

BOILERS for POWER and PROCESS



Kumar Rayaprolu

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Dedication

To my late parents.

To my father,

a power engineer himself, for instilling within me this love for boilers.

To my wife Usha, without whose gentle encouragement and active support,

this project would not have been undertaken

and my teenage daughters Ramya and Amulya,

without whose software and data entry help,

this book would not have seen the light of the day. It is for the manner all of

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them during the past two years that this book could be completed.

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Preface

This is a *practical desk book* on water tube boilers for *practicing engineers* and a *reference book* for *students of heat and power*. It has been written by an experienced boiler professional with an all-round technocommercial background of nearly four decades. Let me hasten to dispel a possible interpretation of a “practical book” as a book dealing with only nuts and bolts. On the contrary, this book delves into the theoretical aspects required for a practicing boiler engineer. It tries to recapitulate and build on the forgotten fundamentals of a busy power engineer, providing a higher level of understanding and a wider exposure to various modern boiler and firing technologies.

This book, after providing a brief (but deep) theoretical background of scientific topics involved in boiler technology (namely, heat transfer, fluid flow, combustion, fuels, water, and materials) goes on to describe the different contemporary construction details and thereafter elaborates on the various industrial and utility boilers based on the different combustion systems. Profusely illustrated with design and practical data, it is positioned as a desk book for any boiler engineer, and is meant to be consulted every now and then.

Reader friendliness is most essential for a technical book that covers a lot of ground. There is a lot of design data provided in this book through charts, graphs, guidelines, and comparisons, which are needed by a reader. To make referencing easy, such data are collated and presented as lists of references and useful data in the front matter and appendices that definitely add to the utility of this book for beginners as well as the experienced. They are

- A set of frequently needed process calculations of a boiler
- Glossary providing ready definitions to a number of commonly used (or misused) boiler terms

This book is written with the following people in mind:

- Consultants who require a broad perspective and a peripheral, but accurate, understanding to be able to specify and engineer a boiler plant, both at bid and detailed engineering stages
- Boiler designers who need to deepen their understanding of the fundamentals and construction features
- Operating engineers who need to know the why and how facts about various boilers that they encounter
- Project execution professionals who need to know both the macro and micro details of boiler plants
- Graduates and postgraduate students opting for courses in heat power or boiler technology who need practical inputs

In fact, this book should be of interest to any engineer in the field of power who wants to know more about contemporary boilers. Engineers in lower and middle management levels and who still must battle with technicalities and management issues should find this volume particularly interesting and directly useful.

There has always been a gap in the technical literature of boilers, which is a mature and vastly multidisciplinary subject. Mostly one has to learn about boilers, peripherally, as part of power plants and slowly build knowledge on that platform in practice. It has been even more challenging to learn about industrial boilers, as they have been the poor cousins of utility boilers in relation to available data. Information on boiler parts and sub-systems has always been manufacturer-specific and scattered and scanty. Books such as *Steam* and *Combustion* have been of great help, but they are more like handbooks and are OEM specific. There has been no easy route to learn about boilers.

It is this long disjointed process that is intended to be short-circuited with this book by adopting a different route, a different approach.

The difference in the route adopted is that this book makes an effort to fill this gap by providing directly usable, practical reference material on water tube boilers by

1. Judiciously mixing theoretical and practical knowledge
2. Presenting in a compact manner
3. Covering the essential details of both industrial and power boilers

The practical bent of this book can be gauged by a glance at the contents. The structure can be likened to an edifice (Section III) standing on two main pillars (Sections I and II). The pillars are the boiler fundamentals and boiler engineering, whereas the edifice is the firing technology with appropriately customized boilers. Briefly stated,

1. There is a short description of the theoretical aspects of boilers in the five chapters of Section I.
2. This is followed by an elaboration of various parts and subassemblies of the boiler along with the essential auxiliaries in the three chapters of Section II.
3. Boilers with various firing systems including the recent technologies of fluidized bed combustion and heat recovery steam generators are discussed in the six chapters of Section III.

The difference in the treatment of the subject in this book can be summarized as *brevity with lucidity*, making it possible to enhance the effectiveness of reading and cover a wider area.

This is achieved by

- Very focused and sharp descriptions with bullets and numbering to highlight the subject matter
- Numerous illustrations with appropriate labeling, which goes beyond the accompanying descriptions
- Presenting data in tabular form to capture, for example, differences or essentials

Every effort is made to avoid repetition. It is expected that the 14 chapters of this book will make relatively easy reading, taking the reader to much higher levels of understanding with less fatigue. There is a sincere effort here to lighten the burden of learning an advanced subject.

In an evolution lasting over a century and a half, several firing technologies and numerous boiler arrangements have made their appearance with only a few of them

surviving today. The bewildering variety of boilers has been replaced by a limited number of more efficient and competitive models, optimized in recent times by computerization and tested for survival by global competition. The boilers are now more fuel flexible, dynamically responsive, and enjoy a better-build quality not only due to more optimized designs, but also due to the availability of superior steels and refractories. This book tries to focus on these aspects in contemporary water tube boilers, keeping the historical background and outdated matter to the bare minimum.

This book maintains its focus on only water tube boilers and their immediate auxiliaries, with no extension to the associated ancillary plants such as coal and ash handling, scrubbers for gas cleaning, water treatment, and so on. Instrumentation and electricals have not been covered. Manufacturing and erection and commissioning have also been omitted for the same reason. Thus the subject is given a more detailed treatment without increasing the size of this book. Smoke/flue/fire tube and other similar boilers are not included here. Even waste heat boilers, including liquor-fired boilers and refuse-fired boilers, are left out because of limited and special interest. Only boilers of general and wider interest, for both utility and industrial applications, are elaborated here.

Besides the technicalities, the business aspects of each type of boiler are examined to make the presentation of more practical value. Why are the bubbling bed boilers so popular for coal and lignite firing in the developing world, although they have not been sold for over two decades in the developed world? Will circulating bed boilers marginalize the pulverized fuel firing? Such issues are as important and interesting for engineers involved in the technology selection stage.

A vast and continuously evolving subject like boilers cannot be fully captured in terms of its breadth, depth, and latest incremental improvements. However, amidst all this change, the fundamental concepts and configurations remain intact, which is what this book essentially aims to present.

Turning to a personal note, the author considers himself rather fortunate to have started his career in the boiler industry in the late 1960s when boiler making was in its infancy in India. As various boilers were introduced progressively as early entrants in the industry, the author had the opportunity of working closely with various European and American collaborators in technology transfer and indigenization, and subsequently in boiler development. With nearly four decades of uninterrupted boiler experience, the author can work with various types of industrial and utility boilers—pulverized coal, stoker, oil and gas, bagasse, fluidized bed, black liquor recovery boilers, and heat recovery steam generators behind gas turbines. In his long career, the author worked with boilermakers, power consultants, and EPC contractors making power plants. This experience has helped him develop some deep insights into the total technology of boiler making, which is presented in a simplified manner in this book.

On the whole, the author is fairly satisfied that a large canvas of the subject is covered without losing brevity and crispness. Several friends have contributed in the preparation of this book through their valuable suggestions and painstaking reviews. Yet it is reasonable to expect some errors that may cause minor irritation to the readers. The author shall be grateful to receive feedback on omissions and mistakes to enable corrections in the future.

Finally, the author feels that his efforts will be rewarded only when this book helps serious readers gain better clarity and deeper understanding of the fascinating and vast subject of water tube boilers.

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A book of this size would not have been possible without the support of several friends and well wishers. The least that a grateful author can do is to thank them in person and acknowledge their contributions for wider appreciation. Likewise, several organizations have lent help by allowing their pictures to be incorporated, which greatly enhances the utility of this book; any author feels happy when he can openly acknowledge and record such generosity.

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<i>ESP makers</i>	Hamon Research—Cottrell, United States
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Author



Kumar Rayaprolu has been associated with boilers of various types and capacities ever since his graduation from college in 1969. He started as a postgraduate trainee with the Indian subsidiary of the former Babcock & Wilcox Ltd of U.K. After a year on the shop floor and two years with the parents at Renfrew (Scotland), London, and various construction sites, he spent the next five years in commissioning and proposals.

He moved on to work with a boiler company making industrial boilers (mainly stoker-, oil-, and bagasse-fired boilers) to the designs of Foster Wheeler (Canada) in 1978 and then with a consulting engineering company, Engineers India Ltd, which was originally founded as Bechtel India.

Fluidized bed combustion (FBC) boilers made their first entry into India in the early 1980s, and the author moved to Ignifluid India Ltd in 1982, which was a joint venture formed for Ignifluid type FBC boilers with the former Fives-Cail-Babcock (FCB) of France, to manage engineering and projects. After six years, he had an opportunity to head the marketing function of the newly formed Thermax Babcock & Wilcox. After three years, the author took over the newly formed boiler division at Krupp Industries Ltd in 1990, to make circulating fluidized bed combustion (CFBC) boilers from the former Deutsche Babcock of Germany. The author spent 10 years establishing the new business unit and nurturing it to health and growth. He moved in 2000 to India's largest engineering company, Larsen and Toubro Ltd, to head its Captive and Cogeneration Power and HRSG divisions for five years.

Mr. Rayaprolu considers himself fortunate in having an early advantage in the 1970s when boiler manufacturing started gathering momentum in India. As part of the technology transfer process, the author visited the facilities of many leaders in the industry, such as Babcock of United Kingdom, United States, Canada, and Germany, Foster Wheeler of Canada and United States, LLB of Germany, and so on. The author has gathered a well-rounded and overall experience of design, development, engineering, project execution, estimation, proposals, marketing, manufacturing, and commissioning. He was a business head for more than 15 years, but managed to continue engineering activities throughout his career.

The author has had an uninterrupted association with boilers for nearly four decades and has naturally developed some deep technical and business insights that he always wanted to share. This book, painstakingly compiled over the past two years, is the result of such passion. He has been personally associated with the engineering of all types of boilers described in this book.

Mr. Rayaprolu is married and has two daughters. He is now in Pune, western India, about 200 km from Mumbai, as the president of newly formed Utility Boiler Division of Walchandnagar Industries Ltd.

Structure of this Book

Boilers constitute a vast, mature, and interesting subject that attracts a sizable number of engineers and keeps them fascinated for most of their lives. This book is meant to help those who have been initiated into the field and who desire to clarify their fundamentals, delve deeper into the design and engineering aspects, and learn more about the various types of boilers popularly employed in the industries and utilities.

The readers are urged to spend a few minutes reading this introductory note to understand the structure of this book, which can facilitate in selecting and reading the main text. The process of assimilation can be easier and faster.

This book is essentially divided into three sections that address three different aspects of boilers, namely, the

1. Scientific body of knowledge behind all steam generation
2. Study of parts and auxiliaries common to all boilers
3. Combustion systems and boilers built around them—some popular designs

Although it is a good idea to read all chapters in sequence, it is not strictly required. As a matter of fact, a reader can choose the sequence he likes best. A practicing and seasoned engineer may, in fact, prefer to read chapters in Section III first, whereas the designers and younger readers may prefer chapters in Sections I and II dealing with the basics.

In all, there are 14 chapters covering the essence of the subject of boilers in reasonable detail, with modules covering boiler calculations and a glossary of boiler terms at the end.

Section I

The first section is devoted to the *fundamentals*. It deals with the *science of boilers*. Essentially a boiler burns a given fuel to release its heat, which is then used to convert water into steam.

The first chapter titled “Boiler Fundamentals” is a primer on the basics of a boiler, starting from the definition of what a boiler is. Boiler classification, scope, efficiency, testing, performance evaluation and enhancement, design codes, and data capture are the main topics examined. The fundamentals relating to heat, fuel, water, and materials are examined in the subsequent four chapters. Boiler technology is built on a large number of engineering subjects such as fuels, combustion, heat transfer, fluid flow, high-temperature materials, water chemistry, and metallurgy. Each of these is a full-fledged discipline but only areas applicable to boilers are captured here.

The two chapters on “Heat and Flow” (Chapter 2) and “Fuels and Ash” (Chapter 3) are the most essential and core chapters for thermal design. No doubt, a boiler designer would need a larger body of knowledge and data than what can be presented in any book to be able to actually perform design. However, the bare essentials provided here along with the calculations in appendices help a reader not only as a welcome refresher course on core fundamentals but also to perform the basic process calculations. This should be of

great benefit to consulting and operating engineers. Moreover, in these days of extensive dependence on software programs, it is not unusual for designers to lose touch with the core formulae and graphs, hidden away in the programs somewhere. A brief summary as provided here is of great help in refreshing and staying in touch with the fundamentals. Chapter 2 starts with the properties of steam and water and covers the elements of heat transfer, fluid flow, combustion, and circulation before concluding with the utilization of steam in various power plant cycles. Chapter 3 deals with the properties of prime waste and biofuels and their combustion in boilers, along with the effects on boiler design in adequate detail. Ash characteristics and effects on boiler design form the second part of the chapter.

Chapter 4, "Water Conditioning," restricts itself to the effects of water on boilers, deaeration, conditioning, and carryover. It does not deal with water treatment. Also, water as a subject is not considered here but only the aspects of interfaces with boilers are covered.

Chapter 5, "Boiler Materials," dealing with structural steels, high-temperature boiler quality steels, and refractory materials, should be of use for pressure part (PP) and mechanical design of boilers. Boiler steels (plates, tubes, pipes, castings, and forgings of PP quality) are briefly explained with the help of tables giving their composition, strength, and equivalent specifications from other codes. Likewise, the structural steels and refractory and insulation materials are also tabulated and briefly explained. Concise writeups on properties and classification of steel, heat treatment processes, corrosion, and erosion are provided as main refresher topics of metallurgy. Erosion of PPs and refractories is a serious problem, and erosion protection along with wear-resistant ceramics is briefly described.

These five chapters contain equations, graphs, and tables packed with a lot of practical and theoretical data that is proven in practice. A reader can use the data presented in this book reliably.

Section II

The second section deals with the *design and engineering* aspects of a boiler. Any fired boiler consists of

- Firing equipment to burn the fuel
- Heating surfaces (HSs) to capture the heat released
- Auxiliary equipment to move the water and steam in a safe and desired manner

All systems are appropriately connected by pipes and ducts and supported by structures. In terms of a bill of material, therefore, a boiler is an assemblage of

- PPs and airheater (AH)
- Nonpressure parts (NPPs)
- Auxiliaries and firing equipment

This is a classical way of dividing the boiler even for equipment estimation purposes. This section is also divided on similar lines into three chapters.

However, the different firing devices are discussed in relation to in various types of boilers in Section III, which are classified as per the firing method. Section II deals with the *boiler engineering*. A lot of design information, gas velocity limits, and constructional features are presented to bring the description into a sharper focus.

Chapter 6, "Heating Surfaces," deals with the design and construction of all heat exchangers (HXs) in a boiler, namely the furnace, evaporator (EVAP), superheater (SH), reheater (RH), economizer (ECON), and airheater (AH). Chapter 7, "Fabricated Parts," covers the unheated PPs (drums and integral piping), draft plant, and structure. In Chapter 8, "Boiler Auxiliaries," only the essential boiler auxiliaries are covered, namely, the fans, dust collectors, soot blowers (SBs), level gauge valves, and safety valves. Construction and performance aspects along with selection considerations for a boiler application are discussed here with an eye on their effect on total boiler performance and reliability.

Section III

The last section deals with various types of *boilers based on the type of firing*. This section discusses various types of combustion processes and the boilers built around them.

It should be of interest to all practicing engineers as the practical issues of design, sizing, construction, and some operational points are discussed. These chapters are light on theory and heavy on design and practice. They are directly useful for practicing engineers.

Chapter 9, "Industrial and Utility Boilers," starts with the essential differences between the two (reheating considered as the dividing line) and goes on to describe the several types and their design features. Various industrial boilers are categorized, briefly touched upon (as they are elaborated in subsequent chapters) with pile and semipile burning taken up for a detailed discussion. Likewise, the utility boilers are also classified appropriately and concepts of supercritical boilers are briefly explained.

Chapter 10, titled "Burner Firing," is dedicated to burners and boilers for oil and gas firing, covering both the prime and the lean fuels. With the surge in fuel prices and combined cycles (cc) gaining ground, the oil- and gas-fired boilers are confined to process applications. Package (bidrum A, O, and D types) and field- erected (single and bidrum) boilers are the two categories in the industry and both are explained in this chapter. The discussion on burners includes types, parts, igniters, and scanners. Engineering aspects of burners and parts, limits of various boiler configurations, design principles of oil- and gas-fired boilers are some of the salient issues in this chapter.

Chapter 11 deals with "Stoker Firing," which is restricted to burning biofuels today. Various grates and mass and spreader stoker (SS) firing are described in detail followed by descriptions of various stoker-fired boilers. Design and construction aspects of different stokers and principles of stoker-fired boiler design are elaborated in this chapter.

Chapter 12, "Fluidized Bed Combustion," encompasses both BFBC and CFBC combustors and boilers. Starting with the process of FBC, its characteristics, advantages, and limitations, this chapter covers both BFBC and CFBC boilers in much detail. In BFBC, the process, design variables, components are explained before we take up the principles of BFBC boiler design. A similar pattern is followed for CFBC. In case of CFBC, there are many designs with differing principles. Four popular designs are elaborated, compared, and contrasted to bring out finer points of difference. After describing the CFBC boilers for utility application, the chapter is ended with a short description on Ignifluid boilers, the earliest CFBC. The chapter contains many useful design tables such as the process parameters of BFBC and CFBC, besides several comparisons, for example, BFBC versus CFBC, CFBC versus PF, and so on.

Chapter 13 explains "Pulverized Fuel Firing." After a brief overview covering the advantages and limitations, direct and indirect firing, milling plant, burners, and boilers

are covered in detail. Various types of feeders (volumetric and gravimetric) and mills (ball, beater, and vertical) are detailed. Different parts and configurations of burners are explained. Tangential, circular, down-shot burners in front wall, opposed, and corner firing modes are elaborated. This chapter also covers brown coal firing before describing the various types of PF-fired boilers. There is a section on design principles of PF boilers.

Chapter 14, on “Waste Gas Firing (Heat Recovery System Generators),” deals with HRSG behind GT, the only waste heat boiler of the utility sector and the latest generation utility boiler that comes in the size of an industrial boiler. After elucidating the differences between WHRB and HRSG, there is a fairly detailed account on GTs explaining their basics, cycles, types, manufacturers, models, and performance before starting on the HRSGs. Scope, thermal and mechanical design aspects, components, types (vertical and horizontal), and performance testing are explained. A short note on OTSGs is added. There are several useful tables and graphs.

Appendices and Glossary

A set of boiler process calculations appears in Appendix A, which will be very useful for boiler engineers and students alike. Likewise, a carefully prepared *glossary of boiler words* with crisp definitions, provided at the end of this book, will be very valuable.

Description

This book stresses brevity of description so that a wider area can be covered without taxing the reader. It also aims to clarify fundamentals at every stage so that a deeper understanding is created. Accordingly, appropriate tables, charts, and illustrations are copiously added to supplement the text, which is kept purposely brief. Many tables are very carefully and painstakingly prepared to compare and contrast important data.

The description is divided into several small paragraphs, which are titled and numbered, to make the reading and remembering as effortless as possible.

Abbreviations

To shorten the description and simplify reading, a set of standard abbreviations for various boiler terms are used, a list of which appears at the end of this book. The reader is urged to become familiar with these first.

Units, Standards, and Conversions

Every advanced nation has its own material standards and boiler codes. But American standards are more extensively used world over and hence it was decided to follow them

when explaining the materials, design practices, and testing and equipment codes. This raises the question of what units to be followed. The SI units have not fully gained currency in many places and the MKS is not altogether superseded. The FPS that continues to be popular is built on that platform.

At many places where equivalent units are mentioned, the figures in brackets are appropriately rounded off the reading and remembering more easy.

A list of applicable *conversions of units* is given at the beginning for a ready reference.

List of Reference Data Tables and Graphs

As mentioned earlier, the description in this book has been supplemented with numerous charts and tables. Many of them are standard and need to be referred to repeatedly in the course of work. All tables and graphs are therefore separately listed to draw the attention of readers so that they can refer them frequently. Many times a reader may not remember all data and these lists can be helpful. These are classified as

- List of Tables
- List of Calculations
- Design Guidelines
- Fuel and Ash Data
- Technology Comparisons
- Some Important Descriptions

Further Readings

References used in preparing the various chapters and study material useful for further understanding are provided at the end of each chapter. Many are in the form of technical articles from magazines and institutions.

Finally, this book has been compiled not for reading once and storing away but to be used repeatedly as a desktop reference material of long-term value.

Conversion of Units

Length

1 in. (")	2.54 cm or 25.4 mm
1 ft (')	12 in.
	30.48 cm
1 cm	0.3937 in.
1 mm	0.03937 in.
	1000 μm
1 m	3.281 ft
	39.37 in.
1 mil (""") or thousandth	1/1000 in.
	0.0254 mm
	25.4 μm
1 μm or micron	10^{-6} m
	10^{-3} mm

Area

1 in. ²	6.45 cm ²
	645 mm ²
1 ft ²	144 in. ²
	929 cm ²
	0.0929 m ²
1 cm ²	100 mm ²
	0.155 in. ²
1 m ²	10,000 cm ²
	10.76 ft ²

Volume

1 in. ³	16.39 cm ³ /ml
1 cc/1 ml	0.061 in. ³
1 ft ³	1728 in. ³
	28.32 l
	0.0283 m ³
1 l/1 dm ³	61 in. ³
	1000 cc/ml
	0.22 Imperial gallon
	0.2642 U.S. gallon
1 m ³	1000 l/dm ³
	35.31 ft ³
	264.2 U.S. gallons
	220 Imperial gallons

1 Imperial gallon	277.4 in. ³ 4.55 l 1.2 U.S. gallons
1 U.S. gallon	231 in. ³ 3.785 l 0.833 Imperial gallon
1 fluid ounce	28.13 cc

Weight

1 (U.S. long) ton (t)	2240 lb 1016 kg 1.016 te
1 metric ton or 1 tonne (te)	2205 lb 1000 kg 0.984 long tons 1.102 short tons
1 short ton	2000 t 907 kg
1 lb	16 oz 7000 gr 0.454 kg
1 kg	2.205 lb
1 g	15.43 gr
1 oz	28.35 g
1 gr	64.8 mg
1 stone	14 lb 6.35 kg

Force

1 lbf	4.45 N
1 kgf	9.807 N
1 N	0.248 lbf 0.102 kgf
1 tonf	9.964 kN
1 tef	9.807 kN

Pressure

1 atmosphere (atm) (physical)	760 mmHg 10 m of water head 14.7 psi 1.033 kg/cm ² 1013 mbar 1.013 bar

1 atmosphere (metric) or 1 kg/cm ²	736 mmHg 9.684 m of water 14.22 psi 981 mbar
1 bar	1000 mbar 10 ⁵ Pa 10 ⁶ dynes/cm ² 750 mmHg 1.02 kg/cm ² 14.5 psi
1 mbar	0.4 in. w.g. 10.02 mm w.g. 100 Pa
1 Pa	1 N/m ² 1 kg/m s ² 0.01 mbar
1 MPa or 1 N/mm ²	145 psi 10.2 kg/cm ² 10 bar
1 lb/ft ²	0.1922 in. w.g. 4.88 kg/m ² 47.88 Pa
1 ton/in. ²	1.575 kg/mm ² 157.5 kg/cm ² 15.44 MPa
1 te/in. ²	1.551 kg/mm ² 155.1 kg/cm ² 15.20 MPa
1 psi	2.036 in. Hg 2.307 ft water 0.0703 kg/cm ² 703 mm w.g. 0.0695 bar 68.947 mbar
1 kg/m ²	1 mm w.g. 9.81 Pa 0.2048 lb/ft ²
1 kg/mm ²	0.635 ton/in. ² 0.645 te/m ²
1 in. w.g. head	5.2 lb/ft ² 0.036 psi 249 Pa 2.49 mbar
1 ft water head	0.434 psi 29.89 mbar
1 mm water	98.07 Pa 0.98 mbar
1 m water head	0.1 kg/cm ²
1 in. Hg head	0.491 psi 3386.4 Pa 33.864 mbar

1 mHg head	1.36 kg/cm ² 1333 mbar

Velocity

1 fps	0.3048 m/s
1 fpm	0.0051 m/s
	0.3048 m/m
	18.29 m/h
1 mps	3.28 fps
	196.8 fpm
1 m/min	0.0547 fps
	3.28 fpm

Mass Velocity

1 lb/ft ² h	4.8824 kg/m ² h
	1.355×10^{-3} kg/m ² s
1 kg/m ² h	0.2048 lb/ft ² h

Volume Flow

1 ft ³ /s	0.0283 m ³ /s
1 ft ³ /min	0.472×10^{-3} m ³ /s
	0.0283 m ³ /min
	1.699 m ³ /h
1 m ³ /h	0.589 ft ³ /min
	3.675 Imperial gpm
	4.41 U.S. gpm

Density and Specific Volume

1 lb/ft ³	16.02 kg/m ³
1 gr/ft ³	2.288 g/m ³
1 kg/m ³	0.0624 lb/ft ³
1 ft ³ /lb	0.0624 m ³ /kg
1 m ³ /kg	16.02 ft ³ /lb

Concentration

1 g/ft ³	2.288 g/m ³
1 g/m ³	0.437 g/ft ³
	0.0703 g/Imperial gpm

1 g/Imperial gallon	1426 g/m ³
1 g/L	14.26 mg/L
	70.2 g/Imperial gallon

Power and Heat

1 therm	10,000 Btu
1 kW h	3413 Btu
(energy/work)	860 kcal
	3.6 MJ
1 J	10 ⁷ erg
	0.7375 ft lb
	0.000948 Btu
	1 W s
	1 kg m ² /s ²
1 Btu	778 ft lb
	107.6 kg m
	0.2520 kcal
	1.055 kJ
1 kcal	3088 ft lb
	427 kg m
	3.968 Btu
	4.1868 kJ
1 W	1 J/s
(power/heat flow)	1 N m/s
	1 kg m ² /s ²
1 kW	738 ft lb/s
(power/heat flow)	102 kg m/s
	1.341 hp
	1.360 metric hp (PS)
	3413 Btu/h
	860 kcal/h
1 Btu/h	0.293 W
1 horse power (hp)	33,000 ft lb/min
	550 ft lb/s
	76 kg m/s
	1.014 PS
	0.746 kW
1 metric hp	32,550 ft lb/min
1 pferdestärke (PS)	542 ft lb/s
	0.986 hp
	0.735 kW
1 Btu/lb	0.556 kcal/kg
(calorific value)	2.326 kJ/kg
1 kcal/kg	1.8 Btu/lb
	4.1868 kJ/kg
1 kJ/kg	0.423 Btu/lb

1 Btu/ft ³ /h (volumetric release)	8.90 kcal/m ³ /h 10.3497 W/m ³
1 kcal/m ³	0.1124 Btu/ft ³
1 Btu/ft ² (heat flux)	2.712 kcal/m ² 3.154 W/m ²
1 kcal/m ²	0.3687 Btu/ft ² 0.2846 kcal/m ² 4.1868 kJ/m ²
1 MW/m ²	317,193 Btu/ft ² 860,000 kcal/m ² /h
1 Btu/lb°F (specific entropy)	4.1868 kJ/kg K
1 kJ/kg K	0.2388 Btu/lb°F
1 Btu/ft ² °F (heat transfer coefficient)	4.88 kcal/m ² °C 5.678 W/m ² K
1 kcal/m ² °C	0.2048 Btu/ft ² °F 1.163 W/m ² K
1 W/m ² K	0.1761 Btu/ft ² °F 0.860 kcal/m ² °C
1 Btu/ft ² °F/ft (thermal conductivity)	1.488 kcal/m ² °C/m 1.731 W/m K
1 kcal/m ² °C/m	0.672 Btu/ft ² °F/ft 8.06 Btu/ft ² °F/in.
1 Btu/ft ² °F/in.	0.124 kcal/m ² °C/m 0.144 W/m K
1 kJ/kWh (heat rate)	0.948 Btu/kWh 0.239 kcal/kWh

Water at 16.7°C (62°F)

1 ft ³	62.3 lb
1 lb	0.01604 ft ³
1 Imperial gallon	10 lb

Water at 4°C (39.2°F) (Maximum Density)

1 ft ³	62.4 lb
1 lb	0.01602 ft ³
1 m ³	1000 kg
1 L	1 kg
1 kg/m ³	1 part/1000 or 1 g/L
1 g/m ³	1 ppm or 1 mg/L

Viscosity–Dynamic

1 poise (P)	0.1 N–s/m ²
	0.1 kg/m–s
	0.1 Pa–s
	0.00209 lb–s/ft ²
1 centi poise (cP)	0.01 P
	1 m Pa–s

Viscosity–Absolute/Kinematic

1 stoke (st)	1 cm ² /sec
	100 mm ² /sec
	10.76×10^{-4} ft ² /sec
1 centistoke (cst)	1 mm ² /sec
	10.76×10^{-6} ft ² /sec
1 ft ² /sec	92903 mm ² /sec

Emission: NO_x

1 ppm dv (dry volume)	1.912 mg/DSCM
	2.05 mg/N m ³
	1/1196 gr/DSCF
1 mg/Nm ³	0.932 mg/DSCM
	0.487 ppm
	1/2455 gr/DSCF
1 lb/MBtu on NCV at 3% O ₂ (± 2% accuracy)	760 on natural gas
	800 on refined gas
	725 on fuel oil

Emission: SO₂

1 ppm dv (dry volume)	2.66 mg/DSCM
	2.857 mg/N m ³
	1/860 gr/DSCF
1 mg/N m ³	0.932 mg/DSCM
	0.35 ppm
	1/2455 gr/DSCF

Emission: CO

1 ppm dv (dry volume)	1.164 mg/DSCM
	1.25 mg/N m ³
	1/1965 gr/DSCF

1 mg/N m ³	0.932 mg/DSCM
	1.250 ppm
	1/2455 gr/DSCF

Emission: VOC

1 ppm dv	0.666 mg/DSCM
(dry volume)	0.714 mg/N m ³
	1/3440 gr/DSCF
1 mg/N m ³	0.932 mg/DSCM
	1.40 ppm
	1/2455 gr/DSCF

Preamble

Boilers Today

A boiler can be described as a conversion device for producing steam from fuel. Its basic features are decided by the fuels and the size by the amount of steam demanded by the turbine or plant it feeds. Over the decades, fuels used in boilers as well as the sizes of plants have steadily increased, making modern boilers far smarter and more complex than they were before. Besides, there are more combustion technologies today than in the past, increasing the variety of the boilers. Take a look at the boiler scene that prevailed some 50 years ago:

- The mean size of the boilers was smaller.
- They were feeding on fewer fuels that were relatively better in quality.
- Demands of multifuel firing and extreme boiler efficiencies were not necessary.
- Dynamics were more gentle, as the instrumentation was not sophisticated.

Coal was the primary fuel except in certain countries that later became mainly OPEC nations. The quality of coal was also generally much superior, as opencast mining was not so widely practiced. The oil situation was getting better as cheap oil promised to get cheaper and a lot of oil-based power generation was on the horizon. Natural gas (NG) was yet to come into common use. Gas turbine (GT) technology was in its infancy, and GT-based power, which was more expensive, was generated in small quantities as peak power or convenience power. There were no heat recovery steam generators (HRSGs) to talk about. Fluidized bed combustion (FBC) was yet to appear and pollution issues had not gathered momentum.

The utility market was ruled by pulverized fuel (PF)-fired boilers at the upper end and stoker-fired boilers at the lower end, with coal as the primary fuel. The industrial base was not as large, and the basic industries were yet to attain the present-day sizes, and hence smaller PF and larger stokers were meeting the process requirements as well. In OPEC areas and richer countries, oil firing was also extensively employed. Oil- and gas-fired boilers were very popular, and extensive modularization had taken place.

Self-sufficiency of each nation was the practice, in preference to globalization. Trade among countries was limited and carried on within certain groups, with many trade barriers among the groups. This limitation encouraged a profusion of manufacturers catering to limited defined markets. Naturally, the firms were smaller in size and scale, and there was a bewildering variety of shapes, sizes, and designs. The age of computers had not arrived yet, and the optimization of products was low.

All of this situation changed gradually in the 1980s and 1990s. Fuel issues underwent a tectonic change with changes in the power generation practices and boiler designs. This was followed by the oil shock of mid-1970s. Some genuine softening in oil prices that began to be seen in 1990s withered away, dashing all hopes of reviving oil as a primary fuel. This high oil price has led to the resurgence of NG because of better availability and

simultaneous creation of the required infrastructure. And dramatic growth and consolidation in the GT business.

- Bigger and better GTs, achieving progressively higher cycle efficiencies, leading to ever lower CO₂ and NO_x emissions, managed to eclipse coal for over a decade from the mid-1990s.
- Heat recovery steam generators, as a separate line of business, have now come to be established by a very different set of manufacturers who were small waste heat boiler makers in the former times.
- Extensive LNG facilities now serve markets that are far away from supply zones.

Despite a setback of a decade for coal due to the popularity of NG, coal has seen a very active period of technological growth.

- The quality of coals has declined over the years although the pollution limits have been progressively reduced, providing encouragement for FBC technologies to assert themselves for firing solid fuels.
- Lower NO_x limits have changed the burner and furnace designs.
- Lower SO_x limits have spurred the business of deSO_x units for PF boilers using high-sulfur coals.
- Low CO₂ demands from power plants have brought supercritical boilers into focus again.
- Fuel flexibility and environment friendliness of FBC boilers have heightened the interest in them worldwide to consume fuels that were hitherto considered unusable.
- Interest in renewable energies has been growing steadily, coupled with distributed power generation, making biofuels a small but important segment.

The utility market has undergone a total metamorphosis all over the world with the separation of generation and distribution and dismantling of tariffs and protections. This privatization effort has led to the growth of new entities called independent power producers (IPPs) with multinational locations, whose main objective is to generate power at the lowest cost. Naturally the premium is on the highest efficiency and reliability along with optimum fuel and operating flexibility. These new parameters have started driving the market, demanding boilers with better standards, higher efficiencies, and larger sizes, which are more environmentally compliant. Gold plating of specifications practiced by many rich utilities has started, yielding to superior functionality and standardization.

Meanwhile, there has been a fundamental shift in the business of basic industries from the advanced world to the developing nations. The industry has been built to world-class sizes to satiate the global demand with a great ecological awareness hitherto not prevalent. Naturally, the industrial boiler market has also started needing bigger and more efficient boilers with better fuel flexibility, and, in many cases, with multifuel capability.

- Stokers have been relegated to firing biofuels.
- Bubbling fluidized bed combustion (BFBC) boiler is the mainstay for the industry for the lower range (in the developing markets), whereas circulating fluidized bed (CFBC) is preferred for the higher range. Pulverized fuel-fired boiler is slowly exiting in favor of CFBC.
- The captive and cogeneration (cogen) power requirements have become sizable and comparable with, if not bigger than, the utility power plants that existed a

couple of decades ago. They are served by, generally, PF boilers that are more efficient and environment friendly.

- In the hydrocarbon sector, the captive and cogen plants have assumed greater and greater capacities with the growth of the main plants and the availability of larger GTs.
- Cogeneration, as a concept, has also made rapid progress in traditional chemical and allied industries, driving up the steaming conditions and efficiencies of the boilers.

The situation of the past years was very placid. The fuels were limited, sizes smaller, applications restricted, instrumentation and control sluggish, water treatment still under active evolution, pollution controls almost nonexistent, efficiencies of both the boiler and the auxiliaries relatively lower, and finally the optimization of designs and operation was less than adequate with no computer support. With all these changes having taken place, the contemporary boilers are significant upgrades over the earlier models. Fluidized bed combustion boilers and HRSGs are new additions to the boiler family as they were not in existence 50 years ago. At the same time, there has been marginalization of the stokers with a new role for them. With the widening of energy needs and a greater variety of applications, boilers of all types and sizes are required.

The shrinkage of world economy in 1990s along with the dismantling of barriers and globalization of markets leading to the shift of business and industry to the Asian markets has seen severe attrition among equipment makers of all power gear, which has been very painful. As a matter of fact, the consolidation efforts in the industry are still going on. The overcapacity that prevailed earlier has now practically disappeared. The manufacturing base has substantially moved to Asia. However, the design and development activity continues to stay with the United States and Europe within the firms that have survived. Many boiler companies have been made parts of EPC companies that supply power plants.

Have the boilers changed a great deal among all these changes of business, markets, manufacturers, fuels, technologies, etc? The answer is bound to be a mixed one. The boilers have undoubtedly changed in size, versatility, response, environmental compliance, and even combustion techniques. But they have undergone few changes in terms of the fundamentals or the building blocks. One can notice a change in the way they are organized, but the blocks are almost the same. The concepts have evolved to a higher level, but the fundamentals have remained untouched.

This book, which goes into these details of boiler fundamentals and engineering and explains the current technological progress with various types of firing systems, should provide interesting and helpful reading to any serious power engineer.

Section I

Boiler Fundamentals

1

Boiler Basics

1.1 Introduction

A boiler, as the name suggests, is a device that boils (water to produce steam). More scientifically, a boiler converts the chemical energy in fuel into the heat energy in steam, or the heat energy of hot gases into the heat energy of steam when no firing is involved. The earliest form of boiler is the kettle.

Boilers have been used for over a century and a half in many countries of Europe and America and also in Japan, South Africa, Russia, and Australia. In the recent years, with rapid industrialization of the developing world, vast power-generating capacities have been added, particularly in countries such as China and India. The intent of this chapter is to, first of all, define the boiler terminology and then study the preliminary aspects such as boiler classification and specification. Thereafter, certain common topics, namely boiler efficiency, performance testing, boiler evaluation, boiler design for optimum performance, boiler codes, and design data preservation, are examined.

1.2 Classification of Boilers

Boilers are also called steam generators. They have been around for more than 150 years. Boilers of the early eighteenth century were no more than large kettles. Since those early days boilers have made great progress in terms of size, variety, flexibility, versatility, reliability, and complexity. An attempt to classify boilers is made in the following sections.

1.2.1 Definition of a Boiler

Boiler codes define a boiler variously. A boiler is a pressure-holding container producing steam at a pressure of generally 2 bar and higher. There is, however, no universal definition.

1.2.2 Classification

There are several ways of classifying boilers as shown in the following sections. The list covers most types but cannot be construed as complete.

1.2.2.1 First Classification

The first classification of boilers is based on what flows through the boiler tubes.

- *Fire or smoke or flue tube or shell-type boilers* in which flue gases are inside and water is outside
- *Water tube boilers* in which water is inside and flue gases are outside

- *Combination (combo boiler)* in which flue gas and water flow both outside and inside the tubes; in this type contains an external furnace and shell-type boiler in a sequence

Fire tube boilers are basically suitable for

- Clean fuels such as oil and gas, since the dusty fuels cause fouling and erosion as they travel in the tubes
- Smaller sizes up to 35 tph, limited by the size of shell
- Small superheaters (SHs) of $\sim 50^\circ\text{C}$, as there are arrangement problems for accommodating large SH surfaces
- Low pressures of usually <25 atm limited by the pressure-holding capacity of the shell

They are popular in the process industry for small steam requirement despite

1. A poorer safety record inherent to the design
2. Lower thermal efficiencies
3. Poorer environmental compliance, primarily due to low cost, compact size, and quick deliveries

Fire tube boilers of smaller size are vertical and those of larger size are horizontal. Figure 1.1 depicts their range. The minimum capacity of a water tube boiler is usually around 5 tph.

Combo boilers are generally used for solid fuel firing in lower ranges of up to 30 tph for lower pressures <25 atm. Fire tube and combo boilers are not discussed in this book.

1.2.2.2 Based on End Use

- Industrial boilers
- Utility boilers
- Marine boilers
- Nuclear boilers

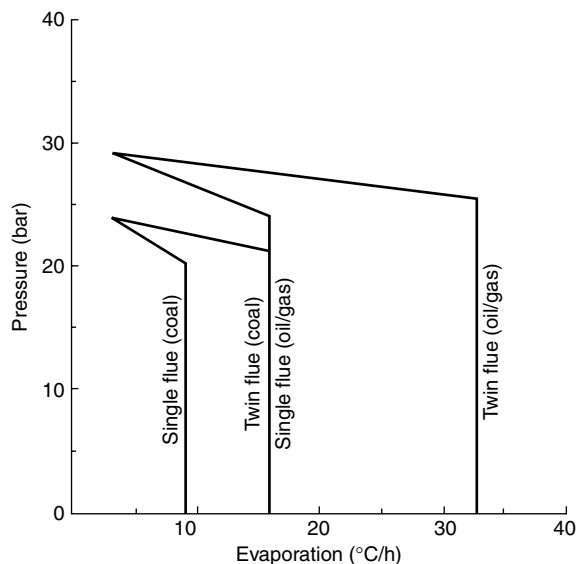


FIGURE 1.1

Range of smoke or flue tube shell boilers.

Only the industrial and power utility boilers are discussed here and in Chapters 9 through 14.

1.2.2.3 Based on Type of Firing

- Mass/pile burning boilers
- Stoker-fired boilers
- Burner-fired boilers
- Bubbling fluidized bed combustion (BFBC) boilers
- Circulating fluidized bed combustion (CFBC) boilers
- Pulverized fuel (PF) boilers
- Liquor-fired boilers
- Waste heat boilers

Most of these boilers are further classified as follows:

- Stoker-fired boilers are categorized as chain grate, dump grate, spreader stoker, and reciprocating grate.
- Bubbling fluidized bed combustion boilers are grouped as underbed and overbed.
- Circulating fluidized bed combustion boilers are classified as hot cyclone, cold cyclone, U-beam, and compact designs.
- Pulverized fuel boilers are categorized as wall-fired and corner-fired boilers.
- Waste heat boilers are separated as process waste heat recovery boilers (WHRBs) and boilers behind heat recovery steam generators (HRSGs); only the latter are discussed in this book. HRSGs are classified into vertical and horizontal designs.

Most of these boilers are described in Chapters 9 through 14.

1.2.2.4 Based on Operating Pressure

- Subcritical boilers
- Supercritical (SC) boilers

with ~200 bar serving as the dividing line. These are discussed in detail in Chapter 9.

1.2.2.5 Based on Circulation

- Natural circulation or drum-type boilers
- Forced circulation boilers
- Once-through (OT) or no-drum boilers

1.2.2.6 Based on Draft

- Natural or balanced draft boilers
- Forced draft (FD) or pressurized fired boilers

Boilers can be further classified based on construction features.

1.2.2.7 Based on Construction

- Package boilers
- Field-erected boilers

1.2.2.8 Based on Type of Support

- Top-supported boilers
- Bottom-supported boilers
- Middle- and girdle-supported boilers

1.2.2.9 Based on Furnace Construction

- Two-pass boilers
- One and a half-pass boilers
- Single or tower-type boilers
- Down-shot boilers

1.2.2.10 Range and Diversity of Boilers

Boilers are made in various shapes and sizes to burn a variety of fuels with the end purpose of producing varying amounts of steam for either process or power or both. An attempt is made here to capture practically the whole range of fired boilers, from the humble smoke/flue tube boilers for modest steam to the ultra-supercritical (USC) for megapower plants in a single graph to let the reader get acquainted with the magnitude and variety. Figure 1.2 helps to provide an insight into the diversity. It is to be noted that

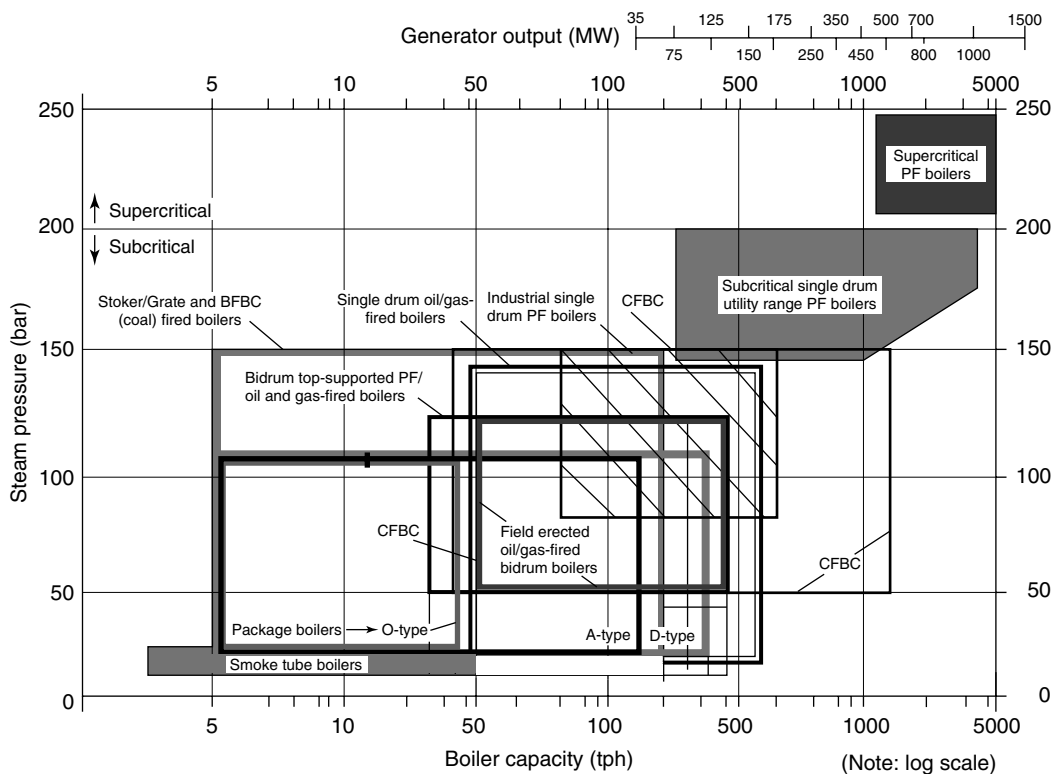


FIGURE 1.2

Range of steam generators along with approximate electric power equivalents.

the boiler capacity is on a log graph, which helps at once to accommodate the entire range, but also renders a visual distortion.

1.3 Boiler Specifications

Boilers are always specified by the four most important attributes, in addition to the types of fuel to be fired:

1. Steam flow or evaporation
2. Steam outlet pressure (SOP)
3. Steam outlet temperature (SOT)
4. Feed water (FW) inlet temperature

1.3.1 Steam Flow or Evaporation or Boiler Output

This is the amount of steam generated from the FW supplied at a certain temperature. It is the capacity or the rating of the boiler expressed in pounds per hour (lb/h), kilograms per hour (kg/h), or kilograms per second (kg/s).

In a reheater (RH) boiler, heat is added to steam to raise its temperature from inlet to outlet condition. This also forms a part of evaporation.

As the feed temperature varies a good deal and reheating is invariably present in utility boilers, boiler ratings are better designated by the *heat duty* than evaporation. This is expressed in million British thermal units per hour (MBtu/h), million kilocalories per hour (Mkcal/h), or megawatt thermals (MWth).

$$\begin{aligned}\text{Heat duty of a non-RH boiler} &= W_s(H_s - H_w) \\ \text{Heat duty of an RH boiler} &= W_s(H_s - H_w) + W_{\text{srh}}(H_{\text{ro}} - H_{\text{ri}}) \quad (1.1) \\ &(\text{MBtu/h, Mkcal/h, or MWth})\end{aligned}$$

where

$$\begin{aligned}W_s &= \text{main steam flow} \\ W_{\text{srh}} &= \text{RH flow} \\ H_s &= \text{enthalpy of SH outlet steam} \\ H_w &= \text{enthalpy of FW at inlet} \\ H_{\text{ro}} \text{ and } H_{\text{ri}} &= \text{RH steam enthalpies at RH outlet and inlet, respectively}\end{aligned}$$

1.3.1.1 Maximum Continuous Rating

Maximum continuous rating (MCR) is the ability of the boiler to generate and supply the declared amount of steam continuously and effortlessly without any kind of short-fall or side effects (such as overheating or slagging or overloading) on the main boiler or auxiliaries.

It is, in fact, the minimum assured evaporation under specified conditions. With the test block margins available in the various auxiliaries, it is possible to obtain 8–10% more

steam from the boiler when it is new. Of course, with aging, a substantial portion of this overcapacity would be lost, mainly as the surfaces foul up and parts wear out. If the fuels, for which the boiler is designed, do not deteriorate and the boiler does not suffer any serious accidents like explosions, and the O&M practices are good, a well-designed boiler with proper margins meets its MCR rating even at the end of its designed life of usually 30 years.

At the time of selection and ordering of the boiler plant if the various scenarios on load and fuel are clearly developed, adding further capacity to avoid a possible derating over time is unnecessary and wasteful. As the resulting oversized boiler would operate at less than the rated condition, the running costs (mainly the auxiliary power costs of fans and pumps and milling) are all going to be higher, in addition to the initial cost.

1.3.1.2 Peak Rating

Peak rating is the evaporation that can be sustained by the boiler for a specified period of, for example, 2 or 4 h in a day, to meet an increased need in either the process or the power plant.

- Peak duty is always met at a fractionally reduced efficiency, as the final exit temperature of the gas from the unit would be more than that at an MCR condition (as the fuel flow is higher), leading to higher stack losses.
- Usually the peak duty does not exceed 110% MCR and 4 h in a day, and it is mostly met by making use of the design and test block margins of the boiler and the auxiliaries without having to oversize the equipment.
- However, if the peak rating or duration is higher, the boiler plant has to be resized suitably with the efficiency optimized at MCR or normal continuous rating (NCR) and the equipment sized to suit the peak rating. Often in a power plant the peak duty is also to meet the turbine valve wide open (VWO) condition, which is usually ~5–10% of the turbine MCR flow. This is the maximum flow when all the control valves in the turbine inlet chest are fully open. This condition can give additional power with a new turbine and can protect against a possible loss of power in the later years due to the aging factors.
- Running the boiler continuously at its peak rating is best avoided because the life of the boiler is affected due to sustained higher temperatures in furnace, SH, and RH areas, causing slagging, fouling, and erosion problems besides a higher loss.

The concept of peak rating does not apply to HRSGs. Gas turbine (GT) ratings are given at their optimum conditions and GTs are scarcely operated at temperatures higher than the design loads for the fear of severe shortening of life of hot parts.

1.3.1.3 Normal Continuous Rating

Normal continuous rating is slightly lower than MCR and represents the condition at which the boiler would be operated most of the time; and naturally it is the condition at which the efficiency needs to be optimized. This is typically at 90% MCR. In power plant application, NCR usually corresponds to the MCR of the turbine and the MCR to the VWO condition or more.

1.3.2 Types of Pressures

1.3.2.1 SH Outlet Pressure

Superheater outlet pressure is the pressure at which steam is available for further consumption.

- Usually it is ~5% higher than process or turbine inlet pressure to account for the piping loss, that is, pressure losses in piping, bends, flow nozzle, and valves.
- In fixed-pressure boilers, this pressure is held constant as the turbine inlet valves vary the steam pressure to the inlet nozzles. In variable-pressure boilers, where steam is supplied directly to the turbine inlet nozzles, the SOP varies with load.

1.3.2.2 Drum Pressure

Drum pressure is the pressure at which the circulation of steam and water takes place in evaporator circuits. Drum pressure is ~10% higher than SOP to account for steam pressure loss in SH and attemperator.

1.3.2.3 Design Pressure

In principle, the boiler design pressure is usually the lifting pressure of the second safety valve (or the highest set safety valve lifting pressure if there are more than two safety valves) on the drum and it forms the basis for the strength calculations of the boiler pressure parts (PPs) in drum-type boilers. The design pressure limits the *maximum operating pressure* of a boiler.

Reheater design pressure is the highest safety valve lift pressure (SVLP) on the inlet side of the RH. Boiler codes may vary slightly in defining the design pressures for boiler and RH.

1.3.2.4 RH Inlet and Outlet Pressures

These pressures are turbine-dependent based on the power cycle design. Unlike SOP, which is held constant in drum-type boilers, RH pressure slides downward at lower loads.

1.3.2.5 Calculation Pressure

Calculation pressure is the design pressure, adjusted for factors such as the static head and used for calculating the strength of individual components. There may be a single boiler design pressure, whereas the calculating pressures can vary for different boiler parts.

1.3.3 Outlet Temperatures

1.3.3.1 SH Outlet Temperature

Superheater outlet temperature is the temperature at which the steam leaves the SH. It is usually the highest temperature attained by the steam in a boiler. RH steam is sometimes slightly higher than the SH steam in large utility boilers. Superheater outlet temperature up to ~350°C is usually not controlled, being used mainly for process heating. Then SOT reduces as the load reduces. For power application, the SOTs are generally >400°C and are required to be controlled in two ways:

1. By limiting the temperature within a band of $\pm 5^\circ\text{C}$ for the safety of the turbine casing by means of an *attemperator*

2. By keeping the temperature constant up to usually 70% load by sizing the SH larger (a range of 70–100% is then known as the *steam temperature control* [STC] range of the boiler)

It is important that the STC is decided judiciously as the SH, the most expensive surface of the boiler, becomes unnecessarily larger. Steam temperature control can vary from 50 to 100% MCR, but is mostly limited to 70–100% in power plants. At <70% MCR, the drop in SOT is not all that steep when there is large radiant SH.

Automatic combustion control (ACC) is different from STC. Combustion control is the regulation of fuel and air in right proportions to provide an optimum combustion, which is usually performed by ACC logic. This is usually designed to operate in auto mode between ~40% MCR and peak load, which is more than adequate for meeting the load variations in most process and power applications. At lower loads, the boiler has to be operated manually. To make ACC extend to even lower MCR is very expensive as the flow measurements are difficult.

1.3.3.2 RH Outlet Temperature

Reheater outlet temperature (RHOT) is the temperature at which steam leaves the RH. Reheater inlet temperature is turbine-dependent and it is lower at lower loads. The RHOT is required to be held constant for optimum cycle efficiency. Since RH pressure is one-third of the main steam pressure, the RHOT is usually equal to or preferably higher than the SOT.

1.3.4 Feed Water Temperature

Feed water temperature (FWT) varies from as low as 85°C for very low-capacity process plants with no feed heating (when there is no FW contamination) to as high as 270°C in very high-pressure (HP) power plants with several stages of feed heating. Feed water temperatures to boilers are usually at five levels.

1. At 85°C (usually return condensate from process and not deaerated), the FW needs to be dosed with adequate quantities of sodium sulfite to protect the internals from pitting. It can enter the economizer (ECON) thereafter only if the fuel contains negligible sulfur to cause no corrosion. Otherwise it needs to be heated in the lower drum or in the external heat exchanger (HX) to safe temperature.
2. At 105°C, the FW is deaerated and heated in a deaerator. This is the most common temperature with process industries. Depending on S in fuel, the FW may be heated in the deaerator itself or in lower drum or in external heater by 10–15°C to protect the ECON or the ECON can be avoided by use of an AH.
3. The next level is between 130 and 140°C, common with small power plants of ~15 MWe where HP heaters are avoided, and increased heating is done in the deaerator itself.
4. When HP heaters are in line, the FWTs are usually between 160 and 270°C, depending on the size of the turbine, as it should be large enough to accommodate the steam extractor nozzles.
5. In HRSGs, where there is no regenerative feed heating, the condensate enters the preheater section of the HRSG directly and it is between 30 and 40°C.

1.3.5 Fuels

Fuels have the most profound effect on the size and shape of a boiler, because all boilers have to be primarily built around the characteristics of the fuel to be burnt. When the fuels

for the project are understood, the resultant customization of the boiler is better. Fuel flexibility in a boiler is most desirable, for multiple fuels as in the case of industrial boilers or a wide range of the same fuel as in the case of utility boilers; as it enables plant owners to optimize the fuel cost. But every flexibility brings a performance penalty and a trade-off is necessary.

Prime or principal or main fuel is the fuel around which the boiler is built and the performance is guaranteed.

Start-up fuel is the fuel with which the boiler is started up and loaded until it is ready for taking the main fuel. Oil firing in case of PF boilers, gas firing for CFBC boilers, and oil/charcoal for BFBC boilers are some examples of start-up fuels.

Alternate fuel is available as an alternative to the main fuel, and usually full generation is obtained on both fuels with appropriate guarantees. Alternate fuel is planned when disruption of main fuel is a distinct possibility. In bagasse-based cogeneration (cogen) plants, coal or oil is planned as an alternate fuel during the off-season. Oil- and gas-fired boilers, coal- and lignite-fired boilers, bagasse and husk-fired boilers are some of the examples of employing alternate fuels where the fuels are somewhat similar and use the same firing equipment. Dissimilar fuels and firing equipment are also employed to meet such demands when burners are used along with stokers, FBC, or PF to cite a few examples. This type of operation is expensive in both start-up costs and running costs. Auxiliary equipment in the boiler has to be sized for the condition that governs it. The performance is generally lower, as there is usually some intentional tramp air ingress through the idle equipment to keep it cool, and the power consumption of the oversized auxiliaries increases.

Auxiliary or additional fuel is available in the plant and is to be burnt along with the main fuel in *cofiring* mode. When the quantities are small, there are no specific requirements other than merely a disposal in the boiler in a safe and profitable manner. Pith firing in paper plants along with coal is an example.

However, the performance demands of combined firing of main and auxiliary fuels would be more rigorous. In steel plants, coke oven gas or blast furnace gas firing along with coal illustrates the case in point.

Supplementary fuel is available in case of an emergency. In HRSGs behind GTs in cogen projects, oil or gas firing is done to get additional steam to the extent of even 100% for process needs. Of course the boiler would need to be modified suitably, mainly in upgrading the metallurgy and installing additional combustion equipment and safety devices. In GT-based power plants, supplementary firing is done for meeting the peak requirements to the extent of 10% of power. During this period the efficiency is lower as the fuel passes through the steam cycle and not the GT cycle.

Cofiring or cocombustion is the simultaneous firing of two or more fuels. This is useful when the auxiliary fuel is difficult to burn due to high moisture or ash. Many biofuels are disposed of in the cofiring mode as long as they do not create slagging and fouling problems.

