\ t = 2353.24$°C

Problem 10.7 The percentage composition of petroleum by weight is given below:

C—84.5; H—12.8; O—1.5; S—1.2

Determine

(a) the volume of air required for complete combustion of 1 kg petroleum

(b) the volume of flue gas per kg of petroleum burned

(c) the specific weight of the flue gas
(d) the calorific value of petroleum
(e) the calorimetric temperature of combustion

Also draw the material balance.

Solution

Step (I) Composition of Petroleum

In Terms of Weight%	In Terms of Mol. Vol.
C = 84.5	C = 84.5/12 = 7.0416
H = 12.8	H = 12.8/2 = 6.4
O = 1.5	O = 1.5/32 = 0.0468
S = 1.2	S = 1.2/32 = 0.0375

Step (II) Oxygen Requirement

Mol. Vol. (according to Dulong)	Combustion Reaction Vol.)	Oxygen Requirement For Combustion (Mol.
C = 7.0416	$C + O_2 \longrightarrow CO_2$	7.0416
H = 6.4 – 2 (0.0468) = 6.3064	$H_2 + 0.5O_2 \longrightarrow H_2O$	3.1532
O = 0.000		
S = 0.0375	$S + O_2 \longrightarrow SO_2$	0.0375
		ΣO_2 = 10.2323 Mol. Vol./100 kg of petroleum burned

Step (III) Air Requirement

Air required = 10.2323 + 10.2323(3.762)
(Oxygen) (Nitrogen)

= 48.7262 mol. vol. for combustion of 100 kg of petroleum

Hence, the combustion air required for 1 kg of petroleum

= 48.7262 (22.4/100)Nm^3 = 10.9146 Nm^3

Ans.

Step (IV) Volume of Flue Gas

Basis: 100 kg of petroleum

Reactant	Combustion Reaction	Product of Combustion
C (7.0416 mol)	$C + O_2 \longrightarrow CO_2$	CO_2 = 7.0416 mol. vol.
H (6.4 mol)	$H_2 + 1/2O_2 \longrightarrow H_2O$	H_2O = 6.4 mol. vol.
S (0.0375 mol)	$S + O_2 \longrightarrow SO_2$	SO_2 = 0.0375 mol. vol.
		N_2 = 10.2323 (3.762) = 38.4939 mol. vol.
		Σ Volume = 51.973 mol. vol.

Petroleum Burned	Flue Gas Produced
100 kg	51.973 mol. vol. = 51.973 (22.4) Nm^3
1 kg	51.973 (22.4)/100 = 11.6419 Nm^3

Ans.

Step (V) Specific Weight of Flue Gas

Flue Gas	Composition	Weight (kg)
CO_2	7.0416 mol. vol.	309.8304
H_2O	6.4 mol. vol.	115.2
SO_2	0.0375 mol. vol.	2.4
N_2	38.4939 mol. vol.	1077.829
		Σ = 1505.2596 kg/100 kg of petroleum burned

Therefore, the specific weight of flue gas

= 15.0525/11.6419 = 1.292 kg/Nm^3 ***Ans.***

Step (VI) Material Balance

Basis: 100 kg of petroleum

Input			Output		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) *Fuel*					
C	7.0416	84.4992	CO_2	7.0416	309.8304
H	6.3064	12.6128	H_2O	6.4	115.2
H_2O	2(0.0468) = 0.0936	1.6848	SO_2	0.0375	2.4
S	0.0375	1.2	N_2	38.4939	1077.829
(B) *Air*					
O_2	10.2323	327.4336			
N_2	38.4939	1077.8292			
		Σ = 1505.2596			Σ = 1505.2596

Step (VII) Calorific Value of Petroleum

Reactant	Combustion Reaction	Heat of Combustion (kcal/kg)	Heat Evolved/ Absorbed (kcal)
C	$C + O_2 \longrightarrow CO_2$	(+) 8137.5	(+) 8137.5 (84.4992)/100 = 6876.122
H	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	(+) 28905	(+) 28905 (12.6128)/100 = 3645.729
S	$S + O_2 \longrightarrow SO_2$	(+) 2181.25	(+) 2181.25 (1.2)/100 = 26.175
			Σ = 10548.026 kcal/kg of petroleum

Hence the calorific value of petroleum

= 10548.026 – [0.0936 (18) (586)/100]

= 10538.153 kcal/kg

Ans.

Step (VIII) Calorimetric Temperature of Combustion

1st Assumption: Let this temperature be 2300°C

Gas	Heat Content at 2300° (kcal/kg)	Quantity of Heat Reqd. to develop 2300°C Temp. (kcal/kg of petroleum)
CO_2	656.863	$656.863\left(\frac{309.83}{100}\right) = 2035.158$
H_2O	1486.444	$1486.444\left(\frac{1.6848}{100}\right) = 25.0436$
SO_2	451.593	$451.593\left(\frac{2.4}{100}\right) = 10.8382$
H_2	8878	$8878\left(\frac{12.6128}{100}\right) = 1119.7643$
N_2	634.143	$634.143\left(\frac{1077.829}{100}\right) = 6834.9771$
		Σ = 10025.781

This value is too small.

2nd Assumption: 2400°C

Gas	Heat Content at 2400°C	Quantity of Heat Reqd. to develop 2400°C
CO_2	688.091 kcal/kg	2131.912 kcal/kg of Petroleum burned
H_2O	1602 "	26.990 "
SO_2	473.062 "	11.353 "
H_2	9318 "	1175.260"
N_2	665.571 "	7173.717"
		Σ = 10519.232

3rd Assumption: 2500°C

Gas	Heat Content at 2500°C (kcal/kg)	Quantity of Heat Reqd. to develop 2500°C Temp. (kcal/kg of petroleum burned)
CO_2	719.318	2228.663
H_2O	1725.666	29.074
SO_2	494.531	11.868
H_2	9762	1231.261
N_2	697.321	7515.928
		Σ = 11016.794 kcal/kg of petroleum burned

2500°C	11016.794 kcal/kg of petroleum burned
t°C	10578.255 kcal/kg of petroleum burned
2400°C	10519.232 kcal/kg of petroleum burned

$$\frac{2500 - 2400}{11016.794 - 10519.232} = \frac{t - 2400}{10578.255 - 10519.232}$$

$\therefore\ t = 2411.86$°C ***Ans.***

Problem 10.8 The percentage composition of producer gas is given below in terms of volume

CO—20; H_2—15.5; N_2—54; CH_4—1.25; C_2H_4—1.3; O_2—0.4; CO_2—7.55

Determine the

(a) theoretical volume of air required for complete combustion of 1 m^3 of producer gas

(b) volume of flue gas per m^3 of producer gas burned

(c) specific weight of the flue gas
(d) calorific value of producer gas
(e) calorimetric temperature of combustion

Also draw the material balance.

Solution

Step (I) Air Requirement for Combustion

Basis: 1 Nm^3 of producer gas

Composition	Combustion Reaction	Oxygen Requirement
CO = 0.2 Nm^3	$CO + 1/2\ O_2 \longrightarrow CO_2$	1/2 (0.20) = 0.1 Nm^3
H_2 = 0.155 Nm^3	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	1/2(0.155) = 0.0775 Nm^3
CH_4 = 0.0125 Nm^3	$CH_4 + 2O_2 \longrightarrow CO_2 + H_2O$	2(0.0125) = 0.025 Nm^3
C_2H_4 = 0.013 Nm^3	$C_2H_4 + 3O_2 \longrightarrow 2CO_2 + 2H_2O$	3(0.013) = 0.039 Nm^3
N_2 = 0.54 Nm^3 O_2 = 0.004 Nm^3 CO_2 = 0.0755 Nm^3		ΣO_2 Requirement = 0.2415 Nm^3 for burning 1 Nm^3 of producer gas

Since the gas itself contains 0.004 Nm^3 of O_2, the theoretical volume of oxygen required for complete combustion of 1 Nm^3 of producer gas

$= 0.2415 - 0.004 = 0.2375\ Nm^3$

Hence, the volume of air required

$= 0.2375 + 0.2375\ (3.762) Nm^3$

$= 1.1309\ Nm^3$ per Nm^3 of producer gas burned

Ans.

Step (II) Volume of Flue Gas

Basis: 1 Nm^3 of producer gas

Reactant	Chemical Combustion	Volume of the Combustion Product	
		CO_2	H_2O
CO (0.2 Nm^3)	$CO + 1/2\ O_2 \longrightarrow CO_2$	0.20 Nm^3	—
H_2 (0.155 Nm^3)	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	—	0.155 Nm^3
CH_4 (0.0125 Nm^3)	$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$	0.0125 Nm^3	0.025 Nm^3
C_2H_4 (0.013 Nm^3)	$C_2H_4 + 3O_2 \longrightarrow 2CO_2 + 2H_2O$	0.026 Nm^3	0.026 Nm^3
		Σ = 0.2385 Nm^3	Σ = 0.206 Nm^3

Hence the total volume of combustion products per 1 Nm^3 of producer gas burned

$$= \underbrace{0.2385 + 0.0755}_{(CO_2)} + \underset{\text{(water)}}{0.206} + [\underset{\text{(Nitrogen)}}{0.54 + 0.2375\ (3.762)}]$$

$= 1.953\ Nm^3$ ***Ans.***

Step (III) Specific Weight of Flue Gas

Basis: 1.953 Nm^3 of flue gas

Composition	Volume (Nm^3)	Weight (kg)
CO_2	0.2385 + 0.0755 = 0.314	0.314 (44/22.4) = 0.6167
H_2O	0.206	0.206 (18/22.4) = 0.1655
N_2	0.54 + 0.2375 (3.762) = 1.433	1.433 (28/22.4) = 1.7912
		Σ = 2.5734

Therefore, the specific weight of flue gas

$= 2.5734/1.953\ kg/Nm^3 = 1.317\ kg/Nm^3$

Ans.

Step (IV) Calorific Value of Producer Gas

Reactant	Combustion Reaction	Heat of Combustion	Heat Evolved (kcal/Nm^3 of producer gas burned)
CO (0.2 Nm^3)	$CO + 1/2O_2 \longrightarrow CO_2$	2436.42 kcal/kg of CO	$\frac{2436.42(0.2)(28)}{22.4}$ = 609.105
H_2 (0.155 Nm^3)	$H_2 + 1/2O_2 \longrightarrow H_2O$	28905 kcal/kg of H_2	$\frac{28905(0.155)(2)}{22.4}$ = 400.024

CH_4	$CH_4 + 2O_2$	12025	$\frac{12025(0.0125)(16)}{22.4}$
(0.0125 Nm^3)	$\longrightarrow CO_2 + 2H_2O$	kcal/kg of CH_4	= 107.366
C_2H_4	$C_2H_4 + 3O_2$	12350	$\frac{12350(0.013)(28)}{22.4}$
(0.013 Nm^3)	$\longrightarrow 2CO_2 + 2H_2O$	kcal/kg of C_2H_4	= 200.687
			Σ = 1317.182 kcal/Nm^3 of Producer Gas burned

Step (V) Calorimetric Temperature of Combustion

1st Approximation: Let this temperature be 1600°C

Flue Gas Constituent	Volume (Nm^3)	Specific Heat at 1600°C (kcal/Nm^3.°C)	Δ H (kcal)
CO_2	0.314	0.539	0.314(0.539) (1600) = 270.793
H_2O	0.206	0.435	0.206 (0.435) (1600) = 143.376
N_2	1.433	0.331	1.433 (0.331) (1600) = 758.916
			Σ = 1173 kcal

This value is too small. So let us have a second approximation.

2nd Approximation: 1800°C

Flue gas Constituent	Volume (Nm^3)	Specific Heat at 1800°C (kcal/Nm^3°C)	ΔH (kcal)
CO_2	0.314	0.545	0.314(0.545) (1800) = 308.034
H_2O	0.206	0.452	0.206 (0.452) (1800) = 167.601
N_2	1.433	0.335	1.433(0.335) (1800) = 864.099
			Σ = 1339.73 kcal

1600°C 1173.0 kcal/Nm^3 of Producer Gas burned

t°C 1317.18 kcal/Nm^3 of Producer Gas burned

1800°C 1339.73 kcal/Nm^3 of Producer Gas burned

$$\therefore \frac{1800 - 1600}{1339.73 - 1173} = \frac{t - 1600}{1317.73 - 1173}$$

$\therefore t = 1772.95$°C **Ans.**

Material Balance

Basis: 1 Mol. Vol. of producer gas

Input			Output		
Mol. Vol.		Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) *Fuel*					
CO	0.20	0.2(28) = 5.6	CO_2	0.314	0.314(44) = 13.816
H_2	0.155	0.155(2) = 0.31	H_2O	0.206	0.206(18) = 3.708
CH_4	0.0125	0.0125(16) = 0.20	N_2	1.433	1.433(28) = 40.124
C_2H_4	0.013	0.013(28) = 0.364			
N_2	0.54	0.54(28) = 15.12			
O_2	0.004	0.004(32) = 0.128			
CO_2	0.0755	0.0755(44) = 3.322			
(B) *Air*					
O_2	0.2375	0.2375(32) = 7.6			
N_2	0.2375 × 3.762 = 0.8934	0.8934(28) = 25.017			
Total		= 57.6613	Total = 57.648		

Problem 10.9 From the following percentage composition (by volume) of town gas, determine the calorific value of and calorimetric temperature of combustion.

Also draw the material balance

TOWN GAS	H_2	CH_4	CO	CO_2	N_2
	45	24.5	18	5.5	7

Solution

Step (I) Calorific Value

Basis: 1 Nm^3 of town gas

Town Gas Constituent (Nm^3)	Combustion Reaction	Heat of Combustion (kcal/kg)	Heat Evolved (kcal/Nm^3 of Town Gas)
H_2 (0.45)	$H_2 + 1/2O_2 \longrightarrow H_2O$	28905	$\frac{28905(0.45)(2)}{22.4}$ = 1161.361
CH_4 (0.245)	$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$	12025	$\frac{12025(0.245)(16)}{22.4}$ = 2104.375
CO (0.18)	$CO + 1/2O_2 \longrightarrow CO_2$	2436.42	$\frac{2436.42(0.18)(28)}{22.4}$ = 548.194
CO_2 (0.055)			
N_2 (0.07)			
			Σ = 3813.931 kcal/Nm^3 of Town Gas burned

In order to determine the calorimetric temperature of combustion, it is necessary to know the composition of the products of combustion.

Step (II) Air Requirement for Combustion

Basis: 1 Nm^3 of Town Gas.

Town Gas Constituent	Combustion Reaction (Nm^3)	Oxygen Requirement (Nm^3)	Air Requirement Nm^3
H_2 (0.45 Nm^3)	$H_2 + 1/2O_2 \longrightarrow H_2O$	0.5 (0.45) = 0.225	
CH_4 (0.245 Nm^3)	$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$	2(0.245) = 0.490	0.805 + 0.805 (3.762) = 3.833
CO (0.18 Nm^3	$CO + 1/2O_2 \longrightarrow CO_2$	0.5(0.18) = 0.09	
		Σ = 0.805	

Step (III) Volume of Flue Gas

Basis: 1 Nm^3 of Town Gas

Reactant	Combustion Reaction	Volume of the Products of Combustion	
		CO_2	H_2O
H_2 (0.45 Nm^3)	$H_2 + 0.5\ O_2 \longrightarrow H_2O$		0.45 Nm^3
CH_4 (0.245 Nm^3)	$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$	0.245 Nm^3	0.49 Nm^3
CO (0.18 Nm^3)	$CO + 0.5\ O_2 \longrightarrow CO_2$	0.18 Nm^3	—
		Σ = 0.425 Nm^3	Σ = 0.94 Nm^3

Hence the total volume of the flue gas produced due to combustion of 1 Nm^3 of town gas

= 0.425 + 0.055 (CO_2) + 0.94 (H_2O) + {0.805 (3.762) + 0.07} (N_2)

= 4.5184 Nm^3

Step (IV) Material Balance

Basis: 1 Mol. Vol. of Town Gas

Input			Output		
	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) *Fuel*					
H_2	0.45	0.45(2) = 0.9	CO_2	0.425 + 0.055 = 0.48	0.48(44) = 21.12
CH_4	0.245	0.245(16) = 3.92	H_2O	0.94	0.94(18) = 16.92
CO	0.18	0.18(28) = 5.04	N_2	3.028 + 0.07	3.098(28) = 86.74
CO_2	0.055	0.055(44) = 2.42			
N_2	0.07	0.07(28) = 1.96			
(B) *Air*					
O_2	0.805	0.805(32) = 25.76			
N_2	0.805× 3.762 = 3.028	3.028(28) = 84.784			
		Σ = 124.784			Σ = 124.784

Step (V) Calorimetric Temperature

1st Approximation: Let the calorimetric temperature of combustion be 2100°C

Flue Gas Constituent	Volume (m^3)	Sp. Heat at 2100°C (kcal/m^3°C)	Δ H (kcal)
CO_2	0.48	0.555	0.48(0.555)(2100) = 559.44
H_2O	0.94	0.49	0.94 (0.49)(2100) = 967.26
N_2	3.098	0.34	3.098 (0.34)(2100) = 2211.972
			Σ = 3738.672

This value is too low.

2nd Approximation: Calorimetric temperature of combustion be 2200°C

Flue Gas Constituent	Volume (m^3)	Sp. Heat at 2200°C (kcal/m^3.°C)	Δ H (kcal)
CO_2	0.48	0.56	0.48 (0.56) (2200) = 591.36
H_2O	0.94	0.505	0.94 (0.505) (2200) = 1044.34
N_2	3.098	0.343	3.098 (0.343) (2200) =2337.750
			Σ = 3973.45

This value of ΔH suggests that the calorimetric temperature of combustion should lie between 2100°C and 2200°C.

$$\frac{2200 - 2100}{3973.45 - 3738.672} = \frac{t - 2100}{3813.931 - 3738.672}$$

$\therefore\ t = 2132°C$ ***Ans.***

Problem 10.10 A coal sample having the following composition by weight:

C—75%; H—5.25%; O—9.7%; N—1.38% S—0.95%; Moisture—4.75%; Ash—2.97% is to be burned in air.

Determine the volume of air requirement to burn 1 kg of coal by (a) stoichiometric method (b) mol method.

Solution

(A) Stoichiometric Method

Basis: 1 kg coal

Fuel Constituent	Combustion Reaction	O_2 Requirement (kg)	Remarks
C (0.75 kg)	$C + O_2 \longrightarrow CO_2$ (12) (32) (44)	0.75 (32/12) = 2	Already 0.097 kg oxygen is available in coal
H (0.0525 kg)	$H_2 + 1/2O_2 \longrightarrow H_2O$ (2) (16) (18)	0.0525(16/2) = 0.42	Therefore, the oxygen to be supplied = 2.4295 − 0.097 = 2.3325 kg
S (0.0095 kg)	$S + O_2 \longrightarrow SO_2$ (32) (32) (64)	0.0095 (32/32) = 0.0095	
		Σ = 2.4295	

Therefore, the air to be supplied
= 2.3325 (100/23)
= 10.141 kg/kg of coal burnt.

Mass of Air Requirement	Molecular Wt. of Air	Density of Air at NTP	Volume of Air Requirement
10.141 kg/kg of coal burnt	$\frac{79 \times 28 + 21 \times 32}{79 + 21}$ = 28.84	28.84/22.4 = 1.2875 kg/Nm^3	10.141/1.2875 = 7.876 Nm^3/kg of coal burnt

(B) Mol Method

Basis: 100 kg coal

Fuel Constituent	kmol	Combustion Reaction	Oxygen Required
C = 75 kg	75/12 = 6.25	$C + O_2 \longrightarrow CO_2$	(+) 6.25 kmol
H = 5.25 kg	5.25/2 = 2.625	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	(+) 2.625 (1/2) = 1.3125 kmol

S = 0.95 kg	0.95/32 = 0.0297	$S + O_2 \longrightarrow SO_2$	(+) 0.0297 kmol
O = 9.7 kg	9.7/32 = 0.303		(−)0.303 kmol
			Σ = 7.2892 kmol

Therefore, oxygen to be supplied

= 7.2892 (22.4) Nm^3

Hence, the volume of air required

= 7.2892 (22.4) (100/21)

= 777.5146 Nm^3/100 kg of coal burnt

= 7.775 Nm^3/kg of coal burnt ***Ans.***

Problem 10.11 If the coal in Problem 10.10 is burned in 50% excess air, what will be the volumetric composition of the dry flue gas?

Solution

Coal (kg)	Stoichiometric Requirement		Nitrogen Supplied (kmol)	With 50% Excess Air	
	Oxygen (kmol)	Air (kmol)		Nitrogen Supplied	Oxygen Supplied
100	7.2892	7.2892 (100/21) = 34.71	34.71 − 7.2892 = 27.421	27.421 (0.5) = 13.71 kmol	7.2892 (0.5) = 3.6446 kmol

Flue Gas Composition (Dry basis)	Volumetric Composition
CO_2 = 6.25 kmol	6.25/51.055 = 12.24%
SO_2 = 0.0297 kmol	0.0297/51.055 = 0.058%
O_2 = 3.6446 kmol	3.6446/51.055 = 7.138%
N_2 = 27.421 + 13.71 = 41.31 kmol	41.131/51.055 = 80.56%
Total = 51.055 kmol	

Problem 10.12 A liquid fuel containing only carbon and hydrogen is burnt to produce a flue gas of the following analysis (by volume)

CO_2—11%; O_2—7.5%; N_2—81.5%

Determine

(a) the composition of fuel by weight

(b) the excess air used

Solution

Step (I) Oxygen Content in Flue Gas (Dry)

Basis: 100 kmol of dry flue gas

Flue Gas Constituent	kmol	Oxygen Content (kmol)	Remarks
CO_2	11	11	$C + O_2 \longrightarrow CO_2$ (1 kmol) (1 kmol) (1 kmol)
O_2	7.5	7.5	Free oxygen
		Σ = 18.5	

Step (II) Actual Air Used

Basis: 100 kmol dry flue gas

Nitrogen Content	Actual Air Used	Oxygen in Air Supplied
81.5 kmol	81.5 (100/79) = 103.164 kmol	103.164 (21/100) = 21.664 kmol

Step (III) Hydrogen Content in the Fuel

Basis: 100 kmol dry flue gas

Oxygen Supplied	Oxygen Content in Flue Gas	Oxygen Consumed in Water Formation	Hydrogen Content in Fuel
21.664 kmol	18.5 kmol	21.664 − 18.5 = 3.164 kmol	2(3.164) = 6.328 kmol

Step (IV) Fuel Composition

Basis: 100 kmol fuel

Carbon Content	Hydrogen Content	C : H Ratio
11(12) = 132 kg	6.328(2) = 12.656 kg	132 : 12.656 = 91.25% : 8.75%

Step (V) Percentage Excess Air

Basis: 100 kmol flue gas

Flue Gas Constituent	Oxygen Requirement	Oxygen Supplied	Excess Oxygen Supplied	% Excess Air
CO_2 = 11 kmol	11 kmol	21.664 kmol	21.664 − 14.164 = 7.5 kmol	7.5(100)/14.164 = 52.95 ***Ans.***
H_2O = 6.328	$\frac{1}{2}$(6.328) kmol = 3.164			
	Σ = 14.164 kmol			

Problem 10.13 A liquid fuel contains:

C—84%; H—16%

It is burnt with a quantity of excess air so that flue gas contains:

CO_2—12.5%; CO—1.2%; O_2—0.75%; N_2—84.55%; H_2O—rest by volume

Determine

(a) the ratio of air to liquid fuel
(b) the percentage of excess air

Solution

Step (I) Flue Gas (Dry Basis)

Basis: 1 kmol of flue gas

Flue Gas Constituent	kmol*	Weight (kg)	Weight/kg of Flue Gas	Wt. of Carbon/kg of Flue Gas
CO_2	0.125	0.125 (44) = 5.5	5.5/29.75 = 0.1848	0.1848 (12/44) = 0.0504 kg
CO	0.012	0.012 (28) = 0.336	0.336/29.75 = 0.01129	0.01129 (12/28) = 0.0048 kg
O_2	0.0075	0.0075 (32) = 0.24		
N_2	0.8455	0.8455 (28) = 23.674		
		Σ = 29.75		Σ = 0.0552

* (mole per cent = volume per cent)

Step (II) Air: Fuel Ratio

Now, wt. of C/kg of fuel = 0.84

Wt. of C/kg of dry flue gas = 0.0552

Therefore, the wt. of dry flue gas/kg of fuel

= 0.84/0.0552

= 15.217 kg

$$H_2 + \frac{1}{2}O_2 \longrightarrow H_2O$$

(2) (18)

Hence water vapour produced per kg of fuel burnt

= 18(0.16)/2

= 1.44 kg.

Therefore, total weight of flue gas

= 15.217 + 1.44

= 16.657 kg/kg of fuel

Now, 1 kg fuel + air supplied

= 16.657 kg of flue gas

Air supplied = 16.657 – 1 = 15.657 kg/kg of fuel

Therefore, air: fuel ratio = 15.657 : 1 ***Ans.***

Step (III) Stoichiometric Air

Basis: 1 kg fuel

Fuel Constituent	Combustion Reaction	Oxygen Requirement (kg)	Air Requirement (kg)
C = 0.84 kg	C + O_2 12 32 $\longrightarrow CO_2$	(0.84 × 32/12) = 2.24	2.24 × 100/23 = 9.739
H = 0.16 kg	H_2 + 1/2 O_2 (2) (16) $\longrightarrow H_2O$	(0.6 × 16/2) = 1.28	1.28 × 100/23 = 5.565
			Σ = 15.304

Step (IV) Percentage Excess Air

Basis: 1 kg Fuel

Air Supplied	Air Requirement	Excess air	% Excess Air
15.657 kg	15.304 kg	15.657 – 15.304	(0.353/15.304) (100) = 2.30

Ans.

Problem 10.14 The analysis of coal fired in a boiler and the flue gas produced are as follows

Coal C—25%; H—5%; O—7.5%; Non-combustible—62.5% (by weight)

Flue Gas CO_2—11%; CO—1.5%; N_2—83%; O_2—4.5% (by volume)

Determine

(a) the weight of air supplied per kg of coal burned
(b) the per cent excess air

Solution

Step (I) Oxygen Requirement

Basis: 1 kg coal

Fuel Constituent	Combustion Reaction	Oxygen Requirement (kg)	Remarks
C (0.25 kg)	$C + O_2 \rightarrow CO_2$ 12 32 44	0.25 (32/12) = 0.666	Already 0.075 kg O_2 is available in coal
H (0.05 kg)	$H_2 + O_2 \rightarrow H_2O$ (2) (16) (18)	0.05 (16/2) = 0.4	Hence actual O_2 requirement = 1.066 – 0.075 = 0.9916 kg/kg of coal
O (0.075 kg)		—	—
Ash (0.625 kg)		—	—
		$\Sigma = 1.066$	

Step (II) Air Requirement

The theoretical amount of air requirement for combustion

= 0.9916(100/23)

= 4.311 kg/kg of coal

(cf. Air contains N_2 and O_2 in approximately 77: 23 ratio by weight)

Step (III) Air Supplied

Basis: 100 kg of fuel

Working in kmol we get, the overall combustion reaction as:

$$\frac{25}{12}C + \frac{5}{2}H + \frac{7.5}{32}O_2 + aO_2 + 3.76a\ N_2 \longrightarrow b\ CO_2 + d\ CO + e\ O_2 + f\ N_2 + g\ H_2O$$

Equating the coefficients of carbon

$$b + d = \frac{25}{12} = 2.08 \quad \text{(I)}$$

Since volume % = mol %,

$$CO_2 = \frac{b}{b+d+e+f} = \frac{11}{100} = 0.11;$$

$$CO = \frac{d}{b+d+e+f} = \frac{1.5}{100} = 0.015$$

$$O_2 = \frac{e}{b+d+e+f} = \frac{4.5}{100} = 0.045;$$

$$N_2 = \frac{f}{b+d+e+f} = \frac{83}{100} = 0.83$$

From these relationships we get:

$b/d = 0.11/0.015 = 7.33$ (II);

$f/d = 0.83/0.015 = 55.33$ (III)

From equations (I) and (II) we get, $d = 0.249$

Therefore, from equation (III), $f = 13.77$

Again, $3.76\ a = f = 13.77$; $\therefore\ a = 3.66$

Therefore, air supplied per 100 kg fuel

$= a(32) + f(28)$

= 502.819 kg

Hence, air supplied per kg of fuel = 5.028 kg

Step (IV) Excess Air

Basis: 1 kg fuel

Air Supplied	Actual Air Requirement	Excess Air	% Excess Air
5.028 kg	4.311 kg	5.028 – 4.311 = 0.717 kg	(0.717/4.311)(100) = 16.63

Problem 10.15 A flue gas has the following analysis on dry basis CO_2—11%; CO—1.2%; O_2—7.2%; N_2—80.6% (by volume)

If the fuel contains 87.6% carbon by mass, determine the percentage of carbon burnt to carbon monoxide by mass.

Also determine the mass of dry flue gas per kg of fuel burnt.

Solution

Step (I) Total Carbon in Flue Gas

Basis: 100 kmol flue gas

Flue Gas Constituent	kmol	Weight (kg)	Carbon Content (kg)	C Per kg Dry Flue Gas (kg)
CO_2	11	11(44) = 484	484(12/44) = 132	146/3004.8
CO	1.2	1.2(28) = 33.6	33.6(12/28) = 14.4	= 0.04872
O_2	7.2	7.2(32) = 230.4	—	
N_2	80.6	80.6(28) = 2256.8	—	
		Σ = 3004.8	= 146.4	

Step (II) Per cent of Carbon Burnt to Carbon Monoxide

[14.4/146.4]/100 = 9.83%

Ans.

Step (III) Mass of Dry Flue Gas

As only the carbon content in the fuel burns to produce dry flue gas, so the dry flue gas produced per kg of fuel

= 0.876/0.04872 kg

= 17.98 kg ***Ans.***

Problem 10.16 A fuel (C—83%; H—16%; Non-combustible—1 %) was completely burnt with excess air in a furnace. On a testing analysis, the dry flue gas registered CO_2—7.98% by volume.

Calculate the amount of air supplied per kg of fuel and the products of combustion per kg of fuel.

Solution

Step (I) Oxygen Requirement

Basis: 100 kg of fuel

Let the supplied air contained a kmol of oxygen. Therefore, it was associated with 3.76 (a) kmol of nitrogen (cf. $N_2/O_2 = 79/21 = 3.76$)

Computing the combustion reaction in kmol we get,

$$\frac{83}{12}C + \frac{16}{2}H_2 + aO_2 + 3.76a\ N_2$$

$$\longrightarrow b\ CO_2 + d\ O_2 + 3.76a\ N_2 + \frac{16}{2}\ H_2O$$

Equating the coefficients of carbon: $b = 83/12$

= 6.916

Equating the coefficients of oxygen:

$$a = b + d + \frac{8}{2}$$

$$= 6.916 + d + 4$$

$$= 10.916 + d \qquad \text{(I)}$$

Again, $$\frac{b}{b+d+3.76a} = \frac{7.98}{100} = 0.0798$$

or

$6.916/[6.916 + d + 3.76\ (10.916 + d)] = 0.0798$

[Putting the value of a from Eq. (I)]

$d = 8.13$ kmol

$a = 10.916 + 8.13 = 19.047$ kmol

Step (II) Air Supplied

Basis: 100 kg fuel

Oxygen Supplied	Nitrogen Supplied	Total Air Supplied
19.047 kmol	3.76(19.047) kmol	609.524 + 2005.268
= 19.047(32) kg = 609.524 kg	= 3.76 (19.047) (28) kg = 2005.2681 kg	= 2614.792 kg

Therefore, mass of air supplied per kg of fuel

= 26.147 kg ***Ans.***

Step (III) Combustion Products

Basis: 100 kg fuel

Combustion Products	kmol	Weight (kg)	Per kg Fuel
CO_2	6.916	6.916(44) = 304.304	3.04 kg
H_2O	8	8(18) = 144	1.44 kg
O_2	8.13	8.13(32) = 260.16	2.60 kg
N_2	3.76 × 19.047	3.76 × 19.047 × 28 = 2005.268	20.05 kg
Ash	—	1.00	0.01 kg

Problem 10.17 A fuel gas has the following analysis by volume:

H_2—51%; CH_4—22%; CO—15%; N_2—5%; CO_2—3%; C_2H_4—2%; O_2—2%

Calculate the minimum volume of air required for complete combustion of 1 m^3 of the fuel gas.

If 5 m^3 of air be supplied per m^3 of the fuel gas, determine the percentage composition of the combustion products by volume.

Solution

Step (I) Oxygen Requirement and Combustion Products

Basis: 100 kmol of fuel gas

Fuel Gas Constituent	kmol	Combustion Reaction	O_2 Requirement (kmol)	Combustion Products	
				CO_2 (kmol)	H_2O (kmol)
H_2	51	$H_2 + 1/2O_2 \longrightarrow H_2O$	51/2 = 25.5	—	51
CH_4	22	$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$	2(22) = 44	22	2 × 22 = 44
CO	15	$CO + 1/2O_2 \longrightarrow CO_2$	15/2 = 7.5	15	—
N_2	5			5 (Nitrogen)	
CO_2	3			3	—
C_2H_4	2	$C_2H_4 + 3O_2 \longrightarrow 2CO_2 + 2H_2O$	3(2) = 6	4	4
O_2	2		(–)2		
			Σ = 81 kmol	Σ = 44(CO_2) + 5(N_2) + 99(H_2O)	

Step (II) Minimum Amount of Air Requirement

Fuel	O_2 Requirement	Air Requirement
100 kmol	81 kmol	
100 m^3	81 m^3	
1 m^3	0.81 m^3	0.81 (100/21) = 3.857 m^3

Ans.

Step (III) Excess Air

Theoretical air requirement = 3.857 m^3/m^3 of fuel

Supplied air = 5 m^3/m^3 of fuel

Therefore, excess air

= 5 – 3.857 = 1.14 m^3/m^3 of fuel

= 114 kmol/100 kmol of fuel

Step (IV) Percentage Composition of Flue Gas

Basis: 100 kmol of fuel gas

Combustion Products	Composition (kmol)	Percentage Composition
CO_2	44	44(100)/566.703 = 7.76%
N_2	$5 + \frac{385.7(79)}{100}$ = 309.703	$\frac{309.703 + 90.06}{566.703}(100)$ = 70.54%
H_2O	99	73.5(100)/566.703 = 17.47%
N_2 (excess air)	114(79/100) = 90.06	
O_2 (excess air)	114(21/100) = 23.94	23.94 (100)/566.703 = 4.22%
	Σ = 566.703	

Problem 10.18 A liquid fuel upon combustion in excess air produces flue gas of following percentage composition (by volume) on dry basis:

CO_2—8.86%; CO—1.25%; O_2—7%; N_2—82.89%

The liquid fuel has the following percentage composition (by mass):

C—84%; H—15%; O—1%

Determine the mass of air supplied per kg of fuel burnt.

Solution

Step (I) Oxygen Requirement

Fuel Constituent	Mass kg of Fuel	Combustion Reaction	Oxygen Requirement Per kg Constituent (kg)	Per kg Fuel (kg)
C	0.84	$C + O_2 \longrightarrow CO_2$	32/12 = 2.666	2.666(0.84) = 2.24
H	0.15	$H_2 + 1/2O_2 \longrightarrow H_2O$	$\frac{32(1/2)}{2}$ = 8	8(0.15) = 1.2
O	0.01		—	(–) 0.01
				Σ = 3.43

Step (II) Theoretical Air Requirement

Theoretical oxygen requirement

= 3.43 kg/kg of fuel

Theoretical air requirement = 3.43 (100/23)

= 14.91 kg/kg of fuel

Step (III) Fuel Gas Analysis

Flue Gas Constituent	% by Volume	(% by Volume) × (Mol. Wt.)	% by Mass
CO_2	8.86	8.86(44) = 389.84	$\frac{389.84}{2969.76}(100)$ = 13.127
CO	1.25	1.25(28) = 35	$\frac{35}{2969.76}(100)$ = 1.178
O_2	7	7(32) = 224	$\frac{224}{2969.76}(100)$ = 7.542
N_2	82.89	82.89(28) = 2320.92	$\frac{2320.92}{2969.76}(100)$ = 78.151
		Σ = 2969.76	

Step (IV) Excess Air

Basis: 1 kg dry flue gas

Flue Gas Constituent	Mass (kg)	Mass of Carbon (kg)
CO_2	0.13127	0.13127 (12/44) = 0.0358
CO	0.01178	0.01178 (12/28) = 0.00504
		Σ = 0.04084

Mass of C/kg of fuel = 0.84 kg

Mass of dry flue gas/kg of fuel = 0.84/0.04084

= 20.563 kg

Mass of excess O_2/kg of fuel = 20.563(0.07542)

= 1.5509 kg

Mass of excess air/kg of fuel = 1.5509 (100/23)

= 6.743 kg

Ans.

Step (V) Air Supplied

Stoichiometric air/kg of fuel = 14.91 kg

Mass of excess air/kg of fuel = 6.743 kg

Total air supplied = 14.91 + 6.743 = 21.653 kg

Ans.

Excess Air (Alternative Method)

Nitrogen Balance Method

Nitrogen in dry flue gas = Total N_2 from air

Mass of N_2/kg fuel = 20.563 (0.78151) = 16.07 kg

Mass of air/kg fuel = 16.07(100/77) = 20.87 kg

Ans.

Problem 10.19 The fuel supplied to a boiler contains 79% carbon, 7% hydrogen, 8% oxygen and 6% ash (by mass) as fired. The supplied air is 50% in excess of the stoichiometric air. Determine the mass of dry flue gas per kg of fuel.

If the boiler house temperature is 25°C and the flue gas temperature is 300°C, calculate the energy carried away by the dry flue gas per kg fuel burned.

Gas	Specific Heat (kcal/kg °C)
CO_2	0.222
N_2	0.242
O_2	0.313
Air	0.237

Solution

Step (I) Stoichiometric Oxygen Required

Basis: 1 kg fuel

Fuel Constituent	Mass (kg)	Combustion Reaction	Oxygen Requirement (kg)
C	0.79	$C + O_2 \longrightarrow CO_2$ (12, 32)	(32/12) (0.79) = 2.106
H	0.07	$H_2 + 1/2O_2 \longrightarrow H_2O$ (2, 16)	(16/2) (0.07) = 0.56
			(–) 0.08
O	0.08		Σ = 2.586

Step (II) Stoichiometric Air Required

2.586(100/23) = 11.246 kg/kg of fuel

Step (III) Mass of Dry Flue Gas Per kg of Fuel

Basis: 1 kg fuel

Stoichiometric Air (kg)	Actual air Supplied (kg)	Total Mass of Flue Gas	Mass of Water Produced (kg)	Mass of Dry Flue Gas (kg)
11.246	11.246 (1.5) = 16.869	16.869(Air) + 1 (Fuel) = 17.869 kg	0.07(18/2) = 0.63	17.869 – 0.63 = 17.239

Ans.

Step (IV) Energy Content of Dry Flue Gas

Basis: 1 kg fuel

Dry Flue Gas Constituent	Mass (kg)	Specific Heat (kcal/kg.°C)	ΔΘ (°C)	Heat Content (kcal)
CO_2	$\frac{44(0.79)}{12}$ = 2.896	0.222	275	2.896(0.222)(275) = 176.841
N_2	$\frac{11.246(77)}{100}$ = 8.659	0.242	275	8.659(0.242)(275) = 576.284
Air	$\frac{11.246(50)}{100}$ = 5.623	0.237	275	5.623(0.237)(275) = 366.479
				Σ = 1119.604

Problem 10.20 The analysis of coal fired in a boiler shows the following composition by mass:

Carbon—81%; Hydrogen—9%; Oxygen—2%; Ash-8%

The rate of coal consumption in the boiler is 0.9 t/h and air supplied by a blower is 30% in excess of stoichiometric air.

Calculate:

(a) the intake air volume when the intake conditions at the blowers are 100 kN/m^2 and 291°K.

(R_{air} = 0.287 kJ/kg°K)

(b) the percentage composition (by mass) of dry flue gas

Solution

Step (I) Stoichiometric Oxygen

Basis: 1 kg coal

Coal Composition	Mass (kg)	Combustion Reaction	Oxygen Requirement (kg)
C	0.81	$C + O_2 \rightarrow CO_2$ (12, 32)	(32/12) (0.81) = 2.16
H	0.09	$H_2 + 1/2O \rightarrow H_2O$ (2, 16)	(16/2) (0.09) = 0.72
O	0.02		(–) 0.02
			Σ = 2.86

Step (II) Theoretical Air Requirement

Basis: 1 kg coal

Theoretical Oxygen Requirement	Theoretical Air Requirement
2.86 kg	2.86(100/23) = 12.434 kg

Step (III) Supplied Air

Basis: 1 kg coal

Theoretical Air	Excess Air	Supplied Air
12.434 kg	12.434 (30/100) = 3.73 kg	12.434 + 3.73 = 16.164 kg

Hence the air supplied per second

= 16.164 (0.9) (1000)/3600 kg

= 4.041 kg

Step (IV) Volume of Supplied Air

Working Formula: $PV = mRT$

P	m	R	T	V(volume flowrate)
100	4.041	0.287	291°K	$\frac{4.041(0.287)(291)}{100}$
kN/m^2	kg/s	kJ/kg. °K		
				= 3.375 m^3/s

Step (V) Dry Flue Gas Composition

Basis: 1 kg coal

Dry Flue Gas Composition	Mass (kg)	% Composition by Mass
CO_2	(44/12) (0.81) = 2.97	(2.97/16.274)(100) = 18.25 ***Ans.***
O_2 ← From excess air	2.86 (0.3) = 0.858	(0.858/16.274) (100) = 5.27 ***Ans.***
N_2 ←	$\frac{16.164(77)}{100}$ = 12.446	(12.446/16.274) (100) = 76.476 ***Ans.***
	Σ = 16.274	

Problem 10.21 A boiler generates 2500 kg of steam per hour—the steam being 97% dry at pressure 1.4 MN/m^2.

The boiler feedwater temperature = 328°K

Boiler efficiency = 72%

Calorific value of coal = 27500 kJ/kg

Coal composition by mass;

C—84%; H—6%; O—3%; Ash—7%

Air supply: 25% in excess of stoichiometric air.

Specific heat capacity of water = 4.187 kJ/kg K

Calculate:

(a) the feed rate of coal per hour
(b) the mass of air supplied per hour
(c) the percentage analysis of flue gases by mass

Solution

Step (I) Energy to Generate Steam

From steam table

Abs. Press. (MN/m^2)	Satd. Temp. (°C)	Sp. Enthalpy H_w	(kJ/kg) L
1.4	195	830	1957.7

Specific enthalpy of generated steam

= 830 + 1957.7 (0.97) kJ/kg

= 2728.970 kJ/kg

Sp. Enthalpy of Generated Steam	Sp. Enthalpy of Feedwater	Energy to Generate Steam	Energy to Steam per Hour
2728.97 kJ/kg	4.187(328 – 273) kJ/kg = 230.285 kJ/kg	2728.97 – 230.285 = 2498.685 kJ/kg	2498.685 (2500) kJ/h

Step (II) Mass of Coal Consumption per Hour

Energy Supplied to steam per Hour (kJ/kg)	Boiler Efficiency	Energy Required from Coal Feed (kJ/kg)	Calorific Value of Coal	Feedrate of Coal per Hour (kg/h)
2498.685 (2500)	72%	2498.685 (2500)/0.72	27500 $\frac{kJ}{kg}$	$\frac{2498.685(2500)}{0.72(27500)}$ = 315.49 ***Ans.***

Step (III) Theoretical Air Requirement

Basis: 100 kg coal

Coal Constituent	Mass (kg)	Combustion Reaction	Oxygen Requirement (kg)	Theoretical Air Requirement
C	84	$C + O_2 \longrightarrow CO_2$ 12 32	(32/12) (84) = 224	269(100/23) = 1169.565 kg
H	6	$H_2 + \frac{1}{2} O_2$ 2 16 $\longrightarrow H_2O$	(16/2) (6) = 48	
O	3		(–)3	
			Σ = 269	

Step (IV) Supplied Air

Theoretical Air per kg of Coal	Excess Air (kg)	Mass of Supplied Air per kg Coal	Coal Consumption	Air Supplied
11.6956 kg	25% (11.6956) = 2.9239	11.6956 + 2.9239 kg = 14.6195 kg	315.49 kg/h	14.6195 × 315.49 = 4612.31 kg/h

Step (V) Flue Gas Composition

Basis: 1 kg coal

Coal Constituent	Mass (kg)	Combustion	Flue Gas Produced			
			H_2O	CO_2	N_2	O_2
C	0.84	$C + O_2 \longrightarrow CO_2$ (12) (44)		$\frac{44(0.84)}{12}$ = 3.08 kg	(from total air supply) 14.62 × 0.77 = 11.25 kg	(from excess air) 2.923 × 0.23 = 0.67 kg
H	0.06	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	$\frac{18(0.06)}{2}$ = 0.54 kg			

Basis: 1 kg coal

Flue gas Composition	Mass (kg)	Per cent Composition
CO_2	3.08	3.08 (100/15.549) = 19.80
H_2O	0.54	0.54 (100/15.549) = 3.47
N_2	11.257	11.257 (100/15.549) = 72.39
O_2	0.67	0.67 (100/15.549) = 4.30
	Σ = 15.549	

Problem 10.22 From the two following combustion reactions:

$C + 1/2O_2 \longrightarrow CO + 2436.42$ kcal/kg of C

(s) (g) (g)

$C + O_2 \longrightarrow CO_2 + 8137.5$ kcal/kg of C

(s) (g) (g)

determine the calorific value of carbon monoxide. Check the result with the following:

$CO + 1/2O_2 \longrightarrow CO_2 + 2436.42$ kcal/kg of CO

(g) (g) (g)

Solution

Step (I) The calorific value of carbon monoxide is determined with the help of the following combustion reaction

$$CO + \frac{1}{2}O_2 \longrightarrow CO_2 + Q$$

Replacing CO and CO_2 from 1st and 2nd reactions we get,

$$\left(C + \frac{1}{2}O_2 - 2452.5 \text{ kcal/kg of C}\right) + \frac{1}{2}O_2$$

$$= (C + O_2 - 8137.5 \text{ kcal/kg of C}) + Q$$

or $Q = (8137.5 - 2452.5)$ kcal/kg of C

$= 5685$ kcal/kg of C

Step (II) Check

$$C + \frac{1}{2}O_2 \longrightarrow CO$$

(12) (28)

$$\therefore Q = 5685\ \frac{12}{28} \text{ kcal/kg of CO}$$

$= 2436.4285$ kcal/kg of CO which is in excellent agreement with the check-data.

Q. *What is the Higher Calorific Value (HCV) or Gross Calorific Value of Fuel?*

Ans. It is the total energy liberated by the complete combustion of 1 kg of solid/liquid fuel or 1Nm^3 of gaseous fuel and, in all cases, when the combustion products are cooled to the original fuel temperature. (The standard temperature is 15°C, usually)

Q. *What is the Lower or Net Calorific Value (LCV) of fuel?*

Ans. It is the net energy liberated by the complete combustion of 1 kg of solid/liquid fuel or 1 m^3 of gaseous fuel and, in all cases when the combustion products are cooled to 100°C without the condensation of steam.

Q. *What is the difference between heat evolved at constant volume and heat evolved at constant pressure?*

Ans. Heat evolved at constant pressure

= Calorific value at contant pressure

Heat evolved at constant volume

= Calorific value at constant pressure + work done

= Calorific value at constant pressure + PV – work

$$= \text{Calorific value at constant pressure} + \frac{n}{M}(1.985)T$$

(cf.: $PV = nRT = \frac{n}{M}(R_m)T$; where R_m = molar gas constant = 1.985 kcal/kmol°C

M = molecular weight of the gas)

Problem 10.23 Determine the higher calorific value of carbon when it is burnt to

(a) CO_2
(b) CO

at a constant volume.

Given HCV at constant pressure for

$C + O_2 \longrightarrow CO_2$ is 8137.5 kcal/kg of °C

$C + 1/2\ O_2 \longrightarrow CO$ is 2452.5 kcal/kg of °C

Solution

Step (I) $\boxed{C \longrightarrow CO_2}$

$C + O_2 \longrightarrow CO_2 + 8137.5$ kcal/kg of C
(s) (g) (g)

Here, Δ volume = 1 – 1 = 0

$[HCV]_{vol} = [HCV]_{press} = 8137.5$ kcal/kg of C

Ans.

Step (II) $\boxed{C \longrightarrow CO}$

$C + 1/2\ O_2 \longrightarrow CO + 2452.5$ kcal/kg of C
(s) (g) (g)

Here, Δ volume $= 1 - \frac{1}{2} = \frac{1}{2}$ kmolar volume

$$[HCV]_{vol} = 2452.5 + \left(\frac{1}{2}\right)\left(\frac{1.985}{12}\right)(273) \text{ kcal/kg °C}$$

= 2475.07 kcal/kg of °C ***Ans.***

Problem 10.24 A fuel contains 86% carbon and the rest hydrogen. Determine its probable formula.

Estimate the

(a) $[HCV]_{press}$
(b) $[HCV]_{vol}$

Given

$C \longrightarrow CO_2$ $[HCV]_{press} = 8137.5$ kcal/kg of C
(s) (g)

$H_2 \longrightarrow H_2O$ $[HCV]_{press} = 34180$ kcal/kg of H
(g) (l)

Solution

Step (I) Formula of the Fuel

Let the formula of the fuel be C_xH_y.

$$x : y :: \frac{86}{12} : \frac{14}{1} = 7.16 : 14 = 1 : 2$$

C_xH_y is CH_2. Since no fuel can exist as such, C_xH_y becomes C_2H_4, which is ethylene.

Step (II) Calorific Value at Constant Pressure

Combustion reaction of ethylene is

$C_2H_4 + 3O_2 \longrightarrow 2CO_2 + 2H_2O$
(g) (g) (g) (l)

$$[HCV]_{press}^{C_2H_4} = [HCV]_{press}^{C \longrightarrow CO_2} + [HCV]_{press}^{H_2 \longrightarrow H_2O}$$

= 8137.5 kcal/kg of C + 34180 kcal/kg of H

Molecular weight of ethylene is

$2 \times 12 + 4 \times 1 = 28$

28 kg C_2H_4 = 24 kg C + 4 kg H

$$[HCV]_{press}^{C_2H_4} = (8137.5)(24/28) + (34180)(4/28)$$

kcal/kg of C_2H_4

= 11857.85 kcal/kg of C_2H_4 ***Ans.***

Step (III) Calorific Value at Constant Volume

$$[HCV]_{vol}^{C_2H_4} = [HCV]_{press}^{C_2H_4} + [PV - \text{workdone}]$$

Now, PV – workdone $= \frac{n}{M}(1.985)\,T$

Because of combustion reaction,

$n = [2] - [3 + 1]$
$(CO_2) \quad (O_2) \quad (C_2H_4) = -2$

PV – workdone $= -\frac{2}{28}(1.985)(273)$ kcal/kg of C_2H_4

$= -38.7075$ kcal/kg of C_2H_4

$[HCV]_{vol}^{C_2H_4} = 11857 - 38.7$

$= 11818.3$ kcal/kg of C_2H_4

Ans.

Problem 10.25 A coal containing 81% C, with a calorific value 32400 kJ/kg is burnt to produce a flue gas of the following composition by volume:

CO_2—13%; CO—1.25%; O_2—5.5%; N_2—80.25%

Calculate the

(a) weight of carbon converted to CO per kg coal
(b) percentage heat lost due to incomplete combustion

$C + O_2 \longrightarrow CO_2 + 34071.71$ kJ/kg of C
(s) (g) (g)

$C + \frac{1}{2}O_2 \longrightarrow CO + 10268.61$ kJ/kg of C
(s) (g) (g)

Solution

Step (I) Carbon ⟶ CO

Fraction of coal C burnt to CO

$$= \frac{\%CO}{\%CO + \%CO_2} = \frac{1.25}{1.25 + 13}$$

$= 0.0877$ kg/kg of C burnt

Therefore, in burning 1 kg of coal, i.e. 0.81 kg C, the weight of carbon transforming to CO is

$= 0.0877\,(0.81)$

$= 0.071$ kg/kg of coal

Ans.

Step (II) Per cent Heat Loss

Due to conversion of C to CO, heat lost

$= 34071.71 - 10268.61$ kJ/kg of C

$= 23803.1$ kJ/kg of C

Heat lost per kg coal burnt $= 23803.1\,(0.071)$

$= 1690$ kJ

$\therefore$ Heat Loss $= \frac{1690}{32400}(100) = 5.216\%$

Ans.

Problem 10.26 A solid fuel contains 74% carbon and 16% ash. The ash discharged from the furnace contains 20% carbon.

Estimate:

(a) the weight of carbon lost in the ash per kg of fuel
(b) the percentage carbon burned
(c) the heat lost by the incomplete combustion

Solution

Step (I) Carbon Associated with Ash

If it is assumed that the ratio of carbon associated with ash is the same both in the solid fuel and the ash discharged then,

$$\frac{x}{16} = \frac{20}{(100-20)}$$

where x is the carbon associated with ash in 100 kg solid fuel.

$\therefore\ x = 4$ kg C/100 kg of fuel

Step (II) Carbon Lost in Ash

Fuel	C Lost in Ash
100 kg	4 kg
1 kg	0.04 kg

Ans.

Step (III) Per cent Carbon Burned

Fuel	Carbon Content	Effective Carbon
100 kg	74 kg	74 – 4 = 70 kg

$\therefore$ %C burnt = (70/74) (100) = 94.59

Ans.

Step (IV) Heat Lost Due to Incomplete Combustion

The loss of heat due to incomplete combustion is due to slippage of carbon into ash.

Thus heat lost = (4/100) (8137.5) kcal/kg of fuel

= 325.5 kcal/kg of fuel.

Therefore, per cent heat loss due to incomplete combustion

= (325.5/8137.5) (100) = 4%

Ans.

Problem 10.27 Hot air is blown over red-hot coke (C—84%; Ash—10%) to manufacture producer gas whose composition is as given below:

CO—26%; CO_2—5%; H_2—16%; N_2—51%; CH_4—2%

The calorific value of the gas is 5900 kJ/Nm^3 and the ash discharged from the plant contains 15% carbon.

Calculate

(a) the mass of carbon gasified per kg of coke

(b) the volume of gas produced per kg of coke feed

(c) the heat available in the gas per kg of coke fired

Solution

Step (I) Mass of Carbon Gasified

Assuming the ratio of carbon associated with ash is the same in both the coke and the final ash discharged,

$$\frac{x}{10} = \frac{15}{(100 - 15)}$$

Where x is the carbon per 100 kg of coke

x = 1.764 kg C/100 kg coke

Coke	Total Carbon	Carbon Lost to Ash	Carbon Gasified
100 kg	84 kg	1.764 kg	84 – 1.764 = 82.236 kg

Mass of carbon gasified = 0.822 kg/kg of coke

Step (II) Volume of Producer Gas Produced

Basis: 100 kmol of producer gas

Gas Composition	Kmol	Carbon Content (Kmol)
CO	26	26
CO_2	5	5
H_2	16	
N_2	51	
CH_4	2	2
		Σ = 33

Basis: 100 kg fuel

Fuel Composition	Carbon Content	Carbon Gasified	Kmol C Gasified
C	84 kg	82.236 kg	82.236/12 = 6.853

CARBON		PRODUCER GAS
33 kmol	generating	100 kmol
$\therefore$ 6.853 kmol		100(6.853/33) = 20.766 kmol = 20.766(22.4)Nm^3 = 465.173 Nm^3

Therefore, the volume of producer gas manufactured per kg of coke feed

= 4.6517 Nm^3

Ans.

Step (III) Heat Available in the Gas

Basis: 1 kg coke

Gas Produced	Calorific Value	Heat in the Gas
4.6517 Nm^3	5900 kJ/Nm^3	4.6517 (5900)kJ = 27445.22 kJ = 27.44 MJ

Ans.

Problem 10.28 In a combustion chamber a mixture of air-benzene vapour is burned. Calculate the available heat in the air-benzene mixture at NTP taking theoretical minimum air for combustion of benzene (lower calorific value = 40363 kJ/kg).

Also determine the percentage change of volume due to combustion.

Solution

Step (I) Combustion of Benzene

The chemical reaction accompanying the combustion of benzene is

$$C_6H_6 + \frac{15}{2}O_2 \longrightarrow 6\ CO_2 + 3H_2O + 40363$$

kJ/kg of benezene

Now that this oxygen comes from air, the overall reaction is

$$C_6H_6 + (15/2)\ O_2 + 3.76(15/2)\ N_2 \longrightarrow$$
$$6\ CO_2 + 3H_2O + 3.76\ (15/2)\ N_2 + 40363$$

kJ/kg of benezene

(cf. kmol of N_2 in air/kmol of O_2 in air = 3.76)

Step (II) Calorific Value of Air-Benezene Mixture

Air-Benezene Vapour Mixture

Total Kmol of Reactants	Calorific Value
1 + 15/2 + 3.76 (15/2) = 36.7	40363 kJ/kg of C_6H_6 = 40363 × 78 kJ/mol of C_6H_6 i.e. 40363 × 78 kJ/kmol of above air-benezene mix

Hence the available heat in 1 Nm^3 of air-benezene vapour mixture

= 40363 × 78/(36.7 × 22.4)

= 3829.69 kJ/Nm^3

Ans.

Step (III) Volume Change Due to Combustion

Reactants (Total Kmol)	Products (Total Kmol)	Kmol	% Volume
36.7	6 + 3 + 3.76(15/2) = 37.2	37.2 – 36.7 = 0.5	(0.5/36.7)100 = 1.362

Ans.

Problem 10.29 In a standard engine a mixture of air and n-heptane vapour is tested taking air: n-heptane ratio 20 : 1 by mass.

Determine the calorific value/m^3 of the mixture at NTP.

Calorific value of n-heptane is 45220 kJ/kg

Also determine the percentage composition (by volume) of the dry exhaust gas assuming complete combustion of n-heptane.

Solution

Step (I) Combustion Reaction of n-Heptane

Taking 100 kg n-heptane and working in kmols we get,

$$\frac{100}{100}C_7H_{16} + aO_2 + 3.76a\ N_2$$
$$\longrightarrow b\ CO_2 + d\ O_2 + 3.76a\ N_2 + eH_2O$$

where a, b, c, d and e denote the number of kmols

Step (II) Oxygen Supplied

n-Heptane	Air	Oxygen
100 kg	20(100) kg	20(100) (23/100) kg = 20(23) kg = 20 (23)/32 kmol = 14.375 kmol = a

Step (III) Calorific Value

Basis: 100 kg Fuel

Reactants	Kmol	Volume at NTP
C_7H_{16}	1	69.425×22.4 m^3 = 1555.12 m^3
O_2	14.375	
N_2	14.375 (3.76) = 54.05	
	Σ = 69.425	

Calorific value of 1 kmol of fuel (100 kg n-heptane) + air mixture occupying 1555.12 m^3 at NTP is = 45220 (100) kJ

Calorific value of 1 Nm^3 of air-heptane mixture

= 45220 (100)/1555.12 kJ

= 2907.814 kJ

Ans.

Step (IV) Percentage Composition (by Volume) of the Dry Exhaust Gas

By equating the coefficients of carbon and nitrogen, we get

b = 7 kmol

3.76 a = 3.76 (14.375) = 54.05 kmol

d = a – kmol of stoichiometric O_2

Now, $C_7H_{16} + 11O_2 \longrightarrow 7\ CO_2 + 8\ H_2O$

$d = a - 11 = 14.375 - 11 = 3.375$ kmol

Basis: 100 kg fuel

Combustion Products	Kmol	Percent by Volume
CO_2	b = 7	7(100/64.425) =10.86
O_2	d = 3.375	3.375 (100/64.425) = 5.24
N_2	3.76 a = 54.05	54.05 (100/64.425) = 83.89
	Σ = 64.425	

Problem 10.30 In a certain coal fired furnace, the coal has the following composition by mass:

C—83.5%; H—6.5%; O—4%; Moisture—3.5%; Ash—2.5%

Determine the theoretical temperature of combustion and the mean specific heat of the flue gas if the combustion is complete with minimum air and 30% excess air.

Given: Calorific value of coal = 7550 kcal/kg

$[C_p]_{CO_2} = [C_p]_{N_2} = [C_p]_{O_2} = 0.241$ kcal/kg°C

$[C_p]_{H_2O} = 0.469$ kcal/kg°C

Air contains O_2 21% by volume and 23% by mass.

Solution:

Step (I) N_2 : O_2 Mol Ratio in Air

Since volume per cent = mol per cent, so

kmol of N_2/kmol of O_2 = 79/21 = 3.76

Step (II) Combustion Equation

Basis: 100 kg coal

$$\frac{83.5}{12}C + \frac{6.5}{2}H_2 + \frac{4}{32}O_2 + xO_2 + 3.76\ x\ N_2 + \frac{3.5}{18}H_2O$$

$$\longrightarrow y\ CO_2 + 3.76\ x\ N_2 + \frac{3.5}{18}H_2O + p\ H_2O$$

Now p = 3.25 kmol; y = 83.5/12 = 6.958 kmol

x = minimum O_2 supplied = $y + p \cdot (1/2) - 1/8$

= 6.958 + 3.25/2 – 1/8 = 8.458 kmol

Step (III) Combustion Products

$N_2 = 3.76x = 3.76\ (8.458) = 31.802$ kmol

H_2O = (3.5/18) + 3.25 = 3.444 kmol

$CO_2 = y$ = 6.958 kmol

Step (IV) Mass of Flue Gas

Basis: 100 kg coal

Flue gas produced:

N_2 = 31.802 kmol	= 31.802 (28)	= 890.456 kg
H_2O = 3.444 kmol	= 3.444 (18)	= 61.992 kg
CO_2 = 6.958 kmol	= 6.958 (44)	= 306.152 kg
		Total = 1258.600 kg

Step (V) Percentage of Mass of Flue Gas Composition

N_2 = (890.456/1258.6) (100) = 70.75%

H_2O = (61.992/1258.6) (100) = 4.925%

CO_2 = (306.152/1258.6) (100) = 24.325%

Step (VI) Means Sp. Heat of Flue Gas

$$M\ C_P = M_{CO_2}\,[C_p]_{CO_2} + M_{N_2}\,[C_p]_{N_2} + M_{H_2O}\,[C_p]_{H_2O}$$

or 1258.6 (C_P) = 306.152 (0.241) + 890.456 (0.241) + 61.992 (0.469)

$\therefore\ C_P$ = 0.2522 kcal/kg°C

Ans.

Step (VII) Combustion Temperature

Calorific Value of fuel =

[mass of combustion products] × [average sp. heat] × [combustion temperature Θ_c)]

$\therefore\ \Theta_c$ = 7550/[(1258.6/100) (0.2522)] = 2378°C

Ans.

cf. Combustion Products

= 1258.6/100 kg/kg of coal

Calorific value

= 7550 kcal/kg of coal

Step (VIII) Minimum Oxygen and Air Requirement

Minimum O_2 required per kg of coal

= 8.458 (32)/100

= 2.70 kg

Minimum air requirement

= 2.70 (100/23)

= 11.76 kg

Step (IX) Percentage Mass of Flue Gas Composition with 30% Excess Air

Now, stoichiometric air = 11.76 kg

Therefore, 30% excess air

= 11.76 (30)/100

= 3.528 kg

Therefore, total mass of the flue gas per kg of fuel

= M_{CO_2} (= 3.06 kg) + M_{N_2} (= 8.90 kg) + $M_{air\ excess}$ (= 3.528 kg) + M_{H_2O} (= 0.62 kg) = 16.108 kg

Therefore, percentage mass of

CO_2 = (3.06/16.108)/100 = 18.99%

N_2 = (8.90/16.108)/100 = 55.25%

H_2O = (0.62/16.108)/100 = 3.85%

Air_{excess} = (3.528/16.108)/100 = 21.90%

Step (X) Mean Sp. Heat of Flue Gas with Excess Air

16.108 C_P = 3.06 (0.241) + 8.90 (0.241) + 3.528 (0.241) + 0.62 (0.469) = 4.0233

$\therefore\ C_p$ = 4.0233/16.108 = 0.2497 kcal/kg. °C.

Ans.

Step (XI) Theoretical Combustion Temperature with Excess Air

Θ_c = 7550/[(16.108) (0.2497)] = 1877°C

Ans.

Problem 10.31 A fuel oil consists of 84.5% carbon, 12.5% hydrogen, 2.5% oxygen and 0.5% residual matter by mass.

Working from first principles, determine the minimum theoretical air required for complete combustion of 1 kg of this fuel oil.

Also estimate

(a) the higher calorific value

(b) the lower calorific value of this oil

Given 1. Specific enthalpy of water vapour formed by combustion = 2445 kJ/kg at 25°C

2. $C + O_2 \longrightarrow CO_2$ + 33.8 MJ/kg of C referred to 25°C

3. $H_2 + O_2 \longrightarrow H_2O + 144$ MJ/kg of H referred to 25°C.

Solution

Step (I) Combustion of Carbon

$C + O_2 \longrightarrow CO_2$

$12 + 32 = 44$

$1 + 32/12 = 44/12$

Therefore, 1 kg C requires 32/12 kg O_2 to produce 44/12 kg CO_2

Step (II) Combustion of Hydrogen

$2H_2 + O_2 \longrightarrow 2H_2O$

$4 + 32 = 36$

$1 + 8 = 9$

Therefore, 1 kg H_2 requires 8 kg O_2 to produce 9 kg H_2O.

Step (III) Theoretical Quantity of Air Requirement

F.O. Constituent	Constituent Mass (kg/kg of fuel)	Oxygen Required (kg)
C	0.845	0.845(32/12) = 2.253
H_2	0.125	0.125(8) = 1
O_2	0.025	(–) 0.025
Residual mass	0.005	
	Total O_2 required = 3.228 kg/kg of F.O.	

Therefore, theoretical air requirement

= 3.228/(23/100)

= 14.036 kg/kg of fuel oil

Ans.

(cf. Air contains 23% O_2 by mass)

Step (IV) HCV of Fuel Oil

HCV = (0.845) (33.8) + (0.125) (144) MJ/kg

= 46.561 MJ/kg of F.O.

Ans.

Step (V) LCV of Fuel Oil

LCV = HCV – Sp Enthalpy of water vapour formed by combustion

= 46.561 – (9) (0.125) (2.445)

= 43.810 MJ/kg of F.O.

Ans.

Problem 10.32 A certain coal sample was tasted in a bomb calorimeter to determine its calorific value. The following readings were recorded:

Mass of coal sample = 1.253 g

Mass of water = 2.5 kg

Water equivalent of the apparatus = 765 g

Temperature rise of water = 2.85°C

Temperature correction for cooling = (+) 0.018°C

Estimate the calorific value of the coal sample.

Take the specific heat capacity of water

= 4.187 kJ/kg°K

Solution

The calorific value of coal can be determined by energy balance.

Energy liberated by coal sample = Energy gained by water and the apparatus

or $1.253 \times 10^{-3} \times [CV]_{coal}$

$= (2.5 + 0.765)\ (2.85 + 0.018)\ (4.187)$

$$\therefore\ [CV]_{coal} = \frac{39.207}{1.253 \times 10^{-3}}$$

= 31290.62 kJ/kg

Ans.

Q. *Is this heating value available when coal is fired in a boiler?*

Ans. No.

Q. *Why?*

Ans. Water gives up its enthalpy in condensing in the bomb but not in the boiler. Moreover, the explosion in the bomb is a constant volume process whereas the combustion of coal in a boiler furnace is a constant pressure process.

Problem 10.33 During the determination of calorific value of a fuel gas by using a gas calorimeter, the following results were recorded:

Water collected = 0.8 kg

Inlet temperature = 20°C

Outlet temperature = 38°C

Gas consumed = 0.0035 m^3

Gas pressure = 95 mm of H_2O column absolute

Gas temperature = 25°C

Barometric pressure = 780 mm Hg

Estimate the calorific value of gas in kJ/Nm^3.

Normal m^3 is measured at 0°C and 760 mm Hg

$[C_p]_{H_2O}$ = 4.187 kJ/kg°K

Solution

Step (I) Energy Liberated

The amount of energy released by 1 m^3 of the fuel gas under test condition

= 0.8 (4.187) (38 – 20)/0.0035 = 17226.5 kJ

Step (II) Gas Pressure

Gas pressure = 780 + 95/13.6 = 786.985 mm Hg

Step (III) Gas volume in Normal State

Applying the formula $\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2}$, we get

$$V_N = \frac{786.985}{760}\left(\frac{273+20}{273+25}\right) = 1.0181 \text{ m}^3$$

Step (IV) Calorific Value

The calorific of the fuel gas = 17226.5/1.0181

= 16919.7 kJ/Nm^3

= 16920 kJ/Nm^3 ***Ans.***

Problem 10.34 A fuel gas having the following composition

H_2—54%; CH_4—25%; CO—9.5%; C_3H_6—3.5%; CO_2—3%; N_2—4.5% and O_2—0.5%

is burned in a boiler whereupon a flue gas of following composition is produced.

CO_2—8.5%; O_2—7%; N_2—84.5%

This gas heats up air from 290 K to 650 K in the air preheater and leaves it at 480 K.

Determine the temperature at which the flue gas enters the air preheater.

Take specific heats of air, dry flue gas and water vapour equal to 1.005, 1.048, 2.029 kJ/kg K respectively.

Solution

Step (I) Carbon Content in Fuel Gas

Basis: 100 kmol of fuel gas

Constituent	Mass of Constituent	Carbon Content
CH_4	25 kmol	25 kmol
CO	9.5 kmol	9.5 kmol
C_3H_6	3.5 kmol	3(3.5) = 10.5 kmol
CO_2	3 kmol	3 kmol
		Σ = 48 kmol

Step (II) Composition of Dry Flue Gas

Basis: 100 kmol of fuel gas

The amount of dry flue gas produced upon combustion of 100 kmol of fuel gas

= 48 (100/8.5)

= 564.70 kmol

(cf.: 100 kmol of flue gas contains 8.5 kmol C as CO_2)

Dry Flue Gas Composition	Mass (kg)	
CO_2	(8.5/100) (564.70)(44)	= 2111.978
O_2	(7/100)(564.70)(32)	= 1264.928
N_2	(84.5/100)(564.70)(28)	= 13360.802
		Total = 16737.708

Step (III) Hydrogen Content in the Flue Gas

Basis: 100 kmol of fuel gas

Constituent	Mass of Constituent (kmol)	Hydrogen Content (kmol)
CH_4	25	25(4/2) = 50
C_3H_6	3.5	3.5(6/2) = 10.5
H_2	54	54
		Total = 114.5

Step (IV) Mass of Water Vapour Produced

114.5 kmol of H_2 upon combustion will produce

= 114.5 (18) kg water

= 2061 kg water

Step (V) Mass of Air Supplied For Combustion

Now, x kmol AIR + 100 kmol FUEL GAS upon combustion produce 564.70 kmol FLUE GAS

Therefore, by nitrogen balance,

(79/100) x + 4.5 = (84.5/100) (564.70)

$\therefore$ x = 598.318 kmol/100 kmol of flue gas

Therefore, the mass of air used for combustion

= 598.318 (28.9) = 17291.39 kg $\approx$ 17291 kg

[cf. Mol. Wt. of Air = 28.9]

Step (VI) Flue Gas Temperature Inlet to Air Preheater

By energy balance,

Heat lost by dry flue gas plus water vapour = Heat gained by the air in the air preheater

or [16737.708 (1.048) + 2061 (2.029)] (T – 480)

= 17291 (1.005) (650 – 290)

$\therefore$ T – 480 = 287.98

$\therefore$ T = 767.98 K

$\approx$ 768 K

Ans.

Problem 10.35 Steam is generated in a waste-heat boiler at pressure 1.17 MPa by the flue gas obtained from the combustion of producer gas N_2—60%; CO—26%; CO_2—5%; H_2—9% in a rotary furnace.

The flue gases enter the waste-heat boiler at a temperature 925 K and leave it at 500 K.

Calculate

(a) the mass of flue gas produced per m^3 of producer gas burned

(b) the mass of water evaporated in the waste heat boiler per m^3 of producer gas burned

(c) the percentage of heat recovered in the WHB

Given Boiler efficiency = 74%

Feed water temperature inlet to WHB = 350 K

Excess air used for combustion = 25%

Take C_p of flue gas = 1.05 kJ/kg K

Enthalpy of steam at 1.17 MPa = 2781 kJ/kg

Calorific value of CO = 12.7 MJ/m^3

Calorific value of H_2 = 10.78 MJ/m^3

Solution

Step (I) Stoichiometric Air

Basis: 100 kmol of producer gas

$$2\ CO + O_2 \longrightarrow 2CO_2$$

2 kmol CO require 1 kmol of O_2 for complete combustion

$\therefore$ 26 kmol CO require 26/2 i.e. 13 kmol O_2 for complete combustion.

$$2H_2 + O_2 \longrightarrow 2H_2O$$

2 kmol of H_2 require 1 kmol of O_2 for complete combustion

9 kmol of H_2 require 9/2 i.e. 4.5 kmol of O_2 for complete combustion

Therefore, O_2 requirement for complete combustion = 13 + 4.5 = 17.5 kmol/100 kmol of producer gas

Therefore, stoichiometric air requirement

= (13 + 4.5) (100/21)

= 83.333 kmol/100 kmol of producer gas

Step (II) Air Supplied

Actual air supplied = 25% excess of stoichiometric air

= (125/100)/(83.333)

= 104.166 kmol/100 kmol of producer gas

This supplied air contains

O_2 : 104.166 (21/100) = 21.875 kmol

N_2 : 104.166 – 21.875 = 82.291 kmol

Step (III) Flue Gas

The flue gas produced contains:

CO_2: 26 kmol (from combustion of CO) + 5 kmol (free CO_2) = 31 kmol = 31 × 44 = 1364 kg

H_2O : 9 kmol (from the combustion of H_2)

= 9(18) = 162 kg

O_2: 21.875 kmol (as supplied) – 17.5 kmol (used in combustion)

= 4.375 kmol = 4.375 (32) = 140 kg

N_2: 82.291 kmol (as supplied) + 60 kmol (from the Producer Gas

= 142.291 kmol = 142.291 (28) = 3984.148 kg

Therefore, the total mass of the flue gas produced

= 1364 + 162 + 140 + 3984.148

= 5650.148 kg per 100 kmol of producer gas burned

Step (IV) Flue Gas per m^3 of Producer Gas Burned

1 kmol of PROD. GAS occupies 22.4 m^3 at NTP

∴ 100 kmol of PROD. GAS occupy 2240 m^3 at NTP

∴ 5650. 148 kg flue gas is produced due to combustion of 100 kmol. i.e. 2240 Nm^3 of producer gas

Therefore, 5650.148/2240 = 2.522 kg flue gas is produced per Nm^3 of producer gas burned

Ans.

Step (V) Per cent Heat Recovered in the WHB

Heat lost by flue gas in WHB

= 2.522 (1.05) (925 – 500) kJ/m^3 of PROD. GAS.

= 1125.442 kJ/m^3 of PROD.GAS.

Boiler Efficiency

$$= \frac{\text{Actual heat used to raise steam in WHB}}{\text{Total heat lost by flue gas in WHB}}$$

Therefore, actual heat utilized to generate steam

= 0.74 (1125.442) = 832.827 kJ/m^3 of producer gas

Heat released by 1 m^3 of producer gas upon combustion

= 0.26 (12.7) + 0.09 (10.78) MJ

= 4.272 MJ = 4272 kJ

Therefore, % heat recovered in WHB

= (832.827/4272) (100) = 19.49%

Ans.

Step (VI) Mass of Water Evaporated

Heat transferred to BFW = 832.827 kJ/m^3 of producer gas

Enthalpy of water = 2781 – 4.187 (350 – 273)

= 2458.60 kJ/kg

(cf. $[C_p]_{H_2O}$ = 4.187 kJ/kg K)

Mass of water evaporated = 832.827/2458.60

= 0.338 kg/m^3 of producer gas burned

Ans.

Problem 10.36 N-hexane vapour and dry air in stoichiometric ratio at pressure 2.5 kgf/cm^2 abs. and temperature 127°C are ignited in a closed vessel and after complete combustion, the products are cooled until condensation ensues.

Determine:

(a) the volume per kg of the mixture before combustion

(b) the pressure and temperature of water vapour produced
(c) the pressure of the products when condensation just begins

Air contains 23% O_2 by mass and 21% by volume.

Solution:

Step (I) Molar Ratio of N_2 and O_2 in Air

Air N_2 = 79% by volume i.e. 79% by mol;

O_2 = 21 % by volume i.e. 21% by mol

Therefore, the molar ratio of N_2 : O_2 in air = 79/21 = 3.76

Step (II) Combustion of n-Hexane

The stoichiometric equation for chemical combustion of n-hexane can be represented as:

$$C_6H_{14} + 9\frac{1}{2}O_2 + 9\frac{1}{2}(3.76)N_2 \longrightarrow 6\,CO_2 + 7H_2O + 9\frac{1}{2}(3.76)N_2$$

Total kmol in the reaction mixture

$$= 1 + 9\frac{1}{2} + 9\frac{1}{2}(3.76) = 46.22$$

Step (III) Partial Pressure of the Reactants

Now, partial pressure = [mol fraction] × [total pressure]

i.e. $p = xP$

Here, P = 2.5 kgf/cm^2 abs.

Component	Mol Fraction	Partial Pressure
C_6H_{14}	1/46.22	(1/46.22)2.5 = 0.0541 kgf/cm^2 abs.
O_2	9.5/46.22	(9.5/46.22) (2.5) = 0.5138 kgf/cm^2 abs.
N_2	9.5(3.76)/46.22	9.5(3.76/46.22) 2.5 = 1.932 kgf/cm^2 abs.

Step (III) Specific Volume of the Reaction Mixture

Applying the universal gas law equation we get,

$PV = mRT = m \cdot (R_m/M)T$

where R_m = Molar gas constant

= 848 kgf/(kmol K)

$m = (PV)\,M/(R_m\,T)$; M = molecular weight

Constituent	Partial Pressure (kgf/cm^2 abs.)	Volume (m^3)	Mol. wt.	Mass (kg)
C_6H_{14}	0.0432	1	86	$\frac{(0.0541\times10^4)(1)(86)}{848(127+273)}$ = 0.1371
O_2	0.5138	1	32	$\frac{(0.5138\times10^4)(1)(32)}{848(127+273)}$ = 0.4847
N_2	1.932	1	28	$\frac{(1.932\times10^4)(1)(28)}{848(127+273)}$ = 1.5948
				Σ = 2.2166

Therefore, the total mass of the reaction mixture

= 2.2166 kg/m^3.

Sp. volume of the mixture

= 1/2.2166

= 0.4511 m^3/kg

Ans.

Step (V) Mass of Combustion Products and Steam

Total mass of the combustion products, as obtained from the stoichiometric equation, is

$$= 6(44) + 7(18) + 9\frac{1}{2}(3.76)(28) = 1390.16$$

CO_2 H_2O N_2 kg/kmol

Mass of steam (water vapour) produced

= 7(18)

= 126 kg.

Therefore, the mass of the water vapour per m^3 in the closed vessel

= (126/1390.16) (2.2166) = 0.2009 kg/m^3

Step (VI) Specific Volume of Steam

Sp. volume of steam = 1/0.2009 = 4.977 m^3/kg

From steam table:

Pressure (satd.) (kgf/cm^3 abs.)	Saturation Temp. (°C)	Sp. Volume (m^3/kg)
0.34	71.6	4.74
0.32	70.2	5.01
Difference = (+) 0.02	Difference = (+) 1.4	Difference = (–) 0.27
Sp. Volume Diff.	Saturation Temp. Diff.	Press. (satd) Diff
– 0.27 m^3/kg	(+) 1.4°C	(+) 0.02 kgf/cm^2 abs.
– 0.033	(+) (1.4) (0.033/0.27) = (+) 0.171°C	(+) 0.02 (0.33/0.27) = (+) 0.0024 kgf/cm^2 abs.
	Steam Pressure	Saturation Temp.
Therefore, for sp. volume of steam 4.977 m^3/kg.	0.32 + 0.0024 = 0.3224 kgf/cm^2 abs.	70.2 + 0.171 = 70.37°C

Ans.

Step (VII) Pressure of the Products

Let P be the total pressure of the products mixture when condensation just starts.

Applying partial-pressure equation

$$p_{steam} = x_{steam}\, P$$

$$\text{or } 0.3224 = \frac{7}{6+7+9\frac{1}{2}(3.76)}\ (P);$$

$$\therefore\ P = 2.244 \text{ kgf/cm}^2 \text{ abs.}$$

Ans.

Problem 10.37 Coal burnt in a stoker furnace contains 85% C, 5% H and rest non-combustibles. The ash collected during the trial runs of the boilers contains ash + unburnt fuel 13% of the supplied fuel and they contain 20% unburnt fuel.

The analysis of dry flue gas:

CO_2 —15%; CO—2.5% by volume

Determine

(a) the mass of excess O_2 and air supplied to the furnace per ton of coal burnt

(b) the furnace efficiency

Given

1. Higher Calorific Value of coal = 7700 kcal/kg
2. $C + O_2 \longrightarrow CO_2$ + 8051 kcal/kg of C burnt
3. $CO + O_2 \longrightarrow CO_2$ + 2371 kcal/kg of CO burnt
4. Air contains O_2 23% by mass & 21% by volume.

Solution

Step (I) Useful Carbon in the Fuel

Ash + Unburnt fuel = 13% of total fuel burnt

Carbon content left unburnt

= 0.13(0.2)

= 0.026 kg/kg of fuel burnt

Therefore, useful carbon per kg of coal fired

= 0.85 – 0.026

= 0.824 kg

Step (II) Air Supplied

Let x kmol of air be supplied per kg of coal burnt.

Therefore, the combustion equation becomes,

$$\frac{0.824}{12}C + \frac{0.05}{2}H_2 + 0.21\ x\ O_2 + 0.79\ x\ N_2 \longrightarrow y\ CO_2 + z\ CO + 0.025\ H_2O + p\ O_2 + 0.79\ x\ N_2$$

Since combustion is not complete, the flue gas contains some amount of CO as well as free O_2 due to excess air supply.

By carbon balance: $y + z = 0.824/12 = 0.0686$ (I)

The percentage of CO_2 and CO in the flue gas being 15% and 2.5%, $y/z = 15/2.5 = 6$, $y = 6z$ (II)

By O_2 balance: $0.21x = y + z/2 + 0.025/2 + p$ (III)

CO_2 in the dry flue gas:

$0.15 = y/[y + z + p + 0.79x]$ (IV)

From equations (I) and (II) we get,

$6z + z = 0.0686$

$\therefore z = 0.0098$ kmol

From equation (I) $y = 0.0686 - 0.0098$

$= 0.0588$ kmol

Substituting these values in equation (III), we get,

$0.21\ x - 0.0588 - 0.0098/2 - 0.025/2 = p$

or

$0.21\ x - 0.0762 = p$ (V)

Substituting the known values in equation (IV) we get,

$0.15 = 0.0588/[0.0588 + 0.0098 + 0.21x - 0.0762 + 0.79x]$

$= 0.0588/[x - 0.0076]$

or

$x = [0.0588/0.15] + 0.0076 = 0.3996$

$p = 0.21\ (0.3996) - 0.0762 = 0.007716$ kmol

Therefore, excess O_2 in the flue gas per kg of coal

$= 0.007716(32) = 0.2469$ kg

Therefore, O_2 supplied

$= 0.21\ (0.3996)$ kmol/kg of coal

$= 0.21\ (0.3996)\ (32)$ kg/kg of coal

$= 2.6853$ kg/kg of coal

Ans.

Therefore, air supplied

$= 2.6853(100/23)$

$= 11.675$ kg/kg of coal

Ans.

Step (III) Heat Lost

Now, heat lost per kg of coal = heat lost due to incomplete combustion of C + heat lost due to unburnt fuel

Basis: 1 kg coal

Constituent of Flue Gas	Mass of Carbon
CO	$z = 0.0098$ kmol $= 0.0098(12) = 0.1176$ kg
CO_2	$0.824 - 0.1176 = 0.7064$ kg

Therefore from heat balance equation, heat lost/kg of coal

$= 0.1176\ (8051 - 2371) + 0.026(8051)$

$= 877.294$ kcal,

Step (IV) Furnace Efficiency

$\eta_{fur} = (7700 - 877.294)/7700 = 0.8860$

i.e. 88.6%

Ans.

11

COAL PULVERIZATION

Q. *What are the advantages of pulverized coal firing systems?*

Ans. 1. Pulverization brings about a large increase in surface area per unit mass of solid fuel. Since combustion is a surface reaction, greater the extent of coal surface available, higher will be the rate of combustion. Herein lies the success of pulverized coal fired systems.
2. Less excess air is required for complete combustion because of greater surface area of fuel exposed
3. Higher combustion air temperatures ensure higher cycle efficiency
4. A good range of coal right from anthracite to peat can be successfully burnt
5. Better combustion control enables the system to respond quickly to extensive load variation
6. Better response to instrument control on auto
7. Large amount of heat release makes it very suitable for super thermal power stations where the rate of steam generation is as high as 2000 t/h.
8. Slagging and clinkering problems are low
9. Carry over of unburnt fuel to ash is practically nil
10. Ash handling problem low
11. Can operate successfully in combination with gas and oil fired systems
12. Cold start-up of boilers is very rapid and efficient
13. Less furnace volume is required
14. Low banking loss

Q. *How is the process of coal pulverization carried out?*

Ans. It is a two stage process

I. Stage: raw and lump coal is crushed to a particle size not more than 15-25 mm in the crusher

II Stage: crushed coal is delivered into raw coal bunkers and from here it is transferred to grinding mills that grind the feed into the final particles of 200-300 mesh size. During grinding hot air is blown through the fuel to dry it to impart good fluidity of the coal dust.

Q. *What is a pulverization system?*

Ans. It is a family of equipment in which coal is ground, dried and fed to the burners of a boiler furnace.

Q. *How is a pulverization system classified?*

Ans. This classification is based on the method of delivery of pulverized fuel (coal) to boiler furnaces and accordingly pulverization systems are of two types—central and individual.

Q. *What is a central system?*

Ans. In this system coal is pulverized on a centralized basis, the pulverized fuel is stored in a central bin wherefrom it is distributed through pipelines between the boilers. (Fig. 11.1).

Q. *What is an individual system?*

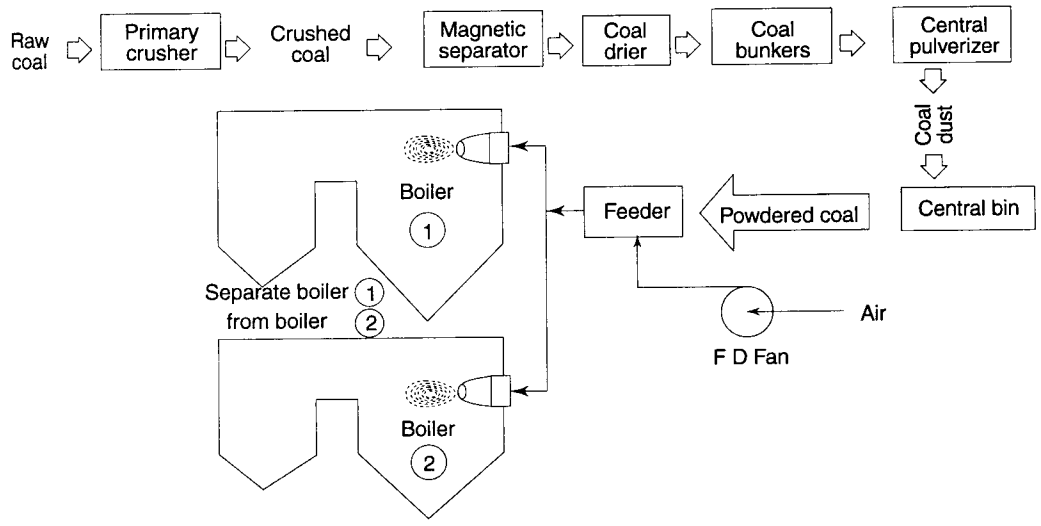


Fig. 11.1 *Schematic flow diagram of central pulverization system.*

Ans. In this case each boiler is provided with its own pulverizing unit while certain provisions are made to transfer the pulverized coal to neighbouring boilers to increase the reliability of the fuel supply. (Fig. 11.2).

Q. *What are the advantages of a central system over an individual system?*

Ans. 1. Greater flexibility and better response to abrupt load variation
2. Less power consumption per ton of coal pulverized
3. Operation of burners is independent of coal preparation
4. Pulverizer can be taken shutdown when there is enough reserve of pulverized coal
5. F.D. fan handles only air and so there is no erosion problem of fan blades
6. Affords better control over fineness of coal
7. Less manpower input
8. More efficient economically, especially when moist brown coal is pulverized.

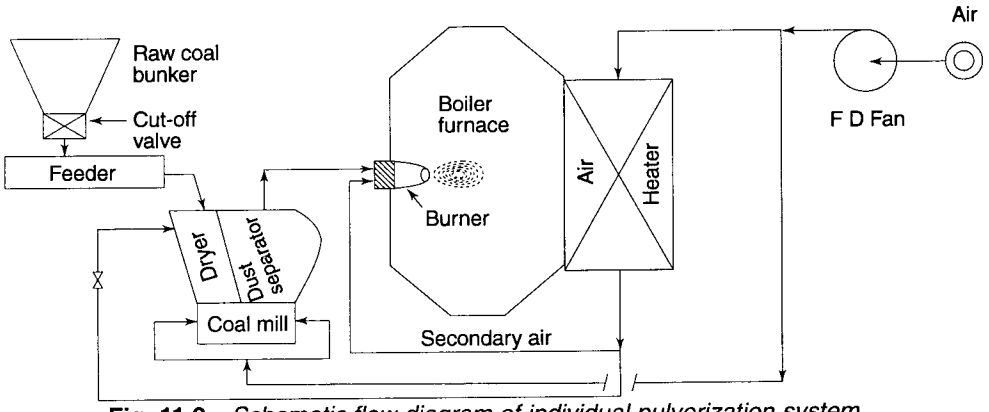


Fig. 11.2 *Schematic flow diagram of individual pulverization system.*

Q. *What are the disadvantages of a central system as compared to an individual system?*

Ans. 1. More expensive. Higher in first cost
2. Occupies more floor space
3. Higher power consumption of the auxiliaries. Hence overall power consumption per ton of coal handled is higher than the individual system
4. Greater possibility of fire hazard due to storage of large amount of powdered coal
5. More intricate in operation and coal transportation becomes more complex
6. Operation and maintenance cost is higher
7. Dryer is essential
8. Operation is less reliable.

Q. *What are the advantages of an individual system over a central system?*

Ans. 1. Simpler in lay-out, design and operation
2. More economical
3. More reliable
4. Allows direct combustion control from the pulverizer
5. No drying unit is required
6. Affords better control of fuel feed
7. Lower maintenance charge.

Q. *What are the disadvantages of an individual system with respect to a central system?*

Ans. 1. Lesser degree of flexibility
2. Poor performance of pulverizing unit at part load
3. If one pulverizing unit goes out of order, its corresponding boiler unit has to be shutdown
4. Greater erosion of F.D. fan blades as these handle both air and abrasive coal particles.

Q. *How many types of individual pulverization system are there?*

Ans. Two types: closed system and open system.

Q. *How is this subdivision made?*

Ans. This is made on the basis of how the drying agent is utilized upon fuel drying.

In the closed system, the drying agent is directed into the boiler furnace together with the dried pulverized coal.

In the open system, it is used as dust carrier. Hot air is carefully cleaned from coal fines and ejected into the stack bypassing the boiler furnace.

Q. *Describe the individual pulverization system with closed fuel drying and direct dust blowing into the furnace.*

Ans. From the coal bunker, crushed coal is delivered to the grinding mill via the coal feeder. At the same time hot air (523-673 K), called primary air, is also directed into the mill to dry up the fuel and transfer it to the burners.

Coarse fractions of the pulverized coal are separated out in the dust separator, after which the fuel and air (which has picked up moisture from the fuel) mixture (353-400K) is supplied through pulverized fuel pipelines into the furnace burners to which secondary air is separately charged.

Q. *What factor(s) determines the quantity of primary air to be used for drying and transportation of pulverized coal?*

Ans. Fuel quality, particularly the moisture content.

Q. *What fraction of total combustion air is the primary air?*

Ans. It varies from 30 to 50% of the total consumption of air for combustion.

Q. *How does primary air vary with the moisture content of solid fuel?*

Ans. Greater the moisture content of the solid fuel, greater is the amount of primary air required for drying.

Q. *What is done in the case of extremely moist fuel?*

Ans. In this case, the primary air is blended with a part of the furnace gases to effect efficient drying.

Q. *Why is primary air blended with a part of the furnace gases?*

Ans. Hot primary air alone becomes economically inefficient to bring down the moisture content of extremely moist pulverized coal to the level required for efficient combustion. As the greater portion of pulverized coal enters the combustion zone at reduced temperature, the fuel combustion becomes unstable.

Q. *If the pulverization system is to become part and parcel of a boiler, what conditions should be fulfilled to ensure reliable operation?*

Ans. 1. Number of grinding mills installed should be at least three
2. The number of mills in operation minus one mill must ensure at least 90% of the rated load of the boiler.

Q. *How is the productivity of a grinding mill related to the fuel consumption of the boiler?*

Ans. It is given by the relationship

$$G_M \geq 0.9\ B_F/(N-1)$$

where G_M = productivity of the grinding mill

B_F = fuel consumption of the boiler

N = number of installed mills attached to the boiler.

Q. *The pulverized coal particles experience a resistance, i.e. suffer pressure drop during their journey from the mill to the burners. How is this problem overcome?*

Ans. By the head developed by the F.D. fan that ensures operation under a slightly excessive pressure.

Q. *What is the pressure upstream of the mill?*

Ans. 1 to 2.5 kPa.

Q. *But this would mean a hazard to safety and dust pollution. How can this problem be tackled?*

Ans. The only solution is to keep the equipment perfectly air-tight.

Q. *What are the discrete advantages of this direct blowing system?*

Ans. 1. Simple in operation
2. Pulverizing unit is compact
3. Consumption of electricity per unit ton of coal dust transportation is low
4. Fuel supply can easily be automatically controlled.

Q. *How does the pulverization system with closed fuel drying and intermediate dust bunkers differ from the closed fuel drying and direct dust blowing system?*

Ans. The characteristic distinguishing feature is that in the former case the prepared pulverized coal is separated from the carrier air in a cyclone.

The coal dust is then led to an intermediate bunker from where it is fed to pulverized coal pipelines by a special feeder. (Fig. 11.3).

Now the moistened air (80-100°C i.e., 353-373 K) at the cyclone exit carries 10-15% of the finest coal particles. Since this can not be discharged through the stack, it is blown by a mill ventilator into the primary air duct and gets distributed among the pulverized coal pipelines.

Q. *What is the discrete advantage of an intermediate dust bunker system over the direct dust blowing system?*

Ans. The primary advantage is that there is no need to match the mill productivity with the boiler productivity.

Q. *Why?*

Ans. It is due to the provision of an intermediate pulverized fuel bunker. Each mill, as such, can operate at optimal load.

Q. *What modifications are done in the case of less active coals with low yield of volatiles when the intermediate dust bunker system is in line?*

Ans. In this case the temperature of the pulverized coal-air mixture is raised to facilitate the ignition of coal dust by feeding 1/4 th to 1/5 th of the primary air into the air duct and then into the pulverized coal pipelines by an auxiliary hot blast

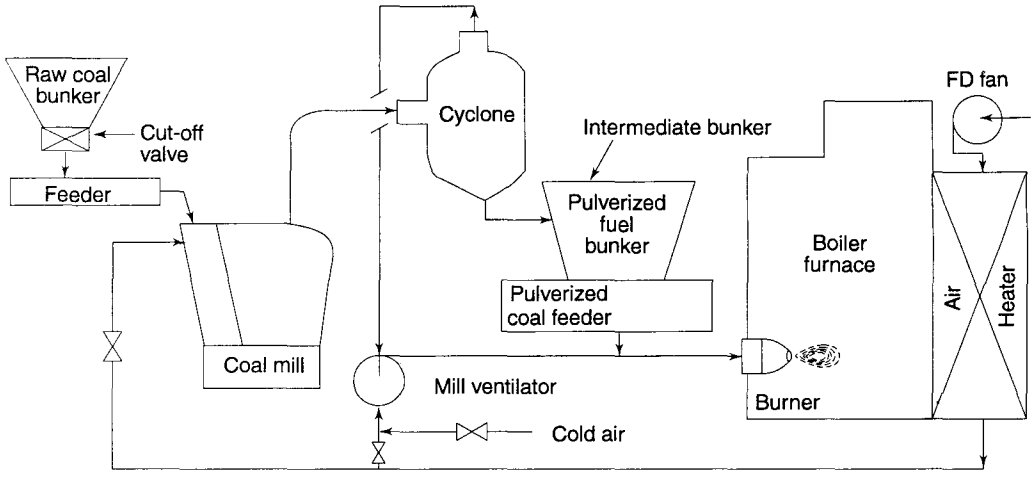


Fig. 11.3 *Pulverization system with closed fuel drying and intermediate dust bunker.*

fan, over and above 15–25% of the primary air directed into the pulverization system as usual.

Q. *Is this air sufficient for complete fuel combustion?*

Ans. No.

Q. *How is this corrected?*

Ans. Moistened primary air carrying out 10-15% coal fines from the cyclone exit is fed into the combustion zone through an annular channel around the main burners or through special discharge burners. (Fig. 11.4).

Q. *What are the disadvantages of an intermediate bunker system?*

Ans. 1. The equipment is bulky as well as intricate
2. Higher consumption of electric energy in dust transportation because of elevated hydraulic resistance
3. Storage of a large mass of pulverized fuel adds to fire and explosion hazard.

Q. *How can the unit energy consumption for dust transportation be reduced?*

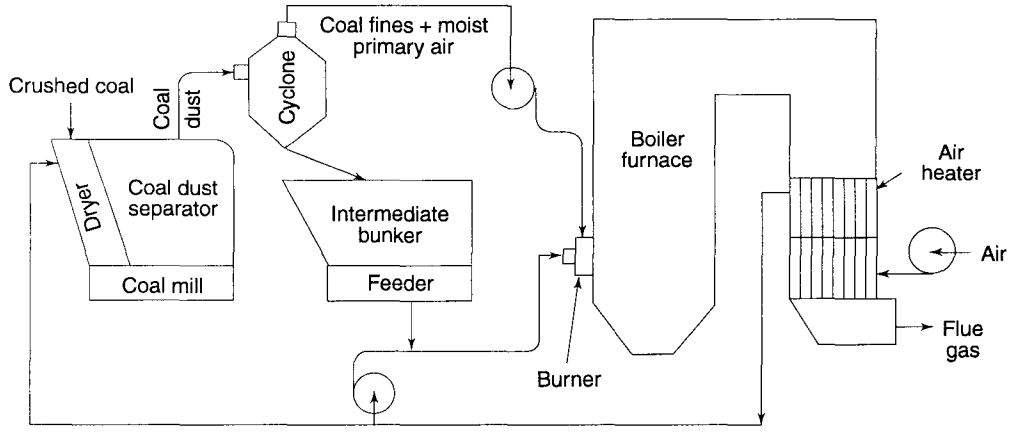


Fig. 11.4

Ans. By using compressed air and a high fuel-air ratio.

In the conventional system, the fuel-air ratio is 0.4-0.6 but by using compressed air, in a recent technique, this ratio has been increased to 30-60 (i.e., 30-60 kg dust per kg of primary air) imparting high fluidity to coal dust which is then conveniently transported through small dia (60-90 mm) pipelines.

Q. *How does the individual pulverization with open drying system operate?*

Ans. This system is adopted for solid fuels with high moisture content. The fuel is dried at elevated temperature by flue gas (400–450C, i.e., 673–723 K) taken off in an amount of 6-10% of the gas volume from the flue gas duct downstream of the economizer.

The coal dust is transported from the pulverizing unit to the cyclone separator with this high temperature drying agent that exits the cyclone with 10% of the finest fuel fines. This moistened gas together with suspended coal fines is then directed to a system of multicyclones (a set of 150-250 small cyclone elements) and an electrostatic precipitator to separate out the flue-gas borne dust. [Fig. 11.5]

The separated dust flows by gravity through chutes into the intermediate pulverized fuel bunker from where it is fed to burners via pulverized fuel pipelines.

The drying agent leaving the dust collector is combined with the flue gas exit of the air heater and discharged into the air after being cleaned in the main electrostatic precipitator of the plant.

Q. *What are the advantages of the open system of fuel drying?*

Ans. 1. Quality of fuel improves because of high temperature drying
2. Efficiency of fuel combustion increases
3. Lower aerodynamic resistance and lower waste gas temperature as the volume of the combustion products is reduced in the flue gas ducts.

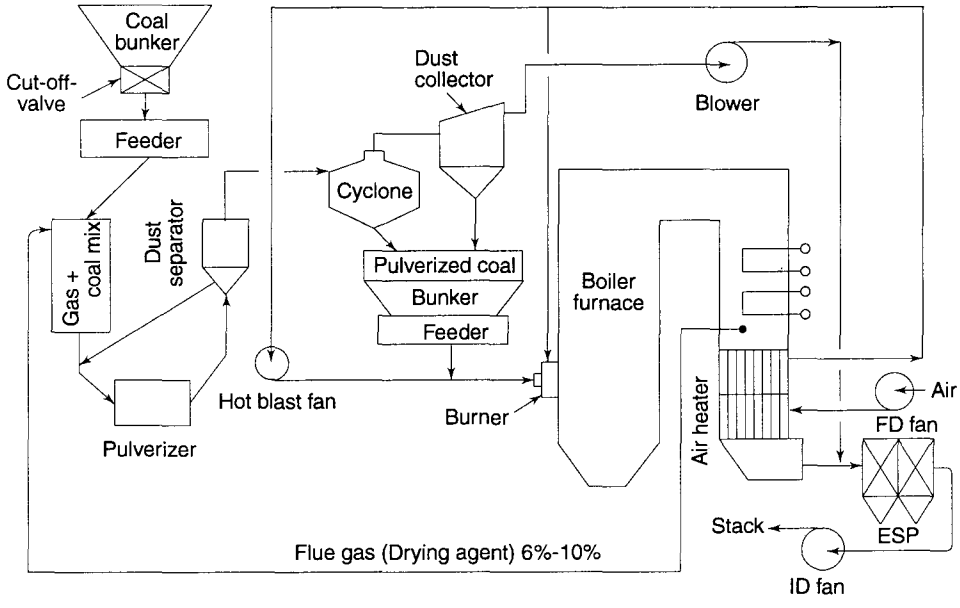


Fig. 11.5 *Individual pulverization with open drying system.*

Q. *What are the drawbacks of the open system of fuel drying?*

Ans. 1. Along with the discharged drying agent some fuel fractions are lost
2. Higher energy consumption to effect separation and purification of moist drying agent
3. With improper operation of the dust collectors or a high moisture content in the drying agent, a substantial amount of coal dust escapes into the atmosphere leading to air pollution.

In spite of good operation 1-2% of the fuel is lost. Hence this system is limited to extremely moist fuel which cannot be otherwise burnt efficiently by conventional methods.

Q. *What determines the quality of pulverized coal?*

Ans. Milling fineness and the relative concentration of individual fractions.

Q. *How are these characteristics determined?*

Ans. By sieve analysis. A sample of pulverized coal is allowed to pass through 4-5 standard sieves with progressively decreasing mesh size which is the clear size of the mesh expressed in micrometers. And the total sieve residue R_x is determined by the total dust residue one particular sieve of mesh size x micrometer and that on all other sieves above it with larger mesh size, expressed as a percentage of the initial sample mass.

Q. *Sometimes finer particles coalesce readily introducing an error in sieve analysis. How can this be avoided?*

Ans. By blowing the finest dust particles in an air classifier to grade it to size, after the screening operation is performed.

Q. *What is integral particle-size distribution curve (or total residue curve)?*

Ans. It is the curve obtained by graphically plotting the result of sieve analysis—the sieve mesh size x (μm) being laid off as the abscissae and the total sieve residue, R_x, as the ordinates. [Fig. 11.6]

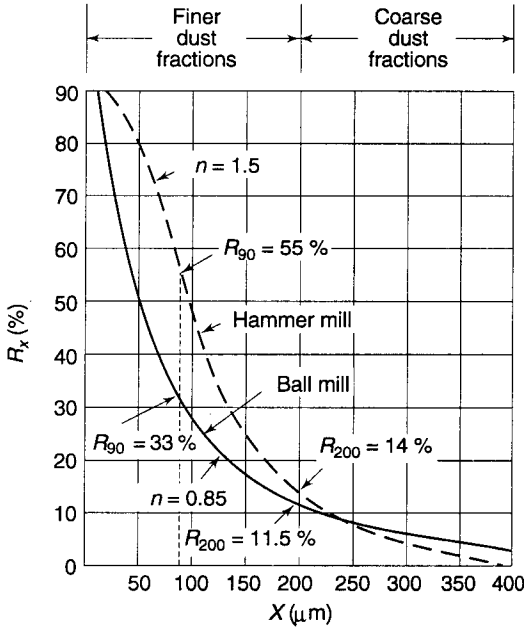


Fig. 11.6 *Integral particle-size distribution curve.*

Q. *What is the nature of the curve?*

Ans. It is an exponential curve described by the equation

$$\ln\left[\frac{R_x}{100}\right] = -bx^n$$

or $$R_x = 100 \exp(-bx^n)$$

where b and n are constants depending on the quality of fuel and grinding technique. (Fig. 11.6).

Q. *What is the importance of the polydispersity coefficient of dust?*

Ans. Its importance lies in its characterization of the structure of dust and its particle size distribution.

Q. *How?*

Ans. Differentiating the above equation with respect to x, the mesh size (μm), we get

$$y = -\frac{dR_x}{dx} = 100\ bnx^{n-1} \exp(-bx^n)$$

$$= R_x\ bnx^{n-1}.$$

Now plotting y (% concentration of dust particles of the size x μm) vs. mesh size x (μm), several curves can be obtained depending on the value of the polydispersity coefficient (n) of the dust. (Fig. 11.7).

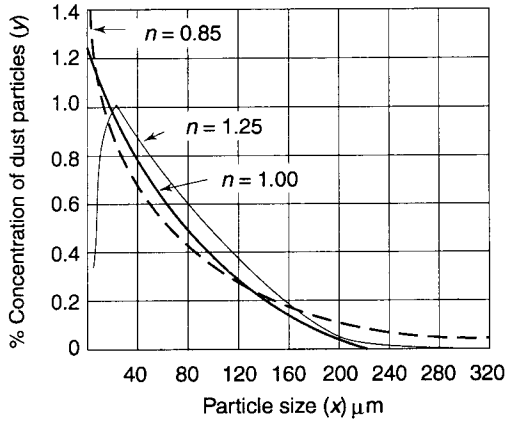


Fig. 11.7

For $n > 1$, the curve shows a maxima in the zone $x = 15 - 25$ μm, thus showing that such a dust sample has a relatively small content of the finest fractions.

For $n \leq 1$, the curves show that the dust samples contain a higher quantity of the finest fractions.

Q. *What is the immediate impact of the concentration of coarse particles in boiler furnaces?*

Ans. Greater the concentration of the coarse particles (> 250 μm) in pulverized coal, greater is the heat loss with unburned carbon.

Q. *How can the energy consumption in pulverization be determined if the surface area of the dust produced is known?*

Ans. This can be computed with the help of Rittinger's equation

$$E_{gr} = E^{\circ}_{gr}\ (A_d - A_c)$$

where E_{gr} = energy of grinding, kWh/kg

E°_{gr} = unit consumption of electric energy in grinding to produce 1 m^2 of ground surface

A_c = initial surface area of 1 kg of crushed coal, m^2/kg

A_d = final surface area of 1 kg of produced dust, m^2/kg

Since $A_d >> A_c$, $E_{gr} \approx E^{\circ}_{gr} A_d$

From this equation it is possible to determine the energy consumption for pulverization from the surface area of dust produced,since the value of E°_{gr} for a wide range of solid fuels is known.

Q. *How is the actual surface area of the dust determined?*

Ans. It is obtained by multiplying the theoretical surface area of the dust produced with the shape factor

$$[A_d]_{\text{actual}} = k_s\ [A_d]_{\text{th}}$$

where k_s = shape factor

The theoretical surface area of dust (m^2/kg) is calculated with the help of the following equation

$$[A_d]_{\text{th}} = \frac{4.5 \times 10^5}{\rho} \frac{1}{n} \left[\ln \frac{100}{R_{90}}\right]^{1/n}$$

where ρ = density of ground fuel, kg/m^3

n = polydispersity coefficient

Q. *What is the value of the shape factor (k_s) for coal?*

Ans. It is usually taken as 1.75.

Q. *What is the density of pulverized coal?*

Ans. It varies from 1700 to 1800 kg/m^3.

Q. *What should be the value of polydispersity coefficient for pulverized fuel?*

Ans. $n > 1$

Q. *Why?*

Ans. In this case, the coal dust will contain a small concentration of very fine fractions and a small concentration of coarse fractions.

Q. *Why is the moisture content (% by weight) of pulverized fuel important?*

Ans. The moisture content of pulverized fuel should be at the recommended level.

Moisture content above this level will entail certain difficulties, such as

(a) lowering of boiler productivity
(b) loss of fluidity
(c) formation of slums in the bukers
(d) clogging of feeders and chutes
(e) reduction in the ease of transport.

Moisture content below the recommended level brings the possibility of

(a) self-ignition at the place of storage
(b) explosion when mixed with air.

Q. *Storage and handling of fuel has always been a major concern to all coal-fired plants. The concerns intensify when the plants switch over to low sulphur coal high in moisture which makes the coal soft and cohesive and gives it poor flow characteristics. What are the effects of such a "switchover"?*

Ans. This results in significant reduction in "live" storage capacity and stagnation of coal in the bunker. Stagnant coal must be dislodged by air cannons, vibrators or beating with sledge hammers manually otherwise stagnant coal may invite spontaneous combustion in the bunker.

Q. *What can be the remedy?*

Ans. The answer to this problem is the use of polymer linings to improve the flow characteristics of coal bunkers.

When 384 MW Riverside station of Northern States Power CO. (NSP) switched over from free-flowing bituminous coal to low -sulphur sub-bituminous coal, the plant's storage bunkers experienced significant stagnation, causing several fires and one explosion. The utility installed a TIVAR 88 polymer lining (13mm thick) down the sloping of the bunker walls of one of its two units. TIVAR 88, claims its manufacturer Poly Hi Solidur, Fort Wayne,Ind., sports a very low coefficient of friction and high resistance to abrasion and corrosion. Installation of the lining improved the "live" storage capacity by 64% over the original design.

Q. *How does the explosion hazard originate with pulverized coal?*

Ans. Coal has the fundamental property of auto-ignition. Greater the degree of surface area of coal particles exposed to air, more rapid is its self-ignition even at a lower temperature. Because of the gaseous products of combustion, a large amount of volume expansion occurs and that's how an explosion is born.

Larger the amount of fine fractions and higher the yield of volatiles, more intensively will the coal dust suspended in air in a closed volume explode.

Q. *What factors primarily contribute to the explosion for a given quality of pulverized coal?*

Ans. 1. Temperature of coal dust-air mixture
2. Coal dust-air ratio.

Q. *What is the most dangerous concentration of coal dust in air?*

Ans. It is within 0.3 to 0.6 kg coal dust/m^3 of air.

Q. *If the coal dust suspended in air in a closed volume undergoes auto-ignition, what parameters will undergo abrupt change?*

Ans. Temperature and pressure.

Q. *What preventive measure is taken?*

Ans. Safety (relief) valves are installed to let out a part of the coal dust-air mixture should the pressure rise abruptly.

Q. *What are the concentration limits of O_2 in the drying agent, below which fuel dust will not explode?*

Dust Sample	O_2 Content
Peat	16%
Oil shales	16%
Brown coals	18%
Coals (other)	19%

Q. *How can the oxygen concentration in the drying air be reduced?*

Ans. By blending hot air with the gaseous products of combustion.

Q. *What is the probability of explosion with the yield of volatiles?*

Ans. Greater the yield of volatiles, greater is the probability of explosion. Lower the yield of volatiles, lower is the probability of explosion.

Q. *What is the safe limit of the yield of volatiles?*

Ans. A fuel having yield of volatiles less than 8% is explosion-safe.

Q. *Why must the temperature of coal-dust and air mixture downstream of the mill be strictly controlled?*

Ans. A high temperature of coal dust-air mixture makes it prone to explosion.

Q. *What should this temperature limit be?*

Ans. 70-80°C (343-353 K) for coal with high volatiles.

120-130°C (393-403 K) for coal with low volatiles.

Q. *What do you mean by the term coefficient of grindability?*

Ans. It is the ratio of unit energy (kWh) consumptions of a standard laboratory mill in grinding a reference solid fuel and the fuel under consideration, provided that both have the same initial particle size and the same ground dust characteristics i.e.

$$k_{gr} = E_r/E$$

Q. *How is the optimal value of grinding in terms of sieve residue R_{90} related to the yield of volatiles?*

Ans. $[R_{90}]^{opt} = 4 + 0.8n\ W_{vol}$

where n = polydispersity coefficient

W_{vol} = yield of volatiles

Q. *How many types of grinding mills are there? What is their principle and speed characteristics?*

Ans.

Grinding Equipment	Grinding Principle	Speed Characteristics
1. Ball-tube mill	Impact, abrasion	Low (15-30 rpm)
2. Roller mill	Crushing	Medium (50-80 rpm)
3. Hammer mill	Impact	High (750-1000 rpm)
4. Paddle-type mill	Impact	High (1400-1500 rpm)
5. Pulverizing fan	Impact	High (750-1450 rpm)

Q. *For grinding which type of fuel, are ball-tube mills preferred?*

Ans. Fuels with relatively low yield of volatiles.

Q. *For grinding which type of fuel, are hammer mills preferred?*

Ans. Fuels like brown coals, peat, oil shales.

Q. *In which cases are pulverizing fans preferred?*

Ans. Soft ($k_{gr} > 1.5$) and very moist brown coals.

Q. *Briefly describe a ball-tube mill.*

Ans. A ball-tube mill (or simply ball mill) consists of a large rotating drum (2-4 m in diameter and 3-10 m in length) partially filled with steel balls (30-60 mm dia). The inside surface of the drum is clad with armour plates and outside surface with heat and sound insulation. The drum is rotated by an electric motor via a speed reduction gear and a large driven wheel attached to the drum.

Crushed fuel and hot air are fed to the drum through the inlet pipe while the pulverized fuel-air mixture is taken out through the exit pipe via the classifier that retains the oversized particles to be ground again.

Dampers located in the exhaust fan inlet, dust control the mill output by varying the flow of air through the mill and hence the rate of fuel removed from the mill.

Q. *What is the energy consumption of a ball mill per ton of coal ground?*

Ans. 20-25 kWh.

Q. *How is the optimal rotational speed of a ball mill determined?*

Ans. It is 0.76 times the critical speed, i.e.

$N_{opt} = 0.76\ N_{cr}$

where N_{cr} = critical rotational speed of the drum in revolutions per second

Q. *What is critical rotational speed?*

Ans. It is the minimum rotational speed at which the balls stick to the drum wall as their weight is counterpoised by the centrifugal force due to rotation.

$$N_{cr} = 0.75\ [D_d]^{-1/2}$$

where D_d = drum diameter

Q. *What is the mechanism of grinding in a ball mill?*

Ans. As the drum rotates, it lifts the balls to a certain height over the wall, imparting to them a potential energy which is expended as the balls detach from the wall and fall. The impact of the falling balls and the abrasion between them grind the solid fuel.

Q. *What are the principal factors upon which grinding capacity depends?*

Ans. Drum length and drum diameter.

Q. *What is the drying capacity of a grinding mill?*

Ans. It is the quantity of fuel that can be dried in the mill from the initial moisture content to the desired value.

Q. *Why it is advisable to run ball mills at full load?*

Ans. Energy consumption of a ball mill due to rotation is virtually independent of the mass of the fuel charged to the drum because of the large mass of the balls and drum. And as a result, as the quantity of charge to the drum decreases, the unit energy consumption for grinding E_{gr} increases.

$$E_{gr} = E_m/B_m \text{ kWh/kg}$$

where E_m = power consumption for mill rotation, kW

B_m = mill productivity, kg/h

That is why it is always economical to run the ball mill at full load.

Q. *What are the advantages of a ball mill?*

Ans. 1. This type of mill can be successfully employed for pulverizing a wide range of solid fuels right from oil shales, pits to anthracite—the hardest variety of coal.
2. Infiltration of metallic objects occasionally present in the coal does not seriously affect the mill operation
3. The operation is simple
4. Low initial cost.

Q. *What are the drawbacks of a ball mill?*

Ans. 1. Wear and tear of the armour plates and balls due to impact and abrasion
2. High operating cost, particularly for harder fuels

Unit energy consumption is up to 35 kWh/t for anthracite.

Q. *How is the wear of the balls compensated?*

Ans. By introducing new balls periodically into the ball mill.

Q. *Briefly describe the operation of a hammer mill.*

Ans. A rotor with discs to which hammers are hinged rotates inside a steel casing clad with an armour plate (25-30 mm thick) inside.

Rotating hammers with a circumferential speed of 50 to 60 m/s strike the fuel lumps and crush

them into smaller pieces which get pulverized by the abrasion in the gap between the hammers and casing.

The primary air fan induces through the pulverizer a flow of air that lifts the coal dust. The airborne fuel dust is subjected to a centrifugal dust separator to throw the oversize particles back into the grinding section while the finely divided fuel particles suspended in primary air are discharged through a centrally located dust-discharging duct.

Q. *For which type of solid fuels, is a hammer mill preferred to a ball mill?*

Ans. For fuels having $k_{gr} \geq 1.1$

Brown coals, oil shales, pits and coals with volatiles 28% belong to this category.

Q. *Why?*

Ans. With such kinds of fuel, the unit consumption of electric energy for grinding, in the case of hammer mill is 8-12 kWh per ton of ground fuel—which is 30-50% less than that required in the case of ball a mill.

Q. *Briefly describe the operation of a roller mill.*

Ans. A roller mill (also called bowl mill) consists of stationary rollers mounted on an electrically driven rotating bowl. Coal fed through the hopper gets pulverized by attrition as it passes between the sides of the rollers and bowl.

Hot primary air introduced into the pulverizer through the bottom of the bowl carries off coal dust into the centrally located classifier fitted at the top. Coarse particles drop back into the bowl through the centre cone of the classifier while the fine coal dust-air mixture is led away to the burner.

Q. *What are the advantages of a roller mill (i.e. bowl mill)?*

Ans. 1. Low unit energy consumption (12-15 kWh/t)
2. Small dimensions
3. Reduced noise level
4. The classifier can be adjusted to alter the degree of coal fineness while the mill is on
5. Since the mill operates at negative pressure, leakage of coal from the mill casing in practically nil.

Q. *What are the disadvantages of a roller mill?*

Ans. 1. Sensitive to metallic objects should they get into the mill along with coal
2. Uneven wear of the grinding parts presents repairing complexities

Q. *In which cases are roller mills preferred?*

Ans. Systems
(a) using direct dust blowing
(b) grinding moderately hard coals with relatively low moisture content and hard fractions

Q. *What are the typical bearing problems that are encountered in bowl mills?*

Ans. 1. Flaking and pitting
2. Rust and corrosion
3. Retainer damage
4. Scratch and scuffing
5. Smearing
6. Brinelling and nicks
7. 'Pear skin' and discoloration
8. Cracking and chipping.

Q. *What is flaking?*

Ans. It refers to the process of metal removal in the form of flakes at the surface layer of the bearing.

Q. *What is pitting?*

Ans. It is the formation of minute holes on the raceway due to rolling fatigue. The hole has a depth of a abraded bottom.

Q. *What are the causes of flaking and pitting?*

Ans. There are three causes

1. Negative internal bearing clearance in operation
2. Misalignment in the mounting of inner or outer ring
3. Formation of scratches, brinelling and nicks of rust on the raceway, caused during installation.

Q. *What is the remedy for flaking?*

Ans. 1. Use bearing rated for larger load
2. Use lubricant of higher viscosity for better film formation.

Q. *What is the remedy for pitting?*

Ans. This can be avoided by
1. protecting bearing from contamination by dirt and foreign matter. This requires careful handling.
2. using lubricant of higher viscosity for better film formation.

Note: Dent and corrosion appear similar to dipping. One should be careful in judging them.

Q. *What is rust that occurs on bearing surfaces?*

Ans. Rust is a film of metallic oxide, hydroxide or carbonate formed on bearing surfaces by chemical reactions.

Q. *What is the nature of corrosion occuring on bearing surfaces?*

Ans. It erodes the bearing surface because of electrochemical attack of the metal by sulphide or chloride ions in acidic or alkaline media.

Q. *Why does rust occur on the bearing?*

Ans. If exposed to humid atmosphere over a prolonged period, bearing surfaces may develop several spots of rust on the raceway at intervals corresponding to the ball or roller pitch.

Q. *Why does corrosion occur on the bearing?*

Ans. It occurs due to sulphide attack or chloride attack i.e. when sulphide or chloride, contained in lubricant additives, is dissolved at high temperature.

It also occurs when there is ingress of water in the bearing.

Q. *How can the problem of rust and corrosion be minimized?*

Ans. These can be averted by
- keeping bearing free from rust during storage
- periodical check of the lube oil.

Q. *How can damage to the retainer be identified?*

Ans. 1. Marks and deformation
2. Cracking and chipping
3. Rust and corrosion
4. Wear.

Q. *What is the probable cause of deformation of the retainer?*

Ans. The retainer is made of an alloy of low hardness. So it can be easily dented or deformed by external force or interference with other parts due to misalignment of bearing and abnormal vibration.

Q. *What remedial actions can be taken to avoid deformation of the retainer?*

Ans. 1.Check the bearing for proper mounting and alignment
2. Check the lube oil system
3. Go for vibration monitoring
4. Consult the bearing manufacturer when such abnormal vibration is noticed.

Q. *What is scratch appearing on the bearing surface?*

Ans. It is a shallow mark produced by sliding contact. It follows the direction of sliding.

Q. *Why does scratch occur?*

Ans. Faulty handling of bearing during mounting and dismounting is responsible for scratches.

Q. *What remedy do you suggest for scratches?*

Ans. 1. Keep the L.O. (lube oil) clean
2. Improvise the technique of mounting and dismounting of the bearing.

Q. *What is scuffing?*

Ans. Smelting of the bearing surface due to high contact pressure.

Q. *What is the basic difference between 'scratch' and 'scuffing?*

Ans. Scratch is not accompanied by any apparent melting of the material whereas scuffing is characterized by a high heat generation effect contributing to local melting of bearing metal.

Q. *Why does scuffing occur?*

Ans. Scuffing on the roller end faces and ribs occurs due to inadequate lubrication, clogging by foreign materials and excessive pre-load or abnormal thrust load.

Q. *How can scuffing be avoided?*

Ans. By

(a) improving the sealing efficiency
(b) proper handling and mounting of bearing
(c) periodic check of whether abnormal load is applied.

Q. *What do you mean by smearing?*

Ans. It is an aggregate of minute welds on the rolling surface.

Q. *What is the cause to the genesis of smearing?*

Ans. It is caused by slipping of the rolling elements on the raceway and thereby breaking the oil-film in the process.

In ball-bearings, the balls spinning and sliding are the probable causes.

In a roller-bearing, it can often occur when a roller is entering or leaving the loaded zone.

Smearing is associated with very high heat generation that is responsible for a cluster of minute welds.

Q. *How can smearing be avoided?*

Ans. 1. Proper design and alignment to avoid sliding movement of rolling elements and raceways
2. Using high-pressure-resistant lubricant.

Q. *What is the difference between brinelling and nicks?*

Ans. Both refer to surface indentation. While brinelling (indentation on raceway) is produced through plastic deformation occuring at the point of contact between the raceway and the rolling elements, nicks, on the other hand, result from rough handling such as hammering.

Q. *What is the cause of brinelling?*

Ans. It is the outcome of

- careless handling during mounting and dismounting
- clogging by solid foreign particles.

Q. *How can brinelling be avoided?*

Ans. 1. Keep the bearing clean
2. Keep the lubricant clean
3. Use improved technique for mounting and dismounting of bearings.

Q. *What do you mean by "pear skin"?*

Ans. It refers to minute brinell marks covering the entire rolling surface.

Q. *Why does it occur?*

Ans. Inadequate lubrication or clogging of lubricant due to infiltration of foreign particles into it are two possible causes.

Q. *What is the remedy for 'pear skin' effect?*

Ans. This can be avoided by

1. keeping the lubricant clean
2. using an adequate lubricant.

Q. *What is discoloration?*

Ans. It is characterized by loss of lusture. The rolling surface looks rough.

Q. *What is the cause of discoloration?*

Ans. It is due to lubricant burning caused by adherance of a coloring substance from aged/deteriorated lubricant.

Q. *What is the remedy for discoloration?*

Ans. 1. Improving the lubricating system.
2. Making running condition of the bearing light.

Q. *What is cracking of the bearing?*

Ans. Cracks or fissures appearing on the bearing surface is called cracking. It leads to bearing failure.

Q. *Why does it occur?*

Ans. It results from
1. hammering on a part of the bearing during mounting or dismounting.
2. excessive internal load because of improper mounting
3. seizure of bearing due to foreign matter
4. excessively tight fitting, or extremely inaccurate shape of shaft or housing.

Q. *What are the preventive measures against cracking?*

Ans. 1. Ensure adequate clearance between the bearing and the shaft of the housing
2. Use clean lube oil
3. Prevent rapid heat build-up

Q. *What is chipping?*

Ans. Loss of metal in the form of chips occuring on a part of the rib or roller-end.

Q. *How does it occur?*

Ans. It occurs due to
1. excessive thrust load or shock load
2. hitting during mounting or dismounting

Q. *How can chipping be avoided?*

Ans. Harness improved technique in mounting or dismounting of bearing.

Q. *What auxiliary equipment would you have with a pulverizer?*

Ans. 1. Dust separator
2. Cyclone
3. Raw coal feeder
4. Dust duct
5. Pulverized coal bunkers.

Q. *Why is a dust separator required?*

Ans. Its sole function is to separate dust into coarse and fine fractions. While the fine fractions are led away by primary air to the burners, the coarse particles are dropped out to the mill for regrinding.

Q. *How is the separation effected?*

Ans. The separation can be effected in three ways using centrifugal, inertial and gravitational forces.

Q. *Briefly describe the operation of a centrifugal separator.*

Ans. It is fitted with two concentric cones. Coal dust-primary air mixture is directed to the bottom inlet of the separator with a flow velocity 15-20 m/s. The dust laden air experiences a volume expansión in the annular space between the cones, its flow velocity reduces to 1/3rd, producing the effect of gravitational separation. Down along the walls of the cone, slide the coarsest coal particles and return to the mill. From the outer cone the coal dust-air mixture enters the inner cone through the inlet vanes which are tilted to impart a swirling motion to the dust-air flow. The coarser particles drop off by, centrifugal effect and dust with necessary fineness is led through the central dust-duct. (Fig. 11.8).

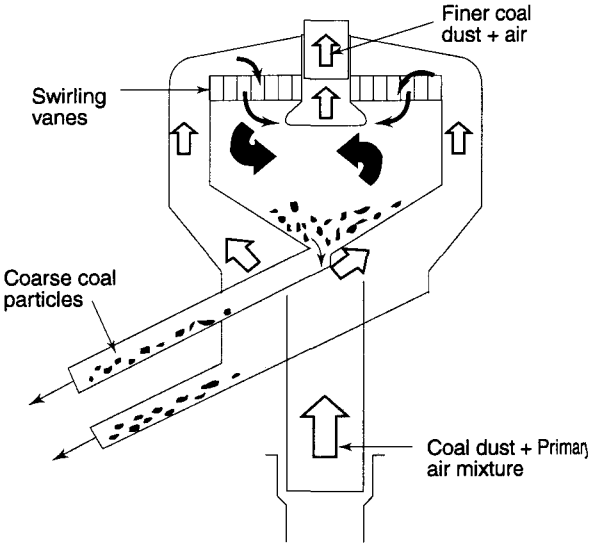


Fig. 11.8 *Dust separator.*

12

PULVERIZED COAL FIRED FURNACES

Q. *By how many methods can coal be burned in boiler furnaces?*

Ans. Three methods:

1. Flame combustion (Fig. 12.1 a)
2. Cyclone combustion (Fig. 12.1 b)
3. Fluidized-bed combustion (Fig. 12.1 c)

Q. *What is the basis of this classification?*

Ans. Aerodynamic characteristic of combustion system that determines the conditions of contact of the burning fuel with an oxidant.

Q. *Which method of burning coal is the most popular in modern power engineering?*

Ans. Flame combustion.

Q. *What is flame combustion?*

Ans. Burning of pulverized coal in a suspended state in the combustion air in the furnace space is called flame combustion.

Q. *How rapid is the combustion?*

Ans. Combustion takes place within a very short period of 1-2 s.

Q. *What is cyclone combustion?*

Ans. A process in which combustion of particles is effected in the presence of intensive turbulent motion of air.

Q. *What is the difference between cyclone combustion and flame combustion?*

Ans. In cyclone combustion, fuel particles are subjected to a great turbulence by the combustion air supplied and they burn off more quickly. Whereas in the case of flame combustion, the fuel particles are so fine that they get easily airborne and as a result combustion takes place in a suspended state in the furnace space.

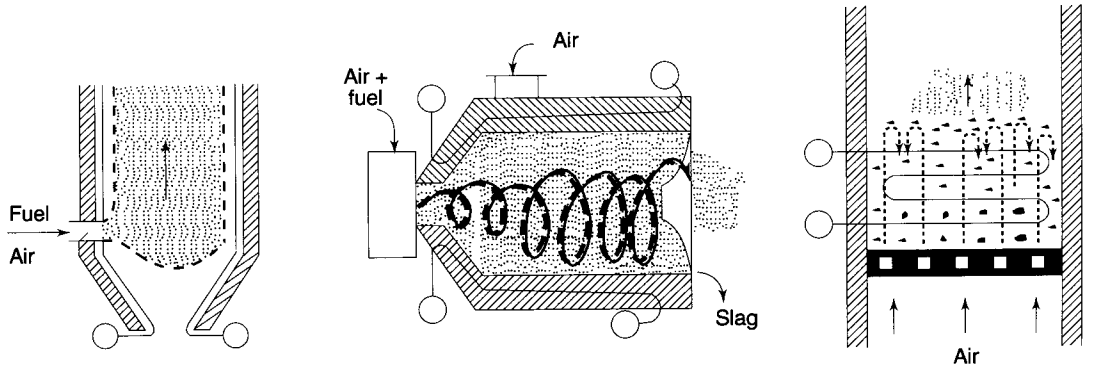


Fig. 12.1 *(a) Flame combustion* *(b) Cyclone combustion* *(c) Fluidized-bed combustion*

Only finely divided coal particles are suitable for flame combustion whereas the cyclone method is good for the combustion of coarse coal dust and even crushed coal.

Q. *Why are cyclone furnaces called slagging type furnaces?*

Ans. Due to cyclone combustion, a high temperature is developed in such furnaces, with the effect that slags produced are in a molten state and liquid slag is discharged off. Hence such furnaces are called slagging type.

Q. *What is fluidized-bed combustion?*

Ans. Solid fuels (coal, bagasse, etc.) reduced to 1-6 mm size can be successfully burnt in a fluidized state over a grate at the bottom of which combustion air is blown through. The velocity of air is so controlled that the fuel particles are lifted off the grate and are reciprocated in the vertical plane. The finer and partially burnt fuel particles are carried off to the upper layer of the fluidized bed, whereupon their flow velocity decreases and they undergo complete combustion.

Q. *What is the thickness of such a bed?*

Ans. It varies. Usually it ranges from 0.5 to 1 m.

Q. *What is the specific characteristic of a fluidized bed?*

Ans. It expands in volume by 1.5-2 times during operation.

Q. *What is the bed temperature?*

Ans. 800–1000°C (1073–1 273 K).

Q. *How are the boiler tubes placed in such a bed?*

Ans. They are placed in the form of in-line or staggered tube bundles arranged in and above the bulk of the fluidized bed.

Q. *What are the advantages of low furnace temperature in the fluidized bed?*

Ans. 1. Overheating is prevented
2. NO_x emission is reduced.
3. Introduction of such solid additions as limestone in the bed to neutralize SO_2 and SO_3 produced during combustion is possible.

Q. *How is a pulverized fuel fed furnace characterized geometrically?*

Ans. Geometrically a furnace can be characterized by its linear dimensions

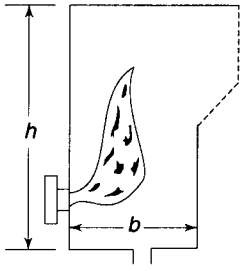


Fig. 12.2(a)

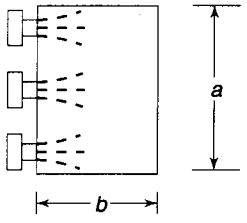


Fig. 12.2(b)

front width a, depth b and height h (Fig. 12.2)

These parameters are determined on the basis of
(a) rated fuel consumption
(b) thermal and physico-chemical properties on fuel.

Q. *What is the cross-sectional area of the furnace normal to the path of the flue gas?*

Ans. $A_f = ab$, m^2

Q. *What is the principal thermal characteristic of a steam boiler furnace?*

Ans. It is the heat power of the furnace measured in kilowatt.

$$Q = B_f H$$

where Q = total heat release rate in the furnace, kW

B_f = rate of fuel consumption, kg/s

H = calorific value of fuel, kJ/kg

Q. *What is the heat release rate per unit cross-sectional area of the furnace?*

Ans. It is the total heat release rate in the furnace divided by the cross-sectional area of the combustion zone, i.e.

$$q = Q/A_f \qquad \text{kW/m}^2$$

Q. *Upon which factors does the q depend?*

Ans. It depends on the

1. kind of fuel
2. type of burners
3. arrangement of burners.

Q. *What is the value of q?*

Ans. The heat release rate per unit cross-sectional area of a furnace (q) ranges from 3500 to 6500 kW/m^2.

Q. *How can a furnace be characterized on the basis of burner arrangement?*

Ans. The furnace can be characterized on the basis of heat release rate per burner-tier if the burners are laid out in a number of tiers whence

$$q_t = Q_t/A_f$$

where Q_t = heat release rate of all burners in a tier, kW

q_t = heat release rate per unit area per tier

Q. *What is the value of q_t?*

Ans. It ranges from 1 200 to 2 400 kW/m^2.

Q. *What will happen if the values of q and q_t are allowed to go beyond their limiting value?*

Ans. It will bring about intensive clinkering of the water-walls, particularly in the burner zone, and rising of the surface temperature of tube metal dangerously.

Q. *What is the value of the depth of a pulverized coal fired furnace?*

Ans. Its value ranges from 6 m to 10.5 m.

Q. *What factors exert an influence on the section of depth of furnace?*

Ans. The depth of the furnace is chosen such that

(a) burners can be arranged properly

(b) free flame-propagation does not bring about contact between flame tongues and waterwalls.

Q. *What is the value of the front-width of pulverized coal fired furnace?*

Ans. It ranges from 9.5 m to 30 m.

Q. *On which factors does its value depend?*

Ans. 1. The quality and nature of fuel

2. The thermal power, i.e. steaming capacity of the boiler.

Q. *How can it be determined?*

Ans. It can be calculated using the formula

1. $A_f = a \cdot b$ when A_f and b are known
2. $a = 0.67\sqrt{G_s}$

where, G_s = steaming capacity of the boiler, t/h

Q. *How does height of the furnace vary?*

Ans. It ranges from 15 m to 65 m.

Q. *What factors are to be considered in the determination of furnace height?*

Ans. Its value should be such that it will

(a) ensure complete combustion of the fuel along the flame length within the furnace

(b) allow sufficient space to layout the waterwalls on the furnace wall to cool the products of combustion to the specified temperature.

Q. *How is the furnace height determined to ensure complete combustion of fuel?*

Ans. It is determined on the basis of the following formula

$$h_f = \bar{v}\,\tau$$

where $\bar{v}$ = average gas velocity in the furnace cross-section, m/s

τ = residence time of unit volume of flue gas in the furnace, s.

Q. *What is the allowable heat release rate of the furnace?*

Ans. It characterizes the energy release rate per unit volume, kW/m^3 of the furnace

$$q_v = Q/V_f = G_s\ H/V_f$$

where V_f = volume of the furnace, m^3

Q. *What is the value of the allowable heat release rate?*

Ans. Its value varies from 120 kW/m^3 for coal-fired dry-bottom furnaces to 210 kW/m^3 for slagging-bottom furnaces.

Q. *How does the allowable heat release rate vary with the residence time of the unit volume of the gas in the furnace?*

Ans. It increases with the decrease of and decreases with the increase of the latter as can be seen from the figure (Fig. 12.3).

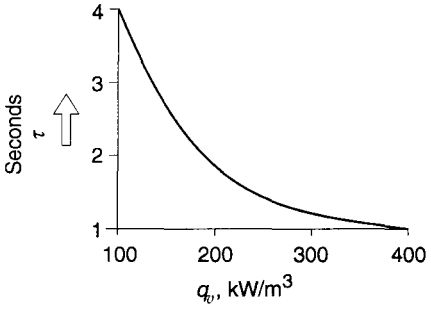


Fig. 12.3

Q. *Why does the increase in boiler capacity bring about an increase of Θ_2, which is the specified temperature to which combustion products are to be cooled by the waterwalls?*

Ans. With the increase of boiler capacity, the volume of the furnace increases and it increases more substantially than the surface area of the waterwalls. Therefore, the available unit surface area of the waterwalls per m^3 of the furnace volume becomes lower, with the effect that combustion products leave the furnace space at a higher temperature than the specified temperature Θ_2.

Q. *How can the cooling surface area of a boiler be increased without altering the furnace dimensions?*

Ans. By inserting curtain walls (or platen).

Q. *What are these?*

Ans. These are additional tube-walls mounted in the furnace space dividing it into two or more sections. (Fig. 12.4)

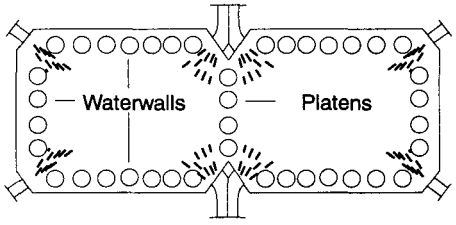


Fig. 12.4(a)

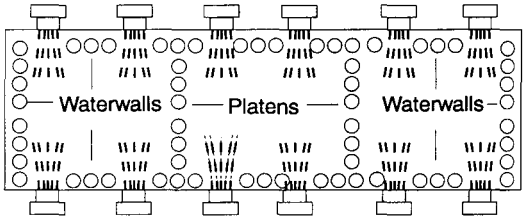


Fig. 12.4(b)

Q. *In what respect does the curtain wall, i.e. platen differ from conventional waterwalls laid on the furnace wall?*

Ans. Conventional waterwalls arranged on the sides of the furnace receive heat from one side whereas curtain wall tubes receive heat from both sides and hence these are characterized by a higher heat release rate.

Q. *How can the desired intensity and complete combustion of pulverized coal be achieved?*

Ans. By proper supply and intensive mixing of the pulverized fuel (primary airborne coal pow-

der) with the secondary air in the burner assembly.

Q. *What is the function of a burner?*

Ans. A burner does not ignite a fuel. Its sole function is to produce two individual flows—one of fuel dust-air mixture and the other of secondary air—for ignition and active burning in the furnace space.

CASE STUDY Coal-Burner Burnout A utility deriving power from PC-fired units experienced burnout of PC-burners after running satisfactorily for a long time.

Operating conditions and settings were checked.They remained unchanged, except that the fuel was changed from high-sulphur coal to low-sulphur coal having 4.652 MJ/kg more heat and 2% lower ash content. The grindability and volatilities were alike.

The high-sulphur coal had considerably more dust fines (up to 10% of the total) and the utility had to do more grinding to stop slagging in the furnace. But the fuel-switchover did not give any slagging problem.

Q. *Why did the burn-out occur? What is the solution, as the utility would have to burn this low-sulphur coal to keep costs down?*

Ans. Overheating of burner tip caused the burnout. Use of too fine coal set the flame very close to the burner tip as the fines burn too quickly. High calorie coal shot up burner tip temperature beyond its tolerance limit causing burner failure.

The solution would be to move the flame out from the burner. For this

(a) flame velocity is to be decreased
(b) mill discharge temperature is to be reduced
(c) pulverizer is to be set for a coarser grind as the coars coal will burn further out from the burner because of the larger time needed.

High calorie coal needs modified burner setting so as not to

1. burn fuel too close to the burner
2. allow flame licking furnace walls
3. have sparklers from coarse coal
4. have too bright flame, indicating that the excess air is in the right range.

Observation of the fire through inspections doors above the firing level should be conducted by the operating personnel to regulate the point at which the ignition of coal takes place by adjusting the damper. By frequent checking, one can establish damper settings suitable for the coal burnt.

Q. *Why are coal dust-primary air mixture and hot secondary air introduced into the furnace space at different speeds and with different degrees of turbulence?*

Ans. To ensure good intermixing of the ignited fuel with the secondary air to complete the combustion. As a result active burning takes place in the furnace space.

Q. *How many types of pulverized coal fired burners are there?*

Ans. 1. Straight flow burner.
2. Turbulent (vortex) burner.

Q. *What are straight flow burners?*

Ans. Straight flow burners produce long-range jet with low expansion angle and less turbulence of secondary and primary air flows. (Fig. 12.5)

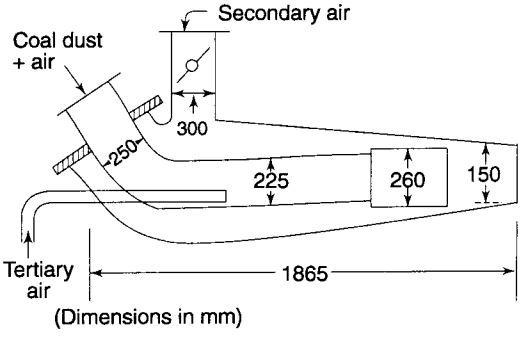


Fig. 12.5 *Straight flow burner.*

Q. *What is the main drawback of this type of burner?*

Ans. Poor intermixing of primary air-coal dust flow with the secondary air flow. So a single burner is not enough to bring about efficient combustion.

Q. *What is done for efficient combustion?*

Ans. A series of burners are compounded to produce an assembly of straight-flow burners. [Fig. 12.6]

As a result of this, the jets from various burners will interact with one another to effect complete combustion in the furnace space.

Q. *For what kind of solid fuels, are straight-flow burners employed?*

Ans. These are employed with high-reactive solid fuels like brown coals, high volatile coals, peat, oil shales, etc.

Q. *What is the velocity of coal-dust-primary air flow at the burner exit?*

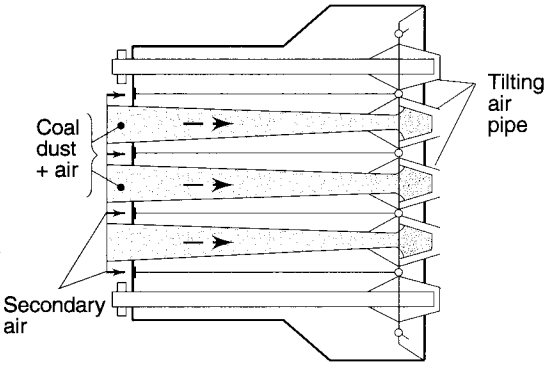


Fig. 12.6 *An assembly of straight flow burners.*

Ans. 20-28 m/s.

Q. *What is the optimal value of secondary air?*

Ans. 35-45 m/s.

Q. *What are vortex burners?*

Ans. As the name implies, vortex burners feed the coal dust-primary air mixture as well as secondary air in the form of jets with high turbulence. [Fig. 12.7]

The jet of ignited fuel-air mixture gets intensively mixed with the whirl of secondary air as the fuel jet propagates in the form of a cone-shaped expanding flame.

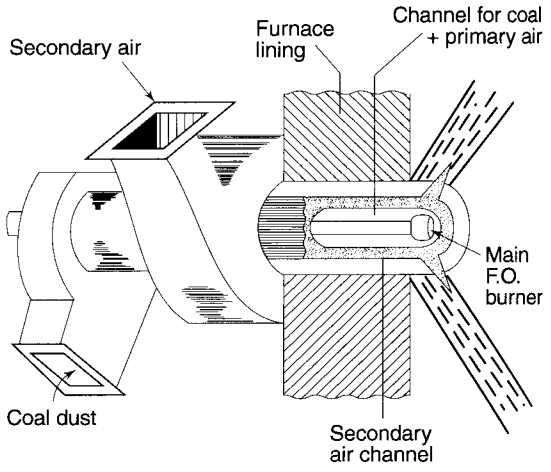


Fig. 12.7 *Vortex burner.*

Q. *How many types of vortex burners are there?*

Ans. Four types

(a) Two-scroll burners
(b) Straight-scroll burners
(c) Scroll-vane burners
(d) Vane-type burners.

Q. *What is the throughput capacity range of turbulent burners?*

Ans. 1-4 kg/s of fuel.

Q. *What is the range of their heat generation capacity?*

Ans. 25 to 100 MW.

Q. *What is the heat generation capacity of two-scroll and scrollvane burners?*

Ans. It ranges from 75 to 100 MW.

Q. *What is the most important aerodynamic characteristic of vortex burners?*

Ans. The most important aerodynamic characteristic of vortex burners is the vorticity parameter. It ranges from 1.5 to 5—greater the whirling of the secondary air flow, greater is its value.

Q. *What are the features of a burner with a high vorticity parameter?*

Ans. Such type of burners produce a wider jet with a larger angle of expansion and with a wider zone of recirculation of the hot furnace gases to the flame root, ensuring quicker fuel preheating and combustion.

Q. *For what kind of solid fuels, are burners with high vorticity parameters used?*

Ans. Low-reactive fuels with a relatively low yield of volatiles.

Q. *What are the axial velocities of primary and secondary air in vortex burners?*

Ans. Primary air velocity varies from 16 to 25 m/s.

Secondary air velocity varies in the range (1.3-1.4) times primary air velocity.

Q. *What is the primary importance of axial velocities of primary and secondary air?*

Ans. To achieve complete burning of the fuel.

Q. *What are combined burners?*

Ans. These are burners that can operate simultaneously or alternately on a variety of fuels—solids, liquids and gaseous. [Fig. 12.8]

Q. *Where are combined burners installed?*

Ans. In high capacity steam boilers.

Q. *What are the basic factors to be taken into account in the arrangement of burners?*

Ans. Burners are arranged on the furnace walls to

(a) ensure as complete combustion of fuel in the furnace core as possible
(b) create favourable conditions for slag removal
(c) avoid clinkering of the furnace walls.

Q. *What is embrasure of vortex burners?*

Ans. It is the diameter of their port, D_p.

Q. *How are vortex burners laid on the furnace walls?*

Ans. They are fixed on the furnace walls such that the gap between each other is (2.2—3) D_p while that between the side wall and adjacent burner is (1.6—2) D_p.

Q. *Why is such an arrangement preferred?*

Ans. To avoid premature interaction between adjacent flames and to prevent flame tongues from licking the walls. (Fig. 12.9a, 12.9b, 12.9c).

Q. *In which case is the opposite double front arrangement made?*

Ans. This arrangement is made particularly in the case of high-capacity steam boilers, where the

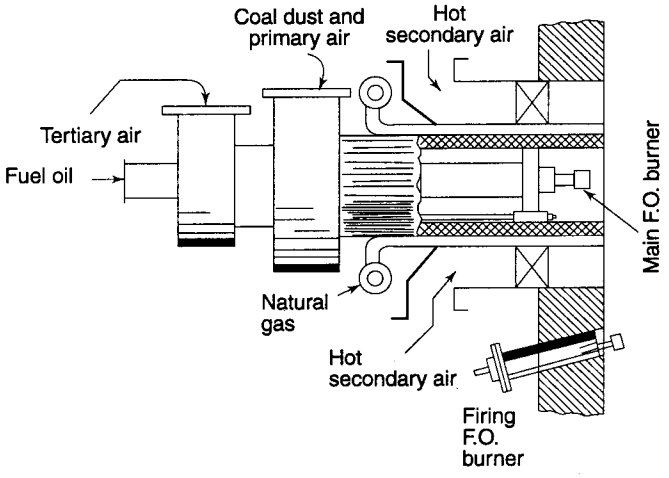


Fig. 12.8 *Combined burner assembly.*

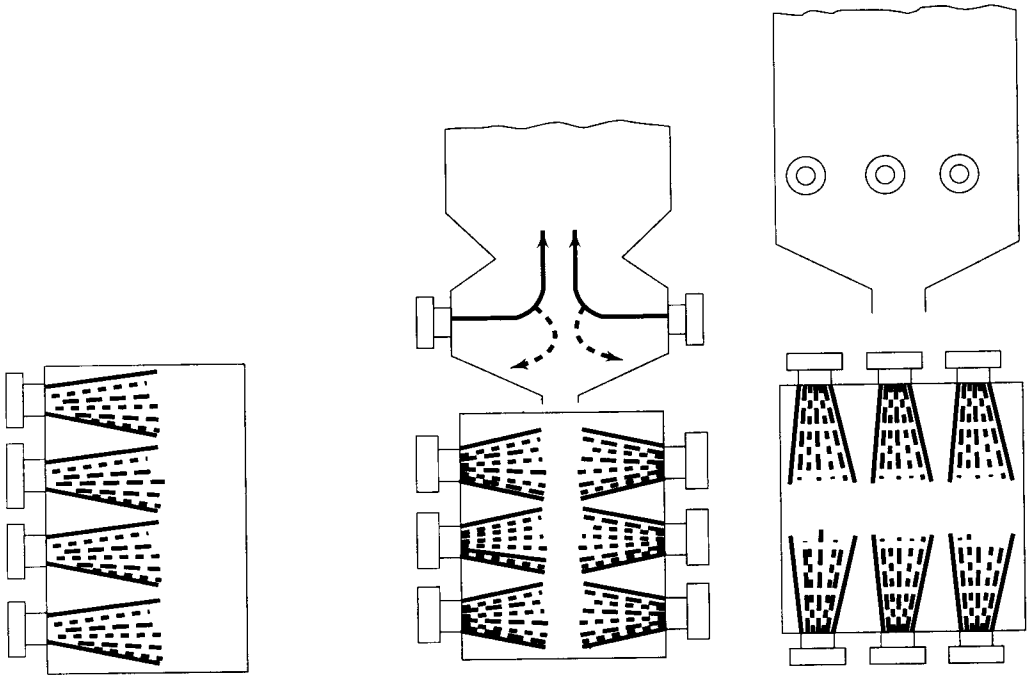


Fig. 12.9

high heat generation rate demands a good many burners that cannot be arranged on a single front wall even in two tiers.

Q. *What are the advantages of the opposite double front arrangement of vortex burners?*

Ans. 1. High heat generation rate.
2. More uniform heat absorption by waterwalls.
3. Less clinkering problem due to the high temperature maintained throughout the furnace forasmuch as the colliding flames are deflected both upwards and downwards
4. Suitable for slag-bottom furnaces.

Q. *What should the furnace width be in order to ensure efficient interation of opposite flames propagating from a double-front (opposite) arrangement of turbulent burners?*

Ans. (5-6) D_p.

Q. *In which case are vortex burners laid in an opposite arrangement on the side walls?*

Ans. Low capacity boilers. The burners are laid in a single tier.

Q. *How are straight flow burners arranged?*

Ans. They are arranged into
(a) opposite displaced arrangement (Fig. 12.10a)
(b) corner arrangement (block arrangement) (Fig. 12.10b)
(c) corner arrangement with tangential jets (tangential arrangement) (Fig. 12.10c)

Q. *Which of these arrangements finds the widest application?*

Ans. Tangential arrangement.

Q. *Why?*

Ans. Because of

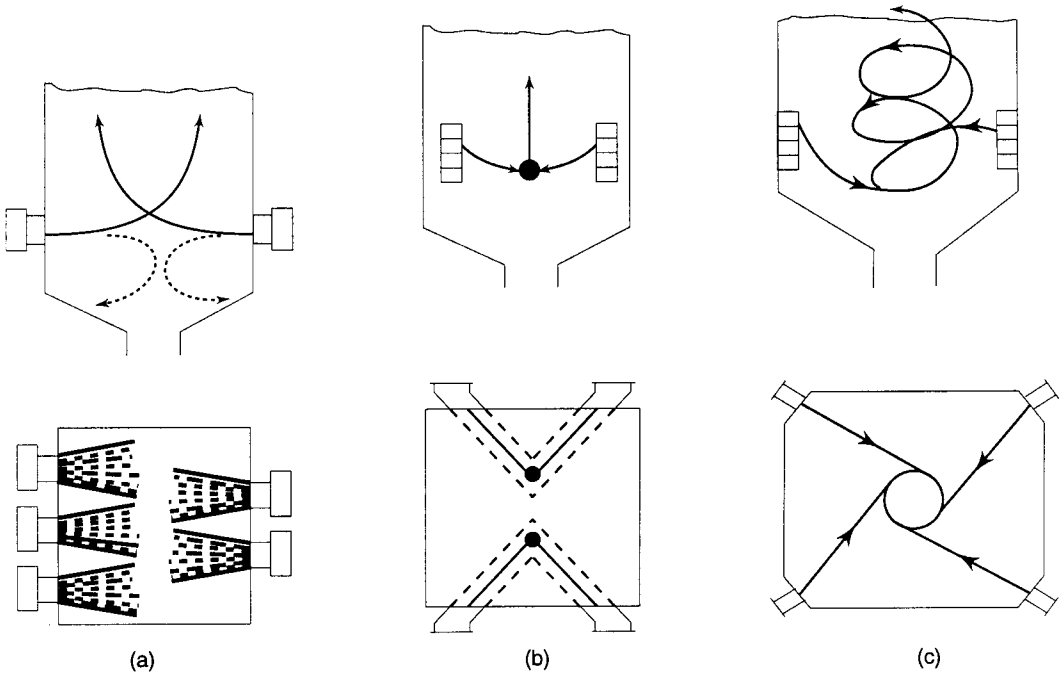


Fig. 12.10

(a) high heat-generation capacity and hence suitability for high capacity boilers
(b) uniform heat distribution between the furnace walls
(c) low clinkering probability.

Q. *What is the ratio of front width to depth of the furnace in the case of tangential burner arrangement?*

Ans. The ratio is 1–1.2 i.e. the furnace is nearly square in cross-section.

Q. *Why is such a selection made?*

Ans. It endows best aerodynamic characteristics in the furnace space.

Q. *What are dry-bottom furnaces?*

Ans. These are furnaces in which slag is removed in the solid state.

Q. *What are the patterns of flame motion in dry-bottom type furnaces?*

Ans. 1. Straight flow S-shaped flame (Fig. 12.11a)
2. Opposite straight flow flame (Fig. 12.11b)
3. Vertically turbulized flame (Fig. 12.11c)
4. Combination of straight and horizontally turbulized flame Fig. (12.11d)

Q. *Why are dry-bottom furnaces equipped with a dry-bottom hopper?*

Ans. The dry-bottom hopper intensively cools the products of combustion in the furnace bottom. As a result, molten slag droplets entering into this zone get quickly cooled, solidified and fall along the sides of the hopper into the slag-collection pit. (Fig. 12.12).

Q. *How much of the total ash content is collected in this way?*

Ans. About 5–10% of the total ash content of fuel.

Q. *Why are the granulated slag particles collected in the water bath?*

Ans. The water bath acts as a hydraulic seal preventing the entry of cold atmospheric air from beneath into the furnace.

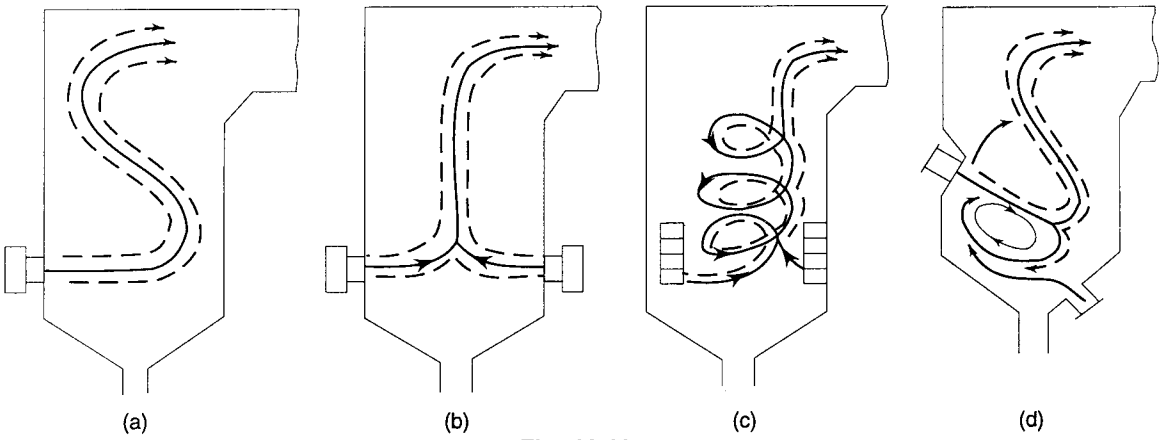


Fig. 12.11

Q. *Why are the heat release rates per m^2 of furnace cross-section and per m^3 of furnace volume not high in the case of dry-bottom type furnaces?*

Ans. The furnace is so designed that its aerodynamic characteristics will not allow the flue gas to attain ash deformation temperature near the surface of the waterwalls to avoid the problem of clinkering. That is why average heat release rates per m^2 and per m^3 of the furnace are not high (3-4 MW/m^2 and 100-140 MW/m^3 respectively).

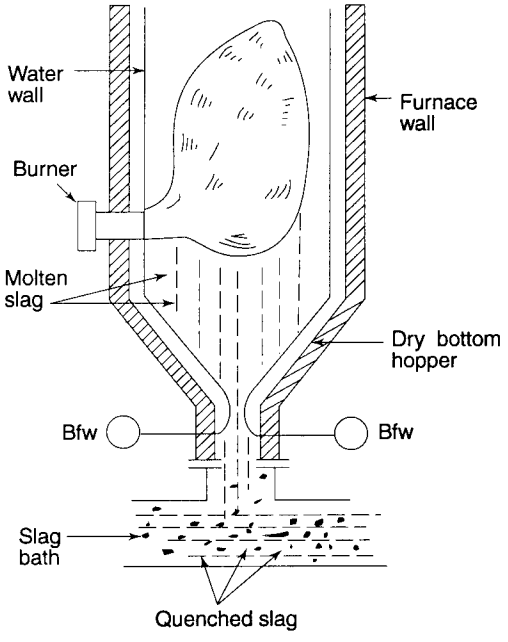


Fig. 12.12 *Dry-bottom furnace fitted with dry-bottom hopper*

Q. *For what kind of pulverized solid fuel, are dry-bottom type furnaces employed?*

Ans. Solid fuels with volatiles exceeding 25%, i.e. coals with moderate to high yield of volatiles.

Q. *How do the different fractions of pulverized fuel burn up in the combined straight flow and horizontally turbulized flame?*

Ans. Burnt up in the straight portion of the flame are fine fractions of the pulverized solid fuel, whereas the coarser particles are thrown to the bottom, dragged by the jet of secondary air and burnt off completely into vortex motion.

Q. *The excess air ratio, in dry-bottom furnaces, at the furnace exit is 1.15-1.2, despite the fact that the excess air ratio in the burners is lower (1.05-1.1). Why?*

Ans. It is because of the inevitable ingestion of cold air into the furnace from outside.

Q. *What are the slag-bottom type pulverized fuel fired furnaces?*

Ans. These furnaces are designed so as to remove slag in the molten state.

Q. *What is the fundamental requirement for this?*

Ans. The temperature of the combustion products in the lower portion of the furnace should be higher than the slag fluidity.

Q. *What should the temperature of hot gas at the bottom be?*

Ans. It should be

$$\Theta_{gas} \geq [\Theta]^{ash}_{soft} + (50 - 100°C)$$

where, $[\Theta]^{ash}_{soft}$ = Ash softening temperature

Q. *How can such conditions be provided at the furnace bottom?*

Ans. By shifting the flame closer to the furnace bottom and insulating the waterwall tubes in this zone with carborundum refractories.

Q. *How is this heat-insulation applied?*

Ans. For sound attachment of the refractory to the tubes, pins 10-12 mm in dia and 12-15 mm long are first welded on the waterwall tubes' surface facing the fireside. Then refractory coating is applied to ensure heat insulation.

Q. *What is the nature of the bottom of the slag-bottom type furnace?*

Ans. It is horizontal or slightly inclined towards the centre of the furnace.

Q. *What is the profile of the molten slag in the slag-bottom furnace?*

Ans. The slag-bottom type furnace is provided with one or two refractory lined slag holes (500 mm × 800 mm) at the bottom-centre. Molten slag pours off these holes into the slag bath where they solidify on being quenched with water.

Q. *What fraction of the total ash is removed as molten slag in the slag-bottom type furnace?*

Ans. About 20-40 per cent.

Q. *How can the combustion of pulverized solid fuel be organized in a salg-bottom type furnace?*

Ans. It can be done in either of the three following ways:

(a) with straight flow flame
(b) with intersecting flame jets
(c) with vortex flame

Q. *How many types of slag-bottom furnace are there with straight flow flame?*

Ans. Two:

(a) straight-wall furnace [Fig. 12.13 (a)]
(b) constricted-section furnace [Fig. 12.13 (b)]

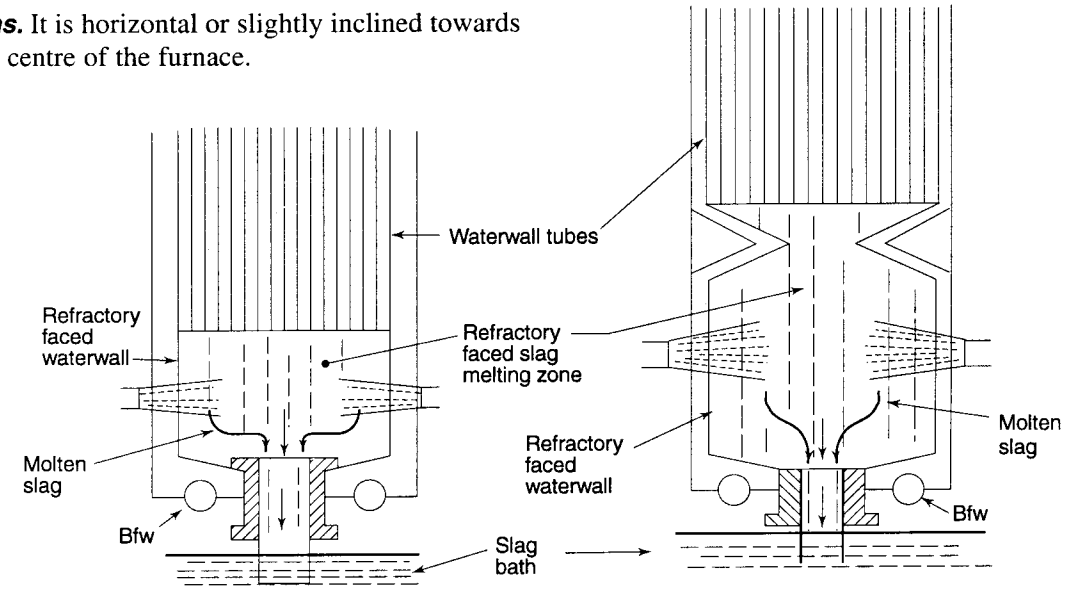


Fig. 12.13 *(a) Straight-wall furnace* *(b) Constricted section furnace*

Q. *What are the main disadvantages of the straight-wall (open-shaft) furnace?*

Ans. 1. Limited combustion control at loads below 70 to 80% of the rated capacity
2. Slag solidification is encountered on the waterwalls and then at the bottom as a large proportion of generated heat is given up to the upper zone
3. Only 10-15% of the total ash is removed as liquid.

Q. *What are the advantages of constricting two opposite walls in the slag-bottom furnace with straight flow flame?*

Ans. It isolates the combustion chamber within the furnace
(a) reducing heat flow substantially to the upper zone
(b) ensuring high temperature (1600-1800°C) in the combustion chamber
(c) removing 20-40% of total ash in the molten state
(d) enabling the boiler to run in a wider range of loads.

Q. *How many types of slag-bottom furnaces with intersecting jets are there?*

Ans. Two types:
(a) single-wall constricted (Fig. 12.14 a)
(b) both-walls constricted (Fig. 12.14 b, c)

Q. *What is the flame profile in slag-bottom furnaces with intersecting jets?*

Ans. Such furnaces are fired with straight flow burners which are so arranged as to turbulize the fuel-air feed around the horizontal axis. Since combustion takes place in the flame, the flame propagates in turbulence around the same horizontal axis. It rebounds from the refractory faced waterwall opposite, makes a full turn and after that hot gases of combustion intersect with oncoming jets of fresh fuel dust-air mixture and quickly reheat them to ensure sustained combustion.

Q. *How many types of slag-bottom cyclone furnaces are there?*

Ans. Two:
(a) horizontal cyclone-type primary furnace (Fig. 12.15 a)
(b) bottom-type primary furnace open at the top (Fig. 12.15 b)

Q. *How does combustion in cyclone furnaces proceed?*

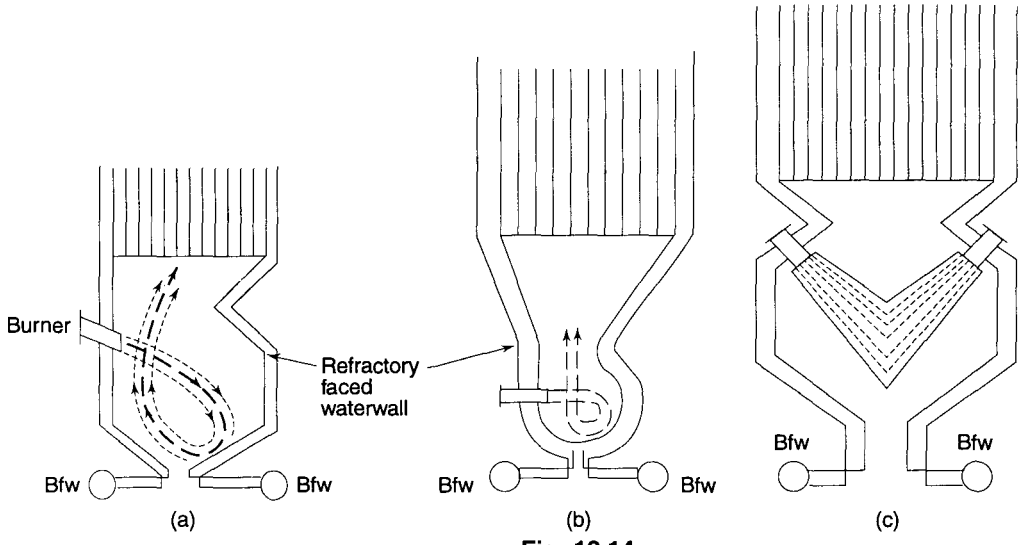


Fig. 12.14

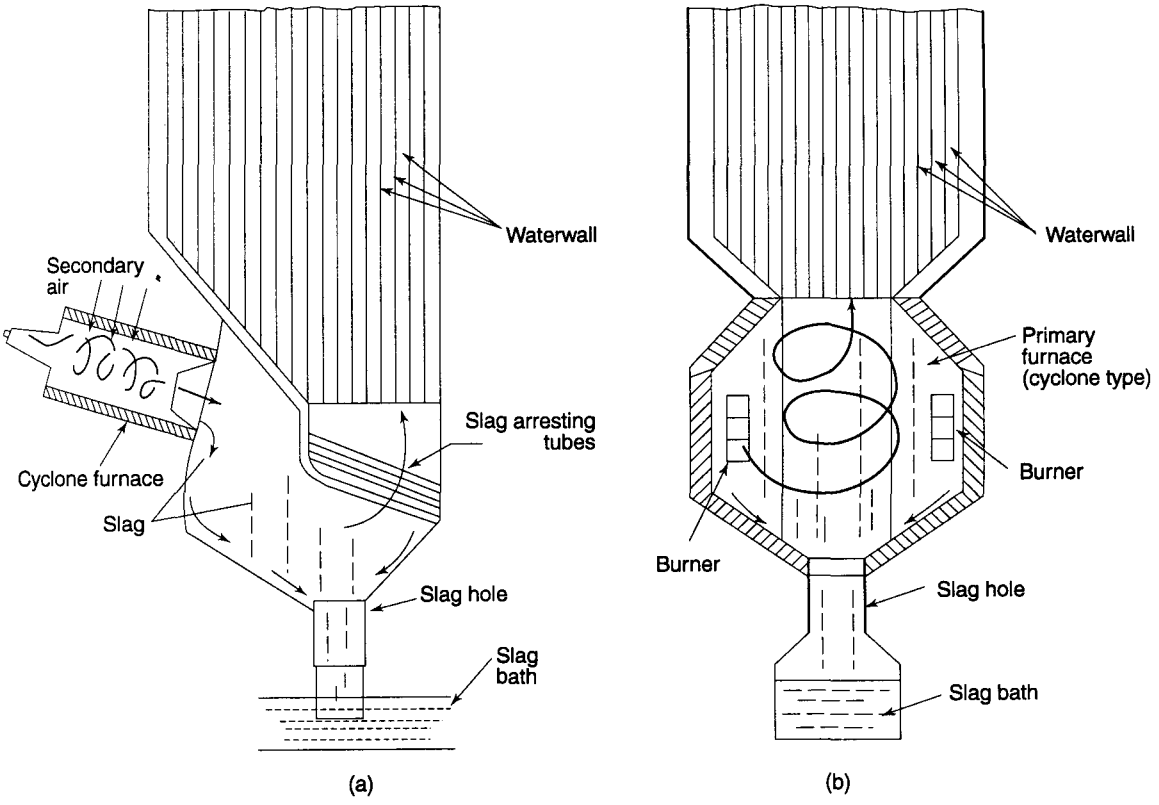


Fig. 12.15 *Slag-bottom cyclone furnace.*

Ans. A high degree of turbulence is induced to the coal dust-air mixture in the primary furnace either by tangential high-speed jets of secondary air (80-125 m/s) or tangential fuel dust-air mixture jets from burners. Combustion takes place in the flame.

The fuel particles in the primary furnace are acted upon by two forces centrifugal and aerodynamic.

The centrifugal force throws the fuel particles onto the walls of the primary furnace while the aerodynamic force tends to lift the fuel particles and gases from the primary furnace. The ratio of these two forces depends on the particle size and that is why the fuel particles get unevenly distributed in the primary furnace. While the coarser particles, upon which the centrifugal force is more prevalent than the aerodynamic force, are thrown against the furnace walls and get involved in the vortex motion until they burn off completely, the finer fractions, under the influence of more aerodynamic force than centrifugal force burn in the centre.

Q. *Briefly describe a slag-bottom horizontal cyclone-type primary furnace.*

Ans. These are usually made to a diameter of 1.8 to 4 m while in length the cyclone is 1.2 to 1.3 times its diameter.

Anything from pulverized fuel to crushed fuel can be used, and this saves the cost of fuel pulverization.

The furance temperature is as high as 1800-1900°C (2073 – 2173 K) and the heat release rate is high (2 – 6 MW/m^3).

Large fraction of ash is removed to slag. About 60 to 85% of total ash is removed as slag.

Excess air ratio: 1.05 – 1.10

Heat power of the cyclone: 150 – 400 MW.

Q. *The total heat release rate of a horizontal cyclone-type furnace does not exceed 0.2 to 0.3 MW/m^3, in spite of the above statement. Why?*

Ans. It is because of the extended shaft that is needed to cool the furnace gases.

Q. *What are the primary advantages of a slag-bottom type furnace over a dry-bottom type furnace?*

Ans. 1. The heat loss with unburnt carbon, when the same kind of fuel is burnt, can be reduced by one-third in a slag-bottom type furnace.
2. The total heat release rate per unit furnace volume of a slag-bottom type furnace comes out to be 20% higher on the average. And that means the slag-bottom type furnace can be made smaller and more compact.
3. Because of better tightening of the bottom portion, there is less infiltration of air into the furnace. As a result, the heat loss with waste gases is somewhat lower.
4. Because of molten slag, the ash disposal system is less expensive.

Q. *What are the drawbacks of a slag-bottom type furnace?*

Ans. 1. Not all fuels are suitable for a slag-bottom type furnace. Fuels with low ash melting point, 1150-1300°C (1423-1573 K), can be conveniently burnt while fuels having ash melting point 1350°C (1623 K) present particular difficulties, and the conditions for the formation of molten slag should be accurately calculated.
2. A great amount of heat is lost with the slag since more ash is removed as high temperature slag. And this may be more than the heat saved with the minimization of unburnt carbon.
3. The possibilities of boiler load control are restricted by the conditions of slag removal in the case of single-shaft slag-bottom type furnace.
4. High flame core temperature bring about a higher yield of NO_x than a dry-bottom type furnace.

Q. *What fuels are advantageous for combustion in slag-bottom furnaces?*

Ans. 1. Low-reactive fuels like anthracite, semianthracite, lean coals
2. Fuels with low ash melting point.

Q. *Why are fuels with low ash melting point not suitable for dry-bttom furnaces?*

Ans. They may cause severe clinkering of the waterwalls.

13

UPGRADING PC-FIRED BOILERS

Q. *What are the equipment upgrades to enhance the availability, efficiency and output of a pulverized coal-fired boiler?*

Ans. 1. Selective Catalytic Reduction of NO_x (SCR)
2. Heat Pipe Primary Air Heaters (HPPAH)
3. Tubular Air Heater Sleeving
4. Corrosion resistance tube material to address high temperature coal ash corrosion of reheater and superheater tubes
5. Superheater and reheater outlet header replacement with P91 alloy and improved header design
6. Integral separator start-up system to provide cycling capability to once-through units (OTUs)
7. Spiral-wound waterwalls for OTUs
8. Rotating (dynamic) classifiers for vertical spindle coal mills
9. Fully-fired "Hot-windbox" combined-cycle conversion
10. Coal Flame Diagnostic Systems.

These are ten general equipment upgrades among a variety of aftermarket retrofit products. Because of they are general in nature, they can be used to upgrade existing PC-fired units and are not limited in application to any specific manufacturer's boiler.

Q. *What is the operating principle of a SCR?*

Ans. Selective Catalytic Reduction (SCR) is a process in which NO_x is removed in the presence of a catalyst, by the injection of ammonia in the flue gas. The principal denitrification chemical reactions are

$$4NO + 4NH_3 + O_2 \longrightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \longrightarrow 3N_2 + 6H_2O$$

At present, commercially available catalysts are made primarily of titanium dioxide (TiO_2), tungsten trioxide (W_2O_3) and vanadium pentoxide (V_2O_5). They are most effective in the temperature range 475°K – 815°K.

Q. *What is NO_x removal efficiency of SCR system hooked up to a PC-fired unit?*

Ans. The deNO_x ing efficiency varies from 40% to 60% +. If low NO_x burners are installed upstream, only relatively low NO_x removal efficiency is required.

Q. *Can you cite specific examples of retrofitting PC-fired units with the SCR system?*

Ans. The first two US coal fired units that got the SCR retrofits are

1. Chambers Works Congeneration Plant in Carneys Point, New Jersey
2. Indiantown Cogeneration Plant at Indiantown, Florida

Both units spray aqeous ammonia into the FG that flows vertically down through the SCR reactors.

Design Parameters	Chambers Works Cogen Plant, NJ	Indiantown Cogeneration Plant, FL
Nominal rating (MW_e)	285	390
Start-up data	July 1993	Dec., 1994
Fuel	Pulverized coal	Pulverized coal
Flue gas	High sulphur and high dust	Intermediate sulphur and high dust
Gas flow (Nm^3/h per unit)	2 SCR Units	
	500 000	1 200 000
Gas temperature at SCR inlet	663°K	643°K
Flow direction	Vertical; downward	Vertical; downward
Catalyst type	Honeycomb	Plate
Ammonia system	Aqueous NH_3	Aqueous NH_3
NO_x at inlet (ppmvd)	196	179
NO_x removal efficiency	63%	40%

Source: SP93-9 (Technical Paper/Foster Wheeler Energy Corporation

Q. *Where is the SCR unit located?*

Ans. It is fitted between the economizer and the air heater (Fig. 13.1).

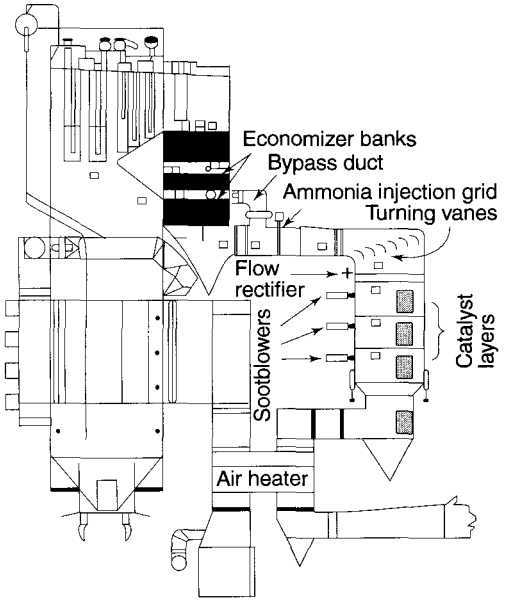


Fig. 13.1 *The SCR unit is located between the economizer and air heater. (Chambers Steam Generator).*

Source: SP93-9 (Technical Paper/Foster Wheeler) Courtesy: Foster Wheeler Energy Corporation/ Clinton/NJ 08809-4000/USA

Q. *Why has this location been selected?*

Ans. This location gives the most optimum flue gas temperature range for commercially available catalysts.

Q. *What are the components that build up the SCR system of the above two units?*

Ans. The SCR system consists of

1. a partial economizer bypass duct
2. an ammonia injection grid
3. turning vanes
4. a flow rectifier
5. a SCR reactor or catalyst layers
6. soot blowers
7. associated ducting.

Q. *Why is the partial economizer-bypass-duct incorporated into the SCR system?*

Ans. To control the FG temperature.

If the FG temperature drops below the optimum temperature, more flue gas is bypassed the economizer to set the FG temperature to the right level at the SCR inlet.

Q. *Chambers and Indiantown Units burn high and intermediate sulphur coal respectively. What must be the design feature of the SCR unit for sulphur-containing coal?*

Ans. Sulphur-containing coal entails the risk of formation of ammonium sulphate and bisulphate:

$$S + O_2 \longrightarrow SO_2$$

$$SO_2 + \frac{1}{2}O_2 \longrightarrow SO_3$$

$$SO_3 + H_2O \longrightarrow H_2SO_4$$

$$NH_3 + H_2SO_4 \longrightarrow NH_4HSO_4 + (NH_4)_2SO_4$$

that may plug the air heater downstream. Therefore, special care is exercised in the design of SCR unit to minimize the chances of formation of the above salts. These measures include the use of the largest available catalyst cell size, maintaining the FG temperature throughout the operating load range, above the critical ammonium salt formation temperature, and keeping the ammonia slip at a minimum.

Q. *What are the major design features of the Chambers SCR system?*

Ans. 1. An economizer bypass duct
2. Specially contoured turning vanes
3. A flow rectifier
4. A three-layered catalyst bed which is of homogeneous honeycomb type
5. Sootblowers.

Q. *Why has the economizer bypass duct been installed?*

Ans. The basic objective is to maintain optimum FG temperature to avoid downstream plugging of air heaters. For low load operation, a part of the FG is bypassed around a portion of the economizer to maintain the minimum flue gas temperature so as to avoid the formation of ammonium sulphate and bisulphate.

Q. *What is the purpose of installing specially contoured turning vanes?*

Ans. These vanes are designed on the basis of the scale-model flow test. They are mounted to provide uniform gas flow distribution and, at the same time, to minimize gas-side pressure drop.

Q. *Why has the flow rectifier been incorporated?*

Ans. Made of square-shaped pipes, the flow rectifier straightens out the gas flow entering the SCR reactor or catalyst layers thereby minimizing the erosion potential.

Q. *What is the purpose of using a multilayered catalyst bed?*

Ans. A multilayered catalyst enhances catalyst life and NO_x removal efficiency. Initially the top two layers of the SCR reactor are charged with catalyst, followed by an addition of catalyst in the 3rd layer later, to maintain the NO_x removal efficiency for a 10 year period.

Q. *Why is sootblower a necessity in an SCR system?*

Ans. High dust load of flue gas mechanically fouls the catalyst surface and tells upon the NO_x removal efficiency of the catalyst. Hence steam-operated sootblowers are placed upstream of the catalyst layers for occasional dust-off of the catalyst surface.

Q. *What is HPPAH?*

Ans. It is Heat Pipe Primary Air Heater which is basically an assembly of individually-sealed, inclined pipes containing a working fluid (Fig. 13.2). The hot FG flows downward in a duct in the counter-current direction to the cold air that flows upward in an adjacent duct. Heat from the flue gas is transferred to the air via heat pipes which are transverse to both gas and air streams. The FG and air ducts are separated by a divider plate which is fully seal-welded to preclude interpass leakage (Fig. 13.3).

Q. *Usually rotary-type regenerative primary air heaters are installed for preheating primary air. How is the steam generation unit upgraded when these air heaters are replaced by HPPAH?*

Ans. When rotary-type regenerative primary air heaters are replaced with heat pipe primary air heaters, leakage of air into the gas side of the air heater is prevented thus improving both thermal and pressure drop performances for the plant. It also improves PA fan performance by the elimination of leakage.

Note: Air leakage monitored at the Pleasants Station and Crist Plant units have indicated essentially zero leakage of air into the gas stream.

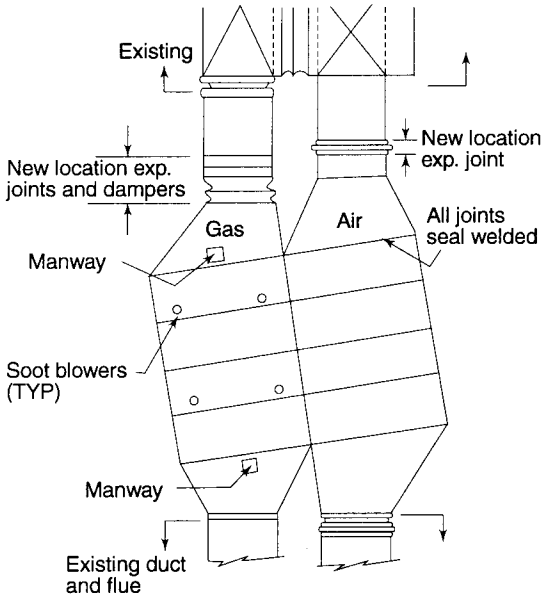


Fig. 13.2 *General arrangement of a typical Heat Pipe Air Heater.*
Source: SP93-9 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Energy Corporation/ Clinton/NJ 08809-4000/USA

Q. *What are the main advantages of an HPPAH system?*

Ans. The main advantages of an HPPAH spring from its 'zero-leakage', characteristic. These include:

(a) reduced PA fan power consumption,
(b) extended capacity range of the existing PA fan system, and
(c) higher PA temperatures at low loads.

Q. *Is there any operational limitation of HPPAH as compared to conventional primary air heaters (PAH)?*

Ans. Unlike coventional PAHs, the heat pipe PAH has a specific permitted operating temperature range.

Q. *If the plant is run under off-design operating parameters, how will it affect the HPPAH unit?*

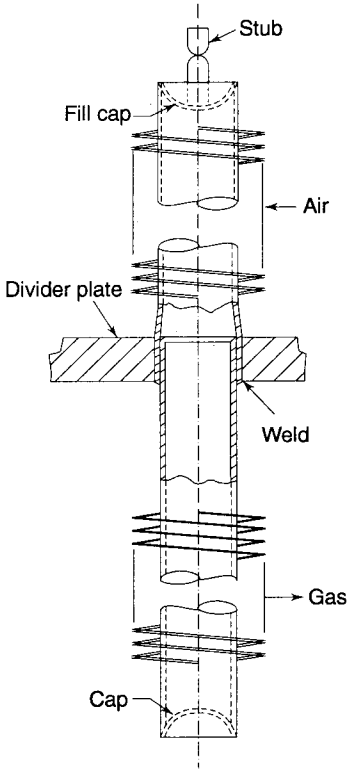


Fig. 13.3 *Heat Pipe Air Heater welded tube (Details).*
Source: SP93-9 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Energy Corporation/ Clinton/NJ 08809-4000/USA

Ans. Off-design plant operations will develop higher-than-design gas temperatures in different zones within the HPPAH.

Q. *How can this problem be tackled?*

Ans. It can be addressed by providing a controllable amount of air inleakage. Figure 13.4 demonstrates this method of attemperating high gas temperatures by providing a controlled amount of ambient air inleakage during these off-design events.

Note: FD fan or PA fan discharge can also be utilized as the source of controllable cold air inleakage.

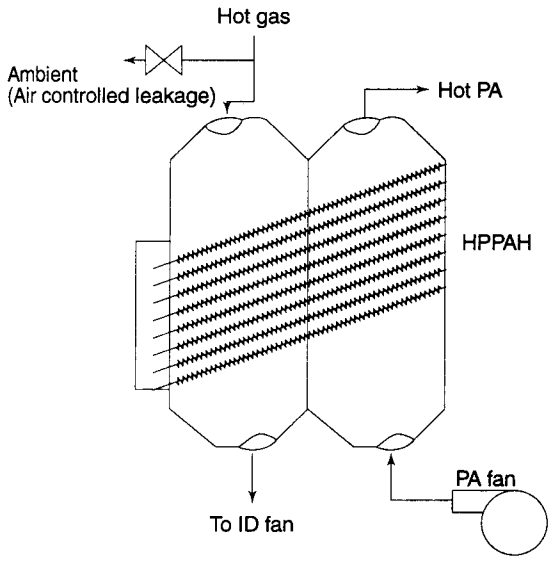


Fig. 13.4 *Schematic flow diagram of controlled air leakage for overheat protection of heat pipe air heaters.*

Source: SP93-9 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Energy Corporation/ Clinton/NJ 08809-4000/USA

Q. *Can you cite an 'off-design' operation?*

Ans. One such off-design case is operating with its boiler's convection duct severely fouled. Under this circumstance, the economizer exit gas (FG) temperature remain high and well above its design value.

Q. *How can a utility steam generation unit be upgraded through tubular air heater sleeving?*

Ans. Certain companies have developed and patented special tools which are used to install sleeves on the inside dia of air heater tubes as a means of repairing erosion/corrosion damage and thereby upgrading the unit in the form of life extension.

Q. *How is air heater sleeving carried out?*

Ans. It is a two-stage process requiring two separate tools to complete the job.

The first one is used to install the sleeve and set in place by deforming the sleeve into the tube past the end of the sleeve farthest from the tubesheet. This sleeve-to-tube joint is shown in the upper part of Fig. 13.5. The tool designed for this purpose by Foster Wheeler Energy Corporation (FWEC) is hydraulically operated and harnesses a conical mandrel to expand a collet into the sleeve, which in turn expands into the tube. The joint is deformation-controlled, i.e. the radial expansion of the sleeve into the tube is controlled to a precise value by the design operation of the tool. The cycling of the tool, which happens very quickly, assures that the joint is made. Once the joint (mechanical) is made, the sleeve is locked into position and the tool slips out. One such typical tool can install sleeves from 200 mm to 2440 mm long.

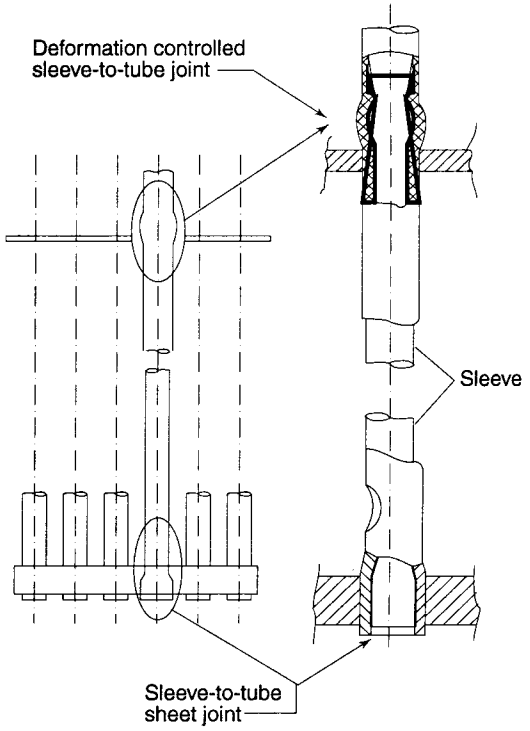


Fig. 13.5 *Tubular air heater sleeve repair method.*

Source: SP93-9 (Technical paper/Foster Wheeler)
Courtesy: Foster Wheeler Energy Corporation/ Clinton/NJ 08809-4000/USA

Now the 2nd tool is used to expand the sleeve into the air heater tube at the tubesheet. This sleeve-to-tubesheet joint is shown at the lower part of Fig. 13.5. This tool is also hydraulically operated and compresses two "rubber donuts" between a nut and a flange anvil to squeeze the sleeve into contact with the tube.

Q. *What is the basic advantage of this method of tube sleeving?*

Ans. It is a quick, efficient and economical life extension alternative to retubing of tubular air heaters.

Q. *How is this realized?*

Ans. Tubular sleeving makes a leakfree-repair, as both ends of the sleeve are expanded into the original air heater tube. This seals both ends of the sleeve, and completely isolates the damaged areas of the tube from the flue gas flow stream.

Q. *One technical paper presented at "The International Symposium for Improved Technology for Fossil Power Plants", March 1 – 3, 1993 held at Washington, D.C. says:*

There exists a class of coal-fired units, designed in the period 1955-1964, which had design throttle and reheater steam temperatures in excess of 565°C. Most of these units had subsequently reduced their steam outlet temperatures set points to below 565°C..... Their loss in availability was sufficiently serious that it had subsequently become a general industry practice to design new units to not greater than 540°C throttle steam temperature and not greater than 565°C reheater steam temperature. To this date, these temperature limits have been a major barrier to improving the steam cycle efficiency of the PC unit.

Q. *What is the basic reason that seals the higher temperature limit of both the throttle and reheated steam?*

Ans. This is due to the failure of the heated tubes due to liquid-phase coal-ash-corrosion. The alloys commonly used as materials of construction of these tubes are not sufficiently resistant to aggressive slag attack under high temperature over prolonged period.

Note: Therefore there lies the ample scope of upgradation of the steam generating unit by developing improved alloys of superlative corrosion resistance at high temperatures.

Q. *At what temperature range is the liquid-phase coal-ash-corrosion maximum?*

Ans. EPRI-sponsored research has led to invaluable insights into the mechanism of liquid-phase coal-ash-attack and credible data of corrosion rate comparisons of several improved alloys resulted. These data show

> a metal surface temperature in the range of 895 °K – 975 °K gives rise to the maximum rate of liquid-phase coal-ash-corrosion.

Q. *Is there any recent development of alloy chemistry to withstand liquid-phase coal-ash-corrosion?*

Ans. One such recently developed alloy is HR3C. It exhibits much reduced corrosion rates and sports superlative high temperature strength.

Q. *What are the performance and prospect of HR3C?*

Ans. Tests conducted by FWEC at five different coal-fired plants have shown that HR3C demonstrates very low corrosion rates.

The alloy was found sufficiently promising enough that two units at the TVA Gallatin station had their convective reheater tube assemblies replaced with Sumitomo HR3C in 1990 and 1991.

Prior to these replacements, the T22 and 304H* Gallatin reheater tube assemblies needed replacement on a 7-yr basis, due to tube failure caused by liquid-phase coal-ash-corrosion. Based upon insitu corrosion testing with the new HR3C assemblies, a corrosion life in excess of 20-yrs is expected, assuming the use of the current coal and current reheater outlet steam temperature setpoint.

For those units which have had their steam outlet setpoints reduced due to liquid-phase coal-ash-corrosion, replacement of the existing superheater or reheater tubing with HR3C may permit these units to restore the original design outlet steam temperatures, for improved heat transfer rate or could be replaced simply for improved availability.

[H^* means heat resistant]

Q. *The last decade has seen an increase in the need to cycle units originally designed for base-load service. What is the adverse effect of this cyclical operation on superheater and reheater systems of the unit?*

Ans. It leads to the fatigue damage of the outlet headers of the superheater and reheater by the cyclically applied thermal stresses during restart.

Q. *How do these fatigue damages take shape?*

Ans. 1. ID bore hole edge cracks, not limited to the inter-ligament direction
2. Stub cracking, originating at the OD of the stub-to-header weld
3. Stub cracking, originating at the ID of the weld.

Q. *How is thermal stress responsible for ID bore hole edge cracks related to header wall thickness?*

Ans. The magnitude of thermal stress at this location is directly proportional to the square of the header wall thickness.

Q. *In this context which one of the alloys SA335P11, SA335P22 or SA335P91 is the one most useful to withstand fatigue stress during thermal transients?*

Ans. Reducing the wall thickness being the most effective way of increasing fatigue life, it becomes most expeditious to use the alloy SA335P91 to reduce the wall thickness, inasmuch as it exhibits

(a) higher allowable stress at elevated temperatures.
(b) equivalent high thermal diffusivity.

Q. *Is there any other method to counter ID bore hole edge cracks?*

Ans. 1. Providing a generous radius at the tube stub bore hole edge
2. Improving the header ligament efficiency by using nozzle reinforcement resulting in a thinner header wall thickness
3. By using two parallel smaller headers in lieu of one large header
4. By modifying the operating procedures and/or control logic to reduce the magnitude of imposed thermal transients.

Q. *If you find that cracking at this location is limited to the inter-ligament direction, what can you infer regarding the nature of failure?*

Ans. It is likely a creep failure accelerated by a low local ligament efficiency.

Q. *What should be done in this case?*

Ans. Redesign of the header geometry is advised.

Q. *What does the stub cracking originating at the OD of the stub-to-header weld indicate?*

Ans. It indicates insufficient tube stub flexibility for the imposed differential motion of the header vs. enclosure wall penetrated by the stubs.

Q. *How can this stub-flexibility be enhanced to minimize stub cracking originating at the OD of the stub-to-header weld?*

Ans. (a) Various design improvements can be used to increase the length and out-of-plane routing
(b) Replacing solid refractory seals with flexible, explosively formed stub seals
(c) If excessive header bowing is the cause of differential growth, the bowing can be eliminated by redesigning the header to get symmetrically opposed nozzle geometry.

Q. *What is the mechanism of formation of stub cracking, originating at the ID of the weld?*

Ans. This problem usually has its origin at the superheater headers of once through units (OTUs)

which utilize a socket-type stub-to-header weld. The crack emanates from the toe of the weld, where a pre-existing crack is provided as part of the weld detail. During the restart load ramping of OTUs, substantial stub-to-header temperature differentials exist, which gives rise to high stresses at the stress raiser formed at the toe of the weld.

Q. *What is the remedy to this problem?*

Ans. This problem can best be solved by utilizing a full penetration weld in lieu of the economical socket weld and is further improved by the use of nozzle reinforcement of the header.

Another solution is the reduction in the magnitude of the restart thermal transients during load ramping. Those restart transients inherent in the flashtank type startup system be reduced by upgrading the startup system to the Integral Separator Startup System (ISSS). (See later).

Q. *Most domestic once through units (OTUs) were originally designed for base-load-service. What does this "base load design" mean technically?*

Ans. The term 'base load design' can be loosely defined as not suitable for more than 2000 restart cycles prior to developing some identifiable form of fatigue damage.

Q. *What are the highest priority areas of fatigue damage?*

Ans. The components mostly afflicted with fatigue damage are

1. the HP turbine rotor, shaft and casing
2. the main steam outlet header
3. the reheater outlet header
4. the transfer piping between the boiler and turbine

Q. *What basic factors determine the extent of cyclic fatigue damage to these priority areas?*

Ans. 1. Severity of the thermal transients experienced during restart load ramping
2. Physical design of the component.

Q. *For domestic OTUs, how are these transients aggravated?*

Ans. 1. By the use of constant throttle pressure operation
2. Main steam flowpath switching from the flashtank superheater bypass to once-through operation
3. Poor start-up system control response
4. Lack of a large turbine bypass system.

Q. *How do the restart thermal transients during a typical load ramp on an OTU determine the unacceptable fatigue damage to a turbine in a cycling unit?*

Ans. Fig. 13.6 portrays restart thermal transients at the throttle and HP turbine Ist stage bowl during a typical load ramp on an OTU with a flashtank start-up system.

Over the load range of 15%-25%, there is the boiler's inherent dip in main steam temperature and this is magnified by the simultaneous decrease in turbine throttle valve opening during the throttle pressure ramp with the effect that a larger dip in the Ist stage bowl temperature is generated via Joule-Kelvin cooling. It is this dip in the Ist stage temperature which determines that the cyclic fatigue damage to the turbine would be unacceptable for a "cycling" unit; loosely defined as a unit suitable for 10,000 restart cycles.

Note: Add to this the poor start-up system control response. This combined with thermal transients contribute to a substantial variation in throttle steam conditions between successive restarts.

Q. *How can the OTU's restart throttle conditions be made acceptable for routine cycling operations?*

Ans. This can be done by modifying the start-up system.

Q. *How should the start-up system be modified?*

Ans. One such modification is the Integral Separator Startup System (ISSS). It also improves the low-load heat rate and control response.

Q. *How does the ISSS operate and overcome the restart thermal transients?*

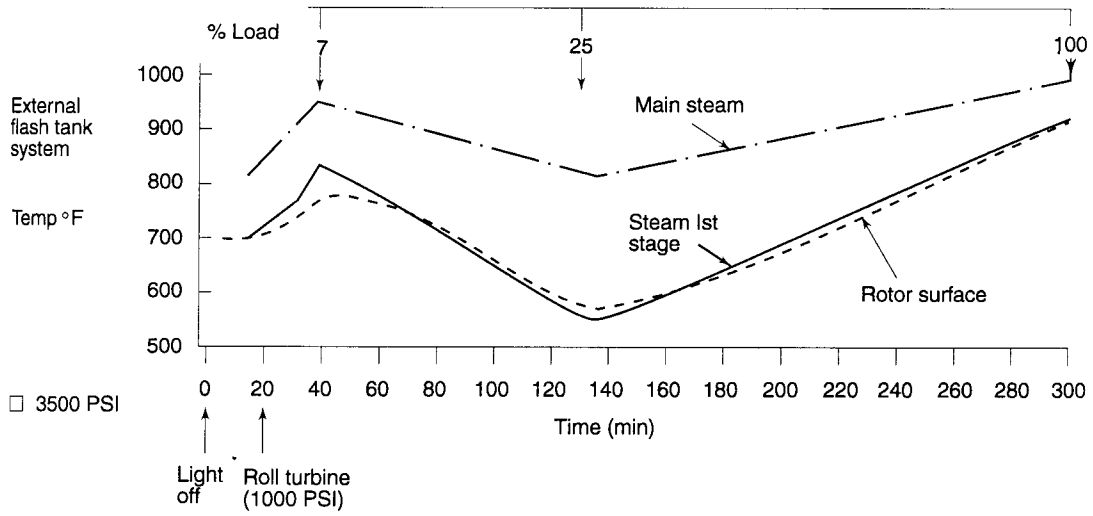


Fig. 13.6 *Typical 'DIP' in throttle steam and 1st stage bowl temperatures for an OTU with a flashtank start-up system.*
Source: SP93-9 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Energy Corporation/Clinton/NJ 08809-4000/USA

Ans. ISSS schematically presented in Fig. 13.7 eliminates the main steam flow path switching operation by eliminating the external flashtank.

All high pressure working fluids exiting the furnace are throttled across the boiler division valves and the resulting two-phase fluid stream is separated in multiple steam-water separators. These separators, integral to the main steam flowpath, are designed to the full boiler design pressure, and are never isolated from the boiler.

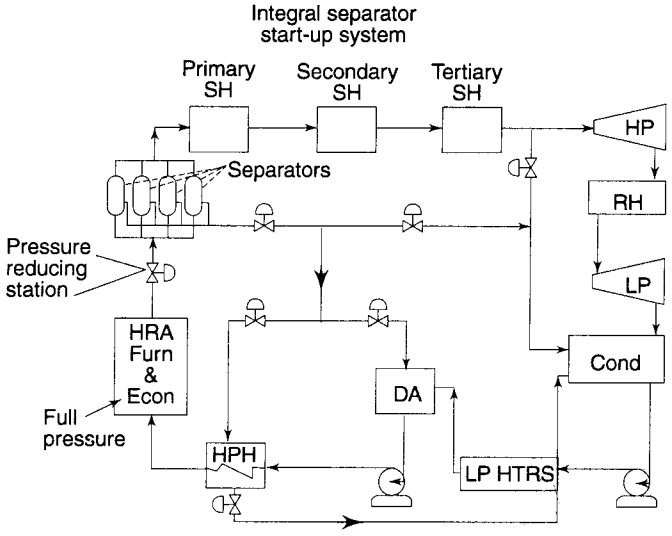


Fig. 13.7 *Schematic representation of Integral Separator Start-up System.*
Source: SP93-9 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Energy Corporation/Clinton/NJ 08809-4000/USA

The saturated steam from the separator vapor outlet is superheated in two sequential stages of the superheater, permitting the use of an interstage spray-attemperator for conditioning the start-up throttle steam temperature. Due to the repeatability of the boiler outlet process conditions available with this start-up system, the start-up spray flowrate can be programmed as a function of the main steam flow to yield an inherent monotonically increasing throttle steam temperature with load.

The dip in the Ist stage temperature prevalent with flashtank startup systems is further offset by the combined application of a monotonically increasing throttle steam temperature with load and by the use of a hybrid variable throttle pressure ramp to 50% admission. Such a variable pressure programme reduces the Joule-Kelvin cooling at the throttle valve during restart. A typical process conditions at the throttle and first stage bowl during restart with the ISSS with hybrid variable throttle are illustrated in Fig. 13.8.

Q. *The high pressure working fluid at the furnace outlet is throttled at pressure reducing station (see Fig. 13.9) and the resulting double-phase fluid stream is separated in the multiple steam-water separators. The throttling is done across the W-type valve (control valve) and the Y-type valve (stop valve). Is it necessary to replace these valves in retrofit cycling applications?*

Ans. In such cases it is generally necessary to replace "W" valves with larger, anti-cavitation type control valves to ensure long-term, noise-free operation at low loads.

The original stop-valve type or "Y" valve should be replaced with a control-valve also capable of tight shut-off service, a 40:1 turndown ability, and electrohydraulic actuator.

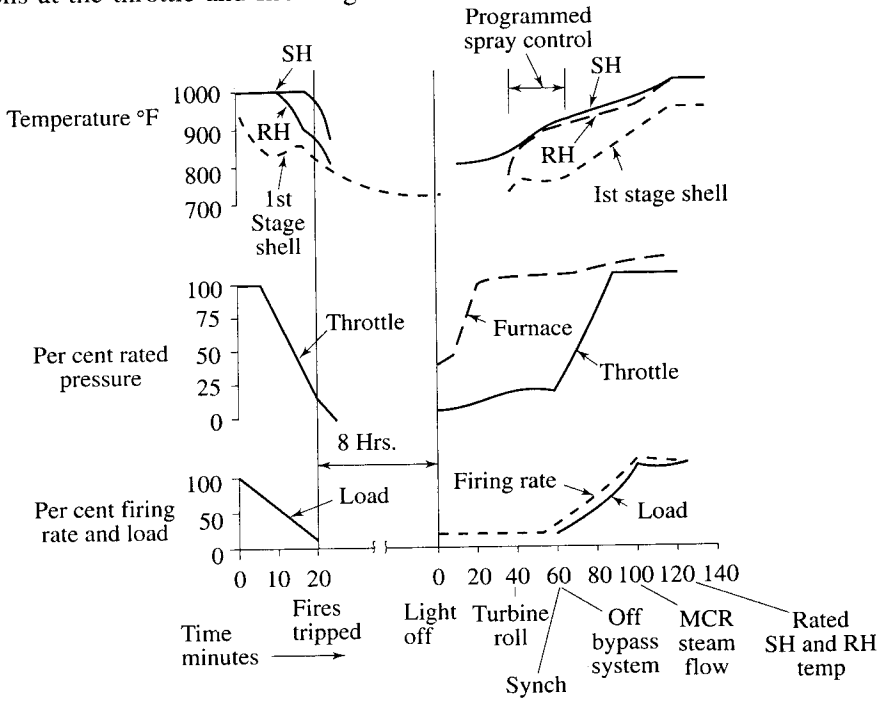


Fig. 13.8 *Hot restart conditions for an OTU retrofit with the ISSS a using a 60% hybrid-variable throttle pressure program.*

Source: *SP93-9 (Technical Paper/Foster Wheeler)*
Courtesy: *Foster Wheeler Energy Corporation/Clinton/NJ 08809-4000/USA*

Q. *What should be the nature of the spray control valve?*

Ans. The start-up spray control valve should be supplied as a multistage, low-recovery, anit-cavitation valve.

Q. *For more than two decades, spiral-wound furnace enclosure walls have been successfully used in European and Japanese OTUs. What for are they used?*

Ans. Their primary purpose, for new installations, is to enable variable pressure operation of both the furnace and superheater circuits thereby eliminating the need for ribbed tubes and the furnace circuit outlet pressure reducing station or the use of multiple series circuits with two phase flow mixing/distributing headers.

In retrofit applications, their primary purpose is to correct long-standing design deficiencies in those OTUs that demonstrate low waterwall availability, high waterwall maintenance costs, or MCR load limitation due to a high furnace pressure drop resulting from field corrections of original design deficiencies.

Q. *What is the advantage of variable pressure operation of the furnace?*

Ans. It lowers BFW pump power requirement during low load operation and translates to a 2% heat rate improvement at 20% MCR.

Q. *What is the most fundamental issue that goes against the spiral wound waterwall?*

Ans. The increased fabrication cost of the spiral wound waterwall goes against the spiral wound waterfall.

Note: However this higher fabrication cost of spiral wound waterwall is offset by the cost saving accruing from the elimination of series circuit downcomers and the elimination of the furnace outlet pressure reducing station. Fig. 13.9

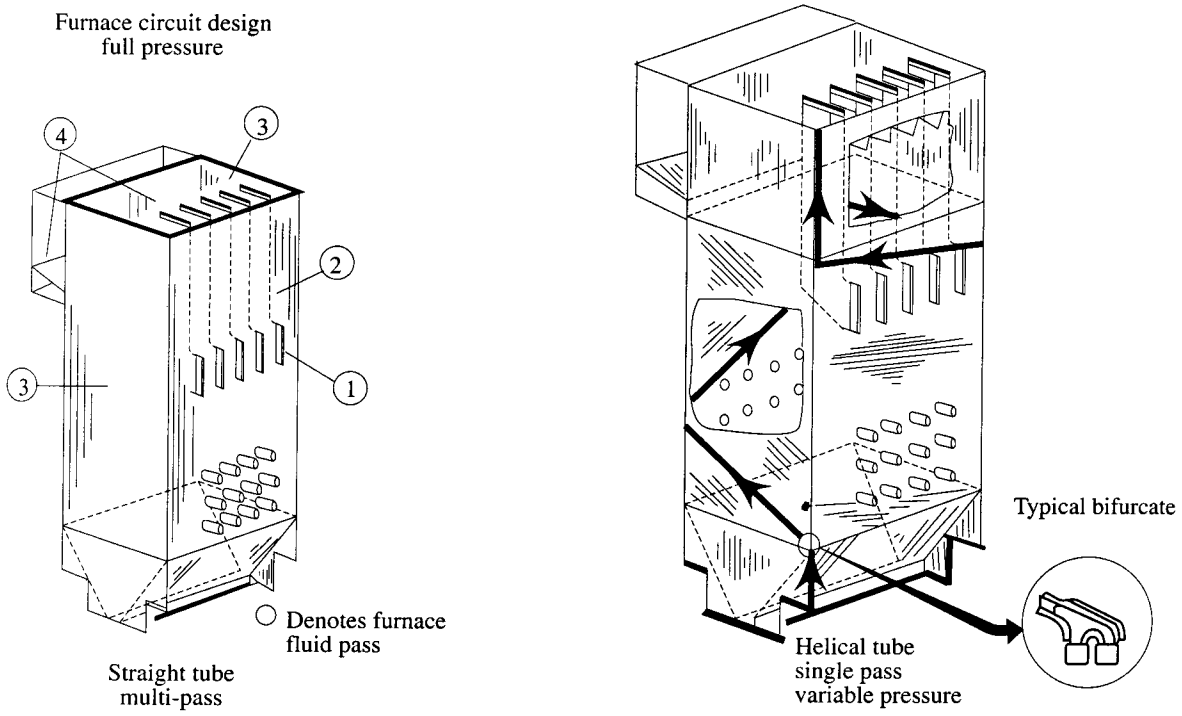


Fig. 13.9 *Comparison of vertical tubed furnace vs. spiral wound furnace.*
Source: SP93-9 (Technical Paper/Foster Wheeler)
Courtesy: FWEC/Clinton/NJ 08809-4000/USA

describes the schematic comparison of a vertical tube furnace and spiral wound furnace.

Q. *There are many supercritical OTUs that exhibit "Alligator Cracking", i.e. waterwall circumferential cracking and many subcritical OTUs have experienced short-term waterwall tube failures due to critical heat flux (CHF) events caused by tube-to-tube flow unbalances. Do you think the spiral-wound design would be a solution to these problems?*

Ans. Yes. A properly designed conversion to the spiral-wound design is a viable method of permananetly correcting such systematic design problems and that too without incurring MCR frictional pressure drop penalties above the original design allotment.

Q. *Some of the problematic domestic subcritical units which had extraordinarily high waterwall outage rates (endowing only 45% availability) have had their furnace problems addressed by replacing their smooth bore 13 mm ID waterwall tubes with single-lead ribbed tubes, and had additional circuit inlet orificing added to improve circuit flow distribution/sensitivity. In some of those cases, the increased pressure drop penalty was partially addressed by adding partial bypass lines around heated boiler circuits, but load limitation due to excessive pressures at the BFW pump was unavoidable in the time period prior to annual acid cleaning.*

Do you think such a field solution can improvise upon revamping the furnace with a spiral-wound design?

Ans. Yes. The above field solution can be improved upon by replacing the lower furnace with a spiral wound (smooth bore) furnace, with sufficient mass flowrate to limit post-dryout thermal stresses, and a minimum smooth bore tube ID of 20 mm to extend the acid cleaning interval to 3 yrs (for units using AVT). Smaller ID tubes may be rationalized with the combined-oxygenated feedwater treatment method. Forasmuch as the inherent thermal-hydraulic characteristics of the spiral-wound design will require less inlet orificing for stability/sensitivity purposes, full MCR capability would be restored to those units previously limited by furnace circuit pressure drop.

Q. *There are many supercritical units that experience*

1. *excessive waterwall outage due to alligator cracking*
2. *unacceptable levels of supercritical heat transfer deterioration at full load.*

Can these problems be eliminated by using the spiral-wound design?

Ans. Yes. For many of those supercritical units which badly suffer from excessive outage due to routine replacement of alligator cracked waterwall panels, a conversion to the spiral-wound design will eliminate this problem.

Due to other part-load requirements, the full load mass flowrate in a spiral-wound unit (using smooth bore tubes) will also be sufficiently high to avoid unacceptable levels of supercritical heat transfer deterioration at full load. This is easily obtained by varying the spiral azimuthal angle and the number of tubes.

Q. *In which units are the rotating (dynamic) classifiers used as equipment upgrades?*

Ans. These devices have found increasing application in the existing fleet of older, coal fired units in Europe where the stringent air pollution control laws are forcing the utilities to resort to furnace fuel staging to reduce NO_x levels at the furnace outlet.

Q. *How does this system of dynamic classifiers upgrade a PC-fired unit?*

Ans. Compared to a conventional mill which utilizes a stationary classifier, the 200-mesh fineness is improved from passing 70% up to 80%, and the 50-mesh fineness is improved from passing 96% to over 99.5%. It is the 50-mesh fineness that determines unburned carbon in staged combustion, and it is the improvement in unburned carbon that accentuates the need to install this device. The improved fuel fineness also reduces burner-to-burner fuel flow unbalances and reduces lower furnace slagging tendencies.

Q. *How does the fully-fired "Hot-windbox" combined cycle conversion upgrade a utility?*

Ans. Using a natural gas fired combustion turbine to supply secondary air to the windbox, a 25% station capacity increase may be associated with as much as a 5% improvement in the net station cycle efficiency (LHV) and a corresponding reduction in specific CO_2 emissions.

Q. *How do the Coal Flame Diagnostic Systems upgrade a PC-fired unit?*

Ans. Several manufacturers offer Coal Flame Diagnostic System. Due to recent technological developments it is now possible to estimate

(a) individual coal burner flame temperatures
(b) NO_x levels
(c) CO levels
(d) fuel: air stoichiometries

by monitoring each burner with a probe attached to the fiber optic cable, ultimately routed to a common fiber optic multiplexor. Each burner's flame is sequential analyzed by a flame spectrum analyzer, where each flame's emissive strength vs. frequency is determined, analyzed by using modern signal analysis methods and further processed by a multi-tasking PC.

The principal objective of such flame diagnostic systems is to permit individual burner tuning to minimize NO_x and CO levels while permitting safe, ultralow excess air levels with its associated higher boiler efficiencies.

Source: Equipment Upgrades for Pulverized Coal-Fired Utility Steam Generators—S.M. Cho and F.D. Fitzgerald (FWEC)

(Tech. Pap. presented at the International Symposium for Improved Tech. for Fossil Power Plants, March 1-3, 1993, Washington, D.C.

Courtesy: Foster Wheeler Energy Corporation/ Clinton/NJ 08809-4000/USA

Q. *Following the enactment of the Energy Policy Act of 1992, the power industry has moved towards competitive generation where low price wins and overall performance counts. Companies that produce electricity at or below the market-established base price will be able to sell all the power they produce while those generating Power at a higher cost will only be able to sell electricity when demand outstrips the low-cost supply.*

How can these old units survive in this competitive environment?

Ans. Upgradation of old units through

1. minimization of operating costs by increasing fuel flexibility, reducing other operating costs and boosting efficiency
2. improving availability
3. maximizing incremental capacity to avoid costly asset additions
4. reducing maintenance and outage time
5. optimizing emissions control to minimize cost, particularly variable operating cost.

Q. *The range of coal-fired units extend from 1950s-vintage low-pressure units (≈ 100 MW) to as large as 1300 MW modern supercritical units. What is the most basic problems that differentiates the old units from the large, modern units so far as upgradation is concerned?*

Ans. The design of these giant units is so specialized and complex that even a modest change in coal or modifications in operations may culminate into dramatic deterioration in unit performance and major equipment changes. So upgradation of these units has become rather a challenging task.

Q. *A conventional mode of upgradation is replacing boiler and auxiliary components in-kind as and when they reach the end of their useful life.*

Do you agree with this traditional concept even in the context of today's competitive environment?

Ans. This in-kind replacement is obsolete in today's competitive environment. Economics dictate that a component upgrade be implemented rather than an in-kind replacement if availability,

performance, or operating cost can be improved by the use of cutting-edge technology to net a cost advantage. If the operating costs can be brought down by a component upgrade, even if it means replacement of an equipment with a costlier module, then that upgradation should be hastened even if the individual component has not reached the end of its useful life.

Q. *What are the traditional approaches to upgrading and enhancing boiler system operation?*

Ans. These include various combinations of

(a) preliminary design studies
(b) bid package preparation
(c) project material bids
(d) separate erection bids.

Q. *Very often several different but related items are bid separately.*

Do you accept this traditional approach as a sound step to upgradation?

Ans. In today's competitive market, this traditional approach is proving to be less acceptable.

Q. *Why?*

Ans. Because this leads to the genesis of an adversarial relationship between the customer and the supplier. Different goals and objectives cause limited communication and breed less-than-optimal performance. As a consequence, the customer (powerplant) gets a particular solution to a specified problem instead of the 'the best' overall solution.

Q. *How can this problem be solved?*

Ans. Upgradation and project enhancements are unique efforts that require partnering, through longterm commitment, between the customer and supplier. And their common target will be to achieve a specific common project through maximizing the effectiveness of each partner's resources. This teaming up will bestow new and creative solutions through objective assessment to get the 'job' (upgradation) done. The joint teamwork will establish clear project objectives with measurable benchmarks, targets and incentives. Risks and rewards should be shared.

Q. *How does this customer-supplier partnership lead to a cost-saving upgradation? Is there any specific example?*

Ans. The most decisive phase of customer-supplier tie-up is project evaluation and conceptual design.

In one upgradation project, deNO_x ing was envisaged through combustion system upgrade hooking up with an SCR system downstream. However, through extensive calculation and simulation of a model it was found that a modified combustion system would be sufficient to meet the permissible limits of NO_x emission levels, thus cutting the current project scope and cost by 13 million US dollars. SCR system came out to be redundant!

Q. *A variety of coal-fired-plant upgrades and enhancements have demonstrated improved performance and reduced cost.*

Which is the key one among these upgrades?

Ans. Upgrading fuel flexibility.

Q. *Why?*

Ans. Fuel costs typically make up 70% or more of the plant's variable operating costs.

Q. *How is fuel flexibility ensured?*

Ans. A variety of options are available using

(a) individual coal with pulverizer upgrade
(b) blended coal
(c) co-firing with gas
(d) co-firing with low-cost fuels such as petroleum coke, Orimulsion etc.

Q. *How does pulverizer upgrade enhance overall system performance?*

Ans. Pulverizers are critical elements in reducing operating costs, meeting emission control requirements and beget boiler system flexibility especially when fuel-switch is involved.

Q. *For reduced emission we should install low-NO_x burners. What has the pulverizer to do with this?*

Ans. In fact installing low-NO_x burners (LNBs) to reduce emissions will increase loss-on-ignition (LOI). This means an increase in unburned coal carried over to ash. This LOI cannot be reduced unless coal fineness is improved.

Q. *How does fuel flexibility influence the capacity and performance of coal pulverizers?*

Ans. If there is a fuel-switch to a lower volatile coal there will be an increase in the amount of unburnt carbon in the ash unless coal fineness is improved. And that increases the load on the pulverizer.

Switching to a low-cost or low-sulphur coal can limit pulverizer capacity if the new coal is more difficult to grind, i.e. having low grindability or has a lower heating value. Lower-heating-value coals increase coal mass flowrate through the pulverizer for the same heat input to the boiler.

Q. *What is the harm if the load on the pulverizers is raised?*

Ans. New plant operating modes may require lower loads on the pulverizers where vibration and uneven pulverizer operation become important.

Q. *So how can we upgrade the pulverizer without taxing it with excessive load?*

Ans. One method is to instal a dynamic pulverizer system (Fig. 13.10) having an extended range of performance brought about by multistage rotating classifiers.

Another pulverizer design upgrade is to replace the stationary primary air throat (ring) with rotating elements resulting in reduced pressure-drop, extended component wear life and easier replacement facility.

Q. *Fuel switch frequently calls for greater pulverizer turndown capability. How can this be accommodated in pulverizer upgrade?*

Ans. The answer to this problem is installing a variable load system for the grinding elements. Manual or automatic speed adjustment of the dynamic classifier optimizes coal fineness as a function of the pulverizer through put. It makes immediate accommodation of fuel changes possible and permits superior mill turndown without the excessive vibration that occurs when the coal load in the mill is insufficient to maintain a stable coal layer between the grinding elements.

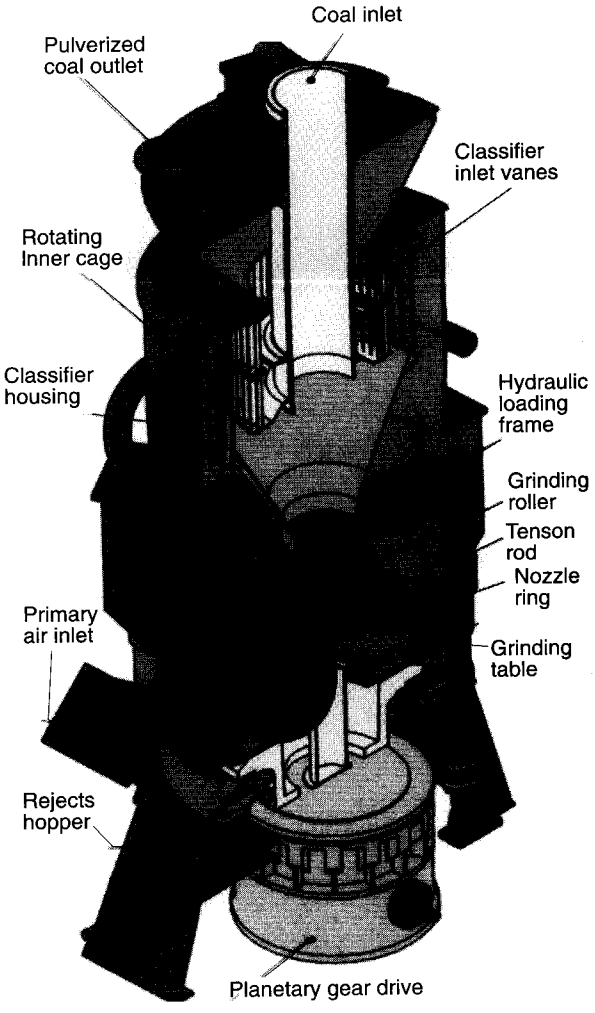


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Fig. 13.10 *Dynamic pulverizer system lends itself to plant upgrades for reduced NO_x emissions and low LOI enough to increase boiler efficiency by more than 0.5%.*

Q. *Is there any hazard associated with grinding high-volatile coals?*

Ans. Yes, explosion potential arising out of high-volatile coals.

Q. *How can this be prevented?*

Ans. Installing inerting systems reduces the risk of explosion potential.

Q. *Why is the modification of a variety of pressure parts in the steam-water circuit required in PC-fired upgradation?*

Ans. This may be due to

1. initial design deficiencies
2. changeover of the boiler from base-load operation to cycling service
3. change in heat absorption profile as a result of fuel switch.

Q. *If due to some reasons or other, a utility fails to respond to the necessity of upgrdation of pressure parts while making a fuel-switch or shifting its boiler from base-load duty to cycling service, what are the disadvantages it will encounter?*

Ans. Its boiler will be prey to following limitations:

1. less-flexible load-following operation
2. increased downtime
3. higher maintenance costs and hence unit price of its generated power will go high
4. limited boiler capacity.

Q. *What are the areas of steam-water side upgrades?*

Ans. Boiler upgrades involving steam-water circuit frequently have the following problems:

1. Tube overheating due to flow, stability or heat-transfer problems
2. Excessive water-side deposition caused by low flow
3. Feedwater control fluctuations
4. Drum level excursions
5. Header cracking and distortion
6. Overall steamflow limitation due to excessive water carryover to steam to the superheater or steam carryunder in the downcomer water flow.

Q. *What is the basic problem encountered during upgradation in these areas?*

Ans. These problems being highly interactive and complex, any upgrade that brings about a small pressure drop or flow change in one area culminates to significant deterioration elsewhere in the system.

Q. *Then what is to be done before upgrading the steam-water circuit?*

Ans. This requires detailed circulation analysis prior to any upgradation in the steam-water path.

Q. *What are these upgrades?*

Ans.

1. Revamping the boiler drum by installing low-pressure-drop-drum internals and thereby enhancing flow in drum boilers
2. Changing the drum internals to reduce water carryover and steam carryunder
3. Redesigning the circuit flowpaths
4. Addition/deletion of heat transfer surfaces
5. Replacing plain tubes by ribbed tubes.

Q. *Can you substantiate your claim that redesigning circuit flowpaths and/installing low-pressure-drop-drum internals really upgrade boiler performance?*

Ans. A large drum type boiler of western USA had been experiencing from wingwall tube-failures due to overheat. These problems prevented the boiler from operating at full load. A detailed engineering survey and model analysis of the original design were carried out only to find that water chemistry (and hence deposition), as originally thought, was not responsible for the problem, rather low flow velocities and flow imbalances resulting from film boiling inside the tubes were to blame.

Accordingly the boiler was revamped using the following solutions.

1. installing low-pressure-drop-drum internals to increase flow

2. redesigning the wingwalls to increase the absorption and driving head in the circuits and minimize any chance of instability
3. increasing the angle of the panel tubes (Fig. 13.11) from 17° to 40°
4. using ribbed tubes to prevent film-boiling.

Q. *The present trend in the power industry is to retire older and smaller units and instal larger units in their place. What is the most challenging task faced by these large boilers to survive competition?*

Ans. Conventionally, these large steam generation units are assigned to base-load duties. However, they are required today to perform cycling service and to operate as effectively and efficiently at low loads to economically meet total load demands. This is rather a challenging task for large units designed for base-load service because many

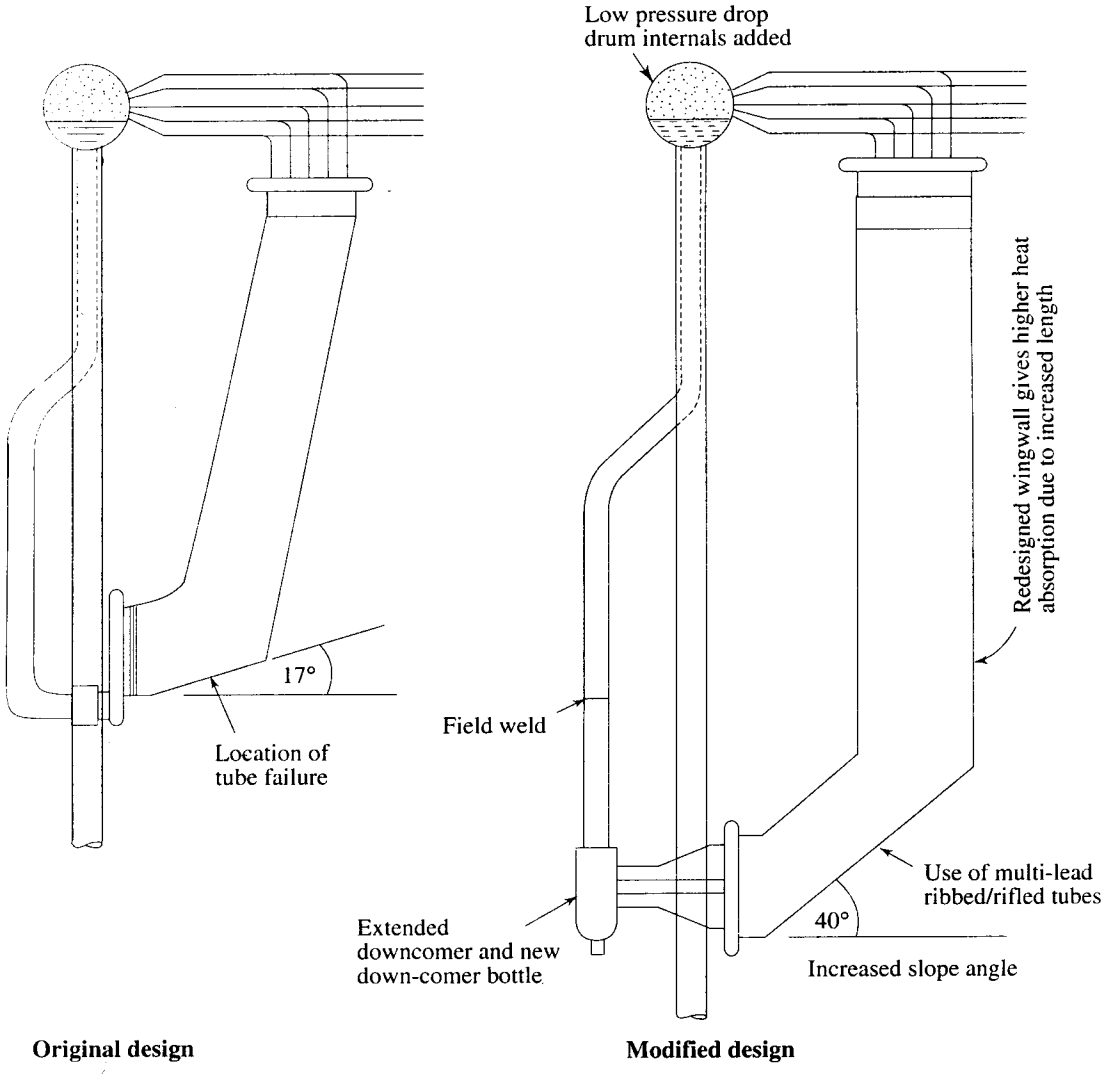

Fig. 13.11 *Redesigning the wingwalls increased absorption and circulation upgrades minimizing the chance of instability. Increasing the panel-tubes' angle and the use of ribbed/rifled tubes prevented film-boiling.*

boiler components and auxiliaries get badly affected.

Q. *What are the problems that crop up when large boiler units are subjected to cycling service?*

Ans. 1. Fatigue failures in the economizer and lower furnace tubes
2. Structural damage to areas such as windbox supports
3. Large temperature excursion varying from 110° to 200°K differential
4. Low flow in individual circuits when load is dropped to 15% of MCR
5. Mismatch between steam and gas flow requirements in steam turbines.

Q. *What upgrades and modifications can solve these problems?*

Ans. 1. An off-line recirculation system for drum type boilers is to be installed for use when the boiler is shutdown
2. Providing revised circulation systems for once-through units (OTUs) where series and parallel connections can be changed to accommodate sufficient flowrates in all tubes at all loads
3. Providing superheater bypass and dual pressure capacity to ensure better matching of steam pressure & temperatures from the boiler to turbine
4. Revamping OTU boiler furnace by replacing older multiple universal pressure circuit by spiral-wound furnace tubes in case OTU is supposed to swing from 100% MCR to 15% MCR during cycling service.

Q. *Why do you suggest an off-line recirculation system as a good revamp option for drum type boilers?*

Ans. This arrangement will feed a small amount of recirculation through the furnace and economizer, when the boiler is shutdown, to prevent temperature stratification and potential thermal shock during start-up.

Q. *Why do you think the superheater bypass and dual pressure capacity systems are sound upgrades?*

Ans. These systems will enhance the start-up speed of the boiler from low load or an off-load condition.

Q. *What are the problems that plague high-temperature headers and hence give best opportunities for revamping?*

Ans. High temperature superheater and reheater outlet headers operating at and above 755°K are the haunting grounds of HT creep even under normal operating conditions. The situation aggravates if the boiler is subjected to cycling service which generates thermal and mechanical stresses that give birth to creep fatigue. Creep fatigue combined with creep expedites the damaging process that leads to failure much sooner than creep alone. Cycling stresses accelerate weld crack, ligament failure and nozzle cracking in the high-temperature headers.

Q. *What upgrades are necessary to prevent these problems?*

Ans. The following upgrades can be used to counter high-temperature header problems.

1. New header design to reduce stresses
2. Using forzed instead of welded outlet nozzles
3. Increasing ligament spacing by spreading the header penetrations out around the header circumference instead of clustering them together. This reduces high stresses.
4. Redesigned tube hole penetrations to reduce stress concentrations.
5. Providing longer unrestricted tube legs to permit more flexibility to accommodate motion.
6. Using SA335 – 91 alloy (9% Cr + 1% Mo/V) to extend header life. Use of 9V alloy (SA335 – 91) in the superheater outlet header permits thinner header tubewalls which are less susceptible to creep failure damage.

Q. *Fuel-switch can result in cost benefits and in some cases reduced emissions. So fuel-switch is an august scheme to any thermal powerplant. Therefore, a designer need not be worried and should go ahead with upgradation program to accommodate fuel switchover.*

Do you accept this?

Ans. Introducing fuel-switchover is not so easy. Along with cost benefits and reduced emissions, a designer must essentially consider excessive surface slagging, fouling, and plugging brought about by change in ash chemistry due to fuel-switch as some heat transfer configurations are more sensitive than others.

Q. *How will the upgradation get affected in the event of increased furnace slagging invited by fuel-switchover?*

Ans. Increased furnace slagging will reduce heat absorption in the economizer and this results in higher furnace exit-gas temperatures (FEGTs). Elevated temperatures at the superheater inlet can invite superheater overheating, aggravate fouling and result in excessive attemperator flowrates. These high attemperator flowrates in turn tell upon overall cycle efficiency, and in some cases, handicap the utility with limited boiler load, because of insufficient spray capacity. The steam temperature control range is also reduced. And if the unit is an older one, it will suffer more badly from corrosion, erosion and mechanical/structural problems.

Q. *How will the upgrades battle excessive slagging, fouling and plugging in the event of fuel-switch?*

Ans. Economizer is to be redesigned. Design options include

1. tube spacing
2. tube arrangement
3. bare/fin tube heat exchange surface
4. support relocation
5. gas velocity adjustment
6. gas bypass baffles/distributors
7. erosion barriers
8. sootblower shields.

Q. *If these modifications are implemented what benefits it will yield?*

Ans. It will

(a) reduce fouling
(b) improve cleanability
(c) reduce pressure loss
(d) reduce forced outage rates
(e) limit corrosion, erosion and mechanical damage.

Q. *What is the basic problem faced by the designer to make such an upgraded design?*

Ans. To perform upgraded design in a limited, pre-existing space.

Q. *What are the upgrades in the high-temperature convective shaft of the furnace to reduce overheating and fouling?*

Ans. This requires furnance-arch modification to ensure uniform gasflow distribution at the superheater inlet, thereby reducing the risk of overheating and fouling. Fortunately, the superheater and reheater geometries are flexible and can be designed to curtail fouling/slagging, erosion, and plugging or modify overall thermal performance.

Superheater and reheater tubes need material-of-construction (MOC) upgrades in case excessive temperature restrict boiler load. This gives an extra margin for uninterrupted operation.

Surface treatments and coatings—like chromizing—can be good upgrade options. They reduce steam-side oxidation/exfoliation and drastically cut down fireside corrosion.

Infurnace low-NO_x combustion technology may invite local corrosion of superheater tubes and membrane panels. Surface coatings have been reported to extend tube life.

14

FUEL OIL AND GAS FIRED FURNACES

Q. *Why can natural gas and fuel oil be burnt on furnaces of the same design?*

Ans. Because of common combustion characteristics:

1. Both natural gas and fuel oil contain practically no moisture and they give rise to roughly the same volume of combustion products.Thus the blowers of steam boiler run efficiently irrespective of whe-ther fuel oil or natural gas is being burnt in the boiler furnace.
2. Combustion of either fuel takes place in the vapour state and the intensity of burning in either case is determined by the conditions of intermixing. Combustion mechanism is the same.
3. Both fuels have nearly the same value of highest allowable heat release rate per unit volume of the furnace. For fuel oil it is 300 kW/m^3 and for natural gas 350 kW/m^3. And as such for the same steam output of a boiler, the furnace dimensions for these two kinds of fuel can be taken to be the same for practical purposes.
4. Both fuels are practically free from ash-formation problem upon combustion. Therefore, clinkering of waterwall tubes does not arise and slag-handling facilities are unnecessary. This is why furnaces for both fuels are designed with a horizontal or slightly inclined bottom.
5. More homogenization of air-fuel mixture is possible as both fuels are in a vapour state prior to ignition. This means virtually complete combustion with less amount of excess air.
6. For both fuels, air can be preheated to the same temperature 250–300°C (523–573 K) making it possible to install combined gas-fuel oil burner system.
7. Both fuels produce a relatively short flame core-zone near the burners during intensive burning.

Q. *How many type of gas and fuel oil fired furnaces are there?*

Ans. There are five types:

1. Open-type furnace with single-front, multitier burners layout. (Fig. 14.1a)
2. Double-wall constriction and double-front burners. (Fig. 14.1b)
3. Open-type furnace with opposite double-tier burner arrangement. (Fig. 14.1c)
4. Open-type furnace with opposite cyclone primary furnaces. (Fig. 14.1d)
5. Furnace with straight flow having burners at the bottom. (Fig. 14.1e)

Q. *In how many tiers are the burners laid out in the single-front arrangement?*

Ans. Usually three or four tiers.

Q. *What are the advantages of this arrangement?*

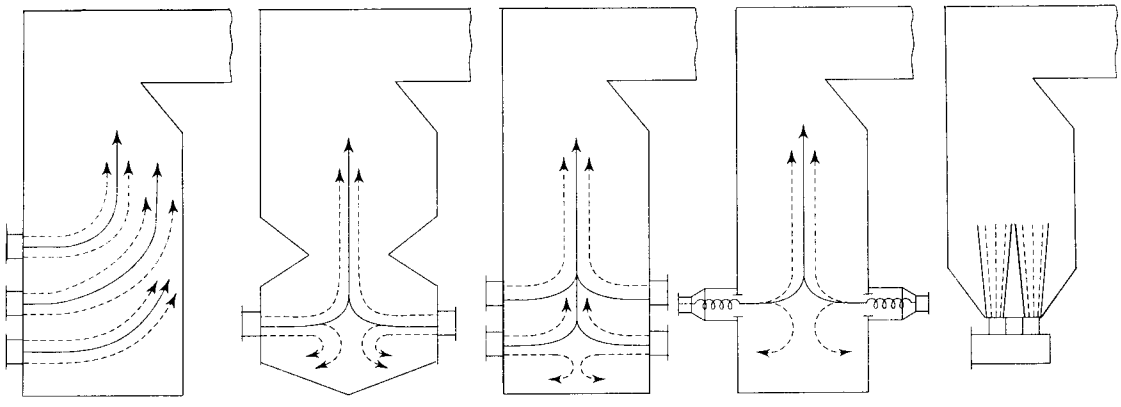

Fig. 14.1

Ans. Less expensive and operation is more convenient.

Q. *What are its drawbacks?*

Ans. The chief disadvantages being:

(a) non-uniform filling of furnace space by the flame

(b) incompatible with furnaces of short depth (< 6m) because of intolerably high heat absorption with the consequence that there is a high temperature rise in the rear waterwall.

Q. *What are the primary advantages of opposite arrangement of burners?*

Ans. 1. Higher heat release rate (20–30% higher than single-front burners) in the flame core zone

2. Conditions are favourable for concentrating the flame at the centre resulting in the uniform distribution of flame heat throughout the furnace space.

Q. *When a boiler is switched over from fuel oil to natural gas firing, heat absorption in the furnace space decreases. Why?*

Ans. Flames produced by natural gas have lower emissivity than those produced by fuel oil upon combustion. Since the mode of heat transfer within the furnace space is of radiative type, decrease in flame emissivity results in lowering of the heat absorption rate.

Q. *Why are the combustion products at the furnace outlet at a higher temperature in the case of natural gas firing system than fuel oil firing?*

Ans. As heat absorption rate in the furnace space decreases because of lowering of flame emissivity when the furnace is fired with natural gas, combustion products will exit the furnace at a higher temperature.

Q. *What changes are done when a furnace with straight flow having burners at the bottom is switched over from fuel oil firing to natural gas firing? Why?*

Ans. The degree of whirling of secondary air flow is increased.During fuel oil combustion, the degree of swirling of secondary air is decreased to allow the flame to reach up to a greater height of the furnace with the effect that local heat flow to the waterwalls noticeably decreases.

And when firing natural gas, the degree of swirling is increased to make the flame wider and shorter.

Q. *Sometimes fuel oil or furnace oil is referred to as an ideal kind of fuel. Why?*

Ans. It is composed almost entirely of hydrocarbons. It contains only traces of oxygen and negligible amounts of moisture and ash. Hence the combustion of F.O. is practically the combustion of hydrocarbons with no solid residue leftover. Hence it is called an ideal fuel.

Q. *How is fuel oil burnt in the combustion chamber?*

Ans. There are three ways of burning fuel oil in the combustion chamber:

(a) Direct combustion of F.O. in combustion chamber, in natural mass
(b) Combustion of pulverized F.O.—pulverization being carried out by atomizers or spray burners.
(c) Combustion of vapourized F.O.—vapourization being carried in drip conversion boxes.

Q. *What is the direct method of combustion of F.O.?*

Ans. It is the simplest and oldest method. Oil flows, by gravity, into a cast iron box placed in the combustion chamber. (Fig. 14.2).

Air flow into the combustion chamber is controlled by means of shutter above the box and channels below the box.

Fuel consumption is 4 kg/h and flame length approximately 1 m.

Q. *For what purpose is it used?*

Ans. Chiefly used in small-capacity room heaters and cooking stoves.

Q. *What do you mean by pulverization of liquid fuel?*

Ans. It means atomization of liquid fuels, i.e. dispersing liquid fuel jet in a fine churn of spray into the dispersing medium.

Q. *Why is it necessary?*

Ans. For efficient combustion of liquid fuels.

Q. *How?*

Ans. As the fuel oil gets pulverized, its surface area increases manyfold and finely dispersed fuel oil particles become intimately mixed with combustion air. Greater the surface area exposed for combustion and better the intermixing with the air, more complete and rapid will be the combustion process.

Q. *How can F.O. be atomized?*

Ans. By three methods:

(a) **Steam Atomization**—fuel oil, at the exit of the burner, is pulverized by the atomizing action of one or more jets of steam.
(b) **Air Atomization**—fuel oil is atomized in the same way as steam atomization—the only difference is that air instead of steam is used as the atomizing agent.

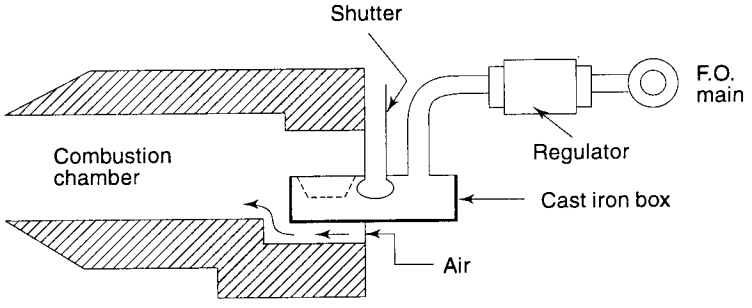

Fig. 14.2 *Simplest and the oldest method for direct firing of fuel oil.*

(c) **Mechanical Atomization**—fuel oil is broken down into finely divided minute particles by means of mechanical devices.

Q. *What are the advantages of steam atomized oil burners?*

Ans. 1. Simplicity in burner design
2. Easy operation of the burner
3. Low perheating temperature (upto 80°C) for fuel oil
4. Very useful in smaller installations.

Q. *What is their main drawback?*

Ans. High consumption of steam for atomization (30–40% of fuel oil consumption).

Q. *How are steam atomized oil burners classified?*

Ans. Their classification is based on the nature and shape of the flame produced. Accordingly, they are classified into:

(a) **Round shaped burners**—that produce a round, long or short flame, with slightly expanded central zone.

(b) **Flat burners**—that produce a long tape-like flame or short turbulent flame.

Q. *Apart from the shape of the burner nozzle, what is the other main difference between round-burners and flat-burners?*

Ans. It is the flow path of the fuel and its atomizer.In round burners, the stream of fuel oil is allowed to pass through the inner or outer pipe whereas in the case of flat burners the fuel oil flow is directed either through the same path as the steam or through a channel parallel to the steam channel.

Q. *What is the mechanism of steam atomization of fuel oil?*

Ans. A jet (or jets) of steam ejected at a pressure of 0.4 to 0.6 MN/m^2 is directed upon a stream of fuel oil. As the steam with high kinetic energy collides with the jet of fuel oil, it, by imparting its kinetic energy to F.O. disintegrates the fuel oil stream into minute droplets, approximately 0.01 mm or even less in diameter. These disintegrated particles are called pulverized fuel oil and that's how steam atomization of fuel oil is effected.

Q. *Briefly describe some steam atomized fuel oil burners.*

Ans. 1. **Shukhov burner:** made of phosphor-bronze. It consists of two concentric tubes—inner tube for oil and outer tube for steam flow. (Fig. 14.3).

While the cross-sectional area of the oil outlet remains constant, the size of the ring-shaped passage for steam may be increased or decreased by the to-and-fro movement of the inner tube with the help of a handwheel.

Fuel oil delivery through the inner tube is controlled by means of a gate valve mounted on the fuel oil main while the steam supply can be dou-

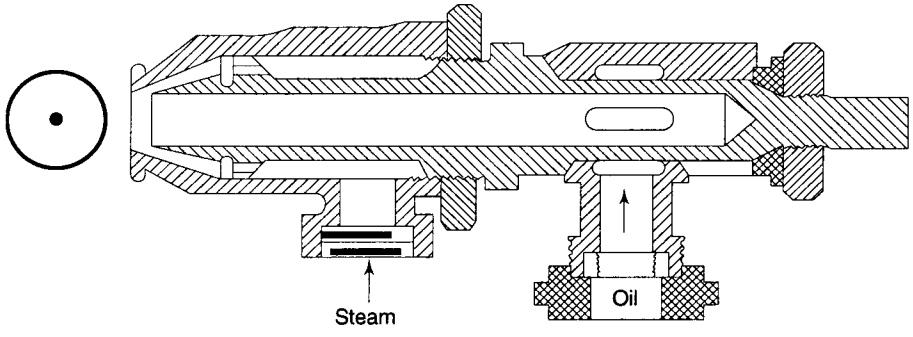

Fig. 14.3 *Shukhov burner.*

bly controlled by the handwheel as well as by the gate valve installed in the steam main. Consumption of fuel oil is controlled either by change of velocity of the discharge or by changing pressure in the spray burner.

Oil consumption: 3.5–195 kg/h
Oil aperture: 2–16 mm
Steam aperture: 4.5–20 mm

2. Vagener burner: is similar to the Shukhov burner. Oil is delivered through the inner tube and steam in the annulus between the inner tube and the nozzle.(Fig. 14.4)

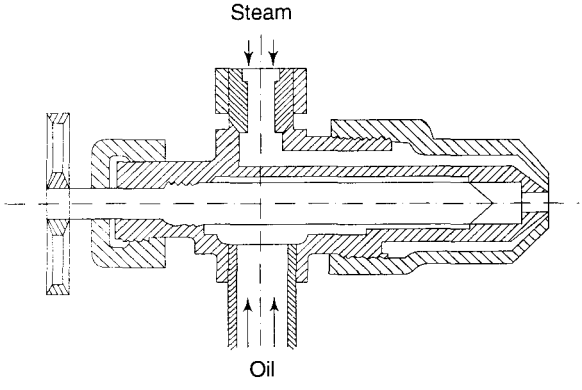

Fig. 14.4 *Vagener burner.*

The outer surface of the inner tube is fitted with oblique ribs to produce swirling motion in the steam to provide better intermixing of air with atomized fuel.

Normal capacity = 100 kg F.O./h

Now this capacity can be increased by 50% without appreciable steam consumption.

3. Varganov burner: is fitted with multiple nozzles to effect atomization as well as swirling motion of both oil and steam.

Oil flows through the inner pipe to the inserted nozzle that delivers it into the atomizing chamber in the form of a swirl. At the same time, steam is delivered through the outer pipe to the nozzle. The pattern of threading on the cylindrical portion of the nozzle induces a rotary motion in the same direction as the F.O. stream. Owing to the peculiar shape of the atomizing chamber, the spiral rotary flow of steam smoothly narrows down before the primary nozzle and strikes the spiral flow of the fuel oil obliquely. This preheats the oil as well as accelerates the flow. (Fig. 14.5).

From the atomizing chamber, the steam-fuel oil mixture enters the final atomizing chamber through the primary nozzle. Here, further intermixing takes place.

Ultimately, the ready-mixture issues through the final nozzle into the combustion chamber where a further atomization of fuel takes place under the action of centrifugal force.

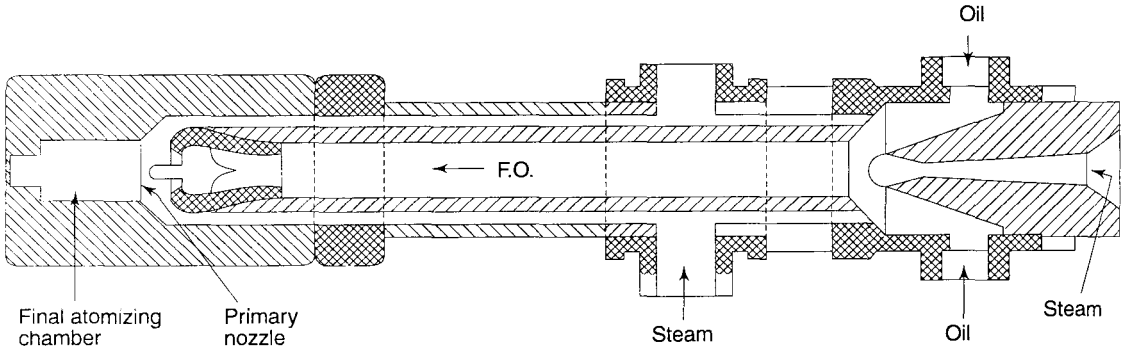

Fig. 14.5 *Varganov burner.*

4. Saha's burner: was designed by A.K. Saha. Oil is distributed to pass through several holes (3 mm dia) while atomizing steam is passed through the central pipe to the central nozzle of 4 mm dia. (Fig. 14.6)

Burner capacity 30–35 kg F.O./h

Q. *Apart from the classification based on the shape of the flame, how can steam and air atomized burners be classified?*

Ans. They can be classified as:

(a) **Internal mixing burners**—where atomizing fluid (steam or air) and oil impinge within the burner assembly. (Fig. 14.7).

(b) **External mixing burners**—where steam (or air) is directed into the oil stream or oil is directed into the atomizing fluid at the burner outlet.

Q. *How many kinds of steam (or air) atomizers are there?*

Ans. There are three kinds of steam atomizers.

1. Low pressure atomizer: using air (0.105-0.115 MN/m^2) as the atomizing medium. A larger proportion and sometimes the entire combustion air is used as atomizing fluid.

Turndown Ratio 2 : 1 – 5 : 1

2. Medium pressure atomizer: using air at 0.23-0.3 MN/m^2. Less than 10% of the combustion air is required to atomize the fuel.

Turndown ratio 10:1

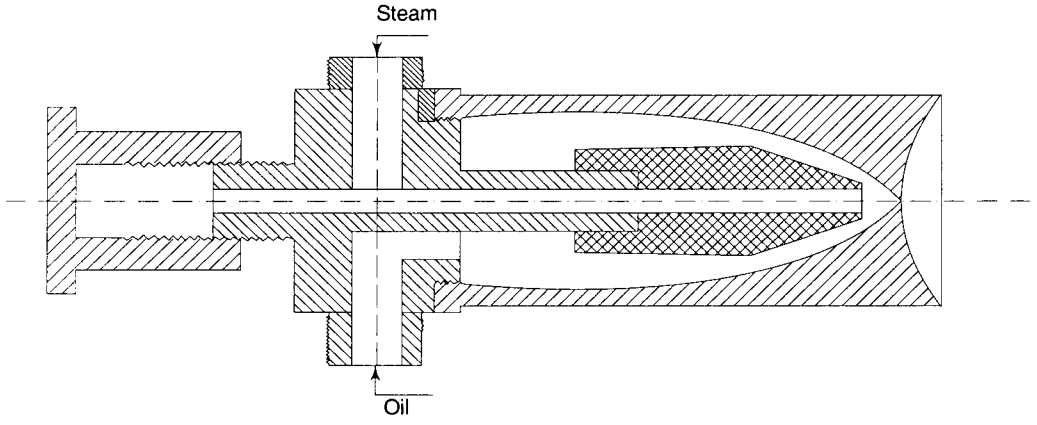

Fig. 14.6 *Saha's burner.*

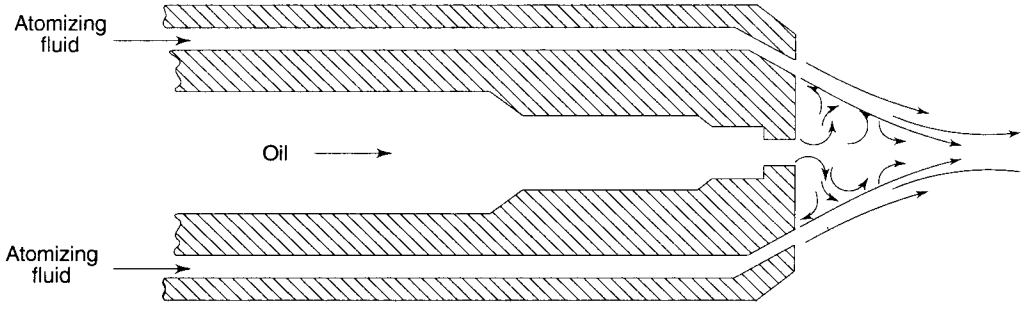

Fig. 14.7 *Internal mixing burner.*

3. High pressure atomizer: using air or steam at pressure exceeding 0.3 MPa (0.3 MN/m^2). Steam requirement: 0.3 – 0.5 kg/kg of fuel oil.

Q. *What is turndown ratio?*

Ans. It is the ratio of maximum to minimum load.

Q. *Briefly describe an air atomized burner.*

Ans. A commonly used air atomizer is as shown in Fig. 14.8. Oil flows through the central pipe fitted with the nozzle at one end and oil regulator at the other end. The oil stream issuing from the nozzle meets at a sharp angle the air stream flowing through the outer cylinder. Ribs are fitted to the path of the airflow to induce vorticity to air stream for better mixing with the pulverized fuel. (Fig. 14.8).

Q. *What amount of air is required for the pulverization of 1 kg of fuel oil?*

Ans. Theoretically 14 kg (approx).

Q. *How is droplet size dependent on the viscosity of F.O.?*

Ans. It is directly proportional to the viscosity of F.O.

Q. *How does droplet size vary with the pressure of fuel oil?*

Ans. It varies inversely with the cube root of fuel oil pressure.

Q. *How is mechanical pulverization of fuel oil carried out?*

Ans. This is carried out by delivering fuel oil under excessive pressure (2.5–4.5 MPa, i.e. 2.5–4.5 MN/m^2) into the whirling chamber and forcing it through a narrow hole or nozzle. Fuel oil enters the whirling chamber through a number of tangential channels and it acquires intensively turbulized spiral motion. Depending on the ratio of the tangential and axial velocity components, the whirling fuel oil film expands at the burner outlet and gets disintegrated by the oncoming air flow into numerous fine particles traversing a parabolic path. (Fig. 14.9)

Q. *Upon which factors do the fineness of atomization and the size and shape of the fuel oil particles depend?*

Ans. These depend on the following three factors:

1. **Burner Capacity** which in turn depends on nozzle diameter and fuel oil pressure.
2. **Spiral Pitch of the Fuel Oil** which is the function of the nozzle diameter
3. **Flow Resistances** as offered by the turbulent flows and frictions.

Q. *How is the throughput capacity of a mechanical burner related to the fuel oil pressure?*

Ans. The relation is:

$$B = b\,\mu\,A\sqrt{P\rho}\ ,\ \text{kg/s}$$

where B = throughput capacity of the burner, kg/s

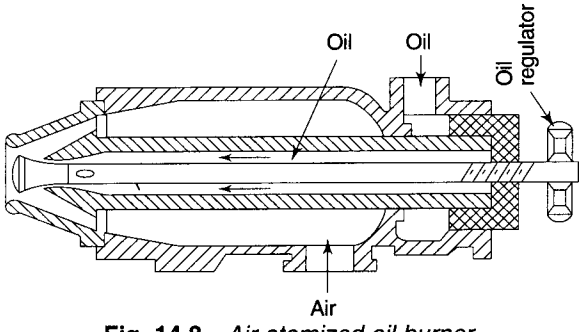

Fig. 14.8 *Air atomized oil burner.*

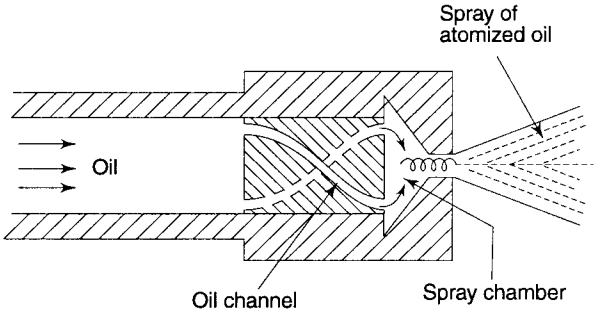

Fig. 14.9 *Mechanical pulverization of oil.*

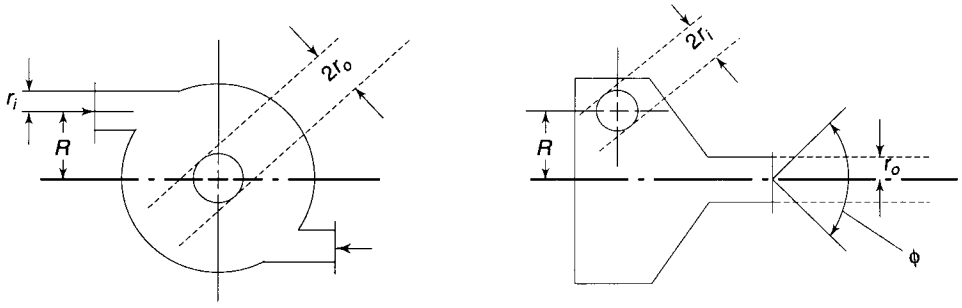

Fig. 14.10

b = multiplication factor
μ = flowrate coefficient
A = cross-sectional area of the ejecting nozzle, m^3
P = fuel oil pressure, MPa (MN/m^2)
ρ = fuel oil density, kg/m^3

Q. *What is the throughput capacity of a powerful centrifugal burner?*

Ans. It varies from 3 to 16 t/h for burners with nozzle diameter

$$d_o = 4 - 10 \text{ mm}.$$

Q. *What are the principal characteristics of a mechanical burner?*

Ans. The principal characteristics of a burner are

1. Dimensionless geometric parameter, Z

$$Z = R\ r_o/r_i^2$$

where R = distance between the burner-axis and axis of the tangential channel
r_o = nozzle radius
r_i = radius of the internal gas whirl

2. The coefficient of free cross-sectional area

$$f = 1 - (r_i/r_o)^2$$

3. The flowrate coefficient, μ

4. The jet expansion angle, ϕ

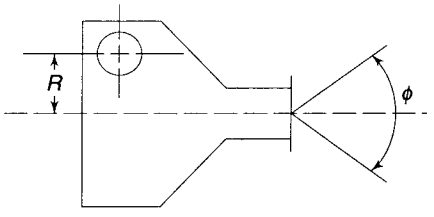

Fig. 14.11

Q. *How do these characteristics vary with the geometric characteristics of a burner?*

Ans. Fig. 14.12

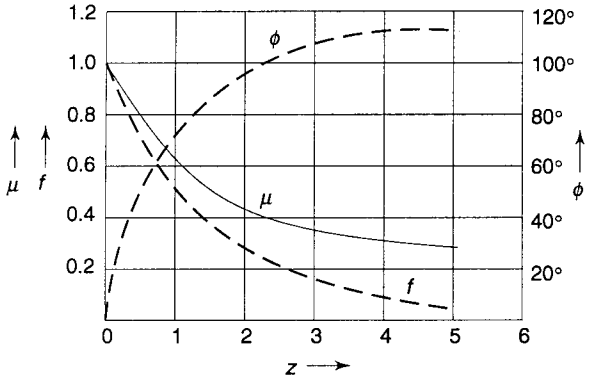

Fig. 14.12

Q. *Describe a mechanical atomizer.*

Ans. 1. **Körting atomizer:** It consists of a pear shapped nozzle into which is concentrically abutted a rod with rectangular threading at its nozzle-end. (Fig. 14.13)

Fitting closely to the inner walls of the nozzle, the threading provides high pitched passages. The rod terminates with a pointed end, the outer shape of which conforms exactly to the inner shape of the nozzle.

The outlet aperature of the rod varies from 1 to 2 mm in diameter depending upon the spray capacity of the burner which varies from 50 to 80 kg of fuel oil per hour.

F.O. preheated to 50–60°C is directed to the burners at 5–12 atm. pressure.

2. Adjustable mechanical atomizer: it is fitted with gadgets to adjust and alter the nozzle-diameter, thus controlling and adjusting the capacity of the burner. (Fig. 14.14).

Q. *Mechanical burners have a narrow throttling range. Why?*

Ans. Its throughput capacity, i.e. flowrate through the nozzle is directly proportional to the square root of pressure of the fuel oil feed. As a result this type of burner has a narrow throttling range, because doubling the pressure will increase the rate by 40% only.

Q. *What will happen if, during atomization, the fuel oil pressure is gradually decreased?*

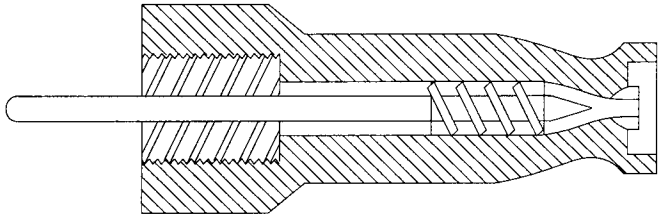

Fig. 14.13 *Körting burner.*

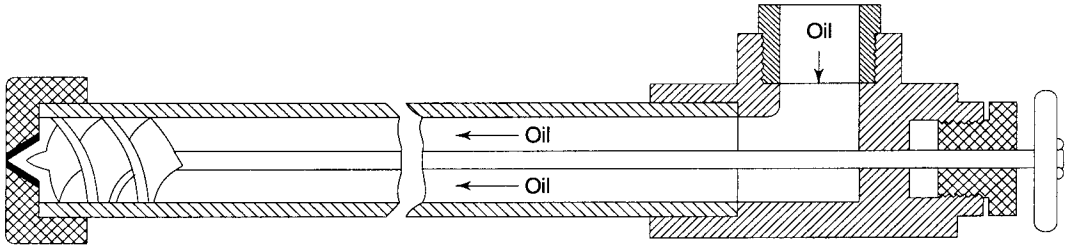

Fig. 14.14 *Adjustable mechanical atomizer.*

Ans. As the fuel oil pressure is gradually decreased, droplets of atomized fuel oil will grow in size. Ultimately there will be a minimum fuel oil pressure at which the droplets will grow too large to burn completely.

Q. *What is a rotary burner?*

Ans. It is a special type of burner in which atomization of fuel oil is achieved by centrifugal force. (Fig. 14.15).

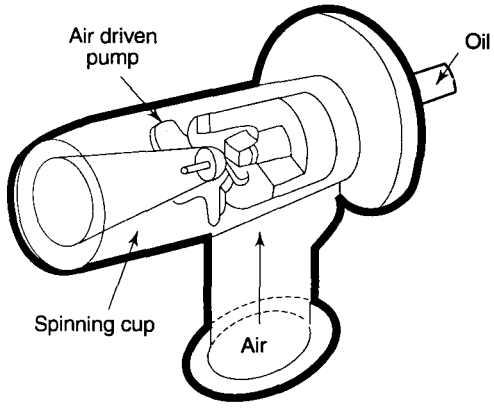

Fig. 14.15 *Rotary fuel oil burner.*

Preheated oil streams through the central pipe and ejects upon the inner surface of the spinning cup—a hollow tapered cup revolving round the same horizontal axis of oil flow.

As the oil spreads over in the form of a thin film over the surface of the rotating cup, it is thrown off the periphery of the free end of the cup by centrifugal force. The velocity of oil flow and its thickness over the circumference of the cup-rim remain uniform because of the uniformity of the cup surface.

The result: Good atomization and uniformity in droplet size.

The cup is rotated by a turbine driven by a portion (15%) of the atomizing air required for combustion. Air is supplied at a pressure of 0.2–0.35 MPa (MN/m^2).

Q. *What is the turndown ratio of a rotary atomizer?*

Ans. 5 : 1.

Q. *What are the advantages of a rotary atomizer?*

Ans. 1. Good atomization
2. Droplets produced are more uniform in size than those produced by any other method.
3. Much less sensitive to viscosity change of fuel oil.
4. Much less liable to clogging by grit than other mechanical atomizers.

Q. *What is its main drawback?*

Ans. Carbon deposition.

When the burner is taken shutdown, deposition of carbon particles, due to thermal cracking of fuel oil induced by radiation heat from the hot surroundings, takes place on the rotary cup surface, destroying its smoothness.

Q. *Briefly describe a steam-mechanical burner.*

Ans. It is a common oil burner befitted with an additional capacity of steam atomizing. Instead of centrifugal whirling chamber, an axial whirling device fitted with a conical dissector is provided in the burner assembly.

Oil stream flowing through the central pipe acquires a spiral motion in the whirler and ejects from the conical dissector in the form of jet. (Fig. 14.16).

Steam, supplied at a pressure of 0.2–0.4 MPa, passing through the annular channel at near critical speed penetrates the fuel oil jet and disintegrates it into fine droplets.

Steam consumption for atomization: 10% of F.O. flowrate

Capacity control: 20–100% of the rated value.

Q. *Why is the quantity of atomizing air requirement much higher (1.5 times higher) than that of atomizing steam when F.O. is atomized?*

Ans. This is due to the higher energy content of steam.

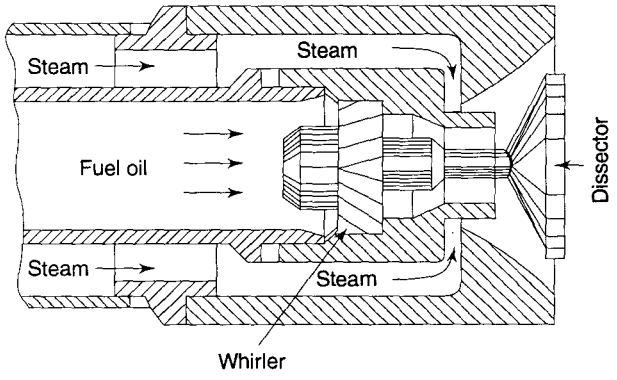

Fig. 14.16 *Steam-mechanical burner.*

Steam jet with higher thermal and kinetic energy penetrates the fuel oil jet more easily than air jet with lower energy content. Upon collision with the oil jet, steam imparts more thermal as well as kinetic energy to the oil stream which therefore disintegrates into fine droplets. Hence, for a given quantity of fuel oil pulverization, steam requirement is less than air requirement.

Q. *In steam-mechanical burners oil is ejected from the nozzle in the form of a thin hollow cone. What is the range of thickness of this cone?*

Ans. 50–100 μm.

Q. *What is secondary atomization?*

Ans. The oil film ejected from the burner nozzle in the form of a thin hollow cone expands and breaks into fine droplets which proceed at a speed 60-80 m/s. These particles get further atomized by the dynamic pressure of the oncoming stream of the atomizing medium (air or steam). This process is called secondary atomization.

Q. *Upon which factors, does the droplet size of atomized oil depend in the case of steam-mechanical burners?*

Ans. 1. Energy of the atomizing steam
2. Efficiency of steam utilization for fuel oil atomization.

Q. *The size of the largest oil droplet in the case of powerful mechanical burners may be as large as 1.5–2 mm in size. So why should the heat release rate per unit volume of the furnace using these powerful mechanical burners not be more than 200–250 kW/m^3?*

Ans. Because of their size, larger droplets (1.5–2 mm) will take more time to evaporate and burn (roughly equal to 1.5–2 s).

Hence from the correlation between the heat release rate per unit volume and the residence time of the furnace gas (that vertically lifts the larger droplets upwards) we find heat release rate/m^3 of the furnace should not exceed 200-250 kW/m^3 so as to ensure complete combustion of the fuel. (Fig. 14.17).

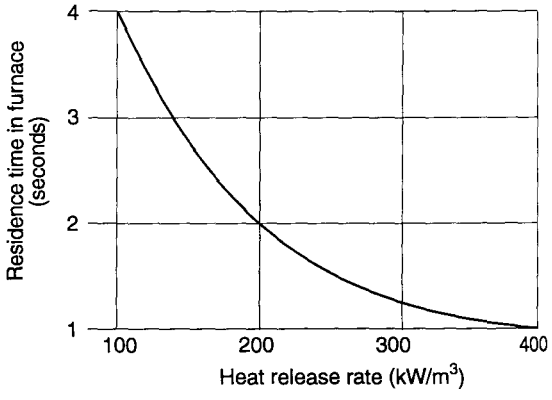

Fig. 14.17

Q. *How many methods are there to control the throughput capacity of a fuel oil burner?*

Ans. There are two methods:

(a) By controlling the fuel oil pressure (qualitative method)
(b) By switching some of the burners on and off (quantitative method)

Q. *What difficulties are encountered in the qualitative method of fuel oil control?*

Ans. In order to reduce the load, it requires substantial reduction of initial pressure. For instance, if throughput is to be reduced from 100% to 60% of the rated value, it turns out that fuel oil pressure must be reduced to 0.37 of the initial value forasmuch as throughput capacity is proportional to the square root of fuel oil pressure. On the other hand, a sharp drop in fuel oil pressure in mechanical burners will result in a lower intensity of whirling, producing a thicker film, lower velocity at nozzle outlet and larger droplets. Hence sharp pressure reduction is inadmissible.

Whereas an increase of F.O. pressure to increase the burner throughput will need more intricate and expensive equipment for oil transport and flowrate control. And all these would mean higher operating cost.

Q. *Why is the throughput capacity of the mechanical burners controlled by the combined use of qualitative and quantitative method?*

Ans. As stated above.

Q. *How does quantitative control lend itself to qualitative control?*

Ans. When a boiler furnace is fitted with a good number of oil burners, the load on the boiler can be reduced by switching off some of the burners in a group. This will result in a higher delivery pressure of the F.O. supplied to the rest of the burners in line, thus allowing the boiler load to be further controlled by varying the fuel oil pressure.

Q. *Steam-mechanical burners are very useful for high-capacity steam boilers. Why?*

Ans. Because they ensure throughput control in the whole range of operating loads. At lower loads, fuel oil is atomized by the energy of steam.

Q. *How are gas burners classified?*

Ans. 1. BURNERS IN WHICH GAS-AIR MIXTURE IS PREPARED PRIOR TO COMBUSTION:

(a) High pressure injection burners with single-stage suction.
(b) High pressure injection burners with multistage suction.

2. BURNERS IN WHICH GAS-AIR MIXTURE IS PRODUCED IN THE COURSE OF COMBUSTION PROCESS:

(a) Diffusion burners
  (i) cylindrical type
  (ii) flat type
  (iii) combined type
(b) Irregular turbulent burners
  (i) parallel tubes (coke-over burners)
  (ii) ports (open-hearth furnace burners)
  (iii) channels (glass furnace burners)

3. SUBMERGED COMBUSTION BURNERS

(a) Low pressure injection type of Saha
(b) Kemp and Hammond burner

Q. *What volume of hot air is required to burn 1 m^3 of natural gas?*

Ans. Roughly 20 m^3.

Q. *Why is the gas supply channel smaller in cross-sectional area than the air duct of gas burner?*

Ans. It is because the volume of combustion air required per m^3 of natural gas burned is very large.

Q. *How can proper intermixing of the gas and air be ensured?*

Ans. By directing the stream of gas in the form of thin jets of high penetrability into the air stream.

Q. *How can the degree of penetrability of natu ral gas jets in air stream be increased?*

Ans. By raising the gas velocity to as much as 120 m/s.

Q. *What is the air velocity?*

Ans. It is 25 – 40 m/s.

Q. *How is gas introduced to the air stream?*

Ans. 1. Single jet entering at right angles to air-flow. (Fig. 14.18)

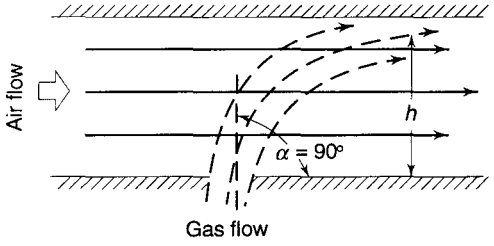

Fig. 14.18

2. Single jet entering at angle $\alpha < 90°$ to air-flow. (Fig. 14.19)
3. Multiple jets entering at $\alpha > 90°$ to air-flow. (Fig. 14.20)

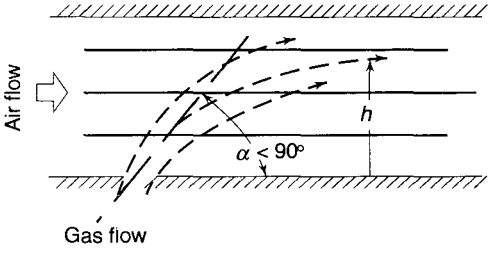

Fig. 14.19

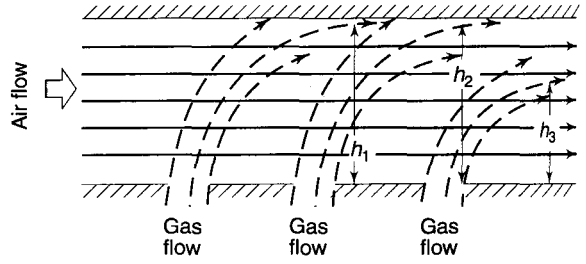

Fig. 14.20

Q. *What is the depth of penetration?*

Ans. It is the distance (h) along the normal from the root of the jet to the point where the direction of the jet becomes coincident with that of the air-flow.

Q. *On which factors does the depth of penetration depend?*

Ans. Diameter of the jet and the ratio of gas and air stream velocities.

Q. *What are the principal parameters of a gas-burner?*

Ans. **1. Relative length (l_m) of the internal mixing zone**

$$l_m = L_m/D$$

where D = diameter of the outlet port of the burner. (Fig. 14.21).

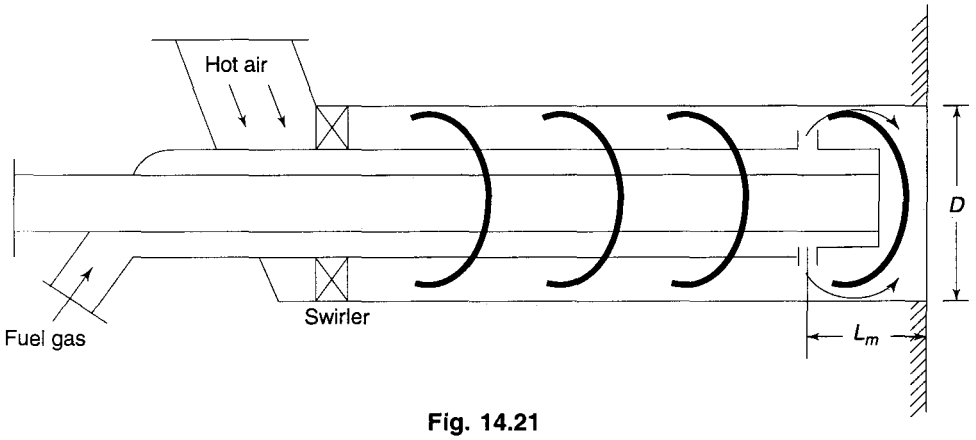

Fig. 14.21

2. Aerodynamic parameters determining the intensity of turbulent mixing

$$n = [\rho_a/\rho_g]\ [v_a/v_g]^2$$

where ρ = density

v = flow velocity

"a" stands for air and "g" stands for fuel gas.

3. Dimensions, shape and arrangement of gas ports

Q. *Name two injection burners.*

Ans. 1. Bunsen burner.
2. Teklu burner.

Q. *What are diffusion flames?*

Ans. These are the flames produced when fuel gas and air flow separately into the combustion chamber and undergo intermixing as the burning proceeds.

Q. *What determine the rate of combustion in diffusion flames?*

Ans. 1. Fuel-gas/air ratio
2. Degree of turbulence of gas and air streams.

Q. *What is an important characteristic of such flames?*

Ans. The flames are very luminescent in character which contributes to a high degree of flame emissivity effecting, therefore, a high degree of radiative heat transfer.

Q. *Why are these flames luminescent?*

Ans. Since the intermixing of the gas and air does not take place in the burner proper but in the furnace space, a part of the gas (mainly hydrocarbons) undergoes pyrolysis (thermal dissociation) in the high temperature zone where oxygen is deficient. As a result, carbon particles (soot) are produced. These incandescent carbon particles emit a luminous flame.

Q. *What are the advantages of diffusion flame burners?*

Ans. 1. They do not backfire as there is no air within the burner to sustain combustion.
2. Particularly useful where very large volumes of low calorific value gases are to be burned.
3. Very effective when both gas and air are to be preheated, but not to be intermixed because of the dangers of pre-ignition, to produce a high flame temperature.
4. Combustion is silent.
5. Quality and nature of fuel gas can be varied without affecting burner operation.
6. No necessity of accurate adjustment of the gas and air ports.
7. Gas supplied is at low pressure (up to 0.110 kPa) and hence the system is less expensive.

Q. *What flames are called premixed flames?*

Ans. These are flames produced by the burners where gas and air are mixed whilst cold and combustion proceeds as the mixture leaves the burner assembly.

Q. *What are combined gas-fuel oil burners?*

Ans. These burners are provided with the capacity of burning fuel oil and fuel gas simultaneously or separately.

Q. *What is the chief advantage of such burners?*

Ans. Both fuels can be burned under almost optimal conditions.

Q. *What is an air register?*

Ans. It is an air-guiding device to effect intensive turbulization of airflow for efficient intermixing with the fuel.

Q. *How many types of air-registers are there?*

Ans. Three:
1. Scroll type (Fig. 14.22a)
2. Tangential vane type (Fig. 14.22b)
3. Axial vane type (Fig. 14.22c)

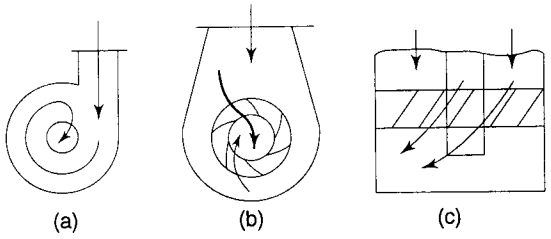

Fig. 14.22 *Different types of air-registers.*

Q. *What is the main drawback of a scroll type register?*

Ans. Too bulky.

Q. *Where is it employed?*

Ans. In low-capacity burners.

Q. *Out of these three air-registers which offers least hydraulic resistance?*

Ans. Air-register with axial vanes.

Q. *How many types of gas-oil combined burners are mainly used in high-capacity boilers?*

Ans. Two types:

1. **Co-axial Gas-Fuel Oil Burner** with central gas supply. (Fig. 14.23)
2. **Gas-Fuel Oil Burner** with peripheral and central gas supply. (Fig. 14.24)

Q. *How does the co-axial gas-fuel oil burner with central gas supply operate?*

Ans. From the central annular header the natural gas flows through two rows of holes of different diameter, while air is delivered through a tangential vane register imparting vorticity to the air stream. The flowrate of air is controlled by a moving disc valve. So when the boiler load is reduced, air flowrate decreases maintaining the original whirling intensity and conditions necessary for better fuel-air intermixing.

Fuel oil supplied through a pipe symmetrically mounted in the natural gas duct is atomized and burnt in the fuel oil burner (mechanical).

Air velocity = 40 m/s

Gas supply pressure = 2.5–3 kPa

Ignition of the mixture (fuel oil-air or fuel gas-air) is accomplished by an electric ignitor.

Q. *How does the gas-fuel oil burner with peripheral and central gas supply operate?*

Ans. Fuel oil is atomized in a steam-mechanical burner mounted in the central channel to which are charged both air and natural gas. This air is supplied to cool the fuel oil burner. (Fig. 14.24)

The main air supplied through central and peripheral air boxes is passed through axial and tengential vanes. At reduced boiler load, air flowrate through the peripheral annular channel is diminished by means of a control gate.

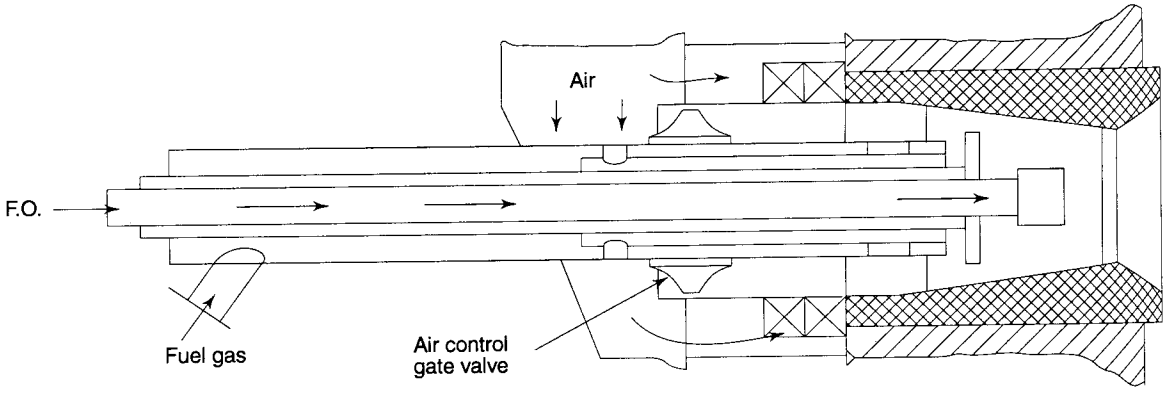

Fig. 14.23 *Co-axial gas-fuel oil burner with central gas supply.*

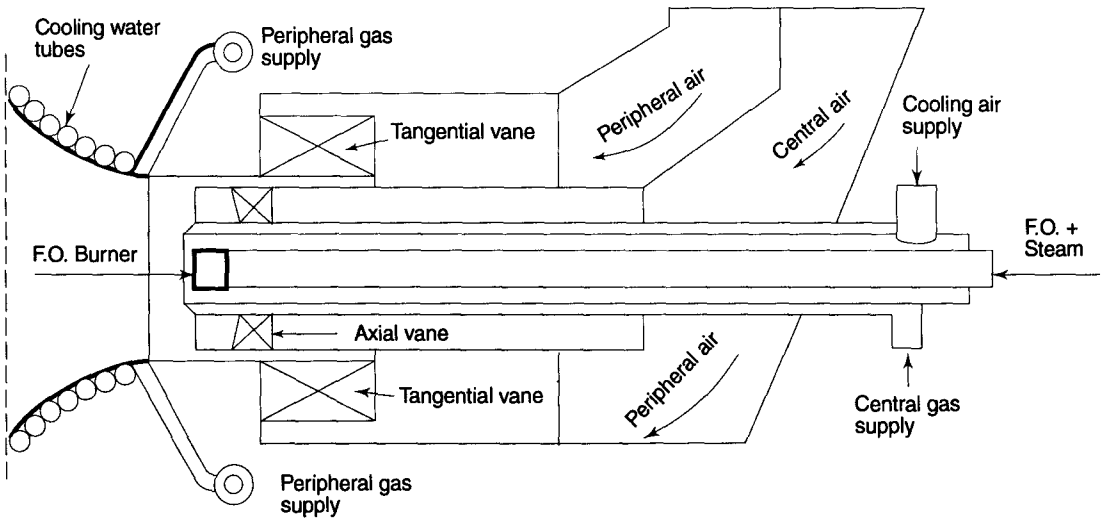

Fig. 14.24 *Gas-fuel oil burner with peripheral and central gas supply.*

Fuel oil is supplied at a pressure of 4.5 MPa.

CASE STUDY ***Burner Refractory Cracking***

The oil-fired steam generators of a US powerplant have cropped up a burner-refractory problem. The plant has experienced repeated cracking of refractory in the throat zone during the past year; though it had no trouble with its boiler refractory in the past.

It was surmised that fuel oil was responsible and vanadium in the FO could cause the cracks. Supposedly vanadium compounds were deposited on the refractory and then flexed with temperature changes at shutdown to initiate cracks.

The burner location and setting remain the same as always, and loads and half-yearly scheduled shutdowns are unchanged.

Why did refractory cracking at burner nose occur?

How can the cracking of boiler refractory be stopped?

Ans. The refractory cracking might have been due to the following reasons.

(a) **Insufficient expansion allowance:** With prefired refractory tile, a burner throat will crack at the mortar joints when fired and the cracks will become visible when cold.

(b) **Burner oil spray impinging on the throat:** Such an impingement, especially when vanadium is present, causes the surface to chip and spall and eventually erode away.

The Central Electricity Generating Board, London has developed a standard to overcome similar problems of cracking and spalling around oil burner throats. This requires quality control of refractory materials, appropriate method of gunning and securing the refractory to the furnace tube and maintaining at initial prefiring curing period.

1. An inquiry into the vendor's data as to the mineral composition of refractory and its thermal expansion behaviour will be helpful.
2. Gunning and securing of the refractory to the furnace tube are a very important consideration. One sound method of placing the refractory is to divide the peripheral area into segments, using a material that will burn away quickly on light-off but remain in place for the curing period. Segments should be small enough to breathe with the tubes to which they are attached. Use of split-studs, Y-shaped or V-shaped, instead of straight ones gives good result. With plastic refractory, one must be extra careful of venting and curing before start-up. Otherwise entrapped moisture, unable to escape, will turn into steam and the refractory may explode.
3. The plant supervisors and operators must be careful when steam cleaning or water-washing combustion-chamber spaces, to prevent water from getting behind the refractory.
4. Oil spray from the burner must not impinge on the throat refractory at any point. If it does, the oil nozzle is to be pushed forward until the pattern clears refractory.

Of course, this may disturb the flame pattern and cause impingement. In addition, piping changes may be required.

15

LOW NO_x BURNERS

Q. *What are low NO_x burners and why are they installed in SGPs?*

Ans. These are coal, gas, oil and multifuel-fired burners to provide the most cost-effective means of attaining reduction in NO_x emissions of at least 50% without adversely affecting boiler reliability or performance. When the capability exists to fire alternative fuels, such as natural gas and/or heavy fuel oil, within the same burner while maintaining low NO_x emissions, additional emission reductions can be achieved.

Note: As per strict air quality standards enforced by the United States Environmental Protection Authority (EPA), it is an integral part of all existing and modern large industrial and utility steam generators to maintain NO_x emission within the prescribed limits providing a clean and safe environment.

Q. *Cite some specific examples of low NO_x burners.*

Ans. 1. Axial, staged, return-flow (ASR) burners of Deutsche Babcock Werke AG
2. Distributed air flow (DAF) low NO_x burner of Coen Co., Inc.
3. Micro-NO_x burner of Coen Co., Inc.
4. Controlled flow/split flame (CF/SF) burner of Foster Wheeler
5. Internal fuel staged (IFS) low NO_x burner of Foster Wheeler
6. Tangential-fired low NO_x (TLN) burner of Foster Wheeler
7. Swirl tertiary staged (STS) burner of Riley Stoker Corporation

Q. *What are the basic design features of an ASR burner?*

Ans. It is a parallel-flow swirl burner with a self-aspirating flue gas recirculation design (Fig. 15.1) meant for the combustion of fuel oil and/or flue gas.)

Primary air supplied through the inner burner throat meets a part of the combustion airflow required. The burner assembly is provided with a primary air register thereby changing the flame shape. Using an adjustable inlet nozzle, the burner may be operated as a parallel flow burner, a swirl burner, or an intermediate setting, with parallel and/or swirl flow (Fig. 15.2).

The secondary air taken from the windbox is fed in through a double-shell tube at the outlet of the mixing chamber.

For further retardation of combustion, flue gas is aspirated into the combustion zone via an annular cross-section through the airflow from the primary air throat.

Q. *How is NO_x reduction accomplished by the ASR burner?*

Ans. The NO_x generation is kept at a minimum by

1. feeding the combustion air in several stages*

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* Staging restricts the supply of combustion air in the combustion zone to a bare excess of the stoichiometric level of O_2 and this inhibits the NO_x formation mechanism.

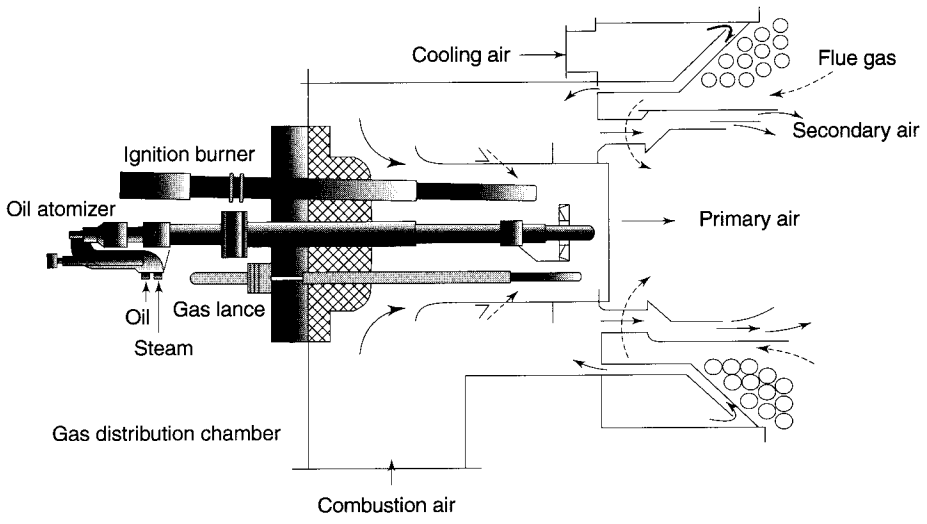

Fig. 15.1 *Axial, staged, return-flow (ASR) burner assembly reduces NO_x emission by feeding the combustion air in several stages axially and sequentially, separating the primary and secondary airs to slow combustion.*

Source: IPS, 1988

2. separating the primary and secondary airstreams by flue gas to slow down combustion.
3. adjusting the fuel feed position which not only alters the furnace depths but also reduces NO_x emission.

Q. *What is DAF burner?*

Ans. It is Distributed Air Flow multistaged low NO_x burner, designed for low NO_x applications on single or multiple burner units.

Q. *What are the basic design features of DAF burners?*

Ans. DAF burners are specially designed with high space heat release, low flame volumes avoiding excessively long or wide flame to the tune of compact boiler furnace dimension.

Show in Fig. 15.3 is the Coen's DAF low NO_x burner.

It can accept such other low NO_x techniques as flue gas recirculation, and front or sidewall NO_x ports for oil firing.

Adaptable to burning gaseous and/or liquid fuels such as NG, refinery gas, hydrogen, coke oven gas, landfill gas, light and heavy FOs, refinery pitch, coal/water slurries and wastefuel streams.

It can be packaged with windbox, FD fan, piping, burner management and controls for integrated multi-burner set-up.

Particulates emission ranges are typically below the EPA requirement (0.043 g/MJ) with FOs containing 0.1 ash or less.

Adaptable to a wide variants of atomizers for firing different liquid fuels such as light grade to heavy FOs and coal-water slurries, employing steam, air or natural gas atomization.

The inner core venturi-section reduces combustion air pressure drop that helps in reducing the fan horsepower cost.

Can simultaneously fire liquid and gaseous fuels for reducing operating expenses.

Fitted with multiple gas spuds arranged to minimize NO_x formation

Q. *What are the special advantages of Coen's DAF burners?*

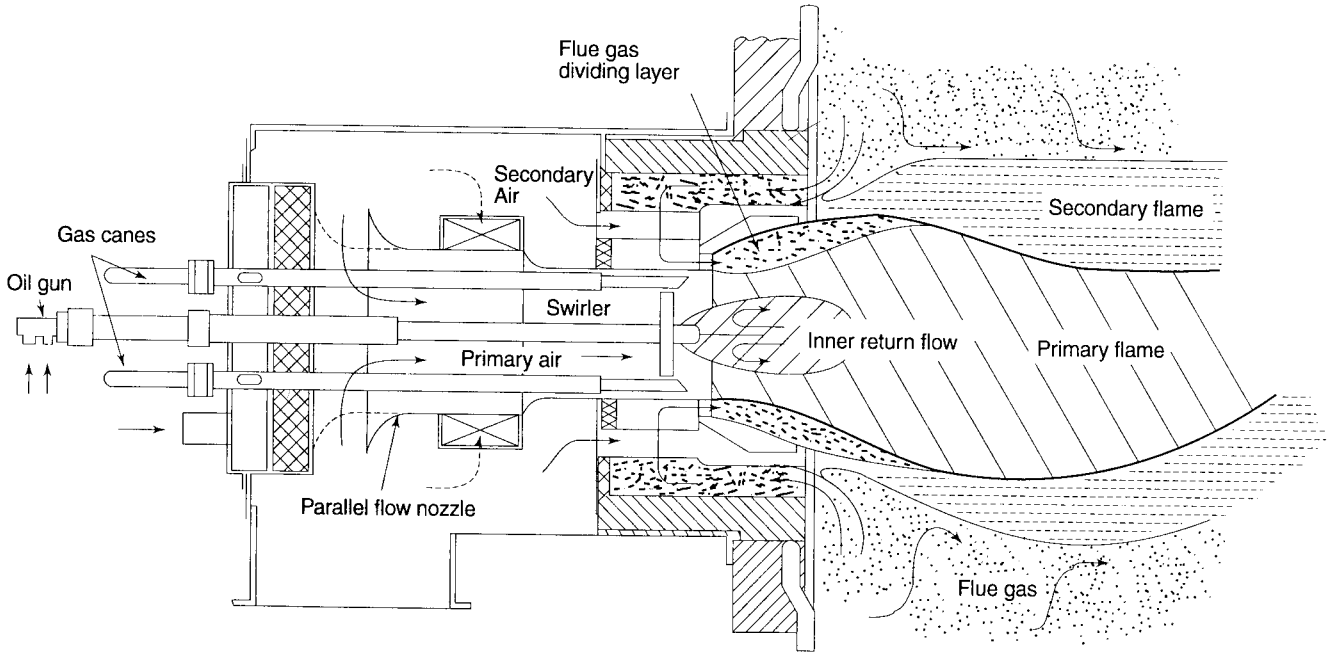

Fig. 15.2 *Low-NO_x ASR Burner.*

Source: RST-112 (Technical Paper/Riley Stoker Corporation)
Courtesy: Riley Stoker Corp./Worcester/MA 01615-0040/USA

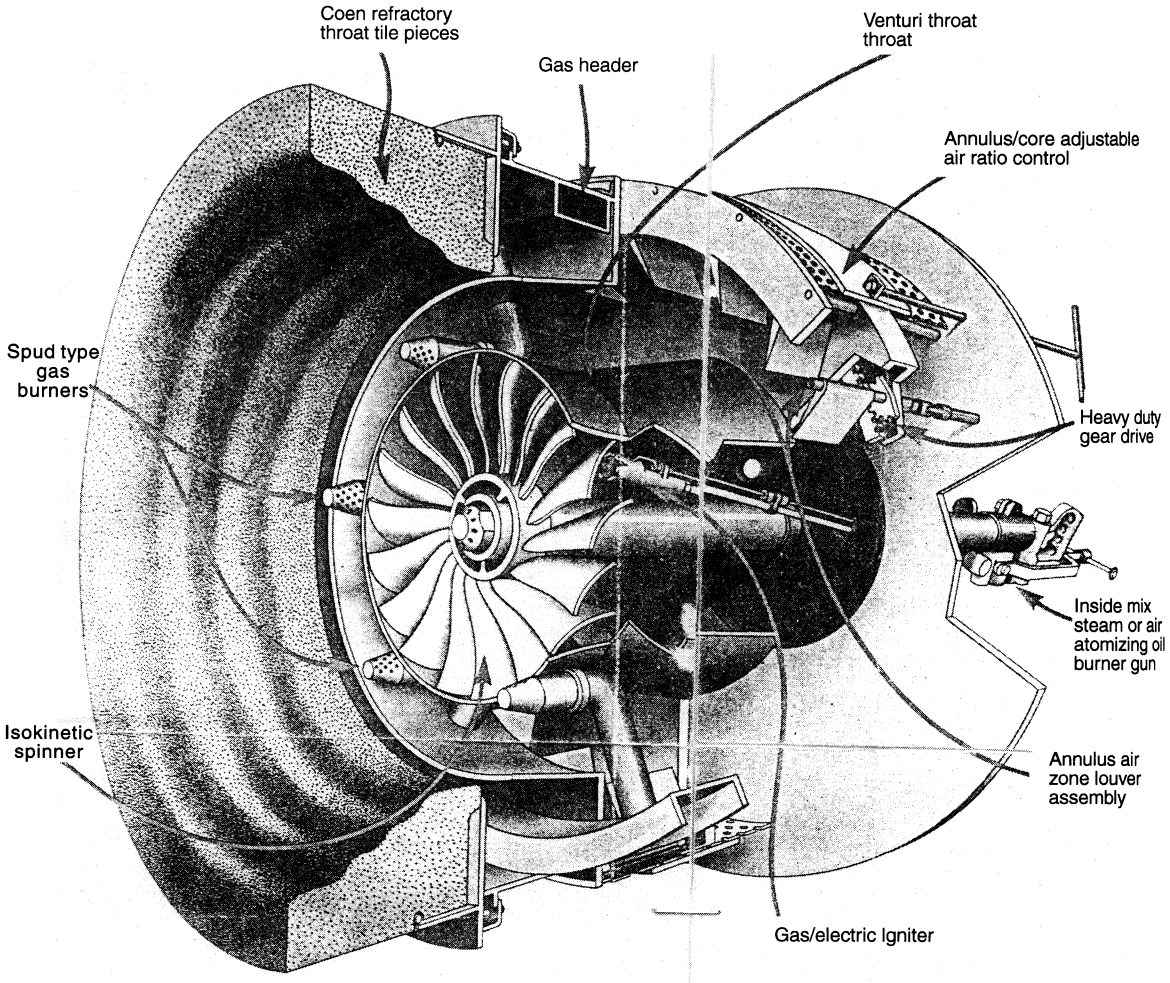

Fig. 15.3 *Coen's DAF burner system, adaptable to burning gaseous and/or liquid fuels, sports high turndown ratio (10 : 1) and achieves NO_x reductions of 80% or more.*

Source: Coen bulletin: DAF/93
Courtesy: Coen Co., Inc./Burlingame/CA 94010/USA

Ans. • Flame produced is neither excessively long nor too wide rendering the burner extremely compatible with compact boiler furnace

• High turndown ratio, the burner is capable of firing over a 10 : 1 range

• The multistage design can deliver significant thermal NO_x reduction:

reductions of 80% or more are possible when combined with other Coen low NO_x techniques.

Q. *How is the reduction of thermal NO_x achieved with a DAF burner?*

Ans. The DAF burner consists of two separate air zones. The inner core air stream establishes a strong, central recirculating air zone directly downstream of the "isokinetic" spinner (Fig. 15.4) which aids in burner stability throughout the burner firing range. The outer annulus air zone employs adjustable swirl which is used in shaping the burner flame to optimize flame conditions and emission levels.

The "isokinetic" spinner generates a strong recirculation zone, assisting in NO_x reduction. This zone is essentially a source of flue gas that results in local entrainment of gases by fuel jets which help reduce thermal NO_x (Fig. 15.5).

Q. *What is Micro-NO_x burner?*

Ans. It is the patented low NO_x burner, of COEN CO., Inc., specially designed for commercial and small industrial boilers, process furnaces and fired heaters. (Fig. 15.6).

Q. *What are the basic design features of a Micro-NO_x burner and how does it operate?*

Ans. The Micro-NO_x burner consists of two separate air zones. The primary air stream establishes a strong central recirculating air zone directly downstream of the "isokinetic" spinner (Fig. 15.7), aiding in burner stability throughout the burner firing range. The secondary air zone has a uniquely designed fixed spinner which, together with the air proportionating damper, shapes the burner flame and helps optimize air distribution.

The Micro-NO_x sports a gas spud design based on computer flow modeling and field performance.

The isokinetic spinner generates a strong recirculation current of partially burned combustion products and permits local entrainment of these gases by fuel jets.

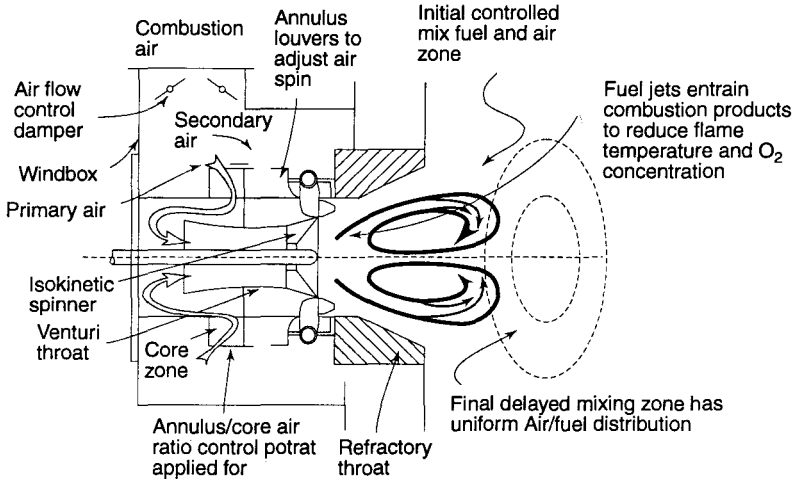

Fig. 15.4 *Operation of DAF multistaged low Nox burner. Isokinetic spinner generates a strong recirculation zone where the combustion products entrained by fuel jets reduce flame temperature and local O_2 concentration.*

Source: Coen Bulletin: DAF/93

Courtesy: Coen Co., Inc./Burlingame/CA 94010/USA

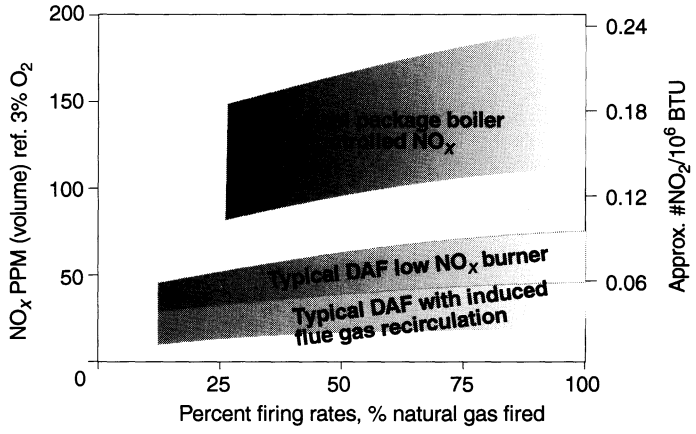

Fig. 15.5 *Performance comparison chart showing distinct gain in thermal NO_x reduction by flue gas recirculation technique.*

Source: *COEN bulletin: DAF/93*
Courtesy: *COEN CO., Inc./Burlingame/CA 94010/USA*

The gas burner flame has a few small evenly distributed fingers close to the heat absorbing surface and a hollow centre. This ensures effective radiant heat transfer and avoids the formation of a typical hot spot zone in the centre. Over and above, combustion of the gas jets from each finger is staged in such a way that a partially burned jet stream shields over another jet stream to reduce the peak temperature of each finger and also to quench thermal NO_x formation.

Q. *What is the performance of the Micro-NO_x burner?*

Ans. A typical Micro-NO_x burner gives out NO_x emission in the range of 50–75 ppm (Fig. 15.8) whereas a typical Micro-NO_x design with induced flue gas recirculation (typical FGR rate is 7%) restricts NO_x emission in the range of 10–20 ppm which is about 10% of uncontrolled NO_x emission from a typical package boiler (see Fig. 15.8).

Q. *What are the basic features of Micro-NO_x systems?*

Ans. 1. Lowest emission (see Fig. 15.8)
2. Highest combustion efficiency. Stack O_2 level lies between 2 and 3.5% of oxygen
3. Lowest fluegas recirculation required. Typical FGR rate is less than 7%.
4. Ruggedly built. It has long industrial life, dependable operation and reduced maintenance cost
5. Minimum start-up time. Coordinating the air damper with the fuel control valve and the FGR control valve ensures lowest O_2, NO_x and highest efficiency.
6. High turndown range, typically 5 : 1 on liquid fuel, and between 5 : 1 and 8 : 1 on NG
7. Custom designs allow for superior performance
8. Compatible with microprocessor-based burner management system. Honeywell RM7800 or Fireye E100 systems are standard.

Q. *"Foster Wheeler Corporation, NJ (USA) has developed two low NO_x burner designs which differ in only one critical component, operate in exactly the same manner and yet achieve significantly different NO_x levels".*

What are these two burners?

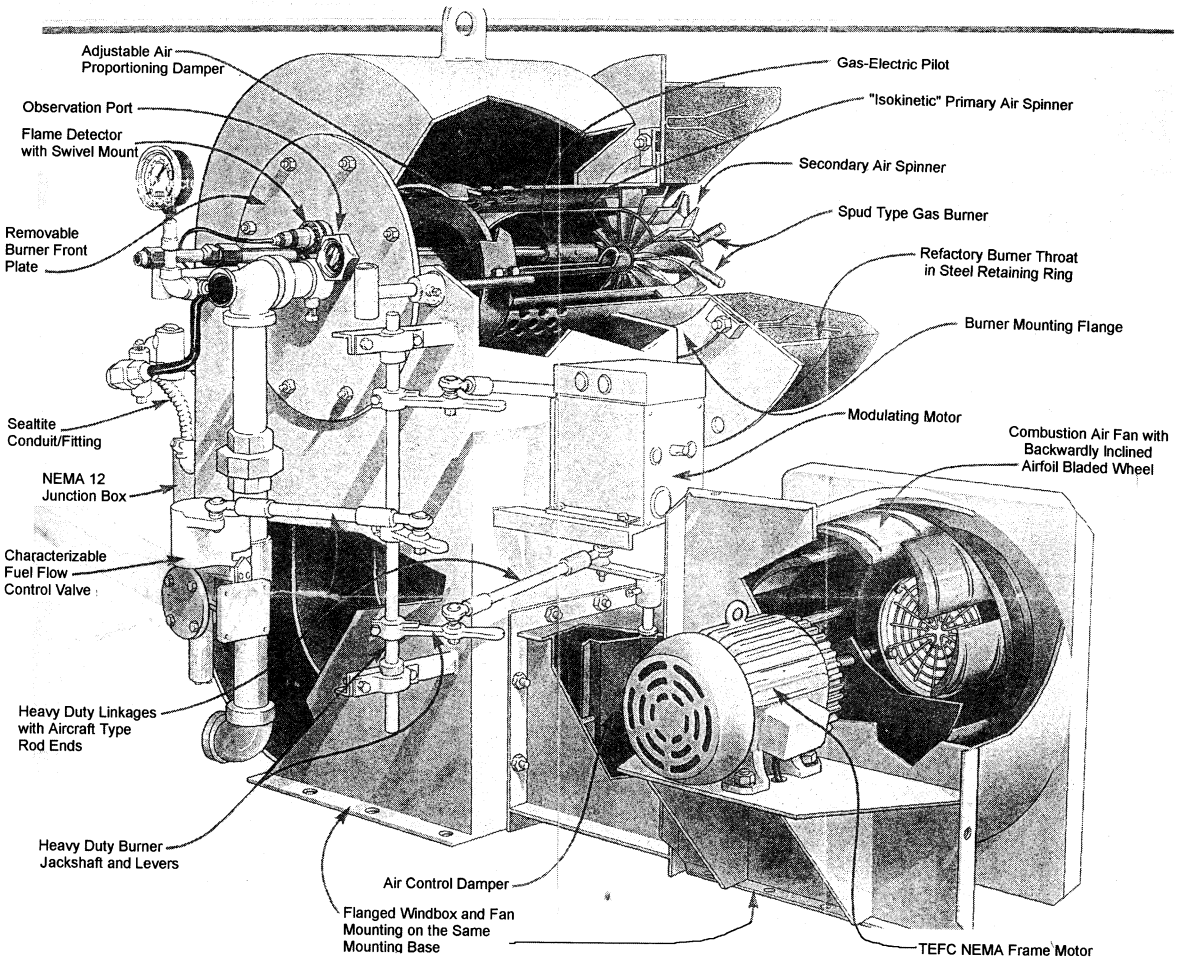

Fig. 15.6 *Micro-NO_x burner ensures lowest NO_x CO emission, highest combustion efficiency, operates with high turndown and requires minimum start-up time.*

Source: COEN Brochure : Micro-NO_x/93
Courtesy: COEN Co., Inc./Burlingame/CA 94010/USA

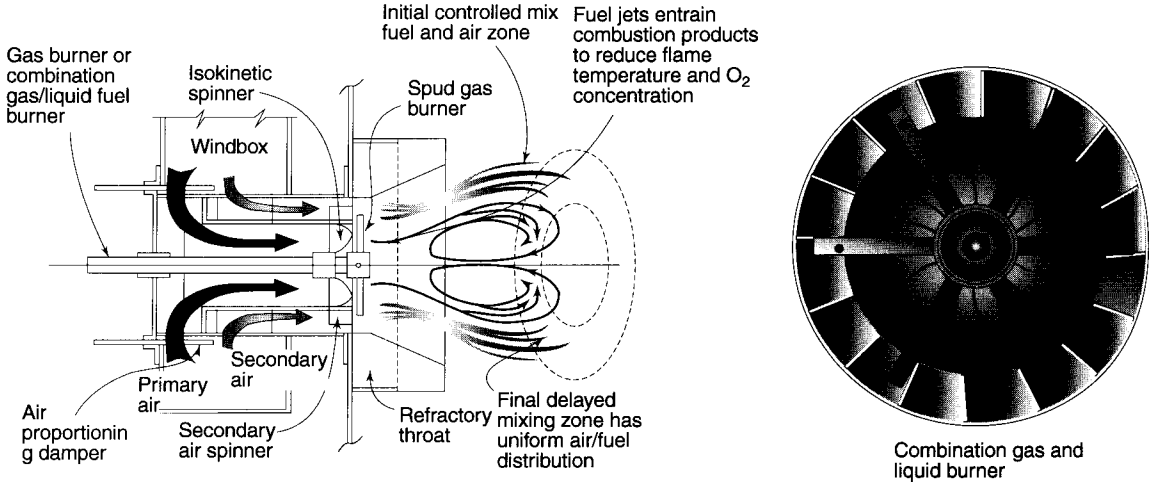

Fig. 15.7 *Isokinetic spinner generates a strong recirculation of partially burned combustion products and allows local entrainment of these gases by fuel jets.*

Source: COEN Brochure : Micro-NO_x/93
Courtesy: COEN Co., Inc./Burlingame/CA 94010/USA

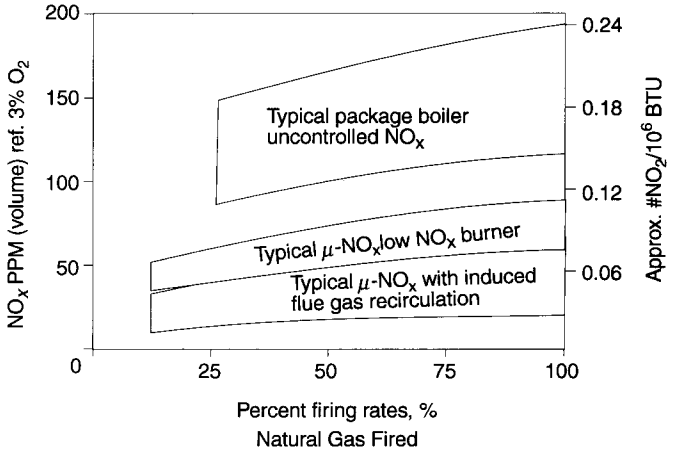

Fig. 15.8 *Performance comparison chart of micro-NO_x burners and conventional burners.*

Source: Micro-NO_x (COEN CO., Inc.)
Courtesy: COEN CO., Inc./Burlingame/CA 94010/USA

Ans. 1. Controlled Flow/Split-Flame (CF/SF) burner (Fig. 15.9)
2. Internal Fuel Staged™ (IFS) burner (Fig. 15.10)

Q. *What is Controlled Flow/Split-Flame burner?*

Ans. It is an Internally Staged ™design (Fig. 15.11) which is defined as:

a low NO_x burner design which two-stages the secondary airflow and internally stages the primary air-fuel flows within the burner's throat while maintaining turbulent burner flame patterns and low pressure drop: 150 mm H_2O.

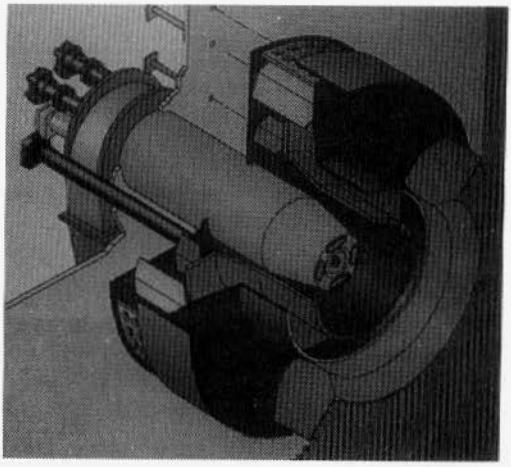

Fig. 15.9 *Controlled Flow/Split-Flame (CF/SF) burner reduces NO_x emission by air staging.*

Source: SP93-10 (Technical Report/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

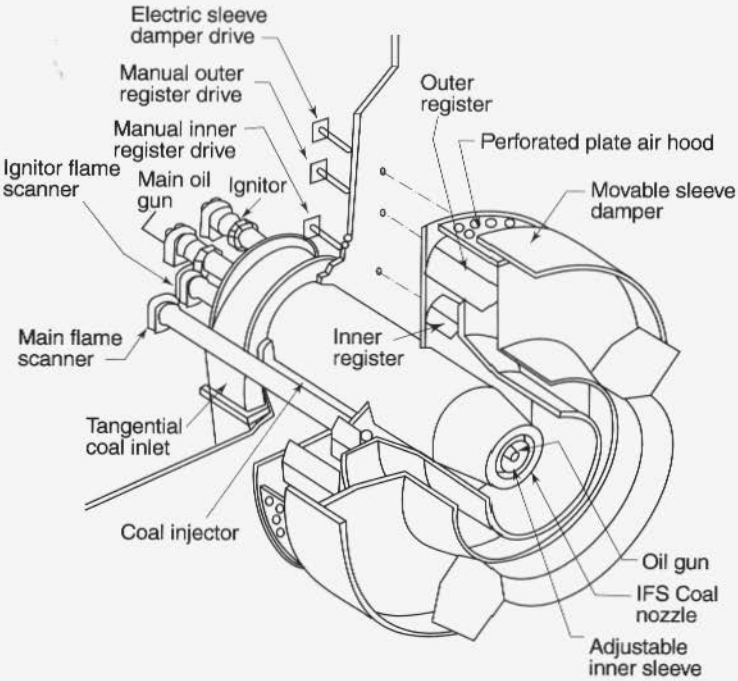

Fig. 15.10 *INTERNAL FUEL STAGED LOW NO_x BURNER ™splits the secondary air into two stages and fuel-air stream mixtures into internally stages so that coaxial flames are produced.*

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

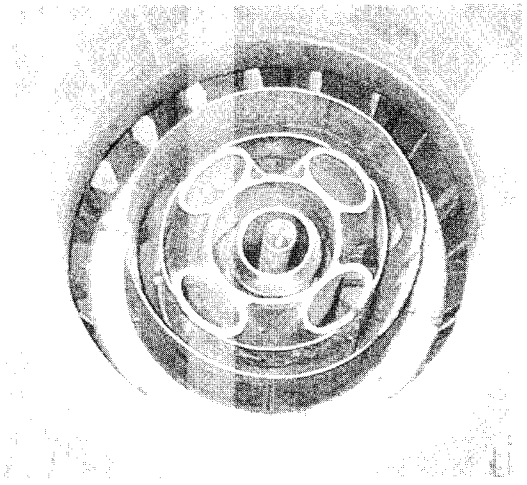

Fig. 15.11 *CF/SF ™low NO_x burner as installed on a retrofitted 800 MW boiler.*

Source: SP 94–2R94 (Technical Bulletin/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

Q. *How is the name Controlled Flow/Split-Flame derived?*

Ans. This name is derived from the operating functions of the burner:

1. ***Controlled Flow*** for the dual register design which provides for the control of inner and outer swirl zones alongwith a sleeve damper which allows independent control of the quantity of secondary airflow to the burner.
2. ***Split-flame*** for the coal injection nozzle which develops a split-flame pattern (Fig. 15.12) for obtaining low NO_x emissions.

Q. *What is the principle of Internal Fuel Staging?*

Ans. It is a low NO_x burner which two-stages the secondary airflow and internally stages the fuel and primary airflows such that coaxial flames are developed within the burner's throat while maintaining classical turbulent burner flame patterns and a low pressure drop of 150 mm H_2O.

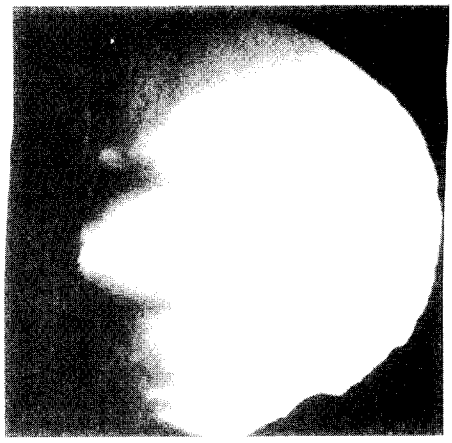

Fig. 15.12 *Typical split-flame from CF/SF™ low NO_x burner.*

Source: SP94–2R94 (Technical Bulletin/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809–4000/USA

Q. *What is the difference between IFS and CF/SF burners?*

Ans. From the above two figures (Fig. 15.9 and 15.10), it is apparent that the two designs are nearly identical only the split-flame coal nozzle tip has been replaced by the IFS nozzle tip.

All other mechanisms are identical, as is the method of operation.

Q. *What are the common features of the CF/SF and IFS low NO_x burners?*

Ans. Both are mutifuel devices: pulverized coal and oil and/or natural gas fired units. They share the same basic components:

1. **Perforated Plate with Sleeve Damper:** is used to optimize secondary airflow vertically and horizontally within the windbox to obtain equal burner stoichiometries. The sleeve damper has CLOSED, IGNITE and OPEN positions and is used, instead of the main radial vane register, to shut off the airflow when the burner is out of service. Controlled by an electrically operated linear drive, it is not modulated with load.

2. **Dual Series Registers:** improvise flame-shape control by double-staging the secondary air. The blades and drive mechanism of this configuration are well 'shaded' from direct flame radiation and that ensures the mechanical reliability feature of this system. Consequently, the registers operate at windbox temperature and do not overheat, warp or bind. Additionally once the flame is optimized for proper shape, the registers are fixed. They remain in their optimum positions and are not modulated with load or closed when the burner is taken out of service since the sleeve damper performs the latter function.
3. **Split-Flame Nozzle:** segregates coal into four concentrated streams with the effect that the coal volatiles are driven off and the resulting char particles are burned under more reducing atmosphere than otherwise would occur without the split-flame nozzles. The nitrogen content of the volatiles, under these combustion conditions, escapes as N_2, substantially reducing NO_x formation. The IFS coal nozzle generates a coaxial flame surrounded by split-flames.
4. **Adjustable Coal Nozzle:** Allows primary air-coal velocity to be optimized without changing primary airflow.

Q. *What is the NO_x control performance of both CF/SF and IFS burners?*

Ans. The CF/SF low NO_x burner has been retrofitted to 21 utility steam generators, totaling over 8000 MW of capacity. Table 15.1 presents a chronological listing of CF/SF retrofit experience:

The average NO_x reduction attained, without supplementary NO_x controls such as overfire air, is greater than 55%.

Table 15.2 is a listing of IFS retrofits completed and under contract:

NO_x reduction averages nearly 65% without overfire air.

Figure 15.13 contains comparative data from eight units, including two (2) duplicates, totaling nearly 5000 MW.

Table 15.1
Controlled Flow/Split-Flame Low NO_x Burner Experience List

Retrofitted Steam Generators Unit Size (MW)	O.E.M.	Year	NO_x (lb/10^6 Btu) Before	After
360	FW	1979	1.0	<0.45
110 Kpph	CE	1984	0.85	< 0.45
275	FW	1981	+	<0.45
525	FW	1981	+	<0.45
650	FW	1986	1.0	<0.45
500	FW-UK	1986	1.15	<0.55
800	B&W	1989	1.3	<0.50
800	FW	1990	1.1	<0.45
500	FW	1990	1.15	<0.45
225	FW	1990	1.1	<0.5
500	FW-UK	1990	1.15	<0.5
800	B&W	1991	1.30	<0.45
500	FW	1991	1.15	<0.45
650	FW	1991	1.30	<0.55
650	FW	1991	1.35	<0.6
525	FW	1991	1.40	<0.6
Total 8260 MW				

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA.

Table 15.2 *Internal Fuel Staged Low NO_x Burner Experience List*

Unit Size (MW)	O.E.M.	Year	NO_x (lb/10^6 Btu) Before	After
In Operation				
200	B&W	1991	0.9-1.0	0.35-0.40
160	FW	1992	1.0-1.1	0.40-0.45
650	FW	1992	1.3-1.4	0.45-0.50
300	FW	1992	1.5-1.6	0.55-0.60
250	R-S	1993	1.0-1.1	0.40-0.45
350	R-S	1993	1.0-1.1	<0.50
Σ = 1,910				
3 × 200	B&W	2 × 300	FW	
3 × 160	FW	2 × 150	R-S	
2 × 650	FW	2 × 525	FW	
5 × 835	FW	1 × 359	FW	
		Σ = 8,495		
Total IFS:			10,405 MW	
Total CF/SF:			8,260 MW	
Total Low NO_x Conversions			18,665 MW	

Source: SP93-10 (Technical Paper/Foster Wheeler)

Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

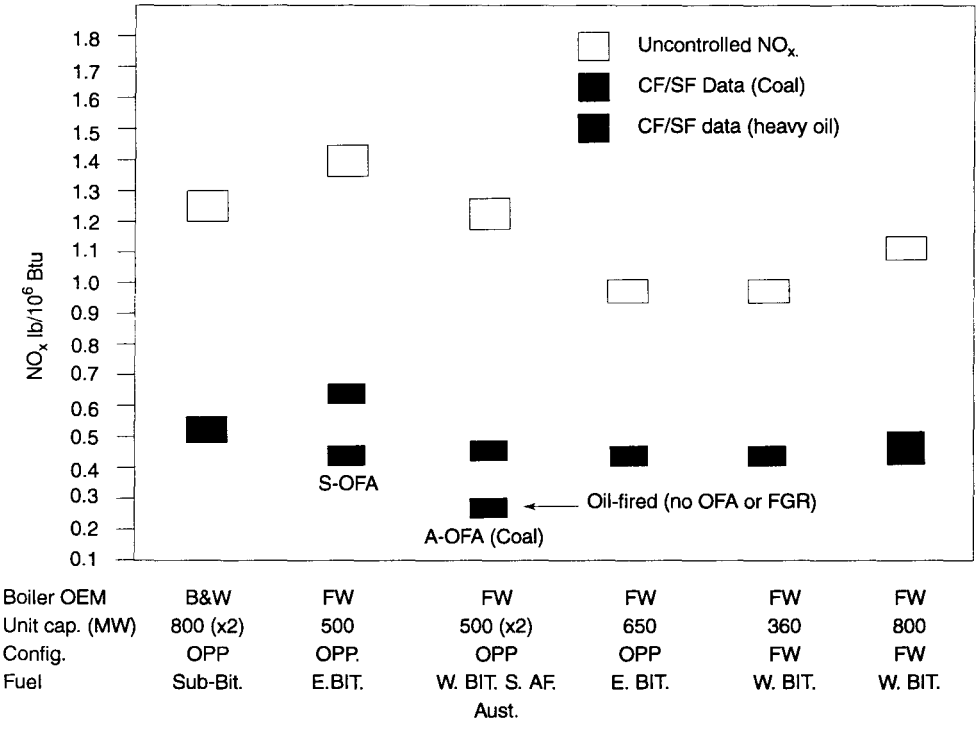

Fig. 15.13 *CF/SF low NO_x burner—typical experience.*

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

The data shows consistent NO_x reduction:

- without any supplementary controls (such as OFA), NO_x reduction averages over 55% with a minimum reduction over 50%.
- NO_x level was reduced over 50% with the burners only and nearly 70% with the S-OFA system
- Two 500 MW Units retrofitted with combination coal/heavy oil CF/SF low NO_x burners and an advanced OFA system demonstrated that:
  NO_x got reduced, when firing only coal, about 60% to 275 ppm at 6% O_2 without overfire air (OFA) and to about 165 ppm at 6% O_2 for a total reduction of nearly 80%.

Q. *What is AOFA?*

Ans. It is Advanced Over Fire Airport system.

Fig. 15.14 shows a typical AOFA arrangement of Foster Wheeler Corporation.

FW's AOFA system is characterized by a set of overfire airports located well above the top row of burners and the overfire airport level. One port is located above each burner column with an additional port near each sidewall. The above figure shows a 4-burner-wide arrangement using six overfire airports on each firing wall.

Q. *What is the difference between AOFA and older overfire air arrangements?*

Ans. Older overfire air arrangements use fewer ports and provide shorter residence time. They can achieve only about 20–30% NO_x reduction.

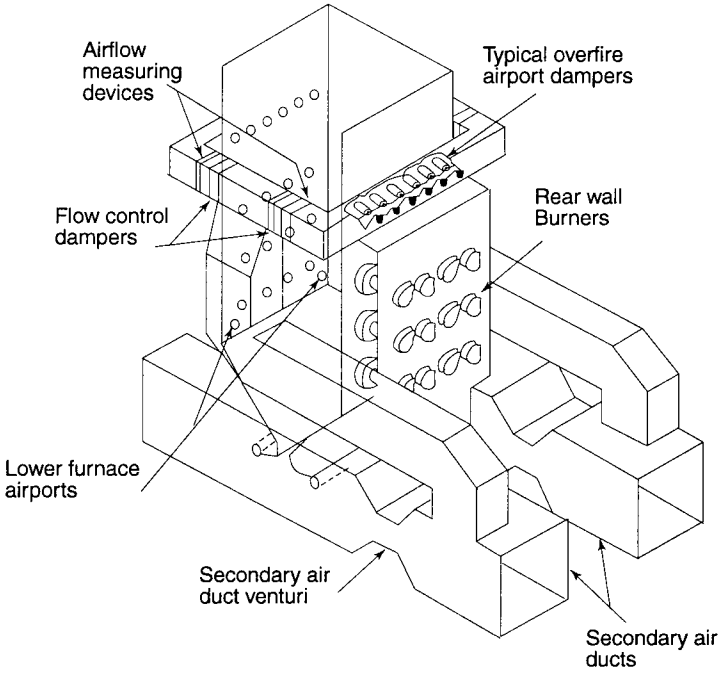

Fig. 15.14 *TYPICAL ADVANCED OVERFIRE AIRPORT SYSTEM sports a set of overfire airports placed well above the top burner tier to provide a long residence time.*

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

The AOFA system increases the NO_x reduction capability to the 40—50% range.

Q. *How does the NO_x emission level vary with the load when the AOFA is closed and open?*

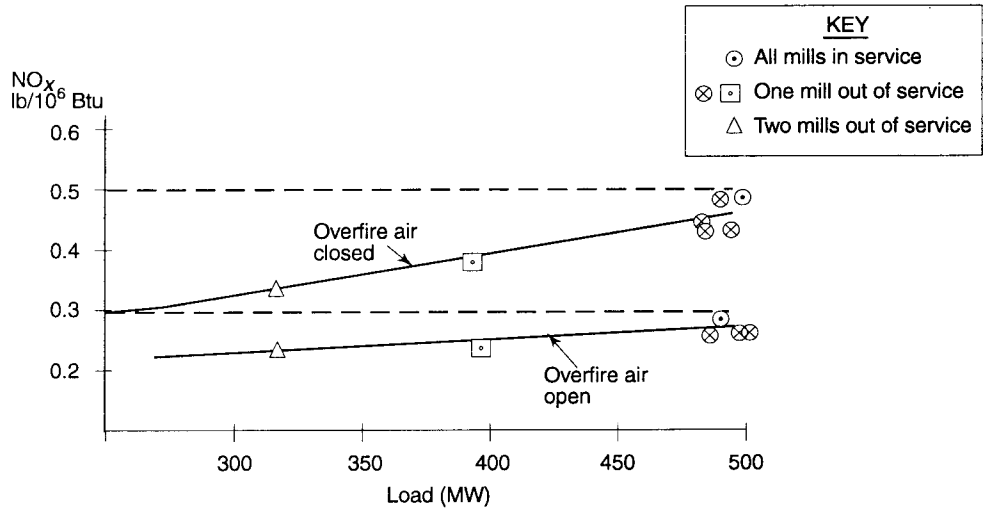

Fig. 15.15 *Advanced low NO_x retrofit 500 MW boiler.*

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

Ans. Figure 15.15 illustrates the comparative gain in reducing NO_x emission levels, with AOFA closed and open, as the boiler load changes.

Load was reduced in the manner normal for that station with pulverizers taken out of service at the same loads they were prior to the low NO_x retrofit.

NO_x emissions decreased montonically from full load values which average 0.199 g/MJ and 0.1148 g/MJ with AOFA ports closed and open respectively. At no time did NO_x emissions exceed 0.215 or 0.129 g/MJ with AOFA closed or open respectively.

Q. *What is the field experience of retrofitting CF/SF low NO_x burners in thermal power plants?*

Ans. The results of over 8000 MW of retrofit field experience can be summarized as follows:

1. A minimum of 50% NO_x reduction is always attained with this burner without supplementary NO_x controls
2. NO_x emissions are insensitive to coal volatile matter content and FC/VM ratio
3. When combining the CF/SF burner with a standard overfire air system, NO_x reductions of 65—70% are attainable
4. When combining the CF/SF burner with an Advanced Overfire air system NO_x reductions of 75—80% are attainable
5. When firing heavy oil, the CF/SF burner retains its NO_x control capability.

Q. Do the coal characteristics exert any influence on NO_x emission levels of an IFS burner?

Ans. Detailed testing of the IFS burner was performed using two varieties of bituminous coals:

(a) low volatile bituminous (23% VM; FC/VM > 3)
(b) high volatile bituminous (33% VM; FC/VM = 1.5)

Table 15.3 shows no significant difference in NO_x levels due to coal VM or FC/VM ratio with either the older CF/SF burner or the new IFS.

Table 15.4 lists IFS testing data on two typical coal samples. The test was performed on FW's Combustion and Environmental Test Facility.

Table 15.3 *CETF Comparative Data CF/SF vs IFS*

Fuel V.M. (%)	23		33	
N_2(%)	1.87		1.59	
X_s O_2 (%)	3.5-3.6		3.5-3.6	
Burner Type	CF/SF	IFS	CF/SF	IFS
NO_x (lb/10^6 Btu): Avg.	0.41	0.273	0.40	0.260
Std. Dev.	0.033	0.014	0.035	0.011
CO Avg.	54	59	70	75
Std. Dev.	13	11	15	17
NO_x Reduction (%)	—	33.4	—	35.0

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

Table 15.4 CETF Fuels: IFS Testing

VM	32.70	23.49
FC	48.16	59.41
ASH	9.11	4.34
H_2O	10.03	7.86
C	67.34	77.37
H	4.50	4.68
O	5.60	3.19
N	1.59	1.87
S	1.85	0.79
HHV	11,935	13,877
NO_x Reduction	79.5%	73%
NO_x Level	0.26	0.273

No Significant Difference in NO_x Emissions Due To Coal Characteristics

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

Q. *What is the field experience of retrofitting the improved version of Foster Wheeler's Internal Fuel Staged burners in thermal powerplants?*

Ans. The field experience of retrofitting IFS low NO_x pulverized coal/oil/gas burner can be summerized as follows:

- A minimum of 60% NO_x reduction is always attained with this burner without supplementary NO_x controls, representing a 20% improvement over the CF/SF low NO_x burner capability
- With advanced overfire air systems, the new IFS PC-fired burners are expected to bring NO_x levels down to less than 0.129 g/MJ. When equipped with SCR systems such boilers will attain stack NO_x emission close to 0.043 g/MJ
- The IFS design has been field demonstrated to retain its NO_x control capability when firing natural gas.

Q. *What is tangential fired low NO_x (TLN) burner?*

Ans. Foster Wheeler Energy Corporation has developed a tangential fired low NO_x buner system that has demonstrated its remarkable NO_x capabilities. Shown in Fig. 15.16 is an isometric view of a TLN module.

Q. *What are the specialities of FW's TLN burner?*

Ans. 1. It comes in the form of a complete module, i.e. the TLN retrofit is a total 'plug-in' design which can be fitted within the existing windbox and secondary air ducts. No change in the pressure part nor structural modifications are required.

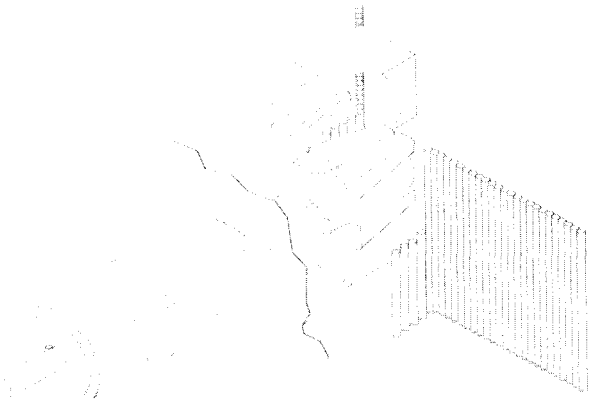

Fig. 15.16 *Tangential fired low NO_x burner. Shown here is the FW's TLN module capable of restricting NO_x emission level in the range of 0.15 – 0.173 g/MJ on a 310 MW steam generator.*

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

2. There is no separate overfire air system nor any generic overfire air system outside the windbox.
3. NO_x level reduction capacity is quite remarkable.

0.15 – 0.17 g/MJ (tested on a 310 MW steam generator)

Q. *What is TLN burner performance?*

Ans. Table 15.5 summarizes key baseline vs. TLN boiler performance parameters.

The TLN system is intended to attain NO_x levels below 0.1935 g/MJ, approximately 40 – 50% NO_x reduction, without the use of any OFA. At

Table 15.5 Boiler Performance Comparative Data

	Baseline	**TLN**
Load (MW)	300	300
Feedwater Flow (Klb/hr)	1816	1824
SH Spray (Klb/hr)	53	42
RH Spray (Klb/hr)	40	46
Throttle Press. (psig)	2402	2404
Main Steam Temp. (°F)	1061	1043
RH Temperature (°F)	1013	1003
NOx (lb/10^6 Btu)	0.68*	0.38
Unburned Carbon (%)	9.19 at 4.2% O_2	8.0% at 3.5% O_2
CO (ppm)	20 - 40	20 - 40

* With "concentric" firing; original equipment baseline 0.70 - 080 lb/10^6 Btu as reported by WEPCo.

Source : SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

this stage of TLN development, that goal is not being attained:

NO_x reduction with TLN burners only is about 25 – 30%.

Figure 15.17 shows the data results comparing pre-retrofit uncontrolled operation with NO_x emissions from the TLN system.

Foster Wheeler Energy Corporation has found that a relatively small amount of secondary air

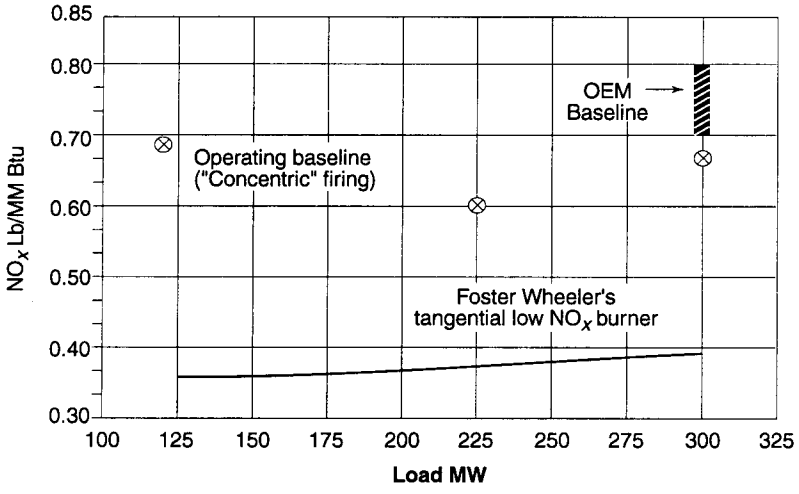

Fig. 15.17 *NO_x vs. load data of OAK CREEK Unit 7 boiler.*
Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

staging, within the windbox, significantly enhances the NO_x reduction from 25 – 30% to 50 – 55% (see Table 15.6)

Comparing the data points (1) and (2), it becomes evident that there is no 'Level-out-of-service' effect, i.e. NO_x is not reduced when the top burner level is taken out of service and the secondary-air-control-dampers are closed.

Comparing data points (1) and (2) with (3), shows that NO_x reduction from baseline uncontrolled

Table 15.6
In-Windbox Staging Test Result

	Load	Burner Level Out of Service	Sec. Air Damper Position	NOx lb/10^6 Btu	% NOx Reduction
(B)*	300 MW	None	—	0.7 - 0.8	—
(1) +	300 MW	None	—	0.6 - 0.65	25-30
(2)+	300 MW	Top	Closed	0.6 - 0.65	25-30
(3)+	300 MW	Top	Open	0.35 - 0.40	50-55

* Uncontrolled Baseline with original equipment.
\+ With TLN System.

Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-400/USA)

levels is doubled when secondary air staging is used.

Q. *How is the secondary air staging (SAS) inducted in to the TLN system?*

Ans. The SAS level is installed within the existing windbox, but above the burners, with the burner levels lowered to provide room for the SAS level (Fig. 15.18)

The SAS system consists of an overfire air module with tiltable nozzles, manually controlled biasing dampers and an electrically driven secondary air control damper. The SAS control damper is tied into the boiler's burner management system.

Note: 'Separate' or 'Advanced' overfire air systems are not required to attain the regulatory level, but would be necessary to guarantee NO_x levels down to less than 0.172 g/MJ.

Q. *What led to the genesis of the STS burner?*

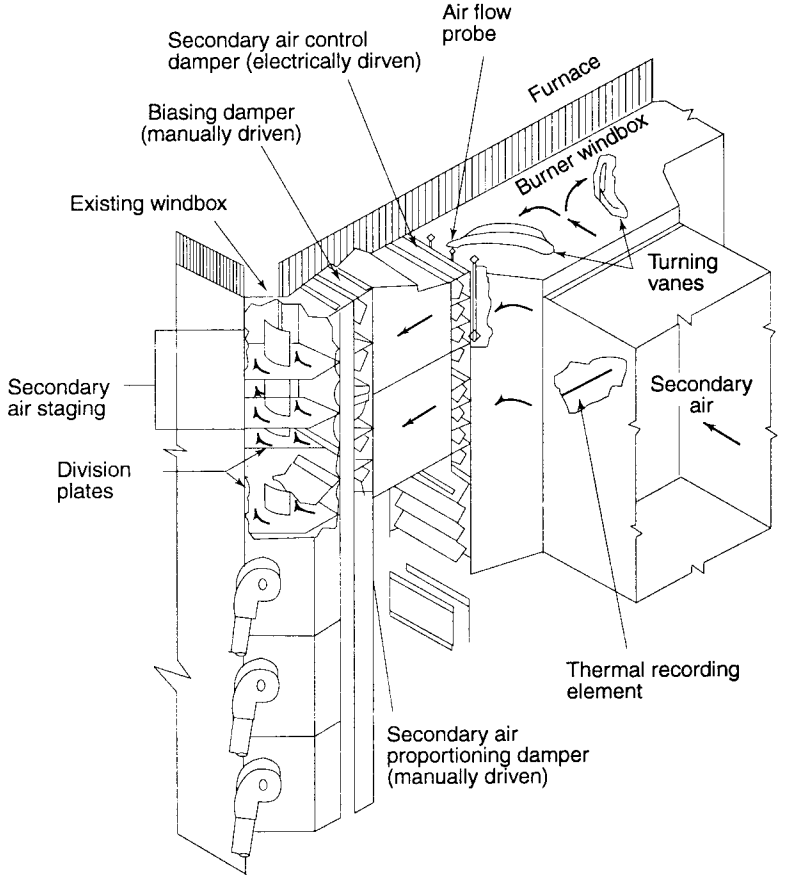

Fig. 15.18 *Modified TLN plug-in system incorporating secondary air staging. Shown here is the TLN-SAS module of Foster Wheeler Energy Corporation.*
Source: SP93-10 (Technical Paper/Foster Wheeler)
Courtesy: Foster Wheeler Corporation/NJ 08809-4000/USA

Ans. Pioneering research work at the Riley Research Centre, Worcester, Massachusetts, USA has led to the development of the Swirl Tertiary Staged (STS) burner—Babcock low NO_x gas and oil-fired burner systems for retrofit on US wall-fired boilers with common windbox/multiple burner firing arrangements.

Q. *What are the basic design features of the STS burner?*

Ans. Intended for retrofit applications, the STS burner is designed to fit within existing burner openings. In order to reduce the size of the required burner opening, the STS burner does not incorporate the flue gas self-aspiration system of Deutsche Babcock's ASR burner.

An illustration of a commercial STS burner is shown in Fig. 15.19.

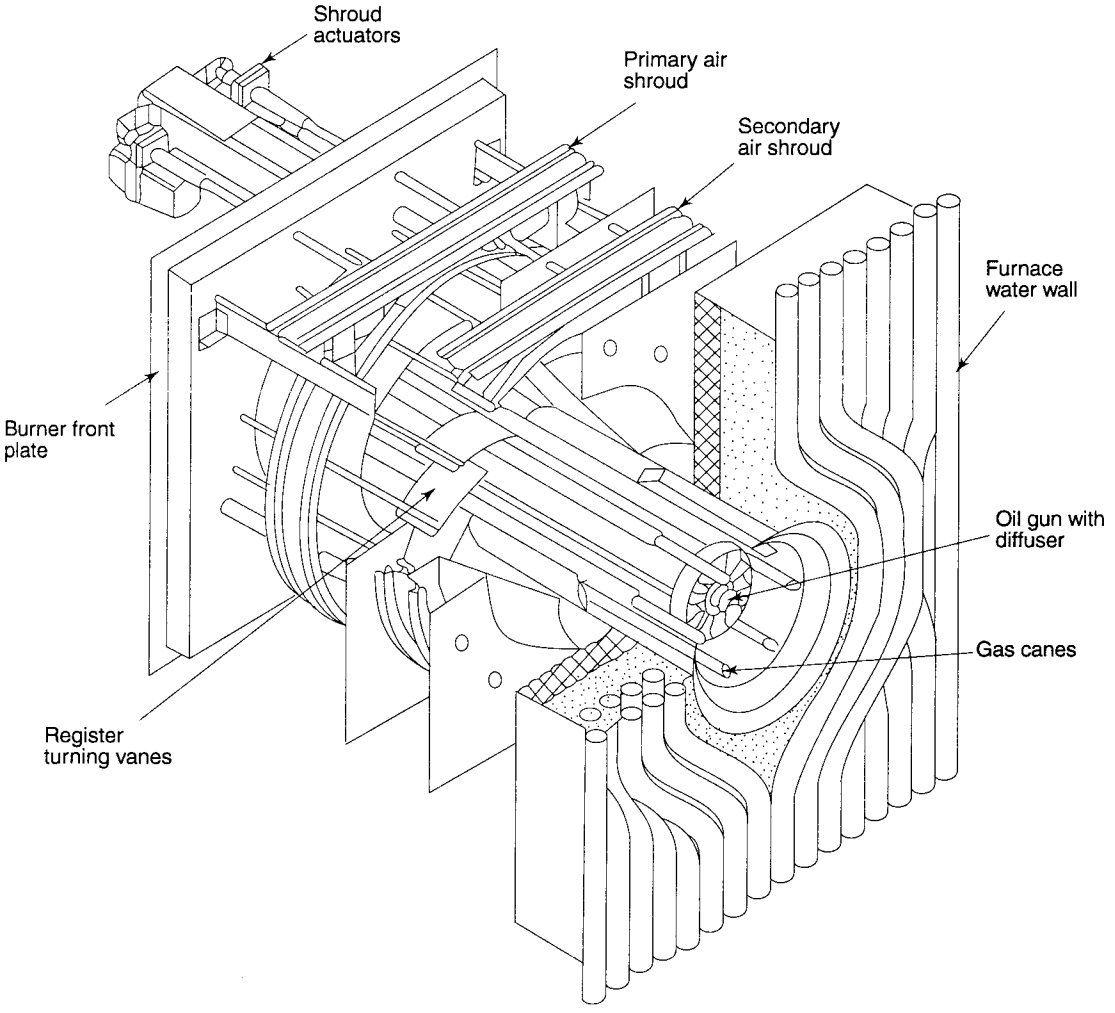

Fig. 15.19 *Riley STS burner designed for retrofit applications employs similar gas and oil gun configurations used in the ASR burner system.*

Source: RST-112 (Technical Paper/Riley Stoker Corporation)
Courtesy: Riley Stoker Corp./Worcester/MA 01615-0040/USA

Primary air is delivered to the centre of the burner fitted with gas lances, central oil gun and a primary air fixed vane swirler. The gas lance and oil gun configurations are similar in design to the fuel injection system employed on the ASR burner. A secondary air register with curved overlapping blades ensures variable swirl control for the outer secondary air. A separation gap is employed between the inner primary air core and the outer secondary air annulus to help maintain distinct primary and secondary combustion zones.

The STS burner is also equipped with movable flow control shrouds which slide over the primary and secondary air inlet passages. These flow control shrouds can be used to:

1. balance windbox airflow to each burner. A flow measuring impact probe is positioned in the primary airpath as a relative indicator for balancing individual airflows to each burner.
2. control the primary/secondary air split independently of swirl vane position.

The turndown capability of the burner can be enhanced by partially closing the shroud at low loads but maintaining sufficient swirl for flame stabilization.

Q. *What is the STS burner performance?*

Ans. Pilot-scale test results for the Riley commercial STS burner configurations are displayed in Fig. 15.20 and Fig. 15.21.

The fuel oil (# 6) used for these tests contained 2% sulphur and 0.5% fuel nitrogen and an asfaltene content of approximately 12%. Combustion air for these tests was preheated to approx. 545°K.

Figure 15.20 presents unstaged NO_x and CO emissions as a function of excess O_2 while Fig. 15.21 summarizes the combined effects of external FGR and air staging on STS burner performance.

NO_x emissions of less than 90 ppm were achieved on 6 oil using OFA and FGR.

CASE STUDY

Designed by Babcock and Wilcox and originally equipped with a wood-fired grate, a 79 t/h process steam boiler located at a paper mill is now exclusively gas-fired. In 1992, this unit was retrofitted with 6 NOs. of STS gas-fired burners with individual firing capacities of 40 million kJ/h. Combustion air is preheated to above 475°K. The installation is void of FGR facility.

Full load unstaged NO_x emissions for this unit were compared with pilot-scale STS burner and it was found that the measured field emissions were approximately 60% higher than the pilot-test NO_x value. Higher O_2 levels were measured in the boiler duct.

Q. *Why are the field emission levels so high?*

Ans. The industrial boiler is an old junk with a large amount of air infiltrating through casing leaks and various furnace penetrations. This is reflected in the higher O_2 levels of FG.

More than four-fold increase in burner area heat release.

Q. *Deutsche Babcock is currently installing modular AFS burners with firing capacities of 21 to 42 million kJ/h on firetube boiler and small industrial watertube boilers in Germany. What is an AFS burner?*

Ans. Axial Flame Stage (AFS) burner is the newly patented low-NO_x multifuel burner of Deutsche Babcock and designed for small industrial and commercial firing applications.

AFS burners are designed for combustion air temps. of up to 366°K, but can be adapted for air preheat applications up to 533°K.

Q. *How does the AFS burner control NO_x emission?*

Ans. By:

(a) Axial staging of primary and secondary air
(b) Staged fuel addition.

Q. *What is its performance?*

Ans. Test results show:

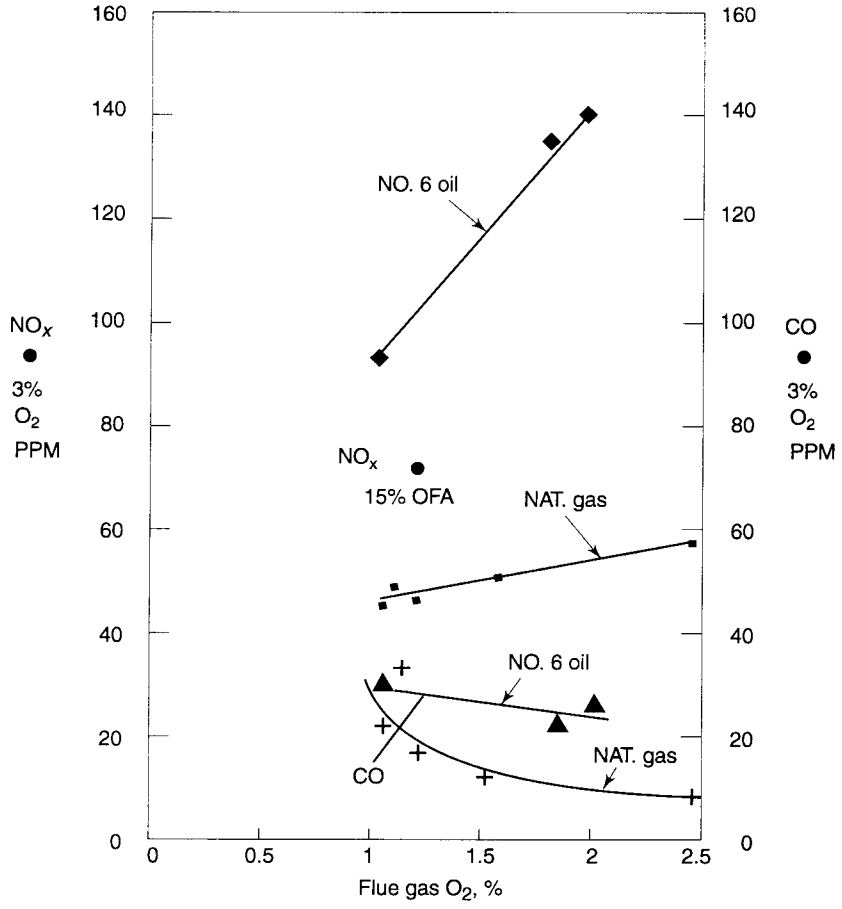

Fig. 15.20 *The effect of excess air on prototype (85 x 10^6 Btu/hr) STS burner NO_x and CO emissions—Riley Pilot Facility, No FGR.*

Source: RST-112 (Technical Paper/Riley Stoker Corporation)
Courtesy: Riley Stoker Corp./Worcester/Mass. 01615-0040/USA

(a) NO_x emissions of less than 25 ppm can be achieved with increasing amounts of flue gas recirculation.
(b) CO emissions of 5 to 30 ppm have been achieved on gas-fired field operating units.

AFS burner performance on natural gas and light fuel oil is summarized in Figs 15.22 and 15.23 respectively.

Q. *How does the AFS burner work?*

Ans. The AFS burner (Fig. 15.24) employs both internal and external gas injection nozzles. Fuel staging is achieved by splitting the gas input between the internal gas nozzles located in the primary air passage and the outboard external gas nozzles located around the burner periphery.

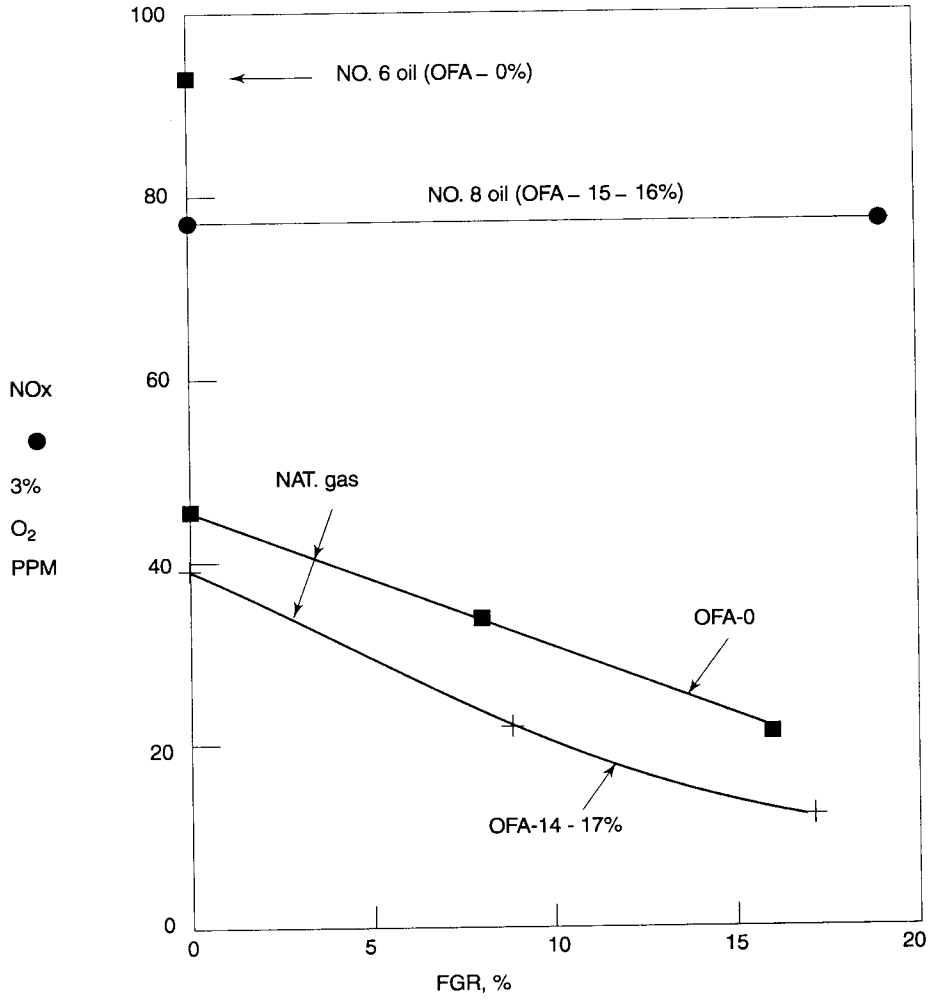

Fig. 15.21 *The effect of flue gas recirculation and overfire air on STS burner NO_x emissions.*

Source: RST-112 (Technical Paper/Riley Stoker Corporation)
Courtesy: Riley Stoker Corp./Worcester/Mass. 01615-0040/USA

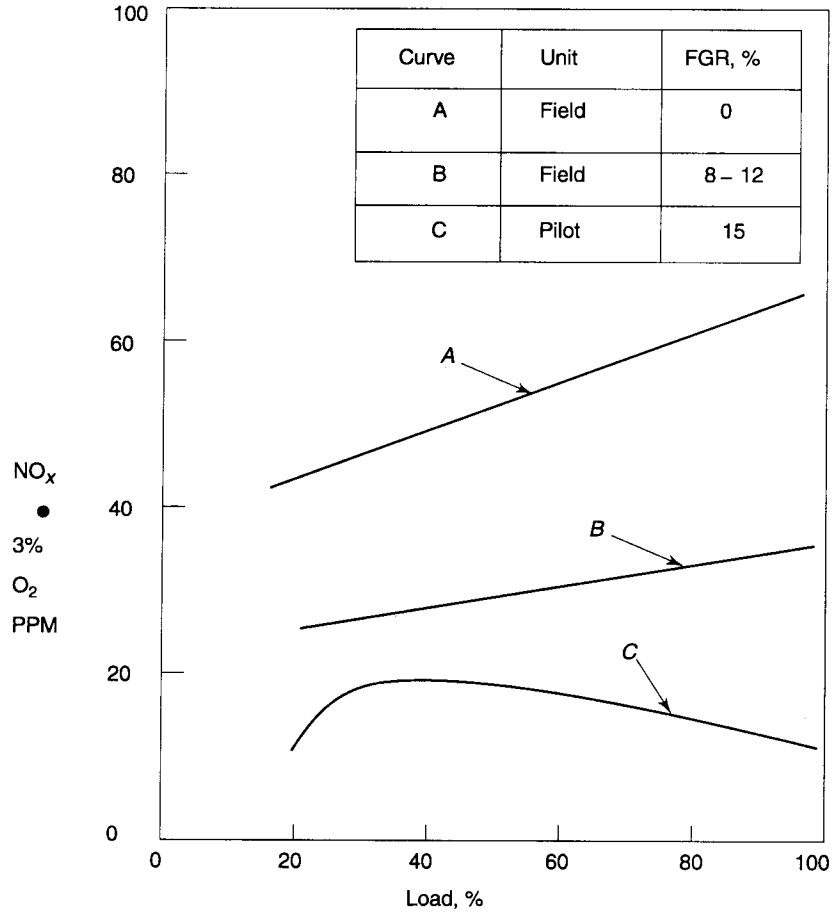

Fig. 15.22 *AFS burner NO_x performance—natural gas firing.*

Source: *RST-112 (Technical Paper/Riley Stoker Corporation)*
Courtesy: *Riley Stoker Corp./Worcester/Mass. 01615-0040/USA*

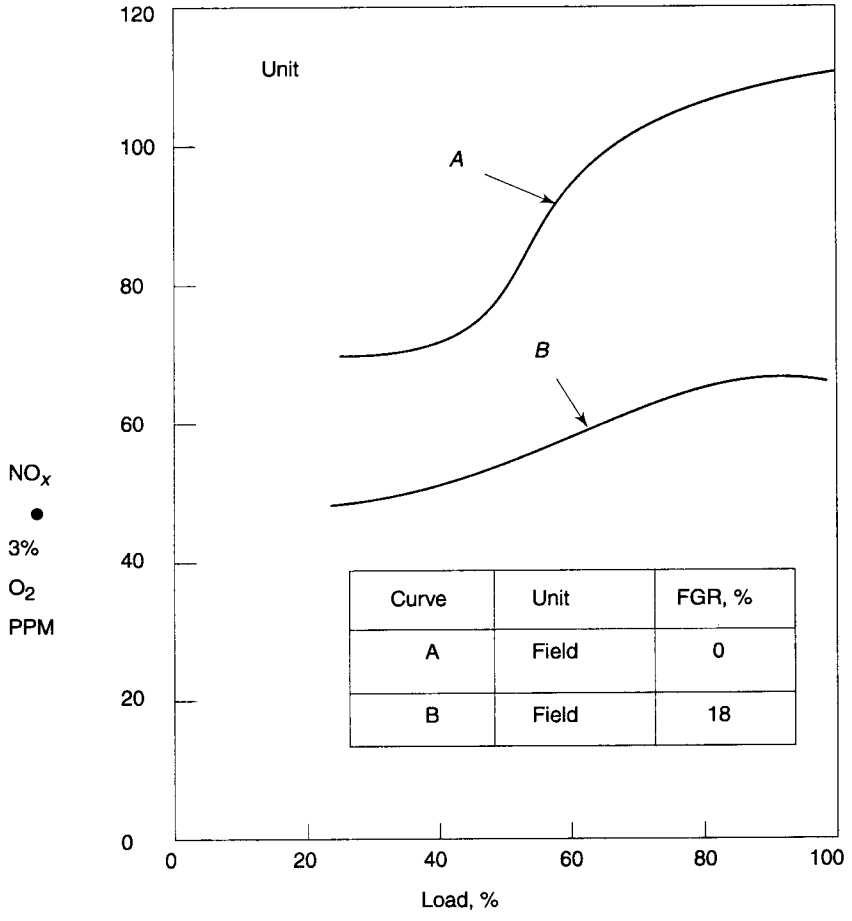

Fig. 15.23 *AFS burner NO_x performance—light oil firing.*

Source: RST-112 (Technical Paper/Riley Stoker Corporation)
Courtesy: Riley Stoker Corp./Worcester/Mass. 01615-0040/USA

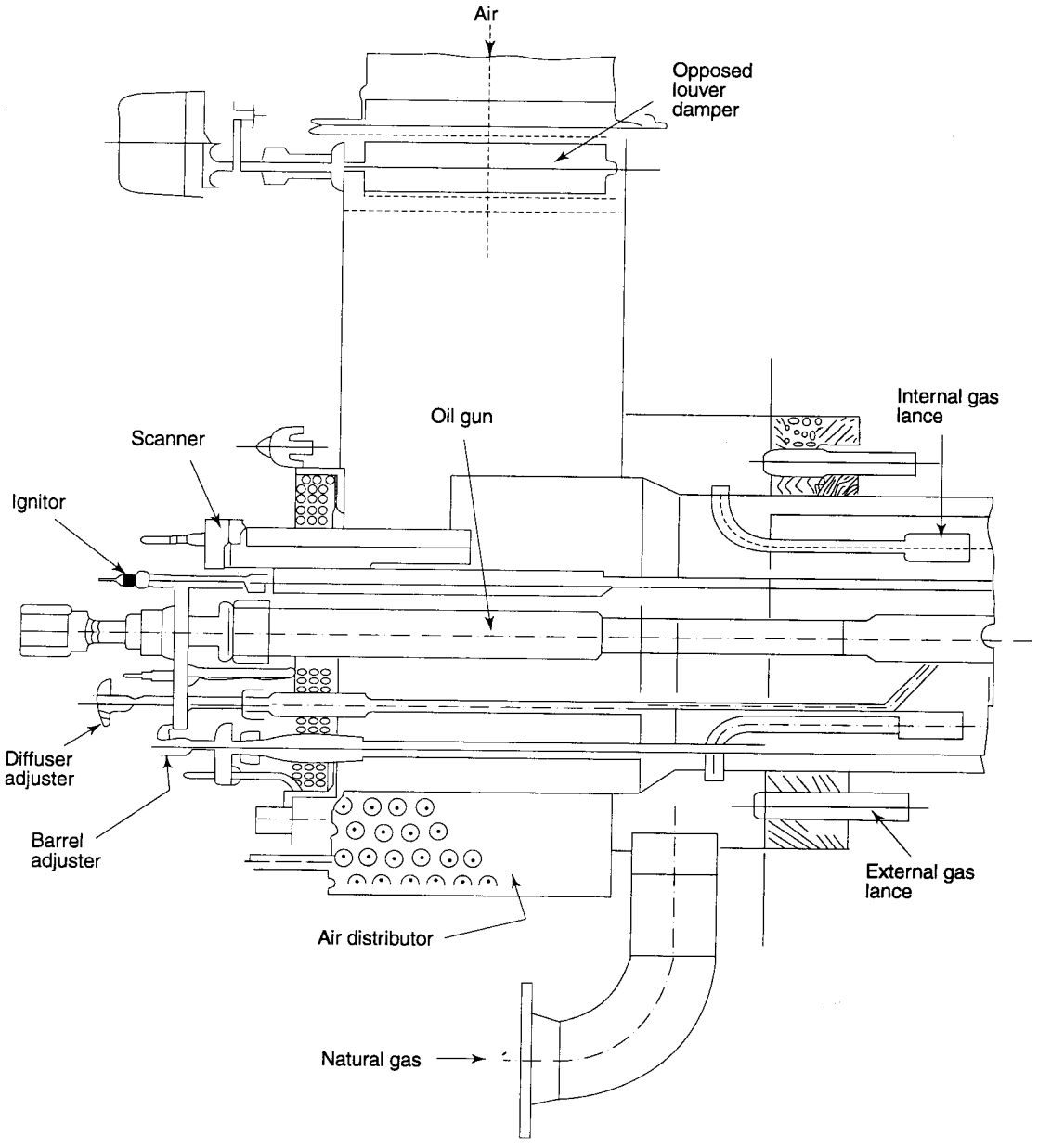

Fig. 15.24 *AFS air and fuel staged burner.*

Source: *RST-112 (Technical Paper/Riley Stoker Corporation)*
Courtesy: *Riley Stoker Corp./Worcester/MA 01615-0040/USA*

16

EMISSIONS CONTROL

Q. *Emissions control, now-a-days, is as much a part of boiler design as combustion and steam generation. What control options are available to control emission from a boiler?*

Ans. The following options are now available for optimizing emissions control from utility and industrial powerplants:

1. Precombustion options
2. In-furnace control options
3. Post-combustion control processes
4. Auxiliary equipment tie-ins

Q. *What are the precombustion options?*

Ans. 1. Physical coal cleaning to remove
   (a) ash
   (b) pyrites
2. Chemical coal cleaning
3. Fuel oil preparation through
   (a) settling
   (b) blending
   (c) salts removal
4. Fuel-oil emulsification
5. Chemical additives
6. Gasification/liquefaction
7. Using coal/water or coal/oil slurries
8. Densification of fuel/wastes
9. Fuel conversions (converting MSW and other low grade fuels into gaseous and liquid fuels)

Q. *What are the in-furnace control options?*

Ans. 1. Combustion control by utilizing
   (a) low excess air
   (b) LNO_x burners
   (c) flue gas recirculation
   (d) fuel reburning
2. Advanced low-NO_x burners
3. Furnace sorbent injection
4. Limestone-injection multistage burners
5. Slagging combustors
6. Ammonia-injection
7. Urea-injection
8. Fluidized bed combustion
9. Co-combustion

Q. *What are the post-combustion control processes?*

Ans. 1. Ammonia-injected FGD
2. Wet lime/limestone FGD
3. Spray-dryer FGD
4. SCR
   (a) hotside
   (b) coldside
5. SNCR
6. $DeSO_xNO_x$ systems
7. Fabric filters
8. Mechanical collectors
9. ESP
   (a) hotside
   (b) coldside
10. Wet particulate scrubbing
11. Electron beam processes
12. Sodium-sorbent injection
13. Calcium-sorbent injection

Q. *What are the auxiliary equipment tie-ins?*

Ans. 1. FGD reheaters
- (a) gas-gas exchangers
- (b) gas-liquid-gas exchangers
- (c) indirect air preheater
- (d) direct combustion
- (e) inline reheat
- (f) flue gas bypass

2. Stack
- (a) wet-stack operation
- (b) conventional operation

3. Cooling towers
- (a) natural draft
- (b) mechanical draft

4. Once-through cooling
5. Air-cooled surface condensers
6. FGD exhaust discharge through CT

Q. *What is coal-cleaning?*

Ans. Coal-cleaning is probably the most important fuel-preparation technique in all coal-fired utilities. It means physically separating ash, non-combustibles and pyritic sulphur from coal.

Note: For more about coal-cleaning, please see Appendix-IV.

Q. *How is coal-cleaning related to emissions control?*

Ans. From PC-fired units non-combustibles escape mostly as flyash. Pyrites contribute to SO_x emission.

Therefore, coal-cleaning reduces particulate emissions and minimizes SO_x load in the FG. Also it plays a positive role in emission control strategy:

> It could significantly reduce the size of a fabric-filter, ESP or scrubber unit downstream, improve its operation and reduce operatingcosts.

Q. *What is the negative aspect of coal-cleaning?*

Ans. Coal contaminant removal is inherently associated with energy loss in the form of fines drained off the cleaning circuit. For instance, high sulphur coals may see reductions of 50% of S-content while retaining 90% of the coal's heating value. Whereas achieving 50% sulphur reduction, through coal-cleaning, from low-sulphur coals means a substantial loss of kJ.

Q. *Fuel oil has been deteriorating in quality just like coal, especially the residual oil burned at utility stations. How does it matter so far as emissions are concerned?*

Ans. This FO quality deterioration is manifested as aggravated particulate emissions from boilers.

Q. *Who is the culprit?*

Ans. The most important culprit is the asphaltenes content in FO.

Q. *How do they affect quality?*

Ans. They are distributed as finely dispersed colloid in the oil phase which agglomerates to form tar particles that travel to burners. Since this tarry mass does not volatilize readily, it results in poor combustion that aggravates emissions problems.

Q. *What is the remedy to this problem?*

Ans. Dosing chemical additives that stabilize asphaltenes.

Q. *What are these additives?*

Ans. These are usually a mixture of nitrates of potassium and ammonium.

One such proprietary additive is Polarchem-L2* which is a liquid comprising of KNO_3 and NH_4NO_3 in an aqueous solution with suitable homogenizers, inhibitors and pH stabilizers.

Q. *How does this additive control particulate emissions?*

Ans. Polarchem-L2 generates oxygen that oxidizes the unburnt carbon throughout the system thereby reducing the emission of C-particulates.

$$2KNO_3 + 2C \longrightarrow 2KNO_2 + 2CO + \text{Heat}$$

$$2KNO_2 + C \longrightarrow K_2O + 2NO + CO + \text{Heat}$$

$$2NH_4NO_3 + 2C \longrightarrow 4H_2O + 2CO + 2NO_2 + \text{Heat}$$

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* Marketed by Kubo Combustion Efficiency Chemicals Pvt. Ltd.

NO reacts with O_2 to become NO_2 which also oxidizes carbon particulates.

$$12\ NO_2 + 24\ C \longrightarrow 6\ N_2 + 24\ CO + \text{heat}$$

$$24\ CO + 12O_2 \longrightarrow 24\ CO_2 + \text{heat}$$

The non-combustible fraction of coal, mostly iron oxides and impurities from fuel, form dry and heavy particles settling in the bottom ash.

Source: POLARCHEM-L2 (Technical Information Bulletin)

Q. *Can it reduce SO_x emissions?*

Ans. Yes, Vanadium content of FO gets oxidized to V_2O_5 which catalyzes the oxidation of SO_2 to SO_3. However, the potassium nitrate fraction of Polarchem-L2 binds the vanadium pentoxide into a stable, non-corrosive, high melting (m.p. > 2275°K) potassium vanadate (K_3VO_4)

$$4\ KNO_3 \longrightarrow 2\ K_2O + 4\ NO_2 + O_2$$

$$4V\ (\text{fuel}) + 5O_2 \longrightarrow 2V_2O_5$$

$$3K_2O + V_2O_5 \longrightarrow 2K_3VO_4$$

With vanadium pentoxide out of the system, conversion of SO_2 to SO_3 sharply drops. And whatever traces of SO_2/SO_3 is left, potassium oxide forms stable salts with them

$$K_2O + SO_2 \longrightarrow K_2SO_3$$

$$K_2O + SO_3 \longrightarrow K_2SO_4$$

That is how fuel additives fight the emission of SO_x.

Q. *How much chemical additive is injected?*

Ans. It varies from one manufactuer's product to an other and depends on the quality of fuel being fired, fireside condition and existing problems on the fireside boiler. For Polarchem-L2 this dosage limit is:

0.25 – 0.50 litre/ton of fuel being fired.

Q. *How does fluidized-bed combustion (FBC) go in favour of emission control?*

Ans. FBC units operate at a much lower temperature (1090°K – 1145°K) than conventional PC-fired or stoker-fired boilers. And that is the key to controlling both NO_x and SO_2.

Fluidization promotes turbulence that makes the entire bed material in the combustor behave like a liquid. Improved mixing generates heat at substantially lower and more uniformly distributed temperatures—typically 1100°–1150°K, as compared to a stoker-fired or pulverized-coal burning unit. This operating temperature is well below the formation point for thermally induced NO_x. If staged combustion is harnessed, it will minimize fuel-bound NO_x formation as well.

Over and above, the operating temperature range is selected such that the reactions of SO_2 with a suitable sorbent (frequently limestone) get thermally balanced. And this implies a trade-off between maintaining high SO_2-removal capability and maximum combustion efficiency.

Q. *What are the hurdles to justifying more capital-intensive NO_x-reduction measures in small, low-capacity boiler units?*

Ans.

1. Low residence time restricts the application of overfire air (OFA) without excessive loss of thermal efficiency or induced smoking
2. Compact furnace design ill-affords combustion modifications that extend flame length causing flames to impinge against tubewalls
3. Peak boiler efficiency and minimal NO_x emissions occur close to the minimum O_2 level in the FG exit. And this point marks the threshold of smoke or unburnt C-emissions. Therefore, it is not practically a sound proposition or even safe to operate at this condition unless the boiler is equipped with sophisticated combustion controls and flame-quality monitoring systems
4. Greater emphasis is laid on efficient use of steam in process industries, where

small boilers are fitted, rather than on emission level that limits boiler heat input or the volume of FG.

Q. *What are the prudent steps in NO_x control strategy?*

Ans. 1. Optimizing and fine tuning existing equipment
2. Control of air: fuel ratio
3. Flue gas recirculation (FGR)
4. LEA firing
5. Off-stoichiometric combustion (OSC)
6. Use of low NO_x burners (LNBs)
7. Reburning
8. Post combustion control
   (a) selective catalytic reduction (SCR)
   (b) selective non-catalytic reduction (SNCR)

Q. *What do you mean by optimizing and fine tuning existing equipment to reduce NO_x emissions from boiler units?*

Ans. These are the first and fundamental steps, particularly important for PC-fired units.

Balancing fuel feed to the burners and maintaining the coal fineness are essential prerequisites to any PC-fired boilers. However, industrial installations pay less premium to flow measuring and optimizing fuel distribution.

The prevailing practice is to balance PC flow to within 5%, burner-to-burner. However, much better results can be obtained by inducting the new standard ISO 9931 that involves using existing measurement and control devices to strategically balance fuel feed to specific burners of furnace regions in a manner so as to match the existing air flowrates or create off-stoichiometric firing and/or burnout zones.

Burner optimization also calls for good maintenance of burners because misalignment, poor vane and impeller conditions can limit control over the combustion. That is, monitoring and upkeeping of burners are an integral part of minimizing NO_x emissions.

No less important is close monitoring of furnace walls that harbour excessive slag build-up due to localized/severe sub-stoichiometric firing conditions. This slag accumulation tells upon boiler efficiency and adversely affects NO_x emissions control strategies. Therefore, soot blowing is of significant importance in optimizing NO_x emissions.

Q. *How does the control of air: fuel ratio exerts its influence in NO_x emissions?*

Ans. Combustion air is split into two main parts—primary air and secondary air. As the feed air continues to be split and manipulated, it requires more precise measuring and control of these streams for effective reduction of NO_x emissions.

For burning fuels with high furnace heat release rates (i.e. fuels with high volatile content), for industrial boiler units upgraded from original design or for units burning coal with a significantly higher heat content than design, controlling primary air/fuel ratio is essentially critical to reducing NO_x emissions.

Mal-distribution of air can result from:

1. increasing branching resulting in a greater likelihood of substantial variation in flowpath resistance
2. accumulation of debris and/or ash particles in air ducts leading from both operating and standby airfans/sources.

All this complicates accurate flow measurement of combustion air and adversely affects combustion control.

Q. *How can the combustion control be upgraded economically?*

Ans. The relatively inexpensive ways of upgrading combustion control are to harness digital processing units and reliable, advanced, in situ technologies for CO, O_2 and NO_x measurement.

Q. *How do they upgrade?*

Ans. These latest technologies offer improved capabilities of upgrading combustion control through

(a) precisely matching air/fuel ratios under dynamic conditions
(b) ease of making adjustments/alterations appropriate to fuel changes
(c) optimizing firing conditions based on an increased array of input signals.

Q. *Selecting/specifying fuels—both coal and fuel oil—with lower levels of fuel-bound nitrogen is the latest in the plant's overall NO_x reduction strategy.*

Do you think this strategy is a sound one?

Ans. Reducing fuel nitrogen alone will not reduce NO_x emission to required levels, it can take the burden off other control strategies, thus reducing costs.

Q. *What are the in-furnace technologies that are commercially exploited as a means of controlling NO_x emissions from fossil-fuel fired boilers?*

Ans. The most practical and cost-effective options are as follows:

(a) Reduced combustion-air heating
(b) Low-excess-air (LEA) firing
(c) Overfire air (OFA) injection
(d) Flue gas recirculation (FGR)
(e) Off-stoichiometric combustion (OSC)
(f) Steam/water injection
(g) Low-NO_x burners (LNBs)

Q. *What is the NO_x reduction efficiency of these techniques?*

Ans. Typically 15% – 30%.

Q. *Why does reducing combustion-air heating reduce NO_x emissions?*

Ans. This reduces flame temperature and that effectively lowers NO_x formation.

Q. *However, lowering the amount of air preheating will adversely affect the thermal efficiency of the boiler. How can this be offset?*

Ans. This can be offset by enlarging the economizer.

Note: *Thus this technique is useful particularly* in new facilities.

Q. *Why does flue gas recirculation (FGR) reduce NO_x emission?*

Ans. Water vapour in the FG absorbs more heat than air alone. FGR dilutes the excess air in the combustion zone.

Thus flue gas recirculation quenches the peak flame temperature in the combustion zone and reduces superstoichiometric oxygen level. As a consequence, NO_x formation is reduced.

Note: This technique has also reduced particulate emissions at some installations.

Q. *How is FGR accomplished?*

Ans. Typically the flue gas is introduced into the combustion air upstream of the windbox. This is accomplished through the suction of the FD fan or by installing a booster fan.

Alternatively, the FG is introduced at the burner exit which is known as plenum FGR.

Q. *What is the advantage of plenum FGR?*

Ans. It is an efficient and highly controllable approach.

Q. *Is there any trouble with it?*

Ans. It is not always possible or practical to do this with all burner designs.

Q. *Between premix FGR and equal amounts of plenum FGR, which one achieves greater NO_x reductions?*

Ans. Premix FGR.

Q. *What are the disadvantages of the FGR technique?*

Ans. 1. Excessive amounts of premix FGR—generally more than 20% with conventional burners—tells upon flame stability, causing boiler vibration and inconsistent operation
2. Loss of boiler efficiency
3. Over and above the capital costs, the FGR fan O & M costs and costs associated with the loss of boiler efficiency can be significant.

Q. *How does LEA firing contribute to low NO_x emissions?*

Ans. It reduces the O_2 concentration in the local flame zone, thereby reducing the formation of both thermal and fuel NO_x.

Q. *What distinct advantages does the LEA technique beget?*

Ans. 1. It is easy to implement—no configurational modification in the boiler is required
2. NO_x reduction efficiency is considerable
3. It leads to increase in boiler efficiency.

Q. *What is the NO_x reduction efficiency of LEA firing?*

Ans. Typically 44%.

Q. *How much of boiler efficiency is increased due to LEA firing?*

Ans. Increase of boiler efficiency up to the extent of 2.5% has been reported using LEA firing.

Q. *What is the essential prerequisite to LEA firing?*

Ans. Control of combustion of the process.

It is essentially required to ensure safe operation of the boiler and must be effective in taking care of load swings and variations in fuel quality.

Q. *What are the limitations of LEA firing?*

Ans. 1. Increased fouling and corrosion because of the reducing atmosphere
2. Increased CO-emissions
3. Incomplete fuel burnout

Q. *What are the off-stoichiometric combustion techniques?*

Ans. • Biased burner firing (BBF)
• Burners out of service (BOOS)
• overfire air (OFA)

Q. *How does BBF go into action?*

Ans. The set up is framed by two rows of burners: the bottom row(s) of the burners create a fuel-rich combustion zone, while the upper row(s) of burners accomplish a lean-fuel combustion.

Q. *How does BOOS system take into action?*

Ans. BOOS system works with multiple tiers of burners. It aims at reducing NO_x emission through staged combustion by operating most of the burners under fuel-rich condition while introducing only air through the remaining burners (usually the top row). Such an operation gives rise to a crude form of air-staging.

Note: BOOS is a simple technique applicable to multiple-burner-level oil/gas fired units and not thought to be an appropriate one for retrofitting coal-fired boilers.

Q. *What is its NO_x reduction efficiency?*

Ans. It reduces NO_x emissions to an extent of 50%.

Q. *How does OFA manage to reduce NO_x emissions?*

Ans. Its control strategy is based on air-staging.

Q. *How is this OFA technique accomplished?*

Ans. OFA injection brings into effect two-stage combustion (TSC) implemented by injecting a portion (15–20%) of the total combustion air above the flames through OFA ports located atop the topmost tiers of burners or above the grate for a stoker-fired system burning solid fuels like coal, solid wastes etc.

Q. *On which factors does the success of the OFA system depend?*

Ans. The effectiveness of the OFA technique basically depends on the adequate mixing of OFA with the combustion products. And therefore, parameters such as port location, number of OFA ports and their geometry, spacing, pressure drop, furnace dimensions as well as fan capacity must be given top priority to get the best out of OFA.

Q. *What are the disadvantages with OFA?*

Ans. Retrofitting existing boilers with OFA ports requires

1. a detailed, site-specific analysis to evaluate compatibility with the existing boiler design, materials, and operating constraints.
2. addition of ductwork and new furnace wall penetrations—a capital expense that most utilities want to avoid.
3. decreased combustion efficiency and deterioration of final steam conditions.

Q. *How does water or steam injection reduce NO_x emissions?*

Ans. Water/steam injection used with oil/gas-fired burners reduces the peak flame temperature, thus reducing NO_x formation.

Note: A similar response can be obtained by burning an oil-water emulsion.

Q. *How do LNBs reduce NO_x emissions?*

Ans. All LNBs put into effect staged combustion to achieve lower NO_x emissions.

Either air can be staged or fuel can be staged or both air and fuel can be staged. There still is another approach:

Incorporating FGR into the burner producing rapid mixing, not air staging.

These burners control mixing of the fuel and the combustion air in a pattern that keeps flame temperatures low and dissipates heat quickly, thereby avoiding the generation of localized hot zones. As soon as the fuel-air stream is injected into the furnace, these LNO_x burners split, instead of mixing, it into distinctly separate primary and secondary combustion zones, thereby accomplishing staging of the flame at the burner.

Q. *What is reburning?*

Ans. Reburning is a technique that reduces NO_x of combustion products into nitrogen and water by injecting hydrocarbon fuel as a reducing agent.

Q. *Reburning is also called staged-fuel injection. Why?*

Ans. Reburning is accomplished through the creation of three distinct reaction zones:

(I) **Primary Zone**—created by the primary fuel operated at or near stoichiometric conditions

(II) **Sub-Stoichiometric Zone**—is a reburn zone produced by the injection of reburn fuel whereupon NO_x produced in the primary zone gets reduced

(III) **Burnout Zone**—where air is injected to complete burnout.

Q. *How are these accomplished?*

Ans. Reburning is integrated into the burner. Reburn fuel is injected to penetrate the swirl-induced internal recirculation zone (IRZ). The tertiary burn-out air is physically segregated from the primary and reburn zones and injected downstream in the furnace (Fig. 16.1)

Q. *What is the NO_x reduction capacity of the reburning system?*

Ans. Studies with PC primary fuel and utilizing NG, COG, heavy FO and coal as reburn fuel have shown that NO_x can be reduced to below 150 ppm (0% O_2) compared to the baseline, uncontrolled level of 1328 ppm (0% O_2), irrespective of reburn fuel type, without affecting burn-out to an appreciable degree.

If the reburn fuel's nitrogen content is low, NO_x reductions of 50% can be achieved.

NO_x reductions of up to 80% have been obtained in oil-over-oil configurations through FGR and fuel reburning.

If reburning is combined with low-NO_x burners, total NO_x reductions of 90% are possible.

Q. *Which fuel is used as reburn fuel?*

Ans. Theoretically, any fuel can serve as a reburn fuel. However, natural gas is the most successful candidate.

Q. *Why natural gas?*

Ans. Because of its

(a) generally clean-burning characteristics
(b) complete volatility
(c) more compatibility with smaller furnaces
(d) not having any fuel-bound nitrogen.

Q. *How is sorbent injection carried out?*

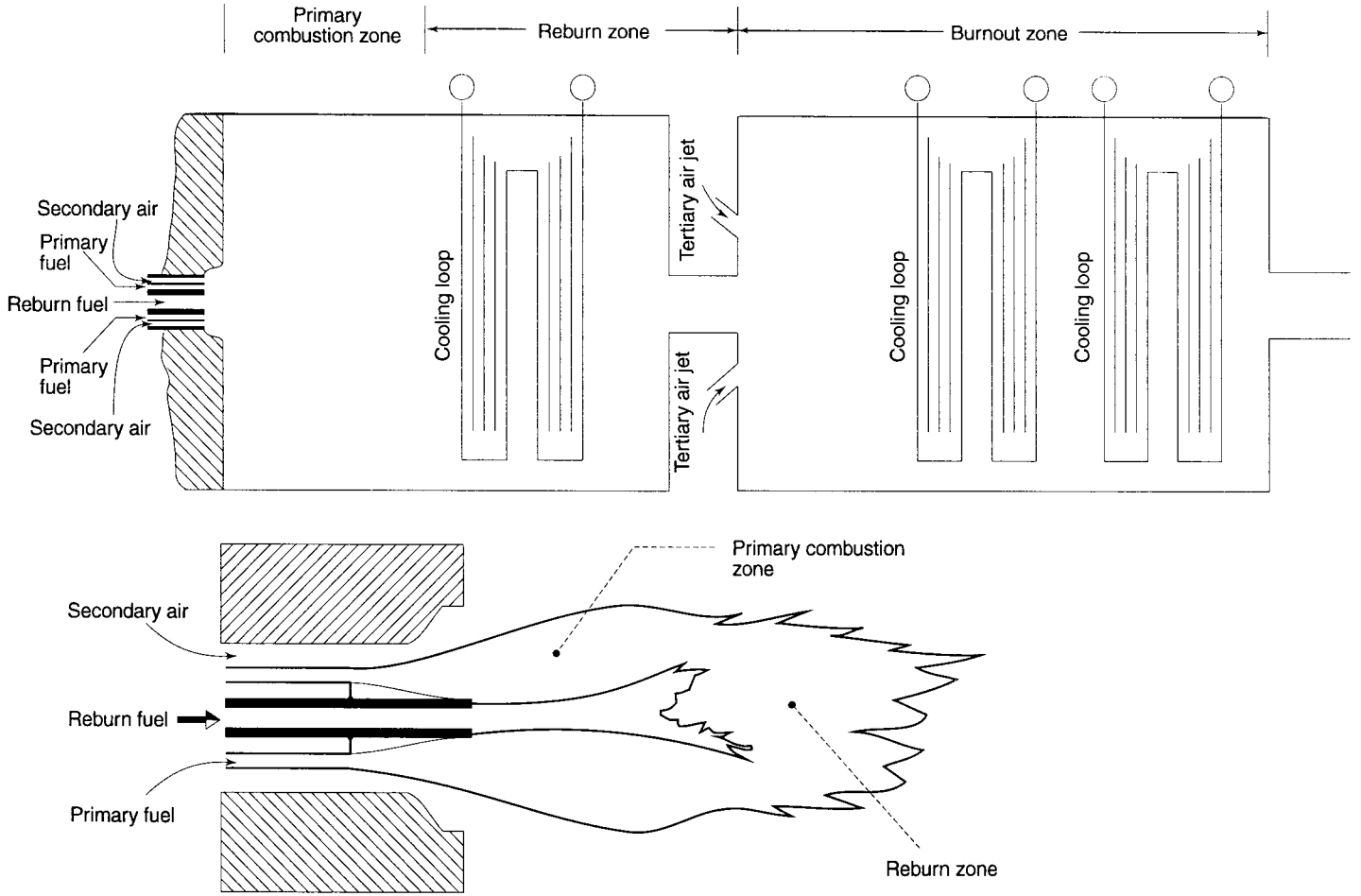


Fig. 16.1 *Reburning system works on fuel-staging. Combustion is accomplished in three distinct zones. While primary and reburn fuels and primary and secondary airs are introduced through burners, tertiary air jets are injected down-stream to complete combustion.*

Ans. The sorbent is pulverized, transported to the furnace and injected right at the burner or into the flue gas farther downstream (Fig. 16.2) and the reacted solids are collected in an ESP or fabric filter.

Q. *What is the positive effect of the sorbent injection method?*

Ans. A modest amount of SO_2 can be removed.

Q. *What is its SO_2 removal efficiency?*

Ans. 30% – 70%.

Q. *How can this upper range be accomplished?*

Ans. 1. By enhancing FG humidification
2. Upgrading of the sorbent reagent

Q. *What do you mean by upgrading of sorbent reagent?*

Ans. Replacing conventional limestone by pressure-hydrated lime and calcium hydroxide.

Q. *What is the adverse effect of sorbent injection?*

Ans. 1. Fouling of heat-transfer surfaces
2. Increased solids loading on bag filters and ESP.

Note: Sorbent injection is an attractive proposition when combined with NG reburning.

Q. *How does the SCR system control NO_x emissions?*

Ans. It is a post-combustion process in which ammonia is injected into the exhaust gas upstream of the catalyst bed (Fig. 16.3) whereupon NH_3 reacts with NO_x to form molecular nitrogen and water vapour

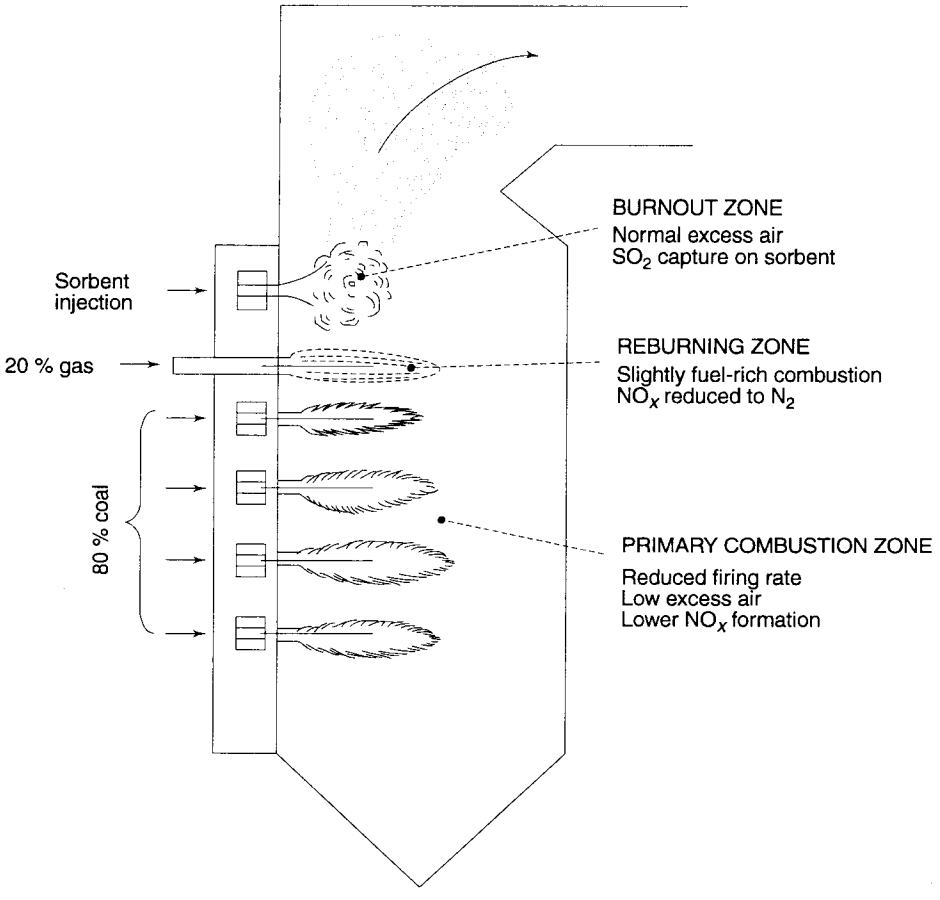


Fig. 16.2 *Sorbent injection combined with gas reburning.*

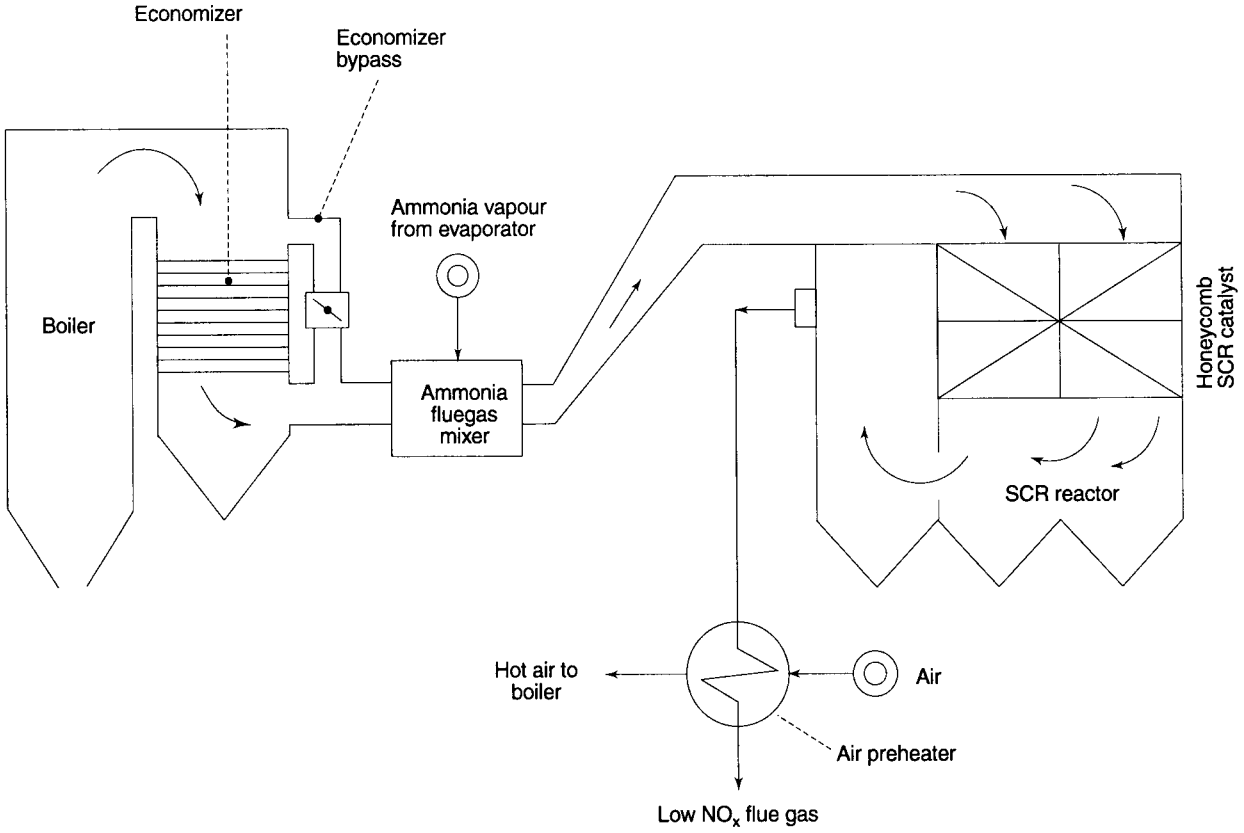


Fig. 16.3 *Ammonia is injected to flue gas upstream of catalyst bed.*

$$4NO + 4NH_3 + O_2 \longrightarrow 4N_2 + 6H_2O$$
$$6NO + 4NH_3 \longrightarrow 5N_2 + 6H_2O$$
$$NO + NO_2 + 2NH_3 \longrightarrow 2N_2 + 3H_2O$$

Q. *What is its NO_x removal efficiency?*

Ans. 90% + depending on the inlet conditions.

Q. *Which catalyst is used?*

Ans. The catalyst is vanadium, platinum, rhodium or titanium compound impregnated on a metallic or ceramic substrate or integral with a honeycomb shaped substrate (Fig. 16.4)

Q. *What is the reaction temperature?*

Ans. 590°K–670°K

Q. *How is ammonia introduced?*

Ans. Ammonia diluted to 5% by carrier fluid (compressed air or steam) is injected into the flue gas path (Fig. 16.5)

Q. *What are the most critical parameters in this process?*

Ans. 1. Adequate mixing of NH_3 with the flue gas
2. Dozing the right amount of ammonia.

Q. *What are the drawbacks of the SCR process?*

Ans. 1. **Limited Temperature Range:** SCR is a temperature-sensitive process—being most successful over the range of 590°K – 670°K. Below 590°K, the rate of reaction is just too slow for effective NO_x reduction while above 700°K, ammonia gets increasingly activated to get oxidized to NO_x whereupon permanent damage occurs to some catalysts.
2. **Ammonia Handling:** ammonia is a hazardous chemical. Potential for accidental spillage during transportation or leakage during storage must be addressed. Ammonia slippage (unreacted NH_3) has given rise to visible white plume in the stack*.
3. **Catalyst Problems:** The catalyst may 'die' out (become inactive) over a period of 1-5 yrs due to
   (a) sintering (reduction of pore volume)
   (b) blinding (choking of active sites, i.e. pores by the deposition of solids)
   (c) poisoning by alkali metal viz. potassium, trace heavy metals and SO_3
   (d) erosion by flyash.

Also the spent catalysts pose disposal problems as they contain heavy-metal oxides which are hazardous.

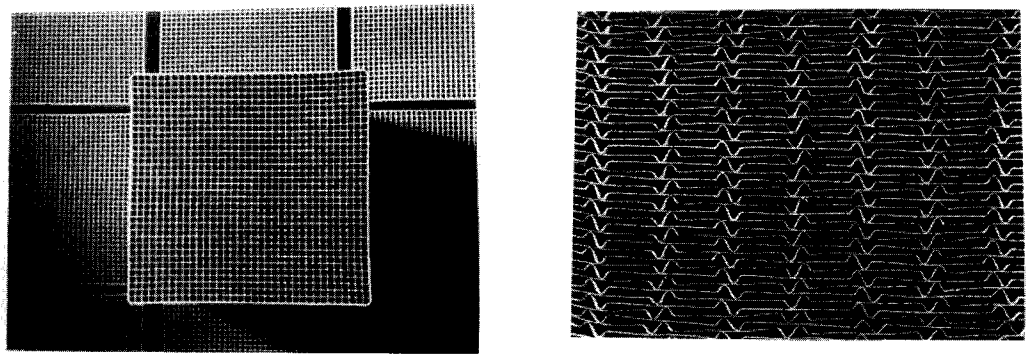


Fig. 16.4 *Honeycomb (left) and plate-type (right) catalytic converters for NO_x reduction in flue gases of varying composition.*
Source: *Siemens Power Journal 3/93*
Courtesy: *Siemens Power Generation Group (KWU), Erlangen, Germany*

* Ammonia reacts with HCl vapour of FG resulting in white fumes of ammonium chloride
$NH_3 + HCl \longrightarrow NH_4Cl$

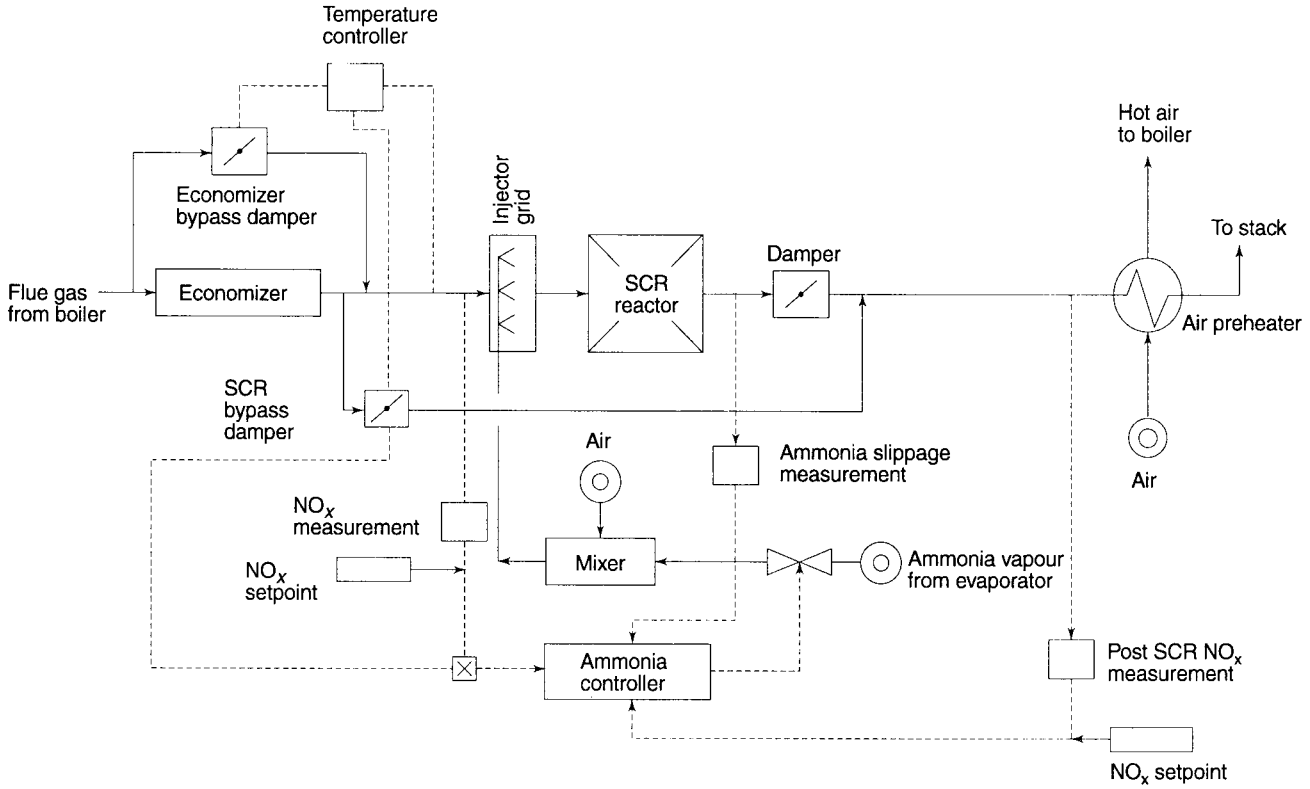


Fig. 16.5. *Ammonia diluted by air stream is injected into flue gas prior to its entry to the SCR reactor.*

Q. *Where is the SCR reactor located?*

Ans. Location of the SCR reactor is vital. It exercises profound influence on reactor performance and costs involved. For coal-fired boilers with low dust emission, the SCR is installed downstream of the hot side ESP (Fig. 16.6) whereas for high dust-load-FG systems SCR is installed upstream of the cold side ESP. This is because in low-dust systems, catalyst erosion is rarely a problem.

SCR units can also be installed farther downstream just before the stack to avoid contamination and fouling of downstream equipment.

Q. *How does the question of fouling of dowstream equipment arise?*

Ans. Ammonia reacts with SO_3 of flue gas to produce ammonium bisulphate

$$SO_3 + H_2O \longrightarrow H_2SO_4$$
$$NH_3 + H_2SO_4 \longrightarrow NH_4HSO_4$$

which deposits on the air heater downstream.

Q. *How does the SNCR system reduce NO_x emissions?*

Ans. In working principle it is same as that of the SCR except that denoxing takes place in the absence of a catalyst.

Anhydrous ammonia, urea or their aqueous solutions are injected into the furnace at the appropriate temperature zone to accomplish reduction of NO_x to N_2 and H_2O

$$NO + NO_2 + 2NH_3 \longrightarrow 2N_2 + 3H_2O$$

$$\left.\begin{matrix} NH_2 + NO \\ CO \\ NH_2 + NO \end{matrix}\right\} \longrightarrow CO + 2N_2 + 2H_2O$$

$$\left.\begin{matrix} NH_2 + NO \\ CO \\ NH_2 + NO_2 \end{matrix}\right\} \longrightarrow CO_2 + 2N_2 + 2H_2O$$

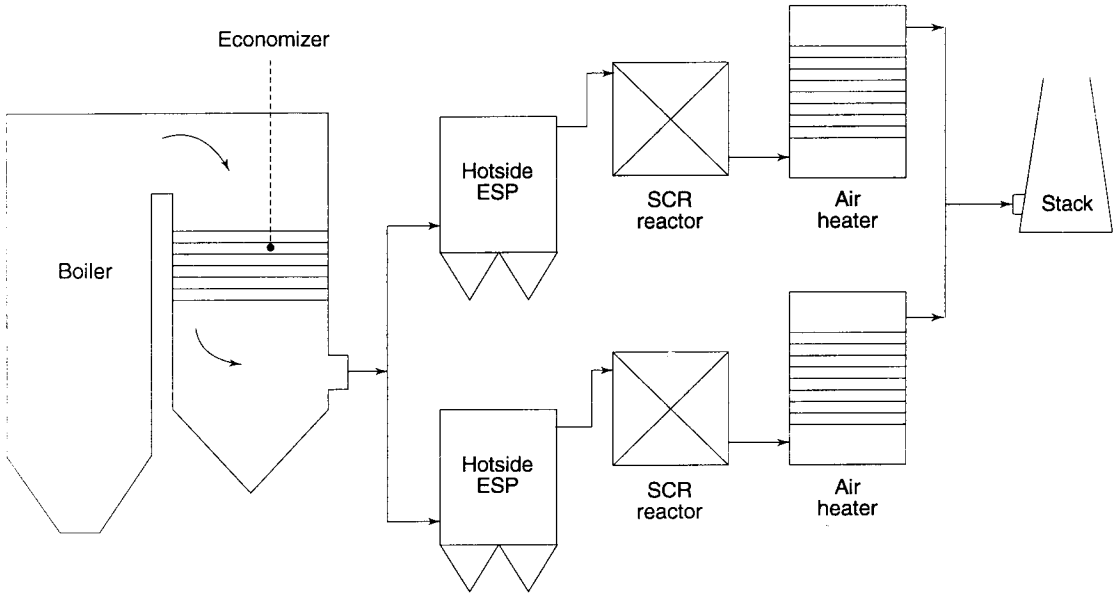


Fig. 16.6 *SCR reactor lined up with hot-side ESP upstream.*

Q. *As a deNO_xing agent urea is gaining ground over ammonia. Why?*

Ans. Ammonia is a hazardous gas. Its transportation, storage and injection pose problems and tie up more capital. As against these, urea has the following advantages

1. It is a non-toxic, non-hazardous chemical, absolutely safe to handle
2. It is introduced either as solid or as an aqueous solution.
3. It is less costly to inject as a liquid than NH_3 as a gas
4. Ammonia injection system generally requires an evaporator to convert liquid NH_3 (as it is commonly supplied) to gas.

Q. *At what temperature is SNR accomplished?*

Ans. Usually over the FG temperature range of 1150°K – 1370°K.

Q. *In earlier designs, the injection grids were located in the flue gas stream but eventually they have given way to wall injectors. Why?*

Ans. The key to the success of the SNR process lies in adequate mixing of the reducing agent with the flue gas. Hence the erstwhile locations of injection ports were replaced by wall injectors which have resulted in significant improvements in the mixing characteristics.

Q. *What are the disadvantages with SNR system?*

Ans.
- Ammonia slippage
- Formation of ammonium bisulphate and precipitation thereof in the air heater when burning high-sulphur coals
- Marked tendency to increase CO content in the flue gas.

Q. *What is the NO_x removal efficiency of the SNR system?*

Ans. As much as 80%.

Q. *ESPs are particularly useful in controlling flyash emission. This technique gained popularity in the early 1970s for plants burning low-sulphur coals with high-resistivity flayash. How was the concept of Hotside ESP born?*

Ans. ESPs are very effective in collecting high resistivity ash. However, collecting such particulates is hindered by power limitations at temperature below 590°K. Thus, collecting ash above this temperature is the design basis for the hotside ESP.

Q. *Installed in PC-fired boilers burning low-sulphur coals, a problem known as sodium-ion depletion crops up in ESPs. What is this phenomenon?*

Ans. This phenomenon is called sodium-ion depletion which takes place due to migration of sodium ions through the ash layer on the collecting plate, leaving a film of flyash with excessively high resistivity. Coals with low sodium content in the ash are particularly prone to this phenomenon.

Q. *Therefore, how can ESP performance degradation be prevented under such circumstances? By adding sodium-compounds?*

Ans. Efforts have been made in commercial units to prevent degradation of ESP performance by adding Na compounds to coal. But this creates potential problems with increased slagging of boiler tubes.

Q. *What is the particulate removal efficiency of ESP?*

Ans. Under optimal conditions, modern ESPs are capable of achieving particulate removal efficiencies of 99.7% and higher. Fortunately this is well within the regulatory levels of CAA (Clean Air Act of USA).

Q. *Do you think 'optimal conditions' are always present?*

Ans. No.

Q. *What happens actually?*

Ans. Optimal flue gas conditions are not always present. Flue gas conditions change dramatically after a fuel switch or the installation of some sort of emission control technology upstream of ESP.

Since ESPs are sensitive to flue gas conditions, the performance of ESPs suffer badly under these circumstances.

Q. *What is the viable remedy to this?*

Ans. Gas conditioning has been shown to be an effective means of returning flue gas to the "optimal" conditions required for efficient ESP operation following a fuel switch to a lower sulphur coal.

Q. *Why is gas conditioning a necessity while installing ESP to collect flayash particulates?*

Ans. To understand this, a basic knowledge of ESP technology is necessary.

An ESP is essentially a large box fitted with alternate rows of collection and discharge electrodes. As flue gas flows through the box, high voltage applied to the discharge electrodes charges the suspended particles of the gas stream. These charged particles are pushed by the force of the voltage to the vicinity of the collection electrodes,where they adhere and are held there primarily by the flow of electric current through the layer of collected particulates until rapping dislodges them off.

Under acceptable resistivity levels and other good operating conditions, ESPs can exhibit collection efficiency as high as 99.9% +. However, high particle resistivity (typically above 5 E 10 ohm. cm) will severely affect the ESP's overall collection efficiency. As an alternative to enlarging the ESP, gas conditioning can restore the required resistivity conditions to ideal performance levels.

Note: Auto gas conditioning is made while burning high-sulphur coals. A small fraction of the SO_2 produced by the combustion of coal is converted to SO_3 (typically less than 2%). When temperature and humidity conditions are favourable, the sulphur trioxide thus generated gets absorbed on the surface of the flyash particles and is sufficient to reduce electrical resistivity of these ash particulates.

However, the amount of sulphur trioxide naturally formed by the combustion of low-sulphur coal may be insufficient to reduce the resistivity of flayash enough to ensure satisfactory ESP performance.

Q. *How can gas conditioning be made?*

Ans. Early applications of gas conditioning used liquid SO_3 which was vaporized and diluted with air used as carrier stream. As an alternative to this, concentrated H_2SO_4 was vaporized with hot air. Both technologies were capable of reducing flayash resistivity to desired levels, but shared the common problem of storage and handling of a difficult and toxic material.

The second generation of gas conditioning technology used SO_2. Commercially available SO_2 was vaporized and injected into a filtered hot airstream upstream of a catalytic converter that converted the SO_2 to SO_3. This system provided lower equipment and installation costs, ensured operational simplicity, and improved reliability.

At present, molten sulphur is burned to produce SO_2 which is introduced upstream of the catalyst bed. This is the most widely practised FG-conditioning technology today.

More recently, EPRI has developed its own technology EPRICON which is the outcome of EPRI's investigations into gas conditioning, in an attempt to develop a simpler alternative to the conventional SO_3 flue gas conditioning available. EPRICON operates by withdrawing a small fraction of the FG from a location in the boiler where the operating temperature is in the range of 700° – 755°K. This slipstream is passed over a catalyst bed, where over 50% of the SO_2 is converted to SO_3. The SO_3-rich slipstream is reinjected before the ESP to increase SO_3 concentration, improving ESP performance.

Q. *How does the EPRICON process operate?*

Ans. The process (Fig. 16.7) operates by withdrawing a small fraction in the convective shaft where the flue gas temperature ranges from 700°K

to 755°K. This fraction of flue gas, also called slipstream, is then passed over six-layers of catalyst bed heated by the gas. The catalyst converts 30 – 70% of the SO_2 in the FG to SO_3. The slipstream, now SO_3-rich, is reinjected into the gas stream somewhere between the air heater and ESP to provide the required SO_3 for the reduction of resistivity.

Note: Research-Cottrell has installed this technology in a 250 MW electric utility boiler, and has demonstrated a high conversion rate and significant precipitator performance improvements.

Q. *How much of the flue gas is withdrawn as slipstream?*

Ans. It depends on case-by-case conditions. If, for instance, 5 ppm of SO_3 is enough to treat the flyash adequately and the flue gas contains 500 ppm of SO_2, it is enough to draw 1 to 2 per cent of FG as slipstream.

If 15 ppm of SO_3 is needed, it will be adequate to draw a little over 3% of FG (containing 500 ppm of SO_2) as slipstream.

Three per cent is considered to be the upper limit of a range for continuous operation that has been identified as economically and technically desirable.

Q. *What are the advantages with the EPRICON system?*

Ans. 1. EPRICON process provides required FG-conditioning without the need for external agents, such as liquid SO_2 or vaporized molten sulphur
2. It eliminates the need to filter the gas of particulates prior to its entry to the gas-conditioning chamber
3. It eliminates the need for an additional fan to move the conditioned gas into the ESP.

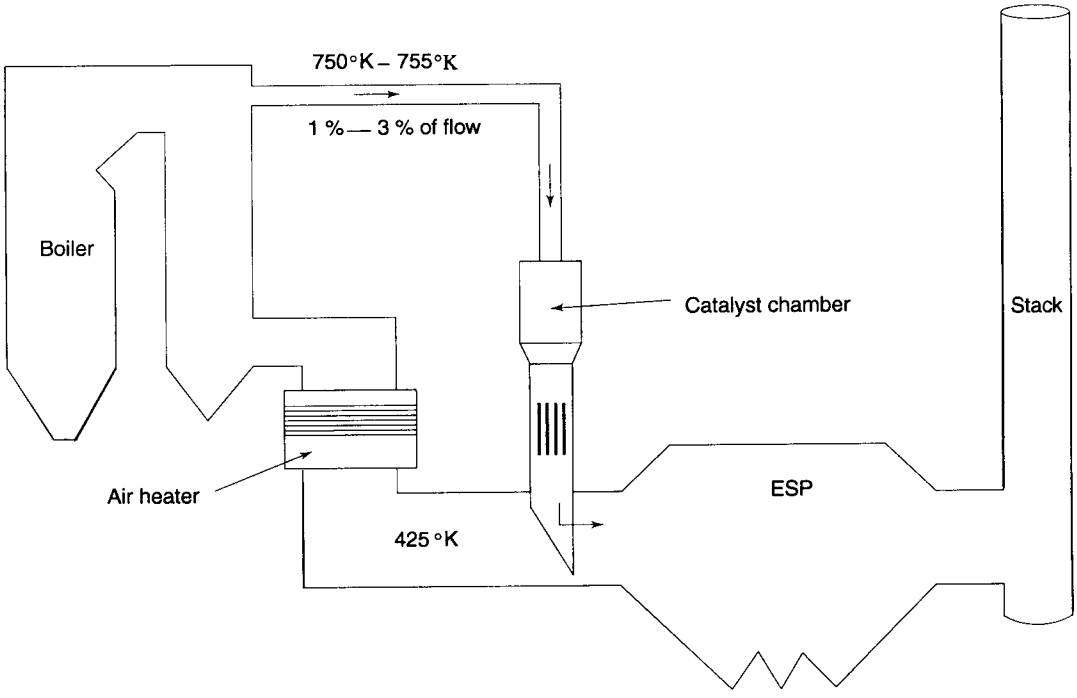


Fig. 16.7 *EPRICON process. A part of the flue gas stream is diverted to a converter to produce a SO_3-rich slipstream which is returned to the mainstream upstream of ESP to ensure necessary gas-conditioning.*

Q. *What is the capital cost of installation of the EPRICON system?*

Ans. The EPRICON technology, based on two 250 MW installations, is expected to cost under $4.50/KW on a completely installed turnkey basis. Installation, labour and auxiliaries such as dampers, expansion joints and access systems comprise over 50% of the total system cost.

Source: EPRICON: Agentless Flue Gas Conditioning for Electrostatic Precipitators—Peter Paul Bibbo (Research-Cottrell, Inc.)

Q. *What do you mean by DeSONO$_x$ing?*

Ans. It means simultaneous control of SO_2 and NO_x from flue gas stream.

Q. *How is this achieved?*

Ans. Many novel technologies are available today to get rid of NO_x and SO_2 simultaneously from FG stream.

1. ABB Combustion Engineering, Inc., Milan, Italy has developed a very sophisticated deSO_xNO_x process under the tradename of WSA-SNO_x which has achieved SO_x/NO_x removal efficiency as high as 95%/90%. It harnesses SCR and catalytic conversion of $SO_2 \longrightarrow SO_3$ in tandem.
   NH_3 is injected to the gas stream upstream of the SCR bed where NO_x is broken down to harmless N_2 and water.

$$NO + NO_2 + 2NH_3 \longrightarrow 2N_2 + 3H_2O$$

   This is followed by catalytic conversion of SO_2 to SO_3

$$SO_2 + O_2 \text{ (excess air)} \xrightarrow[C-\text{particle}]{\text{Unburnt}} SO_3.$$

   and the absorption of SO_3 in an absorber. This system has an additional advantage of reducing flyash load as well.
2. KAMMAG Engineering Co., Vienna, Austria has developed a denoxing process called NONOX. It has SO_2/NO_x removal efficiency of 95%+/95%+.
   This process utilizes wet-phase oxidation of sulphur dioxide by ozone. SO_2 is oxidized to SO_3 as

$$O_3 \longrightarrow O_2 + \dot{O}$$

$$SO_2 + \dot{O} \longrightarrow SO_3$$

$$H_2O + SO_3 \longrightarrow H_2SO_4$$

   The sulphur trioxide thus generated is absorbed by water in an absorption tower to remove it from the system as sulphuric acid.
   NO_x is eliminated by a NH_3-Water system in a counter-current tray tower with high turbulence.
   Ozone generator is an expensive gadget and adds significantly to capital cost and process complexity as well.
3. EBARA International Corporation, Greensburg, Pasadena (USA) has poineered Electron Beam Technology for the destruction of SO_x and NO_x.
   The process works on the humidification of the FG followed by ammonia injection and irradiation by electron-beam generator at 330°K – 425°K.
   Humidification of flue gas converts SO_x/NO_x into corresponding acids which are absorbed by NH_3

$$SO_2 + H_2O \longrightarrow H_2SO_3$$

$$SO_2 + NH_3 + h\nu \longrightarrow S + N_2 + H_2O$$

$$H_2SO_3 + NH_3 \longrightarrow NH_4HSO_3$$

$$NO_2 + H_2O \longrightarrow HNO_2 + HNO_3$$

$$HNO_3 + NH_3 \longrightarrow NH_4NO_3$$

   The solids—ammonium nitrate, bisulphite and sulphur—are collected downstream by the fabric filter or ESP.
   SO_2/NO_x removal efficiency has been claimed to be 95%/80%.
4. DEGUSSA Corporation, South Plainland, New Jersey (USA) has developed and claimed that its DESONOX process has

a SO_2/NO_x removal efficiency of 85%/80%.

This process works with a SCR and a catalytic SO_2 converter in tandem. Ammonia is injected into the flue gas stream upstream of the air preheater and the ammoniated gas is then treated in a SCR to carry out the denoxing.

This is followed by air injection to accomplish the oxidation of SO_2 to SO_3 upon ceramic honeycomb catalyst. The flue gas is then stripped off SO_3 in an absorption tower removing SO_3 from the system as sulphuric acid.

The system needs hotside ESP to safeguard downstream catalyst beds from particulate fouling. Also the final exit gas requires reheating for its discharge through the chimney.

5. Lime/Urea Hydrate Injection process has been developed by Fossil Energy Research Corp., Laguna Hills, California (USA).

   The process operates with the injection of dry, powder lime/urea hydrate in the high temperature zone, preferably in the 1225°K—1420°K regime of the furnace.

   Lime absorbs SO_x and urea hydrate scavanges NO_x. Solids (calcium sulphate and bisulphite) are collected in the ESP or high-temperature-fabric-filter downstream.

SO_2 removal efficiency = 60 – 95%

NO_x removal efficiency = 50 – 80%

Q. *Nearly all coal-fired boilers in Japan employ wet-limestone gypsum-producing-FGD systems. How are these processes characterized?*

Ans. Gypsum-producing processes for coal-fired utility boilers are characterized according to the type of sorbent (viz. calcium hydroxide or calcium carbonate) and additive (sodium or magnesium based) used.

Sulphuric acid is added to the main scrubber to help control pH. The most popular system incorporates a prescrubber to remove chlorides and fluorides, collect the remaining flyash and cool the gas.

This system is also characterized by a separate oxidation step.

Q. *How does such a system operate?*

Ans. One such FGD plant installed at the 700 MW coal-fired boiler at the Takehara station of Electric Power Development Corporation, Japan is shown in Fig. 16.8.

It sports a very efficient hotside ESP installed upstream to keep the dustload low at the scrubber inlet. This results in less flyash contamination of the gypsum product without having a prescrubber loop.

The flue gas is treated by two trains of hotside ESPs and SCR reactors and then passes through two regenerative heaters arranged in parallel. A booster fan is located between the reheater and the scrubber and a scavenging fan is added to prevent leakage of the untreated gas into the cleaned gas.

Flue gas is introduced into the Ist scrubber with a two-stage spray, and from there it goes into the IInd scrubber (main absorber with a six-stage spray). Cleaned gas flows to a mist eliminator and finally through the reheater and off it goes to the vent via stack.

Limestone slurry is fed to the main absorber where the best part of the SO_2 in the FG is absorbed. A portion of the circulating slurry in the IInd scrubber is sprayed into the Ist scrubber where sulphurous vapours are abstracted by lime producing calcium sulphite.

Calcium sulphite slurry leaving the Ist scrubber is pumped to oxidation tank where sulphuric acid and oxygen is bubbled through to convert calcium sulphite to gypsum

$$2\ CaSO_3 + O_2 \xrightarrow{H^+} 2\ CaSO_4$$

Gypsum is separated in a thickener, then further de-watered in a centrifuge.

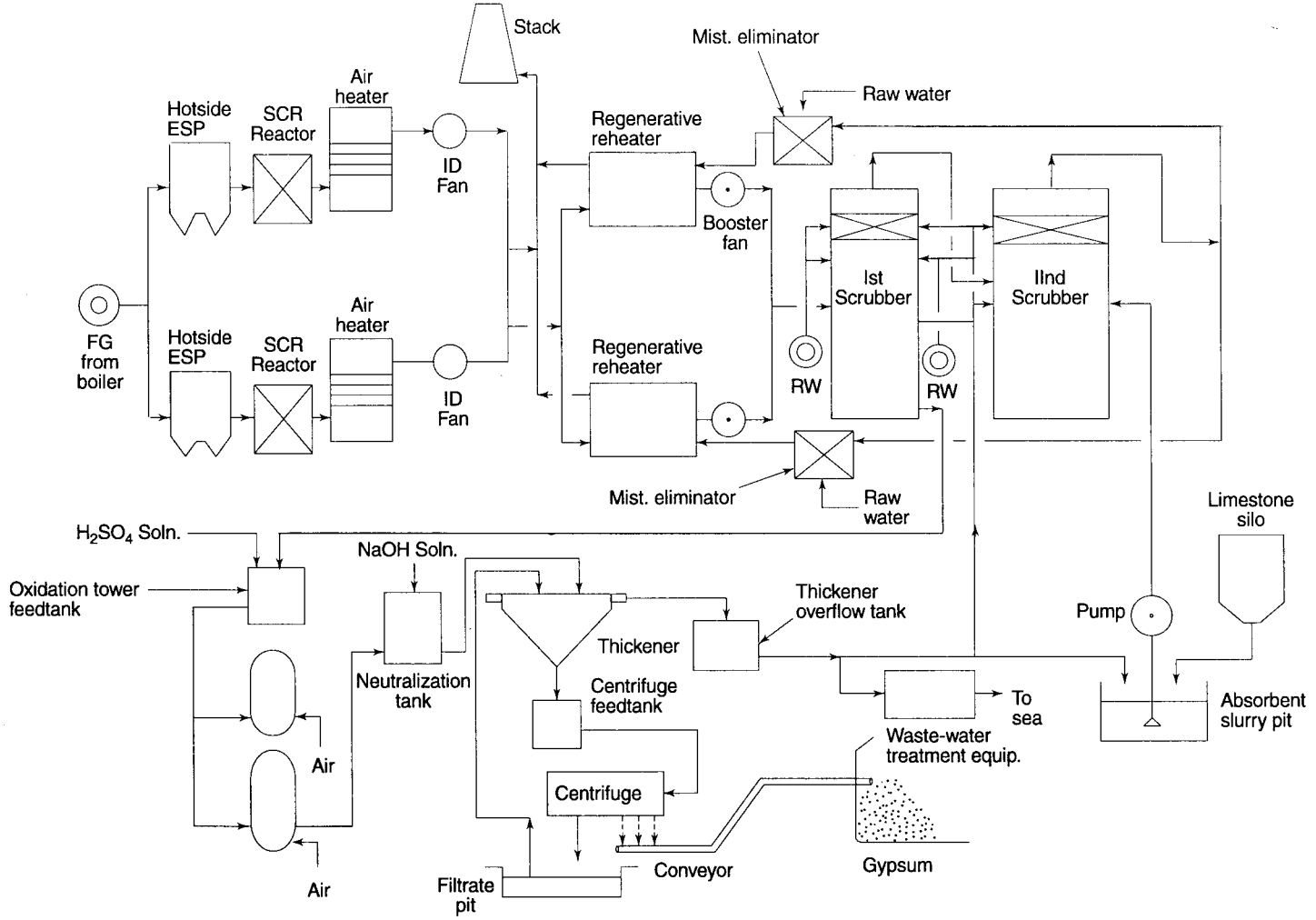


Fig. 16.8 *FGD system installed at Takehara Power Station, Japan. It features sulphuric acid addition during the oxidation step, two parallel trains of hotside ESPs and SCR reactors upstream. The unit produces saleable gypsum.*

Q. *What is the efficiency of this system?*

Ans. The electrostatic precipitators remove 99.6% of the flyash.

The scrubbers remove 90 – 98% of the SO_2 as well as 70-90% of the remaining particulates.

Q. *What is the performance of the Takehara FGD plant?*

Ans. The performance data for the Takehara FGD plant is depicted in Table 16.1

After 2100 hrs. of operation the plant was taken s/d and the following was observed

1. A scale less than a mm thick at the top of the mist eliminator in the Ist scrubber
2. Water containing soft deposits was found in the duct between the reheater and the Ist scrubber.

Q. *GE Environment Systems in its technical report presented at the POWER-GEN Americas '94 Conference held at Orlando, Florida on Dec. 9, 1994, claims that ammonia scrubbing provides the lowest cost option for SO_2 control.*

What factors substantiate this claim with respect to the limestone/gypsum process?

Ans. 1. The ammonia-based flue gas desulphurization (FGD) process produces a valuable ammonium sulphate byproduct which earns more revenue than gypsum resulting from the wet-limestone process.

2. Though the cost reduction programs of the wet limestone/gypsum scrubbing process are still being developed and implemented, this technology has reached maturity and further gains in cost reduction will be relatively small. The gain in cost reduction is unlikely to be sufficient to make limestone/gypsum scrubbing or buying allowances. Most utilities are finding that limestone is a costly option.
3. Producing valuable byproducts from SO_2 scrubbing is a promising avenue to achieve substantial scrubbing cost reduction. Since the byproduct quantities are large, significant markets for these products must also exist. Revenues from sale of the byproducts must be large enough to partly or wholly offset the investment for the scrubbing system. Possible byproducts from which significant are:

   Gypsum, sulphuric acid, elemental sulphur and ammonium sulphate.

However, gypsum is not a valuable byproduct—its primary outlets are the wallboard and cement industries. On the contrary, production of salable gypsum adds to the scrubbing costs due to improved dewatering and wastewater treatment facilities required for purification of the gypsum byproduct.

Table 16.1 *Performance test vs. design data of TAKEHARA wet-limestone FGD unit*

Parameters	Design	Test Run
Boiler load (MW)	700	700
SO_2 content (ppm)	1000 (inlet)/< 100 (outlet)	505 (inlet)/< 34 (outlet)
SO_2 removal efficiency	> 90%	93.3%
Free moisture in gypsum product (%wt)	< 10	6.65
Calcium carbonate (98.9% purity) (t/h)	9.5	4.7
Byproduct gypsum (t/h)	18.5	8.2
Industrial water usage (m^3/h)	112.2	115
Power consumption (MW)	17.4	14

Source: POW/FEB/1987

Sulphuric acid or elemental sulphur are obviously more valuable than gypsum, but they add a great deal of process complexity and cost to the scrubbing technology. The revenues for the sale of acid or sulphur are not sufficient to pay for the added cost over the gypsum producing technology.

Hence these byproducts are not being widely produced.

Enter the new ammonia scrubbing technology and with that production of ammonium sulphate as a byproduct has become a reality. The ammonium sulphate byproduct has a large outlet in the fertilizer industry and because of its high product-of-value, can generate substantial revenue to partly or wholly offset the scrubbing cost.

Note: These are the reasons why Dakota Gasification Co. has selected the GE Ammonium Sulphate Process, first-of-a-kind FGD system that will produce approximately 200,000 t/y of high-purity, granulated ammonium sulphate byproduct. It is scheduled to be in operation by the end of 1996.

Q. *How is the ammonium sulphate process carried out?*

Ans. After flayash removal in the ESP, the hot FG is first introduced into a prescrubber vessel where it is sprayed with saturated ammonium sulphate liquor (Fig. 16.9).

The flue gas gets cooled through adiabatic saturation and due to evaporation of water from the saturated liquor of ammonium sulphate, crystals of ammonium sulphate appear in the prescrubber unit. Thus the prescrubber acts as an evaporator-cum-crystallizer in which the waste heat of the FG is effectively utilized for the production of $(NH_4)_2SO_4$ without the need of expensive exter-

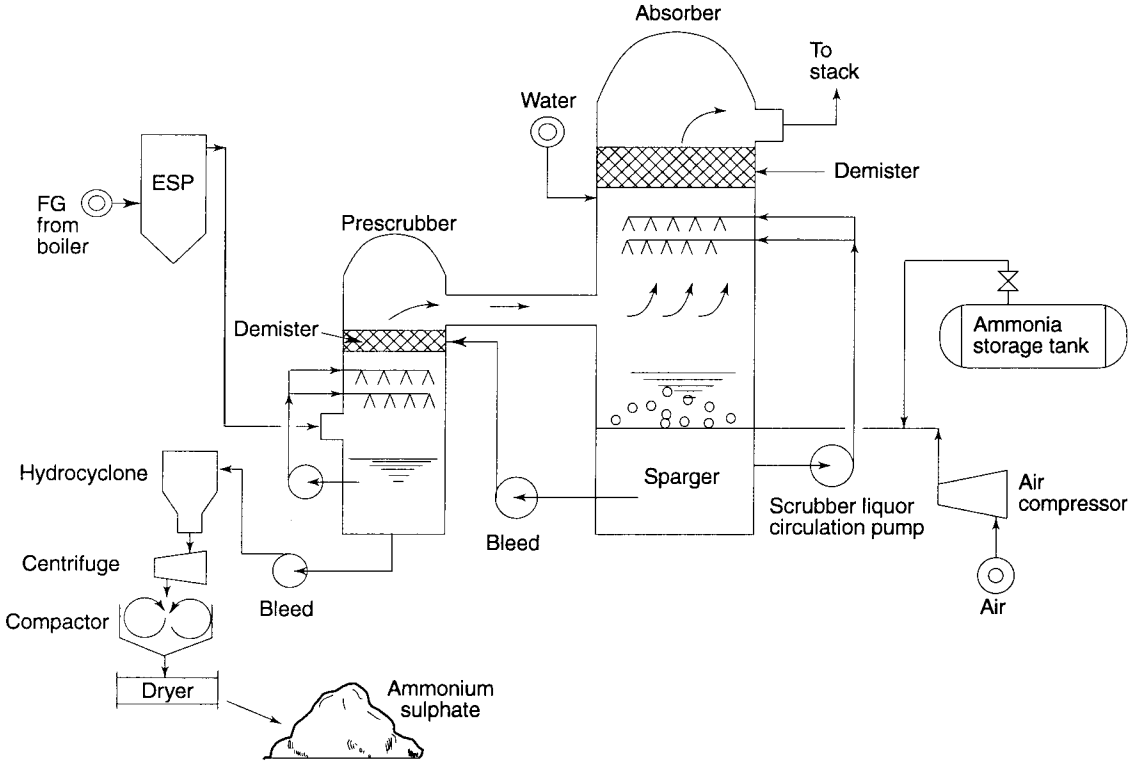


Fig. 16.9 *Ammonia scrubbing technology retains many of the simplicities of the once through limestone/gypsum process.*

nal heat sources. The prescrubber liquor is virtually a slurry of ammonium sulphate crystals recycled from an agitated tank.

No ammonia is added to this slurry, thus the pH drops to less than one with the effect that only a little amount of SO_2 gets absorbed in the prescrubber.

The cooled, saturated FG leaving the prescrubber is first passed through a bulk entrainment separator and then introduced into the SO_2 scrubber.

In the absorber, sulphur dioxide is removed from the flue gas by counter-current contact with sprays of dilute ammonium sulphate. The dilute ammonium sulphate solution is recycled to the absorber sprays from a recycle tank which also acts as an oxidation reactor.

Air is sprayed into the base of the recycle tank whereupon absorbed SO_2 gets oxidized to form ammonium sulphate.

The clean gas is finally passed through a mist eliminator to remove any droplets and then vented to the atmosphere through a stack.

All of the M/up water to the process is added to the absorber. This ensures that the absorber liquor is always dilute and therefore readily oxidizable.

An appropriate amount of the absorber liquor is automatically bled from the absorber to remove the equivalent amount of ammonium sulphate formed.

An amount of prescrubber liquor containing ammonium sulphate crystals is automatically withdrawn with density control for dewatering and separation of the product.

Q. *What is the chemistry of the ammonium sulphate FGD process?*

Ans. Ammonia is highly soluble in water and because of its strong alkalinity, aqeous ammonia solution readily absorbes SO_2 from FG to produce ammonium sulphite which, being thermally unstable, is

$$SO_2 + 2NH_3 + H_2O \longrightarrow (NH_4)_2SO_3$$

subsequently oxidized to highly stable ammonium sulphate by aerobic oxidation

$$(NH_4)_2SO_3 + 1/2\ O_2 \longrightarrow (NH_4)_2SO_4$$

The actual mechanism of the reactions is more complex and proceeds via sulphite-bisulphite & sulphate-bisulphate formation.

The oxidation mechanism occurs through chain reactions initiated by free radicals such as $\dot{H}SO_3$ and $\dot{H}SO_5$ and is significantly influenced by catalytic activities of transition metal ions and the inhibiting effect of oxygen scavenging compounds such as polythionates.

Q. *The most nagging problem in the ammonium sulphate process is the ammonia vapour loss to FG. What is the adverse effect of this ammonia slip?*

Ans. Excessive ammonia loss leads to plume visibility due to the formation of ammonium sulphite, sulphate and chloride aerosols, which are submicron in size and consequently, very difficult to remove from the flue gas stream.

Q. *Many attempts in the past at ammonia scrubbing of flue gas have been bogged down just because of the inability to control ammonia slip and plume visibility.*

What explanation do you have to account for this 'inability'?

Ans. The inability to control ammonia slip can be traced directly to the ammonia vapour pressure relationship to pH and the amount of sulphate oxidation in ammoniacal scrubbing liquor.

Inasmuch as ammonia is a strong alkali, it has a great affinity for SO_2, thus permitting the compact absorber with very low liquid to gas (L/G) ratios. However, low L/G ratios necessitate a relatively high pH and high ammonium sulphite levels in the scrubbing solution to provide the buffering capacity for SO_2 absorption. Both of these conditions generate high ammonia vapour pressure and therefore unavoidable ammonia slips into the flue gas stream.

Q. *What design modifications is necessary to avoid this ammonia slip?*

Ans. Ammonia slip can be avoided by designing the scrubbers with relatively large liquid to gas (L/G) ratio and with insitu forced oxidation of sulphite in the scrubbing liquor.

The scrubber-design with large L/G ratio permits low pH operation driving more ammonia from vapour to solution

$$SO_2 + 2\ NH_3 + H_2O \longrightarrow (NH_4)_2SO_3$$

and therefore, negligible ammonia vapour pressure in the scrubbing liquor.

Over and above, the insitu forced oxidation of sulphite to a very stable sulphate salt further ensures that the scrubbing liquor is mostly ammonium sulphate

$$(NH_4)_2SO_3 + 1/2O_2 \longrightarrow (NH_4)_2SO_4$$

This makes more vaporized ammonia to pass into solution lowering ammonia vapor pressure further.

Thus ammonia slip can be avoided through low pH and insitu forced oxidation.

Q. *What concentration of absorber liquor (ammonium sulphate solution) is used to absorb SO_2 from flue gas?*

Ans. The exact dilution of the absorber liquor is a function of the hot FG temperature as well as by the SO_2 concentration in the flue gas. Fig. 16.10 portrays this relationship.

As this figure shows, even up to a very high sulphur dioxide concentration of 6100 ppm, the ammonium sulphate concentration in the absorber liquor is less than 30%. But such a high SO_2 content in FG is rarely encountered. Normally with high-sulphur coals, SO_2 concentration of 3000 ppm is commonly encountered and for the absorption of this much amount of SO_2, the ammonium sulphate concentratin would be about 15%.

Q. *What are the economics of ammonium sulphate (AS) process in comparison to other FGD processes?*

Ans. The Ammonium Sulphate (AS) process uses ammonia on a once through basis, similar to the limestone/gypsum process with the effect that its capital cost is comparable to that of the limestone/gypsum process. This is particularly true when crystalline ammonium sulphate is produced.

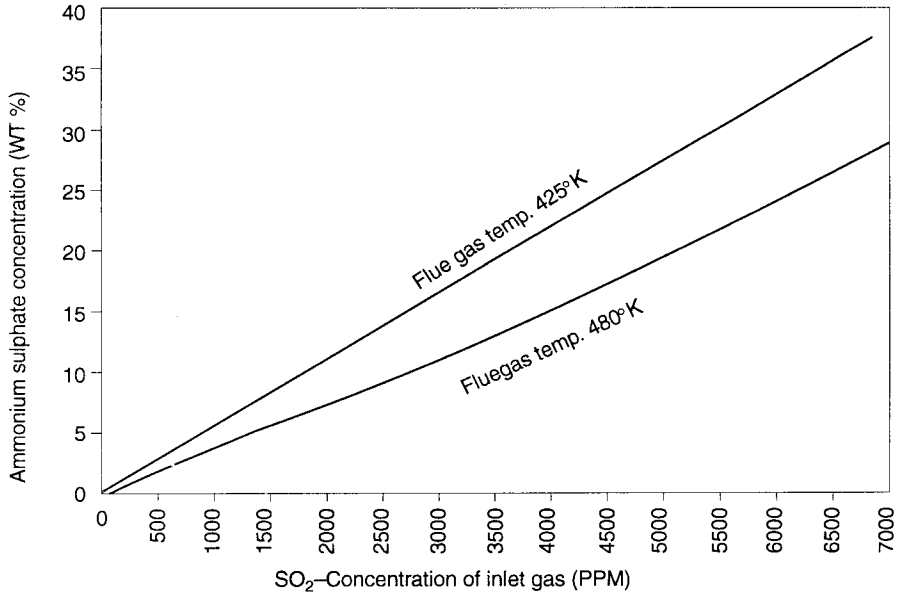


Fig. 16.10 *Predicted concentration of ammonium sulphate liquor in absorber as a function of inlet gas temperature and SO_2 concentration in a typical coal-fired boiler.*

Though granulation, screening and conditioning equipment needed to produce premium grade AS tax about 30% additional investment, this extra investment load is much smaller than that required to produce sulphur or sulphuric acid from the regenerative type FGD system whose capital costs exceed more than 100% over that required for the limestone/gypsum process. The increased revenues of ammonium sulphate over that of gypsum exercise a dramatic effect in lowering the cost of scrubbing:

In the case of gypsum byproduct, which is mostly disposed of as landfill, the net payback is negative whereas the ammonium sulphate generates 11 million dollars of revenue per annum at an ammonium sulphate sell price of $85/ton. This large payback can be used to substantially counterpoise the investment cost for AS scrubbing of SO_2 (Table 16.2).

From the breakeven curve it can be shown that for ammonium sulphate prices of $ 50/t and higher, the AS process is the most economical choice when burning coal with a sulphur content of 2% or higher.

Q. *Can NO_x be formed in a wood-fired boiler?*

Ans. Yes.

Q. *Can it grow up to contribute to emission problem?*

Ans. Yes. Not only can it be the source of NO_x problem but also it can give rise to particulate emissions higher than the prescribed limit of local standard.

Q. *Can you cite an example?*

Ans. Foster Wheeler Energy Corporation, Livingston, New Jersey (USA) had supplied wastewood-fired boiler, @ 91 t/h steam generating capacity, to Procter & Gamble Co., Long Beach, California in 1983. The boiler is fitted with a fixed-pinhole-grate spreader-stoker combustion system.

Though the plant was designed to ensure BACT (Best Available Control Technology), the unit failed to comply with the Californian law.

The unit was beset with NO_x emission problem. The source of NO_x was traced to the higher-than-expected nitrogen content of the incoming woodwaste.

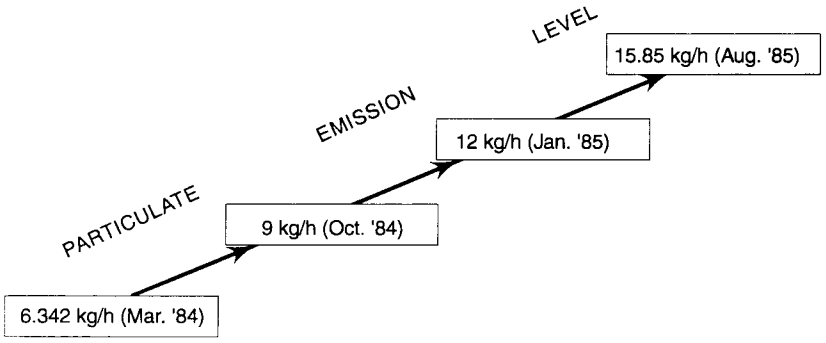
Shortly after start-up, this unit like all other woodwaste-fired installations in California, got into the trouble of meeting the state's stringent NO_x emission requirements. To combat the NO_x problem, the company had embarked on a program to control the woodfuel characteristics and their impact on combustion. This strategy, though helped reduce emissions, didn't result in sustained compliance on a long-term basis.

Table 16.2 *Annual payback analysis comparison for a 500 MW utility burning 3.5% sulphur coal with 95% SO_2 removal and 80% load factor*

Cost/Revenue Parameter	Ammonium sulphate Process ($ million)	Limestone/gypsum Process ($ million)
Cost of reagent	8*	1.8**
Revenues from byproduct	19*	1.3**
Net back	11*	3.1

* Ammonia Price = $ 145/t ; Ammonia Consumption = 56 000 tpy
Ammonium Sulphate Price = $ 85/t ; Amm. Sulf. Production = 224 000 tpy

** Limestone Price = $10/t ; Limestone Consumption = 180 000 tpy
Gypsum Price = $ 4/t ; Gypsum Production = 330 000 tpy



At the same time, the plant was not able to meet the particulate emission limit (4.536 kg/h). Conditions deteriorated steadily as the fuel quality got worse—good construction lumber waste was gradually replaced by large quantities of processed wood such as plywood and particle board. Particulate emissions steadily increased.

Q. *Usually NH_3 is added to combat NO_x emission. Was it not tried?*

Ans. Non-catalytic ammonia reduction process was tried

$$NO + NO_2 + 2NH_3 \longrightarrow 2N_2 + 3H_2O$$

Exxon Research and Engineering Co., Florham Park, NJ supplied the ammonia injection system introducing ammonia to the upper furnace region within a temperature range of 1085°K – 1365°K.

NH_3-injection system was complete with a 54 m^3 tank, supply and injection piping (Fig. 16.11).

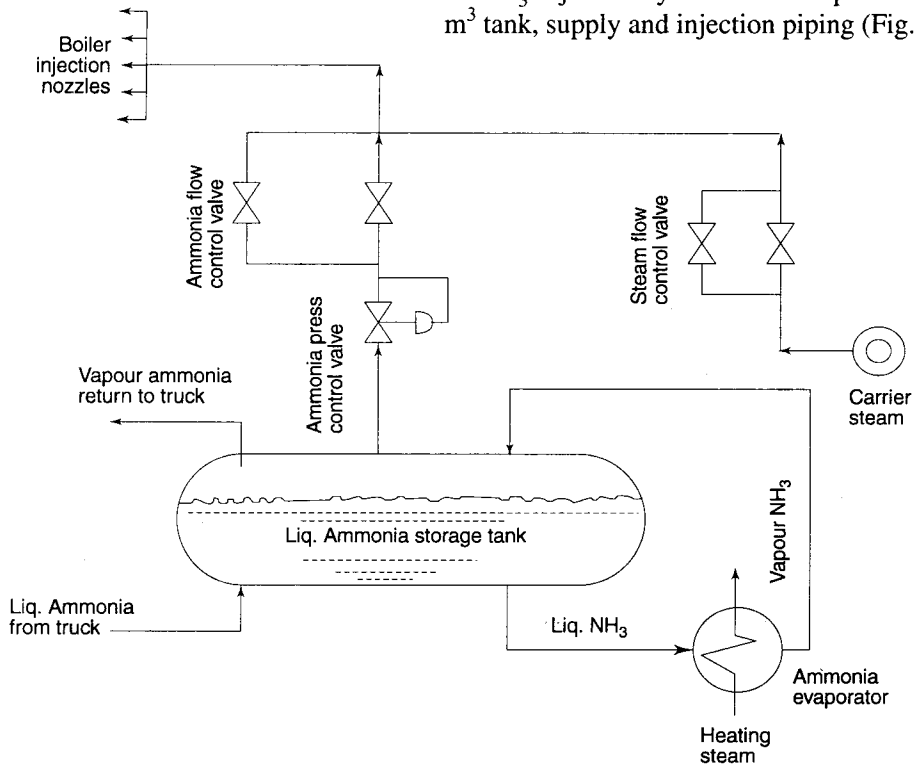


Fig. 16.11 *Ammonia injection system. Superheated steam was used as carrier fluid for injecting NH_3 into the furnace.*

Saturated NH_3 leaving the tank at 600 kPa is pressure reduced to 500 kPa and is then mixed with superheated steam at 490°K and the mixture is then admitted to the furnace through one of several levels of injectors located on the boiler frontwall, depending on the steam load.

Q. *What was the outcome?*

Ans. Depending on operating conditions such as boiler load, outlet O_2 concentration, undergrate airflow, grate cleaning periods and woodwaste fuel quality varied success to NO_x-reduction was achieved (Fig. 16.12).

With ammonia is to nitrogen oxides molar ratios varying from 0.4 to 3.0, NO_x reductions between 35% and 70% were reported at 3% O_2 in the flue gas.

Q. *Had it any adverse effect?*

Ans. Yes. With the increase of NH_3/NO_x ratio, ammonia slippage i.e. ammonia escaping reaction with NO_x, [i.e. concentration of free NH_3 in the flue gas] increased. When the A/N ratio exceeded 2, the ammonia slip shot up drastically beyond 10 ppm (Fig. 16.13).

Also NH_3-injection resulted in solid byproducts that aggravated particulate emissions problem.

Q. *How did the solids byproduct arise?*

Ans. Injected NH_3 reacted with the hydrogen chloride vapor in the flue gas to form solid ammonium chloride in the temperature range between 395°K and 340°K.

Q. *Could a venturi-scrubber be a solution?*

Ans. It was tried but found less than satisfactory in meeting permit limits, besides giving rise to high pressure drop.

Q. *So what about a fabric filter?*

Ans. Fabric filters suffered from a severe limitation:

> Unfit for operation for FG temp. below 365°K – the dewpoint of acid vapors.

In order to collect NH_4Cl as solid particulates, the FG had to be cooled to below 355°K the dissociation temperature of ammonium chloride.

Q. *How was this problem tackled?*

Ans. The engineers installed the wet ESP.

The ESP demonstrated lowest emission rates at the lowest operating ΔP compared to the two scrubbers—for comparable capital costs.

Concurrently, it successfully arrested ammonium chloride particulates generated as a result of NH_3 injection.

The combined effect of NH_3-injection system and ESP were:

(a) particulate emissions dropped below 4.536 kg/h
(b) NO_x emission reduced to 250 ppm

Both these two met the emission restrictions of California state.

Q. *As a host of new potential environmental compliance issues—air-toxic regulations, solid-waste restrictions, global warming, CO_2 discharges, water management etc.—are coming up, the regulatory environment becomes uncertain. As a result, the utilities are reacting by spending as little as possible to new, capital-intensive technologies. Instead, they are directing their environmental management system to intergrate low-cost emission control techniques with existing hardware to maximize emission control.*

What are these low-cost techniques that achieve significant emissions control?

Ans. 1. **Fuel-Switch**: Simply selecting fuels with more favourable emissions characteristics is a basic emission-compliance strategy. Many utilities have opted for switchover from typical high-sulphur coals to low-sulphur coals, though it often necessitates modifications to coal-handling equipment.

Displacing coal with biomass is a fuel-related strategy for achieving incremental SO_2 emissions reduction. Percentages of biomass fired, based on heat input, is generally in the range of 5% to 20%.

If natural gas (NG) is available at the battery limit, it can also incrementally dis-

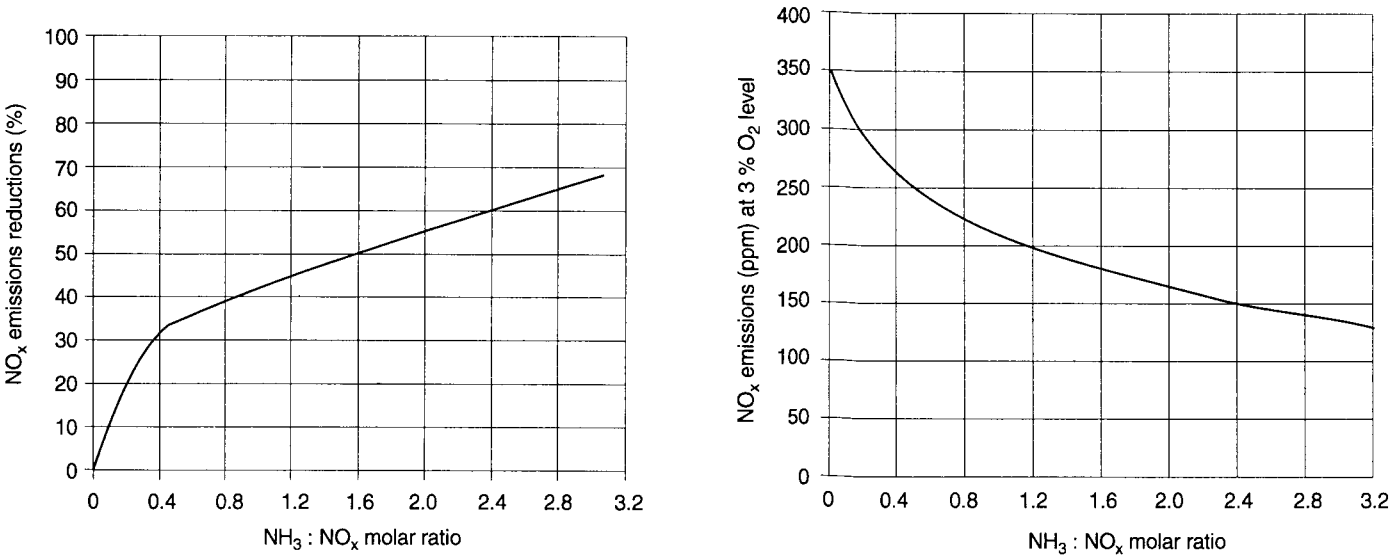


Fig. 16.12 *NO_x emission reductions closely followed ammonia-injection ratio.*

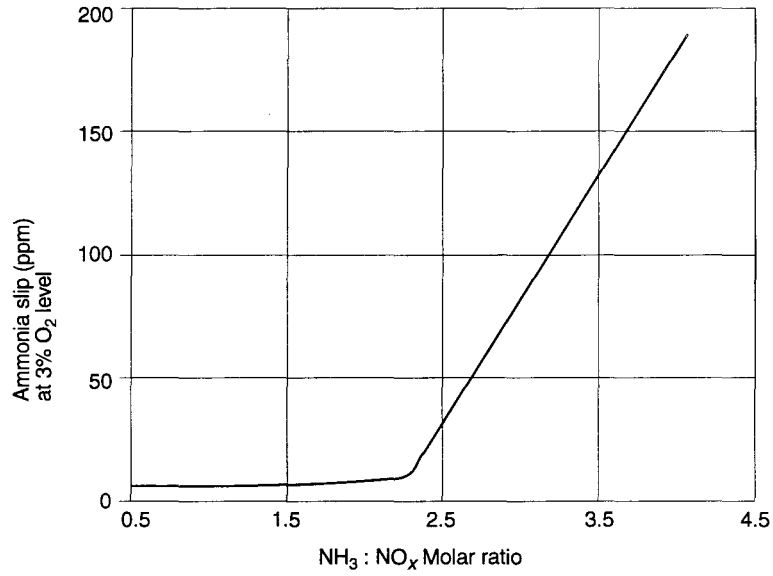


Fig. 16.13 *Ammonia slip increased abruptly when NH_3 : NO_x ratio exceeded 2.*

place coal—and the resultant SO_2 emissions. NG firing, through gas-reburning strategy can also significantly bring down the NO_x emissions as well.

2. **Equipment Tuning, Proper Maintenance and/or Economical Retrofits:**
   (a) Replacing/tuning pulverizers
   (b) Upgrading components
   (c) Balancing coal and air flows to individual burners
   (d) Correlating coal specifications with boiler operating parameters more closely
   (e) Modifying coal and air distribution in the furnace through close-coupled or separated OFA injection or using sweeping air along the furnace walls
   (f) Revamping existing burners with low-NO_x burners
   (g) Minimum NO_x generation through entire fuel preparation and furnace system optimization
   (h) Control system upgradation by applying more sophisticated process-control schemes, measuring and manipulating air and/or fuel flows accurately and inducting computers to automate and optimize the process (Fig. 16.14). Utilities have achieved as much as 40% NO_x reduction solely through process optimization.

   Software packages developed and refined for this purpose have demonstrated their potential to greatly reduce, possibly eliminate, the hardware component of a NO_x-control retrofit.
3. **FGD Upgradation:** Conventional wet limestone/gypsum process still continues to be the main workhorse of the FGD industry because of its best stiochiometry, lowest reagent consumption, and highest efficiency of the available processes. Nevertheless, FGD system suppliers have made great strides in simplifying processes while boosting performance. As a result capital costs for conventional wet lime/limestone FGD systems have come down drastically in the last few years—with

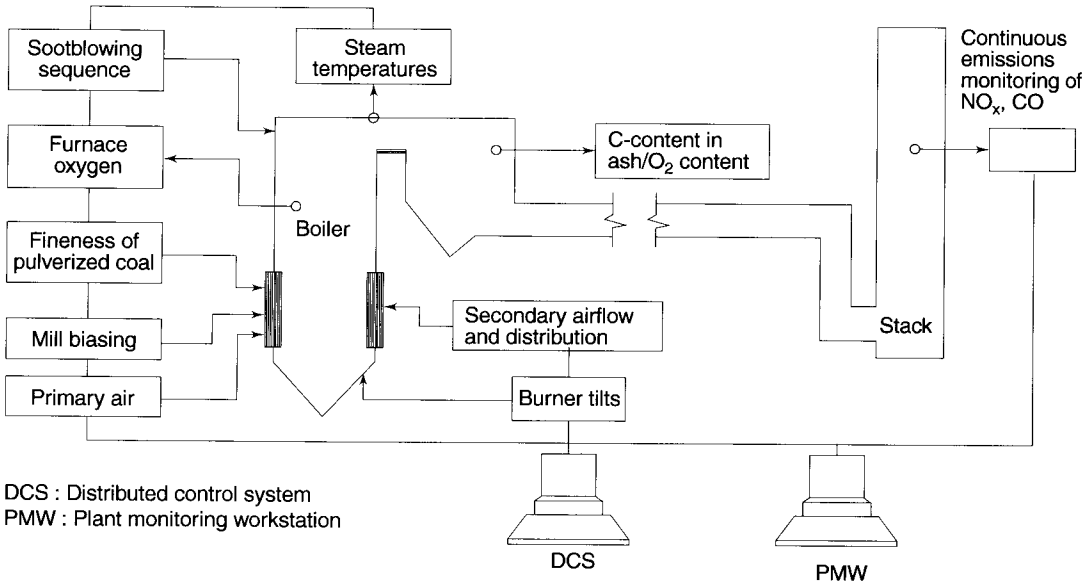


Fig. 16.14 *Optimizing the combustion process is the key to dramatic NO_x-reductions.*

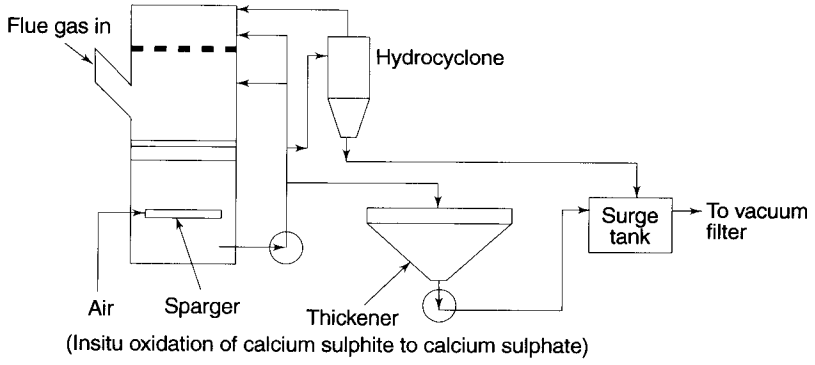
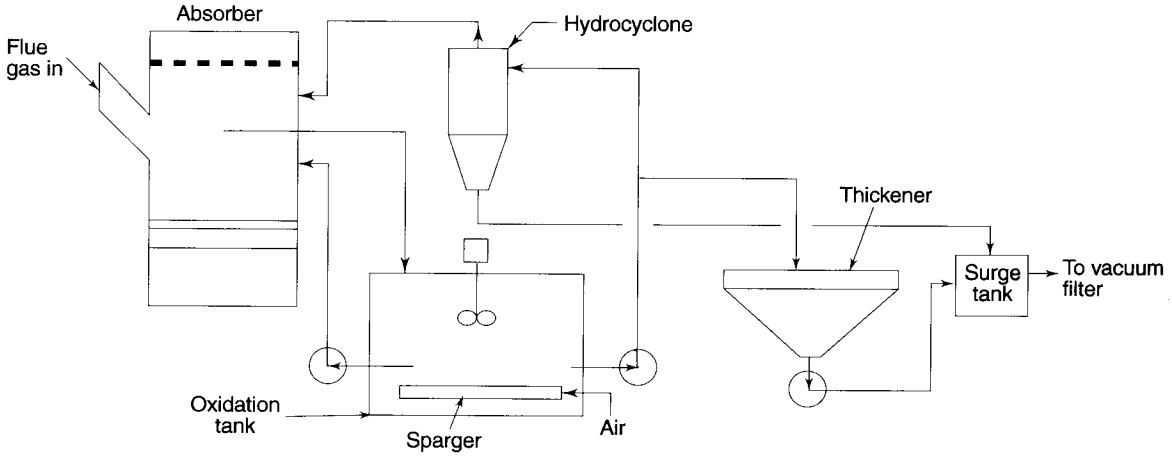


Fig. 16.15 *Scrubber upgradation through replacement of external oxidation by insitu oxidation.*



performance going up. One FGD system purveyor has claimed its FGD plant would reduce capital investment by another 30%, making it competitive with coal switching.

The techniques for achieving these cost-reductions and performance-gains are

(a) Adding new absorber internals
(b) Providing advanced nozzle arrangements and a more sophisticated distribution system to evenly distribute the reagent into the flue gas
(c) Incorporating high-performance mist-eliminators capable of handling gas velocities ≤ 6 m/s
(d) Using ultrafine grades of limestone particles
(e) Eliminating external oxidation tanks and integrating insitu aerobic oxidation right into the bottom of the absorber tower (Fig. 16.15).
(f) Replacing large, cumbrous dewatering tanks with more efficient mechanical devices such as hydrocyclones
(g) Replacing high-pressure spray nozzles with a fluidized slurry contactor (a wiremesh grid) through which the FG disperses into the reagent. This technique ensures adequate mixing by harnessing the kinetic energy of the FG
(h) Converting limestone-based FGD systems to magnesium-enhanced lime/gypsum process
(i) Injection of dry sorbents into the FG duct followed by humidification of the gas stream
(j) Replacing both the spray-dryer and dry sorbent spray nozzles with more advanced type Y-jet dual fluid atomizer. This application can reduce power consumption, reduce reagent droplet size for enhanced activity while keeping pressure drop losses low. 90% SO_2 removal efficiency at a 70 – 75% sorbent utilization ratio has been reported.

4. **Combining SCR and SNCR Processes:** has become the latest strategy in controlling NO_x emissions. Already the costs of SCR catalysts have gone down and for modest NO_x removal requirements, SNCR systems have become popular.

   Efforts are still on to lower the costs further and/or pegging the performance limit somewhere between those of SNCR and SCR. Combining catalyst-based and non-catalytic NO_x reduction techniques may offer a high level performance at lower cost than full SCR (Fig. 16.16).
5. **Insitu Flue Gas Conditioning:** is an ingenius technique to enhance the performance of ESP. The process operates by withdrawing slip-stream from FG and passing it through a converter where horizontal catalyst and non-catalytic substrates are placed in the vertical flue gas flow with deflectors. Depending on the amount of SO_3 necessary, deflectors block flue gas from the catalytic modules.

The process takes advantage of the fact the catalyst materials, including those used to convert NO_x to elemental nitrogen and water, are also effective in converting SO_2 to SO_3 which is used as a gas conditioning agent to lower the electrical resistivity of the flyash particulates to facilitate their capture by ESP.

Sources:

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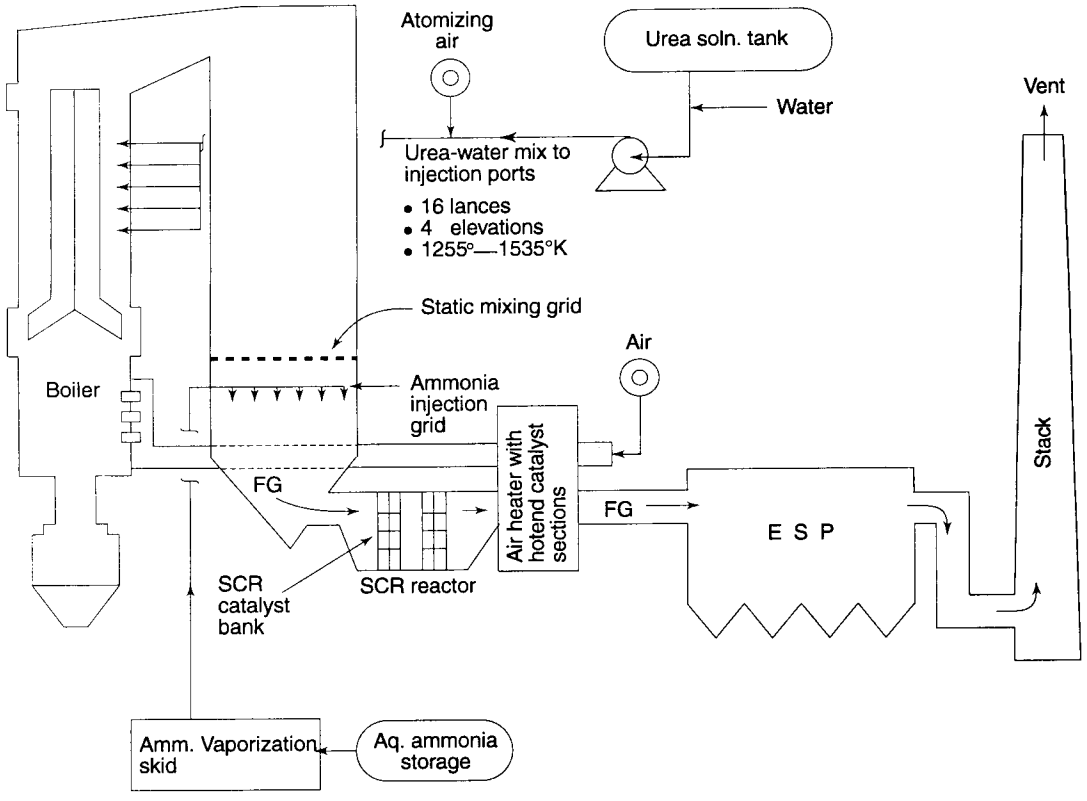

Fig. 16.16 *SCR and SNCR process in tadem. This system is likely to achieve high NO_x reduction efficiency at reduced cost.*

Siemens Power Journal (Vol. 3/1993)

EPRICON: **Agentless Flue Gas Conditioning for Electrostatic Precipitators**—Peter Paul Bibbo (Research-Cottrell, Inc.)

Ammonia Scrubbing Provides the Lowest Cost Option For SO_2-Control—GE Environment System

(Presented at the POWER-GEN Americas 1994 Conference, Dec.9/1994, Orlando, Florida)

17

DUST COLLECTION

Q. *Why is dust collection a necessity?*

Ans. The flue gas exhaust of pulverized coal fired boilers contains flyash which constitutes 80% of the ash in the coal. They are so fine that most of them pass through a 300 mesh screen. They are an environmental hazard from the point of view of human and animal health and crop growth. Hence their concentration in flue gas must be brought down below 0.5 g/Nm^3 before letting it out free in the atmosphere.

Emission Standards for Thermal Power Plants

Rating	Concentration of Particulate Matter in Flue Gas (mg/Nm^3)		
	Protected Area	Other Area	
		After 1979	Other
< 200 MW	150	350	600
> 200 MW	150	150	—

Q. *What is the basic difficulty in eliminating the flayash?*

Ans. It is their fineness that escapes removal. The size of the particles varies from 1 μ to 80 μ.

Q. *What is the ash percentage in Indian coals?*

Ans. 25 to 50%.

Q. *How can dust be removed from the flue gas?*

Ans. It can be removed both mechanically and electrically.

Q. *What are the basic requirements for a good dust collector?*

Ans. 1. It must be able to remove very fine flyash particles
2. Should have high operating efficiency
3. Flawless operation at all load variations
4. Durable
5. Should occupy minimum floor space
6. Should be wear resistant to erosion problem inflicted by abrasive flyash
7. Low investment cost
8. Low operation and maintenance cost

Q. *How many types of mechanical flyash (dust) collectors are there?*

Ans. These are basically two types: dry type and wet type.

Dry type system incorporates:

Gravitational separators

Cyclone separators.

Wet type system includes:

Spray type scrubbers

Packed bed scrubbers

Impingement type separator.

Q. *How many types of electrical gas cleaning devices are there?*

Ans. Two types: Rod type and Plate type.

Q. *How does a gravitational separator work?*

Ans. It works on the basic principle of gravity.

If the dust laden gas is expanded in a duct, the flow velocity will drop and that will settle some dust particles. (Fig. 17.1)

Changing the gas flow direction will bring about some precipitation of the heavier dust particles (Fig. 17.2)

Placing baffles in the path of dust laden gas will bring down some heavier particulate solids due to loss of kinetic energy upon impingement. (Fig. 17.3)

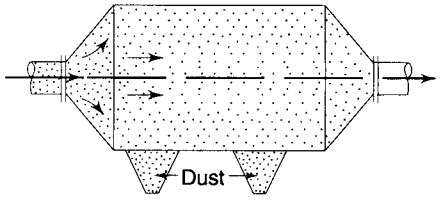

Fig. 17.1

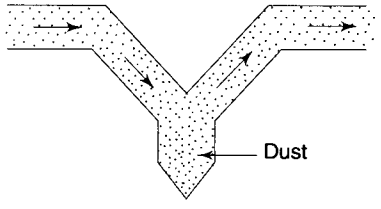

Fig. 17.2

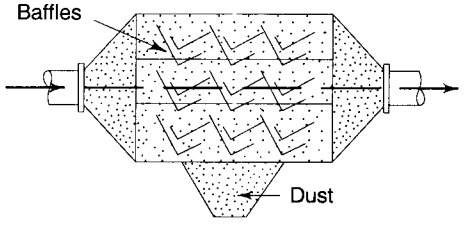

Fig. 17.3

Q. *What are the drawbacks of a gravitational system?*

Ans. It cannot remove fine dust particles. Only large sized and heavier particles can be removed.

It is bulky and requires large space.

Q. *What is a bag house dust collector?*

Ans. It is a flue gas filter made of cloth fabric that collects fine dust particles from the flue gas as it passes through it.

Q. *What is the efficiency of its dust removal?*

Ans. A well designed and properly maintained bag house dust collector can collect 99.9% of the particulate solids of size 1 μ and above. And its efficiency is independent of the amount of dust in the flue gas.

Q. *How does the bag house dust collector work?*

Ans. It works reversibly. Dust laden flue gas is allowed to pass through the bags of cloth. These arrest the suspended dust particles and allow the clean gas to pass out. When the pores of the fabric filters get clogged, it is regenerated by a gentle reverse flow of air.

Q. *What is the limitation of bag house dust collectors?*

Ans. They are used for low sulphur coal (less than 1%).

Q. *Why?*

Ans. The cloth fabric of the bag house filter is sensitive to H_2SO_4 attack, which is formed at 160°C (433K—the dew point temperature of H_2SO_4) and below from sulphur trioxides and water vapour.

$$S \xrightarrow{O_2} SO_2 \xrightarrow{O_2} SO_3 \xrightarrow{H_2O} H_2SO_4$$

Sulphur from coal

Q. *Presently, cloth fabric impregnated with teflon is used. Why?*

Ans. It will resist possible deterioration from acid mist should the flue gas temperature drop below DPT of H_2SO_4.

Q. *How does a cyclone separator work?*

Ans. The dust laden flue gas is allowed to enter a conical shell tangentially setting up a swirling motion in the body of gas which casts off heavier

particulate solids by imparting to them a centrifugal force. (Fig. 17.4)

Dust particles collected at the bottom are separated out.

Q. *What is the collection efficiency of this system?*

Ans. It ranges from 60 to 99% depending on the size of the dust particles and the pressure drop across the cyclone.

Particle Size	Collection Efficiency		
	P = 2.5 cm of H_2O	P = 6 cm of H_2O	P = 7.5 cm of H_2O
Up to 10 μ	62%	67%	70%
(10–20) μ	(95–96)%	(97–98)%	98%
(20–45) μ	(98–99)%	99%	99%
> 45 μ	99%	99.5%	99.6%

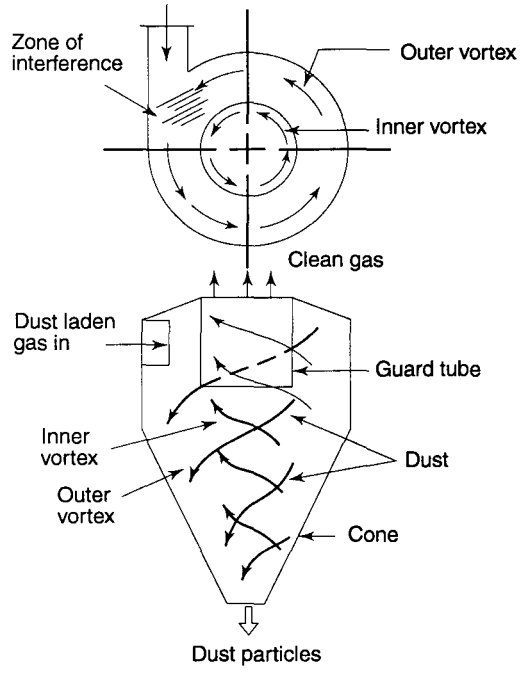

Fig. 17.4 *Cyclone separator.*

Q. *What are the advantages of a cyclone separator?*

Ans. 1. Low maintenance cost
2. Higher efficiency for bigger size particles
3. Higher efficiency at higher load.

Q. *What are its disadvantages?*

Ans. 1. Fine dust particles escape separation
2. Non-flexible in terms of volume handled
3. Efficiency declines with the increase of fineness of the particles
4. Considerable loss of pressure
5. More power requirement to produce very high vortex velocity of the flue gas.

Q. *What is an electrostatic precipitator (ESP)?*

Ans. It is a device to precipitate suspended flyash and dust particles from the flue gas by ionizing the particles in an electric field and collecting them subsequently on oppositely charged electric plates (or rods).

Q. *Who first introduced an ESP?*

Ans. Dr. F.G. Cottrell in the year 1906.

Q. *In some cases it is used in combination with a cyclone separator. Why?*

Ans. To upgrade the dust removal efficiency of the system.

Q. *How does using an ESP in combination with a cyclone separator upgrade dust removal efficiency?*

Ans. Sometimes unburnt coal particles are dragged along with flyash in the flue gas. Large amount of coal particles will adversely affect the collection efficiency of the electrostatic precipitator. Hence, the best part of it is separated out in the cyclone separator before feeding the fluegas to the ESP.

Q. *How does the electrostatic precipitator work?*

Ans. The dust laden flue gas enters the ESP through an inlet channel and passes through a gas distributor that distributes the flue gas evenly over the parallel arrays of discharge electrodes spaced alternately with collection electrodes. The gas

flow may be horizontal or vertical. It can also be arranged in parallel or series.

The discharge electrodes (usually negative) are in the form of a wire, most commonly, a smooth wire having a small radius of curvature (2.5 mm OD), weighted or supported to retain the right physical tension and location. They are energized at 45–70 kV.

The collecting electrodes come in the shape of plates or tubes of well-reinforced, light-guage metal. They are usually positively charged or grounded.

The high intensity electric field created causes the particulates in the gas stream to acquire negative charges transferred from ionized gas molecules of the same polarity. These charged dust particles accelerate towards the collection electrodes where their charges get neutralized, whereupon they fall into a collection hopper beneath the unit. Waves after waves of charged dust particulates migrate continually to the collection electrodes where they transfer their charge and fall into the hoppers by gravity, thus effecting a separation from the gas stream.

The high voltage discharge system is supported by insulators that also isolate it from grounded components.

ESPs operate in the temperature range 95°-450°C (commonly). However, some units operate up to 950°C. The operating pressure is 600 mm of water gauge but operation up to 40 atm is possible. The pressure drop through the unit is 15–30 mm water.

Q. *What is the mechanism of dust collection by ESP?*

Ans. Electrostatic percipitation is based on corona discharge that provides a simple and stable means of charging and collecting suspended dust particles in a moving stream of gas.

Step (I): Ionization Gas molecules in the vicinity of the high voltage discharge electrode (negative) break down to form a train of plasma—a stream of positively charged ions plus free electrons. This occurs when the applied voltage reaches a critical level.

Step (II): Corona generation The free electrons being repulsed by the discharge electrode move towards the positive (ground) surface and collide with the gas molecules, forming negative ions in the process.

The negatively charged ions having lower mobility form a negatively charged space-cloud which is called corona. (Fig. 17.5).

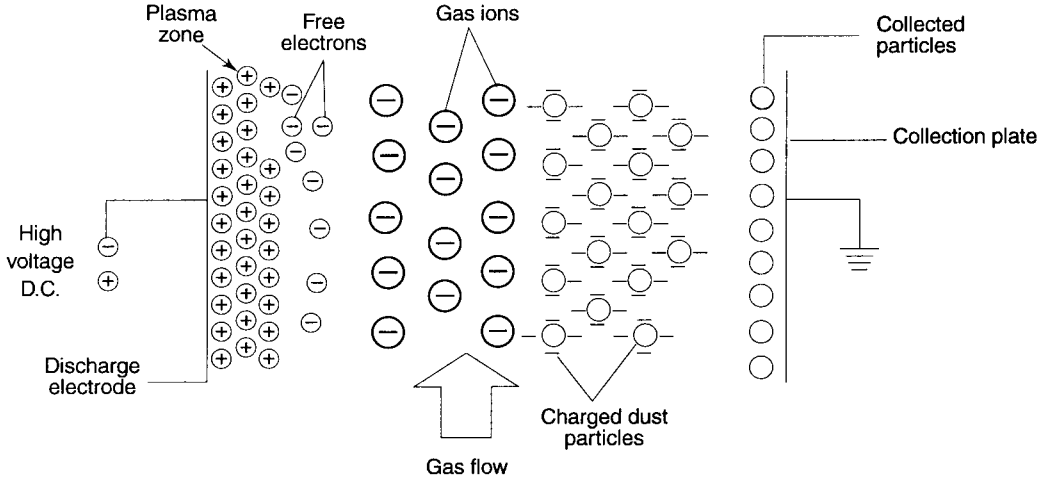

Fig. 17.5 *Dust collection mechanism in ESP.*

The space charge tends to stabilize the corona by reducing the further emission of high-energy electrons.

Step (III): Charging and collecting dust particles Following the establishment of corona, the dust particles entering it become negatively charged by the ions present. Thereafter these ionized particles are attracted by the positively charged electrode called collecting electrode, where their charges are neutralized and they settle on the electrode surface.

Step (IV): Particle removal is the final step. The collected dust particles are removed, in the dry process, by rapping the collecting surface electromagnetically, pneumatically or mechanically to slough away the particles into a hopper. In the wet process, the deposited material is rinsed with an irrigating liquid.

Q. *What are the advantages of an ESP?*

Ans. It is the most effective method to remove very fine particulates, as fine as 0.01 μ, which escape removal by mechanical separators.

Very useful for high dust loaded gas. Flue gas containing dust particles as high as 100 g/Nm^3 can be effectively cleaned.

High dust removal efficiency (99 to 99.5%)

Operation is easy and smooth

Minimum draught loss

Least maintenance cost

Both wet and dry dust can be removed.

Q. *What are its disadvantages?*

Ans. 1. High capital cost of equipment.
2. Power requirement is considerably high and that is why the electricity bill for operation of the unit mounts.
3. Removal efficiency drops with the increase of gas velocity.
4. A good amount of floor-space is occupied.

Q. *What fundamental steps are involved in the electrostatic precipitation of particulate solids?*

Ans. Three steps are involved:
1. Charging of the suspended particles
2. Collection of the charged particles under the influence of electrostatic field
3. Removal of deposited particles from the collection plates.

Q. *What factors affect dust removal by an ESP?*

Ans. 1. Particle size
2. Particle resistivity
3. Field strength
4. Corona characteristics
5. Flue gas velocity
6. Area of collecting surface
7. Rapping.

Q. *How can the collection efficiency of an ESP be computed?*

Ans. It can be done with the help of the following equation:

$$\eta = 1 - \exp\left(-A\, V_M / V\right)$$

where $V_{\dot{M}}$ = migration velocity of the particle.

$$= \frac{r\phi_1 \cdot \phi_2}{2\pi\Theta}$$

r = radius of the particle

ϕ_1 = strength of the particle charging field

ϕ_2 = strength of the particle collecting field

Θ = viscosity or fractional resistant coefficient of the gas

V = gas flow through the precipitator

A = effective collecting area.

Q. *How can the collection efficiency be raised?*

Ans. By increasing the collection area and migration velocity.

Q. *How is it influenced by particle size?*

Ans. Collection efficiency increases with the increase of migration velocity and decreases with the drop of the latter. As migration velocity is directly proportional to particle size, collection efficiency will increase with the increase of particle size and decrease with the fineness of the particle.

Q. *How does gas velocity affect the collection efficiency of an ESP?*

Ans. The efficiency of the collector increases with the decrease of gas velocity and decreases with its increase. (Fig. 17.6)

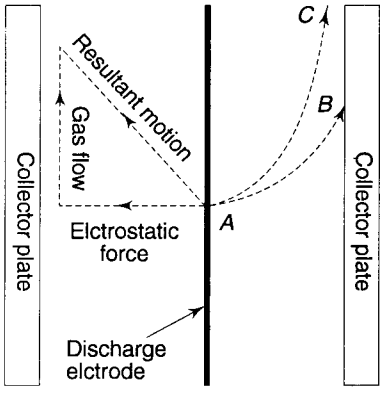

Fig. 17.6

The ionized particulates follow the path of the resultant of two mutually perpendicular forces—electrostatic force and gas flow.

If the electrostatic force > force exerted by gas flow, the particle will traverse path *AB* and get deposited on the collector plate.

If on the other hand electrostatic force < force exerted by gas flow, the particle will follow the more curved path *AC* and escape precipitation.

Q. *Why should the linear gas velocity be low?*

Ans. This is to avoid turbulence in the inter-electrode space and in the hoppers. Turbulence or any eddies in these regions will lead to reentrainment of dust particles.

Also, limitation to higher gas velocities is imposed by the residence time required for particle charging and collection.

Q. *What is the gas velocity range in an ESP?*

Ans. ESPs are known to operate in the gas velocity range from 0.6 m/s to 60 m/s. However, its value is greatly dependent on the nature of dust, its density, resistivity and attainable migration velocity.

For stack emissions of boilers burning low sulphur coals, the fly ash velocities of 1.5-2.5 m/s are chosen to avoid reentrainment whereas this value is limited to only 0.6 m/s for particulate emissions from recovery boilers.

Q. *If the inlet velocity of dust laden gas is too high what may happen, other than reentrainment?*

Ans. For the successful operation of an ESP, it is basically required that proper spacing between the collection and discharge electrodes be maintained. If the inlet velocity of dust laden gas is too high, some of the collection electrodes may buckle and some of the wires (discharge electrodes) may displace slightly to one side. Any such deviation from the designed dimensional spacing generates sparkovers which cause a considerable loss in efficiency and increased wastage of power.

Q. *What is particle resistivity?*

Ans. It is a measure of the ability of a particle to accept a charge, i.e. to become ionized.

Higher resistivity of a particle means greater is its resistance to becoming ionized and so it offers greater resistance to the passage of electric current. Consequently, lower resistivity means it is conductive.

Q. *What factor primarily influences particle resistivity?*

Ans. Particle resistivity depends on the composition and amount of microconstituents present. If the flyash and particulates contain metallic oxides coating their surfaces, their resistivity will be sufficiently low.

Q. *What is the unit of resistivity?*

Ans. Ohm-cm.

Q. *What is the suitable range of resistivity for good collection efficiency?*

Ans. 10^4 to 10^{10} Ohm-cm.

Q. *What is the critical level of resistivity?*

Ans. 10^{10} Ohm-cm.

Q. *If the particle resistivity is higher than this range, how will it affect the ESP's performance?*

Ans. If the particle resistivity is 2×10^{10} Ohm-cm. or higher, ESP efficiency will decrease. This is due to two reasons:

1. Particulates of high resistivity require high current densities and high discharge voltages. ESP operability decreases under these conditions.
2. High resistivity leads to back corona, causing reentrainment of deposited particles back to the gas stream from the collecting electrodes. This means reduction in ESP efficiency as the reentrained particles are to be recollected.

Q. *Why do particulates with low resistivities account for low ESP efficiency?*

Ans. Particulates with low resistivities bring down the ESP efficiency by way of higher reentrainment phenomenon.

If the particles have too little resistivity, usually 10^8 Ohm-cm or less, they will be readily conductive. As soon as they reach the collection electrode, they get neutralized but this happens so fast that the particles still retain some residual momentum that bounces them off the collection plates and causes severe reentrainment.

Q. *What difficulties are encountered with sulphur dust?*

Ans. Sulphur particles have high resistivity. They do not readily sacrifice their negative charge to the collecting electrodes.

Q. *What difficulties are encountered with carbon particulates?*

Ans. Carbon particulates have very low resistivity. They readily give up their negative charge and become positively charged particles. This causes the particulates to be repelled back into the gas stream of negatively charged particles.

Due to their low resistivity they are collected and repelled in this way may times and finally escape into the atmosphere.

Hence the presence of large quantities of carbon particulates in the flue gas will adversely affect the collection efficiency of the electrostatic precipitator.

Q. *What is the solution to this problem?*

Ans. Installation of a cyclone separator upstream of the ESP to separate out as many carbon dust particles as possible to reduce the load on the ESP.

Q. *What is the effect of moisture content on resistivity?*

Ans. Higher the moisture content lower is the resistivity.

Q. *Why does humidity lower resistivity?*

Ans. It increases conductive condensation on the particulate surface.

Q. *What is the effect of temperature on the resistivity of dust particles?*

Ans. Their resistivity sharply increases with the rise in temperature upto a certain temperature range, reaches a maxima and then falls off with further rise in temperature (see Fig. 17.7).

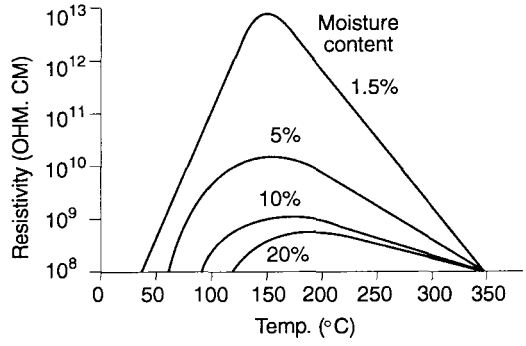

Fig. 17.7 *Dependence of particle resistivity on temperature.*

Q. *Does particle resistivity has any influence upon rapping?*

Ans. Particle resistivity exerts a critical influence on the electrical force causing the particles to stick to the collecting plates. Greater the resistivity of the particles, slower will be their rate of charge transfer, i.e. to get neutralized, and naturally they adhere to the collecting surface with a greater force. Therefore, higher rapping force is required to dislodge them from the collecting plates.

Q. *Between low-sulphur coal and high-sulphur, coal, which one will yield more ash and flue gas per MW of power generation?*

Ans. Low-sulphur coal.

Q. *What will the problem be if we use low-sulphur coal?*

Ans. It will require higher collection efficiency of ESP not only because of higher load of dust and flyash particles but also due to higher resistivity of the dust by several times that of high-sulphur coal.

Q. *How can this problem be coped with?*

Ans. By gas conditioning.

Q. *What is gas conditioning?*

Ans. Injecting small amounts of sulphur troxide in the flue gas to reduce the electrical resistivity of the flyash, with the effect that the particulates will become more amenable to collection in the ESP.

To put it simply, it will enhance the collection efficiency of the electrostatic precipitator.

Q. *What is the economy in gas conditioning?*

Ans. It eliminates the need for overdesigning the ESP and reduces the capital cost.

Q. *Humidity lowers the resistivity of particulate solids in the flue gas. How can this effect be enhanced?*

Ans. By injecting small quantities of conditioning agents. The condensed water droplets on the particulate surface will absorb the conditioning agent (SO_3) having higher conductivity and lower resistivity.

Q. *What are the most commonly used gas conditioning agents?*

Ans. Sulphuric acid and ammonia.

Q. *In which cases is sulphuric acid generally used?*

Ans. Low-sulphur coals.

Q. *In which cases in ammonia used?*

Ans. High-sulphur coals.

Q. *Usually, ash particles carry some sulphate on their surface. Will it enhance the performance of ESP or decrease it?*

Ans. It will increase the performance of ESP.

Q. *Why does the presence of sulphate on ash particles enhance the performance of an ESP?*

Ans. Sulphates have higher electrical conductivity and lower electrical resistivity. Hence deposited sulphates on particulate surface will lend to better electrical performance of the ESP.

Q. *If the sulphate level is lower how will it affect the collection efficiency of the ESP?*

Ans. It will reduce the performance of the ESP.

Q. *What is the critical sulphate level of ash particles?*

Ans. Research works indicate it to be 0.5% of the gas.

Q. *How much SO_3 in the flue gas is sufficient to maintain the resistivity of the flyash below critical level?*

Ans. Usually 10 to 20 ppm.

Q. *High-sulphur (3%) coal needs NH_3 injection in the flue gas for conditioning. Why?*

Ans. High-sulphur coal will yield a greater amount of SO_3 than that required to maintain the resistivity of the dust particles below the critical level. This excess SO_3 is absorbed on dust particles and reduces their resistivity below the de-

sired range. Hence ammonia in combination with steam is injected to the flue gas to take care of this excess SO_3.

Q. *Why is steam also added with ammonia?*

Ans. To complete the following reaction:

$$SO_3 \xrightarrow{H_2O} H_2SO_4 \xrightarrow{2\,NH_3} (NH_4)_2\,SO_4$$

Q. *In which state is SO_3 added?*

Ans. Liquid SO_3 and vapour SO_3 (obtained by vapourization of H_2SO_4 and catalytic conversion of SO_2 to SO_3).

Q. *Which method is mostly used?*

Ans. Sulphur burning method.

Molten sulphur is atomized in the combustion chamber with high velocity air and completely burned to SO_2 which is cooled (950° to 350°C) and catalytically converted to SO_3 in a one-stage V_2O_5 bed.

Q. *What is sparkover?*

Ans. The gas pockets between the deposited dust particles behave as insulators. However under the condition of low to medium particle resistivities, the voltage drop across the deposited dust layer may exceed the dielectric strength of the gas in the pores of the layer. As a result of this, a spark will occur in the dust layer and an instantaneous drop in potential across the layer will take place.

Q. *How can a sparkover be avoided?*

Ans. Sparkover can be avoided if the ESP is run at reduced current densities.

Q. *But if the precipitator is to run at reduced current densities, its efficiency will fall. Is it not?*

Ans. Yes; as it will lead to lower migration velocities.

Q. *What is the countermeasure to it?*

Ans. A good solution is to increase the collection area of the precipitator.

Q. *What is 'ivy' effect?*

Ans. Ionized dust particles (negatively charged) continually arrive at the collection electrode (ground or positively charged) whereupon their charges get neutralized. However if the rate of charge neutralization is too low, the second wave of dust particles that will arrive at the collection electrode may be so strongly attracted by the electrostatic pull of the electrode that they will sandwich between them and the collection electrode the first group of dust particles, thereby preventing the latter from falling into the hopper.

As this process continues, the dissipation of dust charge becomes increasingly difficult since more and more time is required by the outermost charged particles to bleed through the dust layer to the collection electrode and get neutralized. The particles cannot loose their charge rapidly as their resistivity is too high, so they tend to cling to the surface of the dust layer already deposited on the collection plate. This phenomenon is called 'ivy' effect as it closely resembles an ivy clinging to a wall.

Q. *What is particle reentrainment?*

Ans. It describes the phenomenon of reentry of deposited dust particles from the collector electrode back into the gas stream.

Q. *Why particle reentrainment occurs?*

Ans. It occurs chiefly due to

(a) inadequate surface area of the collection electrodes of ESP
(b) inadequacy in dust removal from the hopper.

Also it occurs during rapping and in cases where particles with low resistivities are encountered. These particles retain some leftover momentum despite their charge-neutralization at the collection electrode. This residual momentum rebounds them back into the gas stream to effect reentrainment.

Q. *How does reentrainment reduce the ESP's performance?*

Ans. Reentrainment reduces the ESP's performance as the reentrained dust particles are again to be removed from the carrier gas.

Reentrainment means more power drain of ESP because of increase of the dust load in the vicinity of charging and collecting electrodes.

Furthermore, if reentrainment occurs in the last field, it may lead to an unacceptable level of particulate emission to the atmosphere.

Q. *What is the effect of 'ivy' effect?*

Ans. As a result of the 'ivy' effect (also called fish-net effect), the effective collection potential falls with the increase in thickness of the dust layer adhering to the collection plate. This brings about a steady increase in the power drain of the ESP to maintain the required efficiency. And this fact is clearly unacceptable from the operation point of view. Furthermore, fine particulates, under these circumstances, escape collection.

Q. *How can this problem be overcome?*

Ans. To prevent the 'ivy' effect from happening, it is required that the collection plates and discharge electrodes be periodically vibrated (this process is called rapping) so that the intensity of rapping matches the adhesion characteristics of the deposited particles.

Q. *What is rapping?*

Ans. Rapping is the periodic agitation or vibration of discharge wires and collection electrodes with hammers called rappers.

Rapping can be done mechanically, electromagnetically and pneumatically.

As a result of rapping, dust particles slough away from the electrode surfaces and drop into the collection hoppers.

Q. *By which method can the maximum rapping force be exerted?*

Ans. Rapping induced by mechanical rappers.

Less force is exerted by pneumatic rappers and even lesser by an electromagnetic system.

Q. *What is the spacing of rappers?*

Ans. These can be spaced every 125 mm along the plates.

Q. *In which direction is rapping done?*

Ans. In the direction of gas flow.

Q. *When is rapping done—while the unit is on-line or shutdown?*

Ans. It is carried out when the unit is on-line.

Q. *What is the danger in rapping?*

Ans. Apart from reentrainment loss, rapping may also bring about catastrophic failure of the ESP if the support grids, discharge wires and collection electrodes are not designed to withstand the increased rapping force induced to reduce the dust build-up on electrodes. The wires may snap and plates may warp, thus inviting disaster. Also excessive dust puffing may bring about the same tragic failure.

Q. *What is space charge effect?*

Ans. If the rate of ionization of dust particles substantially exceeds the rate of their collection by collecting plates, there occurs a high concentration of dust particles in the vicinity of discharge wires. These negatively charged particles saturate the charging field and effectively reduce the electric field around each discharge electrode.

As this occurs, new batches of charged dust particles leaving the discharge wire are repulsed by the negatively charged dust cloud saturating the charging field.

Therefore, there is a net energy loss and a considerable decline in collection efficiency.

Q. *What is back corona?*

Ans. This is another problem is an ESP particularly those in which collecting electrodes are positively charged. This occurs when electrical breakdown results from high resistivity dust particles at low voltages and currents. As a result, the generation of positively charged ions within the dust layer at the collection electrode and the migration of these ionized dust particles with accelerated speed towards the discharge (negative) electrode takes place. And they tend to neutralize the ions of opposite polarity produced at the discharge wire, thereby reducing ESP's performance.

Q. *What are the corona characteristics of an ESP operating at maximum power output?*

Ans. Steeply rising characteristics.

Q. *What is the effect of the temperature of the stack gas on the corona characteristics?*

Ans. It is enhanced with the rise in temperature of the stack gas.

Q. *A vast majority of ESPs operate without any untoward incident. But some electrical faults occur even in new installations. What are they?*

Ans. 1. Insulator breakage

2. Control instability

Q. *What is the prime cause of insulator breakage?*

Ans. Sparking at the base of the support insulator.

Q. *What is the cause of control instability?*

Ans. Radio frequency (RF) noise generation affecting microprocessor controls is the cause of control instability (Fig. 17.8)

Q. *Do these problems cause the precipitators to operate below the guaranteed emission levels?*

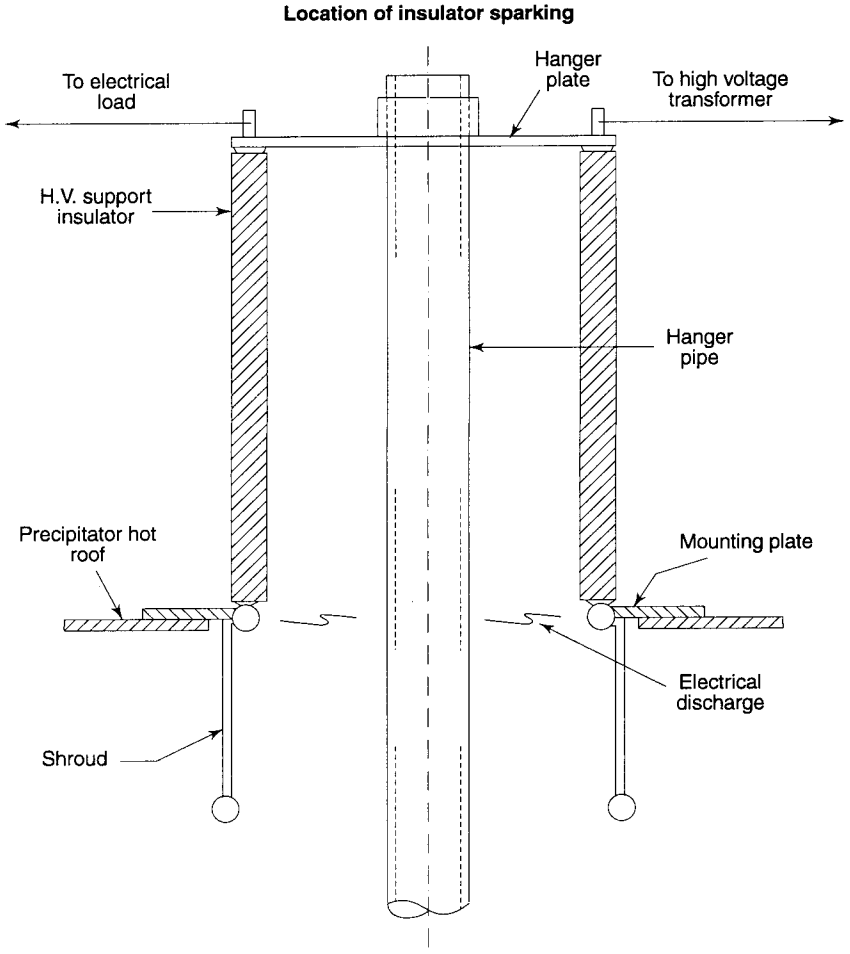

Fig. 17.8

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Source: Precipitator Electrical Problems Encountered with 105 kVP TRs and sixteen inch Plate Spacing—Peter Aa (POWER. GEN SHOW/Anaheim/California/Dec. 1995).

Ans. No.

Q. *Is there any physical manifestation in case of high RF noise?*

Ans. If the RF (radio frequency) noise is too intense, visible electrical discharges may be observed jumping across the two high-tension guard flanges within the close vicinity of a jumper wire.

Q. *What are the causes of RF noise?*

Ans. It is believed to be the outcome of the combination of sparking frequency, transients generated by the avalanche diodes in the transformer's full wave bridge rectifier, and the right combination of impedence and capacitance of the ESP load.

Q. *What should be implemented to eliminate this problem?*

Ans. More ground jumpers and earth returns than specified by vendors may contribute to the RF noise problem. Implementing the vendor's ground specifications is expected to eliminate the problem.

Q. *What if proper grounding fails to correct the problem?*

Ans. New RC compensated diodes and additional TR output chokes should be evaluated in the field.

Q. *What are the checkings that are to be done at site while going to correct the sparking problem and RF noise problem?*

Ans. 1. Installations with sparking at the base of the support insulator are to be inspected in order to confirm proper manufacturing and assembly of the components.
2. Smoothness of the mounting plate corona ring and hanger pipe is to be carefully checked
3. Alignment of the hanger pipe and corona ring are to be checked to ensure that clearances are not too close.

Q. *Why should smoothness of the mounting plate corona ring and hanger pipe be checked carefully?*

Ans. Sharp edges on these components act as corona concentrators and can cause increased sparking in these areas.

Q. *Direct observation of sparking at the base of the support insulator is extremely difficult to achieve in the field. So what is to be done in order to evaluate the problem?*

Ans. This requires a high voltage laboratory to conduct a testing program. The tests should be designed to develop a solution to the flashover problem. Basically, the tests should focus on relatively small adjustments to existing designs, rather than new designs requiring major precipitator modifications.

Q. *However, increasing the dia of the hole in the hot roof and the ID of the support insulator will mitigate the sparking problem at the base of the insulator. Is it not an obvious solution?*

Ans. Yes, it is a possible solution. It will increase clearance between the support insulator and the support pipe.

Q. *Should we go in for this solution?*

Ans. No.

Q. *Why should we avoid this solution?*

Ans. This will require major structural modifications at the insulator support points.

Q. *So how should we institute a high-voltage lab testing?*

Ans. Computer modelling is to be harnessed to develop electrical field strength (lines of force) plots. It will lend to better visualization of what is going on within the insulator/hanger pipe area.

The lines of force should be reshaped so that they can be kept from concentrating at the base of the insulator, thereby eliminating the sparking problem.

That is, two types of tests should be designed—one to reshape the electrical lines of force and the other to electrically insulate the area between the hanger pipe and the corona shield. This re-

quires different shaped rings to reshape the lines of force. The insulation tests involves an insulating sleeve around the hanger pipe and insulating skirt around the corona shield.

It will be convenient if the insulators and reshapers are evaluated on a mobile test stand.The mobile unit will enable the lab personnel to assemble and make ready an assortment of different configurations, then wheel them up into position in the high voltage cage. This will help to reduce the set-up time between the tests and keep ambient conditions constant. On the mounting plate at the top of the mobile stand are located the support insulator and its associated gaskets, hanger pipe, hanger plate, etc.

Note: In one typical experimental set-up, the hanger plate was connected to a 150 KVP at transformer-rectifier set rated at 500 ma and an electrical load that simulated an actual precipitator load. The mounting plate was connected to the return side of the bridge rectifier (ground). A microprocessor controller—the fast action of which allowed individual flashovers to be monitored without repetitive strikes—controlled the TR set. Lab technicians recorded electrical readings at flashover for comparison between tests, and between multiple energizations during the same test.

Q. *Why is it imperative to maintain constant ambient conditions while conducting lab test programs?*

Ans. Though ambient temperature changes do not cause appreciable variations in test results, changes in humidity do have an effect.

Q. *So what is to be done for this?*

Ans. Use is to be made of a humidifier and a dehumidifier to keep humidity constant in the test cage between tests.

Q. *What design modifications are made to overcome the flashover problem?*

Ans. Field tests conducted by the Research-Cottrell team using various methods of reshaping the electrical field or insulating surfaces from the electrical field found six setups exhibited the most promising result:

1. Teflon Shield (Fig. 17.9)
2. Reshaping Ring (Fig. 17.10)
3. Alumina sleeve (Fig. 17.11)
4. Dropped Skirt (Fig. 17.12)
5. Conical Support Insulator (Fig. 17.13)
6. Conical Insulator with Alumina Sleeve (Fig. 17.14)

Q. *Which configuration is the best one?*

Ans. Secondary voltage levels at flashover plotted as a ratio of the 'standard' configuration to the test configuration confirmed dropped skirt design to be the best one while the cylindrical insulator with alumina sleeve and reshaping ring proved to be more or less equally promising (Fig. 17.15)

Q. *Why is a wet-type dust collection method adopted?*

Ans. It is directed solely at reducing the SO_2 emission in the stack gas because of stringent restrictions imposed by the government to maintain the quality of the environment.

Problems arise due to burning of low-sulphur coal producing ash particles of very low resistivity, making the ESP inefficient.

Hence the control of SO_2 emission in the exhaust gas, when low-sulphur coal is burned, is better obtained by introducing scrubbers—wet-type dust collection system—just upstream of the exhaust gas stack.

Q. *What is the benefit of wet-type mechanical dust collectors?*

Ans. Gases like SO_2 and H_2S as well as smokes and fumes can be economically removed.

Q. *How does a wet-type mechanical dust collector work?*

Ans. The dust laden flue gas and washing liquid (water + lime) move counter-currentwise in the scrubbing tower—the gas going up while the liquid raining down.

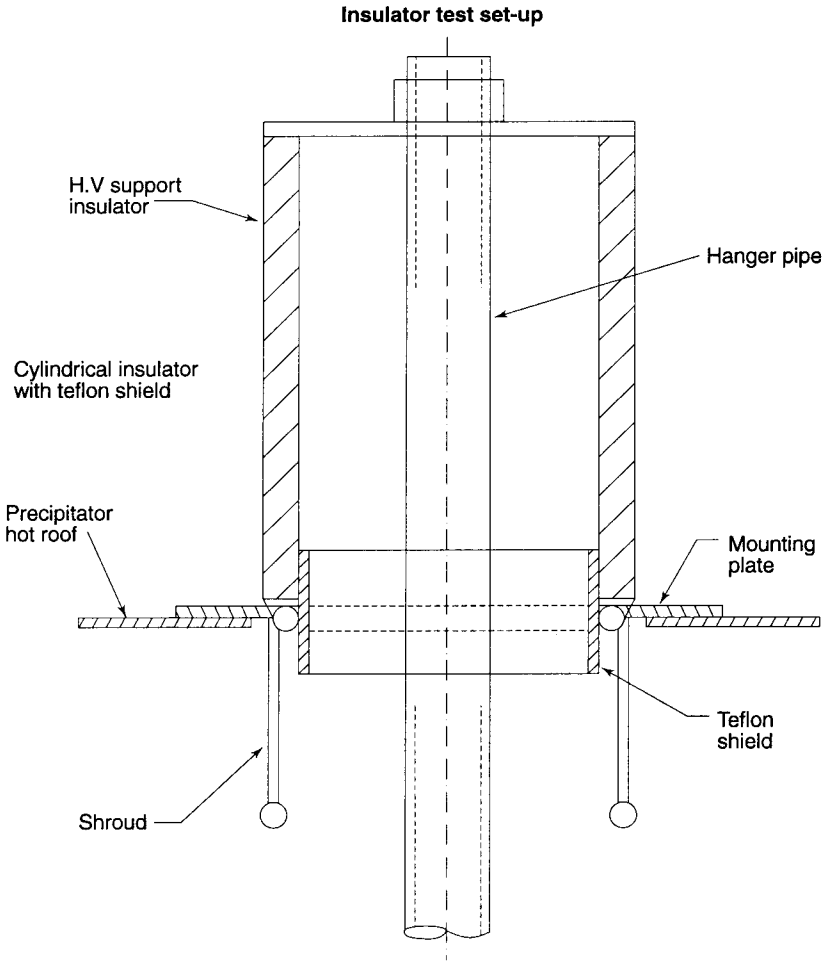

Fig. 17.9 *Teflon shield. A thick sheet of teflon (200mm wide) was formed into a tube and inserted at the upper corona ring. The tube held in place by its own force was centered on the ring allowing 100 mm to extend above and below the ring. It ensured additional insulation between the hanger pipe and the corona ring, and minimized flashover.*

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Source: Precipitator Electrical Problems Encountered with 105 kVP TRs and sixteen inch Plate Spacing—Peter Aa
(POWER GEN. SHOW/Anaheim/California/Dec.1995)

The SO_2 and H_2S get dissolved while in contact with the alkaline water while dust particles produce a thick liquid with the water collected at the bottom. The clean flue gas escapes from the top.

Q. *What is the mechanism?*

Ans. Liquid (lime-water) sprayed as fine droplets in the scrubber collide with the dust particles, wet their surfaces and become heavy and sticky. When these wetted particles conglomerate, they grow in size until they become heavy enough to drop out of the flue gas stream.

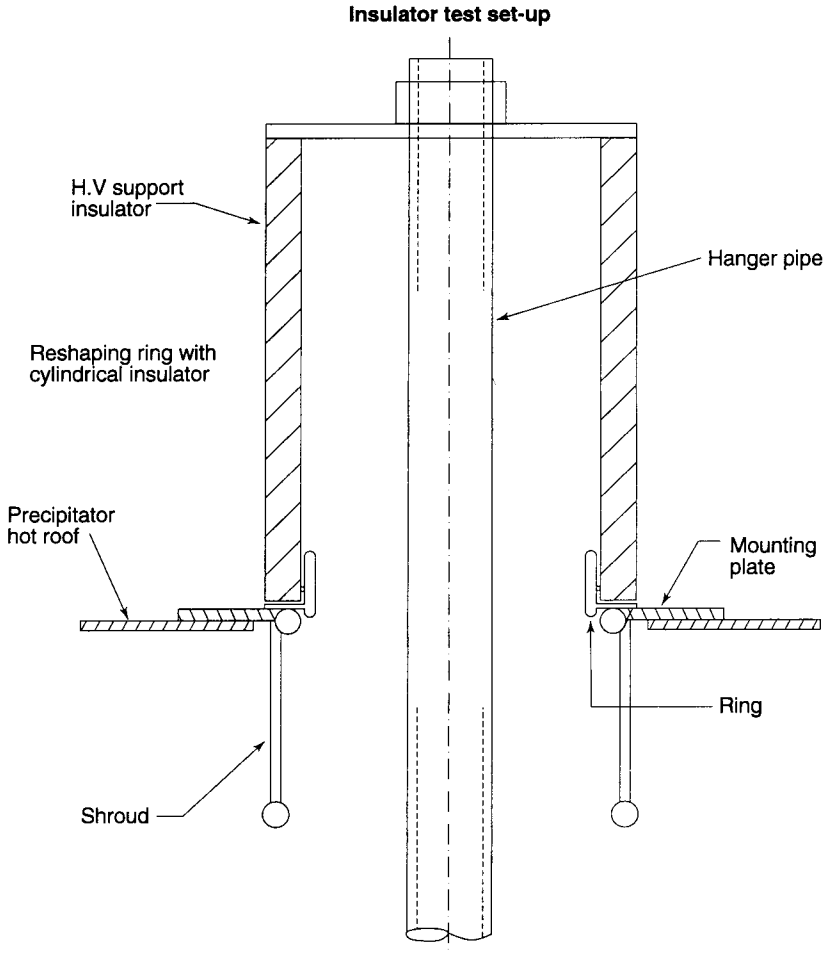

Fig. 17.10 *Reshaping ring. It is a metallic device, oblong-shaped hoop placed at the juncture of the support insulator and the corona ring on the mounting plate.*

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For soluble gases like SO_2 and H_2S, the interfacial mass transfer takes place across the gas-liquid droplet boundary.

This mass transfer is enhanced by lime which forms compounds with the absorbed SO_2 and H_2S. (See Fig. 17.16)

$$Ca(OH)_2 \xrightarrow{SO_2} Ca(HSO_3)_2$$

$$Ca(OH)_2 \xrightarrow{H_2S} Ca(HS)_2 + CaS$$

Q. *How can the efficiency of a scrubber be improved?*

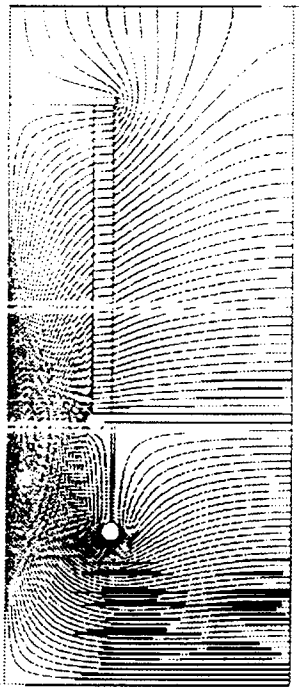

Fig. 17.10a *Plot of electrical field strength.*

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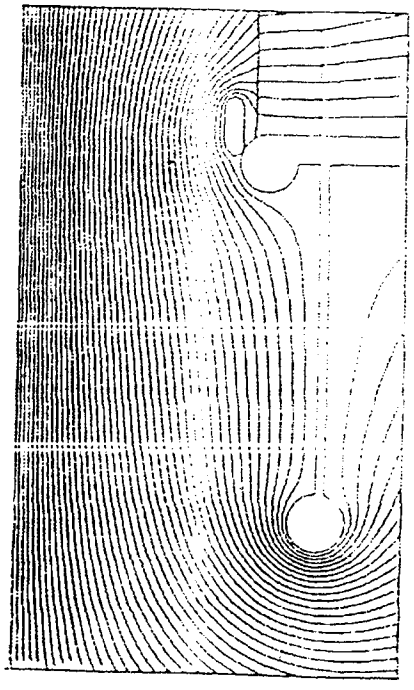

Fig. 17.10b *Plot of electrical field strength with reshaping ring.*

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(POWER GEN. SHOW/Anaheim/California/ Dec. 95)

Ans. Finer the water droplets, higher will be the absorption efficiency.

And greater the difference in relative velocities between the dust particles and water droplets, greater will be the collection efficiency of the scrubber.

Q. *How many types of scrubbers are there for the collection of dust and reduction of SO_2 in the flue gas?*

Ans. In general there are three:

1. *Packed type*
2. Spray type
3. Cyclone type

Q. *How does a packed type scrubber function?*

Ans. Dust laden flue gas is fed near the bottom of the scrubber housing a high density polyethylene packing with a 1 to 3 m (sometimes 5 to 10 m thick packing layer is used for satisfactory reduction of SO_2 and H_2S in the stack gas) thick layer.

Lime-water is sprayed through nozzles from the top. (Fig. 17.17)

The flowrate of water is maintained such that it affords good wetting of the packing.

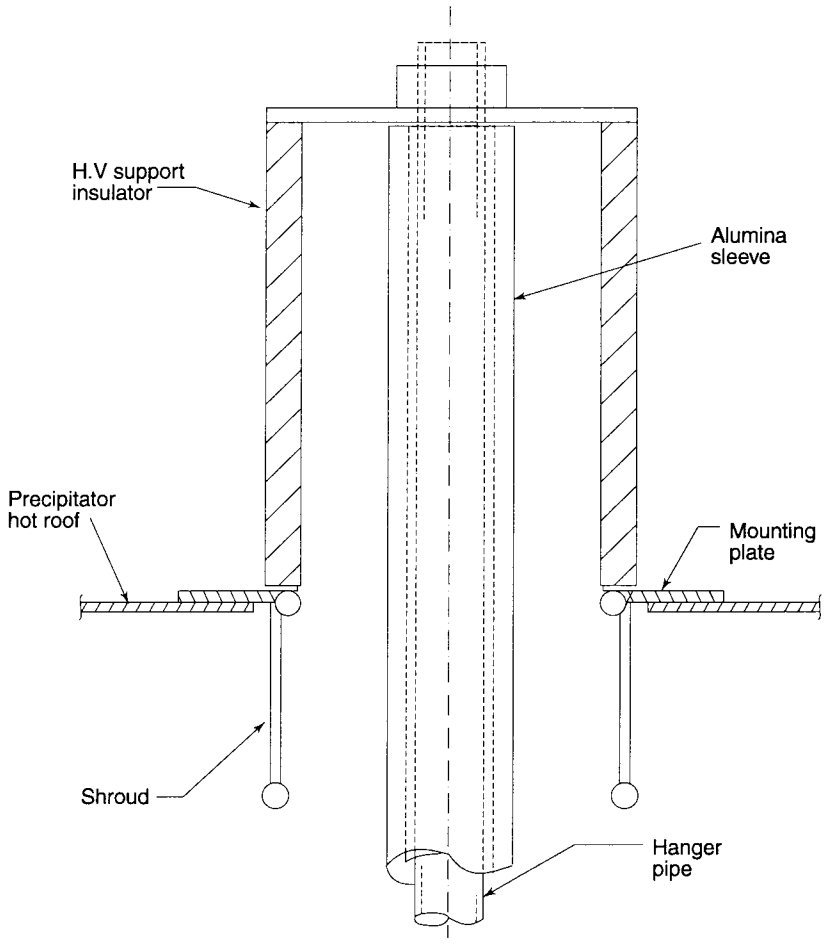

Fig. 17.11 *Alumina sleeve with cylindrical insulator.*

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Source: Precipitator Electrical Problems Encountered with 105 kVP TRs and sixteen inch Plate Spacing—Peter Aa.
(POWER GEN. SHOW/Anaheim/California.Dec. 1995)

Most of the finer dust particles as well as SO_2 and H_2S are washed off the flue gas which is then let out to the atmosphere.

Q. *What is the material of construction of a packed-bed scrubber?*

Ans. Fibre-reinforced plastic.

Q. *Why?*

Ans. It is resistant to corrosion. Scrubber liquor is highly corrosive as it contains dissolved acidic oxides such as SO_2, SO_3, etc.

Q. *Why is high density polyethylene (HDPE) used as tower packing?*

Ans. It is resistant to corrosion.

Q. *What is the main disadvantage of this system?*

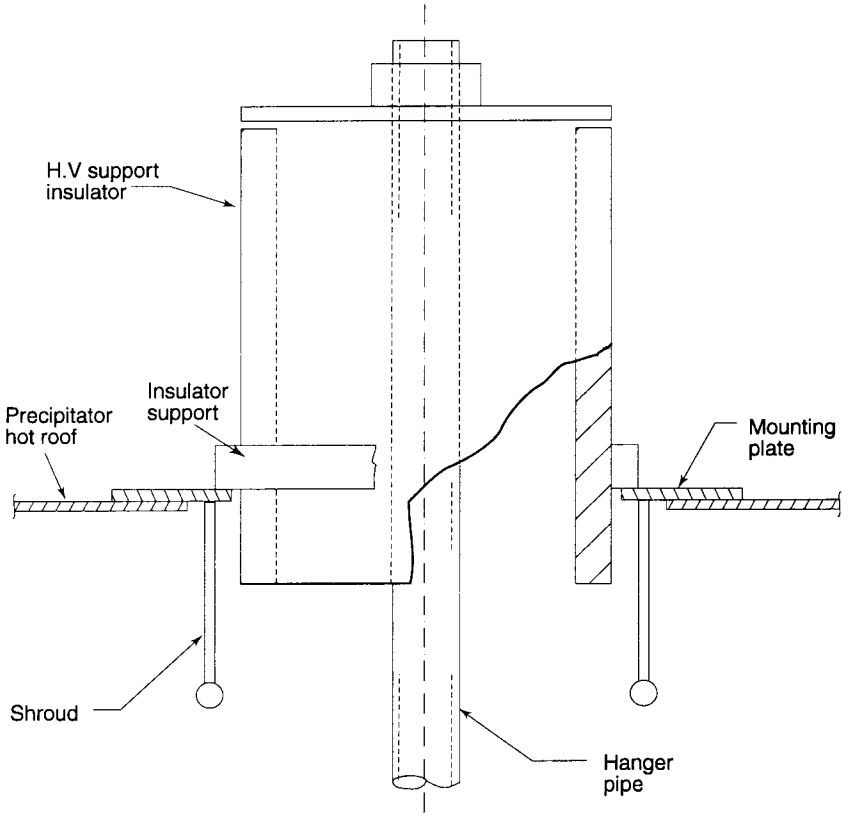

Fig. 17.12 *Dropped skirt.*

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Ans. High pressure drop of the flue gas.

Q. *How does a spray-type scrubber work?*

Ans. It is the simplest kind of all wet type scrubbers.

Flue gas and water droplets move counter-current in the scrubber. The liquid particles wet the dust particles which then conglomerate and drop out.

Water is distributed in a fine spray through successive layers of spray nozzles from the top while the dust laden gas is uniformly distributed across the tower cross-section by a gas distribution plate near the bottom (Fig. 17.18)

Clean gas escapes from top via a mist eliminator to avoid entrainment and carryover.

Q. *What is the limitation of a spray-type scrubber regarding particle size of dust?*

Ans. Its application is limited to the particle sizes 10 μ and higher.

Q. *What are the advantages of spray-type scrubbers?*

Ans. 1. Negligible pressure drop of the flue gas

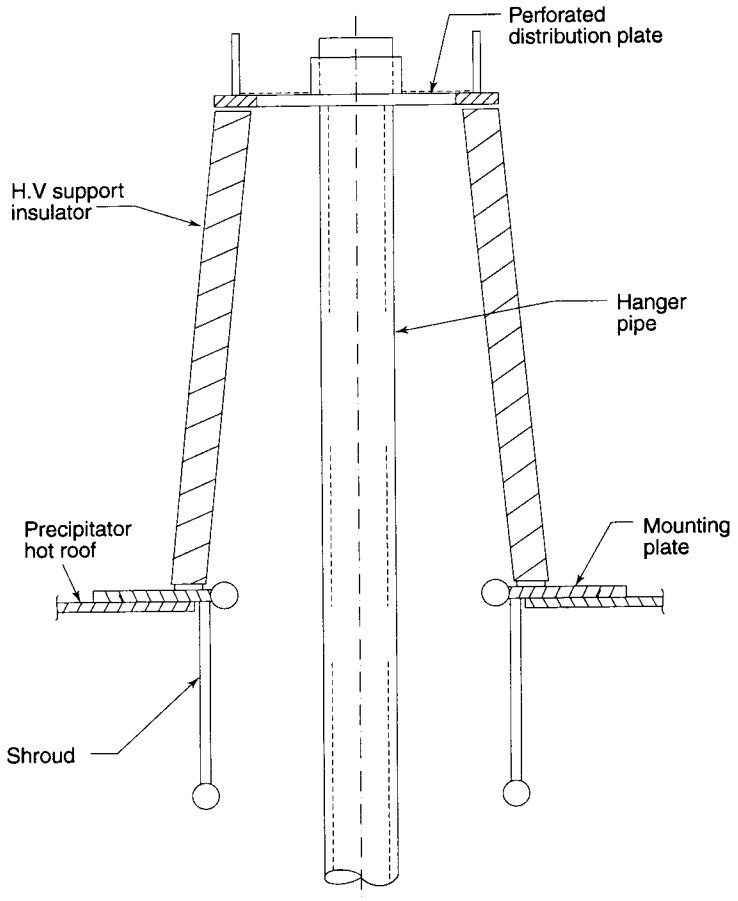

Fig. 17.13 *Conical insulator.*

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(POWER GEN. SHOW/Anaheim/California/Dec. 1995)

2. Simplicity in design
3. Low capital cost.

Q. *Why is a two-stage spray scrubber preferred to a single-stage spray tower?*

Ans. To enhance the efficiency for SO_2 and particulate solid removal.

Q. *How?*

Ans. It is composed of two systems—rod scrubber and spray tower—hooked up in series. (Fig. 17.19)

The particulate solids are removed in the rod scrubber and SO_2 is removed in the spray tower.

Q. *Why is the spray tower reaction effluent fed to the rod scrubber effluent?*

Ans. To supply the seed crystals necessary to provide nucleation sites for non-scale forming homogeneous crystallization of calcium sulphate otherwise it would lead to calcium sulphate scaling due to oxidation in the scrubber. (Fig. 17.19).

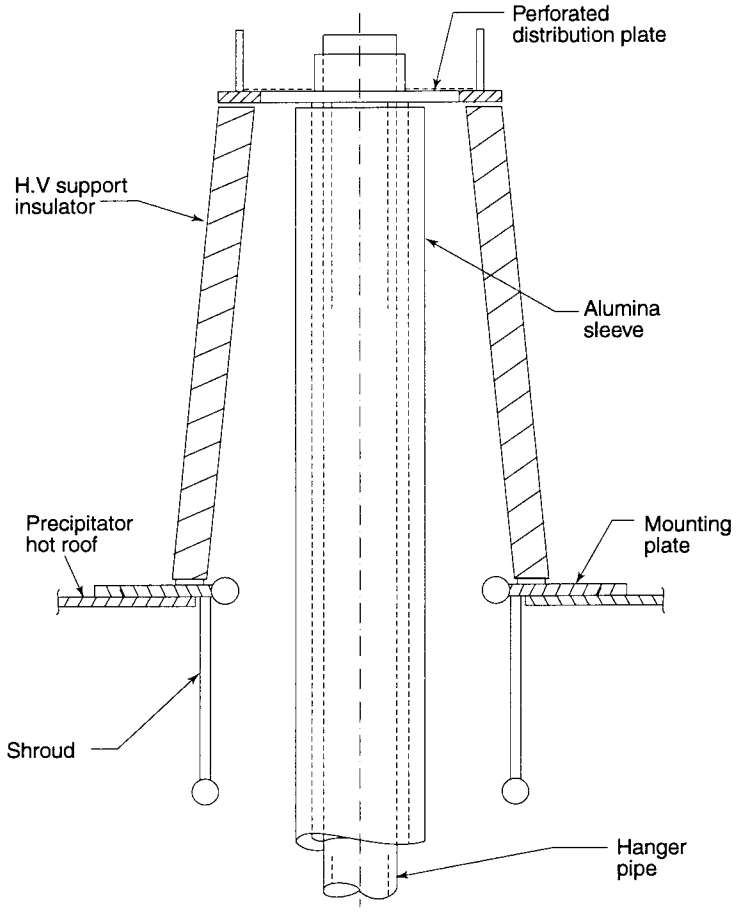

Fig. 17.14 *Conical insulator with alumina sleeve.*

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Q. *When does scaling occur in the scrubber?*

Ans. In the wet process using lime + water as scrubbing liquid, two type of scales are encountered:

Calcium sulphite scale $CaSO_3 \cdot 0.5H_2O$

Calcium sulphate scale $CaSO_4 \cdot 2H_2O$

These two scales are formed when the solutions are supersaturated to the point where crystallization takes place, with the effect that large, agglomerated crystals, instead of small individual, separate crystals, are formed. The primary disadvantage of microcrystals is that they form on the walls, piping and nozzles of the system causing clogging.

Q. *How can the formation of sulphite scales be avoided?*

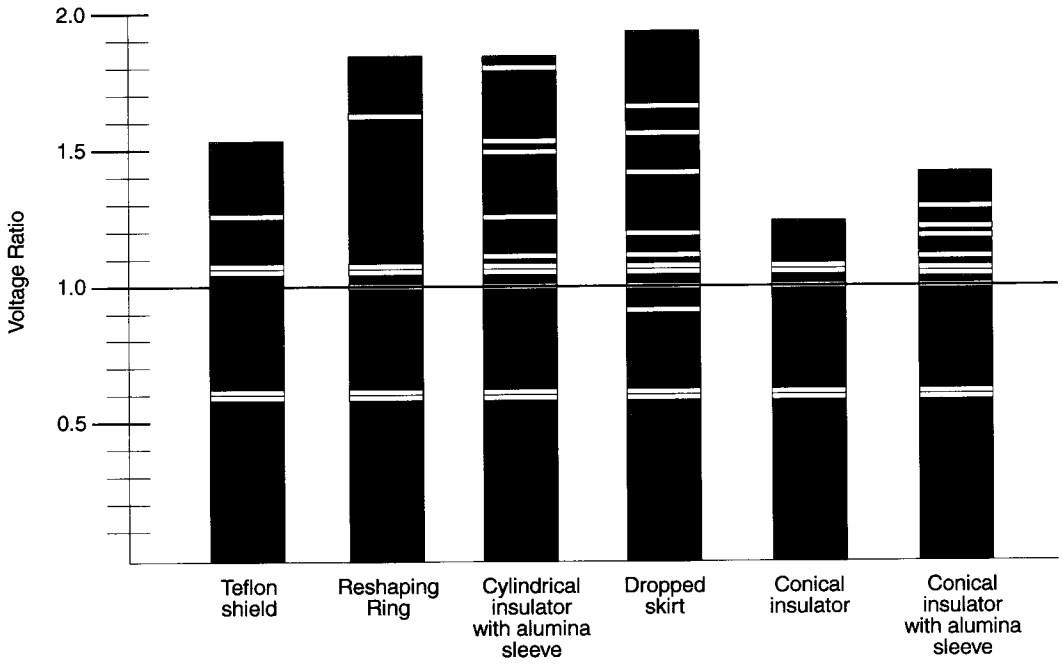

Fig. 17.15 *Test data confirmed dropped skirt to be the best configuration. The horizontal lines in each bar represent an average of the different tests.*

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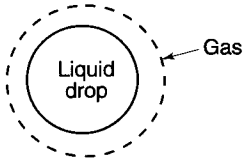


Fig. 17.16

Ans. By controlling the pH of the scrubbing liquid (lime + water) and maintaining it in the range 5–7.

Q. *Sulphur dioxide in the flue gas produces bisulphite and sulphite ions in contact with water. So how does sulphate occur?*

Ans. Due to oxidation in the scrubber, reaction tanks and thickeners.

Q. *How can this scaling be minimized?*

Ans. By feeding seed crystals of $CaSO_4$ in the scrubbing liquor. They will form isolated nucleation sites for growth of calcium sulphate crystals which will precipitate out, forming no scales.

Q. *Air is bubbled through the reaction tank. Why?*

Ans. Air will induce forced oxidation of sulphite ions to sulphate in the reaction tank

$$SO_3^{2-} + O_2 + H_2O \longrightarrow SO_4^{2-} + 2OH^- - 2e$$

The best portion of sulphite in the reaction tank is converted into sulphate and precipitated out as $CaSO_4$. Therefore, when this solution is recycled to the scrubber the concentration of sulphite ions in the solution is so less that there will be very little scaling on the limestone surfaces by $CaSO_4$

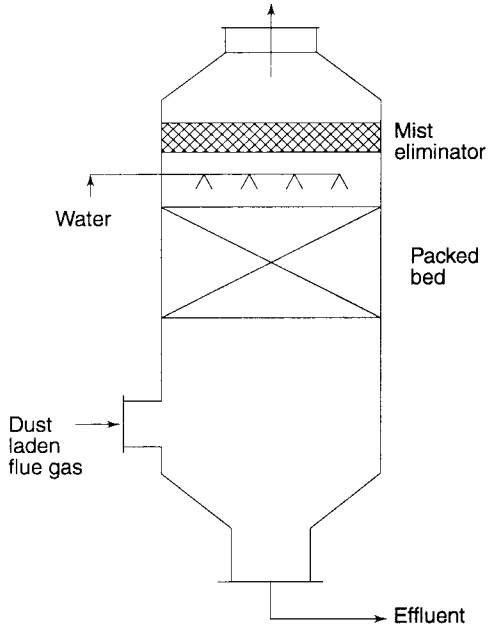


Fig. 17.17 *Flue gas scrubber (packed bed type).*

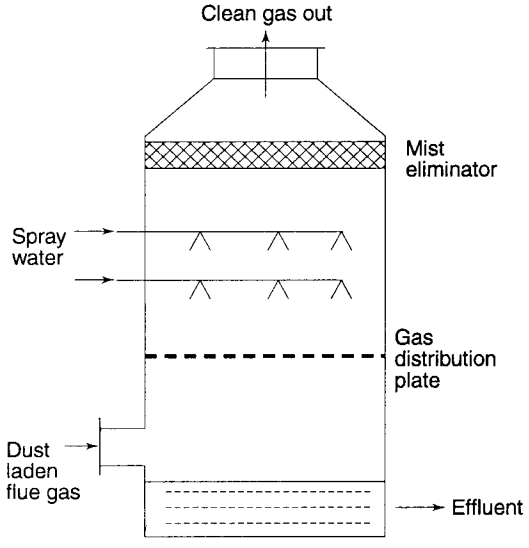


Fig. 17.18 *Spray-type scrubber.*

formed due to oxidation of $CaSO_3$ by oxygen in the flue gas. (Fig. 17.20)

Q. *What is a cyclone scrubber?*

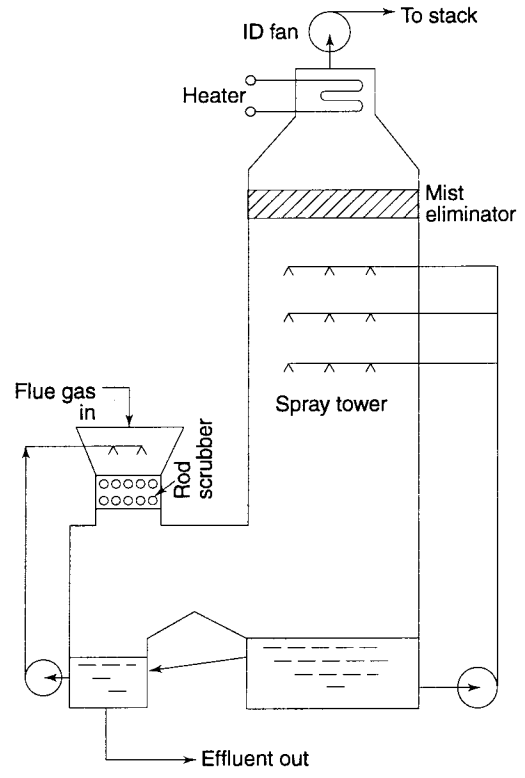


Fig. 17.19 *Two-stage spray scrubber.*

Ans. It is a kind of wet-type mechanical separator in which the flue gas enters tangentially through a cyclone.

Q. *How does a cyclone scrubber operate?*

Ans. As the flue gas enters tangentially near the base of the scrubber and swirls upwards, it comes in contact with a heavy dose of water droplets sprayed through centrally located spray nozzles. Dust particles absorbed by water droplets get sticky, conglomerate and drop out and collect in the dust settling tank at the bottom. (Fig. 17.21)

The clean overflow liquid from the settling tank is recycled to the spray chamber.

Q. *What about its efficiency?*

Ans. The efficiency is usually high.

Q. *Is there any other major advantage of a cyclone scrubber?*

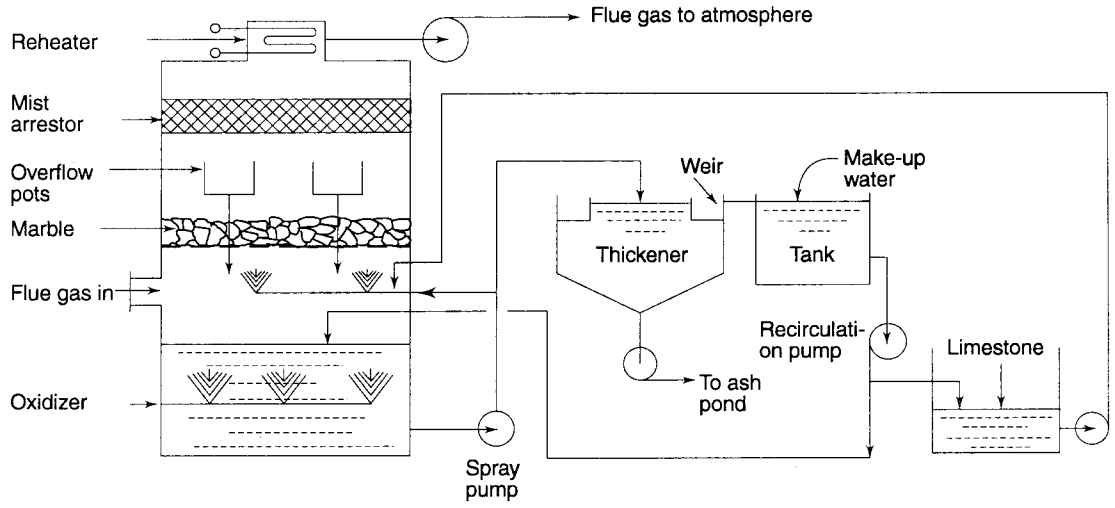


Fig. 17.20

Ans. A lion's share (85–90%) of soluble gases like H_2S, SO_2 and SO_3 are absorbed and eliminated from flue gas. SO_2 content (610-860 ppm) is reduced to 120–380 ppm.

Q. *What is the water pressure at the nozzle?*

Ans. It varies. It ranges from 2 to 20 kgf/cm^2.

Q. *What is the draught (draft) loss at full rating?*

Ans. It is usually 40 to 50 mm of the water column.

Q. *What are the major problems encountered in wet-type scrubbing?*

Ans. Corrosion and erosion problems.

Q. *Why are corrosion and erosion encountered in wet type scrubbing?*

Ans. Sulphur dioxide and sulphur trioxide fumes in the flue gas produce acid mists with water at the saturation temperature (most high efficiency scrubbers quench the flue gas to its saturation temperature).

These acids quickly act upon metals and alloys; affecting scrubber and auxiliary equipment (like pumps, fans, heat exchangers, etc.) as well.

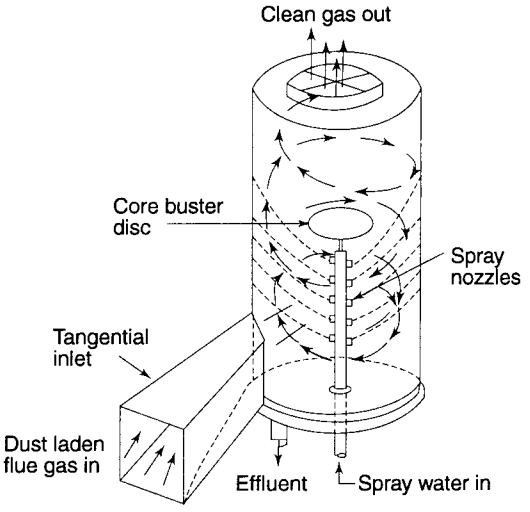


Fig. 17.21 *Cyclone scrubber.*

Q. *What factors enhance corrosive attacks?*

Ans. 1. Humidification of the flue gas
2. High gas inlet temperature
3. High percentage of suspended particulate solids
4. High gas and scrubbing liquid velocities.
5. Acid strength of the recycled liquor.

Q. *Sometimes SO_2 and SO_3 laden flue gas is prequenched before entering the main scrubber spraytower. Why?*

Ans. As the SO_2/SO_3 is absorbed by water, an ill-defined junction of wet and dry gases results. In this junction, the scrubbing liquid is sucked into the inlet gas duct by eddy currents creating high localized acid concentrations. To avoid this undesirable phenomenon, the flue gas is prequenched.

Q. *Why is this eddy current created?*

Ans. Just imagine a water droplet surrounded by a flue gas film. As the SO_2/SO_3 inside the gas film is absorbed and dissolved in the droplet within, the contraction of gas film takes place. This gas film 'contraction' of a large multitudes of droplets will create eddy currents.

Obviously, the volume contraction of flue gas also takes place when it is quenched by water at lower temperatures, thus generating an eddy current. (See Fig. 17.22)

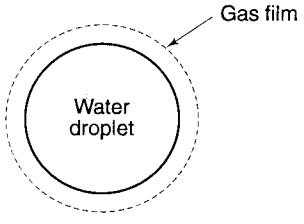


Fig. 17.22

Q. *What should the material of construction of the scrubber be to avoid corrosion?*

Ans. Frequently they are made of stainless steel lined with acid proof bricks. Fiberglass reinforced plastic is also in vogue. Sometimes ceilcote linning is also applied on stainless steel for best results against corrosion and erosion.

Q. *Apart from corrosion resistance, is there any added advantage of acid resistant bricks?*

Ans. Abrasion resistance and resistance to spalling.

Q. *When fireclay acid bricks are used for linning, the flue gas temperature is maintained at 400°C (673 K) or below, why?*

Ans. Scalling off (i.e. spalling) will occur as the droplets of scrubbing liquor impinge on the brick linning of the scrubber wall.

Q. *Which brick is most suitable for this purpose?*

Ans. Among all acid resistant bricks, silicon carbide brick yields best results.

Q. *Why?*

Ans. Not only is it acid resistant but also resistant to spalling at temperatures as high as 1400°C (1673 K).

Q. *Is it applied widely?*

Ans. High installation cost limits its use.

Q. *What are the limitations of brick linning?*

Ans. 1. It puts certain limitations on the design of the scrubber.
2. It greatly increases the weight of the vessel.
3. Access to the scrubber becomes difficult.
4. Additional cost burden.

Q. *What is ceilcote?*

Ans. It is a thermosetting resin.

Q. *What are its advantages as a linning material?*

Ans. 1. Only a 4 to 12 mm thick coating is required.
2. Can be reinforced with glass or cloth to increase it tensile strength and lower its coefficient of thermal expansion
3. Highly resistant to corrosion and thermal shock
4. High impact and abrasion resistance
5. Capable of functioning at high temperature
6. Life span is 10 years or more under severe operating conditions.

Q. *What are the disadvantages of wet-type scrubbers?*

Ans. The quantity of water requirement for scrubbing is very large (20 to 30 litres per 1000 Nm^3 of gas handled).

The system is costly as special material of construction (S.S) and special linning are to be used. For the given gas conditioning, a wet-type scrubber cost 25% more than a double-stage cyclone separator.

Flue gases having a high load of dust particles impair its efficiency.

Its operating cost is about five times that of an ESP.

Q. *Why in many cases is a dry mechanical collector hooked up in series with an electrostatic precipitator?*

Ans. To reduce the initial cost of the collector system as well as to maintain an overall high collection-efficiency.

The ESP has a falling efficiency characteristic with increasing load while a cyclone separator (i.e., dry mechanical collector) has a gradual upward efficiency characteristic with increasing load. (Fig. 17.23).

So when these two collector systems are hooked up in series an overall constant high efficiency over a considerable range of load variation results.

Q. *Which one is installed ahead of the other?*

Ans. Mechanical collector is installed before ESP.

Q. *Why?*

Ans. The mechanical collector removes the heavier particles and its efficiency increases with larger particle size. The ESP is best fitted for removing finer particles and exhibits higher performance with reduced dust load. Much of the dust load is reduced by a mechanical collector (cyclone separator) installed upstream of the ESP.

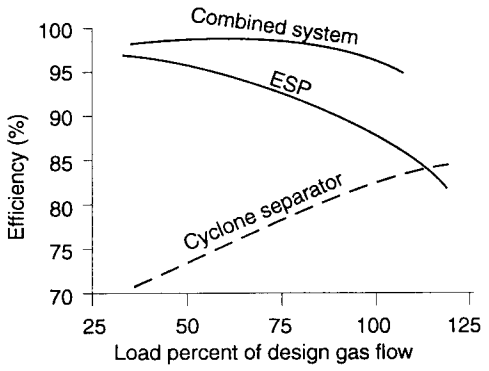


Fig. 17.23 *Efficiency characteristics of ESP, cyclone separator and a combined system.*

Q. *What is a better location for the ESP—upstream of the air heater or downstream of it?*

Ans. The problem is moot. But arguments favour its location upstream of the air heater.

Q. *Why should the ESP be located upstream of the air heater?*

Ans. ESP upstream of the air heater will keep the heat transfer surface of the air heater clean of dust and soot with the effect that the rate of heat transfer to air will not be impaired over a prolonged period.

Low-sulphur coals (S content 0.4–0.8%) produce on combustion, ash particles of high electrical resistivity. In such cases the ESP performs poorly until or unless the flue gas temperature is increased (above 270°C, i.e., 543 K) or the gas is conditioned (by adding SO_3). If the flue gas temperature after passing through the air heater drops below 543 K, installation of the ESP downstream of the air heater will impair the efficiency of the ESP dealing with low-sulphur coal ash.

Therefore, for efficient performance of ESP dealing with low-sulphur coal ash, it should be allowed to work at flue gas temperature above 543 K and that makes its installation upstream of the air heater imperative.

Finally, whatever be the coal composition, the performance of ESP upstream of the air heater is not affected, provided the flue gas temperature is above 340°C (613 K). It is because at this high temperature, the electrical conductivity of dust particles is substantially higher enabling them to be more responsive to the ESP.

[ESP upstream of air heater is called hot-side ESP].

Q. *Why is dust control imperative in coal-fired boiler plants?*

Ans. Dust is a health and safety hazard as well as a nuisance.

Q. *What is the maximum allowable limit?*

Ans. As per OSHA's (Occupational Safety and Health Agency) standard respirable coal dust emissions should not exceed 2 mg/m^3 provided the coal dust contains not more than 5% silica.

Q. *How is coal dust produced?*

Ans. Coal dust is produced by two mechanisms
(a) impact and
(b) wind erosion

during handling and storage.

Q. *What are the sources that create coal-dust by impact?*

Ans. 1. Unloading
2. Stacking
3. Crushing
4. Conveying

Note: The level of dust emission depends, by and large, on the amount of handling the coal subjected to plus the ability of the coal-handling equipment to contain dust.

Q. *Where is the dust generated due to erosion mostly prevalent?*

Ans. In the coal yard during handling and storage.

Q. *On which factors does the dustiness of coal depend?*

Ans. Coal is a heterogeneous mass and by nature itself is dusty. The dustiness of coal depends chiefly on its surface moisture and size distribution.

The susceptibility of the coal type to oxidation and its friability (i.e. the ease of being crumbled) also contributes to its dustiness.

Coal susceptible to oxidation on exposure to air during storage and containing less surface moisture degrades to coal dust more readily.

Q. *How can wind-induced coal dusting be prevented?*

Ans. By providing stackers with
(a) telescopic chutes
(b) lowering wells

And also by completely enclosing the active piles.

Q. *How can coal dusting be reduced?*

Ans. By using water sprays.

This system wets the coal and increases its surface moisture thereby reducing dusting dramatically.

Q. *What is the mechanism of dust removal by the wet-spray method?*

Ans. Spray droplets collide with airborne dust particles, wet them down. Soaked and heavy, the suspended coal particles settle more rapidly. (Fig. 17.24)

Note: Water is also sprayed on coal stockpiles in the yard to keep their surfaces wet and protect them from wind erosion.

Q. *Can the conventional water-spray system remove very fine dust particles?*

Ans. No.

Conventional water-spray system is not effective to remove respirable fraction of dust fines.

Q. *Why?*

Ans. Conventional spray-nozzles produce water droplets in size range of 40–60 μ which can adequately knock down dust particles in the same

approximate size range. However, water droplets in this size range are less effective in arressting very fine airborne dust particles, particularly the respiratory fraction, which escape arrest by streamlining around larger water droplets.

Q. *How can this problem with finer dust be solved.*

Ans. Use of

1. Air atomizing nozzles
2. Ultrasonic atomizing nozzles

to produced very fine droplets to suppress very fine suspended dust particles.

Charged foggers have been developed to impart a charge to water droplets to enhance the collection efficiency of statically charged dust particles.

Q. *What are the basic drawbacks of this water-spray system?*

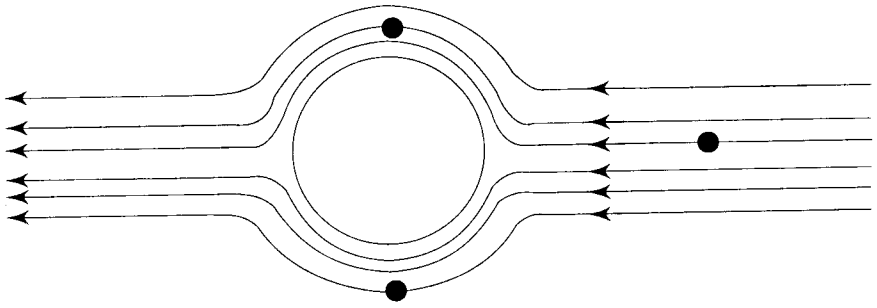
Ans. All water-spray systems are fretted with two fundamental disadvantages.

1. Lowering of coal's heating value as the coal gets soaked in water mass. This effect becomes significant if the watered fuel is fed directly to the furnace.
2. Huge quantity of water is required, particularly during the hot and dry days of summer, to constantly rewet the stockpiles to keep the dust down. It is manpower intensive and may strain available water reserves.

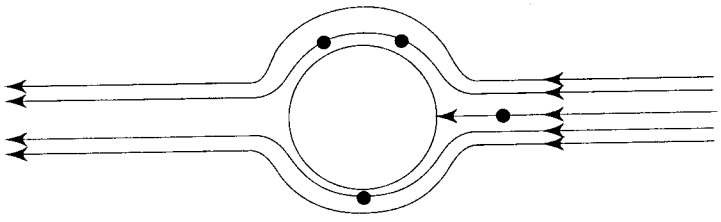
In colder climates, water may aggravate frozen coal problems. Therefore, routine spraying of piles is not generally feasible even though dusting persists.

Q. *Why with some coals, dust control by water-spray system is more difficult than with others?*

Ans. The success of the water-spray system to contain coal-dust lies in the ability of water droplets to wet the coal particles, i.e. not only does a water droplet have to hit a dust particle to cap-



Small particles streamline past the large droplets and escape capture



Smaller particles are arrested by smaller droplets

Fig. 17.24 *Particles are wetted and get captured.*

ture it, it also has to wet the particle, otherwise the droplet and dust particle will bounce off.

Now, coal is a very heterogeneous mass composed of maceral (organic part) and mineral (inorganic portion) substances. While the inorganic substances are relatively easy to wet, the organic counterpart is very difficult to wet. As a result some coals are more difficult to wet than others, depending on their composition and rank.

Q. *How can the wetting of coal dust be improved?*

Ans. To improve the wetting of coal and spreadover of surface water on coal, wetting agents are introduced. These are common surfactants like soap.

Q. *How do these surfactants act?*

Ans. They reduce the surface tension of water and allow it to wet and spread much more uniformly and rapidly.

Q. *How can water consumption be reduced?*

Ans. By dosing chemical additives that either reduce water consumption rate or evaporation rate. These are foaming agents that are mixed with water and then mixed with compressed air in the foam-chamber to produce a high expansion foam. These foaming chemicals permit expansion of a liquid volume so that less water is required for distribution. Water consumption rates can be reduced by 30% in many cases.

Q. *Why are foam suppressants more efficient in controlling fine dust?*

Ans. Foam bubbles are born with a great deal of internal stress so they implode when they chance upon a dust particle (Fig. 17.25)

Upon implosion they disintegrate to numerous fine droplets which are finer than those produced by spray techniques. These fine droplets collide in turn with fine dust particles and wet them down.

Q. *Where these suppressants are mostly used?*

Ans. They are preferred by plants where water supply is scarce or where water sprays have proven inadequate.

Q. *What is the dosage of foam suppressants?*

Ans. Usually 1%–2% of solution.

Q. *What other suppressants are used to counteract the evaporation of water?*

Ans. 1. Lignosulphonates—byproducts of pulp and paper industry
2. Latexes
3. Asphalts
4. Waxes
5. A wide variety of polymers

Basically, any inexpensive material with film-forming or encrusting properties is a candidate for dust suppressant.

Q. *What are residual suppressants?*

Ans. These are generally wetting agents or foams in combination with latex, lignosulphonates or other film-forming or adhesive compounds.

Q. *What are the advantages of residual suppressants?*

Ans. Basically designed for application during unloading, the residual dust suppressants treat the bulk of the fuel and remain effective during storage and subsequent reclaim.

Unlike encrusting agents, they can be used on active piles. As fresh surface is exposed, the

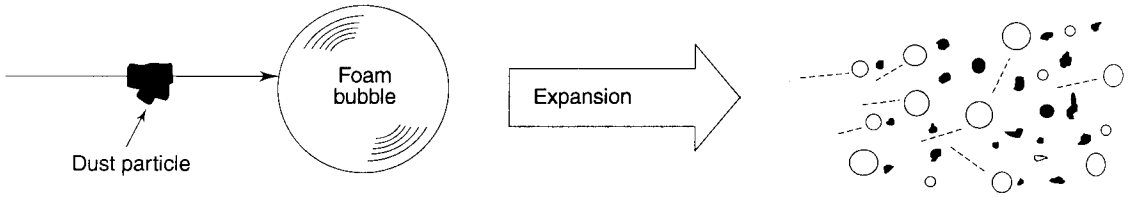


Fig. 17.25 *Subdivision of a large foam bubble into fine droplets that arrest more dust fines.*

suppressant gets activated to renew the coating or cause the conglomeration of coal fines.

Q. *What are the dust emission factors of coal-fired powerplants?*

Dust Source	Emission Factor (kg dust/t of coal)
COAL DELIVERY	
Railcar unloading	0.181 (unloaded)
Barge delivery	0.020 (unloaded)
Truck unloading	0.181 (unloaded)
Conveyors	0.018 (unloaded)
COAL STORAGE	
Loading onto pile	0.036 (loaded)
Vehicular traffic	0.072 (stored)
Loading out	0.045 (loaded)
Wind erosion	0.040 (stored)
TRANSFER & CONVEYING	0.018–0.453 (handled)
FLYASH HANDLING & DISPOSAL	9–45 kg dust/t ash

Q. *What are the basic trends of dust control management?*

Ans. The costs of dust-control systems do not contribute to plant production. So the utilities tend to install the least expensive controls first, harnessing mechanical collectors, water sprays or additives only as the last resorts.

Environmental agencies encourage plants to adopt RACT (Reasonably Available Control Technology) tactics rather than BACT (Best Available Control Technique) system to keep fugitive dust emissions perceptibly down.

Q. *What are the guidelines for sound dust-control management?*

Ans. 1. Identification of the motives. If safety is the prime factor, planning should be done to take an integrated approach to the whole system.
2. Conducting a site survey and inspection of the coal handling system thoroughly. The site-survey characterizes emissions sources, evaluates the effectiveness of current controls and forms the very basis of revamping of existing system.
3. Improvement of maintenance and operating procedures.
4. Overhauling and modification of coal handling system. Sealing cracks, plugging holes, installing curtains, skirts or covers to contain fugitive dust.
5. Estimating whether mechanical dust collectors or wet-spray systems or a combination of the two is the most cost effective and best suited control technology. Wet suppression and additive systems are less capital intensive and offer flexibility.
6. Laboratory test of the effectiveness of the additives is imperative before trying them in the field.
7. Selecting a good supplier having a wide range of dust-control equipment and chemicals.
8. It is better to tackle dust control in-house, if the plant already owns or is able to construct equipment. Wet suppression equipment is relatively straightforward in design and many dust-suppressant formulations are commercially available.
9. Preventive maintenance is absolutely essential for dust controls. Routine inspection and maintenance are the best method of obtaining full value from the control system.

18

ASH HANDLING SYSTEM

Q. *What is ash?*

Ans. Ash is the incombustible material that remains when coal is burned.

Q. *How can it be classified?*

Ans. Ash can be classified as either inherent or accidental depending on the source from which it is derived. Accordingly the former is called intrinsic ash and the latter is called extrinsic ash.

Q. *What is intrinsic ash composed of?*

Ans. Oxides of silicon, alkali metals (Na, K) and alkaline earth metals (Ca, Mg).

Q. *How do they come?*

Ans. The come into the body of coal from the original vegetable matter from which coal was formed. Also they might have been ingested into coal during its formation when mineral rich water infiltrated into it.

Q. *Is it separable or inseparable from the coal substance?*

Ans. Inseparable.

Q. *How can it be removed?*

Ans. Through flotation processes.

Q. *What is extrinsic ash?*

Ans. It is dirt, shales, clay, pyrites and ankerites picked up from the adjacent earthy or stony bands in the coal seam.

Q. *How can they be eliminated?*

Ans. Washing and cleaning eliminate most of the extrinsic ash.

Q. *What is the per cent of ash content of coal?*

Ans. Ash content in coal may vary from 8 to 10% to as high as 20 to 50% depending upon the grade of coal.

Q. *How does it vary with the quality of coal?*

Ans. Better the quality of coal, lower is the ash content. Hence for inferior grade coal, the ash content is higher than anthracite or semi-anthracite variety of coal.

Q. *Ash is detrimental to the combustion process. Why?*

Ans.
1. It lowers the gross calorific value of coal.
2. It must be disposed of after combustion and as such entails a separate system called ash handling system.
3. Ash with low fusion point forms a deposit on the tube walls, affecting the generation of steam
4. Low fusible ash forms clinkers that contribute to clogging as well as cause severe corrosion of bar grates of the stoker furnace.

Q. *What is the difference between the ash and the mineral matter in coal?*

Ans. Ash left after coal is burned differs in quantity and composition from the original ash present in the coal. For the sake of clarity, the original ash in coal before combustion is usually termed mineral matter.

Composition of Typical Coal Ash (%)

Constituents	I(White)	II(Buff)	III(Red)
SiO_2	57.9	41.1	36.9
Al_2O_3	38.1	33.5	25.7
Fe_2O_3	5.7	17.1	25.1
Na_2O }	3.1	2.6	3.3
K_2O }			
CaO	0.5	3.8	5.7
MgO	0.7	1.9	3.3

Q. *So coal contains mineral matter that undergoes certain changes into ash. What are these principal changes?*

Ans.

1. DEHYDRATION OF HYDRATES

$$CaSO_4 \cdot 2H_2O \longrightarrow CaSO_4 + 2H_2O \text{ (Loss 2\%)}$$

2. DECOMPOSITION OF CARBONATES

$$CaCO_3 \longrightarrow CaO + CO_2 \text{ (Loss 44\%)}$$

$$MgCO_3 \longrightarrow MgO + CO_2$$

3. OXIDATION

$$FeS_2 + \frac{3}{4}O_2 \longrightarrow \frac{1}{2}Fe_2O_3 + 2S \text{ (Loss 33\%)}$$

$$S + O_2 \longrightarrow SO_2 \longrightarrow SO_3$$

4. COMPLEX FORMATION

High temperature combinations of oxides, silicates and free silica

$$Na_2O + SiO_2 \longrightarrow Na_2SiO_3$$

$$Na_2O + Al_2O_3 \longrightarrow 2\ NaAlO_2$$

5. VOLATILIZATION OF ALKALI CHLORIDES

This is usually negligible.

Q. *Why does ash have to be discharged and dumped at a site sufficiently far away from the thermal power plant?*

Ans. 1. Ash is dusty and irritating. Being easily airborne, it causes inflammation in the eyes.

2. It generates toxic gases and corrosive acids when it comes in contact with water.

Q. *What problems beset the ash handling system?*

Ans. 1. Easily fusible ash forms large clinkers on conglomeration. They must be crushed to a convenient size before discharging onto a conveying equipment.

2. Abrasiveness of ash wears out the conveyor parts. hence a special conveyor must be designed to handle the ash.

3. Transportation of hot ash is difficult as well as hazardous. Hence it must be quenched before transportation. (Fig. 18.1)

Q. *If the silica content of ash is higher, what trouble will originate?*

Ans. Greater the silica content, the greater is the erosion problem.

Q. *Is there any scope of utilization of coal ash?*

Ans. Ash can be utilized for

1. land filling
2. road making
3. filling abandonded quarries
4. manufacture of cement.

Q. *Into how many types can the modern ash handling system be classified?*

Ans. Four.

Q. *What are they?*

Ans. Mechanical system

Hydraulic system

Pneumatic system

Steamjet system

Q. *How does a mechanical ash handling system function?*

Ans. Hot ash issuing out of a boiler falls over a conveyor belt through a water seal. (Fig. 18.2)

The hot ash gets cooled on quenching and is carried continuously by the conveyor belt to the

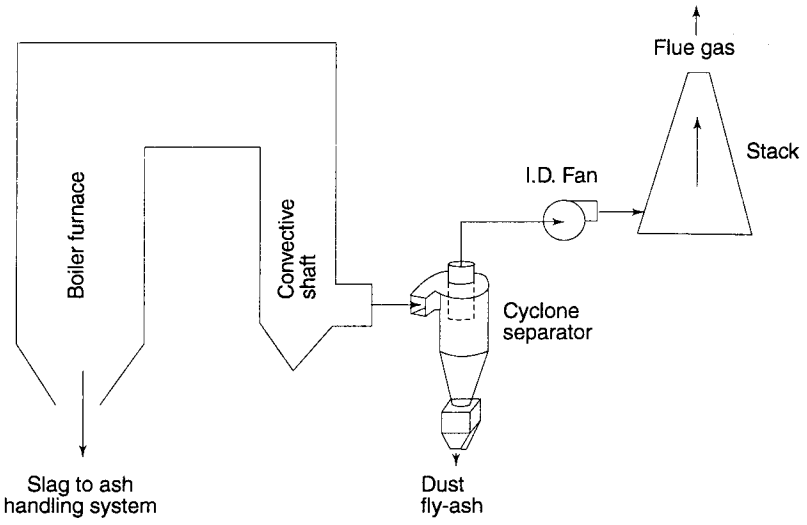


Fig. 18.1 *In a typical coal-fired system, molten ash goes to ash handling system while the flyash is collected in the cyclone separator downstream.*

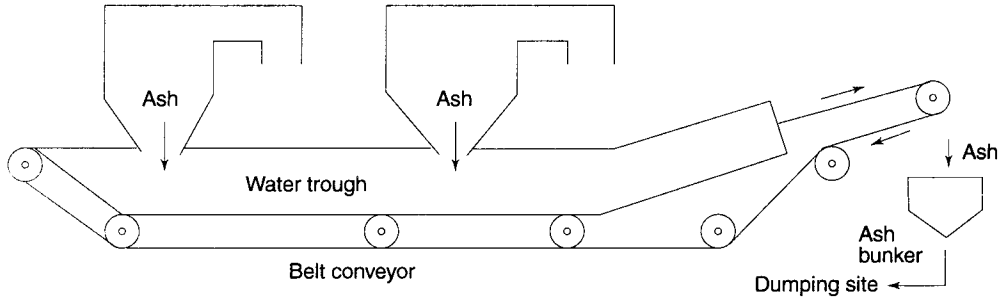


Fig. 18.2 *Mechanical ash handling system.*

dumping site or ash-bunker from where it is trucked away.

Q. *What is the main limitation of the mechanical system of ash handling?*

Ans. It is generally used for low capacity, coal fired power plants.

Q. *What is the maximum capacity of this system?*

Ans. 5 t/h

Q. *What is the approximate life span of this system?*

Ans. 5 to 10 years.

Q. *What are the major advantages of this system?*

Ans. 1. Low power consumption
2. Continuous ash removal

Q. *Can you mention any power station in India where such an ash handling unit is operating?*

Ans. Khapaskheda power station near Nagpur.

Q. *How does the hydraulic ash handling system differ from a mechanical ash handling system?*

Ans. In the case of a hydraulic ash handling system, water instead of a conveyor belt is used to transport the quenched ash to the ash sump where ash is settled out.

Q. *How many types of hydraulic ash handling system are in vogue?*

Ans. There are two types of hydraulic ash handling systems:

(a) Low-velocity system
(b) High-velocity system

Q. *How does the low-velocity system operate?*

Ans. Ash from the furnace grate falls into a channel of water possessing low velocity and is carried to sump tank where it is settled, reclaimed and transported while the separated water is recycled. (Fig. 18.3)

One stand-by channel is provided to each boiler.

Q. *What is the velocity of water flow?*

Ans. 3 to 5 m/s.

Q. *Would you prefer a high limit of velocity or lower limit?*

Ans. Higher limit, of course.

Q. *Why is a higher limit of velocity preferred?*

Ans. It expedites the ash transporting.

It reduces abrasion of the channel (trough) as the ash tends to ride on water instead of scouring the bottom.

Q. *What is the ash carrying capacity of this system?*

Ans. 50 t/h through a distance of 500 m.

Q. *How does the high-velocity system work?*

Ans. High pressure water jetting out from the nozzles fitted at the top (i.e. near the stoker bed) and on the sides strike the hot and molten ash as it rolls off the chain-grate. (Fig. 18.4)

Water from the top nozzles quenches the ash while that from the side nozzles feeds the necessary driving force to transport the ash down the channel provided at the bottom.

The ash is allowed to settle in the settling pit and the separated water is recycled.

Q. *What is the capacity of this system?*

Ans. Ash as much as 120 t/h can be carried by this system and discharged at a distance of up to 1 km.

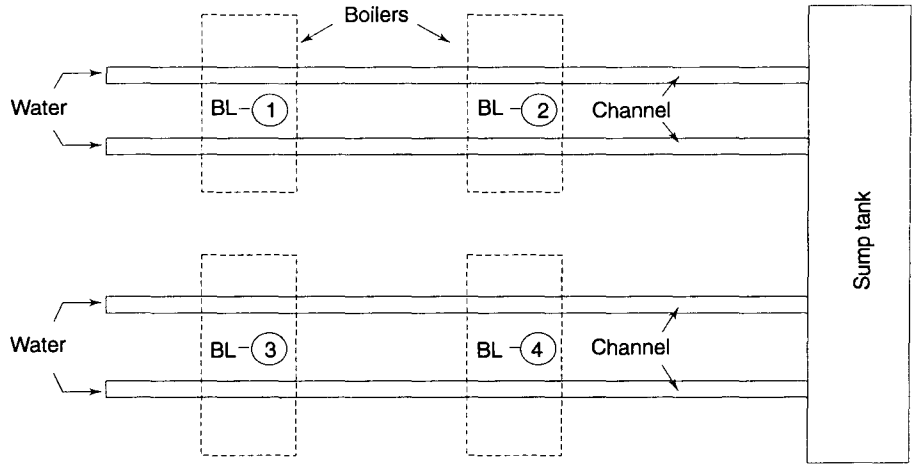


Fig. 18.3 *Low-velocity hydraulic ash handling system.*

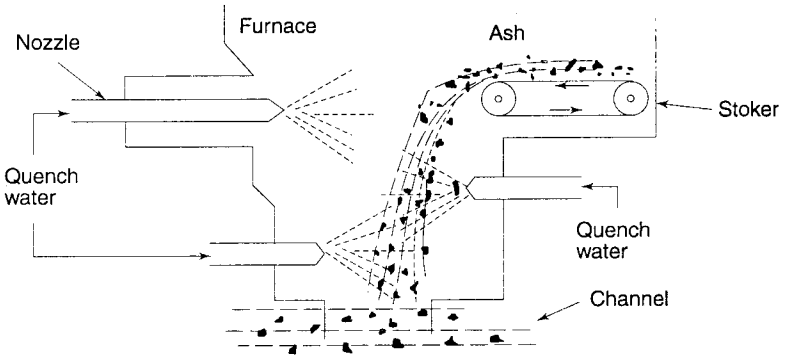


Fig. 18.4 *High-velocity ash handling system.*

Q. *What is the disadvantage of the high velocity system?*

Ans. The water channel and the sump meant for conveying the ash should be made of corrosion and wear resistant material as the abrasive ash forms corrosive acids in contact with water.

Q. *Can this system be employed in the case of a pulverized coal fired boiler also?*

Ans. Yes. High pressure water jets directed against the continually flowing molten stream of ash, quench and disintegrate the mass into small particles which drop into a sluice-channel. A second set of nozzles transports them to cast iron downcomers discharging into the main sluice-channel whereform it is finally transported to the sump-pond.

Q. *What are the advantages of a hydraulic ash handling system?*

Ans. 1. Clean and dust free operation
2. High ash handling capacity 120 t/h. hence more suitable for super thermal power stations.
3. Can handle molten ash stream also
4. Ash can be disposed of at a site 1 km from the steam generation plant.
5. There are no working parts in contact with ash. Hence erosion problem is minimum.

Q. *What are the advantages of a high-velocity hydraulic system over a low-velocity one?*

Ans. It is very difficult to assess.

The water requirement of a low-velocity system is two to three times as much as the high-velocity system, whereas the power requirement to pressurize water through the nozzles in a high-velocity system is two to three times the power requirement for running a low-velocity system.

However despite high power requirement, the high-velocity system handles high-ash-concentrated fluid and minimizes the chocking problem of the sluice.

Because of the higher ash handling capacity of the unit, the high-velocity system allows intermittent operation—20 to 25% of the time required by a continuous low-velocity system. From this point of view, the electricity requirement per ton of ash handled is 1/3 rd to 1/2 of that required by an equivalent low-pressure system.

However the low-velocity system is gaining ground because of

(a) simplicity of operation
(b) economical in running costs
(c) economical in installation costs.

Q. *How does the pneumatic ash handling system work?*

Ans. A high velocity air stream is directed to collect ash and dust from all discharge points. The ash from boiler units falls through the hopper, passes through crushers and drops into the stream of air.

Air-borne ash and dust particles are separated in cyclone type separators. Finally the air is allowed to pass through a filter and vented to the atmosphere by an exhauster fan. (Fig. 18.5)

The ash collected in the ash separators is trucked away for disposal.

Q. *What quality of ash can be handled by this method?*

Ans. Abrasive ash as well as finely divided ash and soot.

Q. *Air from the final filter bed is discharged into the atmosphere by an exhauster. What kind of exhauster is chosen for this purpose?*

Ans. **Mechanical exhauster** where a large tonnage of material is to be handled.

Steamjet exhauster for small and medium size plants.

Waterjet exhauster where a large quantity of water is abundantly available economically.

Q. *What is the ash carrying capacity of a waterjet exhauster?*

Ans. 5 to 30 t/h.

Q. *What are the advantages of a pneumatic ash handling system?*

Ans. 1. Dust free operation is possible as all flyash and dust is eliminated
2. No spillage problem or rehandling trouble
3. Dry handling of ash eliminates the chances of ash freezing, picking or sticking in the storage bin
4. Flexibility in application to suit various plant conditions
5. Installation cost per ton of ash handled is less in comparison to other systems.

Q. *What are the disadvantages of a pneumatic ash hardling system?*

Ans. 1. Wearing of the crusher as well as the pipeline by the abrasive ash inflicts high maintenance charge
2. Noisy operation.

Q. *How does a steamjet system function?*

Ans. In this case high velocity steam instead of air is passed through a pipe to carry off dust and ash particles of considerable size. The ash is separated in the cyclone type separators and deposited in the ash hopper.

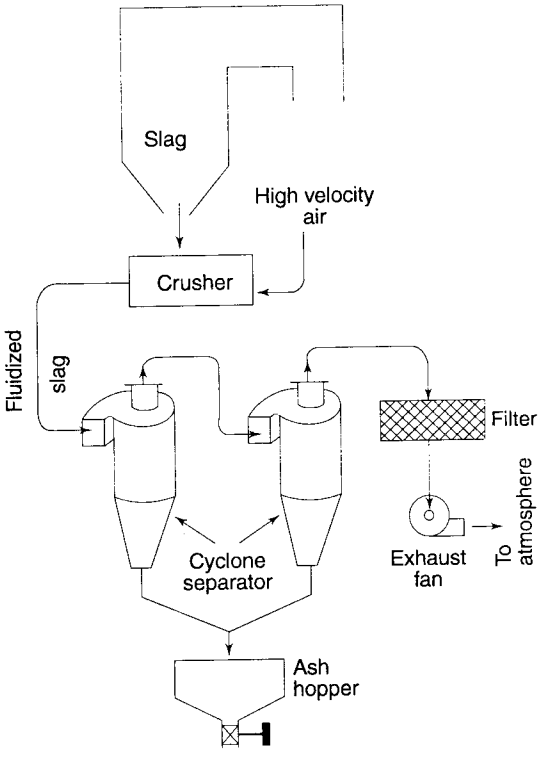


Fig. 18.5 *Pneumatic ash handling system.*

Q. *What are the advantages of a steamjet system?*

Ans. 1. Requires less floorspace
2. Can be installed in an inaccessible/awkward position also

3. The self-generated steam can be directed to operate this system. Hence no auxiliary drive is required.
4. The system is economical for ash disposal through a horizontal distance of 200 m and vertical distance of 30 m
5. Low installation cost.

Q. *What disadvantages is the steamjet system fraught with?*

Ans. 1. Erosion of pipelines due to abrasive ash
2. Capacity of ash handling is limited to 15 t/h
3. Noisy operation.

Q. *What is the basis that determines the utilities of ash?*

Ans. Many beneficial uses of ash have been identified according to their characteristics. The ash characteristics determine how the material will react with the environment and how it will be utilized. Both the chemical and physical characteristics of ash determine its potential for utilization.

Q. *What are the potential applications of ash?*

Ans. The applications with high potential are
1. structural fill
2. stabilized road base
3. soil stabilization
4. SO_2 scrubber and industrial sludge stabilization
5. agricultural use
6. brick production. (Fig. 18.6)

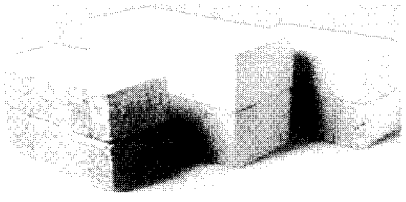


Fig. 18.6 *Bricks formed by flyash & bottom ash await sintering in a commercial autoclave.*

Source: *POWER (March/April 2000)*
Courtesy: *The POWER Magazine, The McGraw-Hill Co., NY 10020, USA*

The applications with moderate potential are
1. cement production
2. concrete block production
3. sewage sludge stabilization
4. mineral filler
5. synthetic aggregate
6. ceramic products
7. mineral wool
8. grout/mine backfill.

Q. *What are those chemical characteristics of ash that determine its utilization?*

Ans. 1. Element composition
2. Carbonate content
3. Alkalinity.

Q. *What are the physical properties of ash that determine its utilization?*

Ans. 1. Moisture content
2. Bulk density
3. True density.
4. Loss on ignition (LOI)

Q. *The chemical composition of CFB (circulating fluidized bed) residues are different from conventional coal ash. Why?*

Ans. This is because of the lower operating temperature used and the addition of sorbent (limestone) for SO_2 emission control.

Q. *What are the characteristics of CFB residues?*

Ans. CFB residues are high in calcium and sulphate content, but have relatively low concentrations of alumina, iron oxide and silica.

Typically, CFB residues are not pozzolanic glassy particulates like the residues found in conventional Class F and Class C flyashes (ASTM Method C618).

Q. *The characteristics of CFB as generated is very different as is evident from Table 18.1 and 18.2. Why?*

Ans. This is because the ash characteristics are not only affected by the feed of fuel, sorbent, and other additives but also the operating conditions.

Q. *What do the above two tables (Tables 18.1 and 18.2) suggest if you make a comparative study of ash of gob-fired plants and coal-fired plants?*

Ans. Pyroflow ashes from gob-fired plants are composed of a relatively high concentration of alumina, iron oxide and silica, but are low in cal-

Table 18.1 *Characteristics of Pyroflow Fly Ashes From Different Fuels*

	Coal	Gob	Mixed Fuel*
Chemical Composition (As Received):			
Carbon, %	2.1–9.2	2.3–5.0	6.60–9.30
Carbonate %	1.3–3.0	1.3–1.6	N/A
Unburned Carbon, %	3.8–9.0	2.0–4.6	N/A
Ash Minerals–			
Na_2O, %	0.2–1.3	0.2–0.3	0.3–0.3
K_2O, %	0.5–1.1	1.9–2.1	0.5–1.1
MgO, %	0.6–5.0	1.1–1.3	0.8–4.0
CaO, %	24.2–35.7	15.1–17.2	28.5–34.2
Fe_2O_3, %	5.4–15.5	7.2–7.6	5.1–6.0
Al_2O_3, %	5.5–8.4	16.2–17.0	6.8–11.1
SiO_2, %	18.5–39.5	41.9–43.2	15.1–27.1
P_2O_5, %	<0.1–0.2	<0.1–0.2	0.2–0.3
TiO_2, %	0.3–0.5	0.9–1.0	0.7–0.7
SO_3, %	8.0–17.5	6.5–9.4	12.2–13.5
Alkalinity as $Ca(OH)_2$, %	20.5–36.2	11.7–17.5	27.8–47.2
Physical Properties (As Received):			
Moisture, %	0.0–0.5	0.3–0.4	0.6–0.8
LOI, %	8.3–13.5	5.8–8.6	13.2–19.4
Bulk Density, g/cm^3	1.0–1.6	0.9–1.0	1.1–1.1
True Density, g/cm^3	2.7–2.8	2.5–2.6	2.6–2.6

* The mix of 40-60 % (weight %) of coal with wood chips.

Source: Beneficial Uses of CFB Ash—L J Young and J L Cotton (Technical Paper PTP-101, AHLSTROM)

cium oxide. The ash content of gob is 42-62%, which is much higher than coal. Therefore, more gob ash is left leading to a higher concentration of alumina, iron oxide and silica in the total ash.

Q. *The above two tables reveal that CFB flyash contains higher contents of carbonate, carbon, unburned carbon, and free lime than bottom ash. Why?*

Ans. This is the outcome of a short residence time in the boiler due to the small particle size of flyash.

Q. *Which is the most distinctive feature of CFB ash that has led to its many beneficial uses?*

Ans. The most distinctive feature of CFB ash is the high concentration of free lime derived from the incomplete utilization of limestone. Many beneficial uses of CFB residues stem from this feature.

Q. *How is the agricultural utilization of CFB ash realized?*

Ans. For many years, lime/limestone has been used by farmers for

1. neutralizing soil acidity to near optimum conditions for the crops or plants to grow
2. providing a direct source of plant nutrients to support plant life
3. increasing the supply of other nutrients to stimulate microbiological activities in the soil.
4. improving soil lith.

Studies have demonstrated that the high free-lime content makes FBC residues an effective agricultural limestone substitute.

Table 18.2 *Characteristics of Pyroflow Bottom Ash From Different Fuels*

	Coal	Gob	Mixed Fuel*
Chemical Composition (As Received):			
Carbon, %	0.3–4.5	0.5–0.7	0.9–1.2
Carbonate, %	0.2–2.2	0.2–0.4	N/A
Unburned Carbon, %	0.2–4.1	0.5–0.7	N/A
Ash Minerals:			
Na_2O, %	0.1–0.8	0.3–0.3	0.1–0.2
K_2O, %	0.2–2.8	2.1–2.1	0.7–0.9
MgO, %	0.7–1.5	0.8–1.2	0.8–5.1
CaO, %	11.8–53.0	7.4–15.4	38.3–38.4
Fe_2O_3, %	1.7–2.8	3.0–3.3	1.9–2.9
Al_2O_3, %	1.4–13.6	17.8–21.9	5.9–6.1
SiO_2, %	6.3–79.7	49.0–58.4	18.9–18.9
P_2O_5, %	<0.1–0.3	0.1–0.2	0.2–0.2
TiO_2, %	0.1–0.7	0.9–1.4	0.3–0.4
SO_3, %	3.5–35.8	5.7–8.9	21.7–27.8
Alkalinity as $Ca(OH)_2$, %	13.2–27.2	5.2–13.6	24.4–36.0
Physical Properties (As Received):			
Moisture, %	0.0–0.4	0.2–0.5	0.2–0.2
LOI, %	1.6–7.8	2.2–2.6	5.2–6.3
Bulk Density, g/cm^3	1.3–1.8	1.4–1.4	1.7–1.7
True Density, g/cm^3	2.5–2.9	2.5–2.6	2.6–2.6

* The mix of 40-60 %(weight %) of coal with wood chips.

Source: Beneficial Uses of CFB Ash—L J Young and J L Cotton (*Technical Paper PTP-101, AHLSTROM*)

CFB ash generated from coal feed or mixed fuel which contains a higher freelime content are better candidates for agricultural applications than the ash collected from gob-fired boilers. CFB ashes are successfully sold to farmers for agricultural liming.

Q. *How does CFB ash act as an acidic waste stabilizer?*

Ans. The free lime in CFB residues can be used to neutralize acidic wastes from a variety of processing operations. The alkalinity of CFB ashes (see Table 18.1 and 18.2) indicate the potential neutralization capacity of the residues. Although the lime content in the ash determines the amount of ash needed to neutralize waste, it is not as critical as when it is used for agricultural liming, which has to compete with natural lime and limestone in the market. Regardless of what type of fuel—coal, gob or mixed fuel—is being fed into CFB, the ash generated contains sufficient alkalinity to neutralize acidic waste.

Q. *How can CFB ash act as a sludge stabilizer?*

Ans. The free lime in the ash also serves as a good sludge stabilizer. The exothermic reaction of free lime and water, and the high alkali characteristics of ash, offer an ideal mechanism to pasteurize and stabilize the sludge. Blending sludge with CFB ashes forms a solid and stable material which can also make handling sludge easier. This is particularly useful where sludge waste is difficult to handle and dispose.

Q. *Is there any specific example of how CFB ash acts as a sludge stabilizer?*

Ans. N-Viro Energy System, Ltd., has been marketing a soil-like material called V-Viro Soil, which is a mixture of alkaline admixture and

sludge. Initially, they used kiln dust as the alkaline admixture, but now they commonly use fluidized-bed ash to pasteurize and stabilize municipal wastewater sludge.

Q. *Why do they prefer FBC ash?*

Ans. They have found that using FBC ash appears to control odour better than other alkaline admixtures.

Q. *Why is this possible?*

Ans. The fineness and high carbon content found in FBC ash increases absorption.

Q. *What is the prospect of CFB ash as a structural fill?*

Ans. CFB residues offer several advantages over common earth borrow materials because of its low unit weight and moderate cementitious property of the material. The free lime, silica, alumina, iron oxide, and calcium sulphate contents in the residue beget self-hardening property. The reactivity is generally enhanced by the silica, alumina, and iron oxide components when the residue is utilized as a fill material. Thus the CFB ash from gob-fired boilers has better prospects as a structural fill than ash from coal or mixed fuel-fired plants.

Q. *How is ash rock produced?*

Ans. Ash rock is produced by blending a mixture of bottom ash and flyash, conditioning the mixture with water, compacting it to at least 90% relative compaction, and curing for a minimum of 7 days.

Q. *What is the utility of ash rock?*

Ans. Ash rock (cemented ash) is crushed and screened to remove any oversize material. The resulting product is a sandy gravel aggregate minus 25 mm in size that can be used as an aggregate for road surfacing and base material.

Q. *Flyash is essentially a mixed oxides of alkali and alkaline earth metals. Is there any prospect of using it as mineral filler, in place of standard inert pigments, in paints?*

Ans. The VALSPAR CORPN. (now a part of Ameron Co., Brea, California, USA) has developed a tower coating using flyash as the mineral filler. This flyash tower coating, it has been claimed, is equivalent to standard filler.

To date, flyash is primarily being used in high-building coatings, such as transmission tower coatings, epoxy floor coatings, high-build urethans (gloss & low sheen) and block fillers. Besides, these heavy-duty, high-build tower coatings are also extensively used on power substation steel & more frequently on steelpoles instead of multicoat.

Q. *How well does the flyash coating work?*

Ans. 1. A single coat applied by brush/roller application to a minimum dry-film thickness of 6 mils can be expected to give service life by 15y or more
2. *Improve abrasion resistance.* Flyash consists of small glass-like ceramic particles that are very resistant to abrasion
3. *Resistant to salt attack.* Performance is slightly better than the same product with conventional mineral fillers (ASTM B 117 at 1000h)
4. *Resistant to exposure.* Unaffected by exposure. Equal to same product with conventional mineral fillers (ASTM D1014, 3500h)

Q. *What are the advantages of using flyash as coating material?*

Ans. 1. Lower material cost
2. Lighter paint
3. As flyash with a smaller particle size becomes available, it may be used in many other coatings as well.

19

CARRYOVER, SCALE AND SLUDGE

Q. *What are the principal impurities in leakages in condensers?*

Ans. **Chlorides/Sulphates/Bicarbonates** of calcium, magnesium and sodium.

Colloidal impurities of organic matter, silicic acid

Suspended matter.

Gases (O_2, CO_2, N_2)

Q. *What are the chief impurities in DM water?*

Ans. 1. Sodium compounds
2. Products of metal corrosion
3. Gases like O_2

Q. *Why are these impurities, even in trace amounts, unwanted in BFW?*

Ans. They can precipitate, under favourable conditions, from water and form deposits on the heating surfaces, thus impairing heat transfer and causing high temperature rise of tube walls.

Q. *How is that soluble impurities in water are carried off into steam?*

Ans. Explosion of water bubbles in the steam drum disperses fine droplets of water into steam over the water level and these entrained water particles contribute their dissolved impurities to steam.

Q. *Where will these steam-borne impurities deposit?*

Ans. In the superheaters and steam path of turbines.

Q. *Why are deposits in superheaters intolerable?*

Ans. The outlet portion of superheater coils, even at the rated heating loads, operate at the upper admissible temperature limit of the tube metal. Even a slight layer of deposits can, therefore, raise the metal temperature to an inadmissible level and promote creep phenomena and scale formation.

Q. *Why are deposits in the steam path of a turbine extremely undesirable?*

Ans. They increase the roughness of the blades and friction losses and therefore turbine efficiency is reduced. Heavy deposits in the steam path of turbine can cause additional axial pressure requiring a decrease in the turbine power.

Q. *What are the slightly soluble impurities that may be present in boiler water?*

Ans. 1. Calcium and magnesium salts
2. Oxides and Hydroxides of structural materials (Fe, Ni, Cu, Zn and Al) with which the aqueous heat transfer agent may come into contact.

Q. *What are those in readily soluble groups?*

Ans. Sodium salts (Na_3PO_4, Na_2SO_4) and sodium hydroxide.

Q. *What are the principal scale formers in water?*

Ans. $CaSO_4$, $CaCO_3$ and $Mg(OH)_2$

Q. *What is scale?*

Ans. It is the general name ascribed to sufficiently dense deposits appearing on heating or cooling surfaces and capable of reducing the normal heat transfer in a boiler unit or heat exchanger.

Q. *How do scales form?*

Ans. Those dissolved impurities in water which have the lowest solubility product under particular conditions crystallize first. Some of them crystallize on the heating surfaces and form scales. Surface roughness on solid heating surfaces can serve as centres of scale formation.

Q. *What is sludge?*

Ans. These are loose, friable deposits resulting from the settling, accumulation and thickening of suspended substances in the bulk of the solution.

Slimy accumulations in boiler drums, waterwall headers and various tanks are referred to as sludge.

Q. *How does sludge form?*

Ans. Those dissolved substances in water which crystallize in the bulk of the solution form sludge. Disperse and colloidal particles and gas bubbles suspended in water serve as centres of sludge formation.

Q. *How many types of scales are there?*

Ans. There are four types of scales.

1. **Alkali-earth scales:** $CaCO_3$, $CaSO_4$, $CaSiO_3$, $Ca_3(PO_4)_2$, MgO, $Mg(OH)_2$, $Mg_3(PO_4)_2$
2. **Iron-oxide scales:** $FeSiO_3$, $Fe_3(PO_4)_2$, $NaFePO_4$ (sodium ferrophosphates), Fe_2O_3, Fe_3O_4
3. **Copper scales:** CuO, Cu_2O
4. **Silicate scales:** various compositions

Q. *What is the immediate effect of scale formation?*

Ans. It results in the increased temperature of the tube walls exposed to flue gas.

$$\Theta_{wall} = \Theta_{H_2O} + \frac{\Delta x_{scale}}{k_{scale}} Q + \frac{Q}{h_2}$$

where, Θ_{wall} = wall temperature (°C or K)

Θ_{H_2O} = temperature of water (°C or K)

Δx_{scale} = thickness of scale (m)

k_{scale} = thermal conductivity of scale (W/m K)

Q = rate of heat flow (W/m^2)

h_2 = coefficient of heat transfer from the tube wall to water (W/m^2 K)

Q. *How will you calculate the extent of scale formation over a length of time?*

Ans. It can be determined by the formula

$M = C_{fw}\, EG_{fw}\, t/10^3$, gram

where C_{fw} = concentration of scale and sludge-forming substances in feed water (mg-equiv./kg.)

E = equivalent weight of scale

G_{fw} = flow rate of feed water (t/h)

t = time in hours

Q. *When will scales form?*

Ans. If the product of the concentrations of anions and cations exceed the solubility product of the scale former

$$[M^{n+}\,[A^{n-}] = \text{S.P.}_{scale}$$

where $[M^{n+}]$ and $[A^{n-}]$ represent the concentrations of the cations and anions of the scale forming compound MA which ionizes as

$$MA \rightleftharpoons M^{n+} + A^{n-}$$

and its equilibrium constant being

$$K_{eq} = \frac{[M^{n+}][A^{n-}]}{[MA]} = [M^{n+}]\,[A^{n-}]$$

cf. [MA] = 1

Q. *What is the rate of scale formation of the alkali-earth group?*

Ans. It is

$$M = 1.3(10^{-13})\ CQ^2,\ \text{mg/[(cm}^2\text{) (}h\text{)]}$$

where C = concentration of scale forming substances (mg/kg of water)

Q = rate of heat flow, (W/m^2)

Q. *Is there any other factor responsible for the formation of scales of sparingly soluble substances?*

Ans. Yes. It is the increase in concentration of the substances in the boiler water due to the evaporation effect. The degree of concentration by evaporation is determined by the formula

$$C_{ev} = \frac{C_{bw}}{C_{fw}}$$

where, C_{bw} = concentration of some compounds in boiler water

C_{fw} = concentration of some compounds in feedwater

Q. *Does it vary? If so, by how much?*

Ans. Yes, it varies from spot to spot in the boiler drum as evaporation differs at different spots.

It varies from 10 to 200 and above.

Q. *Can such spots occur in boiler tubes?*

Ans. Yes. They originate at points where the tube is subjected to a high thermal stress or high rate of heat flow.

Q. *Is there any other factor contributing to scale formation?*

Ans. Substances showing negative temperature-gradient of solubility also contribute to scale formation with rising temperature which brings about the drop in the solubility of these salts.

Q. *Where is iron-oxide scale formation more prominent?*

Ans. Zones of tubes subject to high rates of heat flow, i.e. in the zone where the burners are fitted, above and below the ignition belt, at the spots where the burner-flame strikes onto the heating surfaces.

Q. *Where are the iron-oxide scales encountered more—high duty or low duty boiler units?*

Ans. High duty boiler units.

Q. *What is the pattern of deposition?*

Ans. They concentrate mainly on the half of the perimeter of a tube facing the boiler furnace.

Q. *What are the basic components of iron-oxide deposition?*

Ans. Iron oxides or iron phosphates (depending on the scale forming conditions).

Q. *How does iron get into the feedwater?*

Ans. As a result of corrosion of structural materials in the water condensate circuit.

Q. *What is the rate of formation of iron-oxide depositions?*

Ans. It is $\dot{M} = 5.7\ (10^{-14})\ [C_{Fe}]_{bw}\ Q^2$ mg/[(cm^2) (h)]

Where, $[C_{Fe}]_{bw}$ = concentration of iron in boiler water, mg/kg of water.

Q = the rate of heat flow, W/m^2

Q. *When do iron-phosphate depositions occur?*

Ans. It will occur under the conditions when

(a) concentration of phosphates PO_4^{3-} in the boiler water is sufficiently high (> 80 mg/kg)

(b) boiler water has low pH values.

Q. *What is the effect of iron-phosphate scaling?*

Ans. It leads to honeycomb corrosion of the metal of the tubes.

Q. *Is the iron-oxide scale uniform throughout?*

Ans. Obviously not. It has two layers:

1. **Internal Layer**—dense and firmly bonded to the metal surface
2. **External Layer**—loose and porous; feebly bonded to the surface of the internal layer.

Q. *How does the internal layer of a ferric oxide scale form?*

Ans. Oxidation of metal at the surface forms the dense and rigid oxide film which is the internal layer of the iron-oxide scale.

Q. *Does it exercise any harmful effect?*

Ans. No. The rigid film of ferric oxide protects the metal underneath from further corrosion.

Q. *How does the external layer form?*

Ans. It forms mainly from the coagulation of the colloidal and disperse particles.

Q. *Does it exercise any harmful effect?*

Ans. Yes. Because of its low thermal conductivity, it impairs heat removal from the metal surface.

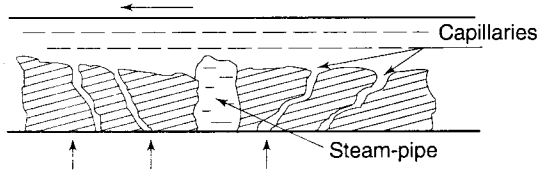


Fig. 19.1

Moreover, it gives rise to the 'wick effect': Water is sucked through numerous capillary pores in the layer and forms steam as it comes in contact with the heating surface. The steam ejects through a wide channel (known as 'steam-pipe'): (Fig. 19.1). This local circulation concentrates impurities (including corrosion-active impurities like alkalis and chlorides) at the metal surface and enhances corrosion.

Q. *If the capillary pores get clogged, will the heat transfer rate improve?*

Ans. If the capillaries get clogged due to deposition of other impurities present in water, the heat transfer may be sharply impaired.

Q. *What is the effect of pH on the rate of deposition of the iron-oxide external layer?*

Ans. At subcritical pressures and oxygen concentration of the order 0.4 mg/kg, the rate of deposition is as depicted in the curve. (Fig. 19.2).

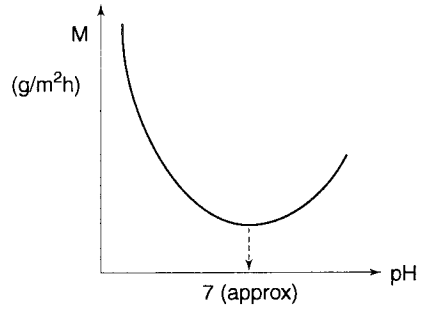


Fig. 19.2

It drops sharply from low pH values, reaches a minimum at pH value approximately 7 and then increases again with the increase of pH.

Q. *Where are the copper scales most likely to be formed?*

Ans. Sections subjected to a high rate of heat flow ($Q \geq 200$ kW/m^2) and mostly on the part of the tube circumference facing the furnace.

Q. *What is the main factor responsible for the formation of copper deposits?*

Ans. It is due to the introduction of copper compounds into boiler units with BFW.

Q. *How does it occur in the deposits?*

Ans. Copper is present in both the metallic state and in the form of oxides.

Q. *Is the copper uniformly deposited over the deposition layer?*

Ans. No. The copper content diminishes in the direction from the surface layer toward the tube wall (from 70–90% to 10–15%).

Q. *Why may all the non-volatiles infiltrated into a once-through boiler unit with feedwater remain in the unit as depositions or get entrained by steam into the turbine?*

Ans. It is because the once-through boiler units are operated without blowdown.

Q. *Why does higher steam pressure increase the blade deposits of the turbine?*

Ans. It is due to the solvent action of steam. Higher the steam pressure, higher is the solvent action, which increases the fraction of substances entrained by generated steam and taken away from a boiler.

Q. *Why are the depositions of scale forming compounds of calcium, magnesium and iron-oxides maximum in the region of quasiphase transition?*

Ans. The region of quasiphase transition characterizes itself as the region of maximum heat capacity. Here a substantial reduction in the solubility of many substances (CuO, SiO_3^{2-}, $Mg(OH)_2$, $CaSO_4$ and others) is observed with the growth of enthalpy. (Fig. 19.3)

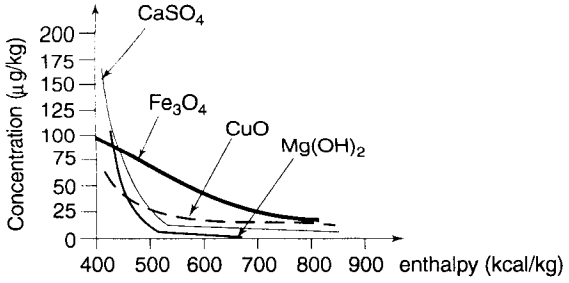


Fig. 19.3

Note: Enthalpy of a substance increases with the increase of its heat capacity.

Q. *What determines the solubility of impurities in superheated steam of subcritical pressure?*

Ans. The properties of superheated steam as well as those of the impurities with which the steam is in contact determine the solubility of impurities in the superheated steam at subcritical pressure.

Q. *Upon which process parameters, are the properties of both superheated steam and impurities dependent?*

Ans. Temperature and pressure.

Q. *How does temperature affect the properties of impurities?*

Ans. It is the temperature upon which the intermolecular forces of attraction and bond strength between the ions of a solid impurity depend substantially. As the temperature is raised the bonds get weakened allowing the solid phase to pass over the steam.

Q. *How does pressure affect the properties of impurities?*

Ans. Though a great pressure can weaken the bond strength between the ions of a solid impurity, in the existing range of operating pressure of boilers it exerts little effect on the behaviour of the solid phase.

Q. *How can temperature influence the capacity of superheated steam to dissolve solid impurities?*

Ans. The pressure remaining constant, the degree of superheat of the steam increases with the rise in temperature and at the same time the density of steam decreases, with the effect that a sharp decline in the dielectric permittivity of water and polarity of water molecules is observed. As a result, the dissolving capacity of superheated steam first decreases due to increase in temperature. However, with a further increase of temperature, at constant pressure, the crystalline bonds in the solid impurities get impaired resulting in the increased solubility of those substances in the superheated steam. (Fig. 19.4)

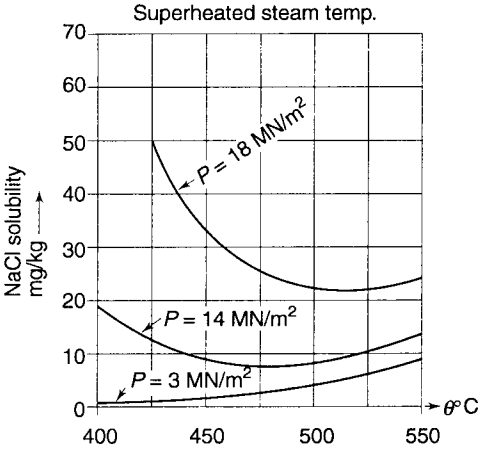


Fig. 19.4 *Solubility of NaCl in superheated steam at subcritical pressures.*

Q. *How does pressure exert its influence on the dissolving capacity of superheated steam?*

Ans. It exercises a strong influence on the dissolving power of steam. With the increase of pressure, the density of superheated steam increases and consequently the steam gains a higher dissolving power.

Q. *If the concentration of an impurity in steam is lower than its isobaric (constant pressure) solubility, what will happen?*

Ans. Steam will simply dissolve it and carry it off. It will deposit them wherever it suffers an enthalpy drop, i.e. on the turbine blades.

Q. *If, on the other hand, the concentration of an impurity in steam is greater than its isobaric solubility, what will happen?*

Ans. The exces of solid impurity will get deposited in the superheater path while the leftover will deposit on the turbine blades.

Q. *How do the solid impurities pass from water to saturated steam?*

Ans. By two ways:

1. they become steam-borne as the droplets of boiler water contaminate the steam
2. they pass into steam as the latter dissolve them and carry them off.

Q. *How does droplet carryover take place.*

Ans. It results from two processes:

1. breaking of water into fine droplets
2. destruction of steam bubbles

If the steam-water mixture is introduced into the boiler drum above the water level of the drum, the high speed jets of the mixture strike all kinds of baffles and partition plates placed on their path to quench their kinetic energy. After collision with these metal plates and baffles, the water content of the jets breaks into droplets of varying size. The higher the kinetic energy of the steam-water jet entering the drum, finer are the droplets generated. Fine droplets are easily carried off by steam. Along with these droplets the solid impurities pass into the steam.

If the steam-water mixture is introduced into the boiler drum below the level of the boiler water, steam bubbles are formed. These bubbles rise to the disengagement surface, i.e. the water surface of the drum and break through the water film and form droplets. Projected in all directions, the droplets may reach demister (steam separating device) and get entrained by steam thereafter.

Q. *What factor leads to more intensive carryover?*

Ans. It is the high heating load.

Higher the heating loads, higher will be the velocity of exit of steam-water jets into the drum and higher will be their kinetic energy. Higher the kinetic energy of the steam-water jets, greater will be their power of atomization of water mass into finer droplets upon impact with the baffles. As a result a more intensive water carryover takes place.

Q. *Where is the concentration of water droplets highest?*

Ans. Just at the disengagement surface.

Q. *What kind of water droplets will be entrained by steam if its rising velocity is low?*

Ans. The finest water droplets.

Q. *Why does the water content of steam output turn out to be higher at higher heating loads?*

Ans. With the increase of heating loads, the flowrate of steam will increase and that will entrain larger and larger water droplets resulting in higher water content of output steam.

Q. *What is the relationship between the water content of steam and the heating load?*

Ans. It is given by

$$W = AD^x$$

where, W = water content of steam

D = heating load

A and X are functionally dependent on the pressure, concentration, ionic composition of

impurities in water and the design of the drum. (Fig. 19.5)

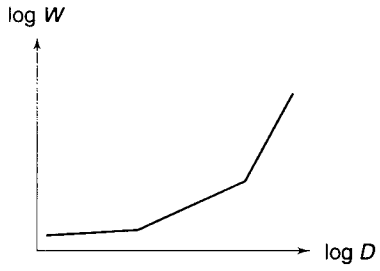


Fig. 19.5 *Effect of heating load on the water content of steam.*

Q. *What is the rate of evaporation per m^2 of water surface?*

Ans. It is the average flowrate of steam related per unit square metre of the disengagement surface.

$$R_F = \frac{D}{F}$$

Where F = area of disengagement surface, m^2

Q. *What is called the rate of evaporation per m^3 of steam space?*

Ans. It is the average velocity of steam related to one cubic metre of steam space

$$R_V = \frac{D}{V}$$

Q. *If at constant rate of evaporation per m^2 of disengagement surface the height of steam space is altered, will it affect the water content of steam?*

Ans. Yes. If the steam-space height is reduced, larger droplets may reach the region of high steam velocities at the inlet to the steam circulating tubes and therefore, the steam will contain more moisture.

If on the other hand, the height of the steam-space is increased, the larger droplets may not have sufficient kinetic energy to reach the steam circulating tubes, with the effect that the water content of the output steam will be considerably lower.

Q. *What is the soaring velocity of water droplets in the steam drum?*

Ans. It is the relative velocity of a water droplet at which its weight is counterpoised by the force of resistance (↑) offered by the up-flowing steam

$$V_{so} = 1.155 \sqrt{\left(\frac{d}{\varepsilon}\right)\left[\frac{\rho_w}{\rho_s} - 1\right]}$$

where V_{so} = soaring velocity of a water droplet

d = droplet dia

ε = coefficient of resistance

ρ_w = density of water droplet

ρ_s = density of steam

Q. *An increase in pressure will always result in higher water content of steam. Why?*

Ans. With the increase in pressure, the surface tension of water decreases with the effect that the size of the water droplets gets reduced, i.e. more and more fine droplets are produced. These finer water droplets easily become steam-borne increasing the water content of steam.

Q. *But increase in pressure will increase the density of steam and so it will offer greater resistance to rising droplets. Is it not?*

Ans. Yes, of course. But comparatively, pressure has a stronger effect on the transporting ability of steam than on its resistance.

Q. *What is the effect of the salt content of BFW on the water content of steam?*

Ans. This results in a water swell in the steam drum. A large number of water droplets with high concentration of impurity are ejected and that critically impairs the steam quality.

Q. *What is the critical concentration of a substance in BFW (Boiler Feed Water)?*

Ans. It is the concentration of the substance at which the water level suddenly swells up and increases the entrainment of moisture in steam (Fig. 19.6).

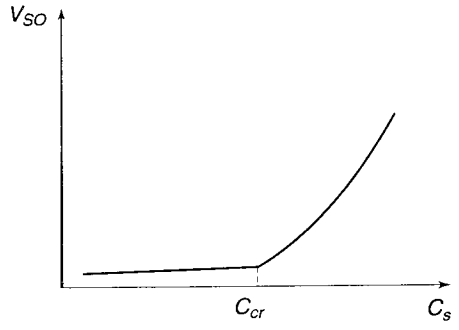


Fig. 19.6

Q. *What determines the quality of steam?*

Ans. It is determined by the quantity of various substances—both volatile and non-volatile, collectively called impurities—present in it.

Q. *What is distribution coefficient?*

Ans. The ratio between the quantities of substances distributed in steam and BFW is known as distribution coefficient

$$[K_d]_{\text{total}} = \frac{C_s}{C_{\text{bfw}}}$$

where C_s and C_{bfw} represent the concentration of salt in steam and boiler feewater respectively.

Q. *What is carryover in terms of distribution coefficient?*

Ans. It is $C_s = C_{\text{bfw}}\,[K_d]_{\text{total}}$

Q. *How many kinds of carryover are there?*

Ans. Two kinds:

droplet carryover and selective carryover.

Q. *What is selective carryover?*

Ans. It is encountered when a substance (or a group of substances) transfers into the steam phase in quantities comparatively much larger than other substances.

Q. *What is the cause of selective carryover?*

Ans. It originates due to the fact that certain substances (impurities) contained in the boiler water exhibit markedly higher dissolving capacity in high pressure steam in comparison to other substances.

Q. *Can you cite an example?*

Ans. Silicic acid (H_2SiO_3) is a good example. Its solubility in steam increases rapidly with the rise of steam pressure from 7 MN/m^2.

20

STEAM CONTAMINATION AND ITS CONTROL

Q. *How can the quality of steam be described?*

Ans. It is frequently described in terms of the amounts of Na, SiO_2 and CO_2 dissolved in steam and expressed in mg/kg or microgram/kg.

Q. *Why does contamination occur?*

Ans. Various dissolved substances in the boiler water pass into steam which therefore gets contaminated.

Q. *How can this be expressed?*

Ans. This can be conveniently expressed in terms of the distribution coefficient as the distribution of substances between the liquid and the vapour phase takes place.

$$K_d^{\text{total}} = \frac{C_s}{C_{bw}}$$

where K_d^{total} = total distribution coefficient

C_s = concentration of total quantity of any substance (or the sum of substances) in steam, mg/kg

C_{bw} = concentration of total quantity of any substance (or the sum of substances) in boiler water, mg/kg

Q. *How can the true and apparent distribution coefficients be distinguished?*

Ans. The true distribution coefficient (K_t^d) refers to the distribution of a given substance of certain form whereas apparent distribution coefficient (K_a^d) characterizes the distribution of a given substance in all forms.

Q. *How is K_t^d expressed?*

Ans. It is expressed as $K_t^d = \frac{C_s}{C_{bw}} \left[\frac{\rho_s}{\rho_{bw}} \right]^n$

ρ_s and ρ_{bw} are the densities of steam and boiler water respectively, kg/m^3.

n = co-ordination number of characterizing the nature of substances.

Q. *Does the value of K_t^d vary with temperature and pressure?*

Ans. Yes. The value of K_t^d increases with temperature and pressure, particularly for those substances which have a large value of n

These substances are

CaO	$n = 5.5$	NaOH	$n = 4.1$
MgO	$n = 3.1$	NaCl	$n = 1.9$
SiO_2	$n = 1.9$		

Q. *How does the increase of working pressure of the boiler affect the steam quality in once-through boilers?*

Ans. In once-through boilers, the load of dissolved substances carried by the boiler water is partly deposited on the heating surfaces and the rest escapes with the steam as working fluid gets continuously evaporated. As the pressure is increased, the concentration of impurities in steam increases and so the steam quality increasingly

deteriorates until it approaches that of feedwater. (Fig. 20.1)

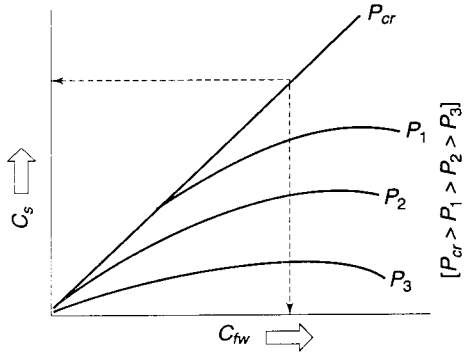


Fig. 20.1

Q. *What factors affect the quality of steam generated in natural circulation boiler units?*

Ans. The quality of saturated steam is affected by

(a) the design features of a boiler unit
(b) the operating conditions for drum-type boiler units
(c) the quality of boiler feedwater.

Q. *What do you mean by "design features of a boiler unit" so far as steam contamination is concerned?*

Ans. It means

1. height and volume of steam space in the boiler drum
2. the mode of introducing steam-water mixture into the drum
3. the method of steam extraction from the drum
4. efficiency of the drum internals, etc.

Q. *How does steam contamination arise from the standpoint of volume of steam space in boiler drum?*

Ans. This arises from the fact that the steam space may be loaded non-uniformly giving rise to local high rate of evaporation in the steam space. This local overloading is produced by a non-uniform steam release from the drum or by concentrated introduction of the steam-water mixture in the drum. This may also arise due to improper design and layout of drum internals or their maloperation.

Q. *What is the rate of evaporation per unit steam space of the drum?*

Ans. It is given by

$$R_d = \frac{G_s\, v}{V_{ss}}\ (10^3),\ \text{m}^3/(\text{m}^3\text{h})$$

where G_s = steam generating capacity of the unit, $\frac{t}{h}$

v = specific volume of steam, m^3/kg

V_{ss} = steam space of the drum, m^3

Q. *What is the residence time of steam in the drum?*

Ans. It is the inverse of the average rate of evaporation per unit steam space. It is given by

$$\tau = \frac{1}{R_d}$$

Q. *How does steam contamination increase with the increase of the evaporation rate per unit steam space?*

Ans. As R_d increases, the residence time of steam in the drum steam space decreases and as a result the soaring velocity of steam in the steam space increases, contributing to a higher degree of steam contamination.

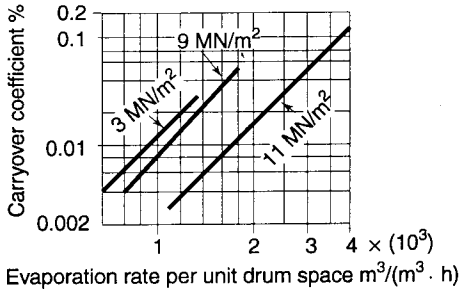


Fig. 20.2

This fact can be best understood from the accompanying figure (Fig. 20.2).

Q. *What factors primarily determine steam contamination when steam-water mixture is introduced below the water-level of the boiler drum?*

Ans. 1. Rate of evaporation per unit evaporating surface, R_s, $m^3/(m^2h)$
2. Height of the steam space, h_{ss} (Fig. 20.3)

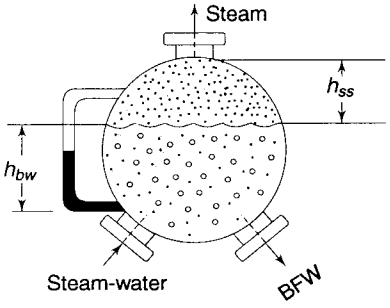


Fig. 20.3

Q. *How can the rate of evaporation per unit evaporating surface be expressed?*

Ans.

$$R_s = \frac{G_s v}{A} (10^3),\ m^3/(m^2.h)$$

where, A = evaporating surface area, m^2

Q. *How can steam contamination be reduced by altering the rate of evaporation per unit evaporating surface and the height of steam space?*

Ans. Steam contamination with BFW carrying impurities can be reduced by either decreasing R_s or increasing h_{ss}.

Q. *How does the velocity of steam bubbles moving through boiler water affect the height of steam space in cases of boiler units where steam-water mixture is introduced below the level of water in the drum?*

Ans. Steam bubbles moving through the height of boiler water h_{bw} (see above Figure 20.3) have a retention time equal to

$$\tau_s = \frac{h_{bw}}{v_s} \text{ where } v_s = \text{steam velocity}$$

So lower the steam velocity, greater is the retention time of the steam-bubbles inside the boiler water and therefore the water becomes more and more saturated with steam and gets converted into a steam-water mixture whose density is considerably lower than that of water. As a result, the volume of water enlarges, its level in the drum rises and the height of steam space decreases.

Note: This phenomenon is called swelling of boiler water. As the height of steam space decreases, the quality of steam decreases.

Q. *How does steam contamination vary with the height of steam space?*

Ans. Lower the height of steam space greater is the steam wetness. Moreover, for the same steam space height, steam wetness increases with increase in steam pressure. And for the same degree of wetness, it requires less space height for low pressure steam than for high pressure steam. These can be illustrated with the help of the adjacent Figure. (Fig. 20.4)

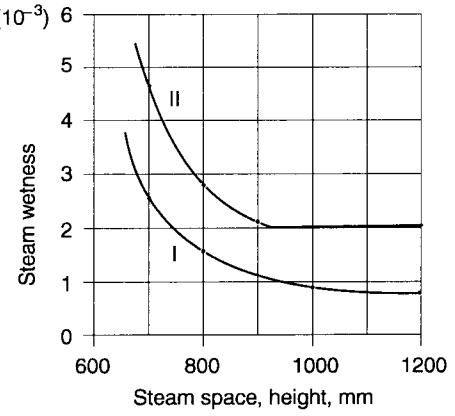


Fig. 20.4 *Steam contamination as a function of height of steam space.*

curve	P	R_S
I	11 MPa	100 $m^3/m^2.h$
II	18.5MPa	50$m^3/m^2.h$

Q. *Why is the concentrated feed of steam-water mixture below the water level in the boiler drum undesirable?*

Ans. It gives rise to high local rates of steam flow through the evaporating surface with the effect that steam contamination intensifies.

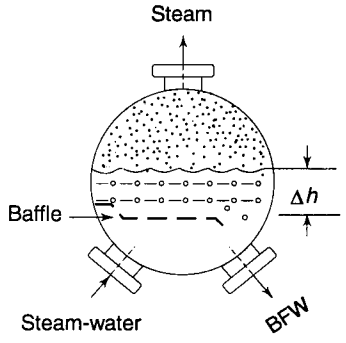


Fig. 20.5 *Baffle resists boiler water swelling, thereby reducing steam contamination.*

Q. *How can this be avoided?*

Ans. One good measure is to place a perforated plate (baffle plate) in the body of the boilerwater in the drum. It resists boilerwater swelling and therefore, the evaporating surface is loaded uniformly and contamination of steam is reduced. (Fig. 20.5)

Q. *How does the steam quality vary with the change of the operating parameters of the boiler drum?*

Ans. With the variation of steam demand, the operation of a boiler unit may undergo a change in the level of boiler water and steam pressure. And that results in variation in the quality of steam produced. As the load is increased steam contamination rises. Steam contamination up to point *A* is within admissible limits and beyond that it increases abruptly and becomes inadmissible. (Fig. 20.6).

Q. *What is the difference between steam quality and quality steam?*

Ans. 'Steam quality', generally means the percentage of gaseous water flowing through a pipe or a system. For example, if 95 kg gaseous water and 5 kg of liquid water pass through a pipe, then the steam quality is said to be 95%.

On the other hand, 'quality steam' means not only dry steam but also a clean steam free from non-condensable gases and entrained particles.

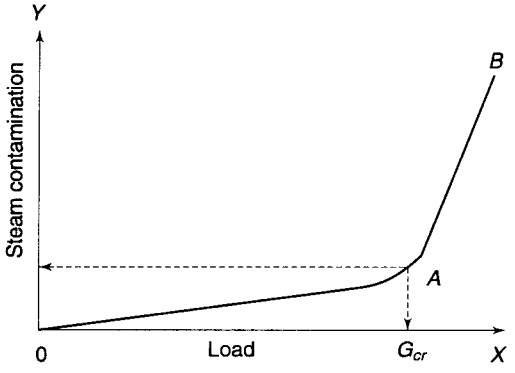


Fig. 20.6 *Steam contamination vs. Load graph.*

Q. *Why is greater emphasis laid now-a-days on the production of quality steam?*

Ans. 1. It ensures better heat transfer
2. Since the steam is clean, the flow controllers as well as pressure controllers enjoy longer working life
3. Quality steam is free from entrained particles. So it does not clog parts with the effect that effective pressure and temperature control is ensured.
4. Dirty steam causes valves to leak. But quality steam being free from entrained particles does not erode and corrode valve body parts. So the risks of leak development are minimized.
5. Since quality steam is free from non-condensable gases, its heat transfer characteristic is not impaired.

Q. *Why are non-condensable gases in steam undesirable?*

Ans. 1. Non-condensable gases reduce the steam's temperature and its partial pressure.

2. Accumulation of non-condensable gases (including air) in the steam header limits its steam flow
3. Non-condensable gases in steam reduce its heat transfer quality
4. They cause corrosion.

Q. *How does air make its way into steam?*

Ans. Air makes its entry to the steam system when the system is shutdown. It also enters through the vacuum breakers of temperature controlled processes.

Q. *How do the non-condensable gases accumulated in steam limit the heat transfer characteristic of steam?*

Ans. The non-condensable gases are forced to the heat transfer surface by the condensing flow of steam. They form a stagnant film on the surface (Fig. 20.7).

This film is a good insulator, for instance if air forms a film 0.25 mm thick, it will offer the same resistance as a water film 5 mm thick. That is, the accumulated mass of non-condensates in steam exercises a considerable resistance to the flow of heat from the steam.

If allowed to accumulate over a prolonged period, these non-condensable gases will occupy enough volume to enforce an effective blockade to the steam flow and all energy transfer will cease to operate.

Non-condensable gases reduce the partial pressure of steam. Higher the steam pressure, the higher are its temperature and energy content. So lowering of partial pressure of steam will mean reduced heat transfer from steam, as less heat is transferred at a lower temperature.

Q. *Apart from severely limiting the thermal energy transfer, what other adverse effect/effects may result from blocked condensate flow?*

Ans. It may result in dangerous water hammer.

Q. *How do the non-condensable gases in steam initiate corrosion?*

Ans. Non-condensable gases like CO_2 and O_2 find their way to the system of steam generation as dissolved carbonates/bicarbonates and dissolved oxygen respectively. These gases are liberated in the boiler and mix up with steam.

The carbon dioxide so released reacts with water (condensate) when the condensing steam is cooled and forms a weak carbonic acid.

$$CO_2 + H_2O \rightleftharpoons H_2CO_3 \rightleftharpoons H^+ + HCO_3^-$$

The liberated proton attacks iron in the steam pipe. The iron dissolves and forms a soluble bicarbonate. (Fig. 20.8).

As the protective coating of the metal is eaten away, corrosion proceeds further.

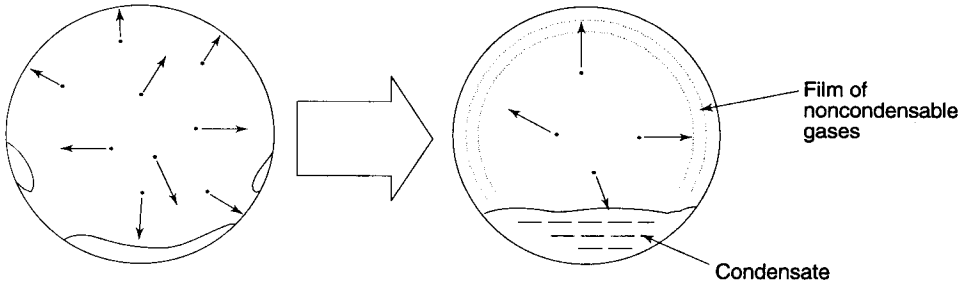


Fig. 20.7 *Non-condensable gases are forced to the surface of a heat-transfer pipe by the condensing steam. Here they form an insulating film.*

If oxygen is also present, then rust forms and carbon dioxide is released with the effect that more corrosion of the steam pipeline occurs. Until and unless these gases are removed (by venting), they will continue to corrode the metal surface. (Fig. 20.8)

Q. *It is certain that the presence of non-condensable gases lowers the partial pressure of steam. Does this reduced steam pressure have any effect other than lowering the rate of heat transfer from steam?*

Ans. With the decline in steam pressure, its enthalpy decreases. As the energy content of the steam decreases, it slows down the rate of heat transfer, pressing a demand for more steam flow. More steam means faster steam flowrate and that brings about further pressure drop, wasting more total energy. Not only this, higher steam demand causes faster steam velocity causing pipe erosion and noise in the piping.

Q. *How does liquid water come into the steam?*

Ans. The present day trend is to place large heat-transfer surfaces into compact equipment packages. As more steam comes from smaller units, it is very likely that water may get carried over with the steam.

Also, there is some heat loss due to radiation as steam flows through the distribution system. This may result in some condensation.

The treatment of BFW with chemicals may upset boiler operation and contribute to overflow (priming).

Q. *How can steam quality be measured?*

Ans. It can be determined by a throttling calorimeter. It is a direct process and gives the most

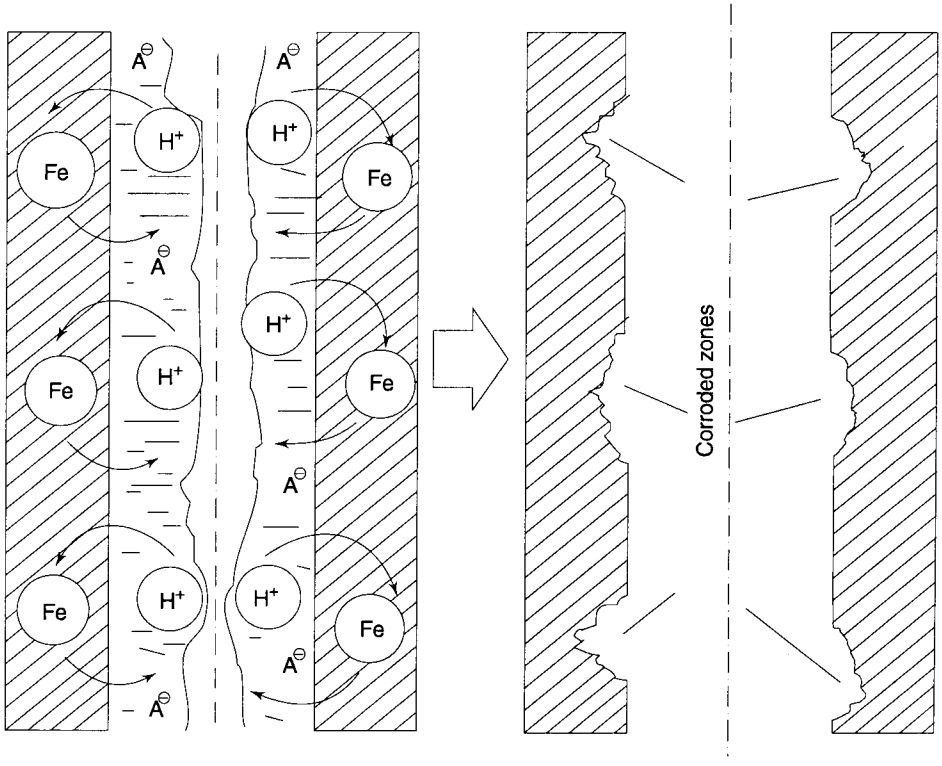


Fig. 20.8

accurate result with steam samples below 4 MPa, whose moisture content exceeds 0.5%.

Q. *What is its working principle?*

Ans. Insulated and installed in a steam header at sample source, the throttling calorimeter allows steam to expand through it and to the atmosphere. Since the steam expands without doing any work, its enthalpy (i.e. heat content) will remain unaltered. However, if the steam is dry, this pressure drop will naturally superheat the steam causing its temperature increase. If on the other hand, steam is wet, i.e. steam itself contains the moisture, then its expansion to the atmosphere through the throttle will reduce its temperature, as its enthalpy will heat up the suspended water droplets.

By comparing these two temperatures, the steam quality is determined.

Q. *If the steam quality degrades, what does this indicate?*

Ans. Degradation of steam quality may be due to a problem with

1. feedwater level control
2. feedwater treatment
3. separators
4. mist eliminators
5. improper boiler size.

Q. *What objectives should be part of the program in order to achieve steam quality?*

Ans. 1. Steam should be generated at high pressure (up to 4 MPa) to take advantage of specific volume which decreases with the increase in pressure of steam. It is even better to deliver steam at a pressure higher than the highest pressure steam consumer (e.g. steam turbines) to make allowance for pipe pressure drop. Thus at higher pressure and lower specific volume more steam can flow through the piping system. In other words for the same flowrate, the pressure drop will be less.

2. The steam velocity in the distribution network (piping) should not go beyond 60 m/s and the total pressure drop in the piping should not exceed 20% of boiler pressure.

Q. *What measures should be adopted to avoid the accumulation of liquid and dirt in the steam header?*

Ans. To avoid this problem, drip legs fitted with dirt pockets should be installed at 150 m intervals of the distribution header, upstream of risers and elevated expansion loops and at the end of headers. Strainers should be fitted just upstream of the control valves and steam traps to arrest dirt, thus protecting them from clogging.

Q. *Why is it imperative that steam traps should discharge condensate at or near its saturation temperature?*

Ans. If traps are not properly designed, they will back up condensate and allow it to cool. This will accelerate carbonic acid corrosion. To avoid this problem steam traps should discharge condensate at or near the saturation temperature of steam.

Note: Please see APPENDIX-VII for more about STEAM TRAPS.

Q. *What is critical load?*

Ans. It specifies the boiler load above which steam contamination becomes inadmissible. It is G_{cr} corresponding to the point A in Figure 20.6.

Q. *What is admissible load?*

Ans. All subcritical loads, i.e. loads in the region to the left of A are admissible loads. And the maximum admissible load according to the conventional standard is 70 to 80% of the critical load, i.e.

$$G_{ad}^{\max} = (0.7 - 0.8)\ G_{cr}$$

Note: The design capacity of boiler = $G_{ad}^{\max}$

Q. *Is the critical load for a given boiler unit constant?*

Ans. No. It is directly proportional to the height of steam space and efficiency of steam-water separation devices and inversely proportional to the boiler feedwater concentration.

Q. *Why is it undesirable to operate boilers under conditions of sudden and large variation of steam demand?*

Ans. An abrupt increase in load may result in a sharp drop of steam pressure and lead to priming of boiler water. Sudden drop of steam pressure is accompanied by swelling of boiler water reducing the steam space. As a consequence, steam contamination is increased and the steam quality is decreased.

Q. *How does the nature of steam demand influence the quality of steam?*

Ans. As above.

Q. *Due to abrupt change in steam demand, in which case will the quality of steam be affected more—low pressure boiler unit or high pressure boiler unit?*

Ans. High pressure boiler unit.

Q. *For a boiler unit in service, two levels of BFW in the boiler drum are prescribed—one is upper water level and the other is a lower water level. Why?*

Ans. The upper water level is taken so as to ensure high quality steam generation while the lower water level is taken for reliable circulation.

Q. *What is the suggested water level in the boiler drum, as good practice?*

Ans. It is most desirable to operate boiler units with the BFW in the boiler drum maintained at a middle level and without its sharp variations.

Q. *Will the steam generated in a properly designed and well operated boiler unit still have any chance of contamination?*

Ans. Yes.

Q. *How?*

Ans. The quality of steam generated depends upon the quality of boiler feedwater apart from the design features of the boiler unit and its operation.

Q. *How does the steam quality vary with the salt concentration in boiler water?*

Ans. Steam quality deteriorates steadily with the increase in salt content in the BFW (C_{bw}). Upto point A, the carry over of salt to steam due to salt content in the boilerwater is within admissible limits. A further increase in C_{bw} produces a sharp deterioration in steam quality. So point A marks the maximum admissible limit of salt concentration in boiler water. (Fig. 20.9)

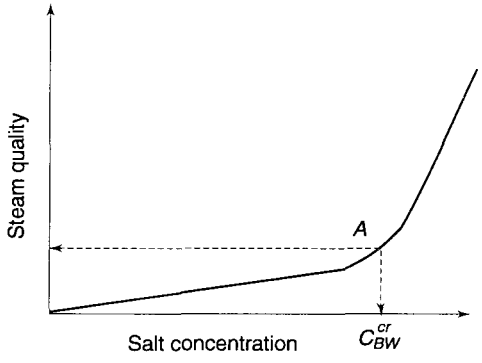


Fig. 20.9 *Steam quality as a function of salt concentration in BFW.*

Q. *What is the critical salt concentration in boiler-water?*

Ans. It characterizes the salt concentration in boiler water above which steam quality becomes inadmissible. It is C_{bw}^{cr} corresponding to the point A in Fig. 20.9

Q. *What is the admissible salt concentration in the BFW?*

Ans. All salt concentrations in the BFW in the region to the left of A are admissible. And the maximum admissible salt concentration is taken as 70 to 80 per cent of the critical salt content, i.e.

$$C_{bw}^{ad} = (0.7 - 0.8)\ C_{bw}^{cr}$$

Q. *What is foaming?*

Ans. It is the formation of stable foam on the evaporating surface in the boiler drum.

Q. *Why does it occur?*

Ans. Increase in salt concentration in the BFW is the primary factor leading to foaming.

Q. *Does it tell upon the quality of steam?*

Ans. Yes.

Q. *How?*

Ans. Foam swells and disintegrates into minor droplets of water carrying dissolved salts which thus contaminates the steam above the disengagement surface and affects its quality.

Moreover, in the case of intense foaming, flakes of foam may get ingested into the superheater coil imparting a high water content to steam, thereby increasing its wetness and salt carryover.

Q. *What are the major factors contributing to the genesis of foaming?*

Ans. 1. High salt content in boilerwater
2. Presence of oils and grease in boiler water
3. Presence of suspended sludge in a finely dispersed state in boilerwater.
4. High alkali concentration in boilerwater.

Q. *What is priming?*

Ans. Infiltration of BFW into steam lines of the boiler drum.

Q. *Why does it occur?*

Ans. It occurs due to

(a) Sharp pressure drop in the drum because of abrupt increase of steam load
(b) penetration of oil or alkali in the BFW in amounts exceeding the allowable standard

Q. *How do oils and grease find their way to the feedwater?*

Ans. This may occur due to

(a) leakage of fuel oil heater coil
(b) contamination of steam heating or purging lines by oil from oil burners
(c) penetration of oil from dirty filters in the hot well.

Q. *What is the difference between foaming and priming?*

Ans. Foaming characterizes stable foam formation, i.e. continuous formation of bubbles possessing sufficiently high surface tension to prevent them from coalescing and breaking, with the effect that they retain their bubble forms even after their disengagement from the water surface.

Priming refers to the state of unstable foam formation resulting in the discharge of steam contaminated with excessive amount of water droplets because of violent ebullition in the boiler observed periodically.

Q. *What causes foaming?*

Ans. Foaming is chiefly due to contamination of boilerwater with oil, soap, organic matter, suspended matter or other foreign particles.

Q. *What is the cause of priming?*

Ans. Priming is primarily due to surging (swelling) of water in the steam drum and is induced by a high water level in the drum. The violent movement of steam bubbles to the disengagement surface and their explosion causes this swelling and temporarily raises the water level in the steam drum. The exploding bubbles spray water droplets in the steam space and these are carried over by steam.

Q. *What is foamover or foampriming?*

Ans. It is the carryover of foam from the steam drum with the steam.

Q. *In which part of the turbine, are the salts carried over by steam mainly deposited?*

Ans. The salts passed onto steam primarily fall out on turbine blades.

Q. *What is the direct consequence of salt deposition on turbine blades?*

Ans. The smooth blade surface gets rougher, blade-channel profiles get distorted and redistribution of heat drop in the turbine occurs due to uneven scaling. As a result turbine efficiency decreases.

Q. *What is the mechanism of salt deposition on turbine blades?*

Ans. The superheated steam fed to the turbine always contains certain non-volatile substances. They may be present in the form of dry, hard particles and in a dissolved state. At steam pressures exceeding 7 MPa (7 MN/m^2), the superheated steam carries a large fraction of the carried-over salt in the dissolved state. And as the temperature and pressure drops of the steam take place through stages of the turbine, the solubility of these dissolved salts in steam also decreases. So when steam becomes supersaturated with respect to a certain substance at any turbine stage, that very substance will settle on the blades of that turbine stage.

If at the turbine inlet, steam is saturated with respect to a substance, the latter starts to deposit onto the blades of even the first turbine stages. However, if the concentration of a particular substance dissolved in steam is less than the concentration at saturation, the fall-out of the substance will occur in the latter stages where a supersaturated solution of the substance in steam is formed.

Dry deposition on the blades also takes place as the dry, hard particles strike and adhere to the blade surfaces.

Q. *What kinds of deposits precipitate on steam turbine blades?*

Ans. The compounds forming deposits on turbine blades can be divided into two classes:

1. **Water Soluble Compounds:** belonging to this class are sodium silicate (Na_2SiO_3), sodium sulphate (Na_2SO_4), sodium chloride (NaCl) and sodium hydroxide (NaOH).
2. **Water Insoluble Compounds:** these are iron oxide, aluminium oxide and silicic acid.

Q. *What compounds fall out in the superhigh pressure and high pressure cylinders of supercritical-pressure turbines?*

Ans. These are mainly the oxides of copper, iron and silicon, [CuO, Fe_2O_3 and SiO_2].

Q. *What compounds primarily get deposited in the intermediate pressure and low pressure cylinders of steam turbines?*

Ans. Mostly compounds containing Na_2SiO_3, SiO_2 and to some extent Fe_2O_3.

Q. *How can the quantity of deposition in the turbine blades be controlled?*

Ans. The best way of controlling blade deposition of turbines is to generate a high quality of steam. But if deposits form, they are removed by washing the blades with wet steam whereupon water soluble deposits are transferred into the washings giving rise to partial washing-off.

In cases of deposits which are poorly soluble in water, recourse to certain chemicals, such as EDTA, hydrazine and sodium hydrate are taken. These reagents are injected to wet steam to wash out poorly water-soluble deposits from turbine blades.

Q. *How can high quality steam be generated?*

Ans. Methods of producing high quality steam vary depending on the working parameters of the plant. But in general it can be done by

(a) improving the quality of feedwater
(b) ensuring effective separation of water droplets from the generated steam
(c) harnessing steam washing
(d) putting into effect stage-evaporation.

Q. *How can impurities from the steam-water cycle be removed to improve the quality of circulating water?*

Ans. The impurities that penetrate into boiler units due to leakage of cooling water in turbine

condensers, make-up water and corrosion processes can be brought down to satisfactorily low levels by a blow-down technique. However this method is effective only for drum-type subcritical pressure boiler units.

By blowing down a fraction of the boiler water and its replacement by feedwater make-up, an excessive concentration of undesirable substances in boilerwater is prevented. Since in drum type boilers, the purity of the generated steam is determined by the quality of water from which it is produced, blowdown adequately tackles the problem by ensuring a lower concentration of impurities in the boilerwater. However, blowdown is inapplicable in once-through boilers—both subcritical and supercritical pressure units. In these cases the turbine condensate is treated in a special demineralizing plant to produce polished water which is recycled. That is how feedwater quality is improved.

Q. *What is blowdown?*

Ans. Blowdown in defined as the removal from a boiler unit or evaporator a fraction of the boilerwater either continuously or intermittently, in order to prevent an excessive concentration of undesirable dissolved substances in boilerwater.

Q. *In which type of boilers can blowdown be put into effect?*

Ans. Drum-type boiler units as well as once-through boiler units befitted with separators and operated at a subcritical pressure.

Q. *How many types of blowdown are known?*

Ans. Two: continuous and intermittent.

Q. *What is the objective of continuous blowdown?*

Ans. It is to maintain a definite concentration of dissolved non-volatile substances in the boilerwater.

Q. *What is the purpose of intermittent blowdown?*

Ans. It is undertaken to remove sludge from a boiler unit.

Q. *How do continuous and intermittent blowdown tanks operate?*

Ans. Blowdown water from the boiler drum is flashed in the blowdown flashtank whereupon the feed is separated into two phases

(a) flashsteam
(b) hot liquid (frequently called condensate)

The flashsteam escapes through the exhaust port (Fig. 20.10) provided at the top of the flashtank while the hot liquid containing some steam condensate flows out through a drain pipe by gravity. The siphon provided at the outlet of the drainpipe helps in maintaining a column of water inside the blowdown tanks, which can be ascertained by the level indicator (gauge glass) mounted outside.

Q. *What problems are faced at sites in the case of blowdown tanks newly installed?*

Ans. It has been observed that steam, instead of hot liquid, flows out through the outlet drainpipe.

Q. *What is the problem with this?*

Ans. Steam escaping through the liquid drainport splashes around. This steam is sucked up by the FD fans/PA (pulverizer air) fans, especially if the fan suction faces the outlet pipe.

This steam is also sucked up by the cooling fans of the high tension motors of FD/PA fans. This is hazardous.

The situation becomes worse when the EBD (Emergency Blowdown) is operated.

Q. *What is the genesis of this problem?*

Ans. The narrow escape passage provided at the entry to the exhaust port of steam is the origin of the trouble.

A baffle arrangement is provided at the entry of flashsteam to exhaust port to trap moisture and hot liquor. Typically a 5 mm circumferential entry is provided, which is too narrow an opening

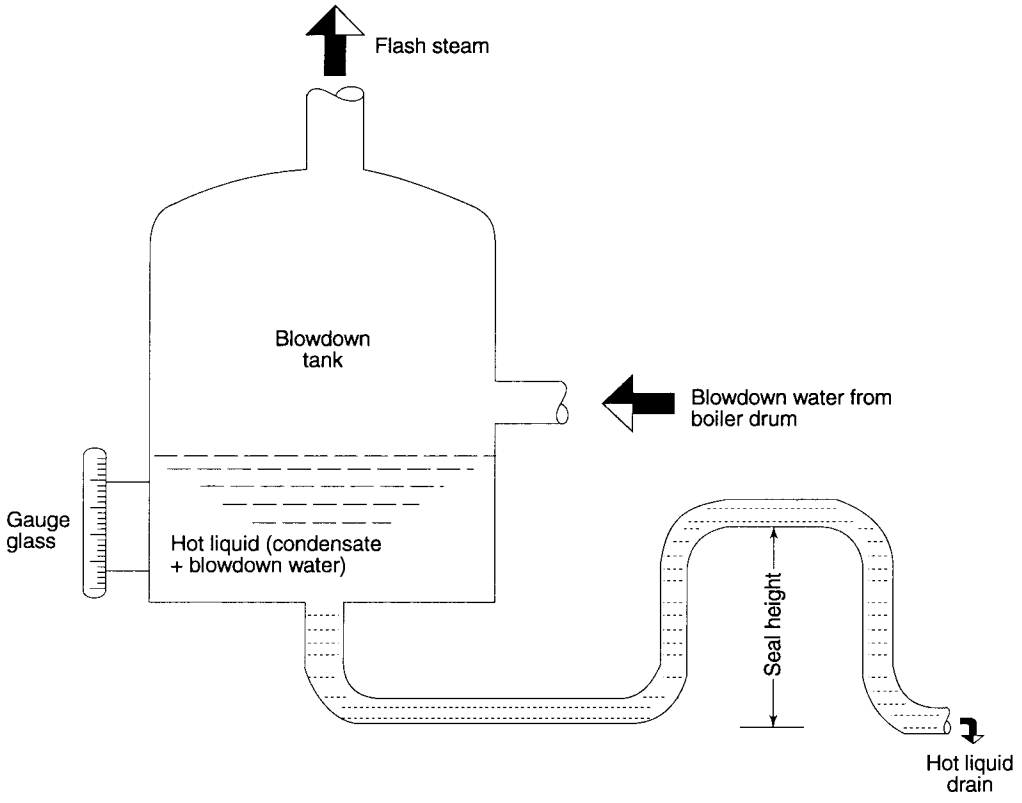


Fig. 20.10 *Blowdown water from the boiler drum flashes into the blowdown tank. The flashsteam escapes through the exhaust port at the top while the hot liquid (condensate + blowdown water) accumulates at the bottom of the blowdown tank.*

for the full volume of steam to pass. Moreover, the number of perforated holes in the bottom plate is not enough, usually 8 in number, each nearly 2 mm in size, (not shown in the figure). This causes pressurization of the vessel which ultimately results in excess steam getting pumped through the drain which is the path of least resistance.

Q. *What is the solution?*

Ans. The only solution to this problem lies in reducing the restriction posed by the baffle at the steam inlet to exhaust port.

Cut and remove a circular section (say 150 mm dia) from the bottom plate of the baffle (Fig. 20.11).

Q. *How does this modification become effective?*

Ans. Steam gets ample clearance for escape. As a result it passes only through the exhaust pipe.

Condensate water flows out only through the drainpipe.

Constant water level is maintained in the BD tanks

Note: This modification was effected at site. No abnormality has been reported since then.

Q. *How is blowdown control accomplished?*

Ans. By monitoring the specific conductivity of the boiler drum water, BFW and make-up feedwater on a daily basis.

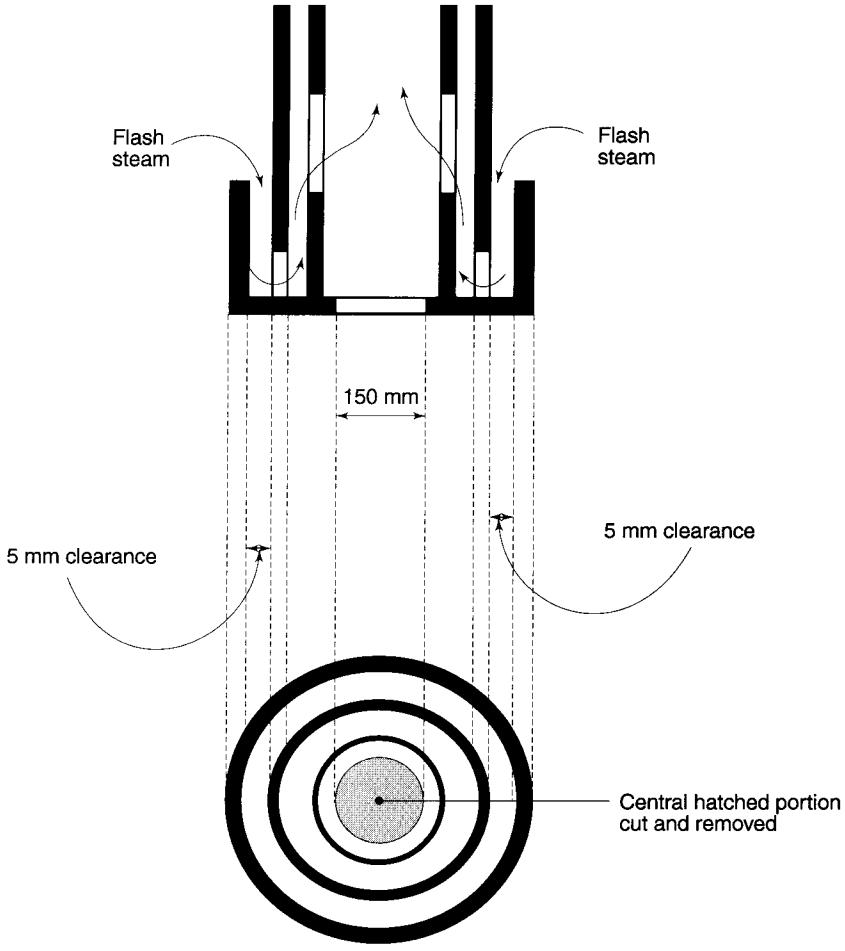


Fig. 20.11 *Baffle arrangement.*

The reading in micromhos is proportional to the dissolved solids.

$$P = \frac{\lambda_F}{\lambda_M} \times 100$$

$$B_{\text{M/UP}} = \frac{\lambda_M}{\lambda_{BDW}} \times 100$$

$$B_{\text{BFW}} = \frac{\lambda_F}{\lambda_{BDW}} \times 100$$

where, P = make-up water, %

λ_F = specific conductivity of BFW at the feedwater pump, micromhos.

λ_M = specific conductivity of make-up water at the inlet to BFW preheater, micromhos

$B_{\text{M/UP}}$ = blowdown, % of makeup water

B_{BFW} = blowdown, % of BFW

λ_{BDW} = specific conductivity of boiler drum water, micromhos.

Q. *Thus we see that blowdown is computed in terms of two blowdown percentages—one based*

on make-up water flow and the other based on BFW flow. Which one is more advantageous?

Ans. The blowdown based on make-up water flow is more advantageous to plants that meter this stream only. Moreover for a multiboiler unit, this system is preferable as only one reading is needed for the entire plant.

Problem 20.1: A boiler generates 22.68 t/h steam of 1.378 MPa. The specific conductivity parameters of

Boiler drum water = 4000 micromhos

BFW at the pump outlet = 120 micromhos

Makeup water at the entry to the BFW preheater = 240 micromhos

Calculate

1. Make-up water, %
2. Blowdown on the basis of M/UP water.
3. Blowdown on the basis of feedwater.

Solution

$$P = \frac{\lambda_F}{\lambda_M} \times 100 = \frac{120}{240} \times 100 = 50\%$$

$$B_{M/UP} = \frac{\lambda_M}{\lambda_{BDW}} \times 100 = \frac{240}{4000} \times 100 = 6\%$$

$$B_{BFW} = \frac{\lambda_F}{\lambda_{BDW}} \times 100 = \frac{120}{4000} \times 100 = 3\%$$

Problem 20.2 The boiler blowdown contains a potential amount of heat which can be recovered for feedstream preheating.

A boiler receives 11.69 t/h of BFW makeup and 11.69 t/h of return condensate via the BFW preheater and generates 22.68 t/h of steam (1.378 MPa) while discharging 0.70 t/h of water as blowdown.

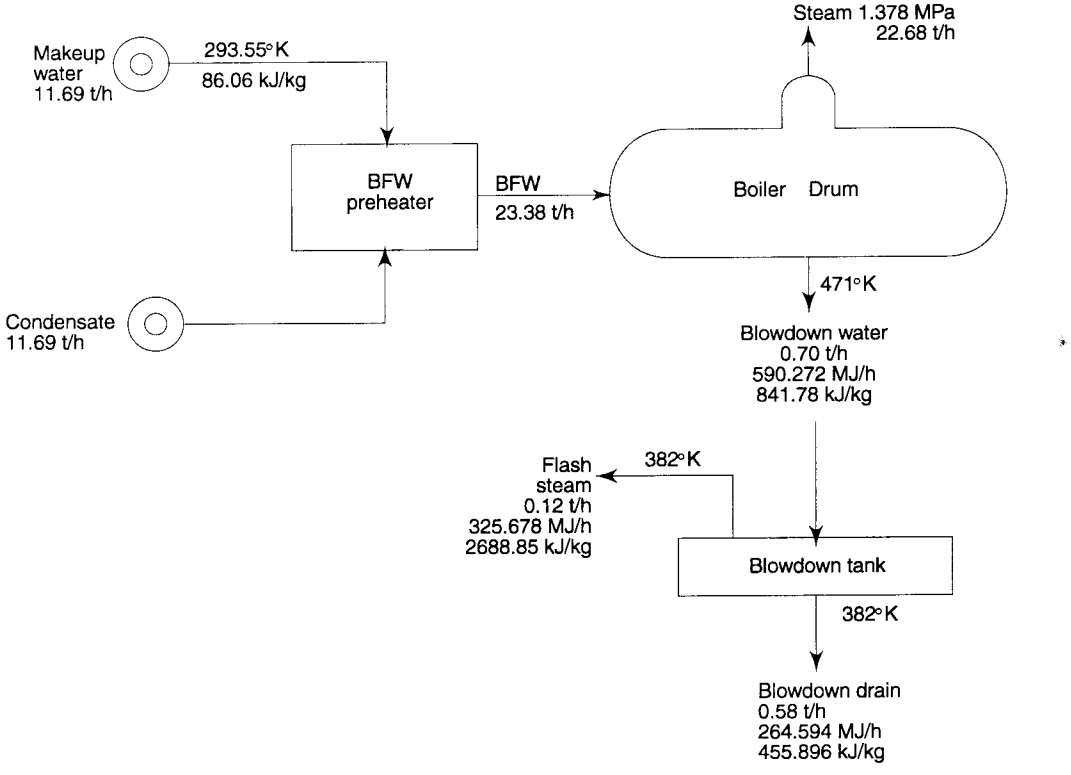


Fig. 20.12

Much of the blowdown heat can be recovered by either of two ways:

I. Single-step heat recovery: The blowdown flashtank is bypassed and blowdown water from the boiler drum is passed straight through the BFW preheater to heat up the feedwater. (Fig. 20.13)

II. Two-stage heat recovery: The boiler blowdown is flashed in the blowdown tank whereupon a sizeable fraction of blowdown heat is released into the flashsteam and the rest goes to the condensate drain which can be used to heat up the feedwater. (Fig. 20.14)

Calculate the per cent heat recovery in the

1. single-stage process
2. two-stage process.

Solution In the first case, the heat abstracted from blowdown water

$$= 11.69\ (127 - 86.062)$$

$$= 478.565 \text{ MJ/h}$$

Heat input rate = 590.272 MJ/h

$$\% \text{ Heat recovery} = \frac{478.565}{590.272} \times 100 = 81\%$$

In the second case, the heat abstracted from blowdown water

$$= 11.69\ (100 - 86.062)$$

$$= 162.935 \text{ MJ/h}$$

To this add the heat retrieved by flashsteam.

Total heat recovered = 162.935 + 325.678 = 488.613 MJ/h

Heat input rate remains the same, i.e. 590.272 MJ/h

$$\% \text{ Heat recovery} = \frac{488.613}{590.272} \times 100$$

$$= 82.77\%$$

Thus the two-stage process is somewhat more effective in retrieving the wasteheat of boiler blowdown.

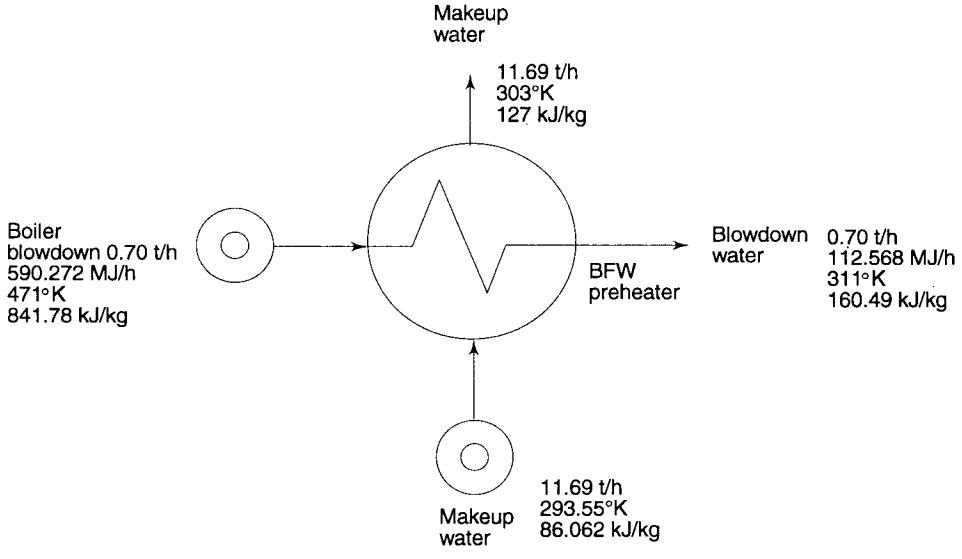


Fig. 20.13 *Single-step heat recovery.*

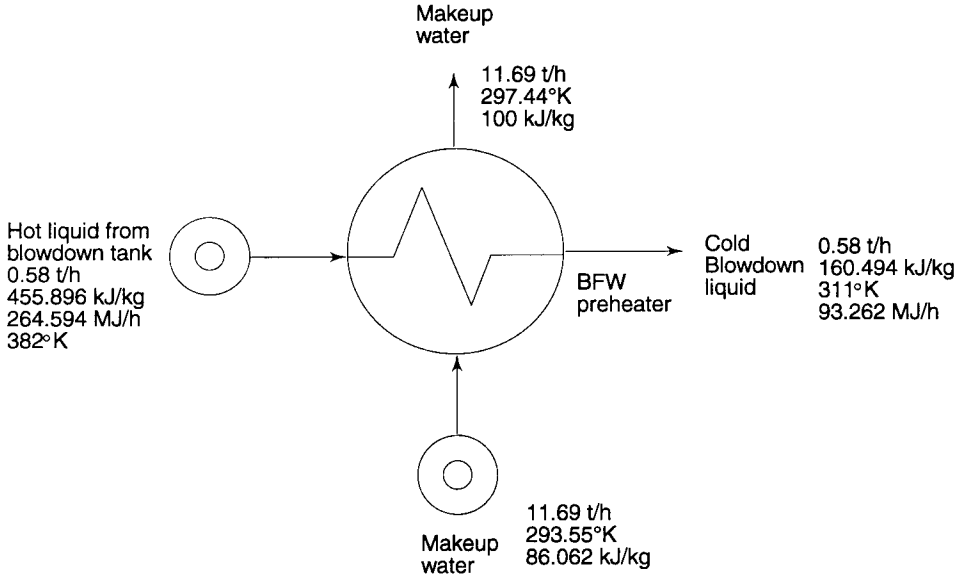


Fig. 20.14 *Two-step heat recovery.*

Q. *Which one of the above two blowdown heat-recovery-systems is preferable?*

Ans. Double-step one.

Q. *Why?*

Ans. The single-step process renders the heat exchanger (feedwater preheater) more susceptible to scaling problems on the make-up water side due to increased temperature rise.

The two-step process, on the other hand, results in more condensate in the system. This reduces the amount of make-up and recovers more of the heat.

Q. *In case the heat recovery equipment goes out of service, what should be done?*

Ans. Provision for draining blowdown water to the sewer must be made in both systems when the heat recovery unit goes off.

Q. *What are the problems encountered in blowdown heat recovery systems?*

Ans. 1. Fouling induced by flashsteam
2. Fouling induced by blowdown water
3. Flooding of flashtank
4. Dry tank.

Q. *How does the flashsteam produced by blowdown water inflict fouling?*

Ans. The low-pressure flashsteam generated in the blowdown tank carries some droplets of blowdown water. The turbulence induced by flashing breaks a part of the blowdown water into a fine mist of spray. These droplets carry a rich load of dissolved solids which get steamborne thereafter. This contaminated LP steam causes deposition in the equipment using it.

Q. *How can this problem be solved?*

Ans. Much of this problem can be solved by fitting into the blowdown tank

(a) a demister (mesh pad) above the inlet of blowdown water
(b) a steam baffle before the exit port of the flashsteam.(Fig. 20.15)

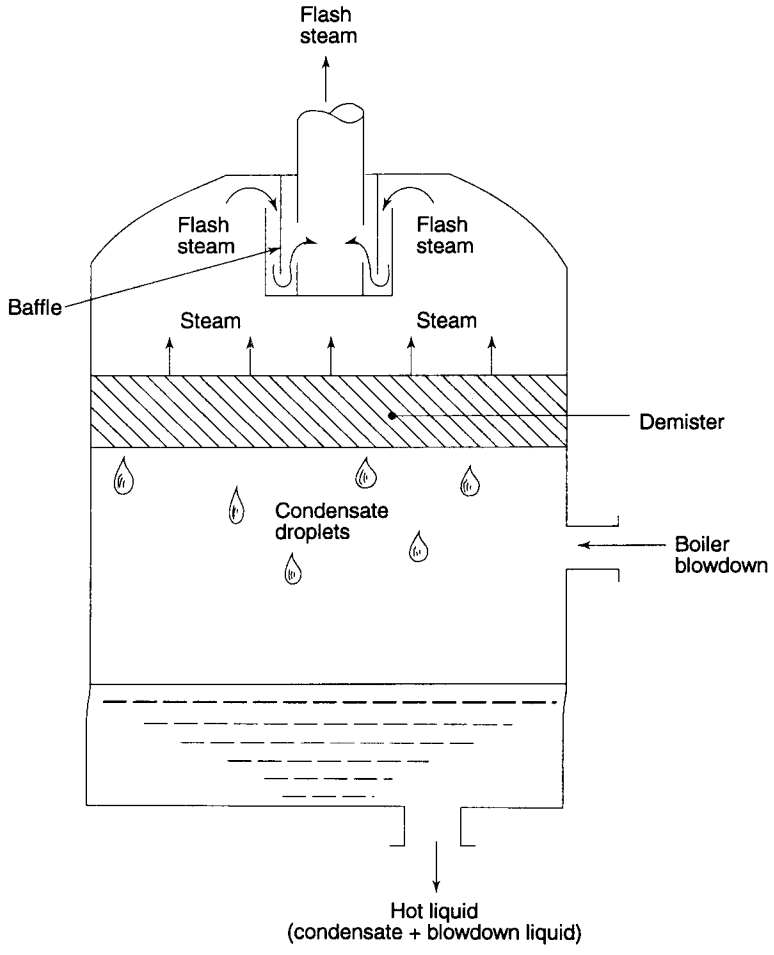


Fig. 20.15

Q. *Why should a gauge glass be always there on the flashtank?*

Ans. To avoid the risk of vessel flooding and to avoid it from running dry.

Q. *What is the harm if there is flashtank flooding?*

Ans. It means carryover of condensate in the flashsteam, i.e. contaminated steam will result from flashing. Also it will risk the deposition of solids in the heat exchanger where this steam-water mixture is used as heating stream.

Q. *What should be the minimum condensate level in the tank?*

Ans. 50–75 mm.

Q. *If the minimum condensate level is less than 50 mm what will happen?*

Ans. This may risk the tank going dry. If the tank is dry, the blowdown water may drain into the sewer. Also a dry tank will invite the backflow of flashsteam from the process to the blowdown tank and from there to the sewer (the path of least resistance), thus negating the whole concept of heat recovery.

Q. *What can be done to avoid the backflow of steam?*

Ans. Put a NRV in the flashsteam line.

Q. *A control valve is to be provided on the boiler blowdown line and it should be provided as close to the blowdown tank as possible. Why?*

Ans. As the blowdown water goes through the valve, some flashing may occur whereupon the generated flashsteam will pressurize the line preventing the flow of blowdown water into the flashtank.

Q. *What can be done to ensure proper level regulation in the flashtank?*

Ans. Proper level regulation is the key to efficient flashtank operation. As such the vessel should be equipped with a LRCA(level regulator control and alarm) so that a reasonably constant low-level is maintained in the tank. There should be HIGH-LEVEL and LOW-LEVEL annunciator should the water level in the blowdown tank goes above or below the permissible level so that the operator can act accordingly to bring the water level back to the allowable range.

Q. *What are the problems associated with the using of blowdown water for heat recovery?*

Ans. The major problem is scaling—deposits will occur on the blowdown water side of the H.E. If fouling is severe it will bring about an increased pressure drop resulting in flashtank flooding and poor quality, LP flashsteam.

Q. *A schematic flow diagram for a typical heat recovery system with CBD (continuous blowdown) is shown. (Fig. 20.16)*

Here heat recovery from hot blowdown is made by passing it through the BFW preheater. Why is a pump not installed to induce forced circulation of blowdown water in the H.E.?

Ans. Installation of such a pump is avoided as it would mean

(a) higher running cost
(b) cavitation problem

apart from the cost of pump and its standby.

Q. *What should be the location of the flashdrum?*

Ans. It must be located at a much higher elevation than the BFW pre-heater.

Q. *Why must the flashdrum be located at a higher elevation than the BFW preheater?*

Ans. Since the flow of hot blowdown water from the flashdrum to the H.E. is gravitational, there arises the risk of cavitation which can be avoided by locating the flashdrum unit at a higher elevation. This also bestows enough head for the blowdown to overcome the flowpath resistance in the heat exchanger tubes.

Q. *The quantity of steam flashed depends on deaerator pressure. How can this be true?*

Ans. The quantity of steam flashed depends on flashdrum pressure. Inasmuch as the flashsteam is fed directly to deaerator, so the flashdrum pressure depends upon the operating pressure of the deaerator which in turn controls the quantity of steam flashing.

Q. *How can the quantity of steam be calculated that would flash in the flashdrum?*

Ans. Use is to be made of the following relationship to calculate the % of steam flashed:

$$\therefore \%\ \text{of flashsteam} = \frac{SH - SL}{LH} \times 100$$

where, SH = sensible heat in the boiler blowdown, kJ/kg

SL = sensible heat of hot blowdown at the flashdrum outlet, kJ/kg

LH = latent heat of vaporization of steam at flashdrum operating pressure, kJ/kg

Q. *What is the advantage of sending hot blowdown to the raw water sump?*

Ans. Recycling of flashdrum blowdown to raw water pump, if it's quality is better than raw water itself, would mean

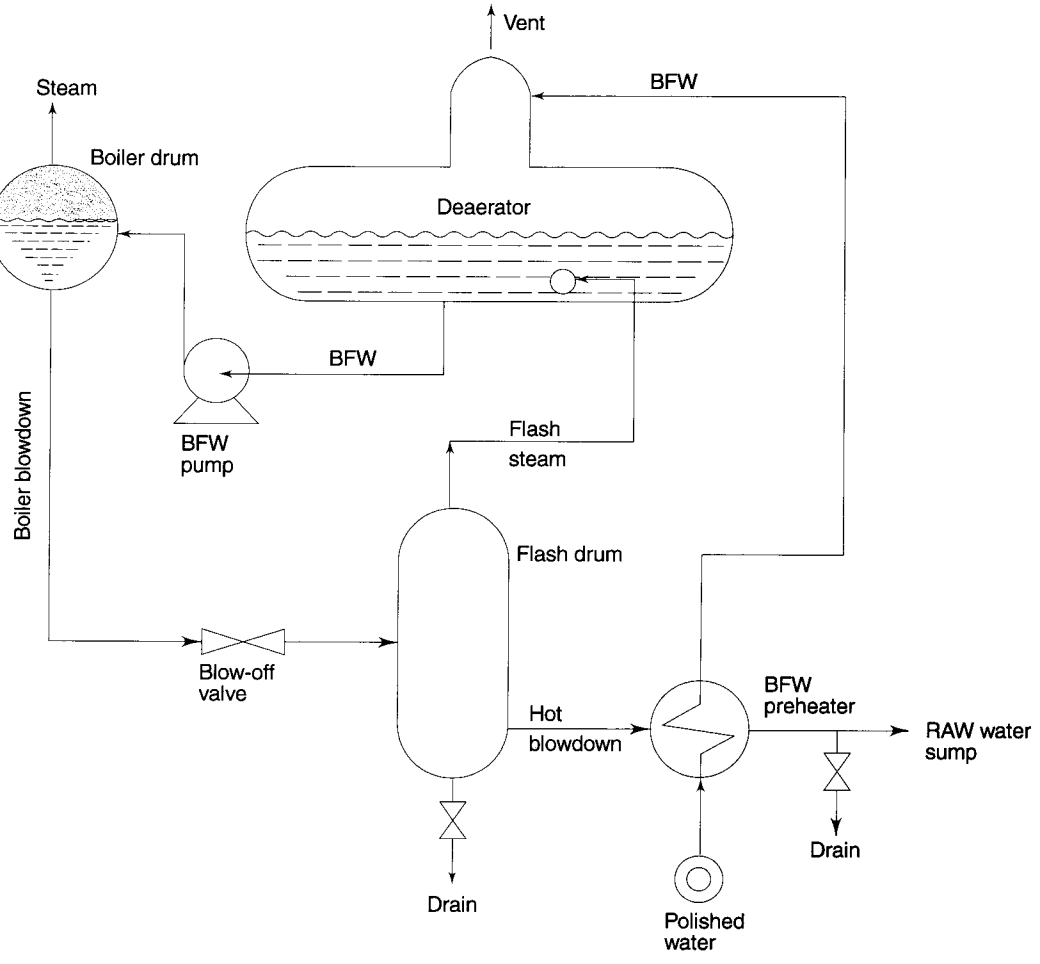


Fig. 20.16

(a) less consumption of fresh raw water
(b) reduced load on the ion-exchange beds of the DM plant

Problem 20.3 Design a suitable heat recovery system for the blowdown of a oil-fired, firetube boiler with the following specifications?

Steam generating capacity = 50 t/h

Operating pressure of the boiler = 1 MPa

Deaerator pressure = 101 kPa

CBD rate = 20% of the boiler capacity

Temperature of *BD* water at the flashdrum outlet = 373°K

Temperature of BD water at BFW preheater outlet = 303°K

Temperature of BFW at the inlet to BFW preheater = 303°K

Flashdrum pressure = 50 kPa (assume)

Calorific value of oil = 42 MJ/kg

Cost of polished water = Rs. 75 per ton

Cost of oil (FO) = Rs. 5/kg

The hot BD of FD (flashdrum) is used in the BFW preheater to preheat the BFW while the flashsteam goes to deaerator to deaerate the BFW.

Solution The above heat recovery system brings about savings

1. in terms of fuel saved for preheating BFW
2. from condensing flashsteam.

Quantity of BD = 20% of steam generation capacity of the boiler

$= 0.2\ (50)$

$= 10$ t/h

Sensible heat in the boiler BD, SH = 712 kJ/kg

Sensible heat in hot blowdown at the FD outlet = 418.7 kJ/kg

Latent heat of vaporization of steam at the FD operating pressure = 1989 kJ/kg

$$\therefore \quad \% \text{ flashsteam} = \frac{712 - 418.7}{1989} \times 100$$

$$= 14.746\ \%$$

Quantity of flashsteam = 0.14746 (10) = 1.4746 t/h

Heat content of flashsteam = 1.4746(1000) × Latent Heat at 50 kPa

$$= 1474.6 \left[\frac{kg}{h}\right] \times 1989 \left[\frac{\text{kJ}}{\text{kg}}\right]$$

$= 2932\ 979$ kJ/h

$\simeq 2933$ MJ/h

Hot water BD of flashdrum

= Boiler BD - Flashsteam generated

$= 10 - 1.4746$

$= 8.524$ t/h.

Heat recovered from the flashdrum BD water = 8.524 (1000) × Specific Heat × Δ Temperature

$= 8524\ (4.187)\ (373 - 303)$

$= 2,498,299$ kJ/h

$\simeq 2498$ MJ/h

Therefore, total recoverable heat available from the boiler BD

$= 2933 + 2498$

$= 5431$ MJ/h

Rise in temperature of BFW in the BFW preheater

$$= \frac{2498 \times 10^3}{(50 - 1.4746)\ (1000)\ (4.187)} + 303$$

$= 315.29°K$

Note: 50 t/h steam is generated in the boiler from the BFW out of which 1.4746 t/h is returned to the system as flashsteam

Rise in BFW temperature $\Delta\theta_{BFW} = 315.29 - 303 = 12.29°K$

Heating value of FO = 42 MJ/kg = 42 000 kJ/kg

Amount of heat recoverable from the boiler BD = 5431 MJ/h

Quantity of fuel saved in raising BFW temperature through 12.29°K = $\frac{5431}{42}$

$= 129.309$ kg/h

Cost of FO = Rs. 5/kg

$$\text{Annual savings of FO} = 129.309 \left(\frac{\text{kg}}{\text{h}}\right) \times 5 \left(\frac{\text{Rs}}{\text{kg}}\right) \times 24 \left(\frac{\text{h}}{\text{day}}\right) \times 300 \left(\frac{\text{days}}{\text{y}}\right)^*$$

= Rs. 4, 655, 124 per annum

Quantity of flashsteam condensing in the deaerator = 1.4746 t/h

The flashsteam upon contact with cascading BFW in the deaerator condenses, reducing the quantity of BFW make-up requirement.

Cost of polished water (i.e. BFW) = Rs. 75/*t*

* Taking 300 days of operation per annum.

Quantity of polished water recycled as flashsteam = 1.4746 t/h

∴ Savings from flashsteam condensate

$$= 75 \left(\frac{\text{Rs}}{\text{t}}\right) \times 1.4746 \left(\frac{\text{t}}{\text{h}}\right)$$

$$= \text{Rs. } 110.595/\text{h}$$

Annual savings of polished water (makeup)

$$= 110.595 \left(\frac{\text{Rs}}{\text{h}}\right) \times 24 \left(\frac{\text{h}}{\text{day}}\right) \times 300 \left(\frac{\text{days}}{\text{annum}}\right)$$

= Rs. 796 284

Therefore, total annual savings

= Rs. 4, 655, 124 + Rs. 796, 284

= Rs. 5, 451, 408

Additional equipment required to tap the blowdown heat are

1. Flashtank
2. BFW Preheater

Sizing of flashtank

Mass of boiler BD = 10 t/h

Mass of water flashed to steam = 1.4746 t/h

Mass of water drained as flashtank BD = 10 − 1.4746 = 8.5254 t/h

Flashtank hold-up = 8.5254 (t/h) × 1.075 (m^3/t) = 9.1648 m^3/h

Specific volume of saturated water at 50 kPa = 1.075 m^3/t

As a standard practice, an equal volume is required for actual blowdown.

Total volume of water = 2(9.1648) = 18.3296 m^3

Taking the steam separating space (disengagement zone) equal to twice the total volume of the tank, volume of the flashtank

= 2(18.3296)m^3

= 36.6592 m^3

L/D = 2 (say)

$$\therefore \text{Volume of flashtank} = \frac{\pi}{4} \cdot D^2 \cdot 2D = \frac{\pi}{2} \cdot D^3$$

$$\therefore \frac{\pi}{2} \cdot D^3 = 36.6592$$

or, D = 2.8577 m

and L = 5.7154 m

As per ASME Boiler Code, minimum thickness for shell and dished ends for a flashtank fabricated from black carbon steel should be 9.52 mm. So let us assume the design thickness of the shell and dished ends to be equal to 10 mm.

Empty weight of flashtank including dished ends, supports, nozzles etc. = 7.5 t (approx.)

Cost of fabrication = Rs. 30/kg of C-steel

$$\therefore \text{Cost of flashtank} = 30 \left(\frac{\text{Rs}}{\text{kg}}\right) \times 7500 \text{ (kg)}$$

= Rs. 225,000

BFW preheater

The total heat transfer area for shell-and-tube type heat exchanger required for BFW preheating = 28 m^2 (approx)

Note: Design calculation not shown

Fabrication cost = Rs. 40, 000/m^2 of heat transfer area for the operating pressure

∴ Cost of H.E. = Rs. 40, 000 × 28

= Rs. 1, 120, 000

Total equipment cost = Rs. 225, 000 +

Rs. 1, 120, 000 = Rs. 1, 345, 000

Piping cost = 20% of equipment cost

Instrumentation cost = 15% of equipment cost

Structural cost = 10% of equipment cost

Erection and commissioning = 10% equipment cost

Contingency = 10% of equipment cost

$\therefore$ Approximate total investment = C_E + (0.2 + 0.15 + 0.1 + 0.1 + 0.1) C_E

= 1.65 C_E where, C_E = Equipment cost

= 1.65 × Rs. 1, 345, 000

= Rs. 2, 219, 250

Total savings = Rs. 5, 451, 408

Thus theoretically there is a considerable amount of savings in terms of money. But given the efficiency of boiler and heat recovery equipment, the actual saving will not be that much.

Besides, we've taken a very conservative costs of the equipment and not their competitive price.

Boiler efficiency = 80% (Say)

H.E. efficiency = 90% non-fouling status (say)

Efficiency of the system = 0.8 × 0.9 = 0.72

Actual savings = Rs. 5, 451, 408 × 0.72

= Rs. 3, 925, 013

Therefore, we can conclude that the actual saving per annum is still higher than the total investment.

Note: The costs assumed in the foregoing calculations may not be accurate. Nevertheless, they provide the basic guidelines for designing such a system.

For accurate economic feasibility, one must impute the prevailing costs of the equipment, piping, instrumentation, erection and the interest rate on the total investment.

Problem 20.4 18.9 t/h of steam (4.13 MPa) is generated at 80 per cent efficiency in a pulverized coal fired boiler hooked up with continuous blowdown (CBD). Blowdown (BD) rate is 5%. Compute the heat loss per ton of BD.

Compare this loss to the saving from heat recovery in a typical BD heat-recovery system depicted below. (Fig. 20.17).

Ambient make-up water temperature = 294°K

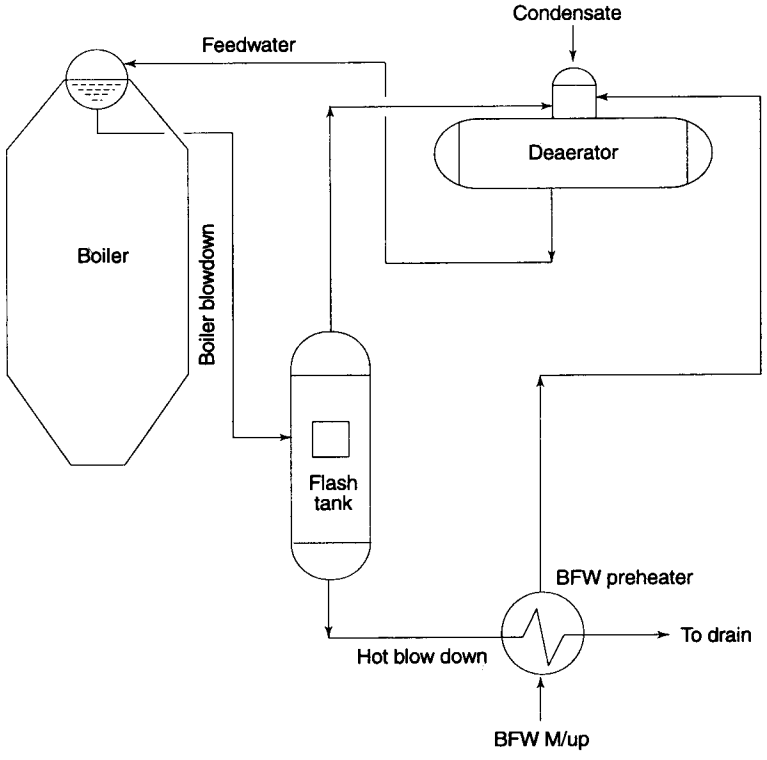


Fig. 20.17 *A typical blowdown heat-recovery system.*

Flashtank operating pressure = 70 kPa

Per cent of boiler BD flashed = 28%

BD temperature at BFW preheater outlet = 322°K.

Fuel cost = Rs. 60 per GJ

1 GJ = 10^9 J

Comment.

Solution A huge amount of energy is wasted if the CBD is let down to drain. However, a great deal of this waste heat can be recovered through flashing and BFW preheating.

Makeup BFW rate

$$= \frac{\text{Steam generation rate}}{(100 - \text{blowdown percent})/100}$$

$$= \frac{18.9}{(100-5)/100} \; t/h$$

$$= 19.894 \text{ t/h}$$

Steam production equivalent of the blowdown

= BFW M/up rate – steam flowrate

= 19.894 – 18.9

= 0.994 t/h

Heat loss rate per ton of BFW

= Specific Heat × (Saturation temperature of BFW – Ambient temperature of BFW M/up)

$$= 4.187 \left(\frac{\text{kJ}}{\text{kg.}\,^\circ\text{K}}\right) (526 - 294)\,(^\circ\text{K}) \times 1000 \left(\frac{\text{kg}}{\text{t}}\right)$$

$$= 971\,384 \left(\frac{\text{kJ}}{\text{t}}\right)$$

= 971.38 MJ/t

Heat loss from CBD to draining

When the CBD water is drained straightaway the heat in the BD stream is lost forever. Thus, the total heat loss from the draining of boiler BD

= Heat loss per ton of BD × BD rate

$$= 971.38 \left(\frac{\text{MJ}}{\text{t}}\right) \times 0.994 \left(\frac{\text{t}}{\text{h}}\right)$$

$$= 965.5517 \left(\frac{\text{MJ}}{\text{h}}\right)$$

$$= 23,\, 173.241 \; \frac{\text{MJ}}{\text{day}}$$

Fuel-cost equivalent of the blowdown

= (Heat loss per day) (Fuel cost)/Boiler efficiency

$$= 23\,173.241 \left(\frac{\text{MJ}}{\text{day}}\right) \times 60 \left(\frac{\text{Rs}}{\text{GJ}}\right) \times \frac{1}{10^3} \left(\frac{\text{GJ}}{\text{MJ}}\right) / 0.8$$

= Rs. 1738 per day (approx.)

Blowdown flowrate Through BFW preheater

28% of boiler BD is flashed to steam. So 100 – 28 = 72 percent of the BD is available for exchanging heat in the H.E. (BFW preheater).

Since the total BD rate is 0.994 t/h, therefore, the flowrate of BD water through the BFW preheater

= 0.994 (0.72)

= 0.71568 t/h

Heat loss in the BD heat-recovery system

The blowdown water which is not flashed flows through the BFW preheater to heat up the incoming BFW M/up and then is discharged to the drain. Therefore, a fraction of the heat load of BD water from the flashtank is lost to sewer.

$\therefore$ Heat loss to sewer per unit mass of water discharged

$$= 4.187 \left(\frac{\text{kJ}}{\text{kg}\cdot^\circ\text{K}}\right) \times (322 - 294)\ (^\circ\text{K})$$

$$= 117.236 \text{ kJ/kg}$$

$$= 117.236 \text{ MJ/t}$$

BD rate to drain = 0.71568 t/h

$\therefore$ Total heat loss to the drain

$$= 117.236 \left(\frac{\text{MJ}}{\text{t}}\right) \times 0.71568 \left(\frac{\text{t}}{\text{h}}\right) \times 24 \left(\frac{\text{h}}{\text{day}}\right)$$

$$= 2013.683 \left(\frac{\text{MJ}}{\text{day}}\right)$$

Comparison of the two systems

Heat recovered without heat-recovery system = 0

Heat recovered with heat-recovery system

$$= 23\ 173.241 - 2013.683$$

$$= 21\ 159.558 \text{ MJ/day}$$

Savings with heat-recovery system

$$\% \text{ Heat recovered} = \frac{21\,159.558}{23\,173.241} \times 100 = 91.31\%$$

Cost of lost heat without any heat recovery = Rs. 1738 per day

$\therefore$ Saving = 91.31% of Rs. 1738/day

= Rs. 1586.9731 per day

$\therefore$ Annual savings = Rs. 1586.9731 × 300

= Rs. 476, 092 (approx)

assuming 300 days of operation per annum

Comments Almost invariably fuel costs rise every year. So it will increase the annual saving. Of course, the cost of the BD heat-recovery equipment must be offset against this saving.

Q. *What is the general equation of blowdown?*

Ans. Blowdown is directed to set up and ensure a salt balance for boiler water, i.e.

Mass of salts entering a boiler unit

= Mass of salts removed from the boiler unit

Therefore, the mass balance (of total dissolved salts) equation is

$$C_{fw}\, G_{fw} = C_s\, G_s + C_{bw}\, G_{bd} \qquad (20.1)$$

where G_{fw}, G_s and G_{bd} refer to mass flowrate (*t/h*) of feedwater, steam and blowdown water respectively.

C_{fw}, C_s and C_{bw} correspond to concentration of salt in feedwater, steam and boilerwater respectively.

Q. *What is per cent blowdown?*

Ans. It is the ratio of rate of blowdown to the rate of steam generation expressed in percent, i.e. the blowdown rate in relation to steam

$$p^s_{bd} = \frac{G_{bd}}{G_s} \times 100 \qquad (20.2)$$

Again,

$$G_{fw} = G_s + G_{bd} \qquad (20.3)$$

Therefore, from equation 20.1 and 20.3 we get,

$$G_{bd} = \left[\frac{C_{fw} - C_s}{C_{bw} - C_{fw}}\right] G_s \qquad (20.4)$$

$$\therefore \quad p^s_{bd} = \left[\frac{C_{fw} - C_s}{C_{bw} - C_{fw}}\right] 100 \qquad (20.5)$$

Also per cent blowdown can be expressed in relation to feedwater

$$p^{w}_{bd} = \frac{G_{bd}}{G_{fw}} \times 100 \qquad (20.6)$$

or, $$p^{w}_{bd} = \left[\frac{C_{fw} - C_s}{C_{bw} - C_s}\right] 100 \qquad (20.7)$$

Salt content in boiler water

$$C_{bw} = C_{fw} \frac{100}{p^{w}_{bd}} \qquad (20.8)$$

Salt content in steam

$$C_s = \frac{Y}{100} C_{bw} \qquad (20.9)$$

where Y = coefficient characterizing the carryover of dissolved substances from boiler water to generated steam

$$= \frac{C_s}{C_{bw}}$$

The salt balance equation can also be written as

$$(1 + p^{s}_{bd})\, C_{fw} = (Y + p^{s}_{bd})\, C_{bw} \qquad (20.10)$$

Introducing the carryover coefficient, equation 20.5 takes the from

$$p^{s}_{bd} = \left[\frac{C_{fw} - Y\, C_{bw}}{C_{bw} - C_{fw}}\right] 100 \qquad (20.11)$$

From this equation we get

$$C_{fw} = \left[\frac{p^{s}_{bd} + 100\, Y}{p^{s}_{bd} + 100}\right] C_{bw} \qquad (20.12)$$

$$C_{bw} = \left[\frac{p^{s}_{bd} + 100}{p^{s}_{bd} + 100\, Y}\right] C_{fw} \qquad (20.13)$$

The percentage of dissolved substances removed by

(a) STEAM IS

$$\phi_s = \frac{100}{p^{s}_{bd} + 100} \frac{C_s}{C_{fw}} \times 100 \qquad (20.14)$$

(b) BLOWDOWN IS

$$\phi_{bd} = 100 - \phi_s \qquad (20.15)$$

Problem 20.5 For a given drum-type boiler unit operating at subcritical pressure, the salt content of boiler feedwater is 45 mg/kg.

Determine the per cent of salt removed by blowdown water and by steam (as carryover) if the blowdown rate in relation to feedwater is 2.2%.

Take carryover coefficient = 0.01%

Solution

We must make use of the formulae 20.14 and 20.15 to determine the per cent of salt removed by blowdown water and by steam generated. And for that purpose we must know the value of C_s beforehand.

Step (1) Determination of C_s

Working formulae: $$C_s = \frac{Y}{100} C_{bw} \qquad (20.9)$$

$$= \frac{Y}{100} C_{fw} \frac{100}{p^{w}_{bw}}$$

Y	C_{fw}	p^{w}_{bd}	C_s
0.01	45 mg/kg	2.2	$\frac{0.01}{100}(45)\frac{(100)}{2.2} = 0.2045$ mg/kg

Step (II) Determination of ϕ_{bd} and ϕ_s

Working formulae:

$$\phi_s = \frac{100}{p^{s}_{bd} + 100} \frac{C_s}{C_{fw}} \times 100 \qquad (20.14)$$

$$\phi_{bd} = 100 - \phi_s \qquad (20.15)$$

p^{w}_{bd} is given but p^{s}_{bd} is not. So we are to calculate the latter. This can be done as follows:

Taking $C_s \approx$ O, Eq. (20.5) and (20.7) simplify to

$$p^s_{bd} = \frac{C_{fw}}{C_{bw} - C_{fw}} \times 100 = \frac{\frac{p^w_{bd}}{100}}{1 - \frac{p^w_{bd}}{100}} \times 100$$

$$= \frac{p^w_{bd}}{100 - p^w_{bd}} \times 100$$

$$= \frac{2.2}{100 - 2.2} \times 100 = 2.249\%$$

C_s	C_{fw}	p^s_{bd}	ϕ_s
0.2045 mg/kg	45 mg/kg	2.249%	$\frac{100}{2.249 + 100} \frac{0.2045}{45} \times 100$ = 0.44% **Ans.**

$\phi_{bd} = 100 - \phi_S = 100 - 0.44 = 99.56\%$ ***Ans.***

Problem 20.6 For a drum-type boiler unit, the concentration of chlorine in feedwater and boilerwater is 55 and 245 mg/kg. Determine the blowdown rate for the boiler if 25% of make-up water is used in the feed system of the boiler unit.

Solution Here we shall use the formula

$$p^w_{bd} = \frac{C_{fw}}{C_{bw}} \times 100$$

(See problem 20.5) to calculate the blowdown rate from the salt concentration in feedwater and boiler-water.

Since 25% of the make-up water is used in the feed system

$$p^w_{bd} = 0.25 \frac{C_{fw}}{C_{bw}} \times 100$$

$$= 0.25 \frac{55}{245} (100) = 5.61\% \quad \textbf{Ans.}$$

Problem 20.7 A drum-type boiler unit (Fig. 20.18) operating at 3.348 MPa (3.348 MN/m^2) discharges water to a flash-tank in a continuous-blowdown hookup. The flash tank is maintained at a pressure 0.198 MPa (0.198 MN/m^2). Determine the amount of steam separated in the flash-tank per ton of blowdown water if the coefficient accounting for the loss of heat to the surroundings is 0.98.

Solution **Step (I)** The blowdown flashtank is maintained at a pressure considerably lower than the boiler pressure. And because of this pressure, a fraction of boilerwater, β, gets evaporated in the flashtank such that

$$\beta = \frac{\eta E_{bw} - E_w}{E_s - E_w}$$

where E_{bw} = enthalpy of boilerwater, kJ/kg

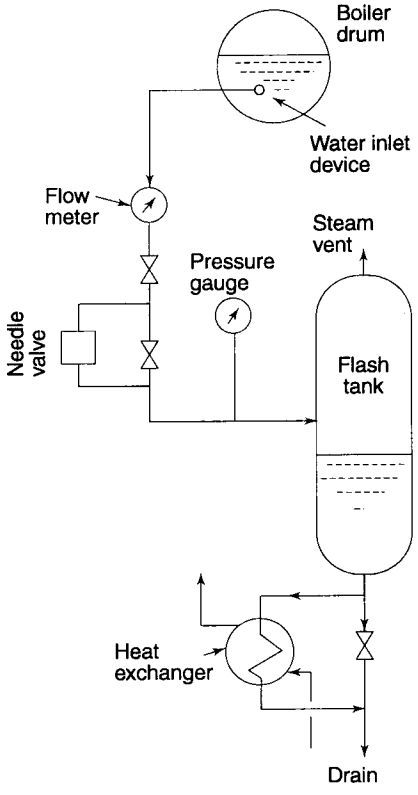


Fig. 20.18

E_w = enthalpy of water in flashtank, kJ/kg

E_s = enthalpy of steam generated in flashtank, kJ/kg

η = coefficient accounting for heat loss to the surroundings

Now

E_{bw} at 3.348 MPa = 1037 kJ/kg

E_w at 0.198 MPa = 503.7 kJ/kg

E_s at 0.198 MPa = 2706 kJ/kg

$$\beta = \frac{(0.98)(1037) - 503.7}{2706 - 503.7} = \frac{512.56}{2202.3} = 0.2327$$

Step (II) Now the quantity of steam generating in the flashtank of the continuous blowdown hookup is

$$G_s^{fl} = \beta G_{bd} = 0.2327\ (1) = 0.2327\ \text{t/h}$$

Problem 20.8 The double-stage blowdown of a 9.87 MPa boiler unit is as shown in Fig. 20.19.

Calculate the per cent of dry, saturated steam separated from each flashtank if $\eta = 1$.

Solution The fraction of boilerwater that evaporates in the flashtank can be expressed as per cent by the formula

$$\beta = \frac{\eta\, E_{bw} - E_w}{E_s - E_w} \times 100$$

1st Flastank				
E_{bw} at 9.87 MPa	E_w at 1.55 MPa	E_s at 1.55 MPa	η	β
1402 kJ/kg	852 kJ/kg	2793 kJ/kg	1	$\frac{1.402 - 852}{2793 - 852} \times 100$ = 28.33% ***Ans.***

2nd Flashtank

E_{bw} at 1.55 0. MPa	E_w at 198 MPa	E_s at 0.198 MPa	η	β
852 kJ/kg	503.7 kJ/kg	2706 kJ/kg	1	$\frac{852 - 503.7}{2706 - 503.7} \times 100$ = 15.81% ***Ans.***

Problem 20.9 The total dissolved solids (TDS) in the boilerwater of a drum-type

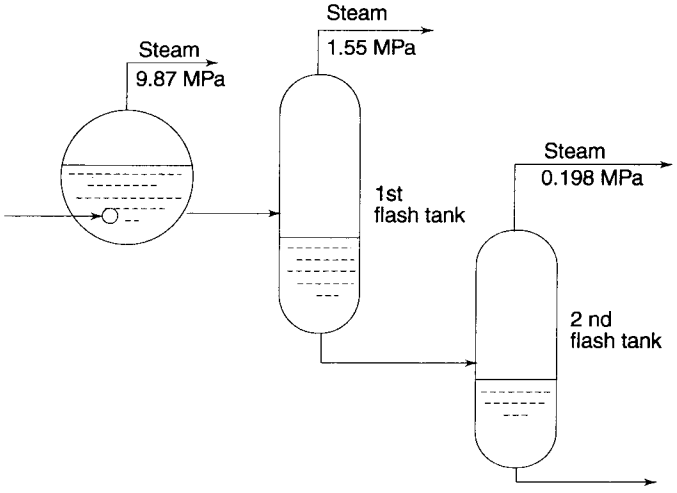


Fig. 20.19

subcritical pressure boiler is 1 175 mg/lt. What should be the maximum admissible content of TDS in softened water so as not to exceed the blowdown rate of 4.75%, if make-up water amounts to 20%?

Solution We shall use the formulae Eq. 20.5

$$p^s_{bd} = \frac{C_{fw} - C_s}{C_{bw} - C_{fw}} \times 100$$

to determine the maximum admissible TDS in softened water.

If we ignore the salt carryover by steam, the above equation simplifies to

$$p^s_{bd} = \frac{C_{fw}}{C_{bw} - C_{fw}} \times 100$$

In the present case, make-up water amounts to 20% and accordingly the above equation becomes

$$p^s_{bd} = \frac{0.2\,C_{fw}}{C_{bw} - 0.2C_{fw}} \times 100$$

Computing the numerical values,

$$4.75 = \left[\frac{0.2\,C_{fw}}{1175 - 0.2\,C_{fw}}\right] \times 100$$

or $$1\,175 - 0.2\,C_{fw} = 4.21\,C_{fw}$$

$$\therefore \quad C_{fw} = \frac{1175}{4.41} = 266.40 \text{ mg/kg} \quad \textbf{\textit{Ans.}}$$

Problem 20.10 The ratio of salt content in boilerwater to that in feedwater for an H.P. boiler fitted with blowdown is 41. Determine the amount of salts getting onto the boiler with feed, removed by blowdown water and as carryover (by steam), expressed as percentage. Take $Y = 0.01\%$

Solution We shall use the following two formulae to determine the percentage of salt removed by blowdown (ϕ_{bd}) and that removed as carryover (ϕ_s):

$$\phi_s = \frac{100}{100 + p^s_{pd}}\, Y\, \frac{C_{bw}}{C_{fw}}\,(100) \qquad (20.14)$$

[cf. $C_s = Y\,C_{bw}$; Y = per cent of carryover]

$$\phi_{bd} = 100 - \phi_s \qquad (20.15)$$

Now, $\frac{C_{bw}}{C_{fw}}$ is given; Y is also given; p^s_{bd} is unknown.

Step (I) Calculation of p^s_{bd}

Working formula: $p^s_{bd} = \frac{p^w_{bd}}{100 - p^w_{pd}} \times 100$

p^w_{bd} is not known but it is calculated as follows

$$p^w_{bd} = \frac{C_{fw}}{C_{bw}}\,100 = \frac{100}{41} = 2.44$$

$$p^s_{bd} = \frac{2.44}{100 - 2.44} \times 100 = 2.5$$

Step (II) Determination of ϕ_s and ϕ_{bd}

p^s_{bd}	Y	$\frac{C_{bw}}{C_{fw}}$	ϕ_s
2.5%	0.01%	41	$\frac{100}{100 + 2.5}\,\frac{0.01}{100}\,(41)\,(100)$ $= 0.4\%$ ***Ans.***

$\therefore\ \phi_{bd} = 100 - 0.4 = 99.6\%$ ***Ans.***

Problem 20.11 Under identical conditions of the preceeding problem (20.10) determine the amounts of silica (as silicic acid) removed from the boiler as carryover with steam and blowdown water if the concentration of silica in boilerwater is 7.5 mg/kg and in feedwater 0.2 mg/kg.

Take $Y_{SiO_2} = 0.75\%$

Solution

Step (I) Determination of silica carryover by steam

Working Formula $\phi_s = \dfrac{100}{100 + p^s_{bd}} Y \dfrac{C_{bw}}{C_{fw}} \times 100$

p^s_{bd}	Y	C_{bw}/C_{fw}	ϕ_s
2.5	0.75/100	7.5/0.2	$\dfrac{100}{102.5}\ \dfrac{0.75}{100}\ \dfrac{7.5}{0.2}$ (100) = 27.43% ***Ans.***

Step (II) Determination of silica removed by blowdown water

$$\phi_{bd} = 100 - \phi_s = 100 - 27.43 = 72.57\%$$

Problem 20.12 The steam load of a boiler is raised from 155 t/h to 175 t/h keeping the rate of blowdown unchanged. If the rate of blowdown in relation to steam is 4%, determine the initial and final salt contents of boilerwater. The salt content of feedwater is 50 mg/kg.

Solution

Step (I) Calculation of initial salt content in boilerwater

Working formula: $p^s_{bd} = \dfrac{C_{fw} - C_s}{C_{bw} - C_{fw}} \times 100$ (20.15)

Taking $C_s \approx 0$, it becomes

$$p^s_{bd} = \frac{C_{fw}}{C_{bw} - C_{fw}} \times 100$$

Putting the appropriate numerical values,

$$4 = \frac{50}{C_{bw} - 50} \times 100$$

$$\therefore \quad C_{bw} = 50 + \frac{50\,(100)}{4} = 1300 \text{ mg/kg}$$

Ans.

Step (II) Calculation of final salt content in boilerwater

Working formula: $G_{bd} = \dfrac{C_{fw} - C_s}{C_{bw} - C_{fw}} G_s$ (20.4)

Calculation of G_{bd} at 155 t/h steam load:

Taking $C_s \approx 0$,

$$G_{bd} = \frac{50}{1300 - 50}\ (155) = 6.2 \text{ t/h}$$

Calculation of C_{bw} (final) Using the above formula,

$$6.2 = \frac{50}{C_{bw} - 50} \times 175;$$

$$\therefore \quad C_{bw} = 1461 \text{ mg/kg}$$

Q. *What are drum internals for?*

Ans. Their basic objective is to ensure purity of saturated steam generated in the boiler drum.

Q. *How is this done?*

Ans. They quench the kinetic energy of the steam-water mixture jets entering the drum, bring about coarse separation of steam from water and finally dry the steam, i.e. eliminate water droplets suspended in steam (fine separation).

Q. *What is the driving force effecting the separation of water from steam?*

Ans. It is the density difference between water and saturated steam. Greater the difference, the easier the moisture is separated.

Q. *What factors determine whether a water droplet suspended in steam will be carried-off by steam or settled in the boiler drum?*

Ans. There are two forces that act upon the water droplet suspended in the steam space of the boiler drum. These two are—upward force (i.e. lifting force) due to rising velocity of steam in the drum and downward force due to gravity. The relationship between these two forces and the time

of their action determine whether the water droplet will be carried off by steam or settle on the water surface of the boiler drum.

Q. *What is the effect of pressure on steam-water separation?*

Ans. Higher the pressure of the steam, higher will be the rising velocity of steam in the drum and lower will be the density difference between water and saturated steam. And these reduce the ease of separation of water from saturated steam.

Q. *How can this problem be coped with?*

Ans. This problem can be tackled in a number of ways. One of them is settling separation : steam is allowed to distribute uniformly over the free steam space of the drum. This will ensure lowest possible rising velocities of steam in the drum creating a favaourable condition for the moisture droplets to settle on the evaporating surface. All modern steam-separation circuits involve a large free vapour space to ensure settling separation.

The other method is to deploy deflecting metal baffles and slotted or solid partitions on the path of steam flow. As the wet steam strikes the baffle, its kinetic energy gets quenched and the water droplets adhere to the baffle's surface. The steam changes its direction of motion and the residual water droplets are thrown out of the flow by the action of the centrifugal force.

Q. *What are the simplest and most efficient steamwater separation devices?*

Ans. These are perforated steel plates having perforation dia ranging from 5 to 12 mm.

Q. *Where are they placed?*

Ans. One plate is placed 10-15 cm below the average water level in the drum. This one is called the submerged plate.

The other one is placed in the steam space at the top of the boiler drum. This one is called the perforated baffle.

They equalize the distribution of steam over the cross-section of the drum.

Q. *What is the principal steam separating device in high capacity steam boilers?*

Ans. It is the cyclone separator (see Fig. 20.20)

Q. *Where is it arranged?*

Ans. It is mounted inside the boiler drum (Fig. 20.21)

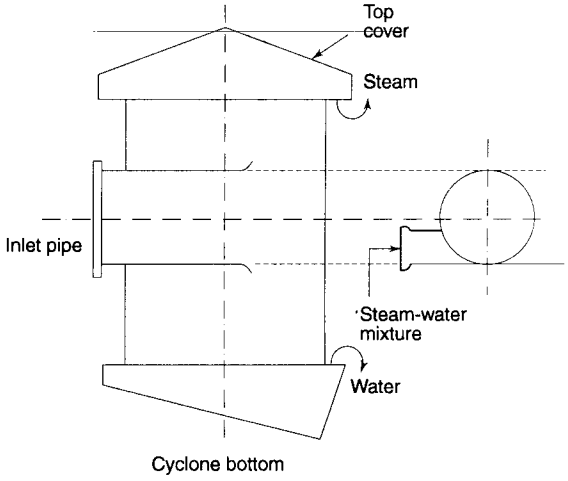


Fig. 20.20 *Cyclone separator.*

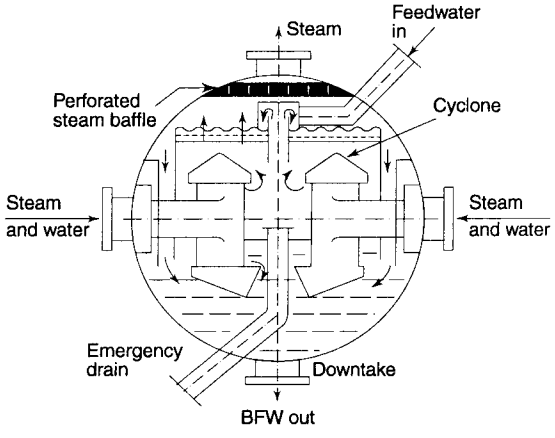


Fig. 20.21 *Cyclone separator mounted inside a boiler drum.*

Q. *How many kinds of cyclone separators are known?*

Ans. Two types: internal cyclone separator and external cyclone separator (Fig. 20.22)

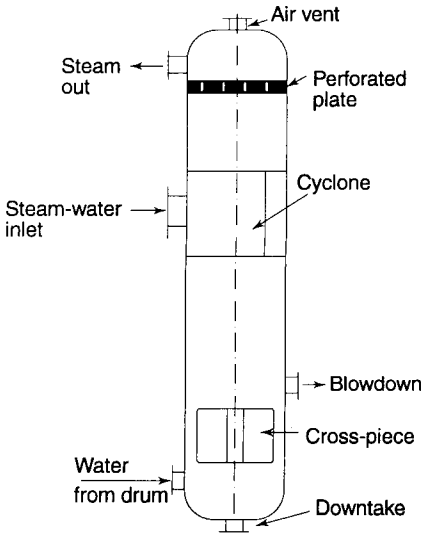


Fig. 20.22 *External cyclone separator.*

Q. *How does a cyclone separator effect steam-water separation?*

Ans. It does so by impactless quenching of the kinetic energy of the steam-water flow. It is a hollow cylinder (dia 300–400 mm) for internal cyclone separators and 350–450 mm for external cyclone separators. And through a special duct, a steam-water mixture enters the cylinder tangentially to the walls so that a rotational motion is imparted to the flow. Centrifugal force produced at the expense of the kinetic energy of the steam throws the water droplets suspended in steam to the walls of the centrifuge while the steam flows uniformly upward along the generating-line in the centre of the cyclone-cylinder.

Q. *What is the important drawback of this steam-separating system?*

Ans. Cyclone steam-water separators increase the hydraulic resistance of the circuit and hence cannot be used where the circulating head is insufficient.

Q. *Are the steam-water separating devices capable of removing substances dissolved in steam?*

Ans. No.

Q. *So what is done for this in addition to mounting separating devices?*

Ans. Boiler drums are fitted with steam washing devices

Q. *What is the basis of the steam washing principle?*

Ans. It is based on the fact that if saturated steam is brought into contact with high quality condensate of feedwater, a redistribution of dissolved solids between the liquid and vapour phase will take place, whereupon a considerable load of dissolved particles in steam will transfer to the wash water and improve the steam quality.

The same conclusion is evident from the equation $K_d = \frac{C_s}{C_{bw}}$ where C_s and C_{bw} are the concentrations of impurities in steam and boilerwater.

Since the distribution coefficient (K_d) for a particular impurity is constant at a constant pressure, a cleaner steam can be obtained at K_d = constant, by decreasing the concentration of impurities in water (C_{bw}), i.e. by washing steam with polished water or condensate.

Q. *In what device is steam washing carried out?*

Ans. Bubble-cap steam washer.

The simplest steam washing device is as shown in Fig. 20.23. It is a perforated plate onto which washing water is poured. (Fig. 20.23)

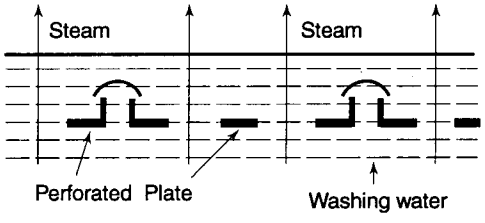


Fig. 20.23 *Bubblecap steam washer.*

The steam velocity is so adjusted as not to allow water to pass through the perforations.

Q. *Where is the steam washing carried out?*

Ans. In the boiler drum. Feedwater is used for washing the steam (Fig. 20.21). It is fed to the perforated plate having edges bent up to hold a certain layer of washing water. The flowrate of the feedwater is governed by the steam generation capacity. In modern units, the entire feedwater is charged to a distribution header and the excess of water flows down a slit in the header directly into the water space of the boiler drum without taking part in steam washing.

Q. *What is the basis of multistage evaporation?*

Ans. This can be determined as follows.

Under steady-state operating conditions, the following mass balance equation must hold good in the boiler drum.

$$C_{fw}\, G_{fw} = C_s\, G_s + C_{bd}\, G_{bd}$$

Now if $C_s \approx 0$, the above equation transforms to

$$C_{fw}\, G_{fw} = C_{bd}\, G_{bd}$$

$$\therefore \qquad C_{bd} = C_{fw}\, \frac{G_{fw}}{G_{bd}}$$

Now, writing the distribution coefficient

$$K_d^{\text{total}} = \frac{C_s}{C_{bd}}$$

$$\therefore \qquad C_s = C_{bd}\, K_d^{\text{total}} = C_{fw}\, \frac{G_{fw}}{G_{bd}}\, K_b^{\text{total}}$$

As is evident from this equation, the salt content in steam can be reduced

(a) by reducing G_{fw}. But this is inadmissible as it would mean reducing the boiler load

(b) by decreasing C_{fw}—the salt content in feedwater, which can be done either by demineralizing the make-up water or by reducing the amount of chemically treated water used as make-up for the feed system.

However, demineralization cannot be used in all cases. And a cut in the amount of make-up water will necessitate a greater fraction of condensate or distillate in feedwater. This proves impossible to satisfy in many cases.

(c) by increasing the rate of blowdown. However higher blowdown rate (> 5%) without stage evaporation facility leads to inadmissibly high heat losses. Hence, boiler units are fitted with multistage evaporation systems so that high quality steam can be produced by increasing blowdown without inflicting much heat loss.

Hence salt content in steam can be reduced by taking recourse to stage-evaporation.

Q. *Briefly describe two-stage evaporation.*

Ans. It may be considered as two independent steam boilers sharing the same steam space but having two independent water-flow circuits (No. I and II).

The water space of the boiler drum is separated into two compartments by a partition plate, an opening in which ensures free communication of water between these two compartments. (Fig. 20.24).

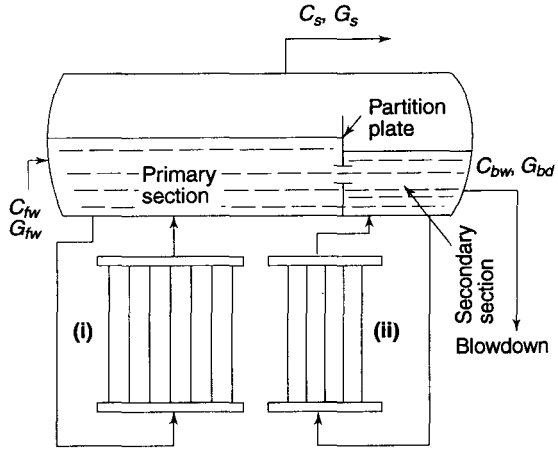


Fig. 20.24 *A two-stage evaporation unit.*

Feedwater is charged to the larger compartment called primary section or stage. The blowdown water from the primary section serves as feedwater for the secondary stage of evaporation which is also called the saline section.

Therefore, stage evaporation is based on creating a differential salt concentration in the boiler water by introducing two waterflow circuits forming primary and secondary sections.

A much larger fraction of steam is generated in the primary section having water with salt content considerably less than the blowdown water, whereas only a small fraction of the total steam is generated in the saline section having higher salt content. It follows, therefore, that forasmuch as the steam produced by the primary stage (section) is many times greater than the quantity of steam produced by the secondary section, the overall quality of the steam generated in the boiler unit provided with two-stage evaporation is higher than the quality of steam produced in a single-stage boiler unit operating under otherwise identical conditions.

Q. *How can it be numerically proved that the salt content in steam generated in the primary section is materially less than the salt content in the steam produced in the saline section?*

Ans. The salt content in steam produced in the primary section is

$$C'_s = Y' \frac{C_{fw}\, G_{fw}}{G'_{bd}} \qquad (20.16)$$

The salt content in steam generated in the secondary section is

$$C''_s = Y'' \frac{C'_{bw}\, G'_{bd}}{G''_{bd}} \qquad (20.17)$$

Dividing equation 20.16 by 20.17 we get

$$\frac{C'_s}{C''_s} = \frac{Y'}{Y''} \frac{C_{fw}}{C'_{bw}} \frac{G_{fw}}{G'_{bd}} \frac{G''_{bd}}{G'_{bd}}$$

Now putting, $Y' = Y''$; $G'_{bd} = (p^w_{bd})'\, G'_{fw}$;

$$G''_{bd} = (p^w_{bd})''\, G'_{fw}$$

in the final equation we get

$$\frac{C'_s}{C''_s} = \frac{C_{fw}}{C'_{bw}} \frac{(p^w_{bd})''}{(p^w_{bd})'} \qquad (20.18)$$

since, $\frac{C_{fw}}{C'_{bw}} < 1$ and $\frac{(p^w_{bd})''}{(p^w_{bd})'} < 1$, so $C'_s < C''_s$

i.e. the salt concentration in steam produced in the primary stage is less than that produced in the secondary or saline section (stage).

BASIS: STEAM GENERATION CAPACITY OF THE BOILER = 100 t/h

For the boiler unit as a whole

$$(100 + p^s_{bd})\, C_{fw} = 100 C_s + p^s_{bd}\, C_{bw} \qquad (20.19)$$

For I stage evaporation

$$(100 + p^s_{bd})\, C_{fw} = (100 - n)\, C'_s + (n + p^s_{bd})\, C'_{bw}$$

where n = steam generation capacity of the II stage (t/h or per cent)

Substituting, $C'_s = Y'\, C'_{bw}$ the above equation becomes

$$(100 + p^s_{bd})\, C_{fw} = (100 - n)\, Y'\, C'_{bw} + (n + p^s_{bd})\, C'_{bw}$$

or, $$C'_{bw} = \frac{100 + p^s_{bd}}{(100 - n)\, Y' + (n + p^s_{bd})}\, C_{fw}$$

Since, $(100 - n)\, Y' \ll (n + p^s_{bd})$,

$$C'_{bw} = \frac{100 + p^s_{bd}}{n + p^s_{bd}}\, C_{fw} \qquad (20.20)$$

For II stage evaporation

$$(n + p^s_{bd})\ C'_{bw} = nC''_s + p^s_{bd}\ C''_{bw}$$

Putting $C''_s = Y''C''_{bw}$, we get

$$(n + p^s_{bd})\ C'_{bw} = (nY'' + p^s_{bd})\ C''_{bw}$$

or
$$C''_{bw} = \frac{n + p^s_{bd}}{nY'' + p^s_{bd}}\ C'_{bw} \qquad (20.21)$$

If Y'' and n are small, the product $n\ Y''$ can be ignored with respect to p^s_{bd}, hence

$$C''_{bw} = \frac{n + p^s_{bd}}{p^s_{bd}}\ C'_{bw} \qquad (20.22)$$

The material balance equation for impurities in steam is

$$100\,C_s = (100 - n)\ C'_s + n\ C''_s$$

or,
$$C_s = \left(1 - \frac{n}{100}\right) C'_s + \frac{n}{100}\ C''_s \qquad (20.23)$$

If k is the ratio of salt concentrations between the saline section and primary section then

$$k = \frac{C''_{bw}}{C'_{bw}}$$

Hence equation 20.21 becomes

$$k = \frac{n + p^s_{bd}}{n\ Y'' + p^s_{bd}} \qquad (20.24)$$

or,
$$n = \frac{k - 1}{1 - k\ Y''}\ p^s_{bd} \qquad (20.25)$$

Problem 20.13 For a given boiler unit it is required to produce steam of the following quality:

Silica concentration in steam = 0.038 mg/kg

Total dissolved solids in steam = 0.22 mg/kg from the following parameters:

Concentration of TDS in make-up water = 245 mg/kg

Concentration of silicic acid in make-up water = 1.2 mg/kg

Carryover coefficient of silicic acid = 1.2 %

Carryover coefficient of TDS = 0.029 %

Make-up DM water = 25% of feedwater.

Determine whether it is feasible to generate steam of the above quality without exceeding a blowdown rate of 3%

Solution The steam quality is defined by the expressions

$$C_s^{TDS} = Y_{TDS}\ C_{bw}^{TDS}$$

and
$$C_s^{H_2SiO_3} = Y_{H_2SiO_3}\ C_{bw}^{H_2SiO_3}$$

where C_s^{TDS} and $C_s^{H_2SiO_3}$ refer to concentrations of TDS and silicic acid in steam.

Y_{TDS} and $Y_{H_2SiO_3}$ refer to the carryover coefficient in relation to total dissolved solids (TDS) and silicic acid respectively. C_{bw}^{TDS} and $C_{bw}^{H_2SiO_3}$ correspond respectively to the concentration of TDS and silicic acid in boiler water.

So we are to determine C_{bw}^{TDS} and $C_{bw}^{H_2SiO_3}$ to ascertain whether the steam quality will be within the prescribed standard or not.

Now,
$$C_{bw} = \frac{100 + p^s_{bd}}{p^s_{bd}}\ C_{fw}$$

Step (I) Calculation of C_{fw}^{TDS}

$$C_{fw}^{TDS} = \alpha_{TDS}\ C_{ch}^{TDS}$$

where α_{TDS} = fraction of chemically treated water with salt content C_{ch}^{TDS}

$$C_{fw}^{TDS} = \frac{25}{100}\ (245) = 61.25 \text{ mg/kg}$$

Step (II) Calculation of $C_{fw}^{H_2SiO_3}$

$$C_{fw}^{H_2SiO_3} = \alpha_{H_2SiO_3}\, C_{ch}^{H_2SiO_3} = \frac{25}{100} \quad (1.2)$$

$$= 0.3 \text{ mg/kg}$$

Step (III) Calculation of C_{bw}^{TDS}

$$C_{bw}^{TDS} = \frac{100+3}{3} (61.25) = 2\ 102.91 \text{ mg/kg}$$

Step (IV) Calculation of $C_{fw}^{H_2SiO_3}$

$$C_{bw}^{H_2SiO_3} = \frac{100+3}{3} (0.3) = 10.3 \text{ mg/kg}$$

Step (V) Determination of steam quality

$$\text{Now, } C_s^{TDS} = Y_{TDS}\, C_{bw}^{TDS} = \frac{0.029}{100} (2\ 102.91)$$

$$= 0.6098 \text{ mg/kg}$$

$$C_s^{H_2SiO_3} = Y_{H_2SiO_3}\, C_{bw}^{H_2SiO_3} = \frac{1.2}{100} (10.3)$$

$$= 0.1236 \text{ mg/kg}$$

Conclusion It is evident from the calculated result that at blowdown rate 3%, the desired steam quality will not be achieved.

Problem 20.14 Now to raise the steam quality as specified in Problem 20.13, the boiler unit is fitted with means of multistage evaporation, keeping the blowdown rate to 3%.

Determine the steam generating capacity of the secondary section.

Also determine the salt and silicic acid contents of steam in each section and in the whole boiler.

Solution Since the value of k ($= C''_{bw}/C'_{bw}$) usually falls within the range 3 – 10, let's assume $k = 5$

Step (I) Calculation of steam generation capacity of secondary section

$$\text{Working formula: } n = \frac{k-1}{1-kY''}\, p_{bd}^s \quad (20.25)$$

Ignoring kY'', the above equation becomes

$$n = (k-1)\, p_{bd}^s = (5-1)(3) = 12\ \% \quad \textbf{Ans.}$$

Step (II) Calculation of salt content in boilerwater in the primary section

$$\text{Working formula: } (C'_{bw})^{TDS} = \frac{100 + p_{bd}^s}{n + p_{bd}^s}\, C_{fw}^{TDS} \quad (20.26)$$

p_{bd}^s	n	C_{fw}^{TDS}	$(C'_{bw})^{TDS}$
3%	12%	61.25 mg/kg	$\frac{100+3}{12+3}$ (61.25) = 420.58 mg/kg

Step (III) Calculation of silica content in boilerwater in the primary section

Working formula:

$$(C'_{bw})^{H_2SiO_3} = \frac{100 + p_{bd}^s}{n + p_{bd}^s}\, C_{fw}^{H_2SiO_3}$$

p_{bd}^s	n	$C_{fw}^{H_2SiO_3}$	$(C'_{bw})^{H_2SiO_3}$
3%	12%	0.3 mg/kg	$\frac{100+3}{12+3}$ (0.3) = 2.06 mg/kg

Step (IV) Steam quality in primary section

Salt content in the steam (I-stage)

$$(C'_s)^{TDS} = Y'_{TDS}\, (C'_{bw})^{TDS}$$

$$= \frac{0.029}{100} (420.58)$$

$$= 0.12 \text{ mg/kg} \quad \textbf{Ans.}$$

Silicic acid content in the steam (I-stage)

$$(C'_s)^{H_2SiO_3} = Y'_{H_2SiO_3}\, (C'_{bw})^{H_2SiO_3}$$

$$= \frac{1.2}{100} (2.06) = 0.0247 \text{ mg/kg}$$

Ans.

Step (V) Calculation of salt content in boilerwater in the secondary section

Working formula:

$$(C''_{bw})^{TDS} = \frac{n + p^s_{bd}}{p^s_{bd}} (C'_{bw})^{TDS}$$

p^s_{bd}	n	$(C'_{bw})^{TDS}$	$(C''_{bw})^{TDS}$
3%	12%	420.58 mg/kg	$\frac{12+3}{3}$ (420.58) = 2102.9 mg/kg

Step (VI) Calculation of silicic acid content in boilerwater in the secondary section

Working formula:

$$(C''_{bw})^{H_2SiO_3} = \frac{n + p^s_{bd}}{p^s_{bd}} (C'_{bw})^{H_2SiO_3}$$

p^s_{bd}	n	$(C'_{bw})^{H_2SiO_3}$	$(C''_{bw})^{H_2SiO_3}$
3%	12%	2.06 mg/kg	$\frac{12+3}{3}$ (2.06) = 10.3 mg/kg

Step (VII) Steam quality in the secondary section

Salt content in the steam (II-stage)

$$(C''_s)^{TDS} = Y''_{TDS} (C''_{bw})^{TDS}$$

$$= \frac{0.029}{100} (2102.9) = 0.6098 \text{ mg/kg}$$

Ans.

Silicic acid content in the steam (II-stage)

$$(C''_s)^{H_2SiO_3} = Y''_{H_2SiO_3} (C''_{bw})^{H_2SiO_3}$$

$$= \frac{1.2}{100} (10.3) = 0.1236 \text{ mg/kg}$$

Ans.

Step (VIII) Steam quality in the boiler as a whole

Working formula:

$$C_s = \left(1 - \frac{n}{100}\right) C'_s + \frac{n}{100} C''_s \quad (20.23)$$

Average salt content,

$$C^{TDS}_s = \left(1 - \frac{12}{100}\right) (0.12) + \frac{12}{100} (0.6098)$$

$$= 0.1787 \text{ mg/kg}$$ ***Ans.***

Average silicic acid content,

$$C_s^{H_2SiO_3} = \left(1 - \frac{12}{100}\right) (0.0247) + \frac{12}{100} (0.1236)$$

$$= 0.036 \text{ mg/kg}$$ ***Ans.***

Problem 20.15 A high pressure boiler has the following feedwater quality:

Salt content = 45 mg/kg

Silicic acid = 0.23 mg/kg

It is outfitted with 2-stage evaporation such that carryover coefficient for silica in primary and secondary saline sections is 0.75 and 0.55% respectively.

If the rate of boiler blowdown is 2.75% determine

(a) concentration of total dissolved solids in the boilerwater in both primary and secondary sections

(b) concentration of silicic acid in the boilerwater in both primary and secondary sections

(c) silicic acid concentration in the overall steam produced

Given $C''_{bw}/C'_{bw} = 4$

Solution

Step (I): Let's first calculate the percentage of steam generated in the primary section.

Working formula:

$$n = \frac{k-1}{1-kY''}\ (p_{bd}^{s}) \qquad (20.25)$$

Since $kY'' \ll 1$, $n = (k-1)\ p_{bd}^{s}$

$$= (4-1) \qquad (2.75)$$

$$= 8.25\%$$

Step (II) TDS in boilerwater of primary section

Working formula:

$$(C'_{bw})^{TDS} = \frac{100 + p_{bd}^{s}}{n + p_{bd}^{s}}\ (C_{fw})^{TDS} \qquad (20.20)$$

p_{bd}^{s}	n	C_{fw}^{TDS}	$(C'_{bw})^{TDS}$
2.75%	8.25%	45 mg/kg	$\frac{100+2.75}{8.25+2.75}$ (45) = 420.34 mg/kg ***Ans.***

Step (III) Silicic acid content in boilerwater of primary section

p_{bd}^{s}	n	$C_{fw}^{H_2SiO_3}$	$(C'_{bw})^{H_2SiO_3}$
2.75%	8.25%	0.23 mg/kg	$\frac{100+2.75}{8.25+2.75}$ (0.23) = 2.148 mg/kg ***Ans.***

Step (IV) TDS in boilerwater of secondary section

$(C'_{bw})^{TDS}$	n	p_{bd}^{s}	$(C''_{bw})^{TDS}$
420.34 mg/kg	8.25%	2.75%	$\frac{8.25+2.75}{2.75}$ (420.34) = 1681.36 mg/kg ***Ans.***

Step (V) Silicic acid content in boilerwater in the secondary section.

$(C'_{bw})^{H_2SiO_3}$	n	p_{bd}^{s}	$(C''_{bw})^{H_2SiO_3}$
2.148 mg/kg	8.25%	2.75%	$\frac{8.25+2.75}{2.75}$ (2.148) = 8.59 mg/kg ***Ans.***

Step (VI) Average silicic acid content in the overall steam

Working formula:

$$C_s^{H_2SiO_3} = \left(1 - \frac{n}{100}\right)(C''_s)^{H_2SiO_3} + \frac{n}{100}\ (C''_s)^{H_2SiO_3} \qquad (20.23)$$

$$(C'_s)^{H_2SiO_3} = Y'_{H_2SiO_3}\ (C'_{Bw})^{H_2SiO_3}$$

$$= \frac{0.75}{100}\ (2.148)\text{mg/kg} = 0.0161\ \text{mg/kg}$$

$$(C''_s)^{H_2SiO_3} = Y''_{H_2SiO_3}\ (C''_{bw})^{H_2SiO_3}$$

$$= \frac{0.55}{100}\ (8.59)\ \text{mg/kg} = 0.0472\ \text{mg/kg}$$

$$C_s^{H_2SiO_3} = \left(\frac{1-8.25}{100}\right)(0.0161) + \frac{8.25}{100}\ (0.0472)$$

$$= 0.0186\ \text{mg/kg} \qquad \textbf{\textit{Ans.}}$$

Problem 20.16 For a high pressure boiler fitted with multistage evaporation, a project envisages that the total dissolved solid in the boilerwater in the primary section should not exceed 420 mg/kg and the upper limit of silicic acid content in the secondary section should be 8.5 mg/kg.

The make-up water amounts to 15% of feedwater.

The make-up water quality:

TDS content = 400 mg/kg

Silicic acid content = 2 mg/kg

Determine

(a) the limiting quality standard for boilerwater

(b) the blowdown rate prescribed by the standard

(c) the concentration ratio for boilerwater filling I and II-stage

(d) the content of total dissolved solid in the I and II stage evaporating section.

Solution

Step (I) Calculation of C_{fw}^{TDS}

$$C_{fw}^{TDS} = \alpha_{TDS}\, C_{ch}^{TDS} \text{ (see Problem 20.13)}$$

$$= \frac{15}{100}\,(400) = 60 \text{ mg/kg}$$

Step (II) Calculation of $C_{fw}^{H_2SiO_3}$

$$C_{fw}^{H_2SiO_3} = \alpha_{H_2SiO_3}\, C_{ch}^{H_2SiO_3} = \frac{15}{100} \qquad (2)$$

$$= 0.3 \text{ mg/kg}$$

Step (III) Determination of blowdown rate

Now, $(C'_{bw})^{TDS} = 420$ mg/kg (given)

$(C''_{bw})^{H_2SiO_3} = 8.5$ mg/kg (given)

But, $$(C'_{bw})^{TDS} = \frac{100 + p_{bd}^s}{n + p_{bd}^s}\, C_{fw}^{TDS}$$

or, $$420 = \left[\frac{100 + p_{bd}^s}{n + p_{bd}^s}\right] 60$$

or, $$7 = \frac{100 + p_{bd}^s}{n + p_{bd}^s} \qquad (I)$$

Also, $$(C''_{bw})^{H_2SiO_3} = \frac{n + p_{bd}^s}{p_{bd}^s}\,(C'_{bw})^{H_2SiO_3} \qquad (II)$$

and $$(C'_{bw})^{H_2SiO_3} = \frac{100 + p_{bd}^s}{p_{bd}^s}\, C_{fw}^{H_2SiO_3} \qquad (III)$$

From equations (II) and (III) we get

$$(C''_{bw})^{H_2SiO_3} = \frac{100 + p_{bd}^s}{p_{bd}^s}\, C_{fw}^{H_2SiO_3}$$

or, $$8.5 = [(100 + p_{bd}^s)/p_{bd}^s]\ 0.3$$

or, $$p_{bd}^s = 3.658\% \approx 3.66\%$$

Step (IV) Determination of fraction of total steam generated in the secondary section

Computing the value of p_{bd}^s in equation (I) we have,

$$7 = \frac{100 + 3.66}{n + 3.66}$$

$\therefore$ $$n = 14.808 - 3.66 = 11.14\%$$

Step (V) Calculation of $(C''_{bw})^{TDS}$

$$(C''_{bw})^{TDS} = \frac{n + p_{bd}^s}{p_{bd}^s}\,(C''_{bw})^{TDS}$$

$$= \frac{11.14 + 3.66}{3.66}\,(420)\text{mg/kg}$$

$$= 1698.36 \text{ mg/kg} \qquad \textbf{Ans.}$$

Step (VI) Concentration ratio for boilerwater filling I and II stages

$$k = \frac{(C''_{bw})^{TDS}}{(C'_{bw})^{TDS}} = \frac{1698.36}{420} = 4 \qquad \textbf{Ans.}$$

Problem 20.17 If the carryover coefficient for silicic acid in the primary and secondary sections in problem 20.16 are 0.8 and 0.55% respectively, determine the quality of overall steam in relation to the silicic acid content.

Solution The quality of overall steam can be determined with the aid of the formula:

$$C_s = \left(1 - \frac{n}{100}\right) C'_s + \frac{n}{100}\,(C''_s) \qquad (20.23)$$

Hence the silicic acid concentration in the overall steam is

$$C_s^{H_2SiO_3} = \left(1 - \frac{n}{100}\right) Y''_{H_2SiO_3}\,(C'_{bw})^{H_2SiO_3}$$

$$+ \frac{n}{100}\, Y'_{H_2SiO_3}\,(C''_{bw})^{H_2SiO_3}$$

$$\text{Now, } (C'_{bw})^{H_2SiO_3} = \frac{100 + p^s_{bd}}{n + p^s_{bd}} C_{fw}^{H_2SiO_3}$$

$$= \frac{100 + 3.66}{11.14 + 3.66} (0.3) = 2.10 \text{ mg/kg}$$

n	11.14%
$Y'_{H_2SiO_3}$	0.8%
$Y''_{H_2SiO_3}$	0.55%
$(C'_{bw})_{H_2SiO_3}$	2.10 mg/kg
$(C''_{bw})_{H_2SiO_3}$	8.5 mg/kg
$C_s^{H_2SiO_3}$	$(1 - 11.14/100)\,(0.8/100)\,(2.10) + \frac{11.14}{100}\left(\frac{0.55}{100}\right)(8.5)$
	= 0.020 mg/kg **Ans.**

Problem 20.18 Taking data from Problems 20.13 and 20.14, determine the percentage of silicic acid carried over by steam from the primary and secondary sections. Also compare these carryovers of silicic acid with that carried over by steam before the boiler was fitted with 2-stage evaporation.

Solution

Step (I) In the primary section of the two stage evaporator, the following material balance equation can be drawn

$$(100 + p^s_{bd})\, C_{fw} = (100 - n)\, C'_s + (n + p^s_{bd}) C'_{bw}$$

If C_{fw}, C'_s and C'_{bw} are taken as the silicic acid concentration in feedwater, in the steam of the primary section and in the boilerwater of the primary section, then

$(100 - n)\, C'_s$ = carryover of silicic acid by steam in the primary section

$(n + p^s_{bd})\, C'_{bw}$ = carryover of silicic acid by boilerwater in the primary section.

Therefore, the relative percentage of silicic acid carried over by steam from the total amount of silicic acid entering with the feedwater is

$$R_1^{H_2SiO_3} = \frac{(100 - n)\, C'_s}{(100 + p^s_{bd})\, C_{fw}} (100)$$

$$= \frac{100 - 12}{100 + 3}\left(\frac{0.0247}{0.3}\right)(100) = 7\%$$

Step (II) In the secondary section, the amount of silicic acid carried over by steam is $n\, C''_s$.

$$R_2^{H_2SiO_3} = \frac{n\, C''_s}{(100 + p^s_{bd})\, C_{fw}} (100)$$

$$= \frac{12\,(0.1236)}{(103)\,(0.3)} (100) = 4.8\% \textbf{ Ans.}$$

Step (III) Before the boiler was provided with 2-stage evaporation, the silicic acid carryover by steam amounted to

$$\frac{100\,(0.1236)}{(100 + 3)\,(0.3)} (100) = 40\% \textbf{ Ans.}$$

Problem 20.19 If in Problem 20.14 the flow of boilerwater from the 2nd-stage to 1st-stage is at a rate of 4% of the steam generating capacity of the boiler, determine, with the help of the data in Problem 20.13 and 20.14, the amount of silicic acid carryover by steam from the boiler.

Solution If "r" be the water flow from the II-stage to the I-stage, expressed as a percentage of G_s (the steam generating capacity of the boiler unit), then equations 20.20 and 20.22 modify to

$$C'_{bw} = \frac{(100 + p^s_{bd})\, C_{fw} + r\, C''_{bw}}{r + n + p^s_{bd}} \quad (20.26)$$

$$C''_{bw} = \frac{r + n + p^s_{bd}}{r + p^s_{bd}} C'_{bw} \quad (20.27)$$

Putting the appropriate numerical values we get from equation 20.26,

$$C'_{bw} = \frac{(100+3)(0.3) + 4C''_{bw}}{4+12+3}$$

$$= 1.62 + 0.21\ C''_{bw}$$

From equation 20.27 we get,

$$C''_{bw} = \frac{4+12+3}{4+3}\ C'_{bw} = 2.71\ C'_{bw}$$

Solving these two equations we get,

$$C'_{bw} = 1.62 + 0.21\ (2.71)\ C'_{bw}$$

$\therefore$ $C'_{bw} = 3.75$ mg/kg

$C''_{bw} = 2.71(3.75)$ mg/kg

$= 10.16$ mg/kg

Therefore, the concentration of silicic acid in steam

(a) Primary section: $C'_s = Y'_{H_2SiO_3}\ C'_{bw}$

$$= \left(\frac{1.2}{100}\right)(3.75) = 0.045 \text{ mg/kg}$$ ***Ans.***

(b) Secondary section:

$$C''_s = \left(\frac{1.2}{100}\right)(10.16) = 0.1219 \text{ mg/kg}$$ ***Ans.***

Hence the amount of silicic acid carryover by the overall steam

$$C_s = \left(1 - \frac{n}{100}\right) C'_s + \frac{n}{100}\ C''_s$$

$$= \left(1 - \frac{12}{100}\right)(0.045) + \frac{12}{100}\ (0.1219)$$

$$= 0.054 \text{ mg/kg}$$ ***Ans.***

Q. *How can the quality of steam be expressed mathematically?*

Ans. Actually steam quality is determined by the concentration and the composition of the impurities, viz. silicic acid, salts, gases etc. contained in it. Since these impurities swing between steam and boilerwater, a proportionality factor Y is drawn into the equation to define the coefficient of carryover of a given impurity by steam

$$C_s = Y \cdot C_{bw} \qquad (20.28)$$

where, C_s = concentration of an impurity in steam, mg/kg

C_{bw} = concentration of that impurity in boilerwater, mg/kg

This relationship holds good for impurities such as SiO_3^{2-}, various salts and NaOH but not for NH_4^+ salts and CO_2.

Q. *What is the value of Y?*

Ans. For 4–11 MPa boilers the value of Y ranges from:

0.0001 – 0 .0005 for total salt carryover

and 0.005 – 0.01 for silicic acid.

Q. *How can the steam quality be determined?*

Ans. One method utilizes partial steam condensation. It serves a dual purpose

I. To increase the concentration of steam-contained impurities

II. To release some quantity of condensate that will wash out the entire steam flow whereupon the impurities contained in the steam almost completely pass into the solution.

Therefore, if due to partial condensation of saturated steam [G'_s, kg/h], G_m kg/h of moisture is liberated, then by mass balance

$$G'_s \cdot C_s = G_m \cdot C_m \qquad (20.29)$$

where, G'_s = steam flowrate, kg/h

G_m = moisture (condensate) flowrate, kg/h

C_s = concentration of a particular impurity in steam, mg/kg

C_m = concentration of the said impurity in the moisture after washing of the steam, mg/kg

$$\text{whence } \varphi = \frac{G'_s}{G_m} = \frac{C_m}{C_s} \tag{20.30}$$

φ is referred to as the degree of sample enrichment. It indicates how many times the concentration of impurities in the moisture is greater than their concentration in steam prior to its partial condensation.

Forasmuch as throttling is accompanied by partial steam condensation, high-pressure steam can be wetted, i.e. humidified by throttling it. Therefore, the moisture content of steam (expressed in %) as a result of throttling is

$$W_s = \frac{\Delta E}{E_{\text{vap}}} \times 100 \tag{20.31}$$

$$\varphi = \frac{E_{\text{vap}}}{\Delta E} \tag{20.32}$$

where $\Delta E = E_{s,a} - E_{s,b}$

$E_{s,a}$ = enthalpy of saturated steam after throttling, kJ/kg

$E_{s,b}$ = enthalpy of H.P. steam before throttling, kJ/kg

E_{vap} = heat of vaporization at the pressure downstream of the throttle valve, kJ/kg

Q. *Why is the partial condensation method and not the direct concentration measurement of steam followed?*

Ans. The concentrations of impurities in steam C_s are rather too low and this poses difficulties in their exact determination because the sensitivity of the methods of concentration analysis applied usually happens to be inadequate over the concentration range encountered.

Problem 20.20: A boiler generates 3.2 MPa/723°K steam which is to be cooled to 683°K by injecting condensate (at 423°K) into the header by a spray-attemperator.

If the salt content of the attemperated steam is not to exceed 200 μg/kg, calculate the maximum admissible salt content in the spray-water.

Given

TDS in boilerwater = 1.5 g/kg

Carryover coefficient of steam = 0.01%

Enthalpy of steam before attemperation = 3.34 MJ/kg

Enthalpy of steam after attemperation = 3.25 MJ/kg

Enthalpy of spray-water = 630 kJ/kg

Enthalpy of evaporation at 423°K = 1.79 MJ/kg

Solution If G_w kg of water is sprayed per kg of SH steam with salt concentration C_s and C'_s before and after attemperation respectively, then by mass balance on the basis of 1 kg SH steam

$$C'_s = G_w \cdot C_w + (1 - G_w) \cdot C_s$$

$$\text{whence, } C_w = \frac{C'_s - (1 - G_w).C_s}{G_w} \tag{20.33}$$

Therefore, C_w, the concentration of salt in spray-water can be computed by determining the values of G_w and C_s.

From the given data

$C'_s = 200\ \mu\text{g/kg} = 0.2\ \text{mg/kg}$

$C_{bw} = 1.5\ \text{g/kg} = 1500\ \text{mg/kg}$

$Y = 0.01\ \%$

$E_{s,b} = 3.34\ \text{MJ/kg}$

$E_{s,a} = 3.25\ \text{MJ/kg}$

$E_w = 630\ \text{kJ/kg} = 0.63\ \text{MJ/kg}$

$E_{\text{vap}} = 1.79\ \text{MJ/kg}$

Now, $C_s = Y \cdot C_{bw}$ (20.28)

$$= \frac{0.01}{100} \times 1500$$

$$= 0.15 \text{ mg/kg}$$

From heat balance, *Basis*: 1 kg SH Steam

Heat content of feed steam before attemperation	+	Heat content of the water sprayed
= Heat content of steam after attemperation	+	Heat absorbed in evaporating the water sprayed

or, $(1 - G_w) \cdot E_{s,b} + G_w \cdot E_w = E_{s,a} + G_w \cdot E_{vap}$

whence, $$G_w = \frac{E_{s,b} - E_{s,a}}{E_{s,b} - E_w + E_{vap}} \qquad (20.34)$$

$$= \frac{3.34 - 3.25}{3.34 - 0.63 + 1.79} = 0.02$$

$$\therefore \quad C_w = \frac{0.2 - (1 - 0.02)\,(0.15)}{0.02} = 2.65 \text{ mg/kg}$$

Therefore, the condensate water used as spray-liquid must have salt content less than or equal to 2.65 mg/kg.

Ans.

Problem 20.21 Condensate is sprayed through a surface attemperator to a steam header containing SH steam generated in the HP boiler. The salt content of the spray liquid is equal to 35 mg/kg. Calculate the leakage of condensate spray in the attemperator in terms of percentage of boiler capacity.

Given

Salt content of SH steam upstream of attemperator = 0.15 mg/kg

Salt content of steam just downstream of attemperator = 0.2 mg/kg

Solution Drawing up mass balance Fig. 20.25, on the basis of 1 kg SH steam, over the attemperator yields

$$1 \cdot C_s + G_w \cdot C_w = 1 \cdot C''_s + G_w \cdot C_s$$

or, $$G_w = \frac{C'_s - C_s}{C_w - C_s} \qquad (20.35)$$

where, C_s = concentration of salt in steam upstream of attemperator, mg/kg

$= 0.15$ mg/kg

C'_s = concentration of salt in attemperated steam, mg/kg = 0.2 mg/kg

C_w = salt content in the attemperator water, mg/kg

$= 0.35$ mg/kg

Computing these data in the above relationship (Eq. 20.35) we get,

$$G_w = \frac{0.2 - 0.15}{0.35 - 0.15}$$

$= 1.434 \times 10^{-3}$ kg of spray-water/kg of SH steam

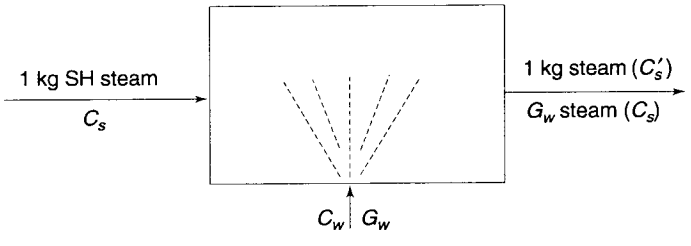


Fig. 20.25

= 0.1434% in terms of percentage of boiler capacity **Ans.**

Problem 20.22 In a high-pressure boiler saturated steam at 11 MPa is generated at the rate of 100 t/h.

In order to determine the salt content of this steam, a sidestream at the rate of 60 kg/h is taken as a sample steam valve and then flashed into the flashdrum (Fig. 20.26) where moisture separated from the flashsteam is sent to a salt gauge via a cooler.

Enthalpy of evaporation at flashdrum (FD) pressure = 1.84 MJ/kg

Calculate

1. Moisture content of steam as a result of throttling
2. The degree of sample enrichment
3. The amount of moisture formed

Solution The moisture content of steam as a result of throttling

$$W_s = \frac{\Delta E}{E_{vap}} \times 100$$

$$= \frac{2.8 - 2.71}{1.84} \times 100$$

$$= 4.8913\ \% \qquad \textbf{Ans.}$$

Sample enrichment

$$\varphi = \frac{E_{vap}}{\Delta E} = \frac{1.84}{2.8 - 2.71} = 20.4444$$

Ans.

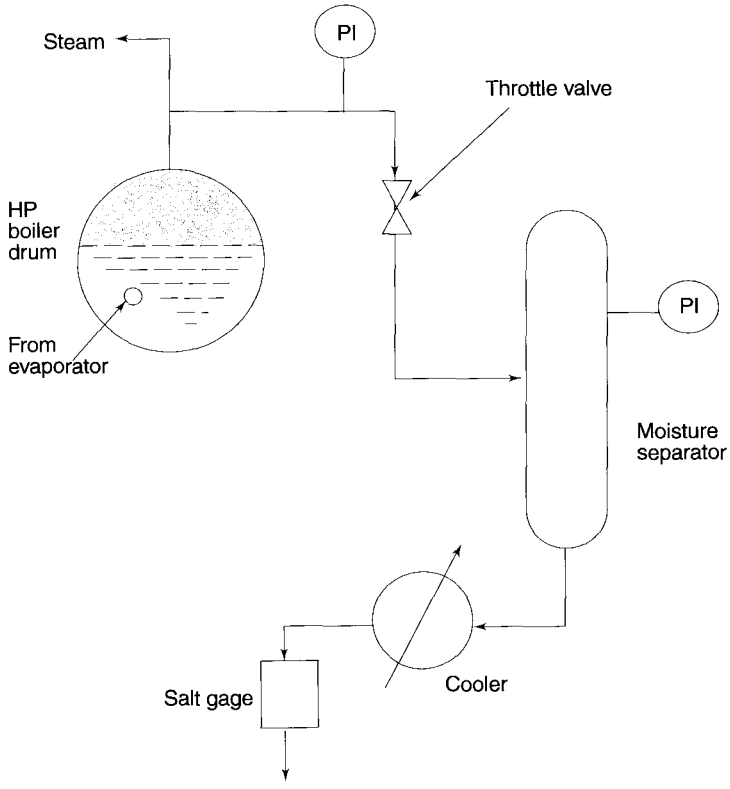


Fig. 20.26 *Schematic diagram of metering the salt content of steam.*

Therefore, the amount of moisture formed

$$G_m = \frac{G'_s}{\varphi} = \frac{60}{20.4444} = 2.9347 \text{ kg/h} \quad \textbf{Ans.}$$

Problem 20.23 Determine the design values of the total salt content and SiO_3^{2-} concentration in a sample of water taken from the moisture trap in Problem 20.22 under the following conditions:

Salt content of boilerwater = 800 mg/kg

Silicic acid of boilerwater = 6.2 mg/kg

$$Y_s = 0.02\%$$

$$Y_{SiO_3^{2-}} = 0.7\%$$

Solution The salt content in steam

$$C_s = Y_s \cdot C_{bw}^s = \frac{0.02}{100} \times 800 = 0.16 \text{ mg/kg}$$

The silicic acid concentration in steam

$$C_{SiO_3^{2-}} = Y_{SiO_3^{2-}} \cdot C_{bw}^{SiO_3^{2-}}$$

$$= \frac{0.7}{100} \times 6.2 = 0.0434 \text{ mg/kg}$$

From the enrichment-relationship

$$\varphi = \frac{C_m}{C_s}$$

we have,

the salt content in steam-condensate,

$$C_m = 20.4444\ (0.16)$$

$$= 3.27 \text{ mg/kg} \quad \textbf{Ans.}$$

The silicic acid content in steam-condensate,

$$C_m^{SiO_3^{2-}} = 20.4444\ (0.0434) = 0.8872 \text{ mg/kg}$$

Ans.

Q. *Does the concentration of substances in boilerwater change continuously when the boiler is i/1?*

Ans. Yes.

Q. *On which factors does this nature of change in boilerwater quality depend?*

Ans. 1. Quality of BFW, C_{fw}
2. Steam load of boiler, G_s
3. Blowdown rate of the boiler, p_{bd}^s

A change in any of these factors brings about a consequent change in boilerwater quality.

Note: Blowdown rate p_{bd}^s is expressed in terms of per cent blowdown with respect to steam generation capacity of the boiler, i.e.

$$p_{bd}^s = \frac{G_{bd}}{G_s} \times 100$$

where, G_{bd} = blowdown rate, t/h

G_s = steam generation rate, t/h

Q. *How does the quality of boilerwater change with the increase of steam load?*

Ans. An increase in steam load causes an increase in the concentration of dissolved substances in boilerwater.

Q. *How can the change in the concentration of total dissolved solids (TDS), alkalinity,* SiO_3^{2-} *and other impurities in boilerwater be quantitatively specified?*

Ans. As soon as the start-up of a boiler filled with BFW is made, the concentration of substances in the boilerwater begins to rise. This rate of increase depends on whether the BD is lined up or not.

The rate of increase in the content of TDS, SiO_3^{2-}, pH and other impurities may be specified by

$$C_{bw}^{\tau} = C_{fw} + \frac{G_s}{V_w} [C_{fw} - C_s]\tau \quad (20.36)$$

where, C_{bw}^{τ} = concentration of substances in the boilerwater at any instant τ, mg/kg

C_{fw} = concentration of substances in boiler feedwater, mg/kg

G_s = steam-generating capacity of the boiler, t/h

V_w = volume of water-space in boiler, m^3

τ = time in operation after start-up, h

The rate at which the concentration increases

$$\frac{C_{bw}^{\tau} - C_{fw}}{\tau} = \frac{G_s}{V_w} (C_{fw} - C_s) \qquad (20.37)$$

Q. *So as long as heating continues (i.e. boiler remains i/l), C_{bw}^{τ} will increase. Does it mean that the concentration of substances in the boilerwater will increase infinitely?*

Ans. The solubility of substances dissolved in boilerwater is limited. Therefore, C_{bw}^{τ} cannot go on increasing indefinitely. Over and above, an increase in C_{bw}^{τ} is accompanied by an increase in the carryover of substances from the boilerwater to steam. These two factors restrict the increase in concentration of substances in the boilerwater (C_{bw}^{τ}).

Q. *If the content of dissolved substances in boilerwater much exceeds that in generated steam, how can the time, τ, required for the concentration of dissolved substances in boiler water to become equal to C_{bw}^{τ} be computed?*

Ans. Given $C_{bw} \gg C_s$

Therefore, the above expression (Eq. 20.36) simplifies down to

$$C_{bw}^{\tau} = C_{fw} + \frac{G_s}{V_w} \cdot C_{fw} \cdot \tau$$

$$\therefore \qquad \tau = \frac{1}{C_{fw}} \left(C_{bw} - C_{fw}\right) \frac{V_w}{G_s} \qquad (20.38)$$

Q. *What factor is responsible for the high rate at which the concentration of boilerwater impurities increases?*

Ans. For modern heavy-duty drum-type boilers, the evaporation ratio G_s/V_w is very high, as much as 3 to 4. Under this circumstance, the rate of increase in the concentration of impurities in boilerwater becomes very sharp

$$\frac{\Delta C_{bw}}{\tau} = \frac{G_s}{V_w} [C_{fw} - C_s] \qquad (20.39)$$

$$= (3 \text{ to } 4) \text{ times } [C_{fw} - C_s]$$

where, ΔC_{bw} = increase in concentration of substances in boilerwater

$$= C_{bw}^{\tau} - C_{fw}$$

$\frac{G_s}{V_w}$ = evaporation ratio

= 3–4 for high-duty drum-type boilers

Q. *What is its importance?*

Ans. The boiler operator must keep this fact in mind particularly when the BD system is inefficient, otherwise the rapid increase in salt concentration in boilerwater will bring about higher level of salt carryover to steam.

Q. *If the boiler is kept in service for a long time with BD i/l, what will the concentration of boilerwater be?*

Ans. When a boiler is started and BD lined up, the concentration of impurities in the boilerwater increase in accordance to

$$C_{bw}^{\tau} = \frac{100 + p_{bd}^{s}}{p_{bd}^{s}} \left[1 - \exp. \left\{ -\frac{G_s^{s} \cdot p_{bd}^{s}}{100\, V_w} \cdot \tau \right\}\right] C_{fw} \qquad (20.40)$$

$$= \frac{100 + p_{bd}^{s}}{p_{bd}^{s}} \cdot C_{fw} \cdot [1 - \exp(-B\,\tau)]$$

where, $B = \frac{G_s \cdot p_{bd}^{s}}{100\, V_w}$

If the boiler is kept in service for a prolonged period, $\tau \longrightarrow \infty$, the value of C_{bw}^{τ} approaches a limit

$$C_{bw}^{o} = \frac{100 + p_{bd}^{s}}{p_{bd}^{s}} \cdot C_{fw} \qquad (20.41)$$

Q. *How much will it take to enrich the concentration of impurities in boilerwater from $C_{bw}^{\tau_1}$ to $C_{bw}^{\tau_2}$ where $\tau_2 > \tau_1$?*

Ans. For any drum type boiler operating with blowdown in line, the concentration of impurities in boilerwater at any instant τ is

$$C_{bw}^{\tau} = \frac{100 + p_{bd}^{s}}{p_{bd}^{s}} \cdot C_{fw} \cdot [1 - \exp.(-B\,\tau)]$$

If the boiler is kept in service for a long time, i.e. as $\tau \longrightarrow \infty$,

$$C_{bw}^{\tau} = C_{bw}^{o}[1 - \exp.(-B\,\tau)]$$

where, C_{bw}^{o} = ultimate limit of impurities concentration in the boilerwater, mg/kg

$$= \frac{100 + p_{bd}^{s}}{p_{bd}^{s}} \cdot C_{fw}$$

Putting

$$C_{bw}^{\tau}/C_{bw}^{o} = m, \text{ we get}$$

$$1 - m = \exp.(-B\,\tau)$$

or, $\ln(1 - m) = -B\,\tau$

$$\therefore \qquad \tau = \frac{-\ln(1-m)}{B}$$

Now C_{bw}^{o} denotes the maximum admissible concentration of impurities in the boiler water while $C_{bw}^{\tau_1}$ and $C_{bw}^{\tau_2}$ indicate the intermediate concentrations.

$$\tau_1 = \frac{-\ln(1-m_1)}{B}$$

where, $m_1 = C_{bw}^{\tau_1}/C_{bw}^{o}$

and

$$\tau_2 = \frac{-\ln(1-m_2)}{B}$$

where, $m_2 = C_{bw}^{\tau_2}/C_{bw}^{o}$

$$\therefore \qquad \Delta\tau = \tau_2 - \tau_1$$

$$= \frac{1}{B}[\ln(1 - m_1) - \ln(1 - m_2)]$$

$$= \frac{1}{B} \cdot \ln\left(\frac{1-m_1}{1-m_2}\right) \qquad (20.43)$$

Problem 20.24 A 200 t/h boiler is lined up with a closed BD after a month-long turnaround.

TDS in BFW = 36 mg/kg

Water space of the boiler = 50 m^3

How long it will take the TDS concentration in BW to reach its normal value (1236 mg/kg)?

Solution The BD is closed.

$$C_{fw}^{\text{TDS}} = 36 \text{ mg/kg}$$

$$V_w = 50 \text{ m}^3$$

$$C_{bw}^{\tau} = 1236 \text{ mg/kg}$$

$$\tau = ?$$

Ignoring the TDS concentration in steam during start-up period, eqn. 20.36 transforms to

$$C_{bw}^{\tau} = C_{fw} + \frac{G_s}{V_w} \cdot C_{fw} \cdot \tau$$

or, $1236 = 36 + \frac{200}{50}(36)\,\tau$

$$\therefore \qquad \tau = 8.33333 \text{ h} = 8\text{h } 20 \text{ min} \qquad \textbf{\textit{Ans.}}$$

Problem 20.25 If the same boiler in Problem 20.24 is put into operation with 3% blowdown,

how long it will take the TDS concentration in BW to attain the same normal concentration?

Solution Let τ be the required time. During this period of boiler operation TDS level in BW approaches its ultimate value (say 99% of C^o_{bw})

$$\therefore \qquad m = 0.99$$

Therefore, τ may be computed from

$$\tau = \frac{-\ln (1 - m)}{B} \qquad (20.42)$$

$$B = \frac{G_s \cdot p^s_{bd}}{100\ V_w} = \frac{200 \times 3}{100 \times 50} = 0.12$$

$$\therefore \qquad \tau = \frac{-\ln (1 - 0.99)}{0.12} = 38.376\ h$$

$$= 38 \text{ h } 22.6 \text{ min} \qquad \textbf{Ans.}$$

Problem 20.26 A boiler not outfitted with multistage evaporation was *i*/1 with 4% blowdown rate. Due to a faulty hook-up, its blowdown rate suddenly dropped to 2%.

At the time of BD changeover, the TDS content of BW amounted to 1175 mg/kg.

Determine the time span over which the total solid content of BW will increase by 300 mg/kg.

Steam generation capacity of boiler = 150 t/h

Boilerwater space = $45 m^3$

Solution Due to the decrease in BD rate, the TDS concentration in BW will rise. However, it will never cross the ultimate limit.

TDS content of FW before BD rate was changed

$$C_{fw} = \frac{p^s_{bd}}{100 + p^s_{bd}} \cdot C^{\tau}_{bw}$$

$$= \frac{4}{100 + 4} (1175)$$

$$= 45.192 \text{ mg/kg}$$

Maximum TDS content in BW

$$C^o_{fw} = \frac{100 + p^s_{bd}}{p^s_{bd}} \cdot C_{fw}$$

$$= \frac{100 + 2}{2} (45.192)$$

Note: Max. TDS content in BW will occur when BD rate is at a minimum

$$= 2304.807 \text{ mg/kg}$$

Due to the fall of BD rate, the TDS content of BW rises from 45.192 mg/kg to the maximum admissible limit of 1175 + 300 = 1475 mg/kg over a time span, say τ_1, whence

$$\tau_1 = \frac{-\ln (1 - m_1)}{B};$$

$$= \frac{-\ln (1 - 0.6399)}{0.0666}$$

$$= 15.322 \text{ h}$$

$$m_1 = C^{\tau_1}_{bw} / C^o_{bw}$$

$$= 1475/2304.807$$

$$= 0.6399$$

$$B = \frac{G_s \cdot p^s_{bd}}{100\ V_w}$$

$$= \frac{150\ (2)}{100\ (45)}$$

$$= 0.0666$$

At the same 2% BD rate, the TDS content of BW will increase from 45.192 mg/kg to 1175 mg/kg in time, say τ_2, whence

$$\tau_2 = \frac{-\ln (1 - m_2)}{B};$$

$$= \frac{-\ln (1 - 0.5098)}{0.0666}$$

$$= 10.695 \text{ h}$$

$$m_2 = C^{\tau_2}_{bw}/C^{o}_{bw}$$
$$= 1175/2304.807$$
$$= 0.5098$$

Thus the time interval during the course of which the TDS concentration in BW increases from 1175 mg/kg to 1475 mg/kg is

$$\Delta\tau = \tau_1 - \tau_2$$
$$= 15.322 - 10.695$$
$$= 4.627 \text{ h}$$
$$= 4 \text{ h } 37.6 \text{ min}$$ ***Ans.***

Problem 20.27 A 20 t/h boiler is 1/up with a closed BD. TDS in BFW = 36 mg/kg

Water space in boiler = 16.5 m^3

How long it will take for the TDS concentration in BW to reach its normal value (1236 mg/kg)?

Why does the difference in rate rise in the concerned boiler and in the boiler of Problem 20.24?

Solution Using eqn. 20.36

$$C_{bw} = C_{fw} + \frac{G_s}{V_w} \cdot C_{fw} \cdot \tau \qquad (20.36)$$

to calculate the time τ required to enrich BW with salt content of 1236 mg/kg from the initial value of 36 mg/kg.

Substituting the known data as get

$$1236 = 36 + \frac{20}{16.5} (36)\ \tau$$

$$\therefore \qquad \tau = 27.5 \text{ h}$$

The rate of BW enrichment

$$\frac{C_{bw} - C_{fw}}{\tau} = \frac{G_s}{V_w} \cdot C_{fw}$$

or, $$\frac{\Delta C_{bw}}{\tau} \propto \frac{G_s}{V_w}$$ the evaporation rate

C_{fw} is constant.

Thus the rate of enrichment of BW with dissolved salts is directly proportional to the evaporation rate of the boiler provided feedwater quality remains unchanged.

In Problem 20.24, the evaporation rate = $\frac{200}{50}$

= 4 t/h per m^3

In the present problem, the evaporation rate

= $\frac{20}{16.5}$ = 1.212 t/h per m^3

Because of much higher evaporation rate in the 200 t/h boiler, the concentration of salts in *BW* rises much faster in the 200t/h boiler than in the 20 t/h boiler.

Problem 20.28 The CBD of a boiler operating with a load of 150 t/h failed suddenly. At the instant of BD failure the TDS content of BW was 1150 mg/kg.

Determine the time interval left to the boiler engineer to undertake corrective measures before the concentration of BW rises to the maximum admissible limit.

Thermo-mechanical test data revealed that the TDS content of BW should not exceed 1450 mg/kg.

Feedwater quality = 45 mg TDS/kg FW

Water space of boiler = 50 m^3

Solution From the given data

$$G_s = 150 \text{ t/h}$$

$$C_{fw} = 45 \text{ mg/kg}$$

$V_w = 50\ \text{m}^3$

$C_{bw}^{\tau_1} = 1150\ \text{mg/kg}$

$C_{bw}^{\tau_2} = 1450\ \text{mg/kg}$

$\Delta\tau = \tau_2 - \tau_1 = ?$

$$\tau_1 = \frac{\Delta C_{bw}}{C_{fw}} \cdot \frac{V_w}{G_s} = \frac{1150 - 45}{45} \cdot \frac{50}{150}$$

$$= 8.1851\ \text{h}$$

$$\tau_2 = \frac{\Delta C_{bw}}{C_{fw}} \cdot \frac{V_w}{G_s} = \frac{1450 - 45}{45} \cdot \frac{50}{150}$$

$$= 10.4074\ \text{h}$$

$\therefore \quad \Delta\tau = 10.4074 - 8.1851 = 2.2223\ \text{h}$ ***Ans.***

21

PREVENTION OF DEPOSIT FORMATION IN BOILER UNITS

Q. *How can the formation of depositions in drum-type boiler units be prevented?*

Ans. This can be achieved by adopting the following measures:

1. Intensive softening of make-up water
2. Boiler water treatment
3. Preventing BFW from contamination with the products of corrosion of structural material
4. Elimination of leakage of cooling water in the turbine condenser.
5. Prevention of local high heat flow rates through steam generating tubes.

Q. *What is the aim of boiler water treatment?*

Ans. Basically it is designed to render the scale formers, whatever may penetrate into the boiler unit, harmless and to eliminate their deposition on heat transfer surfaces.

Q. *How is this done?*

Ans. By introducing orthophosphates or salts EDTA (ethylene diamine tetracetic acid) into boiler units.

Q. *What is the object of phosphate treatment of BFW?*

Ans. To create conditions that will favour the formation of sludge instead of scale, i.e., scale formers $CaSO_4$; $CaSiO_3$ will precipitate as loose sludge along with other sludges, viz. $CaCO_3$; $3Ca_3(PO_4)_2 \cdot Ca(OH)_2$ which are removed from the boiler unit by blowdown. To be more particular, phosphate treatment is directed to prevent the formation of calcium scales rather than scales in general.

Q. *What does phosphate treatment result in?*

Ans. Phosphate treatment leads to the formation of scale of trimagnesium phosphate $Mg_3(PO_4)_2$.

Q. *What are phosphate-dosers?*

Ans. Trisodium phosphate, Na_3PO_4

Tripolyphosphate, $Na_5P_3O_{10}$

Hexametaphosphate, $(NaPO_3)_6$

Q. *When trisodium phosphate is dissolved in water what principal reaction takes place?*

Ans. TSP dissolves in water to liberate phosphate ions (PO_4^{3-}) which undergo hydrolysis to render the solution alkaline

$$PO_4^{3-} + H_2O \rightleftharpoons HPO_4^{2-} + OH^-$$

Q. *Why is this reaction particularly useful for boilers operating at higher pressure (> 7 MN/m^2)?*

Ans. For boiler units operating at higher pressure, the above reversible reaction forms the very basis of the method of purely phosphate alkalinity. As

the solution is concentrated on evaporation, the equilibria shifts from right to left eliminating the aggressive free sodium hydrate which would otherwise give rise to intergranular corrosion.

Q. *However there is the nitrate treatment method to control the aggressivity of boiler water. Why can this system not be adopted in the case of boilers operating at higher pressures (> 7 MN/m^2)?*

Ans. At higher pressures, nitrates are not stable and sodium nitrate decomposes, rendering the treatment useless. However, the phosphate ion (PO_4^{3-}) is of sufficient strength and it does not disintegrate or dissociate in boiler water at higher steam pressure and rising temperature and permits prevention of calcium scale formation.

Q. *Why is the BFW made sufficiently alkaline when polyphosphates are used?*

Ans. This is because polyphosphates undergo hydrolysis in aqueous solutions to produce mono and disodium phosphates which are potentially acidic:

$$NaH_2PO_4 \Leftrightarrow Na^+ + HPO_4^{2-} + H^+$$

$$Na_2HPO_4 \Leftrightarrow 2Na^+ + H^+ + PO_4^{3-}$$

That is why the boiler water must be sufficiently alkaline to ensure their neutralization.

Q. *Why does the method of purely phosphate alkalinity commonly use a mixture of trisodium phosphate and one of the acid phosphates, say $(NaPO_3)_6$?*

Ans. It is because the BFW may entail some carbonate or bicarbonate ions that must be eliminated to avoid scaling.

Hence recourse to acid phosphate is taken so that the mixture of Na_3PO_4 and $(NaPO_3)_6$ conforms to the composition Na_2HPO_4 that removes HCO_3^- and CO_3^{2-} ions as follows:

$$HPO_4^{2-} \Leftrightarrow H^+ + PO_4^{3-}$$

$$H^+ + HCO_3^- \rightarrow H_2O + CO_2 \uparrow$$

$$2H^+ + CO_3^{2-} \rightarrow H_2CO_3 \rightarrow H_2O + CO_2 \uparrow$$

Q. *However prolonged treatment of water with the introduction of acid phosphates has in some cases resulted in scaling of iron phosphates in sections of water-wall tubes exposed to high heat flowrate. The result is honey-comb corrosion. How can this be eliminated?*

Ans. This can be eliminated by maintaining a ratio $A_{ph}/A_{tot} = 0.5–0.6$ in the boiler water.

where A_{tot} = total alkalinity

A_{ph} = alkalinity due to PO_4^{3-} ions

Q. *Why during phosphate treatment, is the pH of boiler water maintained above 8.5?*

Ans. Phosphate treatment only prevents the formation of calcium scale rather than scale in general and hence creates conditions so that all Ca^{2+} ions are eliminated as loose sludge of hydroxylapatite $3Ca_3(PO_4)_2 \cdot Ca(OH)_2$. Since this compound contains two OH^- ions, care is to be taken to have the BFW with a sufficient concentration of hydroxyl ions, i.e. the boiler water with pH in excess of 8.5.

Q. *If this condition is not obeyed what will happen?*

Ans. It will lead to the formation of iron phosphate deposits.

Q. *What should be the lower limit of phosphate ion concentration in boiler water?*

Ans. This can be obtained from the following formula

$$i_{ph} = N + 0.1\ C_{SiO_3^{2-}} + 0.01\ C_{SO_4^{2-}}$$

where N = constant = 5 mg/kg for boilers without multistage evaporation and 3 mg/kg for boiler with multistage evaporation.

$C_{SiO_3^{2-}}$ and $C_{SO_4^{2-}}$ are the concentrations of SiO_3^{2-} and SO_4^{2-} ions in feedwater, mg/kg.

Q. *How can the amount of trisodium phosphate introduced continuously into the boiler in service be determined?*

Ans. This can be done with the help of the formula

$$P_1 = \frac{100}{C_{ph}}\left[28.5H_t\,(1 + p_s) + p_s i_{ph}\right]$$

where

28.5 = equivalent of PO_4^{3-} ion in hydroxylapatite
C_{ph} = concentration of PO_4^{3-} in the commercial product introduced, %
H_t = total hardness of feedwater, mg-equiv./kg
p_s = blowdown in fractions of boiler capacity
P_1 = amount of phosphate chemical, kg/h

Also, it can be determined in terms of feedwater rate and steam-generating capacity of the boiler as follows:

$$P_2 = \frac{G_{fw}}{10C_{ph}}\,[28.5\,H_t + p_{fw}\,i_{ph}]$$

$$P_3 = \frac{G_s}{10C_{ph}}\,[28.5\,H_t\,(1 + p_s) + p_s\,i_{ph}]$$

G_{fw} = feedwater rate, *t/h*
G_s = steam-generating capacity of the boiler, *t/h*
p_{fw} = blowdown in fraction of feedwater.

Q. *How can the rate of phosphate feed be determined in terms of volume?*

Ans. It can be determined by using the formula

$$V_{ph} = \frac{G_s}{10C_s \cdot \rho \cdot n}\,[28.5\,H_t\,(1 + p_s) + p_s\,i_{ph}]$$

where C_s = concentration of TSP in solution, %
ρ = density of TSP in solution, kg/m^3
$n = C_{PO_4^{3-}}/C_{Na_3PO_4} = 0.579$

Problem 21.1 The feedwater of a boiler unit operating without multistage evaporation upon analysis shows that the concentrations of silicate and sulphate ions are equal to 0.015 gm/kg and 0.055 gm/kg respectively.

Determine the excessive amount of phosphates.

Solution The PO_4^{3-} concentration can be determined by using the formula

$$i_{ph} = N + 0.1\,C_{SiO_3^{2-}} + 0.01\,C_{SO_4^{2-}}$$

N	$C_{SiO_3^{2-}}$	$C_{SO_4^{2-}}$	i_{ph}
5 for a boiler operating without multistage evaporation	0.015 gm/kg = 15 mg/kg	0.055 gm/kg = 55 mg/kg	5 + 0.1(15) + 0.01 (55) = 7.05 mg/kg ***Ans.***

Problem 21.2 A boiler fitted with multistage evaporation is to be started with *BFW* quality $C_{SiO_3^{2-}}$ = 10 mg/kg; $C_{SO_4^{2-}}$ = 120 mg/kg.

Determine the quantity of trisodium phosphate ($Na_3PO_4 \cdot 12H_2O$) required, if the water space of the boiler is 80 m^3. Take the content of PO_4^{3-} in commercial TSP equal to 25%.

Solution

Step (I) Calculation of excess phosphate required

Working Formula:

$$i_{ph} = N + 0.1\,C_{SiO_3^{2-}} + 0.01\,C_{SO_4^{2-}}$$

N	$C_{SiO_3^{2-}}$	$C_{SO_4^{2-}}$	i_{ph}
3	10 mg/kg	120 mg/kg	3 + 0.1 (10) + 0.01 (120) = 5.2 mg/kg

Step (II) Quantity of trisodium phosphate required

This can be determined by the formula

$$P_0 = V_b\,\frac{i_{ph}}{10C_{ph}}$$

V_b	i_{ph}	C_{ph}	P_0
80 m^3	5.2 mg/kg	25%	80(5.2)/10(25) = 1.664 kg

Ans.

Problem 21.3 It is found that the requirement of phosphate ion concentration in the BFW for a boiler to be lined up is 18 mg/kg. The boiler water space measures 60 m^3. Calculate the amount of trisodium phosphate ($Na_3\,PO_4 \cdot 12H_2O$) required to be fed in the feedwater.

Also determine the percentage fraction of TSP that will be bound by the calcium content present in BFW that fills the boiler.

Calcium hardness in feedwater = 10 μg-equiv./kg Express the result as tricalcium phosphate.

Solution

Step (I) Amount of trisodium phosphate required

Working Formula:

$$P_0 = \frac{V_b\ i_{ph}}{10 C_{ph}}$$

V_b	i_{ph}	C_{ph}	P_0
60 m^3	18 mg/kg	25% (see above)	60 (18)/10(25) = 4.32 kg ***Ans.***

Step (II) Quantity of Ca^{2+} ions in 60 m^3 of *BFW*

60 m^3 water = 60 (1000) kg of water

Ca^{2+} hardness = 10 μg-equiv./kg = 10 (10^{-3}) *mg-equiv./kg*

∴ Quantity of Ca^{2+} ions present in 60 m^3 water

= 60 (1000) (10 × 10^{-3}) mg-equiva. = 600 mg-equiv.

∴ 600 mg-equiv. of Ca^{2+} ions will be bound by 600 mg-equiv. of total TSP added.

Step (III)

Mol. Wt. of $Na_3PO_4 \cdot 12H_2O$	Eq. Wt. of $Na_3PO_4 \cdot 12H_2O$
3(23) + 31 + 4(16) + 12(18) = 380	380/3 = 126.666

Hence the amount of TSP present (in terms of mg-equiv.)

$$= \frac{4.32(1000)10^3}{126.666} = 34.10 \times 10^3 \text{ mg-equiv.}$$

Hence the fraction of TSP that will be bound by the calcium present = $\frac{600}{34.105 \times 10^3} = 0.01759$

i.e. 1.759% ***Ans.***

Problem 21.4 A steam generation plant equipped with three boilers each with a steam generation capacity of 120 t/h receives boiler feedwater with a hardness of 7.5 μg-equiv./kg.

Estimate the daily consumption of trisodium phosphate in the three boilers and also its percentage removed from the boilers with blowdownwater.

The silicate and sulphate ion concentrations in feedwater are 45 mg/kg and 325 mg/kg, respectively.

Rate of blowdown = 3.2%

Take concentration of PO_4^{3-} in commercial trisodium phosphate = 25%

Assume no multistage evaporation.

Solution

Step (I) Determination of the concentration of excess PO_4^{3-} ions

Working formula:

$$i_{ph} = N + 0.1\ C_{SiO_3^{2-}} + 0.01\ C_{SO_4^{2-}}$$

N	$C_{SiO_3^{2-}}$	$C_{SO_4^{2-}}$	i_{ph}
5	45 mg/kg	325 mg/kg	5 + 0.1 (45) + 0.01 (325) = 12.75 mg/kg

Step (II) Daily consumption of TSP in the three boilers

Working Formula:

$$P_3 = \frac{G_s}{10 C_{ph}} [28.5\ H_t\ (1 + p_s) + p_s\ i_{ph}]$$

G_s 3 × 120 × 24 t/day
C_{ph} 25%
H_t 7.5 μg-equiv/kg = 7.5 × 10^{-3} mg-equiv/kg
p_s 3.2% = 0.032
i_{ph} 12.75 mg/kg

P_3 $\frac{3(120)(24)}{10(25)}$ [28.5(7.5 × 10^{-3}) 1.032 + 0.032 (12.75)]
= 21.724 kg/day ***Ans.***
(0.905 kg/h)

Step (III) TSP removed with blowdown

Rate of TSP consumed = 0.905 kg/h

Out of this, TSP spent in water conditioning

= 0.032(12.75) kg/h

= 0.408 kg/h

$\therefore$ TSP wasted with blowdown water

$= 0.905 - 0.408 = 0.497$ kg/h

$\therefore$ % of TSP lost with blowdown water

$$= \frac{0.497}{0.905}\ 100 = 54.917$$ ***Ans.***

Problem 21.5 If purely phosphate alkalinity is maintained in boilers, obtain the formula to determine the excess amount of PO_4^{3-} in boiler water, i_{ph} (mg/kg), required to neutralize feedwater alkalinity ΔA_{fw} (mg-equiv./kg).

Solution The alkalinity in feedwater is neutralized by di-and monosodium phosphate in accordance with the following reactions:

$$HPO_4^{2-} \rightarrow PO_4^{3-} + H^+ \xrightarrow{OH^-} PO_4^{3-} + H_2O$$

$$H_2PO_4^{1-} \rightarrow PO_4^{3-} + 2H^+ \xrightarrow{2OH^-} PO_4^{3-} + 2H_2O$$

And the PO_4^{3-} concentration in the feedwater required to neutralize alkalinity ΔA is

$$i_{fw} = \frac{95}{n}\ (\Delta\ A)$$

where n = neutralization capacity for acid phosphates. It is 2 for monosodium phosphate and 1 for disodium phosphate.

Again, $\Delta A = A_{fw} - 0.4\ H_t$

where H_t = total hardness in feedwater

0.4 = factor accounting for the quantity of alkali and phosphates consumed in the formation of 3 $Ca_3(PO_4)_2 \cdot Ca(OH)_2$ [Hydroxylapatite]

Hence the excess PO_4^{3-} (mg/kg) in boiler water

$$i_{ph} = \frac{100\ (95)}{n\ p_s}\ (A_{fw} - 0.4\ H_t)$$

Problem 21.6 Purely phosphate alkalinity is maintained in boilers. The alkalinity and hardness of feedwater are 14 and 4.5 μg-equiv./kg respectively. Blowdown rate is 2.5% and a standard excess of PO_4^{3-} concentration equal to 35 mg/kg is maintained.

Determine if there is any excess phosphate in the boiler over the prescribed standard.

If so, what mixture (molar ratio) of mono and disodium phosphate is required to ensure the prescribed standard of PO_4^{3-} alkalinity.

Solution

Step (I) Determination of excess phosphate (if any)

The neutralization of excess alkali is carried out as follows

$$H_2PO_4^- + OH^- \longrightarrow PO_4^{3-} + H_2O$$

Here

n	A_{fw}	H_t	p_s	Excess PO_4^{3-} ion concentration
1	14 μg-equiv/kg	4.5 μg-equiv/kg	2.5	$i = \frac{100\ (95)}{1(2.5)}\ [14 - 0.4 \times 4.5] \times 10^{-3} = 46.36$ mg/kg

The calculated value of i_{ph} shows that the PO_4^{3-} ion concentration in the boiler water is higher than that prescribed by the standards.

Step (II) Therefore, it is necessary to make the use of a mixture of monosodium and disodium phosphate to ensure the concentration of the phosphate, $[C_{PO_4^{3-}}]_{st}$ as prescribed by the standard.

Therefore, we are to calculate the value of n—the neutralizing capacity of the phosphate mixture

$$n = \frac{100\ (95)}{p_s \left[C_{PO_4^{3-}}\right]_{st}}\ (A_{fw} - 0.4\ H_t)$$

$$= \frac{100\ (9.5)}{2.5\ (35)}\ [14 - 0.4\ (4.5)] \times 10^{-3} = 1.32$$

Step (III) Proportion of mono and disodium phosphate

Let x be the fraction of monosodium phosphate

$$1 + 2x = 1.32; \qquad \therefore \quad x = 0.16$$

Therefore, the mixture should be Na_2HPO_4 + 0.16 NaH_2PO_4 ***Ans.***

Q. *Can the phosphate treatment ensure scale-free operation?*

Ans. No. It fails to prevent the formation of iron-oxide and cuprous salt depositions. Frequently phosphate chemicals themselves become the source of depositions, viz. iron phosphates.