1.4 Scope of Boiler Plant

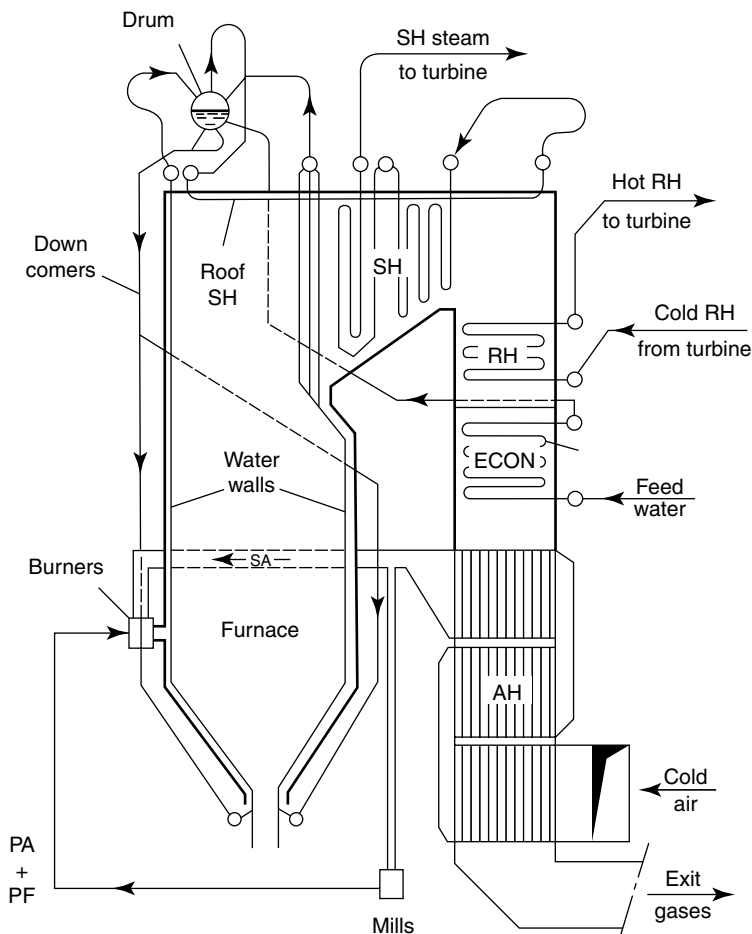
1.4.1 Inputs and Outputs

There are four main inputs and four outputs for any conventional boiler, excluding the RH. The terminal points (TPs) in these circuits define the end points of the scope of supply, with all equipment between the TPs within the scope of boiler suppliers. Table 1.1 the classical

TABLE 1.1

Boiler Inputs and Outputs

Inputs	Terminal Points for Inputs	Outputs	Terminal Points for Outputs
Water	NRV upstream of ECON or drum	Steam	MSSV or NRV
Air	FD and PA/SA fan inlets	Gas	ID fan discharge
Fuel	Feeder	Ash	Hopper bottom
Chemicals	NRV in dosing lines	Blowdowns and drains	Dirty or clean blowdown vessels

**FIGURE 1.3**

Drum-type RH utility boiler with ECON and AH as back-end equipment.

scope and TPs shows a typical large conventional boiler in a power or a cogen plant, which is depicted in Figure 1.3.

In a water and steam circuit, the boiler scope starts at the nonreturn valve (NRV) at the ECON or the drum inlet (if there is no ECON) and ends at the main steam stop valve (MSSV) or NRV (if provided). In case of variable-pressure boilers, where there is no MSSV, the scope ends at the turbine inlet valve.

TABLE 1.2

Heat Recovery Steam Generator Inputs and Outputs

Inputs	Terminal Points for Inputs	Outputs	Terminal Points for Outputs	Comments
Water	NRV upstream of ECON or drum	Steam	MSSV or NRV	For each circuit
GT exhaust	Inlet gas duct	Gas	Stack discharge	
Fuel	Supplemental fuel skid (if applicable)	Ash	Not applicable	
Chemicals	NRV in the dosing lines	Blowdowns and drains	Dirty or clean blowdown vessels	For each circuit
Air	Fresh air fan inlet (if applicable)	—	—	

In an air and gas circuit, the scope begins at the inlet flanges of the FD fan. Also it starts at the suction flanges of PA and SA fans where the suction is from the atmosphere. The scope ends at the discharge of the induced draft (ID) fan at a suitable point, but usually at the stack inlet.

In a fuel circuit, the scope starts at the inlet flange of the feeder for solid fuels or at the fuel main stop valve for liquid and gaseous fuels. The scope ends at the ash hoppers.

The isolating valves on the chemical dosing lines on the feed and drums determine the limits. The drain and blow-off lines and continuous blowdown lines terminating in the dirty and clean blowdown vessels, respectively, are included along with the tanks and their escape pipes.

Dust-collecting equipment may or may not form a part of the scope. Deaerators and feed stations are also not included as they are in the turbine island. The TPs for a typical HRSG are somewhat different, as shown in Table 1.2.

1.4.2 Boiler Package

This term describes a package that is supplied by the boilermaker. In utility boilers, the orders are usually for basic boilers and the scope is as described earlier. As the boilers become smaller, it is normal to include the dust-collecting equipment. Also included are the immediate peripheral items such as the chemical dosing system comprising pumps, drives, and tanks and feed station including deaerator and feed pumps with their drives. In industrial boilers, boilermakers also often supply steel stacks. Many times some lengths of feed and steam piping are also part of the boiler scope.

Boiler package or package boiler? Boiler package is not to be confused with package boiler, which is a small shop-assembled oil- and gas-fired compact boiler.

1.4.3 Boiler Island

In large green field plants such as refineries and petrochemical plants, a certain area is defined as the boiler island and all equipment in that area is required to be supplied by the boilermaker; also, all the TPs would be at the battery limits requiring considerable amounts of piping and pipe rack. All auxiliary plants mentioned earlier would form a part of the boiler.

Boiler island in a power plant has a different connotation: the total power plant is divided into three components, namely the boiler island, turbine island, and balance of plant (BOP). Besides the main boiler, the chemical dosing and dust-collecting packages are usually parts of the boiler island.

1.5 Heat Balance for Boiler Efficiency

1.5.1 Energy Balance in Boiler

Figure 1.4 depicts the energy balance in a boiler showing the fuel and air energy inputs and steam energy outputs from both SH and RH and the various losses are shown in Table 1.3.

1.5.2 Boiler Efficiency Calculations

Like any other equipment, a boiler has to be configured and operated at the optimum efficiency—a function of the fuel and interest costs. As the fuel costs have increased, the boilers have also improved in their efficiency. In gas-rich countries, for example, GTs still operate on open cycle with no HRSGs to recover the heat. The payback period to install the HRSGs is too long to be economical.

The most important of all the boiler parameters is the efficiency calculation. The process is extremely simple with just about six steps. But the essence of the boiler design with all refinements is captured in those few steps. Each defining parameter has to be carefully evaluated to ensure that it can indeed be translated into reality in a working boiler. For example, the excess air level should be acceptable to the firing equipment and the infiltration should be realistic. The final exit gas temperatures must be economically feasible and cause no corrosion. The efficiency calculation is the first and the last calculation for any boiler, as the committed efficiency figure has to be finally demonstrated in the field.

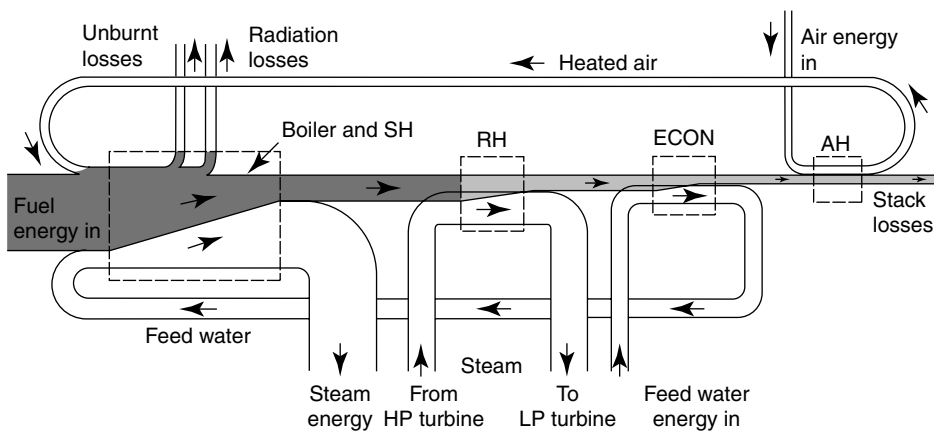


FIGURE 1.4
Energy balance in a boiler plant. (From *Power Magazine*. With permission.)

TABLE 1.3
Heat Inputs, Outputs, and Loss

Heat Inputs	Heat Outputs	Heat Loss
Fuel	SH steam	Stack
Air	RH steam	Unburnt
		Radiation
		Unaccountable

This is practically the only calculation that the customer and consultant should be interested in receiving from a boilermaker. This proposal stage calculation has to be validated with the performance stage calculation at startup, proving the claim a year or two later. It is to be noted that although the result is the same, there is a difference in the design and field calculations because the inputs are different at both stages. This will be evident in the next few paragraphs.

Efficiency on gross calorific value (GCV) or net calorific value (NCV)? Boiler efficiency is measured on the basis of GCV or NCV, both capturing different aspects of operation. Also refer to Section 3.2.1.1.3. The former, popular in the United States and the countries following the American systems, indicates how much of the *total fuel heat is converted* into the heat in steam whereas the latter, popular in Europe and the countries following the European systems, indicates how much of the *available heat of fuel is converted* into the heat in steam.

Net calorific value is the practically available heat of fuel included in total heat (GCV) arrived at after discounting the heat carried away by water vapor (inherent in fuel and produced by the burning of H_2 in fuel), assuming the vapor pressure to be ~ 0.07 atm or 1 psia. Accordingly, the NCV works out as

$$NCV = GCV - 1040 (m + 9H_2) \text{ Btu/lb} \quad \text{or} \quad GCV - 578 (m + 9H_2) \text{ kcal/kg} \quad (1.2)$$

where 1040 Btu/lb or 578 kcal/kg is the latent heat of evaporation. This figure varies slightly with the testing code adopted; 1055 Btu/lb or 586 kcal/kg is another figure used. But the difference is very small.

A biofuel such as bagasse gives an efficiency as low as 68% on GCV due to its very high moisture, whereas its equivalent on the basis of NCV is as high as 90%. From NCV it is clear that the boiler is highly efficient having reclaimed such a high percentage of available heat, whereas the modest 68% gives a misleading picture. But the efficiency of GCV determines how much fuel is needed to make the required steam. The difference, however, is not so large with prime fuels. With coal, typically, the difference is $\sim 4\%$, for example, 88 and 92% on GCV and NCV with PF firing, respectively. Both concepts are efficient.

Two processes are at work, namely

- Heat release from fuel in the firing equipment
- Heat absorption in the heating surfaces of the heat released

How well the two processes are performed determines the efficiency. Add to it a couple of inevitable systemic losses such as radiation loss (L_r) from the boiler's enclosure and sensible heat loss of the ash and the picture is complete. Efficiency of a boiler is always measured with ambient conditions as the datum and the atmosphere as the sink. The ambient conditions have a significant effect on the efficiency and the design.

1.5.3 Effect of Ambient Conditions on Boiler Efficiency and Design

Ambient conditions, namely temperature, humidity, altitude have an important role in determining the efficiency of a boiler and the sizing of auxiliaries.

- Stack loss, which constitutes $\sim 70\text{--}80\%$ of the total loss, is measured with ambient temperature as the datum. The efficiency would therefore appear to be lower by $\sim 0.25\%$ for each 5°C increase in ambient temperature.

- It is important to ascertain the range of temperature and humidity variation to ensure proper sizing of the fans and other volumetric devices. It is not unusual to encounter an ambient temperature variation of -5°C to $+50^{\circ}\text{C}$ in the tropics and -20°C to $+35^{\circ}\text{C}$ in temperate climates. This translates to a variation of nearly 20% in the specific volume of air.
- The fan must be sized by the maximum temperature and the motor rating by the minimum temperature.
- All motors are required to withstand the highest ambient temperature and the insulation has to be suitable.
- Gas turbine outputs vary dramatically as depicted in the figures of Chapter 14.
- Thermal insulation is another area affected by the ambient temperature. Economical insulation results when there is a difference of $20\text{--}25^{\circ}\text{C}$ between the ambient and the lagging temperatures. This can result in a surface temperature of $70\text{--}75^{\circ}\text{C}$ in summer in the tropics. There can be a doubling of insulation thickness if a flat 60°C is to be met at all times under such conditions!

The effect of humidity is rather small in both boiler efficiency and auxiliary sizing. Altitude has a major impact on the sizing of fans as the specific volume of air increases with altitude.

1.5.4 Breakup of Losses

$$\text{Gross efficiency of boiler} = 100 - (\% \text{ Loss } 1 + 2 + 3 + 4) \quad (1.3)$$

where

1. Stack loss consists of
 - a. Dry gas loss (Ldg)
 - b. Moisture loss (Lm)
 - c. Humidity loss (Lh)
2. Unburnt loss (Lub)
3. Radiation loss (Lr)
4. Unaccountable loss (Lu)

1.5.4.1 Stack Losses

These are measures of

1. How well the flue gases are cooled
2. How low the flue gas quantities are kept

There is a practical limit to the cooling of flue gases for each fuel without running the risk of low-temperature corrosion as depicted in the graphs of ECON and AH portions in Chapter 6. The excess air for the fuel is a function of the type of firing and the tightness of setting. A tight boiler setting inhibits the inward leakage of tramp air or outward leakage of flue gas for balanced and forced draft boilers, respectively. The stack loss typically forms $\sim 70\text{--}80\%$ of total loss.

The L_m varies from 8 to 20% for most fuels depending on the fuel moisture, fuel H_2 , excess air, and exit gas temperature. The L_{dg} forms the rest, as the L_h is rather small at $<0.1\%$.

$$(a) \text{ Dry gas loss } (L_{dg})\% = \frac{W_g(T_g - T_a) \times C_p \times 100}{GCV/NCV} \quad (1.4)$$

$$(b) \text{ Moisture loss } (L_m)\% = \frac{(9H_2 + m) \times (H_s - h_a) \times 100}{GCV} \quad (1.5)$$

or

$$\text{on NCV basis}\% = \frac{(9H_2 + m) \times (H_s - h_a - 578) \times 100}{NCV}$$

$$(c) \text{ Humidity loss } (L_h)\% = \frac{W_h \times (H_s - h_a) \times 100}{GCV/NCV} \quad (1.6)$$

where

W_g = weight of gas leaving the system in kilograms per kilogram of fuel burnt (not fired)

W_h = weight of moisture in air in kilograms per kilogram of fuel burnt (not fired)

T_g = temperature of flue gas leaving the system in degrees Celsius

T_a = temperature of air entering the system in degrees Celsius and the ambient temperature in most cases, less air heated from external source

C_p = mean specific heat of gas between T_g and T_a in degrees Celsius

W_a = weight of air in steam AH in kilograms per kilogram

H_2 = percent hydrogen in fuel by weight

M = percentage of moisture in fuel by weight

H_s = enthalpy of steam at T_g and 0.07 bar (1 psia) is equal to 578 kcal/kg

h_a = enthalpy of water at T_a in kilocalories per kilogram

1.5.4.2 Unburnt Loss

Unburnt loss is a measure of how well the fuel is burnt in the firing equipment for the excess air chosen. Efficiency of heat release of the firing equipment is measured by the amount of carbon burnup, which is

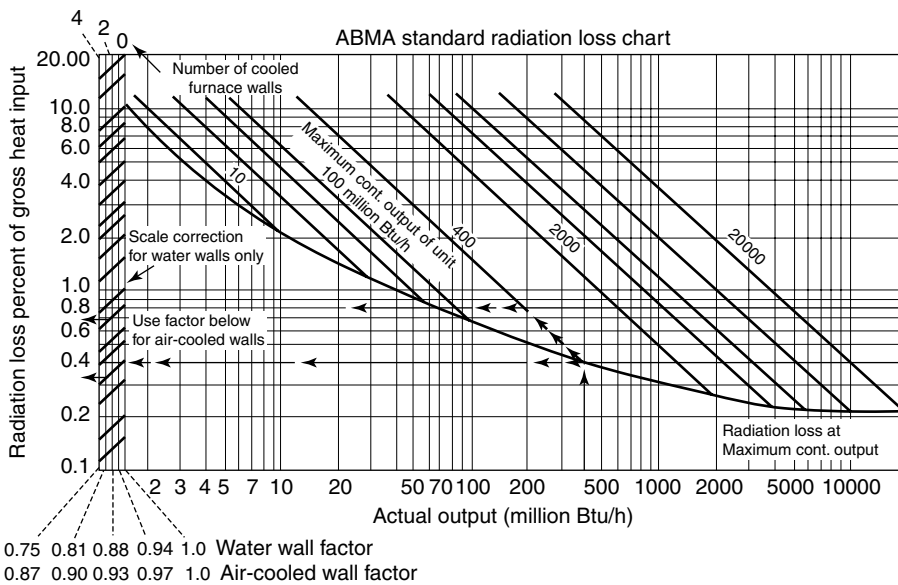
$$C_b = \frac{(100 - \% \text{ carbon in the residue})}{\% \text{ total carbon at inlet}} \quad (1.7)$$

Carbon burnup varies a great deal with different types of fuels, firing equipment, excess air, and ash content. For gas and oil, carbon burnup is nearly 100% for coal, 98–99% for CFBC and PF, 90–95% for BFBC, and 80–90% for stokers. The finer the fuel size and greater the turbulence, the lower the excess air requirement and higher the carbon burnup. Carbon burnup is also influenced by volatile matter (VM) in fuel. Unburnt loss is generally ~1–2% for PF and CFBC, 4–6% for BFBC, 4–10% for coal, and 2% for bagasse. The correct way to estimate this loss is to calculate from the proprietary data of the firing equipment manufacturer and compare with the previous field results to see if it needs any correction. Unburnt losses for various fuels and firing methods are listed in Table 1.4.

TABLE 1.4

Unburnt Losses from Various Fuels in Different Firing Devices

Method of Firing	Carbon Burnup (%)	Unburnt Loss (% of Gross Calorific Value)
Gas	100	0
Oil	~100	~0
PF and CFBC (coal)	>98	<2
Bubbling fluid bed combustion (coal)	85–90	4–6
Stoker (coal)	80–90	4–10
Stoker (bagasse)	~98	~2

**FIGURE 1.5**

Radiation loss as per American Boiler Manufacturers Association (ABMA).

1.5.4.3 Radiation Loss

Radiation losses are below 1%, and become smaller as the boiler size and water cooling increase. Generally the American Boiler Manufacturers Association (ABMA) graph is followed (Figure 1.5).

- This is a comprehensive loss caused by radiation and convection conductance for the entire boiler, that is, the main boiler setting, ducting, and milling plant.
- The surface to ambient temperature difference is considered as 50°F (~27°C) and the air velocity 100 ft/m (~0.5 m/s).
- A furnace wall must have at least one-third of its projected surface covered by water-cooled walls before reduction in L_r is permitted.

There are several limitations in this graph, yet it is very popular because of its convenience and the low value of L_r . For example, the loss from a compact oil-fired boiler is the same as that from a large PF-fired boiler of the same evaporation, as the graph is based on the boiler output and not on the surface area. Likewise, FBC boilers were uncommon when this graph was evolved. Radiation losses from big high-temperature cyclones are not accounted for here. Suitable additional losses may have to be considered.

1.5.4.4 Unaccountable Losses (L_u)

Unaccountable losses cannot be exactly quantified and are small enough to be combined and assigned a reasonable value. They comprise, usually,

- Heat loss in ash
- Effects of sulfation and calcination reactions in FBC boilers
- Unstated instrument tolerances and errors
- Any other immeasurable losses

For example, in oil firing, the heat carried away by the atomizing steam falls in the last category. The L_u are considered usually for various fuels as given in Table 1.5.

In FBC the sensible heat loss is high, as the bed material also gets discharged along with ash. The loss is higher if limestone is also added for desulfurization. As it is possible to measure or estimate the bottom discharge, it is customary to adopt sensible heat loss instead of L_u .

1.5.4.5 Manufacturers' Margin and Tolerance

Manufacturers' margin (MM) and tolerance come into picture when the calculated efficiency figures are to be converted into guarantees. These are somewhat subjective. Tolerance figure may or may not be allowed. If not allowed, the calculated figures are reduced suitably and minimum efficiency is offered.

Manufacturer's margin is a safety figure accounting for any inaccuracies of design, manufacturing, and erection that can take place inadvertently. It is also to account for any unexpected variation in performance.

Tolerances cover errors and omissions as well as instrument tolerances encountered in performance trials. These are usually subject to mutual agreement between the buyer and the seller.

It is best to eliminate MM and tolerance and evaluate on a minimum efficiency basis, as practices differ in different countries. The accepted figures in the industry for L_u , MM, and tolerance are listed in Table 1.5.

TABLE 1.5

Normally Accepted Figures for Unaccountable Losses, Manufacturers' Margins, and Tolerances

Fuel	Firing	Unaccountable Loss (%)	Tolerance	Manufacturers' Margin (%)
Gas	Burner	0.25		0.25
Oil	Burner	0.25	+0/−5.0% of losses	0.25
Coal	PF	0.25		0.5
	Grate	0.5	+0/−6.5% of losses	1.0
Biofuels	Grate	1.0		1.0

1.5.4.6 Heat Credits

Heat credits are sometimes considered when the power consumed in fans and mills is sizable and a part of energy is returned to the system in the form of heat. In CFBC boilers, for instance, the FD and PA fan heads are high enough to heat the incoming air by 20–30°C, which merits its consideration for heat credit. Also see Section 12.3.4.

1.5.4.7 Efficiency on NCV

For arriving at boiler efficiency on the basis of NCV, multiplying the efficiency by the NCV/GCV fraction is a rough method, which is nearly correct and good enough for normal purposes. If a more accurate figure or loss breakup is desired,

- Losses 1a, 1c, 2, 3, and 4 have to be adjusted by the NCV/GCV ratio.
- Adjustment has to be made in loss 1b alone for heat carried away by water vapor as given earlier.

See page 17: The example in Appendix A explains this adequately.

1.5.5 Typical Efficiency Calculation

For a hypothetical stoker-fired boiler, the efficiency calculations are as given in Appendix A. Any efficiency calculation has the following two parts:

1. Combustion calculation
2. Estimation of loss account to arrive at the efficiency by difference

Using the efficiency figure, the fuel fired and fuel burnt can be estimated, which paves the way for further calculations. The efficiency calculation in Appendix A is self-explanatory.

1.6 Performance Testing of Boilers

Heat balance and performance testing are final steps of boiler implementation. The final act of performance testing is followed by taking over of the plant by the owner and final financial settlements. The warranty period of the boiler commences thereafter. Therefore, it is very important that the testing procedures are conducted impartially to avoid expensive legal battles. American Society of Mechanical Engineers (ASME) performance test code (PTC) 4 is very widely followed. BS 2885 and DIN 1942 are the equivalent British and German codes.

Performance testing is best done on a new boiler before the natural wear and tear sets in. But this is usually not possible for various reasons. At the time of sale it is usual to decide the time limit before which the testing is to be carried out and the way it is to be performed. In small and medium plants it is possible to vent the steam for the duration of testing and complete the formality of testing.

Is it necessary to conduct the performance test? If it is not mandatory as per contractual terms, the test is often waived. This is because the preparatory work for testing is demanding in terms of manpower and other resources. Besides, it is necessary that the plant be handed over to the supplier to allow for tuning of the boiler for about a week. This leads to a certain loss of boiler availability, which the plant may not be able to afford. Also, the plant operators can easily determine whether a boiler is meeting performance

standards. A boiler test is usually required only when there is a fear of reduced or marginal performance.

$$\text{Gross efficiency} = \frac{\text{net output}}{\text{total input}} \% \quad (1.8)$$

It is a direct measurement of efficiency if steam output can be measured. Rewriting the formula by substituting $\text{output} = \text{input} - \text{loss}$, we arrive at

$$\text{Gross efficiency} = 100 - \frac{\text{heat loss}}{\text{fuel input}} \% \quad (1.9)$$

The loss is measured instead of the output. Boiler efficiency as derived this way is the gross efficiency. When the heat equivalent of auxiliaries is subtracted from the output, the efficiency calculated is the net efficiency. The input comprises the fuel input plus the heat credits to the system if any, such as the air temperature rise in the fans. Thus,

$$\text{Gross efficiency} = 100 - \frac{\text{heat losses}}{\text{fuel heat input} + \text{heat credits}} \% \quad (1.10)$$

Performance evaluation serves two purposes:

1. A routine measurement in a running plant to assess whether course correction is needed
2. Acceptance of a new or refurbished boiler to check whether the promised performance has been delivered

1.6.1 Input–Output Method

This (or direct method as per BS) is a simple method for calculating the efficiency, which gives an approximately correct value, but with a wide tolerance. It is good enough to reveal the general picture routinely in small-to-medium oil- and gas-fired boilers, which use fuels with nearly constant CV levels that are amenable to a fairly accurate flow measurement. This procedure can be misleading in case of coal firing where the fuel varies constantly in CV and density. This method is certainly not good enough for acceptance test in boilers of any meaningful size, as the procedure involves measuring the steam and fuel flows that may not be accurate enough.

1.6.2 Heat Loss Method

Heat loss (or indirect method as per BS) is

1. *Practical* because it calls for no flow measurements to calculate efficiency
2. *More accurate* because it involves measuring only the loss and not the efficiency

In measurement of any loss, the sensitivity of any inaccuracy is considerably reduced on the final result. For example, in a boiler of 80% efficiency, a 2% error of a parameter reflects as 1.6% in the final result from the input–output method whereas it reduces to only 0.4% from the heat loss method. This is because it is 2% of 80% in the former, whereas it is 2% of

20% in the latter. This method has been overwhelmingly adopted in the industry, particularly for acceptance testing.

ASME PTC 4.1 (1964 and reaffirmed in 1991) specifies an abbreviated test procedure more suitable for

1. Routine testing of all boilers
2. Acceptance testing of industrial boilers

Only the major loss is considered and only the chemical heat of the fuel is taken as the input. Humidity loss is small and is not considered in abbreviated testing.

For utility boilers a *long test*, considering all loss and heat credits, is recommended, but many times the abbreviated procedure is adopted for its practical approach and simplicity. Besides, the costs of boiler testing are lower.

The main measurements in the heat loss method for calculating efficiency are

- Temperatures (feed in, SH out, RH in, RH out, exit gas, and ambient air)
- Pressures (SH out, drum, SH in, and RH out feed)
- Flue gas analysis at exit preferably by Orsat analyzer
- Heating values of ash and fuel

Steam flows of SH and RH are also measured to establish the evaporation, but they do not figure in calculating the efficiency. They are measured to ensure that the flow conditions are met. The *salient points* with regard to the performance testing of boilers are as follows:

- For setting the boiler parameters correctly and tuning the performance and controls, the boiler should be handed over to the manufacturer a couple of weeks or so before the test, as required. Larger boilers require longer tuning time. For industrial boilers a week should be sufficient.
- More time is required to set up the test instrumentation, particularly the thermocouples, gas sampling lines, and ash-collecting probes. In a large utility this can take typically 6 weeks. The time may be reduced if more gauge instrumentation is accepted instead of test instrumentation.
- The actual test should be short, >4 h as per code and <6 h by practice, as running the boiler with constant load is not easy in power and process plants. Also there should be no soot blowing and blowdown.
- Peak and minimum output demonstration tests are kept outside of this main test period.
- Part load efficiency test or testing on alternate fuels, if required, is scheduled for different days.
- The duration of the test, procedure, scope, fuels, tolerances, etc. should be agreed in advance.
- The testing of the boiler should be a steady state operation; the boiler should be running at the prescribed load for a few hours before and after the test.
- All the instruments are required to be of test quality and must be calibrated. It is normally necessary to perform trials for a couple of days to get systems, instruments, and manpower properly tuned.
- All test readings are taken usually at 15 min intervals except for fuel and ash samples that are taken every hour.

The test codes explain the requirements in detail, and they must be referred to for more information on procedures, precautions, and calculations.

The enthusiasm to determine the exact efficiency should be tempered with the reality it is an expensive and difficult task to isolate a boiler for testing purposes for a week or two. Many times, therefore, the testing is not undertaken, particularly when the operating staff is convinced that the boiler meets needs.

1.6.3 Calculation of Efficiency from Performance Test Results

The principle behind calculation of efficiency is as follows:

- Losses 1a, 1b, and 2 are calculated from test results.
- Loss 3 is read from ABMA chart.
- Loss 4 is agreed before the test.

For calculating Lub (loss 2) in the case of PF-fired and FBC boilers, the ash distribution between fly ash and bottom or bed ash is often agreed upon, based on the boiler operation. This is because the loss is <2% and the sensitivity of error in the ash distribution is very small in comparison to the effort required to collect the data correctly. The code gives the following formulae for arriving at the losses 1a, 1b, and 2 using

- Flue gas analysis (CO_2 , CO , O_2 , N_2 percent by volume in dry flue)
- Fuel analysis (C, H, S percent in fuel)
- Carbon in flue gas (C_g) and ash in percent by weight
- Temperature of exit gas and inlet air
- GCV or NCV in kilocalories per kilogram

The given formulae are used for calculating the losses 1a, 1b, and 2 on a GCV basis.

- Loss 1a:

$$\text{Dry gas loss (Ldg)\%} = \frac{W \times 24(T_g - T_a)}{\text{GCV}} \quad (1.11)$$

where W is the weight of dry flue gas per kilogram of fuel.

$$W = \frac{11\text{CO}_2 + 7(\text{CO} + \text{N}_2) + 8\text{O}_2}{3(\text{CO}_2 + \text{CO})} (C_g + \frac{S}{183}) \quad (1.12)$$

where C_g is the weight of carbon in flue gas per kilogram of fuel.

- Loss 1b:

$$\text{Moisture loss (Lm)\%} = \frac{[(100 - T_a) + 539 + 0.5(T_g - 100)](9\text{H}_2 + m)}{\text{GCV}} \quad (1.13)$$

TABLE 1.6

Measurements and Tolerances for Heat Loss Method

Measurement	Measurement Error (%)	Error in Calculation of Boiler Efficiency (%)
Gross calorific value (coal)	0.50	0.03
Gross calorific value (oil/gas)	0.35	0.02
Orsat analysis	3.00	0.30
Exit gas temperature	0.50	0.02
Inlet air temperature	0.50	0.00
Ultimate analysis of coal—C, H ₂	1.00	0.10
H ₂ O in fuel	1.00	0.00

Note: All figures in percentage are $\pm$ for both error and efficiency; air and gas temperature measurements were made by calibrated devices.

- Loss 2:

$$\text{Unburnt loss (Lub)\%} = \frac{\text{percent ash in fuel} \times C_a \times 80.78}{\text{GCV}} \quad (1.14)$$

where C_a is percentage of combustibles in fly and bottom or bed ash.

PTC 4.1 provides for a certain tolerance when it specifies measurement errors for all types of instruments used in testing and the corresponding error in calculated efficiency. This works out to approximately $\pm 0.3\%$ for the overall efficiency figure.

Table 1.6 lists the accepted measurement error of each variable and its effect on the test result. The maximum effects are, as shown in the table, in the analyses of coal by bomb calorimeter and gas by Orsat analyzer.

1.6.4 New 1998 Boiler Performance Test Code

PTC 4.1 issued in 1964 and reaffirmed in 1991 was superseded and withdrawn in 1998 to be replaced by a new code PTC 4 that corrects many deficiencies of PTC 4.1 and makes the testing more accurate. However, PTC 4.1 in many parts of the world continues to be followed. Table 1.7 shows the essential differences between the two codes.

Even if the test uncertainty is eliminated and the tests are performed with the same type of instruments to the same levels of accuracy, the results of the tests conducted by the two methods would marginally vary. This is, first of all, because of slight differences in fuel efficiency as per PTC 4 and gross efficiency as per PTC 4.1 in the way the heat credits are treated. PTC 4 defines the reference temperature, makes heat credit accounting compulsory, and adopts certain minor improvements in the calculation methods. PTC 4 is, on the whole, a more comprehensive test code based on modern measurement, data reduction, and calculation with uncertainty analysis included and is therefore superior to PTC 4.1. There are certain differences in the estimation of loss and credits between the two codes as shown in Table 1.8.

TABLE 1.7

Salient Points of Difference between PTC 4.1—1964 (1991) and PTC 4—1998

Parameter	Performance Test Codes (PTC) 4.1	Performance Test Codes (PTC) 4	Remarks
Gross versus fuel efficiency	100 – (heat loss/fuel input + heat credits) %	100 – (heat loss – heat credits/fuel input) %	Fuel efficiency replaces gross efficiency of PTC 4.1; fuel flow is directly calculable
Test uncertainty	Not considered	Uncertainty values listed in 1.3-1 and level to be agreed	Mainly driven by economical instrumentation and data sampling procedures chosen; Section 4 of PTC 4 provides background and guidance
Radiation and unaccountable loss	ABMA radiation loss curve to be used	Losses are accurately evaluated; ABMA curve not used	
Reference temperature	Usually ambient; heat credits can be neglected	25°C to be adopted and heat credits and loss are calculated	With a fixed reference temperature, all results are on the same basis and are directly comparable
Output	Energy absorbed by working fluid	Energy absorbed by working fluid that is not recovered within steam generator envelope; for example, steam to SCAPH	
Objectives		Better covered	Test objectives or performance parameters
Corrections		Better defined	Corrections to design conditions
Flue gas	Based on measured O ₂ and CO ₂	Based on measured O ₂ , both wet and dry	For efficiency calculations
Calculation of losses and credits	Specific heat	Enthalpy	In PTC 4, the enthalpies of dry air, dry flue gas, moisture vapor, and fuels are defined by equations (curve fits)
Fuel analysis	Mass basis	Conversion from volumetric to mass is also provided	

1.6.5 Performance Testing of Waste Heat Recovery Boilers

PTC 4.1 does not cover the waste heat and special-purpose boilers for which testing procedures must be evolved and agreed. Waste heat recovery boilers are components of process plants, and certain expectations besides steam production need to be met. Over the years, each process has undergone a certain method of testing and evaluating performance. The previous histories are helpful for developing suitable methods and procedures.

1.6.6 Performance Testing of Heat Recovery Steam Generators

There are major differences in the way the HRSGs behind GTs are tested compared to conventional boilers, even WHRBs. The HRSG is treated as part of a combined cycle power plant (CCPP) instead of a stand-alone steam generator.

- For HRSGs behind GTs PTC 4.4 is applied and not PTC 4.
- The performance test is a direct test.

TABLE 1.8

Differences in Measurements of Losses and Credits between PTC 4.1 and PTC 4

Loss	PTC 4 Item	PTC 4.1	PTC 4.1 Abb. Test	H/C _p Potential Difference	Notes
1a	Dry gas loss	Yes	Yes	Yes	—
1b	Moisture loss from H ₂ and H ₂ O	Yes	Yes	No	No change
1c	Moisture in air loss	Yes	No	No	No change
	H ₂ O vapor in fuel loss	No	No	—	New item
2	Unburned carbon loss	Yes	Yes	—	No change
3	Surface radiation and convection loss	Yes	Yes	—	As noted earlier, the calculation procedure is different, and PTC 4 generally yields greater loss for coal-fired units
4	Sensible heat of residue loss	Yes	No	Yes	Users may agree on residue split if not measured
New	Hot air quality control equipment loss	No	No	—	New item added to distinguish the loss due to the hot air quality control equipment separate from the steam generator
	Entering dry air and moisture in dry air credit	Yes	No	Yes	—
	Sensible heat in fuel credit	Yes	No	Yes	—
	Auxiliary equipment power credit	Yes	No	—	No change
	Loss and credits for sorbent reactions	No	No	—	Different from prior industry values published by the ABMA

- No separate efficiency guarantees are demanded of HRSGs as the guarantees for total CCPP are given.
- HRSG is required to only demonstrate the (1) gas pressure loss and (2) steaming conditions of HP, IP, and LP steam circuits at the specified loads with the GT exhaust gas supplied at specified quantities and temperatures.
- Steam pressures and temperatures are noted along with inlet and exhaust gas pressures and temperatures of the HRSG. It is normal to adopt this direct method and perform the test that lasts at least 2 h.
- The plant must be running at nearly the same load as the test load, for some time before and some time after the test, to attain a steady-state condition.
- There should be no blowdown during test.
- The drum levels at the beginning and end of the test should be nearly the same.
- The frequency of test readings can be at more than 10 min for all primary readings except for flowmeter readings that must be recorded every 5 min.
- The code specifies the measuring tolerances (Table 1.9).

TABLE 1.9

Tolerances for Direct Measurement of Parameters (PTC 4.4)

Variable	Variation
Water flow to ECON	±2%
ECON recirculation flow	±3%
DeSH water flow	±4%
Blowdown flow	±4%
Fuel flow to gas turbine	±2%
Supplemental fuel flow	±2%
GT power output	±2%
GT to boiler	±10°F
Stack gas temperature	±10°F
Water temperature to ECON	±10°F
Steam temperature at DeSH exit	±10°F
Ambient temperature	±5°F
Barometric pressure	±1%
Steam pressure	±2%
Flow	
Air	±2%
Heat recovery steam generator gas	±2%
GT exhaust	±2%

Note: Variation of any station observation from reported average test condition during a test run.

1.7 Boiler Evaluation

- Boiler specification and purchase are very important functions as the life of a boiler plant exceeds 30 years. Proper purchase can save huge amounts in capital and running expenditure and an error can be disastrous.
- Because a boiler is a customized item, it costs a lot of time and effort for the boilermaker to prepare a bid and an equal effort by the customer for evaluation. The efforts can be saved if the specification is prepared carefully and the evaluation is done efficiently.
- It is normal to advise the bidders of the evaluation terms at the time of bidding so that the proposals received are responsive and tailored for compliance.

The two most important parameters for evaluation are

1. Efficiency
2. Auxiliary power consumption

The cost of fuel and the regime of interest rates govern loading factors. Higher fuel and interest costs demand greater efficiency that justifies the additional cost via a faster return on investment. The following points should be considered in evaluating boilers:

- The first step is a careful analysis of the plant requirement under all conditions of operation, at both full and part loads. A proper set of specifications is required and only thereafter are bids requested.

- A request for quotation must include parameters for evaluation and the corresponding loading factors, to enable the bidders to understand the operating philosophy and respond in the most appropriate manner.
- The specification must clearly state what parameters must be met without fail and what items may be customized. What are the criteria for rejection of bid or award of contract?

On receipt of bids at the buyer's office a comparison must align the bids with the specifications. Usually this involves detailed technical discussions. Only then can the bid evaluation take place. A typical basis for bid evaluation considers these points:

- A plant has to be designed for the best efficiency and the least auxiliary power.
- Of 8760 h in a year it is reasonable to assume that the plant would operate for 8000 h, after accounting for statutory shutdowns and maintenance. The plant would operate at ~85% of the rated load on an average. Alternately, it is even better to calculate the number of hours for each load at which the plant would be operating.
- Estimated running of plant on each fuel and the realistic landed cost of fuel should be noted.
- If a plant is expected to operate at part loads for longer times the part load performance data are to be obtained from the boilermaker and evaluation worked out suitably. This is because the part load performance varies among boilers and technologies. For example, the part load performance of a BFBC is significantly lower than that of CFBC or PF and one may erroneously opt for BFBC based only on full-load performance.
- Auxiliary power for boiler normally takes into account only the fan power as the feed station is part of the turbine island in power plants.
- Since the auxiliary power of the total power plant has to be minimized, loading factors for pressure drops across the SH and RH must be specified upfront to the boilermaker.
- All loading factors address the performance and not the build quality. Loading for nonavailability of the boiler, after factoring into account the statutory shutdown and any other forced major conditions, is sometimes done to enhance the reliability factor.

The evaluation process consists of calculating the annual fuel and power consumptions of the various bids for the specified number of operating hours and converting them into monetary values based on the given costs. The bid with the least operating costs is the one to be selected. Alternatively the differential cost on any base bid can also be worked out and loaded on the other bids. Boilers, particularly the medium and larger ones, are tailor-made and the evaluation factors promote a greater level of customization to meet specific needs.

1.8 Boiler Design for Optimum Performance

The goals of good boiler design include:

- Customization to meet specific requirements
- Optimization of performance
- Good build quality for reliable operation

Performance optimization is the most important, mainly by lowering of the boiler losses and auxiliary power consumption. The losses that can be lowered are only stack and unburnt losses, and the savings in power are mainly in the fans and pumps. The following are some of the measures usually adopted.

1.8.1 Stack Loss Reduction

There are two important components to the stack loss: (1) exit gas temperature and (2) excess air at the last heat trap.

- *Exit gas temperature* should be as low as possible, consistent with the avoidance of low-temperature gas side corrosion as depicted in Figure 6.36. This works out to a temperature of $\sim 140^{\circ}\text{C}$ (285°F) for most coal-fired boilers where there is no appreciable sulfur in fuel.

The larger the surface, the better the cooling of gases, and the higher the boiler efficiency. But there is a sharp rise in costs, as surfaces required to cool the gases are significantly hotter at lower gas temperatures as shown in Figure 1.6. Approximately 40% of total HS of boiler residing in AH captures only $\sim 10\%$ of the total heat. The benefit lies in understanding the cut-off point beyond which the cost of adding surface outweighs the gain in efficiency.

- *Excess air* should be at minimum without compromising on the completeness of combustion as evidenced by only some traces of CO in flue gas. This requires a good layout of ducting to distribute the combustion air uniformly, besides a careful metering of air and fuel. Optimum excess air for each type of firing is listed in Table 2.12.

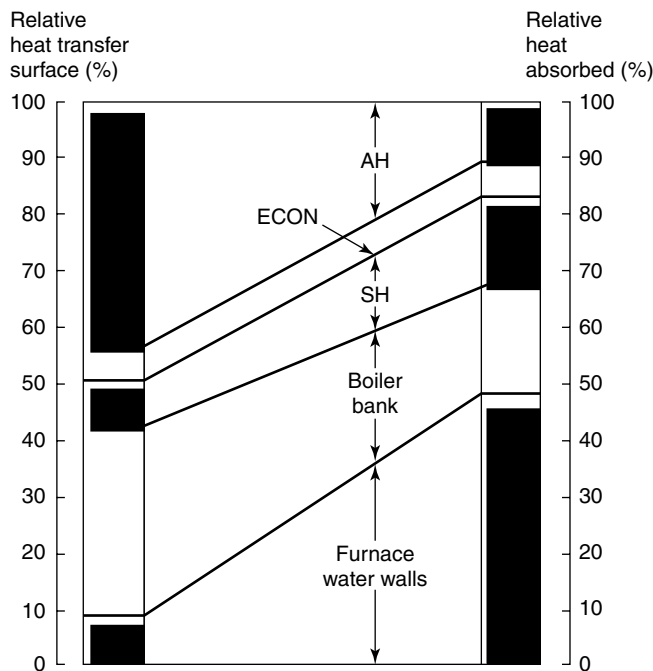


FIGURE 1.6

Relative effectiveness of heating surfaces. (From *Power Magazine*. With permission.)

- *Air infiltration* into the furnace setting and boiler should be minimized in a balanced draft boiler to reduce the weight of gases exiting. Membrane panelings of furnace, welded joints in all flues and ducts, pressure-tight casing, and high-quality leak-proof expansion joints can keep the air infiltration to a minimum. The joints through which air can leak inside, such as the gaps around the stoker and spaces around the suspension rods, should be carefully sealed.
- *Gas bypassing*. Many times the desired cooling of the flue gas does not take place despite the provision of adequate surfaces based on the consequent loss of efficiency. This can be traced to the flue gas bypassing around the tube banks due to excessive gaps. Lack of suitable deflection baffles is the cause that has to be remedied.
- *Gas leakages*. Gas and air bypass ducts to protect the AH against low-temperature corrosion during startups and low loads are simple and effective, but are difficult to seal in normal operation, unless they are very small and closed with pneumatically operated dampers. Leakage through them can increase the exit gas temperature.

1.8.2 Unburnt Loss Reduction

- Unburnt loss indicates how well the firing equipment and furnace are sized and matched such that
 - The three Ts—time, temperature, and turbulence—are adequately addressed.
 - Heat release rates of the firing equipment and the volumetric heat release rate of furnace are judiciously selected to burn the fuel optimally.
 - Air pressures, temperatures, and distribution are selected properly to help release the fuel heat fully. For example, hot air is necessary for proper burning of biofuels. It is also good for coal but depending on the coal properties, the temperatures should be limited to less than certain limits to avoid clinkering or caking.
- Sizing of solid fuel is of paramount importance in the firing to limit the unburnt carbon in the ash.
- Selecting proper bed temperatures in FBC or firing temperatures in PF is another factor for reducing the unburnt carbon.
- Proper arches in stoker firing deflect the gases on to the bed and aid ignition and effective burnout.

1.8.3 Radiation Loss Reduction

- All the walls of the furnace are to be fully water-cooled, as achieved regularly in modern boilers by membrane walls. Refer to Chapter 6.
- The boiler along with ducts and piping is insulated such that the surface temperature is not more than 20–25°C over the prevailing ambient temperature.

1.8.4 Fan Power Reduction

- Lowering the gas velocities over the tubes can reduce gas pressure drop in the boiler. But this reduces the heat transfer rates and makes the boiler larger and

more expensive. A balance between the heat transfer rate and the pressure drop is necessary, which is largely taken care of by following the recommended optimum gas velocities and tube spacing cited in Chapter 6.

- Lowering the excess air quantity is necessary to lower the volumetric capacity of the fans; this concept helps in choosing fans of correct size and reducing the fan power.
- Choosing the highest available fan efficiency, even by paying a bit more, is prudent as the fan power may reduce drastically. Refer to Chapter 8 for more details on fan selection.
- For small fans up to ~150 kW, belt drives are popular as they provide the optimal revolutions per minute (rpm) for the duty that consumes the least power.
- Variable-speed hydraulic couplings, installed between the constant-speed motor and the fan, reduce the speed of the fans at lower loads, and help to reduce the power consumption more effectively than inlet guide vanes.
- Variable-frequency drives, which vary the motor speeds by varying the frequency of the power to the motor, are better but more expensive.
- When the fans are large, as in utility applications, axial flow design is considered, at least for clean application, as axial flow is inherently more efficient. They are, no doubt, more expensive, are delicate, and demand more careful operation, but become more economical for larger sizes based on life cycle costing.

1.8.5 Feed Pump Power Reduction

Feed pumps absorb the most auxiliary power in a power plant, and hence power savings here make a big difference in actual kilowatt hour (kWh) terms.

- Reduction of SH and RH losses is a normal measure to reduce pump power.
- Adding minimum test block margins consistent with good operating practice is another important step.
- Selection of pumps at the highest efficiency point is the best way to secure the least power (refer to Section 2.5.8).
- Speed variation by hydraulic coupling or by variable-frequency drives (VFD) helps to reduce the pump power even more.
- Variable-pressure operation of the power plant is the next step in saving even greater power, applicable largely for large utility boilers.

1.9 Designing to Boiler Codes

All the leading boiler-making countries have their own boiler and pressure vessel codes. These codes evolved after the early boilers experienced disastrous explosions on account of failure of PPs due to the rise of internal pressure. The boiler codes are

essentially extensions of pressure vessel codes customized for fired equipment. It should be clear that the boiler codes are concerned with safety aspects only and not with the sizing or thermal design of boilers. Besides the boilermakers and steam users, the insurance companies, the labor and safety departments of the government, and the bureaus of standards are all participants in formulating the codes. In some countries the codes are evolved and enforced by the designated government department that deals with public safety.

Boilers along with their mountings and fittings, pressure vessels, and piping are covered together as one body.

The boiler codes comprehensively deal with safety aspects in all areas of boilermaking and operation including boilers for nuclear applications.

- Mechanical design
- Manufacturing and workmanship
- Materials and stresses
- Inspection and testing
- Documentation and marking
- Care and operational guidelines
- Welder qualification

ASME Boiler and Pressure Vessel Committee. The American code for boilers, which is perhaps the most extensively followed code even outside of the United States and Canada (where its use is mandatory), was developed under the aegis of Boiler and Pressure Vessel Committee (BPVC) of ASME, first formed in 1911. The first issue of ASME BPVC was in 1915 and was titled *Boiler Construction Code 1914 edition*. Today it has its sections developed by three subcommittees working on

1. *Components books* for power, nuclear, and heating boilers and pressure vessels
2. *Service book* for materials, nondestructive examination, welding, and nuclear in-service inspection
3. *Technology* for design, safety valve requirements, boiler and pressure vessel accreditation, and nuclear accreditation

The ASME Boiler and Pressure Vessel (BPV) Code of 2007 has 12 sections as shown in Table 1.10.

Piping. The ASME code for pressure piping B 31 is divided into several sections covering power, fuel gas, chemical plant, refrigeration, and so on. B 31.1 is the most relevant section for power engineers.

National Fire Prevention Association (NFPA). ASME Boiler and Pressure Vessel (BPV) codes do not deal with firing equipment or burner management systems, which are equally important for boiler safety. They are covered by the design rules evolved by NFPA. There are more than 300 code books published by NFPA covering all possible areas where fire hazard can be present.

TABLE 1.10

Sections of American Society of Mechanical Engineers Boiler and Pressure Vessel Committee 2007

No.	Section
I	Rules for construction of power boilers
II	Materials, Parts A–D
III	Rules for construction of nuclear facility components, Parts 1–3
IV	Rules for construction of heating boilers
V	Nondestructive examination
VI	Recommended rules for care and operation of heating boilers
VII	Recommended guidelines for care of power boilers
VIII	Rules for construction of pressure vessels
Div. 1	Pressure vessels
Div. 2	Pressure vessels—alternative rules
Div. 3	Alternative rules for construction of high-pressure vessels
IX	Welding and brazing qualifications
X	Fiber-reinforced plastic pressure vessels
XI	Rules for in-service inspection of nuclear power plant components
XII	Rules for construction and continued service of transport tanks

Note: Leading boiler codes of other countries also cover these aspects. Perhaps the ASME code is the most comprehensive, besides being regularly updated every 3 years.

However, the code applicable to boilers is only NFPA 85, titled *Boiler and Combustion Systems Hazards Code*, whose purpose is to contribute to operating safety and to prevent uncontrolled fires, explosions, and implosions in equipment as described in Section 1.1.

This code is applicable to

- Single burner boilers
- Multiple burner boilers
- Stoker-fired boilers
- Atmospheric fluidized-bed boilers with a fuel input rating of 3.7 MWth (12.5 million Btu/h) or greater
- Pulverized fuel systems
- Fired or unfired steam HRSGs

Documents referenced within this code are considered part of the requirements of NFPA 85. These are given in Table 1.11.

Boiler auxiliaries. The design rules for boiler auxiliaries are not specified, unless they are pressure holding. The valves, mountings, and fittings are covered by ASME BPV code but not the fans, AHs, mills, etc. For these auxiliaries, design rules are not mandated by codes but ASME PTCs are available.

Performance test codes. ASME PTC, as the name suggests, defines testing of auxiliary equipment for acceptance purposes. These codes cover all equipment in a power plant including boiler, HRSG, AH, mills, steam purity, etc. Table 1.12 lists more than 21 PTCs that are relevant to boiler engineers.

TABLE 1.11

National Fire Prevention Association Codes Relevant to Boilers

Code	Title	Edition
85	Boiler and combustion systems hazards code	
30	Flammable and combustible liquids code	2003
31	Standard for the installation of oil-burning equipment	2001
54	National fuel gas code	2002
69	Standard on explosion prevention systems	2002
70	National electrical code	2002

TABLE 1.12

List of Performance Test Codes Relevant to Boilers

PTC	Year	Title
4	1998	Fired steam generators
4.2	1969 (R1997)	Coal pulverizers
4.3	1968 (R1991)	Air heaters
4.4	1981 (R1992)	Gas turbine heat recovery steam generators
6	1996	Steam turbines
6A	2001	Test code for steam turbines—appendix to PTC 6
6-S		Procedures for routine performance test of steam turbines
8.2	1990	Centrifugal pumps
11	1984 (R1995)	Fans
12.3	1997	Deaerators
19.1	1998	Measurement uncertainty
19.2	1987 (R1998)	Pressure measurement
19.3	1974 (R1998)	Temperature measurement
19.7	1980 (R1988)	Measurement of shaft power
19.8	1970 (R1985)	Measurement of indicated power
19.10	1981	Flue and exhaust gas analyses
19.11	1997	Steam and water sampling, conditioning, and analysis in the power cycle
21	1991	Particulate matter collection equipment
22	1997	Performance test code on gas turbines
25	1994	Pressure relief devices
36	1998	Measurement of industrial sound
38	1980 (R1985)	Determining the concentration of particulate matter in a gas stream
46	1997	Overall plant performance
PM	1993	Performance monitoring guidelines for steam power plants

1.9.1 Basics of Boiler Pressure Part Design

The PPs of a boiler consist essentially of rounds of three types categorized as (1) drums, (2) headers, and (3) tubes. The PP design of boiler components is primarily built around a thin shell of components, where the thickness is derived from the formula

$$t = \frac{pd}{2f} + c \quad (1.15)$$

where

p = calculation pressure of the component

d = mean diameter

f = allowable stress at the design temperature

c = design allowance to cover for effects such as corrosion and erosion

Pressure. Design pressure of the boiler is generally the highest safety valve lifting pressure. Some codes demand that all the components be designed uniformly to a single pressure, namely the boiler *design* pressure. In such a case the design and calculation pressures are the same.

Some codes permit adjustments to the design pressure to take into account the pressure drops in the steam pipes and tubes and also the effects of the static head. The design pressure in such case will be adjusted to arrive at the *calculation* pressure.

The pressure that a component can safely withstand without exceeding the safe permissible limits at the specified design temperature is the *maximum working* pressure.

Temperature. The design temperature of the boiler component is the maximum temperature to which it can be subjected under upset conditions. This can occur typically when there are load rampups, peak loads, unbalance in steam and gas flows and temperatures, operation with slagging and fouling, and so on. For different components the margins to be added for arriving at the design temperature are different and the code specifies the values.

Allowable stresses. The stress values to be used in the design are temperature-dependent.

- Tensile strength governs the stress values up to a temperature of $\sim 300\text{--}350^\circ\text{C}$ ($\sim 570\text{--}660^\circ\text{F}$). Drums and all headers, except for SH and RH, are therefore decided by tensile strength considerations. ECON and evaporator tubes also fall in this category in most cases. ASME specified, since 1998, a safety factor of 3.5 over the room-temperature tensile strength. European codes are less conservative, as they adopt a lower factor in the range of 2.5–2.7.
- Yield strength governs the stress values between ~ 300 and 500°C ($\sim 570\text{--}930^\circ\text{F}$) depending on the metallurgy. The safety factor adopted by ASME is 1.5, which is the same as that for the European practice. Bulk of the lower-end SH and RH tubes and headers fall in this range.
- Creep strength or stress to rupture, whichever is lower, governs the stress values to be adopted for high-end tubes and headers of SH and RH.
- Creep strength is the average stress to produce 0.01% creep rate in 1000 h as per ASME with a safety factor of 1.
- Stress to rupture is considered for 100,000 h. It is the lower of (1) 80% of the minimum or (2) 67% of the average stress to rupture.

ASME specifies directly the allowable stress values to be adopted at various temperatures based on the aforementioned considerations. Many other codes do not specify the allowable stresses but provide the ultimate strength values and the formulae from which the stress values are to be derived.

Unlike the thermal design, the PP design to the codes is simpler in concept and content. There are design rules to be followed and a set of manufacturing standards to be observed to achieve safe and acceptable results in PP making because the PP design affects the safety.

TABLE 1.13

Allowable High-Temperature Stresses (ksig) for Select Pressure Part Materials

Material	Temperature (°F)												Material	
	500	600	650	700	750	800	850	900	950	1000	1050	1100		
<i>Plates</i>														
SA 285 Gr. C	15.7	15.3	14.8	14.3	13.0	10.8	8.7							C-steel
SA 515 Gr. 70 and 516 Gr. 70	20.0	19.4	18.8	18.1	14.8	12.0	9.3							C-Mn
SA 299	21.4	20.4	19.8	19.1	15.7	12.6	9.3							C-Mn-Si
SA 302 Gr. B	22.9	22.9	22.9	22.9	22.9	22.9	20.0	13.7						Alloy
<i>Tubes and pipes</i>														
SA 178 and SA 192	13.4	13.3	12.8	12.4	10.7	9.2	7.9	5.9						C-steel
SA 178C and 210 A and SA 106 Gr. B	17.1	17.1	17.1	15.6	13.0	10.8	8.7	5.9						C-steel
SA 213 Gr. T11 and SA 335 Gr. P11	16.2	15.7	15.4	15.1	14.8	14.4	14.0	13.6	9.3	6.3	4.2	2.8	1 ¼ Cr, ½ Mo	
SA 213 Gr. T 12 and SA 335 Gr. 12	16.5	16.3	16.0	15.8	15.5	15.3	14.9	14.5	11.3	7.2	4.5	2.8	1 Cr, ½ Mo	
SA 213 Gr.T22 and SA 335 Gr. P22	16.6	16.6	16.6	16.6	16.6	16.6	16.6	13.6	10.8	8.0	5.7	3.8	2 ¼ Cr, 1 Mo	
SA 213 Gr. T91 and SA 335 Gr. P91	24.1	23.7	23.4	22.9	22.2	21.3	20.3	19.1	17.8	16.3	12.9	9.6	9 Cr, 1 MoV	

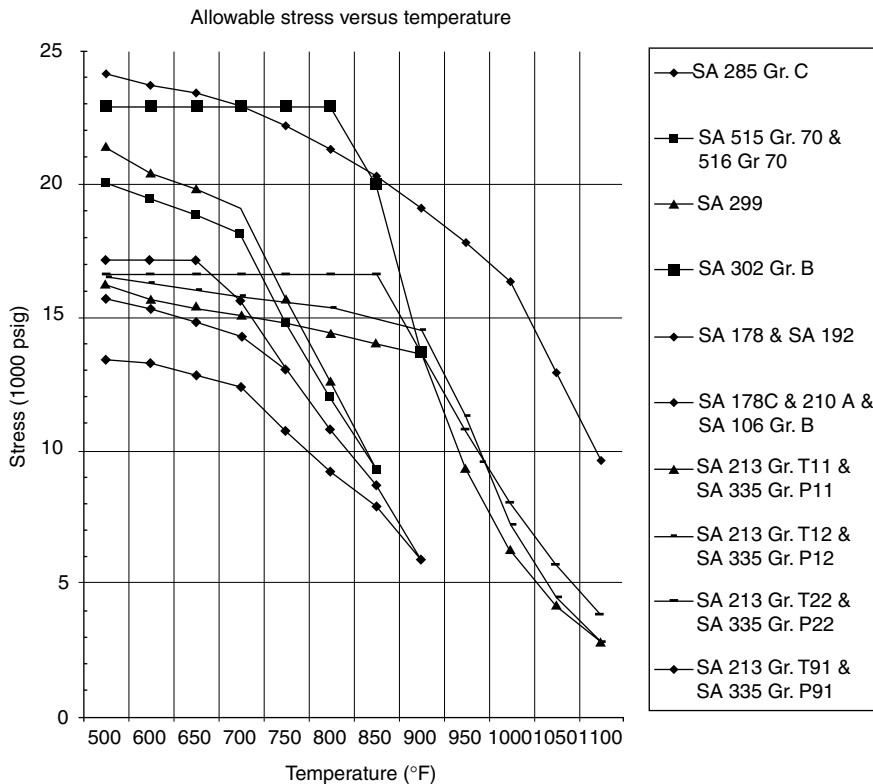
Note: As per ASME BPVC 2007.