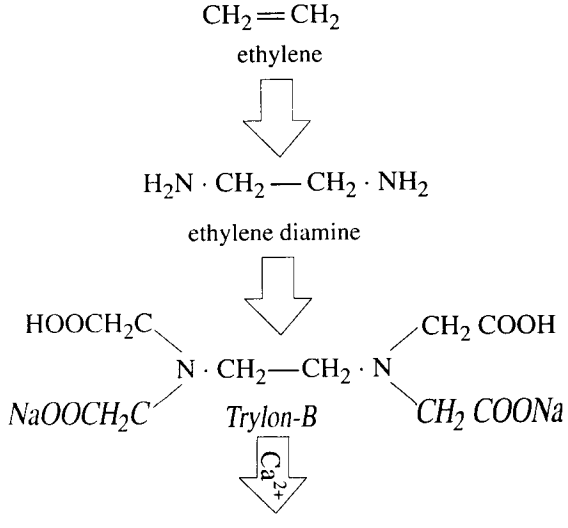
Q. *Then how can the boiler water be conditioned for scale-free, sludge-free operation?*

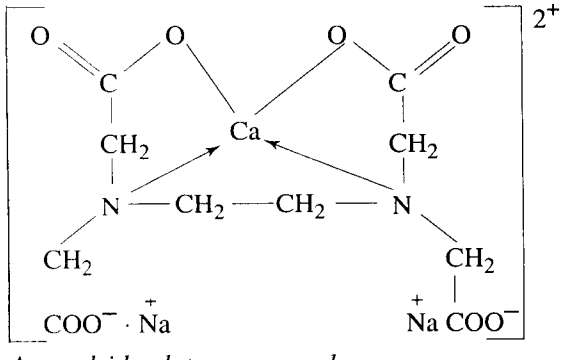
Ans. This can be done by treating the boiler water with complexing agents that ensure not only scale free, sludge-free operation but also corrosion-free operation under certain circumstances.

Q. *What are these agents?*

Ans. EDTA (ethylene-diamine tetracetic acid)

Trylon-B (disodium salt of above)





A quadridendate compound

Q. *How is the treatment with Trylon-B carried out?*

Ans. A 1.5% or weaker solution of Trylon-B alkalized by NaOH or NH_4OH to pH 8.5 is introduced into the feedwater of a drum-type boiler.

Q. *At which point?*

Ans. At the suction of the BFW pumps.

Q. *How does it act?*

Ans. This complexing agent traps the cations of scale formers into strong, well soluble chelates (complexonates). As a result no sludge and scale forming compounds form in the boiler units.

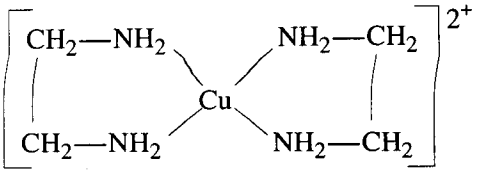
Trylon-B treatment also enables binding iron into a complex and that reduces its chance of carryover with steam.

Q. *What are sequestering agents?*

Ans. Sequestration means masking of metal ions by formation of soluble chelate compounds. Hence sequestering agents come to mean those specific chelating agents that react with a certain metal ion (or ions) to produce soluble chelates.

Q. *What are chelates?*

Ans. Cyclic co-ordination complexes in which the ring is closed by two or more points of attachment of the co-ordinating group with the metal ion.



Cupric ethylene diamine cation

Q. *How is the EDTA or Trylon-B treatment more efficient than phosphate treatment in preventing caryover of iron with steam?*

Ans. Compared with phosphate treatment, it can reduce the carryover of iron with steam by 50% or more.

Q. *How can the quantitative estimation of the consumption of complexing agent for boiler water treatment be done?*

Ans. This can be done using the formula

$$\dot{M} = [186\, H_{fw} + 6.7\, C_{Fe} + 6C_{Cu}]\, G_s(10^{-2}),\ \text{g/h}$$

where

H_{fw} = feedwater hardness, microgram-equiv./kg

C_{Fe} = iron concentration in feedwater, μg-equiv/kg

C_{Cu} = copper concentration in feedwater, μg-equiv/kg

G_s = steam generation capacity of the boiler, t/h

Q. *What is the main objective difference in boiler water treatments with a complexing agent between medium pressure (4 MPa = 4 MN/m^2) boiler units and super high pressure (15 MPa = 15 MN/m^2) boiler unit?*

Ans. The main object of boiler water treatment, in the case of a medium pressure boiler is to prevent the formation of alkali-earth and iron oxide depositions, as the BFW in this case contains much higher concentrations of Ca^{2+}, Mg^{2+} and Fe^{2+} ions than the BFW in the case of superhigh pressure boiler units.

The feedwater for superhigh pressure boilers is deeply deionized (softened). So the hardness is minimum. Hence the complexing agent treatment is directed mainly to preventing the formation of iron-oxide scale, reduce the carryover of iron-oxides with steam and protect the units against steam-water corrosion.

Q. *Despite the effectiveness of complexing agents such as EDTA and Trylon-B, the feedwater of intermediate pressure boiler unit is subjected to phosphate treatment preferentially. Why?*

Ans. This is solely due to the economic point of view. The phosphate treatment is cheaper. And its use is justified so long as PO_4^{3-} ions are sufficient to ensure scale-free as well as reliable operation of tube metal subjected to a high rate of heat flow.

Q. *But EDTA will also decompose at a higher temperature. Will it continue to preserve its complexing capacity beyond that?*

Ans. EDTA and its salts start to decompose at about 423 K and decomposition proceeds at a higher rate with increase in temperature and ends at about 573 K. But still the gaseous products of decomposition of primary complexonates preserve their complexing capacity. When steam condenses and the gaseous decomposition products redissolve, the complexing capacity revives.

Q. *Why does it sometimes become necessary to make the boiler water more alkaline?*

Ans. It will make the scale-forming substances penetrating into a boiler unit precipitate as $CaCO_3$ and $Mg(OH)_2$ in the form of loose sludge not adhering to surfaces while in a non-alkaline medium, (e.g. in turbine condensers) the calcium carbonate will deposit on the heating or cooling surfaces as a dense scale.

Moreover, alkalization of boiler feedwater is applied when it is necessary to neutralize the ammonium salts of strong acids

$$[NH_4]_2SO_4 \Leftrightarrow 2NH_4^+ + SO_4^{2-}$$

$$NH_4^+ + H_2O \xrightarrow{\text{hydrolysis}} NH_3 + H_3O^+$$

$$H_3O^+ + OH^- \xrightarrow{\text{neutralization}} 2H_2O$$

or when it is necessary to raise the alkalinity of BFW to neutralize the acid phosphates.

Q. *How can the quantity of alkaline reagents introduced into a boiler unit to maintain a certain alkalinity of BFW be determined?*

Ans. It can be determined on the basis of 100% pure chemical reagent using the formula

$$G_A = G_s(10^{-3})\, [H_{nc}\,(1 + p_s) + p_s\, A_{bw}]E,\ \text{kg/h}$$

where H_{nc} = non-carbonate hardness, mg-equiv./kg

G_s = steam generating capacity of the boiler, t/h

p_s = blowdown in fraction of boiler capacity

A_{bw} = required/admissible alkalinity of BFW, mg-equiv/kg

E = equivalent of the given alkaline reagent.

Q. *If the calcium and magnesium hardness in BFW be H_{Ca} and H_{Mg}, then how can the amount*

of scale-forming substances penetrating into the boiler unit be derived from the above formula?

Ans. The rate of sludge formation in feedwater is

$$G_{sl}^{fw} = G_s(10^{-3})\,[(1 + p_s)\,(50\,H_{Ca}) + (1 + p_s)\,(29\,H_{Mg})],\ \text{kg/h}$$

$$= G_s(10^{-3})\,(1 + p_s)\,[50\,H_{Ca} + 29\,H_{Mg}],\ \text{kg/h}$$

Q. *Which reagent is usually used to make the soft BFW more alkaline?*

Ans. Sodium hydroxide.

Q. *Why are soda ash or sodium bicarbonate which are cheaper than caustic soda not used to make the soft BFW more alkaline?*

Ans. The use of these alkalizing reagents is restricted only to boiler units operated at a pressure of up to 1.6 MPa (1.6 MN/m^2), because of the thermal and hydrolytic decomposition of these compounds

$$2NaHCO_3 \xrightarrow[\Delta]{} Na_2CO_3 + H_2O + CO_2$$

$$CO_3^{2-} + H_2O \longrightarrow CO_2\,(\uparrow) + 2OH^-$$

Since CO_3^{2-} is unstable at higher temperatures, the effectiveness of alkaline treatment decreases and the generated steam gets contaminated with carbon dioxide. (Fig. 21.1).

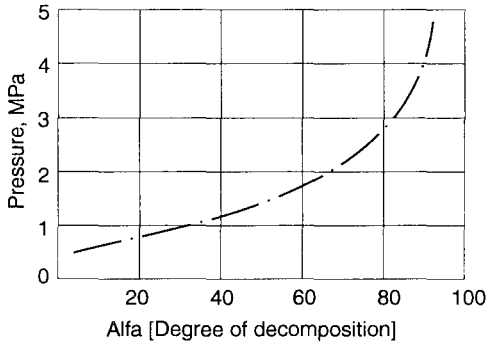


Fig. 21.1 *Instability curve of CO_3^{2-} ions.*

Q. *What happens if steam is contaminated with carbon dioxide?*

Ans. It is undesirable since it will give rise to carbon dioxide corrosion of metal in the condensate circuit.

Q. *How is the quantity of carbon dioxide passing into the generated steam found out?*

Ans. This can be determined by the equation

$$\dot{M}_{CO_2} = 22[A_b\,(1 + \alpha) + \alpha\,A_c] = 22[A_b + \alpha\,A_t],\ \text{mg/kg}$$

where

α = degree of decomposition of caustic soda

$A_t = A_c + A_b$ = total alkalinity, mg-equiv./kg

A_c = carbonate alkalinity, mg-equiv./kg

Factor 22 is the equivalent weight of CO_2.

Problem 21.7 A steam generation plant runs with three boilers each of 120 t/h steam generation capacity. If the actual alkalinity of feedwater is 225 microgram-equiv./kg, determine the daily consumption of NaOH per ton of feedwater to maintain the boiler water alkalinity at 10 mg-equiv./kg. Take the blowdown rate as 3%. Also determine the daily NaOH requirement.

Solution This can be done by using the formula

$$G_A = \left[\frac{p_s}{1 + p_s}(A_{bw}) - A_{fw}\right]E,\ \text{mg/kg of}$$

feedwater.

where p_s = blowdown rate

A_{bw} = boilerwater alkalinity, mg-equiv./kg

A_{fw} = feedwater alkalinity, mg-equiv./kg

E = equivalent of the alkalizing reagent.

p_s	A_{bw}	A_{fw}	E_{NaOH}	G_A
3%	10 mg-equiv/kg	225 micro-equiv/kg = 0.225 mg-equiv/kg	40	$\left[\frac{0.03}{1.03}(10) - 0.225\right]40$ = 2.65 mg/kg = 2.65 g/t

Therefore the daily NaOH requirement

$= 3 \times 120 \times 24 \times 2.65 = 22900$ gm $= 22.9$ kg.

Ans.

Problem 21.8 Three boiler units each having steam generation capacity of 150 t/h require internal water treatment of their feedwater to maintain alkalinity of BFW at 10 mg-equiv./kg. If soda ash is used as the alkalizing reagent, determine the annual consumption of soda ash on the basis of 7920 h running hours of each boiler with a blowdown rate of 5%.

Take non-carbonate hardness of feedwater equal to 2.5 mg-equiv/kg.

Solution On the basis of 100% pure Na_2CO_3, the annual consumption of soda ash can be determined by the formula

$$G_{Na_2CO_3} = G_s(10^{-3})\ [H_{nc}(1 + p_s) + p_s A_{bw}]\ E_{Na_2CO_3}$$

Step (I) One boiler unit (150 t/h) is considered

G_s	H_{nc}	p_s	A_{bw}	$G_{Na_2CO_3}$
150 t/h	2.5 mg-equiv/kg	5%	10 mg-equiv/kg	$150\ (10^{-3})\ [2.5\ (1 + 0.05) + 0.05\ (10)]\ 53$ $= 24.8437$ kg/h

Step (II) Annual consumption of Na_2CO_3

$G_{Na_2CO_3}$	*No. of boiler units*	*Total running hours*	*Total consumption of Na_2CO_3 per annum*
24.8437 kg/h per boiler	3	7920 h	24.8437(3) (7920) kg $= 590287.5$ kg $= 590.287$ t

Problem 21.9 A boiler house is fitted with six low-pressure boilers each of steam-generating capacity 5 t/h. The feedwater is a mixture of condensate and raw water the total hardness in which is 1.8 mg-equiv./kg and carbonate hardness 1.2 mg-equiv./kg. Internal treatment of BFW is applied by using Na_2CO_3 to maintain the alkalinity of boiler water to 15 mg-equiv./kg. If the rate of blowdown is 5%, calculate the rate of consumption of Na_2CO_3.

Solution Consumption rate of soda ash for internal treatment of boiler water with known hardness can be carried out by using the formula

$$G_{Na_2CO_3} = G_s(10^{-3})\ [H_{nc}\ (1 + p_s) + p_s\ A_{bw}]\ E_{Na_2CO_3}$$

Step (I) Calculation of non-carbonate hardness (H_{nc})

Working Formula $H_t = H_c + H_{nc}$

where

H_t = total hardness, mg-equiv./kg
H_c = carbonate hardness, mg-equiv./kg
H_{nc} = non-carbonate hardness, mg-equiv./kg

H_t	H_c	H_{nc}
1.8 mg-equiv./kg	1.2 mg-equiv./kg	$(1.8-1.2)$ $= 0.6$ mg-equiv./kg

Step (II) Consumption rate of soda ash

G_s	H_{nc}	p_s	A_{bw}	*No. of boilers*	$G_{Na_2CO_3}$
5 t/h	0.6 mg-equiv/kg	5%	15 mg-equiv/kg	6	$6\ (5 \times 10^{-3})$ $[0.6(1 + 0.05)$ $+ 0.05(15)]53$ $= 2.194$ kg/h

Ans.

Problem. 21.10 Determine the volume of the storage tank, in the preceding problem, required for daily consumption of soda ash taken in the form of 4% solution with density nearly equal to 1000 kg/m^3. Assume the tank is 75% filled with the solution.

Solution

Step (I) Volumetric rate of flow of soda ash solution

Solution strength	Mass flow rate of soda ash	Volume flowrate
4% = 4 kg Na_2CO_3/100 kg soln.	2.194 kg/h	$\frac{2.194}{40}\ \frac{\text{kg}}{\text{h}} \times \frac{\text{m}^3}{\text{kg}}$ $= 0.05485$ m^3/h

$$= \frac{4\text{kg } Na_2CO_3}{100 \times \frac{1}{1000} \text{ m}^3 \text{ solution}}$$

$= 40$ kg Na_2CO_3/1 m^3 of solution

Step II

Vol. flowrate of soda ash	*Daily requirement of soda ash soln.*	*Required capacity of tank*
0.05485 m^3/h	0.05485 (24)m^3	0.05485 (24)/0.75 = 1.755 m^3 ***Ans.***

Problem 21.11 A boiler of an electric power station is filled with 65 m^3 of water. This BFW is to be made alkaline with a solution of 35% of NaOH solution available at the end of the battery limit so as to ensure a 1% solution of NaOH in it. Determine the volume of reagent solution required.

Density of 35% NaOH solution = 1380 kg/m^3

Density of 1% NaOH solution = 1000 kg/m^3

Solution The feedwater must be made alkaline so as to obtain 65 m^3 of BFW of 1% NaOH solution.

Step (I)

The mass of BFW

= 65(1000)

= 65000 kg solution (1% NaOH)

Mass of NaOH present in it

= 65000(1/100)

= 650 Kg

Step (II) Volume of 35% NaOH solution required

35 kg NaOH contain in 100 kg solution (35% NaOH)

$$= \frac{100}{1380} \text{ kg (m}^3\text{/kg)} = \frac{100}{1380} \text{ m}^3 \text{ solution}$$

650 kg NaOH will contain in $\frac{100}{1380}\frac{650}{35}$ m^3 solution

= 1.345 m^3 solution ***Ans.***

Problem 21.12 The boilers, 100 t/h of capacity each, are generating steam at 3 MPa (3 MN/m^2) from the BFW having bicarbonate alkalinity 0.10 mg-equiv./kg and carbonate alkalinity 0.25 mg-equiv./kg. Determine the amount of CO_2 contained in the steam.

Take the degree of decomposition of sodium carbonate at 3 MPa pressure = 0.9

Solution The quantity of CO_2 passing into steam can be determined with the aid of the formula

$$\dot{M}_{CO_2} = 22[A_b\ (1 + \alpha) + \alpha\ A_c], \text{ mg/kg}$$

A_b	A_c	α	$\dot{M}_{CO_2}$
0.10 mg-equiv/kg	0.25 mg-equiv/kg	0.9	22 [0.10 (1 + 0.9) + 0.9 (0.25)] = 9.13 mg/kg ***Ans.***

Problem 21.13 A steam generation plant is fitted with three boilers each of steam generation capacity 10 t/h. Feedwater contains total hardness 2.5 mg-equiv./kg and carbonate hardness 1.2 mg-equiv./kg. Soda ash is used as the alkalizing agent to maintain boilerwater alkalinity equal to 15 mg-equiv./kg.

Determine

(a) the hourly consumption (kg/h) of soda ash if blowdown rate is 5%
(b) the rate of sludge formation, kg/h
(c) the concentration of sludge in boilerwater, mg/kg. Take average equiv. of Ca^{2+} and Mg^{2+} ions present = 43.

Solution

Step (I) Consumption rate (kg/h) of soda ash

(a) The concentration of soda ash required to maintain the prescribed alkalinity in BFW is given by

$C_{Na_2CO_3} = (H_t - A_i)\ (1 + p_s) + p_s\ A_{bw}$, mg-equiv/kg

where H_t = total hardness in feedwater, mg-equiv./kg

p_s = blowdown rate

A_i = initial alkalinity of feedwater, mg-equiv./kg

A_{bw} = boilerwater alkalinity, mg-equiv./kg

H_t	A_i	p_s	A_{bw}	$C_{Na_2CO_3}$
2.5 mg-equiv/kg	1.2 mg-equiv/kg	5%	15 mg-equiv/kg	(2.5 – 1.2) (1 + 0.05) + 0.05 (15) = 2.115 mg-equiv./kg

(b) ***Soda ash consumption***

Feedwater requirement of each boiler = 10 t/h

Overall feedwater requirement of SGP

= 3(10)

= 30 t/h

Hence the rate of consumption of soda ash

$$= 30 \times 10^3 \frac{\text{kg}}{\text{h}} \times 2.115 \frac{\text{mg-equiv}}{\text{kg}}$$

$$= 30 \times 10^3 \times 2.115 \times 53 \text{ mg/h}$$

$$= 30 \times 10^{-3} \times 2.115 \times 53 \text{ kg/h}$$

= 3.362 kg/h ***Ans.***

Step (II) Rate of sludge formation (kg/h)

The rate of sludge forming in BFW can be conveniently expressed as

$$Q_{s1} = G_s(1 + p_s)H_t\, E_a,\ g/h$$

where G_s = rate of steam generation, *t/h*

p_s = blowdown rate

H_t = total hardness is feedwater, mg-equiv./kg

E_a = average equivalent of the sum of Ca^{2+} and Mg^{2+} ions present in BFW.

G_s	p_s	H_t	E_a	Q_{s1}
30 *t*/h in three boilers	0.05	2.5 mg-equiv/kg	43	30(1 + 0.05) (2.5) (43) = 3386 g/h = 3.38 kg/h ***Ans.***

Step (III) Concentration of sludge in BFW

The sludge concentration in BFW is given by

$$C_{s1} = \frac{1 + p_s}{p_s}(H_t)E_a,\ \text{mg/kg}$$

p_s	H_t	E_a	C_{s1}
0.05	2.5 mg-equiv./kg	43	$\frac{1.05}{0.05}$ (2.5) (43) = 2257.5 mg/kg ***Ans.***

Problem 21.14 An industrial boiler house with total steam generating capacity 75 t/h at 1 MPa (1 MN/m^2) utilizes a mixture of raw water (60%) and condensate. The raw water is of the following quality

Total hardness = 3.9 mg-equiv./kg

Carbonate hardness = 2.2 mg-equiv./kg

Calcium hardness = 2.6 mg-equiv./kg

Soda ash is used as the alkalizing reagent to maintain boiler water alkalinity at 12 mg-equiv./kg.

Blowdown rate is 5%

Determine

(a) the concentration of CO_2 in steam

(b) the rate of sludge formation in the boiler

(c) the concentration of the sludge.

Take $E_a = 43$.

Solution

Step (I) Since the feedwater is a mixture of 60% raw water containing carbonates and bicarbonates, the CO_2 carryover to steam produced is entirely due to raw water.

Hence the concentration of CO_2 in generated steam

$$C_{CO_2} = 22[A_b\ (1 + \alpha) + \alpha\ A_c] \times (60\%),\ \text{mg/kg}$$

where A_b = bicarbonate hardness in raw water, mg-equiv./kg

$$= H_t - H_c$$

A_c = carbonate hardness in raw water, mg-equiv./kg

α = degree of dissociation of Na_2CO_3 at the working pressure of the boiler

α = 0.34 cf. PRESSURE vs. ALFA curve at 1 MPa (Fig. 21.1)

Factor 22 = equiv. wt. of CO_2

A_b	α	A_c	C_{CO_2}
3.9 – 2.2 = 1.7 mg-equiv./kg	0.34	2.2 mg-equiv./kg	22[1.7 (1.34) + 0.34 (2.2)] (0.6) = 39.94 mg/kg

Step (II) Rate of sludge formation in boilers

Working Formula

$$G_{sl} = G_s(1 + p_s)\ [50H_{Ca} + 29H_{Mg}],\ g/h$$

G_s	p_s	H_{Ca}	$H_{Mg} = H_t - H_{Ca}$	G_{sl}
75 t/h	0.05	2.6 mg-equiv./kg	3.9 – 2.6 = 1.3 mg-equiv./kg	75(1 + 0.05) [50 (2.6) + 29 (1.3)] × (0.6) = 7923.6 g/h = 7.92 kg/h ***Ans.***

Step (III) Concentration of sludge in boiler

Working Formula

$$C_{sl} = \frac{1 + p_s}{p_s}\ (H_t)E_a,\ mg/kg$$

p_s	H_t	E_a	C_{sl}
0.05	3.9 mg-equiv./kg	43	$\frac{1.05}{0.05}$ (3.9) (43) (0.6) = 2113 mg/kg ***Ans.***

Q. *How can scale formation on the waterside heating surfaces of once-through boiler units be prevented?*

Ans. This can be done by eliminating the sources of feedwater contamination.

Q. *What are the primary sources of feedwater contamination?*

Ans. 1. Presence of dissolved oxygen in BFW from deaerator to boiler drum. It acts as a depolarizer and contributes to corrosion

$$O_2 + 4e + 2H_2O \longrightarrow 4OH^-$$

2. Presence of dissolved CO_2 in the condensate leading to corrosion of heaters and evaporators

$$CO_2 + H_2O \longrightarrow HCO_3^- + H^+$$

$$2H^+ + Fe \longrightarrow H_2 + Fe^{2+} \xrightarrow{HCO_3^-} Fe(HCO_3)_2$$

3. Leakage of cooling water in turbine condenser—a tube and shell type heat exchanger.

Q. *How does the infiltration of cooling water into the intertubular space of a turbine-condenser occur?*

Ans. This occurs through the expansion joints between the condenser tubes and the tube plate as well as through the hair-cracks in the walls of the tubes.

Q. *How can the leakage of cooling water in the turbine-condenser be measured?*

Ans. This can be measured in terms of leakage which is given by the formula

$$(\phi)_l = \frac{C_{cond} - C_s}{C_{cw} - C_s} \times 100$$

where, C refers to concentration. Subscripts "cond", "s" and "cw" stand for condensate, steam and cooling water respectively.

Q. *How can this problem be solved?*

Ans. By incorporating a demineralizing unit downstream of the turbine condenser. This will eliminate from the condensate the ionic and dispersed impurities and bring down the water condition within the prescribed limit.

Q. *What type of corrosion takes place in the feedwater circuit in once-through boiler units?*

Ans. Oxygen corrosion due to dissolved oxygen.

$$O_2 + 4e + 2H_2O \longrightarrow 4OH^-$$

$$2Fe \longrightarrow 2Fe^{2+} + 4e$$

$$\text{(Adding)}\ 2Fe + O_2 + 2H_2O \longrightarrow 2Fe(OH)_2$$

If sufficient amount of oxygen is present, ferrous hydroxide gets oxidized to ferric hydroxide which falls out on the tube wall

$$2Fe(OH)_2 + \tfrac{1}{2}O_2 + H_2O \longrightarrow 2Fe(OH)_3\ (\downarrow)$$

$$\xrightarrow[\Delta]{} Fe_2O_3 \cdot 3H_2O$$

Besides, due to oxygen corrosion, formation and deposition of copper oxides also takes place.

Q. *At which section of the heating surface, does the iron oxide mainly deposit?*

Ans. In the region of intense heat flow, i.e. at the bottom radiant heat-transfer part.

Q. *In which pattern?*

Ans. On the semi-circumference of the heating tubes facing the furnace. (Fig. 21.2)

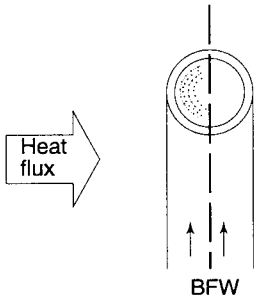


Fig. 21.2

Q. *How can this scaling be avoided in once-through boiler units?*

Ans. By EDTA treatment of feedwater.

This forms a complex with Fe^{2+} and Fe^{3+} ions and eliminates the accumulation of iron oxides at the bottom radiant zone of heat-absorbing surfaces.

Q. *However the iron-complex of EDTA undergoes thermolysis leading to precipitation of magnetite on tube walls. So how can this method be effective?*

Ans. Most of the magnetite precipitates before water reaches the bottom radiant heat-absorbing parts. Nearly 70–80% of the magnetite falls out in the economizer. This is how the effectiveness of EDTA treatment is retained.

Q. *How does the formation of solid carbonate deposits take place in the tubes of turbine condensers?*

Ans. It takes place due to decomposition of soluble bicarbonate

$$Ca(HCO_3)_2 \longrightarrow \underset{\text{(scale)}}{CaCO_3} + CO_2(\uparrow) + H_2O$$

Q. *How is the formation of calcium carbonate deposit in turbine condensers prevented?*

Ans. By adopting any one of the following processes

(a) acidification
(b) lime treatment
(c) phosphate treatment
(d) recarbonation process

Q. *How does acidification eliminate carbonate scaling?*

Ans. Acidification carried out by introducing sulphuric acid to the makeup water adds free H^+ ions that destroy the HCO_3^- ions as follows:

$$HCO_3^- + H^+ \longrightarrow H_2O + CO_2\,(\uparrow)$$

Q. *Why is it important to meter out the correct amount of acid introduced into the make-up water?*

Ans. This is because excess acidity will increase the corrosivity of water while less acidity will fail to ensure scale-free operation.

Q. *How can lime treatment serve the purpose, i.e. prevent carbonate scaling?*

Ans. Lime $Ca(OH)_2$ converts all HCO_3^- ions into CO_3^{2-} without the formation of CO_2

$$HCO_3^- + OH^- \longrightarrow CO_3^{2-} + H_2O$$

Q. *Between acidification and lime treatment, which one is more efficient?*

Ans. Lime treatment. By acidification, only a small fraction of HCO_3^- ions are destroyed, whereas by lime treatment entire bicarbonate ions are removed from the water.

Q. *So the lime treatment system in the return water circuit is preferable. Is it not?*

Ans. Though lime $Ca(OH)_2$ treatment destroys all the bicarbonate ions, it is seldom applied to return water circuit since this involves the installation of an expensive plant.

Q. *What is recarbonation process?*

Ans. It is a process by which CO_2 concentration in water containing HCO_3^- ions is increased by blowing the furnace gas through the layer of water or mixing it with water by means of a water-operated ejector.

Q. *How does the dissolved free carbon dioxide so introduced prevent scaling?*

Ans. It shifts the following equilibra from right to left

$$HCO_3^- + H^+ \Leftrightarrow H_2O + CO_2$$

and therefore bicarbonate decomposition to carbonate ceases

$$2HCO_3^- \xrightarrow{\Delta} H_2O + CO_2 + CO_3^{2-}$$

Q. *How many methods are known to clean boiler units and heat exchanger off deposits?*

Ans. Two methods—mechanical and chemical.

Q. *How is mechanical cleaning of deposits carried out?*

Ans. It involves the use of various type of scrappers, wire brushes, etc.

Q. *In which case is this method suitable?*

Ans. For small boiler units and simple heat exchangers.

Q. *How is chemical cleaning performed?*

Ans. It is carried out by circulating cleaning agents—acids, alkalies and complexing agents—through the boiler or heat exchanger circuit.

Q. *What is the difference between prestarting cleaning and planned or scheduled cleaning?*

Ans. Prestarting cleaning is carried out in the case of newly installed boilers before they're put into operation. This is directed primarily at removing rust and welding rag, iron-scale, burrs and other impurities from the steam-water circuit.

Whereas scheduled cleaning is the periodic cleaning in the course of service of the boilers, aimed at removing all kinds of deposits formed during operation.

Note: Both are chemical cleaning

Q. *What reagents are used for chemical cleaning?*

Ans. Hydrochloric acid, caustic soda, ammonium hydroxide, citric acid, maleic acid and other organic acids a well as the complexing agent EDTA.

Q. *Why is hydrochloric acid preferred?*

Ans. It is abundantly available and is the cheapest of all cleaning chemicals.

Q. *In which cases is it particularly used?*

Ans. For cleaning low-capacity boiler units, heat exchangers and surface condensers of turbines.

Q. *Why is it not favoured for cleaning high-capacity units, particularly supercritical-pressure boiler units?*

Ans. Due to the aggressiveness of the acid as well as the intricate layout of cleaning.

Q. *What is the basic advantage of organic acids?*

Ans. They are less aggressive than HCl.

Q. *What are the disadvantages of using organic acids as chemical cleaning agents?*

Ans. Firstly, these chemicals are expensive. Secondly, they present difficulties in wastewater treatment.

Q. *What is the most successful reagent?*

Ans. It has been found by experience that a mixture of complexing agent (EDTA) and organic acid (say, citric acid) taken in a 1:1 proportion the most suitable reagent.

Q. *How is scheduled washing of boiler units performed?*

Ans. First the boiler unit is washed with a mixture of EDTA and organic acid solution to dissolve away the scales.

When all the deposits have been removed, the solution is displaced from the boiler unit by polished water. Boiler surfaces are flushed with polished water to dislodge traces of leftover impurities.

It is then followed by a neutralization operation with an alkaline solution.

Finally, the cleaning is terminated by passivating the metallic surfaces by nitrite-ammonium or hydrazine-ammonium or complexon passivation treatment.

22

CHARACTERISTICS OF STEAM-WATER FLOW

Q. *What is circulation velocity?*

Ans. It is the velocity of water at the saturation temperature given by the relation

$$v_{cir} = \frac{G_m}{A\rho}$$

where

G_m = mass flowrate of steam-water mixture through the tubes system, kg/s.

A = free cross-sectional area for the passage of steam-water mixture, m^2

ρ = density of water at saturation temperature, kg/m^3

Q. *What is the circulation ratio?*

Ans. It is the inverse of mass steam content

$$K = \frac{1}{x} = \frac{G_m}{G_s}$$

where, G_s = mass flowrate of steam through the tube system

Q. *What is mass steam content?*

Ans. It is the ratio of the quantity of steam produced to the quantity of circulating water for the same interval of time:

$$x = \frac{G_s}{G_m}$$

Q. *What is the volume steam content?*

Ans. It is the volume fraction of steam in a steam-water mixture flow having identical velocities of water and steam.

$$\beta = \frac{V_s}{V_s + V_w}$$

Q. *What is actual steam content?*

Ans. It is the fraction of the tube cross-section occupied by steam

$$\varphi = \frac{A_s}{A}$$

Q. *What is the relation between actual steam content and volume steam content?*

Ans. $$\frac{\varphi}{\beta} = \frac{v_m}{v_s}$$

i.e. the ratio of actual steam content to volume steam content is equal to the ratio of velocity of steam-water mixture to the velocity of steam

$$\beta = \frac{V_s}{V_m + V_w} = \frac{v_s A_s}{v_m A} = \frac{v_s}{v_m}\varphi$$

Q. *When does the actual steam content equalize with the volume steam content?*

Ans. φ will become equal to β, if $v_s \approx v_m$. This condition will prevail if the relative velocity between steam and water reduces to zero

$$v_r = v_s - v_w = O$$

i.e.

$$v_s = v_w = v_m$$

Since with the increase of pressure, the relative velocity of steam decreases, as the pressure approaches the critical value, φ tends to β.

Q. *Will the regime of flow pattern of steam-water mixture through heating tubes vary with the spatial arrangement of tubes?*

Ans. Yes; the structure and flow-mode, under identical conditions, will vary on the spatial arrangement of the tubes, i.e. whether horizontally laid or vertically laid.

Q. *How many kinds of flow-modes of steam-water mixture in vertical tubes are known?*

Ans. Five types

1. Bubble Flow
2. Emulsion Flow (Frothy Flow)
3. Slug Flow
4. Dispersed annular flow (Wet-wall Flow)
5. Inverse Disperse-Annular Flow (Dry-Wall Flow)

Q. *What is bubble flow?*

Ans. It is a low-velocity adiabatic flow of steam-water mixture characterized by rare fine vapour bubbles distributed in it. It contains a very insignificant amount of steam. (Fig. 22.1)

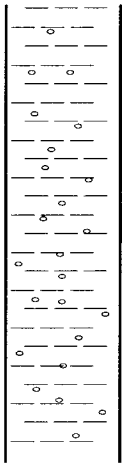


Fig. 22.1 *Bubble flow.*

Q. *What is emulsion flow?*

Ans. With the increase of steam content and higher mass velocity of steam-water mixture, the bubble flow is converted into emulsion flow. It is characterized by a relatively large number of fine vapour bubbles (Fig. 22.2)

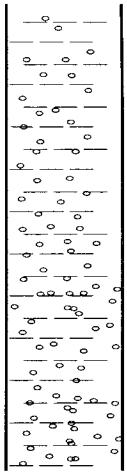


Fig. 22.2 *Emulsion flow.*

Q. *What is slug flow?*

Ans. If mass velocity of steam-water mixture is low but steam content increases with higher heat transfer, the fine bubbles of steam will coalesce to form large cylindrical bubbles (called slugs) with a diameter comparable to that of the tube and length many times the diameter. This flow regime is called slug flow. Each 'slug' is followed by a trail of fine vapour bubbles suspended in the thin liquid bridge separating two consecutive slugs. (Fig. 22.3)

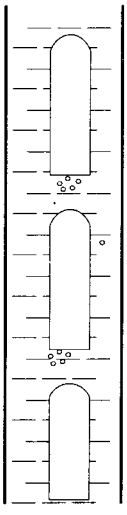


Fig. 22.3 *Slug flow.*

Q. *What is wet-wall flow?*

Ans. It is the next stage of slug flow when the steam content further increases.

If the steam/water ratio increases, the water bridges separating the slugs will get narrowed down and ultimately disappear with the slugs merging into a long, continuous vapour column trapping atomized water droplets within.

This column moves along the core of the tube and is separated from the tube wall by a narrow film of water layer moving along the wall. This flow regime is called disperse-annular flow or wet-wall flow (Fig. 22.4)

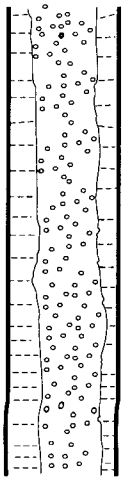


Fig. 22.4 *Wet-wall flow.*

Q. *What is dry-wall flow?*

Ans. The water film separating the vapour column from the tube wall, in wet-wall flow, gradually loses its water mass at higher steam pressure and higher steam velocity. With the increase of steam pressures and steam velocity, more and more of water from the film is carried off as droplets, decreasing the thickness of the water-film on the tube surface. This reduced film quickly evaporates forming a vapour film while the water droplets removed from the water film coalesce to form a continuous stream of water in the core. Thus the liquid fills the core of the tube while a vapour film separates it from the heat-exchange surface. This type of flow is called dry-wall flow (Fig. 22.5).

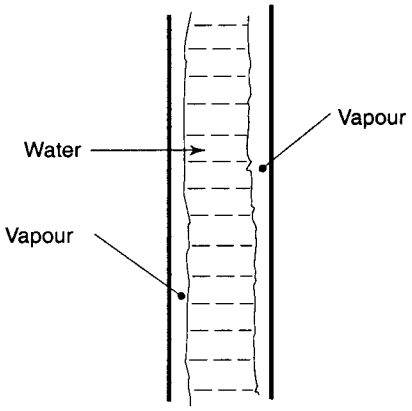


Fig. 22.5 *Dry-wall flow.*

Q. *What is the nature of flow of the steam-water mixture in horizontal tubes?*

Ans. The steam-water flow in a horizontal tube is characterized by a non-uniform distribution of steam and water over the tube cross-section. This is because of the difference in density between steam and water at any temperature lower than critical temperature. At temperatures below the critical temperature, the density of steam is lower than that of water. So, steam will flow primarily along the upper tube wall while the main mass of water will flow along the lower tube wall. However, the flow-mode depends also on the velocity of flow and diameter of the tube (see below).

Q. *How many kinds of flow-modes of steam-water mixture in horizontal tubes are known?*

Ans. Two types:

1. Nearly symmetrical flow of water and steam
2. Asymmetrical flow of steam-water mixture.

Q. *How is symmetrical flow of steam-water mixture in a horizontal tube observed despite a density difference between steam and water?*

Ans. Such flow is observed in horizontal tubes with diameter 30–40 mm and inlet velocity of water greater than 1 m/s.

The vapour bubbles formed initially on the tube wall detach themselves, under these circumstances, move along the mainstream of water and coalesce to form large bubbles which increase in number with increase in the quantity of steam produced. Eventually, there results a combined flow of two phases, the distribution of which becomes nearly symmetrical about horizontal axis and resembles wet-wall flow in vertical tubes. (Fig. 22.6).

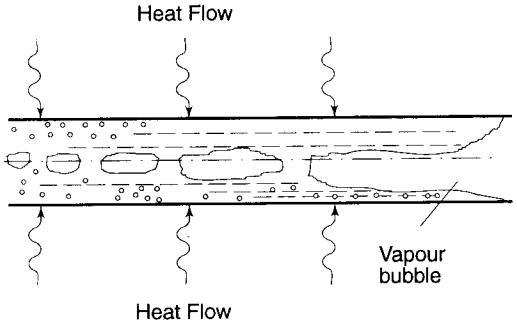


Fig. 22.6 *Symmetrical flow of steam-water mixture in a horizontal tube.*

Q. *What happens, i.e. how will the flow-mode change if the inlet velocity of water is less than 0.5 m/s in horizontal steam-generating tubes?*

Ans. At such a low inlet velocity of water into horizontal steam generating tubes, the two-phase flow is separated resulting in asymmetrical motion of water and steam along the flow path. (Fig. 22.7).

Steam bubbles formed will merge into larger formations which will attach themselves to the upper wall of the tube, as steam has lower density than water. These steam bubbles will flow along the upper wall of the tube while water will flow predominantly along the lower wall of the steam generating tube.

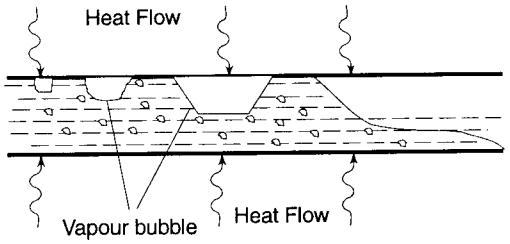


Fig. 22.7 *Asymmetrical flow of steam-water mixture in a horizontal steam-generating tube.*

Q. *How do the pressure, temperature, density and dielectric permittivity change in the water-steam path of subcritical and supercritical boilers?*

Ans. For subcritical pressure boilers, abrupt change in thermophysical characteristics takes place within the boiler furnace where conversion of water to steam takes place. As the water to steam transition takes place, the density of water abruptly changes to that of steam. Similarly dielectric permittivity of water changes abruptly to that of steam but temperature remains constant in this zone. (Fig. 22.8)

For supercritical pressure boilers, the transition of water to steam does not take place, unlike subcritical pressure boilers, at constant temperature. There is a smooth, gradual rise in the temperature in this zone (Zone-II). (Fig. 22.9)

The change in thermophysical properties (density, dielectric permittivity) of the working fluid in the zone of high heat capacity is rather smooth, not abrupt as with subcritical pressure boilers.

Q. *How do the density and dielectric permittivity of water vary with pressure?*

Ans. The variations have been shown graphically. (Fig. 22.10)

As is evident from the figure the density of water is substantially different from that of steam at any particular pressure. But this difference becomes narrower and narrower as the pressure

of the working fluid is increased. Eventually the density of both steam and water coincide at the critical pressure. Analogous statements can be made in the case of dielectric permittivity of the working fluid.

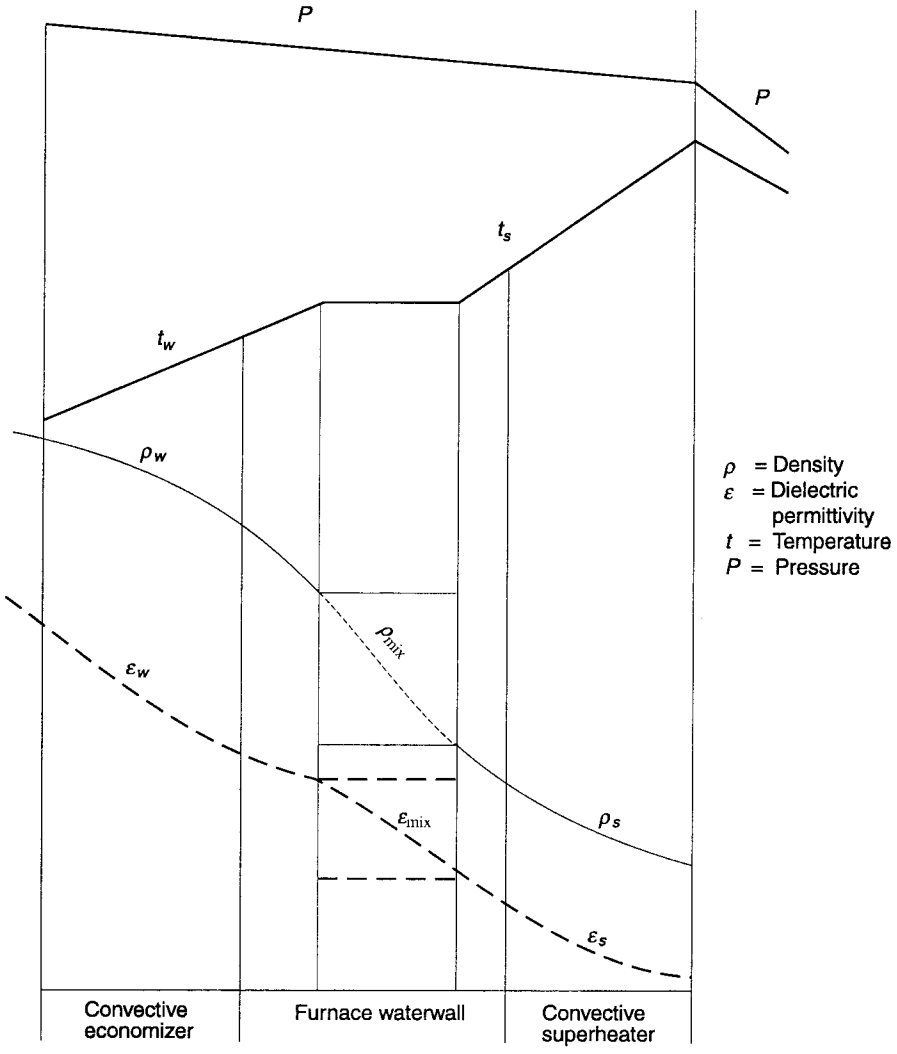


Fig. 22.8

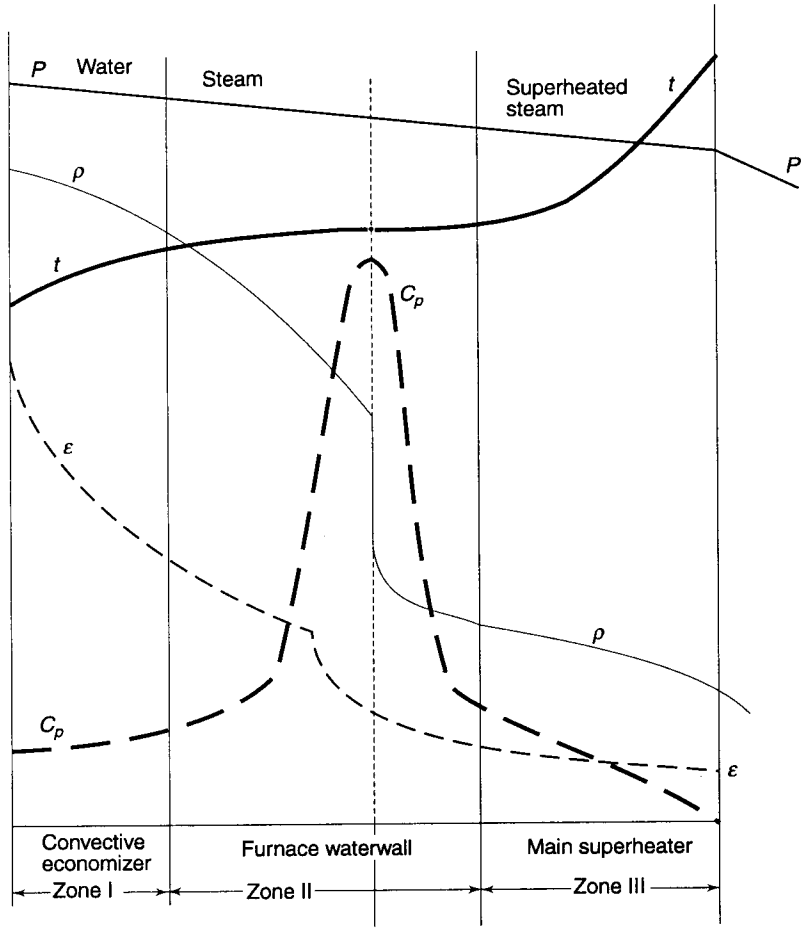


Fig. 22.9

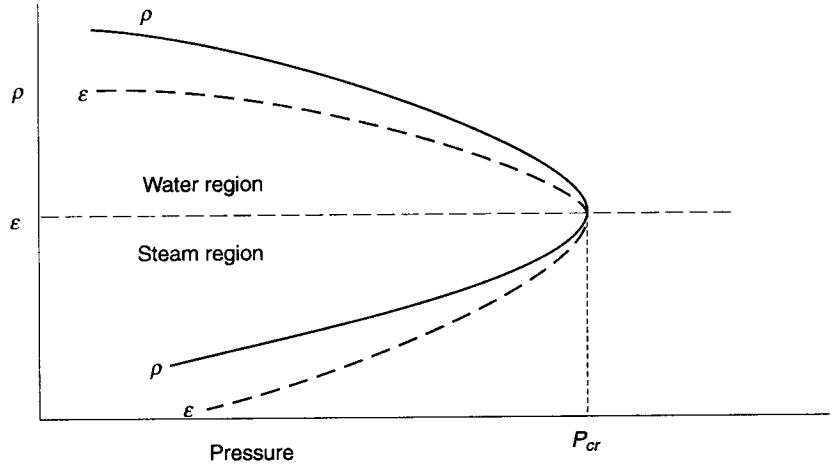


Fig. 22.10

23

TEMPERATURE CONDITIONS AND HEAT TRANSFER

Q. *Into how many zones can a boiler be divided on the basis of mode of heat transfer?*

Ans. Three zones.

ZONE-I consisting of waterwalls, i.e. heating surfaces arranged within the furnace, receives heat mainly by radiation from the hot (1200–1400°C) gaseous products of combustion in the furnace core.

ZONE-II comprising mainly of platens and water-walls, receives heat partly by radiation and partly by convection. In this zone gas temperature is quite high (800–1200°C) and so a substantial portion of heat transfer takes place by radiation.

ZONE-III composed of economizer, air heater and some superheater banks receives heat primarily by convection as this zone has a relatively low temperature (800–900°C) of combustion products contributing a very negligible fraction of radiant heat transfer.

Q. *In order to ensure stable operation of a boiler furnace, it is basically required to remove actively, through the heating surface, the heat released in the furnace. How can this be ensured?*

Ans. By virtue of motion of the working fluid at a definite mass velocity.

Q. *How does the boiler load variation in free-circulation plants affect the mass velocity of the steam-water mixture through the evaporating tubes?*

Ans. For steam generating plants operating on free-circulation, i.e. gravity circulation, the working fluid—steam-water mixture—moves under the free circulation head set up when the tubes are heated up. (Fig. 23.1)

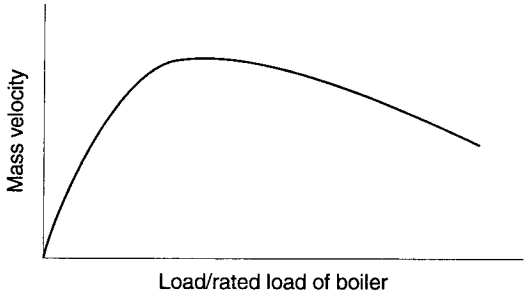


Fig. 23.1 *Circulation velocity of steam-water mixture in SGP changes with the load of its boiler.*

When the boiler load is increased, the mass flowrate at the inlet to the evaporating tubes rises sharply at first and on reaching a maximum value gets almost stabilized or even decreases somewhat.

Q. *Why does this decrease in the mass flowrate of the working fluid take place in a free-circulation boiler even after its maximum value has been reached with the increase of boiler load?*

Ans. It is because with the increase of steam generation rate, resistance to the flow of working fluid through the evaporating tubes increases due to higher unit volume of steam generation.

Q. *What is the effect of boiler load on the mass velocity of the working fluid in a multiple forced circulation boiler?*

Ans. In such types of boilers, circulation of water and steam-water mixture through evaporating tubes is effected by a circulation pump, with the effect that mass flowrate of working fluid remains practically constant irrespective of boiler load. (Fig. 23.2).

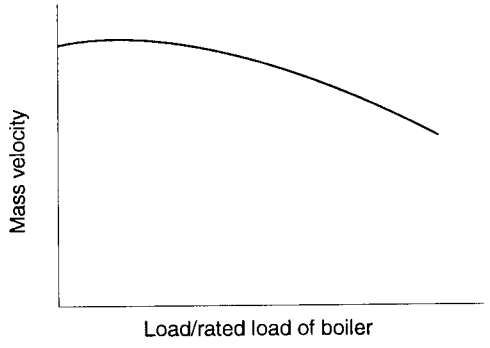


Fig. 23.2 *Mass velocity of working fluid in a multiple forced circulation boiler remains practically constant with the change of boiler load*

That's why the mass velocity vs. boiler load curve is roughly parallel to the load axis except for a slight declination at higher load which is due to the higher resistance to flow offered by higher steam generation.

Q. *What is the effect of boiler load variation on the mass flowrate of the working fluid in the case of a once-through boiler and forced circulation boiler?*

Ans. In the case of once-through boiler units, the mass flowrate of working fluid is directly proportional to the boiler load. Hence mass velocity vs. boiler load diagram is a straight line (*AB*). (Fig. 23.3)

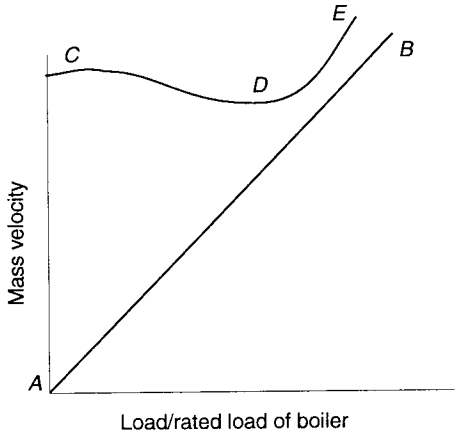


Fig. 23.3 *Mass velocity of working fluid in once-through boiler increases with boiler load while that in the case of combined circulation changes on the principle of multiple forced circulation and once-through operation.*

For combined circulation boilers working on the principle of multiple forced circulation at low loads and on the once-through principle at high load, the mass velocity vs. boiler load curve is as shown (*CDE*). Naturally, *CDE* is the resultant of two curves as depicted in the earlier two diagrams (see above). The line *CD* corresponds to operation on the principle of forced circulation while *DE* corresponds to that on once-through operation.

Q. *Why is load-shedding restricted to no less than one-third of the rated load in the case of once-through boiler plants?*

Ans. Since in the case of such boilers, the mass flowrate of water and steam-water mixture is proportional to the boiler load, load-shedding of more than 30% of the rated load would reduce the mass flowrate to an inadmissibly low value causing tube burnouts.

Q. *On which factors do the temperature conditions in evaporating tubes, for a given heat release rate in a furnace, depend?*

Ans. On three parameters:

1. mass flowrate of working fluid
2. pressure of the flow
3. steam content of water-steam mixture.

Q. *How does the boiling crisis (i.e. burnout conditions) originate in the evaporating tubes with bubble flow of the steam-water mixture?*

Ans. So long as the temperature of the tubes is maintained at a substantially low level *AB*, the steam content in the steam-water mixture with bubble flow is moderate and a thick liquid film adheres to the tube wall. (Fig. 23.4).

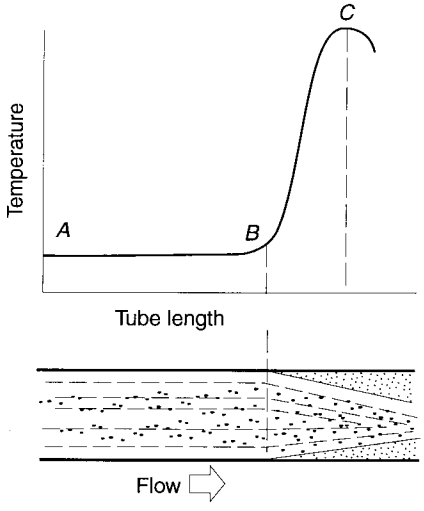


Fig. 23.4

As the working fluid flows and is heated up increasingly along the tube length, more and more liquid mass of the water film gets converted into vapour bubbles which stick to the inner wall of the tube. These vapour bubbles coalesce, grow in size and eventually form a continuous vapour film separating the flowing liquid from the heated tube wall. Presently, the main mass of the liquid flows through the central core while a film of vapour surrounds it. Since the heat transfer coefficient of water vapour is much less than liquid water, the prevailing condition sharply impairs the conditions of heat transfer. The effect of a sharp fall of heat transfer due to change from bubble boiling to film boiling is called ***boiling crisis***.

Q. *What is critical load?*

Ans. It is the heating load at burnout conditions.

Q. *What happens to the tube walls under boiling crisis?*

Ans. Under these conditions, the layer of superheated steam adhering the inner tube wall grows thicker and the overall heat transfer coefficient plummets sharply, with the effect that there is a greater intensity of incident heat on the tube wall surface than the rate of heat removal by the working fluid. This brings about a sharp rise in the wall temperature and often in the burnout of the tube wall.

Q. *Will the boiling crisis arise in the case of evaporating tubes with steam-water mixture in disperse-annual flow?*

Ans. Yes.

Q. *How does boiling crisis arise in evaporating tubes with steam-water mixture in disperse-annular flow?*

Ans. The disperse-annular flow is wet-wall flow in which a water film flows along the tube walls and hence wets it while steam saturated with water droplets moves in the core of the tube. (Fig. 23.5).

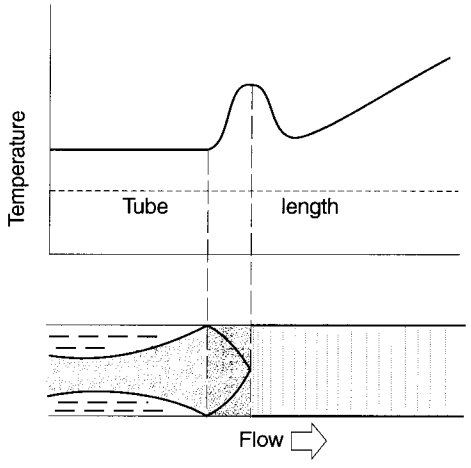


Fig. 23.5 *Boiling crisis occurring with steam-water mixture in disperse-annular flow.*

When heated, the water film gets thinner due to evaporation and breaks off, leaving a microfilm on the wall. This microfilm also gets destroyed under a particular heating load and is disintegrated into individual islets and streaks whose number and size diminish in the course of further evaporation. As a result, a continuous layer of steam adheres to the wall while the diminutive number of water droplets carried down the mainstream of flow in the core gradually evaporate along the direction of flow. Since the vaporization is more intense at the walls, the water droplets are repulsed from the tube walls into the steam flow. Therefore, under these circumstances, heat transfer occurs through a continuous layer of steam instead of a continuous layer of water before heating. This sharply decreases the heat transfer coefficient and the wall temperature increases resulting in boiling crisis.

Q. *What is the important difference between the boiling crisis in bubble flow and that in disperse-annular flow?*

Ans. When a boiling crisis occurs, the temperature of the tube wall rises much more substantially in the case of bubble flow than in the case of disperse-annular flow.

Q. *Why do the burnout conditions in tubes heated unevenly occur at much higher values of critical load than in tubes heated uniformly from all sides?*

Ans. For unevenly heated tubes, the front side facing the furnace is most intensively heated while the rear side is heated least intensively. This results in transverse circulation of the working fluid from the less heated tube zone to the more heated tube zone, i.e. from the rear side of the tube wall to the front side. (Fig. 23.6) Due to this turbulence, some quantity of heat is transferred by conduction to the tube material in the direction opposite to the heat flow from the furnace. This brings about a cooling effect of the working fluid, thus retarding the boiling crisis.

Q. *Why in modern powerful steam boilers, do evaporating tubes have their inner surface screw threaded?*

Ans. This will enhance the turbulization of the working fluid and deter a boiling crisis, by introducing a cooling effect.

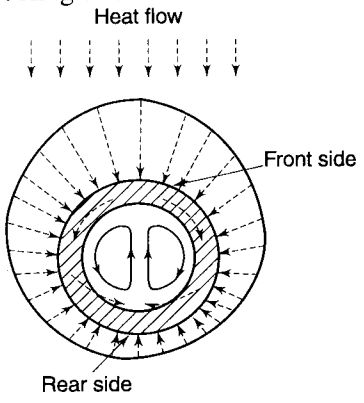


Fig. 23.6 *Unevenly heated boiler tube sets up transverse circulation of the working fluid from the less heated zone to the more heated tube zone.*

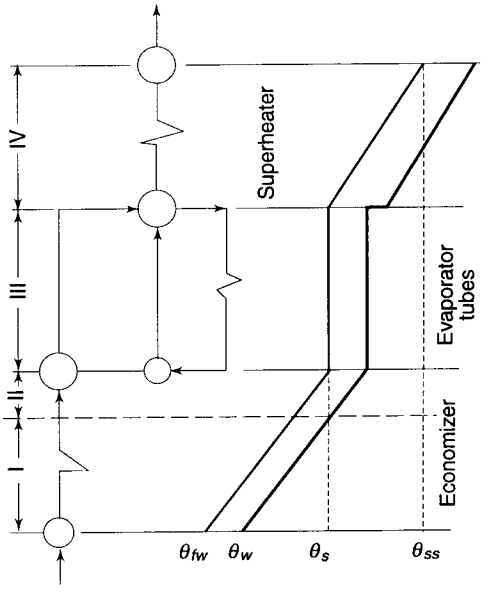


Fig. 23.7 *Temperature variation in the steam-water path of a drum type subcritical pressure boiler.*

Q. *How do the temperature and mode of heat transfer vary in the steam-water path of a drum type subcritical pressure boiler?*

Ans. Temperature variations in the water-steam path of a drum-type subcritical pressure boiler can be best described by Fig. 23.7.

The temperature of the feedwater (θ_{fw}) is raised to the saturation point (θ_s) in the economizer. And therefore, in the evaporating tubes the entire heat absorbed goes to evaporate the steam-water mixture at a fixed temperature (θ_s); while in the superheater, the temperature of the steam is further raised to the value θ_{ss}—the temperature of the superheated steam.

Q. *What is the mass steam content at the boundary between sections III and IV?*

Ans. Unity, i.e. the entire water content in the steam-water mixture is evaporated to steam.

Section	Equipment	Temperature Condition	Mode of Heat Transfer	Remarks
(I)	ECONOMIZER	Feedwater temperature (θ_{fw})as well as wall temperature (θ_w) gradually increase but both remain below the saturation temperature $\theta_{fw} < \theta_w < \theta_s$	Convection. Heat transfer occurs due to temperature gradient $\Delta\Theta = \theta_w - \theta_{fw}$	Heating intensity is low (5 – 10 kW/m^2) but coefficient of heat transfer is high (2 – 5 kW/m^{2}K) and that's why the wall temperature is only a few degrees higher than the feedwater temperature.
(II)	ECONOMIZER	Feedwater temperature (θ_{fw}) gradually approaches saturation temperature (θ_s) while wall temperature (θ_w) gradually exceeds θ_s $\theta_{fw} \rightarrow \theta_s < \theta_w$	Unstable bubble boiling	Surface boiling has already set in on the tube walls. As the vapour bubbles are formed, they get detached from the tube walls, pass into the bulk of water flow and condense there, raising the temperature of the flow.
(III)	EVAPORATOR TUBES	The temperature of a steam-water mixture θ_{fw} becomes equal to boiling temperature θ_s. Wall temperature θ_w remains higher than θ_s throughout $\theta_{fw} = \theta_s < \theta_w$	Stable bubble boiling	Heat transfer coefficient is substantially large (50–100 kW/m^{2}K) and therefore, temperature difference between the tube wall and steam-water flow is marginal. Heat transfer takes place independent of flow velocity but it is dependent on the heating intensity and pressure of the flow.
(IV)	SUPERHEATER	Steam is superheated to to the rated superheat temperature (θ_{ss}). Along with it increases the wall temperature	Convective heat transfer through single phase medium, i.e. steam	Since steam has a lower coefficient of heat transfer than water film, heat transfer to superheated steam worsens and the temperature of the tube wall increases.

Q. *What is the temperature profile in the steam-water path of once-through subcritical pressure boilers?*

Ans. Analogous to drum type, the temperature of feedwater in a once-through subcritical-pressure boiler is raised to the saturation point θ_s in the economizer, with the effect that the entire heat absorbed by the evaporating tubes goes to evaporate the water and the temperature of the steam-water mixture remains nearly constant at θ_s throughout the evaporating tubes. Finally, the steam at θ_s is superheated to superheating temperature θ_{ss} in the superheater. (Fig. 23.8)

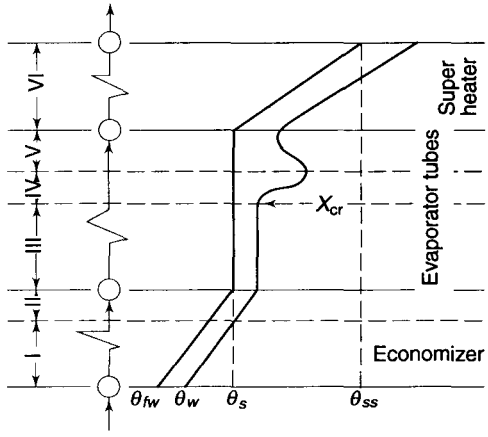


Fig. 23.8 *Temperature profile in the steam-water path of once-through subcritical pressure boiler.*

In the economizer section I, both the feedwater and wall temperature lie below the saturation temperature θ_s

i.e. $\theta_{fw} < \theta_s$; $\theta_w < \theta_s$

Heat transfer takes place by convection through water-film adhering to the tube wall. Because of a high heat transfer coefficient (5–10 kW/m^{2}K) the wall temperature is only marginally greater than temperature of the flow.

In section II, the temperature of the flow θ_{fw} is lower than θ_s but the wall temperature is higher than θ_s all through. Heat transfer takes place by unsteady surface-boiling whereupon vapour bubbles formed on the tube wall pass into the bulk of the water flow, condense and raise the flow temperature.

In the evaporator sections III, IV and V, the temperature of the water-steam mixture remains essentially constant at θ_s throughout, as the water mass is gradually converted into steam. Heat transfer takes place through stable bubble boiling.

But the steam content varies along the length of the evaporating tubes in the range $O < x < 1$. And at steam content corresponding to x_{cr}, at the boundary between sections III and IV, boiling crisis occurs due to deterioration of heat exchange conditions as the water film dries up. This results in a sharp increase of wall temperature.

However, after attaining a maxima, the wall temperature of the evaporating tubes sharply decreases as the increase of steam velocity brings about an increase in the heat transfer coefficient, with the effect that more of the heat deposited to the tube wall is transferred to the steam. At the boundary between sections IV and V the entire liquid water is converted into steam. And any heat added thereafter goes to superheat the steam.

Q. *What is the effect of flow pressure on boiling crisis?*

Ans. As the pressure of the flow is increased, it goes to reduce the surface tension, so boiling crisis will occur at a much lower value of x_{cr} (critical dryness fraction, i.e. mass steam content).

Q. *What is the effect of higher heating load on boiling crisis?*

Ans. Higher heating load means a quicker evaporation rate of water from the steam-water flow and that means boiling crisis will arise at a lower value of x_{cr}.

Q. *What is the principal effect of boiling crisis on the evaporating tube?*

Ans. Since heat transfer conditions deteriorate in the zone of boiling crisis (which can move

along the length of the evaporation tube under certain circumstances) the tube metal in this zone is subjected to abrupt temperature changes that will induce thermal fatigue in the affected region.

Q. *How can this be reduced?*

Ans. The high temperature gradient between the internal surface of the tube and the flow in the transition zone of boiling crisis can be reduced to within 80°C—a tolerable limit by maintaining a sufficiently high flow velocity.

Q. *What is the effect of tube bends of the evaporating surface on the temperature conditions of the working fluid in a steam generation plant?*

Ans. The tube bends induce a centrifugal force on the working fluid towards the outside of the bend. The fluid in the core of the flow being less intensively heated than that near the wall, it is much denser than the fluid adjacent to the wall. And therefore, the fluid in the core of the flow possesses higher kinetic energy than that near the tube wall. As a result, the fluid in the core of the flow is thrown, under the influence of centrifugal force, towards the outside of the bend where it displaces the fluid of lower density towards the centre of the tube. Thus two symmetrical vortices are developed at the bend, (Fig. 23.9) over and above the main axial flow.

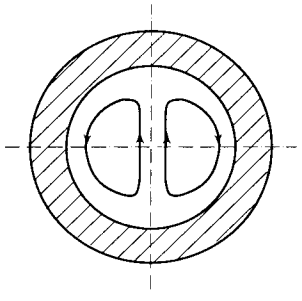


Fig. 23.9 *Two symmetrical vortices are developed in the working fluid at the tube bend.*

The narrow band left between these two opposing vortices on the inside wall cools less intensively than it would otherwise, resulting in deterioration of heat transfer in this local zone.

Whereas, on the outside of the band, the heat transfer conditions are better because of higher heat removal by transverse motion of two opposing symmetrical vortices and the wall temperature remains lower.

Q. *What is the coefficient of heat spread?*

Ans. The coefficient of heat spread for a particular tube point subjected to uneven heating is defined as the ratio of the actual temperature to the temperature that would appear at that point should the heating be uniform with the maximum heat flowrate q_{max}.

Q. *Why is the range of deteriorated heat transfer (boiling crisis) larger in horizontal tubes (15-20 mm dia) than in vertical tubes of the same dia though heating is uniform over the periphery?*

Ans. It is because the asymmetry of the steam-water flow, in the horizontal tubes, under the influence of gravitational forces worsens the internal heat transfer in the upper region more than in the lower region. Whereas, for a uniformly heated vertical tube this a symmetry in the flow of the steam-water mixture does not arise.

Q. *What problems arise in horizontal evaporating tubes having separated flow of the working fluid at subcritical pressure?*

Ans. Because of separated flow, heat transfer is unsymmetrical resulting in higher temperature on the upper surface and lower temperature on the lower surface of the horizontal tubes. The separation of flow between two phases—water and steam—is effected by gravitational forces. (Fig. 23.10).

Waves may form on the separating surface with their tops periodically splashing onto the overheated wall of the upper surface. Repeated water splashing causes a sharp cooling of the tube wall which will be subjected to thermal shock due to periodic heating and cooling. This can result in fatigue in the tube metal.

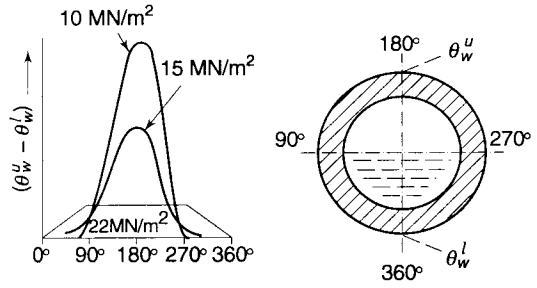


Fig. 23.10 *Unsymmetrical heat transfer results from separated flow.*
θ_w^u = *Upper wall temp.*
θ_w^l = *lower wall temp.*

Q. *Why are horizontal tubes in free-circulation boilers not heated?*

Ans. Free-circulation boilers are characterised by low flow velocities in evaporating tubes which, if laid horizontal, will give rise to metal fatigue in the tube due to periodic heating and cooling resulting from separation of flow, as stated above.

Q. *Why does this problem not arise in the case of once-through boilers over a wide range of heating loads?*

Ans. In this case, flow separation does not arise because of high flow velocities.

Q. *What will be the effect on horizontal evaporating tube heating, for separated flow of the working fluid, if the tube wall thickness is increased or the tube is replaced by a similar tube of metal with higher thermal conductivity?*

Ans. In either case, the heat deposited on the tube surface will be spread through the tube metal and thereby the elevation of temperature of the upper portion of the tube with respect to its lower portion will get somewhat diminished, reducing thermal fatigue arising from flow separation.

Q. *What is the effect of deposits on the temperature conditions on the heating surface?*

Ans. Impurities present in the BFW in a dissolved or suspended state will form deposits on the inner wall of the evaporating tubes. And these grow in thickness with the operation of the boiler. Since the deposits have thermal conductivities of their own, the inner surface temperature of the tube will be

$$\theta_w^{\text{in}} = \theta_f + q_{\text{in}} \left(\frac{1}{\alpha} + \frac{\Delta x}{\lambda} \right)$$

where,

θ_f = flow temperature
q_{in} = heating intensity on the inside surface
α = coefficient of heat transfer from the inner wall to the working fluid.
Δx = thickness of deposit
λ = thermal conductivity of the deposit

For a clean tube, the above equation reduces to

$$\theta_w^{\text{in}} = \theta_f + \frac{q_{\text{in}}}{\alpha}$$

Depending on chemical composition, the thermal conductivity of the deposits may vary:

from 0.1 to 0.5 W/m.°K for mineral deposits and from 3 to 5 W/m.°K for ferric oxides

As such, with larger thickness (Δx) of the deposited layer and with a lower thermal conductivity (λ), the thermal resistance across the wall to the working fluid is higher and resulting in higher wall temperature (θ_w^{in})—even a layer of deposit of a few fractions of a millimeter is enough to raise the wall temperature to a value inadmissible for reliable operation of the tube metal. With the increase in running hours of boilers, the deposits grow thicker and thermal resistance of the deposited tube wall goes higher, with the effect that tubes of the waterwall get intensively heated raising the wall surface temperature to a level that delimits the continuous operation of the steam generation plant.

24

HYDRODYNAMICS OF CLOSED HYDRAULIC SYSTEM

Q. *What feature ensures reliable and lasting operation of the free-circulation circuit of boilers?*

Ans. For boilers with free-circulation circuit, the vertical evaporating tubes (i.e. uptake tubes) are arranged inside the boiler furnace and downtake tubes outside. This results in a density difference between the water columns in the downtake tubes and the columns of steam-water mixture in the uptake tubes. (Fig. 24.1).

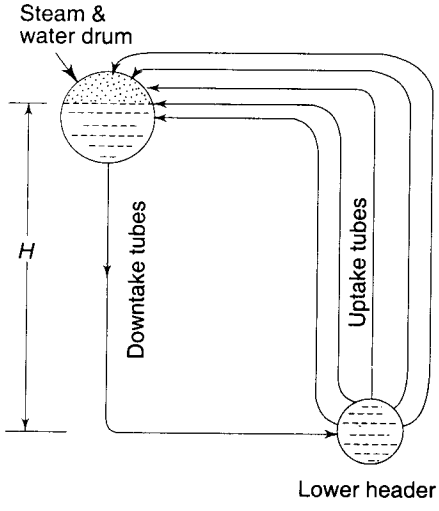


Fig. 24.1 *Free-circulation circuit of boilers puts uptake tubes inside the furnace and downtake tubes outside it.*

Because of this density difference, a continuous circulation of water and steam-water mixture is developed in the circuit and this ensures a continuous and efficient heat removal from the heating surfaces. Therefore, the tube metal is maintained within a tolerable temperature level ensuring prolong and reliable operation of the free-circulation circuit.

Q. *What is the driving head of the free-circulation circuit?*

Ans. It is given by

$$S_{drv} = H\,(\rho_{H_2O} - \rho_{mix})\,g = \Sigma\Delta P_{Hydr}.$$

where H = height of water level in the boiler drum from the base of the evaporating tubes

ρ_{H_2O} = density of water

ρ_{mix} = density of steam-water mixture

$\Sigma\,\Delta P_{Hydr}$ = sum of all hydraulic resistances in the circuit

$= \Delta P_{up} + \Delta\, P_{dwn}$

ΔP_{up} = resistance in the uptake tubes

ΔP_{dwn} = resistance in the downtake tubes

Q. *What is the useful circulation head?*

Ans. It is the difference between the driving circulating head and resistance of the uptake tubes

$$S_{usf} = S_{drv} - \Delta P_{up} = \Delta P_{dwn}$$

i.e. useful circulating head is expended to overcome the resistance of the downtake tubes.

Q. *What is the effect of circulation velocity on useful head?*

Ans. This can be determined with the help of S_{usf} vs. v_{cir} curves obtained at various values of resolved steam velocity v_s^{res*} (Fig. 24.2)

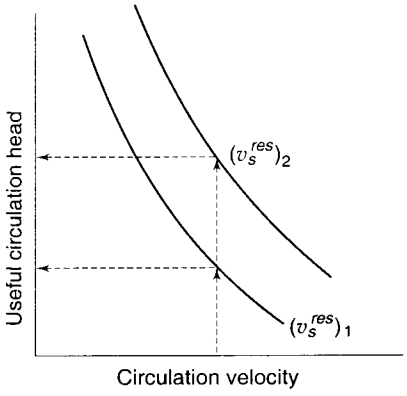


Fig. 24.2

$$v_s^{res} = G_s/(A\rho_s)$$

where

G_s = mass flowrate of steam, kg/s

A = area of cross-section of the steam generating tube, m^2

ρ_s = steam density, kg/m^3

From the curves it is evident that for the same circulation velocity, useful circulation head increases with the increase of resolved steam velocity, i.e. with the increase in heating rate.

***Resolved steam velocity:** is the velocity that steam would have in a particular cross-section of a steam-generating tube if it is completely occupied by steam.

Q. *What is the effect of pressure on the useful circulating head?*

Ans. This can be determined by plotting the useful circulating head against different flow pressures under identical conditions. (Fig. 24.3).

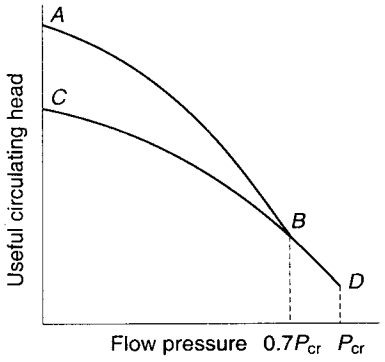


Fig. 24.3 *Effect of flow pressures on the useful circulating head .*

From the curves it is evident that the useful circulating head decreases with the increase in working pressure. This is because as the pressure increases, the density of the steam-water mixture in the uptake tubes increases and as a result, ΔP_{up} increases and S_{usf} decreases.

$$S_{usf} = S_{drv} - \Delta P_{up}$$

(*AB* has been drawn by ignoring the relative velocity of steam and water while *CD* has been drawn by taking this relative velocity into account.)

As the pressure approaches the critical value, S_{usf} gradually reduces to a low value whereupon free circulation becomes practically non-existent.

Q. *What is the ultimate pressure at which reliable free-circulation is still possible?*

Ans. 18–19 MPa (18–19 MN/m^2)

Q. *Why on plotting S_{usf} vs. P_{flow}, are two curves obtained—one when the relative velocity of steam and water is considered and the other when the relative velocity of steam and water is ignored?*

Ans. The relative velocity of steam with respect to water is functionally dependent on the flow pressure which in turn determines the value of the useful circulating head. When the pressure is low, steam formation is large and so the relative velocity of steam is rather high. Therefore, for a particular pressure (below critical pressure), there will

be two useful circulating heads—one due to consideration of the relative velocity of steam and the other due to ignoring it.

Q. *How does the density of steam-water mixture vary with the circulation velocity in the uptake and downtake tubes?*

Ans. For uptake tubes, the density of steam-water mixture will increase with the increase of the circulation velocity while for downtake tubes it is just the reverse. (Fig. 24.4).

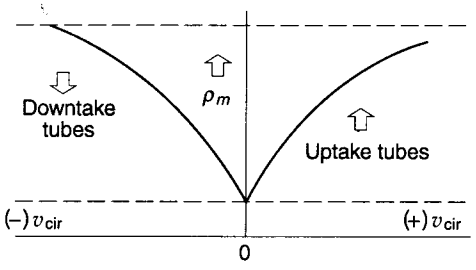


Fig. 24.4

Q. *What is the effect of steam-slippage and friction upon the useful circulating head in both uptake and downtake tubes?*

Ans. In uptake tubes, the useful circulating head decreases due to steam-slippage and friction with the increase of circulating velocity. (Fig. 24.5).

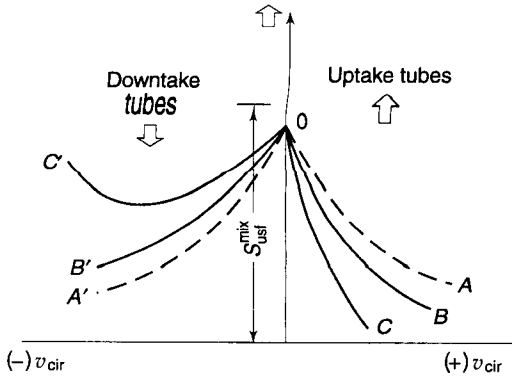


Fig. 24.5

Whereas in the case of downtake tubes these two factors tend to increase the useful circulating head with the increase of circulation velocity.

OA and *OA'* correspond to theoretical S_{usf} *vs* · v_{cir} curves when friction factor and steam slippage are ignored.

OB and *OB'* correspond to S_{usf} *vs* · v_{cir} curves when steam slippage has been considered.

OC and *OC'* correspond to S_{usf} *vs* · v_{cir} when both steam slippage and friction factors are taken into account.

Q. *Why does the useful circulating head decrease with the increase of circulation velocity in uptake tubes of closed hydraulic systems?*

Ans. For upward motion of the steam-water mixture through the evaporating tubes, the increase of circulation velocity increases the relative velocity between steam and water which in turn decreases the actual steam content but increases the density of the mixture resulting in a decline of S_{usf}.

cf. $S_{usf} = S_{drv} - \Delta P_{up} = H(\rho_{H_2O} - \rho_{mix}) - \Delta P_{up}$

Q. *Why does the useful circulating head increase with the increase of circulation velocity in the downtake tube of a closed hydraulic system?*

Ans. For downward motion, the increase of the relative velocity of steam and water (with the increase of circulation velocity), increases the actual steam content and decreases the density of the steam-water mixture, resulting in an increase of S_{usf}.

Q. *What is make-up velocity?*

Ans. It corresponds to the velocity of flow of makeup water supplied to the evaporating tubes such that the rate of steam generated is compensated by the rate of water supply when there is no circulation through the evaporating tubes.

Q. *What does the term make-up velocity (v_{mu}) imply?*

Ans. It implies that

1. the quantity of water supplied to the evaporating tubes is low
2. the entry of water to the evaporating tubes is possible either from the bottom or from the top.

Q. *What is the effect of pressure on the total hydraulic characteristic of a steam-generating tube both at lower and higher pressure?*

Ans. This can be understood better graphically.

The curve to the right of the ordinate represents the hydraulic characteristic corresponding to the ascending motion of the working fluid while that to the left to the descending motion. (Fig. 24.6)

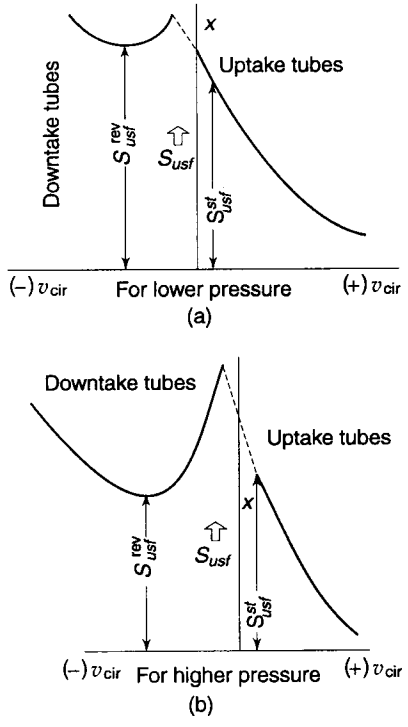


Fig. 24.6

At point X on the right-hand branch, the circulation velocity is practically nil and circulation virtually ceases. The velocity of feedwater at this point is called make-up velocity.

Q. *Why does the hydraulic characteristic corresponding to descending motion always lie higher than that corresponding to ascending motion for lower pressure evaporating tubes, whereas in the case of higher pressure systems a considerable portion of it lies lower than the portion of the hydraulic characteristic corresponding to ascending motion?*

Ans. It is because, at lower pressure, the effect of relative steam velocity is high and therefore S_{usf} decreases in ascending tubes and increases in the descending tubes with the increase of circulation velocity. Therefore, the hydraulic characteristic of descending tubes lies higher than that of ascending tubes.

Whereas at higher pressure, the steam velocity and hence hydraulic resistance are low and therefore a sizeable portion of the hydraulic characteristics of the descending tube lies below the portion of the hydraulic characteristic of ascending tubes.

Q. *What is circulation stagnation?*

Ans. It marks the phenomenon of zero circulation, i.e. the point at which circulation virtually ceases in a natural circulation system. This point is reached when the circulation velocity equals the make-up velocity.

Q. *What is the useful stagnation head?*

Ans. It is the useful head corresponding to zero circulation. (The ordinate of the point X on the hydraulic characteristic of ascending tubes.)

Q. *In which of the following cases will the circulation stagnation arise—evaporating tubes connected into the water space of the steam-drum or evaporating tubes connected into the steam space of of the steam-drum?*

Ans. In both cases circulation stagnation may arise.

Q. *Why does circulation stagnation arise in the above two cases?*

Ans. It is because, in the first case (when the evaporating tubes are connected to the water space) with circulation stagnation, the water is at liberty to enter the evaporating tubes from the bottom as well as from the top and it moves very slowly upwards or downwards in the evaporating tubes while steam moves only upwards bubbling

through the column of water in the ascending tubes. (Fig. 24.7).

Whereas in the latter case, the slowly moving useful head of water is insufficient to overcome the hydraulic resistance in the descending tubes and to lift the working fluid to the topmost level in the ascending tubes of the circuit. (Fig. 24.8)

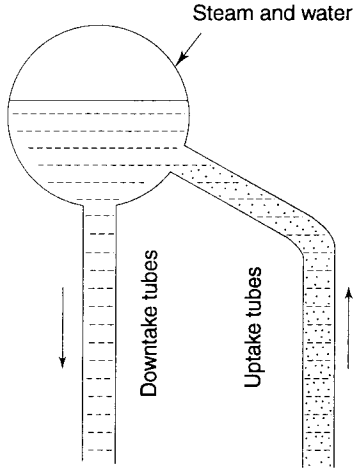


Fig. 24.7

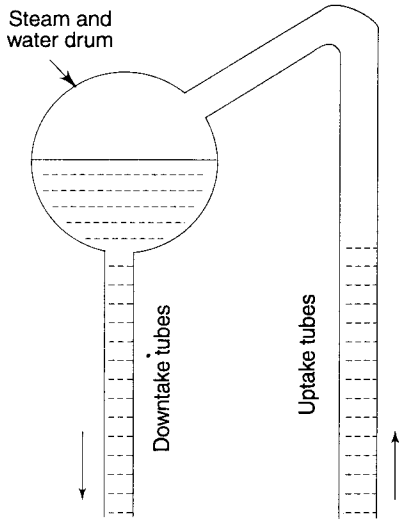


Fig. 24.8

Q. *What is circulation reversal?*

Ans. In the hydraulic characteristic of descending tubes (for both lower pressure and higher pressure system), there is a dip, i.e. a minima beyond which the useful circulation head increases with the decrease in the circulation velocity, i.e. ascending motion occurs in the downtake tubes. That is, it is at this point that the change from ascending to descending motion occurs in the uptake tubes. This transition is called circulation reversal.

Q. *What do you mean by useful head of reversal, S_{usf}^{rev}?*

Ans. It is the useful circulating head at which the change from ascending to descending motion takes place in an evaporating tube.

Q. *What is the effect of clinkering on the hydraulic characteristics of steam-generating tubes?*

Ans. Since clinker has a low thermal conductivity, a clinkered tube will receive substantially less heat than an unclinkered (i.e. clean) tube. And therefore, differently heated tubes will produce different quantities of steam and will develop different driving circulating heads—clean tubes will develop the highest driving head. Differently slagged tubes will develop different driving heads, always lower than that in the clean tubes.

Now that all the ascending tubes are connected to common headers and operate under the same useful circulating head, S_{usf}

$$S_{usf} = \Delta P_{dwn}$$

the useful circulating head will be the same for all the tubes in the circuit. However due to non-uniform heating this useful head, common for all tubes, will correspond to different flowrates of water circulating in these tubes with the effect that little water will pass through some of the tubes. As a result, such circulation disturbance as circulation starvation or even circulation reversal may occur.

Q. *What is circulation reliability?*

Ans. Absence of circulation disturbances.

Q. *How can circulation reliability be ensured?*

Ans. By taking recourse to reliability criteria as cited below:

1. Criterion of Stagnation

$$\left[S_{\text{ust}}^{\text{st}} / S_{\text{usf}}^{\text{cir}}\right] > 1.1$$

2. Criterion of Circulation Reversal

$$\left[S_{\text{usf}}^{\text{rev}} / S_{\text{usf}}^{\text{cir}}\right] > 1.1$$

3. Criterion of Free Water Level (Fig. 24.9)

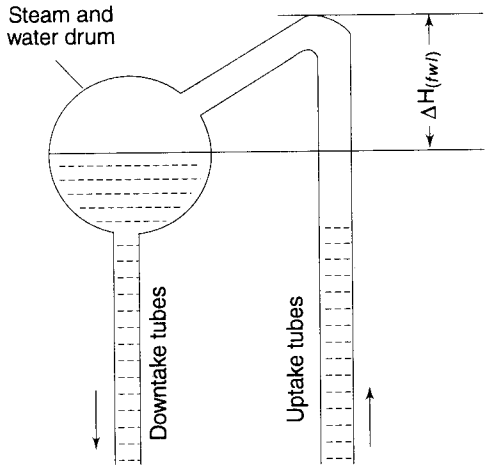


Fig. 24.9

$$\left[\left(S_{\text{usf}}^{\text{st}} - \Delta P_{\text{fwl}}\right) / S_{\text{usf}}^{\text{cir}}\right] > 1.1$$

where, ΔP_{fwl} = pressure loss in raising the steam-water mixture above the free water level of the boiler drum.

Q. *How may steam bubbles from in the downtake tubes?*

Ans. If the pressure drop at the inlet of the downtake tubes becomes greater than the water level in the boiler drum, the pressure of water at the inlet to the downtake tubes will drop to such a low level that the water will boil in the zone of reduced pressure. And thus steam bubbles will form and be dragged down by the circulating water into the downtake tubes.

Q. *What is the effect of this?*

Ans. Since steam bubbles take some time to condense, these bubbles are entrained by the waterflow over an appreciable length of the downtake tubes. Therefore, the downtake tubes get filled with a steam-water mixture instead of water alone. Since steam offers higher hydraulic resistance to flow than water, downtake tubes filled with substantial quantity of steam bubbles will suffer from loss of driving circulating head.

Q. *What are the main causes for the appearance of steam in downtake tubes?*

Ans. 1. Sudden pressure drop in the boiler
2. Entrainment of steam bubbles from the steam space of the drum
3. Entrainment of water bubbles from the water space of the drum

Q. *How does the entrainment of steam bubbles from the steam space of the drum to downtake tubes take place?*

Ans. As water enters the downtake tubes, its hydrostatic pressure head decreases substantially due to appearance of velocity head as well as due to unavoidable energy losses on local resistances.

If water pressure at the entry of downtake tubes is less than its pressure at the water-level in the drum, steam will form in the zone of reduced pressure at the entry of the downtake tubes. Under these circumstances, steam cones may form at the disengagement surface (i.e. water-steam separating surface) so that a large amount of steam will ingress from the steam space into the system of downtake tubes giving rise to disturbances in the water circulation of the circuit.

Q. *Does the formation of steam cone take place in the case of boilers with free circulation only?*

Ans. No. It may occur in boilers with both free and forced circulation.

Q. *How can this be prevented?*

Ans. By maintaining the water level in the drum at a safe height above the inlets to the downtake tubes, so that the hydrostatic pressure head in the drum is always greater than the pressure head at the inlet to the downtake tubes.

Q. *Does the diameter of the downtake tubes have any function regarding the formation of steam cone?*

Ans. Yes: the probability of formation of steam cone increases with the increase in diameter of the downtake tubes.

Q. *How does the entrainment of steam from the water-space of the drum into the downtake tubes take place?*

Ans. This phenomenon can occur if the circulation velocity of water in the circuit is substantially high, whereupon steam bubbles formed below the disengagement surface will not get any chance to separate and are thus entrained by the downward flow of water into the downtake tubes.

Q. *When may such a case arise?*

Ans. If the outlets of the evaporating tubes in the drum are placed close to the inlet of the downtake tubes.

Q. *How can the entrainment of steam bubbles from the water-space of the boiler drum to downtake tubes be prevented?*

Ans. This can be reduced by

(a) proper arrangement of partitions
(b) separating the steam-water mixture in cyclones.

25

DEAERATION AND DEOXYGENATION

Q. *What is deaeration?*

Ans. Deaeration is the process of removing dissolved corrosive gases (O_2 and CO_2) from water.

This process is also called degasification.

Q. *Why are these gases corrosive?*

Ans. Dissolved oxygen acts as a depolarizer and contributes to the corrosion of metal

$$O_2 + 4e + 2H_2O \longrightarrow 4OH^-$$

Carbon dioxide dissolved in water liberates H^+ ions that attack metal

$$CO_2 + H_2O \Leftrightarrow H_2CO_3 \Leftrightarrow H^+ + HCO_3^-$$

CARBONIC ACID

Q. *What is deoxygenation?*

Ans. It is the process of removal of only oxygen from water.

Q. *How can deaeration be distinguished from deoxygenation?*

Ans. Deaeration is the removal of both O_2 and CO_2 from water while deoxygenation involves the removal of O_2 only.

Deaeration is a thermal method. Water is heated to bring about degasification, whereas deoxygenation is carried out mainly by chemical techniques.

Q. *What is the basis of thermal deaeration?*

Ans. Upon heating water, the solubility of gases dissolved in it decreases because their partial pressures in the gas phase above the water level drop off.*

So when water at a given pressure is heated to boiling point degasification is effected.

$$x_{H_2O} = n_{H_2O}/\Sigma\, n;\ x_{O_2} = n_{O_2}/\Sigma\, n;$$

$$x_{CO_2} = n_{CO_2}/\Sigma\, n$$

Now $$x_{H_2O} + x_{O_2} + x_{CO_2} = 1$$

where x stands for the mole fraction of a component.

As the mole fraction of O_2 and CO_2 decreases in the vapour phase so does their partial pressure

$$p_{O_2} = x_{O_2} \cdot (\text{Total pressure})$$

$$p_{CO_2} = x_{CO_2} \cdot (\text{Total pressure})$$

(Since the solubility of gases in a liquid is proportional to their partial pressure above the liquid phase, the decrease in the partial pressures of oxygen and carbon dioxide as a result of heating of water lowers the solubility of O_2 and CO_2 in water.)

Q. *What is the effect of BFW pressure on deaeration?*

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* (As the water is heated, more and more water molecules transfer from the liquid phase to vapour phase. This brings about an increase in the mole fraction of water in the vapour phase, consequently reducing the mole fraction of O_2 and CO_2 in the vapour phase.)

Ans. No effect, in practice.

Q. *Can deaeration be effected at a pressure higher or lower than the atmospheric pressure?*

Ans. Yes; this can be done as the feedwater pressure exerts practically no effect on deaeration.

Q. *What is a deaerator?*

Ans. It is the apparatus wherein deaeration is carried out.

Q. *How are deaerators classified?*

Ans. Deaerators are classified according to the working pressure under which they operate.

Type of Deaerator	Working Pressure
1. Vacuum Deaerator	0.116 MN/m^2
2. Atmospheric Deaerator	0.12–0.17 MN/m^2
3. High Pressure Deaerator	0.17–0.7 MN/m^2

Atmospheric deaerators can be subdivided into direct-contact (mixing) deaerators and overheated-water deaerators.

Also deaerators can be classified in accordance with the mode of steam-water distribution in them.

1. Atomizing deaerator
2. Tray-type deaerator
3. Film-type deaerator

Note: For more details, please see APPENDIX-II

Q. *How do direct-contact deaerators function?*

Ans. They consist of a deaerator column fitted on the top of the storage tank.

The deaerator column is a hollow cyclindrical vessel provided with

(a) perforated, horizontal trays arranged one above the other.
(b) water distribution device at the top.
(c) Steam distributor at the bottom. (Fig. 25.1).

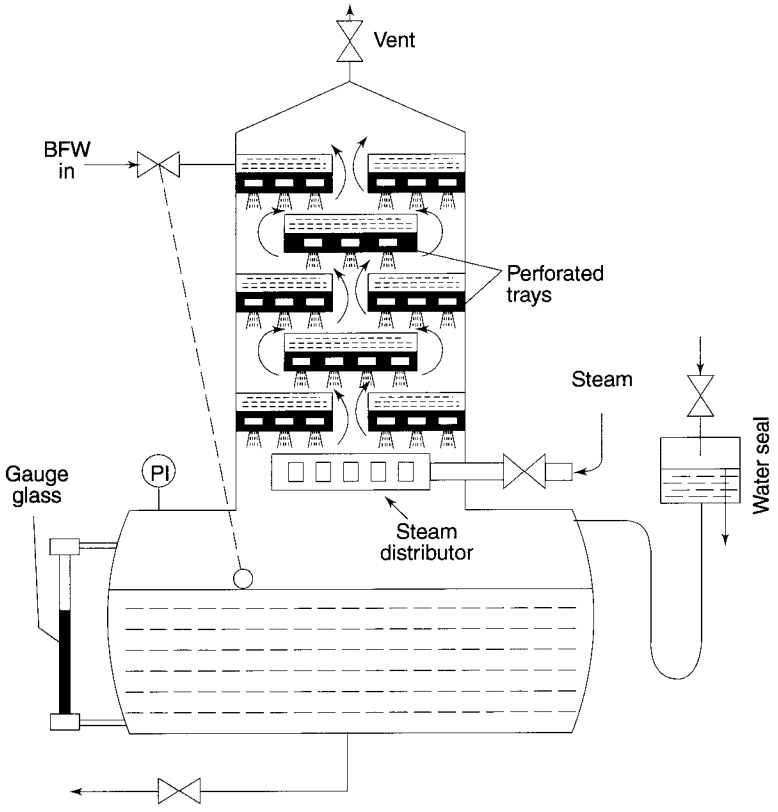

Fig. 25.1 *A direct-contact deaerator.*

Feedwater enters the deaerator from the top and is evenly distributed, by means of the distributing device, into the perforated trays fitted at the bottom. Water fills the perforations (dia 5–7 mm) and rains down and comes in contact with heating steam delivered into the lower portion of the deaerator column through the steam distributor. As a result of heat exchange between the steam going up and the feedwater stream flowing down, the water gets heated up to its boiling point and the gases (O_2, CO_2) dissolved in it are transferred to the gas phase. These gases together with non-condensing vapour are vented into the atmosphere through a vent valve or pass into a vent condenser where the steam is condensed and the O_2 and CO_2 are vented.

The deaerated water is collected in the storage tank which is fitted with gauge glass, pressure gauge and hydraulic seal to avoid the formation of high pressure or vacuum in the deaerator.

Q. *Does the storage tank of a deaerator function as a storage for water only.*

Ans. No. Here the remaining dissolved gases are discharged from water. Over and above, desorption takes place here.

Q. *Why does the desorption of dissolved gases from water take place in the storage tank, since degasification takes place in the deaerator column?*

Ans. It is due to the fact that some individual streams of water may bypass or not get fully degasified in the deaerator column, thereby carrying some dissolved oxygen and carbon dioxide into the storage tank. Therefore, removal of these dissolved gases takes place in the storage tank that affords enough space above the water level for desorption to take place.

Q. *What is steam-jet deaeration?*

Ans. It is a modern process that injects heating steam into the body of water in the storage tank.

Q. *Why is steam-jet deaeration more effective than direct-contact deaeration?*

Ans. When jets of steam at increased pressure are introduced in the body of feedwater, it agitates the water more intensively over and above heating it. The rate of heat transfer is much higher and it keeps the water in a state of boiling. These ensure more complete removal of dissolved gases than direct-contact deaeration which may suffer from partial degasification in some individual streams of water due to lack of adequate contact with the heating steam.

Q. *What is the demerit of steam-jet deaeration?*

Ans. It utilizes steam of increased pressure.

Q. *What conditions must be fulfilled for successful operation of the deaerator?*

Ans. 1. The temperature of deaerated water must be equal to the saturation temperature of water corresponding to the pressure at which the deaerator operates.
2. Sufficient heating steam must be delivered to the deaerator to ensure continuous boiling of water undergoing deaeration.
3. The feedwater charged to the deaerator must be disintegrated into fine droplets to ensure better heat transfer between the heating steam and feedwater. Hence perforated trays find widest application.
4. The deaerator must be provided with sufficient venting to purge all the non-condensing gases out of the system and to ensure minimum partial pressures of these gases in the upper part of the deaerator. Reduction of partial pressure will enhance desorption of dissolved gases.
5. If two or more deaerators are operated in parallel, all must be operated at same pressure.

Q. *Why is it necessary to maintain the deaerated temperature equal to the saturation temperature of water corresponding to the pressure in the deaerator?*

Ans. It keeps the deaerated water boiling and that will ensure the removal of leftover dissolved gases from the water in the storage tank.

Q. *What will happen if the heating steam supplied to deaerator is insufficient?*

Ans. Insufficient steam supply will cause a drop in the deaerator pressure and will fail to provide enough heat to maintain the water in continuous boiling condition—a must for deaeration. As a result, there will be only partial deaeration.

Q. *If the venting of non-condensing gases from the deaerator is not sufficient what harm will it cause?*

Ans. If the non-condensing gases (O_2, CO_2) collected at the top of the deaerator column are not adequately vented, it will increase the partial pressures of oxygen and carbon dioxide (p_{O_2}, p_{CO_2}). Increase of partial pressures of O_2 and CO_2 will set up the reverse process of degasification, i.e. cause transfer of O_2 and CO_2 from the gas phase to liquid (water) phase and that will impair deaeration.

Q. *Why are several deaerators working in parallel maintained at the same operating pressure?*

Ans. To avoid water flow from one storage tank to the other.

Q. *What are the limits for an atmospheric-type deaerator to operate without steam-jet deaeration?*

Ans.
1. The carbon dioxide content in the heating steam should not exceed 3-5 mg/lt.
2. The bicarbonate alkalinity in deaerated water should not be less than 0.3 mg-equiv./lt.
3. Residence time of deaerated water in the storage tank should not be more than 15 minutes.

Q. *What are the causes that contribute to increased concentration of oxygen and carbon dioxide in deaerated water in the storage tank?*

Ans.
1. Inadequate deaerator vent leading to accumulation of non-condensing gases and increase in their partial pressures
2. High feedwater flowrate inadmissible at the given water temperature causing hydraulic impacts
3. Delivery of O_2-containing condensate directly into the storage tank and to the deaerator
4. Frequent pressure drop in the deaerator
5. Faulty deaerator internals
6. Delivery of overheated condensate on to the second tray
7. Delivery of relatively "cold" flows with higher O_2 content to 2nd/3rd tray of deaerator.

Q. *What is vacuum deaeration?*

Ans. Deaeration is carried out in vacuum (rarefaction), i.e. at a pressure less than atmospheric pressure.

Q. *In which cases is vacuum deaeration carried out?*

Ans. Low-capacity, low-pressure boilers, requiring water at a temperature less than 373 K.

Q. *Why is vacuum deaeration needed for water deaeration at a temperature less than 373 K?*

Ans. Since the saturation temperature of water at 1 atm. pressure is 373 K, water at a temperature less than 373 K will boil if the pressure is less than atmospheric. Hence vacuum is needed to effect deaeration of water at temperatures less than 373 K.

Q. *Does the amount of vacuum depend on the temperature of the water deaerated?*

Ans. Yes. Lower the temperature, the higher must be the vacuum while higher the temperature, the lower the vacuum.

Q. *What methods are practised to carry out chemical deoxygenation of water?*

Ans. Two methods:

1. Sulphite treatment of water
2. Hydrazine treatment of water

Q. *What is the basis of chemical deoxygenation of water?*

Ans. This is based on the principle that there are certain water soluble substances that are capable of binding water-dissolved oxygen by virtue of a chemical reaction with it in aqueous solution.

Q. *What are these substances that are used for chemical deoxygenation of water in SGP?*

Ans. Sodium sulphite (Na_2SO_3) and hydrazine (N_2H_4)

Q. *What is the basis of sodium sulphite treatment?*

Ans. It is based on the reducing property of sodium sulphite as a result of which it gets oxidized to sodium sulphate by the following chemical reaction with oxygen dissolved in water.

$$2Na_2SO_3 + O_2 \longrightarrow 2Na_2SO_4$$

Q. *What is basically required from this reaction when it is applied in practice?*

Ans. The fundamental requirement is that this reaction must go to completion in the time interval during which water flows from the sulphite dosing point to the inlet of the economizer of the boiler unit.

Q. *What is done for this purpose?*

Ans. Water temperature is maintained at 353 K and an excess sulphite concentration (at 2mg/l) is ensured.

Q. *How is sodium sulphite dosed?*

Ans. It is added in the form of an aqueous solution (3 to 6%).

Q. *How is the quantity of sodium sulphite to be added determined?*

Ans. It is determined with the help of the formula:

$$C_{Na_2SO_3} = 8C_{O_2} + 2, \text{ mg/kg}$$

where $C_{Na_2SO_3}$ = concentration of sodium sulphite solution, mg/kg

CO_2 = concentration of dissolved oxygen, mg/kg

Q. *When sodium sulphite solution is prepared and stored, what important precaution should be taken?*

Ans. Care should be taken to seal the Na_2SO_3 solution from contact with atmospheric air.

Q. *Why?*

Ans. Otherwise, the sodium sulphite solution will absorb atmospheric oxygen and get oxidized to inert sodium sulphate, thereby decreasing the deoxygenation capacity of the sulphite solution.

Q. *Why is sodium sulphite unsuitable for deoxygenation treatment in high-pressure boiler units?*

Ans. At high-pressure and high temperature, sodium sulphite becomes unstable and undergoes decomposition rendering sulphite treatment for deoxygenation meaningless.

$$Na_2SO_3 + H_2O \longrightarrow 2NaOH + SO_2$$

Q. *What is the basis of chemical deoxygenation using hydrazine?*

Ans. Hydrazine is a strong reducing agent and in aqueous solution (it is highly soluble in water) it reacts with dissolve oxygen

$$N_2H_4 + O_2 \longrightarrow N_2 + 2H_2O$$

and thus lends a convenient system to remove oxygen dissolved in water.

Q. *How is it commercially available?*

Ans. It is available as:

Hydrazine hydrate: $N_2H_4.H_2O$

Hydrazine hydrochloride: $N_2H_4.HCl$

Hydrazine sulphate: $N_2H_4.H_2SO_4$

Q. *What is the difference between hydrazine hydrate and hydrazine sulphate?*

Ans. Hydrazine hydrate is a colourless liquid showing weak alkalinity in aqueous solution. It readily absorbs O_2, CO_2 and moisture from air.

Hydrazine sulphate is a solid, poorly soluble in cold water. It aqueous solution exhibits acidic properties.

Q. *What are the principal factors that affect the deoxygenation (reducing) capacity of hydrazine?*

Ans. 1. TEMPERATURE—hydrazine will remove dissolved oxygen at an appreciable rate only at water temperature ≥ 373 K
2. pH VALUE—at pH value < 7, hydrazine fails to prevent corrosion and even intensifies it.

However, at pH 9–9.5, temperature 373—380 K, hydrazine in excess of 20 microgram/kg eliminates all dissolved oxygen in a matter of just 2 to 3 seconds.

Q. *Hydrazine hydrate but not hydrazine sulphate can be used as a suitable deoxygenation reagent in once-through boiler units. Why?*

Ans. It is because hydrazine hydrate leaves no solid residue on decomposition

$$N_2H_4 + O_2 \longrightarrow N_2 + 2H_2O$$

Therefore, the total dissolved solid in feedwater is not increased.

Moreover, the decomposition products (N_2, H_2O) being harmless, no corrosion takes place to add the products of corrosion to the boiler feedwater. Since, in once-through boiler units, water is continuously evaporated, lower the salt content of feedwater, lower is the risk of deposit formation. That's why hydrazine hydrate is most suitable in these type of boiler units.

On the other hand, hydrazine sulphate adds sulphate radical to the feedwater. Moreover, it is acidic in nature. Hence it may contribute to the formation of ferrous sulphate that will fall out on the heating surfaces in once-through boiler units impairing the over-all heat transfer rate.

Q. *For which type of boiler units, is hydrazine sulphate suitable?*

Ans. Only fit for drum-type boiler units.

Q. *Why is hydrazine sulphate suitable only for drum-type boiler units?*

Ans. The drum-type boiler units are fitted with blowdown facility and that reduces the TDS of boiler feedwater within tolerable limits if its value is increased by ferrous sulphate formed when hydrazine sulphate is used as the deoxygenation reagent.

Q. *Does hydrazine only eliminate dissolved oxygen when treated with boiler feedwater?*

Ans. Apart from binding dissolved free oxygen in water, hydrazine also reduces oxides of iron and copper formed due to corrosion of metal.

$$6\ Fe_2O_3 + N_2H_4 \longrightarrow 4Fe_3O_4 + N_2 + 2H_2O$$

$$2CuO + N_2H_4 \longrightarrow 2Cu + N_2 + 2H_2O$$

It also reduces ferric hydroxide to ferrous hydroxide

$$4Fe(OH)_3 + N_2H_4 \longrightarrow 4Fe(OH)_2 + N_2 + 4H_2O$$

and curbs the nitrite corrosion in high-pressure boiler units.

Q. *What are the operating conditions that tax deaerators of power-plants?*

Ans. The frequent temporary stops, bypasses, load swings, dumps and high pressure requirements can be taxing for powerplant deaerators.

Q. *What can be done to ensure that a deaerator will give optimum performance through its service life?*

Ans.

1. Monitor non-condensate levels (i.e. gas levels) at the exit in the deaerator unit periodically—as often as weekly or bi-weekly depending on how far results vary the from target value
2. Go for thorough inspection of deaerator internals once/twice a year
3. Problems like loss of stripping action, droplets c/o and damage to internals may occur when plant operating changes are

made. Therefore, the operators must consider the impact of frequent temporary stops, load swings, bypasses etc. on the deaerator when such changes are made.

4. Maintain normal water levels in the deaerator.
5. Ensure the equalizers are sized adequately. Relocate the equalizers, if necessary, to eliminate water-stream impingement on the tray section.
6. Strengthen the tray sections so that they can withstand stresses resulting from flashing.
7. Check for knocking or rapping produced by waterhammer. If these sounds persist, check for mechanical intergrity of the support structures.
8. Check valves if waterhammer is a problem.
9. Install appropriate instrumentation.
10. If hot condensate and cold make-up (hence contaminated with DO) are to be combined, get the mixing done in a mixing tank which is to be installed upstream and properly vented.
    This mixing can also be achieved in a SS teejoint 10–15 pipe dia upstream of the deaerator.
11. Replace the spray-valves, that chatter or fail to produce an overlapping set of hollow spray patterns, with sturdy one-piece valves with a one-piece stem and plug made of SS304 or 316.
12. Ensure that the valves are neither overfed nor underfed. Overfeeding produces larger droplets while underfeeding prevents optimum stripping.

Q. *What are the general guidelines while selecting a new deaerator unit to get the optimum performance?*

Ans. 1. Specify the deaerator which is suitable for both minimum and maximum loads.
2. Select the one that incorporates one-piece trays and sports sufficient openings between trays to keep pressure drop at a minimum.
3. Choose a spray-valve with a built-in stem support. This ensures centering of the valve in any position from fully closed to fully open.
4. Consider incorporating postweld heat-treatment in the design.

Q. *Hydrazine has been the traditional oxygen scavenger in boiler feedwater. Is there any good substitute for it?*

Ans. Yes; BWT-265, a proprietary boiler water treatment chemical manufactured by Ross Chemical Inc., Omaha, Nebraska (USA).

Q. *What is its efficacy?*

Ans. It is about 40 times more potent than hydrazine in its reducing power. It converts ferric ion (Fe_2O_3) contained within the boiler system to non-adhering ferrous iron (Fe_3O_4) forming a self-protective magnetite coating in the process and thereby keeping the boiler tubes free from corrosion (Fig. 25.2).

© ROSS CHEMICAL, INC., Omaha, Nebraska, USA.

Fig. 25.2 *BWT-265 chemistry keeps boiler tubes free from corrosion.*

Q. *What are the physical characteristics of BFW-265?*

Ans.

- It is a liquid—clear to slightly amber in colour

- Specific gravity = 1.056
- pH = 7 (approx)
- Solubility in water: complete

This non-volatile, fire-hazard-free formulation is a odourless liquid having sodium hydroxide as the principal hazardous ingredient present only to the extent of < 2%. It is stable and slightly irritant to the skin.

Q. *How does a deaerator (DA) give rise to waterhammer?*

Ans. Following a turbine trip and consequent loss of bleed heating steam to the DA, the deaerator pressure drops whereupon the still-hot water tin the vertical downcomer to the BFW pumps goes to boil in part (Fig. 25.3a and 25.3b). The steam may remain in small bubbles or coalesce into large pockets. As this steam moves upward rapidly it forces water up into the storage tank and even the DA. The escape of the steam (Fig. 25.3c) leaves a void in its wake, i.e. in the suction downcomer and then a descent of water for 12–25 m sets the stage for heavy impact of column rejoining, with shock waves radiating out from the impact surface. This is how a pressure drop in DA system degenerates to a waterhammer.

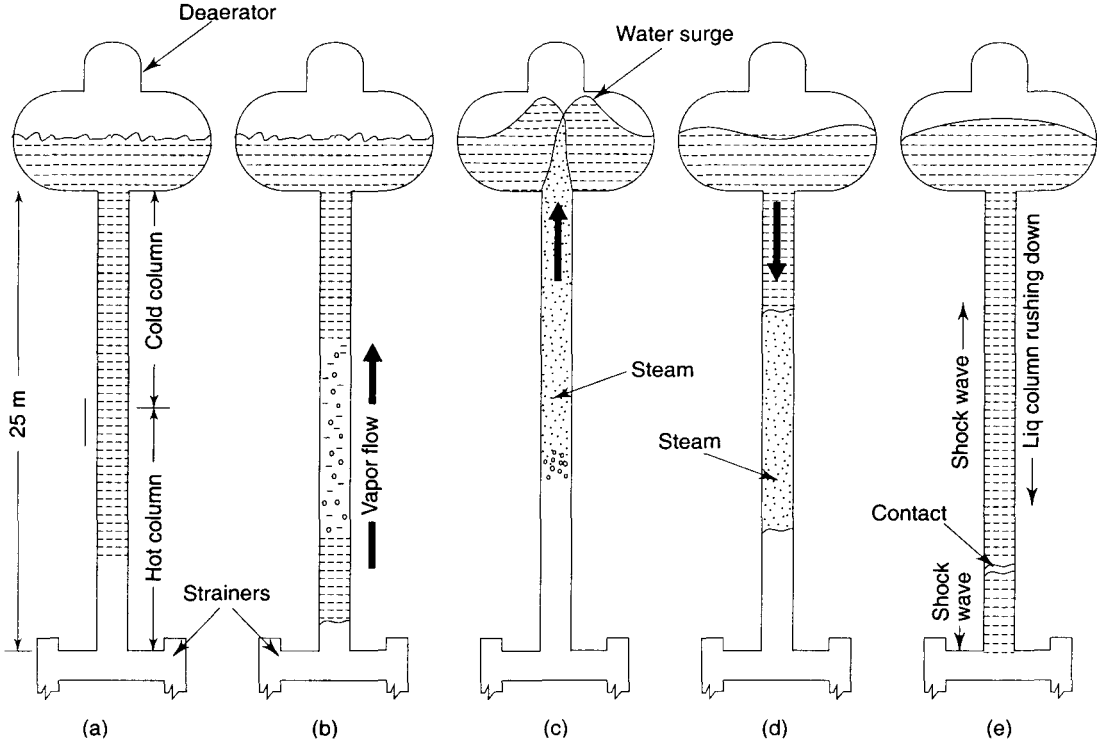

Fig. 25.3 *Following a turbine trip (or other event causing a pressure dip in the DA), the deaerator pressure falls whereupon steam forms in the downcomer (Figs a and b). As the steam moves up (Fig. c) it leaves a void behind. Thereafter a mass of cooler water from the DA storage tank rushes to the pocket (Fig. d). Such a descent of water for 12-25 m causes heavy impact where the descending water column meets the stationary water column in the downcomer (Fig. e).*

26

COOLING WATER TREATMENT AND COOLING TOWER

Q. *What do you mean by cooling water?*

Ans. It is the water that is circulated through the equipment to absorb and carry away the heat.

Q. *Why is recycling of cooling water a necessity?*

Ans. This is mainly due to two reasons:

1. Yawning gap between the demand of C/W of ever increasing industries and the availability of suitable water resources makes it almost essential to strive for maximization of water reuse.
2. The mounting costs of chemicals used for cooling water treatment to inhibit scale and corrosion makes it incumbment upon the users to manipulate circulating cooling water to as high a concentration cycle as possible, without impairing heat transfer efficiency.

Q. *What are the objectives of cooling water treatment?*

Ans. There are three major, interlinked objectives:

1. Control of corrosion
2. Control of scale
3. Control of fouling

Note: Please see APPENDIX-II

Q. *What factors catalyze corrosion in a cooling water system?*

Internal Factors

1. Material of construction (MOC)
2. Chemical nature/structure of the metal and alloy
3. Design and fabrication of the heat exchangers and surface condensers coming in contact with the cooling water system.

External Factors

1. *Dissoslved Oxygen (DO).* The corrosion of mild steel increases with the increase in the level of DO in C/W.
2. *pH.* The corrosion rate accelerates with the fall of pH.
3. *Total Dissolved Solids (TDS).* They hike up electrical conductivity of the solution thereby creating a corrosive environment. Chloride and sulphate ions agressively attack the protective coating on metals.
4. *Temperature.* The corrosion rate increases with the increase in temperature.
5. *C/W flow.* An increase in rate of C/W flow generally tends to increase the rate of corrosion.

Q. *TDS promotes corrosion by increasing the electrical conductivity of solution. Then why does the corrosion rate drop at higher salt levels?*

Ans. Higher TDS concentration brings about a marked decrease in dissolved oxygen (DO). This DO acts as a cathodic depolarizer and brings more and more metal into the solution.

Thus the decrease in corrosion rate at higher salt levels is caused by a decrease in the solubility of oxygen.

Q. *What types of corrosion are generally encountered in a cooling water system?*

Ans. There are three types of corrosion.

1. ***Pitting***, i.e. localized attack under tuberculation
2. ***Gauging***, i.e. etching of metal surfaces, frequently noticed as a result of corrosion under deposition.
3. ***General corrosion***, i.e. loss of metal from the surface due to development of low pH environment.

Q. *What is the solution towards control and prevention of corrosion in a cooling water system?*

Ans. Broadly speaking there are two types of solutions:

(a) Metallurgical and Engineering solution
(b) Environmental solution

Q. *What does metallurgical solution mean?*

Ans. Selecting exotic metals and alloys which are resistant to corrosion in the environment to which they are exposed.

Such a metallurgical solution proved to be positively costly in most cases. Hence it is, in general, opted for the extreme condition.

Normally the materials of construction (MOC) of cooling equipment in powerplants and numerous chemical industries are carbon steel (CS), admiralty brass, cupronickel alloy and stainless steel (SS). Carbon steel is the most economical and most favored MOC till date in the recirculating cooling water system in USA. However, some plants have upgraded tube materials all the way to Inconel or Incolloy. But these materials are too expensive to buy economy. Another trend in some West European countries for the past decade is to harness plastic coated CS tube bundles in some critical coolers. This coating must be impervious to corrosion and should prevent fouling by providing a smooth surface. Performance of plastic coated C/W cooled heat exchangers have been reported to be good, though heat transfer resistance of such plastic coatings is a factor to be reckoned with.

Q. *What is the engineering solution to the control and prevention of corrosion in a C/W system?*

Ans. Engineering solution to the problem of corrosion is based on proper design and fabrication of the heat exchanger (HE) system. For instance, the normal design practice is to a maintain C/W flow velocity of 1 m/s through HEs. However, operation of carbon steel HE systems at this flowrate and at pH > 8, especially in a non-chromate program, is frequently met with excessive deposit formation and fouling coupled with subsequent corrosion-under-deposition in many cases. Hence the modern trend is to maintain C/W velocity at a minimum of 1.5 m/s, so that any deposit from C/W side is flushed off from the system.

Among other engineering solutions to C/W-induced corrosion problem are:

(a) Providing horizontal cut baffles in place of vertical cut baffles
(b) Provision for venting the non-condensates accumulated in the HE system.
(c) Provision for draining the coolers
(d) Provision for air bumping
(e) Provision for backflushing arrangement
(f) Provision for isolating the critical coolers

Inasmuch as a surface free from deposit is normally less vulnerable to corrosive attack, main emphasis is given to design cooler to control deposit of any form on the cooler surface.

Q. *What is the environmental solution to a C/W system corrosion problems?*

Ans. 1. Passivating the metal surfaces to render them resistant to corrosive aqueous environment.

2. Making the aqueous environment non-aggressive/less aggressive to the metal by subjecting the C/W to corrosion inhibitory treatment.

Q. *What is passivation of a metal surface?*

Ans. Formation of a thin, impervious film on the metal surface so that corroding agents fail to reach the base metal surface under-neath.

Q. *How is passivation carried out?*

Ans. It is a two-stage process

I. Precleaning
II. Prefilming (passivation)

Precleaning is carried out by circulating a cleaning solution through the cooling system to slough off mill scale, oil, grease, rust and other accumulated foreign materials that could reduce heat transfer, restrict flow and impair corrosion protection. All new or idle equipment are subjected to this precleaning procedure.

Immediately after precleaning, the active metal surfaces are passivated or prefilmed by circulating a passivating fluid through the system. After this film is established, continuous low treatment level of inhibitors is subsequently given to maintain the passive-film intact by restoring slight breaks that may occur due to minor variations in environment.

Q. *What is this precleaning liquid?*

Ans. Normally it is a solution of a polyphosphate, surfactant and antifoam.

Q. *How long is this solution circulated and under what operating conditions?*

Ans. Duration of circulation varies from 8 to 24 hrs.

Operating temp. = 323°K–343°K

pH range = 5.5–7.0

However this scavenging operation can be carried out at ambient temperature and at pH range 6–7 when formulations based on organic phosphonates, low mol. wt. organic polymers, surfactant and antifoam agents are used.

Q. *What is the passivating solution?*

Ans. The most efficient prefilming/passivating solution utilizes a combination of chromate, polyphosphate and zinc

Chromate: 50–300 mg/lt

Polyphosphate: 400–600 mg/lt

Zinc: 50–100 mg/lt

Q. *How long is this solution circulated and under what operating conditions?*

Ans. Circulation duration: 6–7 h

Operating temperature: 323°K–333°K

pH range: 6–7

Q. *Is the prefilming solution circulated as soon as the precleaning solution circulation is stopped?*

Ans. No. Thorough blowdown of the precleaning solution is mandatory before prefilming.

Note: **Likewise prefilming is followed by heavy** blowdown till the normal inhibitor level is restored.

Q. *What is the basic directive of corrosion inhibitory treatments of cooling waters?*

Ans. To stifle either the anodic or the cathodic reaction or both.

Q. *Why?*

Ans. Corrosion in the C/W system is an electrochemical process. Oxidation takes place at the anode whereupon metal dissolves and goes into the solution

$$M - ne \longrightarrow M^{n+}$$

while reduction takes place at cathode

$$H^+ + e \longrightarrow H \longrightarrow H_2$$

completing two half-cell reactions.

Now if this anodic reaction is blocked (anodic protection) or the cathodic reaction is blocked (cathodic protection) the corrosion cell with not be set up and the metal parts in contact with the C/W will remain intact.

Q. *Between anodic and cathodic protections which one is the less preferred choice?*

Ans. Anodic protection.

Q. *Why?*

Ans. Due to large ratio of cathodic area to anodic area, a very high dosage of anodic inhibitors has to be used to ensure complete blockage of the anodic half-cell reaction. If this is not done, severe pitting corrosion will occur at the unprotected sites due to increase in localized current density at these spots.

Q. *Name an important anodic inhibitor.*

Ans. By far the most effective anodic inhibitor is chromate. For the past quarter of a century it has served industries very satisfactorily.

Q. *What is its efficacy?*

Ans. When used in concentrations of 200–500 mg/l (CrO_4^{2-}) in the circulating water, it can achieve a minimum of 95% corrosion inhibition in most waters.

Q. *Why is chromate treatment not favoured today?*

Ans. Chromate is a pollution hazard. The permissible level of Cr^{6+} in drainage water is just 0.1 mg/l only (MINAS*). Therefore, such high concentrations of chromate in C/W systems pose serious effluent disposal problem.

Q. *Then what is the other viable and environmentally safe inhibitor?*

Ans. Polyphosphate.

Q. *What is its advantage?*

Ans. It has got excellent synergistic effect on chromate, i.e. when these two anodic inhibitors are used together, the concentration of chromate can be drastically curtailed without affecting the degree of corrosion inhibition.

Q. *What is the technical name of this chromate-polyphosphate dual anodic inhibitor approach?*

Ans. Dianodic treatment.

Q. *At what pH range this dianodic treatment is carried out?*

Ans. At a pH range of 6–7.

Q. *What are the concentrations of ingredients of this dianodic inhibitor system?*

Ans. Typically

Chromate: 20–70 mg/l

Polyphosphate: 5–40 mg/l

Q. *What is the efficacy of this system?*

Ans. In the pH range of 6–7 it has been so successful in combating corrosin, pitting and tuberculation of a C/W system that it virtually became the standard corrosion inhibitory program throughout the world and would certainly have continued to do so many years to come had it not been for stringent pollution control regulations that has banned, in some countries, the discharge of chromate to any water course altogether.

Q. *What is the corrosion rate when C/W is subjected to this dianodic treatment?*

Ans. Corrosion rate seldom exeeds 1 mpy with carbon steels and it is less with copper based alloys.

Q. *What agent is introduced to the C/W system to enforce cathodic protection?*

Ans. Zinc.

Q. *How does it act as a cathodic inhibitor?*

Ans. Zinc is more electropositive than iron. So it dissolves preferentially to iron in H.E. tubes

$$Zn - 2e \longrightarrow Zn^{2+}$$

and thus it safeguards the condensers and coolers.

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* Minimal National Standards

Moreover, zinc ions precipitate as a film of zinc hydroxide or phosphate at the site of cathdodic reaction:

$$Zn^{2+} + 2OH^- \longrightarrow Zn(OH)_2$$

$$Zn^{2+} + HPO_4^{2-} \longrightarrow Zn(HPO_4)$$

Q. *How can the anodic protection be hooked up with cathodic protection?*

Ans. Zinc ensures cathodic protection by stifling cathodic reaction. The chromate-polyphosphate system ensures anodic protection by foiling the anodic half-cell reaction. When these two inhibitor programs are combined and used simultaneously in the cooling water system, equivalent or better corrosion protection can be achieved with even further reduction in chromate concentration (beneficial from the standpoint of environmental safety).

That is how the concept of zinc-chromate-polyphosphate corrosion inhibitory treatment of C/W was born.

Q. *What is the concentration of individual components of this 'double-protection' system?*

Ans. Chromate (CrO_4^{2-}): 10–20 mg/l

Polyphosphate: 2–5 mg/l

Zn: 2–5 mg/l

Q. *What is the efficiency of this system?*

Ans. This zinc-dianodic approach can give rise to 95% corrosion inhibition in the pH range of 6–7 with a much lower concentration of chromate than in the simple dianodic approach.

Q. *What is the basic approach of the ultralow chromate program and the non-chromate program?*

Ans. The mounting pressure against the use and discharge of chromate has ushered a new generation of corrosion inhibitory programs such as the ultralow chromate program and the non-chromate program.

Both seek to use a high pH C/W treatment. But operating C/W in the alkaline range invites the problems of deposit formation and subsequent under-deposit-corrosion. However, this deposit formation can be throttled by using deposit control agents or dispersants. So both ultralow and non-chromate programs rely on dispersant chemistry.

Q. *How does ultralow chromate program work?*

Ans. Treating cooling water with a solution of CrO_4^{2-} concentration 5–10 mg/l plus sufficient dispersant (5–50 mg/l) in the pH range of 7.5–9.

Q. *What is the efficacy of this system?*

Ans. Corrosion rates on mild steel $\leq$ 2 mpy has been reported both from extensive laboratory testing and field applications.

Q. *Why has the non-chromate program come into being?*

Ans. Use of chromate as a corrosion inhibitor and discharge thereof into wastewater has already been banned in many countries with the promulgation of the pollution control act. This is the singlemost cause of the advent of the non-chromate treatment program.

Q. *What is the basis of non-chromate program?*

Ans. It takes the advantage of the versatile properties of organic polyphosphates, orthophosphates and polymeric dispersants.

Polyphosphates inhibit corrosion by giving anodic protection.

Orthophosphates and phosphonates combined with Ca^{2+} inhibit corrosion by cathodic protection.

Organic polymeric dispersants inhibit corrosion by keeping the metal surfaces free from deposits or providing a polymeric protective film on the metal surfaces.

Q. *What is the efficacy of this treatment?*

Ans. Overall corrosion protection ranges from very good to excellent with corrosion rates normally contained to the limit of 1 to 5 mpy.

Q. *What inorganic polyphosphates are normally used?*

Ans. SHMP (Sodium hexametaphosphate)

STPP (Sodium tripolyphosphate)

Q. *What types of phosphonates are used?*

Ans. Triphosphonates

Diphosphonates

Q. *What are these dispersants?*

Ans. They are low mol. wt. organic polymers usually belonging to one of the following types

(a) polyacrylamides
(b) partially hydrolyzed polyacrylamides (PHPA)
(c) polyacrylates
(d) polymethacrylates.

Q. *What are the advatnages of the chromate treatment over the non-chromate treatment?*

Ans.

1. Most efficient corrosion inhibitor
2. Simpler system
3. Microbiological growth control is much easier over the operating pH range
4. More effective fouling control (as chromate treatment operates over a lower pH range)
6. Much less sophisticated than the non-chromate system which requires a sound understanding of dispersant chemistry and surface phenomenon
7. Economically more favourable.

Q. *What is the disadvantage of the chromate treatment compared to the non-chromate treatment?*

Ans. Pollution hazard is the prime and singlemost drawback of the chromate treatment.

The ingredients of the polyphosphate-phosphonate-polymer dispersant based program are much less toxic and are biodegradable. Whereas chromate is a very stable inorganic compound which is potentially toxic to biosphere and not biodegradable at all. Therefore, chromate removal treatment of C/T purge must be foolproof. And in most cases this proves to be a costly affair.

Q. *The polyphosphate-phosphonate-dispersant based non-chromate inhibitory program is preferred as its components are easily biodegradable. But what is its negative aspect?*

Ans. Since these ingredients are biodegradable, they contribute to the growth and proliferation of most of the aquatic microbes that give rise to fouling and corrosion.

Q. *Then why not dose chlorine to control these microbes?*

Ans. It is admittedly true that chlorine is a potentially efficient and most versatile biocide. But it is less effective over the pH range 7.5–8.5 in which the non-chromate program is operative.

Q. *What factors contribute to microbial growth in C/T?*

Ans.

(a) Temperature
(b) Aeration
(c) pH
(d) Sunlight
(e) Nutrient level

Q. *What microbes are found in C/W system?*

Ans.

(a) Bacteria
(b) Fungi
(c) Algae
(d) Yeast

Q. *What do they do?*

Ans. They give rise to microbiological corrosion.

Q. *What is microbiological corrosion?*

Ans. Deterioration of metal by corrosion processes occuring either directly or indirectly as a consequence of the metabolic activity of the microbes.

Q. *What is the characteristic of such corrosion?*

Ans. They are basically localized in nature and hence difficult to monitor and easily escape detection before serious damage is inflicted.

Q. *How do these microbes contribute to corrosion?*

Ans. They

(a) directly influence the cathodic or anodic half-cell reactions
(b) tell upon the resistance of the passive film on the metal surface due to microbial machanism or product of metabolism.
(c) create a corrosive low pH environment (acid producer)
(d) establish a barrier of growth concentration or cell activity

Q. *How can these microbes be classified?*

Ans. They can be classified in to six general groups:

1. Acid producers
2. Slime formers
3. Oxidizers
4. Sulphate reducers
5. Hydrocarbon feeders
6. Mould growers

Q. *What do the acid producers do?*

Ans. They odixize

(a) sulphur and sulphur compounds to sulfuric acid
(b) ammonia and ammonium salts to nitric acid
(c) oxidize organic compounds to organic acids

Q. *Name two important acid producing bacteria?*

Ans.

1. NITROSOMONAS
2. NITROBACTER

They belong to the genera of nitrifiers.

Q. *What are their characteristics?*

Ans. Both are autotropic.

Both utilize CO_2 of air as their only source of carbon . They derive energy for growth by oxidizing ammonia to nitrous acid (**Nitrosomonas**) and nitrite to nitric acid (**Nitrobacter**).

Q. *What is the function of* ***Nitrosomonas****?*

Ans. These bacteria oxidize ammonia and ammonium salts to nitrite or nitrous acid

$$NH_4^+ + 1\frac{1}{2}O_2 \xrightarrow{\text{Nitrosomonas}} 2H^+ + NO_2^- + H_2O + 0.332 \text{ kJ}$$

Q. *Under what operating conditions are they most active?*

Ans. The optimum conditions for their growth and multiplication are

pH: 8–8.5

Temp.: 298°K–308°K

Q. *What is the function of* ***Nitrobacter****?*

Ans. They oxidize nitrite to nitrate:

$$NO_2^- + \frac{1}{2}O_2 \xrightarrow{\text{Nitrobacter}} NO_3^- + 0.09 \text{ kJ}$$

Q. *Can they oxidize ammonia?*

Ans. No

Q. *At what operating conditions are they most active?*

Ans. Optimum conditions:

pH: 7–7.7

Temp.: 298°K–308°K

Q. *So bacterial nitrification is associated with the release of H^+ ions. How much alkalinity do they consume in the process?*

Ans. About 7 mg/l of alkalinity is destroyed by bacterial nitrification of about 1 mg NH_3/1 of water.

Note: pH level of the C/W may go down to as low as 5, producing a severe corrosive environment if corrective action is not taken.

Q. *What are slime formers?*

Ans. They are the appended part of autotropic or heterotropic bacteria, certain algae, yeast and fungi that form slimy deposits.

Q. *What do they do?*

Ans. They form slimy deposits, create concentration cells and contribute to underdeposit corrosion.

Q. *What is slime?*

Ans. They are jelly-like accumulations of microorganisms and their excretions or products of their metabolism.

They are usually enmeshed with various organic and inorganic debris.

Q. *How do these slime formers contribute to corrosion?*

Ans. They contribute to corrosion indirectly.

They stimulate the formation of deposits which give rise to concentration cells or harbour sulphate reducing bacteria in the anaerobic area under these deposits.

So they contribute to underdeposit corrosion and create most difficult fouling problems.

Q. *What are 'oxidizers'?*

Ans. They are iron bacteria belonging to crenoform group.

Q. *What do they do?*

Ans. They oxidize ferrous ions in water to ferric ions and bring about massive deposits of ferric hydroxide on the cathodic site.

They are also slime formers.

Q. *What happens as a consequence of this bacterial action?*

Ans. Deposition of voluminous reddish brown slimy deposits of ferric hydroxide, as a result of this bacterial activity, causes tuberculation and pitting at cathodic sites, especially in the zones of low water velocities.

Iron oxide deposits brought about by the metabolism of iron-bacteria create anaerobic conditions beneath these deposits creating an ideal condition for anaerobic sulphate reducing bacteria for growth. This sulphate reducing bacteria reduces SO_4^{2-} to H_2S which lowers pH and contributes to localized pitting attack.

Q. *What are the characteristics of the oxidizer or iron-bacteria?*

Ans. These organisms are generally autotropic. They are highly aerobic attached form of bacteria that derive their energy for growth by oxidizing Fe^{2+} ions to Fe^{3+} ions. They abstract the energy liberated in the process:

$$Fe^{2+} - e \rightleftharpoons Fe^{3+} + Q \text{ kJ}$$

Q. *But as soon as $Fe^{2+} \rightleftharpoons Fe^{3+}$ equilibrium is reached, corrosion of iron will not occur. Then how can the iron-bacteria propagate this corrosion endlessly?*

Ans. This bacteria simply upsets the equilibrium by putting more and more iron into the solution.

$$Fe - 2e \longrightarrow Fe^{2+}$$

As more ferrous ions become available the foregoing equilibria is pressed to the right (La Chatelier Brown principle).

Q. *What are sulphate reducers?*

Ans. These are bacteria that reduce sulphate to hydrogen sulphide (discussed later).

Q. *What is their nature?*

Ans. They are spore forming organisms and mostly heterotropic. Usually they are anaerobic in nature, but some species can function autotropically and under aerobic conditions provided there is a source of hydrogen.

Q. *Why is the biocide treatment of cooling water necessary?*

Ans. Cooling water used in boiler plants and in any industry is basically vulnerable to microbiological infection by bacteria, algae and fungi. Microbial fouling is one of the major problems encountered in the operation of cooling towers, cooler-condensers and other heat exchangers. It adversely affects the cooling performance of the

system by forming a black slime, which is a bacterial metabolic product. This substance deposits on the internal surfaces of pipelines and heat exchanger tubes, thus obstructing the free flow of water and reducing the heat transfer coefficient.

Over and above,there is the sulphate reducing bacteria—*Desulphovibrio Desulphuricans* in the C/W. This anaerobic bacteria produces hydrogen sulphide from sulphate ions

$$SO_4^{2-} + 4H_2O + 8e \longrightarrow S^{2-} + 8OH^-$$

Hydrogen sulphide ions, thereby promote the corrosion of iron pipelines

$$H_2S \longrightarrow H^+ + SH^-$$

$$Fe - 2e \longrightarrow Fe^{2+}$$

$$2H^+ + 2e \longrightarrow H_2$$

$$2H_2S + Fe \longrightarrow 2SH^- + Fe^{2+} + H_2$$

Enter the algae. They are of vegetative origin and subsist on the internal structure of cooling towers, thus decreasing the efficiency of heat transfer of the cooling tower.

Fungi also attack the timber parts of the cooling tower causing serious damage.

Therefore, the application of a suitable biocide is all but necessary to overcome these problems.

Q. *What is Desulphovibrio Desulphurican?*

Ans. It is a spore forming organism, predominantly heterotropic and anaerobic in nature.But some species can even function autotropically and under aerobic conditions provided there is a source of hydrogen. They thrive in the pH range of 5.5–8.5 and a wide temperature range of 273°K to 373°K, optimum being 297°K to 315°K. They reduce sulphate ions to H_2S which is highly corrosive.

Q. *Cite examples of some known biocides.*

Ans. The well known international disinfectants are:

1. Lauryl dimethyl benzyl ammonium chloride
2. Cetyl trimethyl ammonium bromide.

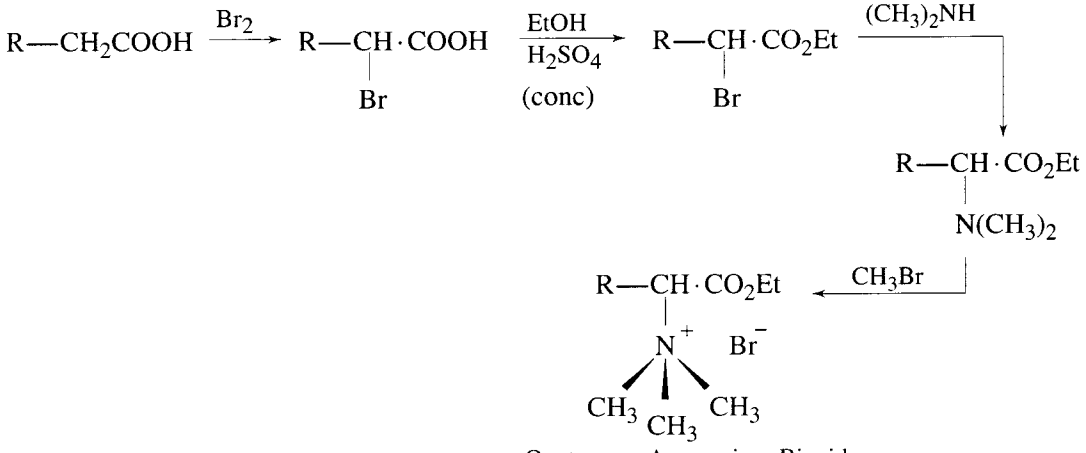
In the mid-eighties Projects and Developments of India Ltd. has introduced an efficient quaternary type biocide:

Palmitic acid based quaternary ammonium biocide.

Q. *How is it made?*

Ans. The process comprises the following steps:

1. Bromination of fatty acid
2. Esterification
3. Amination of the bromoester
4. Quaternization of the amine derivative
5. Isolation of the purified product.



Quaternary Ammonium Biocide

Q. *What is its efficacy?*

Ans. This biocide was tested on algae, total bacteria, sulphate reducing bacteria and fungi present in C.T. waters. The biocide was found to be toxic to the algal cells at a concentration of 60 ppm with a contact period of 6 h. However, this biocide present to the extent of 20 ppm only proved itself to be optimally toxic to total bacteria and sulphate reducing bacteria.

Q. *What are the physical characteristics of quaternary ammonium biocide prepared from C_{12}–C_{18} fatty acids?*

Ans. They are

(a) white crystalline solids
(b) quite stable in the pH range of 7–8.5 which is generally encountered in modern C.T.s.
(c) odourless
(d) least toxic to aquatic life than most of the existing disinfectants

Q. *What is the optimum dose of these fatty acids based biocides?*

Ans. A concentration of 10–20 ppm is quite satisfactory to inhibit the microbiological growth of algae, total bacteria, sulphate reducing bacteria and fungi in any C.T. systems.

Q. *What are the important factors that determine the optimum dose of quaternary ammonium biocide?*

Ans. The bactericidal action of quaternary ammonium biocide is functionally linked to its surface activity. And hence, solubility and stability of the biocide in water play an important role in imparting biocidal activity.

Q. *What is the mechanism of its biocidal action?*

Ans. Quaternary ammonium biocides [Quats] function in a variety of ways to inhibit the growth of micro-organisms thriving in the cooling tower water.

The biocide is adsorbed on the bacterial cell and forms a chemical bond with the negative charge associated with the cell wall thereby reducing the cell-permeability. The amine group is the source of positive charge development on the biocide molecule which thereby forms an electrostatic bond with the negatively charged sites on the cell-wall of the micro-organisms. This chemical linkage disturbs the osmotic pressure balance between the organism and the surrounding medium. As a consequence, inflow of nutrients into the cell and discharge of waste products from the cell-wall ceases and the organism is thus killed.

These biocides may also act the other way. They react with the protein part of the bacterial cell causing precipitation, denaturization, redispersion and complex formation and hence kill the micro-organisms. The quaternary ammonium biocide cleave (fission) the nucleoproteins of bacteria.

Biocides may also act by deactivating various enzymes, particularly those involved in respiration and glycolysis , inside the bacterial cell and cease the metabolic processes.

Q. *But which one is the best and most economic biocide today?*

Ans. Chlorine.

This is effective for all types of microbiological growth. There is no microbe in the world that can stand against chlorine.

Q. *However, each organism can develop specific resistance up to a certain level against each biocide. What is the impact of the microbial specific resistance when chlorine is added?*

Ans. Microbes also develop a specific resistance, up to a certain degree, to chlorine dosing. This specific resistance controls the concentration of free residual chlorine and the contact time. It is the free chlorine that kills the bacteria.

Q. *How much free residual chlorine is required and over what contact time to kill the nitrifiers?*

Ans. Free chlorine concentration ranging from 0.3 to 0.5 mg/1 over a period of residence time of 5–10 minutes can kill all the nitrifiers.

Q. *How much free residual chlorine is required and over what contact time to kill all the slime formers and sulphate reducers?*

Ans. Free chlorine of concentration 1 mg/l is required over a residence time of 1h (at least) to weed out these bacteria effectively.

Q. *Why do slime formers require higher residual chlorine concentration over higher residence time than nitrifiers?*

Ans. Slime formers are relatively more resistant to chlorine. They owe their higher resistance against biocide to their slimy sheath. This protective shield encapsulates the bacteria allowing them to function within for some more time.

Q. *Which micro-organism is the most resistive?*

Ans. Algae.

Q. *How much chlorine do they require for total elimination?*

Ans. As much as 1 kg/l of free chlorine over a period of several hours.

Q. *Chlorine is an oxidizing biocide which is non-selective. Is there any non-oxidizing biocide which is selective as well?*

Ans. Such biocides are

I. Chlorinated Phenates
- (a) Sodium pentachlorophenate (NaPCP)
- (b) Sodium trichlorophenate (NaTCP)

II. Quaternary Ammonium Compounds which exhibit good selective effects on the control of bacterial slime.

Q. *Under what situations is chlorine not so effective as a biocide?*

Ans. C/W systems contaminated with amonia, urea or hydrocarbons etc.

Q. *Why?*

Ans. Chlorine is a very reactive agent and a powerful oxidant having affinity for hydrogen. So it instantly attacks hydrogen or compounds of hydrogen

$$2\ NH_3 + 3Cl_2 \longrightarrow N_2 + 6HCl$$

$$CO(NH_2)_2 + 2Cl_2 \longrightarrow CO + N_2 + 4HCl$$

and only partially removes micro-organisms.

Q. *Under these circumstances which biocides prove to be effective?*

Ans. These are mostly the blends of:
- (a) methylene bisthiocyanate
- (b) bis(tributylene) oxide
- (c) dodecylguanidine hydrochloride
- (d) organic bromo-compounds.

Used together, some of them exhibit synergistic effect.

Q. *What are the major scale formers that come from C/W?*

Ans.
1. Calcium carbonate
2. Calcium phosphate
3. Zinc phosphate
4. Calcium sulphate
5. Magnesium salts
6. Silica
7. Corrosion products

Q. *How and where does their deposition take place?*

Ans. They precipitate from solution as solids which are deposited on heating surfaces.

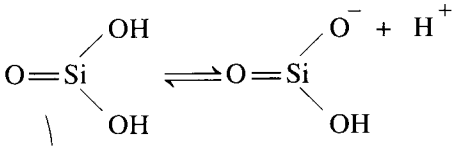
The deposition is the outcome of crystallization of salts from a locally supersaturated solution.

Q. *How is the scale controlled by varying the pH?*

Ans. The solubility of the scale formers, barring silica, decreases with the increase of pH. Thus lowering of pH with sulphuric acid helps to prevent scale formation in most cases.

Q. *Why does the solubility of silica decrease with the decrease in pH?*

Ans. Silica precipitates as silicic acid that weakly ionizes as



Insoluble form Soluble form

With the lowering of pH (i.e. by adding mineral acid), the concentration of H^+ increases in the solution. And that presses the above reversible reaction to the left converting soluble silica to its insoluble form.

Actually silicic acid exists in aqueous systems as a suspension of colloidal silica which coagulates at lower pH values.

Q. *What is the basic disadvantage of scale control by acid treatment?*

Ans. It increases the load of total dissolved solids in water. Nevertheless, scale control by sulphuric acid does not pose much of a problem with a lower concentration cycle and with a turnaround (shutdown) schedule every 12 months or less.

Note: However, with improve process requirements, improved water and energy conservation, stringent pollution control rules and turnarounds extended up to 24–36 months, the pH control of scale formation has evolved into a new generation of scale inhibitory program.

Q. *How do these antiscalants act?*

Ans. They prevent and control scale formation by modification of the crystal habit of precipitating salts.

Q. *What are these new breed of antiscalants?*

Ans. They are organic polymers, polyelectrolytes and organophosphorous compounds.

Q. *Give a typical example an antiscalant.*

Ans. HEDP (1-Hydroxyethylidene-1, 1-diphosphonic acid) and formulations thereof.

They are marketed as DESCOPHOS products, e.g.

DESCOPHOS-50: A sodium salt of HEDP with active ingredient 10% is very suitable for corrosion protection & descaling

DESCOPHOS-50A: Active form of HEDP (active ingredient 60%)

DESCOPHOS-50B: Active form of HEDP (active ingredient 40%)

DESCOPHOS-50C: Complete formulation of HEDP; ensures very good protection from corrosion and scaling

DESCOPHOS-50D: Active form of HEDP (active ingredient 10%)

DESCOPHOS-50E: Potassium salt of HEDP (active ingredient 10%)

Q. *What are the of advantages DESCOPHOS?*

Ans. They act simultaneously as scale and corrosion inhibitors. As scale inhibitors they are

(a) more effective than polyphosphates
(b) persistent in their activity
(c) very stable at higher operating temperature
(d) very stable over a wide pH range and in the presence of other contaminants
(e) economical.

Q. *What is the fundamental basis of the latest trend in the scale inhibitory program?*

Ans. As far back as in the 1930s, it was observed that sodium hexametaphosphate (SHMP) in the concentration range of only 1–10 ppm was sufficient to inhibit precipitation from a supersaturated solution of calcium carbonate. The latest trend in the scale inhibitory program is based on this strange chemical response to a substoichiometric level of an additive. This phenomenon is called threshold effect.

Q. *What is the threshold effect of DESCOPHOS in comparison to other scale inhibitors like sodium hexametaphosphate, trisodium phosphate?*

Ans. Descophos exhibits a far stronger threshold effect than SHMP which is stronger than TSP. (Fig. 26.1).

Q. *How does DESCOPHOS act as a scale inhibitor?*

Ans. Descophos is absorbed on the growth sites of the crystals during crystallization process.

Crystal growth is retarded and normal growth stops. Any crystals that grow with descophos infiltrated within the lattice get distorted. That is

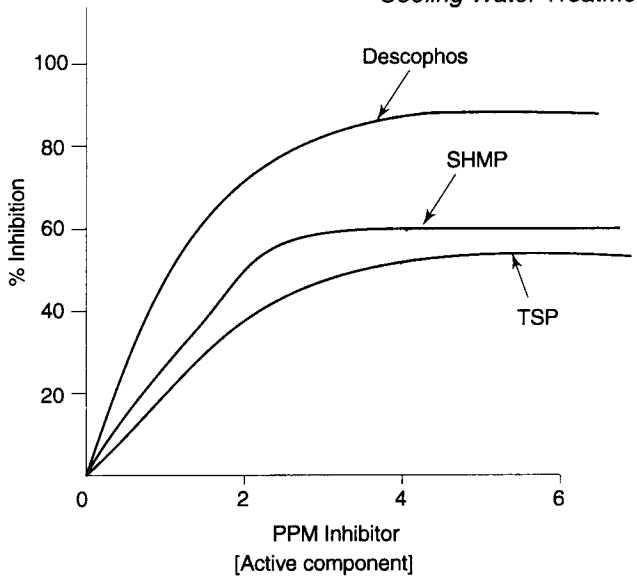


Fig. 26.1 *Seven-Day per cent Scale inhibition in a system of C_{CaCO_3} = 400 ppm; pH = 10 ; TEMP. = 298°K.*

how descophos products function as very effective scale inhibitors in different saturated systems, e.g. in the precipitation of $CaCO_3$, $CaSO_4$, $Fe(OH)_3$, $Al(OH)_3$, $Cu(OH)_2$ and $Co(OH)_3$ etc.

Q. *What is the hydrolytic stability of DESCOPHOS in an aqueous system under different environmental conditions?*

Ans. Descophos products are quite stable to hydrolysis and far stabler than SHMP under various conditions of temperature, extreme pH and in the presence of several cations and anions and over a longer duration. (Fig. 26.2).

Sodium hexametaphosphate is a common polyphosphate used as an antiscalant but upon hydrolysis it produces orthophosphate which combines with calcium to cause fouling in C/W system. Whereas descophos is much more stable and does not disintegrate in the system.

Q. *What is the concentration range in which DESCOPHOS is effective as an antiscalant?*

Ans. Descophos products inhibit scale deposition at the substoichiometric level. The degree of inhibition depends on the concentration of descophos present in the system. Usually 1–2ppm of active acid of the descophos product is sufficient for scale inhibition in a C/W at a pH value 10.

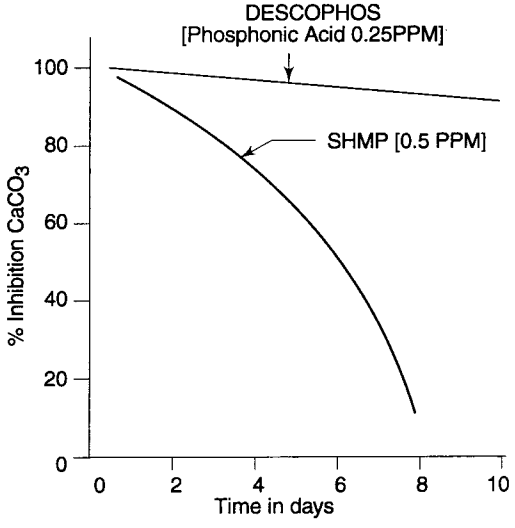


Fig. 26.2 *Time dependence of inhibition effect of HEDP and SHMP on precipitation of $CaCO_3$ at 338.5°K.*

Q. *Is it stable to chlorine?*

Ans. Descophos products (50A-50E) are quite stable in the presence of Cl_2 in the cooling water system. Descophos 50 or 50A is recommended where chlorine is dosed to the CT to keep bacterial growth at bay.

Q. *How does DESCOPHOS inhibit scaling?*

Ans. Descophos products are sequestering agents producing chelate complexes with many metal ions, even in the presence of precipitating agents, in cooling water. For example, every mole of active acid phosphonate inhibits 2 moles of $CaCO_3$ from precipitation. It keeps the metal surfaces (in contact with C/W) clean by complexing them with scale forming metal ions.

Q. *Can its sequestration effect be enhanced?*

Ans. Yes; adding zinc salts to descophos products greatly improves the sequestration capacity of the inhibitor.

Note: Over and above, this gives better corrosion protection—an added advantage—by retaining useful concentration of Zn^{2+} in the solution for a longer period as well as slowly depositing the zinc chelate complex film on the surface giving desired corrosion protection.

Q. *How far are they are environmentally compatible?*

Ans. 1. Descophos products are safe.
2. They are non-toxic to fishes.
3. They are non-degradable in activated sludge sewage treatment.
4. Their BOD is almost zero.

Q. *Are they costly?*

Ans. They are comparatively more economical than other antiscalants. The inhibitor concentration (in ppm) required for various antiscalants at cost ratio unity is:

Inhibitor	PPM ('as is' basis)
Descophos–50A	1.7
Sodium tripolyphosphate	9.0
Sodium hexametaphosphate	7.0

Q. *The biocidal action of chlorine is realized through its oxidizing power. Cite any other commercially successful C.T. biocide that kills bacteria in the analogous way.*

Ans. SANOSIL SUPER C is such a product of M/s Sanosil AG, of Switzerland.

Q. *What is it?*

Ans. It is a multicomponent biocide. Its active component is hydrogen peroxide stabilized by silver.

Q. *How does it act?*

Ans. It kills microorganisms by the oxidizing power of hydrogen peroxide while the silver component, which acts as a catalyst in trace amounts, ensures that the effect is long-lasting.

Q. *What are the characteristics of SANOSIL Super C?*

Ans. It is a non-corrosive, non-toxic, easy-to-handle clear liquid, safe for microbiological control of cooling water system.

It is highly soluble in water and its high solubility increases its penetration power in slimy masses and water bodies.

Q. *What is the pH range for its optimum effectivity?*

Ans. 6 to 8

Q. *Can it be added directly to the C.T. basin?*

Ans. Yes; it can be introduced straightaway to the C.T. basin or at any other suitable location, where good distribution can be assured.

Q. *Against which bacteria does SANOSIL Super C exhibit strong biocidal action?*

Ans. Species of

1. Escherichia
2. Thiobacillus
3. Sphaerotilus Achromobacter
4. Pseudomonas
5. Ferrobacillus
6. Anaerobic Desulphovibrio

Q. *Against what species of fungi is SANOSIL Super C most effective?*

Ans. Species of

1. Aspergillus
2. Penicillium
3. Fungi Imperfectly
4. Basidiomycetes

Q. *What algae species are killed by SANOSIL Super C?*

Ans. 1. Blue green algae
2. Green algae

Q. *What is the dosage and mode of dosing?*

Ans. Initially a shock dose of 100–200 ppm Sanosil Super C, based on hold-up capacity is added, subsequently a dose of 25–50 ppm is added at 3–5 days interval depending upon the microbial load of the system.

Q. *What is the efficiency of the SANOSIL system?*

Ans. At 25 ppm it kills 90% of all bacteria reported above (including sulphate reducers).

Q. *What are the advantages of SANSOIL?*

Ans. 1. It is environmentally compatible
2. Effectiveness continues at elevated temp. (308°–318°K)
3. Good stability in storage
4. Non-irritant to skin and eyes in the prescribed dosage
5. Odour-free and does not produce foam.

Q. *What is Halocide®?*

Ans. It represents a new generation of bromine-release biocides which has been EPA (Environment Protection Agency, USA) registered.

Halocide® is a registered, trademarked and patented product of Ross Chemical Inc. (USA). The name has been coined from two words—halogen and biocide.

Halocide is a unique halogenated dialkylhydantoin derivative in briquette form (Fig. 26.3) which functions as a disinfectant, algaecide, fungicide, bactericide and/or slimecide through the release of active bromine and chlorine.

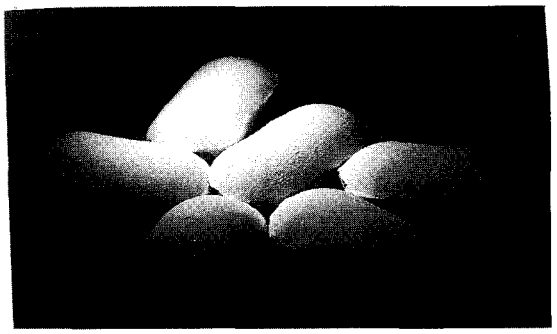


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Fig. 26.3 *Halocide® Briquettes (42 mm × 22 mm × 13 mm; WT. = 12g).*

Q. *But other bromine-release and chlorine-release compounds viz. BCDMH* and DCDMH* are available in the market. And they are well known for their pronounced biocidal effectiveness. So how does Halocide® outvie these two, itself being a hydantoin derivative?*

Ans. It is true that both BCDMH and DCDMH provide a concentrated source of active halogen in a chemically stable, safe, easy-to-use-solid form and that they have been compacted with the help of binders making them available commercially in briquette, stick or tablet form.

However, these products, in general, are slow dissolving, dusty and lacking in physical integrity and it has often been difficult to provide sufficient halogen quickly enough for adequate biocontrol. Plugging of feed systems has frequently been reported.

In this context, Halocide® has exhibited

(a) Improved wet and dry physical stability
(b) Increased solubility
(c) Higher purity by eliminating binders
(d) Reduced dusting
(e) Suitability for both slug and continuous feed.

Q. *What are the advantages of using Halocide® as a C/W chemical?*

---

* BCDMH = Bromochlorodimethylhydantoin

* DCDMH = Dichlorodimethylhydantoin

Ans. Halocide® provides a concentrated source of active halogen in a chemically stable, safe, easy to use solid briquette form (Fig. 26.4).

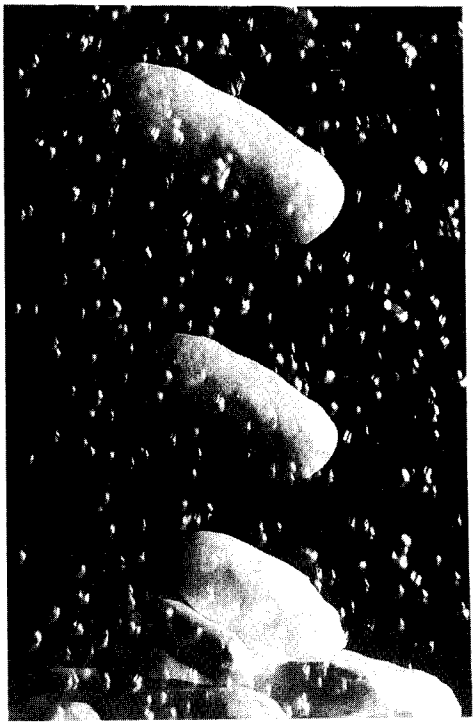

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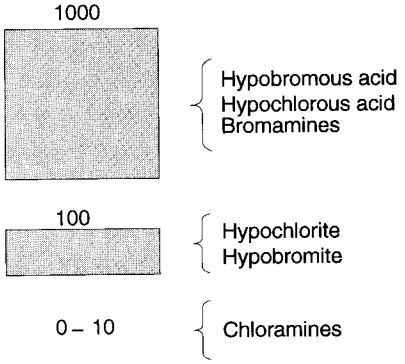
Fig. 26.4 *Halocide® in action.*

And thus it has the following benefits:

1. Releases a combination of bromine and chlorine that react synergistically and enhance the biocidal activity of one another
2. Generates weak hypohalous acids (both hypobromous and hypochlorous) in order to achieve microbial control.



This differs from chlorine which generates 'strong acids' that lowers the C/W system's pH which among other things, increases corrosion (Fig. 26.5) and degrades other chemicals present in the system.

3. Remains quite effective in high pH water systems. This benefit is of particular value in C/W systems where ammonia inleakage increases the water pH.
4. Effective in the presence of hydrogen sulphide, ammonia and other hydrocarbons
5. Since it is manufactured in solid-state-form, it completely eliminates the risk of accidental leakage of gas/spillage of liquids
6. Safe to handle
7. Harmless to the environment at recommended levels
8. Compatible with other water treatment chemicals
9. Active in both acid and alkaline pH ranges. But it is generally recommended for use in systems which operate at pH levels above 7.5.
10. Can be introduced to C/W systems by the slug or shock method to reap the following benefits:

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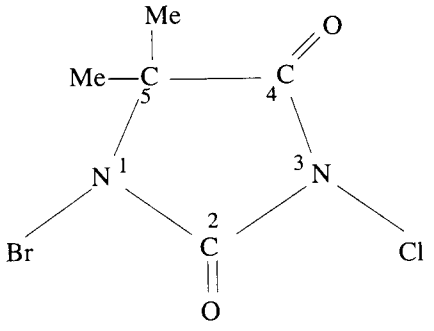
Fig. 26.5 *Effect of chlorine gas vs Halocide® on corrosion coupons.*

(a) Greater Treatment Effectiveness–slug feed produces relatively high biocide levels over a short span (Fig. 26.6), thus reducing microorganism resistance and acclimation, thereby achieving broader microbial control.
(b) Reduced Chemical Consumption (2 to 6 fold).
(c) Less Chemical Interaction as biocide treatment is set up for periodic dosage.

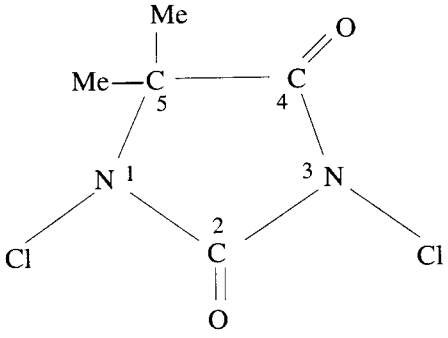
11. Provides more than adequate microbiological control while not exceeding 0.5 ppm of total halogen and 0.2 ppm free halogen.
12. Other special features include:
    (a) low-use cost performance
    (b) simplicity of application
    (c) labour savings
    (d) compliance with NPDES discharge limits.

Q. *What are the active ingredients of Halocide® briquette?*

Ans. ***Active Ingredients***	***Composition***
1-Bromo-3-chloro-5, 5-dimethylhydantoin	60.0%
1, 3-Dichloro-5, 5-dimethylhydantoin	27.4%
1, 3-Dichloro-5-ethyl-5-methylhydantoin	10.6%
Note: Inert ingredients	2.0%



1-Bromo-3chloro-5, 5-dimethylhydantoin



1-3-Dichloro-5, 5-dimethylhydantoin

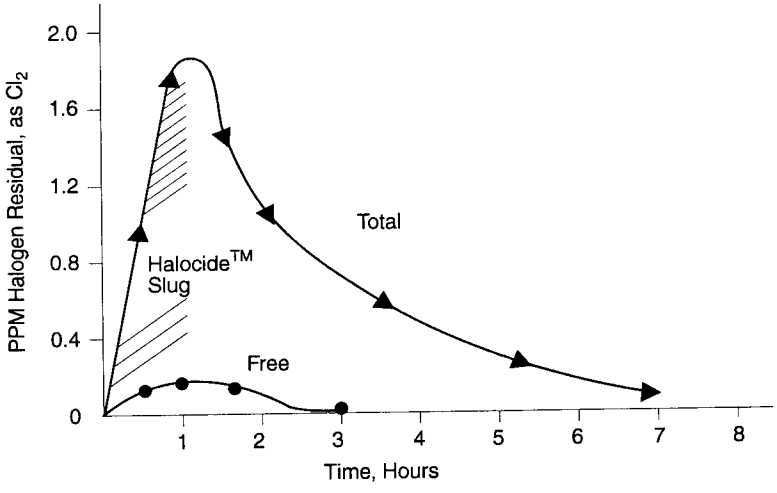


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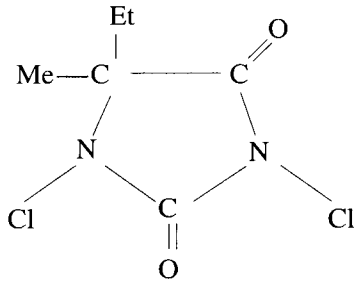
Fig. 26.6 *Slug treatment with HALOCIDE® provides a resource of total available halogen for effective bio-control. The level of free halogen at any time is minimized.*



1-3-Dichloro-5-ethyl-5-methlhydantoin

Q. *What is Halocide® chemistry?*

Ans. Halocide® is a mixture of halogenated dimethylhydantoin (DMH) and methylethylhydantoin (MEH). The incorporation of MEH makes possible

(a) the production of a hard, durable, low-dusting briquette

(b) 2 to 3-fold increase in product solubility over DMH-based products (Fig. 26.7).

(c) the elimination of binders.

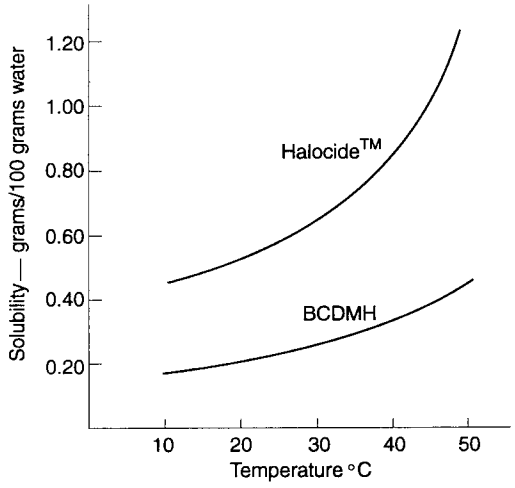


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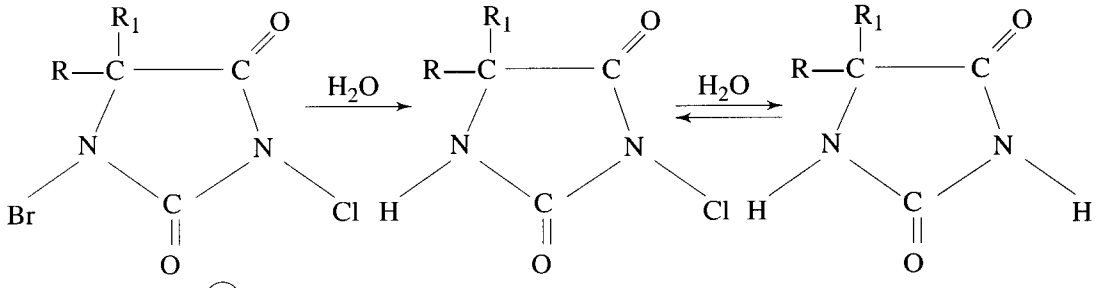
Fig. 26.7 *Solubility comparison. HALOCIDE outsurpasses BCDMH as regards to solubility at any temp.*

This proprietary formulation provides sufficient free halogen on demand for microbiological con-



R, R_1 = Methyl, Ethyl groups

trol while maintaining a reserve of additional halogen.

Q. *How much of chlorine and bromine is available from Halocide®?*

Ans. Available halogen as chlorine = 59–63%
Available chlorine = 39.9%
Available bromine = 39.2%

Q. *What are the typical physical properties of Halocide®?*

Ans.

Colour	— Off-white
Odour	— slight halogen
Briquette wt	— 12 g
Briquette density	— 1600 kg/m^3
Nominal briquette dimension	— 42 mm × 22 mm × 13 mm
pH (1% slurry at 298°K)	— 3.6
Decomposition temp.	— 453°K
Solubility in water	— 0.54 g/100g at 298°K

Q. *Do you think bromine is a new entrant in the biocide market?*

Ans. No. Bromine products have been used effectively since the 1940's to disinfect pools, spas, cooling water, drinking water and wastewater, and new bromine products continue to be developed.

Q. *Can you cite a typical example of the new family of bromine-based microbiocides used for cooling water?*

Ans. It is TOWERBROM which is the registered trademark of Occidental Chemical Corporation.

Q. *Where is it introduced to the C/W?*

Ans. It is introduced in the recirculating water systems.

Q. *What is Towerbrom?*

Ans. It is a new generation of solid bromine biocide made of sodium bromide and chlorinated isocyanurate.

(TOWERBROM = Cooling TOWER BROMide)

Q. *In the recent years bromine products have made significant inroads into the biocide market that was dominated by chlorine. Why?*

Ans. The primary reason is the safety factor:

Bromine entails much less safety hazards than that associated with the use of gaseous chlorine.

Bromine is an excellent microbiocide for a large number of bacteria, fungi, algae, amoebic cysts and viruses.

Bromine fits better in the recent trend towards more alkaline cooling water operating conditions.

Finally, hypobromous acid is more effective than hypochlorous acid in ammonia-contaminated cooling water.

Q. *Why is bromine a superior biocide to chlorine in the alkaline range (pH levels above 7.5)?*

Ans. Both operate on the same biocidal chemistry. Free bromine and free chlorine dissolves in water to form hypobromous and hypochlorous acids respectively which behave as weak acids dissociating in water to the following equilibrium:

$$H_2O + X_2 \longrightarrow HOX + HX$$

where $X_2 = Cl_2, Br_2$

$$HOBr \rightleftharpoons H^+ + {}^-OBr$$

$$pK_{298°K} = 8.7$$

$$HOCl \rightleftharpoons H^+ + {}^-OCl$$

$$pK_{298°K} = 7.5$$

The microbiocidal efficacy of each acid is highly pH dependent, decreasing at higher pH levels. This clearly indicates that the undissociated forms are the microbiocidally active species, while the hypohalite ions are much less effective. Inasmuch as the pK value of HOBr is higher, it undergoes less dissociation at a given pH (Fig. 26.8).

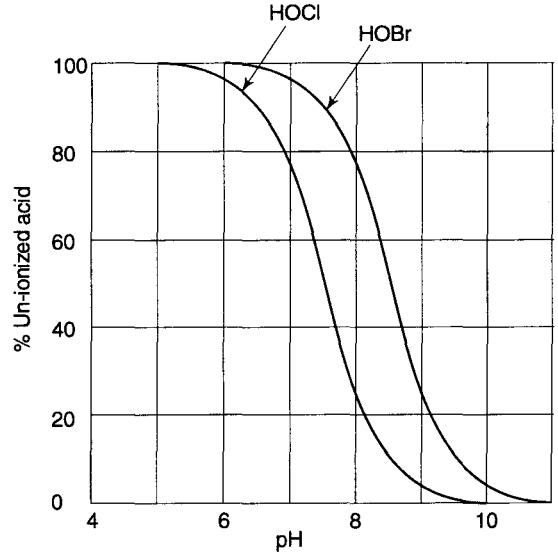


Fig. 26.8 *The dissociation of HOCl and HOBr is highly dependent on pH.*

This stability of HOBr in the higher pH range makes bromine a more potential biocide than chlorine, especially in the pH range of 7.5 to 9.5.

Q. *Why does this problem occur in this range of pH (7.5 to 9.5)?*

Ans. This is an important range for those cooling water recirculation systems where alkaline

corrosion control programs are progressively the heavy-metal-based programs which are becoming environmentally unacceptable.

Q. *How does the ammonia-contaminated water tell upon the microbiocidal effectiveness of hypobromous and hypochlorous acids?*

Ans. Both acids react with dissolved ammonia to form halamines such as NH_2Br or NH_2Cl

$$NH_3 + HOBr \longrightarrow NH_2Br + H_2O$$

Thus the potential microbiocidal component is lost.

Q. *This being true, then how is hypobromous acid more effective than hypochlorous acid in ammonia-contaminated C/W?*

Ans. The differential behaviour of bromamine and cloramine to water accounts for this.

Bromamines hydrolyze readily to re-release HOBr very rapidly

$$NBr_3 + 3H_2O \rightleftharpoons 3HOBr + NH_3$$

$$NHBr_2 + 2H_2O \rightleftharpoons 2HOBr + NH_3$$

$$NH_2Br + H_2O \rightleftharpoons HOBr + NH_3$$

with the effect that the microbiocidal potential of brominating agents is quickly restored.

In sharp contrast to bromamines, chloramines are more stable than bromamines, so they hydrolyze very slowly to re-release HOCl and as a consequence the formation of chloramines sharply reduces the microbiocidal effectiveness of HOCl. Microbiocidal potential drops, due to the formation of chloramines, to one-thousandth of HOCl.

Q. *Despite distinct advantages of bromine over chlorine, the fact remains that transition from chlorine to bromine is a very slow process. Why?*

Ans. Erstwhile bromine products available in the market did not provide the combination of convenience, cost and safety desired.

Even some of the current bromine products are inconvenient or dangerous to handle. For example, both Br_2 and BrCl are hazardous materials, since they are both toxic, liquefied gases. They require careful handling to avoid leakage. Thus, they closely resemble chlorine gas and its potential problems.

Now consider NaBr. It is a liquid often added separately to water being treated with chlorine microbiocides. This treatment liberates Br_2 which generates HOBr—the more effective microbiocide. This is a cost-effective method, no doubt but it involves two chemical feeds and hence two separate feed systems are required. Often the bromide is added in a stoichiometric ratio to chlorine. This is unnecessary and escalates the treatment cost.

However, there are solid bromine biocides which are considerably safer to handle. These are hydanatoin-based bromine products:

BCDMH (1-Bromo-3-chloro-5, 5-dimethylhydantoin)

DANTOBROM* (60% BCDMH + 27% DCDMH + 11% DCEMH)

where DCDMH = 1, 3-Dichloro-5, 5-dimethylhydantoin

DCEMH = 1, 3-Dichloro-5-ethyl-5-methylhydantoin

These have their limitations too.

Q. *What is the problem with BCDMH?*

Ans. BCDMH is only slightly soluble. Hence it requires large feeders and water flowrates to achieve the desired dissolution rates. In addition, BCDMH tablets dissolve rather poorly than its granules requiring an additional dosage of several percent inert to obtain acceptable results.

Q. *What is the problem with DANTOBROM?*

Ans. Though it has been claimed that Dantobrom has a faster dissolution rate than BCDMH, field experience has found this insignificant.

Q. *Do the hydantoins exercise any adverse effect on the microbiocidal capacity of their halogen derivatives?*

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* DANTOBROM is a trademark of Lonza Co.

Ans. Yes. Once the available halogen has been used up, the bromo-, chloro-derivatives of hydantoins yield 5, 5-dimethylhydantoin (DMH) as the leftover component. In high recycle system, the DMH concentration may reach a critical level that can erode the microbiocidal efficacy of BCDMH by combining with HOBr, thus removing free bromine from the CW.

DMH reacts with free halogen—either chlorine or bromine—in a breakpoint type reaction. Forasmuch as this reaction creates a halogen demand, a part of the available halogen in BCDMH is consumed to destroy the ring. As a consequence, it calls for usage rate and with this the operating cost mounts due to obvious reasons.

Q. *What about the speed of the reaction, i.e. DMH ring destruction by the available halogen of BCDMH?*

Ans. Quite fast. The reaction occurs to a significant extent before the dissolved microbiocide even leaves the feeder.

Q. *Why is the speed of the reaction fast?*

Ans. BCDMH concentration is at its highest in the feeder. So the reaction is fastest in the feeder.

Q. *Does the mode of dosing have any impact on this side-reaction?*

Ans. Yes. Inasmuch as the rate of the reaction is proportional to BCDMH concentration, shock dosing makes largest impact on it. In such cases the feeder is shut off and the tablets sit in water for long periods of time.

Q. *Bromine products do not provide cost benefit. Why?*

Ans. Many bromine products contain large amounts of bromine. That is why they are more expensive and have relatively low available halogen contents.

Q. *How much bromine per mole of available halogen is contained in the following three species: Br_2, BrCl, BCDMH?*

Ans.

Biocide	Equivalent Bromine Per Mol of Available Halogen
Br_2	2.0
BrCl	1.0
BCDMH	0.5

Q. *What is the basis of the development of the new generation of solid bromine biocide?*

Ans. The target is to develop a product which will be highly soluble (and hence more efficient) and containing a smaller percentage of bromine while still lending itself as bromine biocide.

Q. *How this can be done?*

Ans. By recycling the bromine with most of the available halogen being supplied by a more economical source, such as chlorine.

Q. *Thus a solid, bromine-donating microbiocide would be more efficient and safer if it were highly soluble and capable of being fed from a totally dry storage container.*

Is there any formulation available in the market to meet these objectives?

Ans. Chlorinated isocyanurate—sodium bromide.

The result of mixing sodium bromide with chlorinated isocyanurate is that it offers the benefits of a bromine biocide in recirculating C/W systems without sacrificing the oxidizing power of chlorine.

Q. *In which form is chlorinated isocyanurate used?*

Ans. Both granular and tablet forms.

Q. *When is the granular form used?*

Ans. For shock dosing.

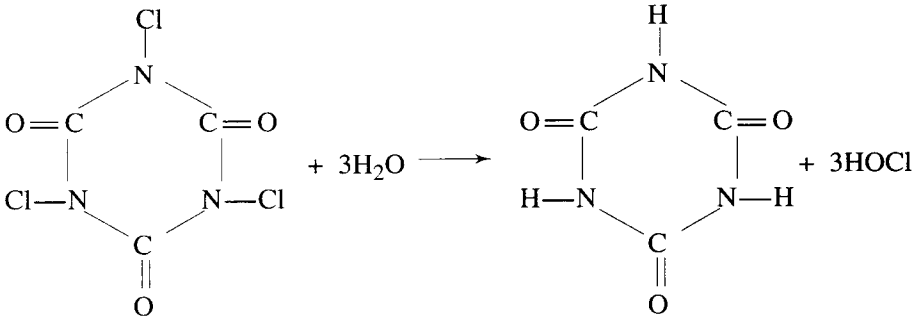
Q. *Why is the granular form used for shock dosing?*

Ans. Granular form goes into solution faster than tablets (more than 15 times faster) instantly rais-

ing the free halogen concentration over a localized zone as desired by shock dosing.

Q. *What is the chemistry of chlorinated isocyhanurate-sodium bromide formulation?*

Ans. The chlorinated isocyanurate undergoes hydrolysis to release HOCl that oxidizes bromide ions to OBr^-:



Trichloro-s-triazinetrione

$$HOCl + Br^- \longrightarrow HOBr + Cl^-$$

HOBr acts as microbiocide.

The high solubility and dissolution rate of the mixture render the system capable of simultaneously supplying free chlorine and bromide to the water at rates so that the stoichiometries of the following reactions are satisfied under most application conditions

$$HOCl + Br^- \longrightarrow HOBr + Cl^-$$

$$K_{eq} = 9.55 \times 10^5$$

$$\Delta F = -7.566 \text{ kcal}$$

$$\overline{O}Cl + Br^- \longrightarrow OBr^- + Cl^-$$

$$K_{eq} = 1.96 \times 10^4$$

$$\Delta F = -5.826 \text{ kcal}$$

The high negative free energies and equilibrium constants for these reactions indicate that they occur readily and that the bromine forms are heavily favoured. The presence of bromide insures that some of the free halogen present will be in the form of free bromine, which is better at killing microorganisms than chlorine.

Q. *What basic condition must the chlorinated isocyanurate-sodium bromide system fulfil so that it can operate completely as a bromine microbiocide?*

Ans. It must insure at least one mole of bromide in water for each mole of free chlorine.

Q. *What is required to fulfil this basic condition?*

Ans. The mole ratio of the sum of all bromine-containing species (HOBr, OBr^-, Br^-) to the sum of all free halogen species (HOBr, OBr^-, HOCl, OCl^-) present in water must exceed unity,

i.e. $$\sum m_{BROM} / \sum m_{HAL} > 1$$

where m represents no. of moles

subscripts *BROM* and *HAL* represent all bromide species and all free halogen species respectively.

Q. *What is the utility of such a ratio?*

Ans. It is a convenient way to express the extent of conversion of free chlorine to free bromine. Also it is a measure of the performance of a formulation functioning as a bromine microbiocide.

Q. *The 'mole ratio' maintained in the water or the 'mole ratio' in the microbiocide itself before it is added to the water—which one determines the type of performance of the biocide?*

Ans. The mole ratio maintained in the water.

Q. *A biocide vendor says that his solid bromine biocide maintains a ratio of bromide concentra-*

tion (in mg/lt) to free halogen concentration (in mg/lt as Cl_2) of value 1.127.

How far is he true from the standpoint of his product acting as a bromine biocide?

Ans. A bromine biocide should maintain a Br^-/Cl_2 mole ratio of at least unity which in terms of weight ratio comes out to be 1.127.

Q. *How does chlorinated isocyanurate-sodium bromide system lend itself for the shock dosing mode?*

Ans. The very high solubility and dissolution rate of the mixture allow the entire dose to be added in minutes. Fig. 26.9 shows the concentration of free available chlorine and bromine during a shock dose. The free halogen concentration builds up rapidly then gradually drops off as the demand is fulfilled.

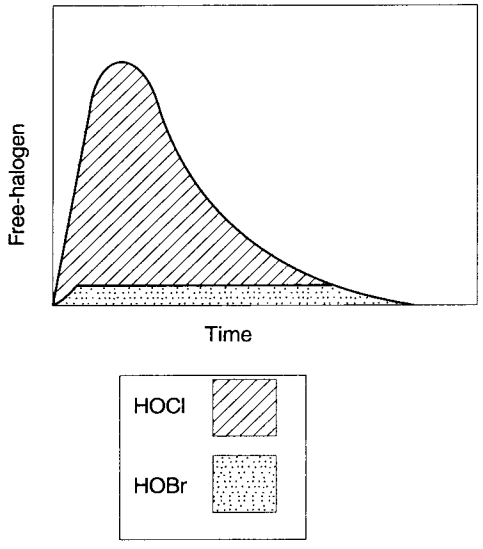


Fig. 26.9 *Shock feed halogen profile.*

For the Ist phase of the shock there is an excess of free chlorine so the formulation essentially functions as a mixed chlorine and bromine system. This is desirable since chlorine is an oxidizer, in both the acid and hypochlorite forms, than bromine at any pH.

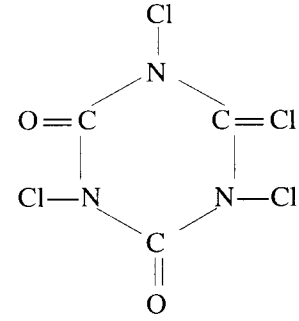
Q. *What is the comparative solubility of chlorinated isocyanurate-sodium bromide with respect to hydantoin-based products?*

Ans.

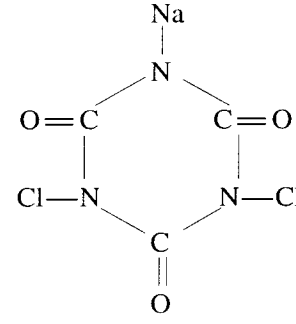
Product	Solubilities in Water (g/100 g at 298°K)
93% Trichloro-isocyanurate + 7% NaBr*	1.2
93% Sodium dichloroisocyanurate + 7% NaBr**	20
Dantobrom	0.54
BCDMH (granules)	0.20
BCDMH (tablets)	0.15

Q. *What are the structures of chlorinated isocyanurate commercially used as a biocide?*

Ans.



Trichloro-s-triazinetrione
(Trichloroisocyanurate)



Sodium dichloro-s-triazinetrione
(Sodium dichloroisocyanurate)

* commercially marketed as TOWERBROM 991/993

** commercially marketed as TOWERBROM 960

Q. *What are the advantages of chlorinated isocyanurates over hydantoin-based products?*

Ans. Compared to hydantoin-based products, the chloro-derivatives of isocyanurate react much faster with water supplying free chlorine and bromide to the water almost simultaneously in accordance to the following reactions:

$$HOCl + Br^- \longrightarrow HOBr + Cl^-$$

$$OCl^- + Br^- \longrightarrow OBr^- + Cl^-$$

This happens due to higher solubilities of chlorinated isocyanurates over hydantoin-based products.

For a typical CT application where the free halogen concentration is 0.1–0.5 mg/l and the bromide concentration is about 1–5 mg/l, the reaction half-life is 1–10 minutes. The reaction half-life is generally shorter than the mixing time of most cooling systems and is much smaller than the lifetime of the micro-biocide with the water.

The reaction product DMH of hydantoin-based microbiocide consumes available halogen and this may become competitive to halogen release rate of BCDMH under critical concentration level of DMH. Decidedly this tells upon the efficacy of BCDMH. The cyanuric acid released by the chlorinated-isocyanurate has been found not to react with halogen further.

In hydantoin-based CT programs bromine recycle is not possible whereas isocyanurate-based systems work because bromide is continuously recycled with the effect that the amount of bromide added only goes to make up the amount lost.

Q. *How does chlorinated isocyanurate-sodium bromide formulation ensure bromine recycle?*

Ans. As chlorinated isocyanurate + NaBr is continuously fed to a CT which contains no bromine initially, the active component generates HOCl, and the sodium bromide releases Br^- ions, which are quickly oxidized to HOBr and OBr^-.

As the hypobromous acid and hypobromide ion react with microorganisms and debris, they revert back to bromide ion which is then reactivated by the free chlorine. That is how bromide is continuously recycled (Fig. 26.10).

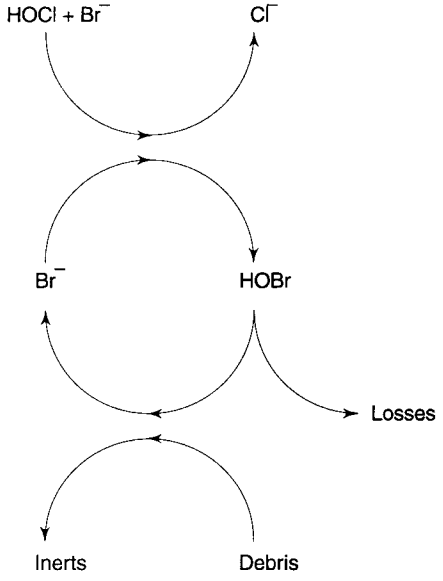


Fig. 26.10 *Schematic diagram of bromide recycle loop.*

Q. *How are the killing efficiencies of bromine and chlorine compared?*

Ans. It is measured in terms of per cent kill plotted against Br^-/Cl_2 mole ratio (Fig. 26.11) as determined from dynamic lab experiments.

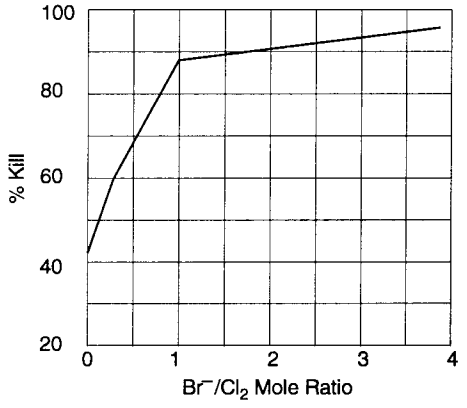


Fig. 26.11 *Effect of Br^-/Cl_2 mole ratio of killing efficiency from dynamic lab experiments using a culture of wild organisms.*

Conditions: Free halogen = 0.5 mg/1 as Cl_2

pH = 8

Q. *What do you infer from this figure?*

Ans. 1. The killing efficiency of HOBr is considerably better than that of HOCl at a pH of 8
2. The killing efficiency increases linearly from a ratio of zero to a ratio of one and then levelled off.

Q. *How can the cost performance of a CT microbiocide be determined?*

Ans. By harnessing usage rate.

Accurate usage rates are established through each trial run over a period of several weeks or months. By comparing the usage rates at similar conditions, particularly at identical heat loads, the cost performance of one biocide with respect to other can be made.

Q. *Is there any practical data regarding usage rate of biocides for comparative study of their cost performance?*

Ans. TOWERBROM 993* (84% available halogen), DANTOBROM** (62% available halogen), and BCDMH (55% available halogen) are all bromine microbiocides. The predicted usage rate for TOWERBROM 993 is 65% of the BCDMH usage and 74% of the rate for DANTOBROM.

Under identical test conditions, their usage rates are tabulated as below:

Field Trial	Microbiocide	Relative Usage rate as predicted	Relative Usage rate (Actual)
1	Towerbrom 993 vs. BCDMH	65%	56%
2	Towerbrom 993 vs. BCDMH	65%	48%
3	Towerbrom 993 vs. Dantobrom	74%	76%
4	Towerbrom 993 vs. BCDMH	85%	75%

Q. *What do you mean by a cooling tower?*

Ans. A cooling tower is a heat exchange system that removes waste heat from a process system fluid, usually water.

Q. *Where do the cooling towers find their application?*

Ans. Cooling towers are used in both utility and industrial applications. For utilities, this includes power, congeneration, geothermal and waste-to-energy plants; for industrial applications, it includes chemicals, petrochemicals, pulp and paper and pharmaceutical plants. C/Ts are also used in buildings requiring large air conditioning facilities.

Q. *On which factors does the selection of the type of cooling tower depend?*

Ans. The type of tower selected to cool a process system's water is determined by the economic and environmental considerations of the individual application.

Q. *How many types of cooling towers are there?*

Ans. 1. Wet cooling tower
2. Dry cooling tower
3. Hybrid cooling tower

* registered trademark of Occidental Chemical Corpn.

** registered trademark of Lonza Co.

Note: The ***relative usage rate*** of a microbiocide is its usage rate divided by the usage rate of a reference microbiocide under identical service conditions.
The ***predictive relative usage rate*** is based on the relative available halogen contents.

Q. *What do you mean by a wet cooling tower?*

Ans. Usually, the process water is cooled by the evaporation of water in a cooling tower. The heated water is distributed over a medium, called the tower's 'fill'. As the water falls through the fill, colder air passes through the tower either vertically (counterflow) or horizontally (crossflow), usually with the assistance of fans. Subsequently, the process water is cooled by mass and heat transfer. As evaporation (latent heat exchange) occurs naturally, the temperature of the heated water is reduced. (Cooling water via evaporation removes approximately one per cent of its volume for every 5.5°K of cooling). This type of tower is called a WET COOLING TOWER. (Fig. 26.12 and Fig. 26.13). The cooled water is then either returned to the process system (closed-looped) or to a body of water (once-through system)

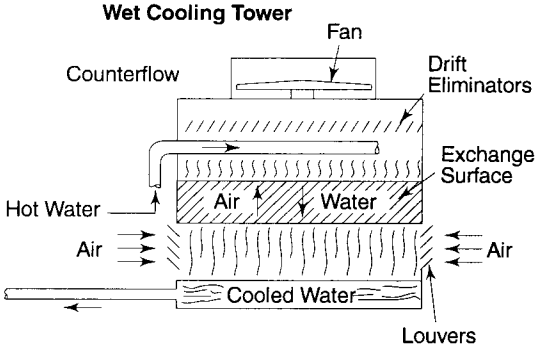


Fig. 26.12 *Counterflow wet cooling tower*

Source: HCT 002R (Brochure, Hamon Cooling Towers).

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Q. *What is a dry cooling tower?*

Ans. In dry cooling systems, the heated water or steam is piped through a bundle of tubes (Fig. 26.14) which can be made of either metal or plastic.

If the primary fluid is heated water, the water temperature is reduced as the water is cooled by conduction and convection (sensible heat exchange) of the air traveling across the heat exchanger. This is called a CLOSED-CIRCUIT DRY COOLING TOWER. If the system handles steam, the steam will be condensed. This is called an air-cooled steam condenser.

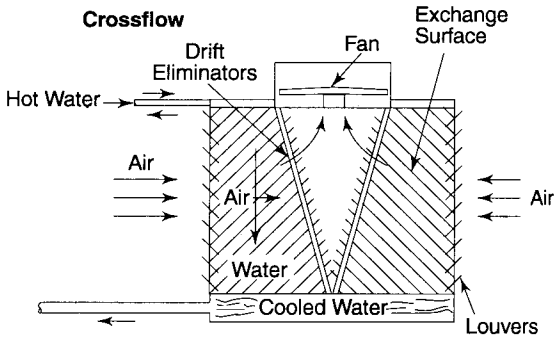


Fig. 26.13 *Crossflow wet cooling tower*

Source: Brochure HCT 002R (Hamon Cooling Towers).

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

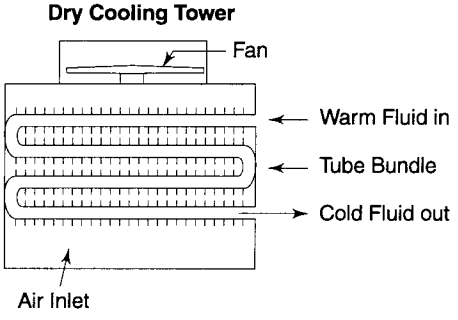


Fig. 26.14 *Dry cooling tower*

Source: Brochure HCT 002R (Hamon Cooling Towers)

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Q. *What are hybrid cooling towers?*

Ans. These are characterized by their mode of cooling mechanism, i.e. they cool water by both latent heat exchange and sensible heat exchange techniques (Fig. 26.15).

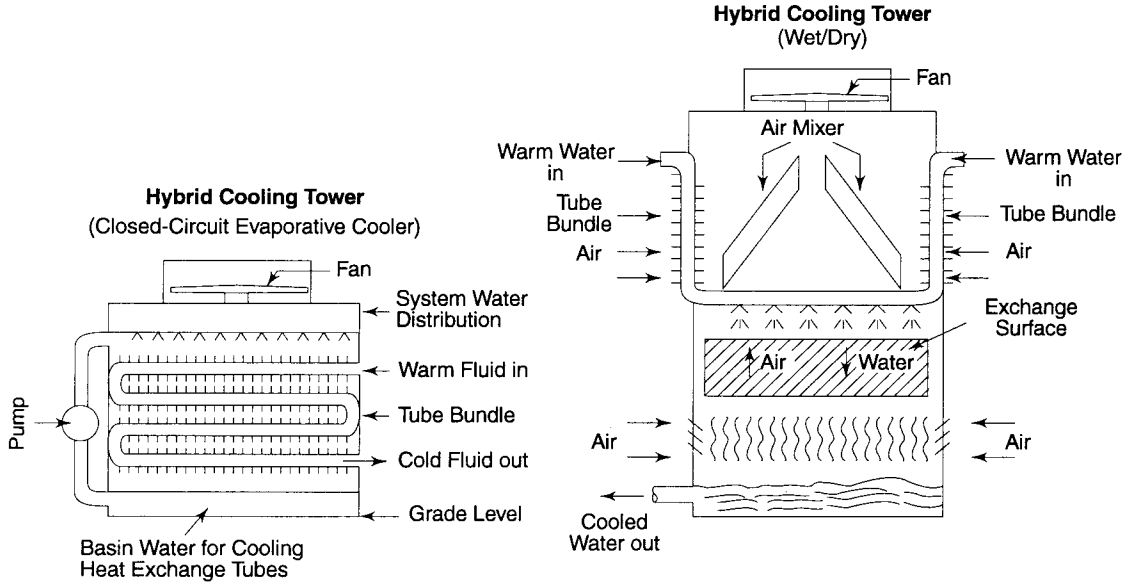


Fig. 26.15 *Hybrid cooling tower*

Source: *Brochure HCT 002R (Hamon Cooling Towers)*
Courtesy: *Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA.*

Q. *What are the basic reasons for cooling water?*

Ans. There are three primary reasons for cooling water

1. Cooled water is more energy efficient as it provides the system with a cooler process solution
2. The volume of the circulating water is only marginally altered, thus eliminating the need for large quantities of make-up water
3. Cooled water is environmentally acceptable because if the cooled water is returned to a natural body of water, it will not disturb the aquaculture.

Q. *When is the 'dry approach' made?*

Ans. There are applications when wet C/Ts are not the proper heat exchange medium. These applications include:

1. Systems which need to recover more than 99% of the process water
2. Systems which cannot have a visible plume
3. Systems in which the solution cannot be exposed to the atmosphere (such as gas or corrosive solution)
4. Systems which are under pressure or vacuum

Q. *What do you mean by counterflow tower?*

Ans. A tower in which the air flows upwards through the fill material and encounters with the falling hot water.

Q. *What is crossflow tower?*

Ans. A tower in which air flows across the fill material and interfaces perpendicularly with the falling hot water is known as a crossflow tower.

Q. *What is air inlet of C/T?*

Ans. It is the opening at the lower portion of the tower that allows air to enter.

Q. *What is exhaust air?*

Ans. Exhaust air is the mixture of air and its associated vapour discharged from the tower.

Q. *What is plume?*

Ans. It is the visible vapour exhaust from a cooling tower.

Q. *What do you mean by evaporation rate in a cooling tower?*

Ans. Amount of water evaporated from the circulating water by the cooling process. Evaporated water is pure water, whereas drift has the same chemical concentration as the circulating water.

Q. *What is dry/wet tower?*

Ans. It is dry heat exchanger system combined with an evaporative cooling tower that is used to reduce the make-up water requirement.

Q. *What is wet/dry tower?*

Ans. It is an evaporative cooling tower combined with a dry heat exchanger system, used to reduce or abate cooling tower plume during cold weather operation.

Q. *What do you mean by cooling tower range?*

Ans. It is the temperature difference between the inlet hot water and the outlet cold water temperature.

Q. *What is the utility of this parameter?*

Ans. This value combined with the flow, determines the heat load the tower must remove.

Q. *What is dry heat exchanger?*

Ans. A cooling system that employs a series of tubes of either metal or thermoplastic material through which the heated water circulates to become cool.

Q. *What is meant by dry bulb?*

Ans. It is the temperature of the inlet or ambient air adjacent to the cooling tower as measured by a dry-bulb thermometer.

Q. *What is wet bulb?*

Ans. It is the temperature of the inlet or ambient air adjacent to the cooling tower as measured by a psychrometer. It is also known as the thermodynamic wet-bulb temperature or the temperature of adiabatic saturation.

Q. *What is its significance?*

Ans. This is the theoretical cooling limit of a wet cooling tower.

Q. *What do you mean by the term 'approach' related to C/T?*

Ans. It is the difference between the ambient wet bulb temperature and the cold water outlet temperature.

Q. *What is the importance of this parameter?*

Ans. This factor is critical in designing the tower.

Q. *What do you mean by natural draft cooling tower?*

Ans. It is a tower in which the air movement depends upon the difference in density between the ambient air surrounding the tower and the internal air. This tower typically finds application in systems cooling more than 45000 m^3/h of water but has been used in applications as low as 14000 m^3/h.

Q. *What do you mean by mechanical draft cooling tower?*

Ans. It is tower in which the air movement is effected by one or more fans.

Induced Draft fans are situated at the air exhaust

Force Draft fans are situated at the air inlet.

Q. *What is cold water basin?*

Ans. In a wet tower, the basin is the channel under the tower that receives the cooled water and directs its flow to the suction line or pump.

Q. *What is blowdown?*

Ans. It is the water discharged from the C/T system to control concentration of chemicals and minerals in the circulating waters.

Q. *What is make-up water?*

Ans. Water added to the circulating water system to replace water lost from the system by evaporation, drift, blowdown and leakage.

Q. *What is cooling tower fill?*

Ans. The fill within the cooling tower is the critical thermal component. In wet cooling towers or hybrid towers, it is the medium over which the hot water is distributed as it is being cooled. Its primary function is to provide the environment for efficient heat transfer.

Q. *What is the mechanism of cooling effected by fill?*

Ans. Fill stretches the falling water droplets into films, thereby providing extended surface area for water-air contact. This enhances the heat and mass transfer between the water and circulating air into the tower whereupon the water achieves the specified cooling over a short flowpath.

Q. *How many types of fills are used?*

Ans. There are two basic types of fills:

1. Film fill
2. Splash/grid fill

Q. *What is film fill?*

Ans. Film fills are thermoplastic fills produced in a modular honeycomb design. The standard film-type fill consists of thermoformed corrugated sheets of rigid polyvinyl chloride (PVC), impervious to decay, fungus and biological attack (Fig. 26.16 and Fig. 26.17). Film fill creates a very large surface area on which the hot water disperses itself as a thin film of water that interacts with the air travelling through the tower, thus achieving the specified cooling.

Q. *What are the splash/grid fills?*

Ans. These are available in several thermoplastic formulas (Fig. 26.18)

The exchange surface required for cooling is provided by the water droplets themselves.

Applicable for both counterflow or crossflow cooling towers, this fill made of either poly-propylene or high density polyethylene accommodates and deters build-up of algae, debris and suspended solids.

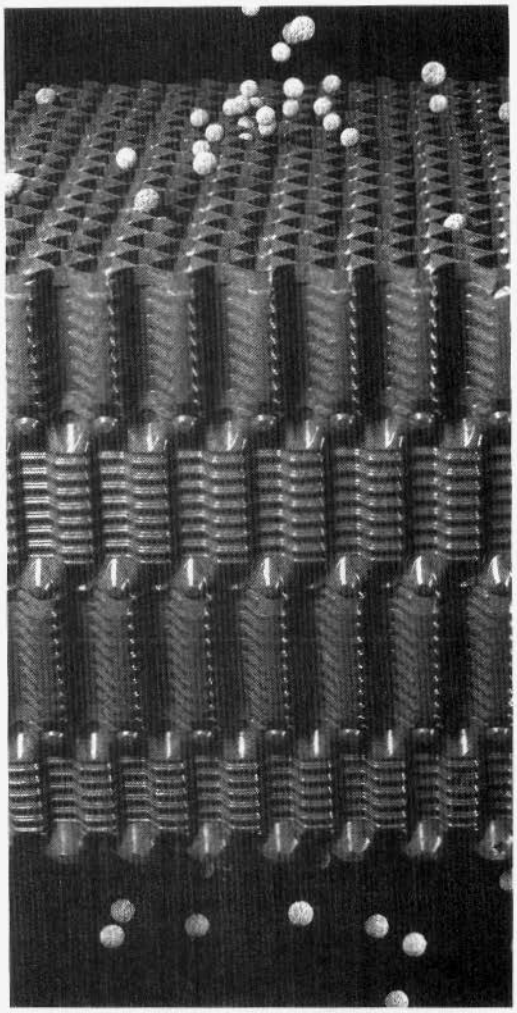


Fig. 26.16 *Hamon Coolfilm™ film-fill made of corrugated PVC sheets solvent welded together to form a standard module size of 1800 mm x 600 mm x 500 mm High. The Modules are stacked horizontally, each layer perpendicular to the other. The design allows for an optimal heat transfer per unit volume of fill with the corrugation on the vertical axis to help reduce the possibility of clogging, and to allow condenser cleaning balls to pass through.*

Courtesy: Hamon Cooling Towers/Bridgewater/ NJ 08807-0830/USA

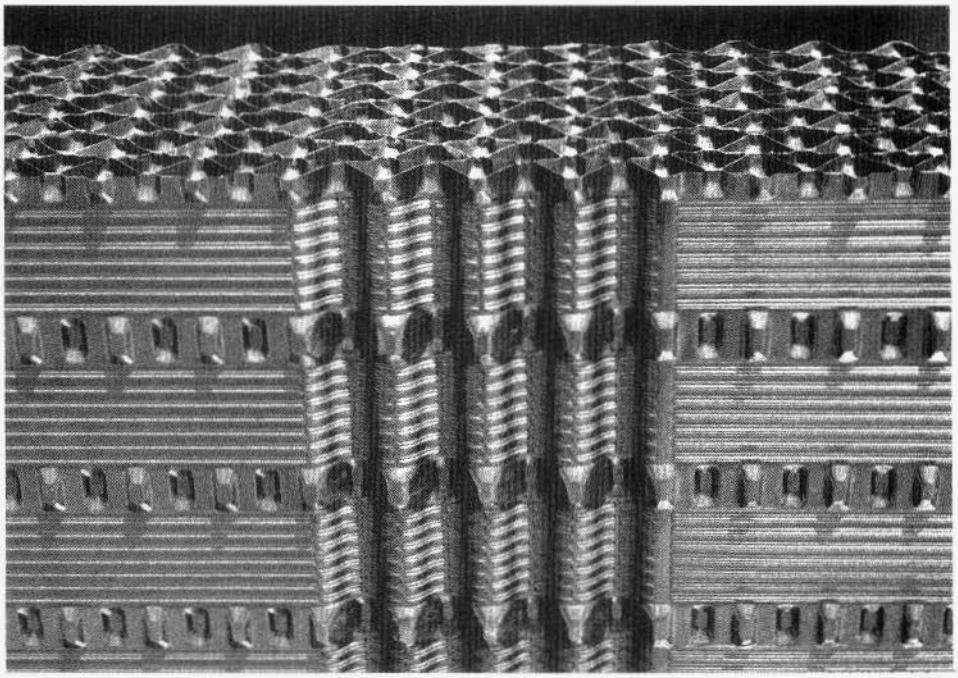


Fig. 26.17 *Hamon cleanflow antifouling film type fill made of thermoformed corrugated sheets of rigid PVC. The sheets are solvent welded to form modules. Each such module consists of vertically channeled flat and corrugated surfaces, which essentially avoids contact between the sheets, thus eliminating water concentration. The horizontal corrugations and their location within the sheet promote optimum mixing of air and water.*

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

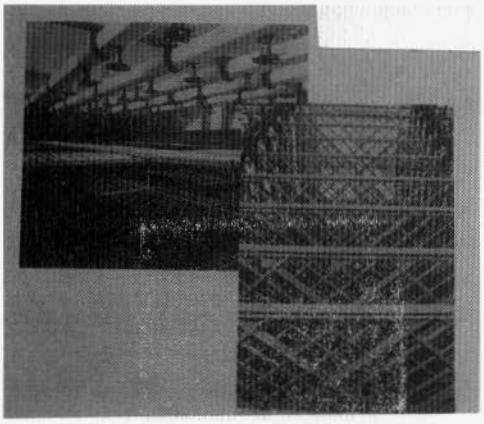


Fig. 26.18 *Hamon Cooldrop™ Splash/Grid fill*

Source: Brochure HCT 002R (Hamon Cooling Towers)

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Standard designs come fitted with fasteners so that they can be mechanically fastened to a stainless steel suspension system (Fig. 26.19) to prevent fill from dislodging by wind gusts, uplift or extreme icing conditions.

Q. *What are the basic disadvantages with film fill?*

Ans. 1. Fouling of counterflow film fills, especially those with diagonally cross fluted designs.
2. High fill performance is associated with high pressure drop that may totally offset their performance advantage.

Q. *How can the degree of fouling be estimated?*

Ans. Generally it is measured in terms of weight gain due to fouling as a function of time.

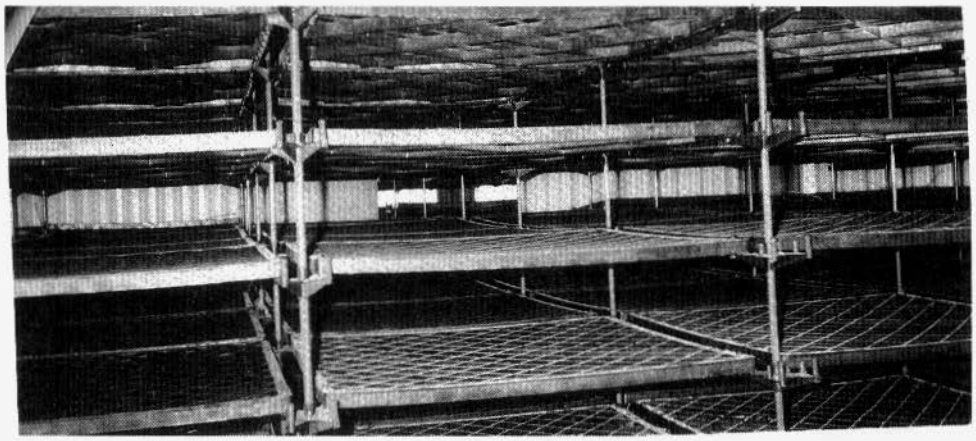


Fig. 26.19 *Hamon Cooldrop™ grid fastened to a stainless steel suspension system maximize droplet surface area, reduce pressure drop and contain 2% carbon black additive for increased durability against UV radiation.*

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Source: Hamon Cooling Towers/Brochure:HCT 002R

Q. *Why is this method used?*

Ans. The weight measure is easy to conduct on any cooling tower site. Weight gain gives a good indication of the fill pack tendencies with regard to fouling.

Q. *What is lacking in it?*

Ans. It does not directly address the thermal performance of a CT, which is the main interest of CT users.

Q. *How can the weight gain be demonstrated as a function of time?*

Ans. 1. In a certain CT thermal performance testing program conducted by Hamon, it was observed that both fill designs *C* and *E** demonstrated a fouling cycle of about 80 days with two periods of 40 days each.

During the 1st phase of 40 days, there was a steady rate of weight gain (Fig. 26.20) due to bacterial growth. The second phase that followed exhibited the stability period when the bacteria died out and weight reduced, and then followed by new growth on the old base.

2. After the initial period of 80 days, the cells were shut off for 10 days to dry the fill. When restarted, the CT fills exhibited weight loss correlating with the washing of attached mud and detached organisms.

3. Weight gain after 240 days of operation was found to be 10 times the dry pack weight for pack C and 4 times for pack E.

Q. *Is the tower capability affected due to fouling of CT fill?*

Ans. Obviously. During the foregoing test, the fill C lost 30 to 50% tower capability, while fill type E remained relatively unaffected, always about 100% ± 10% capability (Fig. 26.21).

Q. *Why did the tower capability of E-fill CT get affected less badly than C-fill CT?*

C : a high efficiency standard design with vertical offset flutes

E : a fill with vertical flutes designed specifically to resist fouling without sacrificing cooling effectiveness. Both are Hamon fill designs

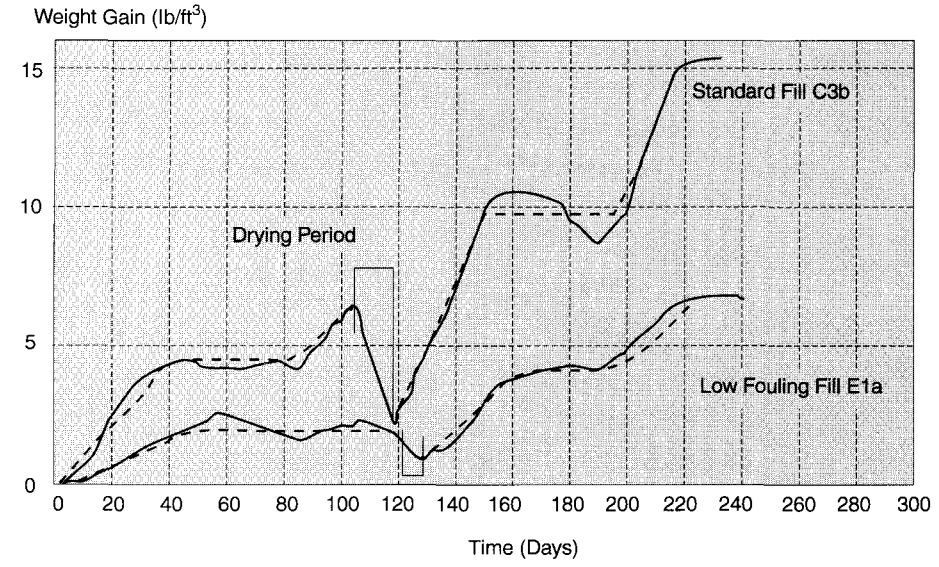


Fig. 26.20 *Fouling test of fill $C3_b$ and $E1_a$. Weight gain v. time.*
$C3_b$: Offset vertical flute-3 crossed tiers and no free space between the tiers
$E1_a$: Vertical flute; one sheet
Source: TP 93-06 (Technical Paper/Hamon-Sobelco)
Courtesy: HAMON COOLING TOWER/Bridgewater/NJ 08807-0830/USA

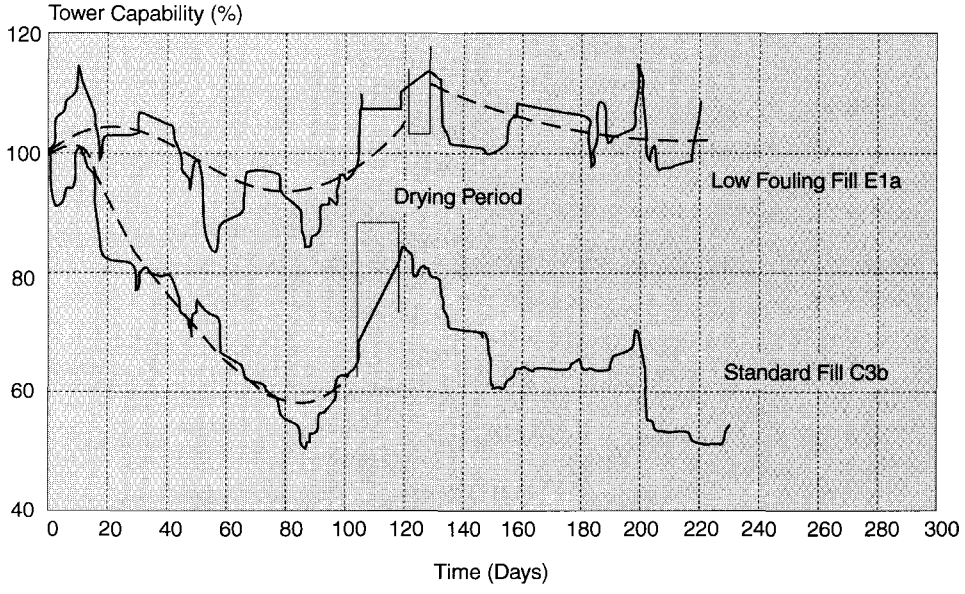


Fig. 26.21 *Tower capability of standard C-fill CT suffers more badly than CT packed with low fouling E-fill.*
Source: TP93-06 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Ans. C-fills are more compact and hence more efficient and more prone to fouling. The $C3_b$ variant has 3 cross tiers with no free space between the tiers. Hence for fill-C some temporary performance recovery is obtained by pack drying and cleaning, but the packs get fouled again shortly in service.

As against this, E-fills are low fouling packs and hence they do not harm the CT capability badly.

Q. *Why is fill-C more prone to fouling while fill-E is not?*

Ans. In pack *C*, the fouling matter concentrates at the contact points and in the area where the sheet profile reverses.

At these locations the fouling blocks and reduces the water film flow and increases the airside pressure drop, thereby reducing performance.

To the contrary, pack E permits foulant concentration vertically behind the contact points. There are relatively few contact points compared to the total surface area. Hence the fouling rate is small. Other areas of the sheet surface remain relatively clean.

Q. *On which factors does the thermal efficiency of a fill depend?*

Ans. It depends on

(a) pressure drop
(b) fill performance index

Q. *What is fill performance index?*

Ans. It is defined by the term *K.a.V/L*

where, K = mass transfer coefficient,

$$\frac{\text{kmol}}{(\text{h})\,(\text{m}^2)(\text{concen. difference})}$$

a = specific surface of packing, m^2/m^3 of packed depth

V = molar flowrate of vapour phase, kmol/h

L = molar flowrate of liq (water) phase, kmol/h.

The measured *K.a.V/L* is always calculated at a given constant *L/V*, using the characteristic curve of the fill.

Q. *Do you think that weight gain measurement is the ideal criteria in determining the thermal performance of a CT?*

Ans. No. However, a rough correlation between weight gain and increased pressure drop can be established (Fig. 26.22). Please note that thermal efficiency of a fill is a combination of ΔP and K.a.V/L.

Q. *Thermal performance of a CT depends on the fouling of CT fills. As such do you think water chemistry like pH, conductivity total dissolved solids, TSS, BOD and calcium exert influence on fouling rate?*

Ans. Though it is of particular interest that fouling process is the sequence of biological growth and accumulation of suspended solids, it has been observed, during the test period, that no correlation seemed to exist between the fouling rate and water quality.

This also confirms the theory that fouling is related to the life cycle of the bacteria which attaches to the suspended solids. This has been determined by analysis of the fouling matter which has been removed from the fill.

Q. *What should be the fill design, so far as fouling is concerned, to avoid loss in thermal performance?*

Ans. The fill must be designed to be resistant to fouling. And the non-fouling fill should have a vertical flute. It has been observed that such fill designs show little thermal performance reduction even with relatively significant weight addition via fouling.

Q. *Fouling of fill also affects pressure drop and heat exchange coefficient. How does it occur?*

Ans. The crossing sheets of the fill designs induce blockage due to biological growth in the fill that captures silt/suspended solids. This affects

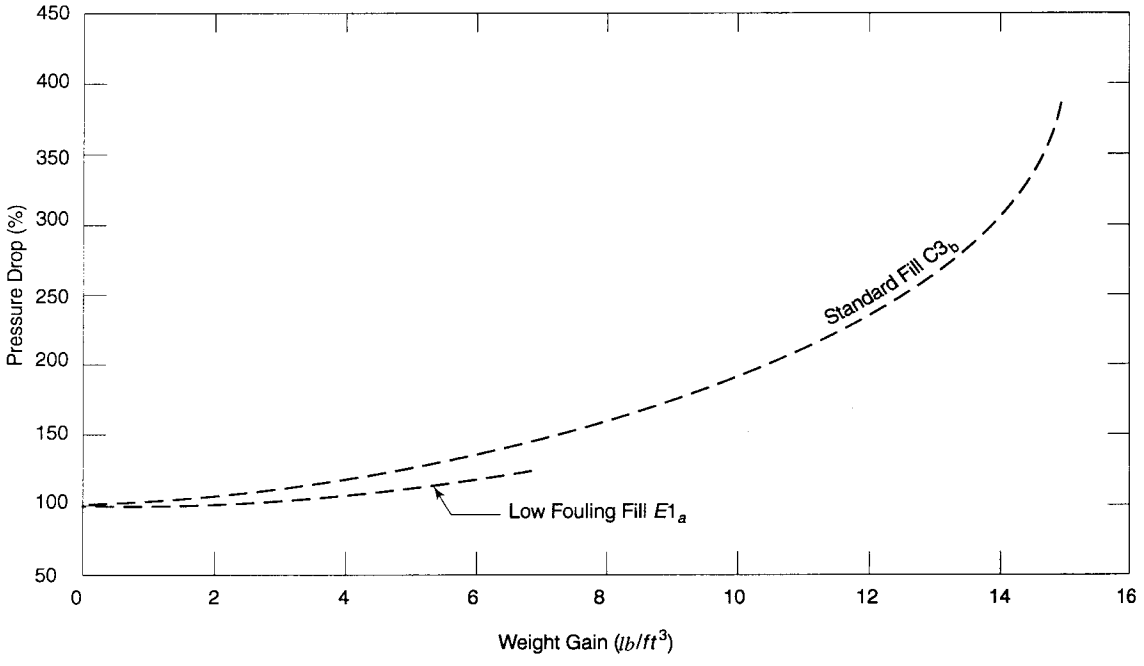


Fig. 26.22 *Correlation between pressure drop and weight gain (Fouling).*
Source: TP 93-06 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

first the heat exchange coefficient, and later the pressure drop.

Q. *How does fouling vary with pack depth?*

Ans. PVC fill fouling studies conducted by the Southern Company Services (SCS) in Georgia Power Company's Plant Bowen Unit-4 cooling tower* have revealed that there exists a tendency for fouling accumulation to increase from top to bottom within each pack (Fig. 26.23).

Weight gain based fouling in the lower layers has been found, in some cases, to be up to 60 times that found in the top layer of the same design.

* The test was conducted by replacing the existing cement asbestos (CAB) sheet fill with PVC packings near the tower center of existing bays. All pack designs were bottom supported by fiberglass box beams or a woodframe system. Installed depth for each fill was selected to match the airside pressure loss of the displaced CAB fill whenever possible.

For modular (stacked) fill designs, one or two test modules were selected within each fill layer for monitoring. For packings with one piece design two vertical modules were monitored.

Fill pack weight gain was used to represent the degree of fouling. Each test module was weighed 'wet' following installation for an initial baseline reading.

Nomenclature of each fill corresponds to *AXB*.
where, *A* = fill identifier
X = number of layers
B = type of stacking
a = one sheet
b = crossed tiers, no free space between the tiers
c = parallel tiers, no free space between the tiers
d = parallel tiers, small free space between the tiers (12 mm to 38 mm)
e = large free space between the tiers (> 12 mm)

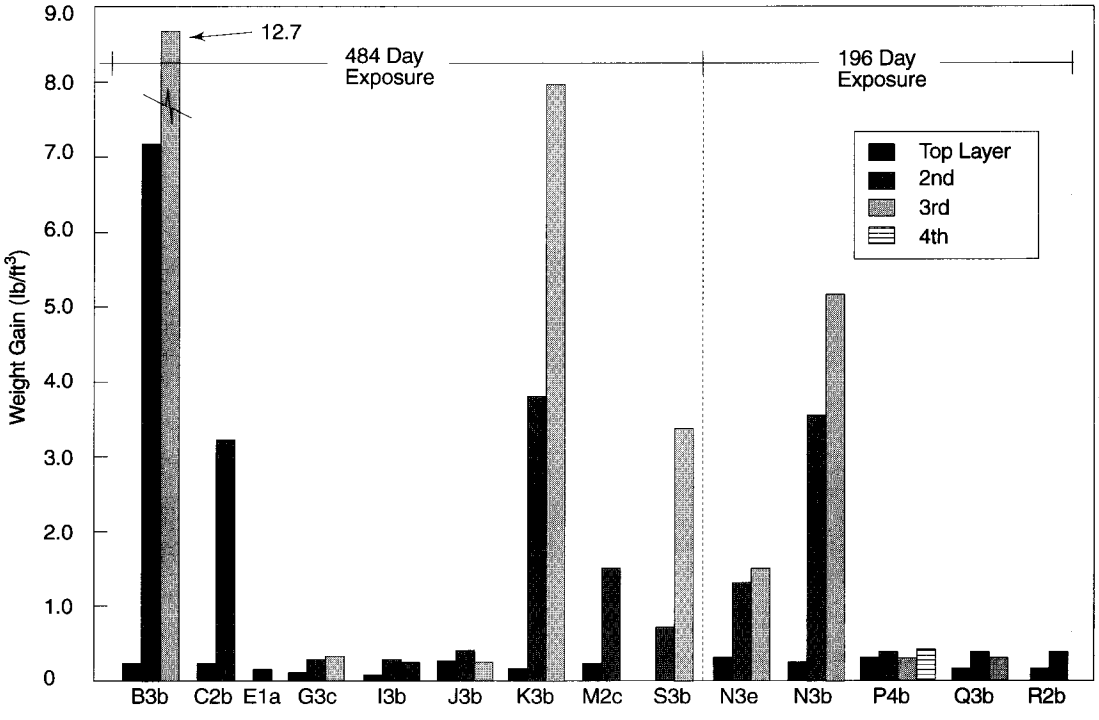


Fig. 26.23 *Fouling vs. Pack module position.*
Source: TP 93-06 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Q. *How does pack density influence fill fouling?*

Ans. Generally, there is a marked propensity of fouling tendency for 'high density' fills. Characterizing the fill density by surface area to volume ratio (A/V), the plot in Fig. 26.24 has been generated.

Figure 26.24 depicts weight gain with respect to normalized A/V for fills with 484 days exposure. The data indicate an increase fouling rate with higher A/V. Forasmuch as film fill A/V is usually directly related to specific thermal performance (per meter), high performance fills should tend to foul more readily than other designs.

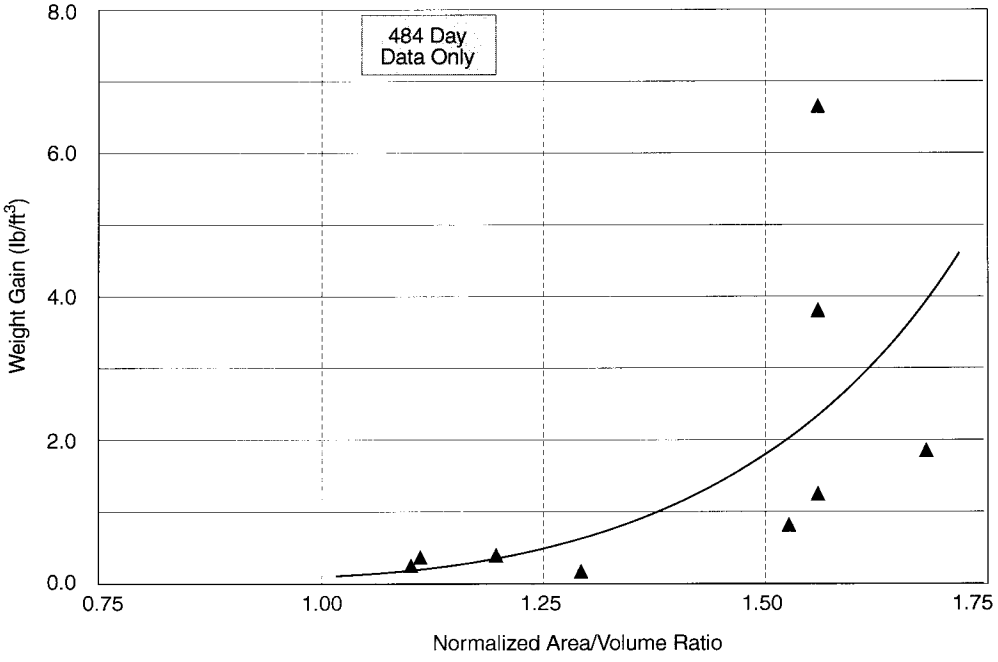


Fig. 26.24 *Fouling vs Pack density.*
Source: TP 93-06 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Q. *Why are low A/V fill designs somewhat resistant to fouling?*

Ans. It is related to water velocity patterns within the fill. Water film speed varies inversely with A/V. Low A/V fills may prevent fouling by providing film velocity in excess of a critical 'attachment velocity' for contaminants. Lower layers offer the lowest film speeds within the pack and hence the highest potential for contaminant attachment.

Q. *How does the fouling vary with pack spacing?*

Ans. Fouling decreases with the increase of pack spacing. Fig. 26.25 shows that spacing decreased fouling rate by a factor of approximately 3 (second and third layer fouling rates).

Q. *Fouling plagues fill. What is the conclusion as to the*
(a) fouling rate
(b) fill design
(c) fill spacing
(d) water quality in controlling fouling of CT fills?

Ans. 1. Fouling is caused by biological organisms capturing suspended solids
2. CT fill fouling exhibits seasonal variation due to seasonal effect on bacterial activities. Winter periods show reduced fouling.
3. No fill is totally immune from fouling. Certain film fills foul at a much higher rate than others
4. The amount of fouling significantly impacts the performance of some film fills while others go relatively unaffected
5. A vertical flute design seems to be essential to achieve low fouling characteristics

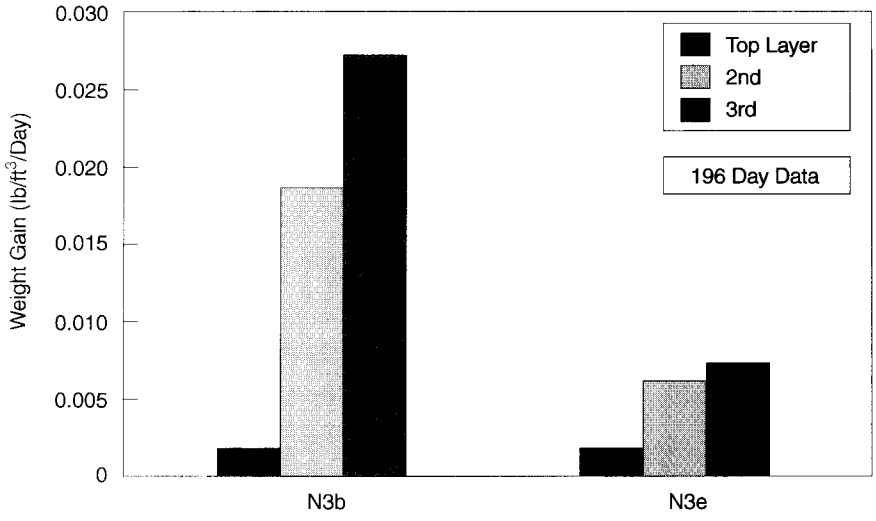


Fig. 26.25 *Comparison of fouling rates over 196-days-of-exposure-date indicates reduced fouling due to spacing of fills.*

Source: *TP 93-06 (Technical Paper/Hamon-Sobelco)*

Courtesy: *Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA*

6. Relatively low A/V fill designs and vertical flute arrangements reduce the potential to foul.
7. For layered fills, fouling is much more pronounced in the lower levels.
8. Separation or spacing of multiple layer pack designs reduces fouling rate.
9. A water treatment program aimed at filtration of suspended solids and control of biological growth is important to at least stabilize fouling and to limit its detrimental impact on the CT performance.

Source Research of Fouling Film Fill— Michel Monjoie; Russell Noble and Gary R. Mirsky Technical Paper No. TP 93-06/Hamon Cooling Towers

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Q. *For several years many cooling towers have been designed with a plume abatement device to reduce or avoid the plume in some weather conditions, mainly in winter. Why?*

Ans. This weds the advantage of the non-visible plume of the dry cooling tower with the advantage of the high-efficiency of the wet cooling tower.

Q. *How does the visibility of a plume arise?*

Ans. Visible plume is the supersaturated matrix of air with microdroplets of water.

Practically, a wet CT is a direct contact heat exchanger designed to transfer heat load from water to air, mainly by evaporation.

The temperature and the humidity of the contacting air stream increase during this heat exchange process, up to the saturation point and beyond. The condensation droplets (dia from 0 to 10 μ) are generated from the saturation point, putting the air conditions in the state of 'supersaturation'. The same conditions are generated in clouds or mists.

The visibility of the plume comes from these condensation droplets, just as they make clouds or mist visible.

Q. *In this context what is meant by making the plume non-visible?*

Ans. Making a plume non-visible means evaporating existing condensation droplets, and avoiding any recondensation during the dilution process of the rejected air in the atmosphere.

Q. *What is a wet-dry plume abatement cooling tower?*

Ans. It is essentially a hybrid cooling tower designed to run without any visible plume during the whole dilution of the rejected air in the atmosphere at some ambient air state for which a normal wet cooling tower gives a visible plume.

Q. *How does the dilution process operate?*

Ans. It goes from the periphery of the rejected air stream to its centre. It gives temperature and humidity gradients in the air stream even if the rejected air is perfectly uniform.

Q. *On which factors does the dilution process depend?*

1. Temperature of ambient air
2. Humidity of ambient air
3. Local wind velocity

Q. *How can the dilution process be represented graphically?*

Ans. It is represented graphically on a psychrometric chart (Mollier diagram) with the straightline joining the point defining the exit air state to the point defining the inlet air state.

Note: This line may not cross the saturation line if a visible plume is to be avoided.

Q. *What are the assumptions on the basis of which the dilution process is represented on Mollier diagram?*

Ans. 1. The atmospheric air temperature and its humidity are assumed to be uniform in the whole dilution process
2. The atmospheric air temperature and its humidity are equal respectively to the inlet air temperature, and its humidity at the CT respectively.
3. The rejected air at the CT exit is uniform in temperature and humidity.
4. The wind velocity has zero effect.
5. Condensation droplets that make the plume visible are generated only when the humidity level goes beyond 100%.

Q. *Is it true that the wet/dry plume abatement cooling tower does not give any visible plume at all?*

Ans. No. These towers may give, for ambient air or operating conditions other than the design point, no plume at the cooling tower exit but a visible plume at a distance from the exit. Sometimes it may give a plume even from the fan exit.

Q. *Why does the plume in a cooling tower become visible at the fan exit?*

Ans. Since misting occurs at the periphery of the discharge air, the plume will be visible from the fan exit.

Design Example: On the Mollier diagram (Fig. 26.26), the plume abatement design point is the exit air at 23°C with 60% humidity (point A) mixed with inlet air of –5°C with 70% humidity (point A′). The straightline joining these two points is tangent to the 90% humidity curve.

Discuss whether there will be visible plume.

If the same tower is operated with an inlet air temperature of –8°C with 100% humidity (point *B′*) what will be the exit air temperature at 80% humidity? Also examine whether there will be any visible plume in this case.

Solution When the cooling tower is operated with inlet air at –5°C with 70% humidity, the mixing of this inlet air with the exit air of 23°C with 60% humidity (point A), the maximum humidity of the air is 90% during the dilution process. Therefore, the cooling tower does not give any visible plume, the humidity of air always being lower than 100% (line *AA′*).

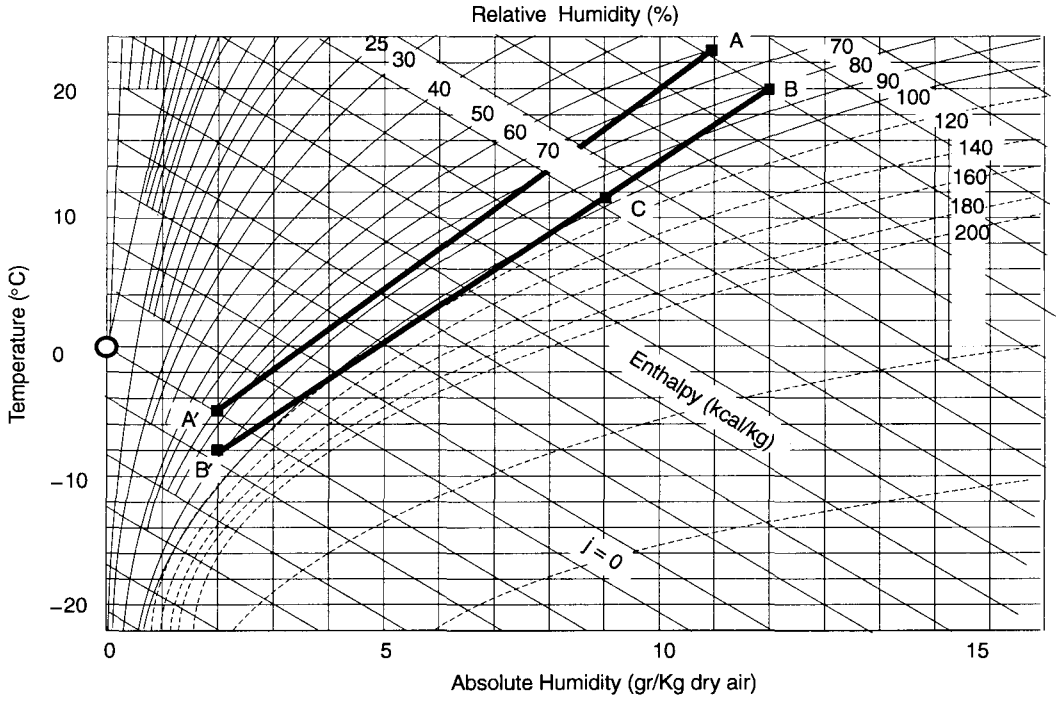


Fig. 26.26 *Graphical Representation of a Dilution Process in a Wet/Dry Plume Abatement Cooling Tower.*

Source: *TP 94-15 (Technical Paper/Hamon-Sobelco)*

Courtesy: *Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA*

The same cooling tower running at an inlet air of –8°C with 100% humidity (point B') will have exit air at 20°C with 80% humidity (point B). The straightline joining these two points crosses the saturation line at point C.

Theoretically the cooling tower has no visible plume at the fan exit (dilution between points B and C), but at a distance from the exit (dilution between points C and B').

Q. *Obviously air with lower humidity and/or higher temperature than the design point, may not have any visible plume. Does it reflect that the hybrid cooling tower is performing well?*

Ans. The visibility of the plume is not a good criteria to check the quality of a wet/dry plume abatement cooling tower unless all the working conditions of the CT viz. flow, range, air temperature and humidity are exactly on the design point.

Q. *Why is great importance attached to the choice of design point of a wet/dry plume abatement cooling tower?*

Ans. The choice of plume abatement design point is very important as it directly affects the size and the price of the wet/dry cooling tower.

Q. *How many types of wet/dry cooling tower are there?*

Ans. There are two basic types of hybrid CT

1. Parallel air circuit type (Fig. 26.27)
2. Series air circuit type (Fig. 26.28)

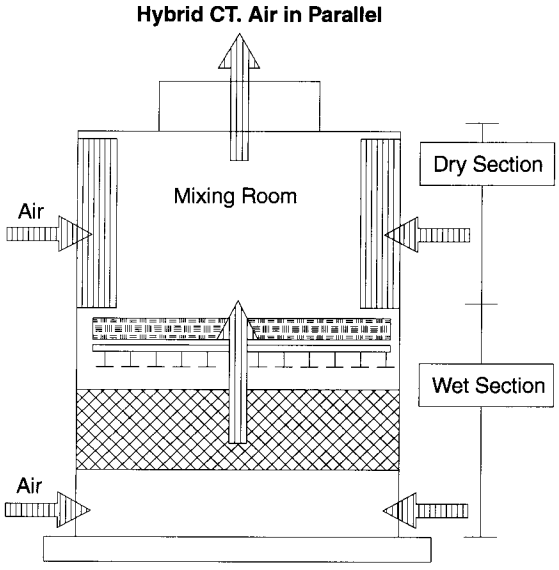


Fig. 26.27 *Hybrid cooling tower. Air in Parallel.*
Source: TP 94-15 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Tower/Bridgewater/NJ 08807-0830/USA

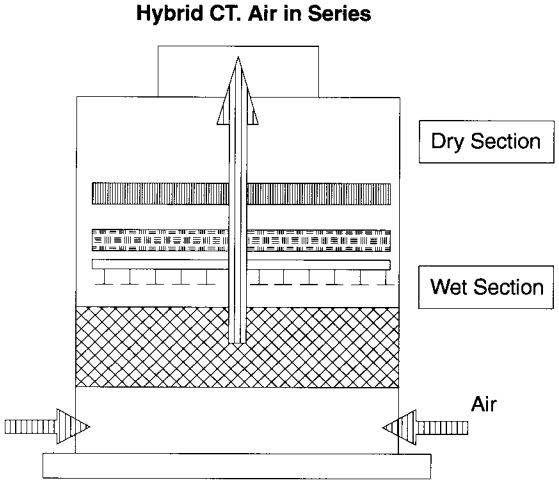


Fig. 26.28 *Hybrid Cooling Tower. Air in series .*
Source: TP94-15 (Technical Paper/Hamon-Sobelco)
Couresty: Hamon Cooling Tower/Bridgewater/NJ 08807-0830/USA

Parallel air circuit type hybrid CT comes in two distinct designs

(a) One having parallel water circuit
(b) Other having series water circuit

Q. *How is the plume abatement in a parallel air circuit type hybrid CT achieved?*

Ans. Plume abatement is obtained by mixing the air from the wet section of the CT with the heated section of the CT.

Q. *How does the 'parallel water circuit' design operate?*

Ans. This design has parallel water circuits for the dry and wet sections—separate water flows to both sections.

This means that the heat loads for both sections are supplied from two different units.

The visibility of the plume can be adjusted with the temperature supplied to the dry section.

Q. *How does the 'series water circuit' design operate?*

Ans. The hot water circulating flow coming from the process passes first, totally or partially, in the dry bundles and then in the wet section of the cooling tower (one heat load for both sections).

Q. *How is the flow of air through the dry and wet sections of this 'series water circuit' type CT regulated?*

Ans. By installing

(a) moving screens
(b) shutters
(c) garage doors
(d) movable louvers

in front of the dry or/and the wet section.

Q. *What is the advantage of installing such air-flow regulators?*

Ans. This rewards some flexibility to product against freezing of the cooling tower (in cold countries) and to get better thermal performance when it is necessary.

Q. *If its dry section is shut off, what will happen to the wet/dry tower?*

Ans. It will transform the wet/dry cooling tower to a 100% wet cooling tower.

Q. *How is the operational flexibility induced by the moving screens realized?*

Ans. Adjusting the screens alters the conditions of the thermal operation of the tower.

With the screens of the dry section fully open, the CT attains zero flexibility in the plume abatement. While shutting the screens of the wet section prevents the entry of frigid air, thus avoiding freezing of cooling water.

Q. *What is the difference between the parallel water circuit design and the series water circuit design of hybrid CT as regard to the plume abatement design point?*

Ans. **Parallel Water Circuit:** Since the plume visibility can be adjusted with the temperature supplied to the dry section, the plume abatement design point must be based on the given heat load in the dry section (temperature and flow).

Series Water Circuit: Since the conditions of the thermal operations can be varied by adjusting the screens, the plume abatement design point must be associated with a given thermal performance.

Q. *How is plume abatement obtained in the series air circuit type of hybrid tower?*

Ans. Plume abatement is obtained by heating the air of the wet cooling tower with dry bundles located above the drift eliminator.

The visibility of the plume can be adjusted with the temperature supplied to the dry bundles that receive heat load from an external source at a high temperature level, viz. steam or hot water.

Q. *Adjusting the plume visibility by adjusting the heat input to dry bundles will affect the thermal performance of the CT. Is it true?*

Ans. No. Such a design doesn't affect the thermal performance of a cooling tower while the plume visibility is adjusted.

Q. *What do you mean by humidity plume performance curve?*

Ans. It is a typical plume performance curve, of hybrid cooling towers, showing maximum plume humidity and moisture content during the dilution process (Fig. 26.29).

The above graph (showing the maximum plume relative humidity as a function of the inlet dry bulb temperature with inlet relative humidity appearing as curve parameters) is drawn for one working condition of the cooling tower. And a set of such curves corresponding to several working conditions may be available from the cooling tower supplier.

Q. *What are the working conditions that must be specified on the plume performance graph?*

Ans.

1. Type of water circuit, i.e. whether parallel or series air circuit with full or partial flow in the dry section
2. Waterflow on the dry section (as and when applicable)
3. Waterflow on the wet section
4. Cooling range
5. Water or steam temperature entering the dry section (when applicable)
6. Position of the louvers or garage doors (when applicable)

Q. *How is the value of maximum plume relative humidity obtained?*

Ans. It is calculated by using a psychrometric chart as being the value of the humidity curve tangent to the straightline joining the inlet air state to the exit air state.

Q. *For some air conditions, the above straightline joining the inlet air state to the exit air state may cross the saturation line giving rise to supersaturated humidity state that corresponds to a liquid water content in the air, i.e. for some weather conditions, the exit air of a wet/dry plume abatement cooling tower may be in a supersaturated state. However, most of the*

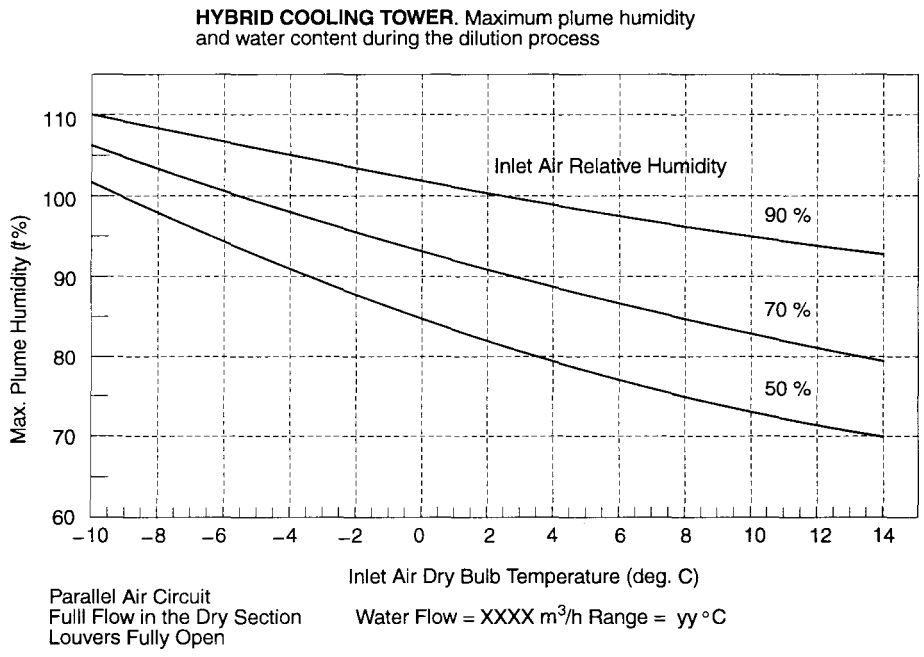


Fig. 26.29 *Typical plume performance curves of a hybrid cooling tower.*
Source: TP 94-15 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

psychrometric charts do not consider the supersaturated curves.

Is it possible to have direct comparison of test result with the expected value given by the plume performance curve?

Ans. Using such a chart, it is impossible to directly compare any test results in the supersaturated air state with the expected value given by the plume performance curves.

Q. *How the air relative humidity in the supersaturated zone of the psychrometric chart calculated?*

Ans. The procedure to draw the 'supersaturated' relative humidity curve is illustrated through the following example showing how to draw a curve of 120% relative humidity.

Step-I: Take one arbitrary air temperature for example:

$$T = 20°C$$

Step-II: Read the absolute humidity on the saturation line corresponding to this air temperature:

For $T = 20°C$, $W_s = 15.1$ g/kg dry air (Point A)/ See Fig. 26.30

Step-III. Multiply the absolute humidity by the 'supersaturated' humidity for which you want to draw a curve:

For 120% R.H., $W_a = 15.1(1.2) = 18.12$ g/kg (Point *B*)

Step-IV. Plot on the air temperature line (for instance 20°C) the calculated 'oversaturated' humidity (Ex. : 18.12 g/kg). This gives one point of the 'supersaturated' humidity curve.

Step-V. Repeat the same procedure for other air temps. (arbitrary).

Step-VI. Draw the curve with these points.

Problem: What will be the relative humidity at point *C* in Fig. 26.30?

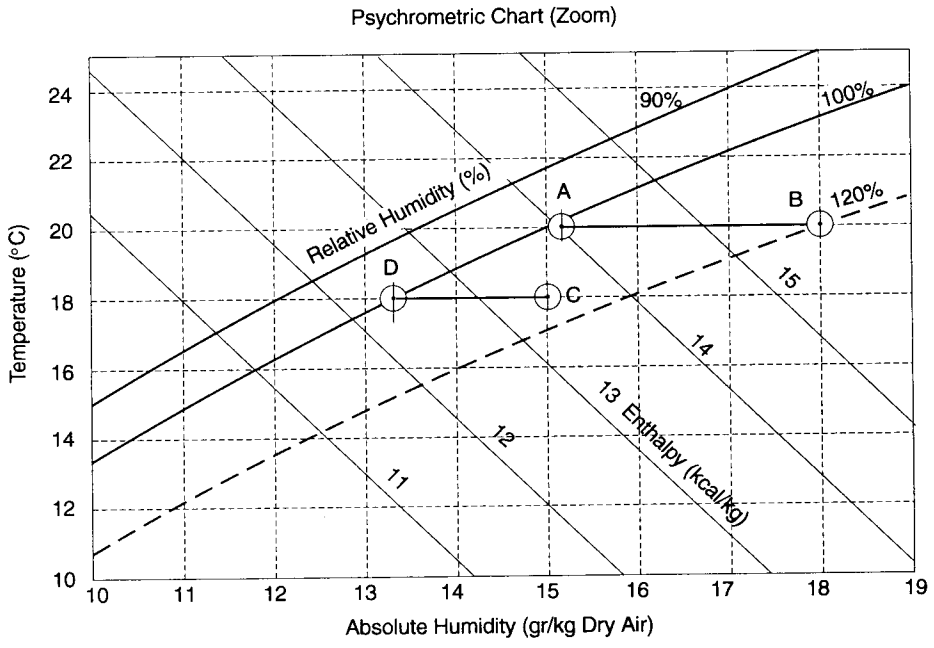


Fig. 26.30 *Psychrometric chart showing the curve of 120% R.H. drawn (Dotted line).*
Source: TP 94-15 (Technical Paper/Hamon-Sobelco)
Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Solution Read the temperature and the absolute humidity from the Y-and X-coordinates of the psychrometric chart:

For point C, $T = 18°C$

$W_a = 15$ g/kg

Now read out the absolute humidity on the saturation line corresponding to the air temp.:

For $T = 18°C$

$W_s = 13.4$ g/kg (Point D)

Finally, the supersaturated humidity is the ratio between both humidities:

$RH = W_a/W_s = 15/13.4$

$= 1.119$ i.e. 111.9% ***Ans.***

Source: Testing Procedure for Wet/Dry Plume Abatement Cooling Towers—Michel Monjoie and Jean-Pierre Libert

(Technical Paper TP 94-15/Hamon-Sobelco)

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Q. *What are the various elements of a modern cooling tower?*

Ans. 1. Fans.
2. Drift eliminators
3. Water distributors
4. Fill

Q. *What is the basic design principle of modern C.T. fans?*

Ans. The fan blades are fabricated from fibreglass-reinforced epoxy designed in the same way as aircraft propellers with the purpose of churning maximum cooling air through the tower.

Now a velocity recovery (VR) fan stack is employed to produce a synergistic effect—it gives approximately 7% more air.

Q. *How is this VR effect enforced?*

Ans. This VR effect works on the principle of venturi, i.e. if you increase the velocity of a fluid, its pressure will decrease and consequently its effective volume will increase.

To apply this principle, the fan stack is designed similar to a venturi with the narrow diameter at the fan blade plane of rotation and flaring the top out with the effect that the air velocity is increased through the waist of the stack. The reduced pressure then sucks in greater volume of cooling air through the tower.

Q. *What does this flared top diameter do?*

Ans. It reduces the back-pressure of the exit-air-velocity that the fan must work against.

Q. *What should be the minimum fan stack height so that the VR system becomes effective?*

Ans. 1.8m (6 ft.)

The stack height increases with the height of the flared fan cylinder.

Q. *What is the least expensive way to increase the throughput of air through a forced-draft C.T.?*

Ans. To pitch the fan blades at the maximum angle permitted by the motor plate amperage.

Q. *What are the other methods to increase air flow?*

Ans. By installing

1. Velocity recovery fan stack
2. Larger motor
3. Larger fan
4. Both larger fan and motor

Q. *What typical mechanical problems are encountered in the operation of C.T. fans?*

Ans. 1. Unbalance of drive shaft.
2. Unbalance of fan at low speed
3. Defects in gear bearing
4. Defects in gear
5. Corrosion of the gear/fan mounting structure
6. Loosening of the structure mounting bolts

Q. *What may be the outcome of these problems?*

Ans. They may lead to catastropic failures and expensive repair. Repairing of a C.T. fan means a 4 to 5 days downtime loss. Steam generation and power production usually get hampered during these repairs.

Q. *How can these problems be avoided?*

Ans. By periodic inspection and routine monitoring of cooling tower fans.

Q. *What challenges are being faced in the monitoring of C.T. fans?*

Ans. The very configuration of the machine itself and its physical location make monitoring difficult.

Of course, with the advent of advanced monitoring instrumentation, things have become much easier and economical to either periodically or continuously monitor the condition of the CT fans.

Q. *Do C.T. fans have any in-built safety device?*

Ans. Traditionally cooling tower fans come fitted with vibration cut-off switches that shutdown the unit when vibration exceeds a preset level.

Q. *How does it work?*

Ans. It works on a ball and spring mechanism to acutate when excessive vibration is sensed.

Q. *Then why should condition monitoring be done?*

Ans. Vibration switches have a track record of unsatisfactory service life and have failed to actuate under emergency conditions. Severe mechanical damage has frequently been attributed to defective vibration cut-out devices. Operators receive little early-warning of mechanical failure.

Moreover, vibration data from the motor does not reveal the condition of the gear box. Flexible bushings at the hub and 6 m of drive shaft all but isolate the gear box from the motor.

Q. *How is data acquired in advance to avert major failures?*

Ans. Many facilities to monitor the condition of fan/drive motor are available. Since the fan motor is easily accessible, it is quite easy to install transducers for continuous monitoring or to take periodic vibration readings with the help of a vibration meter or data collector.

Likewise, many facilities are available to monitor the condition of the gear boxes. Usually, the transducers are located on the gear box and the transducer output is routed to signal the conditioners or transducer switch located outside the machinery. By wiring transducer outputs to a switch box or signal conditioner, it becomes quite convenient to take readings with a portable data collector. (Fig. 26.31)

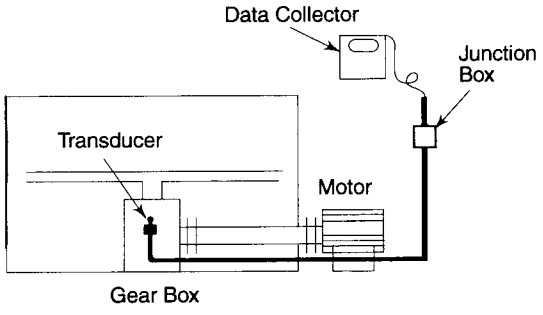


Fig. 26.31 *Cooling tower fan set*

The signal reported by the transducer can also be recorded by vibration meters, real-time analyzers and magnetic tape recorders. The signals from several transducers can be routed through a single switchbox making it possible to record the vibration data of several machines simultaneously on the central control panel. This is an added advantage to the technicians.

When this type of monitoring scheme is implemented, vibration measurements can be recorded and trended on a regular basis (weekly or monthly), as part of the predictive maintenance program. In case the trends indicate a possible problem, the technician should go for the spectra data to track down the root of the problem.

Q. *What are the most common faults encountered with tower structure?*

Ans.

1. Decaying lumber
2. Deteriorated venturis
3. Corroded fasteners

Q. *What are the mechanical problems encountered in the operation of C.T. fans?*

Ans.

1. Fan unbalanced
2. Cracked blades
3. Blades improperly pitched
4. Loose blade assembly on the hub
5. Non-uniformity in blade-venturi clearance
6. Water collected inside blades

Q. *What are the problems associated with the gearbox?*

Ans.

1. Damaged pinion gear
2. Damaged low-speed gear
3. Defective input shaft bearing
4. Defective shaft bearing
5. Corroded structural supports

Q. *What are the mechanical problems that plague the drive shaft?*

Ans.

1. Unbalanced shaft or coupling
2. Damaged coupling
3. Shaft bending
4. Cracked shaft
5. Misalignment of motor-gearbox

Q. *What are the general problems that arise in the operation of C.T. fan motors?*

Ans.

1. Faulty bearings
2. Unbalanced armature
3. Loose rotor bars
4. Worn endbell housings
5. Soft foot
6. Single phasing

Case Study The vibration spectra of a C.T. fan motor is shown in Fig. 26.32a and that of the fan gearbox obtained simultaneously is shown in Fig. 26.32b.

Q. *What can you infer from these diagrams?*

Ans. Figure 26.32a indicates that the motor is operating, from the vibration point of view, within the permissible range of vibration levels.

The gearbox (fan) spectral data (Fig. 26.32b) on the other hand tell a different story. The predominant vibration frequency, as indicated by the 3rd harmonic, is 405 cpm which is 3 times the fan running speed. This high 3X vibration indicates mechanical looseness.

Q. *What should be done under these circumstances?*

Ans. The fan should be taken shutdown. The gear/fan assembly is to be removed for inspection and repair.

It is very likely that some cracks are there which cause loose hub assembly.

Fact After the fan was taken out of service and the gear/fan assembly was inspected, severe cracks were actually noted on the fan hub assembly.

The hub was repaired and the fan returned to service. The spectrum of gearbox after repairs is shown in Fig. 26.33.

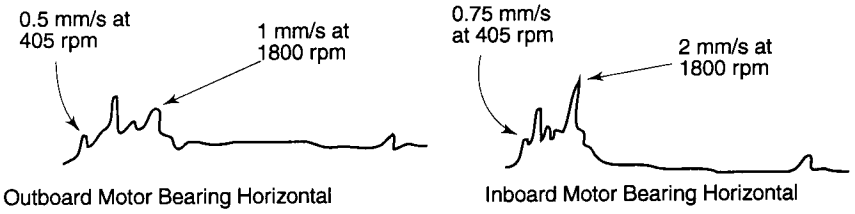


Fig. 26.32(a) *Motor vibration spectral data*

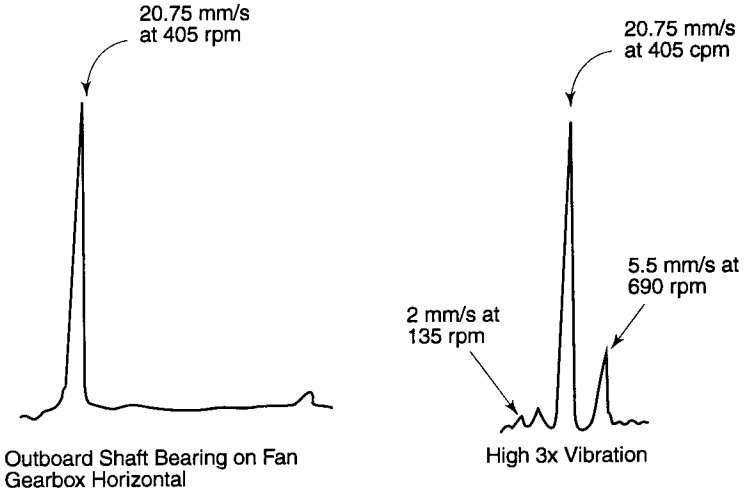


Fig. 26.32(b) *Gearbox spectra data.*

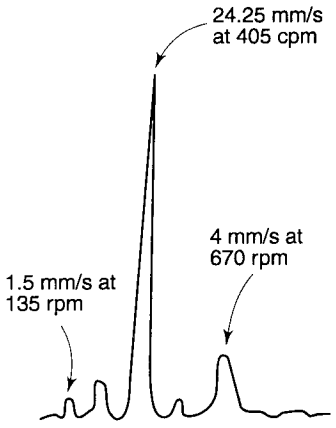


Fig. 26.33 *Gearbox spectral report after repairs.*

Q. *What does this spectrum suggest?*

Ans. The vibration signature of the gear/fan assembly is very high after repairing. It is still higher than what earlier data revealed. Such a high degree of vibration is not permissible. Probably the fan hub assembly deteriorated during/after the repair.

Note: The fan was taken out of service, the gear/fan assembly was again removed and inspected whereupon a severe crack was observed causing insufficient hub-to-shaft contact. The shaft and hub were lapped to a proper fit and reinstalled. The fan was lined up and the spectral data of gear/fan assembly was recorded. (Fig. 26.34)

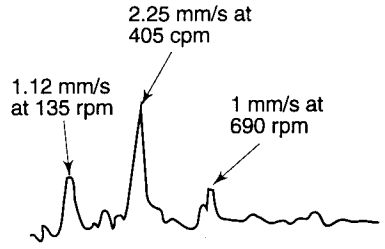


Fig. 26.34

Q. *What do you infer from the spectral data of the gear/fan assembly?*

Ans. The gear/fan system, after the hub-and-shaft repair, operated within acceptable vibration levels.

However, a fair level of vibration (2.25 mm/s) at three times the fan running speed still remained.

Q. *Why is residual vibration still there?*

Ans. It might be due to tower resonance.

Q. *If the vibration monitoring of the fan and gearbox were not carried out what could have been the eventualities?*

Ans. The fan would loose, within a very short time, one or two blades hurling into the draft tube. The resulting total imbalance would destroy the fan thereafter, inflicting considerable loss in terms of damage and downtime.

Q. *What is the operating speed of the C/T fans?*

Ans. The fans normally operate in the range 72–180 rpm depending on load requirements.

Q. *Why it is convenient to display vibration recordings of C/T fans and gearbox assembly in the control room?*

Ans. C/T poses a safety risk, due to exposure to chlorine and other chemicals, to operating personnel taking periodic virbation readings on cooling tower fans. Therefore, continuous monitoring systems with vibration readings displayed at protected locations like the central control room, enable the fans to be monitored without risking the safety of personnel.

Q. *The Monsanto Chemical Company monitors 29 cooling tower fans on three different cooling towers in Pensacola, Floride (USA). Using a dual digital display mode a continuous monitoring system performs a 'watchdog' monitoring function to read the vibration levels on multiple fans in each cooling tower.*

One readout is filtered for low frequency velocity [1 to 100 Hz] and the other readout is filtered for higher frequency [100 to 1000 Hz].

1 Hz = 1 cycle per second

Which frequency range is most sensitive to fan, motor and drive shaft vibration?

Which frequency range is more sensitive to gearbox bearings and gearmesh faults?

Ans. ***Low frequency range:*** 1–100 Hz is most sensitive to fan, motor and drive shaft vibration.

Higher frequency range: 100–1000 Hz is most sensitive to gearbox bearings and gearmesh faults.

Q. *How is the transducer mounted on the gearbox?*

Ans. It is stud-mounted on the input pinion gear housing.

Q. *What factors should be considered in selecting the type of transducer?*

Ans. Operating conditions as well as environmental conditions.

In the cooling tower environment, the transducer is exposed to such demanding atmosphere as very high air velocity, 100% humidity and corrosive chlorine that attacks steel supports and instrument cables.

Q. *Under the onslaught of this aggressive environment, what is the useful service life of a transducer?*

Ans. Six months to four years.

Q. *On which factors does the reliability of a transducer depend?*

Ans. It depends on

(a) How well the transducer casing is sealed
(b) How frequently it is removed
(c) How it is replaced for the maintenance of the drive shaft and gearbox assembly.

Q. *Which one of the two*

I. accelerometer integrated to velocity
II. accelerometer integrated to acceleration is more reliable in monitoring the mechanical conditions of cooling tower fans?

Ans. The accelerometer integrated to velocity has proved to be more reliable.

Q. *Why?*

Ans. This is because the resulting displacement signals, when acceleration is electronically integrated twice, are oversensitive at low frequencies causing frequent false alarms.

Q. *It is a common practice to install a 24-volt surge protection system for the accelerometers and monitoring system. Why?*

Ans. This is to safeguard the accelerometers and monitoring system against lightning strikes.

Q. *Why this is required since the C/T deck is already provided with lightning rods?*

Ans. Lightning rods installed on the C/T decks do not prove to be sufficient protection.

Note: *During one thunderstorm, the Monsanto facility suffered from bad damage. The lightning struck within 90 m of the C/T and damaged several accelerometers and monitors.*

Q. *Where are these surge protectors located?*

Ans. The surge protection isolation blocks are placed at the first junction box where the accelerometer lead cable goes outside to the cooling tower deck.

Q. *Certain operating speeds of cooling tower fans are unacceptable for sustained operation. Why?*

Ans. A C.T. fan is a variable frequency drive machinery which operates from 72 to 180 rpm depending on load requirements. However, due to structural resonances in the tower, certain operating speeds are unacceptable for sustained operation. These resonating frequencies released by the fan rotating over the prohibitive range of rpm (critical speed) vary because of looseness in the C.T. support timbers and corrosion of steel members and subject the entire set-up to unwanted, high vibration deteriorating the system over time.

Q. *What should be done to avoid this?*

Ans. Analytical vibration instrumentation is absolutely essential to ensure safe operation over these speed ranges.

Q. *What is drift?*

Ans. Water droplets suspended in air and discharged from the cooling tower is called drift.

Q. *Why it is formed?*

Ans. Drift is the byproduct of the evaporative cooling process taking place in the C.T.

Q. *Why is drift unwanted?*

Ans. Drift escapes the system as mist or vapour and that means loss of cooling water which must be supplied as make-up.

Q. *Can it be eliminated?*

Ans. No. Drift cannot be eliminated from the discharge plenum.

Q. *What are the basic differences between the wood slat drift eliminators and cellular drift eliminators?*

Ans. The old fashioned wood salt drift eliminators generated high pressure losses. They are prone to allow suspended water droplets to escape at higher air velocity operating modes.

Cellular units can operate at higher velocities producing greater levels of cooling and drift loss remains below legal minimums.

Q. *What is the mode of water distribution in C.T.?*

Ans. In conventional systems, drop-through orifices are used. Each orifice drops a solid column of water on a lattice work of the wood whereupon the water gets splashed over the top of the fill. This is an outmoded mechanism of water distribution.

In cellular units the spash decks are replaced with efficient redistribution decks or target orifice nozzles. In either case, the water gets more evenly distributed at the tower top with the effect that the entire height of the tower is available for cooling rather than having a part of it functioning only to break up and splash the water.

Q. *What is the fundamental advantage of cellular fill over the conventional wooden splash-bar?*

Ans. With the conventional wooden splash-bar slats, only the exterior surface of a water droplet is cooled. Whereas a cellular fill stretches water droplet into a thin film that is cooled faster and colder by air at lower operating pressure.

Q. *What operational difficulties are encountered with the splash-grids?*

Ans. They get usually broken and dislodged from their position after a few years of service.

Q. *What is the advantage with a target distribution nozzle?*

Ans. Target distribution nozzles with built-in splashers ensure positive uniform water distribution automatically.

Q. *What is the advantage of retrofitting a C.T. with cellular fill?*

Ans. It dramatically enhances the cooling tower's performance.

It can reduce the water temperature by 6 to 8°K which in turn increases the capacity of some towers by as much as 50%.

Q. *What is the mode of air-water flow in C. Towers?*

Ans. Both the conventional cooling towers with wooden splash-bar slats and modern cooling towers fitted with cellular fill can operate with air-water in crossflow

air-water in counterflow configuration.

Q. *What is the basic design problem associated with conventional cooling towers with wooden splash-bars?*

Ans. The C.T. must be designed with the objective to cool the water down to the specified temperature range to take care of the process heat load downstream. However, with cooling towers provided with conventional splash-bars, only the exterior of the water droplets gets cooled as the water bounces from slat to slat on its way down, irrespective of whether the air-water streams are in crossflow or counterflow. This requires a very

long vertical travel to cool down the water to design conditions. Greater the height of the means more wood there should be in the tower. More wooden slats invite higher pressure drop requiring larger motor wattage and fan diameter.

Q. *Why is the pressure drop per m^3 of cellular fill much higher than that with wood fill?*

Ans. The cellular fill is much more compact than wood fill. Both the air and water have to share the same tortuous flowpath in cellular fill towers. On the contrary, in the woodfill conventional towers, there is much more void space. This explains why the pressure drop of air is much less in woodfill towers than in more compact cellular units.

Q. *Despite higher pressure drop in cellular fill towers, this type of tower is mostly favoured. Why?*

Ans. Cellular fill is very compact and it requires less depth of cellular fill to produce the same or greater cooling results. Therefore, it generates much less total pressure drop providing a greater volume of usable cooling air.

Square-spray nozzles and cellular fill can together significantly boost water capacity and lower water temperature at the C.T. outlet.

Q. *Why water is cooled more rapidly in cellular units than in C.T.s with wooden splash-bar slats?*

Ans. Water droplets raining down through a maze of wooden splash-bar are solid-spheres. Since a sphere occupies the least surface area for a given volume, only a minimum surface area of suspended droplets gets exposed to the upflowing air current. Therefore, the heat and mass transfer mechanism remains restricted only to the external surface of the droplets. And it will take considerable lapse of time to cool the interior of the droplet.

On the contrary, the cellular fill stretches the water droplets, falling on them from distributor nozzle. into a stretch of film increasing its exposure to air (counterflow or crossflow) staggeringly. Because of enhanced gas-liquid contact, water gets more rapidly cooled and over a short flowpath.

Q. *Cellular fill is very expensive. Is it economical to revamp a conventional C.T. with wood splash-bar grid by a cellular fill?*

Ans. Cellular fill is decidedly costlier than the wooden splashbar system. However, it ensures a drastic improvement in C.T. performance that begets a rapid payback.

Q. *What is V-bar fill?*

Ans. It is state-of-the-art plastic extruded bars putting in combination the splash and film-cooling configuration producing colder water than conventional wooden slats.

Q. *What is the reason for high heat transfer of the 'V' configuration?*

Ans. When these V-bars are installed with the apex up, a part of the cascading water droplets is turned into a thin film of water sliding down the sides of the bar. This enhances the heat transfer across the gas-liquid interface resulting in rapid cooling of water film than solid water droplets. This film cooling is greatly enhanced when the bars are installed parallel to the airflow rather than at right angles to the entering air.

Q. *Why the air flowing parallel to the V-bars ensures more cooling than air flowing right angles to the V-bar?*

Ans. Air flowing parallel to the V-bars facilitates rapid spreadover of the falling water droplets into a film of flowing liquid on the sloping sides of the bar, whereas the vertical airflow impedes the water spreadover down the slopes of the V-fills. (Fig. 26.35).

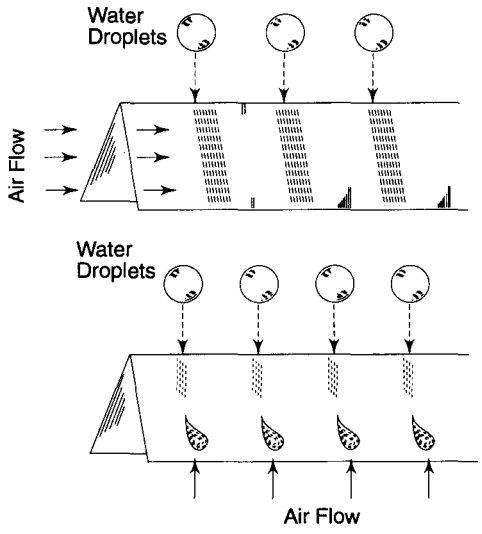


Fig. 26.35 *Air flowing parallel to the V-bars (Top illustration) brings about more liquid spreadover of falling water droplet than air flowing vertically to the V-bars (Bottom illustration).*

Q. *What are the main characteristics of a C.T.?*

Ans.

1. **Hydraulic load**, i.e. the throughput capacity G, t/h of cooled water.
2. **Heating load**, i.e. capacity

$$Q = G \cdot C_p \cdot \Delta T \text{ in J/h}$$

where, $\Delta t = t_2 - t_1$ = temp. gradient in C/W

t_1 = initial temp. of water at C.T. inlet, °C

t_2 = final temp. of water at C.T. outlet, °C

C_p = specific heat of C/W, J/kg.°C

3. **The sprinkling intensity**, G/F, $m^3/(m^2.h)$

where, F = effective surface area of the fill, m^2

Problem 26.1 Determine the sprinkling area for a cooling tower with throughput capacity of 10000 m^3/h.

Inlet water temp = 34°C

Temp. gradient of cooling water = 10°C

Dry-bulb air temp. = 27°C

Relative humidity = 80%.

Solution Use is made of two following nomograms to compute cooling tower calculations.

Step-(I) Temperature correction (ε_T)

From the TEMP. CORRECTION vs. DRY-BULB AIR TEMP. graph (Fig. 26.36)

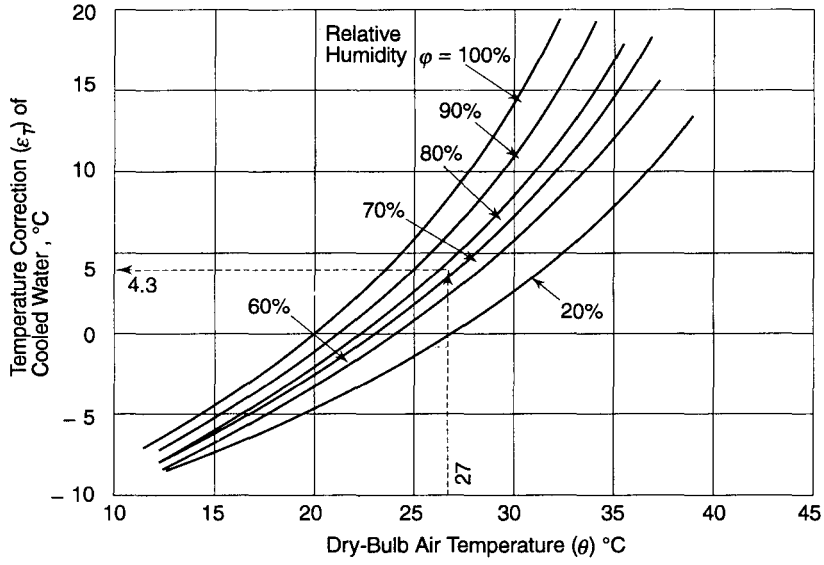


Fig. 26.36 *Temperature correction vs. dry-bulb air temperature graph.*

ε_T = 43°C at ambient air (dry-bulb) temp. of 27°C

Step-(II) Reduced temperature of cooled water

Introducing the above temperature correction, we get the final C/W temp. at the tower outlet

$$= 34 - 4.3 = 29.7°C$$

Step-(III) Sprinkling intensity

From the C/W OUTLET TEMP. vs. SPRINKLING INTENSITY graph, (Fig. 26.37) we get

$$G/F = 5.25 \text{ m}^3/(\text{m}^2 \cdot \text{h})$$

Step-(IV) Effective surface area for fill

$$F = 10\,000/5.25 = 1904.76 \simeq 1905 \text{ m}^2$$

Ans.

Q. *The purpose of a CT is to remove heat from water. However, it must be environmentally compatible too. Today, any power plant design almost invariably includes a cooling tower. Why?*

Ans. The reason is to prevent large thermal discharge into the local water source, viz. river, lake, bay or ocean.

Q. *Because of concerns for the environment, what factors are to be considered in the design of a CT?*

Ans. The environmental considerations not only affect the type of tower to be utilized, but also design materials, components and accessories, and even the manner as to how the materials are to be handled. The following factors are to be considered from the environmental point of view.

1. Chemical and mineral composition of the discharged water
2. Effects of the discharge plume
3. Quantity of water evaporated
4. Temperature of the discharge water
5. Noise generated due to CT operation
6. Conservation of the electric power Consumed by the Fans and Pumps
7. Aesthetics
8. Flue Gas injection into natural draft towers from scrubbers

Q. *How does the environmental concern arising out of the chemical and mineral composition of the discharge water affect a CT design?*

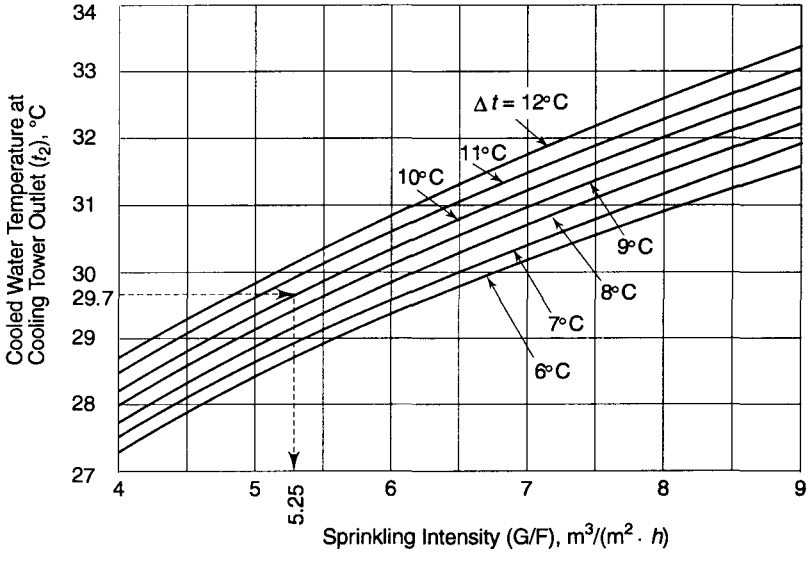


Fig. 26.37 *C/W outlet temp. vs. sprinkling intensity graph.*

Ans. The circulating water stream in the CT system is usually chemically treated. Previously dissolved minerals get concentrated, preservative treatment and other chemicals are added, and the water temperature increases. Therefore, the materials of construction of CT hardware must be resistant to the water treatment program and the corrosive effects of the concentrated minerals and chemicals.

In an evaporative tower system, a small part of the circulating water is always drained as CT blowdown. This blowdown water must be monitored of its chemicals and minerals concentration and sometimes retained in a holding pond before the water is finally discharged.

Sometimes, because of the chemical content of the 'new' water it cannot be discharged outside the factory boundaries. This is the case of facilities with 'zero discharge' requirements.

If drained to a natural water basin, CT discharge with rich load of minerals and biocides will disturb the ecology and may even upset the aquatic life of natural reservoirs.

These kinds of considerations have or could cause changes in the material of construction of CT hardware, for example, to avoid wood preservative treatments which leach out of the wood, CT constructions are now increasingly made of fiberglass, coated steel or concrete structures substituting more economical pressure treated wood.

Q. *How does the discharge plume become an environmental concern?*

Ans. Plume changes visibility on access roads, public roads and inflicts interference to aircrafts if the CT lies in an approach path to an airport. These assume serious proportions during the winter months. Also in cold climate installations, there arises the potential danger of freezing or condensation of plume on local roadways.

Q. *How does the CT design modification reduce the plume effect?*

Ans. Design modifications are made to components which can elevate the plume level e.g. by fan stack extensions.

Another way is to use a natural draft tower.

Another viable technique is to install a plume abatement CT, i.e. to desaturate the discharge air to eliminate the visibility of the plume. This reduces near field effects.

Q. *How does the CT 'drift' become an environmental concern?*

Ans. Drift contains salts and minerals that exercise their effects on local vegetation, soil contamination and pose hazards to persons, automobiles, or plant equipment (e.g. flashover on the transformers in the switchyard adjacent to CT). Freezing of the droplets on local roadways is also a concern in cold climates.

Q. *What design modification is necessary to mitigate 'drift-effect'?*

Ans. This requires the installation of improved versions of drift eliminators. These high efficiency retrofits are available for use in all cooling towers. These eliminators, of course, add pressure drop to some extent, slightly increasing the consumed power or reducing the cooling effectiveness.

Q. *How is the quantity of water evaporated and to some extent, blowdown, become an environmental concern in the design of a CT?*

Ans. This is particularly a cause of concern in arid areas where water is scarce and the quantity of water available from wells varies seasonally and requires to be rationed or proportioned.

Q. *How can this problem be redressed through CT design modification?*

Ans. Variation of seasonal water consumption can be marginally accommodated by using variable speed motors or adjustable fans. The utilization of finned tube heat exchangers as in a dry/wet CT or a dry tower with a wet tower is the only

means to significantly curtail water consumption (evaporative cooling is eliminated or minimized).

Complete elimination of water consumption can be achieved by using dry towers or air cooled steam condensers.

Q. *How does the temperature of discharge water become an environmental concern?*

Ans. In certain situations it is permissible to return the CT discharge to the original body of water, as in an open cycle. In this case the concerns are for the effects of thermal loads on the aquatic life in that body of water and damage to the fish population caused by the pumping equipment.

Note: *EPA restricts the discharge water temperature to a certain permissible range and the offenders are charged with a penalty fee or forced to operate the facility at reduced capacity or to be shut down.*

Q. *What design modifications are incorporated to avoid this unwanted thermal load of CT discharge?*

Ans. Coolers are installed in an open cycle. However, these systems are frequently characterized as marine life and vegetation presentation which fouls the piping and fill of the CT.

Therefore, these systems must incorporate cleaning and removal facilities to avoid fouling. Thermal contingencies may have to be provided to avoid having the discharge temperature limits exceeded.

Non-fouling film fill or splash fills must be installed when fouling is anticipated. Cleanout systems, such as flush valves, must be incorporated. Extra cells may have to be procured to permit cleaning while in service.

Q. *How is noise produced during CT operation?*

Ans. Noise in a CT is generated from the water slashing effect and by the mechanical equipment, i.e. fan, motor, and gear reducer.

Q. *How can the 'noise' become an environmental concern?*

Ans. Usually a CT is located close to the boundary line and away from the main buildings of the factory. So it is required to enforce a noise emission limitation both inside the plant to safeguard worker safety and at the plant boundary to reduce noise pollution level to the adjacent locality.

Note: *In the United States, OSHA issues noise regulations to ensure inplant workers' safety, while EPA, DEP issue noise emission limitations at the plant boundary.*

Q. *What measures are adopted to attenuate the noise level?*

Ans. Each noise source can be attenuated a variety of ways or the whole tower can be attenuated using mufflers or attenuators.

Anti-splash devices are installed to muffle the noise.

Machine noise is reduced by using slow speed fans, high efficiency or multiple pole motors, high quality gearing, multiple gear reductions, noise enclosures around the motors. The ultimate is the incorporation of acoustic baffles around the air inlet and over the fan discharge.

To reduce noise level at the boundary line, planting of woods to produce a non-reflective green belt around the property line is done.

Q. *How can the electricity consumed by the fans and pumps be reduced?*

Ans.
1. By installing high efficiency models.
2. By selecting the proper fill media. Film fills require less pumping height thus reducing the operating power of the circulating water pumps.
3. By controlling fan speed and fan pitch. Substantial quantity of electric energy can be saved this way and also by incorporating variable speed motor controllers, variable speed hydraulic drives, and hydraulically variable fan blades.

Q. *Emission control of the flue gas discharged from the combustion process of coal burning has become a global concern. Various new technologies are available for this. The latest among them is the FG injection into the natural draft towers. How does this scheme operate to ensure 'environmentally clean' discharge?*

Ans. In countries like Germany, the flue gas is scrubbed into existing power generating units to reduce the load of flyash and acid vapours further. However, this cools the flue gas which whereupon looses its buoyancy and as a result it does not possess enough 'lift' to get exhausted through the chimney. To tide over the situation the existing natural draft tower is called upon to 'pull' the flue gas from the scrubber. This not only dilutes the exhaust stream into the atmosphere above the power plant but also makes a second round of elimination of flyash and corrosive vapours.

Q. *What modifications are made to accommodate this feature, i.e. FG injection to a ND Tower?*

Ans. 1. Providing fiberglass ducts from the scrubber into the tower above the drift eliminators
2. Installing a gas diffuser above the drift eliminators
3. Modifying the internal structure to support the diffuser
4. Coating all the concrete superstructures with acid resistant spray or coating
5. Installing of low ΔP fill to maintain and/or improvise the efficiency of the CT.

Q. *Why is mechanical draft type CT constructed with Douglas Fir very popular in the United States?*

Ans. This tower is most efficient and economical. There are counterflow and crossflow types with film or spash fills. Standard drift rates as low as 0.0002% are achievable. Cooling capability is very high.

Note: *Cooling capability is measured as approach of cold water temperature to ambient wet bulb temperature.*

Q. *How can such a tower be an environmental concern?*

Ans. The wood used in the construction of such tower is usually treated with preservative chemicals. These chemicals can leach out and are discharged in the blowdown. This blowdown water is environmentally detrimental.

Q. *What is the life expectancy of CTs made of wood?*

Ans. Expected life varies and can be 10 to 20 years for Douglas fir. Whereas 40 years life has been logged on redwood structures. Redwood has been used with and without pressure treatment.

Q. *Why is the number of wood structures shrinking?*

Ans. 1. Limited availability of quality timbers due to forest closing
2. Increasing cost
3. Environmental consideration
4. Availability of alternative materials of construction for the structure at competitive price.

Q. *What are the alternative MOC used in the construction of CT?*

Ans. 1. Coated carbon steel
2. Fiberglass
3. Concrete

Q. *What are the drawbacks of coated carbon steel?*

Ans. Wet tower environment cuts short the life of galvanized steel. The success of other coatings is dictated by the type, application and the prevention of flaws in the coatings at all times. Severe corrosion restricts its application with water conditions with pH below 7.

Q. *What is the performance of fiberglass as a material of construction of a CT?*

Ans. The use of this material has largely been limited to piping, siding and fanstacks. However, entire structures have been recently built.

It should have very good resistance to moisture, temperature and a wide range of pH.

Q. *What is the life expectancy of fiberglass CT?*

Ans. Not yet known.

Q. *When is the concrete cooling tower preferred?*

Ans. Concrete is used primarily for large cooling towers.

Q. *What are the disadvantages associated with concrete towers?*

Ans.

1. Concrete coated with protective coatings should be used where low pH or high Cl^- concentrations are encountered
2. Sulphate resistant concrete type 5 or 2A is to be used if high SO_4^{2-} concentrations are expected
3. Air entrainment is to be specified to prevent damage due to the effects of freezing/thawing
4. Spalling and rusting of steel is a nagging problem. This requires placement of reinforcement relative to the surface or the use of epoxy coated reinforced steel.

Q. *The wet/dry towers are primarily used for plume abatement and prevention of local fogging and icing. So when are dry/wet towers used?*

Ans. They are mainly used for water conservation.

Q. *What should be the basic design considerations of such a tower (dry/wet type)?*

Ans.

1. The expected tower heat load and waterflow should be matched with the available make-up water quantity as an extreme condition on a month-to-month basis.
2. The wet section is to be sized liberally so as to operate for a maximum amount of time and to be used in case more than the expected make-up is available.
3. The material of construction of the dry section of the tower should be selected from Cu-Ni based alloys or stainless steels to deter corrosion by salts in the drift.
4. Freeze control and drainage of the heat exchanger tubes need special design considerations.

Q. *When are natural draft towers used?*

Ans. They are (Fig. 26.38) usually preferred when large quantities of water are circulated. Applications include typically central power stations or refineries in geographical localities having consistently high temperatures and high ambient humidity.

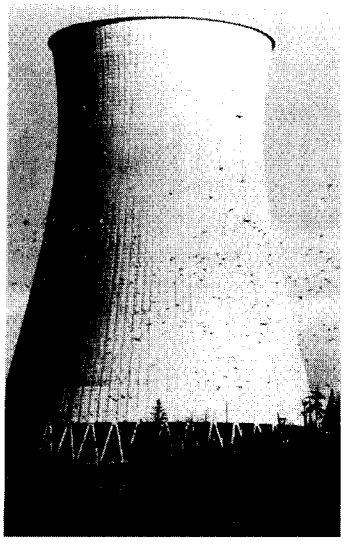


Fig. 26.38 *Hyperbolic natural draft concrete cooling tower.*
Source: *HCT 002R (Hamon Cooling Towers Brochure)*
Courtesy: *Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA*

Q. *How is a CT drift estimated?*

Ans. The amount of drift discharged from a CT is usually estimated as a percentage of circulating waterflow.

Q. *What is the standard limit for drift emissions?*

Ans. It is 0.008% of the circulating waterflow.

Q. *What is the basic requirements in order to achieve a drift rate equal to half the reference value, i.e. 0.004%?*

Ans. It needs the installation of high efficiency drift eliminators (e.g. cellular type or tight spacing extruded wave type).

Q. *What is the impact of such installation on cost factors?*

Ans. Capital cost goes up marginally by 1% and the added resistance to airflow increases fan brake horsepower that in turn raises the operating cost by about 1%.

Q. *If the drift rate is to be hunkered down to 0.001%, what retrofitting is needed?*

Ans. This can be achieved by installing two layers of high efficiency drift eliminators.

Q. *What will be the cost involvement?*

Ans. The impact on capital cost will be around +4% while the added fan brake horsepower will raise the operating cost by about 5%.

Q. *What is the incumbent on the utility or plant using CT drift eliminators?*

Ans. It calls for additional care and maintenance through the life period of the equipment to achieve and sustain high quality drift elimination with proper sealing of locations that would allow air bypass.

Q. *How will the capital cost and operating cost vary to incorporate design modifications in various cooling towers to meet environmental criteria?*

Ans. The relative cost comparison for the various cooling tower types designed to meet environmental criteria are shown in Table 26.1.

Table 26.1 *Relative cost comparison for the various cooling tower types*

Tower Type	Capital Cost Percent	Operating Cost Percent
* **Douglas FIR**	100	100
* **Redwood**	112	100
* **Concrete**	140	90
* **Steel**	135	98
* **FRP**	145	98
* **Splash Fill**	120	150
* **Non-fouling film fill**	110	102
* **Reduced Drift**		
0.004% Drift	101	101
0.001% Drift	104	105
Plume Abatement		
32 DBT	420	120
20 DBT	520	130
12 DBT	560	140
Reduced Noise		
5 dBA	110	100
10 dBA	130	107
30 dBA	300	112
Dry/Wet		
25% Water Conservation	375	175

Note: The occupied ground area for each tower marked "*" was kept constant in order to achieve more comparable values.

Source: TP 92-02 (Technical Paper/Hamon-Sobelco)

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA

Basis The basic conditions of design of a CT used to take care of C/W requirement of a 50 MW congeneration facility:

C/W	:	10900 M^3/h
Range	:	9°K
Approach	:	7°K
Wet bulb temp.	:	295°K
Wind velocity pressure	:	1.436 kPa

Source: The Latest Worldwide Technology in Environmentally Designed Cooling Towers—Gary R. Mirsky; Jean-Pierre Libert; Kathy Bryant and Franz Bouton (Technical Paper TP 92-02/Hamon-Sobelco)

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807-0830/USA.

COOLING TOWER DESIGN

A CT is to be designed to take care of a heat load of 30 MW.

Max. temp. of recirculated water at CT inlet = 322°K

The water is to be cooled to 302.44°K

The water equivalent at this range = 1316 m^3/h

The locality has a wetbulb temp. of 297°K.

The tower is provided with fans to deliver 342.3 m^3/s of air at wetbulb 297°K.

Design the tower if it is provided with a ground area of 7.3 m × 7.3 m.

During a test run, under steady atmospheric conditions, the CT showed:

C/W temp.at tower inlet = 319°K

C/W temp. at tower outlet = 299°K while the psychrometer reading showed:

Wetbulb temp. = 291°K

If the air and water loadings are maintained at their design values, check whether this CT can guarantee its performance:

"Cooling 1316 m^3/h of water from 322°K to 302.44°K when the wetbulb is 297°K".

Test for CT performance for overload and underload. The CT manufacturer supplied the data:

LIQ **Loading** (%)	**Temp. Range** (°K)
120	323–303.66
100	322–302.44
80	320.5–301

For the given CT fill, at the specified gas/liquid loading:

$$K_x.a = 1794 \text{ kg/h.m}^3. \text{ (kg/kg)}$$

Check Estimate how much C/W from 322°K to 302.44°K can the tower provide when the wetbulb is at 294°K.

Solution: The total heat transfer, dq, in a CT is equal to the enthalpy decrease of the total water quantity or the enthalpy increase of the total air mixture

$$dq = L \cdot C_p \cdot dT = G \cdot dH$$

$$= K_x \cdot (H - H) \cdot a \cdot dV$$

where, L = liquid loading, kg/(h.m^2 of ground area)

G = gas loading, kg/(h.m^2 of ground area)

C_p = specific heat of liquid, kJ/(kg.°K)

dT = temp. difference of hot liquid at any particular elementary tower cross-section, °K

H = enthalpy of the gas, kJ/kg of dry air

H' = saturation enthalpy of the gas, kJ/kg of dry air

K_x = overall coefficient of mass transfer, kg/[h.m^2.(kg/kg)]

a = surface of packing or fill, m^2/m^3 of packed bed

V = tower volume, m^3

The above equation is the key equation for the calculation of the design and analysis of the

performance of CTs. K_x, the overall mass-transfer coefficient is analogous to overall heat-transfer coefficient.

The next requirement is to determine the actual enthalpy at any point in the tower. On the basis of enthalpy balance at any point in the tower

$$L \cdot C_p \cdot dT = G \cdot dH$$

This is the Eqn. of a straightline of slope C_p L/G (i.e. the slope is the product of liquid to air loading and specific heat of liquid).

Therefore, the value of H at any point on the operating line is obtained from

$$H_2 = H_1 + C_p \cdot \frac{L}{G} \cdot (T_2 - T_1)$$

Now, the enthalpy of inlet air at 297°K wetbulb (i.e. air saturated at 297°K)

$$H_1 = 91 \text{ kJ/kg dry air}$$

Air loading = 342.3 m^3/s at 297°K wetbulb.

Density of dry air in air + water vapour mix at 297°K = 1.154 kg/m^3

Ground area = 7.3 m × 7.3 m = 53.29 m^2

$$L = 1316\left(\frac{m^3}{h}\right) \times \frac{1}{53.29}\left(\frac{1}{m^2}\right) \times 998\left(\frac{kg}{m^3}\right)$$

$$= 24645.67 \text{ kg/(m}^2\text{.h)}$$

$$G = 342.3\left(\frac{m^3}{s}\right) \times \frac{1}{53.29}\left(\frac{1}{m^2}\right) \times 1.154\left(\frac{kg}{m^3}\right) \times 3600\left(\frac{s}{h}\right)$$

$$= 26685.74 \text{ kg/(h.m}^2\text{)}$$

$$\text{Slope} = C_p \cdot \frac{L}{G} = 4.174 \frac{24645.67}{26685.74} = 3.855$$

C_p = average specific heat of water = 4.174 kJ/(kg.°K) over the temp. range 322–302.44°K

∴ Enthalpy of air at 322°K:

$$H_2 = 91 + 3.855\ (322 - 302.44)$$

$$= 166.40 \text{ kJ/kg dry air}$$

On the ENTHALPY vs. TEMPERATURE diagram (Fig. 26.39) a straightline is drawn joining H_1 and H_2. The area enclosed between the saturation line (H_1' H_2') and the operating line (H_1H_2) represents the driving potential for heat transfer, which is obtained by numerical integration.

In order to facilitate the sizing of the tower, we need to calculate the NDU—the number of diffusion units i.e. the number of times the average potential may be divided into to bring about the desired enthalpy change over the entire height of the tower:

$$\text{NDU} = \int \frac{dT}{H' - H} = K_x \cdot a \cdot \frac{V}{L}$$

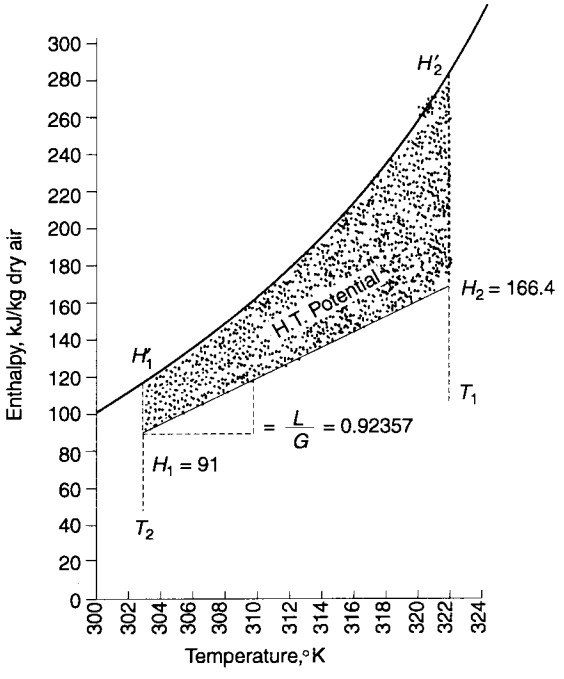


Fig. 26.39 *Saturation line and operating line of a CT performing between the limits of 302.44°K and 322°K.*

T (°K)	H' (kJ/kg)	H (kJ/kg)	$H' - H$ (kJ/kg)	$(H' - H)_{av}$ (kJ/kg)	$\frac{dT}{(H' - H)_{av}}$
302.44	116.3	91	25.3		
305	132	101	31	28.15	0.09094
308	149.33	112.43	36.89	33.945	0.08837
311	169	124	45	40.945	0.07326
314	192	135.56	56.43	50.715	0.05915
316	218	143.27	74.72	65.575	0.03049
319	248	154.84	93.16	83.94	0.03573
322	282.6	166.40	116.19	104.675	0.02866

$$\text{NDU} = \int \frac{dT}{H' - H} = 0.4066$$

For a particular type of fill if the height of one diffusion unit is known, the total height of the tower required to achieve the desired cooling performance can be obtained as the product of NDU & HDU i.e.

$$Z = \text{NDU} \times \text{HDU}$$

Now,

$$\text{NDU} = K_x \cdot a \cdot \frac{A \cdot Z}{L}$$

Since the loading is based on 1m^2 of ground area, i.e. $A = 1\ \text{m}^2$

$$Z = \frac{\text{NDU} \times L}{K_x \cdot a}$$

$$= \frac{0.4066\ (24645.67)}{1794} \cdot \frac{\frac{\text{kg water}}{\text{m}^2 \cdot \text{h}}}{\frac{\text{kg water}}{\text{h} \cdot \text{m}^3\ (\text{kg/kg})}}$$

$$= 5.586\ \text{m}$$

Height of a diffusion unit

$$\text{HDU} = \frac{Z}{\text{NDU}} = \frac{5.586}{0.4066} = 13.737\ \text{m}$$

Cooling Tower Guarantee Utilities buy a cooling tower. A utility specifies the quantity of water and the temperature range it requires for its process. The CT manufacturer proposes a tower designed for a given approach to the 5 per cent wetbulb in the locaility of the plant and guarantee the fan power with which it will be accomplished.

After a cooling tower has been erected and placed in operation on this basis, an acceptance run is made to determine whether or not the CT is meeting the guarantee.

Each performance calculation may, therefore, be split into two parts:

1. Computation of the number of diffusion units required to remove the desired heat load from the cooling water of the utility
2. Determination of the NDUs the tower can actually perform.

At all conditions, No.2 should exceed No: 1 for the obvious reason.

$$\therefore \quad Z = \frac{\text{NDU} \cdot L}{K_x \cdot a} = \frac{0.43137\ (24645.67)}{1794}$$

$$= 5.926\ \text{m} \approx 6\ \text{m}$$

which is greater than the height required to cool $1316\ \text{m}^3/\text{h}$ of water from 322°K to 302.44°K at the fan performance, specified by the CT manufacturer, at wetbulb of 297°K.

T (°K)	H' (kJ/kg)	H (kJ/kg)	$H' - H$ (kJ/kg)	$(H' - H)_{av}$ (kJ/kg)	$\frac{dT}{(H' - H)_{av}}$
299	101	71	30		
302.44	116.3	84.26	32.04	31.02	0.11089
305	132	94.13	37.87	34.955	0.07323
308	149.33	105.69	43.64	40.755	0.07361
311	169	117.26	51.74	47.69	0.06290
314	192	128.825	63.175	57.457	0.05222
316	218	136.535	81.465	72.32	0.02765
319	240.27	146.94	93.326	87.395	0.03089
					NDU = 0.43137

Therefore, a tower (7.3m × 7.3 m × 6 m high) designed on the basis of CT inlet/outlet temperature of 319°K/299°K at a wetbulb reading of 291°K will be capable of producing 1316 m^3/h of 322°K to 302.44°K water, under same air and water loadings, when the wetbulb is 297°K.

Therefore, CT guarantee is met

Load Performance

Now let us calculate CT performance for overload and underload.

LIQ Loading (%)	Temp. Range (°K)
120	323–303.66
100	322–302.44
80	320.5–301

If the water and air loadings on a CT are varied in any way, the number of diffusion units the tower is capable of providing gets simultaneously altered. Normally, the loadings on a single cell cannot be changed very greatly. In fact a variation of 20% from the mean of the design water loading is the maximum anticipated value and accordingly, the maximum discharge capacity will be about 120% of design and the minimum allowable discharge capacity will be about 80% of design.

When the operating wetbulb is lower than the design wetbulb, it is desirable to utilize the increased potential to produce more cooling water of the original design temperature range.

For 1316 m^3/h of liquid rate, $L/G = 0.92357$

For 120% of Design

$$\frac{L}{G} = 1.2\ (0.92357) = 1.10828$$

At 303.66°K, $H_1 = 91$ kJ/kg dry air

At 323°K, $H_2 = 91 + 4.174 \times 1.10828\ (323 - 303.66)$

$= 180.466$ kJ/kg dry air.

T (°K)	H' (kJ/kg)	H (kJ/kg)	$H' - H$ (kJ/kg)	$(H' - H)_{av}$ (kJ/kg)	$\frac{dT}{(H' - H)_{av}}$
303.66	123.51	91	32.51		
305	132	97.19	34.81	33.66	0.039809
308	149.33	111.07	38.26	36.53	0.082124
311	169	124.95	44.05	41.15	0.072904
314	192	138.83	53.17	48.61	0.061715
316	218	148.08	69.92	61.545	0.032496
319	248	161.96	86.04	77.98	0.038471

322	282.60	175.84	106.76	96.4	0.031120
323	298.19	180.46	117.73	112.245	0.008909

$$K_x \cdot a \cdot \frac{V}{L} = \int \frac{dT}{(H' - H)_{av}} = 0.367548$$

For 80% of Design

$$\frac{L}{G} = 0.8(0.92357) = 0.73885$$

At 301°K, H_1 = 91 kJ/kg dry air

At 320.5°K, $H_2 = 91 + 4.174 \times 0.73885\ (320.5 - 301)$
$= 151.138$ kJ/kg dry air

T (°K)	H' (kJ/kg)	H (kJ/kg)	$H' - H$ (kJ/kg)	$(H' - H)_{av}$ (kJ/kg)	$\frac{dT}{(H' - H)_{av}}$
301	110	91	19		
302.44	116.3	95.44	20.86	19.93	0.07225
305	132	103.33	28.67	24.765	0.10337
308	149.33	112.59	36.74	32.705	0.09172
311	169	121.84	47.16	41.95	0.071513
314	192	131.09	60.91	54.035	0.05552
316	218	137.26	80.74	70.825	0.02823
319	248	146.51	101.49	91.115	0.03292
320.5	265.4	151.138	114.262	107.876	0.01390

$$K_x \cdot a \cdot \frac{V}{L} = 0.46945$$

L/Q Load (%)	*L/G*	$C_p \cdot L/G$	$K_x \cdot a \cdot V/L$
80	0.7388	3.084	0.46945
100	0.9235	3.855	0.4066
120	1.1082	4.626	0.3675

The values of $K_x \cdot a \cdot V/L$ are plotted against $C_p.L/G$ (Fig. 26.40).

Quantity of Water that can be Cooled to Design Temperature Range when the Wetbulb Temperature Drops.

In order to calculate the quantity of water that can be cooled from 322°K to 302.44°K when the wetbulb temperature falls from 297°K to 294°K, we need to go through iteration:

Step-I Assume a suitable value of *L/G*

Step-II Compute $K_x \cdot a \cdot V/L$

Step-III From Fig. 26.40 read out the value of $C_p.L/G$ corresponding to $K_x.a.V/L$ determined in Step-II.

Step-IV Check whether the value of *L/G* obtained in previous step tallies with the assumed value of *L/G*. If it does not, repeat the whole operation with another suitable value of *L/G*.

Trial No: 1

Assume $L/G = 1.138$

$H_1 = 80.25$ kJ/kg dry air

$H_2 = 80.25 + 4.174 \times 1.138\ (322 - 302.44)$
$= 173.16$ kJ/kg dry air

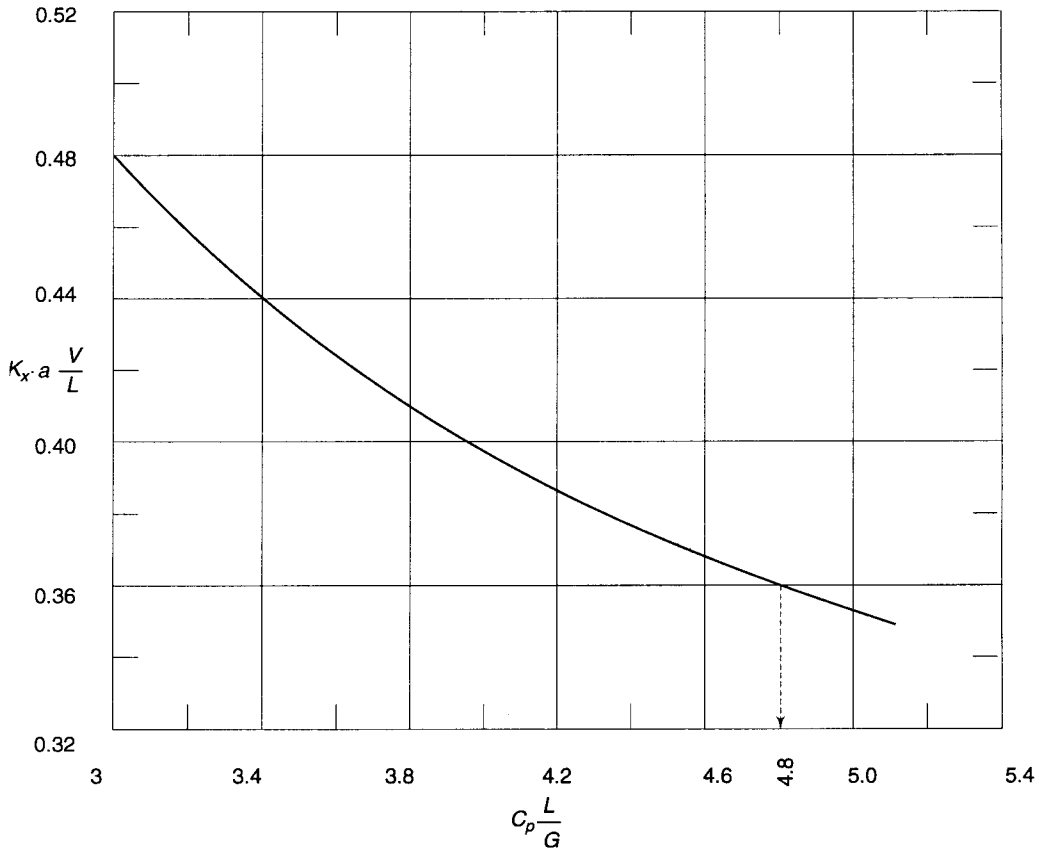


Fig. 26.40 *Dependence of NDU* $\left(K_x \cdot a \cdot \frac{V}{L}\right)$ *on CT loading.*

T (°K)	H' (kJ/kg)	H (kJ/kg)	$H' - H$ (kJ/kg)	$(H' - H)_{av}$ (kJ/kg)	$\frac{dT}{(H' - H)_{av}}$
302.44	116.3	80.25	36.05		
305	132	92.41	39.59	37.82	0.067689
308	149.33	106.66	42.67	41.13	0.072939
311	169	120.91	48.09	45.38	0.066108
314	192	135.16	56.84	52.465	0.057180
316	218	144.66	73.34	65.09	0.0307266
319	248	158.91	89.09	81.215	0.0369389
322	282.6	173.16	109.44	99.265	0.030221
					$K_x \cdot a \cdot \frac{V}{L} = 0.36180$

For $K_x.a.V/L = 0.3618$, $C_p.L/G = 4.8$ [Fig. 26.40]

$\therefore$ $L/G = 4.8/4.174 \simeq 1.15$ which is very close to our assumed value (1.138)

The deviation is only 1.05%

Therefore, we need no further approximation.

$\therefore$ The total water that can be produced with a temp. of 302.44°K at the CT outlet

$$= 1316\left(\frac{m^3}{h}\right) \times \frac{1.15}{0.92357}$$

$$= 1638.641 \text{ m}^3/\text{h}.$$

Note: Please refer to APPENDIX-II for two specific examples on **Performance Test** of a plume abatement CT.

27

WATER TREATMENT AND DEMINERALIZATION

Q. *What is meant by clarification of water?*

Ans. It means the removal of coarse-dispersed suspended solids as well as colloidal impurities from water.

Q. *How is it achieved?*

Ans. Coarse-dispersed suspended solids are separated from water by a sedimentation and filtration processes.

Q. *How is water clarified by sedimentation?*

Ans. It is a process carried out in large settling tanks wherein a large bulk of water is kept stationary to allow coarse-dispersed suspended solids to settle by gravity on the bottom of the settling tank and the sediment is removed periodically by the slow motion of horizontal scrappers.

Q. *What are the disadvantages of sedimentation?*

Ans. 1. It is a very slow process taking a long time to remove appreciable quantities of suspended solids
2. It never ensures complete elimination of suspended impurities from water.
3. It requires large-capacity settling tanks.

Q. *What is filtration?*

Ans. It is the process of clarification of water by passing it through a filter bed composed of a porous material that retains coarse suspended solids on its surface and in the pores.

Q. *What is the driving force of filtration?*

Ans. It is the pressure drop through the filter bed.

Q. *On which factors does the pressure drop through the filtering bed depend?*

Ans. 1. Height of the filtering bed
2. Rate of filtration
3. Particle size (i.e. grain diameter) of the filtering material
4. Degree of contamination of the filter bed by impurities trapped

Q. *What is meant by coagulation of water?*

Ans. It is process of removal of colloidal impurities from water by conglomeration of small colloidal particles into bigger particles having enough mass to settle by the action of gravity.

Q. *What is the process opposite to coagulation?*

Ans. It is called peptization, i.e., transition of a solid into a colloidal-state.

Q. *What is the mechanism of coagulation?*

Ans. The colloidal particles owe their existence to the electric charges developed on the surfaces by the metal cations from which they form, or by the absorption of cations or anions from the solution (in the case of organic sols). Since all the

colloidal particles of a given colloidal solution carry like charges, they repel each other and as a result they cannot spontaneously conglomerate into large particles.

Coagulation is effected by dosing of stimulants that neutralize the charges of the colloid particles which thereby coagulate on collision with similar other neutralized particles.

On standing, the coagulated particles grow in size and become too large to outweigh gravity by the buoyant force exerted upon them by water. And they settle on the bottom as gelatinous and porous flakes.

Q. *What are these stimulants called?*

Ans. Coagulants.

Q. *What chemicals are used as coagulants in water-treatment plants?*

1. Alum, K_2SO_4, $Al_2(SO_4)_3 \cdot 24H_2O$
2. Aluminium sulphate, $Al_2(SO_4)_3 \cdot 18H_2O$
3. Ferrous sulphate, $FeSO_4 \cdot 7H_2O$
4. Ferric chloride, $FeCl_3$

Q. *In which state are they introduced into water?*

Ans. They are dosed in the form of a solution with 5–10% concentration.

Q. *Why is it necessary to maintain some degree of alkalinity in the water being treated with a coagulant?*

Ans. It is because the H^+ ions liberated due to hydrolysis of metal ions (Fe^{2+}, Al^{3+}, etc.) of the coagulants reduce the alkalinity of water

$$Fe^{2+} + 2H_2O \Leftrightarrow Fe(OH)_2 + 2H^+$$

$$Al^{3+} + 3H_2O \Leftrightarrow Al(OH)_3 + 3H^+$$

$$HCO_3^- + H_2O \rightleftharpoons H_2O + CO_2 + OH^-$$

$$H^+ + OH^- \longrightarrow H_2O$$

and since the process of coagulation is very sensitive to pH (It should be 5–7 when an Al-coagulant is used; 8–10 when Fe-coagulant is used), some amount of alkaline substances are added to adjust the pH of water.

Q. *What alkaline agents are used?*

Ans. NaOH, Na_2CO_3, $Ca(OH)_2$.

Q. *How can their amounts be determined?*

Ans. The amount of alkali to be added for correcting the pH is determined by the formula:

$$A_{cg} = \dot{M}_{cg} + 0.4 - A_t$$

where

A_t = total alkalinity, mg-equiv./kg

A_{cg} = alkalinity of coagulated water, mg-equiv./kg.

$\dot{M}_{cg}$ = dose of coagulant, mg-equiv./lt.

Q. *Why is pH an important factor of consideration during the process of coagulation?*

Ans. As coagulation proceeds, it is expedient to create conditions in water so as to precipitate out most of the coagulants, otherwise these added salts will increase the load on the ion-exchanger in the demineralizing plant as well as contaminate the ion-exchange resin to an inadmissible degree.

This entails the risk of penetration of Fe^{2+} and Al^{3+} ions into the boiler units.

Therefore, it is essential to precipitate out these metal ions as less soluble hydroxides produced due to hydrolysis

$$Al^{3+} + 3H_2O \Leftrightarrow Al(OH)_3\downarrow + 3H^+$$

$$Fe^{2+} + 2H_2O \Leftrightarrow Fe(OH)_2 + 2H^+$$

$$2Fe(OH)_2 + \frac{1}{2}O_2 + H_2O \longrightarrow Fe(OH)_3\downarrow$$

However, the solubility of these hydroxides $Fe(OH)_3$ and $Al(OH)_3$ is a function of the pH. Lower the pH, higher is the acidity of the medium, so more of the precipitated hydroxide will pass into the solution. Again for aluminium hydroxide precipitate, if pH is maintained at ≥ 8, it will dissolve by forming aluminate ions

$$Al(OH)_3 + OH^- \longrightarrow AlO_2^- + 2H_2O$$

Hence, when aluminium compounds are used as coagulants, the water pH is maintained in the range 5–7. For iron compounds it is 8–10.

Q. *What basic steps are involved during the process of softening of water?*

Ans. 1. Estimation of the amounts of chemical required on the basis of chemical analysis of raw water.
2. Dosing of the reagents in calculated amounts
3. Rapid and thorough mixing of the chemicals with the raw water to effect quick flocculation
4. Settling the flocs and separation of precipitated solids
5. Removal of clarified water.

Q. *What is the reason for water hardness?*

Ans. Hardness of water is due to the presence of calcium and magnesium salts: bicarbonates, carbonates, chlorides, sulphates and nitrates. Presence of iron, aluminium and managanese salts also contributes to water hardness, but normally these are not present in appreciable quantities. Normal carbonates are also found, but only occasionally and in highly alkaline water. Nitrates are usually present in minor quantities while it has been found that sulphates on the average exceed chlorides.

Q. *How can hardness be classified?*

Ans. It can be classified as carbonate (more accurately, bicarbonate) and non-carbonate hardness.

Classification	Carbonate Hardness	Non-Carbonate Hardness
Calcium Hardness	Calcium bicarbonate, $Ca(HCO_3)_2$ Calcium carbonate, $CaCO_3$	Calcium sulphate, $CaSO_4$ Calcium chloride, $CaCl_2$
Magnesium hardness	Magnesium bicarbonate, $Mg(HCO_3)_2$ Magnesium carbonate, $MgCO_3$	Magnesium sulphate, $MgSO_4$ Magnesium chloride, $MgCl_2$

Q. *What is the basis of water softening by the precipitation method?*

Ans. The scale forming cations Ca^{2+} and Mg^{2+} are precipitated from water by binding them with anions like CO_3^{2-} and OH^- to produce less soluble compounds, viz. $CaCO_3$, $MgCO_3$ and $Mg(OH)_2$ so the most of these harmful cations are eliminated from the system.

Q. *How are these CO_3^{2-}, OH^- ions added to the water?*

Ans. By adding the following reagents individually or in combination
1. slaked lime, $Ca(OH)_2$
2. caustic soda, NaOH
3. soda ash, Na_2CO_3

Q. *What is lime treatment?*

Ans. It is treating raw water with a solution of slaked lime.

Q. *What chemical processes occur during lime treatment?*

Ans. The bicarbonate hardness is eliminated

$$HCO_3^- + OH^- \longrightarrow H_2O + CO_3^{2-}$$

$$\xrightarrow{Ca^{2+}} CaCO_3\downarrow$$

Magnesium hardness is removed partly

$$Mg^{2+} + 2OH^- \longrightarrow Mg(OH)_2\downarrow$$

Alkalinity of initial water is decreased somewhat

$$CO_2 + 2OH^- \longrightarrow CO_3^{2-} + H_2O$$

Q. *What are the effects of lime treatment?*

Ans. The lime treatment
(a) affects carbonate hardness; it is decreased to 0.7–1 mg-equiv./lt.
(b) removes magnesium ions from water if there are OH^- ions present in sufficient excess
(c) removes water-dissolved CO_2
(d) reduces total dissolved solids (TDS)

(e) decreases the total hardness in lime-treated water.

Q. *What is the main drawback of this treatment?*

Ans. It does not ensure deep water softening. Magnesium ions are removed only partially.

Q. *What is lime-soda treatment?*

Ans. In this process, water is treated with a mixture of soda ash and lime and the water is heated to 360–370 K, whereupon water can be softened to a residual hardness of 200 microgram-equiv./kg.

Q. *What processes develop during lime-soda treatment?*

Ans. Permanent hardness is mostly eliminated

$$CaCl_2 + Na_2CO_3 \longrightarrow CaCO_3\downarrow + 2NaCl$$

$$MgSO_4 + Na_2CO_3 \longrightarrow MgCO_3\downarrow + Na_2SO_4$$

Q. *What is the basic advantage of lime-soda treatment over lime treatment?*

Ans. The non-carbonate hardness that remains after lime treatment is eliminated by lime-soda treatment. This residual hardness is mainly due to Ca^{2+} which is precipitated by soda-ash (Na_2CO_3)

$$Ca^{2+} + CO_3^{2-} \longrightarrow CaCO_3\downarrow$$

Q. *What is soda-sodium hydrate treatment?*

Ans. In this process water is treated with an $NaOH + Na_2CO_3$ mixture.

Q. *Why is the solubility of calcium carbonate in water given fundamental importance in the softening of water?*

Ans. Primarily because it is the chief scale forming agent and also contributes to corrosion. Hence knowledge of the solubility data of this compound is necessary to avoid scale formation and control corrosion as well as to predict the results of many of the softening reactions occurring in this process.

Q. *What is the solubility of calcium carbonate in water?*

Ans. Pure calcium carbonate added to distilled water in the absence of carbon dioxide will go into solution to the extent of 15–20 ppm at room temperature.

Q. *What factors affect the solubility of calcium carbonate?*

Ans. 1. Temperature
2. Presence of Ca^{2+} or CO_3^{2-} ions (Common Ion Effect)
3. pH
4. Inhibitors.

Q. *What is the effect of temperature on the solubility of calcium carbonate in water?*

Ans. Calcium carbonate has a negative temperature gradient of solubility, i.e. its solubility decreases with increase in temperature

$$\left[S_{CaCO_3}\right]^{15°C} = 1.12\left[S_{CaCO_3}\right]^{20°C}$$

$$\left[S_{CaCO_3}\right]^{25°C} = 0.88\left[S_{CaCO_3}\right]^{20°C}$$

where $\left[S_{CaCO_3}\right]^{15°C}$, $\left[S_{CaCO_3}\right]^{20°C}$ and $\left[S_{CaCO_3}\right]^{25°C}$ represent the solubility of calcium carbonate at 15°, 20°C and 25°C respectively.

Q. *How does the common-ion-effect exert an influence upon the solubility of $CaCO_3$?*

Ans. When raw water is treated with lime, $Ca(OH)_2$, to convert all the calcium bicarbonate to the normal carbonate, the Ca^{2+} ions liberated by the lime

$$Ca(OH)_2 \Leftrightarrow Ca^{2+} + 2OH^-$$

increase the concentration of Ca^{2+} to such a level that solubility product of calcium carbonate is reached

$$[S.P.]_{CaCO_3} = \left[Ca^{2+}\right]\left[CO_3^{2-}\right]$$

$$= 4.8 \times 10^{-9} \text{ at } 20°C$$

whereupon calcium carbonate is precipitated, with the effect that calcium hardness can be reduced to about 35 ppm at 15°C 20°C.

However if the raw water contains calcium bicarbonate as well as magnesium bicarbonate, the added lime will convert the latter into soluble magnesium carbonate

$$Mg(HCO_3)_2 + Ca(OH)_2 \longrightarrow$$
$$MgCO_3 + CaCO_3\downarrow + 2H_2O$$

which will increase the concentration of CO_3^{2-} ions in water thereby depressing the solubility of calcium carbonate even below 35 ppm by the same principle of common-ion-effect.

Q. *What is the effect of pH on the solubility of $CaCO_3$?*

Ans. The solubility of calcium carbonate in water is minimum at pH 9.4, but rises steeply thereafter with the increase of pH.

Q. *Why does the solubility of calcium carbonate increase sharply at pH above 9.4?*

Ans. This is due to the formation of soluble calcium hydroxide

$$CaCO_3 + 2OH^- \Leftrightarrow Ca(OH)_2 + CO_3^{2-}$$

The solubility product of $Ca(OH)_2$ is much higher than $CaCO_3$.

Q. *What is the effect of inhibitors on the solubility of $CaCO_3$?*

Ans. Inhibitors present in water in the form of tannins, organic wastes, sewage, etc. retard the precipitation of $CaCO_3$ or distort its crystal formation, thereby the apparent solubility of calcium carbonate increases.

Q. *Why has it become the standard procedure to express all types of hardness as calcium carbonate?*

Ans. The compound calcium carbonate ($CaCO_3$) has a molecular weight of 100 and that renders calculations greatly simplified if all types of hardness are expressed as calcium carbonate. That's why bicarbonate, carbonate, hydroxide alkalinity as well as sulphate, chloride, nitrate and phosphate ions present are reported as calcium carbonate.

Conversion Factors for Converting PPM of Ions into PPM of Calcium Carbonate*

	For ppm, as $CaCO_3$	
	Divide by	*Multiply by*
Cations		
Calcium, Ca^{2+}	40.08	2.495
Magnesium, Mg^{2+}	24.305	4.114
Sodium, Na^+	45.978	2.175
Potassium, K^+	78.196	1.279
Anions		
Chloride, Cl^-	70.906	1.410
Sulphate, SO_4^{2-}	96.057	1.041
Nitrate, NO_3^-	124.008	0.806
Phosphate, PO_4^{3-}	63.314	1.579
Bicarbonate, HCO_3^-	122.034	0.819
Carbonate, CO_3^{2-}	60.009	1.666
Hydroxide, OH^-	34.0146	2.940

*PPM = Parts Per Million

Q. *What is the analytical data required for the raw water for softening calculations?*

Ans. 1. Free carbon dioxide which is equal to 2.27 (ppm of CO_2)
2. Bicarbonate
3. Calcium bicarbonate
4. Magnesium bicarbonate
5. Sodium bicarbonate
6. Bicarbonate hardness excess of calcium
7. Non-carbonate hardness
8. Calcium non-carbonate hardness.

Q. *How can bicarbonate hardness be estimated?*

Ans. It is equal to M-alkalinity, M stands for methyl orange. Titrating a measured volume of raw water with the standard mineral acid using methyl orange as the indicator

$$HCO_3^- + H^+ \longrightarrow H_2O + CO_2$$

Normal carbonates are rarely present in raw water. If these are present then there will be phenolphthalein alkalinity,

i.e. carbonate = 2 [P-alkalinity].

Therefore, the carbonate concentration

= M-alkalinity—2 (P-alkalinity)

Q. *How is the bicarbonate hardness excess of calcium estimated?*

Ans. It is obviously magnesium bicarbonate or sodium bicarbonate or their sum.

Q. *How is non-carbonate hardness computed?*

Ans. It is equal to the excess of total hardness over M-alkalinity.

Q. *How is calcium non-carbonate hardness computed?*

Ans. It is equal to the calcium in excess of calcium bicarbonate.

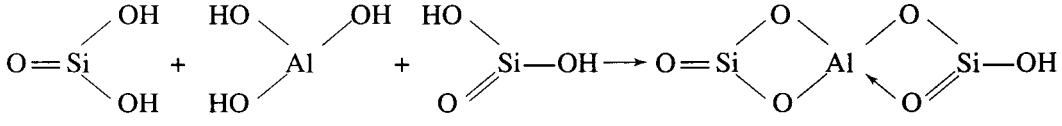
Q. *What is the basis of silica removal from raw water?*

Ans. Silica is removed from raw water by the precipitation method but it is not carried down as a true precipitate.

Silica is found in raw water as coarse-dispersed solids and as colloids. While the former can be readily separated by a settling process, the latter is removed by the precipitation method. In colloidal state silica exists as silicic acid (H_2SiO_3) produced due to hydrolysis of silicates

$$SiO_3^{2-} + 2H_2O \longrightarrow H_2SiO_3 + 2OH^-$$

The presence of mineral acid hastens the process. The colloidal silica goes down only when it is absorbed by the hydroxide of iron, magnesium and aluminium



These metal hydroxides result from the hydrolysis of coagulants.

Q. *What factors should be taken into consideration to effect silica removal by ferric hydroxide or magnesium hydroxide?*

Ans. 1. Silica removal occurs by absorption
2. There is an optimum pH range for each process
3. The efficiency of silica removal is affected by temperature
4. As the silica concentration is reduced, the efficiency of the process gradually falls off and thereby increasingly larger quantities of $Fe(OH)_3$ or $Mg(OH)_2$ are required for each additional ppm of silica removed
5. The effectiveness of silica removal is basically controlled by the degree of hydrolysis of ferric oxide or magnesium oxide added.

Ferric hydroxide forms hydrous ferric oxide which then dehydrates in the absence of water.

$$Fe(OH)_3 \Leftrightarrow Fe_2O_3 \cdot nH_2O \Leftrightarrow Fe_2O_3 + nH_2O$$

Magnesium oxide undergoes hydrolysis as

$$MgO + H_2O \Leftrightarrow Mg(OH)_2$$

It has been found that hydroxides precipitated in situ are far more effective than externally precipitated oxides.

6. The reactions are rapid and take less time than that provided for settling process.

Q. *How is ferric hydroxide introduced in raw water?*

Ans. It is introduced in the form of commercial ferric sulphate marketed as a coagulant which, upon hydrolysis by caustic soda or lime produces ferric hydroxide in raw water.

Q. *What is the optimum pH value for silica removal by ferric hydroxide?*

Ans. It is about 9.

Q. *What is the efficiency of the process?*

Ans. Silica content in raw water can be brought down to as low as 2 ppm but it varies with the quality of water.

Q. *How much quantity of ferric sulphate is required for each ppm of silica removed?*

Ans. For raw water containing silica to the extent less than 10 ppm, ferric sulphate required is 15–20 ppm for each ppm of silica removed. At higher silica concentrations, the quantity of ferric sulphate required for each ppm of silica removed may be as low as 10 ppm.

Q. *Why does this method suit the cold-softening process best?*

Ans. It has been found that efficiency of silica removal by ferric hydroxide decreases with the increase of temperature and vice versa.

Q. *What is the chief disadvantage of this process?*

Ans. This method increases the non-carbonate hardness of water in the form of calcium sulphate.

Q. *How is magnesium hydroxide introduced into raw water for silica removal?*

Ans. Sometimes the source of magnesium hydroxide is the natural magnesium hardness present in water, which produces $Mg(OH)_2$ when raw water is treated with excess lime.

$$Mg^{2+} + Ca(OH)_2 \longrightarrow Mg(OH)_2 + Ca^{2+}$$

Over and above, magnesium hydroxide can be supplied from various sources: magnesium sulphate, magnesium oxide and dolomitic lime.

Q. *What is the efficiency of this process?*

Ans. At 20°C, about 1 ppm of silica is removed for about 6–7 ppm magnesium hardness precipitated. And the efficiency of silica removal increases rapidly as the temperature is raised further.

Q. *Magnesium oxide prepared from calcined magnesite can be added directly to raw water in the dissolver whereas dolomitic lime cannot be so applied. Why?*

Ans. Magnesium oxide normally reacts with water (20°C) in 20–30 minutes and goes into solution. This rate of dissolution is a function of the pH—lower the pH more rapid is the rate of dissolution.

Dolomitic lime, usually available as hydrated dolomitic lime [32% MgO, 62% $Ca(OH)_2$] is a source of magnesium oxide which, however, will not dissolve in cold water in an environment of high pH. Since the calcium hydroxide present in the dolomitic lime provides a high pH rapidly, the associated MgO remains inert.

Q. *Then how can this magnesium oxide of dolomitic lime be brought into solution?*

Ans. For this purpose, it is basically necessary that the pH of the water should be lowered below the pH range that prevails for the precipitation of magnesium hydroxide. This requires a separate dissolution tank were the bicarbonate alkalinity or the free carbon dioxide of raw water will dissolve magnesium oxide.

If the natural water fails to dissolve sufficient MgO to ensure necessary silica removal, carbon dioxide must be added from an external source to the dissolving tank.

1. $HCO_3^- \Leftrightarrow H^+ + CO_3^{2-}$

   $MgO + 2H^+ \longrightarrow Mg^{2+} + H_2O$
2. $CO_2 + H_2O \Leftrightarrow H_2CO_3$

   $MgO + H_2CO_3 \longrightarrow MgCO_3 + H_2O$

Important: It is well nigh impossible to predict precisely what amount of Mg^{2+} ions must be precipitated from any water supply to ensure a specific silica removal.

Q. *To what treatments is cooling water subjected to:*

Ans. 1. Biocide treatment
2. Chlorine treatment
3. Quat-2C treatment
4. Alkali/Acid treatment
5. Phosphate treatment
6. Chromate treatment
7. Betz Polynodic 620 BE treatment, etc.

Q. *What is biocide treatment?*

Ans. Dosing sodium penta and trichlorophenate to cooling water.

Q. *What is the mode of dosing?*

Ans. Shock dosing.

Q. *How is this shock dosing carried out?*

Ans. 200 kg sodium pentachlorophenate is dosed to 2400 m^3 of cooling water in 1 hour. (Interval : Fortnight)

In another typical cooling water system, 80 kg of sodium pentachlorophenate and 40 kg of sodium trichlorophenate are added to 2000 m^3 of cooling water within 1 hr.

Q. *Are they added directly?*

Ans. Sodium trichlorophenate is dosed directly while a 5% solution of sodium pentachlorophenate is injected.

Q. *At what interval is this dosing made?*

Ans. Usually 15 days.

Q. *What is its objective?*

Ans. To kill the algae and rupture the algal material.

Q. *Why is killing of bacteria imperative?*

Ans. Bacteria (nitrosifying) converts dissolved ammonia to NO which is converted to NO_2 by nitrifying bacteria. The latter is acidic in aqueous layer causing corrosion.

Q. *Why is chlorine treatment made?*

Ans. To kill bacteria. Chlorine is a bactericide.

Q. *At what pH is this made?*

Ans. 7.5–8.0

Q. *Why is this range preferred?*

Ans. In this range of pH chlorine reacts with water which is slightly alkaline to produce hypochlorite that liberates nascent oxygen to burst out bacteria cells.

$$Cl_2 + OH^- \longrightarrow Cl^- + H^+ + OCl^- \longrightarrow \dot{O} + Cl^-$$

Q. *What quantity of chlorine is added?*

Ans. One typical installation handling 2400 m^3 of cooling water doses 60 kg Cl_2 per day.

Q. *What is the mode of chlorine dosing?*

Ans. It may be dosed continuously from a chlorinator at the varied rate as desirable.

Shock dosing of chlorine is also made. Dosing 60 kg of chlorine in just 2–3 hrs, i.e. 20–30 kg/h rate is one typical example.

Q. *Is chlorine injected directly?*

Ans. It is not injected directly from 1 ton cylinder. It is dissolved in water and then injected.

Q. *Why is chlorine not injected directly from the cylinder?*

Ans. To avoid
(a) uneven distribution.
(b) loss of chlorine.

Q. *What is QUAT-2C?*

Ans. It stands for Quaternery Ammonium Compound.

Q. *Is it a biocide?*

Ans. Yes.

Q. *How is it added?*

Ans. Shock dosing.

Q. *At what rate is it dosed?*

Ans. It varies with the total bulk of cooling water handled. One installation (2000 m^3 C/W capacity) doses 120 kg of this compound in just 10–15 minutes.

Q. *At what interval is it dosed?*

Ans. Usually a week.

Q. *Is chlorination continued during biocide dosing?*

Ans. No. After 48 hours.

Q. *What is Betz Polynodic 620 BE?*

Ans. It is a phosphate doser.

Q. *Why is it dosed?*

Ans. To eliminate the formation of scales of calcium and magnesium carbonates.

Q. *How does it eliminate these?*

Ans. It forms gelatinous, or colloidal calcium/magnesium phosphate with the scale former, Ca^{2+} and Mg^{2+}, there inhibiting their precipitation as carbonates.

Q. *In the recent trend toward more alkaline cooling waters, bromine replaces chlorine in cooling water treatment, What are the advantages of bromination over chlorination in cooling water treatment?*

Ans. Depending on plant conditions, the potential advantages of bromine treatment are

1. Lower chemical costs
2. Reduced corrosion, i.e. under-deposit corrosion of condenser tubes (copper alloy) as initiated by Cl_2 can be avoided thereby eliminating the need for condenser retubing
3. Reduced requirement for cleaning of main surface condensers
4. Reduced environmental hazard
5. Reduction of lost output at plants fitted with condensers having marginal design surface area.

Q. *What are the environmental benefits from the use of bromine for cooling water treatment?*

Ans. 1. Bromine is a more effective biocide than chlorine. Therefore it allows major dose reductions.

2. Bromine and its compounds (bromamines) undergo rapid decay thereby minimizing their impact on aquatic life in the effluent receiving water mass.

Q. *Why does bromine treatment of cooling water have an edge over chlorine treatment regarding corrosion control?*

Ans. Bromination leads to improved biofouling control than chlorination of cooling water. The immediate impacts of this are reduced under-deposit corrosion and microbiologically induced corrosion (MIC) of stainless steels.

Q. *In what kind of water—acidic, alkaline or neutral—are the benefits of bromination most apparent?*

Ans. Alkaline waters and those waters that contain ammonia.

Q. *Why alkaline waters are most suitable for the efficacy of bromine treatment?*

Ans. Bromine acts as a biocide in the form of HOBr (hypobromous acid) which acts as an oxidizing agent.

$$Br_2 + H_2O \longrightarrow HOBr + HBr$$

The stability of HOBr depends on the pH of water. HOBr is primarily available as an effective biocide in the alkaline range—higher alkalinity than required for chlorine.

Q. *What is the principal mechanism underlying bromine's biocidal activity?*

Ans. The biocidal activity of bromine is explained in three distinct steps

1. FORMATION OF HYPOBROMOUS ACID Bromine reacts with water forming hypobromous acid

$$Br_2 + H_2O \rightleftharpoons HBr + HOBr$$

2. CHEMICAL EQUILIBRIUM BETWEEN HOBr AND HYPOBROMITE IONS

$$HOBr \rightleftharpoons H^+ + OBr^-$$

Higher the pH of the solution, more the equilibria shifts towards the right bringing about greater concentration of hypobromite ions (OBr^-)

3. DISSOCIATION OF HYPOBROMITE IONS (OBr^-)

Hypobromite ions dissociate to liberate nascent oxygen that ruptures the cells of algae

$$OBr^- \longrightarrow O + Br^-$$

Q. *Why does hypobromous acid remain available as a more effective biocide than hypochlorous acid at a significantly higher pH?*

Ans. HOBr and HOCl both act as biocides.

The dissociation curves of these two show that the efficacy of bromine is retained at a significantly higher pH than chlorine (Fig. 27.1)

This explains why biocidal activity of bromine is superior to chlorine in alkaline cooling waters. It renders, for example, a much lower survival rate of slime-forming bacteria *Pseudomona* under equivalent dosages at pH 8.2. (Fig. 27.2)

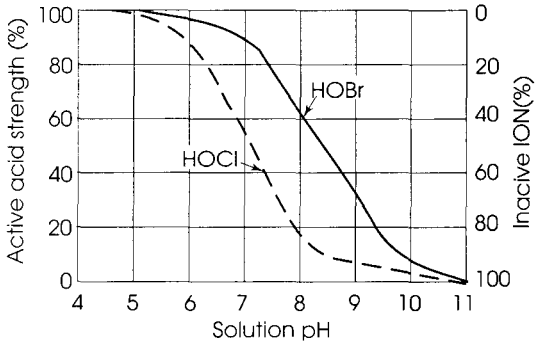


Fig. 27.1 *Dissociation curves of hypohalous acids. HOBr remains available as an effective biocide at a pH significantly higher than HOCl .*

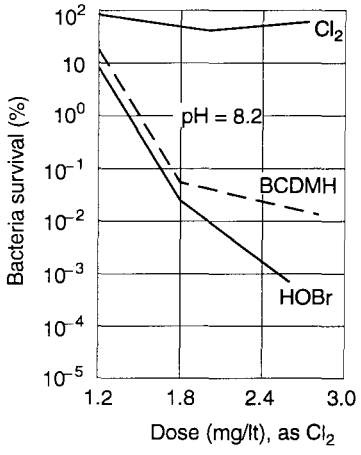


Fig. 27.2 *Bactericidal Power. Both HOBr and BCDMH are far stronger biocidal to PSEUDOMONA Bacteria in alkaline water.*

Q. *Is there any other effective brominating agent?*

Ans. Yes; bromochlorodimethylhydantoin (BCDMH).

Q. *When Cl_2 or Br_2 or BCDMH is dosed to the cooling waters containing ammonia or nitrogen-based compounds what do they form?*

Ans. They form haloamines.

Q. *What are the basic differences between bromamines and chloramines?*

Ans. The biocidal activity and the mode of decay are the two significant features that distinguish Bromamines from chloramines.

Bromine as both HOBr and BCDMH is a far more effective biocidal than chlorine for *Pseudomona* bacteria in cooling waters containing ammonia.

In constrast to chloramines, bromamine reactions are reversible by the pH effect.

Bromamines decay more rapidly than do chloramines.

Because of their higher biocidal activity and rapid decay, bromamines are far more beneficial to the environment as compared to the more presistent chloramines. (Fig. 27.3)

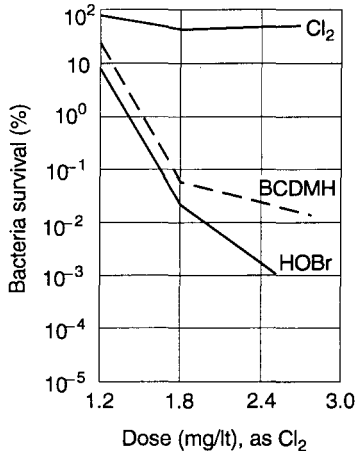


Fig. 27.3 *Bactericidal Power. Both HOBr and BCDMH are far stronger biocidal to pseudomona bacteria in alkaline water.*

Q. *How does the problem of corrosion in the cooling water circuit arise from chlorination or bromination?*

Ans. Chlorine and bromine are oxidizing biocides. Overfeeding of these biocides, it has been reported, stimulates corrosion of some metals and alloys. Copper alloys are particularly sensitive to these. Hence these biocides should be applied prudently.

Free oxidant (Cl_2 or Br_2) attacks the metal which passes into the solution

$$Cu \longrightarrow Cu^{2+} + 2e$$

$$Cl_2 + 2e \longrightarrow 2Cl^-$$

and the degree of corrosion largely depends on the oxidation-reduction potential and pH at the metal-solution interface. For copper alloys, the corrosion is an oxidation process which is much more energetically favoured by the higher oxidation potential of chlorine than bromine. Moreover this copper corrosion is lower in a slightly alkaline condition when the concentration of oxidant is less but it accelerates with rapidity when oxidants are introduced at higher pH.

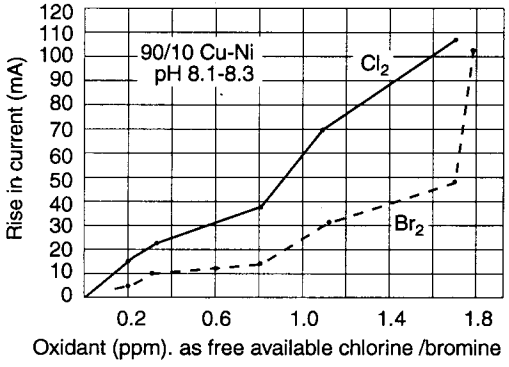


Fig. 27.4 *Electrochemical measurements indicate chlorine to be more corrosive on 90/10 copper-nickel alloy than bromine*

Laboratory tests carried out to study the comparative effects of chlorine and bromine on 90/10 Cu/Ni alloy using natural cooling water having TDS (total dissolved solids) value 1400 ppm, pH 8.2 ± 0.1 at 298 K revealed that chlorine exerts two to three times the corrosive influence of bromine at equivalent oxidant levels (see Fig. 27.4).

Potentiostatic measurements were carried out to observe the rise and decay of corrosion effect while oxidant levels (ppm) were measured continuously as free available chlorine (FAC). In separate test runs, various dosage levels of each oxidant were used and the current readings were recorded at the maximum sustained rise upon treatment. The rise in corrosion current plotted against oxidant concentration (ppm) generated the above curves indicating the corrosive influence of chlorine on copper alloy to be considerably higher than bromine.

However, similar experiments carried out at pH 6–7 did not produce a significant increase in corrosion current even at higher concentrations of free Cl_2 or Br_2.

Q. *Why at pH levels slightly in the acidic range (6-7), is the corrosion of copper or copper alloys by free chlorine or bromine not significant even at higher oxidant levels?*

Ans. At a lower pH, i.e. neutral to acidic range, copper needs higher oxidation potential for its oxidation to copper ions.

Q. *What is the comparative effect of chlorination and bromination of cooling water on irons?*

Ans. Treatment of cooling water by chlorine or bromine yields halide ions that attack iron at low pH. The effect of bromide ions is similar to that of chloride ions. So far as stress-corrosion cracking of austenitic stainless steels is concerned, the aggressivity of bromide ions is considerably lower than chloride ions.

Q. *What is the effect of free available chlorine or bromine on other metals in the cooling water circuit?*

Ans. Manganese fouling (i.e. manganese corrosion) has bene reported. Manganese like copper,

requires, much lower potential in alkaline water for its oxidation.

Q. *What is the remedy to this problem?*

Ans. Prudent use of biocide (Cl_2/Br_2), lower oxidant dosage and reduced oxidation potential are the controlling factors to combat manganese corrosion.

Q. *To what extent does the change over from chlorine to bromine for cooling water treatment reduce corrosion?*

Ans.

Chemical Dosed	Treatment Rate (kg/day)	Duration of Dosing	Corrosion Rate (mil/yr)	
			During Dosing	Daily Average
Cl_2 (only)	680	60 min	6–8	0.8
Cl_2/Br_2	340	30 min	4–8	0.3
Cl_2/Br_2	91	30 min	0.3	0.1

Q. *Texas Utilities Electric in its two gas-fired supercritical units of 565 MW and 775 MW capacity uses lake water for cooling. However, the lake water being typically highly alkaline (pH 8.8-9.1), its auxiliary cooling water system had experienced severe corrosion problem with poor biofouling control while very high rates of chlorination were applied. However upon switch over to bromination, corrosion rates have been reduced substantially.*

What do you infer from this practical case study?

Ans. The efficacy of bromine in reducing substantially the microbiologically influenced corrosion as sociated with poor biofouling control is much higher than chlorine, though chlorine is potentially a more powerful oxidizing agent than bromine at any given pH. Bromine exercises better biofouling control than chlorine.

Q. *Severe manganese fouling and pitting corrosion of 304-stainless steel tubings of condensers had been reported from a 3-unit (total capacity 1900 MW) lignite-fired plant of Monticello using lake water for cooling while continuous chlorination was being practised for biofouling control. The pH of lake-water varied in the range 8-8.8 in summer.*

However upon adoption of bromine treatment for more than 3 years, the condenser-tube failures have been drastically reduced.

What do you infer from this case study?

Ans. Chlorine having higher oxidation potential than bromine had induced more rapid rate of corrosion of manganese/iron at elevated pH > 8.

Moreover, its efficacy as a biofoulant is less than that of bromine in substantially high alkaline cooling water. Therefore, the switchover to bromine chemistry has enhanced the life of the condensers tubes and reduced biofoulant induced corrosion.

Q. *What do the initials AVT stand for?*

Ans. All-Volatile boilerwater Treatment.

Q. *Why is the sodium limit of 3 ppb for both drum and once-trhough boilers on AVT the most stringent requirement as per EPRI (Electric Power Research Institute) of USA?*

Ans. It is because sodium compounds (NaOH, NaCl) are the major boiler-tube and turbine blade corrodants.

Q. *Why is adherence to an even lower limit of sodium, where possible, sometimes suggested?*

Ans. It is primarily due to the fact that sodium limit of 3 ppb will not always ensure the prevention of sodium hydroxide deposition in low-pressure turbines.

Q. *But why is the sodium level (as per EPRI recommendation) for steam 5 ppb for drum-type boilers on phosphate treatment?*

Ans. It is because a fraction of sodium will be tied up in the form of sodium phosphate compounds which are not corrosive.

Q. *What are the target values of sodium, as per EPRI, for boiler water?*

Ans. For boilers operating at a pressure of 60 atm. the maximum permissible value for sodium concentration is about 6 ppm, for boilers with

working pressure of 140–145 atm it is about 2.8 ppm and is as low as 0.55 ppm for 195–197 atm boilers (See Fig. 27.5).

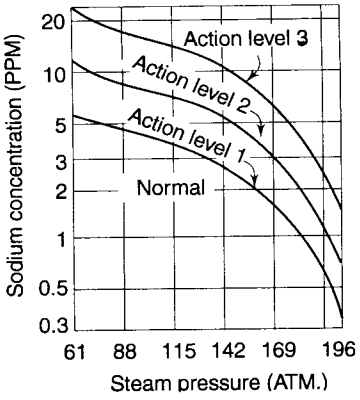


Fig. 27.5 *Sodium target values. These are based on those for reheat/ superheated steam.*

Q. *Why are the values (Na^+ concentration) set for higher pressure boilers lower than usually observed?*

Ans. This is required to maintain a high standard of turbine-steam purity and to minimize phosphate hideout during load changes.

Q. *What action is to be taken, if for a 60 atm boiler, the Na^+ limit exceeds 6 ppm?*

Ans. If it is greater than 6 ppm but less than 12 ppm, Action Level (1) is to be taken, i.e. to return to normal levels within one week.

Q. *What are the values of Na^+ concentration for Action Level (1) for 115 atm, 145 atm and 195 atm boiler units?*

Ans.

Boiler Operating Press	**Na^+ Concentration Range for Action Level (1)**
115 atm	$4 < [Na^+] < 8$ ppm
145 atm	$2.8 < [Na^+] < 5$ ppm
195 atm	$0.55 < [Na^+] < 0.95$ ppm

Q. *What are the values of Na^+ concentration for Action Level (2) for 115 atm, 145 atm and 195 atm boilers?*

Ans.

Boilers Operating Press	**Na^+ Concentration Range for Action Level 2**
115 atm	$8 < [Na^+] < 15$ ppm
145 atm	$5 < [Na^+] < 12$ ppm
195 atm	$0.95 < [Na^+] < 2$ ppm (approx)

Q. *What do you mean by Action Level (2)?*

Ans. It means return to normal level must be effected within 24 hours.

Q. *If for example sodium concentration exceeds 12 ppm in a 145 atm boiler or 2 ppm in a 195 atm boiler what measure should be taken?*

Ans. Switchover to Action Level (3), i.e. shutdown to be taken within four hours.

Q. *Why should there, be a switchover to Action Level (3)?*

Ans. To avoid rapid corrosion of boiler-tubes as effected by highly acidic boilerwater pH.

Q. *Plants using AVT assume all the sodium to be present as NaOH. Why?*

Ans. It is due to the fact that sodium hydroxide is more volatile than other sodium compounds (NaCl, Na_2SO_4) available in boilerwater. (Fig. 27.6)

Q. *How does sodium get into the condensate?*

Ans. It finds its way to the condensate via make-up water treatment system and condenser leakage.

Q. *Why is chloride monitoring required?*

Ans. It exercises a deleterious effect on steam turbines, boilers and condensate-polisher performance.

Q. *What types of deleterious effects does chloride have on steam turbines?*

Ans. It initiates corrosion fatigue, stress-corrosion cracking and pitting type corrosion on bladings.

Q. *What are the deleterious effects chloride exercises on boilers?*

Ans. Corrosion, hydrogen damage and pitting.

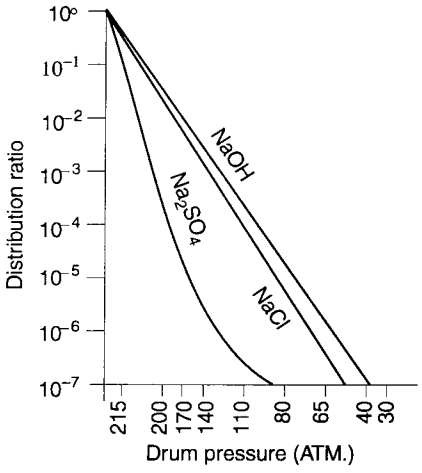


Fig. 27.6 *Distribution ratios of various sodium salts in steam. Sodium Hydroxide has the highest distribution ratio. Hence it is more easily carried over by steam than any other sodium salt found in boiler water.*

Q. *What is the limit of chloride in steam?*

Ans.

3 ppb for reheat units
5 ppb for non-reheat units } according to EPRI

Q. *What is the basis of these values?*

Ans. These are based on the solubility of sodium chloride in superheated steam.

Q. *What is the basis of boilerwater chloride limits?*

Ans. Boilerwater chloride limits are derived on the basis of mechanical and vapourous carryover.

Q. *In which form of compound, is chloride normally carried over in AVT (All-Volatile boilerwater Treatment) plants?*

Ans. Ammonium chloride.

Q. *Why in plants using AVT, are target values of chloride ions assumed on ammonium chloride rather than sodium chloride?*

Ans. Ammonium chloride is more violatile than sodium chloride and so measurement on the basis of ammonium chloride rather than sodium chloride gives more conservative boilerwater chloride values. (Fig. 27.7)

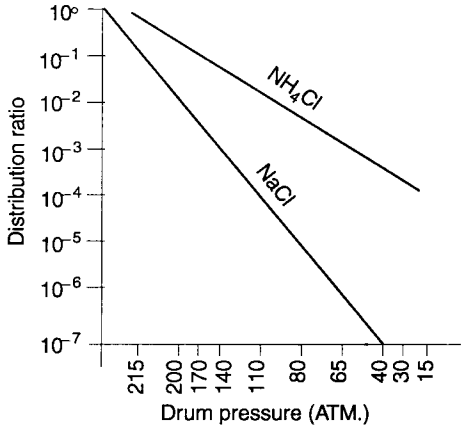


Fig. 27.7 *Distribution ratios of NaCl & NH_4Cl in steam. Ammonium chloride has higher carryover coefficient than sodium chloride.*

Q. *What is the chloride limit in make-up water for boilers using phosphate treatment?*

Ans. It is 3 ppb (as per EPRI).

Q. *Why is sulphate carryover in steam undesirable?*

Ans. This is because of its corrosive action to turbines during operation and to boilers both on- and off-load.

Q. *What are the sulphate limits in superheated steam?*

Ans.

3 ppb for reheat units
5 ppb for non-reheat units } according to EPRI

Q. *Why are these identical to those of chlorine?*

Ans. Sulphate limits, as prescribed above for superheated steam, are identical to those of chlorides, as the solubility of sodium sulphate is similar to that of sodium chloride.

Q. *What is the basis of these sulphate values?*

Ans. These are based on mechanical and vapourous carryover with steam.

Q. *In which form/forms silica may occur in boiler water?*

Ans. Silica may occur either in dissolved state or colloidal state.

Q. *Which 'form' is called reactive silica?*

Ans. Silica in dissolved form is called reactive silica.

Q. *Which 'form' is called unreactive silica?*

Ans. Silica in colloidal form is called unreactive silica

Q. *Why is dissolved silica called reactive silica?*

Ans. Silica in dissolved form is volatile and easily carried off by the steam. Its solubility in steam commensurates with steam-temperature and pressure. this dissolved silica carried over by steam precipitates where steam pressure (and enthalpy) drops, i.e. in the turbine blades. These are very difficult to dislodge from sites with the effect that the efficiency and capacity of the turbine get reduced.

Q. *Is it true that quite a significant amount of colloidal silica passes into condensate/feedwater undetected with make-up water?*

Ans. Yes.

Q. *What are the silica limits for steam?*

Ans.

Steam Generation Unit	Silica Limit
Reheat type	10 ppb
Non-reheat type	20 ppb

Q. *Which one of the two—vapourous carryover and mechanical carryover—is the major source of silica in steam?*

Ans. Vapourous carryover.

Q. *Why is a silica target-value of maximum 10 ppb for condensate and make-up water selected?*

Ans. It will ensure maximum blowdown control and flexibility in operation during excursions.

Q. *Why is phosphate controlled to ensure a sodium to phosphate molar ratio in the range 2.3 to 2.8 with excursions limited to 2.9?*

Ans. To prevent the presence of free NaOH.

Low sodium-to-phosphate ratios are also maintained to avoid acid attack.

Q. *Why are excusions limited to a minimum ratio of 2.1?*

Ans. To avoid the formation of phosphoric acid.

Q. *What is the effect of dissolved oxygen in boiler-water?*

Ans. Dissolved oxygen in boiler water is unwanted because of its corrosive effect throughout the cycle and the carryover and deposition of corrosion products as a result.

Q. *How can its presence in boilerwater be minimized?*

Ans. By using chemical scavengers like hydrazine in high pressure units and mechanically with deaerators.

Q. *What is the target value, according to EPRI, of dissolved oxygen in the deaerator effluent?*

Ans. 7 ppb.

Q. *Why is the dissolved oxygen monitoring at the inlet to deaerator required?*

Ans. It serves as a check on the effectiveness of deaeration and chemical scavenging.

Q. *If a chemical scavenger (say hydrazine) is added just upstream of the deaerator what will be the effect?*

Ans. This will supplement mechanical scavenging of dissolved oxygen from the BFW and improve the deaerator's efficiency.

Q. *What decides whether the chemical scavenger (N_2H_4) feedrate is adequate or needs modification?*

Ans. The hydrazine residual at the deaerator inlet compared to the dissolved oxygen concentration serves as the basis for control of the feedrate of hydrazine.

Q. *Can you identify an inexpensive as well as reliable on-line method for monitoring the overall level of contamination?*

Ans. Specific conductivity measurement.

Q. *How can the specific conductivity measurement lead to the determination of contaminants and their form?*

Ans. The boilerwater impurities that lend themselves to specific conductivity measurement are all ionic in nature. And the specific conductivity (i.e. ionic mobility) of such an ionic impurity depends on the form of ion—salt, acid or alkaline form. Therefore, the specific conductivity measurement monitors the overall level of the contaminants that are present and their form.

Q. *What does degassed cation conductivity reflect?*

Ans. It reflects only the total non-volatile anionic impurity level.

Q. *What do economizer-inlet cation conductivity target values reflect?*

Ans. They reflect the sum of the cation conductivities contributed by individual anions and infiltration of carbon dioxide to air inleakage.

Q. *What is the targeted value of condensate and steam cation conductivity in power-plants?*

Ans. Below 0.1 μS/cm (micro Siemens/cm)

Q. *What is the level of sodium and chloride impurities in condensate that power-point operators generally strive to maintain?*

Ans. Less than 3 ppb, i.e. less than 3 μg/lt.

Q. *Why is a reliable water-quality monitoring system required?*

Ans. 1. To measure accurately and consistently the concentrations of impurities in the boilerwater to ensure high water and steam quality
2. To record data
3. To alert the operators when the prescribed limits are exceeded.

Q. *What is water demineralization?*

Ans. It means the removal of cations and anions of substances dissolved in water.

Q. *How is demineralization carried out?*

Ans. Pretreated water free from coarse-dispersed and colloidal impurities is passed through a series of cation exchangers where cations like Ca^{2+}, Mg^{2+}, Na^+, NH_4^+ and other metal ions are substituted by H^+ ions. Then it is passed through a series of anion exchangers where anions like SO_4^{2-}, NO_3^-, NO_2^-, HCO_3^-, CO_3^{2-} and Cl^- are substituted by OH^- ions. The resulting water is demineralized water. (Fig. 27.8)

Q. *What is ion-exchange resin?*

Ans. Resins are cross-linked polymers of styrene and divinylbenzene. They are hard, insoluble substances formed into beads. (Fig. 27.9)

They attain ion-exchange properties when an acid group (say SO_3H) or a basic group [say—$N^+(CH_3)_3$] is introduced to its pendant phenyl groups as a result of electrophilic substitution.

Q. *How can a cation-exchange resin be produced?*

Ans. When such a polymer of divinylbenzene is sulphonated, an insoluble resin with sulphonic acid groups appended to its surface as a result of electrophilic substitution on the pendant phenyl groups (from styrene units) is obtained. (Fig. 27.10).

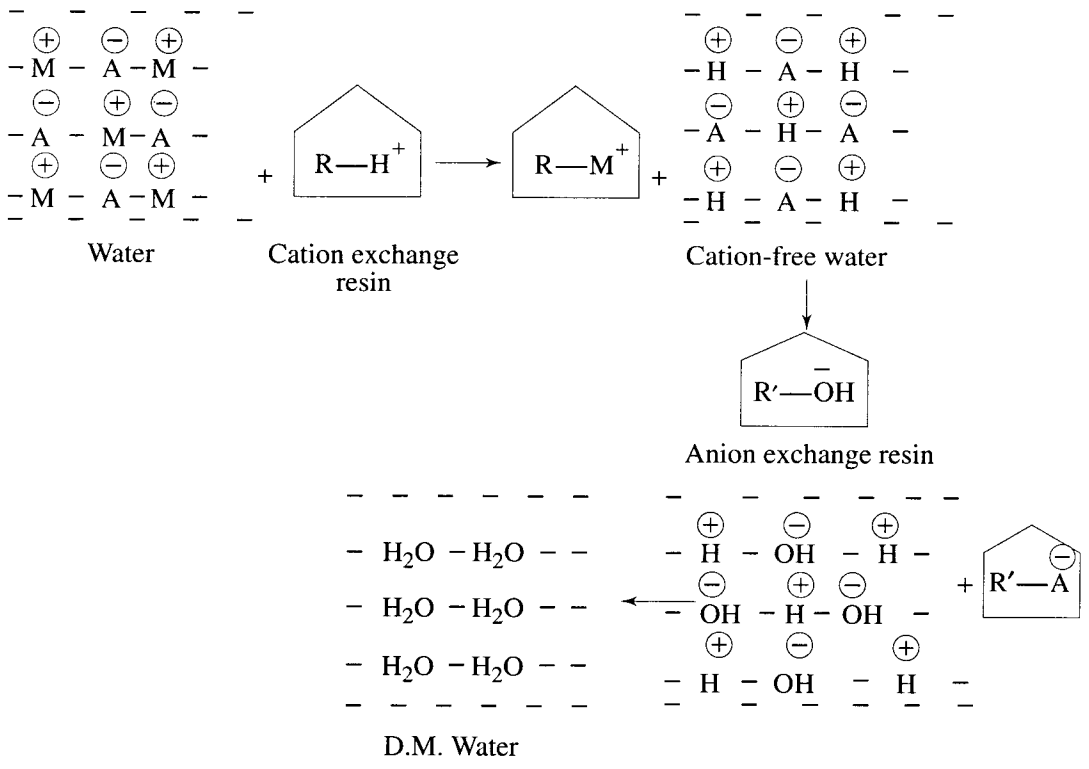


Fig. 27.8 *Demineralization process*

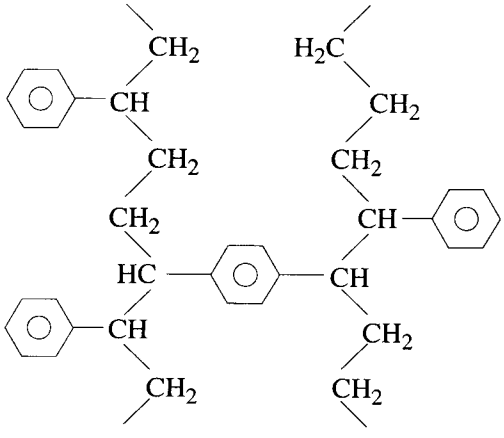


Fig. 27.9 *Resin structure.*

This sulphonic acid substituted resin is called the **cation-exchange resin** or **cation exchanger**.

Q. *Why does the sulphonated resin serve as a cation exchanger?*

Ans. The protons of substituted SO_3H (sulphonic acid) groups are only held electrostatically and are very labile. They easily migrate away in an adjacent water phase as long as another positive ion from the aqueous solution can move in to take its place and balance the negative sulphonate groups, (Fig. 27.11).

Q. *How can an anion exchange resin be produced?*

Ans. The polymerized divinylbenzene upon chloromethylation followed by trimethyl amination yields another resin known as anion exchange resin. (Fig. 27.12).

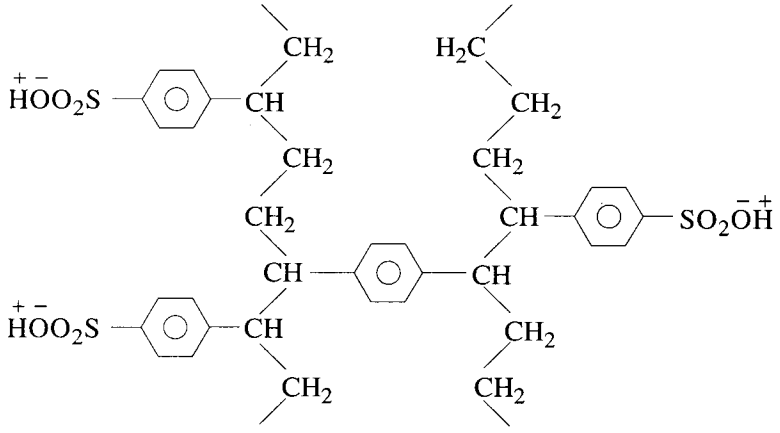


Fig. 27.10 *Sulphonated derivative of styrene divinylbenzene polymer is a cation exchange resin.*

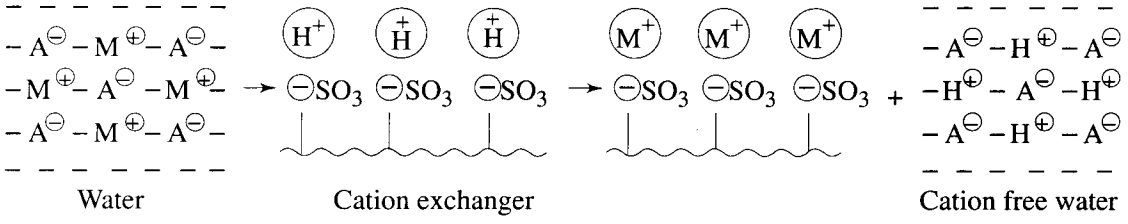


Fig. 27.11 *Cation exchanger removes reversibly the metal cations from the treated water.*

Q. *How does this resin serve as an anion exchanger?*

Ans. The hydroxyl group of substituted trimethyl amine ($—N^+(CH_3)_3OH$) is held by a weak electrostatic force on the surface of the base molecule of the resin and is capable of being replaced by another negative radical or ion from the aqueous phase. That is how it lends the resin anion exchange properties. (Fig. 27.13).

Q. *How can the overall process of demineralization be described schematically?*

Ans. It involves two basic steps:

1. Removal of metal cations (Ca^{2+}, Mg^{2+}, Fe^{2+}, Na^+, K^+, Al^{3+} represented by M^{n+}) in the cation exchanger
2. Removal of the anion (like CO_3^{2-}, HCO_3^-, SO_4^{2-}, Cl^-, etc. represented by A^{n-}) by the anion exchanger. (Fig. 27.14)

Q. *Why is softened water and not untreated water fed to the DM-unit?*

Ans. Water treatment reduces the quantum of total dissolved solids (TDS) in water and therefore, softened water contains less amount of TDS, organic impurities, coarse-dispersed and colloidal impurities than untreated water. Therefore, the load on the DM-unit becomes much less when softened water instead of untreated water is used.

Q. *Why should the water charged to a DM-Unit be free from coarse dispersed and colloidal impurities?*

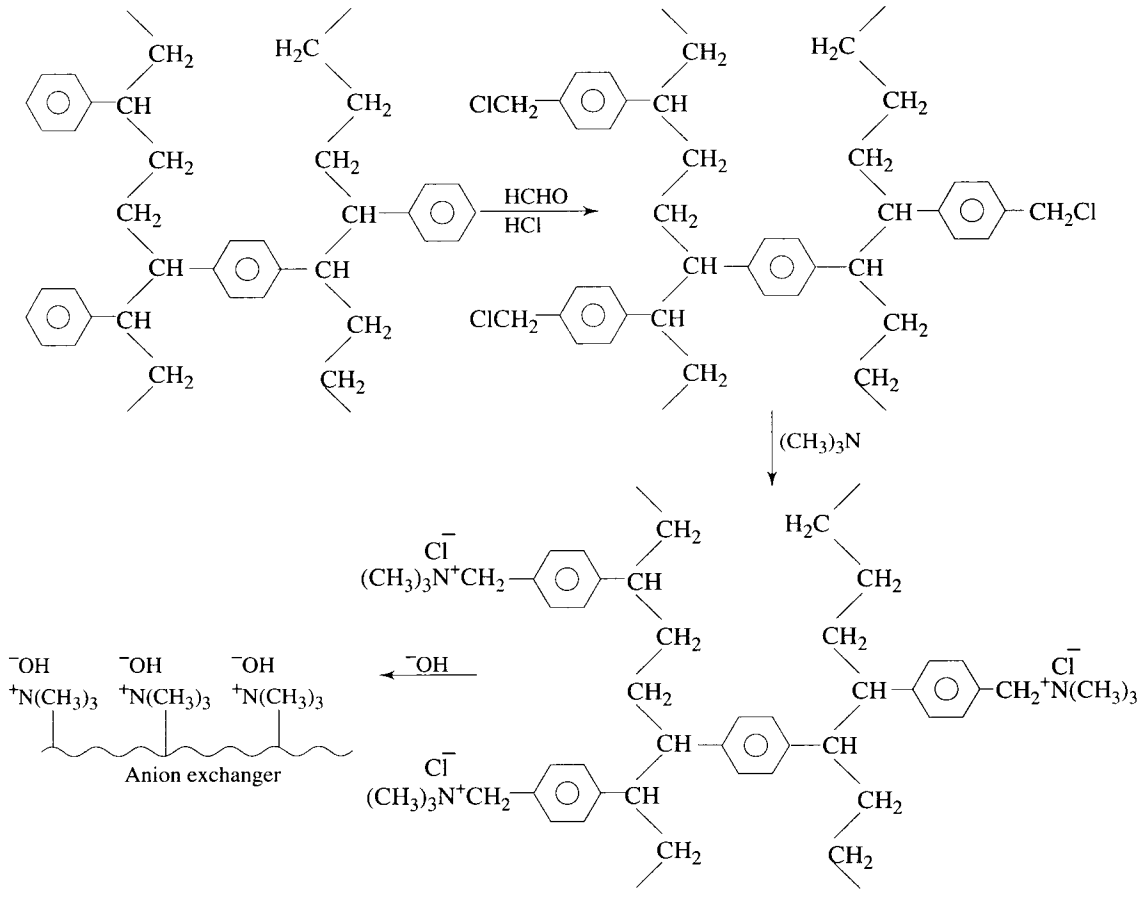


Fig. 27.12 *Anion exchanger is a styrene-divinylbenzene polymer with substituted trimethylamine cations.*

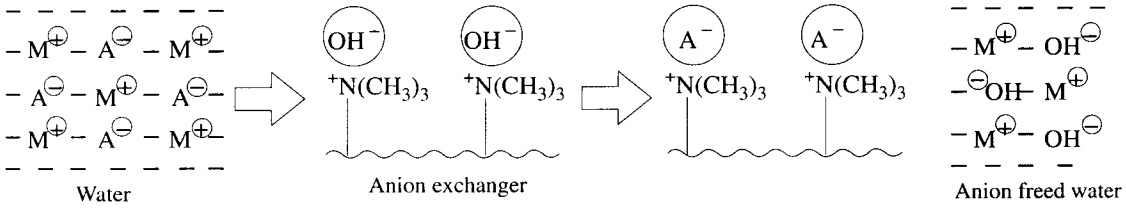


Fig. 27.13 *Anion exchanger removes reversibly the negative radical or ion from treated water.*

Ans. These may precipitate on the resin surface affecting the overall performance of the demineralizing unit.

Q. *Why is water first passed through a cation-exchanger and then the anion-exchanger but not the other way around?*

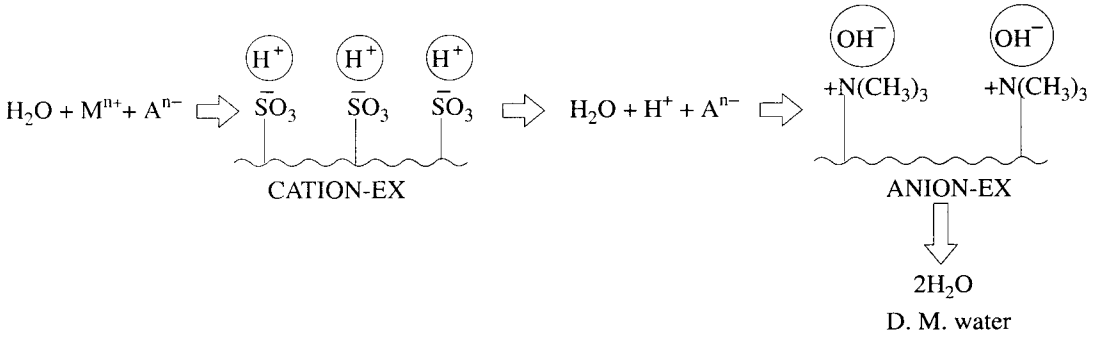


Fig. 27.14 *The process of demineralization is realized through the combined action of cation and anion exchangers.*

Ans. When water is treated in the sequence:

$$\text{WATER} \longrightarrow \boxed{\text{Cation-Exchanger}} \longrightarrow \boxed{\text{Anion-Exchanger}} \longrightarrow \text{DM WATER}$$

the water at the exit of the cation-exchanger becomes acidic due to substitution of metal cations by the H^+ ions of resin

$$R—H^+ + M^+ A^- \longrightarrow R—M^+ + H^+ + A^-$$

(TDS)

These freed H^+ ions go to liberate CO_2 from HCO_3^- ions present

$$HCO_3^- + H^+ \longrightarrow H_2CO_3 \longrightarrow H_2O + CO_2$$

in the aqueous phase and thereby reduce the load on the anion-exchanger as well as lower the pH so that insoluble sulphates are not precipitated,

$$Ca^{2+} + SO_4^{2-} \longrightarrow CaSO_4\downarrow$$

to impair the activity of the resin bed.

If, on the other hand, treated water is passed first through an anion-exchanger and then a cation-exchanger, water at the exit of the anion-exchanger will be alkaline

$$R—OH + A^- + M^+ \longrightarrow R—A + OH^- + M^+$$

ANEX

as a result of which carbonates and sulphates of certain metal cations will be precipitated over the resin bed impairing the exchange-efficiency of the anion exchanger.

Q. *How is the degree of demineralization measured?*

Ans. It is measured conveniently by the conductivity test. As the water gets deminizeralized its conductivity λ decreases or resistivity ρ increases

$$\lambda = \lambda^+ + \lambda^- \text{ Ohm}^{-1} \text{ cm}^{-1}$$

$$= (0.1—0.2) \times 10^{-6} \text{ Ohm}^{-1} \text{ cm}^{-1} \text{ for deep demineralized water}$$

where λ^+ = conductivity of cations

λ^- = conductivity of anions

$\rho = (5—10) \times 10^6$ Ohm cm. for deep demineralized water

Q. *Why is quantitative estimation of TDS in DM water not preferred?*

Ans. It is a laborious and time consuming process.

Q. *Apart from ion-exchange method what are the other methods of demineralizing water?*

Ans. 1. Electrodialytic method
2. Hyperfiltering (reverse osmosis) method
3. Thermal method
4. Magnetic method.

Q. *What is the drawback of the ion-exchange method?*

Ans. When the resin beds are exhausted, i.e. when all the H^+ ions of the cation-exchanger and all the OH^- ions of the anion-exchanger have been replaced by cations and anions respectively, the resin beds are regenerated by the using concentrated sulphuric acid (cation-exchanger) and caustic alkali (anion-exchanger) respectively. And as this takes up great quantities of these chemicals the expenditure mounts.

Q. *Why is sulphuric acid and not nitric acid used during regeneration of the cation exchanger?*

Ans. Nitric acid is an oxidizing agent which will oxidize resin molecules which are polymeric organic compounds.

Q. *Why is hydrochloric acid not commonly used for the regeneration of cation-exchangers?*

Ans. It is costly.

Q. *Why are organic acids not used for regeneration of cation-exchangers?*

Ans. These are weak acids and will accomplish only partial regeneration of exhausted cation exchangers. Moreover, they are costly.

Q. *Why is a mixed bed used in a DM-Unit?*

Ans. A mixed bed containing both cation-and anion-exchange resins is used to arrest silica slippage

DM WATER → MIXED BED → POLISHED WATER

(Silica: 0.7 ppm] [Silica : 0.01 ppm]

(Fig. 27.15)

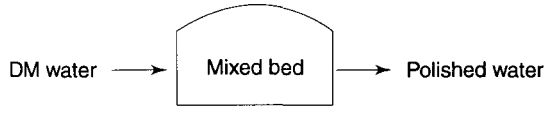


Fig. 27.15

Q. *What is sodium slippage?*

Ans. Due to their relatively smaller size, sodium ions have higher charge density on their surface. That is why they get highly hydrated, rendering the Na^+ ions to slip past the resin (cation-exchanger) bed and contribute to the increase in electrical conductivity of the DM water output.

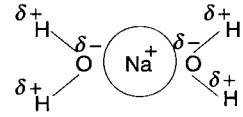


Fig. 27.16 *Hydrated sodium ion*

Q. *How much will the conductivity of DM water be increased if Na^+ slippage is 1 ppm?*

Ans. Usually 5 micro MHO/cm.

Q. *What is the difference between a Strong Acid Cation Exchanger (SAC) and a Weak Acid Cation Exchanger (WAC)?*

Ans. The only distinguishing feature is that the former contains strong acid groups such as—SO_3H (sulfonic acid group) and the latter contains weak carboxylic acid group (—COOH) substituted on the appended phenyl nucleus of the resin—a porous and permeable, inert, polymeric organics substance. That is, the former has SO_3H groups and the latter—COOH groups in the cation exchange sites.

Q. *What is the advantage of an SAC over a WAC?*

Ans. SAC can function well at all pH values while WAC fails to function effectively at pH below 5.

SAC can remove all cations associated with both strong and weak acids were as WAC can remove cations of weak acids only, i.e. cations associated with water alkalinity , silicic acids and organic acids.

Q. *What is the chief advantage of Weak Acid Cation Exchangers (WAC) over Strong Acid Cation Exchangers (SAC)?*

Ans. Weak Acid Catex (WAC) have comparatively very high regeneration efficiency as a result of which they require only 110–120% ex-

cess acid over theoretical quantity of acid for regeneration, whereas SACs require as much as 150% to 300% more acid than the theoretical quantity.

Another advantage of WACs is that they require very dilute acid, as low as 0.5%, for their efficient regeneration. This dilute acid can be readily available from waste acid regenerant of SAC.

Q. *What is the difference between Strong Base Anion Exchangers (SBA) and Weak Base Anion Exchangers (WBA)?*

Ans. The Strong Base Anex (SBA) have quarternary amine ($—\overset{+}{N}\cdot R_4$) groups while Weak Base Anex (WBA) have primary amine ($R\cdot\overset{+}{N}\cdot H_3—$), secondary amine ($R_2\overset{+}{N}H_2—$) and tertiary amine ($R_3\cdot\overset{+}{N}H—$) groups substituted on the appended phenyl nucleus of the resin for exchange of anions.

Q. *What is the advantage of a Strong Base Anex (SBA) over a Weak Base Anex (WBA)?*

Ans. SBA can remove all anions—the conjugate base of all acids right from sulphuric, hydrochloric and nitric to weak acids like silicic acid and carboxylic acids whereas WBA can readily remove SO_4^{2-}, Cl^-, NO_3^-—the conjugate base of strong acids H_2SO_4 HCl and HNO_3 but not the anions of weak acids, viz. silicic acids, carboxylic acids, etc.

Unlike WBA, SBA can function well in the entire range of pH.

Q. *What is the advantage of WBA over SBA?*

Ans. Weak Base Anex have higher regeneration efficiency than Strong Base Anex. As such WBA require only 120–140% excess of theoretical regenerant whereas SBA require as much as 150-300% excess over theoretical regenerant.

SBA must be regenerated with strong alkali, i.e. caustic soda (NaOH) solution alone. WBA, in contrast, require less expensive alkali, viz, soda ash (Na_2CO_3) solution or ammonia solution for regeneration. They can be regenerated even with the spent caustic regenerant of SBA.

Q. *What parameters characterize the ion exchangers?*

Ans. A number of parameters are involved. The most important among them being

1. Operating exchange capacity
2. Granulometric composition (grain size)
3. Bulk mass
4. Swelling factor
5. Thermal stability.

Q. *What is operating exchange capacity of an ion exchanger?*

Ans. It is the gram-equivalents of ions absorbed by 1 m^3 of ion exchanger. Hence it is expressed in terms of g-equiv./m^3. So when this value is reached during service cycle, the ion exchanger is said to have been exhausted.

Q. *Why cannot the initial water having high salt content (≥ 800 ppm) be softened sufficiently in one softener?*

Ans. This is because of the counterion effect—a phenomenon which occurs as follows.

As water with high salt content is passed through the bed of the hydrogen cation exchanger, the concentration of H^+ ions grows in the water. As it flows downward, more and more H^+ of cation exchangers are replaced by cations like Ca^{2+}, Mg^{2+}, N^+H_4, etc. The concentration of H^+ ions becomes maximum at the bottom part of the bed. This increased concentration of H^+ ions counteracts the dissociation of cation exchangers, obeying the La Chatelier Brown principle,

$$R—H \rightleftharpoons R^- + H^+$$

H-exchanger

thereby reducing the rate of ion-exchange process near the bottom zone of the bed. Therefore, a good amount of cationic load remains in the effluent.

Q. *It is said that a decrease in HCO_3^- ion concentration in the water being subjected to hydrogen cation exchange treatment intensifies the counterion effect. How does this happen?*

Ans. The presence of HCO_3^- ions has some favourable effect in counteracting the counterion effect as induced by liberated H^+ ions by rich load of cations in water passing through a bed of H-cation exchanger. These HCO_3^- ions bind the H^+ ions

$$HCO_3^- + H^+ \longrightarrow H_2CO_3 \Leftrightarrow H_2O + CO_2$$

thereby reducing the concentration of H^+ ions accumulated in water during the course of cationic exchange So H^+ ion-enrichment cannot take place (near the bottom of the bed) and therefore counterion effect is much reduced.

Therefore it is evident that with the decrease of bicarbonate concentration in the initial water, the counterion effect intensifies.

Q. *What is the swelling factor?*

Ans. Ion exchange resins swell in water. The degree by which they swell in volume is defined by swelling factor, ϕ, which is given by

$$\phi = A\ H\ M_b/Q_c$$

where A = Area of cross-section of cation-exchange bed, m^2

H = Height of the bed, m

M_b = Bulk mass of cation exchange resin, t/m^3

Q_c = Quantity of cation exchange resin, t

Q. *What is its significance in the practical field?*

Ans. Swelling factor must be taken into consideration during charging of ion exchange resin in the vessel. Otherwise, the bed thickness may be rather high and entail the risk of resin loss during backwashing.

Q. *What do you mean by the term breakthrough?*

Ans. It refers to the amount of contaminating cations (Ca^{2+}, Mg^{2+}, Na^+, for example) and anions Cl^-, SO_4^{2-}, etc.) entrained by the water softened by H-cation exchange and anion exchange bed respectively.

During regeneration of the hydrogen cation exchanger, all the absorbed cations, viz, Ca^{2+}, Mg^{2+} and Na^+ are not removed. Particularly those saturating the cation exchange sites of the resin at the bottom layers of the bed cannot be removed by the common straight-flow regeneration technique.

Now during the service cycle these retained cations are liberated by the H^+ ions transferred to the water from the top layers of the bed. These cations will then deteriorate the quality of softened water. Hence the magnitude is determined in terms of breakthrough, i.e. the milligram of cations entrained per kg of effluent water.

$$C_{br} = \frac{C}{1 + \dfrac{k\eta_r}{(100 - \eta_r)}},\ \text{mg/kg}$$

where

C = Concentration of removed ions from treated water, mg/kg

k = Distribution coefficient of ions between ion-exchange bed and water

η_r = Degree of regeneration, %

A similar explanation is valid for an anion exchanger.

Q. *To what type of ion-exchange material, does the term silicon capacity refer to?*

Ans. Strongly Basic Anion Exchangers (SBA).

Q. *What does it mean?*

Ans. It is an important characteristics of SBA defining the quantity of silicate anions (SiO_3^{2-}), in gram-equivalents, absorbed by 1 m^3 of the resin.

Q. *On which factors does the silicon capacity of the anion exchanger depend?*

Ans. 1. pH value of the water

2. Initial concentration of silicate ions $HSiO_3^-$ in water
3. Specific alkali consumption for regeneration
4. Filtering rate, etc.

Q. *How can penetration of large amounts of carbon dioxide into the water-condensate circuit of a boiler-turbine unit be avoided?*

Ans. This can be done by taking recourse to a greater dosage of ammonia into the feedwater.

Q. *Why?*

Ans. This ammonia will pass into solution and maintain the desired pH level (9–9.2) in the boiler feedwater. This will transform all dissolved CO_2 into carbonate anions which will be conveniently removed by the anion exchanger

$$NH_3 + H_2O \Leftrightarrow NH_4OH \Leftrightarrow \overset{+}{N}H_4 + \overline{O}H$$

$$CO_2 + H_2O \Leftrightarrow H^+ + HCO_3^- \Leftrightarrow CO_3^{2-} + 2H^+$$

$$H^+ + OH^- \longrightarrow H_2O$$

Q. *What is the normal flowrate of water in the Catex and Anex during a service cycle?*

Ans.

	WAC	SAC	Anion Exchangers
FLOWRATE:	6 – 9	18 – 24	9 – 24

(m^3/h per m^2 of resin bed)

Q. *Why is the flowrate of water, during a service cycle, through a WAC lower than that through an SAC?*

Ans. The rate of cation exchange in a WAC is much slower than that in an SAC. Hence lower flowrate is to be maintained in a WAC to avoid slippage of cations.

Q. *When is the regeneration cycle to be started?*

Ans. It is to be started as soon as the resin beds are exhausted, i.e. when all the exchange sites of catex and anex have been saturated with undesirable ions picked up from the water in the course of its demineralization.

Q. *When can it be said that the SAC bed is on the verge of exhaustion and ready for regeneration?*

Ans. It is indicated by a sharp drop in hydrogen ion (H^+) concentration and/or fall of conductivity of water after the SAC bed.

Q. *Why does a sharp drop in H^+ concentration and/or fall in conductivity of water after the SAC bed indicate that the SAC bed is ready for regeneration?*

Ans. As the cation exchanger bed nears its exhaustion, a very small number of active sites will be available on the resin surface for the exchange of their H^+ ions by the metal cations present in the water. Therefore, there will be an abrupt decline in the H^+ ion concentration in water at the outlet of the SAC.

Moreover, as the H^+ ions are more labile than any other cation, they have higher ionic conductivity than any other cation and therefore an abrupt decline in H^+ ion concentration as a consequence of exhaustion of the resin bed means a sharp drop in conductivity of water at the exit of the SAC bed.

Q. *When can it be said that the WAC bed is on the verge of exhaustion and needs regeneration?*

Ans. It is marked by a sharp increase in hardness and/or alkalinity in the water just after the WAC bed.

Q. *Why does an increase in hardness and/or alkalinity in the water just after the WAC bed indicate that the WAC bed needs regeneration?*

Ans. Weak Acid Cation Exchangers (WAC) can remove only those cations which are associated with weak acids, viz. carbonic acid, silicic acid and organic acids, so the exhaustion of WAC bed means an increase in these cations in the exit water. Had these cations been removed by the WAC bed, there would have been sufficient concentration of H^+ ions (transferred from resin) in water which would combine with the anions of

these weak acids and prevent their hydrolysis to cause alkalinity in water.

When WAC is active $\begin{cases} H^+ + HSiO_3^{1-} \rightleftharpoons H_2SiO_3 \\ H^+ + CO_3^{2-} \rightleftharpoons H_2CO_3 \end{cases}$

When WAC is exhausted

$$\begin{cases} HSiO_3^- + H_2O \text{ — hydrolysis} \rightarrow H_2SiO_3 + OH^- \\ CO_3^{2-} + H_2O \text{ — Hydrolysis} \rightarrow HCO_3^- + OH^- \end{cases}$$

Accounts for alkalinity

Q. *What indicates the exhaustion of an anion exchanger?*

Ans. It is marked by a sharp increase in the silicate concentration or abrupt fall of conductivity followed by its rise again in the water at the outlet of anion exchanger.

Q. *What principal steps are involved in the regeneration cycle?*

Ans. The following four steps are involved in the regeneration cycle:

1. Backwashing
2. Acid injection to Catex bed
   Alkali injection to Anex bed
3. Slow rinse
4. Fast rinse.

Q. *What is backwashing?*

Ans. It is the upward flow of softened water through the resin bed. The water is forced through the underdrain of the bed. It flushes up the bed and agitates each bead in a turbulent motion and finally discharges out of the service water distributor and runs into waste.

Q. *What is the purpose of backwashing?*

Ans. Backwashing dislodges the resin fines and filtered particulates from the interspaces of resin beads and therefore cleans the resin surface to ensure efficient regeneration by acid (for Catex regeneration) or alkali (for Anex regeneration) treatment.

Q. *What is the normal duration of backwashing?*

Ans. It is carried out till a clear backwash effluent results. Normally it takes 10 to 15 minutes to complete backwashing.

Q. *What is the flowrate of backwash water?*

Ans. It usually ranges from 12 to 24 m^3/h per m^3 of Catex bed and 3 to 9 m^3/h per m^2 of Anex bed.

Q. *On which factors backwash flowrate depend?*

Ans. 1. Type of resin
2. Backwash-water temperature.

Q. *What is the strength of acid taken to regenerate a cation exchanger?*

Ans. Strong Acid Cation Exchangers are regenerated with 2–6% H_2SO_4

Weak Acid Cation Exchangers are regenerated with 0.5–0.7% H_2SO_4

Q. *What is the flowrate of acid for regeneration?*

Ans. SAC beds are regenerated with an acid flowrate of about 5–10 m^3/h per m^3 of resin bed.

WAC beds are regenerated with an acid flowrate of about 10 m^3/h per m^3 of resin bed.

Q. *What is the strength of alkali taken to regenerate anion exchangers?*

Ans. 4–5% NaOH solution.

Q. *What is the flowrate of regenerant alkali?*

Ans. 5–10 m^3/h per m^3 of resin.

Q. *Is the regenerant fed to the exhausted resin bed in upward flow or downward flow?*

Ans. The regenerant is charged to the resin bed from the top and distributed evenly through the regenerant distributor. The regenerant flows down the bed by gravity and regenerates the beads in the process, and discharges out through the bottom drain into waste.

Q. *Why are some demineralizing plants befitted with sorption filters charged with activated charcoal and set upstream of anion exchangers?*

Ans. This is a measure to trap the organic substances present in the treated water. Since these substances cannot be completely removed by conventional pretreatment, they find their way to the anion-exchange grains and get sorbed as ions. Macro molecules of organic substances infiltrating into the pores of anion-exchangers, particularly SBA, are very difficult to dislodge from the exchange sites during the course of regeneration and therefore poison the anion exchange resins and reduce their exchange capacity. However, activated charcoal filters mounted upstream of the anion exchanger will trap these unwanted organic molecules and safeguard the exchanger.

Q. *Why is alkali or acid injection followed by slow rinsing?*

Ans. After alkali (Anex bed) or acid (Catex bed) treatment, the rejuvenated resin beds are subjected to a low downward flow of rinse water containing an insignificant amount of ions. This is carried out to remove any remaining alkali or acid.

Q. *Why is slow rinse to be followed by fast rinse?*

Ans. Fast rinsing of the resin bed, at a rate of 15–20 m^3/h per m^3 of resin, follows slow rinsing to dislodge any local regenerant trapped in the interspace of resin beads. The flow is downward.

Q. *How is a mixed bed demineralizer regenerated?*

Ans. A mixed bed demineralizer is an infinite series of cation and anion exchangers packed in a single column. When exhausted as determined by conductivity test and/or silica measurement—the bed can be regenerated through the following successive steps:

1. BACKWASHING: The bed is thoroughly backwashed to separate completely the anion exchange resin from cation exchange resin into two beds. Anion exchangers being lighter than the more compact cation exchangers form the top bed.
2. ACID INJECTION: Regenerating acid (H_2SO_4) is charged to the column through the bottom distributor. It moves up through the catex bed which gets regenerated in the process and the acid flows out of the interface collector to the drain.
3. ALKALI INJECTION: The caustic is introducted from the top via the upper distributor and moves down the anex bed which whereupon gets regenerated. The alkali then flows out of the interface collector to the drain.
4. RINSING: The bed is then subjected to a short rinse to purge out any excess acid or alkali remaining.
5. MIXING: The anion and cation exchange resins are then thoroughly agitated by air introduced from the bottom to mix them uniformly.
6. FINAL RINSING: The column is filled up with polish water and rinsed till the effluent is of acceptable quality to declare the M.B. ready for line-up.

Q. *What combination of cation exchanger and anion exchanger should be most economical where silica and CO_2 removal from feedwater is not essential?*

Ans. Strong Acid Cation Exchanger (SAC) is to be hooked up in series upstream of a Weak Base Anion Exchanger (WBA)

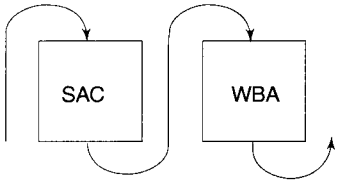


Fig. 27.17

While the metal cations are absorbed in the SAC bed, silicate and carbonate anions slip through the anion exchanger downstream as it is a weak base type.

Q. *What is the advantage of such a system?*

Ans. Equipment as well as regeneration costs are low.

Q. *However, if silica removal is not required but CO_2 elimination is necessary, what demineralization system would serve the purpose most economically?*

Ans. One degasifier (DG) should be lined up in series downstream of the above system. (Fig. 27.18)

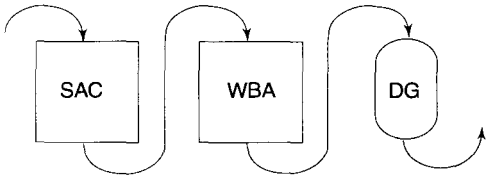


Fig. 27.18

The CO_3^{2-} anions, escaping arrest by WBA, form gaseous carbon dioxide with the H^+ protons liberated in the SAC bed:

$$CO_3^{2-} + H^+ \rightleftharpoons HCO_3^- \xrightarrow{H^+} H_2CO_3 \longrightarrow H_2O + CO_2$$

The carbon dioxide is eliminated in the degasifier downstream of the WBA.

Q. *What is the conductivity of effluent water after the degasifier above?*

Ans.

λ = 10–20 μ S/cm.

cf. [1 μ S/cm = 1 micro Siemens/cm

= 10^{-6} Ohm^{-1} cm^{-1}/cm]

Q. *Which demineralizing system will be technically suitable to remove silica (along with other ions) from treated water where alkalinity is low?*

Ans. A Strong Acid Cation Exchanger (SAC) and Strong Base Anion Exchanger (SBA) joined in series will serve the purpose. (Fig. 27.19).

SAC bed eliminates all cations associated with both strong and weak acids and SBA bed removes all anions associated with both strong and weak acids, viz silicic acid.

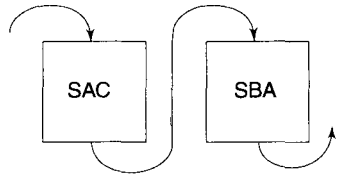


Fig. 27.19

Q. *What will be the silica level in the effluent in this case?*

Ans. It will be in the range 0.02—0.1 ppm.

Q. *What will be the conductivity of this effluent?*

Ans. 5—10 μS/cm, i.e. (5 – 10) $\times$ 10^{-6} Ohm^{-1} cm^{-1}/cm

Q. *What is the chief disadvantage of this set-up?*

Ans. High chemical costs.

Q. *Which demineralizing system will ensure efficient removal of silica from treated water whose alkalinity is high?*

Ans. One degasifier inserted between SAC and SBA beds in the above combination will fulfill the task.

Much of the carbonate alkalinity will be eliminated in the degasifier (Fig. 27.20).

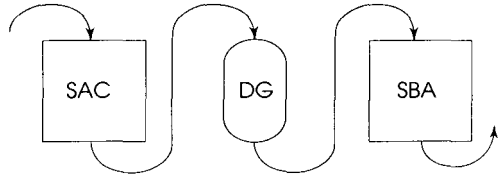


Fig. 27.20

$$2H^+ + CO_3^{2-} \longrightarrow H_2O + CO_2$$

(effluent of SAC bed)

thereby reducing the load on SBA.

Q. *What will be the silica level in the effluent?*

Ans. 0.02—0.1 ppm.

Q. *What is the advantage of this system?*

Ans. Low chemical cost.

Q. *Why does this system have a low chemical cost?*

Ans. Degasifier eliminates the CO_3^{2-} ions and thereby minimizes the load on the Strong Base Anion Exchanger downstream. This will ensure a longer service period of the SBA before it is being subjected to regeneration. This buys economy in regenerant expenditure.

Q. *If silica removal (along with other ions) is required from water having high alkalinity, high chloride and sulphate concentrations, what demineralization system will be both technically and economically viable?*

Ans. One each of Strong Acid Cation Exchanger, Weak Base Anion Exchanger, Degasifier and Mixed Bed hooked up in series will fulfill the requirement.

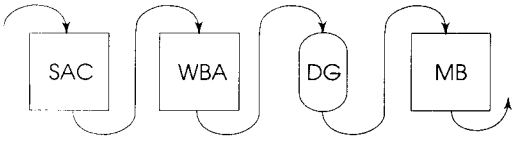


Fig. 27.21

While SAC bed eliminates all the cations belonging to both mineral acids (HCl, H_2SO_4, etc.), and weak acids (silicic acid, carbonic acid), the WBA bed removes all anions of strong acids (HCl, H_2SO_4). As the effluent of WBA bed passes through the degasifier, the CO_3^{2-} ions are eliminated as CO_2. Silica that is not arrested in the WBA bed is eliminated in the M.B.

Q. *What is the silica content of the final effluent of this system?*

Ans. 0.02—0.1 ppm

Q. *What is the conductivity of the final effluent?*

Ans. 5—15 μS/cm

Q. *What demineralizing system will effectively remove silica (together with other ions) from water with high alkalinity, high hardness and high chloride and sulphate?*

Ans. A WAC-SAC system linked to a WBA-SBA system via a degasifier will ensure demineralization plus silica removal. (Fig. 27.22)

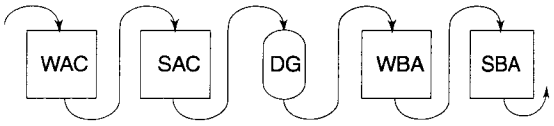


Fig 27.22

The WAC bed reduces the load on the SAC bed by removing all cations associated with weak acids like silicic acid.

The SAC bed removes all cations.

The degasifier eliminates CO_3^{2-} ions and thereby reduces the load on WBA bed which further reduces the load on the SBA bed by scavenging out SO_4^{2-}, Cl^- anions readily.

Q. *What is the silica level in the final effluent of this system?*

Ans. It ranges from 0.02 to 0.1 ppm.

Q. *What is the advantage of this system?*

Ans. Lowest chemical costs.

Q. *What are the disadvantages of this system?*

Ans. 1. Equipment cost is high
2. Repumping is required

Q. *Which convenient DM system will ensure polish water output economically from the treated water which has high alkalinity and high sodium content?*

Ans. The following arrangement (Fig. 27.23) of exchangers and degasifier hooked up in series may ensure this.

Nearly all cations associated with both strong and weak acids are eliminated in the 1st SAC bed.

Followed by this, the degasifier removes all carbonate ions from the acidic effluent of SAC and thereby reduces the load on SBA that

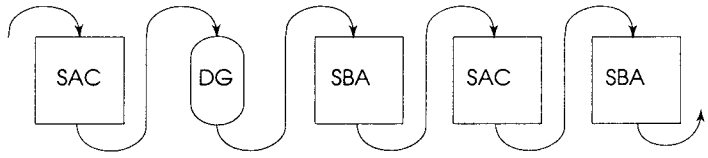


Fig. 27.23

$$CO_3^{2-} + 2H^+ \longrightarrow H_2O + CO_2$$

removes all anions—those of both strong and weak acids.

Any leftover cations and anions slipping out will be arrested in the final SAC and SBA beds respectively.

Q. *What is the silica content in the final effluent?*

Ans. As low as 0.01 to 0.05 ppm.

Q. *What is the conductivity of the polish water obtained this way?*

Ans. 0.1—5 μS/cm, i.e. (0.1—5) $\times 10^{-6}$ ohm^{-1} cm^{-1}/cm

Q. *What is the advantage of this system?*

Ans. Low chemical costs.

Q. *What are the disadvantages of this combination?*

Ans. It requires repumping and the equipment cost is high.

Q. *If polish water (i.e. highly pure DM water) is required from treated water which has high alkalinity and high dissolved solids, what convenient DM system will ensure this?*

Ans. A combination of SAC, degasifier and SBA will ensure DM water (Fig. 27.24)

which when passed through a mixed bed which is an infinite series of cation and anion exchange systems will produce polish water.

Q. *What is the silica content of the polish water output of this system?*

Ans. As low as 0.01 to 0.05 ppm.

Q. *What is the conductivity of the final effluent?*

Ans. 1 μS/cm.

Q. *What is the advantage of this system?*

Ans. Low chemical costs.

Q. *What are the disadvantages of this system?*

Ans. It requires repumping and the equipment cost is high.

Q. *What factors are responsible for the malfunctioning of the demineralization system?*

Ans. There are basically four principal factors:

1. Mechanical failures
2. Resin degradation and/or fouling
3. Improper operational controls
4. Abrupt changes in the characteristics of feedwater.

Q. *What types of mechanical failures are responsible for the malfunctioning of a DM system?*

Ans. This means physical defects in the equipment of the DM system and may come in the form of broken or plugged distribution laterals, clogged underdrain screens and malfunctioning of multiport valves.

Q. *What do you mean by resin degradation?*

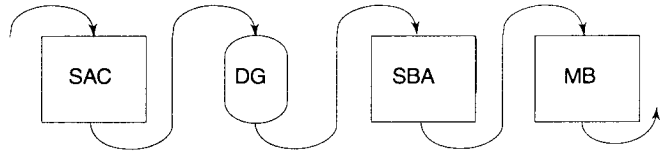


Fig. 27.24

Ans. It refers to the breakdown of ion exchange properties of resin inflicted by some external agencies or processes.

Q. *How many types of resin degradation are there?*

Ans. 1. Physical degradation of resin
2. Chemical degradation of resin
3. Resin degradation by fouling.

Q. *How does physical degradation of resin occur?*

Ans. It may be due to
(a) osmotic shock
(b) thermal shock
(c) mechanical shock.

Q. *What is osmotic shock?*

Ans. Periodic contraction of resin beads during service cycle and expansion during regeneration cycle induce in the resin structure a physical shock that is called the **osmotic shock**.

Exhausted catex-bed swells when it is subjected to regeneration. SAC swells by 6–8% when it is converted from sodium to hydrogen form during regeneration. The beads again shrink during service cycle as avilable H^+ ions at cation-exchange sites get increasingly replaced by metal cations. This bead expansion followed by bead contraction creates osmotic shock on the resin beads.

In a likewise fashion anex-bed swells upon regeneraion & contracts during service cycle. In fact strong base anion exchange resins (Type I & II both) swell more than the strong acid cation-exchange resins. And so they also undergo osmotic shock due to regeneration and service cycles.

Q. *What is thermal shock?*

Ans. It is the strain induced to the resin structure due to rapid variations of temperature.

Q. *How does it occur?*

Ans. Thermal strain is inflicted to resin when it is subjected to a cold regeneration cycle after a hot service cycle and then repeating the total cycle all over again.

Also the resin may suffer from thermal degradation if it is subjected to operations at temperatures higher than those for which it is designed.

Q. *How is mechanical strain induced to a resin bed?*

Ans. This is due to the load exerted by the resin fines upon the rest of the bed. The resin fines shift to the top of the bed and increase the pressure drop over the bed. As this pressure drop mounts, more resin beads break down to fines which migrate to the top of the bed and inflict more mechanical strain on the resin bed.

Q. *What is the effect of mechanical strain on resin bed?*

Ans. 1. Production of more fines a cumulative way
2. Increase of pressure drop in the resin bed
3. Increased channeling
4. More resin loss during back washing.

Q. *What is chemical degradation of resin?*

Ans. It refers to breakdown of chemical structure of resin resulting from fission of divinylbenzene crosslink of the resin polymer.

Q. *Why does this occur?*

Ans. This occurs due to oxidation of C—C bonds of the cross-link by dissolved oxygen or chlorine

$$Cl_2 + H_2O \longrightarrow 2HCl + O$$

This nascent oxygen produced by dissolved chlorine is powerful enough to rupture the divinyl cross-link.

Q. *What is the effect of chemical degradation of resin?*

Ans. This brings about
(a) hydration of resin and swelling of resin beads

(b) greater pressure drop across the bed
(c) more channeling
(d) more loss in ion-exchange capacity.

Q. *What is resin degradation by fouling?*

Ans. Resin may degrade due to fouling arising from surface coating of resin beads by

(a) metal oxides and inorganic salts
(b) organic substances
(c) oil
(d) microbiological organisms.

Q. *What metal oxides and inorganic salts are known to foul resin beads?*

Ans. These are:

Metal Oxides	Inorganic Salts
Fe_2O_3	$CaCO_3$
Fe_3O_4	$Mg(OH)_2$
CuO	$CaSO_4$
ZnO	Silicate salts
Al_2O_3	

changed with H^+ ions of the hydrogen cation exchanger. These absorbed Fe^{2+} ions are difficult to dislodge during the regeneration cycle, from the exchange site particularly after aging.

Q. *What is the impact of iron fouling on resin?*

Ans. The immediate impacts are:

1. loss of capacity
2. cracking or fragmentation of resin
3. iron leakage.

The most severe condition occurs when Fe^{2+} ions migrate to the inner matrix of a resin bead. When these migrated ions subsequently get oxidized to the ferric state, it becomes extremely difficult to remove them from the body of the resin whereupon the resin suffers from a loss of ion-exchange capacity.

Q. *Why does iron fouling of resin lead to bead-cracking?*

Constituent	Fouling Level			Catex-BED		
(% of Resin wt.)	*Very low*	*Low*	*Moderate*	*Heavy*	*Severe*	*Extremely severe*
Fe^{3+}	< 0.2	0.2—0.35	0.35—0.5	0.5—1	1—1.5	> 1.5

Q. *How does iron oxide fouling occur?*

Ans. Iron may find its way to the resin bed either as insoluble form (Fe^{3+}) or soluble form (Fe^{2+}). Its sources being the corrosion products of water distribution pipeline, contaminated regenerants, organically sequestered iron suspended in the raw water, contamination of turbine condensate by cooling water due to leakage in the turbine condenser, etc. Insoluble ferric oxide (Fe_2O_3) is retained on the surface of the resin beads by virtue of filtration action through the bed. The impervious layer of ferric oxide on resin surface inhibits efficient resin-water contact and thereby reducing the exchange capacity of the resin.

The soluble ferrous ions, on the other hand, find their way to exchange sites by being ex-

Ans. Ferrous ions absorbed and migrated into the body of the resin beads may undergo oxidation during the service cycle whereupon the ferrous ions are converted to insoluble ferric hydroxide occupying a larger volume. As this process occurs in the inner matrix, the affected beads are subjected to internal stress resulting in resin fracture.

Q. *What is the source of copper oxide fouling?*

Ans. The copper and brass tubes of the turbine condenser are the source of copper oxide fouling.

The corrosion and erosion of such tubes transfer CuO and Cu_2O in the condensate which carries them down and deposits them on the resin bed and thereby causes copper oxide fouling.

Q. *How does alumina fouling occur?*

Ans. If the feedwater brings in alumina or aluminium salts because of malfunctioning of alum clarifier in the water treatment plant, flocs of alumina (Al_2O_3) or soluble Al^{3+} ions will appear in the resin bed. While insoluble Al_2O_3 will deposit itself on the resin surface in the same way as Fe_2O_3, soluble aluminium ions will be absorbed at the cation exchange sites of the resin by replacing hydrogen ions (H^+). Since these Al^{3+} ions are held so tightly to the resin, they cannot be easily removed by straight-flow regeneration techniques, thereby decreasing the number of available sites for cation exchange.

The insoluble Al_2O_3 layer on the resin beads is too impervious to allow efficient resin-water contact, with the effect that ion-exchange capacity of H-ion exchanger is reduced.

Q. *What are the adverse effects of aluminum foulant on resin?*

Ans. It tells upon the resin capacity.

What is more harmful of it is that once it accumulates on the bead surface, it gradually penetrates into the body of the beads. And once settled within the body, it cannot be dislodged by normal regeneration. (see Table below)

Q. *Why is it more difficult to remove Al^{3+} ions than Ca^{2+}/Mg^{2+} ions fouling the cation exchange resins?*

Ans. Cation resins have a higher inherent affinity for aluminum ions than for calcium and magnesium ions. So Al^{3+} ions are less readily removed than Ca^{2+}/Mg^{2+} ions during regeneration.

Q. *Why do cation exchange resins have higher affinity for Al^{3+} ions than Ca^{2+}/Mg^{2+} ions?*

Ans. Al^{3+} ion, because of its high surface density of charge* compared to Ca^{2+}/Mg^{2+} ions, is most potentially attracted by the electrostatic pull of the nucleophilic (nucleus seeking, i.e. positive charge loving) appendage of the cation exchange resin molecule.

Q. *Since supercritical pressure once-through boiler unit require highly pure feedwater, how can the concentration of these dispersed and ionic impurities in BFW be brought down to the prescribed level?*

Ans. Such removal can be ensured by a special demineralizing system befitted with mechanical filters and mixed bed units lined up with a series of cation exchanger, degasifier and anion exchanger.

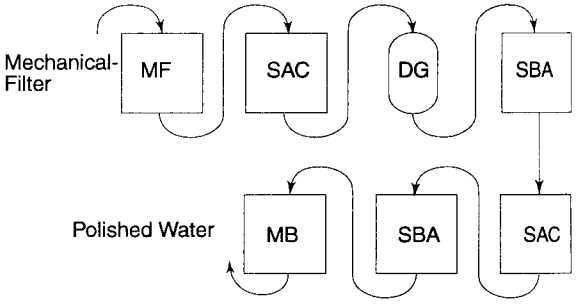


Fig. 27.25

Mechanical filters will remove the dispersed impurities, mainly the corrosion products while the mixed bed will almost completely eliminate any cations or anions escaping absorption in the ion exchangers upstream.

CONSTITUENT (% of Resin wt.)	FOULING LEVEL			CATEX-BED		
	Very low	Low	Moderate	Heavy	Severe	Extremely severe
Al^{3+}	< 0.25	0.25—0.5	0.5—0.7	0.7—1	1—1.5	> 1.5

* The ionic radius of Al^{3+} is much smaller than that of Ca^{2+} or Mg^{2+} : $R_{Al^{3+}} << R_{Mg^{2+}} < R_{Ca^{2+}}$ where, R = ionic radius

Q. *What are mechanical filters?*

Ans. These may be

(a) cellulose tubular-element precoat-type filters
(b) sulphonated-coal filters
(c) electromagnetic filters

Q. *What are the advantages of cellulose tubular-element precoat-type filters?*

Ans. They

(a) possess high unit capacity 500 m^3/h
(b) ensure reliable filtration of suspended impurities in water.

Q. *What are its drawbacks?*

Ans. It is beset with certain basic operational difficulties like

(a) removal and precoating of cellulose layer
(b) the necessity of fitting cellulose traps downstream to arrest drained cellulose.

Q. *What is the chief advantage of sulphonated coal over the cellulose variant of mechanical filters?*

Ans. Better operational reliability. Besides, it also removes, unlike cellulose filters, the NH_4^+ ions from water.

Q. *What is the usual bed thickness of sulphonated coal type mechanical filters?*

Ans. 0.8 to 1 m.

Q. *What is the basic limitation of electromagnetic filters?*

Ans. They remove from water only the magnetic substances leaving all other dispersed impurities free to pass out. That is only the particles of Fe_3O_4 are retained by electromagnetic filters.

Q. *Then why is the use of electromagnetic filters, instead of cellulose tubular-element precoat-type filters or sulphonated coal filters justified?*

Ans. Since the corrosion products consist predominantly of Fe_3O_4, the use of electromagnetic filters is justified.

Q. *What are the impacts of calcium and magnesium fouling on resin?*

Ans. The immediate impacts are:

(a) reduced capacity
(b) hardness leakage.

Use of inadequate quantities of sulphuric acid during the regeneration step leads to a gradual build-up of hardness ions (Ca^{2+}, Mg^{2+}) both on the surface of the beads and within the bead structure. Once such a foulant migrates deep into the resin matrix, it becomes extremely difficult to dislodge it during normal regeneration. This shortens the service cycle and, even worse, reduces resin life. (see Table below).

Q. *Why does calcium carbonate and magnesium hydroxide fouling occur?*

Ans. This is due to inadequate performance of lime softener and/or filtration operation in the raw water treatment plant. Minute particles of calcium carbonate or magnesium hydroxide may be carried over along with feedwater into the demineralizing system or they may also result from their after-precipitation downstream of pretreatment due to malfunctioning of the softener.

Q. *How does calcium sulphate fouling occurs?*

Ans. The possibility of calcium sulphate fouling arises during the regeneration of the cation ex-

CONSTITUENT (% of Resin wt.)	FOULING LEVEL					
	Very low	Low	Moderate	Heavy	Severe	Extremely severe
Ca^{2+}	< 1	1–2	2–4	4–5	5–7	> 7
Mg^{2+}	< 0.5	0.5–0.7	0.7–0.9	0.9–1.5	1.5–2.0	>2

changer bed with sulphuric acid if the regenerant acid (H_2SO_4) concentration is high and its flowrate is low, the calcium ions replaced by H^+ ions of acid from the saturated resin will form sparingly soluble calcium sulphate which will settle as insoluble solid on the surface of the resin beads and thereby cause Ca-sulphate fouling of the resin.

Q. *What is the minimum concentration of sulphuric acid that will entail the risk of $CaSO_4$ fouling of resin beads?*

Ans. The possibility of calcium sulphate fouling becomes significant if the H_2SO_4 concentration exceeds 5% strength.

Q. *Higher the strength of H_2SO_4, greater is the risk of calcium sulphate fouling. Why?*

Ans. The calcium sulphate precipitates from the solution as soon as the ionic product of Ca^{2+} and SO_4^{2-} ions reaches the solubility product of $CaSO_4$.

$$\text{S.P.}_{CaSO_4} = \overbrace{[Ca^{2+}][SO_4^{2-}]}^{\text{IONIC PRODUCT OF } Ca^{2+} \text{ \& } SO_4^{2-} \text{ IONS}} = 2.3 \times 10^{-4}$$

i.e. $[Ca^{2+}]$ $[SO_4^{2-}]$ represents the ionic product of Ca^{2+} and SO_4^{2-} ions.

The presence of sulphuric acid of higher strength (> 5%) increases the concentration of SO_4^{2-} ions in the aqueous phase and with that the ionic product of Ca^{2+} and SO_4^{2-} ions reaches the value of solubility product of $CaSO_4$ early, causing the precipitation of calcium sulphate. This is due to the common ion effect induced by the sulphate ions of the sulphuric acid added as regenerant.

Q. *If the flowrate of regenerant acid (H_2SO_4) is below 10m^3/h per m^3 of resin bed, calcium sulphate fouling also occurs. Why?*

Ans. Low flowrate of regenerant acid solution will endow ample opportunity to facilitate the nucleation and growth of the $CaSO_4$ crystals in the aqueous phase and will allow them to settle on the surface of the resin beads. On the other hand, higher flowrate will drift the crystals away before they grow appreciably in size to settle by gravity, besides scavenging them off the resin beads if they chance to settle on them (resin).

Q. *Why does silica fouling occur?*

Ans. This occurs due to improper regeneration of both strong and weak base anion exchangers. This is due to the formation of colloidal silicic acid within the resin beads as follows. When anion exchangers are regenerated by alkali, the silicate anions $HSiO_3^-$ together with other anions are replaced from the exchange sites of the resin by the hydroxyl ions OH^- liberated by alkali. Since silicate ion is the salt of a weak acid, it undergoes hydrolysis to produce soluble silicic acid:

$$HSiO_3^- + H_2O \longrightarrow H_2SiO_3 + OH^-$$

This soluble silicic acid eventually polymerizes into a colloidal form of silicic acid which causes silica fouling.

Q. *How can fouling silica be minimized?*

Ans. Leaching out the colloidal silica entrapped in the resin beads by warm (50°C) water before subjecting the anion exchangers to warm alkali (NaOH solution) for regeneration.

Q. *How does organic fouling occur?*

Ans. If the raw water source is surface water, there is the likelihood that it may get contaminated with sewage effluent and decaying organic bodies which may add some heavy organic acids, viz. humic acid, fulvic acid and tannic acid to the raw water. These acids, mainly in the colloidal form, escape separation during pretreatment of water and get absorbed at the exchange sites of the anion exchanger. Upon being absorbed by the resin, they close the resin pores and as a consequence the capacity of the ion exchanger is reduced and regeneration becomes incomplete.

Q. *Why do they attack the anion exchangers?*

Ans. Most of these organic foulants, being basically acidic in nature, will naturally seek basic exchange sites and that's why anion exchangers are mostly affected.

Q. *Apart from extrinsic organic foulants, can the organic fouling of resin take place?*

Ans. Yes. The breakdown of divinylbenzene crosslink in the cation exchangers because of oxidation and transfer of the reaction products to the anion exchangers downstream may also irreversibly foul the anion exchange resins.

Q. *Between a weak base anion exchanger and a strong base anion exchanger which one is more resistant to organic fouling?*

Ans. Weak Base Anion Exchanger (WBA).

Q. *Why is WBA more resistant to organic fouling?*

Ans. The Weak Base Anion Exchangers actually exchange their hydroxyl ions for the anions of organic acids and thus scavenge them out of water.

Note: *Because of this scavenging action WBA protects costlier SBA downstream.*

Q. *How does oil fouling affect the ion exchange process of resin?*

Ans. Oil infiltrating the resin bed will coat the beads and agglomerate them into larger particles, with the effect that there will be an increased pressure drop across the bed, besides channeling and premature breakthrough.

Q. *How does microbial fouling affect the ion exchange resin?*

Ans. Microbiological organisms have been found to anchor themselves on the surface of resin and they grow and proliferate by deriving their food from such compounds a nitrates, phosphates, ammonia, oils and other organic compounds. As these microbes, particularly in slimy form, grow, increased pressure drop across the resin bed occurs and water-resin contact is reduced, causing highly contaminated effluent.

Q. *What is the critical ratio of total organic carbon (TOC) to total anions as* $CaCO_3$?

Ans. 1.7×10^{-3}

Q. *What will happen in case this ratio is exceeded?*

Ans. Fouling of anion resins by organics will progressively intensify as anion exchange resins are very susceptible to organic fouling.

Q. *What will be nature of harm?*

Ans. Forasmuch as very few organics are eluted during regeneration, this organic fouling will inflict irreversible loss of capacity.

Q. *Why?*

Ans. Most surface organics are hydrophobic in character. 'Hydro' means water and 'phobic' means disliking. So these water repelling molecules do not entangle water molecules to get themselves evicted from their adsorption-sites. As a result they are strongly held by the strong-base anion resins which are equally hydrophobic. This explains why the organic fouling of resin is most likely irreversible.

Q. *Some plants resort to conventional off-line, alkaline-brine technique. Why is this practised?*

Ans. To reduce organic fouling.

Q. *How?*

Ans. These surfactants are dosed to impart a high degree of hydrophilicity ('Hydro' means water and 'philicity' mans affinity) to both the contaminant and the resin, so that the organic foulants can be ionically replaced during the regeneration step. That is, the ultimate objective is to evict the surface coating organics from the beads and to return normal ion-exchange capacity to the resin.

Q. *Is this any effective process?*

Ans. Though most hydrophilic surfactants do their best, the cleaning is never complete.

Q. *How do the organic foulants act?*

Ans. These foulants having relatively high molecular weights readily block the exchange sites.

Q. *What are the results of organic fouling?*

Ans. 1. Premature leakage
2. Poor effluent quality as regards to silica, pH and conductivity
3. Higher rinse-water requirements as much as 20 to 60 m^3 of resin
4. Cracking and fragmentation of beads if they penetrate the beads
5. Degradation of ion-exchange capacity of resin by blocking exchange sites.

Q. *Oils are hydrophobic substances, so how are they held on the ionic surface of ion-exchange resins?*

Ans. Here weak van der Waals forces come to play. They hold the oil molecules at the adsorption sites on the resin beads.

Q. *What are the effects of oil fouling?*

Ans. The sticky mass of oil film spreading over the resin beads puts up a barrier to the diffusion mechanism of ions at the exchange sites.

This surface film interlocks the beads into a mesh of large entities that gives rise to the 'channeling effect'. This leads to short circuiting through the resin beds and poor regeneration efficiency.

Note: *Oil level as low as 0.5 mg per litre of influent water can lead to resin fouling within a span of only a few months.*

Q. *How can you precisely determine the nature of fouling?*

Ans. By use of resin-analysis data:
1. Organic fouling by TOC measurement of alkaline-brine extracts
2. Physical appearance of resin slurries
3. Fouling level of catex bed by interpreting cation-resin ash analysis
4. Fouling level of anex bed by interpreting anion-resin ash analysis
5. Dry-weight cation-resin capacity
6. Dry-weight capacities of SBA and WBA.

Q. *What is the key informations that is got from resin tests?*

Ans. 1. Loss of exchange capacity
2. Factors responsible for capacity degradation
3. Factors responsible for irreversible damage, if any
4. Types and concentrations of foulants.

Q. *What directives do such information address?*

Ans. 1. Replacement of the resin bed
2. Process continuation without any change
3. Modification of the regeneration technique
4. Adjustment of run length
5. Cleansing of the resin with an appropriate chemical
6. Implementation of additional pretreatment in influent water.

Q. *What benefits does cleaning of the resin with an appropriate chemical have?*

Ans. This system can prove very effective in
(a) maintaining or improving effluent quality
(b) minimizing progressive, reversible resin fouling
(c) upgrading throughput capacity
(d) extending the service life of resin.

The overall effect is reduced plant costs and the elimination of many knotty problems downstream.

Q. *Do you think that this chemical cleaning system will ensure 100% clean-up of the resin?*

Ans. No.

Q. *So what are the limitations of this system?*

Ans. 1. 100% clean-up is never achieved. Severely fouled resin cannot be restored to

virgin state in a single step. Rather, it requires cleaning several times to defoul the resin and that is too to an acceptable level only.

2. Loss crosslinkages are never restored
3. Conversion of fragmented beads to whole beads is never possible.
4. For strong base anion-exchange resins the lost potential of the functional group cannot be restored until and unless the lost capacity is caused purely by blockage of exchange sites by organic or chemical foulants.

Q. *What do you mean by ash content of resin?*

Ans. Total inorganic impurities present in it.

Q. *Does it have any influence on the chemical cleaning of resins?*

Ans. Yes. If the ash content exceeds 10%, chemical cleaning of resins will be less than satisfactory.

Note: *For anion-exchange resins organically fouled with more than 12 mg C per gm of wet resin, exchange potential cannot be effectively restored through a single cleaning process.*

Q. *What is the best approach to optimizing resin performance and service life?*

Ans. **Ist Step:** Identify the potential foulants.
IInd Step: Match the appropriate cleaning chemical to the problem
IIIrd Step: Initiate periodic off-line and on-line cleaning before the resin becomes badly fouled.

Case Study

A papermill in southern USA was suffering from reduced throughput capacity.

Fouling of the catex-unit by inorganic ions was identified as the culprit.

So the company organized a cleaning program for the rebedded resin. Following pretreatment with citric acid, visual inspection and on-the-spot tests were carried out. All indicated that the resin was clean. The system was lined up but the throughput capacity was still reduced. Resin analysis showed the total ash content dropped meagerly from 3.46% to 3.13%.

Thereafter, the company switched over to a different chemical for cleaning and made a 2nd cleaning run with it, which restored the dry-weight capacity to the rated value of the resin. Following the 2nd clean up, the ash content dwindled further to 1.95%.

Q. *What do you infer from this case study?*

Ans. The Ist cleaning was incomplete and ineffective. Citric acid was not the right chemical for cleaning the fouled catex-bed of the papermill. It provided only a very thin recovery of the ion exchange capacity of the fouled cation exchange resin.

However, the IInd cleansing chemical proved itself very effective. It dislodged most of the cationic foulants and restored the dry-weight capacity to the rated value of the catex-bed.

Q. *What other conclusions can you draw from this case study?*

Ans. Proper resin cleaners must be identified to suit to the fouling problem of a particular resin system. Properly selected and applied, these resin cleaners exercise a significant, positive impact on the water quality, resin life, regenerant consumption and operating cost.

If applied indiscriminantly, they are likely to escalate operating costs and polarize the users with a false sense of security about the resin condition.

Q. *Given a choice between cleaning and replacement of a fouled resin bed how does one decide which program to select?*

Ans. The annual resin analysis report is referred.

A complete resin analysis gives a comprehensive survey of

(a) capacity
(b) density

(c) moisture content
(d) iron fouling
(e) organic fouling
(f) ash analysis

This data will indicate the extent to which the resin's chemical functionality and/or physical properties have degraded and hence will provide the very basis for a choice between cleaning and replacement.

Depending on the year of service of the resin and the operating problem directly related to the resin quality, one may go for chemical cleaning or switch over to replacement after giving due emphasis to the resin analysis data.

Q. *For the sake of resin analysis, from which part of the bed is the sample to be collected and when?*

Ans. Resin sample is to be collected from the core.

The sample must be taken immediately after completion of the regeneration cycle.

Q. *Why?*

Ans. The resin, just after complete regeneration, attains the peak of its exchange capacity for the service cycle that will follow.

Resin sample taken from the core gives the most meaningful results than that taken from any other point of the bed.

Q. *Given a sample of SAC (Strong-Acid Cation exchange resin) with 8% cross-linkage when should rebedding of this resin be done?*

Ans. 1. It should be done if the fraction of cracked beads exceed 50% and broken beads 20%. This is valid on the basis of 90% perfect whole beads in the initial charge.
2. If the moisture content exceed 60%
3. If total ash content exceeds 13.5% and moisture content approaches 60% and the resin that rendered its service for a period exceeding its average lifespan.
4. Dry-weight-capacity is less than 4.8 meq/g and ash content is 2%.

Q. *What criteria precipitates the decision to rebed an anion-exchange resin?*

Ans. The resin should be replaced if the
1. moisture content exceeds the upper limit of the new-resin
2. cracked-bead content exceeds 50% and broken beads exceed 20%, assuming 90% perfect whole-bead content initially
3. capacity loss of SBA exceeds or equals 50%
4. organic fouling exceeds 20 mg C/g of wet resin and the resin has crossed its average life span
5. iron fouling exceed 3% in the ash.

Q. *What do you mean by improper operational controls that contribute to malfunctioning of DM systems?*

Ans. Improper operational controls mean deviation from the designed values of:
(a) service flowrate
(b) backwash flowrate
(c) slow-rinse flowrate
(d) fast-rinse flowrate
(e) regenerant flowrate
(f) regenerant concentration
(g) regenerant dosage
(h) water temperature

Q. *If the service flowrate is higher than the designed values, what difficulties may be encountered in a demineralizing system?*

Ans. It may cause
(a) bed compaction and higher pressure drop across the bed as a consequence
(b) channeling
(c) premature breakthrough.

Q. *If, on the contrary, the service flowrate is below the designed value, what difficulties may crop up?*

Ans. 1. Ion slippage
2. Reduced capacity of the DM system.

Q. *If the concentration of regenerant is higher than the prescribed value what will happen?*

Ans. 1. It will lead to osmotic shock
2. It will foul the H-cation exchanger with $CaSO_4$.

Q. *If the concentration of the regenerant is very low, i.e. below the prescribed range of strength what will be the effect?*

Ans. Unsatisfactory regeneration.

Q. *If the regenerant flowrate is very high what will be the effect?*

Ans. Unsatisfactory regeneration because of reduced contact-time.

Q. *If from the record it is found that there is a gradual increase of rinsing time during each regeneration cycle, what conclusion may you draw, provided the same rinse flowrate is maintained everytime?*

Ans. This simply indicates that the resin bed is getting fouled.

Q. *If there is permanent deviation of influent water characteristics turbidity, total hardness, silica, organic impurities, heavy metallic compounds and the presence of dissolved oxidizing agents—what will the effect be on the demineralization of water?*

Ans. It may lead to
(a) production of water having inadmissible degrees of impurities
(b) capacity loss
(c) degradation and/or fouling of resin.

Q. *What factors are responsible for a high pressure drop across the resin bed?*

Ans. 1 Bed compaction
2. Too much accumulation of resin fines in the bed
3. Higher service flowrate
4. Slimy microbial growth
5. Channeling
6. Increased turbidity
7. Broken underdrain
8. Clogging of internal distributor with resin fines.

Also, a defective pressure gauge may show a high pressure drop.

Q. *If bed compaction is the cause of high ΔP across the resin bed what is the remedy to it?*

Ans. Thorough agitation of the bed either pneumatically (i.e. by blowing air through the bed) or mechanically (i.e. by stirring) after backwash.

Q. *What is the remedy to the high pressure drop across the bed due to the increased load of turbidity in the influent water?*

Ans. It needs adequate pretreatment of the feedwater and a mid-cycle backwash.

Q. *How can microbial growth in the form of slime be inhibited?*

Ans. Proper pretreatment of feedwater to kill the micro-organisms in it.

Q. *How can channeling be reduced?*

Ans. By adjusting the service flowrate and backwash.

Q. *How can the problem of high ΔP across the resin bed due to accumulation of resin fines be eliminated?*

Ans. These resin fines being lighter than beads themselves collect on the top of the resin bed. They must be removed by thorough backwashing over an extended period while keeping the manhole open and scrapping off the fines from the bed-top.

Q. *If the internal distributor is clogged by resin fines causing high ΔP across the bed, what should be done to eliminate this?*

Ans. Backwashing and cleaning the distributor. It is to be repaired if found damaged.

Q. *What are the reasons for a low pressure drop across the resin bed?*

Ans. 1. Low flowrate
2. Reduced bed depth due to resin loss.

Q. *What should be done in the first case?*

Ans. Service flowrate should be adjusted to the proper value.

Q. *What factors are responsible for resin loss?*

Ans. Resin loss may be due to
(a) backwash
(b) underdrain failure
(c) wearing out of resin due to ageing.

Q. *What are the causes of loss of capacity of an ion exchanger?*

Ans. 1. Higher load of exchangeable ions in the influent water.
2. Inadequate regeneration
3. Resin degradation by oxidants
4. Resin fouling
5. Resin ageing
6. Resin loss taking place
7. Excessive rinsing
8. Channeling and improper distribution of feedwater
9. Capacity overtaxed in previous run.

Also a defective flow recorder may show a false indication of loss of capacity.

Q. *If the increase in the load of exchangeable ions in the feedwater is responsible for capacity loss, what is the remedy for it?*

Ans. Ionic load in water should be reduced. And therefore adequate pretreatment of the raw water to reduce its removable ions as much as possible is necessary so that the exchangeable ionic load of the influent water entering the DM unit is within the desirable range for satisfactory functioning of the ion exchangers.

Q. *If inadequate regeneration is the cause of "loss of capacity", what should be done to counter it?*

Ans. Proper regeneration. And that needs correct concentration and correct flowrate of the regenerant as well as the correct temperature of regeneration. For this purpose it may be necessary to check the regenerant concentration over and above its dilution system.

Q. *If resin deterioration by oxidation has been detected what should be done?*

Ans. Carryover of dissolved chlorine in influent water should be checked and complete dechlorination should be ensured.

Q. *How can resin fouling, causing loss in capacity, be avoided?*

Ans. The following measures should be undertaken to counteract resin fouling:
1. Proper pretreatment of water
2. Proper backwash
3. Checking the regenerants for foulants
4. Checking influent water for foulants
5. Ensuring proper regeneration of resin

Q. *What is the remedy to the problem of resin ageing?*

Ans. Resin analysis should be checked to determine the useful resin life. Normally cation exchangers suffer 5% yearly loss in capacity and anion exchangers 20%. If the checking shows more loss, the resin is better replaced.

Q. *If resin loss is detected, what should be done?*

Ans. 1. Carryover of resin with backwash water is to be checked.
2. Excessive backwash is to be avoided.
3. Designed backwash rate is to be maintained.

Q. *What are the possible factors responsible for the poor quality of the output water of a DM Plant?*

Ans. 1. Catex bed exhausted
2. Anex bed exhausted
3. Channeling
4. Leaky valves causing leakage of exchangeable ions
5. Overrunning capacity
6. Poor regeneration
7. Fouling of resin
8. Resin deterioration due to ageing and/or oxidation
9. Excessive service flowrate
10. Low service flowrates

11. Low temperature
12. High pH in treated water due to regenerant (Caustic alkali) valve leakage
13. Increase of Na^+ ions in influent water
14. Higher hardness of influent water
15. High silica in the feedwater
16. Low pH in treated water due to overrunning of anion exchanger capacity.

Q. *What are the reasons for excess leakage of* Na^+ *ions in treated water?*

Ans. It may be due to
(a) increase in Na^+ load in influent water
(b) inadequate rinse
(c) oxidation of resin
(d) capacity overrun.

Q. *How can this problem be overcome?*

Ans. 1. Quality of influent water is to be analyzed
2. Analysis of resin is to be done to check the presence of cation exchange resin on anion exchange resin
3. The quality as well as concentration of the acid (regenerant) are to be checked
4. Regeneration of the cation exchanger with higher concentration of acid is to be performed.

Q. *Why does hardness in the effluent water of a DM plant occur?*

Ans. It may be due to
(a) slippage of cation through the cation exchanger
(b) hardness in water used during the regeneration cycle.

Q. *What is the remedy for the high pH of the treated water of a DM plant?*

Ans. 1. Checking any leakage of regenerant (caustic alkali) valve. Zero-leaking operation of the valve is to be ensured.
2. pH monitoring equipment is also to be checked and rectified if found malfunctioning, as a faulty pH meter will show wrong pH values.

Q. *What are the reasons for low pH of the treated water of a DM plant?*

Ans. 1. Valve leakage
2. Overrunning of anion exchanger capacity
3. Organic fouling of anion exchangers.

Q. *What measures should be adopted to battle this problem?*

Ans. 1. Any valve leakage of regenerant (acid) is to be checked and leakage rectified
2. Proper treatment of influent water in the water treatment plant upstream to destroy its organics before it is delivered to the battery limit of the DM unit
3. Anion exchanger bed is to be checked for its performance
4. Also it is necessary to check the pH monitoring instrument.

Q. *Why does silica slippage in the treated water of a DM plant occur?*

Ans. 1. Higher silica load of influent water
2. Organic fouling of anion exchanger
3. Anion exchanger capacity overrun
4. Higher temperature of influent water
5. Silica deposition on anion exchange resin.

Q. *How can silica slippage be contained?*

Ans. 1. Pretreatment of influent water is necessary to destroy the organics
2. Regeneration of anion exchanger at higher regeneration level is to be ensured
3. The resin bed is to be preheated with warm water (50°C) to dislodge the absorbed silica and then it is to be regenerated by warm (50°C) alkali.

Q. *If overrunning capacity is the cause of loss of capacity of the ion exchange process, what should be done?*

Ans. 1. Throughput rate is to be reduced
2. End of run determination is to be evaluated.

Q. *In which forms does the malfunctioning of the mixed bed of a DM unit appear?*

Ans. 1. Overall poor quality of output water in general
2. Higher silica slippage
3. Low pH of effluent
4. High pH of effluent
5. High conductivity of effluent.

Q. *Why does poor quality of treated water from MB occur?*

Ans. It may be due to one or more of the following causes:
1. Inadequate regeneration of ion exchangers
2. Valve leakage
3. Inadequate bed depth
4. Poor mixing after regeneration
5. Improper resin separation during backwash for regeneration.

Q. *What are the causes of silica slippage from a Mixed Bed?*

Ans. 1. Resins have got exhausted
2. Improper anion exchanger regeneration because of inadequate separation during backwash
3. Fouling of anion exchange resin by organic substances
4. Not maintaining the correct quality and concentration of regenerant.

Q. *Why does low pH of mixed bed effluent occur?*

Ans. It may be due to
(a) permature exhaustion of anion exchange resin of MB due to silica or organic fouling.
(b) Improper mixing of anion and cation exchanger resin beads.

Q. *What is the remedy to this problem?*

Ans. 1. Chemical cleaning of the fouled component of the mixed bed is required.
2. Regeneration should be supplemented by thorough mixing of the cation and anion exchange resins.

Q. *What are the causes of high pH of the MB effluent?*

Ans. 1. Load variation influent to mixed bed.
2. Overexhaustion of the cation exchanging component.

Q. *What are the reasons for high conductivity of water at a mixed bed outlet?*

Ans. 1. Channeling and poor distribution
2. Unsatisfactory regeneration due to improper separation of cation and anion exchange resins of the MB during backwash
3. Fouling of anion exchange component by organics
4. Overexhaustion.

Q. *What should the DM-plant operators basically know about their ion-exchange resins?*

Ans. They must be kept well-informed of
(a) the type of resin being used
(b) the length of time a resin has been in service.

Over and above they should know the name of the manufacturer as well as its identification number, plus the date of resin rebedding and the resin batch number.

Q. *Why?*

Ans. This is required for timely replacement of deteriorated resins. The resins must not be kept in service after they outlive their economic usefulness.

Since no two resins have identical characteristics, they should therefore be purchased under a well-defined set of specifications. Also within a given type and brand, resin characteristics vary from batch-to-batch. Therefore, a desirable range should be indicated for specified characteristics.

Q. *Very often it is said that buying resins should be done with as much consideration as buying a new equipment. Why?*

Ans. Firstly, a resin is an expensive commodity.

Secondly, it is a vital component of the demineralization system, often the critical element of the entire water-treatment complex.

Q. *What basic factors are to be considered when a new resin is purchased?*

Ans. 1. Quantity of resins to be procured
2. Quality of the resin
3. Quality of treated water from the DM unit
4. Consumption of regenerant
5. Neutralization-chemical requirement for spent regenerant.

Q. *Why is it recommended to retain samples of demineralizer resins from new shipments?*

Ans. A resin is a costly item. For a modern powerplant, the value of an ion-exchange resin can be as high as Rs. 1,500,000 to Rs. 30,000,000. To help protect this investment, samples of as-received resins should be collected and retained as they provide the baseline data and background information. In case the resin quality comes into question after it is put into service, the above can be referred to.

Q. *Why is this required since manufacturers cling to quality-control steps to ensure that all resins despatched conform with their specifications?*

Ans. It is true that resin manufacturers apply quality-control procedures to ensure that the resin produced in batches conforms to its specifications. In most cases resins do meet specifications. Sometimes the production lots do not and it is not rare that these off-spec lots slip through the inspection steps.

Therefore, if problems crop up later due to deficiency in one of the batches of the resin shipment, there will be no way, if the resin sample is not collected and preserved, to establish which one is to blame—the resin or the maloperation.

Q. *What steps are prerequisite to resin sampling?*

Ans. 1. Label each drum with the production-lot number
2. Inventory each shipment by resin type and lot number. Use colour coding.
3. Group together all drums of a particular resin type
4. If a single production lot comprises ≥ 30 separate packages, sample 10% of the packages. If it consists of < 30 packages, sample at least three; if fewer than three, sample each one
5. If a given resin consists of two or more lots, treat each lot separately as stated above.

Q. *How is a resin sample collected?*

Ans. ASTM (American Society for Testing and Materials) method is used as follows

For **Wet Resin**

1. Put the drum upside down and allow it to stand overnight to redistribute excess water
2. Set the drum upright. Rock it from side to side. Open it then
3. Select at least 3 Nos. of sampling points (see Fig. 27.26)
4. Insert the sampling probe—a plastic cylinder (50mm dia)—through the resin bed at each sampling point separately and thrust it to the bottom (Fig. 27.27).
5. Withdraw the tube loaded with sample and empty its contents into a clean container
6. Thoroughly mix all aliquots.

Transfer to a plastic bag and seal it.

For **Dry, Free-Flowing Resin**

Harness the grain sample collector (Fig. 27.28)

It consists of two concentric brass tubes with a row of opening in each. The inner tube is rotated to match the openings. At this alignment, grains from the core enter the hollow inner tube which is rotated again to retain the sample.

The sample collector is withdrawn and the sample is unloaded into a plastic container and sealed.

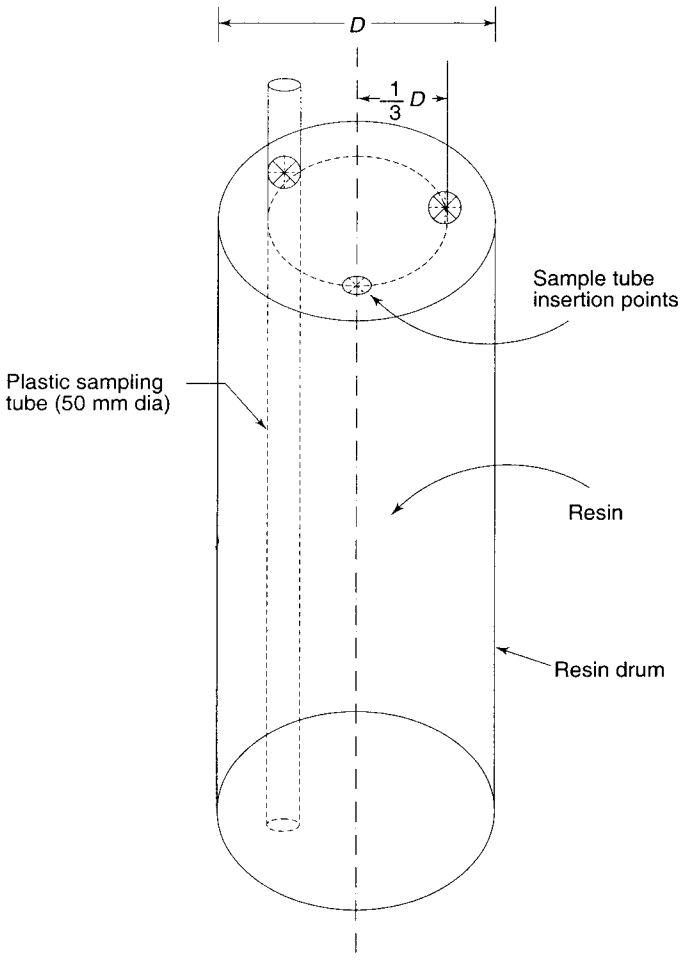


Fig. 27.26 *ASTM method of resin sampling. Select at least 3 Nos. of sampling points located 1/3 D apart from the centre of the drum.*

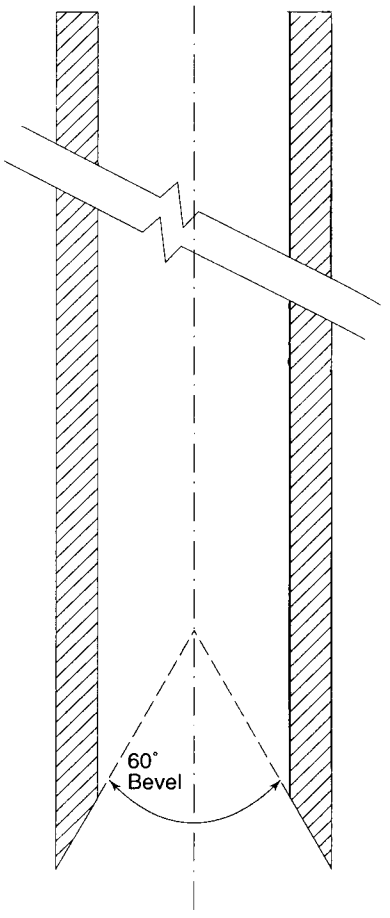


Fig. 27.27 *Plastic sampling tube (50 mm ID) is inserted into wet-resin container. When withdrawn it retains resin sample within.*

Q. *Why is the quantity of resin to be procured an element of consideration?*

Ans. Maintaining resin inventory guards against sudden resin loss from system vessels, which could call for a plant shutdown. Some plant engineers prefer to have sufficient resin inventory for at least one complete demineralizer train; new batch of resin is procured when the inventory is depleted.

Q. *What precautions would be taken in storing resins?*

Ans. The first and the most important step is to ensure that the resin beads do not run dry.

Secondly, storing must provide insurance against temperature excursions, i.e. variation of temperature over a wide range.

Finally, if the resin inventory is maintained in a complete standby train, use is to be made of that train in rotation with all other trains.

Q. *Why should the beads not be allowed to dry out during storing?*

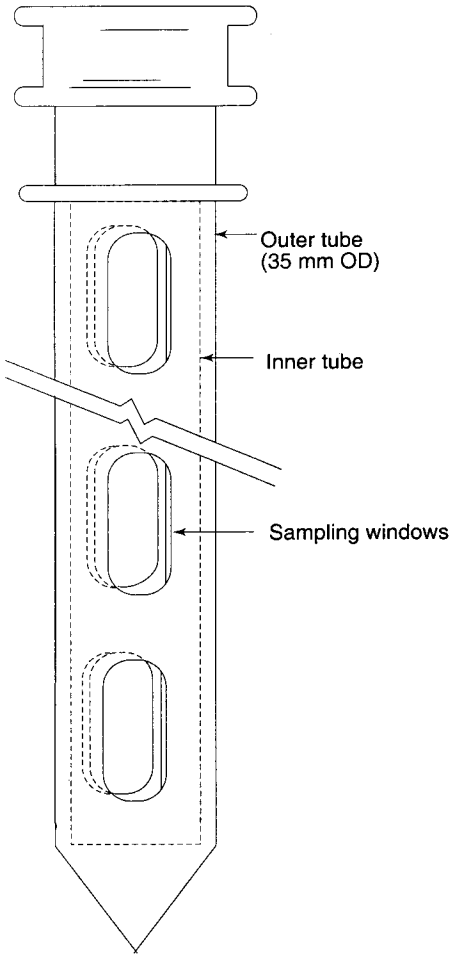


Fig. 27.28 *Grain sample collector. It consists of two concentric tubes with windows. The inner tube rotates within the outer tube.*

Ans. Once allowed to dry out, resin beads develop crack or even undergoes fragmentation when rewetted.

Q. *What kind of beads are susceptible to this type of cracking?*

Ans. Gel type beads and puckered beads are more easily broken than perfect whole beads.

Q. *What steps should be taken to keep resin beads from drying?*

Ans. Resins should be kept sealed in the manufacturer's containers which should be opened only before loading the system vessels with the resin.

Q. *What should be done to avoid storing resin where it is likely to be subjected to a wide range of temperatures?*

Ans. The resin must be stored away from
(a) direct sunlight
(b) a boiler house
(c) outdoors in freezing temperatures.

Q. *What are the essential parameters that determine resin quality?*

Ans. 1. Moisture content
2. Bead integrity
3. Loss of capacity
4. Fouling

Q. *How does the moisture content determine resin quality and call for resin replacement?*

Ans. An increase in moisture content is a clear indication of decrosslinkage of a resin structure of known matrix, functional groups and ionic form. An increase in moisture content over the typical rated value for a new resin can invite the following problems:

1. resin loss during backwashing
2. increased ΔP across the resin bed
3. organic pick-up from the cation resin
4. organic fouling of downstream anion resin

When the moisture content of a conventional gel-type cation resin exceeds that of new resin by 5% or an anion resin exceeds that of a new resin by 2 to 3%, the bed should be replaced.

Q. *What is decrosslinkage of resin? What harm does it do?*

Ans. A resin is a macromolecule in which the monomer or a set of monomers form an insoluble three-dimensional matrix through internal crosslinkages. Decrosslinkages break this structural integrity.

Decrosslinkage during service degrades resin performance.

Q. *What do you mean by bead integrity?*

Ans. Retaining the perfect whole-bead configuration.

Q. *How can you ascertain bead integrity in a given beads population?*

Ans. This should be ascertained through microscopic examination of the given bead population. As the cracks are not visible to the naked eye, the beads must be subjected to scanning under a microscope that will reveal the physical conditions of the bead. Accordingly, the given bead population can be classified into three fractions:

(a) perfect whole-bead
(b) cracked whole-bead
(c) fragmented bead.

Q. *What is the effect of an increase in fragmented fractions in a resin bed?*

Ans. Any increase in the fragmented fraction in a resin bed can result in derating of the resin's ion-exchange capacity.

Q. *How does this capacity reduction occur due to fragmentation of resin beads?*

Ans. Two factors are responsible for this:

(a) channeling effects
(b) loss of resin-fragments from service vessels.

Q. *How does this resin loss due to fragmentation occur?*

Ans. Backwashing during the resin regeneration process washes out the fragmented fines and that is how resin is lost.

Q. *Why do resin beads undergo fragmentation?*

Ans. Internal cracks within the beads can grow and ultimately lead to fragmentation of the beads.

Q. *If fragmentation is a problem, when should the resin bed be replaced?*

Ans. A bed-core resin sample is to be collected and examined. If fragmentation is found to be more than 20% of the total, it indicates poor bed stability. When this occurs, the bed must be replaced.

Q. *What is channeling?*

Ans. Formation of isolated low-resistance paths within a resin bed.

Q. *Why is it formed?*

Ans. It is formed due to accumulation of suspended solids (resin particles), air pockets etc.

Q. *What is the usual tolerance limit for loss of capacity?*

Ans. In normal cases a capacity* loss of up to ≤ 7% for strong-acid cation (SAC) exchanger is not likely to cause a serious concern. However, a loss greater than 7% or 8% from that of the new resin can give birth to capacity problems for that resin type (SAC).

For weak-acid cation exchange resins (WAC), capacity limitation crops up when the total capacity loss exceeds 20% of the new resin of the same type.

Q. *At what percentage of capacity loss, should the resins be replaced?*

Ans. Rebedding of the WAC exchanger is to be considered when the total capacity loss exceeds 20%.

For anion exchange resins replacement of resin is required when the loss of capacity approaches 50% in the case of a SBA (strong-base anion) exchanger and 25% in the case of a WBA (weak-base anion) exchanger.

Q. *What do you mean by salt-splitting capacity?*

Ans. It is the ability of a resin to convert salts into their corresponding acids and bases.

Q. *How does fouling tell upon resin performance?*

Ans. It impedes the ion-exchange speed, i.e. reaction kinetics and brings forth varying ionic strengths in the resin.

Q. *What is the outcome of resin fouling?*

* Salt-splitting dry-weight capacity

Ans. 1. Extended rinse periods
2. Reduced throughput volumes
3. Poor treated-water quality (DM plant output).

Q. *What are the chief foulants of cation exchange resins?*

Ans. 1. Calcium (Ca^{2+})
2. Aluminum (Al^{3+})
3. Barium (Ba^{2+})
4. Iron (Fe^{2+}/Fe^{3+})

Q. *What are the principal foulants of anion exchange resins?*

Ans. 1. Organics
2. Silica
3. Iron

Q. *"All resins are susceptible to fouling". Is it true?*

Ans. Yes. All resins experience fouling to some extent.

Q. *How can the degree of fouling by metallic ions and silica be assessed?*

Ans. The best way to ascertain the degree of fouling by metallic cations and silica is ash analysis.

Q. *How will you opt for resin replacement from the result of ash analysis?*

Ans. If the degree of fouling of the cation exchanger, as determined by the ash analysis, exceeds 13% and if the resin has been in service longer than the expected life span for that type, it is better to reject the bed and refill the vessel with a new batch.

Q. *How is the organic fouling of a resin bed measured?*

Ans. Anion exchange resins are attacked by organic foulants. This type of fouling is measured by a parameter called TOC (Total Organic Carbon) present in the alkaline brine wash from a resin sample.

Q. *What is the TOC limit that calls for resin replacement?*

Ans. In case the TOC content exceeds 20 mg/g (wet basis) and the service period of the resin has exceeded its expected life span, it should be replaced.

Q. *How does the treated-water quality in the DM plant show up resin degradation?*

Ans. Poor effluent quality results with the fouling or degradation of resin. It shows up in

1. higher cation slippage from CATEX, i.e. higher hardness leakage from a cation exchanger
2. lower pH value of ANEX bed effluent
3. higher sodium contamination if the resin is strongly basic
4. very gradual drop in conductivity during resing operation on the ANEX bed
5. higher organic leakage from a DM unit.

Q. *If any of these is indicated in a resin bed, what action should be taken?*

Ans. Check whether the normal resin life has expired.

In case the resin has not been operated longer than its expected life span, check all the steps in the regeneration procedure. If they are found OK, try to improve effluent quality by cleaning the resin bed. If cleaning fails to improve the quality of effluent, check all the vessel internals and oncoming feedwater quality. If the vessel internals are in OK condition and feedwater quality has not changed, replace the bed resin.

Q. *How can regenerant consumption be an indicator of resin fouling or degradation?*

Ans. Chemical consumption for regeneration starts to increase, commensurate with resin fouling/degradation and at the same time the operating cost begins to mount.

Q. *Do you think that increased regenerant consumption is only due to degraded or fouled resin bed?*

Ans. No.

Q. *What are the other reasons that contribute to increased regenerant consumption?*

Ans. 1 Defective vessel internals
2. Resin loss
3. Deterioration in feedwater quality
4. Improper regeneration.

Q. *Therefore, how can it be ascertained that increased regenerant consumption is purely due to fouling of resin?*

Ans. If upon thorough examination it is found that the system vessel internals are alright, (feedwater quality remaining the same as before) and the steps of regeneration are followed exactly as per the instruction manual, it can then the concluded that increased regenerant consumption is only due to degraded/fouled resin quality.

Q. *What parameters must be specified when a new resin is to be procured?*

Ans. In order to derive optimum performance from the ion-exchange system the buyer must explicitly identify the resin needed. A complete description of the resin needed should be specified in the order form. The specification should include the:

(a) resin matrix
(b) functionality
(c) ionic form

The specification sheet must also include the following data.

1. Exchange capacity
2. Moisture content
3. Per cent swelling
4. Sieve analysis
5. Bead integrity
6. Total ash content

The buyer must obtain and analyze a preshipment sample having the same identification number as the actual shipment and he should reject the entire lot if it does not meet the specifications.

Q. *What is the maximum exchange capacity of a strong-acid, gel-type cation-exchanger with 8% crosslinkage fully sulphonated so that every styrene and divinylbenzene ring has one sulphonic acid group?*

Ans. The maximum capacity, as calculated should be 5.3 meq/g (milliequivalents per gam) on a dry-weight basis.

Q. *What are the capacities of such resins in commercial practice?*

Ans. Usually between 4.8 – 5.15 meq/q dry-basis or 1.8 – 2.0 meq/ml on a weight-volume basis, backwashed and in place in the column.

Q. *Why does the exchange capacity vary from one manufacturer to another for the same type of resin?*

Ans. Resin crosslinakges vary widely from one manufacturer to another because of different manufacturing techniques.

Even the same type of resin produced by the same manufacturer has been observed to vary considerably from one batch to another in this respect.

Q. *In which from is the Type I Styrene-Divinylbenzene anion exchange resin supplied?*

Ans. Usually in the chloride form.

Q. *What should be the minimum capacities of the SBA and WBA of Type I resin?*

Ans. On dry basis these should be

Type I	**Minimum Capacity**
SBA	3.15 – 3.30 meq/g
WBA	0.70 – 0.85 meq/g

Q. *What should be the minimum capacities of SBA and WBA of gel Type-II resin?*

Ans. On dry-basis these should be

Type II	**Minimum Capacity**
SBA	2.4 – 2.6 meq/g
WBA	1.1 – 1.2 meq/g

Q. *How does the moisture content modify the molecular structure of resin?*

Ans. Moisture content of resin is a measure of nominal cross-linkage within resin beads. Moisture content is reduced with the increase of crosslinkage.

Q. *What should be the moisture-holding capacity of SAC (Strong Acid Cation exchange resin) supplied in the hydrogen form with 8% crosslinkage?*

Ans. 50-55%

Q. *What should be the moisture content of SBA in the chloride form?*

Ans. 53 – 60% for SBA (Type I)
39 – 45% for SBA (Type II)

Q. *What is the risk of buying resin from the open market?*

Ans. The resin may be found very high in moisture if the moisture content had not been specified before the indent is made. The vendor may push the resin from old inventory.

Q. *Cation exchange resin is marketed in both sodium and a hydrogen forms. Which form is preferred?*

Ans. It is beneficial to purchase resin in the sodium form.

Q. *Why?*

Ans. SAC swells by 6% to 8% when it is converted from sodium to hydrogen form during regeneration. Therefore, 100 m^3 of 8% crosslinked sodium-form cation exchange resin will swell to about 106 m^3 during regeneration. Therefore, if Na-resin is purchased, less bulk will have to be handled.

Q. *Do the SBAs also undergo swelling upon regeneration?*

Ans. Yes. The strong base anion exchange resins (Type I and II both) swell more than the strong acid cation exchange resins.

Q. *What is their per cent swelling when they are regenerated from chloride to hydroxide form?*

Ans. 15% – 20% swelling for most cases of SBA–I
10% – 15% swelling for SBA–II.

Q. *An anion-exchanger vessel is provided with a top sightglass. What is its utility?*

Ans. It enables the operator to view the resin-bed surface. Therefore, the progress of the regeneration process can be judged from changes observed in the surface level.

Q. *What information can be got from the sieve analysis data of resin?*

Ans. 1. Population, in terms of volume, of resin beads retained on different-size sieves
2. The effective size of the resin batch
3. The uniformity coefficient of the batch.

Q. *Suppose while going to buy a resin, the resin vendor specifies only the per cent retained on a 16-mesh sieve and the per cent passed through a 50-mesh sieve. Is this enough to assess the resin batch?*

Ans. It is not a sufficient specification.

Of course, it carries some value for mixed-bed resins.

Q. *What about the effective size?*

Ans. It should be neither too large nor too low.

The effective size range of 0.45 – 0.55 mm is mostly specified.

Q. *What about the uniformity coefficient?*

Ans. It should be as close to unity as possible.

Q. *A resin batch is specified as*

Effective size : 0.55 mm
Uniformity coeff. : 1.6

What will the mesh size of the majority of the beads be?

Ans. The majority of the beads will be in the range of 20 to 30 mesh size.

Q. *Another batch is specified as:*

Effective size : 0.43 mm

Uniformity coeff. : 1.4

In which size range, will the bulk of the beads belong?

Ans. 30–40 mesh range.

Q. *What if one buys a resin batch having bulk of the beads less than 0.43 mm size?*

Ans. Smaller size beads result in considerable bed expansion than larger ones. Therefore, if the charge of a new resin in the exchanger vessel undergoes considerable volume expansion compared to the previous charge and the backwash rate is not adjusted accordingly, it may result in carryover loss of a large fraction of the charge or there might be inadequate bed clean-up.

Q. *What is the harm if the bead-uniformity coefficient exceeds 1.6?*

Ans. It will tell upon the backwash operation which will be less effective. That is why the maximum uniformity coefficient specified is 1.6.

Q. *What does the total ash content of resin imply?*

Ans. It reveals the extent of inorganic contamination of resin.

Q. *What should the ash content of a brand new resin be?*

Ans. Less than 0.1% irrespective of whether the resin is of SAC or SBA type.

Q. *Sometimes resins are shipped with ash content as high as 0.15%. What substances contribute to this impurity?*

Ans. The higher impurity level is contributed by calcium in the cation exchange resin and aluminum in the anion exchange resin.

Q. *What are the negative aspects of cracked beads?*

Ans. Cracked whole beads are more liable to fragmentation than uncracked and unpuckered perfect beads.

An increase of fragmented fraction of beads in a resin bed results in more bed compaction that invites channeling. This phenomenon adversely affects the throughput capacity of the bed and degrades the quality of the effluents.

Q. *What should the whole-bead concentration in the new charge of resin be?*

Ans. At least 99% with 90% to 95% perfect whole beads.

Q. *If this bead integrity is not specified while placing the indent for a new shipment, what will happen?*

Ans. The resin shipment, under this circumstance, may contain too high a population of cracked, fragmented or puckered beads.

Q. *What should the maximum level of cracked whole-bead concentration, after subjecting the resin to alternate treatments with 5% hydrochloric acid and 5% caustic acid respectively be?*

Ans. 15%

Q. *Why is this specification required?*

Ans. To avoid elaborate osmotic-shock.

Q. *What are the benefits of using resin beads of uniform particle size (UPS)?*

Ans.
1. Higher throughput
2. Higher TOC (Total Organic Carbon)
3. Lower silica-slippage
4. Reduced rinse-water requirement
5. Improved control over resin losses during regeneration
6. Reduced resin cross-contamination during regeneration.

Q. *What is the most fundamental problem associated with the resins manufactured by traditional methods?*

Ans. Resins made by traditional methods have beads of sizes over a wide range. Though resorting to screening narrows the distribution somewhat, this can inflict damage to the bead surfaces whereupon the beads will loose their effectiveness and the product quality will go down.

Q. *Why are UPS resins the most preferred choice?*

Ans. They beget certain distinct advantages:

I. Service Cycle—Because of UPS characteristics, the beads have uniform ion-exchange potential and therefore, the exchange front moves down the bed, as the resin beads get exhausted, during the service cycle.

II. Backwashing—For a resin-bed of non-uniform beads, backwashing concentrates the larger beads in the bottom of the vessel. As the exchange front arrives there, ionic breakthrough occurs almost immediately making it a necessity to regenerate the bed and as a result this part of the bed remains virtually unutilized. But with resins of uniform size, the exchange zone at the bottom is much sharper and breakthrough is not as rapid, so more of the resin capacity is used.

III. Rinsing—Less water is required for rinsing UPS beads. Also rinsing is much faster.

IV. Regeneration—The regenerant consumption in the case of UPS resins is much less than resins conventionally manufactured.

V. Capacity Increase—UPS resins can produce sizeable increase in operating capacity. A 15% capacity increase, for instance, can lower the cost of NaOH about Rs. 300 000/m^3 resin over a typical five year resin lifetime.

Q. *Why are small diameters of UPS resin beads preferred?*

Ans. It reduces resin losses when backwashed.

The small resin beads lead to faster, more efficient regeneration and increased operating capacity.

Q. *Why do smaller beads lead to faster regeneration than the larger beads?*

Ans. For a solid of given volume, the surface area increases with the degree of subdivision. Therefore, smaller size beads will expose much greater specific surface area, i.e. surface area per unit mass than beads of a larger size when the same resin type is considered.

Forasmuch as the regeneration process kinetics is based on surface chemistry, the particle size determines the rate at which the regenerant chemical diffuses into the particle to dislodge the contaminant ions. That is why smaller beads of resin lead to faster, more efficient regeneration.

Q. *Why is less water needed to rinse smaller uniform beads?*

Ans. Rinsing is also tied to diffusion mechanism, i.e. smaller the resin beads, the higher will be the rate of rinsing. So less water is required to rinse smaller uniform beads to a point where ionic removal of contaminant ions produces adequate purity.

Case Study

SINOPEC, a Chinese petrochemical complex where stratified resin beds were selected for make-up deionization started up in 1979.

Type-II resin made by Rohm and Haas Co., Philadelphia, Pa was selected as the SBA to take care of the entire load of chloride and sulphate in the feedwater. Upstream of it was installed a WBA bed.

The plant operated continuously for 10 years without any change of resin.

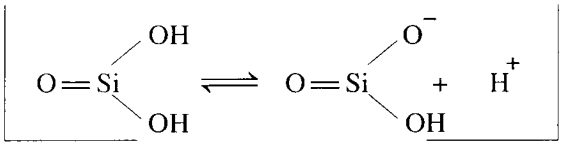
Q. *What is the reason behind this success?*

Ans. While the SBA (Type II resin) successfully took up the load of Cl^- and SO_4^{2-} ions, it was given complete protection from microbial fouling provided by the MICROPOROUS WBA installed upstream of the SBA.

Q. *The Type II resin bed had to be replaced after 10 years as a sharp rise in silica was detected.*

Why did this happen despite the fact that the Type II anion exchanger was guarded by the WBA bed?

Ans. The WBA system is capable of arresting the anions of strong acids (HCl, H_2SO_4 etc.). So it failed to protect the downstream SBA effectively from silica fouling arising from silicate anions which thereby fouled the SBA bed downstream. Since the silicate concentration in the influent water was very low, it took a decade to destroy the ion-exchange capacity of the strong-base anion exchange resins.



Q. *What is the basic difference between coflow regeneration and countercurrent regeneration* (CCR)?

Ans. In the coflow process the regenerant flows in the same direction as the service flow.

In the CCR process (also called counterflow process), the regenerant flows in the direction countercurrent to the service flow.

Q. *In which sense is coflow method advantageous?*

Ans. 1. Simplicity in operation
2. Modest bed depths.

Q. *What is the major disadvantage of the coflow system?*

Ans. Excess regenerant is needed to elute impurities remaining at the bottom of the bed. These appear as ionic leakage early in the succeeding cycle.

Q. *What are the disadvantages of CCR?*

Ans. 1. Higher resin-bead wear
2. Higher pressure-drop across the bed
3. Reclassifies the bed according to particle size rather than the extent of their regeneration. This impedes bed performance in the subsequent cycle.

Q. *What is the major advantage of CCR?*

Ans. It yields purer water with less regenerant.

Q. *Reducing the exposure of personnel to radiation in nuclear power stations has been the ongoing objective in most nuclear programs. In Pressurized Water Reactor (PWR) plants, in particular, one of the factors which influence the build-up of radiation fields has been shown to be the Lithium/Borate (Li/B) ratios used in the reactor coolant. The performance of the ion-exchange resins used to treat the primary coolant is greatly influenced by the Li/B coolant chemistry aimed at reducing radiation fields. How does the Li/B ratio exert influence on the performance of IEX resins?*

Ans. Ion exchange (IEX) resins are used to help control Li/B chemistry and to purify water in the PWR primary coolant loops. Nuclear grade anion exchangers are used to remove three critical coolant contaminants: Chloride (Cl^-), sulphate (SO_4^{2-}) and fluoride (F^-). This is done by passing a small side stream of primary water through CVCS (Chemical and Volume Control System). The CVCS consists of heat exchangers, filters, and resin beds for treating the water. The IEX beds function to remove radionuclides, such as Cesium–137 and Iodide–131. They also remove contaminants, such as chloride, which can inflict corrosion damage to the components of the primary coolant circuit.

The operating conditions for the purification of mixed beds are such that a small volume of resin will treat a relatively large volume of recirculated reactor coolant over a long period of time. Therefore, under these conditions the IEX resins operate essentially in equilibrium with the bulk coolant solution. Resin performance is thus equilibrium controlled, and the relative selectivity of a resin for various competing ions will dictate resin performance.

Works of Rozenberg[1] and Kashiwai[2] have shown that the equilibrium chloride capacity of anex resin gets significantly reduced by increasing the concentration of lithium (Li^+) and boron [$B(OH)_4^-$ and $B_3(OH)_6^-$] in the coolant solution. The work of Kashiwai et. al. has clearly demonstrated that increasing LiOH caused marked increase in the ionization of broic acid. The

1. J. Rozenberg—Behaviour of Ion Exchange Resins with respect to Chloride (European Nuclear Conference/Paris, 1975)
2. T. Kashiwai et. al.—The Behaviour of Impurity around Ion Exchanger in PWR Primary Circuit (Proceedings British Nuclear Energy Society Conference/Bournemouth/Oct. 1983)

increased concentration of various anionic borate species thus reduces the equilibrium chloride capacity of the anion exchanger.

Q. *How does the build-up of radiation fields outside of the reactor core in PWR systems take place?*

Ans. Primarily it is caused by the deposition, activation and transport of corrosion products within the primary reactor cooling loop. Also a reactor system in which crud is first deposited on the fuel core, activated by neutron bombardments and then later redissolved and redeposited on cooler surfaces such as the steam generator, can develop significant out-of-core radiation fields.

Q. *What is the driving force for crud precipitation on loop component surfaces?*

Ans. It is the Temperature Coefficient of Solubility (TCS) for the corrosion products.

A negative TCS value causes dissolving from cool surfaces and precipitation on relatively hotter surfaces. A positive coefficient has the reverse effect.

Q. *How does the solution pH control out-of-core radiation fields?*

Ans. The sign (+ or –) of the TCS is dependent upon the solution pH. If the coolant pH can be maintained such that the TCS value is near zero or very slightly positive, there should be no driving force for crud precipitation on core surfaces where activation occurs.

Note: *This is the basis for the coordinated Li/B chemistry currently recommended by EPRI.*

Q. *The current guideline of EPRI for controlling extra-core radiation fields of PWR is based upon magnetite solubility behaviour. How does the coordinated Li/B chemistry influence magnetite solubility?*

Ans. The minimum lithium concentration for minimum magnetite solubility at 558°K is presented in Fig. 27.29.

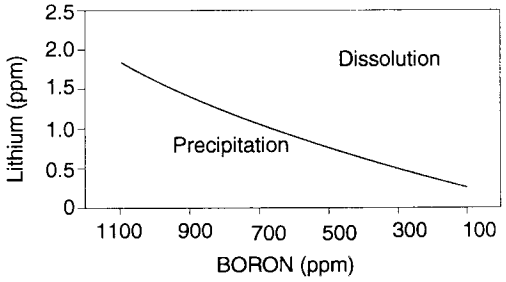


Fig. 27.29 *Minimum lithium concentration for minimum magnetite solubility at 558°K and 25 ml H_2/kg coolant*
Source: REP-141 (Technical Paper/ROHM & HAAS)
Courtesy: ROHM and HAAS/PA 19105/USA

Q. *However the studies of Solomon et. al.[1] have indicated that nickel ferrites are the predominant crud species in PWR coolant. What should be the Li/B ratio to keep off-core radiation potential at bay?*

Ans. Obviously a higher Li/B ratio must be used to achieve a zero or slightly positive temperature coefficient of solubility based on nickel ferrite. However, EPRI has proposed a Li/B control range as shown in Fig. 27.30.

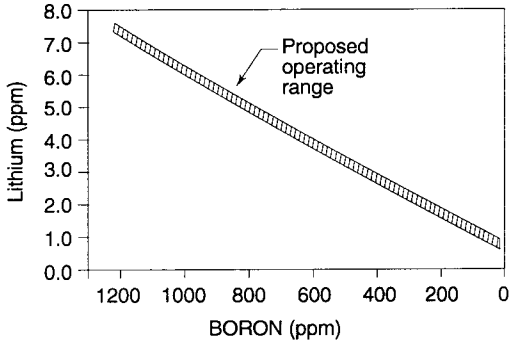


Fig. 27.30 *Minimum lithium concentration for zero temp. coeff. of nickel ferrite solubility at 566°K and 25 ml/kg coolant.*
Source: REP-141 (Technical Paper/ROHM and HASS)
Courtesy: ROHM and HAAS/PA 19105/USA

1. Y. Solomon et. al.—*Crud Effects and PWR Coolant Chemistry* (Proceedings of British Nuclear Energy Society/Bournemouth/Oct., 1983)

Provided that no adverse reactions occur with the materials of construction of the primary cooling circuitry, it appears that use of higher Li/B ratios in the PWR coolant may reduce radiation exposure.

Q. *What are the Li and B levels in the primary cooling circuit of PWR?*

Ans. The current practice for precritical reactor coolant is to maintain the following levels of Li and B:

2.2 (± 2%) Li

1875 (± 3%) B

Q. *Why is it more advantageous to use high selectivity anion resin than conventional nuclear grade anion exchange resin, so far as accidental ingress of chloride ions into the reactor coolant is concerned?*

Ans. The equilibrium chloride capacity of high selectivity anex resin is much higher than that of conventional nuclear grade anex resin (Fig. 27.31).

The performance curve of conventional nuclear grade resin reveals that raising the Li level from 2.2 ppm to 5.2 ppm reduces the equilibrium chloride capacity of this type of resin by roughly one half. This means that to any given Cl^- concentration limit in the reactor coolant the capacity of the purification mixed bed for Cl^- is cut by half. This is really hazardous, in augmenting off-core radiation potential, if there occurs an accidental slippage of chloride in the primary coolant circuit.

As against this, the performance of the high selectivity anion resin at both 2.2 and 5.2 ppm Li is significantly better than that of a conventional resin. For instance, at the 5.2 ppm Li condition, conventional nuclear grade resin can hold only 1.25 equipv. per cent chloride at a 100 ppb chloride solution limit whereas under the same conditions resin of higher selectivity can hold 3.5 equiv. percent chloride, that is providing a nearly threefold advantage in useful capacity.

Shown in Fig. 27.32 are the equivalent capacity curves of conventional nuclear grade anion resin and high selectivity anion resin for fluoride ions.

Q. *The slope of all the curves is distinctly steeper than that of equilibrium capacity curves of resins. Why?*

Ans. Anion exchange resins have a lower selectivity for fluoride than for chloride.

Q. *What about the comparative equilibrium chloride and fluoride capacities of both resins?*

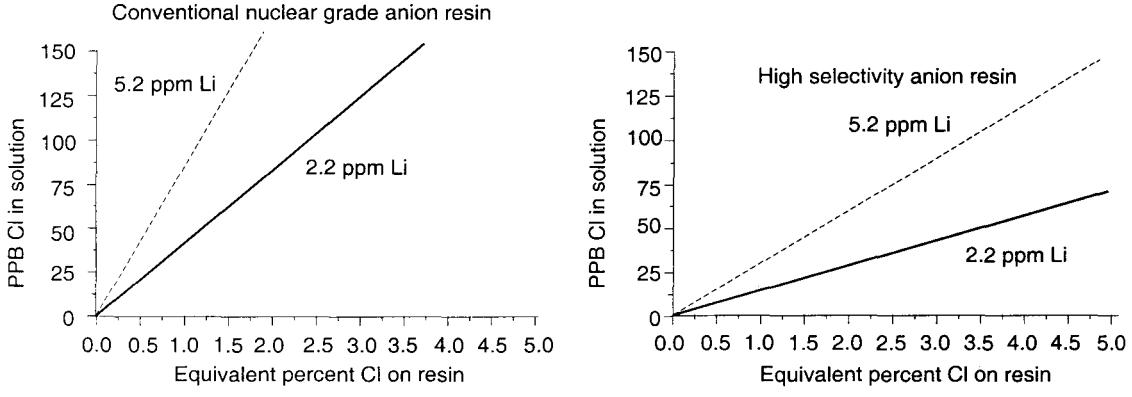


Fig. 27.31 *Equilibrium chloride capacity of resins in 1875 ppm B, with Li, AT 322°K.*

Source: REP-141 (Technical Paper/ROHM & HAAS)
Courtesy: ROHM and HAAS/PA 19105/USA

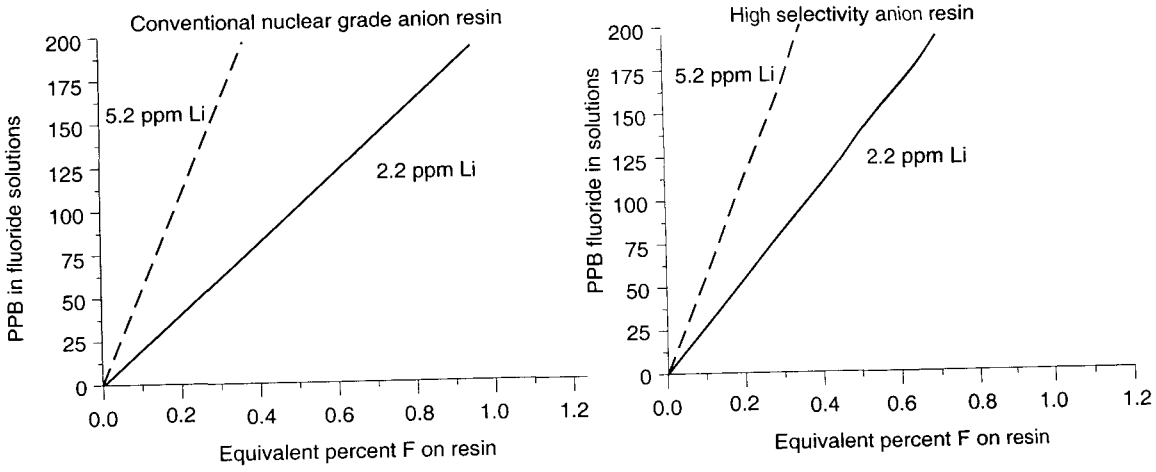


Fig. 27.32 *Equilibrium fluoride capacity of resins in 1875 ppm B with Li, AT 322°K.*

Source: REP-141 (ROHM and HAAS)
Courtesy: ROHM and HAAS/PA 19105/USA

Ans. Both resins have an extremely low equilibrium capacities for fluoride in a Li/B system. At the high Li/B condition the capacity of the resins for fluoride is negligible.

Q. *The equilibrium sulphate capacity of the conventional nuclear grade resin is shown in Fig. 27.33.*

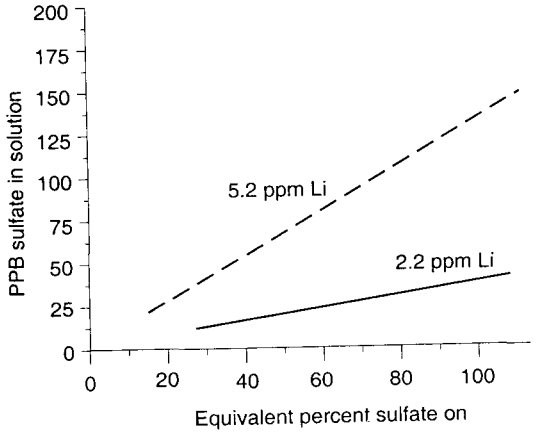


Fig. 27.33 *Equilibrium sulphate capacity of conventional nuclear grade resin in 1875 ppm B, with Li, at 322°K.*

Source: REP-141 (Technical Paper/ROHM and HAAS)
Courtesy: ROHM and HAAS/PA 19105/USA

What do you infer from this graph regarding the sulphate capacity of the resin as against its chloride and fluoride capacities (Fig. 27.31) and Fig. 27.32)?

Ans. The conventional nuclear grade anex resin has a much higher capacity for sulphate than for chloride or fluoride. Even under high lithium condition, the conventional nuclear grade anex resin has an extremely high capacity for sulphate.

Note: *This conventional resin can load roughly half its sites to the sulphate form and still meet a proposed 100 ppb sulphate limit in the bulk coolant solution. Because of this sulphate control is not a problem in reactor coolant.*

Q. *What is the reason for high sulphate capacity of conventional nuclear grade anion resin?*

Ans. This is probably due to divalent character of the sulphate (SO_4^{2-}) radical, that increases the surface-density of charge of this anion increasing its loading capacity on the exchange sites of the anex beads.

Q. *What is the indirect effect of very high resin selectivity for sulphate in case all the three contaminants—chloride, fluoride and sulphate–are present simultaneously in the primary coolant?*

Ans. High levels of sulphate loading on the resin will tend to displace chloride or fluoride which are more weakly held. So the coolant will get enriched with more corrosive anionic species than sulphate.

Q. *What should be the limits of the chloride, fluoride and sulphate concentrations in the primary coolant of PWR to control corrosion of materials of construction of this circuit?*

Ans. EPRI[1] has set the following limits for control of the aggressive anionic species:

CHLORIDE : 150 ppb

FLUORIDE : 150 ppb

SULFATE : 100 ppb

Q. *On what factors does the ability of CVCS to control these anionic impurities depend?*

Ans.(a) Total resin capacity
(b) Selectivity of resin
(c) Initial resin purity

The first two combined determine the effective "size of the sink" for holding a specific impurity while the initial resin purity determines "how full the sink is" at the onset of operation.

Case Study: A certain PWR operates with a primary coolant mass of 250 000 kg with a coolant chemistry of 2.2 ppm Li and 1875 ppm B. At the start, an 850 litres of mixed bed of resin is put in line in the CVCS and the bed comes to equilibrium with the bulk coolant. The effect of resin chloride level on the reactor coolant as Cl^- ion ingress occurs is shown in Fig. 27.34.

Q. *What do you infer from the above two graphs as to the effect of* Cl^- *ion ingress?*

Ans. If the new anex resin contained 0.1 equivalent per cent chloride, the reactor coolant would rise to 3.8 ppb Cl^- when the coolant was absolutely chloride-free at time zero. Under the same conditions of zero chloride level of coolant, the coolant chloride level would be 10 times higher,

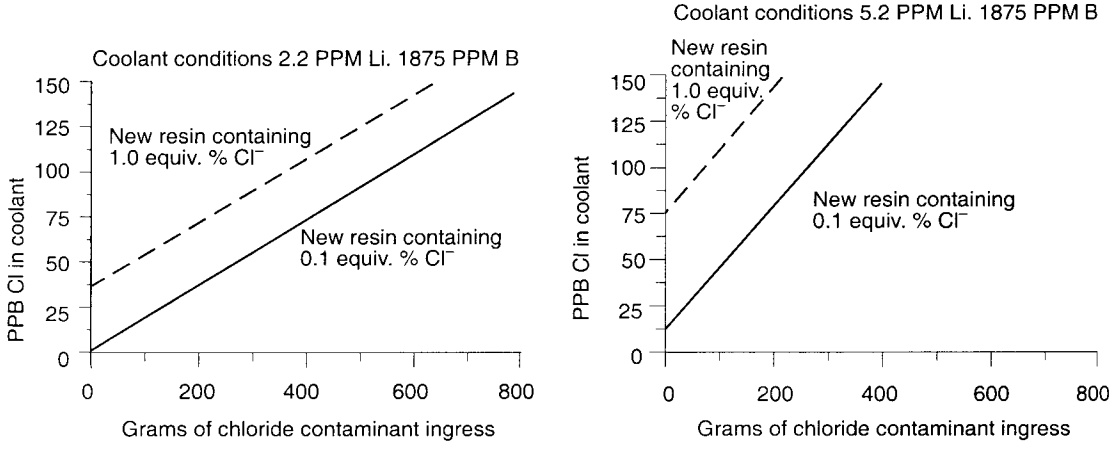


Fig. 27.34 *Effect of new resin chloride level on reactor coolant as chloride ingress occurs.*
Mixed bed resin volume = 0.85 m^3
Total Coolant Mass = 250 t
Source: REP-141 (Technical Paper/ROHM and HAAS)
Courtesy: ROHM and HAAS/PA 19105/USA

1. R. Shaw—PWR Primary Water Chemistry Guidelines (EPRI Report/NP 4762SR/Sep., 1986)

if the anion exchanger had 1.0 equivalent per cent chloride.

With the increasing levels of chloride ingress, the ppb of Cl^- in PWR coolant increases more steeply as the coolant conditions shift from lower Li-level to higher Li-level (better say, higher Li/B ratio).

Conclusion: If the resin contains higher level of chloride and/or the PWR coolant contains higher level of lithium, the ion exchange performance of the nuclear grade resin will get drastically degenerated, allowing more corrosive-anionic-species (e.g. Cl^-) to remain freely available in the bulk of coolant, thus increasing the corrosion potential of the coolant.

Q. *What do you expect of resin performance as to* F^- *and* SO_4^{2-} *removals under identical* Li/B *coolant chemistry and identical purity?*

Ans. Resin performance for flouride removal would be much worse than for chloride, whereas sulphate removal would be much better.

Q. *Changes to higher Li/B ratios in the primary coolant may be very favourable for reducing the build-up of the out-of-core radiation fields but will significantly reduce the ability of conventional nuclear grade anion exchange resin to control chloride and fluoride.*

What should be the suggested action plan for CVCS applications of resin?

Ans. If the current trends in the primary coolant chemistry (i.e. higher Li/B levels in the PWR coolant) continue to gain acceptance, greater care must be taken to control corrosive anionic impurities. Greater emphasis should be given to the purity of new resin for CVCS applications.

Obviously the use of higher selectivity anion resin is far more promising than nuclear grade resin in controlling chloride levels.

Far greater care must be taken to avoid all chances of fluoride ion leakage into the PWR coolant circuit, since flouride control by ion exchange is very difficult.

Source: The Effect of Selectivity of the Performance on Anion Exchange Resins in PWR Primary Coolant
—B.J. Hoffman and M.J. Gavaghan (REP-141 presented at IEX '88)

Courtesy: ROHM and HAAS/PA 19105/USA

Traditional manufacturing practice produces ion exchange resins in a stirred-tank reactor. The size distribution of the resins produced this way fit a bell shaped, gaussian curve (Fig. 27.35).

Q. *Can the ends of this curve be tightened by screening to produce a batch of resin of narrow size distribution?*

Ans. Yes; by screening the size distribution can be narrowed down to some extent.

Q. *What is the disadvantage of this technique?*

Ans. Excessive screening can score the bead surface reducing the physical properties of the resin. It would also significantly reduce the product yield.

Q. *By use of a novel manufacturing process, it is now possible to economically produce resin of very narrow particle size distribution (Fig. 27.36).*

Why is much greater emphasis laid on the manufacture of tightly sized resins?

Ans. Resins with very narrow particle size distribution give outstanding performance in both mixed bed and single bed applications.

Q. *How is this performance realized?*

Ans. No matter which resins are used, an ion exchange resin employed in the DM plant has to go through the same four operating steps:

(1) backwash
(2) regeneration
(3) rinse
(4) service.

BACKWASH: Tighter particle size control makes it possible to produce resin with a smaller average diameter (500—600 μ) without risking resin loss during backwash.

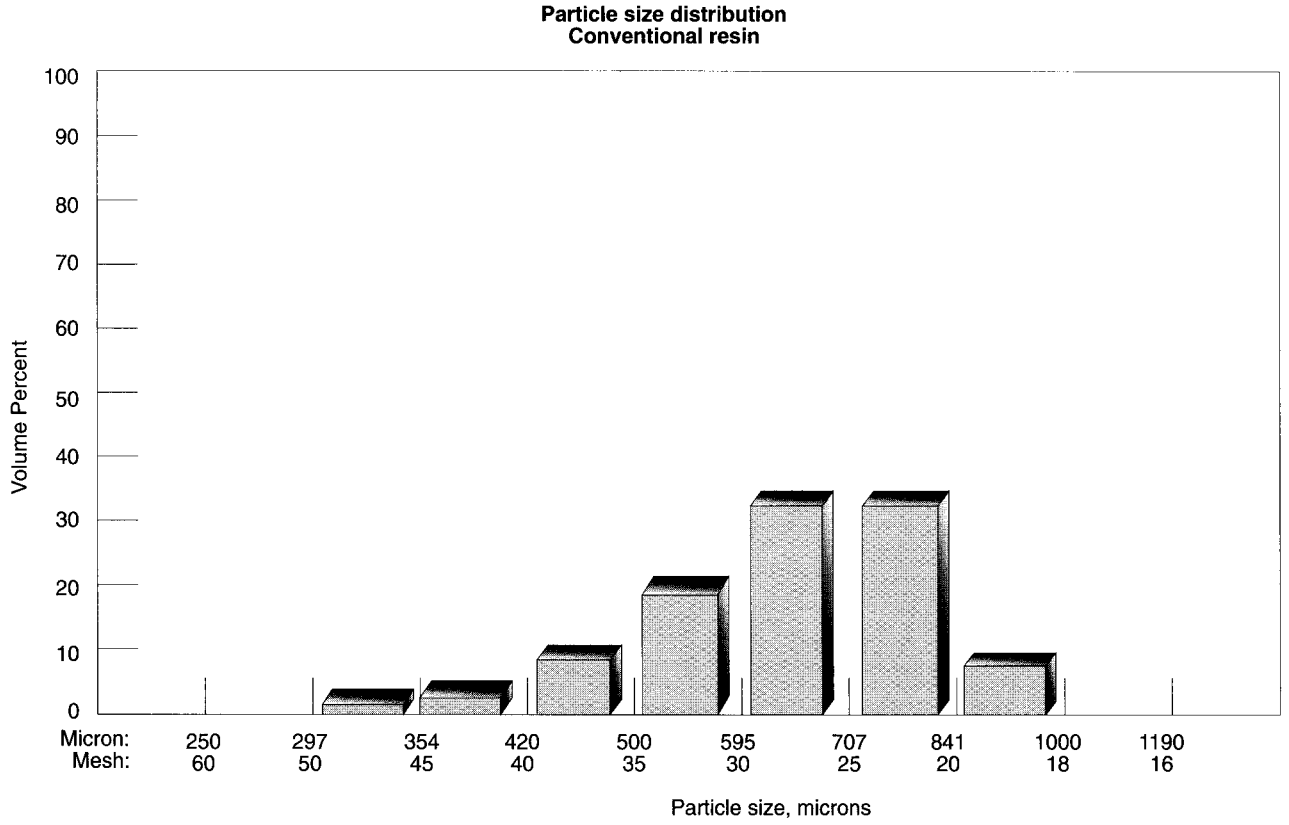


Fig. 27.35 *Particle size distribution of conventional resin.*

Source: Technical Paper (Form No. 177-1457-1090), Dow Chemical Company
Courtesy: The DOW Chemical Co./Midland/MI 48674/USA

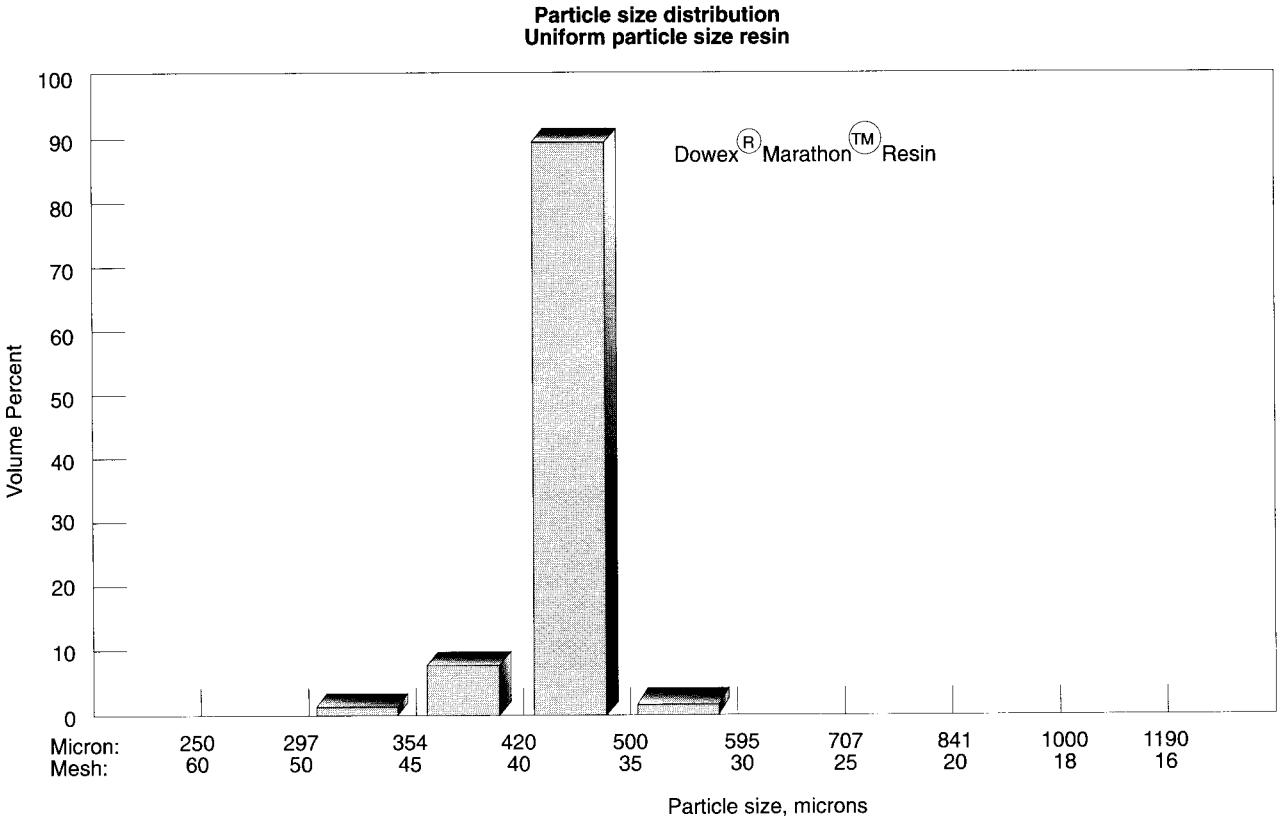


Fig. 27.36 *Particle size distribution.*

Source: Form No. 177-1457-1090 (Technical Paper/The Dow Chemical Company)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

Backwash classifies the bed. The largest beads migrate to the bottom of the vessel, the smallest beads rise to the top. The gradation in size from the top to bottom of the resin bed has significant impact on the performance of the vessel. The largest beads get only partially regenerated and give rise to ionic-leakage during the service cycle.

This classification can almost be eliminated with resin beads within a narrow size distribution.

REGENERATION: The smaller resins are regenerated much more quickly and completely than their larger counterparts (Fig. 27.37).

Therefore, a bed with gaussian distributed resin beads will have, during the regeneration operation, its smaller beads at the top of the bed to be highly regenerated (since they're contacted by the most concentrated regenerant) while the largest beads classified to the bottom of the vessel will come to contact with the least pure regenerant and get poorly regenerated.

As against this, the resins which are produced with a smaller, more uniform particle size have certain advantages

(a) the smaller the resin, the faster and more complete the regeneration will be thereby increasing the operating capacity of the resin

(b) resin with the smaller and more uniform particle size will have higher per cent regeneration including the resin at the bot-

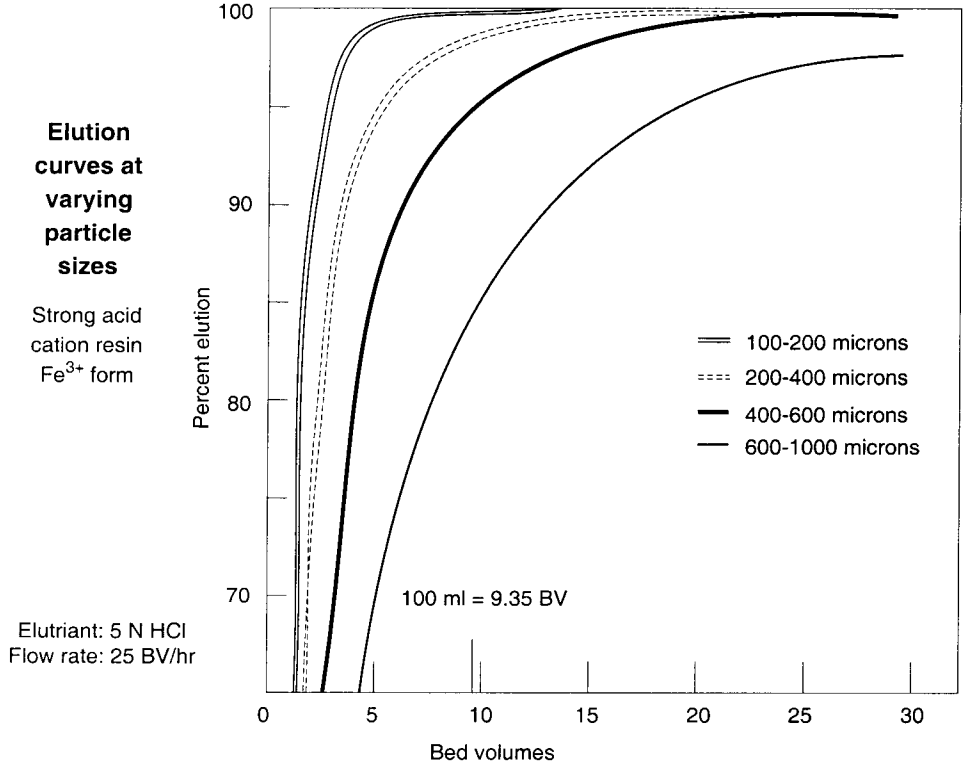


Fig. 27.37 *Comparative ability of resins of various sizes to elute captured ions.*

Source: Form No. 177-1457-1090 (Technical Paper/The Dow Chemical Company)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

tom of the bed and that minimizes the risk of ionic leakage during service cycle.

RINSE: A smaller uniform resin will rinse more quickly using less of a vessel's exchange capacity.

SERVICE: A bed of regenerated resin can be visualized as a number of stages or exchange zones stacked one atop the other. The height of an exchange zone is the height of the resin required to remove the ions in the feedwater to the vessel. As the top of the bed becomes exhausted, the exchange zone moves further and further down the bed (Fig. 27.38).

One of the factors that determine the height of an exchange zone is the size of the resin. The smaller the resin, the more rapid the exchange kinetics and the smaller the exchange kinetics, the smaller the exchange zone. The exchange isoplanes are much sharper for smaller sized particles.

In a gaussian sized resin there are obviously a number of exchange zones of different heights. At the bottom of the bed the resins are very large and the exchange zone will be wide. When the exchange front reaches the bottom of the vessel, breakthrough of ions will begin to occur almost immediately.

If the resins in a vessel are of uniform size, the height of the exchange zone remains constant from the top to the bottom of the vessel. The exchange zone at the bottom of the vessel will be much sharper and breakthrough will not oc-

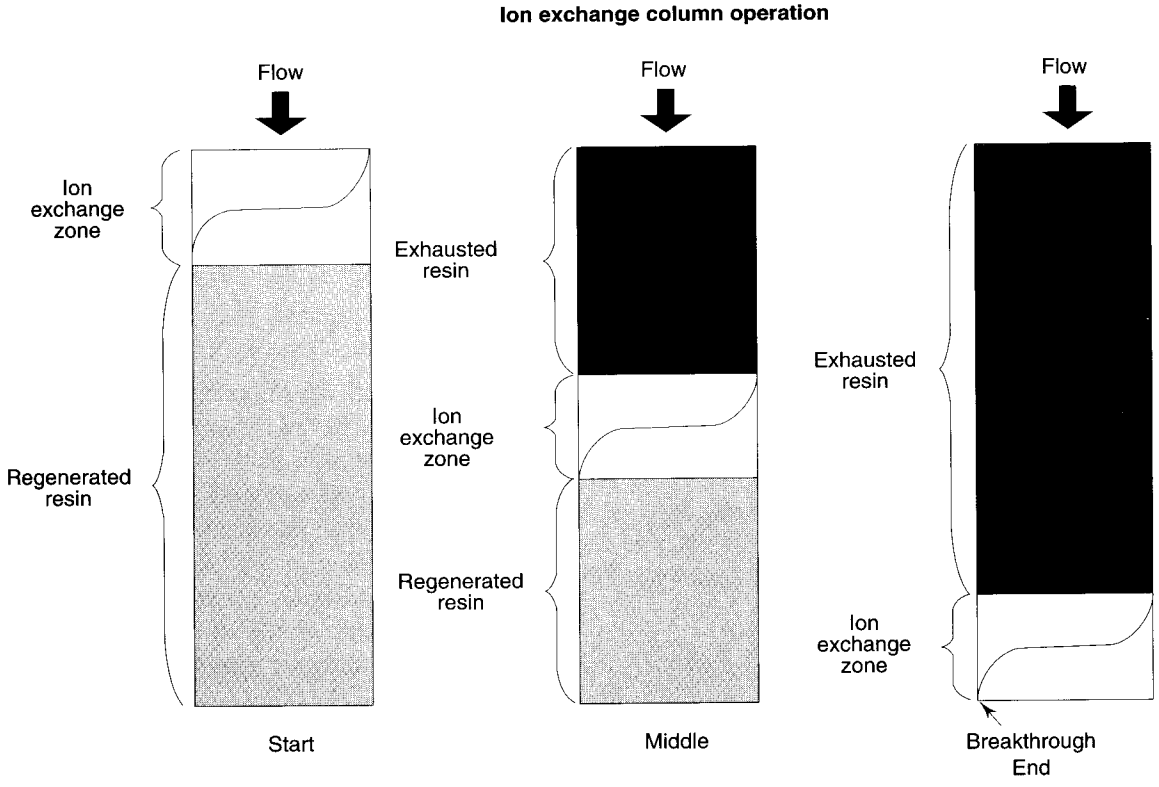


Fig. 27.38 *Movement of exchange front down the column.*

Source: Form No. 177-1457-1090 (Technical Paper/Dow Chemical Company)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

cur as quickly. More of the resin capacity at the bottom of the column will be used.

Q. *Is there any specific example of uniform sized resin contributing to greater operating capacity?*

Ans. In its paper submitted at the 1988, the International Water Conference, Detroit Edison detailed a trial run at one of their plants with the objective to compare the performance of conventional type-II anion resin to that of a uniform sized resin. They reported that the uniform sized resin has up to 24% greater operating capacity, used 40% less rinse water, and had equal or lower silica leakage.

In another trial run conducted at an eastern pulp and paper plant, USA, the performance of a conventional type-I strong base anion resin was compared to its uniform sized counterpart. Both resins were new when the trial began and the evaluation was run in identical side-by-side trains. The trains were operated following the same procedures. The uniform resin produced 20% more water per regeneration and required 33% less rinse water.

A southern chemical plant, USA compared a Gaussian sized, macroporous type-I resin to a uniform size type-I resin. The choice of the macroporous resin was due to the high level of organics in the water and the frequent brine cleanings required. The resins were run side-by-side under the same conditions. In data collected over 6 months of service, the uniform sized resin had an average throughput that was 25% greater. The uniform resin also required as much as 57% less rinse water.

A midwestern utility, USA had a demineralizer that was limited on cation capacity. To ensure that they never exceeded the sodium breakpoint, they performed several carefully controlled runs while monitoring sodium leakage. After determining the cation capacity limit, the system was set up to regenerate on throughput. They replaced the conventionally sized cation resin with a uniform sized cation resin. They obtained 20% more water per regeneration and the cation capacity limit was not reached even after months of operation.

Source: Impact of Particle Size on Single Bed Demineralizer Performance (Form No. 177-1457-1090 Technical Paper/The DOW CHEMICAL COMPANY)

Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

Q. *Articles published during the mid-nineties argue that demineralization for industrial water treatment is steadily becoming the domain of membrane processes based on reverse osmosis (RO).*

What is the economic crossover point at which RO outperforms IEx?

Ans. According to some experts, the economic crossover point at which RO outperforms ion exchange system for demineralization of M/up water occurs at a TDS level of 75 ppm.

Q. *Is it true that RO is superior to IEx?*

Ans. Modern packed-bed demineralization with reverseflow regeneration counters the notion that reverse osmosis is superior to ion exchange.

Q. *How do you conclude that?*

Ans. Three recent developments have completely changed the basis for the IEx vs. RO debate, even at TDS levels as high as 400 to 500 ppm. These are:

I. An improved understanding of the operating characteristics of RO.
II. Use of uniform-particle-size (UPS) resin
III. Refinement of the packed-bed reverseflow (RF) demineralization technique.

Q. *Why does TDS determine the location of economic crossover point?*

Ans. TDS denotes the total of all ions present in make-up water. Hence it closely approximates the osmotic pressure exerted by salts in solution—an important parameter in the RO-system design.

Note: *This definition of TDS must be differentiated from its use to denote total exchangeable cations, expressed as $CaCO_3$ equivalent.*

Q. *What should be the rational basis in choosing a demineralization process?*

Ans. This should be based on rigorous analysis of

1. process and economics using actual water conditions
2. raw-water analysis
3. required product flowrate
4. required product quality
5. discharge constraints

Q. *What makes RO demineralization less economical than a modern IEx system, particularly at high TDS levels, such as 300-500 ppm?*

Ans. By the application of packed-bed/RF technique using UPS grade resin.

Q. *Why does the above application make the RO demineralization less economical than a modern IEx system?*

Ans. In any columnar adsorption system, countercurrent, i.e. reverseflow (RF) regeneration drastically improves effluent quality and regeneration efficiency.

Use of packed beds with UPS resin leads to ultrahigh regeneration efficiencies, extremely low ionic leakage, very low rinse-water requirements, and simpler, more reliable equipment design.

Q. *Between reverseflow and coflow systems, which one is more preferable?*

Ans. Reverseflow system.

Q. *Why is a reverseflow system more prefered?*

Ans. In a coflow system ionic breakthrough (leakage) occurs earlier than in a reverseflow system for the same water composition and flow.

Q. *Why does this so happen?*

Ans. Consider a coflow system (Fig. 27.39, left).

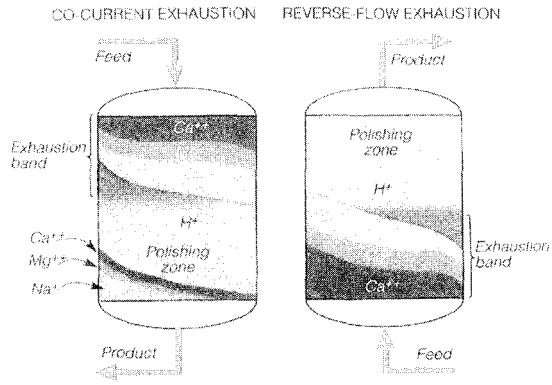


Fig. 27.39 *Coflow and reverseflow systems during service (exhaustion) cycle. The polishing zone at the bottom of catex bed of coflow system is not entirely in H^+ ionic form. Whereas in reverseflow system the contaminant ions are absent from the polishing zone.*

Source : POWER, Aug. 1995 (McGraw-Hill Companies,/NY 10020/USA)

©: McGraw-Hill Companies

During the service cycle, the capacity of the upper resin layers is depleted whereupon the exhaustion band gradually moves downward to the polishing zone at the vessel bottom. It is this polishing zone that controls the ionic leakage. However, as a result of downflow regeneration, not all the resin in this zone is in the pure ionic hydrogen (RH^+) form (Fig. 27.39/left). That is, this polishing zone is always contaminated with Ca^{2+}/Mg^{2+}/Na^+ ions. During the service cycle, the H^+ ions liberated in the upper layers combine with the sulphate ions present in the feed. These acids liberate the contaminant ions, as a result of regeneration of $R–Ca^{2+}$, $R–Mg^{2+}$, $R–Na^+$ resins present in the polishing zone, thereby giving rise to ionic leakage much earlier than the reverseflow system which has the same ionic profile but no 'contaminant zone' (Fig. 27.39, right)

Q. *Cocurrent systems are not much efficient. Do you agree with this statement? If so, why?*

Ans. Yes. The efficiency of a resin bed is measured by the extent of resin utilization. For coflow

systems, this depends largely on the amount of resin lying above the polishing zone.

Now, with a polishing zone of volume V, if the overlying resin volume is 2V, then 33% of the total resin bed is virtually unused. And as such the maximum utilization can be 67% for the obvious reason and that too only if the resin in the upper zones is fully exhausted, which rarely happens in practice.

In case the overlying resin volume is 4 times that of the polishing zone, only 20% is unused and utilization efficiency approaches 80%. Forasmuch as the overlying resin rarely becomes completely exhausted, capacity utilization is less than 50% in most cocurrent systems.

Q. *How can, therefore, the operating efficiency of a coflow system be increased?*

Ans. By increasing the bed-depth.

Q. *What are the disadvantages of adding more bed-height?*

Ans. It will lead to

1. higher system capital
2. higher operating cost
3. degradation of product quality

Q. *How does increasing the bed-depth of a coflow system tell upon product quality?*

Ans. In downflow (coflow) systems, the polishing zone of the resin in a classified bed has the largest resin beads at the bottom. Increasing the bed-depth, under this circumstance, erodes product quality due to two reasons:

I. exhaustion kinetics is controlled by surface-layer diffusion
II. larger resin beads give rise to smaller total surface area in a specific resin volume.

Q. *Is there any remedy?*

Ans. UPS resins help address this issue.

Q. *Regeneration of the coflow resin bed is less efficient than packed-bed/RF regeneration. Why?*

Ans. Due to some inherent deficiencies, coflow systems suffer from lower regeneration efficiency than packed-bed reverseflow ones.

Backwashing precedes regeneration. In coflow beds, backwashing is done for about 0.25 h at a flowrate great enough to expand the bed 100%. Actually, this much bed expansion is needed only for the top several inches of the bed where most of the TSS impurities collect. This process tantamounts to a waste of time and water. Over and above, the unnecessary expansion of the rest of the bed disturbs the polishing zone—much of the resin in this zone gets intermixed with the resin lying immediately above it. Besides, raw water is used in most backwashing and this leads to further exhaustion of the lower resin layers.

Cocurrent regeneration introduces the largest amount and highest concentration of pure regenerant at the top of the resin bed, which, however, is not the section that controls product-water quality. Unfortunately, the bottom of the bed that really controls the product-water quality "sees" all the ions released by regenerant in the overlying zones and thereafter receives only a small fraction of feed regenerant at the end of this step (Fig. 27.40, left)

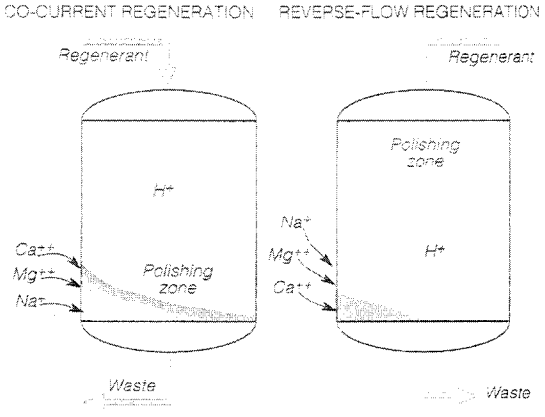


Fig. 27.40 *Downflow regeneration of cocurrent and reverseflow systems. The ionic profile produced by this process leads to early Na^+-leakage from coflow systems. Whereas the highly regenerated resin located near the exit of the packed-bed/RF yields very high quality effluent.*

Source: POWER Magazine (Aug. 1995/ McGraw-Hill Co., NY 10011/USA)

©: McGraw-Hill Co.

As a consequence of particulate-diffusion-rate-control mechanisms of IEx-bed-regeneration, coflow beds suffer from reduced regeneration efficiency due to the presence of larger beads at the bottom of the classified bed.

By contrast, the resin in the polishing zone of packed-bed RF regeneration sees the largest amount of pure regenerant producing an ionic-bed-profile. (Fig. 27.40, right). This highly regenerated polishing zone—product-water quality controller—is devoid of any contaminant ions and thereby produces a very high quality effluent in the subsequent service cycle.

Q. *What are the benefits of packed-bed/RF systems?*

Ans. A packed-bed is very compact and as such it occupies lesser space of the IEx vessel than a cocurrent or traditional countercurrent system to perform the same demineralization duty.

1. RF system yields very high water quality by placing the polishing zone at the top of the vessel and keeping the polishing zone free from contaminant ions by virtue of its mode (countercurrent) of regeneration
2. RF operation requires much lower chemical and rinse-water consumption and consequently, gives rise to much lower wastewater production.
3. When UPS resin is used, RF design results in higher capacity utilization, lower leakage, and much lower chemical consumption.
4. RF system with packed-bed of UPS resin eliminates mid-vessel internals, and further reduces both capital and maintenance costs by simplifying the design of the upper and lower distributor/collectors
5. Packed-bed/RF system operates on plugflow hydraulics that virtually eliminate any hideout regenerant solution thereby greatly reducing the regeneration time
6. The system efficiency easily exceeds 90% besides giving a much higher degree of reliability
7. With UPS resin beads, ΔP is lower than standard larger-sized resin beads
8. In most cases, mixed-bed polishing will not be required as a RF system will result in an effluent quality of 1 μmho/cm or less from a FW with TDS level of 300–400 ppm
9. Packed-bed/RF systems are amazingly adaptable, i.e. they can operate well under changing water conditions—they, unlike RO, need no normalization calculations, very accurate and continuous pH monitoring/control, tight feedwater-temp. control or particularly high operating skill.

Q. *How can packed-bed/reverseflow demineralizer stake its claim of superiority to reverse osmosis system?*

Ans. The economic advantages of PB/RF demineralizer system over RO/MB polisher can be illustrated through cost calculations of typical plants using water with different impurity concentrations.

The cost calculations presented below do not include pretreatment, land, building, and resin and membrane replacement.

Case-I. A pulp and paper plant in the southern United States requires a steady supply of 96.51 m^3/h of high quality water:

Na—0.4 ppm as $CaCO_3$

SiO_2—0.02 ppm

Conductivity—2.0 μmho/cm

For this system, the operating cost of PB/RF IEx process has been compared with the operating cost of RO/MB technology (Table 27.1).

Normally with low-TDS water, the IEx system is more economical than the RO/MB system, but the cost difference is surprising, though it is not at all surprising that PB/RF can achieve such high effluent quality without polishing.

Over and above, the comparison-table shows that PB/RF system requires significantly lower

water consumption than the RO/MB system. Most RO systems operate at 75% recovery and that means a 25% reject at all times.

Case-II. A typical Cogeneration facility in the northeastern US requires a continuous supply of 82.43 m^3/h of high-quality BFW (Na—0.2 ppm as $CaCO_3$; SiO_2—0.02 ppm; Conductivity—0.1 μmho/cm] from its feedwater with 272 ppm TDS. And as before, RF demineralization enjoys significant capital and operating-cost advantages (see Table 27.2).

Table 27.1 *Annual operating cost for a Southern US pulp and paper plant using feedwater of specification:*

[Ca^{2+} – 28; Mg^{2+} – 12; Na^{+} – 19; K^{+} – 6; HCO_3^{-} – 35; SO_4^{2-} – 10; Cl^{-} – 19; NO_3^{-} – 1; CO_2 (as CO_2) – 0; SiO_2 (as SiO_2) – 10 ; TDS – 95.3] ppm

COST ELEMENT	*SYSTEM TYPE*							
	Packed-BED/RF IEX Cost, $/100M^3$				*RO/MB Train Cost, $/100M^3$*			
	Usage	*Low*	*Medium*	*High*	*Usage*	*Low*	*Medium*	*High*
Energy, kWh/$100M^3$	NA	—	—	—	76.618	3.963	4.491	5.284
Sulfuric acid, kg/$100M^3$	26.156	1.057	1.321	1.585	7.397	0.264	0.264	0.528
NaOH, kg/$100M^3$	59.973	11.089	15.059	18.758	7.397	1.585	1.849	2.113
Antiscalant, ppm	NA	—	—	—	132.1	2.113	2.377	2.642
Neutralizer, kg/$100M^3$	31.175	1.321	1.585	1.849	Na	—	—	—
Excess water, $M^3/100M^3$	895.638	0.792	0.792	1.056	9106.974	6.869	9.247	11.360
Sewer, $M^3/100M^3$	895.638	0.792	1.321	2.113	9106.974	6.869	13.738	20.607
Total Cost Per $100M^3$		15.851	20.078	25.361		21.663	31.966	42.534
System Capital Cost	$ 450 000				$ 985 000			

Table 27.2 *Annual operating cost for a Northeastern US cogeneration facility using feedwater of specification:*

[Ca^{2+} – 113; Mg^{2+} – 45; Na^{+} – 29; HCO_3^{-} – 127; SO_4^{2-} – 22; Cl^{-} – 38; CO_2 (as CO_2) – 2; SiO_2 (as SiO_2) – 7; TDS – 272] ppm

COST ELEMENT	*SYSTEM TYPE*							
	Packed-BED/RF IEX Cost, $/100M^3$				*RO/MB Train Cost, $/100M^3$*			
	Usage	*Low*	*Medium*	*High*	*Usage*	*Low*	*Medium*	*High*
Energy, kWh/$100M^3$	NA	—	—	—	89.299	4.491	5.284	6.341
Sulfuric acid, kg/$100M^3$	84.808	3.434	4.227	5.019	21.664	0.792	1.057	1.321
NaOH, kg/$100M^3$	38.045	7.662	9.511	11.360	8.718	1.849	2.113	2.642
Antiscalant, ppm	NA	—	—	—	132.1	2.113	2.378	2.642
Neutralizer, kg/$100M^3$	28.005	5.548	7.133	8.454	NA	—	—	—
Excess water, $M^3/100M^3$	1603.694	1.321	1.585	2.113	9165.098	6.869	9.247	11.360
Sewer, $M^3/100M^3$	1603.694	1.321	2.378	3.699	9165.098	6.869	13.738	21.136
Total Cost Per $100M^3$		19.286	24.834	30.645		22.983	33.817	45.442
System Capital Cost		$ 635 000				$ 930 000		

28

REVERSE OSMOSIS

Q. *Why is combining reverse osmosis (RO) pretreatment with ion exchange demineralization gaining increasing acceptance among the producers of high purity boiler feedwater?*

Ans. Low-pressure reverse osmosis (RO) membranes installed ahead of ion exchange bed reduce operating costs dramatically.

Q. *Is there any specific example of cost saving generated by installing RO?*

Ans. 1. When faced with increasing demand for quality BFW from high-mineral-content water supply, Container Corporation of America (CCA) installed a reverse-osmosis (RO) unit to pretreat the demineralizer feed for its Fernandina Beach (Fla) mill, instead of adding another demineralizer train.

The state-of-the-art RO technology of FILMTEC®, a subsidiary of The Dow Chemical Co., USA has resulted in following benefits

(a) Water of higher quality than anticipated is being produced
(b) Cost saving is more than 25%
(c) Operating-cost saving for the WTP has exceeded the original projection
(d) The $ 1-million operating-cost saving has made possible a payback period of approximately 3.9 years
(e) Based on an economic life of 16 years, the rate of return for the project is 19.8%.

Source: POWER (March '94 reprint)

Courtesy: The Dow Chemical Co./MI 48674/US

2. The impact of RO on water production and make-up costs is illustrated dramatically by the experience of a large electric utility, Texas Utility Electric Company in their two gas/oil fired electric generating units at the Permian Basin Steam Electric Station located in Monahans, Texas.

Before it installed FILMTEC RO membranes upstream of the ion-exchange demineralizer, the utility was dissatisfied with the DM unit's performance on a number of counts:

(a) loss of strong-base capacity was resulting in frequent anion replacement
(b) regenerations required large acid and caustic dosages
(c) low throughput capacity necessitated frequent regenerations

Together, these reasons added up to unacceptably high operating costs.

After installation of FILMTEC RO membranes (Fig. 28.1), the TDS content of feedwater to DM plant dropped from 450 ppm to less than 6 ppm

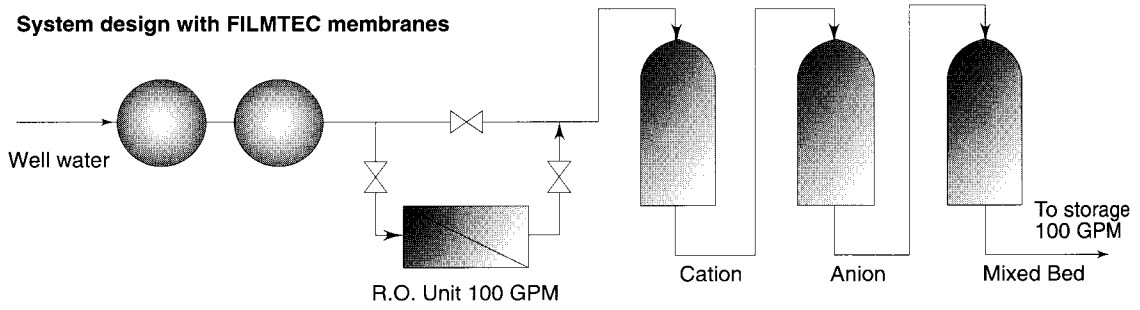


Fig. 28.1 *RO Unit installed ahead of DM train cuts down load on ion exchange system.*
Source: Filmtec Bulletin (Form No. 609-00026-992AMS)
Courtesy: The Dow Chemical Co./MIDLAND 48674/USA

and silica levels fell from 28.5 ppm to less than 1 ppm (Table 28.1).

Table 28.1 *Reverse Osmosis/Deionizer System Profile Water Analysis*

Constituent	*Raw Water*	*RO Permeate*	*% Rejection*	*Mixed Bed Effluent*
Ca	47	0.11	99.8	<0.01
Mg	15	0.04	99.7	<0.01
Na	60	1.0	98.3	<0.01
K	4	<0.5	–	<0.01
Fe	<0.01	<0.01	–	–
Sr	0.88	<0.01	>98	<0.01
Cl	61	0.9	98.5	<0.01
SO_4	105	1.3	98.8	<0.01
HCO_3	190	4.9	97.4	–
SiO_2	28	0.45	98.4	<0.002
pH	7.8	7.5	–	6 to 8
Conductivity	705	10.7	98.5	0.1

All constituents except conductivity and pH are expressed as mg/1. Conductivity is expressed as micro S/cm @ 25°C, pH is expressed as standard units.

Source: Filmtec Bulletin (Form No. 609-00026-992AMS)
Courtesy: The Dow Chemical Co./MIDLAND/MI 48674/USA

The decreased loading on the ion exchange system reduced the need for resin regeneration from three times a week to three times a year, increasing the volume of water produced between regenerations by over 6000%—from 164,000 gallons to 10,000,000 gallons.

As a result of the improvement, the utility was able to reduce the cost of deionized water for boiler make-up by over $ 150,000 per year (Table 28.2).

Table 28.2 *DI Water Costs—Before/After Installing Reverse Osmosis Unit*

	Before RO	*After RO*
Water	$0.77	$0.013
Power	0.02	0.16
Chemicals	6.19	0.207
Resin Replacement	0.84	0.60
Membrane Replacement	–	0.526
Filter Replacement	–	0.035
Total Cost $/1,000 gallons	7.82	1.54

Source: Filmtec Bulletin (609-00026-992AMS)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

Q. *What is reverse osmosis?*

Ans. Reverse osmosis is a pressure driven membrane process capable of removing small particles, dissolved salts and low molecular weight (100 mol. wt. cut-off) organics from a feedwater stream.

Q. *What is the basis of reverse osmosis?*

Ans. If two aqueous solutions containing differential salt contents are kept separated by a semipermeable membrane, the system develops an

inherent tendency for water molecules (not the salt) to permeat across the membrane layer to dilute the more concentrated solution. This process is called ***osmosis***. The driving force per unit membrane cross-section, dependent on the concentration difference, is the ***osmotic pressure***.

However, this natural process can be reversed if some external pressure higher than the system's osmotic pressure is applied on the concentrated solution side whereupon water will pass from the more concentrated solution, through the membrane boundary, to the less concentrated solution. This is the basis of reverse osmosis (Fig. 28.2).

If one compartment contains pure water and the other salt or mineral-rich water, the process of reverse flow will produce pure water, since the membrane is not permeable to salt.

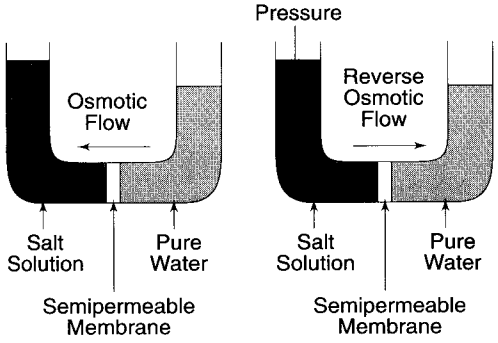


Fig. 28.2 *Reverse osmosis, the finest level of liquid filtration today, requires the application of pressure to force water from salt water side to pure water side.*

Source: *Filmtec Bulletin/Form No. 609-00022-1190 AMS*

Courtesy: *The Dow Chemical Co./Midland/MI 48674/USA*

Q. *How is osmotic pressure related to total dissolved solids (TDS).*

Ans. As a rough rule of thumb, there is about 7 kPa (1 psi) of osmotic pressure for every 100 ppm of TDS.

Q. *Can the RO process go on indefinitely?*

Ans. No. The salt solution would require increasingly higher pressure to force water through the membrane; ultimately the membrane could become clogged by precipitated salts and other impurities.

Q. *What is done in practice?*

Ans. In actual practice, RO devices employ crossflow filtration as shown in Fig. 28.3.

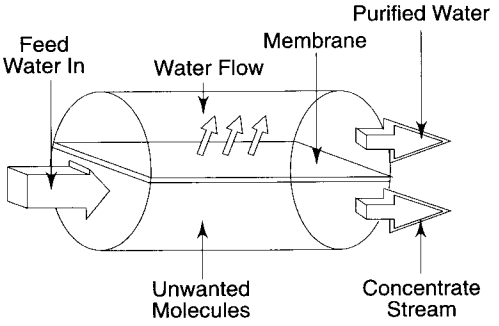


Fig. 28.3 *In corssflow filtration the feed stream is split into two parts—a purified water stream and a concentrate stream that sweeps away the excess salts rejected by the membrane.*

Source: *Filmtec Bulletin Form No. 609-00022-1190AMS*

Courtesy: *The Dow Chemical Co./Midland/MI 48674/USA*

This method uses a pressurized feed stream which flows parallel to the membrane surface. Only a portion of this feed stream passes through the membrane as **permeat** and the remainder of the stream known as the **reject** or **concentrate** provides a continuous sweep of rejected ions and particles from the membrane surface.

Q. *How are the RO membranes classified?*

Ans. They are classified by their cross-sectional morphology as

(a) asymmetric
(b) thin-film composite.

Q. *What are the asymmetric membranes?*

Ans. These membranes have a dense salt rejecting layer (which is relatively thin) and a thick, porous support layer—both of which are composed of the same polymer such as cellulose acetate (CA).

Q. *What are cellulose acetate membranes?*

Ans. Cellulose acetate (CA) membranes are the oldest form of commercial RO membranes. They are available in diacetate and triacetate (CTA) grades, and in blends of these grades (CA/CTA).

CA membranes get their name not from their structure, but from the material used in their fabrication. All commercial CA membranes are structurally classified as asymmetric. The dense surface skin 'membrane' and thick, porous supporting underlayer have exactly the same polymer and chemical composition but are structurally dissimilar.

Q. *How are these CA membranes fabricated?*

Ans. It is a one-step process

by casting a film or spinning a fibre from a solution of cellulose acetate and solvent(s). The film of fibre is then coagulated in a water bath to form the asymmetric structure.

This bath also removes the solvents from the membrane. The thin surface skin formed by this process rejects salts and permits water permeation. The remainder of the structure provides physical strength to the surface skin while allowing water to permeate to the product water side. Figure 28.4 shows the cross-section of a CA membrane.

Q. *What are thin-film composite membranes?*

Ans. The term "thin-film composite" describes the manner in which these reverse osmosis membranes are fabricated. Thin-film composite membranes usually consist of layers of dissimilar materials joined together to form a single membrane. This layered construction permits the

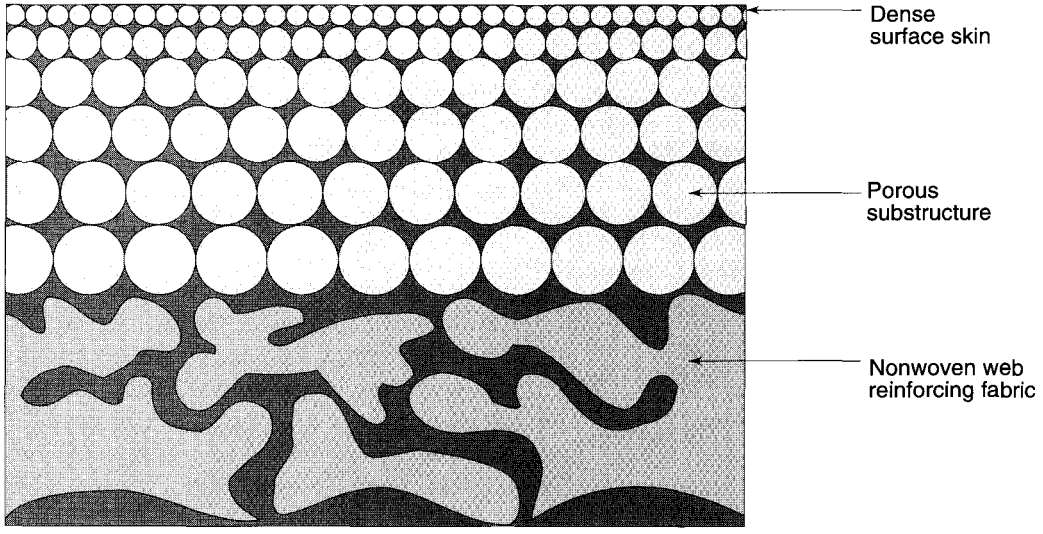


Fig. 28.4 *Cross-section of a cellulose acetate membrane.*
Source: Filmtec Technical Bulletin (Form No. 609-00054-1192AMS)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

use of material combinations that optimize the performance and durability of the membrane.

For example, FILMTEC FT 30* membrane features a thin aromatic polyamide barrier layer that provides high water flux, salt and silica rejection, and excellent chemical resistance. Beneath this outer layer is a thick microporous polysulphone sublayer that supports the barrier layer, offers necessary porosity and strength properties, and resists compaction under RO pressure conditions (Fig. 28.5).

Q. *How is the thin-film membrane FT30 fabricated?*

Ans. The polysulphone layer is cast onto a non–woven polyester inner web that contributes overall structural strength. Thereafter, the barrier layer is applied by interfacial polymerization.

Q. *What are the advantages of thin-film composite membranes over cellulose acetate membranes?*

Ans. 1. Excellent hydrolytic resistance for greater membrane stability and longer life.

2. Superior salt rejection capability rewards higher quality product water (see Table 28.3).

Table 28.3 *Comparison of Typical Salt Passage Data for Cellulose Acetate and FT30 Membranes*

Salt	CA	FT30
NaCl	5%	2%
$NaHCO_3$	5%	3%
$MgSO_4$	2%	<1%
$CaSO_4$	2%	<1%
$NaNO_3$	15%	8%
SiO_2†	15%	2%

† *Dissolved reactive silica*

Source: Filmtec Technical Bulletin (Form No. 609-00054-1192 AMS)

Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

The Filmtec FT 30 thin-film composite membrane passes 50% less salt than a cellulose acetate membrane.

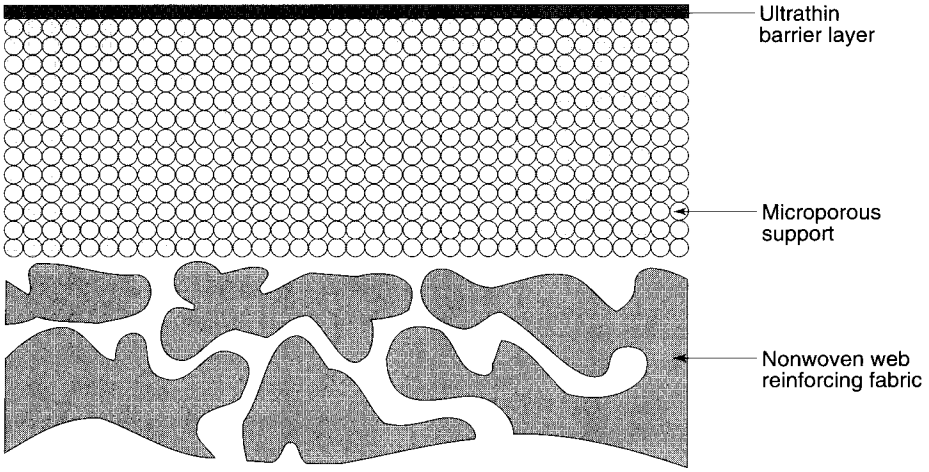


Fig. 28.5 *Cross-section of a thin-film composite reverse osmosis membrane.*
Source: Filmtec Technical Bulletin (Form No. 609-00054-1192 AMS)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

* FT 30 is the proprietary product of Film Tec Corporation, a wholly owned subsidiary of The Dow Chemical Company, Midland, USA.

3. Superior organics rejection also contributes to higher water purity (Fig. 28.6).

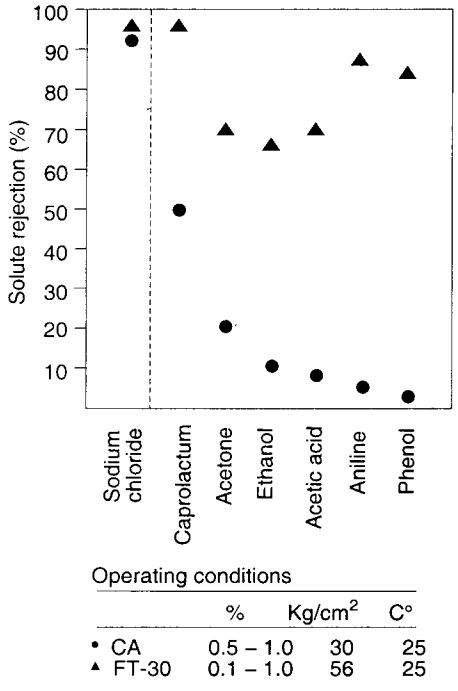


Fig. 28.6 *While CA membranes exhibit very low organic solute rejections, the Filmtec FT30 membrane provides consistently higher rejection performance.*
Source: Filmtec Technical Bulletin (Form No. 609-00054-1192 AMS)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

4. Strong/resilient membrane structure for greater durability
5. Excellent membrane flux means higher productivity and lower operating pressures
6. Compaction-resistant sublayers stand up to pressurized operation, contribute to longer service life
7. Wide operating pH range for produced water (pH 2—11) (Fig. 28.7).
8. Broad operating temperature range for produced water (273°K to 318°K)

Q. *What are the disadvantages of thin-film composite membranes?*

Ans. Its sole disadvantage is its limited tolerance to chlorine*. Continuous chlorination causes attack on the aromatic polyamide structure of the barrier layer.

Q. *How can this limitation of thin-film membranes be overcome?*

Ans. Dechlorination of RO feedwater is essential.

See Appendix–X

Q. *What are the advantages of cellulose acetate membranes?*

Ans. 1. Relatively low purchase cost
2. Tolerant of chlorine in feedwater

Q. *What are the disadvantages of CA membranes as against thin-film membranes?*

Ans. 1. Hydrolysis by acids and alkalis can lead to deterioration of the membrane structure
(CTC membranes offer better hydrolysis resistance than diacetate grades.)
2. Membrane susceptibility to biodegradation means continuous chlorine disinfectant protection is often required.
3. Inferior salt rejection characteristics tell upon product water purity.
4. pH tolerance range is narrow:
— pH 4 to 8 for continuous operation
— pH 3 to 9 cleaning
This narrow pH tolerance reduces operating flexibility and greatly restricts cleaning capabilities
5. Narrow temperature limits (273°K to 308°K) because compaction rates above 308°K are unacceptable. Therefore, strict control of operating conditions is essential and that may limit the speed and effectiveness of the cleaning operation.

* However FT 30 membranes have a chlorine tolerance of up to 1000 ppm-hours before noticeable loss of salt rejection is observed.

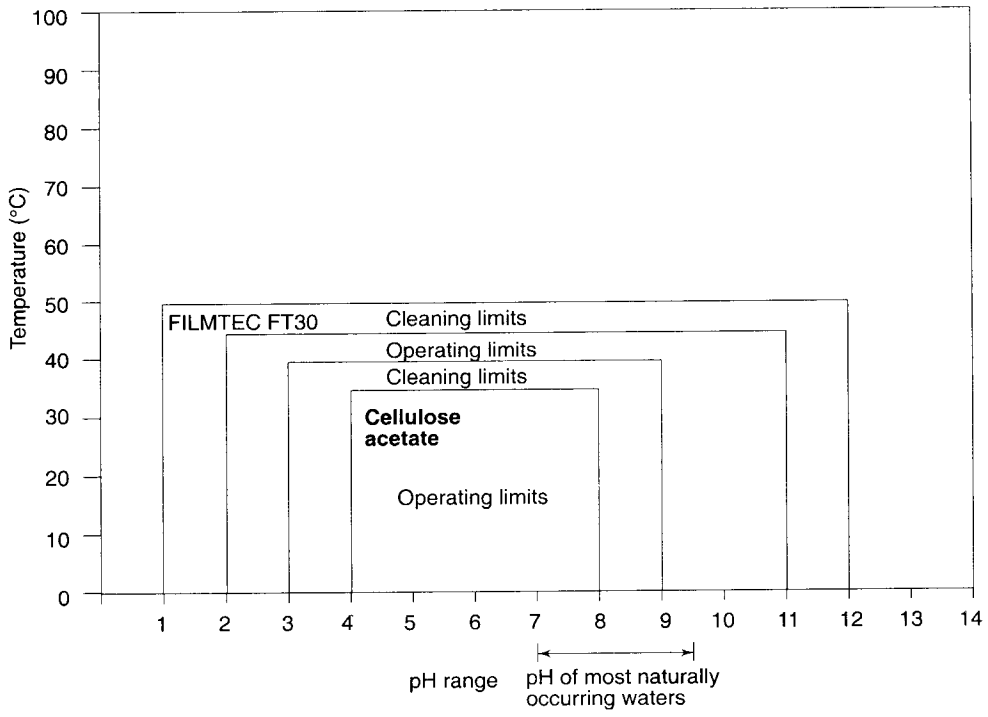


Fig. 28.7 *Comparison of operating and cleaning parameters of FT30 and CA membranes.*
Source: Filmtec Technical Bulletin (Form No. 609-00054-1192AMS)
Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

6. Asymmetric membranes tend to compact into increasingly dense structures under the continuous high feed pressures used in reverse osmosis systems, resulting in abbreviated service life.
7. 40–50% lower membrane permeability means operating pressures required to achieve desired productivity and salt rejection levels are nearly doubled, so energy costs are significantly higher.

Source: Filmtec Technical Bulletin (Form 609-00054)

Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

Q. *Why is it imperative to pretreat feedwater before it is subjected to reverse osmosis?*

Ans. Pretreatment of feedwater is essential to optimize performance and increase life expectancy of the RO system.

Q. *Why is greater emphasis laid on the selection of proper pretreatment of feedwater to RO system?*

Ans. Selection of proper pretreatment will maximize efficiency and membrane life by minimizing fouling, scaling, and membrane degradation. Pretreatment of feedwater must be a total system approach for continuous and reliable operation.

Q. *What are the prerequisites for selecting the best scheme for pretreating of feedwater?*

Ans. 1. Feed source
2. Type of RO membrane that is to be used
3. Recent water analysis for the feed source.

Q. *Why is knowing the source of the feedwater important?*

Ans. Suspended matters (e.g. silt), colloidal suspension and biological material present in feedwater vary from source to source. Even they are present in different quantities in surface water and ground water both having the same level of TDS. Therefore, these impurities and their loads dictate the selection of unit operations such as clarification, multimedia filtration as well as chemical dosing with coagulants such as aluminium sulphate or ferric chloride to reduce or remove materials that will cause fouling of reverse osmosis elements.

Q. *How does the choice of RO membrane determine the pretreatment scheme for a reverse osmosis system?*

Ans. If the cellulose acetate (CA) membrane is selected, then the pretreatment must include acid dosing to lower the feed pH (typically to a range of pH 5.0–6.0) so that hydrolysis of the membrane itself is minimized during operation.

Also, the CA membrane is susceptible to biodegradation due to bacterial attack. Therefore, one must go for chlorination of feedwater to minimize bacterial activity to ensure safe and lasting life of the cellulose acetate membrane.

Choice must be made in a likewise manner if one chooses to use non-cellulosic membranes such as thin-film composite polyamide. If these membranes are installed, one must be extra careful to remove chlorine or other oxidizing agents from the feedwater.

Q. *Why is a recent chemical analysis of the water source an essential prerequisite for deciding the pretreatment scheme?*

Ans. A recent chemical analysis of the water source is very essential for proper design of the pretreatment prior to the RO system. The analysis should contain all the information prescribed in Table 28.4.

This set of information being available the system designer can look at the solubilities of sparingly soluble salts, and determine the steps required to treat the feedwater. This information is also useful to determine the recovery at which the RO system will operate. Sometimes the feedwater contains sufficient quantities of materials that will precipitate if the pretreatment steps are not adequate.

Q. *What are the sparingly soluble salts that are most commonly encountered in the feedwater?*

Ans. 1. Calcium carbonate
2. Calcium sulphate
3. Calcium fluoride
4. Barium sulphate
5. Strontium sulphate
6. Silica.

Q. *How is the effect of calcium carbonate made void in the pretreatment step?*

Ans. Calcium carbonate precipitates over the alkaline range. Therefore, it is usually treated by acid or antiscalant dosing.

Q. *How is scaling by salts such as calcium, barium and strontium sulphates controlled?*

Ans. By use of a scale inhibitor.

The purpose of the inhibitor is to prevent, for a short period of time, the formation of scale in the reverse osmosis unit, thereby permitting the RO unit to operate above the solubility limits for these salts.

Note: Even though it is possible to operate in this manner, many designers of the RO system advocate the use of the inhibitor to protect the membranes instead of allowing them to operate above the solubility limits of the scale formers. That is they want the antiscalant to offer an 'insurance policy' for the safe operation of RO.

Q. *How can the silica scaling potential be minimized?*

Ans. Usually, RO systems are designed to operate below the solubility limit of silica. The silica

Table 28.4

WATER ANALYSIS

Project _____ Date _____

Feed Source _____ pH _____ TDS _____

Cations ppm	as Ion	as $CaCO_3$	Anions ppm	as Ion	as $CaCO_3$
Ca			Cl		
Na			F		
Mg			SO_4		
Fe			NO_3		
Mn			SiO_2		
K			PO_4		
Ba			HCO_3		
Sr			CO_3		
NH_4^+			OH		
			CO_2		
$KMnO_4$ - value					

Alkalinity (as $CaCO_3$) M _____ P _____

Hardness (as $CaCO_3$) carbonate _____ non- _____

Temperature Range _____ SDI _____ Turbidity _____ N.T.U.

Cl_2 (free) _____ Bacteria (count/ml) _____

Conductivity _____ microSiemens/cm _____

Source: 609-00036 (Technical Paper/The Dow Chemical Co.)
Courtesy: The Dow Chemical Co./Midland/MT 48674/USA

solubility is a strong function of temperature and pH. To prevent silica scaling, the feedwater may be heated or softened.

Note: RO systems are known to operate effectively with up to 150 ppm of SiO_2 in the brine stream at temperature $\geq 298°K$.

Q. *Reverse osmosis elements are cleaned on a periodic basis. Why?*

Ans. The objective is to clean the RO membrane off the deposited foulant or scale in order to maximize the service life of the RO system.

Q. *What are these cleaning agents?*

Ans. Depending on the nature of the foulant or scale, either alkaline or acidic cleaning solutions are used. Table 28.5 lists some of the common solutions used to clean a typical reverse osmosis membrane.

Q. *When you can tell that the RO system needs to be cleaned?*

Ans. The best guideline is to follow ASTM (American Society for Testing and Materials) procedure. The procedure, D 4516–85, describes how to manipulate the data to a set of standardized conditions. The standardized (or normalized) data are then graphed. Tallying the RO system performance with the graph helps one to determine

Table 28.5 *Common Cleaning Solutions for Cleaning Filmtec FT 30 Membrane*

Foulant	CLEANER	[A]	[B]	[C]	0.2% HCl	0.5% H_3PO_4	2% Citric acid	0.2% NH_2SO_3H	1% $Na_2S_2O_4$
Inorganic Salts $CaCO_3/CaSO_4/BaSO_4$					Best	OK	OK	OK	
Metal Oxides (e.g. Iron)						Good		OK	Good
Inorganic Colloids			Good						
Silica		OK							
Biofilms		Best	Good	Good					
Organics		OK	Good	Good					

A = 0.1% NaOH + 0.1% Na-EDTA at pH 12, 303°K Max

B = 0.1% NaOH + 0.05% Na-DSS at pH 12, 303°K Max

C = 1% STP = 1% TSP + 1% Na-EDTA

Active ingredients are represented in weight per cent.

the time when the RO elements need cleaning. RO membrane manufacturers recommend cleaning a reverse osmosis system when the standardized permeate flow has decreased by 10 per cent.

Note: Another procedure, though not a reliable one, is to use pressure drop as the indicator. When the ΔP across the entire system or one of the stages in a multistage system increases by 15% from the reference condition, it is recommended to clean the RO system.

Q. *Is there any other indicator?*

Ans. Yes; it is the salt passage (or decrease in salt rejection) that calls for RO system cleaning.

At any time, an increase in salt passage exceeding 5%, indicates that the system should be cleaned or at least inspected of a mechanical leak in the system (such as a faulty O-ring seal) so that the reason for the higher permeat TDS can be identified.

Q. *Why is it required to clean reverse osmosis systems one stage at a time?*

Ans. To avoid cross-contamination.

Q. *What is the general cleaning procedure of a reverse osmosis system?*

Ans. There are six steps.

1. **Mixing** of cleaning solution in the mixing tank constructed of polypropylene or fibreglass reinforced plastic (FRP). It is recommended that the solution be maintained at:

318–323°K	at	pH 2–10
308°K	at	pH 10–11
303°K	at	pH 11–12

2. **Low flow pumping.** The mixed, preheated solution is then pumped to the vessel at conditions of low flowrate and low pressure to displace the process water. Use is to be made of enough pressure just to compensate for the pressure drop from the feed inlet to the concentrate outlet. The pressure should be low enough that essentially no permeate is produced. The concentrate

is dumped to prevent dilution of the cleaning solution.

3. **Recycling.** Following the displacement of process water, cleaning solution remains as the concentrate stream which is recycled to the cleaning solution tank and allowed to stabilize its temperature.
4. **Soaking.** The recirculation pump is switched off whereupon the RO elements begin to soak. Soaking period normally lasts up to a maximum of 1 hour but for difficult fouling an extended soak period (10–15 hrs) is beneficial. During this extended soak period, a low recirculation rate equal to about 10% of the normal cleaning is continued to maintain a high temperature all through soaking.
5. **High flow pumping.** The cleaning solution is fed to the vessels at high rates (see Table 28.6) for 30-60 mins to flush out the foulants.

Table 28.6 *Recommended Feed Flowrate Per Pressure Vessel*

Feed Pressure (kPa)	Element Dia (mm)	Feed Flowrate (m^3/h)
138–414	63.5	0.68–1.13
138–414	100	1.81–2.27
138–414	200	6.81–9.08

In case the RO elements are heavily fouled (which should never happen), a flowrate which is 1.5 times those mentioned in above table may aid cleaning.

6. **Flushing out.** The membrane is flushed out of cleaning solution by using prefiltered raw water, provided it does not give rise to scaling problems.

See Appendix–X

Q. *Why is it imperative, during low-flow-pumping-stage of membrane cleaning, to maintain a pressure low enough that essentially no permeate is produced?*

Ans. A low pressure minimizes redeposition of dirt on the membrane.

Q. *During the high-flow-pumping stage of the cleaning operation, excessive pressure drop may pose a problem. What is the maximum recommended pressure drop?*

Ans. About 138 kPa per element or 414 kPa per multi-element vessel, whichever value is more limiting.

Q. *Why is the 'flush out' stage carried out at 293°K?*

Ans. To prevent precipitation, the minimum flushout temperature is kept around 293°K.

Source: Roughing Demineralization with Reverse Osmosis ahead of Ion Exchange—S.S. Whipple and S.S. Beardsley (Technical Report 609-00036/The Dow Chemical Company)

Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

Q. *The Midwest Power Systems, Inc. reports that its George Neal generating stations at Sioux City, Iowa are realizing savings of $1000/day in demineralizer operating costs following the incorporation of a reverse-osmosis (RO) pretreatment system. How is this cost saving being realized?*

Ans. RO trains installed upstream of IEx beds for pretreatment of raw water remove dissolved minerals from the feedwater. Membrane rejection rates for silica, salts, and minerals (such as iron and manganese) are typically as high as 98.5% to 99.8%. Thus an RO pretreatment system drastically cuts down load of DM trains downstream and generally pays for itself quickly in reduced chemical costs alone—often within three years. The cost saving is realized through significant reduction in the amount of caustic and acid needed for periodic regeneration of ion-exchange resins.

Q. *What about the dependability and cost-effectiveness of RO systems?*

Ans. Their dependability is beyond doubt and cost-effectiveness is total.

More than 230 RO units, now operating throughout United States alone, attest to their dependability and cost-effectiveness.

Q. *What are the advantages of RO used as a roughing demineralizer?*

Ans. This system has the following basic benefits

I. extending the operating intervals between IEx resin regenerations that, in turn, reduces both labour and chemical costs
II. drastically curtailing the load on DM-units downstream thereby producing high quality DM water
III. improving safety which is particularly significant because the acid and caustic pump seals spring leaks periodically. Therefore, the less you need to use the pump, the better
IV. dependability and operational simplicity.

Q. *The total installed cost of a RO retrofit is staggeringly high. Nevertheless, induction of a RO unit upstream of DM train is favoured. Why?*

Ans. It is true that the initial investment cost of a RO unit is high, yet its payback period is less than 2 years in most cases. Midwest Power Systems Incorporated's Neal South station is a standing example. It got its RO retrofit in 1991.

Prior to the retrofit, Neal South's cost for producing deionized M/up water was $2.93 per thousand gallon. Regeneration of the ANEX and CATEX beds occured daily while the costs for sulphuric acid and caustic, in 1990, were $192300; resin-cleaning costs were $7500, including labour. Resin replacement added another $5000.

After the 1st full year of operation with the RO system in line, the total cost for these items in 1992 plummeted down to $6500—a saving of $198000 plus. Demineralizer run lengths stretched to 3 months, increasing treated-water throughput between regenerations to 10 million gallons whereas during preretrofit period only 100,000 gallon could be treated by either of the ANEX and CATEX beds without regeneration.

With a total installation cost of $278,000, the RO retrofit paid for itself in just 18 months.

Q. *Why is electrodialysis-reversal (EDR) pretreatment not preferred to RO pretreatment?*

Ans. EDR system, compared to RO systems, is inefficient. It is unable to remove silica from make-up water.

Q. *What are the shortcomings of the RO system?*

Ans. 1. Plugging of membrane pores by particulates and bacteria
2. Leakage of dissolved CO_2.

Q. *Can you cite a typical example of membrane fouling by particulates?*

Ans. Following the RO retrofit, the Neal South power generating station suffered badly from fouling of the RO membranes by the large amount of particulates in water—mostly ferric iron, along with bacteria. The aeration of the wellwater led to the oxidation of Fe contaminant that was not completely removed before entering the RO system. As a result the RO units required cleaning at 2 to 3 weeks interval.

Q. *How was this problem solved?*

Ans. The Company prevented exposure of make-up water to air and thereby maintaining anaerobic conditions between the well and the pretreatment system. The engineers have extended cleaning intervals from 2-3 weeks to 3-4 months using this method.

Q. *What agent is used in cleaning?*

Ans. EDTA plus only small quantities of sulphuric acid.

Q. *Why EDTA?*

Ans. It is a chelating agent that traps and binds Fe^{2+} ions.

Q. *How long does it take to clean RO units of the Neal South station?*

Ans. It takes only eight hours to clean the fouled RO system whereupon it regains its original performance.

Q. *Why is dissolved CO_2 a concern to the reverse osmosis system?*

Ans. RO membranes remove minerals and salts, not gases. CO_2 dissolved in water escapes rejection by the membrane and thereby passes into the RO product.

Q. *In case dissolved CO_2 infiltrates into the RO product, what will happen?*

Ans. Dissolved CO_2 causes ionic loading to the anion resin, shortening the run length between the regenerations of anion beds.

Q. *What is the solution to this CO_2 problem?*

Ans. Installing a degasifier just upstream of the anion exchange resins. Using antiscalants for membrane protection.

Q. *How can we get the best out of a RO retrofit?*

Ans. 1. Replace bag and cartridge filters bimonthly
2. Recalibrate instruments at regular intervals
3. Upkeep the pump system
4. Maintain daily logs on system performance to spot the need for membrane cleaning. Membranes are cleaned at intervals of three to six months.
5. Check for Silt Density Index (SDI) at regular intervals.

Q. *How is critical stage identified, i.e. is it essential to go in for membrane cleaning?*

Ans. It is indicated by increasing conductivity, contamination or pressure differentials.

Q. *What is the normal life period of a RO membrane?*

Ans. 5–7 years.

Source: Power/Feb. 1995/P: 34–38

Q. *Pacificorporation has replaced its high maintenance evaporator in the make-up system at Dave Johnston power station with a combination RO/CDI retrofit as shown below (Fig. 28.8). What are the positive benefits of such a replacement?*

Ans. It

(a) improved operation and water quality
(b) ensured high water recovery
(c) ensured low energy consumption
(d) eliminated generation of any hazardous waste
(e) cut O & M cost by 85%.

*

Q. *As the above figure shows, the system sports two banks, connected in parallel, of RO units each comprising two stages and likewise two CDI units in parallel. Do you think the system is redundant?*

Ans. Yes. The system is fully redundant.

Q. *Why have the engineers opted for such redundancy?*

Ans. Though fully redundant, the system allows for maintenance without interrupting plant operation.

Q. *What is CDI?*

Ans. Continuous Deionization

It is a combination of ion exchange and electrodialysis reversal processes.

Q. *What is the basic advantage of CDI?*

Ans. It eliminates the need for regeneration performed periodically in ion exchange systems.

Q. *How does the CDI system operate?*

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* The system, after one year of operation, brought forth fruit: 32 million gallons of high purity water (despite severe variation in raw-water quality and temperature) over and above trouble-free, low-maintenance operation.

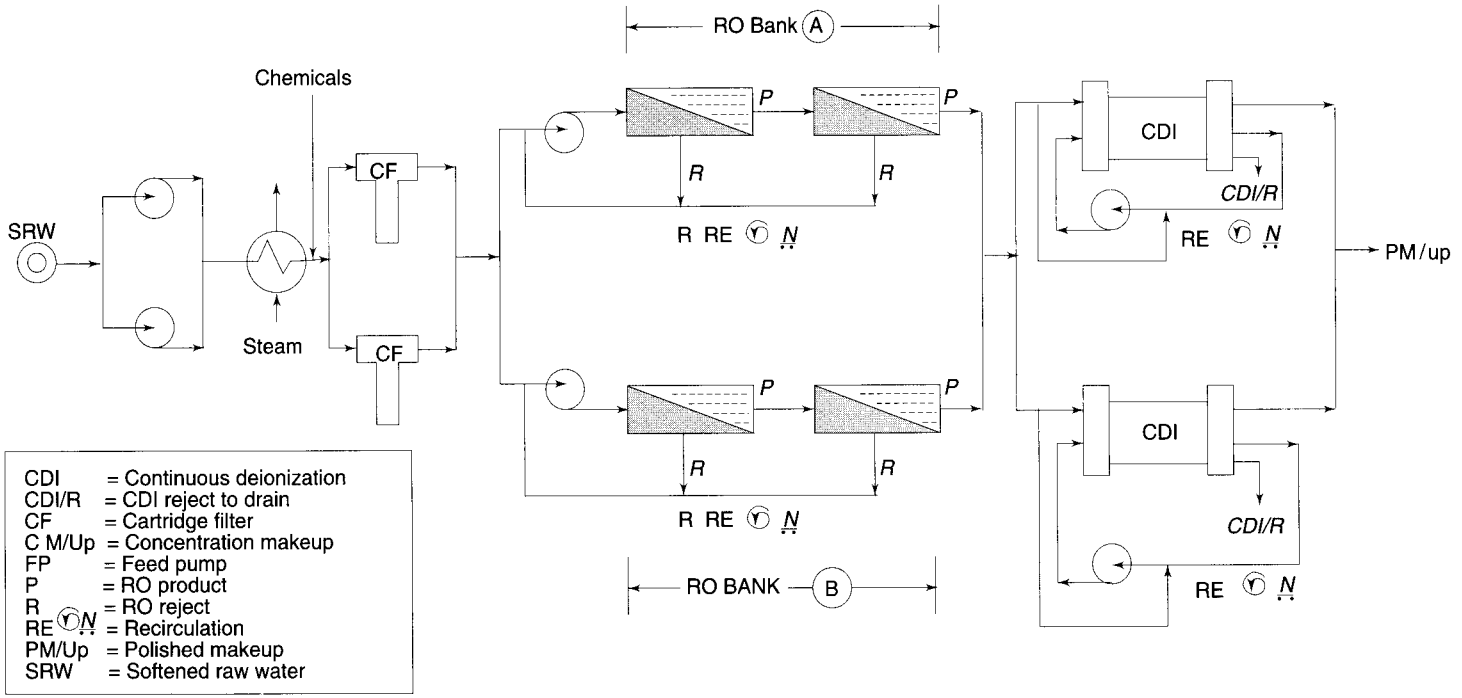


Fig. 28.8 *RO/CDI combination eliminates resin regeneration, yields higher quantity of highly pure water (Inspite of seasonal fluctuation of raw-water quality) through problem-free, low-maintenance operation.*

Ans. It comprises mixed IEx resins stuffed in compartments formed by alternate cation and anion permeable membrane pairs of the conventional EDR stack.

Under the influence of an applied electric field, impurity ions migrate towards oppositely charged electrodes and a current excess created in the diluting compartments (alternate cells) splits the water molecules into H^+ and OH^- ions at the electrodes. Moving rapidly in opposite directions, these hydrogen and hydroxyl ions dislodge trace impurity ions adhering to resin beads. This in effect regenerates the resin while producing high-quality water simultaneously and continuously.

Q. *What is the operating cost of this RO/CDI combined system in comparison to that of the evaporator system in producing polished make-up?*

Ans. Operating cost of RO/CDI system is about \$1.50 to \$1.75/1000 gallons as compared to \$11/1000 gallons of the evaporator system.

29

SCALING OF FIRESIDE OF HEATING SURFACES

Q. *What are the harmful effects of ash deposition on boiler tubes?*

Ans. Uneven ash deposition on fireside steam generating surfaces of drum-type boiler may lead to alarming disturbances in circulation. The situation aggravates with higher steam generating parameters (temperature and pressure). For once-through supercritical pressure boilers, ash deposits on the waterwalls of the furnace bring about a large amount of temperature maldistribution.

Under the aggressive slag blanket, corrosion may occur and result in tube rupture.

Large aggregate of slags detached from the furnace waterwalls can cause mechanical breakage of waterwall tubes at the furnace bottom upon impaction.

Q. *What are the adverse effects of flyash deposition?*

Ans. Flyash clogs convective gas duct with the effect that greater resistance is imparted to the motion of flue gas. This may result in a loss of steam-generating capacity as high as 50 to 70% from the rated value. Over and above, this may bring down non-stop boiler operation to 20–30 days.

Not only this, flyash deposits on convective heat transfer surfaces build up additional thermal resistance and lead to a loss of boiler efficiency.

Q. *What factors should be considered and what measures should be taken in order to ensure that the heating surface of boilers is maintained in a clean state?*

Ans. Modern furnace engineering lays crucial importance on maintaining boiler heating surfaces clean. Ans this necessitates that the following factors be considered:

1. Boiler design
2. Boiler operation
3. Economic efficiency of SGP.

The measures that are imperative in this regard is to study

1. chemical and mineral composition of fuels fired
2. physical properties of fuel
3. heating rates
4. flue gas composition
5. effect of temperature.

Q. *What are the sources of scaling that form on the outer surface of waterwalls in the boiler furnace?*

Ans. The genesis of scale forming on the fireside surface of waterwalls is attributed to the various mineral impurities present in the organic mass of solid fuels which are burnt in boiler furnaces.

Q. *How do these mineral impurities in solid fuels deposit as scale on the outer wall of the boiler tubes?*

Ans. When pulverized solid fuels are burnt, a part of the mineral impurities in the fuel are melted and combined into larger aggregates which precipitate as slag at the furnace bottom while the majority, in the form of fine particles, are carried off as ash from the furnace. Depending on their melting point, viscosity and thermal conductivity these ash particles adhere to the external surface of the steam generating tubes leading to scale formation.

Initially, the low fusible compounds, such as NaCl, Na_2SO_4, $CaCl_2$, $MgCl_2$ and $Al_2(SO_4)_3$ with m.p. 970–1 125 K are vaporized in the high temperature zone and first condensed from the flue gas stream onto the clean surface of boiler tubes which is at a temperature of always less than 970 K. Upon condensing, these low melting compounds form a primary sticky layer onto which are deposited high-melting ash particles. Together they form a strong bond and firmly adhere to the tube surface as scale. This process is also called slagging.

Q. *How can the ash-slags be classified?*

Ans. This classification is based on the ash composition:

1. LOW FUSIBLE ASH containing compounds like NaCl, Na_2SO_4, $CaCl_2$, $MgCl_2$ and $Al_2(SO_4)_3$ with melting point in the range 700–850°C (973-1 123 K). They vapourize in the high temperature zone of the flame core and condense on the surface of relatively cooler waterwall tubes.
2. MEDIUM FUSIBLE ASH containing compounds like Na_2SiO_3, K_2SO_4 and FeS having melting point in the range 900–1100°C (1 173-1 373 K). They form a primary sticky layer on the waterwall and platen tubes if the high temperature zone is very close to the tubes.
3. HIGH MELTING ASH containing oxides of iron, calcium, magnesium, silicon (SiO_2, CaO, MgO, Al_2O_3, Fe_2O_3, etc.) with their melting point 1600–1800°C (1873–2073 K) exceeding the highest temperature of the flame core. They remain solid throughout.

Besides, there is another convenient way to classify slag and ash deposits encountered in steam generation plants. Depending on the bonding characteristic of slag/ash particles and the mechanical strength of deposited layer, slag and ash deposits are classified into

1. loose deposit
2. bonded deposit, also called sintered deposit.

Q. *What are loose deposits?*

Ans. These are deposits that form without chemical reactions, exhibit no capillary attraction and contain no sticky component in the matrix.

Q. *What are the effects of loose deposits of slaglash?*

Ans. 1. Reduction of thermal efficiency of heating surfaces
2. Clogging (partial) of clear space of gas ducts.

Q. *What is the effect of built-in ash collectors on coarse particles in flue gas?*

Ans. They arrest the coarse particles suspended in flue gas and thereby diminish their concentration in it.

Q. *Does the built-in ash collectors exert any influence on the formation of loose deposits?*

Ans. They intensify the formation of loose deposits.

Q. *What is bonded deposit?*

Ans. It is a denser layer of slag firmly bonded to the heat transfer surfaces of the boiler. At higher flue gas temperatures, most of the ash particles suspended in the flue gas remain in the plastic stage and may form a sticky mass on the outer surface of the waterwall and superheater tubes. It

quickly grows in thickness by arresting flyash particles from flue gas and subsequently such physico-chemical processes as caking, crystallization, sulphation, etc. may occur to strengthen the bond.

Q. *What factors govern the formation of bonded deposits?*

Ans. Bonded deposits are mainly encountered in solid fuel fired boilers. They are also known to occur in fuel oil fired boilers if the fuel oil contain mineral components such as sodium, vanadium, calcium, magnesium etc.

They form on high-temperature heating surfaces. Aerodynamic factors coupled with chemical reactions involved in the deposited layer of ash govern the formation of bonded deposits. The deposited ash must contain chemically active as well as high binding (i.e. low fusible) components.

Q. *What factors are responsible for the formation of bonded ash deposits?*

Ans. The following principal factors are responsible for the formation of bonded ash deposits.

1. The mineral matter present in the fuel
2. The behavioural pattern of mineral constituents of fuel during the process of combustion
3. Furnace temperature
4. Heating rate
5. Length of exposure of mineral matter of fuel to high temperature
6. Flue gas composition
7. Temperatures of flue gas, flyash and heating surfaces in those zones where formation of ash deposits is more likely.
8. Physico-chemical processes taking place inside the deposited mass of ash.

Q. *What is the nature of scale deposited on the fireside surfaces of the waterwall in boiler furnace?*

Ans. It is a double layer deposit—the internal layer is dense, rigidly adhering to the tube surface (bonded deposits) while the external layer consists of fine solid particles (loose deposits) of high-melting ash loosely held to the surface of the inner layer.

Q. *How does this double layer deposit form?*

Ans. The inner layer is formed due to the condensation of low-melting ash from the flue gases on the tube surface as a thick sticky film that arrests the high-melting fine ash particles falling on it. Saturated with fine ash particles, the molten slag on the tube surface solidifies to form the primary dense layer of slag firmly bonded to the tube surface. The temperature of the outer surface of the primary layer then gradually increases and that inhibits further condensation of low-melting ash from the flue gas. Therefore, further deposits of high melting ash particles on the rough outer surface of the primary layer become loosely held and these fine particles form loose specks of secondary layer. (Fig. 29.1)

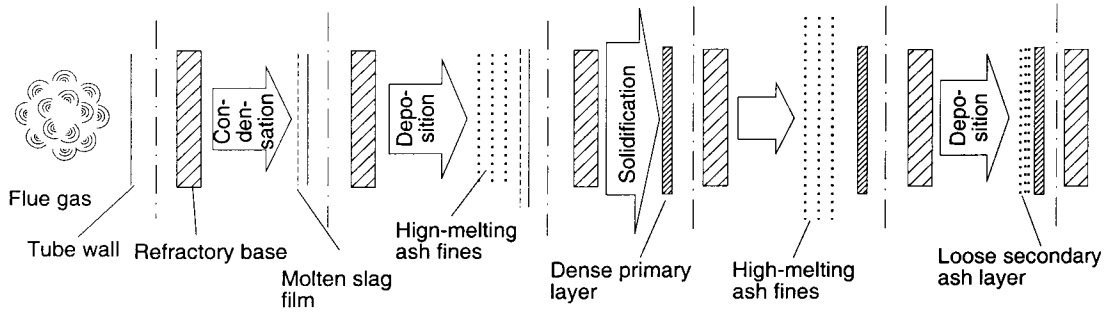


Fig. 29.1 *Mechanism of double-layer deposit formation.*

Q. *What is the reason for an ash being low-melting or high-melting?*

Ans. The fusibility of ash is determined by the amount of different metal oxides and silica present in the ash.

These metal oxides (CaO, MgO, FeO and Fe_2O_3) form eutecites with silica (SiO_2) or alumina (Al_2O_3). Usually ash produced by most solid fuels contains metal oxides in the range 5–40%. Higher percentage of metal oxides lowers the melting point of the eutectic giving rise to low-melting ash while Al_2O_3 + SiO_2 content higher than 80% tends to increase the melting-point of the ash which, therefore, becomes high-melting.

Q. *Does the mechanical strength of primary ash deposits have any effect on slagging of heat exchange surface in the boiler?*

Ans. Yes. It is one of the principal characteristics that determine the slagging properties of fuel.

Q. *On which factors does the mechanical strength of primary ash particles depend?*

Ans. 1. Mineral fraction of fuel
2. Method of fuel combustion

Q. *How can the primary ash deposits be classified on the basis of their mechanical strength?*

Ans. The mechanical strength of ash particles is determined by their compressive strengths. On the basis of their different compressive strengths (σ), the primary ash deposits can be divided into

1. LOOSE or FRIABLE: These are easily crushed in fingers and have $\sigma \leq 1$ MN/m^2
2. DENSE: These are weakly sintered bonded. They are hardly crushed in fingers. σ in the range 1—3 MN/m^2
3. STRONG: Particles having σ in the range 3—7 MN/m^2
4. VERY STRONG: Particles having $\sigma > 7$ MN/m^2

Q. *Some primary ash deposits contain predominantly (up to 80%) hematite Fe_2O_3. How are ash deposits of ferric oxide produced?*

Ans. Such deposits are frequently encountered in those boilers that burn high-sulphur coals, e.g. brown coals. These coals contain iron pyrites which upon incomplete oxidation form low-fusible (melting point 1175—1225K) compounds viz. FeO-FeS eutetic. So when such fuels are burnt, these low-fusible eutectics get vaporized and deposited in the relatively cooler part (convective duct) of the boiler.

Q. *What is sulphation?*

Ans. It is a kind of sintering that may occur in the furnace if there is an unfavourable mineral composition in the fuel. That is, if the calcium oxide content in the ash is more than 40% and if SO_2 is present in the flue gas, the process of sintering may start in the friable deposited layer formed on the heating surfaces. This results in the growth of a dense, strongly bonded slag deposit on the tube surfaces of waterwalls, platens and superheaters.

$$CaO + SO_2 + \frac{1}{2} O_2 \longrightarrow CaSO_4$$

Q. *What is the upper temperature limit of sulphation?*

Ans. Depending on the proportions of acidic (SiO_2, Al_2O_3, TiO_2) as well as basic (CaO, MnO, Fe_2O_3) oxides present in the ash, the upper temperature limit of sulphation is 1375—1575 K.

Q. *Does the intensity of slagging depend on the geometry of tube layout?*

Ans. Yes. Horizontal and slightly inclined tubes suffer from more intensive slagging than vertical tubes.

Q. *In which zone of the boiler furnace are the loose deposits likely to form with no dense underlayer on the tube surfaces?*

Ans. It occurs in the zone where the flue gas temperature is as low as 600–700°C (873–973K), i.e. the convective shaft of the furnace. (Fig. 29.2)

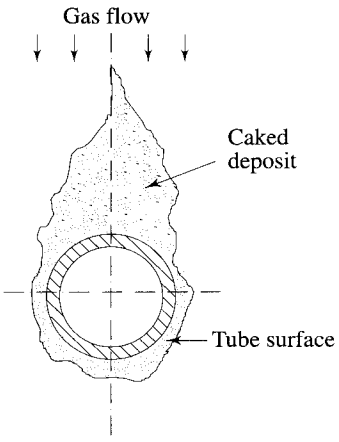


Fig. 29.2 *Formation of loose deposits with no dense underlayer .*

Q. *Why is the subsurface dense layer absent?*

Ans. It is because the low-melting compounds that form the dense, primary layer on the tube surfaces due to condensation from flue gases have already been exhausted before this low temperature region (600–700°C).

Q. *Does the direction of flue gas flow exert any influence upon the magnitude of friable ash deposition?*

Ans. Yes. The back side of the tubes relative to the gas flow direction collect more deposit of loose ash particles than the front sides which collect loose deposit only at low flue gas velocity (Fig. 29.3)

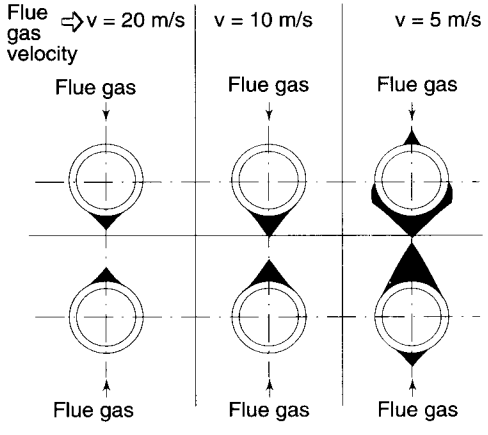


Fig. 29.3

Q. *Why?*

Ans. The deposits tend to collect on that part of the tube surface which is in the turbulent zone as per the profile of fluid flow (Fig. 29.4).

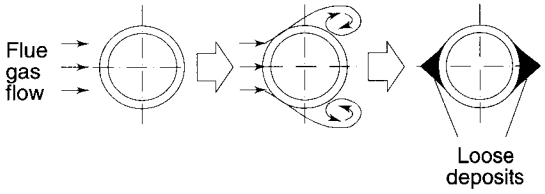


Fig. 29.4

Q. *In which case will the loose deposits of ash particles form on the front-side of the tubes?*

Ans. Only at low flue gas velocity (< 5 to 6 m/s) or if the flue gas carries a load of very fine flyash.

Q. *What is the size of the ash particles loosely deposited on the tube surfaces?*

Ans. Their sizes vary predominantly in the range of 10–30 μm.

Q. *What about the ash particles that lie outside this range?*

Ans. Ash particles having a size of less than 10 μm are so fine that they are called inertialess particles. They move along the flue gas profile and therefore, the probability of their settling on the tube surface is very low.

Ash particles having a size greater than 30 μm are called coarse particles. Because of their larger mass and higher kinetic energy they're less likely to adhere to the tube surface. On collision they kick off loose deposits from the tube surface.

Q. *Does the loose deposit of ash particles affect the heat transfer?*

Ans. Yes; it impairs the heat transfer across the tube wall by reducing the overall heat transfer coefficient.

Q. *How can this be estimated?*

Ans. This can be estimated by the factor called fouling coefficient which is given by

$\varepsilon = \delta_{slg} / k_{slg}$, m^2K/W

where

δ_{slg} = average thickness of the slag, m

k_{slg} = thermal conductivity of the slag, W/m K

It determines the thermal resistance of slag layers.

Q. *On which factors does the degree of tube fouling depend?*

Ans. It depends on

(a) time of exposure of the tube surface to ash laden flue gases (Fig. 29.5)

(b) size composition of the ash particles—finer fractions causing more intensive fouling than coarse fractions

(c) flue gas flow velocity—lower the gas flow velocity, thicker is the deposition. (Fig. 29.5)

(d) mode of tube layout in the boiler furnace—staggered or in-line as well as the longitudinal pitch or the staggered tube bunches.

Q. *Why does the degree of fouling decrease as the gas velocity increases?*

Ans. The degree of fouling is determined by the thickness of the loose deposits comprising chiefly of medium fractions (10 – 30 μm). Ash particles in this range continuously settle on the tube surface while ash particles in the coarse range (>30 μm) continually destroy the layer on collision. Ultimately the final thickness of the deposited loose layer is governed by the dynamic equilibrium between these two processes.

As the flow velocity of the flue gases increases, the kinetic energy of the ash particles increases and with that rises the destructive effect of coarse particles in proportion to the third power of velocity. Therefore, the net result is that the thickness of the loose deposits on the tube surface decreases.

Q. *How does the degree of tube fouling depend on the arrangement of tube in the boiler furnace?*

Ans. The tube fouling depends not only on the type of tube arrangement—staggered or in-line formation—but also on the longitudinal pitch p_2 of the staggered bunches. This has been demonstrated in the following figure. It is clear from the graph that under the conditions of identical gas velocity and tube diameter, the fouling coefficient for in-line tubes is about 2 to 3.5 times that for staggered tubes. (Fig. 29.6)

Q. *Why is it not advisable to operate pulverized coal fired water-tube boilers at gas velocity as low as 3–4 m/s?*

Ans. It is due to inadmissible fouling which occurs in this gas velocity range. The degree of fouling of fireside heating multiplies with the fall of

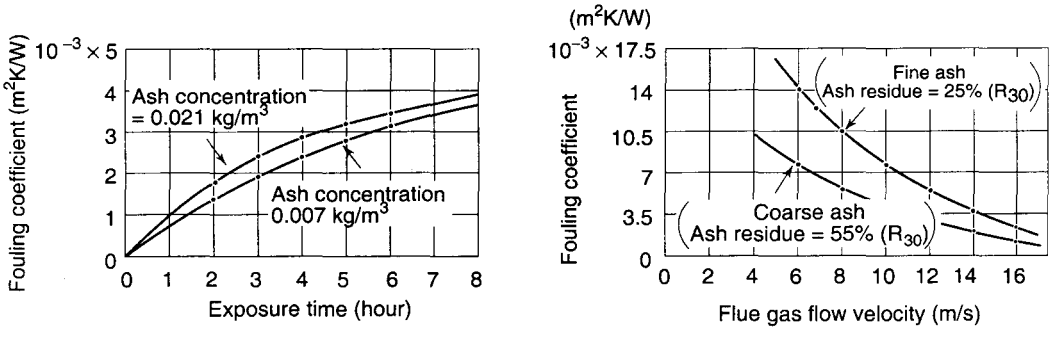


Fig. 29.5

flue gas velocity and it increases significantly if the flue gas velocity is reduced to 3 to 4 m/s.

Q. *What should be the nominal gas velocity at the rated load?*

Ans. 5–6 m/s.

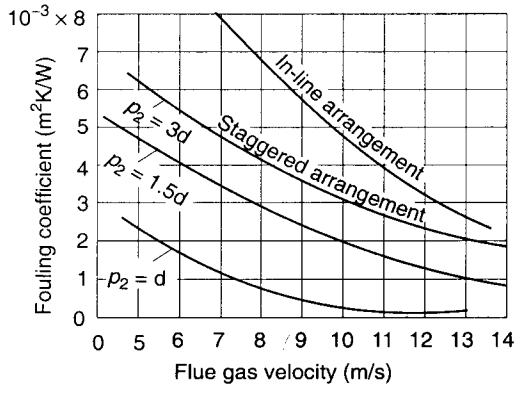


Fig. 29.6

Q. *What kind of deposits form on the heating surfaces in boilers fired on high-sulphur fuel oil?*

Ans. Two kinds of deposits:

(a) sticky deposits

(b) dense glassy deposits.

Q. *In which temperature zone do they fall out on the tube surfaces?*

Ans. In the zone with gas temperature ≤ 600°C (873 K)

Q. *What is the composition of sticky deposits?*

Ans. It consists primarily of vanadium compounds (mainly vanadium pentoxide) and sulphates.

Q. *What is the composition of dense deposits?*

Ans. It consists mainly of iron sulphate and the oxides of calcium and sodium.

Q. *What is the particularity of the deposits that form during fuel oil burning?*

Ans. These deposits have a tendency to develop quickly impairing greatly the rate of heat transfer.

Q. *How do such depositions occur in fuel oil fired boilers?*

Ans. Fuel oils burnt in boilers are characterized by low ash content (0.07–0.15%), whereas some of them may be rich in sulphur (as high as 3–3.5%). Besides, the ash contains an assortment of mineral fractions—mainly the compounds of calcium, magnesium, sodium, silicon, vanadium and iron. These specific mineral impurities together with a high content of sulphur lead to ash depositions.

When fuel oil is burned, the combustion products may contain all sorts of vanadium oxides: VO, V_2O_3, V_2O_4 and V_2O_5—the higher valent oxides have lower melting point and hence particularly more harmful from the standpoint of fouling of the heat exchange surface. Major portion (60—80%) of ash of fuel oils constitutes mostly of low-melting components of flyash. Represented symbolically,

$$\Sigma\ Na_2O + V_2O_5 + SO_3$$

these low-melting compounds of flyash play a decisive role in forming ash deposits.

Fouling of waterwall tubes in the form of sticky deposits begins at temperatures above 815 K. This sticky film of sodium vanadates ($5Na_2O \cdot V_2O_4 \cdot 11V_2O_5$), endows itself as the substrate to arrest flyash particles. The temperature of the primary deposited layer gradually increases because of impaired heat transfer characteristics through this deposited sticky mass to the tubewall. With the increase of its surface temperature, ash layer becomes more plastic and capable of retaining higher load of fusible fractions of flyash. As a result, the overall process leads to the formation of strong bonded deposits.

Q. *Does the Na/V ratio plays any role in determining the characteristics of deposited ash in fuel oil fired boilers?*

Ans. Yes; with the increase of sodium/vanadium ratio in ash, its sticky property increases. It is

found to be maximum with Na/V ratio in the range of 3.7–9.5.

Q. *It has also been reported that the process of fouling of heating surfaces also occurs at temperatures below or slightly above the dew point of flue gases (320—500 K). Why does this occur and what is the mechanism of such an attack?*

Ans. This is due to the condensation of sulphuric acid and water vapour from the flue gases. They form an adhesive film sticking to the tube surface and arresting and retaining higher quantities of flyash particles which dissolve in the viscous acidic film producing a solution of mineral components of fuel, hydrocarbons and corrosion products of sulphuric acid. They constitute of 70–80% water-soluble salts, mainly sulphates.

Q. *Below the dew point, fouling of heating surfaces by flyash is more intense. Which factors are principally responsible for this?*

Ans. The rate of fouling increases with

1. the increase of sulphur content of fuel
2. the increase of excess air/fuel ratio
3. the deep shedding of boiler load causing a substantial drop in the temperature of heating surfaces.

Q. *How can this temperature drop be estimated?*

Ans. This can be estimated from the relationship

$$\theta_w = [\theta_w]_r \left[\frac{G}{G_r}\right]^{1/3}$$

where,

θ_w = wall temperature at current load

$[\theta_w]_r$ = wall temperature at rated load

G = current steam load

G_r = rated steam load

Q. *Does the ash-deposition on low-temperature heating surfaces also occur in solid-fuel fired boilers?*

Ans. Yes. But they differ substantially from those formed in fuel oil fired boilers. Flue gas, in solid-fuel fired boilers contains a much higher load of flyash containing substantial quantity of coarse particles which under high gas velocity (5–6 m/s) produce abrasive effect on the primary ash deposits.

Q. *How can the fouling ability of flyash be characterized?*

Ans. This can be conveniently expressed in terms of the ratio of the sums of basic and acidic components in the ash, i.e. by

$$\Sigma B/\Sigma A$$

where,

$$\Sigma B = CaO + MgO + Fe_2O_3 + Na_2O + K_2O$$

$$\Sigma A = SiO_2 + Al_2O_3 + TiO_2$$

Q. *What are the known methods of cleaning the deposits from heating surfaces?*

Ans. There are several methods:

1. steam jet blasting
2. water jet blowing
3. air blasting
4. shot blasting
5. vibration cleaning
6. heat-wave cleaning
7. thermal cleaning.

Q. *What is steam jet blasting?*

Ans. Saturated/superheated steam at a pressure of about 4 MPa(4 MN/m^2) is injected with the help of multi-jet retractable blowers to clean radiant heating surfaces and convective superheaters.

Q. *What is water-jet blowing?*

Ans. Jets of water issuing at high velocity are directed on the fouled surfaces of heating tubes. Upon collision with the mass of deposit, the water particles transfer their momentum to the deposits which therefore get dislodged.

Q. *What is the advantage of a water jet over steam and air jets in cleaning deposits from the heating surface of boiler tubes?*

Ans. The effectiveness of these three types of jets depend on the kinetic energy they carry. Greater the kinetic energy of the projectile, greater will be its range and consequently, greater will be its capacity to remove deposits.

Water jets possess the highest kinetic energy and so have the highest range. This coupled with the higher thermal conductivity of water than steam or air makes water jets superior to steam and air jets in cleaning waterwalls.

Q. *What is the demerit of a water blowing system?*

Ans. Because of its high thermal conductivity, water jets have the highest thermal effect on dense deposits. As such it may bring about sharp quenching of the tube metal unless its amount is carefully calculated.

Q. *What is vibration cleaning?*

Ans. High frequency vibration is transmitted to the heating tubes by means of vibrators attached to rods cooled by water. The transmitted sonic waves disturb the bond between the deposits and tube metals and therefore dislodge the scales from the tubes' surface. By this process platens and in-line tube banks are cleaned.

Q. *What is shot-blasting?*

Ans. It is an efficient method of cleaning deposits from convective heating surfaces (fireside) by utilizing the kinetic energy of flying cast iron shots 3 to 5 mm dia. Shots are projected on the deposited surfaces by high speed jets of air. Airborne, they are carried upwards and distributed over the entire cross-section of the downtake shaft of the boiler furnace. The process lasts 20 to 60 s and its intensity varies from 150–200 kg/m^2 of the convective shaft cross-section.

Q. *What is heat-wave cleaning?*

Ans. This method is based on the application of low-frequency sound waves generated as a result of an explosion perfected in a special explosive-combustion impulse chamber. The acoustic waves set the tubes vibrating which weakens the bond between the deposits and the tube metal.

Q. *What is thermal cleaning?*

Ans. It is based on raising the temperature of the regenerative air heaters to 250–300°C by cutting the air supply to the apparatus. The sticky deposits get dried up while the sulphuric acid is vapourized.

Q. *What will be the effect of improper selection of flue gas velocity, apart from tube fouling in the boiler furnace?*

Ans. It may lead to intensive erosion of tube metal in certain places, resulting in thinning of the walls and even break-through of the tubes.

Q. *What is the process called?*

Ans. Abrasive erosion.

Q. *What is the mechanism of abrasive erosion (or wear)?*

Ans. Coarse ash particles, because of their mineral composition, are very hard and they frequently possess sharp edges.

Flue gas-borne coarse ash particles possess sufficient kinetic energy and when these hard and sharp particles strike the tube surfaces they chip off microscopic layers of the tube metal. Since this is a continuous process, it leads to gradual thinning of the tube wall at critical places.

Besides ash, particles of unburnt fuel (coal), particularly those of a harder variety (anthracite or semianthracite) are capable of causing abrasion of the tube surfaces.

Q. *On which factors does the abrasion wear of boiler tubes by ash particles depend?*

Ans. It depends on several factors like

1. abrasiveness of ash particles, i.e. SiO_2 content in ash
2. total ash content of fuel
3. flue gas velocity
4. angle of attack

Q. *What is the angle of attack of gas flow for greatest abrasion wear of staggered tubes in the crossflow of the gas path?*

Ans. 30°–60°.

Q. *Which factors determine the intensity of wear of heating surfaces?*

Ans. 1. Kinetic energy of ash and unburnt fuel particles
2. The flux of ash particles, i.e. the number of ash particles passing through unit surface area per unit time
3. Non-uniformity of ash concentrations in the gas flow
4. The time of exposure.

Q. *The characterization of ash is extremely important to predict the mineral transformation in coal particles during combustion, that control the characteristics of the resulting ash particles. What method are available today to fully characterize ash with respect to the ash deposition processes?*

Ans. Two methods have been developed and are used at present:
1. Computer Controlled Scanning Electron Microscopy (CCSEM)
2. Scanning Electron Microscopy Point Count (SEMPC)

Q. *What is the advantage of the CCSEM technique?*

Ans. The CCSEM analysis of ash produces the same type of results as the CCSEM analysis of coal. As a result, a direct comparison can be made between the coal mineralogy and the species observed in the ash samples. This is of fundamental importance as it provides the data base from which the relevant ash-transformation-models can be constructed. For instance, comparison of the data can show that there is significant reaction between the calcite and clay particles. Equally important is the size of various ash particles produced in the ash with respect to ash deposition forasmuch as the size and shape of the particles influence the trajectory of the particles at or near tube surfaces. Thus it is possible to establish the effect of coal preparation (grinding, pulverizing, cleaning etc.) and combustion conditions on the size and mineralogy of the ash particles.

Q. *The SEMPC technique was developed specifically to determine the phases and characteristics of ash particles and deposits. What is the data that this technique provides?*

Ans. • Full chemical composition of random points within the sample
• Average chemical composition of the sample
• Complete phase analysis including crystalline and amorphous
• Viscosity and base/acid ratio of amorphous phases.

Q. *How does the SEMPC technique provide the above data?*

Ans. This involves the systematic microprobe analysis of over 240 points within a suitable prepared sample. A complex normative analysis of the quantitative data determines if the chemical composition of each point corresponds to ones of over 40 known crystalline phases common to coal, coal ashes, or deposits (based on extensive X-ray diffraction analysis data). Failure to classify the composition amongst the crystalline phases causes the point to be classified as amorphous. The chemical composition of the amorphous phases are harnessed to obtain a measurement of viscosity of the various phases by Kalmanovitch-Frank method that computes viscosity not only for full coal ash chemical compositions but also for simple silicate phases such as that produced following reaction between silica and sodium.

Q. *Is the deposition of the ash a function of the bulk ash chemistry?*

Ans. No; it is a matter of probability of an ash particle sticking to a surface.

Q. *If the ash particles are not sticky will the ash deposits on the tubes grow?*

Ans. No.

Q. *What are the three phases of ash deposition on tubes?*

Ans. 1. Ash particles sticking to the tubes (INITIATION STEP)
2. Collection of ash particulates on the sticky layer of deposited ash (GROWTH STEP)
3. Formation of troublesome hard-bonded deposits through chemical interaction between different mineral substances present in the deposited ash.

Q. *What factors control the probability of deposit initiation?*

Ans. 1. Size, shape and momentum of FG-borne ash particulates
2. Temperature
3. Amount of liquid phase on the surface of the particle
4. Chemistry (i.e. base/acid ratio) of the liquid phase
5. The viscosity and surface tension of the liquid phase
6. Structure and nature of the metal surface.

Q. *How can the probability of deposit initiation be studied?*

Ans. The procedure used by David P. Kalmanovitch of Riley Stoker Corporation is as follows

1. From the CCSEM analysis of the ash sample an estimate on the size distribution of the major species is established. These species will tend to dominate the particle flux impacting the metal surface.
2. The SEMPC data is used to estimate the amount of liquid phase available in the sample.
3. The viscosity of the various liquid phases is computed on a particle by particle basis and the data is presented in the form of population histograms called viscosity distributions. The viscosity is then calculated at a given temperature, usually the gas temperature in the region of the surface of the target.

By studying the data one can establish a scale or a relative degree of sticking probability. Figure 29.7 compares the viscosity distribution of amorphous phases at 1375°K of two coal ashes.

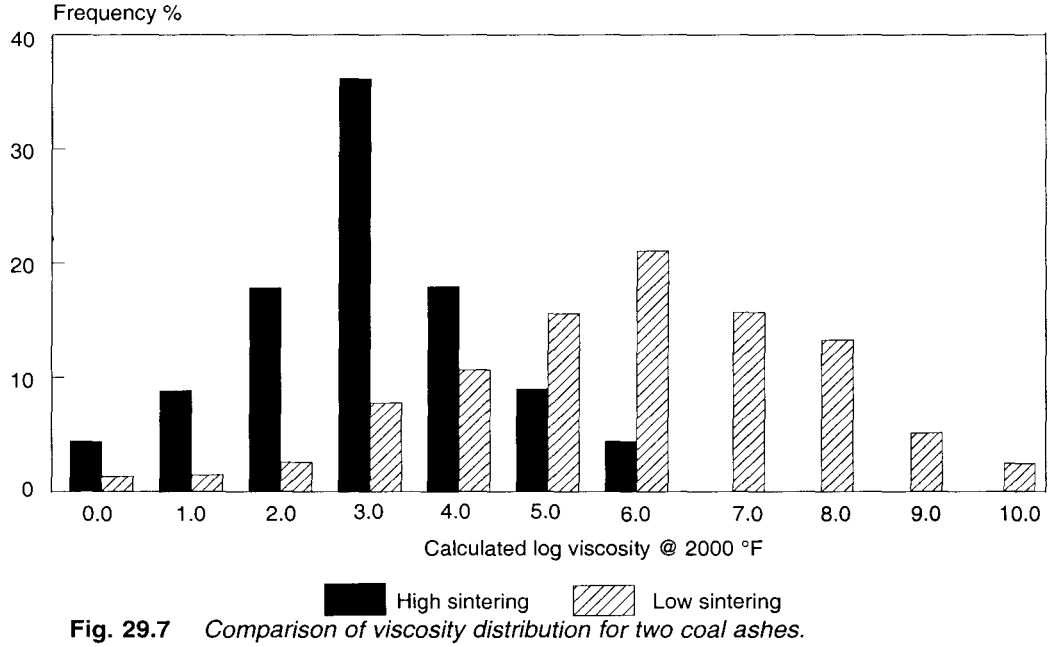


Fig. 29.7 *Comparison of viscosity distribution for two coal ashes.*

Source: *RST-89 (Technical Paper/Riley Stoker Corporation)*
Courtesy: *Riley Stoker Corp./Worcester/MA 01615-0040/USA*

Ash with a high population of low viscosity liquid phases will have a higher propensity to form a deposit on the metal surface than ash with a bulk of amorphous phases with high viscosities.

Clearly it is the proportion of liquid phase and its viscosity in the ash particles that plays the primary role in ash build-up on the tubes of the heat recovery surfaces. For example, if the ash has only 10% liquid phases at a given temperature, then clearly the amount of particles that can adhere is greatly reduced. Conversely, ash with 100% liquid phases will increase the probability of the particle sticking at even relatively high viscosities. However, when all the various factors are considered, the viscosity of the liquid phases dominates the probability of particle sticking and hence the formation of the initiating layer.

Q. *What kind of ash particles initiate the deposit layer?*

Ans. Deposit layer is formed by ash particles with low viscosity and diameters within the size range of 10–40 μm.

Note: This has been reported by D.P. Kalmanovitch and his team as a consequence of their drop tube deposition studies at the University of North Dakota Energy and Environmental Research Center.

Q. *What does this data indicate?*

Ans. 1. The importance of particle size and viscosity in the formation of the initial deposit layer
2. Coals which form ashes with smaller size particles, lower amount of surface liquid phases, and high-viscosity-liq-phases will have a low propensity to form an initiating layer.

Q. *As the deposits grow, they also develop strength. Why is it imperative to have knowledge of the development of strength of the deposited ash layer?*

Ans. The development of strength of the growing ash deposit is important as it affects the degree of difficulty of removal. Knowledge of the time needed for a given deposit to form a hard bonded mass on the tube surfaces can be used to establish soot-blowing cycles, load cycling to shed deposits, and other methods.

Q. *How does the ash layer grow and gain strength?*

Ans. An ash deposit is a consolidated mass of fine ash particles. Ash particles, the bulk of which are less than 50 μ in dia, strike and adhere to the sticky layer of slag on the tube surfaces. The collected mass undergoes sintering to form deposits centimeters or more thick.

Q. *What is sintering?*

Ans. It is a process of consolidating a system with a high surface area to a system of lower surface area.

Q. *How is sintering affected by particle size?*

Ans. According to Frenkel model of sintering extended to coal ash by Raask, the reduction of pore volume of a packed collection of spheres of known radius with a fixed viscosity is proportional to the surface tension of the liquid phase and inversely proportional to the viscosity and radius of the particles. Based on this model one can say that at a given temperature, the rate of formation of a hard bonded deposit will be greater for a collection of small particles with low viscosity than for a collection of large particles with high viscosity.

Q. *Though this model gives valuable fundamental insight into the formation of hard-bonded deposits, it suffers from certain drawbacks. What are they?*

Ans. 1. The Frenkel model is for packed, relatively homogeneous (both with respect to size and composition/viscosity) particles. The analysis of ash particles has shown that there is a wide variation in the size, shape and chemical composition of the particles.

2. It does not take into account the fact that chemical reactions can occur between the various phases.
3. The model assumes systematic packing as if they are manually packed. However, ash particles are transported to the surface of the deposit by aerodynamic forces so that sintering occurs between random particles.

Q. *How can we have an estimate of deposit growth from CCSEM and SEMPC studies?*

Ans. From CCSEM and SEMPC analyses we get the size distribution of the ash particles, the phase assemblage, viscosity, and chemical composition of the liquid phases on a particle-by-particle basis. Use can be made of this data to gain some insight into the degree or relative degree of sintering the ash particles will undergo within the deposit and that will enable us to assess the degree to which the surface of the deposit will become the dominant factor in the rate of growth. This is the probability of an impacting ash particle adhering to the surface becoming more dependent on the target surface. It is convenient to review the complex process with respect to measurable parameters. Therefore, if we decide on a temperature, for viscosity calculations, we can use the data from CCSEM and SEMPC analysis to obtain a relative degree of sintering. From this we can assess the extent to which a captive liquid phase will form and hence the rate of growth.

Note: The above analysis must be based on the assumption of constant particle flux approaching the tube.

Q. *What is the major driving force for sintering of two ash particles of equal size, amount of liquid phase and viscosity?*

Ans. If two ash particles of equal size, amount of liquid phase, and viscosity are in contact, the sintering process will derive its driving force from the tendency to reduce the surface area.

However, if the two particles have solid and liquid phases what can react, the reaction or the potential to react becomes a major driving force with respect to the sintering process.

Q. *How can this be estimated through SEMPC study?*

Ans. From the SEMPC data one can calculate the base-to-acid ratio for each of the liquid phases as well as the population density similar to the viscosity distribution. The distribution is usually multimodal and this multimodality indicates the extent to which the reactions can occur between the ash particles in a deposit. This data is then used to establish the degree of reactivity that can occur between adjacent particles. The greater the degree of reactivity, the greater the driving force for the reactive liquid phase sintering.

Source: A Practical Approach to Predicting Ash Deposition, —David P. Kalmanovitch (RST-89/Technical Paper/RILEY STOKER CORP

Courtesy: Riley Stoker Corporation/Worcester/ MA 01615-0040/USA

30

CORROSION OF WATERSIDE HEATING SURFACES

Q. *What is corrosion?*

Ans. Corrosion is the destruction of meterials—metals, non-metals and refractories—under the action of aggressive surrounding media (e.g. steam, water, furnace gas) as a result of chemical and or electrochemical processes taking place on the surface of the materials.

Note: We'll limit our discussion to the corrosion of metals and alloys only.

Q. *What is erosion?*

Ans. Erosion is purely a physical phenomenon which describes the wearing of surface material by mechanical processes such as friction, impact, etc.

Q. *In how many forms does corrosion manifest itself?*

Ans. Two forms: Uniform and non-uniform corrosion.

Non-uniform corrosion is also called local corrosion.

Q. *How can uniform corrosion be distinguished from non-uniform corrosion?*

Ans. Uniform corrosion describes the destruction of metal over the entire surface whereas in non-uniform corrsion, the destruction of metal is limited to a local spot or point and may penetrate deeply into the body of the metal.

Q. *How can non-uniform corrosion be classified?*

Ans. It may be classified as

(a) spot corrosion
(b) point corrosion
(c) honeycomb corrosion
(d) intergranular (intercrystalline) corrosion
(e) selective corrosion

Q. *What is selective corrosion?*

Ans. It is the selective destruction of one of the component metals of an alloy system, e.g., the dissolution of only zinc from a zinc-copper alloy (brass) system.

Q. *Where is this type of corrosion encountered in power plants?*

Ans. In turbine condensers. The brass tubes of turbine condensers are exposed to river or seawater for cooling purposes and as a result they undergo dezincification, i.e. selective dissolution of zinc.

Q. *Does the dezincification tell upon the structure and performance of turbine condensers?*

Ans. Yes. The elimination of zinc makes the brass brittle and leaves a dendritic copper structure. It leads to leakages in the tubes and deteriorates the heat transfer efficiency of the condenser.

Q. *How can chemical corrosion be distinguished from electrochemical corrosion?*

Ans. Chemical corrosion involves purely chemical processes that characterize direct interaction between the metal and the surrounding media without the generation of electric current. For example, iron is attacked by superheated steam at 650–775 K and higher:

$$3Fe + 4H_2O \longrightarrow Fe_3O_4 + 4H_2$$

This is purely a chemical interaction between iron and steam and does not involve any electric current.

Electrochemical corrosion describes the destruction of metal by electrochemical attack whereupon one of the two metal components preferentially dissolves in the presence of an electrolytic solution and a flow of electric current is set up between these two different metal components otherwise electrically connected.

Corrosion, i.e. oxidation takes place at the anode wherefrom metal passes into solution

$$(Zn \longrightarrow Zn^{2+} + 2e)$$

And deposition of metal (or liberation of hydrogen gas), i.e. reduction takes place at the cathode

$$(Cu^{2+} + 2e \longrightarrow Cu)$$

The free electrons liberated at the anode go to the cathode by the external conductor and set up an electric current between the cathode and anode.

Hence electrochemical corrosion involves both chemical processes (oxidation and reduction) as well as the flow of electric current.

Q. *What is polarization?*

Ans. It describes the electrode process leading to a diminishing rate of corrosion because of the drop in the potential difference between the anode and cathode.

The corrosion rate is proportional to the current strength which is directly proportional to the potential difference between the cathode and anode

$$I = (V_c - V_a)/R$$

where R = resistance of the overall circuit.

As the corrosion proceeds, the p.d. $(V_c - V_a)$ gets smaller and smaller until it reaches such a small value that the corrosion process practically ceases. This phenomenon is called **polarization**.

Q. *What leads to polariztion?*

Ans. Polarization is an electrode phenomenon effecting the cessation of the corrosion process.

The rate of electron transfer from the anode to cathode is initially equal to the rate of reduction of cations (take for example H^+ ions) in the cathode. However with the lapse of time, some of the hydrogen molecules liberated

$$H^+ + e \longrightarrow H$$

$$H + H \longrightarrow H_2$$

get deposited on the surface of the cathode and form a layer of H_2 gas bubbles. This hydrogen-gas-layer on the cathode surface deters the penetration of the oncoming H^+ ions to reach the cathode surface

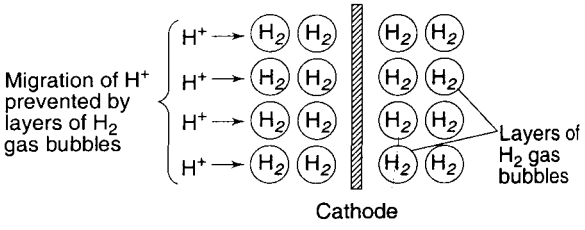


Fig. 30.1 *Migration of H^+ ions prevented by layers of H_2 gas bubbles.*

But due to the electrostatic pull of the cathode these H^+ ions adhere to the surface of the hydrogen gas layer and form between them and the anode a back e.m.f. (electromotive force) that reduces the original potential difference between the primary anode and cathode. As the p.d. between the cathode and anode decreases, the flow of electric current nearly stops leading to termination of corrosion.

Q. *What is depolarization?*

Ans. The electrode process that reduces polariztion (i.e. intensifies electrochemical corrosion) is called depolarization.

Q. *What are depolarizers?*

Ans. These are the substances that contribute to depolarization.

Q. *What do they do?*

Ans. They bind the free electrons.

Q. *What are the fundamental requirements for an electrochemical corrosion to proceed?*

Ans. 1. A galvanic couple, i.e. two metals having different electrode potentials
2. An electrolyte in contact with the galvanic couple
3. Depolarizers.

Q. *How is the galvanic cell produced on the inner surface of steel tubes carrying boiler water?*

Ans. The material of construction of boiler tubes is not uniform throughout and the galvanic cell is set up because of electrochemical heterogeneity of the various sections of the surface and the presence of water as electrolyte. (Fig. 30.2)

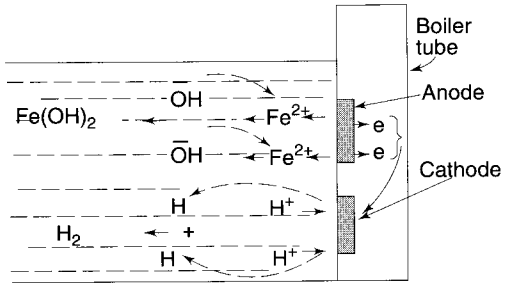


Fig. 30.2 *Galvanic cell is set up on boiler tube surface because of inhomogeneity of tube material.*

If one section be electrically more negative than the other section on the surface, the electrochemical attack takes place and the destruction of iron from the anode occurs.

Q. *What substances act as depolarizers in a steam generation unit?*

Ans. Depolarizers are those which bind the free electrons. Such substances are:

1. OXYGEN: $O_2 + 2H_2O + 4e \longrightarrow 4OH^-$
   This process is called oxygen depolarization.
2. HYDROGEN: $2H^+ + 2e \longrightarrow 2H \longrightarrow H_2$
   This process is called hydrogen depolarization.
3. SODIUM NITRITE:
   $NO_2^- + H_2O + e \longrightarrow NO + 2OH^-$

Q. *How do nitrites appear in boiler water?*

Ans. Nitrites appear because of the oxidation of ammonium ions by nitrifying bacteria

$$NH_4^+ \longrightarrow NO_2^- + NO_3^-$$

These bacteria anchor at the surface of the pipelines and mechanical filters.

Q. *How can these bacteria be eliminated?*

Ans. By periodical chlorination of bacteria-infected pipelines.

Q. *What factors lead to the development of electrochemical corrosion?*

Ans. Two types of factors: Internal and external. Among the internal factors are

(a) the type of metal and its grade
(b) the cleanliness of the metal, i.e. whether having metallic or non-metallic inclusions
(c) the presence of stress due to manufacturing processes or heat treatment.

External factors are

(a) the nature of the surrounding medium
(b) pH of the electrolyte
(c) presence of depolarizers.

Q. *Under normal working conditions what factor is most decisive in determining the intensity of corrosion of the heat transfer equipment on the waterside?*

Ans. It is the dissolved oxygen in water.

Q. *How does it intensify the corrosion?*

Ans. It acts as a depolarizer, and readily accepts the free electrons liberated by the iron of the walls of the boiler tubes or equipment

$$Fe - 2e \longrightarrow Fe^{2+}$$

$$O_2 + 2H_2O + 4e \longrightarrow 4OH^-$$

$$Fe^{2+} + 2OH^- \longrightarrow Fe(OH)_2$$

So iron will continue to dissolve from the surface of the tubes or vessels in contact with the boiler water so long as dissolved oxygen remains in the latter.

Q. *What happens as a result of this oxygen corrosion?*

Ans. It causes pronounced local destruction of the metal surface leading to the formation of pits. This type of oxygen corrosion occurs at pH ≥ 7

At pH < 7, i.e. in acidic media, the presence of dissolved oxygen leads to uniform corrosion.

Q. *How does oxygen come into the boiler water?*

Ans. It gets into the water from air.

Q. *Why is deaerated water or condensate not allowed to come in contact with the atmosphere?*

Ans. To avoid contamination by O_2 (as well as CO_2) from air, which may lead to corrosion.

Q. *Why is contamination by CO_2 to be avoided?*

Ans. Dissolved CO_2 in water liberates H^+ ions

$$CO_2 + H_2O \Leftrightarrow H_2CO_3 \Leftrightarrow H^+ + HCO_3^-$$

that act as a depolarizer intensifying the corrosion of metal surfaces

$$H^+ + e \longrightarrow H$$

$$H + H \longrightarrow H_2\uparrow$$

Q. *Why is carbon dioxide corrosion more likely to occur in equipment and pipelines in contact with condensate than those in contact with softened water or natural water?*

Ans. Softened water or natural water contains to some extent HCO_3^- ions which establish the following equilibria with H^+ ions

$$HCO_3^- + H^+ \Leftrightarrow H_2CO_3 \Leftrightarrow H_2O + CO_2$$

Thereore, the presence of HCO_3^- ions (e.g. in softened or natural water) will press the equilibria to the right and deter the dissolution of CO_2 in water. Hence CO_2 corrosion does not occur in pipe lines/equipment in contact with softened or natural water.

However, the metal surface in contact with the condensate is very prone to CO_2 attack, as carbon dioxide quickly dissolves in the condensate because of the absence to bicarbonate ions in the condensate water.

Q. *Why is a CO_2 solution in water more aggressive than an HCl solution in water at the same pH value?*

Ans. Hydrochloric acid is a strong acid and so the entire HCl is completely dissociated into H^+ and Cl^- ions. Therefore, as the corrosion process develops, the neutralization of H^+ ions on the cathode continues. However, this decrease in H^+ ions is not compensated for unlike the case of CO_2 dissolved in water

$$CO_2 + H_2O \Leftrightarrow H_2CO_3 \Leftrightarrow H^+ + HCO_3^-$$

in which case as the concentration of available H^+ ions is depleted a fresh supply of H^+ ions is made by the dissociation of H_2CO_3.

That's why a CO_2 solution is more aggressive than a HCl solution at the same pH value.

Q. *How does the presence of bicrabonate ions in the course of steel corrosion lead to further corrosion?*

Ans. In the course of steel corrosion ferrous ions are liberated, which combine with the bicarbonate ions if present in the solution.

$$Fe^{2+} + 2HCO_3^- \rightleftharpoons Fe(HCO_3)_2$$

However, under certain circumstances ferrous bicarbonate undergoes decomposition liberating free CO_2

$$Fe(HCO_3)_2 \rightleftharpoons Fe(OH)_2 + 2CO_2$$

This free CO_2 again dissolves in water to give rise to carbon dioxide corrosion

$$CO_2 + H_2O \rightleftharpoons H^+ + HCO^-_3$$

$$Fe - 2e \longrightarrow Fe^{2+}$$

$$2H^+ + 2e \longrightarrow 2H \longrightarrow H_2$$

However, this corrosion is possible if water contains sufficient dissolved O_2 to oxidize ferrous hydroxide and throw it out of equilibria.

$$4Fe(OH)_2 + O_2 + 2H_2O \longrightarrow 4Fe(OH)_3\downarrow$$

Q. *How can corrosion products deter further corrosion?*

Ans. Since corrosion is a surface phenomenon, the products of corrosion are formed on the surface of the metal.

Now if the corrosion products firmly adhere to the metal surface and form a layer sufficiently dense, they will then effectively isolate the base metal from the surrounding aggressive media and also prevent the penetration of depolarizers to the metal surface, with the effect that the corrosion process terminates.

Q. *How does the rate of oxygen-corrosion vary with the temperature of the medium?*

Ans. The rate of oxygen-corrosion increases steadily and continuously, in the cse of a closed system (i.e., oxygen-contaminated water is heated in a closed vessel), with the increase of temperature whereas in the case of an open system (i.e. in a tank exposed to atmosphere), the corrosion-rate increases first with the rise of temperature, reaches a maximum at 350–360 K and then drops. (Fig. 30.3)

Q. *Can oxygen-free pure water give rise to erosion/corrosion in the pipeline?*

Ans. Yes. Though erosion/corrosion (E/C) in single phase (pure water) systems is a rare phenomenon, but it still does occur and is much less severe than that in two-phase systems.

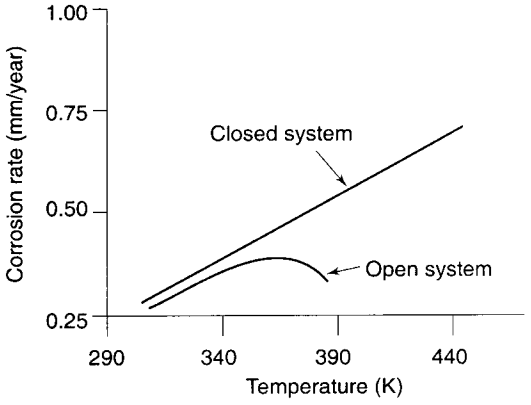


Fig. 30.3 *Dependence of oxygen-corrosion on temperature.*

Q. *What factors are responsible for erosion/corrosion in pure water pipes?*

Ans. 1. Material of composition
2. Poor piping geometry
3. High water velocity
4. Inadequate water chemistry
5. High temperature

Q. *Can you site an instance of pipe failure due to E/C of pure water?*

Ans. A 450 mm dia feedwater suction header carrying high purity water at 463°K blew off killing four workers and injuring four others in December 1986.

The accident took place on Unit-2 of Surrey Nuclear Powerplant (Virginia Power Co.) while operating at full load shortly after 60-days-refueling outage. The rupture occurred in a 90°-elbow in 450 mm line made of ASTM A-106, Grade-B, extra strong CS pipe (seamless). The elbow had been in service since the unit went commercial in 1973.

Q. *Why did this rupture occur?*

Ans. It was due to extreme wall thinning (12.7 mm thick CS pipewall had been worn out to as little as 1.2 mm) caused by erosion/corssion of oxygen-free highly-pure water.

Upon inspection it was revealed that poor piping geometry was the potential cause for erosion/corrosion. Because of this design deficiency there developed regions of high flow and considerable turbulence at the 90°-elbow. The magnetite formed as the corrosion product of iron developed an adhensive film on the surface and protected further loss (corrosion) of sub-surface iron. However, due to considerable turbulence of the high pressure water system, the layer of magnetite was removed, resulting in an almost smooth steel surface. Again the magnetite layer was formed on this bare surface and again it was washed away. This process continued and the pipewall at the elbow got thinner and thinner. Eventually, it gave way.

Q. *How can such a mishap be averted?*

Ans. The failure of high-pressure pipelines due to *E/C* related problems can be avoided through condition monitoring and preventive maintenance. The total action program includes

(a) developing a list of the components most susceptible to E/C
(b) conducting a series of ultrasonic testing of these components
(c) evaluating the results of the NDT so that the rate of wear can be determined.

From the data so obtained parallels can also be drawn to the other units based on physical and chemical operating conditions.

Forasmuch as the ultrasonic examination method has an inherent error of ± 5%, the inspection data are not definite to help in calculate actual component wear rate of remaining life. However, the data do report that no rapid or acceleration erosion rates exist at the inspected zones. Based on these, a recommendation can therefore be made either to replace the part of the equipment or allow it to pass several years in service prior to the next inspection.

Q. *How does carbon dioxide make its way up into the steam-water circuit of a thermal power plant?*

Ans. It appears as bicarbonates (HCO_3^-) and carbonate CO_3^{2-} ions in the boiler feedwater makeup as well as in the condensate of turbine condensers (because of leakage of cooling water). In the boiler unit these ions decompose and liberate CO_2.

Q. *What is the most harmful effect of CO_2-corrosion?*

Ans. It is the contamination of feedwater with the products of corrosion (oxides or iron).

Q. *What is the effect of feedwater on CO_2-corrosion?*

Ans. It proliferates with the increase of feedwater temperature.

Q. *How can carbon dioxide corrosion best be prevented?*

Ans. This can be done by:

(a) Appropriate methods of makeup water treatment to reduce adequately the amount of free CO_2 in steam
(b) Eliminating the condensate of heating steam from regenerative feedwater heaters
(c) Treating feedwater with ammonium ions
(d) Treating steam with film forming amines
(e) Complete venting of CO_2, O_2 from the steam space of heaters.

Q. *How will ammonium ions introduced into the feedwater makeup control carbon dioxide corrosion?*

Ans. Ammonium ions bind the crbon dioxide in aqueous phase

$$NH_3 + H_2O \Leftrightarrow NH_4^+ + OH^-$$

$$CO_2 + H_2O \Leftrightarrow H^+ + HCO_3^-$$

$$NH_4^+ + HCO_3^- \longrightarrow (NH_4)HCO_3$$

$$NH_4^+ + (NH_4)HCO_3 \longrightarrow (NH_4)_2\,CO_3 + H^+$$

$$H^+ + OH^- \longrightarrow H_2O$$

Q. *But ammonia escapes from the solution phase to vapour phase on heating in a boiler unit. How will it curb CO_2-corrosion in the condensate?*

Ans. Ammonia escapes into the steam in the boiler unit. And when the steam condenses in the turbine condenser subsequently, the vapour ammonia again gets dissolved in the condensate to produce ammonium ions. And carbon dioxide contained in the condensate as CO_3^{2-} and HCO_3^- ions is completely bound by ammonium ions.

Q. *If ammonia dissolves in the condensate, will it change the pH of the latter?*

Ans. Yes. It will make the condensate alkaline and the pH value of the condenate will be ≥ 8.3.

Q. *In which form is ammonia introduced into the steam-water circuit?*

Ans. Ammonia is added into the feedwater as the

(a) aqueous solution NH_4OH
(b) aqueous solution of NH_4Cl or $(NH_4)_2SO_4$.

Q. *What is the difference between using NH_4OH and NH_4Cl or $(NH_4)_2SO_4$ as the ammoniating agent?*

Ans. NH_4OH is distinctly basic

$$NH_4OH \Leftrightarrow NH_4^+ + OH^-$$

However, NH_4Cl or $(NH_4)_2SO_4$ being salts of a strong acid and weak base undergo hydrolysis to liberate H^+ that makes the solution of these reagents potentially acidic

$$\underset{(aq.)}{NH_4Cl} \Leftrightarrow \underset{(aq.)}{NH_4^+} + \underset{(aq.)}{Cl^-}$$

$$NH_4^+ + H_2O \rightleftharpoons NH_4OH + H^+$$

Hence, when these latter reagents are used to introduce ammonia in the steam-water circuit, care must be taken to ensure that the boiler water is sufficiently alkaline.

Q. *What is the effect of oxygen corrosion in a steel economizer?*

Ans. Poorly deaerated feedwater circulating in the steel economizers results in oxygen corrosion (pitting) with the effect that flaws in the tubes appear. Through these flaws water gushes out with tremendous velocity and erodes the adjacent tubes producing through-holes in them. Since the economizer tubes are closely packed, tubes fail one after another, inflicting great damage to the overall economizer.

Q. *Do the iron economizers suffer from oxygen corrosion as do the steel economizers?*

Ans. No.

Q. *Why?*

Ans. The oxygen present in the feedwater produces on the tube surface a hard, passive film of Fe_2O_3 that prevents further oxidation of the base layer:

$$Fe \longrightarrow Fe^{2+} + 2e$$

$$Fe^2 + 2OH^- \longrightarrow Fe(OH)_2$$

$$4Fe(OH)_2 + O_2 + 2H_2O \longrightarrow 4Fe(OH)_3$$

$$4Fe(OH)_3 \longrightarrow 2Fe_2O_3 + 6H_2O$$

Q. *In which section of the economizer, is oxygen corrosion most prevalent?*

Ans. In the inlet sections.

Q. *In the boiler drum, the riser tubes suffer from a lesser degree of oxygen-corrosion than downcomer tubes. Why?*

Ans. It is due to the deaerating effect of steam bubbles in the riser tubes.

Q. *What is outage corrosion?*

Ans. It is the out-of-service corrosion. It is a type of electrochemical corrosion affecting idle boiler units.

Q. *How does this corrosion arise?*

Ans. When a boiler is taken out-of-service and left shutdown for a long period for maintenance jobs, the boiler pressure gradually diminsihes and vacuum develops in the drum. This sucks in air, with the effect that contamination of boiler water with oxygen takes place. Even if the boiler water is completely drained from the boiler drum, its

internal surface remains wet and gets contaminated with infiltrated oxygen. And this initiates oxygen corrosion.

Q. *Why are the superheaters thoroughly washed before laying for a long shutdown?*

Ans. The deposits adhering to the superheater tube surface are capable of dissolving in the moisture that forces its way into the boiler unit alongwith infiltrated air during long outage time. This becomes enriched with oxygen and contributes to the development of electrochemical corrosion.

Q. *How can outage corrosion be avoided in the boiler unit?*

Ans. This can be prevented by adopting the following methods:

1. Dry storage of boiler units
2. Wet storage of boiler units
3. Protecting the boiler unit by coating it with a 10% $NaNO_2$ solution film
4. Filling the *boiler* unit with hydrazine solution
5. Treating the internal surfaces of boiler unit with complexing agents
6. Preserving the boiler unit in a nitrogen atmosphere.

Q. *How is dry storage of boiler units put into effect?*

Ans. After cooling down the boiler unit, all the mains and pipelines are isolated, boiler water is drained, the deposits are removed and the surfaces are dried keeping the air vents open.

Following the completion of drying, water absorbents (anhydrous $CaCl_2$, CaO and silica gel) filled in trays are placed in the boiler drum in about $2kg/m^3$ of the drum spce. All manholes are tightly closed. The absorbents are periodically checked and replaced if necessary.

Q. *How is wet storing of the boiler unit performed?*

Ans. After shutdown, the boiler unit is cooled, the drum is drained to remove all sludge, it is isolated, filled with deaerated water under a deaerator pressure and boxed up.

Q. *Why does the coating of a nitrite film on the internal surfaces of the boiler unit prevent oxygen corrosion?*

Ans. The nitrite ions passivate the metal surface by producing a thin film of ferric hydroxide on the surface

$$3NaNO_2 + Fe + 3H_2O \longrightarrow 3NO + Fe(OH)_3 + 3NaOH$$

and this film prevents the penetration of dissolved oxygen, which acts as a depolarizer, to the metal underneath the film.

Q. *How does filling the boiler unit with hydrazine solution protect the internal surfaces of the unit from oxygen corrosion?*

Ans. Hydrazine itself reacts with dissolved oxygen

$$N_2H_4 + O_2 \longrightarrow N_2 + 2H_2O$$

to remove any traces of local oxygen that may be present in the deaerated water filling the boiler unit during shutdown.

Q. *At which points of the boiler units, does intercrystalline (i.e. intergranular) corrosion appear?*

Ans. In riveted and expanded joints exposed to boiler water.

Q. *How does it appear?*

Ans. First, it appears in the form of a very fine crack invisible to the naked eye. Gradually it develops with time and eventually becomes quite detectable to the eye.

Q. *Why is it called intergranular corrosion?*

Ans. It originates at the boundary between the adjacent crystal grains under stress and propagates along the grain boundary to relieve internal

stress. That is why it is called intergranular corrosion.

Q. *What factors lead to the initiation of intercrystalline corrosion?*

Ans. The following three factors must be present and act simultaneously to give rise to intercrystalline corrosion:

1. Presence of internal stress (tensile stress close to yield point) in the body
2. Leakage in riveted or expanded joints
3. Aggressiveness of boiler water.

Q. *If any of these three factors is absent, will intercrystalline corrosion occur?*

Ans. No.

Q. *Among these which one is a primary cause for the genesis of intercrystalline corrosion in boiler units?*

Ans. It is the thermal strain in the boiler elements associated with high internal stresses in the metal.

Q. *How does it originate?*

Ans. It arises due to non-uniform heating or cooling of the boiler components, abrupt load-shedding in the boiler and sudden shutdown of the boiler unit for technical reasons. The rapid and non-uniform cooling produces a thermal strain in the riveted and expansion joints and causes circular cracks to appear in tubes at the joints.

Q. *Is it true that intercrystalline corrosion also appears at the spots under local cooling in the boiler drum?*

Ans. Yes.

Q. *What are these spots?*

Ans. These are where phosphate solution feed pipe, water-gauge pipes, feedwater lines and intermittent-blowdonw pipes are connected to the boiler drum.

Q. *What about the aggressivity of boiler water to prevent fracturing due to intercrystalline corrosion?*

Ans. Regarding the aggressivity of boiler water, it has been found that sodium hydrate concentration of as much as 5 to 10% is sufficient to react with metal. That is why the relative alkalinity of boiler water should not go higher than 20%.

Q. *What is the relative alkalinity?*

Ans. It is an important indicator of the boiler water's aggressiveness. Expressed in per cent, it is determined by the relationship

$$A_{\text{rel}} = \frac{40(100A_{bw} - 2C_{PO_4^{3-}})}{C_{bw}} \times 100$$

where

A_{bw} = boiler water alkalinity, mg/l

$C_{PO_4^{3-}}$ = phosphate ion concentration in boiler water, mg/l

C_{bw} = total dissolved salt content in boiler water, mg/1.

Q. *What methods are applied to control the aggressivity of boiler water?*

Ans. Two methods are applied—one is nitrate treatment and the other is phosphate treatment.

NITRATE TREATMENT: makes use of dissolved sodium nitrate whose concentration in boiler water must be as

$$C_{NO_3^-} \geq (0.35 - 0.4)40\ A_{bw}$$

However, this method, though an effective process of controlling free sodium hydrate, is applicable to boiler units operating at a pressure ≤ 7 MPa.

PHOSPHATE TREATEMENT: makes use of trisodium phosphate in solution to eliminate the aggressive free sodium hydrate from boiler water. This method, also known as the method of purely phosphate alkalinity, is applied to boiler units operated at pressures higher than 7 MPa.

Q. *Why is nitrate treatment inapplicable to boiler units operating at pressures higher than 7 MPa?*

Ans. At higher pressures and consequently higher temperature the nitrate ions become unstable and decompose rendering the treatment futile

$$2NaNO_3 \xrightarrow[\Delta]{} 2NaNO_2 + O_2$$

Q. *What is vapour-water corrosion?*

Ans. It is the destruction of metal by the chemical attack of water vapour at elevated temperature.

Water vapour attacks carbon steel at temperatures 673K and higher producing magnetite and hydrogen

$$3Fe + 4H_2O \longrightarrow Fe_3O_4 + 4H_2$$

Whereas it attacks alloy-steels above 800–850 K.

Q. *What factors contribute to vapour-corrosion of metals?*

Ans. These are:

(a) high rates of heat flow (≥ 230 kW/m^2)
(b) disturbed circulation in steam-water circuit
(c) film-type boiling leading to metal overheating.

Q. *In which sections of boiler units, is vapour (steam) corrosion most prevalent?*

Ans. Superheater coils and waterwall tubes.

Q. *Why is vapour corrosion most prevalent in superheater coils and waterwall tubes?*

Ans. These are the zones of high heat flowrates and temperature reaches critical values.

Q. *How can vapour-water corrosion be controlled and prevented?*

Ans. By eliminating those factors that lead to tube overheating.

Q. *Can this be prevented by changing or improving the water control of boiler units?*

Ans. No.

Q. *Why ?*

Ans. It is because vapour-water corrosion depends on the operating conditions of the boiler units as well as the hydrodynamic processes involved.

Q. *What is hide-out corrosion?*

Ans. This refers to the destruction of metal underneath a layer of sludge settling on the water-side surface of boiler tubes. Since it remains hidden under the layer of sludge, it is called hide-out corrosion.

Q. *Why does it occur?*

Ans. It occurs due to insufficient treatment of boiler water containing suspended substances which fall out on the walls of the boiler tubes forming a solid sediment.

Also it occurs due to the destruction of iron underneath the deposits of iron-oxide that act as a depolarizer.

$$Fe + 4Fe_2O_3 \longrightarrow 3Fe_3O_4$$

Q. *A layer of Fe_2O_3 on metal (Fe) surface passivates the base metal by sealing it from dissolved oxygen. Then how can it contribute to corrosion?*

Ans. This is because Fe_2O_3 itself acts as a source of oxygen. It supplies oxygen that functions as a depolarizer to hasten the process of corrosion.

$$3Fe_2O_3 \xrightarrow[\Delta]{} 2Fe_3O_4 + \frac{1}{2}O_2$$

$$Fe \longrightarrow Fe^{2+} + 2e$$

$$2Fe(OH)_2 + \frac{1}{2}O_2 + H_2O \longrightarrow 2Fe(OH)_3$$

$$\xrightarrow[\Delta]{} Fe_2O_3 + 3H_2O$$

Q. *How does it appear?*

Ans. It appears on the metal surface as pits or cavities filled with Fe_2O_3 at the top and Fe_3O_4 at the bottom.

Q. *How can this be prevented?*

Ans. By reducing the penetration of oxide of iron Fe_2O_3 ($\leq$ 100 microgram/kg) and the oxides of copper (CuO, Cu_2O) into the boiler units.

Q. *What methods are adopted to prevent intensive corrosion in the water-condenser circuits of the supercritical-pressure boiler-turbine units?*

Ans. The following methods are adopted to slow down the corrosion process.

1. Alkaline method
2. High Alkaline method
3. Neutral method
4. Complexonate method

Q. *At what pH, is the alkaline (correction) method carried out?*

Ans. At pH range 9.0–9.2

Q. *Why?*

Ans. It has been found that the feedwater of supercritical pressure boiler units becomes least aggressive at a pH value equal to 9.

Q. *What alkalizing agent is used?*

Ans. Ammonia (in an amount so that its concentration does not exceed 800 microgram/kg in feedwater).

Q. *How does it maintain the pH within the prescribed range?*

Ans. Ammonia dissolves in water to produce a weak base NH_4OH which dissociates to liberate hydroxyl ions

$$NH_3 + H_2O \Leftrightarrow NH_4OH \Leftrightarrow NH_4^+ + OH^-$$

It is these OH^- ions that ensure the prescribed pH value.

Q. *Why in addition to ammonia, is hydrazine also added?*

Ans. Hydrazine is a strong reducing agent. Its use is directed to arrest the water-dissolved oxygen and reduce it to water

$$N_2H_4 + O_2 \longrightarrow N_2 + 2H_2O$$

and thereby prevent corrosion processes.

Q. *At which points in the water-condensate circuit of the boiler-turbine unit, are ammonia and hydrazine dosed?*

Ans. Ammonia is injected downstream of the deaerator or L.P. Regenerative feedwater heater.

Hydrazine is introduced downstream of the DM (demineralizing) plant.

Q. *What would happen if ammonia were injected downstream of the DM plant in place of hydrazine?*

Ans. The pH value of water downstream of the DM plant becomes less than 9. And if ammonia was introduced to correct the pH of DM water, it would increase the concentration of copper in the BFW upstream of the deaerator above the prescribed limit (5 microgram/kg) and in the case of low-pressure regenerative BFW heaters it would intensify the corrosion of the heating surfaces made of brass.

Q. *Does the pH value set up by ammonia remain constant over the entire section of the steam-condensate circuit in the boiler-turbine unit?*

Ans. No.

Q. *Why?*

Ans. The pH of ammonia solution is functionally dependent on the solubility of ammonia in water, which is directly proportional to the temperature of water. Higher the water temperature, lesser will be the solubility of ammonia and accordingly lesser will be the free hydroxyl ions

$$NH_3 + H_2O \Leftrightarrow NH_4OH \Leftrightarrow NH_4^+ + OH^-$$

and consequently the pH of the solution will be lower.

Q. *Will there be any harm if the pH in the water-condensate circuit of the boiler-turbine unit is raised to 9.5–9.6 by adding more ammonia?*

Ans. Yes. A pH value in this range is inadmissible since it will give rise to corrosion of the brass tubes of the turbine condenser.

Q. *Why is it difficult to ensure anticorrosive conditions in all sections of the water-condensate circuit when ammonia is used as the alkalizing reagent?*

Ans. It is because the pH of the circuit varies due to variation of the solubility of ammonia in feedwater at different temperatures in different sections of the water-condensate circuit.

At a temperature of 453 K, the amount of ammonia needed to maintain the pH of feedwater at 9 is 600 microgram/kg while at 523 K, the amount of ammonia needed becomes as high as 1400 microgram/kg to ensure the same pH. However at the turbine condenser (303–305 K) such a concentration of ammonia will raise the pH to a level 9.5–9.6 which is dangerous as it will lead to caustic embrittlement of the brass tubes of the condenser.

Q. *Then how can this difficulty be overcome?*

Ans. This problem can be tackled by using such chemical such as morpholine and cyclohexylamine instead of ammonia. These are alkaline amines and required to a considerably lesser extent than ammonia.

Q. *How is an anticorrosive environment created by the high-alkalinity method?*

Ans. It is done by dosing more ammonia to the water-condensate circuit to raise the pH value equal to 9.5–9.6.

Q. *Why is this method adopted?*

Ans. It has been found by experience that this method is highly effective. It has proved itself extremely reliable in protecting the pipelines and the equipment against corrosion.

Q. *What is the main disadvantage of this method?*

Ans. It expedites the corrosion of brass. Since all the tubes of turbine condensers are generally made of brass, they must be replaced by steel tubes (pearlitic grade) in order to fit this environment.

Q. *What is the basis of corrosion prevention by the neutral method?*

Ans. Using no chemical reagents, this method relies entirely on the protective ferric oxide film produced on the steel surface by the dissolved oxygen at higher pressures and elevated temperatures. It is this protective film that inhibits further corrosion.

Q. *What conditions must be fulfilled to adopt this technique successfully?*

Ans. The following conditions must be rigidly observed for the successful application of the neutral method:

1. The water must be deeply deionized, i.e. it should be polished water with conductivity ≤ 0.15 μS/cm at 298 K.
2. pH range 7–7.5
3. The quantity of dissolved oxygen
   20–200 microgram/kg at 473 K
   10–20 microgram/kg above 473 K

Q. *What are the additional advantages of the neutral method of preventing corrosion in the water condensate circuit?*

Ans. 1. It lends to simplified chemical control
2. It affords great savings in reagents such as ammonia, hydrazine, sulphuric acid and caustic alkali
3. The time gap between two successive regenerations of ion-exchange resin-beds in the DM plant is increased
4. It decreases the concentration of iron in the water-condensate circuit.

Problem 30.1 The oxygen corrosion of iron is an electrochemical process that involves the following reactions:

$$2Fe + O_2 + 2H_2O \longrightarrow 2Fe(OH)_2$$

$$4Fe(OH)_2 + O_2 \longrightarrow 4Fe(OH)_3\downarrow$$

Calculate the amount of dissolved oxygen required to inflict damage by corrosion on a layer of metal 0.15 mm thick over an area 100 m^2 surface accompanied by the formation of ferric hydroxide.

Also determine the amount of magnetite formed. (Density of iron = 7.8 gm/c.c.)

Solution **Step (I) Overall Corrosion Reaction**

Multiplying the 1st reaction by two and adding the result with 2nd reaction we get the overall reaction

$$\underset{4(55.8)}{4Fe} + \underset{3(16\times 2)}{3O_2} + 6H_2O \longrightarrow 4Fe(OH)_3$$

Step (II) Oxygen Consumption in Corrosion

By stoichiometry, the amount of oxygen involved in corrosion of iron

$$M_{O_2} = 3O_2/4Fe = 3(16 \times 2)/4\ (55.8)$$
$$= 0.4301 \text{ gm/gm of Fe}$$

Mass of iron in the layer 0.15 mm thick and 100 m^2 surface area

$$M_{Fe} = \underset{cm}{(0.15/10)}\ \underset{(cm^2)}{(100 \times 10^4)}\ \underset{(gm/c.c.)}{(7.8)}$$
$$= 1.17 \times 10^5 \text{ gm}$$

Hence the amount of oxygen consumed in the given corrosion

$$= 0.4301 \times 1.17 \times 10^5$$
$$= 50321.7 \text{ gm} = 50.321 \text{ kg}$$ ***Ans.***

Step (III) Amount of Magnetite Formed

$$\underset{2(55.8)}{2Fe} + \frac{3}{2}O_2 \longrightarrow \underset{(2\times 55.8 + 3\times 16) = 159.6}{Fe_2O_3}$$

Mass of magnetite formed

$$M_{Fe_2O_3} = \frac{159.6}{2(55.8)} \times 1.17 \times 10^5 \text{ gm}$$
$$= 167.322 \text{ kg}$$ ***Ans.***

Problem 30.2 Determine the amount of hydrogen liberated in the corrosion process involved in Problem 30.1 assuming H^+ ions instead of oxygen are involved as depolarizer.

Solution

Step (I) Basic Equation of Corrosion with H_2-Depolarization

$$Fe \longrightarrow Fe^{2+} + 2e$$
$$2H^+ + 2e \longrightarrow 2H \longrightarrow H_2$$

Adding these two we get the overall corrosion-reaction

$$\underset{(55.8)}{Fe} + 2H^+ \longrightarrow Fe^{2+} + \underset{(2)}{H_2}$$

Step (II) Quantity of H_2 Liberated

$$M_{H_2} = (2/55.8)\ (1.17 \times 10^5)\text{gm}$$
$$= 4193.54 \text{ gm}$$
$$= 4.193 \text{ kg}$$ ***Ans.***

Problem 30.3 Calculate the number of pits that will form as a result of pitting corrosion in the feedwater circuit of a boiler unit during its one year service. Base your calculations on the following data.

Boiler capacity = 120 t/h
Blowdown rate = 4%
Operating hours of the boiler in 1 year = 7920 hr.
Dimension of pits (cone-shaped):
Base diameter = 9 mm
Depth = 3 mm
Oxygen content in BFW = 0.025 mg/kg
(Assume the entire dissolved oxygen takes part in pitting corrosion)
Density of steel = 7.8 gm/c.c.

Solution **Step (I) Blowdown (t/h)**

Working Formula: $p^s_{bd} = \dfrac{G_{bd}}{G_s} \times 100$

where p^s_{bd} = per cent blowdown
G_{bd} = blowdown rate, *t/h*
G_s = boiler's steam generation capacity, *t/h*

p^s_{bd}	G_s	G_{bd}
4	120 t/h	4 × 120/100 = 4.8 t/h

Step (II) Feedwater Flowrate (t/h)

By mass balance:

$$G_{fw} = G_{bd} + G_s$$

$$G_{fw} = 4.8 + 120 = 124.8 \text{ t/h}$$

Step (III) Quantity of Dissolved Oxygen involved in the entire Corrosion Process during 1-yr service of the boiler

Total mass of feedwater,

$$M_{fw} = 124.8 \times 7920\text{t}$$
$$= 124.8 \times 7920 \times 10^3 \text{ kg}$$

Total mass of dissolved oxygen,

$$M_{O_2} = (124.8 \times 7920 \times 10^3)\ (0.025) \text{ mg}$$
$$= 24.7104 \text{ kg.}$$

Step (IV) Mass of Metal involved per Pit

Volume of metal involved per pit = $\frac{1}{3}\pi r^2 h$

(Fig. 30.4)

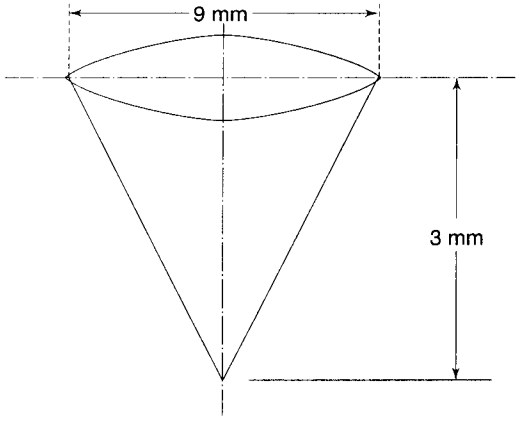


Fig. 30.4

$$= (1/3)\ (\pi)\ (9/2)^2\ (3) \text{ mm}^3$$
$$= 63.617 \text{ mm}^3 = 0.0636 \text{ cm}^3$$

Mass of metal involved per pit,

$$m_{Fe} = 0.0636 \times 7.8 \text{ gm}$$
$$= 0.4962 \text{ gm}$$

Step (V) Mass of Oxygen involved per Pit

The overall reaction of corrosion of iron involving oxygen as depolarizer

$$4Fe + 3O_2 + 6H_2O \longrightarrow 4Fe(OH)_3$$
$$4(55.8)\ \ 3(32)$$

Mass of iron involved per pit = 0.4962 gm

∴ Mass of oxygen involved per pit

$$= \frac{3(32)}{4(55.8)} \times 0.4962 = 0.2134 \text{ gm}$$

Step (VI) Total Number of Pits

The total number of pits formed during 1-yr service of the boiler

$$N = \frac{M_{O_2}}{m_{O_2}} = \frac{24.7104 \times 10^3}{0.2134} = 115794 \quad \textbf{\textit{Ans.}}$$

Problem 30.4 Determine the amount of Fe_2O_3 that forms in the boiler during 7920 h of service under the conditions of Problem 30.3.

Solution The amount of ferric oxide formed can be calculated with the help of the following reaction:

$$2Fe + \frac{3}{2}O_2 \longrightarrow Fe_2O_3$$
$$2(55.8) \qquad\qquad 159.6$$

$$M_{Fe_2O_3} = \frac{159.6}{2(55.8)} \times (0.4962 \times 115\ 794)$$
$$= 82169.66 \text{ gm}$$
$$= 82.169 \text{ kg} \qquad \textbf{\textit{Ans.}}$$

Problem 30.5 Assuming that the entire amount of magnetite forming in the boiler under conditions as described in Problem 30.4 remains in the boiler as deposit, calculate its thickness falling out of 10% of the total heating surface (1200 m^2).

Take the density of magnetite = 5.25 gm/c.c.

Solution Mass of the deposit = 82.169 kg
Density of deposit = 5.25 gm/c.c.
Volume of deposit = 82169/5.25 cm^3
= 15651.238 cm^3
Area of heating surface covered by deposit
= 1200 (10/100) = 120 m^2 = 120 × 10^4 cm^2
Therefore, the depth of deposit
= 15651.238/(120 × 10^4)
= 0.013 cm = 0.13 mm ***Ans.***

Problem 30.6 The degree of vapour-water corrosion in the superheater coils is measured in terms of the quantity of hydrogen entrained by the superheater steam.

In a superheater of a boiler unit, the concentration of hydrogen in superheated steam amounts to 0.12 mg/kg. If the steam generating capacity of the boiler unit is 200 t/h, estimate the amount of metal affected by vapour-water corrosion.

Solution The amount of iron damaged by vapour water corrosion can be calculated with the help of the reaction:

$$3Fe + 4H_2O\ (steam) \longrightarrow Fe_3O_4 + 4H_2$$
$$3(55.8) \qquad\qquad 4(2)$$

Now the rate of hydrogen passing to superheated steam

$$= 200 \times 10^3 \times 0.12\ mg/h = 24\ g/h$$

Therefore, the amount of metal attacked by steam

$$= \frac{3(55.8)}{4 \times 2} \times 24 = 502.2\ g/h \qquad \textit{Ans.}$$

Problem 30.7 A superheater coil has a total heating surface of 800 m^2. If 10% of this surface area gets affected by vapour-water (steam) corrosion, determine the time required to reduce the superheater tube thickness by 0.1 cm.

Steam contains hydrogen 0.1 mg/kg
Average steam load of the boiler = 200 t/h

Solution

Step (I) Mass of Iron involved in Vapour-Water Corrosion

Total heating surface area of superheater
= 800 m^2

Heating surface affected by vapour-water corrosion = 800 (10/100) = 80 m^2.

Volume of iron attacked by vapour-water corrosion = (80 × 10^4) (0.1) = 80 000 cm^3

Mass of iron involved in corrosion

M_{Fe} = Volume of Iron × Density
= 80000 × 7.8 = 624 000 g = 624 kg.

Step (II) Mass of Hydrogen evolved in the vapour-water Corrosion

$$3Fe + 4H_2O \longrightarrow Fe_3O_4 + 4H_2$$
$$3(55.8) \qquad\qquad 4(2)$$

Mass of hydrogen liberated when 624 kg of iron suffers from vap-water corrosion is

$$M_{H_2} = \frac{4(2)}{3(55.8)} \times 624 = 29.82\ kg$$

Step (III) Time Interval for the above Corrosion

Rate of hydrogen evolution
= (200 × 10^3) (0.1) mg/h = 20 g/h

Required time = 29.82 × 10^3/20 = 1491 h

Ans.

Problem 30.8 Determine the quantity of ferric oxide (Fe_2O_3) that must be present in the BW to provoke boiler metal corrosion of an intensity equal to that caused by DO of 0.03 mg/kg, assuming that the entire dissolved oxygen goes to oxidize metal into ferrous iron.

The boiler remains in service for a period of 1000 h, drawing FW at the rate of 150 t/h.

Solution Even in the absence of DO, electrochemical oxidation of the boiler metal in service takes place. Corrosion products themselves initiate such type of attack. Ferric oxide is one such example. It is formed on the water-side of heat-transfer surface of the boiler system

$$Fe + DO \longrightarrow Fe_2O_3 \text{ (initial passivating layer)}$$

The ferric oxide (Fe_2O_3) so formed is capable of oxidizing iron into magnetic ferrous-ferric oxide (Fe_3O_4)

$$4Fe_2O_3 + Fe \longrightarrow 3Fe_3O_4$$

$$Fe_3O_4 \equiv FeO \cdot Fe_2O_3$$

Subsequently, when the boiler is opened for repairs, this ferrosoferric oxide reverts to Fe_2O_3 due to exposure to atmospheric air

$$4Fe_3O_4 + O_2 \longrightarrow 6Fe_2O_3$$

That is Fe_2O_3 serves as a solid depolarizer.

DO attacks Fe through the following pair of half-cell reactions

$$O_2 + 4e + 2H_2O \longrightarrow 4OH^-$$

$$Fe - 2e \longrightarrow Fe^{2+}$$

$$2Fe + O_2 + 2H_2O \longrightarrow Fe(OH)_2$$

$2 \times 56 \quad 32$

$= 112$

O_2 content in 150 t/h of FW (DO = 0.03 mg/kg) over a 1000h duration

$$= 0.03\left(\frac{\text{mg}}{\text{kg}}\right) \times 150 \times 10^3\left(\frac{\text{kg}}{\text{h}}\right) \times 1000 \text{ (h)}$$

$= 4500$ g

32 g DO corrode 112 g Fe to Fe^{2+}

$\therefore$ 4500 g DO corrode 112(4500)/32 = 15.75 kg Fe

Now,

56 kg Fe is attacked by 4×160 kg Fe_2O_3

$$\therefore \text{ 15.75 kg Fe is attacked by } \frac{4 \times 160}{56} \times 15.75$$

$$= 180 \text{ kg } Fe_2O_3 \qquad \textbf{Ans.}$$

Problem 30.9 Determine the nitrite concentration in FW that is equivalent to the DO content of 0.03 mg/kg, assuming that only half of the nitrites present takes part in the process of nitrite corrosion.

Solution Nitrite corrosion is represented by

$$3NaNO_2 + Fe + 3H_2O \longrightarrow 3NO + Fe(OH)_3 + 3NaOH$$

$3 \times 69 \quad 56$

This is similar to the corrosion with oxygen depolarization

$$4Fe + 3O_2 + 6H_2O \longrightarrow 4Fe(OH)_3$$

$4 \times 56 \quad 3 \times 32$

$\therefore$ 3×32 mg O_2 corrodes 4×56 mg Fe

$$\therefore \text{ 0.03 mg/kg } O_2 \text{ corrodes } \frac{4 \times 56}{3 \times 32}(0.03)$$

$= 0.07$ mg Fe/kg water

56 mg Fe iron is attacked by 3×69 mg $NaNO_2$

$$\therefore \text{ 0.07 mg/kg water is attacked by } \frac{3 \times 69}{56}(0.07)$$

$= 0.25875$ mg $NaNO_2$/kg FW

This represents half the NO_2^- concentration present in feedwater. Therefore,

$C_{NO_2^-} = 0.5175$ mg/kg water.

Q. *What are the gases other than carbon dioxide and oxygen that may find their way to the feedwater system and contribute to corrosion?*

Ans. These are hydrogen sulphide, ammonia, sulphur dioxide, chlorine, etc.

Q. *What is the source of hydrogen sulphide?*

Ans. It comes chiefly from dissolved sulphides which are occasionally found in the surface water as a result of bacterial decomposition of organic

substances or from miscellaneous pollution. However, for well-waters the only source of sulphides is the soluble mineral sulphides.

Q. *Why is hydrogen sulphide in a dissolved state corrosive?*

Ans. Hydrogen sulphide dissolves in water to produce weak acid:

$$H_2S \Leftrightarrow H^+ + SH^-$$
$$(aq.)$$

These liberated protons (H^+) act as a depolarizer and contribute to corrosion

$$Fe \longrightarrow Fe^{2+} + 2e$$

$$2H^+ + 2e \longrightarrow H_2$$

Hydrogen sulphide, even in small quantities, reacts acidic and may be responsible for active corrosion of iron even in the presence of oxygen. Moreover, it has been observed that turbines having nickel alloy parts undergo damage due to the action of hydrogen sulphide (carried over by steam) upon nickel.

Q. *How can the hydrogen sulphide from water be removed?*

Ans. This can be done satisfactorily by the reduction of the pH value of the water followed by good aeration.

Q. *How does aeration help in driving off hydrogen sulphide?*

Ans. It removes dissolved sulphides by the scrubbing action of air and by oxidation.

Q. *Why should pH be lowered to eliminate hydrogen sulphide?*

Ans. Hydrogen sulphide, upon dissolving in water, undergoes the following ionic equilibria

$$H_2S \Leftrightarrow H^+ + SH^-$$
$$(aq.)$$

which is shifted to the left if more H^+ ions are added, i.e. the pH is lowered. So at a low pH, lesser amount of H_2S will dissolve in water, facilitating H_2S removal from the feedwater system.

Q. *Why is the presence of sulphide ions in feedwater unwanted?*

Ans. Many metals are rapidly corroded by relatively high concentrations of sulphides. Stainless steel and brass which can effectively withstand attack in an oxidizing medium undergo aggressive attack by water containing sulphides.

Q. *Why is hot water more corrosive than cold water?*

Ans. With the increase in temperature of water, the convection current increases and viscosity decreases and these two factors accelerate the diffusion of oxygen through the metal surface film.

Moreover, with the increase of water temperature, its pH value decreases which in turn accelerates the deposition of atomic hydrogen (depolarizer) on cathodic areas.

Q. *What is the effect of water alkalinity on the corrosion of iron?*

Ans. Though it has been established by experience and tests that the corrosion rate of iron by alkalies diminishes to a certain minimum as the concentration of the base increases, high concentrations of alkalies to the point of supersaturation as are encountered under the conditions of film-boiling, greatly accelerate rather than retard corrosion of steel.

Q. *What is the mechanism of attack?*

Ans. It proceeds via the mechanism of protective film destruction. The upper surface of tubes which are only slightly inclined from the horizontal as is the case in dry-bottom furnaces and in the floors of slag-bottom furnaces, may be blanketed with steam causing high local temperatures of the metal surfaces. Intermittent splashing of water frequently wets these partially insulated surfaces leading to higher concentration of NaOH in these areas. High caustic alkalinity tends to reputure the protective ferric-oxide (Fe_2O_3) film.

The combined effect of higher temperatures and destruction of this oxide film causes grooving of tubes and ultimate failure.

Q. *What is the remedy?*

Ans. 1. Cut in caustic alkalinity of boiler feedwater
2. Controlling heat input
3. Improving circulation
4. Increasing the inclination of the tubes.

Q. *In many cases severe corrosion has been reported beneath the layer of protective ferric oxide film resulting in the loss of metal at the corroded area and even accompanied by embrittlement of steel. Why?*

Ans. This is due to alkaline attack. Though a dilute solution of sodium hydroxide apparently assists in developing an impervious oxide film, higher concentration of alkali tends to open it up while a very concentrated solution actually destroys it by forming soluble iron complexes. Therefore, local high concentrations of sodium hydroxide impair the protective film, enhance the generation of hydrogen and increase the rate of hydrogen embrittlement of metal.

Q. *What are the mineral acids that may contaminate the boiler feedwater supplies?*

Ans. These are hydrochloric, nitric and sulphuric acids.

Q. *Where do they come from?*

Ans. They come from industrial wastes discharged into the surface or underground supplies. Many mine waters have a high acid content. Hence mine drainage is frequently responsible for the mineral acids in the feedwater.

Q. *What is the effect of these mineral acids in the BFW if these are not neutralized?*

Ans. They will cause rapid destruction of metals of boilers and auxiliary equipment in the form of pitting corrosion that may lead to tube failure or equipment breakdown.

Q. *It has been observed that iron salt present in the form of ferric sulphate increases the corrosivity of water whereas the opposite effect has been noted when iron is present in the form of ferrous sulphate, when the dissolved oxygen concentration, the velocity and temperature of water and other factors are constant. Why?*

Ans. Ferric ions act as a depolarizer.

$$Fe^{3+} + e \longrightarrow Fe^{2+}$$

So iron present in the feedwater in the ferric state increases the aggressivity of water.

Whereas, ferrous ions present in water react with dissolved oxygen and inhibit corrosion.

Q. *Why does the presence of magnesium chloride in water increases the corrosiveness of the latter?*

Ans. Dissolved magnesium chloride undergoes hydrolysis to produce hydrochloric acid

$$MgCl_2 + 2H_2O \Leftrightarrow Mg(OH)_2 + 2HCl$$

Since magnesium hydroxide separates out as insoluble precipitate, the above equilibria continues to shift to the right to generate more and more hydrochloric acid that accounts for increasing corrosivity of the feedwater.

Q. *A relatively small amount of dissolved magnesium chloride may lead to active corrosion. Why?*

Ans. Dissolved magnesium chloride undergoes hydrolysis liberating hydrochloric acid that attacks iron

$$MgCl_2 + 2H_2O \Leftrightarrow Mg(OH)_2 + 2HCl$$

$$Fe + 2HCl \longrightarrow FeCl_2 + H_2$$

The ferrous chloride resulting as a preliminary corrosion product reacts further with magnesium hydroxide to produce back magnesium chloride:

$$FeCl_2 + Mg(OH)_2 \longrightarrow Fe(OH)_2 + MgCl_2$$

which again undergoes hydrolysis and initiates the cycle again.

This explains why a small amount of dissolved magnesium chloride may lead to active corrosion that may go on indefinitely.

Q. *Sodium chloride is mildly corrosive; so its presence in the feedwater does little harm. But in the presence of magnesium sulphate, it becomes actively corrosive. Why?*

Ans. Sodium chloride is a neutral salt. So its aqueous solution is not corrosive. But in the presence of magnesium sulphate, it reacts with the latter to form magnesium chloride

$$2NaCl + MgSO_4 \longrightarrow Na_2SO_4 + MgCl_2$$

which undergoes hydrolysis, liberating hydrochloric acid that actively corrodes the metal surface

$$MgCl_2 + 2H_2O \longrightarrow Mg(OH)_2 + 2HCl$$

Q. *How can this corrosion by magnesium salt be inhibited?*

Ans. This can be done by neutralizing the magnesium chloride with an alkali

$$MgCl_2 + 2NaOH \longrightarrow Mg(OH)_2 + 2NaCl$$

Q. *Are there any magnesium salts other than magnesium sulphate or chloride that may lead to corrosion in the boiler?*

Ans. Magnesium carbonate and magnesium nitrate in the presence of sodium chloride give rise to active corrosion:

$$MgCO_3 + 2NaCl \longrightarrow MgCl_2 + Na_2CO_3$$

$$MgCl_2 + 2H_2O \longrightarrow Mg(OH)_2 + 2HCl$$

$$Mg(NO_3)_2 + 2NaCl \longrightarrow MgCl_2 + 2NaNO_3$$

$$MgCl_2 + 2H_2O \longrightarrow Mg(OH)_2 + 2HCl$$

$$NaNO_3 + HCl \longrightarrow NaCl + HNO_3$$

Q. *Does corrosion occur under the scales?*

Ans. As a general rule, scale formation inhibits corrosion since the deposited salts mechanically protect the metal and prevent direct contact between the corrosive agent and the metal.

Q. *But still corrosion beneath the scale or even under the protective coating applied to protect the metal surface have been reported. Why?*

Ans. Corrosion results when the protective coating gets cracked, permitting the water, containing a fairly larger concentration of corrosive salts, to concentrate between the laminations produced by a hair crack of the protective layer. These salts dissociate at the metal surfaces and corrode the latter.

Q. *How many forms of pitting corrosion arise in boiler deterioration?*

Ans. Three types:

1. Air-bubble pitting
2. Scab pitting
3. Soft scab pitting.

Q. *What does air-bubble pitting looks like?*

Ans. It appears in the form of isolated hemispherical pits often capped by loose, soft corrosion products. These, when dried, are black iron oxide covered with a layer of red dehydrated ferric oxide.

Q. *Where can this type of pitting corrosion be located?*

Ans. It is likely to be found on any surfaces in contact with water where air bubbles may collect, but mainly on the roof of steam and water drums.

Q. *What is the principal cause of this corrosion?*

Ans. Air bubbles that are liberated attach themselves to metal surfaces, thereby triggering anodic attack due to localized electrolytic action, and oxygen acts as a depolarizer.

Q. *What does scab pitting look like?*

Ans. It appears as deep localized pitting capped by a scab of hard scale. This is the scale of black magnetic iron oxide which cannot be dislodged by wire brushes.

Q. *Where does this pitting occur?*

Ans. It occurs usually in hotter zones of heating surfaces. Here the corrosion products, as soon as they form, get quickly consolidated in a hard scab by heat.

Q. *What is the cause of scab pitting?*

Ans. Use of partially treated or untreated impure boiler water containing dissolved salts as well as gases, rendering water pH ranging from 4.8 to 9.4.

Q. *What does soft scab pitting look like?*

Ans. They appear as broad, shallow pitting covered with fairly hard corrosion products composed of black magnetic iron oxide capped by a layer of red dehydrated ferric hydroxide.

Q. *Where does this soft scab pitting appear?*

Ans. It occurs usually in superheater tubes and headers and in main steam lines.

Q. *What is the cause of soft scab pitting?*

Ans. This is chiefly due to deposition of salts by priming in superheaters, steam main followed by condensation when the boiler is shutdown giving rise to formation of droplets of electrolyte and the initiation of a pit by differential aeration.

Q. *General wastage is a type of internal deterioration of the boiler. In how many varied forms does it appear?*

Ans. It appears in the form of

1. tube-wall thinning
2. necking and grooving
3. galvanic attack

Q. *What does tube-wall thinning look like?*

Ans. It appears as a general reduction in the thickness of the tube-wall over a considerable area with or without the presence of the blankets of corrosion products.

Q. *Where can this be located?*

Ans. It is more or less evenly distributed over the water wall surfaces. It is most likely in hotter areas.

Q. *What is the cause of tube-wall thinning?*

Ans. Acidity in feedwater.

Q. *What do necking and grooving look like?*

Ans. They appear as a circumferential band of corrosion.

Q. *Where can these be found?*

Ans. On the waterside of the fire tubes (where they enter end plates or combustion chamber), stay tubes and stay bolts.

Q. *Why do they occur?*

Ans. They result from stress. Expansion and contraction of adjacent endplates result in stresses that cause repeated localized flaking of protective films.

Q. *What signals the appearance of galvanic attack?*

Ans. Reduction in metal thickness in localized areas.

Q. *What is the usual location of this attack?*

Ans. In areas where steel is not homogeneous in composition and also near places adjacent to non-ferrous boiler mountings.

Q. *What is the cause of galvanic attack?*

Ans. Ferrous and non-ferrous metals in contact with an electrolyte or steel areas of non-homogeneous composition in contact with the electrolyte set up microunits of the galvanic cell wherein a potential differential is set up between the anode and cathode. The metal dissolves at the anode.

Q. *How can corrosion-fatigue responsible for boiler deterioration classified?*

Ans. They may be classified as

(a) corrosion-fatigue in tubes
(b) corrosion-fatigue in steam and water drums
(c) corrosion-fatigue in steam mains.

Q. *What does the corrosion-fatigue in tubes look like?*

Ans. It appears as a network or series of cracks over the tube surfaces in the waterside.

Q. *What is the usual location of corrosion-fatigue in tubes?*

Ans. In the hottest zone of boiler and superheater tubes and also frequently in inherently curved tube or tubes which got buckled due to prolonged operation.

Q. *What is the cause of this type of corrosion-fatigue?*

Ans. Non-uniform circulation of working fluid in tubes causing alternate overheating and cooling inducing thermal fatigue stress in the walls. Presence of residual stresses and a corrosive environment also accelerate this type of cracking.

Q. *What does corrosion-fatigue in steam and water drums look like?*

Ans. It appears as fissures covered under the layers of corrosion products. That's why they' re difficult to locate. It is usually associated with deep pitting.

Q. *What is the usual location of such types of attack?*

Ans. It starts at the arboring in tube plates, extends axially, eventually joining two or more holes.

Q. *What is the cause of fatigue-corrosion in steam and water drums?*

Ans. Bending stresses induced due to the lack of a common neutral axis between the wrapper plate and the tube coupled with excessive cold working due to initial rough machining operation are responsible for such a type of attack. It is accelerated by thermal stress and the presence of an aggressive environment.

Q. *What is the appearance of fatigue-corrosion in steam mains?*

Ans. It appears as lines of cracks on the bores of pipes.

Q. *What is the usual location of these type of cracks?*

Ans. Bores of steam pipelines particularly in the base of corrugations.

Q. *What is the cause of corrison-fatigue in steam mains?*

Ans. Bending stresses due to movement during operation. This is accelerated by the presence of a corrosive environment.

Q. *How can boiler deterioration at elevated temperatures be classified?*

Ans. It can be classified as
(a) high temperature oxidation
(b) bursts
(c) creep-cracking at high temperature

Q. *What is the appearance of high-temperature oxidation?*

Ans. It appears as a continuous layer of hard black scale of magnetic iron oxide.

Q. *Where is high temperature oxidation most prevalent?*

Ans. Internally it occurs in fire row and superheater tubes. It also occurs in drums and headers.

Externally it occurs on surfaces in direct contact with furnace gases.

Q. *What is the cause of high temperature oxidation?*

Ans. For internal attack, the poor circulation of the working fluid is responsible. Improper circulation results in overheating in a steam atmosphere.

For external attack, local flame impingement, poor circulation and scaling on the waterside are responsible.

Q. *What is the appearance of boiler deterioration in the form of bursts occurring at elevated temperatures?*

Ans. They appear as splits in the form of longitudinal gaps. These may or may not be associated with balloning.

Q. *Where do they usually appear?*

Ans. They usually appear in the hottest part of the evaporator and superheater tubes.

Q. *Why do they occur?*

Ans. Water starvation in the evaporator and steam starvation in the superheater tubes are chiefly responsible for tube bursts. They lead to overheating which deteriorates the mechanical properties of the tube material with the effect that the tubes burst even under working pressure.

Q. *What does the creep-cracking occurring at elevated temperatures look like?*

Ans. It appears as cracks and splits associated with layers of oxide scale on tube surfaces.

Q. *What is the usual location of such a type of attack?*

Ans. In superheater tubes.

Q. *What is the cause of such an attack?*

Ans. Overheating at around 550°C coupled with restricted expansion induces thermal stresses in the metal and they are accountable for creep-cracking at elevated temperatures.

Q. *It has been found in practice that boilers that had been in service for many years under normal operating conditions experienced no difficulty. But when they were greatly overloaded under increased demand, tube failures occurred. Why?*

Ans. These tube failures are due to creep-cracks at high temperature. At the higher ratings defective circulation of the working fluid develops in certain tubes, resulting in overheating of metal and that brings about creep, causing tube failure.

Q. *What morphological changes occur during this type of tube failure?*

Ans. Photomicrographs of the metal at points of greatest heating revealed the complete spheroidization of carbides. And also the masses of spheroids representing the original pearlitic grains were elongated in the direction of greatest stress. At temperature 650°C and above, low-carbon steels or completely spheroidized steel will recrystallize, in the presence of a critical strain.

Q. *Intergranular disintegration on the waterside of steam generating tubes has been reported in high pressure boiler units. What is the appearance of this intergranular corrosion?*

Ans. In the affected areas, layers of metallic copper, oxides of copper and black oxide of iron are found deposited. Beneath these deposits large corrosion pits are formed and beneath these pits severe deterioration of the metal in the form of intergranular disintegration takes place.

Q. *Wherefrom do metallic copper and its oxides appear?*

Ans. These are the corrosion products of the condenser and other heat exchanger tubes which are made of copper-alloy in general.

Q. *What agents accelerate intergranular corrosion?*

Ans. Dissolved gases like ammonia and carbon dioxide in the condensate accelerate this type of attack.

Q. *What role does copper play in stimulating intergranular corrosion?*

Ans. Copper deposits create an anodic condition beneath the black iron oxide resulting in corrosion of the metal and production of atomic hydrogen. This atomic hydrogen penetrates the steel, causing decarburization and intergranular corrosion.

Q. *Boiler-tube failures have been reported in certain cases where corrosion of the metal is found under an adherent formation of black iron oxide accompanied by embrittlement of the adjacent steel. What is the most apt designation of this failure?*

Ans. Corrosion embrittlement.

Q. *What is the mechanism of corrosion embrittlement?*

Ans. This type of corrosion is initiated by excessive heat or improper circulation of the working fluid resulting in the rise of metal temperature—not high enough for overheating but sufficient to cause film-boiling. Under this condition, water vapour dissociates and the metal reacts with oxygen producing a magnetic oxide film on the metal surface and liberating hydrogen

$$H_2O \longrightarrow 2H + O$$

$$2Fe + 3O \longrightarrow Fe_2O_3$$

As the corrosion propagates, the corrosion product deposited on the tube surface gets washed away and the tube cross-section gets thinner and thinner.

The hydrogen formed now penetrates the steel along the crystallographic planes or grain boundaries and reacts with the oxides, nitrides and carbides of steel to form gaseous products within the metal. As a result tremendous pressures are developed causing rupture of metal at the grain boundaries.

Moreover, if this corrosion proceeds sufficiently, the thinned tube portion becomes weakened enough not to withstand the high operating pressures of the boilers and may be blown out of the tube walls by the internal steam and water pressure.

Q. *It has been found that magnetic oxides, when allowed to accumulate, compact and adhere to the protective oxide films, can damage the latter. Why?*

Ans. Once the heavy magnetic oxides formation upon the protective oxide film has been established, the protective film gets penetrated with the effect that the resultant deposit, not being homogeneous, no longer protects the steel. This is followed by the attack of the metal by steam or water beneath the black iron oxide layer. The protective film is destroyed substantially and the corrosion rate is enhanced.

EROSION & CRACKS AT BOILER-DRUMS

Case Study—A NG-fired steam generating station has encountered unforeseen boiler drum problems in two of its four units—each fitted with Germany made single-drums having the same capacity.

All the 4 units of the boiler drums (ID = 2089 mm; Length = 10 516 mm; Wall thickness = 110 mm) having a capacity of 272 t/h operate at 9.65 MPa/783 K.

The Units 1 and 2 started three years prior to Units 3 and 4 developed very deep erosion and cracks at both dish ends of the steam drums. The other two drums continued trouble-free operation.

The cracks and eroded areas at various locations around the manhole were ground out whereupon the drums continued uneventful operation over the next decade. However, recent inspections of drums showed more cracks at different locations and considerable erosion on areas not ground during initial repair. Boiler drums of Units 3 and 4 surprisingly continue to sustain smooth operation as before showing no sign of cracks or metal loss.

All the four boiler drums have been receiving the same quality of BFW coming from a single DM Unit.

What is the genesis of this problem?

What precautions should be taken to protect boiler drums from this damage?

Ans. This type of problem of boiler drum erosion and cracks is an uncommon phenomenon and quite dangerous for a high-pressure boiler of this size.

The problem is very likely to be a typical case of stress corrosion cracking. Forasmuch as the erosion and cracking are only on the drum ends, the problem is almost certainly associated with the metallurgy of the heads*

* Water conditions in the drum might have contributed to the problem, but it could not be the only cause. The sound, trouble-free operation of Units 3 and 4 support this theory.

Obviously the metal in drums 1 and 2 differs from their head metal giving rise to a galvanic cell of some sort, while chemically treated feedwater acts as an electrolyte. A local action might have been set up in the drum and could have proceeded during outage when the boiler was hot-rinsed.

The original metal could be responsible too. Perhaps non-homogeneity of constituents generated erosion and corrosion cracks.

Preventive Measures

1. Checking of all water treatment records, right from the beginning for all boilers
2. Correcting WT programs to keep up to the specification
3. Checking whether Units 1 and 2 were subjected to more cycling than Units 3 and 4
4. A thorough examination by radiography or ultrasonics to ensure that no subsurface cracks/defects are present in boiler drums
5. The boiler manufacturer must be called back to get the metal analysis and history.

31

CORROSION OF FIRESIDE HEATING SURFACES

Q. *How can the fireside corrosion of heating surfaces in boiler units be classified?*

Ans. It can be classified as

(a) high temperature corrosion (600°C and above)

(b) low temperature corrosion (< 600°C)

Q. *How does the high temperature corrosion of heating surfaces on the fireside of the boiler unit take place?*

Ans. Corrosion of the waterwall tubes in the boiler furnace takes place in the zone of the flame core because of the attack of the tube-metal by sulphurous gases present in the combustion products.

Superheater tubes and their fastening elements experience damage of metal by the vanadium oxides present in the flue gases.

Q. *What kind of fuels give rise to corrosion on the fireside of waterwalls in the boilers?*

Ans. Pulverized coal (anthracites, semianthracite, lean coals) having very low yield of volatiles and fuel-oil with high sulphur content.

Q. *Which section of the waterwall tubes is most afflicted by corrosion of combustion gases?*

Ans. It is most predominant in the tubes section at the burner level or immediately above it.

Q. *What is the rate of corrosion of the metal surface in this zone of the tube surface?*

Ans. It may be as high as 2.5–4mm per annum rendering waterwall tubes, usually 5 to 6 mm thick, out of service in less than a year.

Q. *What is the main corrosion-active component in the furance gases?*

Ans. It is hydrogen sulphide.

Q. *What is the mechanism of hydrogen sulphide corrosion of tube metal?*

Ans. It proceeds via following steps:

1. **Chemical reaction of the tube metal with H_2S**

$$Fe + H_2S \longrightarrow FeS + H_2$$

2. **Oxidation of ferrous sulphide layer**

$$FeS + 2O_2 \longrightarrow FeSO_4$$

3. **Flaking-off of ferrous sulphate** The ferrous sulphate layer produced on the tubewall surface flakes off due to erosion exposing the fresh tube metal to further corrosion (Fig. 31.1)

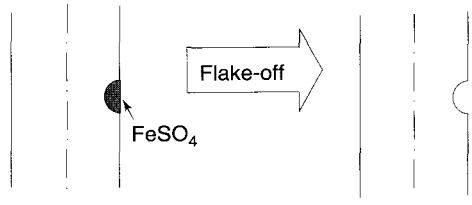


Fig. 31.1 *Ferrous sulphate flakes off as a result of hydrogen sulphide attack.*

Q. *How can damage due to corrosion of the external surface of waterwall tubes by hydrogen sulphide be avoided?*

Ans. An effective way is to mix and distribute evenly the fuel and air between the burners so that excess air ratio in each burner is always greater than unity. This will reduce the chances of formation of zones deficient in oxygen where hydrogen sulphide attack is likely to take place.

Burners should be aligned to keep off the flame from direct heating of the waterwall.

Q. *What is vanadium corrosion?*

Ans. It refers to the attack of superheater tubes by the vapours of vanadium pentoxide formed in the furnace gases.

If the fuel contains sodium, the furnace gases will contain, among other, sodium vanadate ($Na_2O \cdot 5V_2O_5 \cdot V_2O_4$)—a low fusing compound (m.p. $\approx$ 600°C) forming a thin film of corrosive liquid on the superheater tube surface at 610–620°C. This film attacks carbon, low-alloyed and austenitic steels.

Q. *Do the oxides of sulphur have any influence on vanadium corrosion?*

Ans. Yes. It is augmented by the presence of oxides of sulphur in the flue gases. Particularly dangerous is sodium pyrosulfate ($Na_2S_2O_7$). The corrosivity of V_2O_5 increases manifold in combination with the oxides of sulphur.

Q. *How can vanadium corrosion be reduced?*

Ans. It can be reduced in two ways.

(a) Keeping the superheater temperature below 600°C (873 K)
(b) Dosing alkaline additives to fuel oil.

Q. *What are these alkaline addivites?*

Ans. For instance, $MgCl_2$ added in amount 0.6 to 0.8 kg per ton of fuel oil.

Q. *Where does the low temperature corrosion occur?*

Ans. It occurs on the heating surfaces of the air heaters only.

Q. *Why does this corrosion take place?*

Ans. This corrosion takes place due to the attack of the metal by sulphuric acid vapour in the flue gases.

Q. *How does sulphuric acid vapour form in the flue gas flow?*

Ans. The sulphur present in the fuel is oxidized to sulphurous anhydride during the combustion of fuel

$$S + O_2 \Leftrightarrow SO_2$$

The sulphur dioxide so produced gets further oxidized to sulphur trioxides (sulphuric anhydride) by atomic oxygen

$$SO_2 + O \rightleftharpoons SO_3$$

In the zones where temperature drops below 500°C, the sulphur trioxide reacts with water vapour and produces sulphuric acid vapour which

$$SO_3 + H_2O \longrightarrow H_2SO_4$$

is carried off by the gas stream.

Q. *How is the atomic oxygen available in the boiler furnace to oxidize SO_2 to SO_3?*

Ans. It is produced by the chain reactions of combustion and thermal dissociation taking place in the high-temperature zone of the flame.

Q. *But the formation of SO_3 from SO_2 is an exothermic reaction. So how will it be formed in the high temperature zone where atomic oxygen is available?*

Ans. Because of the exothermic nature of the reaction

$$SO_2 + \frac{1}{2}O_2 \Leftrightarrow SO_3$$

the sulphur trioxide that appears noticeably on the boundary of the flamecore dissociates completely on completion of combustion.

However, its concentration is regained as the temperature in the gas path decreases gradually so that at gas temperatures 1200–1250°C (1473–

1523K), the dissociation of SO_3 ceases almost totally.

Apart from atomic oxygen, the presence of soot particles deposited on the heating surfaces may serve as a catalyst to oxidize SO_2 to SO_3 by oxygen in excess air.

Q. *What is dew point?*

Ans. It refers to the temperature at which moisture condenses on a solid surface. It is also called thermodynamic dew temperature.

Q. *Has it any significance regarding corrosion on the fireside of heating surfaces?*

Ans. Yes. If the dew point of sulphuric acid vapour in its partial pressure in the flue gases is reached, a film of highly corrosive sulphuric acid will settle on the tube surfaces and corrode the metal.

Q. *What is the dew point of sulphuric acid vapour?*

Ans. It is roughly in the range 140°–160°C (413–433K).

Q. *What is the effect of temperature on the rate of acid corrosion, on the heating surfaces in contact with flue gases produced by combustion of high-sulphur fuel oil?*

Ans. This can be best understood with the help of the **rate of corrosion** ($g/m^2.h$) vs. **temperature** curve. (Fig. 31.2)

As the curve shows, the intensity of corrosion is very pronounced in two temperature ranges—one at 60–80°C (333–353K) and the other at 90–120°C (363–393K).

As the wall temperature decreases from 145°C (418K, dew point) the corrosion rate increases sharply, reaches a maxima in the temperature range 100–110°C (373–383 K) and then drops steeply, reaches a minima at 80°C (353 K) and again rises sharply at wall temperature below 80°C (353 K).

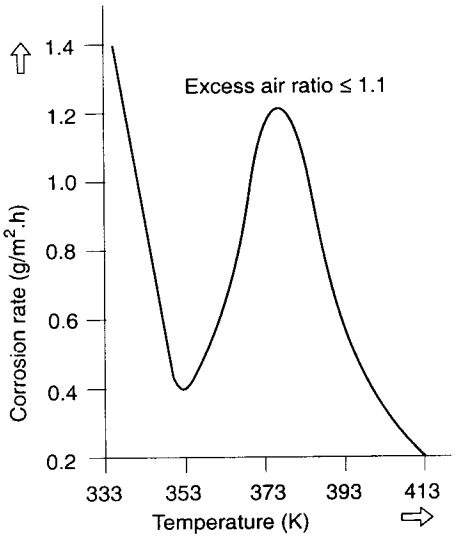


Fig. 31.2 *Acid corrosion as a function of temperature of heat transfer surface.*

Q. *Why does the intensification of corrosion take place in the 60–80°C (333–353 K) range?*

Ans. It is due to the dissolution of metal by sulphurous acid condensing on heating surfaces in this temperature range

$$H_2O + SO_2 \longrightarrow H_2SO_3$$

Sulphurous acid is an unstable acid dissociating at temperature above 80°C (353 K).

Q. *Why does intensive corrosion take place in the temperature range 90–120°C (363–393 K)?*

Ans. It is mainly due to the attack of H_2SO_4 condensing on the metal surface. The rate of corrosion increases with the increase of the rate of condensation of H_2SO_4 vapours.

Q. *It has been observed that the rate of corrosion initiated by the oxides of sulphur at 80–120°C (353–393 K) is much less if lowest allowable excess air is maintained. Why?*

Ans. When lowest allowable excess air is supplied to ignite the high sulphur fuel oil, the combustion gases contain a much higher percentage of SO_2 than SO_3.

Since sulphur dioxide-corrosion is prevalent at temperatures less than 80°C (353 K), because of the thermal instability of sulphurous acid

$$H_2SO_3 \longrightarrow H_2O + SO_2$$

flue gases containing a lesser percentage of SO_3 and consequently lesser amount of H_2SO_4 that would otherwise initiate intensive corrosion in the temperature range 80–120°C (353–393K), become less aggressive in this temperature range. (Fig. 31.3)

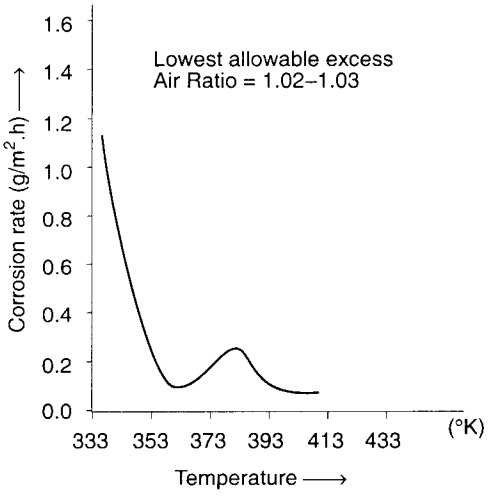


Fig. 31.3

For preventing dewpoint corrosion during boiler shutdown see APPENDIX–III.

Q. *What is the effect of chlorine in coal?*

Ans. It contributes to the corrosion of coal-fired boiler systems.

Q. *How is chlorine present in coal?*

Ans. It is present in coal in three major forms:

- Inorganic chlorides
- Organochloride
- Chloride ions in brine and other waters ingressed into the body of coal

XAFS (X-ray-Absorption and Fine-Structure) spectroscopic study has revealed that for most US coals, chlorine is present in the form of Cl^- ions in the moisture infiltrated into the microcracks and pores in coal. And in other cases the presence of chlorine has been identified in the form of crystalline NaCl precipitated from the chlorine-rich solution as coal is dried.

Q. *What is chlorine concentration in coal?*

Ans. Its varies from country to country, one coal mine to another and even within the same basin.

British coal contains an average of 0.25% Cl (by wt.) which can extend up to 0.8%.

US Appalachian coal contains on an average 500 ppm of Cl. All western coal basins average less than 200 ppm. Coal in the southern, northern and central parts of the Appalachian basin have Cl concentrations of 308 ppm, 855 ppm and 954 ppm respectively.

Q. *Do chlorides in coal accelerate fireside corrosion in boilers?*

Ans. Yes.

Q. *What happens to the chlorides when coal is burned?*

Ans. The chlorides are released as hydrogen chloride (HCl) during the combustion process.

Q. *What is the mechanism of corrosion induced by the chloride content of coal when the latter is fired in a boiler?*

Ans. The chloride tied to coal is released as hydrogen chloride when the coal is burned. HCl gas is highly corrosive above 530°K.

Addition of oxygen (always present as excess air is always supplied) to HCl increases the corrosion rate by an order of magnitude.

Gas temperature in the superheater/reheater regions of 500 MW boilers ranges from 870°K to 925°K. In this temperature range, HCl promotes the release of sodium and potassium from coal-ash. Both then react with the gaseous sulphur to form sulphates.

The Na, K sulphates deposit on relatively colder heat transfer surfaces downstream. Sulphate deposition can lead to thick ash build-up. The outer surface of these deposits may become

hot enough to generate a high SO_3-partial pressure, leading to the formation of a molten-alkali sulphate layer at the metal surface. This molten mass of alkali-sulphate is very corrosive and that is how HCl brings about indirect corrosion-damage; but it is directly related to the Cl-content of coal.

Q. *How much HCl is released when chloride containing coal is burned?*

Ans. About 80 ppm of HCl is released for each 0.1% of Cl in coal.

Q. *How can corrosion associated with high-Cl coals be overcome?*

Ans. The solution is to use a thicker-than-normal frontwall when mild steel tubes are used.

Another good option is to use high-chromium AISI 310 with 1% niobium extruded over carbon steel.

Also, use can be made of plasma spray coatings containing 50% Cr and 50% Ni. They have been reported to limit corrosion rates provided careful attention is paid to maintain the quality of the spraying process.

Q. *What is the effect of reducing atmosphere containing hydrogen sulphide on chloride corrosion?*

Ans. In reducing environment, HCl is known to diffuse through the protective metal oxide to attack the base metal to form volatile iron chlorides. Such an attack contributes to intergranular corrosion and promotes cracking in the oxide scales.

Reducing regions are usually localized within the furnace and are very difficult to control.

Q. *In which regions of the furnace HCl attack under reducing conditions is prevalent?*

Ans. The evaporator tubes are mostly affected.

Q. *What is the remedy to this problem?*

Ans. The most practical solution lies in the improvement of tube material only in the affected areas.

Q. *What is the effect of temperature on Cl-induced corrosion?*

Ans. At temperatures $\geq 1170°K$ virtually no Cl-related corrosion attacks. But at lower temperatures (825°K–925°K), considerable chloride attack is known to occur on the protective oxide-surface layer of metal.

However, at temperatures below 343°K–low enough to humidify HCl vapour and to form an aqueous acidic condensate—the Cl-related backend corrosion becomes significant.

Q. *What about chloride attack in the fluidized bed combustor?*

Ans. The reports of British Coal's research facility at Cheltenham reveal the following findings for FBCs (fluidized-bed combustors).

1. Corrosion and deposition are not directly linked to the Cl-content of coal
2. No serious superheater corrosion in FBCs despite high Cl-content of British coals
3. Negligible corrosion and deposition for evaporator tubes
4. In reducing environment, as sometimes occur close to coal feedpoints, the combination of sodium sulphate (Na_2SO_4) and sodium chloride (NaCl) can corrode superheater tubes. Inbed tubes are worst affected. The risk of this attack mounts as the FBC goes to operate with lower excess air to combat NO_x pollution.

Q. *What are the effects of coal-chlorides on FGD (flue gas desulphurization) systems?*

Ans. In wet FGD systems, the effects are all negative. Higher Cl-content of coal leads to higher HCl build up:

(a) causing corrosion problems
(b) affecting scrubber efficiency by reducing alkalinity of suspended water-droplets meant for absorbing SO_2/SO_3 vapours.

In dry FGD systems, the effects of HCl are both positive and negative:

(a) HCl in the flue gas improves SO_2 removal capabilities resulting in lower reagent costs
(b) The addition of an amount of calcium chloride equivalent to a 0.2–0.3% rise in Cl-content, reduces lime consumption by 25%.

However, these benefits must offset the following negative effects:

(a) Incomplete droplet drying,
(b) Corrosion of stainless steel components of the system,
(c) Higher ΔP downstream of fabric filters,
(d) Degraded performance of ESP.

Q. *Is there any precombustion Cl-removal system from coal?*

Ans. There is one method, though costly

(a) Grinding the coal to a fine powder
(b) Slurrying the powder in hot water.
(c) Settling the mass in a tank and allowing the overflowing liquid drain away.
(d) Air-drying the solid.

This technique leaches out most of the chloride content in coal.

Note The cost of precombustion coal treatment for Cl-reduction may justify the option for using improved materials of construction of evaporators and superheaters to resist chloride attack.

Q. *Can the flyash reduce SO_2-SO_3 corrosion?*

Ans. Yes; provided it contains certain basic metals like calcium, magnesium, sodium, etc. These are basic in nature, and will react with acidic SO_2/SO_3 to form chemical compounds and reduce their harmful effect.

Q. *What should be the wall temperature to avoid low temperature corrosion?*

Ans. The wall temperature should be always 10–15°C higher than the sulphuric acid dew point. (Fig. 31.3)

32

EVAPORATORS

Q. *What is an evaporator?*

Ans. It is a boiler auxiliary where generation of steam takes place.

Q. *Where is it located?*

Ans. The evaporating surfaces, also called steam-generating surfaces, are always laid out for the most part within the shaft of the furnace.

Q. *What kind of heat does it absorb?*

Ans. Radiant heat (mainly).

Q. *How much of the total heat released in the furnace is absorbed by the waterwalls of the evaporator?*

Ans. 30–60% of the total heat released in the furnace.

Superheated Steam		BFW Temp.	Heat Distribution		
Pressure	Temp.		Evapo-rator	Super-heater	Econo-mizer
4 MN/m^2	713°K	418°K	60%	20%	20%
10 MN/m^2	813°K	488°K	49%	30%	21%
14 MN/m^2	843°K	503°K	32–39%	36–46%	22–25%

Q. *Why is the economizer of medium pressure (4 MN/m^2) generally of the boiling type?*

Ans. It is because the total heat demand (62%) for generating steam is too high to be covered by the radiant heat absorbed by the evaporator's heating surfaces. Hence a part of the heat spent on water evaporation is transferred to the economizer wherein water is, therefore, not only heated to the saturation temperature but also partially vapourized.

Q. *Why can the economizer of high-pressure (14 MN/m^2 or more) drum-type boilers be of the non-boiling type?*

Ans. In these cases the fraction of the heat utilized for steam generation in the evaporator is considerably less. As a result the total radiant heat absorbed by the evaporating surfaces in the furnace shaft is enough to produce the required quantity of steam and so the economizer can be of the non-boiling type.

Q. *What forms the evaporating surfaces of evaporators?*

Ans. Boiler-water tubes arranged in the furnace shaft in the form of waterwalls constitute the evaporating surfaces. They absorb radiant heat.

Q. *How many types of waterwalls are used in practice?*

Ans. They may be

(a) smooth or bare tubes in design (Fig. 32.1A)
(b) gas-tight with finned tubes (Fig. 32.1B)
(c) gas-tight with welded-on-rectangular finned tubes. (Fig. 32.1C)
(d) smooth tubes with intertubular space filled with building-up metal (Fig. 32.1D)

Q. *Where are the bare-tube waterwalls employed?*

Ans. In all boiler systems fitted with balanced draft furnaces.

Q. *How are the waterwalls arranged in natural circulation boilers?*

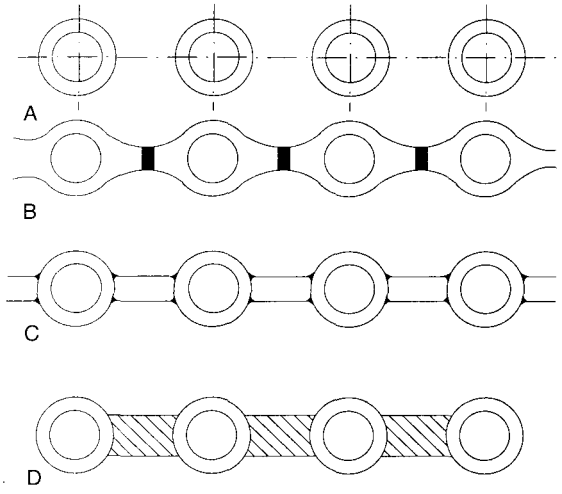


Fig. 32.1 *Different types of waterwall tubes*

Ans. They are laid out in the furnace shaft almost exclusively in vertical pattern or at a steep angle.

Q. *How are the waterwalls arranged in once-through and multiple forced circulation boilers?*

Ans. They can be oriented within the furnace space at any angle, i.e. the waterwalls may be horizontal, vertical or ascending-descending.

Q. *What are the causes of non-uniform heating of the waterwalls of evaporators?*

Ans. The principal cause of non-uniform heating is the slagging of tubes. Since slagging is never uniform over the entire evaporating surface of the waterwalls, heavily slagged and consequently poorly heated tubes receive less heat than clean tubes. That is why the slagged tubes develop a lower driving circulating head than clean tubes with the effect that less cooling (circulating) BFW passes through them. Being cooled inadequately, such slagged tubes may become over-heated in the tube portions free from slag.

Secondly, the uneven heating across the width of the waterwalls of the circulation circuit may be due to an improperly designed circulation circuit or due to clinkering or misalignment of some tubes. Tubes in the middle of a furnace wall generally receive about twice as much radiant heat as absorbed by the corner tubes. Besides, tubes around the burner port and those at a certain height from the port are not directly exposed to the radiant heat of the flame, i.e. they turn out to be shaded.

Sometimes some tubes become misaligned when tube fastenings get loosened. Protruded from tube rows, these off-rank tubes receive more heat than the adjacent tubes.

Q. *How can the circulation ratio be increased to improve the operating conditions of waterwalls?*

Ans. This can be done by increasing the cross-section of the downtake tubes. This will reduce the hydraulic resistance in the downtake (descending) tubes and ensure a higher flowrate of water through the uptake tubes as well as through the slagged (poorly heated) tubes—uptake and downtake as well. Therefore, a more or less uniform circulation head is established.

Q. *How is waterwall sectionalizing?*

Ans. It is a system that combines a group of waterwall tubes heated similarly into a section which is fed separately with BFW.

Q. *Why is this done?*

Ans. To avoid uneven heating of evaporating tubes. (Fig. 32.2)

The corner waterwall tubes cannot develop the same useful head $S_{usf} = \Delta P_{des}$ (i.e. the pressure drop in descending tubes) as do the middle waterwall tubes because the former receive substantially lesser heat than the latter ones. Therefore, circulation stagnation or circulation reversal is likely to appear in these corner tubes. However, if this bunch of corner tubes can be sectionalized into a separate circulation circuit by

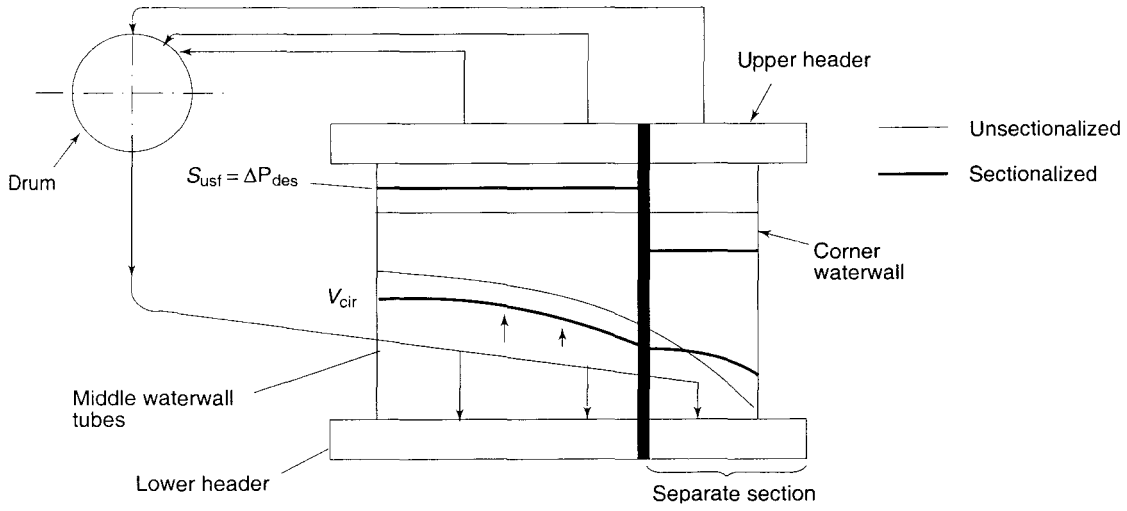


Fig. 32.2 *Waterwall sectionalizing is intended for avoiding uneven heating of evaporating tubes.*

placing partitions in the upper and lower headers, the circulation velocities in the two circuits—one comprising the middle waterwall tubes and the other, corner tubes—can be roughly equalized. And for the same non-uniformity of heating across the width of the waterwall, the useful circulation head in the separated section will decrease somewhat but the margin to circulation stagnation and circulation reversal will enlarge considerably.

Q. *What kind of waterwall is applied in gravity circulation boilers?*

Ans. Usually bare-type waterwalls.

Q. *What are the dimension of waterwall tubes in high pressure boilers?*

Ans. ID: 40–50 mm of uptake tubes.

ID: 60–160 mm of downtake tubes.

Downtake tubes may be much larger (ID: 600–800 mm) for high capacity boilers.

Q. *What is the arrangement of waterwalls in the furnace of a high pressure boiler?*

Ans. Front-, rear- and side-waterwalls comprise of a system of parallel vertical tubes. All the upper headers are mounted approximately on the same height and suspended from the boiler structure, i.e. the boiler structure carries the suspended waterwall system. (Fig. 32.3)

The entire waterwall tube system is attached with movable rigidity belts of steel, which on heating, can move freely with the tubes.

Q. *How are the waterwalls arranged in once-through boiler units?*

Ans. They are arranged either horizontally or vertically.

Q. *What is the pattern of layout of horizontal waterwall tubes in once-through boilers for enhancing the reliability of operation?*

Ans. For enhancing circulation reliability, the waterwall tubes must be more or less uniformly heated. In a horizontal layout, the evaporating tubes are wound around the periphery of the furnace so that if one of the furnace sides is heated more intensively than the others this non-uniformity of heating will have no ultimate effect. Since all tubes are wound on all the sides of the furnace, any degree of non-uniform heating across the width or depth of the furnace will be distributed equally in all parallel sides.

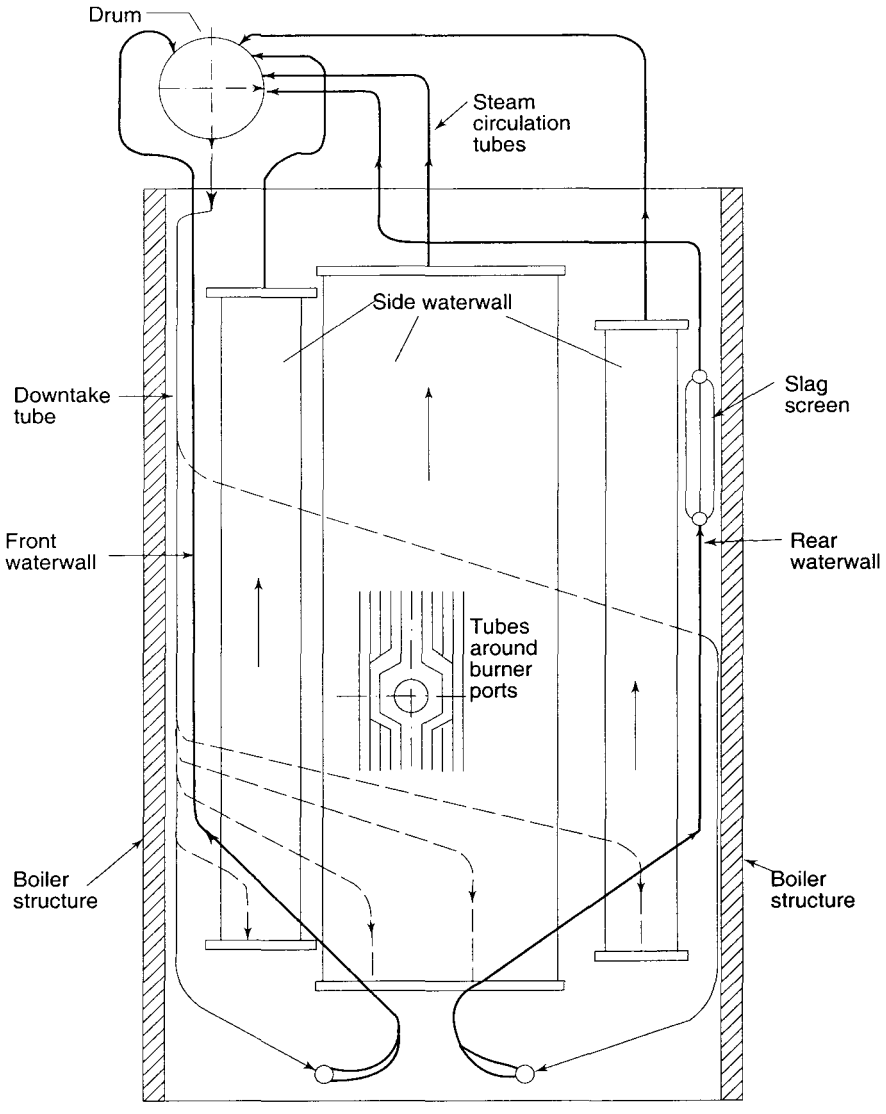


Fig. 32.3 *Layout of waterwalls in the furnace of a high pressure boiler.*

For high capacity boilers, the evaporating tubes are divided into a number of parallel tube bands which are arranged in the furnace, i.e. the mainstream of boiler feedwater is divided into a number of parallel flows. The parallel bands of two side waterwalls are slightly inclined (12°–15°) while the front and rear waterwalls are laid horizontally. (Fig. 32.4)

Q. *Why for high-capacity high-pressure once-through boilers with horizontally arranged waterwall tubes, are the tubes arranged in a number of parallel tube bands?*

Ans. For high-capacity, high-pressure boiler units, the waterwall tubes are made of small diameter (ID: 25–40 mm) to economize on the tube mass.

But because of high-capacity, the number of parallel tubes must be increased to maintain the same mass flowrate. The greater number of tubes and smaller tube diameter make it necessary that the width of the tube band should be increased and with wider tube band the uneven heating along the height of the furnace in the parallel tubes of a band becomes increasingly prominent. For this reason, the waterwall tubes are divided into a number of parallel tube bands and the mainstream of the feedwater flow is divided into a number of parallel flows which are fed to the system of parallel tube bands.

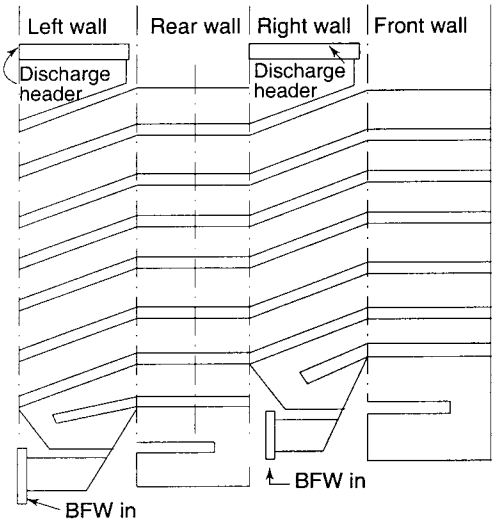


Fig. 32.4 *Layout pattern of horizontal waterwall in once-through boiler units.*

Q. *How are the vertical waterwalls in once-through boiler units arranged?*

Ans. They are arranged similar to those in gravity circulation boilers. They are laid up on the whole surface of the furnace walls and are sectionalized across the furnace width for more uniform heating. These individual sections are joined in series through downtake tubes to result in a multipass system. (Fig. 32.5)

For high-capacity, once-through vertical boiler units, the narrow vertical waterwall tubes are

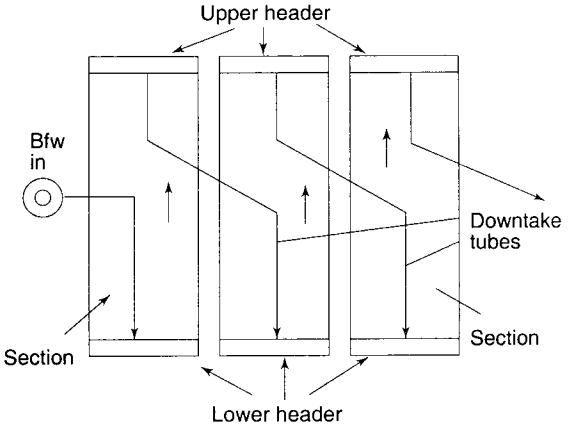


Fig. 32.5 *Layout pattern of vertical waterwall in once-through boiler units.*

sectionalized into parallel bands. These parallel bands are connected with one another in series. (Fig. 32.6)

Q. *How are the waterwalls in a gas-tight boiler arranged?*

Ans. They are arranged in the form of vertical sections.

Q. *What is the most important requirement for gastight waterwalls for reliable operation?*

Ans. The basic requirement is that the temperature difference of the working fluid in the adja-

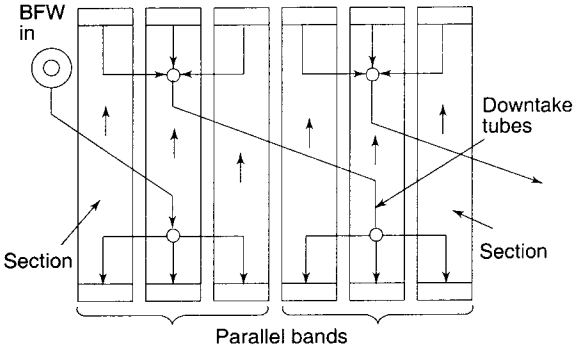


Fig. 32.6 *Sectionalizing of vertical waterwall tubes for high-capacity, once-through boiler units.*

cent tubes (for a single-pass scheme) or between adjacent section ($\theta'_2 - \theta'_1$) and ($\theta_2 - \theta_1$) (for a two-pass scheme) should not exceed 50–100°C. (Fig. 32.7)

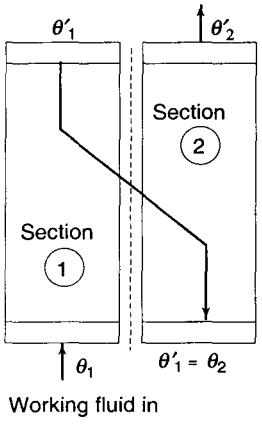


Fig. 32.7 *All-welded 2-Pass waterwall.*

Measures are taken to keep the temperature difference ($\Delta\theta$) between welded sections as low as possible. (Fig. 32.8)

Q. *If these measures are not taken what will happen?*

Ans. The welded sections will develop excessive temperature stresses that may even lead to the break through of tubes.

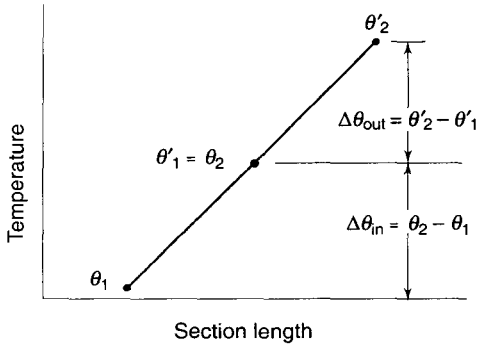


Fig. 32.8

Q. *What measures are taken to reduce the temperature difference between adjacent sections to below 50–100°C?*

Ans. The following methods are adopted in practice:

1. intermixing of the working fluid along its path
2. cold flow by-passing
3. recirculating the combustion products
4. recirculating the working fluid.

Q. *How does cold flow by-passing ensure the reduction of $\Delta\theta$ between welded sections?*

Ans. This is done by by-passing a portion of the cold flow, i.e. a portion of the working fluid is bypassed around the 1st section of the heated waterwall tubes. (Fig. 32.9). This results in a higher outlet temperature of the working fluid from the 1st-section because of the increased heat absorption per unit flowrate. Therefore, the temperature difference between the welded sections [$\Delta\theta_{out} = \theta'_2 - \theta'_1$] is effectively reduced. (Fig. 32.10)

Q. *How much quantity of working fluid is bypassed?*

Ans. It is determined by the ratio of the mass velocities of the working fluid and the heat release rate in the furnace. It is roughly equal to 20% of the rated load.

Q. *How can $\Delta\theta$ between the welded sections be reduced to an allowable limit by recirculating the working fluid?*

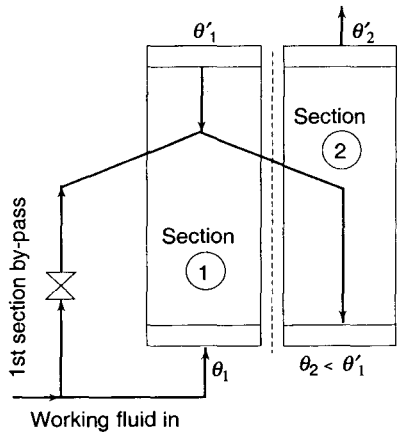


Fig. 32.9 *Cold flow bypassing.*

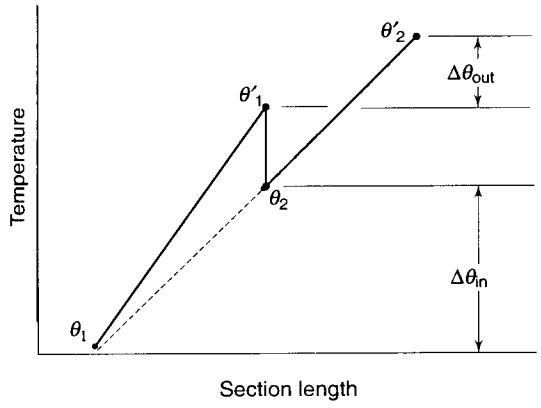


Fig. 32.10 *Cold flow bypassing reduces effectively the temperature difference between the welded sections*

Ans. This is done by drawing a portion of the hot working fluid from the exit of the 2nd section and feeding it to the stream at the inlet to the 1st section. (Fig. 32.11)

Therefore, the temperature of the working fluid at the inlet to section (1) is raised and that reduces the gain in the enthalpy of the working fluid. Therefore, the margin between θ_1 and θ_2 is reduced, i.e. $\Delta\theta_{IN}$ is decreased to a safe value. (Fig. 32.12).

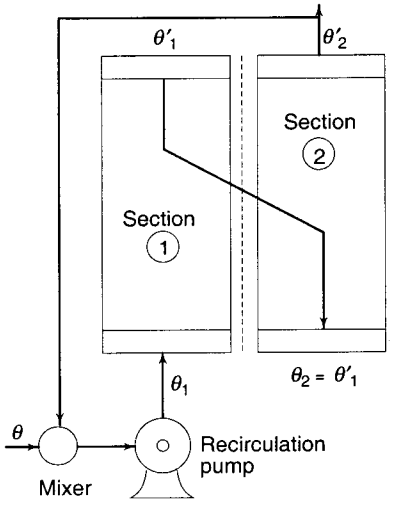


Fig. 32.11

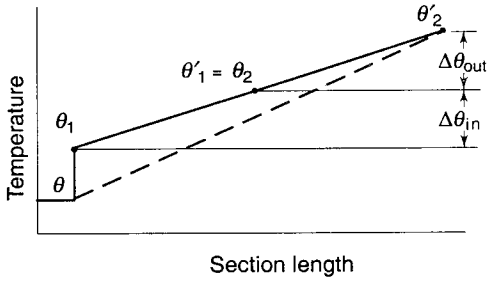


Fig. 32.12 *Working fluid recirculation reduces effectively the temperature difference between the welded sections.*

Q. *On which factor does the temperature conditions of adjacent sections of waterwalls depend?*

Ans. These depend on the recirculation ratio.

Q. *What is recirculation ratio?*

Ans. It is the ratio of the mass flowrate of the working fluid with recirculation (G_r) to the mass flowrate of the working fluid without recirculation (G), i.e.

$$r = \frac{G_r}{G}$$

Q. *How does it influence the temperature difference between adjacent welded sections?*

Ans. As the recirculation ratio increases, i.e. G_r increases, the temperature at the inlet of section (1), i.e. θ_1 increases. Therefore, for the same heating intensity, the $\Delta\theta_{IN}$, i.e. $(\theta'_1 - \theta_1)$ between two adjacent welded section decreases. So higher the value of r, lower will be the temperature difference between the adjacent sections. This can be better understood from the $\Delta\theta$ vs. r curve. (Fig. 32.13)

Q. *What is the additional advantage of the method of recirculation of the working fluid?*

Ans. It makes start-up possible at low loads.

Q. *At how much low-load does it ensure start-up?*

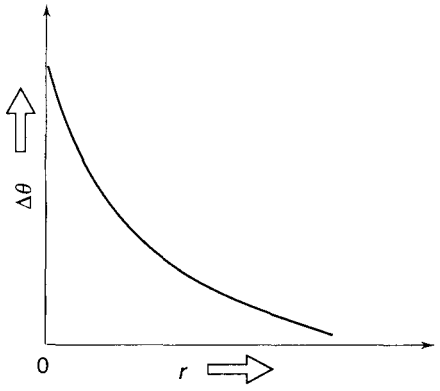


Fig. 32.13 *Temperature difference between the adjacent welded sections decreases with the increase of recirculation ratio.*

Ans. As low as 15% of rated load with recirculation.

Q. *Why does start-up occur at 15% of the rated load?*

Ans. Because this system ensures reliable cooling of the waterwalls at low-loads during start-up when the furnace is lighted up with fuel oil having a high heat release rate.

Q. *Why are the vertically laid waterwalls of high-capacity boilers divided vertically into stages by parting joints and connected with one another by mixing headers?*

Ans. To avoid the risk of non-uniform heating which may be dangerous.

For high-capacity boilers, waterwall tubes are intensively heated in the furnace and so with the increase in tube length the rate of heat absorption increases and with that, the probability of maldistribution of heat increases. For this reason the waterwalls of high-capacity boilers are divided vertically into stages.

As a result of this separation, the increase in enthalpy of the working fluid in each stage decreases and that brings down the highest temperature of the tube walls.

Q. *How does the recirculation of the combustion products ensure reliable operation of waterwalls?*

Ans. Recirculation of the gaseous products of combustion taken off the zone at a lower temperature (350–380°C) downstream of the economizer and injected to the furance zone of high temperature dilutes the oxidant in the zone of high heat release rate and prolongs the combustion process. As a result, the heat release rate reduces and furnace temperature decreases and therefore, the probability of maldistribution of heat in the tubewalls reduces.

Q. *What are the plus points of gas-tight all-welded waterwall tubes over bare-tube waterwalls?*

Ans. Gas-tight all-welded waterwall tubes require less mass per unit area of radiant heat-absorbing surface than that of bare-tube waterwalls.

The fins of the welded waterwalls lend themselves as active heating surfaces and they transfer heat to the working fluid, increasing the rate of heat absorption.

The fins welded to the gas-tight waterwalls behave like good clamps holding the tubes perfectly in-line. Therefore, the probability of misalignment of tubes, which may occur in the bare-tube waterwalls is practically nil. Since misalignment is absent no tube can shadow the other.

Gas-tight waterwalls compared to bare-tube waterwalls have relatively a thin refractory layer and therefore can be waterwashed without risk of moistening the heat-insulating surface. Hence, corrosion that may take place in inaccessible places is minimized.

Q. *Why is uniform heating of all-welded gas-tight waterwall tubes more essential than that of bare-tube waterwall?*

Ans. It is because non-uniform heat distribution between the adjacent welded tubes will develop substantial thermal stresses on the welded fins which may fail.

Q. *If the uniformity in heat distribution between the all-welded gas-tight waterwalls of high-capacity boilers is sought by increasing the number of separate flows what complications may arise?*

Ans. It will

(a) complicate the automatic control
(b) increase the number of fittings
(c) tell upon the reliability of operation of waterwalls increasing the temperature difference between welded tubes
(d) increase the number and mass of unheated tubes, causing a sharp rise in the hydraulic resistance of the circuit.

Q. *So how can this uniformity in the heating of gas-tight waterwalls of high capacity boilers be ensured?*

Ans. By increasing the number of passes connected in series.

Q. *Where are the refractory-faced waterwalls mounted?*

Ans. These are placed in the zones of intensive combustion, such as slagbottom furnaces, cyclone furnaces and in boiler furnaces that burn low volatile fuels.

Q. *How many types of refractory-faced waterwalls are used in practice?*

Ans. There are three types of refractory-faced waterwall:

1. Smooth-tube (vertical waterwall) (Fig. 32.14)
2. Membrane-type (vertical waterwall) (Fig. 32.15)
3. Platen wall (Fig. 32.16)

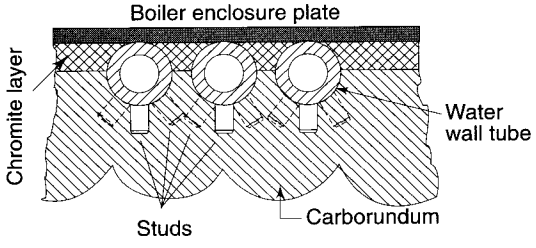


Fig. 32.14 *Smooth-tube (vertical waterwall).*

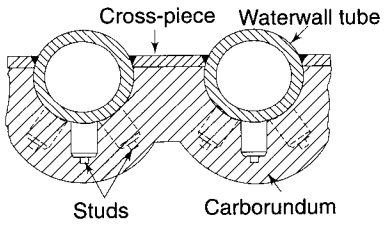


Fig. 32.15 *Membrane-type (vertical waterwall).*

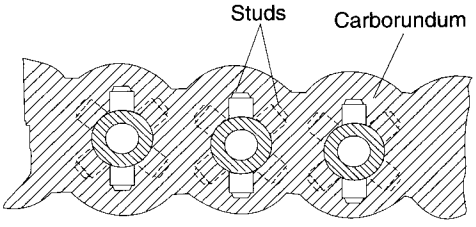


Fig. 32.16 *Platen wall.*

Q. *How are refractory-faced waterwall made?*

Ans. These are made from metal tubes welded with studs (10–12 mm diameter and 15–25 mm in length) that form the frame for holding a refractory paste made of carborundum or chromite. The refractory facing is compacted by means of a pneumatic hammer to ensure better contact of the refractory with the surfaces of the studs and the tubes. Heat is transferred from the refractory face to the watercooled tube directly as well as through the studs.

For more about refractories & their installation procedure, please turn to APPENDIX–III

Q. *Why is the chromite facing sometimes covered on the fireside by a layer of carbondum paste?*

Ans. To impart a higher resistance to slag attack.

Q. *Does the amount of heat absorption by refractory-faced waterwalls depend on the number of studs?*

Ans. Yes; it increases with the increase of the density of the stud arrangement.

Q. *What do you mean by the term "stud density"?*

Ans. It is the ratio of the total cross-sectional area of all studs per unit surface area of the waterwall tubes.

Q. *What is the stud density for high-capacity boilers?*

Ans. It varies from 0.15 to 0.25.

Q. *What factor delimits the stud density?*

Ans. It is the technological feasibility of stud welding.

Q. *How does the temperature vary across the refractory-faced waterwall?*

Ans. The temperature distribution across the refractory-faced waterwall is illustrated by the accompanying figure. (Fig. 32.17)

Q. *What problem is commonly encountered with refractory-faced waterwalls?*

Ans. It is the burn-off of the refractory facing and the studs as they are subjected to high operating temperature conditions.

Q. *On what factors does the life of a refractory faced waterwall depend?*

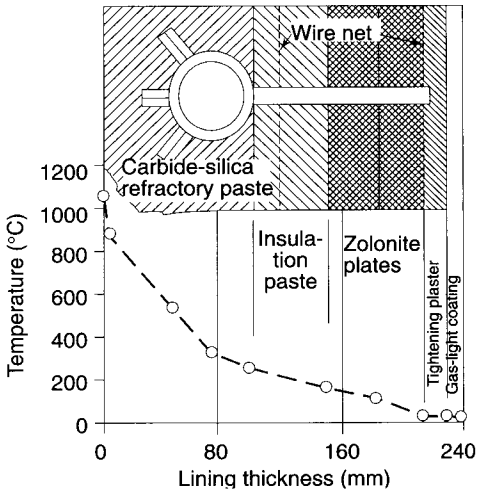


Fig. 32.17 *Temperature distribution across the refractory-faced waterwall.*

Ans. There are several factors:

1. temperature conditions of the furnace
2. thermal conductivities of the refractories
3. refractoriness of the refractory material
4. contact resistance between the refractory facing and the metal
5. size and shape of the studs
6. material of the studs
7. nature of the slag.

33

SUPERHEATERS

Q. *What is a steam superheater?*

Ans. It is a boiler auxiliary designed to superheat saturated steam produced in the evaporator to a specified temperature.

Q. *How are superheaters classified?*

Ans. Depending on the mode of heat transfer from the furnace to superheater surfaces, the superheaters are divided into:

(a) CONVECTIVE SUPERHEATERS which absorb heat mainly by convection
(b) RADIANT SUPERHEATERS which absorb radiant heat from the flame in the furnace core
(c) PLATEN SUPERHEATERS that absorb both radiant and convective heat.

Q. *Where are these located?*

Ans. **Convective superheaters** are placed in the convective gas duct.

Radiant superheaters are arranged on the furnace walls.

Platen superheaters are mounted on the top of the furnace and partially in the flue gas duct between the convective and radiant heating surfaces.

Q. *How many kinds of superheaters are deployed?*

Ans. Two kinds:

1. Primary superheater
2. Intermediate superheater.

Q. *What is the function of primary superheater?*

Ans. To superheat the saturated steam produced in the evaporators.

Q. *What is the function of intermediate superheaters?*

Ans. It is to reheat the turbine-exhaust steam to a superheat temperature once more.

Intermediate superheaters are also called reheaters.

Q. *What is called superheating?*

Ans. Production of steam at a temperature higher than the saturation temperature is called superheating.

Q. *What is degree of superheat?*

Ans. It is the temperature imparted to steam above its saturation temperature at a given pressure.

Q. *How can the condition of superheat be expressed?*

Ans. This can be done in two ways:

1. in terms of the degree of superheat for a given pressure
2. the actual temperature and pressure of the steam.

Q. *When does the significance of the term 'superheat' fail?*

Ans. At steam pressure above the critical point. Because, beyond this point no saturation steam exists, so the term superheat is no longer applicable.

Q. *Why is superheated steam less erosive and corrosive than wet, saturated steam?*

Ans. Wet, saturated steam carries water droplets but superheated steam has no entrained moisture

and as such the latter is less erosive and corrosive than the former.

Q. *Why are desuperheaters also installed with superheaters?*

Ans. Mainly due to two reasons:

1. to control the superheated steam temperature by injecting DM water to superheated steam
2. to produce saturated steam to run the boiler auxiliaries.

Q. *If saturated steam is charged to the boiler auxiliaries for their operation, then why is steam not directly taken from the boiler drum?*

Ans. If the wet, saturated steam used for running the boiler auxiliaries is directly taken from the steam drum, then the superheater may not receive as much steam as is required for the necessary cooling of its coils. This phenomenon is called **superheater starvation** and may lead to superheater tube failure. To avoid this problem, the entire saturated steam separated in the boiler drum is charged to the superheater and then a part of the output steam is desuperheated, according to requirements, for running the boiler auxiliaries.

Q. *Why is saturated steam, not superheated steam used to run small boiler auxiliaries?*

Ans. The use of superheated steam requires more stringent measures to be adopted regarding close clearances, special lubrication, expansion control, etc. which mean higher construction costs.

Q. *On which factors does the ratio of the superheating surface to boiler convection surface depend?*

Ans. 1. Fuel burned
2. Steam temperature as required.

Q. *Why is the installation of convective superheater alone not favoured in large steam generation units with high superheat demands?*

Ans. For generating steam with a high degree of superheat, in a large steam generation plant, the use of convective type superheater alone is rather impractical because of two fundamental reasons:

1. Convective superheaters are not befitted for high degree of heat absorption as are radiant superheaters. As a result, much of the generated heat in the boiler furnace is lost to flue gases escaping at higher temperature. This means loss of overall performance of the steam generation plant.
2. Due to the problem of slagging, the flue gas temperature at the furnace exit is fixed and furnace parameters should be controlled so as not to allow the flue gas temperature to exceed this limit. The use of a convective superheater alone in a large steam generation unit will not allow the flue gas exit temperature to be brought down below the prescribed limit.

Q. *What factor(s) cause the vulnerability of a radiant superheater?*

Ans. Overheating.

Q. *What factors contribute to the overheating of radiant superheaters?*

Ans. 1. Vulnerability during start-up.
2. Deposition of scale on the steam-side of superheater coils impairing heat transfer.
3. Flame impingement directly upon the superheater coils.

Q. *How can flame impingement be avoided?*

Ans. By

1. burner adjustment
2. tilting the burner
3. increasing the distance between the burner and the radiant superheater surface
4. proper flame control.

Q. *How can the failure of radiant superheater coils due to scale formation on the steam-side be prevented?*

Ans. The only solution is to enhance steam purification before it is charged to the superheater.

Q. *When may the possibility of superheater tube burnout arise?*

Ans. It will occur under conditions where there is insufficient steam flow to cool the superheater tubes adequately and such conditions may arise:

1. DURING START-UP: until or unless steam generation begins and steam flows in to protect the superheater tubes, the heat absorbing surface of the radiant superheater is cooled by radiation to the waterwall tubes. Now if steam flow fails to be established in the superheater tubes or a series of tubes while the furnace attains the operating temperature, there is a chance of tube burnout in the superheater.
2. NON-DRAINABLE SUPERHEATER: if a portion of the superheater is not completely drainable, then it will hold some quantity of steam condensate when the superheater is under shutdown. Now when the superheater is taken in line, there will be no flow of steam through the superheater circuit until this stored condensate evaporates or is blown out. Because of stoppage of steam flow, the superheater will starve, causing tube burnout.
3. IMPROPER DESIGN: if the areas adjacent to burner ports are not properly designed, it may give rise to deflection of the flame which in turn may strike the superheater tubes causing burnouts.

Q. *In which cases are separately fired superheaters installed?*

Ans. Separately fired superheater is installed in cases where

(a) absolute control of the temperature of process steam is required
(b) high degree of superheat is to be maintained in the process steam at a distance considerably far away from the SGP battery limit
(c) process plants or turbo-alternators require a higher steam superheat temperature than can be maintained in the existing steam generation plant
(d) process requires steam of high temperature (870 K and above) without regard to pressure.

Q. *What factors influence the design of convective superheaters?*

Ans. 1. Flue gas velocity
2. Steam velocity
3. Temperature difference between the flue gas and steam
4. Direction of gas flow—parallel or cross-flow.
5. Cleanliness of the tubes.

Q. *Which factors primarily influence the design of radiant superheaters?*

Ans. 1. Temperature of the furnace
2. Temperature of steam
3. Amount of heat absorbing surface exposed to radiant heat
4. Cleanliness of the tube surface.

Q. *What is the tube dia of convective superheaters?*

Ans. The ID of convective superheater tubes varies from 20 to 30 mm.

Q. *What is the material of construction of convective and radiant superheaters?*

Ans. They are made from high-alloyed Cr-Ni austenitic-class steel. A few typical compositions being:

	Cr	Ni	W	Mo	Ti	Nb	B	Fe	*Working Temperature*
1.	13–15	13–15	2–3	0.45–0.6	—	—	—	rest	up to 925°K
2.	17–19	11–13	—	—	0.65	—	—	rest	-do-
3.	15–17	15–17	2–3	0.5–1	—	0.5–1	0.005	rest	up to 980°K
4.	15–17	12–15	2–3	—	—	1–1.3	0.005	rest	-do-

For more about Materials of Construction see APPENDIX–III.

Q. *Why are these made from the austenitic-class of steel?*

Ans. It is because the austenitic-class of steels have high heat and corrosion resistance.

Q. *How does it gain higher corrosion resistance?*

Ans. It is due to the presence of high content of chromium. Chromium metal produces a hard and impervasive layer of Cr_2O_3 on the tube surface exposed to flue gas. This prevents further penetration of oxygen or corrosive gases to the base metal and thus resists high temperature corrosion.

Q. *Why are titanium and niobium added?*

Ans. To prevent austenitic-steels from intergranular corrosion.

Q. *How do titanium and niobium prevent austenitic-steels from intergranular corrosion?*

Ans. These metals (Ti, Nb) are strong carbide-forming elements. They can combine with the entire available carbon and bind it into their carbides and thus prevent the formation of chromium carbides precipitates at the boundaries of the austenitic grains.

Q. *Why are molybdenum and tungsten added?*

Ans. These elements when alloyed with austenitic steels impart to the latter, higher heat resistance.

Q. *Why do molybdenum and tungsten impart higher heat resistance?*

Ans. They from strong compounds, Fe_2Mo and Fe_2W, which are highly dispersed throughout the matrix of the austenitic steel, thus imparting to the latter higher heat resistance.

Q. *Finned tubes absorb more heat than smooth tubes. Yet superheaters are usually made from smooth tubes. Why?*

Ans. It is because smooth tubes are

(a) much less expensive than finned tubes.
(b) much simpler to manufacture
(c) easier to clean
(d) less prone to fouling by ash.

Q. *What is the main drawback of smooth tube superheaters?*

Ans. They suffer from lower heat absorption capacity at moderate flue gas velocities.

Q. *What is the ID of the reheater tubes?*

Ans. It is larger than that of convective superheater tubes and may be upto 50 mm.

Q. *Why are the reheater tubes made substantially larger in diameter?*

Ans. Since the reheater steam pressure (3–4 MN/m^2) is not high, it is required that the hydraulic resistance of the reheater should not be high. That is why reheater tubes are made of substantially larger diameter.

Q. *Why is the reheater arranged in a zone of moderate heating?*

Ans. It is because if the reheater is placed in a high temperature zone, the intensive heating of the external surfaces of the reheater tubes can lead to an inadmissible rise to temperature due to a low value of the coefficient of heat transfer from the inner wall to the steam. This may turn out to be too high for the pearlitic class of steel from which reheater tubes are made.

Q. *Why will the temperature be too high for the pearlitic class of steel from which reheater tubes are made?*

Ans. Pearlitic class of steel is low-alloyed steel. They do not contain tungsten or a sufficient quantity of molybdenum to gain higher heat resistance property. Since they also lack titanium and niobium—the stabilizing elements—higher heating temperature may lead to intercrystalline corrosion due to chromium carbide precipitation.

Q. *What is the material of construction of reheater tubes?*

Ans. These are made of low-alloyed pearlitic-class steels.

	Cr	Mo	V	Si	Nb	B	Fe	*Operating Temperature*
1.	1–1.25	1–1.2	0.15–0.3	–	–	–	rest	up to 855°K
2.	1.5–2	0.5–0.7	0.2–0.4	0.4-0.7	–	0.005	rest	-do-
3.	2–2.5	0.5–0.7	0.2–0.4	–	0.5-0.8	–	rest	-do-

Q. *However placing the reheater tubes in the moderate temperature zone will decrease the overall heat transfer to the steam requiring higher surface area of the tubes, which may be economically unfavourable. So what can be done to overcome this problem?*

Ans. The overall heat transfer to the steam in the reheater can be substantially raised even in the moderate temperature zone by designing the reheater tubes into internally finned or rifled tubes. (Fig. 33.1B). This will extend the internal surface area of the tubes and will intensify the rate of heat transfer. (Fig. 33.1)

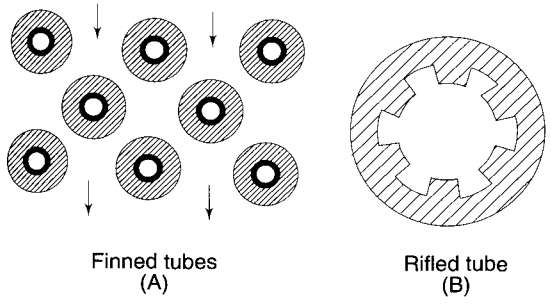


Fig. 33.1

Q. *How many types of superheater coils are used?*

Ans. These may be single pass or multi-pass. Multipass tubes may again be divided into:

(a) 2–pass (Fig. 33.2C)
(b) 3–pass (Fig. 33.2D)
(c) 4–pass (Fig. 33.2E)
(d) glove-type multi-pass tubes. (Fig. 33.2A)

Q. *How many types of convective superheaters are known?*

Ans. Depending upon the direction of motion of steam and combustion products in a convective superheater, the superheaters may be divided into

(a) counterflow type (Fig. 33.3A)
(b) parallel-flow type (Fig. 33.3B)
(c) mixed-flow type (Fig. 33.3C and 33.3D)

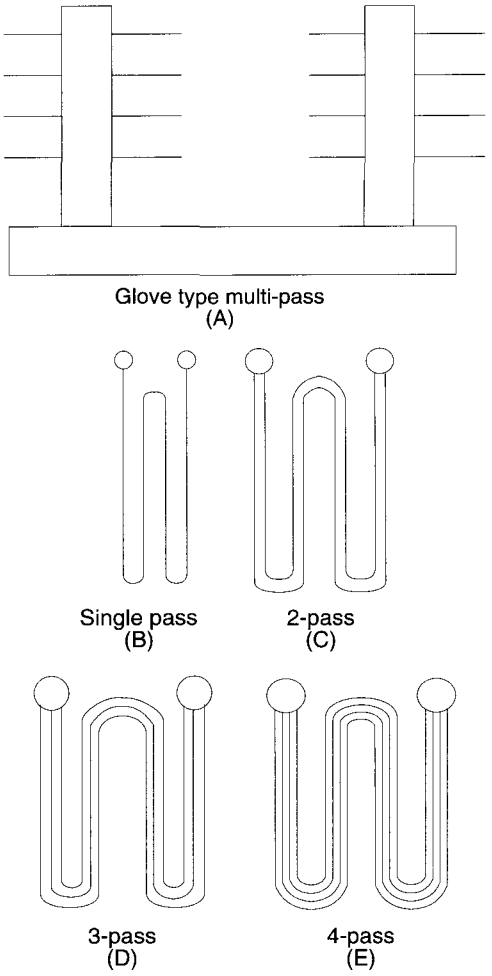


Fig. 33.2 *Different types of superheater coils.*

Q. *Out of these three types of convective superheaters, which one develops the highest temperature gradient between the combustion products and steam?*

Ans. The counterflow type superheater.

Q. *What is the main drawback of this type of convective superheater?*

Ans. It is the problem of burn-through of the last coils at elevated temperatures.

Q. *Why does this occur?*

Ans. This occurs due to the fact that both the working fluid (steam) and the combustion products are at the highest temperature here, subjecting the tube metal to a very demanding temperature condition.

Q. *Out of these three types of convective superheaters, which one has the lowest temperature gradient between the combustion products and steam?*

Ans. Parallel-flow superheater.

Q. *Why does the parallel-flow superheater have the lowest temperature gradient between the combustion products and steam?*

Ans. Here the superheater tube metal is exposed to the most favourable temperature conditions because the tube coils at the outlet which have steam at the highest temperature are in contact with the flue gases which have already been partially cooled at the inlet section of the superheater.

Q. *What about the mixed-flow superheater?*

Ans. It strikes a good balance between counterflow and parallel-flow superheaters, i.e. temperature gradient is not too high, nor is the cost economically unfavourable.

Q. *How can the superheater coils be arranged?*

Ans. Either vertically or horizontally (Fig. 33.4)

Q. *What are the advantages of vertical superheaters over horizontal superheaters?*

Ans. Vertical superheaters are much less intricate in design, as regards their fastening, than horizontal superheaters.

They arrest less slag than their horizontal counterparts.

Q. *What is the chief disadvantage of vertical superheaters?*

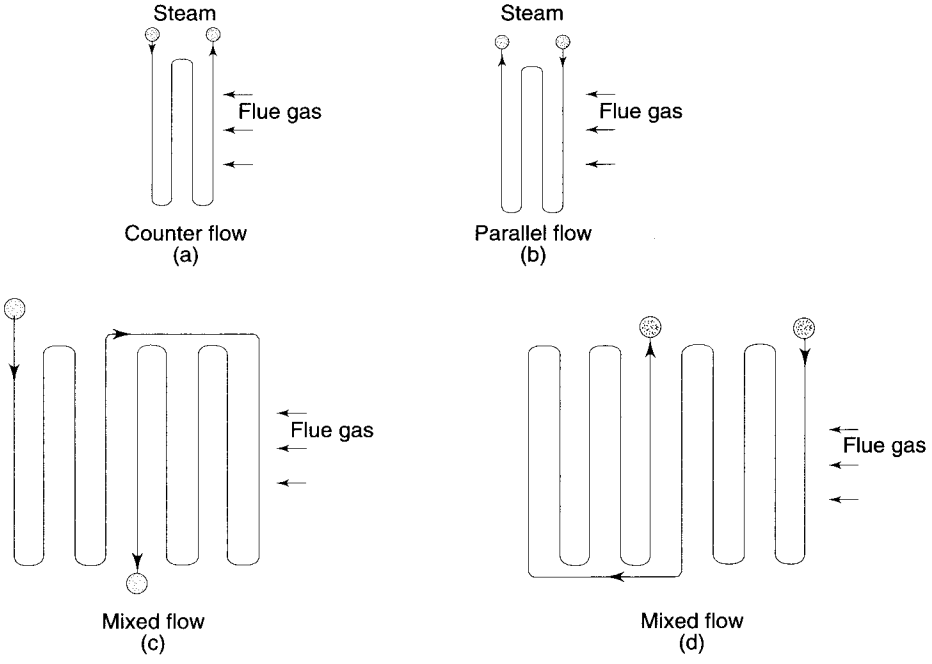


Fig. 33.3 *Different types of convective superheaters.*

Ans. The main drawback is that these are undrainable, i.e. the condensate cannot be completely drained off the circuit. And this may lead to internal corrosion of tubes and create certain technical difficulties during boiler firing.

Q. *Can the condensate from a horizontal superheater be completely drained?*

Ans. Yes.

Q. *Where is the radiant superheater located in once-through boiler units?*

Ans. It is usually located on the furance roof and the walls of the horizontal flue duct.

Q. *Where is the radiant superheater of a drum-type boiler unit located?*

Ans. On the furnace roof, if the heating surface of superheater is not too large. Otherwise it is placed partly on the vertical walls of the furnace.

Q. *What are the advantages of radiant superheaters over convective superheaters?*

Ans. 1. Fewer elements are required than in convective superheaters
2. Better access to tubes
3. They have low hydraulic resistance in the steam-path and low resistance on the gas side
4. Ensure better furnace cooling and that reduces furnace temperature and maintenance
5. Over the entire load range 25–100%, the steam temperature characteristics remain substantially horizontal.

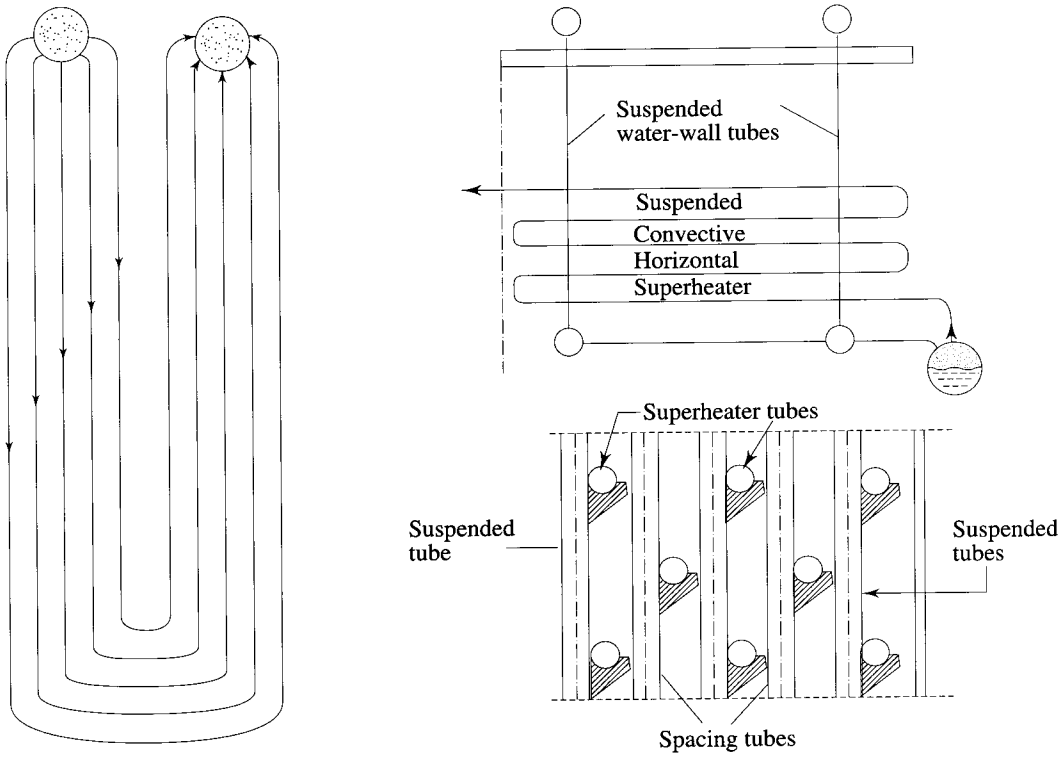


Fig. 33.4 *(a) Superheater coils laid out vertically (b) Superheater coils arranged horizontally.*

Q. *Why do radiant superheaters offer much lower resistance on the gas side than convective superheaters?*

Ans. Convective superheaters are placed directly in the path of flue gases which must come in contact with convective superheater tubes to transfer heat by the process of convection. Whereas radiant superheater coils are arranged on the furnace walls. They receive heat by radiation from the flame. They do not obstruct the flow of combustion products and hence offer less resistance to the flue gas stream.

Q. *What is the reason behind the high thermal efficiency of platen superheaters?*

Ans. It is because they absorb both radiant and convective heat.

Q. *How much of the total heat of superheating is absorbed by platens?*

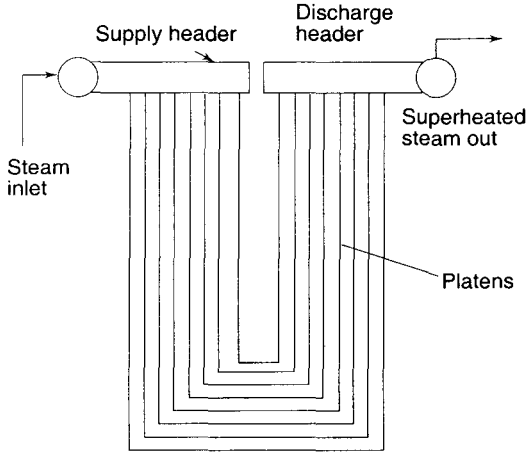


Fig. 33.5 *Platen*

Ans. As much as 50% of the total heat of superheating.

Q. *What is a platen?*

Ans. A platen is an assembly of smooth tubes* set into the pattern of a flat-gastight band with inlet and outlet headers. (Fig. 33.5)

* (finned tubes have been tested)

Q. *How are platens arranged?*

Ans. They can be arranged either horizontally or vertically with a spacing of 500–1000 mm between them.

Q. *Since platens operate under lower temperature conditions, they may suffer from slagging problems. How is this problem tackled?*

Ans. The ash deposition problem is taken care of by the platens themselves. Softened ash particles that deposit and solidify on the surface of the platens form loose deposits which are self-cleaned due to vibration. Therefore, ash deposits cannot grow to an appreciable thickness.

However for boilers fired with high-slagging fuel grades, dense deposits can be a problem on platen surfaces.

Q. *Are all the tubes of the platens uniformly heated?*

Ans. No. Front tubes are much more strongly heated than other tubes.

Q. *What can be the outcome of this?*

Ans. The heavily heated external tubes may turn out to operate under critical conditions.

Q. *How can the reliability of operation of platens, therefore, be enhanced?*

Ans. These can be done by either of the three methods.

1. Shadowing the external tubes from intensive heating by a system of tubes of some other heating surfaces carrying working fluid at much lower temperature. (Fig. 33.6)

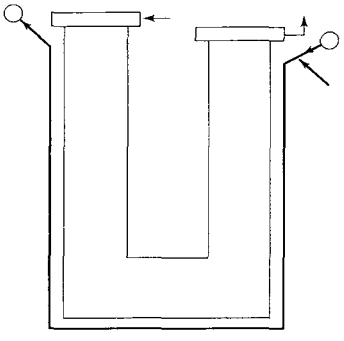


Fig. 33.6

2. Shortening the length of the external tubes. (Fig. 33.7)
3. Enlarging the diameter of the tubes operating under the heaviest conditions. (Fig. 33.8)

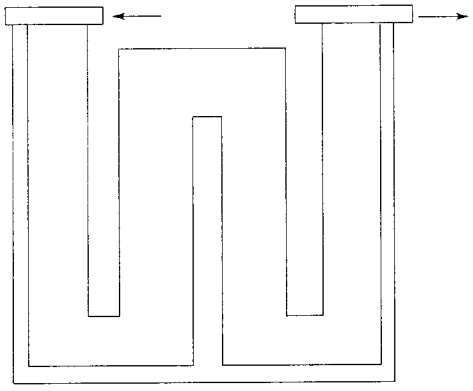


Fig. 33.7

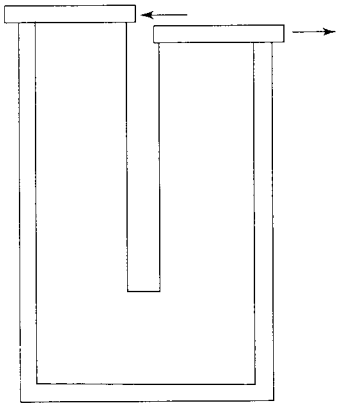


Fig. 33.8

Q. *Why is the superheater temperature not allowed to rise substantially over the upper limit of the rated value?*

Ans. To avoid superheater tube failure due to creep and scaling.

Creep is a physical phenomenon characterized by plastic deformation under the action of constant load at an elevated temperature. As the temperature is increased, the rate of creep is increased precipitating the premature rupture of superheater tubes.

Scaling leads to the thinning of metal tubes and is aggravated by the intensive heating loads or high stresses due to pressure in tubes.

Q. *What is the service life of superheater tubes for reliable operation?*

Ans. About 15 years.

Q. *How much is the service life of superheaters affected with the rise of temperature above the rated value?*

Ans. A 15 to 20°C rise in operating temperature over the rated value of the superheater can cut short the service life of a superheater by half.

Q. *In which cases is the risk of rise of superheater temperature over the rated (average) value maximum?*

Ans. In the cases of superheaters fitted to high-capacity boilers because of higher heat absorption of the superheaters.

Q. *Why is the risk of rise of superheater temperature over the rated value maximum in the case of superheater fitted to high capacity boilers?*

Ans. The superheaters of high-capacity boilers are placed in the gas ducts having a large area of cross-section. And therefore, for horizontal ducts, superheater tubes are heated extremely uneven over the width and height of the ducts while for vertical ducts they are unevenly heated over the width and depth of the ducts. That is, non-uniform heating of superheater tubes occurs along the length of the duct for horizontal superheaters and along the height of the gas duct for vertical superheaters.

Q. *How can this non-uniform heating of superheater tubes across the width of the gas duct be diminished?*

Ans. This can be done by sectionalizing the superheater across its width as well as along the length of the duct. This is achieved by transferring steam in a cross-over manner, as shown. (Fig. 33.9A and 33.9B)

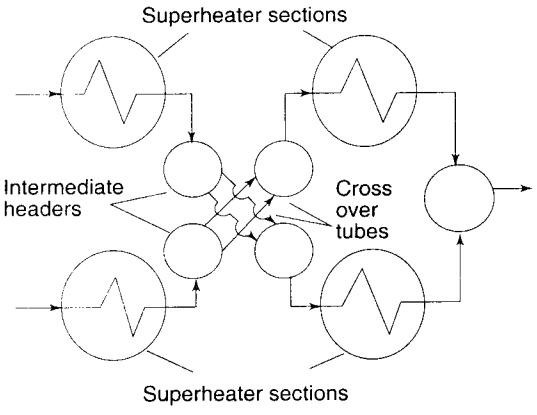


Fig. 33.9(a)

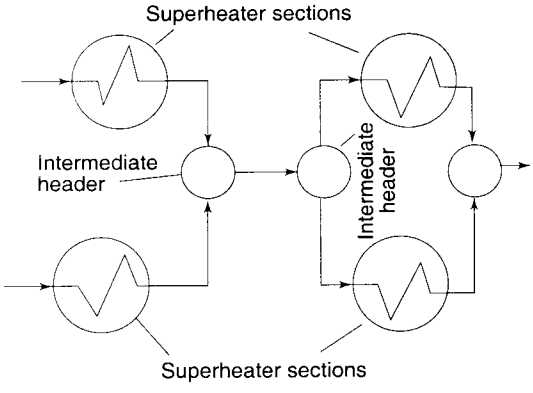


Fig. 33.9(b)

Q. *What factors determine the location of superheaters in the flue gas duct?*

Ans. There are two important parameters that chiefly determine the position of the superheater in the gas duct. These are arrangement of evaporator and steam parameters.

Q. *How does the evaporator arrangement determine the position of superheater in the case of medium-pressure boilers?*

Ans. For medium-pressure boilers with operating pressure 4MPa (4 MN/m^2) and superheated steam temperature about 710–715°K, the evaporating surfaces occupy the lion's share of the furnace space since they absorb 60–62% of the total heat absorbed in the boilers. Therefore, the superheater which absorbs 20% of the total heat absorption is of convective type and occupies a position immediately behind the membrane wall. (Fig. 33.10)

Q. *Where is the superheater of a high-pressure (P = 10 MPa, i.e. 10 MN/m^2 and θ_{ss} = 810-815°K) boiler located?*

Ans. In this case the superheater is composed of: roof superheater which is partly radiant partly convective:

a radiant platen superheater and a convective superheater.

The platen section is arranged in the upper section of the furnace and in front of the rear waterwall tubes. (Fig. 33.11)

The convective section is located in the horizontal portion of the gas duct.

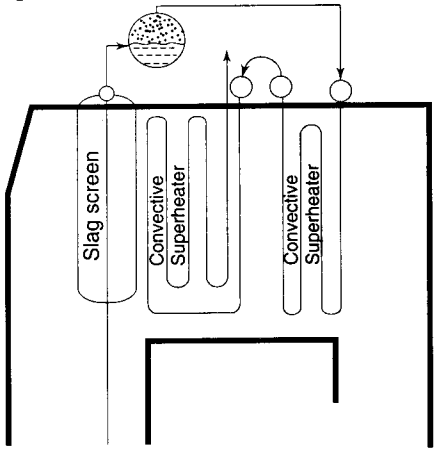


Fig. 33.10 *Layout of superheaters in the case of medium pressure boilers. They are of convective type.*

All the three sections are connected in series. And steam from the boiler drum is fed to the superheater in the following sequence:

Steam → Roof superheater → Platen section
↓
Convective section

Q. *How are the superheaters positioned in the case of high-pressure (P = 14 MPa, i.e., 14 MN/m^2 and θ_{ss} = 820°K) boilers?*

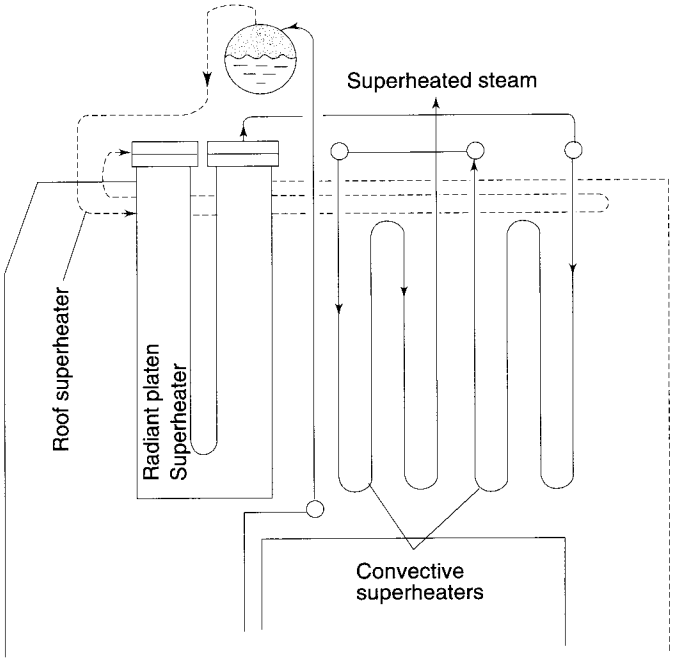


Fig. 33.11 *Convective superheaters are located in the horizontal portion of the flue gas duct.*

Ans. The superheater layout is the same as in the case of 10 MPa/θ_{ss} = 810°K superheater; besides, one reheat superheater (called reheater) is added in the convective shaft of the flue gas duct (Temp 1120°K) (Fig. 33.12)

Q. *Why is the radiant section of the superheater connected to the steam path first in the sequence,* i.e.

Steam Drum — steam → **Radiant Superheater**

Convective Superheater ← steam —┘

Ans. The radiant section of the superheater operates under the most heavily heated conditions. So it runs the greater risk of the tube surface temperature exceeding the rated value. Hence it must be adequately cooled to keep tube metal temperature within the upper limit of the admissible temperature. That is why saturated (relatively much colder) steam is fed to the radiant superheater straight from the steam drum rather than the superheated steam from the convective section of the superheater. By this method, the reliability of operation of superheater tubes is enhanced.

Q. *What is necessary to regulate the temperature of superheated steam?*

Ans. 1. To perform load changes
2. To alter operating variables.

Q. *Why is the term "control" applied to mean the regulation of superheated steam temperature?*

Ans. When it is required to put into effect load changes and carry-out corrections for the operating variables without changing the equipment to provide the desired superheated temperature, it is called control.

Q. *How are load changes controlled?*

Ans. By
(a) changing the number of boilers in operation
(b) varying the number of burners in line
(c) varying the rate of fuel burning.

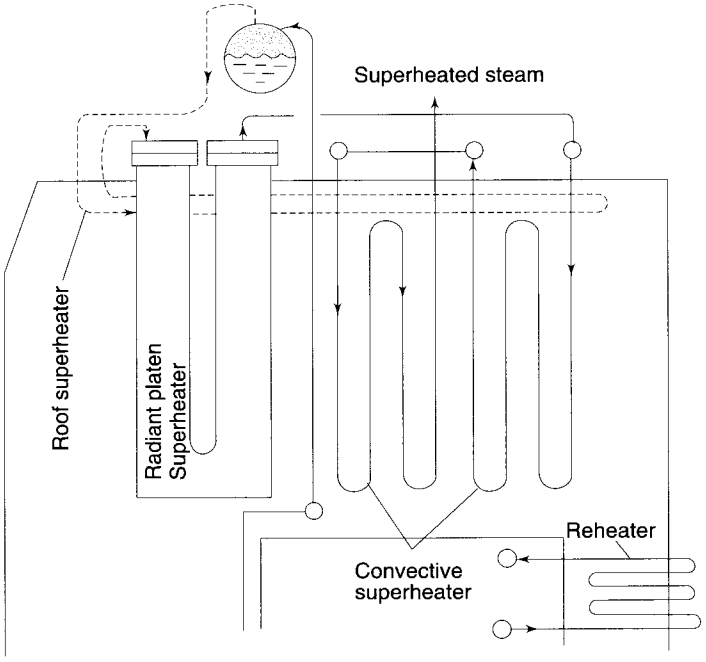


Fig. 33.12 *A reheater is introduced into the convective shaft of the flue gas duct over and above the existing convective superheater.*

Q. *How can the operating variables be controlled?*

Ans. By the method of:

(a) excess air control
(b) gas recirculation
(c) gas by-pass control
(d) adjustable burner control
(e) control of combined radiant-convective superheaters
(f) control of superheat with sootblowers
(g) control of differently fired twin furnaces
(h) control of separately fired superheaters.

Q. *How does the method of excess air control provide the desired temperature to the superheated steam?*

Ans. If the excess air supply is increased, the superheated steam temperature at the exit of the convective superheater, operating at partial load, will increase. This is because, as more excess air is introduced the furnace heat absorption decreases, for the same steam generation rate, while the gas mass flowrate increases with its increased total heat content that goes to raise the degree of superheat. (Fig. 33.13)

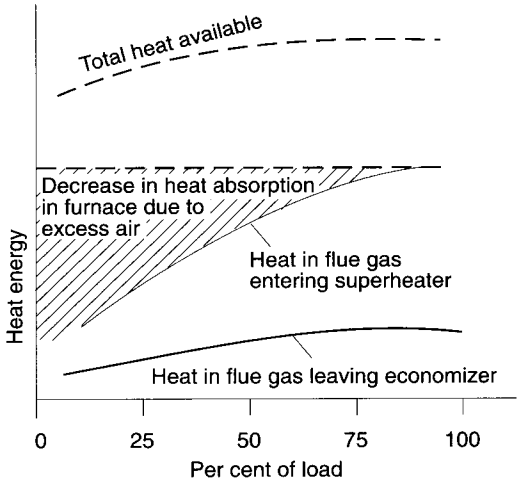


Fig. 33.13 *Excess air supply raises the superheated steam temperature at the outlet of convective superheater.*

However, the radiation superheater responds conversely when excess air flow is increased because of the dilution of flame emissivities of the combustion products in the furance.

Q. *How does the gas recirculation method serve to control the superheated steam temperature?*

Ans. Recirculation of a portion of the combustion products to the furnace increases the mass flowrate of the flue gases through the convective superheater and that increases the superheated steam temperature at the outlet of the convective superheater. Therefore, by regulating the percentage of recirculating combustion gases, the desired superheat steam temperature can be maintained (Fig. 33.14)

Q. *At which point of the furnace are the recirculating gases introduced?*

Ans. The hot gases are introduced below the combustion zone.

Q. *What are the advantages of the gas recirculation method of superheat control?*

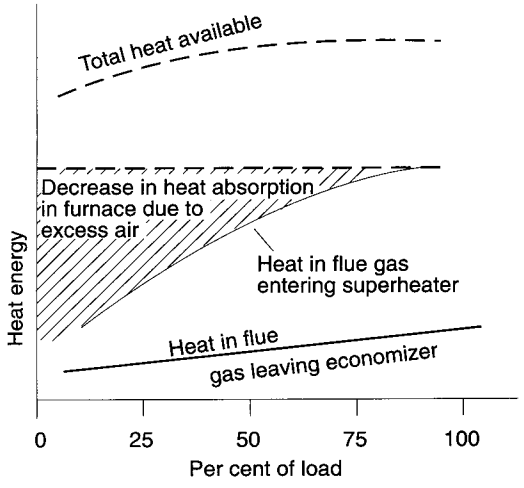


Fig. 33.14 *Flue gas recirculation increases the superheated steam temperature at the outlet of convective superheater.*

Ans. 1. The efficiency of the process is relatively high
2. Ensures close regulation over a wide operating range
3. Minimizes slagging that helps to longivate plant operation
4. Befits well with high-capacity modern units.

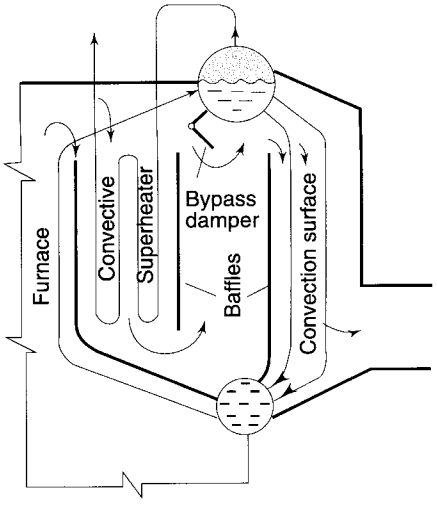


Fig. 33.15 *Gas bypass method to control superheated steam temperature.*

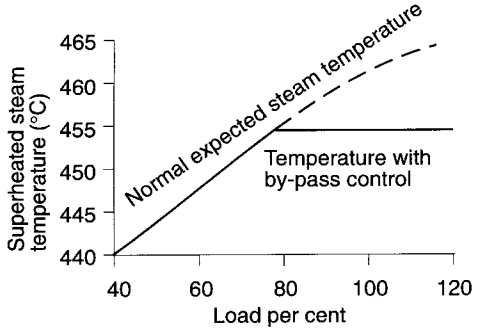


Fig. 33.16 *Superheated steam temperature control by gas bypass method.*

Q. *What are its drawbacks?*

Ans. 1. High initial investment
2. Relatively higher operation cost.

Q. *How does the method of gas-bypass control ensure superheated steam temperature control?*

Ans. In this case the superheater is designed oversize so that at partial load conditions, say 70–80%, it is capable of producing the required degree of superheat. (Fig. 33.16). And the boiler tube banks are disposed in such a manner that a portion of the combustion gas can be by-passed around the superheater elements with the aid of by-pass dampers. These dampers can be controlled manually or automatically to ensure the desired superheat temperature of the steam at the superheater exit. (Fig. 33.15)

Q. *What are the drawbacks of a gas-bypass control system?*

Ans.
1. Though made of alloy steel, the regulating dampers suffer from high temperature corrosion and fatigue
2. Variable draft loss
3. Control is better and more sensitive provided dampers are not opened more than 50%
4. Hunting of dampers occurs with abrupt load change
5. Control is not too prompt.

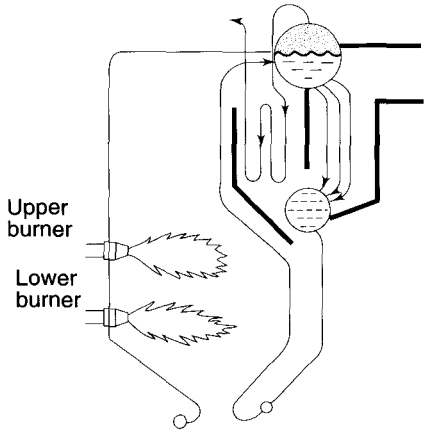


Fig. 33.17

Q. *If this system is associated with so many drawbacks, why it is so popular?*

Ans. Because of the low investment cost.

Q. *How does the adjustable burner control method lend itself to superheat temperature control?*

Ans. Satisfactory superheat temperature can be maintained by adjustable burner control which changes the radiant heat absorbing capacity of the waterwalls and ensures the required flue gas temperature at the furnace outlet.

For low loads, it is preferable to maintain the flame in the upper zones of the furnace so the upper burners are taken in line. And for heavy loads, it is best to light up both the upper and lower burners so that the entire furnace volume may be utilized to maintain the desired outlet temperature of the combustion products. Thus by shifting the principal combustion zone, the furnace outlet temperature can be regulated and that in turn ensures effective control of superheat temperature over a wide load range. (Fig. 33.17)

The furance outlet temperature can also be regulated (Fig. 33.19) by tiltable burners (Fig. 33.18) which can be tilted in the vertical plane to shift the position of the combustion zone.

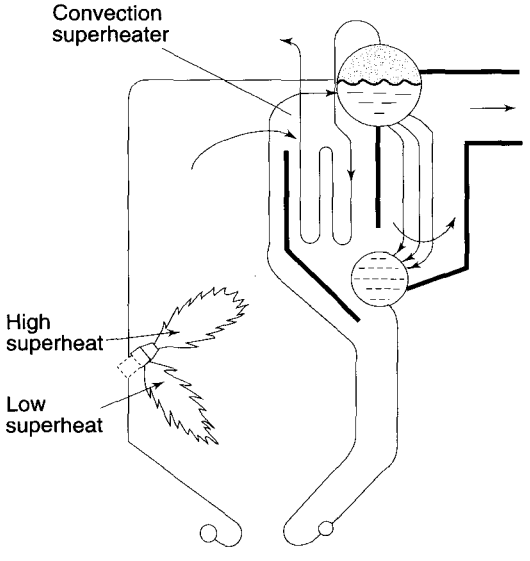


Fig. 33.18

Fig. 33.19

Q. *Why is the adjustable burner control system used in conjunction with interstage desuperheating?*

Ans. This is done to ensure

(a) quicker response to load change
(b) effective constant superheat temperature over a wide load range
(c) no hunting
(d) wider operating range
(e) close control (± 3°C)
(f) operation simplicity

Q. *Frequently adjustable burner control is used in conjunction with gas bypass control. Why?*

Ans. 1. To increase the capacity range
2. To ensure a very close control of superheat temperature (± 1.5°C)

Q. *How does the control of combined radiant-convective superheaters ensure the regulation of the superheat temperature of steam?*

Ans. This system works relatively simply and on the basis of compensating characteristics. An increase in excess air (or flame length) reduces the radiant heat transfer but increases the convective heat transfer. A reduction in excess air (or flame length) imparts the opposite effect. Variation in the heat absorption in the two superheaters alters the temperature of the superheated steam passing through them. That is how a radiant-convective superheater combination functions over the entire control range and regulates the final superheat temperature.

Q. *How can the superheat temperature be controlled in differentially fired twin furnaces?*

Ans. Such a system of steam generator may have

(a) a radiant superheater in one furnace while convective superheater common to both furnaces (Fig. 33.20) or
(b) a superheater in one furnace section only or
(c) more superheating surface exposed to one furnace than to the other.

So by varying the firing rate (i.e. by introducing a differential firing rate) in each furnace section, the rate of heat absorption in the radiant and convective superheaters can be varied on a compensating basis and that lends an element of superheat control.

Q. *How can sootblowers be deployed for the control of superheat?*

Ans. This is made possible by employing sootblowers to clean

(a) the radiant superheater tubes' surface, when the superheat is low, to increase the net heat absorbed by the superheater thereby raising the superheat temperature
(b) other furnace surfaces, when the superheat is high, to enhance the effectiveness of furnace cooling, i.e. to increase the rate of heat absorption by waterwall with the ultimate effect that the percentage of heat absorbed by the superheater is reduced and superheat temperature drops.

Q. *How does the separately fired superheater ensure superheat temperature control?*

Ans. These superheaters operate independent of the operation of the saturated steam boiler. The degree of superheat control imparted by them is achieved by

(a) adjustable burner control
(b) gas recirculation method
(c) control of excess air supply.

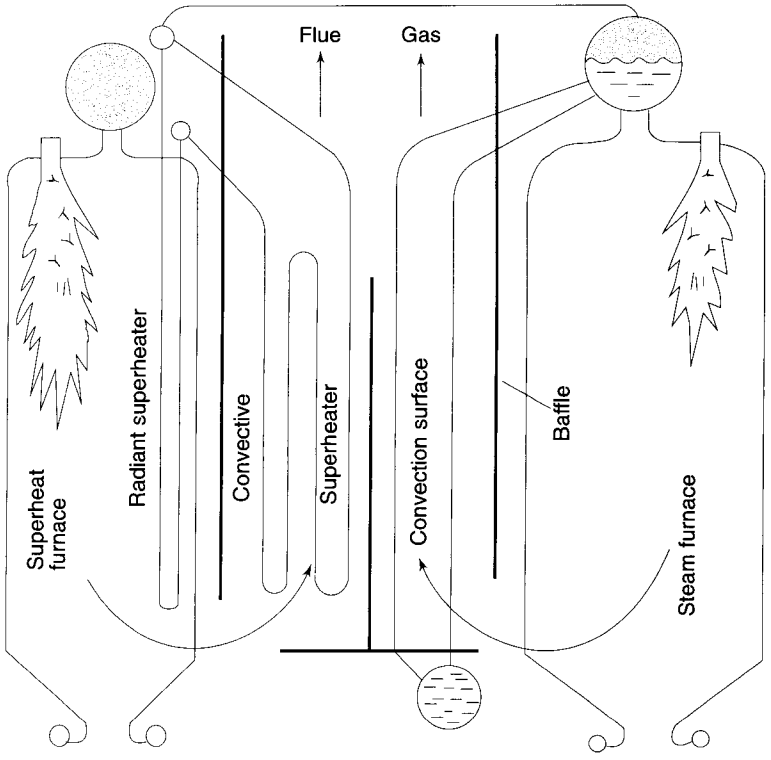


Fig. 33.20 *Twin-fired furnace.*

Q. *Are there any suitable methods to control superheat?*

Ans. 1. Blending the superheated steam with the returned steam
2. Raising the steam velocity through the superheater
3. Recirculating a portion of the superheated steam back to the steam and water drums.

Q. *Where is the recirculation of a part of the superheated steam to steam and water drums carried out?*

Ans. In the Loeffler positive circulation boilers.

Q. *What is the control characteristic of a superheater?*

Ans. It is the relationship between the boiler load and the superheated steam temperature.

Q. *Is it same for all superheaters?*

Ans. No.

Q. *How does it vary for radiant, convective and combined superheaters?*

Ans. The control characteristics of the these three superheaters are represented by θ_{ss} vs. G_s (the steam load) curves. (Fig. 33.21)

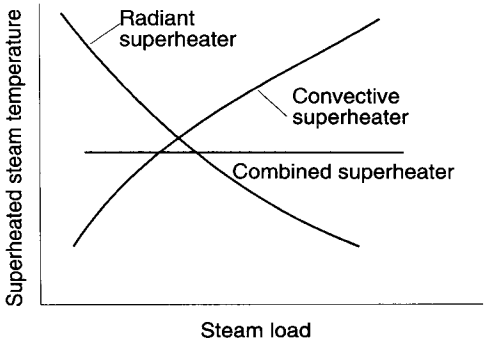


Fig. 33.21

For radiant superheaters it falls off with the increase of load while it increases with temperature for convective superheater.

In combined superheaters, having properly selected dimensions of the radiant and convective sections it remains constant.

Q. *Why does the control characteristics of a radiant superheater fall with increase in steam load?*

Ans. As the boiler load is increased, the quantity of fuel burning is increased. However this increased rate of fuel burning influences very little those parameters that govern the quantity of heat absorbed by the radiant heating surfaces. Therefore, the heat absorption in a radiant superheater does not increase in the same scale as the flowrate of steam through it. As a result, the heat absorption per unit steam flowrate decreases.

Q. *What are the parameters that govern the quantity of heat absorbed by radiant superheaters?*

Ans. Combustion temperature, flame emissivity and the thermal efficiency of the waterwalls.

Q. *Why does the control characteristics of a convective superheater increase with the increase of steam load?*

Ans. In this case as the rate of fuel burning increases with the increase of steam load, the quantity of flue gases produced increases and this raises the rate of convective heat transfer almost in the same proportion as the boiler load.

With the higher rate of fuel burning the flue gas velocity increases resulting in an increased rate of convective heat transfer in proportion to the power of 0.6–0.65 of gas velocity.

Thus as a result of increased rate of fuel combustion, the radiant heat absorption in the furance decreases bringing about higher exit temperature of flue gases from the furnace. Therefore, the temperature gradient in the region of the convective superheater becomes higher.

The increased gas velocity and the higher furnace exit temperature of flue gases with the increase of boiler load are responsible for the superheated steam-temperature increasing at a higher rate than does the boiler load.

Q. *Is it possible to obtain constant-temperature superheated steam despite the increase of steam load?*

Ans. Yes, it is possible theoretically by properly selecting the dimensions of radiant and convective superheaters.

Q. *Why can this not be met under practical conditions?*

Ans. The temperature of the superheated steam is affected by certain operating conditions such as

1. temperature of the BFW
2. excess air ratio in the furnace
3. the degree of cleanliness (regarding slagging) of waterwalls and the superheater
4. moisture content of the fuel.

Q. *How does the boiler feedwater temperature affect the superheated steam temperature?*

Ans. For drum-type boilers, the decrease of feedwater temperature results in a higher superheated steam temperature. It is because, for drum-type boilers, the heating surface of the superheater is fixed and as the feedwater temperature decreases the steam generation capacity of the waterwall decreases with the effect that for constant fuel consumption the quantity of heat absorbed by the superheater from the flue gases increases per unit flowrate of steam.

For once-through boilers lower feedwater temperature leads to reduced superheated steam temperature. It is because, as the feedwater temperature decreases, the temperature of the generated steam decreases and as the rate of heat absorption, in the superheater, per unit flowrate of steam remains constant this results in a drop in superheated steam temperature.

Q. *How does the excess air ratio influence the superheated steam temperature?*

Ans. An increase in the excess air ratio in the furnace results in greater quantity of combustion products passing through the convective shaft resulting in a higher rate of heat transfer in the zone of the convective superheater. So as a result of more intensive heat exchange in this zone the temperature of the superheated steam increases.

Q. *How does the moisture content in fuel influence the superheated steam temperature?*

Ans. As the moisture content in the fuel increases, the superheated steam temperature increases.

Q. *Why does the superheated steam temperature increase with increase in the moisture content of fuel?*

Ans. It is because, with the increase of moisture content of the fuel, the mass of combustion products passing through the superheater increases. This results in higher convective heat transfer and consequently the superheated steam temperature rises.

Moreover, higher the moisture content of fuel, greater is the number of triatomic molecules in the combustion products. Since these have an elevated flame emissivity, they increase the heat transfer coefficient on the fireside resulting in higher temperature of superheated steam.

Q. *How does cleanliness of superheater tubes affect the superheated steam temperature?*

Ans. Slagging fouls the superheater tubes and destroys the cleanliness of the tube's surface.

Since slags have a lower heat transfer coefficient than clean metal tubes, slagging impairs the rate of overall heat transfer in the superheater and thus decreases the temperature of superheated steam.

Q. *Why is it difficult in the case of once-through boiler to maintain a steady temperature of superheated steam with the increase of steam load?*

Ans. In the case of once-through boiler units there is no definite zone of phase transition (liquid water → steam), i.e. a distinct boundary line between the evaporator and superheater is absent and as such the actual heating surface area available for superheating the steam varies with the variations of the operating parameters of the boilers.

In this case, the temperature of the superheated steam, with the increase of boiler load, can be maintained constant by controlling the ratio of the boiler feedwater flowrate to fuel consumption. Since these boilers have a low accumulating capacity, they are rather sensitive to the variations of feedwater flowrate and fuel consumption. This culminates in variations in the temperature of superheated steam.

Q. *What are the reasons for abnormally high superheated steam temperature with constant load?*

Ans. 1. Too high excess-air
2. Too low feedwater temperature
3. Slagged up furnace
4. Secondary combustion
5. Malfunctioning of steam temperature indicating and controlling equipment.

Q. *What are the reasons for abnormally low superheated steam temperature with constant load?*

Ans. 1. Too low excess-air
2. Too high feedwater temperature
3. Excessive slagging of superheater tubes (external surface)
4. Excessive moisture carryover from the boiler drum
5. Malfunctioning of steam temperature indicating and controlling equipment.

Q. *Will the superheated steam temperature get affected when the boiler is priming?*

Ans. Yes. It will drop suddenly.

Q. *How far is the temperature of the superheated steam allowed to vary from the rated value?*

Ans. It is allowed to vary from (+) 5° to (–) 10°C of the rated value.

Q. *Is it possible to maintain the superheated steam temperature within such a narrow range*

despite the variations of steam load even in the case of the combined system of the radiant-convective superheaters?

Ans. No.

Q. *Then what measures can be undertaken so as not to allow the superheated steam temperature to vary beyond this admissible range?*

Ans. There are two methods for controlling the superheated steam temperature. These are: steam control and gas control.

Q. *How far should these controls be effective?*

Ans. These methods should be effective enough to maintain the superheated steam temperature within the specified limit in the load range from 30% to 100% while in the case of reheated steam from 60% to 100% of the rated value.

Q. *What is the basis of steam control?*

Ans. This method is based on curtailing the enthalpy of the superheated steam by transferring a part of its heat to the feedwater or by injecting polish water (deeply deionized water) to the superheating steam. As a result, the temperature of the superheated steam decreases.

Q. *What is the basis of gas control?*

Ans. This method is based on the fact that if, by any suitable means, the rate of heat absorption on the fireside of the heating surfaces can be reduced or regulated then as a consequence the temperature of the superheated steam can be reduced or regulated.

Q. *What are these "suitable means" to control the rate of heat absorption on the fireside of heating surfaces?*

Ans. 1. Changing the flame position in the furnace
2. Recirculating the combustion products
3. By-passing a portion of combustion products around the superheater.

Q. *How is steam control accomplished?*

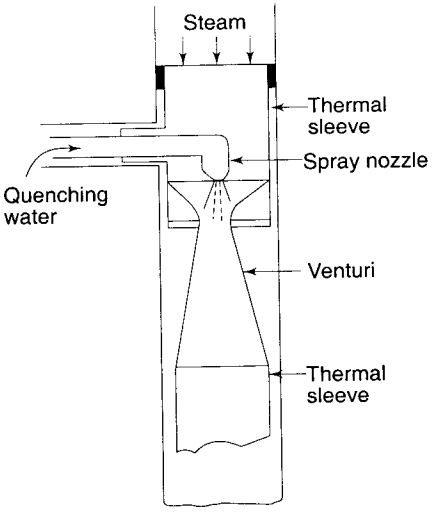


Fig. 33.22 *Spray attemperator.*

Ans. This is carried out in surface-type attemperators as well as in spray-type attemperators.

Q. *What is an attemperator?*

Ans. The attemperator (desuperheater) is basically a heat exchanger in which the superheated steam is cooled either by a direct heat exchange with cold condensate sprayed into the flow of the superheated steam (SPRAY-TYPE) (Fig. 33.22) & (Fig. 33.23) or indirect heat exchange with feedwater in tube-and-shell type heat exchanger (SURFACE TYPE).

Q. *Why is it not economically favourable to inject a condensate to the flow of reheated steam as a method of controlling temperature?*

Ans. From the reheater, the superheated steam goes to the medium pressure cylinder of the steam turbine. As such the additional quantity of MP steam produced due to the injection of condensate to the flow of superheated steam enters along with the main steam into the turbine by-passing the high pressure cylinder. This excess steam, if it exceeds the requirement of the turbine under operating load, must be vented to avoid pressure build up in the MP steam header. That is why the

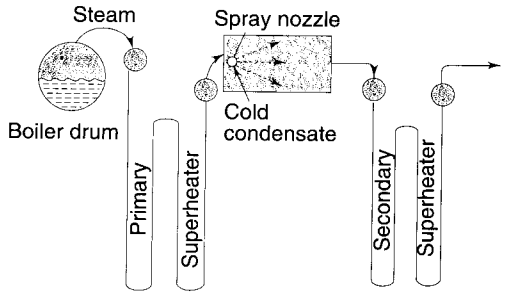


Fig. 33.23 *Spray-type attemperator.*

injection of condensate of reheated steam is economically unfavourable.

Q. *Where is the attemperator mounted?*

Ans. It is located either downstream of the superheater (Fig. 33.24) or placed in-between two superheaters (Fig. 33.25) or placed upstream of the superheater (Fig. 33.26).

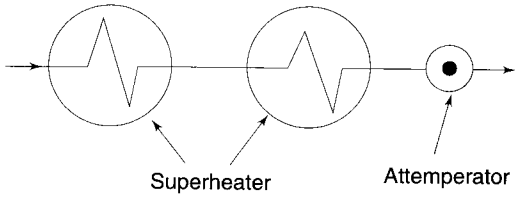


Fig. 33.24 *Attemperator located downstream of superheater.*

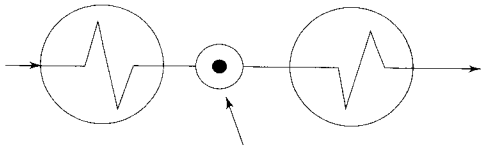


Fig. 33.25 *Attemperator located in-between two superheaters.*

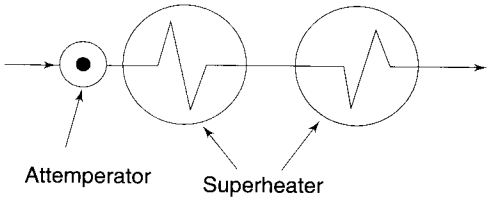


Fig. 33.26 *Attemperator located upstream of the superheater.*

Q. *Is the method of locating attemperator downstream of the superheater used for controlling the temperature of the main superheated steam?*

Ans. No.

Q. *Why?*

Ans. It does not safeguard the superheater against excessive rise of steam temperature.

Q. *Are the other two types of attemperator arrangements used in practice?*

Ans. Yes. They adequately safeguard the superheater and the turbine.

Q. *How does superheated steam temperature vary with these three versions of attemperator arrangement?*

Ans. (Fig. 33.27) (Fig. 33.28) and (Fig. 33.29)

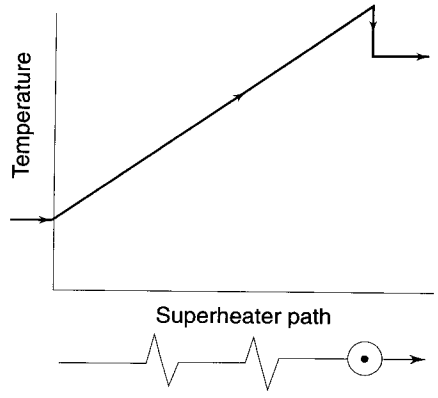


Fig. 33.27 *Attemperator mounted downstream of superheaters.*

Q. *Briefly describe the spray-type attemperator.*

Ans. It consists of an atomizing nozzle inserted into the superheated steam header through a pipe connection. The nozzle holes are 3–6 mm in diameter and the nozzle is covered by a metallic jacket having a gap of 6–10 mm from the header wall. This protective jacket is fitted to avoid direct contact of the cold condensate with the header wall which is heated to the temperature of superheated steam.