The thermal design defines the performance of the boiler and sizes the surfaces, whereas the PP design defines the metallurgy, weight, manufacturing, and quality. The build quality of the boiler is defined and it has a major bearing on the final cost.

The PP calculations are relatively simple, but the practices adopted are continuously refined and upgraded to improve the overall PP reliability and lower the manufacturing cost, besides addressing all the issues of ever-escalating pressures and temperatures.

Table 1.13 tabulates the allowable stress values for some of the popularly permitted materials as per ASME BPVC of 2007 and these are converted into a graph as shown in Figure 1.7. A few interesting points to note are as follows:

- The stress values decrease rather rapidly at high temperatures.
- The deterioration is more marked with carbon steel, limiting its usage at elevated temperatures >450°C (~850°F).
- SA 302 is a popular alloy plate material for high-pressure drums due to its sustained high tensility.
- Cr material, 9%, is very well suited for high-temperature tubes and pipes because of its much higher stresses.

**FIGURE 1.7**

Allowable high-temperature stresses for selective pressure part materials as per ASME BPVC 2007.

Although ASME presents a wide range, the boiler manufacturers narrow their choices to a few select materials, typically as shown in Table 1.13, for practical reasons.

Refer to Chapter 5 that deals with PP materials in detail.

1.10 Capturing Basic Design Data

Boiler design is divided into two phases:

1. Process and basic engineering consisting of
 - a. Thermal design for sizing of all HSs, auxiliaries, and P&I schemes
 - b. Firing equipment design and integration with the main boiler
 - c. Layout design of total boiler plant and PPs
 - d. Electrical and instrumentation engineering as per scope
2. Detailed engineering and drafting mainly consisting of
 - a. PP design dealing with all PPs and integral piping

- b. Structural design of the main boiler (hot and cold structures) to arrive at load data for foundations
- c. Design of flues and ducts, hoppers, casing, and bunkers
- d. BRIL design
- e. Drafting

Process and basic engineering forms the essence of boiler technology and is mainly thermal design (combustion, heat transfer, and fluid flow), as opposed to the detailed engineering, which is primarily mechanical and structural design. Because a boiler is a custom-engineered product, design is calculation- and drawing-intensive. Even if two boilers were of identical construction, fuel characteristics would usually be different, calling for a fresh set of performance calculations. The boiler calculations can be broadly classified in the following manner.

1. Process calculations: calculations for each load and each fuel or any given fuel combination:
 - a. Boiler heat duty calculation
 - b. Combustion calculations for each fuel
 - c. Unit air and gas weights
 - d. Preliminary heat balance or boiler efficiency
 - e. Fuel fired and fuel burnt
 - f. Heat input and heat available
 - g. Total air and gas weights
2. Selection and sizing of firing equipment including coal pipes for PF firing
3. Calculations for sizing of heating surfaces
 - a. Furnace, division wall, and platen/wing wall SH
 - b. Hot surfaces—SH and RH
 - c. Evaporator surfaces such as boiler bank
 - d. Back end—ECON, AH, SCAPH
4. Sizing of auxiliaries
 - a. Air and gas circuits such as fans, electrostatic precipitator (ESP), flues, and ducts
 - b. Water and steam circuit such as pumps, valves, and piping
5. Structural calculations
6. Strength or PP calculations to codes
7. Any other case-specific calculations

Of these calculations,

- Items 1 and 4 are of interest to the boiler users and consultants as well as the boilermakers.
- Items 2 and 3 are proprietary in nature and are of interest only to the boilermaker.
- Items 5 and 6 are boiler-specific, of use to the boilermaker and the concerned inspection agencies and insurance companies.

Calculations 1 and 4 are featured in Appendix A for a typical industrial coal-fired boilers equipped with spreader stokers.

It is essential that all the important parameters of basic engineering be captured for boiler commissioning and for future reference and further development by all concerned—boilermaker, owner, and consultant based on the following documents:

- Contact data sheets (CDSs)
- Process and instrumentation diagrams (P&IDs)
- Boiler main and auxiliary arrangement and layout drawings
- PP arrangement
- Firing equipment arrangement and layout

CDS and P&IDs are most frequently consulted for commissioning and future designing.

Contact data sheets are comprehensive documents prepared at the end of the basic design and updated a few times during the contract period to incorporate the finalized details of mainly the auxiliaries. A typical CDS consists of the following data:

- Details of client, consultant, and inspection agents, and existing plant details as applicable
- Steaming, fuel, ambient conditions, electrical, instrument, site, wind, soil, and other related data
- Construction material, safety codes, and any other mandatory design requirements
- Guarantees for boiler performance, auxiliary power, emissions and noise, and any other parameters
- Construction notes of all HSs such as furnace, SH, RH, ECON, AH, and SCAPH
- Specifications of auxiliaries such as fans, motors, valves and mountings, and attemperators
- Specifications of all common auxiliaries such as feed pumps, deaerators, feed tanks, and turbines
- Sizing and design limits of all PPs such as drums, tubes (coils, panels, and loose), headers, and pipes
- Sizing of firing equipment—mills and burners, grate and feeders, air and ash nozzles as applicable
- Soot blower selection and piping schemes
- Anticipated performance
- Any other data relevant to the project

The expected performance from the boiler at various loads and fuels is captured in these formats, which evolved over several decades. These data are given to the commissioning and operating engineers to provide a benchmark for tuning the operations to obtain optimum performance from the boiler.

Process and Instrumentation Diagrams. The following P&IDs are usually prepared based on the type of boiler and firing:

- Steam and water
- Air and gas

- Fuel and ash
- Chemical dosing
- Milling and feeding
- Deaerator and feed pumps

Does the P in P&ID stand for process or piping? The debate is inconclusive but the process is converted into piping when all the details are incorporated.

Further Readings

Acceptance testing of steam generators—DIN 1942.

Acceptance tests for industrial boilers and steam generators—BS 845.

ASME Boiler and Pressure Vessel Code Section 2—Materials.

ASME Boiler and Pressure Vessel Code Section 1—Power Boilers.

Bender, R.J. Special report on steam generation, *Power Magazine*, June 1964.

Codes for acceptance tests on stationary steam generators of the power station type—BS 2885.

Michael, H., 1990, Comparison between American and German code to power boilers, *ASME Transactions*.

Power Test Codes—Fired steam generators—ASME PTC 4—1998.

Power Test Codes—Performance test code on overall plant performance—ASME PTC46.

Power Test Codes—Steam generating units—ASME PTC 4—1998.

Power Test Codes—Steam generating units—ASME PTC 4.1—1964 (reaffirmed in 1991).

Specification for water tube steam generating plant—BS 1113.

VGB directives for ordering high capacity boilers.

VGB directives for the construction and inspection of high capacity steam boilers.

Woodroff, E.B., Lammers H.B., Lammers T.B. *Steam Plant Operations*, 8th edition. 2004. McGraw-Hill, New York.

2

Heat and Flow

2.1 Introduction

This is the most *scientific* chapter in the entire book. Combustion, heat transfer, and fluid flow are the subjects on which boiler technology is built. These disciplines involve myriad applications. Only certain facets of these subjects are applicable to boilers. This chapter tries to capture those relevant portions for a quick reference and recapitulation. Many figures and tables are included for reference and preliminary calculations. However, for detailed calculations of boiler designers a much larger body of data is needed. Readers in search of more theoretical background should refer to books on specific subjects.

The thermal design of a boiler is largely based on the subjects covered in this chapter. Computerization of thermal calculations has greatly aided in enhancing the speed, accuracy, repeatability, complexity, and volume of calculations. Because of the facility of computer-aided calculation, many alternatives with several fuels at different loads are routinely worked out by boiler designers with no appreciable fatigue. While the modern designer is an expert user of the programs and an innovative interpreter of results, he or she is far removed from the fundamentals. This chapter seeks to remedy this disconnect by providing the theoretical background succinctly.

The same principle applies to practicing boiler engineers.

In this chapter the following topics are covered as briefly as possible with an intent to provide a ready refresher material for a practicing engineer. All the key words are italicized for emphasis.

1. Steam and water properties
2. Heat transfer
3. Fluid flow
4. Circulation
5. Combustion
6. Thermodynamic cycles

2.2 Steam and Water Properties

Water, along with its vapor phase—steam, is the working fluid of the boiler. When *subcooled water* is heated at a certain pressure in a closed space, its temperature rises until it reaches its *boiling point* and becomes *saturated water*. (Water below the boiling temperature is called

subcooled water.) Further addition of heat at that pressure only produces steam bubbles that escape into the space above, but the temperature does not increase. This process is termed *boiling*, which is the addition of heat at constant pressure and constant temperature. This heat, called *latent heat*, turns out progressively more steam, and the *dryness* of the *wet steam* keeps increasing until all the water is converted into steam. When the dryness reaches 100%, it becomes *saturated steam*. Further addition of heat raises the steam temperature to make *superheated steam*. These stages are shown in Figure 2.1.

The latent heat progressively reduces with the increase in steam pressures until it becomes zero at the *critical point*. At this pressure of 221.2 bar/225.5 kg/cm² abs (3206.2 psia) with the corresponding steam temperature of 374.1°C (705.4°F), the water turns into steam directly without the intermediate stage of evaporation. These values are based on ASME steam tables, which can be at a fractional variance from other tables. These are *critical pressure and critical temperature*, and higher conditions are *supercritical* (SC) conditions. In the industry it is normal to refer to conditions >250 bar as *ultra-supercritical*.

2.2.1 Boiling/Evaporation

Boiling is the addition of latent heat at constant temperature. It is of two types. Consider heating water in a pan. When the heating is relatively low, bubbles form at the bottom and rise up, carrying heat with them. The bottom surface is always covered by the water film, which keeps the surface cool and close to the liquid temperature. This is *nucleate boiling*, and all efforts are made to stay in this regime in a boiler as the water absorbs its latent heat.

When the heating is too high and heat flux is large, the water film at the bottom quickly evaporates and is replaced by a steam film with low conductance. As a result, the surface is no longer cooled adequately and tends to attain a temperature close to the heat source, becoming severely overheated in no time. This is *film boiling*, which must be avoided in boiler practice under all conditions. Water moving at velocities of 2–3 m/s at the entry to a tube can effectively prevent film boiling, such as in the evaporator surfaces of boilers.

2.2.2 Laws for Steam and Water

- Water is an *incompressible* liquid and obeys all the laws of liquids.
- Steam is a *compressible* vapor and obeys the laws of gases.
- The wet steam is a mixture of water and steam and follows the laws of compressible fluids in a two-phase flow.

2.2.3 Density

The density of saturated water, which is 958 kg/m³ (59.8 lb/m³) at 100°C, decreases with increasing pressure, as the saturation temperature increases, making the water expand. The density of steam, on the contrary, increases with increasing pressure as it is compressed. This density differential at any pressure is the driving force behind promoting circulation in an evaporator circuit. At a pressure of 70 bar, water is ~20 times heavier than steam. At a pressure of 200 bar, the density differential narrows to ~3, which is still adequate to have natural circulation in boilers. At the critical point the two densities become equal—315.5 kg/m³ (19.7 lb/ft³), as shown in Figure 2.2.

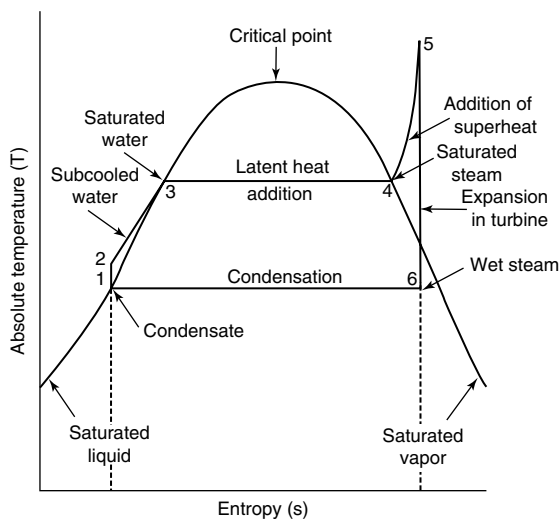


FIGURE 2.1
T-s diagram of steam and water.

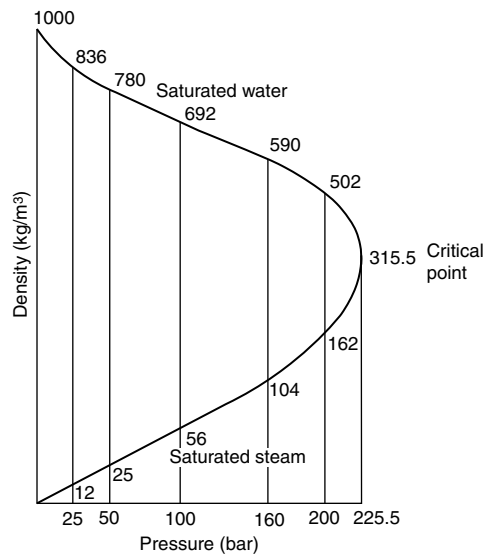


FIGURE 2.2
Density variations of saturated water and steam with pressure.

TABLE 2.1
Distribution of Heat in Various Parts of a Boiler at Different Pressure Levels

SOP (bar)	SOT (°C)	RHOT (°C)	FWT (°C)	Heat Absorbed (%)			
				Feed	Latent	SH	RH
10	Sat	—	100	14	86	—	—
45	400	—	150	20	64	16	—
100	470	—	135	32	46	22	—
185	540	540	250	26	23	35	16

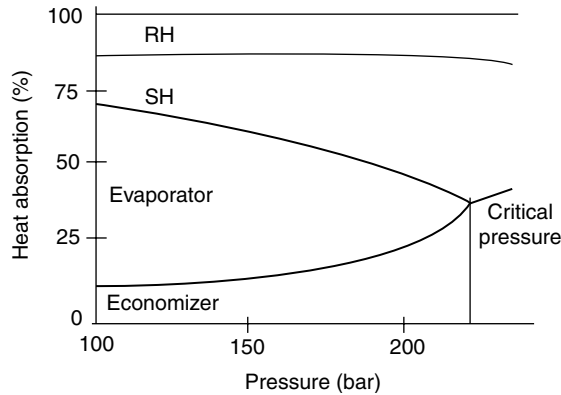
2.2.4 Heat Distribution at Various Pressure Levels

With increasing steam pressure, the latent heat addition reduces. Consequently, the workloads of the superheater (SH) and reheater (RH) keep increasing while that of evaporator/boiler keeps reducing. Table 2.1 illustrates this point. Figure 2.3 illustrates this for pressures >100 bar. The heating surfaces (HSs) also maintain a similar trend as the pressures increase.

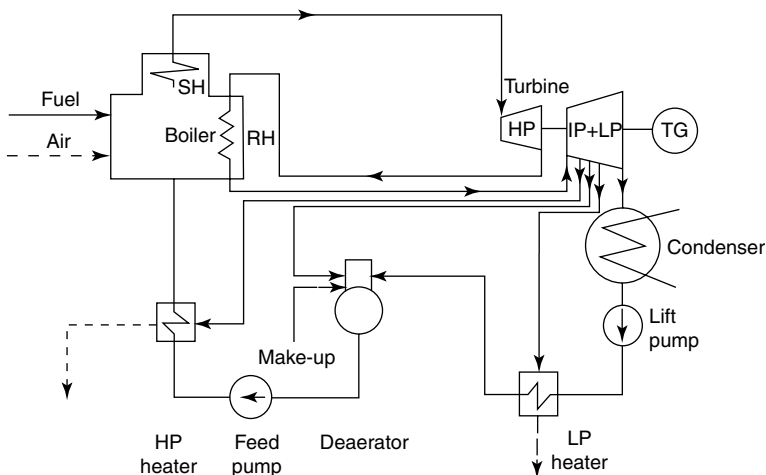
2.2.5 Steam/Rankine Cycle

The purpose of raising steam in a boiler in a power plant is to expand it in a *turbine* to derive mechanical energy from heat energy (and with the help of a generator convert it into electrical power). The fully expanded steam (to vacuum levels) is converted back into water by cooling and condensing the vapor in a *condenser* and returning to the *feed pump* to pressurize the subcooled water to the required boiler pressure. This cycle is called the steam or Rankine cycle; the salient features of which are as follows:

- Heat from the condenser is wasted and it pays to minimize this loss.
- *Cycle efficiency* = (total heat of steam – heat loss in condenser)/total heat of steam
= area under 1234561/area under 12345 in Figure 2.1.

**FIGURE 2.3**

Workload of heating surfaces as the pressure increases.

**FIGURE 2.4**

Simplified schematic of a steam cycle in a power plant.

- In the total heat of steam, the heat to RH is also included if an RH is installed. The cycle efficiency improves with the RH as the heat to steam increases more than the loss from condenser.
- The cycle efficiency increases when
 - The steam is generated at the highest possible pressure and temperature.
 - The condenser vacuum is the lowest possible.
 - The condenser vacuum is limited by the cooling water inlet temperature and the permissible temperature rise.
- Cycle efficiency can be further improved by *regenerative heating* of the condensate, by extracting some part of steam from the turbine and transferring its heat to the condensate, instead of expanding to the condenser pressure fully and losing all the latent heat to the cooling water. This is done progressively over several pressure levels in the turbine to transfer the optimum energy to increase the efficiency.

Figure 2.4 shows a simplified steam cycle with two-stage regenerative feed heating.

2.2.6 Steam and Water Properties

Reliable and accurate properties of steam and water are essential for boiler sizing and operation. For all practical purposes the existing tables are reliable and accurate enough for boiler design and acceptance despite minor differences among them.

2.2.7 Mollier Chart or Enthalpy–Entropy (H–s) Diagram

Total H–s chart in imperial units (Figure 2.5) as well as an extract of the relevant portion for boiler operation in SI (Figure 2.6) is included here for reference.

2.2.8 Temperature–Entropy (T–s) Diagram

The T–s diagram in imperial units is shown in Figure 2.7, which is used for plotting the steam cycle and understanding the way the steam by weight (SBW) increases as the water is heated. Refer to Chapter 9, where the water and steam conditions of a typical SC boiler are plotted on a T–s diagram in SI units.

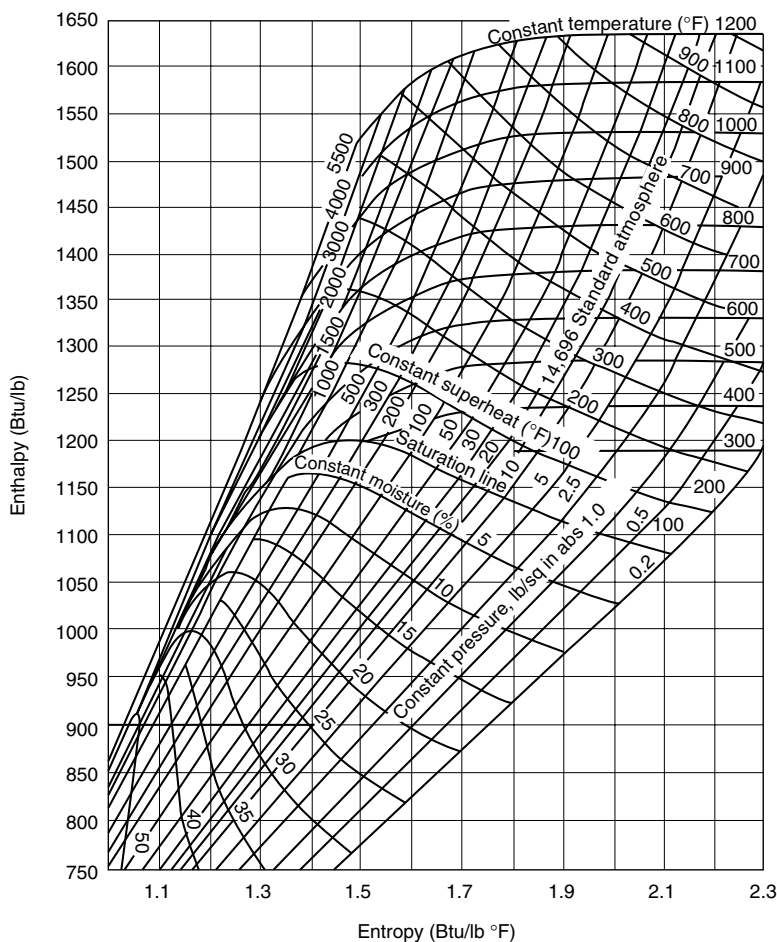


FIGURE 2.5

H–s or Mollier diagram in imperial units. (From Babcock and Wilcox Company, U.S.A. With permission.)

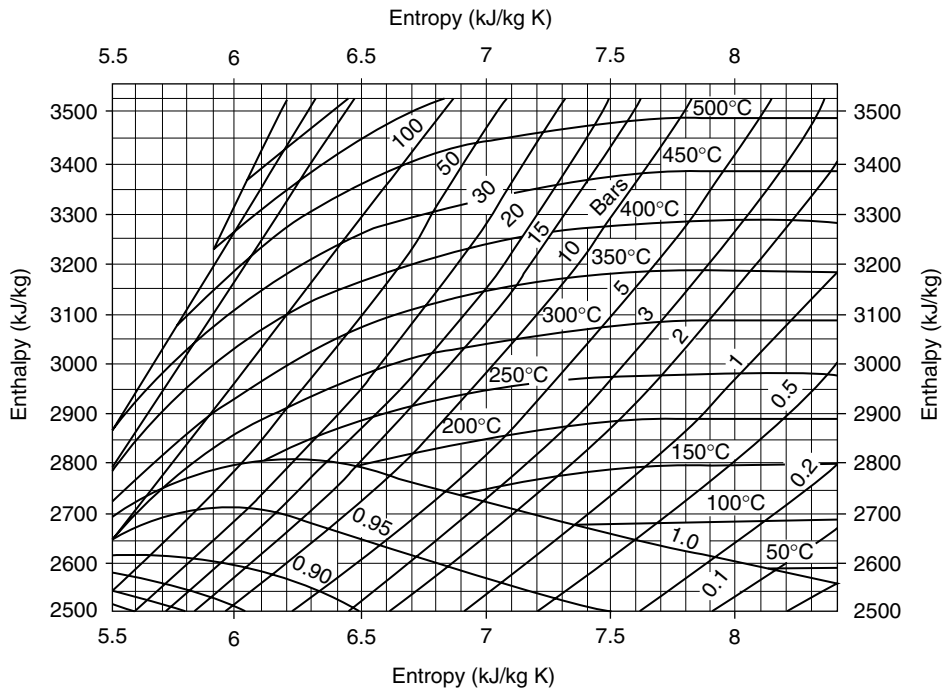


FIGURE 2.6
Mollier chart in SI units.

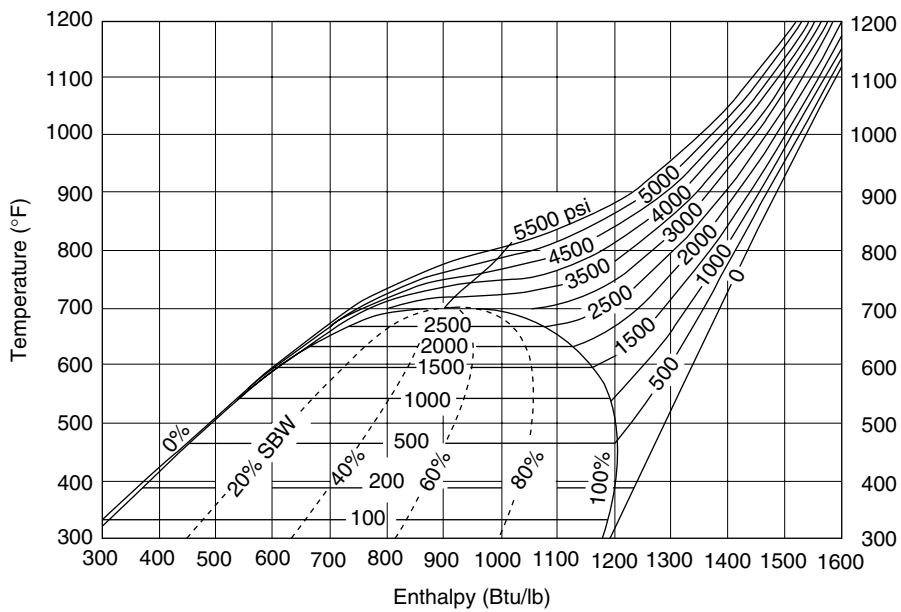


FIGURE 2.7
T-s diagram for steam in British units. (From Babcock and Wilcox Company, U.S.A. With permission.)

2.3 Heat Transfer

Heat transfer deals with the transmission of thermal energy from higher- to lower level by any one or a combination of the three classical modes, namely, *conduction*, *convection*, and *radiation*. The fundamentals of these heat transfer processes are individually simple, but the applications are complex because of the simultaneous occurrence of several modes of heat transfer, irregular shapes involved, dynamic conditions, and so on. That is why heat transfer is a not-so-exact science, as the variables are many and the situations dynamic. Also, a very large body of data on fundamental properties of materials is required.

1. *Conduction* is the transfer of heat from one part of a body to the other or from one body to another in physical contact. It is the flow of energy that occurs in a substance without appreciable movement of molecules due to lattice vibrations and flow of free electrons. Heat flow from flue gases to water/steam across the metal wall in a boiler, loss of furnace heat to the surrounding atmosphere through insulation, and heat loss from hot steam/water pipes through insulation are all examples of conduction.
2. *Convection* is the flow of energy from the surface to the surrounding fluid due to conduction and mixing of fluid molecules. It is the transfer of heat
 - a. From one point to another within a fluid due to its movement or
 - b. From one fluid to another by mixing of fluids or
 - c. Between a solid and a fluid through a relative motion between them
 Heat flow from flue gases to tube banks and heat loss from the lagging of boiler or pipe are examples of convection.

Convection can take place in

- a. A single phase as in *forced* or *free convection*.
 - i. *Forced convection*. An external force moves the fluid over the surface. The velocities and the resultant heat transfer rates are naturally higher.
 - ii. *Free convection*. Only a natural force is at work, such as gravity or buoyancy. The velocities and the heat transfer rates are lower.
- b. Two phases as in *boiling* or *condensation*
 - i. *Boiling*. When a liquid absorbs heat from a surface, which is at a temperature higher than the saturation temperature, there is a change of phase as the liquid turns into vapor; this is called boiling.
 - ii. *Condensation*. When a vapor gives out heat in contact with a surface, which is at a temperature lower than the saturation temperature, there is a change of phase as the vapor turns into liquid; this is called condensation.
3. *Radiation* is the transfer of heat by electromagnetic waves from the surface without the need of any medium. Heat flow in a boiler furnace is almost entirely by radiation.

2.3.1 Heat Flow

The general equation for heat flow is

$$q = UA\Delta t \quad (2.1)$$

or

$$= \frac{A\Delta t}{R}$$

where

q = rate of heat flow in Watts or kilocalories per hour (Btu/h)

U = overall heat transfer coefficient in Watts per square meter degree Celsius or kilocalories per square meter hour degree Celsius (Btu/ft² h °F)

A = surface area in square meters (ft²)

Δt = temperature difference causing flow in degree Celsius (°F)

$R = 1/U$, the overall combined resistance

2.3.2 Conduction

The presence of a temperature gradient is essential for conduction to take place. The heat flow and the temperature gradient are related as defined in *Fourier's law*, which states that the rate of flow of heat flux by conduction in any direction is directly proportional to the temperature gradient present in that direction.

$$\frac{q}{A} \propto \frac{t_1 - t_2}{l}$$

$$\frac{q}{A} = \frac{k(t_1 - t_2)}{l} \quad (2.2)$$

where k is the constant of proportionality called thermal conductivity.

Thermal conductivity can be defined as the rate of flow of heat flux caused by unit temperature difference. It follows that the heat flow by conduction is governed by the equation

$$q = \frac{kA(t_1 - t_2)}{l} \quad (2.3)$$

where

k = thermal conductivity in Watts per meter degree Celsius or kilocalories per square meter per degree Celsius per centimeter (Btu/ft² h °F/in. or Btu/ft² h °F/ft)

l = thickness of plate in centimeters (ft or in.)

A = area in square meters (ft²)

$(t_1 - t_2)$ = temperature gradient in degree Celsius (°F)

Certain interesting aspects of thermal conductivity are as follows:

- Metals are good conductors, and refractory and insulating materials are bad conductors (with low conductivity). k for pure metals is the highest and decreases with the rise in impurities. The range of k is given in Tables 2.2 and 2.3.
- With increase in temperature the thermal conductivity of
 - Most pure metals decreases with the exception of aluminum and uranium
 - Alloys may increase or decrease
 - Insulating materials generally increases
 - Most liquids reduces, with the exception of water due to the decrease in density
 - Gases increases
- Heat transfer by conduction in fluids is small in comparison with convection and obeys the same laws as solids.

TABLE 2.2
k Values of Common Materials at Room Temperature

k (W/m °C)		k (W/m °C)	
<i>Metals</i>		<i>Nonmetals</i>	
Copper	380	Asbestos	0.23
Aluminum	225	Plastic	0.58
Brass	110	Wood	0.17
MS	40–50	<i>Fluids</i>	
CI	25–30	Water	0.59
SS	16–20	Oil	0.15
		Air at NTP	0.026

TABLE 2.3
Range of k Values for Materials

k (W/m °C)	
Metals	10–400
Alloys	12–120
Refractory and insulating materials	0.023–2.9
Liquids	0.2–0.5
Gases and vapors	0.006–0.05

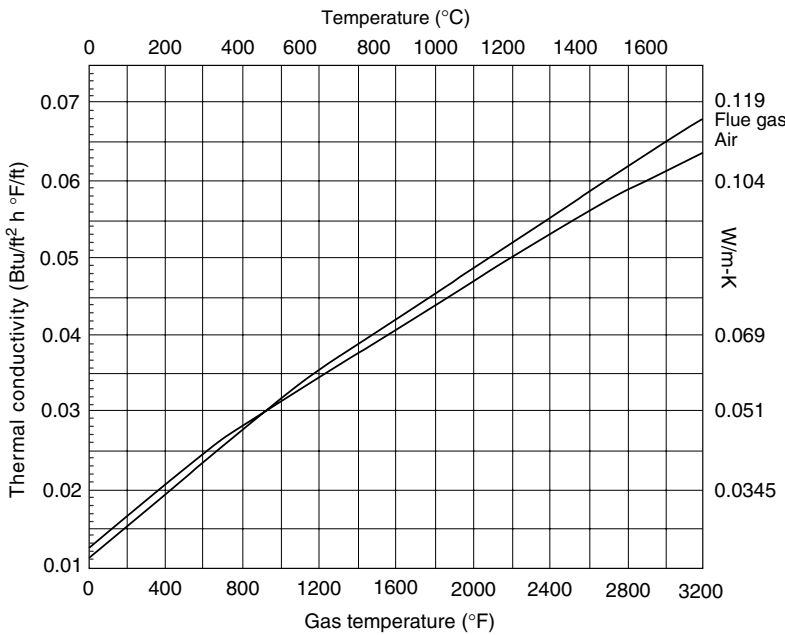


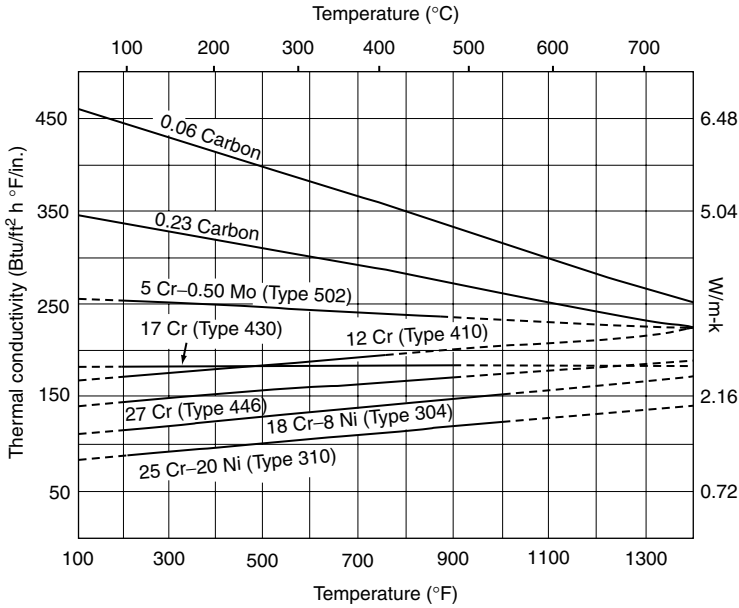
FIGURE 2.8
Thermal conductivity (k) of air and flue gas at various temperatures.

- The variation in thermal conductivity with temperature is almost linear for most materials as given by the equation (Figures 2.8 and 2.9)

$$k = k_0(1 + \beta t) \tag{2.4}$$

where k_0 is the thermal conductivity at 0°C and β is the temperature coefficient of thermal conductivity. β is +ve for nonmetals and insulating materials (with the exception of magnesite) and -ve for metals (with the exception of aluminum and certain nonferrous materials).

- k for water changes by just over 50% from 0°C to critical point.
- k for gases increases with increasing temperature.
- Good conductors of heat are also good conductors of electricity. The ratio of thermal and electrical conductivities is the same for all metals at the same

**FIGURE 2.9**

Thermal conductivity (k) of select boiler metals at high temperatures.

temperature, and the ratio is directly proportional to the absolute temperature of the metal.

$$\frac{k}{\sigma T} = \text{constant}$$

2.3.3 Convection

Heat transfer by convection between a fluid and a solid is governed by

$$q = U_c A (t_1 - t_2) \quad (2.5)$$

where U_c is the convection film conductance in Watts per square meter degree Celsius or kilocalories per square meter hour degree Celsius ($\text{Btu}/\text{ft}^2 \text{ h } ^\circ\text{F}$).

2.3.3.1 Free Convection

Free or natural convection is the heat transfer that occurs due to the movement of fluid particles caused by density changes associated with temperature differential in a fluid. Heat transfer by free convection, for example, on the outside of a clad surface, where the surface temperature difference sets up a thermal current, is calculated by Equation 2.5 with free-convection film conductance taken as

$$U_{fc} = C(t_1 - t_2)^{1/3} \quad (2.6)$$

where C is the coefficient depending on shape and position and $(t_1 - t_2)$ is the temperature difference between the surface and fluid (air). Here the flow velocities and coefficients are much lower in comparison with the forced convection.

2.3.3.2 Forced Convection

The coefficient of heat transfer in forced convection depends on a number of variables, namely viscosity (μ), density (ρ), thermal conductivity (k), specific heat (C_p), and velocity (v).

Viscosity (μ) (absolute or dynamic) is the property of the fluid that determines its *resistance to shearing stresses*. It is a measure of the internal fluid friction that causes resistance to flow. Viscosity can also be defined as the *shear stress to produce unit rate of shear strain*. The unit of viscosity is Newton seconds per square meter (N s/m^2) or kilograms force seconds per square meter (kgf s/m^2) or pounds force seconds per square feet (lb fs/f^2). In CGS units the measure is dyne seconds per square centimeter or poise. The viscosity of water at 20°C is 1 cP. Figures 2.11 and 2.12 depict the absolute viscosity of water and steam, respectively.

Kinematic viscosity (ν) is the ratio between the absolute or dynamic viscosity and the density of fluid, that is, $\nu = \mu/\rho$. The unit is the square centimeter per second (cm^2/s) (Stoke) or square meter per second (m^2/s) or square feet per second (ft^2/s).

$$1 \text{ cSt} = 1/100 \text{ St} = 100 \text{ mm}^2/\text{s}$$

Heat transfer data and fluid flow phenomena are correlated with the help of *dimensionless numbers* and the coefficient of heat transfer is deduced. The important dimensionless numbers are

1. *Reynolds number* (Re) indicates the type of flow—*viscous or turbulent*. Osborne Reynolds demonstrated, with a simple experiment of passing a mixture of water and dye of the same specific gravity through a horizontal glass tube, that three regimes of flow exist—laminar, turbulent, and transition flows, depending on the predominance of viscous or inertial forces. Figure 2.10 depicts the flow of dye in all the three regimes.
 - a. Reynolds number represents the *ratio of inertial to viscous forces*.
 - b. Inertial forces are roughly proportional to the square of velocity, and viscous forces to the first power. Loss of pressure head is approximately proportional to v^2 in turbulent flow and v in laminar flow.

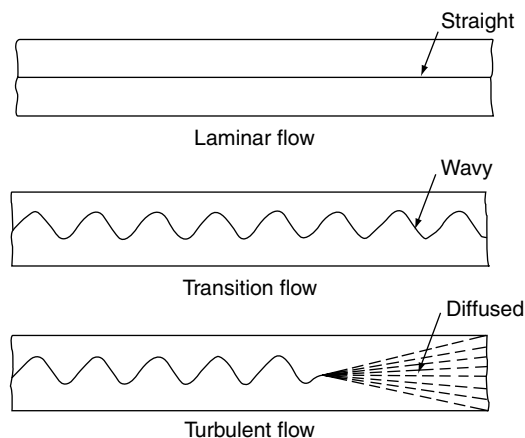


FIGURE 2.10
Types of flow.

- c. At low velocities ($Re < 2000$) the viscous forces dominate, resulting in a viscous or laminar flow, whereas at high velocities ($Re > 4000$) inertial forces dominate resulting in a turbulent flow.

$$Re = \frac{GD}{\mu} = \frac{\rho v D}{\mu} \quad (2.7)$$

where

G = mass velocity in kilograms per square meter hour

D = pipe diameter in meters

μ = absolute fluid viscosity in kilograms per meter hour

ρ = density in kilograms per cubic meter

v = velocity in meters per second

Equation (2.7) can also be rewritten as

$$\frac{\rho v^2}{\mu v / D} \quad \text{or} \quad \frac{\text{internal force}}{\text{viscous force}} \quad (2.8)$$

Figures 2.11 and 2.12 depict the absolute viscosity of water and steam, respectively.

2. *Prandtl number (Pr)* is primarily a measure of *ease of heat transmission through the fluid*. It is also a ratio of momentum diffusivity to thermal diffusivity.

$$Pr = C_p \frac{\mu}{k} \quad (2.9)$$

- a. It represents temperature gradient similarity.
- b. It can be rearranged as

$$\frac{\mu/\rho}{k/\rho C_p} = \frac{\text{kinematic viscosity}}{\text{thermal diffusivity}} \quad (2.10)$$

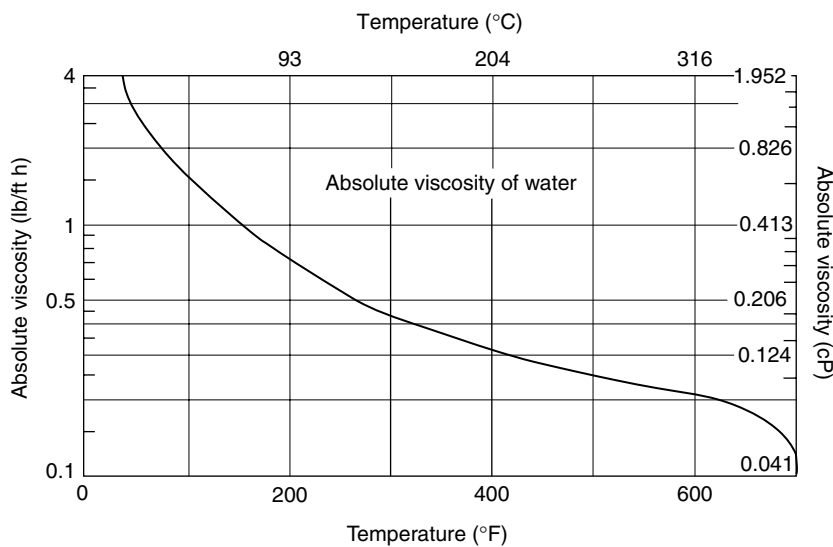
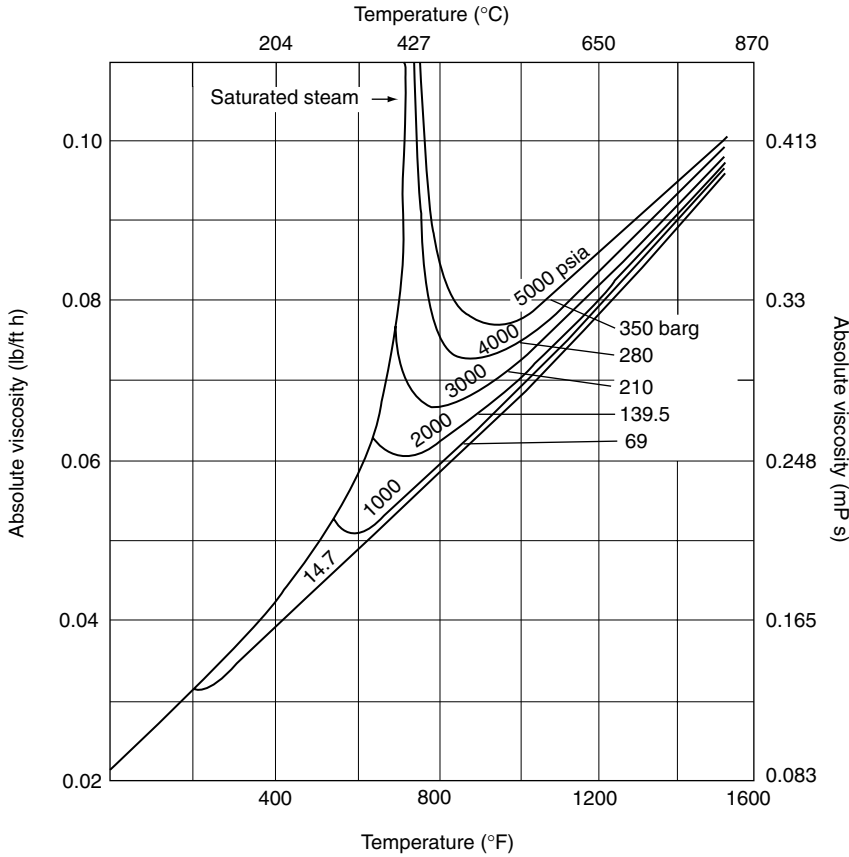


FIGURE 2.11
Absolute viscosity of water.

**FIGURE 2.12**

Absolute viscosity of steam. (From Babcock and Wilcox Company, U.S.A. With permission.)

- c. It can be considered as specific heat C_p divided by k/μ , the ratio of thermal conductivity to viscosity. A high conductivity or low viscosity helps to stimulate heat flow.
3. *Nusselt number (Nu)* is basically a *ratio of heat transfer by convection to heat transfer by conduction*.

$$Nu = \frac{U_c D}{k} \quad (2.11)$$

It is also the ratio of the size factor to the thickness of the boundary layer k/U_c .

4. *Stanton number (St)* is the *ratio of heat absorbed to that available for absorption*.

$$St = \frac{U_c}{C_p G} \quad (2.12)$$

The ratios are related as $Nu = St Re Pr$.

5. *Grashoff number (Gr)* is the *ratio of the product of the inertia force and the buoyancy force to the square of viscous forces*. Gr has a role in free convection, similar to that of Re in forced convection. Free convection increases with increase in Gr.

In the absence of a uniform free stream temperature, there is a need to use a *mean temperature* that can be either of the following:

1. Mean film temperature (T_{mf}) as used for fluid flow *over flat surfaces*, that is, the arithmetic mean of the surface temperature of the plate (T_s) and the undisturbed film temperature (T_f) of the fluid flowing across it

$$T_{mf} = \frac{T_s + T_f}{2}$$

2. Bulk mean temperature as used for fluid flow *inside pipes or ducts*, that is, the arithmetic mean of the bulk inlet and bulk outlet temperatures

$$T_{mb} = \frac{(T_{b_{in}} + T_{b_{out}})}{2}$$

2.3.3.3 Laminar Flow Inside Tubes

For both horizontal and vertical tubes, the convection conductance for laminar flow U_{cl} in kilocalories per square meter per hour per degree Celsius (British thermal units per square feet per hour per degree Fahrenheit) is given by the empirical formula derived by McAdams

$$U_{cl} = 1.86 \frac{k}{U_i} \left(\frac{\mu}{\mu_s} \right)^{0.14} \left(\frac{GD_i}{\mu} \frac{C_p \mu}{k} \frac{D_i}{L} \right)^{1/3} \quad (2.13)$$

where μ_s is the viscosity at the surface temperature and L is the heated length of straight tube.

2.3.3.4 Turbulent Flow Inside Tubes

For both heating and cooling of fluids inside clean conduits, U_{cl} (the convection conductance in turbulent longitudinal flow) is developed from the following equations:

$$Nu = 0.023 Re^{0.8} Pr^{0.4} \quad (2.14)$$

$$U_{cl} = U'_{cl} F_{pp} F_t \quad (2.15)$$

where

U'_{cl} = basic convection conductance in longitudinal flow $0.023 G^{0.8} / D_i^{0.2}$

F_{pp} = physical properties factor $C_p^{0.4} k^{0.4} / \mu^{0.4}$ at film temperature

F_t = temperature factor $(T_{film} / T_{bulk})^{0.8}$, where T_f is (average surface temperature + average bulk temperature)/2

2.3.3.5 Turbulent Flow Outside Tubes (Cross Flow)

This is developed from the following equation:

$$Nu = 0.287 Re^{0.61} Pr^{0.33} F_a \quad (2.16)$$

$$U_{cc} = U'_{cc} F_{pp} F_a F_d$$

where

U'_{cc} = basic convection conductance in cross flow $0.287 G^{0.61} / D_o^{0.39}$

F_{pp} = physical properties factor $(C_p^{0.33} k^{0.67}) / \mu^{0.28}$ at film temperature

F_a = tube arrangement factor depending on Re and tube spacing
 F_d = depth factor

2.3.3.6 Turbulent Flow Outside Tubes (Longitudinal Flow)

This is derived from flow inside the tubes, with the tube of inner diameter D_i substituted by the equivalent diameter D_e , which is

$$4(L_1L_2 - 0.785D_o^2)/\pi D_o$$

where L_1 and L_2 are tube pitches and D_o = the tube OD.

Figure 2.13 illustrates the flow of gases outside and inside the tube bundle in cross and longitudinal manners.

2.3.4 Radiation

Every surface emits electromagnetic waves in all directions. Radiation is the heat transfer in which energy flows in the form of electromagnetic waves. The principles of radiation are as follows:

- Heat incident on a surface is absorbed, transmitted, or reflected, and the respective fractions are known as absorptivity, transmissivity, and reflectivity. The sum of the three is always unity.
- Bodies that are good absorbers are equally good emitters of radiation.
- A *blackbody* absorbs the entire radiation incident on it and does not reflect or transmit any part of it. No actual bodies are completely black.
- A *white body* fully reflects, whereas a *transparent body* fully transmits the entire incident radiation. An *opaque surface* does not transmit any radiation.
- When a surface is in thermal equilibrium with its surroundings, the emissivity of the surface equals its absorptivity. This is known as Kirchhoff's law.
- Emissive power is the radiant flux from the surface at a particular temperature.
- The radiation emitted by a blackbody is proportional to the fourth power of its absolute temperature and surface area. This is known as the Stefan–Boltzmann law.

$$q = \sigma \epsilon ST^4 \quad (2.17)$$

where

σ = Stefan–Boltzmann constant

ϵ = emissivity

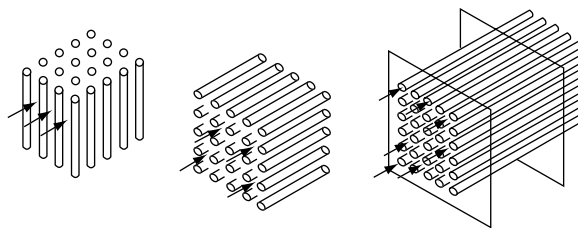


FIGURE 2.13

Cross and longitudinal flows outside tubes and longitudinal flows through tubes.

S = area

T = absolute temperature

- ϵ is the ratio of heat emitted by a body to the heat emitted by a blackbody at the same temperature.
- The radiation from a blackbody extends over a whole range of wavelengths but remains concentrated over a narrow range.
- A number of commercial surfaces have emissivities of 0.8–0.95 and behave like blackbodies.

When two blackbodies at temperatures T_1 and T_2 (where $T_1 > T_2$) exchange heat, the heat flow from body 1 to body 2 is

$$q_{12} = F_{12}\sigma S_1(T_1^4 - T_2^4)$$

where F_{12} is the angle factor depending on the geometry. Emissivity factor and angle factors are further suitably added in this equation. Heat transfer in furnaces is substantially by radiation. With most fuels, the radiation is *luminous*. Only a few gases like the blast furnace gas (BFG) exhibit *nonluminous* radiation.

2.3.4.1 Nonluminous Radiation

Gases like CO , CO_2 , SO_2 , and water vapor absorb and emit radiation at certain wave lengths outside the visible range. Nonluminous radiation is rarely encountered in a furnace, whereas it is always present in the intertube heat transfer in SH, RH, and convection banks at temperatures higher than $\sim 400^\circ\text{C}$.

2.3.5 Combined Heat Transfer

In practice, heat transmission involves the combination of any two or all three heat transfer mechanisms. The individual conductances (U s) are combined into a single conductance similar to the electrical circuitry. Resistance $R = 1/U$ and the resistances are added when in series to arrive at the overall resistance.

2.3.5.1 Convection and Conduction

A clean tube wall separated by two fluids on either side is an example. The overall resistance

$$R = R_1 + R_2 + R_3$$

where 1, 2, and 3 represent the outside film, tube metal, and inside film resistances, respectively.

$$\begin{aligned} \frac{1}{U} &= \frac{1}{U_{c_o}} + \frac{1}{2k} \frac{1}{d_o \log(d_o/d_i)} + \frac{1}{U_{c_i}} \frac{d_i}{d_o} \\ \frac{1}{U} &= \frac{1}{U_{c_o}} + \frac{1}{U_{c_i}} \end{aligned} \quad (2.18)$$

Ignoring the metal resistance that is very small in comparison to the film resistances

$$U = U_{c_o} \times \frac{U_{c_i}}{U_{c_o} + U_{c_i}}$$

2.3.5.2 Convection and Radiation

A tube bank receiving heat from gas by convection and nonluminous radiation is an example. The overall resistance

$$R = \frac{1}{\left((1/R_{rg}) + (1/R_{cg})\right)} + R_{tw} + R_{cs} \quad (2.19)$$

where

R_{rg} = gas film resistance to radiant heat flow

R_{cg} = gas film resistance to the convection heat flow

R_{tw} = resistance of tube wall to conduction heat flow

R_{cs} = resistance of the cold fluid film to convection heat or ignoring the tube metal resistance

$$\frac{1}{U} = \frac{1}{(U_{rg} + U_{cg})} + \frac{1}{U_{cs}} \quad (2.20)$$

This is the method to calculate the heat transfer coefficients for most boiler, SH, RH, ECON, and AH surfaces. Since accuracy is important, the tube wall resistance should also be included. The standard heat flow Equation 2.1 is applied, with Δt changed to Δt_m

$$q = UA\Delta t_m$$

where Δt_m is the log mean temperature difference (LMTD) causing the flow

$$\Delta t_m = \frac{(\Delta t_1 - \Delta t_2)}{\log_e (\Delta t_1 / \Delta t_2)} \quad (2.21)$$

where Δt_1 and Δt_2 are the initial and final temperature differences. A graphic solution is presented in Figure 2.14.

The log mean temperature difference is the hypothetical temperature difference which, when maintained constant along the HX results in the same rate of heat flow as that obtained through the actual heat exchange.

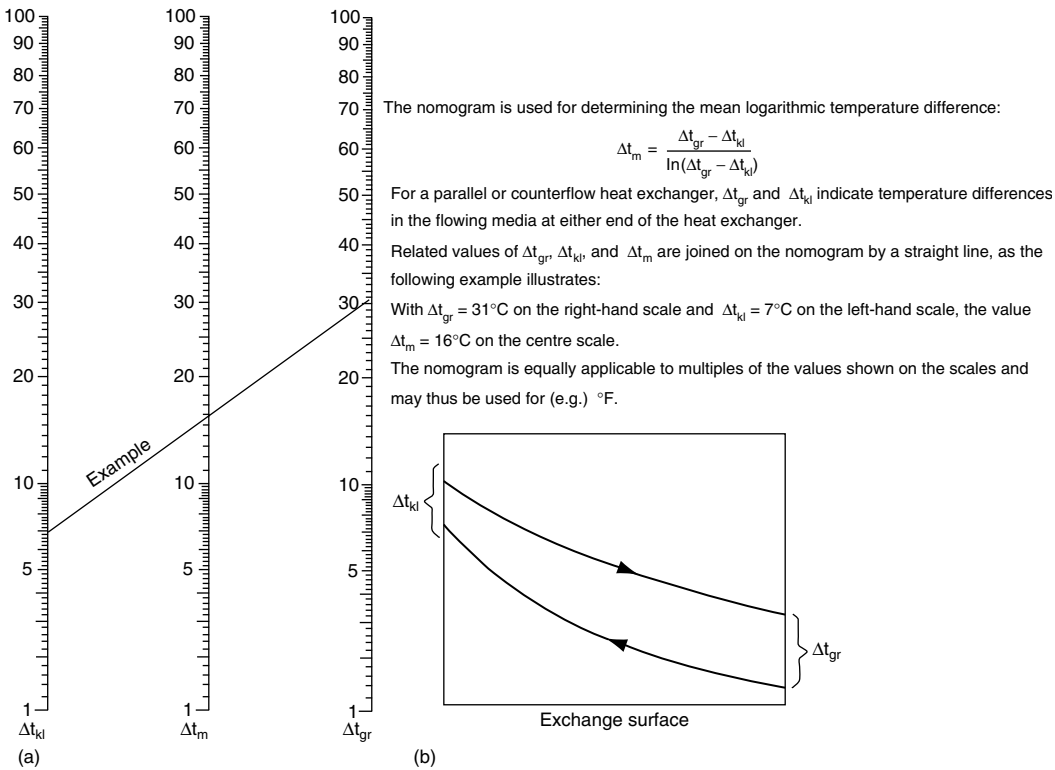
The *effectiveness* of HX is the ratio of actual heat flow from the exchanger to the maximum possible heat that can be achieved if one of the fluids can be made to undergo the maximum possible change in temperature.

2.3.6 Extended Surfaces

Inadequate HS with the subsequent temperature drop and low convective heat transfer is caused by use of extended or finned surfaces. Fin tubes employed in ECONs and heat recovery steam generators (HRSGs) are examples. Some common shapes are shown in Figure 2.15, but several configurations are possible. For proper fin design the knowledge of temperature distribution along the fin is necessary.

Fin effectiveness or efficiency is the ratio of the amount of actual heat transferred to the maximum possible heat transfer if the entire fin area is at the base temperature.

Straight or rectangular fins are the most popular as they are both easy and economical to manufacture, are light in weight, and offer minimum resistance to flow. Economizers for coal firing applications employ straight fins along tube axes. Tapered fins are of great practical importance as they give the maximum heat flow per unit weight. Annular fins



are used extensively in the HRSGs. Studs are employed very commonly in many areas of boilers, notably for holding the refractory and simultaneously transferring heat.

2.4 Fluid Flow

What exactly is a fluid?

- Fluid is a term used for both liquids and gases.
- Vapor is an inexact term but is generally understood as gas near the saturation condition where liquid and gas phases exist together.
- Water and steam, air and flue gas, and fuel oil and fuel gas are the main fluids operating in a boiler.

Ideal and real fluids. An ideal fluid, which of course does not exist, is one that has no viscosity or surface tension and is incompressible. However, fluids with low viscosity, such as water and air, can be considered as ideal fluids under certain conditions to simplify the analysis. Real or practical fluids are the opposites of ideal fluids and are commonly found.

Newtonian and non-Newtonian fluids. Newtonian fluid is one in which the shear stress is directly proportional to the rate of shear strain or velocity gradient. Non-Newtonian fluid is the opposite (Figure 2.16).

Types of flow.

- Steady and unsteady flows
- Uniform and nonuniform flows
 - Laminar and turbulent flows
 - Compressible and incompressible flows

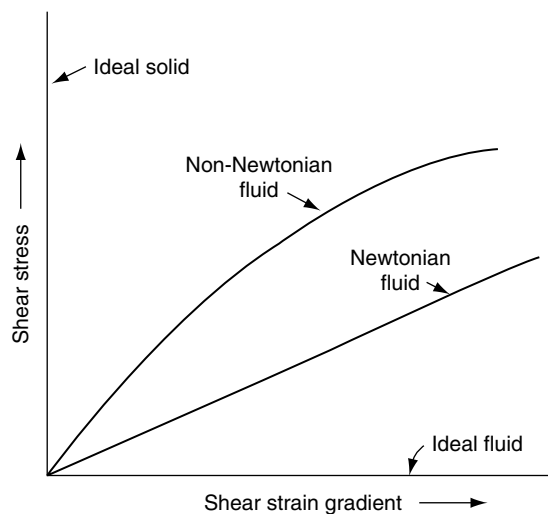


FIGURE 2.16
Types of fluids.

- Rotational and irrotational flows
- One-, two-, three-dimensional flows

2.4.1 Bernoulli's Equation

The most basic and universally applied law in fluid flow is the *Bernoulli's* equation, which is essentially an energy conservation law—the sum of pressure and velocity/kinetic energy in a flowing fluid is constant and mutually convertible. Stated differently, for a steady and ideal flow of incompressible fluid, the total energy comprising pressure, kinetic, and datum energies is constant at any point in the fluid.

$$p_1 + \frac{V_1^2}{2g} + Z_1 = p_2 + \frac{V_2^2}{2g} + Z_2 \quad (2.22)$$

where

p = pressure head in meters (pressure in kilograms per square meter $\times$ specific volume in cubic meters per kilogram)

V = velocity in meters per second

Z = elevation in meters

2.4.2 Material Balance or Continuity Equation

Another important law governing the fluid flow is the continuity equation or material balance:

$$Q = AV \quad (2.23)$$

where Q is the flow in cubic meters per second and A is the area in square meters. It follows that as the fluid flows from body 1 to 2

$$Q = A_1V_1 = A_2V_2 \quad (2.24)$$

Usually, adiabatic flow is assumed but occasionally isothermal flow may be more correct.