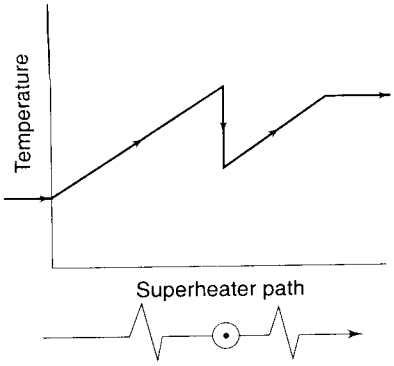


Fig. 33.28 *Attemperator mounted in-between two superheaters.*

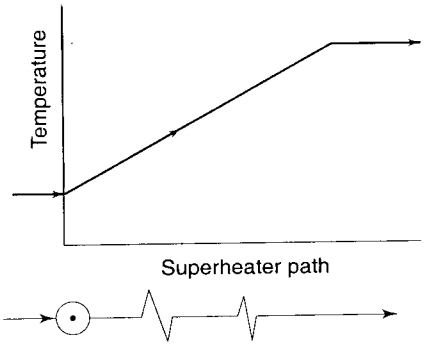


Fig. 33.29 *Attemperator provided upstream of the superheaters.*

Cold condensate is sprayed through the atomizing nozzle into the flow of superheated steam and the protective jacket ensures the complete evaporation of the droplets as they travel along the length of the jacket which is 4-5 m long. (Fig. 33.30)

Q. *Why is spray-type attemperator arranged close to the superheater outlet?*

Ans. To quench the superheated steam before its temperature before the spray nozzle runs too high.

If this is not done the local temperature of the steam header upstream of the attemperator will be so high that it may impair the operating conditions of the header metal in that place.

Q. *Why is the condensate used for spraying through the attemperator obtained by condensing saturated steam directly from the boiler instead of using feedwater as the quenching fluid in some cases of drum-type boilers?*

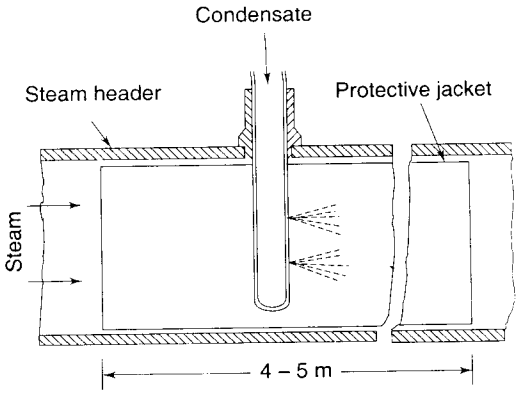


Fig. 33.30 *Spray-type attemperator in action.*

Ans. It is because spray-type attemperators are sensitive to the quality of water used for spraying. If the feedwater of drum-type boilers are mineralized, then the spray water is obtained by condensing a part of the steam taken directly from the drum.

Q. *How is more than one spray-type attemperator positioned in the circuit to prevent an excessive temperature rise downstream of the superheaters?*

Ans. Here, two arrangements of two and three spray-type attemperators are shown schematically for superheat control. (Fig. 33.31).

Q. *How is a surface-type attemperator arranged in the circuit?*

Ans. It is joined in series with the economizer. (Fig. 33.32)

Q. *In which cases are surface-type attemperators used?*

Ans. They are employed in low-capacity boilers.

Q. *Why are surface-type attemperators employed in low-capacity boilers?*

Ans. The surface-type attemperator with indirect cooling mechanism is not as efficient as the spray-type attempertor in controlling the high superheat

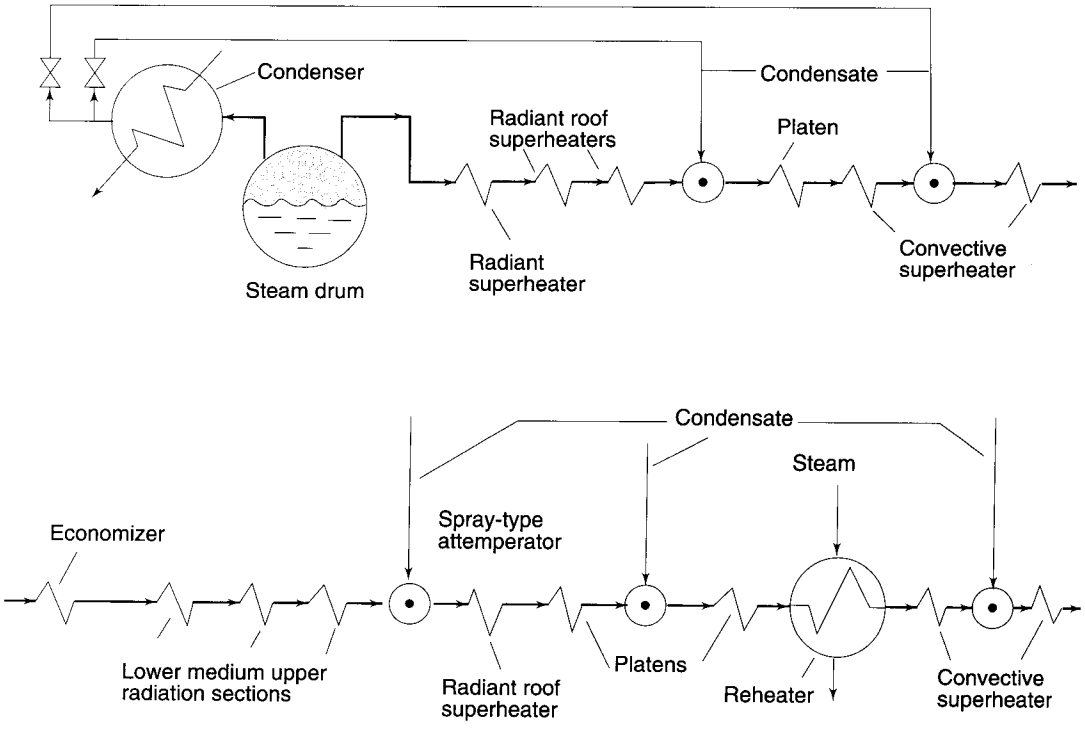


Fig. 33.31 *More than one spray-type attemperator inducted in the circuit prevents excessive temperature buildup downstream of the superheaters.*

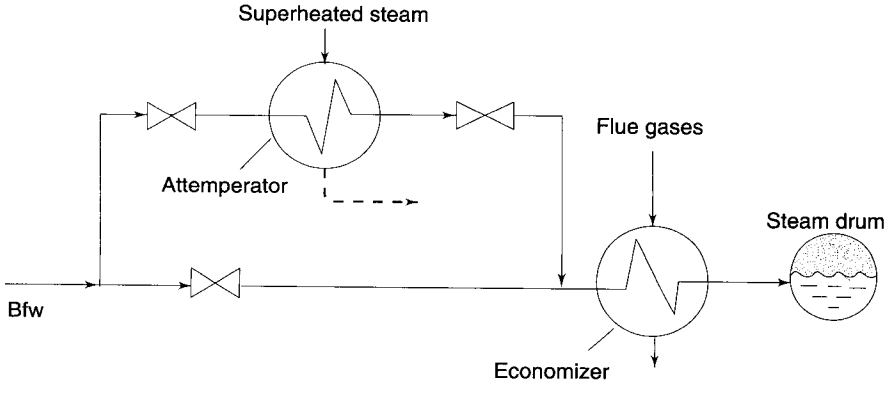


Fig. 33.32 *BFW is shunted through a surface-type attemperator.*

temperature of the large quantity of steam generated in high-capacity boiler units.

DESUPERHEATER NOZZLE DEPOSITS

Case Study A US refinery harnesses its two steam generators (91 t/h at 8 MPa and 708°K) to feed superheated steam to the turbo-generator and for process use.

However, a few months after start-up, its attemperator (desuperheater) gave birth to trouble netting poor temperature control and instability.

Careful inspection through spray nozzles revealed fine black powdery deposition plugging the water holes. The nozzle, itself a ventury, is contracted to a short throat and then enlarged again in conical form. The sprayholes slanting downstream are in the nozzle wall, about one-third of the way along the conical enlarging section. Downstream from the holes was another layer of deposit of black powder along the conical wall. Chemical analysis of the powder showed the following compositions:

Fe_3O_4—51.5%; Fe_2O_3—43.4%; SiO_2—1.5%; CaO—1.5%; MgO—0.5%

This deposit was similar to loose deposit detected in the lower and upper parts of the boiler drum.

The nozzles were replaced but they got plugged soon. So the refinery changed to another design having the outer downstream end rounded and the water sprayholes radial and at the narrow throat. Though the plugging problem is gone, the plant engineers are doubtful of lasting benefit.

Water pH is maintained at 11.5 or a little below.

DM water is used as BFW.
DO at boiler inlet is < 0.007 ppm

Phosphate, caustic and hydrazine treatments are used.

What are these deposits in the desuperheater spray nozzles?

What is the source of such deposits?

What precautions should be taken in operation and maintenance?

Ans. The problem is most likely not with the steam but with the spraywater injected through the attemperator onto the superheated steam.

The source of desuperheating water has not been indicated. Normally, it would be the BFW, and if this is the case here, then the deposits originated in the condensate and/or M/up water. The deposits are the feedwater borne TDS which deposit onto the nozzle holes as the spraywater is flashed.

As might be expected, the largest source of impurities in the boiler-feed and spraywater systems is the plant's condensate return system from the process. This renders pH control in all distant areas difficult. Where low pH conditions exist, corrosion can be rapid. Since same BFW pumps usually supply both boiler water and desuperheater spraywater, infiltration of corrosion products from return condensate brings about similar deposits in boiler drum and desuperheater sprayholes.

Also the possibility of erosion-corrosion due to boiler carryover cannot be ruled out. Carryover of boiler water to the desuperheater is a serious matter which renders condensed steam sampling at the superheater inlet almost mandatory.

The deposits, which were mostly Fe_3O_4 and Fe_2O_3, might have been caused by erosion of superheater tubes because of droplets c/o. Either the boiler has been operated at high drum level or it is fitted with poor steam separator.

Preventive Measures

1. Taking pH samples at remote points and feeding amines.
2. Continuous venting of CO_2 from the desuperheating condenser (The composition of the deposits suggested the presence of carbon dioxide that might have got into the system through thermal decomposition of carbonate and bicarbonate alkalinity)
3. Replacing the existing single nozzle with two new nozzles—one with water sprayholes in the diverging part of the nozzle and the other with sprayholes in the throat
4. Proper treatment of the condensate, probably with a filming amine, to keep corrosion at bay.
5. A thorough cleaning of the steam drum is advisable at each plant shutdown
6. Use of SS material for the spraynozzles.

Q. *Why is a live-steam reheater employed?*

Ans. It is used to equalize the temperature between the superheated steam (live steam) produced in the radiant superheater and that (reheated steam) produced in the reheater.

A decrease in boiler load is accompanied by a sharp rise in the temperature of the live steam in the radiant superheater and a substantial drop in the reheated steam temperature in the convective reheater. (Fig. 33.33)

Hence to equalize the temperature in both, it is justifiable to abstract some of the heat from the live steam (main steam) and transfer the same to the reheated steam. This is achieved in a heat-exchanger that is called *live-steam reheater.*

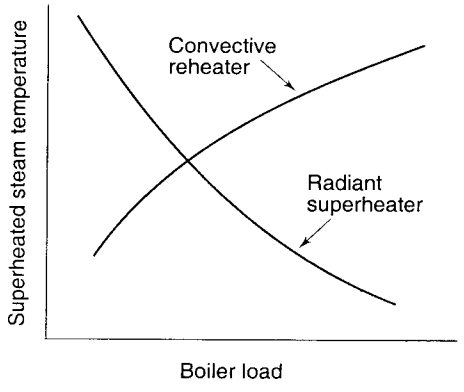


Fig. 33.33

Q. *Briefly describe a live-steam reheater.*

Ans. It is a U-shaped shell-and-tube heat exchanger comprising of 10–20 U-tubes of 25–30 mm dia mounted in a 300–400 mm header.

Live steam (superheated) flows through the tubes and the reheated steam through the shell-side. A part of the flow of the live steam is bypassed past the heat exchanger to control the temperature.

Q. *Why is the live-steam reheater made U shaped?*

Ans. To ensure

(a) better compensation of thermal expansion of the system of tubes
(b) more compactness.

Q. *What is the range of steam temperature control of the live-steam reheater?*

Ans. 30–45°C

Q. *How does the variation in the boiler load affect the performance of a live-steam reheater?*

Ans. As the boiler load is decreased, the rate of heat absorption of the live-steam superheater increases; if the boiler load is increased the heat absorption in the live-steam reheater decreases.

Q. *Why is the performance of a live-steam reheater inversely proportional to the boiler load?*

Ans. Since the live-steam reheater is connected in series downstream of the radiant superheaters wherein superheated steam temperature increases with the decrease of boiler load, the rate of heat absorption of live-steam reheater increases with the higher outlet temperature of superheated steam from the radiant superheater.

If the boiler load is increased, it will bring about a sharp drop in the temperature of the live-steam outlet of the radiant superheater and consequently the heat absorption in the live-steam reheater will decrease.

Q. *Show the arrangement of the live-steam reheater connected in the circuit.*

Ans. In the following arrangement (Fig. 33.34) the entire high pressure superheated steam having a high degree of superheat passes through the live-steam reheater that reheats the medium pressure steam. A portion of the M.P. steam is bypassed around the live-steam reheater for necessary control of temperature of the reheated steam.

In the following arrangement (Fig. 33.35) a bypass valve has been inserted in the high pressure superheated steam path so that only about 5% of this steam is allowed to enter the live-steam

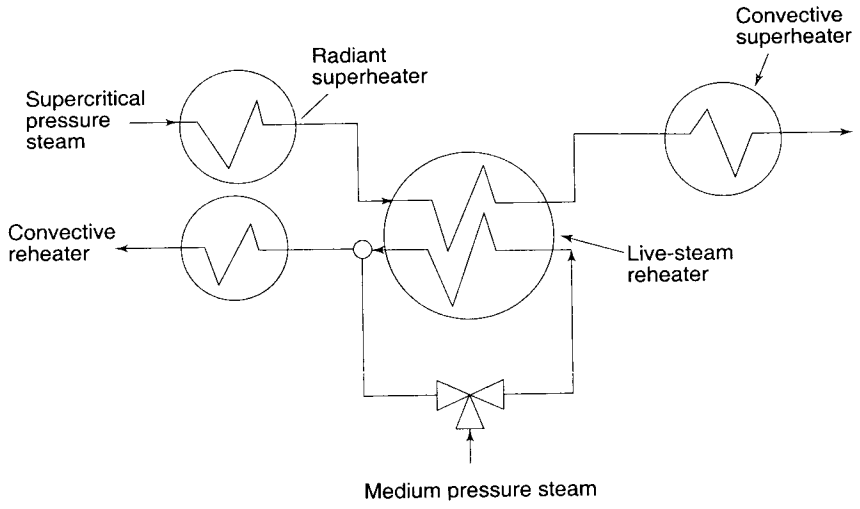


Fig. 33.34 *A typical live-steam reheater circuit. Entire H.P. superheated steam passes through the reheater to heat up the M.P. steam.*

reheater and the rest passes through the by-pass valve when the boiler is running at its rated load.

At reduced load, the flow rate of MP steam decreases but the temperature of the HP superheated steam exit of the radiant superheater increases, so under this condition a greater portion of HP steam is allowed to pass through the live-steam reheater to ensure a constant reheated steam temperature.

Q. *What is the drawback of the system that sends the entire HP superheated steam through the live steam reheater?*

Ans. Its main drawback is loss of high power due to substantial hydraulic resistance in the superheated steam path.

Q. *What is the drawback of the system that introduces a by-pass valve to the HP superheated steam path?*

Ans. This by-pass valve (control valve) must be capable of functioning at a high temperature and pressure and high flowrate. It must have a large cross-section.

Q. *How is gas control effected?*

Ans. It is effected by:

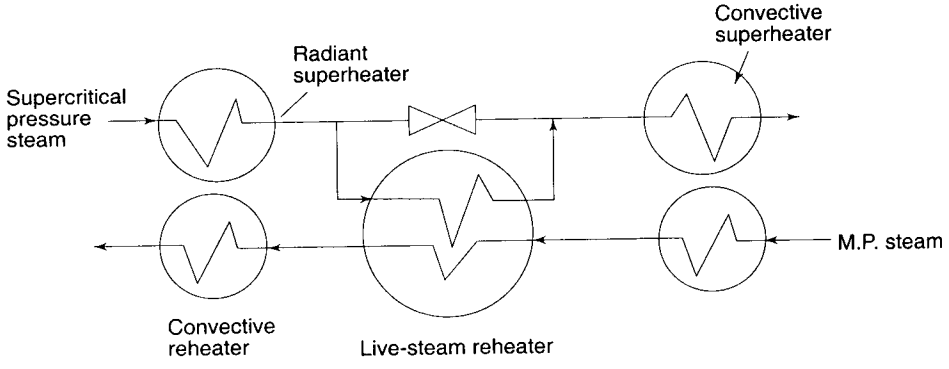


Fig. 33.35 *Another typical live-steam reheater circuit. Only about 5% of the H.P. superheated steam is allowed to pass through the reheater for heating the M.P. steam while the rest is bypassed.*

(a) recirculating or by-passing the combustion products or
(b) changing the flame position in the furnace or
(c) switching on and off the burner tiers.

Q. *What are the drawbacks of the gas control method?*

Ans. It complicates the boiler operation by influencing the temperature of the superheated steam. It involves a loss of heat with waste gases. Additional power is required for draft.

Q. *Why is gas control employed only in combination with steam control in modern boilers?*

Ans. Gas control alone cannot satisfactorily control the temperature of the superheated steam in the specified range.

Q. *Why does the recirculation of combustion products taken off at a lower temperature and delivered into the furnace affect the temperature of the superheated steam generated?*

Ans. Combustion products tapped at the lower temperature (520–650 K) zone of the convective shaft and blown to the furnace back makes redistribution of heat even between the heating surfaces. The extent of heat redistribution depends on the recirculation ratio, i.e. the fraction of the total combustion products recycled. Therefore, it affects the rate of steam generation, the temperature of steam and the temperature of the flue gases. Consequently, the temperature of the superheated steam alters.

Q. *How does the recycling of the combustion products affect the temperature of the superheated steam with the change in boiler load?*

Ans. This can be best understood with the help of **superheated steam temperature** vs. **boiler load** graph. (Fig. 33.36)

With the increase in recirculation ratio, the direct heat absorption in the furnace decreases and the temperature of the combustion products at the outlet of the furnace increases. Moreover, the flowrate of gases through the superheater increases. This increased flowrate and higher outlet temperature of the combustion products increases the convective heat transfer and therefore, the temperature of the superheated steam also increases. Since the increase in recirculation ratio is accompanied by a fall of the boiler load, it can be said that with the drop of boiler load the temperature of superheated steam increases. (Fig. 33.36)

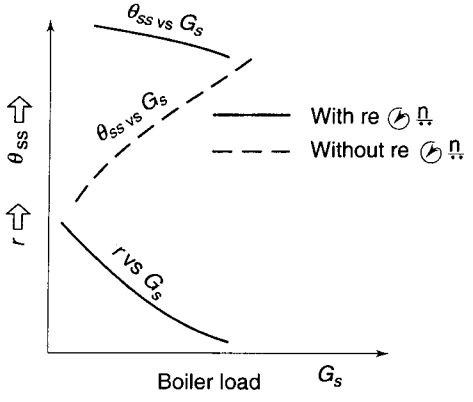


Fig. 33.36 *Temperature vs boiler load.*

Similarly with the increase of boiler load, the recirculation ratio decreases and this results in higher furnace temperature, and consequently the temperature of the superheated steam in the radiant superheater increases. Therefore, with change in boiler load the temperature of the superheated steam changes very little, i.e. the fluctuation of superheated steam temperature is minimized.

Q. *At which point in the furance are the recirculated combustion products introduced?*

Ans. The cold (520–620°K) combustion products taken off the convective shaft can be admitted into the upper or lower portion of the furnace. (Fig. 33.37)

Q. *How is the furnace operation affected if the cold recirculated combustion products are introduced into the lower portion of the furnace?*

Ans. When the cold recirculated flue gases are introduced into the lower portion of the furnace,

it decreases the furnace temperature and consequently decreases the rate of radiant heat absorbed by the waterwalls. Therefore, the temperature of the combustion products at the outlet of the furnace increases. Since, as the recirculation increases the total mass flowrate of gases through the superheater, the increased flowrate and higher outlet temperature of the combustion products increase the superheated steam temperature in the convective superheater.

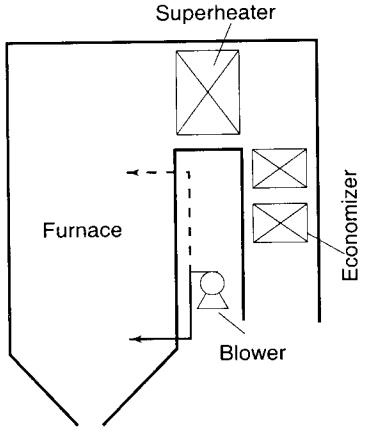


Fig. 33.37

Q. *How is the furnace operation affected if the cold recirculated combustion products are introduced into the upper portion of the furnace?*

Ans. It affects the furnace operation a little but prevents the superheater tubes from slagging by lowering the inlet gas temperature to the superheater by a substantial degree. Moreover, lowering of the temperature of the flue gases in the superheater somewhat decreases the rate of heat absorption by steam.

Q. *How does the flame position affect the temperature of the superheated steam?*

Ans. The furnace temperature and the pattern of temperature distribution within the furnace determine the rate of heat absorption by the evaporator waterwalls which, as a consequence, determines the furnace outlet temperature of the flue gases entering the convective gas duct. Therefore, by varying the position of the flame, the heat absorption in the furnace and the furnace outlet temperature of the flue gases can be varied. This as a consequence brings about a change in the rate of heat absorption by the reheaters and convective superheaters which are arranged in the convective shaft.

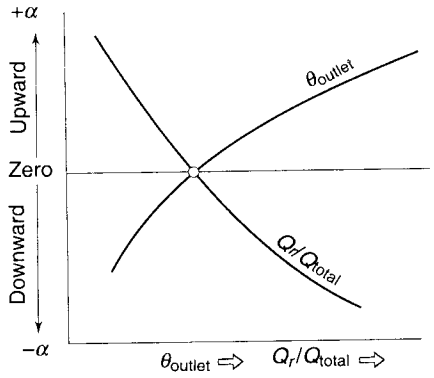


Fig. 33.38

Q. *How will the furnace outlet temperature of flue gases be affected if the burners are tilted down?*

Ans. If the burners are tilted downwards, the temperature of the furnace core increases and that increases the radiant heat absorption by the waterwalls in the furnace, i.e. the fraction of the total absorbed heat shared by radiant heat (Q_r/Q_{total}) increases. Therefore, temperature of the flue gases at the furnace outlet decreases. (Fig. 33.38)

Q. *How will the flue gas temperature at the burner outlet be affected if the burners are tilted up?*

Ans. It will decrease the rate of heat absorption by the waterwalls and therefore, the furnace outlet temperature of the flue gases in the convective shaft increases.

Q. *How will you orient the burners, when the boiler load drops, so as to maintain a steady temperature of the reheated steam?*

Ans. As the boiler load drops, the temperature of the superheated steam in the convective superheater diminishes. In order to maintain a constant temperature of the superheated steam in the reheater, the temperature of the flue gases at the furnace outlet is increased and this is done by tilting the burners upwards. (Fig. 33.39)

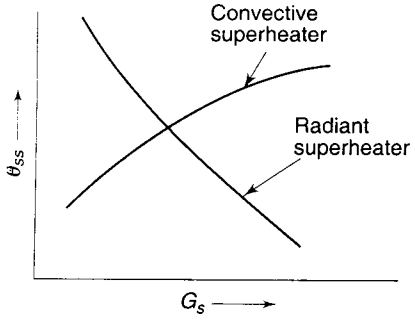


Fig. 33.39

Q. *How far is the gas control method by tilting burners capable of covering boiler load variation to maintain a constant temperature of the reheated steam?*

Ans. It can cover boiler load range of 100% to 70% to maintain a constant temperature of the reheated steam.

Q. *How can the position of the flame in the furance be changed other than by tilting the burners?*

Ans. This can be done by turning on and off some of the burner tiers.

Q. *Suppose a boiler furnace has three tiers of burners such that operation with any two can ensure 100% steam generating load. Depending on load variation which tier should be turned on?*

Ans. At low loads, the rate of steam superheating decreases. Therefore the burners in the upper tiers are turned on.

At high loads, the steam superheating increases and consequently the burners of the lower tiers are turned on.

Q. *How can the temperature of the reheated steam be controlled by by-passing of the combustion products?*

Ans. This can be done by

(a) providing a free gas duct between the reheater sections for passing the combustion products through it. The gas flowrate is controlled by the gate valve. (Fig. 33.40)

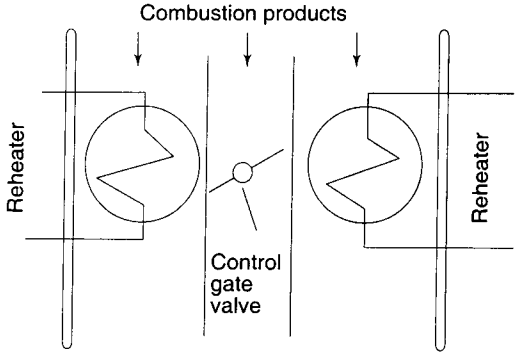


Fig. 33.40

(b) distributing the combustion products between the reheater sections and economizer mounted in parallel gas ducts (split duct) by means of control gate valves. (Fig. 33.41)

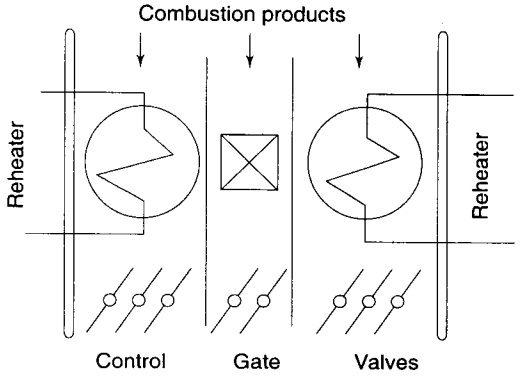


Fig. 33.41

(c) distributing the combustion products between the reheater section and economizer mounted in parallel gas ducts by means of a control fan. (Fig. 33.42)

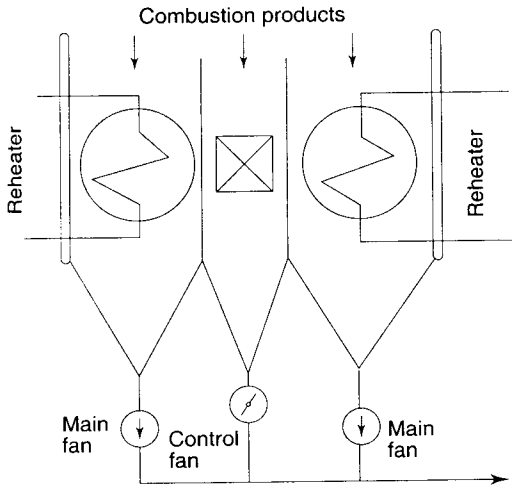


Fig. 33.42

Q. *What is done in the case of tube failure?*

Ans. What should be done in the case of one or more tube failures of a natural circulation boiler is dictated by the size of the failure.

If the failure is such that the water level can be maintained in the gauge glass by using the normal make-up system, the boiler can be kept in service until it is more convenient to take it off the line and make the necessary repairs.

If the failure is such that the water level cannot be maintained in the gauge glass, then the boiler should be shut down immediately.

A leak in the superheater tube should be investigated at the earliest possible time and the unit should be taken for normal shutdown.

An economizer tube leak can be detected by sound and/or increased make-up water requirement. The leak should be detected at the earliest possible time.

34

ECONOMIZERS AND AIR HEATERS

Q. *What are economizers and air heaters?*

Ans. They are heat recovery equipment that pick up heat from the combustion products of a boiler furnace to heat up the boiler feedwater (ECONOMIZER) and combustion air (AIR HEATER).

Q. *Why are they installed?*

Ans. Forming essential parts of a complete system of steam generating unit they are installed to conserve as much heat of fuel combustion in the boiler furnace as is possible and to increase the capacity of a boiler or decrease the size of a prospective boiler for a stipulated output. That is, the fundamental basis of their installation is to reduce the steam output cost.

Q. *If instead of installing these heat recovery equipment, in order to conserve as much combustion-gas-heat as possible, the entire temperature drop of the flue gases is allowed to take place over the boiler surfaces what would happen?*

Ans. This would be uneconomical and would increase steam generation cost and reduce boiler efficiency.

In the boiler proper, the flue gas temperature is allowed to drop to a level at which it becomes more economical to discontinue heat absorption through boiler surfaces (waterwalls) at saturation temperature and to initiate this heat absorption against at a later point downstream, i.e. in an economizer or air heater which operates under the law of diminishing returns. Since there always exists a most economical flue gas temperature above and below which steam production costs mount, the excessive reduction in flue gas temperature within the boiler will increase the capital investment as well as fixed charges that will eat away any gain in efficiency.

Q. *How far do these heat recovery equipment (economizer, air heater) bring about fuel economy and boost the overall efficiency of the boiler?*

Ans. It has been seen in practice that fuel saving to the extent of 1% is achieved for each 16°C reduction in the flue gas temperature in the heat recovery equipment (calculation is based on coal with calorific value 7 222 kcal/kg and CO_2 yield 13%).

Moroever, when these are installed, the overall efficiency of the boiler increases by 3–5%.

It is only by incorporating economizers and air heaters in the SGP has it been possible to bring down the flue gas temperature at the stack outlet to as low as 150°C (or even lower) and thereby attain a boiler efficiency as much as 88–90%.

Q. *Under which circumstances is the installation of these heat recovery systems may not stand justified?*

Ans. In the following cases:

1. If fuel is available abundantly at low cost
2. If the steam generation unit is taken in line only occasionally
3. If the unit is meant for standby service.

Q. *What factors determine the temperature to which the flue gases, passing through the economizer and air heater, are to be cooled?*

Ans. This temperature is determined by

(a) the amount of heat that can be extracted from the flue gases
(b) inlet temperature of the BFW to the economizer and combustion air to the air heater
(c) dew point of the flue gases
(d) optimum exit temperature below which any gain in efficiency is offset by higher capital investment and fixed charges.

Q. *Are these heat recovery equipment associated with any disadvantages?*

Ans. These equipment

(a) need sound operation and good maintenance
(b) are sensitive to dust and dirt-laden flue gases which may clog the heat exchangers
(c) bring about draft loss and hence draft fans are necessary to overcome the resistance imposed by them
(d) require that a part or all of the flue gases, at low load, is to be by-passed to avoid cold-end corrosion
(e) entail design complications if their service is required at low loads.

Q. *How is the heat recovery system (economizer and air heater) arranged?*

Ans. It must be accommodated within the limited space of the plant and the arrangement should ensure good accessibility for operation and maintenance, over and above harnessing design economy.

Usually the air heater is placed behind the economizer. Sometimes it is located in-between two economizer sections but it is never placed above the economizer. Into this circuit is incorporated a flyash collector which is placed either ahead of the economizer or in-between the economizer and air heater or behind the air heater.

An ID fan is fitted to the economizer for flue gas circulation while the air heater is provided with both ID fan (flue gas circulation) and FD fan (combustion air circulation). If the unit size is small, a by-pass around the heat recovery equipment and ID fan is embodied in the unit to ensure natural draught (draft) chimney operation during emergencies.

The heat exchange tubes of the economizer and air heater may be disposed horizontally or vertically in the gas duct for single or multiple passes and crossflow of flue gases. The combined heat recovery system may be located above, alongside, adjacent or behind the boiler.

Q. *What factors are considered in designing the economizer and air heater of a boiler?*

Ans. They must be adequately designed so as to

(a) maximize the rate of heat transfer from the flue gases
(b) buy economy in metal use
(c) minimize wear of tube surface due to abrasive ash particles
(d) minimize fouling and corrosion.

Q. *From the standpoint of heat transfer how does the air heater differ from the economizer?*

Ans. It differs from an economizer in that the temperature gradient between the hot combustion products and air is much lower than that between the combustion products and water (BFW). And the overall heat-transfer coefficient in the air heater is lower than that in the economizer.

Q. *Why is the surface area of an air heater very large (larger than the entire surface-area of all elements of the steam-water path)?*

Ans. It is due to a very low heat transfer coefficient between the combustion products and air. Therefore, the air heater needs a very large surface area for heat exchange so as to heat up the combustion air to the desired temperature level.

Q. *How much heating surface area does an air heater require?*

Ans. It depends on the capacity of the boiler. It may range from 30 m^2 to 300 000 m^2.

Q. *Why is such a large surface area required?*

Ans. Because of a very low value of the heat-transfer coefficient between the combustion products and air.

Q. *How does the temperature gradient vary during air heating?*

Ans. As the figure shows, the temperature of air varies more sharply than that of the combustion products. (Fig. 34.1)

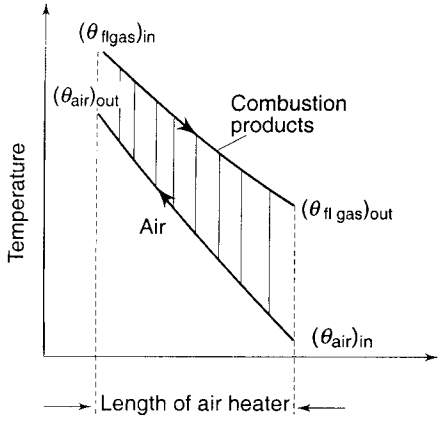


Fig. 34.1 *Temperature profile in the air heater.*

Q. *Why is air, in the air heater, heated more quickly than the combustion products are cooled?*

Ans. The air that is heated in the air heater contains less moisture (triatomic molecule) than the combustion products which have higher water vapour concentration (depending on the moisture and hydrogen content of the fuel) as well as such triatomic gases as CO_2 SO_2, etc. Triatomic molecules have higher heat capacities. Therefore, the volume and heat capacities of the combustion products are much greater than those of air composed predominantly of diatomic molecules such as N_2 and O_2. Hence the ratio of water equivalents of air and combustion products:

(Sp. Heat × Volume) of AIR/(Sp. Heat × Volume) of COMBUSTION PRODUCTS

is always less than unity which means that air is heated more quickly than the combustion products are cooled.

Q. *Why does the temperature gradient, as the air is being heated, decrease to a minimum at the hot end of the air heater?*

Ans. It is because the temperature of combustion air in the air heater rises more quickly than the combustion products are cooled. Therefore, the margin between the heating curve of air and the cooling curve of combustion products narrows down at the hot end (i.e. at the inlet of hot combustion products or the outlet of combustion air). Therefore, the temperature gradient between the combustion products and the air is at its lowest in the hot end of the air heater.

Q. *What is the temperature difference between the combustion products and the air in the hot end of the air heater?*

Ans. Usually it lies in the range of 30–50°C.

Q. *Why is it not desirable to allow the temperature difference between the combustion products and air at the hot end of the air heater to drop below 30–40°C?*

Ans. If $\Delta\theta$ at the hot end is allowed to drop below 30–40°C, it means an increase in temperature of the hot air. As the temperature difference in the hot portion becomes too low, the rate of heat exchange in this zone will be poor. Therefore, it will bring about a higher temperature of combustion products at the outlet of the air heater. Or it will need a higher heat transfer surface area of the air heater to bring down the temperature of the waste gas (combustion products) at the outlet of the air heater to the desired level.

Q. *How does preheating the air influence the temperature of the waste gas (combustion products at the outlet of the air heater) at various ratios of water equivalents?*

Ans. This effect of air heating on waste gas temperature is depicted in the adjacent figure (Fig. 34.2). Computation has been done on the following basis:

C_a, C_{cp} are the specific heats of air and combustion products respectively. V_a, V_{cp} are the volume of air and combustion products respectively.

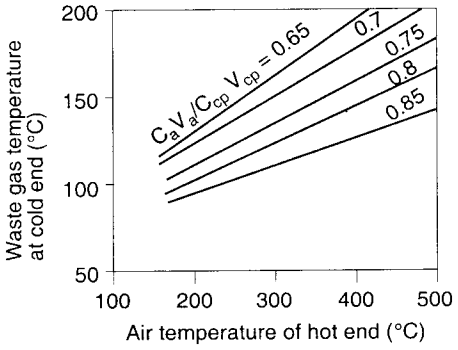


Fig. 34.2

Air inlet temp. = 30°C

$\Delta\theta$ at hot end = 40°C

As can be seen from the figure, to preheat air to 400°C at W.EQ. ratio = 0.8, the temperature of the waste gases at the outlet of the air heater is about 150°C. Whereas for fuels with higher moisture content (W. EQ. ratio = 0.65), the same degree of air preheating requires that the waste gas temperature outlet of the air preheater should be about 200°C.

Q. *What conclusion can you draw from it on the efficiency of the air heater regarding the moisture content of fuel?*

Ans. As the moisture content in the fuel increases, the ratio of water equivalents between air and combustion products decreases and with that the efficiency of the air heater decreases.

Q. *What are the advantages of air preheating?*

Ans.

1. Improved combustion and efficient use of fuel
2. Stabilized fuel ignition which improves low load combustion
3. Increased steam generation capacity (kg/m^2 h) and higher boiler efficiency which increases by 1% for every 20°C rise of the preheated air temperature
4. Better utilization of low grade, high ash fuel.
5. Higher thermal efficiency as most of the heat from the combustion products is recovered.
6. Greater load flexibility.
7. Reduction in boiler heating surface due to increase in overall boiler efficiency because of improved combustion.
8. Greater the preheat, lower the SO_3 in the flue gas and therefore the stack outlet temperature can be lowered resulting in greater heat utilization.
9. Air preheating ensures complete burning of fuel resulting in less slagging and cleaner flue gas and this reduces boiler outage for cleaning.

Q. *What are the disadvantages of air preheating?*

Ans.

1. Increases maintenance cost of stoker and furnace refractory
2. Entails the risk of serious damage due to deposition and ignition of combustibles
3. Operation of entire steam generation unit may be critically hampered due to clogging
4. Requires an F.D. fan and ducts for air passage and that needs careful design calculation for draft loss
5. Any air leakage necessitates higher fan output, i.e. taxes F.D. fan more electric power unit
6. Leakage is difficult to detect until the corrosion is in an advance stage requiring a major repairing or total replacement and greater outage time

Q. *How does the boiler load variation affect the efficiency of the air preheater?*

Ans. As the boiler load is increased, it simultaneously increases the volume and temperature of

the flue gases. This results in higher convective heat transfer through the air heater and improves the efficiency of the latter.

Q. *Where is the air heater installed?*

Ans. It is installed in the convective shaft of the furnace and downstream of the economizer.

Q. *Why?*

Ans. Its purpose is air preheating by utilizing the waste heat of the combustion products downstream of the economizer, where the temperature of the combustion products is sufficiently high, 625–725 K. By abstracting the waste heat from the combustion products, the flue gas temperature is brought down to 395–435 K at the outlet of the air preheater, before letting them escape to atmosphere.

Q. *How does high-sulphur fuel combustion affect the air preheater?*

Ans. The air preheater operates in the zone of lowest temperature of combustion products, therefore a part of its surface near the cold end (where the waste gas temperature may be 120–160°C) will be at a temperature equal to the dew point of sulphuric acid (140°C) produced on reaction of SO_3 with the moisture content in the combustion products. This corrosive acid film deposited on the surface of the air heater at the cold end will contribute to severe corrosion of the tube metal surface.

Q. *How many kinds of air heaters exist?*

Ans. Two:

1. recuperative air heaters
2. regenerative air heaters

Q. *What is a recuperative air heater?*

Ans. These are mostly tubular heat exchangers in which heat from combustion products or some other heat source is transferred continuously to the air as the air flows through the shell-side and combustion products through the tube-side.

Q. *What is a regenerative air heater?*

Ans. It is a kind of heat exchanger in which the heat transfer surface is alternately heated and cooled by charging it alternately with combustion products and air.

Q. *How many methods are used in practice to heat up air?*

Ans. There are three types of air heating:

1. direct heat transfer from combustion products (as in a tubular air heater) (Fig. 34.3)
2. indirect heating through an intermediate heat-transfer agent (solid packing) (Fig. 34.4A, B)
3. combined heating in which air is heated up by low-temperature waste-steam or water as well as by combustion gas. (Fig. 34.5)

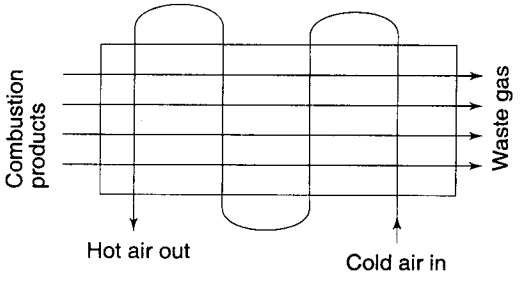


Fig. 34.3 *Tubular air heater*

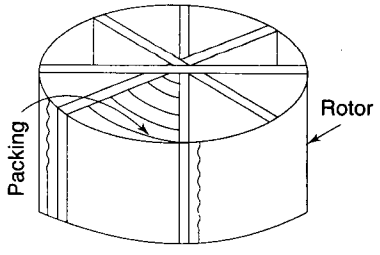


Fig. 34.4(a)

Q. *In which apparatus is direct heating of air by combustion products carried out?*

Ans. Recuperative air heater.

Q. *Briefly describe a recuperative air heater.*

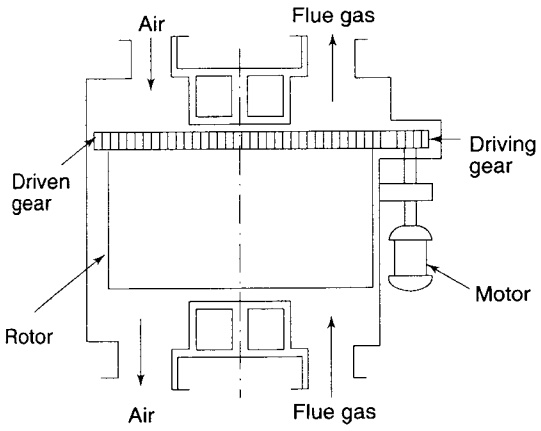


Fig. 34.4(b)

Ans. These are predominantly shell-and-tube heat exchangers in which combustion products flow through the tubes and air moves between the tubes, i.e. in the shell-side in cross-current flow with the combustion products. (Fig. 34.6)

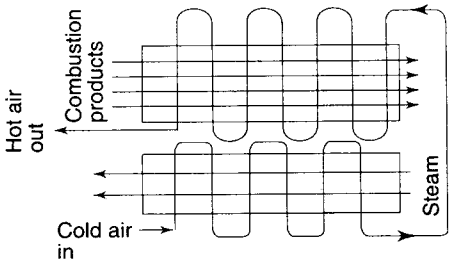


Fig. 34.5

The tubes (OD 30–40 mm and thickness 1.25–1.50 mm) are welded at both ends to tube plates. The upper plate is 20–25 mm thick while the lower one 15–20 mm thick. The tubes are arranged in a staggered configuration.

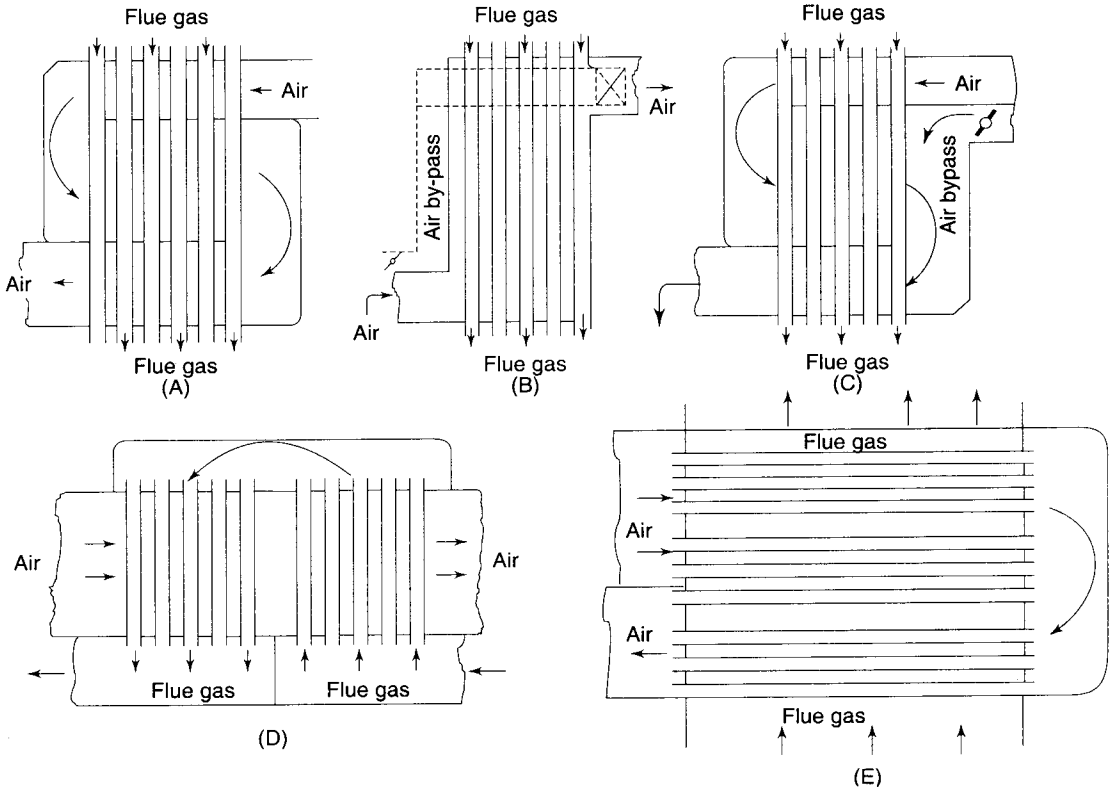


Fig. 34.6 *Recuperative air heater.*

A number of partitions are placed in the air path to get optimal air velocity for heat exchange. Air boxes are fitted where a change in the direction of air flow is necessary.

The tube system is capable of expanding upwards when heated.

Q. *What is the flow scheme of air in the air heater of boilers of moderate capacity?*

Ans. Single-flow scheme (Fig. 34.7)

Q. *What is the flow scheme of air in the air heater of high-capcity boilers?*

Ans. Split-flow scheme in which air is distributed in the heater into two or more separate flows. (Fig. 34.8)

Q. *Why is the split-flow scheme adopted in preference to the single-flow scheme in the air heater of high-capacity boilers?*

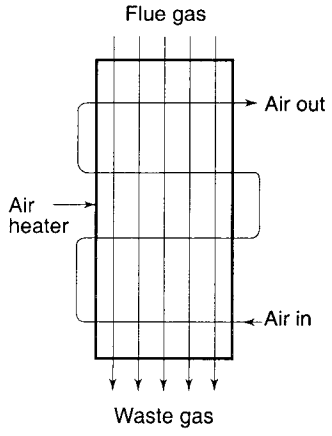


Fig. 34.7 *Air heater with single-flow scheme.*

Ans. High-capacity boilers need a larger quantity of combustion air for preheating. Therefore, the air preheater with single-flow air path must be of greater height to accommodate larger air

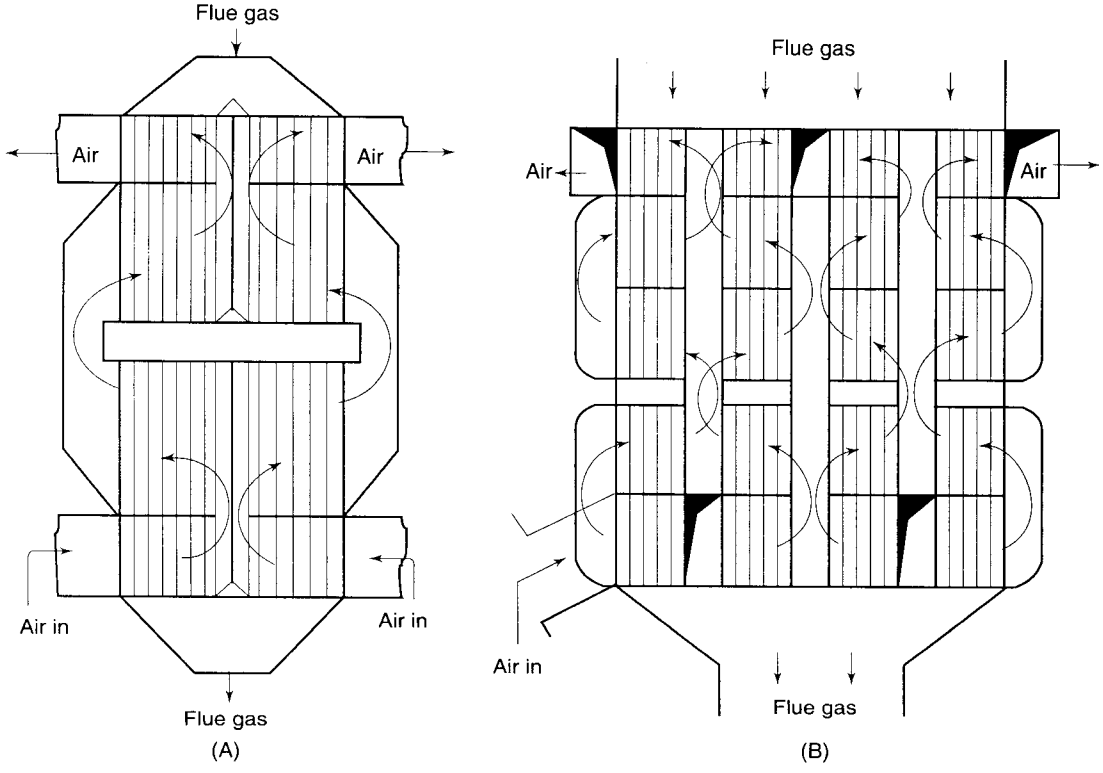


Fig. 34.8 *Air heater with split-flow scheme can handle large air flowrate.*

flowrate. This uneconomically large height can be substantially cut short by increasing the number of passes for air by adopting the split-flow scheme for air dividing the air in the heater into two or more separate flows.

Q. *Is the heat-transfer coefficient at the gas side greater or the coefficient of heat-transfer at the air side, in the air heater?*

Ans. The heat-transfer coefficient at the air side is greater than the heat-transfer coefficient at the gas side.

Q. *How can the heat-transfer coefficient at the gas side of the air heater be increased?*

Ans. By replacing straight-tubes with corrugated-tubes having a sinusoidal shape of constant radius of curvature.

Q. *But corrugated-tubes will get clogged by ash particles when the combustion products flow through them impairing the reliability of operation of the air heater. Is it not?*

Ans. Yes.

Q. *How can this problem be overcome?*

Ans. By reversing the flow scheme, i.e. by taking air through the tubes and combustion products through the shell.

Q. *Between the straight-tube air heater and corrugated-tube air heater, which one is more efficient.*

Ans. The corrugated-tube air heater is more efficient than the straight-tube air heater.

Q. *What are the chief advantages of corrugated tube air heaters?*

Ans. 1. Higher efficiency than a straight-tube air heater
2. Require less metal (about 50% less) than straight-tube air heaters of the same capacity
3. About 1/3rd less costly than conventional type straight-tube air heaters.

Q. *What are the basic advantages of straight-tube air heaters?*

Ans. 1. Simplicity in design feature
2. Reliability in operation
3. More gas-tight operation than any other type of air heater.

Q. *What is the basis of heat transfer through an intermediate heat-transfer agent?*

Ans. The working principle of this system is that heat instead of being directly transferred to the air from the combustion products through the wall of the heat transfer surface is transmitted first to an intermediate heat-transfer agent and then to air.

Q. *In which type of air heater is this principle put into practice?*

Ans. Regenerative air heaters.

Q. *What material is used as intermediate heat-transfer agent?*

Ans. Usually steel sheets used as solid packing act as intermediate heat-transfer agents. (Fig. 34.4a)

Q. *Are the sheets plain or corrugated?*

Ans. Both kinds are employed.

Q. *What is the most commonly used regenerative air heater?*

Ans. Rotary type regenerative air heater.

Q. *Where is the packing placed?*

Ans. It is placed into a hollow cylindrical drum called rotor which slowly rotates about its vertical axis by a gear and motor drive mechanism. (Fig. 34.4b) The rotor is divided into several sectors by radial partitions.

Q. *How is air preheating accomplished in the regenerative air heaters?*

Ans. As the rotor rotates slowly (0.5–0.35 rpm), the gas and air paths are intersected alternately by the rotating packing. Therefore, when the packing in some of the sectors receive heat from the combustion products, heat is given out to air by the packing in the other sectors.

Q. *What is the diameter of the rotor?*

Ans. It usually comes with a diameter of 10 m. In some cases rotor dia is as large as 15 to 18 m are used for regenerators in high-capacity plants.

Q. *What is the heating surface area of packing?*

Ans. 300–350 m^2 per cubic metre of rotor packing.

Q. *What is the contact time of gas/air flow with the packing?*

Ans. It is usually less than half-a-minute.

Q. *What is the thickness of the packing sheets?*

Ans. 0.6–1.25 mm.

Q. *Do the packings in a regenerative air heater come in the form of sheets only?*

Ans. No. In some cases packing is made up of balls of metal, ceramic or glass.

Q. *What are the basic drawbacks of corrugated packing?*

Ans. 1. Rapid destruction of thin sheets of metal due to erosion and corrosion
2. Low heat-transfer coefficient in longitudinal flow.

Q. *What is the relation between the flows of combustion products and air in the rotary regenerative air heater?*

Ans. These two flows are in counter-current relations.

Q. *How is combined air heating accomplished?*

Ans. Air is preheated by low-temperature steam (or hot water) in a steam-air heater (or low-pressure economizer-air heater) and then finally heated in the tubular air heater by the combustion products.

Q. *What are the advantages of this combined system of air heating?*

Ans. It fits well in combating low-temperature corrosion when high-sulphur fuel is used.

Secondly, the waste-heat of the turbine exhaust steam is utilized in air preheating, thus decreasing the heat loss in the circuit.

Q. *What is the steam air heater?*

Ans. It is a tubular heat exchanger in which low-temperature steam flows in the tubes while air flows in the shell-side in cross-current flow. (Fig. 34.9)

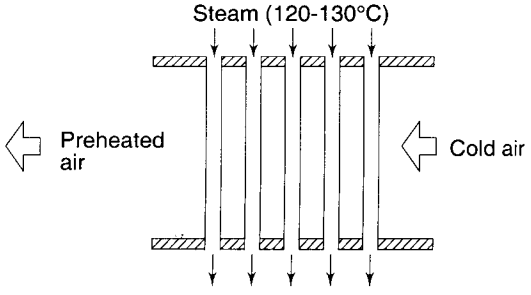


Fig. 34.9 *Steam-air heater.*

Q. *What is the temperature of this heating steam?*

Ans. About 120–130°C.

Q. *Where does this steam come from?*

Ans. It is the worked-off steam from the steam turbine.

Q. *At which point in the circuit is this steam-air heater introduced?*

Ans. Downstream of the air blower. [Fig. 34.10]

Q. *How does the combined scheme of air preheating with economizer and air heater operate?*

Ans. In this scheme air is preheated in a closed cycle low-pressure economizer-air heater system.

The preheated air is finally heated in a tubular air heater by hot combustion products. [Fig. 34.11]

Q. *What is the advantage of this circuit?*

Ans. Air inleakage is substantially reduced.

Q. *Why is the system made closed?*

Ans. The system operates by closed cycle so that contamination of the condensate by corrosion products is prevented.

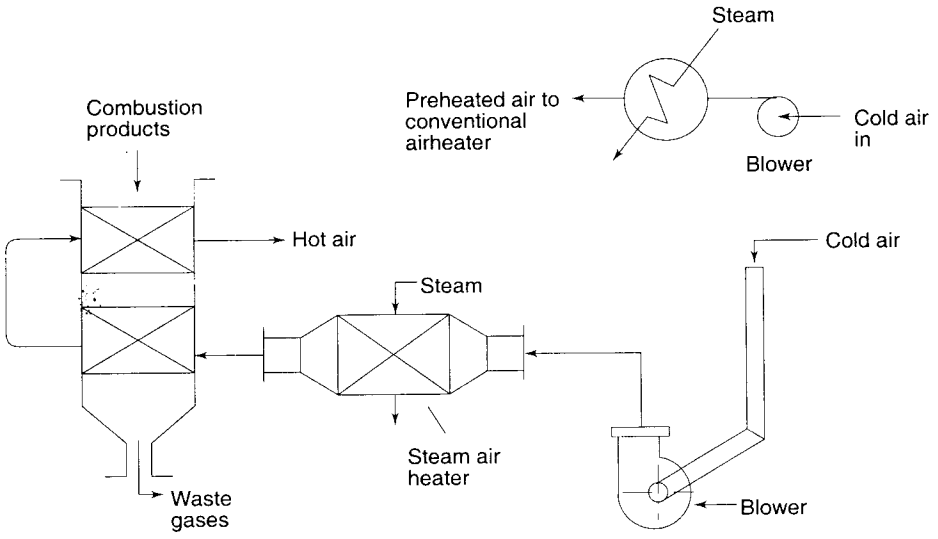


Fig. 34.10 *Steam-air heater is provided downstream of the air blower.*

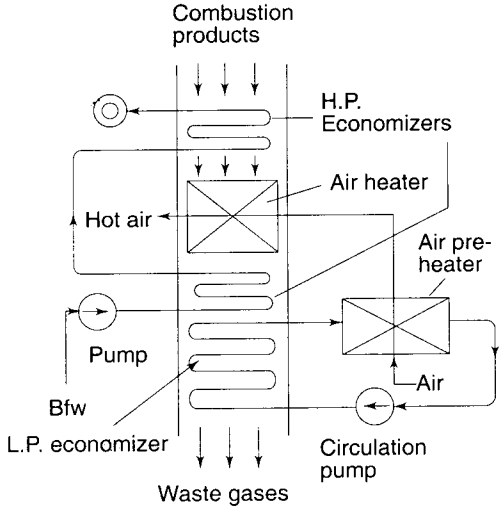


Fig. 34.11 *Combined system of air heating*

Q. *What is the temperature of deaerated water in the closed loop?*

Ans. It is kept slightly greater than 140°C—the dew point of H_2SO_4.

Q. *Why is the temperature of deaerated water in the closed loop kept slightly greater than 140°C?*

Ans. Otherwise acid vapour will condense on the heat exchange surface and contribute to acid corrosion and loss of metal.

Q. *Among all the known methods of combating low-temperature corrosion of heating surfaces which ones are the most efficient?*

Ans. 1. Raising the working temperature of heating surfaces (metal) above the dew point.
2. Operating the air heater in those regions of the curve where the corrosion is low. (Fig. 34.12)
3. Burning fuel at the lowest excess air ratio.

Q. *What is the most widely applicable method for raising the working temperature of the heating surfaces?*

Ans. The local temperature of the wall of the heating surface is given by

$$\theta_w = (\theta_a)_i + \left(\frac{q}{\alpha}\right)_i$$

where, $(\theta_a)_i$ = air temperature at the inlet

q = rate of heat transfer

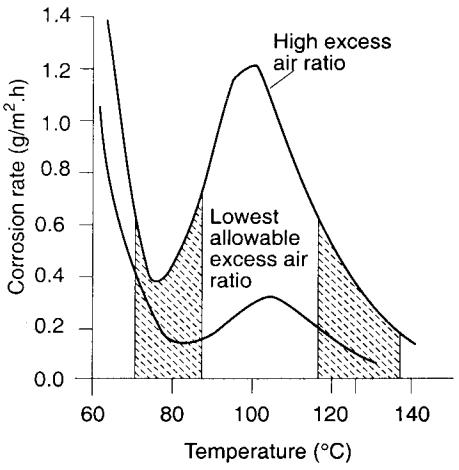


Fig. 34.12 *Corrosion rate vs. temperature.*

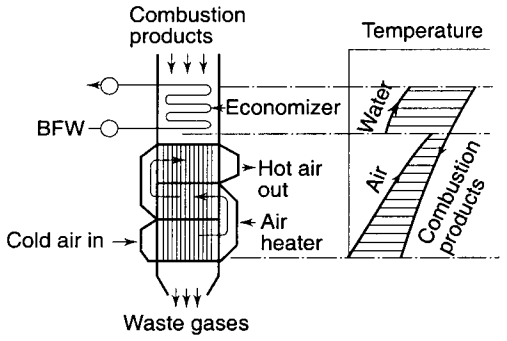


Fig. 34.13 *Single-stage arrangement of economizer and air heater.*

α = coefficient of heat transfer from the wall to air.

So by increasing the inlet air temperature, the working surface temperature can be raised.

Therefore, the most widely applied method is to preheat air in the steam-air preheater and then subject the preheated air to conventional air heaters.

Q. *What are the other methods in fighting low-temperature corrosion in air heaters?*

Ans. 1. Replacing steel tubes with glass tubes (OD: 30–40 mm; thickness: 3.5–4 mm) where the corrosion is particularly intensive
2. Application of corrosion-resistance paints to heating surfaces. These paints are acid-and heat-resistant enamels
3. Injecting additives (e.g. aq. solution of $MgCl_2$) to high-sulphur fuel oil. These will neutralize the acid vapours of the combustion products.

Q. *Why can the burning of high-sulphur fuel oil at the lowest excess air ratio reduce low-temperature corrosion?*

Ans. Low-temperature corrosion due to condensed film of sulphuric acid produced on combustion of high-sulphur fuel oil can be minimized by using minimal excess air ratio. With low excess air ratio, the excess of O_2 supplied to fuel burning is low. Therefore, combustion products will contain less SO_3 and therefore, the sulphuric acid corrosion will be lower.

Q. *Graphically describe the distribution of temperature gradients in a single-stage arrangement of economizer and air heater.*

Ans. Figure 34.13.

Q. *What is the difference between the temperature distribution curves of the economizer and the heater hooked up in a single-stage arrangement?*

Ans. In the economizer, the temperature gradient at the hot end increases while that at the hot end of the air heater decreases.

Q. *Why does the temperature gradient at the hot end of the economizer increase?*

Ans. It is because water has a much higher heat capacity than air causing an appreciable higher rate of cooling of the combustion products in the economizer than in the air heater.

Q. *In the single-stage circuit what is the limit of air preheating for efficient operation?*

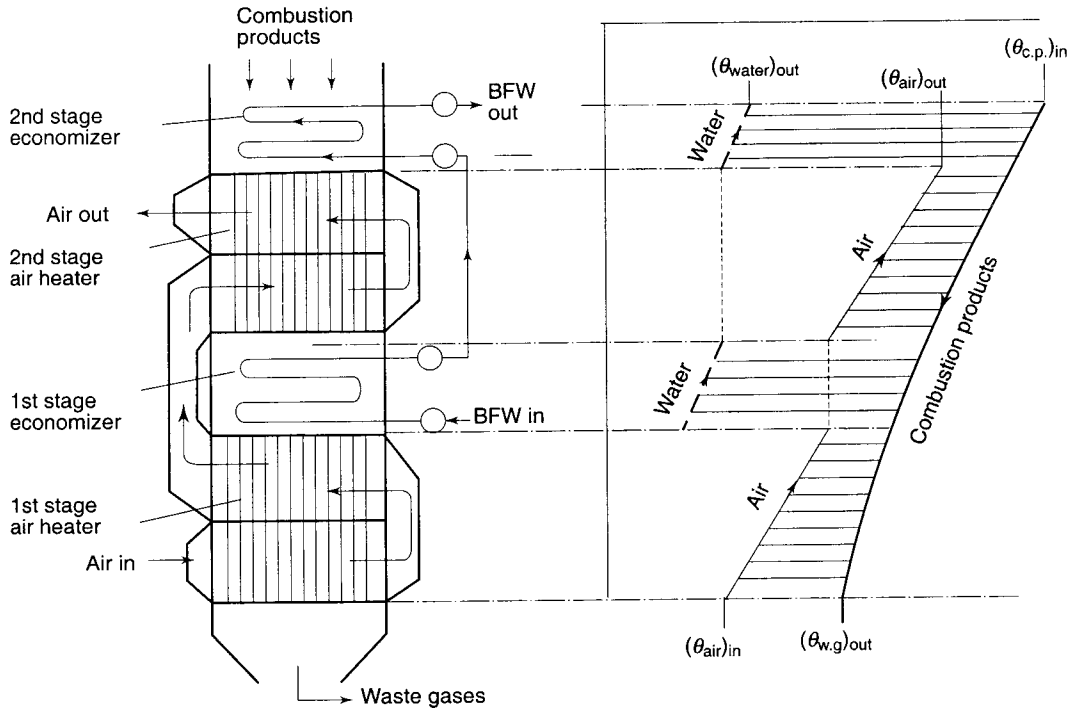


Fig. 34.14 *Two-stage arrangement of the economizer and air heater.*

Ans. 250–350°C.

Q. *If the air is to be preheated to a higher temperature, say 350–450°C, what arrangement should be done?*

Ans. Two stage arrangement in which the economizer is placed between the two sections of the air heater. (Fig. 34.14)

Q. *Why is a hot section of the economizer placed before the second stage of the air heater?*

Ans. The tubes of air heaters are made of carbon steel that limits the allowable surface temperature to 500°C. Therefore, this means that for air preheating to 400–425°C, the temperature of the combustion products should not exceed 570-580°C. Since the temperature of the combustion products downstream of the superheater is appreciably higher (600–650°C), in order to protect the metal of the air heater tubes, the combustion products must be cooled to 580°C before allowing it to pass through the air heater. Hence a hot section of the economizer is mounted before the 2nd stage of the air heater.

Q. *What is an economizer?*

Ans. It is a tube-and-shell type heat exchanger designed for preheating the BFW before it is fed to the evaporator via the boiler drum. The tubes are either straight or given the shape of coils.

Q. *Why is the term economizer applied?*

Ans. An economizer is essentially a shell-and-tube type heat exchanger which recovers waste heat from the flue gas and transfers it, as sensible heat, to the BFW before it is mixed with the circulating boiler feedwater. This added heat goes to improve the economy of the steam generator and herein lies the implication of the term economizer.

Q. *The present trend in boiler design is to increase the heat absorbing surface of the economizer and proportionally decrease that of the steam generator i.e. waterwall. Why?*

Ans. It is due to a greater heat transfer in the economizer than in the convection surfaces of the boiler. Since BFW enters the economizer at a temperature much lower that of the boiler steam, more effective heat transfer takes place at this point than in the convection waterwalls of the boiler.

The non-steaming economizers with air heater included occupy 25–30% of the heating surface as compared to the boiler heating surface. This figure doubles when the air heater is excluded from the system. For steaming economizers this figure comes out to be 25–50%.

Q. *Compared to the air preheater, what distinct advantages does an economizer possess?*

Ans. 1. It befits small capacity plants and those operating at low pressure well because of low initial cost
2. Lower requirement of auxiliary power
3. Endows quicker steam generation capacity when operated with on-off cycles
4. Requires less space for a given duty
5. Cuts down the load on the furnace and the burners more effectively.

Q. *What is an integral economizer?*

Ans. It is a special type of economizer having vertical banks of tubes arranged within the boiler casing.

Q. *In which type of boilers is it used?*

Ans. With bent-tube boilers only.

Q. *Sometimes an integral economizer may be of the intertube type having the elements placed between the tubes of a boiler convection bank. Why is this arrangement chosen?*

Ans. If affords a compact and economical design of the economizer by eliminating the need for separate casing and supports.

Q. *How many kinds of integral economizers are known?*

Ans. Generally three:
1. Single-drum type
2. Double-drum type
3. Steaming economizer type.

Q. *How does a double-drum type economizer function?*

Ans. It comprises of two drums—one upper and the other lower, interconnected by banks of vertical tubes. Into the compartmented upper drum is introduced the boiler feedwater which then moves down one bank of tubes to the lower drum from which it flows back again (completing a 2-pass unit) before being discharged into the boiler drum.

The flue gas path is baffled vertically to ensure counterflow in the multipass (usually 2- or 3-pass) arrangements; also it may be in a single or multipass-crossflow arrangement with the water circuit in some cases.

Q. *In which cases are steaming economizers installed?*

Ans. These are meant for generating steam at higher output rates, i.e. these are provided for high-capacity steam generating units.

Q. *Why is a steaming economizer incompatible with high-feed make-up boiler units?*

Ans. It is because of the inherent problems associated with suitable treatment of boiler feedwater at high rate.

Q. *What are the dimensions of economizer tubes.*

Ans. ID : 20–30 mm and thickness: 2.5–3.5 mm.

Q. *Why are small dia tubes chosen?*

Ans. To maximize the rate of heat transfer and minimize fouling.

Q. *What is the extent of draft loss in an economizer?*

Ans. It usually ranges from 60–75 mm of water column. It rarely exceeds 100 mm of the water gauge.

Q. *Why is the BFW delivered to the economizer at a pressure 10–20% over the boiler pressure?*

Ans. This will make the necessary allowance for the pressure drop in the BFW as it passes through

the economizer tubes, BFW regulator (if any), piping and valves.

Q. *At which point is the BFW regulator located in the economizer?*

Ans. At the discharge end of the economizer.

Q. *Why is it placed there?*

Ans. To increase the feedwater pressure as well as to minimize the possibility of steam formation.

Q. *Is it possible to operate the economizer at a pressure lower than boiler pressure?*

Ans. Yes.

Q. *In which case is it possible?*

Ans. Occasionally, some cast-iron economizers are installed to operate at a pressure lower than boiler pressure.

Q. *Then how does this system function in conjugation with the boiler working at higher operating pressure?*

Ans. A booster pump is fitted into the water circuit downstream of the economizer. This pump boosts up the hot BFW at the outlet of the economizer to a pressure necessary for delivering it to the boiler drum.

Q. *Does the inlet temperature of the BFW to the economizer affect the efficiency of the latter?*

Ans. Yes; as the inlet feedwater temperature is raised, the efficiency of the economizer decreases.

Q. *What is the maximum temperature limit of the BFW normally before its entry into the economizer?*

Ans. Normally it is not allowed to exceed 105°C, however in some high-pressure plants the BFW is preheated to 200°C before its entry to the economizer.

Q. *Why is the boiler water often recirculated to the economizer?*

Ans. 1. To increase the pH of feedwater by 2–4% which is adequate.
2. To raise the temperature to avoid cold end-condensation.

Q. *What is the pH value of water in steel tube economizers?*

Ans. 8 to 9.

Q. *Why is the final temperature of BFW at the economizer outlet usually kept at a temperature about 10°C less than the saturation temperature?*

Ans. Steam formation will occur within the economizer tubes if the boiler feed is restricted or cut off.

Q. *What harm will it cause?*

Ans. This will cause water hammer and thermal stress in the economizer tubes. When the boiler feed is restricted or cut off, a considerable portion of water in the economizer will convert to steam which will escape rapidly as soon as the boiler feed is resumed, leaving the economizer partially empty. When water surges in to fill this void space, it will give birth to water hammer as well as temperature strains that may finally result in economizer tube failure.

Q. *In which case does the above limitation on the BFW temperature at the outlet of economizer not exist?*

Ans. In the case of steaming economizer where steam formation takes place within the economizer itself.

Q. *Earlier steam generating units would install economizer by-pass flues. What are the utilities of such by-passing?*

Ans. This system
(a) prevents cold-end condensation during start-up
(b) harnesses the natural draft when economizer or ID fan goes out of service
(c) prevents the formation of steam in the economizer.

Q. *What are the usual materials of construction of economizer tubings?*

Ans. These are made of
(a) steel for high pressure steam generators
(b) cast iron for lower pressure steam generators.

Q. *What kind of steel?*

Ans. Low alloyed pearlitic-class steels; Mn: 0.9–1.25%; Si: 0.7–1.0%

Note: For more details of MOC, please refer to APPENDIX–III.

Q. *What are the advantages of steel tubes used in the economizer?*

Ans. 1. They ensure a more compact economizer design.
2. Permit steam generation at elevated pressure and temperature and at higher rate.
3. Ensure a higher rate of heat transfer for a given weight
4. Cost is relatively low.

Q. *Are these steel tubes bare or provided with extended surfaces?*

Ans. Both kinds are known. Fins, rings and studs are welded to the top and bottom of steel tubes of the economizer.

Q. *What modification is done to increase the rate of heat transfer from the flue gas side and to increase the compactness of the apparatus?*

Ans. Fins are welded on the gas-side tube surface of the economizer. These increase the effective heating surface area on the gas-side and hence the heat absorption.

Q. *What are the advantages of finned tubes over plain tubes used in the economizer?*

Ans. 1. This system increases the heating surface resulting an overall gain in heat absorption on the gas-side and hence higher steam output rate
2. Prevents the tube from sagging
3. Minimizes slag deposition on the tube top
4. Finned tubes with rectangular fins occupy a volume which is 1/3-1/4th less than the volume occupied by plain tubes for the same draft and same amount of metal.
5. The economizer becomes more compact. The dimensions of the economizer are curtailed by 40–50%

Q. *Other than rectangular fins what fins are used in finned-tube economizers?*
1. Trapezoidal fins
2. Helical fins
3. Circular fins.

Q. *In which cases can economizer tubes be made of cast-iron?*

Ans. Cast iron materials are best suited for the purpose of low pressure operation. Also these are found suitable when
1. BFW is not fully treated
2. BFW is not totally deaerated
3. Operational attention and maintenance are hampered.

Q. *How many types of economizers are used in practice?*

Ans. Two types: Boiling and Non-boiling.

Q. *What is a boiling type economizer?*

Ans. This type of economizer is characterized by the transformation of a part of the boiler feedwater (BFW) into steam.

Q. *How much of BFW is converted into steam in a boiling type economizer?*

Ans. Maximum 25%.

Q. *What is a non-boiling type economizer?*

Ans. In this type of economizer, the BFW is heated below the saturation point.

Q. *What are membrane type economizers?*

Ans. These are made up of plain tubes with steel-membranes (steel sheets 2–3 mm thick) welded in between the straight portion of the tubes. (Fig. 34.15)

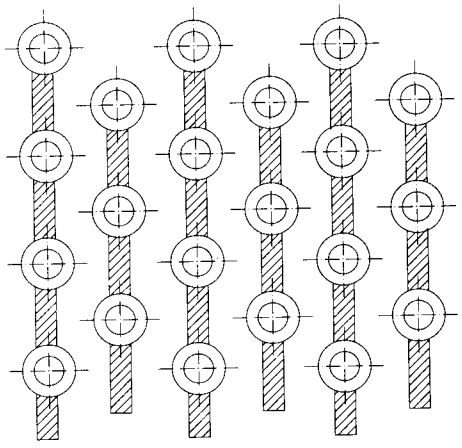


Fig. 34.15 *Tubes welded with steel membranes enhance the heat transfer characteristics of membrane type economizer*

Q. *What are the advantages of membrane type economizers over plain tube type economizers?*

Ans.

1. Higher efficiency
2. More reliable in operation
3. Require less metal for the same amount of heat absorption.

35

STEAM CONDENSERS

Q. *What is a steam condenser?*

Ans. It is a heat exchanger wherein steam is condensed either in direct contact with cooling water or indirect contact with cooling water through a heat transfer medium separating them.

That is, a steam condenser is either a direct contact or indirect contact heat exchanger.

Q. *How many types of steam condenser are known?*

Ans. Two main types:

1. JET CONDENSER (direct contact heat exchanger)
2. SURFACE CONDENSER (indirect contact heat exchanger)

Q. *What is a jet condenser?*

Ans. It is a direct contact heat exchanger in which steam to be condensed comes into direct contact with the cooling water (cold condensate) which is usually introduced in the form of a spray from a jet. (Fig. 35.1)

Upon contact with the cooling water, the steam gives up its enthalpy and gets cooled and ultimately settles as condensate.

Q. *What is a surface condenser?*

Ans. It is a shell-and-tube heat exchanger in which steam is condensed on the shell-side while cooling water flows through the tubes. The condensate and cooling water leave the system separately.

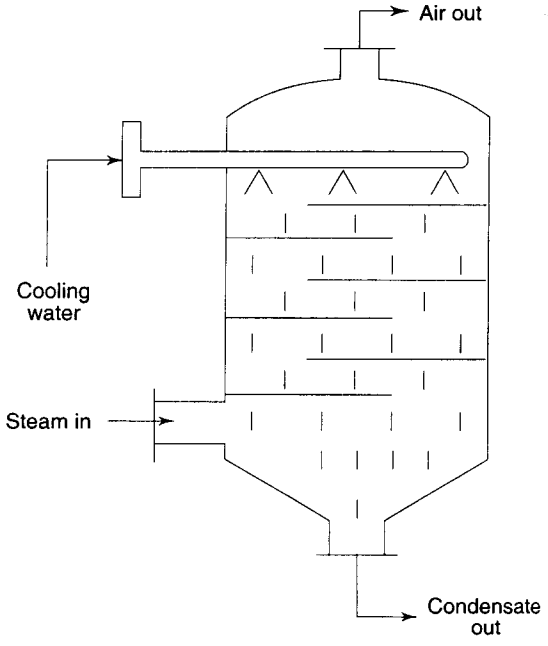


Fig. 35.1 *Jet condenser.*

Q. *How many types of jet condensers are known?*

Ans. Three types:

1. Parallel flow type
2. Contra flow type
3. Ejector type.

Q. *What is a parallel flow jet condenser?*

Ans. It is a kind of jet condenser in which both exhaust steam and cooling water enter the con-

denser at the top, both flow downward and the steam condensate discharges from the bottom of the condenser.

Q. *How many types of parallel flow jet condenser exist?*

Ans. Two types:

1. Low level parallel flow jet condenser
2. High level parallel flow jet condenser.

Q. *How does the low level parallel flow jet condenser function?*

Ans. Exhaust steam is introduced from the top of the condenser while cold condensate is sprayed upon it through multiple jets. As steam comes in cntact with cold condensate particles, its enthalpy drops and it settles at the bottom as condensate. (Fig. 35.2)

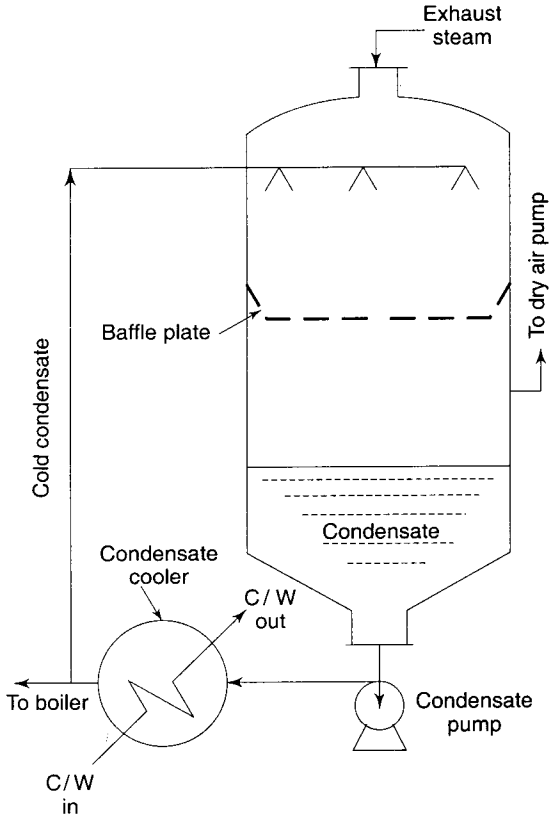


Fig. 35.2 *Operating principle of low-level-parallel-flow jet condenser.*

Vacuum is maintained in the condenser with the aid of a dry air pump which also extracts air present in the condenser.

The condensate collected at the bottom is cooled in the condensate cooler by cooling water and is partly recycled and partly sent as boiler feedwater.

Q. *What is the principle of operation of a high-level-parallel-flow jet condenser?*

Ans. This condenser, also called a *barometric condenser*, works as follows:

The condenser is mounted on a long pipe (at least 10.34 m) called a barometric leg which acts identical to a barometer.

Now if water is used in the barometer then the barometric height would be 10.34 m. If some vacuum exists in the condenser, the height of water column (h) will be less than 10.34 m. Now it is possible, by using this condenser leg, to drain away the condensate from the condenser.

This vacuum is maintained by constant high level discharge from the atmospheric tank through the atmospheric leg that dips deeply into the water in the atmospheric tank. (Fig. 35.3)

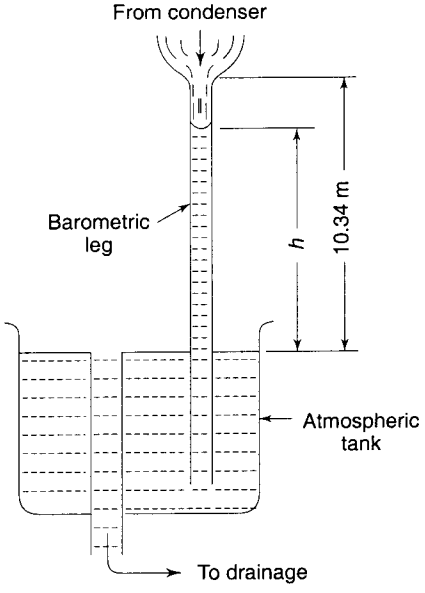


Fig. 35.3 *Operating principle of high-level parallel-flow jet condenser.*

Q. *What is a contra-flow jet condenser?*

Ans. In this type of jet condenser the cooling fluid (cold condensate) and exhaust steam flow in a counter-current direction—steam goes up and cold condensate rains down.

Q. *How many types of contra-flow jet condensers exist?*

Ans. Two types:

1. LOW LEVEL CONTRA-FLOW JET CONDENSER
2. HIGH LEVEL CONTRA-FLOW JET CONDENSER

Q. *How does the low-level contra-flow jet condenser operate?*

Ans. Exhaust steam enters the condenser near the bottom and moves up through a pipe P. As it goes up, it comes in direct contact with cold condensate distributed into the condenser through perforated trays T_1, T_2 and T_3. (Fig. 35.4).

Vacuum is maintained through an air suction pump.

Condensate collected at the bottom is partly sent as BFW and the rest is recycled via the condensate cooler.

Q. *Between the low-level contra-flow jet condenser and low-level parallel-flow jet condenser which one is more efficient?*

Ans. The low-level contra-flow jet condenser is more efficient.

Q. *Why?*

Ans. It is because the hottest steam comes in contact with the hottest water. So as steam goes more and more up, it comes into contact with more and more colder condensate and that enhances the steam condensation.

Q. *How does the high-level contra-flow jet condenser work?*

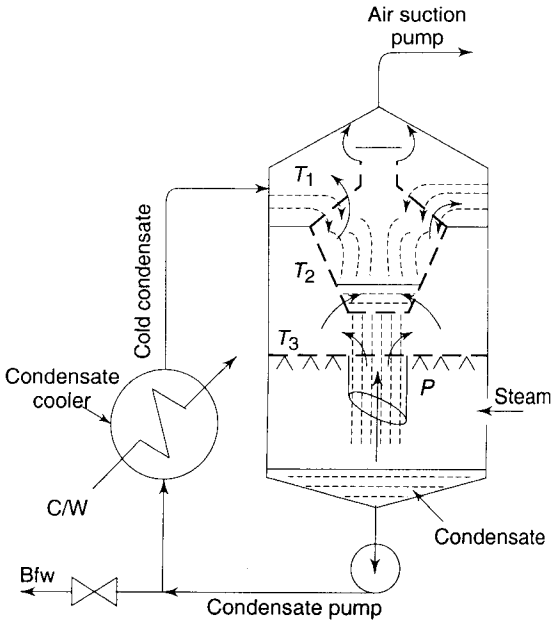


Fig. 35.4 *Operating principle of low-level contra-flow jet condenser.*

Ans. The condenser is placed 10.34 m above the hot-well. The condenser is operated at a pressure somewhat less than atmospheric pressure such that the water level in the tail pipe remains always below 10.34 m. And therefore, any steam condensing to the condensate is spontaneously drained off. (Fig. 35.5).

Q. *What is an ejector condenser?*

Ans. It is a kind of jet condenser in which mixing of cooling water and steam takes place in a series of combining cones and the kinetic energy of the steam is expended to drain off the condensate and cooling water from the condenser. (Fig. 35.6)

Q. *How does it work?*

Ans. Cooling water is forced through a series of cones and gets mixed with steam coming through ports.

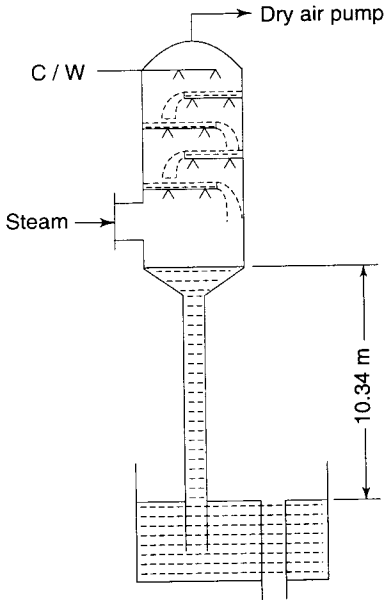


Fig. 35.5 *Operating principle of high-level contra-flow jet condenser.*

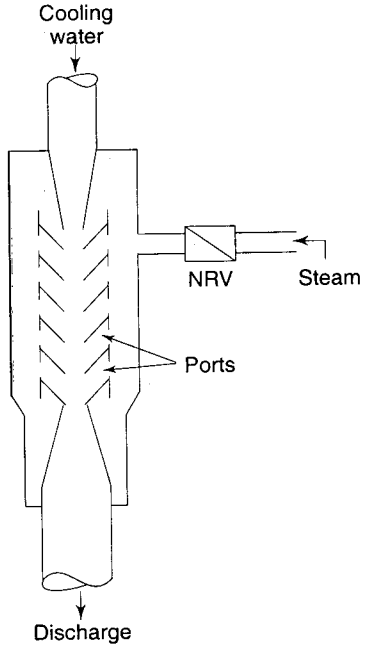


Fig. 35.6 *Ejector condenser.*

As the cooling water flows through the series of nozzles, it suffers more and more pressure drop and at the same time its velocity gradually increases. (Fig. 35.6)

Due to this pressure drop, more and more steam is drawn through the ports, gets intimately mixed with the cooling water jet and condenses thereafter.

A NRV (non-return valve) is provided on the steam inlet line to prevent the backflow of condensate in case of failure of the cooling water supply.

Q. *How many types of surface condensers are known?*

Ans. Four types.

1. Downflow type
2. Central flow type
3. Inverted flow type
4. Evaporative condenser type.

Q. *How does the downflow type surface condenser act?*

Ans. Exhaust steam is admitted to the top of the condenser which is a tube-and-shell type crossflow heat exchanger. Cooling water flows through the tubes and extracts heat from the steam which is on the shell-side. After having condensed on the surface of the water tubes, steam is converted into condensate which is discharged from the condenser bottom. (Fig. 35.7)

Q. *How does the central flow type surface condenser works?*

It is also a shell-and-tube type crossflow heat exchanger, at the centre of which is located the suction of an air extraction pump so that the entire steam moves radially inward and comes in better contact with the outer surface of the nest of tubes through which the cooling water flows. The steam condensate is extracted from the bottom by the condensate-extraction pump (Fig. 35.8)

Q. *How does the inverted type surface condenser work?*

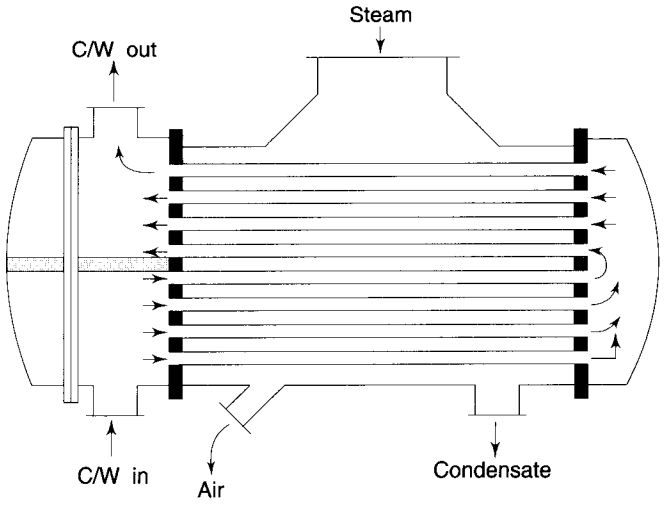


Fig. 35.7 *Downflow type surface condenser.*

Ans. In this type of condenser, steam is admitted at the bottom and flows upwards in cross-flow with the cooling water flowing in the tubes. The air extraction pump draws its suction from the top of the condenser, maintaining a steady upward current of steam which after having been condensed on the outer surface of the water tubes is removed by the condensate extraction pump.

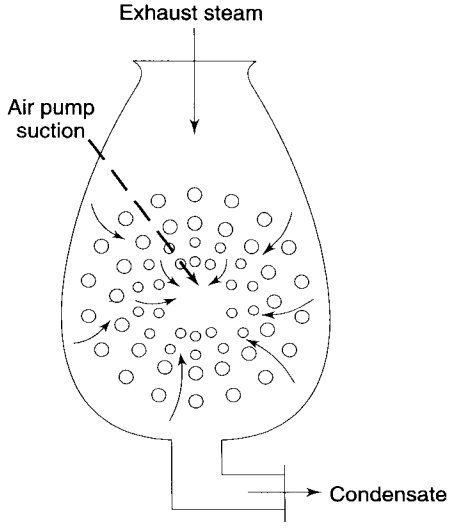


Fig. 35.8 *Working principle of central flow type surface condenser.*

Q. *How does the evaporative condenser function?*

Ans. Exhaust steam from the turbine is condensed inside the finned tubes as cooling water rains down from the top through the nozzles. A part of the cooling water in contact with the tube surface evaporates by drawing enthalpy from the steam which upon losing its latent heat condenses and discharges out as condensate. (Fig. 35.9)

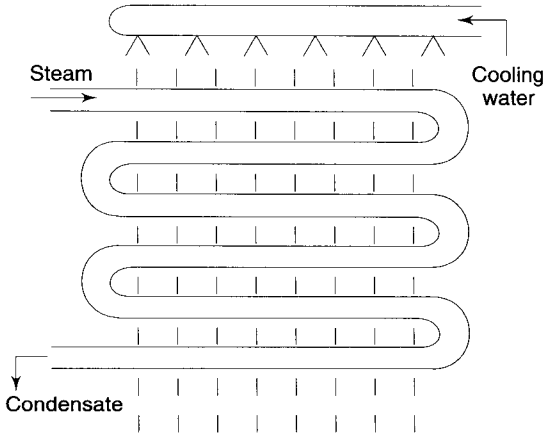


Fig. 35.9 *Working principle of evaporative condenser.*

Q. *Where is the evaporative condenser used in practice?*

Ans. In those cases where the shortage of cooling water is acute.

Q. *What are the prime functions of a condenser?*

Ans. There are two important functions of condenser

1. It reduces the back pressure upon the turbine to a considerable degree and therefore, the work done per kg of steam during expansion is increased
2. The exhaust steam condensate can be recycled as boiler feedwater.

Q. *What are the auxiliary equipment required for operating a steam condenser?*

Ans. 1. Cooling water (which may be cold condensate) circulation pump. Generally, it is a centrifugal one
2. Arrangement for cooling the condensate (i.e. a heat exchanger) in case the condensate is recycled to extract heat from the exhaust steam
3. An air pump or steam ejector to remove air and other non-condensing gases from the condenser
4. An extraction pump (usually centrifugal) to remove condensate from the condenser.

Q. *What should be the basic criteria for an efficient steam condenser?*

Ans. 1. Maximum amount of steam condensed per unit area of available heat transfer surface.
2. Minimum quantity of circulating coolant required.
3. Minimum heat transfer surface required per kW capacity
4. Minimum power drawn by the auxiliaries.

Q. *Why is vacuum maintained in the steam condenser?*

Ans. By maintaining a vacuum in the steam condenser, the efficiency of the steam-power plant can be increased as greater the vacuum in the system, greater will be the enthalpy drop of steam. Therefore, more work will be available per kg of steam condensing.

Secondly, the non-condensate (air) can be removed from the condensate-steam circuit by pulling and maintaining a vacuum in the steam side. Therefore, the condensate can be used as boiler feed.

Q. *What are the advantages of a jet condenser over a surface condenser?*

Ans. 1. Simplicity in design
2. Lower in manufacturing cost
3. Lower maintenance cost
4. Occupies lesser floor space
5. Requires lesser amount of cooling water.

Q. *What are the advantages of a surface condenser over a jet condenser?*

Ans. 1. A surface condenser imparts to power generation plant a higher thermal efficiency
2. The condensate can be reused as boiler feed-water
3. Auxiliary power requirement is less than that of a jet condenser
4. Less amount of air is carried to the boiler.

Q. *What are the limitations of a surface condenser?*

Ans. 1. It is very bulky and as such requires more floor space
2. Its manufacturing, running and maintenance costs are high.

Q. *What should be the requirements of an ideal surface condenser used for steam power plants?*

Ans. 1. Uniform distribution of exhaust steam throughout the heat transfer surface of the condenser
2. Absence of condensate sub-cooling
3. There should not be any leakage of air into the condenser

4. There should not be any tube leakage
5. The heat transfer surface in contact with cooling water must be free from any deposit as scaling reduces the efficiency of heat exchangers.

Q. *What do you mean by vacuum?*

Ans. Vacuum means any pressure below atmospheric pressure.

Q. *How is vacuum in a condenser usually measured?*

Ans. It is measured by means of a *Bourdon pressure gauge* which is calibrated to read the pressure in mm of mercury below atmospheric pressure.

Q. *If the gauge pressure of a condenser is 630 mm of Hg, what will be the absolute pressure in the condenser?*

Ans. It means the pressure in the condenser is 630 mm below atmospheric pressure.

The atmospheric pressure is 760 mm of Hg, the absolute pressure in the condenser is

$= 760 - 630 = 130$ mm Hg $= 130\ (0.1334) = 17.34$ kN/m^2

Q. *On what factors does the degree of vacuum in a condenser depend?*

Ans. It depends on the partial pressure of steam and the partial pressure of air in the condenser.

Q. *What will be the absolute pressure in the condenser?*

Ans. $P_{abs} = p_{steam} + p_{air}$

where

P_{abs} = Absolute pressure in the condenser

p_{steam} = Partial pressure of steam

p_{air} = Partial pressure of air in the condenser.

Q. *What is the vacuum efficiency of a condenser?*

Ans. It is the ratio of actual vacuum at the steam inlet to the maximum obtainable vacuum in a perfect condensing plant, i.e. it is the ratio of actual vacuum to ideal vacuum.

$$\text{Vacuum Efficiency} = \frac{\text{Actual Vacuum}}{\text{Ideal Vacuum}}$$

$$= \frac{P_{atm} - (p_{sat} + p_{air})}{P_{atm} - p_{sat}}$$

where

P_{atm} = Atmospheric pressure

p_{sat} = Saturation pressure of steam at condenser inlet

p_{air} = Partial pressure of air in the condenser.

Problem 35.1 A surface condenser operates at a vacuum of 635 mm Hg and exhaust steam enters the condenser at 49°C. Calculate the vacuum efficiency of the condenser if the barometric pressure is 760 mm Hg.

Solution Vacuum efficiency of the surface condenser

$$= \frac{\text{Actual Vacuum}}{\text{Ideal Vacuum}} = \frac{\text{Actual Vacuum}}{P_{atm} - p_{sat}}$$

Now, actual vacuum = 63.5 cm Hg

p_{sat} at 49°C = 0.12 kgf/cm^2

= 0.12/0.01359 cm of Hg

= 8.83 cm Hg

Ideal Vacuum = 76 – 8.83 = 67.17 cm Hg

Vacuum Efficiency = (63.5/67.17) (100)

= 94.53%

Ans.

Problem 35.2 The vacuum in a condenser is 685 mm Hg when the barometer is recording 765 mm Hg. Correct this reading to the standard barometer of 760 mm Hg.

Solution Absolute pressure in the condenser = [Actual barometer reading] – [Actual Vacuum]

= 765 – 685 = 80 mm of Hg

Correct Vacuum = 760 – 80 = 680 mm Hg

Q. *What is condenser efficiency?*

Ans. The widely accepted definition is

Condenser Efficiency

$$= \frac{\text{Rise of Temperature of Cooling Water}}{\left[\begin{array}{l}\text{Temp. corresponding}\\ \text{to the vacuum in}\\ \text{the condenser}\end{array}\right] - \left[\begin{array}{l}\text{Inlet Temperature}\\ \text{of Cooling Water}\end{array}\right]}$$

Note: There is actually no standard and universal definition of condenser efficiency.

Problem 35.3 A surface condenser operates under a vacuum of 680 mm Hg. The cooling water inlet and outlet temperatures being 33°C and 40°C respectively.

Determine the efficiency of the surface condenser if the barometer reading is 760 mm Hg.

Solution

Step (I) Absolute Pressure in the Condenser

Condenser Efficiency

$$= \frac{\Delta\theta \text{ of Cooling Water}}{\left[\begin{array}{l}\theta_{sat} \text{ corresponding}\\ \text{to the abs. press. in}\\ \text{the condenser}\end{array}\right] - [\theta_{in} \text{ of Cooling Water}]}$$

Now, absolute pressure in the condenser

= 760 – 680 mm Hg

= 80 (1.0322/760) kgf/cm^2

= 0.10865 kgf/cm^2

Step (II) Saturation Temperature Corresponding to 0.10865 kgf/cm^2

Saturation Pressure	Saturation Temperature
0.12 kgf/cm^2	49°C
(–) 0.10 kgf/cm^2	(–) 45.5°C
0.02 kgf/cm^2	3.5°C

Difference 0.02 kgf/cm^2 correspond to sat. temperature difference of 3.5°C.

Difference 0.00865 kgf/cm^2 correspond to sat. temperature 3.5 (0.00865)/0.02 = 1.5°C

Hence the saturation temperature corresponding to 0.10865 kgf/cm^2

= 45.5 + 1.5 = 47°C

Step (III) Condenser Efficiency

$$\eta_{cond} = \frac{40 - 33}{47 - 33} = 0.5 \text{ i.e. } 50\% \qquad \textbf{Ans.}$$

Problem 35.4 The vacuum produced in a surface condenser is 685 mm of Hg when the barometer reading is 760 mm of Hg. The condensing steam temperature is 36°C. the net volume of steam space is 25 m^3.

Determine:

(a) the partial pressure of air

(b) the mass of air present in the condenser

Solution

Step (I) Partial Pressure of Air

$$P_{abs} = p_{sat} + p_{air};$$

$$\therefore \quad p_{air} = P_{abs} - p_{sat}$$

Now, P_{abs} = (760 – 685) mm of Hg

= 75 mm Hg = 75 (0.001359) kgf/cm^2

= 0.10192 kgf/cm^2

Partial pressure of air = 0.10192 – p_{sat} at 36°C

= 0.10192 – 0.06 = 0.04192 kgf/cm^2

Ans.

Step (II) Mass of Air in the Condenser

Applying the characteristic gas equation

$PV = mRT$ we get,

$$(0.04192 \times 10^4)\ (25) = m(29.27)\ (273 + 36)$$

$$\therefore \quad m = 1.1588 \text{ kg} \approx 1.16 \text{ kg}$$

Ans.

Problem 35.5 A certain surface condenser condenses 20 t/h of exhaust steam (49°C) from a turbo-alternator. The dryness fraction of the steam is 0.85.

Determine the flowrate of cooling water.

Cooling water inlet temperature = 33°C

Cooling water outlet temperature = 42°C

Condensate temperature at the exit = 49°C.

Solution

Step (I) The flowrate of cooling water can be computed from the heat balance equation of the surface condenser, where

Total heat rejected by condensing steam = Net heat gained by cooling water

Now, the latent heat of the condensing steam at 49°C = 568.6 kcal/kg

Since it is 0.85 dry, the total heat rejected by condensing steam

$= (20 \times 10^3/3600)\ (568.6 \times 0.85)$ (kg/s) (kcal/kg)

If the flowrate of cooling water is $\dot{M}$, then

$\dot{M}\ (1)\ (42 - 33) = (20 \times 10^3/3600)\ (568.6 \times 0.85)$

(kcal/kg. °C) (°C) (kcal/s)

$$\therefore \quad \dot{M} = (20 \times 10^3/3600)\ (568.6 \times 0.85)/9$$

$$= 298.339 \text{ kg/s} = 1074 \text{ t/h}$$

Ans.

Problem 35.6 Designed to handle 15 t/h of steam, a surface condenser receives steam at 0.10×10^4 kgf/m^2 and 0.95 dry. The cooling water inlet and outlet temperatures are 27°C and 36°C respectively.

Determine the flowrate of cooling water if the condensate leaves at saturation temperature.

Solution

Step (I) Heat Load of Condensing Steam

Steam is at 0.10×10^4 kgf/m^2:

Total heat of the water, H_w = 45.4 kcal/kg

Latent heat, L = 570.5 kcal/kg

Total heat of the condensate, H_{w_c}

= 45.4 kcal/kg

Heat extracted from condensing steam per unit time

$= [15 \times 10^3/3600]\ [H_w + xL - H_{w_c}]$

(kg/s) (kcal/kg)

$= (15 \times 10^3/3600)\ (0.95)\ (570.5)$ kcal/s

= 2258.229 kcal/s

The cooling water takes care of this rate of heat extraction.

Step (II) Flowrate of Cooling Water

If $\dot{M}_{cw}$ is the flowrate of cooling water and its specific heat = 1 kcal/kg. °C, then

$$\dot{M}_{cw}(1)\ (36 - 27) = 2258.229$$

$$\therefore \ \dot{M}_{cw} = 2258.229/9 = 250.914 \text{ kg/s} = 903.29 \text{ t/h}$$

Ans.

Problem 35.7 A surface condenser operates at a vacuum of 699.2 mm of Hg when the barometric head is 760 mm of Hg.

It receives steam at a rate 10 t/h which is 0.9 dry. Calculate the

(a) condenser efficiency

(b) cooling water flowrate.

Cooling water inlet temperature = 33°C

Cooling water outlet temperature = 40°C

The condensate leaves the condenser at saturation temperature.

Solution

Step (I) Absolute Pressure in the Condenser

$$P_{abs} = 760 - 699.2 = 60.8 \text{ mm of Hg}$$

$$= 60.8 \times 0.001359 \text{ kgf/cm}^2$$

$$= 0.0826 \text{ kgf/cm}^2$$

Step (II) Condenser Efficiency

Saturation temperature corresponding to 0.0826 kgf/cm^2 = 42°C.

Cooling Water Temperature		Temperature Corresponding	Condenser Efficiency
Inlet	Outlet	To Vacuum in the Condenser	(η_{cond})
33°C	40°C	42°C	$\frac{40-33}{42-33}$ (100) = 77.77% ***Ans.***

Step (III) Cooling Water Flowrate

STEAM, at 0.0826 kgf/cm^2 → Latent heat = 572.6 kcal/kg

Heat load of condensing steam

$$= \frac{10 \times 10^3}{3600} (H_w + xL - H_{w_c});$$

$$= \frac{10^2}{36} (x \cdot L) \text{ kcal/s}$$

$$= (10^2/36)\ (0.9)\ (572.6)$$

$$= 1431.5 \text{ kcal/s}$$

H_w = total heat of water at 42°C

L = latent heat of steam at 42°C

H_{w_c} = total heat of condensate at 42°C.

(cf. $H_w = H_{w_c}$)

x = dryness fraction of steam

Let the mass flowrate of cooling water be $\dot{M}_{cw}$

$\therefore \quad M_{cw}\ (C_p)_{cw}\ (\Delta\theta)_{cw} = 1431.5$

or, $\quad \dot{M}_{cw} = 204.5 \text{ kg/s} = 736.2 \text{ t/h}$

Problem 35.8 A surface condenser condenses steam at the rate of 20 t/h which leaves the condenser at the corresponding saturation temperature. The condenser operates at a vacuum of 680 mm Hg.

Determine:

(a) condenser efficiency

(b) flowrate of cooling water

(c) number of condenser tubes.

Given:

Cooling water inlet temperature = 33°C

Cooling water outlet temperature = 43°C

Mean velocity of cooling water = 2.5 m/s

Internal diameter of condenser tubes = 19.6 mm

Barometer pressure = 760 mm Hg

Steam is 0.95 dry.

Solution

Step (I)

Vacuum in the Condenser	Barometric Pressure	Absolute Pressure in the Condenser
680 mm Hg	760 mm Hg	760-680 = 80 mm Hg = 80 (0.001359) = 0.10872 kgf/cm^2

Step (II)

Dry Satd. Steam Pressure	Satd. Steam Temperature	Total Heat of the Condensate	Latent Heat
0.12 kgf/cm^2 (–) 0.10 kgf/cm^2	49°C (–) 45.4°C	49 kcal/kg (–) 45.4 kcal/kg	568.6 kcal/kg (–) 570.5 kcal/kg
0.02 kgf/cm^2	3.6°C	3.6 kcal/kg	(–) 1.9 kcal/kg
0.00872 kgf/cm^2	1.56°C	1.5 kcal/kg	(–) 0.8284 kcal/kg
0.10872 kgf/cm^2	45.4+1.56 = 45.96°C	46.96 kcal/kg	570.5–0.8284 = 569.671 kcal/kg

Step (III) Condenser Efficiency

$$\eta_{cond} = \frac{\text{Rise in Temperature of Cooling Water}}{\left[\begin{matrix}\text{Temp. corresponding} \\ \text{to vacuum in the} \\ \text{condenser}\end{matrix}\right] - \left[\begin{matrix}\text{Inlet temperature} \\ \text{of cooling water}\end{matrix}\right]}$$

$$= \frac{43-33}{46.96-33} = 0.716 \text{ i.e. } 71.6\% \qquad \textbf{\textit{Ans.}}$$

Step (IV) Cooling Water Flowrate

Heat rejected by condensing steam = Heat absorbed by cooling water

or, $(20 \times 10^3/3600)\ (0.95)\ (569.671)$

$= \dot{M}_{cw}(C_p)_{cw}(\Delta\theta)_{cw} = \dot{M}_{cw}(1)(43–33)$

$\therefore\ M_{cw} = 300.7$ kg/s **Ans.**

$= 300.7/1000$

$= 0.3\ m^3/s$ **Ans.**

Step (V) Number of Condenser Tubes

Volumetric flowrate through a single tube

$= (\pi/4)d^2v$

where d = ID of condenser tubes

v = velocity of flow of C/water

n is the total number of condenser tubes, then

$(\pi/4)\ d^2\ v\ n = 0.3$

or $(\pi/4)\ (0.0196)^2\ (2.5)\ (n) = 0.3$

or, $n = 398$ **Ans.**

Problem 35.9 The following parameters were recorded for a surface condenser.

Condenser vacuum = 690 mm Hg

Barometric pressure = 760 mm Hg

Mean condenser temperature = 37°C

Condenser exit temperature = 30°C

Rise in temperature of cooling water = 10°C

Rate of steam condensation = 25 t/h

Rate of cooling water flow = 1200 t/h

Determine:

(a) the mass of air present per unit volume of the condenser

(b) the dryness fraction of steam at the inlet to condenser

(c) the vacuum efficiency of the condenser.

Solution

Step (I) Absolute Pressure in the Condenser

Condenser Vacuum	Barometric Pressure	Absolute Pressure in the Condenser
690 mm Hg	760 mm Hg	760 – 690 = 70 mm Hg = 70 (0.001359) = 0.09513 kgf/cm^2

Step (II) Mass of Air/M^3 of Condenser Volume

Partial Pressure of Steam at 37°C	Abs. Press. in the Condenser $P_{abs} = p_s + p_{air}$	Partial Pressure of Air in the Condenser
0.064 kgf/cm^2	0.09513 kgf/cm^2	0.09513 – 0.064 = 0.03113 kgf/cm^2

Applying the characteristic gas equation,

$PV = mRT$, we get

$$\frac{m}{V} = \frac{P}{RT} = \frac{0.03113 \times 10^4}{(29.27)\cdot(273+37)}$$

$= 0.0343\ kg/m^3$ **Ans.**

Step (III) Dryness Fraction of Steam

Steam, 37°C → Sensible heat, $H_w = 36.99$ kcal/kg

Latent heat, $L = 576.4$ kcal/kg

The dryness fraction of steam can be determined from the heat balance equation:

$$\dot{M}_s\ (H_w + xL - H_{cond}) = (\dot{M}\ C_p\ \Delta\theta)_{cw}$$

or $25\ (36.99 + x576.4 - 30) = (1200)\ (1)\ (10)$

$\therefore\ x = 0.82$ **Ans.**

Step (IV) Vacuum Efficiency

$$\eta_{cond} = \frac{\text{Condenser Vacuum}}{\text{Ideal Vacuum}}$$

$$= \frac{690}{760 - (0.064/0.001359)}\ (100)$$

$= 96.77\%$ **Ans.**

Problem 35.10 A surface condenser operating at a mean temperature of 30°C and vacuum 700 mm Hg receives exhaust steam from a steam turbine at the rate of 10 t/h.

The air leakage is 0.35 kg per ton of steam admitted.

Barometric pressure is 760 mm of Hg.

Determine the capacity of a suitable dry air pump required for the condenser.

Take the volumetric efficiency of the pump as 85%.

Solution

Step (I) Absolute Pressure in the Condenser

Barometric Pressure	Condenser Vacuum	Absolute Press. in the Condenser
760 mm Hg	700 mm Hg	760 – 700 = 60 mm Hg = 60 (0.001359) = 0.08154 kgf/cm^2

Step (II) Partial Pressure of Air

Partial Press. of Steam at 30°C	Abs. Press. in the Condenser	Partial Press. of Air in the Condenser $p_{air} = P_{abs} - p_s$
0.0432 kgf/cm^2	0.08154 kgf/cm^2	0.08154–0.0432 = 0.03834 kgf/cm^2

Step (III) Capacity of Air Pump

Leakage of air = 0.35 kg/t of steam admitted

Therefore, the rate of air leakage = 0.35 (10) = 3.5 kg/h

Applying the characteristic gas equation, $PV = mRT$ we get,

$$(0.03834 \times 10^4)\ (\dot{V}) = 3.5(29.27)\ (273 + 30)$$

$\therefore\ \dot{V} = 80.96\ \text{m}^3/\text{h}$

$\therefore$ Capacity of air pump = 80.96/(85/100)

= 95.249 m^3/h ***Ans.***

Q. *What are the sources of air in the condenser?*

Ans. Air may find its way into the condenser through

(a) boiler feedwater as dissolved gases. From the boiler it is carried off by steam and to the turbine and finally to the condenser

(b) flange leakage

(c) cooling water (for jet condenser) containing a certain amount of dissolved air in it.

Q. *What are the effects of air leakage in the condenser?*

Ans. 1. It increases the back pressure on the turbine with the effect that there is less heat drop and low thermal efficiency of the plant.

2. The pressure of air in the condenser lowers the partial pressure of steam which means steam will condense at a lower temperature and that will require greater amount of cooling water.

3. It reduces the rate of condensation of steam, because air having poor thermal conductivity impairs the overall heat transfer from the steam-air mixture.

Problem 35.11 A jet condenser is on duty to maintain a vacuum of 700 mm of Hg while condensing dry steam at a rate of 2.5 t/h.

Determine the mass flowrate of cooling water = 25°C.

The cooling water plus condensate discharges at 40°C.

Solution

Step (I) Absolute Pressure in the Condenser

Vacuum in the Condenser	Barometer Pressure	Absolute Pressure in the Condenser
700 mm Hg	760 mm Hg	760 – 700 = 60 mm Hg = 60 × 0.001359 = 0.08154 kgf/cm^2

Step (II) Steam at 0.08154 kgf/cm^2

Steam Pressure (kgf/cm^2)	Steam Temperature (°C)	Sensible Heat (kcal/kg)	Latent Heat (kcal/kg)
0.10 (–) 0.08	45.4 (–) 41.1	45.4 (–) 41.1	570.5 (–) 572.9

Diff. 0.02	4.3	4.3	(–) 2.4
0.00154	$\frac{4.3 \times (0.00154)}{0.02}$ = 0.33°C	$\frac{4.3 \times (0.00154)}{0.02}$ = 0.33	$\frac{(-)(2.4) \times (0.00154)}{0.02}$ = (–) 0.1848
0.08154	41.43	41.43	572.71

Step (III) Heat Extracted for Condensing Steam

Heat released by condensing steam

$= 2.5 \times 10^3 (572.71 + 41.43 - 40)$

$= 2.5 \times 10^3 \times 574.14$ kcal/h

Step (IV) Cooling Water Flowrate ($\dot{M}_{cw}$)

$M_{cw} (C_p) (\Delta \theta)_{cw} = 2.5 \times 10^3 \times 574.14$

$\therefore \dot{M}_{cw} = 2.5 \times 10^3 \times 574.14 / [(1) (40 - 25)]$

$= 95690.33$ kg/h

$= 95.690$ t/h ***Ans.***

Problem 35.12 A surface condenser receives steam (0.09 kgf/cm^2 and 0.9 dry) at a rate of 15 t/h. The temperature of the condensate is 37°C which is same for the air extraction pipe.

The amount of air leakage is 5.25 kg/h.

Determine the heat transfer surface required if the average heat transmission rate is 25000 kcal/m^2 h.

Also determine the cylinder diameter for the dry air pump, if it is single acting at 72 rpm with stroke/bore ratio 1.25 and volumetric efficiency 80%

Solution

Step (I) Rate of Heat Extraction

STEAM, 0.09 kgf/cm^2 Sensible heat = 43.25 kcal/kg

Latent heat = 571.7 kcal/kg

Therefore, heat extraction rate

$= 15 \times 10^3 (43.25 + 571.7 - 37)$ kcal/h

$= 8669.25 \times 10^3$ kcal/h.

Step (II) Heat Transfer Surface of Condenser

Average heat transmission rate = 25000 kcal/m^2.h

$= 25 \times 10^3$ kcal/m^2.h

Heat extraction rate = 8669.25×10^3 kcal/h

Therefore, heat transfer surface of the condenser

$= 8669.25 \times 10^3 / (25 \times 10^3)$ m^2 = 346.7 m^2 ***Ans.***

Step (III) Volume of Air Handled by the Pump

Partial Press. of Steam at 37°C	Condenser Pressure	Partial Pressure of Air
0.064 kgf/cm^2	0.09 kgf/cm^2	0.09 – 0.064 = 0.026 kgf/cm^2

Applying the characteristic gas equation $PV = mRT$ we get,

$(0.026 \times 10^4)(V) = (5.25/60)(29.27)(273 + 37)$;

or, $V = 3.053$ m^3/min

Step (IV) Pump Cylinder Diameter

Volumetric Flowrate of Air	Volumetric Efficiency of the Pump	Capacity of the Pump
3.053 m^3/min	80%	3.053/0.8 = 3.817 m^3/min

$\therefore \frac{\pi}{4} D^2 LN = 3.817$

where D = cylinder dia

L = stroke length

N = rpm

or $(\pi/4) (D^2) (1.25\ D) (72) = 3.817$

$\therefore$ $D = 0.3779$ m = 37.79 cm ***Ans.***

Problem 35.13 A surface condenser operates at a pressure of 0.14 kgf/cm^2 absolute. Dry, saturated steam is condensing at a rate 20 t/h. From the given data calculate the heat transfer area required for the surface condensation of steam and also determine the number of tubes required.

Cooling water inlet temperature = 33°C

Cooling water outlet temperature = 40°C

Condensate temperature at exit = 50°C

ID/OD of surface condenser tubes = 19/26 (mm)

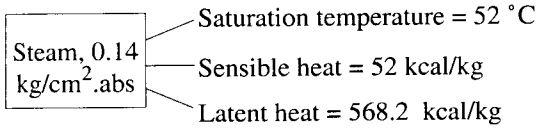
Length of each tube = 3 m

Number of passes = 2

Overall heat transfer coefficient for surface condenser, U_o = 0.85 kcal/s/m^2/°C

Solution

Step (I) Steam Parameters



Step (II) Nature of cooling

Steam condenses at 52°C.

Condensate leaves at 50°C.

Therefore, there is under cooling.

Step (III) Heat Load of Condenser

$$q = \dot{M}_s\ (H_w + L - H_{cond})$$

$$= (20 \times 10^3/3600)\ (52 + 568.2 - 50)\ \text{kcal/s}$$

$$= 3167.78\ \text{kcal/s}$$

Step (IV) Log-Mean-Temperature-Difference of Surface Condenser

	Inlet	Outlet
Steam	52°C	52°C
C/W	33°C	40°C
Diff.	19°C	12°C

$$\therefore \Delta\Theta_{lm} = \frac{19 - 12}{\ln\left(\frac{19}{12}\right)}$$

$$= 15.23°C$$

Step. (V) Heat Transfer Surface

Working Formula: $q = U_o\, A_o\, \Delta\theta_{lm}$

where q = rate of heat transfer, kcal/s

U_o = overall heat transfer coefficient, kcal/s/m^2/°C

A_0 = external surface area of all tubes, m^2

Computing the known values,

3167.78 = 0.85 (A_o) (15.23);

$\therefore A_o$ = 245 m^2 ***Ans.***

Step (VI) Number of Condenser Tubes

If n is the number of tubes required per pass, then

2 (n) $(\pi\ D_o\ L) = A_o$ where D_o = OD of tubes

or 2 (n) (π) (0.026) (3) = 245

$\therefore n$ = 500

L = length of single tube

Factor (2) for double pass.

Hence the total number of tubes required

= 1000 ***Ans.***

Q. *What are the two major factors that are responsible for most of the problems associated with the condenser non-availability and poor performance?*

Ans. 1. Tube fouling
2. Tube degradation.

Q. *What is the remedy to this problem?*

Ans. The traditional remedy takes shape in the form of plugging the pitted or eroded tubing.

Tube replacement becomes imperative when too many tubes have been put off service.

Q. *What are the other alternatives?*

Ans. 1. Inlet-end tube coatings
2. Full-length coatings
3. Full-length liners
4. Plastic or metal inserts

The above alternatives offer viable and cost-effective alternatives for life extension of powerplant condensers.

Q. *What are these inserts?*

Ans. They are metallic or non-metallic caps of length 250-300 mm, sufficient to cover the inlet ends of the condenser tubes. They have a tapered outlet end to preclude erosion or corrosion downstream of the inserts.

Q. *What are full-length liners?*

Ans. They are thin metallic hollow tubes used to repair condenser tubes that have developed through-wall failures or excessive overall deterioration. They tight fit within the tube and are thin enough (W/thk : 0.4–0.5 mm) to maintain the design heat-transfer rate.

Q. *What is the selection criteria of condenser tube coatings?*

Ans. 1. Service history
2. Application flexibility
3. Performance data
4. Potential effect on tube fouling
5. Heat transfer.

Q. *Cite examples of certain typical tube coatings.*

Ans. 1. PLASTOCOR—an epoxy phenolic manufactured by Techno Coat, Germany
2. APF—a polyester manufactured by Sumitomo Ltd.
3. Si-14E—a baked phenolic of Heresite Co.
4. SPECOAT—a catalyzed epoxy of Specialty Engineering Co.

Case Study

A certain surface condenser with the following data

Effective surface area	= 2511 m^2
No. of tubes (Admiralty brass)	= 5360
Tube OD	= 22 mm
Tube length	= 6.782 m
Tube length (active)	= 6.706 m

uses Susquehanna River water circulating through the tubes at 2.134 m/s for condensing turbine exhaust steam on the shellside. Fifteen of its tubes are used for coating and liner evalaution.

Results of heat-transfer tests performed during January, April, and September 1986 are tabulated below:

Cleanliness Factors For Coatings and Liners

Tube Sample	Relative Cleanliness As On		
	01–Jan '86	23–APR.'86	09–SEP.'86
Fresh (uncoated)	100	103	73
Used (uncoated)	84	55	62
APF coated	107	88	71
Plastocor coated	88	68	51
90/10 Cu/Ni liner	32	18	17
AL-6X liner	15	16	19

Q. *What do these data indicate?*

Ans. Particularly high cleanliness factor for APF which is a polyester coating.

Also the PLASTOCOR exhibited comfortably high cleanliness.

Both lined tubes showed very low cleanliness factors.

Q. *Why did the APF coating result in a high cleanliness factor?*

Ans. This is attributed to enhancement of its heat-transfer characteristics because of the surface smoothness achieved.

High degree of surface smoothness discouraged internal fouling and that accounted for better heat-transfer rate.

Q. *Why did the lined tubes register such a poor performance?*

Ans. Poor metal-to-metal contact was responsible for this. Despite successful mechanical fit-up procedure, there was no assurance of a tight-fit. Given the typical wider tolerances of old tubing, the poor contact produced a large gap resistance varying from tube to tube.

Case Study

(*continuation*)

PLASTOCOR coating exhibited a 30% increase in heat-transfer resistance. The Cu/Ni liner pro-

duced about a 100% increase and the APF coating little change.

Accelerated erosion test was conducted as follows:

Coolant containing a load of 800 ppm sand was circulated through the tubing at 2.134 m/s for the first 500 hrs. For the next 1250 hrs the circulation was continued with a sand content increased to 1000 ppm and circulation velocity 3 m/s.

Boroscopic inspection of coated-tube samples was performed after 100, 500, 600, 1000, 1500 and 1750 hrs. The samples were split and photographed at these intervals.

It is important to note that 500 hrs of accelerated erosion testing was taken equivalent to 3 yrs of operation and 1750 hrs at the higher velocity (3 m/s) and sand content (1000 ppm) was equated to about 10 yrs (rather conservative estimate as highly abrasive silica was used). Result are as follows:

1. Unacceptable level of erosion was evident at the downstream end of all plastic and metallic inserts after 1500 hrs.
2. Si-14E and Plastocor showed no penetration after 1750 hrs.
3. The APF polyester coating showed significant erosion after only 600 hrs.

Q. *What does this study indicate about heat transfer?*

Ans. Full length coatings have little effect on heat transfer and can be used to protect tubes from corrosion.

Q. *What can be assessed from the erosion test result?*

Ans. Liners and full-length coatings are capable of providing tube protection over their full length.

Inserts and inlet-end coatings are only partially successful. They protect the inlet ends only.

Q. *What is the expected lifetime of full-length coating?*

Ans. It may be 10 yrs.

Q. *What is the drawback of these inserts?*

Ans. They demonstrate the potential to trigger 'step erosion' of the parent tube just downstream of the inserts.

Case Study

Present day capital costs and present worth of lifecycle costs were compared with two surface condenser designs:

(a) a 5000-tube condenser with 6 m tube length

(b) another 20 000-tube condenser with 12 m tube length

for condenser retubing and for in-situ applications of full-length coatings. The results of analysis are tabulated below:

Capital Cost Comparison

Tube Sample	Condenser With	
	5000 tubes	20 000 tubes
Retubing:		
Admiralty brass	1.00	1.00 (Base value)
Titanium	1.52	1.60
Coating:		
APF coating	0.76	0.41
Plastocor coating	0.48	0.40
Inlet-end	0.08	0.037
Insert:		
Nylon	0.06	0.025
Metallic	0.20	0.13
Liner	0.31	0.24

Lifecycle Cost Comparison

Tube Sample	Net Present Value	
	10 yr life	20 yr life
Retubing:		
Admiralty brass	1.00	1.00 (Base)
Titanium	1.7	2.1
Coating:		
APF	0.7	1.4
Plastocor	0.5	0.95

Q. *What can you infer from this cost analysis?*

Ans. For condensers suffering from inlet-end corrosion, coatings can provide an economic alternative to retubing.

For full-length corrosion, use of full-length coatings may be a cost-effective alternative to retubing with titanium [Even retubing with SS is decidely costlier than full-length coating].

Note: However for a 20yr life expansion, retubing may be preferable.

Q. *What are the implications of full-length coating?*

Ans. Full-length coating is a very economical method for protecting tubes from corrosion (sulfide attack) and possibly biofouling.

When the suspended solids in cooling water are not very abrasive and when tube metal loss does not exceed 30%, coatings should be the 1st choice of preference to ensure 10 or more years of service life against sulphide attack and general erosion and corrosion.

Tube coatings, inserts, and liners can be retrofitted in-situ and at a lower cost than retubing.

Q. *What are the causes of condenser tube blockages and tube leaks?*

Ans. 1. Increased concentration of organic compounds in the C/W that promotes microbial activities
2. Low flow velocity of C/W at condenser inlet
3. Restricted use of chlorine
4. Inadequate travelling screens

Q. *On which factors does the severity of tube blockage depend?*

Ans. 1. Plant location
2. Type of C/W system
3. Quality of C/W
4. Design of the travelling screen

Q. *How does the increased concentration of organic compounds in C/W lead to condenser tube failure?*

Ans. The principal cause of condenser tube failure is internal corrosion.

The rate of tube corrosion is enhanced when organic matter such as seaweed, mussels, algae etc. is permitted to remain in the condenser tubes. These organic substances deteriorate through anaerobic decomposition releasing hydrogen sulphide and ammonia which attack the tube surfaces quickly resulting in pitting and intergranular corrosion.

Q. *How do the low C/W velocities contribute to condenser tube failure?*

Ans. Low C/W velocities at condenser inlet contribute to increased biological growth and allow mussels, clams and aquatic plants to accumulate on the tube surface. The severity of tube blockage depends not only on the C/W velocity but also on the type of C/W system and the quality of C/W. These aquatic plants and animals not only restrict the flow of C/W but also lead to corrosion of tube surface upon decay.

Q. *Why is the use of chlorine restricted?*

Ans. For environmental reasons.

Q. *How does the travelling screen contribute to fouling of the condenser?*

Ans. An inadequately designed travelling screen allows passage or carryover of debris, small fry and aquatic plants.

Q. *How can the condenser tubes be kept clean?*

Ans. The travelling screens must be properly designed. Now-a-days large utilities (500 MW) harness sponge rubber ball tube cleaning system in order to minimize fouling. These balls float in the water and are dragged through the condenser tubes by C/W. As the balls squeeze their passage through the tubes, they slough out debris and deposits from the tube surface thus effecting a mechanical cleaning.

Q. *What are the benefits of the tube cleaning system?*

Ans. 1. Constant heat transfer coefficient in condensers
2. Reduction of C/W consumption due to efficient heat exchange
3. Prevention of corrosion due to diminution of microbial concentration on the tube surface
4. Building up of a protective film on the inner surface of condenser tubes.

Q. *Suppose the system is using sponge rubber balls for cleaning the condenser tubes. Is there any need for paying attention to travelling screens?*

Ans. If the travelling screens are not properly kept, the sponge-rubber-ball-tube cleaning system will not be effective.

Q. *Why is the spong-rubber-ball-tube cleaning system not effective if the travelling screens are not properly kept?*

Ans. Debris will accummulate in the condenser and these debris will prevent the sponge balls from travelling through the tubes and this may lead to marine growth on the tubewalls.

Q. *Then how can this problem be overcome?*

Ans. It can be overcome by incorporating a debris filter to the tube cleaning system.

Note: A survey in Japan a few years back had revealed that with the incorporation of debris filter, incidence of tube leakage reduced by 97%.

Q. *How does it work?*

Ans. The debris filter installed in the C/W line just upstream of the condenser collects debris. As the mass of collected debris builds up, the pressure differential across the filter rises until the set point pressure is reached. The resulting signal initiates the backwashing process whereupon the debris discharge valve opens and the lower pressure in the debris discharge line causes C/W to backflow. As the rotor is driven past each individual chamber, each filter is backwashed in turn.

Q. *Biofouling—such as from barnacles and oyster shells—in circulating C/W systems can plug the condenser with the inevitable consequences of reduced efficiency and power output. How can this problem be overcome?*

Ans. Earlier, biocides were used to kill organic growth. But regulatory restrictions have disallowed any form of toxic coating in stationary applications. And that has dramatically limited the available options to the use of non-toxic coatings to reduce condenser fouling.

Silicone-based foul-resistant coatings have proved to be the best candidates reducing the frequency of waterbox and condenser tube cleanings.

Q. *Are there any other benefits of using silicone coatings?*

Ans. Apart from their foul-release property, silicone-coatings reduce the frequency of intake pipe and flume cleaning, improve heat transfer characteristics.

Q. *Is there any powerplants that can attest to the success story of silicone-based coating?*

Ans. San Diego Gas and Electric Co., Long Island Lighting Co. and several utilities have reported very promising results by applying silicone-based foul-release coatings to intake pipes and flumes.

Q. *Why are they called foul-release coatings?*

Ans. These silicone-based coatings, in fact, do not poison the micro and macroorganisms. The organics instead grow in size until their weight causes them to slide off.

Q. *What is surface condenser to a steam turbine?*

Ans. It is the cold end of the thermodynamic cycle of a steam turbine installation.

Q. *Why it is so called?*

Ans. Surface condenser lends itself as a heat sink so that the prime mover can operate between two temperature ends—higher temperature of the source (inlet superheated steam temperature) and

lower temperature of the sink (outlet temperature of the condensate)

Q. *What are the main functions of a surface condenser?*

Ans. Three

I. Providing heat sink. Here change of phase of the working fluid takes place
II. Creating very high vacuum with the effect that heat rejection takes place at very low temperature
III. Recycling of the working fluid

Q. *Why is greater emphasis laid on proper expansion of condenser tubes?*

Ans. The surface condenser is a shell-and-tube heat exchanger with C/W flowing through the tubes while steam condensing on the shell-side.

For safe and trouble-free operation, it requires proper expansion of the tubes. Improper expansion of the tubes almost inevitably leads to tube-joint failure resulting in ingress of C/W into the steam-condensate circuit. Recirculation of contaminated working fluid entails damage to boiler tubes and superheaters inviting expensive repairs and downtime loss.

Q. *What major points are to be considered while carrying out tube expansion?*

Ans. Tube expansion must ensure

I. a good hydraulic and mechanical joint
II. a durable seal that is resistant to corrosion and essentially free of longitudinal stress
III. a leakproof optimum joint with adequate strength for the intended service life, with minimum amount of cold working and reduction of tubewall thickness.

Care must be exercised to avoid the risk of over expansion and under expansion.

Q. *How can under-expansion be detected and recified?*

Ans. 'Under-expansion' can be detected by the hydraulic test and corrected by re-expanding.

Q. *What about over-expansion?*

Ans. The 'over-expansion' of condenser tubes cannot be easily detected.

It imposes excessive cold-worked stress in the metal. These, in turn, result in undue enlargement of tube holes and fracture of ligaments between the holes. And therefore, the joint becomes weak and poor.

Q. *What are the probable causes of over-expansion of tubes?*

Ans. I. Tube plate hole dia variation, i.e. the diameter being more than the specified value
II. Torque variation, i.e. the applied torque being higher than what is required
III. Tubewall thickness variation, i.e. thickness being more or less than what is specified
IV. Poor workmanship
V. Use of improper tools
VI. Use of unsuitable measuring gages
VII. Frequency of checking being very low
VIII. Use of substandard lubricants.

Out of these, the first three are considered to be the most significant.

Q. *Why does the tube plate hole dia variation take place?*

Ans. Due to improper machining, fabrication and finishing (manually controlled opration).

Q. *Why does torque variation occur?*

Ans. The tube expander is preset to operate at a particular torque. However, the applied torque may vary due to voltage dips. Frequent fluctuations in voltage of power supply require frequent setting of the operating torque of the machine.

Q. *What steps are taken to ensure proper expansion of the condenser tubes?*

Ans. Following the assembly of condenser at site:

1. Clean the tubeplate holes properly using round steel brushes
2. The tubeplate holes are usually distributed in different zones. Check the hole dia. Use bore-dial gauge for the purpose.

Mark those hole-dias which are beyond drawing tolerance.

3. Estimate the minimum and maximum of tubeplate hole diameters within the limit of drawing tolerance.
4. From the total number of tubes to be inserted in a particular zone, make a random check on 20-30% tubes for their outer and inner diameters by using outside micrometer and bore-dial gauge respectively.

   Enter the reading into a log. The difference between these two readings gives the tubewall thickness. Calculate the average value of the tubewall thickness. Use it for that particular zone.
5. Estimate the minimum and maximum value of inside dia of the expanded tube, for a particular zone as follows. Give due allowance for per cent thinning of the tubewall due to expansion:

ID of tube after expansion

$$[d_i]_{exp} = d - \frac{(100 - t)(d_0 - d_i)}{100}$$

$$\text{Per cent thinning, } t = \left[1 - \frac{t_2}{t_1}\right] \times 100\%$$

Tube expansion length, y = 70 to 80% of x

where, d = tubeplate hole dia
d_o = OD of tube
d_i = ID of tube
} Fig. 35.10

$[d_i]_{exp}$ = ID of tube after expansion

t_1 = tube thickness before expansion = 1/2 $[d_o - d_i]$

t_2 = tube thickness after expansion = 1/2 $[d - (d_i)_{exp}]$

t = per cent thinning

x = tubeplate thickness.

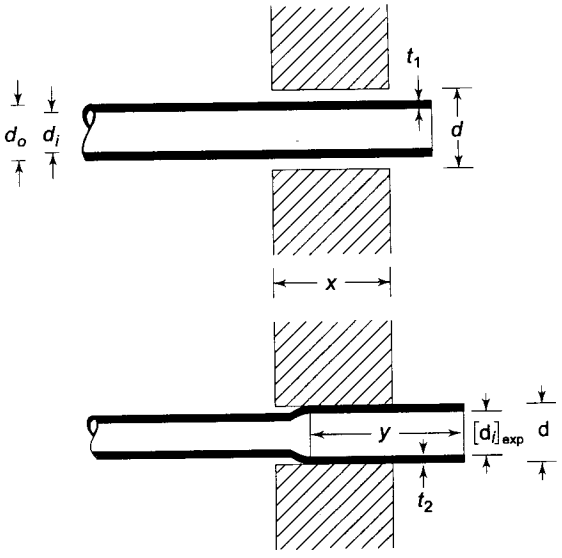


Fig. 35.10

6. Insert these tubes into the tubeplate holes, in a particular zone, after properly cleaning the tube ends and tubeplate holes.
7. Set the torque of the tube expander to achieve the desired value of ID of the tube after expansion and the correct length of expansion inside the tubeplate perforations.
8. After expansion of further tubes, go for checking, from time to time, for correct expansion by using the bore-dial gauge.
9. Classify oversize tubeplate holes [d > specified value in the drawing] into different categories as per their dia.
10. Repeat the steps 4 to 9 for expansion of tubes in these oversized tubeplates.

Q. *What type of tube expander is used in general?*

Ans. The most commonly used expander is the self-feeding parallel expansion type that come fitted with a ball bearings thrust collar. The ends of the rollers are generally ground to produce a smooth bend from the expanded portion of the tube to the unexpanded portion. These expanders are adjustable for the length of expansion.

Q. *Why is the mandrill, during expansion, placed perpendicular to the tube dia?*

Ans. If this is not done, improper expansion will be the outcome.

Q. *What should be the length of expansion?*

Ans. It should be in the range of 70—80% of the tubeplate thickness and not more than this value.

Q. *What additional measures should be taken to complement the process of tube expansion?*

Ans. Care must be taken:

1. to hold the mandrill perpendicular to the dia of the tube
2. not to expand the tube beyond (0.7—0.8)x where x = tube plate thickness.
3. to clean and polish, with fine-grain emery paper, the outside of tube-ends to a length of 100 mm on either side (This removes oxide scales and foreign matter)
4. to check the surface of the tubeplate holes
5. to use good quality grease or glycerine
6. to avoid percentage thinning beyond the specified value as stated in the drawing.

Note: Carry out tube expansion on the basis of a actual measurement of tubeplate hole, OD and ID of tubes. Do not accept what is given to you.

Q. *Why is it recommended to check the surface of the tubeplate holes?*

Ans. The objective is to check for the following defects:

(a) longitudinal scratches
(b) helical circles.

Q. *Why should the above defects be checked?*

Ans. These defects will result in leakage during hydraulic testing or operation.

Q. *What should be done in such cases?*

Ans. The holes should be blocked.

Q. *Why one must be particular about the percentage thinning of tubes?*

Ans. The extent of thinning must be done in accordance with the value specified in the drawing. Over-expansion usually leads to premature tube failure while under-expansion may lead to leakage from the tube expansion joints.

Case Study CONDENSER TUBE FAILURES

A utility befitted with 2 × 110 MW identical units restarted one of them after a 16-month shutdown and discovered that about a 1000 of the Al-brass tubes of the surface condenser were leaking. This tantamounted to about 8% of the total 13 600 tubes (ID 22 mm/thickness 1 mm) expanded in a mild-steel plate.

The collant used is riverwater (at 303°K) having the following specifications:

pH	:	7.7–8.2
Sediment at 303 K	:	1388 mg/1
Free CO_2	:	4.7 mg/1
SiO_2	:	7.2 mg/1
Salt content	:	3.07 mval/1*
Hardness	:	2.52 mval/1
Total alkalinity (M-value)	:	2.4 mval/1
Ca^{2+}	:	2.07 mval/1
Mg^{2+}	:	0.42 mval/1
Na^+ and K^+	:	0.59 mval/1
Cl^-	:	0.21 mval/1
SO_4^{2-}	:	0.45 mval/1
NO_3^-	:	0.02 mval/1
HCO_3^-	:	2.4 mval/1

The tube bundle was pulled out and inspected whereupon dozens of irregular circumferential cracks were noticed on the outside surface of a number of tubes. However, there was no longitudinal cracking. Reddish-brown encrusted deposits trailed next to the cracked segment at the inside. Crack propagation profile revealed, when a

* mval/1 = ppm as $CaCO_3$

large crack was opened up for inspection, step-like contour. Radial markings on the step-areas indicated a crack initiation at the inner surface, with severe corrosion in the initiation region.

Metallographic examination of the cracked sections, both tangential and longitudinal, revealed that the propagation was in branched transgranular fashion.

Analysis revealed that the reddish-brown crust was composed of

Al	3% (by wt.)
Cu	2% (by wt.)
Ca	0.4% (by wt.)
Mg	0.3% (by wt.)
Zn	0.3% (by wt.)
K	0.1% (by wt.)
Ni	0.006% (by wt.)
Na	0.0003% (by wt.)

with a base of silica, iron and oxygen.

Tube alloy was aluminum-brass of ASTM spec. B111.

Why did such corrosion occur?

What was the mechanism of corrosion?

How can the recurrence of such a problem be prevented in case of shutdowns for long periods again?

Ans. Cracking in the condenser tubes resulted from stress-corrosion—under the simultaneous onslaught of a sustained stress and the corrosive environment. The stress may be low and the corrosive environment mild, however the combination gives sudden unexpected failure.

The stresses may be residual in the metal, applied tensile stress or cyclic stress.

The presence of sulphate and chloride ions make the environment aggressive. In the presence of sulphate-reducing bacteria, SO_4^{2-} is reduced to S^{2-} ions that attack copper-alloys.

Exposure of brass to moist atmosphere with traces of ammonia is especially drastic (dezincification). Ammonia and its compounds are potent agents. Free CO_2 dissolved in water may also contribute to corrosion. This type of attack Ammonia-stress-corrosion-cracking particularly occurs during out-of-service periods, because the oxygen needed for failure would be available only then. This oxygen, acting as a depolarizer, might have leaked into the tubes during shutdown. Micropitting is induced by oxygen enhanced crack propagation.

Preventive Measures

1. Retubing the condenser with a more resistant alloy such as 90/10, or 70/30 Cu/Ni or 304SS or Ti (best solution). Forasmuch as approximately 8% of the total tubes went out of service, it is only a matter of time before minimum tube surface area would be reached, calling for condenser retubing.
2. Cyclic vibration, from inadequate tube-support spacing, poor tube fit in supports, adjacent rotating machinery should be avoided
3. Corrosion removes the protective oxide film. Therefore, it may be useful, though at a sacrifice of the heat transfer coefficient, to coat the condenser tubes (inside) with 0.60 mil-thick epoxy coating and then soaking the condenser with a solution of methylene bis-thiocyanate to destroy the bacteria
4. To reduce the biological activity it is advisable to dose hypochlorite into the circulating water for 30 min immediately before shutdown.
   Alternatively, slime control by chlorination could be considered for the period preceding shutdown.
5. Drying the tubes with warm air to remove traces of water and kill residual slime. Once dried, the condenser should be kept dry.

6. For prolonged outage a nitrogen blanket to keep away oxygen would be beneficial. Another alternative, a less desirable one, would be flooding the condenser with hydrazinated DM water.

Case Study CONDENSER TUBE FAILURE

Over the past one-and-a-half decades, a certain process plant in Pakistan had experienced condenser tube failures in its 2 × 65 MW turbo-gen units. The problems had been so severe that the plant was forced to take unscheduled shutdowns to retube the admiralty-brass tubes three times.

Surprisingly, only very few defects occured during normal operation before shutdown. However, hundreds of tube leakages sprang up in each time when the plant was restarted after 3-4 months of outage for overhaul. This happened even though the condenser tubes were cleaned with nylon brushes and water jets and then dried with dry air. Condenser doors and drains used to be kept open to avoid flooding from leaky inlet and outlet valves.

The river water used for cooling purpose contained 100–4000 ppm silt. The temperature in the turbine room remained over 311°K—far above the dewpoint.

Another baffling part of the problem is that most of the failures occured in one area (See Fig. 35.11).

Both condensers have recently been retubed with aluminum brass.

Why did this problem occur?

What is the best method to protect tubes from this type of corrosion?

Ans. The trouble that it was is actually dezincification. Very likely ammonia concentrating on the steam side (i.e. shellside) attacked tubes that had very little condensate collecting on them. This happens particularly in the air-cooler section where ammonia concentration is 300-600 times that in the hotwell. Excessive amine dosing in the BFW could have contributed to the presence of ammonia in the condensate, attacking tubes from the shellside.

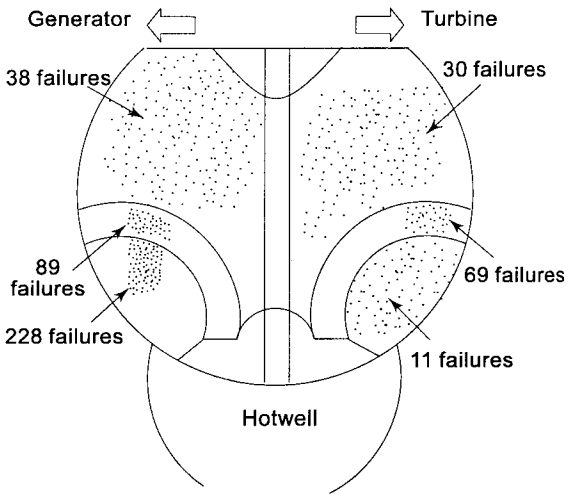


Fig. 35.11 *Distribution of condenser tube failures.*

Also the tubes might have failed from inside. Decay of organic materials borne by riverwater could be responsible for ammonia concentration in the tubeside causing dezincification from inside.

Dezincification, in fact, results from local electrolysis—a local electric cell is set up by the dissimilar metals present in the tube alloy and ammonical water acting as an electrolyte whereupon zinc selectively leaches out from anode:

$$Zn - 2e \longrightarrow Zn^{2+} \quad \text{(at anode)}$$

$$NH_3 + H_2O \rightleftharpoons NH_4^+ + \overline{O}H$$

$$H_2O + NH_4^+ \rightleftharpoons NH_3 + H_3O^+$$

$$2H_3O^+ + 2e \longrightarrow 2H_2O + H_2 \quad \text{(at cathode)}$$

Tubes are known to fail from inside even though they are cleaned and dried as much as possible at shutdown. The central zones of tubes may still hold some dirt/deposits as highly silted cooling water is circulated through the tubes. This CW stream carrying a load of organics deposits them as a sticky layer which decays to liberate ammonia during shutdown. This explains failure due to outage and leaks become conspicuous as

the plant makes a start-up. However, this won't explain the local failure at the bottom of the condenser towards the generator side. This might have resulted from erosion during normal operation, because of exhaust steam impinging almost directly from the turbine exhaust, creating high temperatures in the greatest failure area, where corrosion would be most active. It may be that the drains from the auxiliary condensers are connected to the condenser in these areas and the inlets are not properly baffled giving rise to local high temperatures that favour dezincification. Of course, steam velocity, steam quality and flow distribution exert influence on the extent of erosion on the steam side.

Stress-corrosion cracking from ammonia might have occured during outage.

It is difficult to take for granted that those condenser tubes that did not fail in service right before shutdown developed leaks right after shutdown. Actually, the failure had occured previously but the leakage was prevented from becoming obvious until the tubes were cleaned and the debris removed. Small plugs of dezincified materials might have been knocked off by the cleaning operation.

The simple solution where admiralty brass is affected by dezincification is to safeguard the tubes by using an inhibitor. The most satisfactory inhibitor for this purpose is a carefully controlled dosage of 0.04% arsenic. Other inhibitors like antimony or phosphorus would also serve the purpose.

Another remedy is to install a cathodic-protection system.

However, replacing the admiralty brass tubes with aluminum brass tubes will not be a solution. For the uninhibited Al-brass will also give way to dezincification.

Another sound solution might be the replacement of the tubes in the air-cooler zone by 316SS.

36

STEAM TURBINES

Q. *What is the principle of a steam turbine?*

Ans. If high-velocity steam is allowed to blow on to a curved blade, the steam will suffer a change in direction as it passes across the blade, and leaves it as shown. (Fig. 36.1)

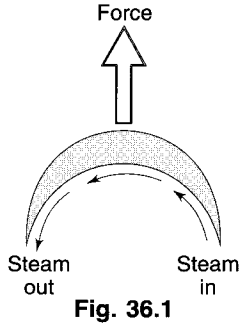


Fig. 36.1

As a result of its change in direction across the blade, the steam will impart a force to the blade. This force will act in the direction shown. (Fig. 36.1)

Now if the blade were free, it would move in the direction of force as depicted. If, therefore, a number of blades were fixed on the circumference of a disc which is free to rotate on a shaft, then steam blown across the blades in the way described, would cause the disc to rotate. This is the working principle of a steam turbine.

Q. *What is the definition of a steam turbine?*

Ans. A steam turbine is a prime mover that derives its energy of rotation due to conversion of the heat of energy of steam into kinetic energy as it expands through a series of nozzles mounted on the casing or produced by the fixed blades.

As defined by *Neilson*: The turbine is a machine in which a rotary motion is obtained by the gradual change of the momentum of the fluid.

Graham's definition: the turbine is a prime mover in which a rotary motion is obtained by the centrifugal force brought into action by changing the direction of a jet of a fluid (steam) escaping from the nozzle at high velocity.

Q. *What is the essential distinguishing feature between a steam turbine and reciprocating steam engine?*

Ans. In a steam turbine, the heat energy of steam is converted into kinetic energy by allowing it to expand through a series of nozzles and this kinetic energy of steam is then imparted to the turbine blades mounted on a shaft free to rotate this prime mover.

In a reciprocating steam engine, the pressure energy of steam is directly utilized to overcome the external resistance. Here, the utilization of the K.E. of input steam is negligibly small.

Q. *What are the advantages of steam turbines over reciprocating steam engines?*

Ans.
1. A steam turbine has higher thermal efficiency than reciprocating steam engines
2. The brake horse power of steam turbines can range from a few HP to several hundred thousand HP in single units. Hence they are quite suitable for large thermal power stations
3. Unlike reciprocating engines, the turbines do not need any flywheel as the power delivered by the turbine is uniform

4. Steam turbines are perfectly balanced and hence present minimum vibrational problem
5. High rpm 18000-24000 can be developed in steam turbines but such high speed generation is not possible in the case of reciprocating steam engines
6. Some amount of input energy of steam is lost as the reciprocating motion of the piston is converted to circular motion

This loss does not arise in the case of steam turbines.

7. Unlike reciprocating steam engines, no internal lubrication is required for steam turbines due to the absence of rubbing parts.
8. Steam turbines, if well designed and properly maintained, are more reliable and durable prime-movers than steam engines.

Q. *How can steam turbines be classified?*

Ans. They can be classified with respect to:

1. the action of steam:
   (a) **Impulse** (b) **Reaction** (c) **Impulse and reaction combined**
2. the number of step reductions involved:
   (a) **Single stage** (b) **Multi-stage**
3. whether there is one or more revolving vanes separated by stationary reversing vanes.
4. the direction of steam flow:
   (a) **Axial** (b) **Radial** (c) **Mixed** (d) **Tangential** (e) **Helical** (f) **Reentry**
5. the inlet steam pressure:
   (a) **High pressure** (b) **Medium pressure** (c) **Low pressure**
6. the final pressure:
   (a) **Condensing** (b) **Non-condensing**
7. the source of steam:
   (a) **Extraction** (b) **Accumulator**

Q. *What are the difference between impulse and reaction turbines?*

Ans. The impulse turbine is characterized by the fact that it requires nozzles and that the pressure drop of steam takes place in the nozzles (Fig. 36.2)

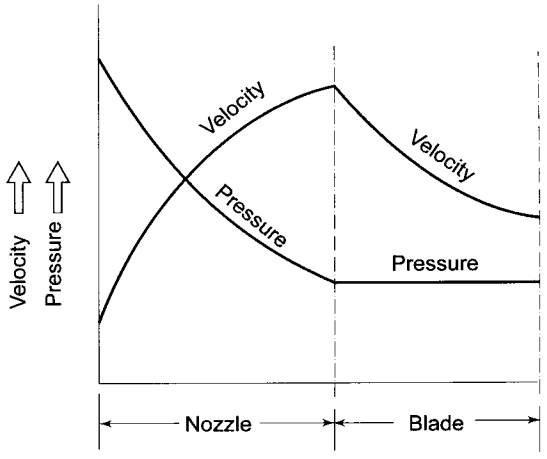


Fig. 36.2

The reaction turbine, unlike the impulse turbines has no nozzles, as such. It consists of a row of blades mounted on a drum. The drum blades are separated by rows of fixed blades mounted in the turbine casing. These fixed blades serve as nozzles as well as the means of correcting the direction of steam onto the moving blades (Fig. 36.3).

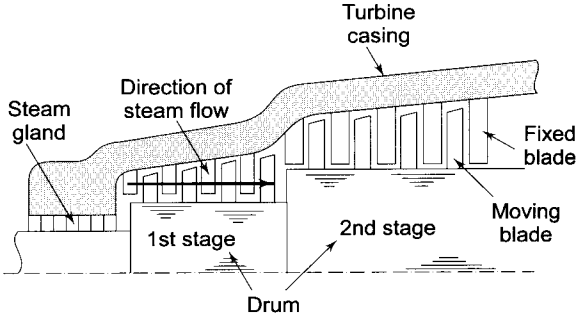


Fig. 36.3

In the case of reaction turbines, the pressure drop of steam takes place over the blades. This pressure drop produces a reaction and hence causes the motion of the rotor (Fig. 36.4).

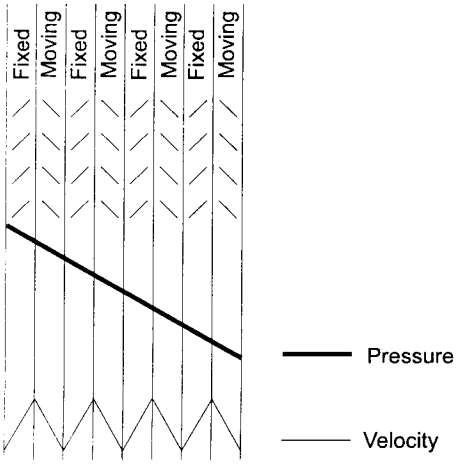


Fig. 36.4

Q. *Why are simple impulse turbines not so common?*

Ans. 1. Since the whole pressure drop from the boiler to the condenser pressure takes place in a single row of nozzles, the velocity of the steam entering the turbine is very high. If some of this velocity is used up in a single row of turbine blading, as in the de Laval turbine, the speed of rotation of the wheel will be too high to be useful for practical purposes, as there is the danger of structural failures due to excessive centrifugal stresses.

2. Steam exits from the turbine with a sufficiently high velocity, meaning a considerable loss of kinetic energy.

Q. *How can these disadvantages be overcome?*

Ans. These disadvantages can be overcome by compounding.

1. Velocity compounding
2. Pressure compounding
3. Pressure-Velocity compounding.

Q. *How is velocity compounding accomplished?*

Ans. This is accomplished by an arrangement with alternate rows of fixed blades and moving blades. The fixed blades are mounted on the casing while the moving blades are keyed in series on a common shaft. The function of the fixed blades is to correct the direction of entry of steam to the next row of moving blades.

The high velocity leaving the nozzles passes on to the 1st row of moving blades where it suffers a partial velocity drop. (Fig. 36.5)

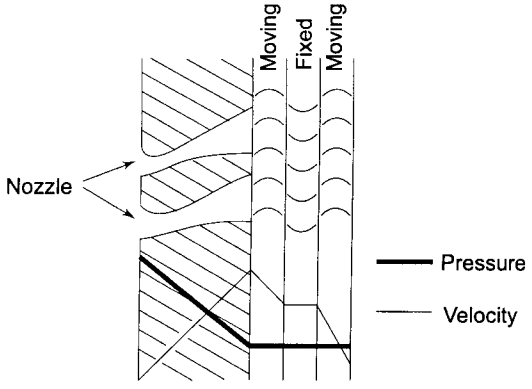


Fig. 36.5

Its direction is then corrected by the next row of fixed blades and then it enters the 2nd row of moving blades. Here the steam velocity is again partially reduced. Since only part of the velocity of the steam is used up in each row of the moving blades, a slower turbine results. This is how velocity compounding works.

Q. *In which turbine is velocity compounding utilized?*

Ans. Curtis turbine.

Q. *How is pressure compounding accomplished?*

Ans. This is accomplished by an arrangement with alternate rows of nozzles and moving blades.

Steam enters the 1st row of nozzles where it suffers a partial drop of pressure and in lieu of that its velocity increases. The high velocity steam passes on to the 1st row of moving blades where its velocity is reduced. (Fig. 36.6)

The steam then passes into the 2nd row of nozzles where its pressure is again partially reduced and velocity is again increased. This high veloc-

ity steam passes from the nozzles to the 2nd row of blades where its velocity is again reduced.

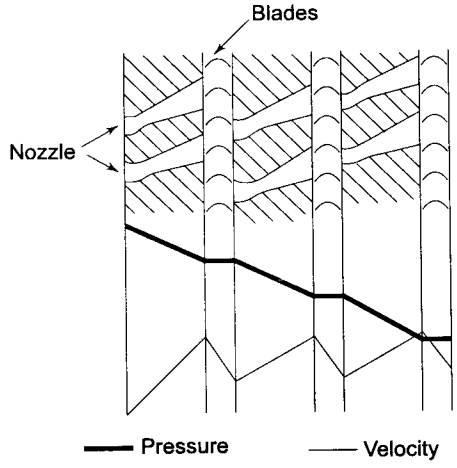


Fig. 36.6

Thus pressure drop takes place in successive stages. Since a partial pressure drop takes place in each stage, the steam velocities will not be so high with the effect that the turbine will run slower.

Q. *In which turbine is this pressure compounding used?*

Ans. Rateau and Zoelly turbines.

Q. *How is pressure-velocity compounding accomplished?*

Ans. It is a combination of pressure compounding and velocity compounding.

Steam is expanded partially in a row of nozzles whereupon its velocity gets increased. This high velocity steam then enters a few rows of velocity-compounding whereupon its velocity gets successively reduced. (Fig. 36.7)

The velocity of the steam is again increased in the subsequent row of nozzles and then it is allowed to pass onto another set of velocity compounding that brings about a stagewise reduction of velocity of the steam.

This system is continued.

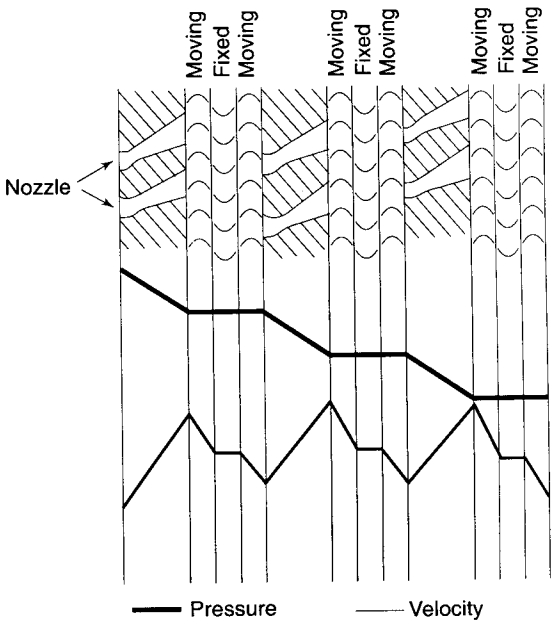


Fig. 36.7

Q. *In which turbines, is this pressure-velocity compounding principle employed?*

Ans. Moore turbines, Curtis turbines.

Q. *What are the advantages of velocity compounding?*

Ans. 1. The velocity compounding system is easy to operate and operation is more reliable.
2. Only two or three stages are required. Therefore, first cost is less.
3. Since the total pressure drop takes place only in nozzles and not in the blades, the turbine casing need not be heavily built. Hence there is economy in material and money.
4. Less floor space is required.

Q. *What are the disadvantages of velocity compounding?*

Ans. 1. Steam velocity is too high and that is responsible for appreciable friction losses.
2. Blade efficiency decreases with the increase in the number of stages. (Fig. 36.8)

3. With increase in the number of rows, the power developed in successive rows of blades decreases. Forasmuch as the same space and material are required for each stage, it means, therefore, that all stages are not economically efficient.

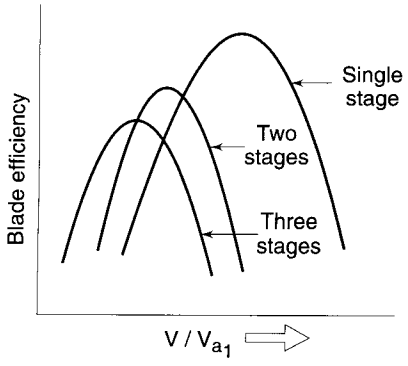


Fig. 36.8

Q. *Where are velocity compounded steam turbines mostly employed?*

Ans. They are chiefly used as the prime mover for

(a) centrifugal pumps
(b) centrifugal compressors
(c) low capacity turbo-generators
(d) feed pumps of high capacity power plants.

Q. *What are the losses in steam turbines?*

Ans. 1. **Residual Velocity Loss:** This is equal to the $V_o^2/2gJ$ kcal/kg where V_o is the absolute velocity of steam at the blade exit.
2. **Loss due to Friction:** Friction loss occurs in the nozzles, turbine blades and between the steam and rotating discs. This loss is about 10%.
3. **Leakage Loss**
4. **Loss due to Mechanical Friction:** Accounts for loss due to friction between the shaft and bearing.
5. **Radiation Loss:** Though this loss is negligible, as turbine casings are insulated, it occurs due to heat leakage from turbine to ambient air which is at a much lower temperature than the turbine.
6. **Loss due to Moisture:** In the lower stages of the turbine, the steam may become wet as the velocity of water particles is lower than that of steam. So a part of the kinetic energy of steam is lost to drag the water particles along with it.

Q. *Describe the velocity diagram of an impulse turbine.*

Ans. Refer to Fig. 36.9, V_1 = absolute velocity of steam entering the moving blade, m/s

V_2 = absolute velocity of steam at the outlet from the blade, m/s.

V_b = linear velocity of the moving blade, m/s

V_{r_1} = relative velocity of steam to moving blade, at the inlet, m/s.

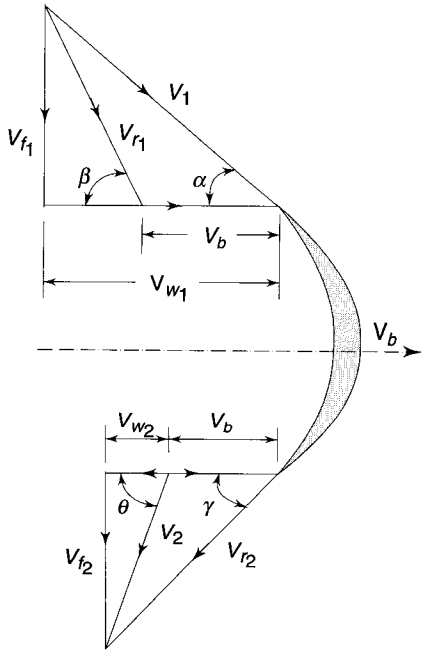


Fig. 36.9 *Velocity diagram of an impulse turbine.*

V_{r_2} = relative velocity of steam to the moving blade at the outlet, m/s.

V_{f_1} = velocity of flow at inlet, m/s. It is the axial component of V_1.

V_{f_2} = velocity of flow at outlet, m/s. It is the axial component of V_2

V_{w_1} = velocity of whirl at inlet, m/s. It is the horizontal component of V_1

V_{w_2} = velocity of whirl at outlet, m/s. It is the horizontal component of V_2

α = nozzle angle

β = blade angle at inlet

γ = blade angle at outlet

θ = angle of discharge of the exit steam with the tangent to the wheel.

Since both the inlet and the exit velocity triangles have the common vector, V_b, these two can be combined into a single diagram, for the sake of convenience in solving the problems. (Fig. 36.10)

Assuming there is no frictional loss at the blades,

$V_{r_1} = V_{r_2}$

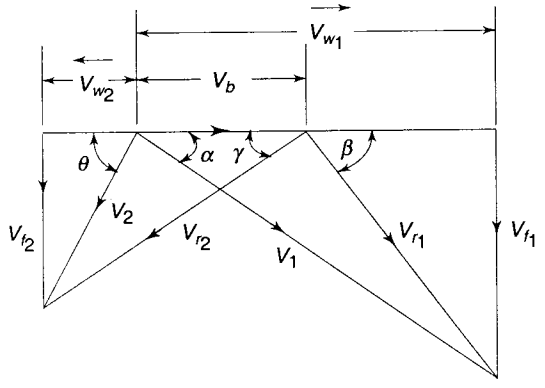


Fig. 36.10

Q. *What is the work done on the blades per second?*

Ans. Now, work done = Force × Distance
By Newton's Laws,

Force = Rate of change of momentum

= (Mass) × (Change of Velocity).

The change in velocity of the whirl produces the force on the blades. Therefore, change in the velocity of whirl = $- V_{w_2} - V_{w_1}$

i.e. change in the velocity of whirl

$= - (V_{w_1} + V_{w_2})$

Workdone on the blade/s

$$= \frac{W}{g} (V_{w_1} + V_{w_2}) (V_b) \text{ kgf. m/s}$$

The negative sign shows that this force acts in a direction opposite to the rotation.

Q. *What is the rim horse power of the turbine wheel?*

Ans. It is the horse power developed by the wheel

$$= \frac{W}{g} (V_{w_1} + V_{w_2}) (V_b/75)$$

(1HP = 75 kgf.m/s)

Q. *What is the blade efficiency?*

Ans. Also called diagram efficiency, the blade efficiency is the ratio of the work done on the blades to the energy supplied to the blades.

$$\eta_b = \frac{\text{Work done on the blade / kg of steam}}{\text{Energy supplied to the blade/kg of steam}}$$

$$= \frac{(V_{w_1} + V_{w_2})}{\frac{V_1^2}{2}} (V_b) = 2V_b \frac{(V_{w_1} + V_{w_2})}{V_1^2}$$

Q. *What is the stage efficiency?*

Ans. If ΔH is the total heat drop in the nozzle ring, then the total energy supplied per stage is $J \Delta H$, kg · m/kg of steam.

$$\therefore \text{ Stage Efficiency} = \frac{V_b (V_{w_1} + V_{w_2})}{W J \Delta H} \left(\frac{W}{g}\right)$$

$$= \left(\frac{V_b}{g}\right) \frac{(V_{w_1} + V_{w_2})}{J \Delta H}$$

Problem 36.1 Steam issues from nozzles, inclined at an angle 24° to the direction of motion, with a velocity 1000 m/s on to the blades of a single stage impulse turbine.

The linear velocity of the blades = 400 m/s

Blade angles at inlet = Blade angles at outlet.

Steam enters the blade without shock.

Frictional loss over the blades is nil.

Steam flowrate = 4000 kg/h

Calculate:

(a) inlet angle of the blades
(b) force exerted on the blades in the direction of their motion.
(c) power developed by the rotor.

Solution From the combined velocity diagram, inlet angle of the blades = 39°. (Fig. 36.11)

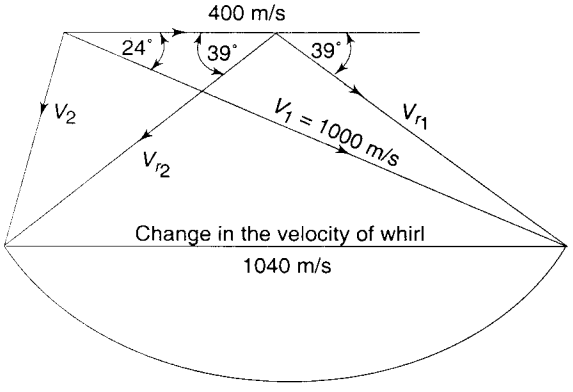


Fig. 36.11

Force exerted on the blade

= [Mass flowrate of steam] × [Change in the velocity of whirl]

= (4000/3600) (1040)

= 1.155 kN

Power developed

= Force × Distance/time

= $1.155(V_b)$ = 1.155 (400) = 462 kW

Ans.

Problem 36.2 Steam with a velocity of 600 m/s is directed upon the blades of a single stage impulse turbine at an angle 22° to the direction of motion. The average diameter of the blade ring is 1250 mm. The blade angles at inlet and exit are the same and equal to 37°.

Determine:

(a) the speed of the turbine
(b) the absolute velocity of steam leaving the blades
(c) torque on the turbine rotor when the steam flowrate is 5 t/h

Base your calculation on shockless entry of steam and frictionless flow over the blades.

Solution

Step (I) Velocity Diagram

Horizontal AE is drawn. Drawn subtended 22° to AE, AC represents 600 m/s in the scale 1 cm ≡ 100 m/s. (Fig. 36.12)

Since it is known that inlet angle ($\angle EBC$) will be 37°, $\angle ABC$

= 180° − 37° = 143°.

$\therefore$ $\angle ACB$ = 180° − (22° + 143°) = 15°.

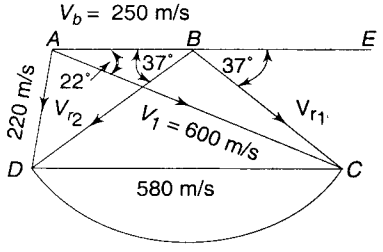


Fig. 36.12

Hence from C, CB is drawn making 15° angle with AC.

Step (II) Turbine Speed

From the velocity diagram,

AB = blade speed = V_b = 250 m/s

$\therefore$ $\pi\, dN$ = 250 m/s; or $N = \dfrac{250}{(\pi)1.25}$

= 63.6619 rps

≈ 3820 rpm

Ans.

where N = turbine speed,

Step (III) Absolute Velocity of Steam at Outlet

Now, absolute velocity of steam leaving the blades, V_2 is represented by AD.

V_2 = 200 m/s from the velocity diagram

Ans.

Step (IV) Torque

Force exerted on the turbine rotor

= Steam flowrate × Change in the velocity of whirl

= (5000/3600)/(580)

= 805.555 N

Therefore, torque on the turbine rotor

$= F \cdot (d/2)$ = 805.555 (1.25)/2 = 503.47 Nm

Ans.

Problem 36.3 The nozzle angle for a simple impulse turbine is 20° and the steam leaves the nozzle at 400 m/s. The blade velocity is 180 m/s. What should be the inlet and outlet angles for the blades so that the blades experience no axial thrust?

Due to friction the velocity of steam as it passes over the blades is reduced by 15%.

Also determine the power developed if the steam flow is 10 kg/s and the kinetic energy of the steam finally leaving the turbine.

Solution

Step (I) Velocity Diagram

AB is drawn to scale (1 cm ≡ 50 m/s) to represent the blade speed V_b = 180 m/s. (Fig. 36.13)

From A, and at 20° to AB, a line AC, to the same scale is laid off such that AC represents the absolute velocity of the steam as it leaves the nozzle.

$V_1 = AC$ = 400 m/s

BC is joined to complete the triangle ABC. Now BC represents the relative velocity of steam at the inlet to the blade.

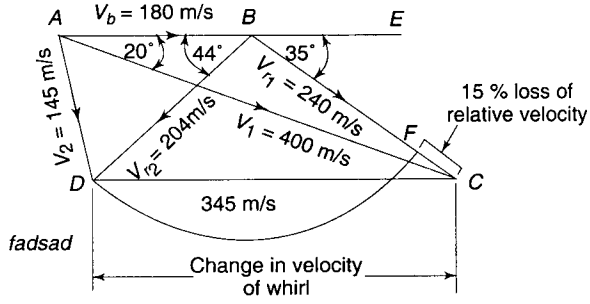


Fig. 36.13

From the diagram, $BC = V_{r_1}$ = 240 m/s.

Now, in its passages over the blade, 15% of this velocity is lost. Length FC corresponds to 15% of BC.

[15% BC = (15/100) (240) = 36 m/s]

Taking B as centre, arc FD is drawn—its radius being BF. Now in order that there will be no axial thrust on the blades, there must be no changes in the velocity of flow, i.e., $V_{f_1} = V_{f_2}$.

This means that peaks of both the inlet and outlet velocity triangles must be at the same level. Hence a horizontal is drawn from C and it intersects the arc at $D \cdot AD$ and BD are joined.

Therefore, AD = velocity of flow at the outlet = 145 m/s. from the figure.

Step (II) Blade Angles

Blade angle at inlet, $\beta = \angle EBC = 35°$

Blade angle at outlet, $\gamma = \angle ABD = 44°$

Ans.

Step (III) Power Developed

Power developed for steam flowrate 10 kg/s

= Mass Flowrate × Blade Velocity × Change in Velocity of Whirl

$$= 10(180)\,(345)\,\frac{\text{kg}}{\text{s}}\,(\text{m/s})\,(\text{m/s})$$

$= 621000$ (kg m/s^2) m/s $= 621 \times 10^3$ N m/s

$= 621 \times 10^3$ W $= 621$ kW **Ans.**

Step (IV) K.E. of Steam

The kinetic energy of steam finally leaving the wheel

$= \frac{1}{2}$ (Mass Flowrate) (Relative Velocity of steam at outlet)^2

$= \frac{1}{2}$ (10) $(204)^2$ J/s $= 208$ kJ/s

Ans.

Problem 36.4 The rotor of a single stage impulse turbine is 500 mm in a dia. It runs at 150 rps. Nozzles are at 20° to the plane of the wheel. Steam leaves the nozzles at 750 m/s. If the friction factor is 0.8 determine:

(a) the horse power developed per kg steam per second

(b) the blade efficiency.

Take blade outlet angle = 30°

Solution

Step (I) Blade Velocity

Blade speed, $N = 150$ rps.

Blade velocity, $V_b = 2\ \pi Nr$

$= 2(\pi)\ (150)\left(\frac{500}{1000}\frac{1}{2}\right) = 235.6$ m/s

Step (II) Velocity Diagram

$\alpha = 20°$; $\gamma = 30°$; $V_1 = 750$ m/s. (Fig. 36.14)

From the horizontal EF, AB is cut off so that $AB = V_b = 235.6$ m/s.

With the known parameters,

ABC is completed.

From the diagram:

$BC = V_{r_1}$ = relative velocity of steam to moving blade at inlet

= 540 m/s (From the diagram)

$Vr_2 = 0.8\ (V_{r_1}) = 0.8\ (540)$ m/s

= 432 m/s

From point B, BD is drawn making an angle 30° to AB · BD is cut off-so that $BD = 432$ m/s. AD is joined.

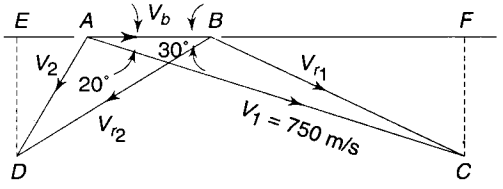


Fig. 36.14

Now AD represents the absolute velocity of steam at the blade outlet.

From the diagram, $AD = 260$ m/s.

From points C and D two perpendiculars CF and DE are dropped on EF.

EF corresponds to a change in the velocity of whirl. From the diagram, $EF = 834$ m/s.

Step (III) Power Developed

Therefore, the horse power developed by the wheel per kg

$= \frac{1}{9.81}$ (834) (235.6)/75 = 267

Ans.

Step (IV) Blade Efficiency

Blade efficiency $= 2\ V_b\ [V_{w_1} + V_{w_2}]/V_1^2$

$= 2(235.6)\ (834)/(750)^2$

$= 0.6986$ i.e. 69.86% **Ans.**

Problem 36.5 A De Laval type steam turbine receives dry steam at 16 kgf/cm^2 absolute and discharges at 1.8 kgf/cm^2 absolute. The mean diameter of the blade is 1500 mm and the rotational speed of the blade is 4074 rpm. If 10% of the available enthalpy drop is lost to friction in the nozzle, calculate:

(a) the absolute velocity of steam at the outlet from the blade

(b) the diagram efficiency.

Take nozzle angle = 22°

blade friction factor = 0.8

Solution

Step (I) Dryness fraction of Exhaust Steam

Since the expansion of steam in the nozzle is isentropic (cf. the process is adiabatic),

Entropy of steam before expansion = Entropy of steam after expansion

or, $1.535 = 0.355 + x(1.712 - 0.355)$

$x = 0.869.$

Therefore, steam is 0.869 dry at the turbine outlet.

Step (II) Adiabatic Enthalpy Drop

Initial Enthalpy, kcal/kg H_1	Final Enthalpy, kcal/kg H_2	Enthalpy Drop, kcal/kg $\Delta H = H_1 - H_2$
204 + 463 = 667	116.6 + 0.869 (528.5) = 575.86	667–575.86 = 91.14

Step (III) Velocity of Steam at Inlet

10% of this enthalpy drop is lost to friction, so the rest 90% goes to increase the kinetic energy of steam. Therefore, the absolute velocity of steam at the inlet to the blade

$$V_1 = \sqrt{2\,g\,J\,(0.9)\,(\Delta H)}$$

(cf. J = 427 kgf.m/kcal)

$$= \sqrt{2(9.81)(427)(0.9)(91.14)}$$

$$= 828.97 \text{ m/s}$$

$$\approx 829 \text{ m/s}$$

Step (IV) Velocity Diagram

Blade rpm = 4074

Blade velocity, $V_b = (2\pi)\ (1.5/2)\ (4074/60)$ m/s

= 320 m/s (cf. $V_b = 2\ \pi\ r\ N$)

From the diagram, BC = 550 m/s = V_{r_1} (Fig 36.15]

$\angle CBE = 42°$ = blade angle at inlet.

As the blade is symmetrical, the blade angle at the outlet will be also 42°.

So $\angle ABD$ is drawn equal to 42°.

D is such a point on BD that

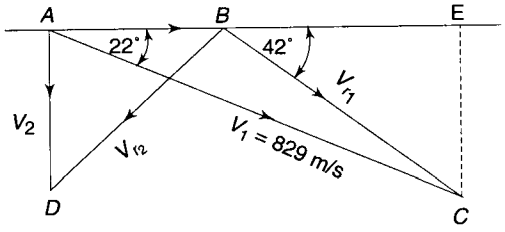


Fig. 36.15

$BD = V_{r_2} = 0.8\ V_{r_1} = 0.8\ (550) = 440$ m/s

AD is joined to complete the outlet triangle.

Step (V) Steam Velocity and Diagram Efficiency

From the diagram, the absolute velocity of steam at the outlet

$V_2 = AD = 330$ m/s

Diagram efficiency = $2V_b\ (V_{w_1} + V_{w_2})/V_1^2$

From the diagram,

$V_{w_1} + V_{w_2} = AE = 770$ m/s

Diagram efficiency = $2(320)\ (770)/(829)^2$ = 0.717 i.e. 72%

Problem 36.6 Steam at 10 kgf/cm^2 absolute and dry is supplied to the nozzles of a simple impulse turbine at a rate 10 t/h. As the steam passes over the blades it suffers a velocity drop of 15% due to friction. The blade speed is 5560 rpm. Blade dia = 1030 mm.

Determine the

(a) net horse power developed at the shaft coupling

(b) steam condition when it

(i) leaves the nozzle

(ii) leaves the blade

(iii) flows through the exhaust pipe.

Given Exhaust steam pressure = 0.8 kgf/cm^2 abs.

Nozzle angle = 22°

Blade angle at outlet = 30°

Different losses sum up to 2.5 h.p.

Nozzle efficiency = 0.82

Solution

Step (I) Steam Condition After Expansion

Since the expansion of the steam in the nozzle is adiabatic, i.e., isentropic,

Entropy of steam before expansion = Entropy of steam after expansion

or $1.575 = 0.293 + x\ (1.777 - 0.293)$

$\therefore\ x = 0.863$

Step (II) Enthalpy Drop

Enthalpy of steam (10 kgf/cm^2 absolute) at nozzle inlet = 663. 3 kcal/kg

Enthalpy of steam (0.8 kgf/cm^2 absolute) at nozzle outlet

$= 93 + 0.863\ (543.4) = 561.95$ kcal/kg

Therefore, enthalpy drop of steam in the nozzle

$= 663.3 - 561.95 = 101.35$ kcal/kg

Useful enthalpy drop = 0.82 (101.35) = 83.107 kcal/kg

Step (III) Steam Velocity at Nozzle Exit

Steam velocity at the exit of the nozzle

$= \sqrt{2\ g\ J\ \Delta\ H}$

$= \sqrt{2(9.81)\ (427)\ (83.107)}$

= 834 m/s

(cf. J = 427 kgf. m/kcal)

Step (IV) Velocity Diagram

Blade speed,

$V_b = 2\pi\ r\ N = 2(\pi)\ (0.1030/2)\ (5560)$

$= 300$ m/s

Taking 1 cm ≡ 100 m/s, AB is drawn to represent V_b equal to 300 m/s. (Fig. 36.16)

$\angle BAC$ is drawn equal to 22°.

In the same scale AC is drawn equal to 834 m/s, i.e.

$AC = V_1 = 834$ m/s = velocity of steam inlet to blade.

BC is joined. From the diagram,

$BC = V_{r_1} = 570$ m/s.

Now the relative velocity of steam at the exit

$V_{r_2} = V_{r_1}(1 - 15/100) = 570\ (0.85) = 484.5$ m/s.

$\angle ABD$ is drawn equal to 30°. Point D is such that $BD = 484.5$ m/s.

AD is joined

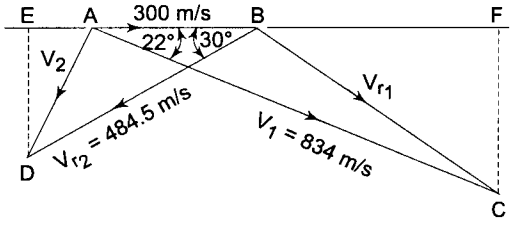


Fig. 36.16

$AD = 272$ m/s (from the diagram)

From points, D and C, perpendiculars DE and CF are dropped on AB extended.

EF = Δ Velocity of whirl = 890 m/s (from the diagram)

Step (V) Blade H.P

Blade h.p.

$= \frac{W}{g}$ [Δ Velocity of Whirl] [Blade Velocity]/75

$= \frac{(10 \times 1000/3600)\ (890)\ (300)/75}{9.81} = 1008$

Allowing different losses, we get net h.p. at the shaft coupling

= 1008 – 2.5 = 1005.5

Ans.

Step (VI) Dryness Fraction of Steam at Nozzle Exit

Let the dryness fraction of steam at nozzle exit be x_e.

Useful enthalpy drop of steam = 83.107 kcal/kg

Initial enthalpy of steam = 663.3 kcal/kg

Final enthalpy of steam = 663.3 – 83.107

= 580.193 kcal/kg

$\therefore$ 580.193 = 93 + x_e (543.4); or x_e = 0.896

Ans.

Step (VII) Dryness Fraction of Steam at Blade Outlet

Energy available at the shaft coupling

= 1005.5 (75)/427 = 176.61 kcal/s

Steam flowrate = 10(1000)/3600 kg/s

= 2.778 kg/s

Energy drop (available for workdone) per kg of steam

= 176.61/2.778 = 63.574 kcal.

Now, from the diagram, the velocity of steam at blade exit is

$AD = V_2$ = 272 m/s.

Therefore, kinetic energy of steam

$$= \frac{1}{2} (W/g) (V_2)^2 \text{ kgf.m}$$

$$= \frac{1}{2} (W/g) (V_2)^2/\text{J kcal}$$

$\therefore$ K.E./kg of steam = $V_2^2/(2gJ)$

= $(272)^2/(2 \times 9.81 \times 427)$ = 8.831 kcal

Since the loss of K.E. due to friction reappears as heat, enthalpy, of steam at the blade exit (at 0.8 kgf/cm^2 absolute)

$H_{exit} = H_{in}$ – Energy Drop for W/Done – K.E. loss due to friction

= 663.3 – 63.574 – 8.831 = 590.895 kcal/kg

If x_0 is the dryness fraction of steam at the blade exit, then

H_{exit} = 93 + x_0 (543.4)

or 590.895 = 93 + x_0 (543.4); or, x_0 = 0.916

Ans.

Step (VIII) Steam Condition at the Exhaust Pipe

Assuming the entire K.E. of steam is converted into heat in the exhaust pipe, then enthalpy of steam at exhaust pipe

$H_{exh} = H_{in}$ – Energy Drop for W/done

= 663.3 – 63.574 = 599.726 kcal/kg.

If x_p is the dryness fraction of steam at the exhaust pipe then,

93 + x_p (543.4) = 599.726; $\therefore$ x_p = 0.932

Ans.

Problem 36.7 The following data is available for a single stage impulse turbine.

Steam pressure inlet to nozzles = 15 kgf/cm^2 absolute

Steam pressure at nozzle outlet = 1.5 kgf/cm^2 absolute

Steam condition at entry to the nozzles = 0.98 dry

Velocity carryover from previous stage = 120 m/s

Energy lost to friction = 5% of the theoretical available energy

Nozzle angle = 20°

Blade angle at outlet = 27°

Mean blade speed = 40% of velocity of steam at the nozzle exit

Turbine output = 495 h.p.

Steam flowrate = 5 t/h.

Determine
(a) the blade velocity coefficient
(b) the energy lost in the blade per second
(c) the diagram efficiency
(d) the overall stage efficiency.

Solution

Step (I) Steam Condition at Nozzle Outlet

Due to adiabatic (isentropic) expansion in the nozzles,

Entropy of steam before expansion = Entropy of steam after expansion

or, $0.551 + (1.541 - 0.551)\ (0.98)$

$= 0.341 + (1.727 - 0.341)\ (x)$

$\therefore\ x = 0.85$

Step (II) Enthalpy Drop

Initial enthalpy of steam (0.98 dry, 15 kgf/cm^2 absolute)

$= 200.7 + (466)\ (0.98) = 657.38$ kcal/kg

Final enthalpy of steam (0.85 dry, 1.5 kgf/cm^2 absolute)

$= 111 + 532\ (0.85) = 563.20$ kcal/kg

Therefore, adiabatic enthalpy drop in the nozzle

$= 657.38 - 563.20 = 94.18$ kcal/kg

Step (III) Useful Energy at the Nozzle Exit

Theoretical enthalpy drop of steam in the nozzle = 94.18 kcal/kg

$$\text{K.E. of steam at nozzle inlet} = \frac{1}{2}\ \frac{(120)^2}{9.81\,(427)}$$

$= 1.718$ kcal

$$\left[\text{cf. K.E.} = \frac{1}{2}\ \frac{W}{g}\ \frac{V^2}{J}\ \text{kcal}\right]$$

Therefore, theoretical energy available at the nozzle exit = 94.18 + 1.718 = 95.898 kcal/kg

Energy lost to friction in the nozzle = 5% of the theoretical enthalpy drop in the nozzle.

Therefore, useful kinetic energy available = 0.95 (95.898) kcal/kg steam = 91.10 kcal/kg steam

Step (IV) Steam Velocity at Nozzle Exit

This is also the absolute velocity of steam at the blade inlet, i.e.

$$V_1 = \sqrt{2g\,J\Delta H} = \sqrt{2(9.81)\,(427)\,(91.10)}$$

$= 873.6$ m/s

Step (V) Mean Blade Velocity

$V_b = 40\%$ of $V_1 = 0.4\ (873.6) = 349.44$ m/s.

Step (VI) Change in Velocity of Whirl

H.P.

$= (W/g)$ (Change in velocity of whirl) $(V_b/75)$

or, $495 = \dfrac{(5 \times 10^3/3600)}{9.81}$ (Change in velocity of whirl) (349.44/75)

Change in the velocity of whirl = 750.40 m/s

Step (VII) Velocity Diagram

AB is drawn to represent blade velocity, V_b = 349.44 m/s in suitable scale 1 cm ≡ 100 m/s.

From points A and B, the angles BAC and ABD are drawn equal to 20° (nozzle angle) and 27° (blade angle at outlet) respectively. (Fig. 36.17)

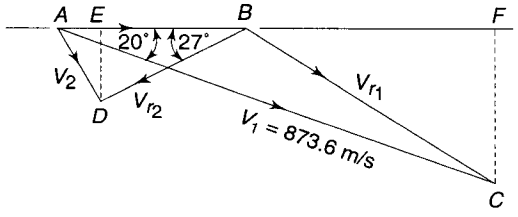


Fig. 36.17

AC is cut off to represent absolute velocity of steam at turbine inlet

$V_1 = 873.6$ m/s in the same scale.

CF is the perpendicular dropped on AB extended.

EF is measured out equal to 750.40 m/s to represent the change in the velocity of whirl.

At point E, $DE \perp AB$ is drawn. It meets BD at D.

Then BD = relative velocity of steam to moving blade at outlet. From the diagram:

$BC = V_{r_1} = 557$ m/s

$BD = V_{r_2} = 309$ m/s

$AD = V_2 = 158$ m/s

Step (VIII) Blade Velocity Coefficient

Blade velocity coefficient

= Ratio of relative velocities of steam relative to blade at exit and at inlet

$= 309/557 = 0.5547$

Ans.

Step (IX) Energy Lost

The energy lost in the blades per second

$$= \frac{1}{2}\frac{W}{g}\left(V_{r_1}^2 - V_{r_2}^2\right)$$

$$= \frac{1}{2}\frac{(5000/3600)}{9.81}\left[(557)^2 - (309)^2\right] \text{ kgf.m}$$

$= 15203$ kgf.m

Ans.

Step (X) Diagram Efficiency

Workdone per kg steam

$$= \frac{H.P.(75)}{\dot{M}(427)} = \frac{495\,(75)}{(5000/3600)\,(427)}$$

$= 62.60$ kcal

where $\dot{M}$ = Steam flowrate, kg/s

Diagram efficiency = Workdone/Useful K.E. available at nozzle exit

$= 62.60/91.10 = 0.6871$ i.e. 68.71%

Step (XI) Overall Stage Efficiency

Overall stage efficiency = Workdone/Theoretical K.E. available at the nozzle exit

$62.60/95.898 = 0.6527$ i.e. 65.27%

Ans.

Problem 36.8 A reaction turbine has speed 2650 rpm and drum dia 2000 mm. At a particular ring, the blade height is 175 mm and discharge angle is 30°. The exhaust steam from the ring is 0.94 dry and has pressure 0.8 kgf/cm^2 absolute. Find the power developed at that particular ring if the steam consumption is 54 t/h.

Receiving angle is 50°.

Solution

Step (I) Area of Flow

The area of flow of steam at the ring with drum dia 2000 mm and blade height 175 mm is

$= \pi(D + h)h = \pi(2 + 0.175)\,(0.175)$ m^2

$= 1.1957$ m^2

where D = drum dia; h = blade height

Step (II) Blade Speed

$V_b = \pi(D + h)$ N/60 $= \pi(2 + 0.175)\,(2650/60)$

$= 301.78$ m/s

Step (III) Velocity Diagram

In the case of the reaction turbine V_1 is made equal to V_{r_2} and $V_2 = V_{r_1}$

$\alpha = \gamma$

Here, $\alpha = \gamma = 30°$ (Fig 36.18)

$\beta = \theta$, the blade angle for shockless entry = 50°

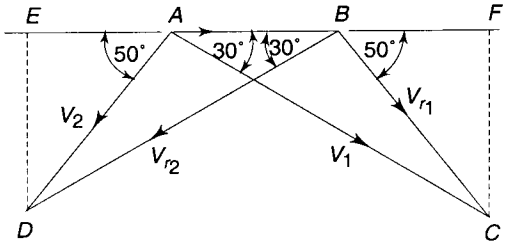


Fig. 36.18

Step (IV) Power Developed at the Particular Ring

Change in the velocity of whirl = EF = 840 m/s

Velocity of blade = $V_b = AB$ = 301.78 m/s

Mass flowrate of steam = $54 \times 10^3/3600$ kg/s
= 15 kg/s

H.P. developed at the rim

= (W/g) (Δ Velocity of Whirl) ($V_b/75$)

= (15/9.81) (840) (301.78)/75

= 5168.09 i.e. 5168

Ans.

Problem 36.9 At a stage in a reaction turbine, the mean drum diameter is 1.5 m and the mean blade height is 150 mm. The blade tip angles of fixed and moving blades at inlet and exit are 30° and 20° respectively.

The turbine is supplied with steam at the rate 720000 kg/h and the stage efficiency is 85%.

Determine:
(a) the axial velocity of steam flow
(b) the blade speed
(c) the power output of the stage
(d) the specific enthalpy drop in this stage
(e) the percentage of increase in relative velocity in the moving blades due to expansion in these blades.

The steam is dry, saturated at 15 kgf/cm^2 absolute.

Solution

Step (I) Axial Velocity

Axial velocity of flow of steam

V_a = Volumetric Flowrate of steam/Annular area of flow

Now, at 15 kgf/cm^2. absolute the specific volume of steam

= 0.134 m^3/kg

Mass flowrate of steam = 720000 kg/h

= 720000/3600 kg/s = 200 kg/s

Volume flowrate of steam

= Mass flowrate × Specific volume of steam

= 200 (0.134) = 26.8 m^3/kg

Annular area of flow = $\pi(D + h)h$

= π(1.5 + 0.15) (0.15) = 0.7775 m^2.

$$\therefore V_a = \frac{26.8}{0.7775} = 34.469 \text{ i.e. } 34.47 \text{ m/s}$$

Ans.

Step (II) Velocity Diagram

On a horizontal EF, a perpendicular CF is drawn at F such that CF = 34.47 m/s which is the axial velocity of flow of steam. Now, A is another point on EF such that

$AF = CF \cot 20° = 34.47\ (2.747) = 94.69$ m/s

Similarly B is a point such that BF

= $CF \cot 30°$

= 34.47 (1.732) m/s

= 59.70 m/s

From point A, AE is cut off such that AE = 59.70 m/s

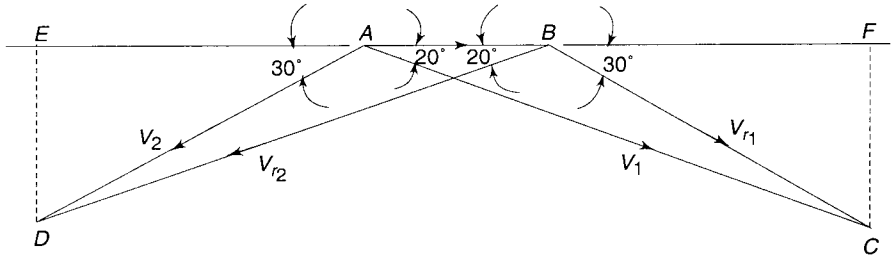


Fig. 36.19

Now, $AB = AF - BF = 94.69 - 59.70$

$= 34.99$ m/s

Step (III) Blade Speed

Blade speed is represented by AB. From the velocity diagram, (Fig. 36.19)

$AB = 34.99$ m/s $= V_b$

i.e. blade speed = 34.99 m/s

Ans.

Step (IV) Power Output

Now the power developed at this stage is

H.P. $= (W/g)$ (Δ Velocity of Whirl) $(V_b/75)$

Now the change in the velocity of whirl

$= EF = AE + AB + BF$

$= 59.70 + 34.99 + 59.70$ m/s $= 154.39$ m/s.

$V_b = 34.99$ m/s; $W = 720000$ kg/h $= 200$ kg/s

$\therefore$ H.P. $= (200/9.81)\ (154.39)\ (34.99)/75$

$= 1468.46$

Ans.

Step (V) Specific Enthalpy Drop

Let the specific enthalpy drop in this stage be ΔH.

$\Delta H = V_b\ (V_{w_1} + V_{w_2})/h$ where,

η = stage efficiency

$= 34.99\ (154.39)/0.85 = 6355$ kJ/kg

Ans.

Step (VI) Per cent Increase in Relative Velocity

From the diagram,

relative velocity at inlet, $V_{r_1} = BC$

$= CF$ cosec $30°$

$= 34.99\ (2) = 69.98$ m/s

relative velocity at outlet,

$V_{r_2} = BD = CF$ cosec $20°$

$= 34.99\ (2.92) = 102.30$ m/s

Increase in relative velocity $= 102.30 - 69.98$

$= 32.32$ m/s.

% increase in relative velocity

$= (32.32/69.98)\ (100) = 46.18\%$ ***Ans.***

Problem 36.10 The following data are available for a reaction turbine.

Steam pressure at inlet = 20 kgf/cm^2 absolute

Steam temperature at inlet = 300°C

Steam pressure in the condenser = 0.2 kgf/cm^2 absolute

Speed of the turbine = 5600 rpm

Power developed = 25000 h.p.

Reheat factor = 1.05

Stage efficiency = 80%

Axial velocity of steam = 75% of the blade velocity.

Blade height = 0.10 times of mean blade diameter one step below. Calculate the

(a) steam consumption per horse power hour

(b) drum dia if the exhaust steam (0.2 kgf/cm^2. abs.) is 0.94 dry.

Solution

Step (I) Adiabatic Specific Enthalpy Drop

As the steam expands in the turbine adiabatically (assumed), from 20 kgf/cm^2 absolute to exhaust pressure 0.2 kgf/cm^2 absolute, its specific enthalpy drops from

720 kcal/kg (from Mollier Chart)

$\Downarrow$

530 kcal/kg (-do-)

$\therefore \Delta H = 720 - 530 = 190$ kcal/kg

Step (II) Work done

Now, workdone during expansion $= \Delta H \times \eta_{int}$

where η_{int} = internal efficiency

= Stage efficiency × Reheat Factor

$= 0.80 \times 1.05 = 0.84$

$\therefore$ Work done $= 190(0.84) = 159.6$ kcal/kg of steam

Step (III) Steam Consumption Per H.P. Hour

Now 1 h.p. = 75 kgf. m/s

1 h.p.h = 75(3600) kgf.m = 75 (3600)/427 kcal

Work done/kg of steam = 159.6 kcal

Steam consumption/h.p.h

= 75(3600)/[(427) (159.6)] kg = 3.96 kg

Step (IV) Steam Consumption

Horse power developed at the turbine = 25000

Steam consumption/h.p.h = 3.96 kg

$\therefore$ Steam consumption/h = 25000(3.96) kg

= 99000 kg

$\therefore$ Steam consumption/s = 99000/3600 kg

= 27.5 kg

Step (V) Blade and Axial Velocity

Blade velocity, $V_b = \pi DN/60$

Speed in rpm = πD (5600)/60 where, N = blade rpm

= 293.215 D

D = average blade dia

Axial velocity, $V_a = 0.75\ V_b = 219.911\ D$

Step (VI) Drum Dia

Now the specific volume of exhaust steam (0.2 kgf/cm^2 abs. and 0.94 dry) = 0.94 (7.79) m^3/kg = 7.3226 m^3/kg

Now, Area × Axial velocity of flow = Mass flowrate of steam × Sp. Volume of steam

$\therefore\ \pi Dh\ (V_a) = 27.5\ (7.3226)$

where h = blade height = 0.1 D (as given)

or D (0.1 D) (219.911 D) = 201.3715

$\therefore\ D = 1.428$ m

$\therefore\ h = 0.1\ (1.428) = 0.1428$ m

Therefore, drum dia

= $D - h = 1.428 - 0.1428 = 1.285$ m

Ans.

Q. *What is the cause of turbine deposits?*

Ans. Turbine deposits are steam-borne foreign matter settled on turbine blades. Substances dissolved in the BFW transfer partly from the water to the steam, during the process of evaporation. They get dissolved in the steam and are carried into the turbine.

Q. *What type of deposits are formed?*

Ans. These deposits are broadly divided into two main types:

1. Water-Soluble deposits
2. Water-Insoluble deposits

Q. *What are the water-soluble deposits?*

Ans. NaCl, Na_2SO_4, NaOH and Na_3PO_4.

Q. *What are the water-insoluble deposits?*

Ans. SiO_2 (mainly).

Q. *Where do water-soluble deposits prevail?*

Ans. In the high-and intermediate-pressure sections of steam turbines.

Q. *Where do silica-sediments prevail?*

Ans. At the end of the intermediate-pressure section as well as in the low-pressure section of the turbine.

Q. *How can turbine deposition be prevented?*

Ans. By upgrading the quality of steam. That is by ensuring proper

(a) boiler feedwater quality
(b) steam boiler model
(c) boiler design
(d) boiler operation

Q. *What are the consequences of turbine depositions?*

Ans. It has three kinds of effects:

1. **Economic Effect**
   (a) Reduction in turbine output
   (b) Decrease in efficiency requiring higher steam consumption
2. **Effect of Overloading and Decreasing Reliability in Operation**
   (a) Pressure characteristic in the turbine gets disturbed with the effect that

thrust and overloading of thrust bearing increase
(b) Blades are subjected to higher bending stresses
(c) Natural vibrations of the blading are affected
(d) Vibration due to uneven deposition on turbine blading
(e) Valve jamming due to deposits on valve stems

3. **Corrosion Effect**
(a) Fatigue corrosion
(b) Pitting corrosion
(c) Stress corrosion.

Q. *How does deposit formation on turbine blades affect turbine efficiency?*

Ans. About 500 g of deposits distributed more or less evenly all over the blading section can bring turbine efficiency down by 1%.

Q. *How can the detection of deposits in a turbine be made during operation?*

Ans. 1. Pressure Monitoring
2. Internal Efficiency Monitoring
3. Monitoring Exhaust Steam Temperature
4. Monitoring Specific Steam Consumption.

Q. *How does pressure monitoring ensure detection of turbine deposits?*

Ans. Pressure of steam expanding in the turbine is measured at characteristic points, i.e. at the wheel chamber, points of pass-out, inlet/outlet of H.P., I.P. and L.P. stages of the turbine.

The turbine manufacturer provides the pressure characteristics in the form of graphs.

At 1st commissioning, the user supplements these theoretical curves with those derived from actual measurements. These are actual pressure characteristics for a clean turbine. Now these pressure characteristics are compared with those obtained during operation in the later period.

Under identical conditions, an increase in pressure shows the formation of deposits.

For a steam throughput in the range 70–100%, an increase in wheel chamber pressure of more than 10% indicates severe blade depositions.

Q. *How does the internal efficiency monitoring lend to the detection of turbine deposits?*

Ans. The internal efficiency of the turbine is given by

$$\eta_i = \frac{[\Delta H]_{pro}}{[\Delta H]_{ad}} \times 100$$

where $[\Delta H]_{pro}$ = process heat drop

$[\Delta H]_{ad}$ = adiabatic heat drop

In the economic rating range, η_i varies negligibly with steam flow. However, blade depositions restrict the passage of steam flow, i.e. change the inner condition of the steam turbine with the effect that η_i alters in comparison to original values.

The process heat drop and adiabatic heat drop are obtained from a Mollier-chart for the corresponding values of steam parameters—pressure and temperature—at initial and final conditions. And η_i is calculated by computing these values in the above equation.

Q. *By monitoring the exhaust steam temperature, how can the blade deposition be predicted?*

Ans. Immediately after the 1st commissioning, the different values of exhaust temperature for different steam flowrates are precisely determined and plotted against steam flow. This will produce the first actual graph. This is for a clean turbine.

Similar graphs are to be drawn at later periods for comparing with the initial graph.

A rise in exhaust steam temperature under the same conditions refers to deposit formation.

An increase in exhaust steam temperature by more than 10% in the range of 70-100% steam flow indicates inadmissible blade depositions. Shutdown is to be taken and blades are to be washed off deposits.

Q. *How can monitoring specific steam consumption tell you that there has been blade deposition?*

Ans. The specific steam consumption in a turbine is given by

$$d = D/E$$

where D = steam flowrate, kg/h

E = electricity output at terminals, in k Wh.

D and E are measured as precisely as possible and corrected over the specific volume, after the 1st commissioning. And the value of d is determined. This ascertains the specific steam consumption for a clean turbine.

This value is compared with the other values of d determined in the same way after some given periods of operation. Any deviation from the initial value is due to blade deposits in most cases.

Q. *How can the deposits be removed?*

Ans. Water-soluble deposits may be washed off with condensate or wet steam.

Water-insoluble deposits are removed mechanically after dismantaling the turbine.

Experience shows that water soluble deposits are embedded in layers of water-insoluble deposits. And when the washing process is carried out, water soluble parts of the deposit dissolve away leaving a loose, friable skeleton of water-insoluble deposits which then break loose and wash away.

Q. *How is the washing of turbine blades carried out with the condensate?*

Ans. The washing is carried out with the condensate at 100°C.

The turbine is cooled or heated up to 100°C and filled with the condensate via a turbine drain.

The rotor is turned or barred by hand and the condensate is drained after 2 – 4 hours.

It is then again filled with the condensate at 100°C (but upto the rotor centre-level), the rotor is rotated and the condensate is drained after sometime. This process is repeated several times.

Q. *How is turbine blade washing with wet steam carried out?*

Ans. Wet steam produced usually by injecting cold condensate into the superheated steam, is introduced to the turbine which is kept running at about 20% of the nominal speed.

For back-pressure turbine the exhaust steam is let out into the open air through a gate valve. For a condensing turbine, the vacuum pump is kept out of service while cooling water is running, with the effect that the entering cooling steam is condensed. The condensate is drained off.

The washing steam condition is gradually adjusted to a final wetness of 0.90–0.95.

It is important:

(a) not to change washing steam temperature by 1°C/min

(b) to keep all turbine cylinder drains open.

Q. *What are the possible causes of excessive vibration or noise in a steam turbine?*

Ans. These are:

(a) Misalignment
(b) Worn bearings
(c) Worn coupling to driven machine
(d) Unbalanced coupling to driven machine
(e) Unbalanced wheel
(f) Piping strain
(g) Bent shaft

Q. *How will you detect that misalignment is the probable cause of excessive vibration?*

Ans. Coupling to the driven machine is disconnected.

The turbine is run alone.

If the turbine runs smoothly, either misalignment, worn coupling or the driven equipment is the cause of the trouble

Q. *How can misalignment be rectified?*

Ans. The bolts holding the flanges together are tightened. The coupling is checked for squareness between the bore and the face. At the same time axial clearance is checked. Using gauge block and feeler gauges, the gap between coupling faces 180° apart is measured. After rotating the coupling-half 180°, the gap at the same points is measured. After this, the other coupling is rotated 180° and the gap at the same points is remeasured. These measures should come within a few thousands of an inch. Dividing the coupling faces into four 90° intervals, the distance between the coupling faces at thess intervals is measured with the aid of a gauge block and feeler gauges. These gap measurements should come within 0.005 inch for proper angular shaft alignment. After proper alignment at room temperature, the two halves of the coupling are connected.

Q. *What is the remedy for worn bearings causing excessive vibration?*

Ans. The bearings should be replaced.

Q. *What should be done in case unbalanced coupling to the driven machine is suspected to be the cause of excessive vibration?*

Ans. The coupling halves are removed. Checking for unbalance is carried out.

Q. *What should be done if excessive vibration is due to an unbalanced wheel?*

Ans. The turbine wheel is checked if it has got unbalanced due to overspending.

The turbine wheel must be rebalanced or replaced.

Q. *Why does such 'unbalancing' occur?*

Ans. If the turbine is kept idle for a long spell without complete drainage of exhaust casing, the solid matter can deposit in the lower half of the wheel causing unbalance.

Q. *How can the problem of 'excessive vibration or noise' due to piping strain be avoided?*

Ans. The inlet as well as exhaust steam lines should be firmly supported to avoid strains from being imposed on the turbine.

Adequate allowance should be made for expansion of steam pipes due to heat.

Q. *What is the remedy for a bent shaft causing excessive vibration?*

Ans. The runout of the shaft near the centre as well as the shaft extension should be checked.

If the runout is excessive, the shaft is to be replaced.

Q. *What are the factors that contribute to bearing failure in a steam turbine?*

Ans. The possible causes of bearing failure are:

(a) not using correct type bearing and inadequate mounting
(b) improper lubrication
(c) inadequate water cooling
(d) misalignment
(e) bearing fit
(f) excessive thrust
(g) unbalance
(h) rusting of bearing.

Q. *What should be done in the case of bearing failure due to improper bearing?*

Ans. Correct type of ball bearings should be used. The worn out ball bearings should be replaced.

Q. *How can bearing failure due to improper lubrication be avoided?*

Ans. Only the recommended lubricant should be used.

Q. *How can bearing failure due to inadequate water cooling be prevented?*

Ans. The jacket temperature should be maintained in the range of 37°–60°C

The flow of cooling water should be adjusted accordingly.

Q. *How does bearing fit bring about bearing failure?*

Ans. It is desirable that ball bearings should fit on the turbine shaft with a light press fit. If the fitting is too tight, it will cause cramping. And on the other hand if the fitting is too loose it will cause the inner race to turn on the shaft. Both conditions are undesirable. They result in wear, excessive vibration and overheating. And bearing failure becomes the ultimate result.

Q. *How to avoid excessive thrust to save the bearings?*

Ans. To avoid excessive thrust, the coupling should be kept clean and installed such that no excessive thrust is imparted to the turbine from the driven equipment.

Q. *What causes the rusting of the bearing?*

Ans. Rusting on bearing surface may occur due to improper storage.

Q. *What factors cause excessive steam leakage under carbon rings?*

Ans. 1. Dirt under rings
2. Shaft scored
3. Worn or broken carbon rings.

Q. *What causes dirt deposition under the carbon rings?*

Ans. Steam borne scale or dirt foul up the rings if steam is leaking under the carbon rings.

Q. *What is the remedy for worn carbon rings?*

Ans. These should be replaced with a new set of carbon rings. The complete ring is to be replaced.

Q. *What are the possible causes for the turbine not running at rated speed?*

Ans. The possible causes are:
(a) too many hand valves closed
(b) oil relay governor set too low
(c) inlet steam pressure too low or exhaust pressure too high
(d) load higher than turbine rating
(e) throttle valve not opening fully
(f) safety trip valve not opening properly
(g) nozzles plugged
(h) steam strainer chocked.

Q. *What are the possible causes of the speed of the turbine rotor increasing excessively as the load is decreased?*

Ans. 1. Throttle valve not closing fully
2. Wearing of throttle valve seats.

Q. *What factors contribute to excessive speed variation of the turbine?*

Ans. 1. Improper governor droop adjustment
2. Improper governor lubrication
3. Throttle assembly friction
4. Friction in stuffing box
5. High inlet steam pressure and light load
6. Rapidly varying load.

Q. *How can the speed variation be reduced by making a governor droop adjustment?*

Ans. If the internal droop setting is increased, the speed variation will reduce.

Q. *How does improper governor lubrication arise?*

Ans. In the event of low governor oil level or if the oil is dirty or foamy, it will cause improper governor lubrication.

Q. *What is the remedy to the above problem?*

Ans. The dirty or foamy lube oil should be drained off, governor should be flushed and refilled with a fresh charge of proper oil.

In the event of low level, the level should be built up by make-up lube oil.

Q. *How can the problem of excessive speed variation due to throttle assembly friction be overcome?*

Ans. The throttle should be dismantled. All the moving parts should be checked for free and smooth movement. Using very fine grained emery paper, the throttle valve, seats and valve stem should be polished.

Q. *What is the possible cause of slow start up of a steam turbine?*

Ans. This may be due to high starting torque required by the driven equipment.

Q. *What are the possible causes of a governor not operating?*

Ans. 1. Restriction of throttle valve reflex
2. Failure of governor control on start-up.

Q. *What may be the cause of the failure of governor control on start-up?*

Ans. If it is found that after start-up, the speed increases continuously and the governor is not closing the throttle valve, it may be that the governor pump has been installed in the wrong direction.

Q. *What may be the possible causes for the "SAFETY TRIP" tripping during load variation?*

Ans. 1. Light load and high inlet steam pressure
2. SAFETY TRIP set very close to the operating speed of turbine.

Q. *What is the remedy to the 2nd problem?*

Ans. The setting of the SAFETY TRIP should be made at 25% (approx) of the rated speed.

Q. *What may be the possible causes for the SAFETY TRIP to trip at normal speed?*

Ans. 1. Excessive vibration
2. Leakage in the pilot valve
3. Deposition of dirt in the safety trip valve

Q. *How does the dirty SAFETY TRIP valve trip the safety trip at normal speed?*

Ans. Dirt may find its way to the safety trip valve and get deposited around the spring end cap end. This will block the clearance between the safety trip valve and the spring end cap. As a result the steam pressure in the spring cap gets lowered allowing the valve to close.

Q. *What is the remedy to this problem?*

Ans. The spring end cap as well as the safety trip valve should be cleaned.

Q. *Frequent damage to shaft bearing area of a steam turbine rotor occurs due to oil starvation of excessive rotor vibration. How can it be repaired while avoiding costly replacement and downtime?*

Ans. If the damage is slight it can be repaired by chrome plating followed by grinding. However, this can only be used for minor damage as the maximum thickness of plating is limited to 0.6 mm.

A permanent repair of shaft journals can be made by the methods of micro-TIG or submerged arc welding and rematching to original dimensions. Irrespective of the component to be repaired the procedure is similar and is described below:

1. The shaft material is identified so that the right welding and heat treatment procedure can be selected
2. The damaged material of the shaft is machined off
3. NDT is conducted over the machined area to ensure that all the defects have been erased out
4. Using appropriate filler the area is buildup to a larger than the finished diameter
5. The welded area is then heat treated and finally ground to the finished dimensions
6. NDT after heat treating and final machining ensures that the process has been successfully performed
7. Care is taken throughout the entire operation so that no distortion is introduced to the shaft.

Q. *High speed steam turbine rotors have discs forged integrally with the shaft. This forging method is a complex and expensive one that requires several months. The discs of these rotors have steam balance holes machined into them. These holes are necessary to reduce the thrust loading on bearings but also act as crack initiators. These cracks, after many years of operation, grow in size and eventually impair the integrity of the machine. The only recourse hitherto has been to replace the whole rotor with a new one.*

What is the alternative remedy?

Ans. A sound alternative is to repair the damaged disc.

Elliott Co. has developed a method of rebuilding the damaged disc by welding. This method actually manufactures an entire new disc entirely from weld metal:

(a) The damaged disc is cut away and discarded
(b) Using submerged arc welding a new disc is gradually built up on the shaft of the weld metal
(c) After heat treatment the disc is finished, machined and the rotor reassembled.

Success of this method requires

(a) Stringent quality control
(b) Metallurgical knowledge of the original material
(c) Proven proprietary welding procedures carried out using calibrated equipment by ASME qualified welders
(d) NDT from the beginning to the end to ensure integrity of the last step of the process before the next is carried out
(e) Mechanical overspeed tests of the complete rotor.

Q. *Of all the factors that contribute to the unreliability of steam turbines, which one is the most prominent?*

Ans. It is the problem of turbine blade failures that chiefly contribute to the unreliability of steam turbines.

Q. *What factors are responsible for turbine-blade failures?*

Ans. In the high pressure cylinder, the turbine blades are mostly affected by

(a) Solid-particle erosion (SPE)
(b) High-cycle fatigue.

Whereas in the last few stages of the low-pressure cylinder, the blade damage is mainly afflicted by

(a) erosion
(b) corrosion
(c) stress/fatigue damage mechanism.

According to EPRI (Electric Power Research Institute, USA) data stress-corrosion cracking and fatigue are the chief exponents for turbine-blade failures in utility industries.

Factors	Blade Failures
Unknown	26%
Stress-Corrosion Cracking	22%
High-Cycle Fatigue	20%
Corrosion-Fatigue Cracking	7%
Temperature-Creep Repture	6%
Low-Cycle Fatigue	5%
Corrosion	4%
Other causes	10%
	Total 100%

Besides, many damage mechanisms operate in combination of

(a) poor steam/water chemistry
(b) certain blade-design factors that vary from one turbine manufacturer to other
(c) system operating parameters.

Q. *How does the damage to turbine-blades tell upon the efficiency of the unit?*

Ans. The damage to blade profiles changes the geometry of steam flow path and thereby reducing the efficiency of the unit.

Q. *What is the remedy to the damage to blade profiles?*

Ans. Upgrading the turbine.

And depending on the extent of damage, upgrading may involve

1. weld repair of affected zones of the blade
2. replacement of damaged blades by new ones and of new design
3. replacement of base material
4. application of protective coatings to guard against corrosion and erosion damage.

Q. *What does "upgrading" generally means in the context of steam turbines?*

Ans. Upgrading is a most widely used term. It encompasses a variety of meanings viz. life extension, modernization and uprating of steam turbines.

Q. *In which case does upgrading imply life extension of steam turbines?*

Ans. For a capital-short electric utility plant, upgrading comes to mean extending the life of that plant scheduled for retirement.

Q. *In which cases does upgrading mean uprating the turbine capacity?*

Ans. For a electric utility system facing uncertain load growth, upgrading is chiefly uprating. It is an inexpensive way to add capacity in small increments.

Q. *When does upgrading mean modernization of utility industry?*

Ans. Upgrading is really modernization to all those units other than those facing uncertain load growth and low-capital utility system. It involves replacement of damaged parts/components by state-of-the-art components without scrapping the entire machine.

Q. *Which factors affect the extent of an upgrading programme?*

Ans. 1. Age of the unit
2. How it has been operated.

Note: Turbine less than quarter of a century old can simply be upgraded to their original design conditions.

Q. *Can the replacement blades for achieving higher reliability improve the efficiency of the unit?*

Ans. Yes.

Q. *How?*

Ans. When the damaged blades of low-pressure cylinder of steam turbines are replaced by longer and new blades, the efficiency of LP section improves. Efficiency is further boosted by smoother surfaces—when old blades are replaced by new ones or coated or remachined—by virtue of reduced friction loss.

Q. *What are the specific losses incurred by an aging turbine?*

Ans. The losses incurred by an older 600 MW reheat turbine are depicted in Fig. 36.20, which shows the greatest losses occur in the blading, followed by tip clearance losses which are a problem particularly in LP turbines.

Q. *How much is the gain in efficiency when a turbine is upgraded?*

Ans. Usually it is 2% or somewhat more. However, in practice, this increase can be even greater because, for example, deposits accumulating over long periods of operation also result in friction losses due to blade surface deterioration.

Q. *What is the most common practice of turbine upgradation?*

Ans. When older turbines are upgraded, it is the most common practice to replace the stationary and moving blades along with the rotor and inner casing. Fig. 36.21 shows all of these improvements using the example of an LP turbine.

Q. *What is the advantage of replacing the older blades by cylindrical blading?*

Ans. The profiles of the cylindrical blades currently used obtain at high section modulus an optimum profile with a continuous curvature on the suction side. Shown in Fig. 36.22 is the cylindrical blading used by Siemens.

The slight suction side flow deceleration at the outlet impedes flow separation. The well-rounded leading edges render the blades relatively immune to changes in the incident angle of flow while the narrow trailing edges reduce downstream losses. The blade performance has been further improved by reducing its surface roughness with the effect that deposit formation is prevented and efficiency gets a boost. In many cases, the high section moduls of the blade profile allows smaller blades to be used, thus permitting more stages and lower pressure coefficients, which further increases efficiency.

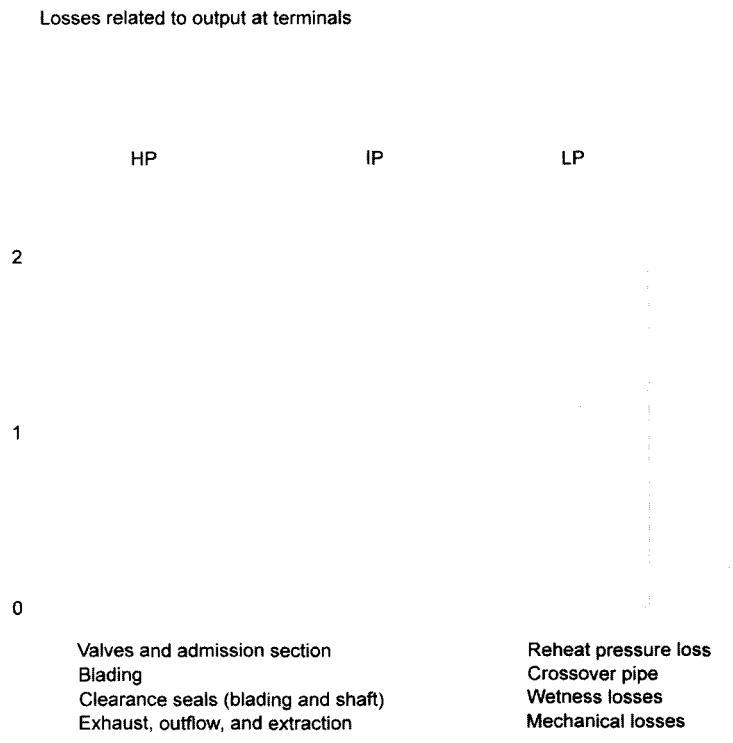


Fig. 36.20 *Turbine losses in a 600 MW reheat turbine-generator (Status : 1970).*
Source: Siemens Power Journal 2/93
Courtesy: Siemens Power Generation/Erlangen/Germany

Q. *Steam turbines are also upgraded by replacing the older blades with twisted blades with integral shrouding. In which part of the turbine these blades are installed?*

Ans. Twisted blades with integral shrouding (Fig. 36.23) can be used in the last stages of high and intermediate pressure turbines and in low-pressure turbines.

Q. *What design features account for its improved performance?*

Ans. The different profiles and the blade cross-section, which is tapered outward, reduce profile losses, while the integral shrouding reduces tip clearance losses. Optimum adjustment of the inflow and outflow angles is also possible, and the blade length can be increased to minimize stage losses and exhaust losses in the final stages.

Q. *How are the free-standing twisted blades designed today?*

Ans. Programs are used to analyze flow in three dimensions. For example, the thermodynamic design of LP blading today optimizes distribution of the mass flowrate over the blade height so that zones exhibiting wall friction or secondary flow will have a low mass flow density.

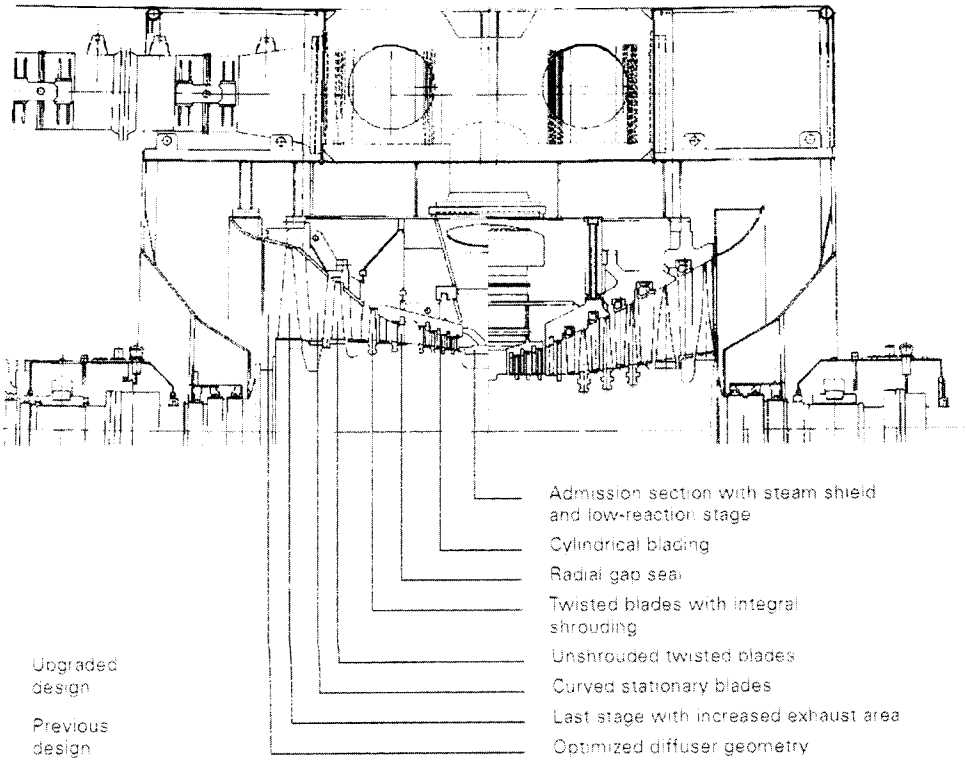


Fig. 36.21 *Extensive upgrading of older steam turbines generally results in an increase in efficiency of more than 2%. This figure shows the steps taken to upgrade a low pressure turbine.*

Source: Siemens Power Journal 2/93
Courtesy: Siemens Power Generation/Erlangen/Germany

Twisted blades are shaped in individual, independent manufacturing steps using modern computational methods which enable an even profile curvature to be produced. Excessive speeds at any point on the contour are avoided. The suction-side contour of the blades produces controlled flow deceleration in the outlet area, which counteracts any flow separation.

Blade areas with a transonic exit flow are provided with straight suction-side contours, and when Mach numbers are high, even with contours that curve backward. The chord lengths of the blade cross-sections and the blade pitch have been optimized. Both of these measures reduce profile losses.

Q. *In many cases it is possible to install a larger last stage when the turbine rotor and inner casing are replaced. What is the advantage of increased exhaust area in the last stages?*

Ans. This larger exhaust area reduces the outflow velocities and hence the exhaust losses.

Q. *How can the effect of increased exhaust area be further enhanced?*

Ans. By

1. expanding condenser vacuum
2. installing an additional LP turbine

As the condenser vacuum is increased, turbine output is enhanced further.

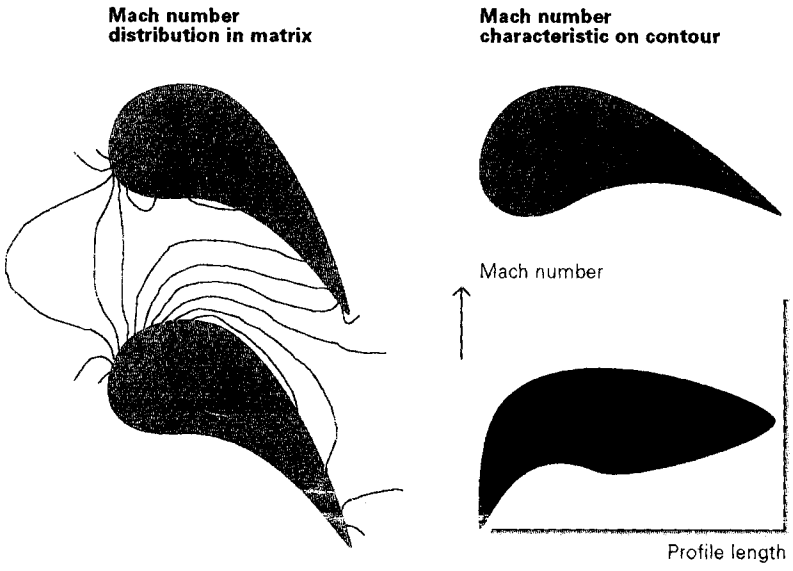


Fig. 36.22 *Reaction profile of cylindrical blading: Profile matrix with lines of equal mach numbers (left) and the mach number characteristic along the profile (right).*

Source: Siemens Power Journal 2/93

Courtesy: Siemens Power Generation/Erlangen/Germany

Q. *How does the improvement of sealing the radial gap between shaft and casing effect of turbine upgradation?*

Ans. Special measures are required to seal the radial gap between the shaft and casing due to the large axial differential expansion. Toothed labyrinth seals placed between the stationary and the moving parts are only effective up to a certain point. Therefore, a double-strip seal is used. It allows greater differential expansion (Fig. 36.24). This seal is effective because the flowrate of leakage steam is relatively low.

Q. *What are the other ways of turbine upgradation?*

Ans. 1. Incorporation of a special admission section in the doubleflow turbines
2. Revamping condensers with new tubes
3. Replacing through-bore or welded-type rotors with monobloc LP turbine rotors
4. Providing rigid inner casing
5. Using blade materials resistant to erosion-corrosion
6. Installing moisture-removal slots
7. Flame hardening the blades

Q. *How does the special admission section benefit the turbine?*

Ans. Incorporation of a special admission section in the central admission area of double-flow turbines increases turbine efficiency. A steam shield, which is mounted on the two inlet stationary blade rows (Fig. 36.25) and forms a steamjet seal between them, prevents tip clearance losses. This shield protects the shaft against the high steam temperature.

Q. *When the surface condensers of turbines are revamped with new tube bundles, what should be the design considerations of the retrofit?*

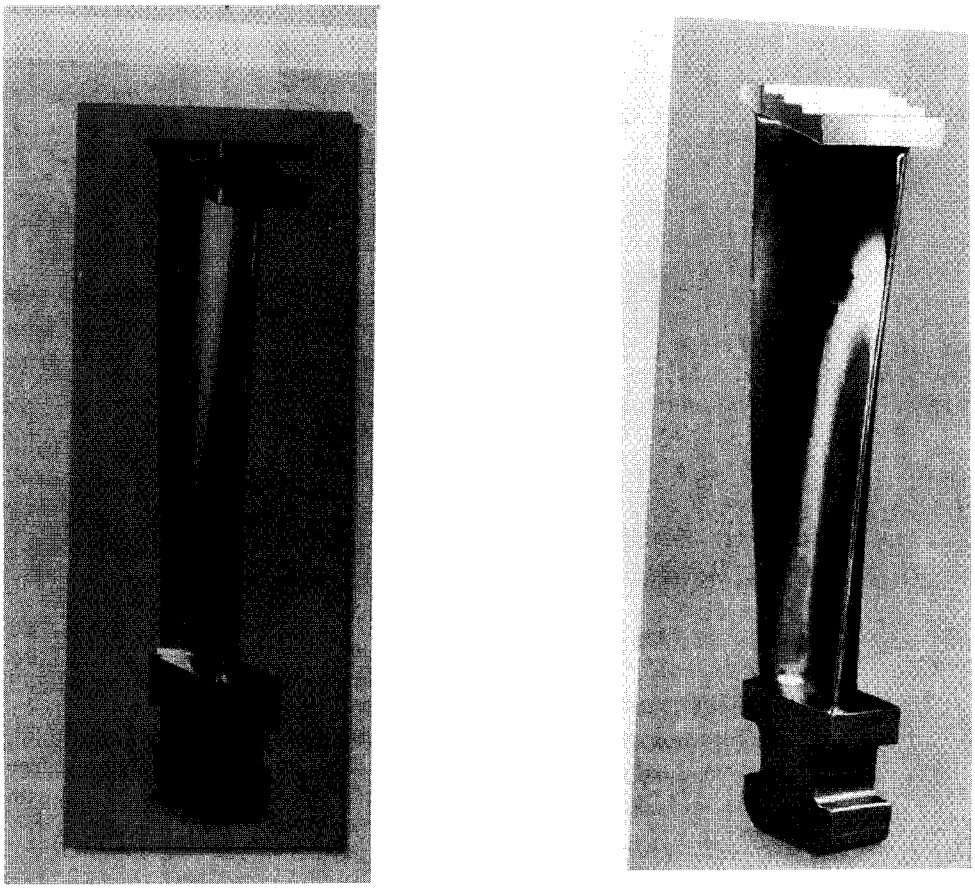


Fig. 36.23 *Twisted moving blades with integral stepped (right) or milled (left) shrouds reduce the profile and stage loss as well as the exhaust loss in the last stages.*

Source: Siemens Power Journal 2/93

Courtesy: Siemens Power Group/Erlangen/Germany

Ans. The new tube configurations must ensure

(a) uniform inflow into all tubes
(b) low pressure drop within and between tube bundles
(c) steam flow directed positively to the air cooler bundle
(d) free condensation drainage with minimal effect on heat transfer
(e) more effective deaeration.

Q. *How are turbines upgraded with monobloc rotors?*

Ans. Turbine rotors are machined from solid vacuum-degassed forgings. One typical material is 26NiCrMoV145 alloy steel equivalent to ASTM A-470C1.6, which exhibits high deep-seated fracture toughness. Finite element analysis confirms that solid rotors are not as highly stressed as rotors with through bores or welded type rotors.

Q. *Why is such a high nickel alloy preferred?*

Ans. Research has shown that forgings from alloys with a lower nickel content have a lower fracture toughness.

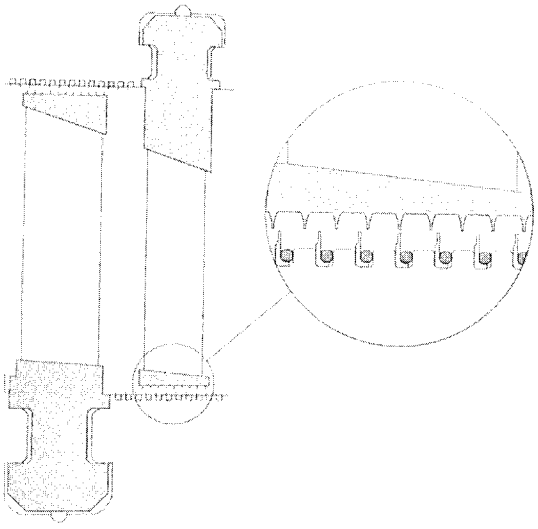


Fig. 36.24 *Design of a double-strip seal which exhibited the lowest relative leakage flow in laboratory tests.*

Source: Siemens Power Journal 2/93

Courtesy: Siemens Power Generation/ Erlangen/Germany

Q. *How does the rigid inner casing upgrade the turbine?*

Ans. The inner casing is designed for rigidity to minimize thermal stresses and to ensure proper alignment between stationary and moving components. This rigidity maximizes interstage seal efficiency, eliminates rubbing, and minimizes steam leakages along horizontal joint.

Q. *Blade materials resistant to erosion-corrosion increase turbine efficiency and availability. What materials are used for fabricating blades to upgrade a turbine?*

Ans. Siemens uses 13% chromium alloy steel for all blading. This material is 100% resistant to erosion-corrosion.

Q. *What materials are used for fabricating casing?*

Ans. In casing materials, a high Cr alloy prevents erosion-corrosion on steam-swept surfaces in areas of heavy moisture. This reduces maintenance on machines that otherwise would be repaired by welding.

Fig. 36.25 *inlet section for intermediate-pressure turbines: steam shield is mounted on and forms a steamjet seal between the two inlet stationary blade rows.*

Source: Siemens Power Journal 2/93

Courtesy: Siemens Power Generation/Erlangen/Germany

Q. *How does the incorporation of moisture-removing slots improve turbine performance?*

Ans. Moisture-removal slots are installed on the last-stage stationary blades of LP turbines. These stationary blades are hollow and connected to the condenser, allowing the excess moisture collecting on the surface of the stationary blades to be drawn off before it can cause water droplet erosion on the last-stage moving blades.

Q. *Why is flame-hardening of blades followed as one of the ways of turbine upgradation?*

Ans. Inspite of designing the inner casing and stationary-blade path to reduce moisture, some will still flow to the LP turbine exhaust. Thus flame hardening the leading edges reduces the effect of water droplet-erosion on blades.

Q. *Why are Stellite strips not used instead of flame hardening?*

Ans. Of course, Stellite strips or similar devices brazed onto the leading edges of the last-stage moving blades are used by some manufacturers to combat this droplet-erosion. However, these strips have caused high local stresses. Therefore, certain renowned companies like Siemens Power Generation resort to flame hardening the leading edges to reduce the effect of water droplet-erosion on blades.

Source: *Siemens Power Journal 2/93*
Siemens Power Journal 2/94
Courtesy: *Siemens Power Group KWU*

Q. *Can you cite some specific examples of turbine upgradation improving the overall performance of steam turbines?*

Ans. 1. In 1985, Siemens Power Corporation performed its first LP steam-path replacement of Unit 2 of BLACK DOG, a 487MW coal-fired plant in Burnsville, Minnesota, USA.

The steam-path replacement was performed at the same time as the boiler was modified to a fluidized bed. The HP turbine steam path was upgraded by replacing the blade carriers and rotors. A new control system and valves were also installed. The LP turbine was provided with a new inner casing and fully bladed monoblock rotor without axial throughbore. The outer casing was machined to accept new shaft steam seals, which replaced the original water seals. Moisture-removal slots were included not only on the blades but also on the casing to reduce the erosion caused by the high moisture content in this non-reheat unit.

The upgradation improved the availability and reliability of BLACK DOG 2 and its full-load output shot up from its pre-upgradation value of 90 MW to 130 MW.

2. CONNECTICUT YANKEE in East Hampton, CT, owned by North East Utilities of Hartford is a 600 MW nuclear power plant which has been in operation since 1968. In 1986, Siemens received a contract to replace the original LP turbines due to long-term reliability concerns. Two new LP turbine rotors manufactured in just 14 months time were installed during a scheduled refueling outage. The replacement turbines had two additional stages of blades, four shrink-fit disks per flow, and 112 cm last-stage free-standing blades. The upgradation boosted up the unit's full-load output from 612 MW to 617 MW.
3. In 1988 Siemens Power Corporation upgraded the 56 MW steam turbine of SIBLEY UNIT 1 owned by the Missouri Public Service Co. of Kansas City, MO. The scope included a completely new HP turbine, valves, control system, and a new fully blade LP rotor with inner casing and seal steam system. The LP rotor and inner casing were designed to fit within the existing bearing and outer

casing supports, and hence no condenser connection or foundation modifications were required. Unit 1's output increased from 56 MW to 64 MW at full load.

4. SCHILLER UNIT is a 179 MW coal- and oil-fired power plant located near Portsmouth. Siemens replaced the LP steam path of Unit 6. Like SIBLEY, this was a double-flow LP turbine with 46 cm last-stage blades. The steam turbine with upgraded LP steam path began commercial operation in Oct. 1990. An acceptance test confirmed that the new LP components exceeded the guaranteed performance improvement.

Source: Siemens Power Journal 2/94
Courtesy: Siemens Power Group

Q. *A question that frequently arises for older design steam turbine-genearator sets—and in conjunction with the requirements of the new ordinance covering large-scale combustion facilities—is whether continued operation of an old plant following upgrading is a practical proposition or whether a new plant should be built.*

Which upgrading options are economically viable to add new life to old turbo-gen sets?

Ans. On a case-to-case basis the following upgrading options are economically viable:

1. Improving the availability of old barrel-type turbines through conversion of radial shaft seals
2. Efficiency improvement measures through modification of:
   (a) drum blades design
   (b) gap seals
   (c) low-pressure blades design
3. Subsequent heat extraction
4. Operation with additional heat recovery from a GT.

Q. *Shown in Fig. 36.26 is a barrel-type turbine with a radial shaft seal.*

Until 1970 nearly all high-pressure barrel-type turbines were fitted with radial shaft seals. However, beyond that, this design was dropped. Why?

Ans. This design has not been used since 1970 on account of the following reasons:

1. Excessive major inspection operations required
2. While smaller barrel-type turbines with a low power output are able to function satisfactorily in the rotor blade rings, higher-output turbines with larger radial dimen-

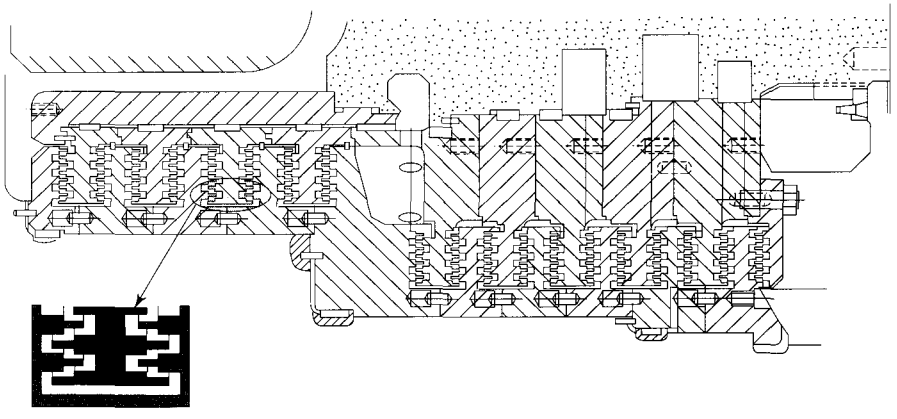


Fig. 36.26 *Barrel-type turbine with radial shaft seal was the most popular design in the pre-seventies.*
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sions are exposed to significantly higher loads, particularly when they are increasingly operated in the peak load range

3. The availability of these turbines is greatly affected by the radial shaft seals. Major shrinkage and centrifugal stressing of the rotor blade rings during frequent temperature excursions cause the rings to expand and hence loosen. The outcome is impact-damaged seals, worn fitted keys and grooves and unserviceable rings.

Q. *What is the remedy to this problem?*

Ans. This situation can be remedied through configurational upgradation, i.e. by switching to an axial geometry.

One good answer is a switchover from the radial shaft seal (Fig. 36.26) to the axial labyrinth shaft seal (Fig. 36.27) while retaining the old turbine shaft.

Another solution is changing the radial shaft seal to axial shaft seal while replacing the old shaft with a new retrofit to enhance turbine efficiency (Fig. 36.28).

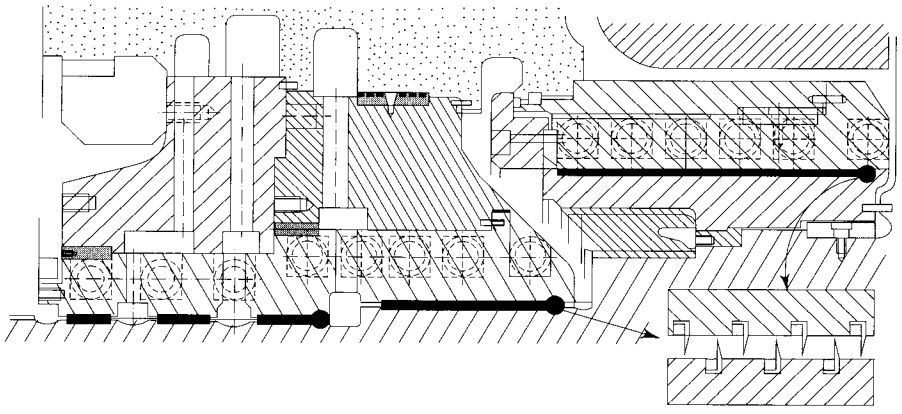

Fig. 36.27 *Turbine upgradation through switchover from the radial shaft seal to the axial labyrinth shaft seal shown here.*

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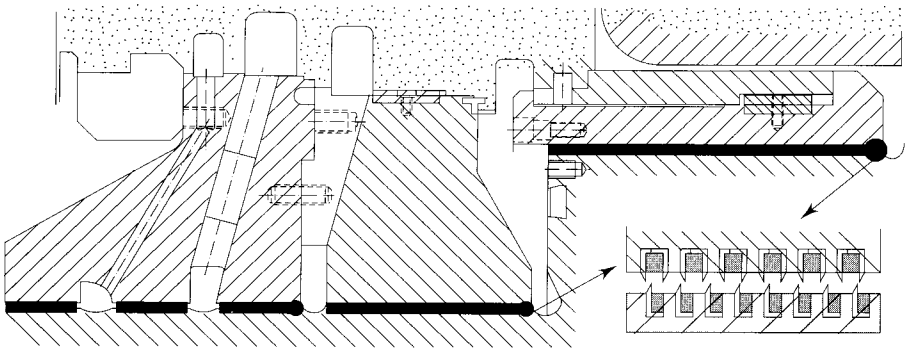

Fig. 36.28 *Upgrading a barrel-type turbine having radial shaft seal with a new shaft and axial tip-to-tip shaft seal.*

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The arrangement shown in Fig. 36.28 has the following advantages:

1. Axial clearance is not limited
2. Major inspection costs are less than 10% of the costs for radial shaft seals
3. Major inspections do not have to be carried out as frequently
4. Shorter inspection time

Q. *Compared to the old radial shaft seal, the steam passage in both the axial labyrinth seal (Fig. 36.27) and the axial tip-to-tip seal (Fig. 36.28) is not increased since the average seal diameter and, in view of the sturdier design, the sealing strip clearance can be smaller.*

Which one of these two axial shaft seals is mostly preferred in current practice?

Ans. The axial tip-to-tip seal with micrometer range spacing is now preferred to the axial system.

Q. *Why is the axial tip-to-tip seal with micrometer spacing preferred?*

Ans. Extensive investigations into the optimum geometry for the tip-to-tip seal have revealed that it is usually superior to the conventional labyrinth shaft seal in terms of efficiency.

An outstanding advantage of tip-to-tip seal is that the axial clearance is not limited.

Q. *What are the specific gains in the conversion of turbines with radial seals to turbines with axial seals?*

Ans. Following conversion, all turbines exhibit excellent running properties. Experience gained through major inspections reveals the following:

1. The cost involved in major inspections is well below 10% of the costs that would have been incurred in overhauling the old radial shaft seals.
2. The duration of major inspection is significantly shorter
3. Expensive parts are no longer required
4. The operating time between two major inspections is no longer limited by the shaft seals
5. The operating characteristics in all load ranges are optimal.

Q. *Shown in Fig. 36.29 are the losses (& hence the reason for limiting the efficiency) of turbogen sets from the 1960s with power output levels of 200 to 400 MW as well as larger sets up to 700 MW from the early 1970s.*

What do you infer from this figure regarding the magnitude of losses?

Ans. The greatest losses occur in the blades, followed by the leakage losses caused primarily by the see-through seals in the LP blades.

Q. *What comprise the drum blade loss in the reheat turbines where drum blades are fitted in the HP, IP and the Ist stages of the LP turbine?*

Ans. The losses essentially comprise the profile and blade tip losses.

Q. *What factors influence these losses?*

Ans. They are influenced by the

1. blade profile itself
2. thermodynamic loading of a stage (pressure coefficient 4)
3. surface quality
4. blade height: blade width ratio—also called side-to-side ratio.

Q. *How has the gradual change in drum blade profiles brought about turbine upgradation?*

Ans. Prior to 1968, profile VN (Fig. 36.30) was used. As the fuel costs were low, nobody bothered with low unit output resulting from low thermodynamic load of VN stages.

In the early 1970s, the profile T2 design (Fig. 36.30) came into being commensurate with the growing demand of blades for higher pressure coefficients. This design exhibited a greater moment of resistance and reduced losses at elevated thermodynamic loads.

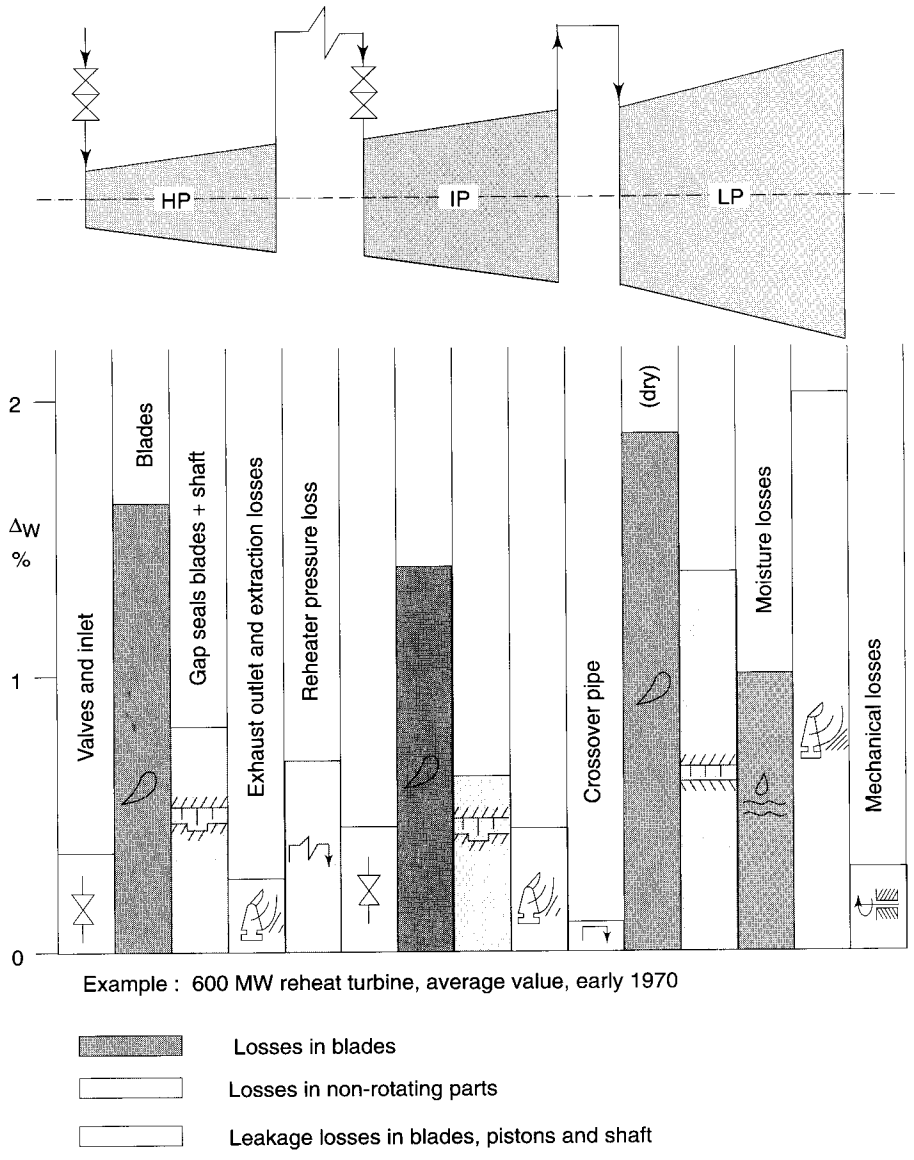

Fig. 36.29 *Shown here are the losses of a Typical 600 MW reheat turbine of the 1970's design. The columns represent the effect on heat consumption of the respective losses.*

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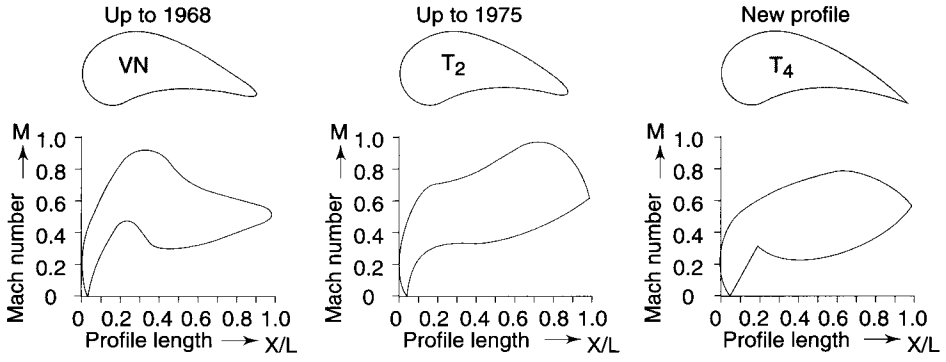

Fig. 36.30 *Mach number characteristics for drum blade profiles VN, T2 and T4.*

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By the mid-1970s, the highest possible levels of efficiency were the prime demand as the fuel costs rose sharply. As a result, a new profile T4 (Fig. 36.30) was born and T2 was phased out beyond 1975.

Designed through modern computation methods, T4 possesses an optimum profile contour with a continuous curvature. Slimmer trailing edge lowers downstream losses. This design prevents flow separation.

Q. *Shown in Fig. 36.31 is a welded stationary blade row used during conversion, having the Ist stage designed as the low reaction stage.*

What are the advantages of such a design upgradation?

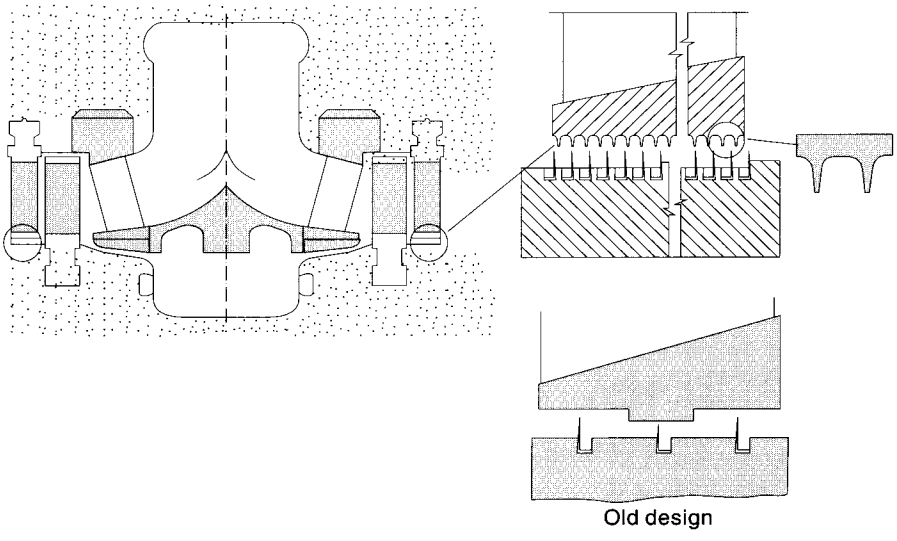

Fig. 36.31 *The new IP first stage design with zero leakage and new shaft seals*

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Ans. The new intermediate-pressure inlet results in the flow through the first diffuser being free from leakage losses due to greater pressure drops in the stationary blade row.

Also the new axial tip-to-tip shaft seal improves sealing at the shrouds of the subsequent diffusers.

Q. *Cylindrical blades of limited height were previously used in the last stages of blades for IP turbines in reheat installation and S turbines in wet steam installations. But they are now disfavoured as twisted blades come into their place. Why?*

Ans. Cylindrical blades suffer from centrifugal stresses which go on increasing with the increase of blade height. Whereas twisted blades, because of their tapered configuration, generate lower centrifugal stresses and can thus be made longer. They also operate at better efficiency levels for these hub-to-tip ratios (lower incident and exhaust losses).

Q. *The gap seals are nowadays designed as tip-to-tip see-thru seals. Frequently, labyrinth seals can only be designed with wide spacing on account of relative expansion. Fig. 36.32 shows result obtained on a test rig specifically set up for this purpose.*

What do you infer from the test result?

Ans. The test rig measurements of the flowrates show

1. full labyrinth minimum losses
2. tip-to-tip seals exhibit particularly low losses wherever full labyrinths could only be used with a wide spacing as a result of major axial expansion.

Q. *In the sixties, use was made of cast stationary blades with thick trailing edges for LP turbines. What were the configurational difficulties with these blades?*

Ans. Because of the thick trailing edges, the last 3 to 4 stages exhibited poor spacing ratio over

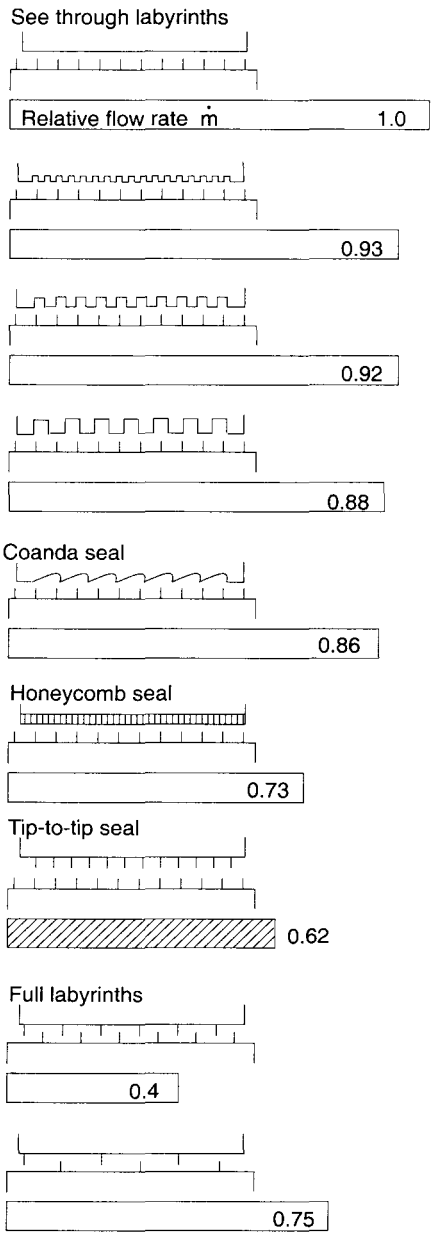

Fig. 36.32 *Test rig measurement of flowrate through gap seals.*
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their outer section and an unsuitable profile contour for transonic flow.

Q. *How were these LP blades upgraded?*

Ans. With the development of flow and vibration computation programs, the blade profile improved continuously. Lower spacing ratio and reduced blade curvature on the suction side downstream of the narrowest cross-section, (Fig. 36.33) that resulted from profiling of the outer section of a new last stage caters to transonic flow.

Q. *What is outcome of such a blade profile of LP stages?*

Ans. It results in lower profile losses and as a consequence of increased deflection, smaller outlet speed components.

Q. *Are there any other advantages?*

Ans. Revamping of existing units can be done easily as the new last-stage blades can be substituted for the old blade grooves without the need for major rework operations in the rotor.

The slimmer trailing edge results in reduced water film thickness and significantly smaller droplets. This reduces the risk of impingement corrosion.

The overall increase in output is roughly 1.5 to 1.8%.

Note: However, the conversion requires a new stationary blade row and a new diffuser which accounts for roughly 0.4% of the overall increase in output gained through conversion of the last LP stages.

Q. *In which part of the steam turbine does stress corrosion cracking (SCC) occur?*

Ans. In the wet stages of the low-pressure turbine.

Q. *In which part of the steam turbine does corrosion fatigue occur?*

Ans. Also in the wet stages of the LP cylinder.

Q. *Where is pitting corrosion mostly prevalent?*

Ans. Upstream of LP stages as well as wet stages of LP cylinder.

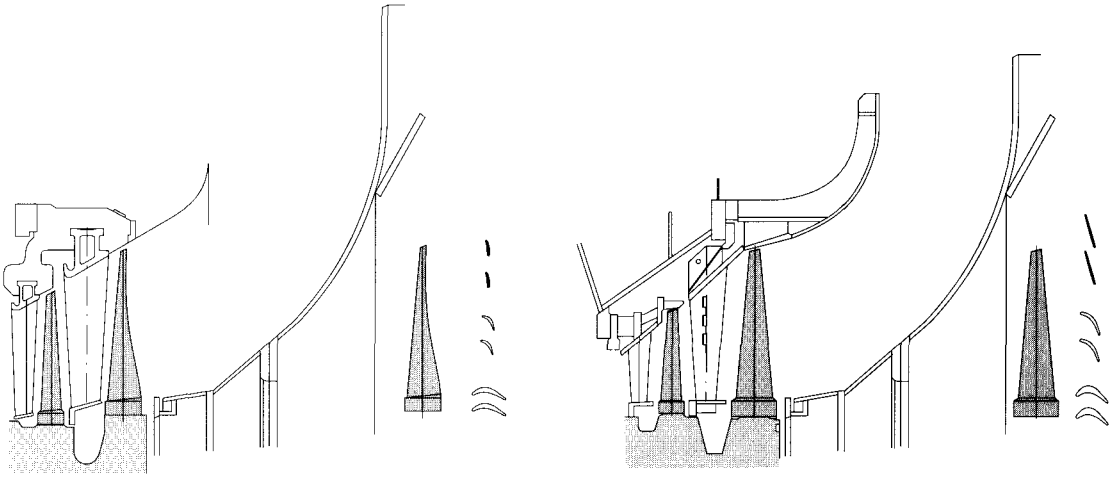

Fig. 36.33 *Virtually all large-scale LP turbines prior to 1969 were fitted with typical last stage (left figure) which was gradually upgraded to a new profile (right) netting in higher efficiency as a consequence of better machining to the transonic flow.*

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Q. *What are the points of SCC attack?*

Ans. SCC attack predominates where corrodents deposit and build-up, i.e. in those blading areas where flowing steam cannot provide a washing effect.

Q. *What are these points in particular?*

Ans. 1. Tie wires
2. Tie-wire holes
3. Brazings
4. Blade covers
5. Tenon holes.

Q. *At what points does corrosion fatigue show up?*

Ans. It attacks trailing edges, near the base of the foil and also the blade-root serrations.

Q. *What is done when cracks due to SCC or corrosion-fatigue are found?*

Ans. The damaged blade is usually replaced as repairing is difficult.

Q. *What is the solution to the problem of SCC/ corrosion fatigue of steam turbine blades?*

Ans. It involves changing the blade material as well as minimizing the presence of corrodents in steam to a permissible level.

Q. *How many types of particle-impact damage occur in turbine blades?*

Ans. 1. Erosion/corrosion
2. Foreign-particle impacts
3. Solid-particle erosion
4. Water damage.

Q. *In which cases does erosion/corrosion damage appear?*

Ans. It is commonly encountered in nuclear steam turbines and old fossil-fuel-fired units that employ lower steam temperatures and pressures.

Q. *In which cases does moisture-impingement and washing erosion occur?*

Ans. These are encountered in the wet sections of the steam turbine.

For nuclear power plants, these wet sections can involve parts of high-pressure cylinder.

Q. *What steps are taken to minimize damage from moisture?*

Ans. The following measures are employed at the design stage to combat impingement corrosion due to moisture.

1. Stellite inserts
2. Hardening of the base metal
3. Moisture-removal devices.

Q. *But despite these preventive measures, damage due to moisture impingement has been found, in certain cases, in the shield and beyond. Why?*

Ans. Shields are designed and fabricated on the basis of predicted range of steam/water quantities impacting the blades at specific angles.

Now if the operating conditions deviate significantly from design parameters then erosion damage will occur. And in some cases it may go beyond normal erosion wear and warrant repair.

Also the corrosion of casing can occur due to blockage/clogging of water drains or extraction thereby forcing the water back into the casing. If this condensate water is carried over to steam path and impacts the blade, thermal-fatigue failure can occur within a short period.

Q. *How does solid-particle erosion occur?*

Ans. Solid-particle erosion, i.e. SPE occurs in the high-pressure blades. And it takes place when hard particles of iron exfoliated by steam from superheater tubes, reheater tubes, steam headers and steam leads strike on the surface of turbine blades.

Q. *When does SPE damage usually occur?*

Ans. It occurs usually during start-up or abrupt load change.

Q. *How does the foreign-particle damage of turbine blades arise?*

Ans. It occurs due to impact on blades by foreign particles (debris) left in the system following outages and become steam-borne later.

Q. *Is there any factor other than corrodents and erodents that contributes to turbine blade failure?*

Ans. Yes; turbine blade damage and failures can be effected by vibration and fatigue.

Q. *How do the problems of vibration and fatigue arise?*

Ans. These are due to

1. flow irregularities introduced because of manufacturing defects, e.g. lack of control over tolerances.
2. system operating parameter, e.g. low flow may excite various modes of vibration in the blades.

Q. *Why are some groups of blades, particularly the first or control stages more prone to fatigue failures than others?*

Ans. Blades in the first or control stages are under partial-arc admission that forces the blades to move into and out of the steam flow causing alternating high-and low-impact forces. This periodic change of impact forces imparts fatigue stress that makes such groups of blades susceptible to fatigue failure.

Q. *In which zone of steam turbines has temperature-creep rupture been observed?*

Ans. Damage due to creep is encountered in high temperature (exceeding 455°C) zones. That is, it has been found to occur in the control stages of the high-pressure and intermediate-pressure turbines where steam temperature sometimes exceed 540°C. In the reheat stage, it has been observed that creep has caused complete lifting of the blade shroud bands.

Q. *When does "stall flutter" occur?*

Ans. This problem is encountered when operating limits are exceeded, i.e. when turbine exhaust pressure exceeds the value what has been recommended by the manufacturer.

Q. *What is its effect?*

Ans. It induces damaging stresses in the blades.

Q. *What is the harm if the rotor is oversped?*

Ans. Oversped rotor grows radially causing heavy rub in the casing and the seal system. As a result, considerable amount of shroud-band and tenon-rivet head damage occurs. (Fig. 36.34).

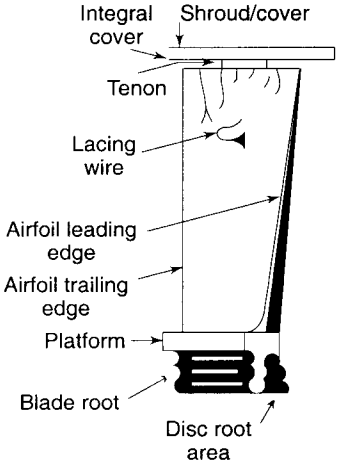


Fig. 36.34 *Blade Components.*

Q. *Why it has been that failures become too common at lacing or tie-wire holes for blades having this type of stiffening?*

Ans. These areas have peculiar susceptible characteristics to damage mechanisms. But the reason is not clear.

It may be that the following causes may act singly or in combination to bring about blade failure:

(a) inadequate manufacturing techniques
(b) poor surface finish at the hole
(c) failure to properly align the wire holes
(d) genesis of very complex stress patterns due to shear stress in the brazed material during operation.

Q. *In how many patterns are tie wires used?*

Ans. In one design, tie wire is passed through the blade vane.

In another design, and integral stub is jointed by welding/brazing.

Q. *Which pattern experiences less problem?*

Ans. The integral stub form.

Q. *What other parts of the steam turbine blades suffer from damage?*

Ans. 1. Blade roots
2. Shroud band

Q. *Why do blade roots suffer from damage?*

Ans. Fatigue is the common cause to the effect of blade root damage. Also this factor is often assisted by a generic type of fault in design or manufacturer.

Moreover, the root-fillet radii are subjected to a high degree of stress concentration with the effect that they crack relatively easily.

Q. *Why do shroud bands suffer from damage?*

Ans. Steam borne solid particles and moisture strike the shroud band continually and in that process they remove material from rivet heads until the rivet becomes too weak to exercise its clamping effect whereupon it fails to hold the band in place.

Q. *What is to be done for erosion-induced damage on high-and low-pressure stage blading?*

Ans. In such cases welding repair can be a good solution and this can be carried out during normal maintenance outage without removing the blade. Using oxyacetylene torch, stellite is generally deposited onto the damaged site. Following this, the weld is subjected to stress-relieving and reprofiling.

In case of erosion penetrating the erosion shield and extending to the base material, a filler material of consistent or identical composition of blade material is used.

In some cases use is made of Inconel alloy to build up the metal base. Therefore, using welding or brazing technique, a new shield can be attached to the blade. If brazing technique is followed, the rebuilt section is stress-relieved prior to the attachment of shield to it. If, on the other hand, the shield is attached by welding, then they are stress-relieved together. (See Fig. 36.35)

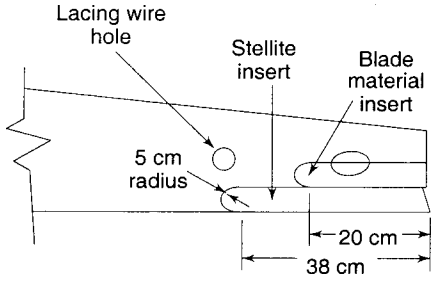


Fig. 36.35

Q. *In some weld-repair cases, it has been found that the stellite survived while the filler material eroded away. Why?*

Ans. If Inconel is used as the filler material, it has the inferior resistance to erosion in comparison to the stellite insert. So filler material erodes away under-neath.

Q. *What is to be done in the case of cracks originating at the lacing-wire holes?*

Ans. These are to be weld-repaired. However, the following factors must be considered:

(a) the length of the crack that appears on the pressure and/or suction face
(b) whether the cracks propagate towards inlet end, discharge end and or both.

Q. *How can damaged tenons be repaired?*

Ans. By adopting modern welding techniques, tenons can be rebuilt. This in some cases results in extended blade life.

Q. *What steps/modifications should be implemented to curtail the damage from moisture impingement?*

Ans. 1. The drainage system should be redesigned. Larger drains are to be provided.
2. More effective water-catchers are to be installed.

3. Radial seals are to be eliminated to remove water before it can chance upon the blades.
4. Nozzle trailing edges are to be thinned to promote the formation of smaller and less harmful droplets.

Q. *How can fatigue damage on high-pressure blades be corrected?*

Ans. Fatigue damage on high-pressure blades arises due to vibration induced by partial-arc admission. This can be corrected by switching over to full-arc admission technique.

Q. *Is there any adverse effect of full-arc admission operation?*

Ans. At low loads, this results in a heat-rate penalty, due to throttling over the admission valves.

Q. *So can you recommend this technique as a permanent measure?*

Ans. No.

This can be recommended in extreme cases or at best temporarily.

Q. *So what should be the more sound approach?*

Ans. The more reasonable and better approach is to replace the damaged blades with new ones that are stiffened by

1. serrating the interface surface of individual blades so they interlock, or
2. welding the blades together.

In some cases, a single monolithic block is machined out to manufacture the blades in a group.

In some other cases, blades themselves are directly welded into the rotor.

Q. *What design modification is adopted to reduce susceptibility of last low-pressure stages to fatigue failure?*

Ans. One modification is to join the blade segments together at the shroud band.

Q. *How does this modification reduce the vibration-fatigue damage?*

Ans. Joining the blade segments together at the shroud band increases the length of the arc—to a maximum of 360°—that alters the natural frequency of the blade grouping from the operating vibration mode.

This design has gained considerable success in commercial service.

Q. *Why are free-standing blades in the last low-pressure stage favoured more, in some cases, than those that are coupled and shrouded together?*

Ans. These free-standing blades are known to provide good and adequate protection against stresses and aggressive environment.

They eliminate all areas viz. shroud/tenon interface and tie-wire/hole area where corrodents can collect.

Q. *Is there any other alternative to improve low-pressure turbine reliability?*

Ans. One sound approach is titanium replacement blades. This will improve turbine reliability if particularly corrosion fatigue is the principle mode of failure of the final two stages.

Test results, conducted at a Texas Utility, have confirmed that titanium alloys possess superior fatigue strength than the conventional blading alloys in the presence of corrodents and stresses commonly encountered in the last-stage environment of the turbines.

Note: Three US utilities have replaced existing low-pressure blades with titanium alloys as far back as 1972 and since then no service related failures have been recorded.

Q. *Titanium replacement blades are a costly approach. Is there any method that can provide a cost-effective protection?*

Ans. Yes, blade coating is one such technique. Extensive laboratory test program followed by field verification trials have confirmed that certain sacrificial coatings can be applied to the existing blade designs to impart increased

resistance to corrosion and erosion. Even the wholesale blade replacement or design changes can be avoided, in certain cases, by use of coatings.

Q. *What are these coatings?*

Ans. 1. Ion deposited aluminium
2. Diffused nickel/cadmium.

Q. *How effective are they?*

Ans. Test results showed that the aluminium coating remained fully protective even at erosion affected areas after one full year of operation of the steam turbine. It is expected that the aluminium coating will withstand a chemically aggressive environment except the extremes in feedwater/steam chemistry.

Nickel/cadmium system has also proved to be a very effective coating against corrosion, and it is more protective than the deposited aluminium coating against erosion.

Q. *Is there any drawback of the nickel/cadmium coating system?*

Ans. Difficulties are encountered in applying this coating uniformly to complex blade geometries.

Q. *Is there any solution?*

Ans. Modification of coating application process seems to be the only viable solution.

Q. *What about the prospect of organic coating?*

Ans. Organic resins, such as TEFLON and RYTON, were investigated as a potential solution. While these coatings could provide the desired surface conditions, they do not bond well to iron, steel and Ni-alloy components.

Q. *How can this problem be overcome?*

Ans. To improve adhesion, the parts should be primed with epoxy-containing particles of the non-stick polymer, or with a slurry of the non-stick material in chromic acid.

Q. *Will these measures enable Teflon and Ryton coatings of the turbine blades to withstand the high temperature and droplet corrosion of expanding steam?*

Ans. Field tests bogged down hope. Water vapor/condensate permeated the polymer film, corroding the metal below, thereby compromising adhesion.

Temperature limitation is a major factor. Polymer coatings are limited by temperature, reducing their effectiveness in steam turbines.

Q. *What are the essential qualities of an organic coating needed for turbine application?*

Ans. 1. The coating will have to survive the varying temperature of superheated steam from the turbine inlet down through the stages and of saturated steam at the outlet
2. It should be non-reactive to steam
3. The coating should be non-stick to prevent fouling and to resist build-up of material deposits
4. It should be non-wetting to shed potentially corrosive condensate
5. It should not interfere with the flow of steam
6. It should essentially be smooth to preserve the turbine's aerodynamics

Q. *What is the answer to the problem of the coating's potential to interfere with steamflow?*

Ans. To tackle this problem, the CYTEC INDUSTRIES, New Orleans, La 70094, USA has prescribed that the coating should be less than 250 μm thick. Over and above, it should be smoother.

Q. *Are there any such organic coating systems available in the market to qualify as per the above requisites?*

Ans. Yes; two proprietary coating products are available with a good track record.

(a) SermeTel 2F-1
(b) SermaLon

Both are from Sermatech International, Limerick, PA 19468, USA.

Since early 1992 these two have been used in different stages of the steam turbine.

Q. *What is SermeTel 2F-1 and where is it applied?*

Ans. Made from an amorphous glassy sealer applied over an electrically conductive aluminium-phosphate base, SermeTel 2F-1 has the capacity to withstand high temperatures up to 840°K.

Since SermeTel 2F-1 is more heat resistant than SermaLon, it is installed in stages operating above the steam saturation line with conditions of high pressure and high temperatures.

Q. *What is SermaLon? Where is it applied and how?*

Ans. SermaLon is a non-wetting coating. It is a high-temperature polymeric resin filled with metal powder.

A layer of this coating is applied to an aluminum-phosphate basecoat. The two layers are then sealed with a high-temperature polymer containing particulate PTFE. This produces an unreactive smooth finish of less than 0.5 μm.

SermaLon is applied to the latter stages of the turbine where the conditions fall below the saturation line resulting in an increase in moisture and decrease in temperature (< 533°K).

Q. *What is the result?*

Ans. Striking improvements in the steam turbine performance were observed:

(a) Steamflow through the turbine dropped by about 5% without any curtailment of turbine efficiency
(b) This reduced flowrate had been found to remain constant for a period of 2y 8 months
(c) During inspection after 32 months of continuous operation, the 8-th stage airfoils of the extraction turbine coated with SermaLon did show few signs of wear and tear.
(d) With improve efficiency, the payback period for these coating systems was only one month.

Source: Chemical Engineering (Jan. 1997/P: 129)

Q. *Do you think that turbine blade failure is the only cause of unreliability of steam turbines? Does upgrading of turbine means replacement of blades and/or improvement of blade design?*

Ans. Not exactly.

Like the blades, the steam-turbine rotors are highly stressed components. They are subject to cracking by a variety of failure mechanisms. Rotor failures do occur. And when they occur the result is catastropic with the complete destruction of the unit and the total loss of generating capacity.

Therefore, special attention should be given to rotor upgrading and repairing techniques.

Q. *In which section of the steam-turbine rotors is the problem of rotor failure mostly prevalent?*

Ans. Rotor failures occur mostly on the large low-pressure rotors.

Q. *What are the basic causes of the problem of rotor failure?*

Ans. 1. Normal wear.
2. Fatigue failure due to high stress.
3. Design deficiency.
4. Aggressive operating environment.

Q. *What types of cracking occur in the LP rotor/shaft?*

Ans. 1. Radial axial-bore cracks
2. Circumferential cracks

Q. *What is the cause of axial-bore cracks?*

Ans. Inadequate toughness of rotor steel and transient thermal stresses.

Q. *What should be the remedial action?*

Ans. For new rotors, control cleanliness of the steel, i.e. inclusion and segregates free and more homogeneous steel shaft is required.

For current rotors, replace the rotor, grind and overbore.

Q. *What is the cause of circumferential cracks?*

Ans. High-cycle fatigue with or without corrosion.

Q. *What is the remedy to this failure?*

Ans. For the existing rotor, weld repair may be a choice; otherwise retire it.

For new rotors, materials with improved pitting resistance should be used.

Q. *Do the radial axial-bore cracks occur in the LP rotor/shaft alone?*

Ans. No. These are also known to occur in the HP as well as IP rotors.

Q. *What are the causes of radial axial-bore cracks on HP/IP rotors/shafts?*

Ans. The predominant cause is creep which may act with or without low cycle fatigue.

Also the cracks result due to poor creep ductility due to faulty heat treatment process.

Q. *Is there any other type of cracking occurring in HP/IP rotors and causing rotor failures?*

Ans. 1. Blade-groove-wall cracking
2. Rotor-surface cracking

Q. *Why do these two types of cracking take place?*

Ans. The cause to the effect of blade-groove-wall cracking is creep with/without low cycle fatigue.

Faulty heat treatment procedure results in poor creep ductility that may also contribute to this type of fault.

Whereas thermal fatigue have been identified as the single cause to rotor-surface cracking.

Q. *What remedial measures must be taken to cope with radial axial-bore cracks?*

Ans. For new rotors, modified heat treatment process is recommended while for existing rotors derating the turbine or replacement of the rotor may be a solution.

Q. *What should be the remedial actions for blade-groove-wall cracking?*

Ans. Modified heat treatment of new rotors is a sound and lasting remedy.

For current rotors, cracks should be machined off and lighter blades should be installed. It is better to retire the cracked shaft.

Q. *What is the remedy for rotor-surface cracking?*

Ans. Current rotor/shaft should be machined off (skin-peeling).

Q. *Failures of IP rotors of shrunk-on-disc design due to stress-corrosion-cracking (SCC) has been observed at alarming frequency in the nuclear powerplants of USA.*

Why does SCC occur at intermediate pressure stage?

Ans. Steam turbines of nuclear powerplants usually operate on wetter steam than those of thermal powerplants. So even at the intermediate pressure stage, steam becomes wet and it precipitates the impurities, i.e. corrodents dissolved in it. These corrodents deposit and build up on rotor shaft causing stress-corrosion-cracking.

Q. *What is shrunk-on-disc rotor?*

Ans. These are built by heat expanding the discs, so that upon cooling they shrink on the main rotor forging.

Q. *Is there any alternative to the shrunk-on-disc design?*

Ans. Yes. Two designs are available at present.

1. Welded rotor in which each individual disc is welded, instead of shrunk, onto the main shaft.
2. Monoboloc rotor in which the entire shaft and blade assembly is manufactured from a single forging.

Q. *What are the stresses to which a steam turbine rotor is subjected during its service life?*

Ans. 1. Mechanical stress
2. Thermal stress
3. Electrically induced stress.

Q. *Why does mechanical stress occur in turbine rotors?*

Ans. The factors that contribute to mechanical stress in the shaft are the centrifugal forces and torques generated due to revolving motion of the shaft as well as bending arising during steady-state operation.

Q. *Why do thermal stress occur in the turbine rotors?*

Ans. Transient operating phases, i.e. start-up and shutdown are the genesis of thermal stress induced to the turbine shaft.

Q. *Why do electrically induced stresses occur in turbine rotors.*

Ans. They originate due to short circuits and faulty synchronization.

Q. *Is it true that a rotor with an axial-through bore experiences more stress than a solid rotor of the same configuration? If so, why?*

Ans. Yes; rotors with axial-through bore suffer from twice as much tangential elastic stresses at the centre as the solid rotor of identical configuration.

This is because of uneven stress distribution in the area of the wheels and blade roots and rotor central bore. Stress in the wheels and the blade root areas is different from that in the rotor central bore.

Q. *Bored rotors have higher stress levels yet they are favoured in preference to solid rotors. Why?*

Ans.
1. Bored shaft is more free from inhomogeneities than solid shaft. A bore removes inclusions and segregates from the centre of the rotor.
2. Direct evaluation of the mechanical properties of the core-bar samples is possible.
3. Non-destructive tests, viz. ultrasonic testing and magnetic particle inspection testing of the rotor from the bore are possible.
4. A bore eliminates entrapped gases (which increase shaft porosity) that gravitate to the centre.

Note: Advanced steel-making techniques today make it possible to manufacture "clean" solid rotor/shaft. Hence the foregoing reasons, according to some experts, why a bored shaft should be opted in preference to a solid shaft stands obsolete.

Q. *Why were cracks at the bore common for high-pressure and intermediate-pressure rotors of the early sixties?*

Ans. These rotors were manufactured from forgings which were not "clean" steel and that's why cracks were initiated at the sites of inclusions and segregation bands in the steel. This coupled with low inherent toughness of rotor materials resulted in bore cracks.

Q. *What is the potential problem of shrunk-on disc type rotor?*

Ans. It is the failure due to circumferential cracks which are not limited to old rotors of early models (1960) but they also take place on present-day rotors.

Q. *What is the nature of circumferential cracking in shrunk-on-disck rotors?*

Ans. Regions of high stress concentration give birth to this type of cracking. It begins in corrosion pits and propagates towards the bore by high-cycle fatigue. It may culminate in a catastrophe, if it penetrates the bore (happily this usually does not occur).

Q. *Rim cracking continues to be a problem of shrunk-on-disc type rotors in utility steam turbines. Where does it occur?*

Ans. Rim cracking has been located at the outer corners of the grooves where the blade root attaches to the rotor.

Q. *Why does rim cracking occur?*

Ans. Poor low-term creep rupture strength or low ductility of the nickel/cadmium/molybdenum/vanadium (NiCdMoV) is the cause of rim cracking.

Q. *What is the nature of rotor surface cracks?*

Ans. They are shallow in depth and have been located in heat grooves and other small radii at labyrinth-seal areas along the rotor.

Q. *Usually it has been found that SCC (Stress Corrosion Cracking) attack takes place particularly at keyways of shrunk-on-disc rotors of low-pressure turbines. Why are keyways prone to SCC attack?*

Ans. Keyways shrunk-fit each disc onto the rotor shaft. They improve the rigidity of the connection between the disc and the central shaft. However, keyways are subjected to abnormal centrifugal forces due to high overspeed, that reduce the amount of shrink. Tangential stresses tend to gravitate at the keyway connection and steam tends to condense there. As a result corrodent impurities like chlorides concentrate at keyways. This factor coupled with high stress concentration lead to SCC attack on keyway areas.

Q. *It has been suggested that a monobloc rotor is a good substitute of shrunk-on-disc rotor. What are the plus points of monobloc design?*

Ans. 1. It is a one-piece-construction, and thus has inherent rigidity.
2. Advanced steelmaking techniques enable building of monobloc rotors almost free from non-metallic inclusion and gas bubbles. Even large monobloc rotors of clean steel are being manufactured today.
3. It exhibits lower inherent stresses.
4. The chance of disc-loosening during operation is eliminated.
5. Highly stressed keyway is eliminated.

Q. *Does the monobloc rotor have any drawback or disadvantage?*

Ans. There are two limitations:
1. It is difficult to test and inspect large solid rotors.
2. Manufacturing is difficult. In fact only limited manufacturing capabilities are available to produce the forgings.

Q. *Is there any other alternative rotor design for upgrading steam turbines?*

Ans. Yes, the welded rotor has been claimed by some manufacturer as being a good alternative for upgrading steam turbines with damaged shrunk-on-disc rotors.

Q. *What are the advantage of welded rotors?*

Ans. 1. A welded rotor is a composed body built up by welding the individual segments. So the limitations on forgings capacity do not apply.
2. Welding discs together results in a lower stress level. Therefore, more ductile materials can be chosen to resist SCC attack.
3. There is no keyway. So regions of high stress concentrations are eliminated.

Q. *Suppose yours is an old utility steam turbine. The rotor is of shrunk-on-disc type. You want to replace it and retrofit welded rotors designed by another manufacturer. What primary factors will you consider and what are fundamental steps you will follow?*

Ans. First step required is to ensure the compatibility with the balance on the components.

Rotor critical speeds are to be checked very carefully.

The geometrical factors at the interfaces are to be measured precisely.

New vibration behviour is to be characterized for the whole machine.

Care must be taken not to disturb the overall steam-circuit parameters. And therefore, the thermodynamic design is to be adopted to existing machine conditions.

Case Study

A steam turbine unit suddenly underwent a 4% loss in capacity. Comparative data before and after the capacity drop revealed:

(a) Reduction of load by 4.9% while feedwater flow dwindled by 3.6%

(b) Ist stage pressure dropped by 4.2% and intermediate valve pressure by 4.4%

(c) High pressure efficiency suffered a loss by 1.8% while intermediate pressure efficiency dropped by a meagre 0.4%

Vibration monitoring was carried out on Ist stage before and after the lowering of capacity. And there was no indication of any change in vibration characteristics.

Q. *Why was loss in capacity observed?*

Ans. This was due to drop in the Ist stage pressure and intermediate valve pressure.

Q. *Was the intermediate stage responsible for the fall in capacity?*

Ans. During normal operation of a steam turbine, all the stages except the Ist and the last stages operate at a constant pressure ratio. Therefore, under changing conditions, any change in stage pressure upstream will be reflected by an equal percentage change in any of the stage pressure downstream.

Here we observe that the percentage pressure drop in the Ist stage almost equals the percentage pressure drop in intermediate stage.

Also we note that the intermediate pressure efficiency has undergone a meagre change.

Therefore, we can conclude that there was nothing wrong in the intermediate stage to reduce the steam flow.

Q. *What was responsible for this flow reduction?*

Ans. The cause of the loss in flow passing capability was very likely due to flow restriction at the front end of the turbine, either in the final stage or the control valves.

Q. *What can be inferred from the vibration monitoring result?*

Ans. No mechanical damage in the Ist stage rotating part is likely.

Q. *Is it a safe conclusion?*

Ans. Obviously not. Mechanical damage in the rotating part can occur without registering any change in vibration characteristics.

Q. *What is your guess?*

Ans. Control valves should be checked for malfunctioning. Deposits on control valves and nozzles could restrict flow.

Fact: *Upon inspection later it was found that one of the four control valves had a broken valve stem. As this valve went off operation, the steam flow reduced, thus resulting in capacity loss.*

Case Study

A steam turbine was found afflicted with loss of efficiency. When an efficiency test was conducted, the efficiency of the intermediate pressure (IP) turbine was found to be 6.9% less as compared to similar test a few months earlier.

Load dropped by 2% and high pressure (HP) efficiency by 1.3%. However, hot reheat pressure went up by 6.9% even at constant opening of IP turbine control valve and LP turbine inlet pressure increased by 2.2%, whereas Ist stage pressure registered a meager increase by 0.3%.

Q. *Do you think that the loss in IP efficiency was due to any restriction in HP stages or a change in pressure of the HP turbine?*

Ans. No. The change in pressure of the HP turbine was negligible. Therefore, the possibility of any area restriction in the HP stage was very unlikely.

Q. *Hot reheat steam pressure went up by 6.9% even at constant opening of the control valve of IP turbine. Plus there was a large decrease in IP stage efficiency.*

What can be infered from these?

Ans. Most probably there was an area restriction either in the interceptor valves or in the following stages of IP turbine.

Q. *What could be the very nature of the trouble?*

Ans. There could be several possibilities:

(a) choking of interceptor valve screens
(b) severe deposits in turbine
(c) reduction in nozzle areas due to erosion.

However, the chances of deposit formation in IP stage turbine were very slender.

Fact: *Upon inspection of the IP turbine stage the followings were revealed:*

(a) the end section got badly damaged due to failure of a number of 9th stage buckets

(b) the diaphragm was damaged by falling buckets that caught between the diaphragm and restricted the steam flow

(c) the ingress of water into the turbine from the extraction bleeding point brought about shell distortion that was the cause of the fall of buckets.

Q. *What is the risk in the entry of wet steam or condensate into HP cylinder of a steam turbine?*

Ans. It may result in bending of the turbine rotor.

Q. *When are the chances of such a "risk" most frequent?*

Ans. During start-up or shutdown of a steam turbine.

Case Study

An AEI-make 120 MW steam turbine operating continuously at 85 MW with 3 mills in operation without oil support tripped due to loss of flame (boiler) and came to a halt.

Barring gear with auxiliary motor was put into operation as the main motor was tripping due to overload.

1. HP exhaust steam temperature dropped from 336°C to 180°C in less than 5 mins
2. HP inner cylinder midmetal temperature dropped from 440°C to 330°C
3. HP outer cylinder differential temperature between the top and bottom, at three locations of inlet/centre/exhaust planes, suddenly shot up from 10°C to 100°C in less than 10 mins
4. Differential temperature between the HP outer cylinder flange and the barrel suddenly made an abrupt jump from 10°C to 140°C
5. HP and IP differential expansion dropped from 3.5 mm to 2.2 mm and 0.9 mm to 0.4 mm respectively
6. Vacuuum during normal operation was 684 mm Hg. But after trip the maximum vacuum that could be pulled was 380 mm Hg.

However, the operator ignored the above indications of the abrupt changes in metal temperature and differential temperature. So when the boiler parameters were restored, he made a start-up within 45 min of tripping.

Accordingly, the speed was raised to 1500—1600 rpm as per hot start-up schedule.

During rerolling, the vacuum dropped to 243 mm Hg, but increased to 480 mm Hg after the gland water sealing valve was opened. The machine got the provision of sealing the glands with water.

Shortly after startup, the HP rotor exhibited a high value of eccentricity (170 – 175 μ) and the bearing experienced a high vibration (150 μ).

HP outer cylinder differential temperature between the top and the bottom was found to be:

200°C at inlet

180°C at centre

150°C at outlet

The turbine was then manually tripped and put on barring. The HP rotor developed a bend of 3.2 mm during operation.

Q. *What is immediately obvious from this case study?*

Ans. Chilling of the HP cylinder had taken place during shutdown.

Q. *How did chilling of the HP cylinder take place?*

Ans. This chilling must have occured due to entry of wet steam or water from the system.

Q. *What were the possible sources of wet steam/water entering the HP cylinder?*

Ans. 1. Gland sealing system
2. HP heater
3. Cold reheat (CRH) spray
4. Attemperator of pressure reduction and desuperheating (PRDS) circuit.

Q. *It was reported that the gland sealing control valve was on AUTO and had been functioning satisfactorily. It was being closed when the speed dropped to 1500 rpm. The operator also closed the isolating valve manually when the rotor speed was 1500 rpm.*

What do you infer from this?

Ans. Gland sealing system was not the culprit, i.e. there had not been any ingress of water from the gland sealing system into the turbine.

Q. *The HP heater was in line during operation. It was isolated after the TRIP. There was no HIGH HEATER LEVEL alarm in the local control panel or in the central control room. The non-return valve (NRV) in the extraction line was opened and inspected. But there was no sign of backflow of water towards the turbine from the NRV internals.*

What can be inferred from this?

Ans. The HP heater was not the source of entry of water into the turbine.

Q. *The reheat temperature was found fluctuating during operation. The cold reheat (CRH) spray arrangement was inspected and the isolating valve (IV) of the CRH spray was opened.*

This diaphragm-operated control valve closing on AUTO as the turbine trips was found OK.

The cold reheat flange joint at the boiler end (provided for steam blowing of the CRH line) was opened but it gave no indication of backflowing of water to the turbine.

What can be concluded from this?

Ans. The CRH spray system was OK.

The ingress of spray water to the turbine is straightaway overruled.

Q. *The DESUPERHEATER of the auxiliary PRDS arrangement received steam from the main header and CRH header (Fig. 36.36)*

Both circuits were provided with a control valve and a non-return valve (NRV).

During initial starting, steam was used to feed the main steam control valve when the main steam pressure would reach to 5.88 MPa (60 kg/cm^2). The CRH system was lined up after the turbine was synchronized and loaded. Thereafter, the control valves of both CRH and PRDS circuits would operate in parallel providing steam to the atemperator. These control valves were so set that in case CRH control valve got stuck up or not able to feed the steam to the system, the main steam CV would open to maintain the PRDS pressure.

On inspection it was found:

1. *the valve seats of NRV of PRDS got detached and damaged*
2. *the spray nozzles of the attemperator were broken.*

Though a drianpot was provided to the CRH loop near the turbine for sensing of water in the cold reheat line and providing an alarm in the control room, yet no HIGH annunciation appeared in the control room.

What do these indicate and what conclusion can you draw from these?

Ans. The ingress of water/cold steam into the turbine did take place from the PRDS system due to failure of NRV and spray nozzle and as a consequence there was a sudden drop in the metal temperature of the HP cylinder.

Q. *What is hydrogen-cooled turbo generator?*

Ans. This generator is of the two-pole type, using radial hydrogen cooling for the rotor winding and indirect hydrogen cooling of the stator winding.

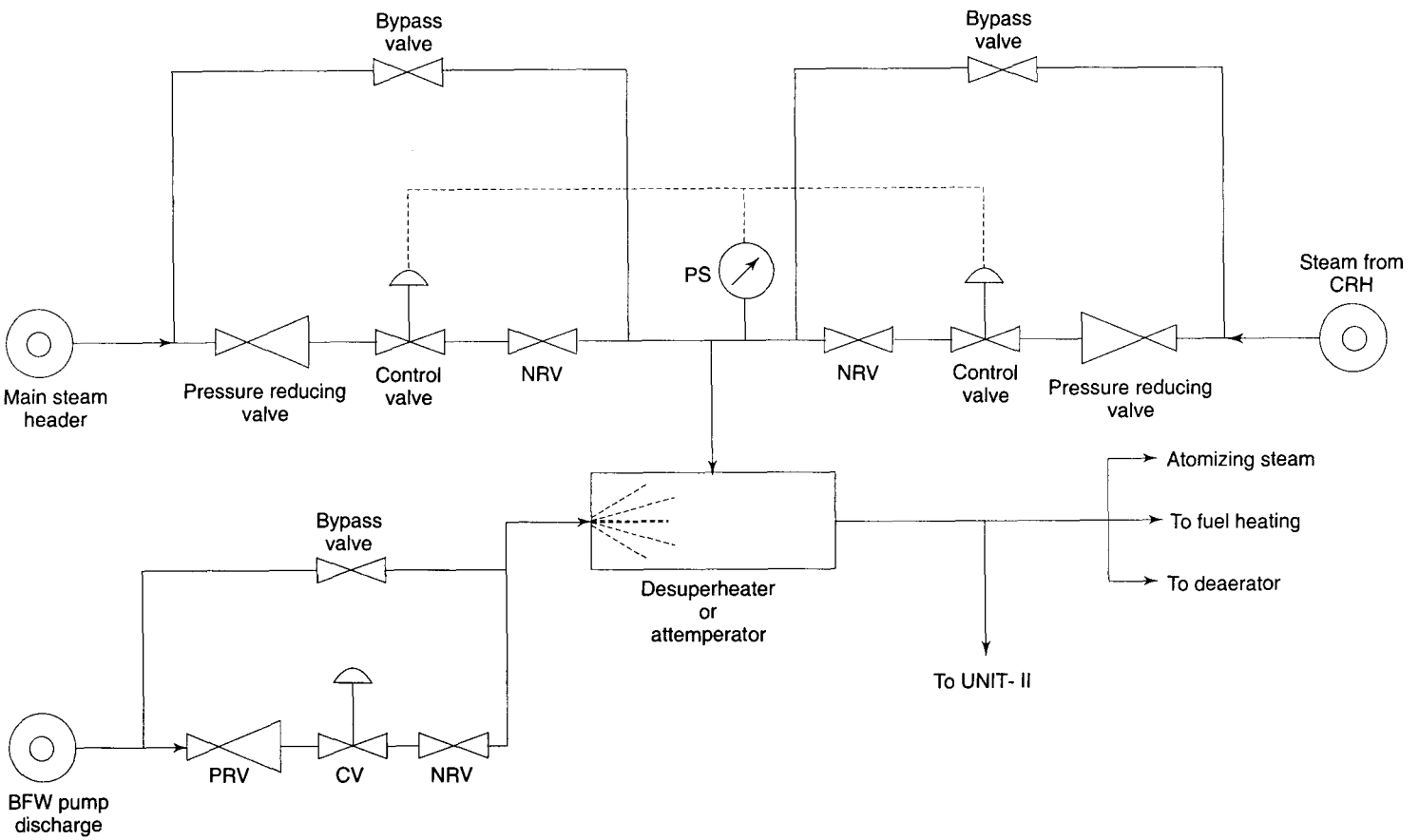


Fig. 36.36 *Pressure reduction and desuperheating.*

The generator frame is of pressure-resistant and gas-tight construction and is equipped with endshields at each end.

Q. *How are the endshields assembled?*

Ans. These are assembled with rubber cords placed in the grooves of top and bottom halves, with two vulnerable joints appearing nearing the horizontal joints of the endshield.

Q. *What is the drawback of this system?*

Ans. It sometimes leads to hydrogen leakage causing forced shutdown of the TG set and that results in a loss of power generation for a considerable period.

Q. *How can this problem be rectified?*

Ans. The traditional method is to replace the existing rubber cord with a new one. But there is another novel method—assembly of the endshields with a single-joint rubber cord.

This method evolved by BHEL (Bharat Heavy Electricals Ltd., India) is as follows

210 MW (LMW) TG

1. Assemble the bottom-half endshield (with bottom-half fanshield) on generator stator without placing square rubber cord. Put inner rubber cord (10mm dia) in the endshield before assembly (Fig. 36.37)

   Fasten the endshield by means of two bolts on each end, i.e. left, right and bottom.

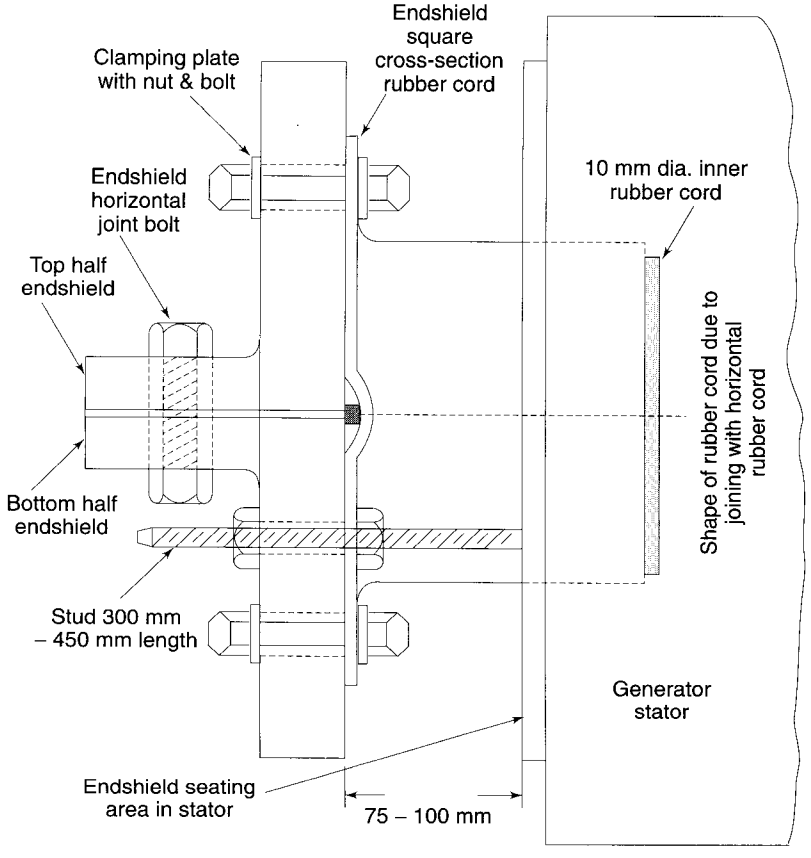


Fig. 36.37 *Assembly of 210 MW (LMW) hydrogen-cooled TG endshield with a single joint rubber cord .*

2. Get the measurement of fan-blade clearances, air-gap, magnetic centre.
3. Insert the horizontal joint rubber cord in the botom-half endshield's groove.
4. Assemble the top-half fanshield and measure the fan clearances, IR value etc.
5. Place the top-half endshield (without square rubber cord) with 10 mm dia rubber cord.

   Fasten two bolts on vertical joint at each end, i.e. left, right and top.
6. Put all the bolts of horizontal joint in position. Tighten alternate bolts. Do not apply much force.
7. Tighten the vertical joints bolts.
8. Fasten the top-half endshield to the top-half fanshield. Measure IR value.
9. Check the bore reading of endshield and rotor in all four positions—left, right, top and bottom.
10. In the stator-top, assemble 450 mm long studs in place of the bolts (3 in Nos.) at 60° angle and in the stator-bottom assemble 300 mm long studs (also 3 in Nos.) in place of the bolts at 60° angle.
11. Remove all the fastening bolts on the vertical joint only (top and bottom)
12. Pull back the endshield assembly to produce a gap of 75–100 mm between endshield and stator all around. Use jack bolts and wooden planks for the purpose.
13. Set the rubber cord, with adhesive, into the groove till the adhesive dries to attach the rubber cord firmly with the endshield.

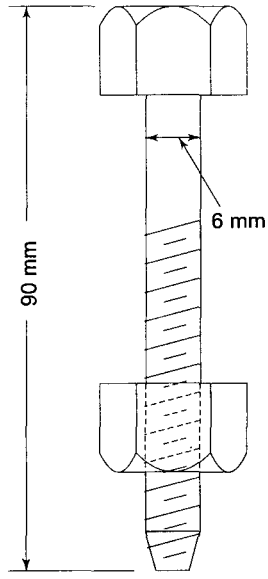


Fig. 36.39 *Clamping bolt.*

14. Remove the clamping plates and bolts when the rubber cord sticks firmly in the groove.
15. Make sure the projection of horizontal rubber cord is cut to such a length that it meets

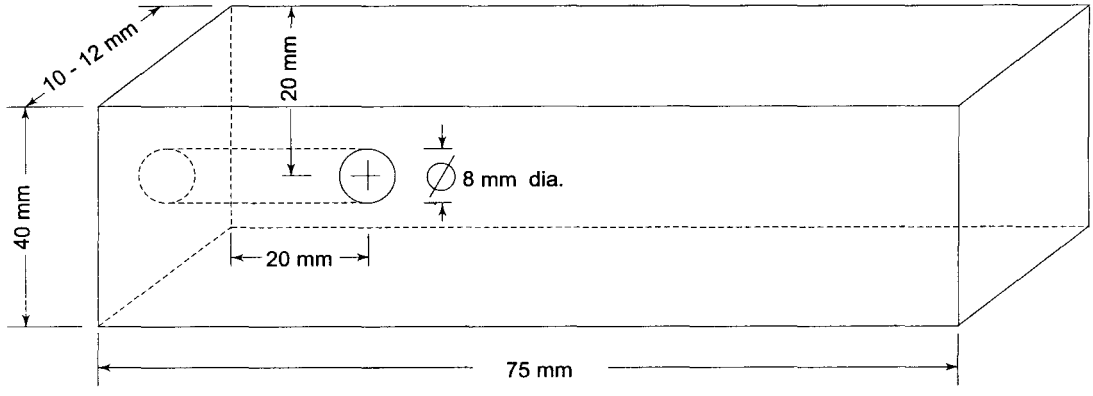


Fig. 36.38 *Clamping plate.*

the vertical joint rubber cord at a shallow valley (Fig. 36.40) and not otherwise (Fig. 36.41 and Fig. 36.42).

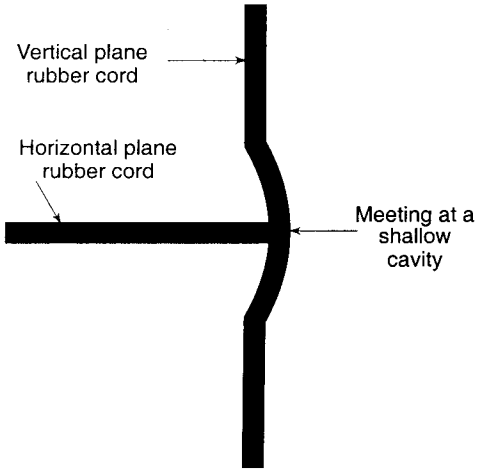


Fig. 36.40 *Horizontal plane rubber cord meets the vertical plane rubber cord at a shallow cavity.*

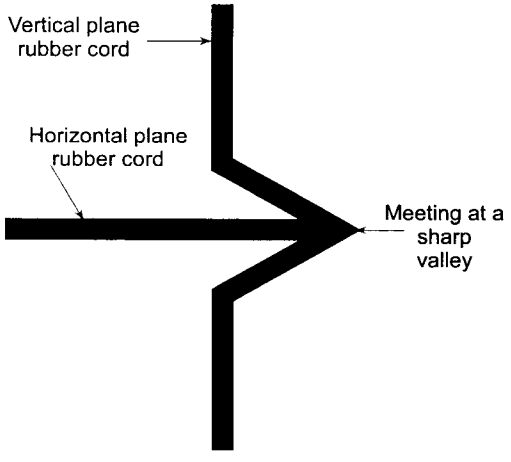


Fig. 36.41 *Horizontal and vertical joint rubber cords meet at a sharp valley (incorrect setting).*

16. Pull out the jack bolts and wooden planks to push back the endshield assembly. Tighten the nuts of studs equally all round.
17. Tighten the horizontal bolts further, starting from the middle of the joint on either end.

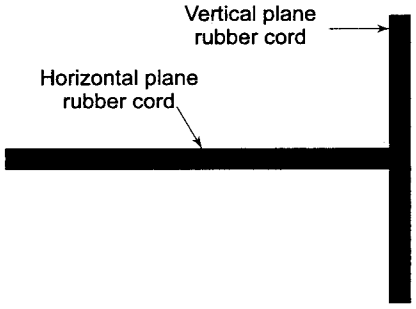


Fig. 36.42 *Horizontal and vertical rubber cords simply touch each other (incorrect setting).*

18. Tighten the vertical joint bolts. Take care so that the rubber cord expands equally all round.
19. Check the bore reading of the endshield assembly and rotor. Compare this result with one before pulling back of the endshield assembly. Normally these two reading tally.

Source: Feedback (May 1990/P-2), BHEL Publication.

Q. *What are the plus points of this novel technique of endshield assembly?*

Ans.
- Hydrogen leakage is slashed down by 50% and more
- Saving in hydrogen gas consumption
- Risk of explosion hazard due to H_2 leakage is much reduced
- The single joint can be placed at any point around the endshield where the leakages would be minimum
- It obviates the downtime loss and increases generator availability.

Note: This novel technique was applied to 210 MW generators of Unit-1, 2, 3, of Tuticorin TPS by BHEL engineers. No H_2-leakage has been reported over a subsequent period of two years.

Q. *Often it has been observed that both the main ejectors remain in operation and sometimes even the starting ejector has to be kept in operation. Why this is so?*

Ans. This is due to vacuum leakage. Excessive air ingress through various joints, glands etc. causes poor vacuum.

Q. *What will happen if the turbine is operated with poor vacuum?*

Ans. Efficiency and durability of the thermal powerplant will decrease considerably.

Q. *What procedure is normally followed for vacuum leak detection?*

Ans. The normal practice for vacuum leak checks is to test the system by filling DM water up to the parting plane.

Q. *What are the disadvantages of this process?*

Ans. The joints above the parting plane are not covered.

The test can be carried out only when the machine is completely cold.

Large quantity of DM water is required.

A time-consuming process indeed.

Q. *What alternative approach do you want to suggest for vacuum leak detection?*

Ans. Vacuum leak detection in turbines by steam pressurization of the vacuum system.

Q. *When it is carried out?*

Ans. During shutdown.

Q. *How is vacuum leak detection carried out?*

Ans. I. Pre-pressurization steps, i.e. preparation of thermal scheme
(a) auxiliary equipment
(b) turbine
II. Steam pressurization of the vacuum system.

Q. *How can the quantity of air leakage in the vacuum system be calculated?*

Ans. Use may be made of the following formula:

$$G_{air} = 6.5 \times 10^{-3} [1 - 0.014 (\theta_{mix} - 60)] d^2 \cdot h$$

to estimate the air leakage in a vacuum system when an air measuring device is not available and there is no system provided to measure the quantity of air from the ejector.

G_{air} = quantity of air leakage in the vacuum, kg/h

h = difference in manometer height, mm of water column

θ_{mix} = temperature of air-steam mixture before the air measuring device (Fig. 36.43)

If the sleeve point A (Fig. 36.44) is connected with U-type manometer filled with water for measuring the pressure before the air-measuring device, the above formula is to be modified to

$$G_{air} = 7 \times 10^{-3} [1 - 0.014 (\theta_{mix} - 60)] d^2 \cdot h$$

Both formulae are referred to 1 ata (i.e. 760 mm Hg).

Use can also be made of the nomogram (Fig. 36.45) to determine the quantity of air sucked by the ejector.

The hole dia of the orifice is so selected as to give h value in the range of 290-400 mm of use water column.

Typical value of orifice hold-dia (d): 13, 16, 19, 26, 29, 31, 33, 36 mm.

Q. *Are turbines a fire hazard?*

Ans. Yes. Turbines are the potential source of fire in a powerplant. About 75 to 94% plant fires start from turbines.

Q. *How does the risk arise?*

Ans. Probably the greatest risk for turbine fires arises from the use of mineral oil (hydrocarbon) in the hydraulic and lube-oil circuit. This fluid is flammable. Any leakage onto the adjacent hot surfaces, viz. superheated steampipes causes fire hazards.

Q. *What are the causes of oil leakage from the hydraulic and lube oil circuits of the turbine?*

Ans. 1. Oil leaks in the bearing and control-oil system lines are caused by equipment

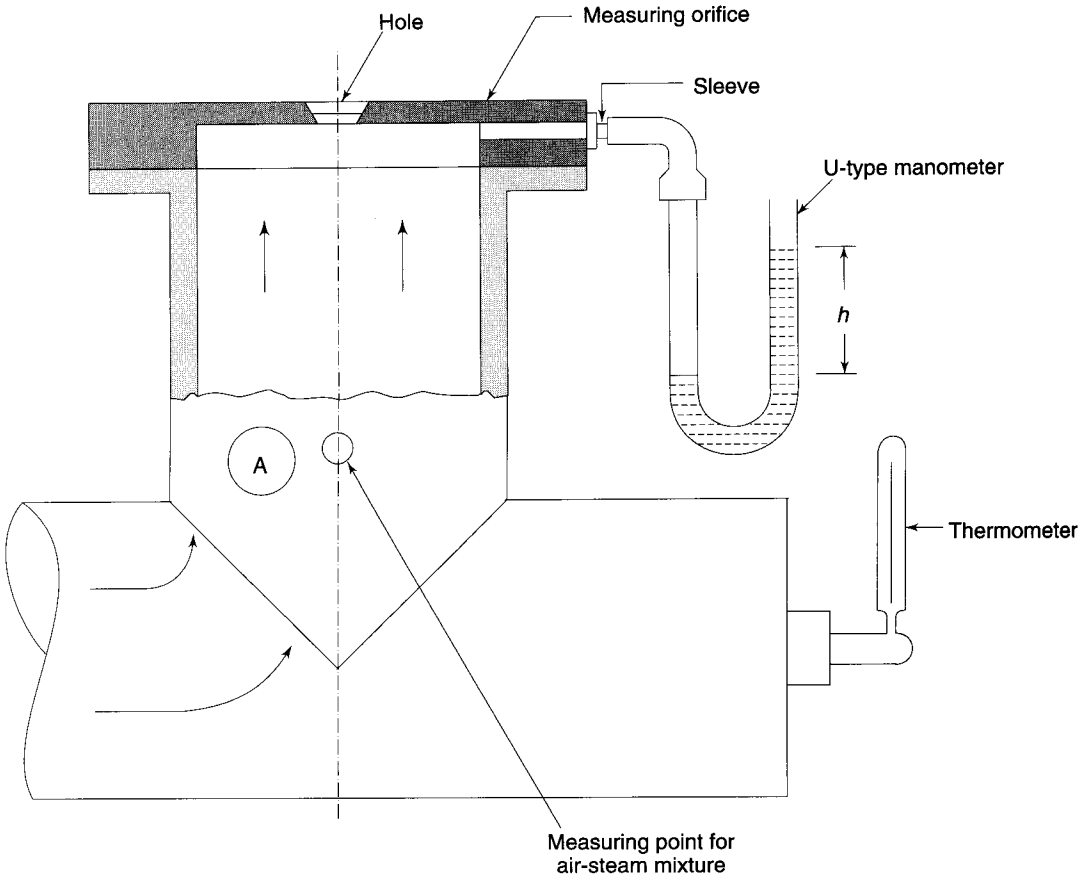


Fig. 36.43

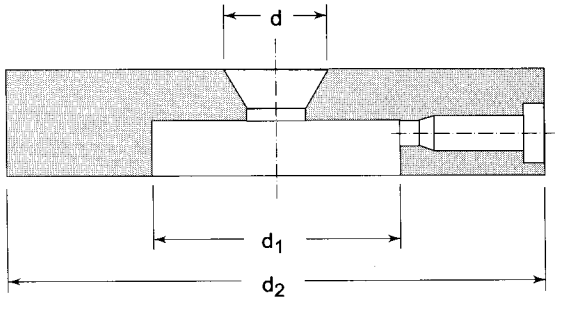


Fig. 36.44 *Typical Values of Orifice Hole-DIA (d):*

13 mm; 16 mm; 19 mm; 23 mm; 26 mm; 29 mm; 31 mm; 33 mm; 36 mm.

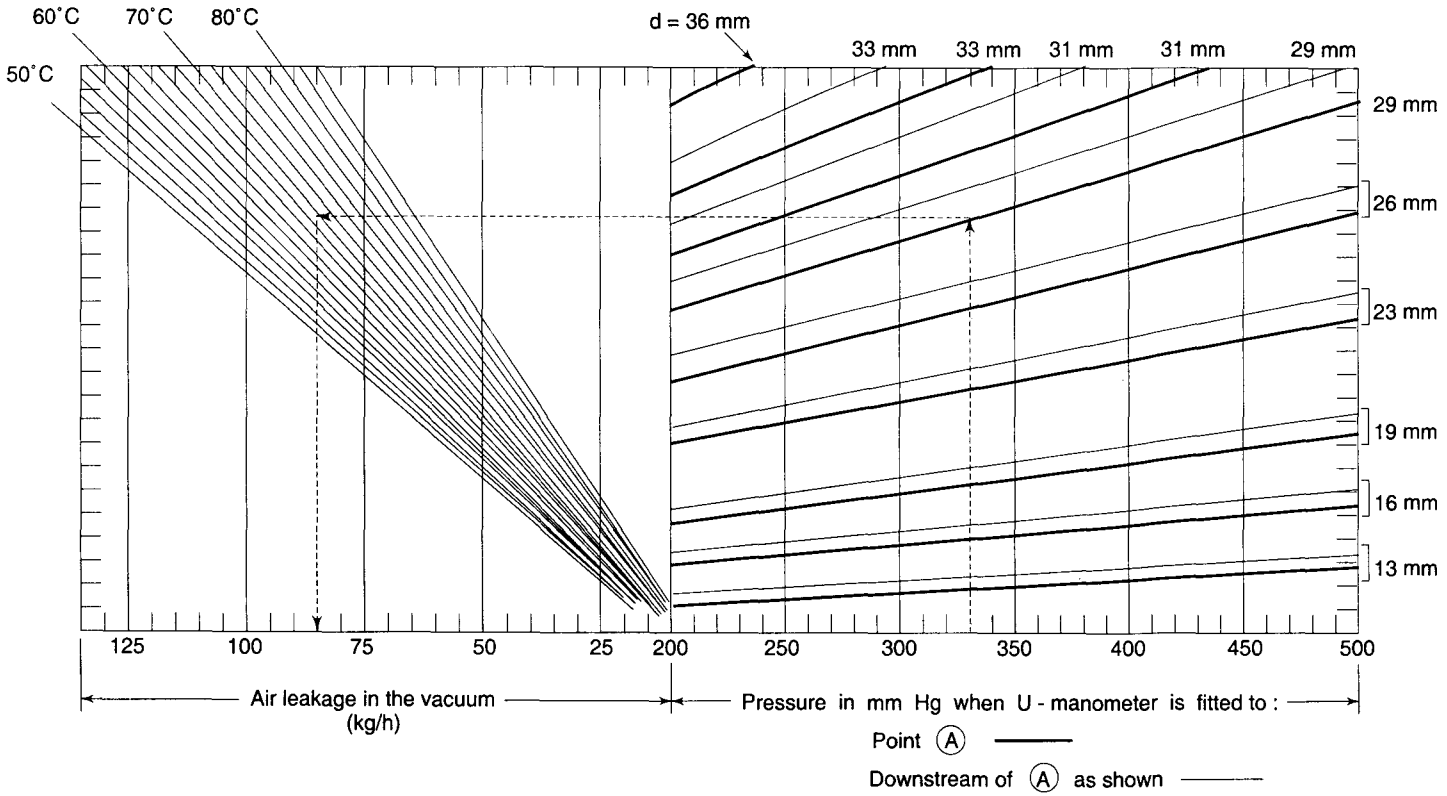


Fig. 36.45 *Nomogram to determine the quantity of air sucked by ejector.*

aging, cracked welds, vibration, loosening of flange joints
2. Defective assembly, repair and errors in inspection lead to badly made welds, poorly positioned pipes that give rise to chafing and vibration
3. Mechanical failures of rotors, couplings and so on cause rupture of oil lines as components disintegrate.

Q. *Are turbine fires an everyday occurrence?*

Ans. Not exactly. But they do happen more frequently than one realizes. At least 72 major fires occured between 1971 and 1993 in Western Europe and USA, reported by VGB Kraftwerkstechnik, Germany.

Note: Actual figure could be significantly much higher, because of power industry's reluctance to expose fire statistics to public.

Q. *What are the implications of turbine fires?*

Ans. The costs of turbine fires can be just enormous. Add to the obvious costs of replacing or repairing fire-damaged equipment and the less-obvious costs of site clearance, cleaning of smoke-damaged equipment, legal fees if casualties are involved. Most important of all, however, are the outage costs which, depending on outage-duration, may outpass all other costs.

Q. *Therefore, it is imperative for plant management to ensure safe and reliable operation of the turbines by protecting them against fire. Is there any fire-protection system as such?*

Ans. A passive measure is gaining ground*. It uses phosphate ester as the hydraulic fluid and lubricant.

Q. *Why is this system adopted for gas turbines also?*

Ans. Apart from the reason of fire hazard, the compelling factor to consider phosphate ester for gas turbines is that in modern GT designs the conventional L.O. systems reach the limit of their performance because of increased thermal stresses as bearing temperatures rise. These rising oil temperatures reduce the life of lube oil to 3000-5000 h.

Selection of a fire-resistant lubricant offers a solution to both problems, particularly if a suitable stabilizer is used to condition the system to extend the fluid life.

Q. *How many types of fire protection are found in and around steam and gas turbines?*

Ans. Two types:
(a) active measures
(b) passive measures

Q. *What is the basic difference between these two?*

Ans. Active measures operate once the fire has started. Passive measures try to prevent the fire from starting.

Q. *What are the common 'active' measures?*

Ans. 1. Water sprinkler systems
2. Halon inerting systems
3. CO_2-gas inerting systems

Q. *What are the traditional 'passive' measures?*

Ans. Use of
1. double-walled piping
2. metal-clad insulation of steam pipes

Q. *Therefore, if these two types of measures are combined will you not feel ensured that the turbine is safe?*

Ans. No; although these measures significantly reduce the risk of fire over unprotected systems.

Q. *What are the disadvantages with these two types of fire-protection systems that fail to ensure 100% safety to turbines?*

Ans. 1. Cost of installation
2. Cost of maintenance
3. Doubts about their availability caused by the difficulties of testing
4. Inadvertent activation.

(* for both GT & ST)

Q. *Is there any other typical disadvantage?*

Ans. Halons are environmental hazards and already phased out in certain countries.

CO_2-gas inerting system may follow a similar route because of the danger to personnel caught in a discharge.

Q. *Passive measures are designed to prevent ignition and as such they are preferable. Are there any latest innovation passive measures?*

Ans. Use of triaryl phosphates as fire-resistant hydraulic fluids and lubricants may offer an optimum solution.

Q. *What are the advantages of these phosphate esters?*

Ans. The chief advantage of these fluids is their pronounced fire resistance. They have an autoignition temp. in the range of 825-865°K and posses inherent self-extinguishing characteristics. That means, if they do ignite, under severe conditions, the flame will quench as soon as the fluid is taken away from the source of ignition.

Q. *Why are triaryl phosphates preferred over other phosphates?*

Ans. The triaryl group ensures good lubrication like mineral oil.

Q. *What are the disadvantages with triaryl phosphates?*

Ans. 1. They are much less viscous
2. They possess pronounced sensitivity to water—a property that results in hydrolysis of the phosphate
3. They exhibit differential compatibility with various types of seals and paints.

Q. *Why is a conditioning agent dosed to triaryl phosphate system?*

Ans. The purpose is to remove the acidity generated by hydrolysis.

Q. *Therefore, in order to switchover your ST from mineral oil to phosphate you simply drain off mineral oil from hydraulic and lube oil console and refil it with fire-resistant ester.*

Will you do it?

Ans. Emphatically not.

Q. *What will you do then?*

Ans. The turbine manufacturer is to be contacted first and foremost to clarify what equipment modifications are necessary for this conversion.

Note: It is neither difficult nor costly to design a new turbine to suit a particular fire-resistant hydraulic fluid or lubricant.

Q. *If it is suggested to split your turbine's hydraulic and lubrication system, with mineral oil being replaced by a fire-resistant fluid, only in the hydraulics, will you go to implement this to avert fire-hazard in your turbine?*

Ans. No.

Q. *Why?*

Ans. This is a faulty suggestion based on the erroneous assumption that most fires originate from the hydraulic system because of higher system pressures and proximity to high-temperature steam headers

Q. *Earliest fluids were blends of polychlorinated biphenyls (PCBs) and phosphates. However, the use of PCB was quickly discontinued. Why?*

Ans. This was discontinued due to
1. toxicity
2. environmental concerns
3. valve erosion problems.

Q. *"Turbine itself feeds fuel to its own fire".*

Will you accept this theory even after replacing mineral oil with fire-resistant fluid in your turbine's hydraulic system?

Ans. Yes. Using a fire-resistant hydraulic fluid does not completely eliminate the risk of fire, though it is a major step in reducing fire hazards. The bearing lubrication system holds a large volume of mineral oil which is responsible for as many fires as the control system. In case of fire, shaft-driven oil pumps continue to feed a fire with oil as long as the shaft is rotating.

Q. *If the oil supply is cut off and the turbine stopped, is it not a good alternative to curb fire proliferation?*

Ans. If the oil supply is switched off, the turbine will grind to a halt and no more oil feed to the fire, no doubt. But that entails the risk of bearing and rotor damage.

Note: When the lubricant and the control fluid both are fire-resistant, the turbine designer needs no longer be faced with such a difficult choice.

Q. *Is there any success story of phosphate ester used as hydraulic fluid and lubricant?*

Ans. As far back as 1982, lubricants of a 200 MW nuclear powerplant at the Kolskaya of the erstwhile USSR were converted from mineral oil to fire-resistant lubricants. Even after 14 years of operation, the initial fill of phosphate ester is still in place and the unit continues to function satisfactorily.

A 10 MW industrial steam turbine in Switzerland was converted in 1982 after foaming and deposition problems were experienced with mineral oil. Today, after operating more than 40 000h, the condition of turbine components remains unchanged and the quality of the fluid, by and large, has hardly deteriorated. The fluid has held up despite load-carrying operation during Spring and Summer, involving many cold starts that always increase stress on the fluid and bearings.

37

CYCLES FOR STEAM POWER PLANTS

Q. *What is the most ideal steam power plant cycle?*

Ans. Carnot cycle.

Q. *Why is it so?*

Ans. Carnot cycle offers the greatest efficiency possible between any two given limits of temperature.

Q. *What processes would be involved if a Carnot cycle were to be operated in a steam power plant?*

Ans. **AF** BFW is fed to the boiler at boiler pressure P_B and volume V_A (Fig. 37.1)

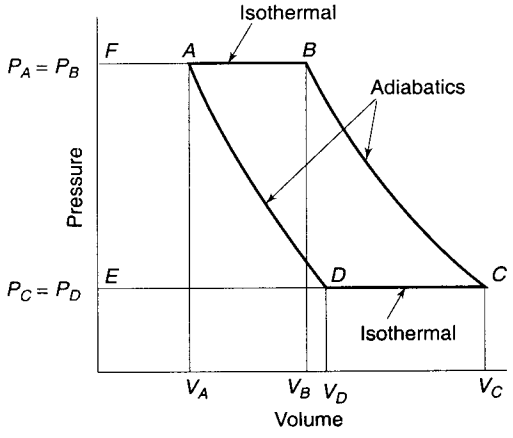


Fig. 37.1 *Carnot cycle*

AB BFW is converted into steam, in the boiler, at pressure P_B and volume of the steam is V_B. Temperature T_B.

BC Frictionless expansion (adiabatic) of steam in the turbine.

CD After expansion, the exhaust steam is condensed isothermally (T_D) in a condenser. Volume of steam drops from V_C to V_D.

DE Partially condensed steam at D and pressure $P_C = P_D$ is fed from the condenser to the feed pump.

DA The residual steam is compressed, in the feed pump, frictionless adiabatically to boiler pressure P_A. This step converts wet steam at condenser pressure to water at boiler pressure.

Q. *How can the efficiency of this cycle be computed from a temperature-entropy diagram?*

Ans. The foregoing processes involved in a steam plant operating in a Carnot cycle can be represented in a $T - \phi$ diagram, as shown. (Fig. 37.2).

The network output from the plant is the area *ABCD*.

(work output = work done by turbine–work done by feed pump

= *FABCDE–FADE*

= area *ABCD*

The area *ABCD* is enclosed by two isothermal processes and two adiabatic processes. Hence this is a Carnot cycle whose efficiency

$$\eta = \frac{T_B - T_C}{T_B}$$

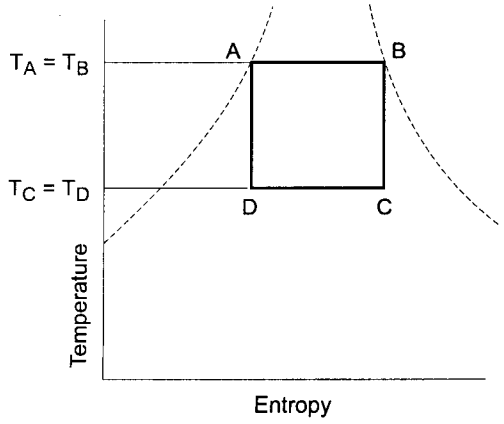


Fig. 37.2 *Carnot cycle on temperature-entropy diagram*

Q. *How far is the Carnot cycle practical for operation in a steam power plant?*

Ans. This cycle, applied to a steam power plant, is practical up to a point.

The isothermal generation of steam in the boiler (process AB) with volume expansion from V_A to V_B is reasonable.

Also reasonable is the adiabatic expansion of the steam in the turbine (process *BC*).

Q. *What is the impractical part of this cycle?*

Ans. The impractical part of this cycle is in the handling of steam in the condenser and feed pump.

Steam is only partially condensed in the condenser and the condensation must cease at *D*.

Furthermore, the feed pump must be capable of handling both wet steam and water.

Q. *How can this cycle be made more practicable for its application in steam power plants?*

Ans. A slight modification to this cycle is introduced: Instead of stopping the condensation in the condenser at some intermediate condition, the condensation is allowed to continue until it is complete at point *D*. At this point there is all water. This condensate can be successfully dealt with in the feed pump pumping it to the boiler at boiler pressure P_B (Fig. 37.3 and 37.4)

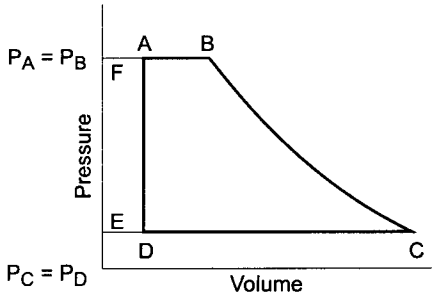


Fig. 37.3

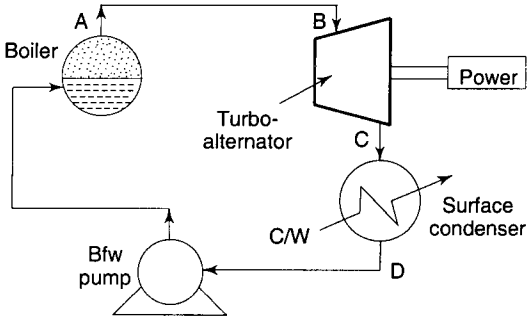


Fig. 37.4

Q. *What is the effect of adopting this cycle?*

Ans. Though this cycle is more practical, it gives rise to lesser thermal efficiency than the Carnot cycle.

Q. *What processes are involved when a steam power plant is working on the Rankine cycle?*

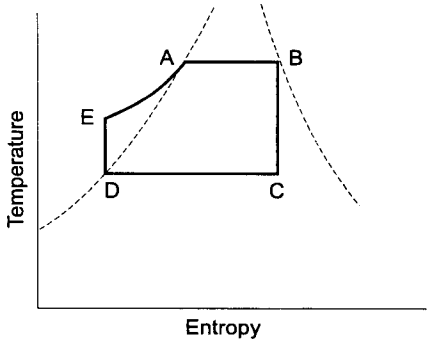


Fig. 37.5

Ans. **FA** BFW at boiler pressure $P_B = P_A$ is delivered to the boiler. Its volume is V_A. (Fig. 37.5)

AB In the boiler, BFW is converted to steam at pressure P_B. The volume of the steam generated is V_B. An isothermal process.

BC Adiabatic frictionless expansion of steam in the turbo-alternator generating electricity.

CD Total condensation of the exhaust steam in the condenser. An isothermal process.

DE Pumping of condensate from condensate pressure $P_C = P_D$ to boiler pressure P_B.

EA Heating the BFW at constant pressure till it attains the saturation temperature corresponding to boiler pressure $P_B = P_A$.

Q. *How can the efficiency of the Rankinge cycle be computed?*

Ans. Total heat supplied by boiler

$= H_B - (h_{W_D} + W)$ per Kg of steam generated.

where, H_B = Enthalpy of steam at B, kcal/kg

h_{W_D} = Liquid enthalpy at D, kcal/kg

W = Mechanical work done by the pump per kg water.

Available work output = $H_B - H_C$ per kg of steam. Net work available per kg of water

$= (H_B - H_C) - W$

$$\text{Rankine efficiency} = \frac{(H_B - H_C) - W}{H_B - (h_{W_D} + W)}$$

Compared with other heat quantities W is very small and hence ignored for all practical purposes.

$$\text{Hence, Rankine efficiency} = \frac{(H_B - H_C)}{(H_B - h_{W_D})}$$

Q. *How can the work done during the Rankine cycle be determined from a P–V diagram?*

Ans. The work done by the feed pump is neglected and if the steam expands in the turbine polytropically ($PV^n = C$).

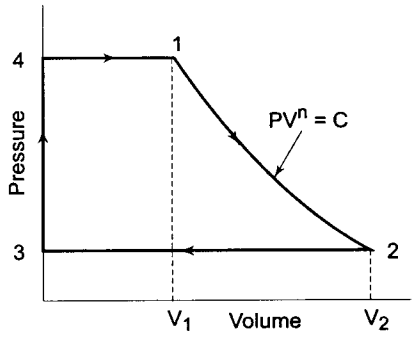


Fig. 37.6

Workdone = Area 4123 (Fig. 37.6)

= Area under 4 – 1 + Area under 1 – 2 – Area under 2 – 3

$$= P_1V_1 + \frac{P_1V_1 - P_2V_2}{n-1} - P_2V_2$$

$$= \frac{n}{n-1}(P_1V_1 - P_2V_2)$$

Q. *What will be the Rankine efficiency when superheated steam is used?*

Ans. Rankine efficiency for the complete cycle generating superheated steam and expanding it through the turbine is (Fig. 37.7)

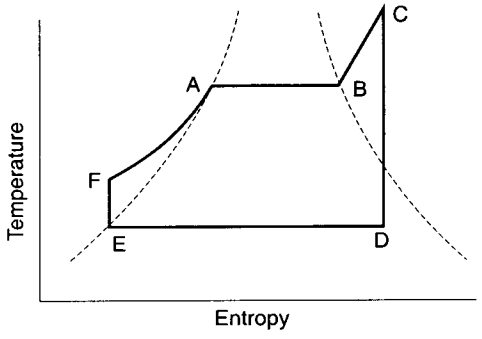


Fig. 37.7

$$\eta = \frac{H_C - H_D}{H_C - h_{W_E}}$$

Problem 37.1 A power plant using steam as the working fluid operates on a Rankine cycle. The turbine receives steam at 3500 kN/m^2 and 623 K and exhausts to the condenser at 10 kN/m^2. The condensate is recycled to the boiler by a BFW pump.

Determine:

(a) the energy supplied in the boiler (including the superheater) per kg of steam generated

(b) the dryness fraction of steam entering the condenser

(c) the Rankine efficiency.

Solution

Step (I) Energy Supplied to Steam

$$H_C = 3139 - \left(\frac{1.5}{2}\right)(3139 - 3095) = 3106 \text{ kJ/kg}$$

$h_{W_E} = 192$ kJ/kg

Energy supplied in the boiler (including the superheater)

$H_C - h_{W_E} = 3106 - 192 = 2914$ kJ/kg

Ans.

Step (II) Dryness Fraction of Steam Entering the Condenser

Since the expansion of steam in the turbine takes place adiabatically, i.e. isentropic, so

$$\phi_C = \phi_D$$

$$\phi_C = 6.961 - (1.5/2)(6.961 - 6.588)$$

$$= 6.681 \text{ kJ/kg. K}$$

Now, $\phi_D = 0.649 + x\,(8.152 - 0.649)$

$\therefore\ 6.681 = 0.649 + x\,(8.152 - 0.649)$

or, $x = 0.80$

Therefore, steam entering the condenser is 0.8 dry

Ans.

Step (III) Rankine Efficiency of the Cycle

$$\eta = \frac{H_C - H_D}{H_C - h_{W_E}} = \frac{3106 - [192 + 0.8(2393)]}{3106 - 192} = 0.34$$

i.e. Rankine efficiency is 34%

Ans.

Problem 37.2 A thermal power plant using steam as a working fluid operates on a Rankine cycle. Steam (0.65 MN/m^2 and 0.85 dry) is fed to the turbine wherein steam is allowed to expand following the law $PV^{1.136}$ = constant. If the condenser pressure is 15 kN/m^2, determine the specific work done.

Solution

Step (I) Final Volume

Pressure (kN/m^2)		Specific Volume (m^3/kg)	
Initial	Final	Initial	Final
650	15	0.293 (0.85) – 0.249	V_2

For expansion $P_1V_1^{1.136} = P_2V_2^{1.136}$

$$V_2 = (P_1/P_2)^{1/1.136}(V_1)$$

$$= (650/15)^{1/1.136}(0.249) \text{ m}^3/\text{kg}$$

$$= 6.871 \text{ m}^3/\text{kg}.$$

Therefore, specific work done

$$= \frac{n}{n-1}(P_1V_1 - P_2V_2)$$

$$= \frac{1.136}{0.136}(650 \times 0.249 - 15 \times 6.871)$$

$$= 491.02 \text{ kJ/kg}$$

Ans.

Problem 37.3 A steam turbine, assumed to be working on the Rankine cycle, receives steam at 15 kgf/cm^2 abs. and temperature 240°C and exhausts at 0.36 kgf/cm^2 absolute.

Sketch the temperature–entropy diagram for this cycle. Describe the Carnot cycle on the same sketch for the same limits of temperature.

Determine the efficiency of each cycle.

Solution

Operating cycle *ABCDE*

Carnot cycle 1234 (Fig. 37.8)

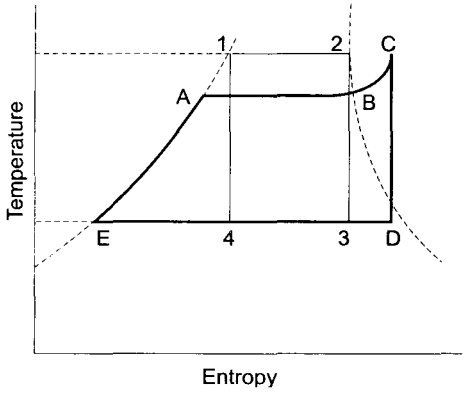


Fig. 37.8

Step (I) Dryness Fraction of steam Entering the Condenser

$\phi_C = \phi_D$ as the expansion is isentropic.

$\phi_C = 1.593$ kcal/kg K from steam table.

$\phi_D = 0.236 + x(1.606)$ kcal/kg K from steam table.

$\therefore \quad 1.593 = 0.236 + x(1.606)$

or, $$x = \frac{1.357}{1.606} = 0.8449$$

Step (II) Total Energy Available for Work Done

$H_C = 692.5$ kcal/kg of steam,

$H_D = 72.9 + 0.8449\ (555.6)$

$= 542.357$ kcal/kg of steam

Total energy available for work output

$= 692.5 - 542.357 = 150.143$ kcal/kg of steam

Step (III) Efficiency of the Cycle

Rankine efficiency

$$= \frac{H_C - H_D}{H_C - h_{W_E}} = \frac{150.143}{692.5 - 72.9} = 0.2423$$

i.e. 24.23%

Ans.

Step (IV) Carnot Efficiency

Temperature of superheated steam = 240°C

Temperature of the exhaust steam = 72.9°C from steam tables

$\therefore$ Carnot efficiency operating in this temperature range

$$= \frac{(240 + 273) - (72.9 + 273)}{(240 + 273)}$$

$= 0.3257$

i.e. 32.57%

Ans.

Problem 37.4 A steam power plant operates on a Rankine cycle. The steam (28 kgf/cm^2 abs.) is dry saturated at the inlet. The exhaust steam pressure is 0.90 kgf/cm^2. absolute.

Determine the thermal efficiency of the cycle

(a) ignoring the feed pump work

(b) considering the feed pump work.

Solution

Step (I) Steam Parameter

STEAM, 28 kgf/cm^2 abs.	Total enthalpy = 669.5 kcal/kg Saturation temp. = 229°C Enthalpy of evaporation = 434.1 kcal/kg
STEAM, 0.90 kgf/cm^2 abs.	Saturation temp. = 96.2°C Enthalpy of evaporation = 541.3 kcal/kg Liquid enthalpy = 96.2 kcal/kg

Step (II) Dryness Fraction of Exhaust Steam

Since the expansion of the steam in the turbine is isentropic,

$\phi_B = \phi_C$

$$\therefore \ln\left[\frac{T_B}{T_O}\right] + \left[\frac{L_B}{T_B}\right] = \ln\left[\frac{T_C}{T_O}\right] + \left[\frac{x\,L_C}{T_C}\right]$$

Computing the known values,

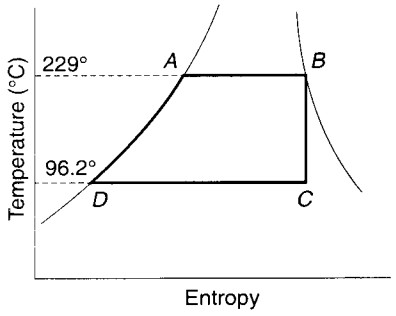


Fig. 37.9

$$\ln \frac{229+273}{273} + \frac{434.1}{(229+273)}$$

$$= \ln \frac{96.2+273}{273} + \frac{x(541.3)}{96.2+273}$$

$$\therefore\ x = 0.799 \approx 0.8$$

Step (III) Rankine Efficiency Ignoring Feed Pump Work

$H_B = 669.5$ kcal/kg;

$H_C = 96.2 + 0.8\ (541.3)$

$= 529.24$ kcal/kg

$h_{W_D} = 96.2$ kcal/kg

$$\therefore\quad \eta = \frac{H_B - H_C}{H_B - h_{W_B}} = \frac{669.5 - 529.24}{669.5 - 96.2}$$

$= 0.2446$ i.e. 24.46%

Ans.

Step (IV) Pump Work

$W = (\Delta P)$ (Specific volume of exhaust steam)

$$= \frac{(P_B - P_C)(v_c)}{427} \text{ kcal/kg}$$

(cf. 1 kcal ≡ 427 kgf.m)

$$= \frac{(28 - 0.90)(0.00104)(10^4)}{427} = 0.66 \text{ kcal/kg}$$

Step (V) Rankinge Efficiency Taking into Consideration Feed Pump Work

$$\eta = \frac{H_B - (H_C + W)}{H_B - (h_{w_D} + W)} \qquad \text{(Fig. 37.10)}$$

$$= \frac{669.5 - (529.24 + 0.66)}{669.5 - (96.2 + 0.66)}$$

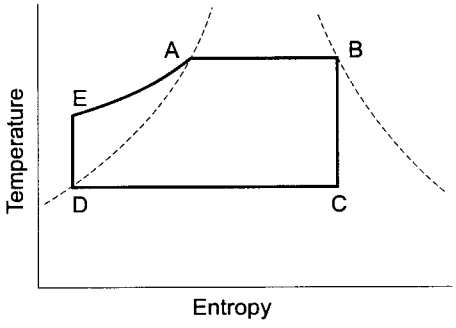


Fig. 37.10

$= 0.2437$ i.e. 24.37%

Ans.

Problem 37.5 Steam at 1100 kN/m^2 and 523K is delivered to the turbo-alternator where it expands isentropically to a pressure of 280 kN/m^2. Then its pressure drops to 35 kN/m^2 at constant volume and it is exhausted to a surface condenser where the steam is completely condensed with no undercooling. The condensate is then pumped back to the boiler.

Estimate:

(a) the efficiency of the cycle

(b) the specific steam consumption per MWH

(c) the Carnot efficiency for the same temperature limits of the cycle.

Solution The powerplant works on the Rankine cycle. It can be diagrammatically represented as shown (P – V diagram), ignoring the feed pump's work. (Fig. 37.11)

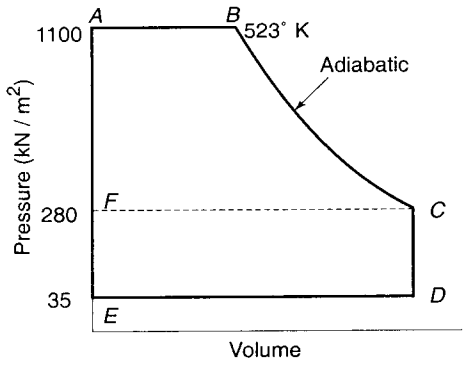


Fig. 37.11

Step (I) Sp. Enthalpy of Steam at B.

H_B = 2942.9 – 0.1 (2942.1 – 2901.8)

= 2938.87 kJ/kg

Step (II) Dryness Fraction of Steam at C.

Expansion B ⟶ C is isentropic, so

$\phi_B = \phi_C$

Now, ϕ_B= 6.925 – 0.1 (6.925 – 6.544)

= 6.887 kJ/kg K

ϕ_C = 1.646 + x(7.015 – 1.646)

= 1.646 + 5.369x

$\therefore$6.887 =1.646 + 5.369 x

or, x = 0.976.

Step (III) Sp. Enthalpy of Steam at C

H_C = 551.5 + 0.976(2170) = 2669.42 kJ/kg

Step (IV) Sp. Volume of Steam at C

$v_C = x\,(0.645) = 0.976(0.645) = 0.6295$ m³/kg

Step (V) Work Done in the Cycle

W = Area $ABCDE$ = Area $ABCF$ + Area $CDEF$

$= (H_B - H_C) + (P_D - P_C)\, v_C$ (Fig. 37.11)

= (2938.87 – 2669.42) +
(280 – 35) (0.6295) kJ/kg

= 423.677 kJ/kg

Step (VI) Cycle Efficiency

$$\eta = \frac{\text{Network output}}{\text{Net energy supplied}} = \frac{W}{H_B - h_{W_E}}$$

$$= \frac{423.677}{2938.87 - 304} = 0.160 \text{ i.e. } 16\%$$

Ans.

Step (VII) Specific Steam Consumption

1 MWH = 10^6 (3600) J = $10^3 \times 3600$ kJ

Available work output per kg of steam

= 423.677 kJ

Specific steam consumption

= $10^3 \times 3600/423.677$

= 8.497×10^3 kg of steam

= 8.497 ton of steam

Ans.

Step (VIII) Carnot Efficiency

$$\eta = \frac{T_B - T_D}{T_B} = \frac{523 - 346}{523}$$

= 0.338 i.e. 33.8%

Ans.

Q. *Apart from the Rankine cycle, what other cycles are adopted in steam power plants?*

Ans. 1. Reheat cycle
2. Regenerative cycle
3. Reheat-Regenerative combined cycle
4. Binary cycle.
5. Superposed cycle.

Q. *Why is the reheat cycle adopted?*

Ans. In modern thermal power plants, the pressure drop of steam due to its expansion in the turbine is considerable. As a result of this, any superheated steam supplied to the turbine may become wet after partial expansion. This wet steam passing over the turbine blades for a prolonged period will corrode and erode the turbine

blades. Just to avoid these problems, the superheated steam after partial expansion in the turbine is reheated at constant pressure in the reheater—a kind of superheater—wherefrom the superheated steam is again delivered to the turbine so that the expansion that will follow will be again in the dry and superheated region. (Fig. 37.12A & 12B)

These are the reasons why the reheat cycle is adopted.

Q. *What is the main purpose of the reheat cycle?*

Ans. Its chief purpose is to increase the dryness fraction of steam passing through the lower stages of the steam turbine.

Q. *Up to what dryness fraction is steam allowed to fall during its expansion in the turbine?*

Ans. It is allowed to fall upto 0.88 but not below it.

Q. *Apart from avoiding corrosion and erosion, what are the other gains of the reheat cycle?*

Ans. It increases the thermal efficiency and decreases the specific steam consumption.

Because of reduced specific steam consumption, the size of the boiler and its auxiliaries for the same output is reduced.

Q. *The reheat pressure is generally kept within 20% of the initial pressure of the steam. Why?*

Ans. If the reheat cycle is operated at low pressure, i.e. less than 1/5th of the initial superheated steam pressure, the overall cycle efficiency may fall below the Rankine efficiency.

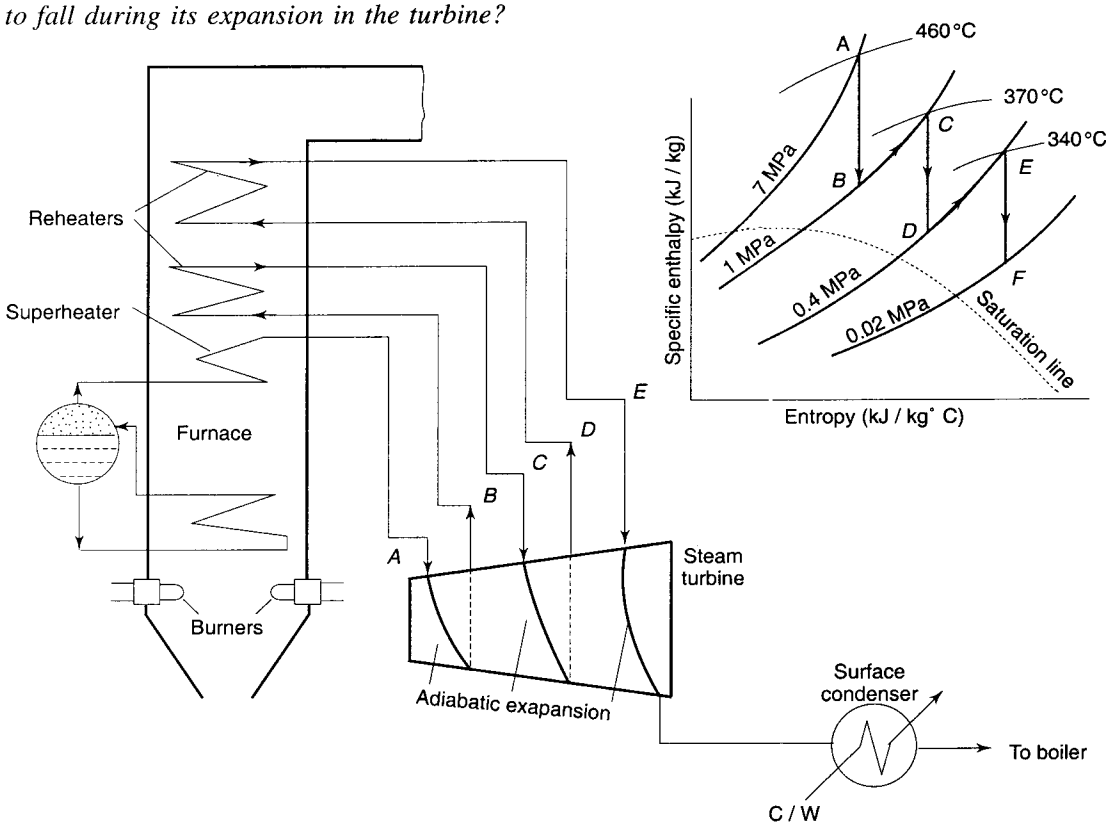


Fig. 37.12 (a) and (b)

Q. *Why is the reheat cycle preferred only for high capacity plants, 50 MW and above?*

Ans. For high capacity plants, superheated steam pressure may be as high as 100 kgf/cm^2 abs. and higher. And at such high pressures, the reheat cycle can be adopted successfully with cycle efficiency higher than Rankine efficiency.

Higher the steam pressure, greater the pressure drop that can be allowed in the turbine before reheating it to the superheated temperature for re-expansion in the turbine and that means higher work output and greater thermal efficiency.

Q. *Why is the reheat cycle not preferred for low capacity plants?*

Ans. It will not justify the cost of reheater installation.

Q. *How can the efficiency of the reheat cycle be determined from the temperature-entropy diagram?*

Ans. Reheat cycle is an improvement on the Rankine cycle by increasing the temperature and pressure of the steam to be delivered to the turbine.

$$\eta = \frac{\text{Total Work Output of the Cycle}}{\text{Total Heat Input}}$$

$$= \frac{[H_C - H_D] + [H_E - H_F]}{[H_C - h_{W_H}] + [H_E - H_D]} \quad \text{(Fig. 37.13)}$$

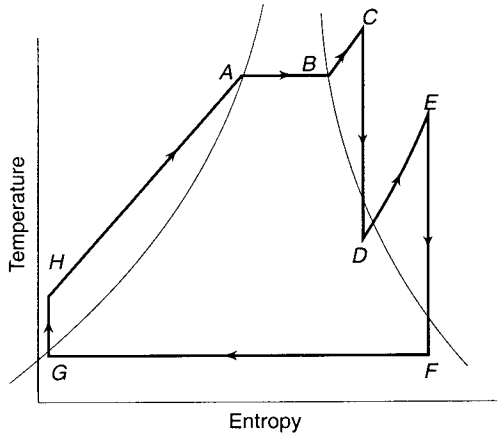


Fig. 37.13

(ignoring the pump work)

Q. *What are the advantages of the reheat cycle over the Rankine cycle using the same turbo-generator and same steam conditions at the inlet to the turbine?*

Ans. 1. Modern power plants use higher pressure steam and due to isentropic expansion, the saturation line is reached earlier, with the effect that most of the turbine stages operate in the saturated steam region. This is highly undesirable as wet steam causes heavy blade erosion due to the impact of water particle on turbine blades. (Fig. 37.14)

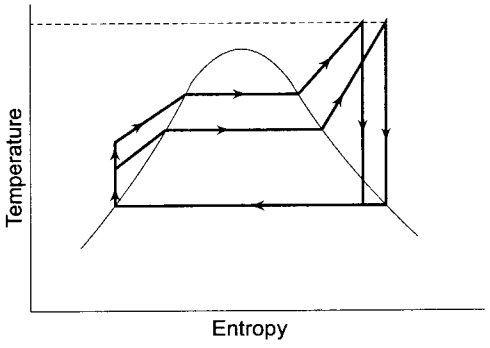


Fig. 37.14

Therefore, reheating is essential for high pressure modern power plants. It also means a longer life for the turbine.

2. Reheating cuts down the mass flowrate of steam input to the turbine by 15–17% thereby reducing the size of boilers and auxiliaries.
3. Reheating reduces the wetness of exhaust steam to as much as half of the Rankine cycle, thereby saving blade erosion by exhaust steam.
4. Fuel consumption is reduced by as much as 4 to 5% due to adoption of reheat cycle.
5. The turbine condenser size is reduced due to lower quantities of steam and heat load handled. As such cooling water requirement is also reduced.

6. For the required thermal performance, relatively lower steam pressures and temperatures will do. And that reduces the cost of material.
7. Higher thermal efficiency.
8. Lower feed pump power.

Q. *What are the main disadvantages of the reheat cycle in comparison to the Rankine cycle?*

Ans. 1. With the adoption of the reheat cycle, the complexity of operation and control mounts.
2. At low loads, the steam passing over the terminal blades of the turbine just before its entry to the condenser gets severely superheated and that may result in blade overheating.
3. The addition of extra pipe and equipment and control system to the reheat cycle make this cycle more expensive than the simple Rankine cycle.
4. It entails additional design problems as the turbine blades of the intermediate stage immediately downstream of the reheater are appreciably larger than the corresponding stages of the non-reheat system.
5. More floor-space is required.

Problem 37.6 A turbo-generator working on the reheat cycle receives steam at 90 kgf/cm^2 abs. and 480°C. It expands frictionless adiabatically to 15 kgf/cm^2 abs. This exhaust steam is reheated to 15 kgf/cm^2 abs. and 480°C and is then allowed to expand in the turbine to the final exhaust steam pressure 0.05 kgf/cm^2 abs., which is saturated.

Work out
(a) the cycle efficiency
(b) the work output

Steam feedrate = 12 kg/s.

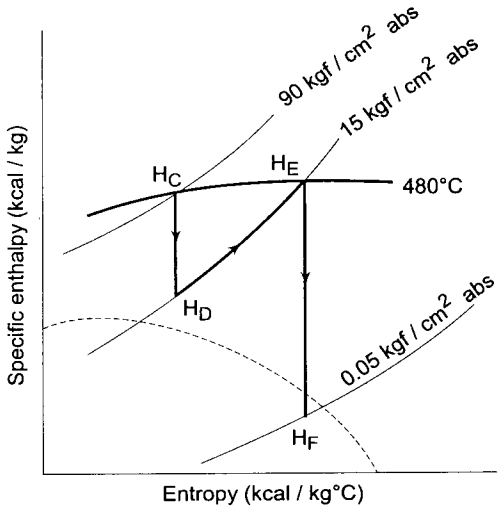
Solution

Step (I) Sp. Enthalpy vs. Entropy Diagram and Temperature vs. Entropy Diagram.
The entire cycle is represented on a $T - \phi$ diagram as shown. (Fig. 37.15 a, b)

Step (II) Sp. Enthalpy of Steam

From the **Sp. Enthalpy vs. Entropy chart:**

Sp. enthalpy of steam at 90 kgf/cm^2 abs. and 480°C is H_C = 798 kcal/kg



(a)

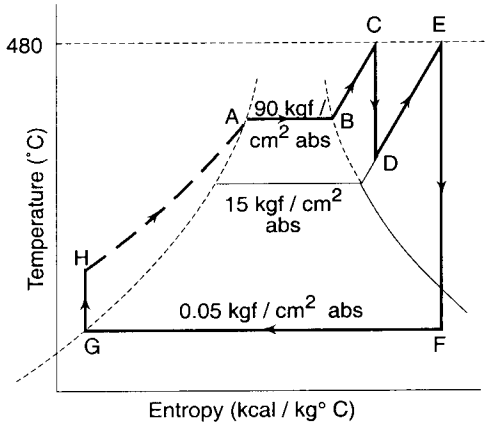


Fig. 37.15(b)

Sp. enthalpy of steam at 15 kgf/cm^2 abs. after isentropic expansion is H_D = 684.8 kcal/kg

Sp. enthalpy of steam at 15 kgf/cm^2 abs. and 480°C is H_E = 820 kcal/kg

Sp. enthalpy of dry, saturated steam at 0.05 kgf/cm^2 abs. is H_F = 546.5 kcal/kg

Sp. enthalpy at G is H_G = 32.6 kcal/kg (from steam tables)

Step (III) Pump Work

Sp. volume of water at 0.05 kgf/cm^2 absolute

= 0.001005 m^3/kg

$\therefore$ Pump work = $(90 - 0.05)\,(0.001005) \times 10^4$ kgf m

= 903.9975 kgf. m

= 903.9975/427 kcal = 2.117 kcal/kg of steam

Step (IV) Total Work Done

$W_{tot} = (H_C - H_D) + (H_E - H_F) + W_p$

$= (798 - 684.8) + (820 - 546.5) - 2.117$

= 384.583 kcal/kg of steam

$\therefore$ Work output per second

= 384.583(12)

= 4615 kcal ***Ans.***

Step (V) Cycle Efficiency

Net work output = 384.583 kcal/kg of steam

Net work input = $(H_C - H_H) + (H_E - H_D)$

= 798 – (32.6 + 2.117) + (820 – 684.8) kcal/kg of steam

= 898.483 kcal/kg of steam

$$\text{Cycle efficiency, } \eta = \frac{384.583}{898.483} = 0.4280$$

i.e. 42.80%

Ans.

Problem 37.7 Steam at 6000 kN/m^2 and temperature 450°C is fed to the turbine of a turbo-alternator where it expands isentropically to a pressure of 1000 kN/m^2 in the 1st stage. This extraction steam is reheated to 370°C at the same pressure and is again expanded in the 2nd stage of the same turbine where its pressure drops to 200kN/m^2. This steam is again reheated to a pressure of 200 kN/m^2 and temperature 320°C and is then passed back to the turbine to be expanded to 20 kN/m^2 in the 3rd stage. The finally exhausted steam is then passed to the surface condenser where it is condensed but not undercooled at the same pressure of 20 kN/m^2. The condensate is then recycled to the boiler.

Assuming adiabatic, frictionless expansion in all cases, determine:

(a) the theoretical power available per cycle if the steam flowrate is 10kg/s

(b) the thermal efficiency of the reheat cycle, neglecting feed pump work

(c) the efficiency of the cycle if there were no reheat.

Solution

Step (I) Sp. Enthalpy vs. Entropy Diagram

The entire cycle can be conveniently described in the specific enthalpy vs. entropy diagram, as shown. (Fig. 37.16)

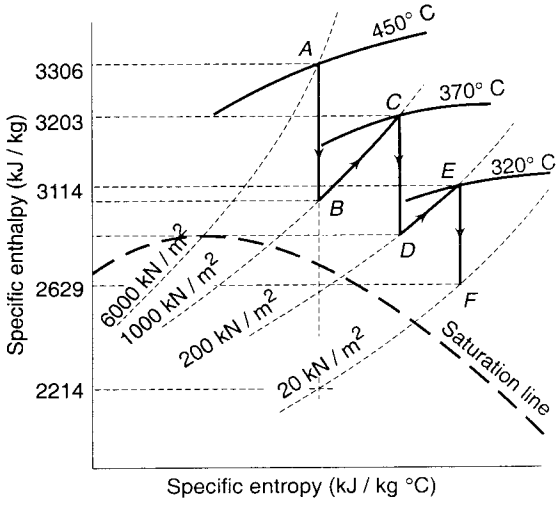


Fig. 37.16

Step (II) Specify Enthalpies of Steam

From the H-ϕ diagram on the specific enthalpy vs. entropy chart we find the specific enthalpies of steam at various points.

H_A = 3306 kJ/kg; H_B = 2851 kJ/kg;

H_C = 3203 kJ/kg; H_D = 2811 kJ/kg;

H_E = 3114 kJ/kg; H_F = 2629 kJ/kg;

H_G = 2214 kJ/kg

Step (III) Theoretical Power Output

Now net work available per kg of steam expanding through the three stages of the turbine.

$$= (H_A - H_B) + (H_C - H_D) + (H_E - H_F)$$
$$= (3306 - 2851) + (3203 - 2811) + (3114 - 2629)\ \text{kJ}$$
$$= 1332\ \text{kJ}$$

∴ Theoretical power output per kg of steam passing through the turbine per second

= 1332 kJ/s = 1332 kW = 1.332 MW

For steam flowrate = 10 kg/s, the theoretical power output per cycle would be = 13.32 MW.

Step (IV) Thermal Efficiency

$$\eta = \frac{\text{Net Work Output/kg of steam}}{\text{Net Energy supplied/kg of steam}}$$

$$= \frac{(H_A - H_B) + (H_C - H_D) + (H_E - H_F)}{(H_A - h_{W_F}) + (H_C - H_B) + (H_E - H_D)}$$

$$= \frac{1332}{(3306-251)+(3203-2851)+(3114-2811)}$$

= 0.3590 i.e. 36%

Ans.

Step (V) Thermal Efficiency with no Reheat

$$\eta = \frac{H_A - H_G}{H_A - h_{W_G}} = \frac{3306 - 2214}{3306 - 250} = 0.3573$$

i.e. 35.73%

Ans.

Q. *From the above numerical example it is evident that the gain in efficiency is insignificant by the application of reheat. So is it useful to adopt the reheat cycle?*

Ans. Despite very little gain in thermal efficiency over the non-reheat cycle, the reheat cycle, in the above example, renders the feed steam always super-heated minimizing the problem of blade erosion.

Q. *What are the different methods of reheating used in practice?*

Ans. 1. Gas reheating
2. Live steam reheating
3. Combined gas and live steam reheating

Q. *How is gas reheating carried out?*

Ans. The intermediate extraction from the high pressure steam turbine is reheated in the duct of flue gases in the boiler furnace and this reheated steam is expanded in the low pressure cylinder of the expansion turbine. (Fig. 37.17)

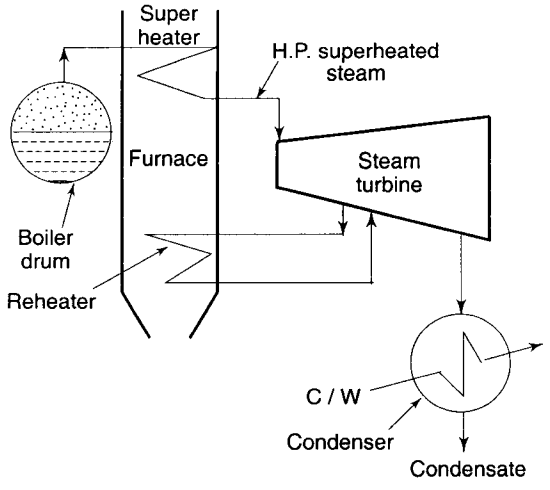


Fig. 37.17 *Gas reheating.*

Usually the steam is reheated to its initial throttle temperature.

Q. *What are the disadvantages of gas reheating?*

Ans. 1. This system requires long and large pipe connections, mounting the cost.
2. With the increase in pipe length, pressure drop of steam increases.
3. This necessitates the provision for expansion and contraction of the steam pipes

4. In case of failure of emergency control, the quantity of steam in the piping and reheater is enough to raise the turbine spinning considerably.

Q. *How is live steam reheating done?*

Ans. This is accomplished by directing part of the superheated steam from the superheater to reheat the extraction steam from the high-pressure cylinder.

The reheating is carried out in a live steam reheater—a specially designed heat-exchanger. (Fig. 37.18)

Q. *What are the advantages of live steam reheating over gas reheating?*

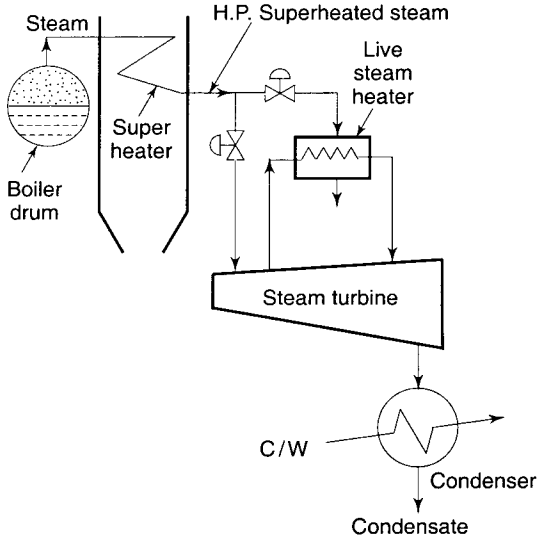


Fig. 37.18 *Live steam reheating.*

Ans. 1. Large pipe connections are avoided as the reheater can be placed near the turbine
2. Mode of operation is simple
3. Simpler temperature control as the alteration of combustion conditions do not affect the live steam reheater
4. More than one reheating can be employed
5. Wet steam reheating can be carried out.

Q. *What is the chief drawback of live steam reheating?*

Ans. The extraction steam from the high pressure cylinder cannot be reheated to its initial throttle temperature.

Q. *How can this difficulty be avoided?*

Ans. By adopting the combined gas and live steam reheating system.

Q. *How is this combined system carried out?*

Ans. The live steam reheating is hooked up in series with gas reheating. The extraction steam from an H.P. turbine is first directed to the live steam reheater and then further reheated in the gas reheater. Finally, this reheated steam is fed to the L.P. turbine. (Fig. 37.19)

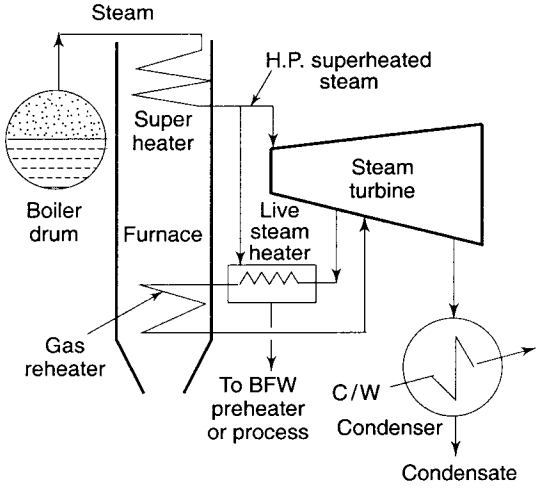


Fig. 37.19 *In the combined system of steam heating the live-steam heater is lined up in series with gas reheater.*

Problem 37.8 A steam turbine working on a reheat cycle receives steam at 100 kgf/cm^2 absolute and 500°C. The steam expands adiabatically to 10 kgf/cm^2 absolute with an isentropic efficiency of 82%.

The steam is then reheated to 10 kgf/cm^2 absolute and 400°C and allowed to expand adiabatically in the lower stage of the turbine up to the

condenser pressure 0.1 kgf/cm^2 absolute with an isentropic efficiency of 85%.

Determine the thermal efficiency of the reheat cycle assuming the pressure loss in the reheater is nil.

If the expansion of steam is carried out in the lower stage of the turbine with an isentropic efficiency 80% without reheating, calculate the thermal efficiency of the cycle.

Boiler feedwater pump work may be ignored

Solution

Step (I) The cycle efficiency can be calculated with the help of specific enthalpy vs. entropy and temperature vs. entropy diagrams (Fig. 37.20B, 20A)

From the **Specific Enthalpy vs Entropy chart:**

Specific enthalpy of steam at 100kgf/cm^2 absolute and 500°C, H_A = 808 kcal/kg

Specific enthalpy of steam at 10 kgf/cm^2 absolute after isentropic expansion H_B' = 666 kcal/kg

Specific enthalpy of steam at 10 kgf/cm^2 absolute and 400°C, H_C = 780 kcal/kg

Specific enthalpy of steam at 10 kgf/cm^2 absolute after isentropic expansion H_D' = 565 kcal/kg

Step (II) Determination of H_B and H_D

$$\frac{H_A - H_B}{H_A - H_B'} = 0.82 \text{ or } \frac{808 - H_B}{808 - 666} = 0.82;$$

$\therefore H_B$ = 691.56 kcal/kg

Similarly,

$$\frac{H_C - H_D}{H_C - H_D'} = 0.85 \text{ or } \frac{780 - H_D}{780 - 565} = 0.85;$$

$\therefore H_D$ = 597.25 kcal/kg

Step (III) Determination of Cycle Efficiency

$$\eta = \frac{(H_A - H_B) + (H_C - H_D)}{(H_A - h_{W_E}) + (H_C - H_B)}$$

$$= \frac{(808 - 691.56) + (780 - 597.25)}{(808 - 45.4) + (780 - 691.56)}$$

= 0.3515 i.e. 35.15%

Ans.

Step (IV) Cycle Efficiency in Absence of Reheating

If there were no reheating, the isentropic expansion of steam (10 kgf/cm^2 abs.) in the low pressure cylinder would take place along BF'. (Fig. 37.21)

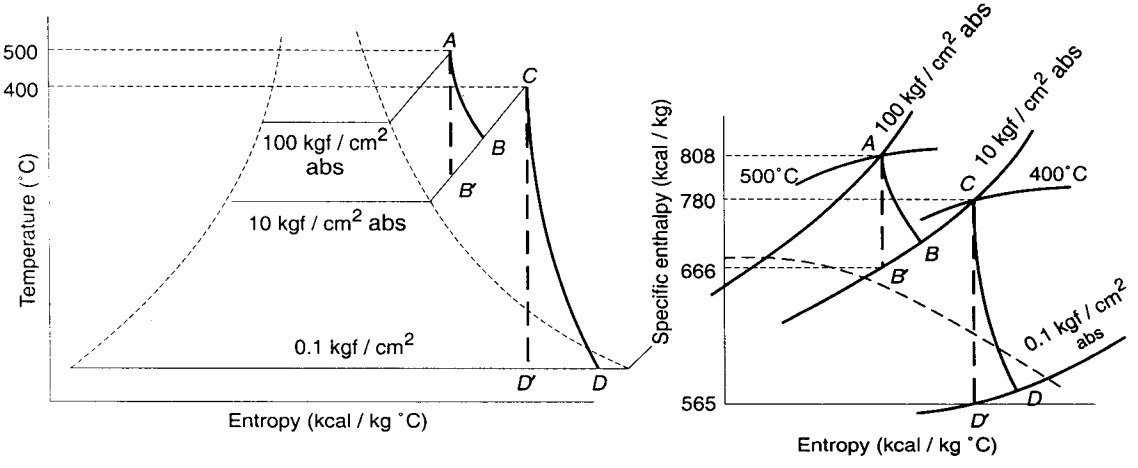


Fig. 37.20 (a) and (b)

From the **sp. enthalpy vs. entropy** diagram we find $H_F' = 515$ kcal/kg

Since, this **isentropic expansion (B)** $\longrightarrow$ **(F')** has 80% efficiency,

$$\frac{H_B - H_F}{H_B - H_{F'}} = 0.80 \text{ or, } \frac{691.56 - H_F}{691.56 - 515} = 0.80;$$

$$\therefore \quad H_F = 550.312 \text{ kcal/kg}$$

Therefore, the thermal efficiency of the cycle without reheating,

$$\eta = \frac{(H_A - H_B) + (H_B - H_F)}{(H_A - h_{w_E})}$$

$$= \frac{H_A - H_F}{H_A - h_{W_E}} = \frac{808 - 550.312}{808 - 45.4}$$

$$= 0.3379 \text{ i.e. } 33.79\%$$

Ans.

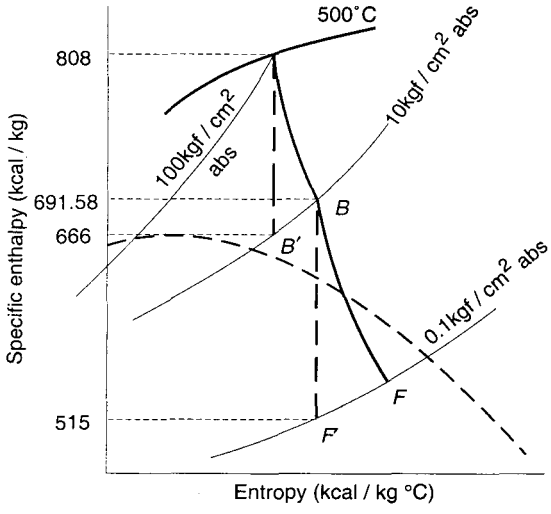


Fig. 37.21

Problem 37.9 A 3-stage steam turbine working on double reheat cycle receives steam at 200 kgf/cm^2 absolute and 550°C. This steam expands in the I stage to 50 kgf/cm^2 absolute and 350°C. The steam is then reheated to 450°C in the reheater where it suffers a pressure loss of 1 kgf/cm^2 absolute. This reheated steam is again expanded in the II stage of the turbine to 10 kgf/cm^2 absolute and 280°C. After this the steam is reheated to 350°C in the 2nd reheater where it suffers a pressure loss of 1 kgf/cm^2 absolute. The reheated steam expands in the III stage of the turbine to a condenser pressure 0.5 kgf/cm^2 absolute. The exhaust steam enters the condenser as dry and saturated.

Determine:

(a) thermal efficiency of the cycle
(b) power developed if steam flowrate = 15 kg/s
(c) isentropic efficiency in each stage.

Solution

Step (I) The different expansion and reheating process of the steam can be represented conveniently on **Specific Enthalpy vs. Entropy** diagrams. (Fig. 37.22)

From the chart:

Point	Sp. Enthalpy
A	$H_A = 814.5$ kcal/kg
B	$H_B = 733$ kcal/kg
B'	$H_B' = 720$ kcal/kg
C	$H_C = 794.5$ kcal/kg
D	$H_D = 718.5$ kcal/kg
D'	$H_D' = 698$ kcal/kg
E	$H_E = 755$ kcal/kg
F	$H_F = 632$ kcal/kg
F'	$H_F' = 611.5$ kcal/kg

Step (II) Work Done

Net work done per kg of steam

$= (H_A - H_B) + (H_C - H_D) + (H_E - H_F)$

$= (814.5 - 733) + (794.5 - 718.5) + (755 - 632)$

$= 280.5$ kcal/kg

Step (III) Heat Supplied

Input heat energy per kg of steam

$= (H_A - h_{W_F}) + (H_C - H_B) + (H_E - H_D)$

$= (814.5 - 80.9) + (794.5 - 733) + (755 - 718.5)$

$= 831.6$ kcal

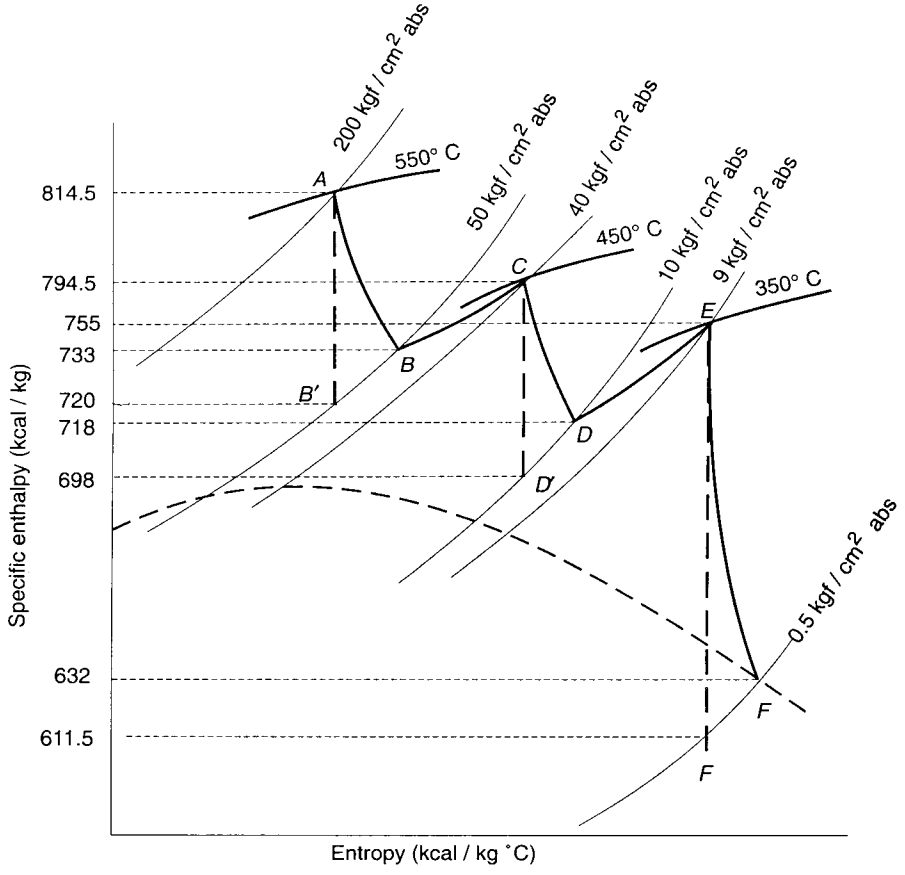


Fig. 37.22

Step (IV) Thermal Efficiency of the Cycle

$$\eta = \frac{280.5}{831.6} = 0.3373 \text{ i.e. } 33.73\% \qquad \textit{Ans.}$$

Step (V) Power Developed

Steam flowrate = 15 kg/s

Work output available = 280.5 kcal/kg of steam

Work output per second = 280.5(15)kcal

Power developed = 280.5(15) (5.6918) H.P.

(cf 1 kcal/s = 5.6918 HP)

= 23948 H.P.

Step (VI) Stage Efficiency

Isentropic efficiency of I stage

$$= \frac{H_A - H_B}{H_A - H_{B'}} = \frac{814.5 - 733}{814.5 - 720}(100) = 86.24\%$$

Ans.

Isentropic efficiency of II stage

$$= \frac{H_C - H_D}{H_C - H_{D'}} = \frac{794.5 - 718.5}{794.5 - 698}(100) = 78.75\%$$

Ans.

Isentropic efficiency of III stage

$$= \frac{H_E - H_F}{H_E - H_{F'}} = \frac{755 - 632}{755 - 611.5}\,(100) = 85.71\%$$

Ans.

Problem 37.10 Steam at 100 kgf/cm^2 absolute and 500°C expands, in the I stage of a steam turbine to 20 kgf/cm^2 absolute, the isentropic efficiency of expansion being 80%. The steam is then reheated to 450°C in the reheater where it suffers a pressure loss of 1 kgf/cm^2 absolute. The reheated steam then expands to a condenser pressure of 0.05 kgf/cm^2 absolute. The isentropic efficiency of expansion is 85%. The turbine is coupled with a generator generating 45 MW of electricity.

If the transmission efficiency from the turbine to the generator is 98% and the generator efficiency is 96%, determine the steam flowrate. Neglect feed pump work.

Solution

Step (I) The expansion and reheating processes are depicted in the **Specific Enthalpy vs. Entropy chart.** (Fig. 37.23)

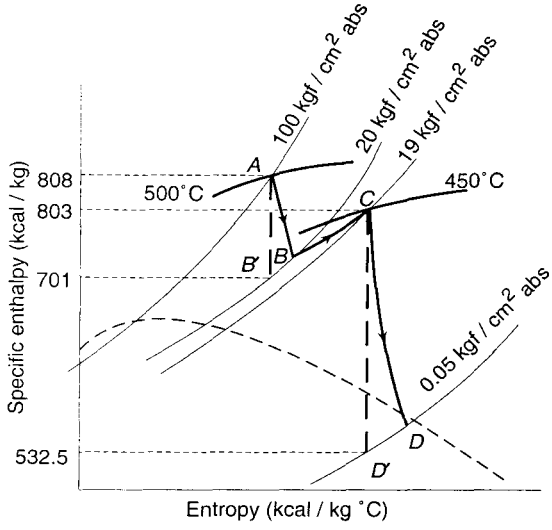


Fig. 37.23

From the chart:

H_A = 808 kcal/kg; H_B' = 701 kcal/kg;

H_C = 803 kcal/kg; H_D' = 532.5 kcal/kg

Step (II) Calculation of H_B

Considering the **expansion of steam (A) ⟶ (B)**

$$\frac{H_A - H_B}{H_A - H_{B'}} = 0.80 \quad \text{or,} \quad \frac{808 - H_B}{808 - 701} = 0.8;$$

$\therefore H_B$ = 722.4 kcal/kg

Step (III) Calculation of H_D

Considering the **expansion of steam (C) ⟶ (D),**

$$\frac{H_C - H_D}{H_C - H_{D'}} = 0.85 \text{ or, } \frac{803 - H_D}{803 - 532.5} = 0.85$$

or H_D = 573.07 kcal/kg

Step (IV) Work Done

Work done per cycle = $(H_A - H_B) + (H_C - H_D)$

= (808 – 722.4) + (803 – 573.07)

= 315.53 kcal/kg of steam

Step (V) Steam Flowrate

Let the mass flowrate of steam be $\dot{M}$ kg/s.

$\therefore \dot{M}$ (315.53) (0.98) (0.96)

= (45 × 10^3) (0.2388)

(cf. 1 kW = 0.2388 kcal/s)

$\therefore \dot{M}$ = 36.20 kg/s ***Ans.***

= 130.32 t/h ***Ans.***

Q. *What is regenerative heating?*

Ans. Also called feed heating, regenerative heating is the process of heating feedwater on its way from the condenser to the boiler by bled steam drawn from various stages of the turbine. The heating is carried out in feed heaters.

Q. *Why is it carried out?*

Ans. There is a large difference between the superheated steam temperature as supplied from the boiler unit to the turbine and the condensate temperature as it leaves the condenser and is recycled to the boiler as BFW.

Now to increase the condensate temperature on its way back to the boiler and, as a consequence, to increase the thermal efficiency of the plant, the process of regenerative heating (feed heating) is introduced.

Under ideal conditions, the heat lost by the steam must be equal to the heat gained by the condensate,

i.e. Area *ABFE* = Area *DGHC* (Fig. 37.24)

This type of heating arrangement results in a cycle efficiency equivalent to Carnot cycle efficiency.

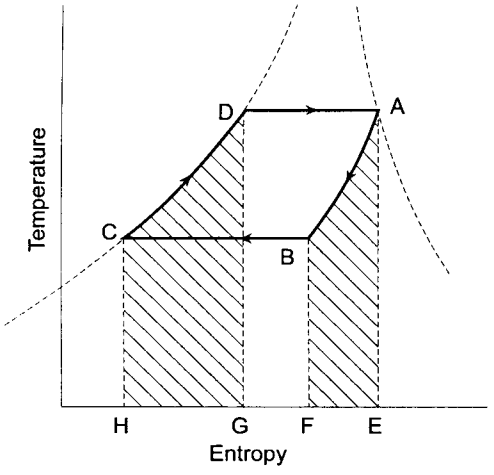


Fig. 37.24

Q. *How is this regenerative heating carried out?*

Ans. In this process, small quantities of steam drawn at various stages of the turbine are allowed to pass through several feed heaters whereupon they condense in the process of either direct heat exchange or indirect heat exchange with the condensate being pumped to the boiler. The bled steam condenses and heats up the turbine condensate which together with the bled-steam-condensate is returned to the boiler.

(Fig. 37.25)

Q. *How is direct contact feed heating carried out?*

Ans. The turbine condensate is sprayed onto the bled steam in the feed heater. The mixed condensate, already heated, is again sprayed into the bled steam at a higher temperature in the subsequent feed heater. In this way the condensate temperature, on its way to the boiler, is raised (Fig. 37.26).

Q. *What is the chief disadvantage of this direct contact feed heater?*

Ans. The main drawback of this system is that the feed pump or recirculation pump has to work with a hot feed. That is why this system is rarely used in practice.

Q. *What are the indirect contact methods for feed reheating?*

Ans. There are three methods:

1. Drain Pump method
2. All Drains to Hot Well method
3. Cascade method.

Q. *How does the drain pump method work?*

Ans. In this system the turbine condensate is increasingly heated as it passes through successive feed heaters where bled steam is introduced to heat up the condensate in the process of indirect heat transfer.

The bled steam condensate is added to the feed line by the drain pump. (Fig. 37.27)

Q. *What is an important disadvantage of the drain pump method?*

Ans. The feed pump and the drain pump have to handle a hot feed.

Q. *How does the method of feed heating with all drains to hot well work?*

Ans. In this system the total condensate—sum of turbine condensate and bled steam condensate—is drained to a single well called hot well from which the feed pump delivers the BFW to the boiler through feed heaters where it is heated up by indirect heat exchange with bled steam. (Fig. 37.28)

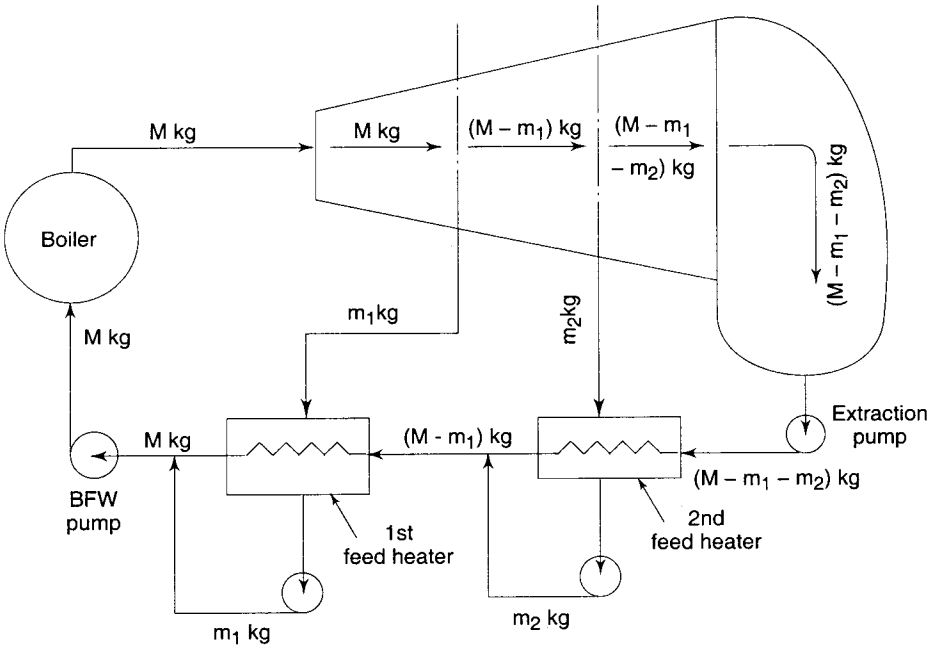


Fig. 37.25 *Regenerative heating of condensate through indirect heat exchange.*

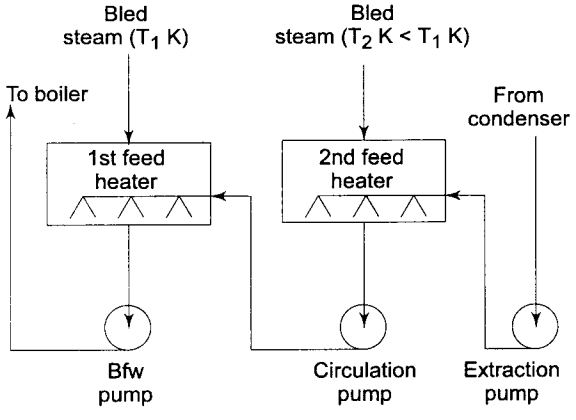


Fig. 37.26 *Direct contact regenerative heating of condensate.*

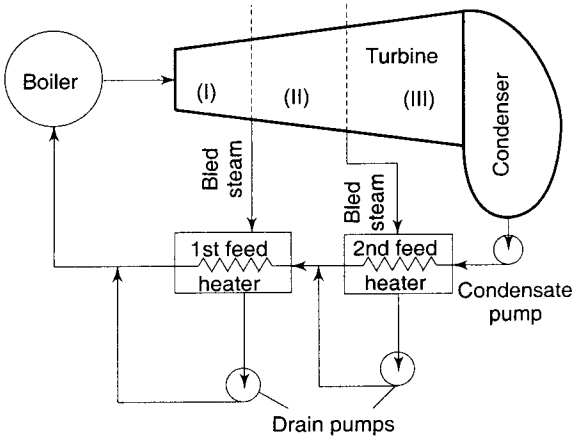


Fig. 37.27 *Regenerative heating of condensate by drain pump method.*

Q. *How does the cascade system work?*

Ans. In this system, the bled steam condensate from the 1st feed heater is sent to a hot well via the 2nd feed heater where it cascades down and exchanges heat (indirect heat transfer) with the feed pumped through the tubes from the hot well to the boiler. The bled steam condensate from the 1st feed heater collecting together with the condensate to the bled steam in the 2nd feed heater is discharged to the hot well wherefrom the con-

densate is pumped back to the boiler through feed heaters. (Fig. 37.29).