2.4.3 Flow through Nozzles and Orifices

- As the fluid passes through a nozzle or an orifice, a drop in pressure and an increase in velocity take place simultaneously.
- For *incompressible fluid* flowing through a nozzle where the approach velocity is negligible, the outlet velocity is

$$V_2 = \sqrt{2g(p_1 - p_2)} = 4.43\sqrt{\Delta p} \text{ m/s} \quad (2.25)$$

where Δp is the difference in pressure head in meters.

- Thus, the velocity of a free jet is dependent only on the differential pressure head that causes the flow, and is independent of the density.
- If the density difference is $<5\%$ at the discharge, mainly arising from a small pressure difference, the fluid can be considered as incompressible and Equation 2.25 can be used.

- For a *compressible fluid* flowing through the nozzle, the outlet jet velocity is

$$V_2 = \sqrt{2g \times (h_1 - h_2)} = 91.53\sqrt{\Delta h} \text{ m/s} \quad (2.26)$$

where Δh is the enthalpy difference in kilocalories per kilogram.

- For steam, Δh can be read from the steam tables or the Mollier chart.
- For other compressible fluids where perfect gas laws are applicable, it is calculated as

$$V_2 = 91.53 \sqrt{\frac{k}{k-1} p_1 \left(1 - \left(\frac{p_2}{p_1} \right)^{(k-1)/k} \right)} \text{ m/s} \quad (2.27)$$

where $k = C_p/C_v$, the ratio of specific heats at constant pressure and volume, and p_1 and p_2 are upstream and downstream pressure heads in meters, respectively.

- The smallest cross section of a nozzle is called the *throat*, where velocity is the highest and pressure the lowest. As the pressure is lowered the velocity keeps increasing at the throat until it reaches the *acoustic* velocity. This is called the *critical flow pressure* (different from the critical pressure).
- Any further reduction in the back pressure does not increase the velocity, and hence the maximum flow in kilograms per second is fixed. However, beyond the throat, as the pressure is lower the specific volume increases and *supersonic* velocities will result.
- For any gas or vapor the ratio of critical to inlet pressure is constant, and it varies from 0.5 to 0.6.

For perfect gases it can be calculated as

$$P_c = P_1 \left\{ \frac{2}{k+1} \right\}^{k/(k-1)} \quad (2.28)$$

where k is a constant 1.4 for air and varies as 1.31 and 1.26 for steam at 7 and 70 bar, respectively.

Critical pressure for air is constant at 0.53 of absolute inlet pressure and varies as 0.544 at 7 bar and 0.551 at 70 bar for saturated steam and 0.553 for SH steam.

2.4.4 Flow Coefficients

The flows resulting from the preceding equations are theoretical and do not take into account an important factor, friction. To arrive at the actual velocity, the ideal velocity should be multiplied by the *velocity coefficient* C_v , which is equal to $\sqrt{1-C_d}$, where C_d is the *drag coefficient*. C_v is 0.98–0.99 for thin orifices.

A jet of fluid issuing from a square-edged orifice attains a minimum cross-sectional area before enlarging again. This minimum area of jet is called *vena contracta*, and the ratio of the area of vena contracta to the area of nozzle is the *contraction coefficient* C_c . For thin orifices, C_c is ~ 0.62 . Overall the product of C_c and C_v is the *flow coefficient* C_q .

2.4.5 Resistance to Flow in Pipes

- Friction comes into play whenever there is flow of a fluid.
- Friction loss is dependent on the flow pattern (laminar or turbulent), fluid properties, the size and form of conduit, and surface condition of the conduit.
- In laminar flow the adjacent layers of fluid flow over each other with no slip at the walls, whereas in turbulent flow there is random flow of particles with shearing of adjacent layers. The layer adjacent to the wall is too thin, and the fluid experiences the roughness of the wall.
- Moody's friction factor captures the effect of friction for all conditions.

2.4.5.1 Losses in Straight Pipe

The friction loss inside a conduit is given by Darcy's formula in meter head

$$h_f = fL \frac{V^2}{2gD_i} \quad (2.29)$$

where

f = Moody's friction factor or four times *Fanning's* friction factor

L = length of pipe/conduit in meters

$V^2/2g$ = velocity head in meters

D_i = pipe bore or equivalent diameter for noncircular conduit (flow area/wetted perimeter) in meters.

- Based on Re and the relative roughness, friction factor f is calculated from Figure 2.17 for turbulent flow, which varies in a narrow band of ~ 0.020 – 0.025 for normal applications of steam and water.

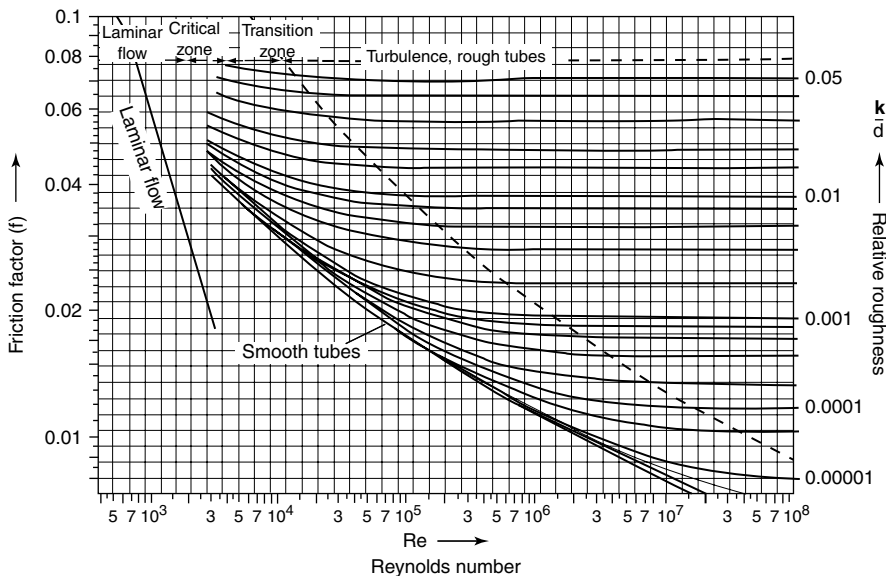


FIGURE 2.17
Friction factor (f) versus Reynolds number (Re).

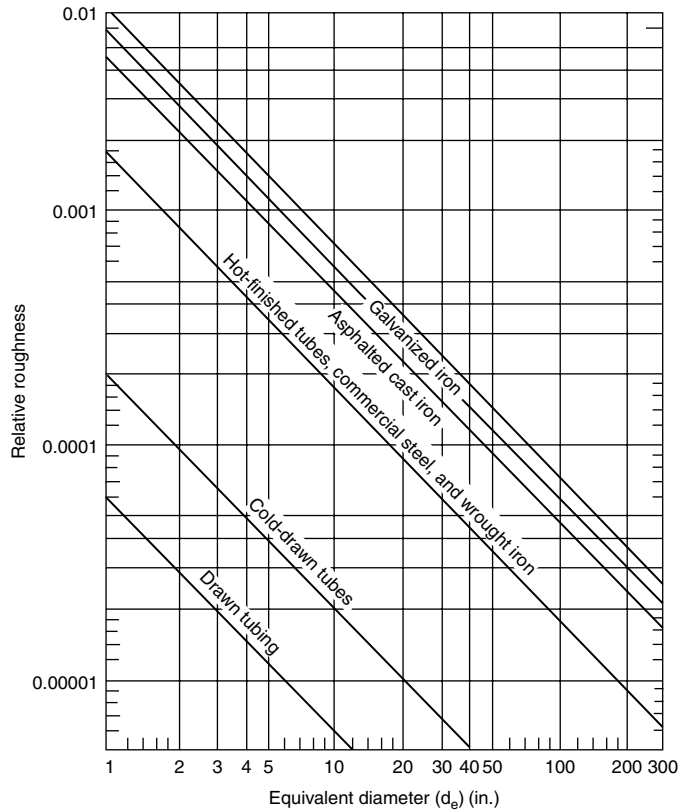


FIGURE 2.18
Relative roughnesses of pipe materials.

- The relative roughnesses (k/d_e or ϵ/d_e) for various materials and equivalent diameters are given in Figure 2.18.
- For laminar flow $f = 64/Re$.
- In practical calculations the effect of aging of pipe should be included by increasing the roughness suitably.

2.4.5.2 Losses in Valves and Fittings

These losses form the major portion of total piping losses as the straight runs in a boiler plant are relatively short and the fittings are many. These losses can be calculated as the equivalent lengths of straight pipes or the number of velocity heads. For valves, these data furnished by the valve makers are both empirical and approximate. The loss in valves is given in meter head by

$$h_f = fL \frac{V^2}{2gD_i}$$

or

$$h_f = N_{VH} \frac{fL}{D_i} \quad (2.30)$$

where N_{VH} is the number of velocity heads.

TABLE 2.4

Equivalent Lengths for Restriction

Restriction	L/D
Entrance	20
Exit	40
Close return bend	50
180° Bend	30
90° Bend	25
45° Bend	15
90° Short-radius elbow	24

TABLE 2.5

Bend Factors

r/d _i	30	60	90	180
1.0	0.200	0.320	0.390	0.51
1.5	0.145	0.220	0.275	0.36
2.0	0.120	0.180	0.220	0.30
3.0	0.100	0.160	0.200	0.25
4.0	0.080	0.130	0.165	0.21
6.0	0.060	0.100	0.130	0.17

TABLE 2.6

Expansion Factors

Expansion angle	20	40	60	80	90
Fe	0.45	0.9	1.2	1.2	1.1

Typical equivalent lengths as the number of diameters are given in Table 2.4.

2.4.5.3 Bend Losses

Bends cause two types of losses. In addition to the friction loss in the developed length of the bend, there is loss due to change in the direction of flow, which is calculated in meter head using the formula $F_b \times VH$, where the bend factor is taken from Table 2.5. It is important to increase F_b by 70% when the bend is immediately followed by a short straight pipe less than 4D.

2.4.5.4 Inlet and Outlet Losses

These losses put together with head are considered as 1.5 VH in meters. These are the combined shock losses at the entry and exit of tubes and pipes.

2.4.5.5 Contraction Loss

This loss is due to reduction in the cross section of flow area. The loss is neglected when the included angle is $< 30^\circ$. When the angle is more than 30° , the loss is calculated in meter head as $0.5(1 - A)VH$, where A is the ratio of smaller to larger area.

2.4.5.6 Expansion Loss

This loss in meter head due to enlargement of cross section is $F_e(1 - A)^2 VH$, where VH is calculated on smaller area (Table 2.6) and F_e is taken as per Table 2.6.

2.4.6 Air and Gas Duct Losses

Duct losses are also calculated in a similar way as pipe losses. But the shapes and the configurations are many and hence not covered here.

2.5 Circulation

2.5.1 Principles of Circulation

Subcooled FW enters the drum, mixes with the circulating boiler water, and attains saturation temperature instantly, as the boiling, circulating water is several times the incoming water flow. This circulating water picks up its latent heat progressively from the hot flue gases to form steam as it goes around the evaporator circuits several times. This steam is continuously separated in the drum by the steam separators. There is a balance between the incoming feed water (FW) and the outgoing steam when the system is properly functioning. *Circulation ratio* is the water in circulation divided by the steam flow. In other words it is the number of times the water has to go around the various evaporator circuits before it is all converted into steam.

Latent heat is added to the circulating water at constant pressure and constant temperature. There is no circulation in SC boilers as it is a forced flow arrangement. In once-through (OT) subcritical boilers also there is no circulation. To take advantage of the relatively low boiling temperature of water (critical temperature is 374.1°C), the hottest portion of the boiler, namely, the furnace, is encased in tubes carrying boiling, circulating water. The screen, division wall, boiler bank (BB), and EVAP tubes also form parts of the circulating system. It therefore follows that the most important use of circulating water is extracting high amounts of heat, particularly in the furnace, to keep the tubes cool. This is only possible as long as the steam bubble formation on the inside of tubes does not give way to a film of steam. In other words the *departure from nucleate boiling (DNB)* does not set in.

It is important to remember that a boiler is not designed for circulation, but for cooling the gases with ECON, evaporator, SH, and RH surfaces. It is then checked for circulation. Adequacy of circulation to prevent DNB is vital in all conditions of operation—at all loads with all fuels and combinations. It means that the velocities of steam–water mixture at all points are high enough to keep the tubes wet with no DNB. This is the essence of circulation requirement, and circulation check should be performed to verify that this condition is fully met. Usually, changes to the supply and riser tube geometry that feed and collect the water–steam mixtures, respectively, in the various circuits are needed to remedy the deficiencies. At times, other measures such as fitting of ferrules, using ribbed/rifled tubes, and so on may also be needed.

2.5.2 Flow in Vertical and Horizontal Tubes

Nucleate and film boiling has been briefly covered in Section 2.2. Figures 12.19 and 12.20 illustrate the flow in vertical and horizontal tubes.

As the water is heated in a vertical tube, a progressively increasing amount of steam is formed as shown in Figure 2.19 from tubes A to E. Water entering the heated tube undergoes these stages in sequence. These stages are not distinct, but blend into each other smoothly.

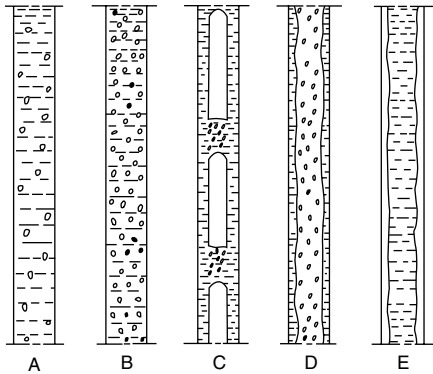


FIGURE 2.19
Flow in vertical tubes.

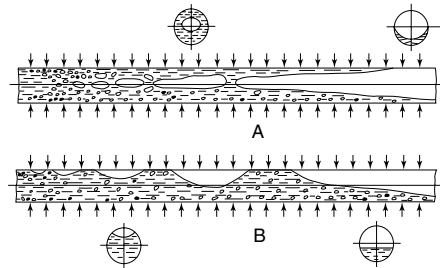


FIGURE 2.20
Flow in horizontal tubes.

1. Tube A is *bubble flow* with low velocity and a few steam bubbles in a predominant water flow.
2. Tube B is *emulsion flow* where the steam bubbles increase and hence produce froth.
3. Tube C is *slug flow* with fine bubbles coalescing to form big bubbles almost filling the bore of the tube.
4. Tube D is *wet wall flow* where the steam fills the tube with an annular film of water cooling the tube.
5. Tube E is *dry wall flow* where the water film is replaced by a thin steam film that has poor cooling ability.

In a horizontal tube the flow patterns are different. Owing to the density difference, all the steam bubbles migrate to the top of the tube and slide along the tube wall.

1. At higher velocities (Tube A) of >1 m/s, the steam bubbles join together and move along with water, resembling wet water flow.
2. At low velocities (Tube B) of <0.5 m/s, the flow is even more asymmetrical and unstable. The water and steam flow separately in the tube.

2.5.3 Departure from Nucleate Boiling

As stated earlier, in the flow of a water–steam mixture, it should be ensured that the wet wall flow is always maintained and the dry wall flow is never allowed to set in, as the cooling provided by the steam film is not adequate to prevent tube overheating and puncture. The point at which this happens is the DNB, which is illustrated in Figure 2.21. It is in the transition zone that the excursion of metal temperature is the highest and, hence the tube failures occur.

The factors promoting DNB are

1. High heat flux
2. Low water velocity
3. High pressure

High heat flux ($>250,000$ kcal/m² h or $\sim 92,000$ Btu/ft² h) cannot be avoided, particularly in the burner zone. There is a limit to increasing the velocities at (higher) pressures >150 bar when the circulation ratios are on the lower side.

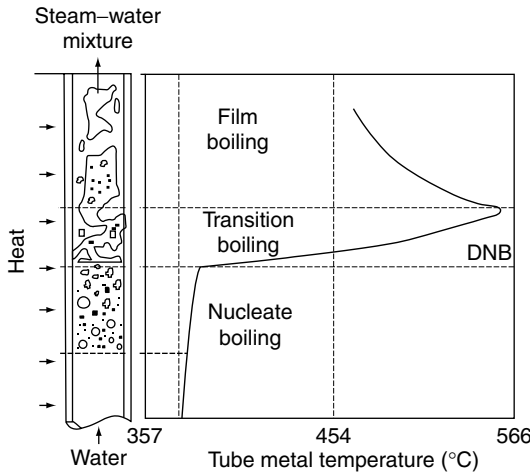


FIGURE 2.21
Departure from nucleate boiling.

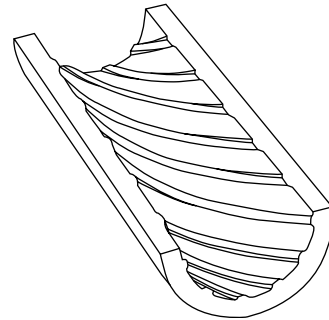


FIGURE 2.22
Rifled/ribbed tube.

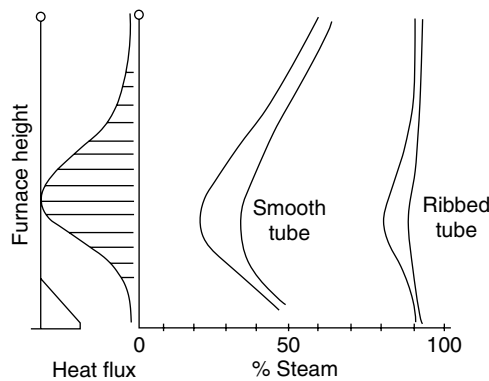


FIGURE 2.23
Effect of ribbed tube on permissible steam quality to avoid DNB.

2.5.3.1 Ribbed or Rifled Tubes

Ribbed or rifled tubes (Figure 2.22) are helpful in delaying the onset of DNB when compared to smooth tubes, as they offer more wetted surface for adherence of water film. The permissible steam by weight percentage (%SBW) for the same heat flux is raised from a range of 20–40% level to a range of 70–90% level by the use of ribbed tubes. Since they are expensive, they are employed around the burner zone and mainly in high pressure and SC boilers. Figure 2.23 illustrates the effect of ribbed tubing on steam by volume percentage (%SBV).

2.5.4 Maintaining Nucleate Boiling

To maintain wet wall flow or nucleate boiling under all conditions, the following criteria must be satisfied for each circuit. A *circuit* is a set of heated tubes of similar shape and heat input that allow upward flow of water.

1. *Exit quality.* SBW at the top of any circuit should be less than a specified limit depending on the drum pressure and the location of burners—whether at the top or bottom—to prevent film boiling at the top of the circuit.

2. *Minimum velocity.* Water velocity at the commencement of the circuit should exceed a specified limit, depending on the inclination of the tubes to prevent the steam bubbles from adhering to the tube walls, causing overheating, and also to prevent sludge accumulation.
3. *Saturated water head (SWH).* The SWH, the ratio of pressure loss (including static head) to the pressure produced by a column of saturated water of the same height, is required to be at a certain specified minimum to prevent flow reversal.

The usual remedy for meeting this requirement is to increase the water flow to the defaulting circuit.

2.5.4.1 Steam by Weight

For drum pressures up to 100 bar, the SBW at the top of a circuit governs the circulation; that is, if the SBW limits are met at the top of the circuit, satisfactory conditions would result at the lower levels. But at higher pressures a more detailed analysis of the heat flux at all levels would be required to check whether safe conditions prevail over the entire tube length.

The exit quality is limited to ~55–85% steam by volume (SBV) to stay within wet wall flow or nucleate boiling. The SBV varies with the pressure, and the approximate limit for conventional boilers is as shown in Table 2.7.

The equivalent SBW for the same SBV increases with pressure as shown in Figure 2.24. It follows that the number of times the water has to complete the circuit reduces with the

TABLE 2.7

Percentage of Steam by Volume (SBV) at Various Pressures

Drum pressure (bar)	20	40	70	100	140	180
SBV (%)	80	75	70	67	65	55

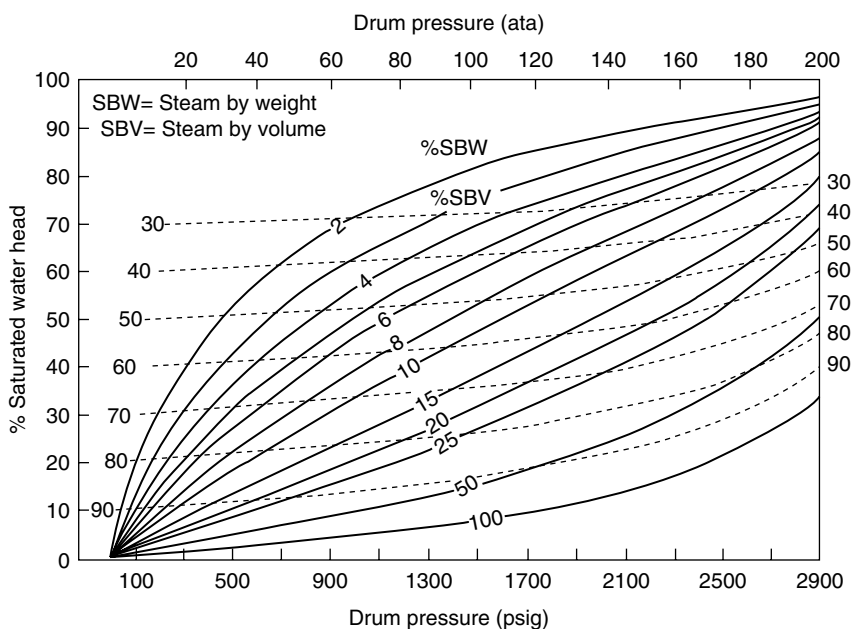


FIGURE 2.24

Relationship between SBV and SBW.

TABLE 2.8
Typical Circulation Ratios for Various Drum Pressures

Drum pressure (bar)	20	40	60	80	100	120	140	160	180
Bidrum boilers	55	40	30	20					
Single-drum boilers			18	15	13	11	10	8	7

TABLE 2.9
Typical Minimum Water Velocities in Circulation

Type of Wall	Minimum Velocity (m/s)	Pressure
Furnace water wall with or without slope	0.60	>100 bar
Furnace water wall with slope >30°	0.30	<100 bar
Furnace water wall with slope <30°	1.00	All
Furnace water wall with slope <30° with heat on top	1.70	All
Vertical boiler tubes	0.15	All
Water-cooled burner throats	0.15	All

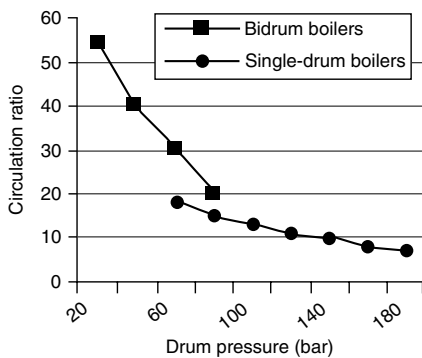


FIGURE 2.25
Typical circulation ratios for single and bidrum boilers.

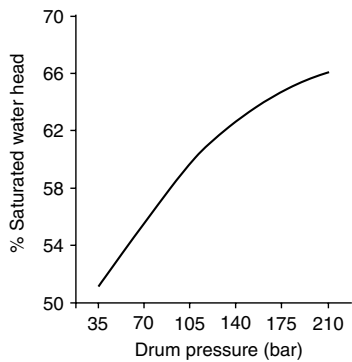


FIGURE 2.26
Minimum percentage of SWH at various pressures.

increasing drum pressure. The circulation ratio falls with pressure (Table 2.8). Typically, for conventional boiler, the circulation ratios are as shown in Table 2.8. They vary with the type of boiler as the geometry varies (Figure 2.25). Certain process boilers with horizontal evaporator banks have lower ratios.

2.5.4.2 Water Velocities

The minimum velocities at the entry to the circuits required for maintaining a good turbulent wet wall flow that prevents steam bubbles from sticking to the walls are shown in Table 2.9.

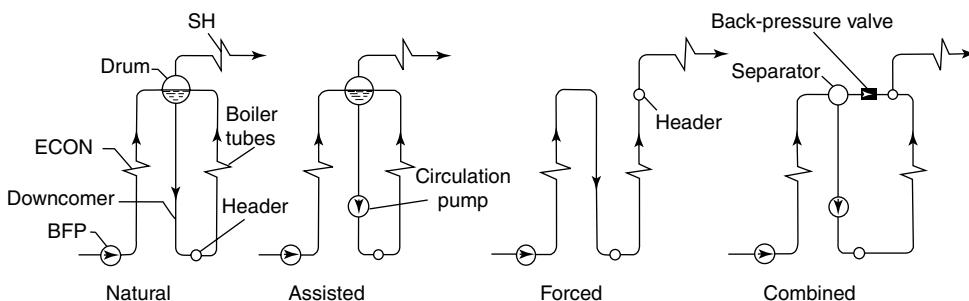
2.5.4.3 Percentage Saturated Water Head

The ratio of the anticipated density and pressure drop characteristics of the steam–water mixture in the riser tubes to the static saturated water column is the percentage saturated water head (%SWH). There are minimum values established from experience. When %SWH falls below these levels, flow reversals can occur between tubes of the same circuit, leading to stagnation and eventual tube failures. The typical minimum %SWH ranges from ~50% to 70%, increasing with the pressure as shown in Table 2.10 (Figure 2.26).

TABLE 2.10

Typical Minimum Percent SWH versus Drum Pressure

Drum pressure (bar)	35	70	105	140	175	200
%SWH	51	56	60	63	65	66

**FIGURE 2.27**
Types of circulation.

2.5.5 Types of Circulation

There are four basic types of circulation and several variations that are possible in boilers:

1. Natural circulation
2. Assisted circulation
3. Forced circulation
4. Combined circulation

These types are illustrated in Figure 2.27. It is very important to realize that regardless of the type of circulation the heat transfer from the gases remains the same and nucleate boiling regime pervades at all times.

It follows generally that

- Almost all the industrial boilers work at subcritical conditions and adopt natural circulation.
- Forced circulation is employed mostly in waste heat boilers to ensure adequate flow at all conditions with
 - Low heat flux
 - Rapidly fluctuating heating/cooling
 - Horizontal evaporators
- Once-through or forced, assisted, and combined circulations are found only in utility boilers. There can be a few variations, depending on whether the operation is at subcritical condition, and fixed or variable SOP, which are described later on.

2.5.5.1 Natural Circulation

Natural circulation is the most common type adopted for subcritical pressures because of its

- Simplicity; no pump or associated equipment
- Self-limiting characteristics

For drum pressures up to 211 bar (3000 psia), where the density differential between water and steam is still ~ 2.5 times, natural circulation has been employed. For higher pressures operation becomes increasingly more expensive because of larger downcomers and risers. Natural circulation relies only on the density difference between the saturated water in the downcomer and the steam–water mixture in the heated tubes.

In Figure 2.28, natural circulation is shown simplistically for a single circuit. The height of the tube is H . The downcomer is unheated and the riser is heated. The thermosyphonic head or circulation that drives the flow is $H(\rho_d - \rho_r)$ and is proportional to

1. The height of column
2. The difference in densities between the downcomer and riser (ρ_d and ρ_r)

It follows that

- Taller boilers and higher pressures go together. The minimum drum centers are in package boilers, and they are rarely < 3 m to provide sufficient thermosyphonic head.
- To enhance the density in downcomers there should be no steam bubbles trapped in the downcomer water after steam–water separation in the steam drum, and it is preferable to use subcooled water. Hence, the addition of ECON water to the steam drum in preference to the water drum.
- The separation of steam from water must be very efficient. Steam-free water under all conditions should be made available by the steam separators.
- The large bore downcomers have to be generously sized to keep the water velocities low so that steam bubbles are not carried along. Vortex breakers in the drum at the entry to the downcomers are provided for the same reason.

As the riser tubes are heated, there is more steam formation resulting in lowering of density in risers and increasing of differential density. The steam so formed rushes upward to the drum and is replaced by cooler and denser water at the bottom. A vigorous circulation is thus set up. The circulating head is more than the friction and shock losses. More heat results in more velocity and hence greater cooling of the tubes. Thus, there is no fear of overheating of the tube in this self-limiting system, which is a great advantage of natural circulation. In the rising part of the natural circulation curve, the friction and impact losses in the risers are less than thermo-syphonic head (Figure 2.29). At a certain point there is more steam in the riser tubes and the friction exceeds the driving force, thus reducing the circulation, as depicted in the drooping part of the curve in Figure 2.29. Natural circulation boilers always operate in the rising part of the curve.

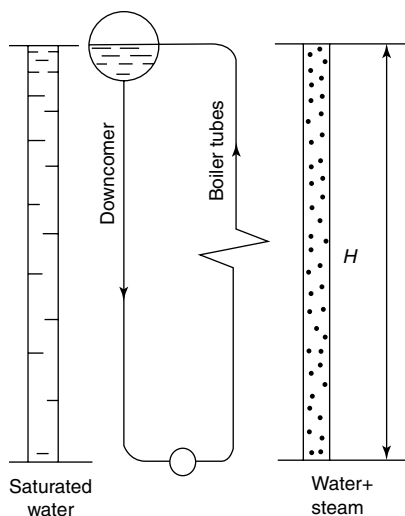


FIGURE 2.28
Typical natural circulation circuit.

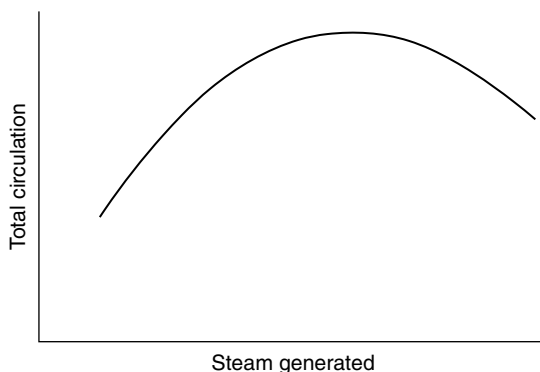


FIGURE 2.29
Self-limiting characteristic of natural circulation.

2.5.5.2 Assisted Circulation or Full Load Recirculation

For pressures of 150 bar and above, mainly for large utility boilers, it is beneficial to supplement the thermosyphonic head by circulating pumps. Additional cost of pumps, ferrules, and associated equipment can be compensated:

- The smaller tubes that can be employed result in lowered tube weights due to reduced tube thicknesses.
- The savings in the downcomer and riser tubes arise from lower sizes and reduced lengths.

In addition, there is a greater flexibility in the disposition of surfaces as the flow can be controlled in tubes. The additional pumping power of the circulating pumps is substantially recovered in the resulting heating of circulating water due to friction in the ferrules. At pressures close to 200 bar, this arrangement provides a good security against circulation lapses. Several large boilers are operating satisfactorily on this principle. Not all boilermakers and customers favor this over the natural circulation, which is simple, time tested, and devoid of any pumps and drives (and hence fractionally more efficient).

2.5.5.3 Forced Circulation and Once-Through Forced Circulation

In the SC stage, all the water entering the boiler progressively turns into steam without having to go through an evaporator cycle as there is no latent heat to be absorbed. There is no circulation, and the circulation ratio is 1. There are no drums in SC boilers as there is no separation of steam and water. The OT journey of water through the furnace tubes is made possible by the pump pressure.

The ECON and SH in natural circulation boilers are always in forced flow condition. Even the furnace tubes are in forced circulation, but the furnace tubes form part of the ECON. Compared to the furnace tubes carrying saturated boiling water

of natural circulation boilers, which are all at the same relatively low temperature, do not experience temperature differential. In the OT boiler

- The tubes attain a much higher temperature and require alloy tubing.
- The adjacent tubes are at different temperatures.
- Greater temperature differential can exist during start-up and upset conditions.

At start-ups and low loads the flow is too inadequate to keep the tubes cool. This is resolved by means of a turbine bypass system with which a minimum required flow can be provided.

In the waste heat boilers mainly operating in the subcritical regime, forced flow is adopted for reasons explained earlier, with a low circulation ratio of ~3.

Forced circulation or OT is adopted for both SC and subcritical boilers in Benson design, also called universal pressure (UP) boilers in the United States, where vertical ribbed tubes are employed in furnace instead of spiral tube circuits.

The pump power is substantially returned to water in the form of heat as there are ferules installed at the entry to the tubes for flow equalization.

2.5.5.4 Combined Circulation

This is a variation of the forced circulation principle, where circulating pumps are provided in addition, to deal with start-up and low loads. During start-ups the water–steam mixture is heated in furnace to ~90%, dryness and the water is separated in separator vessels to be circulated in the boiler again with the help of the circulating pump. The back-pressure valve is kept closed during this period. On attaining the specified load of ~60%, when the pumping is no longer required for tube protection, the valve is opened and the circulating pump is closed to run the boiler in forced circulation mode. This type of circulation is adopted for SC OT boilers. This system lends itself to variable pressure operation. Also a dual pressure operation is possible where the furnace is at SC pressure and SH at subcritical pressure.

2.5.6 Limits for Natural Circulation

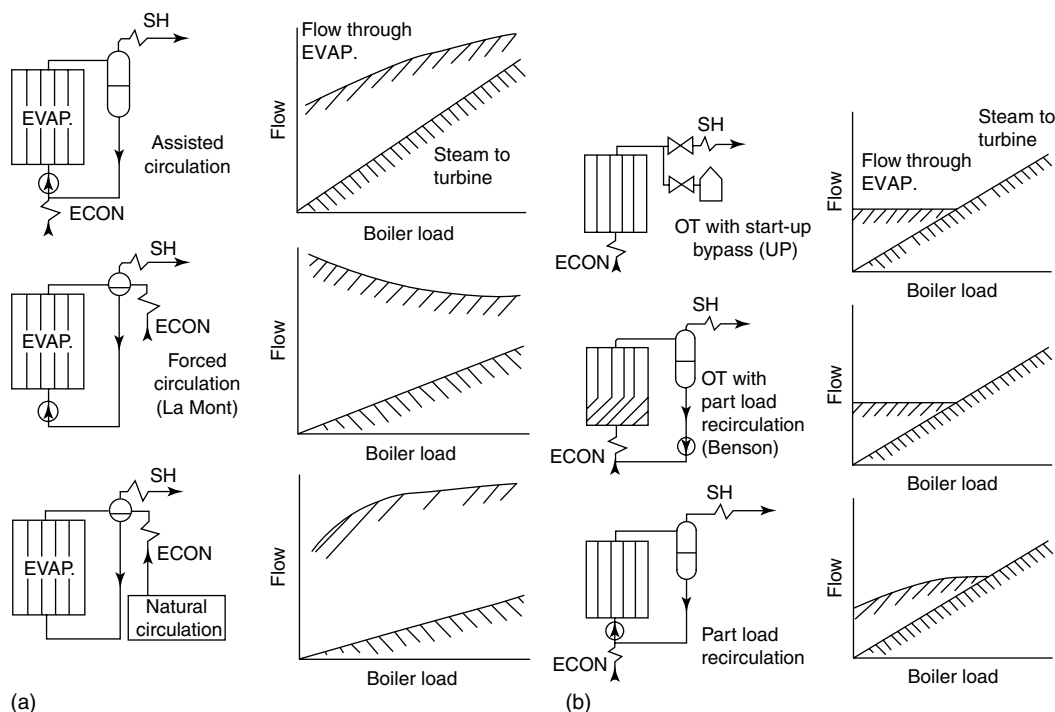
The limits for natural circulation are set primarily by the ability of water in the evaporator circuits to keep the surfaces wet at all loads. In other words, the onset of film boiling on reaching DNB should be avoided. The reduced flow through the evaporator at higher pressure, due to the reduced density differential between water and steam, leads to a possible DNB. This can be avoided solely by increased circulation. This is achieved by increasing the downcomers and risers.

The broad limits for the natural and forced circulation boilers are listed in Table 2.11, where the operation is at fixed SOP in subcritical condition. For sliding or variable

TABLE 2.11
Approximate Limits of Natural and Forced Circulation Boilers in Fixed Pressure Subcritical Operation

Evaporator System	Recirculation Rate	Water Mass Flow (kg/m ² s)	Limiting Drum Pressure (bar) ^a
Natural circulation—plain tubes	4	1200	190
Natural circulation—ribbed tubes	3	1000	200
Forced circulation/La Mont	3	1200–1400	210
Full load recirculation/assisted circulation	1.3	1200	210

^aDrum or separating vessel.

**FIGURE 2.30**

Evaporation processes with (a) fixed and (b) variable SOPs.

pressure employed in modern utility boilers, other advanced systems of circulation are briefly described in the ensuing paragraphs.

The various evaporation processes with fixed pressure operation are depicted on the left sides of Figures 2.30a and 2.30b. The flow through the evaporator, as a multiple of the steam generated at that load, is different for different processes. Likewise, the various evaporation processes with variable pressure operations are depicted on the right side. In the lower range of evaporation a recirculation is superimposed by means of recirculation pumps to increase the mass flow velocities to avoid DNB. For high-capacity utility boilers, variable SOP is increasingly preferred, together with SC pressure, for better cycle efficiency and superior load dynamics. This is described in Chapter 9 in more detail. No details of the evaporation process are given here; only figures are included to provide a simplified view.

2.5.7 Circulation Systems for Subcritical and Supercritical Pressures

From the early twentieth century, efforts have made to operate steam cycles at very high pressures, preferably at SC conditions to gain advantage in cycle efficiency and to avoid recurring tube failures in evaporator system. Benson and La Mont, both engineers from Central Europe, patented their slightly different systems with Siemens and Sulzer, respectively. The Benson system was suitable for all pressures, whereas the La Mont was more suitable for subcritical pressure. Over the years, changes were made to the original principles by the main licensors and the licensed boilermakers to adapt to the needs of the power generation cycles. The Sulzer design is currently in Alstom's possession.

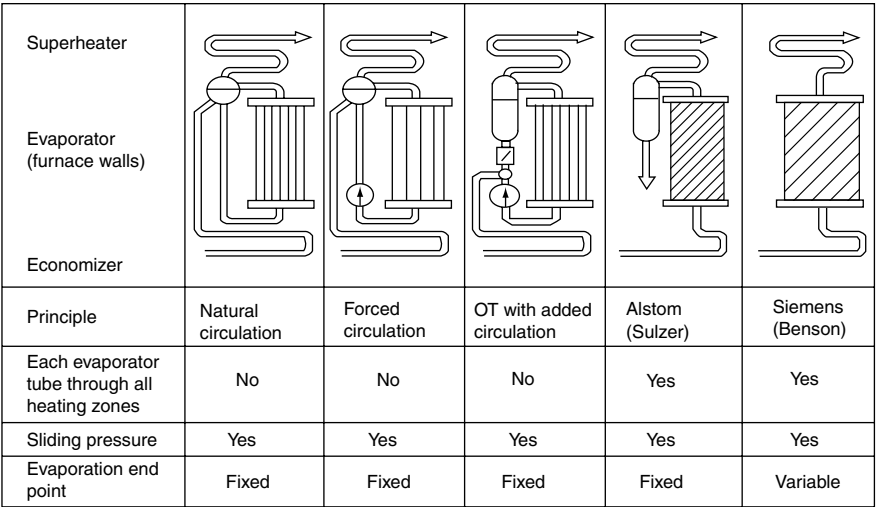


FIGURE 2.31
Subcritical pressure evaporator systems.

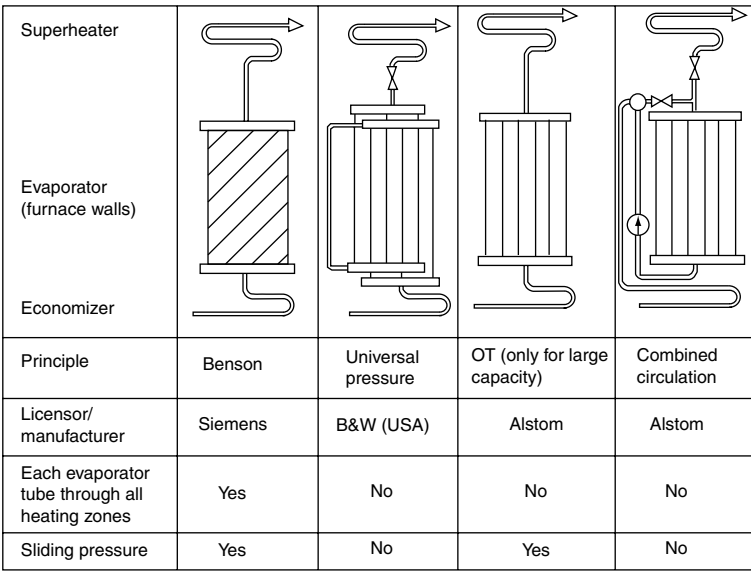


FIGURE 2.32
Supercritical pressure evaporator systems.

The most salient features of the various evaporator systems are depicted in Figures 2.31 and 2.32.

2.5.8 Boiler Feed Pumps

Similar to the fans that set air and gas circuit into motion, the boiler feed pumps (BFPs) activate the water and steam circuit. Both are rotating devices. Together with fans the BFPs constitute important auxiliary features vital for both running and safety.

In smaller industrial plants the BFPs are included in the boiler supply, but in larger plants, where the HP heaters are introduced in the system, the BFPs must be located in the turbine hall and are treated as part of the turbine island. The following guidelines are important in the sizing and selection of BFPs.

2.5.8.1 Number of BFPs

- Boiler feed pumps can feed a single boiler or a battery of boilers.
- At least two BFPs are required with independent sources of drive power.
- However, certain countries permit a single BFP operation, provided the following requirements are met.
 - On failure of the source of energy to BFP, the drive firing of boiler is interrupted.
 - Steam pressure and water supply must be continuously and automatically controlled. Reliability of the FW controller is very important, and evidence of its reliable operation has to be demonstrated.
 - There should be a reliable controlling of firing in the boiler. After interruption of fire, the stored heat in the furnace and boiler passes should not produce excess evaporation that can cause damage. This is particularly important in boilers with large amounts of refractory, such as the CFBCs with hot cyclones or boilers with refractory furnaces.
 - The boiler should be equipped with an automatic trip system to cut off both the fuel and air when the water level in the steam drum drops below the trip level.

2.5.8.2 BFP Drives

- With two BFPs there should be a reliable mechanism to instantly start the standby pump when the running pump fails.
- Boiler feed pumps can be driven by either electric motors or turbines. Considering cycle and plant efficiency, turbines are preferred, as the energy conversion from steam to electric power is not involved. The convenience of installation and lower O&M of motors against the higher expense, complexity, and O&M of turbines have to be carefully evaluated when a particular system permits both.
- In process plants, where steam availability is assured and there is use for LP steam exhausted by the turbines, turbo drives are overwhelmingly preferred to motors. If the electric motors alone are used, care should be taken to employ independent feeders to assure power all the time. In utilities it is normal to have turbine drives for BFPs based on cycle efficiency considerations. Besides, they are more amenable to speed variation, which can make sliding pressure operation possible.

2.5.8.3 BFP Sizing

- Boiler feed pumps consume a lot of power, and in a utility they rank as the highest power consumers. It is therefore necessary to size them carefully to save on the auxiliary power.
- The design capacity of the pumping installation should equal the total evaporation of the boilers fed by the pump, with an added allowance for continuous blowdown

as applicable, together with any additional uses such as the desuperheater spray water.

- A safety margin of usually 10% is added to the pump capacity to arrive at the test block margins in industrial plants. This depends on the class of pump that defines the tolerances on head, capacity, and power. This can also be dictated by the client or consultant based on past practice.
- The design pressure of a BFP is the sum of the following losses added to the highest safety valve lift pressure (SVLP) with a margin of 2.5%.
 - Loss through ECON and connections
 - Loss through fully open feed control valve
 - Loss through feed piping and valves
 - Loss through feed heaters
 - Static head

2.5.8.4 BFP Characteristics

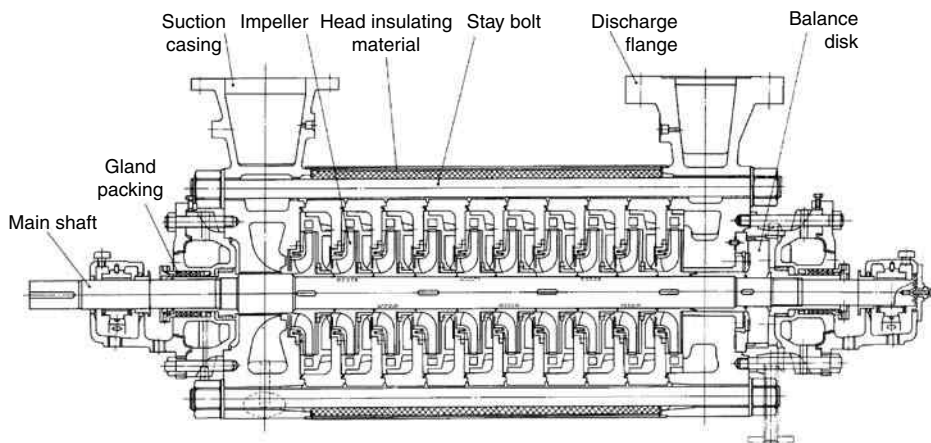
- The operating and design temperature of the pump is the same as that of the upstream deaerator.
- Net positive suction head (NPSH) is a very important consideration as the BFPs operate at relatively high temperature and speed. Flooded suction is necessary. The minimum required NPSH is a function of pump design at the operating speed determined by the pumpmaker. The suction losses should be added, and there must be adequate margin in the available head.
- A continuously drooping characteristic should be opted so that the parallel running of pumps can take place without the fear of hunting. The no-load pump pressure (NLPP) or the head generated at zero flow should preferably be limited to 110% of the design pressure. Higher the NLPP, more expensive are the feed piping and valves.

2.5.8.5 BFP Protection

- An automatic recirculating valve, to protect the pump working against closed discharge valve, is necessary to prevent the overheating of the pump due to the idle churning of water. Below a predetermined flow of ~10–15%, the valve opens and discharges the water to the deaerator or sometimes to the pump suction.
- Pumps must be hydraulically balanced by a balance disk or other means. The leak from the balance chamber is usually piped to the pump suction.

2.5.8.6 Types of BFPs

- There are mainly two designs in the BFP—*radially split* or *ring section* pumps and *axially split* pumps. Radial pumps come with (1) individual ring sections, consisting of impeller and casing sections, which are bolted together and (2) the impeller and casing that are inserted from one end in an external barrel. They are called *ring section* and *barrel* casing pumps, respectively.
- *Radial ring section pumps* are popular due to simplicity and low cost and smaller boilers. For maintenance and access purposes the suction and discharge pipes should be removed from ring sections. This drawback is eliminated with *barrel*

**FIGURE 2.33**

Cross-sectional view of a typical 10-stage radial ring section centrifugal pump.

casing pumps, which are used for high-pressure and large-capacity boilers. Pump internals can be withdrawn from one end of the barrel without touching the piping.

- *Axially split pumps* also offer the same advantage of access to pump internals without disturbance to piping, as the pump casing is made in upper and lower halves and bolted together. The disadvantages are that the casings are heavy and each pump requires a pair of castings, making the pumps expensive. The pump efficiency is decided essentially by the impellers, which are common for all designs of casings.

A typical pump calculation for an industrial boiler is included in Appendix A. A typical ring section pump is depicted in Figure 2.33.

2.6 Combustion

Combustion is the self-sustaining rapid exothermic chemical reaction between the elemental C, H, and S of fuel with O_2 from air due to their affinity. The products of combustion are CO_2 , H_2O , and SO_2 along with heat. C and H are beneficial constituents of fuel, producing heat, whereas S is the least heat generating and most harmful, as the SO_2 produced causes low-temperature corrosion. To make any combustion self-sustaining, the resultant temperature from the exothermic reaction should exceed the ignition temperature of the fuel.

2.6.1 Stages of Combustion

Every combustion process proceeds in three stages.

1. *Drying*. The moisture in the fuel is evaporated rapidly by flash drying, mainly by the hot air and furnace radiation.

2. *Burning of VM.* VM leaves the fuel progressively due to the radiation from the furnace and hot furnace gases and burns in furnace space.
3. *Burning of FC.* The dry and devolatilized fuel burns somewhat slowly, releasing the maximum heat on the grate in stoker firing or in the bed in FBC or in the furnace in PF or oil- or gas-fired boilers.

After flash drying of fuel, for the actual combustion to start, necessary air for combustion and heat energy for ignition are required to enable the fuel reach a certain temperature called the ignition temperature, the minimum temperature at which the combustibles can react with O_2 . The ignition temperature of fixed carbon can be considered as the ignition temperature of fuel as the volatiles leave the bed quickly. The ignition temperatures vary widely (please refer to Table 3.2 and Figure 3.5).

2.6.2 Combustion Chemistry

O_2 is the sole supporter of combustion in boiler furnaces. A *combustible* substance is capable of reacting with O_2 to produce heat. The affinity of a combustible to O_2 governs the speed of combustion. This speed of O_2 reaction can vary enormously—very slow as in the case of rust formation or very instantaneous as in the case of gas firing. Combustion is complete when all combustibles have reacted with O_2 to the full extent to which they are capable of reacting. This is important to note, as C can react to form both CO and CO_2 , but the combustion is complete only when all C is converted into CO_2 . Table 2.12 lists combustibles encountered in boiler furnaces.

2.6.3 Combustion Air

Atmospheric air is a mixture (not a compound) of mainly N_2 and O_2 in the ratio of 79:21 by volume and 77:23 by weight. It also contains small amounts of water vapor, CO_2 , and other inert gases such as argon, but for engineering calculation purposes they are ignored. N_2 reported earlier is inclusive of CO_2 and inert gases.

Dry air together with the *associated water vapor* becomes *wet air*, which is found in the atmosphere. A *psychrometric chart* gives the water content in air at various temperatures and *relative humidity*. Dry air has

- An apparent molecular weight (MW) of 29 kg/kg mol
- Density of 1.29 kg/m³ or 0.0805 lb/ft³ at NTP conditions (760 mmHg, 0°C)
- Specific volume of 0.7728 m³/kg or 12.38 ft³/lb at NTP conditions
- Relative density (w.r.t. H = 1) of 14.38

Dry air/unit O_2 is 4.32 kg/kg. All combustion calculations are performed on a dry air basis, and humidity is added separately to arrive at the wet air (Figure 2.34).

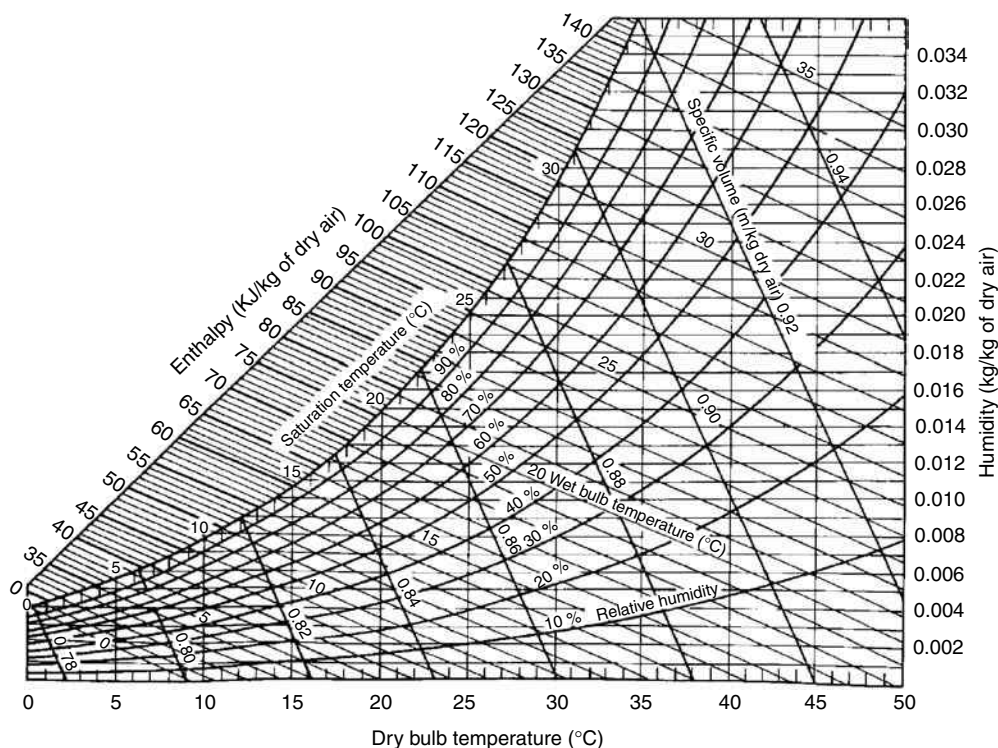
Stoichiometric air is the amount of theoretical air required for the combustion of fuel and can be derived from the fuel composition. In actual practice a certain amount of excess air is needed to complete the combustion, depending on the fuel, firing equipment, combustion temperature, etc. Table 2.13 shows the range of excess air needed for optimum combustion

TABLE 2.12

Heats of Combustion of Select Combustibles

Combustible	Symbol	Molecular Weight	Combustion Reaction	Heat (GCV) (kcal/kg)	Heat (GCV) (Btu/lb)
Carbon	C	12	$C + O_2 = CO_2$	7,833	14,100
Hydrogen	H ₂	2	$H_2 + O = H_2O$	33,945	61,100
Sulfur	S	32	$S + O_2 = SO_2$	2,212	3,983
Hydrogen sulfide	H ₂ S	34	$H_2S + 1.5O_2 = SO_2 + H_2O$	3,944	7,100
Methane	CH ₄	16	$CH_4 + 2O_2 = CO_2 + 2H_2O$	13,266	23,879
Ethane	C ₂ H ₆	30	$C_2H_6 + 3O_2 = 2CO_2 + 3H_2O$	12,400	22,320
Propane	C ₃ H ₈	44	$C_3H_8 + 4H_2O = 3CO_2 + 4H_2O$	12,033	21,660
Butane	C ₄ H ₁₀	58	$C_4H_{10} + 5H_2O = 4CO_2 + 5H_2O$	11,838	21,308
Pentane	C ₅ H ₁₂	72	$C_5H_{12} + 6O_2 = 5CO_2 + 6H_2O$	11,717	21,091

Note: Refer to Appendix B for a comprehensive list of combustibles and their heats of combustion.

**FIGURE 2.34**

Psychrometric chart in SI units.

for various fuels in boiler practice. Also refer to Section 10.2.4 for additional discussion on excess air.

2.6.4 Heat of Combustion

Fuel–air reactions are exothermic and hence produce heat. Various constituents of fuel react with air to produce different amounts of heat. Table 2.12 gives the combustion reaction and heat produced for various combustibles. The higher heating values or gross

calorific values are listed in Table 2.12. These values are measured by *bomb calorimeter* for solid and liquid fuels in which the combustible substances are burned to completion at a constant volume. Calorimeters of continuous or constant flow are used for gaseous fuels. Tables 2.14 and 2.15 list the combustion data for select gases on both weight and volume bases, respectively. Also refer to Appendix B for a detailed chart.

TABLE 2.13

Normal Excess Air Percents for Various Fuels at Full Load

Fuel	Firing	Excess Air by Weight at Full Load (%)
Pulverized coal	Water-cooled furnace	15–20
Coal	Stoker	30–45
Fuel oil	Register burner	3–15
NG, RG, COG	Register burner	3–10
BFG	Scroll	15–20
Bagasse	All	25–35
Black liquor	Recovery furnace	5–7

TABLE 2.14

Combustion Data on Weight Basis (kg/kg)

Combustible	Symbol	Mol. Wt.	Required (kg/kg)		Products of Combustion (kg/kg)				
			O ₂	Air	CO ₂	H ₂ O	N ₂	CO	SO ₂
C to CO ₂	C	12	2.67	11.49	3.67		8.82		
C to CO			1.33	5.75			4.42	2.33	
Carbon monoxide	CO	28	0.57	2.46	1.57		1.89		
Hydrogen	H ₂	2	8.00	34.48		9.00	26.48		
Sulfur	S	32	1.00	4.31			3.31		2.00
Hydrogen sulfide	H ₂ S	34	1.41	6.09		0.53	4.68		1.88
Methane	CH ₄	16	4.00	17.24	2.75	2.25	13.24		
Ethane	C ₂ H ₆	30	3.73	16.09	2.93	1.80	12.36		
Propane	C ₃ H ₈	44	3.63	15.70	3.00	1.63	12.04		
Butane	C ₄ H ₁₀	58	3.58	15.49	3.03	1.55	11.90		
Pentane	C ₅ H ₁₂	72	3.55	15.35	3.05	1.50	11.80		

TABLE 2.15Combustion Data of Gases on m³/m³ Basis

Combustibles	Symbol	Mol. Wt.	Required (m ³ /m ³)		Products of Combustion (m ³ /m ³)				
			O ₂	Air	CO ₂	H ₂ O	N ₂	CO	SO ₂
Carbon monoxide	CO	28	0.5	2.380	1		1.880		
Hydrogen	H ₂	2	0.5	2.380		1	1.880		
Hydrogen sulfide	H ₂ S	34	1.5	7.150		1	5.646		1
Methane	CH ₄	16	2.0	9.530	1	2	7.530		
Ethane	C ₂ H ₆	30	3.5	16.675	2	3	13.170		
Propane	C ₃ H ₈	44	5.0	23.820	3	4	18.820		
Butane	C ₄ H ₁₀	58	6.5	30.970	4	5	24.470		
Pentane	C ₅ H ₁₂	72	8.0	38.110	5	6	30.110		

2.6.5 Three Ts

Time, temperature, and turbulence are the three classical Ts that are required for completeness of combustion.

- *Time.* Adequate time is needed for completing the combustion reaction in the form of residence time in furnace and traveling time in stoker.
- *Temperature.* Minimum ignition temperature has to be reached for initiation of combustion. Higher temperatures of combustion air increase the speed of combustion. Hot air is at times essential, especially for high moisture fuels, to speed the combustion reaction.
- *Turbulence.* An intimate contact of fuel with air is essential. A vigorous turbulence helps mixing and scrubbing of fuel of the ash formed on surface.

2.6.6 Adiabatic Flame Temperature

This is the theoretical temperature that a combustion reaction can produce with complete combustion taking place at stoichiometric condition, assuming that there is no loss of heat to the surroundings and no dissociation. In practice, however, the actual flame temperature will always be lower than the adiabatic temperature, depending on excess air, water cooling and the extent of dissociation.

Dissociation is the breakdown of some CO_2 and H_2O into elements, which is an endothermic reaction occurring at 1650°C and above. Typically $\sim 10\%$ of CO_2 and 3% H_2O can break down, absorbing 2,414 and 33,945 kcal/kg (4,345 and 61,100 Btu/lb) of heat and lowering the flame temperature. It must be remembered that at lower temperatures the gases recombine and generate heat. There is, thus, no loss of heat but only the lowering of flame temperature.

The adiabatic temperature can only be calculated by dividing the total heat by the weight of combustion gases (where the total heat is the heat of combustion + heat of air and fuel) and using the gas tables to arrive at the temperature.

2.6.7 Specific Heats of Gas

Specific heats of gas are required to construct the enthalpy–temperature relationships of gas tables. Specific heat is the heat required to raise the unit weight of substance through unit temperature—kilocalories per kilogram degree Celsius or British thermal units per pound degree Fahrenheit. As all substances vary in volume and pressure with variation in temperature, the specific heat can be at either constant volume or at constant pressure. In liquids and solids there is negligible variation when they are heated or cooled; in gases the change in pressure and volume is sizable. Therefore, there is no difference in the specific heats for solids and liquids, whereas for gases the specific heats are different at constant pressure C_p or at constant volume C_v . Always C_p is higher than C_v by the amount of heat required to do the work of expansion. Figure 2.35 illustrates the mean C_p values at a constant atmospheric pressure for various gases and steam. Instantaneous values will be different from these. For monatomic gases, k value, which is C_p/C_v , is 1.66, and for diatomic gases k is 1.4.

2.6.8 Air and Gas Weights

Combustion air and gas weight estimation from fuel analysis is the first requirement in boiler design or fan sizing.

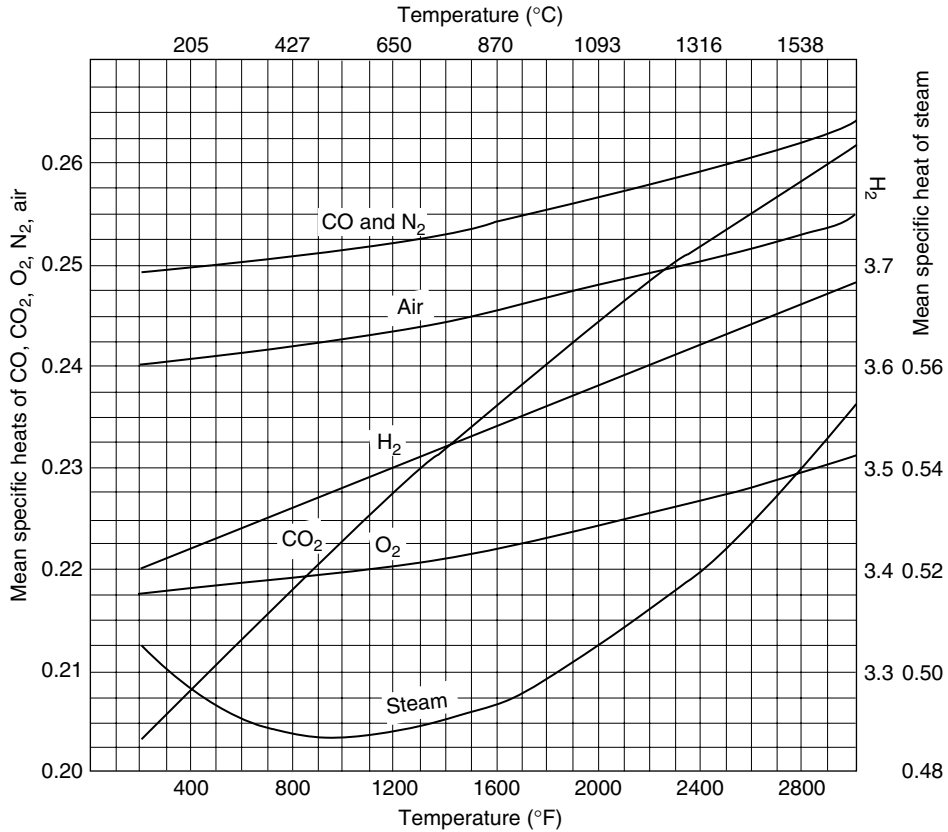


FIGURE 2.35
Approximate mean specific heats of gases and steam.

2.6.8.1 Conversion of Proximate to Ultimate Fuel Analysis for Coals

Proximate fuel analysis (PA) and ultimate fuel analysis (UA) are two ways of expressing the fuel constituents, each with a different purpose as explained in Chapter 1. Ultimate analysis is amenable to calculations using the combustion constants, whereas the PA is better suited for graphical solution. It is possible to arrive at a fairly accurate UA from PA using empirical methods. Gebhardt's method is a popular one where the daf % VM and FC of PA are converted into the daf % of C, H, N, and O in UA as shown:

- % daf C = FC + 0.02 VM² for anthracite
 = FC + 0.9 (VM-10) for semianthracite
 = FC + 0.9 (VM-14) for bituminous coal
 = FC + 0.9 (VM-18) for lignites
- % daf H = VM [(7.35/VM + 10) - 0.013]
- % daf N = 0.07 VM for anthracite and semianthracite
 = 2.1-0.012 VM for bituminous coals and lignites
- % daf O = 100 - (C+H+N)

Fixed carbon and VM are on a daf basis and %C derived includes the %S.

2.6.8.2 Air and Gas Weights from Ultimate Analysis

- From the UA, air and gas weights can be calculated using the table of gas constants or Equation (2.31) to arrive at the dry weights.
- Theoretical dry air for combustion is given as

$$\frac{11.5}{100} \left[\left(C + \frac{3}{8}S \right) + 3 \left(H - \frac{O}{8} \right) \right] \text{ kg of air/kg of fuel fired} \quad (2.31)$$

where C, H, O, and S are percent by weight in UA.

- Humidity in air at ambient conditions can be read from a psychometric chart and added to arrive at the wet air.
- For gas weight on wet basis the weight of actual fuel burnt, that is, fuel weight–ash weight, has to be added to the weight of wet air.

An actual worked-out example for estimating the air and gas weights from UA is provided in Appendix A.

2.6.8.3 Air and Gas Weights from Proximate Analysis for Solid Fuels: Graphical Method

When air and gas weights are to be evolved from PA

- UA can be first calculated from PA and the aforementioned method can be used or
- A graphical solution can be adopted

Both methods give sufficiently accurate results for commercial purposes and vary from 1 to 2%.

The graphical method for solid fuels with PA employs Seyler's chart, which is described in Chapter 3 and daf VM is the base. The range of VM for various fuels is indicated in Figure 2.36. The figure covers a wide range of solid fuels and provides all the necessary combustion data.

- From the PA, daf VM is obtained by dividing actual VM by (1–[ash + moisture]).
- Theoretical combustion air for daf GCV in terms of kilograms per 1000 kilocalories per kilogram can be read from Figure 2.36. Actual air is then obtained by multiplying the GCV.
- H₂ on a daf basis is shown in Table 2.16. This is to be multiplied by (1–[ash + moisture]) to obtain the actual H₂. Nine times H₂ gives the moisture on combustion.
- The actual CO₂ by volume% is equal to

$$\frac{\text{Theoretical maximum CO}_2 \text{ by volume}}{1 + f \text{ (excess air\%/100)}} \quad (2.32)$$

which gives a relationship of CO₂ to excess air. Theoretical CO₂ and factor f are listed in Table 2.16.

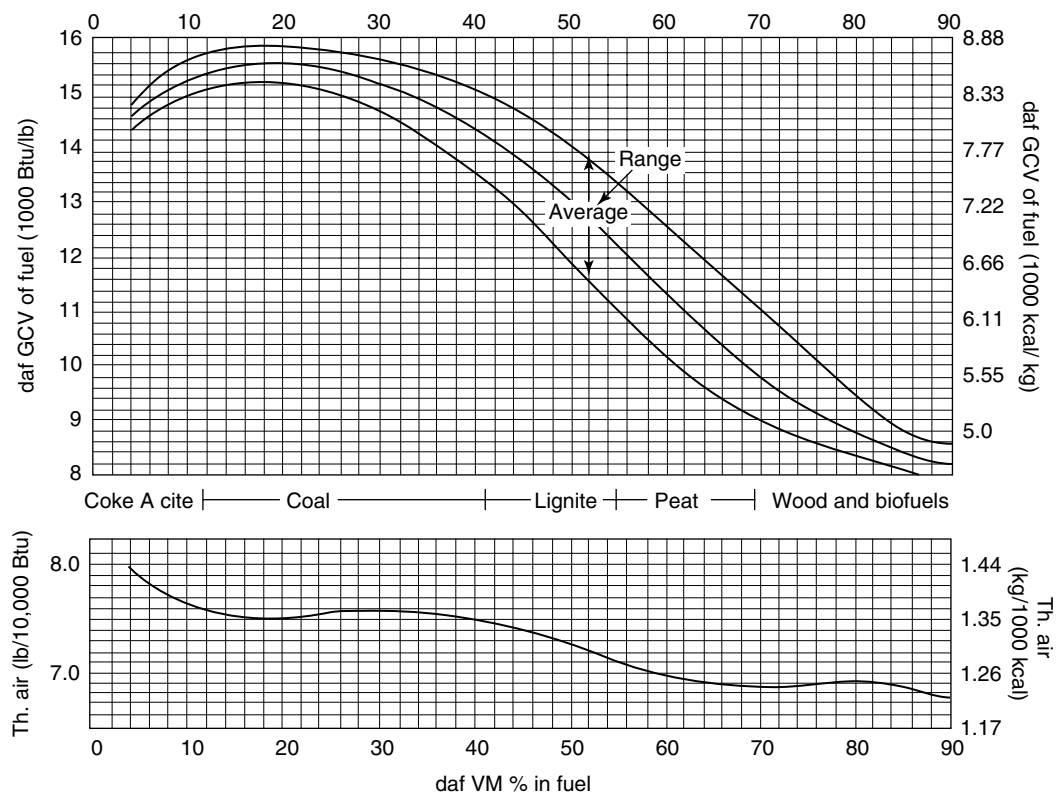


FIGURE 2.36
Combustion properties of solid fuels.

TABLE 2.16
Combustion Parameters for Solid Fuels

	Coke and Anthracite		Coal			Lignite	
	0	10	20	30	40	50	60
Theoretical air (kg/1000 kcal)	1.40	1.3800	1.370	1.36	1.36	1.36	1.36
Theoretical max. CO ₂ (% volume)	20.20	19.300	18.70	18.70	18.80	19.10	19.60
H ₂ on dry ash-free basis		3.800	4.70	5.20	5.40	5.55	5.65
Factor <i>f</i> for calculating CO ₂		1.025	1.03	1.03	1.03	1.03	1.02

**2.6.8.4 Air and Gas Weights from Proximate Analysis
for Liquid Fuels—Graphical Method**

This is a quick and reliable method for calculating the air quantity and CO₂% by volume.

- The kilocalorie method for liquid fuels uses daf H₂ in fuel as the base.
- For each 1% increase in sulfur, the CV has to be reduced by 55 kcal/kg or 100 Btu/lb.
- Normally, higher sulfur is associated with higher hydrogen.

- At lower levels of H_2 the CV values are not very accurate and hence shown as dotted lines (Figure 2.37). However, CO_2 values are not affected.
- This is not applicable for vegetable oils or manufactured oils, which are generally high in O_2 content.

Typically for fuel oil (with moderate sulfur of $\sim 1\%$) and natural gas, the data of Table 2.17 can be applied.

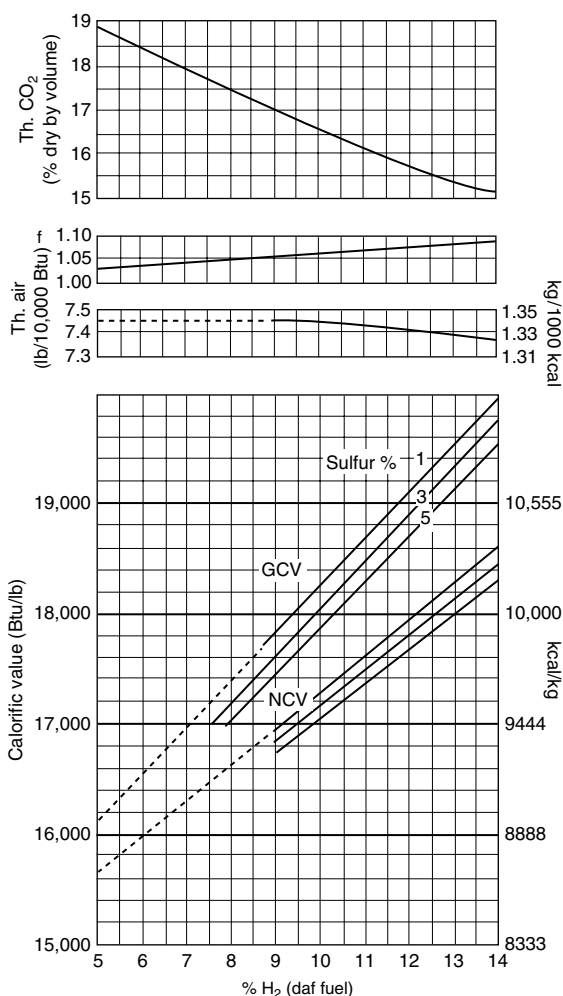


FIGURE 2.37
Fuel oil combustion properties.

TABLE 2.17

Air Requirement for Typical Fuel Oil and Natural Gas

Fuel	GCV (kcal/kg)	Th. Air (kg/1000 kcal)	Moisture (kg/1000 kcal)
Fuel oil	10,200	1.344	0.92
Natural gas	11,200	1.295	1.67

2.6.9 Flue Gas Analysis

This is continuously monitored in a boiler as it is the only way to measure the completeness of combustion. Commercial control room indication is for O_2 , CO_2 , and CO by percentage of volume on dry basis.

- Adequate O_2 reading on panel assures that there is excess air.
- Little or no CO indicates a good mixing of air and fuel leading to complete combustion.
- O_2 or CO_2 is measured by the gauge instrumentation. O_2 measurement is generally preferred due to ease and consistency of measurement and directness of result.
- For testing purposes, CO_2 measurement is mandatory and is usually performed by Orsat analyzer.

2.6.9.1 Orsat Analysis

Orsat analysis is still considered the best method to analyze the flue gases accurately. Orsat apparatus (Figure 2.38) consists of (A) a burette graduated bottom upward into

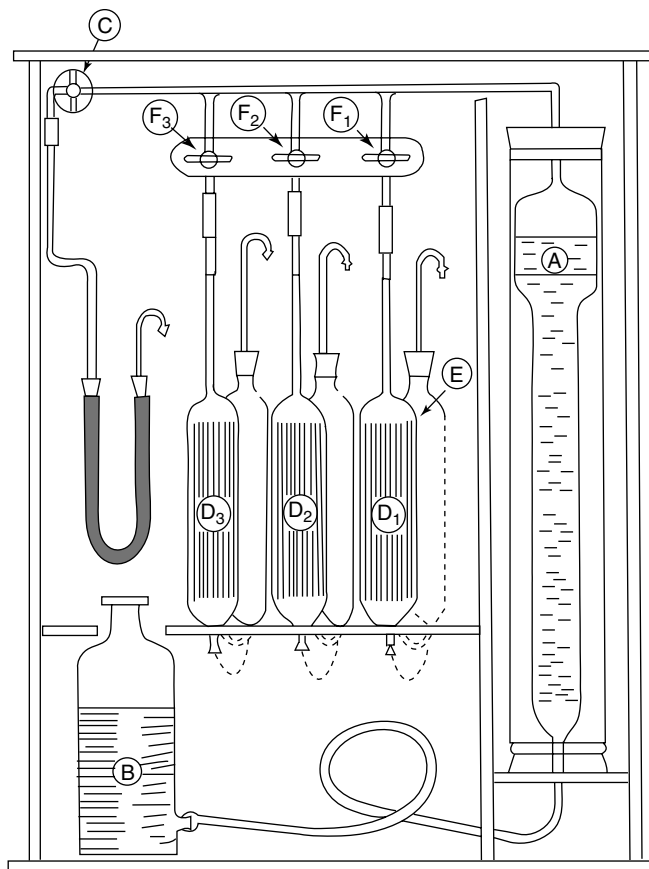


FIGURE 2.38
Orsat analyzer.

100 divisions, (B) an aspirator bottle, and (D_1 – D_3) three pipettes containing absorbents filled with glass tubes or beads (for increasing the area of absorption).

- Potassium hydroxide solution (KOH) for CO_2 (and also SO_2)
- Freshly prepared alkaline pyrogallol or pyrogalllic acid for O_2
- A solution of cuprous chloride (CuCl_2) in NH_3 or HCl for CO (and also for ethylene and acetylene)

Each pipette is connected to an empty pipette behind it so that the absorbent can recede into it as the gas is admitted. There is (C) the main isolating cock for gas retention in the system along with (F_1 – F_3) the three isolating cocks for the three pipettes.

The procedure consists of (1) aspirating 100 cc of gas with the help of the aspirator bottle, (2) absorbing the gas in the three absorbents in a definite sequence, and (3) noting the absorption by difference in the measuring burette. Care, strict adherence to the procedure, and the correct preparation of absorbents to specified concentration are needed to obtain error-free results. For getting proper samples on a sustained basis, a suction pump is used for sucking flue gas, as the aspirator alone is usually not adequate.

2.6.9.2 Some Graphical Solutions for Flue Gas

Weight of dry flue gas per kilogram of fuel from flue gas analysis is given by

$$\frac{11\text{CO}_2 + 7\text{CO} + 7\text{N}_2 + 8\text{O}_2}{3(\text{CO}_2 + \text{CO})} \times \left(C_g + \frac{S}{183} \right) \quad (2.33)$$

where

CO_2 , CO , N_2 , and O_2 = gas volumes in percentage in dry flue gases

S = percentage by weight of sulfur in fuel

C_g = weight of carbon in flue gas per kilogram of fuel

Figures 2.39 through 2.41, illustrate $\text{CO}_2\%$ in flue gas, weight of flue gas, and combustion air for various percentages of excess air for a variety of popular fuels.

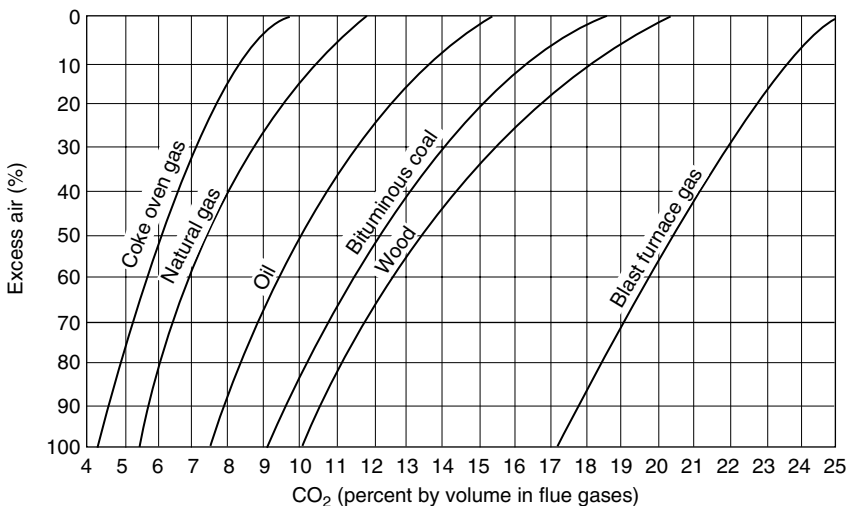


FIGURE 2.39

Percentage of CO_2 in dry flue gas versus excess air. (From Babcock and Wilcox Company, U.S.A. With permission.)

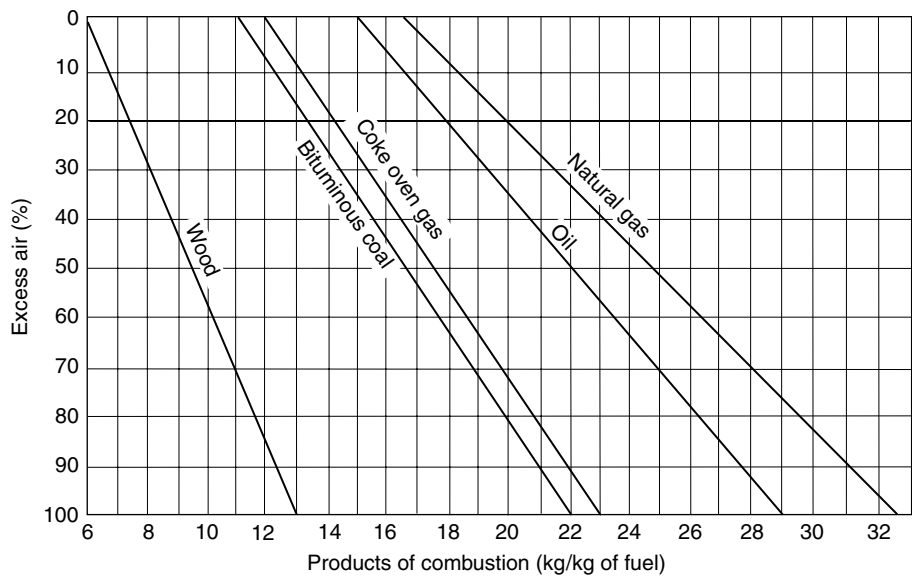


FIGURE 2.40 Percentage of excess air versus flue gas in kilogram per kilogram (kg/kg) of fuel. (From Babcock and Wilcox Company, U.S.A. With permission.)

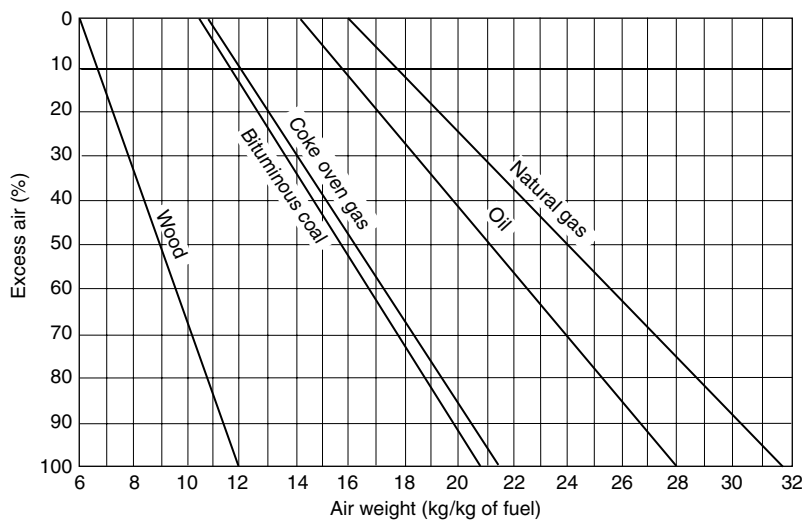


FIGURE 2.41 Percentage of excess air versus air weight in kilogram per kilogram (kg/kg) of fuel. (From Babcock and Wilcox Company, U.S.A. With permission.)

2.6.10 Specific Volume of Flue Gases

Figure 2.42 is very useful in calculating the specific volume of flue gas from the theoretical and actual CO₂ (by volume on dry basis) at various moisture levels (by weight) in flue gas.

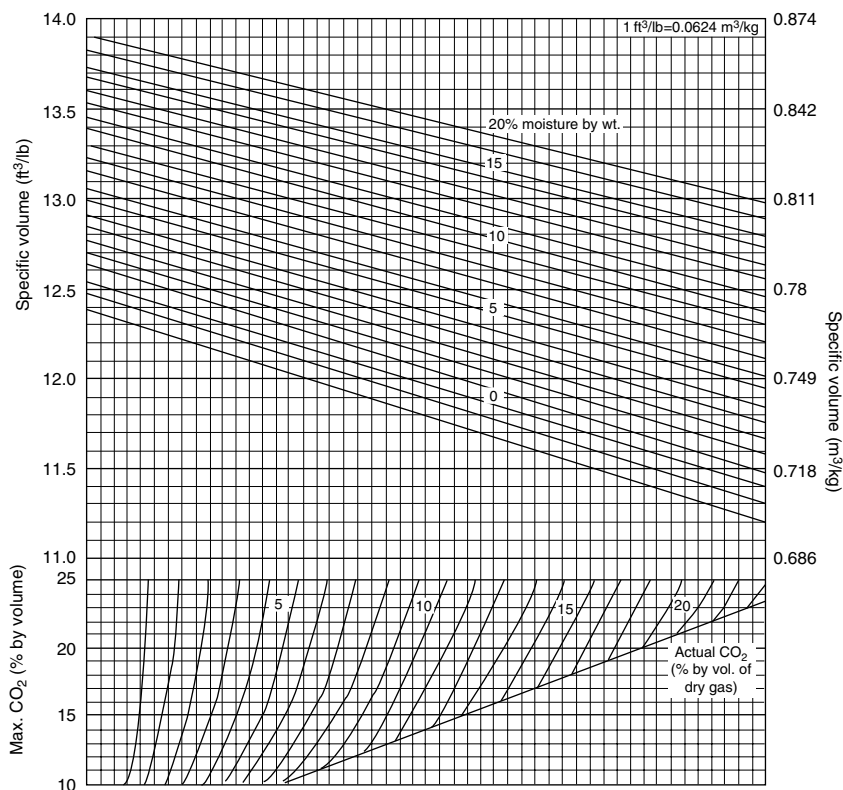


FIGURE 2.42
Specific volume of flue gas at NTP conditions.

2.7 Thermodynamic Cycles

Steam is used in (1) many processes for mainly heating and (2) many ways for power generation. Its utility is both in process industry and power plants. In the process industry it is produced for

1. *Industrial processes* involving mainly heating, steam drives, and other functions
2. *Cogeneration (cogen)* to provide other forms of energy, mainly power

In power plants it is generated for

1. *Captive power* for use by large cement, steel, aluminum, and allied plants
2. *Grid power* to feed the electricity networks for public distribution

Steam is

1. Produced in boilers at a high pressure
2. Expanded in turbines or drives or consumed by processes at a lower pressure
3. Condensed in processes or condensers to revert to water
4. Returned to the BFPs to be pressurized and fed to the boiler again

There is, thus, a *cycle* established between steam generation and condensate return. This *steam cycle* is one of the several thermodynamic or heat engine cycles used in diesel engines and gas turbine (GT) cycles.

2.7.1 Carnot Cycle

Sadi Carnot was the first to introduce the concept of cycle along with reversible processes. See Figure 2.43. The cycle is applicable to any working fluid such as steam and gas. It is represented in chart form in Figure 2.44 and is called the ideal vapor cycle. Here heat is added and rejected at constant temperatures, with expansions and compressions carried out at constant entropies. The Carnot cycle offers the maximum thermodynamic or cycle efficiency between the temperatures of source and sink and is represented by the net work output/total heat input (Figure 2.44). In the T-s diagram it is calculated as

$$\text{Cycle } \eta = \frac{T_1 - T_2}{T_1} = 1 - \frac{T_2}{T_1} \quad (2.34)$$

where T_1 and T_2 are the absolute temperatures of the source and sink, respectively.

The Carnot cycle cannot be replicated in practical world as the processes are reversible and frictionless and adiabatic. But the efficiency determined between heat and sink can represent the maximum to which the other cycles can be compared.

2.7.2 Rankine or Steam Cycle

The Rankine or steam cycle has already been introduced, and the salient points are briefly covered in Section 2.2.5. This cycle as applicable in condensing and cogen power modes is illustrated in Figures 2.45 and 2.46. With nearly 50% of heat rejection in the condenser, the cycle efficiency is ~40% on NCV basis for conventional power plants with subcritical steam parameters. With SC conditions the efficiency can go up to 42–43% and with

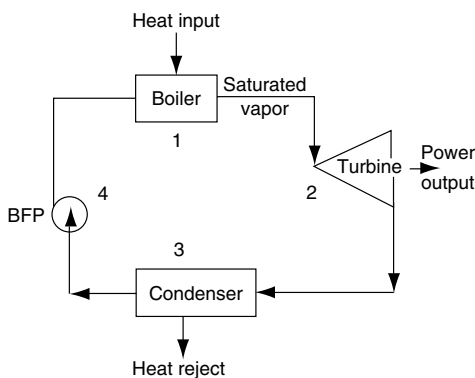


FIGURE 2.43
Carnot cycle in diagrammatic form.

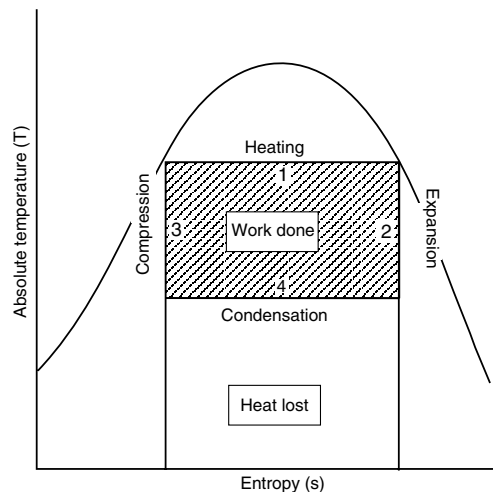
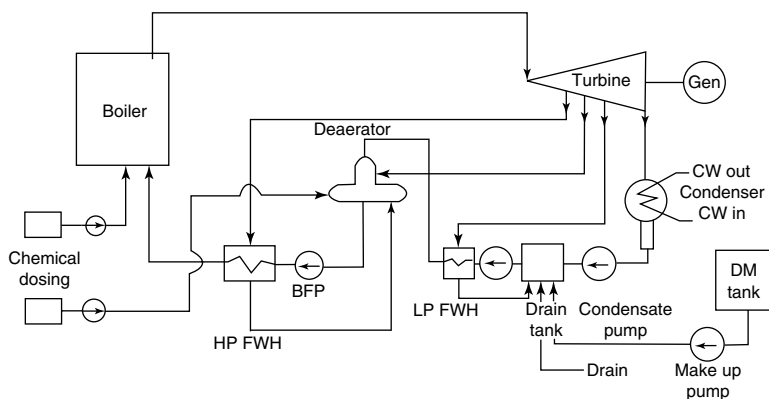


FIGURE 2.44
Carnot cycle on T-s chart.

**FIGURE 2.45**

Simplified steam cycle for power generation with condensing turbine.

ultracritical conditions, up to 44–45%. With regenerative feed heating, the thermal/cycle efficiencies increase significantly as the graphs of Figure 2.47 depict. More FWHs mean higher feed temperatures and cycle efficiency. Practical considerations limit the FWHs as shown in Figure 2.47. The optimum feed temperature rise is generally around 40°C for each FWH.

The cogen cycles, on the contrary, are far more efficient as there is no loss of heat in condensers. Depending on how much of heat is fully consumed in the process, the cycle efficiencies can easily reach 85%.

2.7.3 Brayton or Gas Turbine Cycle

- Unlike the vapor cycle of Rankine, this is a gas-based cycle.
- While the expansion and compression parts of the cycle are isentropic as in the Rankine method the heating and heat rejection parts are at constant pressure and not at constant temperature, that is, isothermal.
- Heat rejection is to the atmosphere and there is no condensation.
- Recycling of working fluid is with reference to atmosphere.

Air, drawn from atmosphere, is compressed to high pressure when fuel is injected and burnt at constant pressure. The resulting hot gases are expanded in a GT, and the emanating cooled gases are rejected to atmosphere that acts as a sink. Figures 2.48 and 2.49 depict the cycle on T-s and P-v charts, respectively, and it is shown in diagrammatic form in Figure 2.50.

Open-cycle operation of GT with exhaust gases rejected to atmosphere, with no HRSG to recover heat, works with the Brayton cycle. With a lot of heat rejection the operation is not efficient. Combined cycle (CC) operation is a preferred solution, unless the fuel is very reasonable.

2.7.4 Combined Cycle

A Brayton cycle superimposed over a Rankine cycle is the CC. The exhaust of the GT is used for steam generation in HRSG, which runs a steam cycle with a condensing turbine. Naturally this is the most efficient of all cycles.

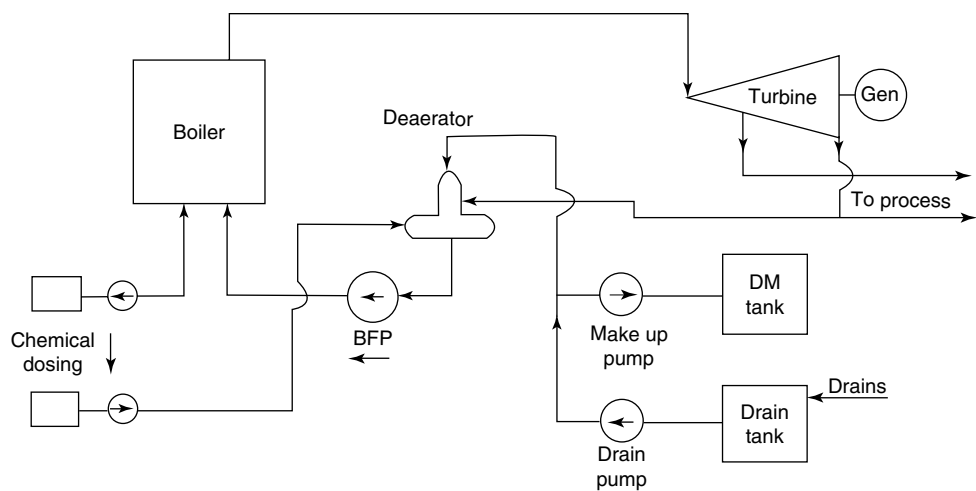


FIGURE 2.46
Simplified cogeneration cycle with back-pressure turbines.

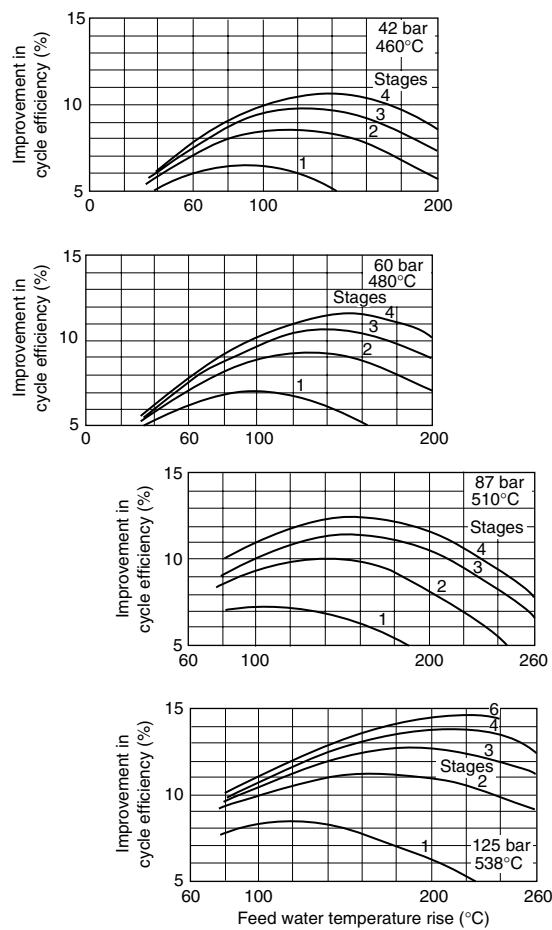


FIGURE 2.47
Improvements in cycle efficiency due to feed water heating by regeneration.

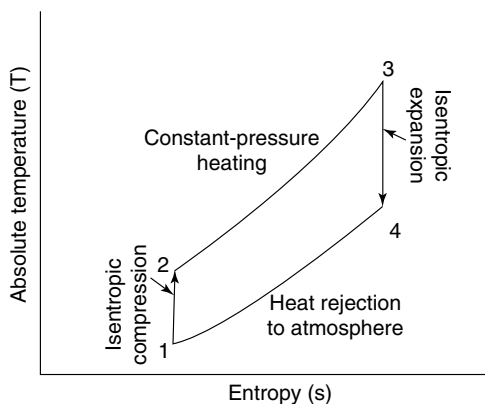


FIGURE 2.48
Brayton cycle on T-s diagram.

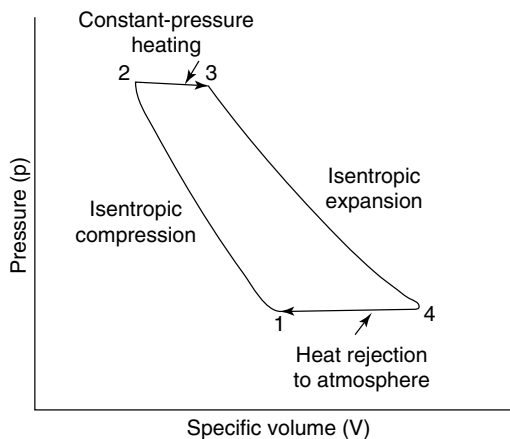


FIGURE 2.49
Brayton cycle on P-V diagram.

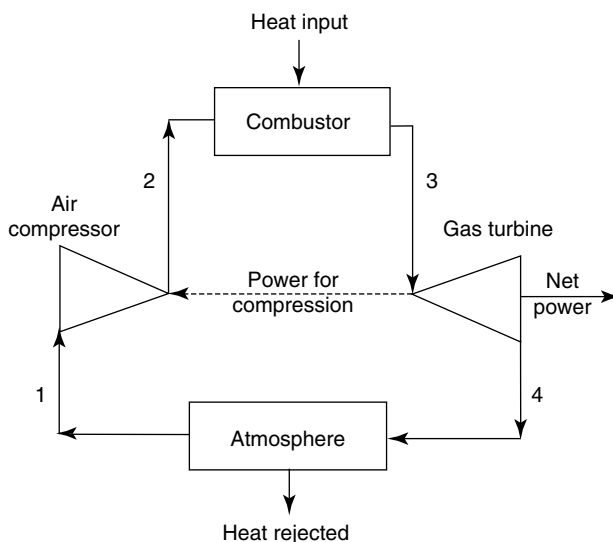


FIGURE 2.50
Components of Brayton cycle.

A combined cycle for power generation is depicted diagrammatically in Figure 2.51. The CC can also be for cogen and is popular with process industries requiring steam in addition to power. Usually a back-pressure turbine takes the place of the condensing turbine to supply steam at the desired conditions.

Combined cycle power plants (CCPPs) have grown dramatically in size and efficiency in the past two decades. The present efficiencies on NCV bases are in excess of 55% with large GTs and approach 60% in the largest configurations. In the cogen mode the efficiencies are much higher.

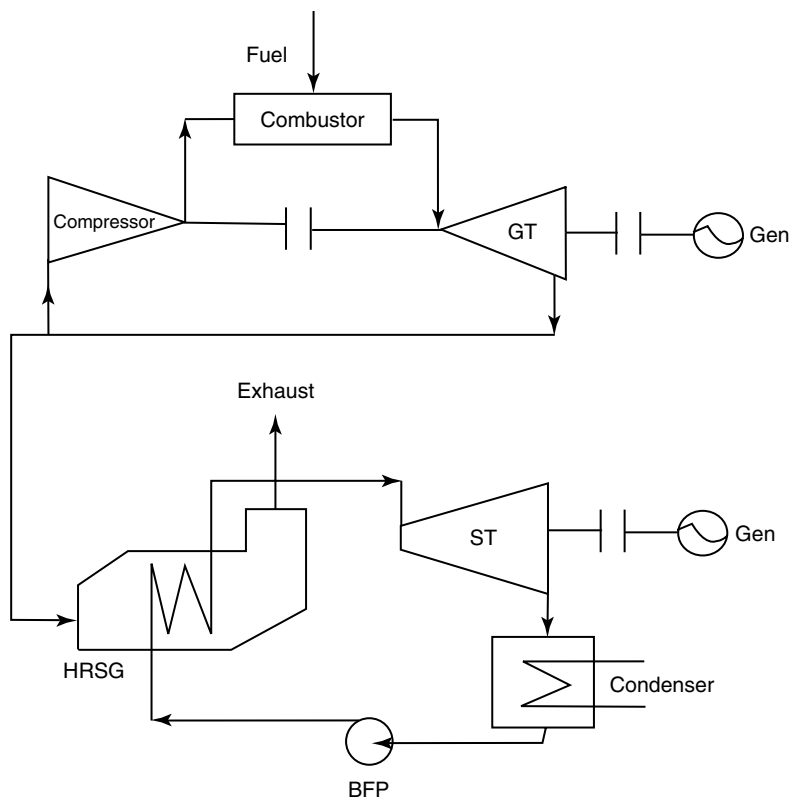


FIGURE 2.51
Components of combined cycle.

Further Readings

Marks' Standard Handbook for Mechanical Engineers.

Perry's Chemical Engineers Handbook.

Pratt, A.D., 1965 reprint, *Principles of Combustion in Steam Boiler Furnace*. B&W Limited, London.

Steam: Its Generation and Use.

3

Fuels and Ash

3.1 Introduction

The entire power plant is built around the fuel, and there is perhaps no other parameter more important. A thorough understanding of the fuel—its burning characteristics, transportation inside and outside the boiler plant, its ash generation and disposal, the environmental aspects, and so on—is necessary for design, selection, operation, and maintenance of the boiler and the power plant. Only those fuels that are primarily used in boilers are discussed in this chapter.

The subject of fuels is vast when aspects such as their availability, mining, treatment, transportation, storage, consumption, by-products, and environmental issues are all considered. The topic becomes more unpredictable and difficult when issues of pricing and geopolitics are considered, particularly for oil and gas. However, this chapter is confined to how a combustion engineer looks at the fuel scenario from the point of burning it in boilers.

For large power plants, the focus is with the prime fuels, as the power costs are to be minimized and the prime fuels are the most competitive. Coal has been the main fuel for power plants in many parts of the world except in areas where oil and gas are available in abundance, such as the Middle East. For some time in the 1960s oil had become abundant, but the oil crisis of the early 1970s has changed this condition permanently, making oil an expensive fuel. Coal reasserted its position since the beginning of this decade as the most dependable relatively low cost fuel; this traditional balance has been disturbed with natural gas (NG) displacing coal as power plant fuel, even in areas where gas was not popular based on the following reasons:

- Greater gas production at more competitive pricing
- Easier availability due to more gas pipes and shipping of liquefied NG (LNG)
- Bigger combined cycle (CC) plants operating at very high overall efficiency
- Power generation in very short periods due to faster deliveries of gas turbines (GTs)

Now coal is again finding favor, as the gas prices climb.

For industry the fuel scene is a little different. Both power and steam are required to be produced competitively, but to a lesser scale as compared with the utilities. Prime fuels are important only when substantial captive or cogenerated power is involved. At other times, for process needs there are various waste or manufactured fuels that can be used. Fuel cost is not always as important to the industry as it is to the utility, as power and steam are only some of the several inputs to the end product.

The fuels can be classified as follows:

1. Fossil fuels such as various grades of coals, oils, and NG
2. Waste fuels such as biofuels, process gases, and spent liquors
3. Manufactured fuels such as producer gas, town gas, and liquefied petroleum gas (LPG)

Fuels can also be classified as solid, liquid, and gaseous. Naturally, the fossil fuels are chiefly used. But in absolute quantity, the use of the other fuels is progressively increasing. Manufactured fuels are not used in any appreciable manner for steam generation based on cost and availability considerations and hence are not discussed in this chapter.

Fossil fuels are not uniformly available across the globe. The estimates of the fuel reserves and how long they would last have often gone wrong, particularly in the developing countries, where the data are still being updated due to exploration activities. Fuel production, transportation, and pricing are mixed with politics and display extreme volatility. This is particularly a characteristic of crude oil and, to some extent, of NG. It has also not been possible to predict the behavior of the fuel market. The large utilities worldwide therefore have found it necessary to diversify fuels and their sources. Also, to gain further economy, multifuel firing is being demanded wherever feasible.

While the fuel decides the type and shape of the boiler, the fuel ash governs the size and disposition of heating surfaces (HSs). The effects of ash are most severe in coal-fired boilers, as coal has the highest ash content compared to all the other fuels. Good coal for burning should also have a benign ash that does not slag, foul, or cause erosion or corrosion. Ash is as important as any fuel.

Fuels and combustion are closely related. Combustion aspects of fuels are discussed in Chapter 2.

3.2 Solid Fuels

3.2.1 Fossil Fuels

3.2.1.1 Coals

Coals are complex substances that are geologically formed from ancient vegetation by the combination of time, pressure, and heat of the earth over several millennia. Depending on how long the vegetable matter has been subjected to these conditions, the resulting coals assume several properties. The most ancient coals under higher pressure would have converted practically all the vegetable matter into fixed carbon (FC), whereas the youngest coals with lesser pressure are still substantially woody and contain much more volatile matter (VM) than FC. Ash is the sand trapped along with wood in the formation of coal.

3.2.1.1.1 Classification of Coals

There are several classifications for coals. In the United States, they are classified by rank as per ASTM D388. Rank is the general measure of degree of coalification. In Europe, there are separate classifications for hard coals and brown coals. Hard coals have gross

TABLE 3.1

Coal Classification

Class	Group	FC (dmmf) (%)	VM (dmmf) (%)	GCV (moist mmf)			Remarks
				MJ/kg	kcal/kg	Btu/lb	
I. Anthracitic	Meta-anthracite	>98	<2				
	Anthracite	92–98	2–8				
	Semianthracite	86–92	8–14				
II. Bituminous	Low-volatile coal	78–86					Nonagglomerating Commonly agglomerating
	Medium-volatile coal	69–78					Commonly agglomerating
	High-volatile coals A, B, and C	<69		24.4–32.6	5830–7780	10500–14000	Commonly agglomerating
III. Subbituminous	A, B, and C coals			19.3–24.4	4610–5830	8300–10500	
IV. Lignitic	Lignite A			14.66–19.3	3500–4610	6300–8300	
	Lignite B			<14.66	<3500	<6300	Also called brown coals

Source: Adapted from ASTM D388.

calorific value (GCV) greater than ~23.86 MJ/kg, 5,700 kcal/kg, or 10,260 Btu/lb on a dry ash-free (daf) basis. A broad classification of coals based on ASTM D388 is given in Table 3.1.

- The properties used for ranking of coals are GCV, M, VM, and agglomerating character.
- Older coals are classified by dry mineral matter free (dmmf) carbon and younger coals by moist mmf GCV.
- Parr's formulae are followed for calculating the mmf C, VM, and GCV using proximate analysis (PA). The moist condition in low-rank fuels refers to the bed, inherent, or equilibrium moisture.
- Agglomerating or caking nature of coals is the swelling property (explained later) and determined by ASTM D720.

These data are presented in graphical form in Figure 3.1. Certain interesting trends can be observed.

- With increasing rank, FC and GCV increase whereas M and VM decrease.
- The ratio of FC to VM is called *fuel ratio*, which increases with rank.
- The higher the fuel ratio, the higher the GCV. But with anthracites, the GCV, in fact, drops, as there is not enough VM to contribute to the heat value.
- Lower ranks have higher VM and O₂ contents, which aid ignition and enhance combustibility and flame stability.
- Low-rank coals produce *self-pulverization* during combustion as the inherent moisture locked in the pores is heated and expands rapidly (volume expansion of 1:1600) to fragment the fuel particles.

In the United Kingdom, Seyler's classification forms the basis on which the analytical data on daf are plotted. Most coals fall in a band in which daf VM and daf GCV are plotted on

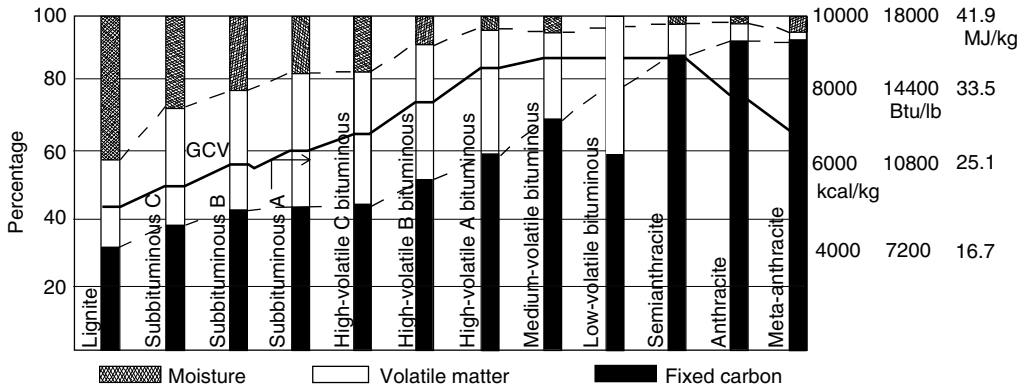


FIGURE 3.1

Proximate analyses and GCV of various classes of coals.

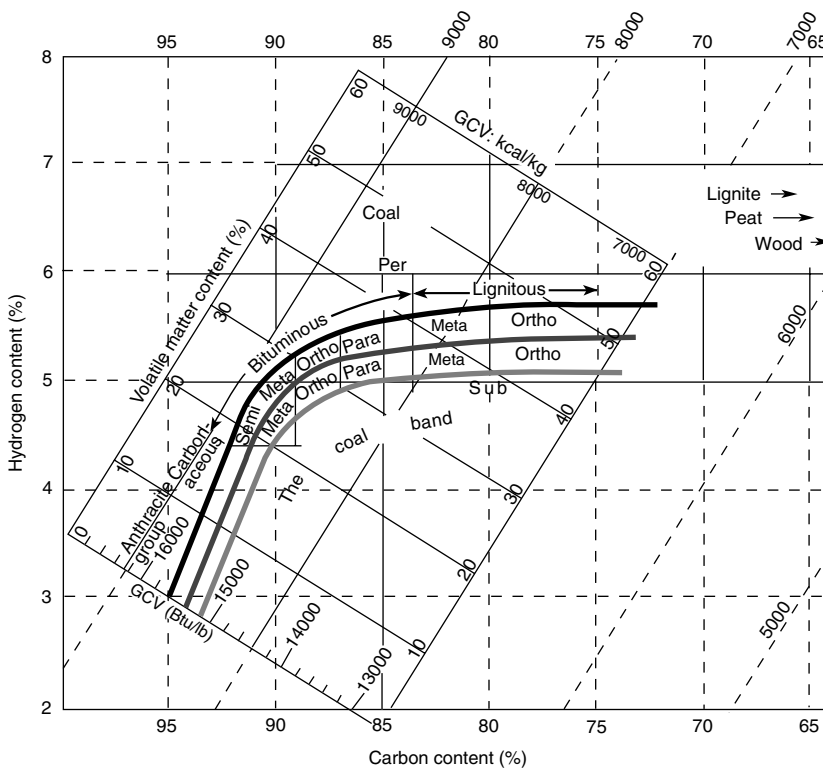


FIGURE 3.2

Seyler's classification of coal. (From Her Majesty's Stationery Office, U.K. With permission.)

X- and Y-axes. When *daf* C and H are also plotted on the two axes, there emerges a comprehensive and reliable chart of coal properties (Figure 3.2).

3.2.1.1.2 Analysis of Coals

The coal analysis is of two types. Both types are important, have different purposes, and are complementary.

3.2.1.1.2.1 *Proximate Analysis* This analysis tells us how the coal burns. It assesses four items:

1. Moisture (M)—the total moisture consisting of inherent/interstitial and superficial/surface moisture
2. Ash (A)—the residue left on burning of the coal
3. Volatile matter—the gaseous portion that burns above bed in free space
4. Fixed carbon—the solid portion of fuel that burns on the grate or in the bed

Moisture and ash together are known as the *burden* or *ballast* as they do not contribute to the heating value (HV).

1. *Moisture*. Total moisture of *as-mined* coal varies a great deal. It is about

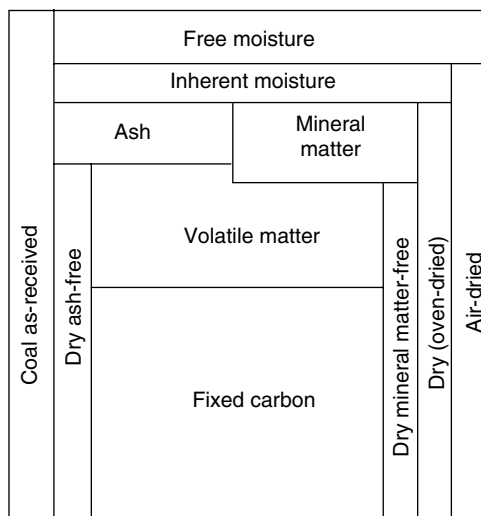
- 5% in low-volatile bituminous coal
- 12% in high-volatile bituminous coal
- 35–65% in lignites

On burning, the moisture cools the flue gases, and hence reduces the tendency to form fuel NO_x . It also increases the volume of gases.

- i. *Inherent moisture* is trapped inside the fuel and is progressively released along with VM up to a high temperature of $\sim 700^\circ\text{C}$. This moisture exists as a quality of the seam in its natural state.
- ii. *Surface moisture* is picked up by coal due to its hygroscopic nature from the surroundings due to
 - Humidity in air
 - Rain or snow exposure during transportation
 - Washing for ash reduction
 - Mining operations
- a. Moisture in the *as-received* coal is the *total moisture* consisting of surface and inherent moisture.
 - i. The visible surface moisture or *free moisture* dries away and reaches equilibrium with the ambient humidity when left exposed to air for some time. This is known as *air-dried* condition of fuel. The moisture left in coal after air drying is the remaining *surface moisture*. It leaves the coal quickly on heating to $\sim 105^\circ\text{C}$. Water held superficially increases as the coal size reduces.
 - ii. When the sample is further heated in the oven to ~ 700 to 750°C , the *inherent moisture* also leaves the coal.

Figure 3.3 shows the different types of moisture at different stages of drying. The air-dried condition is normally used for design purposes.

2. *Ash* is the incombustible mineral matter (MM) left behind when coal is burnt. In the laboratory, it is the residue left on complete combustion at 700 – 750°C in a muffle furnace performed in a carefully controlled and specified manner. Ash is of two types—adventitious and inherent.
 - a. Adventitious ash is the material derived from shale, clay, pyrites, and dirt from earthy or stony bands in the coal seam.

**FIGURE 3.3**

Bases of coal analysis. (From Her Majesty's Stationery Office, U.K. With permission.)

- b. Inherent ash is the mineral substance derived from vegetable matter.

Ash is composed of compounds of Si, Al, Fe, and Ca and, to a lesser extent, compounds of Mg, Ti, Na, and K. Although they are reported as oxides in analysis, they occur in ash as a mixture of silicates, oxides, sulfates, and so on. Ash forms nearly 90% of the MM, which additionally accounts for

- a. The combined moisture and CO_2 expelled from clays and other minerals by heat
 - b. The difference of weight between the original MM and the substance formed due to combustion
3. *Volatile matter* is a complex mixture of organic materials, which volatilizes quickly on heating at $\sim 300^\circ\text{C}$ and burns in suspension in a furnace. The higher the VM, the lower the ignition temperature and greater the combustion speed—it is easier to ignite and burn the coal. Coals with less than $\sim 15\%$ VM on a daf basis are termed low volatile. Their ignition requires higher temperature and burning is slow and hence requires a larger furnace volume.

Volatile matter is ascertained as the percentage loss in weight on heating a gram of coal with no air under standard conditions in a crucible for 7 min at 950°C . Moisture is expelled at the same time but recorded separately.

Expelled VM contains the following:

- a. Water resulting from the combustion of H_2
 - b. Complex mixtures of H_2 , O_2 , CO , CH_4 , C_2H_6 , and other hydrocarbons (HCs)
 - c. Tar, a mixture of HCs and organic compounds especially phenols
- No VM exists as such in coal but is formed chemically on the destruction of coal. Inerts and noncombustible matter form 4% of the total VM in low-volatile coals to 40% in subbituminous coals.
4. *Fixed carbon* is not the carbon obtained in ultimate analysis (UA). It is the carbonaceous residue left in the crucible after driving away the VM. It is not the

total carbon, as total carbon is distributed between FC and VM. It is also not the pure carbon, as it contains traces of H, O, and N and about half the sulfur.

Fixed carbon needs to be burnt in solid state either on the grate or in the bed in fluidized bed combustion (FBC) or as solid particles in pulverized fuel (PF) firing. FC decides the burning equipment. Fixed carbon is not measured but deduced by subtracting $(M + A + VM)$ from 100.

3.2.1.1.2.2 Bases of Reporting Analysis There are several ways of reporting the analysis and the basis should be made clear.

- *As-received basis* is the analysis of coal as received at the plant and delivered for analysis.
- *Air-dried basis*. Coal is always analyzed in this condition. It is ground to pass through a 0.2 mm screen and spread out in a thin layer and allowed to dry until the retained moisture is in equilibrium with the ambient humidity. Then the inherent moisture, VM, and ash are determined and FC is calculated by the difference.
- *Dry basis*. Air-dried VM, FC, and ash are multiplied by $100/100 - IM$, where IM is the inherent moisture.
- *daf basis*. Air-dried VM and FC are multiplied by $100/100 - IM - A$, where A is ash.
- *Dry MM free basis*. Air-dried VM and FC are multiplied by $100/100 - MM - IM$.

Figure 3.3 clarifies these different terms.

3.2.1.1.2.3 Ultimate Analysis This is the chemical analysis of the fuel in which carbon, hydrogen, nitrogen, sulfur, and oxygen (by difference) are determined for their elemental weights in the laboratory by prescribed methods. The UA is useful for the calculation of air and gas quantities and other combustion calculations.

- Elemental carbon is the sum of carbon in FC and VM. The CO_2 in the flue gas is the result of this carbon.
- All the hydrogen in the fuel produces water nine times its weight on combustion. Together with water in the fuel, the total represents the moisture in flue gas.
- Nitrogen as inert material does not participate in combustion. At high temperatures it combines with O_2 to produce traces of fuel NO_x .
- Sulfur in coal occurs in three forms:
 - i. Organic combination
 - ii. Sulfide ion as FeS_2 in pyrite or FeS_x as marcasite crystals
 - iii. Sulfate ion as $CaSO_4$ or Fe_2SO_4

Sulfur on combustion forms SO_2 and partly SO_3 and the latter in combination with water forms sulfurous acid, which produces gas side corrosion in locations that cool flue gases below the acid dew point.