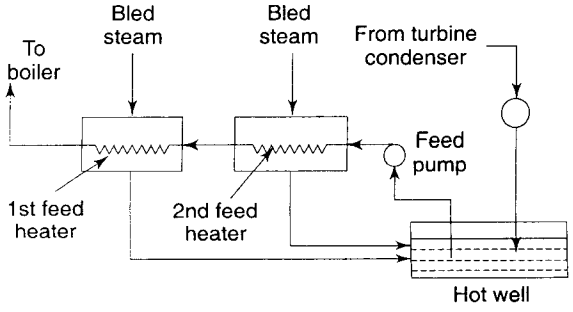


Fig. 37.28 *Regenerative heating of condensate with all drains to hot well.*

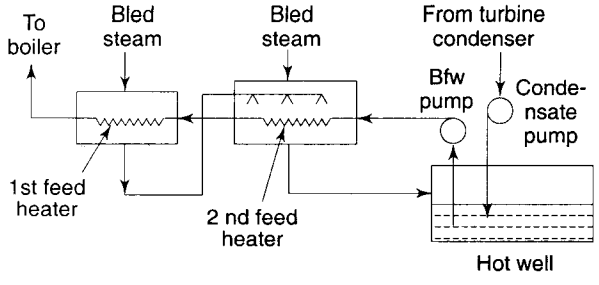


Fig. 37.29 *Regenerative heating of condensate in cascade system.*

Problem 37.11 Superheated steam at a pressure and temperature 7 MPa and 500°C respectively is supplied to a turbine from which steam is bled at pressure 2 MPa and 0.5 MPa for feed heating. In the feed heaters the bled steam is condensed and the liquid enthalpy of feedwater is raised to that of the corresponding bled steam which being condensed is pumped into the feed main.

Determine:

(a) the mass of bled steam per unit mass of supply steam

(b) the thermal efficiency of the system as a whole

(c) gain in thermal efficiency over the system without feed heating.

Given: Turbine condenser's working pressure = 0.05 MPa

Steam efficiency of each section of turbine = 80%

No undercooling of bled steam condensate.

Solution

Step (I) The overall arrangement can be diagrammatically represented as shown (Fig. 37.30).

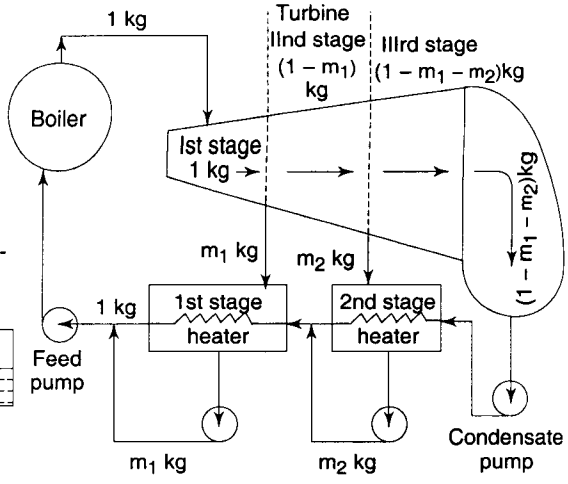


Fig. 37.30

Let 1 kg be the supply steam out of which m_1 kg is the bled steam in the 1st feed heater and m_2 kg is the bled steam in the 2nd feed heater.

Step (II) The expansion of steam in successive stages of the turbine can be conveniently described on the Sp. Enthalpy vs. Entropy diagram. (Fig. 37.31)

From the diagram, the specific enthalpies at A, B', C', D' are:

$$H_A = 3411 \text{ kJ/kg}$$

$$H_{B'} = 3046 \text{ kJ/kg}$$

$$H_{C'} = 2791 \text{ kJ/kg}$$

$$H_{D'} = 2451 \text{ kJ/kg}$$

Considering expansion AB

$$\frac{H_A - H_B}{H_A - H_{B'}} = 0.8; \text{ or } \frac{3411 - H_B}{3411 - 3046} = 0.8;$$

$\therefore H_B = 3119$ kJ/kg

Considering expansion BC

$$\frac{H_B - H_C}{H_B - H_{C'}} = 0.8; \text{ or } \frac{3119 - H_C}{3119 - 2791} = 0.8;$$

$\therefore H_C = 2856.6$ kJ/kg

Considering expansion CD

$$\frac{H_C - H_D}{H_C - H_{D'}} = 0.8; \text{ or } \frac{2856.6 - H_D}{2856.6 - 2451} = 0.8;$$

$\therefore H_D = 2532.12$ kJ/kg

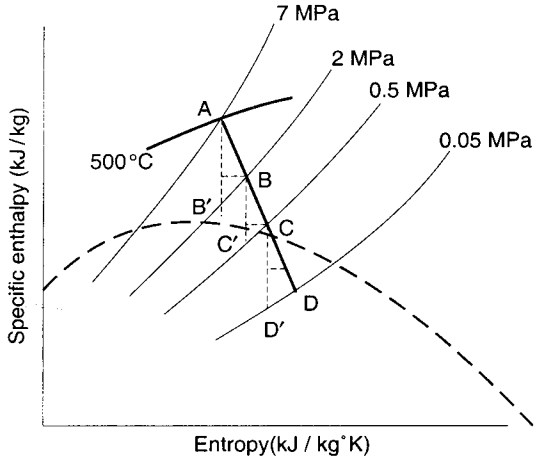


Fig. 37.31

Step (III) Liquid Enthalpy at *B*, *C*, *D*

From steam tables, specific liquid enthalpies at

2 MPa, i.e. $h_{w_B} = 908.5$ kJ/kg

0.5 MPa, i.e. $h_{w_C} = 640$ kJ/kg

0.05 MPa, i.e. $h_{w_D} = 340.5$ kJ/kg

Step (IV) Bled Steam to 1st Feed Heater

Now, the loss of enthalpy by bled steam

= the gain of enthalpy of feedwater

$\therefore (m_1)\ (H_B - h_{w_B}) = (1 - m_1)\ (h_{w_B} - h_{w_C})$

or,

$$m_1 = \frac{h_{w_B} - h_{w_C}}{H_B - h_{w_C}} = \frac{908.5 - 640}{3119 - 640}$$

$= 0.1083$ kg/kg of supply steam.

Ans.

Step (V) Bled Steam to 2nd Feed Heater

By energy balance:

$m_2(H_C - h_{w_C}) = (1 - m_1 - m_2)\ (h_{w_C} - h_{w_D})$

or,

$$m_2 = (1 - m_1)\ (h_{wC} - h_{wD})/(H_C - h_{wD})$$

$$= \frac{(1 - 0.1083)\ (640 - 340.5)}{2856.6 - 340.5}$$

$= 0.1061$ kg/kg of supply stean.

Ans.

Step (VI) Total Work Done per kg of Steam Expanding in the Turbine

The theoretical work done by 1 kg of steam due to expansion stage AB, BC and CD is

$= (H_A - H_B) + (1 - m_1)\ (H_B - H_C) + (1 - m_1 - m_2)\ (H_C - H_D)$

$= (3411 - 3119) + (1 - 0.1083)\ (3119 - 2856.6) + (1 - 0.1083 - 0.1061)\ (2856.6 - 2532.12)$ kJ/kg

$= 780.893$ kJ/kg

Step (VII) Energy Input

Net energy input

$= H_A - h_{w_B} = 3411 - 908.5 = 2502.5$ kJ/kg

Step (VIII) Thermal Efficiency

The thermal efficiency of the entire arrangement

$$\eta = \frac{\text{Theoretical Work/kg of steam}}{\text{Energy Input/kg of steam}}$$

$$= \frac{780.893}{2502.5}\ (100) = 31.20\%$$

Ans.

Step (IX) Without Feed Heating

If there had been no feed heating, the expansion process would be AE as shown. (Fig. 37.32)

$H_A = 3411$ kJ/kg

$H_{E'} = 2372$ kJ/kg

Considering expansion efficiency 80% as before,

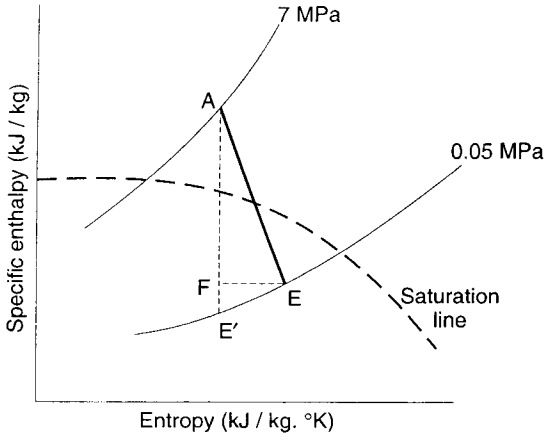


Fig. 37.32

$$\frac{H_A - H_E}{H_A - H_{E'}} = 0.80$$

or, $$\frac{3411 - H_E}{3411 - 2372} = 0.8$$

$\therefore \quad H_E = 2579.8$ kJ/kg

Thermal efficiency

$$= \frac{H_A - H_E}{H_A - h_{W_E}} = \frac{3411 - 2579.8}{3411 - 340.5} = 0.2707$$

i.e. 27%

Ans.

Hence the gain in thermal efficiency due to feed heating

$= 31.2 - 27 = 4.2\%$

Ans.

Q. *What do you mean by topping cycle?*

Ans. It means an additional energy recovery cycle superimposed on a basic power cycle.

[A cycle is a complete course of operations measured in thermodynamic terms from

(a) starting point to starting point (CLOSED CYCLE)

(b) starting point to end point (OPEN CYCLE)

A conventional power plant involves three basic cycles:

1. Gas (Combustion Process)
2. Steam
3. Power]

Q. *What is the utility of a topping cycle?*

Ans. This improves the system heat rate and enhances the utilization of the available heat energy.

Q. *Cite the names of certain topping cycles.*

Ans. 1. Steam topping cycle
2. Gas topping cycle
3. Binary vapour cycle.

Q. *How is a steam topping cycle accomplished?*

Ans. By installing a new boiler plus a turbo-alternator (turbo-generator) that will operate at a higher temperature and pressure than the existing equipment.

And then feeding the extraction steam of this new turbine into the existing turbo-generator and condenser.

Q. *How is a gas topping cycle established?*

Ans. It is a combination of a gas turbine with a steam cycle.

It can be accomplished in two cycles:

1. SUPERCHARGED BOILER CYCLE— Air is compressed by an air-compressor driven by a gas turbine, combustion taking place at high pressure and the combustion products at elevated pressure and temperature are delivered to the gas

turbine to drive the compressor as well as to generate power. (Fig. 37.33)

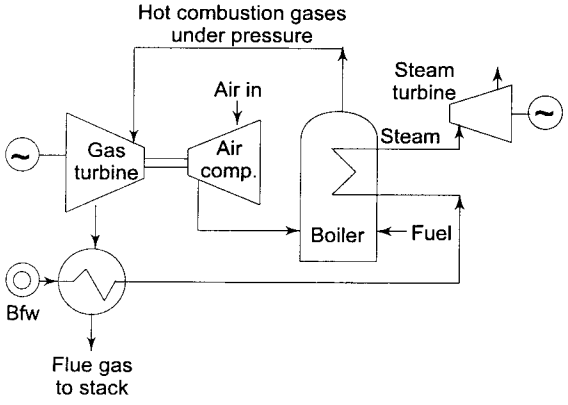


Fig. 37.33 *Supercharged boiler cycle. It combines Gas Turbine and Steam Turbine Cycles.*

2. EXHAUST HEAT RECOVERY CYCLE—Gas turbine exhaust gases are used as a source of recoverable heat and oxygen to supply combustion air to the boiler.

Q. *What are the efficiency gain in a supercharged boiler cycle and exhaust heat recovery cycle?*

Ans. Efficiency gain is 4-12% in the case of a supercharged boiler cycle and 2-8% in the case of an exhaust heat recovery cycle.

Q. *What is the advantage of gas topping cycle?*

Ans. 1. Draft fans are not required which gives a boost to boiler efficiency
2. Neither steam nor electrical energy is expended to deliver combustion air to the burners
3. Air preheater is eliminated
4. Heat is recovered in the form of power
5. Water requirement is reduced
6. Condenser size becomes small
7. Auxiliary equipment sizes also get reduced
8. Improvement of plant efficiency is registered from half-load to full-load.

Q. *What are the advantages of a supercharged boiler?*

Ans. 1. Small furnace volume. Only 25-33% of the heat transfer surface of a conventional boiler is required
2. Higher heat release rate ($53 \times 10^5 - 62 \times 10^5$ kcal/m^3)
3. Design is symmetrical and compact and so minimum quantity of refractory is required. And this gives an edge in size and weight factor.
4. Centralized, remote control operation is possible
5. Close grouping and compact layout
6. Smaller floor space, smaller building, reduced steel supports are required
7. Rapid start-up possible. It requires just 25 minutes to bring a 136 t/h from cold to full steam pressure
8. Lends itself successfully to congeneration whereupon exhaust gas enthalpy can be extracted in a turbo-generator
9. Removal/replacement of parts for repair is relatively easy
10. Mechanical design flexibility.

Q. *What is the exhaust temperature range of a gas turbine?*

Ans. It ranges from 425-485°C

Q. *What is the oxygen content of a gas turbine exhaust?*

Ans. It contains 15–17% oxygen.

(cf. air 21% oxygen by volume)

Q. *Why is this excess air supplied to the turbine inlet?*

Ans. The purpose is:
(a) to complete the combustion process so that no carbon particles or soot can deposit on turbine bladings
(b) to limit the turbine inlet temperature
(c) to ensure the necessary mass flow of gases to power the turbine

Note: A gas turbine handles five times the stoichiometric air required to complete the fuel combustion.

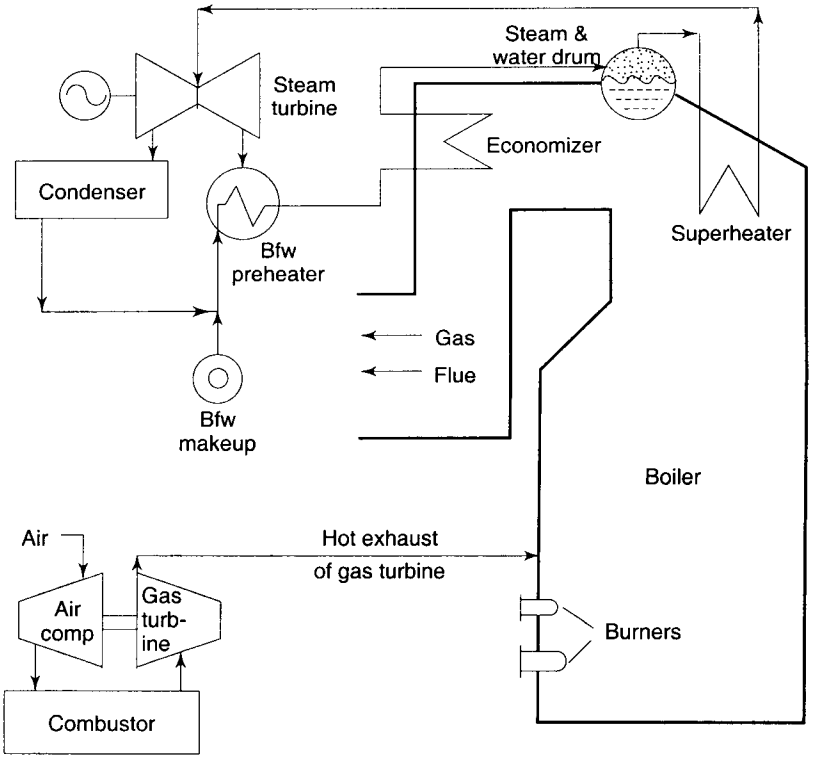


Fig. 37.34 *Exhaust Heat Recovery Cycle.*

Gas turbine exhaust supplies preheated oxygen to the boiler furnace where steam is generated and superheated and then directed to steam turbine

Q. *What are the scopes of utilizing the gas turbine exhaust?*

Ans. The heat load and excess oxygen content of the gas turbine exhaust can be used:

(a) to preheat the entire or part of the total combustion air required by the boiler
(b) to supply the primary air to the pulverizer
(c) to preheat boiler feedwater.

Note: The exhaust of 5 MW gas turbine carries enough heat to generate 16–18 ton steam per hour in a pressurized furnace type of waste heat boiler.

Q. *What do you mean by a binary vapour cycle?*

Ans. It means two or more basic single-stage cycles compounded together, such that the heat rejection from the first stage becomes the source of heat for the second stage (or vice versa) while complete separation of heat transfer media is attained.

Q. *What is the most important binary vapour cycle?*

Ans. It is the mercury-steam cycle.

Q. *Briefly describe the mercury-steam binary cycle.*

Ans. It is composed to two cycles—mercury cycle and steam cycle.

MERCURY CYCLE: Liquid mercury is circulated to the evaporator tubes of the boiler converting the liquid into vapour which is then allowed to expand in the mercury turbine to generate electric power. The exhaust mercury vapour from the turbine is discharged to the mercury con-

denser-boiler where the mercury vapour condenses into liquid releasing its heat of vapourization and is pumped back to the boiler. (Fig. 31.35)

STEAM CYCLE: The heat rejected by vapour mercury in the mercury-condenser-boiler is absorbed by the BFW to generate steam at a desired pressure. This steam is superheated and directed to drive the steam turbine to produce an additional power output.

Fuel is burned in the mercury boiler furnace. The heat released by the fuel is utilized to vapourize the mercury, superheat the steam and preheat the combustion air and boiler feedwater.

Q. *Why is the mercury cycle superimposed upon the steam cycle and not the other way around?*

Ans. Mercury boils at a higher temperature than water at any fixed pressure.

Pressure	B.P. of Hg	B.P. of H_2O
1 atm.	629 K	373 K
12 atm.	811 K	462 K

Thus mercury has a much higher vapour temperature for any saturated vapour condition than that of water. And therefore, mercury is capable of generating steam at considerable pressure at any condensation point.

That is why the mercury cycle tops the steam cycle.

Note: Mercury at 10 atm. boils at 800K. The mercury vapour at this temperature and pressure may be allowed to expand in the turbine to produce power and then it may be used to generate steam at 40.8 atm./525K (saturated).

Mercury vapour at 9.5 atm./797K (turbine throttle) is equivalent to steam at 156 atm./838 K.

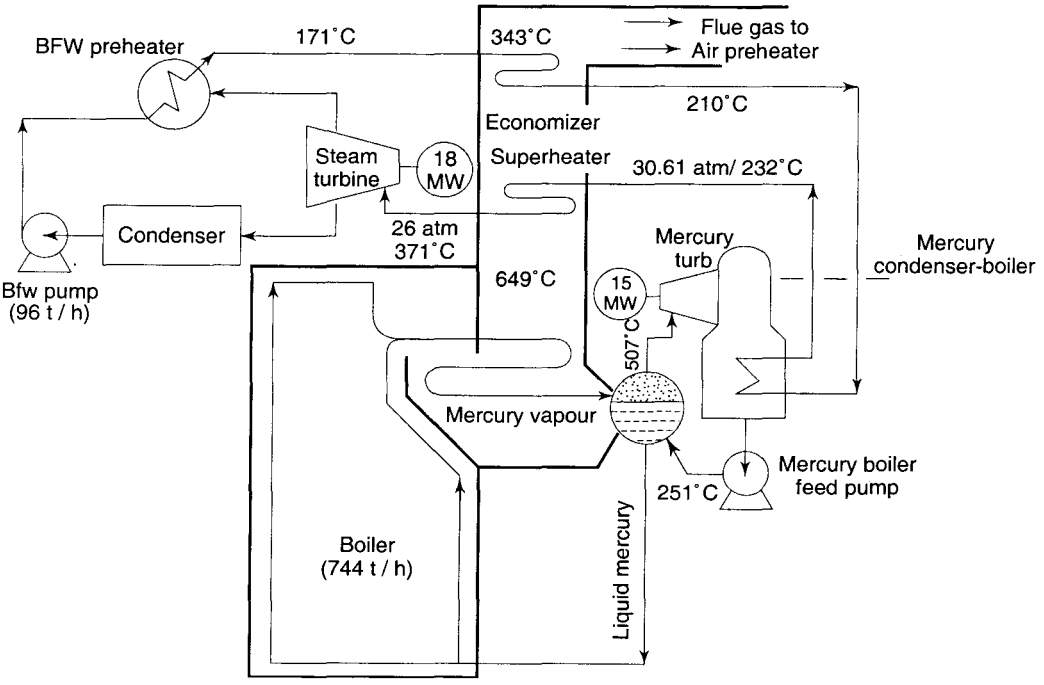


Fig. 37.35 *Mercury-Steam Binary Cycle.*

Mercury cycle is superimposed on the steam cycle whereupon steam is generated in Mercury condenser-boiler where heat is rejected by mercury vapour after being expanded in mercury turbine.

Q. *What are the advantages of the mercury cycle?*

1. High overall plant efficiency
2. High availability (as much as 85%)
3. Operation simplicity
4. Acceptable plant maintenance
5. Reasonable plant cost
6. No operational trouble, though mercury is toxic.

Q. *How does a MHD topping cycle work?*

Ans. MHD (magnetohydrodynamics) topping cycle is superimposed on the steam-turbine bottoming cycle.

The topping cycle is a direct-conversion process in which the fuel is burned at high pressure and at a temperature close to 2750°C. Then potassium compounds are added to the combustion gases to produce a seeding effect to enhance the electrical conductivity. The hot gases are allowed to expand, at sonic velocity, through a channel surrounded by a magnetic field. As the ionized gas travels through the magnetic field, it produces direct current which is converted to **ac** power.

Following this direct conversion process, the combustion gases are passed through a conventional boiler where they transfer their heat to evaporator, superheaters and reheaters to generate high-pressure superheated steam that drives a turbo-alternator. (Fig. 37.36)

Q. *Why are potassium compounds added to the combustion products?*

Ans. The function of potassium is to remove SO_2.

Q. *Why is the potassium recovery unit installed?*

Ans. Potassium seed material is expensive. Economics dictates that it must be regenerated and returned to the combustor.

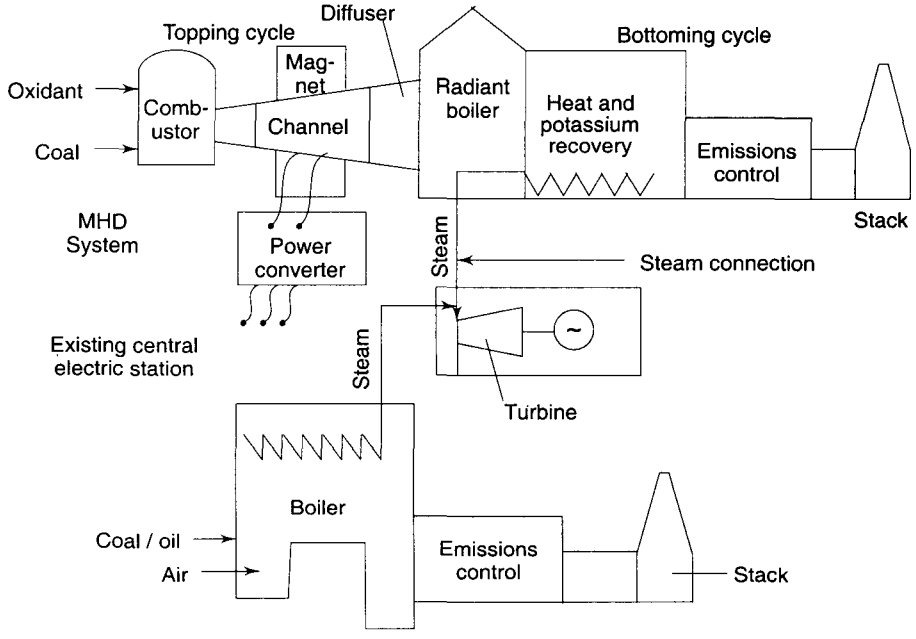


Fig. 37.36 *MHD System superimposed on steam cycle ensures 50% more efficiency than conventional pulverized-coal-fired plants fitted with emission control gadgets.*

38

BOILER DESIGN

Q. *What is the basic problem faced by a boiler designer in designing a steam generating unit?*

Ans. In a steam generating unit two distinct fundamental processes take place:

1. Conversion of the potential energy of the fuel into thermal energy
2. Transfer of this liberated thermal energy to the working fluid to generate steam for useful purpose(s).

This being the case, the basic task of a boiler designer is to maximize the output of these two processes simultaneously. And for that purpose he must design the layout of the entire heat-absorbing surface in such a manner that it will receive maximum available heat in the process of fuel combustion.

However, boiler design is an extremely specialized subject. In practical terms, the designers face mounting difficulties as the process of heat transfer becomes complicated due to constant variations of operating parameters, irregularity in the configuration of heating surfaces and a lot of other factors that enter into the equation simultaneously. Finally, there is another paramount problem—how to obtain maximum efficiency at lowest cost.

Q. *What is basically needed for maximum overall economy, i.e. the boiler running at maximum efficiency but at lowest cost?*

Ans. It needs a balanced design. For this, all component parts must be properly designed and accurately proportioned and linked to the other elements with each process being correctly assessed and related to the other processes involved in the unit as a whole.

Q. *What are these components and processes?*

Components	*Processes*
1. Boiler	1. Air and water preheating
2. Furnace	2. Combustion air supply
3. Fuel burning equipment	3. Combustion products removal
4. Feedwater	4. Ash handling
5. Refractories and baffles	5. Steam separation
6. Foundations and supports	6. Blowdown

Q. *What factors must be taken into account in the design consideration of a boiler?*

Ans.

1. Service requirements
2. Load characteristics
3. Fuel characteristics
4. Mode of fuel burning
5. Hydrodynamics of gas flow
6. Feedwater quality
7. Furnace size, shape and material of construction
8. Type of furnace bottom
9. Boiler proper
10. Boiler operation
11. Capital investment.

Q. *What do you mean by service requirements of a steam generating unit?*

Ans. It implies the nature of service it will render, i.e. whether the unit will be for a public utility central station for production of electricity or for an industrial plant for the generation of steam and or electricity for process use.

Q. *What is the difference between an industrial plant boiler and a central station steam generator in the light of service demanded from them?*

Ans. The primary production equipment of a utility plant is the monobloc unit, i.e. boiler and turboalternator taken as a whole. Whereas in the case of an industrial plant the chief equipment are those which are directly involved in the process for the manufacture of end products.

The basic service required from a utility plant is the efficient manufacture of kilowatts whereas in the case of an industrial plant boiler, the sole aim is the production of end product.

The industrial plant works under more unfavourable conditions of load, water and fuel than the central power station steam generator. The steam load in an industrial plant may be highly unpredictable, hunting continuously between high and low extremes.

Q. *What should be the prime considerations in designing an industrial boiler?*

Ans.

1. Dependability and operational reliability
2. Capital investment
3. Availability
4. Working efficiency
5. Cost of operation
6. Serviceability

Q. *What is the economic justification for a large amount of money being invested to instal a public utility central station steam generator?*

Ans. These set-ups are made purely on the basis of the total cost of electricity production. Though the initial capital investment is very high, the cost per unit output of electricity is very low and that justifies the expenditure of large sums when the plant runs at maximum efficiency with assured lowest unit cost.

Q. *What load characteristics are necessary in the design of a steam generator?*

Ans. The boiler must be so designed as to run at high efficiency under normal load and at the same time should be capable of meeting maximum demand as well as fluctuating load characteristics. Hence the boiler designer should essentially consider the following load characteristics:

1. Maximum load, normal load and minimum load
2. Load factor
3. Nature of load—constant or fluctuating
4. Duration time of each load rate.

Q. *Why do fuel characteristics play an important role in boiler design?*

Ans. From these very characteristics, a boiler designer gets the knowledge of the heat value available from the fuel as well as its such specific properties such as:

(a) ash content and the per cent of volatile matter
(b) nature of ash and its fusion point
(c) unburnt fuel losses as carbon is lost to ash or escapes through flue gases
(d) the presence of such corrosive agents as sulphur and vanadium that will dictate the flue gas exit temperature as well as the material of construction of the heating surfaces of the boiler to avoid the problem of corrosion and slagging.

It is these characteristics that control the fuel burning mechanism in a boiler, which in turn influences the boiler design.

Q. *How does the mode of fuel burning exert an influence upon boiler design?*

Ans. It is the capacity of the fuel burning device that controls the rate of fuel input which in

turn determines the furnace volume and its design specifications.

The design of pulverized coal fired boilers is certainly not the same as stoker or grate fired boilers.

Be it oil fired burners—vapourizing, rotary, gun or steam (or air) atomizing—or gas fired burners, each type dictates its own design peculiarities on the design of the boiler furnace. As the furnace design undergoes a change, so does the layout of the heat absorbing surface of the boiler.

However, it can be safely concluded that the type of fuel burning equipment and the method of firing exercise much greater influence on furnace design than on boiler design.

Q. *How do the gas flow characteristics influence boiler design?*

Ans. The gas flow through the boiler is effected by the differential pressure between the combustion products in the furnace core and the flue gases at the boiler exit. This pressure difference, called draught (draft) may be effected by natural means or by mechanical means to supply the necessary primary and secondary air to sustain and control fuel combustion.

Depending upon whether this draught is produced naturally (by chimney effect) or by mechanical means (by installing induced draught fans, forced draught fans or both), the boiler design is altered accordingly. The quantity of excess air supplied in the form of secondary air influences the boiler capacity as well as furnace temperature.

If the firing rates are high, the draught requirements will be considerably very large and accordingly, the size of the ID and FD fans becomes proportionately much bigger and that increases the size of the boiler unit.

Again, higher boiler efficiency needs combustion air to be preheated and therefore, an air preheater is to be installed almost invariably in the convective shaft of the boiler furnace. And that means a further draft loss which must be taken into account in the overall design of the steam generator.

Q. *In what way does feedwater quality affect boiler design?*

Ans. The presence of dissolved solids and gases, suspended matter and organic contaminants in feedwater cause corrosion, scaling, priming and foaming that effectively impair the performance of a boiler. These undesirable ingredients must be eliminated as much as possible before the feedwater is charged to the boiler. Quality requirements become more stringent with the increase of pressure and temperature of generated steam.

Feedwater quality, together with other factors, influences the design of drum internals, steam separator and steam washer, etc.

Q. *Why is the furnace one of the elements of consideration in boiler design?*

Ans. The furnace volume must be sufficient to maintain the necessary heat release rate and furnace temperature while the combustion space should be sufficient to contain the flame so that it does not directly hit the waterwalls.

The rate of steam generation and the temperature and pressure of output steam dictate the furnace temperature and the heat release rate which in turn govern the size and shape of the furnace, nature and materials of construction of furnace wall and disposition of heat-absorbing surface in the radiant and convective shafts of the furnace.

Q. *Why is furnace bottom design an important part of boiler design?*

Ans. It becomes an essential consideration during designing coal fired boilers. They may be pulverized coal fired or stoker or grate fired. In each case, the removal of ash and slag poses a problem. For pulverized coal firing, the furnace bottom must be cone shaped to drop out all molten slag to be carried off mechanically, pneumatically or by water. In the case of stoker fired boilers, high pressure water jets are directed upon

the ash and molten slag as they spill over the chain at the furnace bottom. The lack of proper furnace design for adequate ash removal may result in excessive slagging of waterwalls impairing the heat transfer characteristics and performance of the boiler.

Q. *What factors control the design of the boiler proper?*

Ans.

1. **The Operating Pressure and Temperature**
2. **The Quality of Steam**—Whether the steam required should be wet, dry or superheated. If wet steam is required, the designer may do away with the separator and superheaters. If 99.5% dry steam is needed, the designer must opt for suitable steam separator. The incorporation of a superheater or reheater becomes obvious of superheated steam or steam reheating is required downstream, e.g in the turboalternator.
3. **Layout of Heating Surface**—The prime aim of the boiler designer is to obtain the best disposal of heat-absorbing surface within the limitations of space as dictated by the furnace and other components.
4. **Heating Surface Requirements**—These depend upon the duty of the element heat exchangers such as primary evaporators, secondary evaporators, superheaters—radiant and convective, reheater, economizer and air preheater.
5. **Circulation of Steam and Water**—natural or forced
6. **Provision for continuous blowdown**
7. **The Capacity of Boiler Drum**
8. **Materials and methods of construction.**

Q. *Why are boiler operation and maintenance considered essential elements in boiler design?*

Ans. The life of a boiler is extended with good, trouble-free operation and adequate maintenance and cleaning.

The designer must make allowance for efficient removal of

(a) soot, slag and ash deposited on the fireside of heating surfaces
(b) scale, sludge and silt settled on the waterside of heating surfaces.

Accessibility for operation, maintenance and repairing must be easy and quick to ensure higher operating efficiency and offset the long outage time.

Adequate provision must be made for

(a) soot blowing
(b) tube cleaning—chemically and or mechanically
(c) washing economizer and air preheater surfaces.

Automation should be injected wherever it leads to higher reliability and greater ease in boiler operation.

Q. *What factors are involved in determining the overall capital investment in designing a boiler?*

Ans.

1. Cost of equipment
2. Cost of fuel
3. Cost of labour and materials for operation, maintenance and repairing
4. Cost of the auxiliaries, e.g. cost of running pumps, fans, ash disposal systems, etc.
5. Expected life of the equipment

Q. *What is the most important limitation on the steam generation capacity of a boiler?*

Ans. It is the rate of fuel combustion in the furnace.

Q. *Why?*

Ans. The rate of fuel burning is limited by the firing equipment and the furnace volume. As soon as the highest efficient combustion rate for any particular fuel is established, the only method of increasing the steaming capacity of a boiler is to

burn more fuel or to change the fuel burning mechanisms for more efficient use of the fuel burnt.

Q. *What other factors impose limitations on the steaming capacity of a boiler?*

Ans. Limitations are imposed by impaired heat transfer characteristics due to

(a) deposition of scale, precipitates and sludge on the waterside of the heat-absorbing surfaces
(b) corrosion erosion, caustic embrittlement, slagging, etc. on the fireside of the heat-absorbing surfaces.

Also, the boiler design itself, the design pressure and temperature, materials of construction and construction methods impose limitations on the steaming capacity of a boiler.

Q. *What factors determine the efficiency of a steam generating unit?*

Ans.

1. Boiler design characteristics
2. The type of fuel and fuel burning device
3. Operating parameters.

Q. *Can a steam generating unit run with maximum efficiency at a load below the rated capacity?*

Ans. Yes.

Q. *What factors affect the maximum efficiency of a steam generator?*

Ans.

1. Derated capacity utilization
2. Loss of combustibles to flue gases, ash and slag
3. Higher excess air supplied
4. High flue gas exit temperature
5. Lack of proper maintenance

Q. *While investigating fuel characteristics, the type of fuel burning equipment and the method of firing, during a boiler design, what is the other factor pertinent to fuel combustion that a boiler designer should basically consider?*

Ans. It is the flame characteristics of the fuel to be burned in the boiler furnace.

Q. *What is that?*

Ans. A flame appears only when fuel molecules in contact with oxidizer molecules (O_2) are raised to the activation energy so that the chemical reactions between the fuel and the oxidizer take place.

Combustion forms a flame in which the reactions of combustion of fuel constituents take place and evolution of heat occurs. As in modern steam generation unit, the combustion of solid, liquid or gaseous fuels is done by the flame-method, i.e. the fuel and air are supplied into the furnace space in the form of turbulent jets which gradually intermix and the flame assumes a definite length and shape which can be conveniently controlled.

The light and heat given off by the flame as well as its length and shape constitute the flame characteristics.

Q. *How do the flame characteristics influence a boiler design?*

Ans. The luminosity of a flame appears due to the presence of solid particles (coke or foreign matter) heated to incandescense by the burning gas. Non-luminous flames are much hotter than luminous flames.

Anthracite coal—pulverized or lump—burns with a transparent or barely visible flame. A boiler designer must limit the heat-absorbing surface to which heat may radiate in the furnace proper so that the furnace temperature does not drop below the ignition point of anthracite.

There is a marked difference between the flames produced by various fuels. Semi-anthracite burns with a short, clear flame; bituminous with a long, luminous flame and sub-bituminous and lignite burn with a long, yellow flame.

Luminosity of oil flames being high, combustion of oil contribute to more radiant heat transfer than convection. As such a boiler designer should lay more emphasis on radiant heat trans-

fer and the design of radiant heat absorbing waterwall tubes in the oil-fired furnace core.

As the gaseous fuels are burnt, the major portion of the heat transfer takes place by way of convection after the combustion products leave the furnace proper. Since the radiation heat transfer is at a minimum, greater emphasis is laid on designing and on the best possible disposal of convective heat transfer surfaces (superheaters, economizers and air heaters) than on water-cooled furnace walls.

Q. *Draw the contour lines of temperature at various depths of the furnace for a down fired radiant boiler.*

Ans. Fig. 38.1

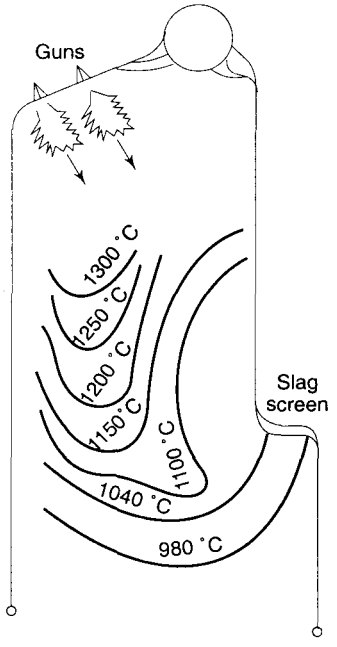


Fig. 38.1 *Isothermal contour lines at various depths of the furnace.*

Q. *How do the heat transfer characteristics affect boiler design?*

Ans. All the three modes of heat transfer—radiation, convection and conduction—enter into the equation, either alone or in combination during theoretical calculations of waterwalls, superheaters, economizers and air heaters.

Radiation heat transfer is prevalent in the core (hottest part) of the furnace and the transfer of radiant energy to the boiler tubes is dependent on the luminosity of the flame and the amount of the heat absorbing surface exposed to the flame.

The rate of radiant heat absorbed by the waterwall is

$$q_{rad} = \varepsilon\, AF\, \sigma\, [(T_1)^4 - (T_2)^4]$$

$$= 5.67\, (\varepsilon)\, AF \left[\left(\frac{T_1}{100}\right)^4 - \left(\frac{T_2}{100}\right)^4\right], W$$

where ε = emissivity of the flame

A = area of cross-section of radiant heat absorbing surface, m^2

F = view-factor

σ = Stefan-Boltzmann constant = 5.67×10^{-8} $W/m^2\ K^4$

T_1 = absolute temperature of flame, °K

T_2 = absolute temperature of radiant heat-absorbing surface, °K

The coefficient of radiative heat transfer is given by

$$h_{rad} = \frac{q_{rad}}{A\Delta\theta} = \frac{5.67\, \varepsilon \cdot F \left[\left(\frac{T_1}{100}\right)^4 - \left(\frac{T_2}{100}\right)^4\right]}{\Delta\theta}$$

Radiative Resistance

$$R_{rad} = \frac{1}{h_{rad} A}$$

$$= \frac{\Delta\theta}{5.67\, \varepsilon \cdot F \cdot A} \left[\left(\frac{T_1}{100}\right)^4 - \left(\frac{T_2}{100}\right)^4\right]$$

°K/W.

Heat transfer in the second vertical shaft and the horizontal duct of the furnace takes place entirely by convection. The rate of the heat transfer from hot flue gases to the heat-absorbing surfaces laid out in this zone is given by

$q_{conv} = h_{conv} A\Delta\theta$, W

where, h_{conv} = coefficient of convective heat transfer, W/m^2 °K

A = area of heat-absorbing surface, m^2

$\Delta\theta$ = temperature difference between hot gaseous products of combustion and tube walls, °K

Convective resistance

$$R_{conv} = \frac{1}{h_{conv} A}, \text{ °K/W}$$

Either natural convection (caused mainly by density differences due to temperature differentials) or forced convection (caused by mechanical force applied to induce motion to the flue gases) is involved and the overall heat transfer coefficient and design of convective heat absorbing elements in the furnace undergo changes accordingly. Heat transfer by the mode of conduction takes place through the wall thickness of the tubes as well as across the scale or depositions on both the inside and upside of the tube surface. The rate of conductive heat transfer through a wall is given by

$$q_{cond} = k A \frac{\Delta\theta}{\Delta x}$$

For a composite wall,

$$q_{cond} = k_1 A \left[\frac{\Delta\theta}{\Delta x}\right]_1 + k_2 A \left[\frac{\Delta\theta}{\Delta x}\right]_2 + k_3 A \left[\frac{\Delta\theta}{\Delta x}\right]_3$$

and conductive resistance

$$R_{cond} = \frac{1}{A} \Sigma \frac{\Delta x}{k}$$

where, k_1 = thermal conductivity of the scale, W/m °K

k_2 = thermal conductivity of the tube wall, W/m °K

k_3 = thermal conductivity of slag deposition, W/m °K

$\left[\frac{\Delta\theta}{\Delta x}\right]_1$ = temperature gradient across the scale, °K/m

$\left[\frac{\Delta\theta}{\Delta x}\right]_2$ = temperature gradient across the tube wall, °K/m

$\left[\frac{\Delta\theta}{\Delta x}\right]_3$ = temperature gradient across the slag, °K/m

If all the three processes of heat transfer take place simultaneously then overall resistance to the heat flow

$$R = R_{rad} + R_{conv} + R_{cond}$$

Therefore, heat flowrate, $q = \frac{\Delta\theta}{\Sigma R} = UA\,\Delta\theta$

where, U is called overall heat transfer coefficient

A boiler designer must consider the internal and external fouling factors while designing the superheaters, waterwalls, economizers, etc.

Therefore, the overall heat transfer coefficient becomes

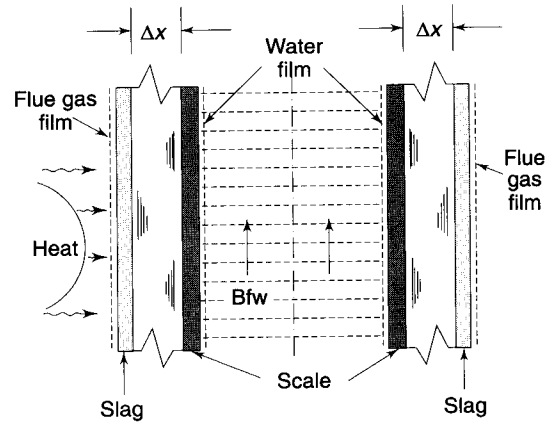


Fig. 38.2

$$U = \frac{1}{\frac{1}{h_o} + \left[\frac{\Delta x}{k} + \frac{1}{h_{s_i}} + \frac{1}{h_{s_o}}\right] + \frac{1}{h_i}} \text{ W/m}^2 \text{ °K}$$

where h_o = coefficient of heat transfer across the flue gas film on the tube surface, W/m^2 °K

h_i = coefficient of heat transfer across the water or air or steam film on the inner surface of the tubes, W/m^2 K

k = thermal conductivity of tube wall, W/m °K

Δx = thickness of tube wall, m

h_{s_i} = coefficient of heat transfer of the scale inside the tube, W/m^2 °K

h_{s_o} = coefficient of heat transfer of the slag outside the tube, W/m^2 °K

Now, if the mode of heat transfer across the hot flue gas film on the outer surface of the tube is both radiative and convective type then the rate of heat transfer (Fig. 38.3)

$$q = q_{\text{rad}} + q_{\text{conv}} = (K_r + K_{cv})\,\Delta\theta$$

where K_r = radiative conductance of hot gas film

$$= \sigma A \varepsilon F (T_1^4 - T_2^4)/\Delta\theta$$

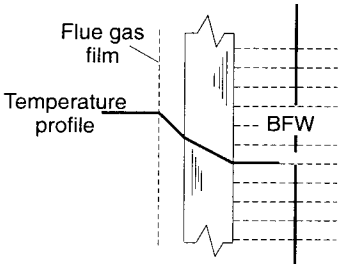


Fig. 38.3

K_{cv} = convective conductance of hot gas film

$$= (h_{cv})_o A$$

$$\therefore\ h_o = \sigma \varepsilon F [(T_1^4 - T_2^4)/\Delta\theta] + (h_{cv})_o$$

Determination of View Factor

Problem 38.1 Two rows of waterwell tubes cover the walls of a boiler furnace. The tubes have outer dia = 100 mm and these are arranged in in-line arrangement with two rows on equal pitch (in the plane parallel to the wall).

Pitch = 500 mm

Determine the mean view factor between the surface of the furnace wall and the waterwall tubes.

Solution

The required view factor can be determined with the help of the formula:

$$F = 1 - \sqrt{1 - (d/p)^2} + (d/p) \arctan \sqrt{(p/d)^2 - 1}$$

where d = tube dia (OD)

p = tube pitch

$$F = 1 - \sqrt{1 - (100/500)^2} + (100/500) \arctan \sqrt{(500/100)^2 - 1}$$

$$= 0.29$$

Ans.

Determination of Coefficient of Heat Transfer by Radiation

Problem 38.2 It is desired to calculate the coefficient of heat transfer by radiation in a superheater placed in the path of a flue gas so that the flue gas temperature at the inlet to and exit from the superheater are 1470°K and 1080°K respectively.

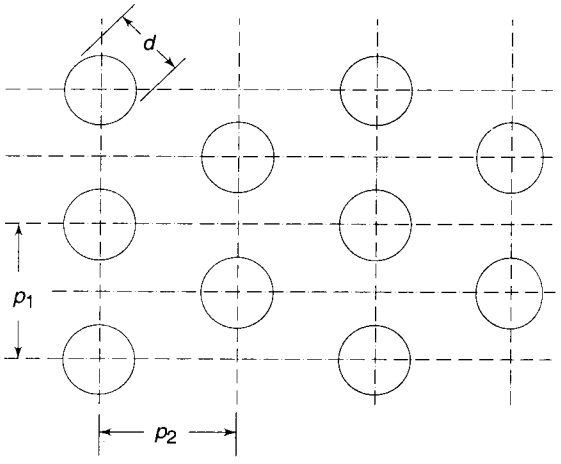


Fig. 38.4

The superheater tubes are staggered in layout as shown with tube pitches:

$$p_1 = p_2 = 2d = 2 \times 40 \text{ mm} \quad \text{(Fig. 38.4)}$$

Average temperature of the heat transfer surface may be assumed to be constant and equal to 870°K.

Flue gas analysis: CO_2 – 12%; H_2O —4.5%

Flue gas pressure = 112.815 kPa (112.815 kN/m^2)

Emissivity of tube surface = 0.8

Solution

Step (I) Average Temperature of Flue Gas

$$T = \frac{1}{2}(1470 + 1080) = 1275\ °K$$

Step (II) Emissivities of CO_2 and H_2O of the Flue Gas

The emissivities of CO_2 and H_2O of flue gas at this average temperature are determined with the help of emissivity curves of CO_2 and H_2O [Lp_{CO_2} vs. temp. and Lp_{H_2O} vs. temp.]

where p = partial pressure of the corresponding gas

L = mean path of a ray in the intertubular space

$$= 1.08d[(p_1\ p_2/d^2) - 0.785]$$

$$= 1.08(0.04)\ [2 \times 2 - 0.785] = 0.1388\ \text{m}$$

$$Lp_{CO_2} = 0.12(112.815 \times 10^3)\ (0.1388)\ \text{m.Pa}$$

$$= \frac{0.12\left(112.815 \times 10^3\right)(0.1388)}{0.981 \times 10^5}\ \text{m atm.}$$

(cf. 1 atm = 0.981×10^5 Pa)

$$= 0.0191\ \text{m atm.} = 1.91\ \text{cm atm.}$$

$$Lp_{H_2O} = 0.045(112.815 \times 10^3)\ (0.1388)\ \text{m Pa}$$

$$= 0.045\ (112.815 \times 10^3)\ \frac{(0.1388)}{0.981 \times 10^5}$$

$$= 0.00718\ \text{m atm.}$$

$$= 0.718\ \text{cm atm.}$$

From Emissivity Curves

For, Lp_{CO_2} = 1.91 cm atm and at temp. 1275°K

$\varepsilon_{CO_2} = 0.059$

Lp_{H_2O} = 0.718 cm atm and at temp. 1275°K

$\varepsilon_{H_2O} = 0.0107$

Step (III) Average Emissivity of Flue Gas

Therefore, the emissivity of the flue gas at mean temperature:

$$\varepsilon = \varepsilon_{CO_2} + \beta\ \varepsilon_{H_2O}$$

$$= 0.059 + \beta\ (0.0107)$$

where β = correction factor.

From β vs. p_{H_2O} curves we determine for Lp_{H_2O} = 0.718 cm atm.

β = 1.04 corresponding to p_{H_2O} = 0.05175 atm.

$$p_{H_2O} = 0.045\ \frac{112.815 \times 10^3}{0.981 \times 10^5}\ \text{atm.}$$

$$= 0.05175\ \text{atm.}$$

$$\therefore\ \varepsilon = 0.059 + 1.04(0.0107) = 0.0701$$

Step (IV) Average Absorptivity of the Flue Gas

This can be determined from the equation:

$$\alpha = \varepsilon_{CO_2}\left[\frac{T}{T_W}\right]^{0.65} + \beta\ \varepsilon_{H_2O}$$

where α = mean absorptivity of the flue gas

T = average temperature of the flue gas, °K

T_W = absolute temperature of the furnace wall, °K

At the tube surface temperature:

$$\varepsilon_{CO_2} = 0.057\ ;\ \varepsilon_{H_2O} = 0.025$$

Therefore, the mean absorptivity of flue gas at the tube surface temperature

$$\alpha = 0.057\left(\frac{1257}{870}\right)^{0.65} + 1.04(0.025)$$

$$= 0.0990$$

Step (V) Rate of Radiative Heat Transfer

The rate of heat transfer, by radiation, from the hot flue gas to the superheater is given by

$$q_{rad} = \frac{1}{2}\,[\varepsilon_w + 1]\ (5.67)$$

$$\left[\varepsilon\left(\frac{T}{100}\right)^4 - \alpha\left(\frac{T_W}{100}\right)^4\right],\ \text{W/m}^2$$

$$= \frac{1}{2}\ (0.8 + 1)\ (5.67)$$

$$\left[0.0701\left(\frac{1275}{100}\right)^4 - 0.099\left(\frac{870}{100}\right)^4\right]\ \text{W/m}^2$$

$$= 6559.057\ \text{W/m}^2$$

Step (VI) Coefficient of Heat Transfer by Radiation

The coefficient of heat transfer by radiation

$$h_{rad} = \frac{q_{rad}}{\Delta\theta} = \frac{6559}{1275 - 870}$$

$$= 16.19\ \text{W/m}^2\ °K$$

Determination of the Coefficient of Heat Transfer by Convection

Problem 38.3 A waterwall, constructed as a staggered bank of tubes, is exposed to the cross-flow of flue gases of the following composition:

N_2—76%; CO_2—13%; H_2O—11% (by volume)

The gas temperature before the bank of tubes is 1 470 °*K* and after the bank of tubes is 1 100 °*K*.

The tube bank is built-up of 4-rows of identical tubes in the direction of the gas flow. (Fig. 38.5)

The transverse pitch, $p_1 = 2.5\ d$

The longitudinal pitch, $p_2 = 2\ d$

The tube diameter, $d = 100$ mm

The average velocity of flue gas in the narrowest cross-section of the bank of tubes $v = 12.5$ m/s.

Ignore the fouling factor.

The mean coefficient of heat transfer by convection from the flue gas to the bank of staggered boiler tubes is to be determined.

Solution The convective heat transfer coefficient from the flue gas to the boiler tubes (clean) disposed in staggered arrangement can be determined by the formula:

$$\text{Nu}_f = 0.41(\text{Re}_f)^{0.6}\ (\text{Pr}_f)^{0.33}\ \phi_s \qquad \text{(I)}$$

Step (I) **The Average Temperature of the Flue Gas**

$$T = \frac{1}{2}\ (1470 + 1100) = 1285°K$$

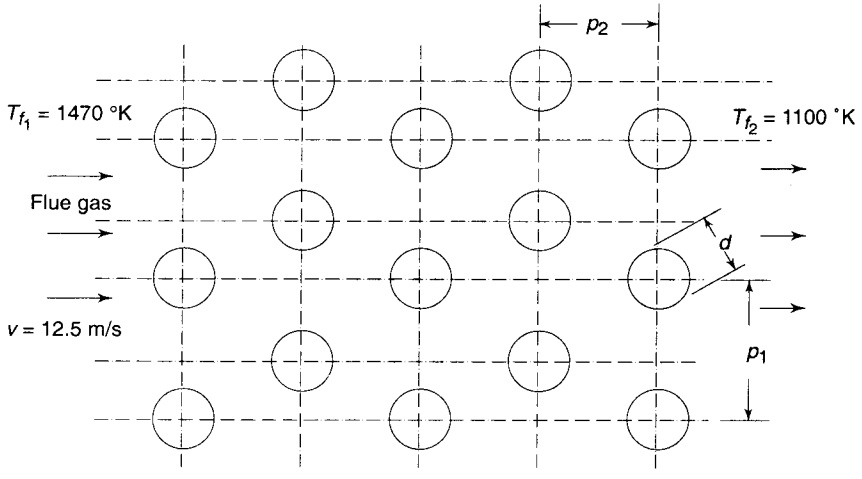


Fig. 38.5

Step (II) Flue Gas Perimeters

At this average temperature the flue gas of the said composition has the following physicochemical properties:

$k = 12.65 \times 10^{-2}$ W/m °K

$\nu = 221 \times 10^{-6}$ m^2/s

$Pr = 0.56$

$\mu = 53 \times 10^{-6}$ Pa.s

$C_p = 1.341$ kJ/kg °K

Step (III) Determination of Reynolds Number

$$\text{Re}_f = d\, v/\nu_f = (100 \times 10^{-3}) \frac{(12.5)}{221 \times 10^{-6}}$$

$$= 5656$$

Since Re_f lies within $(10^3 - 10^5)$, we can apply the formula (I) as stated above.

Step (IV) Nusselt No. at Reference Temperature

Re_f	Pr_f	p_1/p_2	$\phi_s = (p_1/p_2)^{1/6}$*	Nu_f
5656	0.56	2.5/2 = 1.25	$(1.25)^{1/6}$ = 1.0378	$0.41(5656)^{0.6}(0.56)^{0.33}$ (1.0378) = 62.70
			* $p_1/p_2 < 2$	

Step (V) Heat Transfer Coefficient

The heat transfer coefficient referred to the 3rd row of tubes

$$h_3 = Nu_f\, k_f/d = \frac{62.7\left(12.65 \times 10^{-2}\right)}{100 \times 10^{-3}}$$

$$= 79.31 \text{ W/m}^2 \text{ °K}$$

Step (VI) Mean Heat Transfer Coefficient

$$h = \frac{1}{4} \sum_{x=1}^{x=4} h_x = \frac{1}{4} (h_1 + h_2 + h_3 + h_4)$$

$$= \frac{1}{4} (0.6h_3 + 0.7h_3 + 2h_3)$$

where h_1 = heat transfer coefficient for the first row of the tube banks

$= 0.6h_3$

h_2 = heat transfer coefficient for the second row of staggered bank of tubes

$= 0.7h_3$

$h_3 = h_4$

$$h = \frac{1}{4} (3.3h_3) = \frac{1}{4} (3.3)\ (79.31) \text{ W/m}^2\text{°K}$$

$$= 65.43 \text{ W/m}^2\text{°K}$$

Ans.

Design of Double-pass Air Preheater

Problem 38.4 A double-pass air heater is to be designed for a steam generator. It must be capable of handling air at the rate of 90 t/h.

Air is to be heated from 30°C to 274°C.

The flue gas and air are in cross-flow—the flue gas moving through tubes at the rate 72 t/h with a mean velocity 17 m/s and air moves in the shell-side of the tubes with a mean velocity 10 m/s in the narrow cross-section of the tube bank.

ID/OD of the tubes = 50/55 mm

Thermal conductivity of the tube material = 47 W/m°C

The tubes are in staggered arrangement with $p_1 = p_2 = 1.25\ d_2$

Flue gas temperature inlet to air heater = 387°C

The following parameters are to be determined:

1. total heat transfer surface required
2. the height of tubes in one pass
3. the number of tubes to be arranged across the flow of air
4. the number of tubes along the flow of air.

The flue gas composition being: CO_2—13%; H_2O—11%

Solution

Step (I) Average Temperature of Air

The average temperature of air in the air heater

$$\theta_a = \frac{1}{2} (30 + 274) = 152°\text{C}$$

Step (II) Physichochemical Properties of Air

At this average temp. (152°C), air has the following physicochemical properties:

$k = 3.58 \times 10^{-2}$ W/m°C

$\nu = 29.174 \times 10^{-6}$ m²/s

$Pr = 0.6792$

$\mu = 24.18 \times 10^{-6}$ Pa.s

$C_p = 1.0154$ kJ/kg °C

$\rho = 0.830$ kg/m³

Step (III) Heat Load

The amount of heat transferred from the hot flue gas to the air stream

$$Q = \dot{M}_a\, C_p\, (\Delta\theta)_a$$

$$= \left(\frac{90 \times 1000}{3600}\right) (1.0154)\ (274 - 30)$$

$$= 6193.94 \text{ kW}$$

where, $\dot{M}_a$ = mass flowrate of air

$[C_p]_a$ = specific heat of air at mean temperature

$(\Delta\theta)_a$ = temperature difference between the air at inlet and outlet

Step (IV) Flue Gas Temp at Air Heater Outlet

This is done through a trial and error method.

Let as the case of first approximation, the mean flue gas temperature in the air heater = 317°C

$[C_p]_{fg} = 1.128$ kJ/kg °C at 317°C

Therefore, flue gas temperature at the air heater outlet

$$[\theta_{fg}]_2 = [\theta_{fg}]_1 - \frac{Q}{\dot{M}_{fg}\ [C_p]_{fg}}$$

$$= 387 - \frac{6193.94}{\left[\frac{72 \times 1000}{3600}\right](1.128)}$$

$$= 112.45°\text{C}$$

$[\theta_{fg}]_1$ = flue gas temperature at inlet to air heater

$\dot{M}_{fg}$ = mass flowrate of flue gas.

Accordingly, average temperature of flue gas in air heater comes out to be

$$\theta_{fg} = \frac{1}{2}\ (387 + 112.45) = 249.72°\text{C}$$

This figure does not tally with our figure (317°C) assumed.

So as the case of 2nd approximation, let the mean flue gas temperature in the air heater = 250°C. At this temperature:

$[C_p]_{fg} = 1.109$ kJ/kg °C

$$\therefore\ [\theta_{fg}]_2 = 387 - \frac{6193.94}{72 \times \frac{1000}{3600} \times 1.109} = 108°\text{C}$$

and therefore, $\theta_{fg} = \frac{1}{2}\ (387 + 108) = 247.5°\text{C}$

This time the calculated value of θ_{fg} is in close agreement with the assumed value 250°C.

So, $\theta_{fg} = 247°\text{C}$

Step (V) Reynolds No. for Flue Gas at Mean Temperature

Flue Gas 247°C

$\rho_{fg} = 0.6864$ kg/m³

$[C_p]_{fg} = 1.108$ kJ/kg °C

$k_{fg} = 4.40 \times 10^{-2}$ W/m °C

$Pr = 0.66$

$\nu_{fg} = 51.92 \times 10^{-6}$ m²/s

$$[Re]_{fg} = \frac{d_i\ v_{fg}}{\nu_{fg}}$$

$$= \frac{(50 \times 10^{-3})\,(17)}{51.92 \times 10^{-6}} = 16371$$

Step (VI) Reynolds No. for Air at Mean Temperature

$$\text{Re}_a = \frac{d_o\, v_a}{\nu_a} = \frac{(55\times10^{-3})\,(10)}{29.174\times10^{-6}} = 18852$$

Step (VII) Nusselt No. for Flue Gas

$$\text{Nu}_{fg} = 0.021\ (\text{Re}_{fg})^{0.8}\ (\text{Pr}_{fg})^{0.43}$$
$$= 0.021\ (16371)^{0.8}\ (0.66)^{0.43} = 41.122$$

Step (VIII) Nusselt No. for Air

For air in crossflow over a clean bank of tubes

$\text{Nu}_a = 0.41\ (\text{Re}_a)^{0.6}(\text{Pr}_a)^{0.33}\phi$, for staggered arrangement

$$\text{Since, } \frac{p_1}{p_2} = 1.25 < 2,\ \phi = (1.25)^{1/6} = 1.0378$$

$$\text{Nu}_a = 0.41\ (18852)^{0.6}(0.6792)^{0.33}\ (1.0378)$$
$$= 137.616$$

Step (IX) Heat Transfer Coefficient from Tube Walls to Air

$$h_{fg} = \text{Nu}_{fg}\left(\frac{k_{fg}}{d_i}\right) = \frac{41.122\ (4.40\times10^{-2})}{50\times10^{-3}}$$

$$= 36.187\ \text{W/m}^2\text{°C}$$

Step (X) Heat Transfer Coefficient from Tube Walls to Air

$$h_a = \text{Nu}_a\left(\frac{k_a}{d_o}\right) = \frac{137.616\left(3.58\times10^{-2}\right)}{55\times10^{-3}}$$

$$= 89.575\ \text{W/m}^2\ \text{°C}$$

Step (XI) Overall Heat Transfer Coefficient

$$U = \frac{1}{\frac{1}{h_{fg}} + \frac{\Delta x}{k_w} + \frac{1}{h_a}}$$

$$= \frac{1}{\frac{1}{36.187} + \frac{2.5\times10^{-3}}{47} + \frac{1}{89.575}}$$

$$= 25.739\ \text{W/m}^2\ \text{°C}$$

Step (XII) Log-Mean-Temperature-Difference

$[\theta_{fg}]_1 \longrightarrow [\theta_{fg}]_2$ (Fig. 33.6)

$$\frac{[\theta_a]_2 \longleftarrow [\theta_a]_1}{\left([\theta_{fg}]_1 - [\theta_a]_2\right)\quad\left([\theta_{fg}]_2 - [\theta_a]_1\right)}$$

$$\therefore \Delta\theta_{lm} = \frac{\left([\theta_{fg}]_1 - [\theta_a]_2\right) - \left([\theta_{fg}]_2 - [\theta_a]_1\right)}{\ln\left[\dfrac{[\theta_{fg}]_1 - [\theta_a]_2}{[\theta_{fg}]_2 - [\theta_a]_1}\right]}$$

$$= \frac{(387-274)-(108-30)}{\ln\left[\dfrac{387-274}{108-30}\right]} = 94.42\text{°C}$$

Step (XIII) Correction Factor

The correction factor (ε) for tubular 2-pass crossflow heat exchanger is determined from the chart depending on the values of the dimensionless parameters P and R where

$$P = \frac{[\theta_a]_2 - [\theta_a]_1}{[\theta_{fg}]_1 - [\theta_a]_1} = \frac{274-30}{387-30} = 0.683$$

$$R = \frac{[\theta_{fg}]_1 - [\theta_{fg}]_2}{[\theta_a]_2 - [\theta_a]_1} = \frac{387-108}{274-30} = 1.143$$

From the chart, corresponding to the value of $P = 0.683$ and $R = 1.14$ we get,

$\varepsilon \approx 0.85$

$\Delta\theta = \varepsilon\ \Delta\ \theta_{lm} = 0.85(94.42) = 80.257\text{°C}$

Step (XIV) Heating Surface of Air Heater

$$A = \frac{Q}{U\,\Delta\theta} = \frac{6193.94\times10^3}{(25.739)\,(80.257)}$$

$$= 2998\ \text{m}^2$$

Step (XV) Total Number of Tubes

$$n = \frac{\dot{M}_{fg}}{\frac{\pi}{4}\,d_i^2\,v_{fg}\rho_{fg}}$$

$$= \frac{(72\times1000/3600)}{\frac{\pi}{4}\left(50\times10^{-3}\right)^2(17)(0.6864)} = 872$$

Step (XVI) Height of Tubes in One Pass

$$L_1 = \frac{A}{2\pi d_1 n} = \frac{2998}{2(\pi)(50/10^3)(872)}$$

$$= 10.94 \text{ m}$$

Since tube-height becomes abnormally large, let us halve the tube-height and increase the number of tubes two-fold. Therefore,

total number of tubes = $2 \times 872 = 1744$

tube-height in one pass = $\frac{1}{2}(10.94) = 5.47$ m

Step (XVII) The Clear Passage for Air Flow

$$[A]_{\text{clear}} = \frac{\dot{M}_a}{v_a \rho_a} = \frac{(90 \times 1000/3600)}{10 \times 0.83}$$

$$= 3.01 \text{ m}^2$$

Step (XVIII) The Number of Tubes Arranged Across the Flow

$$n_1 = \frac{[A]_{\text{clear}}}{L_1 (p_1 - d_o)}$$

$$= \frac{3.01}{5.47 (1.25 \times 0.055 - 0.055)} = 40$$

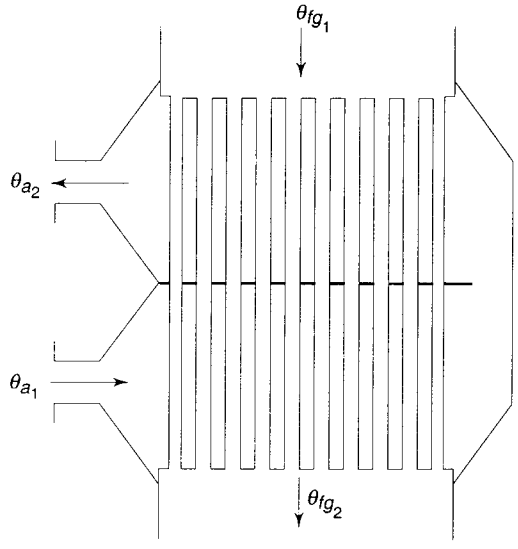


Fig. 38.6 *Air preheater.*

Step (XIX) Number of Tubes Exposed to Longitudinal Flow

$$n_2 = \frac{n}{n_1} = \frac{1744}{40} \approx 44$$

Loop Type Economizer Design

Problem 38.5 A loop type economizer is to be designed out of tubes disposed in a staggered arrangement to heat up the BFW from 140°C to 300°C.

Data Given:

1. **Steel Tube Specifications:**
   ID = 45 mm
   OD = 50 mm
   Thermal conductivity = 26 W/m°C
2. **Tube Layout:**
   Transverse pitch: Longitudinal pitch = 1.05
   Longitudinal pitch = Twice the mean dia of tubes
3. **Boiler Feedwater:**
   Flowrate = 200 t/h
   Mean velocity of flow = 0.75 m/s
   Mode of flow : vertical, from bottom to top
4. **Flue Gas:**
   Composition: CO_2—13%; H_2O—11%
   Mean velocity of flow in the narrowest cross-section of tube-banks = 15 m/s
   Flowrate = 480 t/h
   Temp. inlet to economizer = 800°C

Solution

Step (I) Mean Temp of BFW

$$\theta_w = \frac{\theta_{w_1} + \theta_{w_2}}{2} = \frac{140 + 300}{2} = 220°\text{C}$$

Step (II) Heat Transfer Rate of BFW

Water—220°C

$\rho = 840 \text{ kg/m}^3$

$C_p = 4.615 \text{ kJ/kg °C}$

$k = 64.5 \times 10^{-2} \text{ W/m °C}$

$\nu = 0.148 \times 10^{-6}$ m^2/s

Pr = 0.89

The rate of heat transferred to the BFW in the economizer

= Mass flowrate × Sp. heat × Rise in temperature

$$= \left(\frac{200 \times 10^3}{3600}\right)(4.615)(300 - 140)$$

= 41022 kW

Step (III) Reynolds Number for BFW at Mean Temperature

$$Re_1 = d_i \frac{v}{\nu} = \frac{(45 \times 10^{-3})(0.75)}{0.148 \times 10^{-6}} = 228040$$

Hence the flow is turbulent. Since the randtl number (0.89) is greater than 0.7, we will use the formula

$Nu_1 = 0.021\ Re_1^{0.8} Pr_1^{0.43} (Pr_f/Pr_w)^{0.25}$ to determine the Nusselt number. Since the wall temperature is close to the BFW temperature inside the economizer, $\left(Pr_f/Pr_w\right)_{outlet}^{0.25} \approx 1$

and the foregoing equation simplifies to

$$Nu_1 = 0.021\ Re_1^{0.8}\ Pr_1^{0.43}$$
$$= 0.021\ (228040)^{0.8}\ (0.89)^{0.43} = 386$$

Step (IV) Local Heat Transfer Coefficient for BFW

$$h_1 = \frac{Nu_1 k_1}{d_i} = \frac{386\,(64.5 \times 10^{-2})}{45 \times 10^{-3}}$$

$= 5532.67$ W/m^2 °C

Step (V) Flue Gas Temperature at Economizer Outlet

This is to be determined by trial and error method.

1st Trial Let mean heat capacity of flue gas

$C_{p_g} = 1.27$ kJ/kg °C

$$Q = \dot{M}_g\, C_{p_g}\, (\theta_{g_1} - \theta_{g_2})$$

or, $$41022 = \frac{480 \times 10^3}{3600}(1.27)(800 - \theta_{g_2});$$

$$\therefore \quad \theta_{g_2} \approx 558°C$$

Therefore, mean temperature of flue gas

$$\theta_g = \frac{1}{2}(\theta_{g1} + \theta_{g2}) = \frac{1}{2}(800 + 558) = 679°C$$

At this temperature, the value of heat capacity of the flue gas

$C_{p_g} = 1.234$ kJ/kg °C

2nd trial Let $C_{p_g} = 1.234$ kJ/kg °C

$$\therefore\ 41022 = \left(\frac{480 \times 10^3}{3600}\right)(1.234)(800 - \theta_{g_2});$$

$$\therefore\ \theta_{g_2} \approx 551°C$$

Therefore, mean temperature of flue gas

$$\theta_g = \frac{1}{2}(551 + 800) = 675.5°C$$

At this temperature, the value of heat capacity of flue gas

$C_{p_g} = 1.233$ kJ/kg °C which closely tallies with the assumed value.

Hence the mean temperature of flue gas = 675.5°C

Step (VI) Reynolds No. for Flue Gas

Flue Gas – 675.5°C

$\rho = 0.373$ kg/m^3

$k = 8.06 \times 10^{-2}$ W/m. °C

$\nu = 107.57 \times 10^{-6}$ m^2/s

Pr = 0.612

$$Re_g = \frac{d_\theta v_g}{\nu_g} = \frac{(50 \times 10^{-3})(15)}{107.57 \times 10^{-6}} = 6972$$

Step (VII) Nusselt No. for Flue Gas

Since the economizer tubes are arranged in a staggered arrangement, Nusselt no.

$Nu_g = 0.41\ Re_g^{0.6}\ Pr_g^{0.33}\ \varepsilon$ (where ε = correction factor = 1.008 for $p_1/p_2 = 1.05$)

$= 0.41\ (6972)^{0.6}\ (0.612)^{0.33}\ (1.008)$

$= 71.10$

Step (VIII) Heat Transfer Coefficient for Flue Gas

$$h_2 = \frac{Nu_g\ k_g}{d_o} = \frac{(71.10)\,(8.06 \times 10^{-2})}{50 \times 10^{-3}}$$

$$= 114.61\ W/m^2\ °C$$

In practice, due to fouling, the effective heat transfer coefficient for flue gases is less than its theoretical value. Normally, it is assumed to be 80% of its calculated value.

$$h_2 = 114.61 \left(\frac{80}{100}\right) = 91.688\ W/m^2\ °C$$

Step (IX) Coefficient of Heat Transfer by Thermal Radiation

A considerable portion of heat is transferred by radiation from the hot flue gas to the walls of the tubes. The coefficient of this radiant heat transfer is determined as follows:

1. **Mean Beam Length**

$L = 1.08\ d_o\ (p_1 p_2 / d_o^2 - 0.785)$

$= 1.08(50 \times 10^{-3})\ [(1.05 \times 2\ d_o)\ (2\ d_o)/d_o^2 - 0.785]$

$= 0.1844$ m

2. **Product of Mean Beam Length and Partial Pressure**

$p_{CO_2}\ L = 0.13\ (0.1844) = 0.0239$ m. atm

$p_{H_2O} L = 0.11\ (0.1844) = 0.02028$ m. atm.

3. **Average Emissivity of Flue Gas at 675.5°C**

$\varepsilon_{CO_2} = 0.071;\ \varepsilon_{H_2O} = 0.047;\ \beta = 1.07$

$\varepsilon_g = \varepsilon_{CO_2} + \beta\varepsilon_{H_2O} = 0.071 + 1.07\ (0.047) = 0.1212$

4. **Average Absorptivity of Flue Gas**

The calculation shows $h_1 >> h_2$

Therefore, outer wall temperature of economizer tubes can be assumed to be Average Temp. of BFW + 30°C ≈ 220 + 30 = 250°C

Absorptivity of flue gas at the surface temperature of the tubes

$$\alpha_g = \varepsilon_{CO_2} \left[\frac{T_g}{T_{wall}}\right]^{0.65} + \beta \cdot \varepsilon_{H_2O}$$

$$= 0.063 \left[\frac{675.5 + 273}{250 + 273}\right]^{0.65} + 1.07\ (0.075)$$

$$= 0.1730$$

5. **Effective Emissivity of the Enclosure**

$$\varepsilon = \frac{1}{2}\ [\text{Emissivity of the tubewall} + 1]$$

$$= \frac{1}{2}\ (0.8 + 1) = 0.9$$

6. **Rate of Radiation Heat Transfer**

$$q_{rad} = \varepsilon\ (5.67) \left[\varepsilon_g \left(\frac{T_g}{100}\right)^4 - \alpha_g \left(\frac{T_{wall}}{100}\right)^4\right]$$

$$= 0.9(5.67) \left[0.1212 \left(\frac{675.5 + 273}{100}\right)^4\right.$$

$$\left. - 0.173 \left(\frac{250 + 273}{100}\right)^4\right],\ W/m^2$$

$$= 4345.34\ W/m^2$$

7. **The coefficient of Heat Transfer by Radiation**

$$h_{rad} = \frac{q_{rad}}{\theta_g - \theta_{wall}} = \frac{4345.34}{675.5 - 250}$$

$$= 10.21\ W/m^2\ °C$$

Step (X) Total Coefficient of Heat Transfer from Flue Gas

The total coefficient of heat transfer from flue gas to the tube walls

$$h_{tot} = h_2 + h_{rad} = 114.61 + 10.21$$

$$= 124.82 \text{ W/m}^2 \text{ °C}$$

Step (XI) Overall Heat Transfer Coefficient

$$U = \frac{1}{\frac{1}{h_1} + \left[\frac{\Delta x}{k}\right]_{\text{wall}} + \frac{1}{h_{\text{tot}}}}$$

$$= \frac{1}{\frac{1}{5532.67} + \frac{2.5 \times 10^{-3}}{26} + \frac{1}{123.92}}$$

Step (XII) Long-Mean-Temperature-Difference

$$800°\text{C} \xrightarrow{\text{flue gas}} 551°\text{C}$$

$$\underline{330°\text{C}} \xleftarrow[\text{BFW}]{} \underline{140°\text{C}}$$

$$\underline{\text{Diff. } 500°\text{C}} \qquad \underline{411°\text{C}}$$

Assuming the flue gas in counterflow with water,

$$\therefore \Delta\theta_{lm} = \frac{500 - 411}{\ln (500/411)} = 454°\text{C}$$

Step (XIII) Heating Surface of Economizer

$$A = \frac{Q}{U \Delta\theta_{lm}} = \frac{41022 \times 10^3}{(120)(454)}$$

$$= 752.973 \text{ m}^2 \approx 753 \text{ m}^2$$

Step (XIV) Number of Loops in Parallel

Let the number of parallel loops be n,

$$\left(\frac{\pi}{4} d_i^2 \, v_{\text{water}}\right) \rho_{H_2O} (n) = \left(\frac{200 \times 10^3}{3600}\right);$$

$$\text{or } \left(\frac{\pi}{4}\right) (45 \times 10^{-3})^2 (0.75)(840)(n)$$

$$= \frac{1}{18} \times 10^3$$

$$\therefore n = 55.44 \text{ i.e. } 56 \text{ number of loops}$$

Step (XV) Length of Individual Loop

$$(\pi d_o) \cdot n \cdot L = A$$

$$\text{or } \pi(50 \times 10^{-3})(56)L = 753; \therefore L = 85.60 \text{ m}$$

Design of Loop Type Superheater

Problem 38.6 A loop type of superheater of following duty:

Steam to be superheated = 250 t/h

Superheated steam pressure = 10 MN/m^2

Superheated steam temperature = 525°C

is to be designed so that flue gas is in crossflow with steam.

The superheater coils are to be designed from steel tubes of

$$\text{OD/ID} = 35/30 \text{ mm}$$

Thermal conductivity of the material of the tubes

$$= 25 \text{ W/m °C}$$

Average velocity of steam = 18 m/s

Velocity of flue gas in the narrow section of the bank of tubes = 15 m/s

The tubes are to be disposed in the mode of in-line arrangement with longitudinal and transverse pitch ratio 1.2 and transverse pitch = 2.5 × OD of the tubes.

Flue gas composition: CO_2—13%; H_2O—11%

Flue gas flowrate: 600 t/h

Flue gas inlet temp.: 1200°C

Solution

Step (I) Heat Load

	Saturation Temp. (θ_s)	Enthalpy at θ_s	Enthalpy at 525°C
SUPERHEATED STEAM, 10 MN/m^2	311°C	2725 kJ/kg	3437 kJ/kg
	← From steam tables →		

The rate of superheated steam generation = 250 t/h

Heat load of the superheater

$$= \frac{250 \times 10^3}{3600} (3437 - 2725) \text{ kW}$$

$= 49444.44$ kW

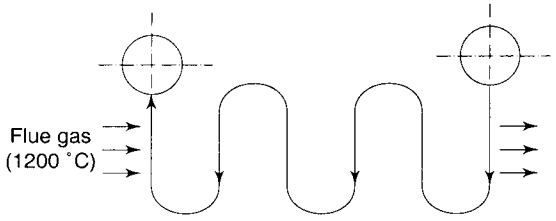


Fig. 38.7 *Loop type superheater*

Step II Steam Parameters

Average temperature of superheated steam

$$= \frac{1}{2}(311 + 525) = 418°C$$

SUPERHEATED STEAM
~~418°C, 10 MN/m²~~

$\rho = 37$ kg/m³
$k = 7.1 \times 10^{-2}$ W/m°C
$\nu = 0.703 \times 10^{-6}$ m²/s
Pr = 1.1

Step (III) Coefficient of Heat Transfer from Wall to Steam

1. **Reynolds Number for Steam**

$$\text{Re} = d_i \frac{v}{\nu} = \frac{(30 \times 10^{-3})(18)}{0.703 \times 10^{-6}} = 768136$$

2. **Nusselt Number for Steam**

$$\text{Nu} = 0.021\ \text{Re}^{0.8}\ \text{Pr}^{0.43}$$
$$= 0.021\ (768136)^{0.8}\ (1.1)^{0.43} = 1117.81$$

3. **Coefficient of Heat Transfer from Tubewall to Steam**

$$h_i = \text{Nu}\ k/d_i = (1117.81)\frac{(7.1 \times 10^{-2})}{30 \times 10^{-3}}$$

$$= 2645\ \text{W/m}^2\ °C$$

Step (IV) Flue Gas Temperature at Outlet

In order to determine the flue gas exit temperature, we must go through successive approximations.

1st Approximation: Let $C_{p_g} = 1.31$ kJ/kg°C for flue gas.

Exit temp. of flue gas, $[\theta_2]_g$

$$= [\theta_1]\ g - \frac{Q}{\dot{M}_g \times C_{p_g}}$$

$$[\theta_g]_2 = 1200 - \frac{49444.44}{\frac{600 \times 10^3}{3600} \times 1.31} = 974°C$$

Therefore, average temperature of flue gas

$$= (1/2)\ (1200 + 974) = 1087°C$$

At this average temperature, the specific heat of flue gas,

$$C_{p_g} = 1.303\ \text{kJ/kg.°C}$$

which is very close to our assumed value. So we need no further approximation and hence the flue gas temperature at superheater outlet = 974°C

Step (IV) Flue Gas Parameters at Average Temperature

FLUE GAS 1087°C

$\rho = 0.259$ kg/m³
$k = 11.64 \times 10^{-2}$ W/m°C
$\nu = 194 \times 10^{-6}$ m²/s
Pr = 0.571

Step (V) Heat Transfer Coefficient from Flue Gas to Superheater Tubewalls

1. **Reynolds No. for Flue Gas**

$$\text{Re} = d_o \left(\frac{v}{\nu}\right)_g = (35 \times 10^{-3}) \left(\frac{15}{194 \times 10^{-6}}\right)$$

$$= 2706$$

2. **Nusselt No. for Flue Gas**

$$\text{Nu} = 0.26\ \text{Re}^{0.65}\ \text{Pr}^{0.33}\ \varepsilon$$

where $\varepsilon = (d_o/p_2)^{0.15}$

p_1 = transverse pitch

p_2 = longitudinal pitch

Given $p_1 = 2.5(35 \times 10^{-3})$ m; $\frac{p_2}{p_1} = 1.2$

$\therefore\ p_2 = 1.2\ (2.5)\ (35 \times 10^{-3})\text{m} = 0.105$ m

$$\therefore \varepsilon = \left(\frac{35 \times 10^{-3}}{0.105}\right)^{0.15} = 0.848$$

$$\therefore \text{Nu}_g = 0.26\ (2706)^{0.65}\ (0.571)^{0.33}\ (0.848)$$

$$= 31.19$$

3. **Heat Transfer Coefficient**

$$h_g = \frac{(\text{Nu}\ k)_g}{d_o} = \frac{(31.19)\ (0.1164)}{35 \times 10^{-3}}$$

$$= 103.729 \approx 104\ \text{W/m}^2\text{°C}$$

This is for clean tubes laid in an in-line arrangement.

Fouling of heat transfer surface of tubes will reduce its value to some extent. So let's assume, the effective heat transfer coefficient is 80% of the heat transfer coefficient calculated for clean tubes.

$$h'_g = 104(0.8) = 83.2\ \text{W/m}^2\ \text{°C}$$

Step (VI) Heat Transfer Coefficient by Radiation

1. **Mean Beam Length**

$$L = 1.08 d_o \left[\left(\frac{p_1\, p_2}{d_o^2}\right) - 0.785\right]$$

$$= 1.08\ (0.035) \left[\frac{(2.5\, d_o)\ (1.2\, p_1)}{d_o^2} - 0.785\right]$$

$$= 0.0378 \left[\frac{(2.5\, d_o)\ (1.2 \times 2.5\, d_o)}{d_o^2} - 0.785\right]$$

$$= 0.2538\ \text{m}$$

Products of Mean Beam Length and Partial Pressure

$$Lp_{CO_2} = 0.2538\ (0.13) = 0.0329\ \text{m. atm.}$$

$$Lp_{H_2O} = 0.2538\ (0.11) = 0.0279\ \text{m. atm.}$$

2. **Emissivity of the Flue Gas at 1087°C**

$$\varepsilon_g = \varepsilon_{CO_2} + + \beta\, \varepsilon_{H_2O} = 0.065 + 1.08\ (0.038)$$

$$= 0.106$$

3. **Absorptivity of Flue Gas**

Let us assume that tubewall temperature is greater than the arithmetic mean temperature of steam by 40 to 42°C.

$$\therefore \Theta_w \approx 418 + 42 = 460\text{°C}$$

At this temperature $\varepsilon'_{CO_2} = 0.075$; $\beta = 1.06$;

$\varepsilon_{H_2O} = 0.07$

$$\alpha = \varepsilon_{CO_2} \left[\frac{T_g}{T_w}\right]^{0.65} + \beta \varepsilon_{H_2O}$$

$$= 0.075 \left[\frac{1087 + 273}{460 + 273}\right]^{0.65} + 1.06\ (0.07)$$

$$= 0.186$$

4. **Emissivity of the Enclosure**

The effective emissivity of the enclosure

$$\varepsilon = \frac{1}{2}(\varepsilon_w + 1) = \frac{1}{2}\ (0.8 + 1) = 0.9$$

5. **Heat Flowrate due to Thermal Radiation**

$$q_{rad} = \varepsilon(5.7) \left[\varepsilon_g \left(\frac{T_g}{100}\right)^4 - \alpha_g \left(\frac{T_w}{100}\right)^4\right]$$

$$= 0.9(5.7) \left[0.106 \left(\frac{1087 + 273}{100}\right)^4 - 0.186 \left(\frac{460 + 273}{100}\right)^4\right]$$

$$= 15848\ \text{W/m}^2$$

6. **The Coefficient of Heat Transfer by Radiation**

$$h_{rad} = \frac{q_{rad}}{\Theta_g - \Theta_w} = \frac{15848}{1087 - 460}$$

$$= 25.27\ \text{W/m}^2\ \text{°C}$$

7. **The Coefficient of Heat Transfer from Flue Gas to Tubewalls**

$$h_o = h'_g + h_{rad} = 83.2 + 25.27 = 108.47\ \text{W/m}^2\text{°C}$$

Step (VII) Overall Heat Transfer Coefficient

$$U = \frac{1}{\frac{1}{h_i} + \frac{\Delta x}{k} + \frac{1}{h_o}}$$

$$= \frac{1}{\frac{1}{2645} + \frac{2.5 \times 10^{-3}}{25} + \frac{1}{108.47}}$$

$$= 102.91 \approx 103 \text{ W/m}^2\,^\circ\text{C}$$

Step (VIII) Log-mean-Temp.-Difference

Assuming the flue gas and superheated steam to be in counterflow

FLUE GAS	1200°C ⟶ 974°C	$\therefore \Delta\theta_{lm} = \frac{675 - 663}{\ln(675/663)}$
525°C ⟵	311°C STEAM	= 668.98°C
Diff.	675°C 663°C	≈ 669°C

Step (IX) Check

Outside Surface Temperature of Tubes

$$\Theta_w = \Theta_g - (U\Delta\Theta/h_o) = 1087 - \left(\frac{103 \times 669}{108.47}\right)$$

$$= 452^\circ\text{C}$$

During calculation of radiation heat transfer we have assumed $\theta_w = 460^\circ$C (cf. Step VI.4). Thus we see that there is a close coincidence between the assumed and calculated temperatures of the tube wall (outer). Therefore, we need no further approximation for the tube wall temperature.

Step (X) Heating Surface of Superheater

$$Q = UA\,\Delta\Theta_{lm}$$

$$\therefore A = \frac{Q}{U\,\Delta\theta_{lm}}$$

$$A = \frac{49444.44 \times 10^3}{103 \times 669} = 717.55 \approx 718\text{m}^2$$

Ans.

Step (XI) Number of Loops

Let N be the number of loops

$$G_s = \left(\frac{\pi}{4} d_i^2\ N\right)(v_s)(\rho_s)$$

$$\text{or } \frac{250 \times 10^3}{3600} = \left(\frac{\pi}{4}\right)(30 \times 10^{-3})^2\,(N)\,(18)\,(37);$$

$$\therefore N \approx 148$$

Ans.

Step (XII) Length of Each LOOP

If L be the length of each loop,

$A = (\pi d_o L)N$

or $718 = \pi(35 \times 10^{-3})L(148)$

$\therefore L = 44.12$ m

Ans.

Q. *How does fluidizing velocity influence the design of the fluidized bed boiler?*

Ans. The fluidized bed boiler must operate at an optimum velocity which is a compromise between capital cost, boiler efficiency and fan power requirement.

If the design velocity is increased, it will yield higher carryover of unburnt carbon particles unless other parameters are adjusted to compensate. Excess air level can be hiked up to burn out the elutriated fuel particles, however this will increase stack gas heat loss.

Again to maintain combustion efficiency at constant excess air, the bed-depth and freeboard height must be increased. A deeper bed will accommodate the tubes in the smaller bed area but will extort more power from fan. Recycling of unburnt char particles to the bed for refiring can be incorporated to maintain efficiency but inert fines will come along to get refired and remove heat from the bed, reducing cost-saving due to high inbed heat transfer rate.

Also increasing the operating velocity adversely affects the efficiency of sulphur retention, necessitating the use of more limestone. There-

fore, design change is required to improve combustion efficiency and sulphur retention at higher velocities. The value of optimum velocity to the context of sulphur retention is dictated by the sulphur content of the fuel and the emission level to be met.

Again lowering of fluidizing velocity boosts up combustion efficiency, improves inbed heat transfer and permits the use of a shallower bed-depth (i.e. lower fan output requirement), but it requires a greater bed area with more feedpoints. And as a general rule it is more expensive to manufacture a short combustion chamber with a large cross-sectional area. Also, the air distributor is an expensive item and so the installation cost mounts with the increase of bed-area.

Therefore, the tradeof between the higher fluidizing velocity-lower combustion efficiency-lower capital cost and lower fluidizing velocity-higher combustion efficiency-higher capital cost is drawn by selecting an optimum fluidizing velocity above which the savings in capital cost (by reducing bed-area) are more than offset by the increase in operating costs due to lower efficiency and higher fan power.

Most of the commercial plants operate within the range of 1—3 m/s, but in a few cases lower and higher velocities are occasionally justified.

Q. *What factors are to be considered in the scale-up of CFB boilers?*

Ans. A CFB boiler consists of

(a) boiler proper—furnace, cyclone and backpass
(b) material handling equipment
(c) air handling equipment
(d) other auxiliary equipment

Most of the equipment used in CFB boilers has already proven its performance in large sizes on other types of boilers and hence needs no scale-up, including:

(a) Furnace construction
(b) Backpass design, construction
(c) Material handling equipment (crushers, feeder, conveyors etc.)
(d) Air/flue gas handling equipment (fans, compressors, ductwork)
(e) Auxiliary equipment (sootblowers, burners, valves)

In scaling-up the CFB boiler in sizes to 400 MW_e (and larger), the following five major design aspects need consideration:

1. Furnace height
2. Furnace depth
3. Number of fuel feedpoints
4. Number of solids returns (from the cyclones)
5. Cyclone diameter.

Q. *How does furnace height becomes the factor of consideration in the scale-up of CFB boilers?*

Ans. In a CFB boiler, the main means of heat transfer to the furnace wall is via the circulating solids. The density of the circulating mass decreases with furnace height. Since furnace surface-to-volume ratio decreases with increasing size, the designer usually gets tempted to increase the height to compensate. However, increasing height beyond the experience base adds risk, inasmuch as the resulting solids density (and so the heat transfer rates) are unknown. As a result, the better option is to limit furnace height to values very close to the experience base ensuring that furnace heat transfer hence temperatures, steam generation rate, fuel burnout and emissions, can be predicted accurately.

To compensate for the lower furnace surface/volume ratio in large boilers, Ahlstrom Pyropower, Inc. (API) utilizes infurnace surface, located in the upper furnace where solids density is low and erosion is not a great problem. The Co. has logged 8 years of successful operation of more than 25 Nos. of CFB boiler scale-ups by utilizing this surface.

Furnace height increases from the 50 MW_e size to the 150—200 MW_e size range. Above 200 MW_e, furnace height is held constant. This is as per API design norm.

Q. *How does furnace depth become an important parameter of consideration in CFB boiler scale-up?*

Ans. Furnace depth affects proper air distribution over the furnace cross-section. While primary air (about 60% of total) is distributed by the air distribution in the furnace floor, secondary air (about 40% of total) is fed from the walls of the lower furnace and must penetrate the dense bed of circulating solids. Excessive depth will result in an air-deficient/fuel-rich zone in the centre of the furnace resulting in poor burnout and increased emissions. To address this when scaling-up, the designer must limit furnace depth to values for which adequate air penetration and hence good performance can be ensured. A limit on furance width is reached somewhere between 300 and 400 MW_e, where plant layout and buckstay design become impractical. One reputed company (Ahlstrom Pyropower) switches to a dual-grid furnace design at such a point. This double-grid system permits the injection of secondary air into the furnace centre allowing depth to be increased.

Furnace depth increases from 50 MW_e size to the 150—200 MW_e size range. Beyond 200 MW_e furnace depth is held constant while at the 400 MW_e a dual-grid configuration permits depth to be increased again.

Q. *How do the number of fuel feedpoints become an element of consideration in the CFB boiler scale-up?*

Ans. The number of fuel feedpoints affects the distribution of fuel over the furnace cross-section. The required number of feedpoints is dictated, to a certain extent, by the burning characteristics of the fuel. Fuels with high volatile load, such as sub-bituminous coal or lignite will burn quickly on introduction into the furnace, using up the oxygen in the area. To air-deficient/fuel-rich zones and the attendant-reduced performance, such fuels inherently require more feedpoints than low-volatile fuels such as bituminous coal or petroleum coke. Therefore, the wise designer must encash on his past experience to provide as many number of fuel feedpoints and their proper location when scaling-up to ensure proper performance.

Q. *Not all part of the fuelfeed is burnt out in the furnace space. So this unburnt fuel must be recycled from cyclone. How do the number of solids returns from the cyclone play a decisive role in the scale-up of CFB boiler units?*

Ans. The number of solids returns from the cyclone (separator) can affect the lateral solids density profile within the furnace. Few returns means higher solids concentrations in the area of the solids return lines, increasing erosion potential. Forasmuch as the fuel can be fed via the solids return lines, the number of solids returns can also affect fuel distribution. Therefore, the designer must provide the required number of solids returns when scaling-up to avoid erosion problem. Ahlstrom Pyropower has addressed this problem by installing its patented dual loopseal (Fig. 38.8), which provides for two solids return lines from a single cyclone.

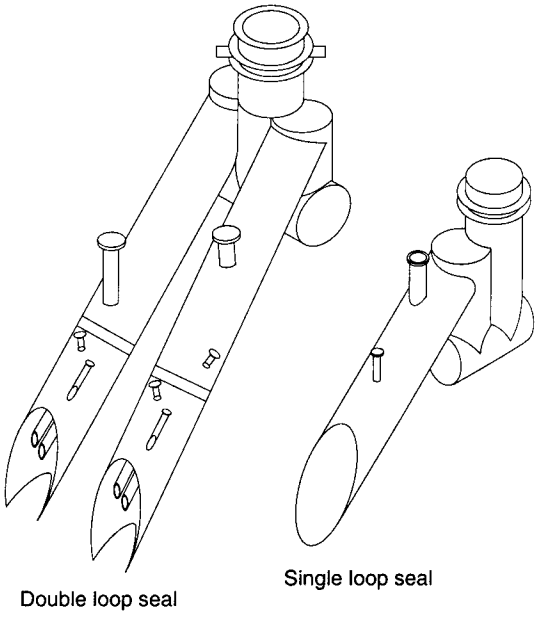


Fig 38.8 *Solids return lines arrangement.*

Source: Technical Paper PTP-97 (Ahlstrom Pyropower)
Courtesy: Ahlstrom Pyropower, Inc.

Q. *How does the cyclone diameter exercise an impact on the scaling-up of CFB boilers?*

Ans. Cyclone diameter exercises its impact on scaling-up indirectly.

Cyclone dia influences cyclone efficiency, which in turn affects solids recirculation rates, furnace solids density and so the furnace temperature/performance. The classical cyclone theory (which assumes no particle-particle interactions) predicts decreased efficiency with increased diameter. However, the inlet solids loading in CFB cyclones is so high that significant particle interaction does occur whereby a larger particle being collected carries other, smaller particles with it to the cyclone wall. Experience shows that larger CFB cyclones do not exhibit lower efficiency. However, cyclone diameter is limited on scale-up to a modest increase over the experience base.

Cyclone diameter increases gradually from 50 MW_e size to the 150 —200 MW_e size range. Above 200 MW_e cyclone dia is held constant.

Q. *Why is the 125 MW_e CFB boiler of Vaskiluodon Voima Oy located in Seinäjoki, Finland provided with three cyclones instead of scaling-up to a single unit of cyclone?*

Ans. The Finnish CO*. has made a very conservative approach as compared to the current practice. The Company's experience with utility-scale CFB boiler began in 1987 with the start-up of the Colorado-Ute boiler (now owned by Tri-State Generation and Transmission Co.).

The Vaskiluodon CFB, designed to fire 100% peat, 100% coal, or any combination in between was started up in 1990. So the designers following the Pyropower's normal practice, avoided scale-up of those key components to minimize scale-up risk.

Note:

1. Three cyclones instead of one distribute the total inventory of recirculatory solids into three separation units, thereby minimizing

{* AHLSTROM PYROPOWER}

(a) the total load on a single scaled-up unit
(b) the risk of nagging erosion potential and increasing the cyclone efficiency and availability.

2. On the basis of past few years of operating experience, scale-up of CFB boilers up to 400 MW_e in size is now being offered with full commercial guarantees and complying with strict emission regulations.

Q. *The 125 MW_e CFB boiler unit of Vaskiluodon Voima Oy, designed to fire 100% peat, 100% coal, or any combination in between, has its boiler size equivalent to that of a 160—170 MW_e boiler firing coal. Why?*

Ans. Since in a CFB boiler, the furnace cross-section is set to provide the required gas velocity, the furance is sized for the fuel producing the highest flue gas flow (in this case, peat), and gas recirculation is used to maintain the desired velocity when firing fuels producing less flue gas flow (in this case, coal). That is why the Vaskiluodon boiler is sized to that of a 160—170 MW_e coal-fired boiler.

Q. *Why is the furnace of V.V. Oy CFB befitted with RH surface?*

Ans. Because of the high gas flow due to peat firing, this regenerative air heater has been installed.

Q. *How is a 400 MW_e Pyroflow boiler designed?*

Ans. The process design for the 400 MW_e Pyroflow is the same as for other Pyroflow boilers. Fuel and sorbent feed size, furnace velocity, furnace temperature, bed pressure drop etc. are unchanged.

The key design features include:

(a) dual-grid air distributor
(b) division wall
(c) omega superheaters
(d) water-cooled cyclone
(e) dual loopseals
(f) innovative fuel feed system

The boiler contains a single, water-cooled furnace with a division wall and dual-grid air distributor. Omega tube panel superheaters are mounted in the upper furnace for primary and secondary superheat duty. Four cyclones are provided, two on each sidewall. The cyclones are water-cooled, and each utilizes water-cooled double loopseals.

Flue gas from the cyclones enters a plenum above the furnace and from there, the convective backpass. The backpass is of conventional design and contains the final superheater, reheater, economizer, and airheater surface.

The system generates 1350 t/h of main steam at 175 bar/541°C

Q. *Why is a dual-grid air distributor used?*

Ans. Dual-grid design (also called Pant-leg design), Fig. 38.9, ensures better air penetration. It allows for practical furnace depth/width dimensions while providing secondary air penetration into the furnace centre, to ensure good performance.

Q. *What is division wall?*

Ans. It is a separate water-cooled wall formed from the tubes which make up the interior walls of the lower furnace.

Q. *Why is it installed?*

Ans. The division wall serves several purposes:

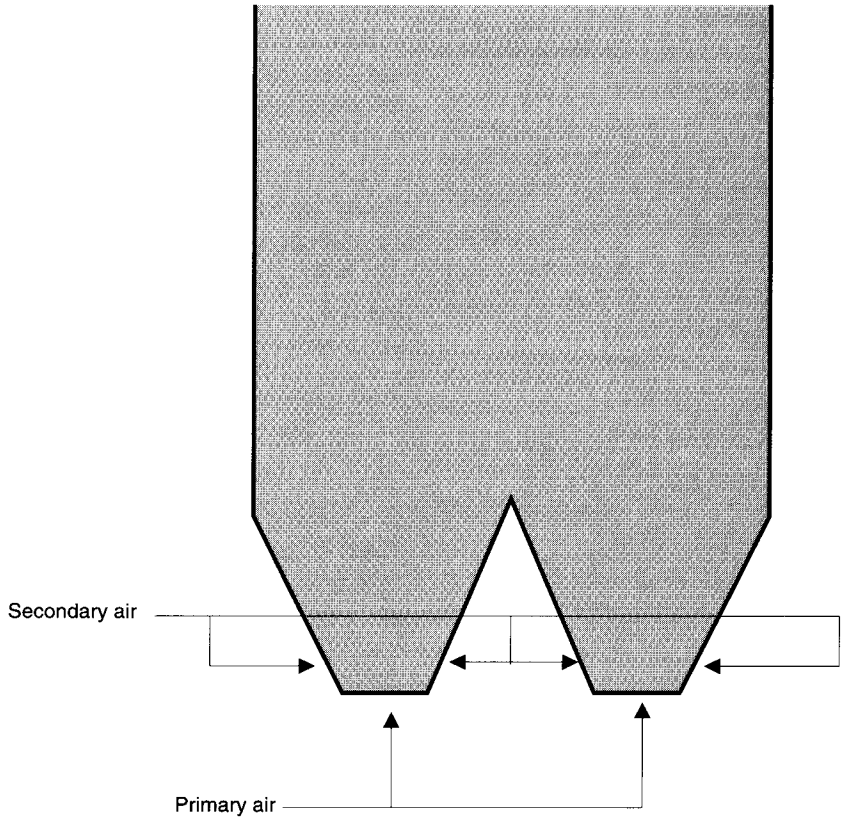


Fig. 38.9 *Dual-grid design.*

Courtesy: Ahlstrom Pyropower

Source: Technical Paper PTP-102 (Ahlstrom Pyropower)

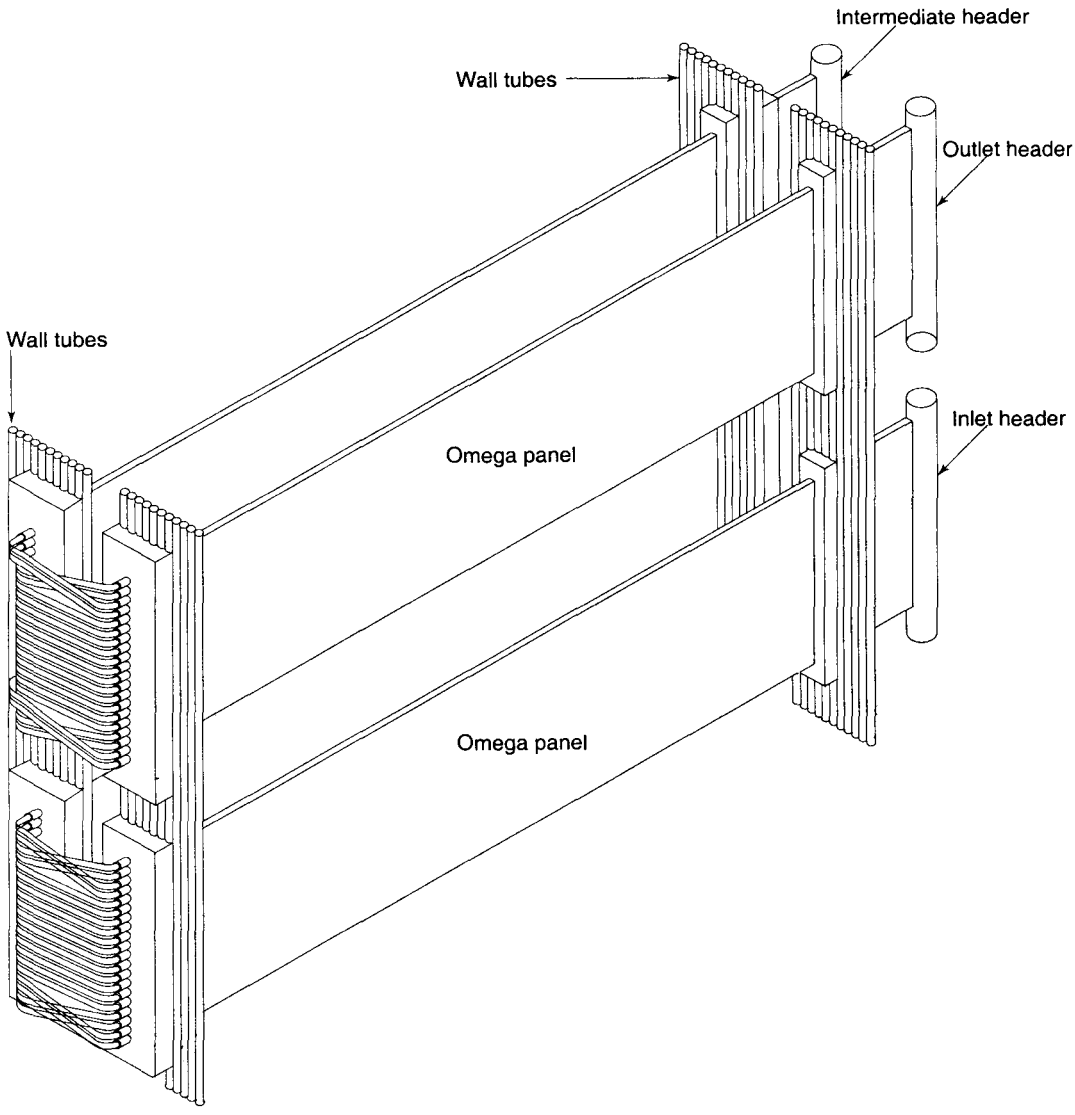


Fig. 38.10 *Omega-surface panels installed in the freeboard space (where erosion potential is much less) are a good substitute for EHE.*

Courtesy: Ahlstrom Pyropower
Source: Technical Paper PTP-102 (Ahlstrom Pyropower)

1. First, it serves to return the water used to cool the interior walls of the lower furnace to the drum, without requiring a circulation pump.

2. Second, the division wall may be used as an intermediate support for the omega tube superheat panels which run across the boiler width.

3. Third, heat absorption by the division wall, which is a part of the evaporative circuit, avoid the need for a wingwall evaporative surface, thus simplifying the design and minimizing cost.

Q. *Why are omega panel superheaters used?*

Ans. The omega tube panel superheaters are used for primary and secondary superheat duty. They are located in the combustion chamber as wingwalls and platens. Also called Omega-surface panels (Fig. 38.10), these heat transfer surfaces are placed in the low-density portion of the bed where erosion is reportedly not a problem.

Use of omega-panel superheaters avoids the need for an external heat exchanger (EHE) with its associated operating and maintenance cost.

They have demonstrated excellent reliability.

Note: To-date omega-panels have been installed in over 20 Pyroflow boilers. First used in 1985, these have demonstrated excellent reliability.

Q. *What is a water-cooled cyclone?*

Ans. The cyclone barrel, cone, dropleg and loopseal are all water-cooled. This circulating water comes from the steam drum via separate downcomers and flows upward through the cyclone by natural circulation and back to the drum via a separate set of risers. The interior of the cyclone and loopseal is lined with a thin layer of refractory anchored by short metal studs. This lining protects the cyclone and loopseal tubing from erosion.

Q. *Why is this water-cooled cyclone used?*

Ans. The water-cooled cyclone offers many advantages over the more typical plate/refractory design:

1. First, the amount of refractory is significantly reduced; from a thickness of 300—400 mm in the plate/refractory design to a thickness of 40—50 mm in the water-cooled design. This reduces weight by 50%, and also reduces refractory maintenance cost.

2. Second, the cyclone skin temperature is reduced via external insulation and lagging. This cuts radiation loss and saves 0.25—0.5% on fuel costs.

3. Third, expansion joints are not needed between the cyclone and furnace. Since both the cyclone and furnace are cooled by the same fluid, and both are top-supported, there is no differential expansion. This reduces expansion joint maintenance costs.

Q. *Why are double loopseals provided in the design of a 400 MW_e unit instead of one?*

Ans. The double loopseal provides for two solids returns to the furnace from one cyclone, improving performance via better solids (and fuel) distribution within the furnace.

Note: To-date, double loopseals have been installed on over 15 Nos. of Pyroflow boilers.

Q. *How have designers tackled the fuel feed systems for the 400 MW_e CFB boiler design, taking into consideration both high volatile and low volatile fuels to be fired?*

Ans. Two alternate fuel feed systems are provided for the 400 MW_e design, depending on the fuel to be fired. For relatively low volatile fuels which burn more slowly, a traditional gravity feed system is used, dropping the fuel into the loopseal return line and (if deemed necessary) into additional feed chutes in the front and rear walls. This results in all fuel being fed from the furnace external walls. This will beget good performance for low volatile fuels which burn less locally and so will be carried throughout the furnace by the high degree of turbulence induced by primary air (fluidizing medium).

High volatile fuels burn more rapidly. Fuels of this kind need to be fed from both the external and internal walls in the lower reaches of the furnace. Air-swept crushers are used to direct the fuel from the crushers to the furnace proper. Crusher design is simple, with no classifiers or preheated air required; the heat of compression from the secondary air fan (secondary air is used for supplying air to the crushers) is sufficient. Since the air introduced to the crushers is not preheated, crusher bearing problem is minimum. With the air-swept crushers, fuel will be charged

to the external plus internal walls of the lower furnace. This gives the necessary distribution of fuel over the furnace cross-section to ensure good performance.

Source: Design and Experience with Utility-scale CFB Boilers —

S.D. Darling and N.W. Andrews

Technical Paper PTP-97 (Ahlstrom Pyropower) presented at Power-Gen Asia' 94 Conference Hong Kong, August 1994.

Q. *Excluding the large quantity of small-size BFB and CFB boilers in China, there are currently over 260 CFB boilers in operation or under construction worldwide. The availability and performance of CFB boilers have been exceptional. Despite good performance, designers and manufacturers have continued to optimize and improve the design of this technology. What are the latest design improvements that the designers have achieved so far?*

Ans. During the development of the CFB boiler (Fig. 38.11 (a)) the two biggest concerns of the designers had been to

(a) overcome the problem of erosion due to circulation of hot bed materials
(b) minimize cyclone refractory maintenance.

They have addressed these problems thru conservative and innovative designs some of which are proprietary in nature.

1. ***Kick-Out Tubes*:** Ahlstrom Pyropower, Inc. has designed and patented KO (Kick-Out) tubes to counter corrosion problems. Fig. 38.11 shows the arrangement of the lower furnace tubes. In the earlier CFB units of Pyropower, the bed material flowing down the furnace walls would hit the refractory interface point and cause an eddying effect which resulted in maintenance of the protective tube weld overlay. The KO tube arrangement avoids the impact of downflowing solids at the interface and so the erosion effect caused by the cascading material is greatly reduced.

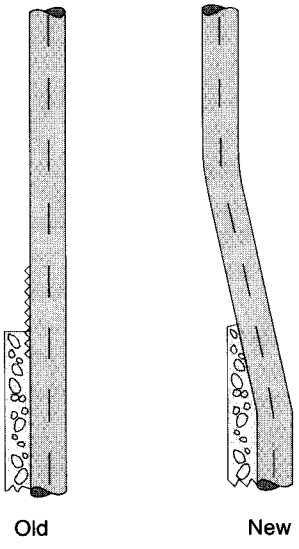


Fig. 38.11 *Lower Furnace Kick-Out Tube Design.*
Courtesy: AHLSTROM PYROPOWER.

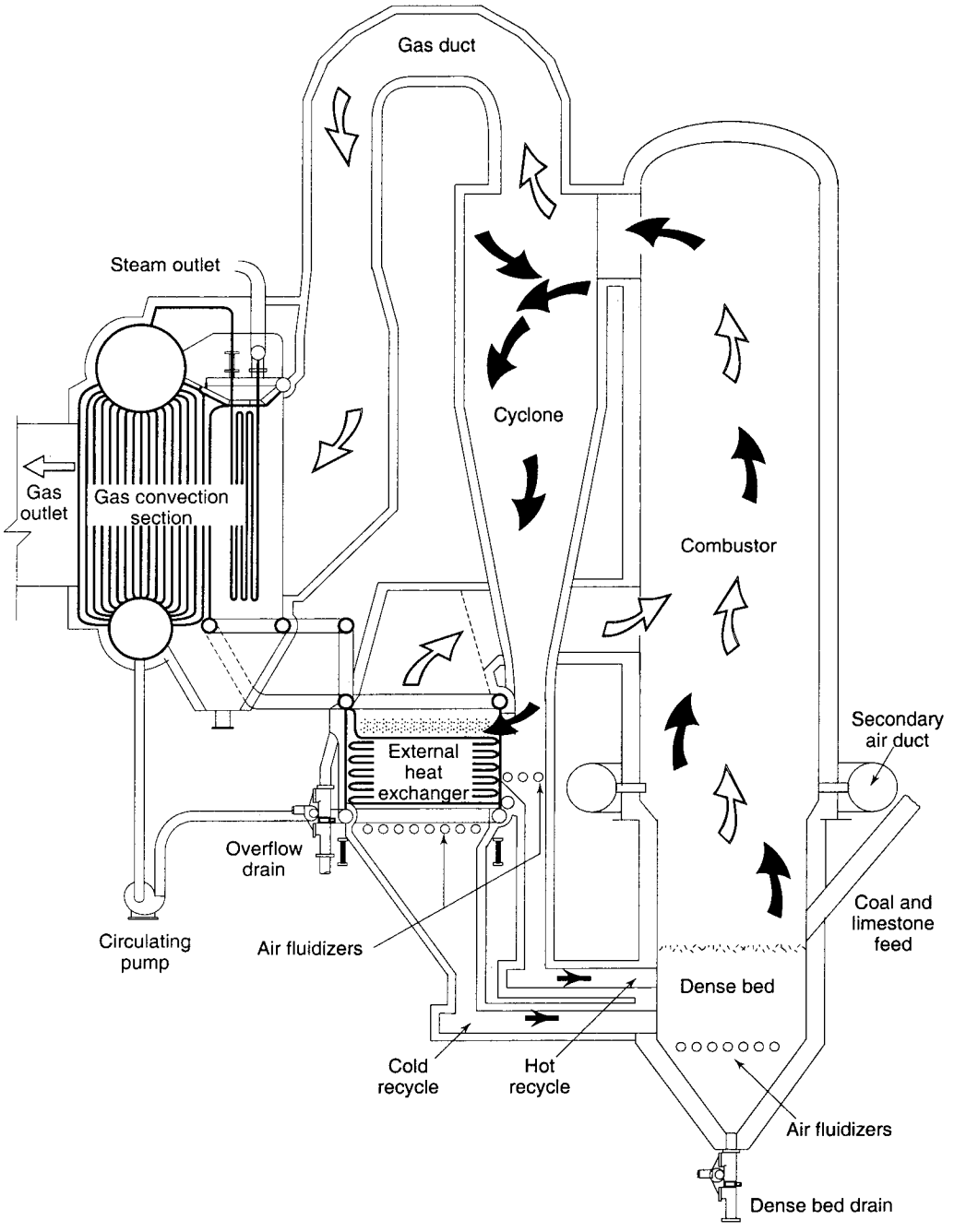


Fig. 38.11 (a) *Advanced Fluidized Bed Steam Generator.*

Source: *Advanced Fluidized Bed Technology applied to Coals and other Fuels—R D Litt & R H Sirois (TECH. PAP: RST–18, RILEY STOKER)*

Courtesy: *RILEY STOKER, Worcester, Massachusetts. 01613, USA.*

2. ***Flame Spray:*** Certain fuels, due to both the chemical make-up (high silica etc.) and sizing, have contributed to localized wear problems. Use of thermal spray coatings has proved to be an economical, long-term solution to erosion problems. Ahlstrom Pyropower, Inc. has developed one such spray system in collaboration with Hobart Tofa Technologies, Flame Spray, Inc. and Amorphous Technologies.

Depending on the application, a variety of different metals are sprayed onto the affected area. The result is a coated surface which can be applied relatively quickly and economically and yet provide years of trouble-free operation.

3. ***Omega Tubes:*** These are flat panels located above the high solids density zone in the furnace to recover the heat from the circulating bed inventory. They are the good replacement for EHEs, yet minimizing erosion potential.

API (Ahlstrom Pyropower, Inc.) has developed the use of omega surface panels and installed this heat recovery system in over 20 Pyroflow boilers with excellent performance report.

4. ***Steam Bypass Reheat Design:*** Designers have sought to restrict the reheater duty in the convective shaft of the boiler. API has developed a unique patented convective reheat design as shown in Fig. 38.12

With this design, all of the reheater duty is achieved by convective heat transfer in the backpass of the boiler. Reheat steam tempera-

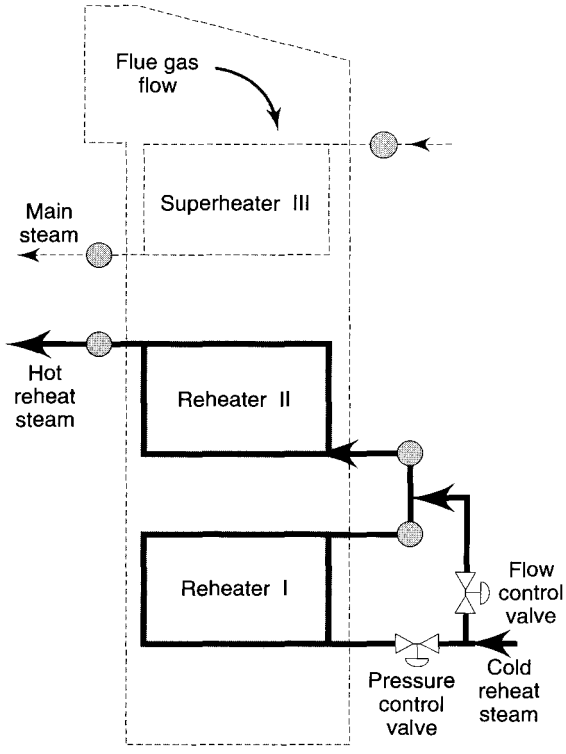


Fig. 38.12 *Convective reheat bypass design eliminates high-maintenance-hot-gas bypass dampers and EHEs as well.*

Courtesy: Ahlstrom Pyropower.
Source: Technical Paper PTP–102 (Ahlstrom Pyropower)

ture control is achieved through bypassing a portion of the reheat flow around the 1st stage reheater bank located in the cooler gasflow zone. Fig. 38.13 shows the relation of flow through the 1st stage reheater and the percentage flow bypassed directly to the final stage reheater versus boiler load.

This design begets two advantages:

(a) elimination of hot-gas bypass-dampers and hence their maintenance cost
(b) elimination of external heat exchangers which are more sluggish in load-following response due to large solids inventory.

Both bypass dampers and EHEs require increased power consumption through fluidizing blowers and also the increased maintenance associated with hot solids flow.

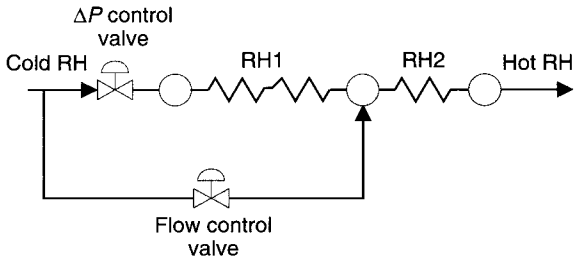
In addition, the API design allows for quicker and simplified cold and hot start-ups due to better steam matching capabilities and the absence of in-furnace or external heat exchanger reheat surface which requires elaborate protection schemes during start-up.

This steam bypass reheat design has been proven and is currently operating extremely well on six Pyroflow boilers.

5. ***Water-Cooled Cyclone:*** Refractory loss of cyclone due to high solids inventory under high turbulence and temperature has continued to be the nagging problem in the operation of CFB boilers. To minimize refractory maintenance concerns as well as to lower radiation losses, designers have developed the water-cooled cyclone (Fig. 38.14). The water-cooled cyclone uses only a thin layer (40—50 mm) of abrasion resistant refractory, as opposed to the much thicker (300–400 mm) refractory used for the plate/refractory cyclone. Additional advantages of the water-cooled cyclone include elimination of expansion joints between the furnace and cyclone and is less in weight (a 50% reduction) which reduces structural steel capital cost.

6. ***Refractory:*** CFB refractory suffers badly due to

(a) thermal cycling
(b) fuel attacks due to alkalies, vanadium and sulphur compounds
(c) erosion.



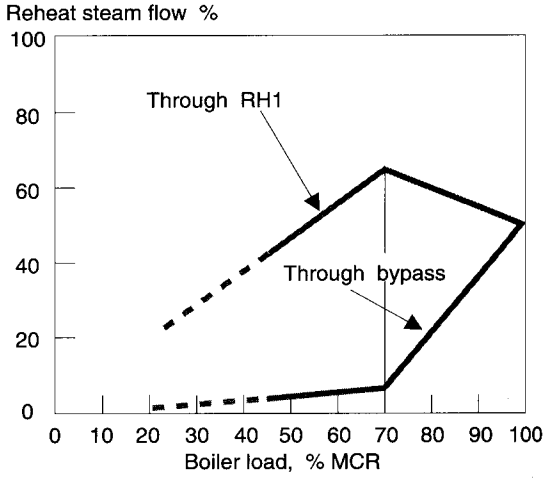


Fig. 38.13 *Reheat steam flow vs. Boiler load.*

Courtesy: Ahlstrom Pyropower.
Source: Technical Paper PTP–102 (Ahlstrom Pyropower)

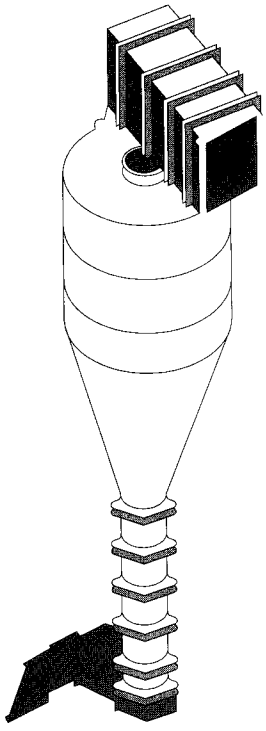


Fig. 38.14 *Water cooled cyclone.*

Source: PTP-102 (Technical Paper/Ahlstrom) Courtesy: Ahlstrom Pyropower/San Diego/CA 92186-5480/USA.

To fight back refractory problems, a variety of different linings including firebrick, plastics, low cement and fused silica castables are used today. In addition to the refractory material, more attention has been given to the proper selection of anchors. New anchor materials such as Incolony 800HT and Haynes Alloy 230 with higher allowable stress levels at high temperatures are formed, machined and welded quite easily. Use is made of a combination of firebrick, castable and gunned materials to provide the optimum mix of erosion protection, insulation and durability. Of late, API has been using low cement gunning mixes which have excellent installed strengths, porosity, chemical resistance and erosion resistance. The innovative refractory designs of API eliminate the concerns of extended startup or shutdown durations, the limitation is only the boiler drum and metal temperatures as opposed to any refractory limitation.

7. ***Combustor:*** The combuster design is conservative to provide reliability with conventional construction techniques. Figure 38.15 represents a suitable design to protect against solid particle erosion and low temperature corrosion.

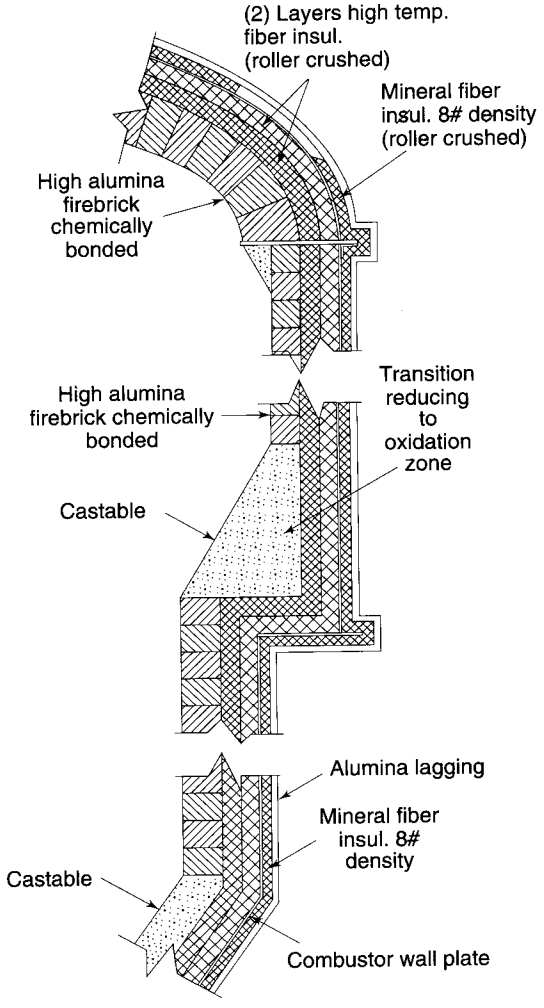


Fig. 38.15 *Combustor wall construction.*

Source: Advanced Fluidized Bed Technology applied to Coals and other Fuels—R D Litt & R H Sirois (Tech. Paper: RST-18, Riley Stoker) Courtesy: Riley Stoker, Worcester, Massachusetts 01613, USA

This design has the advantage of providing positive erosion protection with excellent insulating properties. Since combustor temperature is controlled to 870°C (1600°F)[2] conditions, refractory materials are not exposed to the harsh furnace conditions present in conventional boilers. High alumina brick offers superior erosion protection to metal components and provides for ease of construction. Compared to castable or other fieldcured refractories, bricks offer protection against cracking and spalling since they are manufactured under strict quality control procedures.

Proper fluidization and overall operation are keyed to proper design of the air distribution system. Figure 38.16 represents the configuration of distributors for start-up and continuous operation. This design results in startup distributors protected from plugging during continuous unit operation and provides for a precisely controlled warm-up rate on a unit cold start. Hot products of combustion from an auxiliary burner are used only for start-up.

The primary air distributors are designed to provide complete fluidization to all regions of the combustor, thereby preventing localized clinkering and providing 3 to 1 boiler load turndown at fixed air/fuel ratio without plugging or bed slumping. Additional turndown is available at higher excess air levels. The pipe-type distributors allow for easy bottom withdrawal of oversize materials which may enter with the coal.

8. ***External Heat Exchanger:*** The EHE, represented in Fig. 38.17, is fluidized at a very low velocity –0.3 to 0.6 m/sec (1 to 2 ft/sec). Because of these low velocities and the absence of

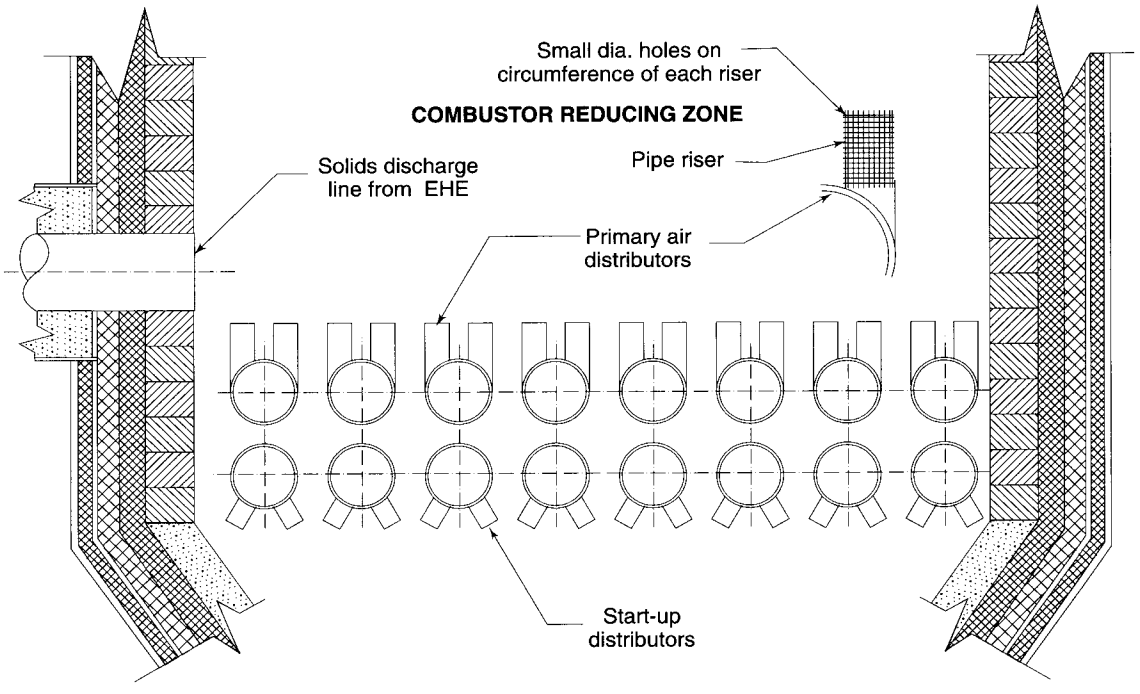


Fig. 38.16 *Dense bed region.*

Source: *Advanced Fluidized Bed Technology applied to Coals and other Fuels–R D Litt & R H Sirois (Tech. Pap : RST-18, Riley Stoker)*
Courtesy: *Riley Stoker, Worcester, Massachusetts 01613, USA.*

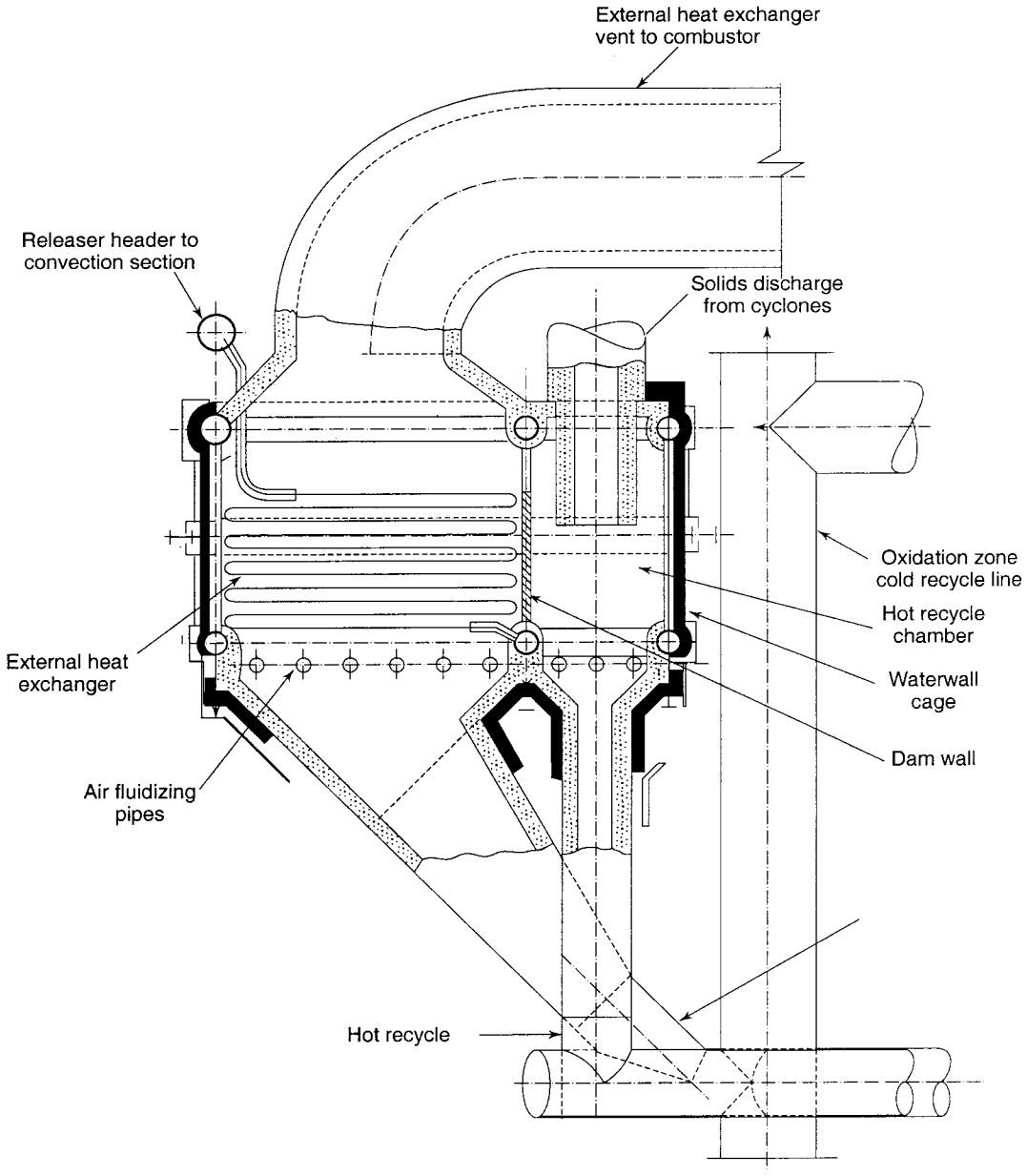


Fig. 38.17 *External heat exchanger.*

Source: *Advanced Fluidized Bed Technology applied to Coals and other Fuels —R D Litt & R H Sirois (Tech. Pap: RST-18, Riley Stoker)*
Courtesy: *Riley Stoker, Worcester, Massachusetts 01613, USA*

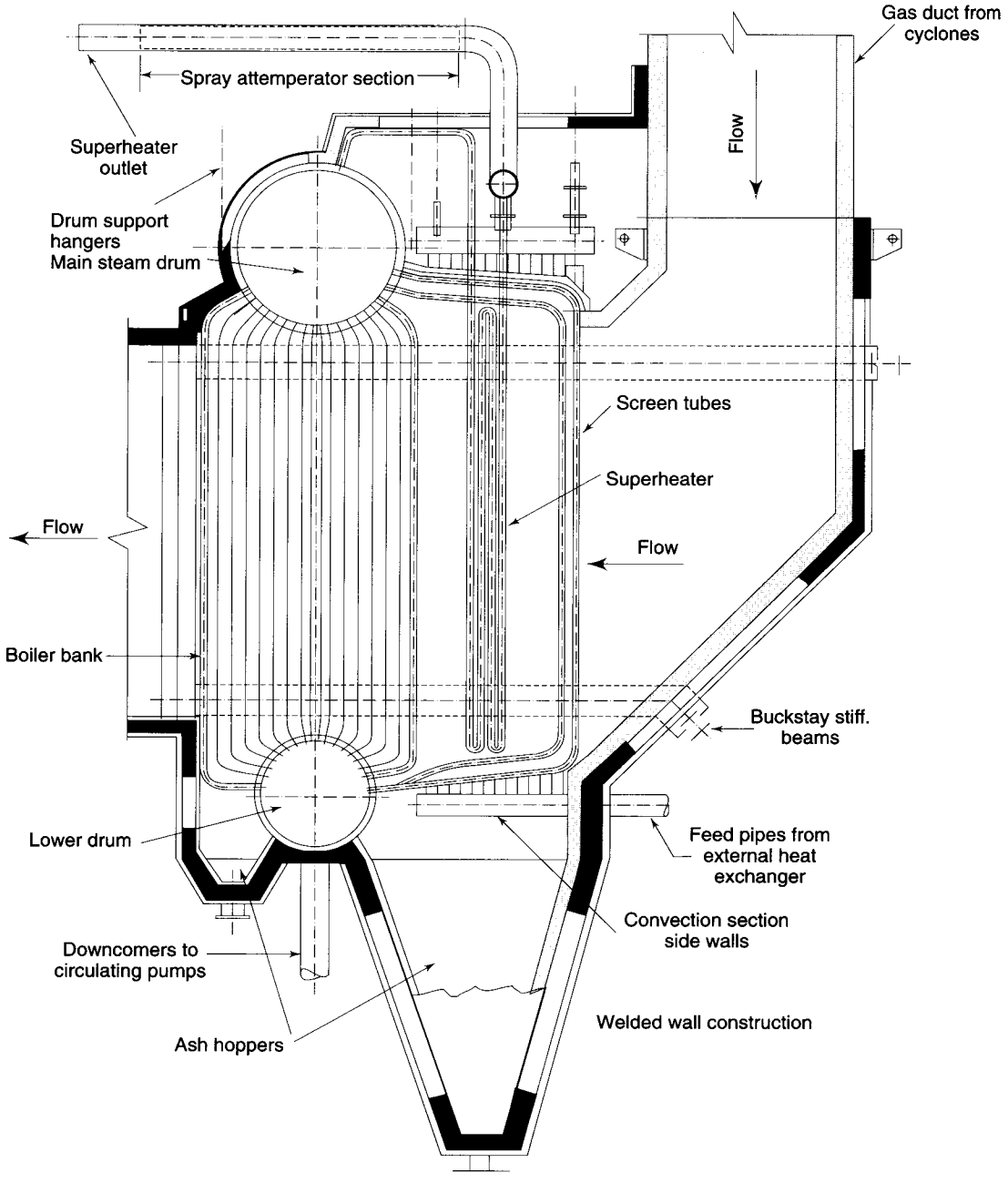


Fig. 38.18 *Gas convection section.*

Source: *Advanced Fluidized Bed Technology applied to Coals and other Fuels—R D Litt & R H Sirois (Tech. Pap: RST-18, Riley Stoker)*

Courtesy: *Riley Stoker, Worcester, Massachusetts O1613, USA.*

a reducing environment, the erosion and corrosion problems normally associated with in-bed tubes are eliminated, while turndown and load response characteristics are improved.

The design provides for a heat transfer coefficient in the order of 293.4 kcal/hr m^2 °C (60 Btu/hr sq ft °F) thus providing for the economical utilization of pressure parts. Also, the environment allows the use of conventional and time-proven material selection, tube support and alignment methods and economical manufacturing and field construction techniques.

*9. **Gas Convection Section:*** This section, along with other downstream heat traps such as the economizer or airheater section, provides for the total duty of the steam generator not done in the external heat exchanger. The design provides for conservatively sized superheater and single pass evaporative section to prevent flyash build-up or localized erosion of pressure parts. The general design, depicted in Fig. 38.18, represents a conventional steam generator arrangement. This design permits wide variation in heating surface allocations and arrangement to meet specified start-up and normal operating conditions.

Q. *What are the design developments that CFB designers have been currently developing?*

Ans. While the process of improving the existing design, cost and performance of CFB boilers is on, the manufacturers are also looking towards the future of this technology. Some of the latest design developments are:

— Compact CFBs

— Larger size CFBs

— Pressurized CFBs

Compact CFB: The second generation of CFB technology has focused on reducing the size of the CFB system. Current designs still retain large high-temperature cyclones between the furnace and convection pass. Efforts to reduce the size of these systems have centered on ways to eliminate the HT cyclone through either of three separation systems:

1. Installing in-furnace separators
2. Traditional HT cyclones cooled by water/steam membrane walls
3. Various kinds of particle-settling chambers and impact labyrinths designed to collect solids without using the centrifugal force.

In one unique design (Pyroflow Compact), the traditional cyclone is replaced by a new kind of centrifugal separator (Fig. 38.19).

Instead of the normal cyclone configuration, this separator consists of flat walls which allow the use of flat water-cooled panels. This results in a rectangular separation chamber having a number of similarities to the traditional cyclone. This separation chamber is equipped with a vor-

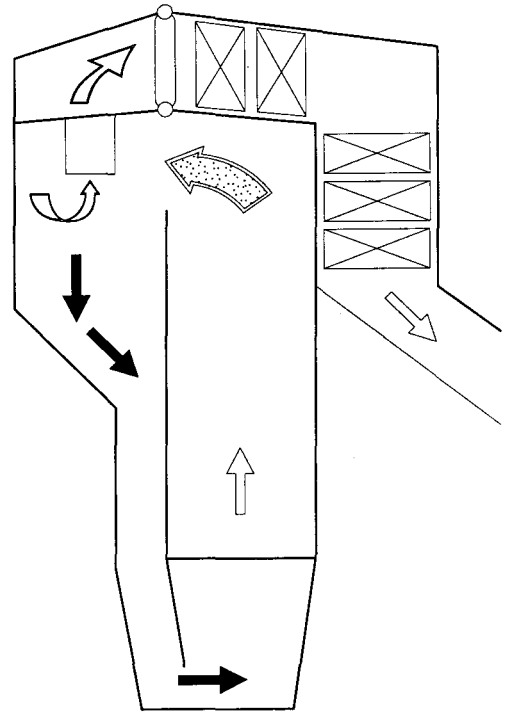


Fig. 38.19 *Pyroflow compact concept.*
Courteys: Ahlstrom Pyropower.
Source: Technical Paper PTP–102 (Ahlstrom Pyropower)

tex finder and has a collection hopper underneath that provides for solids return to the lower furnace.

The walls of the separator are part of the same natural circulation system used to cool the furnace enclosure walls. As a result the rectangular separators can be joined to the furnace without the expansion joints. The combination of the shape of the particle separators and the ability to locate them directly attached to the furnace results in considerable space savings.

Because of the high degree of turbulence coupled with high solids loading in the separators, it is still necessary to cover the water-cooled membrane walls with a thin layer of refractory for the purpose of erosion protection. This benefits the user with some amount of heat recovery in the collection chamber plus unrestricted start-up and shutdown rates. The Pyroflow Compact design begets following advantages over the conventional CFB boiler cyclones:

(a) Simpler in construction, lighter in weight and occupies less space
(b) Total elimination of thermal expansion joints between the furnace and solid separator
(c) Reduced refractory maintenance.

The first commercial plant using this technology went into operation in 1992 in Kuhmon Lämpö Oy, in East Central Finland. This plant burning mainly wood wastes, such as sawdust and bark produces about 80 to 90% of the district heat required by the town of Kuhmon and a third of the yearly electricity consumption. The plant has been operated extremely well and has provided invaluable design data for scale-up.

Larger Size CFB: The world's largest CFB operating todate is the 165 MW_e unit of Nova Scotia Power Station. However, many suppliers are looking forward to scale up this technology to units as large as 600 MW_e. In one unique design to the 400 MW_e unit, the CFB boiler comprises of a water-cooled combustor with dual grid, omega panel superheaters, 4 Nos. of cyclones and backpass with superheater, reheater, economizer and air heater. The dual-grid design patented by Ahlstrom Pyropower, Inc. provides the necessary air penetration for large-size boilers.

The essential design problem in scaling up CFB furnaces is that the heat release volume goes up faster than the surface area of the tube enclosure absorbing the heat. Also, extending the height of the furnace increases costs rapidly. The major concerns in scaling up to larger size units are as follows:

(a) Furnace heat absorption
(b) Furnace air distribution/penetration
(c) Fuel distribution
(d) Solids distribution
(e) Cyclone diameter

API engineers have addressed each of these parameters systematically and conservatively in the scale-up of CFB units to a larger size as demonstrated by the following factors:

(see Table in the next page)

The essential design problem faced by the designers in scaling up CFB boilers is that heat release volume escalates faster than the surface area of the tube enclosures absorbing the heat. And costs mounting commensurate with the furnace height add to the problem. So the designers have selected different ways of coping with this basic tradeoff:

(a) multiple furnaces with a common heat-recovery pass
(b) providing wingwalls, platens or partial division walls in the furnace
(c) use of EHEs (External Heat Exchangers)
(d) pantleg furnace design (dual-grid design)
(e) a full division wall in the furnace
(d) a combination of these features.

Pressurized CFB (PCFB): To address the increasing demand for larger capacity CFBs, improve cycle efficiencies, and to lower air emis-

Equipment	Successful Scale Factors	Scale Factors for 300 MWe	400 MWe
Combustor			
Height	1.0–2.0	1.08	1.08
Depth	1.0–1.7	1.0–1.3	1.00
$\left(\frac{\text{Plan Area}}{\text{Feedpoint}}\right)$	0.5–1.7	1.0–1.2*	1.0–1.2*
$\left(\frac{\text{Plan Area}}{\text{Loopseal return}}\right)$	0.5–3.5	0.75–0.9*	0.75–0.9*
Cyclone			
Diameter	1.1–1.6	1.2–1.4*	1.2–1.4*

where, Scale Factor = $\frac{\text{Size proposed}}{\text{Largest size in operation}}$

Source: PTP–102 (Ahlstrom Pyropower)

* depends on fuel quality.

sions, many suppliers are developing pressurized fluid bed boilers. Today manufacturers are offering both PFBC, which is a pressurized bubbling fluidized bed combustor and the PCFB, which is a pressurized circulating fluid bed boiler. Some manufacturers have chosen to develop the PCFB due to its improved performance.

The PCFB as shown in Fig. 38.20 utilizes conventional atmospheric CFB technology operating under approximately 1–1.6 MPa.g pressures.

The hot gas leaving the cyclone is filtered off particulate solids in a hot gas filter and the clean gas is then expanded across a conventional gas turbine. The gas turbine/compressor provides the necessary combustion air and turns a generator. The exhaust gas from the turbine goes to heat economizer water and so recovers the remaining heat in the exhaust gas. Steam generated in the PCFB goes to a conventional steam turbine/generator set. The result is a combined cycle with an efficiency approximately 20% higher than a conventional coal fired thermal powerplant.

Further developments are under way to take advantage of improved gas turbines. Fig. 38.21 shows the advanced PCFB cycle.

This cycle incorporates a carbonizer and topping combustor to further improve the cycle efficiency. The carbonizer produces a synthetic gas from the coal feedstock which is used to fire a topping combustor and raise the GT inlet temperature from approximately 1145° – 1175°K to 1365°–1645°K. The char from the carbonizer is then the PCFB fuel feedstock. The result is an overall cycle efficiency of approximately 46% versus 34-35% for the conventional coal-fired technologies.

Source: New Developments in Fluidized Bed Boiler Technology

—Chris Lyons

Technical Paper PTP-102 (Ahlstrom Pyropower) presented at Competitive Power Congress 1994, Philadelphia, Penn., June 8-9, 1994.

Q. *How is a FBC boiler designed?*

Ans. It is a stepwise process:

I. **Fuel Feedrate:** The first stage in designing a FB boiler is to calculate the fuel feedrate on the basis of the required thermal output of the boiler and a target efficiency:

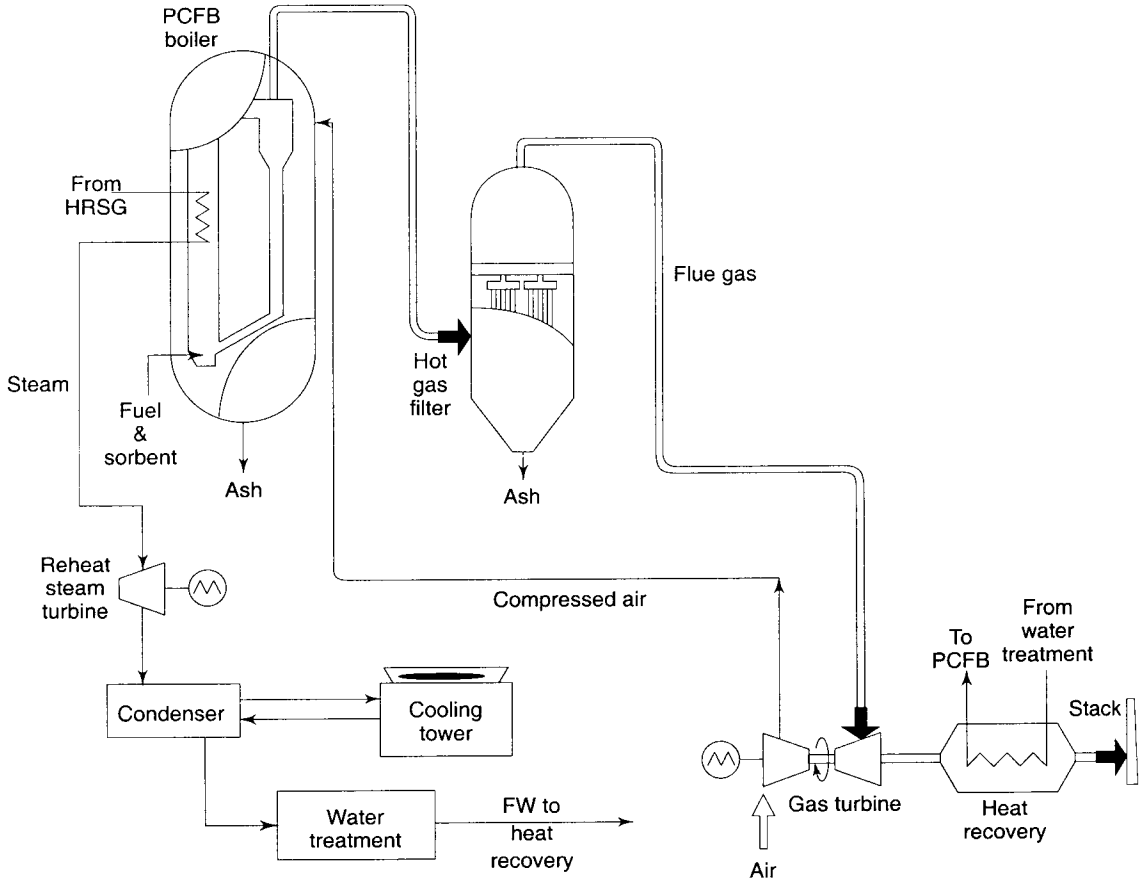


Fig. 38.20 *First generation PCFB cycle.*

Courtesy: Ahlstrom Pyropower
Source: PTP–102 (TECH. PAP./Ahlstrom Pyropower)

$$q_i = \frac{q_o}{\eta} \quad (1)$$

$$F_f = \frac{q_i}{C} \quad (2)$$

where, q_i = heat input to the boiler, W
q_o = heat output of the boiler, W
η = boiler efficiency
F_f = fuel feedrate, kg/s
C = calorific value of fuel, kJ/kg

II. **Air Feedrate:** The air supply rate is calculated from a knowledge of the stoichiometric air requirement and a selected excess air level:

$$F_a = F_f \cdot S_a (1 + X) \quad (3)$$

where, F_a = air feedrate, kg/s
S_a = stoichiometric air, kg air/kg fuel
X = excess air level

$$= \frac{\text{Actual air supply} - \text{Stoichiometric requirement}}{\text{Stoichiomteric requirement}}$$

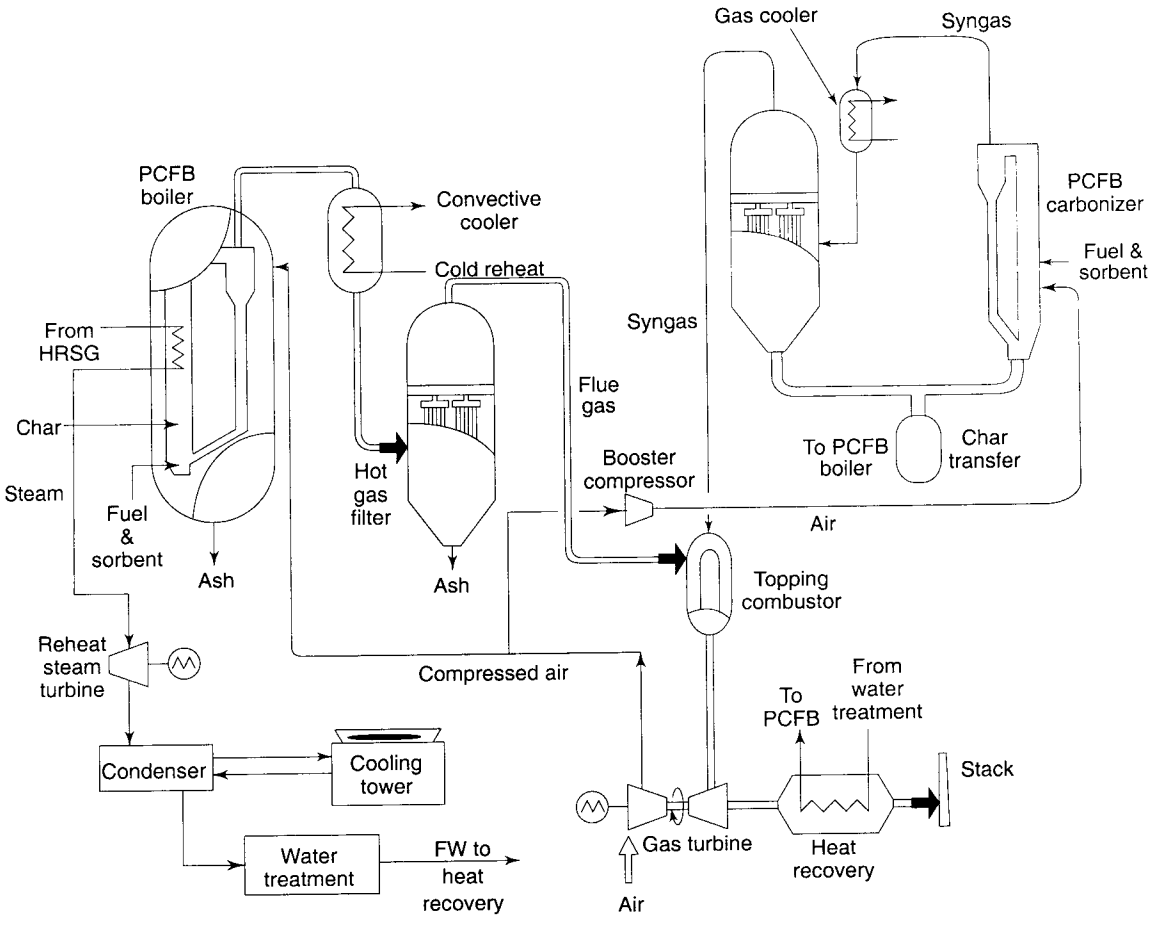


Fig. 38.21 *Advanced PCFB cycle.*

Courtesy: Ahlstrom Pyropower
Source: PTP–102 (TECH. PAP./Ahlstrom Pyropower)

III. **Heat Supply to BED:** Of the total fuel heat input to the boilers (q_i), a proportion remains unburnt and the remainder is released by combustion, mainly in the bed but also in the freeboard. However, a part of the heat liberated in the freeboard zone is transferred back to the bed by particle splashing. Therefore, the rate at which heat is supplied to the bed is

$$q_b = f.q_i \tag{4}$$

where, q_b =heat supply to bed, W

f = fraction of the heat input available in the bed
= 0.9–0.95 (typically)

IV. **Heat Lost to Air and Fuel Preheating:** A part of the bed-heat goes to preheat the air and fuel to bring them to the bed temperature and leaves the bed surface in the form of hot combustion gases containing carryover solids:

$$q_g = [F_f + F_a] \cdot H_g - [F_f \cdot H_f + f_a \cdot H_a] \tag{5}$$

where q_g =heat required to bring air and fuel to bed temperature, W

H_g = enthalpy of dust-laden gas at the bed-surface, kJ/kg

H_f = enthalpy of fuel, kJ/kg

H_a = enthalpy of air, kJ/kg

V. **Heat Lost to Sulphation:** A part of the bed-heat is expended to sulphation—retention of fuel-sulphur by limestone or dolomite

$$CaCO_3 + SO_2 + 1/2O_2 \longrightarrow CaSO_4 + CO_2 + 303 \text{ kJ/g mol}$$

and during the process, heat is required for heating limestone (or dolomite) to the bed temperature and calcination and some heat is released by sulphation. Thus, there will be a net heat requirement, q_s. Where, q_s = net heat requirement for sulphur retention additive, W

VI. **Effective Heat:** Thus the surplus heat becomes available for steam generation

$$q_e = q_b - q_g - q_s \tag{6}$$

where, q_e = effective heat available in the bed for transfer duty, W. This heat must be transferred directly to the inbed tube surface to maintain the bed temperature constant at T_b.

VI. **Surface Area of Inbed Tubes:** The heat flux to surfaces immersed in the bed is usually correlated by:

$$q_t = q_{cv} + q_{rad} \tag{7}$$

where, q_t = heat transfer to the inbed tubes, W

q_{cv} = convective heat transfer (bed-to-surface), W

$= h_{cv} \cdot A\ (T_b - T_t)$

q_{rad} = radiative heat transfer (bed-to-surface), W

$= \varepsilon \cdot \sigma \cdot A\ (T_b^4 - T_t^4)$

$$q_t = h_{cv} \cdot A \cdot (T_b - T_t) + \varepsilon \cdot \sigma \cdot A\ (T_b^4 - T_t^4) \tag{8}$$

where, h_{cv} = bed-to-surface convective heat transfer coefficient, W/(m^2·°K)

A = surface area of tubes in contact with bed, m^2

T_b = bed temperature, °K

T_t = surface temperature of inbed tubes, °K

ε = emissivity

σ = Stefan-Boltzmann constant = 5.667 × 10^{-8} W/(m^2·°K^4)

In a boiler producing saturated steam, convection represents about 75% of the heat transfer; radiation becomes increasingly important at a higher metal surface temperature.

For a FBC boiler with the combustion chamber laid up with waterwalls the above equation can be used to calculate the heat flux to the wall area in contact with the bed, q_w, using a value for h_{cv} appropriate to the wall. Allowance should be made for heat transfer to the wall in the splash zone, through which the coefficient falls off progressively to that for the dust-laden gas in the freeboard.

Radiation heat flux, q'_{rad} from the bed surface to a cooled freeboard should also be estimated.

If $q_w + q'_{rad}$ is found to exceed q_e, the furnace design is modified to reduce the wall-area contacting the bed. This is accomplished either by reducing the bed-depth or installing insulation.

Therefore, using the foregoing equation, the surface area of the inbed tubes required to extract the remainder of the heat is:

$$A_t = \frac{q_e - (q_w + q'_{rad})}{h_{cv}(T_b - T_t) + \varepsilon \cdot \sigma \cdot (T_b^4 - T_t^4)} \tag{9}$$

where, A_t = surface area of the immersed tubing, m^2

VIII. **Tube Length and Tube Arrangement:** The length of the tubing to provide this surface area (A_t) can be calculated from

$$\pi \cdot d_t \cdot L = A_t$$

$$\therefore L = A_t / (\pi d_t) \tag{10}$$

where, L = inbed tube length, m

d_t = OD of inbed tubes, m

The tube diameter (d_t) is typically in the range of 25 to 120 mm

The centre-to-centre pitch is selected such that the gap between tubes is at least 25 mm.

IX. Bed-to-Surface Convective Heat Transfer Coefficient (h_{cv}): The value of the convective heat transfer coefficient, h_{cv}, is determined chiefly by the particle size of the bed material while the tube arrangement and metal temperature exercise only a secondary effect. For a given size of bed particles, the value of the coefficient is not usually changed significantly by variations in the fluidizing velocity within the operating range of the boiler.

$$h_{cv} = h_{pc} + h_{gc} \tag{11}$$

where, h_{cv} = particle convective component, W/(m^2·°K) which remains significant over the particle size range: 40 μm – 1 mm.

h_{gc} = interphase gas convective component, W/(m^2·°K). The threshold of significance for this factor begins at mean particle dia ≥ 800 μm.

1. Particle Convective Component

The particle convective component of the heat transfer coefficient (h_{pc}) principally depends on the bed bubbling behaviour and is responsible for the characteristic sharp increase in the bed-to-surface heat transfer coefficient.

According to Gel' Perin et. al.

$$h_{pc} = \frac{1}{R_a}\left(1 - \frac{R_w}{2R_a}\cdot\left(1 + \frac{2R_a}{R_w}\right)\right) \tag{12}$$

where, R_a = resistance to heat transfer within the packet phase assuming that the particles move in 'packets' through the bulk of the bed

$$= \left(\frac{\tau\pi}{4k_{cr}\cdot\rho_{cr}\cdot C_p}\right)^{1/2}, \text{ m}^2\cdot\text{°K/W} \tag{13}$$

τ = packet residence time adjacent to surfaces, s

k_{cr} = thermal conductivity of bed at minimum fluidization, W/(m·°K)

ρ_{cr} = density of bed at minimum fluidization, kg/m^3

C_p = heat capacity of particle, J/(kg °K)

R_w = resistance to heat transfer at wall, W/(m^2·°K)

$$= \frac{d_p}{2k_w} \tag{14}$$

d_p = diameter of particle, m

k_w = effective thermal conductivity of bed in the near-wall-region, W/(m·°K)

2. Interphase Gas Convective Component

It may be responsible for the entire interphase convective heat transfer when particles fluidized are larger than 3 mm size. The best fit correlation, suggested by Baskakov et. al. (1974), for the interphase gas convective component (h_{gc}) is:

$$\text{Nu}_{gc} = h_{gc}\frac{d_p}{k_o} = 0.009\ [\text{Ar}]^{1/2}\cdot[\text{Pr}]^{1/3} \tag{15}$$

where, Ar = Archimedes No.

$$= \frac{d_p^3\cdot(\rho_p - \rho)\cdot\rho\cdot g}{\mu^2} \tag{16}$$

Pr = Prandtl No.

$$= \frac{\mu\cdot C_{p,g}}{k_g} \tag{17}$$

ρ_p = particle density, kg/m^3

ρ = density of fludizing medium, kg/m^3

$C_{p,g}$ = mean sp. heat of gas, kJ/(kg·°K)

μ = dynamic viscosity of gas, Pa.s

Botterill proposed an alternative empirical correlation

$$h_{gc}\frac{d_p^{1/2}}{k_g} = 0.86\ Ar^{0.39} \qquad (18)$$

for $10^3 < \text{Ar} < 2 \times 10^6$

X. **Overall Bed-to-Surface Heat Transfer Coefficient:** The overall bed-to-surface heat transfer coefficient is the sum of the convective component and radiative component, i.e.

$$h = h_{cv} + h_{rad} \qquad (19)$$

where, h_{rad} = radiative component, W/(m^2·°K)

$$= \frac{q_{rad}}{A\cdot[T_b - T_t]}$$

$$= \frac{\varepsilon\cdot\sigma\cdot A\cdot\left(T_b^4 - T_t^4\right)}{A\,(T_b - T_t)}$$

$$= \varepsilon\cdot\sigma\cdot\left(T_b^2 + T_t^2\right)\,(T_b + T_t) \qquad (20)$$

From the analysis of experimental results a simplified correlation results:

$$h_{rad} = 7.3\ \sigma\cdot\varepsilon_p \times \varepsilon_s\, T_t^3 \qquad (21)$$

for $0.3 < \varepsilon_p < 0.6$

Baskakov (1978) proposed [Process of Heat and Mass-Transfer in Fluidized Bed—A.P. Baskakov (ed.)/Mettalurgia, Moscow]:

$$h = k_g\left[0{\cdot}85\,(\text{Ar})^{0{\cdot}19} + 0{\cdot}006(\text{Ar})^{0{\cdot}5}\cdot(\text{Pr})^{0{\cdot}33}\right]/d_p + 7.3\ \sigma\cdot\varepsilon_p\cdot\varepsilon_s\cdot T^3 \qquad (22)$$

If radiation effects are ignored, the appropriate correlation for the maximum bed-to-surface heat transfer coefficient, as recommended by Zadbroadsky, is:

$$h_{\max} = 35.8\ \rho_p^{0.2}\cdot k_g^{0.6}/d_p^{0.36} \qquad (23)$$

XI. **Bed Temperature:** The volatile matter content in coal can account for up to 40% of the heat released in combustion. During the process of combustion, volatile matter is released and burnt out first and the resulting mass of char burns out then.

In shallow bed fired boilers, it is desired to limit the supply of excess air to maintain the bed temperature without having to use immersed cooling tubes while in deep beds non-combustion of the volatile can produce overcooling. These two extremes are depicted in Fig.38.22.

Drawing a simplified overall heat balance applicable to either system under steady-state condition we get:

Heat released in the bed = Heat absorbed by air
+ Solids heat removal
+ Heat abstracted by cooling surfaces

i.e., $F_f\cdot H^c\cdot\eta_c = F_a\cdot\overline{C}_{P,\,g}\cdot(T_b - T_o) + F_f\cdot\overline{C}_{P,\,s}\,(T_b - T_o) + q_t \qquad (24)$

where, η_c = combustion efficiency

H^c = heat of combustion, kJ/kg

$\overline{C}_{P,\,g}$ = mean sp. heat of the flue gas, kJ/(kg. °K)

T_b = bed temp., °K

T_o = initial air temp., °K

$\overline{C}_{P,\,s}$ = mean specific heat of bed solids, kJ/(kg. °K)

$$q_t = q_t^*\left(\frac{T_b - T_w}{T_b^* - T_w}\right) \qquad (25)$$

q_t^* = heat removed by cooling surfaces at design temperature and flow, W

T_b^* = bed temperature (design), °K

For the sake of convenience we can introduce

$$q_w^* = f\cdot F_c^*\cdot H^c\cdot\eta_c \qquad (26)$$

$$\alpha_c = F_c/F_c^* \qquad (27)$$

$$\alpha_a = F_a/F_a^* \qquad (28)$$

$$r_a^* = r_s\,(1 + X^*) \qquad (29)$$

where asterisked values represent basic design values.

α_c = actual coal flow divided by design value

α_a = actual airflow divided by design value

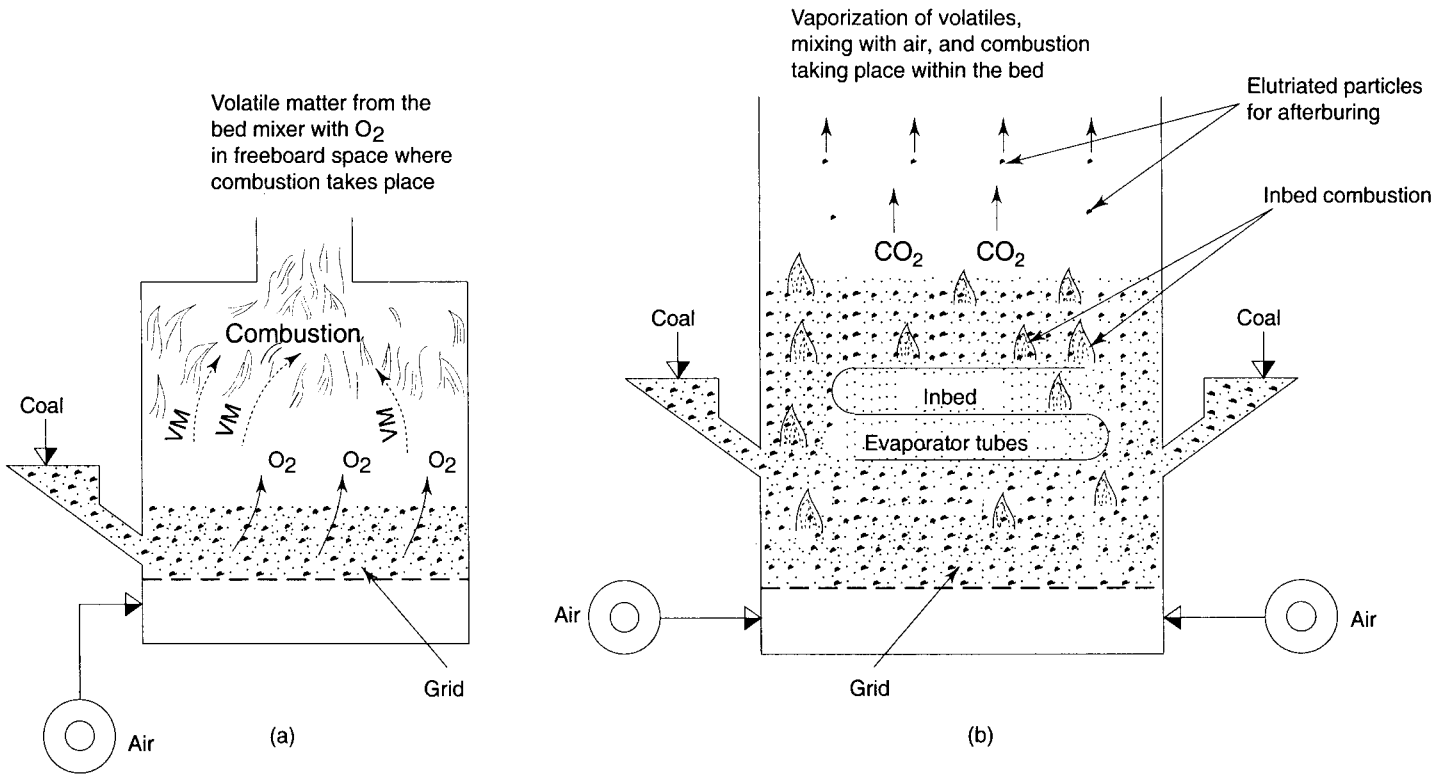


Fig. 38.22 *Emission & Combustion of Volatiles from Fluidized Bed*
(a) Combustion in Freeboard (Shallow Bed)
(a) Inbed Combustion (Deep Bed)

r_a = air/fuel ratio = F_a/F_f

r_s = air/fuel ratio at stoichiometric composition

Substitution of the above parameters in the heat balance results:

$$\alpha_c \cdot H^c \cdot \eta_c = (\alpha_a \cdot r^*_a \cdot C^*_{P,g} + \alpha_c \cdot \overline{C}_{P,s})(T_b - T_o) + f' \cdot H^c \cdot \eta_c \left(\frac{T_b - T_w}{T_b^* - T_w}\right) \quad (30)$$

where, f' = fraction of inbed heat removal

Bed temperature is obtained from this equation.

Note: In typical uses,

1. the design values are set by the fluidization characteristics
2. $\alpha_a = \alpha_c = 1$
3. allowable air flowrate is set by poor fluidization and excessive elutriation
4. $\eta_c \simeq 1$ in deep beds as the VM usually burns within the bed
   $\eta_c \simeq 0.6$ in shallow beds
5. the heat removal fraction, f, is set to obtain the desired bed temperature at design conditions.

Bed Temperature

Problem 38.7 A FBC boiler with inbed evaporator tubes operates with 20% of excess air with a designed bed temperature of 1225°K. If the combustion efficiency is 100%, estimate the bed temperature from the following data:

Tube wall temperature = 490°K

Inlet air temperature = 300°K

Stoichiometric air/fuel ratio = 9

Inbed heat removal efficiency = 50%

Specific heat of flue gas = 1.2 kJ/(kg · °K)

Specific heat of ash = 0.7 kJ/(kg · °K)

Net calorific value of coal = 26 MJ/kg

Solution The actual bed temperature (T_b) can be computed from the heat balance equation (Eqn. 30)

$$\alpha_c \cdot H^c \cdot \eta_c = (\alpha_a \cdot r^*_a \cdot \overline{C}_{P,g} + \alpha_c \cdot \overline{C}_{p,s})(T_b - T_o) + f' \cdot H^c \cdot \eta_c \left(\frac{T_b - T_w}{T_b^* - T_w}\right)$$

$$\alpha_c \cdot (26\,000)(1) = [\alpha_a \cdot 9(1 + 0.2)(1.2) + \alpha_c(0.7)][T_b - 300] + 0.5\,(26\,000)(1)\left(\frac{T_b - 490}{1225 - 490}\right)$$

$$\text{or, } 26\,000\left(\alpha_c - 0.5\,\frac{(T_b - 490)}{735}\right) = [12.96\,\alpha_a + 0.7\,\alpha_c] \cdot [T_b - 300]$$

Taking $\alpha_c = \alpha_a = 0.6$ we get

$$26\,000\left(0.6 - \frac{T_b - 490}{1470}\right) = 8.196\,[T_b - 300]$$

$\therefore\ T_b = 1032.54$°K ***Ans.***

Bed-to-Surface Heat Transfer Coefficient

Problem 38.8 A FBC combustion unit using 20% excess air is held at a constant bed temperature of 1233°K by virtue of inbed evaporator tubes that take care of the generated heat. The bed material is of close size distribution:

$d_p = 500\ \mu m$

$\rho_p = 2667\ kg/m^3$

Estimated thermal conductivity of flue gas is 8.45×10^{-2} W/(m.°K). Calculate the bed-to-surface heat transfer coefficient.

Solution: We shall use Zadbrodsky's relationship (Eqn. 23) to calculate the max. value of bed-to-surface heat transfer coefficient:

$$h_{max} = 35.8\ \rho_p^{0.2} \cdot k_g^{0.6}/d_p^{0.36}$$
$$= 35.8\ (2667)^{0.2}\ (8.45 \times 10^{-2})^{0.6}/(500 \times 10^{-6})^{0.36}$$
$$= 607.536\ W/(m^2 \cdot °K)$$ ***Ans.***

Inbed Evaporator Tube Length

Problem 38.9: If in the above problem, the heat input rate to the boiler is 75 MW, calculate the length of the evaporator coil (tube OD = 75 mm)

Assume 10% bed heat is lost to air-fuel preheating and 5% goes to sulphation.

Skin temperature of immersed tubes = 500°K.

Solution Heat input to boiler

$$q_i = 75 \text{ MW}$$

Assuming 90% of this input energy (fuel) is realized as bed heat

$$q_b = 0.9\ (75) = 67.5 \text{ MW}$$

Taking into account of bed-heat-loss (as given), the effective heat available for transfer to inbed evaporator tubes:

$$q_e = 67.5\ [100 - (10 + 5)]\% = 57.375 \text{ MW}$$

$$\therefore\ 57.375 \times 10^6 = [h_{cv}\ (T_b - T_t) + \varepsilon \cdot \sigma \cdot (T_b^4 - T_t^4)] \cdot A_t$$

$$= [607.536\ (1233 - 500) + 0.45(5.667 \times 10^{-8})\ \{[1\ 2\ 3\ 3]^4 - [500]^4\}] \cdot A_t$$

Taking emissivity of tube surface equal to 0.45

$$\therefore\quad A_t = 114.14023 \text{ m}^2$$

$$\text{or,}\qquad (75 \times 10^{-3}) \cdot l_t = 114.14023$$

$$\therefore\quad l_t = 484.426 \text{ m} \qquad \textbf{Ans.}$$

Inbed Evaporator Design

Problem 38.10 Design an inbed looptype evaporator for a fluidized bed boiler operating at a bed temperature of 1150°K.

BFW temperature at evaporator inlet = 433°K

BFW temperature at evaporator outlet = 573°K

Mean velocity of BFW flow = 0.6 m/s

BFW flowrate = 230 t/h

Evaporator tube dimension: OD/Wall thickness = 50 mm/5 mm

Mean particle size = 850 μm

Particle density = 1550 kg/m^3

Thermal conductivity of flue gas = 0.05 W/(m.°K)

Thermal conductivity of tube metal = 32 W/(m.°K)

Solution In order to estimate the heating surface required to meet the prescribed heat load of the evaporator, we shall resort to the basic equation for heat exchanger performance:

$$q = U.A.LMTD$$

where, q = heat load of the economizer, W

U = overall heat transfer coefficient, W/(m^2·°K)

A = heat exchange surface area of evaporator, m^2

$LMTD$ = logarithmic mean temperature difference between the bed and working fluid, °K

Step I. Calculation of LMTD

For *LMTD* calculation refer to Fig. 38.23

Assuming thorough mixing of particles throughout the bed,

$$LMTD = \frac{\Delta\Theta_1 - \Delta\Theta_2}{\ln\left(\frac{\Delta\Theta_1}{\Delta\Theta_2}\right)}$$

where, $\Delta\Theta_1$ = temperature difference between the bed and the BFW at the evaporator inlet

$$= 1150 - 433$$

$$= 717°\text{K}$$

$\Delta\Theta_2$ = temperature difference between the bed and BFW at the evaporator outlet

$$= 1150 - 573$$

$$= 577°\text{K}$$

$$\therefore\ LMTD = \frac{717 - 577}{\ln\left(\frac{717}{577}\right)} = 644.46°\text{K}$$

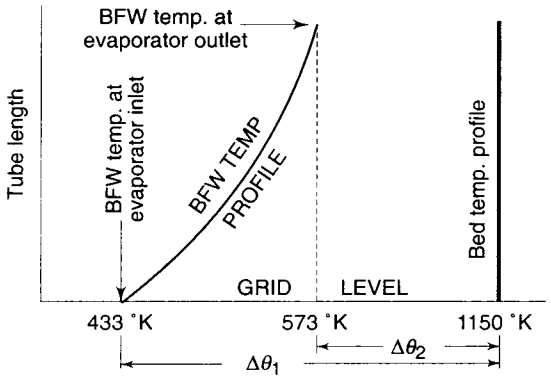


Fig. 38.23 *Temperature variation along a tube submerged in a fluidized bed having uniform temp. throughout.*

The overall heat transfer coefficient, U, is given by

$$\frac{1}{U} = \frac{1}{h} + \frac{1}{h_w} + \frac{1}{(k_w/\delta_w)}$$

where, h = bed-to-surface heat transfer coefficient, W/(m^2·°K)

h_w = heat transfer coefficient for heat transfer from tubewall to BFW, W/(m^2·°K)

k_w = thermal conductivity of tubewall, W/(m^2·°K)

δ_w = tubewall thickness, m

Step II. Bed-to-Surface Heat Transfer Coefficient

Ignoring radiation effects, the maximum bed-to-surface heat transfer coefficient

$$h_{max} = 35.8\ [\rho_p]^{0.2}\ [k_g]^{0.6}/[d_p]^{0.36}$$
$$= 35.8\ [1550]^{0.2}\ [0.05]^{0.6}/[850 \times 10^{-6}]^{0.36}$$
$$= 328.655\ \text{W/(m}^2\cdot\text{°K)}$$

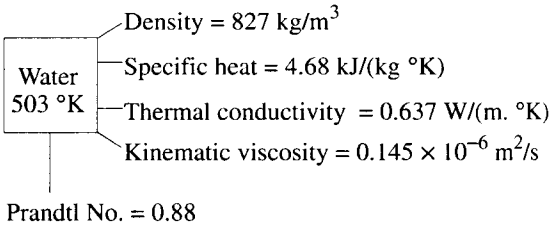
However, as per Botterill et. al's (1984) recommendation we shall take 70% of the value of h_{max} obtained from Zadbrodsky's eqn.

$$\therefore \quad h = 0.7\ (h_{max}) = 230\ \text{W/(m}^2\cdot\text{°K)}$$

Step III. Heat Transfer Coefficient for Water

Arithmetic mean temperature of BFW in the evaporator

$$= 1/2\ (433 + 573)$$
$$= 503°\text{K}$$



Reynolds No. for water at mean water temperature

$$\text{Re} = \frac{v \cdot d_i}{\nu} = \frac{(0.6)\ (50 \times 10^{-3})}{0.145 \times 10^{-6}} = 206\ 896$$

$\therefore$ Re > 10^4 and Pr > 0.7.

Therefore, we shall use the following correlation to determine h_w:

$$\text{Nu} = 0.021\ \text{Re}^{0.8}\ \ \text{Pr}^{0.43} \left(\frac{\text{Pr}}{\text{Pr}_{wall}}\right)^{0.25}$$

where, Pr = Prandtl No. for water at mean BFW temperature (503°K) = 0.88

Pr_{wall} = Prandtl No. for water at wall temperature

Let us take $[\text{Pr}/\text{Pr}_{wall}]^{0.25} \approx 1$ taking into account that the local heat transfer coefficient on the waterside exceeds that on the bedside considerably. Consequently, the wall temperature is close to water temperature

$$\therefore\ \nu = 0.021\ [206\ 896]^{0.8}\ [0.88]^{0.43} = 355.5899$$

$$\therefore\ h_w = \nu \frac{k_w}{d_i} = 355.59 \left(\frac{0.637}{50 \times 10^{-3}}\right)$$
$$= 4530\ \text{W/(m}^2 \cdot\ \text{°K)}$$

Step IV. Overall Heat Transfer Coefficient

$$\frac{1}{U} = \frac{1}{230} + \frac{1}{4530} + \frac{1}{32/(5 \times 10^{-3})}$$

$\therefore \quad U = 211.6479 \text{ W/(m}^2 \cdot \text{°K)}$

Step V. Heat Load of Evaporator

$$q = \dot{M} \cdot C_p \cdot \Delta\theta = \frac{230 \times 10^3}{3600} (4.68) (573 - 433)$$

$$= 41\ 860 \left(\frac{\text{kg}}{\text{s}}\right)\left(\frac{\text{kJ}}{\text{kg} \cdot \text{°K}}\right)(\text{°K})$$

$$= 41\ 860 \text{ kW}$$

Step VI. Heat Transfer Surface of Evaporator

$U.A.\ LMTD = 41\ 860 \times 10^3$

or, $211.6479\ (A)\ (644.46) = 41\ 860 \times 10^3$

$\therefore A = 306.8945 \text{ m}^2$

Step VII. No. of Loops

If 'n' is the number of loops connected in parallel,

$$\frac{\pi}{4} \cdot d_i^2 \cdot v \cdot \rho \cdot n = \frac{230 \times 10^3}{3600}$$

or, $\frac{\pi}{4} (50 \times 10^{-3})^2 \cdot (0.6)\ (827) n = \frac{230 \times 10^3}{3600}$

$\therefore n \approx 66$ loops

Step VIII. Length of Each Loop

If 'l' is the length of an individual section (loop),

$\pi \cdot d_o \cdot n \cdot l = 306.8945$

or, $\pi\ (55 \times 10^{-3})\ (66)\ l = 306.8945$

$\therefore l = 26.9248 \text{ m} \approx 27 \text{ m}$ ***Ans.***

Inbed Evaporator Design

Problem 3.11: Peat is burned in a fluidized bed of sand containing 1% mass of fuel and using 20% excess of stoichiometric air.

Bed temperature = 1125°K

Fuelling rate = 60 MW

Operating velocity of fluidizing air = 2.5 m/s

Density of air at 1125°K = 0.3144 kg/m^3

If 10% of the heat generated in the bed is lost to radiation from the freeboard surface and another 10% escapes through the insulated wall of FBC, estimate the surface area of inbed evaporator tubes required to keep the bed temperature steady at 1125°K.

Also estimate:

1. fuel charging rate
2. air feedrate
3. bed planform area
4. required rate of heat removal from FBC.

BFW preheated to 475°K circulates through the evaporator coils and exits at 625°K.

Percentage composition of peat is:

C – 58% ; H – 5.45%; O – 33.45%; N – 0.75%; Ash – 2.35% (all by wt.)

Bed-to-immersed-tube transfer coefficient

$= 300 \text{ W/(m}^2 \cdot \text{°K)}$

Heat transfer coefficient for heat transfer from tubewall to BFW = 4500 W/(m^2 · °K)

Heat flowrate per kg of fuel burned

= 12 198 kJ/kg.

Also calculate the length of the tubing (ID = 75 mm/W. thick = 6 mm)

Thermal conductivity of the tubewall material = 32 W/(m. °K)

Solution: The heat transfer surface area, A_t, for the inbed evaporator coils can be estimated from

$$q = U \cdot A_t \cdot LMTD$$

where, q = heat removal rate by evaporator tubes, W

U = overall heat-transfer coefficient, W/(m^2·°K)

$LMTD$ = log-mean-temp.-diff., °K

Step I. Overall Heat Transfer Coefficient

The overall heat transfer coefficient, U, can be computed from

$$\frac{1}{U} = \frac{1}{300} + \frac{1}{4500} + \frac{6 \times 10^{-3}}{32}$$

$\therefore \quad U = 267.1614 \text{ W/(m}^2 \cdot \text{°K)}$

Step II. LMTD

	Evaporator Inlet	Evaporator Outlet
BED	1125°K	1125°K
BFW	475°K	625°K
	$\Delta\theta_1 = 650$°K	$\Delta\theta_2 = 500$°K

$$\therefore LMTD = \frac{650 - 500}{\ln\left(\frac{650}{500}\right)}$$

$$= 571.724\text{°K}$$

Step III. Oxygen Requirement for Combustion

PEAT Comp.	WT%	Molar Volume	Modified Molar Volume	Combustion Reaction	Oxygen Required for Combustion (Molar vol.)
C	58	$\frac{58}{12} = 4.833$	4.833	$C + O_2 \rightarrow CO_2$	4.833
H	5.45	$\frac{5.45}{2} = 2.725$	$2.725 - 2(10.45) = 0.635$	$H_2 + 1/2O_2 \rightarrow H_2O$	$1/2(0.635) = 0.3175$
O	33.45	$\frac{33.45}{32} = 1.045$			
N	0.75	$\frac{0.75}{28} = 0.0267$			Total = 5.1505

Step IV. Material Balance of PEAT Combustion

Basis : 100 kg of PEAT

$$PEAT + O_2 + N_2 \longrightarrow CO_2 + H_2O + N_2 + O_2$$

[Air] [Excess Air]

Input			Output		
Component	Mol. Vol.	Weight (kg)	Flue Gas	Mol. Vol.	Weight (kg)
(A) FUEL					
C	4.833	57.996	CO_2	4.833	212.652
H	0.635	1.27	H_2O	2.725	49.05
		96.886	N_2	19.4027	543.275
(B) AIR					
O_2	5.1505	164.816			
N_2	19.376	542.528			
		804.977			804.977

Step V. Calorific Value of PEAT

Reactant	Combustion Reaction	Heat of Reaction	Heat Produced (kJ/kg)
C	$C + O_2 \longrightarrow CO_2$	$34071.71 \frac{kJ}{kg}$	$34071.71 \frac{58}{100} = 19761.59$
H	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	$121025 \frac{kJ}{kg}$	$121025 \frac{1.27}{100} = 1537.02$
			Total = 21298.61

Therefore, 21 298.61 kJ of heat is liberated per kg of peat burned.

Fuel	Stoichiometric Air
96.886 kg	164.816 + 542.518 = 707.344 kg

Step VI. Fuel Charging Rate

Fuelling rate = 60 MW

Heat flowrate per kg of peat burned = 12 198 kJ

$$\therefore \text{ Rate of fuel charging} = \frac{60 \times 10^3 \text{ (kJ/s)}}{21298.6 \text{ (kJ/kg)}}$$

$$= 2.81708 \text{ kg/s} \quad \textbf{\textit{Ans.}}$$

Step VII. Air Feedrate

20% excess air is supplied to induce fluidization as well as to support combustion.

$$\therefore \text{ Air feedrate} = 1.2 \left(\frac{707.344}{96.886}\right) (2.81708)$$

$$= 24.6802 \text{ kg/s} \quad \textbf{\textit{Ans.}}$$

Step VIII. BED Planform Area

Air density = 0.3144 kg/m^3

Air velocity = 2.5 m/s

$$\therefore \text{ Planform area} = \frac{24.6802 \text{ (kJ/s)}}{0.3144 \left(\frac{\text{kg}}{\text{m}^3}\right) \times \left(\frac{\text{m}}{\text{s}}\right)}$$

$$= 31.3998 \text{ m}^2 \quad \textbf{\textit{Ans.}}$$

Step IX. Heat Removal Rate

12 198 kJ of heat is to be removed for every kg of fuel burned. Therefore, the required rate of heat removal

$$= 12\ 198(2.81708)$$

$$= 34\ 362.74 \text{ kW} \quad \textbf{\textit{Ans.}}$$

Step X. Heat Transfer Area

Heat lost to radiation = 10% of the generated heat

Heat lost thru walls = 10% of the generated heat

Heat removal rate by the inbed evaporator tubes

$$= 34\ 362.74\ (0.80) \text{ kW}$$

$$= 27\ 490.19 \text{ kW}$$

$$\therefore 27\ 490.19 \times 10^3 = 267.1614\ (A_t)\ (571.724)$$

$$\therefore A_t = 179.977 \text{ m}^2 \simeq 180 \text{ m}^2 \quad \textbf{\textit{Ans.}}$$

Step XI. Length of Tubing

If l_t be the total length of evaporator tubes,

$$\pi \cdot d_o \cdot l_t = A_t$$

or, $l_t = 180/[\pi\ (81 \times 10^{-3})] = 707.714$ m **Ans.**

Q. *What problems are faced in the design of air distributors and how are they designed?*

Ans. For small-scale FBC units, a porous tile of sintered metal or ceramics serves as an excellent distributor. But for large units, porous tiles present constructional difficulties—many tiles are required to cover large bed areas and it is neces-

sary to seal between them while providing allowance for thermal expansion.

Perforated plate distributor is another popular design. But they have the tendency to allow fall-through of bed materials. Forasmuch as the plates operate at or near the bed temperature, they must be manufactured from a heat-resistant alloy plus they must be designed to retain sufficient mechanical strength at the operating temperature to support the weight of the bed.

Again there are distributors which receive hot gases from oil or gas combustion and direct the combustion gases into the bed for fluidization and heat transfer. Such distributors must be designed to accept the hot gas. One approach is to retain the nozzle standpipe design and water cool the baseplate, with insulation on the underside. The plate can either be of sandwich construction or an alternative design uses heat-resistant steel and allows for thermal expansion. One method of achieving this is to instal a grid of pipes (sparge pipes) with multiple air outlets to introduce the air above the solid base of combustion chamber. The sparge pipes may have drilled holes in the underside or be fitted with nozzle standpipe.

Q. *What is the advantage of sparge pipes?*

Ans. They can expand from the fixed end to accommodate thermal expansion while maintaining a gastight seal.

Q. *What is the disadvantage of sparge pipes?*

Ans. They must be carefully designed. The design must take into account circumferential temperature gradients which can give rise to pipe distortion.

Q. *What is the height of the nozzles above the baseplate?*

Ans. Typically 50–100 mm.

Q. *What is the nozzle dia?*

Ans. Typically 12 to 25 mm.

Q. *How are the nozzles arranged?*

Ans. They are usually arranged on a uniform pitch of 75 to 100 mm over the baseplate.

Q. *How is the hole dia of the nozzles designed to minimize particle fall-through?*

Ans. The hole size is kept in the range of 2–5 mm which is a compromise between having an excessive number and allowing particle fall-through. Larger holes/slots are sometimes used but they are always associated with bubblecaps to prevent fall-through.

Q. *What should be the distributor pressure-drop?*

Ans. A distributor pressure-drop of about 12% of that across the bed-depth (typically 1.5 mm water gauge per mm of static depth) is usually required to ensure uniform distribution for the beds used in fluidized combustion. However, the distributor pressure-drop increases with the square of air flowrate if the bed pressure-drop is held constant. Therefore, it is necessary to provide good distribution of the minimum air flowrate. On this basis, the distributor pressure-drop, at maximum airflow, must be:

48% of bed-drop for 2:1 turndown

108% of bed-drop for a 3:1 turndown.

This requires a distributor with an open area in the range of 0.5 to 2%.

Q. *How is coal fed to the fluidized bed combustors?*

Ans. During the early development of FB boilers, combustion was carried out using crushed coal whereupon it was found necessary to introduce the feed immediately above the distributor to ensure good combustion. This was achieved by pneumatic injection using pipes with a diameter 6 times that of the largest coal particle, to prevent blockage. The number of feed-nozzles varied from 1 to 2 per m^2 of the bed area.

However, more recently, many units have been designed to fire coal as supplied, without crushing and drying. Usually, the coal is metered by a rotary valve or screw on to a chute, down which it drops to the bed surface. This method relies entirely on the bed to distribute the coal, which being fed in large lumps, keeps entrainment of fines at a minimum. Alternatively there is another design that harnesses a spreader to distribute the oncoming coal over a wide bed cross-section. However, this system increases the possibility of rapid entrainment of fines. This method proves to be satisfactory if the feed coal is damp.

There is yet another successful technique: Feeding uncrushed coal below the bed-surface by a screw-feeder.

This system requires less feedpoints as the uncrushed coal has a lower rate of volatile release and elutriation.

Q. *Why is gas firing usually incorporated to fluidized bed coal fired units?*

Ans. It is incorporated so that it can be used to preheat the bed to about 925°K during start-up.

Also it bestows the FBC unit with cofiring capability.

Q. *How is it injected into the furnace?*

Ans. It is always premixed with the fluidizing air.

For small installations this premixing is carried out in the air plenum, but for large units considerable care is required for adopting this approach. Preferably the large plenum should be subdivided into multiple units. A preferred alternative is to inject the gas into the standpipes usually from a gas grid in or below the plenum.

Q. *Why are gas and fluidizing air not introduced separately into the bed?*

Ans. If the gas and the fluidizing airstream are introduced separately to the bed, it is generally observed that it gives rise to above-bed flame above each gas entrypoint. Obviously, this does not heat the bed to a temperature at which combustion occurs below the surface.

Q. *Why is a pilot burner provided above the bed?*

Ans. To light up gas firing.

Q. *Why is the gas start-up unit not used in units designed to operate at high fluidizing velocity?*

Ans. The object of gas firing is that there should be a sheet of flame at the bed surface, giving rapid heating of the bed particles so that combustion moves into the bed at a temperature of about 925°K. Therefore, it is very much essential during start-up that the fluidizing velocity should not exceed the flame speed of the gas being used. This is unlikely for units designed to operate at high fluidizing velocity and therefore, start-up through gas firing becomes void in these cases.

Q. *How is the additive feeding carried out?*

Ans. Limestone ($CaCO_3$) or dolomite ($CaCO_3$ $MgCO_3$) used for sulphur capture are crushed to the correct size to form the fluidized bed. This additive can be blended with coal before firing or it can be charged separately into the furnace by a pneumatic conveying system.

Q. *Why is only one additive-feedpoint usually sufficient?*

Ans. The additives enjoy greater residence time in the bed than fuel particles. So the additive particles introduced to the bed from a single feedpoint get sufficient time to get more or less uniformly distributed throughout the bed inventory.

Q. *How does the bed-inventory dictate the design of FB combustor units?*

Ans. When commercial size grades of coal or other inert-containing solid fuels are fired in FB combustors, there is a gradual accumulation of oversize inerts in the bed. Most of the coal-inerts tied to the ash are of relatively low density causing the ash particles to diffuse throughout the bed,

thereby increasing the mean particle size. This has the effect of increasing the minimum fluidizing velocity and therefore, for a given operating velocity, less gas will pass through the bed as bubbles, reducing the intensity of turbulence. If the accumulated mass of oversize inerts exceeds 20%, the reduced mixing rate will give rise to lateral temperature gradients, eventually leading to clinker formation around the fuel feedpoints. When this might occur, it is imperative to provide a bed-regrading system permitting periodic withdrawal of the bed material, separating the oversize by screening and returning the correct size to the bed.

Large, dense particles such as stones in coal segregate gradually and accumulate as a layer on the distributor. These heavier fractions deflect laterally and can be removed from the bed via a single off-take point provided that the feed material contains a very low percentage of such dense inerts. When this is not the case, it is necessary to make special provision to facilitate withdrawal of segregated materials. This is achieved by incorporating an inclined distributor with the off-take at the lowest point. An alternative approach is to use a spargepipe-distributor with a hopper base underneath, allowing slow withdrawal of segregated mass of inerts from the bed.

Q. *How are the inbed heat transfer tubes arranged?*

Ans. Heat transfer tubes for raising steam are normally laid horizontally for forced circulation of BFW, i.e. if the BFW is circulated by a pump.

For natural circulation boilers, the inbed evaporator tubes must be inclined 10–20° to the horizontal, depending on the particular design. Superheater tubes and airpreheaters are usually arranged horizontally.

Q. *What factors determine the layout of inbed tubes and selection of tube materials?*

Ans. 1. Fouling
2. Erosion
3. High temperature corrosion

For vertically laid tubes, flue gas bubbles tend to flow preferentially upwards in the tubes. And the bubbles in their wake bring solid particles that cause erosion of these tubes at bends from vertical to horizontal within the bed. Similarly, bubbles tend to flow preferentially up the line of the horizontal tubes arranged above each other and for this reason a triangular rather than a square tube-pitch is preferred.

Low fusible components in the fuel may fuse at bed temperature to form clinker on the tube-surface, thereby contributing to inbed fouling.

The fluidized bed is constantly in a state of high degree of turbulence of bed inventory containing highly abrasive silica. These particles inflict erosion to the tube surface. Highbed temperature accentuates mechanical wear out of metals.

Therefore, it is essential to make careful selection of materials for the inbed evaporator, superheater tubes and the tube banks of air-heating units.

Low-chromium ferritic steels are a good choice provided the higher limit of bed temperature is restricted to about 775°K. Austenitic steels such as types 304, 316, 321 and 347 demonstrate good performance up to 925°K with or without sorbent (limestone) addition. For bed temperatures as high as 1175°K, high-strength Ni-based alloys appear to be suitable, provided the bed is operated without limestone or dolomite. This is because with limestone addition, nickel-base alloys can suffer from intercrystalline grain boundary corrosion. For metal temperatures exceeding 925°K in beds of limestone, it is therefore necessary to use an iron-base austenitic steel, particularly type 347, up to 1075°K; above this temperature, it is necessary to use a low-strength super alloy such as GE2541 as a cladding material to protect a high-strength alloy base.

Q. *How is a PFBC (Pressurized Fluid Bed Combustion) unit designed?*

Ans. There are two forms of PFBC

1. **Air Cycle** (Air Heaters Combined Cycle)

2. **Supercharged Boiler** (Supercharged Boiler Combined Cycles)

AIR CYCLE is presented, in its simplest form, schematically in Fig. 38.24

Air from the compressor is split into two streams. While the smaller portion is directed to fluidize the bed and supply combustion air, the major portion is circulated through inbed tubes wherein it is heated (to a temperature approaching the combustor bed temperature) to be mixed with hot filtered flue gas downstream. The combined gas stream is allowed to expand through a GT, to drive the air compressor and to generate power. The exhaust stream is used to produce steam in HRSG and this steam is fed to a ST to generate power.

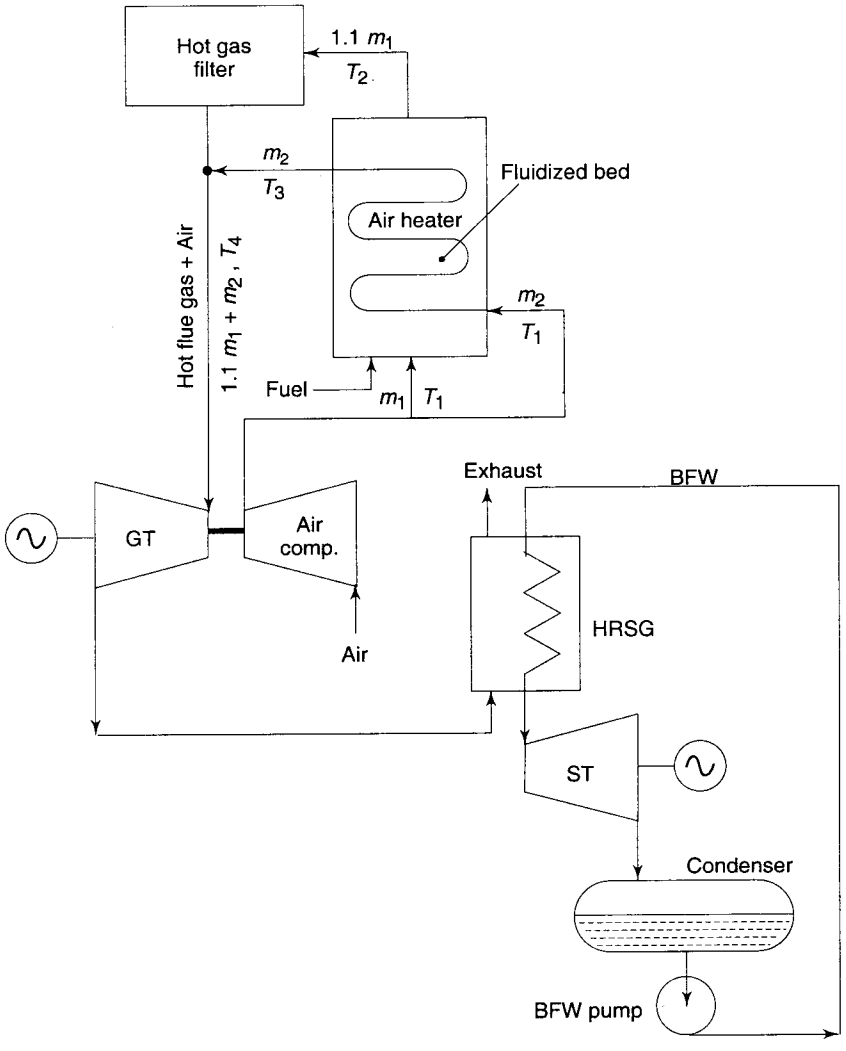


Fig. 38.24 *Basic air cycle.*

A heat balance over the combustor shown in Fig. 38.25 yields the equation:

$$[1.1\ m_1T_2 - m_1T_1]C_p + m_2[T_2 - T_1]C_p = 3100\ \frac{m_1}{\Omega} \quad (31)$$

where, $0.1\ m_1$ = coal mass flowrate (which varies slightly with excess air), kg/s

m_1 = mass flowrate of fluidizing air, kg/s

m_2 = mass flowrate of circulatory air, kg/s

Ω = excess air factor

$$= \frac{\text{Total air}}{\text{Stoichiometric air}}$$

C_p = Specific heat of gas or air, kJ/(kg. °K)

Note: For stoichiometric combustion, the heat input (gross) is about 3.1 MJ/kg air.

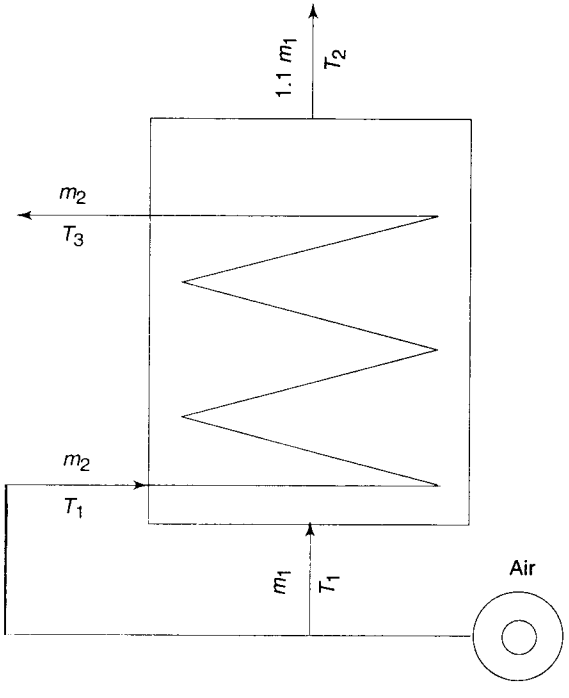


Fig. 38.25 *Heat balance over the combustor*

Heat balance around the mixing point (Fig. 38.26) upstream of the turbine inlet results

$$[1.1m_1 + m_2]T_2 = 1.1m_1T_2 + m_2T_3 \quad (32)$$

A heat balance across the airheater tubes (Fig. 38.27) yields:

$$m_2(T_3 - T_1) \cdot C_p = U \cdot A_t \cdot \Delta T \quad (33)$$

where, U = overall heat transfer coefficient across the tubewall, kW/(m^2 · °K)

A_t = surface area of tubes, m^2

ΔT = *LMTD* between the bed and the air in the tube, °K

From the tube geometry

$$A_t = 4\phi \cdot H \cdot a/d_o \quad (34)$$

and from the fluidizing conditions

$$1.1m_1 = v \cdot \rho \cdot a \quad (35)$$

where, ϕ = fraction of the bed volume occupied by the tubes

H = bed height, m

a = bed cross-sectional area, m^2

d_o = OD of tubes, m^2

v = fluidizing gas velocity, m/s

ρ = gas density at bed surface, kg/m^3

Combining Eqns. (31), (32), (33), (34) and (35) and rearranging we get:

$$H = \frac{v.\rho.d_o}{4.4\ \phi.U.\Delta T}\left(\frac{3100}{\Omega} - (1.1T_2 - T_1).C_p\right) \quad (36)$$

Supercharged Boiler Cycle: It is a combined steam-gas turbines cycle schematically represented in Fig. 38.28.

While the steam generated in the FB supercharged boiler (combustion at superatmospheric pressure) is used to drive the ST, the hot gases of combustion under pressure are allowed to expand in the GT resulting in an overall high efficiency of the combined cycle.

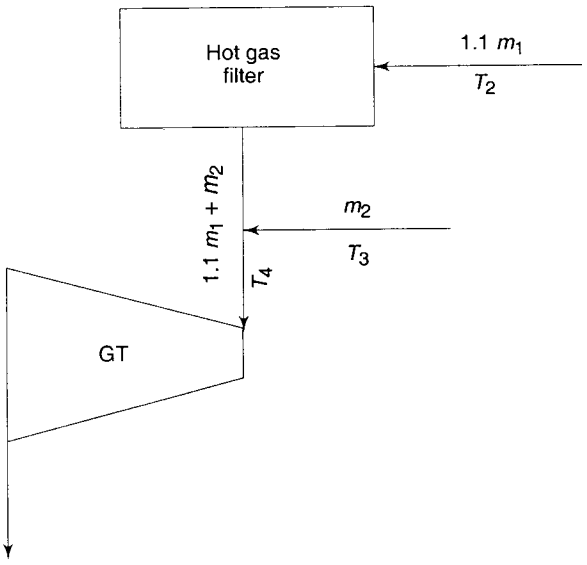


Fig. 38.26 *Heat balance around the mixing point.*

Following the similar analytical procedure for the supercharged boiler combined cycle to that described for the airheater cycle, we get:

$$1.1m_1 \cdot T_4 \cdot C_p - m_1 \cdot T_1 \cdot C_p + m_2 (E_2 - E_1) = 3100 \frac{m_1}{\Omega}$$

where, E = specific enthalpy of water or steam, kJ/kg

$$m_2(E_2 - E_1) = U \cdot A_t \cdot \Delta T$$

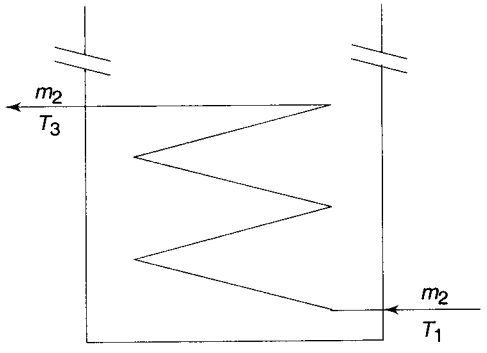


Fig. 38.27 *Heat balance across the airheater.*

$$A_t = 4\ \phi \cdot H \cdot a/d_o$$

$$1.1m_1 = v \cdot \rho \cdot a$$

Combining these Eqns. we get:

$$H = \frac{v.\rho.d_o}{4.4\ \phi.U.\Delta T} \left(\frac{3100}{\Omega} - (1.1T_4 - T_1).C_p \right) \quad (37)$$

This equation is similar to Eqn. 36. However, the overall heat transfer coefficient, U and *LMTD*, ΔT are considerably greater in the supercharged boiler than in the air heater. Therefore, the bed height, H, is considerably reduced.

Combustor Design

Problem 38.12: A *PFBC* Air Circle operates at a pressure of 1 MPa and bed temperature 1173°K.

Heat generated by combustion of coal, using 35% excess air, is abstracted by the inbed cooling coil through which air is circulated whereupon air temperature rises from 573°K (at

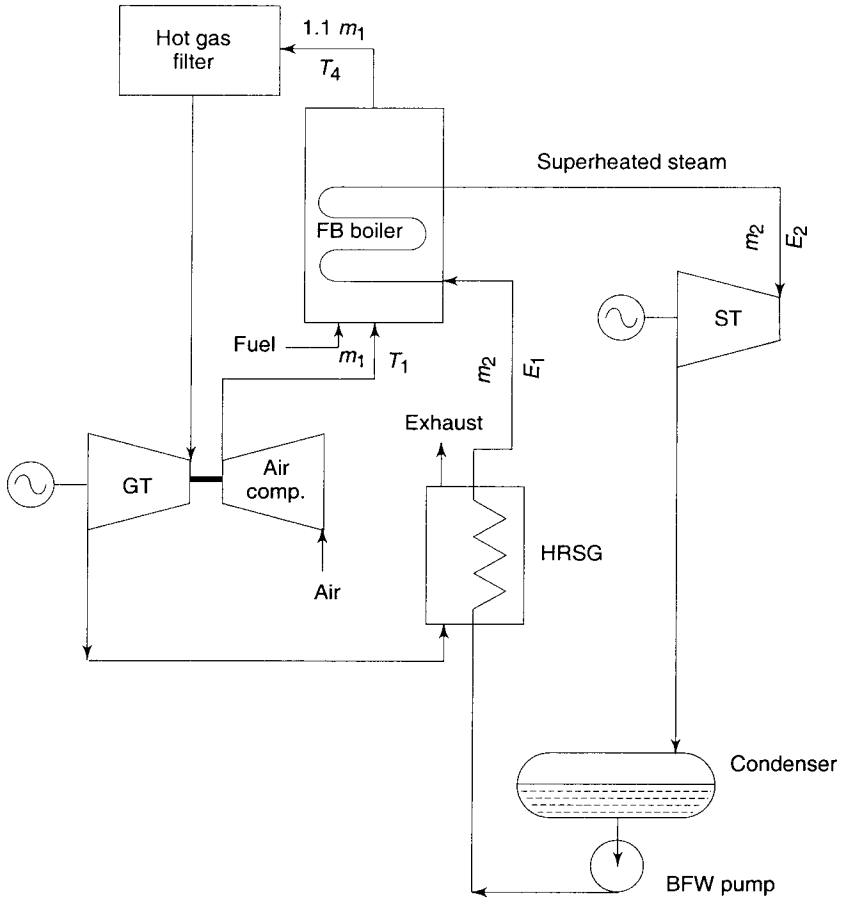


Fig. 38.28 *Supercharged boiler combined cycle.*

the bed inlet) to 1130°K (at the combustor outlet).

Pipe dia of cooling coil is 25.4 mm.

Bed volume occupied by the cooling coil = 17%.

Velocity of fluidizing air = 1 m/s

Flue gas density at the bed surface (1 MPa/1173°K) = 3 kg/m^3. Specific heat of flue gas = 1.29 kJ/(kg·°K)

Estimate the bed height if the overall heat transfer coefficient across the tubewalls = 255 W/(m^2·°K)

LMTD between the bed and the air in tubes = 90°K

Flue gas temperature at combustor outlet = 1173°K

Air + Flue gas mix temperature at GT inlet = 1143°K

Solution The given fluidizing conditions and tube conditions:

$v = 1$ m/s

$\rho = 3$ kg/m^3

$d_o = 0.0254$ m

ϕ = 0.17 forasmuch as 17% of the bed volume is occupied by the tubes

Ω = 1.35 (excess air used is 35%)

U = 0.255 kW/(m^2·°K)

C_p, g = 1.29/(kg·°K)

T_1 = 573°K

T_2 = 1173°K

T_3 = 1130°K

T_4 = 1143°K

Substitution of given data in Eqn. 36 yields:

$$H = \frac{1\,(3)\,(0.0254)}{4.4\,(0.17)\,(0.255)\,90}\left(\frac{3100}{1.35} - (1.1 \times 1173 - 573)\,1.29\right)$$

= 6.08 m ***Ans.***

Combustor Design

Problem 38.13 A PFBC Supercharged Boiler Combined Cycle operates at a pressure of 1 MPa and bed temperature 1173°K.

Heat generated by the combustion of coal under pressure and using 35% excess air is taken care of by the inbed boiler producing superheated steam used to drive the steam turbine.

Pipe dia of boiler tubes = 25.4 mm

Bed volume occupied by boiler tubes = 17%

Velocity of fluidizing air = 1 m/s

Flue gas density at bed surface (1 MPa/1173°K) = 3 kg/m^3

Specific heat of flue gas = 1.29 kJ/(kg·°K)

LMTD between the bed and the steam in tubes = 350°K

Overall heat transfer coefficient across the tubewalls = 300 W/(m^2·°K)

Air temperature at bed inlet = 573°K

Flue gas temperature at combustor outlet = 1173°K

Estimate the bed height.

Solution: From the given data

T_1 = 573°K

T_4 = 1173°K

Substitution of known values in Eqn. 37 results

$$H = \frac{1\,(3)\,(0.0254)}{4.4\,(0.17)\,(0.3)\,(3500)}\left(\frac{3100}{1.35} - (1.1 \times 1173 - 573)\,1.29\right)$$

= 1.330m ***Ans.***

Note: The bed depths calculated in PROBLEMs 38.11 and 38.12 represent the bed depths required to accommodate the tube bank. In practice it is usual to provide an additional space of the 0.5 m to 1 m below the tube bank to allow adequate mixing of coal within the bed.

Q. *What are the fluidizing velocities on the basis of which PFBCs are designed?*

Ans. About 1 m/s for PFBC AIR CYCLES

1–1.5 m/s for PFBC SUPERCHARGED BOILER ST/GT COMBINED CYCLES

Q. *Why are the values of fluidizing velocities chosen for designing PFBCs?*

Ans. These velocities result in:

(a) 8 m (approx) of bed-depth for air cycle

(b) 3–4 m of bed-depth for the supercharged boiler combined cycle. These bed-depth values are only slight extrapolations from existing pilot-scale plants.

The resulting bed-drop of about 6 kPa/m of bed-depth is tolerable. Although for plants operating at full-load, the pressuredrop due to bed-depth does not exercise a major effect on cycle efficiency,

it can become a problem in matching turbine and compressor characteristics at reduced loads (i.e. reduced pressure levels) since it is independent of the pressure level.

Q. *What is the residence time of gas in PFBC beds as against that in AFBC units?*

Ans. PFBC gives much higher bed-residence-time to the gases used in fluidization and combustion; typically up to 8 s for airheaters and up to 4 s for supercharged boilers.

As compared to this, AFBC units permit a maximum of 0.5s of bed-residence-time of gases at atmospheric pressure.

Q. *What is the impact of higher bed-residence-time?*

Ans. It begets higher combustion efficiency and better sulphur removal (sulphation).

39

NUCLEAR STEAM GENERATORS

Q. *What is nuclear fission?*

Ans. The nucleus of heavy elements like U-233, U-235 and Pu-239 has the ability to capture and absorb neutrons, whereupon it gets converted to a compound nucleus. Sometimes this compound nucleus is highly unstable undergoing spontaneous fragmentation into several approximately equal lighter nuclei plus two or three neutrons. This process is called nuclear fission and is accompanied by enormous amount of heat liberation. (Fig. 39.1)

Q. *How much fission energy is available from 1 kg of U-235?*

Ans. It is roughly equivalent to the energy liberated by the combustion of 3086 ton of coal or 1362 m^3 of fuel oil.

Q. *What do you mean by a nuclear chain reaction?*

Ans. It is a self-sustained nuclear fission process which is attained when the production of neutrons equals or exceeds the quantity lost through absorption of non-fissioning materials or leakage.

Q. *What is the difference between fissionable and fertile materials?*

Ans. Fissionable materials are those which are capable of sustaining a fission chain reaction. U-235 is the only fissionable isotope found in nature.

Fertile materials are non-fissionable materials that can be converted into fissionable materials. U-238 and Th-232 can be converted to fissionable material.

Q. *What do you mean by neutron capture?*

Ans. It means absorption of neutrons.

Neutrons, depending on their energy, may be absorbed or scattered by the target nuclei or reactor materials. Usually a slow neutron or thermal neutron is captured while fast neutrons are bounced off. (Fig. 39.2)

Q. *What is neutron balance?*

Ans. In any power reactor where a self-perpetuating fission process is going on, the production rate of neutrons must balance the rate of neutron capture [by target nuclei, reactor materials, fission products (poisons, e.g. $^{135}_{54}Xe$) and control rods] plus the rate of neutron loss through leakage.

Q. *What is critical mass?*

Ans. It is the minimum mass of fissionable material that will sustain a fission-chain reaction.

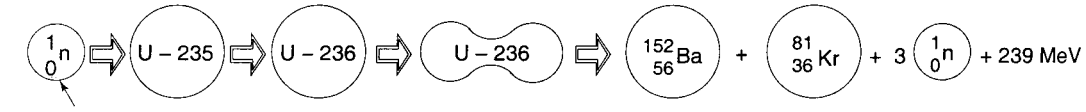


Fig. 39.1 *Nuclear fission mechanism.*

Q. *What is the magnitude of critical mass for naturally occurring fissionable materials?*

Ans. It varies from just 200 gm to as much as half a ton.

Q. *Should the actual fuel loading of a reactor exceed, be equal to or be less than the critical mass?*

Ans. It must exceed the critical mass.

Q. *Why?*

Ans. This is to make-up for fuel burn up and compensate other effects encountered during reactor operation.

Q. *What is fuel burnup?*

Ans. It refers to depletion of fuel in the course of sustained fission reaction in a reactor.

Q. *What do you mean by multiplication factor 'k' for a reactor?*

Ans. It is defined as the ratio of the number of neutrons produced in one generation to the number of neutrons produced in the preceding generation.

Q. *How can a reactor be classified as supercritical, critical or subcritical on the basis of this multiplication factor?*

Ans. For a reactor with k-value greater than one, the neutron population is increasing with time. Since reactor power is directly proportional to the neutron level in the reactor, for $k > 1$, the reactor power is increasing with time. Such a reactor is said to be a ***supercritical reactor.***

If k is exactly equal to unity, a neutron balance is just maintained in the reactor. And such a reactor is said to be a ***critical reactor.***

For k less than unity, the neutron population and the reactor power are decaying with time and the reactor is said to be ***subcritical.***

Q. *What is the reactivity of the reactor?*

Ans. It is defined by the ratio

$$\frac{k-1}{k} = \rho$$

For a supercritical reactor, ρ is positive

For a critical reactor, ρ is zero

For a subcritical reactor, ρ is negative.

Q. *What do you mean by neutron flux?*

Ans. It is the number of neutrons passing through a unit area in unit time

Reactor	*Neutron Flux*
Low-powered reactor	$\phi = 10^{15}$ neutrons/m^2 s
High-powered reactor	$\phi = 10^{20}$ neutrons/m^2 s

Q. *How are reactor neutrons classified?*

Ans. On the basis of their kinetic energy, reactor neturons can be classified into three basic types:

1. SLOW NEUTRONS having K.E. less than 0.1 eV
2. INTERMEDIATE NEUTRONS having K.E. between 0.1 eV and 0.1 MeV
3. FAST NEUTRONS having K.E. exceeding 0.1 MeV

Slow neutrons are also called thermal neutrons. They move with a velocity of about 2200 m/s at 293 K.

Fast neutrons having kinetic energy of about 2 MeV move with a velocity 2×10^7 m/s.

Q. *What do you mean by neutron reaction rate?*

Ans. It is the measure of the rate of target nuclei reacting with the neutrons to produce a given reaction. It is the product of average neutron flux $\bar{\phi}$, the total number of nuclei N reacting with the neutrons and the microscopic neutron cross-section σ for the given reaction, i.e.

Neutron reaction rate = $N \sigma \bar{\phi}$

The fission rate in the reactor core = $N_{\text{fuel}} \sigma_f \bar{\phi}$

σ_f = microscopic neutron cross-section for fission

Q. *What is the microscopic cross-section σ?*

Ans. It corresponds to the area of each target nucleus for producing a given reaction as a result of reacting with projectiles (e.g. neutrons, protons, deutrons, etc.)

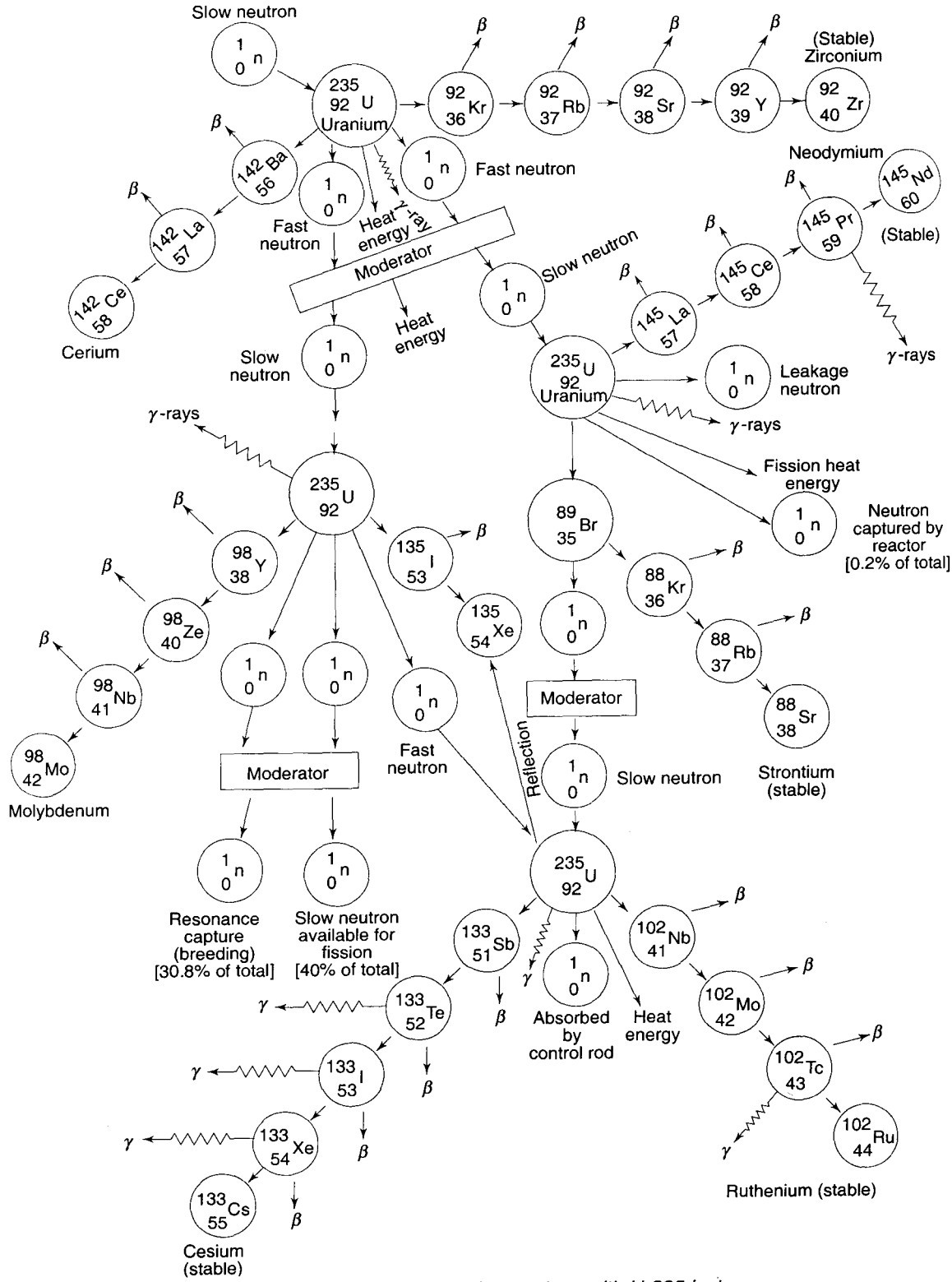


Fig. 39.2 *Typical nuclear fission reations with U-235 Isotope.*

Q. *What is the macroscopic cross-section* Σ*?*

Ans. It is the product of microscopic cross-section (σ) and the isotopic density (N/V, the number of atoms per unit volume)

$$\Sigma = \sigma \frac{N}{V}$$

Note: Neutron reaction rate = $N\sigma\,\bar{\phi} = \Sigma \cdot V \cdot \bar{\phi}$

Q. *What is the fission rate in a given reactor operating at a power level of P* MW_{th} *(i.e. megawatt thermal)?*

Ans. Roughly 3.1×10^{16} fissions should occur to generate energy equal to 1 MW·s.

So for a reactor operating at a power level P MW_{th}

Fission rate = $3.1 \times 10^{16} \times P$ fissions/s

$= N_{\text{fuel}}\,\sigma_f\,\bar{\phi} = \bar{\Sigma}_f\,V_c\,\bar{\phi}$

where N_{fuel} = the number of fuel atoms in the reactor core volume V_c

$\bar{\sigma}_f$ = average microscopic fission cross-section for neutrons

$\bar{\Sigma}_f$ = average macroscopic fission cross-section for neutrons.

Problem 39.1 A 1000 MW nuclear power station operates at a thermal efficiency 33%. The reactor fuel is U-235 and the average thermal neutron flux in the reactor core is 5×10^{17} neutrons/m^2 s.

If the average fission cross-section is 420 barns, determine the reactor fuel loading in terms of U-235.

If the fuel used is in the form of uranium dioxide containing 2.5% enriched UO_2, determine the fuel loading of UO_2 in this system.

Solution: The reactor fuel loading is to be calculated on the basis of the fission rate.

Step (I) Reactor Thermal Power

Reactor thermal efficiency

$$= \frac{\text{Reator electrical power}}{\text{Reactor thermal power}}$$

$$\therefore \text{ Reactor thermal power} = \frac{1000}{0.33}\ \text{MW}_{\text{th}}$$

Step (II) Fission Rate

Fission rate

$$= 3.1 \times 10^{16} \left(\frac{\text{fissions}}{\text{MW}_{\text{ths}}\,\text{s}}\right) \frac{1000}{0.33}\ (\text{MW}_{\text{th}})$$

$= 9.3939 \times 10^{19}$ fissions/s

Step (III) Number of Fuel Atoms

The number of fuel atoms (N_{fuel}) undergoing this rate of fission in the reactor core is given by

$$\bar{\sigma}_f\,N_{\text{fuel}}\,\bar{\phi} = 9.3939 \times 10^{19}$$

or $420 \times$

$$\left(\frac{\text{fission barns}}{\text{fuel atom neutrons}}\right) \times 10^{-28} \left(\frac{\text{m}^2}{\text{barn}}\right)$$

$$\times N_{\text{Fuel}}\ 5 \times 10^{17} \left(\frac{\text{neutron}}{\text{m}^2\text{s}}\right)$$

$= 9.3939 \times 10^{19}$ fissions/s

$$\therefore N_{\text{fuel}} = \frac{9.3939 \times 10^{19}}{(420)\left(10^{-28}\right)\left(5 \times 10^{17}\right)}$$

$= 4.473 \times 10^{27}$ atoms of U-235

Mass of U-235

$$= \frac{4.473 \times 10^{27}\,(\text{atoms}) \times 235(\text{kg/kmol})}{6.023 \times 10^{26}\,(\text{atoms/kmol})}$$

$= 1745.23$ kg $= 1.745$ tons of U-235

Step (IV) Loading of Enriched UO_2

When the reactor is fueled with 2.5% enriched UO_2, it contains mostly $^{238}UO_2$.

$\therefore$ Molecular weight of fuel UO_2

$= 238 + 2 \times 16 = 270$ kg/kmol

Total mass of uranium

$$= \frac{1.745 \text{ tons of U - 235}}{0.025 \text{ tons of U - 235/ton of fuel}}$$

$= 69.809$ t of uranium

$$= \frac{69.809 \text{ tons of uranium}}{238 \text{ tons uranium}/270 \text{ tons of } UO_2}$$

$$= 79.195 \text{ tons of } UO_2$$

Problem 39.2 A 500 MW nuclear power station is on natural uranium with a fuel burnup fraction of 3 kg/ton of fuel loaded. The operation efficiency of the power station is 25% and its installed capacity is utilized over a period of 7000 h per year. Compute the

(a) specific consumption of the burntup nuclear fuel

(b) total annual consumption of nuclear fuel.

Solution: The same quantity of thermal energy (7.9×10^{10} kJ) is always liberated on fission of all the nuclei of 1 kg uranium.

However, as a nuclear reactor operates, 10–20% of the fissionable isotope in the nuclear fuel transforms to non-fissionable isotopes due to neutron capture:

$$^{235}_{92}U + {}^{1}_{0}n \longrightarrow {}^{236}_{92}U$$

$$^{239}_{94}Pu + {}^{1}_{0}n \longrightarrow {}^{240}_{94}Pu$$

with the effect that a lower quantity of heat is generated per kg of fuel burnup. In practical calculations this is taken to be constant and it is normally assumed that the consumption of burnt-up fuel is, on an average, 15% greater than the quantity of fissioned isotopes. Therefore, the quantity of burnt-up nuclear fuel

$$Q = \left(7.9 \times 10^{10} \frac{\text{kJ}}{\text{kg}}\right)(0.85)$$

$$= 6.715 \times 10^{10} \text{ kJ/kg of fissionable U}$$

$$= \frac{6.715 \times 10^{10}}{3600} \frac{\text{kWh}}{\text{kg of U - 235}}$$

$$= 1.865 \times 10^{7} \text{ kWh/kg of U-235}$$

$$= 1.865 \times 10^{4} \text{ MWh/kg of U-235}$$

Step (I) Reactor Thermal Power

$$\text{Reactor thermal power} = \frac{\text{Reactor electrical power}}{\text{Reactor thermal efficiency}}$$

$$= \frac{500 \text{ MW}}{0.25} = 2000 \text{ MW}_{th}$$

Step (II) Annual Thermal Load

Reactor operating hour = 7000 h per year

$\therefore$ Annual thermal load

$= (2000 \text{ MW}_{th})(7000 \text{ h})$

$= 14 \times 10^{6} \text{ MW}_{th} \cdot \text{h}$

Step (III) Annual Consumption of Nuclear Fuel

If the fuel burnup fraction is a (i.e. a kg of U-235 per ton of fuel), then net heat yield of reactor

$= Q \cdot a$ per ton of fuel load

$$= \left(1.865 \times 10^{4} \frac{\text{MW}_{th} \cdot \text{h}}{\text{kg U - 235}}\right) \cdot \left(\frac{3 \text{ kg U-235}}{1 \text{ ton of fuel}}\right)$$

$= 5.595 \times 10^{4} \text{ MW}_{th} \cdot \text{h/ton of fuel}$

$\therefore$ Total consumption of nuclear fuel over a period of 1 y

$$= \frac{14 \times 10^{6} \text{ MW}_{th} \cdot \text{h}}{5.595 \times 10^{4} \text{ MW}_{th} \cdot \text{h/ton of fuel}}$$

$= 250.223$ ton of fuel

Step (IV) Specific Fuel Consumption

$$\text{Specific fuel consumption} = \frac{\text{Qty of fuel consumed}}{\text{per unit energy yield}}$$

$$= \frac{250 \cdot 223 \text{ ton}}{14 \times 10^{6} \text{ MW}_{th} \cdot \text{h}}$$

$$= 1.787 \text{ g/MW}_{th} \cdot \text{h}$$

Problem 39.3 A 500 MW reactor loaded with a uranium fuel (99.3% U-238 + 0.7% U-235) has 6% of its core volume occupied by fuel rods. If it operates 7200 h/year at 80% load factor, compute

(a) annual consumption of fissionable material
(b) maximum allowable burnup
(c) the average fuel-cycle time

Given:

Reactor thermal efficiency = 33%

Reactor core volume = 39 m^3

Capture cross-section : fission cross-section = 1.2

Solution: The fuel (U-235) consumption, fuel burnup etc. are to be computed on the basis of the fission rate.

Step (I) Reactor Thermal Power

Reactor thermal efficiency

$$= \frac{\text{Reactor electrical power}}{\text{Reactor thermal power}}$$

$$\therefore \text{Reactor thermal power} = \frac{500}{0.33}\ MW_{th}$$

Step (II) Fission Rate

Roughly 3.1×10^{16} fissions should occur to generate energy equal to 1 MW·s.

$\therefore$ Fission rate

$$= \left(3.1 \times 10^{16}\ \frac{\text{fissions}}{MW_{th} \cdot s}\right) \cdot \left(\frac{500}{0.33}\right) MW_{th}$$

$= 4.6969 \times 10^{19}$ fissions/s

Step (III) Fuel Volume

Volume of reactor core = 39 m^3

Per cent of core volume occupied by fuel = 6

$\therefore$ Fuel volume, V_f = (39 m^3) (0.06) = 2.34 m^3 = 2.34×10^6 cm^3

Step (IV) Number of U-235 Nuclei in the Reactor

Uranium density = 18.68 g/cm^3

At. wt. of uranium fuel = $0.993 \times 238 + 0.007 \times 235$ = 237.979 g/mol.

Avogadro's No. = 6.023×10^{23} atoms/mol

$\therefore$ No. of uranium atoms per cm^3 of fuel volume

$$= \left(\frac{18.68\ g/cm^3}{237.979\ g/mol}\right) \times \left(6.023 \times 10^{23}\ \text{atoms/mol}\right)$$

$= 0.47277 \times 10^{23}$

Since U-235 constitutes 0.7% of fuel volume, the number of fissionable nuclei in the reactor

$$= \left(0.47277 \times 10^{23}\ \frac{\text{atoms}}{cm^3}\right)(0.007) \cdot (2.34 \times 10^6\ cm^3)$$

$= 7.744 \times 10^{26}$

Step (V) Consumption of Fissionable Nuclei (U-235)

Fissionable U-235 material burned up for power generation

$$= \left(4.6969 \times 10^{19}\ \frac{\text{fissions}}{s}\right) \times \left(\frac{1}{6.023 \times 10^{23}\ \frac{\text{U-235 nuclei}}{\text{mol}}}\right)\left(235\ \frac{g}{\text{mol}}\right)$$

$= 183.259 \times 10^{-4}$ g/s

Step (VI) Annual Consumption of U-235

Annual consumption of fissionable nuclei

= (Fission rate) (Annual operating hour) × (Load factor)

$$= \left(183.259 \times 10^{-4}\ \frac{g}{s}\right)(7200 \times 3600\ s)(0.80) \times \left(\frac{1}{1000}\ \frac{kg}{g}\right)$$

= 380 kg/year

Step (VII) Annual Consumption of U-235

The U-235 is consumed by fission (for power) and by neutron absorption (hence lost). The fraction of productive cross-section is expressed by

$$\alpha = \frac{\text{U-235 total capture cross-section}}{\text{U-235 fission cross-section}}$$

$$= 1.2 \text{ (given)}$$

Total annual consumption of U-235 = 1.2(380 kg/y) = 456 kg/y

Step (VIII) Atom Burnup

Assuming a burnup fraction of 2 (i.e. 2kg U-235 undergoing fission per ton of fuel), the maximum permissible atom burnup

= (Burnup fraction) (Fuel atom density) (Fuel volume)

$$= \left(\frac{2}{1000}\frac{\text{kg}}{\text{kg}}\right)\left(0.47277 \times 10^{23}\ \frac{\text{atoms}}{\text{cm}^3}\right) \times \left(2.34 \times 10^6\ \text{cm}^3\right)$$

$$= 2.2125 \times 10^{26} \text{ atoms}$$

Step (IX) Average Fuel-Cycle Time

Average fuel-cycle time = Burnup/Fission rate

$$= \frac{2.2125 \times 10^{26} \text{ atoms}}{4.6969 \times 10^{19} \text{ fissions/s}}$$

$$= 0.47106 \times 10^7 \text{ s}$$

$$= 1308.52 \text{ h}$$

$$= 54.52 \text{ days.}$$

Q. *What is a nuclear reactor?*

Ans. It is an equipment specially designed to initiate, maintain and control a nuclear fission chain reaction so that the accompanying heat release can be used fruitfully.

In other words, a nuclear reactor can be portrayed as a furnace in which heat is produced because of a fission chain reaction. This generated heat must be removed and in a power reactor, converted to work.

Q. *What are the essential components of all power reactors?*

Ans. 1. Reactor core containing the fissionable material (fuel) and probably a moderator (fuel diluent)
2. A system of control rods/plates
3. A coolant for heat removal
4. A neutron source to trigger the fission
5. A neutron reflector to bring escaping neutrons back to the core
6. A shield for operational safety
7. Structural elements
8. Fuel handling equipment.

Q. *With what fuels is the reactor core loaded?*

Ans. The reactor fuel may be
(a) Uranium-235
(b) Uranium-Thorium mixture
(c) Uranium-Plutonium mixture
(d) Thorium ($^{232}_{90}$Th)
(e) Plutonium ($^{239}_{94}$Pu)

Q. *In which form is the fuel used?*

Ans. The fuel may be
(a) in a metallic form (molten or solid as pellets)
(b) in a oxide form (e.g. uranium dioxide and plutonium dioxide). Nearly all of the present power reactors employ oxides of fuel isotopes.
(c) carbides (uranium carbide and plutonium carbide)
(d) a salt solution (uranyl nitrate, uranyl sulfate, uranyl phosphate, uranium hexafluoride)
(e) molten salts (uranyl fluoride)

Q. *How is fuel distributed in the reactor core?*

Ans. Fuel may be distributed in the reactor in
(a) homogeneous manner
(b) heterogeneous manner.

Q. *In which form is the fuel disbursed in a heterogeneous reactor?*

Ans. In heterogeneous reactors fuel may come in the form of thin rods, hollow tubes, pellets, thin plates sandwiched together or lumps.

The fuel is usually alloyed with (embeded into) a suitable metal (aluminium, zirconium, niobium or molybedenum). The fuel element is cladded (jacketed) with suitable protective material (aluminium, zirconium or stainless steel) to protect it from corrosive attack.

Q. *Why has only limited success been achieved in the use of metallic fuel alloys?*

Ans. Metallic fissionable elements have proved to be unstable during long periods of irradiation and thermal cycling.

They develop a tendency to warp, grow, elongate or distort under intense radiation.

Q. *How is the fuel element distributed in the heterogeneous reactor core?*

Ans. The fuel element is evenly distributed in the reactor core.

The distribution order follows a definite geometrical pattern (lattices) in the matrix of the moderator.

Q. *In which form is the fuel distributed in the homogeneous reactor?*

Ans. The fuel is alloyed with or homogeneously mixed with moderator, diluent and coolant and the mixture is evenly dispersed in the reactor core in the form of solution, slurry or melt. Aqueous slurries (D_2O or H_2O) and liquid metal (molten bismuth) are used. The container material is stainless steel.

Q. *What are the potential disadvantages of heterogeneous reactors?*

Ans. 1. Instability of metallic fuel elements over long exposure of irradiation and thermal cycling
2. Expensive fuel preparation
3. Removal of cladding for reprocessing the fuel is very complicated
4. Fuel reprocessing is doubly expensive.

Q. *What are the potential advantages of homogeneous reactors?*

Ans. 1. Very good heat transfer characteristics
2. Very good nuclear control characteristics
3. Continuous chemical processing of the fuel solution is possible without the need of a dissolving solid fuel element
4. Expensive fuel fabrication is eliminated
5. Expensive refabrication of radioactive fuel material is eliminated.

Q. *What is a moderator?*

Ans. It is a substance incorporated in the reactor core to slow down the fission neutrons (fast neutrons), i.e., a moderator converts a fast neutron into a thermal neutron by absorbing its kinetic energy and thereby increasing the probability of neutron capture by the fissionable material.

Q. *What substances are used as moderators?*

Ans. Only three elements are actually used to moderate neutrons:

1. Ordinary hydrogen ($_1^1H$) or heavy hydrogen ($_1^2H$).
   As a moderator, ordinary hydrogen is used in the form of
   (a) water
   (b) solid and liquid organic compounds (diphenyl and terphenyls)
   (c) intermetallic compounds viz, zirconium hydride.
   Heavy hydrogen is used as the moderating material in the form of heavy water, D_2O.
2. Beryllium
   It is used as pure metal or as beryllium oxide (BeO).
3. Carbon (high purity graphite).

Q. *What should be the essential qualities of a good moderator?*

Ans. It must have the following characteristics.
(a) High macroscopic neutron-scattering cross-section

(b) Low macroscopic neutron-absorption cross-section
(c) Low atomic mass to get the maximum K.E. transfer from the fast neutrons to the moderator atoms
(d) High resistance to the high radiation level in the reactor core
(e) High resistance to corrosion under high pressure and temperature
(f) Good machinability if it is solid
(g) High melting point if it is solid
(h) High chemical stability
(i) High thermal conductivity for better heat transfer in the reactor core.

Q. *What is a diluent?*

Ans. It is a substance that adds mass to the fuel element. It is required particularly in fast reactors for heat removal and temperature reduction purposes.

Q. *What is a reflector?*

Ans. It is a material used in the form of a layer around the reactor core to prevent the escape of neutrons by bouncing them back into the core.

Not only does the reflector return the leakage neutrons to the core, it also slows down fast and intermediate neutrons with the effect that more neutron flux is available for inducing fission and fission energy.

Q. *What is the effect of adding a reflector to a bare thermal reactor?*

Ans. It effectively raises the neutron flux and hence boosts up the power density at the edges of the core. (Fig. 39.3)

That is, the addition of a reflector reduces the critical mass of a reactor by decreasing the rate of neutron leakage and creates a sharp improvement in the ratio of maximum-to-average power in the reactor core by increasing the neutron flux and hence results in greater power generation at the core boundary.

Q. *What is the value of the maximum-to-average power in a reflected assembly?*

Ans. It varies, but one such typical value is

$$P_{max}/P_{av} = 2.4$$

Q. *What materials are used as reflectors?*

Ans. 1. Heavy water (D_2O)
2. Metallic beryllium or beryllium oxide (BeO)
3. Pure graphite

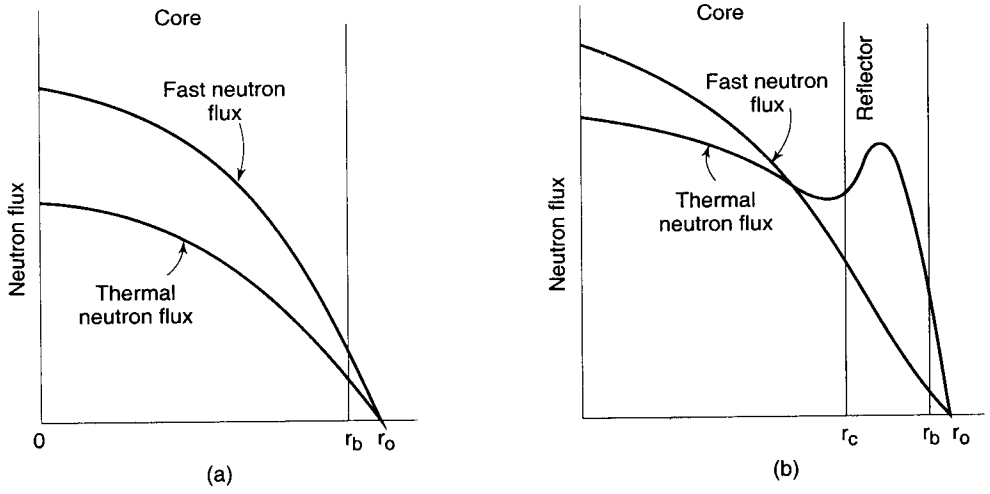


Fig. 39.3 *The thermal neutron flux distribution (a) Bare Reactor Core: (b) Reflector Reactor Core; r_o = extrapolated core radius = r_b + extrapolation distance; r_b = reactor core radius.*

4. Uranium-238 (in production reactors).

Q. *What are the essential qualities of a good reflector?*

Ans. 1. Low macroscopic neutron-absorption cross-section
2. High macroscopic neutron-scattering cross-section
3. High resistance to oxidation
4. High resistance to irradiation
5. High radiation stability.

Q. *What is a coolant?*

Ans. A coolant is a thermal fluid (gaseous or liquid) used to transport thermal energy from the core.

It is passed through the reactor core to remove the heat that is generated as a result of nuclear fission.

Q. *By how many methods can the coolant remove heat from the reactor core?*

Ans. A coolant can transport thermal energy from the core by any one of the following three methods.

1. **Internal Cooling**: circulating the coolant right through the reactor core. Circulation may be forced or natural.
2. **External Cooling:** circulating the liquid fuel through a tube- and shell-type heat exchanger outside the reactor while the coolant abstracts heat from the fuel in the heat exchanger.
3. **Boiling Liquid Cooling:** circulating and allowing the coolant to vapourize within the reactor and to take the reactor heat out.

Q. *Has the coolant any other utility apart from transporting heat from the reactor core?*

Ans. Yes; it can serve as a moderator as well as a fuel carrier.

Q. *What substances are used as coolants?*

Ans. Coolants may be of two types: Liquid or Gas.

Liquid 1. Ordinary and Heavy Water
Coolants: 2. Lithium
3. Sodium
4. Sodium-potassium alloy (22 : 78)
5. Lead-bismuth alloy (44.5 : 55.5)
6. Lead-magnesium alloy (97.5 : 2.5)
7. Diphenyls and terphenyls
8. Petroleum oil
9. Sodium hydroxide

Gaseous 1. Helium
Coolants: 2. Carbon dioxide
3. Air
4. Steam

Q. *What should be the essential qualities of a good reactor coolant?*

Ans. It must have the following properties.

(a) High thermal conductivity
(b) High boiling point, should it be a liquid
(c) High specific heat
(d) High thermal stability
(e) High density
(f) Low viscosity
(g) Low vapour pressure, if it is a liquid
(h) Low melting point

Over and above, it should

(a) Be chemically inert to in-core materials
(b) Have low macroscopic neutron-absorption cross-section
(c) Not become highly radioactive
(d) Non-oxidizing and non-toxic.

Q. *What are the disadvantages of using ordinary water in the primary circuit, i.e. as a reactor coolant?*

Ans. Water has a low boiling point and so it cannot be heated to a substantially high temperature. If it is used as reactor coolant, it must be circulated under high pressure and that makes the whole path too complicated and expensive as well.

Q. *Why are reactor shields used?*

Ans. They are used as envelopes (liquid or solid) to absorb all forms of gamma radiation. They also slow down and capture neutrons.

There are two reactor shields:

1. **Inner (Thermal) Shield** comprises 10% of the total reactor shield thickness yet they absorb 90% of the nuclear radiation that tends to escape.
2. **Outer (Biological) Shield** is several feet thick to protect the operating personnel and the environment from irradiation by γ-rays or neutrons.

Q. *Why are thermal shields used?*

Ans. These are installed to protect the vessel from excessive heating due to gamma-ray absorption.

The absorption of high energy radiations by the steel vessel or concrete shield leads to high temperatures and temperature gradients with the effect that considerable thermal stresses are induced in the structures. Moreover, prolonged exposure to the radiations emanating from the reactor core brings about changes in the properties of the materials. Steel becomes brittle and the concrete form aggregates which swell non-uniformly and that tell upon the strength of the concrete and may cause failure.

To avoid this disaster, reactor vessel and the biological shield are protected by thermal shields made of high heat-resistant and radiation-stable materials (iron or steel) absorbing the excessive radiation energy.

Q. *What should be the qualities of a good shield?*

Ans. The shielding material

(a) must be a heavy element like lead, lead-cadmium alloy, tantalum, iron, iron oxide or barium sulphate to absorb the harmful gamma radiations.

(b) should preferably have a low mass number element, e.g., hydrogen in water, concrete, wood for maximum kinetic energy transfer from the fast neutrons.

(c) should be a good neutron absorber (e.g. boron used as borax, borates or boric acid)

Q. *Each reactor is provided with a reactivity control system. What is the purpose of this system?*

Ans. It is provided to every reactor to serve the following purposes:

1. To start-up the reactor
2. To bring it up to the design load and capacity
3. To increase and sustain the specified power output
4. To shutdown as well as cool down the reactor.
5. To render the reactor subcritical under any abnormal conditions.

Q. *What is the difference between reactor cooldown and reactor shutdown?*

Ans. Cooldown is a process which is the aftermath of shutdown. If a reactor operating at full or part load is put out of operation either for routine maintenance and overhauling or to avoid accidents, the phenomenon is called reactor ***shutdown***.

Whereas cooldown refers to the process of reducing the temperature and pressure of the coolants to their normal values following the reactor shutdown.

Q. *What do you mean by the term "scram capability"?*

Ans. It is a special capability endowed to the reactor by its reactivity control system as a result of which the reactor goes subcritical under any abnormal conditions.

Q. *What do you mean by shim rods?*

Ans. These are coarse control rods.

They are used to compensate for variations in the reactivity when the reactor changes from the cold to the hot state, i.e. they are designed to compensate for variations in the temperature coefficient of reactivity. They are also used to compensate for fission-product processing and fuel burnup.

Q. *What do you mean by automatic or manual control rods?*

Ans. These are fine control rods, also called regulator rods. They are designed to maintain the re-

actor capacity and the basic parameters of the coolant at a specified level by slight variations in the reactivity.

Q. *What are scramming rods?*

Ans. These are safety rods to ensure quick shutdown of the reactor, if there arise some abnormalities.

Q. *In which configurational patterns do the control rods appear?*

Ans.. They may be
(a) cylindrical
(b) prismatic
(c) cruciform
(d) rodded cruciform
(e) spherical.

Q. *What is a chemical shim system?*

Ans. This refers to dosing a neutron-absorbing chemical to the coolant to effect a control of the nuclear fission process in the reactor.

These must have high thermal neutron-capture cross-section. For example, boric acid solution injected into the coolant serves the purpose of reactivity control as boron has high thermal neutron-capture capability.

Q. *How is reactor control achieved?*

Ans. 1. Introducing or removing the strong neutron absorber called control rods (rods, strips or plates) from the core. This is called absorption control
2. Fuel control, i.e. by varying the amount of fuel within the reactor core. If the fuel quantity is reduced below the critical value fission chain reaction will cease
3. Coarse control, i.e. varying the moderator (D_2O) level in the reactor
4. Repositioning the reflector to vary neutron leakage.

Q. *What are the essential characteristics of a good control rod?*

Ans. The control rod
(a) should absorb neutrons in the same way as does blotting paper the extra ink, i.e. it should have very high neutron capture cross-section
(b) should have chemical and radiation stability
(c) should have high melting point
(d) should not react with the coolant or moderator in the reactor core.

Q. *Why is every nuclear reactor core fitted with a neutron source?*

Ans. To provide a source of neutrons to bring start-up neutron level in the core.

Q. *Why is the neutron level during the start-up period monitored?*

Ans. To prevent any inadvertent power excursions during this interval.

Q. *What is the source of neutrons in the reactor?*

Ans. There are two types of neutron sources
1. (α, n) source
2. (γ, n) source

both using beryllium as the target metal.

$$^{9}_{4}\text{Be} + {}^{4}_{2}\text{He} \longrightarrow {}^{13}_{6}\text{C} + {}^{1}_{0}\text{n} + \gamma$$

$$^{9}_{4}\text{Be} + \gamma \longrightarrow {}^{9}_{4}\text{Be} \longrightarrow {}^{8}_{4}\text{Be} + {}^{1}_{0}\text{n} + \gamma$$

$$\downarrow$$

$$2\,{}^{4}_{2}\text{He} + {}^{1}_{0}\text{n} + \gamma$$

The source of α-particles (projectiles) is plutonium-239 which is mixed with beryllium and the mixture is used as neturon source.

The source of γ-rays (projectile) is radioactive antimony-124 (half-life 60 days).

Q. *What should be the threshold energy of this radiation to eject a neutron from beryllium after impingement?*

Ans. 1.6 MeV.

Q. *How are reactors classified?*

Ans. Reactors are classified on the basis of
(a) their use

(b) fuel conversion
(c) neutron energy level.

Q. *How are reactors classified according to their use?*

Ans. Reactors can be designed to generate power either as a prime function or as a byproduct:

1. **Power Reactor:** Designed to produce power. It may be stationary as in a central station utility plant.

   It may be mobile as encountered in a nuclear powered submarines, oceanliners. It may be package type transportable by dismantling.
2. **Production Reactor:** Designed to convert fertile materials into fissionable materials to be used elsewhere.
3. **Research Reactor:** Primarily meant for scientific research, study and investigation in nuclear engineering and basic physics. Here power is produced as a byproduct.
4. **Material Testing Reactor:** Specially designed for case study of
   (a) radiation damage
   (b) tolerance level to irradiation
   (c) beneficial effects of radiation.

Q. *How can reactors be classified according to fuel conversion?*

Ans. Reactors may be
(a) regenerative
(b) non-regenerative type

A regenerative type reactor converts a fertile material like U-238 into fissionable material like Pu-238 by using a part of the neutrons available in the reactor. This generated fuel (always less than what is consumed) augment the life of the core.

A breeder is another form of regenerative reactor that not only converts fertile materials into fissionable materials but also produces more fissionable material than is consumed.

A non-regenerative reactor deplets the reactor fuel to the point where sustained nuclear fission is no longer possible. Such reactors are activated by loading a fresh charge of fuel.

Q. *How can reactors be classified on the basis of neutron energy level?*

Ans. Depending on the energy level of the neutrons used, reactors may be classified as:

1. **Thermal Reactor:** that uses slow neutrons having kinetic energy less than 0.1 eV.
2. **Intermediate Reactor:** reactor in which a portion of the fast neutrons (fission yields) is moderated down to thermal neutrons.
3. **Fast Reactor:** a reactor where fast neutrons are not slowed down.

Q. *How many types of thermal reactors are there?*

Ans. 1. Pressurized Water Reactor using ordinary water under high pressure
2. Heavy Water Reactor (pressurized or unpressurized)
3. Graphite Water Reactor
4. Boiling Water Reactor
5. Organic Cooled and Moderated Reactor
6. Sodium Graphite Reactor
7. Aqueous Homogeneous Reactor
8. Liquid Metal Fuel Reactor
9. Fused Salt Fuel Reactor
10. Dust-Fueled Reactor.

Q. *Apart from the above is there any other basis for classification of reactors?*

Ans. Reactors can also be classified on the basis of

1. Fuel used
   (a) Natural fuel
   (b) Enriched fuel
2. Moderator used
   (a) Ordinary water moderated
   (b) Heavy water (D_2O) moderated
   (c) Graphite moderated
   (d) Beryllium moderated
3. Coolant used
   (a) Ordinary water cooled reactor
   (b) Heavy water cooled reactor
   (c) Gas cooled reactor
   (d) Liquid metal cooled reactor

(e) Organic liquid cooled reactor.

Q. *Briefly describe a pressurized water reactor (PWR) and its working principle.*

Ans. A pressurized water reactor is a thermal reactor where slightly or highly enriched, heterogeneous, clad uranium is used as fuel and ordinary water under high pressure is used as a moderator, coolant reflector.

The fuel used is usually uranium oxide, UO_2, because it is highly resistant to irradiation damage and well adopted to high burnups. It has another big advantage that it is highly resistant to corrosion inflicted by water at high temperature and pressure in case of accidental cladding failure.

Coolant-cum-moderator-cum-reflector is ordinary water which is circulated in the primary circuit by the circulating pump pressurizing the liquid to 100-130 atm. Heat carried by the coolant from the reactor transferred to the DM water of the secondary circuit to generate steam in the heat exchanger. The primary circuit including the heat exchanger is well shielded as the coolant in the primary circuit becomes radioactive. (Fig. 39.4)

The generated steam is directed to the steam turbine to generate electricity.

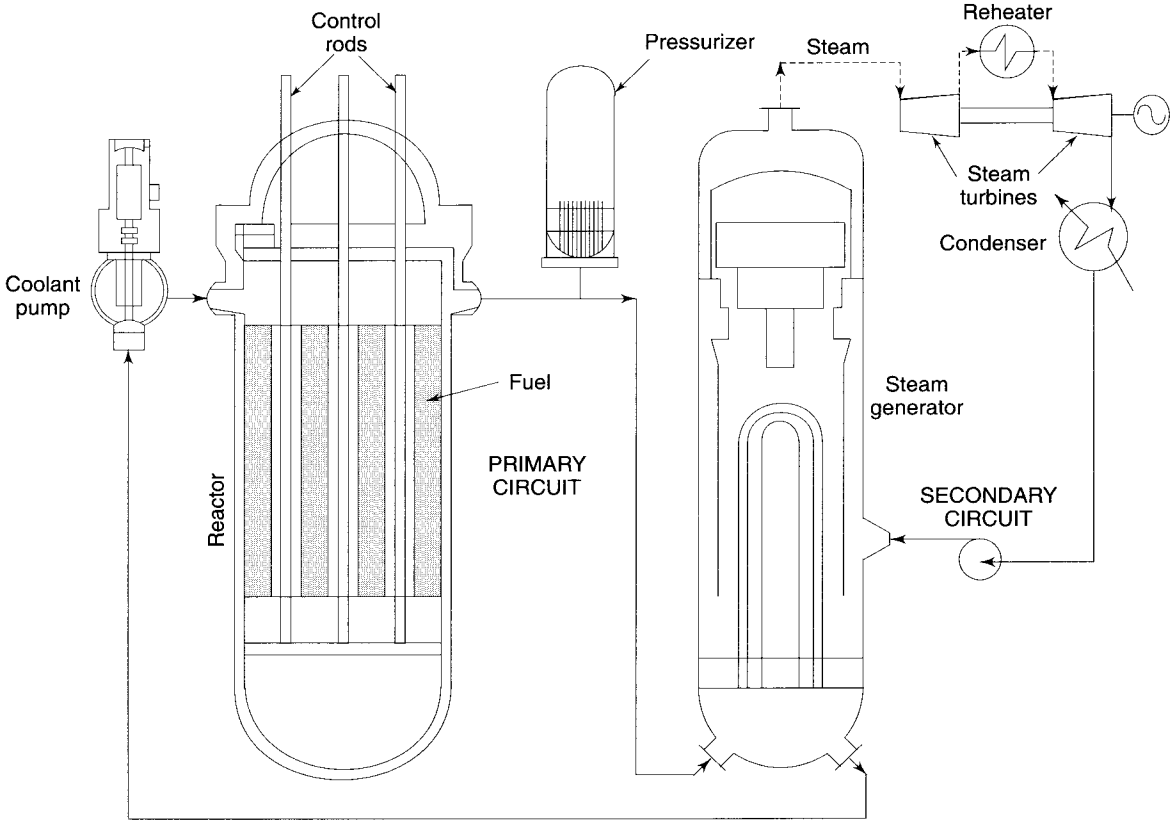


Fig. 39.4 *Pressurized Water Reactor. Nuclear Fission heat is transferred to the reactor coolant while steam is generated in the secondary circuit by indirect heat transfer to the working fluid in the steam generator.*

Q. *What are the advantages of a pressurized water reactor?*

Ans. 1. The principal advantage of a PWR is that it uses ordinary water as a coolant, moderator and reflector. Since water is available abundantly and cheaply, there is great saving in cost.
2. The reactor is very compact and has high power density, 65 KW/litre. It can be made more compact if enriched fuel is used.
3. Small number of control rods are required. Barely 60 control rods are required in a 1000 MW nuclear power plant operating PWR.
4. Greater energy is extracted per unit weight of fuel loaded. Therefore, PWR is ideally fitted for fuel designed for higher burnups.
5. Safe and stable operation as well as self-regulation is possible because of high negative temperature coefficient of PWR.
6. The power demand coefficient of PWR is positive, i.e. when more power is demanded the reactor spontaneously responds to supply the same. The negative temperature coefficient has made this possible.
7. Optimization of the turbine cycle for the purpose of low heat rate supply is possible because of separation of the secondary circuit from the primary circuit.
8. As steam is not contaminated by radiation, inspection and maintenance of the turbine, condenser and feed pump is possible.

Q. *What are the disadvantages of a pressurized water reactor?*

Ans. 1. High capital cost and heavy and strong pressure vessel is required in the primary circuit.
2. Difficulty in obtaining high steam pressure at the turbine.

   Because of low pressure (60-70 kgf/cm^2) in the secondary circuit, the thermodynamic efficiency of this plant is as low as 20%.
3. Corrosion is a severe problem induced by rapidly circulating water under high temperature and pressure. This dictates the use of stainless steel vessel and cladding, that further hikes up the cost.
4. It requires slightly enriched uranium fuel.
5. Fuel reloading takes a couple of months and that means a considerable downtime loss.
6. Deadly and penetrating γ-radiations cause uneven heating of the pressure vessel and thereby inflict thermal stresses in the vessel wall which is already under pressure stresses. This fact further complicates the design.

Q. *What is a fused-salt fuel reactor?*

Ans. It is a homogeneous thermal reactor that uses fused salt (uranium-235 tetrafluoride, UF_4) as the fuel while sodium fluoride and beryllium oxide is used as a carrier.

Q. *What is the purpose of using beryllium oxide?*

Ans. It serves as a moderator as well as reflector.

Q. *Can this reactor be used as a breeder reactor?*

Ans. Yes. In this case lithium fluoride or beryllium fluoride is used as a carrier while thorium tetrafluoride may be used as reflector.

Q. *What are its advantages over an aqueous homogeneous reactor?*

Ans. 1. High temperature operation (825°C) makes possible greater amount of heat transfer from the reactor core and hence higher efficiency
2. Operating pressure is low. So there is a great saving in the first cost as high pressure vessel is not required

3. Extremely stable
4. Completely responsive to power-demand factor.

Q. *What is a dust-fueled reactor?*

Ans. It is a thermal reactor wherein fissionable dust is carried in an inert (Helium) gas.

It can also act as a a breeder reactor if thorium-uranium fuel is used.

Q. *What moderator is used in a dust-fueled reactor?*

Fuel	*Moderator*
Uranium-carbide (enriched)	Graphite moderator lined with silicon carbide
Uranium-dioxide (enriched)	Beryllium oxide moderator lined with alumina

Q. *How is steam generated in nuclear power stations?*

Ans. The tremendous thermal energy liberated due to controlled nuclear fission of heavy nucleids (uranium-233, uranium-235 or plutonium-239) by slow or thermal neutrons within the reactor core is transferred directly or indirectly to the working fluid, i.e. water to generate steam. That is, a nuclear reactor may be thought of as a boiler furnace—a heat source—to produce steam and superheat it.

Steam is generated directly in a single-circuit nuclear power station operating a boiling type nuclear reactor (Fig. 39.5). Also it may be generated indirectly, as a result of heat transfer from the reactor coolant to the working fluid, in a two-circuit nuclear power station (Fig. 39.6) and in a three-circuit nuclear power station (Fig. 39.7).

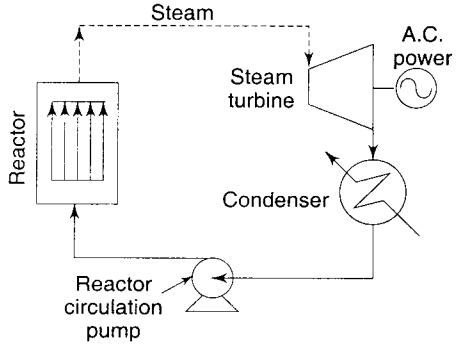


Fig. 39.5 *Single-circuit nuclear power station.*

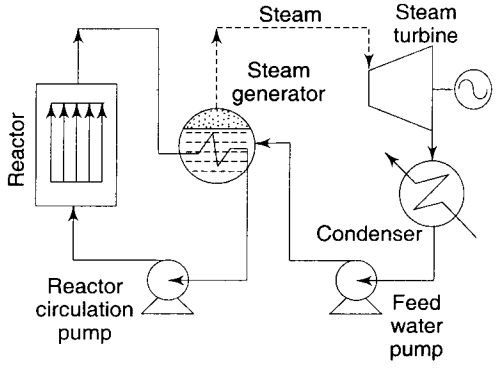


Fig. 39.6 *Two-circuit nuclear power station.*

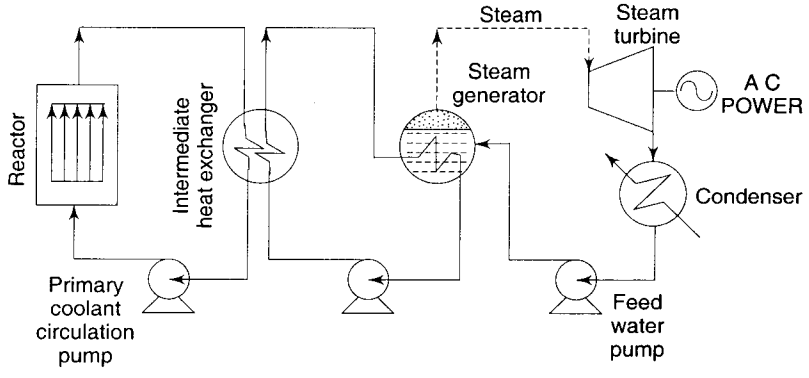


Fig. 39.7 *Three-circuit nuclear power plant.*

Q. *Why do nuclear power stations with aqueous coolant usually operate on saturated steam of pressure 5-7 MPa (about 50-70 atm.)?*

Ans. Water is a low-temperature coolant. And it is the pressurized water reactor where aqueous coolant can be subjected to the highest pressure and hence maximum temperature.

Now if it is required to generate steam at a pressure as high as possible, e.g. P = 63 atm. and the temperature of the aqueous coolant at the reactor inlet be θ'_1 = 593 K, the degree of superheating will be only 20K (see Fig. 39.8).

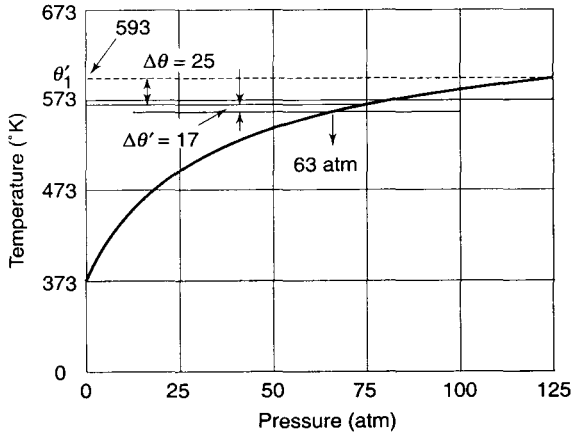


Fig. 39.8 *Selection of working fluid Parameters for generation of steam in water cooled water moderated reactors.*

To ensure active heat transfer we can assume the temperature gradient between the coolant (i.e. pressurized water) and the working fluid to be 25 K, nevertheless, the degree of superheating that can be obtained at 63 atm. will be only 17K = $\Delta\theta'$. This explains why nuclear power stations operating on aqueous coolant usually operate on saturated steam at a pressure of 50-70 atm.

Q. *Why is it essential to superheat the steam, usually by 20K?*

Ans. As the steam expands in the turbine, it increasingly becomes more wet. Wet steam can cause erosion of turbine blades and steam

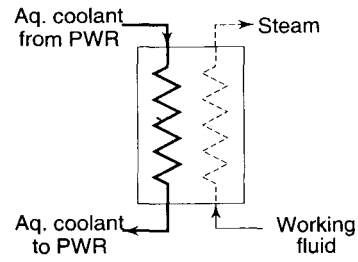


Fig. 39.9

distribution devices and impair the turbine's reliability. Hence to prevent these effects, it is essential to superheat the steam slightly, usually by 20K, so that moisture formation can be avoided.

Steam must be at least 99.8% dry.

Q. *But as the steam expands through the successive stages of the turbine, it will become wet at some stages of the turbine. Therefore, the turbine will operate in the region of wet steam which will reduce the efficiency of the power plant as well as inflict blade erosion on the turbine. What can be done to get rid of this problem?*

Ans. Before the steam becomes wet to the degree at which it becomes inadmissible (generally to the low-pressure cylinder of the turbine) due to the risk of moisture formation and consequent blade erosion, the wet steam (i.e. extraction steam) from the high-pressure cylinder is introduced tangentially to the apparatus, called separating steam superheater, at the top (Fig. 39.10). As it passes through the separator, its moisture is removed and it then sweeps the superheating surfaces heated up by the second-stage heating steam. The steam becomes superheated to 514K and exits from the top. It is then directed to the low-pressure cylinder of the turbine.

Q. *Why can steam of high or supercritical parameters only be produced by using a gas or liquid metal and not water as coolant?*

Ans. Water is a low-temperature coolant while liquid metals or gases are high temperature coolants. In fact, liquid metals and gases have no limitations regarding their temperature at the reactor outlet, while water must be kept under very high pressure to maintain its liquid state to ensure a better heat transfer rate.

Though the gases have poor thermophysical properties, gases with high mass flowrate, i.e. gases under pressure can be used to intensify the heat transfer. Liquid metals have very favourable thermophysical properties that make them perfectly suitable for high temperature coolants without taking any special measures to intensify the heat transfer. (Fig. 39.11)

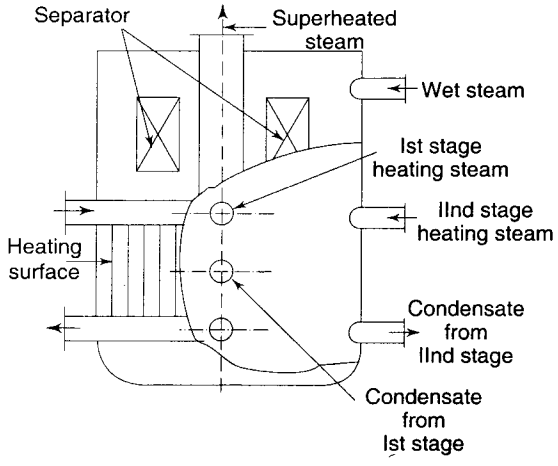


Fig. 39.10 *Separating superheater*

Therefore, only by using these high temperature coolant high or supercritical pressure steam can be produced.

Q. *How much coolant (gas/liquid metal) temperature at the reactor outlet is required to ensure steam superheating to standard parameters e.g. 125–240. atm. and* θ_{ss} *= 818 °K?*

Ans. It has been found in practice that if the temperature of the gas or liquid metal coolant at the reactor outlet is in the range 873-923 °K, then it can ensure steam superheating to the parameters 125–240 atm./θ_{ss} = 818 °K.

Q. *What is the general configuration pattern of steam generators of nuclear power plants?*

Ans. 1. Vertical (Fig. 39.12)
2. Horizontal (Fig. 39.13)

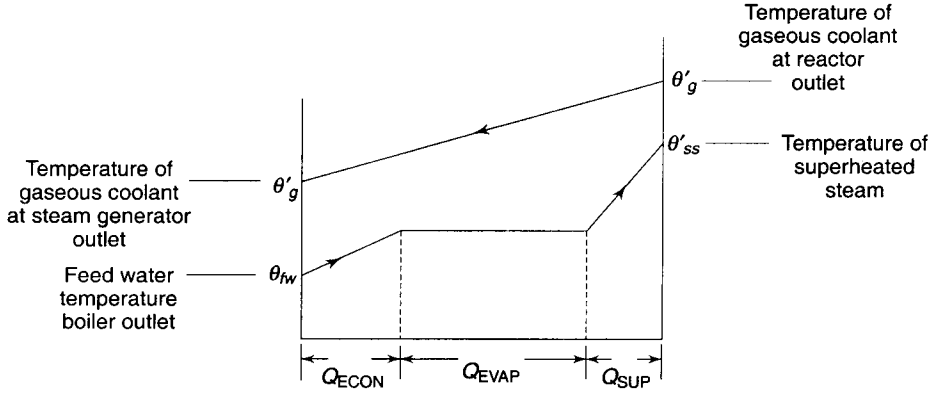


Fig. 39.11 *Temperature vs. Heat Transfer diagram in the steam generator of a gas cooled reactor.*

Q_{ECON} = *Quantity of heat transferred in the economizer*
Q_{EVAP} = *Quantity of heat transferred in the evaporator*
Q_{SUP} = *Quantity of heat transferred in the superheater*

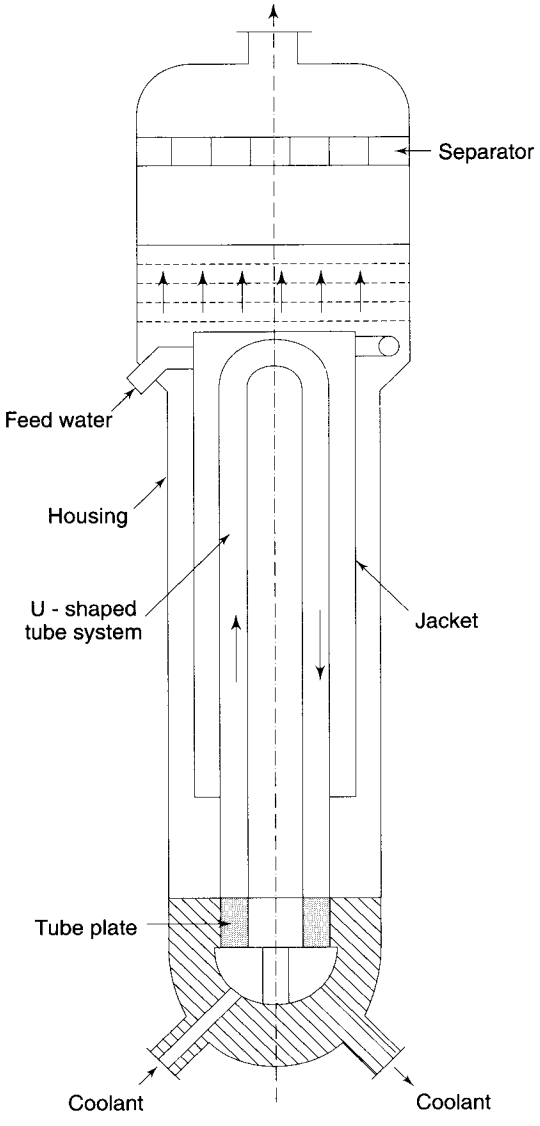


Fig. 39.12 *Vertical steam generator.*

Q. *What type of configuration pattern of steam generators is preferred in the cases of gaseous or liquid metal cooled reactors?*

Ans. Usually vertical.

Q. *What type of configuration pattern of steam generators is selected in the case of water-cooled-water-moderated reactors?*

Ans. Either vertical or horizontal.

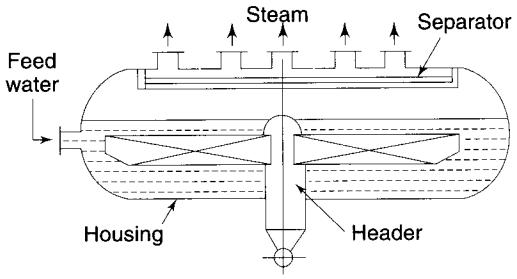


Fig. 39.13 *Horizontal steam generator.*

Q. *What are the chief advantages of a horizontal steam generator of a nuclear power plant?*

Ans. 1. Design simplicity
2. Ease of manufacture
3. Reliable operation.

Q. *What are the chief advantages of a vertical steam generator of a nuclear power plant?*

Ans. 1. Very compact
2. Better radiation safety
3. Greater unit capacity for a given volume.

Q. *What are the comparable features between horizontal and vertical steam generators?*

Ans. 1. Both are more or less equally costly with respect to total cost of the apparatus
2. Both have roughly equivalent performance characteristics and reliability
3. Both can be assembled and tested at the manufacturing site and transported by railroad.

Q. *Why is it not usually favoured to manufacture a steam generator of the horizontal type for a capacity exceeding 300 MW?*

Ans. The size of the horizontal steam generator of capacity beyond 300 MW will be excessively and inconveniently large.

Q. *How many types of steam generators exist for nuclear power stations where water-cooled-water-moderated reactors are used?*

Ans. As regards the processes occurring in the secondary circuit, the nuclear steam generators of water-cooled-water-moderated reactors can be divided into two main types:

1. Natural circulation steam generators
2. Once-through steam generators.

Q. *How can these two be distinguished on the basis of the mode of steam formation?*

Ans. In the natural circulation steam generators, heat is transferred from a submerged heating surface to the working fluid (water) which boils in the bulk on the surface of the heating elements.

In once-through systems, water flows under pressure through a system of tubes or in the intertubular space of the dense tube bundle and gets evaporated to steam as it abstracts heat from tubular heating elements on its way up from the bottom of the steam generator (vertical).

Q. *What are the heating elements of the steam generators?*

Ans. They are a system of tubes. They come in the form of straight tubes, U-shaped tubes, or helical. They may also be assembled into plain curtains.

Q. *What is the diameter and thickness of the tubes forming the heating elements in both horizontal and vertical steam generators?*

Ans. OD : 12–22 mm

Thickness : 1.2–1.5 mm

Q. *How many such tubes are used in high-capacity steam generators?*

Ans. As many as some ten thousand tubes may form the heating surface of high-capacity steam generators.

Q. *Why are all the elements of the primary circuit of a nuclear steam generator of stainless steel?*

Ans. All the elements of the primary circuit are made of stainless steel to eliminate corrosion to avoid leakage of reactor coolant from the primary circuit to the secondary circuit. Contamination of the aqueous coolant by corrosion products is inadmissible.

Q. *The ends of the tubes used as heating elements in steam generators are expanded in tube plates and the tightness of the joints should be very high. Why is such high joint-tightness necessary?*

Ans. To avoid the slightest chance of leakage of reactor coolant in the primary circuit, as this might lead to the contamination of working fluid with radioactive material in the secondary circuit.

Q. *Why is the heat transfer agent in steam generators with aqueous coolant circulated in tubes?*

Ans. To minimize the use of metal in the generator housing.

Q. *Why is the intensity of steam generation different in various portions of the drum of a horizontal steam generator?*

Ans. As the coolant emerging from the reactor and loaded with heat passes through the steam generating coils of the horizontal steam generator, it develops a variable temperature along the length of the coils. This is highest at the coolant's inlet to the steam generator and lowest at the coolant's outlet from the generator. This explains why the steam generation intensity is different in various portions of the drum.

Q. *Is the intensity of evaporation from the disengagement surface also different?*

Ans. Yes.

Q. *How can this be equalized?*

Ans. This can be effected by placing a submerged perforated plate or differentiated supply of boiler feedwater to the coils.

Q. *Between the vertical steam generator and horizontal steam generator which one is affected by higher moisture carryover?*

Ans. Vertical steam generator.

Q. *Why is the vertical steam generator affected by higher moisture carryover?*

Ans. The intensity of evaporation, in the case of vertical steam generators, from the disengagement surface is much higher than in the horizontal type. As a result, vertical steam generators suffer from higher carryover of moisture by steam.

Q. *How can this moisture carryover be diminished?*

Ans. The steam space height of the drum is substantially increased to fit within it two or three steam separating stages. They will produce steam of satisfactory quality (dryness fraction 99.8%).

Q. *What are the advantages of design of vertical nuclear steam generators?*

Ans. 1. Higher compactness that bestows radiational safety
2. Substantial increase of unit capacity
3. Thermal expansion of U-shaped tube bundles where such tubes are used in vertical steam generators, is self-compensatory. This is a big advantage.

Q. *Is there any typical fabrication problem encountered in vertical steam generators with U-shaped tubes?*

Ans. The ends of the U-ends are expanded in the tube plates. For high-capacity steam generators, the thickness of such tube plates may range from 600 to 700 mm. They must be accurately drilled to produce a large number of deep holes to fit a large number of U-tubes for expanding of tube ends. The manufacture and assembly of such plates is expensive as well as complicated. (Fig. 39.14).

Q. *What is the major drawback in vertical, U-tube type steam generators with a bottom tube plate?*

Ans. Here comes the problem of corrosion. The water in a steam generator may contain sludge (particular iron oxide) which tends to accumulate (despite blowdown) in the bottom portion of the tube bundle just near the tube plate. Gradually, the sludge layer is evaporated, increasing the concentration of all water impurities, viz. chloride ions and alkalis within the pores of the sludge layer. Under high temperature and higher concentration, these impurities become potentially corroding and can destroy even stainless steel tubes.

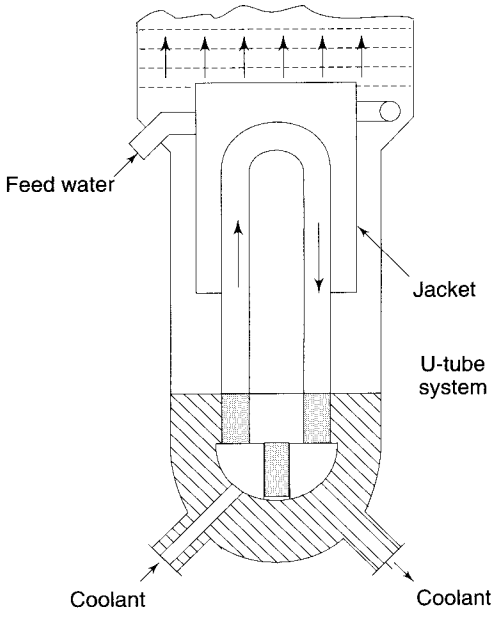


Fig. 39.14 *Vertical steam generator with U-shaped tube system. It needs precision fabrication to fit large number of U-tubes.*

Q. *How can this problem be coped with?*

Ans. This problem can be eliminated by designing vertical-type steam generators without the bottom tube plate.

Q. *How does such a system work?*

Ans. It comprises of two sections:
1. The bottom section that accommodates stainless steel tubes given the shapes of helical coils and expanded into tube plates. The helically coiled tubes are self-compensatory in thermal expansion. The aqueous coolant at a pressure 158-160 atm. moves in the tubes that serve as heat transfer surfaces.

The working fluid is introduced from the top of the helical tube system which is kept submerged in the working fluid to generate saturated steam at a pressure of 60-63 atm. (Fig. 39.15)

The feedwater moves down, by gravity circulation, through a descending channel formed by the jacket surrounding the helical tube system. The working fluid moves ascendingly inside the jacket.

2. The upper section forms the steam space that houses a cyclone type separator (for coarse steam separation, 1st stage) and a vertical annular louver-type separator (2nd stage) to produce dry steam.

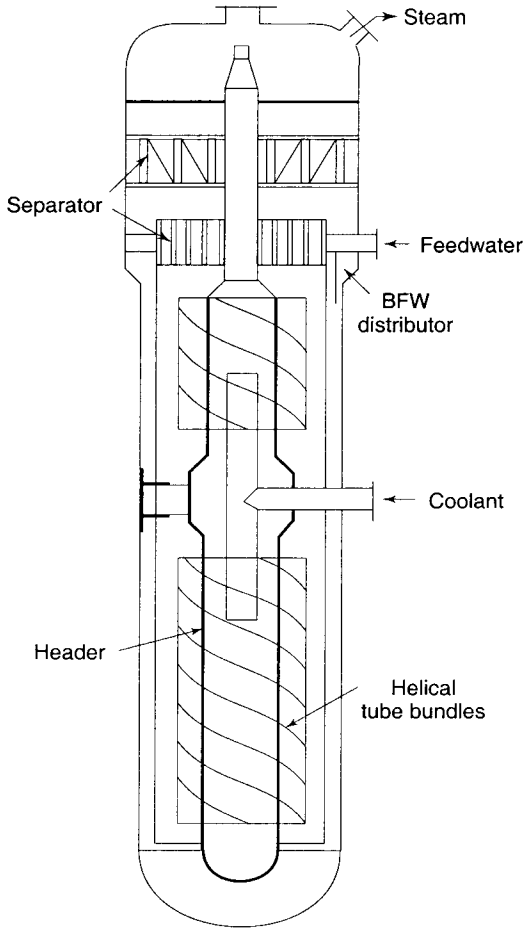


Fig. 39.15 *Vertical steam generator without bottom plate.*

Q. *What is the basic advantage of a vertical steam generator with helically coiled tubes during temperature variation?*

Ans. The thermal expansion and contraction of helically coiled tubes due to temperature variation is self-compensatory.

Q. *What is the principal drawback of such a system?*

Ans. It involves difficulties in the manufacture of helical coiling since the angle of coiling differs from one tube row to other.

Q. *What is the operating principle of a three-circuit nuclear power station?*

Ans. Steam is generated as a result of indirect heat transfer in this system that employs liquid sodium as the reactor coolant and primary heat transfer agent.

In the first circuit (I), molten sodium is pumped through the reactor to transfer heat from the reactor core to the intermediate heat-transfer agent which circulates in the second-circuit (II). (Fig. 39.16)

The heat-transfer agent of the 2nd-circuit (II) may be sodium or an alloy of sodium-potassium. The flow of the heat transfer agent in the 2nd-circuit is made at a pressure higher than liquid sodium flowing in the 1st-circuit.

In the third circuit heat is transferred to the working fluid (water) from the heat-transfer agent of the 2nd-circuit. The steam generated is fed to the steam turbine to drive the turboalternator to generate electricity.

Q. *Why is the heat-transfer agent in the 2nd circuit circulated at higher pressure than liquid sodium in the primary circuit?*

Ans. This is a preventive measure to avoid radioactive contamination of the heat-transfer agent of the 2nd-circuit by that of the first circuit, should

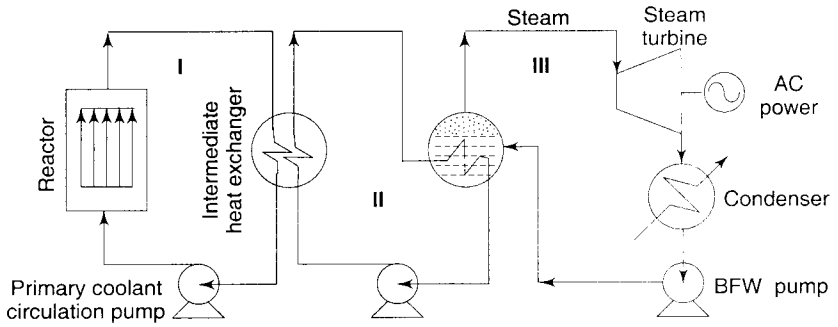


Fig. 39.16 *A Three-Circuit Nuclear Power Station. It involves one intermediate heat exchanger and steam is generated in the second circuit.*

there arise any leakage in the intermediate heat exchanger.

Molten sodium of the 1st circuit becomes highly radioactive due to its direct contact with nuclear fission and fission products. It emits high energy gamma-radiation. If the shielding in the 2nd circuit becomes loose, radioactive sodium will pass into the 2nd circuit and will render Na-K alloy or sodium of this circuit radioactive. Ultimately, radioactivity will pass into the working fluid and endager the safety of the working personnel.

To overcome this problem, the heat-transfer agent of the 2nd-circuit is circulated at a higher pressure than liquid Na of the 1st-circuit.

Q. *Why does a nuclear steam generator involving liquid sodium cooled reactor consist of three circuits instead of one?*

Ans. Liquid sodium while passing through the reactor becomes highly radioactive, which renders one heat exchanger insufficient and the whole heat-exchange system becomes complicated. In order to make the steam generator operation safe, the nuclear power station incorporates three circuits and two successive heat exchangers.

Q. *Briefly describe a steam generator with sodium coolant?*

Ans. It is a shell-type steam generator whose shell diameter (OD) is about 3m or less. The heating surfaces are made of U-tube arranged on the shell periphery. The working fluid is circulated through tubes and the molten sodium circulates in the intertubular space. (Fig. 39.17)

A cylinderical jacket is fitted on the shell to force a countercurrent flow of the coolant and the working fluid. The shell is prevented from overheating by a thermal shield.

Q. *Why is the shell diameter (OD) of a steam generator with sodium coolant 3m or less?*

Ans. For manufacturing ease and transportation facility, the shell-diameter of a steam generator rarely exceeds 3m.

Q. *In the sodium-coolant steam generator, molten sodium (heat-transfer agent) is circulated in the intertubular space and working fluid through the tubes (U-shaped). Why not the reverse?*

Ans. Since the working fluid is circulated at a much higher pressure than the heat-transfer agent (liquid sodium), the former is taken within the tubes and the latter (Na-coolant) in the intertubular space. (Fig. 39.17).

Q. *Can you mention certain basic parameters of a typical sodium-coolant steam generator?*

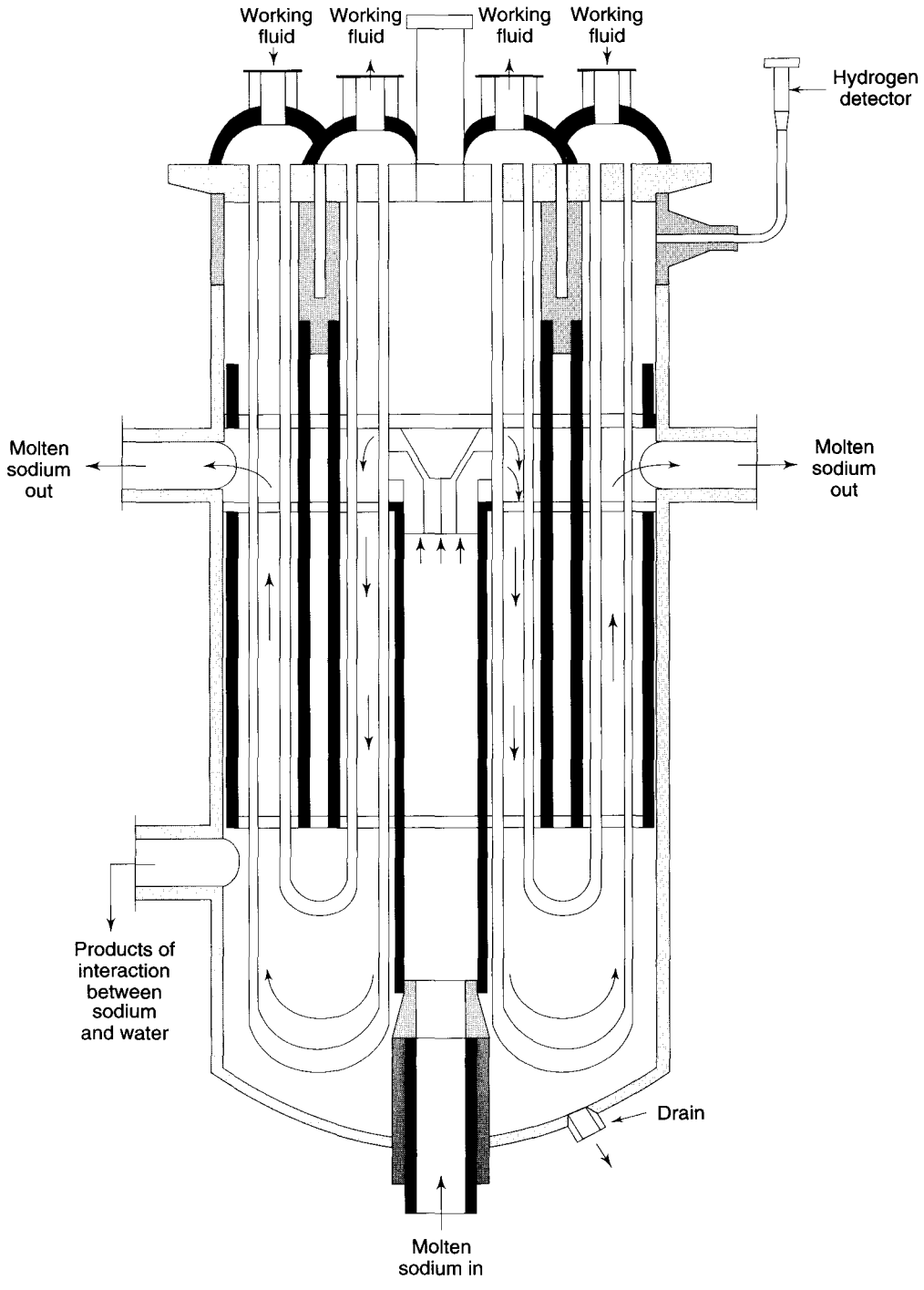


Fig. 39.17 *Sodium-coolant steam generator.*

Ans. One such typical generator with 1320 MW output has the following working parameters:

Temperature of coolant at steam generator inlet = 833K

Temperature of coolant at steam generator outlet = 653K

Superheated steam pressure = 16.3/3.4 MN/m^2

Superheated steam temperature = 813 K/813K.

Q. *What are the advantages of sodium used as a coolant?*

Ans. 1. It has low neutron absorption cross-section (0.5-2 barns). So greater number of slow neutrons will be available for fission process
2. It has low melting point (371K) and high boiling point (1156K). Between these two extreme temperatures, sodium will remain liquid and can be easily pumped and circulated through the reactor in the primary circuit
3. It has high specific heat 0.3 kcal/kg/K
4. Its thermal conductivity is 120 times the thermal conductivity of water. Hence it is a much more efficient heat transfer agent than aqueous coolant
5. It is economically available.

Q. *What are the advantages of liquid metal cooled reactors?*

Ans. 1. High thermal efficiency at low cost
2. Low cost of output power
3. High thermal conductivity and high specific heat of liquid metal render a higher heat removal rate at a much lower flowrate in comparison to gas cooled or water cooled reactors. Hence liquid metal need not be circulated at high pressure.
4. High reactor stability. In other reactors, the reactivity of the reactor increases with the loss of coolant because of the removal of neutron absorber. Hence to avoid overheating, these reactors must be shutdown by inserting control rods. But in the case of liquid metal cooled reactors, the reactivity decreases with the rise of temperature. This is a great advantage from the point of view of safety.
5. The reactor is compact and hence its size is comparatively smaller than other reactors of same power output.
6. If the liquid metal used as a coolant is sodium, then it will be best suited for thermal reactors with slightly enriched fuel. This is due to the low neutron absorption cross-section of sodium.

Q. *What are the disadvantages of liquid metal cooled reactors?*

Ans. 1. With the increase of reactor core temperature, the neutron economy falls off, as the hot moderator subjects the high-energy fission yield-neutrons to resonance and thereby increases the probability of the non-fissionable capture of neutrons
2. Each block of graphite, used as a moderator in sodium cooled reactor must be well cladded to prevent the diffusion of liquid sodium into porous graphite. This sodium-penetration in graphite layers causes mechanical failure. Hence graphite is to be protected from sodium-penetration by cladding, which further adds to the construction cost
3. The liquid metal, particularly sodium, becomes highly reactive as it extracts heat directly from the core. So to avoid contamination by irradiation steam is generated in the secondary circuit and both primary and secondary circuits are well shielded by thick slabs of concrete
4. Compared to other coolants, the leakage of sodium (primary circuit) is very dangerous as sodium becomes highly radioactive due to irradiation

5. All care must be taken to prevent the leakage of sodium in the water-circuit as it will react exothermally with water, producing enough heat as well as radioactive caustic soda, which increases the risk of further contamination.

Q. *What are the advantages of organic cooled and moderated reactors?*

Ans. 1. Organic liquids, viz. diphenyls and triphenyls act both as coolants and very efficient moderators. hence they are called super-moderators
2. Compact core design is possible due to dual characteristics (coolant and moderator) of liquid hydrocarbons
3. Non-corrosive. And therefore, low-cost mild steel piping can be used in the system. This saves initial capital investment
4. Selection can be made from a wide variety of fuels viz., uranium, uranium oxide, uranium carbide or uranium alloy because of excellent moderating properties of the organic coolants
5. Low operating core pressure
6. Steam of higher parameters of pressure and temperature can be produced.

Q. *What are the basic disadvantages with organic fluids used as moderator as well as coolant?*

Ans. 1. Poor heat transfer characteristics , even less than those of water
2. They undergo thermochemical changes due to radiation and heat. As a result they deposit on fuel-can surfaces thereby impairing the heat transfer further
3. Organic fluids being inflammable, adequate protection must be taken to guard against accidents.

Q. *Can you cite an example of a nuclear power plant that uses organic fluid as moderator and coolant?*

Ans. The Piqua Nuclear Power Plant (11.4 MW), Piqua city, Ohio, USA is an example.

Q. *What organic fluid does it use as a moderator and coolant?*

Ans. It uses a mixture of ortho-, meta-terphenyl and para-terphenyl as a coolant and moderator.

Q. *What fuel and control rods are used there?*

Ans. It uses enriched uranium as fuel. Boron is used as control rods.

Q. *What basic condition should a nuclear reactor fulfill in order to act as a breeder reactor?*

Ans. A breeder reactor produces a set of new fissionable material in the course of the burnup of primary fuel. That is, in a breeder reactor, the burnup of primary fuel results in the production of the secondary fuel.

In order to breed, the average number of neutrons produced per neutron absorbed by the fuel ($\eta = \nu\ \sigma_f/\sigma_a$) must exceed 2—one neutron to continue the fission chain reaction and the other neutron to be absorbed by a fertile nucleus to yield a new fissile (i.e., fissionable) nucleus.

For example, when one U-235 nucleus undergoes fission by a thermal neutron, it ejects 2.5 fast neutrons. One out of these 2.5 neutrons goes to sustain the nuclear chain reaction of U-235 fission, 0.6 neutron becomes absorbed by the moderator, coolant and structural elements and the rest 0.9 neutron is capatured by U-238 nucleus to produce a new fissile material Pu-239.

$$^{238}_{92}\mathrm{U} + {}^{1}_{0}\mathrm{n} \longrightarrow {}^{239}_{94}\mathrm{Pu} + 2\,{}^{0}_{-1}\mathrm{e}$$

This plutonium can undergo fission process and is called secondary fuel.

Q. *So in a breeder reactor, the burnup of primary fuel is compensated to some extent by the production of secondary fuel. How can this compensation be measured?*

Ans. This can be measured in terms of the conversion factor, which is the ratio of the number of secondary fuel nuclei generated to the number of primary fuel nuclei depleted.

Q. *What should be the conversion factor in order to "breed" in a reactor?*

Ans. The conversion factor should be unity or higher.

Q. *Why cannot U-235 or Pu-239 be used as a fuel in a thermal breeder reactor despite the fact that the value of η (the average number of neutrons produced per neutron absorbed) exceeds 2 for all fuels and neutrons of all energy?*

Ans. This is because of the absorption of fission neutrons by non-fuel material and some leakage from the reactor core.

When U-235 is used as fuel, the average number of thermal neutrons emitted is 2.12 of which one goes to maintain the fission chain reaction and the remaining 1.12 are left for breeding. Since the loss of neutron due to leakage and absorption by non-fuel material well exceeds 0.12, less than one neutron is available for breeding. This explains why the breeding mechanism ceases shortly.

With plutonium-239 as the primary fuel, the situation is worse, as the fission neutrons (thermal) available as a result of the fission of one Pu-239 nucleus is only 1.94.

Q. *Why are all the breeder reactors necessarily fast reactors?*

Ans. Fast reactors employ fast neutrons as projectiles. The value of η for fast neutrons is much greater than 2 for U-233, U-235 and Pu-239.

	Target	η	Fission Cross Section	Absorption Cross Section
${}^{1}_{0}n \Rightarrow$	U–233	2.6	1.85 barns	1.884 barns
(> 1.5	U–235	2.48	1.28 barns	1.358 barns
MeV)	Pu-239	3.04	1.95 barns	1.990 barns

With respect to fission cross-section they have a relatively high absorption cross-section for fast neutrons—a fact that increases the breeding possibility considerably. With fast neutrons, the chances of fission are less while the chances of neutron absorption by U-233, U-235, Pu-239 and Th-232 are considerably greater. Therefore, when fissions are induced by high-energy neutrons, high breeding ratios can be achieved with any fuel isotope.

Q. *What is the principal advantage of thermal reactors over fast reactors?*

Ans. The low fuel requirement.

If a fast reactor and a thermal reactor are allowed to operate at the same power with the same average fluxes causing fission, the fission rate

$= \bar{\sigma}_f \cdot N_{\text{fuel}} \cdot \bar{\phi}_f$ for the fast reactors

$= \bar{\sigma}_f \cdot N_{\text{fuel}} \cdot \bar{\phi}_{\text{th}}$ for thermal reactors

whereupon $\bar{\phi}_f$ and $\bar{\phi}_{\text{th}}$ become same and equal to $\bar{\phi}$.

Hence the number of fuel atoms, i.e. the total fuel loadings become directly proportional to the microscopic fission cross-sections ($\bar{\sigma}_f$).

The fuel isotope being U-235, the fission cross-section for thermal (0.0253 eV) neutrons is $\bar{\sigma}_f$ = 582 while for fast neutrons (> 1.5 MeV) the fission cross-section is $\bar{\sigma}_f$ = 1.28.

So even if the average flux of fast neutrons exceeds the thermal neutron flux by 10 times, the U-235 fueled fast reactor will have a fuel loading equal to $582/(1.28 \times 10) = 45.4$ times that of a thermal reactor operating at the same power.

Q. *Why is Pu-239 a more preferred fuel than U-233 in a breeder reactor?*

Ans. The average number of neutrons ejected per fast neutron absorbed (η) is 3 when plutonium-239 is used as fuel and it is 2.5-2.6 when uranium-233 is used as fuel.

That is why Pu-239 is more preferable in a breeder reactor.

Q. *Why is no moderator used in a breeder reactor?*

Ans. A breeder reactor is essentially a fast reactor. If a moderator is used to slow down the fission neutrons, the value of η (the average number of neutrons produced per neutron absorbed by the fuel nucleus) will be roughly equal to two where-

upon enough neutrons will not be available for breeding.

Q. *What is the major advantage of a fast breeder reactor?*

Ans. A fast breeder reactor employs high-energy neutrons as projectiles. And upon fission, the target nuclei eject fast neutrons also. Since there is no moderator, these neutrons are not slowed down. Since the structural materials do not absorb fast neutrons, a wide range of choices of constructional material is possible. This is a major advantage.

Q. *What is the major technical drawback of a breeder reactor?*

Ans. A breeder reactor has a very high power density—as high as 430 MW/m^3 of core volume. This is 13 times greater than a BWR, 40 times that of a CANDU reactor and 200 times that of a gas cooled reactor.

Therefore, it is necessary to remove large quantities of heat from the core and for that special coolants and special arrangements are required.

Q. *What is a boiling water reactor (BWR)?*

Ans. In this reactor, saturated steam is generated in the reactor core instead of a separate steam generator, i.e. in this system, fission heat is directly transferred to the water to produce steam which is dried and sent straightaway to the steam turbine.

Q. *In the early models, BWR was tagged into dual-cycle flow systems. Why was such a dual-cycle system in vogue?*

Ans. The dual-cycle flow system BWR consisted of two circuits—primary circuit that generated most of the turbine steam directly in the reactor core and the secondary circuit that contained a steam generator to produce turbine control steam. (Fig. 39.18).

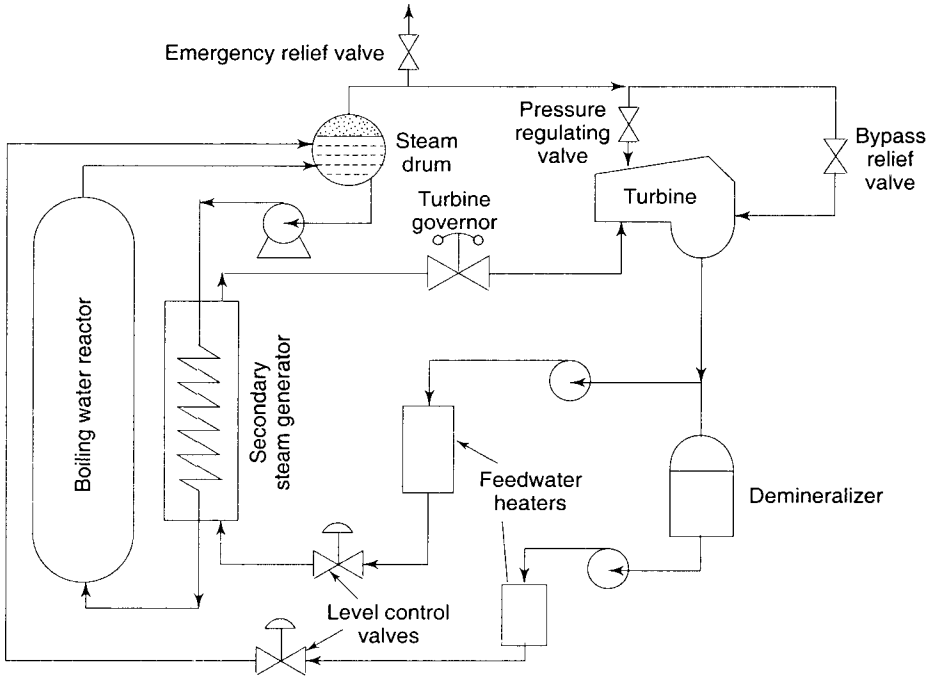


Fig. 39.18 *Schematic Diagram of a Dual-Cycle BWR System. Turbine control steam is produced in the secondary steam generator.*

In any BWR, the reactor power is controlled by the amount of steam bubbles in the reactor core. In a BWR, water is used as a coolant as well as the working fluid and moderator. Therefore, the displacement of water from the core by steam following higher steam demand by the turbine is accompanied by a fall of reactor power unless the control rods are withdrawn. If the reactor steam to the turbine is fed through a throttle valve, and the valve is opened to increase the turbine power, the reactor steam pressure will drop immediately. As the steam pressure in the reactor decreases, the steam volume in the core increases and that will bring about a lower reactor power.

This problem is solved by introducing a secondary circuit incorporating a small secondary steam generator and placing the turbine throttle valve on the secondary steam supply line.

Now with the increase of steam demand by the turbine, the throttle valve is opened, as a result of which the steam parameters—both temperature and pressure—will decrease. This will result in an increase of heat transfer from the primary water in the secondary steam generator and as a consequence the reactor inlet temperature of the feedwater will decrease.

As cold water enters the reactor, it condenses some of the in-core steam increasing thereby the reactor power. This is how the dual-circuit arrangement essentially endows the reactor with an inherent load following capability.

Q. *In the latest BWR steam generator systems, a single-cycle BWR circuit is used. And there is no secondary steam generator. Then how is the reactor power controlled?*

Ans. The reactor power is controlled by altering the recirculation rate through the reactor core with a series of jet pumps. (Fig. 39.19).

With the increase of power demand, the water (working fluid) recirculation rate through the core is increased and that sweeps away the steam bubbles from the core increasing the reactor power level.

Following the fall in reactor power demand, the water recirculation rate through the core with jet pumps is reduced increasing the incore steam volume that downs the reactor power level.

Q. *In the BWR system, the control rods enter from the bottom of the BWR vessel. Why not from the top?*

Ans. The top of the BWR is filled with steam, steam separator and steam drier assembly. Hence the control rods are inserted through the bottom of the BWR.

Q. *Is there any difference in the basic operating principle of control rods between the PWR and BWR systems?*

Ans. The control rods in a PWR enter from the top of the reactor and they are actuated by an electromagnetic system. During emergency, the reactor is scrammed by switching off power to the electromagnets letting the rods drop into the core under the influence of gravity.

However, BWR systems do not rely on gravity for emergency insertion. Here a hydraulic accumulator system is deployed to store enough energy to drive the scram rods into the core in the event of an emergency shutdown.

Q. *While designing as well as operating a boiling water reactor care must be taken that the maximum heat flux is below the DNB (departure from nucleate boiling) value.*

What is DNB? And why is it imperative that the maximum heat flux in the reactor core does not exceed the value of DNB?

Ans. Departure from nucleate boiling—a typical heat transfer phenomenon—can be demonstrated with the help of a boiling heat transfer curve. (Fig. 39.20)

Nucleate boiling is a boiling heat transfer process that takes place at relatively low heat fluxes. In this region vapour bubbles are formed at the surface of the fuel element and break away. Because of high convective heat transfer coefficients

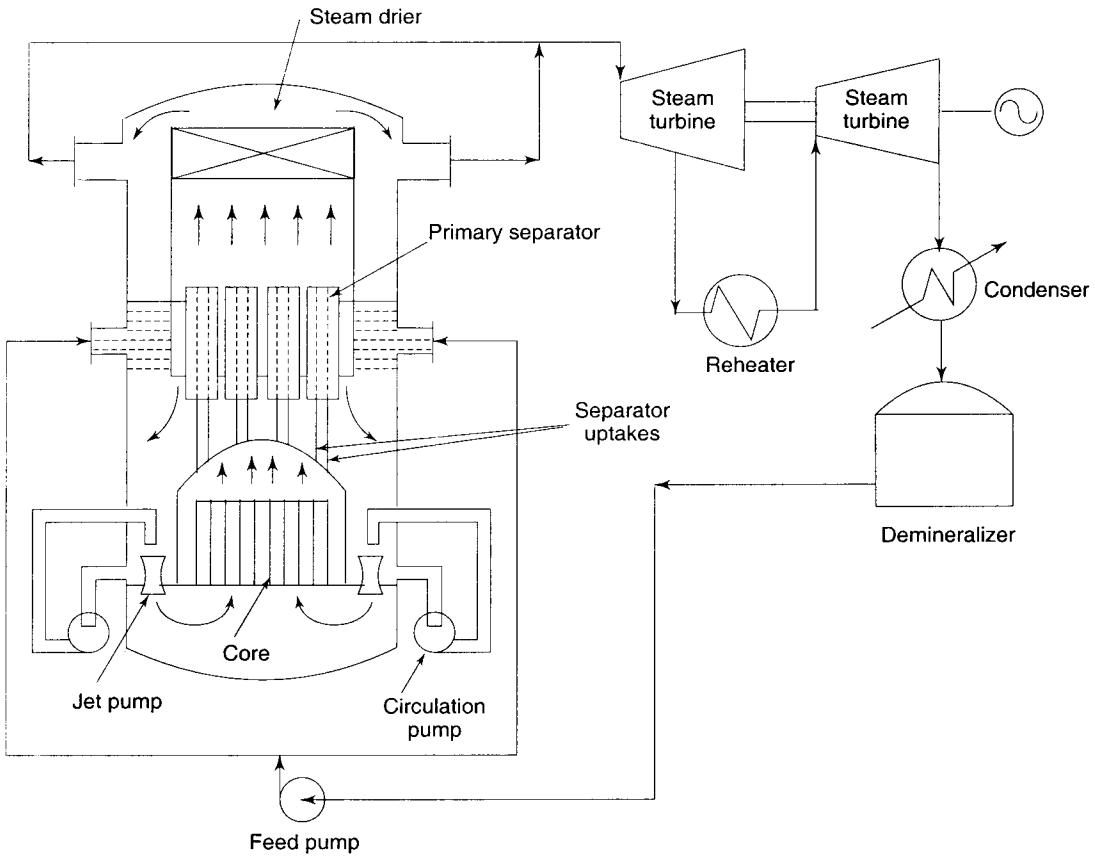


Fig. 39.19 *Boiling Water Reactor. Steam is generated in the reactor core because of direct heat transfer to the working fluid used as coolant also.*

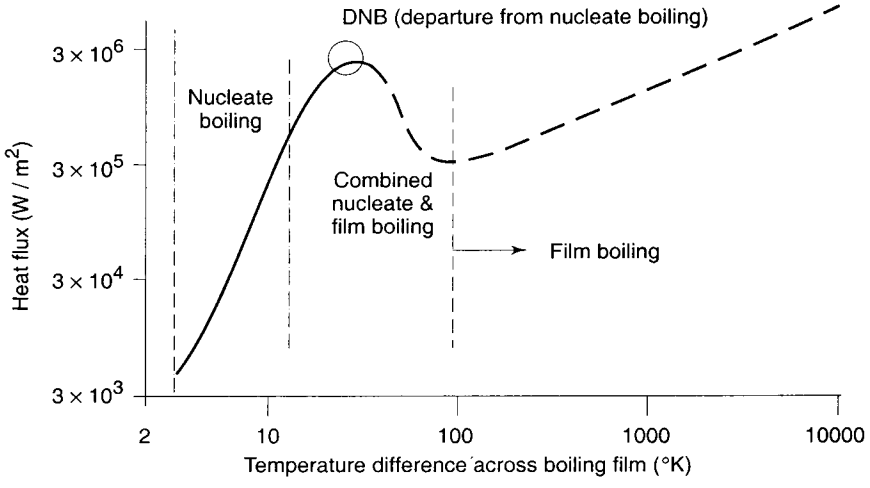


Fig. 39.20 *Typical boiling heat-transfer relationships.*

between the vapour bubble and the fuel element, a very high heat-transfer rate is established resulting in very marginal temperature difference between the saturation temperature and the fuel-element surface.

If the heat flux is raised further, the rate of steam bubble formation will increase and the smaller bubbles will coalesce to form big bubbles, while simultaneously increasing the heat-transfer rate. Ultimately the big bubbles will merge to form long, continuous vapour bubbles almost completely isolating the liquid film from the surface of the fuel element.

The vapour acts as an insulating layer and when the surface of the fuel element is completely covered with vapour, the surface temperature shoots up dramatically. This mode of heat transfer is called *film boiling*. The transition from nucleate to film boiling occurs at the departure from nucleate boiling.

Departure from nucleate boiling (DNB) takes place at high heat flux. Until or unless the heat flux is reduced, the fuel element surface will literally melt. And that is why during design and operation of a BWR (or any liquid cooled reactor) care must be taken to ensure that the maximum heat flux is always below the DNB value.

Q. *So it is extremely essential to operate a BWR at a maximum heat flux which is well below the DNB value. How is this accomplished?*

Ans. This is achieved by differential disposition of fuel rods about the control rod. The fuel rods having lower enrichment of fuel are disposed in the regions of high neutron flux to reduce the power generation of these fuel tubes. (Fig. 39.21)

The less enriched fuel tubes are placed along the outer edge next to the water gap where the control rod is inserted. The control rod shown here is in cruciform configuration. As the cruciform control rods, are withdrawn, the thermal neutron-flux increases sharply in the water gap produced by the control rod withdrawal. However, the thermal neutrons encounter less-enriched fuel elements, the nuclear fission rate becomes moderate and therefore, the heat flux is kept at bay.

Q. *What is HTGR?*

Ans. It stands for High Temperature Gas-cooled Reactor.

Q. *What gas is used for cooling such reactors?*

Ans. 1. Helium
2. Carbon dioxide

Q. *Briefly describe a HTGR and its operation.*

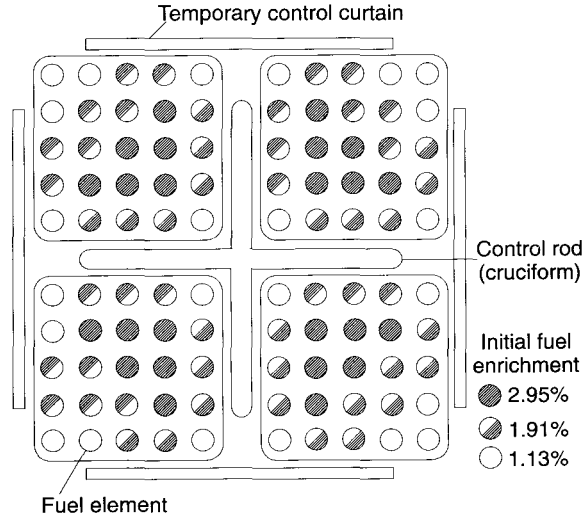


Fig. 39.21 *A typical in-core section of a BWR fuel module. Four fuel elements are symmetrically disposed around a cruciform control rod.*

Ans. Two gas-cooled commercial reactors are in operation in the USA. One is the 40 MW reactor (Peach Bottom-I) of Philadelphia Elec. Co. and the other is the 300 MW power reactor of Ft. St. Vrain.

The reactor is enclosed in a prestressed-concrete pressure vessel (PCPV) along with the helium coolant and steam-generating and steam-superheating equipment. (Fig. 39.22)

These systems are cooled by helium and moderated with graphite. One proposed reactor of 3800 MW will produce steam of high tempera-

ture (515°C) and high pressure (16.55 MN/m^2). The design efficiency of the HTGR is about 38% which is comparable to the efficiency of best fossil-fuel fired units. Its operational parameters are:

Helium (coolant) Inlet Temperature 318°C

Helium (coolant) Outlet Temperature 741°C

Helium Pressure 5 MN/m^2

Throttle Steam Temperature 515°C

Throttle Steam Pressure 16.55 MN/m^2

Reheat Steam Temperature 540°C

Reheat Steam Pressure 4 MN/m^2

Core Power 3 800 MW

Net Electrical output 1 450 MW

Net Thermal Efficiency 38.2%

Another HTGR operating at Sommerset, England has an electrical power output of 248 MW with 26% efficiency. The reactor is a spherical vessel made of low carbon steel. Graphite is used as a moderator as well as reflector. The core is a 24-sided prism through which are inserted fuel rods. The whole reactor is encased in a 3m thick concrete shield that also acts as a biological shield. Carbon dioxide is used as coolant and natural uranium is used as fuel.

Fission heat is transferred to the coolant gas, helium or carbon dioxide, from which heat is extracted by the working fluid in the steam generator to produce dry, superheated steam. The steam so obtained is expanded in the turbo-alternator to generate electricity.

Q. *What is the advantage of using graphite to build the core of HTGR?*

Ans. Graphite is a good moderator as well as excellent refractory material. It can tolerate very high temperatures. Besides, graphite has a high heat capacity. Therefore, the graphite-built core of HTGR will absorb large amount of fission heat without the risk of core meltdown.

Q. *What are the advantages of the gas-cooled reactor?*

Ans. 1 Simplicity in fuel processing
Cladding is not required. Uranium carbide (fuel) and graphite (moderator) are simply ground together and reprocessed.

2. No corrosion problem.
3. Higher stability of graphite at higher temperature and irradiation makes it an excellent high-temperature moderator. Therefore, high reactor core temperature can be obtained without the risk of core meltdown.
4. Both uranium carbide and graphite can withstand high temperatures. Therefore, limiting the fuel element temperature is not that serious a problem as in other types of nuclear reactors.
5. Better neutron economy due to low parasitic absorption.
6. CO_2 being a non-corrosive, non-toxic and non-flammable gas, completely eliminates the possibility of explosion in the reactor (cf. this threat is prevalent in water-cooled reactors)
7. Higher efficiency than Light-Water Reactors (LWR) viz., pressurized-water reactor (PWR) and boiling-water reactor (BWR). Thermal efficiency of LWR ranges from 32 to 33%.

Q. *What are the disadvantages of an HTGR?*

Ans. 1. Very low power density
Gases have very low heat transfer coefficient.

2. Large vessel is required.
Because of low heat transfer coefficient of coolant gas, a large amount of the gas is to be circulated.
3. Fuel loading is a more elaborate process. Besides, it is costly.
4. If helium is used instead of CO_2, leakage of radioactive helium will cause a problem.
5. Circulation of coolant should be higher and that chews up 10-20% of generated power.

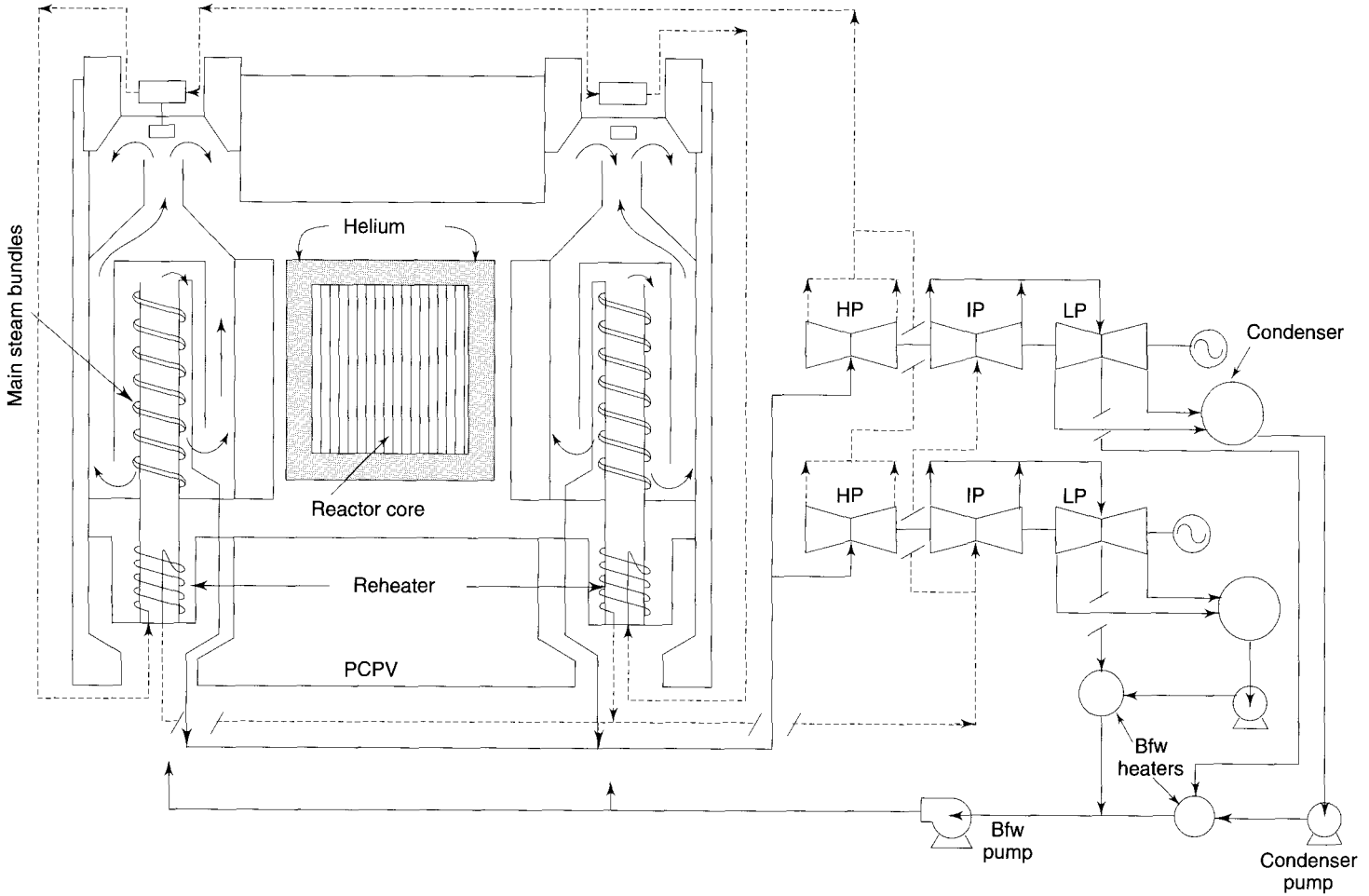


Fig. 39.22 *Schematic diagram of a nuclear power system incorporating a helium-cooled and graphite moderated HTGR.*

6. Higher fuel loading is needed, as the critical mass is high.
7. Complicated control mechanism due to low negative coefficient as helium does not absorb neutrons.

Q. *Gas-cooled steam generators should preferably incorporate an economizer as well as a superheater. If no economizer is installed, what will be the limitation?*

Ans. This can be demonstrated with the help of the accompanying figure (Fig. 39.23) where $[\theta_{wf}]_{ex}$ is the exit temperature of the working fluid producing saturated steam and θ_{ss} is the temperature of the superheated steam at the same temperature of the gaseous coolant.

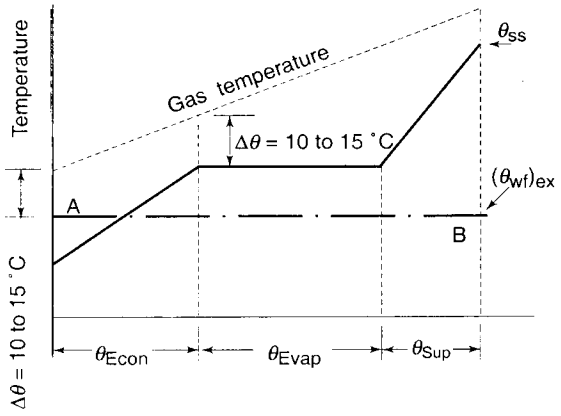


Fig. 39.23 *θ vs Q curve in a gas-cooled steam generator fitted with an economizer and a superheater.*

The temperature gradient $\Delta\theta$ on the colder side should not go below 10°C in order that intensive heat transfer from the coolant to the working fluid takes place.

Now if no economizer is used, saturated steam will be generated at the constant temperature of the working fluid in the steam generator (line *AB*) with the effect that the temperature of the saturated steam will be limited to $[\theta_{wf}]_{ex}$ corresponding to the given value of $\Delta\theta$.

However, if an economizer is incorporated within the gascooled steam generator, it will increase the temperature gradient at the inlet and as a consequence the exit temperature θ_{ss} of steam will rise.

Q. *What is PRISM?*

Ans. It is a liquid-sodium-cooled, uranium/plutonium-fueled reactor designed by General Electric Nuclear Co. to produce 155 MW per module.

PRISM = Power Reactor Inherently Safe Module

Q. *What is the basis of PRISM's inherent safety?*

Ans. 1. All its metallic fuel expands when accidentally overheated. This combined with the incipient thermal expansion of the grid plate assembly generates a large negative reactivity feedback slowing down the chain reaction.
2. In case the shutdown mechanism fails, PRISM's passive heat-removal features ensure large safety margins for coolant temperature so that the reactor module can withstand all conceivable transients.
3. Should there arise a leakage in the reactor vessel, the containment design ensures that the core remains covered with sodium with the effect that heat is transferred passively to air circulating naturally around the containment.

Q. *How do chances of accidental overheating arise?*

Ans. This may result from
1. sodium-coolant loss
2. accidental control-rod withdrawal

Q. *The modern trend is to design a passively safe reactor. What is 'passive safety'?*

Ans. This term implies a special design feature that automatically restores safe operating level to a reactor by natural physical laws—gravity, for example—without human intervention, should

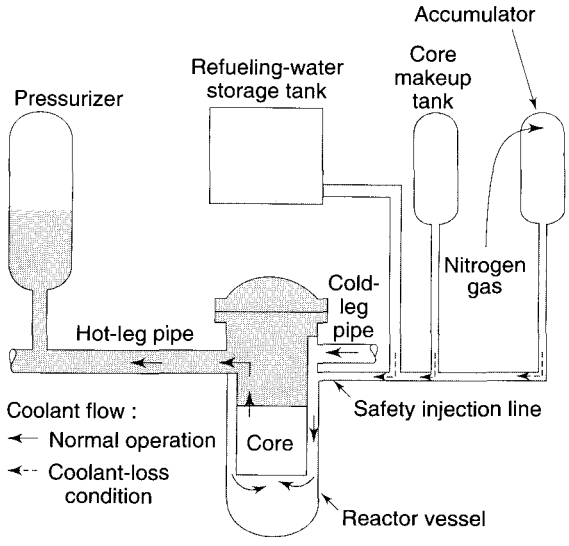


Fig. 39.24 *Heat removal by gravity driven water in AP-600 typifies passive safety features in small LWR designs.*

Source: POWER/November, 1988
Courtesy: Power Magazine (McGraw-Hill Publ./ New York/NY 10011/USA)
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there arise any abnormalities upsetting the normal operation of the nuclear powerplant.

Q. *How can such a passive safety be realized?*

Ans. In SBWR (Small Boiling Water Reactore) use is made of temperature differences and natural convection to draw C/W through the reactor core, thus eliminating the need of a circulation pump for emergency start-up. In the event of accidental loss of coolant, depressurization of the reactor gushes water, from an an elevated pressure-suppression pool, into the core under the force of gravity, keeping the fuel covered without any external intervention. Absence of large pipe attachments below the core level ensures maintenance of the water cover. This is followed by containment cooling provided by a water annulus on the side of the suppression pool.

In another reactor system AP-600, emergency core cooling can operate without human intervention or emergency power supply. In the first step of emergency cooling, water flows into the core under gravity from tanks positioned over the reactor vessel—aided by gas-pressure driven fluid injection to abstract the lions' share of the residual heat generated in the core and the rest of the excess heat is taken care of by air circulating under natural convection over the steel containment structure (Fig. 39.24).

Q. *Uranium fission leads to the generation of radioisotope Co-60 which emits deadly gamma radiation. How can this hazard be minimized?*

Ans. 1. Removal of cobalt-bearing materials from the primary coolant circuit
2. Improved piping-surface preparation to reduce Co-60 pick-up
3. Enhanced system-decontamination procedures.

Q. *What is THTR?*

Ans. It stands for Thorium High-Temperature Reactor.

Q. *Can you cite an example of one such reactor that went into commercial operation?*

Ans. A 300 MW-unit manufactured by Brown Boveri and Co. Ltd. (BBC), Baden, Switzerland went to full commercial operation in 1987. This plant located at the Westfalen Power Station, Hamm-Uentrop, Germany is jointly owned by Hochtemperatur-Kernkraftwerk GmbH and Vereinigte Elektrizitaetswerke Westfalen Ag.

Q. *Briefly describe its design features.*

Ans. It is a sophisticated and advanced nuclear plant design comprising two circuits.

Heat generated in the reactor core is abstracted by helium coolant circulating in the primary circuit and it is then transferred to the feedwater in the secondary circuit to generate steam. Thus, the radioactive primary circuit is completely isolated from the non-radioactive secondary circuit.

The reactor core, called a pebble bed, is dumped with hundreds of thousands of spherical

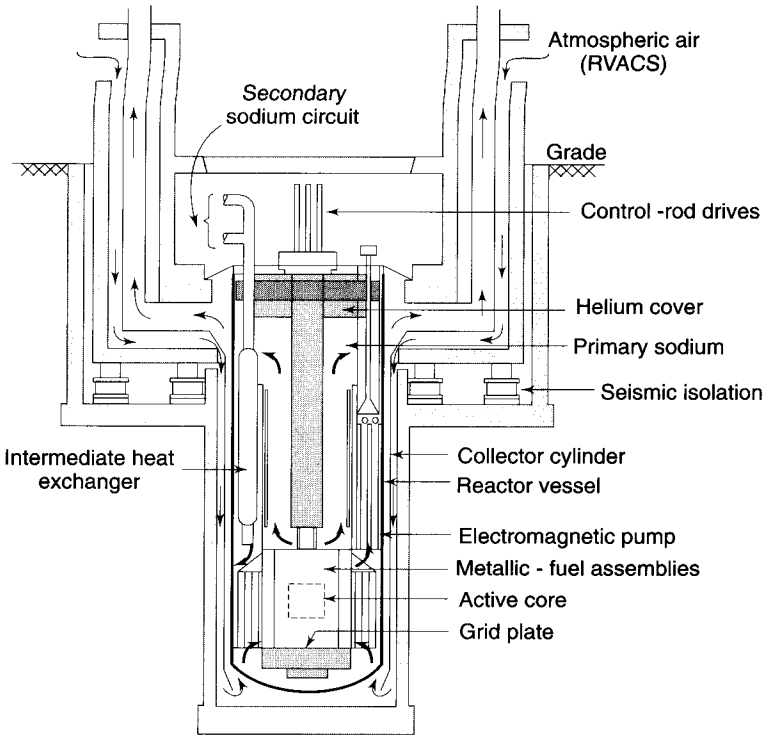

Fig. 39.25 *Core thermal expansion, air cooling of containment characterize passive safety of a sodium-cooled prism.*
Source: Power/November, 1988
Courtesy: Power Magazine (McGraw-Hill Publ./New York/NY 10011/USA)
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elements made of thorium contained in a cylindrical graphite reflector. Helium under pressure is circulated down through the reactor core heated to 1033°K by the spherical fuel elements and is then directed through hot-gas ducts to the steam generators. Fission heat generated is controlled by the reflector rods. The core can be continuously discharged and refueled on line, dispensing with the refueling downtime necessary with light-water reactors.

Q. *How is the performance of a nuclear power plant described?*

Ans. It is described in terms of electrical and thermal capacity.

Q. *How can this be expressed?*

Ans. This can be expressed in terms of the utilization factor, K_{ut}, which is the ratio of the energy actually generated (Q_{ac}) during the time in question (it may be a month, quarter of a year or a year) to Q_{av}, the available energy which the plant can generate operating at a 100% installed capacity during the whole period in question

$$K_{ut} = \left[\frac{Q_{ac}}{Q_{av}}\right](100)\%$$

Q. *On which factor or factors, does the electrical capacity of a nuclear power plant depend?*

Ans. Capacity of the steam turbines (that ultimately convert nuclear heat energy into electrical energy).

Q. *On which factor or factors does the thermal capacity of nuclear power plants depend?*

Ans. 1. Fuel loading
2. Design of the reactor.

Q. *What is the thermal capacity of a reactor operating on U-235 as fuel?*

Ans. It is given by the expression

$$N_r = 3 \times 10^{-11}\ \phi\ \rho\ \sigma_f\ V$$

where 3×10^{-11} J or 190 MeV thermal energy is released upon fission of 1 nucleus of U-235.

ϕ = average neutron flux density

ρ = number of fissile fuel nuclei per unit core volume

V = volume of the reactor core

σ_f = microscopic fission cross-section of U-235.

Q. *What is the difference between pressure-tube reactors and pressure vessel reactors.*

Ans. In pressure-tube reactors, the pressure is taken up by the tubes. The coolant is pumped under pressure through hollow tubes.

In pressure-vessel reactors, the pressure is taken up by the vessel itself where the nuclear fission process is accomplished.

Q. *Why must the water used as a nuclear coolant be thoroughly purified?*

Ans. Water to be used as a nuclear reactor coolant must be thoroughly purified and free from traces of impurities, otherwise these undesired materials will initiate corrosion and erosion of the materials used in the reactor core as well as the entire circuit.

Q. *Ordinary water is an extremely stable, non toxic, non-explosive heat transfer material. Hence it finds its application as a reactor coolant in nuclear power plants. Is there any chance of explosion when ordinary water is used as coolant?*

Ans. Yes; despite its thermal stability, ordinary water undergoes radiolysis, i.e., radiation decomposing water into hydrogen and oxygen as well as hydrogen peroxide

$$H_2O + h\nu \longrightarrow H + OH$$

$$\dot{O}H + \dot{O}H \longrightarrow H_2O_2$$

$$H_2O_2 \longrightarrow H_2O + O_2$$

The mixture of such gases is explosive.

Q. *What factors should be considered in selecting the site for a nuclear power plant?*

1. The land allocating for constructing a nuclear power plant should be of little or no agricultural value.
2. The site should be chosen in the vicinity of a natural body of water, lying on unflooded land so that cooling water required by the powerplant needs to be lifted for a minimum height.
3. The soil at the erection site must have sufficient bearing capacity to minimize the expensive grouting process.
4. The ground water level should be preferably below the bottom of the projected building basements as well as buried services so as to avoid additional expenses required for ground water lowering during construction.
5. The site should preferably have a flat surface bordered with slopes for the construction of power plant buildings and to ensure sufficient surface drainage.

   Besides, nuclear power plants should not be constructed in

   (a) localities of active karst
   (b) localities with a high risk of massive landslides and mudflow
   (c) localities with high risk of avalanches
   (d) localities prone to tsunamis or other natural disasters
   (e) localities likely to be flooded following a failure of a dam upstream
   (f) zones left void after mining
   (g) swamped or overdamped areas under constant inflow of pressure ground water
   (h) localities near and around health resorts, spa and water supply sources.

40

ENERGY FROM WASTE

Q. *What is the latest trend in solid waste management?*

Ans. It aims to attain four primary objectives

1. source reduction
2. recycling
3. waste-to-energy conversion
4. landfilling

Q. *What is source reduction?*

Ans. It means the reduction of the quantum of waste requiring disposal at the source. This needs a radical change in public attitude and in industrial and commercial processes to minimize in solid waste.

Q. *What do you mean by recycling of solid waste?*

Ans. It means sorting out and return to the point of manufacture of those materials from the solid waste for which it is economically feasible to do so, e.g. waste paper can be sorted out and recycled to the paper industry. Aluminium cans of soft drinks and other foodstuffs can be conveniently recycled. So also use-and-throw polythene cups, dishes, trays and cutlery.

Q. *What degree of recycling is economically feasible?*

Ans. Industry experts opine that recycling is economically sound to the extent of 35%. Beyond this it is unlikely.

Q. *Why?*

Ans. 1. Public attitude has not been fully geared to accepting anything and everything produced from recycled materials

2. Source diversity is another problem that renders sorting and recycling of specific materials to the point of manufacture difficult
3. Waste itself poses characteristics that deny 100% total recycle
4. Method of production of waste and the collection responsibility also stand in the way of total recycle.

Q. *What do you mean by waste-to-energy conversion?*

Ans. Burning of waste to produce a valuable commodity—steam and/or electricity.

It also offers a viable means of source reduction, i.e. reducing the volume of waste.

As much as 47 000 tons of solid wastes were gulped down per day by the 160 existing municipal waste-to-energy facilities in the USA in 1989.

Q. *How does "landfilling" play its role in the integrated approach to solid-waste management?*

Ans. Filling the voids on earth with the wastes/residues leftover materials and energy recovery

as well as maintaining environmental health complete the landfilling strategy.

Q. *What is the traditional method of burning solid waste to produce thermal energy?*

Ans. Mass-burning of solid waste.

Q. *How is mass burning of solid waste carried out?*

Ans. Solid refuse is trucked in and unloaded into a storage pit capable of holding a 2 to 4-days supply of refuse.

Large, non-combustible objects are sorted out and rejected.

The solid waste is mixed to a more homogeneous mass, picked up from the garbage pit with the help of a mobile crane and grapple bucket and unloaded into separate feed chutes that supply each boiler.

As the refuse drops down the chute onto a feed table, a series of hydraulically driven charging rams continually pushes the mass into the furnace grate at a rate dictated by fuel or steam demand. The speed of the rams is controlled by motorized flow-control valves. (Fig. 40.1)

The grate consists of three inclined stepped sections where drying, combustion and burnout take place. Each section is composed of alternating arrays of stationary and moving grate bars. The latter agitate the refuse and force it down the grate by a push-pull mechanism.

Primary combustion air is fed under the grate while secondary air, also called overfire air, is injected over the top of the fuel bed to ensure optimum combustion and emission control.

Bottom ash representing 80–90% of the total ash is discharged into the ash chute by the final member of pusher-type conveyors arranged in a cascade along the length of the grate. Also a portion of bottom ash falls through the grate-air-slots.

The system normally runs automatically though manual override from the local panel is possible.

Q. *Why is refuse in the tipping house mixed before feeding it to boiler furnace?*

Ans. Mixing ensures homogenization of fuel to a certain extent. This fuel homogenization improves the operation of the furnace and minimizes load swings due to variations in refuse heating value.

Q. *Why are oversize and otherwise undesirable materials removed from the refuse prior to its feeding by crane grapple down to the feed chutes?*

Ans. They may create problems in the feed chute or ash removal system. The feed chute may get clogged or ash discharging conveyor may get jammed or grate-air-slots may get blocked.

Q. *Why are the feed chutes kept full with refuse?*

Ans. To maintain an air-seal.

Q. *How is this safeguard ensured?*

Ans. An alarm is fitted to ensure a steady rate of feed (fuel) supply. If the level in the feed chute drops below a prescribed limit, an alarm sounds.

Q. *How is the charging-throat area protected against burnback and radiant heat?*

Ans. The whole charging-throat area at the furnace interface is lined with refractory brick or cooled with water.

Q. *Why are the furnace grates upon which refuse burns stepped?*

Ans. To promote burnout.

The steppings expose unburned fuel for better combustion.

Q. *How are the specific refuse burning conditions maintained?*

Ans. Each inclined stepped section of the grate is provided with at least one independent air plenum to supply undergrate primary air. Therefore, the proportion of undergrate combustion air can be varied to fullfil the specific refuse-burning conditions.

Q. *How are grate functions controlled?*

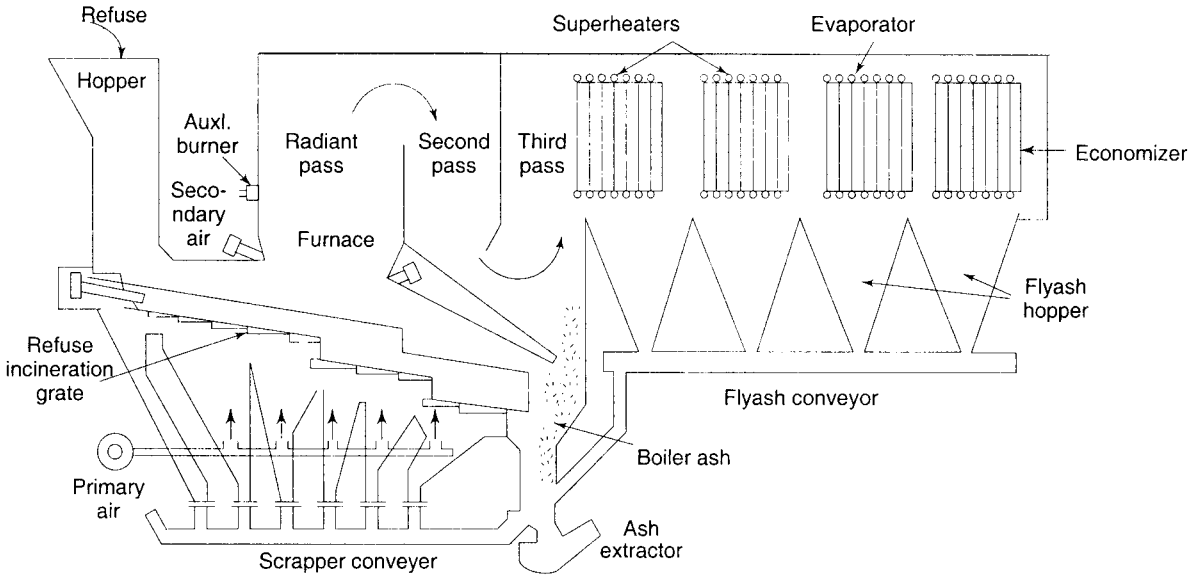

Fig. 40.1 *Multipass mass burning system of solid waste. Municipal solid waste is incinerated on inclined stepped grate sections to provide high combustion efficiency and low emission.*

Ans. Signals generated by a discrete stoker controller control the grate functions. The speed of the charging ram as well as the reciprocation rate of the grate and siftings system are determined by the microprocessor-based controller. This also feeds information on the feed chute and shut-off gate and sounds alarms when the grate and siftings sections have stalled.

Q. *How are the refuse-fired boilers designed to combat the corrosive and abrasive nature of the refuse and flue gas generated?*

Ans. The lower furnace (extending up to 10.5 m above the grate) is lined with a 25 mm thick silicon carbide refractory anchored to the walls with high density pin studs.

Protection is also ensured along the grate line by high-alloy cast blocks. These are replaceable liners. They are bolted to the waterwalls and extend up to 1.2–1.25m above the grate in the charging section and up to 1m above the grate in the discharging section.

Q. *Why is secondary air introduced?*

Ans. It promotes high turbulence thereby ensuring good mixing of volatile gases. As a result, complete combustion of unburnt particles and partial oxidation products of the hydrocarbon fraction of refuse is achieved.

Q. *Why is it imperative to operate the furnace at the correct level of oxygen?*

Ans. Correct level of excess oxygen introduced in the furnace achieves good combustion. Oxygen deficiency may lead to incomplete destruction of toxic hydrocarbons such as furans, dioxins, etc. Appropriate amount of excess oxygen reduces the potential for corrosion.

Q. *How much excess air is used?*

Ans. 80% excess air is used.

Q. *Why 80%?*

Ans. This has been derived from industry experience which suggests that 80% of excess air is just enough to optimize the combustion of solid refuse in the mass-burning system.

Q. *Frequently it is found that mass-burning furnaces are equipped with one or two auxiliary burners. Why?*

Ans. These burners are installed for start-up/shut-down or backup when refuse cannot be fired. Also in response to higher steam demand these auxiliary burners are switched on. Besides, some installations fire these auxiliary burners to ensure the complete destruction of organic compounds formed during combustion.

Q. *How are these auxiliary burners tuned to the complete destruction of organic compounds generated due to the mass-burning of refuse?*

Ans. Mass-burning installations are provided with temperature sensors or some other mechanisms that trigger the firing of auxiliary burners when operating parameters fall below the prescribed limit.

Q. *How are the superheater tubes arranged?*

Ans. Superheaters are of convective type. In a current Foster Wheeler design, parallel-flow superheater tubes are laid out in the convective shaft of the horizontal heat recovery pass.

Q. *Why are these superheater tubes protected from excessive temperature build-up?*

Ans. To avoid the risk of high-temperature corrosion.

Q. *How does the probability of high-temperature corrosion arise?*

Ans. Flyash arrested on superheater tubewalls may gradually build up, impairing the heat transfer from hot flue gas to the steam passing through superheater tubes. As a result, the tube metal temperature will increase and that will fuse the corrosive ash on the external surfaces of the tubes. Under the onslaught of aggressive ash and high temperature, the superheater tubes will fail.

Q. *How can this risk be avoided?*

Ans. The superheater tubes are spaced widely apart to avoid the risk of plugging. And to eliminate ash build-up they are cleaned by mechanical rappers.

Q. *How does this rapping system work?*

Ans. It employs a series of rapping hammers to impart shock forces to the superheater tubes. (Rapping means to induce vibration by means of mechanical shock impulses).

Each tube is independently rapped from one or both sides. Hammer blows induce high shock forces to the tubes continually with the effect that the bond between the slag and tubewall is ultimately broken and the tubes get freed from ash build-up.

However a thin layer of ash always remains adhered to the tubewall to impart some degree of protection to the superheater tubes from corrosion.

Q. *Refuse is a heterogeneous mixture of varied kinds of materials having different heating value. Does this variation in refuse heating value, affect the boiler output in any way?*

Ans. Yes. Variations in refuse heating value cause swings in the boiler output. And this is inevitable.

Q. *How are these swings in boiler output accommodated?*

Ans. To counter the swings in boiler output due to variation in the heating value of the refuse, a turbine-following-boiler control scheme is used. This means a constant boiler header pressure is always maintained by turbine controls while the electrical load is allowed to vary in proportion to the actual output.

Besides, there is a combustion control system that works to minimize load swings by responding to changes in the refuse heating value. This control system is pivoted on two loops—oxygen flow-control loop and furnace exit-gas temperature-control loop. These two loops give a feedback on changes in furnace condition due to variations in the heating value of the refuse which changes the specified steam flowrate. The combustion control system then adjusts the flow of air and fuel to maintain the specified steam flowrate thereby minimizing load swings.

Q. *Upon which factors does the efficient operation of a mass-burning system depend?*

Ans. 1. Optimum regulation of fuel bed depth.
2. Combustion air distribution.

Q. *How is the fuel bed-depth controlled?*

Ans. This is effected by regulating the
(a) refuse charging rate
(b) grate speed.

However, both these factors are functionally dependent on the nature of the refuse being fired as well as the location of the complete burnout on the grate.

Q. *How is combustion air introduced to the massburning combustor?*

Ans. A part of the combustion air is fed undergrate. This is also called primary air. The remaining portion is fed above the bed. It is called overfire air or secondary air.

Depending on the burning pattern and emission characteristics, the primary or undergrate air is distributed to the various air zones where dampers are provided to effect flow control. Usually this air is preheated, but if moisture in the refuse mass is low, air preheating is bypassed.

Overfire ambient air is introduced into the furnace at different levels above the fuel bed.

Q. *How much of the total combustion air is the undergrate air?*

Ans. About 60%.

Q. *Where are the secondary air nozzles located?*

Ans. These high-pressure air nozzles are located at different levels on the front and rear walls.

Q. *What is the basis of the set up of overfire air nozzles at different depths?*

Ans. The following factors provide the basis of the location of overfire air nozzles:

1. NO_x level in the flue gas
2. CO level in the flue gas
3. Observed flame shape
4. Observed flame height

With the change of refuse heating values in different seasons, it requires adjustment of the overfire air system.

Q. *Fireside corrosion of the tube metal of the evaporator is a nagging problem in a mass-burning system. What recent improvement has been done to protect the tubes from the highly corrosive environment?*

Ans. Refractory lining has been found to be effective. However, it demands constant maintenance and measurement of the thickness of the refractory wall. Besides, refractory is prone to slagging, which impairs heat transfer.

In a recent development, a weld-deposited alloy of inconel-625 is applied to the furnace walls. In the zones of higher gas-temperature, Incoloy-825 is used.

Q. *Why are these alloys used?*

Ans. They have high heat and corrosion resistance.

Q. *Is there any other methods to slow down corrosion process in the boiler furnace?*

Ans. The maximum steam temperature is kept in the range 400-450°C in order to keep the tube metal temperature sufficiently low so that carbon steels and other low alloy steels can be used to reduce the corrosion rate. For the same reason, the temperature of flue gases entering the superheaters is kept at 700°C or less.

Q. *What is the present trend of solid waste burning?*

Ans. Instead of burning untreated garbage in the mass-burn facility, the present trend is mass-burn facility with upstream preparation.

Q. *What is upstream preparation of solid waste subject to mass burning?*

Ans. It includes:

1. Primary shredding
2. Separation of light fraction and heavy fraction by density separation
3. Recovery of such materials as ferrous, aluminium, glass, copper, brass from heavy fraction
4. Secondary shredding of light fraction.
   (a) Burning the classified and shredded refuse directly in a boiler
   (b) Anaerobic digestion of the shredded product to produce fuel gas to be burnt in the boiler or gas turbine or internal combustion engine
   (c) Transformation of secondary shreddings into pellets or some other convenient form and then burning them in the boiler
   (d) Pyrolysis of the product of secondary shreddings at an elevated temperature and in the absence of O_2 whereupon the carbonaceous material is thermally decomposed to liquid or gaseous fuel which is burned in the boiler.

Q. *What is the utility of upstream preparation?*

Ans. It offers better combustion control which is particularly necessary to limit the products of incomplete combustion that escape in the flue gas. For example, upstream preparation drastically cuts down the quantities of heavy metals entering the combustor and thereby reduces the emission of metals in the ash or flyash.

Upstream preparation produces refuse-derived fuel (RDF) that can be cofired in the utility boilers with other premium grade fuels. This offers an excellent scope for disposing of large amounts of prepared wastes and at the same time recovering their inherent energy value.

Q. *How many different types of combustor technology convert waste to energy today?*

Ans. 1. Mass-burn units
2. Starved-air modular units
3. Excess-air modular units
4. Fluidized bed combustion

5. Rotary combustor technology
6. Co-firing units that burn wood or coal along with the waste.

Q. *How many different types of emission occur from municipal waste combustors?*

Ans. Four types:

1. Particulates
2. Acid gases, particularly HCl
3. Metals
4. Toxic organics.

Q. *How does HCl occur in the emission from municipal waste combustors?*

Ans. It comes from the combustion of plastic materials (cf. divinyl chloride plastic) and paper in the waste mass.

Q. *What metals are emitted?*

Ans. Cadmium, chromium, arsenic and mercury

Q. *What toxic organics occur in the emission from municipal waste combustors?*

Ans. Mainly dioxins and furans.

Q. *How are these emissions kept at bay?*

Ans. Emissions are minimized by adopting two basic technologies

1. combustion control
2. downstream add-on controls.

Q. *What do you mean by combustion control?*

Ans. This involves:

(a) design of combustors
(b) operation of combustors
(c) control of combustor performance
(d) enhancing the destruction of organic stuffs
(e) reduction of the quantity of uncontrolled particulate matter leaving the furnace
(f) maintaining minimum furnace temperature to reduce NO_x emission

Q. *How can a reduction in the quantity of uncontrolled particulate matter leaving the furnace be achieved?*

Ans. This is achieved through proper mixing of combustion air with the wastes in the furnace.

Q. *What do you mean by add-on control?*

Ans. It comes in the form of

(a) ESP (Electro Static Precipitator) introduced downstream of the economizer.
(b) Spray dryers followed by an ESP
(c) Spray dryers followed by a fabric filter

All are added downstream of the economizer and in the flue gas shaft.

Q. *Is there any particular advantage of a spray dryer-fabric filter combination?*

Ans. This combination eliminates multiple pollutants, viz. dioxins, furans, acid gases, particulate matter, and trace heavy metals.

Q. *What kinds of particulate emissions take place due to municipal waste combustion?*

Ans. Two types:

1. solid particulates
2. condensible particulates.

Q. *How do solid particulates originate?*

Ans. There are non-combustible materials always present in almost all solid wastes. Under normal combustion conditions in the furnace, these produce solid particulates as flyash in the flue gas.

Q. *How do the condensible particulates originate?*

Ans. These are produced when a certain portion of refuse mass entering the combustion zone gets vapourized instead of burning out into CO_2 and water.

These vapourized constituents eventually get cooled downstream and condense on their way from the boiler to the stack.

Q. *In what form are the trace heavy-metals emitted?*

Ans. They are emitted as vapour mainly in the elemental form. They are also released as solid particulate matter in the form of metal oxides, chlorides and sulphates.

Q. *What are the plus points and minus points of wet scrubbers?*

Ans. High efficiency and low reagents requirement are its two plus points.

Its disadvantage are

1. Water consumption
2. Need to treat scrubber bleed stream
3. Its incompatibility with fabric filters.

Q. *Besides the above mentioned pollutants, is there any other pollutant emitted by the municipal waste upon which special attention to be focussed?*

Ans. Yes; it is NO_x.

Q. *How is this generated?*

Ans. It results from the oxidation of nitrogen contained in the waste itself. Also it is generated due to high temperature conversion of atmospheric nitrogen with the available oxygen. The latter is called thermal NO_x.

Q. *How can the NO_x emission from solid-waste incinerators be reduced?*

Ans. This can be implemented through several control measures.

Precombustion Control includes

(a) lowering the nitrogen content of solid-waste introduced into the furnace

(b) minimizing the amount of oxygen available for reaction with the available nitrogen at the point of combustion.

Combustion Control includes

(a) operating the furnace at a lower temperature

(b) selective non-catalytic reduction (SNR) of NO_x by injecting ammonia through large jets fitted in the furnace walls at such locations where temperatures are in the range 870–980°C.

Postcombustion Control includes

(a) selective catalytic reduction of NO_x in the flue gas by ammonia over a catalyst bed downstream

(b) wet scrubbing of flue gases.

Q. *What are the toxic organics that may exit the stack during municipal solid waste (MSW) burning?*

Ans. These are chiefly dioxins and furans.

Q. *In which form do they mainly exit?*

Ans. They may exit in three forms:

1. vapour form
2. condensed form
3. absorbed onto fine particulate form.

Q. *Why do they form?*

Ans. Incomplete combustion of carbon compounds is the genesis of toxic organics.

Q. *What steps should be taken for the efficient destruction of these harmful, incomplete products of combustion?*

Ans. This requires:

(a) adequate control of temperature

(b) supplying appropriate amount of combustion air through appropriate locations in the combustion system.

Q. *What steps should be taken to ensure good furnace operation in a large mass-burning incinarator?*

Ans. 1. Combustible materials are to be separated and non-combustibles to be removed from the refuse feed.

2. Large blocks of combustible materials should be broken into more or less uniform size.

3. Elimination of moisture content of the refuse combustibles should be carried out by air drying to uniformly low levels prior to combustion.

4. Furnace temperature should be controlled to ignite the refuse but it should not be so high as to increase the formation of NO_x or vapourization of metals. Besides, furnace temperature should be below the melting point of flyash.

5. Correct amount of air in the correct location should be injected into the furnace to supply O_2 and ensure uniform tur-

bulence throughout the furnace to permit complete reaction of unburnt matter with oxygen and at the same time minimize the entrainment of bottom ash into the flue gas.

6. Residence time of the combustion products in the combustor should be sufficient to complete combustion.

Q. *Apart from mass burning, what other technologies are available for deriving energy from waste?*

Ans. There are six other technologies available:

1. Fluidized-bed combustion
2. Pyrolysis
3. Supercritical water oxidation
4. Infrared combustion
5. Wet-air oxidation
6. Deep-well wet oxidation.

Q. *What are the prospects of fluidized bed combustion?*

Ans. This offers a clean and efficient method of incinerating a variety of solid waste fuels.

Combustion efficiency is high because of intense mixing of combustion air and combustibles in the turbulent bed.

Boiler efficiencies are comparable to conventional units.

Bed temperature (810–870°C) is substantially low and more uniformly distributed with the effect that NO_x formation is greatly minimized while the destruction efficiency of hazardous organics is as high as 99.99%.

Q. *What types of fluidized-bed combustion are used?*

Ans. Commercially available technologies are:

1. Bubbling-bed units
2. Circulating fluidized-bed (CFB) units.

Both work on atmospheric fluidized-bed combustion.

Q. *Name certain solid wastes that find their way to fluidized bed combustion.*

Ans. 1. Coal mining wastes (e.g. anthracite culm)
2. Petroleum coke
3. Bagasse
4. Bark
5. General wood wastes
6. Sawdust and shavings
7. Nut hulls
8. Rice husk
9. Corn cobs.

Q. *What is culm?*

Ans. Anthracite mining waste-dirt is known as culm. These are waste coals that pile up near anthracite coal fields.

Over the past one and a half century, about 1 billion tons of anthracite culm has been generated in the anthracite mining areas of Pennsylvania, USA. This is a fuel whose ash content is high but heating value is low.

This plus its high moisture content has so far dumped it as waste. However with the advent of the trend of waste-to-energy facilities, 20 projects are operating in Pennsylvania burning culm in fluidized-bed boilers generating 50 MW of power each.

Q. *What is the strongest point in favour of circulating fluidized-bed boilers (CFB) for burning anthracite culm?*

Ans. They can burn pratically anything with heat content—with minimum fuel preparation. They can turn waste into energy. For instances, several culmfired CFB units in Pennsylvania's anthracite coal fields are converting high-grade dirt into electric power. Ash contents of these fuels are as high as 70%.

Municipal solid waste boilers at Alexandria, Virginia gobble up as much as 975 tons of waste per day. In the year 1989, 22 plants in USA alone burned municipal solid wastes at the rate of 32000 tons/day.

Q. *What are the disadvantages associated with CFBs?*

Ans. 1. Lengthy start-up/shakedown period

2. Constant wear and tear of critical auxiliary equipment because of high non-combustible content
3. Very large and complex ash handling system. Power output of the CFB facilities belies the size of the major auxiliary equipments
4. Fuel feed system suffers from improper performances if fuel moisture content, particle size deviate much from design
5. CFBs firing on fuels with high non-combustibles as high as 70% accomplish little regarding solid-waste reduction, for the obvious reason of higher dosage of lime to absorb SO_2
6. Refractory failure is a nagging problem. Refractory failure has been reported in the combustor and cyclone (The Gilberton Power Co., San Diego, California)
7. In many cases fuel preparation is required using heavy-media flotation and centrifuging to separate non-combustibles
8. Tube erosion is a major problem. This has been reported to occur in the economizer and ash cooler (The Westwood Energy Properties, Pennsylvania)
9. Sintering and/or agglomeration are common problems. Agglomeration in the ash cooler has been reported (The Westwood Energy Properties and Frankville Power Corpn.). Many problems stem from moving voluminous quantities of ash.

Q. *How can the refractory failure problem be avoided?*

Ans. 1. Changeover to refractory brick from castable refractory.
2. Increasing the height of the refractory in the combustor zone.

Q. *How do agglomeration and sintering problems arise in culm-fed CFBs?*

Ans. They arise from two main problems:

1. discharging ash from the combustor and/or fabric filter
2. maintaining the ash flowing properly throughout the entire system.

Q. *How can this problem be overcome?*

Ans. 1. Switchover from Vacuum Ash handling System to Pressurized or Partially-pressurized Ash Handling System. (The Gilberton Power Co., California, USA). Using air lance to maintain flow
2. Incorporating Water Cooled Screw Conveyor for continuous removal of oversize ash particles which contribute to the sintering problem
3. Installing control valves on the Fabric-Filter Hoppers and proper adjustment of speeds of the discharge conveyor to avoid leakage of very fine ash.

Q. *What problems are associated with Fuel Feed Systems of culm fired CFBs?*

Ans. 1. Where fuel processing is required prior to its supply to the CFB, high moisture content and improper fuel particle size contribute to the jamming of the fuel feed conveyors (The Gilbetron Power Co., California, USA).
2. If the dryer fails to function properly, the above problem aggravates.
3. Where fuel benefication is not employed (The Westwood Energy Properties, Pennsylvania, USA) proper screening of the fuel is the critical criteria for good combustor performance. High moisture levels make this difficult to achieve.
4. Rotary valves are to be avoided in the fuel feed system.

Q. *Is cofiring compatible with fluidized-bed combustion of solid waste?*

Ans. Yes the fluidized-bed combustion technique has enough flexibility to permit simultaneous combustion of solids, sludges, slurries, liquids and gases in the same unit.

Q. *Can you name such any operating unit?*

Ans. A unit in La Crosse, Wisconsin (USA) burns RDF (Refuse Derived Fuel) and wood in equal amounts at a capacity of 400 tons/day.

Q. *Many utilities can cut fuel costs with RDF. But before they do so, they must select an appropriate unit and analyze the costs. Why?*

Ans. The most essential requirement for successful burning of RDF in a utility boiler is that the introduction of waste fuel does not tell upon the capacity or reliability of the unit anyway. In case the utility has to compromise with the unit's availability, it will invariably invite a huge financial penalty on the refuse-disposal system whereupon RDF burning immediately becomes economically impractical.

For a number of reasons, the fuel value of RDF is less than it might appear. And the RDF preparation plant has to bear the sole responsibility of ensuring that an acceptable fuel is furnished to the utility boiler.

Q. *What cost factors are to be considered for burning RDF in a utility boiler?*

Ans. 1. **Transportation Costs** are considerable. In most cases, it is less expensive on the basis of per ton or mile haulage to transport RDF than raw garbage. It would, therefore, appear to be best to locate the RDF preparation plant close to the garbage and truck the RDF to the plant.

However, in a number of successful cases, the fuel preparation plant is located at the powerplant and the RDF conveyed pneumatically to the boiler.

2. **Unloading Cost:** Unloading the RDF at the powerplant site requires at least a one-day storage facility, and equipment to feed RDF to the boiler. These add to the capacity cost of the project.
3. **Enhanced Cost of Boilers and Auxiliaries:** Precipitators or fabric filters must have increased capacity to handle the increased FG flow and the increased ash handling. Likewise the bottom ash handling system needs additional capacity. Heat exchange surface (evaporators, superheaters and air heaters) of the boiler must be upgraded to withstand potential slagging and fouling problems.
4. **Cost of Fuel-Preparation Plant:** It is entirely a separate and new establishment that involves capital investment in the MSW feeder, shredder, magnetic separator, air classifier, screen and magnetic separator to convert MSW to RDF.

Q. *The efficiency of the utility boiler is reduced when RDF is co-fired with coal. Why?*

Ans. There are three reasons:

1. RDF has a high load of moisture
2. RDF composition is never uniform. Hence excess air must be increased to allow for the variability of the RDF.
3. RDF is pneumatically conveyed by air. This air is cold (i.e. it is not passed through the air heater in PC-fired units) and it reduces combustion efficiency.

Q. *A PC-fired boiler will need modification if coal is co-fired with RDF. Why?*

Ans. RDF burns in the furnace in a completely different manner than does pulverized coal. The RDF particles have a longer burning time and therefore do not form a burner flame pattern. Some of them are lighter and they burnout in suspension similar to pulverized coal-combustion. The other RDF particles are heavier. They get ignited as they fall through coal flames, but spend most of their burning time on the grate. As much as 24% of the RDF fuel value is released at the bottom of the furnace.

This is in sharp contrast to the combustion of pulverized coal, which goes to completion in a second or two. Some particles of RDF that land on the grate take as much as 2 minutes to reach the fully devolatized state and probably twice as long as to go through the complete combustion process.

Q. *If a utility wants to cofire RDF with pulverized coal, what should it do regarding the furnace modification?*

Ans. The utility should install in its PC-fired unit a dump grate to permit complete combustion of heavier particles and prevent over-loading of the ash and ash-hydraulic system.

Q. *What are the prospects of introducing RDF to a boiler firing slagging coal?*

Ans. Coal slagging characteristics in the furnace are critical. Molten slag arrests most of the heavier RDF particles which get only partially burned, but change the fluidity of the ash-melt. Any unit that is already beset with slagging or fouling problems will have more problems when RDF is introduced.

Q. *What is the best way to cofire RDF with coal?*

Ans. Cyclone furnace appears to be excellent for burning RDF (Fig. 40.2).

However, the air pollution control equipment must be carefully checked to see if the capacity is adequate to accommodate RDF burning.

Q. *Do you prescribe for RDF storage?*

Ans. Storage of RDF other than short-term storage to take care of delivery cycles is not necessary.

Q. *Is there any health hazard associated with RDF?*

Ans. None of the plants burning RDF have reported of increased health problems since introduction of RDF firing.

However, good housekeeping is a necessity.

Q. *What are the disadvantages of fluidized-bed combustion of solid waste?*

1. Feed solid waste stream must be closely monitored and sized properly and more or less uniformly

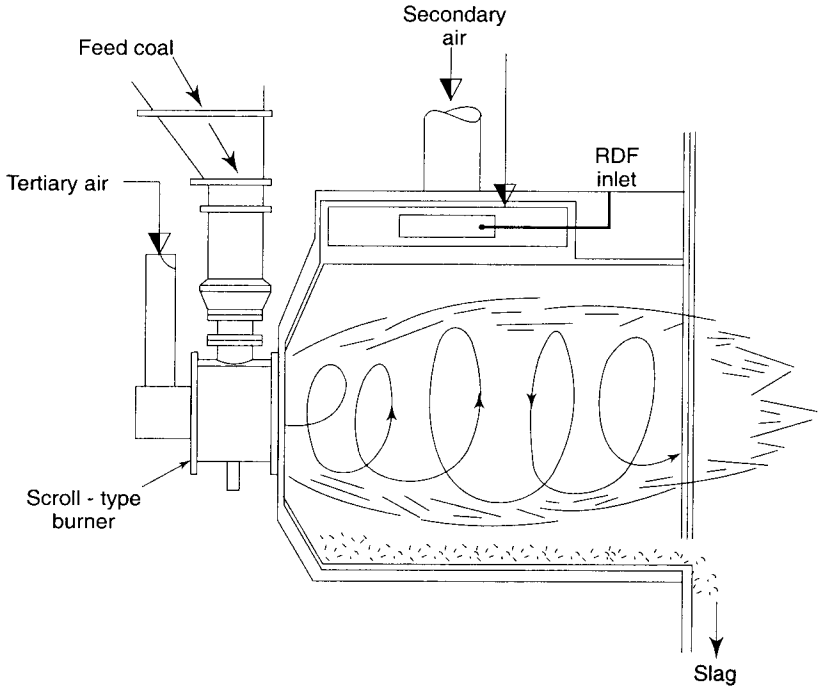

Fig. 40.2 *Refuse can be successfully burned in a cyclone furnace.*

2. Inorganic salts present in the feed waste must be absent as these salts may melt at the bed temperature or form eutectics causing bed seizure
3. At low loads, combustion efficiency is generally poor
4. Inbed tube erosion is a nagging problem.

Q. *What is pyrolysis?*

Ans. "Pyr" means fire while "lysis" means disintegration into simpler products. Thus pyrolysis means chemical decomposition of a material at high temperature in a closed system in the absence of oxygen. It also means destructive distillation.

Q. *What is the fundamental difference between pyrolysis and incineration?*

Ans. Pyrolysis is an endothermic process that takes place in absence of O_2 whereas incineration is an exothermic process that occurs in the presence of oxygen.

Q. *In what type of equipment, is pyrolysis carried out?*

Ans. This can be carried out in any of the following units:

1. Gasifiers
2. Vertical-shaft reactors
3. Rotary kilns lined with refractory inside
4. Regenerative towers.

Q. *What are the products of pyrolysis?*

Ans. 1. GASES–H_2, CH_4, CO, CO_2
2. TARRY LIQUIDS—water plus organic compounds, viz., methanol, acetic acid.
3. SOLID—carbonaceous char.

The derived fuels—gas is partly burnt to supply heat to the reactor while the surplus gas and liquids are available as fuel by-products. These may be burnt in a boiler unit in a gas turbine to generate electricity.

Q. *What are the advantages of pyrolysis?*

Ans. It is a closed system operation and hence contributes very little to environmental pollution.

Q. *What is supercritical water oxidation?*

Ans. In this process aqueous organic as well as inorganic wastes are mixed with air or oxygen in a reactor at temperatures exceeding 374°C and pressure 225 kgf/cm^2.

At these conditions water remains liquid and lends itself as an excellent solvent for organic substances which whereupon reform to gases like CO, CO_2, H_2 and CH_4 and volatile organic liquids, viz. alcohols, aldehydes and furans. No char is produced. These are the primary products which ultimately get fully oxidized to CO_2 and H_2O liberating sufficient quantity of heat which is carried out by the exit liquid stream and can be utilized to produce steam in a heat exchange process (Fig. 40.3).

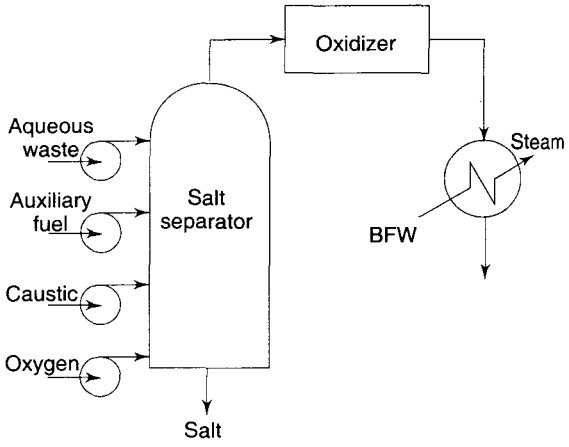

Fig. 40.3 *Supercritical water oxidation.*

Q. *Is there any limitation of the supercritical oxidation process?*

Ans. Yes, its application is limited to liquid feed streams. It is also not applicable to wastes which contain more than 15 to 20% salts or liquid wastes whose primary contaminants are heavy metals.

Q. *What is infrared incineration?*

Ans. This is one of the latest combustion techniques. It employs infrared heating elements in the combustion chambers to incinerate solid waste on a moving chain. (Fig. 40.4)

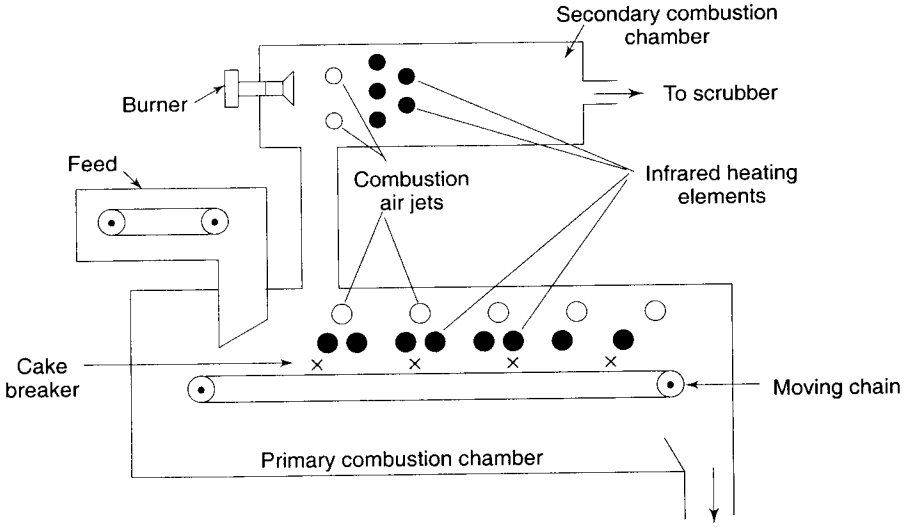

Fig. 40.4 *Infrared Incinerator. It involves two combustion chambers. Combustion is completed in the secondary combustion chamber by simultaneous firing of gas fired burners and infrared heating elements*

There are two combustion chambers to which combustion air is supplied by air jets. While most of the solid waste is incinerated in the primary combustion chamber, gaseous products of partial oxidation of waste are completely burned in the secondary combustion chamber.

Both combustion chambers are ceramic fibre insulated.

Residence time of solid waste in the primary combustion ranges from 5–180 minutes at an operating temperature of 260°C–1040°C.

Gas residence time in the secondary combustion chamber is about 2 seconds. Here upto 100% excess air is introduced and temperature attained is as much as 1260°C by the simultaneous firing of gas fired burners as well as infrared heating elements.

Q. *What are the advantages of infrared incineration?*

Ans. 1. Lower capital cost
2. Greater availability
3. Total mobility for on-site applications
4. Incineration can be carefully controlled and regulated
5. 99.9999% destruction efficiency for toxic hydrocarbons like dioxins and furans.

41

NDE AND CONDITION MONITORING

Q. *What is the utility of non-destructive examination?*

Ans. Non-destructive examination is one of the keys to *Quality Assurance*. The advanced level of development attained in qualified examination methods provides reliable proof of the specified quality (for the most part homogeneity requirements) and a qualitative assessment of parts and components in respect of their operating safety and reliability.

Q. *What are the important wings of NDE?*

Ans. 1. Ultrasonic examination
2. Radiographic examination
3. Liquid penetrant examination
4. Leak testing
   (a) Nekal test
   (b) Helium test
5. Eddy-current examination
6. Magnetic particle examination

Source: Non-Destructive Examinations—Siemens AG/KWU Group

Q. *What is the utility of automated ultrasonic weld inspection?*

Ans. To date automated ultrasonic weld examination has been expedient purely where the scope of examination is extensive, where regions to be examined are not readily accessible or not accessible at all, where a large number of indications are anticipated or where particular demands are made on the information yield.

Q. *What is P-SCAN?*

Ans. It is an automated weld inspection technique developed by Svejsecentralen, Denmark.

Q. *What is the basic difference between a P-SCAN and conventional automatic ultrasonic weld inspection technique?*

Ans. P-SCAN combines the merits of manual and automated examination.

Q. *How is weld examination carried out by P-SCAN technique?*

Ans. The P-SCAN automated weld examination system is a compact portable unit easy to handle (Fig. 41.1)

The system is guided by a flexible magnetic strip which is fastened parallel to the weld. The scanner is firmly attached by magnetism and climbs freely to heights of more than 50 m.

Up to four such units can be used, thus making simultaneous examination for longitudinal and transverse defects possible.

The search units are exchangeable and it is therefore possible to use special search units to suit specific tasks such as nozzle examinations (Fig. 41.2)

Findings are visualized immediately online on a monitor as a multicolor digital display with top, end and side views of the weld shown simultaneously (Fig. 41.3)

The echo amplitude is plotted below the side view. This online display ensures the accuracy of examination: where the diagnosis is not clear-cut,

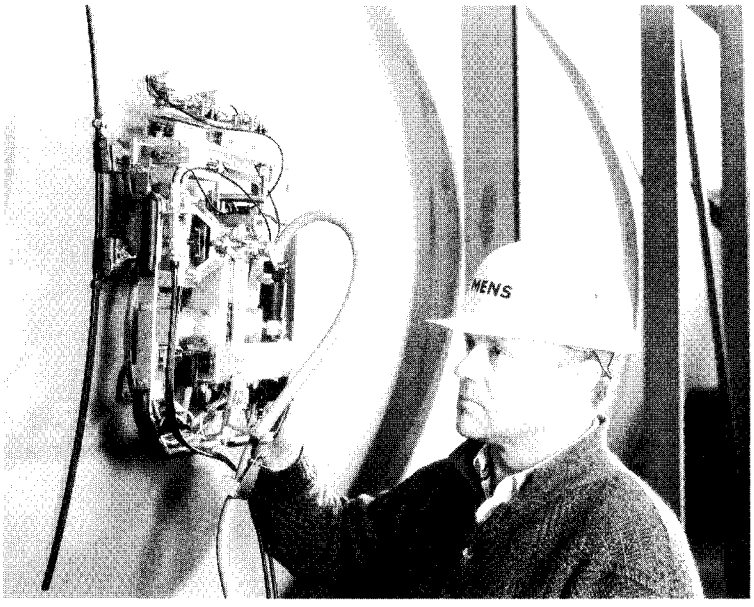

Fig. 41.1 *P-SCANNER is a compact, portable instrument guided by a magnetic strip fastened parallel to the weld.*

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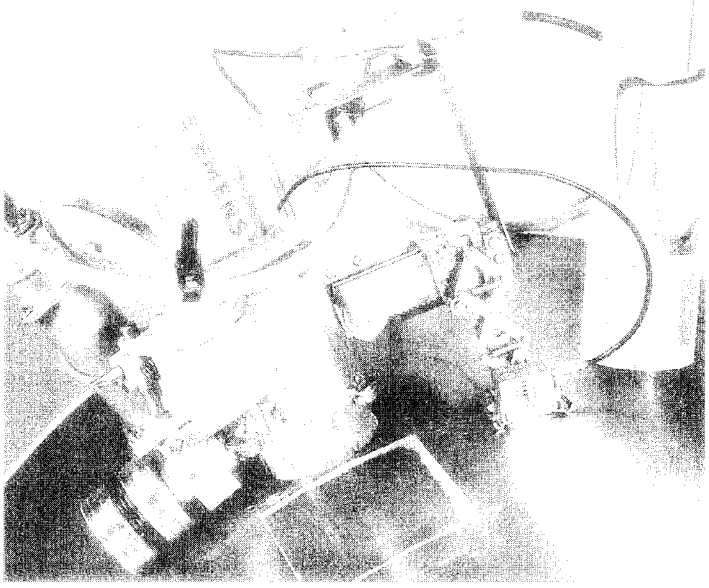

Fig. 41.2 *Scanners are exchangeable. Different scanners are designed to meet specific tasks. Shown here is a scanner for nozzle-to-shell welds.*

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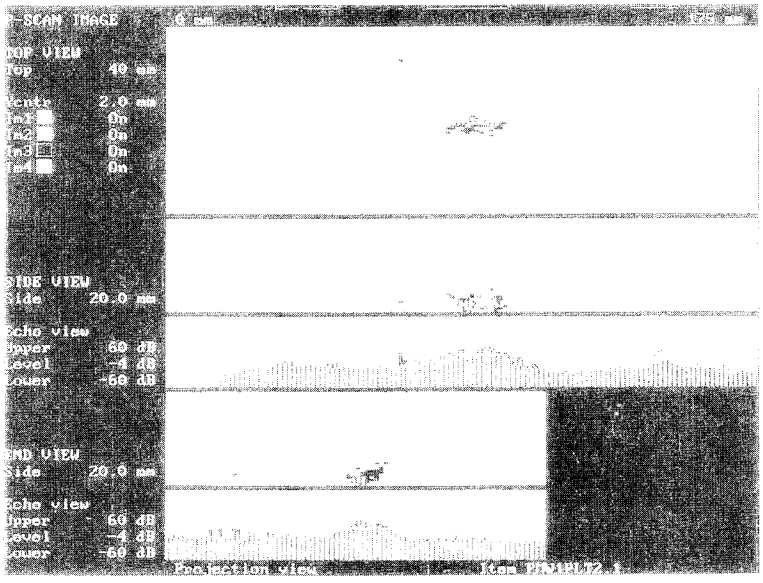

Fig 41.3 *P-SCAN supplies 3-D images; a top, end and side view of the weld. Resolution can be as much as 0.5 mm.*

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a decision on further steps can be made immediately on the spot.

P-SCAN can be used not only to detect weld defects but also wall thinning (Fig. 41.4)

Q. *What are the advantages of the P-SCAN system?*

Ans. 1. The P-SCAN automated weld examination systems is a compact portable unit. It is a low-profile lightweight unit and can be handled by a single person (Fig. 41.5)

2. It is an automated and convenient method of examination based on well established ultrasonic techniques, which offers the mobility of manual examination.
3. For tank/vessel inspection, P-SCAN dispenses with the otherwise necessary equivalent set-up; the scanner is firmly attached by magnetism and climbs freely to heights of more than 50 m. This method can also be used for internal examination.
4. Recorded data is stored on disk and areas of any size can be examined without interruption because of the use of multi-disk magazine.
5. Two added advantages are; excellent reproducibility and immediate comparison of current and previous results displayed directly as the difference. Following an examination, the data can also be evaluated and processed on a personal computer at another location.
6. P-SCAN can be used not only to detect weld defects but also wall thinning.

Q. *What are the chief components of the P-SCAN system?*

Ans. The unit is composed of

(a) P-SCAN Processor

(b) The Scanner

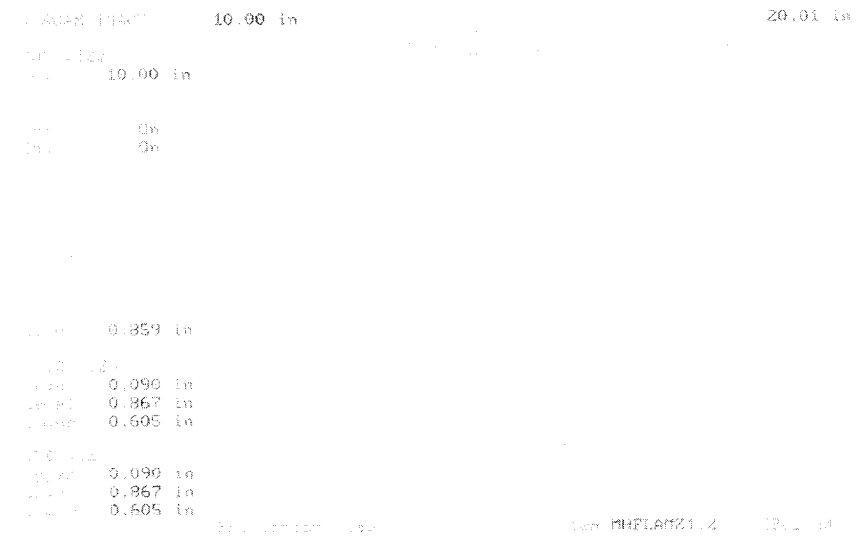

Fig. 41.4 *Besides weld examination, the second principal application of P-SCAN is wall thinning. This picture shows the evaluation of a wall thickness measurement.*

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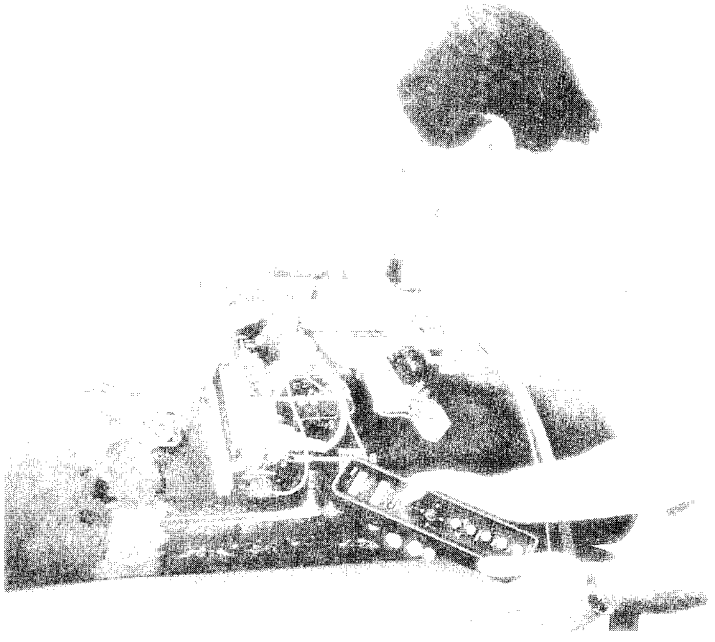

Fig. 41.5 *The P-SCAN unit is portable and lightweight. During examination the system is guided by a flexible magnetic strip. A special scanner guided on a toothed rail with rapid-action lock is available for small-bore piping and piping made of non-magnetic material.*

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(c) Echo Amplitude Recording
(d) PC DATA Processing System

Q. *What is the P-SCAN processor?*

Ans. The P-SCAN is a compact, battery-operated complete stand-alone control and processing system equipped with a four channel UT data recorder, LCD screen, miniature image printer, keyboard and dual disk drives. The processor also features data transfer capability to a separate PC-assisted processing system.

Q. *What is the scanner?*

Ans. The scanner is sized to a conveniently portable module. Scanning speed is adjustable up to 6 m/min. Search unit movements are freely programmable for all types of scanners. The low-profile, slim-line scanner weighs about 15kg and can be handled by a single man.

Q. *How is echo amplitude recording made?*

Ans. Echo amplitudes are recorded and stored together with the corresponding reflector position data. Basically, all echoes are stored regardless of amplitude.

Q. *How is its importance realized?*

Ans. Sensitivity being freely selectable, it is possible to discriminate otherwise indeterminate indications even if coupling and the location of indications prevent optimum scanning. Indeterminate indications can thus be detected even in the immediate vicinity of the noise threshold.

Q. *How does the PC data processing system work?*

Ans. The hardware comprises a personal computer (AT) with 512 Kbyte memory, 20 Mbyte hard disk, two 720 Kbyte disk drives (88 mm), 30 Mbyte laser disk and multicolor printer.

The format of the data disk of the P-SCAN system is first converted to MS-DOS. The entire weld or any section thereof can be analyzed. A top, side or end view of the shape of the weld groove can be faded in to visualize indications relative to the weld.

Source: Automated Ultrasonic Weld Examination—Siemens AG/Power Generation Group KWU.

Q. *What are the functions and purposes of monitoring and diagnostic systems?*

Ans. 1. Various physical parameters are recorded continuously or periodically, and compared with limit values
2. To supplement operational instrumentation and control systems by providing early warnings of incipient damage. Thus they help to minimize any damage, contribute to low-wear operation, and make condition-oriented maintenance possible.
3. The 'off-normal system condition' can be analyzed based on stored data. With an appropriate knowledge base, a more extensive diagnosis can be made, thus permitting future system performance to be forcecasted and instructions for manual intervention to be established.

Q. *What are the strategies of monitoring systems?*

Ans. Monitoring systems are designed for two basically different strategies:

(a) Monitoring and recording of influences on the system during typical plant processes and over its total service life. This means determination of collective loads for typical operation
(b) Recording of primary and secondary parameters which characterize or accompany systems performance, and which change significantly when an anomaly occurs.