- Oxygen in fuel is indicative of the rank; higher O_2 equals lower rank. O_2 represents a loss of fuel potential as it combines with C and H to form CO_2 and H_2O . It reduces the air requirement for combustion. High O_2 and low HV go together. O_2 in fuel is determined by the difference.

3.2.1.1.3 Calorific Value

Calorific value (CV) or HV is the heat content of the fuel expressed in megajoules per kilogram, kilocalories per kilogram, or British thermal units per pound. It can apply to coal as delivered, as fired, as dry, and as daf.

- There are two CVs in practice both representing different aspects. The GCV or higher CV (HCV) is more popular in the United States and United Kingdom, whereas net CV (NCV) or lower CV (LCV) is preferred on the Continent.
- Gross calorific value is the total HV of the fuel, that is, the heat released from the combustion of unit fuel quantity.
- Net calorific value is the heat available from GCV, that is, GCV less the heat in the water vapor.
- Water vapor is formed from the fuel hydrogen and the evaporation of fuel moisture, and it is in the flue gas at a partial pressure of ~ 0.07 to 0.08 kg/cm^2 in a superheated condition. The vapor leaves the boiler in the superheated condition only but without transferring its latent heat. Thus, the heat in water vapor of the flue gas is not available for heating and NCV recognizes this aspect.

$$\text{NCV} = \text{GCV} - (m + 9\text{H}_2) \times \text{latent heat} \quad (3.1)$$

where latent heat is used variously from ~ 2.42 to 2.45 MJ/kg or 577 to 586 kcal/kg (1040 – 1055 Btu/lb).

- Gross calorific value is determined in the laboratory in a specified manner. A unit weight of pulverized coal is burnt in a water-submerged bomb calorimeter and the temperature rise of water is noted. The heat released or GCV is now known, as the water quantity is fixed. The NCV is deduced from GCV by applying the above-mentioned formula.
- For anthracite and bituminous coals, GCV can be calculated using *Dulong's formula* from the UA, which is accurate within 2–3% of the results of the bomb calorimeter. The HV of the coal is due to the presence of C, H, O, and S and also due to heats of dissociation and other phenomena, which cannot be captured correctly, leading to the inaccuracy of the result of the formula.

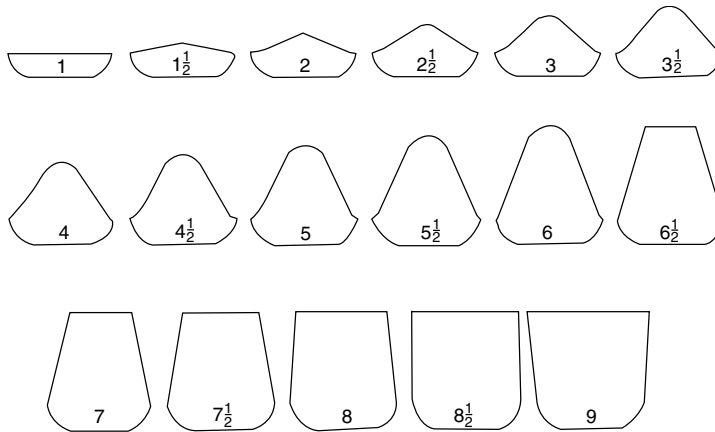
$$\begin{aligned} \text{GCV} &= 80.8\text{C} + 344.6(\text{H} - \text{O}/8) + 22.5\text{S in kcal/kg} \\ &= 145.44\text{C} + 620.28(\text{H} - \text{O}/8) + 40.5\text{S in Btu/lb} \end{aligned} \quad (3.2)$$

where H, O, and S are percentages in UA.

3.2.1.1.4 Grindability Index

Grindability index indicates the ease of grinding the coal, a property that is vital for milling. It is an index showing the relative hardness of that particular coal compared with the standard soft coal with an index of 100.

The principle is that the work done in pulverizing is proportional to the new surface generated. The *Hardgrove* machine, named after the inventor, is a miniature pulverizer in which the amount of grinding energy can be measured. The method involves grinding a sample of 50 g of air-dried and ~ 1.0 to 0.5 mm sieved test coal in the test mill for 60 revolutions and comparing the $75 \mu\text{m}$ fraction with the standard curves. The pulverizer base capacities are rated on the Hardgrove index (HGI) of 50 or 55.

**FIGURE 3.4**

Coke profiles from swelling test. (Adapted from Her Majesty's Stationery Office, U.K. With permission.)

3.2.1.1.5 Caking and Caking Coals

3.2.1.1.5.1 Caking Coals or Agglomerating Coals These coals, when heated, quickly become plastic, fuse together, form large masses of semicoke, and disrupt the combustion process on a bed. This property is of importance to grate firing and bubbling fluidized bed combustion (BFBC) and not for PF and circulating fluidized bed combustion (CFBC). Caking property is worsened with more fines in fuel.

Caking or agglomerating is determined by specified tests in which the coal is heated till the M and VM are driven off and checked to determine whether the sample fuses together or remains as a powder. Depending on the cross-sectional area of the coke button formed, its free swelling index between 1 and 9 is determined (Figure 3.4). *Free burning* coals are nonagglomerating and the opposite of caking coals.

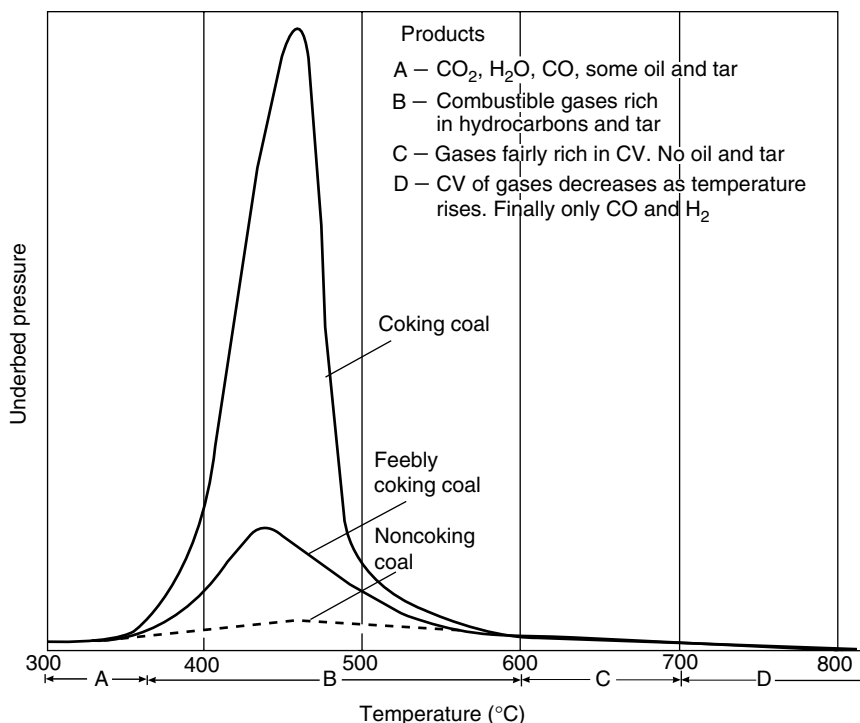
3.2.1.1.5.2 Coking Coals Coking coals make a good coke required for metallurgical purposes to produce high temperatures. When heated in coke ovens, out of contact with air, the coking coals lose their VM and form hard dense coke, consisting of FC and ash of the original coal. Good coking coals generally swell on heating, as reflected by the under-bed pressure in Figure 3.5. This figure also captures the three phases of combustion—drying, devolatilization, and combustion of FC (also see Section 2.6.1). Coals that cake on a fuel bed do not necessarily make good coking coals. Subbituminous coals, lignites, and anthracites are noncaking coals.

3.2.1.1.6 Ignition Temperature

Combustible matter is a substance that has affinity for oxygen. There is a minimum temperature for each fuel and its constituents to enable the combustion reaction to take place, which is called the *ignition temperature*. This is the temperature beyond which more heat is produced in the reaction than what is lost to the surroundings to enable self-sustenance of the combustion. The ignition temperatures of the gases are higher than FC and vary widely but they distill off the fuel at a much lower temperature. Hence, the ignition temperature of coal is considered the same as that of FC (Table 3.2).

3.2.1.1.7 Coals Worldwide

The production of bituminous and subbituminous coals constitutes the maximum. These coals are spread across the globe with the United States, Russia, China, and Europe as the

**FIGURE 3.5**

Behavior of coal on application of heat. (Adapted from Her Majesty's Stationery Office, U.K. With permission.)

TABLE 3.2

Approximate Ignition Temperatures for Various Combustibles

Combustible	Ignition Temperature ($^{\circ}\text{C}$)
Fixed carbon bit coal	408
Fixed carbon semibit coal	465
Fixed carbon anthracite	450–600
Sulfur	243
Kerosene	255–295
Gasolene	260–430
Acetylene (C_2H_2)	304–440
Ethylene (C_2H_4)	480–550
Ethane (C_2H_6)	470–575
Methane (CH_4)	630–750
Hydrogen (H_2)	575–590
Carbon monoxide (CO)	610–655

leading producers. India, Australia, South Africa, and Indonesia are the other producers. Good-quality coals are abundant in the United States and Europe. India, China, and South Africa produce subbituminous coals with high ash content and low CV.

A list of typical steam coals that are suitable for use in power generation is given in Table 3.3 for ready reference. Coals supplied to power stations and for export may be

TABLE 3.3

Typical As-Received Analysis of Coals from Various Countries

Country	Mine/Area	Ash (%)	M (%)	VM(%)	S (%)	GCV		
						MJ/kg	kcal/kg	Btu/lb
Austria	Grunbach	5–12	4–6	35		25.1	6000	10,790
Australia	Queensland	11.6	1.5	37		28.61	6840	12,300
	NSW West	14.6	2.6	30.0	0.7	27	6450	11,610
	NSW South	11	0.6	23.3	3.74	30.5	7290	13,115
Belgium	Low volatile coal	5–7	4–6	14–18		31.8	7550	13,675
	Dry steam coal	7–9	3–6	8–10		31.4	7505	13,500
Czech Republic	Pilsen	9–16	6–13	30–35		20.9–27.2	4995–6500	8,990–11,700
China	Sadovy	8–15	2–7	27–34		27.2–30.1	6500–7200	11,700–12,940
	Chihli Kaiping	13.3	0.6	26		31.1	7435	13,370
	Chihli Penchiu	11.2	0.7	234		31.4	7505	13,500
France	Loire	17–25	3–5.5	8–18		23–25.1	5500–6000	9,890–10,790
	Nord	5–7	2–4	19–21		29.3–32.2	7000–7700	12,600–13,850
	St. Etienne	12–17	4–5	20–30		26.4–28.1	6310–6715	11,350–12,080
Germany	Aachen (dry steam)	6	4	9–13		31.7	7575	13,630
	Aachen (medium volatile)	6	4	24–30		31.5	7530	13,545
	Bavaria	11	10	35–40		22.5	5380	9,675
	Ruhr	7–9	2–7	10–15		29.7–31.0	7100–7410	12,770–13,330
	Saar	3–7	3–5	38		29.3	7000	12,600
	Saxony	5–6	8	30–36		28.1	6715	12,080
India	Bengal slack	16.2	0.5	9.9		28.3	6760	12,170
	Raniganj	14–17	5–11	34–52		23.8–25.9	5690–4900	10,235–11,140
	Orissa	28–31	7–9	27–31	0.3–1	19.3–20.5	4610–4900	8,300–8,815
	Pench Valley	16–32	2–9	17–33	0.6–2.5	20.1–26	4800–6214	8,640–11,180
	Chanda	13–15	10–11	31–36	0.6–1.7	23–25.5	5500–6095	9,890–10,965
	Tandur	18–22	5–7	26–30	0.5–0.8	21.3–24.3	5090–5810	9,160–10,450
Indonesia	Palembang dust	6.6	10.0	28.4		26	6215	11,180
Italy		19	5	39		25.5	6095	10,965
Japan	Kyushu Furukawa	14.4	1.6	34.9		29.3	7000	12,600
Poland	Upper Silesia	4–9	3–7	30–35		28.5–29.7	6810–7100	12,255–12,770
	Katowic	6	4	31.6		31.4	7505	13,500
Russia	Kuznets	5–10	1–7	13–25		28.9–31.4	6910–7505	12,430–13,500
	Ural	21	7	25		33.3	7960	14,320
	Donnetz long flame	21.5	7	40	5.7	23.9	5710	10,280
South Africa	Natal	8.6	4.2	16.7	4.18			
	Transvaal	13.3	2.2	27	0.7	28.18	6735	12,120
Spain	Asturias	8–11	5	7–30		29.3–31.4	7000–7505	12,600–13,500
	Zaragoza	11.3	4–6	28.8		26	6215	11,180
Turkey	Isletme	12	7	30		23	5500	9,890
	Zonguldak	15.5	10	27		26	6215	11,180
United Kingdom	Cardiff	3–8	1.0–3.0	25.0–35.0		31.4–33.5	7505–8005	13,500–14,405
	Cumberland	5.5–8.0	2.5–3.5	30.0–36.0		31.0–31.8	7410–7600	13,330–13,680
	Derbyshire	2.0–7.0	4.5–12.0	31.0–39.0		27.2–31.4	6500–7505	11,700–13,500
	Durham	3.0–10.0	2.0–8.0	25.0–35.0		28.1–31.8	6715–7600	12,080–13,680
	Midlands	3.0–7.0	2.0–10.0	21.0–37.0		28.1–31.8	6715–7600	12,080–13,680
United States	Alabama	9.2	3.6	30.5		31.6	7550	13,590
	Maryland	6.0–9.0	1.5–2.5	20.0–40.0		31.8–33.1	7600–7910	13,680–14,230
	Pennsylvania	6.0–9.0	1.0–2.5	20.0–35.0		32.2–33.1	7695–7910	13,850–14,230
	SW Virginia	5.0–7.0	1.5–2.5	20.0–35.0		33.1–34.3	7910–8200	14,230–14,750

Note: Conversions from MJ/kg to kcal/kg and Btu/lb have been rounded to the nearest five.

at variance to the properties shown. They represent average properties as mined and received.

With the easing of trade norms, trading of coal has been on the rise. Traditionally, Australia, South Africa, and Indonesia have been among the leading exporters, and Japan, Europe, and South Korea have been among the leading importers. This circle of exporters and importers is enlarging.

3.2.1.2 Anthracites

Anthracites are the most ancient and fully formed coals, bordering on graphite on one end and bituminous coal on the other. They are dense, very hard, and brittle. They appear shiny black with no marks of layers. H_2 and inherent moisture vary from 2.8 to 3.9% and 1.5 to 3.0%, respectively.

Most anthracites and semi anthracites have a lower GCV than the highest grade of bituminous coals. With very low VM (2–14% on a daf basis), consisting mainly of methane, the anthracites are difficult to burn.

They need very high temperatures (up to 600°C) to ignite. Burning on spreader stokers (SSs) is not possible but it is possible on chain grate stokers in sandwich mode along with coal (for ignition). Burning in PF mode is now common. It requires more grinding (80–85% through 75 μm) and down-shot firing with W-shaped flames to give adequate time for the combustion of all the FC. Main uses of anthracites are in domestic heating, gas production, and power generation.

Meta anthracite, approaching graphite in structure and composition, burns with a short, smokeless blue flame. Being slow to ignite and difficult to burn, it has little commercial importance. Russia is a major producer of anthracite followed by China, North and South Korea, Western Europe, and the United States.

3.2.1.3 Lignites

The word *lignite* comes from the Latin word *lignum* meaning wood. They are younger coals formed from plants rich in resin and hence high in volatiles and moisture. Lignite is a solid fuel that is more mature than peat and still shows a definitely woody structure.

Freshly mined lignite is tough and requires hammer blows to break down. But on exposure to air for a couple of days, part of the moisture evaporates and the lignite blocks disintegrate on slight pressure. Although it appears to be dry, lignite can contain about 30% moisture. Lignites with high moisture of 50–65% are called brown coals in Europe.

Lignites are lighter and more bulky; that is, the bulk density is less. Upon storage they lose their HV as the volatiles tend to leave the fuel. They are more prone to spontaneous combustion due to high oxygen and volatiles. It is not desirable, therefore, to have large stock piles. The storage bunkers are also sized for shorter duration.

Lignites with ~35% moisture can be ground in pulverizers with high inlet air temperatures. But beater mills are required for brown coals, and gases from the boiler furnace are drawn for fuel drying. HGI has no relevance for brown coals. Lignites can be burnt on chain grates and SSs as well as in both BFBC and CFBC. High alkalies in ash tend to lower the ash fusion temperatures that can cause slagging and fouling. In BFBC, there are chances of in-bed tube fouling and corrosion.

In a way lignite is the opposite of coal in terms of combustion—daf coal has about 60% FC and 40% VM, which is reversed in daf lignite. Lignite therefore ignites at a lower temperature and burns faster. The high O_2 content of lignite reduces the need for

combustion air, but the high moisture in fuel increases the flue gas production. The furnace volume has to be larger and more secondary air (SA) and tertiary air (TA) need to be supplied to burn the large amounts of VM.

Lignite is next only to coal in terms of production and power generation. East Europe produces nearly half of the world's production, followed by Western Europe, Russia, Australia, Turkey, the United States, and India.

Lignite is widely spread across the globe. As the energy costs rise, the mining and burning of these inferior fuels become economically viable. The lignites vary a great deal in their composition and properties being younger coals. Figure 3.6 shows how the various lignites from different regions can be depicted as clusters with A, M, and CV considered. The higher the position of the mine in the graph, the younger the fuel, and more difficult it is to burn. The boilers and the handling equipment also become very large, and the initial investment in the power plant is higher. The running costs are usually lower due to the proximity of the power plant to the mine where the fuel is normally dug out of the open cast mines rather easily. Table 3.4 lists lignites worldwide for a quick reference.

3.2.1.4 Peat

Peat is the youngest of all the coals, still at an early stage of metamorphism of vegetable matter into coal. It is the product of partial decomposition, in the absence of air, of plant remains in marsh lands. Peat is a complex mixture of C, H, and O, which is low in S ($\sim 0.2\%$), N, and ash. Peat is yet to be fully exploited as a fuel in many countries where it is produced.

Peat is largely confined to higher latitudes of Northern countries such as the United States, Ireland, Russia, Sweden, and Finland. In the United States, it is the second most abundant fuel with extensive deposits after coal. Owing to low HV, peat cannot be transported over long distances economically. Russia, Finland, and Ireland have a number of peat-based power stations. In fact, in Sweden and Finland, peat and wood are the only indigenous fuels.

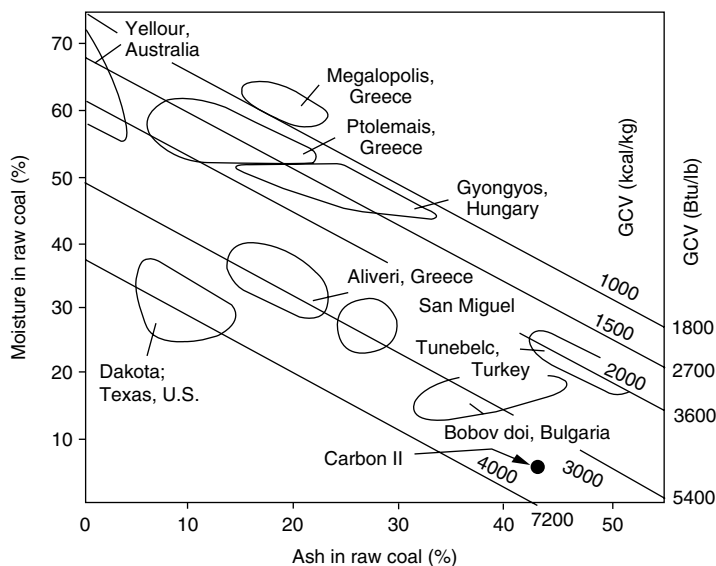


FIGURE 3.6

Typical lignites of the world. (From Babcock and Wilcox Company, U.S.A. With permission.)

TABLE 3.4

Typical As-Received Analysis of Lignites

Country	Mine	Proximate Analysis				GCV (kcal/kg)	Sulfur (%)	Hardgrove Index
		M (%)	A (%)	VM (%)	FC (%)			
Australia	Victoria	66.3	0.7	17.7	15.3	2055		
Canada	Saskatchewan	35.0	8.0	23.4	34.6	4050		
Germany	Frimmersdorf	60.7	2.6	20.0	16.7	2355		
	Saxony	53.1	3.5	25.3	18.1	2500		
	Bittefeld	50.0	6.5	57.0				
Greece	Aliveri	31.0	18.0	30.0	21.0	3130		
India	Neyveli	53.1	4.5	24.2	18.2	2785		
	Surat	24.0	17.0	39.0	30.0	4200		
	Bikaner	51.0	7.3	24.3	17.4	2700	0.8	84.0
	Kutch	34.4	7.2	32.8	25.6	4090	1.77	102.0
Russia-Ural	Bogoslovsk	30.0	14.0	22.3	29.7	3385	0.5	
Russia-Far east	Kirdinsky	33.0	12.7	22.3	32.0	3478	0.3	
Spain		47.7	18.8	17.7	15.8	1700		
Ukraine	Aleksandrisk	55.0	10.8	19.5	14.7	2308	3.6	
United States	North Dakota	34.8	6.2	28.2	30.8	4005		
	Texas	33.7	7.3	29.3	29.7	4080		

TABLE 3.5

Typical Properties of Peat

Type of Peat	Moisture (%)	Density (kg/m ³)	GCV (kcal/kg)
Air dried	25–50	240–400	2200–3900
Mulled	50–55		2050–2950
Briquette	10–12	480–960	4450

TABLE 3.6

Typical Proximate Analysis on Dry Basis

Constituent	Percentage
H ₂ O	—
Ash	2–10
Volatile Matter	55–70
Fixed Carbon	30–40

TABLE 3.7

Typical Ultimate Analysis on daf Basis

Element	Percentage
C	53.0–63.0
H ₂	5.5–7.0
O ₂	30.0–40.0
S	0.3–0.5
N ₂	1.2–1.5

Very high moisture levels are associated with peat. Undrained bog peat can have 80–95% moisture that reduces to ~70 to 90% on draining and 35–55% on air drying. As fired, moisture must be <50% for a stable firing. The properties of peat vary considerably. A typical range of properties and analyses appears in Tables 3.5 through 3.7.

3.2.2 Waste Fuels

3.2.2.1 Coke Breeze

Coke is devolatilized coking coal produced by heating coal in the absence of air in coke ovens. The VM and the moisture are driven out, leaving behind the FC, ash, and sulfur to

TABLE 3.8
Coke from High- and Low-Temperature Carbonizations

	High-Temperature Carbonization By-Product Oven	Low-Temperature Carbonization
Temperature range (°C)	900–1100	500–700
Type of coke	Hard	Not so hard
Coke yield/100 kg coal (kg)	65–75	75–80
Volatiles in coke (%)	1–3	5–15
Gas/ton of coke (m ³)	280–370	110–250
Light oil and tar/ton of coke (L)	40–65	70–190
Ammonium sulfate/ ton of coke (kg)	11–12	5–7
GCV (kcal/m ³)	4700–5300	6000–9800

TABLE 3.9
Typical Proximate and Ultimate
Analyses of Coke Breeze

	Typical
M%	7.3
Ash%	11.0
VM%	2.3
FC%	79.4
	100.0
GCV (kcal/kg)	6480
H ₂ %	0.3
C%	80.0
S	0.6
N ₂ + O ₂ %	0.8
M%	7.3
Ash%	11.0

form a hard substance called coke. The process of decomposing coal into the gaseous and solid fractions is known as destructive distillation or carbonization. Only some coals with certain resinous substances can become plastic and fuse together to form coke. Depending on the coal properties, pressure and temperature employed, and the type of coke oven, the quality of coke varies.

High-temperature distillation is carried out between 900 and 1100°C in by-product ovens, whereas low-temperature carbonization is carried out between 500 and 700°C. At higher temperatures there is a greater evolution of gases, producing metallurgical and gas-making coke. Owing to the high FC, the coke produces a smokeless high-temperature burning, which is required in mostly blast furnaces and, to a much smaller extent, in pig iron cupolas. Low-temperature carbonization yields coke more suitable for domestic use whose production and consumption have declined over years.

About 5% of coke is undersized at <16 mm, which is unsuitable for metallurgical industry and is used mainly for steam generation. Coke breeze is very abrasive, as it contains higher ash than the rest of the coke. Since it has practically no VM, the ignition requires a high temperature.

Coke breeze is best fired in chain-grate stokers along with high-volatile coal in a sandwich manner. Erosion of firing equipment is also limited, as there are less moving parts. Erosion of pressure parts (PPs) is also considerably less, as there is no fuel in suspension. (Tables 3.8 and 3.9).

3.2.2.2 Petroleum Cokes (Petcoke)

During petroleum cracking, the heavy residuals are processed further in a number of ways to produce lighter distillates, which leaves behind heavy residues such as delayed coke, fluid coke, and petroleum pitch, depending on the process adopted. These residues vary considerably.

- Delayed coking is the most widely adopted process, and the majority of the petroleum coke produced is delayed coke. It is called *shot coke* or *sponge coke* because of its appearance. Delayed coke appears like run-of-the mine coal but dull black.

TABLE 3.10

Ultimate Analysis of Delayed and Fluid Cokes

	Delayed Coke	Fluid Coke
M (%)	3–12	
Ash (%)	0.2–3.0	0.2–0.5
VM (%)	8–20	3.0–6.5
FC (%)	71–92	90–95
S (%)	2.9–9.8	4.0–7.5
GCV (kcal/kg)	7800–8700	7800–8100

- Fluid coke is developed using FBC processes and resembles black sand. It consists of small hard spherical particles 200 μm in diameter with very low VM (Table 3.10).

Petcoke has the following properties:

- High CV of 7800–8700 kcal/kg
- Low ash (<1%)
- High sulfur content of 2.9–9.8%
- Low VM
- High FC

Petcoke, despite its good CV, is difficult to ignite and burn due to very low VM and very high FC. Unburnt losses are quite high. Combustion-wise it is similar to high-FC, low-VM fuels, such as anthracite, but for its very high sulfur content. All the impurities of the original crude oil are concentrated in the petcoke as evidenced by very high sulfur and heavy metals in ash, such as vanadium and nickel. SO_2 in excess of 13,000 mg/N m^3 would result in flue gases when petcoke is burnt. Circulating fluidized bed combustion is best suited for burning this difficult fuel, as the desulfurization is easily performed, and recirculation of ash and fuel several times in a furnace ensures a high carbon burnup of >98%. The consumption of limestone for desulfurization, however, is very high, often as much as the fuel consumption.

Petcoke firing is finding a lot of resistance in many advanced countries and pollution norms are rather stringent. This is due to the high level of sulfur in the fuel, which contaminates the ground on which it is stored.

3.2.2.3 Bagasse

Bagasse is the waste product left after crushing of cane and extraction of juice in cane sugar mills. It is a seasonal product, as the crushing campaign lasts from 6 to 10 months in a year; the plant is longer near the equator and gets progressively shorter away from it. Cane is a tropical crop that extends across the globe. Bagasse forms 24–30% of the cane weight. Bagasse burning has been an integral part of the sugar cycle from the beginning. Steam and power requirements of these far-flung rural factories have been adequately met with bagasse-based cogeneration and off-season purchase of grid power. Traditionally the bagasse burning has been carried on inefficiently in sugar mills as there was always excess bagasse left with no great market value, and it is too bulky to transport or store. Burning was a way of disposal of this bulk. In the last couple of decades, there has been a sea change in this scenario with the enhanced possibilities of production of paper, certain value-added chemicals, and cogenerated power. Encouragement of its use for distributed power and

green power even in small quantities has helped in adopting cogeneration in sugar factories in a big way. Bagasse has now attained its rightful place as a good, consistent, and bulk waste fuel in tropical countries that provides good market value. Bagasse burning is also environmentally friendly as combustion temperature is low due to the quenching effect of the fuel moisture and no fuel sulfur to pollute with sulfurous gases. It is now burnt efficiently in vastly improved boilers at increasingly higher pressures and temperatures at low NO_x and SO_x .

- It is a cellulosic and fibrous fuel with a PA of 45–52% M and 1–2% ash, having remarkably consistent properties across the continents varying by only $\pm 2\%$.
- On a daf basis the VM is as high as 85–87%, which makes it highly inflammable on drying and vigorously burning. For the same reasons, the storage of bagasse in summers is fraught with twin problems of degradation of fuel due to loss of VM and fear of spontaneous combustion due to high oxygen. High VM makes burning of bagasse very easy and efficient in boilers.
- With small and uniform fibers, bagasse is easy to transport, distribute, spread, and burn, once its extremely low bulk density and fluffiness causing flow interruptions are properly understood and factored in.
- It is slightly soft and reasonably compressible, which makes it possible to bale and store or transport over some distance.
- With very little and low-density friable ash, there are practically no great problems of slagging and fouling in modern boilers having minimal refractory provided there is adequate furnace volume. In the brick set boilers with small furnaces this used to be a major problem with recurring clinker formation, as traces of sugar residue with low melting temperature would bond with refractory.
- Moisture is the most important aspect of bagasse, and it varies from mill to mill depending on the age, number of mills in tandem, milling process, and so on. Lower moisture improves fuel handling and combustion. Forty-five percent is more or less the optimum moisture that can be attained on a consistent basis with good, well-maintained milling tandem, and it rarely exceeds 52% even with the old mills. Efforts to reduce the fuel moisture to derive great benefits in fuel efficiency and reduced boiler and auxiliary sizes by heating with the outgoing boiler flue gases in bagasse driers have not been successful.
- Ash percentage is small and erosion can be kept under check by proper gas velocities. Use of mechanical harvesters brings a lot of unwanted mud with cane, making it abrasive due to extraneous silica. The inherent ash is light and fluffy.
- Bagasse-based cogeneration is gaining increasing popularity, and when connected to grid, it may be required to generate power even in off-season. The boilers will have to be multifuel to deal with this situation, usually using oil or coal as the auxiliary fuel.
- The ash-fusion temperature of bagasse ash is quite low. In multifuel firing, ashes from both fuels have a tendency to chemically interact to form a eutectic compound whose fusion temperature is lower than that of both the ashes. This leads to the problems of slagging and fouling that are not present when either fuel is fired alone. Slightly larger sizing of furnace volume and wider superheater (SH) tube spacing can eliminate the fouling problem. Analyses and properties of bagasse are given in Tables 3.11 and 3.12.

TABLE 3.11

Proximate and Ultimate Analyses of Bagasse on As-Received and daf Bases

	Range	daf Basis
A (%)	1.0–2.0	—
M (%)	45–50	—
VM (%)	42–44	85–87
FC (%)	5–6	11–12
GCV (kcal/kg)	2200–2300	4600
NCV (kcal/kg)	1750–1850	4250

TABLE 3.12

Properties of Bagasse

	daf (%)
C	47.0
H ₂	6.5
O ₂	44.0
N ₂	2.5
S	Traces

3.2.2.4 Rice Husk

Rice husk is the protective cover on the rice seed, which is removed and rejected in the dehulling/dehusking operation of rice milling. Large amounts of rice husk are generated in the rice mills during the harvesting season. Husk forms between 20 and 25% of weight of dried rice.

- Rice husk is very uniform in size usually <3 mm, requiring no particular fuel preparation.
- Together with its CV of ~3500 kcal/kg, rice husk is an attractive fuel except for its seasonality.
- It requires a lot of space for storage. It is normal, therefore, to adopt multifuel firing to take care of off-season. Captive power plants of 5–20 MW, attached to the rice mills, have been erected in a number of locations instead of transporting husk over longer distances.
- Rice husk has ~15 to 20% ash and is highly abrasive, as the ash contains silica to the extent of 90%.
- It is very dry, containing only ~7 to 9% moisture and not compressible for baling purposes.
- On a daf basis it has ~20% FC and 80% VM, requiring a normal furnace volume and adequate SA. Husk demands a high ignition temperature and adequate time for combustion either on grate or on bed. VM leaves the fuel at ~500°C.

Stoker firing is a good and simple firing system for rice husk. Its low fan power, simple operation, and seamless 1:4 turndown make it ideally suited for husk.

Bubbling fluidized bed combustion is also an alternative, as husk has a good 15–20% ash to create its bed material and is sufficiently heavy to stay in the bed, unlike a light material such as bagasse. The higher fan power is offset by better combustion efficiency of 2–4%. Both designs have to contend with abrasion issues. From an erosion standpoint, overbed BFBC appears better than underbed.

Silica in ash is mostly in crystalline form. Only ~20% is in the amorphous form, and recovering silica in amorphous form has several high-end uses, which can be achieved only on controlled combustion of rice husk, limiting the firing temperatures to ~860°C. For this reason, the husk is pulverized in special mills and burnt in suspension to obtain ash with the desired properties. Analyses and properties of rice husk are given in Tables 3.13 and 3.14.

TABLE 3.13

Proximate and Ultimate Analyses of Rice Husk

	PA			
	Air-Dried Range	daf		daf UA Range
Ash (%)	15.0–18.0	—	C	45.0–55.0
M (%)	5.0–10.0	—	H ₂	5.5–6.5
VM (%)	65.0–70.0	80.0	N ₂	<1.5
FC (%)	12.0–15.0	20.0	S	Traces
GCV (kcal/kg)	3300–3600	4800–5000	O ₂	40.0–45.0
GCV (Btu/lb)	5940–6480	8640–9000		

TABLE 3.14

Properties of Rice Husk and Ash

Husk bulk density (kg/m ³)	100–300
Husk particle density (kg/m ³)	600–600
Bulk density (kg/m ³)	1250–1500
Particle density (kg/m ³)	2300–2800
Ash softening temperature (°C)	>1400
Ash fusion temperature (°C)	>1600
Theoretical air (kg/kg or lb/lb)	2.85
Theoretical CO ₂ (%)	20.6
H ₂ O in flue gas (kg/kg or lb/lb)	0.77
H ₂ in fuel (%)	3.0
Bulk density with 48% M in stacked condition (kg/m ³ and lb/ft ³)	200.0 and 12.5
Loose condition (kg/m ³ and lb/ft ³)	120.0 and 7.5
Angle or repose degrees	45–50 variables

3.2.2.5 Wood

Wood is a complex vegetable tissue composed mainly of carbohydrates, and in common with all types of vegetation, it has a relatively low HV in comparison with coal and oil. HV of different woods should have been nearly the same, but for the presence of varying amounts of resins, gums, and other substances, which creates a wide variation. For the same reason, any formula similar to Dulong for estimation of GCV does not work with wood.

Wood was the prime fuel till the early nineteenth century when coal and, later on, oil started displacing it. In the meanwhile the energy need and production has gone up dramatically. Progressive reduction of forests; better uses for wood, namely, furniture, paper, rayon, and so on; and enormous demand for energy that could be satisfied only by fossil fuels have combined to make wood and its products waste fuels today. In fact, wood-based steam generation is confined to Scandinavia, Canada, the United States, and certain South American countries, where forests are still abundant.

Hard and soft woods are the two broad categories, not based on any hardness measurement, but based on botanical terminology. Hard woods belong to trees with broad leaves and soft woods to trees with scale or needle-like leaves.

TABLE 3.15Ultimate Analysis of Wood
on daf Basis

	Range
C (%)	48.0–59.0
H ₂ (%)	5.8–7.2
O ₂ (%)	32.0–45.0
N ₂ (%)	Traces
S (%)	—
Ash (%)	0.15–2.20
GCV (kcal/kg)	4500–6300

TABLE 3.16

Properties of Wood on daf Basis

VM (%)	80–85
H ₂ (%)	5.9–6.0
Theoretical air (kg/1,000 kcal) ^a	1.235
Theoretical air (lb/10,000 Btu)	6.85
Theoretical CO ₂ (%)	20.25
GCV (daf) (kcal/kg)	4830
GCV (daf) (Btu/lb)	8700

Note: Resinous woods have slightly high CV.^a GCV on daf basis.

In lumber manufacture, nearly 50% of the wood is turned into waste, with about

- 20% in the form of slabs
- 10% as bark
- 20% as sawdust and shavings

Range of analysis of dry wood is given in Tables 3.15 and 3.16, covering both hard and soft woods.

- Moisture content of freshly cut wood varies from 30 to 50%, which reduces to 18–25% after a year of drying. There is a loss of fuel value in the meantime.
- Woods with <50% moisture burn well. Owing to rain, snow, or transportation by water, moisture content can go to as high as 70%. At more than ~65% moisture, the combustion is not self-sustaining, as the heat produced is not sufficient to dry the moisture. Support fuel such as oil is then needed.
- Ash in wood is less at <2.5%.
- There is practically no nitrogen or sulfur, eliminating the fear of fuel NO_x formation and corrosion.
- The moisture content depends on the type, handling, storage, and age of wood. Generally, wood logs can be taken as containing ~40% moisture, sawdust, and chips 15–25%, and wood refuse from seasoned wood 15% moisture.
- The low HV and large bulk make it uneconomical to transport wood or wood waste over long distances, for example, more than 100 km.

Use of wood for steam generation is in the following three areas:

1. Wood producers, namely, saw mills using sawdust, shavings, bark, and other wood wastes
2. Wood users using wood chips
3. Paper mills using waste wet bark produced in the mill

3.2.2.6 Agrofuels

Agrofuels, or biofuels, or vegetable fuels, as they are variously called, are essentially wastes generated by various crops. Fuels such as wood and bagasse are also agrofuels, but because of their relatively large availability, they have been used as regular fuels for a long time and generation of steam and power for a few decades now.

The distinction between agro/biofuels and biomass has to be clearly understood. Agrofuels form only a part of biomass, which is a comprehensive term embracing all organic matter formed, directly or indirectly, by virtue of photosynthesis. Besides agrofuels like crop, forest, agro-industrial residues and purpose-grown trees, biomass includes aquatic plants and even animal wastes.

3.2.2.6.1 Nature of Agrofuels

With increasing energy costs and growing concern toward the environment, there is a heightened interest in harnessing the various agrofuels, although the steam and power they generate on a stand-alone basis is rather modest as of now. The main drawback of agrofuels is their limited and seasonal availability coupled with limited transportability due to their bulky nature. However, with low or no S and very low N_2 , biofuels are ecologically friendly. The disadvantage turns to favor, as small power plants can be put up, distributed over a wide area and close to small communities provided they are built with fuel flexibility. If based entirely on agrofuels, the benefit of carbon credits also accrue.

Policy changes and financial incentives are being extended in many countries to make biofuel firing more acceptable and attractive. Agrowastes by their nature are

1. Bewildering in variety.
2. *Variable in composition.* The variation in properties is large from season to season, place to place, and lot to lot.
3. *Seasonal.* The campaigns for harvesting the crops last from a few weeks to a few months.
4. *Limited.* The quantities generated/harvested/collected are limited. Carting over longer distances is not economical.
5. *Bulky and often fluffy.* This makes long distance transport undesirable and in-plant movement and storage expensive.
6. *Fast degrading.* Being cellulosic in nature, they cannot be stored for long periods.
7. In need of support from a prime fuel to cover seasonality or shortfall in supplies. Alternatively the boilers are equipped to fire multiple agrofuels so that one or the other fuel can be burnt in each season.

Power plants of only 5–30 MW are popular from the view of fuel collection. Often fuels are cofired in limited quantities in large boilers.

3.2.2.6.2 Agrofuel Combustion

A look at the Seyler's chart in Chapter 2 is necessary to gain a better understanding of combustion properties of agrofuels. General properties of agrofuels can be summarized and tabulated as shown in Table 3.17.

It is important to remember that no agrofuel can have, on a daf basis, a GCV $<13,500$ kcal/kg (7,500 Btu/lb) or air requirement <1.21 kg/1,000 kcal (6.8 lb/10,000 Btu) of GCV, which is the minimum for cellulose ($C_6H_{10}O_5$).

Agrofuels are very friendly both from the ease of burning and from environmental compliance views. Stokers are the most appropriate firing equipment. Bubbling beds are also suitable. Since the bulk density is very low, many fuels are not suitable for BFBC as they cannot stay on bed and are carried away. Also, when the ash in fuels is very low, typically $<10\%$,

TABLE 3.17

General Range of Properties of Agrofuels

Parameter	Range	Remarks
VM (daf) (%)	72.0–90.0	
H ₂ (daf) (%)	5.6–5.8	
M (%)	~10.0	
Theoretical CO ₂ (%)	20.2–20.75	
<i>f</i> -factor	1.015–1.005	For CO ₂ calculation
GCV (daf) (kcal/kg)	4500–5500	4000 ± 300 as received
GCV (daf) (Btu/lb)	8000–10000	7200 ± 550 as received
Theoretical air (kg/kcal)	1.22/1000	Actual GCV
Theoretical air (lb/Btu)	6.85/10000	

bed ash replenishment can add to the cost of operations. But for fuels such as rice husk having a good percentage of ash, BFBC makes a good choice as the combustion efficiencies are higher and the boilers more compact if the tube erosion issues can be contained. Readers can refer to Chapter 11 on stoker firing for more details.

- With VM of 70–90% on a daf basis, agrofuels are efficient for both ignition and combustion.
- Negligible amounts of ash in fuel help in speeding up the burning of FC, thus enabling fast and easy burning of fuels with low unburnt loss.
- The ash-handling plant is smaller in size due to less ash produced, but has to be suitable to account for its low density.
- The fuel sizing can be a problem in fuels that are stringy.
- Biofuels are very light and often fluffy. This makes the fuel handling equipment larger.
- These fuels are rich in oxygen. This reduces the air requirement for combustion. Typical air requirement for coals and biofuels is given in the following table. On an average 8–10% less air is required.

Coal	1.31–1.36 kg/1,000 kcal	7.3–7.6 lb/10,000 Btu
Biofuel	1.22–1.24 kg/1,000 kcal	6.8–6.9 lb/10,000 Btu

- Flue gas generation is also lower except when there is high moisture in fuel, like in bagasse.
- In the furnace, as there is more combustion in suspension due to high VM, more SA needs to be supplied than for conventional fuels. Typically SA is ~30% in stoker firing as against 20% for coal.
- An additional (third) row of air nozzles is needed to provide an air curtain in the upper furnace to prevent carry-over of fuel, besides providing air for combustion of volatiles. The carry-over tendency is due to the lower bulk and particle densities and also due to the fines generated in sizing or dehulling operation.
- The furnace exit gas temperature (FEGT) tends to be higher with biofuels than with coal, when both are burning on grates. This is because of greater heat release by VM and at higher levels in furnace compared with coal, which releases more heat close to the grate in burning the higher FC.

Of course, with bagasse the FEGT has to be lower as the gas is cooled by the high amount of moisture in fuel.

Table 3.18 provides combustion data for some minor biofuels. Calorific value is rounded to the nearest five.

3.2.2.6.3 Ash of Agrofuels

The main problem with the combustion of biofuels is the ash composition, which is highly variable among fuels as can be seen from Table 3.19. Although the ash in fuel is less,

TABLE 3.18

Combustion Properties of Minor Agrofuels

Fuel	GCV (Btu/lb)	NCV (Btu/lb)	GCV (kcal/kg)	NCV (kcal/kg)	H ₂ O (%)	Ash (%)	Theoretical Air (kg/kg or lb/lb)	Theoretical CO ₂ by Volume (%)
Coconut shells	7600	7020	4220	3900	10.0	5.0	5.2	20.4
Coffee husks	6700	6110	3720	3395	12.0	3.0	5.0	20.5
Cotton seed husks	7300	6700	4055	3720	11.0	3.0	5.0	20.5
Cotton pods	6500	5950	3610	3305	12.0	7.0	4.45	20.5
Palm nut shells	7500	6910	3720	3840	10.0	3.0	5.15	20.5
Peanut shells	7800	7200	4335	4000	10.0	2.0	5.35	20.4

TABLE 3.19

Properties of Typical Select Agrofuels and Their Ash

	Corn Stems	Corn Cobs	Corn Grain	Straw	Straw Pellets	Rice Husk	Wood Chips	Bark
Dimensions	10 × 100	30 × 50	1–8	0.2–2.5	13 × 25	0.1–2.5	3 × 12	8 × 20
Particle density (kg/m ³)	360.00	385.00	420.00	650.00	1400.00	740.00	920.00	880.00
Bulk density (kg/m ³)	158.00	174.00	235.00	100.00	790.00	120.00	590.00	430.00
M (%)	9.20	8.00	11.90	8.50	8.50	4.10	41.50	58.00
<i>Proximate analysis: as-received</i>								
NCV (MJ/kg)	15.80	16.30	15.20	16.6	16.50	12.90	9.55	6.52
Ash content (%)	2.60	2.40	1.88	6.00	6.10	22.70	0.75	1.81
VM (%)	67.30	69.10	75.00	61.60	61.40	59.70	47.94	31.79
FC (%)	20.90	20.50	11.20	24.20	24.00	13.50	9.82	8.45
<i>Ultimate analysis: (%) dry basis (wt)</i>								
C	42.16	45.57	43.72	41.61		37.81	47.62	48.30
H ₂	6.28	5.93	7.18	6.70		4.68	6.11	6.34
O ₂	45.70	45.89	45.73	44.40		33.52	44.34	39.76
N ₂	0.71	0.74	1.24	0.66		0.28	0.65	1.29
S	0.01	0.02	0.01	0.01		0.03	0.00	0.00
<i>Ash composition (wt %)</i>								
SiO ₂		32.74	43.00	59.52		97.62	6.45	5.88
Al ₂ O ₃		5.05	8.40	2.18		0.01	0.66	0.20
TiO ₂		0.02	0.40	0.02		0.01	0.02	0.02
Fe ₂ O ₃		0.70	5.05	8.76		0.19	2.05	0.33
CaO		2.63	5.10	6.52		0.01	73.05	80.72
MgO		6.83	8.10	2.26		0.59	0.54	0.23
K ₂ O		29.24	15.30	13.16		0.87	4.50	2.57
Na ₂ O		1.38	0.90	1.60		0.11	0.17	0.10
P ₂ O ₅		4.68	13.00	5.07		0.44	1.90	1.30
SO ₃		0.12	0.10	0.36		0.25	1.93	0.95

there is a preponderance of alkali salts, which is problematic. Na and K from the soil nutrients find their way into the ash and they increase progressively as the fertilizer usage increases. These salts are low melting and highly scale forming on superheater (SH) tubes. The ash deformation temperatures are very low, causing serious problems of slagging and fouling. Not all the agrofuels have high alkalinity in ash, as for example, bagasse, rice husk, wood chips, bark, and so on. When high alkalinity is present in ash, the remedy lies in

- Lowering the FEGT below $\sim 800^{\circ}\text{C}$ (1560°F)
- Restricting the final SH temperature
- Minimizing the refractory in the furnace
- Adopting fully water-cooled walls in furnaces
- Increasing the residence times and lowering the volumetric heat release rates
- Preventing carry-over of ash and fuel from furnace by air curtain
- Provisioning generous and judicious soot blower (SB)

such that the gases are cool enough to prevent ash melting and attaching to tubes. Even then an uninterrupted operation of the boiler may not be assured. Density of fuel ash is very low and the tendency to break down into very fine powder is very high, making dust collection rather difficult.

3.3 Liquid Fuels

Crude petroleum and its liquid residues left over in the process of distillation or cracking are the fuel oils used for steam generation. Crude petroleum is burnt for steam generation only infrequently, as the lighter fractions depress the flash point and present a fire hazard. Once the lighter fractions are removed, the oil becomes safe for handling and combustion. The petroleum-based liquid fuels are fuel oils, diesel oils, gas oils, kerosene, and gasoline or petrol.

With the increasing popularity of CCs, fuel oil-based power generation has gone out of fashion based on efficiency and few large oil-based utility boilers have been built except in refineries for consuming the heavy bottoms.

3.3.1 Fuel Oils

This term covers a wide range of oils starting from crude to the lightest products. These are now standardized into six ranges as shown in Tables 3.20 and 3.21.

3.3.1.1 Fuel Oil Properties

1. *Specific gravity* is the ratio between the weights of oil and water at 15°C for the same volume. Usually it is expressed as specific gravity $15/15^{\circ}\text{C}$. API scale is more popular with oil industry and the relationship is as follows:

$$\text{Specific gravity } 15/15^{\circ}\text{C} = \frac{141.5}{131.5 + ^{\circ}\text{API}} \quad (3.3)$$

TABLE 3.20

ASTM Chart of Fuel Oil Properties

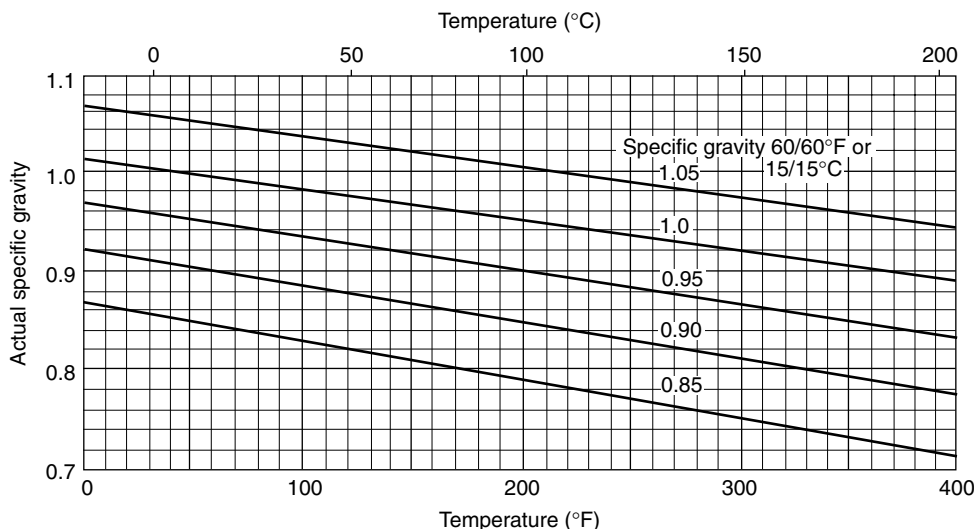
Grade of Fuel	No. 1	No. 2	No. 4	No. 5 Light	No. 5 Heavy	No. 6
Popular designation	Light	Medium				Heavy Bunker C
Usage	Domestic	Domestic				Industry
Flash point (min) °C	38	38	55	55	55	65
Pour point (max) °C	0	−7	−7	—	—	—
Water and sediment volume (%)	Trace	<0.1	<0.5	<1.0	<1.0	<2.0
C residue on 10% bottoms (%)	<0.15	<0.35	—	—	—	—
Ash (%) by wt (max)	—	—	0.1	0.1	0.1	—
Distillation temperatures		282–338	—	—	—	—
10% point C	<215					
90% point C	<288					
Viscosity range						
SSU at 38°C	—	—	45–125	150–300	350–750	900–9000
Seconds Saybolt					23–40	45–300
Furol at 50°C						
API gravity (min)	35	30	—	—	—	—
Sulfur (max) % 0.5	0.5	0.7	No limit	No limit	No limit	No limit

Note: Although the specific gravities of Grades 1 and 2 are specified, for Grades 4–6 they are not specified as they vary with the source of crude and extent of cracking and distillation.

TABLE 3.21

Analyses of Fuel Oils

	No. 1	No. 2	No. 4	No. 5	No. 6
<i>Ultimate analysis</i>					
(wt%)					
S	0.01–0.5	0.05–1	0.2–2	0.5–3	0.7–3.5
H ₂	13.3–14.1	11.8–13.9	10.6–13	10.5–12	9.5–12
C	85.9–6.7	86.1–88.2	86.5–89.2	86.5–89.2	86.5–90.2
N ₂	0–0.1	0–0.10	—	—	—
O ₂	—	—	—	—	—
Ash	—	—	0–0.1	0–0.1	0.01–0.5
<i>Other properties</i>					
API gravity	40–44	28–40	15–30	14–22	7–22
Pour point (°C)	−18 to −45	−18 to −40	−23 to +10	−23 to +27	−9 to +30
<i>Calorific value</i>					
GCV (kcal/kg)	10,930–11,030	10,650–10,970	10,155–10,777	10,555–10,565	9,670–10,550

**FIGURE 3.7**

Variation of specific gravity of fuel oils with temperature.

- a. Specific gravity of 1 corresponds to 10°API. Variation of specific gravity with temperature is illustrated in Figure 3.7.
 - b. The higher the °API, the lower the density and lighter the oil.
 - c. Specific gravity has no technical significance except for conversion of weights to volumes. But this is important as the fuel oils are purchased by volume as barrels, gallons, or cubic meters.
 - d. Specific gravity determination is easy and instantaneous, as it involves merely dipping a hydrometer in the sample and reading the scale.
2. *Calorific value* can be expressed in megajoules per kilogram or kilocalories per kilogram and megajoules per cubic meter or kilocalories per cubic meter. The former is inversely proportional to the specific gravity, as the lighter oils contain more H. Gross calorific value varies from ~10,200 to 10,800 kcal/kg. GCV measurement is done by bomb calorimeter. There are also following approximate relationships:

For uncracked distillate or residue $GCV = 9810 + (38 \times \text{API gravity})$ kcal/kg

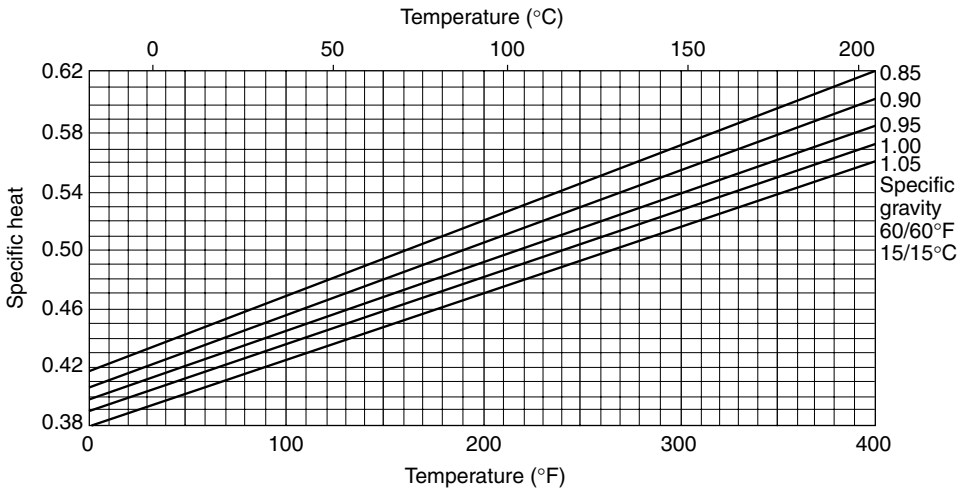
For cracked distillate $GCV = 9878 + (30 \times \text{API gravity})$

3. *Viscosity* is a measure of resistance of fluids to flow due to the internal friction. In liquids this friction is due to the cohesion of molecules. As the cohesion decreases with increasing temperature, viscosity also decreases.

In the *Saybolt Seconds Universal (SSU)* test, viscosity is expressed as the time taken in seconds for the oil at a particular temperature to flow out of a 60 cm³ cup through a specified orifice. It is commonly measured at 100, 150, and 210°F (37.8, 65.6, and 98.9°C, respectively). For more viscous oils, *Saybolt Furol* viscosity is used in which the orifice is a little larger and the readings are roughly one-tenth of universal.

Redwood seconds 1 and 2 (SR1 and SR2) are similar measurements in British practice.

Specific viscosity is a comparison of times taken by the oil and water at 20°C to flow out of a 200 cm³ vessel and is expressed in degrees *Engler*. This is also a popular measurement in Europe.

**FIGURE 3.8**

Variation of specific heat of fuel oils with temperature.

However, none of the above-mentioned forms is a direct measurement of the true viscosity. *Centipoise* ($\text{N s}/1000 \text{ m}^2$) and *centistokes* ($\text{m}^2/10^6 \text{ s}^2$) are the common measures of dynamic (or absolute) and kinematic viscosities.

Dynamic viscosity is the force that exists when a unit area of fluid is moving at unit velocity relative to that of a similar area, unit distance from and parallel to it. The dynamic viscosity of a fluid is the ratio of shearing stress to the rate of deformation. *Kinematic viscosity* is the dynamic viscosity divided by the density. Water at 20°C has dynamic and kinematic viscosities of 1 cP and 1 cSt.

$$\begin{aligned} \text{Stokes} &= 0.00226 \text{ SSU} - 1.95 / \text{SSU} \quad \text{for } 32 < \text{SSU} < 100 \\ &= 0.00220 \text{ SSU} - 1.35 / \text{SSU} \quad \text{for } \text{SSU} > 100 \end{aligned} \quad (3.4)$$

Figure 3.8 shows the variation of specific heat of various liquid fuels with temperature, whereas Figure 3.9 shows the manner in which the viscosity varies with temperature. Equivalent viscosities are also given in Figure 3.9 for a ready reference. A similar figure appears in Chapter 10 (Figure 10.9) dealing with burner firing. There the figure contains parameters relevant to combustion.

4. *Flash point* is the lowest temperature at which sufficient vapor is produced to form an inflammable mixture with air under specified test conditions. Flash point is controlled solely for storage and gives no indication of burning properties of oil.
5. *Pour point* is the temperature at which oil starts to flow under test conditions, although it does not necessarily indicate the temperature at which oil stops flowing. Oils are not allowed to cool below this temperature in tanks from where the supplies are drawn; and in fact, oil should be stored at $\sim 3^\circ\text{C}$ higher than the pour point.
6. *Carbon residue* is the amount of carbon left behind after volatilizing the oil under specified conditions. It is the residue left after a fuel is heated out of contact with air. It is a measure of coke-forming tendencies of diesel oils. It has no significance with other fuel oils. *Conradson* and *Ramsbottom* are the two methods employed.

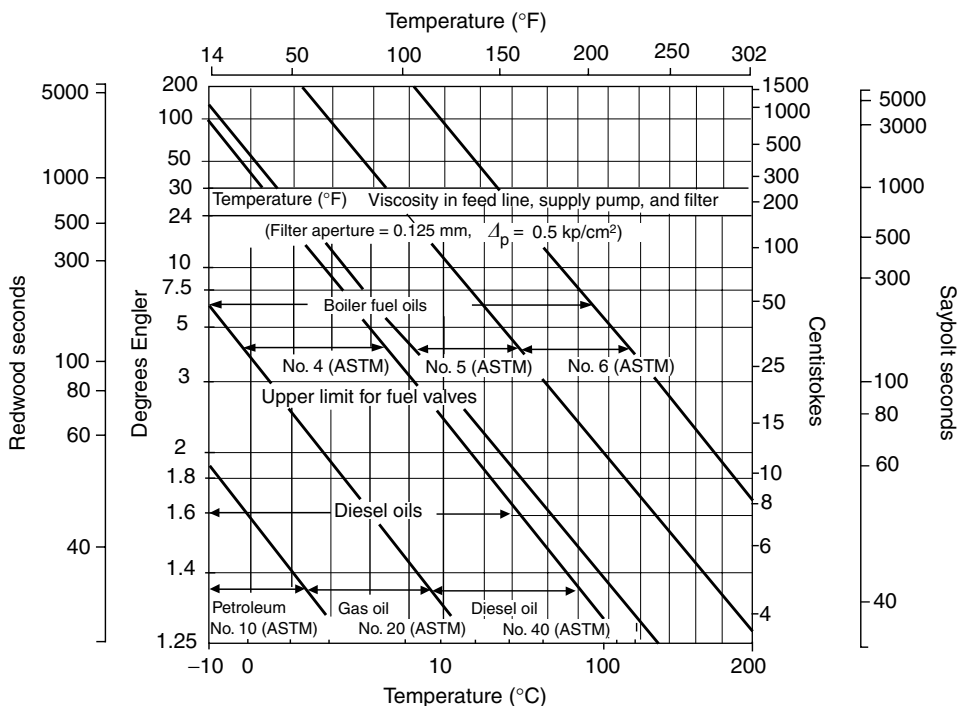


FIGURE 3.9

Viscosity versus temperature chart for various liquid fuels.

7. *Sulfur* affects low-temperature corrosion and chimney height. With high hydrogen content in fuel oils and consequent high water vapor in flue gases on combustion, there is $\sim 4\%$ conversion of S into SO_3 , making the gases more acidic than the flue gases from coal firing with the same percentage of S.

3.3.1.2 Classification of Fuel Oils

Classification of fuel oils into six grades as per ASTM D396 is widely followed. Tables 3.20 and 3.21 summarize the classification.

- Grades 1 and 2 are called light and medium domestic fuel oils specified mainly by the distillation temperature.
- Grade 6 is called the heavy industrial fuel oil or bunker C oil and specified mainly by viscosity.

3.3.1.3 Naphtha

Naphtha is a general term used for spirits having low boiling points ranging from 30 to 170°C . It is used as a feed stock in fertilizer and petrochemical industries. Naphtha is a highly volatile product. It is made from

- Crude oil by direct atmospheric distillation
- Heavy residues by catalytic cracking

Naphtha essentially consists of paraffenic, naphthenic, and aromatic HCs. Naphtha is made in two varieties

1. HAN—high aromatic naphtha
2. LAN—low aromatic naphtha, also called petrochem naphtha

Naphtha is used to a limited extent as fuel in boilers and GTs. It is free of heavy and fouling elements such as vanadium, sodium, and lead. Sulfur is limited to 0.15%. Its GCV is $\geq 10,500$ kcal/kg. Its volatile nature can be understood by its flash point of $\leq 23^\circ\text{C}$.

3.4 Gaseous Fuels

Gaseous fuels are best suited for boilers, provided they are available at the plant gate and, more importantly, on a continuous basis. The most important properties of gaseous fuels are as follows:

1. Composition
2. Calorific value
3. Specific gravity
 - The gas analysis or composition is expressed in volumetric terms on dry basis (moisture-free basis).
 - Analysis is done by chemical means of absorption, distillation, combustion, infrared spectroscopy, or gas chromatography; the last two methods are the most accurate.
 - Calorific value is determined by bomb calorimeter. It is common to denote CV on dry volumetric basis.
 - For combustion calculation purposes, weight basis is needed. This is usually calculated from volume using density.
 - Specific gravity is compared with the weight of air for the same volume. ASTM D1070 covers three methods.

3.4.1 Fossil Fuels

3.4.1.1 Natural Gas

Natural gas is perhaps the nearest to the ideal fuel, as it is almost free of ash and has high CV.

- There are no storage facilities required for the fuel.
- There are no dust collection or ash disposal issues.
- The boiler control is extremely simple, sensitive, and seamless.
- The boiler is very compact.

Natural gas is found usually close to oil deposits, compressed in the underground porous rock or shale formations at pressures as high as 150 bar.

- *Associated gas*. When gas is trapped above oil (which in turn is on top of salty water), it is called associated gas, and it contains heavy HCs.
- *Wet gas*. When gas is in contact with the oil, it is charged with heavy HCs such as pentane (C_5H_{12}) and hexane (C_6H_{14}), which are liquid at ordinary temperature and pressure, and this gas is known as wet gas.

- *Dry gas.* Dry NG comes from wells away from oil deposits and it is free of heavy HCs.
- *Sour gas.* Natural gas containing some mercaptans and high amounts of H_2S is known as sour gas.
- *Sweet gas.* Natural gas free of any of the above-mentioned undesirables is known as sweet gas.

From a combustion view, it is to be noted that the terms wet and dry NG have nothing to do with moisture in fuel but refer to the presence or absence of gasoline vapor. Natural gas is largely a mixture of HCs. Unlike coal or oil, NG has a higher H–C ratio and emits a lower CO_2 , which is beneficial in terms of global warming. The important properties are as follows:

1. *Temperature.* The temperature of NG, as it comes out of the well, varies from 0 to 75°C (~ 32 to 165°F) depending on the depth of the well. A rough indication is 1°C for every 30 m of depth ($\sim 1^\circ\text{F}$ for 50 ft), which is not always realized in practice. At the plant gate, when it has traveled over a long distance from the well in the pipelines, the temperature is likely to be in the range of 5 – 25°C (~ 40 to 80°F) depending on the ambient conditions of terrain that it has traversed. For combustion purposes, it is normal to adopt a standard temperature of 15°C (60°F).
2. *Moisture.* At the head of the well NG contains no moisture unless there has been previous contact with salt water. In the gas pipelines, steam is added to *rehydrate*, that is, saturate with water vapor, to reduce the maintenance costs of pipelines. However, as the pressure is reduced at the time of distribution, the relative humidity drops. It is, therefore, the industrial practice to consider NG in a dry condition and at 15°C (60°F).
3. *Density.* This consists of the weights of individual constituents. Extreme accuracy in calculating the density and the CVs is not warranted, as the values of constituents keep changing. Calculated density is no more accurate than the volumetric analysis on which it is based. An analysis that groups all HCs as CH_4 and C_2H_6 may indicate a lower density than the actual.
4. *Gross calorific value.* It is customary to compute and indicate the GCV of NG in kilocalories per cubic meter or megajoules per cubic meter (or Btu/ft^3) at STP conditions of 15°C and 760 mmHg (60°F and 30 in. Hg) and in dry state. If the gas is saturated with moisture, the CV is to be reduced by 1.74%. Usually the GCV of NG is $10.35 \text{ kW}/\text{m}^3$ or $8900 \text{ kcal}/\text{m}^3$ ($1000 \text{ Btu}/\text{ft}^3$) in the range of 8.7 – $10.5 \text{ kW}/\text{m}^3$ or 7500 – $9500 \text{ kcal}/\text{m}^3$ (~ 850 to $1050 \text{ Btu}/\text{ft}^3$). A much wider range of GCV is also possible when an extreme range of constituents is considered. The HV can be calculated by summing up the heat values of the various gas components, but it will be lower than the actual value determined by the bomb calorimeter as the unsaturated HCs are grouped as C_2H_6 . The density computed also works out to be lower for the same reason. But the GCV on weight basis in kilocalories per kilogram works out to be very nearly the same as the result from the bomb calorimeter.
5. *Constituents of NG.* The principal constituents are methane (CH_4) and the heavier paraffins such as ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}). It also contains 5–20% N_2 , and some NGs contain appreciable quantities of CO_2 and H_2S . Traces of argon, helium, and hydrogen are also present. O_2 may be present if the gas is drawn from wells under suction, and air leakage is present in the pipelines.

TABLE 3.22

Typical Compositions of Natural Gases

Constituents		% Volume	% Volume	% Volume	% Volume	% Volume
Methane	CH ₄	91.70	77.73	99.20	59.20	52.54
Ethane	C ₂ H ₆	4.13	5.56	—	13.90	3.77
Propane	C ₃ H ₈	1.69	2.40	—	—	2.22
Butane	C ₄ H ₁₀	0.52	1.18	—	—	2.02
Pentane	C ₅ H ₁₂	0.30	0.63	—	—	3.44
Hexane	C ₆ H ₁₄	0.21	—	—	—	—
Carbon dioxide	CO ₂	0.33	5.50	0.20	26.2	3.51
Nitrogen	N ₂	1.03	—	0.60	0.70	32.0
Hydrogen sulfide	H ₂ S		7.00	—	—	0.50
Density	kg/m ³		0.91	0.727	1.09	1.07
Gross calorific value at 15°C and 760 mmHg	kcal/m ³		943	895	755	778
	kcal/kg		10,490	12,450	6,990	7,345

H₂S is substantially removed at the head of the well to prevent corrosion of piping. The heavy HCs that are in liquid form are also removed. Further, for ease of pipeline transportation, water and oil are sprayed to *moisten*. For combustion, therefore, as-delivered composition is more relevant than the well-head analysis.

6. *Odorization*. Generally, NG as it comes out of the earth is colorless and odorless and burns with a blue flame. It is highly explosive when mixed with air in right proportions. For this reason, odorization must be done to detect the presence of gas by adding traces of some organic sulfur compounds.

Typical composition of NGs is given in Table 3.22.

- There is a wide variation in the composition, density, and CVs.
- Theoretical CO₂ varies approximately from 12 to 15% at stoichiometric conditions.
- Stoichiometric air requirement can be substantially constant at 1.335 kg/1000 kcal of GCV despite large variation in composition.

Large NG reserves are found in Russia, Iran, Qatar, United Arab Emirates, Saudi Arabia, the United States, Algeria, Venezuela, Nigeria, and Iraq. There are small reserves in several parts of the world. Large importers of NG are mainly the United States, Germany, Ukraine, Italy, and Japan, whereas the exporters are Russia, Canada, Algeria, Norway, Middle East, and Indonesia.

3.4.1.2 Liquefied Natural Gas

Liquefied natural gas is a relatively new fuel gaining popularity since the mid-1960s. Unlike oil, which packs a lot of heat in a small volume, NG is bulky and relatively difficult to transport. This deficiency is largely removed in LNG.

Natural gas is liquefied at -162°C and transported either by pipelines or by large ships. NG needs liquefaction and loading facilities at the production end and regasification and distribution facilities at the consuming end. A ton of LNG is equivalent to nearly 1500 m³ of NG of 8900 kcal/m³ of CV or 2.5 of coal with 5300 kcal/kg of CV.

Algeria, Libya, Middle East, Southeast Asia, and Alaska are the major exporters, with Algeria and Libya exporting to Europe and the United States and the others exporting to Japan, South Korea, and Taiwan.

3.4.2 Waste or Manufactured Fuels

3.4.2.1 Refinery Gas

Refinery gas (RG) is the by-product of both distillation and cracking processes in the refinery. *Distillation* is the process of separating various components of petroleum by their specific gravities when the oil is heated to $\sim 300^\circ\text{C}$ and flashed in a fractionating column. Distillation can occur under vacuum or pressure and in the presence of steam or gas.

Cracking is the thermal decomposition of the oil heated at $450\text{--}550^\circ\text{C}$ and 50 kg/cm^2 pressure and discharged into separators and then to the fractionating tower.

Source. RG is withdrawn from any point in the system:

- From raw gasoline tanks, stabilizers, cracking stills, or adsorbers used for purification
- At below or above atmospheric pressure
- At room temperature or much higher, if taken from the cracking still or fractionating tower

Often RGs are blended and supplied, which is the reason for the wide variation in analyses.

Composition. RG is composed of mainly paraffins with low boiling point— CH_4 , C_2H_6 , C_3H_8 , C_4H_{10} , and C_5H_{12} —and small amounts of olefins. Minor quantities of CO_2 , CO , and H_2 may also be present along with O_2 and N_2 at times introduced to lower the pressure of HCs in the cracking process. Sulfur of the original crude appears as SO_2 unless it has been removed. Typical analyses and properties of RG are given in Tables 3.23 and 3.24.

3.4.2.2 Coke Oven Gas

Coke oven gas (COG) is the waste produced in the destructive distillation of the bituminous coal in the manufacture of coke. Coke oven batteries are charged with coking coal and heated externally to drive out all the VM. Products such as ammonium sulfate, oils, and tars are recovered. The incondensable gases are collected and supplied as COG, which is $\sim 15\%$ by weight of the coal charged into the slot-type coke ovens.

The composition of the gas is dependent on the analysis of raw coal and the length of the time of coking. Mainly the COG consists of H_2 , CH_4 , C_2H_4 , and CO with small amounts of

TABLE 3.23

Refinery Gas Analysis by Percentage Volume
at 15°C , 760 mm wg

Constituent	% Volume
CO_2	0.0–5.0
N_2	0.0–10.0
O_2	0.0–2.5
H_2	0.0–5.0
CH_4	5.0–90.0
C_2H_6	2.0–30.0
C_3H_8	4.0–60.0
C_4H_{10}	0.0–50.0
C_2H_4 and other olefins	0.0–25.0 and higher

TABLE 3.24

Refinery Gas Properties

Density (kg/m^3)	0.4–1.4
GCV (kcal/m^3)	7,900–13,100
GCV (kcal/kg)	4,600–26,600
Theoretical CO_2	10.5–13.9
Theoretical air (kg/1000 kcal)	1.22–1.38

TABLE 3.25

Properties of Coke Oven Gas at 15°C, 760 mm Dry Hg Volumetric Basis

GCV (kcal/m ³)	4760
NCV (kcal/m ³)	4245
Weight of wet gas (kg/m ³)	0.477
Weight of dry gas (kg/m ³)	0.4645
H ₂ O from combustion (kg/m ³)	0.8843
H ₂ O as vapor in gas (kg/m ³)	0.013
Total H ₂ O in flue gas (kg/m ³)	0.8973
Theoretical air (kg/1000 kcal)	1.246
Theoretical CO ₂ (average range)	10.75
	9.5–12.5
<i>f</i>	1.11

TABLE 3.26

Typical Coke Oven Gas Analysis on Cubic Meter Basis

	Range	Typical
CO (%)	5–12	7
CO ₂ (%)	0.1–3.2	2
N ₂ (%)	2.4–12.12	5
O ₂ (%)	0.2–0.6	0
H ₂ (%)	27–57	53
CH ₄ (%)	28–50	29
C ₂ H ₄ (%)	2.7–13	3.5
C ₂ H ₆ (%)		<1
		100
Density (kg/m ³)	0.46–0.63	
GCV (kcal/m ³)	4250–7380	
GCV (kcal/kg)	9100–11700	

CO₂, N₂, O₂, and heavy HCs. COG comes out at high temperatures and contains suspended particles of tar, dust, benzol, and H₂S. It is usually washed and cooled before sending to COG holders. A substantial portion of the COG is used for heating the coke ovens. More than half of the gas is used by the steel companies in boilers. There are two types of coke commonly made: (1) foundry coke and (2) blast furnace coke.

- High-temperature carbonization at ~980°C is adopted for making foundry coke and at 1400°C for making blast furnace coke. Typically a ton of coal with ~31% VM would yield 720 kg of coke and 330 m³ of gas, besides tar, water, light oils, and NH₃. The GCV value lies between 4.13 and 6.22 kW/m³ or 3550 and 5350 kcal/m³ (~400 to 600 Btu/ft³).
- Low-temperature carbonization yields lesser amounts of gas but with higher CV of 5350–8900 kcal/kg (600–1000 Btu/ft³).

Coke oven gas burns readily because of free H₂ and presents no problems in combustion. But the other impurities in gas deposit themselves in the pipelines and burner openings. The burners are required to have larger gas-port openings and easier access for cleaning. Typical analysis and properties of COG are given in Tables 3.25 and 3.26.

3.4.2.3 Blast Furnace Gas

Blast furnace gas (BFG) is the waste product from the conversion of iron ore into pig iron. A blast furnace is charged with ore, coke, and limestone from the top sequentially, and hot air at 600–700°C is blown from the bottom openings. Air travels upward, and while the charge descends, creating an intimate contact, coke reacts with O₂ in air to form CO with some heat. CO reduces the iron ore at this high temperature and frees carbon to form iron and CO₂. Limestone reacts with the products to remove the impurities and in this process it forms more CO₂.

The BFG that exits at the top of the blast furnace contains CO and CO₂ in good measure, along with N₂ and H₂ and traces of CH₄. N₂ is from air whereas H₂ and CH₄ are from the dissociation of water vapor at high temperature inside the blast furnace. The gas is hot (150–425°C), dusty (iron oxide), and low in CV.

The gas pressure varies between 500 and 750 mm w.g. Unfortunately, this pressure varies widely due to the violent movements inside the blast furnace and switching of blast stoves.

TABLE 3.27

Lethal Nature of Blast Furnace Gas

CO (ppm)	Slight Illness After	Serious Illness After	Danger of Death
5000	—	—	Immediate
2000	10 min	20 min	After 1 h
1000	20 min	40 min	After 2 h
500	30 min	90 min	No
200	1 h	Several days	No
100	4 h	Nonexistent	No

This variation is passed downstream and a good solution would be to install a gas holder. But gas holders are both costly and space-consuming.

The dust at the top can be as high as 115 g/dry sm^3 (dsm³) [50 grains/dry scf (gr/dscf)] comparable to CFBC or PF upstream of filter. Since this dust is high, the gas is passed through a mechanical dust collector to reduce loading to 7–35 g/dsm³ (3–15 gr/dscf) followed by one more dry or wet cleaning, which is performed to reduce the dust to <700–2300 mg/dscm (~0.3 to 1.0 gr/dscf). The third stage involves a more vigorous washing or electrostatic precipitation when the dust loading is down to 10–20 mg/dscm (0.005–0.01 gr/dscf).

Blast furnace gas is a heavy gas (about 1.25 times heavier than air) with low GCV, due to large amounts of N₂ and CO. There is practically no sulfur and water vapor on combustion, eliminating any threat of corrosion, both at high and at low temperatures. Older plants yield richer gas, whereas the newer and more efficient plants produce leaner gas. Gas pressure, quantity, and quality vary a great deal, necessitating a support fuel all the time. But the stoichiometric air requirement at ~10.8 kg/1000 kcal/kg of GCV is remarkably constant.

Blast furnace gas requires a high temperature of ~800°C for ignition and burns at ~1100 to 1200°C in a boiler with unheated air. The flame propagation velocity is low, between 25 and 32 m/s at stoichiometric conditions. The gas produces a faintly bluish and almost nonluminous flame with pinkish tinge at the end. This gives a confusing picture of the flame-out condition, making the situation very dangerous, as the leakage of BFG is lethal due to its high CO content. This is captured in Table 3.27. Flame stability is to be ensured by radiation from refractory. Cofiring with other fuels is the easiest way to mitigate the safety issues.

Both dusty dry and wet clean gases are used in boilers with different problems.

- Dusty gases choke the gas passes and burners, also causing erosion and fouling of the HSs.
- Wet gas deposits are too hard to remove.

In a way dustiness is a better nuisance than wetness. Typical analysis and properties of BFG are given in Tables 3.28 and 3.29.

3.4.2.4 CO Gas

During the catalytic cracking of petroleum with a thermofor catalytic cracker (TCC) or fluid catalytic cracker (FCC), the catalysts must be scrubbed clean to remove the coke deposited by the cracking process. This regeneration of the catalyst is performed by burning away the carbon in the regeneration tower with the help of large quantities of high-pressure air at ~2 kg/cm². This air has to be kept to a minimum, in fact to substoichiometric levels, to

TABLE 3.28
Volumetric Gas Analysis of Blast Furnace Gas on Dry Basis

	Range	Typical
CO%	25–35	26
CO ₂ %	6–16	12.5
N ₂ %	55–65	59
H ₂ %	1–3	2.5
CH ₄ %	<5	
		100
Density (kg/m ³)	1.17–1.27	
GCV (kcal/m ³)	720–1280	
GCV (kcal/kg)	570–1080	

TABLE 3.29
Properties of Blast Furnace Gas at 15°C, 760 mm wg on Cubic Meter Basis

	Washed	Unwashed
GCV (kcal/m ³)	800	800
NCV (kcal/m ³)	787	790
Weight of wet gas (kg/m ³)	1.259	1.307
Weight of dry gas (kg/m ³)	1.227	1.227
H ₂ O from combustion (kg/m ³)	0.018743	0.01874
H ₂ O as vapor in gas (kg/m ³)	0.0267	0.08
Total H ₂ O in flue gas (kg/m ³)	0.05	0.0988
Theoretical air (kg/1000 or kcal)	10.77	10.77
Theoretical CO ₂	25.5	25.5
<i>f</i>	0.45	0.45

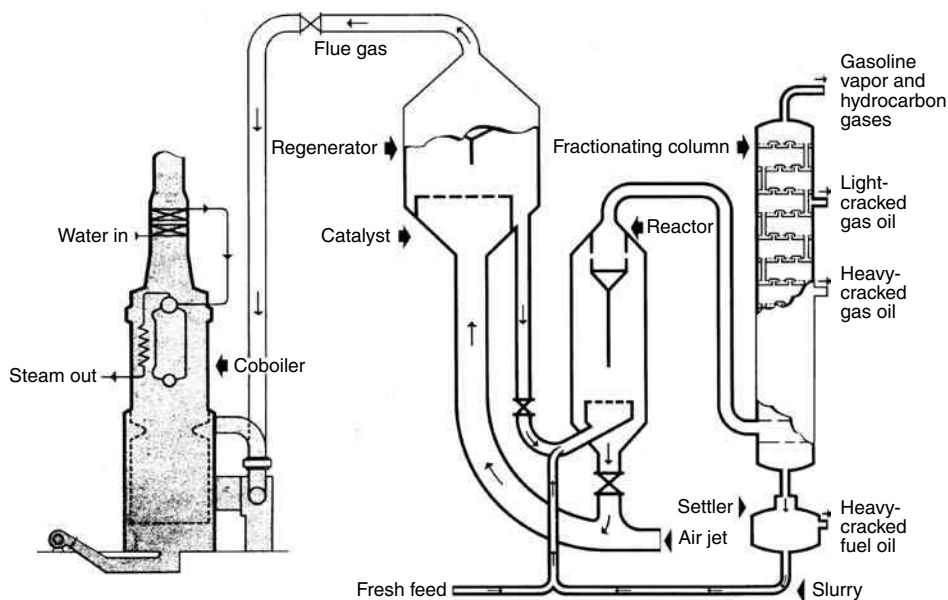


FIGURE 3.10
Schematic of CO gas formation. (From Doosan Babcock Energy Ltd., U.K. With permission.)

contain the temperature to prevent the destruction of catalyst and minimize the compressor power. The combustion therefore produces a good amount of CO and hence this waste gas is termed CO gas.

CO gas leaves the regenerator at a temperature as high as 600–700°C and naturally contains a large amount of sensible heat, although the GCV is <350 kcal/m³ with CO content of 4–10% by volume. CO–CO₂ oxidation takes place in a CO boiler. Catalytic dust carried over is in traces, <40 µm in size. The ignition temperature of CO is 610–660°C and stable combustion takes place if the adiabatic flame temperature is 980°C. An auxiliary fuel with 10% capacity generally fills this need.

CO gas is consumed in the refinery by producing the process steam in the CO boilers that incidentally attenuate the noise and discharge CO₂ instead of toxic CO (Figure 3.10). Typical analysis and properties of CO gas are given in Table 3.30.

TABLE 3.30

Properties of CO Gas on Volumetric Basis

Constituent	Range	Typical
CO%	4–10	8.7
CO ₂ %	6–12	7.2
O ₂ %	0.1–0.6	0.6
N ₂ %	65–80	66.6
H ₂ O%	8–16	16.9
SO ₂ %	0.1–0.3	—
HCs (%)	Traces	—
Total		100
Gas temperature (°C)	600–700	640
Press (mm wg)	800–1500	
Catalyst dust (g/N m ³)	0.2–1.5	

3.5 Ash

Ash is, mercifully, not present in NG and many manufactured gases, refinery gases, and most of the distillates. All coals, fuel oils, sludges, bottoms, tars, cokes, wood and wood products, agrowastes, and waste gases such as BFG invariably contain ash in varying proportions.

3.5.1 Coal Ash

Woody matter, from which coal is derived, is practically free of MM. But coal contains considerable amount of MM brought in by wind and water. When coal is burnt, the residual incombustible matter is ash. Ash forms ~90% of the MM with the remaining having escaped with VM. Ash is the most undesirable constituent.

Ash is an inert material, which

- Must transported along with coal
- Needs continuous removal from boiler to prevent its stoppage
- Demands collection after combustion in an acceptable manner
- Requires disposal.

These costs yield no benefit in return. On the other hand, unless managed properly, ash creates serious problems of

1. Erosion
2. Slagging and fouling
3. Corrosion

Furnace geometry, size and design, location of soot blowers (SBs), spacing of tubes in convection passes, and other parameters are all governed by ash properties. In fact, coal-fired boiler design substantially revolves around the management of ash. The behavior of ash in a boiler at various temperatures and locations can be predicted from the following properties in a reasonably accurate manner.

3.5.1.1 Properties of Coal Ash

3.5.1.1.1 Coal Ash Analysis

Constituents of ash display the following features. They

- Are almost entirely metal oxides
- Vary widely

Ash analysis can be understood in either (1) chemical or (2) mineralogical terms, or preferably both, to gain a complete picture. Ash is actually a mixture of various mineralogical compounds, whose analysis is not easily amenable to standard laboratory methods as chemical analysis. Although the chemical analysis captures all the oxides that make up the ash, it does not tell us in what form they actually exist in the ash.

The chemical constituents of ash are metal oxides. ASTM D3124 provides guidelines for testing a sample of powdered coal required to be burnt in a ceramic crucible to completion at 700–750°C. Chemical analysis is done to determine each constituent and report weight percent. The ash composition varies so widely that there is no standard analysis to benchmark. Coal ash analysis is different from the analysis obtained for bottom ash, fly ash, or furnace slag. Enough data is now available to predict the behavior of ash in a boiler in a reasonably accurate manner. Table 3.31 gives a range of analysis for various constituents of ash.

Understanding the behavior of ash based on the original MM forms is the purpose behind mineralogical analysis. The testing procedure is different. More than 100 mineral species are associated with coal and the reactions among them are complex. Mineralogical analysis can provide clues to certain aspects of ash behavior not fully understood with the aid of chemical analysis. Calcite (CaCO_3), dolomite ($\text{CaCO}_3 \cdot \text{MgCO}_3$), siderite (FeCO_3), pyrite (FeS_2), gypsum ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$), quartz (SiO_2), hematite (Fe_2O_3), magnetite (Fe_3O_4), and rutile (TiO_2) are some of the minerals.

- Ash high in acidic constituents such as SiO_2 , Al_2O_3 , and TiO_2 has high softening temperature, not affected much by reducing temperature.
- Basic oxides such as Fe_2O_3 , Na_2O , K_2O , CaO , and MgO tend to reduce the softening temperature.
- Iron compounds are problematic as S in FeS_2 , in its passage through the furnace, dissociates and reacts with O_2 to form SO_2 and SO_3 .
- S also combines with Na and K to form low-melting compounds that cause corrosion and slagging.

TABLE 3.31
Range of Chemical Constituents of Ash

Oxide	Range (%) by wt	Acidic (A)/ Basic (B)
SiO_2	10–70	A
Al_2O_3	8–38	A
Fe_2O_3	2–50	B
CaO	0.5–30	B
MgO	0.3–8	B
Na_2O	0.1–8	B
K_2O	0.1–3	B
TiO_2	0.4–3.5	A
SO_3	0.1–30	A
Total	100	

3.5.1.1.2 Coal Ash Fusibility

Ash fusibility lends itself to an empirical method of predicting the ash behavior at high temperature so that the sizing of a furnace is done correctly. ASTM D1857 gives the procedure in which the gradual deformation of an ash pyramid, 19 mm high with 6.35 mm equilateral base mounted on a refractory base, is heated in a gas or electric furnace, in reducing and oxidizing atmospheres, at a specified rate to record the four characteristic deformation temperatures shown in Figure 3.11.

1. *Initial ash deformation temperature (IADT)* is the temperature at which the specimen cone begins to soften at the top.
2. *Softening temperature (ST)* is the temperature at which the cone shape is lost and the height and breadth become equal.
3. *Hemispherical temperature (HT)* is the temperature at which the cone reduces to a hemispherical shape.
4. *Fluid temperature (FT)* is the temperature at which the specimen is flat and the molten ash begins to flow.

Initial ash deformation temperature is the most important for boiler design and operation. Softening temperature is often noted, as the stickiness of ash starts increasing at this point.

- Normally the difference between IADT and ST can be 100°C.
- The permissible difference between two runs may be as high as 55–85°C. Standards followed by other countries also differ and great care is needed in using the data.
- All ash deformation temperatures are lower in reducing conditions, and iron compounds have a great influence in depressing the temperatures. Figure 3.12 illustrates the point in a qualitative manner.
- Furnace exit temperatures should be designed for at least 55°C lower than the IADT in reducing conditions.

3.5.1.1.3 Ash Viscosity

The viscosity of molten coal ash can be measured in a rotating-bob viscometer, but it requires a lot of ash and the procedure is very time-consuming and expensive. Fortunately, it can be estimated from the chemical analysis of the ash with sufficient reliability. Ash up to viscosity of 250 P can be removed from the operating boilers. The temperature to attain such level is referred to as T250, which is a benchmark. The following ratios are used to estimate the viscosity, depending on the type of ash.

$$\text{Silica percentage (SP)} = \frac{\text{SiO}_2}{\text{SiO}_2 + \text{Equivalent Fe}_2\text{O}_3 + \text{CaO} + \text{MgO}} \times 100 \quad (3.5)$$

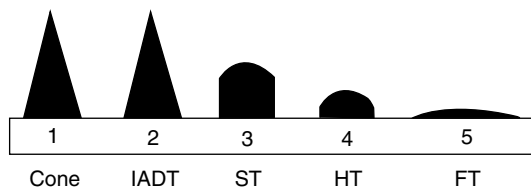
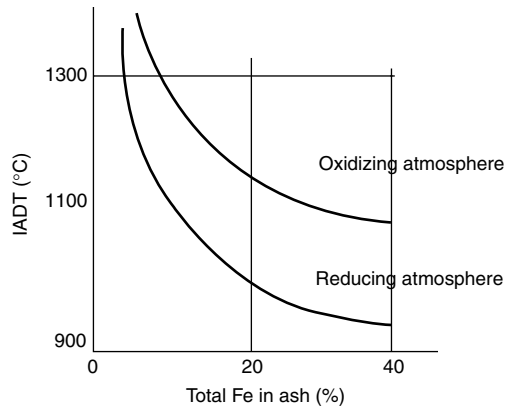


FIGURE 3.11

Four stages of ash deformation temperatures.

**FIGURE 3.12**

Effects of iron compounds and reducing conditions on IADT. (From Babcock & Wilcox Co., U.S.A. With permission.)

where

$$\text{Equivalent Fe}_2\text{O}_3 = \text{Fe}_2\text{O}_3 + 1.11\text{FeO} + 1.43\text{Fe} \quad (3.6)$$

$$\text{Base-acid ratio (B/A)} = \frac{\text{Fe}_2\text{O}_3 + \text{CaO} + \text{MgO} + \text{Na}_2\text{O} + \text{K}_2\text{O}}{\text{SiO}_2 + \text{Al}_2\text{O}_3 + \text{TiO}_2} \quad (3.7)$$

$$\text{Dolomite \%} = \frac{\text{CaO} + \text{MgO}}{\text{CaO} + \text{MgO} + \text{Na}_2\text{O} + \text{K}_2\text{O} + \text{Fe}_2\text{O}_3} \times 100 \quad (3.8)$$

B/A ratio in the range of 0.4–0.7 denotes a high slagging potential.

3.5.1.2 Effects of Ash on Boiler

The ill effects of ash on boiler design have already been mentioned:

1. Erosion
2. Slagging and fouling
3. Corrosion

3.5.1.2.1 Erosion of Boiler Parts due to Fuel Ash

Erosion is a form of wear. *Wear* can be defined as progressive loss of a surface material due to mechanical action involving impingement of abrasive particles. Unlike corrosion, which is a chemical or electrochemical action, wear is purely mechanical. Readers may refer to Chapter 5 on wear-resistant materials. *Abrasion* and *erosion* are two types of wear.

1. Abrasion can be likened to sand-papering in which solid particles move in contact with a parallel surface. Abrasion affects the high spots of the surface without much effect on the main body. The resulting loss of material is smaller in comparison with erosion. Abrasion resistance can be built by a boundary layer of high and preferably hard spots.
2. Erosion is the impingement of hard particles at an inclination, and it has more energy and destructive power than abrasion. The impinging particles cut through the boundary layer and destroy the main matrix. Hence, abrasion-resistant material cannot withstand erosion.

Wear is not a problem that afflicts the oil- and gas-fired boilers. It is an issue only with solid fuel firing, as wear occurs on both fuel and ash sides of the boiler and handling plants. The pulverizers and the coal piping of PF-fired boilers experience wear based on the ash content and constituents. High-ash coals tend to cause wear and the normal solution is to

- Make the wear parts from wear-resistant materials
- Provide sacrificial materials at appropriate places

These methods are described in Chapter 13 dealing with PF boilers. Wear is also experienced in coal bunkers and feeders, and usage of wear liners is a proven solution.

Erosion of hot parts due to ash, particularly the tubes, is a serious problem affecting the availability of solid fuel-fired boilers. The hard constituents of ash, namely, Al_2O_3 and SiO_2 , moving with flue gas at high velocities impinge on tubes, refractory, and other parts in the gas path, causing erosion. Ash, as originally present in coal, is not so abrasive. But after it melts due to high furnace temperatures and recrystallizes, the abrasiveness increases dramatically and the ash is re-formed into crystals with their characteristic sharp edges. FBC ash is less erosive, as it does not melt and hence does not reshape into hard crystals, at least not to the same level of PF. But the amount of ash in bed in BFBC and in recirculation in CFBC is so high that it can cause significant erosion damage to both tubes and refractory. Bed-coil erosion in BFBC and erosion of furnace walls, tube banks in the first pass, and cyclone refractory in CFBC are extremely severe. Erosion is influenced by the following:

- Flue gas velocity.
- Flue gas dust loading.
- Nonuniformity of dust loading and gas velocity across the cross section.
- Density of tubes in a bank.
- Tube disposition in a bank—inline or staggered.
- Gas turns that segregate the ash due to centrifugal action.
- Angle of ash particle impingement. Normal and parallel to the surface, the erosion is found to be minimum, whereas between 20 and 30° in horizontal to the surface, the wear is found to be maximum.

Erosion is an inseparable aspect of boilers firing solid fuels. It can be minimized but not eliminated altogether. The aim is to minimize and predict the erosion rate so that the intervals between the downtimes can be extended to coincide with the planned outages, thus improving the unit availability. The erosion prevention and protection measures essentially fall into two categories:

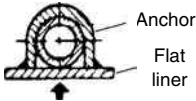
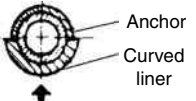
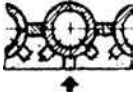
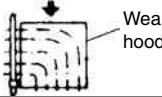
1. Design stage measures
2. Provision of sacrificial protective material

Erosion prevention is essentially achieved at the design stage, mainly by adopting measures that reduce the severity of contact between ash and PPs. Erosion protection is achieved by providing sacrificial protective material. Further, erosion in the boiler is

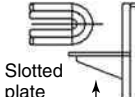
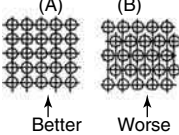
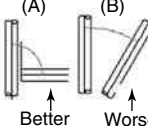
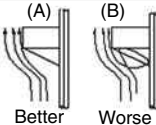
monitored during operation and sacrificial material is increased if erosion persists. This is an on-site protective measure.

1. The design stage erosion prevention measures are as follows:
 - a. *Gas velocities*. Limiting the flue gas velocities is the most important design step to eliminate external tube or refractory erosion. Guidelines for maximum permissible gas velocities are given in Chapter 6.
 - b. *Inline tubes*. Tube disposition is another major point to be noted. Inline tubes reduce erosion dramatically as compared with a staggered arrangement.
 - c. *Bigger furnace*. Limiting the dust loading is done by sizing the furnace chamber generously and providing adequate SA and TA with a strategic placement of nozzles.
 - d. *Tower-type boiler*. Avoiding the gas turns is another important design step. The centrifugal force segregates and hurls the ash toward the edges, causing damage to the PPs in the path. It is preferable, for example, to avoid two-pass boiler banks (BBs) for abrasive fuels. Tower-type boilers are preferred by many customers, as they offer protection against such damage.
2. The sacrificial erosion protective measure is a wear-resistant liner or stud material either attached or welded to the affected tubes. This can be an established design measure or a new preventive measure. In both cases, the erosion patterns have to be carefully studied and appropriate patterns have to be evolved. Possible side effects should also be neutralized.
 - a. Wear liners are likely to render certain amount of tube surface ineffective, whereas studding is likely to increase the effectiveness; both measures call for adjustments of the HS.
 - b. Liners and studs protect the surfaces on which they are placed but they are likely to deflect the ash streams elsewhere, thereby shifting the problem instead of solving it.
 - c. Studs are attached to the tubes by welding and hence they are kept cool. They are usually made of carbon steel (CS). When long studs are needed the cooling efficiency is reduced. The studs should be made of alloy or stainless steel (ss).
 - d. The liners are of CS when they are used for protecting low-temperature sections such as the economizer (ECON) in the second pass of the boiler. But at high temperatures as required in SH, they are made from ss and, at times, from high-temperature alloys like Si–Cr–Al steels. The liners are not welded to the tubes to avoid damage due to differential expansion between the tube and the liner. Since there is no cooling, the liners attain nearly the same temperature as the gas and expand much more than the tube. Unless attached to the tube at close intervals the liner sags and fails to provide proper protection.

Although it appears to be simple to attach a liner to the tube, it is a difficult task in practice. A comprehensive list of proven erosion protection measures is given in Figures 3.13a and b. They should be adopted with great caution.

Designation	Principle	Remarks
Protective strips		Pure deformation wear for high ash in flue gases
Protective shells		For deformation and cutting wear with slightly lower ash in flue gases
Studding and refractory lining		For tube walls and inbed tubes of BFBC with no refractory
Square tubes		For very high ash like in CFBC suited for heavy abrasive wear with parallel flow
Omega tubes		
Protection of tube bends		Suited for protection of tube banks after gas turns

(a)

Designation	Principle	Remarks
Gap cover		This arrangement minimizes high velocity in the lanes
Tube arrangement in-line versus staggered		Erosion of second and following tubes minimized with in-line arrangement
Tube inclination		Erosion is minimum with tubes placed parallel or normal to gas flow than at an inclination
Tube arrangement		In (A) ash particles are deflected into the gas stream and not on to the tubes

(b)

FIGURE 3.13

(a) Special tubes and liners for wear resistance. (b) Tube arrangements for better wear life.

3.5.1.2.2 Slagging and Fouling

Both processes produce high-temperature ash deposits.

- Slagging is the formation of fused slag deposits on furnace walls and other surfaces exposed to radiant heat.
- Fouling is the formation of bonded (sintered or cemented) deposits in mainly SH and reheater (RH) areas from convection heat (Figure 3.14).

Depending on the fusibility, the various compounds of ash can be classified into three categories:

1. *High-melting* compounds such as SiO_2 , Al_2O_3 , Fe_2O_3 , CaO , and MgO , which are
 - a. Pure oxides with fusibility ranges of 1600–2800°C that do not melt but end up in fly ash and retain their original structure
 - b. A cause for erosion but not *slagging*
2. *Medium-melting* compounds such as Na_2SiO_3 , K_2SO_4 , and FeS , which
 - a. Have a fusibility range of 900–1100°C
 - b. Form the base sticky layer on water walls and platens
 - c. Cause *slagging*
3. *Low-melting* compounds, mainly chlorides and sulfates of alkali metals, such as NaCl , Na_2SO_4 , CaCl_2 , and MgCl_2 , which
 - a. Have a fusibility range of 700–850°C
 - b. Form the base sticky layer on SH and RH tubes
 - c. Cause *fouling*

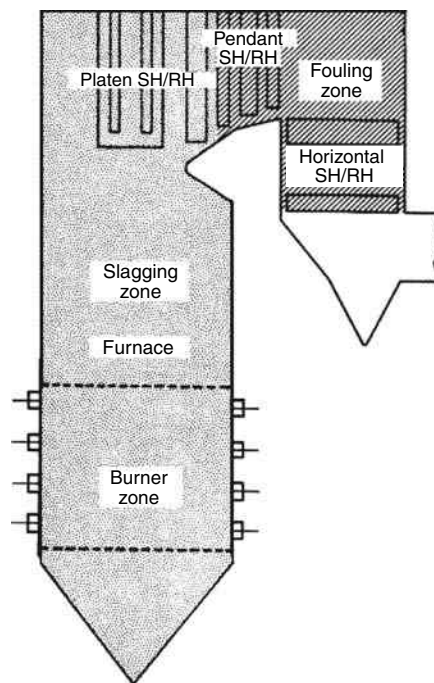


FIGURE 3.14
Slagging and fouling zones in a PF boiler.

- *In slagging* that takes place on furnace, division walls, and platens, the molten ash particles moving in the flue gas stream solidify on contact with tube metal, which is cooler, and form a loose flowing layer. Short retractable SBs or wall deslaggers remove these from a furnace. Long retractable blowers are needed for platens. At times the inner layer attaches itself to the tubes firmly and the outer layer grows in size till it detaches by its own weight and falls on the furnace bottom, causing serious damage such as destroying the floor. Viscosity of ash determines the ease of deslagging.
- *In fouling* that takes place in the tube nests, the action is different. The base sticky layer is formed by the solidification of ash on cooler tubes. Here, the ash layer is not flowing. The temperatures of the outer layer of ash are higher but still cool enough for further ash to solidify and attach itself by fusing. After some growth the ash particles do not solidify, as the temperatures are too high and an equilibrium depth of deposit is reached. These ash deposits are removable by soot blowing. At times, with certain coals, the sintering of ash is very strong, making it difficult to dislodge the deposits with soot blowing.

Slagging and fouling are interlinked. When the furnace slags, the ash deposits reduce the heat transfer and raise the gas temperatures which, in turn, cause more fouling.

Slagging and fouling characteristics have profound influence on sizing the furnace and SH/RH. When a particular coal is highly fouling, the furnace volume should be increased to get the gas temperatures low enough not to cause slagging. Figure 3.15 illustrates the effect. Another solution is to have gas tempering (GT) in which low-temperature flue gas from ECON exit is introduced below the furnace outlet. These measures are expensive.

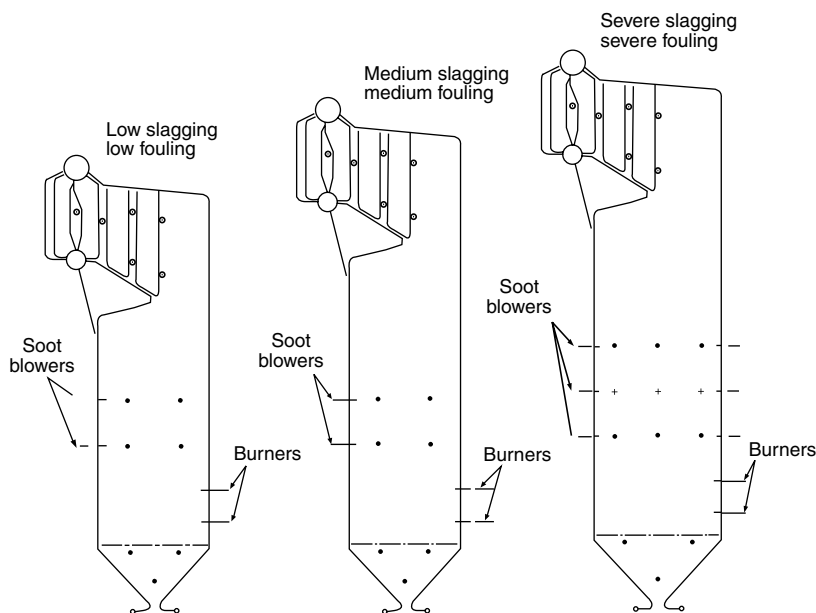


FIGURE 3.15
Effect of slagging and fouling on furnace size and soot blower location.

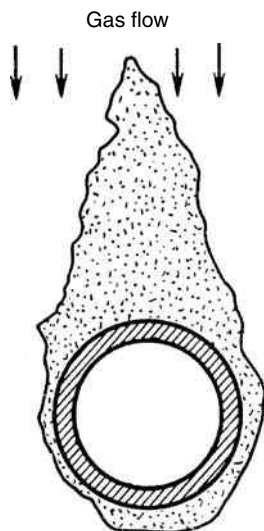


FIGURE 3.16
High-temperature sintered ash deposits.

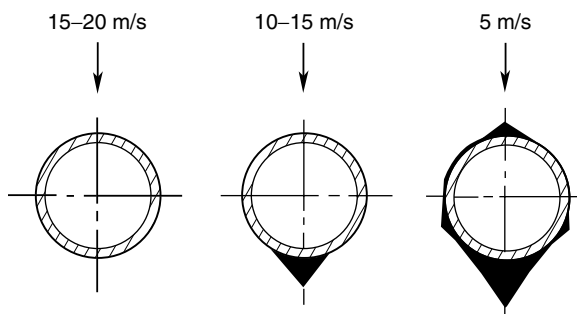


FIGURE 3.17
Low-temperature friable ash deposits downstream building upstream of the tube and decreasing with gas velocity.

Slagging and fouling are controlled by the following:

1. Furnace dimensions
2. SB locations
3. Spacing and bank depth selection of the SH and RH banks.

Besides the ash fusibility and viscosity the following ratios also affect slagging and fouling properties.

- *Base–acid ratio* between 0.4 and 0.7 is a low fusibility range and ash has a higher slagging potential.
- *Silica–Alumina ratio* ranges from 0.8 to 4.0. At >2.8 the fluid temperatures decrease.
- *Iron–calcium ratio* is the ratio of $\text{Fe}_2\text{O}_3/\text{CaO}$. Among the five basic oxide compounds Fe and Ca are the most important and abundant. Fe_2O_3 constitutes 5–40% and CaO constitutes 2–30%. Between 10 and 0.2% the ash fusibility is markedly lower.

Loose deposits in the low-temperature zones, like first-stage SH or ECON with gas temperatures $<600^\circ\text{C}$, ash in flue gas is in solidified form and does not stick to the tubes but forms a friable deposit, which is easily blown away by the action of SBs.

Ash deposits build on the front side of the tube in case of slagging and fouling, whereas it forms on reverse side for the friable deposits. Also, these deposits are velocity governed—less on higher velocities and more on lower velocities. Hence, very low gas velocities of ~ 5 m/s are not recommended (Figures 3.16 and 3.17).

3.5.1.3 Ash Corrosion

Corrosion is the accelerated destruction of the metal by chemical or electrochemical action of salts. While a more detailed and general description of various types of corrosion in

TABLE 3.32

Approximate Limiting Tube Metal Temperatures for Various Gas Temperatures

Gas temperature (°C)	1300	1250	1200	1150	1100	1050	1000	950	900
Limiting metal temperature (°C)	560	565	570	575	585	595	610	630	650

boilers is presented in Chapter 5, only the external corrosion of tubes due to ash is elaborated in this section.

Ash deposits that form on the high- and low-temperature areas of the boiler are responsible for slagging and fouling and corrosion, although the deposits need not necessarily lead to these problems. Corrosion due to coal ash takes place because of the attack of the molten ash salts in the innermost layer of the ash deposit next to the tube. It is rarely found in SH and RH tubes that contain only dusty deposits. The places of corrosion attack are the following:

- Economizer and airheater (AH), arising from low-temperature corrosion
- Furnace SH and RH areas, caused by high-temperature corrosion

3.5.1.3.1 Low-Temperature Corrosion

Causes for low-temperature corrosion are well understood. Sulfur from coal volatilizes at high temperature and combines with oxygen in air to form SO_2 and SO_3 that pass through the boiler and at low temperatures of $<200^\circ\text{C}$ react with the water vapor to form sulfurous and sulfuric acids that cause corrosion. This is elaborated further in Chapter 6.

3.5.1.3.2 High-Temperature Corrosion

In contrast, high-temperature corrosion of coal ash is not fully understood. The reasons and mechanisms of corrosion are subject to different interpretations. However, there is consensus on the preventive measures to be adopted to avoid the damage. Corrosion is measured by the reduction in tube wall thickness in microns per year.

- Coals with sulfur $>3.5\%$ and chlorine $>0.25\%$ attack SH and RH tubes.
- High tube metal temperatures were thought to cause corrosion, but trouble-free working with several high-temperature SHs has brought about an understanding that the combination of both high gas and metal temperatures causes corrosion. Table 3.32 gives approximate limiting safe metal temperatures.
- External corrosion of SH and RH takes place on the upstream side of the tube.
- Corrosion rates are lower in case of austenitic steels such as 18 Cr–8 Ni as compared to ferritic alloy steels (AS) such as 2.25% Cr–1% Mo.
- Corrosion rates are nonlinear, rising sharply above 620°C metal temperatures and peaking between 680 and 730°C before falling sharply.
- Outlet tubes of radiant SH and RH platens, unlike retractable SBs, experience the highest corrosion rates.

3.5.2 Oil Ash

The distillates are free of ash; the residuals concentrate all the ash (with its metallic compounds) and large part of the sulfur of the crude oil. Even then the ash scarcely exceeds

0.2% by weight. This amount of ash in comparison to coal ash may not be impressive but the problems caused are significant.

- Slagging and corrosion of SH and RH
- Low-temperature corrosion of ECON and AH

Na and V are the most important metallic constituents of ash, as they form complex low-melting compounds and vary from traces to 30% each. Sulfur, the other problematic element, varies from 0.7 to 5%. The melting temperatures are between 250 and 680°C (which coincide with the tube metal temperature range) with no sharp melting point but softening and melting over a wide temperature range. The ash constituents are the same as in coal ash with the addition of V and Ni oxides.

Predicting the slagging and fouling tendencies from ash analysis is largely a matter of experience based on the following:

- Ash quantity
- Na and V levels in ash along with other major constituents and their melting temperatures
- S in ash

With tube metal temperatures restricted to 540°C, progressive fouling of furnace and SH does not occur if the combustion conditions and soot blowing practices are in order.

Sulfur is responsible for corrosion at both

1. High temperature—affecting SH and RH tubes due to low-melting ash deposits, which are corrosive when melted
2. Low temperature—affecting ECON, AH, flues, and dust collector due to sulfuric acid from flue gases

It is important to note that high-temperature corrosion rarely occurs at metal temperatures <600°C. SH operating at 540°C is in danger, as the metal temperatures are in the vicinity of 600°C, and several precautions should include

- Oil treatment to remove V, Na, and S
- Use of additives
- Use of corrosion-resistant alloys and coatings
- Low excess-air operation

Maintaining the metal temperature above the acid dew point, the temperature at which the flue gases are saturated with H_2SO_4 , prevents low-temperature corrosion. Reducing the formation of SO_3 by lowering the excess air and treatment of oil with additives are more positive approaches.

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4

Water Conditioning

4.1 Introduction

A peripheral understanding of water is essential for any boiler engineer. The aim of this chapter is to provide such a simplified overview.

Both water and steam tend to dissolve some amounts of material they come in contact with, forming oxides, hydroxides, hydrates, and hydrogen. To protect the equipment, it is essential that water chemistry is controlled. This is done in two stages. Water is first subjected to *treatment* to make it suitable for admitting into the boiler. In the second stage, its dissolved gases are removed and it is turned alkaline as required to convert it into feed water (FW). In its passage from FW to boiler water and thereafter to steam, water is *conditioned* suitably by dosing various chemicals at appropriate places to prevent it from (1) forming scales, (2) causing corrosion, and (3) contaminating steam.

Water conditioning takes place within the boiler island, and naturally, it is what concerns the boiler engineer most. The engineering aspects are given greater stress, with water chemistry as the backdrop.

Boiler failures due to water have substantially reduced over time because of the use of superior water chemicals and better processes, and also because of much deeper understanding of water–boiler interfaces. Simultaneously, the guidelines evolved with the consensus of various interested groups, such as the users, manufacturers, and independent bodies, for the FW and drum water limits for different types of boilers operating at various pressures have greatly simplified water chemistry. If the suggested water limits are properly maintained, pressure part failure is rare.

The responsibility of the boilermakers is to provide the guidelines for FW and boiler water in line with the steam purity requirements of the turbine maker, taking into account the materials of construction and heat fluxes. The duty of the station chemist is to procure a suitable plant and evolve appropriate conditioning as demanded by the power station or process plant.

4.2 Water and Boiler

Water is the raw material converted in the boiler into the end product—steam. The quality or purity of steam is only as good as the quality of input FW and its conditioning in the boiler. In its passage through the boiler, water

- Is heated
- Undergoes phase modification from liquid to vapor
- Is superheated after becoming steam

The change of phase takes place over several cycles in the evaporator circuit in a sub-critical drum-type boiler only, whereas it happens in one shot in a once-through boiler, which therefore demands water of even greater purity. In power plants, the turbine maker decides the steam purity acceptable based on the following criteria:

- The metallurgy of casing and rotor
- The clearances of internal parts in the turbine
- The planned maintenance program

As the turbine inspection intervals lengthen, the steam purity requirements become more stringent.

4.2.1 Effects of Water on Boilers

Water, although adequately treated, harms the boilers in three ways, unless it is *conditioned* suitably:

1. *Corrosion*
2. *Scaling*
3. *Carryover*

4.2.1.1 Corrosion

Corrosion is

1. The dissolution of the metal
2. The formation of an insoluble product (e.g., an oxide)

In both cases, corrosion arising from the interaction of a metal with its environment weakens the metal, leading to a failure in due course. In case of metal oxide, deposited at the site or carried over to another location, heat transfer is impeded or flow restriction is created, which leads to overheating and subsequent failure.

4.2.1.2 Scaling

Scaling is the deposition of impurities carried with FW inside the tubes. Like the metal oxide layer, a scale also can impede the heat transfer or cause flow restriction, both of which lead to tube failure due to overheating.

Scaling can also lead to corrosion by shielding the underlying metal from the protective chemicals in water and steam.

4.2.1.3 Carryover

Carryover is the entrainment of minute water particles along with steam during steam separation, carrying solid, liquid, and gaseous impurities of water, thereby reducing the purity of the steam. Carryover arises from increased

1. Concentration of dissolved and suspended solids in drum water
2. Steam–water disengagement speed

The solids, thus carried over, then deposit as thin scales

- In the superheater (SH) tubes, leading to failure due to overheating
- On the turbine blades, leading to a loss of output

4.2.2 Types of Water

Several types of water are used in a power or process plant, and it is necessary to understand the differences correctly.

- *Raw water.* Water received at the premises of the users regardless of any previous treatment. The sources may be a river, lake, well, mine water, and so on.
- *Treated water.* Water that has received treatment at the premises of the users.
- *Softened water.* Water whose hardness has been removed substantially.
- *Condensate.* Condensed steam returned from a power or process plant without mixing with any other water.
- *Demineralized water.* Water nearly freed from total ionizable dissolved solids by passing through ion exchange materials.
- *Feed water.* Water passing through the feed pumps or ejectors containing any mixture of the above-mentioned waters.
- *Boiler water.* Water in the boiler with steaming in progress.
- *Makeup water.* Water added to the system to compensate for losses.

4.2.3 Water Treatment

The objective of water treatment, combining the external treatment and internal conditioning, in one word is cleanliness—*cleanliness of the wetted parts*. This, in turn, facilitates the production of clean steam, which keeps the boiler, piping, and turbine protected.

External water treatment is done before water is fed into the boiler and is differentiated for a better clarity from the internal *water conditioning* within the boiler island.

- *Water treatment* is the process of making the raw water from any natural source, such as a river, well, or lake, suitable for feeding into a boiler. It converts *raw water* to *FW*.
- *Water conditioning* is the dosing of appropriate chemicals at proper places to the treated water to prevent damage to the internal surfaces of a boiler and make the steam suitable for a turbine or process.

Water treatment consists of the following stages:

1. *Clarification* (sedimentation followed by filtration)—to remove suspended solids
2. *Softening* or *demineralization*—to remove hardness and dissolved solids
3. *Degasification*—to eliminate CO_2 and other dissolved gases

Depending on the level of impurities present in raw water and the FW quality required for the boiler, a suitable water treatment process is selected.

Deaeration. Removal of dissolved oxygen, which is a major cause of corrosion, is carried out in a deaerator before water enters the feed pumps. The deaerator is located in the turbine island in a power plant. But in a process plant or cogen plant, where there are no intervening FW heaters (FWH) between the deaerator and the boiler, a deaerator is part of boiler island and the water treatment package is not handled by the boilermakers but by the water treatment companies.

4.2.4 Impurities in Water

The main impurities in water are summarized in Table 4.1.

4.2.5 Water Terminology

At this stage it is necessary to define a few of the common terms of water technology.

- *Hardness* is the soap lather-destroying property of water caused by soluble salts of Ca and Mg. Total hardness is the sum of concentrations of Ca and Mg salts or hardness, each expressed in terms of CaCO_3 .

TABLE 4.1

Major Impurities in Water and Their Effects and Removal

Item	Description	Effects	Removal
1. Hardness	Ca and Mg salts as CaCO_3	Formation of scales	S, DM, internal treatment, surface agents
2. Alkalinity	HCO_3^- , CO_3^{2-} , OH as CaCO_3	Foaming, carryover, embrittlement, CO_2 in steam causing corrosion in condensate lines	S, DM, HX softening, dealkalization by AX
3. Free acids	HCl, H_2SO_4 , and so on, as CaCO_3	Corrosion	Neutralization with alkalies
4. CO_2		Corrosion in steam and condensate lines	A, Da, neutralization with alkalies
5. SO_4^{2-} ^a		Formation of CaSO_4 scales	DM
6. Cl^- ^a		Adds to corrosive nature of water	DM
7. Na^+ ^a		Corrosion by combining with OH	DM
8. SiO_2		Scale in band insoluble deposits in T	Adsorption in high basic AX in DM
9. Iron and Mn	Fe^{++} (ferrous), Fe^{+++} (ferric)	Deposits in B and water lines	A, F, lime S, CX, surface-active agents
10. O_2		Corrosion in B, HX, and water lines	Da, Na_2SO_3 , corrosion inhibitors
11. DS		Foaming	S, CX by HX, DM
12. SS		Deposits in B, HX, and water lines	F
13. Oil		Excessive foaming and hence carryover	Dual media or activated carbon filtration

Abbreviations: S, softener; DM, demineralizer; Z, zeolite; A, aeration; Da, deaeration; F, filtration; AX, anion exchanger; CX, cation exchanger; TS, total solids; DS, dissolved solids; SS, suspended solids; B, boiler; T, turbine; HX, heat exchangers.