Q. *How is the first strategy implemented? Clarify it through an example.*

Ans. A typical example of first category is the FAMOS fatigue monitoring system. It determines the usage factor in highly stressed components. For this purpose, stress transients are determined or calculated on the basis of pressure and temperature measurements. These lead to the early determination of damaging influences and accord-

ingly appropriate counter measures, viz. by changing the mode of operation, ambient conditions etc. thereby preventing damage and extending service life.

Q. *So is FAMOS a preventive monitoring strategy?*

Ans. Yes; it is primarily so.

Q. *However, the majority of monitoring equipment fall into the 2nd category, i.e. recording of primary and secondary parameters that characterize system performance. What phenomena do they monitor?*

Ans. 1. ***Vibrations:*** whose change indicates a change in structural integrity of components
2. ***Noise:*** It is normally associated with the development of cracks, the appearance of leaks, the impact of detached parts
3. ***Detection of Secondary Effects due to Leak*:** Such secondary effects are temperature, radioactivity changes in electrical variables such as resistance and capacitance
4. ***Leak Detection:*** involves direct detection of the leaking fluid.

Q. *The 2nd monitoring strategy is also called 'phenomenological category'. Do such systems monitor only the primary and secondary parameters associated with system performance?*

Ans. No. These monitoring units provide an early warning in the event of incipient damage. They insure more transparency by supplementing standard operating instrumentation, which must naturally also provide monitoring capability (with the main emphasis on function monitoring). Early warnings triggered by monitoring systems deter the ramification of damage and make it necessary to plan repair. Changes in modes of operation can be initiated promptly and selectively.

Q. *Now-a-days a wide range of sophisticated PC-based monitoring systems collect and record online data on the mechanical condition and operation of powerplant components, detect loose or detached parts, and locate leaks in steam or water carrying components.*

What are these monitoring systems?

Ans. 1. SÜS
2. KÜS
3. FAMOS
4. ALÜS
5. FLÜS
6. ZÜS
7. MCC
8. DAW
9. MDP etc.

Q. *What is SÜS?*

Ans. It is a vibration monitoring system. *

Q. *What tasks does it perform?*

Ans. Detection of changes in the mechanical condition of components.

Q. *How does SÜS detect changes in the mechanical condition of components?*

Ans. By analyzing the components, characteristic vibration behaviour.

Every component has its unique characteristic vibration behaviour. This behavior is dependent upon the component's mechanical properties and can be described with various parameters such as frequency, amplitude etc. which are determined with the help of characteristic vibration functions (preferably auto power density spectra). Because the vibrations are superposed, the parameters of several components are found in one characteristic function. If the vibration behaviour of a component changes, the values of its parameters also change.

The vibration monitoring system, SÜS, enables early detection of changes in the vibration patterns of the reactor coolant system components and reactor pressure vessel internals in pressu-

* Schwingungsüberwachungssystem.

rized water reactor (PWR) plants. In a 1300 MW PWR plant, this permanently installed system monitors 33 different vibration parameters.

Q. *How can the SÜS be demonstrated?*

Ans. SÜS detects mechanical changes in components based on their vibration behaviour. A change in the vibration behaviour of a component (Fig. 41.6) is one of the most sensitive indicators of a change in its mechanical condition, such as:

(a) loss of pretensioning in flow-baffle mounting bolts
(b) reduction in stiffness of the core-barrel hold-down springs
(c) damage of journal bearings in a reactor coolant pump
(d) contact between reactor coolant system components and the building.

SÜS monitoring system is largely automatic during normal steady-state operation. The measured signals are electrically amplified and digitized, and transformed by a multichannel signal processor. The resulting characteristic vibration functions and parameters are compared against a reference value and plotted as a trend. In case the deviations go beyond the predefined response thresholds, the monitoring system signals this by a change of color and indicates the respective

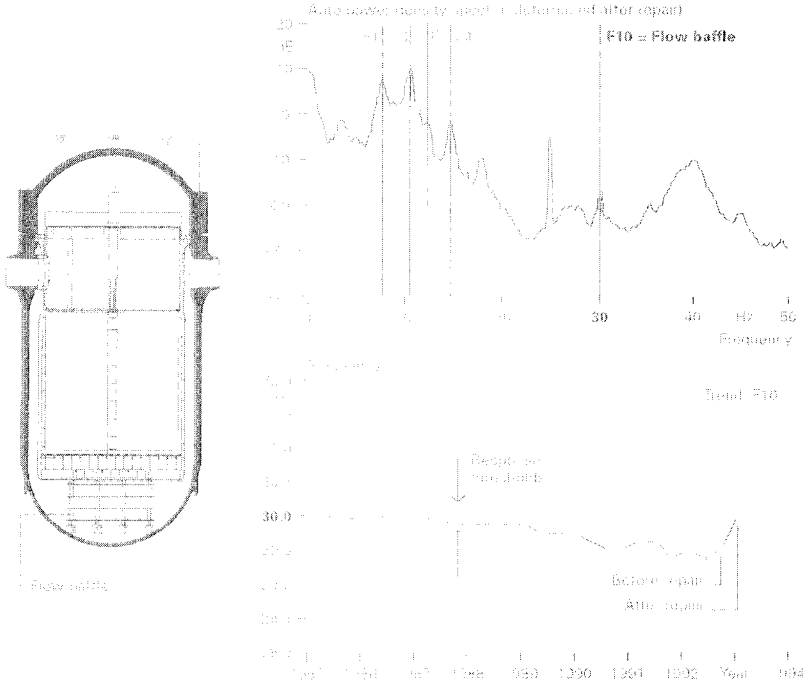

Fig. 41.6 *Change in the first natural bending frequency of the flow baffle which was lowered due to the loss of prestressing in the mounting bolts. This change in vibration behaviour is reflected in the auto power density spectra of SÜS system with the signal measured at RPV closure head.*

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parameter. The response thresholds are based on empirical data, structural-dynamics calculations and experimental analysis.

Note: In future, SÜS is likely to furnish more comprehensive information:

(a) the designation of the component involved
(b) the probable cause of the change in vibration behavior
(c) the required corrective action.

Q. *Where can the SÜS vibration monitoring systems be found today?*

Ans. This advanced and popular system is currently in use in 14 Siemens, one BBR, and 17 VVER (Russian) pressurized water reactors to monitor safety-related components.

Q. *What safety standards does it meet?*

Ans. It meets the requirements of the German Safety Standards KTA 3204 and DIN 25 475.

Q. *What is KÜS?*

Ans. Loose-parts monitoring system. Körperschallüberwachungssystem.

Q. *What tasks does it perform?*

Ans. Detection and approximate localization of loose and detached parts.

Q. *How does the KÜS system perform its tasks?*

Ans. By analysis of the structure-borne noise pulses generated by impact.

When loose or detached parts strike other parts or components they generate structure-borne noise pulses which propagate through the system. The loose parts monitoring system KÜS (Fig. 41.7) detects such noise pulses and analyzes them to determine their source and intensity.

Q. *How is the detection of loose parts made using KÜS?*

Ans. Impacting loose parts, sliding and rolling actions, cavitation, etc. generate structure-borne noise bursts in the reactor coolant system of nuclear powerplants, which propagate through the plant structure. The KÜS loose parts monitoring system detects and records these bursts, analyzes them, locates their origin and thus provides information on the operating condition of components.

Q. *What is the utility of such detection of loose parts?*

Ans. The prompt and reliable detection of loose parts entrained in the coolant prevents sequential damage such as damage to fuel assemblies, pump blades, cladding or to the roller expanded tube sections in the steam generator tubesheet.

The significance of the early recognition of damage is revealed even more conspicuously in the detection of parts that have loosened but are still attached. This type of stationary, structure-borne noise, which is of low intensity, often signals the incipient detachment of mounted parts.

Q. *What are the chief features of KÜS?*

Ans. KÜS is a computer-based loose parts monitoring system that derives its intelligence from the knowledge and experience coined through its field application.

The state-of-the-art KÜS 95 is a computer-based system with digital signal processing. Its chief features are

(a) continuous plant monitoring
(b) differentiation between noise caused by loose parts and that of normal operation
(c) processing up to five events per second
(d) automatic location of lose parts and estimation of their mass
(e) detection of trends
(f) recording of all events
(g) automatic functional check and calibration at defined intervals and self-monitoring of the entire system
(h) generation of status log and documentation
(i) interactive analysis and evaluation of the results.

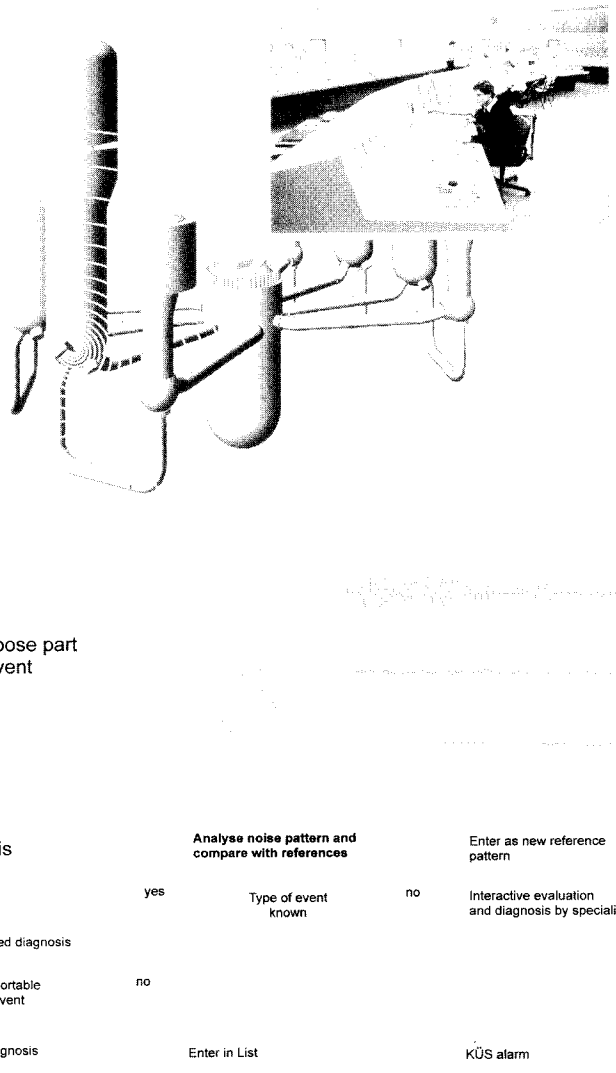

Fig. 41.7 *KÜ S detects loose or detached parts based on high-frequency structure-borne noise pulses generated when such parts-strike other materials. Based on the noise pattern the system determines the types of parts and their approximate locations.*

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Furthermore, event diagnoses can be carried out, which make it possible to virtually eliminate spurious alarms.

The system is menu-controlled (WINDOWS user interface), which generally means using the mouse to select the desired function from the menu. Individual parameters are entered in dialog mode.

Q. *What is the legal significance of KÜ S?*

Ans. From the safety point of view, many countries have made it a statutory obligation on the part of every nuclear powerplant to undertake loose part monitoring of reactor internals. In Germany, loose parts monitoring is considered essential to safety and is therefore a legal requirement in every nuclear powerplant.

Note: KÜS (Siemens AG) specifications are more stringent than the requirements of the German standard "Loose parts monitoring in nuclear powerplants" (DIN 25475, Part 1)

Q. *What is FAMOS?*

Ans. Fatigue Monitoring System

Q. *What tasks does it perform?*

Ans. Recording of transient thermal stresses; calculation of component fatigue.

Q. *What is fatigue and how does it occur?*

Ans. Material fatigue of a component or a part thereof is an unavoidable aging phenomenon. It is caused primarily by cyclic loading as a result of changes in temperature and pressure. Operating experience has shown that thermal loads in particular vary greatly. The magnitude of variation is dependent upon plant-specific operating modes and deviations from specified service loads.

Q. *What are the specific features of FAMOS?*

Ans. FAMOS monitors component fatigue by recording fatigue-related parameters and comparing them against the design data. It makes use of the *multistage concept* and performs a broader analysis of the recorded data to enable evaluation of the long-term availability of components and systems:

Other features of FAMOS are:

(a) infinite data acquisition capacity
(b) adjustable scanning rate
(c) system parameters can be changed during operation
(d) macro programming
(e) powerful standard evaluation programs

Q. *How does FAMOS monitor component fatigue?*

Ans. FAMOS fatigue monitoring is implemented through evaluation of component surface temperatures and of process data in several stages:

1. ***Stage-0 (System Concept):*** It is the preparation phase whereupon a plant-specific fatigue manual is generated based on design calculations and particularly on operational load *data*. The manual contains all components whose materials fatigue relatively quickly as well as the representative process variables required for fatigue evaluation.
2. ***Stages-1 and 2 (Data Acquisition and Analysis):*** During a scheduled plant outage, the data acquisition system is installed (Stage-1). The system continuously records and stores all specified process variables.

   Subsequently, these data are evaluated individually for each component—first at the level of loads (STAGE-2) and, in the case of highly stressed components, at the level of strain (Stage-3). Ultimately FAMOS narrows down the large data stream to a single-value-stream, i.e. the 'material-usage-factor', which serves as a measure of fatigue.
3. ***Stage-3 (Stress and Fatigue Analysis):*** Automated analysis of measured data provides detailed information concerning the fatigue behaviour of both components and systems. Usage factors are also accumulated over time in this stage.

Q. *Why going for STAGE-3 to get explicit determination of the fatigure condition?*

Is Stage-2 not adequate to determine the fatigue condition?

Ans. In many cases, effective improvements can be made after Stage-2 analysis of the data. For instance, by modifying the operating modes of German PWR plants, the fatigue rate of highly stressed components was able to be reduced significantly without having to explicitly determine the fatigue condition.

Q. *What measures are adopted in PWR plants for reducing loads following the FAMOS monitoring and analysis of component fatigue in highly stressed parts?*

Ans. Examples of measures for reducing loads or load cycles are

(a) staggered actuation of pressurizer spray valves
(b) provision of holes in pressurizer spray valves for continuous spraying
(c) narrowing the periods of large temperature differences between the pressurizer and the hot loop during start-up and shutdown
(d) avoiding borating of the pressurizer via the auxiliary spray line during shutdown
(e) minimizing spraying during shutdown
(f) avoidance of intermittent steam generator feed during low-load periods
(g) detection of leaking valves and the resulting slow leakage flows.

Q. *What is ALÜ S?*

Ans. Acoustic Leak Monitoring System. Akustiches Lecküberwachungssystem.

Q. *What tasks does it perform?*

Ans. Prompt detection and localization of leaks from pressurized systems; estimation of leakage rate.

Q. *How does the ALÜ S system work?*

Ans. ALÜ S performs leak detection by evaluating structure-borne noise.

Acoustic detection of leaks in pipelines, vessels, and valves is based on the principle that the escaping fluid generates high-frequency structure-borne noise. The acoustic leakage monitoring system ALÜ S detects this noise within a frequency span of 100-300 kHz using piezoelectric pickups. By including the signal from a neighboring pickup, the rms value of the signal level is extrapolated back to the source of the leak and is also used to determine the leakage rate.

Q. *What are the advantages of this system?*

Ans. 1. The chief advantage of this system is that it quickly detects a leak and its source (Fig. 41.8).

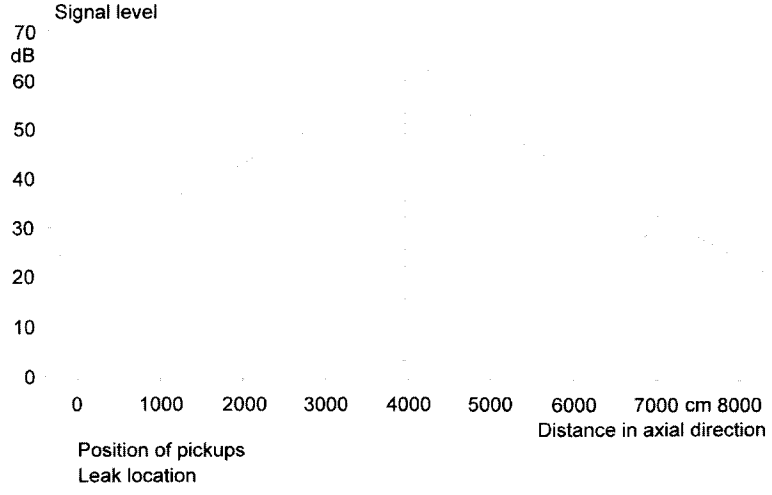

Fig. 41.8 *ALÜ S detects leaks in pressure-retaining systems very quickly and determines their location and approximate leakage rate based on the signal level, which decreases with increasing distance from the location of the leak.*

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The minimum detectable leakage rate during plant operation ranges from 10 l/h to 200 l/h and depends on the background noise level and the component being monitored.

2. ALÜS, because of its high sensitivity, is capable of detecting leakage from subcritical cracks and, in accordance with the leak-before break criterion, can promptly indicate the possibility of any further damage (e.g. a pipe rupture in the reactor coolant system). This is particularly an important safety feature with respect to the Russian VVER plants.

Q. *Where do you find the application of ALÜS?*

Ans. In recent years, the ALÜS system has been frequently used for detecting leaks in the

(a) reactor coolant system
(b) valves such as isolation valves and safety valves (internal leaks)

of VVER plants.

The system automatically and continuously monitor as many as 32 measurement points in the reactor coolant circuit. System operation is automatically tested at regular intervals by generating noise which mimics the noise associated with a leak.

Q. *What is FLÜS?*

Ans. Moisture Leak Detection System. Feuchteleckü berwachungssystem.

Q. *What tasks does it perform?*

Ans. Detection and localization of leaks, even those with low leakage rates.

Q. *How does it work?*

Ans. FLÜS detects the humidity that builds up in the vicinity of a leak by means of a temperature and radiation resistant metallic tube filled with dry air and placed inside the insulation. The tube sports diffusion points through which ambient humidity can infiltrate into at fixed intervals. At predetermined time intervals, the air column is drawn through a moisture sensor (dew-point measurement). The moisture content of the air is measured for each diffusion point and the leakage rate is estimated based on these data. The location of the leak is determined based on the transit time and speed of the air column between the measuring location and the sensor (Fig. 41.9).

The end of the air column sampled in each measurement is selectively marked by means of a defined amount of steam. This test peak defines the reference values for transit time and moisture content and is also used for self-monitoring of the entire system (detector, pump, tube). A leak alarm is issued if a predefined reference curve is exceeded by a specific factor (relative alarm) or if a fixed threshold is exceeded (absolute alarm)

Operated with a PC, this modular system periodically records measured values which are monitored with respect to alarm criteria, and stored. As and when an alarm is issued, reports furnish information on the leakage rate and location, on the alarm itself.

Q. *What are the advantages of FLÜS?*

Ans. (a) The leak detection system FLÜS detects leaks in steam and water circuits
(b) Because of its high sensitivity, it can spot leaks within the accuracy of one meter range
(c) It is capable of detecting leaks in thermally insulated components at an early stage, and evaluates their development over time. Leakage from small cracks (leak-before-break criterion) is also detected.

Q. *What is the capacity of FLÜS?*

Ans. Centrally located inside the containment building of a nuclear power station, FLÜS can control as many as 8 measuring loops, each spanning up to 150 m in length with a spacing of approximately 0.5 m between sensors. Alternatively, a loop of 2 km long (stainless steel with a 6 mm ID) with up to 200 measuring points can also be set up.

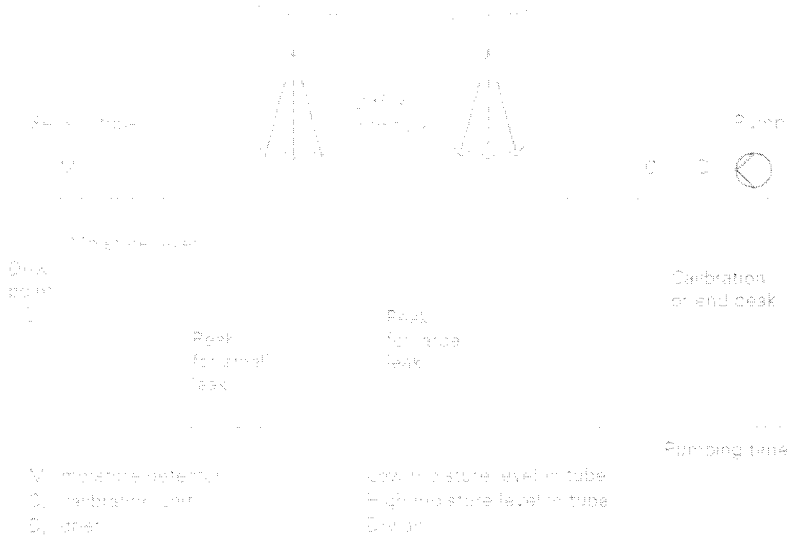

Fig. 41.9 *FLÜ S detects even small leaks in the steam circuit and very accurately determines their location. Leaks are detected based on moisture distribution in a sample air column into which the escaping steam locally diffuses.*

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A leakage rate of 0.05 kg/h is reliably detected; measurable effects are already noticeable at 0.01 kg/h.

The leakage rate is quantifiable if the FLÜ S indicator is calibrated for the respective insulation.

The response time of the FLÜ S system is as short as 15 minutes.

A local increase in moisture can be localized to within 1 m. This tantamounts to a localization error of 1% of the corresponding tube length.

Q. *On which factors does the detectable leakage rate depends?*

Ans. The minimum detectable leakage rate depends on the temperature of the leaking fluid and the design of the component insulation.

Q. *Where has the FLÜ S system been installed?*

Ans. FLÜ S has been qualified for the German PWR plants to detect possible leaks in the RPV closure head.

Q. *What is the operating experience with FLÜ S?*

Ans. Operating experience gained at the Bohunice nuclear powerplant over the course of 1 yr shows that the minimum detectable leakage or leakage rate for the reactor coolant system components is less than 0.1 l or 1 l/h respectively. The localization error for a local steam concentration is less than 1 m or 1% of the corresponding tube length. Small leaks were reliably detected with a measurement cycle time of less than 30 minutes.

Q. *What is ZÜ S*?

Ans. Condition Monitoring System. Zustandsüberwachungssystem

Q. *What tasks does it perform?*

Ans. Monitoring of the operating and mechanical conditioning of machines and structures.

Q. *How does it perform the above tasks?*

Ans. The condition monitoring system ZÜS automatically monitors the mechanical condition and functions of specific machines and structures (Fig. 41.10).

This is done through continuous recording of representative steady state and dynamic data (e.g. pressures, temperatures, vibration amplitudes, or acceleration values) and then comparing these values against predefined reference conditions. Deviations indicate the possible onset of mechanical upset of damage.

Q. *What are the specific features of ZÜS?*

Ans. The state-of-the-art technology of ZÜS utilizes an open, modulator software and hardware configuration that makes it extremely flexible and can be easily configured to meet the requirements of specific applications. Its important features are:

(a) isochronous and speed-synchronous detection of shaft and casing vibrations

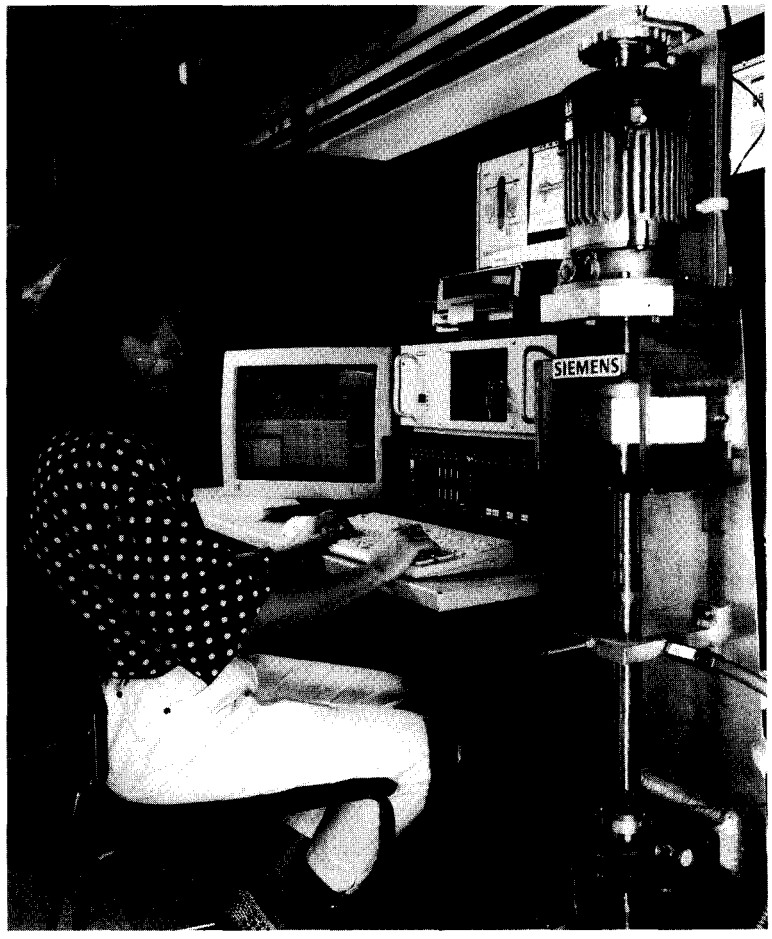

Fig. 41.10 *ZÜS monitors the mechanical condition and operation of machines and structures by comparing measured data with predefined reference conditions. The photo shows a test setup with a motor and shaft held in two bearings. Here ZÜS is analyzing the shaft vibrations.*

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(b) detection of other signals representative of current operating conditions
(c) separation of vibrations into speed-harmonic and non-speed-harmonic components according to magnitude and phase
(d) self-learning capability of terms of reference values and limit values in up to ten speed ranges
(e) intelligent data back-up with generation of trend files
(f) automatic generation of status reports at definable internals.

Source: Condition and Operational Monitoring of Components and Leak Detection—Peter Jax

Siemens Power Journal 3/94, P: 9-15

Q. *It is said that for safe reactor operation, preventive inspection of core components is all but essential. Why?*

Ans. The steadily increasing fuel utilization achieved for nuclear reactors and the resulting increase in fuel assembly service life have narrowed the technological gap between operating parameters and the physical limits of fuel assemblies. To ensure the same high levels of reliability and safety in reactor operation, more and more preventive inspection of fuel assemblies and associated core components are being performed.

Q. *What is the present trend in preventive inspection of core components?*

Ans. In Europe and the United States, the numerous routine preventive inspections performed today have shifted emphasis from locating and correcting defects to continuous monitoring of the operating conditions and performance.

Q. *During refuelling outages, fuel assemblies are inspected regularly. What other core components are inspected regularly during this outage time?*

Ans. 1. Control assemblies
2. Flow restrictor assemblies
3. Fuel assembly channels

Q. *What are the advantages of these routine inspections?*

Ans. These routine inspections, besides assuring compliance with official regulations, have the advantage that they can reveal undesirable deviations well in advance, with the effect that specific corrective measures can be adopted.

Q. *What is the basic procedure for the analysis of the operating performance of core components?*

Ans. During routine inspections, a selection of samples is taken from all core components which is representative in terms of design and in the case of fuel assemblies, also in terms of fuel burnup and power history.

If the appearance of the core components is found deviating from the specified condition, the cause of the deviations is traced out and preventive countermeasures are taken to ensure that they do not recur. This procedure is applied, in particular, to detect fuel rod defects. The purpose is to prevent the leakage of fission products, thereby minimizing the radiation exposure of operating and maintenance personnel.

Lead fuel assemblies are subjected to a thorough inspection. Oxide layer thickness developed on cladding-tubes is continuously monitored.

Q. *What are the inspection techniques most frequently used for monitoring reactor core components?*

Ans. 1. Visual inspection
2. Measurement of oxide layer thickness on fuel rods
3. Failed-fuel detection
4. Control assembly tests
5. Gamma spectroscopy of fuel rods
6. Inspection of fuel assembly channels.

Q. *How is visual inspection performed?*

Ans. For plants powered by pressurized-water reactors (PWRs), core components are inspected with a manipulator used in conjunction with the

refueling machine. An underwater TV camera is positioned at any inspection level between the operating platform and the lower end of the refueling machine mast. The camera can pivot and can move closer to or farther away from the object. Core components that require closer inspection from all sides are rotated and moved vertically in front of the camera using the double grab on the refueling machine.

In powerplants with BWR, the inspection manipulator and camera are utilized with the refueling platform or the fuel preparation machine.

Q. *What are the important features of this inspection device?*

Ans. 1. It is manually operated
2. Suitable for universal applications
3. Fitted with appropriate modules, it can be used for
   (a) dimensional measurements
   (b) measurement of oxide layer thickness
   (c) sampling of CRUD (Chalk River Undefined Deposits) on fuel rods
   (d) removal of debris
   (e) profilometry of PWR control rods

Q. *So this visual inspection camera needs for its mounting, the refueling machine. Can its dependence on refueling machine be avoided?*

Ans. Yes; enter the ULTRAVISION system to eliminate dependence on the refueling machine.

Q. *Where is it mounted?*

Ans. ULTRAVISION inspection equipment is mounted in a stationary location on the fuel storage rack or the elevator for new fuel assemblies, and includes a pivot-mounted underwater television camera on a positioning table (Fig. 41.11).

Q. *Is there any other advantage with ULTRAVISION?*

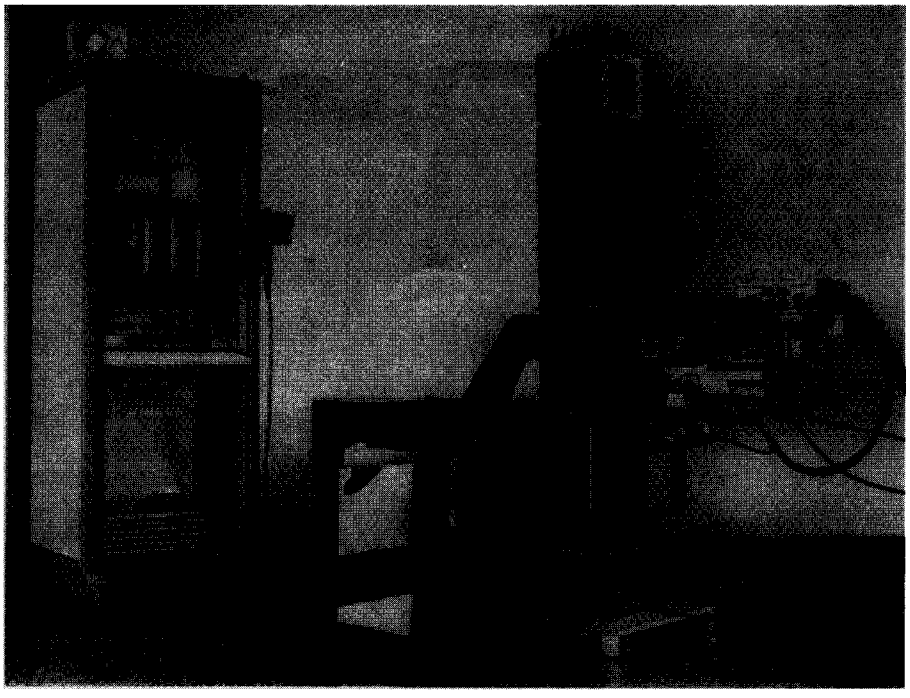

Fig. 41.11 *New ultravision inspection equipment on a focus 16 x 16 PWR fuel assembly.*

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Ans. Yes: this system can be harnessed to perform interim inspections on short notice at any time during unloading and refueling, thus ensuring relief for critical-path scheduling.

Q. *What is the deficiency of visual inspection?*

Ans. Visual inspection gives a general impression of the extent of corrosion based on the appearance of fuel rod surface. But it does not quantify the extent of damage.

Q. *How can this quantitative estimation of corrosion damage be ascertained?*

Ans. By nondestructive examination of the oxide layer thickness.

The eddy-current technique used involves a probe with a high-frequency induction coil that is positioned with the aid of a guide next to any given rod near a spacer (Fig. 41.12).

The refueling machine or the fuel preparation machine is then used to move the fuel assembly past the probe until the next spacer is reached. The motion of the fuel assembly is monitored via a level indicator; the measurement procedure itself is monitored via the underwater TV camera.

Q. *What is the advantage of such type of eddy-current-based thickness-measurement?*

Ans. Continuous measurement of the thickness of the oxide layer is possible. And it becomes a simple matter to assess and interpret changes in fuel rod surfaces due to CRUD or to the flaking off of oxide layers.

Q. *What is the sensitivity of this machine?*

Ans. Oxide layer thickness is measured to within $< 5\ \mu m$.

Q. *When are failed-tube detection tests carried out?*

Ans. These tests are carried out when an increase in the radiation level of the coolant indicates a leak in one or more fuel rods. The radiation level

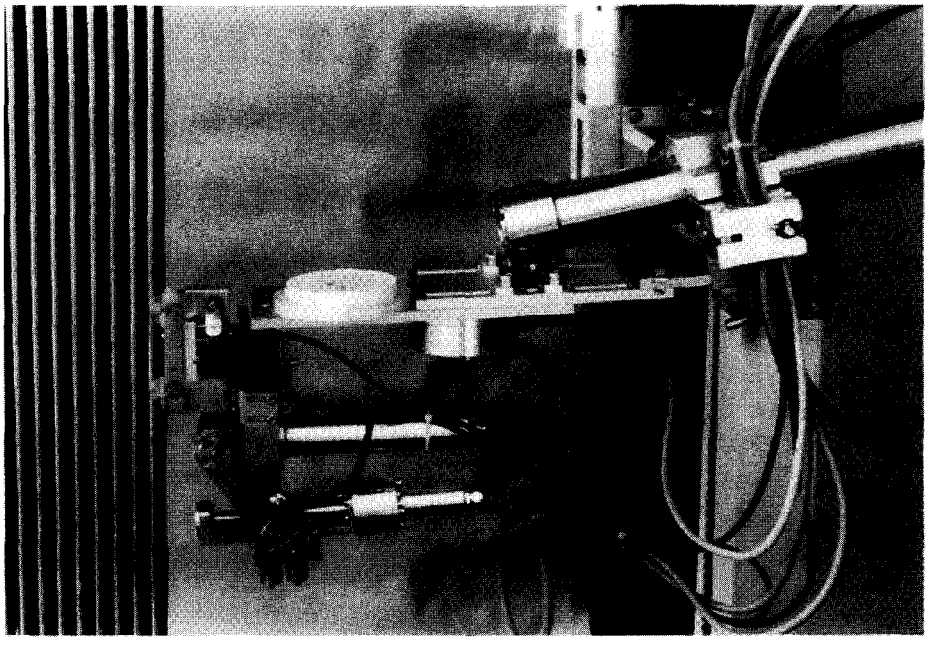

Fig. 41.12 *Measurement of the oxide layer thickness on the peripheral fuel rods in a fuel assembly.*

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of the reactor coolant is monitored continuously during the reactor cycle.

Q. *What are these tests that lead to the detection of failed tubes in the fuel assembly?*

Ans. 1. Sipping test—wet or vacuum
2. Ultrasonic test

Note: The wet sipping test is popular in Europe while the vacuum test is much favoured in the USA.

Q. *How is this wet sipping test carried out?*

Ans. The wet sipping test is based on the fact that water-soluble or gaseous fission products escape from defective (leaky) fuel rods in the event of a temperature increase or pressure decrease. This effect is initiated, during fuel assembly testing, by using an air cushion to temporarily interrupt the flow of coolant inside the fuel assembly. The fuel assembly then begins to heat up allowing fission products to escape through the leaks. Shown in Fig. 41.13 is Siemens. wet sipping station for PWR plants.

It sports a pair of canisters each capable of accommodating one fuel assembly. The canisters have hydraulically-operated lids which are remote controlled. Besides, the canisters are equipped with additional heaters for optimizing the sipping sequence.

The canister-lid system can be done away with a sipping hood (Fig. 41.14) which is meant for testing fuel assemblies of BWR plants.

This hood is lowered down and placed over the open reactor from the refueling platform and can cover up to 8 Nos. of fuel assemblies during the test.

The newest and more versatile sipping stations come fitted with automated control system together with integrated PC and printer (Fig. 41.15). This system cuts down the sipping-test-time

Fig. 41.13 *Sipping station with two test canisters and hydraulically operated lids for testing PWR Fuel Assemblies.*

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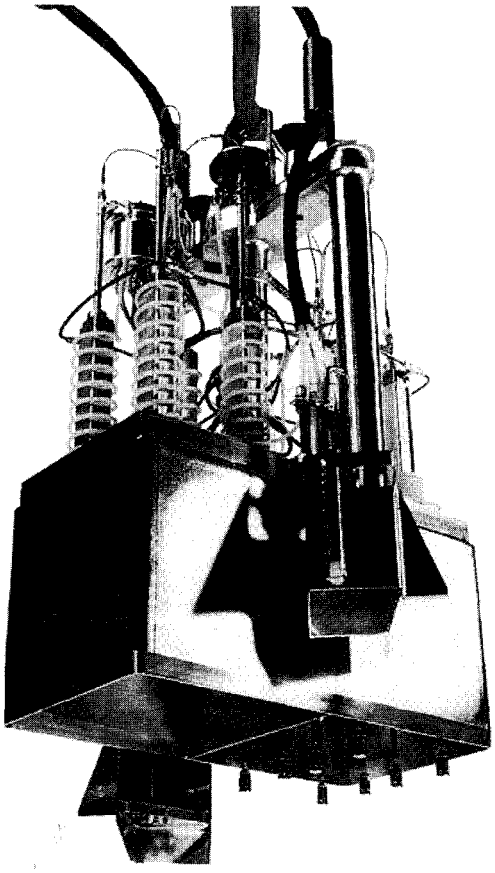

Fig. 41.14 *Sipping hood for testing up to eight BWR fuel assemblies simultaneously.*

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(BWR: 36 h and PWR : 50 h typically) and simplifies operation and manipulation.

Fission products which are either gaseous or soluble in water are measured separately on line with beta or gamma-sensitive detectors after the heat-up phase.

Q. *How does the vacuum sipping system work?*

Ans. The vacuum sipping system, used extensively in the United States, is available for BWR and PWR operators.

The method consists of placing fuel assemblies into a canister, which is then sealed. Air is pumped into the canister to create a void above the fuel assembly. This is followed by a vacuum cycle causing the release of gaseous fission products from any defective fuel rods. A sample of gas is then pumped through a beta detector which will in turn indicate a defective fuel assembly.

Q. *How can the ultrasonic method be applied to detect leaky nuclear fuel rod?*

Ans. Location of any leaky fuel rods in the fuel assembly is detected by the sipping while the location of the leak is pinpointed by ultrasonic test. One such test very popular in the US and pioneered by SIEMENS POWER CORPN (US) is

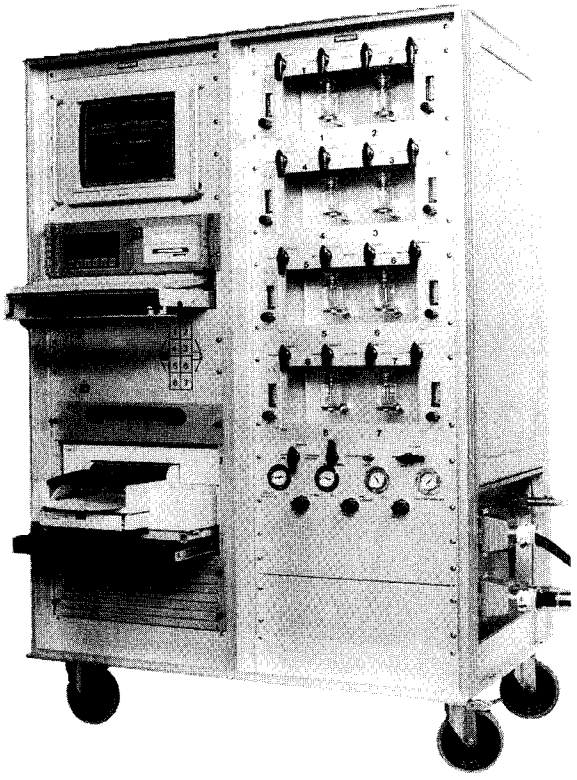

Fig. 41.15 *Mobile sipping station control console with integral PC and printer.*

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the computer-aided ULTRATEST®. This defect-locating ultrasonic system works with up to four probes (Fig. 41.16).

ULTRATEST is normally fixed on the storage rack in the spentfuel pool using the auxiliary hoist of the refueling machine or the building crane, and is installed there by remote control.

Q. *Is ULTRATEST suitable for BWR or PWR?*

Ans. This system is equally well suited to PWR and BWR fuel assemblies.

Q. *How much time does it take to detect and show up the result?*

Ans. It takes only a few minutes per fuel assembly to test all fuel rods, evaluate the results and display the results on-screen or generate a printout.

Q. *Regular inspection and non-destructive examination of control assemblies in LWR reactors are an imperative during refueling. Why?*

Ans. To verify their mechanical and structural integrity.

Q. *What is their importance?*

Ans. It dictates the future course of preventive action, i.e. future operating performance can be forecast based on the results of specific measurements (of depth of wear marks, for example). Premature replacement or repair can be prevented by shifting the aberrant control elements to other locations within the core.

Q. *How are the control assembly tests conducted?*

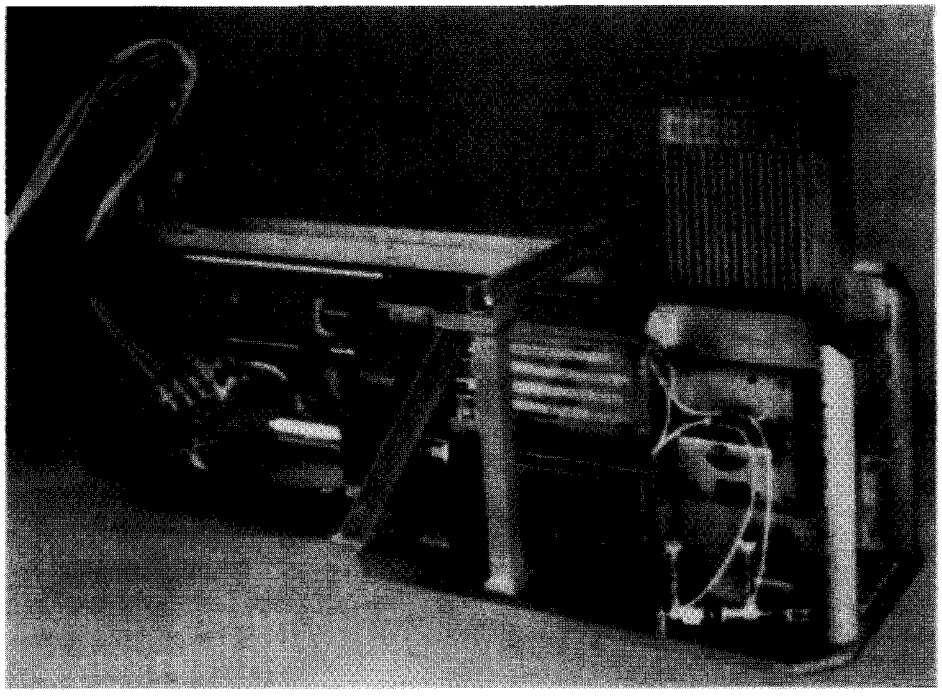

Fig. 41.16 *Ultrasonic defect-locating system ULTRATEST® works with four ultrasonic probes.*

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Ans. Testing of control assemblies requires combined use of

(a) visual inspection
(b) ddy-current examination
(c) profilometry

Q. *Which one of these is most frequently used?*

Ans. Eddy-current examination.

Q. *What for?*

Ans. To check the integrity of all rods in a control assembly in less than eight minutes.

Q. *How?*

Ans. One standard method is to draw all of the control rods through the eddy-current probes in four separate passes per control assembly. The probes are arranged in a testing head (Fig. 41.17) located in the fuel pool during the test.

The test data is recorded in a computer that processes the data and prints out an event log. The results are expressed in terms of percentage of reduction in cross-section according to control rod location and axial elevation and are compared with calculated erosion depths referred to the standard erosion geometries (flat sickle shapes, notches etc.).

Q. *What is gamma spectroscopy of fuel rods?*

Ans. It is a non-destructive examination of exposure of fuel pellets by measuring the fission gas release into the fuel rod from the fuel pellet. This gives the relative and absolute exposure of individual pellets along the length of the fuel rod.

Q. *How is the above procedure performed?*

Ans. Fission gas release is measured by establishing the amount of Kr-85 in the plenum region of the fuel rod. The amount of total gas release can then be calculated based on relationships established in hot-cell examinations. Fuel rod axial exposure can be measured by counting the amount

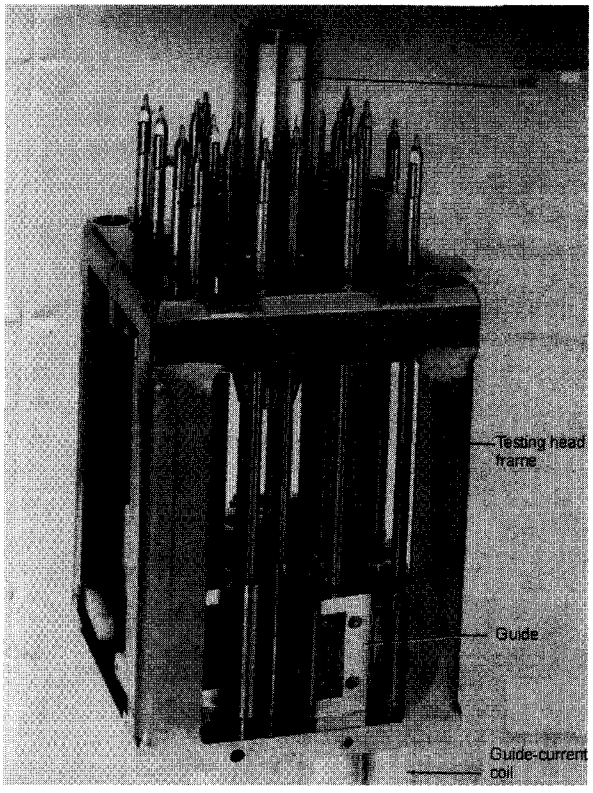

Fig. 41.17 *Eddy-current testing-head for PWR control assemblies.*

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of Cs-137 (relative) or of Cs-137 and Cs-134 (absolute) as a function of axial position.

Q. *What gadgets are used for this?*

Ans. The equipment consists of

1. an underwater camera
2. self-contained lithium-drifted germanium detector maintained at the operating temperature by a liquid N_2 dewar
3. shielding

It takes ≤ 4 h to perform both relative and absolute exposure measurements of fuel pellets.

Source: Safe Reactor Operation Thru Preventive Inspection of Core Components—D.A. Adkisson, K.Knecht & R. Manzel

[Siemens Power Journal (3/94)/P: 39-43]

Q. *BWR pressure vessels of General Electric have welds that are difficult to access from the outside. The United States Nuclear Regulatory Commission (USNRC) requires inspection to the greatest possible extent, from the inside in line with Section XI of the ASME Code. Manual inspection is possible in certain areas and that too entails considerable radiation exposure of personnel. Again limited space available for manipulators and search units hampers the internal inspection of the pressure vessel.*

How can inside inspection of such BWR welds be done?

Ans. All NDEs should be performed using sophisticated manipulators especially designed for this purpose to avoid considerable radiation ex-

posure of personnel. The manipulators of a renowned company (SIEMENS AG) sport state-of-the-art phased-array ultrasonic transducers to the location to the examined and the resultant signal is to be analyzed by a computer system and software. The system generates real-time results in relation to indication size and location. The manipulators perform inspection much faster and eliminate the need for personnel to remain in radiation fields during inspection.

The in-vessel inspection is an ID-mounted ultrasonic equipment (Fig. 41.18) that can reach even the narrowest points (viz. for inspection of areas in the area of jet pumps where a gap of only 50 mm is available above the core shroud baffle). It comprises two systems (Fig. 41.19), each with its own manipulator, working simultaneously yet independently of each other:

(a) an upper manipulator inspects welds and nozzles above the core shroud with greater than 90% coverage
(b) a lower manipulator (Fig. 41.19) inspects welds around the core shroud, including hard-to-reach areas behind the jet pumps. A second upper manipulator may be employed to save time.

With the aid of this system,

(a) simultaneous longitudinal, transverse, and circumferential weld inspection can be carried out without any change out of equipment

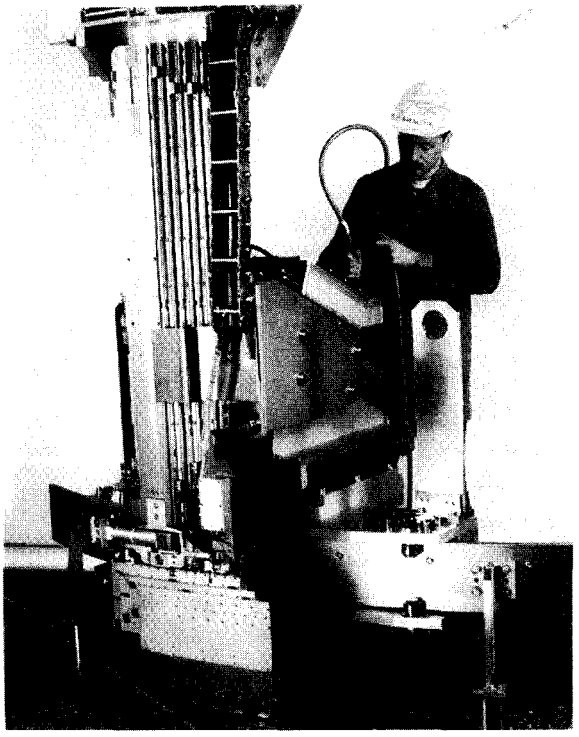

Fig. 41.18 *Lower manipulator system for ultrasonic ID inspection of BWR pressure vessels: The search units (their holders can be seen on the bottom left) can be moved downwards and in a circumferential direction by means of telescoping poles.*

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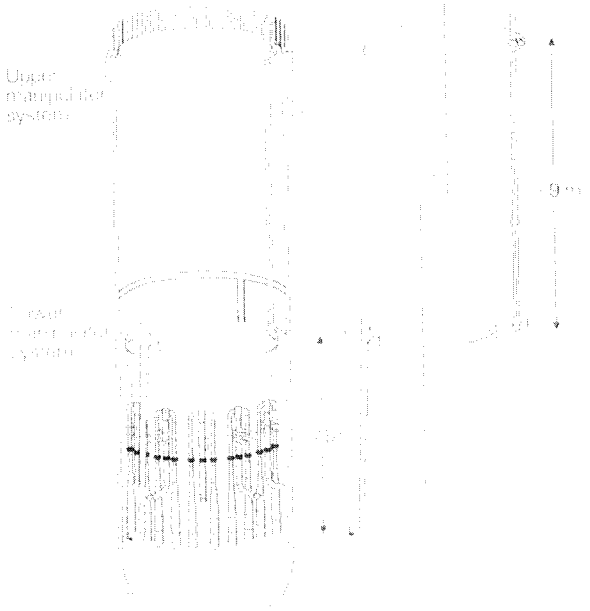

Fig. 41.19 *Areas serviced by the two manipulator systems for internal inspection of BWR pressure vessels.*

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(b) on-vessel inspection time is greatly reduced and remote-operation minimizes personnel exposure.

Siemens subsequently developed a hybrid search unit using the phased-array technique, which is very compact and capable of generating all the scanning angles 0°, 45°, 60° and 70° (as required by Section XI of the ASME Code).

This extremely compact inspection system allows far better coverage of all those weld areas where obstructions hinder inspection.

Inspections for longitudinal and transverse discontinuities can be performed simultaneously thus saving time.

Q. *How much does it take to complete ultrasonic ID examination of a BWR?*

Ans. 8–10 days.

Q. *Can such inspections be carried out during refueling?*

Ans. Yes.

Q. *How far is this system safe from the operator's safety point of view?*

Ans. Radiation exposure of the inspection personnel remains low as the system can be operated from outside the containment at a distance of up to 300 m from the area to be inspected and no change in equipment is necessary when switching from inspection of longitudinal welds to inspection of circumferential welds.

Q. *How far is this system compatible with the nuclear safety standard?*

Ans. It satisfies the requirement for inspection of German Safety Standard KTA 3201.4, by in-

corporating the LLT technique into the hybrid system.

Source: Siemens Service News (Dec. '93)

Siemens Power Journal (Oct. '94)

Q. *What is hydrogen monitoring?*

Ans. It is continuous monitoring of local hydrogen concentrations in the containment of nuclear powerplants without requiring insitu sampling.

Q. *Can you cite a specific example of such a system installed in nuclear powerplant?*

Ans. One such system operates at the 990 MW_e BWR plant at Confrentes in Spain. It was put into operation in April 1993.

Q. *What is it and how does it express H-concentration?*

Ans. It comprises of six sensors housed in the containment, an electronics module in the switchgear building and data displays in the main control room.

The hydrogen concentration is shown in percentage by volume.

Source: Siemens Service News (Dec. '93)

Q. *What is the function of the neutron monitoring system and what is its utility?*

Ans. The neutron monitoring system (Fig. 41.20) monitors the neutron flux level of the core over the range from shutdown to 125% rated power

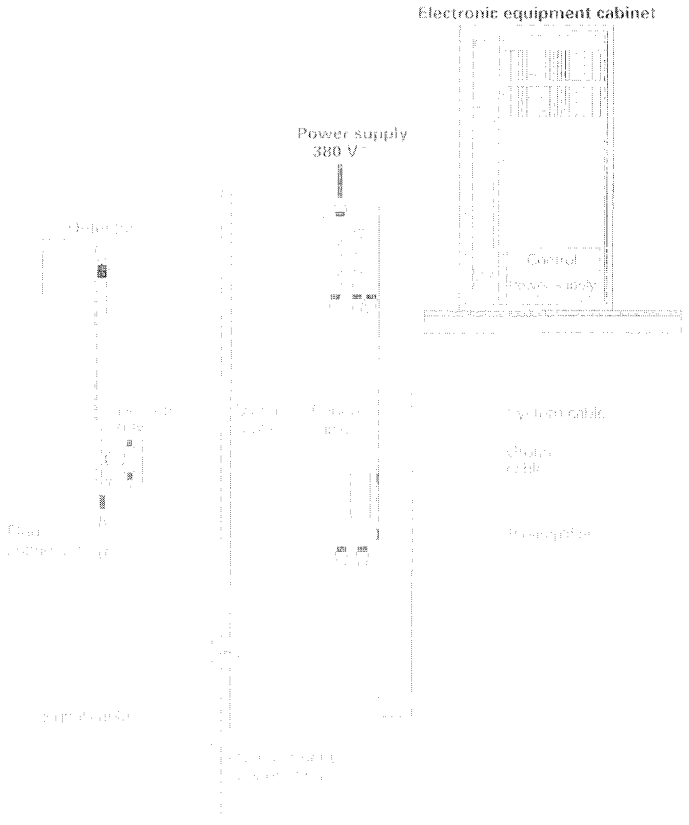

Fig. 41.20 *Schematic diagram of a neutron monitoring system installed in the 378 MW BWR plant at Mühleberg, Switzerland.*

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and three-dimensional power density distribution in the power range.

It provides the control room personnel with current data on neutron flux level and transmits signals to the reactor protection system for initiation of protective measures in case preset limits are exceeded.

Q. *What comprises the neutron monitoring system?*

Ans. It comprises a number of monitoring channels for each of:

(a) source range
(b) intermediate range
(c) power range

Note: The neutron monitoring system (Fig. 41.20) used at Mühleberg prior to its replacement by Siemens' wide-range monitoring system during the 378 MW BWR Plant outage in 1994 consisted of:

(a) 3 Nos. of source range monitoring (SRM) channels
(b) 6 Nos. of intermediate range monitoring (IRM) channels as well as the power monitoring channels.

Q. *What are the advantages of the new wide-range monitoring system installed at Mühleberg?*

Ans.
1. Digital signal processing insures high accuracy
2. Microprocessors harnessed to extend self-monitoring
3. Simplified functional and periodic testing through the use of test routines and signal transmitters
4. Satisfies the requirements of German Nuclear Safety Standards

Source: Siemens Service News (Dec. '93)

Q. *The functional reliability of valves and their actuators is essential for troublefree plant operation. Monitoring function-related parameters provides information on changes in valve performance and their causes, and also enables condition-oriented valve maintenance.*

How is the performance of valves monitored?

Ans. Performance and mechanical condition of the valves are monitored in two stages:

1. Analysis of active power performed at the motor control centre to detect changes as quickly as possible
2. Local diagnosis of all function-relevant parameters to determine the cause of deviations which exceed tolerances.

The first stage quickly displays changes in performance, and the second stage permits detailed analysis.

Q. *How is the diagnostic testing of motor-operated valves carried out?*

Ans. Measurement of active power alone provides general information on both the valve and the associated actuator.

An exact correlation between power consumption and torque can be determined by performing measurements on the actuator. In this case, the calibration and the correction function are determined for the motor power in question.

The pickups are permanently installed in the withdrawable power supply units of the valves at the MCC. The diagnostic unit (MCC-DAW) and the PC analyzer are joined via a diagnostic connector valve ID code. This code ensures that measured data is automatically integrated into the stored master data. Therefore, data can be processed on line right at the test station, thus supplying information on the most important valve functions (Fig. 41.21).

Q. *In case the active power measurement alone does not provide sufficient information for analysis of valve performance, what is to be done?*

Ans. Under this circumstance, reference to local diagnosis is made. It allows a detailed analysis of the valve and its actuator to be performed.

Diagnosis is performed using the compact DAW, which is already in use in powerplants supplied by various vendors, and the PC analyzer (Fig. 41.22).

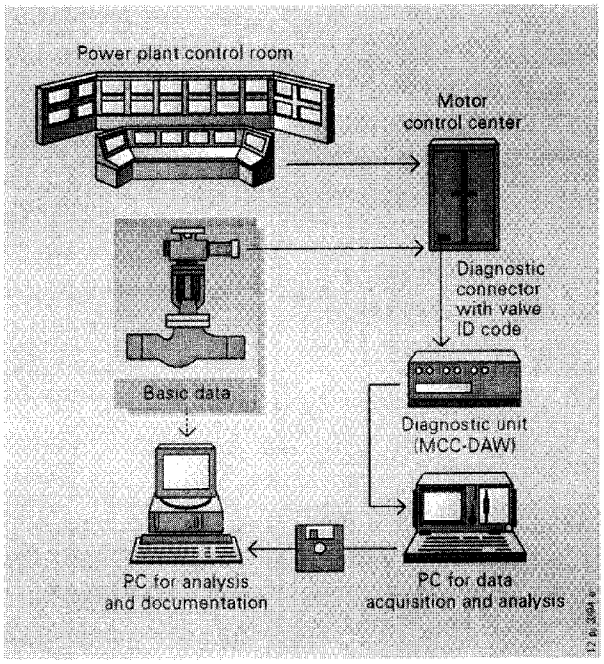

Fig. 41.21 *Analyzing active power at the motor control centre (MCC-DAW) quickly yields internal information on the actuators and valves.*

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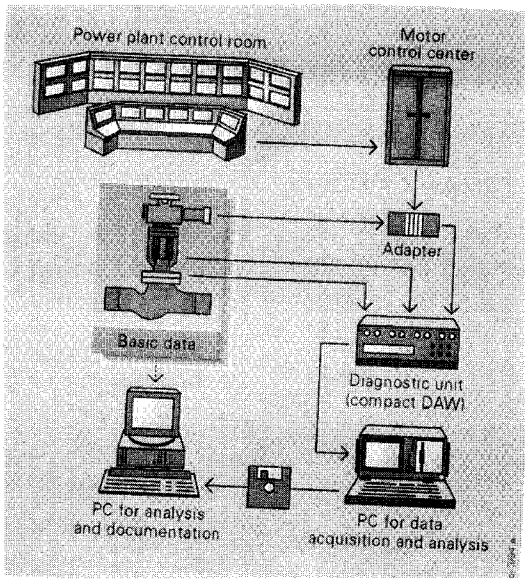

Fig. 41.22 *Local diagnosis using the compact DAW provides detailed information on functional behaviour when active-power measurement alone is not sufficient.*

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The diagnosis procedure records those parameters relevant to mechanical behaviour.

Q. *What are these parameters?*

Ans. 1. Motor power
2. Torque between actuator and valve
3. Steam force
4. Signals from torque and limit switches.

Q. *How can the functional behavior be evaluated by using these parameters?*

Ans. 1. The force sustained at the obturator and at the stuffing box can be determined from the effective stem force
2. The friction in the stem nut can be determined from the quotient of the torque sustained and the stem force
3. The overtravel and excess load can be determined with the position of the limit switches and their cut-off behaviour
4. The cut-off and signal reliability can be determined from the contact resistances and switching times.

Source: Diagnostic Testing of Motor-Operated Valves—Paul Kradepohl and Horst Wolf

[Siemens Power Journal (3/94)/P: 28-29]

Q. *What is gamma-ray computed tomography?*

Ans. It is a non-destructive technology that accurately measures photon transmission.

Note: It is also called gamma-ray scanning.

Q. *What distinguishes it from X-ray radiography, ultrasonics, mechanical dimensional gaging and eddy-current technique?*

Ans. These are all standard non-destructive testing methods that require plant shutdown, a period of cool down, removal of insulation, testing, reinstallation of insulation and start-up—which are as elaborate as expensive.

In contrast gamma-ray tomography is an emerging technology that identifies the defective part of a component in real time.

Q. *What are the field applications of gamma-scanning?*

Ans. Hitherto, it has been deployed to investigate flaws/defects in:
(a) high-pressure steam header
(b) boiler tubes and nozzles
(c) key components of motors
(d) key components of generators
(e) steam and gas turbine casing, blading, rotor and other critical parts

Q. *What is the rate of photon counting?*

Ans. High-speed detector electronics, high-speed array processors, and computerized systems have made this system operating at photon count up to 10 MHz.

Q. *What is the advantage of the digital photon counting system?*

Ans. It provides
(a) wide dynamic ranges
(b) excellent linearity
(c) high signal-to-noise ratios.

Q. *Defects in equipment and piping can be brought under two main types. What are these two?*

Ans. 1. Faulty processing
2. Use degradation

Q. *What do you mean by faulty processing defects?*

Ans. These defects are congenital in nature, i.e. they are there right from the manufacturing of the equipment and supplied as it is from the vendor's plant.

Q. *What are these defects?*

Ans. 1. Inclusions, or blowholes and debris
2. Embrittling impurities
3. Wrong dimensions
4. Improper mechanical assembly.

Q. *In which equipment are such defects common?*

Ans. 1. High pressure steam piping
2. Pumps

3. Valves
4. Boiler tubes
5. Other pressure parts

Q. *What do you mean by use degradation defects?*

Ans. These defects arise from long-term usage of the equipment. They are most frequent in those equipment that operate particularly under demanding conditions, e.g. high temperature, high pressure and in harsh or corrosive environments.

Q. *What are the defects that arise out of use degradations?*

Ans. 1. Corrosion/chemical attack
2. Local overheating effects
3. Stress corrosion cracking (SCC)
4. Fatigue/creep damage
5. Impact/shock damage
6. Internal oxidation
7. Excessive deformation

Q. *Both faulty processing and use degradation are the root cause of failure of equipment. How can they be detected?*

Ans. They are detectable by gamma-ray tomography only.

Q. *How does this technique work?*

Ans. The system involves two basic components:
(a) a gamma-ray source
(b) an array of detectors

The gamma-ray source is a pellet of Co-60 isotope which is a radioisotope that emits a constant photon flux of gamma rays, in million electron volts, as it undergoes nuclear decay. The Cobalt-60 is housed in an exposure system that collimates the rays to a thin fan shaped beam to emanate from a small window in the housing toward the detector array.

The detector array contains as many as 70 to 128 detectors (Fig. 41.23). Each detector embod-

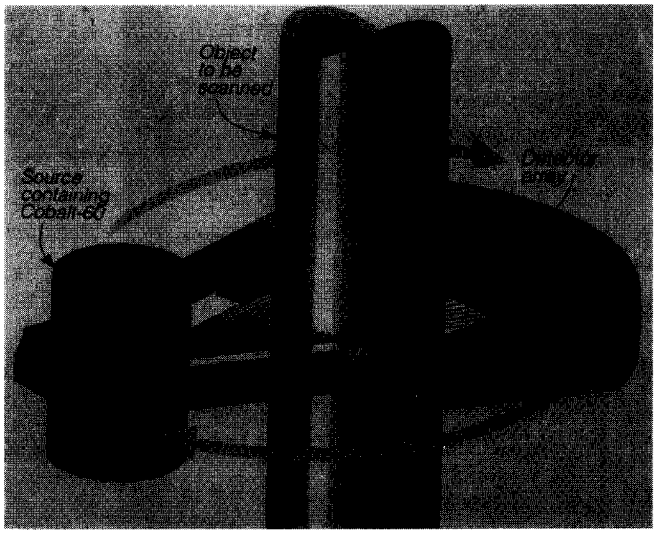

Fig. 41.23 *Gamma-ray computer tomography comprises a gamma-ray-source and an array of detectors. The assembly is rotated around the object to be scanned. The emitted rays are filtered through a slit to produce 'flat beams' that pass through the object and strike the scintillation screen of the detectors.*

Source: POWER/Jan. 1995/P: 46
Courtesy: POWER (McGraw-Hill Publ., NY 10011)
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ies a scintillator. The incoming gamma-rays striking the scintillation screen produces fluorescences through the combined effect of excitation and ionization. The photoelectric effect in a photomultiplier tube hooked up with the scintillator produces a measurable electrical pulse proportional to the energy of the incident gamma-ray photon.

A screening circuit detects only those rays that have been transmitted right through the objects to be scanned, eliminating the detection of scattered photons. Using a scaler model the pulses are then counted and the counts accumulate to produce a measure of the amount of radiation reaching the detector. A computer receives the scaler count data for storage and image processing for reconstruction or analysis of the images.

The computer is mounted in a climate-controlled trailer van.

Q. *How can the tomography of the entire object be done?*

Ans. The exposure device and detector array are mounted in a mobile ring-and-gantry system which can be rotated around a symmetrical object, say a section of pipeline (Fig. 41.24).

Moreover, the exposure-detector unit can be translated along the object. This linear motion plus rotation of the unit permits various angular views, and that makes total scanning of the object possible.

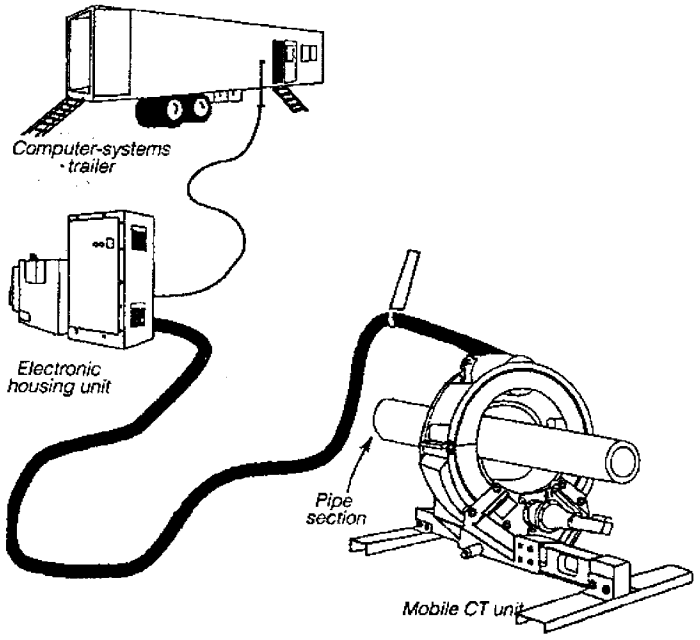

Fig. 41.24 *The assembly of exposure device and detector array mounted in a mobile ring-and-gantry system is rotated around the object to get total scanning (360° exposure).*

Source: POWER/Jan. 1995/P: 47
Courtesy: POWER (McGraw-Hill Publ., NY 10011)
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The count data is processed by a trailer-mounted computer system that produces 3-D density maps of the scanned region.

Note: The tomographic image (tomogram) is produced by a moving radiation source and its detector w.r.t. the object. Reproducing a clear image needs computer manipulation of the various views. The computer assembles them into a two-dimensional, cross-sectional view. In general the exposure-detector system takes profiles (by focussing collimated beams on the plane of interest only) and the computer melds them into a coherent picture.

Q. *A live steam header is carrying high temperature and high pressure steam. Full length pipe inspection is required to detect both volumetric and surface flaws. Can gamma-ray tomography (GRT) be a solution without shutting down the plant?*

Ans. Yes. Gamma-scanning permits complete full-length pipe inspection, including girth welds, in real time. The system can measure OD/ID, wall thickness, internal and surface anomalies, pipe shape dimensions (including eccentricity), and weld density variations.

Q. *How does the gamma-ray tomography lend itself as the convenient tool in a predictive monitoring strategy designed to reduce failures?*

Illustrate through specific examples.

Ans. 1. Using gamma-ray tomography, the scan of a pump impeller (Fig. 41.25) clearly shows a fault in one of the blades.

This information is critically essential as it signals an early warning message that calls for repair/replacement of the demand part before the impeller fails

2. Erosion damage is a headache in all coal-pulverization system. The extent of damage can be quantitatively evaluated by GRT and this information can trigger the necessary remedial action. For instance, Fig. 41.26 shows severe solid-particle erosion of the ceramic liner in the fuel-feed line of a PC-fired boiler.
3. Corrosion damage can be detected by GRT. Fig. 41.27 is the tomogram of a pipe cross-section (400 mm OD and 31 mm W/thickness). The image scan clearly shows internal pitting, already in the advanced stage.

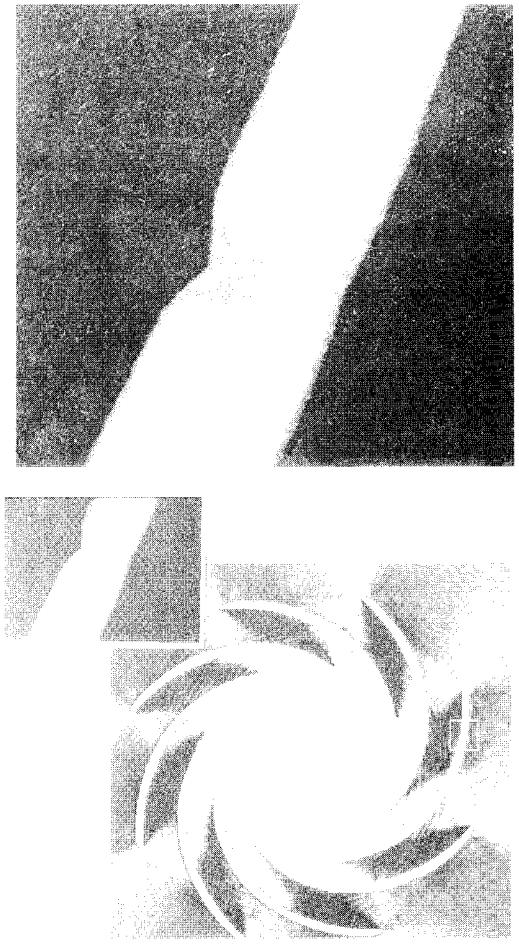

Fig. 41.25 *Gamma scanning has picked up a fault in one of the blades of a pump impeller. The defect has been shown magnified in the inset.*

Source: POWER/Jan. 1995/P: 47
Courtesy: POWER (McGraw-Hill Publ./NY 10011)
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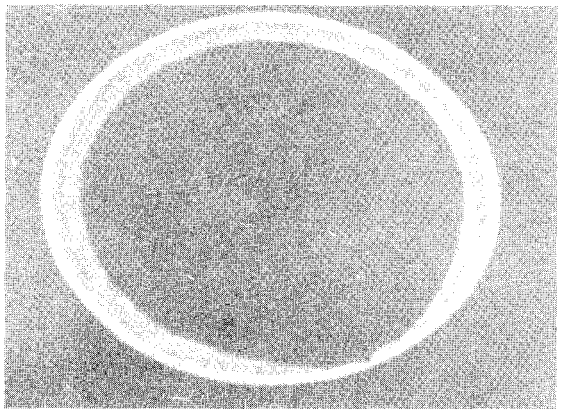

Fig. 41.26 *Gamma-ray tomogram of solid-particle erosion of the ceramic lined wall in the pulverized coal feedline.*

Source: POW./Jan. 1995/P: 48
Courtesy: POWER (McGraw-HIll Publ./NY 10011)
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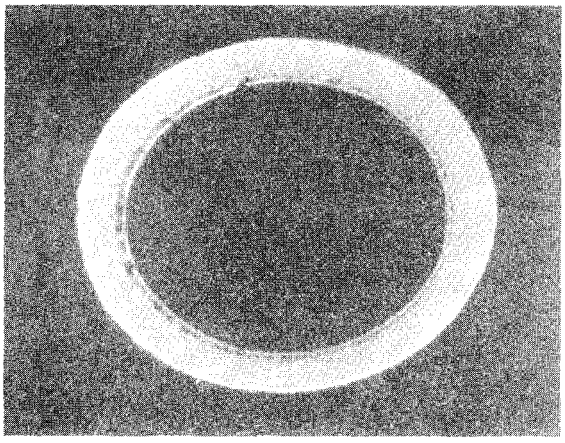

Fig. 41.27 *Gamma scan of a pipe cross-section (OD/Wall Thick. 400 mm/31 mm) showing internal pitting*

Source: POWER/Jan. 1995/P: 48
Courtesy: POWER (McGraw-Hill Publ./NY 10011)
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Q. *How can the interior examination of the recirculation loops of BWR be carried out?*

Ans. By using an underwater pipe crawler. In its innovative design of robotics, Siemens has developed a self-propelled, remote-controlled unit (Fig. 41.28) that combines both ultrasonic and eddy-current examinations which can be conducted in adverse ambient conditions. The above remote-controlled manipulator can perform successful interior examination of austenitic connecting welds in the recirculation loops of BWRs.

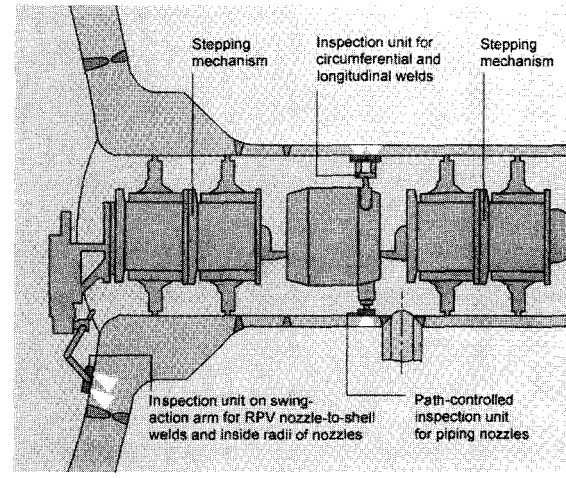

Fig. 41.28 *Underwater pipe crawler for interior examination of the recirculation loops of boiling water reactors*

Source: Siemens Power Journal 2/93
Courtesy: Siemens Power Generation
©Siemens AG

Q. *How can the eddy-current test result be interpreted?*

Ans. Imaging eddy-current examination shows the probe field and reconstructed construction (D-scan) of a flaw (Fig. 41.29).

Q. *What is EMUS?*

Ans. It stands for Electromagnetic excitation of Ultrasound. It is one of the latest sensor technologies developed and patented by Siemens to improve flaw descriptions.

Q. *How does it work?*

Ans. EMUS technology permits the generation of horizontally polarized transverse waves which are particularly well suited for examining special anisotropic structures e.g. dissimilar metal welds (Fig. 41.30).

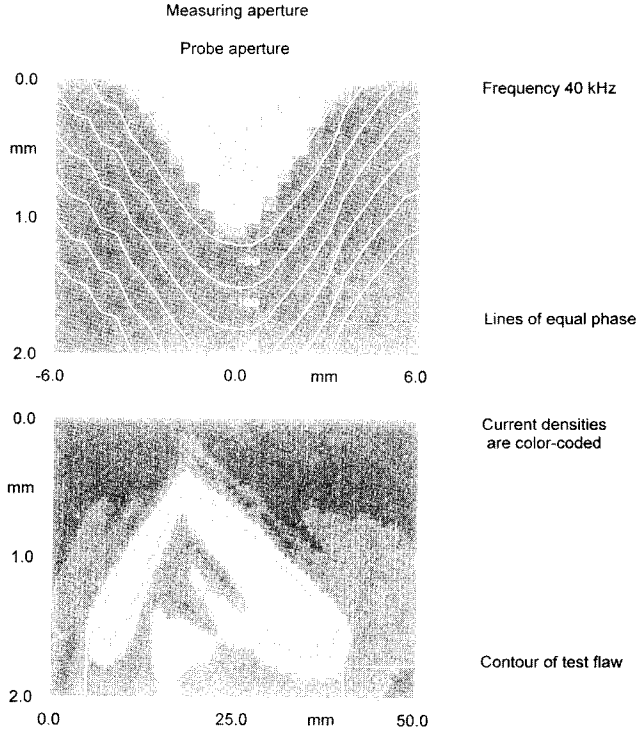

Fig. 41.29 *Imaging eddy-current test method: probe field and reconstructed cross-section (D-scan) of a flaw.*

Source: Siemens Power Journal 2/93
Courtesy: Siemens Power Group KWU
© Siemens AG

Q. *Three dimensional representation of ultrasonic crack data gives the quantitative visualization of flaws in objects with complex geometries. However, translating these images into descriptions of the type and geometry of the flaw requires technical know-how and expertise on the part of the examining personnel. How can this process be simplified?*

Ans. The best way is to analyze the visual images using image processing techniques that perform step-by-step reduction of ultrasonic crack data (Fig. 41.31). In order to simplify this translation process and make it more objective, the filters commonly used in image processing can be used. The Fig. 41.31 shows the reconstruction of a crack which is reduced step-by-step to a linear black and white indication.

Q. *What is the most widely used technique in detecting flaws in ferrous heat-exchanger tubes?*

Ans. The magnetic-flux-leakage examination technique is used for this purpose.

Q. *What are the advantages of this method?*

Ans. 1. Operational simplicity
2. Low cost
3. Proven performance

Q. *Why is the eddy-current method not used for inspecting ferrous HE tubes?*

Ans. Eddy-current methods are not suitable for examining ferromagnetic materials as eddy-current generation in the HE tubing is largely confined to a discrete layer of tubewall thickness. The thickness of the layer depends on the frequency of the imposed electromagnetic wave as

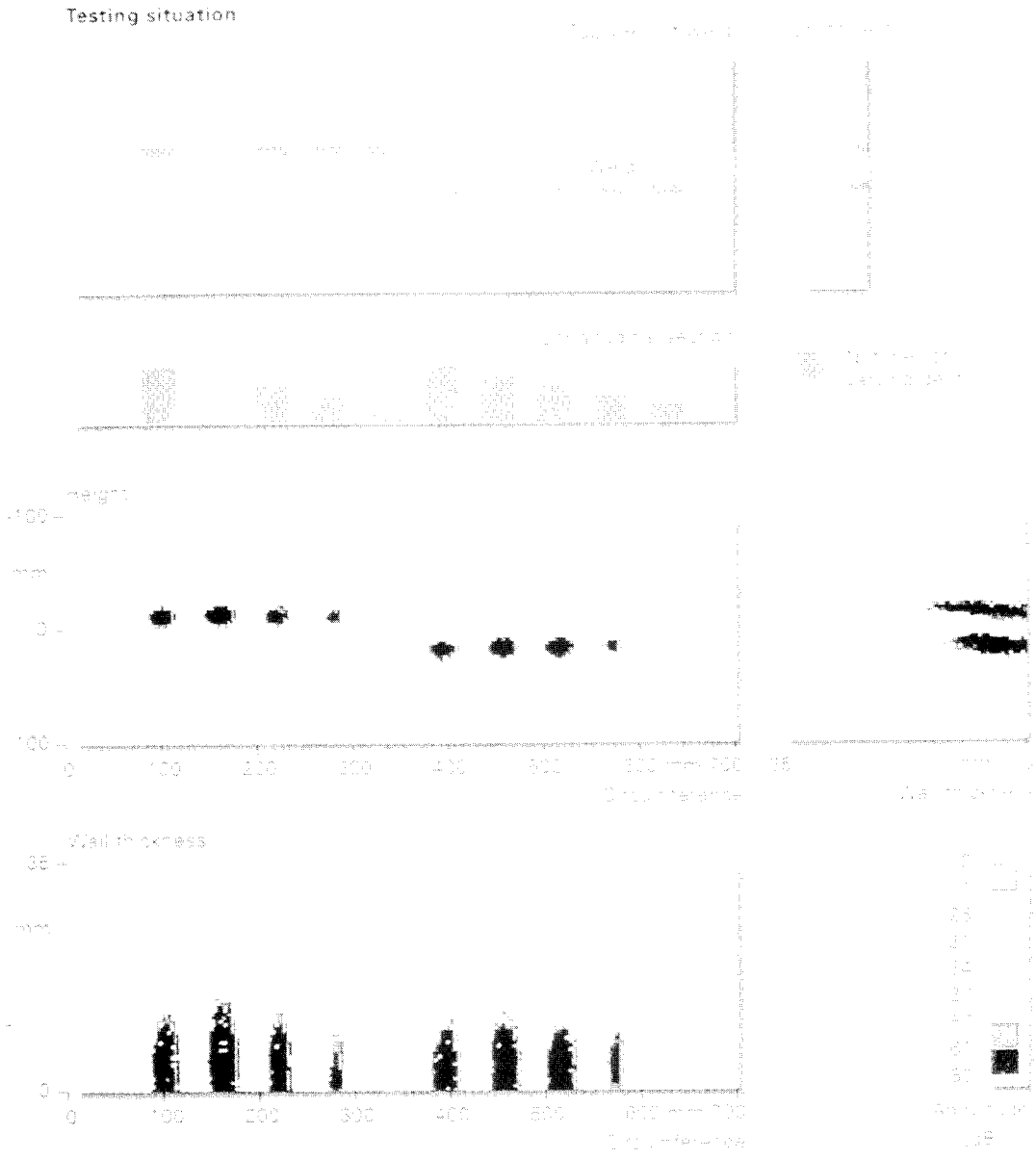

Fig. 41.30 *An austenitic weld difficult to penetrate ultrasonically using conventional methods is transparent using EMUS: the flaws of either side of the weld generate equal amplitudes in both cross and longitudinal sections.*

Source: *Siemens Power Journal 2/93*
Courtesy: *Siemens Power Generation Group KWU*
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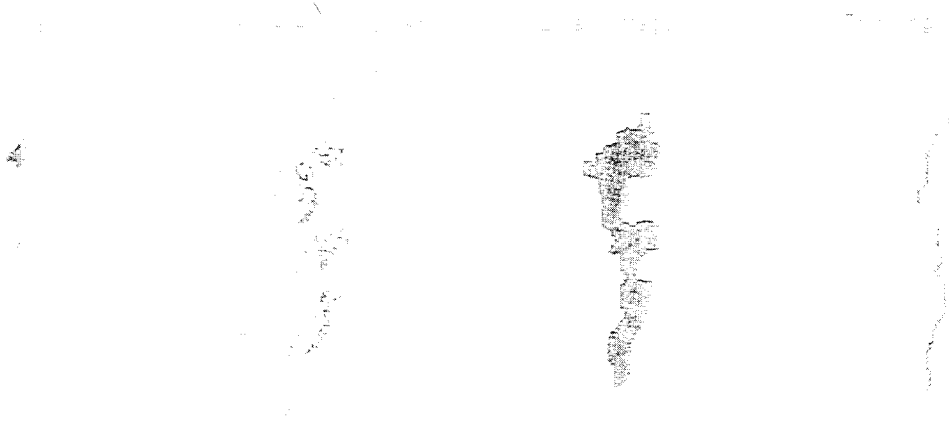

Fig. 41.31 *Step-by-Step reduction of ultrasonic crack data using image processing techniques.*

Source: *Siemens Power Journal 2/93*
Courtesy: *Siemens Power Generation Group KWU*
© Siemens AG
Source: *Trends in In-service Inspection Techniques used in Nuclear Power Plants—Ludwig von Bernus and Kurt Fischer (Siemens Power Journal 2/93)*

well as the magnetic permeability and electrical conductivity of the material.

Ferromagnetic materials are inherently highly permeable and as such the penetration depth is quite shallow with the effect that the effectiveness of conventional eddy-current techniques becomes limited to surface-linked flaws. Inspecting heat-exchanger tubing requires characterization of the entire wall thickness, not just as a thin layer at the inner surface.

Note: The widespread use of ferromagnetic materials in powerplant components seriously limits the application of standard eddy-current techniques.

Q. *What should be the essential qualities of an ideal magnetic-flux-leakage sensor?*
Ans. It must be capable of

(a) inspecting from the internal surface of the tube
(b) detecting and estimating the size of both internal and external tube damage accurately
(c) detecting gradual wall thinning as well as local flaws
(d) locating the source of defect/flaw
(e) distinguishing between damage and non-damage signals (e.g. those from support plates)
(f) Inspecting rapidly with minimum human intervention
(g) having instrumentation that can withstand adverse field conditions.

Q. *Therefore where will you apply eddy-current method?*

Ans. The standard eddy-current methods are applicable to the detection of flaws in non-magnetic heat exchanger tubes.

Q. *How can the limitation on the depth of penetration while applying eddy-current methods to detected flaws in ferromagnetic tubes be avoided*?

Ans. First Method: This one induces magnetic saturation in the tube by applying a pulsed, high-amperage direct current in a magnetizing coil. The general magnetic field induces magnetic saturation through the wall-thickness of the tube.

Second Method: It harnesses a remote-field eddy-current technique to detect the small fraction of eddy-currents in a ferromagnetic material not limited to the surface layer. It is highly sensitive to gradual wall thinning.

Q. *What are the limitations of these two techniques?*

Ans. The first one comes with a complicated probe design. Variations in permeability register false indications. Gradual wall thinning is difficult to detect.

The second method is highly sensitive as it must pick up extremely low signals and as such it comes with a complex probe design for sensing localized wall thinning. The probe sports several small pancake coils around the circumference. The probe is very delicate and expensive and requires sophisticated electronic interfacing.

Q. *How to tide over the problems with eddy-current techniques of flaw detection?*

Ans. EPRI has developed a magnetic flux-leakage sensor which is a simple, low cost equipment with proven performance.

Q. *How does it detect flaws?*

Ans. The probe, containing a magnetizing circuit, is fitted with two sensors: the sharp-defect sensor and the gradual defect sensor. The former detects localized flaws while the latter senses gradual wall thinning.

The probe is inserted into the tube (Fig. 41.32). As it is propelled down the tube it induces a magnetic field in the tubewall*. The magnetic lines of force get intercepted at local discontinuities/flaws (both internal and external). These localized perturbations in the magnetic field generate a signal in the detection coil that can be amplified, recorded, and displayed later for evaluation.

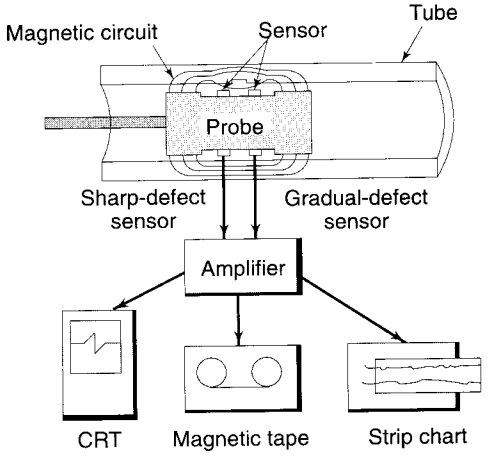

Fig. 41.32 *Magnetic-flux leak detection sensor sports a probe that induces into the tubewall a magnetic circuit which is picked up by two sensors—one for localized flaws and the other for gradual wall thinning.*

Source: POWER/May. 1988/P: 33
Courtesy: POWER (McGraw-Hill Publ./NY 10011)
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Q. *What is the advantage of the EPRI magnetic-flux leakage sensor over the eddy-current technique?*

Ans. 1. Full magnetic saturation is not a necessity
2. Flux perturbations extend over much greater distances than eddy currents and therefore the sensor can detect damages throughout the tubewall.

(* Full saturation is not necessary).

It can even distinguish between outer and inner-surface damage (Fig. 41.33).

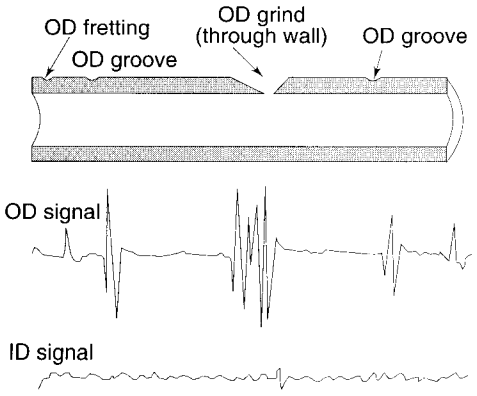

Fig. 41.33 *ID and OD signals are clearly distinguishable. Inspection result shows peaks in OD signals indicating such defects as OD fretting, OD groove, OD grind-through wall.*

Source: POWER/May 1988/P: 34
Courtesy: POWER (McGraw-Hill Publ./NY 10011)
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Q. *Where does the magnetic-flux-leakage method not work?*

Ans. This method fails where the HE tubes are made of admiralty brass, austenitic stainless steel or titanium.

Q. *Why does the magnetic flux-leakage method fail where the HE tubes are made of admiralty brass, austentic stainless steel or titanium?*

Ans. Flaws are the zones of low magnetic permeability that interrupt the high flux density induced in the ferromagnetic material by the probe. Inasmuch as the foregoing alloys do not develop sufficiently high magnetic-flux densities, the flux-leakage method fails in these systems.

Q. *What distinguishes EPRI sensor from the conventional flux-leakage sensor?*

Ans. A conventional flux-leakage sensor fails to detect gradual wall thinning (due to corrosion/erosion) as it is not sensitive enough to detect gradual wall loss. This is due to the fact that gradual defects do not produce suitable flux perturbations to be picked up by the sensor designed for detecting localized defects.

That is why a dual-sensor system is necessary)

To overcome this problem, the EPRI probe is fitted to a Hall-effect sensor to measure the total magnetic flux through the tubewall and to demonstrate, indirectly, the gradual wall thinning.

Note: The EPRI research team has further improved and refined the technique enhancing the sensor's sensitivity to small defects e.g. defects tantamount to only 10% loss of external wall can now be easily detected in C-steel tubing (19 mm ID/2.17 mm wall thickness).

Q. *Why is continuous, online and accurate monitoring of air inleakage into steam turbines imperative?*

Ans. To alert the operators to the possibility of pressure build-up that could damage the condenser vacuum system and trip the powerplant.

Q. *What are the far-reaching effects of steam turbine air inleakage on powerplants?*

Ans. Air inleakage to steam turbines exercises far-reaching physical and chemical effects on the powerplant.

The physical effects are manifested in the form of loss of vacuum in the condenser that, at the extreme, can bring into effect low-pressure-blade-flutter.

The chemical effects are caused by the infiltration of O_2 and CO_2 into the condensate system, that invite nasty corrosion in steam-water circuit.

DO generally affects the feedwater heater train and the steam generator. Oxygen is not fully scavenged up by hydrazine at condenser temperatures and often reacts with feedwater-heater materials. The corrosion products ride the BFW and get deposited in the boiler, contributing to poor heat transfer characteristics and possible tube rupture.

CO_2 causes pitting of rotor steels and accelerates crack propagation. An increase in carbon dioxide concentration in feedwater requires a higher amount of ammonia dosing to maintain the correct pH. Both of these compounds are cover

to the liquid condensed in the turbine-condenser. Also the reaction between dissolved CO_2 and NH_3 increases the ionic concentration in the condensate to a much higher level than what would it be if the CO_2 was not present. The increased ionic strength increases the conductivity of the liquid that further promotes crack growth and may result in disc cracking.

Due to air inleakage, the steam-cycle components undergo outage corrosion though the system is under vacuum. When the unit is off-line, the vacuum extends to the throttle valves. The turbine internals become enclosed in a warm, moist environment. As air leaks in, it adds oxygen to this environment which whereupon becomes extremely corrosive. The situation worsens in case the sealing steam is inadequate when the unit is shutdown. Under these conditions more air inleakage takes place through glands.

Q. *Where is the monitor installed?*

Ans. The monitor is contained in a flanged pipe section that is spilced into the air exhaust line of the evacuation system downstream of the air removal equipment (Fig. 41.34).

Q. *Why is it not installed before the condenser evacuation system?*

Ans. Installation of the air inleakage monitor before the evacuation system would entail two basic problems:

(a) airflow is difficult to measure here because of high partial pressure of water in comparison to the pressure of air

(b) any monitor malfunctioning at this point would probably lead to a unit trip.

Q. *What are the inherent limitations of rotometer based monitor?*

Ans. Accuracy of the rotometer based measurements becomes uncertain due to two reasons:

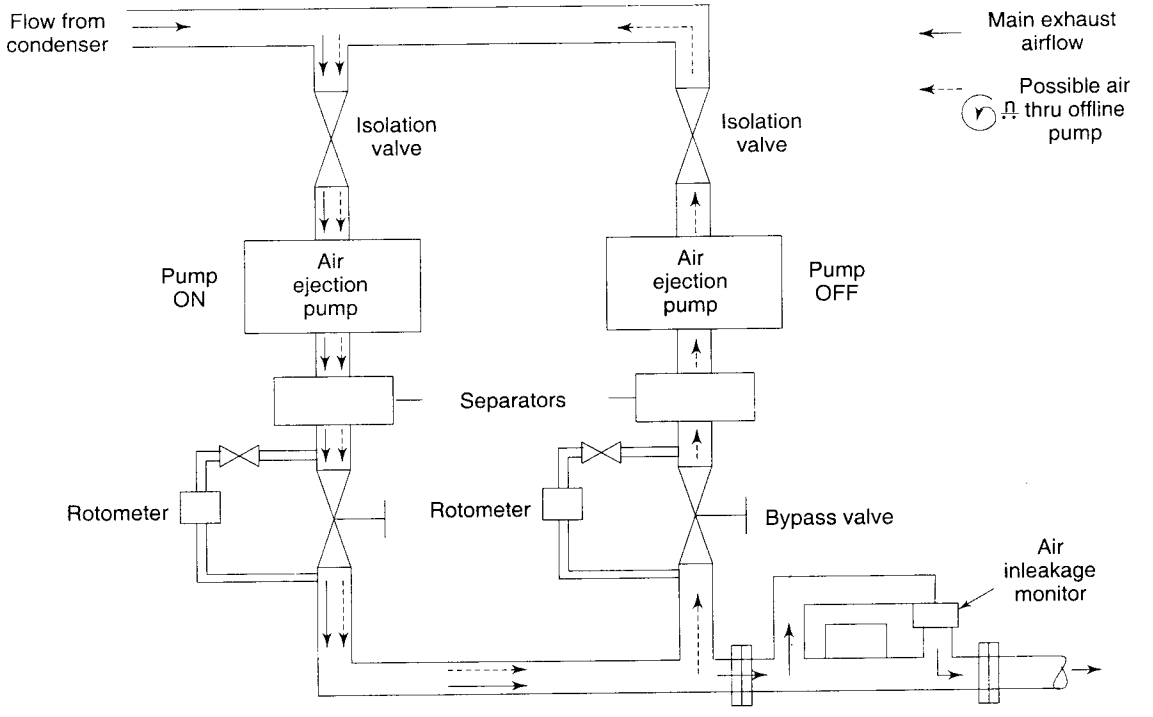


Fig. 41.34 *Monitor is installed downstream of air evacuation system.*

(a) The rotometer gets usually flooded with water and clogged quickly. It may not operate accurately even after blowdown
(b) The ΔP across the rotometer and the frequent poor sealing in its manually operated valve (caused by corrosion) can culminate in an erroneously lower measurement of condenser air exhaust

The accuracy and resolution of the rotometer is generally poor. Also the backflow of air through the off-line parallel exhaust pumps may lead to an appreciably high air-circulation through the pump *i/l*. This will give rise to higher rotometer reading than the actual air inleakage.

Q. *Once air leakage is detected, the immediate step is to find and repair it. What are the generally accepted methods for locating air leaks in a steam turbine?*

Ans. 1. Helium-leak detection
2. Freon-leak detection
3. Ultrasonic leak detection

Q. *How is helium-leak detection accomplished?*

Ans. This method uses helium, the lightest inert gas, as a tracer element. It is sprayed in the vicinity of the potential inleakage path and is drawn into the system through the leak and is measured by a detector paired with mass spectrometry at the turbine exhaust.

Q. *What are the advantages of this method?*

Ans. 1. It is by far the best test method for locating leaks today.
2. Helium mass spectrometry is highly sensitive
3. As a tracer gas, helium is quite attractive, because it is inert, non-flammable, and non-toxic
4. The gas being very light, it penetrates small leaks and diffuses readily.

Q. *What are the drawbacks of this system?*

Ans. 1. Because of its extreme sensitivity, helium may not be the best gas for locating leaks greater than 3.4 Nm^3/h
2. Large leaks tend to overpower current leak detectors even at maximum metering scales. And this fact makes its difficult to evaluate large leaks quantitatively.

Q. *What is freon-leak detection?*

Ans. It is similar to helium-leak detection with the only exception that it draws on freon, instead of helium, as the tracer gas.

Q. *What are the advantages of this system?*

Ans. 1. Less specialized skill is required than for the helium-leak detection technique
2. Large leaks (unlike He-leak method) can be screened and individual leaks pinpointed
3. Easy maintenance of the detector

Q. *Does it have any drawback?*

Ans. Freon is quite heavier than He. Therefore, it takes considerable length of time to dissipate from the region around a leak and for the detector to clear.

Q. *How does the ultrasonic leak detection system work?*

Ans. It detects sounds above 15 kHz associated with a leak. This sound signal is then amplified and converted to audible frequencies of 100 to 4000 Hz.

Q. *What is the basic limitation of this process?*

Ans. It is almost entirely an operator skill oriented process and can be effective only if the operator performing the test has superb hearing and is capable of distinguishing leakage sound from the background noise of the plant.

Q. *How does an online lube-oil sensor tell the state of machine wear?*

Ans. It is a continuous debris monitor developed by the Central Electricity Generating Board's Marchwood (UK) Engineering Laboratories. It is installed in the lube oil circuit just upstream of the filter. It provides an online measurement of the ferrous particles in the oil and hence an online indication of the machine.

The sensor senses flux changes caused by the accumulation of ferrous particles in a magnetic circuit (Fig. 41.35)

This change is converted into an electrical signal which can drive a variety of readouts.

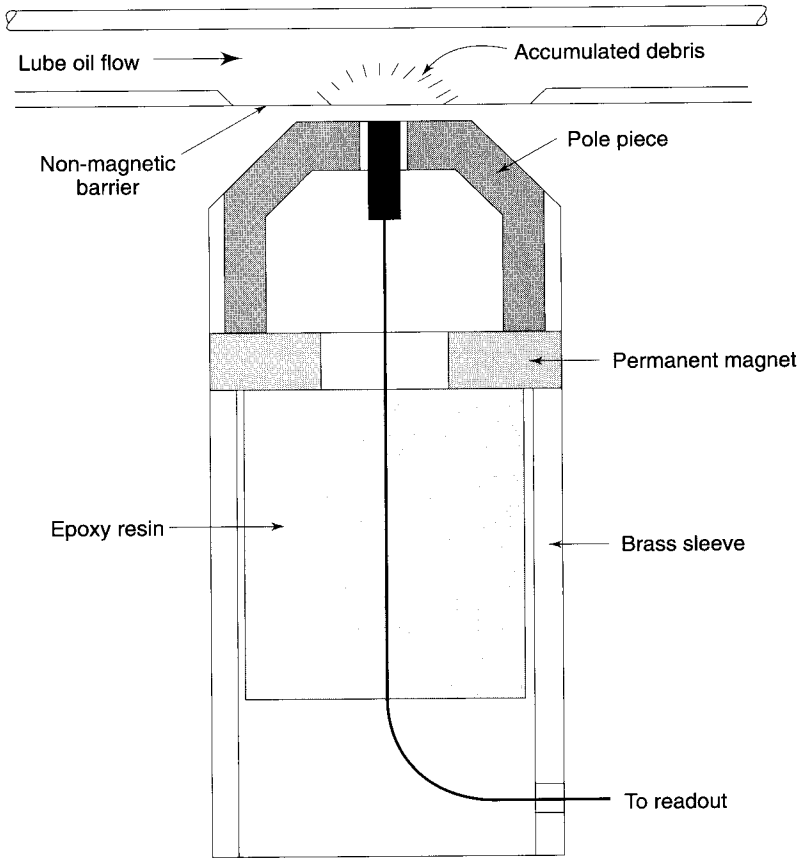


Fig. 41.35 *The online continuous debris monitor senses flux changes caused by the accumulation of ferrous particles.*

Appendix I

Conversion Tables, and Basic Data on Fuels and Combustion

Table AI.1 Length Units

		mm	cm	m	km	in	ft	yd	mi
millimeters	mm	1	0.1	0.001	0.000001	0.03937	0.003281	0.001094	6.21e-07
centimeters	cm	10	1	0.01	0.00001	0.393701	0.032808	0.010936	0.000006
meters	m	1000	100	1	0.001	39.37008	3.28084	1.093613	0.000621
kilometers	km	1000000	100000	1000	1	39370.08	3280.84	1093.613	0.621371
inches	in	25.4	2.54	0.0254	0.000025	1	0.083333	0.027778	0.000016
feet	ft	304.8	30.48	0.3048	0.000305	12	1	0.333333	0.000189
yards	yd	914.4	91.44	0.9144	0.000914	36	3	1	0.000568
miles	mi	1609344	160934.4	1609.344	1.609344	63360	5280	1760	1

Table AI.2 Area Units

		mm^2	cm^2	m^2	in^2	ft^2	yd^2
square millimeters	mm^2	1	0.01	0.000001	0.00155	0.000011	0.000001
square centimeters	cm^2	100	1	0.0001	0.155	0.001076	0.00012
square meters	m^2	1000000	10000	1	1550.003	10.76391	1.19599
square inches	in^2	645.16	6.4516	0.000645	1	0.006944	0.000772
square feet	ft^2	92903	929.0304	0.092903	144	1	0.111111
square yards	yd^2	836127	8361.274	0.836127	1296	9	1

Table AI.3 Volume Units

		cm^3	m^3	ltr	in^3	ft^3	US gal	Imp. gal	US brl
cubic centimeters	cm^3	1	0.000001	0.001	0.061024	0.000035	0.000264	0.00022	0.000006
cubic meters	m^3	1000000	1	1000	61024	35	264	220	6.29
litres	ltr	1000	0.001	1	61.0	0.035	0.264201	0.22	0.00629
cubic inches	in^3	16.4	0.000016	0.016387	1	0.000579	0.004329	0.003605	0.000103
cubic feet	ft^3	28317	0.028317	28.31685	1728.0	1	7.481333	6.229712	0.178127

(Contd)

		cm^3	m^3	ltr	in^3	ft^3	US gal	Imp. gal	US brl
US gallon	US gal	3785	0.003785	3.79	231	0.13	1	0.832701	0.02381
Imp gallon	Imp. gal	4545	0.004545	4.55	277	0.16	1.20	1	0.028593
US barrel for oil	US brl	158970	0.15897	159	9701	6	42	35.0	1

Table AI.4 Mass Units

		g	kg	tonne	shton	Lton	lb	oz
grams	g	1	0.001	0.000001	0.000001	9.84e-07	0.002205	0.035273
kilograms	kg	1000	1	0.001	0.001102	0.000984	2.204586	35.27337
metric tons	tonne	1000000	1000	1	1.102293	0.984252	2204.586	35273.37
short tons	shton	907200	907.2	0.9072	1	0.892913	2000	32000
long tons	Lton	1016000	1016	1.016	1.119929	1	2239.859	35837.74
pounds	lb	453.6	0.4536	0.000454	0.0005	0.000446	1	16
ounces	oz	28	0.02835	0.000028	0.000031	0.000028	0.0625	1

Table AI.5 Density Units

		g/ml	kg/m^3	lb/ft^3	lb/in^3
gram per milliliter	g/ml	1	1000	62.42197	0.036127
kilogram per cubic meter	kg/m^3	0.001	1	0.062422	0.000036
pound per cubic foot	lb/ft^3	0.01602	16.02	1	0.000579
pound per cubic inch	lb/in^3	27.68	27680	1727.84	1

Note: Specific Volume = 1/Density

Specific Gravity G_f for liquids:

$G_f = \rho/\rho_0$

= (density of liquid at upstream temperature)/(density of water at reference conditions)

where reference conditions according to IEC 534 and ISA S75:

for SI units: ρ_0 = 999 kg/m^3 at 15.6 °C and at atmospheric pressure (1.013 bar A)

for US units ρ_0 = 62.36 lb/ft^3 at 60 °F and at atmospheric pressure (14.73 psiA)

Specific Gravity G_g for gases:

$G_g = \rho_{gas}/\rho_0$

= (density of gas at standard conditions)/(density of air at standard conditions)

where standard conditions according to IEC 534 and ISA S75:

for SI units: 15.6 °C and atmospheric pressure (1.013 bar A)

for US units: 60 °F and atmospheric pressure (14.73 psiA)

When gas specific gravity is calculated in standard conditions, the above equation can be simplified to: $G_g = M_w/28.96$, where M_w is molecular weight of gas.

Table AI.6 Speed Units

		m/s	m/min	km/h	ft/s	ft/min	mi/h
meter per second	m/s	1	59.988	3.599712	3.28084	196.8504	2.237136
meter per minute	m/min	0.01667	1	0.060007	0.054692	3.281496	0.037293
kilometer per hour	km/h	0.2778	16.66467	1	0.911417	54.68504	0.621477
feet per second	ft/s	0.3048	18.28434	1.097192	1	60	0.681879
feet per minute	ft/min	0.00508	0.304739	0.018287	0.016667	1	0.011365
miles per hour	mi/h	0.447	26.81464	1.609071	1.466535	87.99213	1

Table AI.7 Pressure Units

		bar	psi	kPa	MPa	kgf/cm^2	mmHg	atm
bar	bar	1	14.50326	100	0.1	1.01968	750.0188	0.987167
pound per square inch	psi	0.06895	1	6.895	0.006895	0.070307	51.71379	0.068065
kilo Pascal	kPa	0.01	0.1450	1	0.001	0.01020	7.5002	0.00987
Mega Pascal	MPa	10	145.03	1000	1	10.197	7500.2	9.8717
kilogram force per cm^2	kgf/cm^2	0.9807	14.22335	98.07	0.09807	1	735.5434	0.968115
millimeter of mercury	mmHg, torr	0.001333	0.019337	0.13333	0.000133	0.00136	1	0.001316
Int.St.Atm.	atm	1.013	14.69181	101.3	0.1013	1.032936	759.769	1
meter of water	mH_2O	0.09806	1.42219	9.806	0.00981	0.09999	73.54684	0.096802
foot of water	ftH_2O	0.02989	0.433503	2.989	0.00299	0.030478	22.41806	0.029506
centimeter of mercury	cmHg	0.01333	0.193328	1.333	0.00133	0.013592	9.99775	0.013159
inch of mercury	inHg	0.03386	0.49108	3.386	0.00339	0.034526	25.39563	0.033425
inch of water	inH_2O	0.002491	0.036128	0.2491	0.000249	0.00254	1.868297	0.002459
Pascal = N/m^2	Pa	0.00001	0.000145	0.001	0.000001	0.00001	0.0075	0.00001
mmH_2O, kp/m^2	kp/m^2	9.81e-05	0.001422	0.009807	0.00001	0.00099	0.073552	0.000097

		mH_2O	ftH_2O	cmHg	inHg	inH_2O	Pa	kp/m^2
bar pound per square inch	bar	10.19784	33.45601	75.01875	29.53337	401.4452	100000	10197.16
kilo Pascal	psi	0.703141	2.306792	5.172543	2.036326	27.67965	6895	703.0943
Mega Pascal	kPa	0.10198	0.33456	0.75019	0.29533	4.01445	1000	101.972
kilogram force per cm^2	MPa	101.978	334.560	750.187	295.334	4014.45	1000000	101972
millimeter of mercury	kgf/cm^2	10.00102	32.8103	73.57089	28.96338	393.6973	98070	10000.36
Int.St.Atm.	mmHg, torr	0.013597	0.044607	0.100023	0.039377	0.535247	133.33	13.59588
meter of water	atm	10.33041	33.89093	75.994	29.91731	406.664	101300	10329.73
foot of water	mH_2O	1	3.280696	7.356339	2.896043	39.36572	9806	999.9337
centimeter of mercury	ftH_2O	0.304813	1	2.242311	0.882753	11.9992	2989	304.7932
	cmHg	0.135937	0.445969	1	0.39368	5.351265	1333	135.9282

(Contd)

		mH_2O	ftH_2O	cmHg	inHg	inH_2O	Pa	kp/m^2
inch of mercury	inHg	0.345299	1.13282	2.540135	1	13.59293	3386	345.2759
inch of water	inH_2O	0.025403	0.083339	0.186872	0.073568	1	249.1	25.40113
Pascal = N/m^2	Pa	0.000102	0.000335	0.00075	0.000295	0.004014	1	0.101972
mmH_2O, kp/m^2	kp/m^2	0.001	0.003281	0.007357	0.002896	0.039368	9.80665	1

Note: Pressure may be expressed with reference to any arbitrary datum. The usual ones are absolute zero and local atmospheric pressure. When a pressure is expressed as a difference between its value and a complete vacuum, it is called absolute pressure. When it is expressed as a difference between its value and the local atmospheric pressure, it is called a gauge pressure. The following figure shows the relationships between absolute pressure, gauge pressure, and barometric pressure.

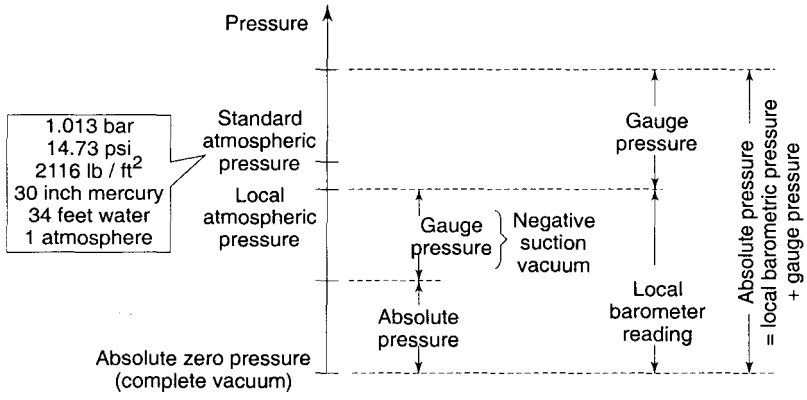


Table AI.8 Commonly used units for volumetric liquid flow

		l/sec	l/min	m^3/hr	ft^3/min	ft^3/hr	gal/min	US brl/d
liter per second	l/sec	1	60	3.6	2.119093	127.1197	15.85037	543.4783
liter per minute	l/min	0.016666	1	0.06	0.035317	2.118577	0.264162	9.057609
cubic meters per hour	m^3/hr	0.277778	16.6667	1	0.588637	35.31102	4.40288	150.9661
cubic feet per minute	ft^3/min	0.4719	28.31513	1.69884	1	60	7.479791	256.4674
cubic feet hour	ft^3/hr	0.007867	0.472015	0.02832	0.01667	1	0.124689	4.275326
US gallon per minute	US gal/min	0.06309	3.785551	0.227124	0.133694	8.019983	1	34.28804
US barrel per day	US brl/d	0.00184	0.110404	0.006624	0.003899	0.2339	0.029165	1

Table AI.9 Commonly Used Units for Volumetric Gas Flow

		Nm^3/hr	scfh	scfm	mscfd	mmscfd	Nl/sec
Normal cub.meter per h	Nm^3/hr	1	35.31073	0.588582	0.847458	0.000847	0.277778
Stand. cub. feet per h	scfh	0.02832	1	0.016669	0.024	0.000024	0.007867
Stand. cub. feet per min.	scfm	1.699	59.99294	1	1.439831	0.00144	0.471944
10^3 St. cub. ft per day	mscfd	1.18	41.66667	0.694526	1	0.001	0.327778
10^6 St. cub. ft per day	mmscfd	1180	41666.67	694.5262	1000	1	327.7778
Normal liter per second	Nl/sec	3.6	127.1186	2.118893	3.050847	0.003051	1

Note: Standard or normal conditions refer to:

for SI units: 15.6°C and atmospheric pressure (1.013 barA)

for US units: 60°F and atmospheric pressure (14.73 psiA)

Typically gas flow rates are presented in normal (NTP) or standard (STD) conditions

When converting volumetric flow rate to mass flow rate, then:

Mass Flow Rate = (Volume Flow Rate)*(Density)

$$\frac{kg}{hr} = \frac{Nm^3}{hr} * \frac{1.013 * 10^5 * Mw}{8314 * 288.75}$$

Note: When converting actual flow to flow in normal conditions ([Nm^3/h] or [scfh]), then:

$$q[Nm^3/hr] = q_{act}[m^3/hr] * \frac{p_1 * T_N}{p_N * T_1}$$

where: p_1 = upstream pressure (SI units: [bar A]; US units: [psiA])

T_1 = upstream temperature (SI units: [K]; US units: [°R])

p_N = standard pressure (1.013 barA or 14.73 psiA)

T_N = standard temperature (288.75 K or 519.75 °R)

Table AI.10 Mass Flow Units

		kg/h	lb/hour	kg/s	t/h
kilogram per hour	kg/h	1	2.204586	0.000278	0.001
pound per hour	lb/hour	0.4536	1	0.000126	0.000454
kilogram per second	kg/s	3600	7936.508	1	3.6
ton per hour	t/h	1000	2204.586	0.277778	1

Temperature Units

K = Kelvin

°C = degrees in Celsius

°F = degrees in Fahrenheit

°R = degrees in Rankine

K = °C + 273.15

= (°F + 99.67)/1.8 + 200

= °R/1.8

°C = K – 273.15

= (°F – 32)/1.8

= °R/1.8 – 273.15

°F = (K – 200) * 1.8 – 99.67

= °C * 1.8 + 32

= °R – 459.67

°R = K * 1.8

= (°C + 273.15) * 1.8

= °F + 459.67

Table AI.11 Torque units

		Nm	kgfm	ftlb	inlb
Newton Meter	Nm	1	0.101972	0.737561	8.850732
kilogram force meter	kgfm	9.80665	1	7.233003	86.79603
foot pound	ftlb	1.35582	0.138255	1	12
inch pound	inlb	0.112985	0.011521	0.083333	1

Table AI.12 Dynamic Viscosity units

		cp	poise	lb/(ft*s)	$lbf*s/ft^2$	Ns/m^2
centipoise, mPa*s	cp	1	0.01	0.000672	0.000021	0.001
$g/(cm*s) = dyne*s/cm^2$	poise	100	1	0.067197	0.002089	0.1
pound per foot second	lb/(ft*s)	1488.16	14.8816	1	0.031081	1.48816
pound force sec. per ft^2	$lbf*s/ft^2$	47880	478.8	32.17396	1	47.88
$Ns/m^2 = kg/(ms) = PI$	Ns/m^2	1000	10	0.671971	0.020886	1

Table AI.13 Kinematic Viscosity units

		cs,cSt	St,stoke	ft^2/s	m^2/s
centistoke	cs,cSt	1	0.01	0.000011	0.000001
stoke = cm^2/s*	St,stoke	100	1	0.001076	0.0001
square feet per second	ft^2/s	92903	929.03	1	0.092903
square meter per second	m^2/s	1000000	10000	10.76392	1

Note: Conversion from dynamic viscosity to kinematic viscosity in SI units is:

$$\text{kinematic viscosity } \eta\ [m^2/s] = \frac{\text{dynamic viscosity } \mu\ [Ns/m^2]}{\text{density } \rho\ [kg/m^3]}$$

$$\text{kinematic viscosity } \nu\ [cs] = \frac{\text{dynamic viscosity } \mu\ [cp]}{\text{specific gravity } G_f}$$

Source: FLOW CONTROL MANUAL

Courtesy: Neles-Jamesbury, Helsinki, Finland

Table AI.14 Mean specific heats of selected gases [kcal/m^3 °C]

Temp (°C)	O_2	N_2	H_2	CO	CO_2	AIR
300	0.3126	0.3023	0.3060	0.3048	0.4358	0.3049
400	0.3155	0.3048	0.3092	0.3060	0.4475	0.3075
500	0.3169	0.3073	0.3107	0.3085	0.4593	0.3088
600	0.3198	0.3085	0.3128	0.3098	0.4691	0.3113
700	0.3112	0.3110	0.3148	0.3123	0.4789	0.3126
800	0.3226	0.3123	0.3168	0.3148	0.4888	0.3152
900	0.3255	0.3148	0.3189	0.3160	0.4966	0.3165
1000	0.3269	0.3173	0.3209	0.3185	0.5045	0.3191
1100	0.3298	0.3185	0.3229	0.3198	0.5123	0.3203
1200	0.3312	0.3210	0.3249	0.3223	0.5182	0.3229
1300	0.3326	0.3223	0.3269	0.3248	0.5241	0.3242
1400	0.3355	0.3248	0.3290	0.3260	0.5300	0.3268
1500	0.3369	0.3273	0.3310	0.3285	0.5339	0.3294
1600	0.3397	0.3285	0.3330	0.3310	0.5378	0.3307
1700	0.3412	0.3310	0.3350	0.3323	0.5418	0.3332
1800	0.3426	0.3322	0.3371	0.3348	0.5457	0.3345
1900	0.3469	0.3348	0.3390	0.3360	0.5496	0.3371
2000	0.3483	0.3372	0.3411	0.3385	0.5516	0.3384

Table AI.15 Heat contents of different gases at various temperatures (kcal/kg)

Temp(°C)	H_2O	CO_2	SO_2	CO	N_2	O_2	H_2
800	380.111	199.068	136.859	201.286	201.286	181.125	2828
900	432.277	227.886	156.672	227.893	227.893	205.031	3190.5
1000	486.111	257.204	176.828	254.821	254.821	229.219	3567.5
1100	541.833	286.931	197.265	282.071	282.071	253.687	3949
1200	599.722	316.931	217.890	309.643	309.643	278.437	4335
1300	660.055	347.159	238.672	337.536	337.536	303.469	4725.5
1400	723.277	377.431	259.484	365.750	365.750	328.781	5120.5
1500	789.555	407.681	280.281	394.286	394.286	354.375	5520
1600	859.444	437.931	301.078	423.143	423.143	380.250	5924
1700	933.388	469.090	322.500	452.321	452.321	406.406	6332.5
1800	1011.611	500.318	343.968	481.821	481.821	432.844	6745.5
1900	1094.833	531.613	365.484	511.643	511.643	459.562	7163
2000	1183.333	562.954	387.031	541.786	541.786	486.562	7585
2100	1277.722	594.250	408.547	572.250	572.250	513.844	8011.5
2200	1378.666	625.590	430.094	603.036	603.036	541.406	8442.5
2300	1486.444	656.863	451.593	634.143	634.143	569.250	8878
2400	1602.000	688.091	473.062	665.571	665.571	597.375	9318
2500	1725.666	719.318	494.531	697.321	697.321	625.781	9762

Conversion Factor

kcal/kg ⟶ kJ/kg Multiply by 4.187

Table AI.16 Characteristics of Other Solid Fuels

Fuel	Heating Value Btu	Proximate Analysis				Ultimate Analysis						
		% Moist	% Ash	% Vol.	% FC	% H_2	% C	% N_2	% O_2	% S	% Moist	% Ash
Wood waste	8,900*	25-60	1.0*	82.0*	17.0*	6.2*	50.3*	0.04*	43.1*	–	–	0.4
Peat	3,586	56.7	6.0	26.1	11.2	8.3	21.0	1.1	62.9	–	–	–
Coke	12,600*	8.5	12.5	1.0*	86.5*	–	–	–	–	0.9	–	–
Coke breeze	9,500	6.5	25.0	3.4	65.1	–	–	–	–	–	–	–
Oil shale	6,300*	15.0	43.0	42.0	–	–	–	–	–	–	–	–
Pulv'd pitch	16,000	0.2	0.1	53.8	46.1	4.1	93.7*	1.0*	0.7*	0.5*	0.1	0.1
Tanbark	8,000*	30-60	–	–	–	6.0	50.0	40.0	–	–	–	4.0
Bagasse	8,300*	–	–	–	–	5.8	46.3	0.3	45.8	–	–	1.8
Rice hulls	6,100	7.4	19.8	59.0	13.8	–	–	–	–	–	–	–
Sewage Sludge	7,500	20	26.9	47.6	5.5	5.0	37.0	1.5	8.9	0.7	20.0	26.9
Straw	56-6700	–	–	–	–	5.0	36.0	0.5	38.0	–	15.7	4.8

* Indicates analysis on dry basis all others "as fired" or "as received". FC abbreviation for fixed carbon.

Table AI.17 Theoretical Combustion Data

Substance	Formula	Theoretical Required (lb.)		Theoretical Products of Combustion (lb.)				
		O_2	Air	CO_2	CO	N_2	H_2O	SO_2
Carbon burned to carbon monoxide	C	1.33	5.75	–	2.33	4.42	–	–
Carbon burned to carbon dioxide	C	2.67	11.49	3.67	–	8.82	–	–
Carbon monoxide burned to carbon dioxide	CO	0.57	2.46	1.57	–	1.89	–	–
Sulphur	S	1.00	4.31	–	–	3.31	–	2.00
Hydrogen	H_2	8.00	34.48	–	–	26.48	9.00	–
Hydrogen sulphide	H_2S	1.41	6.09	–	–	4.68	0.53	1.88
Methane	CH_4	4.00	17.24	2.75	–	13.24	2.25	–
Acetylene	C_2H_2	3.08	13.26	3.38	–	10.18	0.69	–
Ethylene	C_2H_4	3.43	14.78	3.14	–	11.35	1.29	–
Ethane	C_2H_6	3.73	16.09	2.93	–	12.36	1.80	–

Substance	Formula	Theoretical Required (lb.)		Theoretical Products of Combustion (lb.)				
		O_2	Air	CO_2	CO	N_2	H_2O	SO_2
Carbon Monoxide	CO	0.5	2.38	1.0	–	1.88	–	–
Hydrogen	H_2	0.5	2.38	–	–	1.88	1.0	–
Hydrogen sulphide	H_2S	1.5	7.14	–	–	5.64	1.0	1.0
Methane	CH_4	2.0	9.52	1.0	–	7.52	2.0	–
Acetylene	C_2H_2	2.5	11.91	2.0	–	9.41	1.0	–
Ethylene	C_2H_4	3.0	14.29	2.0	–	11.29	2.0	–
Ethane	C_2H_6	3.5	16.67	2.0	–	13.17	3.0	–

Source: Boiler Tube Facts

Courtesy: Senior Boiler Tube Co.

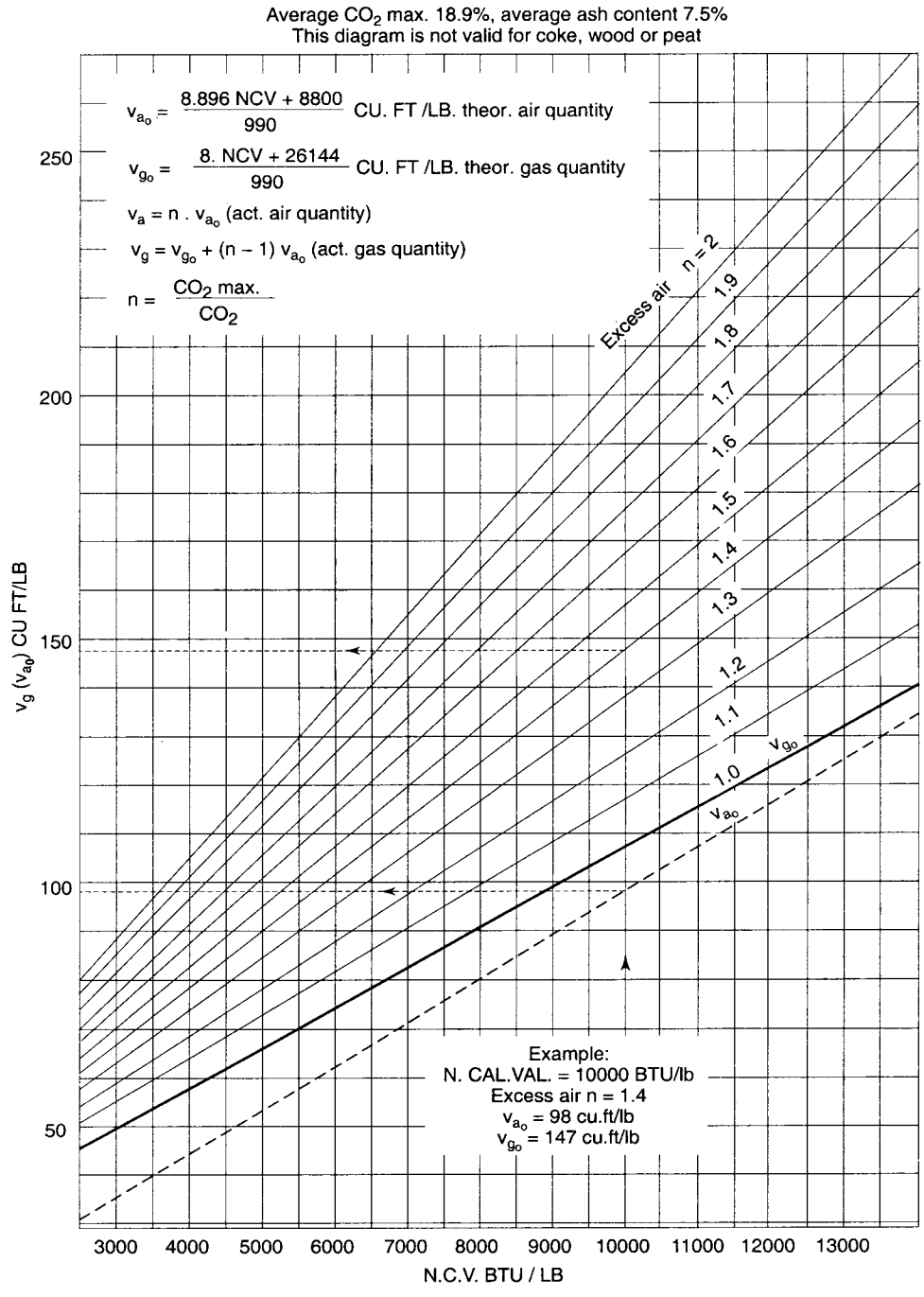


Fig. AI.1 *Waste gases and air requirements for solid fuels (Acc. To W. Boie).*

Source: Boiler Tube Facts
Courtesy: Senior Boiler Tube Co.

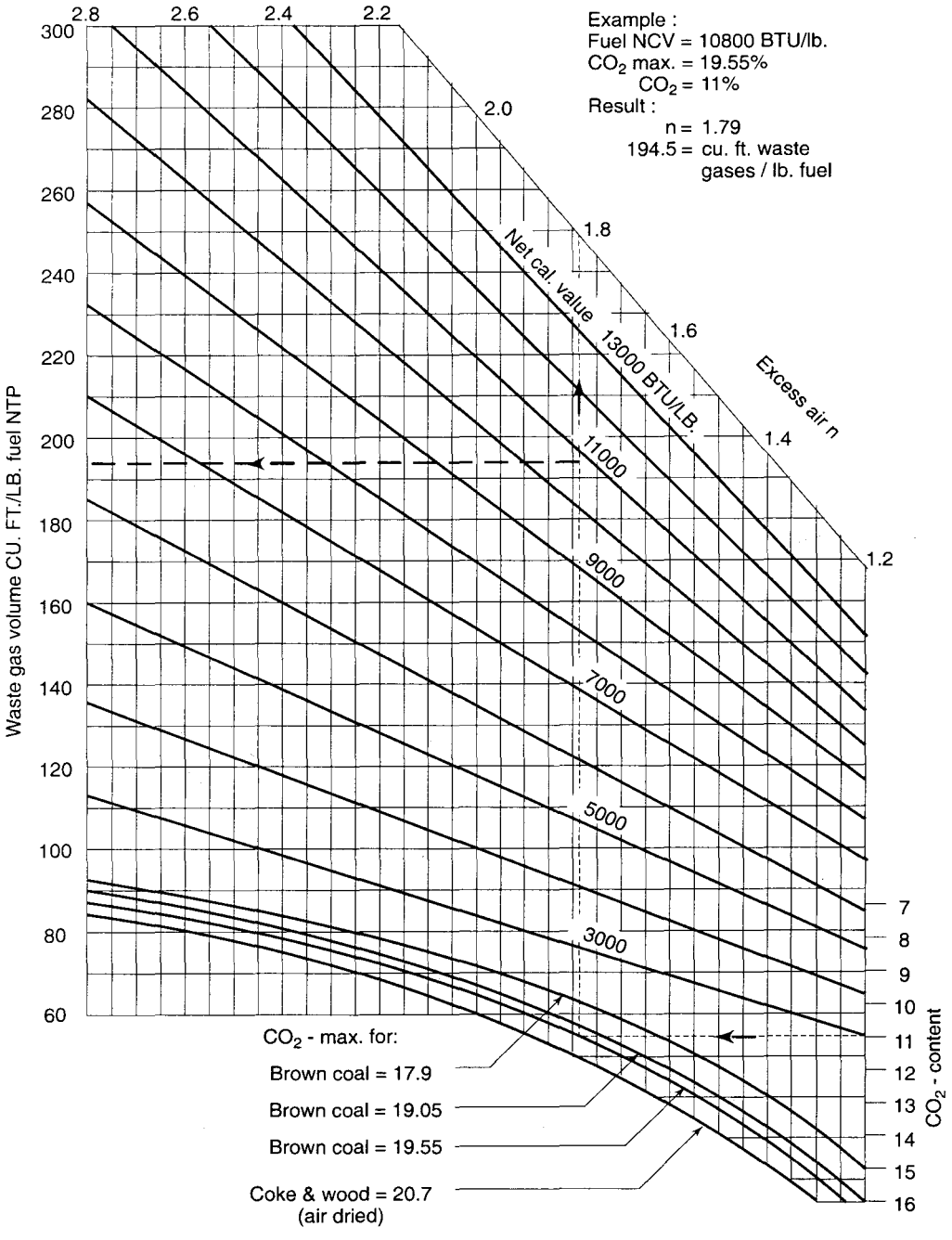


Fig. AI.2 *Waste gas volume for coke & wood.*

Source: *Boiler Tube Facts*
Courtesy: *Senior Boiler Tube Co.*

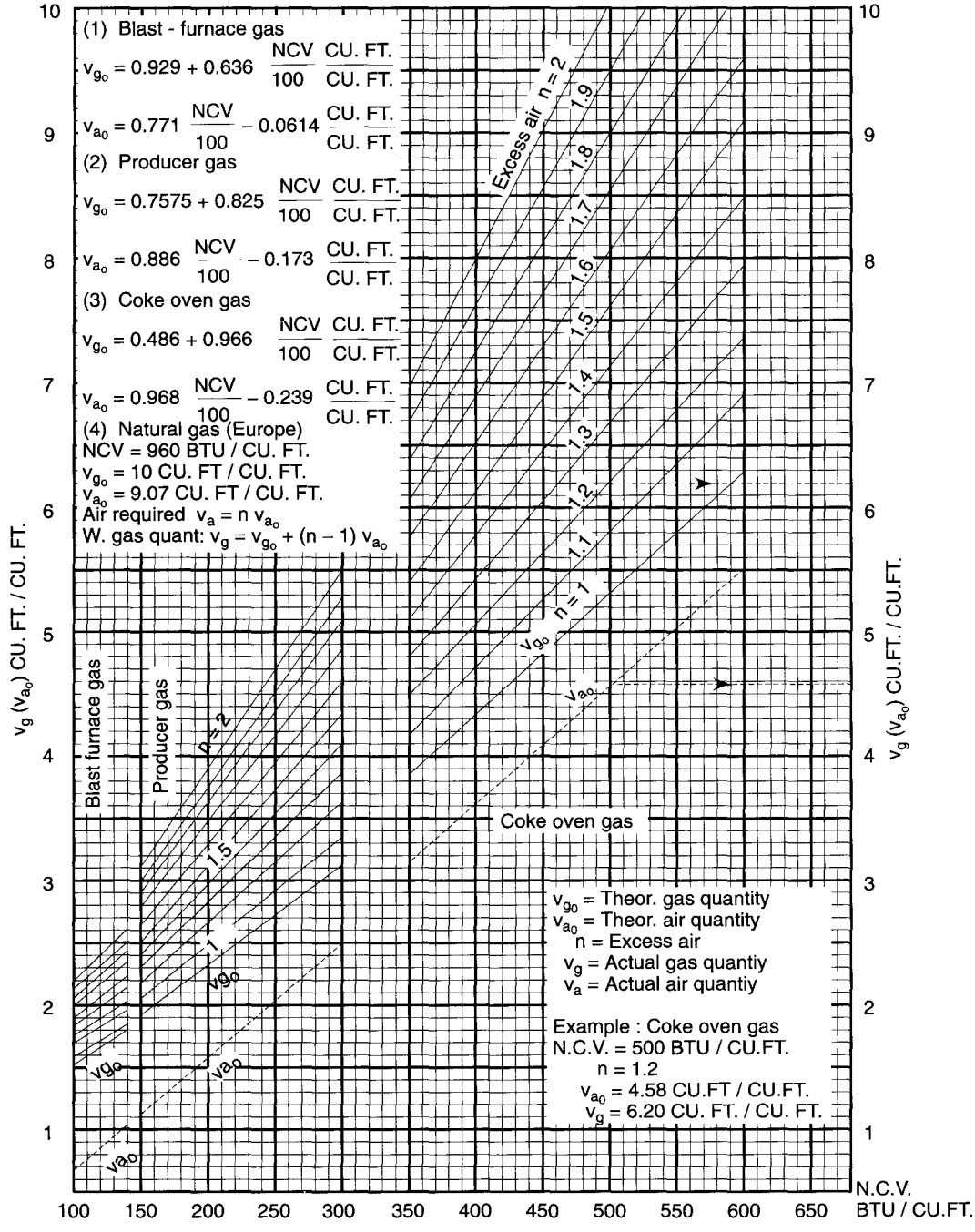
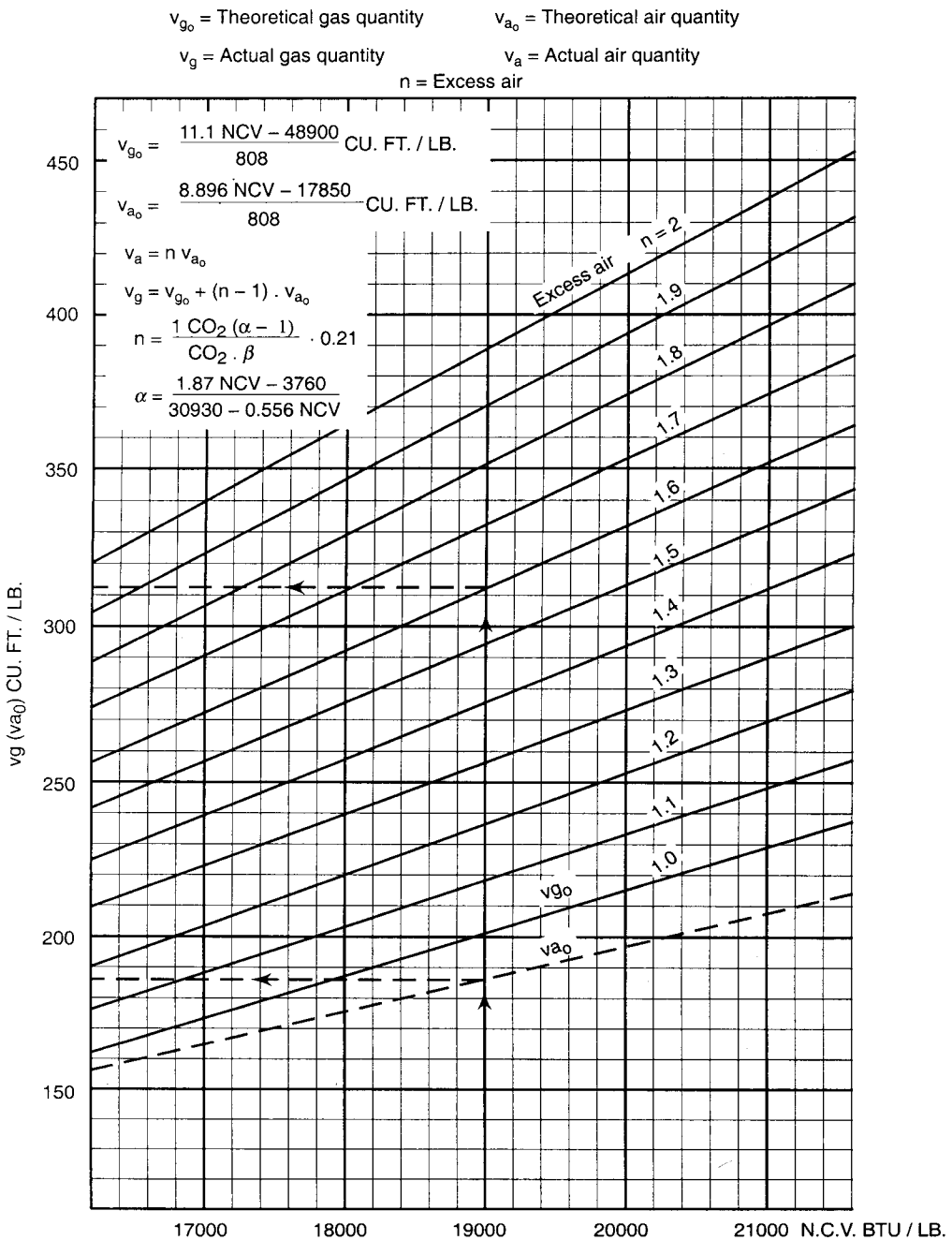


Fig. AI.3 *Waste gases and air requirements for gaseous fuels (Acc. To K. Rummel).*

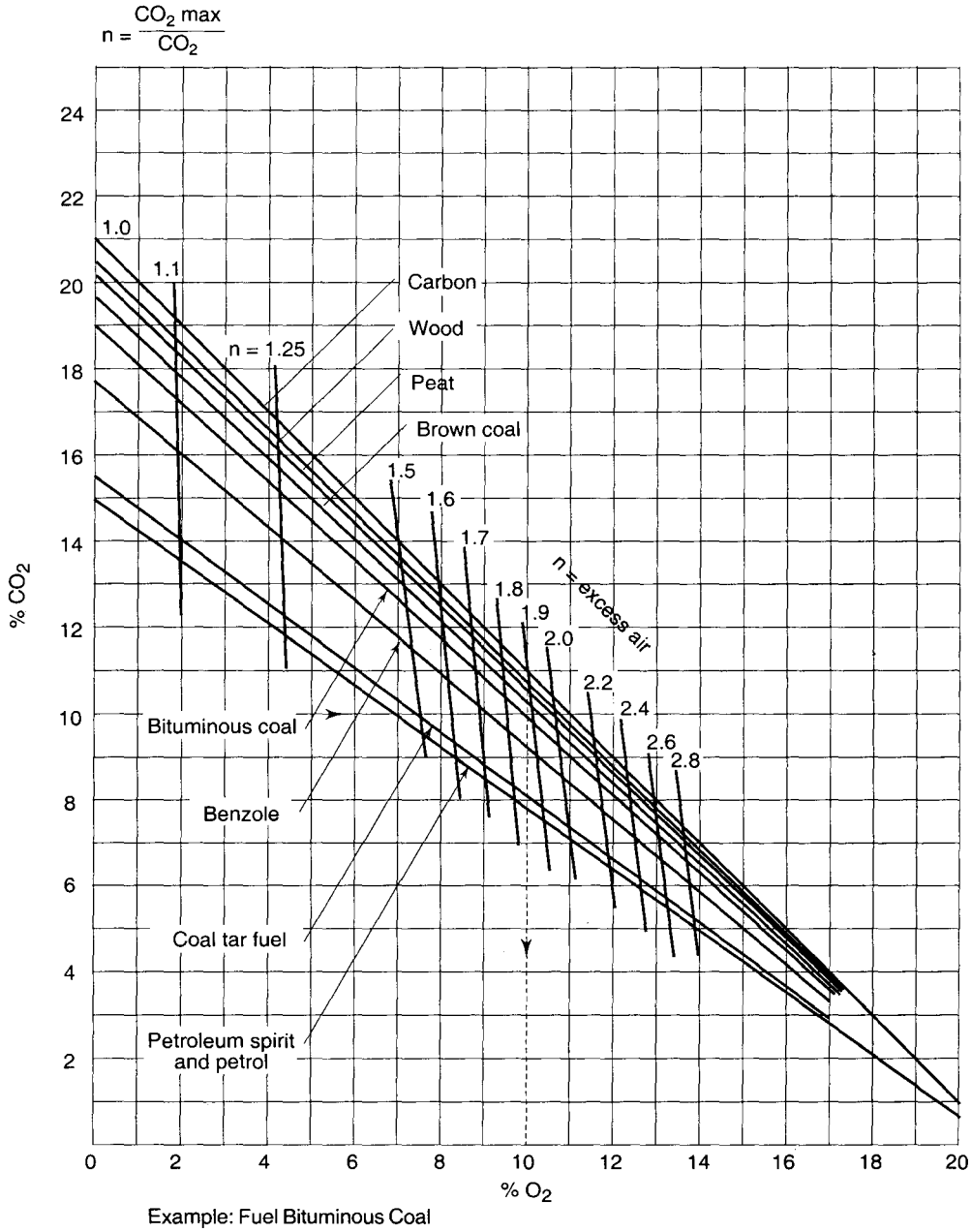
Source: *Boiler Tube Facts*
Courtesy: *Senior Boiler Tube Co.*



Example: NCV = 19000 BTU / LB. n = 1.6 v_g = 313 CU. FT. / LB. v_{a_o} = 186 CU. FT. / LB.

Fig. AI.4 *Waste gases and air requirements for liquid fuels (Acc. To W. Boie).*

Source: Boiler Tube Facts
Courtesy: Senior Boiler Tube Co.



Example: Fuel Bituminous Coal

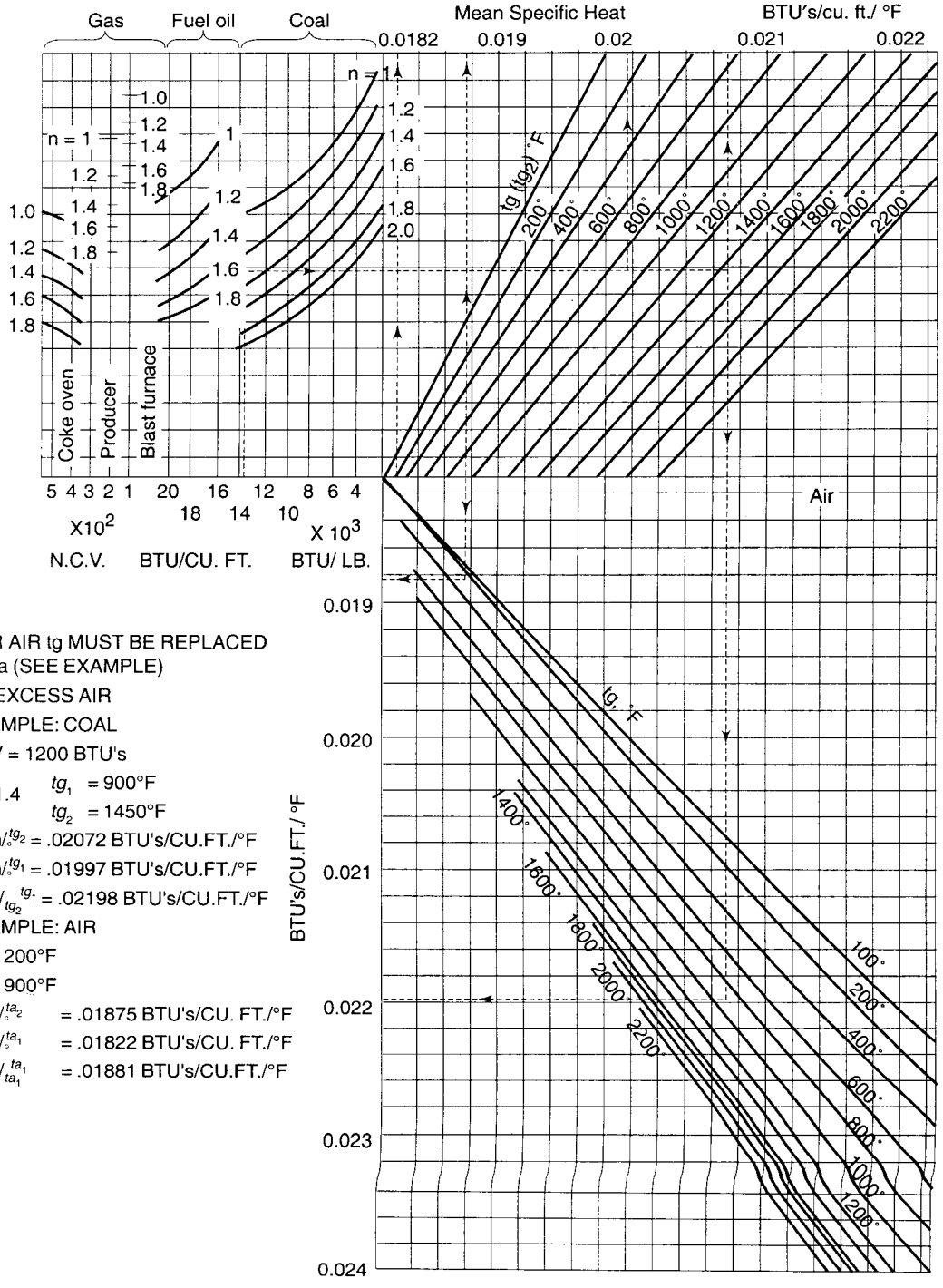
CO_2—Content of the Waste Gases 10% (Measured)

Result: n = 1.9

O_2 = 10% Oxygen in the Waste Gases

Fig. AI.5 *Excess Air, CO_2—and O_2—content of the waste gases for solid and liquid fuels.*

Source: Boiler Tube Facts
Courtesy: Senior Boiler Tube Co.



FOR AIR tg MUST BE REPLACED BY ta (SEE EXAMPLE)

n = EXCESS AIR

EXAMPLE: COAL

NCV = 1200 BTU's

n = 1.4 tg_1 = 900°F

tg_2 = 1450°F

cpm/$^{tg_2}_{\circ}$ = .02072 BTU's/CU.FT./°F

cpm/$^{tg_1}_{\circ}$ = .01997 BTU's/CU.FT./°F

cpm/$^{tg_1}_{tg_2}$ = .02198 BTU's/CU.FT./°F

EXAMPLE: AIR

ta_1 = 200°F

ta_2 = 900°F

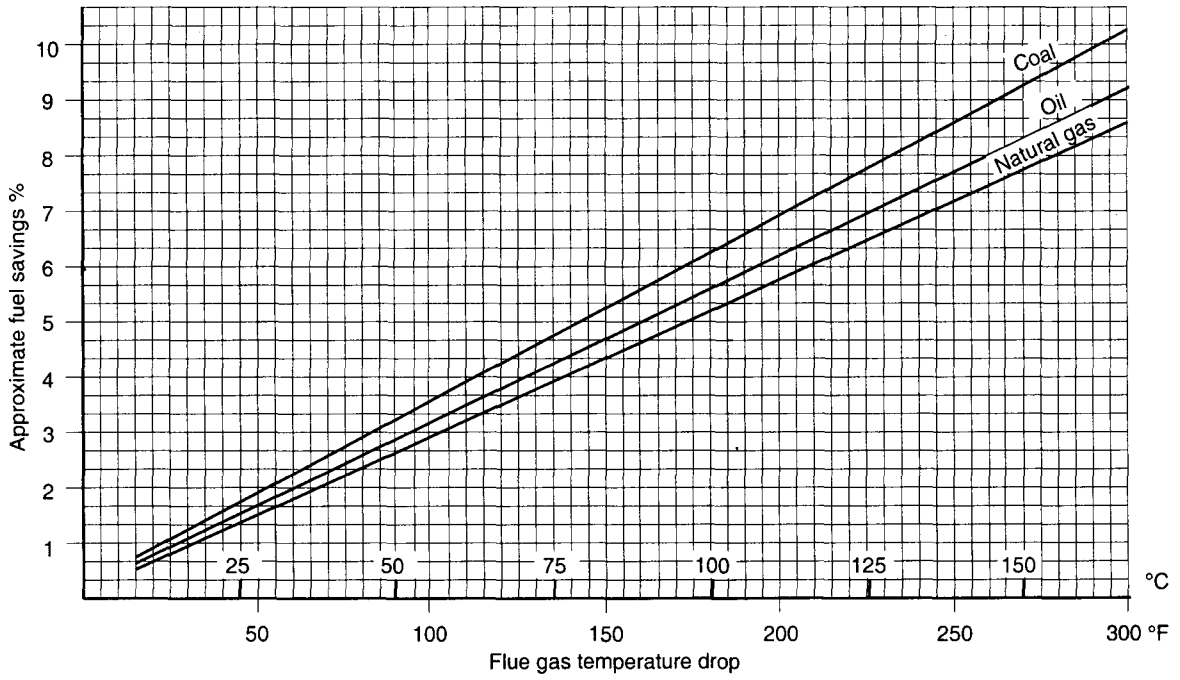
cpm/$^{ta_2}_{\circ}$ = .01875 BTU's/CU. FT./°F

cpm/$^{ta_1}_{\circ}$ = .01822 BTU's/CU. FT./°F

cpm/$^{ta_1}_{ta_1}$ = .01881 BTU's/CU.FT./°F

Fig. AI.6 *Mean specific heat of waste gases and air (Acc. to Justi).*

Source: *Boiler Tube Facts*
Courtesy: Senior Boiler Tube Co.



Approximate Comparison of Fuel Savings and Flue Gas Temperature Drop (Alternatively an increase in evaporation may be obtained)

Fig. AI.7 *Economizer Fuel Savings.*

Source: Boiler Tube Facts

Courtesy: Senior Boiler Tube Co.

Table AI.18 Maximum working pressure for water tube boilers

Maximum allowable working pressures for seamless steel and electric resistance welded steel tubes or nipples for watertube boiler, where expanded into drums for headers, for different diameters and gages of tubes conforming to the requirements of specifications SA-178 Grade A. SA-192, and SA-226

Wall Thickness	Nearest Bwg	Tube Outside Diameter, in																
in	No	1/2	3/4	1	1 1/6	1 1/4	1 1/2	1 3/4	2	2 1/4	2 1/2	2 3/4	3	3 1/4	3 1/2	3 3/4	4	4 1/2	5
0.055	17 -	590	350																
0.065	16	1090	670	470	410	350													
0.075	15 +	1600	1000	720	620	550	430												
0.085	14 +		1340	960	840	740	590	490	410										
0.095	13				1990	1760	760	630	530	460	400	350							
0.105	12 –					1980	1600	1340	1150	570	500	440	390						
0.120	11						1870	1570	1340	1170	1040	930	840	460	420	390			
0.135	10 +							1790	1540	1340	1190	1060	960	880	800	740	680		
0.150	9 +							2020	1740	1520	1340	1200	1090	990	910	840	780	670	590
0.165	8								1940	1690	1500	1340	1210	1100	1020	940	870	760	670
0.180	7									1870	1660	1480	1340	1220	1120	1040	960	840	740
0.200	6 –										1870	1670	1520	1380	1270	1170	1090	950	840
0.220	5											1870	1690	1540	1420	1310	1210	1060	940
0.240	4 +												1870	1700	1570	1450	1340	1170	1040
0.260	3 +													1870	1720	1590	1470	1290	1140
0.280	2 –													2040	1870	1730	1600	1400	1240
0.300															2020	1870	1740	1520	1340
0.320																2010	1870	1630	1450
0.340																	2000	1750	1550
0.360																		1870	1660
0.380																		1990	1760
0.400																			1870
0.420																			1980

Source: *Boiler Tube Facts*
Courtesy: Senior Boiler Tube Co.

Table AI.19 Decimal & millimeter equivalents of B.W.G.and fractions for round seamless steel tubing

BWG or Fraction	Decimal	MM	BWG or Fraction	Decimal	MM	BWG or Fraction	Decimal	MM	BWG or Fraction	Decimal	MM
36	0.004	0.101	20	0.035	0.889	9	0.148	3.75	11/32	0.334	8.73
35	0.005	0.127	19	0.042	1.06	5/32	0.156	3.96	3/8	0.375	9.52
34	0.007	0.177	3/64	0.047	1.19	8	0.165	4.19	00	0.380	9.65
33	0.008	0.203	18	0.049	1.24	11/64	0.172	4.36	000	0.425	10.8
32	0.009	0.228	17	0.058	1.47	7	0.180	4.57	7/16	0.438	11.12
31	0.010	0.254	1/16	0.063	1.6	3/16	0.188	4.77	0000	0.454	11.53
30	0.012	0.304	16	0.065	1.65	13/64	0.203	5.15	1/2	0.500	12.7
29	0.013	0.330	15	0.072	1.82	6	0.203	5.15	17/32	0.531	13.48
28	0.014	0.355	5/64	0.078	1.98	7/32	0.219	5.56	9/16	0.563	14.3
1/64	0.016	0.406	14	0.083	2.10	5	0.220	5.58	19/32	0.594	15.1
27	0.016	0.406	3/32	0.094	2.38	4	0.238	6.04	5/8	0.625	15.87
26	0.018	0.457	13	0.095	2.41	1/4	0.250	6.35	11/16	0.688	17.47
25	0.020	0.508	7/64	0.109	2.76	3	0.259	6.57	3/4	0.750	19
24	0.022	0.558	12	0.109	2.76	9/32	0.281	7.13	13/16	0.813	20.65
23	0.025	0.635	11	0.120	3.04	2	0.284	7.21	7/8	0.875	22.22
22	0.028	0.711	1/8	0.125	3.17	1	0.300	7.62	15/16	0.938	23.82
1/32	0.031	0.787	10	0.134	3.4	5/16	0.313	7.95	1	1.000	25.4
21	0.032	0.812	9/64	0.141	3.58	0	0.340	8.63			

Source: *Boiler Tube Facts*
Courtesy: *Senior Boiler Tube Co.*

Table AI.20 Mean specific heats of gases at constant pressure

From 32°F to 1°F in B. TH. U./LB/°F

Temp. (t°C)	Temp. (t°F)	Air	N_2 and CO	O_2	CO_2	Steam	H_2
100	212	0.2406	0.2490	0.2179	0.2034	0.5048	3.409
200	392	0.2410	0.2494	0.2182	0.2080	0.4964	3.426
300	572	0.2414	0.2498	0.2186	0.2126	0.4909	3.443
400	752	0.2419	0.2504	0.2191	0.2171	0.4881	3.461
500	932	0.2425	0.2510	0.2196	0.2219	0.4871	3.478
600	1112	0.2432	0.2517	0.2202	0.2256	0.4873	3.496
700	1292	0.2439	0.2524	0.2209	0.2297	0.4888	3.513
800	1472	0.2447	0.2533	0.2217	0.2336	0.4913	3.530
900	1652	0.2457	0.2543	0.2225	0.2374	0.4949	3.548
1000	1832	0.2466	0.2552	0.2233	0.2410	0.5000	3.565
1100	2012	0.2477	0.2563	0.2243	0.2445	0.5050	3.582
1200	2192	0.2488	0.2575	0.2253	0.2478	0.5112	3.600
1300	2372	0.2499	0.2587	0.2264	0.2510	0.5185	3.617

(Contd)

Temp. (t°C)	Temp. (t°F)	Air	N_2 and CO	O_2	CO_2	Steam	H_2
1400	2552	0.2512	0.2600	0.2275	0.2540	0.5268	3.635
1500	2732	0.2525	0.2613	0.2287	0.2569	0.5357	3.652
1600	2912	0.2539	0.2628	0.2299	0.2596	0.5458	3.669
1700	3092	0.2554	0.2643	0.2313	0.2621	0.5566	3.687
1800	3272	0.2569	0.2659	0.2327	0.2645	0.5666	3.704
1900	3452	0.2585	0.2675	0.2341	0.2668	0.5790	3.721
2000	3632	0.2602	0.2693	0.2356	0.2689	0.5911	3.739

CALCULATION OF HEATING VALUES FOR LIQUID AND GAS FUELS

I. LIQUID FUELS—**(Uncracked Distillate or Residue)**

A. H_F = Gross heating value = 17,600 + 69(A.P.I. Deg.), (Btu/lb.)

(Cracked Distillate)

B. H_F = Gross heating value = 17,780 + 54 (A.P.I. Deg.), (Btu/lb.)

Note: Avg., Difference between gross and net heating values of fuel oils is 6%

II. GASEOUS FUELS

A. Paraffin hydrocarbons ($C_N H_{2N+2}$)

$$\frac{\text{BTU}}{\text{Cu. Ft. Gas}} = 745N + 258 = \text{Gross heating value}$$

B. Unsaturated hydrocarbons ($C_A H_B$)

$$\frac{\text{BTU}}{\text{Cu. Ft. Gas}} = 459\,A + 132\,B + 135 = \text{Gross heating value}$$

Table AI.21 Table of Heating Values for Typical Fuels

FUEL	Gross Heating Value BTU/CU.FT.for Gases BTU/LB. for Liquids	Net Heating Value BTU/CU.FT.For Gases BTU/LB. For Liquids
Natural Gas	1097	993
Coke Oven Gas	561	500
Raw Prod. Gas	147	137.3
Clean Prod. Gas	138	129
Towns Gas	545	499
Commercial Butane	3190	2935
Blue Water Gas	301	276
Blast Furnace Gas	92.3	90.6
Commercial Propane	2550	-
Ethane	1760	-
No. 1 Fuel Oil	19,800	18,650
No. 2 Fuel Oil	19,600	18,400
No. 3 Fuel Oil	19,350	18,350
No. 6 Fuel Oil	18,300	17,340

Source: Boiler Tube Facts
Courtesy: Senior Boiler Tube Co.

Appendix II

Water Characteristics, Deaeration, Cooling Water Treatment and Cooling Tower Calculations

Table AII.1 Internal treatment of boiler feedwater by chemicals

Corrective Treatment Required	Chemicals to be Dosed
Adjustment of feedwater pH and maintaining boiler water alkalinity to inhibit scaling and corrosion	Soda ash/ Caustic soda/ Sulphuric acid
Internal softening of BFW to prevent scaling	Soda ash/ Phosphates/ Sodium aluminate/ Sodium silicate
Boiler sludge conditioning	Tannins/ Lignin derivatives/ Starch/ Glucose derivatives
Protecting evaporators, stage heaters and pipelines from scaling from hot water	Polyphosphates/ Glucose derivatives/ Lignin derivatives/ Tannins
Chemical deaeration of BFW to inhibit O_2-corrosion	Hydrazine/ Sulphites/ Ferrous hydroxide/ Tannins/ Glucose derivatives
Inhibition of caustic embrittlement	Phosphates/ Nitrates/ Sodium sulphate/ Tannins
Prevention of foaming of BFW	Polyamides/ Polyalkylene glycols
Protective film formation to prevent corrosion	Tannins/ Lignins/ Glucose derivatives
Prevention of corrosion by condensate	Ammonia/ EDTA

Table AII.2 BFW specifications for natural circulation boiler

Water Quality Characteristics	Working Pressure (MN/m^2) up to 4	up to 10	above 10
pH at 298K	9–9.2	9–9.2	9–9.2
Total hardness (μg.equiv/kg)	10(max)	3–5	1
Silica (ppm)	—	0.08	0.04
Dissolved Oxygen (ppm)	0.02–0.03	0.02–0.03	0.01–0.02
Dissolved CO_2 (ppm)	Nil	Nil	Nil
Hydrazine (ppm)	0.02–0.06	0.02–0.06	0.02–0.06
Dissolved Ammonia (ppm)	1	1	1

(Contd)

Dissolved NO_2 (ppm)	—	0.02(max)	0.02(max)
$NO_2^- + NO_3^-$ (ppm)	—	0.02(max)	0.02(max)
Fe(ppm)	0.1–0.2	0.05–0.1	0.02–0.03
Cu(ppm)	0.01–0.02	0.01–0.02	0.005 (max)
Oil (ppm)	1	0.03	0.03

Table AII.3 BFW specifications for once-through boiler units

Water Quality Characteristics	Amount
pH at 298 K	9–9.2
Total Hardness	0.0002
Silica (ppm)	0.015
Dissolved oxygen (ppm)	0.01
Iron (ppm)	0.01
Copper (ppm)	0.005
Hydrazine (excess) (ppm)	0.02–0.06
Oil (ppm)	0.1
Na^+ ions (ppm)	0.005

CHARACTERISTICS OF NATURAL WATER

pH

The pH value of water is defined as the negative logarithm of hydrogen ion concentration to the base 10, the H^+ ion concentration being measured in kg-equivalent per m^3 or gm-equivalent per litre.

$$pH = -\log_{10} [H^+]$$

At 25°C, pure water has a concentration of H^+ ions of 10^{-7} kmol/m^3 and a concentration of OH^- ions of 10^{-7} kmol/m^3. And therefore, the product of $[H^+]$ and $[OH^-]$ ions is 10^{-14} and that means, for pure water

$$pH = 7 \text{ and } pOH = 7$$

and

$$pH + pOH = 14$$

In other words, the pH value is a number between 0 and 14 which indicates the degree of acidity or alkalinity of water. A pH value equal to 7 means the water is neutral, since it contains the same concentration of H^+ ions as OH^- ions. When pH is less than 7, the water is distinctly acidic as it contains more H^+ ions than OH^- ions. For example, if pH = 5, then pOH value of the solution will be pOH= 14 – 5 = 9 and therefore $[OH^-] = 10^{-9}$ kmol/m^3, which is less than the OH^- ion concentration when the water is neutral. Similarly if pH is greater than 7, the water is alkaline.

Alkalinity

It is the total load of that much part of total dissolved solids (TDS) in water which contribute to the increase of the hydroxyl ions concentration in water as a result of hydrolysis or dissociation.

The alkalinity of natural waters is usually due to the presence of HCO_3^{1-}, SiO_3^{2-}, $HSiO_3^-$ and sometimes CO_3^{2-} as well as due to the presence of PO_4^{3-}, HPO_4^{2-} and of OH^- ions. These anions of weak acids undergo hydrolysis to add OH^- ions to water

$$SiO_3^{2-} + H_2O \rightleftharpoons HSiO_3^- + OH^-$$

$$PO_4^{3-} + H_2O \rightleftharpoons HPO_4^{2-} + OH^-$$

Depending upon the anion that is present in water, the alkalinity is classified. For example:

bicarbonate alkalinity is due to the presence of HCO_3^- ions

carbonate alkalinity is due to the presence of CO_3^{2-} ions

hydrate alkalinity is due to the presence of OH^- ions.

The alkalinity of water is usually determined by using methyl orange or phenolpthalein as an indicator. Accordingly, M-alkalinity and P-alkalinity have been distinguished. M-alkalinity refers to total alkalinity.

These two alkalinities are interrelated differently depending upon the nature of alkalinity. For example:

1. for a solution of NaOH
   M-value = P-value
2. for a solution of Na_2CO_3
   M-value = 2P-value

3. for a solution of only bicarbonates

P-value = nil

In some literature, the methyl orange alkalinity, phenolpthalein alkalinity, carbonate alkalinity, bicarbonate alkalinity, etc., are conveniently represented by A_{mo}, A_{ph}, A_c, A_b respectively and accordingly $A_{mo} = A_h + A_c + A_b$

$$A_{ph} = A_h + \frac{1}{2}A_c$$

where

A_h = hydrate alkalinity.

Hardness

The total hardness is defined as the sum of the concentration of calcium (Ca^{2+}) and magnesium (Mg^{2+}) ions present in the water. It is expressed in milligram-equivalents per kilogram (mg-equiv./kg) or microgram-equivalents per kilogram (μg-equiv/kg)

$H_t = H_{Ca} + H_{Mg}$

Hardness is due to the presence of calcium and magnesium salts—bicarbonates, carbonates, sulphates, chlorides and nitrates. And sometimes the presence of aluminium, iron and manganese salts causes water to be hard, but normally these substances are not found in appreciable quantities in natural water.

Therefore, it has become customary to divide hardness into two main types = carbonate and non-carbonate hardness.

Carbonate hardness is due to the presence of calcium, magnesium carbonates and bicarbonates.

Non-carbonate hardness is due to the presence of calcium, magnesium sulphates and chlorides

$$H_t = H_c + H_{nc} = H_{Ca} + H_{Mg}$$

where H_c = carbonate hardness

H_{nc} = non-carbonate hardness

Soft-water features only a total or residual hardness H_t.

The presence of sodium compounds in water does not contribute to its hardness.

Total Solids

It is the net load of non-volatile substances present in water in a colloidal as well as a molecular dispersed state. It is expressed in mg/kg of water.

Total solids is determined by evaporating an unfiltered sample of water to dryness, heating the leftover residue at 380-390K to constant weight. The amount of these substances related to 1 kg of water is the measure of total solids.

Total Dissolved Solids

It refers to the content of dissolved non-volatile substances in water. It is expressed in mg/kg.

It is determined by evaporating a filtered sample free from any suspended matter and drying the residue to constant weight at 380-390K. The amount of these substances related to 1 kg of water gives the total dissolved solids (TDS).

Total dissolved solids can also be determined by measuring the specific conductance or conductivity, of the water.

Total Suspended Solids

It is the amount of non-volatile substances distributed in water in a colloidal state. It is expressed in mg/kg. It is determined from the relation

TSS = TS – TDS

Oxidability

This parameter indicates, to some extent, the degree of contamination of water by organic substances. It is the amount of oxygen required to oxidize, under given conditions, the organic substances contained in a 1 kg water sample and is expressed in milligrams of oxygen/kg of water (mg O_2/kg). Since potassium permanganate is used as the oxidizing agent, oxidability can also be expressed by the quantity of $KMnO_4$, in mg/

kg of water, expended to oxidize the organic substances in the water.

It is important to note that oxidability is not identical to the content of organic substances in water, since no complete oxidization of all the organic substances present in water takes place under the conditions in which oxidability is determined.

Transparency

It characterizes the concentration of total suspended solids in raw water, but it gives only a rough estimate of the TDS, which must be determined by the weight method for accuracy.

It is determined in terms of the height of a water column (cm) held in a glass tube through which it is still possible to read printing or discern two crossed black lines 1 mm thick on a white paper placed underneath the glass tube.

Silica Content

It is the concentration of silicic acid H_2SiO_3 (expressed as SiO_2) in raw water. This silicic acid is produced due to hydrolysis of silicates—salts of a weak acid.

$$SiO_3^{2-} + 2H_2O \rightleftharpoons H_2SiO_3 + OH^-$$

and the process is accelerated at low pH. This silicic acid exists predominantly in a colloidal state which cannot be removed by the processes of settling and filtration. It is only partially removed by the precipitation of hydroxides (iron, aluminium, etc.). Because of its slippage, silica is carried over to boiler feedwater and due to its solubility in steam at higher pressures (4 MN/m^2 and above) and temperature, it is carried over to steam turbines and causes nozzle and blade deposition therein. That is why modern steam generation plants are equipped with demineralization units where silica content in water is reduced to as low as 0.01–0.02 ppm. However, since silicic acid lends itself to removal by the ion exchange process only in the ionic state ($HSiO_3^-$), the presence of colloidal silica complicates the overall desilication process.

ANALYTICAL PROCEDURES

Determination of P-Alkalinity

If the raw water sample contains alkaline hydroxides, carbonates, phosphates and silicates, it will turn pink when a few drops of phenolpthalein indicator are added.

To a measured 100 ml of filtered sample of raw water taken in a flask placed over a white sheet of paper, four drops of neutral phenolpthalein indicator are added. If a pink colour is developed the sample is titrated with 0.02N sulphuric acid solution from a burette. The acid should be added slowly dropwise, the solution well-stirred and the titration carried out till the endpoint is reached, i.e. until the pink colour just disappears.

P-alkalinity (as $CaCO_3$) in ppm

$$= \frac{\text{ml. of Acid}}{\text{ml. of Sample}} \times 1000$$

Example: A 100-ml sample of water requires 8 ml of 0.02N sulphuric acid for complete neutralization. Determine it P-alkalinity.

Solution P-value $= \frac{8}{100} \times 1000 = 80$ ppm.

Determination of M-Alkalinity If the raw water sample does not develop pink color when phenolpthalein indicator is added but turns yellow when methyl orange indicator is added, then the sample contains no alkaline hydroxides or carbonates but bicarbonates, phosphates, etc. M-alkalinity determines total alkalinity.

To a measured 100 ml of filtered sample taken in a flask placed over a white sheet of paper 2 to 4 drops of methyl orange indicator are added to get a distinct straw yellow color. The sample is titrated with 0.02N sulphuric acid from the burette. The acid is added dropwise and slowly and the solution is stirred well. The endpoint is marked by the appearance of a faint pink colour.

M-alkalinity (as $CaCO_3$) is ppm

$$= \frac{\text{ml of Acid}}{\text{ml of Sample}} \times 1000$$

Example: A 100-ml sample of water takes 15 ml of 0.02N H_2SO_4 solution for complete neutralization. Determine its M-alkalinity.

Solution M-alkalinity $= \frac{15}{100} \times 1000 = 150$ ppm.

Determination of Hydroxide Alkalinity If the raw water is practically free of silicates, aluminates and organic matter or present in a small percentage in comparison to hydroxide, the following volumetric method may be used.

To a 100 ml filtered sample taken in a flask placed atop a white sheet of paper, 5 drops of barium chloride solution, [100 gm of $BaCl_2$. $2H_2O$ in 1000 ml of water] are added to precipitate out the carbonate and sulphate ions.

Two to three drops of phenolpthalein indicator are added and the sample is titrated with 0.02N HCl solution from a burette until the pink colour just disappears.

$$\text{OH-alkalinity in ppm} = \frac{\text{ml of Acid}}{\text{ml of Sample}} \times 340$$

Example: A 100 ml sample of raw water requires 6 ml of 0.02N HCl for neutralization. Determine its hydroxide alkalinity.

Solution

$$\text{OH-alkalinity} = \frac{6}{100} \times 340 = 20.4 \text{ ppm OH}$$

Determination of Total Hardness

To a 50 ml sample of clean raw water neutralized by adding drops of 0.1N NaOH or 0.1N H_2SO_4 solution as required, standard soap solution is added from a burette in small increments (0.2 ml at a time) and the bottle is shaken vigorously after each addition. When a permanent foam begins to form, soap solution is added in 0.1 ml increments and shaken as before until with further shaking a foam persists over the surface of water for a period of 5 minutes. Soap solution consumed is recorded.

After this point, a test for a false endpoint is done by adding 0.2 ml more of the solution and then shaking. If the foam disappears, the titration is continued to a final endpoint.

Total Hardness (as $CaCO_3$)

= (ml Soap Solution – ml of Foam Factor) × (Hardness Factor)

Standard Soap Solution 100 gms of powdered castile soap is dissolved in 1000 ml of enthyl alcohol (80%), the solution is allowed to stand overnight and decanted. A portion of the stock solution is diluted with ethyl alcohol (80%) until, when titrated against $CaCl_2$ solution, 1 ml of resulting dilution is equivalent to 1 ml of the standard $CaCl_2$ solution. Accordingly, the rest of the soap solution is diluted.

1 ml of Soap Solution—Foam Factor = 1 mg $CaCO_3$

Foam Factor of the soap solution is determined by adding small quantities of soap solution to 50 ml of freshly boiled and cooled distilled water until a stable foam is formed after shaking. Milliliters of soap solution used is the foam factor.

Hardness Factor is determined by adding 5 ml of standard hard water to 45 ml of freshly boiled and cooled distilled water. The mixture is adjusted to phenolpthalein endpoint, and then titrated with small increments of soap solution and shaken vigorously after each addition of soap solution. The endpoint is marked when a foam stable for 5 minutes is formed.

Determination of Chlorides is done by titrating a fixed volume of water sample with standard silver nitrate solution using potassium chromate as indicator. A red colour is developed when all the chloride has been precipitated by the silver nitrate:

$$Cl^- + AgNO_3 \longrightarrow AgCl + NO_3^-$$

To a 50 ml filtered sample of water, already neutralized by adding drops of 0.1N NaOH or 0.1N H_2SO_4 solution as required, 1 ml of potas-

sium chromate indicator [50 gm of K_2CrO_4 dissolved in 100 ml of distilled water] is added. The sample is titrated slowly with stirring by adding a standard solution of silver nitrate from the burette until a stable slight reddish-orange or pink persists after stirring. It marks the endpoint.

The indicator blank is determined by titrating 50 ml of distilled water (free from chloride) with the same silver nitrate standard solution and by using 1 ml of K_2CrO_4 indicator solution.

Cl^- (as NaCl) in ppm

$$= \frac{(\text{ml of } AgNO_3 \text{ solution—Blank})}{\text{ml of Sample Solution}} \times 1000$$

Determination of Sulphates

The sulphate of water sample is precipitated by benzidine hydrochloride as benzidine sulphate which is dissolved in distilled water and titrated with a standard solution of alkali.

To a 50 ml filtered water sample taken in a 250 ml round bottom flask 10 ml of benzidine solution [11.2 gm of benzidine hydrochloride dissolved in 400 ml of distilled water + 100 ml of 5% HCl solution] is added and thoroughly agitated and allowed to settle for 10 minutes.

The benzidine sulphate is filtered off and to the filtrate a few drops of benzidine hydrochloride is added; if the solution becomes cloudy 2 ml of benzidine solution more is added and shaken and filtered off after settling.

The precipitate is washed with 25 ml of distilled water saturated with benzidine sulphate, carefully transferred to the original flask and dissolved in 25 ml of distilled water. The solution is titrated with 0.1N NaOH from the burette using phenolpthalein as the indicator. The amount of standard NaOH solution consumed is recorded.

Blank is determined by titrating a solution of 10 ml of benzidine hydrochloride solution + 50 ml of distilled water with 0.1N NaOH using phenolpthalein as the indicator. The volume of NaOH consumed is recorded as sulphate blank.

SO_4^{2-} (as Na_2SO_4) = (ml of NaOH for the sample—ml of NaOH for the Blank) × 142, ppm

Determination of Phosphate

Determination of Phosphate as PO_4^{3-} in boiler or evaporator waters which are particularly not too coloured is carried out by the colorimetric method. In case considerable colour is present, the sample is either decolourized or the colour effect is balanced when the colour comparison is made.

This method is based on the formation of phosphomolybdate when molybdic acid is added to the sample water and the production of a blue colour when the phosphomolybdate is reduced by stannous chloride solution. The intensity of blue colour produced is proportional to the quantity of phosphate in the sample.

To a 5 ml of clear, filtered sample taken in a clean test tube 10 ml of molybdic acid solution [10 gms of 85% molybdic acid dissolved in 500 ml of distilled water] is added and mixed. Into this solution added is 2.5 ml of dilute stannous chloride solution [12 gms of $SnCl_2 \cdot 2H_2O$ dissolved in 100 ml of conc. HCl and diluted in 1:50 ratio with distilled water] and mixed. The mixture is allowed to stand for 2 minutes to develop the blue colour.

Blank is prepared by adding to a 2nd test sample of 5 ml, 10 ml of molybdic acid + 2.5 ml of distilled water and mixed. It is then transferred to the colour comparison tube of the photometer, the colour filter is placed, the scale reading is set at zero and the galvanometer is balanced to the zero mark by turning the light-adjusting knob.

The blank is replaced by the blue coloured sample in the colour comparison tube and the galvanometer is now zeroed by turning the knob on the colour density scale. At this point the scale reading is recorded.

The PO_4^{3-} concentration (ppm) in the sample is read out from the Standard Calibration Curve in which the scale readings are plotted against ppm of phosphate in standard phosphate solutions using the same light filter.

Determination of pH Value

This is done by the electromagnetic method using glass and calomel electrodes immersed in the sample and a potentiometer (also called pH meter) which is calibrated to read in terms of pH.

Determination of Dissolved Oxygen

This is based on the oxidation of manganous ion into manganic ion by dissolved oxygen. The manganic ion is allowed to react with potassium iodide to liberate iodine. The quantity of iodine liberated is equivalent to the dissolved oxygen. The endpoint is determined by using a starch indicator.

Determination of Total Solids

This is carried out by the gravimetric method. A measured volume of the sample, 100 ml in the case of BFW, 500 ml in the case of raw water is evaporated in an accurately weighed beaker to dryness over a water or steam bath or on a sand bath. Then it is dried in an oven at 105°C for 1h, cooled in a desicator and weighed.

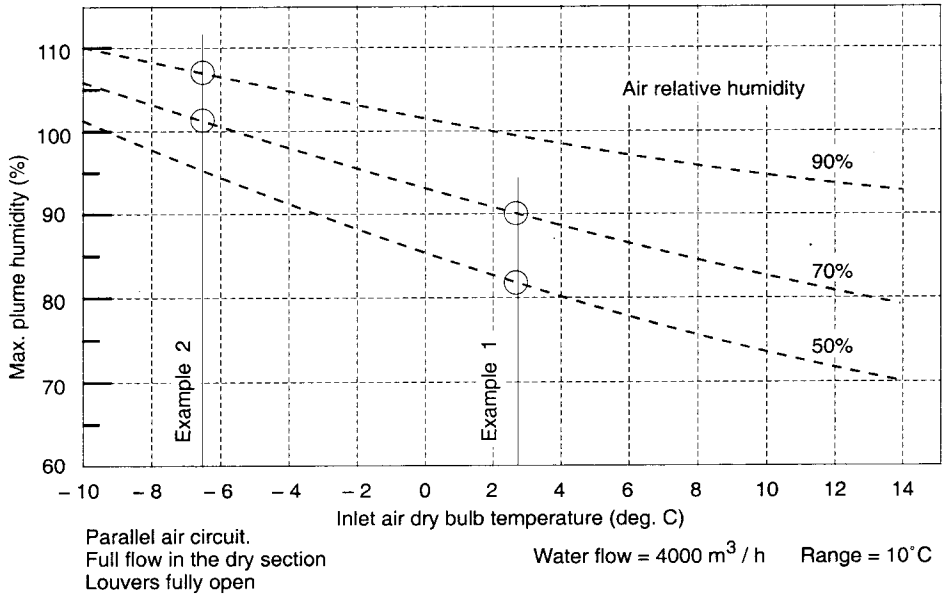
$$\text{ppm of Total Solid} = \frac{\text{Wt of the beaker (in mg)}}{\text{Volume of Sample taken (in litre)}}$$

Determination of Total Dissolved Solids

This is done by measuring the conductivity of a clear, filtered sample and multiplying the result with a conversion factor.

Determination of Total Suspended Solids

It is obtained by subtracting the total dissolved solids from the total solids of the sample.



Hybrid Cooling Tower.
Maximum plume humidity and water content during the dilution process.

Fig. AII.1 *Plume abatement guarantee curve.*

Courtesy: Hamon Cooling Towers/NJ 08807/USA

Determination of Soluble Silica

This can be conveniently done by the colorimetric method. The sample is treated with ammonium molybdate and then acidified whereupon the soluble silica forms silicomolybdate (yellow colour). It is then reduced by sodium sulphite whereupon a blue colour is developed. The intensity of the blue colour is proportional to the concentration of silica. From the standard calibration curve, the silica content in ppm is read out.

To a 10 ml of clear, filtered sample taken in a pyrex glass flask are added 5 ml of HCl [10 ml of conc. HCl diluted to 500 ml with distilled water] and 5 ml of ammonium molybdate [50 gm of ammonium molybdate dissolved in 500 ml of distilled water] solution. The solution is mixed and allowed to stand for 2 min and 10 ml of sodium sulphite solution [140 gms of $Na_2SO_3 \cdot 7H_2O$ dissolved in 500 ml of distilled water] and allowed to stand for 2 min for the full development of the blue colour.

A blank is prepared, the photometer is set at null-point, the comparison tube containing the coloured sample is placed in the photometer, the galvanometer is balanced and the colour intensity is recorded on the photometer.

The silica content (ppm) in the sample is obtained from the Standard Calibration Curve in which the photometer scale readings have been plotted as a function of the ppm of silica.

PERFORMANCE TEST OF A PLUME ABATEMENT CT*

HYBRID COOLING TOWER.

Example 1. (In the saturated zone)

Design and test conditions:

	Design	Test	
Water flow	4000	4000	m^3/h
Hot water	25	27.9	°C
Cold water	15	17.9	°C
Cooling range	10	10.0	°K
Inlet dry bulb	−5.5	3.6	°C
Inlet wet bulb	−6.8	0.5	°C
Atmospheric pressure	1013	1000	mbar
Relative humidity	70	54.9	%

Correction for atmospheric pressure:

RH = 54.9 *1013/1000 = 55.6 %

Exit air measurements

Point	Meas. WB °C	Meas. DB °C	Calc. RH %	Corr. RH_c %	Air Velocity m/sec	
W1	21.2	23.9	79.0	80.0	3.4	*
W2	21.3	24.3	77.0	78.0	15.1	
W3	20.7	24.6	70.8	71.7	16.4	
W4	19.6	25.4	58.7	59.5	14.8	
W5	20.2	25.6	61.5	62.3	6.7	
X1	20.8	23.4	79.5	80.5	4.5	*
X2	20.5	23.8	74.6	75.5	14.6	
X3	20.6	25.2	66.4	67.3	16.7	
X4	19.8	25.9	57.3	58.0	15.4	
X5	20.2	25.3	63.2	64.0	7.8	
Y1	19.9	21.9	83.5	84.6	5.1	*
Y2	19.7	22.4	78.3	79.3	13.9	
Y3	19.0	22.2	74.4	75.3	15.7	
Y4	18.7	22.7	68.8	69.7	15.2	
Y5	18.5	23.4	63.0	63.8	8.2	
Z1	20.1	22.1	83.6	84.7	3.8	
Z2	20.0	22.4	80.6	81.6	12.9	
Z3	19.4	22.6	74.6	75.6	14.9	
Z4	19.5	23.6	68.7	69.6	15.4	
Z5	18.8	24.2	60.3	61.1	7.2	
SUM					227.7	
AVG	19.88	23.83	69.9		11.38	

Correction for atmospheric pressure:

RH = 69.9 *1013/1000 = 70.8

Test interpretation: On the psychrometric diagram, we draw the straight line between the points corresponding to

* *Source:* *Paper No. TP 94-15 presented at the 1994 Cooling Tower Institute Annual Meeting/Houston/Texas/Feb 13-16, 1994*

Courtesy: *Hamon Cooling Towers/Bridgewater/NJ 08807/USA*

DB = 3.6, RH = 55.6% and to

DB = 23.83, RH = 70.8%

(Solid line on diagram) Fig. AII.2.

The straight line is tangent to the 81.5% humidity curve.

RH_r = 81.5% (Fig. AII.2)

Comparison to the expected value On the plume abatement guarantee curve (Fig. AII.1), we read for the air inlet state DB = 3.6 °C
RH = 50% ⟶ Hum = 80.2%

RH = 70% ⟶ Hum = 88.6%

By interpolation DB = 3.6°C

RH = 55.6% ⟶ Hum = 82.6%

RH_e = 82.6%

The measured maximum relative humidity (81.5%) is lower than the expected one (82.6%)

The guarantee of the plume abatement is well fulfilled.

Mixing guarantee On the psychrometric diagram, we draw the straight line from inlet air state DB = 3.6°C, RH = 55.6% and tangent to the maximum expected local relative humidity curve taking into consideration the 7% normal scattering:

RH_m = 81.5 * 1.07 = 87.2%

(Dotted line on diagram).

(Fig. AII.2)

The points W1, X1, Y1, Z1 are above the normal limit. The air flow (sum of the local air velocity : 3.4 + 4.5 + 5.1 + 3.8 = 16.8 m/s) associated with these points represents 7.4 % (lower than the 15% allowed) of the total air flow of the cooling tower. [16.8/227.7) *100 = 7.4%]

The mixing quality is then fulfilled.

Example 2. (In the supersaturated zone)

Design and test conditions:

	Design	**Test**	
Water flow	4000	4000	m^3/h
Hot water	25	27.9	°C
Cold water	15	17.9	°C
Cooling range	10	10.0	°K
Inlet dry bulb	– 5.5	– 6.5	°C
Inlet wet bulb	– 6.8	– 6.8	°C
Atmospheric pressure	1013	1030	mbar
Relative humidity	70	92.5	%
Correction for atmospheric pressure:			
RH = 92.5 * 1013/1030 =		90.9	%

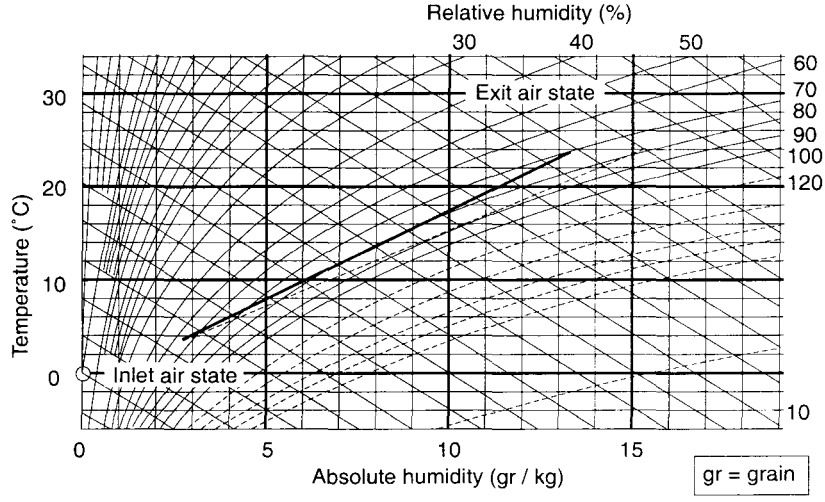


Fig. AII.2

Courtesy: Hamon Cooling Towers/NJ 08807/USA

Exit air measurements

Point	Meas. WB °C	Meas. DB °C	Calc. RH %	Corr. RH_c %	Air velocity m/sec
W1	17.1	18.2	89.8	88.3	4.4
W2	17.3	19.3	82.2	80.9	16.2
W3	17.8	20.8	74.8	73.6	17.1
W4	17.0	20.7	69.3	68.1	14.2
W5	16.6	20.5	67.5	66.4	7.1
X1	16.6	17.6	90.5	89.1	5.5
X2	16.2	17.1	91.4	89.9	14.1
X3	15.9	17.8	82.4	81.1	16.9
X4	15.8	18.8	73.5	72.3	16.0
X5	15.7	19.1	70.4	69.2	8.1
Y1	17.5	18.6	89.9	88.4	4.9
Y2	17.7	19.2	86.5	85.1	14.2
Y3	17.3	19.6	79.8	78.5	16.0
Y4	16.1	19.5	70.7	69.5	15.1
Y5	15.4	18.2	74.8	73.5	8.5
Z1	16.6	17.5	91.5	89.9	4.2
Z2	16.7	18.0	87.9	86.5	12.7
Z3	16.5	19.0	77.8	76.5	14.8
Z4	16.2	20.5	64.5	63.4	15.0
Z5	15.2	20.0	60.2	59.2	8.1
SUM					233.1
AVG	16.56	19.00	78.3		11.66

Correction for atmospheric pressure:

RH = 78.3 *1013/1030 = 77.1

Test interpretation:

On the psychrometric diagram, we draw the straight line between the points corresponding to

DB = – 6.5, RH = 90.9%

and to

DB = 19.0, RH = 77.1%

(Solid line on diagram) (Fig. A II.3)

* If the supersaturated humidity lines are not drawn on the psychrometric chart.
* On the psychrometric chart, we can see that the largest distance between the drawn straight line and the saturated line (100%) corresponds to an air temperature of 1°C.
* Absolute humidity at intersection of 1°C and straight line = 4.65 gr/kg.
* Absolute humidity at intersection of 1°C and saturation line = 4.15 gr/kg.
* Supersaturated humidity = (4.65/4.15) *100 = 112%
* If the supersaturated humidity lines are drawn on the psychrometric chart.
* The straight line is tangent to the 112% humidity curve

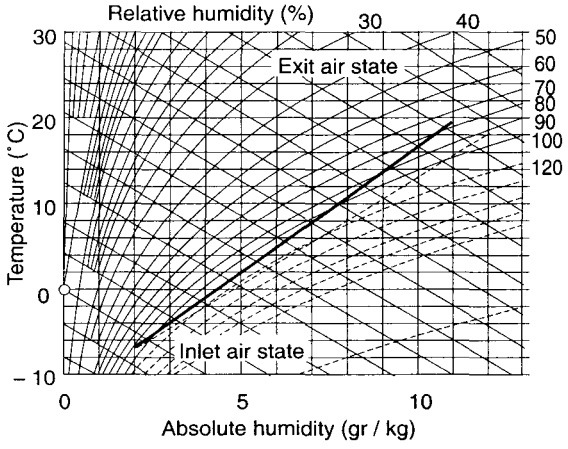


Fig. A II.3

Courtesy: Hamon Cooling Towers NJ 08807/USA

RH_r = 112.0%

Comparison to the expected value.

On the plume abatement guarantee curve, we read for the air inlet state DB = – 6.5°C

RH = 70% ⟶ Hum = 101.7%

RH = 90% ⟶ Hum = 107.3%

By interpolation DB = – 6.5°C

RH = 90.9% ⟶ Hum = 107.6%

RH_e = 107.6%

The measured maximum relative humidity (112.0%) is higher than the expected one (107.6%), but still in the acceptable range of test accuracy. (112.0 < 107.6 + 5)

The guarantee of the plume abatement is well fulfilled.

Mixing guarantee On the psychrometric diagram, we draw the straight line from inlet air state

DB = −6.5°C, RH = 90.9% and tangent to the maximum expected local relative humidity curve taking into consideration the 7% normal scattering:

$$RH_m = 112.0 * 1.07 = 119.8\%$$

(Dotted line on diagram). (Fig. AII.3)

We observe that all the testing points are within the normal scattering.

The mixing quality is then fulfilled.

Two more useful charts are presented in P: 1120 and 1121:

Figure A II.4 Psychromertic chart with "supersaturated" humidity lines.

Fig. A II.5 Relation between wet bulb (ice), dry bulb, humidity.

DEAERATION

... in Industrial Water Conditioning

Why

Corrosion of iron or steel is influenced by three fundamental factors:

1. Temperature
2. pH value
3. Oxygen content

Temperature and pH value control the activity or aggressiveness of corrosion (high temperatures and low pH values increase aggressiveness). The oxygen content is a large factor in determining the extent or amount of corrosion. Figure AII.7 illustrates the expected oxygen content of raw water at various temperatures.

Iron goes into solution in pure water to a slight extent, according to the formula $Fe+2H_2O \longrightarrow Fe(OH)_2 + H_2$, but the ferrous hydrate $Fe(OH)_2$ formed is alkaline and raises the pH value. At a definite pH value further dissolving of iron is stopped. However, if oxygen is present it immediately oxidizes the ferrous hydrate forming ferric hydrate $Fe(OH)_3$ which is insoluble and precipitates, permitting more iron to go into solution and thus the reaction continues until all oxygen is dissipated.

It is evident, therefore, that the removal of oxygen and carbon dioxide from solution is important and essential when conditioning water for industrial use. This is particularly true when boiler feed water and process water are used at elevated temperatures.

How

Deaeration is the mechanical removal of dissolved gases from a fluid. The process of deaeration is most frequently applied in boiler feed water heaters to protect piping, boilers and condensate equipment from corrosion. In other applications deaeration of *cold water* is necessary to protect pipe lines and equipment from corrosion, as well as to provide oxygen-free water required in some processes. Deaeration of service water for buildings and institutions is desirable in order to protect distribution systems.

The three cardinal principles that must be satisfied in any mechanical deaerator are:

Heating: Water must be heated to full saturation temperature (boiling point), corresponding to the steam pressure in the unit. Since, theoretically, the solubility of any gas is zero at the boiling point of the liquid, complete gas removal is not possible unless the liquid is kept at boiling temperature.

For operation at sub-atmospheric pressures, as is the case with cold water deaerators, evacuation or heating, or both, must be applied to create this boiling condition.

Mechanical Agitation: The heated water must be mechanically agitated, by spraying, cascading over trays, or by atomization, to expose maximum surface contact to the scrubbing atmosphere, thus permitting complete release and removal of gases. When water is broken down into fine droplets or thin films, the distance that the gas bubble must travel for release is greatly decreased. Thor-

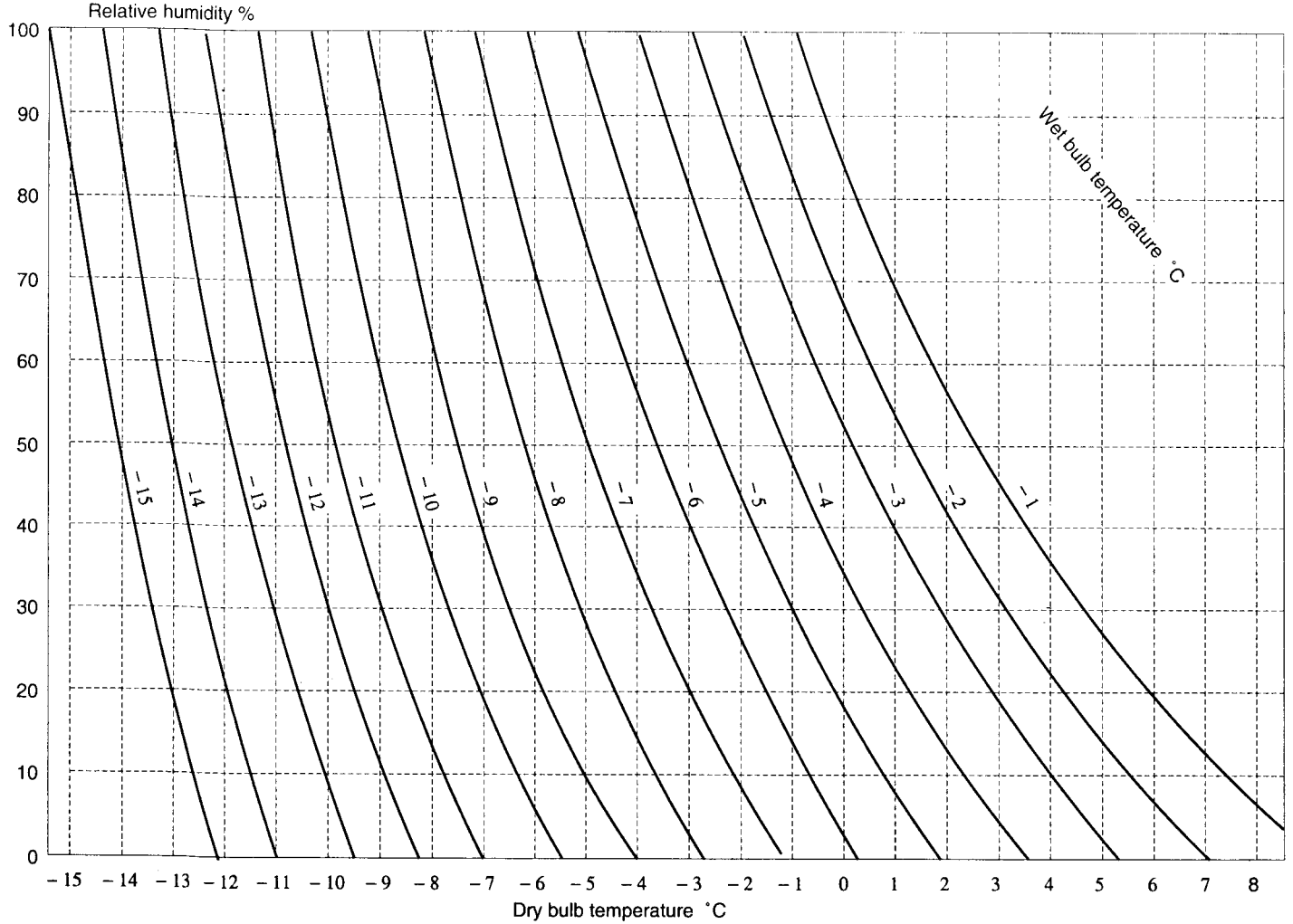


Fig. A II.4 *Relative humidity fct WB, DB Ice on the wet bulb.*

Courtesy: Harnon Cooling Towers/Bridgewater/NJ 08807/USA

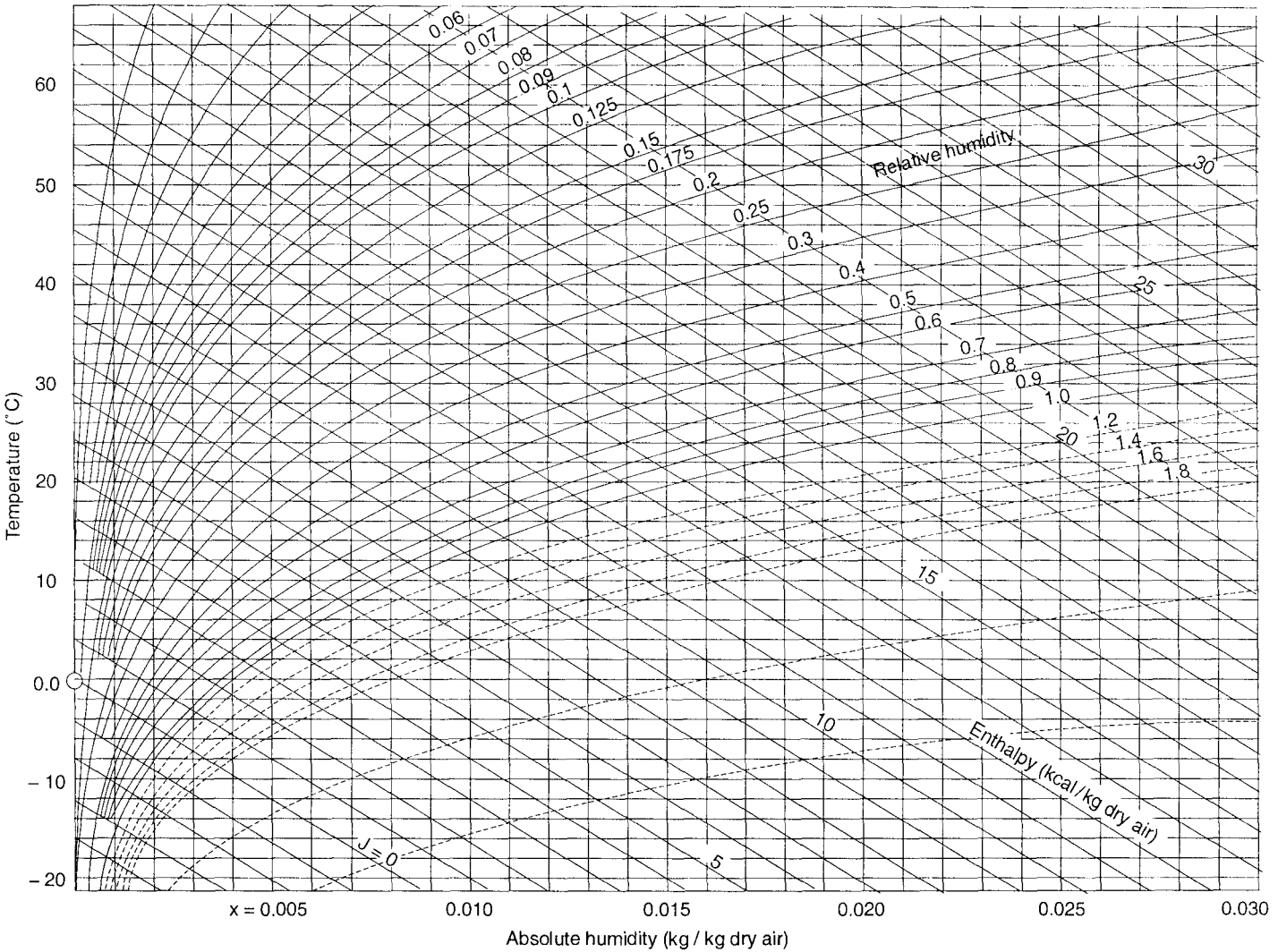


Fig. A II.5

Courtesy: Hamon Cooling Towers/Bridgewater/NJ 08807/USA

ough agitation also overcomes tendencies of surface tension and viscosity to retain the gas bubbles and increases the rate of gas diffusion from the liquid to the surrounding atmosphere. The deaerating equipment, therefore, must provide the most efficient mechanical agitation possible to permit meeting modern requirements of gas removal. Since a normal warranty of "less than 0.005 cc per litre of oxygen" means less than 7 pounds in a *billion* pounds of water, the importance of effective agitation cannot be overstressed.

Complete Gas Removal: Adequate steam must be passed through the water to scrub out and carry away the gases after release. Extremely low partial gas pressure must be maintained since Henry's Law states that the amount of gas which will dissolve in a liquid is proportional to the partial gas pressure in the atmosphere contacting the liquid. It is mandatory that the volume of scrubbing steam be high to produce the low partial gas pressure, and it is equally mandatory that these conditions prevail throughout the deaerating section.

The effect of partial gas pressure and heating is illustrated in Figure AII.6.

Deaerator Types

There are four types of deaerators: Tray or Jet Tray, Atomizing, Cold water and Surface type. All of these types efficiently employ the cardinal principles outlined above.

Tray and Jet Tray Types

The Tray and Jet Tray types are most widely used for heating and deaerating boiler feed water in industrial power plants and central stations. Water is heated to full saturation temperature with a minimum pressure drop and minimum vent, thereby assuring best thermal efficiency. Deaeration is accomplished by spreading the heated water over multiple layers of trays designed to provide maximum spilling or weir edge, thereby giving intimacy of surface contact with scrubbing steam.

Atomizing Type

This type is widely used in marine applications since it is unaffected by normal roll and pitch of the vessel. Widespread use in industrial plants occurs particulary where operating pressures are stable.

The Atomizing type employs a high velocity steam jet to atomize and scrub the preheated water. The break-up of water into foglike particles assures maximum surface exposure and intimacy of contact necessary for complete deaeration.

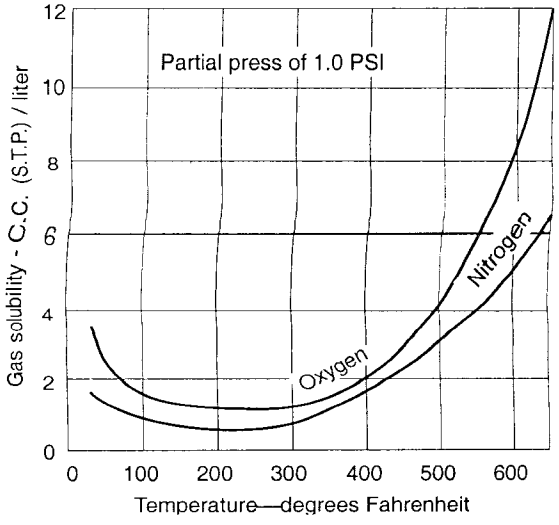


Fig. A II.6 *Solubilities of Nitrogen and Oxygen at One PSI Partial Pressure.*
Courtesy: Cochrane Environmental System, USA

Cold Water Type

Cold Water deaerators are used primarily to eliminate corrosive gases from cooling water, demineralization systems, and industrial water supplies without the addition of heat.

The boiling condition is accomplished by pressure reduction with vacuum-producing equipment. Surface contact with scrubbing vapour is provided by a packing or Rasching rings.

Surface Type

Surface type deaerators are generally used for domestic or service water supplies. To avoid odor

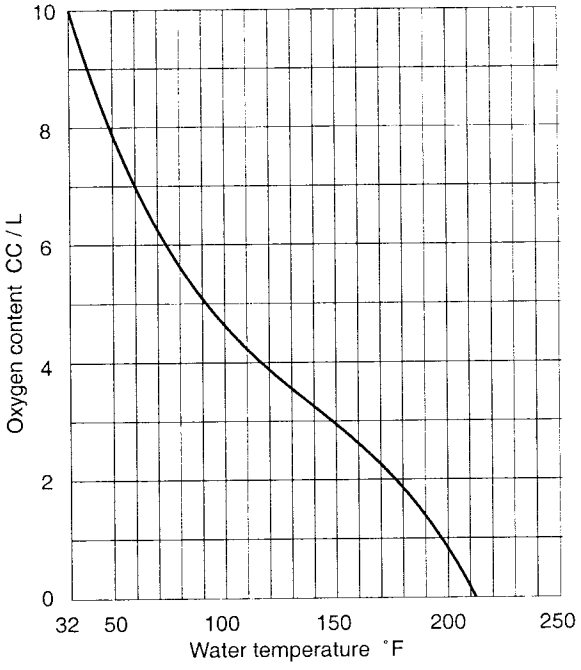


Fig. A II.7 *Oxygen saturation curve*

Courtesy: Cochrane Environmental System, USA

or taste in the deaerated water, scrubbing and deaerating steam is produced from the water by use of an evaporating coil in the deaerator shell. Again, all the basic requirements for complete deaeration are present and corresponding guaranteed performance is assured.

Conclusion

The necessity for deaeration of boiler feed and process water has become so recognized that even small plants now assure longer equipment life and reduced maintenance by employing some type of deaeration.

Deaeration today is an important factor in the successful and economical operation of any modern boiler plant, regardless of its size.

Source: *DEAERATION—WHY? HOW?*

Courtesy: *Cochrane Environmental Systems/PA 19406/USA*

PARALLEL DOWNFLOW TRAY DEAERATORS (FIG. AII.8)

Advantages of the Parallel Downflow Method

- Meets performance requirements with lower inlet feedwater temperature—no need to heat feedwater ahead of deaerator
- Handles higher steam flows through the tray stack
- Eliminates need to install heat exchangers ahead of the deaerator—lowers installation costs
- Water seal between trays and the spray section eliminates direct impingement of the spray on the trays and insures even distribution of the water over the tray stack.
- Higher steam velocities allow use of trays with less open area which maximizes spill-

ing edge and exposes a greater surface of the water to the stripping action of the steam.

- Optimized mixing plus higher steam velocity results in maximum gas removal efficiency.

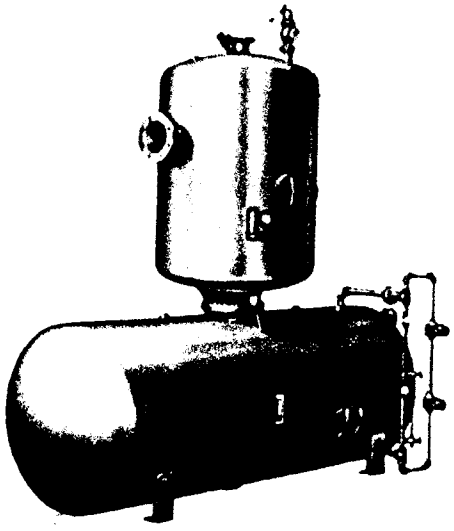


Fig. A II.8

Courtesy: Cochrane Environnment System, USA

Principle of Operation

Water enters preheating compartment and is heated to practically steam temperature. Here the bulk of the noncondensible gases is removed before the water enters the trays.

Heated water passes through water seal type distributors to the tray section. The water seals prevent by-passing of steam into the preheating compartment and insure against noncondensible gases entering tray compartment from preheating section. (Fig. AII.9)

Water passes downward through the trays to complete final deaeration and then goes to storage.

Steam enters at inlet nozzle and passes through ports in tray compartment to space above trays, flowing downward with the water through tray section. This action provides highly efficient distribution over trays, maximum surface contact between steam and water, and prevents damming up of water and possible water hammer. Practically no condensation of steam occurs in tray compartment, since inlet water has been heated to within a few degrees of steam temperature in the preheater compartment. The entire volume of uncontaminated steam is employed in scrubbing action, thus removing the final traces of oxygen.

Steam leaves the bottom of the trays, flows outside the trays to the preheater compartment where it is condensed. Noncondensible gases are discharged to atmosphere.

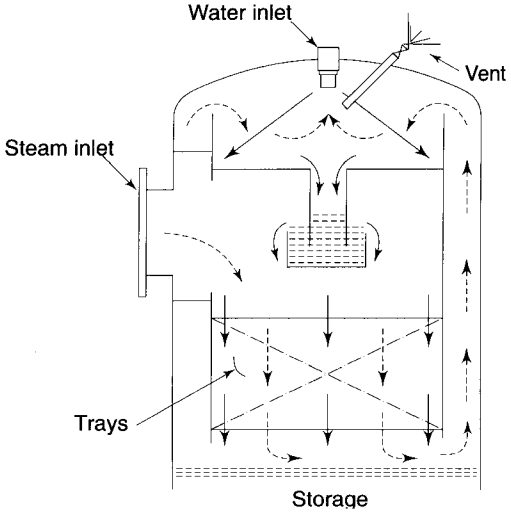


Fig. A II.9

Courtesy: Cochrane Environmental System USA

Construction

(Typical)

Deaerator Top: Welded steel plate,

Storage Tanks: Welded steel plate,

Water Distributor: Type 316 stainless steel, spring loaded nozzle.

Trays: Type 430 stainless steel.

Vent Condenser: Direct contact type with Type 304 stainless steel baffling.

Design Pressure: As required

Deaerating Trays (Typical)

One piece construction, Type 430 stainless steel. (Fig. II.10) Easily handled by one person. Trays designed so that the pressure shell does not come in contact with undeaerated water or concentrated noncondensible gases. Provides excellent performance due to highest spilling edge and baffling area available in any tray design. Affords maximum water "break-up" and retention time.

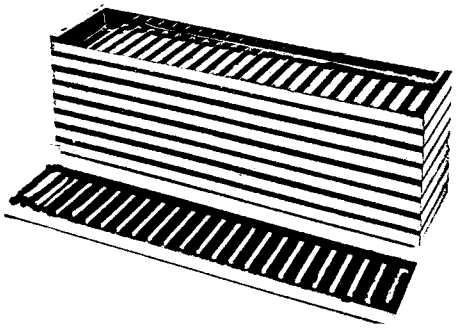


Fig. AII.10

Courtesy: Cochrane Environmental Systems, USA

COUNTERFLOW TRAY DEAERATORS (FIG. AII.11)

Advantages of the Counterflow Method

1. Minimum feedwater temperature rise needed to meet performance specifications
2. Highly reliable for attaining specified results over a varying load range
3. Simplicity of design offers cost savings over the other tray systems for many applications.

Principle of Operation

Incoming water flows through spray nozzles and enters the vent condensing chamber as a thin-walled, hollow cone spray pattern (Fig. AII.12). Latent heat transfer is instantaneous because of the intimate water-to-steam exposure.

As the water reaches the tray stack, its temperature is within 2°F of the saturated steam temperature, and virtually all dissolved oxygen and free carbon dioxide have been removed.

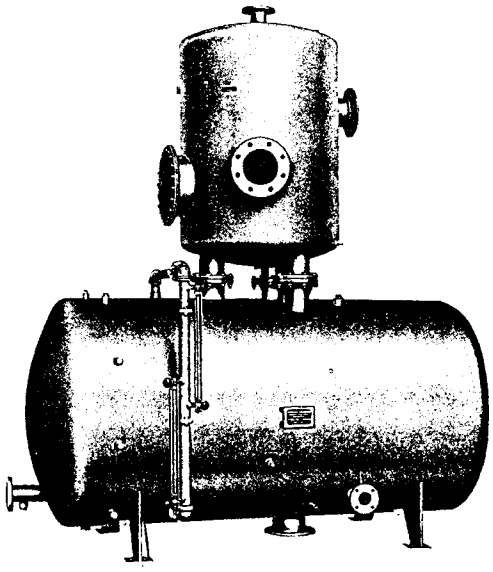


Fig. A II.11

Courtesy: Cochrane Environmental Systems, USA

Nearly all of the steam has now condensed, permitting the non-condensible gases to be carried through the vent by the remaining steam, exiting as a plume.

The water enters the tray stack, and immediately reaches saturation (operation) temperature. With the water preheated, the remainder of the tray stack and counterflow steam are now available to scrub and remove the final traces of oxygen and carbon dioxide.

The preheated water flows down over the trays, zig-zagging its way through the pure steam. The water leaving the bottom layer of trays is "stripped" by the purest steam entering the deaerator and flows into storage completely deaerated and heated.

Construction

Spray valve, valve mounting plate, vent condensing chamber, tray assemblies, tray enclosure walls, steam baffles and vent pipe system are stainless steel.

Vessel heads and shells are low carbon welded steel plate.

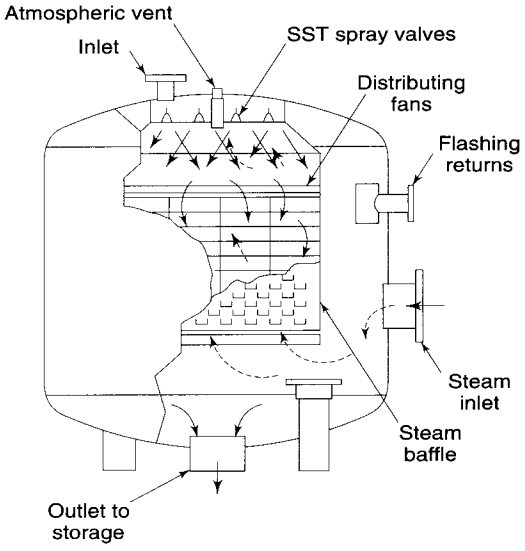


Fig. A II.12

Courtesy: Cochrane Environmental Systems, USA:

All design and manufacture is in accord with the certified to ASME Code for unfired pressure vessels.

Deaerating Trays (Fig. AII.13)

Tray material is Type 430, stainless steel, assembled with stainless steel rivets. Each tray assembly consists of eight tray channels arranged in two staggered tiers of four each (a typical construction).

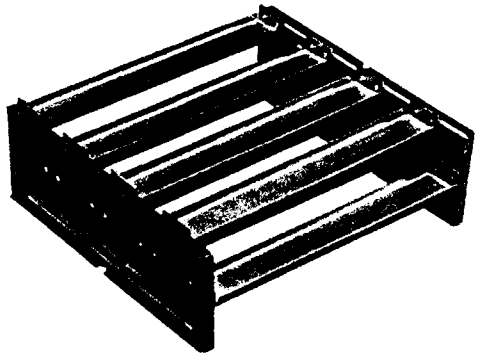


Fig. A II.13

Source: *DEAERATORS*

Courtesy: *Cochrane Environmental Systems/PA 19406/USA*

MARINE ATOMIZING DEAERATORS

Atomizing Deaerators (Fig. AII.14) are superior for marine applications, because they function at, rated efficiency during the normal roll or pitch of the ship, while tray-type deaerators are subject to spill-over at the least deviation from a level position. Specially-designed baffles in the deaerated water storage section act as surge dampeners in rough weather. (Fig. AII.15)

These deaerators provide the economy of direct contact heating and the degree of deaeration of feedwater required by the modern high-pressure marine boilers. Their relatively small size and light weight provide added advantages in marine use.

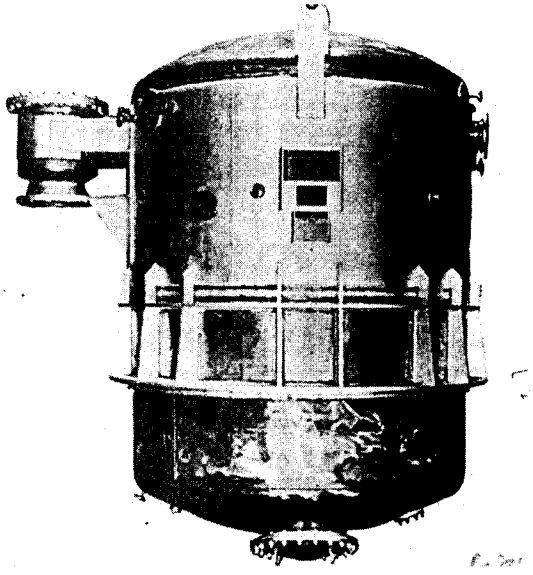


Fig. A II.14 *Marine-type units are provided with special baffles to reduce surge in rough weather.*

Courtesy: Cochrane Environmental Systems, USA

JET-TRAY DEAERATORS

PRINCIPLE OF OPERATION

Water Flow (See Fig. A II.16)

Water enters the unit through spring-loaded stainless steel removable distributors which break the

water up into fine particles for maximum intimacy of contact with steam. Water is heated to practically steam temperature and the bulk of the non-condensible gases is removed in the preheater compartment before the water goes to the trays.

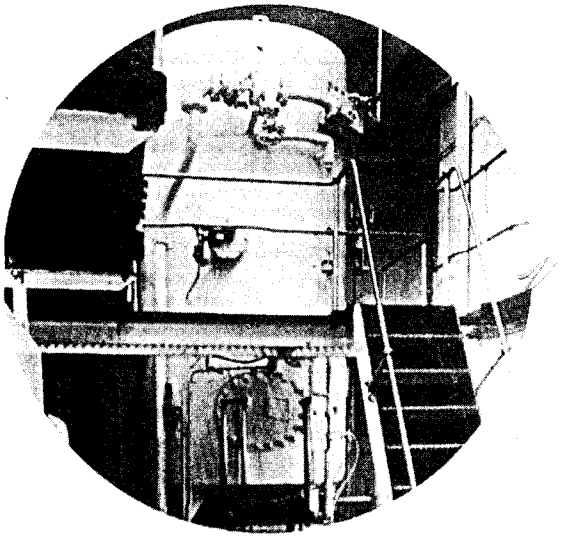


Fig. A II.14a *A typical marine deaerator installation.*

Courtesy: Cochrane Environmental System, USA

Heated and partially deaerated water passes through water seal type distributors to the tray section. The water seals prevent bypassing of steam into the preheater compartment and insure against the passage of non-condensible gases to the tray compartment from the preheating section.

Water passes downward through the trays to complete the final deaeration and then goes to storage.

Steam Flow (See figure AII.16)

Steam enters at inlet nozzle and passes through ports in tray compartment to space above trays, from which it flows downward with the water through tray section. Downflow of steam and water provides highly efficient distribution over trays, maximum surface contact between steam and water, and prevents damming up of water and possible water hammer. Practically no condensation of steam occurs in tray compartment, since inlet water has been heated to within a few degrees of steam temperature in the preheater compartment. The entire volume of uncontaminated steam, therefore, is employed in scrubbing action thus removing the final traces of oxygen.

Steam leaves the bottom of the trays, flows outside the tray compartment to the preheater compartment where it is condensed. Non-condensible gases are discharged to atmosphere.

Construction (Typical)

Deaerator Top-

Welded Steel Plate

Storage Tanks-

Welded Steel Plate

Water Distributor-

Multiple Stainless Steel
Spring-Loaded Nozzles.
Stainless Steel Inlet pipe
and Chamber.

Trays-

Stainless Steel.

Vent Condenser-

Direct contact type with
stainless steel baffling.

Design Pressure-

30 psig. (typical)

ADVANTAGES

1. Controlled steam atmosphere

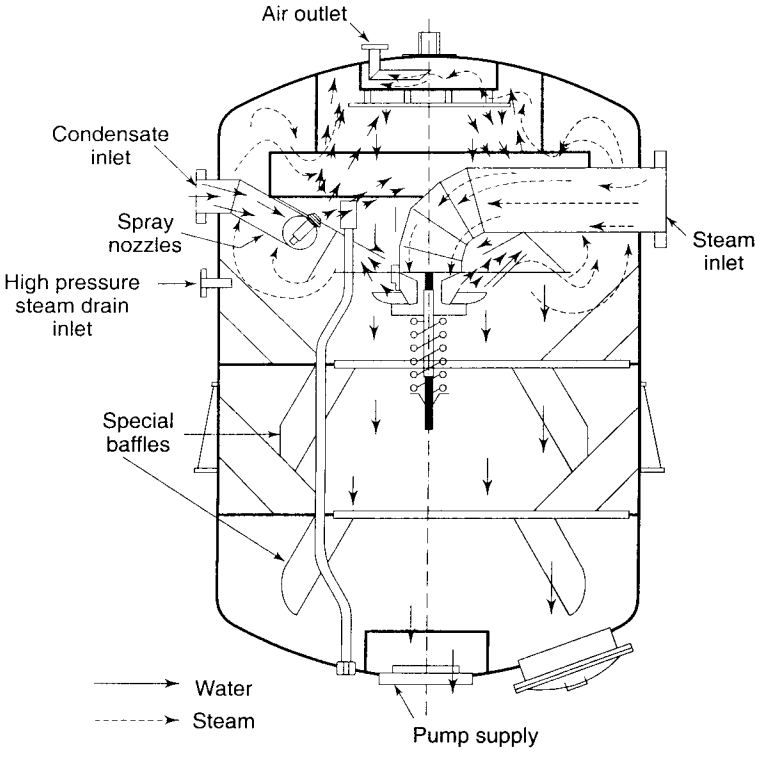


Fig. A II.15 *Deaerating feed tank.*

Source : Atomizing Deaerators for Industrial & Marine Services

Courtesy: Cochrane Environmental Systems/PA 19406/USA

2. Maximum effective scrubbing contact between steam and water assures high efficiency in oxygen removal.
3. Parallel flow of steam and water assures best distribution in tray stack-prevents damming up of water and possible water hammer.
4. Stainless steel trays are easily removed.
5. Design provides tremendous spilling edge with highest deaerating efficiency.
6. Water distributors are removable for inspection.
7. Effective means used to protect pressure shell from contact with corrosive water or gases.

COOLING WATER TREATMENT

Effective operation of cooling water treatment system depends on the control of SCALING, FOULING and CORROSION.

Scale Control

The chief scale formers are:

1. calcium carbonate
2. calcium phosphate
3. calcium sulphate
4. silica

Their order of occurance in CW system is

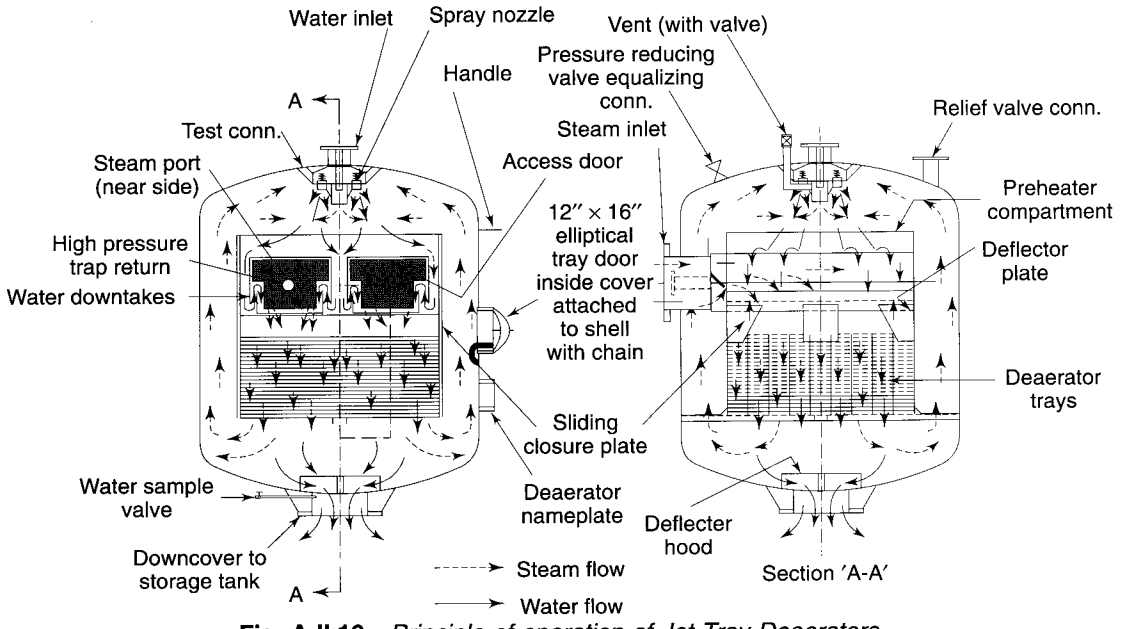
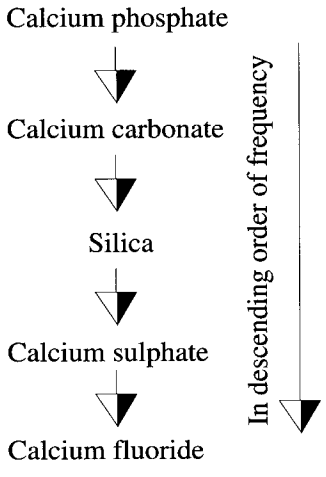


Fig. A II.16 *Principle of operation of Jet-Tray Deaerators.*

Source: UNI-PAC Deaerator for Small & Medium Size Power Plants
Courtesy: Cochrane Environmental Systems/PA 19406/USA



Calcium phosphate supercedes calcium carbonate—traditionally the dominant scale former—because of increased popularity of phosphate-based treatment programs.

Calcium carbonate is the major scale former. Some new formulations of phosphates provide exceptional calcium carbonate scale control. Outstanding among these is phosphono-butane-tricarboxylate (PBTC). It has replaced or supplemented two familiar phosphonates—aminomethylene-phosphonate (AMP) and hydroxy-ethylidine-diphosphonate (HEDP).

50:50 blend of AMP (or HEDP) with PBTC with application levels of 2 – 3 ppm is as effective as 3 – 5 ppm of AMP (or HEDP) alone under severe scaling conditions. This blend has enabled some CW systems to tolerate quite high amounts of calcium hardness—1200 to 2000 ppm.

PBTC is effective to PSI (Practical [Puckorius] Scaling Index) levels down to 3.5 as against 4 PSI for AMP or HEDP.

Several amine and acrylate-based phosphonates exhibit exceptional $CaCO_3$-scale control under severe operating conditions, particularly at high pH levels (9 to 9.5). These are:

I. Co-polymers:

- polymaleate/sulphonate

- polyacrylate/maleate
- polyacrylamide/sulphonate
- phosphino/acrylate

II. Ter-Polymers:

- polyacrylate/acrylamide/sulphonate
- polymaleate/acrylate/sulphonate
- phosphino/maleate/sulphonate etc.

Combinations of several co and ter-polymers are also used. They ensure broader control, i.e. they act as multiple scale-inhibitors (calcium carbonate, calcium phosphate and calcium sulphate).

Most of these act as crystal modifiers. (see Table AII.4)

Calcium phosphate has become the leading scale-former of late. Increased use of phosphate-based corrosion inhibitors and phosphate-containing municipal waste water, and agricultural field-runoff accounts for its predominance. Another source of phosphates is the degradation of previously used phosphonates, viz. AMP, HEDP etc.

Older phosphate inhibitors suffered from their sensitivity to higher temperature, exposure to UV-radiations and Fe^{3+}/Al^{3+} salts and oxides present in the CW system.

Exceptional control of calcium phosphate scale has been provided by the new co and ter-polymers (Table AII.4). They perform well with $CaCO_3$ levels of 1200 ppm or higher and total phosphate (PO_4) of 25 to 30 ppm (even higher).

Ter-polymers, it has been reported, reduce and sometimes completely eliminate $Ca_3(PO_4)_2$ deposits even with Fe-salts present.

Combined use of phosphonates, co-and ter-polymers is gaining ground because of wider spectrum of performance of such combinations.

Calcium sulphate is usually less common. However, due to increased use of reclaimed sewage and wastewater containing high sulphate levels (1000 – 3000 ppm or SO_4) has made it imperative to go for sulphate -scale control, in CW treatment program.

Cooling water with high $CaCO_3$ levels (1200 – 2000 ppm) is particularly susceptible to $CaSO_4$ scale over the pH range of 7 to 8.

Exceptional sulphate-scale control is provided by the polyacrylate/acrylamide co-polymer. This inhibitor applied at levels 2 to 3 ppm (active) has recorded success in with-holding $CaSO_4$ scale in CW systems containing $CaCO_3$ upto 2700 ppm and SO_4 levels as high as 4000 ppm.

Calcium Fluoride leads to scaling in CW systems operated above 10 cycles of concentration. Effective fluoride scale-control dictates the use of ter-polymers.

Silica in CW system rises with the increased use of reclaimed water and high operating cycles.

Ter-polymers have been found to be quite effective in controlling silica-scales. They inhibit SiO_2-scaling through increase of silica solubilities. Use of these formulations has boosted the safe operating levels of silica from 150 – 200 ppm to 250 – 300 ppm at a pH of 8.5 in cooling waters.

Control of Fouling

Fouling is caused by:

- Suspended solids, viz. mud, silt etc.
- Gelatinous matter

There are two types of fouling control measures: *chemical* and *mechanical.*

Chemical control involves the use of dispersants and sludge fluidizers (flocculants).

Co-and ter-polymers are excellent dispersants. They inhibit fouling at dosages of 5 to 10 ppm (active). Usually polymers of high molecular weight (300 000 to 15×10^6) at dosages 0.3 to 1 mg/l are commonly used. These polymers with their large chains trap fine foulant particles whereupon they get converted to a large puffy particles that can be readily dislodged from **HE** tubes.

Surfactants are used to tackle the gelatinous and oily matter. These are polyoxyalkylane derivatives.

Mechanical Fouling-control involves the use of a variety of filters. This is particularly important where the CW system is subjected to high-cycle operation that multiplies the effect of suspended solids.

Sidestream filtration systems—processing 1 – 5% of coolant flow continuously—accrue benefits when slug feeding of biocides brings about periodic excursions of suspended solids.

A new breed of filter of submicron capability (0.5 μ nominal) is particularly attractive for removal of microbial nutrients and other ultrafine airborne particulates without rapid plugging.

Biofoulant Control

Biofoulant—micro and macro-organisms—thrive on

(a) phosphates, phosphonates and polymers which serve as nutrients for micro-organisms

(b) nutrient-rich wastewater which is increasingly reclaimed for CW system.

Biofoulant activity intensifies with the pH increase to the range 8 – 9. Biocidal activity of chlorine is effectively decreased over this range. Again higher CT cycles reduce the stability of some biocides.

Biocides can be grouped into types depending on the mode of their biocidal mechanism:

1. **Oxidizing**
   (a) Bromine
   (b) Ozone
   (c) Chlorine
   (d) Chlorine dioxide
2. **Non-oxidizing**
   (a) Glutaraldehyde triazine
   (b) Dibromo-nitrilo-propionamide (DBMPA) (Table AII.5)

Table A II.4 *Leading Scale-Control Formulation and Methods*

FORMULATION	CONTROL ACTION		
	Stabilization	Dispersion	Crystal Modification
Phosphonate			
PBTC	Primary		
HEDP	Primary		
AMP	Primary		
Polyacrylate	Primary	Moderate	
Co-Polymers			
Acrylate/sulfonate	Slight	Slight	Primary
Acrylate/maleate	Slight	Moderate	Primary
Acrylate/acrylamide	Primary	Moderate	Slight
Acrylate/phosphino	Primary	Slight	Slight
Maleate/sulfonate	Slight	Slight	Primary
Ter-Polymers			
Acrylate/maleate/sulfonate	Slight	Slight	Primary
Acrylate/acrylamide/sulfonate	Slight	Moderate	Primary
Phosphino/maleate/sulfonate	Primary	Slight	Moderate

Source : POWER/May'95/P: 18 (The McGraw-Hill Companies)

Popularity of chlroine has waned as compared to bromine because of its:

(a) reduced effectiveness at high pH
(b) inactivation by ammonia present in reclaimed wastewater
(c) high cost
(d) lower biocidal power w.r.t. Br_2

Ozone (O_3) is a higher derivative of oxygen. It is produced from molecular oxygen by passing air through a high-voltage, and high frequency electric field between two concentric electrodes. O_3-enriched gas is then bubbled through CW, and the residual O_3 maintained at 0.01—0.1 mg/1.

Ozonation is effective against a wide spectrum of bacteria while its use is limited by water quality and operating conditions (temperature 313 K; high organic loading), it can ensure good biocidal action when properly produced, fed and controlled.

Table A II.5 *Biocides and Biocidal Action*

	Biocide	Chief Targets	Remarks
Oxidizing →	Chlorine	Bacteria, algae	Traditionally used : effective at pH 7 – 7.8. Biocidal activity dwindles in the presence of ammonia
	Bromine	Bacteria, algae	Superior to chlorine at pH over 7.5. Retains biocidal effect even in the presence of NH_3
	Ozone	Bacteria, algae and fungi	Very active and volatile; may induce corrosion; may not reach all cooling-system extremities
	Chlorine dioxide	Bacteria	Very volatile; effective at all pH; non-reactive to ammonia
Non - Oxidizing	Glutaraldehyde triazine	Bacteria and algae	Effective over a wide pH range; synergistic with Cl_2 ; inactivated by NH_3; low toxicity level
	Dibromo-nitrilo-propionamide	Bacteria and fungi	Less effective at pH > 7.5; adds glycol to systems

Appendix III

Materials of Construction and Refractory System in Steam Generation Plants

MATERIALS OF CONSTRUCTION FOR BOILERS & AUXILIARIES

Both carbon steel and alloy steels find their way to the manufacture of boilers.

Basic open-hearth steel is also used for making boiler components.

Though Bessemer steel is not fit for high-pressure boiler components yet "killed" Bessemer (i.e. deoxidized steel) is used for fabricating seamless steel tubes.

High-alloy steels made in electric furnaces are usually resistant to corrosion and capable of withstanding high temperatures over a prolonged period. These steels are used for constructing waterwall and superheater tubes, baffles, supports and hanger fittings, soot blower clamps, etc.

The steels that are employed, in general, for the construction of boilers belong to:

(a) Plain carbon steels (rimmed, semi-killed and killed)
(b) Low alloy steels (pearlitic class)
(c) High-alloyed austenitic steels
(d) High-alloyed martensitic and martensitic-ferritic class.

Plain Carbon Steels

These are used for boiler construction with an average carbon content of 0.15 to 0.30%.

Carbon steel parts subject to pressure and exposed to fire should contain a maximum of 0.25% carbon for plate thickness 18-20 mm; for higher plate thickness a maximum carbon content of 0.30% can be recommended. Phosphorus should not exceed 0.04% for acid steel and 0.035% for basic steel. Maximum limit of sulphur content: 0.04%.

Carbon steel boiler components subject to pressure but not exposed to fire are made from flange steels which contains the maximum amount of the following elements:

Mn—0.8%; P—(0.04 – 0.05)%; S—0.05%.

Reasonably resistant to scaling in steam and corrosion by combustion products upto 540°C, carbon steels are sensitive to corrosive oxidizing media at somewhat lower temperatures if these

are under high stress. Only killed steels can be recommended for use in the temperature range above 480°C. The fundamental problem inherent in carbon steel is that its carbide phase is precipitated along the grain boundaries upon prolonged exposure to temperatures above 425°C. This leads to intercrystalline cracks and tube failure. Though some manufacturers recommend the use of carbon steel superheaters to 500°C, the use of carbon steel is generally restricted to temperatures below 425°C.

Carbon steels find their application in the manufacture of boiler drums and vessels at pressures 6 – 12 MN/m^2 and temperatures upto 450°C. These are also used in making tubes of heating surfaces for temperatures upto 480° –500°C.

Low-Alloy Steels

These are superior to carbon steels in that they

(a) retain greater strength and impact resistance at a higher temperature
(b) are more resistant to corrosion
(c) possess high-temperature oxidation resistance and stability.

The low-alloy steels belong to the pearlitic class; they contain a maximum of 4 – 5% of all alloying elements.

Low-alloy steels are resistant to creep at temperatures upto 580°C. Hence these are used in making superheater tubes and headers and steam pipelines—the elements which operate under creep conditions. They are also used for making boiler drums at working pressures upto 18 MN/m^2.

Not only are these creep resistant but also resistant to scale formation at temperatures upto 580°C. They are called refractory steels if they can retain the creep resistance and high temperature scale resistance beyond 580°C.

The chief alloying elements are chromium, molybdenum, silicon and aluminium.

Molybdenum gets dissolved in ferrite and increases the long-term strength and creep resistance. However, prolonged exposure to temperatures exceeding 470°C causes the transformation of the carbide phase into graphite and that restricts the use of plain carbon-molybdenum steel to a maximum temperature of 425° – 470°C.

Elements like chromium, silicon and aluminium impart scale resistance to the steel as they form dense refractory oxides of Cr_2O_3, SiO_2 and Al_2O_3 on the surface of the components. Their coefficients of expansion are very close to that of steel and they protect the base metal from further oxidation. In the making of boiler components, low-alloyed Cr-Mo class steels are frequently used because of their better creep resistance at elevated temperatures, less chances of graphitization and good weldability.

Cr	Mo	Applications
0.4–0.6	0.4–0.6	Steam headers and pipelines
0.8–1.1	0.4–0.6	Superheater tubes for temp. 475–550°C

Vanadium has a strong carbide forming tendency and hence the addition of vanadium (0.15–0.35%) the low-alloyed pearlitic class improves the creep resistance of steel which therefore can be utilized for making boiler elements subjected to higher temperature and pressure.

Cr	Mo	V	Nb	Applications
0.9–1.25	0.25–0.35	0.15–0.35	—	Boiler tubes and steam pipelines operating temperature up to 565°–580°C
1.2–1.5	1–1.25	0.25–0.35	—	Preheaters and steam pipelines subject to operating temperatures up to 565°–580°C
2–2.5	0.5–0.75	0.25–0.35	0.5–0.75	Superheaters operating at temperatures up to 580°C.

Chromium improves the scale resistance of steel. This property can be further boosted by addition of a small quantity of silicon (0.4–0.7%) rendering the pearlitic steel very highly scale resistant. If a very small quantity of boron (0.003–0.005%) is added to it, the steel attains a high degree of refractoriness. However, these steels are very hard and need special care during the heat treatment operation.

Cr	Mo	V	Si	B	Applications
1.5–2	0.5–0.75	0.25–0.35	0.4–0.7	0.005	Superheaters (operating temperatures up to 580°C)

Manganese improves the strength and hardness of steel. To it, if molybdenum is added, the steel gains higher heat resistance (creep resistance). Nickel also improves the strength and hardness as well as the corrosion resistance of steel. Hence this type of steel is used in making boiler drums and feedwater pipelines for supercritical pressure for continuous operation without the risk of creep.

Mn	Ni	Mo	Applications
0.8–1.2	1–1.35	0.45–0.55	Boiler drums (Working Pressure: 14-18.5 MN/m^2)
0.9–1.4	0.75–1.2	–	Feedwater pipelines (Pressure: up to 38 MN/m^2; Temp. : up to 450°C)

High-Alloyed Austenitic Class Steels

They belong to either the high-alloyed chromium-nickel austenite or the chromium-nickel-manganese austenite class whose chief alloying elements are chromium and nickel. Together these two elements may exceed 30% of the steel composition. Both nickel and chromium substantially increase the austenite stability and improve the strength and hardness without any appreciable loss in ductility and toughness.

These have high heat and scale resistance at elevated temperatures and hence find applications in the manufacture of steam pipelines subject to a temperature of 650°–700°C.

The austenitic class of steels owe their high scale resistance to the presence of a high concentration of chromium which forms a protective, impervious, hard chromium oxide film over the surface to prevent the base metal from further oxidation. However, these high chromium steels must be stabilized by adding stabilizing elements, viz. titanium (0.5–1%) and niobium (0.6–1%) to prevent intercrystalline corrosion that occurs due to chromium carbide precipitation at the grain boundaries under prolonged exposure to high temperature. These elements (Ti, Nb) being strong carbide formers prevent the formation of chromium carbides.

Austenitic steels have high heat resistance due to chromium which increases the resistance to softening at elevated temperatures. This property can be further enhanced by adding molybdenum and tungsten which form high-disperse strong compounds Fe_2Mo and Fe_2W in the steel matrix to improve the strength and creep resistance of the structure at an elevated temperature.

High-alloyed Martensitic and Martensitic-Ferritic Class

These are no-nickel steels have chromium (11-15%) as the chief alloying element with the addition of tungsten, vanadium and molybdenum for higher heat resistance. These combinations of alloying elements produce a low-carbon martensite or a martensitic ferrite structure in steel which lacks the following drawbacks of austenitic steel:

1. Austenitic steel is very expensive because of high nickel content.
2. Austenitic steels are liable to stress-corrosion cracking.

Cr	Ni	W	Mo	Ti	Nb	B	Applications
13–15	13–15	2.5–2.75	0.5–0.6	–	–	–	Superheaters and steampipes at temp. up to 650°C
17–19	12–15	–	–	0.65	–	–	-do-
15–17	8–10	–	1.5–2	–	–	–	Steam pipelines at steam temp. up to 650°C
13–15	18–20	2–2.5	–	–	1–1.25	–	Superheater coils and steam pipelines at temp. up to 700°C.
15–18	15–18	2–3	0.5–1	–	0.5–1	0.005	-do-

3. Austenitic steels are prone to weld-decay—formation of annular cracks closed to welds during heating due to sharp drop in ductility.

REFRACTORY SYSTEM IN STEAM GENERATION PLANTS

Refractory is a material used to form a protective lining on the external surface of waterwalls of the boiler; it protects the walls from the products of combustion.

Many early refuse-to-energy plants in the USA experienced operational difficulties which led to frequent shutdown for repairs. Investigations revealed that some facility problems stemmed from the type of refractory used in the plant.

Waste-burning boiler systems achieve maximum efficiency by transferring the heat of combustion to the boiler tubes that line the walls of the combustion chamber. To maximize heat transfer, the tubes are made from heat resistant alloys having a high coefficient of thermal conductivity. To maximize the surface area of the tubing, further increasing heat transfer, steel studs are radially arrayed on tubes.

Heat transfer and boiler efficiency would be further enhanced if the tubes could be directly exposed to the heat of combustion. However, the tubes would quickly corrode and eventually burst in such aggressive environment. A refractory, then, is necessary in order to protect the tubes from the intense heat and corrosive products of combustion.

As the waste burns, temperatures in the combustion chamber of the boiler reach up to 1365°K, which is fortunately, well within the capability range of modern refractory materials.

However, the combustion process yields an enormous mass of ash and slag. They can accumulate on the refractory lining of the waterwalls. Such ash and slag build-up is detrimental to boiler efficiency and needs periodic cleaning which requires an expensive shutdown (outage) of the plant.

Early Plant Problems

Early US utilities borrowing European waste-to-energy technology experienced operational problems due to inadequate heat transfer by the refractory. This led to build -up of slag and ash on the boiler walls to a thickness of several hundred millimeters. The result was a dramatic reduction in heat transfer; boiler efficiency dropped. What's more, combustion chamber temperatures often reached levels higher than design specifications.

Refractory-lined waterwalls must withdraw enough heat to ensure that no gases in excess of design temperatures reach the superheaters. The superheaters are generally unprotected by refractory material and can be damaged by excessive heat. Also it is imperative to extract as much heat as possible by the waterwalls in order to slow down the velocity of the exhaust gases. Gases of excessively high velocity propel ash into the superheaters, economizers and air-preheaters leading to early erosion/corrosion damage.

Operating problems cropped up in early US waste-to-energy facilities because of the difference in the nature of US wastes compared to those in Europe. European waste contains far less paper and plastic than in the US. The results:

US waste burns far hotter and produces more corrosive combustion products.

Therefore, the refractories that performed well in Europe fared badly in USA. This resulted in the development of new refractory systems which are more efficient and longer-lasting.

REFRACTORY SYSTEM

Two types of refractory systems find their extensive application in thermal powerplants and incinerator boilers. One stems from silicon carbide and the other from aluminium oxide.

Silicon carbide (SiC) products are known for their exceptional heat transfer properties and superior durability. Unique SiC grain shape, purity and density form the very basis of its excellent ther-

mal conductivity. Higher the silicon carbide content of a refractory formulation, higher will be its heat transfer and wear resistance.

Aluminum oxide (Al_2O_3) products couple exceptional strength and durability with non-oxidation properties. Because of its high thermal stability, Al_2O_3 is not affected in high oxidation environments.

Superior thermal conductivity means more efficient heat transfer through the boiler tube protection system keeping fireside refractory surfaces cooler whereupon slag does not adhere and heat transfer gets optimized. Optimum heat transfer to the boiler's tubewalls reduces the temperature of the combustion products and lowers the velocity of fluegases with the effect that screen tubes and superheater tubes are protected from erosion and corrosion. That is how a refractory system ensures optimum heat transfer to the waterwalls and at the same time prolongs the life of downstream boiler components netting in high efficiencies, less downtime, less maintenance and lower costs.

Silicon Carbide

Widely used as a ceramic material in steel and metal-melting furnaces, silicon carbide sports high thermal conductivity which is the key advantage of this material. The greater the silicon carbide content of a refractory, the better the refractory can transfer heat to the boiler tubes underneath the refractory.

Operating experiences with incinerator boilers have shown that refractories with a high silicon carbide (SiC) content—80% or more—are well suited to this application.

The thermal conductivity of a refractory containing silicon carbide drops almost exponentially as the SiC content decreases below 80%. A 60% SiC refractory will generally have a thermal conductivity only 50% that of a 90% SiC refractory.

Adherance characteristics of molten slag to the hot face of the refractory is directly related to the temperature of the refractory surface. Slag build-up increases with temperature and fireside refractory temperature decreases with higher heat transfer characteristics of the refractory material. Thus, properly designed and installed, high SiC-content refractories will have little chance of slag/ash build-up because of high thermal conductivity of SiC. Thus, costly downtime for cleaning is limited.

Exceptionally strong and wear resistant, silicon carbide is water insoluble at any temperature and extremely resistant to erosion. Therefore, it remains intact during shoot-blowing operation.

Its superior bond strength is developed at ambient temperatures throughout its applied thickness. Precise formulation insures that the gunning monolith has the lowest rebound available and that the castable monolith has maximum density. Drying and curing time is about three days.

SiC-refractories expand and contract than other refractories during temperature cycling. As a result such refractories have a longer life than others.

Major Disadvantage: Silicon carbide refractories are particularly prone to oxidation in the temperature range of 1125°K to 1375°K. The addition of moisture to the atmosphere accelerates the attack.

This occurs particularly in boilers where MSW is burned. Such boilers use silicon carbide sidewall panels to resist abrasion of the trash being pushed through. A large quantity of water vapour is formed by drying out and burning of trash. In some incinerators an additional large quantity of water in the form of a high pressure spray is added to prevent slag build-up on the wall.

SiC-refractories fail because of rapid oxidation, growth, warpage, cracking and structural failure.

Silicon carbide is attacked by carbon monoxide, water vapour, and some other oxygen bearing gases which may react with silicon carbide as:

$$SiC + CO \longrightarrow SiO_2 + 3C$$

This oxidation rate is affected by the porosity and permeability of the refractory body, bond chemistry, grain size and furnace environment.

As silicon carbide is converted to silica, it undergoes an 80% + volume increase which causes the refractory structures to become weak and crumble.

Phosphate-bonded Silicon Carbide Refractories

Such refractory systems usually contain more than 90% SiC and they offer exceptional heat transfer performance. Phosphates actually act as bonding materials, i.e. they actually bond to the surfaces they protect rather than relying on a close mechanical fit. This bond greatly reduces refractory separation from the metal tube and stud surfaces due to differential thermal cycling. The superior heat transfer capability of the material is enhanced by the direct bond. Drying and curing time is about the same as for cement bonded refractories.

Calcium-Aluminate Silicon Carbide Refractories

The early waste-to-energy utilities in the United States used silicon carbide refractories that had a lower SiC than those now in use. Typically, they contained phosphates as a bonding agent to help the refractory bond to the walls of the boilers.

Unfortunately, phosphate bonds proved to be water-soluble at temperatures below 590°K. Because water in the boiler tubes never exceeded 590°K, this refractory system lining the waterwall remained water-soluble.

With the lower SiC content and density, these early refractories experienced slag and ash build-up. Many plants began to use fire-hoses as means to remove slag and ash and, thereby, recover heat transfer capability. But because the phosphate-bonded refractory was water-soluble, it sloughed off and exposed the boiler tubing.

Quite literally, plant employees were unknowingly washing the protective material off the tubing.

Recent experience has shown that calcium-bonded SiC refractories such as Crystolon LC 904, which are not water-soluble after installation, are not affected at all by water washing. In addition, their high thermal conductivity eliminates slag/ash build-up, so little if any water washing is required.

To maintain high strength, these refractories typically contain a small percentage of calcium-aluminate cement. Calcium-aluminate bonded SiC refractories tend to flow during installation. This feature allow the gunner to more easily obtain maximum density and follow tubewall contour.

Aluminum Oxide Refractory

Both the gunning and castable monoliths provide exceptional strength and will not oxidize in high moisture environments. Their ability to sustain necessary combustion temperatures make them an ideal choice for ignition arch areas in refuse burning systems. Both are non-water-soluble and made from silica/alumina grains completely calcined so that the resulting mullite is a full conversion mullite that will resist spalling during boiler use.

INSTALLATION

Regardless of the type of refractory used, installation is critical to refractory performance.

The thickness of the refractory is a key element in maintaining heat transfer. Therefore, it is extremely important that proper installation techniques be used to assure that proper thickness is maintained:

1. There must be no voids or air spaces
2. Thickness should be limited to 6 – 7 mm above the stud tips
3. Rebound rates, where the material rebounds off the surface during installation, should be minimum (Usually it varies in

the range of 5–20% of the total amount of refractory used).

Higher than necessary rebound affects in two ways. The cost of wasted material is higher than it should be used and, since the heavier, coarser fraction of the mix rebounds, the density can be affected and heat transfer capability reduced.

Installation can be performed either by gunning or by hand application. Using two sets of gunning equipment and working around the clock, application of over 50 tons of refractory can be accomplished in as little as 22 hours. Approximately 48 hours are required for drying and curing. After completion of the curing/drying cycle, the boiler can be filled with warm water and burning commenced.

Hand application has also been used. This can result in a smoother refractory surface which should have less tendency to accumulate slag and ash build-up. Air spaces can be eliminated and thickness can be controlled if the installation is performed properly.

APPLICATION OF PREFORMED REFRACTORY SHAPES

Gunned or trowelled refractories are used in most areas of boilers. However, certain areas or components benefit from preformed refractory shapes. Silicon carbide shields have been developed and tested for superheater tubes.

Shields protect the tubes from excessive temperatures, corrosion, and the abrasion of airborne particles. The refractory shields are an alterantive to metal shields, which experience corrosion at a far greater rate.

Preformed refractory shapes are also used to protect the boiler tube sidewalls at the grate from abrasion and high temperatures. Shapes, rather than gunned refractories are used here because of their better wear resistance properties.

A TECHNICAL PROBLEM

Steel studs are provided on waterwalls to enhance heat transfer rate. However, they pose problems as well.

One problem occurs during refractory installation. The denser stud patterns require closer attention during installation to ensure complete filling and maximum density throughout the refractory thickness, and to obtain maximum heat transfer.

Despite refractory coverage over the studs, there can be corrosion of the studs beneath the refractory. This becomes particularly a problem in the hottest part of the combustion chamber, where corrosive combustion gases permeat the refractory layer and reach the tips of the steel studs. The resulting corrosion of the steel stud is a volume expansion process whereupon the stud tip expands and pops off the refractory coverage and renders it more vulnerable to slag attack.

One typical solution to this problem is to slide the protective jacket of SiC sleeves over the studs before refractory installation. The sleeves, and mortar which holds them on, effectively protect the studs by lowering their temperature. This prevents chemical attack (chemical reaction rates drop as temperatures decrease).

Unfortunately, sleeves also tend to decrease heat transfer to the circulating BFW. Therefore, use of extremely high-conductivity sleeves is strongly recommended. And they must be carefully installed to minimize the air gaps.

Although sleeves deter heat transfer and could lead to higher slag build-up, there is obviously a need for them to protect studs in the highest-temperature areas of some boilers.

A typical boiler might contain as many as 100 000 boiler tube studs. If sleeves are individually placed on all studs (as has been done in many systems), labor costs may run considerably high.

Sources

1. The Basics of Refractory—Donald K. Johnson
(Waste Age, 1987)
2. Technical Bulletin (Norton Refractory System)
3. Technical Bulletin No. S-AP-G2.1.1. (Advanced Ceramics, Norton Co./1 New Bond Street/Worcester/MA 01615-008/USA)

REFRACTORY SYSTEMS

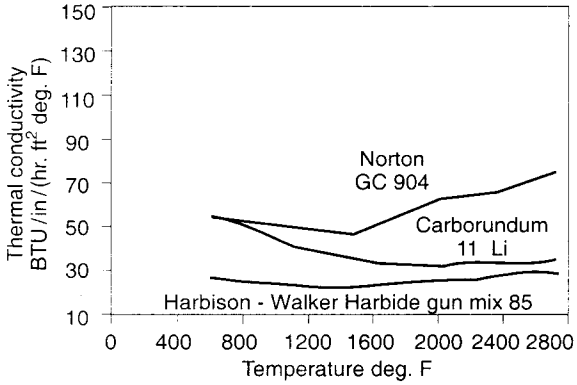


Fig. A III.1 *Thermal conductivity vs temperature of cement bonded silicon carbide gunning mixes.*

INSTALLATION PROCEDURES FOR SILICON CARBIDE TUBE SHIELDS

For 360° interlocking tube shields

1. Butter inside surface on both halves with silicon carbide mortar.
2. Place one half around tube and hold in place, place other half around tube and slide together interlocking the two halves making sure mortar fills all voids between tube and tube shield. (Fig. A III. 4)

For "C" Style and 180° Tube Shields

1. Butter inside surface of tube shield with silicon carbide mortar.
2. Place around tube and compress making sure mortar fills all voids between tube and tube shield. (Fig. A III. 4)
3. Secure with clamps or wire top and bottom.

Crystolon® Silicon Carbide Trowel Mix

TC-143

TC-143 is a dense high purity high silicon carbide content refractory designed specifically for trowel installation on studded tube walls in boilers. It utilizes CRYSTOLON® silicon carbide and a chemical bond to achieve its unique properties. Its high heat transfer has been achieved by maximizing silicon carbide content and installed density. This design allows minimum ash/slag buildup on the walls.

The refractory mix utilizes a unique phosphate bond that creates higher bonding strength than other presently available similar mixes, particularly in the low temperature area adjacent to the tubes and studs. TC-143 provides superior bonding to the metal waterwall surface so that maximum heat transfer is maintained throughout the life of the protective refractory lining in spite of many temperature excursions that normally occur.

***Typical Characteristics*: TC-143**

Chemical Analysis:

SiC	90.0
SiO_2	3.0
Al_2O_3	2.8
Fe_2O_3	0.5
P_2O_5	3.0
Other	0.7

Physical Properties:

Grain Size	10F
Installed Density	150–155 lbs/ft^3

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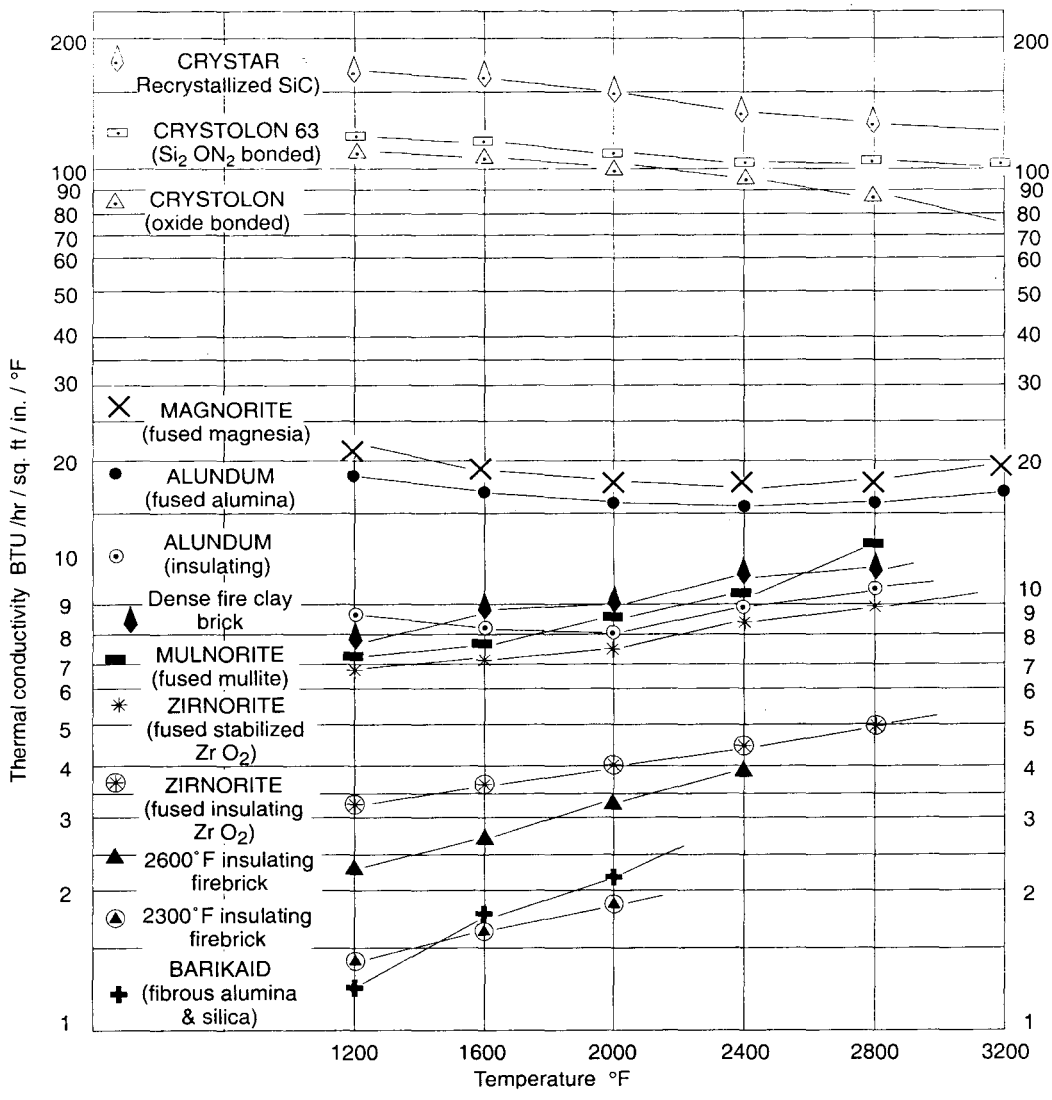

Fig. A III.2 *Thermal conductivity of various refractories.*

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Table A III.1 ***Melting Temperatures of Refractory Materials***

CENTIGRADE			C° *Melting Point*	Temperature of Electric Arc Furnace 4000°C–7230°F	F° *Melting Point*
			3890	**Hafnium Carbide** HfC	7030
			3870	**Tantalum Carbide** TaC	7000
4,000	Arc Light		3540	**Zirconium Carbide** ZrC	6400
3,500	Carbon Sublimes	Temperature			
3,370	Tungsten Melts	range	3300	**Fused Thoria** ThO_2	5970
3,300	Oxy-Acetylene Flame	of			
3,100	Rocket Engines (Combustion Gases)	electric furnace materials			
3,000	Tungsten Lamp Filaments		3140	**Titanium Carbide** Tic	5680
2,900	Oxy-Hydrogen Flame				
2,300	Direct Nitrogen Fixation		3060	**Zirconium Boride** ZrB_2	5540
2,000	Calcium Carbide Furnace				
1,900	Blast Furnace		2950	**Titanium Nitride** TiN	5350
			2900	**Titanium Boride** TiB_2	5250
			2760	**Uranium Oxide** UO_2	5000
			2700	**Zirnorite** Fused Zirconia ZrO_2	4900
			2620	**Magnorite** Fused Magnesia MgO	4750
			2450	**Norbide** Boron Carbide B_4C	4440
			2300	**Crystolon** Silicon Carbide SiC	4170
			2000	**38 Alundum** Aluminum Oxide Al_2O_3	3630
			1900	**Regular Alundum** Aluminium Oxide Al_2O_3	3450
			1840	**Mulnorite** Fused Mullite $3\,Al_2O_3 \cdot 2SiO_2$	3340

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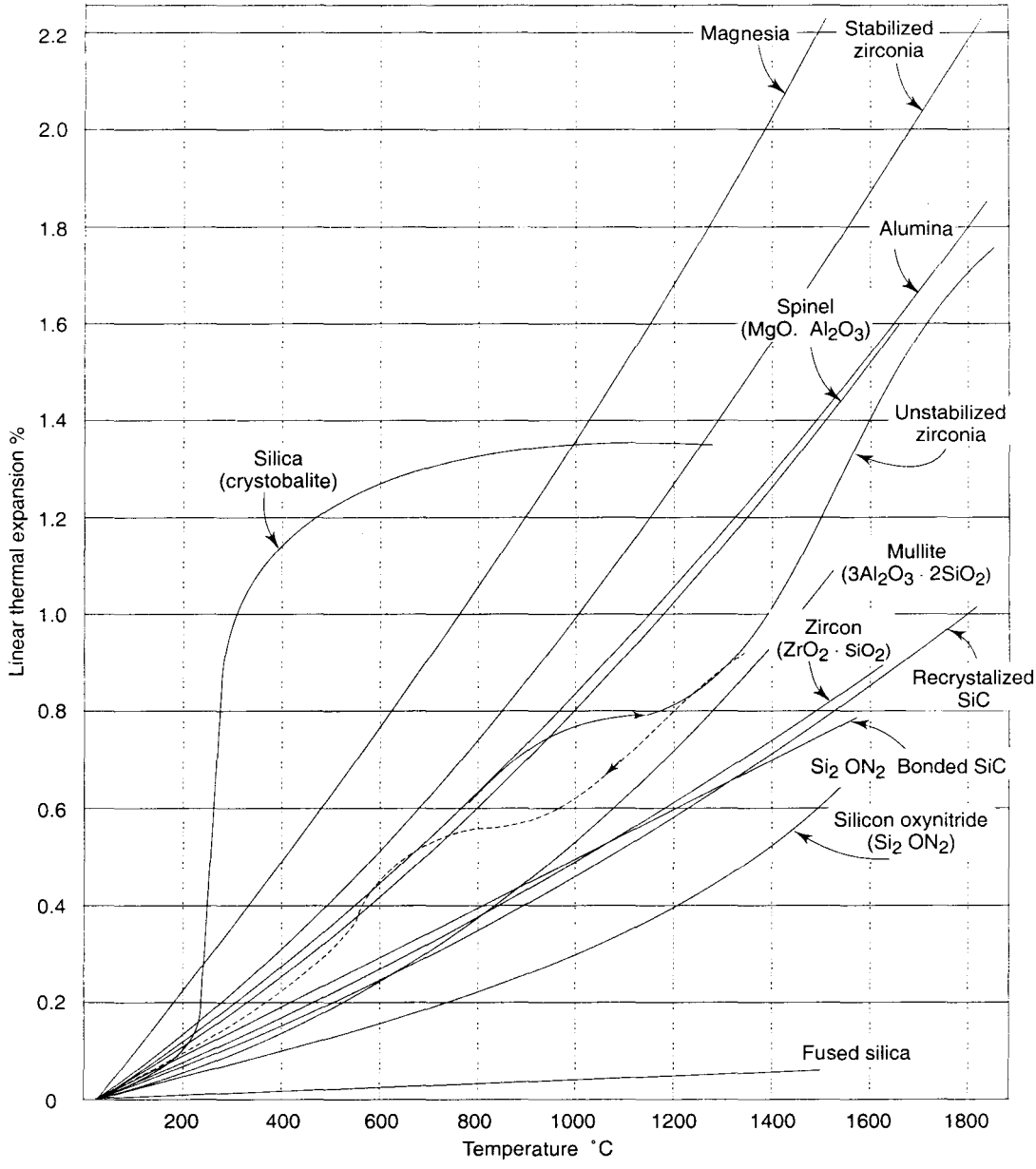

Fig. A III.3 *Typical thermal expansion of refractories.*

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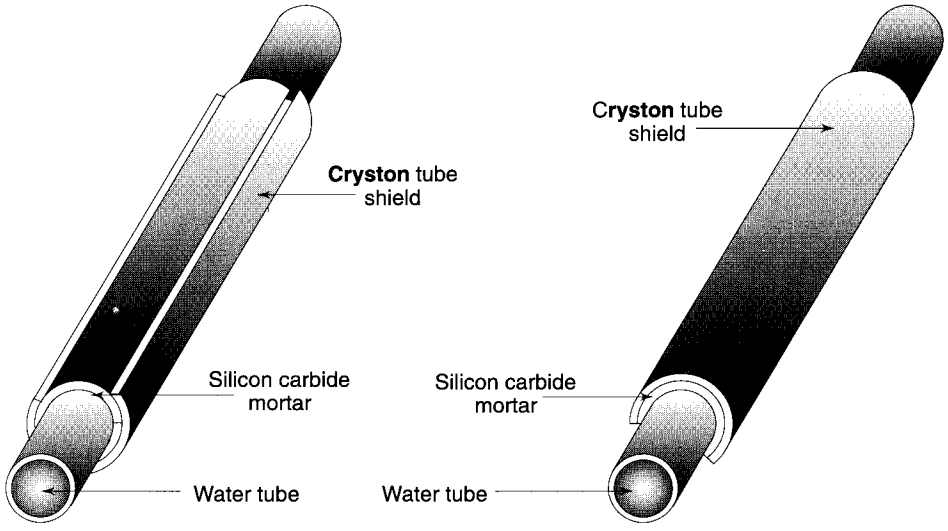

Fig. AIII.4

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Cold Modulus of Rupture:

After Firing to/Holding at

	Dried	392°F (200°C)	752°F (400°C)	1112°F (600°C)	1500°F (815°C)
PSI		1073	1145	1290	1813
MPA		7.4	7.9	8.9	12.5

Hot Modulus of Rupture:

After Firing to/Holding at

	Dried	392°F (200°C)	752°F (400°C)	1112°F (600°C)	1500°F (815°C)
PSI		840	1135	1273	1783
MPA		5.8	7.8	8.78	12.3

Crystolon® Silicon Carbide Trowel Mix

LC-947

LC-947 is a dense high purity silicon carbide castable designed specifically for trowel installation on studded boiler tube walls.

This material utilizes Norton Company's CRYSTOLON® silicon carbide grain and hydraulic bond to achieve its unique high strength properties that develop 12–24 hours after installation.

This unique material develops high strength throughout its applied thickness which allows usage along the grate line of MSW facilities where erosion can be quite severe. This is an excellent material for small repairs near corner areas and around overfire air nozzles. For repairs on upper tube wall areas, its high thermal conductivity allows maximum heat transfer which assures minimum ash/slag build-up.

Typical Characteristics: *LC-947*

Chemical Analysis:%

SiC	77–80
Al_2O_3	17–20
SiO_2	1–4
CaO	2–6
Other	2

Grain Size: 10 F

Installed Density:

Lbs/Ft^3	145–150

Cold Modulus of Rupture:

After Drying and Firing To:

200°C	450 PSI
800°C	850 PSI

Mixing:

For optimum workability and ease of installation mix this material with approximately 8 weight per cent of clean potable water.

Table A III. 2 *Boiler Systems Refractories Features and Benefits*

MATERIAL	FEATURE	BENEFIT
GC-904	Calcium Aluminate Bond	High strength achieved even in relatively cold areas next to waterwalls.
	CRYSTOLON high purity silicon carbide	Extremely dense product when combined with a calcium aluminate bond (160 lbs/ft^3).
	High density	Provides abrasion resistance in severe atmospheres such as: – along grate lines – in CFB boilers
	High thermal conductivity	High thermal conductivity. Maximizes heat flow to waterwalls. Minimizes ash/slag build up on walls. Provides excellent thermal shock resistance.
	Designed as a gunning cement	Density is maximized when material is gunned.

INSTALLATION PROCEDURES FOR GUNNING REFRACTORIES

Introduction

Gunning mixes are designed to assure that not only maximum refractory performance is attained but that rebound is minimized. In order that this is achieved, proper installation and curing techniques must be followed. Outlined in the following are specific recommendations relating to procedures and equipment that will more easily allow the efficient attainment of a good installation.

Prewetting

Obviously water controls the stickiness of a gunning mix and stickiness retards rebound which maximizes density. If water is only added near the nozzle end, it has minimum time to penetrate the fast flowing stream of dry refractory and properly wet it. Therefore, it is necessary that water be mixed with the cement in a paddle type mixer before gunning is started. The amount added, obviously must not affect the mix's ability to flow through the equipment and hoses. Generally this will be approximately 1 – 2% by weight*, how-

GC-904 is the high purity SiC refractory of NORTON Co.

* Weight means for a nominal 100 lb. bag of dry gunning mix, that the normal 1 – 2% water addition will be 1 – 2 pounds per 100 pound bag. 1 pint = 1 pound water.

ever it can be more precisely determined on site by squeezing a handful. When the correct *maximum* amount is added, the handful will form a ball which will easily break up into a granular form when finger pressure is applied. Depending on hose diameter, length, number of bends, etc. clogging could occur and then the amount of water added must be reduced. Prewetted gunning mix must not be allowed to dry out before gunning as its bond ingredients will harden, this is particularly true of hydraulically bonded products. Actual mixing should, however, stay far enough ahead of gunning requirements so that proper moisture levels can be maintained.

In addition using a wet mix will eliminate the discharge of static electricity to the gun operator.

Equipment

Gun Machine Virtually all types of gunning equipment could be utilized. However, it is recommended to use those that utilize a rotating feed wheel under a hopper as they provide a much more even and steady material flow. This makes accurate water control at the nozzle easier and results in better control of density and rebound. It has been found that nozzle size should be 1" only. The gun should be equipped with working pressure gauges and valves to individually control air pressure to the drive motor and material feed connections.

Air Compressor As hose lengths are usually quite long, it is advantageous to have a compressor capable of delivering air at approximately 500 cubic feet per minute at 90 – 100 psi to insure clog free even refractory delivery. The piping and/or hoses from the compressor to the gun should be the same size or larger than the material delivery hose in order to assure that enough air is available. Separate air hoses should be run from the compressor to the air motor drive and material feed connections.

The air should be free of oil and excess moisture. Oil will affect the refractories bonding and water could cause flow/clogging problems. Air should be checked for oil content by bubbling it into a container of water. A slick on the water surface will be noted if oil is present. A spare gun and compressor on site is always recommended.

Water Delivery Water pressure must exceed air pressure so that it is properly distributed into the refractory stream. Obviously both pressure and flow must be uniform and therefore a water pump is often advantageous.

Mixer A paddle type mixer is required for uniform prewetting. A backup mixer is good insurance against installation delays.

Communication Equipment Normally the gun is located some distance from the nozzle man and direct communication is impossible, therefore a radio or telephone headset system of some type is required in order that proper coordination is maintained during installation.

Preparation

Prior to starting actual gunning, equipment should be checked out. Hoses should have no kinks or tight bends that would retard refractory flow. No fittings in pipe or hose should be a smaller diameter in air, material flow, or water lines. Pressures and flows should be measured to ascertain they are correct.

Staging or some type of platform should be erected and positioned so that the nozzle operator can maintain a distance of approximately four feet at right angles to the surface to be gunned. The staging used must allow unobstructed access. Cross bracing, as typically used with "ladder" type staging can be a hindrance and therefore "pipe" staging is usually preferred if not required.

The surface being gunned should be clean, sandblasted to remove most rust, scale; and paint. It should also be dry and free of oil. Finally a system should be established to assure that prewetting (mixing) will keep up with refractory usage.

To enhance clean up of rebound plastic sheets or fabric tarpaulin can be laid down.

Installation

There are several major objectives to be pursued and achieved:

(1) Obtain proper maximum density
(2) Maintain minimum/maximum thickness control
(3) Obtain a reasonably smooth surface
(4) Minimize rebound

Water control at the nozzle is absolutely critical to all of the above. The amount of water and its distribution is what must be maintained. Even distribution is aided by the use of a 18" – 24" section of hose between the water ring and the nozzle as it lengthens mixing time. Using the recommended 1" *maximum I.D. nozzle* and running the feed motor on the gun at a moderately slow speed slows down refractory delivery and makes water control easier. It also aids thickness and surface control. If the feed motor speed is too slow, it will not rotate smoothly and delivery will be pulsing and erractic. Air pressure to the material feed hose should be controlled (typically 25–35 psig) to minimize rebound.

When correctly applied, the refractory surface will exhibit a smooth, slightly wet sheen appearance. Slumping is the result of entirely too much water and requires removal and reapplication as the refractory's density has been affected. Maintaining a distance of approximately 2 – 3 feet from the nozzle to the tube surface and maintaining the gun at a 90 degree angle is the best procedure. In order to prevent laminations, the surface must not be allowed to dry out between passes, therefore it is best not to work on an area of more than 50 square feet.

In order to eliminate gunning over fallen rebound, it is best to gun the floor if required, then, start at the bottom of walls and work up. Rebound will be greatest on the first pass as it is more difficult to bond to the walls than to refractory.

Ideally, once applied, the gunned refractory should not be disturbed. However, when a very smooth or contoured surface is required, some surface adjustment may be necessary. A curry comb is the best tool to remove excess thickness as it leaves an open texture. Trowels and/or floats tend to close up surface porosity making water removal more difficult during the dryout cycle. Trowels should be used only when a very smooth surface is required. Overspraying a thin veneer after trimming back is acceptable but must be done before any setting occurs. This must be done quickly (within 15 minutes) with cement (i.e., calcium aluminate) bonded refractories.

Rebound

Rebound is mainly composed of coarse particles. The properties of the refractory rely on proper distribution of particle sizing therefore if rebound is reused the properties (strength, density, thermal conductivity, etc.,) will be adversely affected. *Rebound cannot therefore be regunned directly or reblended into new gun mix.*

Note: Once installed and before sufficient heat has been introduced to eliminate all moisture from the gunning mixes, they must not be allowed to freeze. Remember that water expands when it freezes and this will at the least weaken the soundness of the lining and could actually cause refractory to spall off the walls.

Source : Technical Bulletin: S-P-C-CT10 (NORTON Co.)

CRYSTOLON® SILICON CARBIDE GUN MIX GC-904

Drying and Curing Schedule

Once installed and before sufficient heat has been introduced to eliminate all moisture from CRYSTOLON® Gunning mixes, they must not be allowed to be frozen. Water expands when it freezes and this will, at the least, weaken the

soundness of the lining and could cause actual spalling off the tube walls.

Because GC-904 is a hydraulic bonded refractory, it must be kept in a high humidity environment immediately after installation for a period of at least 24 hours to allow hydration of the bond; temperature during this period should be held at approximately 70°F. (Fig. AIII.5)

The first step is to remove the water from the refractory. It can be accomplished with hot air inside the boiler or with hot water inside the boiler tubes. The temperature of either should be brought up to approximately 190°F (not to exceed 212°F) and held for a minimum of 24 hours with forced air movement inside the boiler. If air is used (instead of hot boiler tube water), the boiler tubes should be empty to assure optimum dryout.

The next step is to raise air or water temperature to a maximum of 220°F and hold for 24 hours minimum. (Fig. AIII.5)

Thermocouples located on the tube faces and the refractory surface should be used to assure proper temperature measurement. Enough thermocouples should be installed so as to show the walls are uniformly heated throughout the boiler.

The final step is controlled heat input to gradually achieve normal water tube temperature at the end of 24 hours. If possible, burning during this period should be away from the sidewalls. During these steps, the walls should be inspected periodically to assure that any water vapor arising from the refractory surface is only similar to that of a hot cup of coffee. If it is apparent that steam under pressure is being developed within the refractory; water tube temperature should be dropped as soon as possible and remain at that lower level until the steaming subsides. Holes drilled through the membranes between the tubes can be very useful in assuring this.

This essentially completes the refractory drying and curing cycle and normal operating procedures can now occur (Fig. AIII.5)

Crystolon® is the SiC refractory product of Norton Co.

CRYSTOLON® SILICON CARBIDE REFRACTORY GC-943

Drying and Curing Procedure for Studded Boiler Tube Walls

GC-943 is a phosphate bonded monolithic refractory. Bond development begins with initial water addition, but is time dependent also. Minimal strength is developed at ambient temperatures and increases with drying and heating. It is important to keep GC-943 in its "as gunned" wet state for some period of time to allow the water and phosphate to fully react before drying commences. Final strength is a function of temperature – the higher the fired temperature, the greater the strength. A heatup schedule must take into account all of these facts.

Thermocouples located on the refractory fireside surface must be used to assure proper temperature measurement. Sufficient thermocouples should be installed to assure that the refractory covered walls are uniformly heated and temperature near burners are not excessive.

1. After installation, the refractory must be kept at ambient temperature (above freezing) for a minimum of 24 hours to allow the bond reaction to take place. This material can be allowed to stand up to 3 weeks before commencing dryout.
2. The next step is to begin removal of the water from the refractory. This is accomplished with warm water in the boiler tubes. The refractory's fireside temperature should be brought up to approximately 190°F (not to exceed 212°F) and held for a minimum of 24 hours with forced water movement inside the boiler. (Fig. AIII. 6) The heating rate should be a minimum of 15°F per hour and a maximum of 35°F per hour.
3. Refractory hot face (fireside) temperature is then raised to a maximum of 220°F and held for 24 hours minimum using the same rates (Fig. A.III.6). There would be no ad-

verse effect by holding this temperature longer (i.e. 48 hours).

4. The final high temperature refractory cure is achieved during boilout pressure raising procedure. Refractory heat-up rate to desired boiler saturation temperature should be approximately 50°F/hr. This is important because if heat-up is too slow, the refractory fireside surface could become non-permeable and prevent water escape that could lead to steam spalling. A six hour minimum hold at the final temperature is sufficient.

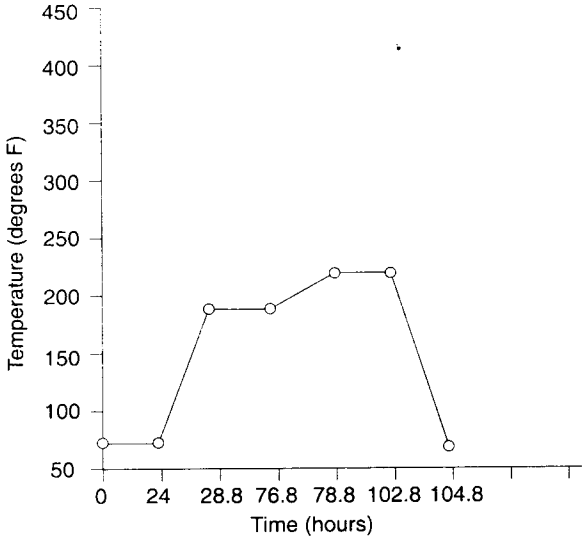


Fig. A III. 5 *Norton Company Refractory Dryout and Cure GC-904.*

This completes the refractory drying and curing cycle and normal operating procedures can now occur.

INSTALLATION & START-UP PROCEDURES FOR TROWEL REFRACTORY MIXES ON BOILER WATERWALLS

Introduction

Normally Troweling Mixes are designed to assure that not only maximum refractory performance is attained but that installation can be performed with a minimum of effort. In order that this is achieved, proper installation and curing techniques must be followed. Outlined in the following are specific recommendations relating to procedures and equipment that will more easily allow the efficient attainment of a good installation.

Preparation

Prior to placing any refractory the surface to be covered should be cleaned of any foreign material, loosely adhering rust, scale and debris. Minimal surface oxidation is acceptable.

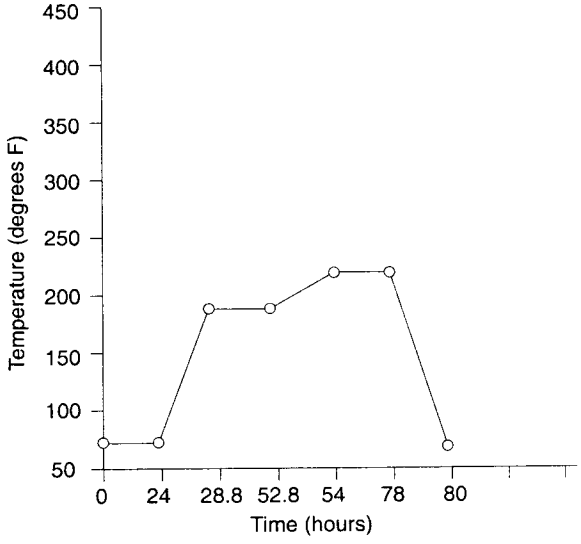


Fig. A III. 6 *Norton Company Refractory Dryout and Cure GC-943.*

On those installation where waterwall panels have been painted for corrosion protection during construction, the paint must be removed by grit blasting prior to refractory application. Alternate corrosion protective coatings in lieu of paint that do not require grit blasting are also available from renowned refractory manufacturers. The surface should also be dry and free of any oil.

All equipment, mixers and tools should be inspected, cleaned and made ready for use.

To enhance clean-up, plastic sheets or fabric tarpaulin should be laid down.

Mixing

A paddle type mixer is recommended to uniformly distribute water into the refractory. A back-up mixer is good insurance against installation delays.

The quantity of refractory mixed should be no more than that which can be placed within a period of 30 minutes. Mixed material allowed to sit unused for longer than this amount of time will begin to hydrate making it difficult to place and the strength of the refractory may be reduced. Ideally the work should be coordinated to keep mixing just ahead of placement.

The quantity of water to be mixed with the refractory can be variable depending upon temperature and humidity conditions at the time of the installation and due to slight variations in the cement binder. Therefore water should be added in a quantity to provide a mix consistency that gives maximum sticking when a ball of material is thrown on the wall but is still workable with a trowel. Approximate water quantity addition is 7 to 8% by weight. Water and refractory materials must be above 60°F and ideally closer to 80°F prior to mixing. Potable water only should be mixed with refractory.

Installation

The major objectives to be pursued and achieved are:

(1) Obtain proper maximum density
(2) Maintain proper thickness
(3) Obtain a reasonably smooth flat surface

Work should begin at the bottom of the wall and proceed upward to avoid placing refractory over fallen material.

To maximize density, voids and air gaps near the waterwall membrane must be eliminated during the application of the refractory. To accomplish this refractory should be placed by throwing handfuls of properly mixed material at the wall and forced into spaces with a rubber gloved hand. This procedure should also be followed when placing material in areas of closely spaced studs.

The refractory should be applied to a maximum thickness of 1/4 inch beyond the tips of studs. To assure proper thickness the refractory should be probed with a metal pin of the correct length. A nail attached to the end of a broom handle has worked well for these measurements.

Sufficient pressure should be applied with a trowel to eliminate voids near the surface. The surface should be trowelled to provide a flat wall surface when finished. A stiff brush or curry comb should then be run across the surface to provide an open texture to aid in removal of water during the dryout phase.

The application of a curing compound is suggested especially in those instances when the dryout procedure will lag the refractory installation by more than 48 hours. A fine water spray periodically applied to the surface is an acceptable alternative. The purpose for either of these steps is to maintain sufficient water to complete hydration. Hydration is exothermic and the surface should not be allowed to dryout before hydration is complete in 24 hours.

INCINERATOR BOILER CRYSTOLON-CRYSTON TUBE BLOCK INSTALLATION PROCEDURES

Introduction

Prefired silicon carbide tube blocks installed on incinerator boiler combustion chamber membrane tube walls offer a more thermally efficient refractory protection system. The benefits are reduced slagging and longer life with lower repair costs.

As shown in Figure AIII.7, they are shaped on the back (tube side) to match the tube and membrane. A silicon carbide mortar is used between the block and tube wall to fill any gaps. This fur-

ther enhances heat flow. In the particular design shown, a threaded stud, washer and nut is utilized to fasten the block to the wall. By tightening to a specific torque level the mortar is squeezed and densified to assure high thermal conductivity.

Tube block designs are available for all sizes of tubes and centerline spacing. In the majority of cases, the fastening stud is welded to the membrane but designs are available for attachment to the tube.

The tube block is designed so that a minimum 1/8"–1/4" wide gap is established for thermal expansion allowance in the horizontal direction. Vertical stud location establishes this expansion gap in the other direction.

Special shape designs are also available for bends such as often located on front and rear wall "bull noses." Where special shapes are not practicable (normally because of additional high mold costs) monolithic high density/thermal conductivity silicon carbide refractories can be used with conventional tube studs for protection.

As typical examples, GC-904 or GC-943 gunning refractories are recommended for these areas. If these areas are small, hand applied versions of these two refractories (LC-947 and LC-143) can be used.

Cutting of Blocks Some cutting of block in order to maximize coverage with block instead of monolithic is required. Ordinary brick saw blades are not adequate. One very popular blade is a Norton Christensen R-5194 diamond blade. These are available in 14", 18", and 20" diameters.

Preparation Typically phosphate bonded mortars are most desirable as they have better thermal transfer properties. It also appears that they actually bond the blocks to the steel walls. In order to accomplish this and to maximize heat flow, the walls must be sandblasted to remove all paint, oil, scale (rust), etc. Some surface oxidation is acceptable as long as no scale exists. In fact, with the use of a phosphate bonded mortar this surface oxidation can enhance bonding.

Sandblasting is recommended to an essentially "white metal" finish.

If sandblasting is to be done sometime prior to tube block installation and considerable oxidation is a concern, then a protective coating must be applied. One such proprietary product is PA-1019 that can be quickly and easily applied by spraying or brushing. This coating does not have to be removed later when refractory is actually installed.

Studs, Nuts, Washers In incinerator boilers, stainless steel is most often recommended and used. In some cases, a 304 SS appears to be adequate but in those with more severe combustion conditions a more corrosion resistant alloy (310 or 316) might be desirable.

Block Orientation and Layout Blocks can be installed with "in line" or staggered joints. Using a layout that keeps cutting and fitting to a minimum is economically desirable. Installing the bottom row first and progressively working up will in most cases keep cutting to a minimum. Tube panel welds made during erection are sometimes not the same exact spacing and will require cutting and fitting. When the membrane is wider than normal, locating the joint between blocks over the membrane is a simple solution. Obviously, an undersized membrane will require cutting at least one block.

Stud Welding Normally a "stud gun" is used for welding. The tube blocks will be torqued to 14 (± 2) foot pounds and, therefore, a good weld is a stringent requirement. A torque test should be utilized during stud welding to assure this.

If the welds are not of the required quality then "stick" welding is sometimes used. Study weld quality must be determined before any tube block installation commences to insure a statistically significant reliability.

Locating Stud Positions The most often used procedure is simply to use an accurately located chalk line "snapped" across the tube fronts. Remember that a minimum 1/8" – 1/4" gap must exist between horizontal rows and that errors can be accumulative as row over row proceeds.

Tube Block Installation Procedures

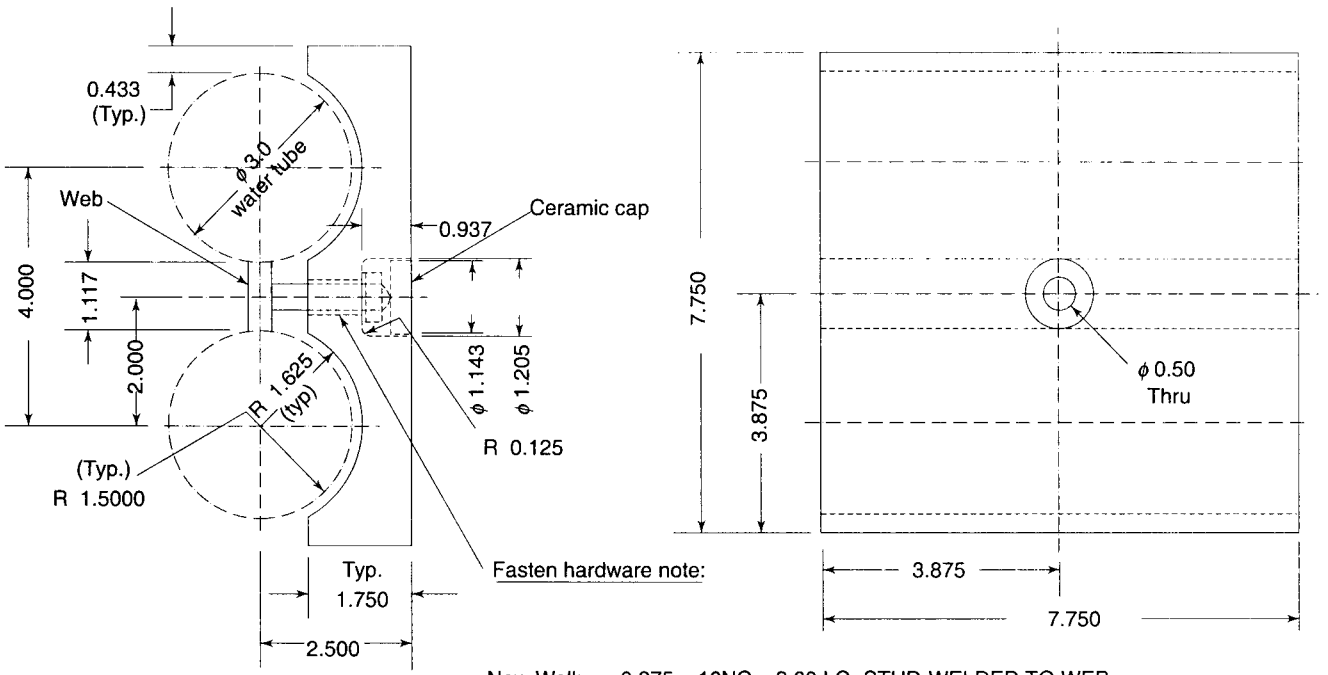
1. Mortar mixing and consistency—most phosphate bonded mortars require premixing 2 – 4 hours before use. Consistency should be that of soft butter.
2. No voids are acceptable between the blocks and tube walls so all rear block surfaces must be completely buttered. In most cases, slap troweling mortar on tube wall membrane is also used.
3. After setting the block against the wall and installing the nut and washer, a socket wrench is used to tighten to about 10 foot pounds while lightly tapping on the centre of the block with a rubber mallet. A torque wrench is normally not used at this point.
4. After 1/2 hour but less than one hour, the block should be torqued to approximately 14 (±2) foot pounds while lightly tapping over only the thicker membrane section of the block with a rubber mallet.
5. Then trowel a specified refractory cement over the countersunk nut and stud to assist corrosion protection, *OR* install a specified mortar and ceramic cap.

Notes

A. Tube block joints should be lightly mortared and excess mortar which has squeezed to the surface should be removed.
B. Cut blocks as required to fit around openings and in corners.
C. At protruding panel welds cut grooves or notches to allow the blocks to fit around the tubes. Without doing this, a stress concentration will cause breakage.
D. Once installed and before sufficient heat has been applied to eliminate all moisture, this refractory system must be protected from freezing.

Dryout and heat-up Schedules Usually typical dryout and heat-up schedules for other refractories installed will suffice for the tube blocks and mortar and these should be established first, then Refractory Supplier should be contacted to assure compatibility.

Source: Technical Bulletin : S-P-CR-BD11 (NORTON Co.)



New Wall: 0.375 – 16NC × 2.00 LG. STUD-WELDED TO WEB
0.375 I.D.Standard Washer
0.375 – 16NC Jam Nut

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Fig. A III. 7 *Tube Block ϕ 3.0 Tube on 4″ Centers.*

Source: Technical Bulletin: S-P-CR-BD11 (NORTON Co.)

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Appendix IV

Coal Formation, Coal Cleaning, Prevention of Boiler from Dewpoint Corrosion, ...etc.

FORMATION OF COAL

Coal originated from prehistoric plants. Buried deep beneath the heaps of earth, the plant bodies underwent morphological changes and gradually converted to coal in the course of millions of years. The conversion was anaerobic and took place under heat and pressure.

The gradual conversion of plant bodies to coal occurred probably via the following steps:

1. Peat Formation

The plant constituents—lignocellulose, vegetable proteins, fats and oils, resins and waxes—underwent fermentation process in peat bog with the evolution of CH_4, CO_2 and H_2O as well as heat.

This was followed by maceration and segregation in the presence of water whereupon the fermented mass converted into colloidal gel and insoluble mater. The product was **peat**.

2. Conversion to Lignites

Under pressure of the earth's crust, peat underwent further consolidation and lost much of its water.

The consolidated mass gradually took the shape of laminates under high pressure, due to the movement of the earth. The product was **lignite**.

3. Formation of Bituminous Coal

Lignite or brown coal gradually transformed to bituminous coal over thousands of years under the influen}ce of increasing pressure and rising temperatures (100–200°C) through the following steps:

(a) Progressive dewatering.

(b) Gradual elimination of oxygen content from the coal mass in the form of CO_2 and H_2O.
The coal became lighter.

(c) Amalgamation and complexation of acidic and alkaline humic substances of decayed vegetable matter.

(d) Conversion of phenolic substances into coking constituents.

4. Conversion to Anthracite

Bituminous coal underwent anthracitization where conditions were favourable, i.e. pressure reached 1500 atm. and temperatures shot up to a great extent. This was the last stage of coal formation. More oxygen content of bituminous was expelled as CO_2 and H_2O and coal became enriched in carbon.

COAL CLEANING

Cleaning of coal means physically separating the ash, and other non-combustibles as well as pyritic sulphur from coal.

Coal cleaning is carried out to ensure better emission control. And almost all coal cleaning is carried out at the mines by the coal companies/ authorities. This adds value to their product.

But not all the coal bound for powerplants is clean coal. About 33% of the coal burnt in powerplants undergoes some sort of cleaning.

Coal cleaning involves the following steps:

1. The raw coal is screened and sized. Standard hammermills, roll crushers and rotary breakers are used to size the raw coal. This is called size reduction which must avoid the creation of a large amount of coal-fines. These are difficult to clean.
   Once crushed, the coal is screened into different size ranges.
2. Screened coal is subjected to a separation process to remove impurities from it.

In jig-type units, water pulsations are fed to a suspension of raw coal in water to effect a separation of the refuse from the coal by size and density. (Fig. A IV. 1).

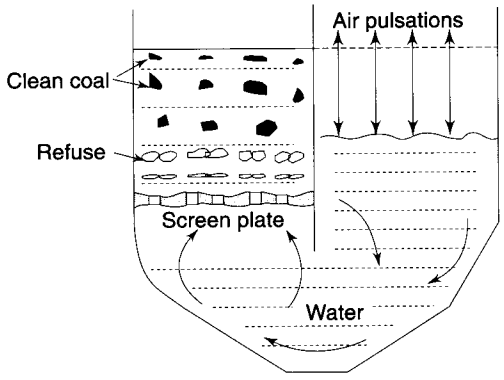


Fig. A IV. 1 *Jig Type Unit. Air pulsation is fed to aqueous suspension of raw coal to force a separation from refuse.*

In advanced coal-cleaning plants froth flotation is used to recover coal fines. This technique is based on hydrophobic and hydrophilic properties of coal to effect a separation. Sized raw coal is introduced in a vessel containing a dense fluid—usually magnetite suspension. Air is introduced to produce fine bubbles to agitate the slurry whereupon particles (pyrites and non-combustibles) with specific gravity greater than the medium sink to the bottom and get discharged as refuse while light particles float and separate as clean coal. (Fig. A IV. 2).

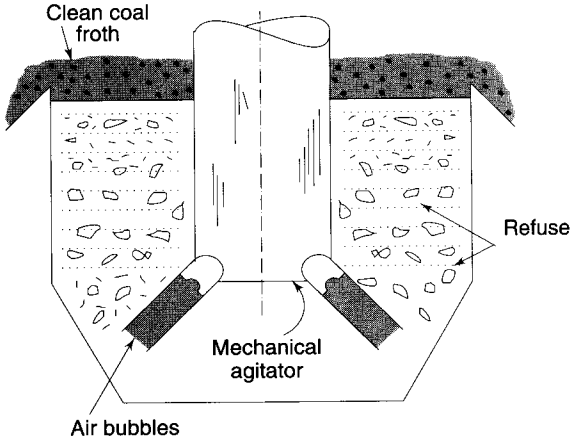


Fig. A IV. 2 *Froth-Cleaning System. Raw coal suspension in magnetite slurry is agitated by air bubbles to effect a separation of raw coal from solid refuse.*

REFERENCE FUEL

It is a conditional fuel that liberates 7,000 kcal (29.309 MJ) of heat per kg of fuel burned.

If $\dot{M}$ be the consumption of a particular fuel that upon combustion will release the same amount of heat as the reference fuel will do for its combustion $\dot{M}_{\text{ref}}$ then

$$\dot{M}\,Q = \dot{M}_{\text{ref}}\,Q_{\text{ref}}$$

$$\dot{M}_{\text{ref}} = \dot{M}\left[\frac{Q}{Q_{\text{ref}}}\right]$$

where Q = heating value of fuel under consideration, kcal/kg

Q_{ref} = heating value of reference fuel, kcal/kg

For the sake of simplicity in calculation of the combustion of various fuels in steam boilers, the concept of reference fuel has been introduced.

CONGELATION TEMPERATURE

It is referred to liquid petroleum products and is a characteristic of its fluidity.

It is the temperature at which liquid fuels become so thick that they remain static in a place and do not flow out for a duration of 60s from a test glass held at a 45° inclination.

Fuel oils having high sulphur and paraffin content are characterized by high congelation temperature (300–315 K).

The usefulness of congelation temperature lies in the selection of the scheme of transportation and storage of fuel oils.

CRITICAL PRESSURE

This is the pressure at which the density of water and steam becomes equal at saturation temperature. This is about 225 kgf/cm^2 (218 atm.) at temperature 374°C.

Because of zero density difference between water and steam, no natural circulation is possible at this point.

When this condition is reached, the entire absorbed heat goes to convert water to steam of the same volume and no absorption of latent heat occurs.

SUPERCRITICAL PRESSURE BOILERS

These boilers are those which operate at a pressure higher than 225 kgf/cm^2 and temperature exceeding 374°C (saturation temperature at critical pressure).

The first supercritical boiler plant that went into operation was PHILO-6 of the Ohio Power Co. It generates steam at 31 MN/m^2 (306 atm.) and temperature 621°C. Its designed steam generation capacity is 306 t/h to drive a 125 MW turbo-generator with a thermal efficiency of 40%. The unit consists of a once-through boiler with three slag-tap bottom cyclone furnaces burning crushed coal.

The second supercritical pressure boiler unit was installed at Philadelphia Electric Co. It is designed to produce steam [34.48 MN/m^2 (340 atm.)/649°C] at the rate of 907t/h to generate 325 MW of power from turbo-alternators. Fuel burned is bituminous and the boiler is Sulzer type—dry-bottom twin furnaces fired with tangential burners located at the corners.

Another giant is the 1 300 MW monobloc unit of the Gavin Power Station, USA. Its once-through boiler unit—61 m high, 34.4 m wide and 15.8 m in depth—has the designed capacity of generating steam (269 atm./538-543°C) is 4 438 t/h. The open-type furnace with a dry-bottom hopper is fitted with 112 pulverized coal fired burners laid out in four tiers on the front and rear walls of the furnace.

SUPERCHARGED BOILERS

These are those boilers in which combustion takes place under a pressure higher than atmospheric pressure. The term "supercharging" refers to a combustion process which is carried out in the furnace at such a pressure that useful work may be obtained from the hot flue gases after they leave the boiler by virtue of their expansion in the gas turbine.

The furnace is operated under considerable pressure, viz. 3–7 kgf/cm^2.

The supercharged boiler cycle affords the generation of steam economically at any pressure and temperature (even at supercritical pressures).

There are two types of supercharged cycles:

1. self-sustained cycle
2. power cycle.

SELF-SUSTAINED SUPERCHARGED CYCLE

Hot pressurized flue gas drives the gas turbine which is coupled to an air compressor to supply combustion air under pressure. There is no electrical power output. [Fig. A IV. 3]

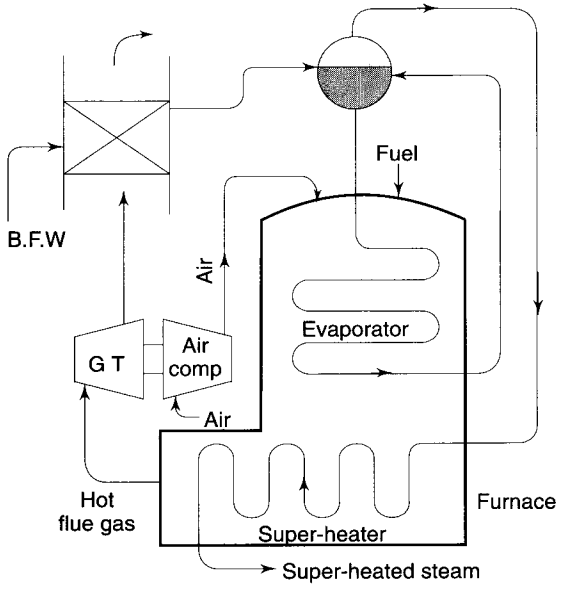


Fig. A IV. 3

POWER SUPERCHARGED CYCLE

In this cycle the gas turbine also generates electric power apart from driving the air compressor for the supply of combustion air. It has a high cycle efficiency. It can be applied to large power generating stations providing a 90% efficiency over a wide load range. [Fig. A IV. 4]

THERMAL CHARACTERISTICS OF WATER WALLS

Incident Heat Flux

Heat absorption by waterwalls in a boiler furnace is mainly by the radiant heat transfer from the high-temperature gaseous products of combustion to the waterwall tubes. The intensity of heat exchange by radiation is determined by the incident heat flux from the flame core onto the waterwalls in the boiler furnace.

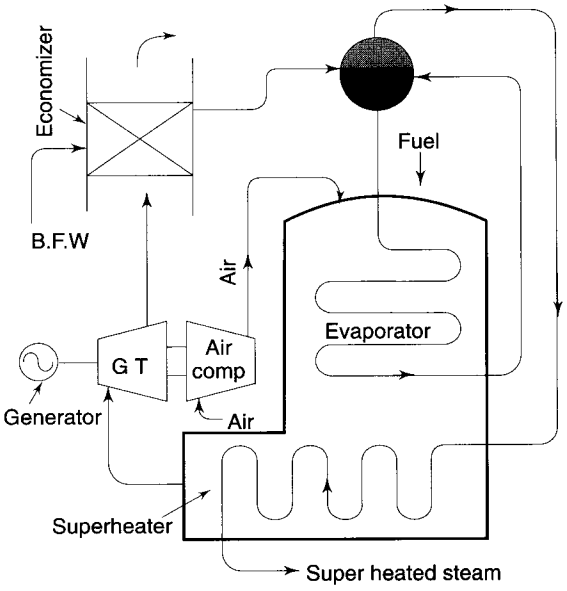


Fig. A IV. 4

According to Stefan-Boltzmann's law, the incident heat flux from the flame core can be expressed in the following form:

$$q_{inc} = \varepsilon_{fl}\,(56.7 \times 10^{-9}) \left[\frac{\theta_{fl} + 273}{100}\right]^4 \times (10^{-3})$$

kW/m^2

where ε_{fl} = flame emissivity

Emissivity of black body = $56.7 \times 10^{-9}\ W/m^2 \cdot K^4$

θ_{fl} = flame temperature, °C

The incident heat flux from the flame core in a boiler furnace is usually in the range 400–700 KW/m^2.

Effective Heat Flux

It is the sum of intrinsic heat flux and reflective heat flux

$$q_{eff} = q_{intr} + q_{refl}$$

The intrinsic heat flux is due to radiation from deposits on the tubes surface and from the refractive lining

$$q_{intr} = \varepsilon_{dep} (56.7 \times 10^{-9}) \left[\frac{\theta_{dep} + 273}{100}\right]^4 \times 10^{-3} [(1 - \varepsilon_{dep}) q_{inc}] x, \text{ kW/m}^2$$

$$= \varepsilon_{dep} (1 - \varepsilon_{dep}) x q_{inc} (\theta_{dep} + 273)^4 (56.7 \times 10^{-20}), \text{ kW/m}^2$$

And the reflected heat flux is

$$q_{refl} = \varepsilon_{refl} (56.7 \times 10^{-9}) \left[\frac{\theta_{refl} + 273}{100}\right]^4 \times 10^{-3} (1 - \varepsilon_{refl}) q_{inc} (1 - x), \text{ kW/m}^2$$

$$= \varepsilon_{refl} (1 - \varepsilon_{refl}) (1 - x) q_{inc} (\theta_{refl} + 273)^4 \times (56.7 \times 10^{-20}), \text{ kW/m}^2$$

x is a factor that determines the fraction of total radiation which falls on the waterwall surfaces. It is essentially the ratio of the surface of the waterwall absorbing radiant heat to the total surface area of the waterwalls inside the furnace.

The effective heat flux in boiler furnaces may run as high as 50–60% of the incident heat flux.

Radiant Heat Flux

It is the numerical difference between the incident heat flux and effective heat flux

$$q_{rad} = q_{inc} - q_{eff}$$

It is the radiant heat flux which is absorbed by the waterwalls and transferred to the working fluid thereof.

Coefficient of Thermal Efficiency of Waterwalls

It is the ratio of the radiant heat flux to the incident heat flux on the waterwall surfaces

$$\phi_{ef} = q_{rad}/q_{inc}$$

This parameter characterizes the fraction of total heat absorbed by the heating surfaces on the furnace walls. It varies with the type of fuel:

Fuel	ϕ_{ef}
Solid	0.4–0.45
Liquid	0.5–0.55
Natural gas	0.65

Higher the value of ϕ_{ef}, higher the operating efficiency of waterwalls, i.e. they will absorb a higher fraction of the total heat.

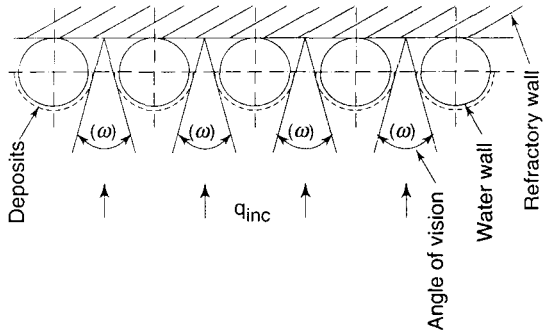


Fig. A IV. 5

The efficiency of the waterwalls is not constant throughout the boiler furnace: it is higher in the zone of the flame core and diminished with the height of the furnace towards the exit from the furnace.

Angular Coefficient of a Waterwall

It is the fraction of total radiation heat falling on the surface of the waterwalls.

This angular coefficient of waterwalls (x) is the ratio of the radiant heat absorbing surface of the waterwalls to the total surface of the waterwalls.

However, calculation of x based on the geometry of the waterwall alone will lead to an erroneous result, because a part of the incident heat flux absorbed by the refractory wall is re-radiated onto the rear surface of the waterwall tubes and thus transferred to the working fluid. Only a

small fraction of the heat flux from the refractory lining within the angle of vision of the flame ($< \omega$) escapes to the furnace volume. (Fig. A IV. 5)

Hence, x is dependent on ω which is a function of tube spacing determined by the tube pitch $p = s/d$. Smaller the tube pitch, i.e. denser the tube spacing, narrower will be the angle of vision, with the effect that a higher fraction of total heat flux falls upon the waterwall surface.

For,

$p = 1.05 - 1.11$, $x = 0.97 - 0.99$

$p = 1$ $x = 1$ (theoretically)

Coefficient of Fouling of Waterwall

It is the fraction of the incident radiant heat absorbed by the waterwall, i.e. it is the ratio of the absorbed radiant heat to the total radiant heat falling on the waterwall surface.

Now, the amount of absorbed radiant heat flux is proportional to the factor $(\theta_{fl} + 273)^4 - (\theta_{dep} + 273)^4$, therefore, the coefficient of fouling of the waterwall

$$\varepsilon = [(\theta_{fl} + 273)^4 - (\theta_{dep} + 273)^4]/(\theta_{fl} + 273)^4$$

where

θ_{fl} = flame temperature, °C

θ_{dep} = temperature of deposits on the waterwall °C

ε is always less than unity and is a measure of the relative cleanliness of the waterwall tubes. Greater the deposit thickness, larger will be the value of absolute temperature of the deposit surface and consequently the coefficient of fouling will be less.

PREVENTING DEW-POINT CORROSION DURING BOILER SHUTDOWN

Very often than not dew-point corrosion leads to tube failure in steam or hot water boilers during maintenance shutdowns or seasonal cycling. When temperatures inside the boiler drop below the dew-point during shutdown, moisture condenses on tube surfaces and reacts with sulphurous ash deposits, forming a highly localized acidic solution (pH < 2). This is followed by rapid attack of the underlying metal surfaces. As a consequence the tube fails within a relatively short time. Aggressive dew-point corrosion can penetrate more than 12 mm of carbon steel in a year.

High-sulphur coal combustion results in heavy ash build up on the fireside of the heat transfer tubes. After the deposits are removed, severe localized wall-thinning is observed.

Stainless steels are not normally used as alternatives to carbon steel in combatting dew-point corrosion because of two reasons:

(a) stainless steels are also susceptible to attack

(b) these are not economical as option.

Several steps can be adopted to prevent dew-point corrosion while the boiler is shutdown:

1. Remove ash, soot and other deposits from the fireside tube and tubesheet surfaces immediately following shutdown
2. Flush ash-free surfaces using water-jet and then air-dry
3. Coat fireside tube and tubesheet surfaces with a light-grade oil to prevent rusting
4. Stack a tray of quick-lime in the ash pits during shutdown to help absorb moisture in the air, lower the relative humidity thereby minimizing the probability of condensate forming. Make periodic checks. Replace the lime if it is no longer dry and powdery.

Note The best solution is switchover to a fuel with low sulphur content.

Appendix V

Determination of Calorific Value and Composition of Fuels

DETERMINATION OF GROSS CALORIFIC VALUE OF COAL

Theory

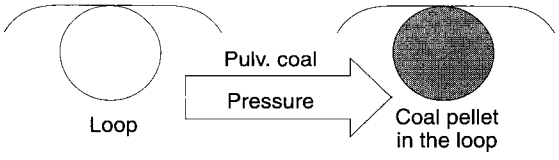
A weighed quantity of coal is completely burned in an enclosure and the released heat is allowed to increase the temperature of water in the calorimeter. Net heat absorbed by water divided by the weight of the sample gives the Gross Calorific Value of coal.

Apparatus Required

1. Mahler Bomb Calorimeter
2. Pelletizer
3. Fine iron wire-piece (10 cm long)
4. Thermometer 20 – 40 ± 0.001°C scale

Method

About 1 gm finely powdered coal sample is pelletized on the loop of the previously weighed iron wire in the pelletizer.



It is then carefully removed from the machine, weighed and placed in the crucible of the bomb calorimeter.

The ends of the loop-wire are attached to the terminal rods to ensure electrical contact. The head of the bomb calorimeter is screwed, tightened and sealed.

The outlet valve of the bomb is closed and oxygen gas from the oxygen cylinder is let in the bomb through the inlet valve till the pressure reaches 2–5 MPa. The inlet valve of the bomb and the outlet valve of the O_2 cylinder are closed.

The bomb is then placed in the calorimeter into which is taken 2000 ml of water. The electrically driven stirrer as well as the thermometer are inserted in the calorimeter.

The stirrer is started and temperature is recorded every 1 minute for 5 minutes. At this point, the ignition switch is pressed and the coal is fired. Temperature readings are taken every 1 minute for another 8 minutes.

Results

Weight of iron wire = 0.0076 g

Weight of iron-wire + Coal sample 0.7523 g

Water equivalent of the calorimeter = 400 g

Water used in the calorimeter = 2000 ml

Temperature Recordings

Initial Period	Firing Period	Final Period
0 min. 23.015°C	5 min. 22.980°C	8 min. 24.996°C
1 min. 23.010°C	6 min 24.940°C	9 min 24.992°C
2 min. 22.999°C	7 min. 24.975°C	10 min. 24.980°C
3 min. 22.999°C	8 min. 24.996°C	11 min. 24.965°C
4 min. 22.989°C		12 min. 24.955°C
5 min 22.980°C		13 min. 24.940°C

Calculations

Weight of sample on the loop

= 0.7523 – 0.0076

= 0.7447 g

Total water equivalent of calorimeter

= 2000 + 400

= 2400 g

Cooling Rate	Initial Period	Final Period
$\frac{\Delta\theta}{t}$	$\frac{23.015 - 22.980}{5}$ = 0.007°C/min.	$\frac{24.996 - 24.940}{5}$ = 0.0112°C/min.

∴ Cooling correction = Length of Firing Period × Average of Initial and Final Cooling Rates

$$= 3 \times \frac{1}{2} (0.007 + 0.0112) = 0.0273°C$$

Therefore corrected temperature rise

= (24.996 – 22.980) + 0.0273 = 2.0433°C

Therefore, Gross Calorific Value of coal

$$= \left[\frac{\text{(Total Water Equiv.} \times \text{Sp. Heat} \times \text{Corrected Temp. rise)} - \text{(Wt. of Iron Loop Wire} \times \text{Cal. Value of Iron)}}{\text{Weight of the Coal Sample}}\right]$$

= (2400 × 4.187 × 2.0433 – 0.0076 × 1600)/ 0.7447 kJ/kg

= 27 555 kJ/kg = 6 581 kcal/kg

Note The same test can be carried out for the determination of the gross calorific value of liquid fuel which is to be held in the bomb calorimeter in a plastic of known calorific value.

PROXIMATE ANALYSIS OF COAL

The proximate analysis is carried out to determine the moisture content, volatile matter, fixed carbon, coke, ash content and calorific value of a coal sample.

Theory

The moisture content is determined by drying the preweighed coal sample to a constant weight at a temperature slightly above the boiling point of water (100°C) under normal conditions.

In another run, the coke content (equal to fixed carbon + ash content) is determined by driving off the total volatile matter as well as the moisture content from a known amount of coal sample. The volatile-matter-free, dry residue is coke which is calculated by weight difference.

Finally, the coke residue in the crucible is burnt off till all the fixed carbon burns out and only the ash remains. By the difference of weights, the ash content is measured.

From these data, the other parameters are computed as follows:

% Volatile Matter = 100 – [Coke % + Moisture %]

% Fixed Carbon = Coke % – Ash %

Determination of Moisture Content

About 1g of coal sample taken in a previously weighed, dry and clean crucible is weighed.

The crucible is heated at 375 K for about an hour in an oven. At this temperature, the moisture content of coal evaporates. The crucible is allowed to cool in a dessicator and reweighed.

This process is repeated till the final constant.

Result

Weight of crucible = 10.7505 g

Weight of crucible + coal = 11.7601 g

Weight of crucible + dry coal = 11.7411 g

Calculation

Therefore, weight of moisture
= 11.7601 – 11.7411 g
= 0.0190 g
Weight of coal = 11.7601 – 10.7505 = 1.0096 g
Therefore,
moisture content = 0.019/1.0096 kg/kg of coal
= 0.0188
% moisture content = 0.0188 × 100 = 1.88 %

Determination of Coke Content

About 1 g of coal sample is taken in previously weighed, dry and clean, crucible. The crucible together with the coal sample is reweighed.

A lid is placed over the crucible which is heated over a bunsen flame for about 7 minutes.

The crucible and contents are reweighed after cooling in a dessicator. The residue is coke.

Result

Weight of crucible = 10.7712 g

Weight of crucible + coal = 11.8351 g

Weight or crucible + coke = 11.4781 g

Calculation

Weight of coke residue = 11.4781 – 10.7712 g
= 0.7069 g

Weight of coal sample = 11.8351 – 10.7712 g
= 1.0639 g

Therefore, coke % = $\frac{0.7069}{1.0639} \times 100 = 66.444$ %.

Determination of Ash Content

The coke residue in the crucible in the above experiment is now heated over a strong bunsen flame with the lid open until all the carbon is burnt off and only the ash remains.

After about 1 h of heating, the crucible is cooled in the dessicator and weighed.

Result

Weight of crucible = 10.7712 g

Weight of crucible + ash = 10.8649 g

Calculation

Weight of ash = 10.8649 – 10.7712 = 0.0937 g

Weight of coal = 11.8351 – 10.7712 = 1.0639 g

Ash % = [0.0937/1.0639] × 100 = 8.80 %

Estimation of Volatile Matter

Volatile Matter % = 100 – (Coke % + Moisture %)
= 100 – (66.444 + 1.88) = 31.676%

Estimation of Fixed Carbon

Fixed Carbon% = Coke % – Ash %
= 66.444 – 8.80 = 57.644 %

Determination of Calorific Value of Coal

Determination of volatile matter % on a dry, ash-free basis:

$$[VM]_{dry} = \frac{VM\,\%}{VM\% + FC\%} \times 100$$

$$= \frac{31.676}{31.676 + 57.644} \times 100 = 35.46\ \%$$

From the $[VM]_{dry}$ vs. α graph (Fig. A V. 1) we find

$\alpha = 90$ for $[VM]_{dry} = 35.46$

GCV = 4.187 [(82) (57.644) + (90) (24.756)] kJ/kg

= 31 727 kJ/kg

= 7577 kcal/kg cf. 1 kcal = 4.187 kJ

Goutal's formula:

GCV = 4.187 [82 (FC) + α $(VM)_{dry}$], kJ/kg

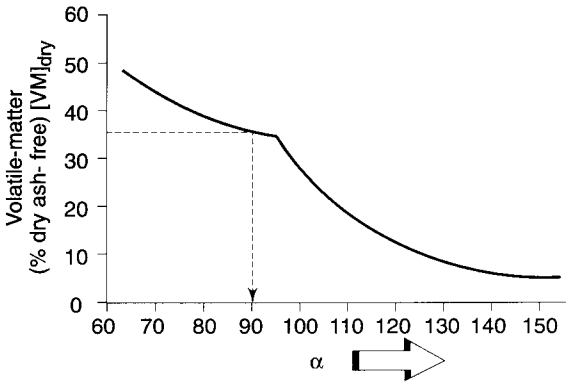


Fig. A V. 1 *Volatile-matter vs. Thermal dissociation curve.*

DETERMINATION OF CALORIFIC VALUE OF A GASEOUS FUEL

Theory

A metered quantity of gaseous fuel is burnt under preset conditions and the heat evolved is allowed to raise the temperature of water flowing at a known and constant rate.

The total heat received by water as determined from its mass flowrate, specific heat and rise of temperature, divided by the volume of gas (corrected to standard state) burned gives the higher calorific value of the gaseous fuel.

The amount of heat of evaporation of the moisture formed due to combustion of hydrogen in the fuel is subtracted from the higher calorific value

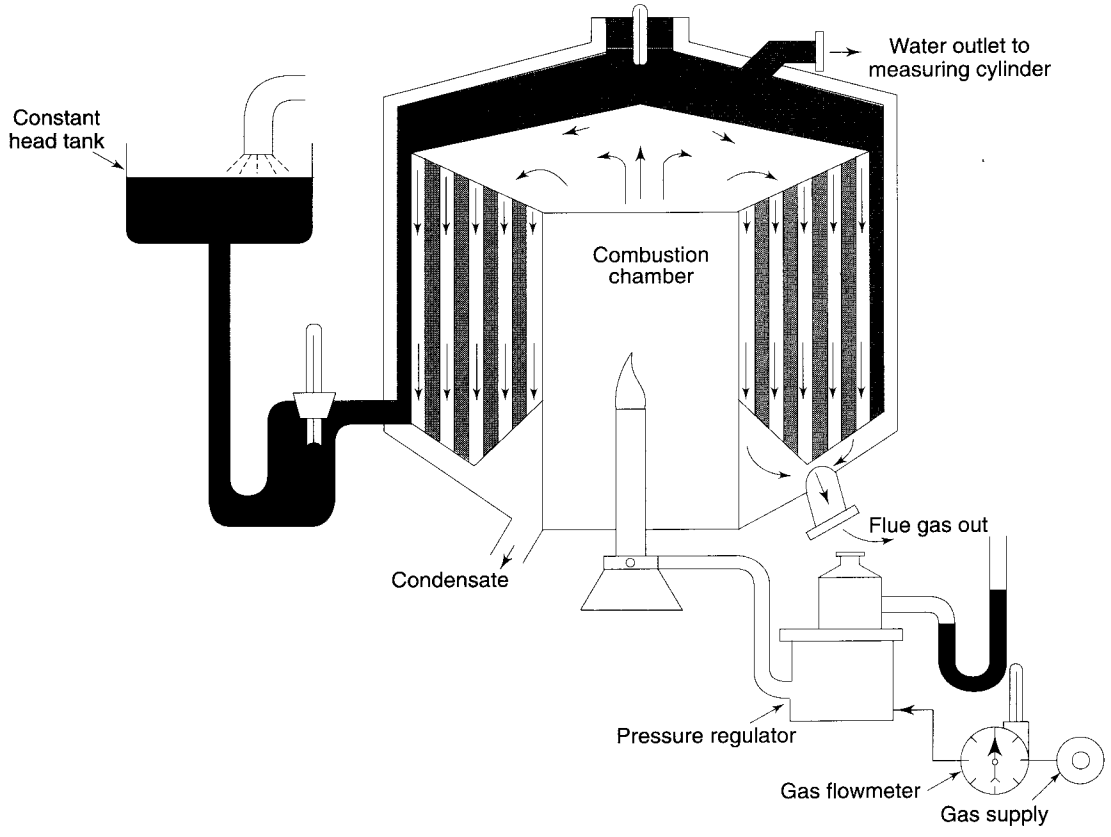


Fig. A V. 2 *Equipment setup for the determination of calorific value of a gaseous fuel.*

to determine the lower calorific value of the gaseous fuel

Apparatus Required

1. Junker's Gas Calorimeter
2. Constant water head tank
3. Thermometers (2 Nos.)
4. Gas meter
5. Gas pressure regulator

Procedure

Thermometers are placed—one at the water inlet to calorimeter and the other at water outlet from the calorimeter. (Fig. A V. 2)

With the aid of the constant head device, the water flowrate surrounding the annular space of the calorimeter is adjusted to about 2 litres/min.

The gas flowrate is set in the range 0.007 0.0085 m^3/min with the help of the gas pressure regulator.

After these adjustments, the equipment is left for 30–45 minutes to attain steady state.

The gas is ignited and readings of temperatures and the volume of water passed are noted after every 1 minute for about 12 minutes.

Results

Volume of gas burned = 0.1012 m^3

Pressure of gas supply = 101.25 kN/m^2

Room temperature = 293 K

Effluent gas temperature = 295 K

Temperature of water at inlet = 291 K

Temperature of water at outlet = 306.70 K

Mass of water circulated = 25 kg

Steam condensed = 0.068 kg

Calculations

***1. Gas Volume Correction*:** As the gas was metered at conditions other than standard conditions, its volume must be corrected to 101.33 kN/m^2 and 288 K.

Corrected gas volume

$$= 0.1012 \left[\frac{101.25}{101.33}\right]\left[\frac{288}{293}\right] = 0.09939 \text{ m}^3$$

***2. Effluent Gas Correction*:** Since the effluent gas usually leaves the calorimeter at a temperature other than room temperature, a correction in the gross calorific value of fuel is necessary by adding or subtracting the figure 8.27 × (Effluent Gas Temp.–Room Temp.) from the calorific value obtained.

In this case, the correction = 8.27 (295 – 293) = (+) 16.57 kJ/m^3

3. Gross Calorific Value of Gas

$$\text{GCV} = \frac{\text{Mass of Water} \times \text{Specific Heat} \times \text{Rise in Temp.}}{\text{Volume of Gas burned}} + \text{Correction}$$

$$= \frac{25\,(4.187)\,(306.70 - 291)}{0.09939} + 16.57$$

$$= 16\,551 \text{ kJ/m}^3$$

4. Lower Calorific Value of Gas: Since the lower calorific value differs from the higher calorific value by the heat of evaporation of the water content of fuel and that produced on combustion of hydrogen in the fuel,

LCV = HCV — (Steam Condensate) (Latent Heat of Steam at 288 K)

$$= 16\,551 - \left[\frac{0.068}{0.09939}\right](2\,454) = 14\,872 \text{ kJ/m}^3$$

cf. Latent Heat of Steam at 288 K = 2 454 kJ/kg

DETERMINATION OF PERCENTAGE COMPOSITION OF A FUEL GAS & ITS CALORIFIC VALUE

Volumetric analysis of a fuel gas as well as its gross and net calorific values can be determined with the help of an Orsat apparatus. (Fig. A V. 3)

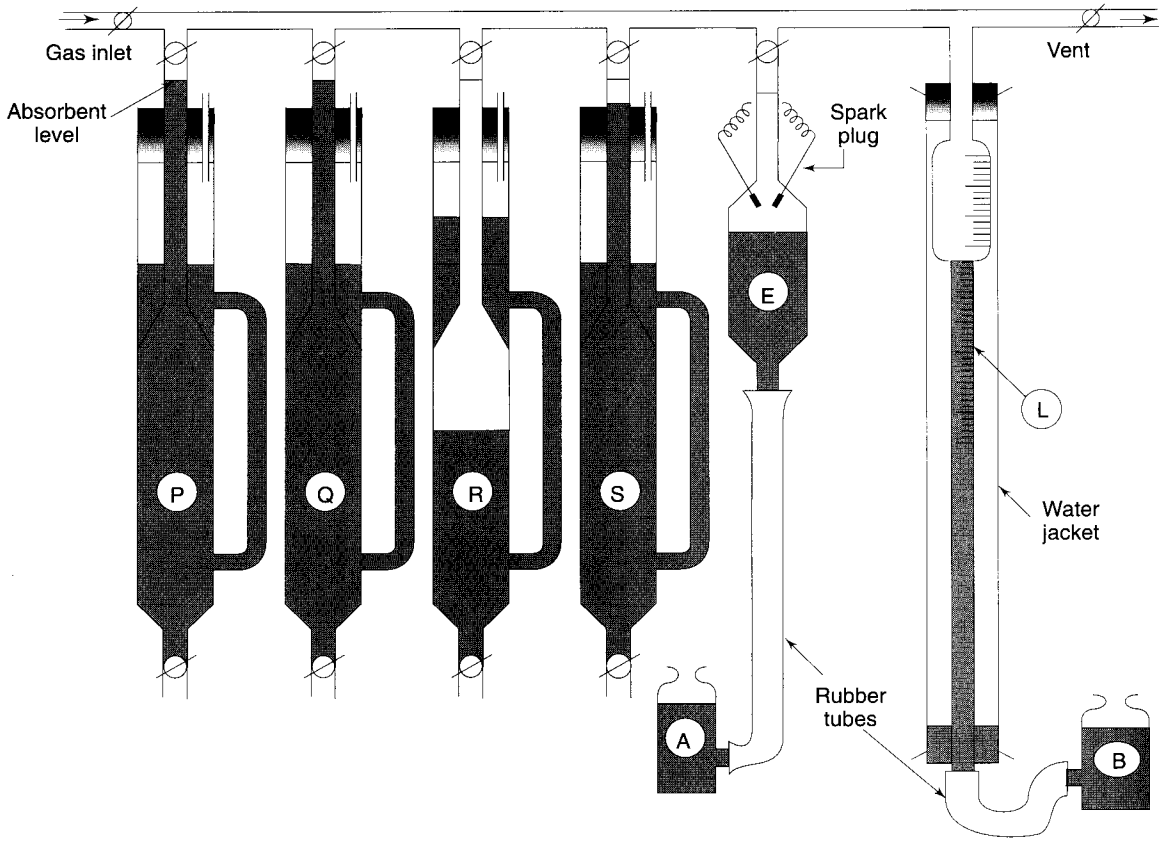


Fig. A V. 3 *Equipment setup for the determination of composition of fuel gas.*

The gas under consideration contains CO, CO_2, H_2, CH_4, C_nH_{2n} (unsaturated hydrocarbons), plus some oxygen and nitrogen.

Apparatus

The entire experiment requires the following apparatus set-up [Fig. A V. 3]

1. Two aspirators A and B for intake of gas in the pipettes and eudiometer
2. Eudiometer tube L for metering intake gas volume and the volume of gas absorbed
3. Pipettes 5 Nos.—P,Q,R,S and E, the last one being provided with a spark plug to ignite the gas-air mixture.

The function of the remaining four pipettes being:

Pipette	Gas Absorbed	Reagent	Concentration
P	C_nH_{2n}	Br_2-water	Saturated Br_2-water + 2 vols. of water
Q	CO	Cu_2Cl_2	16% Cu_2Cl_2 solution in conc. HCl
R	O_2	Alkaline pyrogallol	Pyrogallic acid 1 part + 3 parts water + 24 parts NaOH + 16 parts water
S	CO_2	KOH solution	1 part KOH + 2 parts water by mass.

All these pipettes are filled with some glass rods to increase the area of gas-liquid contact.

Theory

The gas composition is determined volumetrically. The fractions of CO, CO_2, O_2 and unsaturated hydrocarbons in a metered volume of the fuel gas are determined by their absorption in liquid reagents (vide above). The hydrogen and methane contents are estimated by exploding a given volume of the gas-air mixture in the explosion pipette. Their concentrations are calculated from the reduction in volume (due to condensation of water vapour formed) and CO_2 left-over.

When the composition of gas is known, its GCV and LCV are computed out from the known calorific values of its constituents.

Procedure

The levels of the reagents in P, Q, R and S and the water level in E are raised to the marks indicated near the taps by lowering B containing water acidified with a few drops of sulphuric acid and reddened by methyl orange indicator.

Keeping L full of liquid, the apparatus is purged off air by the fuel gas.

50 ml of the gas is drawn into L and the gas tap is closed.

The gas is now transferred to pipette S whereupon its CO_2 content is allowed to get absorbed in the KOH solution.

The gas is then transferred back to L by lowering B, the tap on pipette S is closed and the volume of the gas is noted. Every time the reading is taken, the liquids in B and L are brought to the same level so that gas volumes are measured at atmospheric pressure and at a uniform temperature as provided by the jacket water. This operation is repeated to get constant volume readings (at least three readings).

The same procedure is carried out for pipettes R, Q and P.

Now, to the pipette R all but 10 ml gas is transferred and the vent tap is opened and 40 ml of air is sucked into L. And this mixture of 10 ml. gas and 40 ml. of air is delivered to E by lowering A and then transferred back to L. This is repeated several times to ensure thorough mixing of the gas with air.

Finally, the mixture is driven to E and ignited by means of spark plugs. The volume of the leftover gas is measured in L.

Afterwards, the gas is transferred to the pipette S to estimate the volume of CO_2 produced due to combustion and then it is let out to the atmosphere.

This combustion process is carried out three times—each time taking 10 ml of gas from the pipette R.

Results

Intake sample volume = 50 ml.

Gas Volume after absorption in pipette			
S	R	Q	P
48.6 ml	48.3 ml.	41.5 ml.	41.3 ml.

10 ml. of the left over gas is combustioned with 40 ml. air.

	1st run	2nd run	Average
Volume after combustion	35.7 ml	35.3 ml	35.5 ml
Volume after absorption in S	32.5 ml	32.7 ml	32.6 ml

Calculations

$$\% CO_2 = (50 - 48.6)\ 100/50 = 2.8\%$$

$$\% O_2 = (48.6 - 48.3)\ 100/50 = 0.6\%$$

$$\% CO = (48.3 - 41.5)\ 100/50 = 13.6\%$$

$$\% C_nH_{2n} = (41.5 - 41.3)\ 100/50 = 0.4\%$$

Combustion Reactions					Volume Reduction After Condensation
(i)	$CH_4 + 2O_2$	$\longrightarrow$	$CO_2 + 2H_2O$		2x
	(x) (2x)		(x)	(2x)	
(ii)	$H_2 + 0.5\ O_2$	$\longrightarrow$	H_2O		0.5y
	(x) (0.5y)		(y)		

The CO_2 formed on combustion = 35.5 – 32.6 = 2.9 ml.

And this CO_2 entirely comes from combustion of methane in the 10 ml sample.

$\therefore x = 2.9$ ml

Volume reduction due to combustion = 50 – 35.5

= 14.5 ml

This is equal to the volume of oxygen consumption and water vapour produced condensing out.

$\therefore 2x + 0.5\ y + y = 14.5$

or $2(2.9) + 1.5y = 14.5$; $\therefore \quad y = 5.8$ ml

Gas Sample Volume	CH_4 Content	H_2 Content
10 ml	2.9 ml	5.8 ml
41.3 ml	2.9 (41.3/10) = 11.977 ml	5.8 (41.3/10) = 23.954 ml

Therefore, $CH_4\% = 11.977\ (100/50)$

$= 23.954\%$

$H_2\% = 23.954\ (100/50) = 47.908\%$

Therefore, N_2 % + Error %

= 100 – (2.8 + 0.6 + 13.6 + 0.4 + 23.954 + 47.90)

= 10.738%

CALCULATION OF CALORIFIC VALUES

1. The ***Gross Calorific Value*** of the fuel gas sample is calculated from the calorific values of its constituents.

$$GCV = [0.47908 \times 12\,780 + 0.23954 \times 39\,755 + 0.136 \times 12\,706 + 0.004 \times 62412]\ kJ/m^3$$

$= 17\,623\ kJ/m^3\ (4\,209\ kcal/m^3)$

Gas	Calorific Value
H_2	12 780 kJ/m^3
CH_4	39 755 kJ/m^3
CO	12 706 kJ/m^3
C_2H_4	62 412 kJ/m^3

2. The ***Net Calorific Value*** is obtained by deducting the latent heat of evaporation of water (formed during combustion) from gross calorific value.

Assuming the unsaturated hydrocarbon present almost as C_2H_4, the volume of water vapour produced per 100 m^3 of the sample on combustion can be calculated as:

Constituent	Combustion Reaction	Water Produced
H_2 (47.908 ml)	$H_2 + 1/2\ O_2 \longrightarrow H_2O$	47.908 ml
CH_4 (23.954 ml)	$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$	2×23.954 = 47.908 ml
C_2H_4 (0.4 ml)	$C_2H_4 + 4O_2 \longrightarrow 2CO_2 + 2H_2O$	$2 \times 0.4 = 0.8$ ml
		(Total) 96.616 ml
		$= \frac{96.616}{22.4}(18)$ kg
		= 77.634 kg.

Therefore, the net calorific value of fuel gas

$$= 17\,623 - \frac{77.634}{100}\ (2\,455)\ kJ/m^3$$

(cf. Latent Heat of Steam = 2 455 kJ/kg)

= 15 717 kJ/m^3 (3 754 kcal/m^3)

SUMMARY

Fuel Gas Composition	% (Volume)
H_2	47.908
CH_4	23.954
CO	13.6
O_2	2.8
CO_2	0.6
C_nH_{2n}	0.4
N_2 + Error	10.738
	100.000

Gross Calorific Value

= 17 623 kJ/m^3 (4 209 kcal/m^3)

Net Calorific Value

= 15 711 kJ/m^3 (3 754 kcal/m^3)

Appendix VI

Environmental Pollution and its Control in Boiler Plants

Large boiler units of thermal power plants around the world gobble up as much as 40% of the total global output of fuel, let alone those chemical plants that burn fossil fuels for the generation of steam for process use. And therefore, these fossil-fuel-burning systems pose a substantial threat to the environment by ejecting heat and certain harmful pollutants into the atmosphere and water basins. Since environmental pollution—particularly air and water pollution—knows no political boundaries, it has become a global concern to protect our precious environment from the harmful effluents of industrial plants for the sustained survival of life on earth.

AIR POLLUTION DUE TO FOSSIL-FUEL BURNING

The boiler plants pollute the atmosphere by injecting into it

1. **oxides of nitrogen** (NO_x = NO + NO_2)
2. **oxides of sulphur** (SO_x = SO_2 + SO_3)
3. **solid ash particles** as suspended matters or particulates
4. **vanadium pentoxide** V_2O_5.

However, the types of gaseous pollutants depends on the nature of the fuel burned. When coal is burned, the major pollutants are fly ash, soot, sulphur dioxide and NO_x. Whereas in the case of fuel oil burning, SO_2 and NO_x constitute the major gaseous effluents. However most Indian coals are low in sulphur content, except Assam coal having sulphur content from 2% to as high as 8%.

Over and above the foregoing air pollutants, flue gases may contain carbon-monoxide (CO) and hydrocarbons like CH_4, C_2H_4 and C_{20} H_{12} (benzpyrene) and soot.

Of course, certain components of gaseous effluents from fossil-fuel burning systems are harmless to man. These include water vapour, carbon dioxide, oxygen and nitrogen. Other ingredients as cited above are harmful to the biosphere in varying degrees.

Vanadium pentoxide and benzpyrene are extremely dangerous substances. Vanadium appears in minor quantities in certain fuel oils and when these oils are burned V_2O_5 is formed.

Benzpyrene is formed during any type of fossil-fuel burning under condition of oxygen deficiency and is also formed on the slow decomposition of soot. It is a carcinogen and causes lung cancer.

Carbon monoxide is potentially quite dangerous. It is odourless, colourless and tasteless. The human body can tolerate CO in concentrations upto 10 ppm without any noticeable effect.

Nitrogen dioxide and sulphur trioxide are highly dangerous air pollutants. NO + NO_2 are produced in the high-temperature zones of the flame—the yield of NO_2 being 10% (usually) of the total NO_x formation. NO_x may undergo a photochemical reaction with the hydrocarbons in the atmosphere in the presence of sunlight to release some toxic substances in the air.

Sulphur in the fuel burns off to liberate SO_2 which forms SO_3 in the final stage of flame burning when there is an exigency of atomic oxygen. SO_3 is also produced from SO_2 on the surface of the superheater deposits that act as a catalyst at elevated temperatures. Sulphur trioxide reacts with atmospheric moisture to form an aerosol of sulphuric acid which rains down as acid rain.

Sulphur dioxide is a moderately harmful substance. But because of its acidic nature, like SO_3 and NO_2, it attacks the delicate membrane lining the eyes, nose and respiratory tract. These air pollutants are known to cause four major types of respiratory damage: bronchitis, bronchial asthma, emphysema and lung cancer. They affect plants as well. They burn the leaf's chlorophyl causing red or brown blotches on leaves between the veins.

Suspended particulates cause smog and obscure visibility.

TOXIC RATE

It is convenient to compute the risk of exposure of a living being to a harmful ingredient in air as the ratio of the actual concentration of the substance C (expressed in $\mu g/m^3$) to the highest permissible concentration HPC (expressed in $\mu g/m^3$) of that substance in the air at the breathing level:

$$\phi = [C/HPC]_i$$

This represents the toxic rate of the substance and should always be less than unity.

Since the toxicity level in air increases with the number of harmful substances in it, the presence of multiple toxic components renders their concentrations even at the HPC level inadmissible. That is why in such cases, toxic hazard is estimated by the cumulative toxic rates of these substances:

$$[C/HPC]_{SO_2} + [C/HPC]_{SO_3} + [C/HPC]_{NO_2} + [C/HPC]_{NO} + [C/HPC]_{CO} < 1$$

The highest permissible concentrations of certain toxic substances in air are as follows:

Pollutant	In Inhabited Zones	
	Highest Single Concentration ($\mu g/m^3$)	Average Daily ($\mu g/m^3$)
SO_2	500	50
SO_3	300	100
NO_2	85	85
NO	250	250
CO	3000	1000
$C_{20}H_{12}$ (benzpyrene)	—	0.001
V_2O_5	—	2
Soot	150	50
Ash particles	500	150

AMBIENT AIR QUALITY STANDARD

The Central Board of Water Pollution (INDIA) has prescribed the following air quality standards (adopted in November 1982).

Area Category		Suspended Solids ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	NO_x ($\mu g/m^3$)	CO ($\mu g/m^3$)
A	Industrial and Mixed Use	500	120	120	5000
B	Residential and Rural	200	80	80	2000
C	Sensitive Area	100	30	30	1000

The Environmental Protection Agency (EPA), USA has enforced the following standards for the ambient air quality.

Pollutant	Concentration ($\mu g/m^3$)		Remarks
	Primary	Secondary	
SO_2	80	60	Annual average
	365	260	Max. 24-h concentration not to be exceeded

			more than once in a year
Suspended Particulates	75	60	Annual geometric mean
	260	150	Max. 24-h concentration
CO	10^4	10^4	Max. 8-h concentration
NO_x	100	100	Annual average

The particulate emission standards for coal fired boilers in India are as cited below:

Boiler Size	Particulate Emission (mg/Nm^3)		
	Protected Area	Other Areas	
		Old (before 1979)	New (after 1979)
< 200 MW	150	600	350
≥ 200 MW	150	—	150

AIR POLLUTION MONITORING EQUIPMENT

Equipment	Pollutants	Operating Range	Remarks
1. Air Monitor CEA – 555	SO_2	0–0.5 ppm	Made in U.S.A.
	NO_x	0–5 ppm	
2. SO_2 Monitor Model SO 261	SO_2	0–200 ppm	Industrial Scientific Corpn., U.S.A.
3. Brink Mist Analyzer	Particulate Concentration		Made in U.S.A.
4. IPAC-2000	CO	0–1000 ppm	Industrial Pump and Compressor, Denver, Colorado, U.S.A.
	H_2S	0–500 ppm	

DETERMINATION OF PARTICULATE MATTER IN FLUE GAS

Particulate matter discharged by thermal power plants and coal fired boiler units is potentially harmful to human health. Hence determination of particulate concentration is necessary to regulate the emission of this pollutant.

It consists of:

(a) isokinetic sampling of the flue gas to extract a uniform sample of gas and particulates
(b) separation of particulate solids from the sample
(c) determination of particulate concentration.

For isokinetic sampling, a stainless steel nozzle (ID = 7 mm min) with sharp tapered leading edge is inserted in the gas duct at the transverse points*. The nozzle dia varies with the velocity of flue gas and the amount of sample required.

The other end of the nozzle is inserted into a thimble (made of paper or alundum) set inside a thimble holder. The thimble is a filter media to collect particulates. Paper thimbles can withstand temperatures upto 150°C while alundum can withstand 550°C as well as more corrosive environment. Glass cloth filters made of finely woven glass fibre can also be successfully used on coarse dust and where sampling is to be taken under high dust load.

The thimble holder is connected in series with the condenser (to collect water vapour condensate), a dry gas meter attached with a temperature and vacuum gauge (for metering the conditions of sampled gas) and a vacuum pump or blower or ejector to induce gas flow through the sampling train. (Fig. A VI. 1).

* [For circular stacks, the area of cross-section is divided into a number of equal annular areas the midpoints of which are the location of transverse points. In the case of rectangular stacks, the cross-section is divided into 12 to 15 equal areas and the centre of each area is a location for a transverse point.]

The sampling is to be continued for at least one hour so that at least 1.6 m^3 of dry gas has been withdrawn and the collected mass of particulates amounts to at least 20% of the mass of the filtering medium.

During each run, the gas volume, pressure and temperature as well as condenser temperature are recorded at 5 minute intervals.

Sampling is done for at least 5 minutes at each transverse point, and when it is finished at one point, the sampler is quickly shifted to another point.

When the sampling is over, the sampler is cooled, particulates collected inside the nozzle are carefully brushed into the thimble and weighed. The mass of dust collected in the thimble is found by difference, i.e. by weighing the thimble before and after the run.

CALCULATIONS

1. ***Gas Flowrate*** The sampling rate at the meter

$$V_r = u\, a \left(\frac{T}{T_s}\right)\left[\frac{P_s}{P_a - p - p_{H_2O}}\right]\left(1 - \frac{m_w}{100}\right)$$

where V_r = volume flowrate (m^3/s) as recorded by the gas meter

u = flue gas velocity at sampling point, m/s

a = nozzle area, m^2

T = gas meter temperature,. °K

T_s = temperature of stack gas,. °K

P_s = stack gas pressure, kPa (i.e. kN/m^2)

P_a = atmospheric pressure, kPa

p = suction pressure at gas meter, kPa

p_{H_2O} = vapour pressure of water at condenser exit temperature, kPa

m_w = moisture content of the gas (% by mass)

2. ***Volume of Gas Sampled*** Therefore, the volume of gas sampled

$= V_r\,(t)$, m^3

where, t = sampling period s.

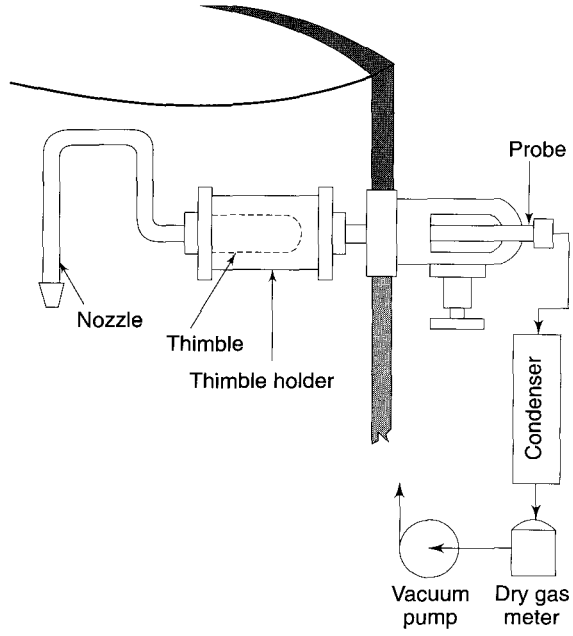


Fig. A VI. 1 *Equipment setup for the measurement of particulates in flue gas.*

Therefore, the volume of gas sampled (dry basis/298°K/101 kPa)

$$V_d = (V_r t)\ \frac{298}{T} \cdot \frac{P_a}{101}\ \text{m}^3$$

And, the volume of gas sampled (wet basis/ 298°K/101 kPa)

$$V_w = V_d \left[1 + \frac{m_w}{100 - m_w}\right]$$

3. ***Dust Concentration*** Dust concentration (dry basis/298. K/101 kPa)

$[\text{Dust}]_{\text{dry}} = M/V_d$, g/m^3

where M = mass of dust collected in the thimble, g.

$[\text{Dust}]_{\text{wet}} = M/V_w$, g/m^3

4. ***Emission Rate*** The dust emission rate

$$\dot{M} = [\text{Dust}]_{\text{wet}} \times V_{\text{fg}}\ , \text{g/h}$$

where V_{fg} = flue gas flowrate, m^3/h

MEASUREMENT OF SO_2 CONCENTRATION IN FLUE GAS

This is carried out with the help of a package analyzer which consists of

(a) probe assembly to extract the sample from the mainstream of flue gas (Fig. A VI. 2)
(b) sample tubing through which the collected sample goes to the instrumentation set-up. The sample tubing is heated electrically to prevent condensation in the lines
(c) gas conditioning unit
(d) analyzer
(e) calibration gas cylinder.

The analyzer which operates on the pulsed fluorescence principle is calibrated to zero calibration, first, by using clean and dry compressed air. Then a series of SO_2/Air mixtures of known concentrations are provided for accomplishing span calibration.

Now, a sample gas is subjected to a source of pulsed UV-light through a monochromatic filter. The high intensity pulsed UV-light energizes SO_2 molecules which emit specific illumination when they return to the ground state.

The emitted light, passing through a filter, impinges on a photomultiplier tube. The intensity of emitted radiation is linearly proportional to the concentration of SO_2 molecules in the sample.

The range of this analyzer is 0-10 000 ppm.

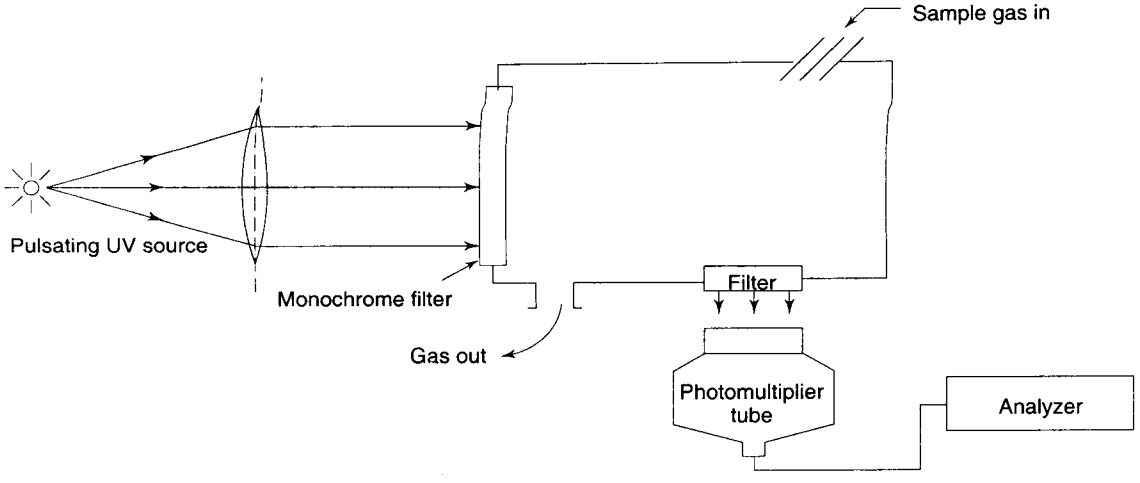


Fig. A VI. 2 *Equipment setup for the measurement of* SO_2 *concentration in flue gas.*

MEASUREMENT OF NO_X CONCENTRATION

It is done with the help of a package analyzer that comprises of

(a) probe assemblies
(b) sample tubing
(c) gas conditioner
(d) analyzer.

The working technique is based on the chemiluminiscence principle.

When in a mixture of NO and NO_2, adequate quantity of ozone (O_3) is introduced, the latter will react with nitric oxide and convert all NO molecules to NO_2 in the excited state:

$$NO + O_3 \rightarrow NO_2^* + O_2$$

When these excited NO_2^* molecules return to the ground state they emanate photons (hν) $NO_2^* \longrightarrow NO_2 + h\nu$ which are measured in the analyzer, thus affording a viable as well as sensitive measurement of NO in the flue gas.

Both NO and NO_2 are measured by this technique.

In one mode, the sample gas is directed to the reaction chamber where only NO content of NO_x reacts with ozone to produce excited molecules of NO_2^*. The chemiluminiscence of these excited NO_2^* as detected and recorded by the analyzer gives the value of NO concentration in the sample. (Fig. A VI. 3)

In the other mode, the entire sample gas is directed to the NO_x converter where all the NO_2 content of NO_x mixture is converted to NO which is then fed to the reaction chamber and the concentration of excited molecules of NO_2^* recorded by the analyzer gives the total concentration of NO + NO_2 in the flue gas.

The difference between these two results is the concentration of NO_2 in the flue gas sampled.

The analyzer records the output on strip-chart and has the range of 0–10 000 ppm with minimum detectable limit 1 ppm.

AIR POLLUTION CONTROL IN FOSSIL FUEL BURNING SYSTEMS

Control of SO_2 Emission

As much as 75% of total sulfur dioxide ejected into the atmosphere come from thermal power stations. With the increased industrial utilization of high-sulfur coal and fuel oils, it has become a

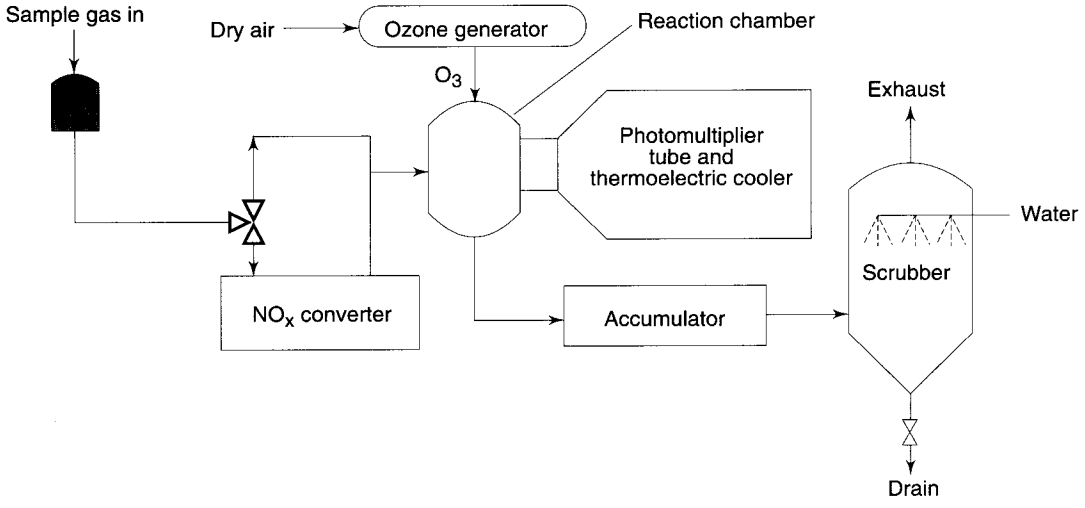


Fig. A. VI. 3 *Equipment setup for the measurement of* NO_x *concentration in flue gas.*

growing concern to reduce the SO_x emission to atmosphere. A number of options are being available in this regard:

(a) Burning low sulphur coals
(b) Desulphurization of coal prior to its combustion
(c) Desulphurization of petroleum
(d) Subjecting fuel oil and high sulphur coal to deep thermal processing to produce gaseous fuel
(e) Post combustion SO_2 removal from waste gases.
(f) Fluidized bed combustion.

Switching over to low sulphur fuels is, however, a short term measure. Desulphurization of coal and liquid fuels, removal of SO_2 from stack gas and adopting advanced technologies of coal combustion are long term measures.

Uptil now, coal desulphurization is in the pilot plant stage. However, coal gasification of high-sulphur feedstock befitted with a sulphur recovery system, according to some experts, may be economically more lucrative. Desulphurization of fuel oils, in the refineries, to produce low-sulphur fuel oil is expensive, yet with steady technological advancement it is increasingly becoming economical.

However, at present the most widely practised method is desulphurization of flue gases. Since the volume concentration of SO_x in the flue gases is rather low (about 0.2%) and the volume of flue gases to be handled is enormous, stripping flue gases off sulphur oxides presents enormous technical difficulties.

There are several methods available for cleaning up flue gases from SO_x:

(a) Dry scrubbing
(b) Wet scrubbing
(c) Absorption of SO_x on coke or activated charcoal bed
(d) Catalytic oxidation of SO_2 to SO_3 and subsequent conversion, as well as removal, of the latter as H_2SO_4.

Dry scrubbing involves absorption and chemical reaction between SO_x and lime/MgO/$CaCO_3$ bed.

Wet scrubbing involves spraying lime slurries or NaOH or caustic soda solution into the flue gas stream.

Scrubbing has added advantages: It removes a substantial quantity of particulate solids.

Wet lime/limestone scrubbing uses lime or lime-stone slurry as the reactive absorbent. But these systems are beset with the problems of

(a) scaling
(b) downtime loss
(c) corrosion of air preheater tubings
(d) plugging of demister
(e) solid waste disposal.

The solid waste ($CaSO_3$) must be stabilized to destroy its quick-sand effect. SO_2 removal efficiency is 70–85%.

Also sulphur dioxide removal efficiency as high as 90% has been achieved by the non-regenerable alkali process using sodium hydroxide as absorbent.

SO_2 removal efficiency of 85-90% is obtained by adopting the double alkali process in which the flue gas is scrubbed with NaOH solution and the scrubber effluent is treated with lime or limestone to regenerate NaOH or Na_2SO_3 and precipitate out calcium sulphite and the sulphates are removed by vacuum filtration.

The MAGOX scrubbing system for flue gas desulphurization uses a fine suspension of magnesium oxide (90% passing through 325 US Standard Mesh) in water as the scrubbing liquid injected in the venturi-throat or just upstream of it. The accelération of flue gas through venturi atomizes the injected MgO-suspension-water into fine droplets (10 μm in size) which form droplet-clouds of 170–300 μm in dia. Because of tremendous turbulence, the SO_2 in the flue gas reacts quickly with MgO suspension and gets removed as magnesium sulphite. Stack gas reheat-

ing is not always necessary. Efficiency of SO_2 removal is above 90%. Magnesium oxide loss (10–12%), dust emission from dryer erosion and chocking of scrubber by fine crystals of $MgSO_3$ are the chief problems.

The CATOX (catalytic oxidation) approach to FGD involves the oxidation of SO_2 to SO_3 by air over a vanadium pentoxide catalyst. The sulphur trioxide produced is absorbed in dilute sulphuric acid. SO_2 removal efficiency is 85%. However this system requires a high efficiency mist eliminator and stack gas reheating after absorber.

Control of NO_x Emission

As much as 40% of the total quantity of NO_x ejected into the atmosphere comes from thermal power plants. However the removal of nitrogen oxides from flue gas presents greater engineering difficulties than that of SO_2. That is due to

(a) lower concentration of NO_x in flue gases. It amounts to 20–50% of SO_2 concentration.
(b) chemical inactivity of NO which is usually present in FG in much larger concentration than NO_2.

Unlike SO_2 whose presence in flue gas is unavoidable until and unless the sulphur content of fuel is eliminated beforehand, the concentration of NO_x in combustion gases largely depends on the combustion technique in the furnace. Nitrogen oxides are produced in two ways during fuel combustion:

1. chemical reaction between aerial nitrogen and oxygen in the high-temperature combustion zone (above 1600°C)
2. oxidation of nitrogen content in fuel. This can take place below 1600°C.

Since the bulk of NO_x produced in the combustion process comes from reaction (1) the chief means of limiting NO_x generation is to lower the temperature in the combustion zone, i.e. to carry out a low-temperature combustion technique as well as reduce the quantity of excess air. This can be achieved by

(a) adopting the fluidized bed combustion technique. As this process contains the combustion temperature in the range 800-900°C, the chances of NO_x formation are minimum.
(b) carrying out combustion with minimum ex-cess air
(c) corner firing
(d) flue gas recirculation
(e) double-stage combustion, particularly with gas fired large boilers.

NO_x emission from steam generation plants can be successfully diminished by

—Selective Non-catalytic Reduction (SNR) of NO_x

—Selective Catalytic Reduction (SCR) of NO_x

SNR system reduces NO_x by injecting ammonia into the furnace gas. Through large jets, ammonia is introduced to the furnace at those points where temperature is in the vicinity of 1140°–1250°K. NO_x reacts with ammonia to form water vapor and elemental nitrogen

$$NO + NO_2 + 2NH_3 \longrightarrow 2N_2 + 3H_2O$$

Successful operation of SNR system demands stringent combustion control and minimum fluctuations of temperature and oxygen content.

While the same chemical principle is involved in SCR process, it differs from SNR in the aspects that ammonia is injected at a different location and by different means. Through specific ports, ammonia is charged to the flue gas and then the reduction is carried out over a catalyst bed (V_2O_5 based on TiO_2) downstream.

SCR unit is installed downstream of a particulate collecting device (bag filter or ESP) fitted beyond the economizer. This, sometimes necessitates flue gas reheating upstream of catalyst bed. Table A VI. 1 enlists some of potential NO_x control Technologies in vogue.

SO_x and NO_x Removal From Flue Gases Japanese scientists of Okayama University have been successful in developing a batch of coprecipitated copper-oxide/titanium-oxide catalysts for the simultaneous removal of SO_x and NO_x from coal and fuel-oil-combustion flue gases.

The catalysts are composed of:

45–47.5 mol % CuO

2.5–5 mol % Cr_2O_3

47.5–52.5 mol % TiO_2

That ensures optimal removal of SO_x and NO_x. These catalysts retain their stability after regeneration (up to 20 times) and are capable of effecting 90% desulphurization and 100% denitrification from flue gases containing 500 ppm each of SO_2 and NO, 5% O_2, 10% H_2O and N_2 at 350°C.

U.K.'s Humphreys & Glasgow Ltd., and Sweden's Nykomb AB (Stockholm) have developed a quenching technique to burn all types of coal but producing cleaner flue gases than conventional or fluidized combustion processes. It limits SO_2 emissions to less than 5 mg of sulphur, i.e. removing as much as 99% of the sulphur in the fuel per MJ and less than 50 mg of NO_2 per MJ. The figures look certainly promising in comparison to 50 mg S and 100 mg NO_2 per MJ for fluidized bed combustion (or conventional coal firing with after-combustion flue gas clean-up).

The method is based on any high pressure, slagging gasifier in the quench mode. The key is to start with a quench to cool the gas and knock out the pollutants.

Control of Particulate Emission

Several devices are available for the removal of particulate solids from the stack gas of thermal power plants and steam generation plants. These are:

(a) Cyclone separator
(b) Fabric filters
(c) Dust scrubbers
(d) Electrostatic precipitators.

Cyclones afford the cheapest investment while ESPs are the costliest amongst all. However, the efficiency of cyclones goes down with particulate size lower than 10 μ.

ESPs have high collection efficiency, as high as 99.9%. Besides, these are capable of eliminating dust particles as small as 0.01 μ. Draft loss is also low: 0.25–1.25 cm of water. And they can operate at gas pressures upto 40 atm.

Fabric filters are liable to chemical attack; moreover they are susceptible to thermal and mechanical shock. Hence their application to control particulate emission is not favoured in thermal power plants.

WATER POLLUTION AND SOLID WASTE DISPOSAL PROBLEM IN BOILER PLANTS

Large boilers of thermal power stations and of process industries contribute to water pollution by way of discharging into the water basin the:

(a) boiler blowdown
(b) SO_2-scrubber waste
(c) cooling waters that mainly cause thermal pollution
(d) waste waters from water treatment plants and demineralizing units
(e) waste waters contaminated with petroleum products
(f) waste waters from hydraulic ash-disposal system.

These discharged waste waters carry a rich load of harmful impurities, viz. heavier metal cations, organic substances and coarse-dispersed solids besides dissolved salts. The toxic substances added to the water basin from boiler plants may adversely affect the hydrobionts—all living organisms inhabiting the water basin. At higher concentrations they will simply perish while at lower concentrations they may suffer from reduced metabolism and growth rate, abnormal

Table A VI.1 ***Potential NO_x Control Technologies***

Technique	Description	Advantages	Disadvantages	Impacts to Consider	Applicability	NO_x Reduction
Low Excess Air (LEA)	NO_x reduction by reducing oxygen availability	• Ease of operation • Amenable to upgradation	$DeNO_x$ing potential is low	• High CO- emission • Flame stability • Flame length which should not be too high to avert 'licking of furnace-wall	All fuels	1–15%
Off-Stoichiometric Combustions (OSC)	Staged combustion creating two zones	• Low operating cost	• BOOS requires high air inflow to contain high CO-emission	• Burner header capacity	All fuels	30–60%
1. BOOS 2. OFA 3. Air Lances	I. fuel-rich II. fuel-lean	• BOOS needs no capital investment	• Capital cost is relatively high for OFA • Moderate capital cost for Air Lance system	• Flame length • FD fan capacity	Multiple-burner devices	
Low NO_x Burners (LNBs)	Staged combustion thru internal staging thus reducing peak flame temperatures and O_2 availability	• Low operating cost • Compatible with FGR as a backup technology to augment $deNO_x$ing	• Moderately high capital cost • Efficiency varies with fuel composition & characteristics, burner design, waste streams ... etc.	• Flame length • FD fan capacity • TD flame stability • Design compatibility	All fuels	30–50%
Flue Gas Recirculation (FGR)	As much as 20 –30% of FG is recirculated back into the combustion zone and thus reducing oxygen concentration in the combustion zone. The net result is	High NO_x reduction potential for NG and other fuels with low fuel-bound nitrogen	• Moderately high capital cost • Moderately high operating cost • Affects system pressure • Affects heat transfer	• FD fan capacity • Pressure drop at burner nozzle • Furnace pressure • TD flame stability	• Gaseous fuels • All low-N fuels	40–80%

(Contd)

Table A VI.1 *(Contd)*

Technique	Description	Advantages	Disadvantages	Impacts to Consider	Applicability	NOx Reduction
	decrease in peak flame temp. and low NO_x generation.			• Flame stability • Efficiency penalty		
Water/Steam Injections (WSI)	Injecting steam/water in the flame core zone and thereby quenching peak flame temp and disfavouring NO_x formation.	• NO_x reduction potential is comparable to FGR system • Moderate capital cost	• Additional fan power requirement to handle increased mass- flow • Penalty on efficiency due to additional water vapour loss and fan power input		• Gaseous fuels • All low-N fuels	40–70%
Reduced Air Preheat (RAPH)	Air preheater modification to reduce preheat. Combustion air temp. drops thereby reducing flame temp. disfavouring the formation of NO_x.	High NO_x reduction potential	• Reduction of air preheat temp brings about a significant efficiency loss (1% for every 22°K drop)	• FD-fan capacity • Efficiency loss	• Gaseous fuels • All low-N fuels	25–65%
Selective Catalytic Reduction (SCR)	Ammonia/Urea soln. dozed into the FG stream upstream of Pt-honeycomb catalyst decomposes NO_x into N_2 and H_2O	High deNO_xing potential	• Very high capital cost • High operating cost • Extensive duct-work is required to and from the reac-tor • Increased pressure drop taxes more ID fan power • Reduced. efficiency Ammonium Sulphate precipitation. • Requires water-wash of air heater	• Space requirements • Ammonia slippage • Hazardous waste disposal problem	• Gaseous fuels • All low-S solid & liq. fuels	70–90%

(Contd)

Table A VI.1 *(Contd)*

Technique	Description	Advantages	Disadvantages	Impacts to Consider	Applicability	NOx Reduction
Selective Non-catalytic Reduction (SNCR) with NH_3-in-jection	It is a thermal deNO_x ing process that relies on NO_x reduction by NH_3 without any use of catalyst. Aq. NH_3 is sprayed or NH_3 + SH steam is injected into FG.	• Low operating cost • Moderate NO_x removal	• Moderately high capital cost • Ammonia handling, storage, vaporiza tion and injection is hazardous job • Ammonia slippage • Appearance of white plume	• Temp. profile • Furnace geometry • Residence time	All fuels	25–50%
Selective Non-Catalytic Reduction (SNCR) with Urea injection	Injection of urea solution into the furnace. Urea dissociates to NH_3 that scavenges generated NO_x.	• Low capital cost • Simple operation • Nontoxic dozing agent • Moderate NO_x removal • Simple system that involves no hazard • Low injection energy	• Essentially a thermal deNO_xing process. • Dependent on temp. • NO_x reduction potential drops at lower loads • Design must consider boiler operating condi tions and design	• Temp. profile • Furnace geometry • Residence time	All fuels	25–50%

change in mutagenesis and reproductive capacity. The maximum permissible concentrations of selected substances in water basins, according to ISI standard are tabulated below.

Table A VI. 2

Effluent Characteristics	General Limits
Temperature, (max)	40°C
pH	5.5–9.0
BOD, mg/l; max	30
COD, mg/l; max	250
Oils and Grease, mg/l; max	10
Ammoniacal Nitrogen (as N) mg/l	50
Phosphates (as P), mg/l; max	15
Sulphides (as S), mg/l; max	2
Fluorides (as F), mg/l; max	2
Cyanides (as CN), mg/l ; max	0.2
Lead (as Pb), mg/l ; max	0.1
Zinc (as Zn), mg/l ; max	5
Copper (as Cu), mg/l ; max	3
Nickel (as Ni), mg/l ; max	3
Cadmium (as Cd), mg/l ; max	2
Chromium (as Cr^{6+}), mg/l ; max	0.1
Mercury (as Hg), mg/l ; max	0.01
Arsenic (as As), mg/l ; max	0.2
Phenolic compounds (as C_6H_5OH), mg/l ; max	1.0

Now the load of impurities discharged into water basins can be decreased in two ways:

1. by purifying the waste waters
2. by reducing the quantitative discharge of impurities from particular technological processes.

Of course, the latter should be given more importance.

THERMAL POLLUTION

The heat released by cooling water (open-circuit) from the turbine condensers of super thermal power stations is enormous. As much as one million kilocalories of heat is dumped per hour in the water basin by cooling water flowing at a rate of 100 000-130 000 kg/MWh from a 1000 MW conventional thermal power plant. This creates a huge zone of elevated temperature in the water basin, reduces its dissolved oxygen and thereby impairs the growth and development of aquatic life.

The zone of elevated temperature in a water basin can be substantially reduced by allowing the inflow of hot discharge water into the basin through:

(a) open spillways with
  (i) transverse and side weir bulkheads
  (ii) distributing grill
(b) submerged jet-type spillways

Open-type spillways (Fig. A VI. 4) allow the discharge water to get cooled as well as saturated with atmospheric oxygen. Jet-type spillways, disperse hot discharge water over a wide zone of water basin through submerged jets intensifying the intermixing of hot water with cold water of the basin.

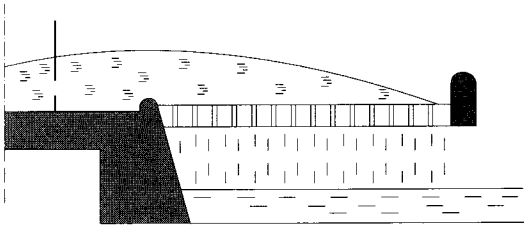


Fig. A VI.4 *Open spillways can substantially cool down the hot discharge water from turbine condenser.*

The thermal load of hot discharge water can also be substantially decreased by incorporating a cooling tower or spray-pond downstream of the surface condenser of the turbine to cool the coolant water before its discharge to the water basin. (Fig. A VI. 5)

WASTE WATERS FROM WATER TREATMENT PLANTS AND DM UNITS

All the boilers generally need water-treatment plant and demineralizing unit for the production

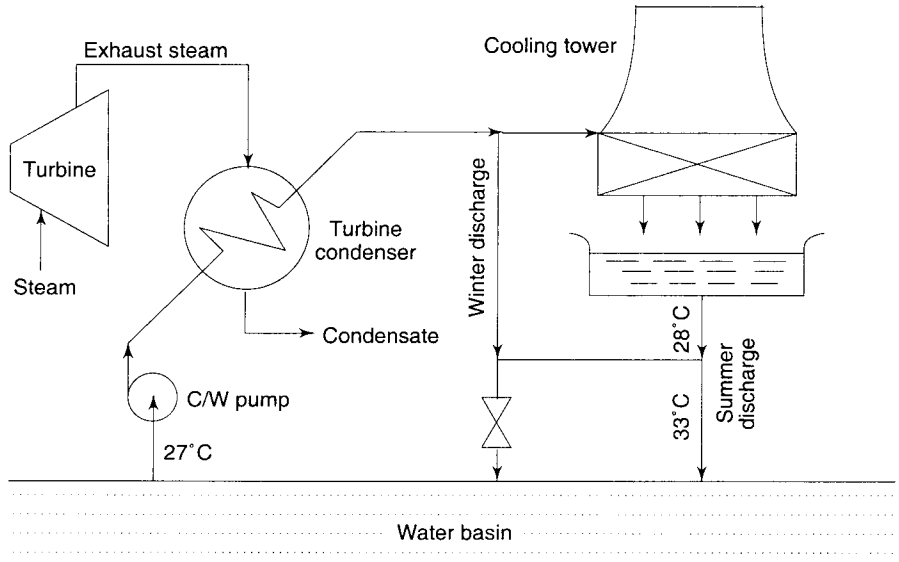


Fig. A VI. 5 *Cooling tower incorporated into the condensate discharge circuit substantially downs the thermal load of the hot discharge water.*

of makeup cooling water and BFW from raw water. The reagents used in the water-treatment plant and DM-unit and the salts resulting from their chemical action must be discharged off as wastes. As much as 1.5–2 tons of various salts are discharged with waste water every hour from a WT-plant of nominal capacity (2 000 M^3/h).

Waste water of water treatment plants (WTP) contains slime, coarse-dispersed solids, organic substances, magnesium hydroxide, calcium carbonate and salts of iron and aluminum. The composition and concentration of various impurities in waste water depends on the quality of raw water and the methods adopted for water treatment. Where lime treatment is adopted, the clarifier blowdown contains sludge of $CaCO_3$ (mainly) and it has elevated pH value (10–10.2).

In the DM-unit, regeneration of H-cation exchanger and OH-anion exchanger is done by using H_2SO_4 and NaOH solutions and as a consequence, the disposed waste water becomes respectively acidic and alkaline in nature.

So the principal effects of discharging waste waters of WTP band DM-units in the water basin are to:

(a) increase the salt content of the basin
(b) raise the concentration of suspended solids
(c) alter the pH of the basin
(d) raise the BOD level of the basin.

That is why the direct disposal of waste waters from the water treatment plant and DM-unit to the water basin is not admissible.

It has been estimated that as much as 700 kg of salts are discharged per hour from a water treatment plant of a boiler producing enough steam to generate 1000 MWh of electrical energy.

1. ***Purification:*** The waste water of water treatment plant (WTP) and discharge from DM-unit may be disposed as follows:

(a) transferring the water water into the hydraulic ash handling system of coal fired boiler units
(b) neutralizing the waste water (pH > 9) of WTP with acid-wastes of the DM-unit
(c) subjecting the waste water to slime separation, i.e. slime dewatering in drum-type vacuum filters and recycling the clarified water for washing of mechanical filters.

Waste water of WTP can be discharged into the hydraulic ash-disposal system of coal fired boiler units provided it does not cause to the formation of deposits in the ash-disposal system.

If the purge water of WTP has a pH value of about 10 (as is the case when lime treatment is employed), it is better to neutralize a part or whole of this alkaline waste water by acid wastes of the DM-unit.

If the PH of waste water is below 6.5 or above 8.5, the water must be neutralized before discharge.

Waste waters from ion-exchangers of DM-units upon mixing together with regenerative waters from cation and anion exchangers have their pH index, in most cases, less than 6. Hence, these waters are neutralized by alkalis, lime, marble and dolomite.

Neutralization by lime is convenient as it does not, unlike other reagents, lead to a sharp increase in the salt concentration in water.

Neutralizing by ammonia is much more convenient. The quantity of ammonia required is not high and the salt content of neutralized water does not exceed that resulting from lime-neutralization process.

Neutralization is carried out in neutralizing tanks. A tank is filled with acidic and alkaline waste waters, a metered quantity of neutralizing solution is charged into it and the liquid is agitated by compressed air at a rate of 0.4-0.8 M^3 per minute/M^2 of the cross-sectional area of the neutralizer.

If the water upon mixing of regenerative wastes is alkaline, then it is better to neutralize it by bubbling flue gases into it. The flue gases contain acidic oxides like CO_2, SO_2, NO_2 which upon dissolution in water will produce acids that neutralize the alkalinity of waste water.

2. ***Reducing Waste Water Discharge of WTP and DM-Units:*** The amount of impurities discharged into the water basin by waste waters from the WTP and DM-unit can be diminished by adopting techniques that will minimize the use of reagents and water for water treatment and regeneration purposes.

The quantity of water used for regeneration of mechanical filters can be drastically cut down by increasing the filtering capacity of mechanical filters. It has been found that the certain volcanic slag have absorbing capacity 2–2.5 times that of quartz sand. And therefore, by using expanded clay instead of quartz sand in mechanical filters it is possible to use less water for regeneration by a factor 2.5–3.5.

The flowrate of wastes from the DM-unit can be effectively reduced by adopting the process of:
(a) continuous ion-exchange
(b) stepwise counter-current ion-exchange
(c) thermal regeneration (instead of chemical regeneration) of ion-exchanges.

The continuous ion-exchange has certain distinct advantages:
(a) smaller size of apparatus
(b) reduction in the quantity of regenerants down to almost theoretical (stoichiometric) quantity
(c) diminishing the flowrates of waste waters down to half to one-third.

The method of stepwise counter-current ion-exchange cuts down the NaOH consumption for regeneration of OH-anion exchanger by 30-40% and brings the H_2SO_4 consumption for regeneration of H-cation exchanger down to near stoichiometric quantity.

Though thermal regeneration—effected by hot water (about 80°C)—has not been found applicable for all kinds of ion-exchange materials, it is possible to thermally regenerate 42% of borate-form anion exchangers.

The colloidal impurities of waste water can be precipitated down by **electrocoagulator** using either Fe-or Al-anodes instead of using chemical coagulants: $FeSO_4$, $Al_2(SO_4)_3$.

Electrocoagulators are of various types—the most popular being those with plate type electrodes or with filled-in electrodes.

A plate-type electrocoagulator is essentially a reservoir into which are vertically suspended a series of parallel electrode plates 10–20 mm apart. Waste water is usually charged into the vessel from the bottom and purified water exits from the top. As a direct current is passed through the electrodes the following processes occur:

(a) electrolytic dissolution of Fe or Al of the anodes

$$Fe - 2e \rightarrow Fe^{2+}$$

(b) reduction of dissolved oxygen at cathodes

$$2H_2O + O_2 + 4e \rightarrow 4OH^-.$$

(c) formation of sparingly soluble $Fe(OH)_2$ or $Al(OH)_3$

$$Al^{3+} + 3OH^- \longrightarrow Al(OH)_3$$

(d) oxidation of chloride ions at the anode

$$Cl^- - e \longrightarrow Cl \xrightarrow{Cl} Cl_2$$

(e) oxidation of organic impurities by free chlorine

(f) removal of CO_2 to a great extent

(g) diminishing of HCO_3^- ion concentration

(h) substantial reduction of silicon, iron and oxygen concentration in water.

It has been possible to decrease organic compounds in water by 70%, silicic acid by 50%, chlorides by 30% by electrocoagulation by using iron anodes. It also reduces the hardness and alkalinity of water.

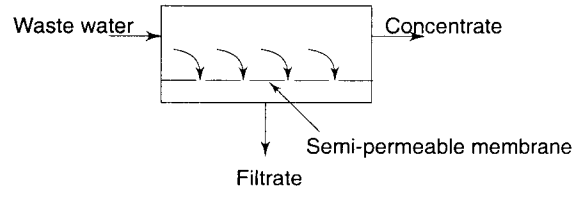


Fig. A VI. 6 *Reverse Osmosis.*

Stripping waste water of its dissolved salts can be effectively accomplished by a physical process known as **reverse osmosis**. In this process, the waste water with dissolved salts is forced through a semi-permeable membrane (Fig. A VI. 6) at a pressure, usually 5–8 MN/m^2, exceeding the osmotic pressure of the solution. The membrane allows only water and a small fraction of salts as ions to pass with the effect that the fil-

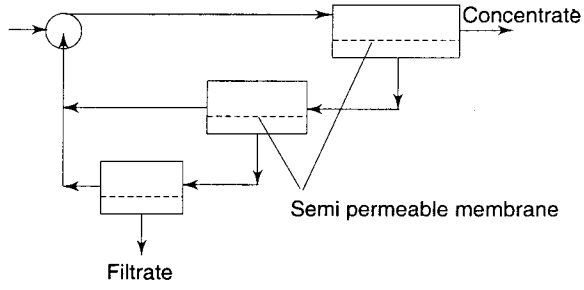


Fig. A VI. 7 *Reverse Osmosis connected in series.*

trate contains an appreciably smaller quantum of dissolved impurities.

Cellulose acetate membrane is the most popular. It can operate at a

(a) wide range of pressure 0.6 to 8 MN/m^2
(b) wide pH range 3–8
(c) temperature range 0–30°C

Cellulose acetate membranes in the form of hollow fibres have

(a) selectivity upto 90% of NaCl dissolved in water
(b) permeability of water 1.25×10^{-5} m^3/m^2s at 1.5–2 MN/m^2

The technique of reverse osmosis, it has been observed, has drastically cut down the consumption of reagents used for water treatment with the effect that the concentration of impurities in discharged waste waters sharply declines. (Fig. A VI. 7)

The line up of reverse osmosis plant upstream of DM-units (Fig. A VI. 8) can slash down the discharge of salt solution by 50% and the cost of desalted water by 25%.

Desalination of waste waters can be successfully carried out by another technique known as **electrodialysis**. The apparatus consists of an assembly of parallel cation and anion exchange membranes (which are selectively permeable to cations and anions respectively) flanked by a stainless steel cathode and platinum coated steel anode. (Fig. A VI. 9)

Water is delivered to the desalting (even) cells. As the electric field is applied to the system, cations migrate towards the cathode by penetrating the cation-exchange membrane and the anions move, likewise, to the anode through the anion-exchange membrane. As a result of this ionic migration, the water in the even cells gets desalted while the concentration of odd cells (brine) increases. Desalinated water and brine concentrate are tapped out separately.

Electrodialysis substantially reduces the use of reagents for the waste water treatment and consequently the amount of salt discharged to waste waters is also diminished. By installing an electrodialysis plant upstream of the DM-unit, the load on the ion-exchangers is radically dropped and so the quantity of regenerants expended per m^3 of DM water yield and the amount of salt discharged with waste water of regeneration are also substantially decreased.

WASTE WATERS CONTAMINATED WITH PETROLEUM PRODUCTS

The petroleum products like lube oils, fuel oils, kerosene, etc. find their way to the water basin

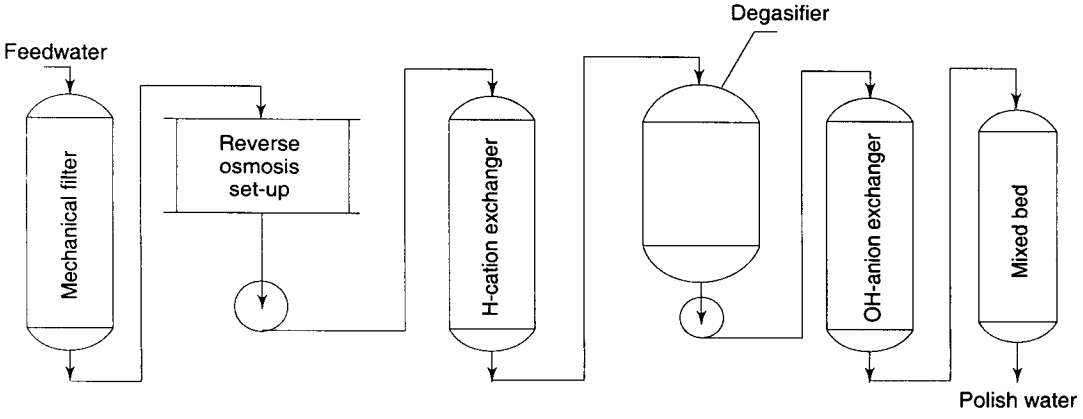


Fig. A VI. 8 *A typical line-up of reverse osmosis plant with a DM-unit.*

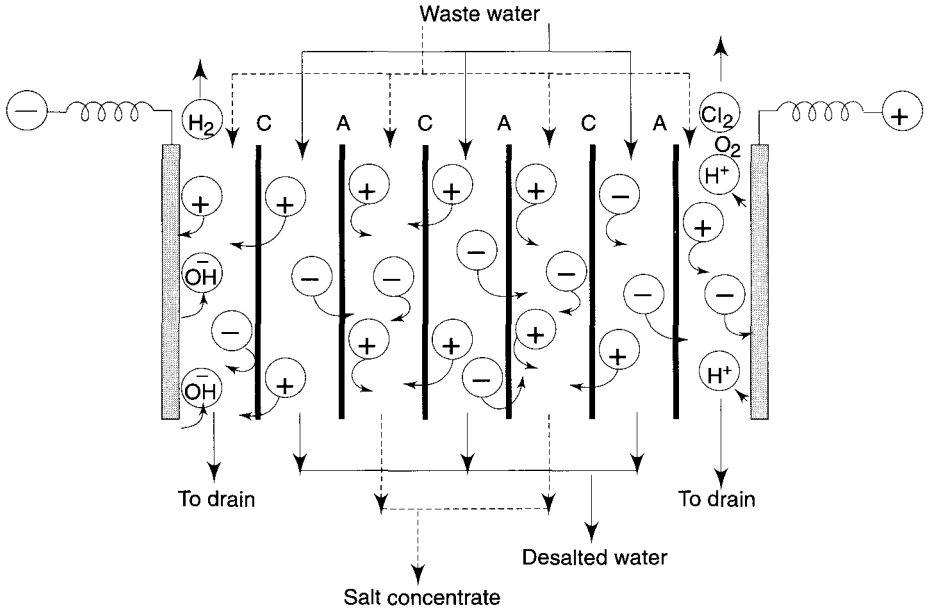


Fig. A VI. 9 *Schematic representation of electrodialysis.*

in an emulsified, colloidal or dissolved state. They are particularly dangerous for water basins. The maximum allowable concentration of petroleum products in the water basin is 0.5 mg/kg of water.

They form films on the water surface, inhibit the natural aeration of water and thereby inflict serious harm to aquatic life.

The main sources of oil in water are:

(a) pump cooling water
(b) condensate discharged from surface condensers
(c) ground water contamination with fuel oil due to spillage.

Waste waters may get contaminated with oil (from 2 to 10 mg/kg) from the oil-systems of turbines and bearings of the rotating mechanisms.

In some cases the same cooling water circuit is involved in turbine oil coolers, the bearings of axiliary machines and turbine condensers. Oil ingression to cooling water system due to leakage in oil coolers may occur and rise as high as 25-30 mg/kg in practical cases. Add to this, a considerable quantity of oily water from turbine tanks and oil regeneration plants.

The flowrate of petroleum-contaminated waste water from a modern thermal plant usually does not exceed 100 m^3/h and oil concentration ≤ 50 mg/kg.

1. ***Purification:*** The oil contaminated waste water is charged to oil traps that separate out efficiently the coarse oil particles of size 80–100 μm or more.

The clarified water is then fed into the flotator where finer oil particles are separated from water at a high rate under pressure flotation.

The purified water is then filtered through a machinical filter. The former consists of double-layer packing of quartz sand (grain dia 2 mm, bed thickness 700 mm) and anthracite (grain dia 3-15 mm, bed thickness 600 mm). The carbon

filter consists of a bed (2500 mm thick) of activated carbon to adsorp oily suspensions.

The final effluent water of this plant is 95% free from oil.

2. Decreasing the Amount of oil contaminated Waste Water: The problem of decreasing the disposal of petroleum contaminated waste-waters can be solved to a great extent if adequate and careful measures are taken:

(a) Special care should be taken during the handling, storage and transportation of fuel oil.

(b) Synthetic detergents should be used, while cleaning emptied oil tank wagons, instead of hot water or steam. This reduces the volume of oily waste water by a factor of more than 10 because of multiple use of washing solution.

(c) For storing fuel oil, steel reservoirs are preferable to reinforced concrete reservoirs. Experience shows concrete reservoirs suffer from substantial oil leakages while steel reservoirs do not.

(d) It is advisable to use tube-in-tube type heat exchanger, while heating fuel oil, to avoid fuel oil leakages.

(e) The problem of turbine oil penetrating into the cooling waters of turbine oil coolers can be prevented by hermetically sealing (with expoxy resins) the joints between the tubes and tube-plates of the oil coolers.

(f) Corrosion of oil cooler tubes often leads to oil contamination of cooling water. Brass tubes, in particular, are susceptible to salt cracking induced by dissolved salts in the cooling water. Hence selection of materials for oil cooler tubes should be made from stainless steel, German silver and titanium to avoid tube leakage due to corrosion.

(g) A good solution to the problem of minimizing oil leakage is to switch-over from shell-and-tube type oil coolers to plate type coolers for more efficient operation, better access to mechanical cleaning, visual inspection and leak detection.

(h) Another visible technique is to set up a separate cooling water circuit to supply cooling water to the turbine condenser, oil coolers, auxiliaries. Oil contamination, it has been found, of up to 30 mg/kg in cooling water normally does not present any problem to the process of cooling.

(i) The leakage of oil from oil lubricated bearings is also a source of oil contamination of waste water. This oil loss from bearing housing can be minimized or prevented by using thick lubricants and special bearing seals.

WASTE WATER OF HYDRAULIC ASH-DISPOSAL SYSTEM

Hydraulic ash-disposal of solid-fuel fired boilers is an efficient ash removal system in which water is allowed to act upon the ash, a part of which dissolves and the rest forms a pulp (suspension) which is pumped to ash-settling ponds where the coarse impurities settle down and the clarified water can either be discharged directly into a water basin (straight flow hydraulic system) or recycled for reuse.

The composition and concentration of impurities transferred from ash to water depends largely upon the chemical composition of ash which may vary appreciably:

SiO_2 : 10 – 70% ; Al_2O_3 : 10–40% ;

Fe_2O_3 : 2 – 30%; CaO : 2–70%; MgO : 0–10%

$K_2O + Na_2O$: 0 – 10% plus it may contain traces amount of compounds of vanadium, germanium, arsenic, mercury, beryllium and fluorine.

The ash-disposal water may be categorized into four groups:

(a) lime saturated water

(b) calcium sulphate saturated water
(c) lime as well as calcium sulphate saturated water
(d) water with relatively low mineral content.

In straight-flow hydraulic ash-disposal system, as much as 10000–15000 metric tons of salts are discharged to the water basin annually from a coal fired boiler producing enough steam to generate 1.25 MW power. Obviously such high discharges of salts to water is not permissible. Therefore, a closed-hydraulic system (in which clarified water is recycled) is adopted in modern boiler plants. However certain salts of calcium, e.g. $CaSO_4$, $CaCO_3$ and $Ca(OH)_2$ form supersaturated solutions with water and then precipitate as scale in fluid transport systems (pumps, pipelines) and therefore present a difficulty to the operation of closed hydraulic system.

Since the ash-disposal waters contain both scale formers and salt contaminants, the essential characteristics of clarified water from an ash-disposal system are:

1. Alkalinity } determine scale formation
2. Sulphate concentrations } determine scale formation
3. Total dissolved salts } determine contamination
4. Concentration of toxic impurities } determine contamination

The pH of clarified water of a hydraulic ash-disposal system may vary from strongly acidic to strongly alkaline. Therefore, the clarified water before its final discharge to the water basin must be treated so that

(a) pH value of the water basin does not alter beyond the specified limit 6.5-8.5
(b) salts content within admissible value
(c) concentration of toxic substances is less than their highest permissible concentration.

Decontamination of Ash-Disposal Water

The high flowrate and high concentrations of impurities in the waste water of a hydraulic ash-disposal system prevent purification of the entire bulk of the ash-disposal system. What can be achieved is decontamination of toxic impurities to a safe level and the principal processes involved are as follows:

1. Precipitation as well as co-precipitation of impurities
2. *Sorption* of impurities
3. Oxidation reduction followed by precipitation.

Removal of impurities by forming sparingly soluble precipitates or by adsorption on the surface of the solid-phase separated in the water mass during the course of the chemical treatment of ash-disposal water is the most popular one. Lime is the most commonly used precipitant, sometimes used with other reagents to enhance decontamination. For example, arsenic is precipitated out from the ash-disposal water by lime as basic arsenate 3 Ca $(AsO_4)_2$. $Ca(OH)_2$. Though it is less soluble among complexes of lime, still it has a solubility 4 mg/kg—a figure which is 18 times the safe level in the water basin.

But if $FeSO_4$ is added together with lime (pH = 9–10), a more insoluble compound, $FeAsO_4$ is precipitated along with some flakes of ferrous hydroxide onto which adsorbed are AsO_4^{2-} ions, thereby reducing the aresenic concentration in the waste water of the hydraulic ash-disposal system down to less than 0.05 mg/kg. Simultaneously, the concentration of harmful chromium is also reduced.

Removal of chromium ions is best achieved by adding Na_2SO_3 together with $FeSO_4$ at pH > 9. The former reduces Cr^{6+} (sexivalent chromium) to Cr^{3+} which separates out as insoluble precipitate $Cr(OH)_3$ and the concentration of chromium ions in clarified water drops to 0.014–0.024 mg/

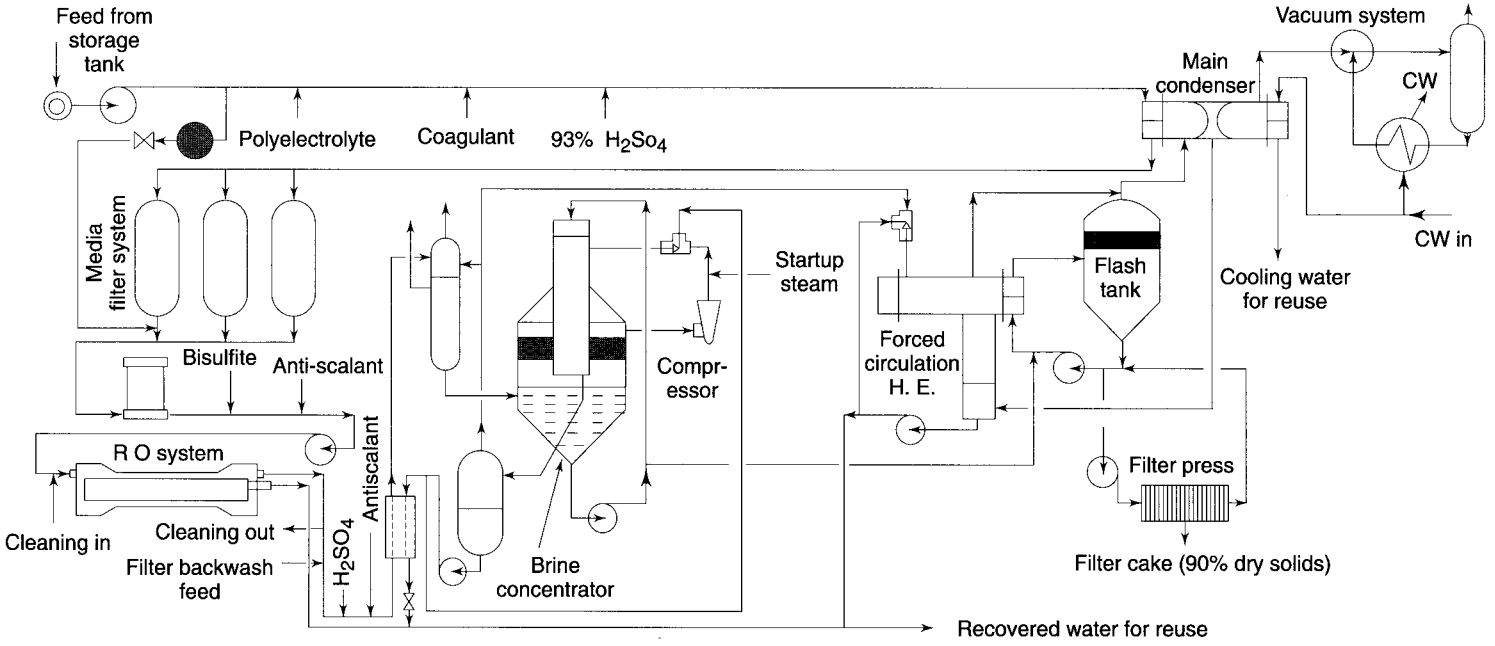


Fig. A VI. 10 *A typical hybrid system for zero liquid discharge.*

Source: Zero Liquid Discharge : Treatment of Powerplant Effluents—Y Y Tom & B E Heimbigner (Power Gen. ASIA 1993, Singapore, September 13-15, 1993)

kg. Simultaneously, the concentration of fluoride ions drops by more than 90%.

Fluoride ions (F^-) are precipitated readily by adding $MgCl_2$ to waste water. However optimal removal of fluoride ions is achieved on adding $MgCl_2$ in amounts of 50 mg/kg of fluorine at pH 10.2–10.4. Fluorides precipitate (CaF_2, MgF_2) out together with flakes of $Mg(OH)_2$.

A better result is obtained in the coagulation process induced by adding $Al_2(SO_4)_3$ at pH < 7. When aluminium sulphate in an amount 18–24 mg/kg of fluorine is added to waste water at pH : 4.5–5.5, the concentration of fluoride ions in decontaminated water reduces practically to zero.

The waste water of hydraulic ash-disposal system can be partially purified by sorption of its toxic impurities on the sorbents. Ash is a good sorbent. It contains aluminosilicates—inorganic ion-exchange materials capable of extracting various metallic ions. Unburnt coal particles in ash also serve as good sorbents of organic substances. It has been found that the greatest reduction of concentration of harmful substances in waste water is attained at an ash content 3–5 g/kg of waste water. Under these conditions, concentration of Cu^{2+} ions is reduced to 0.003 mg/kg, Zn^{2+} ions to 0.02 mg/kg, As^{5+} to 0.44 mg/kg, oil products 5.5–6 mg/kg.

SOLID WASTE DISPOSAL

Ash and slag can be pelletized and then stored on abandoned quarries and bogs, etc., or used as building materials.

They can be used as fillers and binders in the
(a) production of concrete and concrete elements
(b) road construction
(c) manufacture of heat insulating materials
(d) manufacture of sound-proofing materials

They can also be used as the starting materials for the manufacture of aluminium as well as sorbents for purification of different types of waste waters.

If the calcium content of ash is high, it will prove beneficial to the calcination of acid soils.

ZERO LIQUID DISCHARGE

Utilities are looking for wastewater treatment techniques to retrieve almost entire gamut of their effluents as a high quality distillate for reuse and to convert the contaminants of waste stream into manageable solid wastes for disposal. The most popular among these techniques is the ZERO LIQUID DISCHARGE (ZLD) system that can recover 90–99% of the wastewater as a high quality distillate suitable for reuse in the boiler makeup system or the cooling tower while simultaneously producing a clean salt for byproduct sale with only a minor volume of contaminants.

Since no single unit operation is able to provide the level of treatment necessary to achieve zero liquid discharge, the integration of several unit operations is essentially required. Various combinations of treatment processes such as ion exchange, neutralization, precipitation, spray drying, reverse osmosis, evaporation and crystallization have been selected, designed and tested in order to make ZLD a commercially lucrative system through a combination of water conservation, onsite wastewater treatment, and reuse/recycling.

Evaporators and crystallizers are able to concentrate TDS of wastewaters to a disposable mass of solid for offsite disposal while producing a high quality distillate that can be reused within the plant, thereby reducing the load on makeup water requirements. It is often possible to combine various types of evaporator-crystallizer systems with pretreatment technologies like RO, ED to develop a cost effective and efficient `hybrid' system to achieve zero liquid discharge of plant wastewater.

Wastewater Sources

Thermal powerplant and other industrial wastewater sources are:

1. Cooling tower blowdown
2. Demineralizer reagent wastes
3. Boiler blowdown
4. Ash sluice water
5. Fluegas desulphurization effluent
6. Plant rinses, drains and run-off
7. Sanitary wastes
8. Gasification effluent (applicable to ICGCC system)

Inasmuch as wastewater characteristics often vary considerably, even among identical types of plants, it is imperative to carefully consider site-specific requirements when selecting a treatment scheme to achieve ZLD.

Cooling Tower Blowdown Treatment Systems

Normally CTBD receives streams of boiler blowdown, demineralizer regenerant wastes, ash sluice water and area run-off before it is finally discharged to green belt canal. Such a mix-up results in higher or lower concentration of final effluent depending on the source of waste water. DMP effluent and boiler blowdown are usually more concentrated streams, but are only produced for short periods on an infrequent schedule. Whereas overflow of ash-settling pond and surface drainage bear less load of solids than CTBD and hence cause a dilution effect in the CTBD stream. Typical CTBD and mixed stream chemistries are presented in Table A VI. 3 below.

They are characterized by a lower TDS than ICGCC or FGD effluents but are, very often, saturated in calcium sulphate and/or silica. This is due to the fact that the CT often operates at a concentration as high as possible to minimize the intake of M/up water, but also remains just below the saturation point of the scaling salts. Because of this wastewater chemistry, a 'hybrid' system of suitable combination of following techniques are envisaged:

(a) Membrane processes (RO, ED etc.)
(b) Evaporation

Table A VI. 3 *Cooling Tower Blowdown & Mixed Wastewater Analysis Report (Typical)*

Parameter	Case # 1 as $CaCO_3$	Case # 2 as ion	Case # 3 as ion	Case # 4 as ion
Temperature (°K)	NR	300	298	305
pH	7.5	8.1	8.5	7.2
TDS (mg/l)	953	3000	19 200	3000
SiO_2 (mg/l)	2.4	76	22	109
CO_3 (mg/l)	0	NR	NR	0.3
HCO_3 (mg/l)	70	NR	NR	59
SO_4 (mg/l)	875	600	1930	1930
F (mg/l)	NR	0.6	0.1	4.6
Cl (mg/l)	288	1130	10 000	122
P (mg/l)	NR	1.9	2.2	2.5
Ca (mg/l)	736	230	380	534
Mg (mg/l)	248	90	260	158
Na (mg/l)	184	670	6440	119
K (mg/l)	14	79	120	NR

NR : Not Reported

Source: Zero Liquid discharge: Treatment of Powerplant Effluents—Y Y Tom & B E Heimbigner (Power Gen Asia 1993/Singapore/Sep. 13–15, 1993)

(c) Crystallization
(d) Drying
(e) Solar evaporation
(f) Deep-well injection
(g) Injection into the combustion chamber

Utilities generating substantial quantities of wastewater (> 20 m^3/h) with TDS level low enough (< 10000 mg/1) should go in for one of the following options of hybrid system to achieve ZLD :

(a) Membranes + Dryer
(b) Membranes + Evaporator + Dryer
(c) Membranes + Evaporator with Dewatering Device + Crystallizer
(d) Membranes + Crystallizer with Dewatering device

provided that wastewater is non-scaling over the range to be concentrated.

The most common hybrid approach emerging is the one depicted in Fig. A VI.10. It comprises of a RO preconcentrator, falling-film evaporator, forced circulation crystallizer and a plate-and-frame filter press.

The wastewater is pumped to a pretreatment storage tank where a coagulant and polyelectrolyte are added to facilitate the removal of suspended solids in a granular filter media. This is followed by a final filtration step utilizing a cartridge filter and the addition of an anti-scalant and sodium bisulphite to eliminate any residual chlorine. This pretreatment step safeguards downstream membrane systems from clogging and degradation.

The treated effluent is then passed through reverse osmosis that preconcentrates the wastewater about 2–10 concentration factors depending on the initial load of TDS, the scaling salt concentration and the resulting osmotic pressure at full concentration. RO permeat (about 65% of feedstream) is then reused in the plant's CT M/up system, while RO reject is discharged directly to the evaporator.

The evaporator is a vertical, falling-film type vapor compression evaporator (VCE) that receives RO reject as its feed and concentrates the stream to the threshold of sodium salt saturation.

The feedwater is concentrated in the evaporator (Fig. A VI.11). As the feed passes through the tubes, it abstracts the enthalpy of the heating steam condensing in the shellside. When a portion of the water is vaporized, it leaves a concentrated liquor that contains virtually all the dissolved solids contained in the feedstream. Recirculating liquor is introduced at the top of a vertical tube bundle and falls in a thin film down the inside wall of the tubes. The vapour and liquor are then separated at the bottom of the tubes.

Inasmuch as the solubility of silica, sulphates and other scaling constituents are exceeded, the evaporator is operated with an excess concentration of $CaSO_4$ seed crystals in the liquor. This process is known as "seed slurry" process that provides seed crystals to serve as nucleation sites for the precipitation of salts (Fig. A VI.12). As the liquor gets supersaturated due to the continuous evaporation of water, the scale forming salts will precipitate on the existing seed crystals instead of depositing on the tubewalls of the evaporator.

The evaporator concentrates the feed 3–5 times before discharging its brine to the crystallizer.

A forced circulation crystallizer is selected to reduce the evaporator concentrate to a solid form for disposal. The crystallizer is another type of evaporator that is used in applications requiring high solids concentration.

Recirculating liquor is pumped through a heat exchanger under pressure to prevent boiling (BPE results from higher concentration of dissolved solids) and eliminate scale formation in the tubes. The liquor then enters a separator chamber operating at a slightly lower pressure or partial vacuum, causing flash evaporation of water whereupon crystals come into being (Fig. VI. 13)

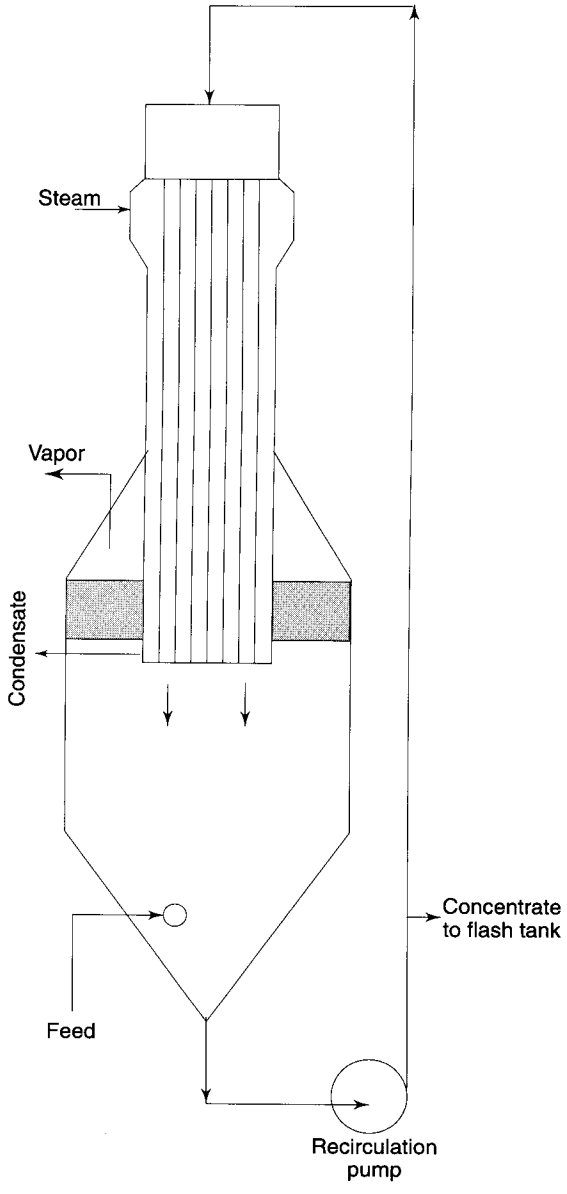


Fig. A VI. 11 *Falling-film evaporator.*

Source: A Hybrid Zero Liquid Discharge Treatment System—K Johanson & T Pankratz (1992 Cogen Turbo Power Conference/Aug. '92/Houston/Texas/USA)

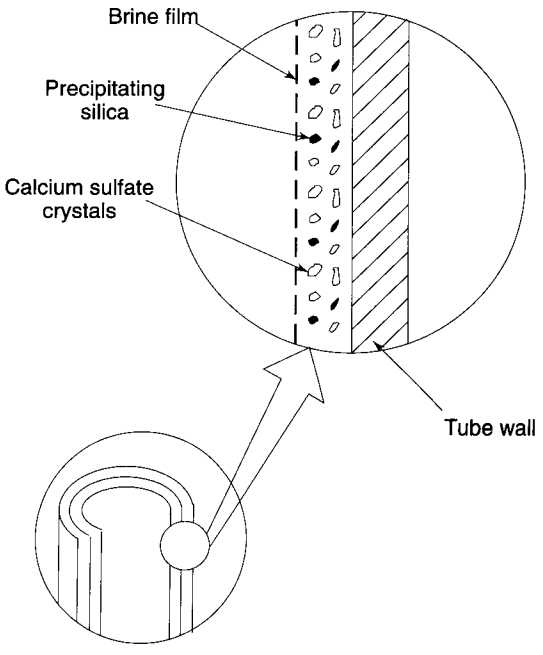


Fig. A VI. 12 *Seeded slurry scale control.*

Source: Zero Liquid Discharge : Treatment of Powerplant Effluents—Y.Y. Tom & B.E. Heimbigner (Power Gen. ASIA 1993, Singapore/September 13–15, 1993).

The crystals formed in the crystallizer are dewatered in a filter-press or a centrifuge to produce a 85–90% dry salt cake for disposal.

The distillates coming from the evaporator and crystallizer can be added directly to the CT M/up system or polished in the DM-unit of the plant prior to reuse as M/up water BFW system.

The Mulberry Combined-Cycle Cogeneration facility near Bartow, Florida, USA is a standing example of how a hybrid ZLD system operates successfully (Fig. A VI.14) producing 2 tons of solids while treating 454 m^3 of wastewater per day in full-load operation.

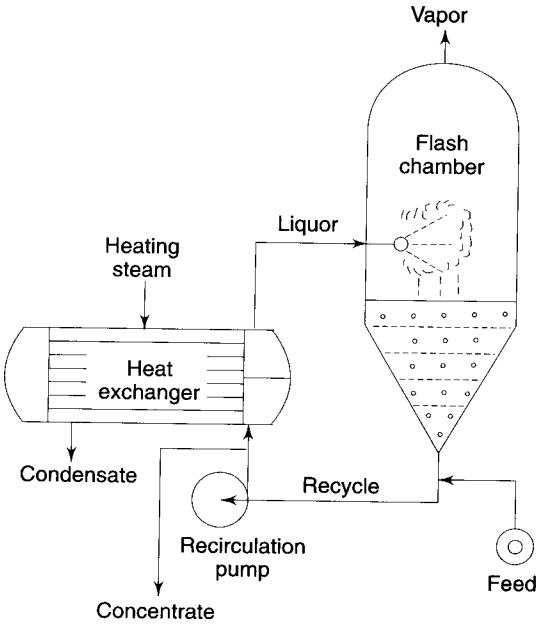


Fig. A VI.13 *Forced circulation evaporator.*

Source : A Hybrid Zero Liquid Discharge Treatment System—K Johanson & T Pankratz (1992 Cogen Turbo Power Conference/August 1992/Houston/Texas/USA)

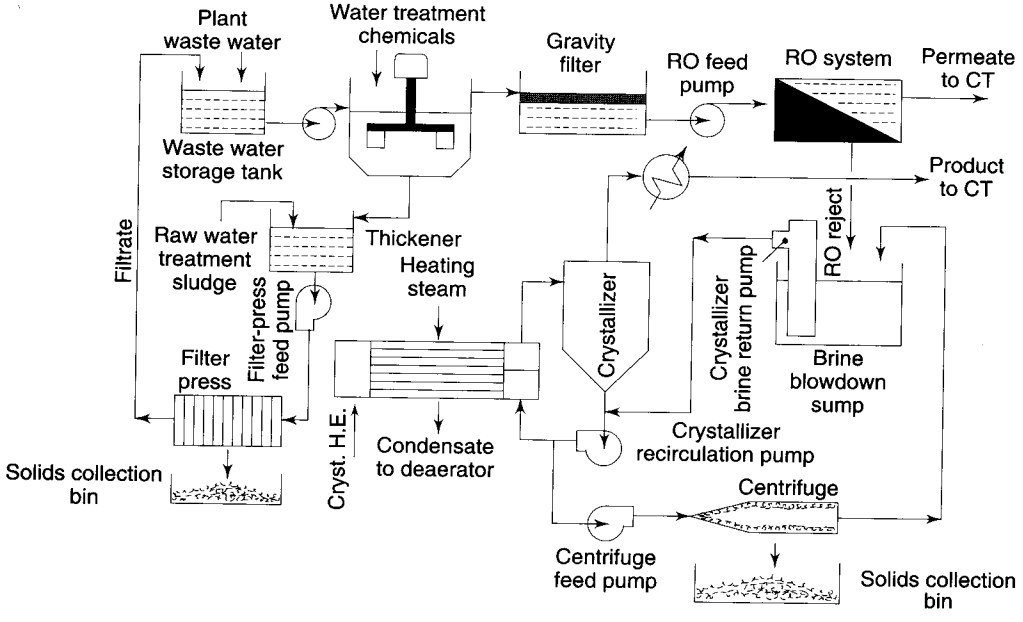


Fig. A VI.14 *ZLD system of Mulberry Cogeneration Facility.*

Source : Power, April 1995/P: 92-94.

Appendix VII

Control Valve Sizing

SIZING EQUATIONS FOR LIQUID FLOW

Liquid flow in non-cavitating or non-flashing conditions is given by equation (1).

$$q = N_1 * F_P * F_R * C_v * \sqrt{\frac{p_1 - p_2}{G_f}} \qquad (1)$$

where q = liquid volumetric flow rate (SI units: [m^3/h]; US units: [gpm])

N_1 = 0.865 (SI units: [m^3/h], [bar A])

= 1.0 (US units: [gpm], [psiA])

F_P = piping geometry factor

F_R = Reynolod's number factor

C_v = valve flow coefficient

p_1 = upstream pressure (SI units: [bar A]; US units: [psiA])

p_2 = downstream pressure (SI units: [bar A]; US units: [psiA])

G_f = specific gravity ($G_f = \rho/\rho_0$ = 1 for water at 15.6°C or at 60°F)

ρ = fluid density (SI units: [kg/m^3]; US units: [lb/ft^3]

ρ_0 = density of water at 15.6°C or at 60°F

= 999 (SI units: [kg/m^3])

= 62.36 (US units: [lb/ft^3]

With an increasing pressure drop ($p_1 - p_2$), the vena contract a pressure in the valve drops below the vapour pressure of the liquid, and the vapour cavities begin to form in the liquid. At a certain point, when sufficient vapour has formed, the flow becomes completely choked, and the flow rate does not increase with increasing pressure drop, if upstream pressure is constant. The corresponding pressure drop is called the terminal pressure drop (Δp_T).

$$\Delta p_T = \left(\frac{F_{LP}}{F_P}\right)^2 * (p_1 - F_F * p_v) \qquad (2)$$

where Δp_T = terminal pressure drop (SI units: [bar]; US units [psi])

F_{LP} = product of the liquid pressure recovery factor of a valve with attached fittings and the piping geometry factor

F_F = liquid critical pressure ratio factor

p_v = liquid vapour pressure at inlet temperature (SI units: [bar A]; US units [psiA])

F_p = piping geometry factor

Consequently, the maximum flow rate (q_{max}) under choked conditions is reached when ($p_1 - p_2$) $\geq \Delta p_T$

$$q_{max} = N_1 * F_{LP} * F_R * C_v * \sqrt{\frac{p_1 - F_p * p_v}{G_t}} \quad (3)$$

When a valve is operated in such a way that the pressure drop is close to the terminal pressure drop (Δp_T), the rate of flow may be less than that predicted by equations (1) or (3) because the real behaviour of the flow rate is approximated using straight lines. However, the error is insignificant.

Factors F_F, F_R, F_P, And F_{LP}

Factor F_F, which is the critical pressure ratio factor for liquids, has an approximate value as given in equation (4).

$$F_F = 0.96 - 0.28 * \sqrt{\frac{p_v}{p_c}} \quad (4)$$

where p_v = liquid vapour pressure at inlet temperature (SI units: [bar A]; US units: [psiA])

p_c = thermodynamical critical pressure (SI units: [bar A]; US units: [psiA])

Factor F_R, which is the Reynolds number factor, usually has a value of 1.0. The Reynolds number factor has an effect in non-turbulent flow, which usually occurs with high viscosity fluids, such as oil, and with low flow velocities and small valve sizes. Reynolds number factor (F_R) can be defined using the valve Reynolds number and figure A VII. 1. The valve Reynolds number is derived from the following equation (5).

$$\mathrm{Re}_v = \frac{N_4 * F_d * q}{v * \sqrt{F_p * F_L * C_v}} * \left[\frac{(F_p * F_L * C_v)^2}{N_2 * d^4} + 1 \right]^{\frac{1}{4}} \quad (5)$$

Where F_d = valve style modifier

= 1 for ball, segment, eccentric rotary plug, and single seated globe valves

= 0.7 for butterfly and double seated globe valves

= 0.5 for Q-trims and other noise attenuating trims

F_L = valve pressure recovery factor

v = kinematic viscosity (SI and US unit: [centistoke])

d = inlet diameter of a valve (SI units: [mm]; US units: [in])

N_2 = 0.00214 (SI units: [mm])

= 890 (US units: [in])

N_4 = 76 000 (SI units: [m^3/h], [mm], [centistoke])

= 17 300 (US units: [gpm], [in], [centistoke])

After calculating the Reynolds number for the valve (Re_v), the Reynolds' number factor (F_R) can be determined from the diagram in Fig. A VII. 1.

The piping geometry factor (F_P) can be calculated as shown in equation (6).

$$F_P = \frac{1}{\sqrt{1 + \frac{\Sigma K}{N_2} * \left(\frac{C_v}{d^2}\right)^2}} \quad (6)$$

where $\Sigma K = K_1 + K_2 + K_{B1} - K_{B2}$

K_1 = upstream resistance coefficient

K_2 = downstream resistance coefficient

K_{B1} = inlet Bernoulli coefficient

K_{B2} = outlet Bernoulli coefficient

N_2 = 0.00214 (SI units: [mm])

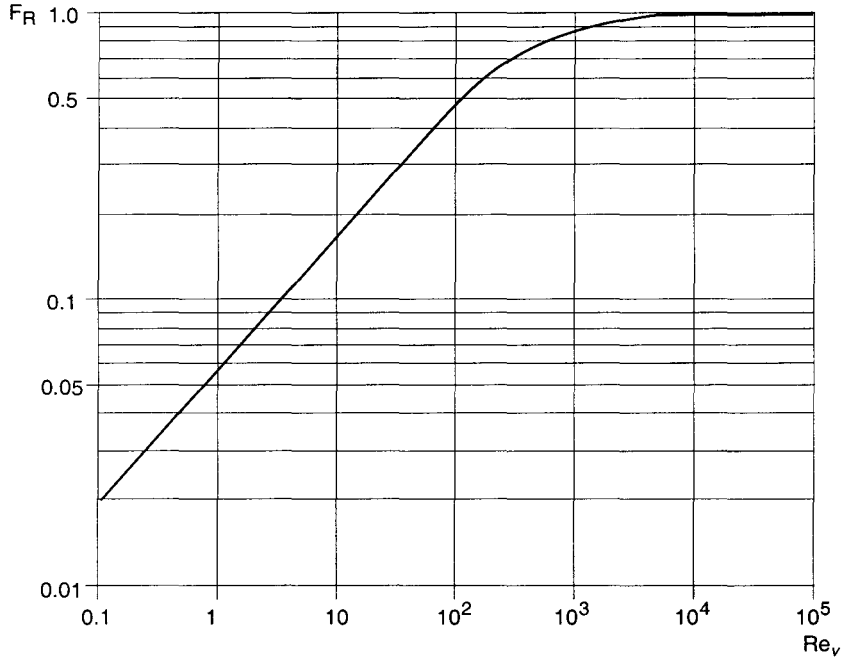


Fig. A VII. 1 *Reynolds number factor (F_R) for liquid flow.*

= 890 (US units: [in])

When the inlet and outlet fittings are identical, $K_{B1} = K_{B2}$, and they cancel out at the equation. If the pipe diameters approaching and leaving the control valve are different, the K_B coefficient are calculated as in equation (7).

$$K_B = 1 - \left(\frac{d}{D}\right)^4 \tag{7}$$

where d = valve inlet diameter for K_{B1} and outlet diameter for K_{B2} (SI units: [mm]; US units; [in])

D = pipe inlet diameter for K_{B1} and outlet diameter for K_{B2} (SI units: [mm]; US units; [in])

For standard concentric reducers, the upstream and downstream resistance coefficients (K_1) and (K_2) can be approximated as shown in equations (8) and (9).

K_1 for inlet reducers:

$$K_1 = 0.5 * \left[1 - \left(\frac{d}{D}\right)^2\right]^2 \tag{8}$$

K_2 for outlet reducers:

$$K_2 = 1 * \left[1 - \left(\frac{d}{D}\right)^2\right]^2 \tag{9}$$

Factor F_{LP} is the product of the liquid pressure recovery factor of a valve with attached fittings and the piping geometry factor (F_P). It is calculated using the given valve pressure recovery factor (F_L) and piping geometry factor (F_P) as shown in equation (10).

$$F_{LP} = \frac{F_L}{\sqrt{1 + \frac{F_L^2}{N_2} * \left(\frac{C_v}{d^2}\right)^2 * \Sigma K_i}} \tag{10}$$

where ΣK_i = head loss coefficient for an inlet fitting = $K_1 + K_{B1}$

N_2 = 0.00214 (SI units; [mm])

= 890 (US units: [in])

SIZING EQUATIONS FOR GAS AND STEAM FLOW

The gas or vapour flow through the valve can be calculated using any of these forms of basic equations (11) to (14).

$$w = N_6 * F_p * C_v * Y * \sqrt{x * p_1 * \rho_1} \quad (11)$$

$$q = N_7 * F_p * C_v * p_1 * Y * \sqrt{\frac{x}{G_g * T_1 * Z}} \quad (12)$$

$$w = N_8 * F_p * C_v * p_1 * Y * \sqrt{\frac{x * M}{T_1 * M}} \quad (13)$$

$$q = N_9 * F_p * C_v * p_1 * Y * \sqrt{\frac{x}{M * T_1 * Z}} \quad (14)$$

$$Y = 1 - \frac{x}{3 * F_k * x_T} \quad (15)$$

$$G_g = \frac{M}{M_{air}} \quad (16)$$

$$x = \frac{p_1 - p_2}{p_1} \quad (17)$$

$$F_k = \frac{k}{1.40} \quad (18)$$

where w = mass flow rate (SI units: [kg/h]; US units: [lb/h])

q = volumetric flow rate (SI units: [Nm^3/h], in which a cubic meter is taken at 1.013 barA and 15°C; US units; [scfh], in which a cubic foot is taken at 14.73 psiA and 60°F)

F_p = piping geometry factor

C_v = valve flow coefficient

p_1 = upstream pressure (SI units: [bar A]; US units; [psiA])

N_6 = 27.3 for SI units ([kg/h], [bar], [kg/m^3])

= 63.3 for US units ([lb/h], [psi], [lb/ft^3])

N_7 = 417 for SI units

= 1360 for US units

N_8 = 94.8 for SI units

= 19.3 for US units

N_9 = 2250 for SI units

= 7320 for US units

Y = expansion factor

ρ_1 = upstream density (SI units: [kg/m^3]; US units; [lb/ft^3]

G_g = gas specific gravity

T_1 = upstream temperature (SI units: [K]; US units: [°R])

Z = compressibility factor

M = gas molecular weight

M_{air} = gas molecular weight for air = 28.96

F_k = specific heat ratio factor

k = ratio of specific heats

If $x \geq F_k * x_T$, then the flow becomes critical and $Y = 0.667$ and $F_k * x_T$ must be used instead of x in equations (11) to (14).

For dry saturated steam, a simplified equation (19) can be used where x may not exceed x_T.

$$w = N_{10} * F_p * C_v * p_1 * \left(3 - \frac{x}{x_T}\right) * \sqrt{x} \quad (19)$$

where N_{10} = 6.6 for SI units [kg/h]

= 1.0 for US units [lb/h]

If $x \geq x_T$, then pressure drop ratio factor (x_T) must be used instead of pressure drop ratio (x). For a valve with attached fittings pressure drop ratio factor (x_{TP}) has to be replaced by pressure drop ratio factor (x_T).

x_{TP} can be calculated as in equation (20) using a given factor x_T

$$x_{TP} = \frac{x_T}{F_p^2} * \left[1 + \frac{x_T * K_i}{N_5} * \left(\frac{C_v}{d^2}\right)^2\right]^{-1} \quad (20)$$

where K_i = sum of inlet velocity head coefficients: $K_1 + K_{B1}$ (see equations (7) and (8))

N_5 = 0.00241 for SI units ([mm])

= 1000 for US units ([in])

Factor Z is the compressibility factor, and for perfect gas has a value of 1.0. In many flows, the fluid behaves as a perfect gas and the compressibility factor (Z) will be 1.

Reduced pressure (p_r) is defined as the ratio of the actual inlet absolute pressure to the absolute thermodynamic critical pressure, as in equation (21). The reduced temperature T_r is defined similarly, as in equation (22).

$$p_r = \frac{p_1}{p_c} \quad (21)$$

$$T_r = \frac{T_1}{T_c} \quad (22)$$

where p_c = thermodynamic critical pressure (SI units: [barA]; US units: [psiA])

T_c = thermodynamic critical temperature (SI units: [K]; US units: [°R])

SIZING EXAMPLES

The sizing examples presented here are based on sizing coefficients of Neles-Jamesbury control valves. The sizing coefficients can be found from Neles-Jamesbury's sizing coefficient tables.

Liquid Flow Sizing Example

D series ball valve is controlling high pressure viscous oil flow. Valve size is 100 mm. What is required capacity C_v and opening of the valve with given flow data?

Flow data:

Water volumetric flow rate	q = 100 m^3/h
Upstream temperature of fluid	T_1 = 85 °C
Valve upstream pressure	p_1 = 42 barA
Valve downstream pressure	p_2 = 41.2 barA

Fluid properties:

Liquid specific gravity	G_f = 0.9
Liquid kinematic viscosity	ν = 10000 cs

Piping configuration:

Upstream pipe diameter	D_1 = 100 mm
Downstream pipe diameter	D_2 = 100 mm
Pipe schedule	sch = 40

Valve sizing coefficients, when $C_v/d^2 \approx 20$:

Pressure recovery factor	F_L = 0.76

Calculation

Pressure recovery factor, including pipe fittings:

$F_{LP} = F_L = 0.76$ (valve and pipe diameter are the same)

Valve style modifier:

$F_d = 1$ (for ball valves)

Estimated valve capacity:

$C_v \approx 320$

Valve Reynolds number:

$$\mathrm{Re}_v = \frac{N_4 * F_d * q}{\nu * \sqrt{F_P * F_L * C_v}} * \left[\frac{(F_P * F_L * C_v)^2}{N_2 * d^4} + 1 \right]^{\frac{1}{4}}$$

$$= \frac{76000 * 1 * 100}{10000 * \sqrt{1 * 0.76 * 320}} * \left[\frac{(1 * 0.76 * 320)^2}{0.00214 * 100^4} + 1 \right]^{\frac{1}{4}}$$

$= 51.8$

Reynolds number factor:

$F_R = 0.35$ (from graph in figure A VII. 1)

Valve required capacity:

$$C_v = \frac{q}{N_1 * F_P * F_R * \sqrt{\frac{\Delta p}{G_f}}}$$

$$= \frac{100}{0.865 * 1 * 0.35 * \sqrt{\frac{0.8}{0.9}}}$$

$= 323$

Valve relative opening h:

$h \approx 75\ \%$

Water Flow Sizing Example

Top entry rotary control valve with Q-trim is controlling cooling water flow. Valve size is 50 mm. What is required capacity C_v and opening of the valve with given flow data?

Flow data:

Water volumetric flow rate	$q = 40\ \mathrm{m^3/h}$
Upstream temperature of fluid	$T_1 = 20°\mathrm{C}$
Valve upstream pressure	$p_1 = 10$ barA
Valve downstream pressure	$p_2 = 1.5$ barA

Fluid properties:

Water specific gravity	$G_f = 1$
Water critical pressure	$p_c = 221.2$ barA
Water vapour pressure in T_1	$p_v = 0.023$ barA

Piping configuration:

Upstream pipe diameter	$D_1 = 50$ mm
Downstream pipe diameter	$D_2 = 50$ mm
Pipe schedule	sch = 40

Valve sizing coefficients, when $C_v/d^2 \approx 4.0$:

Pressure recovery factor	$F_L = 0.9$

Calculation

Pressure recovery factor, including pipe fittings:

$F_{LP} = F_L = 0.9$

(valve and pipe diameter are the same)

Water critical pressure ratio factor:

$$F_F = 0.96 - 0.28 * \sqrt{\frac{p_v}{p_c}}$$

$$= 0.96 - 0.28 * \sqrt{\frac{0.023}{221.2}} = 0.957$$

Terminal pressure drop:

$$\Delta p_T = \left(\frac{F_{LP}}{F_P} \right)^2 * (p_1 - F_F * p_v)$$

$$= \left(\frac{0.9}{1} \right)^2 * (10 - 0.957 * 0.023)$$

$= 8.08$

Check if flow is choked:

$\Delta p > \Delta p_T \rightarrow$ the flow is choked $\rightarrow \Delta p_T$ must be used instead of Δp in sizing

Valve required capacity:

$$C_v = \frac{q}{N_1 * F_P * F_R * \sqrt{\frac{\Delta p_T}{G_f}}}$$

$$= \frac{40}{0.865 * 1 * 1 * \sqrt{\frac{8.08}{1}}}$$

$$= 16.3$$

Valve relative opening h:

$h \approx 70\%$

Gas flow sizing example

R-series segment valve with Q-trim is controlling air flow to atmosphere. Valve size is 80 mm. What is required capacity C_v and opening of the valve with given flow data?

Flow data:

Gas volumetric flow rate (in NTP)	$q = 3700$ Nm^3/h
Upstream temperature of gas	$T_1 = 20°C$
Valve upstream pressure	$p_1 = 4.7$ barA
Valve downstream pressure	$p_2 = 1.2$ barA

Fluid properties:

Molecular weight of gas	$M = 28.9$
Gas compressibility	$Z = 1$
Gas ratio of specific heats	$k = 1.4$

Piping configuration:

Upstream pipe diameter	$D_1 = 100$ mm
Downstream pipe diameter	$D_2 = 150$ mm
Pipe schedule	sch = 80

Valve sizing coefficients, when $C_v/d^2 \approx 6.5$:

Pressure drop ratio factor	$x_T = 0.69$

Calculation

Inlet Bernoulli coefficient K_{BI}:

$$K_{B1} = 1 - \left(\frac{d}{D_1}\right)^4 = 1 - \left(\frac{80}{100}\right)^4 = 0.59$$

Outlet Bernoulli coefficient K_{B2}:

$$K_{B2} = 1 - \left(\frac{d}{D_2}\right)^4 = 1 - \left(\frac{80}{150}\right)^4 = 0.92$$

Inlet reducer K_1:

$$K_1 = 0.5 * \left[1 - \left(\frac{d}{D_1}\right)^2\right]^2$$

$$= 0.5 * \left[1 - \left(\frac{80}{100}\right)^2\right]^2 = 0.06$$

Outlet reducer K_2:

$$K_2 = 1.0 * \left[1 - \left(\frac{d}{D_2}\right)^2\right]^2$$

$$= 1.0 * \left[1 - \left(\frac{80}{150}\right)^2\right]^2 = 0.51$$

Sum of K-coefficients:

$$\Sigma K = K_1 + K_2 + K_{B1} - K_{B2}$$

$$= 0.06 + 0.51 + 0.59 - 0.92$$

$$= 0.24$$

Piping geometry factor F_p:

$$F_p = \frac{1}{\sqrt{1 + \frac{\Sigma K}{N_2} * \left(\frac{C_v}{d^2}\right)^2}} = \frac{1}{\sqrt{1 + \frac{0.24}{890} * 6.5^2}}$$

$$= 0.99$$

Pressure drop ratio factor which includes pipe fittings x_{TP}:

$$x_{TP} = \frac{x_T}{F_p^2} * \left[1 + \frac{x_T * (K_1 + K_{BI})}{N_5} * \left(\frac{C_v}{d^2}\right)^2\right]^{-1}$$

$$= \frac{0.69}{0.99^2} * \left[1 + \frac{0.69 * (0.06 + 0.59)}{1000} * 6.5^2\right]^{-1}$$

$$= 0.69$$

Specific heat ratio factor F_k:

$$F_k = \frac{k}{1.4} = \frac{1.4}{1.4} = 1.0$$

Checking if flow is choked:

$$x = \frac{\Delta p}{p_1} = \frac{3.5}{4.7} = 0.745$$

$$F_k * x_{TP} = 1.0 * 0.69 = 0.69$$

Flow is choked because $x > F_k * x_{TP}$. Therefore $F_k * x_{TP}$ (= 0.69) is used instead of x (= 0.745) in sizing.

Gas expansion factor Y: (for chocked flow)

$Y = 0.667$

Valve required capacity C_v: (for choked flow)

$$C_v = \frac{q}{N_9 * F_p * p_1 * Y * \sqrt{\frac{F_k * x_{TP}}{M * T_1 * Z}}}$$

$$= \frac{3700}{2250 * 0.99 * 4.7 * 0.667 * \sqrt{\frac{1.0 * 0.69}{28.9 * 293 * 1}}}$$

$= 58.9$

Valve relative opening h:

$h \approx 67\%$

Steam flow sizing example

L-series butterfly valve is controlling saturated steam flow. Valve size is 100 mm. What is required capacity C_v and opening of the valve with given flow data?

Flow data:

Gas mass flow rate	w = 7 t/h
Upstream temperature of steam	T_1 = 150°C
Valve upstream pressure	p_1 = 4.75 barA
Valve downstream pressure	p_2 = 4.25 barA

Fluid properties:

Upstream density of steam	$\rho_1 = 2.54 kg/m^3$
Ratio of specific heats	k = 1.3

Piping configuration:

Upstream pipe diameter	D_1 = 100 mm
Downstream pipe diameter	D_2 = 100 mm
Pipe schedule	sch = 40

Valve sizing coefficients, when $C_v / d^2 \approx 16$

Pressure drop ratio factor	x_T = 0.41

Calculation

Pressure drop ratio factor, including pipe fittings:

$x_{TP} = x_T = 0.41$

(valve and pipe diameter are the same)

Specific heat ratio factor:

$$F_k = \frac{k}{1.4} = \frac{1.3}{1.4} = 0.93$$

Check if flow is choked:

$$x = \frac{\Delta p}{p_1} = \frac{0.5}{4.75} = 0.105$$

$$F_k * x_{TP} = 0.93 * 0.41 = 0.38$$

Flow is not choked because $x < F_k * x_{TP}$

Gas expansion factor:

$$Y = 1 - \frac{x}{3 * F_k * x_{TP}}$$

$$= 1 - \frac{0.105}{3 * 0.93 * 0.38}$$

$$= 0.90$$

Valve required capacity:

$$C_v = \frac{w}{N_6 * F_p * Y * \sqrt{x * p_1 * \rho_1}}$$

$$= \frac{7000}{27.3 * 1 * 0.90 * \sqrt{0.105 * 4.75 * 2.54}}$$

= 253

Valve relative opening h:

$h \approx 70\%$

Two-phase flow of liquid and gas sizing example

Top entry rotary control valve with Q-trim is controlling mixture of crude oil and natural gas. Valve size is 150 mm. What is required capacity C_v and opening of the valve with given flow data?

Flow data:

Liquid mass flow rate	w_f = 237 526 kg/h
Gas mass flow rate	w_g = 50 557 kg/h
Upstream temperature of fluid	T_1 = 104°C
Valve upstream pressure	p_1 = 82.7 barA
Valve downstream pressure	p_2 = 34.7 barA

Fluid properties:

Liquid density	ρ_f = 800 kg/m^3
Gas upstream density	ρ_{g1} = 62 kg/m^3
Liquid critical pressure	p_c = 41.4 barA
Liquid vapour pressure in T_1	p_v = 0.37 barA
Gas ratio of specific heats	k = 1.32

Piping configuration:

Upstream pipe diameter	D_1 = 150 mm
Downstream pipe diameter	D_2 = 150 mm
Pipe schedule	sch = 80

Valve sizing coefficients, when $C_v/d^2 \approx 3.4$:

Pressure drop ratio factor	x_T = 0.75
Pressure recovery factor	F_L = 0.91

Calculation

Total mass flow rate:

$w = w_f + w_g$ = 237526 kg/h + 50557 kg/h = 288083 kg/h

Liquid portion of total mass flow rate:

$$f_f = \frac{w_f}{w} = \frac{237526}{288083} = 0.8245$$

Gas portion of total mass flow rate:

$$f_g = \frac{w_g}{w} = \frac{50557}{288083} = 0.1755$$

Pressure drop ratio factor, including pipe fittings:

$x_{TP} = x_T = 0.75$ (valve and pipe diameter are the same)

Specific heat ratio factor:

$$F_k = \frac{k}{1.4} = \frac{1.32}{1.4} = 0.943$$

Pressure recovery coefficient, including pipe fittings:

$F_{LP} = F_L = 0.91$

(valve and pipe diameter are the same)

Liquid critical pressure ratio factor:

$$F_F = 0.96 - 0.28 * \sqrt{\frac{p_v}{p_c}}$$

$$= 0.96 - 0.28 * \sqrt{\frac{0.37}{41.4}} = 0.934$$

Terminal pressure drop of choked two-phase flow:

$$\Delta p_{T-2PH} = (p_1 * F_k * x_{TP}) * f_g + \left(\frac{F_{LP}}{F_P}\right)^2 * (p_1 - F_F * p_v) * f_f$$

$$= (82.7 * 0.943 * 0.75) * 0.1755 + \left(\frac{0.91}{1}\right)^2 * (82.7 - 0.934 * 0.37) * 0.8245$$

$$= 66.5 \text{ bar}$$

Check if flow is choked:

$\Delta p < \Delta p_{T-2PH} \rightarrow$ flow is not choked

Gas expansion factor:

$$Y = 1 - \frac{x}{3 * F_k * x_{TP}}$$

$$= 1 - \frac{\left(\frac{82.7 - 34.7}{82.7}\right)}{3 * 0.943 * 0.75}$$

$$= 0.726$$

Effective density of mixture:

$$\rho_E = \left(\frac{f_g}{\rho_{g1} * Y^2} + \frac{f_f}{\rho_f}\right)^{-1}$$

$$= \left(\frac{0.1755}{62 * 0.726^2} + \frac{0.8245}{800}\right)^{-1}$$

$$= 156.2 \text{ kg/m}^3$$

Valve required capacity:

$$C_v = \frac{w}{N_6 * F_P * \sqrt{\Delta p * \rho_E}}$$

$$= \frac{288083}{27.3 * 1 * \sqrt{48 * 156.2}}$$

$$= 122$$

Valve relative opening h:

$h \approx 70\%$

Pulp Flow Sizing Example

R-series segment valve is controlling flow of mechanical stock. Valve size is 80 mm. What is required capacity C_v and opening of the valve with given flow data?

Flow data:

Pulp volumetric flow rate	$q = 50 \text{ m}^3/\text{h}$
Upstream temperature of pulp	$T_1 = 40°\text{C}$
Valve upstream pressure	$p_1 = 2.1$ bar A
Valve downstream pressure	$p_2 = 1.5$ bar A

Fluid properties:

Pulp consistency	C = 8%
Liquid critical pressure	$p_c = 221.2$ bar A
Liquid vapour pressure	$p_v = 0.1$ bar A

Piping configuration:

Upstream pipe diameter	$D_1 = 80$ mm
Downstream pipe diameter	$D_2 = 80$ mm
Pipe schedule	sch = 40

Calculation

Equivalent flow rate in water:

$k = 0.8$ (from graph of Fig. A VII. 2).

$$q_{\text{water}} = \frac{q_{\text{stock}}}{k} = \frac{50}{0.8} = 62.5 \text{ m}^3/\text{h}$$

Piping geometry factor:

$F_P = 1.0$

(valve and pipe diameter are the same)

Valve required capacity:

$$C_v = \frac{q_{\text{water}}}{N_1 * F_p * F_R * \sqrt{\frac{\Delta p}{G_f}}}$$

$$= \frac{62.5}{0.865 * 1 * 1\sqrt{\frac{0.6}{1}}}$$

$$= 93.3$$

Valve relative opening h:

$h \approx 65\%$

CORRECTION COEFFICIENT k FOR PULP FLOW

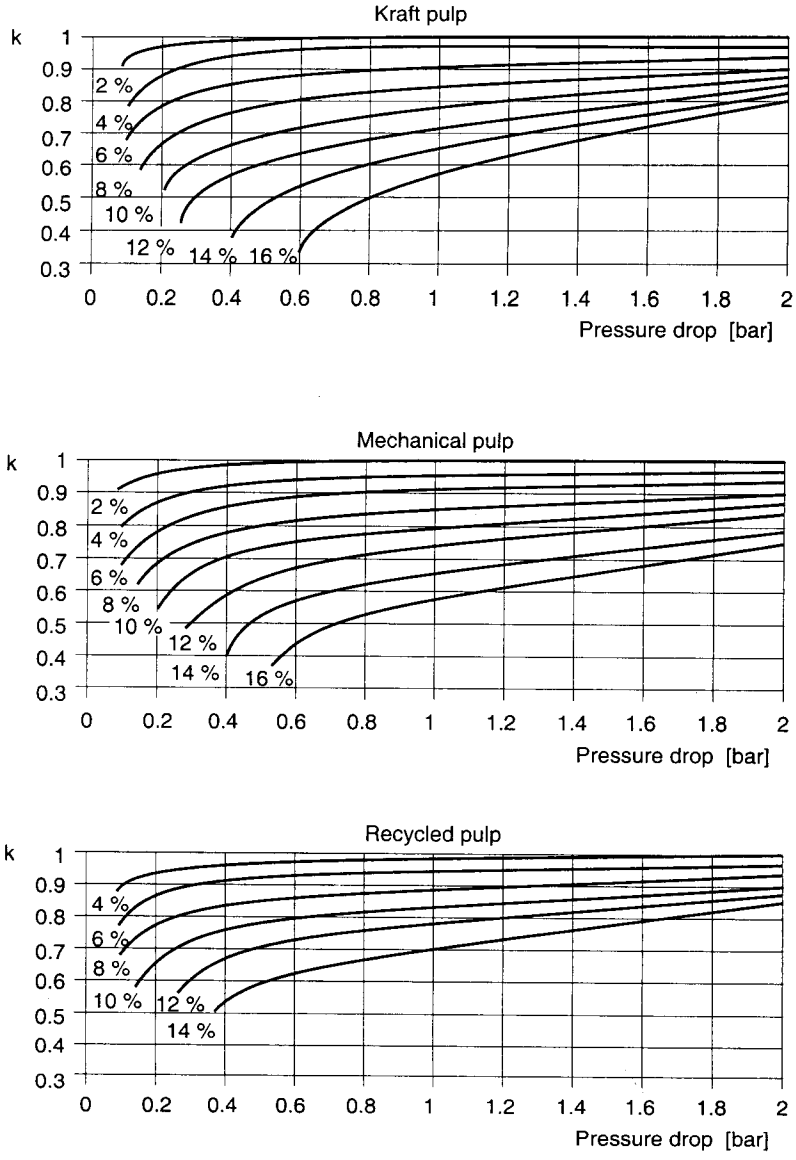


Fig. A VII. 2 *Correction coefficient in SI units.*

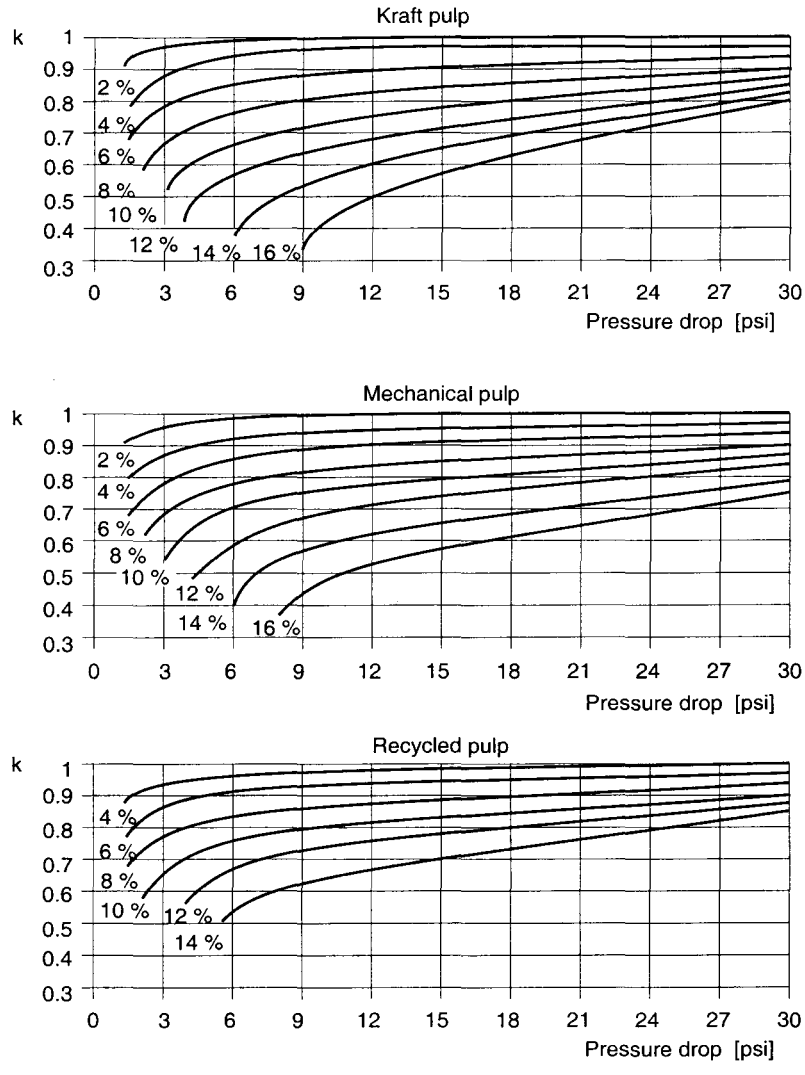


Fig. A VII.2 *Correction coefficient in US units.*

Sourece: Flow Control Manual —Lasse Kamppari(ed.) (Neles-Jamesbury,, Helsinki, Finland, 1994)

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COMMERCIAL SEAT TIGHTNESS

COMPARISON OF SPRING-LOADED AND PILOT-OPERATED SAFETY RELIEF VALVES

Spring-Loaded Safety Relief Valve

Fig. A VII.3 shows load changes at the seal interface of a safety relief valve or direct-acting pilot in relation to working pressure. When the latter is equal to set pressure (P/PT = 1), the load at the interface is zero and the valve stays closed.

The leakoff rate increases towards the safety relief valve nominal flowing capacity.

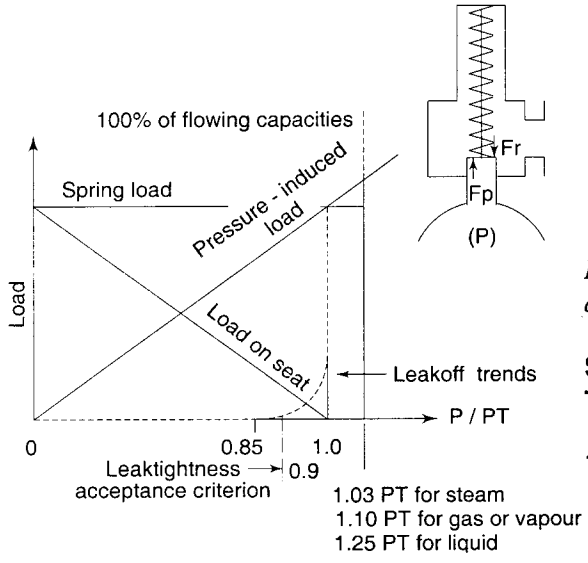

Fig. A VII. 3

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These valves should not be operated between 0.9 and 1 (P/PT).

PT = set pressure.

Pilot-Operated Safety Relief Valve

Up to *P/PT* = 0.98, pressure in the valve head changes identically to the pressure under the disc.

The load at the interface is proportional to the leaktightness pressure in the ratio S/s. (Fig. A VII. 4)

Leaktightness is maintained until the valve starts to open.

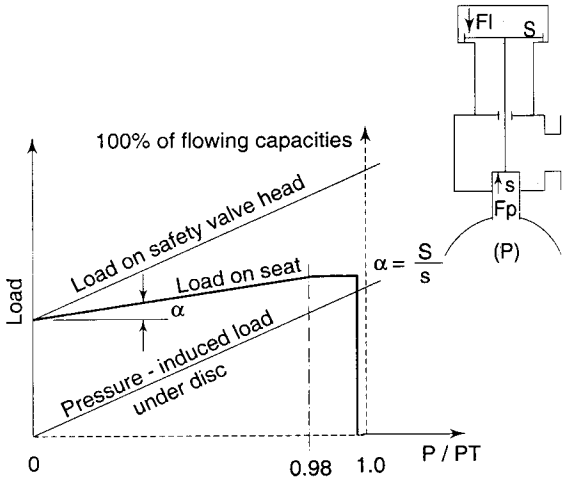

Fig. A VII .4

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It is possible to use this safety relief valve up to a service pressure of 0.98 PT.

SAFETY RELIEF VALVE CODIFICATION (TYPICAL SYSTEM)

1 Kind of Valves

7 Internal-piston valves

8 Bellows-piston valves

2 Types of Valves

5 High-lift valves-semi nozzle

6 High-lift valves-full nozzle

3 Body Material

3 Carbon steel

4 SS 18/8 (AISI 304 or CF8)

5 SS 18/8 Mo (AISI 316 or CF 8M)

6 Steel Cr Mo (A 217WC6)

7 Killed steel (A 352 LCB)
8 Killed steel (A 352 LC 1)
9
0 Other metals

4 Type of Connections

4 Weld ends SW
5 Weld ends : BW
6 Single-outlet flanges
7
8 Other connections

5 Pressure Rating

1 PN 16-ANSI 150
2 PN 40-ANSI 300
3 PN 100-ANSI 600
4 PN 150-ANSI 900
5 PN 250-ANSI 1500
6 PN 420-ANSI 2500
8
9 Other categories

6. Bellows-piston Material

A Inapplicable
H Inconel X 750
I Inconel 600
K Monel K
P SS AISI 302
Q SS AISI 316 L
Z Other materials

7 Inlet Nominal Diameter

Dimensions in inches or millimeters according to standard used.

8 Nozzle/seat Identification

Diameter of flow opening in mm or symbol "API standard 326"

9 Outlet Nominal Diameter

See inlet

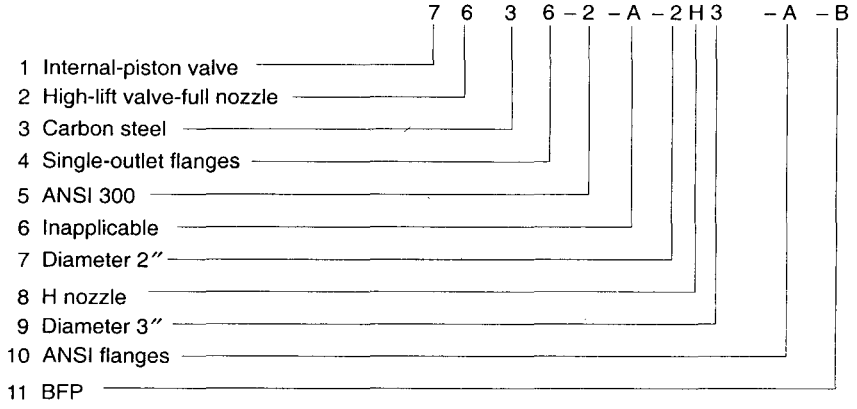
10 Flange or Thread Standards

A ANSI flanges
D DIN flanges
P PN flanges (ISO)
Z Other standards

11 Accessories and Specific Details

A No accessory
B BFP (Back Flow Preventer)
J Disc with elastomer "O" ring
T Disc with teflon seating surface
Z Other accessories

Typical Example of Codification



TECHNICAL INFORMATION

Required for Selecting a Safety Relief Valve

To meet the requirement as quickly as possible, one should provide the following information:

Safety Relief Valve Related to Required Capacity

Quantity
Type of fluid
Applicable codes or standards
Required capacity
Set pressure
Maximum working temperature
Constant or variable back pressure
Allowable overpressure
Type of connection
Materials
Accessories

For liquids

Specific gravity (water = 1)
Viscosity

For gases or vapors

C_p/C_v
Molecular weight or specific gravity (air = 1)
Compressibility factor

Safety Relief Valve if Orifice Size Provided

Quantity
Type of fluid
Applicable codes or standards
Inlet/outlet dimensions
Inlet pressure rating
Area or orifice diameter
Set pressure
Maximum working pressure
Constant or variable backpressure
Maximum overpressure
Type of connection
Materials
Accessories

GENERAL SIZING FORMULAE

AS PER NFE 29-441 (ISO 4126)

1 Gases or Vapors

KG/H

$$A = \frac{W}{395 \times K_d \times N_c \times P \times K_b \times \sqrt{\dfrac{M}{T \times Z}}}$$

2 Steam

KG/H

$$A = \frac{W}{52.5 \times P \times K_d \times K_{sh} \times K_b \times \phi \times x}$$

where $\phi = \dfrac{100 - (2.7644 \times P)}{1061 - (3.3244 \times P)}$

for $110b < P < 200\ b$

$\phi = 1$ for $P \leqq 110$ b

3 Liquids

KG/H

$$A = \frac{Q_m}{161\sqrt{\rho\,(P - P_b)} \cdot (K_d . K_v)}$$

SYMBOLS

A = required effective discharge area in cm^2

W = required gas flow in kg/h

N_c = first flowrate number under critical flow conditions

P = upstream relieving pressure (bar abs)

P = 1.1 Pt + 1.013 at 10% Overpressure

P = 1.03 Pt + 1.013 at 3% Overpressure

M = molecular weight

T = absolute inlet temperature in °K

Z = compressibility factor

K_d = certified coefficient of discharge $0.9 \times K_{d1}$*

K_b = capacity correction factor due to back pressure (gas, vapour, steam)

K_{sh} = correction factor for superheated steam

Q_m = liquid flowrate in kg/h

P_b = backpressure in bar gage

ρ = density in kg/m^3

K_v = capacity correction factor due to viscosity

K_p = capacity correction factor due to overpressure

K_w = capacity correction factor due to back pressure

ϕ = Thomson and Buxton function

x = wet vapour quality

$0.9 \leqq x < 1$

Courtesy: SEBIM Group/Vierzon/France

STEAM TRAPS

Float and Thermostatic

(F & T) TRAP : is the simplest type of mechanical trap that consists of a chamber, a float, and a valve to operate the condensate removal mechanism (Fig. A VII. 5). As the condensate level rises, the float attached directly to the discharge valve opens up the discharge valve whereupon the condensate drains out—the flow is continuous, modulating to the tune of condensate generation.

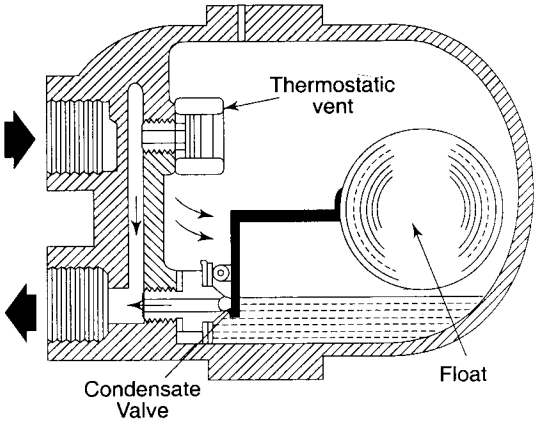


Fig. A VII. 5

Advantages

1. Condensate discharge is continuous
2. Handles rapid pressure excursions
3. Non-condensible gas won't discharge
4. High non-condensible capacity

Disadvantages

1. Float susceptible to damage by water hammer
2. Level of condensate in the chamber can freeze, damaging both float and body
3. Susceptible to corrosion (in some thermostatic air vent designs)

Recommended: for services where heat transfer rates are high and variable; also when a condensate pump is required.

Inverted Bucket (IB) Trap: is a mechanical trap sporting an inverted cylinder or bucket (open at the bottom end) as a float connected directly to the condensate discharge valve mechanism (Fig. A VII. 6). The open end of the inverted bucket is sealed with a pool of condensate at the bottom of the chamber. As the bucket gets filled with steam, it rises due to buoyancy closing the discharge

* K_{d1} = certified coefficient of discharge.

valve. Once the valve is closed, the steam pressure holds the head onto the seat. When condensate floods the bucket, the buoyancy decreases and it sinks, causing the valve to open and pass out the condensate.

Condensate discharge is intermittent.

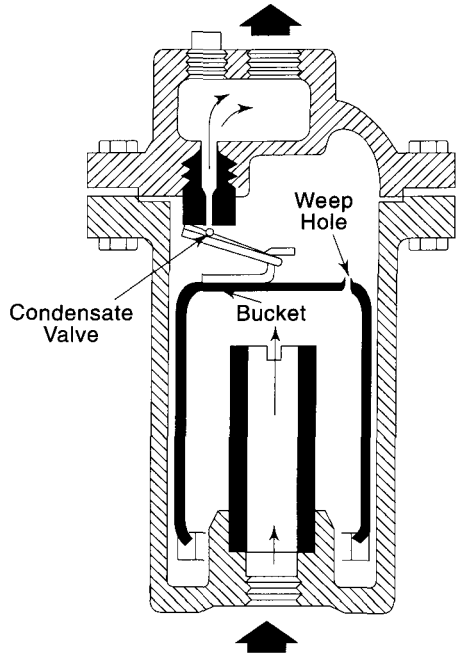


Fig. A VII. 6

Advantages

1. Rugged construction
2. Can withstand water hammer with mechanical damage

Disadvantages

1. Water seal is a must. *Subject to losing prime*
2. Pressure excursions and superheated steam can break water seal
3. Discharges non-condensibles too, though slowly
4. Level of condensate can freeze, damaging the trap body.

Recommended: for continuous operation where rugged construction is important and non-condensible venting is not critical.

Wax-or Liquid Expansion Thermostatic (TS) Trap:

is actuated by a filled element that expands and contracts with temperature changes. Condensate collecting near the trap cools below the set point and the valve opens. When hotter saturated steam reaches the trap, the valve closes (Fig. A VII. 7).

It works well if the pressure (and hence temperature) of steam is constant.

Advantages

1. Utilizes sensible heat of the condensate
2. Immune to damage by superheated steam, water hammer or vibration
3. Resists freezing

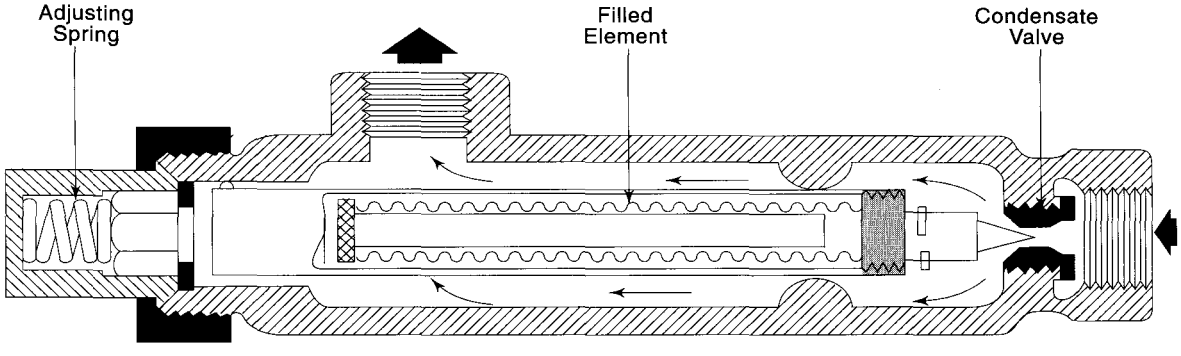


Fig. A VII. 7

Disadvantages

1. Condensate backs up into the drainline and/or process
2. Element subject to corrosion damage

Recommended: for tracing used for freeze protection.

Balanced Pressure (BP) Trap: is a thermostatic trap employed when steam pressure varies and condensate backup is desirable. Like other thermostatic traps, it requires the condensate to be sub-cooled before the trap's valve opens. The differential pressure across the trap valve serves as the mechanism to adjust the trap closure (Fig. A VII. 8).

Advantages

1. Lightweight and compact
2. Unlikely to freeze
3. Maximum discharge of non-condensibles at start-up

Disadvantages

1. Prone to damage by superheated steam, corrosion and water hammer
2. Condensate backs up into the drainline and/or process

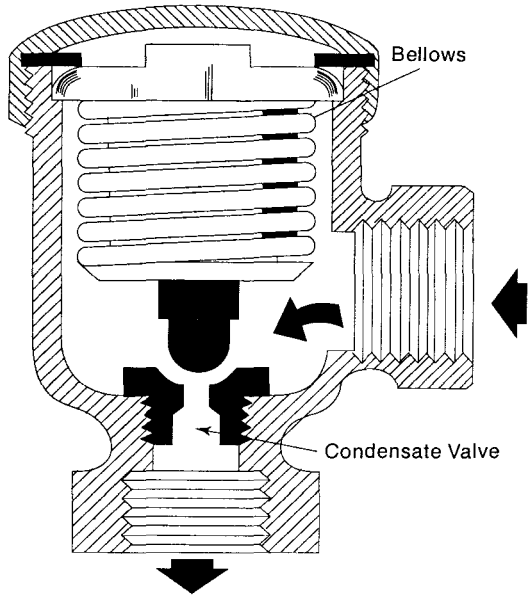


Fig. A VII. 8

Recommended: for steam mains and tracing.

BIMETAL TRAP (BM): is a thermostatic trap that actuates a steam trap valve by harnessing the bending of bimetallic strips/plates due to differential expansion under the influence of temperature change. (Fig. AVII.9)

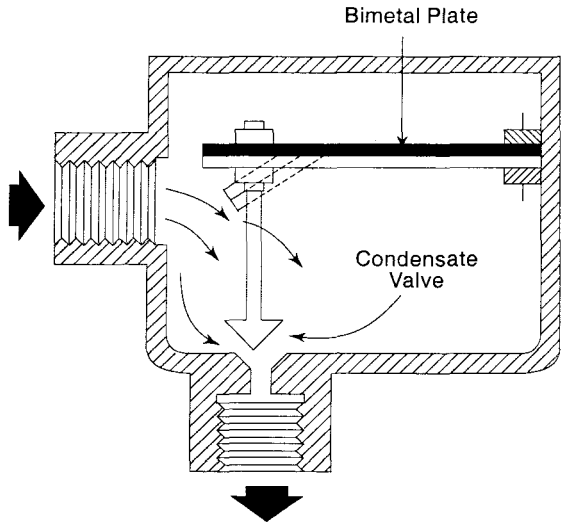


Fig. A VII. 9

Advantages

1. Lightweight and compact
2. Unlikely to freeze
3. Maximum discharge of non-condensibles at start-up
4. Rugged construction. Can withstand corrosion, water hammer and superheated steam

Disadvantages

1. Slow response to load and pressure changes
2. Condensate back-up is more than BP trap
3. Backpressure changes operating characteristics

Recommended: for installation subject to ambient conditions below freezing

THERMODYNAMIC (TD) TRAP: is actuated by kinetic flow. It consists of a disc that normally lies on a flat seat and covers both the inlet and discharge orifices. Cool condensate under process pressure readily flows through the orifice, lifts the disc and flows over the seat to the discharge orifices. (Fig. A VII. 10)

When the condensate is near steam temperature, it flashes generating high velocity flash steam which creates a low pressure area on the bottom of the disc. This low pressure between the disc and the seat, combined with a pressure increase above the disc during flow forces the disc down onto the seat & seals the orifices.

Advantages

1. Compact and simple in construction
2. Handless a wide pressure range
3. Rugged body. Withstands corrosion, water hammer, high pressure swings and superheated steam
4. Audible operation alerts when repair is needed

Disadvantages

1. Operation is noisy
2. Poor operation with very low-pressure steam or high backpressure
3. Requires slow pressure build-up to remove air during start-up to prevent air binding

Recommended: for steam main drips, tracers and also for contant-pressure, constant-load applications.

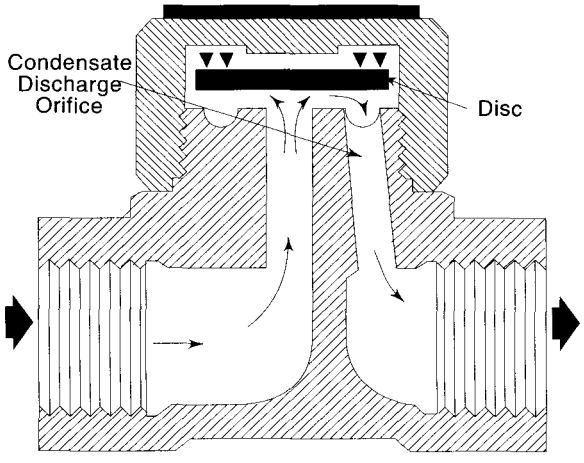


Fig. A VII. 10

Appendix VIII

Steam

STEAM

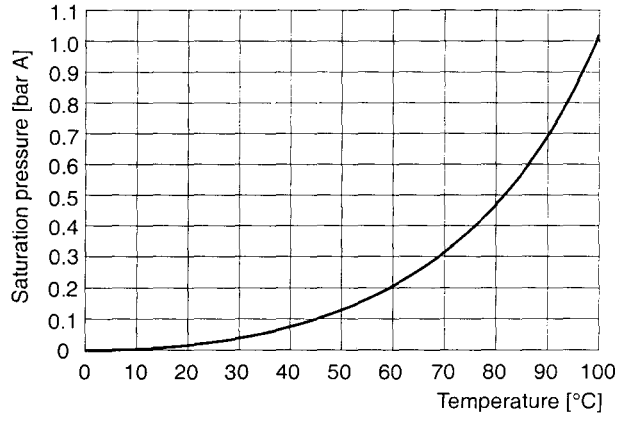


Fig. A VIII. 1 *Saturation pressure of steam between 0°C and 100°C.*

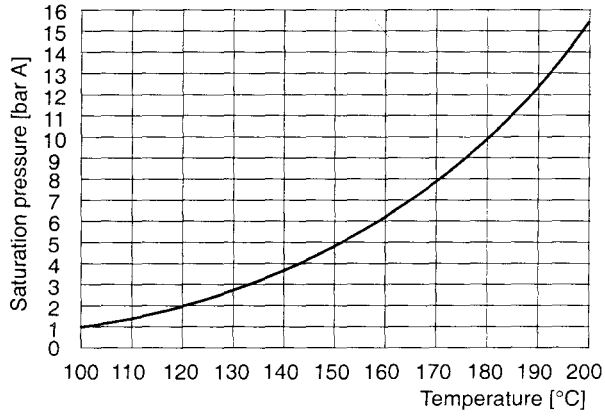


Fig. A. VIII. 2 *Saturation pressure of steam between 100°C and 200°C.*

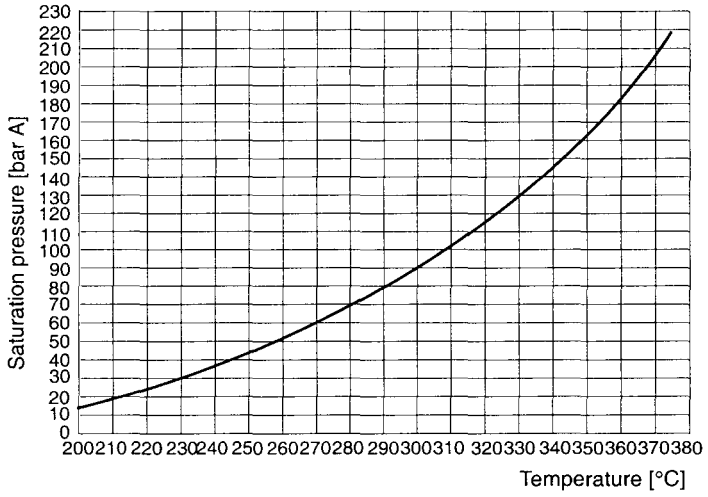


Fig. A VIII. 3 *Saturation pressure of steam between 200°C and 375°C.*

Table A VIII. 1 *Density of saturated steam*

Saturation temperature		Saturation pressure	Specific volume	Density
°C	°K	[bar A]	[m^3/kg]	[kg/m^3]
0	273.15	0.00611	206.140	0.00485
5	278.15	0.00872	147.048	0.0068
10	283.15	0.01227	106.350	0.00940
15	288.15	0.01704	77.9219	0.01283
20	293.15	0.02337	57.7989	0.01730
25	298.15	0.03166	43.3740	0.02306
30	303.15	0.04241	32.9094	0.03039
35	308.15	0.05622	25.2312	0.03963
40	313.15	0.07375	19.5366	0.05119
45	318.15	0.09582	15.2697	0.06549
50	323.15	0.12335	12.0413	0.08305
55	328.15	0.15741	9.57601	0.10443
60	333.15	0.19920	7.67676	0.13026
65	338.15	0.25009	6.20127	0.16126
70	343.15	0.31162	5.04579	0.19819
75	348.15	0.38549	4.13399	0.24190
80	353.15	0.47360	3.40923	0.29332
85	358.15	0.57803	2.82913	0.35347
90	363.15	0.70109	2.36171	0.42342
95	368.15	0.84526	1.98270	0.50436
100	373.15	1.01325	1.67351	0.59755
105	378.15	1.20800	1.41980	0.70432
110	383.15	1.43266	1.21046	0.82613
115	388.15	1.69060	1.03681	0.96450
120	393.15	1.98543	0.89203	1.12104
125	398.15	2.32098	0.77072	1.29748
130	403.15	2.70132	0.66861	1.49564
135	408.15	3.13075	0.58226	1.71743
140	413.15	3.61379	0.50894	1.96488
145	418.15	4.15520	0.44640	2.24013
150	423.15	4.75997	0.39286	2.54541
155	428.15	5.43330	0.34685	2.88311
160	433.15	6.18065	0.30715	3.25573
165	438.15	7.00766	0.27278	3.66590
170	443.15	7.92023	0.24293	4.11642
175	448.15	8.92444	0.21691	4.61024
180	453.15	10.0266	0.19416	5.15048
185	458.15	11.2333	0.17420	5.74044
190	463.15	12.5512	0.15665	6.38365
195	468.15	13.9873	0.14117	7.08386
200	473.15	15.5488	0.12747	7.84505
205	478.15	17.2430	0.11532	8.67152
210	483.15	19.0774	0.10452	9.56782
215	488.15	21.0598	0.09489	10.5389
220	493.15	23.1983	0.08628	11.5900
225	498.15	25.5009	0.07857	12.7269
230	503.15	27.9760	0.07166	13.9557
235	508.15	30.6323	0.06543	15.2832

(*Contd*)

Table A VIII. 1 *(Contd)*

Saturation temperature		Saturation pressure	Specific volume	Density
°C	°K	[bar A]	[m^3/kg]	[kg/m^3]
240	513.15	33.4783	0.05982	16.7167
245	518.15	36.5232	0.05475	18.2641
250	523.15	39.7760	0.05017	19.9340
255	528.15	43.2462	0.04601	21.7361
260	533.15	46.9434	0.04223	23.6808
265	538.15	50.8773	0.03879	25.7797
270	543.15	55.0581	0.03566	28.0454
275	548.15	59.4960	0.03280	30.4923
280	553.15	64.2018	0.03018	33.1362
285	558.15	69.1863	0.02778	35.9946
290	563.15	74.4607	0.02558	39.0874
295	568.15	80.0369	0.02356	42.4372
300	573.15	85.9269	0.02171	46.0694
305	578.15	92.1435	0.01999	50.0130
310	583.15	98.7001	0.01842	54.3017
315	588.15	105.611	0.01696	58.9740
320	593.15	112.891	0.01561	64.0754
325	598.15	120.556	0.01436	69.6593
330	603.15	128.625	0.01319	75.7892
335	608.15	137.117	0.01212	82.5418

SUPERHEATED STEAM

Table A VIII.2 *Specific volume (V) (unit: [m^3/kg]) as a function of temperature (unit: [°C]) and pressure (unit: [bar A]).*

Pressure	Temperature [°C]										
[barA]	100	120	140	160	180	200	220	240	260	280	300
1	1.70	1.79	1.89	1.98	2.08	2.17	2.26	2.36	2.45	2.54	2.64
1.2	-	1.49	1.57	1.65	1.73	1.81	1.88	1.96	2.04	2.12	2.20
1.4	-	1.27	1.34	1.41	1.48	1.55	1.61	1.68	1.75	1.81	1.88
1.6	-	1.11	1.17	1.23	1.29	1.35	1.41	1.47	1.53	1.59	1.65
1.8	-	0.986	1.04	1.09	1.15	1.20	1.25	1.31	1.36	1.41	1.46
2	-	-	0.935	0.983	1.03	1.08	1.13	1.17	1.22	1.27	1.31
3	-	-	0.617	0.650	0.683	0.715	0.748	0.780	0.811	0.843	0.874
4	-	-	-	0.484	0.509	0.534	0.558	0.582	0.606	0.630	0.654
5	-	-	-	0.384	0.404	0.425	0.444	0.464	0.484	0.503	0.522
6	-	-	-	0.317	0.335	0.352	0.369	0.385	0.402	0.418	0.434
7	-	-	-	-	0.285	0.300	0.314	0.329	0.343	0.357	0.371
8	-	-	-	-	0.247	0.261	0.274	0.287	0.299	0.312	0.324
9	-	-	-	-	0.218	0.230	0.242	0.254	0.265	0.276	0.287
10	-	-	-	-	0.195	0.206	0.217	0.227	0.238	0.248	0.258
12	-	-	-	-	-	0.169	0.179	0.188	0.197	0.205	0.214
14	-	-	-	-	-	0.143	0.152	0.160	0.167	0.175	0.182
16	-	-	-	-	-	-	0.131	0.138	0.145	0.152	0.159
18	-	-	-	-	-	-	0.115	0.122	0.128	0.134	0.140
20	-	-	-	-	-	-	0.102	0.109	0.114	0.120	0.126
22	-	-	-	-	-	-	0.092	0.098	0.103	0.108	0.113
24	-	-	-	-	-	-	-	0.089	0.094	0.099	0.103
26	-	-	-	-	-	-	-	0.081	0.086	0.090	0.095
28	-	-	-	-	-	-	-	0.074	0.079	0.083	0.088
30	-	-	-	-	-	-	-	0.068	0.073	0.077	0.081

(Contd)

Table A VIII. 2 *(Contd)*

Pressure	Temperature [°C]										
[barA]	100	120	140	160	180	200	220	240	260	280	300
32	-	-	-	-	-	-	-	0.063	0.068	0.072	0.076
34	-	-	-	-	-	-	-	-	0.063	0.067	0.071
36	-	-	-	-	-	-	-	-	0.059	0.063	0.066
38	-	-	-	-	-	-	-	-	0.055	0.059	0.063
40	-	-	-	-	-	-	-	-	0.052	0.056	0.059
42	-	-	-	-	-	-	-	-	0.049	0.053	0.056
44	-	-	-	-	-	-	-	-	0.046	0.050	0.053
46	-	-	-	-	-	-	-	-	0.043	0.047	0.050
48	-	-	-	-	-	-	-	-	-	0.045	0.048
50	-	-	-	-	-	-	-	-	-	0.042	0.046
55	-	-	-	-	-	-	-	-	-	0.037	0.041
60	-	-	-	-	-	-	-	-	-	0.033	0.036
65	-	-	-	-	-	-	-	-	-	-	0.033
70	-	-	-	-	-	-	-	-	-	-	0.030
75	-	-	-	-	-	-	-	-	-	-	0.027
80	-	-	-	-	-	-	-	-	-	-	0.024

Pressure	Temperature [°C]									
[barA]	320	340	360	380	400	420	440	460	480	500
1	2.73	2.82	2.91	3.01	3.10	3.19	3.29	3.38	3.47	3.56
1.2	2.27	2.35	2.43	2.51	2.58	2.66	2.74	2.81	2.89	2.97
1.4	1.95	2.01	2.08	2.15	2.21	2.28	2.35	2.41	2.48	2.54
1.6	1.70	1.76	1.82	1.88	1.94	1.99	2.05	2.11	2.17	2.23
1.8	1.51	1.57	1.62	1.67	1.72	1.77	1.82	1.88	1.93	1.98
2	1.36	1.41	1.45	1.50	1.55	1.59	1.64	1.69	1.73	1.78
3	0.906	0.937	0.968	1.000	1.031	1.062	1.093	1.124	1.155	1.186
4	0.678	0.702	0.725	0.749	0.772	0.795	0.819	0.842	0.865	0.889
5	0.541	0.560	0.579	0.598	0.617	0.636	0.654	0.673	0.692	0.710
6	0.450	0.466	0.482	0.498	0.513	0.529	0.545	0.560	0.576	0.592
7	0.385	0.399	0.412	0.426	0.439	0.453	0.466	0.480	0.493	0.507
8	0.336	0.348	0.360	0.372	0.384	0.396	0.408	0.420	0.431	0.443
9	0.298	0.309	0.320	0.330	0.341	0.352	0.362	0.373	0.383	0.394
10	0.268	0.277	0.287	0.297	0.306	0.316	0.326	0.335	0.345	0.354
12	0.222	0.230	0.239	0.247	0.255	0.263	0.271	0.279	0.287	0.295
14	0.189	0.197	0.204	0.211	0.218	0.225	0.232	0.238	0.245	0.252
16	0.165	0.171	0.178	0.184	0.190	0.196	0.202	0.208	0.214	0.220
18	0.146	0.152	0.157	0.163	0.168	0.174	0.179	0.185	0.190	0.195
20	0.131	0.136	0.141	0.146	0.151	0.156	0.161	0.166	0.171	0.176
22	0.118	0.123	0.128	0.133	0.137	0.142	0.146	0.151	0.155	0.159
24	0.108	0.112	0.117	0.121	0.125	0.130	0.134	0.138	0.142	0.146
26	0.099	0.103	0.107	0.111	0.115	0.119	0.123	0.127	0.131	0.135
28	0.092	0.096	0.099	0.103	0.107	0.111	0.114	0.118	0.121	0.125
30	0.085	0.089	0.092	0.096	0.099	0.103	0.106	0.110	0.113	0.116

(Contd)

Table AVIII.2 (Contd)

Pressure	Temperature [°C]									
[barA]	320	340	360	380	400	420	440	460	480	500
32	0.079	0.083	0.086	0.090	0.093	0.096	0.099	0.103	0.106	0.109
34	0.074	0.078	0.081	0.084	0.087	0.090	0.093	0.096	0.099	0.102
36	0.070	0.073	0.076	0.079	0.082	0.085	0.088	0.091	0.094	0.096
38	0.066	0.069	0.072	0.075	0.078	0.080	0.083	0.086	0.089	0.091
40	0.062	0.065	0.068	0.071	0.074	0.076	0.079	0.081	0.084	0.087
42	0.059	0.062	0.065	0.067	0.070	0.072	0.075	0.077	0.080	0.082
44	0.056	0.059	0.061	0.064	0.067	0.069	0.071	0.074	0.076	0.078
46	0.053	0.056	0.059	0.061	0.063	0.066	0.068	0.070	0.073	0.075
48	0.051	0.053	0.056	0.058	0.061	0.063	0.065	0.067	0.070	0.072
50	0.048	0.051	0.053	0.056	0.058	0.060	0.062	0.065	0.067	0.069
55	0.043	0.046	0.048	0.050	0.052	0.054	0.056	0.058	0.060	0.062
60	0.039	0.041	0.044	0.046	0.048	0.050	0.051	0.053	0.055	0.057
65	0.035	0.038	0.040	0.042	0.044	0.045	0.047	0.049	0.051	0.052
70	0.032	0.034	0.037	0.038	0.040	0.042	0.044	0.045	0.047	0.048
75	0.029	0.032	0.034	0.036	0.037	0.039	0.040	0.042	0.043	0.045
80	0.027	0.029	0.031	0.033	0.035	0.036	0.038	0.039	0.041	0.042

Note: Density = $(\text{Specific Volume})^{-1}$
Source: FLOW CONTROL MANUAL
Courtesy: Neles-Jamesbury, Helsinki, Finland

EXPLOSIVE WELDING

It is basically a solid state process in which a true metallurgical bond is effected inside the tubesheet or tubehole.

In this form of explosive technology, a low energy charge expands new or existing metal. The resulting mechanical bond is both tight and reliable.

When a tube or tubesheet joint is leaking, the plug is installed at the appropriate place (Fig. AVIII.4) and detonated to form a tight bond (Fig. A VIII.5). If the leak is at the tube-to-tubesheet joint, a section of the tube is removed and the plug is installed to the tubesheet hole.

Plugging H.P. Feedwater Heater Tubes :

Feedwater heater tubes tend to fail in clusters since a leak in one tube often leads to high-ve-

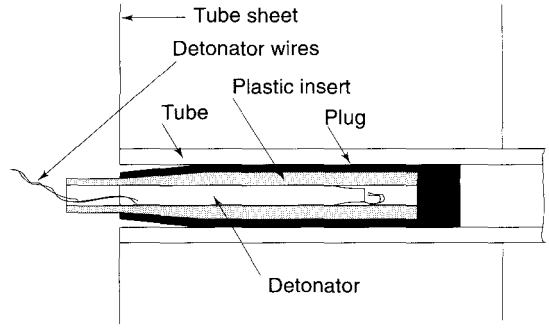


Fig. A VIII. 4 *The plug is placed into the tube ready for welding.*
Courtesy: Senior Engineering Co.

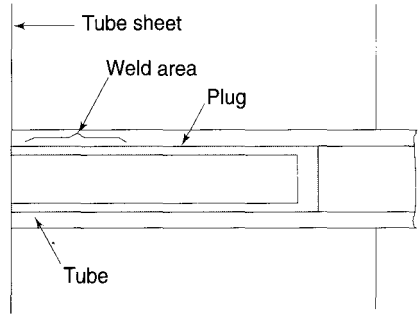


Fig. A VIII. 5 *Plug explosively welded to tube.*
Courtesy: Senior Engineering Co.

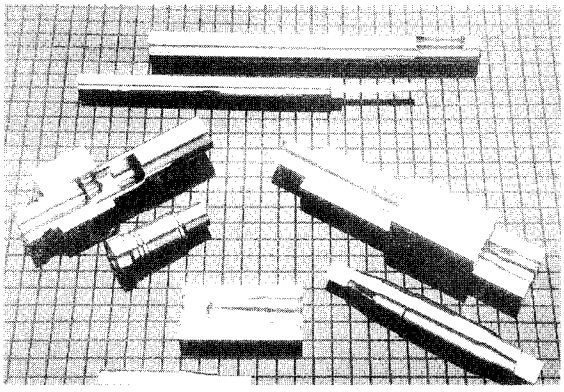


Fig. A VIII. 6 *(Clockwise from top):*

© Senior Engineering Co.

(a) A ferrule and a cutaway demonstration of an explosively expanded ferrule within a tube.
(b) An explosive repair sleeve and a partial-cutaway demonstration of an explosively welded repair sleeve within a tubesheet block (not sectioned) and a tube.
(c) An explosive plug and a cutaway of an explosively welded plug with a tubesheet block
(d) An explosive plug for condensers and a cutaway of an explosively expanded plug within a condenser trubesheet and tube.

Source: Product Information Bulletin (Senior Engineering Co.)

locity feedwater jets and rapid erosion of adjacent tubes. Repair through fusion weld plugging of several adjacent tubes can cause build-up of weld material on the tubesheet face. Expansion and contraction of weld repairs result in additional weld failures and more leaks.

Explosive welding comes to the rescue. Explosive welded plugs (Fig. A VIII. 8) are installed inside the tube (Fig. A VIII. 9) and welded to the tubesheet, thus eliminating tubesheet weld build-up.

Correcting Wormholing:

In these severe cases of erosion and corrosion at the inlet end of the tube to tubesheet junction, leaks develop between the deteriorating tubewall and the ligaments in the tubesheet.

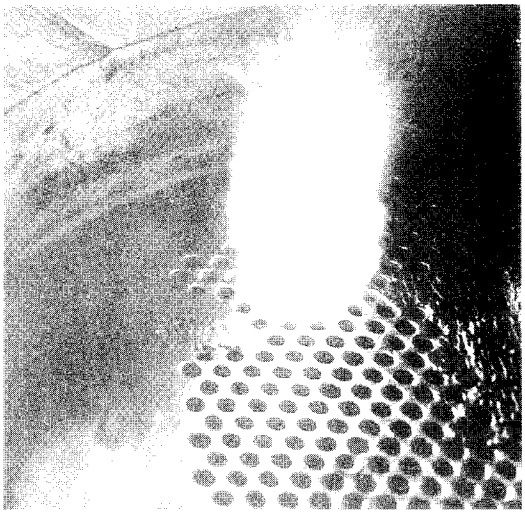


Fig. A VIII. 7 *The actual firing of an explosive plug requires only a mere fraction of a second to bond the tube to the tubesheet. And in that instant, the explosive welding produces a weld length (minimum leakpath) at least 4 to 5 times that or conventional welding methods.*

Source: Product Information Bulletin (Senior Engineering Co.)

© Senior Engineering Co.

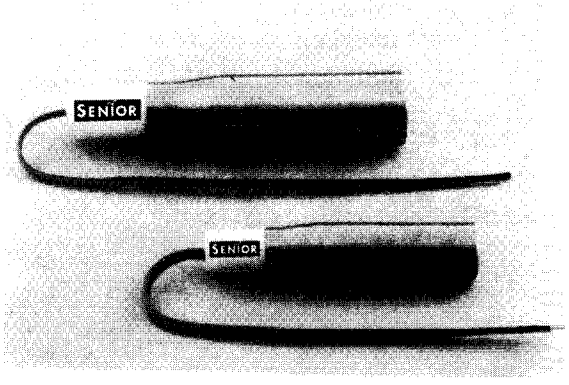


Fig. A VIII. 8 *Explosive weld plugs*

© Senior Engineering Co.

Fig. A VIII. 9 *Installing a plug inside a feedwater heater tube.*

© Senior Engineering Co.

The conventional remedy is to plug the tube. However, that removes the tube from service. The better cure is to install a sleeve by explosive welding. The sleeve forms a new inlet end for the tube. The explosion bonds the sleeve to both the tube and the tubesheet face, while expanding the sleeve into the wormholed area between the bonds. The leak is sealed and the tube is restored to service.

Joining Tube to Tubesheet

A new or replacement tube of a H.E. must be tightly joined and mated to its hole in the tubesheet. The traditional method of TIG welding and mechanical rolling breeds certain problems.

The better way is a dual-step process involving welding and expansion—First, an explosive cartridge welds the tube to the tubesheet. A second cartridge fully expands the tube to exactly match the ID of the tubesheet hole with the effect that a there is a uniform, leak-resistant joint for the entire depth of the tubesheet.

Advantages

1. Compared to conventional welding, explosive welding produces a true kinetic bond with superior joint integrity, and weld-length four to five times the tubewall thickness
2. Inasmuch as the heat affected area is at a minimum, the potential for stress corrosion cracking is reduced and there is no need for post-weld treatment
3. Compared to other methods, explosive welding is faster, especially where there is limited access
4. A more versatile process.
   Tolerances for surface preparation and hole concentricities are far less rigorous, and plugging can be done anywhere within the tubesheet boundary
5. Fast installation reduces downtime
6. Upgrading of reliability.

Source : Product Information Bulletine, Senior Engineering Co., PA 19406-2404, USA.

Appendix IX

General Information on Protection, Filling, Conditioning, Operation and Maintenance of Ion Exchange Resins

1. IONIC FORM AS DELIVERED

Strong-acid cation exchangers are normally supplied in the sodium or hydrogen form, weak-acid resins in the hydrogen form, strong-base resins in the chloride form, and weak-base resins in the free-base form. Other ionic forms of resins are available. Nuclear grade resins, for instance, are processed with high purity chemicals and are supplied in the fully regenerated form.

2. PROTECTION OF ION EXCHANGE RESINS AFTER DELIVERY

If the following precautions are taken when ion exchange resins are kept in storage, or in plants which are shut-down for any length of time, optimum performance will be ensured.

If resins are to be stored in their original packing, the following recommendations should be applied

1. Do not stack bags more than six high.
2. Keep in a covered store at a temperature of between 5 and 40°C
3. Bags which are stacked on top of each other should not in any circumstances be used as supporting structures.
4. During periods of frost, resins may freeze. This is of no consequence and does not affect their quality. Resins should be allowed to thaw in their original packing in normally heated warehouse, before they are loaded in the ion exchange units.

   If resins are to be stored in vessels, it is recommended to keep them in water in salt form. In the case of prolonged plant shut-down, a suitable disinfectant may have to be used.

3. VOLUME MEASUREMENT

The volumes of resin supplied are measured in the ionic form as dispatched, after backwashing, settling and draining to bed surface. This procedure is common to all ion exchange resin manu-

facturers, as the moisture content, weight and volume of the resin can vary according to packaging and supply conditions, inasmuch as some resins are supplied in a partially dried form.

4. FILLING THE COLUMN

Introduction

The qualitative and quantitative efficiency of resin bed, and the pressure drop which occurs in service depend on the way in which the resins are loaded into the column and then decompacted.

Procedure

It is important to note the following.

Before a column is filled with resin, it is essential to check:

1. the general state of the column (bottom collectors, top or intermediate distribution systems, column lining, etc.);
2. that the supporting layer (of silex or anthracite) was not disturbed if resin was previously removed. If it has been disturbed, don't hesitate to change it;
3. the surface level of the supporting layer; it is advisable to indicate this by painting a short horizontal line on the outside of the pressure vessel at the same level;
4. the general condition of the ion exchange resin charge (chemical and physical) if the bed is being topped up.

For the following operations it is recommended to make use of decationised of softened water if it is an anionic resin:

1. Half-fill the column with water.
2. Pour about one third of the resin charge into the column.
3. Open the backwash water valve and allow the water to rise at a rate of 6 to 15 metres per hour. This rate depends on the type of resin and the water temperature.
4. Maintain this upward flow for about 15 minutes. The level of the resin can easily be checked through the open manhole, from which the water overflows.
5. Shut off the flow of backwash water and allow the resin to settle.
6. Open the rinse outlet valve and close it when the water level is about 1 metre above the resin.
7. Repeat operations 2 to 6 when adding the rest of the resin.

   When the complete charge of resin has been loaded into the unit, continue the backwash for 30 minutes to fully expand the bed.
8. Close the backwash inlet valve and allow the resin to settle.
9. Drain the water from the column at a rate of about 6 metres per hour. Close the rinse outlet, when the water level is 10 cm from the surface of the resin bed, then measure the volume of resin.
10. Shut the manhole and pass a final wash (decompacting) flow through the resin as laid down in the operating instruction.
11. Shut off the backwash flow and allow the resin to settle.

The resin is now ready for operation, for regeneration or for purification (see point 5 below).

5. CONDITIONING ION-EXCHANGE RESINS BEFORE USE

Introduction

Most commercially available ion-exchange resins are essentially insoluble and infusible polymers. However, standard resins may contain minute quantities of soluble impurities which should be removed prior to use in certain critical applications.

Conditioning Procedures

The objective of the conditioning treatment is primarily the reduction of taste, odour, and extractible organic materials. The treatment may

be carried out with standard regenerant chemicals using standard regeneration techniques. It is recommended that the treatment is carried out just before start-up.

In some applications of ion-exchange resins, a simple rinse with several bed-volumes of water is adequate. In some cases, chemical regeneration followed by a water rinse is required. For the more critical application, cyclic washing with dilute acid and alkali will remove all but trace residuals of soluble components. The resin may be further cleansed with boiling water for about thirty minutes, although this procedure is not recommended for anion exchangers in the free-base or hydroxide from. Maximum purity can be achieved by washing the cycled salt form of either cation or anion exchange resin with two or more bed-volumes of a polar solvent such as acetone, ethanol or methanol. This brings the extractibles well below the ppm range. Anion exchangers with amine functional groups generally have a slight odour, especially after long storage in closed containers. This odour is easily washed out. Some ion-exchange resins, particularly the type 1 strong-base have a mild odour which may persist through the first few cycles. If taste or odour presents a problem, the resin should be cycled about five times with acid and alkali prior to use.

6. OPERATION

After conditioning the resin according to the above recommendations, the resin is ready for industrial operation.

7. MAINTENANCE

After an overnight shutdownn, it is recommended that the first 2 to 10 bed-volumes (according to resin type) be discarded before the plant is restored into service.

Note: These are general informations recommended by ROHM & HAAS for their popular brand—Duolite and is mostly valid for IEx resins of other manufacturers also.

Source: Duolite Summary Chart

Courtesy: Rohm & Haas/Philadelphia/USA

RESIN CLEANING

Iron Pickup

Hematite (red iron oxide) and magnetite (black iron oxide) are corrosion products found in the steam-condensate loop of power plants. These oxides are present in both particulate and colloidal form in the condensate. A major function of the condensate polisher is to remove these corrosion products. Iron oxides are picked up on the surface of inert resins.

Routine mechanical cleaning (air scrubbing, backwashing, etc.), diligently performed, is adequate for maintaining the color gradient of cation/inert/anion. Occasionally, more aggressive cleaning using a low foam of non-ionic surfactant (Triton® CF-54*) and/or an inhibited hydrochloric acid resin cleaner may desirable. It is advisable to seek technical advice and to perform laboratory scale testing to determine optimum dosages and contact times prior to attempting plant scale resin cleaning using chemical agents.

Floating Tendency and Oil Fouling

The moisture content of inert resins is quite low (about 10%) relative to that of cation and anion exchange resins (about 50%). Since inert resins are not "hydrated", their surfaces tend to be more difficult to wet than those of cation and anion exchange resins. Sometimes after scrubbing and backwashing, a $\frac{1}{8}''$ to 2" layer of inert may be observed floating above the settled anion exchange resin. The inert resin will float due to bubbles of air bridging across inert resin particles causing cluster formation. Most often the quantity of inert resin acting in this manner will

not be sufficient to interfere with normal operation, and no action need be taken. If desired, however, the clusters can be broken by flushing water through the top distributor.

If a resin which had performed properly suddenly develops a floating tendency and/or the cation/inert separation appears less distinct, oil fouling (usually slight) should be suspected. This can be corrected by a Triton® CF-54 assisted cleanup. Routine use of this low foam surfactant has been reported to be beneficial for the separation performance of an inert system subject to trace oil contamination. Occasional use of surfactant will also improve the efficiency of iron removal from the resins.

Resin Cleaning Procedure

1. Calculate the amount of Triton® CF-54 needed to clean the amount of resin contained in the vessel. Triton® CF-54 should be applied at a rate of 0.3 to 0.5 lbs/100 ft^3 of resin. Mix the Triton® CF-54 with water in a 5 gallon pail and put it aside.
2. Drain the vessel to approximately 6 inches above the surface of the bed.
3. Start air mix.
4. Add the diluted Triton® CF-54 to the unit while air-mixing.
5. Continue air-mix for approximately 30 minutes.
6. Immediately after air-mix, backwash* at 4 gpm/ft^2 unit backwash water is essentially clear.
7. Drain the vessel until water level is again 6 inches above the resin.
8. Air-mix the resin for approximately 20 minutes.
9. Immediately after air-mix, backwash again.
10. Proceed with normal regeneration.

Note: These are the general instructions for cleaning Ambersep 359 resin (inert resin)#.

GENERAL RESIN CHARGING INSTRUCTIONS

Condition

The resin vessel(s) should be cleaned thoroughly of old resins. All the internals, liners, etc. should have been inspected and found to be in satisfactory condition. The standard resin charging procedure, as detailed in the operating manual supplied with the original equipment, should be reviewed and available for consultation.

The proper depths and volumes of cation, inert, and anion resins should be estimated and cross-checked against the unit volume.

There are many suitable techniques for loading the resins into the vessel(s). Resin may be added directly from the shipping container through the vessel manway, if this can be done safely and conveniently. However, if this is not the case, resin can be added very quickly using water of a suitable quality to supply a venturi for drawing resin from each shipping container individually. Allow 4-8 minutes per 7 ft^3 drum when estimating total charging time.

Have on Hand

1. Hose providing plant water
2. Triton® CF-54, nonionic surfactant

Safety

Make sure all personnel understand that ion exchange resins are chemicals. They should be treated as such, especially if H^+ form cation or OH^- form anion resin is to be charged. The hydrogen and hydroxide forms of cation and anion exchange resins normally do not cause any skin irritation; however some people may be sensitive to these ionic forms of the resins. Small spills of resin will certainly occur, creating a slipping hazard. Warn all personnel about this and sweep up spills when they occur.

* Observe expanded anion resin level through the upper sight glass. Take care that anion resin is not backwashed out of the vessel.

\# Chemically non-functional copolymer bead form resin.

Regeneration

When Na^+ form cation exchange resin and Cl^- form anion exchange resin are supplied, a double regeneration should be performed before startup.

RESIN CHARGING

Single Tank Regeneration System

1. Charge estimated volume of cation exchange resin.
2. Backwash at 6 gpm/ft^2 (65°F [18°C]) until a clear effluent is obtained.
3. Allow resin to settle. Check cation exchange resin level.
4. Charge estimated volume of inert resin. Add 1.0 gm of Triton® CF–54/ft^3 of inert resin to a 5 gallon pail of water. Mix and add solution to vessel.
5. Spray water from garden hose down on the surface to sink any inert resin showing a tendency to float. Drain to 6" above resin surface.
6. Air mix for 15 minutes.
7. Backwash at 4 gpm/ft^2 until a clear effluent is obtained.
8. Reduce backwash rate of 2 gpm/ft^2 and hold for 10 minutes. Note the location of the cation/inert interface and confirm that the inert zone depth and total bed depth are as planned in relation to the central collector.
9. Carefully add the anion exchange resin so as not to disturb the inert zone. (Once anion exchange resin has been added do not air mix until after regeneration has been completed!)
10. Backwash at 4 gpm/ft^2 until a clear effluent is obtained.
11. Reduce backwash rate of 2 gpm/ft^2 and hold for 10 minutes.
12. Proceed with regeneration.

RESIN CHARGING

Two Tank Regeneration System

1. Charge estimated volume of cation resin to regeneration tank.

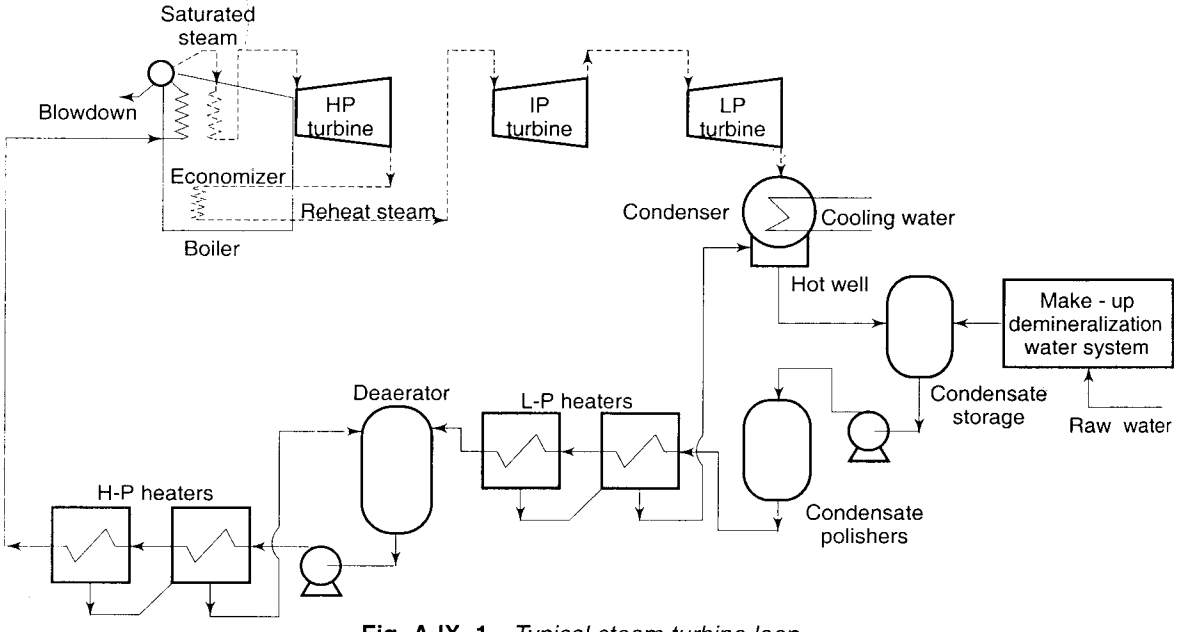


Fig. A IX. 1 *Typical steam turbine loop.*

2. Backwash at 6 gpm/ft^2 (65°F [18°C]) until a clear effluent is obtained.
3. Allow resin to settle. Check cation level.
4. Charge estimated volume of resin. Add 1.0 gm of Triton® CF-54 ft^3 of inert resin to a 5 gallon pail of water. Mix and add solution to vessel.
5. Spray water from garden hose down on the surface to sink any inert resin showing a tendency to float. Drain to 6" above resin surface.
6. Air mix for 15 minutes.
7. Backwash at 4 gpm/ft^2 until a clear effluent is obtained.
8. Reduce backwash rate to 2 gpm/ft^2 and hold for 10 minutes. Note the location of the cation/inert interface and confirm that the inert zone depth and the total bed depth are as planned in relation to the anion transfer point.
9. Charge estimated volume of anion resin to anion regeneration tank.
10. Backwash at 4 gpm/ft^2 until a clear effluent is obtained.
11. Allow resin to settle. Check level.
12. Proceed with regeneration.

Note: Inert resins form a bed between Anex bed at its top and Catex bed at its bottom.

AN INTRODUCTION TO CONDENSATE POLISHING

Condensate polishing is an important part of water treatment for any utility or industrial power generating system. (Fig. A IX. 1)

Water for a steam turbine must be exceptionally pure to prevent damage to the turbine and associated equipment. Steam from the boiler passes through the turbine and expends most of its energy. To minimize the load on the demineralizer and reduce operating costs, the residual low quality steam coming out of the turbine is condensed in a heat exchanger, called a condenser, and recycled to the boiler.

This condensed water or "condensate" picks up some corrosion products as the steam and condensed water pass through piping, heat exchangers, feedwater pumps, and other equipment in the steam turbine loop. A far more serious threat is the contamination that can occur if condenser cooling water with a high level of total dissolved solids (TDS), such as seawater, leaks into the condensate stream. Condensate polishing uses ion exchange resins to remove contaminants from the condensate.

CONDENSATE POLISHING SYSTEMS

Ion exchange resins can be used in a number of ways to treat condensate.

Cation Exchange—"Condensate Scavenging"

Used mainly with industrial low and medium-pressure boilers, a deep bed of a strong acid cation exchange resin operated in the sodium or amine form can act as a "condensate scavenger." This type unit is primarily for the removal of corrosion products from the condensate. Insoluble particulate corrosion products are filtered in-depth on the resin bed and some hardness ions are interchanged with the cation on the resin. The choice of cation resin ionic form depends on the chemistry of the circulating water system.

Cation/Anion Mixed Bed

The most common ion exchange system used in condensate polishing is a mixed bed of strong acid cation exchange resin and strong base anion exchange resin. Mixed beds produce very high quality demineralized water, because ion leakage from either cation or anion resin is quickly removed from the water by the other resin. Deepbed, in-depth filtration (see Figure A IX. 2) is accomplished by maintaining the flow rate high enough to keep surface filter cakes from forming. Typically, the flow rate is about 50 gpm/ft^2. Using a bed depth of approximately 3 feet allows pressure drop across the bed to be maintained at economically acceptable levels. In most cases, a mixed bed condensate pol-

ishing system consists of several vessels operating in parallel (see Fig. A IX.3). Used resins are transferred to a separate system for cleanup and regeneration. In some cases, systems employ disposable mixed bed resins.

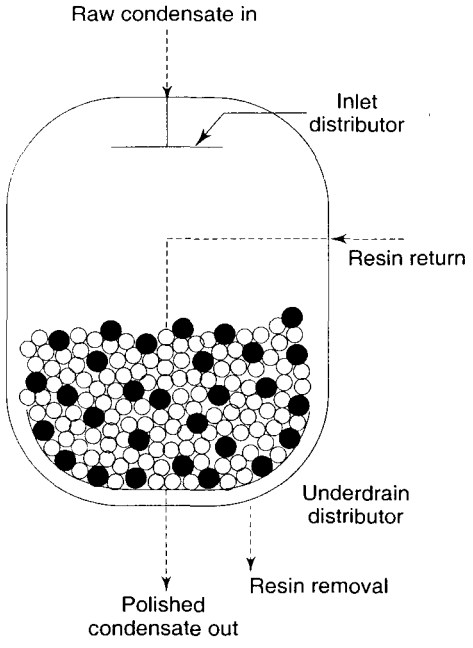


Fig. A IX.2 *Particulate filtration in a typical cation/anion mixed bed.*

External regeneration or regeneration of each resin outside of the condensate polishing vessel has proven to be the most practical approach. Isolation of the regenerant chemicals from the recirculating water loop significantly reduces the incidence of condensate contamination by regenerants. The amount of time that the polisher is off-line is reduced, as well. In external regeneration, the only interruption in polisher service is for transfer of the used resin to the regeneration system and the introduction of newly regenerated resin to the condensate vessel. One regeneration system can service multiple condensate polisher vessels. A typical external regeneration system is shown in Fig. A IX.4 This is the most widely used system today and requires these basic steps.

The used resins must be:

(1) **transferred** completely from the operating vessel to the regeneration system;
(2) **cleaned** to remove the particulate contaminants collected by filtration from the condensate;
(3) **separated** as completely as possible for the regeneration;
(4) **regenerated** independently with the appropriate chemical solution;
(5) **rinsed** thoroughly with demineralized water;
(6) **remixed** carefully;

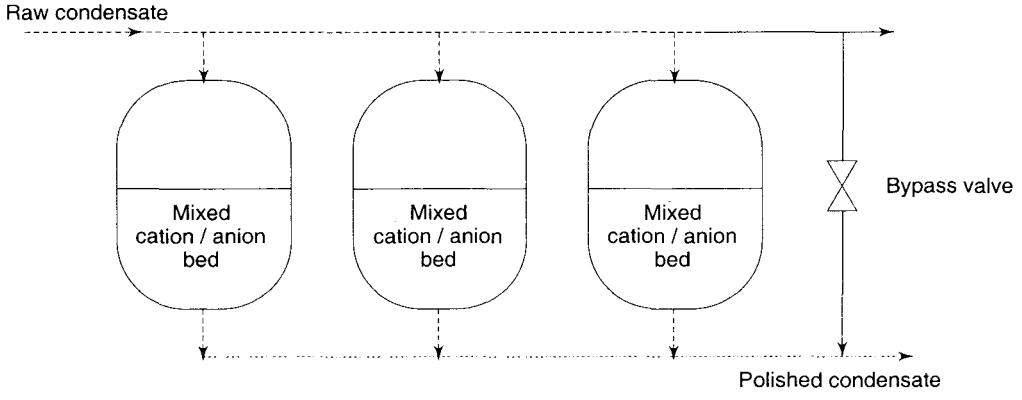


Fig. A IX. 3 *Battery of condensate polishers.*

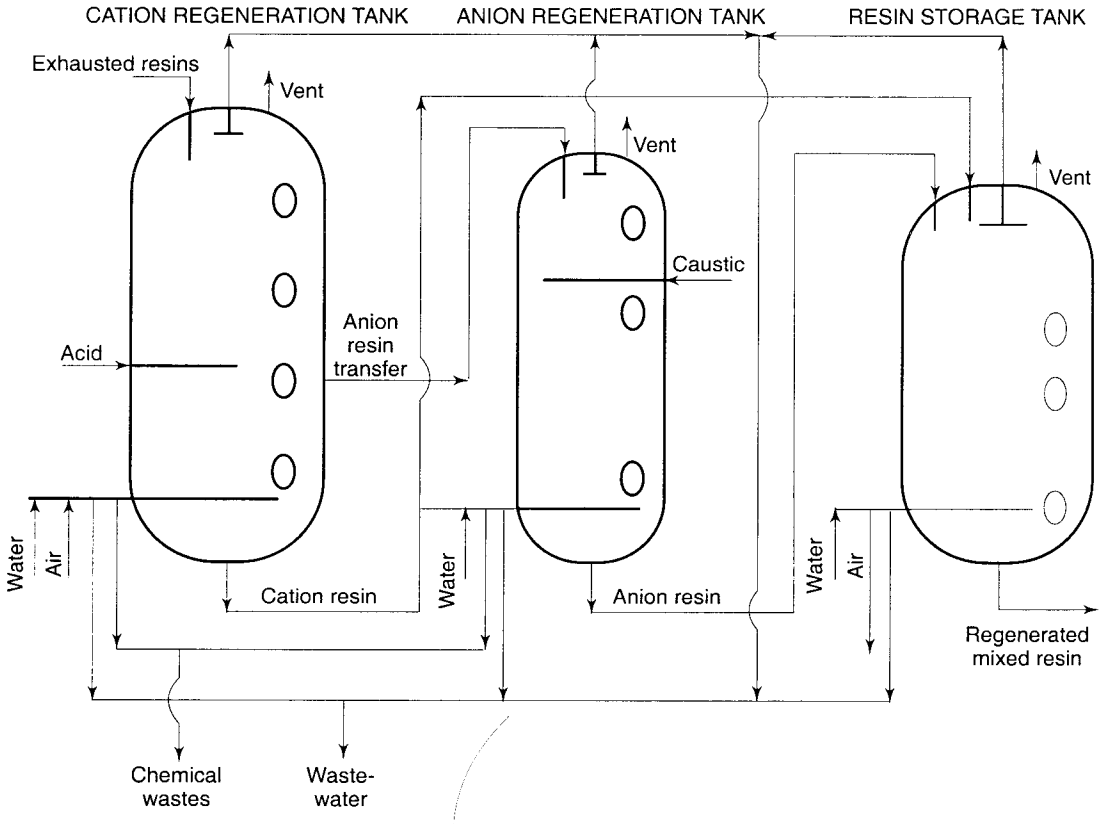


Fig. A IX. 4 *Typical external regeneration system.*

(7) **transferred** to the next available condensate polisher while exercising care to minimize resin separation.

A second approach, which eliminates resin separation, resin regeneration crossover, and regenerant quality problems, is the use of a disposable mixed bed. This approach requires the manufacture and shipment of very clean, and highly regenerated resins by the resin supplier. Disposable mixed bed systems are commonly used for condensate polishing in BWR's, where disposal costs of radioactive waste regenerants would be prohibitive.

Cation Followed by Mixed Bed of Strong Cation/Strong Anion

When AVT is used to control pH and corrosion in a steam generator system, the condensate polisher in the system exhausts quite rapidly. This happens because the amine involved is exchanged onto the cation exchange resin. The higher the pH, the shorter the run time.

One suggested technique for increasing the run time on the mixed bed polisher is to treat the condensate with a hydrogen form cation resin to remove the amine prior to contact with the mixed bed (see Fig. A IX. 5). By taking this amine load off the mixed bed, mixed bed run lengths can be

extended to months. Corrosion products are also removed by the lead cation bed, eliminating solids contamination of the mixed bed. Regeneration of the lead cation can be done on a more frequent basis than the mixed bed, thereby reducing the difficulties of mixed bed regeneration.

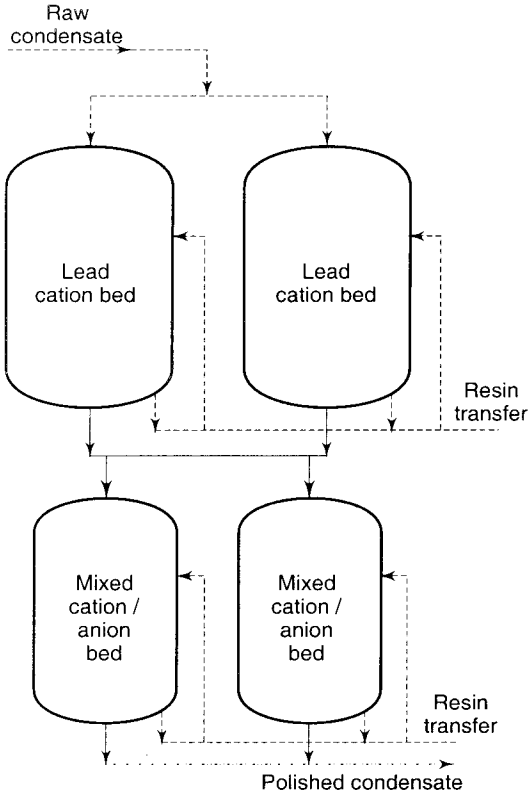


Fig. A IX. 5 *Lead cation bed with mixed bed condensate polisher.*

The use of the two beds in series, cation/mixed bed, increases the pressure loss across the system, increasing pumping costs. The development of ion exchange resins with good bead size uniformity allows optimization of the pressure drop characteristics of the resins.

Cation-Anion-Cation Stacked Bed

A relatively recent development, this process uses a single tank with compartments to contain separate layers of cation, anion, and cation resins (see Fig. A IX.6). The resins are never mixed, with each resin going to its own external regeneration vessel. The lead cation resin is typically not run past the ammonia break in AVT systems. Leakage from the lead cation is polished in the trailing cation resin. Final water quality produced depends on the trailing cation resin regenerant rinse-down, and on the leachable characteristics of both cation resins.

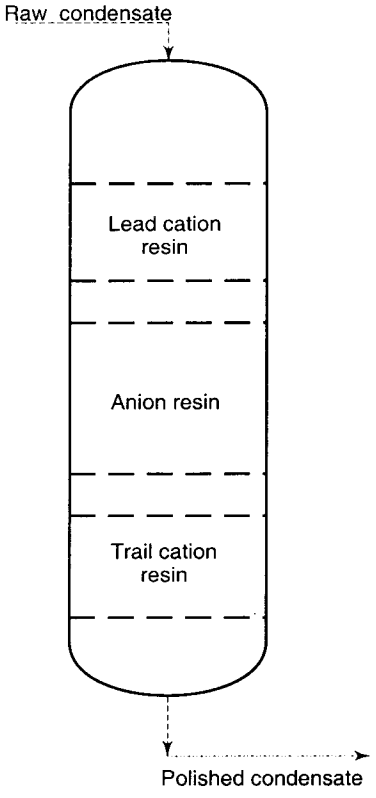


Fig. A IX. 6 *Cation-anion-cation stack bed .*

FACTORS AFFECTING RESIN PERFORMANCE

The performance of an ion exchange resin in a particular system is strongly dependent on the inherent characteristics of the resin itself, the design parameters of the system within which it will

operate, and on the manner in which the operation is controlled.

Resin Characteristics (Cation and Anion)

Resin characteristics having the most significant impact on performance in a condensate polisher include particle size and bead uniformity, ionic capacity and filtration, selectivity, bead integrity, kinetics, oxidative stability, rinse and regeneration efficiency, and color. These characteristics are to some degree interrelated and some overlap may occur in the description.

Particle Size Uniformity

Particle size uniformity affects a number of resin characteristics including the kinetics of reaction, the separability of one resin from another, and the pressure drop across the resin. The introduction of resins with a narrow bead size distribution has been shown to offer many advantages over Gaussian distribution resins. (Fig. A IX. 7)

In high flow rate applications, the ability of ion exchange resins to remove ionic impurities to extremely low levels depends in part on kinetics. Kinetics is determined by both the rate at which ions are transported across the surface of the resin bead and the rate of diffusion of the ion into the resin particle.

At the very low ionic concentrations encountered in the condensate, the surface exchange rate and surface area become important. Since smaller beads have greater specific surface area, their kinetics are faster. In addition, by selecting resins with high bead size uniformity, the larger, kinetically slower beads are eliminated. Figure A IX. 8 and A IX. 9 show the excellent kinetic behaviour of uniformly sized resins during simu-

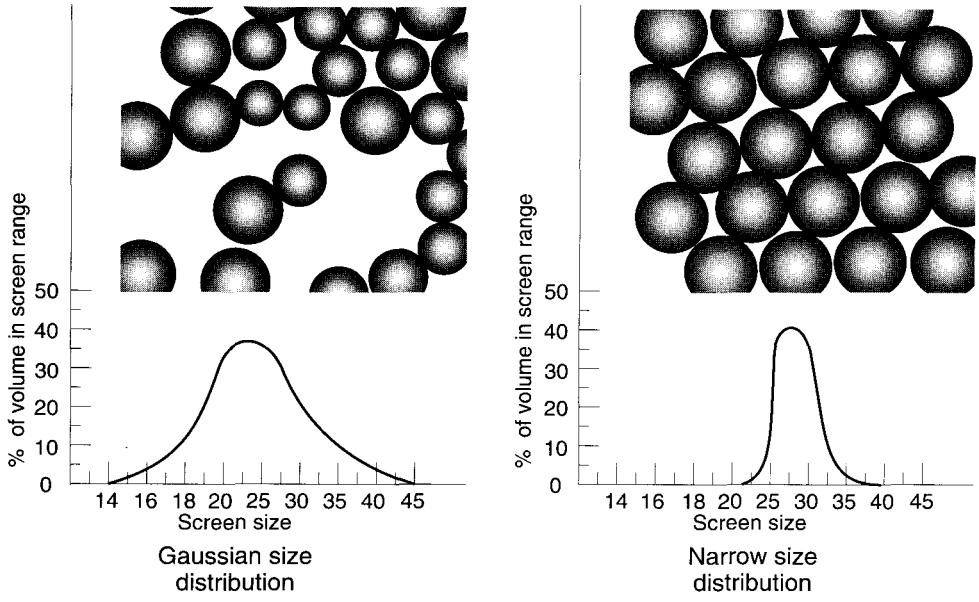


Fig. A IX. 7 *Resin beads with gaussian and narrow size distributions.*

lated and actual seawater condenser leaks at two utilities.

To simulate the effects of a seawater condenser leak, a fossil fuel facility injected a sulphate solution into the feedwater to their condensate polisher. The polisher was using uniformly sized resins. A solution containing 120 ppb sulfate was injected at two times during the service run, first toward the end of the hydrogen cycle and again toward the end of the ammonia cycle.

Figure A IX. 8 shows that the sulphate leakage remained very low when the system was operating in the hydrogen cycle due to the fast kinetics of the uniformly sized resins. In the ammonia cycle the resins response to the simulated sulphate was also rapid. The higher sulphate peak (exaggerated by the log scale on the graph) is caused by the higher pH during the ammonia cycle.

Figure A IX. 9 presents data obtained during an actual condenser leak in a southeast fossil fuel plant. Cation conductivity, which effectively measures anion concentrations, shows the excellent kinetic response even more clearly.

In any particle size distribution, the larger beads will be kinetically slower than the smaller beads. The better the particle size uniformity for

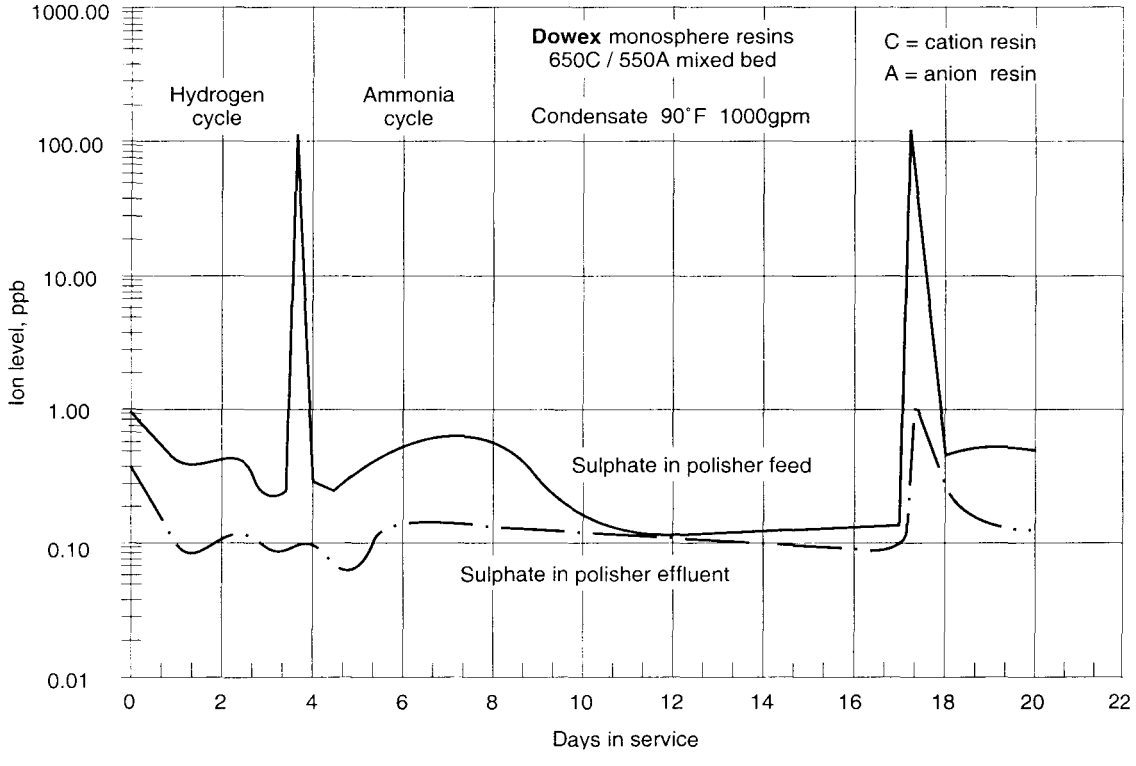


Fig. A IX. 8 *Condensate polisher performance—Dowex Monosphere Resin—simulated condenser seawater leak studies.*

a given average particle size, the fewer number of large, slow-acting beads present. Therefore, the overall kinetics will be better.

Particle Size Uniformity and Separability for Regeneration

Complete separation of the anion and cation resin components of a mixed bed is desirable to facilitate the independent regeneration of each. Resin cross-contamination causes ion leakage problems during the subsequent operating cycle.

The ability to separate one resin from another by backwash depends on differences in their particle size and density. Large, low-density anion beads can fluidize during backwash at the same level as small, more dense cation beads. This can make separation difficult or impossible. By controlling the uniformity of the particle size within each of the resin types, it is possible to optimize the resin separability by backwash fluidization.

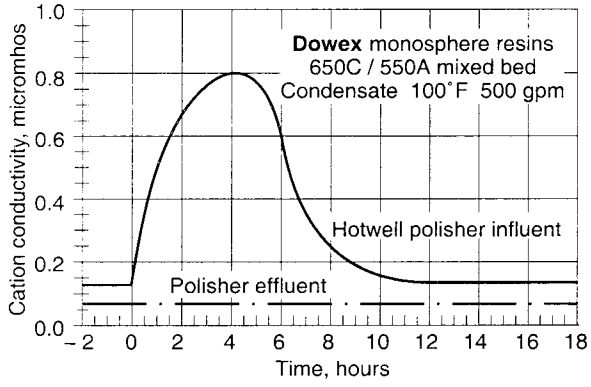


Fig. A IX. 9 *Condensate polisher performance—Dowex Monosphere Resin—during actual condenser leak.*

Particle Size Uniformity and Pressure Drop

The uniformity of resin particle size can also impact the pressure drop across a system. During random packing of a bed, small resin beads tend to nest between larger beads, reducing the void fraction of the bed and thus increasing the pressure loss across the bed during high flow rate applications.

Reducing the relative amount of small and large particles by selecting resin with a uniform particle size distribution increases void fraction. So pressure drop across a bed of resins with uniform particle size distribution is less than pressure drop across a bed containing a broad distribution of particles of the same average particle size.

Filtration

Filtration is a function of the particle size and particle size distribution. The number of "pinch points" between resin beads in a given volume of resin is related to the ability of the resin to filter. Finer resins provide more pinch points and greater filtration. Resins with uniform particle size distribution and smaller average diameter can provide better filtration than large diameter resins with a Gaussian distribution.

In a condensate polisher, the function of the ion exchange resin is twofold: *to provide ion exchange capacity and to provide filtration.*

Capacity

Ionic capacity is defined by two classifications, total and operating. Total capacity is inherent in the resin type, but can vary with changes in resin cross-linkage and water retention capacity. More highly cross-linked gel resins have higher total capacities. Operating capacity is not only a function of total capacity but is also dependent on the regenerability of the resin which relates to resin particle size uniformity. The operating capacity can be affected by flow rates, regenerant dosage and concentration, and bed configuration.

Selectivity

The selectivity of an ion exchange resin is a measure of preference the resin exhibits for the various ions of the appropriate charge. For example, a gel cation exchange resin having 10% cross-

linkage, will exhibit a selectivity of about 1.3 for sodium ion relative to hydrogen ion, at 25°C.

Selectivity is an important consideration in both regeneration and exhaustion operations. The ease with which a given ion can be stripped from a resin is affected by the resin's selectivity for that ion relative to the displacing ion in the regenerant. The more difficult the removal, the more likely ions will be left behind for subsequent leakage during exhaustion. The leakage pattern during exhaustion will reflect the relative affinity the resin has for the exhausting ion and the ion left behind during the previous regeneration. Operating capacity is also greater at a given regeneration dosage for ions less selectively held.

Bead Integrity

Bead integrity in an ion exchange resin must match the needs of the application. Resin beads must be strong enough to remain unbroken under the conditions of operation during the entire cycle. Anion resin fines which develop as the result of broken beads are lost from the system during backwash. Cation resin fines contaminate the anion resin layer during backwash separation. The end result of both these breakage situations is loss of effective capacity and water quality.

In deep bed condensate polishing, operating conditions can be quite severe. High flow rates are typical. Pressure drop increases across the bed as particulate crud is filtered from the condensate. Resin is transported hydraulically for considerable distances undergoing attrition and impingement forces en route. Osmotic forces are encountered during regeneration.

To assure that resins meet these needs, crush tests and attrition tests are to be implemented to define resin strength parameters.

Kinetics

As discussed earlier, the rate at which a resin exchanges one ion for another is a combination of the surface film diffusion rate and the internal bead diffusion rate. Kinetics also relate to the leakage of ions from the resin. Of particular interest in condensate polishing are the kinetics of sulphate ion reaction on strong base anion exchange resins. Sulphate exchange is slower than chloride exchange. Furthermore, deterioration of the anion resin with age, due to oxidation or organic fouling, affects sulphate kinetics more than chloride.

Oxidative Stability

Oxidative stability of ion exchange resins affects the performance of cation resins in a different manner than anion resins in condensate polishing use. Anion resins deteriorate by oxidation to form weak base functionality. Oxidative attack is primarily on the functional group. This results in a resin that is lower in strong base capacity and is kinetically slower.

Because cation resins are predominantly attacked at the backbone structure, various low and high molecular weight leachables can form. Most of these leachables are removed, reversibly, by exchange on the anion resin in the system. Some high molecular weight leachables may not be picked up by the anion resin and could contaminate the condensate. For this reason, it is important to investigate the molecular weight of leachables when selecting cation resin.

Rinse and Regeneration Efficiency

The rinse and regeneration efficiency of resins can directly impact the ionic leakage. Better regeneration results in more complete removal of ionic contaminants from the anion and cation resins. This leads to longer run time and lower total ionic leakage. Regeneration efficiency is significantly improved when resins with uniform particle size distribution are used versus resins with a broader Gaussian particle size distribution.

For example, the sodium leakage curves shown in Figure A IX.10 illustrate this improvement using actual plant data from a U.S. fossil fuel

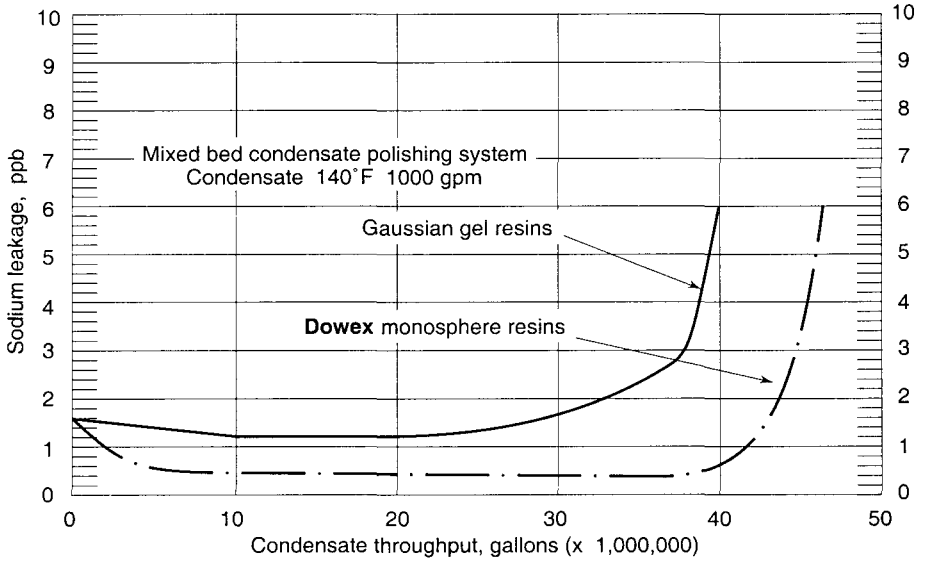


Fig. A IX.10 *Sodium leakage curves—Dowex Monosphere Resins vs. Gaussian Gel Resins.*

plant. The lower sodium leakage and longer run times obtained with uniformly sized gel resins when compared to Gaussian gel resins reflect the more efficient regeneration.

Rinse-down of a resin following regeneration is dependent on the rate of diffusion of the regenerant chemical from the bead interior to the surface of the bead. Thus, rinse efficiency is adversely affected by the larger beads in the resin particle size distribution. Uniform particle size distribution improves the rinse efficiency of a resin due to the absence of larger beads. The effect is illustrated in Figure A IX.11 which shows a comparison of rinse-down curves for a uniformly sized resin vs. a resin with a broad size distribution. These curves were derived from actual plant data taken at a U.S. fossil fuel plant.

Source: Guide to Condensate Polishing—The Dow Chemical Co. Midland/Michigan 48674/ USA.

UPS RESINS

The particle size of ion exchange resins is accepted as being a key factor for good performance in mixed bed (MB) operations. If the condensate polisher or other mixed bed polishing system is to produce high quality water consistently and efficiently, uniform particle size (UPS) resins are a good choice.

DOWEX* Monosphere 550A and 650 C are the two good examples of UPS anion and cation resins (Fig. A IX.12)

Conventional resins vary significantly in size—a characteristic that can impair many areas of resin performance. With UPS resins one is likely to get 90% of the beads within ± 10% of the mean bead size (Fig. A IX.13)

With many conventional resins, the largest beads may be three times the size of the smallest beads. In contrast, UPS resins vary only 35% or less in size from smallest to largest (photo right of Fig. A.IX.13).

Conventional resin beads have gaussian (bell-shaped) distributed resin beads whose size vary up to 300%. As expected, the smaller beads, because of less density, occupy the top of the bed to be highly regenerated, especially since they are

*Trademark of the Dow Chemical Company/Midland/MI 48674/USA

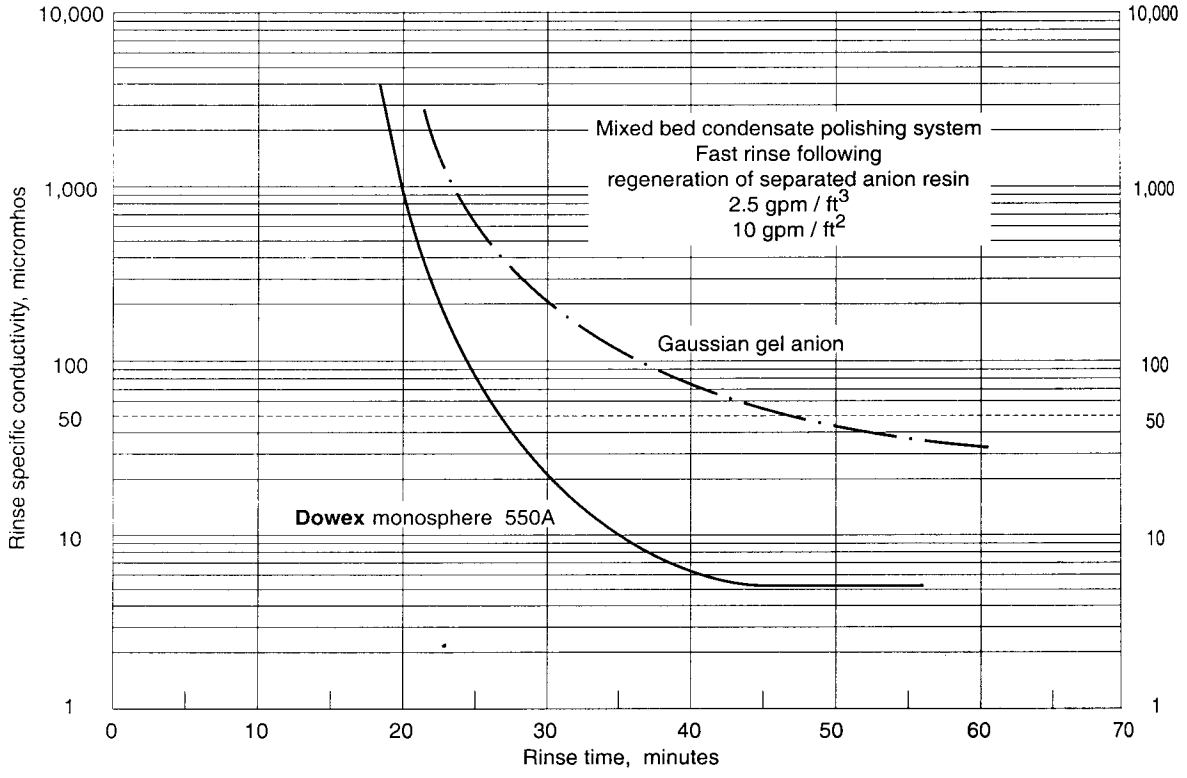


Fig. A IX. 11 *Anion Rinse Down Curves—DOWEX MONOSPHERE Resins vs. Gaussian Gel Resins.*

Source: Guide to Condensate Polishing —The Dow Chemical Co., Midland/Michigan 48674/USA

contacted by the most concentrated regenerant. Large beads settle at the bottom, come into contact with least pure regenerant and get poorly regenerated.

In mixed beds also, even though the anion beads are typically 20% less dense than cation beads, the largest anion beads may still be intermixed with the smallest cation beads after separation. As this happens, some of each resin will get contacted with the wrong regenerant. This cross-contamination results in capacity-lose and even worse, causes sodium or sulphate leakage during the next operating run.

The only answer to this is the use of UPS resins which do not have odd-sized beads. The size uniformity alone provides excellent separation. If the nominal bead size of the anion beads are 100 μ or so smaller than the cation beads, it will accentuate the density difference to result in near-perfect separation, proper regeneration of each resin, and less chance of cross-contamination and leakage.

Higher Capacity

One of the reasons as to why UPS resins fit best to MB systems is their higher capacity which comes in good stead to condenser polishers prone to in-leakage of cooling water.

Today's UPS resins are predominantly gel resins with inherently high capacity. Gel resins have

Fig. A IX. 12 *Dowex monosphere resins:*

650C (left) with bead size 650 μ
550 A (right) with bead size 550 μ
(A = anion resin ; C = cation resin)
© The Dow Chemical Co./Midland/USA

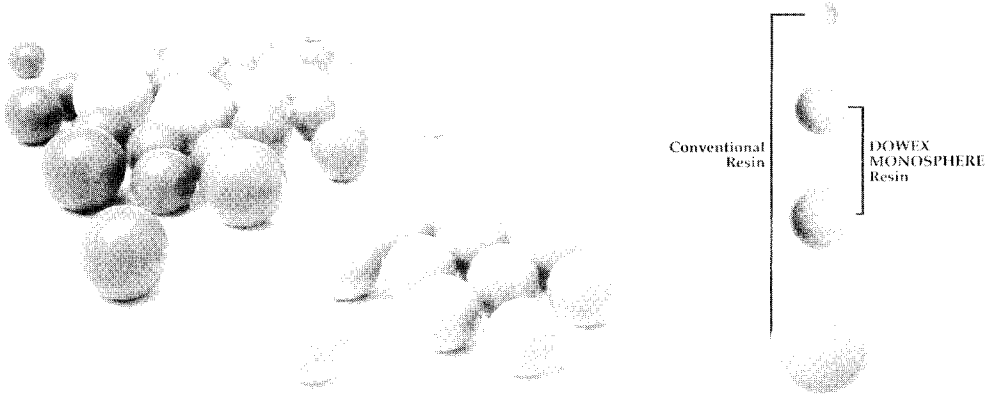


Fig. A IX.13 *UPS resins have about 90% of the beads within ± 10% of the mean bead size (photo left, at bottom right) while conventional resins vary signnificantly in size (photo left, at upper left).*

With many connventional resins, the largest beads may be three times the size of the smallest beads. In contrast, UPS resins may vary only 35% in size from smallest to largest (photo right)

© The Dow Chemical Co./Midland/USA

10–30% greater total capacity than macroporous resins. UPS resins because of their inherent size uniformity exclude large, slow beads. So operating capacity is higher. Under an emergency condition, this extra capacity becomes a bonanza, giving enough time to take action before contamination levels go critical.

Faster Kinetics

Resins of mixed bed systems need fast kinetics to exchange ions quickly so as to ensure good water quality in the presence of in-leakage, particularly in high-flowrate condensate polishers to prevent salt-contaminated water heading for the boiler.

In the early stages of in-leakage, kinetics is essentially a surface phenomenon. Inasmuch as UPS resins do not have large beads present in conventional resins, there is more surface area per unit volume, giving rise to more surface exchange sites and optimum film diffusion capability for more rapid exchange.

The size uniformity of UPS resin systems bestows the kinetic benefits of smaller, more efficient bead size without any increase in pressure drop.

This combination of more surface area and shorter diffusion paths begets faster and more complete access to the full capacity utilization of each resin bead.

Shorter Rinse Time

The absence of larger, odd-size beads brings noticeable improvement in rinse efficiency with UPS resins. Smaller, uniform beads require less water to rinse to a given conductivity endpoint. Plant operations data indicate that rinse time have dropped to $\frac{1}{3}$ rd of the original value when conventional resin beds are replaced by UPS resins. This saves both time and costly rinse water.

Less Resin Loss: Backwash loss of conventional resins is considerable as conventional resins contain some extremely small resin beads that can float and escape through the top outlet of the vessel. Loss of this resin can impair the capacity and kinetics of the mixed bed. Since UPS resins do not have really small beads to start with, the MB maintains the desired ratio of anion to cation resin with no loss of capacity.

FIELD TESTS:

Trial # 1

This trial was run at an eastern pulp and paper plant. It compared the performance of a conventional type I strong base anion resin to its uniform sized counterpart. Both resins were new when the trial began and the evaluation was run in identical side-by-side trains. The trains were operated following the same procedures. The result determined the uniform resin produces 20% more water per regeneration and required 33% less rinse water.

Trial # 2

A southern chemical plant compared a gaussian sized, macroporous type I anion resin to a uniform size type I resin. The choice of the macroporous resin was due to the high level of organics in the water and the frequent brine cleanings that are required. The resins were run side-by-side under the same conditions. In data collected over 6 months of service, the uniform sized resin had an average throughput that was 25% greater. The uniform resin also required as much as 57% less rinse water.

Trial # 3

A southeastern company tested the performance of a uniform particle size, type I anion resin vs an acrylic anion resin. Once again the resins were used side-by-side and data was collected over an

extended period of time. After normalizing for slight variations that were found in the regenerant dosages, it was determined that the uniform size resin produced 29% more water per pound of caustic used.

Trial # 4

A Midwestern utility had a demineralizer that was limited on cation capacity. To insure that they never exceeded the sodium breakpoint, they performed several carefully controlled runs while monitoring sodium leakage. After determining the cation capacity limit, the system was set up to regenerate on throughput. Recently they replaced the conventionally sized cation resin with a uniform sized cation resin. They have been slowly increasing the totalizer setting and currently are producing 20% more water per regeneration. The cation capacity extended.

Economics

The purchase of ion exchange resins can represent a significant investment. However, the cost of resin relative to the cost of operating the ion exchange system is often not appreciated. Regenerant chemicals represent a significant annual operating expense. A resin that can reduce the amount of regenerants used offers significant savings.

To get an understanding of the cost of regenerants, let's look at the following example.

Example 1

Assumptions: acid dosage = 8#/cubic foot
caustic dosage = 6#/cubic foot
1 daily regeneration
acid cost = 4 cents/#
caustic cost = 17 cents/#

The annual cost to regenerate 1 ft^3 of anion resin is:

6#/ft^3 × $ 0.17/# × 365 days = $372.30

The annual cost to regenerate 1 ft^3 of cation resin is:

8#/ft^3 × $0.04/# × 365 days = $116.80

This shows that the *annual* cost of the regenerant chemicals is greater than *the one* time cost for both the anion and the cation resin.

Now lets look at the potential savings in regenerant costs for a uniform sized anion resin that gives 15% greater operating capacity. Assumptions remain the same as in Example No. 1.

Example 2

$372.30 = annual caustic cost per ft^3 of anion

$372.30 × 0.85 = $316.46 = annual caustic cost for the uniform size resin

Savings = $372.30 – $316.46 = $55.85 per year

For a typical resin life of 5 years, the caustic savings would be $279.23 on every cubic foot of resin. If the improvement in operating capacity for a resin is greater that 15%, the savings would increase proportionately.

Source:

1. Impact of Particle Size on Single bed Demineralizer Performance—Daniel B. Rice (The DOW Chemical Co.)
(51st Annual Meeting Intl. Wat. Conf., Oct. 21–24, 1990 Pittsburg/Pennsylvania/USA)
2. DOWEX Monosphere Resin (Bulletin # 177-1405-88 AMS)
3. Guide to condensate Polishing
—The Dow Chemical Co.

UCR-UPS SYSTEM

An advanced process for more productive and efficient ion exchange demineralizer operations is the combination of Upflow Countercurrent Regeneration (UCR) with Uniform Particle Size (UPS) resin.

Why Countercurrent Regeneration?

Countercurrent regeneration systems typically generate 50% less effluent while consuming about half the amount of regenerant chemicals and service water of cocurrent systems. What's more, regeneration time with countercurrent systems is about half that of cocurrent systems while very high water quality is achieved.

In countercurrent regeneration, regenerant chemicals are introduced into demineralizer resin beds in the opposite direction from service flow. This ensures that the most highly regenerated resin is nearest the resin bed service flow outlet.

When water enters the bed during the service cycle, it progressively comes into contact with more highly regenerated resin, which ensures production of high quality demineralized water, minimizes the chance of ionic leakage, and maximizes resin bed operating capacity. By introducting regenerant chemicals at the service flow outlet and maximizing regeneration of the resin beads nearest the exit, regeneration can be performed more quickly and efficiently, with reduced chemical usage, less rinsewater, reduced waste disposal requirements, and lower overall expense.

Downflow Service Cycle Eliminates Problems

Like other countercurrent processes, the UCR-UPS system creates and maintains a highly regenerated zone at the outlfow end of the resin bed to yield consistently high-quality water. But because the service cycle in systems using the UCR-UPS system is downflow, packed beds are less vulnerable to fluctuations or interruptions in feed water flow than are beds operated under countercurrent process with upflow service cycles.

Downflow service also ensures that ionic layering in the resin bed remains largely undisturbed during the service and regeneration cycles and that exhausted resin from the upper portion of the bed does not become mixed into the highly regenerated zone at the bottom, jeopardizing water quality and bed operating capacity.

Uniform Particle Size Resins Contribute to Increased Productivity

The performance advantages of the UCR-UPS system are enhanced by the high operating capacity and regeneration efficiency of uniform particle size resins.

UPS resins feature a narrow particle size range and smaller average beads size than conventional resins. This results in a shorter average bead diffusion path which means these uniform particle size resins regenerate faster and more completely, yielding greater sustained operating capacity.

Self-Cleaning Resin Beds Eliminate the Need for Backwashing

Resins beds utilizing the UCR-UPS system are self-cleaning so the need for resin traps and periodic resin backwashing is eliminated. Any resin fines or other particulates naturally accumulate at the surface of the resin bed during the service cycle and are swept out of the bed at the beginning of each upflow regeneration cycle. The inherent stability of uniform particle size resins further reduces the potential for problems due to resin fragmentation.

In contrast, resin beds in counter-current systems with upflow service cycles must be periodically backwashed to clean fines and particulates from the resin.

Otherwise, fines that rise to the top of the bed will be carried from the vessel by the service flow, resulting in cation contamination of anion beds and potential downstream contamination of the final demineralized product water.

Money-Saving Technology for New and Existing Ion Exchange Demineralizers

The UCR-UPS system offers productivity and cost advantages when incorporated into new

demineralizer systems and in retrofits of existing systems using either cocurrent or older types of counter-current regeneration.

In new systems ... initial capital investment is lower with the UCR-UPS system than with countercurrent "fluidized bed" systems with upflow service because transfer piping and separate holding vessels are not required for resin backwashing. Elimination of such transfer operations reduces system downtime and also spares resins physical stress and the potential for additional attrition that can lead to further particle contamination problems.

New systems based on air or water hold-down technology also compare unfavourably to systems based on the UCR-UPS system due to their limited utilization of potential vessel capacity plus the expense involved in supplying pressurized air or water to these systems.

For retrofits...converting existing cocurrent demineralizer beds to the UCR-UPS system can nearly double ion exchange capacity because each vessel is almost filled with resin and freeboard is almost entirely eliminated.

Freeboard can also be eliminated when converting from the older and less efficient air or water hold-down countercurrent systems, because the UCR-UPS system does not require a separate backwash step.

Upflow Service Packed Bed ("Fluidized" Bed) System

Systems operating with upflow service cycles have a fundamental drawback compared to systems with downflow service ... the packed resin bed is highly vulnerable to fluctuations in feedwater flow. What's more, if service flow is subject to significant fluctuation or is interrupted altogether, ionic stratification in the resin bed can be disturbed. This can cause contamination of the highly regenerated zone nearest the service outlet, therefore compromising the very feature that gives countercurrent system significant water quality and capacity advantages over cocurrent systems.

Prior to downflow regeneration, resin in these systems is allowed to settle to the bottom of the demineralizer vessel, causing particulates to naturally rise to the top surface of the bed. Once regeneration is complete, the resin bed must be returned to its service position at the upper end of the vessel (See Figure A IX.14). To maintain the highly regenerated zone at the top of the resin bed, the resin must be driven upward abruptly to compact it quickly against the inert layer. This subjects the resin to significant physical force which can lead to bead breakage and more resin fines.

Resin traps are an essential component of upflow systems to prevent loss of fines during he service cycle. But traps alone are not an adequate answer to the particulate problem in these systems. Systems with upflow service must be backwashed regularly or else particulates that have accumulated at the top surface of the resin bed can be carried from the vessel by the service flow, allowing cation fines to contaminate downstream anion beds, and particulates from the entire system to contaminate the final demineralizer product water. The bed must also be backwashed to remove any particles present in the feedwater to the demineralizer. Since the service flow enters the bottom of the vessel, where the largest beads are found, and the resin is fluidized, upflow service results in "deep bed" filtration. These particles accumulate over time resulting in increased pressure drop across the bed. Eventually the resin must be backwashed to remove the contaminants.

Because resin beds in upflow fluidized bed systems nearly fill the demineralizer vessels, there is insufficient freeboard for bed expansion during backwashing. Therefore, the resin must be transferred to a separate large holding vessel for the backwashing operation. Installation of holding tanks and related piping contribute to higher capital expense for fluidized bed systems and the out-of-vessel backwashing operations result in system downtime and lost productivity. Transfer operations also subject ion exchange resins to additional attrition forces that can result in bead

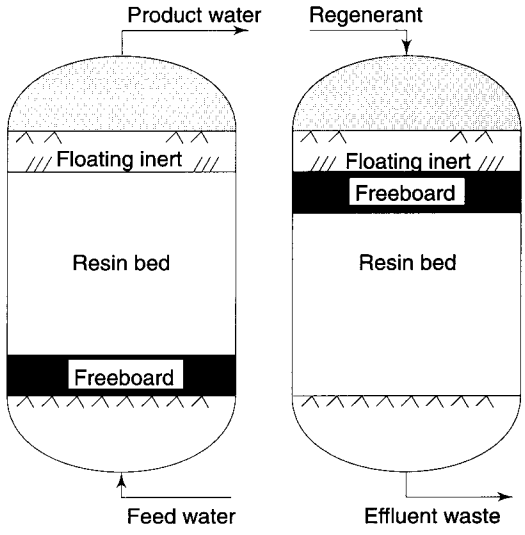


Fig. A IX. 14 *Upflow service packed bed (Fluidized Bed) system.*

Courtesy: The Dow Chemical Co., Michigan/USA

breakage and further problems with particulate contamination.

Air and Water Hold Down Systems

Air and water hold down systems, which have downflow service cycles, employ relatively large volumes of air or water to maintain the packed resin bed during upflow regeneration. The demineralizer vessel can not be filled with resin. Freeboard must be maintained above the middle distributor to accommodate backwash expansion, although this design allows the resin to be backwashed without removing the resins from the vessel. (See Fig. A IX.15)

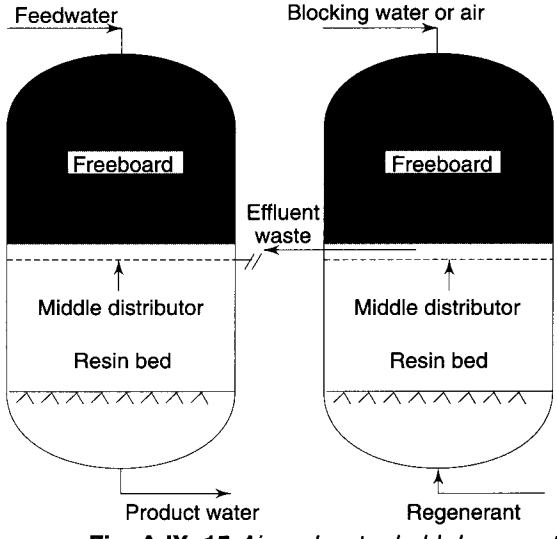


Fig. A IX. 15 *Air and water hold down systems.*

Courtesy: The Dow Chemical Co., Michigan/USA

Other drawbacks of air and water hold down systems include the potential for damage to the middle distributor during operations, the cost of supplying pressurized air or water to the system, the need for periodic resin backwashing to remove fines and other particulates from the bed, and the time and manpower associated with regeneration operations.

Simple Vessel Design Yields More Capacity

Vessel design with the UCR-UPS system is uncomplicated. Freeboard is almost eliminated so that when existing cocurrent resin beds are converted to this countercurrent technology, system modifications are minimal and ion exchange capacity can be nearly doubled.

The top collector/distributor system in the vessel is surrounded by a shallow layer of floating inert material that allows feedwater and regeneration fluids, as well as resin fines and other small particulates, to pass through but restrains the normal size resin beads so that the bed is maintained in a packed state during upflow regeneration.

Because the service cycle operates downflow, the compacted resin bed is not vulnerable to fluctuations in feed pressure. If feed flow is interrupted, there is no danger that ionic stratification will be disturbed and the highly regenerated zone at the bottom of the bed remains intact and uncontaminated by exhausted beads from higher in the bed.

For upflow regeneration, the resin bed is lifted in the compacted state up against the inert layer and the regenerant passes upflow at a rate sufficient to maintain the resin in the packed state. Regeneration serves two purposes, reactivating the ion exchange sites on the resin while cleaning the vessel of resin fines and other particulates.

A Self-Cleaning System

Resin beds operated under the UCR-UPS system are actually self-cleaning and there is no need for resin traps or backwashing to prevent problems due to escaping resin fines or other particle contamination. With the UCR-UPS system, particulates migrate upward and accumulate at the top surface of the resin bed when the resin settles to the bottom of the vessel upon completion of the regeneration cycle. The fines remain at the top of the packed bed during the subsequent downflow service run and are then swept from the bed with effluent fluid at the beginning of the next upflow regeneration cycle. Fig. A IX.16 illustrates service and regeneration cycles with the UCR-UPS system.

Use of Cost-Efficient Layered Beds

The UCR-UPS system employing UPS uniform particle size resins can be used in layered bed configurations to enhance system efficiency and economy. Two layers of resin with a weakly functional resin on top of a strongly functional resin are installed in a single vessel and there is no need for a middle plate to separate the resins. The layers are maintained by the differences in resin particle size and density. (See Fig. A IX.17)

Layered beds are an efficient and economical alternative to employing separate vessels for strongly and weakly functional resins in a demineralizer system. With layered beds, fewer vessels are needed and regeneration chemical efficiency is improved. A layered bed configuration is a highly cost-effective way to take advantage of the high exchange capacity and organics removal of a weak base anion resin to protect and optimize the capacity and service life of the strong base anion resin which contributes high silica removal capabilities to the system.

For Existing Cocurrent Systems...

DM plants with cocurrent systems can take advantage of this advanced system with minimal capital investment, converting their existing equipment to ...

(a) Reduce chemical costs 35 to 55%.

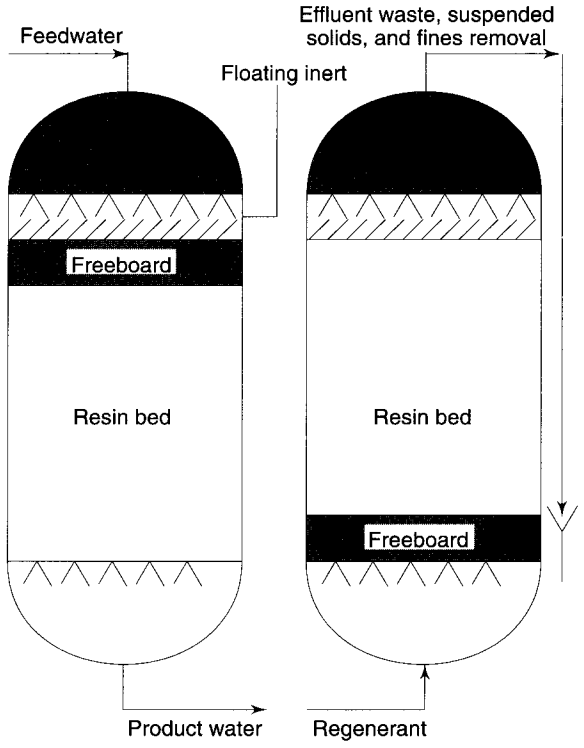


Fig. A IX. 16 *Resin bed operation with the UCR-UPS countercurrent regeneration system. Courtesy: The Dow Chemical Co./Michigan/USA.*

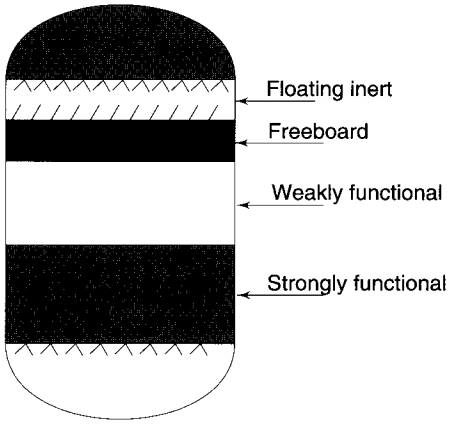


Fig. A IX. 17 *Layered bed utilizing the UCR-UPS system.*

Courtesy: The Dow Chemical Co/USA

(b) Nearly double total ion exchange capacity.
(c) Reduce system downtime.
(d) Improve water quality.
(e) Reduce effluent volumes.
(f) Cut regeneration time and expense.
(g) Reduce service water consumption.

For New Countercurrent Systems

(a) All the efficiency, economy and water quality advantages of countercurrent technology without the problems associated with other countercurrent system.
(b) Reduced vulnerability to feed pressure fluctuations and far less chance that exhausted resin will contaminate the highly

regenerated zone closest to the service flow outlet.

(c) Lower capital costs compared to upflow service systems because there is no need for holding tanks and transfer piping for backwashing operations.

(d) Fewer system problems due to resin fines and other particulates

(e) Greater vessel utilization for maximum ion exchange capacity.

(f) Using layered beds improve demineralizer efficiency, extend resin life, and achieve the highest water quality.

Source: DOWEX UPCORE — The Dow Chemical Co./Michigan/USA

Note: UPCORE represents UP flow Countercurrent Regenration of UPS resins.

COUNTERCURRENT REGENERATION : DESIGN RATINGS

Each manufacturer has its own preferred system configuration for meeting the operational factors and equipment design varies considerably.

Engineering Design Ratings for Hydroxide Cycle Countercurrent Regeneration

Figures A IX. 18-A IX. 22 provide the engineering design ratings for DOWEX SBR-P strong base anion resins in the hydroxide cycle.

Figure A IX. 18 is a master capacity curve presented as a function of regenerant dosage, based on a 100 ppb end-point and 3 foot bed depth. The above figure is used to modify the master curve for the particular resin being rated, and influent

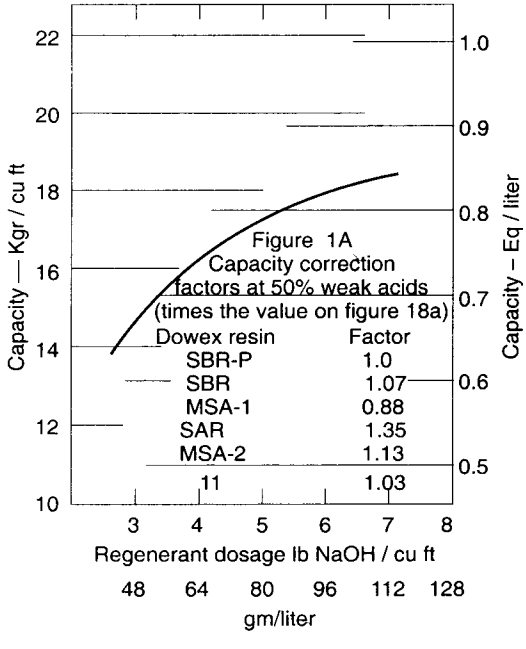


Fig. A IX. 18(a) *DOWEX anion resin-capacity vs reg. dosage to 100 ppb SiO_2 end-point 3' deep bed (At 50% weak acids).*

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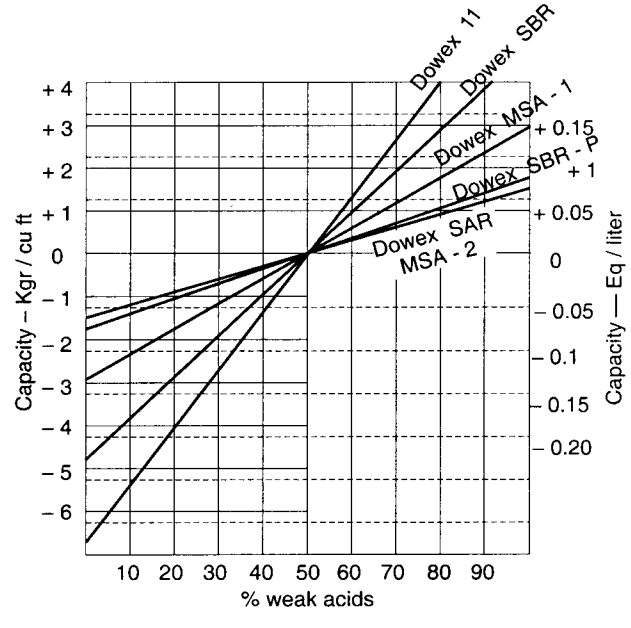

Fig. A IX. 18(b) *Capacity correction factors for % weak acids in water (add to or subtract from product of Figure 18a & 18b.*

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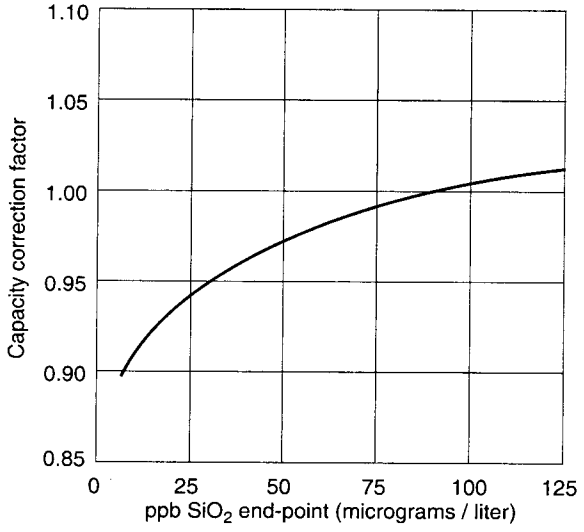

Fig. A IX. 19 *DOWEX anion resin—capacity correction factor for silica end-point.*

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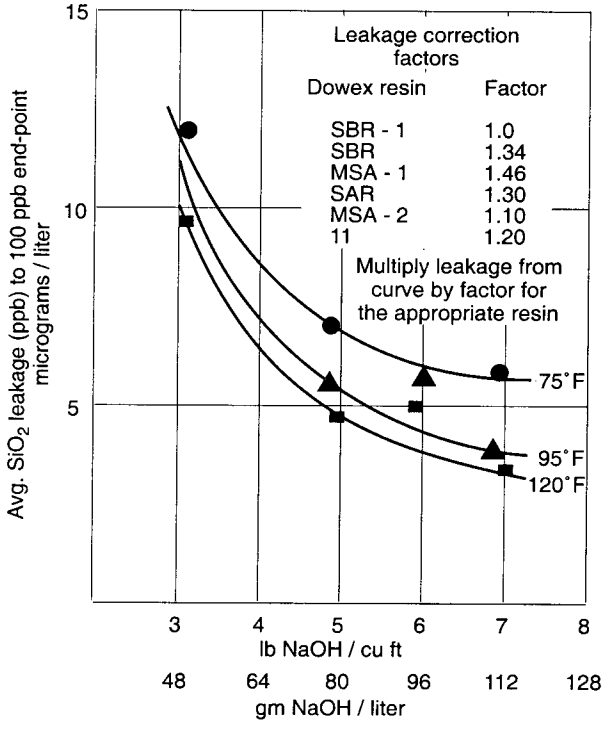

Fig. A IX. 20 *DOWEX anion resin SiO_2 leakage vs regenerant dosage 3' deep Bed; SiO_2 = 0.6% of total anions.*

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water % weak acids, respectively. Figure A IX.19 is a curve for capacity correction for changes in the silica end-point from that used in Fig. A IX. 18. Figure A IX. 20 provides silica leakage data as a function of regenerant dosage, with regenerant temperature as an additional parameter.

Figure A IX. 21 allows correcting for silica leakage based on silica as a percentage of total anions. And Fig. A IX. 22 provides a correction factor for silica leakage as a function of actual bed depth.

Using the Rating Curves

The above figures can be used in a number of ways. Capacity and leakage characteristics can be chosen for a selected regenerant dosage; the appropriate correction factors can then be applied for the desired silica end point for capacity and the desired bed depth for silica leakage. Finally, silica leakage is corrected for the silica percent of total anions.

An alternate approach: First, the user decides what his maximum allowable silica leakage will be. This figure is corrected for the water analysis (silica percent of total anions) using Fig. A IX. 21, and bed depth using A IX. 22. The allowable silica leakage is then used as the basis for selecting a regenerant dosage, using Fig. A IX. 20. At that point the appropriate regenerant temperature can be chosen, based on the relationship of regenerant dosage and temperature for that silica leakage. The capacity available at that regenerant dosage is taken from Fig. A IX. 18 and corrected for the appropriate end point using Fig. AIX. 19. An equipment factor would normally be intro-

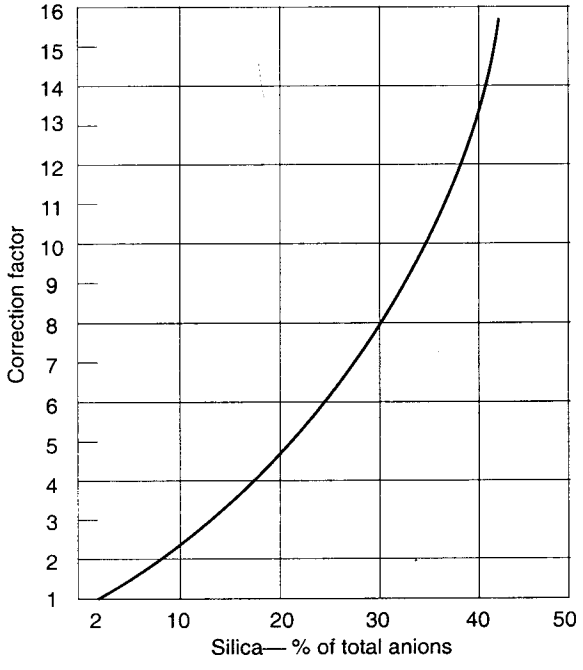

Fig. A IX. 21 *Silica leakage correction factor for silica % of total anions.*

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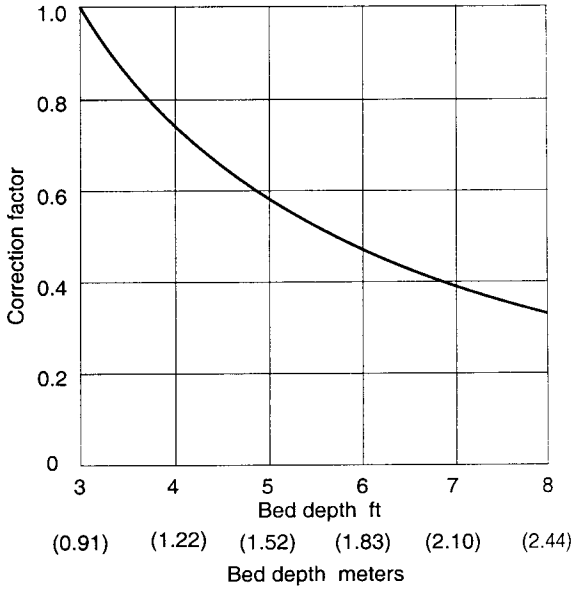

Fig. A IX. 22 *Silica leakage correction factor for bed depth.*

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duced here, since this data is based on ideal equipment operation.

Examples 3 and 4 illustrate the calculations necessary to determine the anion load in systems with and without a degasifier.

These examples will illustrate the calculations for the anion load to DOWEX SBR-P resin. The regeneration conditions, exchange capacity and quantity of deionized water are calculated from these anion loads.

Table A IX.1

	Raw Water	Anion Influent without Degasifier		Anion Influent with Degasifier	
	ppm	ppm	%	ppm	%
HCO_3 as $CaCO_3$	150	0		0	
SO_4 as $CaCO_3$	50	50	18.5	50	43.5
Cl as $CaCO_3$	40	40		40	
NO_3 as $CaCO_3$	10	10	18.5	10	43.4
TA as a $CaCO_3$	250	100			
TMA as $CaCO_3$				100	86.9
SiO_2 as SiO_2	12	as $CaCO_3$ 10	3.7	10	8.7
CO_2 as CO_2	8.8	as $CaCO_3$ 160	59.3	5	4.4
Weak Acids		as $CaCO_3$ 170	63.0	15	13.1
Total Exchangeable Anions		270	100	115	100

Example 3 Anion Influent without Degasifier

The following conditions have been specified:

Maximum allowable SiO_2 leakage 5 ppb. Silica end point 50 ppb. Bed depth—5 ft.

Step 1

The SiO_2 leakage is corrected for the effect of silica % of total anions (Figure A IX. 21) and bed depth (Figure A IX. 22).

$$\text{Correct } SiO_2 \text{ leakage} = \frac{5}{1.3 \times 0.58} = 6.6 \text{ ppb}$$

Step 2

From the water analysis and calculated anion load establish the following factors:

Allowable SiO_2 leakage

(corrected) ..... 6.6 ppb

% SiO_2 of total anions as $CaCO_3$ 3.7

Step 3

Using Fig. A IX. 20 determine regeneration conditions necessary to obtain the required SiO_2 leakage. Prepare a table for comparison. Determine capacity using Fig. A IX. 18 at that regeneration. Correct with Fig. A IX. 19.

Table A IX. 2

	Regeneration			Corrected Capacity	
Silica Leakage ppb SiO_2	Temp. °F	NaOH lb/cu ft	Exchange Capacity kgr/cu ft	End point kgr/cu ft	Regenerant Consumed lb/kgr
6.6	75	5.3	17.8	17.4	0.305
6.6	95	4.0	16.5	16.1	0.249

Example 4: Anion Influent with Degasifier

When a degasifier is installed after a cation exchanger the characteristics of the water to the anion exchanger are altered. The silica ratio to total anions is increased by elimination of most of the CO_2. The specified conditions are the same.

Maximum allowable SiO_2 leakage 5 ppb. Silica end point 50 ppb. Bed depth = 5ft.

Step 1

The SiO_2 leakage is corrected for the effect of silica % of total anions (Figure A IX. 21) and bed depth (Figure A IX. 22).

$$\text{Corrected } SiO_2 \text{ leakage} = \frac{5}{2.1 \times 0.58} = 4.1 \text{ ppb}$$

Step 2

From the water analysis and calculated anion load establish the following factors:

Allowable silica leakage

(corrected) ..... 4.1 ppb

% SiO_2 of total anions as $CaCO_3$ 8.7

Step 3

Using Fig A IX. 18 – A IX. 20 determine regeneration conditions necessary to obtain the required SiO_2 leakage. Determine capacity at the regeneration level using Figure A IX. 18. Correct for SiO_2 end point using A IX. 19. Prepare a table to compare results.

Table A IX. 3

Silica Leakage ppb SiO_2	Regeneration		Exchange Capacity kgr/cu ft	Corrected Capacity	Regenerant Consumed lb/kgr
	Temp. °F	NaOH lb/cu ft		End point SiO_2 kgr/cu ft	
4.1	75	Not attainable at reasonable regenerant dosages			
4.1	95	7.0	16.8	16.4	0.427
4.1	120	6.1	16.5	16.1	0.379

ENGINEERING DESIGN RATINGS FOR HYDROGEN CYCLE COUNTERCURRENT REGENERATION

Figures A IX. 23 through A IX. 26 provide the engineering design ratings for DOWEX HCR-W2 and DOWEX HCR-S resins in the H^+ cycle. Figurs A IX. 23 and A IX. 24 give leakage vs regenerant dosage and capacity vs dosage for hydrochloric acid; Figs A IX. 25 and A IX. 26 provide the same data for sulphuric acid.

Each curve is plotted with the appropriate leakage or capacity figures for waters containing 100% alkalinity. For waters of different alkalinity, a correction factor is inset on each curve.

Using the Rating Curves

Figures A IX. 23 - AIX. 26 can be used in a variety of ways. The appropriate curve for the influent water analysis can be located for a given regenerant dosage, and then leakage and capacity figures can be compared.

Alternately, the allowable sodium leakage can be determined for the product water and this is then divided by the alkalinity correction factor (inset in Fig. A IX. 23). The resulting corrected sodium leakage level is then used on the X-axis of Fig. A IX. 23; the required acid dosage to obtain that leakage is determined by its inter-section with the appropriate percent sodium curve in Fig. A IX. 23. That dosage can then be used to determine the operating capacity at the appropri-

ate percent sodium level. Corrections for water alkalinity are made from the inset in Fig. A IX. 24.

An Example

Since this data is based on ideal equipment operation, an appropriate equipment factor is normally introduced into the calculations to bring them closer to reality. We'll use as an example a water to be demineralized with the following analysis. All hardness is expressed as $CaCO_3$:

		HCO_3	140 ppm = 70%
Ca	80 ppm	SO_4	40 ppm
Mg	80 ppm = 40%	Cl	10 ppm
Na	40 ppm = 20%	NO_3	10 ppm
	200 ppm		200 ppm

$$Mg = \frac{80}{200 - 40} = 50\% \text{ of non Na Cation}$$

Starting with the given value of sodium leakage as 80 ppb (as Na):

1. Calculate the corrected sodium leakage for that alkalinity percentage using Fig. A IX. 23. At 70% alkalinity this correction factor is 1.03, therefore corrected sodium leakage equals 80/1.03 or 77 ppb Na.
2. Interpolating for 20% sodium, four pounds of hydrochloric acid per cubic foot of resin is the appropriate regenerant dosage.
3. Using Fig. A IX. 24 read the kilograins capacity per cubic foot at 20% sodium for the 4 pound/ft^3 regenerant level. This is 26.2 kg/ft^3.
4. Using the inset in Fig. A IX. 24, calculate the correction factor for the influent alkalinity level. At 70% this correction factor is 0.98. Multiplying 26.2 × 0.98 gives a resulting theoretical operating capacity of 25.7 kilograins per cubic foot of resin.
5. Calculate a more realistic operating capacity by multiplying this number by some appropriate equipment factor. At an equipment factor of 85%, for example, the operating capacity will be 21.8 kilograins per cubic foot.

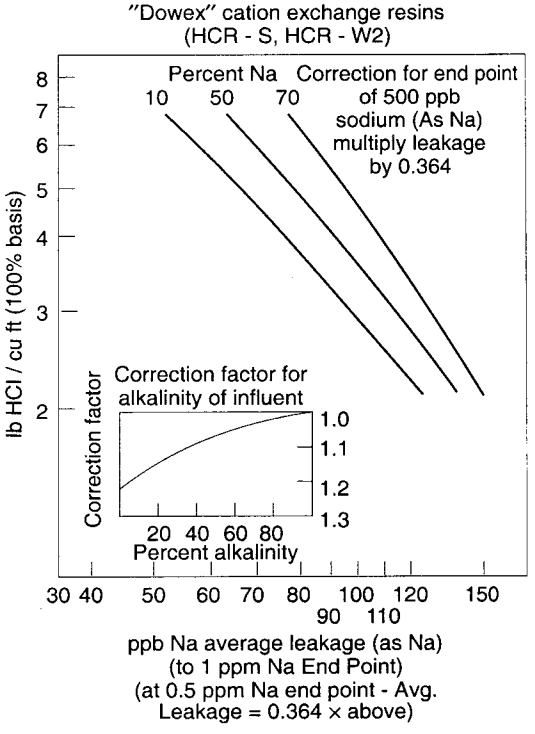

Fig. A IX.23 *Sodium leakage from HCl countercurrent regeneration.*

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CATION RESIN HYDROGEN CYCLE: DESIGN RATINGS

Hydrogen Exchange Engineering Design Ratings

In preparing data for use in predicting exchange capacity and leakage, attempt has been made to take into account as many factors as possible for maximum accuracy. The curves that follow consider the effects of sodium, calcium and alkalinity on capacity and the effects of sodium, free mineral acidity and total dissolved solids on leakage at various regeneration levels.

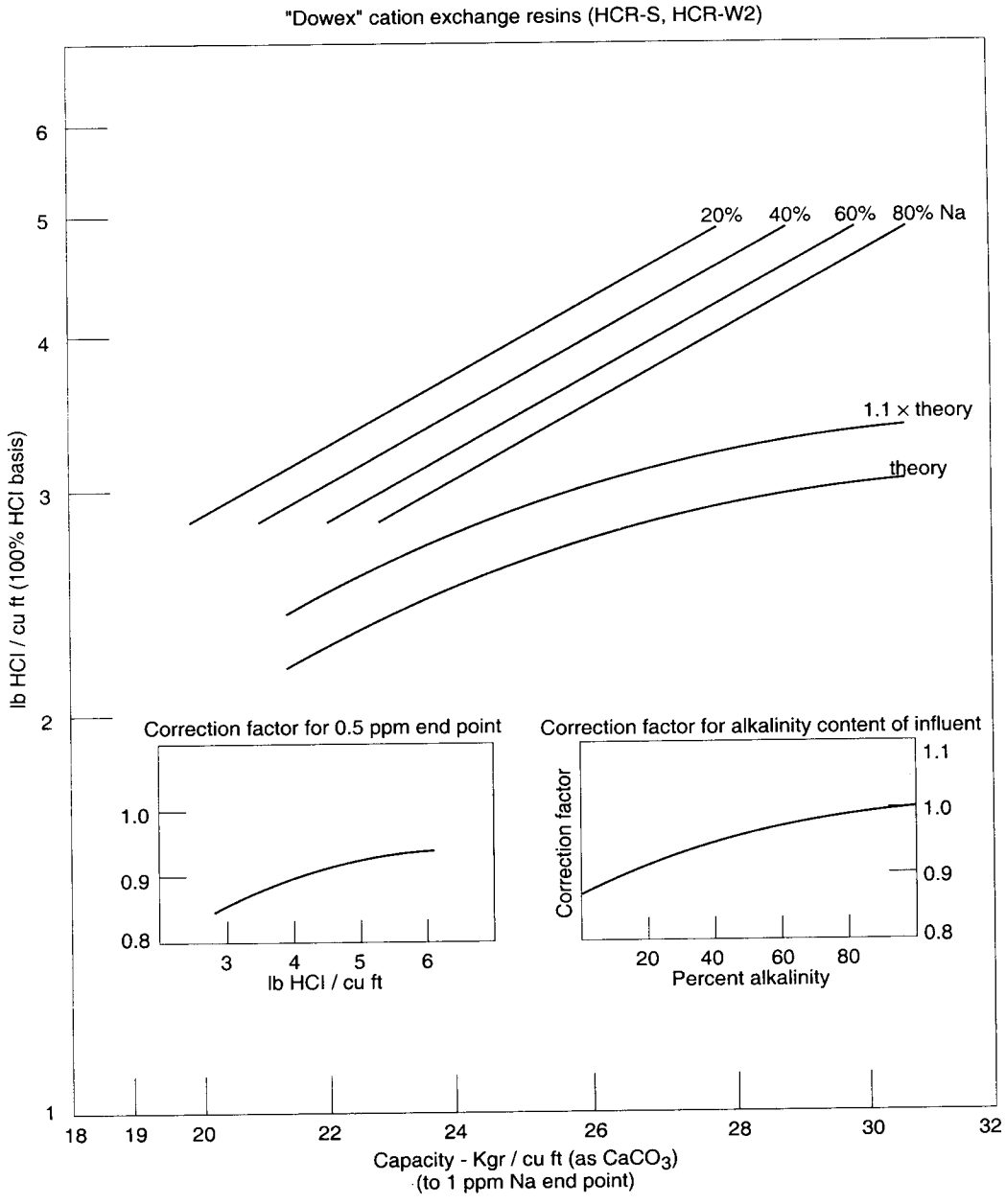

Fig. A IX. 24 *Resin capacity—hydrochloric acid countercurrent regeneration.*

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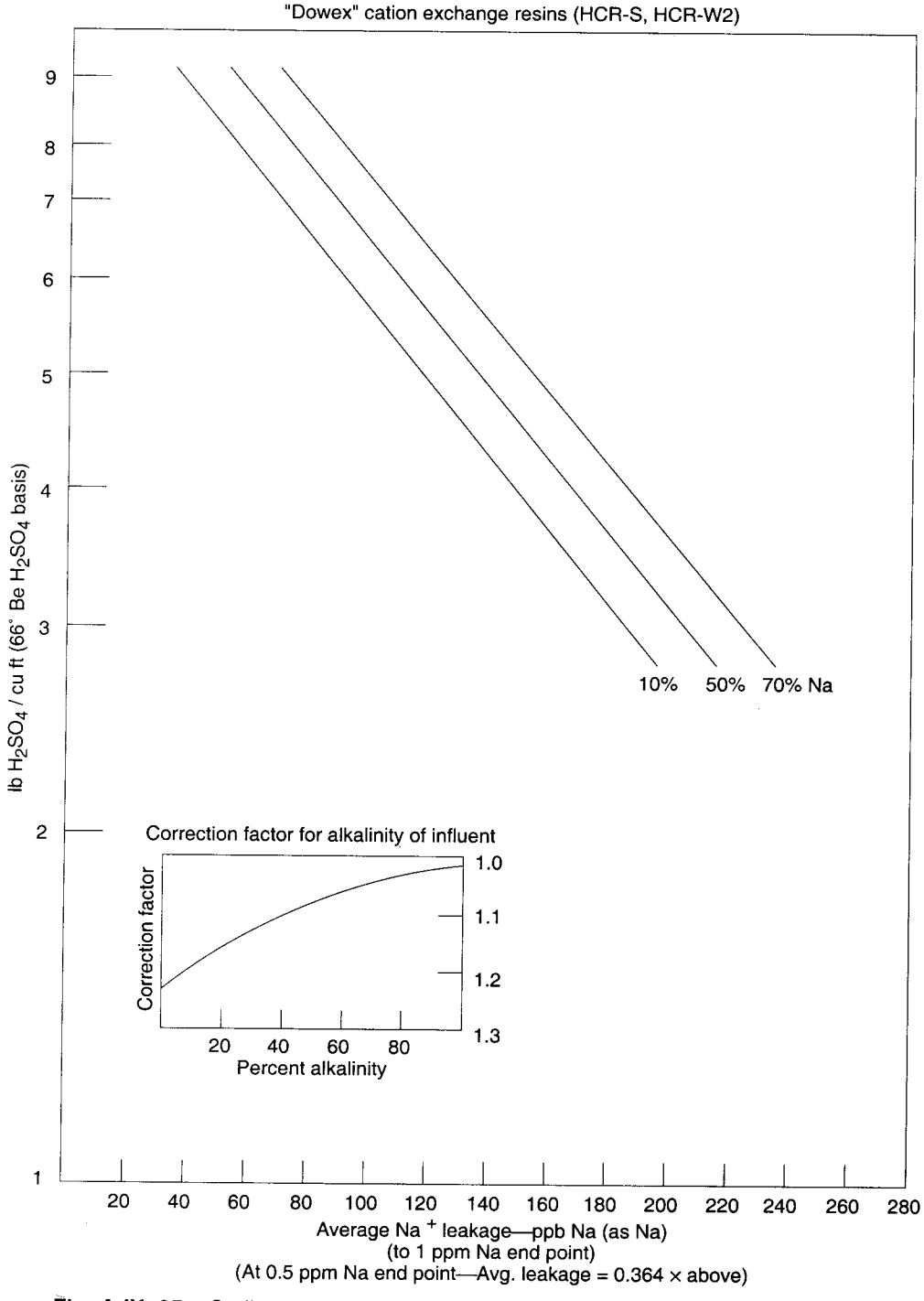

Fig. A IX. 25 *Sodium leakage from sulfuric acid countercurrent regeneration.*

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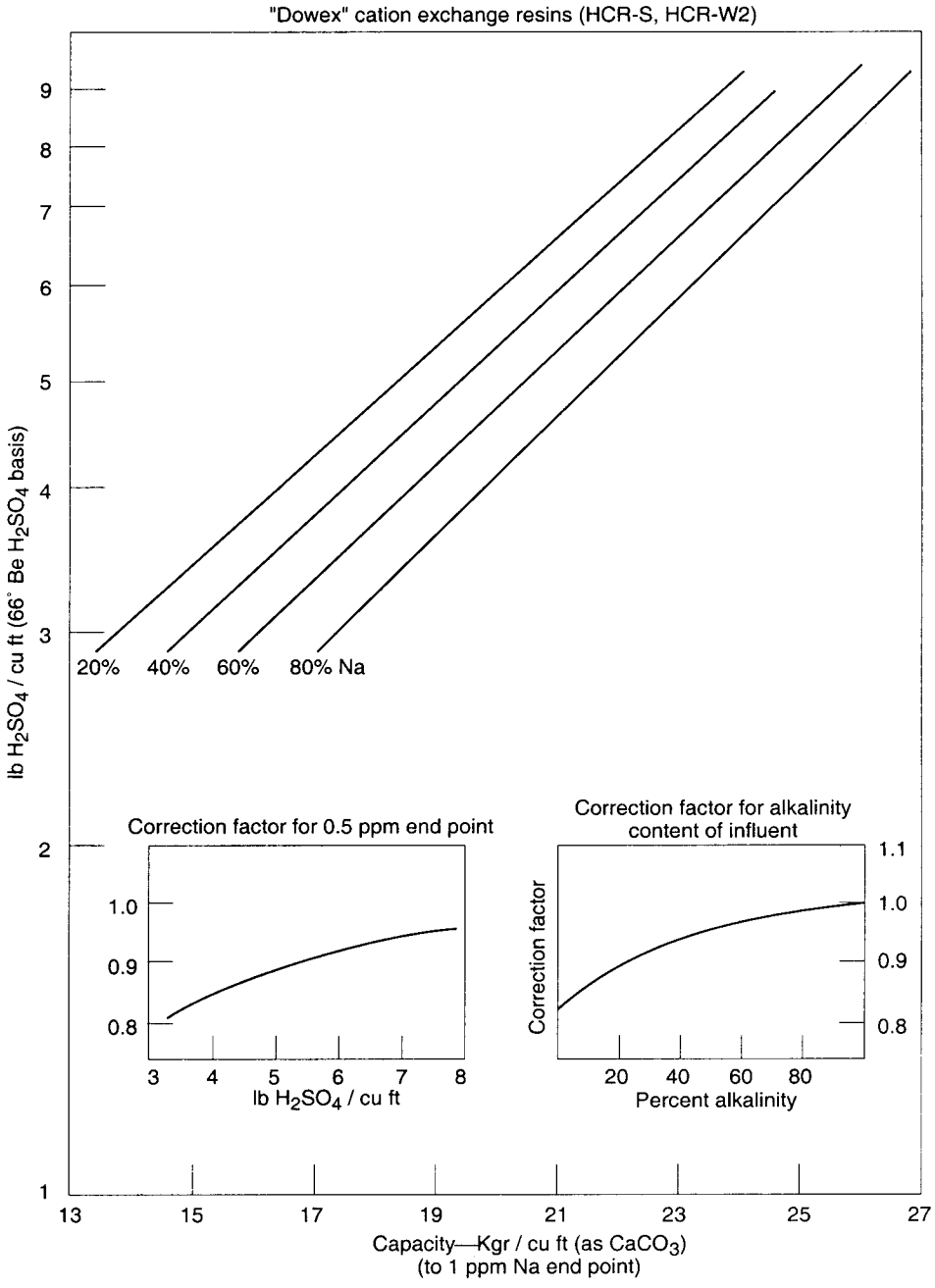

Fig. A IX. 26 *Resin capacity—sulfuric acid countercurrent regeneration.*

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Throughput Capacity vs. Corrected Capacity

Throughput capacity is generally of interest to the design engineer concerned with sizing ion exchange equipment since it defines the volume of treated solution obtained during the service run.

Throughput or operating capacity is obtained by multiplying the usable volume of effluent by the exchangeable ions in the solution being treated. Corrected capacity on the other hand is the actual amount of exchange which takes place during the service run. Corrected capacity is reported. Throughput capacity is determined by multiplying the corrected capacity by:

$$\frac{100}{100 - \%\ \text{leakage}}$$

Percent leakage is the direct percent of Na leakage to total cations.

An understanding of the principal factors involved in ion exchange will aid in better comprehension of the operating capacity-leakage relationship.

The primary property which makes ion exchange resin useful is the reversible change in resin affinity for one ion over another ion as the ionic concentration in the solution around the resin particle changes. There are two important phenomena which govern this; resin selectivity and mass action.

1. Resin selectivity is much greater for multivalent ions over mono-valent ions in dilute solutions. This selectivity decreases as ionic concentration in the solution around the resin particle increases.
2. When ions of the same valence are being exchanged, the selectivity difference is lower and the exchange is much less complete. It is dominated more by mass action than resin selectivity.

Elution of sodium by hydrogen ions is a monovalent-monovalent exchange. Monovalent ions are more easily eluted by low acid concentrations than are polyvalent ions. Acid concentration above 5% does not markedly improve the rate of sodium elution.

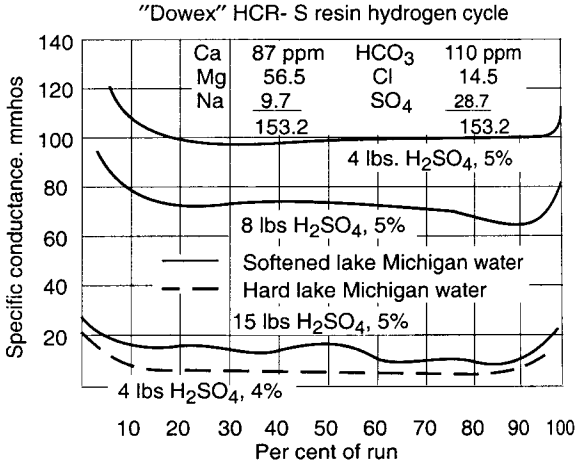

Fig. A IX. 27 *Effect of sodium on water quality and acid requirements.*

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Under a given set of regeneration conditions, virtually the same percentage of a given ion will be eluted from a resin bed. The amount of that ion eluted will depend on the amount or percentage of that ion on the bed at the start of regeneration. This amount will also depend somewhat on the ratio of ions on the bed to each other.

In normal operating practice complete elution (regeneration) is not accomplished. A certain percentage of the ions are left on the bed. The ratio of ions to each other on the bed will be approximately the same as the ratio in the solution entering the bed.

In conventional downflow operation and regeneration, the greatest amount of exchangeable ions remaining will be on the bottom of the resin bed. The amount of sodium left on a cation exchanger after regeneration will be proportional to the sodium in the feed solution and the regeneration level. As sulfate, chloride and nitrate are con-

verted to their corresponding acids by exchange of calcium, magnesium and sodium in the upper portion of a cation exchange resin bed, the free mineral acidity (FMA) formed will have a regenerating effect on the residual sodium, causing leakage. The polyvalent calcium and magnesium ions are more strongly held and will not "leak" off under normal operating conditions.

The amount of sodium leakage will be a function of regeneration level, percent sodium in the exhaustant, and the free mineral acidity formed in the cation exchanger. TMA (theoretical mineral acidity or total mineral anions) is the sum of the chloride, nitrate and sulfate, as calcium carbonate, in the feed solution. FMA will be less than TMA by the amount of the leakage. Operating capacity is a function of the amount of acid utilized during regeneration and is affected by the dissolved solids present. Leakage is related to the ions left on the resin bed from the previous regeneration and is caused by the mineral acidity formed in the bed during operation. From this it can be seen that water quality, acid efficiency and exchange capacity must all be considered when choosing an acid regeneration level. Countercurrent regeneration, properly accomplished in a restrained packed bed, (as opposed to a fluidized bed) eliminates that leakage which is caused by residual cation remaining at the base of the bed. Thus, virtually zero leakage can be accomplished. If rinsewater is not decationized, or if mixing occurs prior to exhaustion, leakage approaching that reported for cocurrent operation may be experienced.

SULPHURIC ACID REGENERATION

The charts for estimating capacity and leakage from DOWEX HCR-S and DOWEX HCR-W2 cation exchange resins, when using suphuricc acid as a regenerant, are found in Fig. A IX. 30–A IX. 36.

Table A IX.4 *Capacity Correction for Bed Depth*

Bed Depth inches	Percent Capacity of 30″ Bed
18	71
24	88
30	100
36	107
42	111
48	114
54	117
60	119

Table A IX.5 *Capacity Correction for Flow Rate*

The effect of flow rate on capacity, at a given bed depth, as a percentage of capacity of a 30 inch bed, operated at 5 gpm/sq ft.

	Sodium Hydrogen Exchange
20 gpm/sq ft	65% of capacity of 30 inch bed at 5 gpm/sq ft
50 gpm/sq ft	25% of capacity of 30 inch bed at 5 gpm/sq ft
100 gpm/sq ft	0% of capacity of 30 inch bed at 5 gpm/sq ft

(30 gr/gal TDS influent, 1 gr/gal end point, std mesh)

INSTRUCTIONS FOR USING RATING CURVES

Leakage

Figure A IX. 30 shows sodium leakage as per cent of corrected total mineral anions vs H_2SO_4 regenerant dosage, for several values of sodium per cent of total cations in the influent water. Corrected total mineral anions are determined by multiplying the total anions by the alkalinity factor taken from the inset on Fig. A IX. 30.

Capacity

Figures A IX. 31–A IX. 36 show capacity as it relates to percent sodium, percent magnesium and

regenerant level at three different percent alkalinity ranges, and are corrected for leakage.

Example

A water to be demineralized with the following analysis:

as $CaCO_3$*

Ca	80 ppm	HCO_3	140 ppm = 70%
Mg	80 ppm = 40%	SO_4	40
Na	40 ppm = 20%	Cl	10
	200	NO_3	10
			200

$$Mg = \frac{80}{200 - 40} = 50\% \text{ of non Na Cation}$$

The required quality from a 2 bed demineralizer is specified to be 10 mmho or 2 ppm as $CaCO_3$ (at pH values over 8.3 and when using strongly basic resins, conductivity meters measure leakage that has been converted to sodium hydroxide, thus accounting for the high conductivity.)

Starting with requirement for Na leakage, (2 ppm) and the influent water analysis, (see tabulation)

(a) Calculate—
% sodium in water (20%)
% alkalinity (70%)

(b) Read—
Corrected total mineral anion factor from curve-for this alkalinity. (0.4) See Note "B"

(c) Calculate—
Corrected total mineral anion (factor times total anions)
($0.4 \times 200 = 80$)

(d) Calculate—
Allowable leakage as % corrected total mineral anions.

$$\left(\frac{2 \times 100}{80} = 2.5\%\right)$$

(e) Read—
H_2SO_4/ft^3 needed to get this from leakage curve for appropriate % Na (20%) = (4.5 #/ft^3)

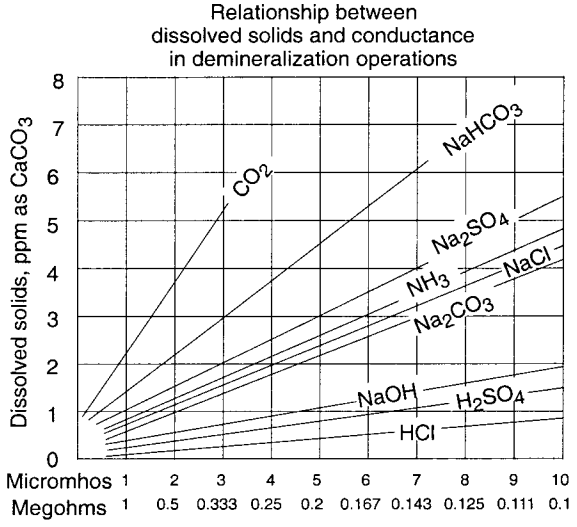

Fig. A IX. 28 *Specific conductance of electrolytes at 77°F.*
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* To obtain grains per U.S. gallon, divided ppm by 17.1

(f) ***Read-***
Capacity at this regeneration level from appropriate curve for the % Na (20%) and alkalinity (70%) = (16.8 Kgr/ft^3)
Note: Kgr = Kilograins

(g) Correct for magnesium % in influent (50% of non Na cations) = (+ 0.6 Kgr)

(h) Add correction to capacity—
16.8 + 0.6 = 17.4 Kgr/ft^3.

(i) Throughput capacity is determined by multiplying this corrected capacity by 100/(100 – % leakage)

[% leakage = (% Na leakage total)] =

$$\frac{2}{200} = 1\%$$

Thruput capacity = (17.4 Kgr/cu. ft.) ×

$$\left(\frac{100}{100-1}\right) = 17.6 \text{ Kgr./cu. ft.}$$

Note A: When applying this rating data the user must remember that the data are based on ideal conditions which do not take into account equipment design or operation factors encountered in the field. Sufficient safety factor should be included by the equipment manufacturer to meet any guarantees he may be required to make regarding capacity. The 80% factor suggested above is an experience factor for the users convenience.

Note B: On higher alkalinity waters, the acid level indicated may be lower than 2.5 lb. per cu. ft. Use 2.5 lbs. per cu. ft. as the minimum acid regeneration level.

HYDROCHLORIC ACID REGENERATION

The charts for estimating capacity and leakage from DOWEX HCR-S and DOWEX HCR-W cation exchange resins, when using hydrochloric acid as a regenerant, are found in Fig. A IX. 37 through A IX. 43.

These data and its use differ from that of sulfuric acid in that no correction factor for alkalinity is required for determination of leakage. In use of hydrochloric acid, no precipitation problems are encountered, and thus, no special stepwise regeneration technique is required. Laboratory data was collected in a similar manner to the sulphuric acid regeneration data in other aspects.

INSTRUCTIONS FOR USING RATING CHARTS

Leakage

Figure A IX. 37 shows sodium leakage as percent of total mineral anions vs HCl regenerant dosage, for several values of sodium per cent of total cations in the influent water.

Capacity

Figures A IX. 38 through A IX. 43 show capacity as it relates to cation content of the influent water, HCl regenerant level and the range of alkalinity in the influent water. These capacity figures have been corrected for leakage.

Example

A water to be demineralized with the following analysis:

as $CaCO_3$

Ca	80 =	HCO_3	120 = 60%
Mg	40 =	SO_4	50
Na	80 = 40%	Cl	20
	200	NO_3	10
			200

Starting with the requirement for sodium leakage (2 ppm) and the influent water analysis (see tabulation):

(a) ***Calculate:***
% sodium in water (40%)
% alkalinity in water (60%)

(b) ***Calculate:***
Allowable sodium leakage as a % of total mineral anions.

$$\left(\frac{2 \times 100}{80} = 2.5\%\right)$$

(c) Read from Fig. A IX. 37, the regenerant level required to obtain this leakage for water containing 40% sodium (4.3 lb HCl/ cu. ft.)

(d) Read from Fig. A IX. 41 for 40% sodium, the corrected capacity obtainable for this regenerant dosage and alkalinity—(See Note A) (23.8 Kgr/cu. ft.)

(e) Determine the throughput capacity by multiplying this capacity figure by:

$$\frac{100}{100 - \%\ \text{leakage}}$$

$$\left(\frac{100}{100 - \left(\frac{2 \times 100}{200}\right)}\right)(23.8)$$

$$= \left(\frac{100}{99}\right)(23.8) = 24.04\ \text{Kgr/cu. ft.}$$

(f) Take 80% of this figure to get field operating capacity of 19.23 Kgr/cu. ft.

Note A: On higher alkalinity waters, the acid level indicated may be lower than 2.5 lb per cu. ft. Use 2.5 lbs per cu. ft. as the minimum acid regeneration level.

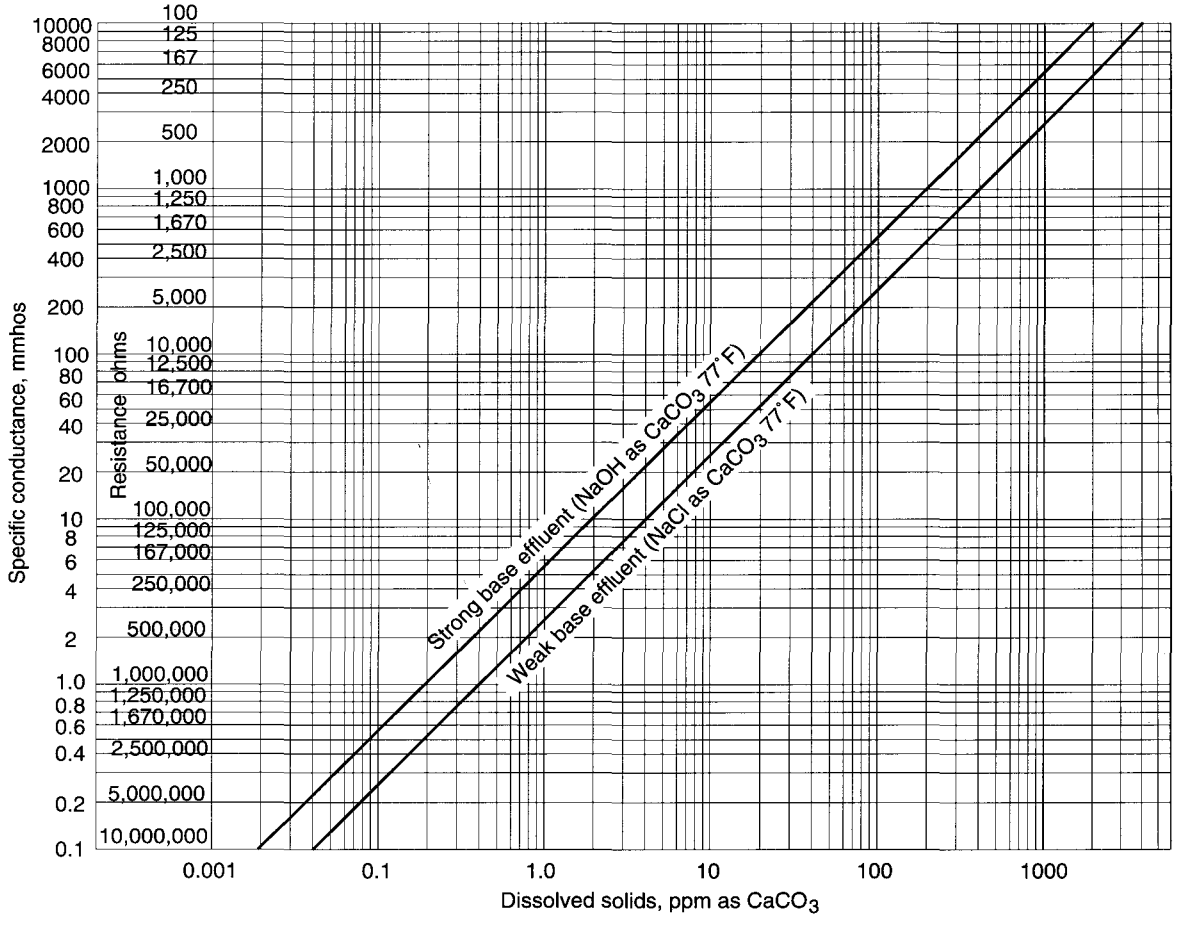

Fig. A IX. 29

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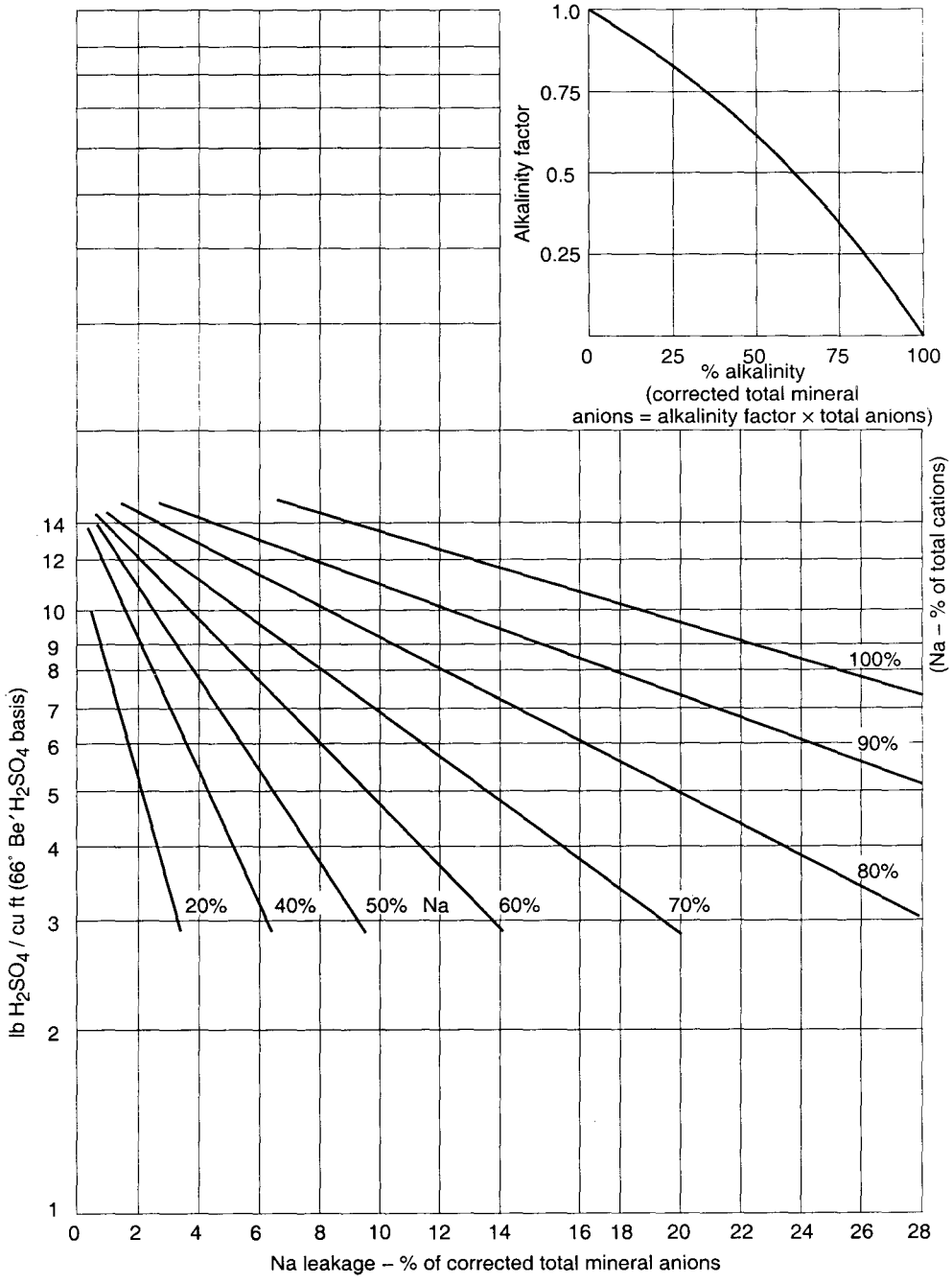

Fig. A IX. 30 *Sodium leakage from H_2SO_4 regenerated DOWEX cation exchange resins.*

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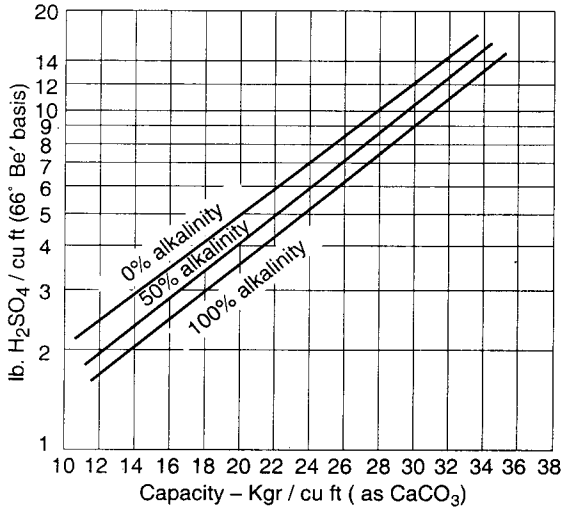

Fig. A IX. 31 *Capacity ratings of DOWEX cation exchange resins with 100% sodium water.*

(Corrected for leakage).

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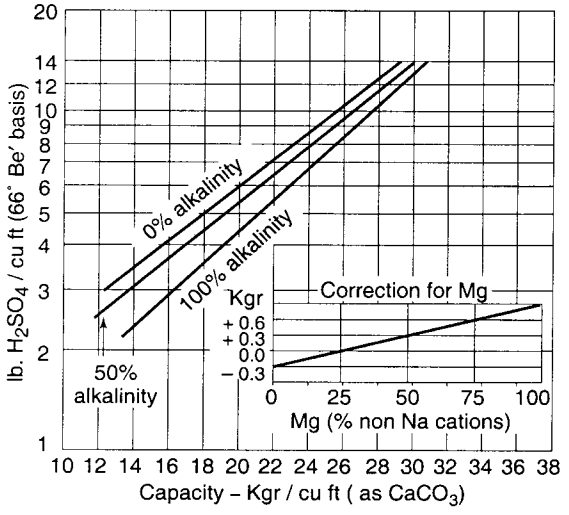

Fig. A IX. 33 *Capacity ratings of DOWEX cation exchange resins with 60% sodium water.*

(Corrected for leakage) Ca/Mg = 3/1

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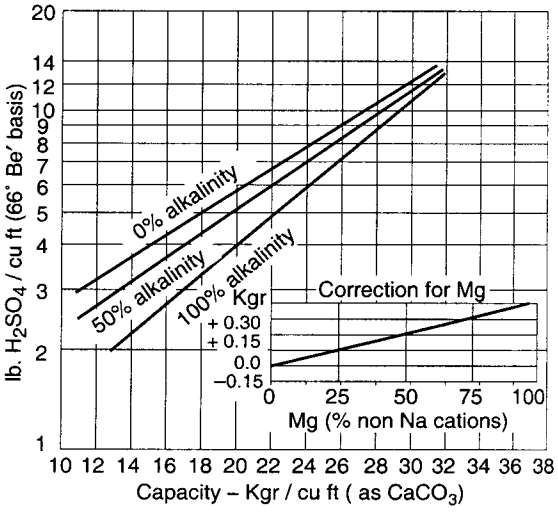

Fig. A IX. 32 *Capacity ratings of DOWEX cation exchange resins with 80% sodium water.*

(Corrected for leakage) Ca/Mg = 3/1

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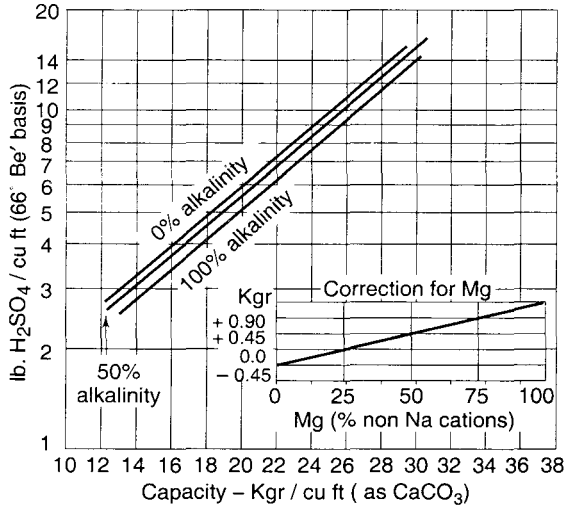

Fig. A IX. 34 *Capacity ratings of DOWEX cation exchange resins with 40% sodium water.*

Ca/Mg = 3/1

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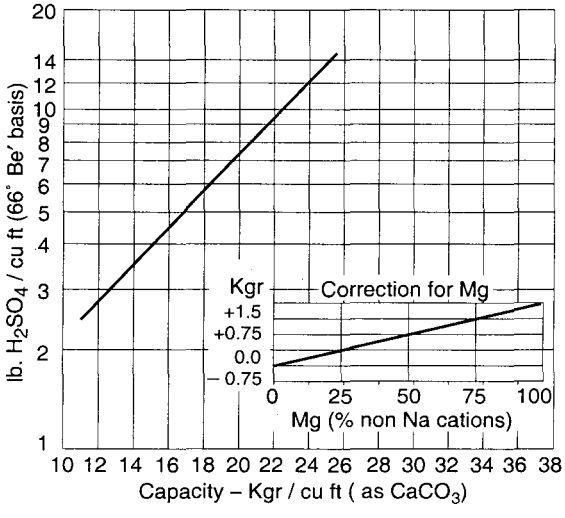

Fig. A IX. 36 *Capacity ratins of DOWEX cation exchange resins—calcium and magnesium only 3/1 ratio.*

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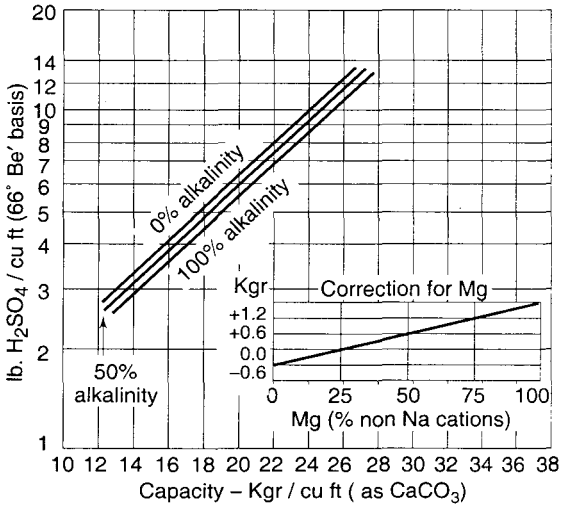

Fig. A IX. 35 *Capacity ratings of DOWEX cation exchange resins with 20% sodium water.*

Ca/Mg = 3/1

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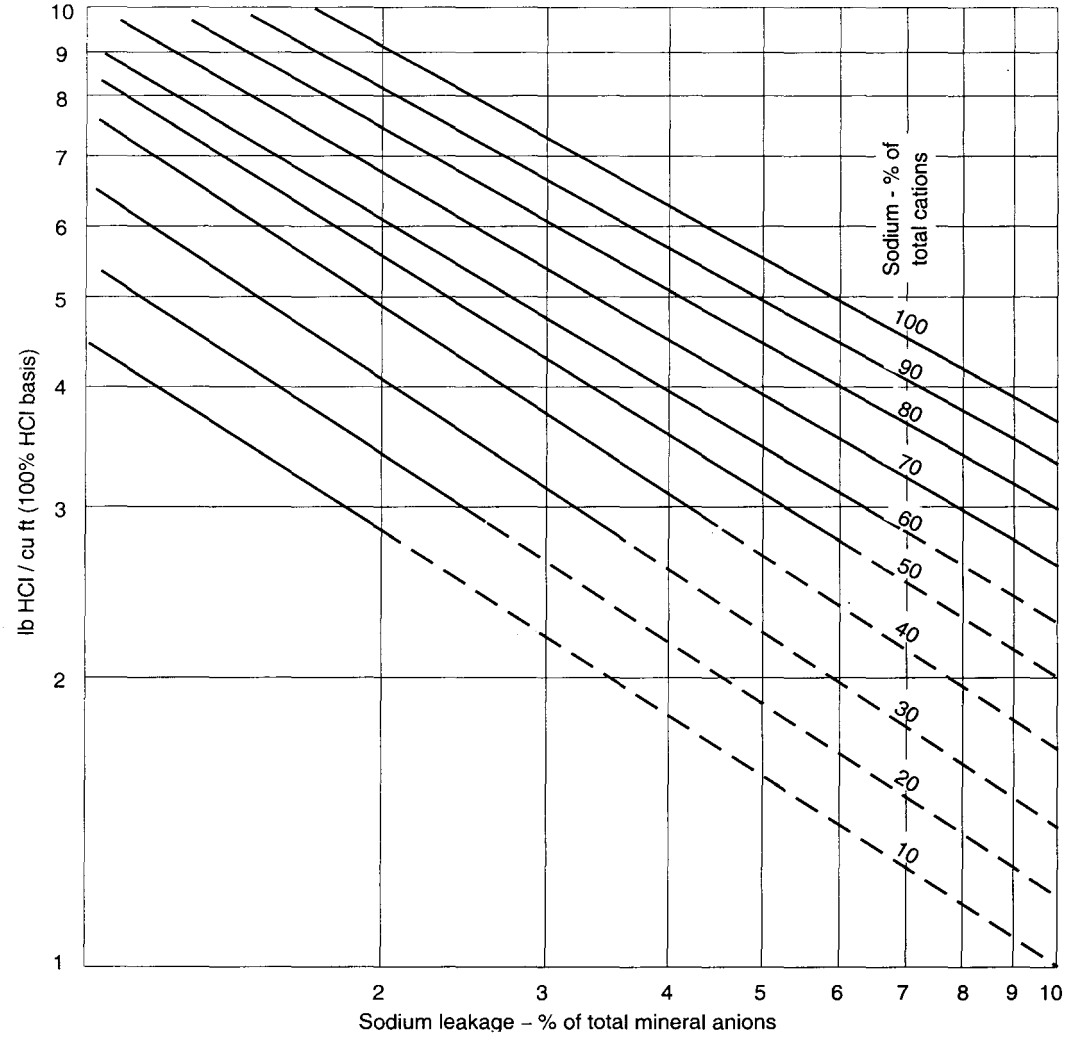

Fig. A IX. 37 *Sodium leakage from HCl regenerated DOWEX cation exchange resins.*

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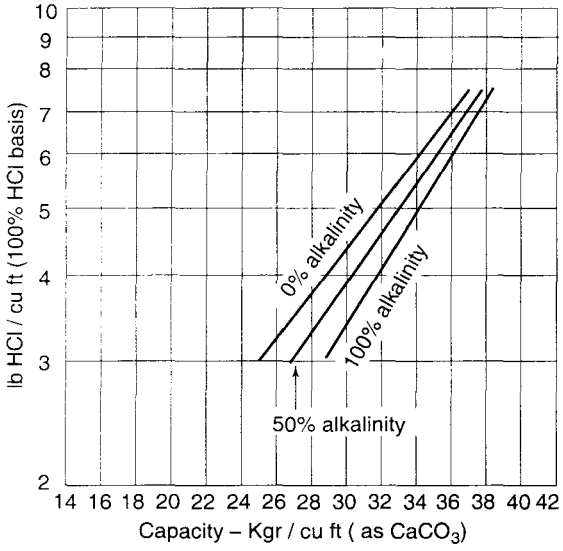

Fig. A IX. 38 *Capacity rating of DOWEX cation exchange resins 100% sodium water.*

(Corrected for leakage)

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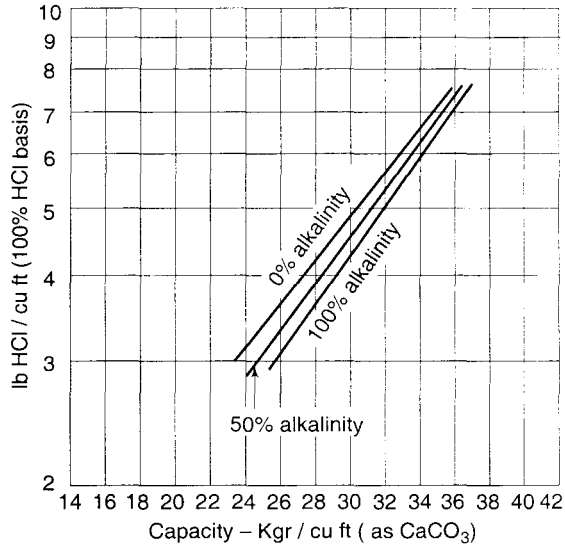

Fig. A IX. 39 *Capacity rating of DOWEX cation exchange resins 80% sodium water.*

(Corrected for leakage) Ca/Mg = 3/1

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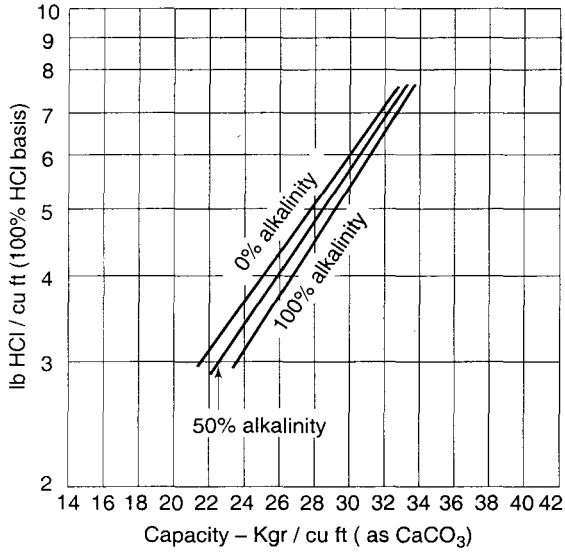

Fig. A IX. 40 *Capacity rating of DOWEX cation exchange resins 60% sodium water. (Corrected for leakage) Ca/Mg = 3/1*

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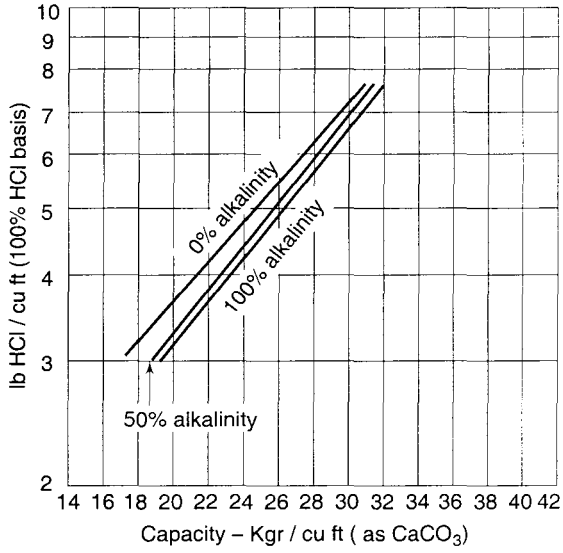

Fig. A IX. 41 *Capacity rating of DOWEX cation exchange resins 40% sodium water.*

(Corrected for leakage) Ca/Mg = 3/1

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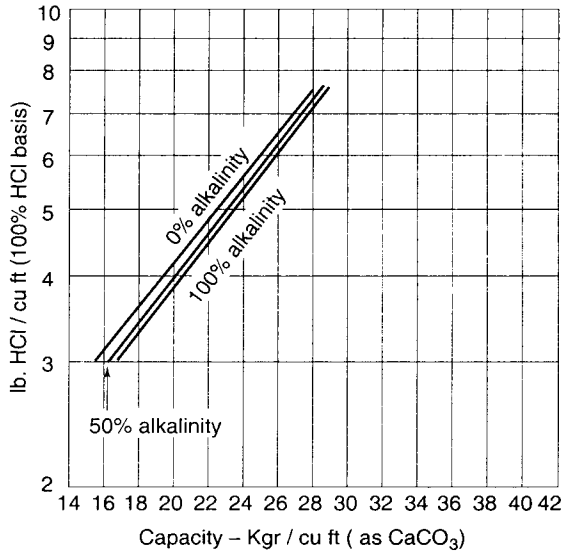

Fig. A IX. 42 *Capacity rating of DOWEX cation exchange resins 20% sodium water. (Corrected for leakage) Ca/Mg = 3/1*

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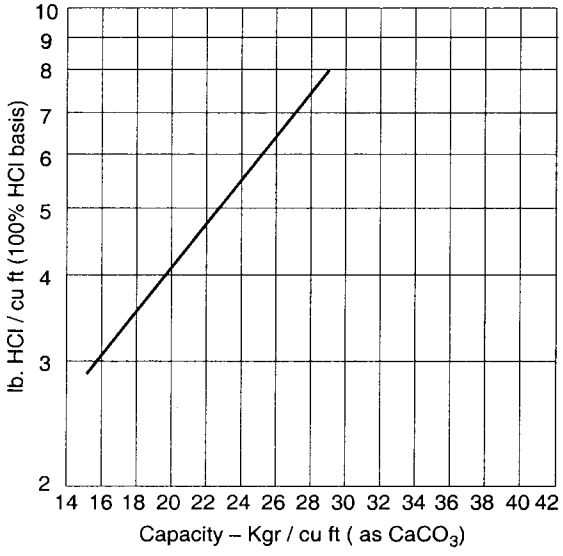

Fig. A IX. 43 *Capacity rating of DOWEX cation exchange resins O sodium. Ca/Mg = 3/1*

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Source: ION ± EXCHANGE (T.D. Index 510.01)

— The Dow Chemical Co., Midland/Michigan 48674/USA

Appendix X

Reverse Osmosis

Basic Reverse Osmosis Equations

The ***homogeneous solution diffusion model*** is the most widely accepted and best fits the reverse osmosis phenomenon. This model describes mass transport in the permeate stream of the RO system. The basic equations (see 1 and 2) for this model are shown below and represent solvent (water) production and solute (salt) concentration in the permeate streams.

1. $F_w = K_w (\Delta P - \Delta \pi)$

Where: F_w = solvent flux, gallons per square foot per day (gfd)

K_w = solvent mass transport coefficient, gfd/psi (also known as A value)

ΔP = transmembrane pressure differential, psi

$\Delta \pi$ = osmotic pressure differential, psi

2. $F_s = K_s (\Delta C) = F_w C_p$

Where: F_s = solute flux, pounds per square foot per day

K_s = solute mass transfer coefficient, gfd (also known as B value)

ΔC = transmembrane concentration differential, lb/gal

C_p = permeate solute concentration, lb/gal

The ***mass balance equations*** for reverse osmosis (see 3 and 4) are shown below:

3. $Q_f = Q_p + Q_c$
4. $Q_f C_f = Q_p C_p + Q_c C_c$

Where: Q_f = feed flow, gal/min

Q_p = permeate flow, gal/min

Q_c = concentrate flow, gal/min

C_f = feed solute concentration, lb/gal

C_p = permeate solute concentration, lb/gal

C_c = concentrate solute concentration, lb/gal

Recovery is defined as shown in equation 5 below and is generally given as a per cent.

5. $R = \dfrac{Q_p}{Q_f} \times 100$

If you combine equations 3, 4 and 5 and rearrange them you can also calculate recovery if you know the concentrations in each feed stream as listed in equation 6 as follows:

6. $R = \dfrac{C_c - C_f}{C_c - C_p} \times 100$

The above recovery equations 5 and 6 are critical in checking the mass balance of an operating RO system. If the recoveries calculated are not in close agreement (± 3% relative basis) then it is likely that an instrument is out of calibration and should be corrected.

Reverse osmosis system performance is generally monitored by tracking the permeate water flow rate and the ***salt passage***. Salt passage in percent can be calculated as shown below in equation 7:

$$7.\ \mathrm{Sp} = \frac{C_p}{C_f} \times 100$$

Salt rejection is simply 100 minus the salt passage in per cent.

In order to be meaningful or valid, the salt passage and permeate flow rate must be normalized to a standard set of conditions as shown in ASTM Standard Designation D4516–85 (reapproved 1989). This normalization of data is generally done using a computer program and the performance is plotted vs. time.

The major variables taken into consideration when normalizing field operating data are feedwater pressure, temperature, and ionic concentration. The influence of pH on performance is unique for different membrane compositions.

Source: Roughing Demineralization with Reverse Osmosis Ahead of Ion Exchange — S S Whipple & SS Beardsley

Technical Paper (No. 609-00036) presented at the 11th Annual Electric Utility workshop (March 21, 1991)

Courtesy: The Dow Chemical Co./Midland/ MI48674/USA

PRETREATMENT FOR REVERSE OSMOSIS SYSTEMS

The purpose of pretreatment is to optimize performance and increase the life expectancy of the reverse osmosis system. Selection of the proper pretreatment will maximize efficiency and membrane life by minimizing fouling, scaling, and membrane degradation. Pretreatment of feedwater must be a total system approach for continuous and reliable operation. In order to select the best scheme for treating a water supply, one must know the feed source for the reverse osmosis system and the type of reverse osmosis membrane which will be used. It is also critical to obtain a recent water analysis for the feed source. If the feed source is a surface water, then it is necessary to have a complete water analysis for the various seasons of the year.

HOW TO START UP AN RO MEMBRANE SYSTEM

Proper startup of reverse osmosis (RO) water treatment systems is essential to prepare the membranes for operating service and to prevent membrane damage due to overfeeding or hydraulic shock. Following the proper startup sequence also helps ensure that system operating parameters conform to design specifications so that system water quality and productivity goals can be achieved.

Before initiating system startup procedures, membrane pretreatment, loading of the membrane elements, instrument calibration, and other system checks should be completed. Following is the recommended RO system startup sequence:

Typical Start Up Sequence (Fig. A X. 1)

(a) Before initiating the startup sequence, thoroughly rinse the pre-treatment section to flush out debris and other contaminants. Follow the specific rinse guidelines for your system type (e.g., brackish water, seawater, etc.) and configuration. Continue rinsing for the specified period without letting the feed enter the elements.

(b) Check all valves to ensure that settings are correct. The feed pressure control and

concentrate control valves should be fully open.

(c) Use low pressure water at a low flow rate to flush the air out of the elements and pressure vessels. Flush at a guage pressure of 30 to 60 psi (2—4 bar). All permeate and concentrate flows should be directed to an approved waste collection drain during flushing.

(d) During the flushing operation, check all pipe connections and valves for leaks. Tighten connections where necessary.

(e) After the system has been flushed for a minimum of 30 minutes, close the feed pressure control valve.

(f) Ensure that the concentrate control valve is open.

(g) Slowly crack open the feed pressure control valve (feed pressure should be less than 60 psig).

(h) Start the high pressure pump.

(i) Slowly open the feed pressure control valve, increasing the feed pressure and feed flow rate to the membrane elements until the design concentrate flow is reached. Continue to send all permeate and concentrate flows to an approved waste collection drain.

(j) Slowly close the concentrate control valve until the ratio of permeate flow to concentrate flow approaches, but does not exceed, the design ratio (recovery). Continue to check the system pressure to ensure that it does not exceed the upper design limit.

(k) Repeat steps "i" and "j" until the design permeate and concentrate flows are obtained.

(l) Calculate the system recovery and compare it to the system's design value.

(m) Check chemical additions of acid, scale inhibitor, and sodium metabisulphite (if used). Measure feedwater pH.

(n) Check the Langelier Saturation Index (LSI) or the Stiff & Davis Stability Index (S&DSI) of the concentrate by measuring pH, conductivity, calcium hardness, and

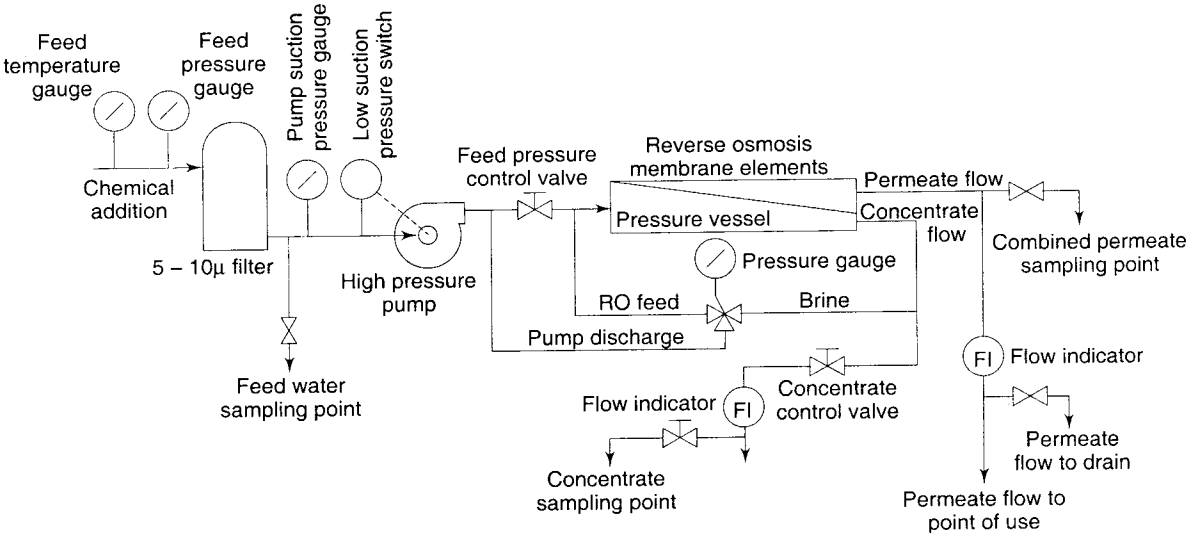

Fig. A X. 1 *Typical RO system.*

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alkalinity levels and then making the necessary calculations.

(o) Allow the system to run for one hour.

(p) Take the first reading of all operating parameters.

(q) Read the permeate conductivity from each pressure vessel and indentify any vessels that do not conform to performance expectations (e.g., vessels with leaking O-rings or other evidence of malfunction).

(r) Draw samples of feedwater, concentrate, and combined system permeate and analyze sample constituents.

(s) Compare system performance to design values.

(t) Confirm proper operation of mechanical and instrumental safety devices.

(u) Switch the permeate flow from drain to the normal operating position.

(v) Lock the system into automatic operation.

(w) Use the initial system performance information obtained in steps "p" through "r" as a reference for evaluating future system performance. Measure system performance regularly during the first 24 to 48 hours of operation to ensure proper performance during this critical initial stage.

Source: Technical Bulletin (# 609-01020-1292 AMS) of Film Tec Corporation, a wholly owned subsidiary of The Dow Chemical Company.

Courtesy: The DOW Chemical Co./Midland/MI 48674/USA

FT 30 REVERSE OSMOSIS MEMBRANE SPECIFICATIONS

The FT30® reverse osmosis membrane gives excellent performance for a wide variety of applications including low pressure tapwater purification, single pass seawater desalination, chemical processing, and waste treatment. This membrane exhibits high rejection at low pressures with very stable long-term operation.

Solute Rejection (approximate) 2000 ppm Solute, 225 psi (1.6 MPa), 77°F (25°C), pH 7 (unless otherwise noted).

Solute	MW	Rejection (%)
Sodium fluoride NaF[1]	42	98
Sodium cyanide NaCN (pH 11)	49	97
Sodium chloride NaCl	58	98
Silica SiO_2 (50 ppm)	60	98
Sodium bicarbonate $NaHCO_3$	84	98
Sodium nitrate $NaNO_3$	85	93
Magnesium chloride $MgCl_2$	95	98
Calcium chloride $CaCl_2$	111	99
Magnesium sulfate $MgSO_4$	120	99
Nickel sulfate $NiSO_4$	155	99
Copper sulfate $CuSO_4$	160	99
Formaldehyde	30	35
Methanol	32	25
Ethanol	46	70
Isopropanol	60	90
Urea	60	70
Lactic acid (pH 2)	90	94
Lactic acid (pH 5)	90	99
Glucose	180	98
Sucrose	342	99
Chlorinated pesticides (traces)	–	99

Operating Limits

Membrane Type	Thin-Film Composition Polyamide
Maximum Operating Pressure	1000 psi (6.9 MPa)
Maximum Operating Temperature	113°F (45°C)
Free Chlorine Tolerance	< 0.1 ppm
pH Range:	
Continuous operation	2—11
Short-term (30 min.), cleaning	1—12

Source: Technical Bulletin (# 609-01020-1292 AMS) of Film Tech Corporation, a wholly owned subsidiary of the DOW Chemical Co.

Courtesy: The Dow Chemical Co./Midland/MI 48674/USA

1. Fluoride rejection is strongly pH dependent (about 75% at pH 5, 50% at pH 4, 30% at pH 3.5 and 0% below pH3). 2. FT30 membrane is available in a wide variety of spiral wound configurations.

CLEANING PROCEDURES FOR THIN-FILM MEMBRANES

The following are general recommendations for cleaning a typical thin-film membrane*

Cleaning Requirements

In normal operation, the membrane in reverse osmosis elements can become fouled by mineral scale, biological matter, colloidal particles, and insoluble organic constituents. Deposits build up on the membrane surfaces during operation until they cause loss in water output, loss of salt rejection, or both.

Elements should be cleaned whenever the normalized water output rate drops by 10 per cent, the salt content in the product water rises noticeably, or the differential pressure (DP) increases by 15 per cent from the reference conditions. (The flow rate and DP established during the first 25 to 48 hours of operation.)

DP should be measured and recorded across each stage of the array of pressure vessels. If the brine channels within the element become fouled, the DP will increase.

It should be noted that the water output rate will drop if feedwater temperature decreases. This is normal and does not indicate membrane fouling. A malfunction in the pretreatment, pressure control, or pump can cause a drop in product water output or an increase in salt passage. If a problem is observed, these causes should be considered. The element may not require cleaning.

Safety Precautions

1. In using any chemicals indicated in subsequent sections, follow accepted safety practices. Consult the chemical manufacturer for detailed information about safety, handling, and disposal.
2. When preparing cleaning solutions, insure that all chemicals are dissolved and well mixed before circulating the solutions to the elements.
3. It is desirable to flush the elements with good quality chlorine free water (20°C minimum temperature) after cleaning. RO product water is recommended, but prefiltered feed water may be used provided that there are no corrosion problems in the piping system. Care should be taken to operate initially at reduced flow and pressure to flush the bulk of the cleaning solution from the elements before resuming normal operating pressures and flows. Despite this precaution, cleaning chemicals will be present on the permeate side following cleaning. Therefore the permeate must be diverted to drain for at least 10 minutes, or until the water is clear when starting up after cleaning.
4. During recirculation of cleaning solutions, the temperatures must not exceed 50°C at pH 2–10, 35° at pH 10–11, and 30°C at pH 11–12.
5. For elements greater than six inches in diameter, the flow direction during cleaning must be the same as during normal operation to prevent element telescoping. The same procedure is recommended also for smaller elements.

Equipment for cleaning is illustrated on the following page.

CLEANING SYSTEM FLOW

Suggested Equipment

The equipment for cleaning is shown in the Cleaning System Flow diagram (Fig. A X. 2). The pH of cleaning solutions used with FILMTEC elements can be in the range of 1 to 12 and there-

* Filmtec FT 30 elements of the Dow Chemical Co., USA

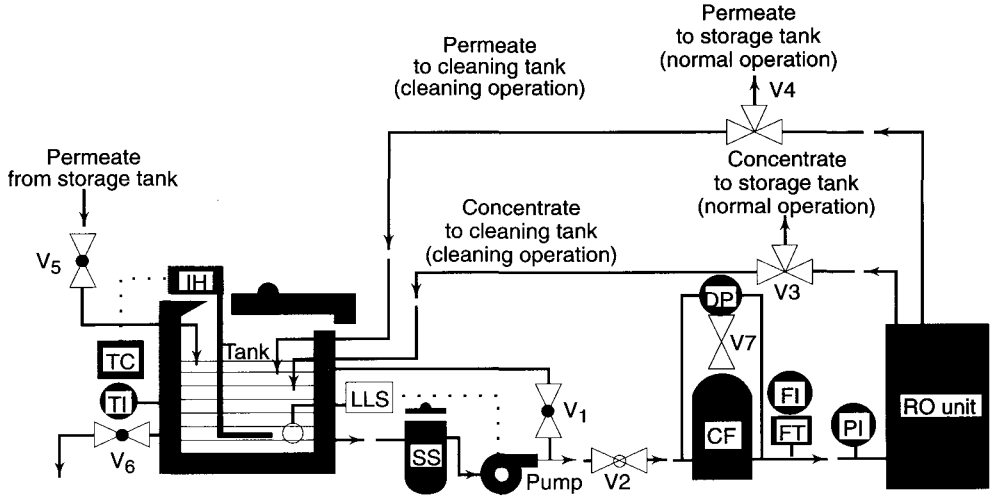

Fig. A X.2

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Tank	Chemical Mixing Tank, polypropylene or FRP	**DP**	Differential Pressure Gauge
IH	Immersion Heater (may be replaced by cooling coil for some site locations)	**FI**	Flow Indicator
TI	Temperature Indicator	**FT**	Flow Transmitter (optional)
TC	Temperature Control	**PI**	Pressure Indicator
LLS	Lower Level Switch to shut off pump	**V1**	Pump Recirculation Valve, CPVC
SS	Security Screen—100 mesh	**V2**	Flow Control Valve, CPVC
PUMP	Low Pressure Pump, 316 SS or non-metallic composite	**V3**	Concentrate Valve, CPVC 3-way valve
CF	Cartridge Filter, 5–10 micron polypropylene with PVC, FRP, or SS housing	**V4**	Permeate Valve, CPVC 3-way valve
		V5	Permeate Inlet Valve, CPVC
		V6	Tank Drain Valve, PVC, or CPVC
		V7	Purge Valve, SS, PVC, or CPVC

fore non-corrosive materials should be used in the cleaning system.

1. The mixing tank should be constructed to polypropylene or fiberglass reinforced plastic (FRP). The tank should be provided with a removable cover and a temperature gauge.

   The cleaning procedure is more effective when performed at an elevated temperature and it is recommended that the solution be maintained at 45–50°C (max.) at pH 2–10, 35°C at pH 10–11, and 30°C at pH 11–12. It is not recommended to use a cleaning temperature below 15°C because of the very slow cleaning rate at low temperatures. In addition, chemicals such as sodium lauryl sulfate might precipitate at low temperatures. Cooling may also be required in certain parts of the world, so heating/cooling requirements must be considered during the design.

   A rough rule of thumb in sizing a cleaning tank is to use approximately the empty pressure vessel volume and then add the volume of the feed and return hoses or pipes.

   For example, to clean eight 8-inch diameter pressure vessels with six elements per vessel, the following calculations would apply.

A. Volume in Vessels

$V_1 = \pi r^2 \times L =$

$$= 3.14 \frac{(4\text{ in})^2}{(144\text{ in}^2/\text{ft}^2)} (20\text{ ft}) (7.48\text{ gal/ft}^3)$$

$V_1 = 52$ gals/vessel

$V_8 = 52 \times 8 = 416$ gals

B. Volume in Pipes, assume 50 ft length total 4" SCH 80 pipe

$V_p = \pi r^2 L$

$$= 3.14 \frac{(1.91\text{ in})^2}{(144\text{ in}^2/\text{ft}^2)} (50\text{ ft}) (7.48\text{ gal/ft}^3)$$

$= 30$ gals

$V_{ct} = V_8 + V_p = 416 + 30 = 446$

Therefore, the cleaning tank should be about 450 gals.

2. The cleaning pump should be sized for the flows and pressures given in Table A X. 1 making allowances for pressure drops in the piping and across the cartridge filter. The pump should be constructed of 316 SS or non-metallic composite polyesters.
3. Appropriate valves, flow meters, and pressure gauge should be installed to adequately control the flow. Service lines may be either hard piped or portable hoses. In either case, the flow rate should be a moderate 10 ft/sec or less.

Cleaning Elements *In-Situ*

There are six steps in the cleaning of elements.

1. **Mix** cleaning solution.
2. **Low flow pumping**. Pump mixed, preheated cleaning solution to the vessel at conditions of low flow rate (about half of that shown in Table A X. 1) and low pressure to displace the process water. Use only enough pressure to compensate for the pressure drop from feed to concentrate. The pressure should be low enough that essentially no permeate is produced. A low pressure minimizes redeposition of direct on the membrane. Dump the concentrate, as necessary, to prevent dilution of the cleaning solution.

Table A X. 1 *Recommended feed flow rate per pressure vessel during high flow rate recirculation*

Feed Pressure* (psig)	Element Diameter (in)	Feed Flow Rate per PV (gpm)
20–60	2.5	3–5
20–60	4	8–10
20–60	6	16–20
20–60	8	30–40
20–60	11	60–80

* Dependent on number of elements in pressure vessel

3. **Recycle**. After the process water is displaced, cleaning solution will be present in the concentrate stream. Then recycle the concentrate to the cleaning solution tank and allow the temperature to stabilize.
4. **Soak**. Turn the pump off and allow the elements to soak. Sometimes a soak period of about 1 hour is sufficient. For difficult fouling an extended soak period is beneficial; soak the elements overnight for 10–15 hours. To maintain a high temperature during an extended soak period, use a slow recirculation rate (about 10 per cent of that shown in Table A X. 1).
5. **High flow pumping**. Feed the cleaning solution at the rates shown in Table A X. 1 for 30–60 minutes. The high flow rate flushes out the foulants removed from the membrane surface by the cleaning. If the elements are heavily fouled, which should never happen, a flow rate which is 50 percent higher than shown in Table A X. 1 may aid cleaning. At higher flow rates

excessive pressure drop may be a problem. The maximum recommended pressure drops are 20 psi per element or 60 psi per multi-element vessel, whichever value is more limiting.

6. Flush out. Prefiltered raw water can be used for flushing out the cleaning solution, unless there will be corrosion problems (e.g., stagnant seawater will corrode stainless steel piping). To prevent precipitation, the minimum flush out temperature is 20°C.

Additional notes: check the pH during acid cleaning. The acid is consumed when it dissolves inorganic precipitates. So if the pH increases more than 0.5 pH units, add more acid.

If the system has to be shut down for a period of 24 hours to one week, the elements should be stored in a one per cent solution (by weight) of sodium metabisulfite. For longer periods, the best medium for storage is an aqueous solution with 18 percent (by weight) propylene glycol and 1.0 percent (by weight) sodium metabisulfite. This solution also provides protection from freeze damage.

Table A X.2 *Simple cleaning solutions for FT30 membrane*

CLEANER	0.1% (W) NaOH 0.1% (W) Na-EDTA pH 12, 30°C max.	0.1% (W) NaOH 0.05% (W) Na-DSS pH 12, 30°C max.	1.0% (W) STP 1.0% (W) TSP 1.0% (W) Na-EDTA	0.2% (W) HCl	0.5% (W) H_3PO_4	2.0% (W) Citric Acid	0.2% (W) NH_2SO_3H	1.0% (W) $Na_2S_2O_4$
FOULANT								
Inorganic Salts (for example, $CaCO_3$, $CaSO_4$, $BaSO_4$)				BEST	OK	OK	OK	
Metal Oxides (for example, iron)					GOOD		OK	GOOD
Inorganic Colloids (silt)		GOOD						
Silica	OK							
Biofilms	BEST	GOOD	GOOD					
Organics	OK	GOOD	GOOD					

1. (W) denotes weight per cent of active ingredient.
2. Foulant chemical symbols in order used: $CaCO_3$ is calcium carbonate, $CaSO_4$ is calcium sulphate, $BaSO_4$ is barium sulphate.
3. Cleaning chemical symbols; in order used: NaOH is sodium hydroxide; Na-EDTA is the tetrasodium salt of ethylene diamine tetraacetic acid and is available from The Dow Chemical Company under the trade name VERSENE®; Na-DSS is sodium salt of dodecylsulphate; STP is sodium triphosphate ($Na_5P_3O_{10}$); TSP is trisodium phosphate ($Na_3PO_4 \bullet 12H_2O$); HCl is hydrochloric acid; H_3PO_4 is phosphoric acid; citric acid is $C_3H_4(OH)(CO_2H)_3$; NH_2SO_3H is sulphamic acid; $Na_2S_2O_4$ is sodium hydrosulphite.

Source: Technical Bulletin (# 609–23010–1292 AMS) of Filmtec Corporation, a wholly owned subsidiary of the DOW Chemical Company

Courtesy: The DOW Chemical Co./Midland/MI 48674/USA

Multi-Array Systems

For multi-array (tapered) systems, the flushing and soaking operations can always be done simultaneously in all arrays. High flow recirculation, however, should be carried out separately for each array, so the flow rate is not too low in the first array or too high in the last. This can be accomplished either by using one cleaning pump and operating one array at a time, or using a separate cleaning pump for each array.

Cleaning Chemicals

Table A X.2, lists suitable cleaning chemicals. Acid cleaners and alkaline cleaners are the standard cleaning chemicals. The acid cleaners are to remove inorganic precipitates including iron, while the alkaline cleaners are to remove organic fouling including biological matter. Sulphuric acid should not be used for cleaning because of the risk of calcium sulfate precipitation.

Preferably reverse osmosis permeate should be used for the cleaning solutions but prefiltered raw water will also work in most cases. The raw water can be highly buffered, so more acid or hydroxide may be needed with raw water to reach the desired pH level, which is about 2 for acid cleaning and about 12 for alkaline cleaning.

PRODUCING BOILER FEEDWATER IN TEXAS

In 1985, Texas Utilities Generating Company installed a reverse osmosis unit at its Monahans, Texas facility as part of a water treatment system to supply boiler feedwater to the power plant. The RO unit, built by Technical Purification Inc., utilizes FILMTEC® FT30 RO membrane to produce 130,000 gpd of < 6 ppm TDS water from a well water supply of 450 ppm dissolved solids, which includes 0.5 ppm iron and 28.5 ppm silica (SiO_2).

After some 40,000 hours of operation it was found that the addition of the RO unit to the water treatment system at the plant dramatically reduced the frequency and cost of regenerating the ion exchange beds. Previously, the operators regenerated the ion exchange resins every 164,000 gallons of water production. With the addition of the RO unit ahead of the ion exchange beds, they could now produce 10,000,000 gallons of ultrapure water before regenerating the beds. That meant they now only had to regenerate three times a year instead of two to three times a week. Because of this, the use of overtime labor at the plant was almost entirely eliminated.

The data from this and other plants show the thin-film composite membrane is superbly suited for boiler feed applications because of its high flux, salt rejection, and silica rejection characteristics. Experience at the Monahans plant showed that FILMTEC membranes consistently provided flux rates of 90 gpm or more, greater than 98.7% salt rejection, and 98.8% silica rejection.

FACTORS AFFECTING RO MEMBRANE PERFORMANCE

Reverse osmosis (RO) technology can be a complicated subject, particularly without an understanding of the specific terminology that describes various aspects of RO system operation and the relationships between these operating variables.

Here follow some of these key terms and a brief overview of the factors that affect the performance of RO membranes, including pressure, temperature, feedwater salt concentration, permeate recovery, and system pH.

Definitions

Recovery—the percentage of membrane system feedwater that emerges from the system as product water or "permeate." Membrane system design is based on expected feedwater quality and recovery is fixed through initial adjustment of valves on the concentrate stream. Recovery is often fixed at the highest level that maximizes

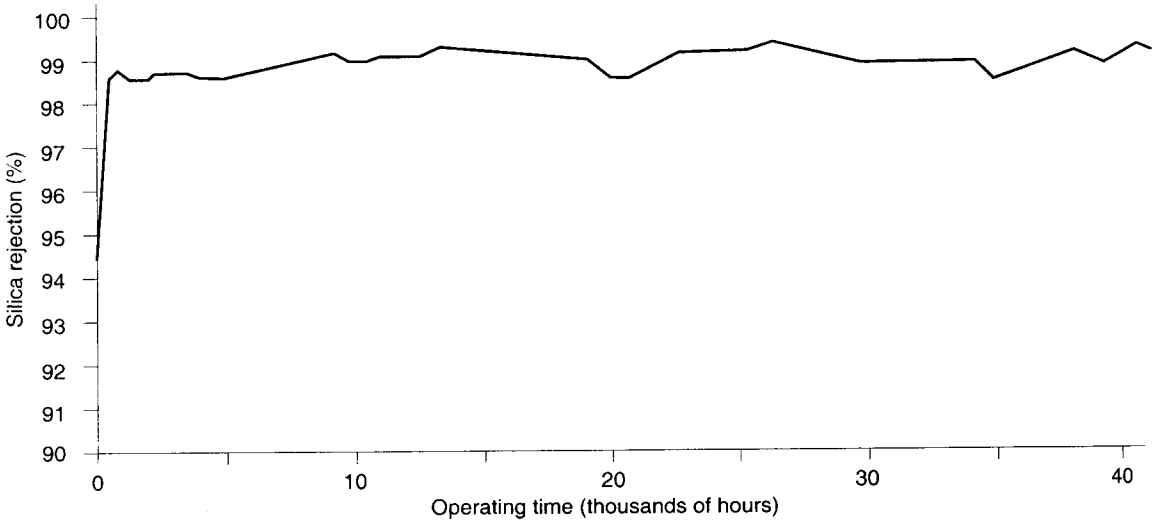

Fig. A X. 3

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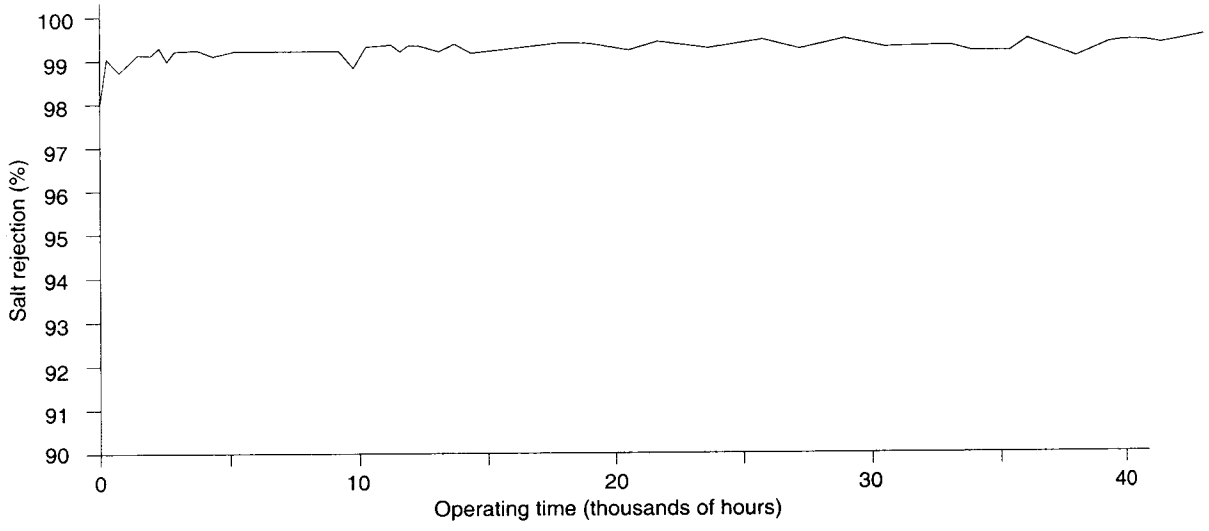

Fig. A X. 4

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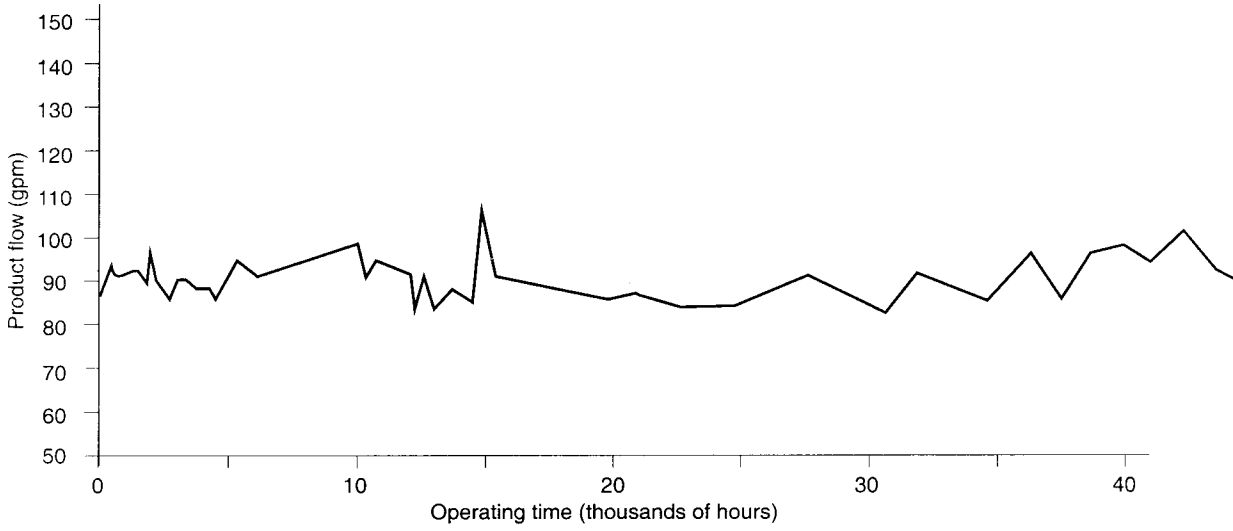

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Fig. A X. 5

Source: *Technical Bulletin (# 609-30030-393 AMS) of Filmtec Corporation, a wholly owned subsidiary of The DOW Chemical Company.*

Courtesy: *The DOW Chemical Co./Midland/MI 48674/USA*

permeate flow while preventing precipitation of super-saturated salts within the membrane system.

Rejection—the percentage of solids concentration removed from system feedwater by the membrane.

Passage—the opposite of "rejection," passage is the percentage of dissolved constituents (contaminants) in the feedwater allowed to pass through the membrane.

Permeate—the purified product water produced by a membrane system.

Flow—Feed flow is the rate of feed-water introduced to the membrane element, usually measured in gallons per minute (gpm). Concentrate flow is the rate of flow of non-permeated feedwater that exits the membrane element. This concentrate contains most of the dissolved constituents originally carried into the element from the feed source. It is usually measured in gallons per minute (gpm).

Flux—the rate of permeate transported per unit of membrane area, usually measured in gallons per square foot per day (gfd).

Dilute solution—purified water solution, RO system product water.

Concentrated solution—brackish water solution such as RO system feedwater.

Effect of Pressure

Feedwater pressure affects both the water flux and salt rejection of RO membranes. Osmosis is the flow of water across a membrane from the dilute side toward the concentrated solution side. Reverse osmosis technology involves application of

pressure to the feedwater stream to overcome the natural osmotic pressure. Pressure in excess of the osmotic pressure is applied to the concentrated solution and the flow of water is reversed. A portion of the feedwater (concentrated solution) is forced through the membrane to emerge as purified product water on the dilute solution side (please see Figure A X. 6)

As shown in Fig. A X. 7, water flux across the membrane increases in direct relationship to increase in feedwater pressure. Increased feedwater pressure also results in increased salt rejection but, as Fig. A X. 7 demonstrates, the relationship is less direct than for water flux.

Because RO membranes are imperfect barriers to dissolved salts in feedwater, there is always some salt passage through the membrane. As feedwater pressure is increased, this salt passage is increasingly overcome as water is pushed through the membrane at a faster rate than salt can be transported.

However, there is an upper limit to the amount of salt that can be excluded via increasing feedwater pressure. As the plateau in the salt rejection curve (Fig. A X. 7) indicates, above a certain pressure level, salt rejection no longer increases and some salt flow remains coupled with water flowing through the membrane.

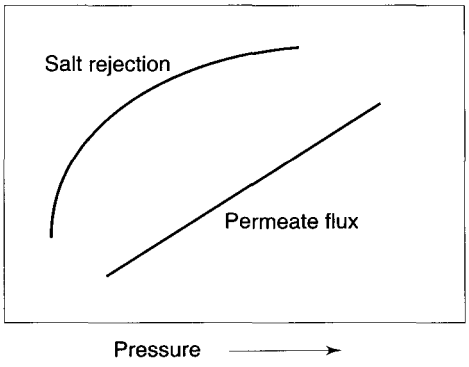

Fig. A X. 7 *Effect of feedwater pressure on flux and salt rejection.*
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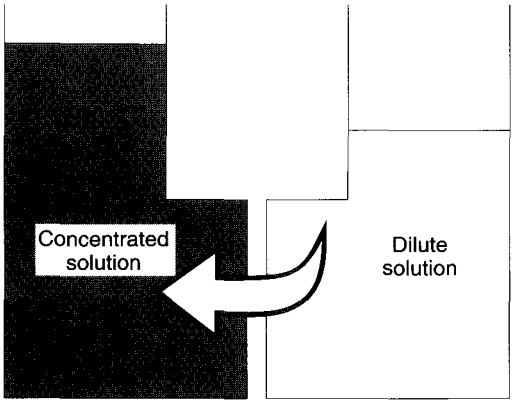
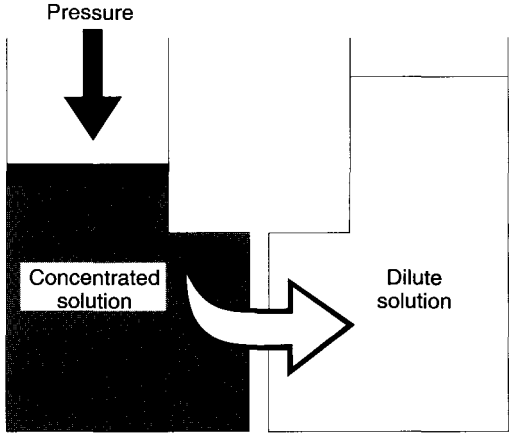
Effect of temperature

As Fig. A X.8 demonstrates, membrane productivity is very sensitive to changes in feedwater



OSMOSIS

Water diffuses through a semipermeable membrane toward region of higher concentratin to equalize solution strength.At equilibrium, the height difference between the concentrated and dilute sides corresponds to the osmotic pressure differential between the two sides.



REVERSE OSMOSIS

Applied pressure in excess of osmotic pressure reverses water flow direction.Hence, the term "reverse osmosis."

Fig. A X. 6 *Overview of Osmosis/Reverse Osmosis.*
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temperature. As water temperature increases, water flux increases almost linearly, due primarily to the higher diffusion rate of water through the membrane.

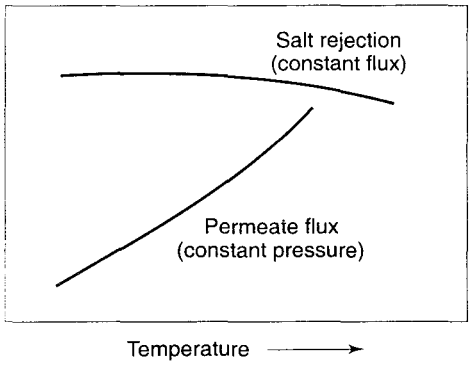

Fig. A X. 8 *Effect of feedwater temperature on flux and salt rejection.*

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Increased feedwater temperature also results in lower salt rejection or higher salt passage. This is due to a higher diffusion rate for salt through the membrane.

The ability of a membrane to tolerate elevated temperatures increases operating latitude and is also important during cleaning operations because it permits use of stronger, faster cleaning processes. This is illustrated by the comparison of the pH and temperature ranges of FILMTEC® FT30 thin-film composite membrane and a cellulose acetate (CA) membrane in Fig. A X. 9.

Effect of Salt Concentration

Osmotic pressure is a function of the type and concentration of salts or organics contained in feedwater. As salt concentration increases, so does osmotic pressure. The amount of feedwater driv-

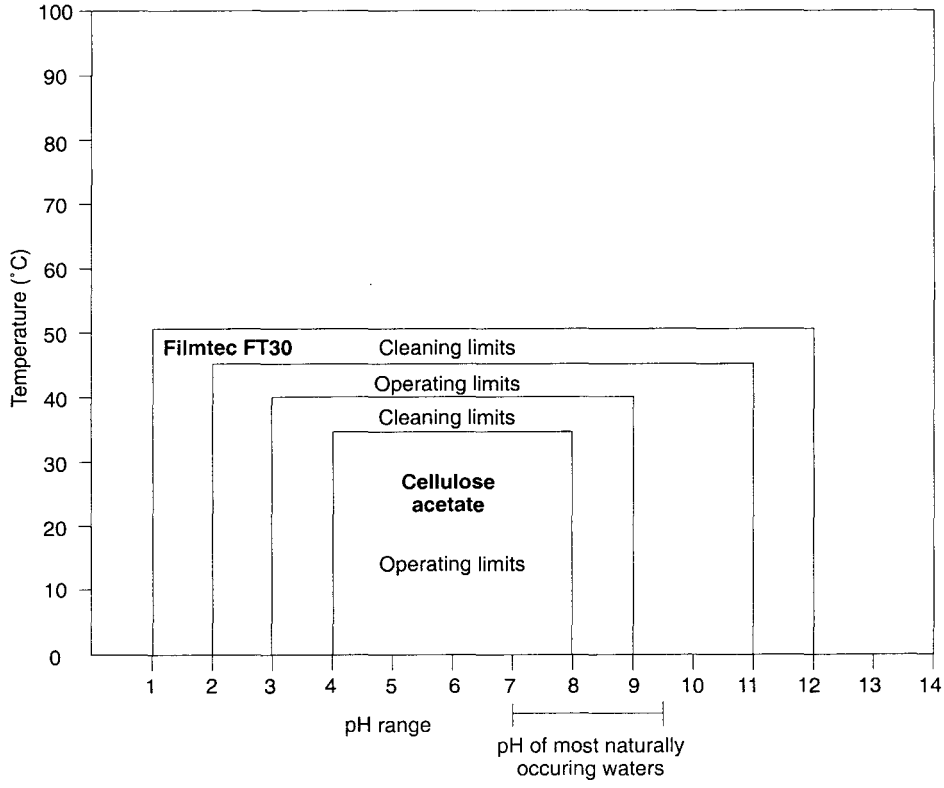

Fig. A X. 9 *Comparison of Operating and Cleaning parameters for FT30 thin-film composite membrane and a CA membrane.*

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ing pressure necessary to reverse the natural direction of osmotic flow is, therefore, largely determined by the level of salts in the feedwater.

Figure A X. 10 demonstrates that, if feed pressure remains constant, higher salt concentration results in lower membrane water flux. The increasing osmotic pressure offsets the feedwater driving pressure. Also illustrated in Fig. A X. 10 is the increase in salt passage through the membrane (decrease in rejection) as the water flux declines.

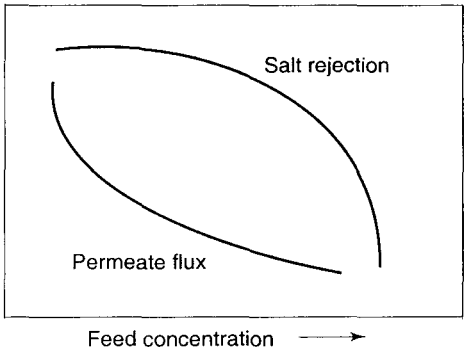

Fig. A X. 10 *Effect of increasing salt concentration on flux and salt rejection.*

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Effect of Recovery

As shown in Fig. A X. 6, reverse osmosis occurs when the natural osmotic flow between a dilute solution and a concentrated solution is reversed through application of feedwater pressure. If percentage recovery is increased (and feedwater pressure remains constant), the salts in the residual feed become more concentrated and the natural osmotic pressure will increase until it is as high as the applied feed pressure. This can negate the driving effect of feed pressure, slowing or halting the reverse osmosis process and causing permeate flux and salt rejection to decrease and even stop (please see Fig. A X. 11).

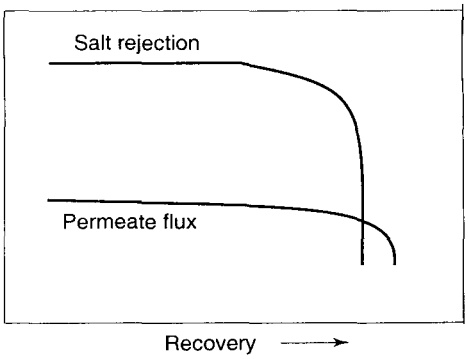

Fig. A X. 11 *Effect of increased recovery on flux and salt rejection.*

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The maximum per cent recovery possible in any RO system usually depends not on a limiting osmotic pressure, but on the concentration of salts present in the feedwater and their tendency to precipitate on the membrane surface as mineral scale. The most common sparingly soluble salts are calcium carbonate (limestone), calcium sulphate (gypsum), and silica. Chemical treatment of feedwater can be used to inhibit mineral scaling.

Effect of pH

The pH tolerance of various types of RO membranes can vary widely. Thin-film composite membranes such as FILMTEC FT30 membrane are typically stable over a broader pH range than cellulose acetate (CA) membranes and, therefore, offer greater operating latitude (please see Fig. A X. 9)

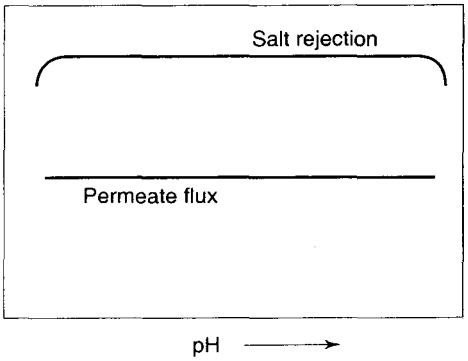

Fig. A X. 12 *Effect of feedwater pH on water flux and salt rejection.*

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Membrane salt rejection performance depends on pH. Water flux may also be affected. Figure A X. 12 shows that water flux and salt rejection for FILMTEC FT 30 membranes are essentially stable over a broad pH range.

As illustrated in Fig. A X. 9, the stability of FT30 membrane over a broad pH range permits stronger, faster, and more effective cleaning procedures to be used compared to CA membranes.

Source : Technical Bulletin (# 609-01010-1292 AMS) of Filmtec Corporation, a wholly owned subsidiary of the DOW Chemical Company

Courtesy: The DOW Chemical Co./Midland/MI 48674/USA

DECHLORINATING FEEDWATER

Chlorine (Cl_2) has been used for many years to treat municipal and industrial water and wastewaters because of its biocidal action. The effectiveness of Cl_2 is dependent on the Cl_2 concentration, time of exposure, and the pH of the water. Chlorine is used for the disinfection of potable water where a residual chlorine concentration near 0.5 mg/l is commonly used. In a water treatment scheme, fouling of water intake lines, heat exchangers, sand filters, etc., may be prevented by maintaining a free Cl_2 residual of 0.5-1.0 mg/l.

When thin-film composite membrane is used in the reverse osmosis (RO) process, the RO feed must be dechlorinated to prevent oxidation of the membrane. If dechlorination upsets occur and if corrected in a timely manner, membrane damage can be minimized.

Definition and Chemistry

$$Cl_2 + H_2O \rightleftharpoons HOCl + H^+ + Cl^-$$

Residual Chlorine

Refers to the total amount of chlorine ("combined" and "free available" chlorine) remaining in the water at the time of measurement.

Combined Available Chlorine

Refers to one or more of the family of chlorine-ammonia compounds, called chloramines, resulting from the reaction of chlorine with ammonia compounds present in water.

Free Available Chlorine

This form is actually hypochlorous acid, hypochlorite ion or a mixture of the two, depending on pH and temperature. Free chlorine is usually present after sufficient chlorine has been added to satisfy the demand of ammonium ions present.

Engineering Considerations

Chlorine is most commonly available as hypochlorites of calcium and sodium or chlorine gas. Capital cost, operating cost and water chemistry will be the predominate factors in deciding which type of system to use.

If the product water from an RO system is chlorinated, care must be exercised to insure that the chlorine does not diffuse back into the membrane. Air breaks, check valves, etc. should be employed appropriately.

Chloramines

Studies have demonstrated that chlorine reacts with organic compounds present in drinking water to produce a variety of trihalomethanes (THMs). Toxicological investigations have implicated certain THMs as carcinogens. The EPA has established a maximum THM contaminant level of 100 ppb for drinking water. To meet this requirement, many water facilities have sought to reduce levels of THMs. This can be done by using chloramine as a disinfectant. Chloramine does not generate THMs. However, considerable controversy has arisen concerning the efficiency of chloramine disinfection and its potential health effects.

In aqueous solution, HOCl reacts with ammonia to form inorganic chloramines in a series of stepwise reactions.

$$HOCl + NH_3 \rightleftharpoons NH_2Cl \text{ (monochloramine)} + H_2O$$

$$HOCl + NH_2Cl \rightleftharpoons NHCl_2 \text{ (dichloramine)} + H_2O$$

$$HOCl + NHCl_2 \rightleftharpoons NCl_3 \text{ (nitrogen trichloride)} + H_2O$$

These reactions are governed primarily by pH and chlorine-to-nitrogen weight ratio.

Dechlorination

Residual chlorine can be reduced to harmless chlorides by chemical reducing agents. Discussion follows on two of the most common proven techniques.

Activated Carbon

Chlorine reacts with activated carbon as follows:

$$C + 2Cl_2 + 2H_2O \longrightarrow 4HCl + CO_2$$

The activated carbon should be replaced or regenerated periodically.

Sodium Metabisulphite

$$Na_2S_2O_5 + H_2O \longrightarrow 2NaHSO_3$$

$$NaHSO_3 + HOCl \longrightarrow HCl + NaHSO_4$$

In theory, 1.37 lbs of sodium metabisulphite will remove 1.0 lb of free chlorine. In practice, however 3.0 lbs of sodium metabisulphite are normally used to remove 1.0 lb of chlorine from brackish water. For seawater, more sodium metabisulphite may be required when dissolved oxygen is present.

Sodium metabisulphite has a usual shelf life of 4-6 months under cool, dry storage conditions. The solution life, however, varies with concentration as follows.

Solution (wt %)	Maximum Solution Life
2	3 days
10	1 week
20	1 month
30	6 months

The dechlorination reaction requires mixing to insure completion. Therefore, static mixers should be utilized and the sodium metabisulphite injected prior to the cartridge filters.

Note:

Filmtec FT30 membrane has a chlorine tolerance of up to 1000 ppm-hourse before noticeable loss of salt rejection is observed.

Though FT30 has a 300 000 ppm-hours tolerance for chloramine, it is possible that free Cl_2 will be present since chloramines are produced by adding ammonia to chlorine. Inasmuch as this free chlorine can be damaging to the membrane, dechlorination should still be considered.

Source: Technical Bulletin (# 609–22010–1292 AMS) of FILMTEC Corporation, a wholly owned subsidiary of the DOW Chemical Company.

Courtesy: The DOW Chemical Co./Midland/MI 48674/USA

Appendix XI

Pump Availability Considerations

A chief goal of the power generating industry is to increase the readiness for service, which is usually referred to as "availability", of its generating equipment as a whole. A considerable potential for improvement of availability in different areas of the US-market was recently identified. Fig. A XI. 1 shows that boiler feed pumps, for instance, account for 1.7 percent loss of generating unit availability; Fig. A XI. 2 shows as a function of generating unit size, the annual cost of such losses, per percent availability loss.

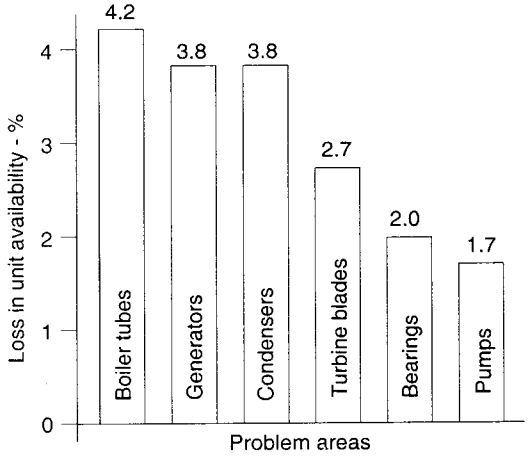


Fig. A XI. 1 *Coal Plant Cycle–Problem Areas (EPRI CS-3158, Power Plant Feed Pumps–The State of the Art).*
Courtesy: Sulzer Brothers Ltd./Winterthur/ Switzerland

PUMP SYSTEM REDUNDANCY

Improvement of the availability of any type of equipment can be considered for all practical purposes, as a joint effort between OEM's and utilities. Ultimate success depends to a large extent on the degree of cooperation between the parties concerned. The connection between single pump availability and generating unit availability for a specific pump arrangement can be expressed initially by a redundancy RD, which is the total available multiple of 100 percent pump generating capacity per unit. Thus, redundancy RD is a measure of available pump standby capacity; for instance, RD = 2 expresses a pump standby capacity of 100 per cent. With increasing redundancy, the inherent availability of a specific pump arrangement in terms of availability increases, but so do the basic investment costs. Therefore, the pump arrangement must be optimized with due consideration of both savings from increased availability and costs from increased investment.

On the basis of probability considerations, the generating unit capability of two different arrangements can differ, even though both arrangements have the same RD. For example, a 4×50 percent arrangement has a greater availability than a 2×100 percent arrangement, although the redundancy of both arrangements is the same. This

is because the flexibility of an arrangement increases, in general, with an increased number of elements, thus providing the possibility to interconnect these elements or even do repair work on them.

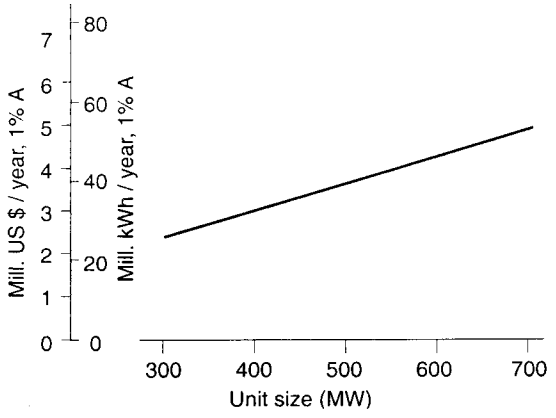


Fig. A X1. 2 *Cost per year of one per cent availability change, based on:*
- 8000 (h/year) generating hours per unit
- 0.09 US $/KWh average sales price per KWh
Courtesy:Sulzer Brothers Ltd./Winterthur/ Switzerland

The pump arrangement availability (AA) can be evaluated for various cases with the same or different RD values by applying the general formula for the probability of success P for parallel systems:

$$P = \sum_{r=m}^{n} \frac{n!}{r!(n-r)!} A^r (1-A)^{n-r} \qquad (1)$$

where

n = number of elements (pumps) of the redundant system

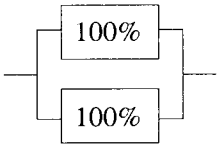
m = number of elements (pumps) working in parallel to achieve 100 % generating capacity

A = single element availability.

The following three examples illustrate the application of this relationship:

Example 1. Parallel Full-Capacity Pumps

For this case, the following values apply:



- RD = 2
- A = 0.95 = single element (pump) availability
- m = 1 (of 2)
- Identical components

Then

$$AA = \frac{2!}{1!(2-1)!} A(1-A)^{2-1} + \frac{2!}{2!(2-2)!} A^2 (1-A)^{2-2} \qquad (1a)$$

$$= 2A - 2A^2 + A^2$$

Thus, $AA = 2A - A^2$

Evaluating for this case,

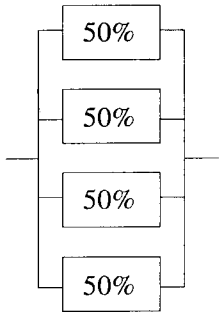
$AA = 2 \times 0.95 - 0.95^2$

$= 0.9975$

The probability of outage is therefore 25 in 10,000.

Example 2. Four Half-Capacity Pumps in Parallel

For the same values of most parameters, this arrangement gives a different result:



- RD = 2
- A = 0.95
- m = 2 (of 4)
- Identical components

From Equation (1)

$AA = 6A^2 - 8A^3 + 3A^4$

Using parameters for this case gives

$AA = 6 \times 0.95^2 - 8 \times 0.95^3 + 3 \times 0.95^4$

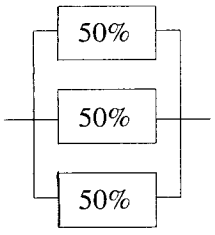
$= 5.415 - 6.859 + 2.4435$

$= 0.9995$

Here, the probability of outage is reduced to 5 in 10,000.

Example 3. Three Half-Capacity Pumps in Parallel

For three pumps of 50 per cent capacity each in parallel, the following applies:



- $RD = 1.5$
- $A = 0.95$
- $m = 2$ (of 3)
- Identical components

From Equation (1),

$$AA = 3A^2 - 2A^3$$

Evaluating this case gives

$$AA = 3 \times 0.95^2 - 2 \times 0.95^3$$
$$= 2.7075 - 1.71475$$
$$= 0.99275$$

Here, an outage probability of 72.5 in 10,000 results.

Figure A XI. 3 shows redundancies for different pump arrangements with respect to their possible combination.

DEFINITION OF AVAILABILITY

Equipment availability (A) is defined as the probability that a unit is in operating condition at any given time. It can be expressed generally as a ratio of reliability and maintainability data to give the percentage of maximum possible operating time within a given period:

$$A = \frac{MTBF}{MTBF + MDT} \times 100\ (\%) \qquad (2)$$

where

A = availability

$MTBF$ = mean time between failures, in hours

MDT = mean downtime, in hours

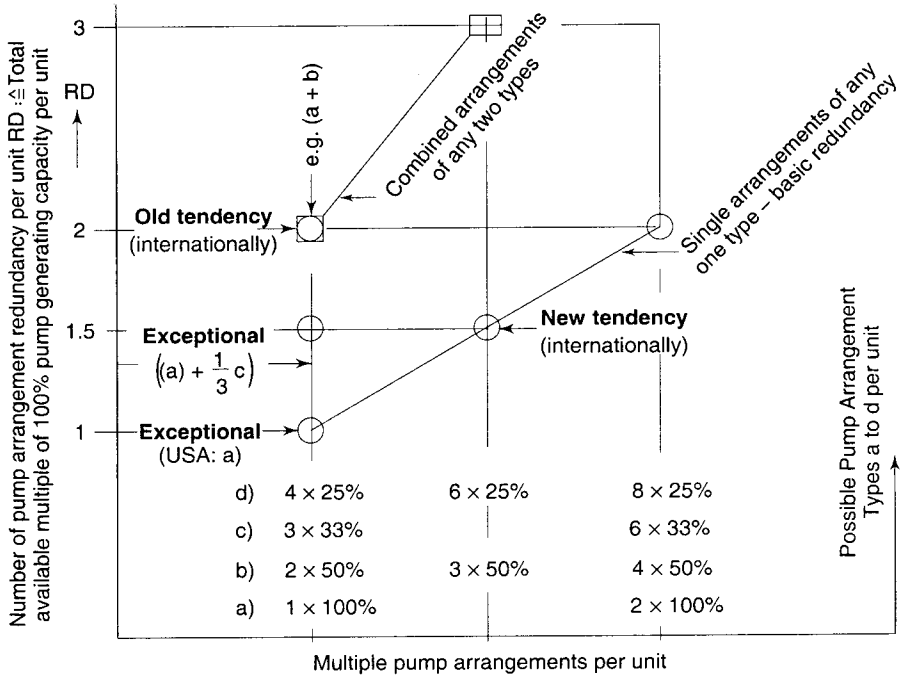


Fig. A XI.3 *Boiler feed pump redundancy as a function of arrangement per unit, for fossil-fuel fired power plants.*

Courtesy : Sulzer Brothers Ltd./Winterthur/Switzerland

MDT expresses the maintainability of a component, and is a qualitative feature for the performance of all maintenance activities.

MTBF is the measure most frequently used to express equipment reliability, representing the quality of a system or unit without maintenance, for design review purposes. The probability that a system or unit will work satisfactorily for a given period of time without maintenance, based on the assumption that the respective failure rate does not change with age, is usually expressed by the following relationship:

$$R = e^{-t/MTBF} \qquad (3)$$

where

R = reliability or probability of successful operation for a time t

e = natural logarithm base

t = time period being considered, in hours

MTBF = mean time between failures, in hours

Figure A XI. 4 presents the more detailed definitions required to establish values for availability.

It also combines the various definitions used in literature for availability. Equations are given for the availability of a unit (A_{unit}) and for a BFP alone (A_{ppe}).

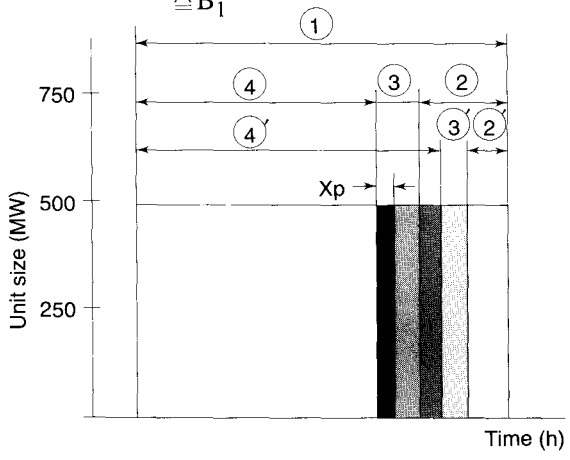
The expression for availability of a generating unit consists of two parts, as shown in Fig. A XI. 4.

$$A_{Unit} = \overbrace{\left(1 - \frac{②}{①}\right)}^{\text{Part 1}} \cdot \overbrace{\left(1 - \frac{③}{①-②}\right)}^{\text{Part 2}} = \frac{④}{①} \qquad (4)$$

$$A_{Unit} = \overbrace{\left(1 - \frac{②}{①}\right)}^{\triangleq \text{ Planned outage}} \quad \overbrace{\left(1 - \frac{③}{①-②}\right)}^{\triangleq \text{ Forced outage}} = \frac{④}{①}$$

Or the condition ②′ ≤ ②it can be defined for the pump only:

$$A_{PPe} = \overbrace{\left(1 - \frac{③'}{①-②'}\right)}^{\triangleq B_2} = \frac{④'}{①-②'} = \frac{④'}{④'+③'}$$



In Equation 4, part 1 concerns planned outages, and Part 2 concerns forced outages.

① Period Hours ≙ 365 × 24 = 8760

② Unit Planned Outage Hours

③ Unit Forced Outage Hours ≙ $\sum_{X_A}^{X_z} X$, with X_A, X_z ≙ Unit Components

④ Unit Operating Hours ≙ Unit Availability

②′ Equivalent Ppe Planned Outage Hours (must be quoted together with A_{ppe})

③′ Equivalent Ppe forced Outage Hours ≙ B2 ≙ Mean downtime (MDT)

④′ Ppe Operating Hours ≙ Ppe Availability ≙ mean time between failures (MTBF)

B_1 Reference Time

x_p = f (③′ RD, No. of Pumps) ≙ Ppe Contribution to Loss of Unit Availability

RD ≙ Number of Pump Arrangement Redundancy Per Unit

e.g.: 1 × 100 % → *RD* = 1
3 × 50% → *RD* = 1.5
1 × 100 % + 2 × 50% → RD = 2

Fig. A XI. 4 *Availability definitions (See also Fig. A XI.3). Courtesy: Sulzer Brothers Ltd./Winterthur/Switzerland*

If the equivalent planned-outage hours attributed to the pump, ②′, are less than or equal to the planned-outage hours of the unit ②, the pump availability is given by Part 2 of Equation (4), or:

$$App_e = \left(1 - \frac{③'}{①-②'}\right) = \frac{④'}{①-②'} = \frac{④'}{④'+③'} \quad (5)$$

where the various terms are defined in Fig. A XI. 4

When calculating generating unit availability, only the pump contribution x_p to the loss of unit availability must be considered of the equivalent pump forced outage hours ③′, with x_p being a function of the redundancy and the number of pumps. The unit forced outage hours ③ are the sum of the x-values of the different generating unit components, e.g. boiler, turbine, pumps, etc. Availabilities of components are to be evaluated and guaranteed based on their respective equivalent component forced outage hours. An equivalent time is the time required for either planned outages, or, for forced outages, for rectification of respective faults. Both are calculated strictly in line with OEM's instructions and standardized component exchange times, as indicated in Fig. A XI. 5.

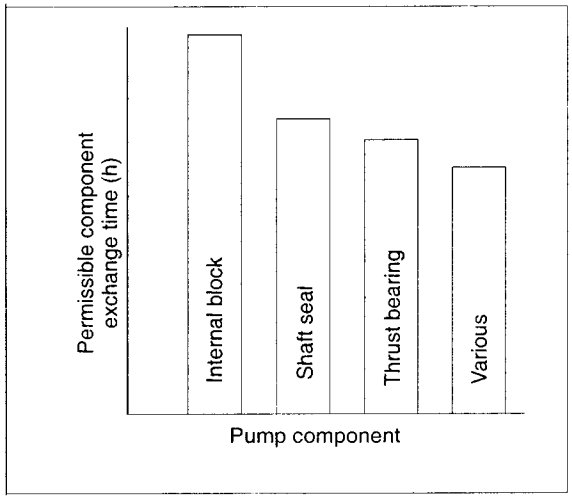


Fig. A XI. 5 *Standardized permissible pump component exchange times .*
Courtesy: Sulzer Brothers Ltd./Winterthur/ Switzerland

The extent to which equipment is entered into availability considerations is subject to negotiations between the parties concerned at the time of signing a contract. Feasible alternatives are

- Complete pump unit, including booster, auxiliary equipment and driver
- Main feed pump only

An example for a possible extent of supply for availability considerations is given in Fig. A XI. 6

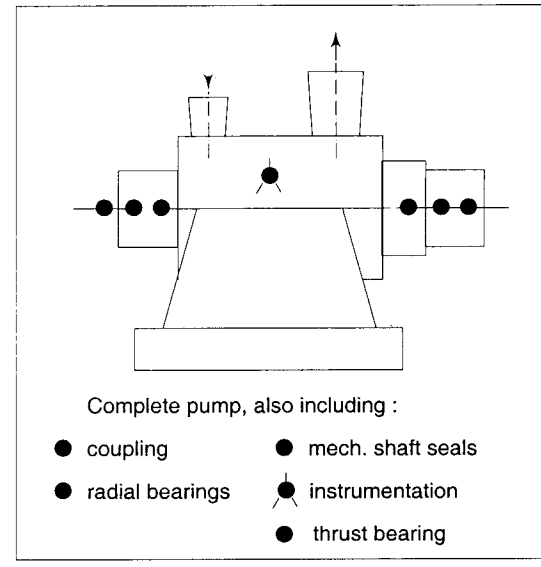


Fig. A XI. 6 *Main feed pump supply for availability A.*
Courtesy: Sulzer Brothers Ltd./Winterthur/ Switzerland

APPROPRIATE MEASURES TO IMPROVE GENERATING UNIT AVAILABILITY

To improve the availability of power plant equipment, the following measures must be taken jointly by the OEM's and the utilities that operate pumps:

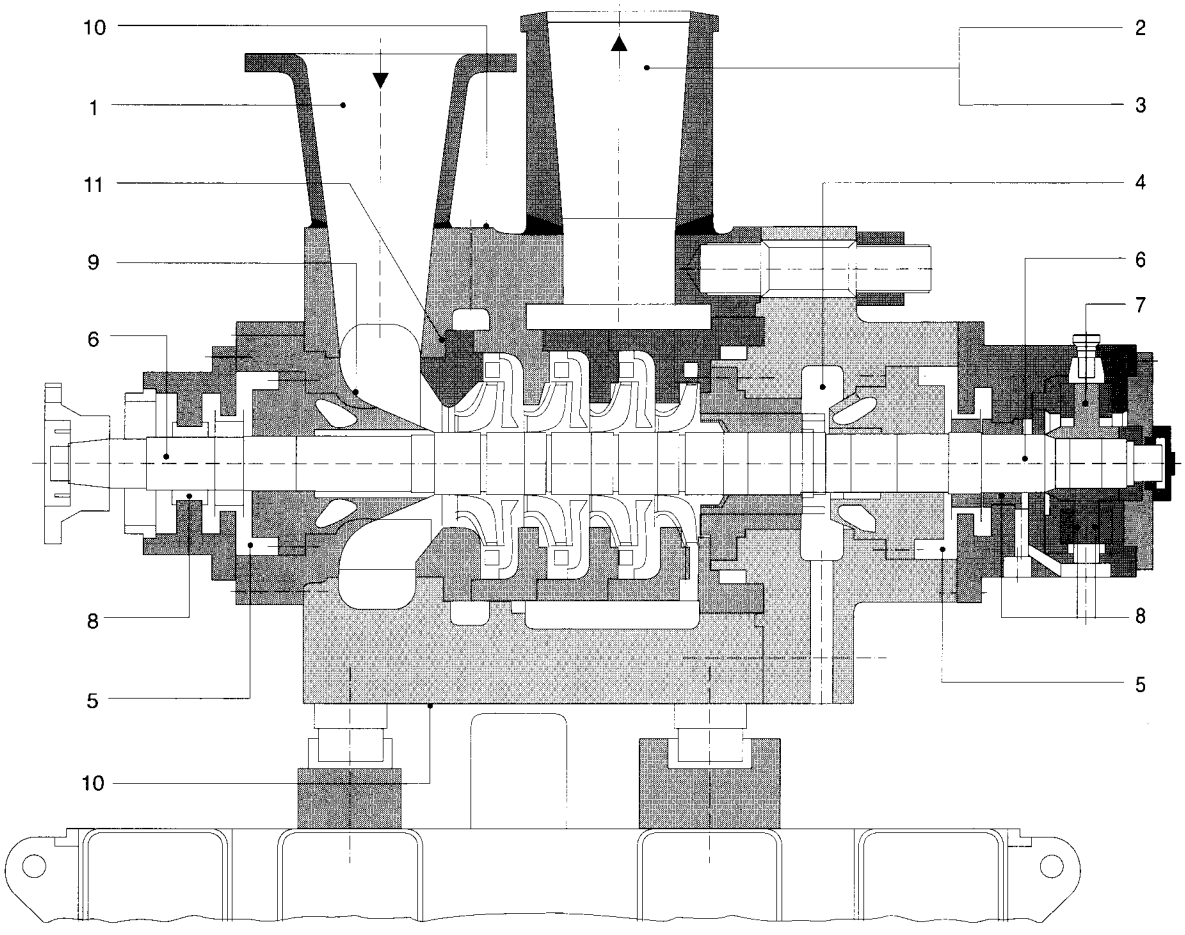
Careful Assessment of Pump Reliability:

The effects of various sources must be assessed in terms of effects on pump reliability.

(a) Pump design features
(b) Complementary purchased pump components
(c) Auxiliary equipment

Predictive Maintenance:

- Monitoring of principal functional parameters, as shown in Fig. A XI. 7 and their integrating into a continuous monitoring and diagnostic system.



1; 2. Differential head	(2)	7. Axial rotor displacement	(1)
3. Flow quantity	(2)	8. Bearing temperature	(1)
4. Balancing water flow	(1)	9. Cavitation noise/pressure pulsation	(1)
5. Seal leakage	(2)	10. Δ T top/bottom	(1)
6. Shaft vibration	(1)	11. Static seal leakage	(2)

Fig. A XI. 7 *Pump leading functional parameters for predictive maintenance purposes, with relative ranking of importance of feature: (1) = 1st importance; (2) = 2nd importance.*
Courtesy: Sulzer Brothers Ltd./Winterthur/Switzerland

Preventive Maintenance

- Periodically scheduled planned outages, with intervals determined by input from both predictive maintenance and experience.

Recording and immediate analysing of outages

Maintenance of appropriate standby service capacity–redundancy

Ensuring of feedback of site experience into design and development

Checking of instruction manuals for compliance with practical requirements

Plant operations strictly in accordance with OEM's erection, maintenance and operation instructions.

Source : *Improved Performance and Availability of Boiler Feed Pumps through Appropriate design Measures and Retrofits —D. Florjancic, A. Simon, G. Eichhorn [SBL] & S. Pace (EPRI).*

Courtesy : *Sulzer Brothers Ltd: /Pump Division /Winterthur/Switzerland*

Appendix XII

NDT of Rotating Equipment Through Vibration Monitoring

Powerplants operate with a vast array of large & small moving machineries:

Steam & gas turbines, generators, ID & FD fans, blowers, crushers, pulverizers, BFW pumps and so on.

Nondestructive testing (NDT) is used to pick up and analyze the vibration signature of these rotating equipment as an effective diagnostic technique for condition monitoring and preventive maintenance of these equipment to prevent their premature breakdown.

MACHINES AND VIBRATION

An ideal machine would produce no vibration at all because all energy would be channelled into the job of work to be done. In practice, vibration occurs as a by-product of the normal transmission of cyclic forces through the mechanism. Machine elements react against each other and energy is dissipated through the structure in the form of vibration. (Fig. A XII. 1)

A good design will produce low levels of inherent vibration. As the machine wears, however, foundations settle, and parts deform, subtle changes in the dynamic properties of the machine begin to occur. Shafts become misaligned, parts begin to wear, rotors become unbalanced, and clearances increase. All of these factors are reflected in an increase in vibration energy, which, as it is dissipated throughout the machine, excites resonances and puts considerable extra dynamic loads on bearings. Cause and effect reinforce each other, and the machine progresses towards ultimate breakdown.

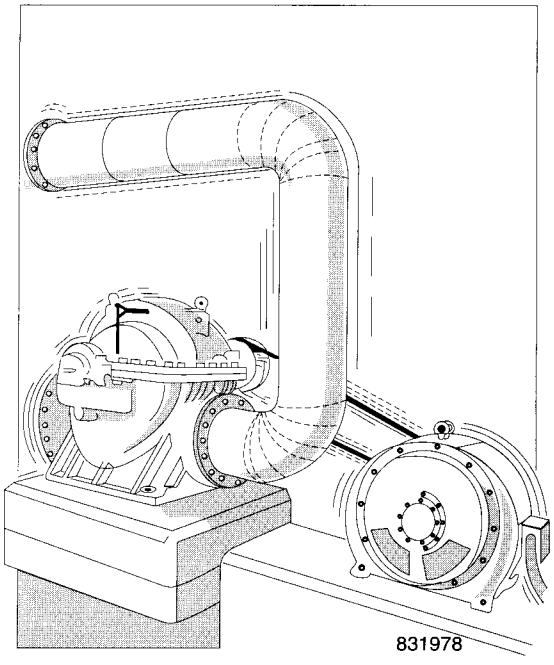


Fig. A XII. 1

In the past, experienced plant engineers have been able to recognise by touch and hearing whether a machine was running smoothly or whether a fault was developing. This cannot be relied upon any longer for at least two reasons: The days of plant attendants with an oily rag and a grease gun at hand who tend "their" machines are gone. The "personal" relationship between man and machine is not economically feasible and not even required because machines are expected to run automatically with only occasional attention from service personnel. Secondly, most modern machinery runs so fast that many tell–tale vibrations occur at such a high frequency that instruments are needed to detect and measure them.

VIBRATION INDICATES MACHINE CONDITION

As we have seen, vibration is normally a destructive by-product of the force transmission through a machine which provokes wear and accelerates breakdown. Machine elements which constrain these forces, for example bearing housings, are usually accessible from the outside of the machine so that vibration resulting from the excitation forces can be measured at these points. (Fig. A XII. 2).

As long as the excitation forces are constant, or vary within certain limits, the vibration level measured will also be constant and vary within similar limits. Furthermore, for most machines, the vibration has a *typical* level and its frequency spectrum has a *characteristic* shape when the machine is in good condition. This frequency spectrum, a plot of vibration amplitude against frequency, is known as the vibration signature of the machine, and is obtained by frequency–analyzing the machine vibration–signal.

When faults begin to develop, the dynamic processes in the machine change and some of the forces acting on machine parts are also changed—thereby influencing the vibration level and the shape of the vibration spectrum.

The fact that vibration signals carry much information relating to running condition of machines is the basis for using regular vibration measurement and analysis as an indicator of machine health trends and the need for maintenance.

INSTRUMENTATION SYSTEMS FOR CONDITION-BASED MAINTENANCE

Instrumentation systems for vibration monitoring can be broadly classified into three levels of sophistication. This classification reflects their speed of operation, how early they can detect faults and how accurately the time of ultimate failure can be predicted.

A Basic System

A simple vibration monitoring scheme can be obtained by combining a straightforward pocket-sized vibration meter to measure overall vibration levels, a stroboscope to measure machine speed and relative motion of machine parts and a headset of listen to machine vibration (Fig. A.XII.3). Overall vibration levels can be compared with general standards or established reference values for each machine. A stroboscope "freezes" reciprocating or rotating machine elements, allowing the human eye to observe their motion. A headset connected to the vibration meter links the operator directly with the internal workings of his machine. These simple techniques are discussed further on pages: 1290-1292.

A Portable Fault Detection/Diagnostics System

Earlier fault detection, combined with diagnosis and breakdown prediction, is possible with a system which performs frequency analysis. Ideally, the system should be portable, capable of withstanding adverse environmental conditions and have the ability to store all measured data. It should also possess the diagnostic capabilities to perform on-the-spot frequency analysis and spectrum plot-out at each monitoring point. Currently recorded spectra can

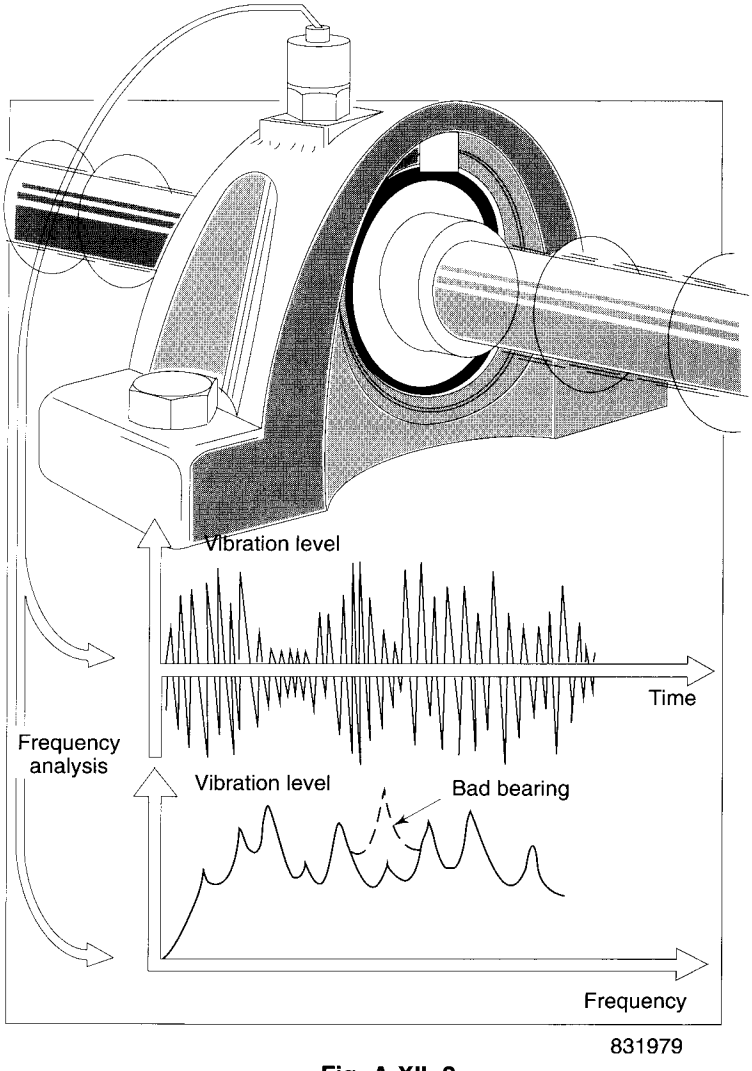


Fig. A XII. 2

then be automatically compared with stored reference spectra to reveal increases in individual frequency components. In-built diagnostics allow further analysis of any suspected fault, leading to an earlier solution to the problem.

Computer-based Systems

As the number of monitoring points and complexity of fault detection increases, a computer-based system will be the most economic solution. A typical system will combine the on-the-spot analysis and detection capabilities allied to a portable system with the centralized database and diagnostic capabilities of a computer. Collection of vibration samples from each machine can be organised by the computer on the basis of a measurement route. The route system ensures that each machine is monitored frequently, and in the manner most appropriate to early detection of faults.

A complementary computer-based system uses a tape-recorder (analogue or DAT) to record vibration signals from each machine on the measurement

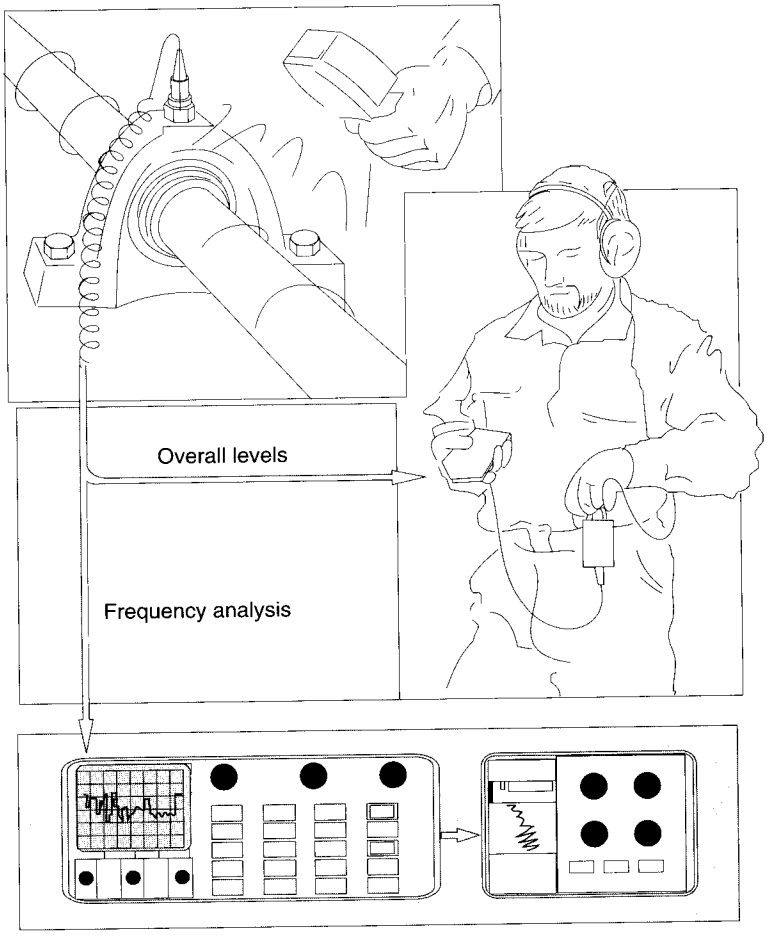


Fig. A XII. 3

route. The measurements are then played back into the computer for post-processing and storage in a central database. Once again, the computer may serve as both a diagnostic tool and a measurement organizer. A major benefit of this method of data collection is that the entire vibration signal is permanently preserved on tape,allowing the signals to be subjected to a wide range of analysis techniques.

Permanent Monitoring

Where the monitored machine is critical to production (and therefore to profit) or where a complete failure of the machine can lead to expensive repairs, permanent monitoring should be considered. Dedicated vibration monitors connected to permanently mounted accelerometers yield instant feedback on changing machine condition. The monitors can activate alarms on detection of excessive vibration levels and if necessary, shut the machine down (Fig. A XII. 4).

THE SIMPLE APPROACH: ONE, TWO, THREE

For those who wish to make a cautious start with vibration measurements for machine condition monitoring, a high-quality, hand-held vibration meter, (Fig. A XII. 5) Ameasuring overall vibration levels, can provide a sound basis for initializing a monitoring program.

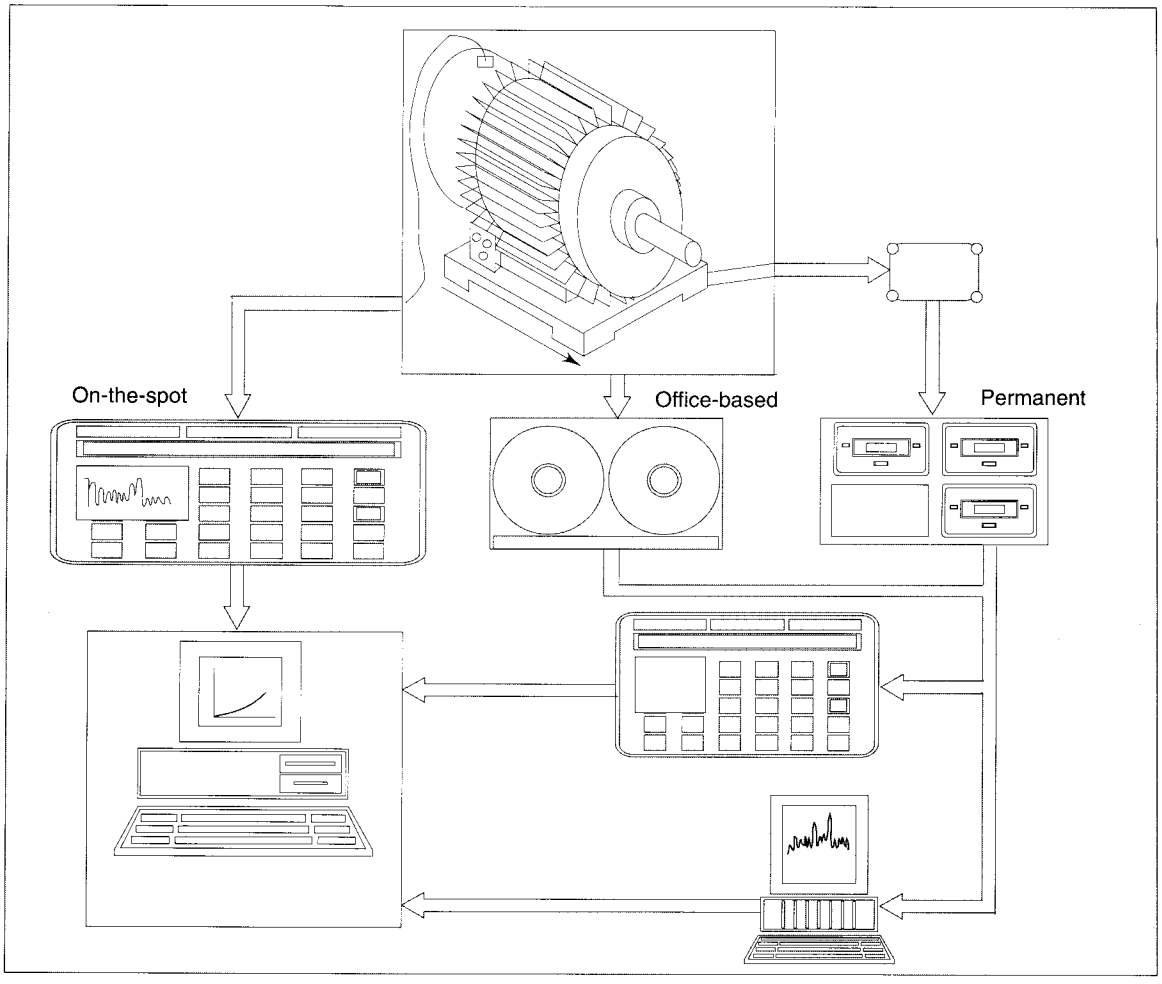


Fig. A XII. 4

Measuring Vibration Levels

A hand-held vibration meter (Fig. A XII. 5) gives a single-digit RMS, max. RMS or Peak level reading of vibratory acceleration or velocity, over selectable frequency ranges. RMS velocity readings can be compared directly with standardised vibration severity criteria values, (see P-1303) to indicate the need for maintenance. Plotting overall levels against time in a trend plot reveals how rapidly machine condition is changing. When the meter is used in conjunction with a pocket computer (Psion Organizer®), the collection and storage of measurements is greatly simplified. Connecting a tape-recorder (analogue or DAT) to the meter, stores the vibration signal for use with a more advanced system at a later date. The wideband meter though is rather limited with respect to early fault detection, diagnosis, and breakdown prediction, when compared to systems using frequency analysis.

In the specific case of rolling element bearings and where vibrations from other sources do not dominate, early warning of bearing deterioration *can be* obtained using the "crest factor" technique. The meter is switched to *simultaneously* measure both the Peak and RMS vibration

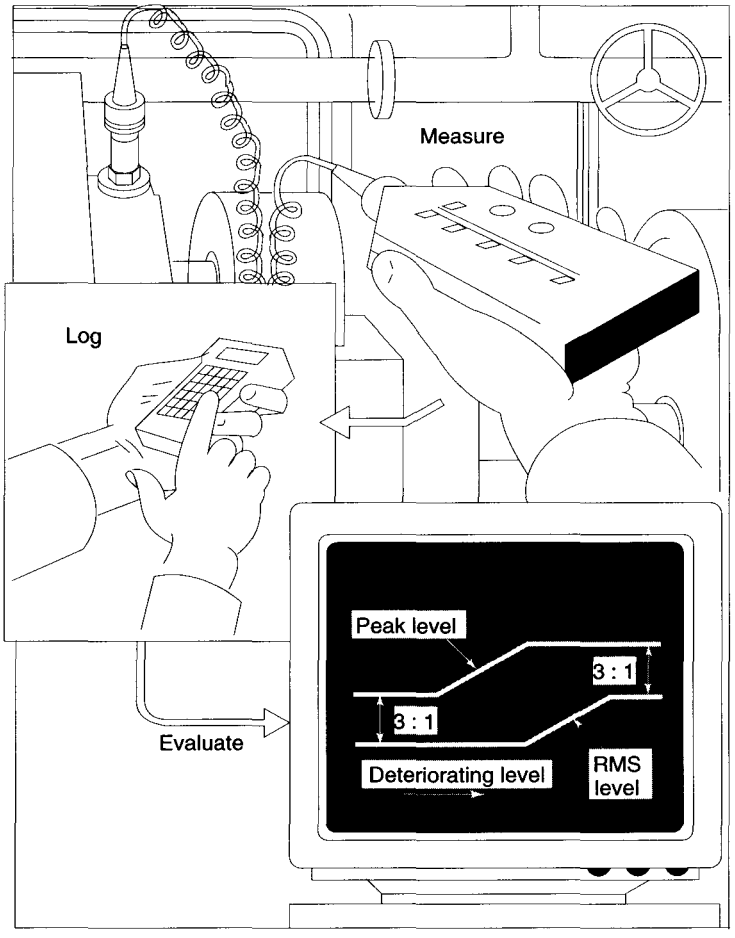


Fig. A XII. 5

levels. When small defects on the balls/rollers and outer and inner races begin to form, they issue high frequency vibration pulses which are measured by the peak detector in the vibration meter. In the early stages, very little change in the RMS level is noted although the peak level increase significantly. This Peak/RMS ratio is called *the crest factor*, and by monitoring it, many rolling element bearing faults can be detected at an early stage of their development.

Listening to Vibration

The machine operator listening to bearing with a screwdriver may seem a totally antiquated method of fault detection, yet the human ear is a perfectly constructed signal analyzer, albeit somewhat lacking in dynamic range. A headset with an integral amplifier connected to the vibration transducer allows the operator to hear how the machine is running (Fig. A XII. 6). Comparing how a machine sounds over a period of time is analogous to comparing frequency spectra, and in the hands of an experienced operator, can be almost as effective.

Looking at Vibration

Finally, there is the question of what we can learn about a machine from visual inspection of its operation? If faults such as misalignment,

unbalance and looseness are allowed to progress, they become visually obvious—no instrumentation is required to detect them. But they could have been detected earlier, if the quality of the visual information was enhanced. A portable stroboscope can "freeze" a rotating component, (Fig. A. XII. 6 top) allowing not alone the speed of rotation to be measured, but also the nature of the rotation. Misaligned shafts may describe non-symmetrical orbits. Looseness may show up as relative movement between the bearing and the housing, an unbalanced rotor can manifest itself in a rocking motion along the length of the rotor.

These and many other faults can be detected by the simple methods outlined here. It should be remembered though, that the more complex the nature of the fault, the more powerful the detection techniques required to locate it.

THE BENEFITS OF FREQUENCY ANALYSIS—EARLY FAULT DETECTION, DIAGNOSIS AND BREAKDOWN PREDICTION

A simple vibration meter, such as the one mentioned in the previous section, measures the

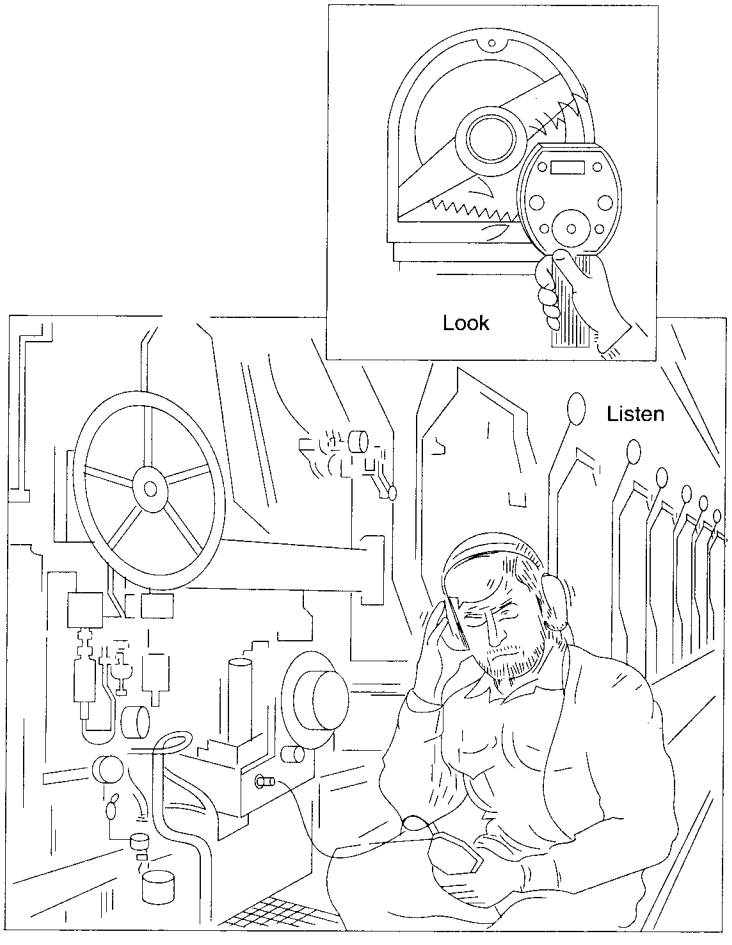


Fig. A XII. 6

overall level of vibration over a wide frequency range. The measured level reflects the vibration amplitude of the dominating frequency component. This is normally the machine rotation speed, and is of course, important to monitor. But when the same vibration signal is frequency-analyzed and the spectrum plotted in graphical form, the level of many more, possibly equally important, frequency components is revealed. These frequency components, which are usually lower in level than that for the rotation speed, *can* result from high excitation forces.

Early Fault-Detection

Figure A XII. 7 illustrates this point. Since the level of the frequency component Ⓑ largely determines the overall vibration level, an increase in the possibly important component Ⓐ can only be detected at an early stage by frequency analysis. Note also that as the analysis bandwidth is reduced, a more detailed spectrum which separates individual peaks is obtained. In general, the narrower the analysis bandwidth, the earlier developing faults can be detected. But on the other hand, the narrower the bandwidth, the longer the analysis takes unless more sophisticated instrumentation is used.

Fault Diagnosis

Not only do level-increases in frequency components give an early indication of faults, but also the frequency at which they occur indicates which machine parts are deteriorating. For each monitoring point, unbalance, misalignment, bearing erosion, gear tooth damage etc. will all have their characteristic frequencies which can be revealed

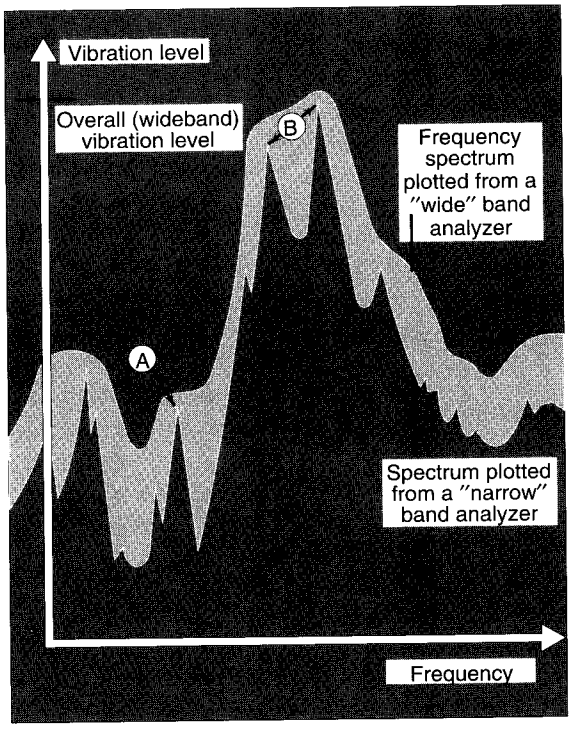


Fig. A XII. 7

with the help of frequency analysis. Trouble-shooting charts are used to illustrate this relationship (see pp: 1308 — 1309).

3D-Plots

A complete overview of the changing nature of a machine's vibration can be obtained by plotting a series of spectra, recorded at fixed time intervals, in a 3-dimensional format (Fig. A XII. 8). The 3D-plot is essentially a trend-graph across the entire frequency spectrum. Analysis of the plot will highlight frequencies where amplitude increases are occurring, and allow direct visual comparison of increases in different areas of the spectrum. Once a potential problem is identified, the measurement interval is decreased to obtain a more quantitative assessment of the specific increases occurring.

Trend Prediction

Plotting the level increase of one or more individual frequency components over a number of periodic measurements, enables level-time trends in the development of faults to be followed. The resulting curves can be extrapolated forward in time to indicate when the condition will reach a danger limit so that maintenance can be scheduled for a convenient date (Fig. AXII.8).

PERMANENT VIBRATION MONITORING OF MACHINERY

A technique which is closely related to the methods of machine monitoring so far discussed is *permanent vibration monitoring.* As the name suggests, permanent monitoring is permanently employed on specific machine(s) to continuously survey their condition (Fig. A XII. 9). Its main purpose is to give early warning of incipient faults and immediate warning of sudden changes in the condition of expensive non-duplicated machinery whose continuous operation is vital to the production process. Fault conditions are detected immediately, or within seconds of occurrence, and trigger alert or alarm signals in the control room allowing the appropriate measures to be taken before catastrophic failure occurs. Such systems are widely used in the power-generation, pulp and paper and petro-chemical industries on turbines, paper machines, feed pumps, gas compressors etc.

What Instruments are Required?

A prime requirement of all permanent monitoring systems is high operational-reliability, long-term stability and immunity to adverse environmental conditions and irregularities which can cause false alarms. They should be of sturdy mechanical design, capable of operating in humid and dustladen conditions. Special "ruggedized" front-end ancillaries such as industrial accelerometers, cables and junction boxes, which can work at high temperatures, are essential requirements. Further, these systems should include an automatic test system to allow the plant operator to immediately check whether the instrumentation is functioning correctly in the event of an alarm.

What should a Permanent Monitoring System Do?

Ideally, it should provide the maximum possible protection for the monitored machine, continuously monitoring each measurement point's overall vibration level and generating alarms when this level exceeds pre-set limits. This should be combined with fully automatic or operator directed cyclical spectrum comparison for each measurement point, generating printed warnings on detection of unacceptable increases within frequency bands.

Overall vibration levels (broadband levels) are continuously monitored over a user-specified frequency range. If preset limits are breached (for example **Minimum**, **Alert**, and **Alarm**), the system can trigger visual or audible alarms. Economical coverage of up to sixteen monitoring points can be achieved by multiplexing the in-

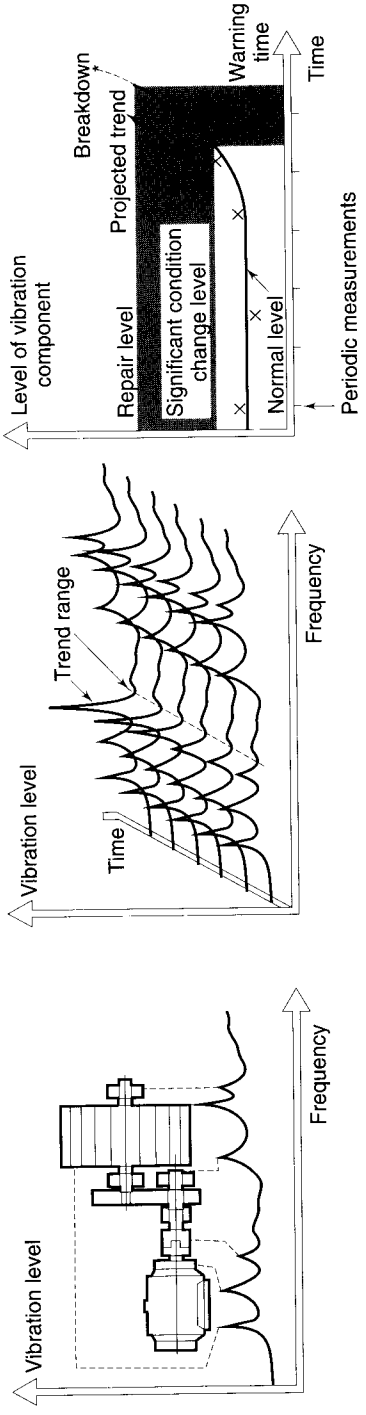

Level of vibration component
Repair level
Significant condition change level
Projected trend
Breakdown
Warning time
Time
Normal level
Periodic measurements
Vibration level
Trend range
Time
Frequency
Vibration level
Frequency

Fig. A XII. 8

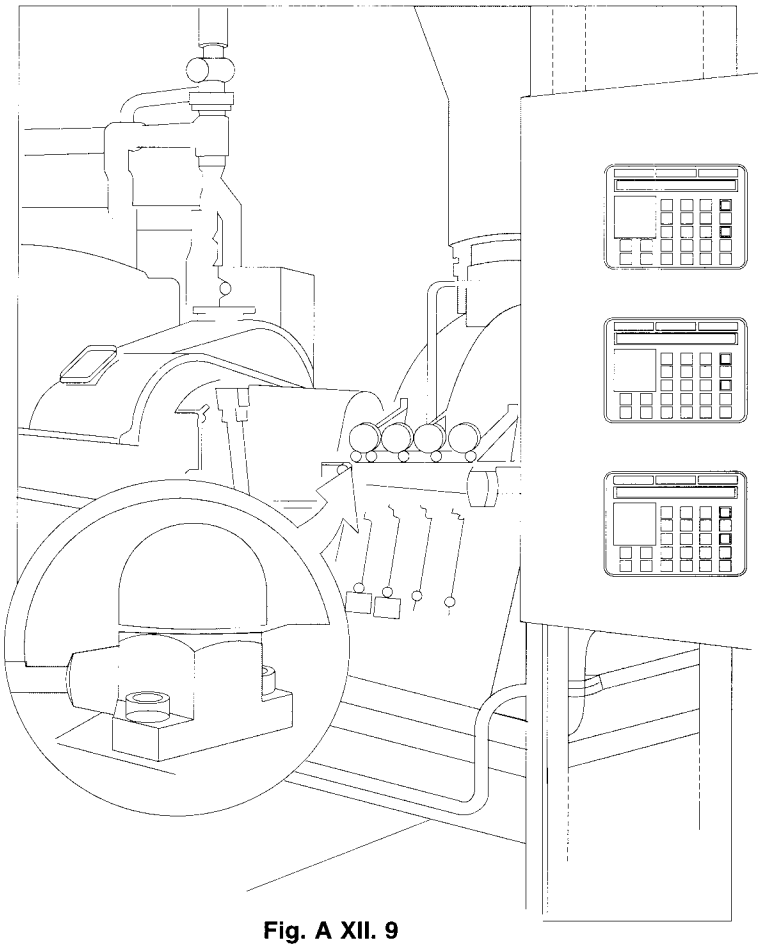


Fig. A XII. 9

puts through a single monitor module. The Multiplexer continuously steps through the chosen channels, dwelling at each channel for a preselected period before automatically moving to the next.

In larger systems, these monitor/multiplexer blocks are connected to a serial data-bus—the system being controlled by an on-line computer (Fig. A XII. 10). The computer, in conjunction with a vibration analyzer can cyclically access each vibration channel, record a frequency spectrum, compare the recorded spectrum with a stored reference spectrum, issue a printed warning on detection of component increases and then step to the next channel, continuously repeating the measurements. Since all reference and fault spectra are stored on disk, the system can also incorporate detection and diagnostic routines such as those discussed earlier.

Special systems are also available for explosive-risk and radioactive areas.

VIBRATION TRANSDUCERS AND MEASUREMENT PARAMETERS

While relative displacement transducers are best for some specific shaft-monitoring applications, seismic transducers which measure absolute vibration are far more suitable for general machine con-

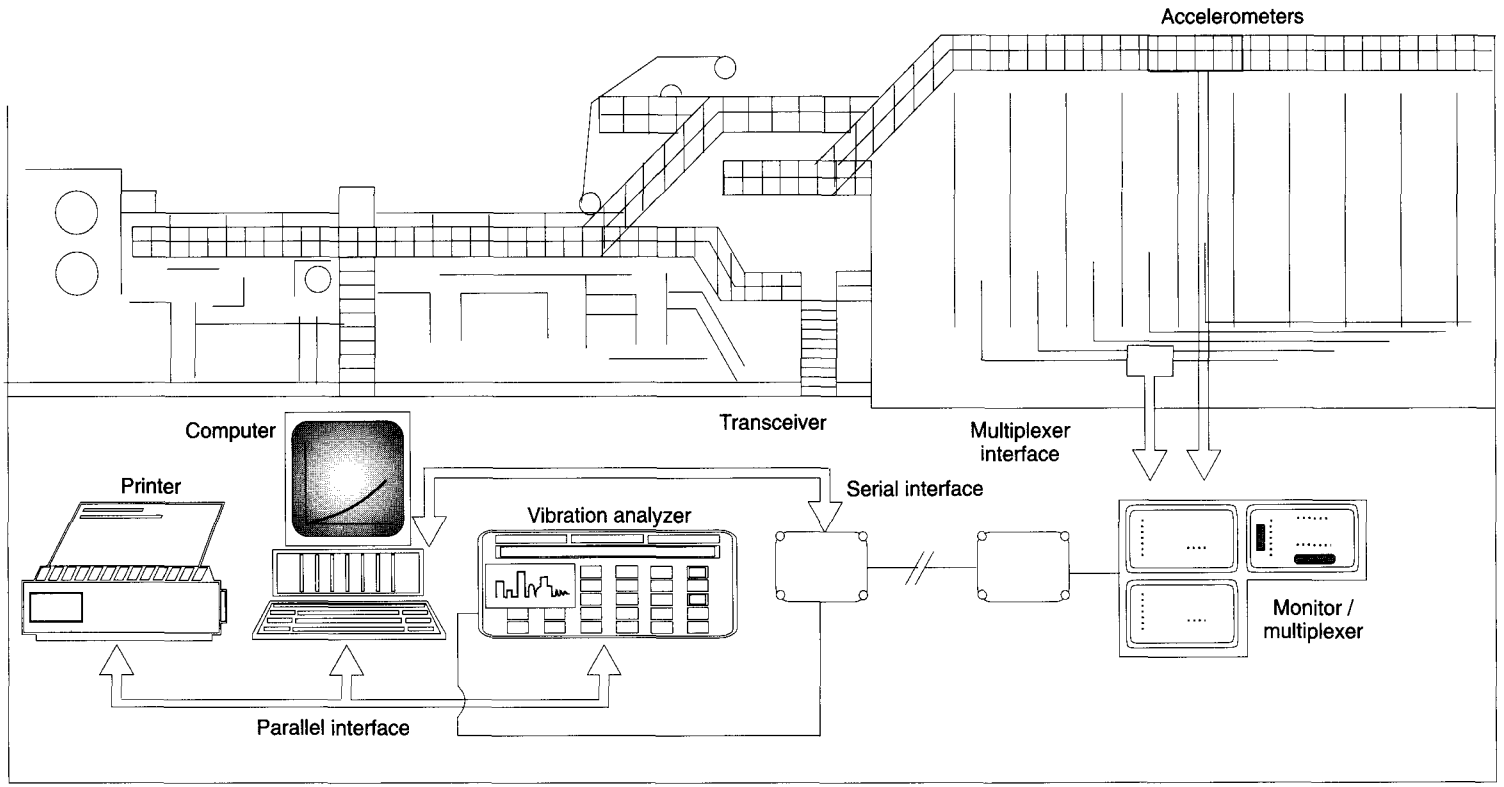

Accelerometers
Computer
Transceiver
Multiplexer
interface
Printer
Serial interface
Vibration analyzer
Monitor /
multiplexer
Parallel interface

Fig. A XII.10

dition monitoring duties. Although relative displacement transducers, such as eddy current or proximity probes, have a frequency range that can extend up to 10 000 Hz they can only effectively detect low frequency components as the higher harmonics usually fall outside the limited dynamic range of these transducers (Fig. A XII. 11).

Popularly-used seismic transducers are the velocity pickup and the piezoelectric accelerometer. Piezoelectric accelerometers have in recent years become by far the most widely used transducer type for machine vibration measurements because of their superior frequency and dynamic ranges, their much smaller physical dimensions, their long-term reliability (no moving parts) and their general robustness. As many monitoring situations require frequency coverage well above 1 000 Hz and require to detect vibration amplitudes over a far greater range than 1 000:1, the piezoelectric accelerometer is the only practical choice.

Choice of Monitoring Parameter

With instrumentation based on the use of an accelerometer pickup, the user is normally free to choose between ***acceleration, velocity,*** *and* ***displacement*** as the measurement parameter. Different engineers have, from habit, different preferences, but let's look at the question from a purely technical viewpoint.

Figure A XII. 12 shows a typical vibration spectrum (plotted on logarithmic axes) from a machine, expressed in terms of the three different parameters. It can be seen that they have differ-

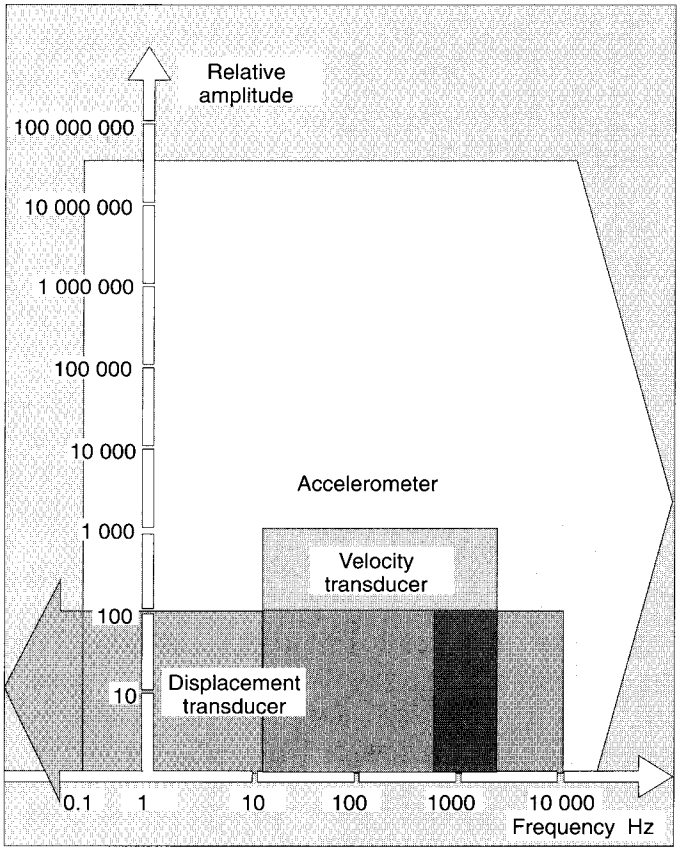


Fig. A XII. 11

ent average slopes, but nevertheless, they have peaks at the same frequencies and the amplitude of the peaks relative to the general slope of each spectrum is the same. Each curve gives an equally true picture of the vibration spectrum. There is a very simple mathematical relationship between the curves so that the value at any frequency on one curve can be converted to a value at the same frequency on one of the other curves (this is in fact done by the integrators in vibration meters).

Note that in the example illustrated, the amplitude range required to display the velocity curve is smallest and thus occupies the least dynamic range in the measuring system and gives a higher signal to noise ratio (more "room" for useful data). It also means that frequency components on this curve need a smaller relative change before they begin to influence the overall (wideband) vibration level. Most components on the other curves need to exhibit much larger changes before they influence the wideband vibration level. The conclusion is that in general, (and especially when using simple instruments giving a single reading over a wide frequency range) the flattest spectrum is the parameter which will enable the earliest detection of faults. This parameter is typically velocity but may sometimes be acceleration, especially where high frequency vibration such as that from rolling elements bearings is of prime interest. Conversely if it is known that faults requiring monitoring occur at low frequencies, choose displacement.

When using an accelerometer, the associated vibration meter, analyzer or preamplifier will normally include integration networks so that the measurement parameter, either acceleration, velocity, or displacement, may be chosen simply by turning a switch. When investigating a new machine or monitoring point one should preferably record frequency spectra of all three parameters

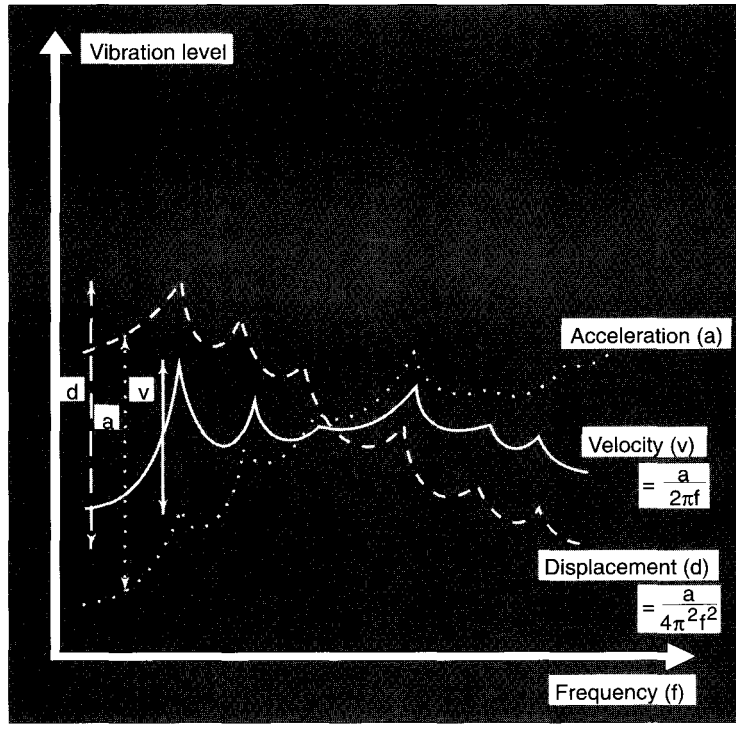


Fig A XII. 12

so that the parameter giving the flattest spectrum in the frequency range of interest can be selected for subsequent monitoring. If an analyzer is not available then choose velocity.

CHOOSING APPROPRIATE AMPLITUDE AND FREQUENCY SCALES

As we have already noted, both large and small components in a vibration frequency spectrum are potential indicators of faults, so the same measuring accuracy is required over a wide amplitude range. Both linear and logarithmic amplitude scales are in common use, but only logarithmic amplitude scales allow vibration components within a sufficiently wide amplitude range to be measured with the necessary accuracy.

Linear versus Logarithmic

Figure A XII. 13 illustrates two scale types having an accuracy and resolution of 1% of full scale, that is, there are 100 possible read-off values. If a read-off accuracy of 10% is required then scale (a), the linear scale, can only be used over a 10:1 range down to level 10 where one step in 10 gives the minimum allowable accuracy of 10%.

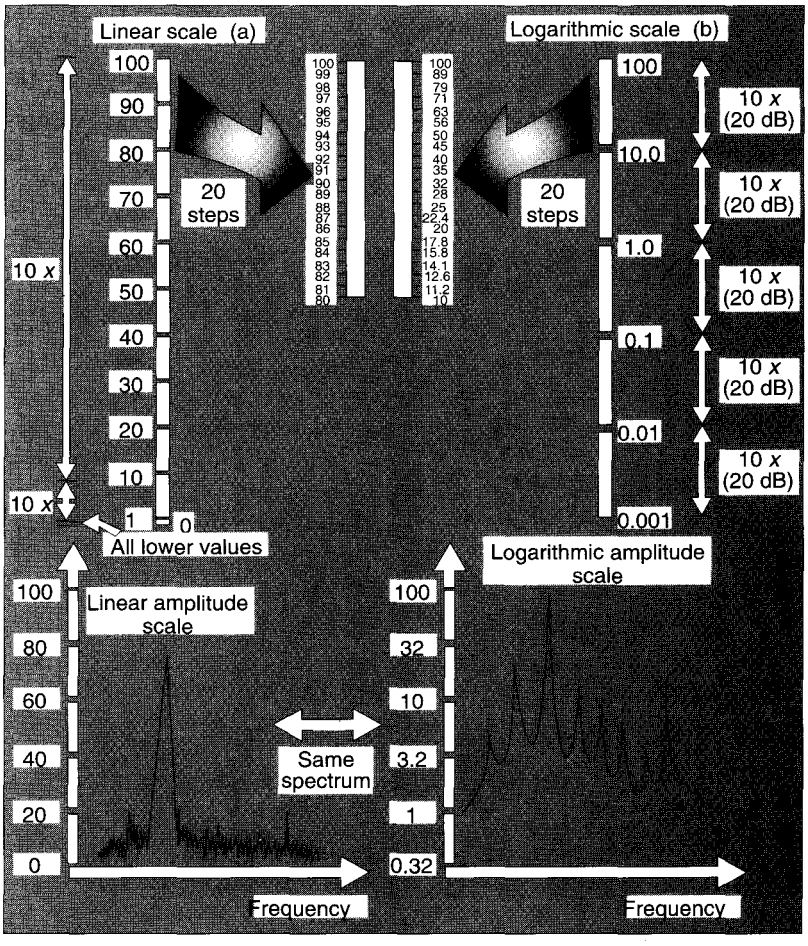


Fig. A XII. 13

When a frequency spectrum is generated on a linear amplitude scale, as illustrated in the lower sketch, only the predominant peaks will usually be within the allowable accuracy range. We cannot hope to follow the relative changes of any but the high level frequency components, while other possible important components only appear as small "blips" crowding the bottom of the spectrum.

Choice of Units

Moving to the logarithmic scale (b), each of the 100 scale values represents an 11% increase over the previous step. Thus, the first 20 steps below full scale cover a range of 10:1 (20 dB), the second 20 steps a further 10:1 range, and so on up to the full 100 steps which cover a dynamic range of 100 000:1 (100 dB). This would be totally impractical with a linear amplitude scale while still maintaining a reasonable accuracy. Such a wide range is not necessary in practice; a range of 300:1 to 10 000:1 (50 – 80 dB) will accommodate a sufficiently wide range of frequency components for machine-monitoring purposes. The lower sketch (Fig. A XII. 14) shows how low-level components can be and accurately measured with a logarithmic scale.

Logarithmic amplitude scales are often calibrated in mechanical units, such as m/s, but dB "units" (familiar from sound measurements) are also widely used. Using dBs, the considerable numerical span of a logarithmic scale is reduced to a compact linear numbering system such that a factor of 10:1 on a log, scale is equivalent to a 20 dB interval (as illustrated with scale (b) in the Fig. A XII. 13). This is advantageous when working with vibration measurements for machine monitoring as it is *ratio* increases in levels (i.e. a fixed number of dBs) which represent the degree of deterioration rather than the actual level itself.

Choice of Frequency Scales

Both linear and logarithmic scales are commonly used on the frequency axis of vibration spectra, and there are benefits with both types. In general, a logarithmic frequency-axis is most suitable for the ***detection*** and ***prediction*** of faults. As already discussed, such a spectral presentation allows the entire vibration signal to be resolved into percentage bandwidth components yielding high resolution at low frequencies, the part of the spectrum where most faults can be detected. For fault *diagnostic* purposes, especially with complex machinery, linear frequency scales are beneficial. They "spread out" the individual frequency components to ease the diagnosis of faults, particularly those which are characterized by a number of harmonically related components or "sidebands". The 120 Hz and 50 Hz component spacing in Fig. A XII. 14 illustrate this.

VIBRATION SEVERITY CRITERIA AND THE EVALUATION OF VIBRATION LEVELS

How Much Vibration is Too Much?

Many engineers start by using one of the published vibration severity standards as a guide for judging machine condition. Some standards, like ISO 2372 (and equivalent national standards) specify limits dependent solely on machine power and foundation type (Fig. A XII. 15). Most general-purpose criteria are based on the RMS value of vibratory velocity over the frequency range 10 to 1 000 Hz, yet many important frequency components often occur at higher frequencies.

Another example of criteria made solely for judging machine condition is the Canadian Government Specification, "Vibration Limits for Maintenance". This defines limits for specific machine types and sizes as shown in the extract on page 1305. It also uses RMS Velocity levels and covers the frequency range 10 Hz to 10 000 Hz.

Although the absolute values suggested by these criteria are not always relevant, they are nevertheless useful in that they indicate the significance of various degrees of vibration level increase. For example, the previously mentioned

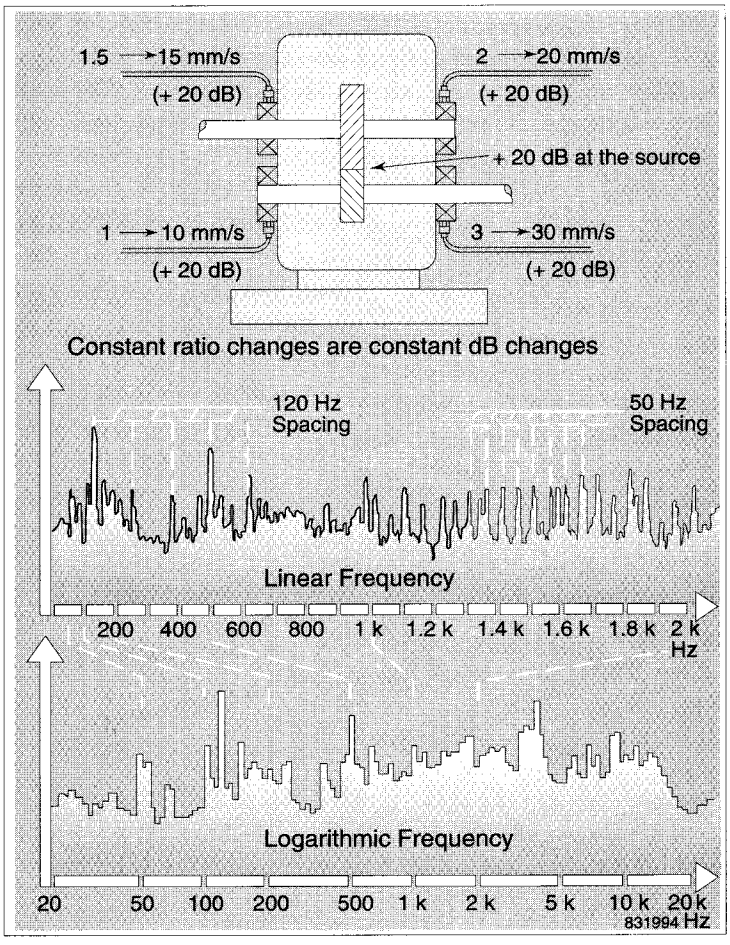


Fig. A XII. 14

ISO 2372 indicates that a level increase by a factor of 2.5 (8dB) is a significant change as it is the span of one quality class. Likewise, an increase by a factor greater than 10 (20dB) is serious as it can take the classification from "good" to "not permissible".

These factors apply to wideband measurements. For reasons which are discussed in the next section they should be applied with circumspection. The classifications are a useful guide to spot-checking machine-condition but are severely limited in their application to early fault detection and diagnosis in any specific machine.

Force × Mobility = Vibration

Vibration measurements on the surface of machine elements reflect the cyclic forces being transmitted at that point. The actual vibration velocity measured is proportional not only to the forces involved but also the *mobility* of the structure at that point. Mobility is a measure of the structure's willingness to be set into motion (and is the inverse of mechanical impedances). The relationship between Force, Mobility, and the resulting Vibration Velocity, with respect to frequency, is illustrated in Fig. A XII. 16. Using logarithmic

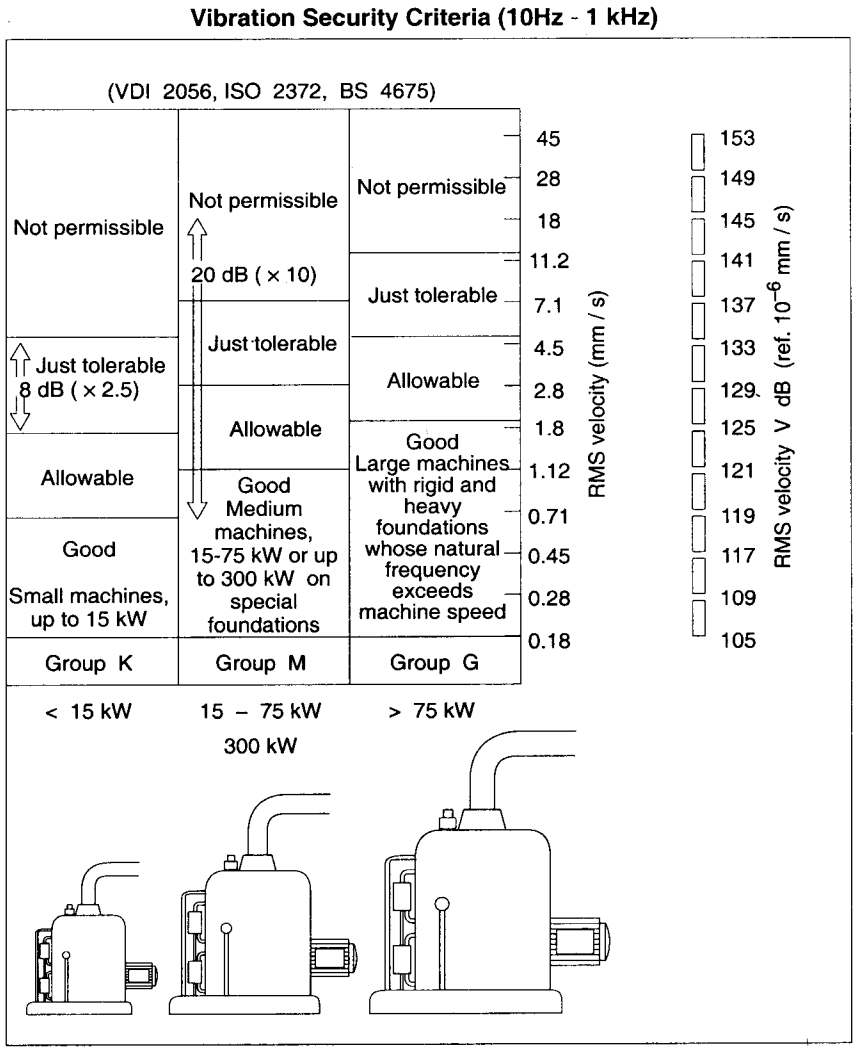


Fig. A XII. 15

scales one can add force and mobility spectra to get a resultant vibration spectrum. Note that in the example shown, the high force component (A) at frequency (n) is countered by a low mobility at frequency (n) so that no special peak is noted in the vibration spectrum.

It is therefore unwise only to look for high-level peaks in the vibration spectrum, low values may also contain information about important force changes. Mobility characteristics of machinery do not usually change significantly with time so one can safely assume that if the vibration level at a given point doubles, the force level has also doubled. For similar machines the mobility at a given point may differ by as much as a factor of 1000:1. Thus it is illogical to use the same absolute vibration limits to indicate the need for maintenance.

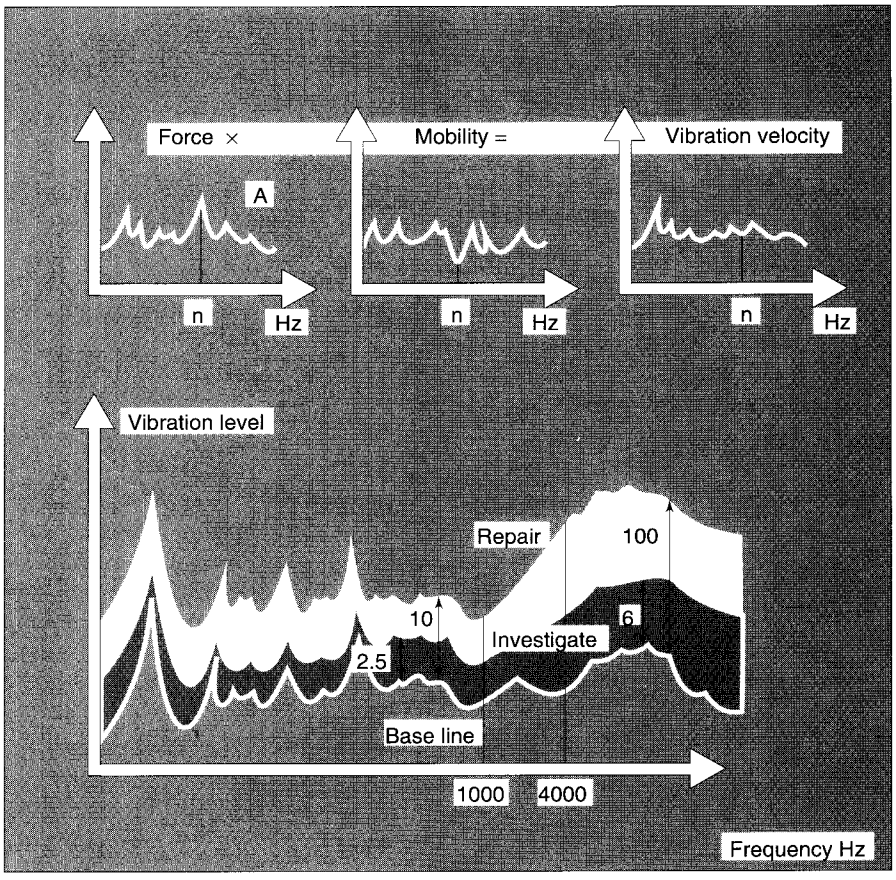


Fig. A XII. 16

A much more reliable indication of machine condition is obtained by concentrating on relative changes, i.e. by specifying a reference "baseline" spectrum or level and allowing certain fixed factor changes. Practice has shown that for frequency components up to 1 000 Hz (and sharp peaks in the 4 to 10 kHz range) an increase by a factor of 2.5 (8 dB) should be considered a significant change in condition warranting investigation, and an increase by a factor of 10 (20 dB) from the reference condition signifies the need for repair—as suggested by the ISO and other criteria. For frequency components above 4 000 Hz these factors can be cautiously increased to 6 (~ 16 dB) and 100 (40 dB) as shown in the Fig. A. XII. 16.

NOTES ON FAULT DIAGNOSIS

Having recognised that a vibration level increase usually indicates a growing fault, the plant engineer will then wish to localize the fault to a particular machine element. Wideband vibration measurements provide very little information to help pinpoint faults. The (wideband) crest-factor measurements mentioned on pages 1290 – 1291 can, however, often isolate the fault to a ball or roller bearing. Generally, a frequency spectrum is the key to diagnosis.

Tracing faults in all but the simplest machines involves a degree of detective work. The frequency spectrum holds the main clue, an increased

Table A XII. 1 *Table of criteria for Bearing Vibration Measurements (10 – 10 000 Hz) Extracted from Canadian Government Specification CDA/MS/NVSH 107: "Vibration Limits For Maintenance".*

Measure overall velocity RMS and allow for the following machine types:	**For New Machines**				**For Worn Machines** (full speed & power)			
	Long life[1]		Short life[2]		Check (recondition) level[3]		Recondition to new (Octave analysis)[4]	
	VdB*	mm/s	VdB*	mm/s	VdB*	mm/s	VdB*	mm/s
Gas Turbines								
(Over 20,000 HP)	138	7.9	145	18	145	18	150	32
(6 to 20,000 HP)	128	2.5	135	5.6	140	10	145	18
(up to 5,000 HP)	118	0.79	130	3.2	135	5.6	140	10
Steam Turbines								
(over 20,000 HP)	125	1.8	145	18	145	18	150	32
6 to 20,000 HP)	120	1.0	135	5.6	145	18	150	32
(up to 5,000 HP)	115	0.56	130	3.2	140	10	145	18
Compressors								
(free piston)	140	10	150	32	150	32	155	56
(HP air, air cond.)	133	4.5	140	10	140	10	145	18
(LP air)	123	1.4	135	5.6	140	10	145	18
(refridge)	115	0.56	135	5.6	140	10	145	18
Diesel Generators	123	1.4	140	10	145	18	150	32
Centrifuges, Oil Separators	123	1.4	140	10	145	18	150	32
Gear Boxes								
(over 10,000 HP)	120	1.0	140	10	145	18	150	32
(10 to 10,000 HP)	115	0.56	135	5.6	145	18	150	32
(Up to 10 Hp)	110	0.32	130	3.2	140	10	145	18

vibration level at one or more known frequencies. This is analogous to a finger-print at the scene of a crime; all that's now necessary is for the detective to compare the finger-print with the prints of known criminals! In machine fault-diagnosis, that is equivalent to knowing the characteristic vibration frequencies of possible faults and finding the ones which match the frequency of the increasing components.

This entails an initial study of specifications and engineering drawings for each machine, making a schematic plan, and recording on it numbers of motor poles, shaft speeds, numbers of gear teeth, and ball/roller bearing data. By simple calculations these are converted to the expected characteristic frequencies of the machine and recorded for future reference.

The trouble shooting charts (A) and (B) list many common faults and their characteristic frequencies in terms of rotation speeds (Table A XII. 2 and A XII. 3). These should be calculated, where relevant, for each machine in the monitoring programme.

DYNAMIC BALANCING OF ROTATING MACHINES

What Causes Unbalance?

Unbalance in a rotor is caused by an uneven distribution of mass, causing the rotor to vibrate. The

Measure overall velocity RMS and allow for the following machine types:	For New Machines		For Worn Machines (full speed & power)	
	Long life[1]	Short life[2]	Check (recondition) level[3]	Recondition to new (Octave analysis)[4]
	VdB* mm/s	VdB* mm/s	VdB* mm/s	VdB* mm/s
Boilers (Aux). Motor Generator	120 1.0	130 3.2	135 5.6	140 10
Sets	120 1.0	130 3.2	135 5.6	140 10
Pumps				
(over 5 HP)	123 1.4	135 5.6	140 10	145 18
(up to 5 HP)	118 0.79	130 3.2	135 5.6	140 10
Fans				
(below 1800 rpm)	120 1.0	130 3.2	135 5.6	140 10
(above 1800 rpm)	115 0.56	130 3.2	135 5.6	140 10
Electric Motors (over 5 HP or below 1200 rpm)	108 0.25	125 1.8	130 3.2	135 5.6
(upto 5 HP or above 1200 rpm)	103 0.14	125 1.8	130 3.2	135 5.6
Transformers				
(over 1 kVA)	103 0.14	- -	115 0.56	120 1.0
(1 kVA or below)	100 0.10	- -	110 0.32	115 0.56

* Ref. 10^{-6} mm/s. Originally an older specification for VdB gave values 20 dB smaller than those found here. (Due to a different dB reference level used.)

(1) Long life is approximately 1000 to 10000 hours.

(2) Short life is approximately 100 to 1000 hours.

(3) When this level is reached, service is called for. Alternatively perform frequent octave analysis and refer to next column.

(4) When this level is exceeded in any octave band repair immediately.

vibration is produced by the interaction of an unbalanced mass component with the radial acceleration due to rotation—which together generate a centrifugal force. Since the mass component rotates, the force also rotates and tries to move the rotor along the line of action of the force. The vibration thus caused will be transmitted to the rotor's bearings, and any point on the bearing will experience this force once per revolution.

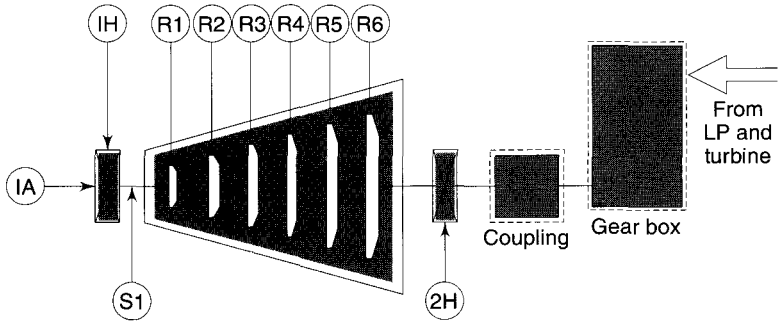
Balancing—What/How?

Balancing is the process of attempting to improve the mass distribution of a rotor, so that it rotates in its bearings without uncompensated centrifugal forces. This is usually done by adding compensating masses to the rotor at prescribed locations. It can also be done by removing fixed quantities of material, for example by drilling.

Machine Details and Characteristic Frequencies

Plant: Petrochem | Section: Ethylene | Date: 5/1/80

Machine Nos.: 2 R1 HP | (High pressure compressor)



Shafts		
Shaft No.	RPM	Rotation frequency (Hz)
S1	3500	58.3

Gears		
Gear No.	No. of Teeth	Mesh. frequency (Hz)

Rotors		
Rotor No.	No. Blades	Bladepass freqeuncy (Hz)
R1	23	1342
R2	25	1458
R3	25	1458
R4	27	1575
R5	27	1575
R6	29	1692

Bearings									
Meas. Point	Bearing Type	D (Pitch dia.)	d (Ball dia.)	n (No. of balls)	ϕ (Contact angle)	f_o (Outer race)	f_i (Inner race)	f_o (Ball)	Discrete Defect frequency (Hz)
1	J								
2	J								

J = Journal Bearing B = Ball bearing R = Roller bearing 8 31997

Fig. A XII. 17

Table A XII. 2 ***Vibration Trouble Shooting Chart (A)***

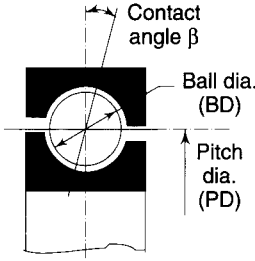
Nature of Fault	Frequency of Dominant Vibration (Hz = rpm/60)	Direction	Remarks
Rotating Members out of Balance	1 × rpm	Radial	A common cause of excess vibration in machinery
Misalignment and Bent Shaft	Usually 1 × rpm Often 2 × rpm Sometimes 3 & 4 × rpm	Radial and Axial	A common fault
Damaged Rollings Element Bearings (Ball, Roller, etc.)	Impact rates for the individual bearing component* Also vibrations at high frequencies (2 to 60 kHz) often related to radial resonances in bearings	Radial and Axial	Uneven vibration levels, often with shocks. * Impact-Rates:  **Impact Rates *f* (Hz)** For Outer Race Defect $f(\text{Hz}) = \frac{n}{2} f_r \left(1 - \frac{BD}{PD}\cos\beta\right)$ For Inner Race Defect $f(\text{Hz}) = \frac{n}{2} f_r \left(1 + \frac{BD}{PD}\cos\beta\right)$ n = number of balls or rollers For Ball Defect $f(\text{Hz}) = \frac{PD}{BD} f_r \left[1 - \left(\frac{BD}{PD}\cos\beta\right)^2\right]$ f_r = relative rev. / s between inner & outer races For Cage Defect $f(\text{Hz}) = \frac{f_r}{2}\left[1 - \frac{BD}{PD}\cos\beta\right]$
Journal Bearings Loose in Housing	Sub-harmonics of shaft rpm, exactly 1/2 or 1/3 × rpm	Primarily Radial	Looseness may only develop at operating speed and temperature (e.g. turbomachines)
Oil Film Whirl or Whip in Journal Bearings	Slightly less than half shaft speed (42% to 48%)	Primarily Radial	Applicable to high-speed (e.g. turbo) machines.

Table A XII. 3 ***Vibration Trouble Shooting Chart (B)***

Nature of Fault	Frequency of Dominant Vibration (Hz = rpm/60)	Direction	Remarks
Hysteresis Whirl	Shaft critical speed	Primarily Radial	Vibrations excited when passing through critical shaft speed are maintained at higher shaft speeds. Can sometimes be cured by checking tightness of rotor components.
Damaged or Worn gears	Tooth meshing frequencies (shaft rpm × number of teeth) and harmonics	Radial and Axial	Sidebands around tooth meshing frequencies indicate modulation (e.g. eccentricity) at frequency corresponding to sideband spacings. Normally only detectable with very narrow-band analysis and cepstrum
Mechanical Looseness	2 × rpm		Also sub-and interharmonics, as for loose journal bearings
Faulty Belt Drive	1, 2, 3 and 4 × rpm of belt	Radial	The precise problem can usually be identified visually with the help of stroboscope
Unbalanced Reciprocating Forces and Couples	1 × rpm and/or multiples for higher order unbalance	Primarily Radial	
Increased Turbulence	Blade and Vane passing frequencies and harmonics	Radial and Axial	Increasing levels indicate increasing turbulence
Electrically Induced Vibrations	1 × rpm or 1 or 2 times synchronous frequency	Radial and Axial	Should disappear when turning off the power

What Equipment is Required?

The minimal necessity for any balancing program is an instrument (or instruments) capable of measuring both vibration amplitude and phase in the frequency range of machine rotation.

Balancing Procedure

The first step in balancing, for example a two-plane rotor, is to mount accelerometers on the bearing housings of both planes. A tacho probe is mounted at a convenient point on the shaft to act as a phase reference mark.The balancing instrument is then tuned to the frequency of rotation of the unbalanced rotor, and a narrow bandwidth selected. The phase and amplitude of vibration of both planes (the original unbalance) is measured. A trial mass is mounted on one plane and the phase and amplitude of both planes is again recorded. The trial mass is then placed on the other plane and the measurements repeated. The correction masses and mounting angles necessary to rebalance the rotor may be calculated directly by resolving the vector forces on the rotor or alternatively by using a programmable calculator running a dedicated balancing program.

If the unbalanced rotor is running at a fluctuating speed or background vibrations are a con-

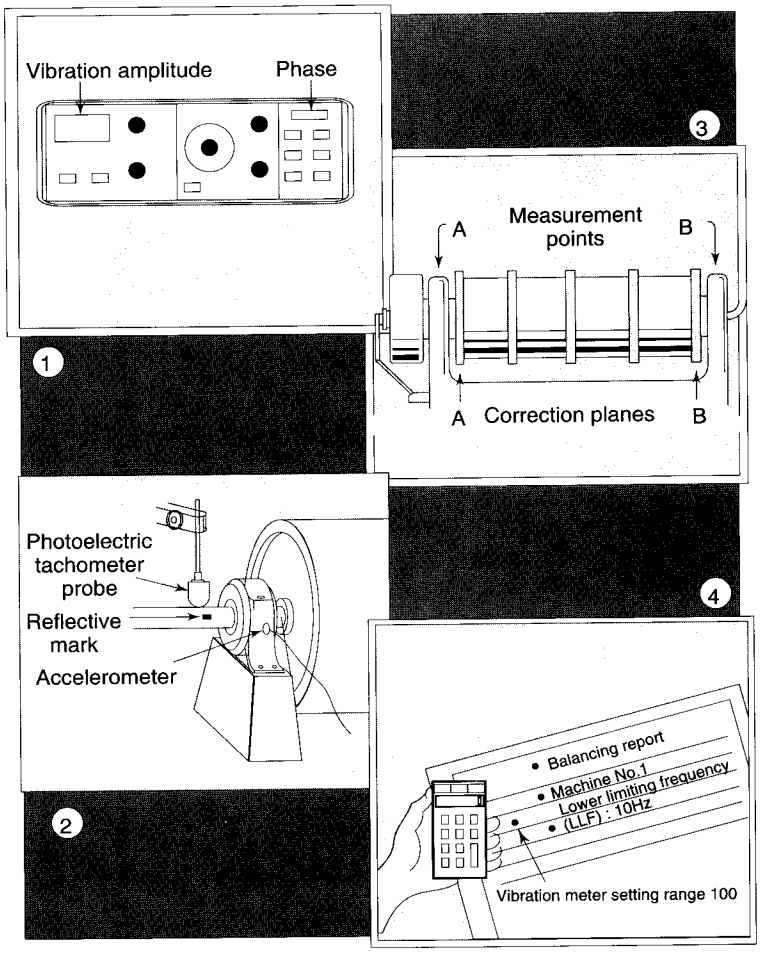


Fig. A XII. 18

sideration, the balancing set should incorporate a tunable tracking filter. The use of such a filter ensures that the vibration meter is always "locked" to a particular frequency component, the fundamental frequency of rotation, regardless of the frequency fluctuations of that component.

Nowadays, portable vibration analyzers used in spectrum comparison monitoring have a built-in balancing capability. The tacho reference probe is connected to the analyzers external filter socket thereby synchronizing the recording of spectra with the rotation speed of the shaft. The technique applied to balance the rotor is very similar to that already discussed. The initial unbalance is measured in both planes, this time by recording a frequency spectrum and reading the amplitude and phase of the fundamental directly from the screen. Trial masses are attached to both planes in turn, the measurements repeated and the correction masses and mounting angles calculated as previously outlined.

Source: *Machine Condition Monitoring [Booklet BR 0267 – 13]*

Courtesy: *Brüel & Kjaer/2850 Naerum/Denmark.*

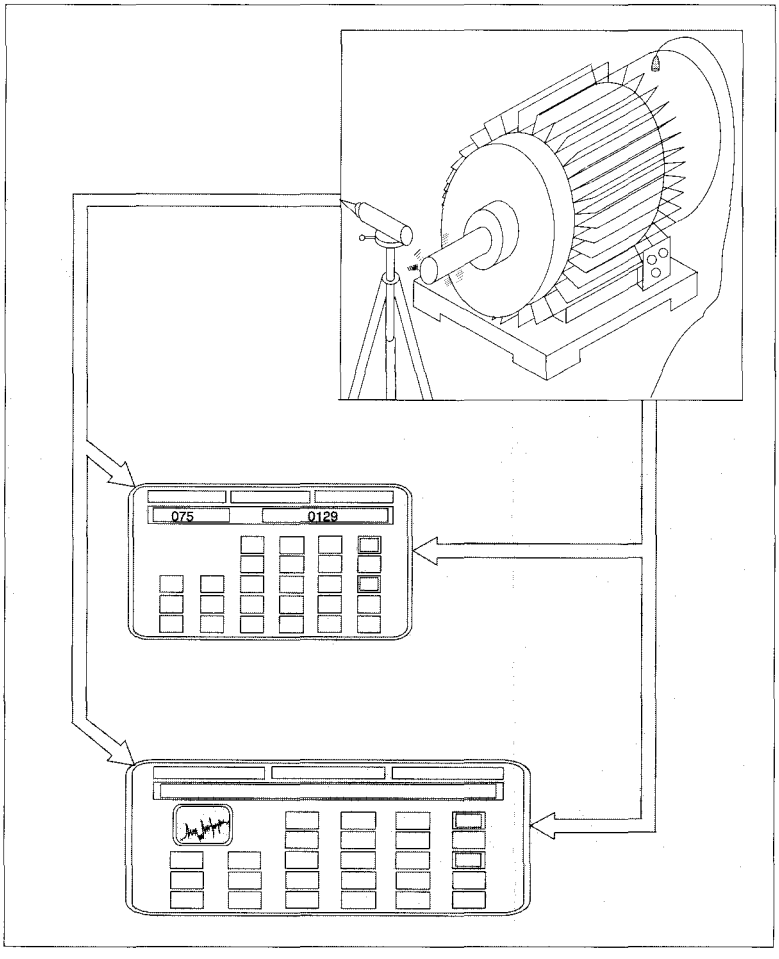


Fig. A XII. 19

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68. DAF/93 (Coen Co. Inc., Burlingame, CA 94010, USA)
69. BCS/1983 (Coen Co. Inc., Burlingame, CA 94010, USA)
70. DUCT BURN/1993 (Coen Co. Inc., Burlingame, CA 94010, USA)
71. CFC/93 (Coen Co. Inc., Burlingame, CA 94010, USA)
72. QLN-1/94 (Coen Co. Inc., Burlingame, CA 94010, USA)
73. Pilot Operated Safety Relief Valves (SEBIM, 18108 Vierzon, France)
74. Ref.D.2.85.11 (SEBIM)
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79. A19100–U412–A223–X–7600 (Siemens Power Generation, D-8520 Erlangen, Germany)
80. A96001–U54–A251–X–7600 (Siemens Power Generation, D-8520 Erlangen, Germany)
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90. A96001–U0l–A303–X–7600 (Siemens Power Generation, D-8520 Erlangen, Germany)
91. A19100–U041–A130–X–7600 (Siemens Power Generation, D–8520 Erlangen, Germany)
92. A19100–U113–A212–V3–7600 (Siemens Power Generation, D-8520 Erlangen, Germany)
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