^a Adds to solids.

Alkaline hardness. If the total alkalinity is greater than the total hardness, the hardness is alkaline hardness caused by HCO_3 , CO_3 , and OH . This is also known as *temporary* hardness or *carbonate* hardness.

Nonalkaline hardness. If the total alkalinity is less than the total hardness, the hardness alkalinity is nonalkaline hardness caused by chlorides, sulfates, and nitrates. This is also known as *permanent* hardness or *noncarbonate* hardness.

- *Alkalinity* is the concentration of alkaline salts present in water measured by titration. Bicarbonate, carbonate, and caustic alkalinity are caused by HCO_3 , CO_3 , and OH , respectively.

Total alkalinity is the sum of the above-mentioned alkalinities in terms of CaCO_3 and is known as M-reading.

Dealkalization is the removal of bicarbonates by ion exchange.

- *Dissolved solids* are the solids in water that would be left behind if all the water was evaporated.
- *Suspended solids* are removed by filtration, coagulation, and sedimentation.

Demineralization or *deionization* is the partial or virtually complete removal of the dissolved solids by treating water in both anion and cation exchangers.

- *Amines* are the organic derivatives of NH_3 categorized as volatile and neutralizing types.

Volatile amines remain volatile in steam.

Neutralizing amines are cyclohexylamine and morpholine that are used for neutralizing CO_2 in condensate and raising pH of FW and boiler water.

Filming amines are octadecyclamines that protect condensate lines by forming a film.

- *Low solids treatment* for the makeup water is employing the demineralizer (DM) water so that the dissolved solids are removed entirely from the chemicals used in the boiler water conditioning.

Zero solids treatment of makeup water is employed only when volatile chemicals are used in boiler water conditioning.

The following three processes must be understood by boiler engineers in proper detail, along with the steam purity requirements of the downstream equipment and process:

1. Deaeration
2. Water and steam conditioning
3. Carryover

4.3 Deaeration and O_2 Scavenging

Deaeration is the removal of dissolved gases, notably oxygen, from water. Dissolved gases cause many corrosion problems. Pitting caused by O_2 (localized corrosion leading to pits) is particularly dangerous because the pits can lead to failure of parts under pressure, even if pitting is not widespread or not much material loss has taken place (Figure 4.1). Ammonia (NH_3) readily attacks Cu and Cu-bearing alloys.

Deaeration can be achieved by either mechanical separation or chemical reaction. The practice in the industry is to adopt the following two consecutive steps:

1. Mechanical separation in hot condition, which is very effective, reliable, and cheap
2. Chemical reaction, which is called scavenging, to remove the traces

4.3.1 Deaeration

Deaeration is done primarily by heating the incoming water, consisting usually of condensate and makeup (and at times certain waste streams in process plants), by low-pressure steam to its saturation temperature when around 98% of dissolved gases separate from water and vent out. Figure 4.2 gives the solubility of O_2 in water. The solubility levels decrease dramatically as the saturation temperature is approached. As even small traces of O_2 are exceedingly corrosive to the feed lines and economizer (ECON), a thorough scrubbing of water is necessary to make it completely free of O_2 . So the deaerators provide a combination of heating and scrubbing and manage to remove all the dissolved O_2 . Scrubbing action is performed inside a deaerator by any of the following, with progressively increasing scrubbing efficiency and reducing steam consumption:

1. Spray
2. Tray
3. Spray and tray arrangements

In scrubbing action, the following two factors are at work:

1. Water droplets are reduced in size so that the trapped gas has to travel smaller distance to reach the periphery.
2. Surface tension and viscosity are lowered to make it easier for the gas to escape.

Steam is the medium for heating the incoming water as it is readily available in a plant, and there is no wastage as the condensed steam is mixed with water. The flow streams of steam and water are in opposite directions in counterflow arrangement for higher heat transfer. Pressure-type deaerators employed in power and process plants deaerate water

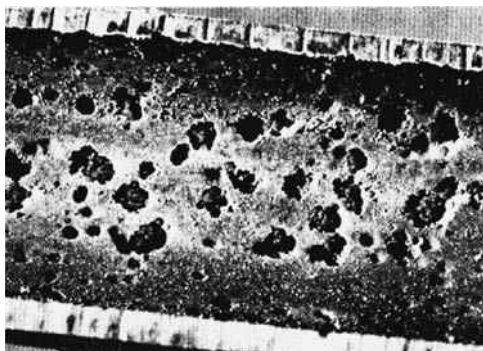


FIGURE 4.1
Failure due to oxygen pitting.

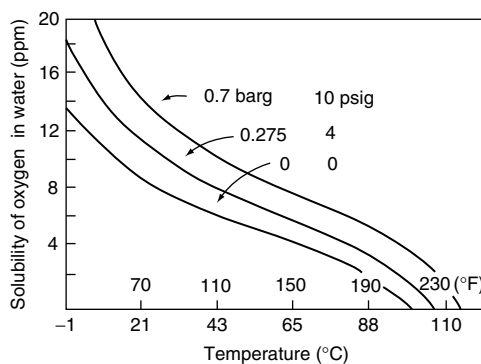


FIGURE 4.2
Solubility levels of oxygen in water.

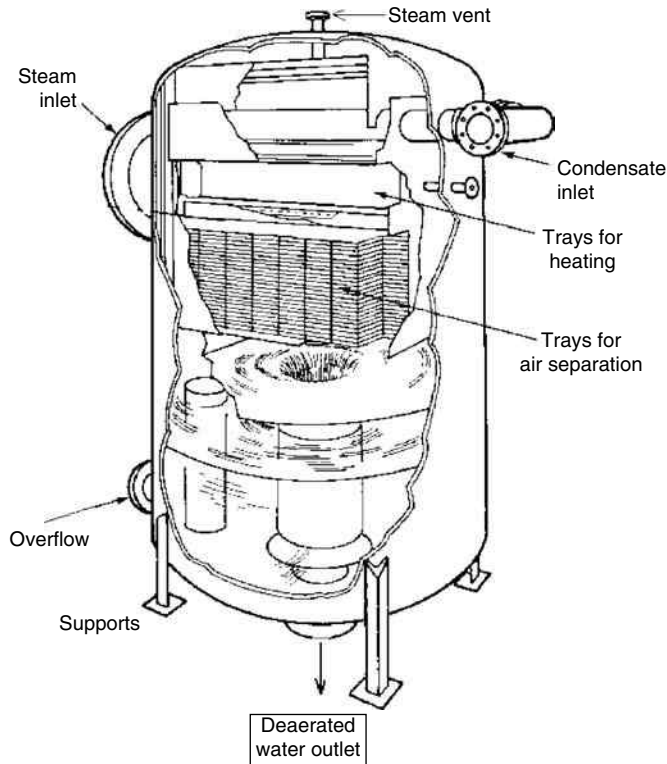


FIGURE 4.3
Spray- and tray-type vertical deaerator without feed tank.

to the extent of <0.005 cc/L or 0.007 ppm (7 ppb) of O_2 with steam vent loss of $<1\%$ inlet steam by weight. A healthy tall plume of ~ 1 m of steam and air from the vent will ensure proper removal of oxygen from a deaerator.

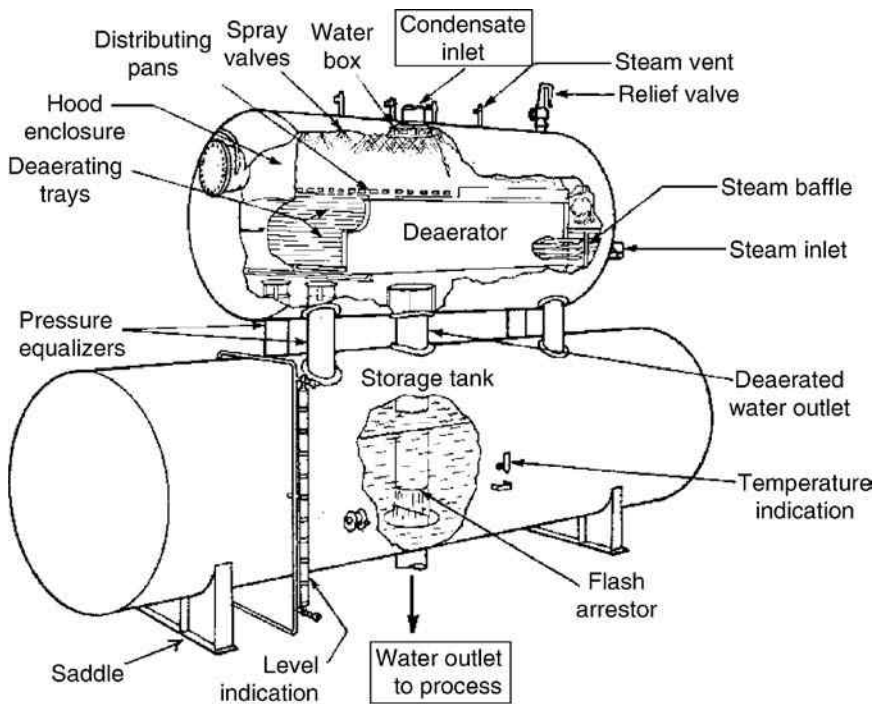
Deaerators can be vertical or horizontal to suit the space and head room. They are mounted on feed tanks, which provide storage as desired, 10–20 min being normal in a power plant.

The shell is made of carbon steel (CS), but the internals that come in contact with gases are of stainless steel (ss), to withstand the corrosion of oxygen. The spring-loaded nozzles of a deaerator are the heart of the system, as they provide the desired shape of spray with required fineness of particles. They are the proprietary items of a manufacturer.

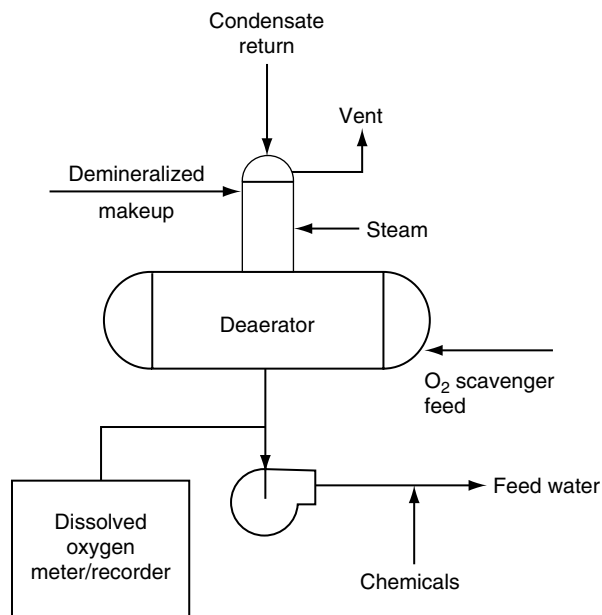
Figures 4.3 and 4.4 show the two types of deaerators—vertical and horizontal—both having spray and tray arrangements for high efficiency and reduced steam consumption. The vertical deaerator here is shown without the tank.

A typical deaerator is shown in Figure 4.5. The deaerators have mainly two limitations:

1. They can remove many dissolved gases of the condensate but not the large quantities of dissolved gases found in the waste streams of many industrial plants.
2. Although free CO_2 is removed entirely, only a small part of the combined CO_2 is released in the deaerator and the bulk is released with the steam in the boiler. Thereafter it is dissolved in the condensate, causing corrosion. This can be controlled by using neutralizing or filming amines.

**FIGURE 4.4**

Spray- and tray-type horizontal deaerator mounted on feed tank.

**FIGURE 4.5**

Schematic arrangement of a deaerator.

4.3.2 O₂ Scavenging

Removal of last traces of oxygen is done by chemical scavengers such as sodium sulfite (Na₂SO₃) or hydrazine (N₂H₄).

4.3.2.1 Sodium Sulfite (Na₂SO₃)

For boilers operating at pressures <70 bar, catalyzed Na₂SO₃ is the most common O₂ scavenger due to its following features:

1. Low cost
2. Ease of handling
3. Nonscaling properties
 - Na₂SO₃ with or without the catalyst is an efficient and fast O₂ scavenger even at low temperatures. But at higher temperatures like 100°C, the reaction is really rapid. For every rise of 10°C the speed of reaction doubles.
 - The reaction proceeds rapidly at pH values between 9 and 10.
 - Na₂SO₃ added to the solids in boiler water increases the carryover, unlike hydrazine, which turns eventually into N₂ and H₂O. This addition is unsuitable where spray attemperation is to be done on steam unless it can be fed beyond the point from which FW for desuperheating is taken.
 - Theoretically, 7.88 ppm of pure Na₂SO₃ is required for each ppm of dissolved O₂. But for technical-grade catalyzed Na₂SO₃, it is appropriate to consider 10 ppm or 10 kg/1 kg of O₂ present in FW.
 - Na₂SO₃ should be dosed only on a continuous basis to achieve complete O₂ removal. Intermittent feeding is not recommended except for low-pressure systems.
 - Fe, Cu, Co, Ni, and Mn are among the most effective materials for acting as catalysts for Na₂SO₃. Typically catalyzed Na₂SO₃ can reduce O₂ nearly completely in 10 s whereas plain Na₂SO₃ can take even 10 min to reduce O₂ from 9.8 to 6.6 ppm.
 - Where ECONs are used, sulfite residuals of 10–15 ppm with pH > 8.3 are recommended for protection against O₂ attack.

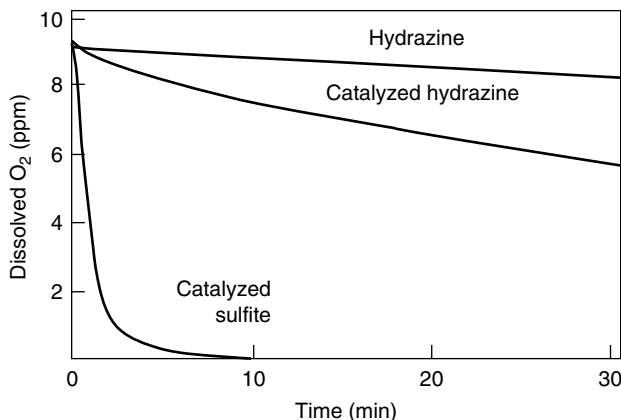
4.3.2.2 Hydrazine (N₂H₄)

For boilers operating at pressures >70 bar, hydrazine is preferred to sulfite as

1. Hydrazine adds no solids to the boiler water.
2. Na₂SO₃ can decompose at higher pressures to form H₂S and SO₂ that can cause corrosion of return condensate system.

As pure hydrazine has low flash point, a 35% solution is used. Theoretically, 1 ppm of hydrazine is required to remove 1 ppm of dissolved O₂ but in reality is between 1 and 1.5 ppm.

- With higher water temperatures and pressures, hydrazine is preferred to Na₂SO₃ although it is much slower because it adds no solids to boiler water. Hence it is well suited to spray attemperator application.
- An added advantage is its ability to passivate Fe- and Cu-bearing surfaces.

**FIGURE 4.6**

Effectiveness of O₂ scavengers.

- Organically catalyzed NH₄, with reaction times speeded 10 to 100 times and with passivating properties also enhanced, is in a position to extend application to a medium pressure of 45 bar.
- Concern about cancer-producing properties dictates extremely careful handling.
- Another concern is the breakdown of hydrazine into ammonia, which is highly corrosive to Cu and Cu-bearing alloys, and a very careful control of the dosage is required.
- Reaction with O₂ depends on the water temperature, pH, and impurities. Figure 4.6 compares the speeds of reaction of Na₂SO₃ and N₂H₄ and the effect of catalyzed N₂H₄.

Substitutes for O₂ scavengers available in the market must be examined closely before using.

4.4 Water and Steam Conditioning

4.4.1 Feed Water

After being duly treated and deaerated, water gets pumped into the boiler as FW, which is heated in the ECON until it reaches the drum. Boilermakers and institutions responsible for water standards in various countries have evolved standards for FW and boiler water over the years, which, if maintained without any lapse during operation, would ensure trouble-free and long life. Table 4.2 gives typical recommended general limits for boiler FW by American Society of Mechanical Engineers (ASME). These recommendations cover the drum water limits as well. Each leading code, such as BS and DIN, has its own recommendations similar to ASME. It is to be noted that depending on the type of boiler, furnace heat flux, and the metallurgy adopted, the limits are further modified by boilermakers for a particular boiler. It is then the responsibility of the station chemist to ensure that the FW quality as specified by the boilermaker is strictly adhered to.

These points regarding FW are to be followed:

- The impurities should be so restricted that the limiting values in boiler water are achieved without excessive blowdown.

TABLE 4.2

ASME Guidelines for Water Quality in Modern Industrial Water Tube Boilers for Reliable Continuous Operation

Boiler Feed Water		Boiler Water					
Drum Pressure				Total Hardness	Silica	Total Alkalinity	Specific Conductance
In barg (approximate)	In psig	Iron (ppm Fe)	Copper (ppm Cu)	(ppm CaCO ₃)	(ppm SiO ₂)	(ppm CaCO ₃)	(μΩ/cm) (Unneutralized)
0.0–20.7	0–300	0.100	0.050	0.300	150	700	7000
20.7–31.0	301–450	0.050	0.025	0.300	90	600	6000
31.0–41.4	451–600	0.030	0.020	0.200	40	500	5000
41.4–51.7	601–750	0.025	0.020	0.200	30	400	4000
51.7–62.0	751–900	0.020	0.015	0.100	20	300	3000
62.0–69.0	901–1000	0.020	0.015	0.050	8	200	2000
69.0–103.5	1001–1500	0.010	0.010	0.000	2	0	150
103.5–138	1501–2000	0.010	0.010	0.000	1	0	100

- Where spray attemperation is employed, silica and solids should be as low as possible. Total solids should be <3 ppm to prevent deposition in SH and <0.1 ppm with austenitic section in SH.
- Spray water silica limit is <0.02 ppm when the boiler is feeding a turbine.
- The dissolved O₂ obtained by physical deaeration must be invariably supplemented by chemical O₂ scavenging. Na₂SO₃ can be used in boilers operating up to 125 barg and where there is no spray attemperation.

For other cases, N₂H₄ is used. It should be remembered that hydrazine is toxic and hence prohibited in hospitals and food manufacturing industries where steam may come in contact with food or beverages.

- pH should be within the range of 8.5–9.2 with Cu alloy FWH and 9.2–9.5 with steel FWH.

Some major impurities found in FW and their impact on various boiler surfaces are given in Table 4.3.

4.4.2 Boiler Water

As steam gets separated from the boiler water, the impurities are left behind, and the boiler water attains a reasonably high level of concentration of impurities and chemicals, which needs to be controlled. This is in order that the

1. Carryover of minute amounts of water particles is restricted by not allowing priming and foaming to take place in the drum.
2. Solids inevitably carried over by the water particles are only in miniscule amounts.

There are established guidelines, such as the ASME recommendations, for efficient use of boilers and piping evolved over a long time by both boilermakers and users. ABMA also provides guidelines that are essentially the same as ASME's (Table 4.4).

TABLE 4.3

Major Impurities in Feed Water and Problems

Item	Form	Source	Feed System	Economizer	Boiler	Superheater	Turbine	Condensate System
CaCO ₃	Sludge	Ca hardness			x			
	Scale	Ca hardness	x	x	x			
CaSO ₄	Scale	Ca hardness			x			
CaSiO ₃	Scale	Ca hardness			x			
		SiO ₂						
CaPO ₄	Sludge	Ca hardness			x			
	Scale	Ca hardness	x	x	x			
Mg(OH) ₂	Sludge	Mg hardness			x			
MgSiO ₃	Sludge	Ca hardness	x	x	x			
		SiO ₂						
Acid Cl	Solution	Cl			x			
Fe oxide	Sludge, scale	Corrosion products			x			
SiO ₂	Scale	SiO ₂			x		x	
Oil	Soap and oil bound sludge	Contamination			x	x	x	
O ₂	Corrosion products	Feed water	x	x	x	x		x
CO ₂	Corrosion products	Free CO ₂ from CO ₃ , HCO ₃	x	x				x

TABLE 4.4

ABMA Standard for Boiler Water Concentrations for Natural Circulation Boilers for Minimizing Carryover

Drum Pressure		Boiler Water		
In barg	In psig	Total Silica ^a (ppm SiO ₂)	Specific Alkalinity (ppm CaCO ₃)	Conductance (μΩ/cm)
0.0–20.7	0–300	150	700	7000
20.7–31.0	301–450	90	600	6000
31.0–41.4	451–600	40	500	5000
41.4–51.7	601–750	30	400	4000
51.7–62.0	751–900	20	300	3000
62.0–69.0	901–1000	8	200	2000
69.0–103.5	1001–1500	2	0	150
103.5–138	1501–2000	1	0	100

^a This value will limit the silica of the steam to 25 ppb as a function of selective vaporization of silica. Specific conductance is unneutralized. 2 ppm = 1 mg/N m3.

4.4.3 Boiler Water Conditioning

The purpose of conditioning treatment is to

1. Prevent scale formation inside pressure parts (PPs) from small amounts of hardness and other impurities of FW
2. Remove traces of dissolved O₂
3. Maintain correct chemical balance in boiler water

The four main types of conditioning treatments adopted are as follows:

1. Phosphate-hydroxide treatment (conventional phosphate treatment) for drum pressures up to 70 bar
2. Coordinated phosphate treatment for pressures >70 bar
3. Chelant treatment for pressures up to 100 bar
4. Volatile treatment for pressures >140 bar

4.4.3.1 Conventional Phosphate Treatment

This treatment is most popular with industrial boiler plants as it suits pressures up to 70 bar and consists of

- Maintaining a pH of 10.5–11.2 with excess OH
- Converting the hardness constituents as flocculent precipitate, which is blown off

Orthophosphate residuals are maintained between 20 and 60 ppm as PO_4 and hydrate alkalinity between 200 and 400 ppm as OH. At pressures >70 bar, these alkalinity levels are too high; hence, this method is unsuitable for boilers operating in this condition.

4.4.3.2 Coordinated Phosphate Treatment

In this treatment, no free caustic is maintained. Phosphate concentration as a fixed relation to boiler water pH is maintained. A molar ratio of 3:1 for $\text{Na}^+:\text{PO}_4^{3-}$ is achieved for trisodium phosphate. If the molar ratio is kept at 2.6:1 (congruent phosphate conditioning), free NaOH does not form. The treatment chemicals are a combination of tri- and disodium phosphates. This treatment is suitable for boilers operating over 70 bar, as caustic corrosion is a serious concern at higher pressures.

The pH correction is done by altering the ratio of tri- and disodium phosphates. To increase the pH, trisodium phosphate is increased. Figure 4.7 illustrates the two regimens of treatment.

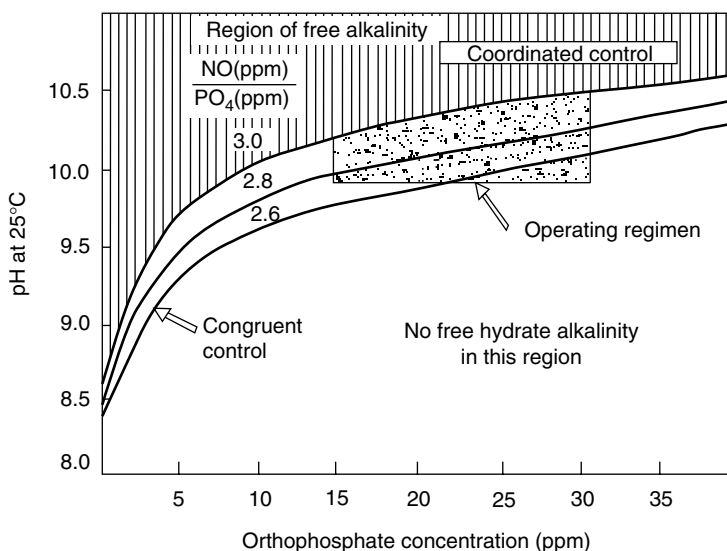


FIGURE 4.7

Operating regimes for coordinated and congruent treatments for pressures from 70 to 110 bar.

4.4.3.3 Chelant Treatment

Organic agents react with residual divalent metal ions, Ca, Mg, and Fe in the FW to form soluble complexes, which are then removed by blowdown. Chelant treatment provides much cleaner boiler surfaces than precipitation treatment. Chelant treatment requires FW to be low in hardness (<2 ppm), which demands softened or DM water. Sodium salts of ethylene diamine-tetraacetic acid (EDTA) and nitriloacetic acid (NTA) are the two most common boiler water chelating compounds. Both the chelants are susceptible to thermal degradation and hence are fed to the FW. Since O_2 hastens the degradation, the FW should be free of O_2 before the chelants are added.

Chelant treatment is capable of providing good scale-free internal surfaces. But the inability to accurately test and control free chelant residuals can lead to overfeeding and subsequent corrosion. Presence of O_2 in boiler water can also lead to excessive chelant corrosion. It is normal, therefore, to add phosphates to the extent of 15–30 ppm to prevent chelant attack during upset conditions caused by HX leakages. Chelant treatment is popular up to a pressure of 100 bar.

4.4.3.4 All-Volatile Treatment

For boiler operating at pressures >140 bar, a *pure water* approach is adopted in which the FW is rendered contamination-free by employing an all-volatile treatment (AVT). All control is directed to FW quality. Corrosion and deposition are kept under check by elimination of all chemicals likely to cause problems, namely, hardness, salts, alkalinity, and so on. The operation is with *zero solids* in boiler water, which naturally gives pure steam output. If there is contamination of FW, there is a possibility of excessive corrosion as the buffering ability of the boiler water is absent. Also the deposits are much harder to remove. Only NH_3 and N_2H_4 are added to the boiler water for pH control between 9.2 and 9.4.

4.4.4 Sludge Conditioning

Anionic polymers are used for sludge conditioning because of their easy removal. The polymer molecules wrap around the suspended boiler sludge, which enhances the fluidity. They also aid in inhibiting scale formation and removing the existing scale. Lignin is the least effective controller.

4.4.5 Boiler Blowdown

Integrated with the boiler water conditioning, blowdown is carried out to discharge the sludge and maintain the desired balance of chemicals. There are two blowdowns in a boiler.

1. *Intermittent blowdown (IBD)* is periodically carried out by specially designed full opening valves for removing suspended solids and sludge in boiler water. It is most effective when operated for brief periods with valve at full open condition, typically once in a shift. It is also called dirty blowdown because it contains sludge. No heat recovery is possible.
2. *Continuous blowdown (CBD)* is achieved by finely regulated micrometer valves and measured by an orifice plate for controlling total dissolved solids (TDS) in boiler water in lower pressures and silica in higher ranges. Heat recovery is possible.

$$\text{CBD as percentage of MCR} = \frac{\text{solids in FW}}{\text{maximum permissible solids in boiler water} - \text{solids in FW}}$$

4.4.6 After-Boiler Protection

In addition to the dissolved O_2 , FW invariably contains CO_2 and traces of NH_3 . The latter is insufficient to cause problems of overconcentration or prevent CO_2 reaction with steam in the formation of carbonic acid in condensate. Natural alkalinity from NaZ treatment is the source of CO_2 .

Cyclohexylamine, morphiline, and diethanolamine are most commonly used amines in industrial practice for corrosion inhibition in the after-boiler section by neutralizing the condensate pH, whereas it is performed by NH_3 and NH_4 in utilities. A filming amine, normally octadecylamine, is commonly used alone or in combination with the neutralizer. Volatilization of these amines at different points in the system gives a wider protection of the steam and condensate lines. The condensate pH is typically maintained in the range of 7.5–8.5.

Filming amines are used to establish a continuous protective film over the after-boiler surfaces, which prevents the contact of potentially corrosive steam and condensate constituents with the interiors of system components. They are added directly into the steam headers. A filming amine program is less costly than a neutralizing amine program.

In NH_3 and N_2H_4 combination, the hydrazine scavenger breaks down to form NH_3 and N_2 and serves as a neutralizer, counteracting the carbonic acid formed when CO_2 dissolves in condensate. NH_3 and N_2H_4 treatment

- Is an all-volatile approach, mainly suited for high-pressure boilers
- Minimizes the introduction of organic compounds into the system
- Affords condensate pH control at a minimal cost

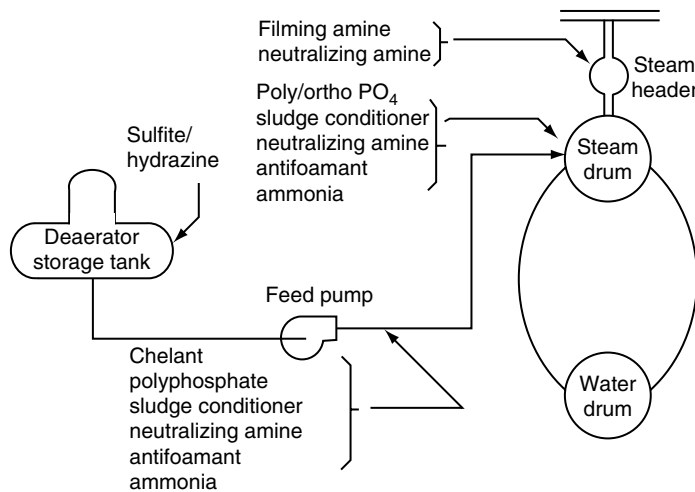
However, excessive NH_3 leads to corrosion due to enhanced pH of the condensate.

4.4.7 Chemical Dosing

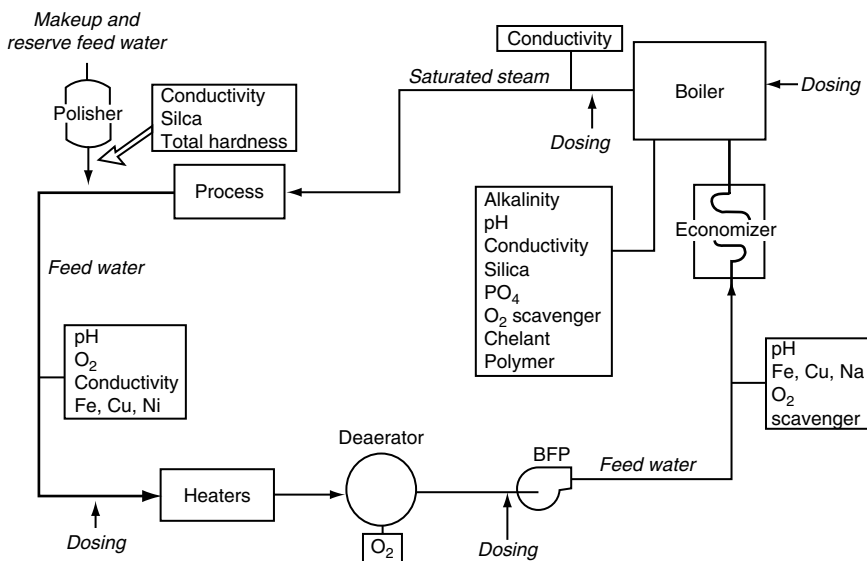
Chemicals are dosed in the boiler circuit at two points (Figure 4.8), and measurements done at several places (Figure 4.9):

1. Before the feed pump at low pressure
2. Into the drum at high pressure
 - a. *Low-Pressure (LP) dosing.* LP dosing of chemicals, upstream of boiler feed pump (BFP) at the discharge of the deaerator, is done with a view to condition the FW to the required levels before the FW enters the ECON or drum. The external water treatment followed by deaeration would have made the FW nearly conform to the limits. LP dosing is done for
 - i. pH correction by dosing NH_3
 - ii. O_2 scavenging to remove the final traces by dosing Na_2SO_3 usually for pressures <70 bar and N_2H_4 for pressures >70 bar (sometimes up to 125 bar)
 - iii. Boiler water conditioning by chelant dosing if chelant treatment is adopted
 - iv. Boiler water conditioning by NH_3 and N_2H_4 dosing if AVT is adopted after boiler protection by amine dosing

- b. *High-Pressure (HP) dosing*. HP dosing of chemicals directly into the steam drum is done to
- Raise and maintain the pH of boiler water to prevent corrosion by dosing NH_3
 - Form soft sludge of the suspended solids that can be intermittently blown down (blow off) by dosing phosphates
 - Condition sludge for better and easier removal by dosing sludge conditioner
 - Prevent buildup of foam inside the drum, which contributes to increased carryover by dosing antifoamants.

**FIGURE 4.8**

Chemical dosing in a boiler plant.

**FIGURE 4.9**

Dosing and measurement points.

4.5 Carryover

Carryover from a drum is the entrainment of contaminants in steam—solid, liquid, or vapors. It consists mostly of boiler water droplets with solids—both suspended and dissolved. Silica is carried over in vaporous form. It is necessary to distinguish between steam purity and quality:

- *Purity* is the amount of contaminant leaving the drum, measured in parts per million.
- *Quality* is the amount of moisture in steam, measured as dryness.

Although the contaminants are in all three phases, steam purity is reported as the carryover of solids. This is because the solids are the most troublesome due to their scale-forming tendency. Solid and liquid impurities are, therefore, water droplets containing mostly Na salts with minor amounts of Ca, Mg, Fe, and Cu. Gaseous constituents found in steam at <130 bar pressure are NH_3 , N_2H_4 , CO_2 , N_2 , SO_2 , SiO_2 , and amines, of which only SiO_2 is troublesome. The others only interfere with steam purity measurement.

Carryover of solids results in deposit formation in SH, stop and control valves, and turbine. It can also contaminate the process streams and spoil the product quality. SH deposits cause tube overheating and lead to failure. Deposits in turbine control valves can cause turbine overspeeding, which is dangerous. Turbine efficiencies can drop by as much as 5% due to the scaling on the blades.

Low-pressure process steam can accept dry steam, and 99% dryness or steam quality is the norm if there is no need to feed a turbine. Decades ago, this was the industry standard until the concept changed from steam quality to steam purity at the initiative of the turbine makers, as better performance and lower turbine maintenance could be assured. The steam purity limit was fixed at 1 ppm maximum. This is still the norm as the boiler-makers find it difficult to execute guarantees with the commercial instrumentation at site, although boilers with well-designed and proven drum internals routinely deliver well below 0.1 ppm of solids. But in modern high-efficiency utility turbines, with much closer tolerances and longer intervals for overhauls, 1 ppm guarantee is found to be unacceptably high. Various utilities and turbine makers demand different purity levels, sometimes almost zero solids, which is impractical. However, there is a consensus with regard to the main offender, namely, silica, the requirement of which is restricted to 0.02 ppm or 20 ppb. As steam expands in the turbine and approaches the saturation point, silica tends to separate out and deposit on the blades. These insoluble deposits on the turbine blades in the medium- and low-pressure zones start affecting the output and, at times, cause vibrations, requiring costly outages for total dismantling and cleaning. At <20 ppb, these deposits could be avoided. The current steam purity standards, though varying somewhat, are built around purity levels that would ultimately deliver silica of <20 ppb. This, together with 0.03 ppm or 30 ppb of solids in steam, is acceptable in most applications to ensure uninterrupted service from SH and turbine.

Carryover is the result of mechanical, chemical, design, and operational factors:

1. *Mechanical*. Minute inefficiency of steam separators, which is inevitable, leakage in separators, high water level, and so on
2. *Chemical*. High solid concentration, excessive alkalinity, presence of oil and other organic contaminants, and the property of silica to evaporate at high pressures

3. *Design*. Higher loading of the separators and greater speed of separation at the steam–water interface
4. *Operational*. High water levels in the drum caused by foaming and priming

4.5.1 Steam Separators

Steam separation in a modern water tube boiler, from a large body of vigorously circulating steam–water mixture (ranging over 5–50 times of the steam output or higher, depending on the boiler pressure) in the confines of a small drum, is a complicated process. The efficiency of separation under steady-state conditions is $>99.999\%$. The turbulence in the drum can throw up slugs of water into the steam space causing priming, because of sudden pressure and flow caused by disturbances, leading to a rise in water levels in the drum.

Steam separation from drum water is effected in two stages.

1. The primary separation is either by centrifugal action as in vertical (Figure 4.10) or horizontal cyclones or by inertial action as in deflection baffles (Figure 4.11), where steam is separated from a large body of water. A large density difference (115 at 15 bar and 20 at 70 bar) coupled with abrupt changes of direction in inertial separators or violent centrifugal action in cyclones separates steam from water effectively.
2. The secondary separation, called steam scrubbing or steam drying, involves separation of small traces of water from large amounts of steam. This is accomplished by providing a large contact surface with flow changes or interceptions as in corrugated baffle plates or demisters. The action is steam *adsorption* due to its affinity to steel. Velocities are kept low to help steam adsorption and prevent re-entrainment.

The deflection baffle plate for guiding the steam from riser tubes to the primary steam separators and the secondary scrubbers are all of bolted construction to permit the periodic inspection of the internal surface of the drum. It is of utmost importance that this assembly is manufactured and installed with great care to prevent any leakage of drum water into steam space.

This two-stage steam separation is very effective. So, when higher purity levels are desired, the solid contents of drum water are reduced.

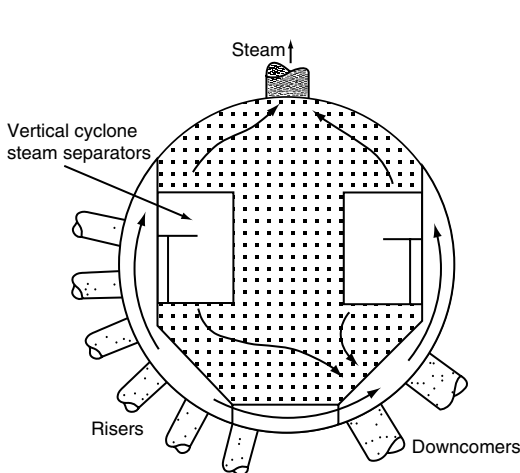


FIGURE 4.10
Centrifugal steam separation.

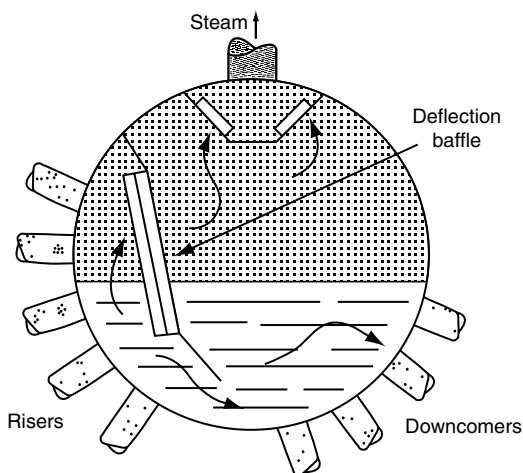


FIGURE 4.11
Inertial steam separation.

Recommended Silica in Boiler Water (ASME, 1975)

Drum Pressure		Silica
In psig	In barg (approximate)	In ppm (maximum)
<300	<20	150
301–450	21–30	90
451–600	31–40	40
601–750	41–50	30
751–900	51–60	20
901–1000	61–70	8
1000–1500	71–100	2
1501–2000	101–140	1

Careful placement of drum internal pipes for dosing, blowdown, and FW distribution is very important to avoid disturbance to the water levels, which can provoke carryover. Drum sizing is important because it can accommodate all the separators and provide adequate volume for reasonable water level fluctuations inevitable in plant operation.

The reader can refer to Section 7.2.1.2 on boiler fabricated parts for additional description on steam separators.

4.5.2 Silica in Boiler Water

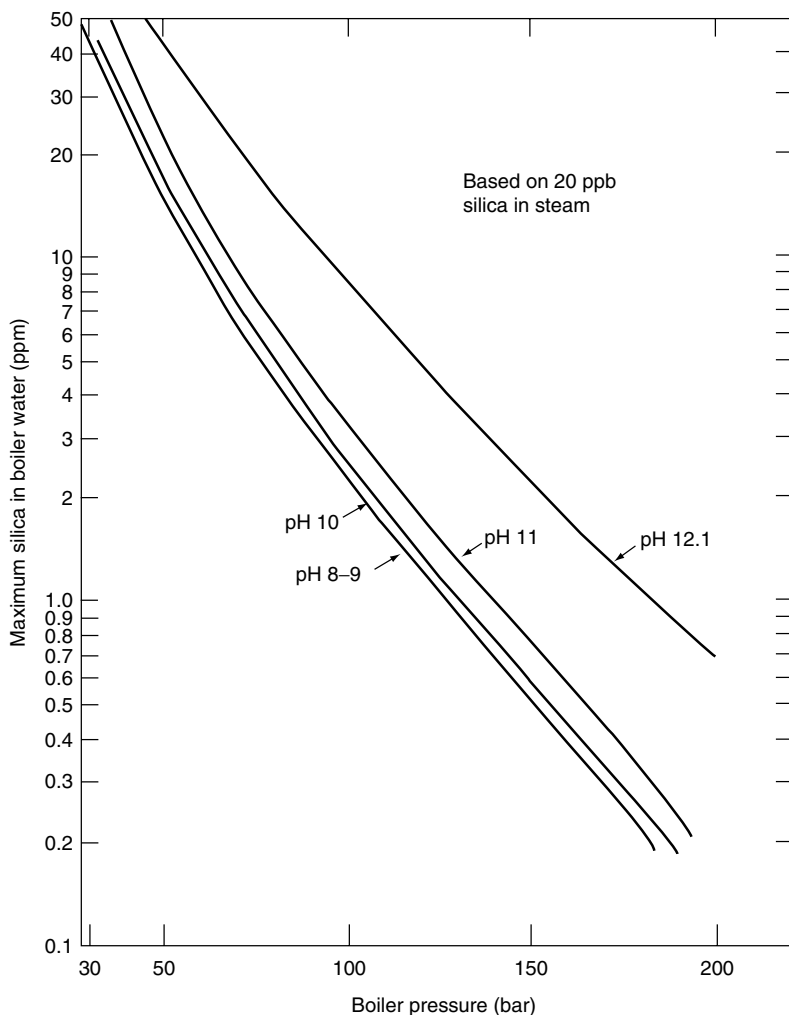
At pressures >80 bar, silica has a tendency to evaporate with steam, thus escaping its capture in steam separators. Selective vaporous carryover of silica can occur at a boiler pressure as low as 30 bar. The only way is to reduce the silica content in drum water. Accordingly, at high pressures, monitoring silica level gains precedence over TDS. Recommended levels of silica in boiler water to obtain 15–20 ppb of silica concentration in steam as per ASME 1975 are given in Table 4.5. Figure 4.12 captures the pH values of the boiler water for higher pressures up to 200 bar.

4.5.3 Loading of Steam Separators

Steam separators in boiler circulation systems provide *water-free steam* to SH and *steam-free water* to downcomer circuits. At higher boiler pressures, the amount of water in circulation reduces. Sizing of drum cyclones is governed by the capacity of

- Water flow at low pressures
- Steam flow at higher pressures

Steam release rates per meter length of drum increase at higher pressures and can vary from 6 tph/m at 10 bar to 20 tph/m at 70 bar and even 60 tph/m at 200 bar for the same diameter of drum depending on the fuel, boiler pressure, type of boiler, and number of separators fitted inside. For pressures >130 bar, the sizing of steam separators is very critical to ensure that no overloading takes place, which can result in higher carryover.

**FIGURE 4.12**

Permissible concentrations of silica in boiler water at various pressures and pH values.

4.5.4 Foaming and Priming

4.5.4.1 Foaming

Steam bubbles routinely keep bursting at the steam–water interface in the drum, causing small water droplets to get entrained into the steam. This interface is the normal water level in the drum or the interface in the steam separators. As the steaming rate increases, a point is reached when the steam bubbles reaching the surface are more than the bubbles bursting, which results in foaming, usually caused when the limits in the drum are exceeded for

- Total and suspended solids
- Alkalinity
- Oil
- Phosphates

Foaming results in an increased carryover as the steam moving toward the outlet tends to carry more particles, since the water level is higher due to foam. Further, as the water level along the drum length is uneven, depending on the locations of level indicators and controls, incorrect feeding of water can aggravate the problem by further increasing the carryover. It is interesting to note that the factors mentioned earlier have been found in the boilers experiencing foaming, but on many occasions, foaming has not taken place in spite of their presence.

4.5.4.2 Priming

Priming is a condition in which slugs of water enter from the drum to the steam outlet due to a combination of:

- Sudden lowering of drum pressure
- Increase in steaming rate
- Foaming tendency

Another factor may be spouting of submerged riser pipe. The water level is raised and the steam space is reduced, leading to the cloud of water droplets and foam to be raised close to the steam outlet. In such conditions, priming occurs and there is excessive moisture in the steam because of the spouting or surging of boiler water. *Note:* Priming is not caused by boiler water conditions but by increased water level. Operating the boiler properly with the specified feed and boiler water conditions is a way to eliminate priming and foaming problems.

4.5.5 Steam Purity Measurement

There are basically two types of steam purity measurements in commercial practice, both amenable to on-load continuous measurements by which peaks and surges can be detected and recorded.

1. Conductivity method for purity levels >0.5 ppm of solids
2. Sodium flame photometer for very accurate measurements of total solids at levels as low as 0.001 ppm or 1 ppb

Steam sampling has to be treated as an integral part of steam purity measurement and must be carefully carried out to derive correct results.

- Sampling lines have to be small bore pipes as short as possible.
- They should preferably be made of ss to prevent the addition of any corrosion products to the sample.
- Reference should be made to ASME PTC 19.11-1997—Steam and water sampling, conditioning and analysis in the power cycle, as it describes the sampling and measurement procedures in proper detail.

4.5.5.1 Conductivity Method

Pure steam and water are nonconductors of electricity. As the impurities increase, the conductivity increases. One part per million of solids impurities in steam corresponds to a conductivity of $\sim 0.55 \mu\text{S/cm}$ ($1 \text{ ppm} = 2 \mu\text{S/cm}$). Commercial purity levels of <1 ppm are very well addressed by this simple, inexpensive, and online measuring system. The only

precaution required is to avoid the ingress of dissolved gases, particularly CO_2 and NH_3 , which interfere with the reading. Degassing devices are available. Per ppm of NH_3 and CO_2 , the conductivity reading is approximately 8 and 5, respectively, much higher than it is for dissolved solids (between 1 and 2), thereby materially affecting the readings. To correct the readings, no direct measurement of individual constituents is possible. But the data can be obtained indirectly by analyzing the boiler water for various constituents and apportioning the solids in steam in the same ratio. The impurities in steam are derived entirely from the boiler water only.

4.5.5.2 Na Flame Photometry

Traces of Na are present in boiler water and in the condensed steam samples in the same proportion as their respective dissolved solids. By measuring them in a photometer and analyzing the boiler water for the solids, it is possible to determine accurately the solids in the steam. Accuracy levels of 6 ppb of solids are claimed by suppliers for portable units that can be used on site. Each 0.1 ppm of Na in steam contains ~ 0.3 ppm of solids.

4.5.5.3 Gravimetric Method

Gravimetric methods measure purity by carefully collecting a large amount of condensed sample of steam, evaporating it to dryness, and measuring the residue. This is slow, requires a careful handling, and does not lend itself to routine or online measurement.

4.5.5.4 Throttling Calorimeter

Another outdated method for dryness of steam is the throttling calorimeter. A sample of saturated steam is expanded through a short orifice into atmospheric pressure and the temperature is measured. The difference between the theoretical and the actual superheats represents the moisture in steam evaporated. Solid content in steam is deduced from the solids in the boiler water. The accuracy is only $\pm 2\%$ moisture that can work out to as high as ± 7 ppm of solids.

Further Readings

ASME PTC 19.11-1997—Steam and water sampling, conditioning, and analysis in the power cycle.

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Strauss, D.S., Keen, S., and Puckorius, P., 1987, Boiler water treatment for low and moderate-pressure plants, *Power*, Special Report, June.

Water Treatment for Industrial Boilers by Babcock and Wilcox Co., Power Generation Division.

5

Boiler Materials

5.1 Introduction

A core boiler, excluding the firing equipment, is mainly built with several high-temperature materials, namely steels and refractories, with structural steels used for support and sheet materials for air and gas transport.

Refractories, heat-facing materials, are steadily being replaced by more steel for easier O&M. There is, however, a comeback of sorts for the refractory materials, with the rise of circulating fluidized bed combustion (CFBC) boilers where they are required in large quantities for furnace and cyclone lining.

Thus, the materials used in the construction of boilers comprise a variety of steels and refractories. Little nonferrous material is used for the outer surface, except aluminum sheet. A boiler is generally made of steel rounds in the form of tubes, pipes, and headers. Even the drums and reheater (RH) headers are rounds rolled from plates, as their diameters are large. Drums of up to 1100 mm OD are usually made of large seamless pipes.

In addition to tubes and headers, there are plates and strips, castings and forgings, and structural rolled and flat sections. The nonmetallic materials are mainly bricks, refractories, insulation, and lagging (BRIL), most of which are used to cover the boiler.

This chapter covers almost all the materials used in boilers in a systematic and simple manner. The various tables present more data. For further details, the reader may refer to the appropriate standards.

5.2 Boiler Parts

A wide variety of both raw materials and components, besides auxiliary plant and equipment, are required to construct a boiler plant. Materials employed in boiler making can be broadly classified as shown in Table 5.1.

Depending on the type of boiler and its scope, each of the three items in Table 5.1 contributes to ~30 to 40% of the cost of the boiler plant. In a typical industrial plant, the common bought-outs (BOs) are often included in the scope of boilers, whereas in larger boilers, item 3c is excluded.

If the BOs are taken out, the boiler is primarily steel and BRIL, with steel divided into boiler steels and structural steels for items 1 and 2, respectively. With the exception of aluminum sheets required for cladding the boiler, there is no requirement for nonferrous materials.

TABLE 5.1

Parts of a Boiler

S. No	Item	Description	Consisting Mainly
1	Pressure parts (PPs)	Pressure-holding parts, mainly FW, drum water, and steam	Drums, tubes, pipes, headers, tanks, forgings, and castings
2	Nonpressure parts (NPPs)	Fabricated items	Structure, flues and ducts, casing and hopper, tubular air heater (AH), cyclones, BRIL
3a	Bought-outs (BOs)	Equipments procured from others	Valves, mountings and fittings, soot blowers, attemperators, fans, electrostatic precipitator (ESP), rotary AH
3b	Firing equipment		Mills, burners, burner management system (BMS), stoker, feeders, air nozzles for fluidized bed combustion (FBC), hot gas generators
3c	Common BOs	Common for the total plant with one or more boilers	Feed pumps, deaerator, ash handling plant, coal handling plant, oil storage, P&H units, gas conditioning skid

Note: BRIL stands for bricks, refractory, insulation, and lagging.

5.3 Boiler Steels

Boiler steels are of high-quality characterized by low carbon and high weldability, high consistency, definite high-temperature properties, and a long history of satisfactory usage. They are manufactured and tested to the specified codes.

All the boiler steels should be procured only from code-approved manufacturers, and code recognition comes only after stringent and periodic verification regarding compliance to the set standards for manufacturing processes, stage inspections, and documentation. The machines, the work procedures, the inspection stages, and even workmen such as welders must be qualified individually. Thus, all the pressure part (PP) materials in a boiler must come from fully recognized sources and meet minimum set patterns conforming to a defined quality.

All boiler PP materials are invariably provided with material test certificates (TCs) in which the material source and all appropriate tests at various manufacturing stages of steel, as outlined in the code are detailed. Usually, the TCs, so prepared by the steel maker, are further certified by an independent third-party agency to confirm the reliability of the reports supplied by the manufacturer.

All steels used in making various parts of a boiler and all stage inspections are recorded as specified by the code, in the designated formats to finally create a manufacturing TC. The manufacturing and material TCs together capture the entire history of a PP.

All this effort is taken because the PPs made from various steels have to withstand a lot of pressure safely at high temperatures, without any leakage or rupture. The manufacturing and material certificates of all boiler parts are compiled as the PP documentation of the boiler. It is then submitted to the code-approved authorities or insurance companies for the mandatory registration of the boiler, prior to commercial operation. A comprehensive documentation for each and every PP is created this way so that the history of a failed part may be traced should any failure occur during the boiler operation.

Today we have almost taken for granted the safety of PPs in boilers, operating even at highest pressures and temperatures. This safety may be attributed to the stringent quality measures evolved at all stages of manufacture of raw steels and components, together with the meticulous documentation at every stage.

TABLE 5.2

Steel Forms Required for Various Pressure Parts

Type of Pressure Part	Raw Steel Required
Drums and reheater header	Plates
Coils for superheater, reheater, economizer	Tubes
Boiler bank	Tubes
Membrane, division wall panels	Tubes and strip
All headers and large-bore downcomers	Large bore pipe
All integral piping	Small bore pipes/tubes
All nozzles including on headers and drums	Forgings

Various PP assemblies and the raw steels required are given in Table 5.2. Thus, the PP material requirements are as follows:

- 1. Plates
- 2. Tubes
- 3. Pipes
- 4. Forgings
- 5. Castings (occasionally)

The mean metal temperature range of 450–480°C is the rough dividing line for carbon steels (CS) and alloy steels (AS).

Boilers require a variety of steels, starting from low-strength low-carbon steels to high-strength high-alloy steels and even stainless steel (ss) for various parts. However, with the success of 9Cr–1Mo–V steels, the use of ss has considerably reduced. The limiting temperature and the strength required are the main factors that decide the appropriate metallurgy. The pattern of a steady progression from carbon to ss is as follows.

Carbon steels	Low carbon High carbon
Alloy steels	C–Mn/C–Mo steels 1 1/4% Cr–1/2 Mo steels 2 1/4% Cr–1% Mo 9Cr–1Mo–V
Stainless steels	

The boiler design codes specify which steels are required.

5.3.1 Boiler Quality (BQ) Plates

Boiler quality plates are required to withstand high pressure and temperature: high pressure in drums, high temperature in RH outlet headers, and both high pressure and temperature in superheater (SH) headers made from plates. The most important requirements of BQ plates are as follows:

- Consistency and uniformity of properties across the length, width, and thickness of the plate
- High purity of steel
- No inclusions or air pockets

These requirements make BQ plates not easy to roll by all mills, particularly in higher thicknesses. Boiler quality plates are characterized by the following:

- Low carbon content for good weldability
- High tensile strength to limit drum thicknesses
- Fully killed (deoxidized)
- High thicknesses

There are three categories of plates available with progressively increasing tensile strength:

1. Carbon steel (low, medium, and high carbon)
2. Low-alloy steel
3. High-alloy steel

Plate selection. The metal temperature and the strength required are the prime considerations.

- In the American boiler-making practice, CS is favored, even with increasing carbon ($\sim 0.35\%$), resulting in thicker drums, as opposed to the European practice of adopting low-carbon low-alloy plates ($\sim 0.25\%$) of higher strength, which yield thinner drums that are more conducive to faster boiler dynamics.
- High-carbon steel plates of both SA 515 and SA 516 are extensively used in the industry. For lower thicknesses up to 40 mm, coarse-grained steel of SA 515 of suitable grade is used, whereas for thicknesses up to 100 mm, fine-grained steel of SA 516 is generally preferred.
- For even higher-pressure applications, SA 299 in CS and SA 302 in AS are popular to contain the thickness.
- High-alloy steels are of European origin and are generally not found in American standards. With higher alloy content and higher tensile and, more importantly, higher yielding strengths, these high-alloy steels reduce the plate thicknesses dramatically. Table 5.3 lists various American and European plate materials in common use.

Plates are generally procured in normalized condition except in the case of plates used for making dish ends when they are obtained in annealed condition. It is always prudent to subject the plates to magnetic particle and ultrasonic testing thoroughly on arrival in the workshop to eliminate any possibility of inclusions and imperfections. There have been cases when inclusions have been detected at the final stage after the drum has been almost completed, upsetting the entire project schedule because drums have long manufacturing cycles. While ordering drum plates, extra material is to be included as specified by the codes for test coupons required for testing purposes.

5.3.2 Boiler Tubes

As indicated in Equation 1.15, the thickness of a PP is directly proportional to the inside pressure and diameter. In case of drums, the diameter is large, but as the temperature is low, the higher stress values of the plate manage to contain the thickness. For tubes, the case is reversed with metals experiencing the highest temperatures in SH and RH and, consequently, having the lowest stress values. The range of tube materials required in a boiler is therefore far higher than the range for plate materials.

TABLE 5.3
BQ Plates—American Specifications and Equivalents

American Plate Specifications (SA)							British Equivalent (BS 1501)	German Equivalent (DIN 17155)
Plate Specifications	Nominal Composition	C%	Tensile (kpsi)	Yield (kpsi)	Tensile (MPa)	Yield (MPa)		
1. Carbon steels								
285 Gr C	C	0.22	55	29	380	200	161–430	H-11
515 Gr 70	C	0.35	70	38	480	265	224–490	C-Mn
516 Gr 70	C	0.35	70	38	480	265	224–490	C-Mn
299	C	0.30	75	40	515	275	224–490	C-Mn
2. Low-alloy steels								
302 Gr B	1¼% Mn–1/2 Mo	0.25	80	50	550	350	—	15 Mo3
3. Medium-alloy steels								
387 11 cl 11	1¼% Cr–1/2 Mo	0.17	75	45	515	315	Gr 620B	13CrO44
387 22 cl 2	2¼% Cr–1% Mo	0.17	75	45	515	315	Gr 622B	10Cr–Mo9 10
4. High-alloy steels								
NA	—	0.17	80	56	551	386	Gr 271 (DUCOL)	15NiCu–MoNb5 (WB36)
NA		0.19	87	61	600	420		

Notes: Brief details of popular drum plates to American standards are provided here and are compared with the other popular equivalent British and German plates. For accurate and current details, the readers must refer to the latest specifications.

Tensile strength reduces as the plate thickness increases. Tensility given here refers to higher thicknesses. Tensile and yield strength values given are the minimum values. Figures in MPa are rounded off.

The equivalent plate indicated is not an identical material. It is the closest by tensile strength but differs in almost all other major parameters.

Plates of high-alloy steels are popular in Europe. The values given in the table against this item are not for American plates but of Ducol and WB36, respectively. NA, not available.

TABLE 5.4

Differences between Tubes and Pipes

Tube	Pipe
Both heat transfer and conveyance	Only conveyance and not heat transfer
Material amenable for closer bending, as C is lower	Material suitable only for limited bending
Welding is easier due to lower C	
Sizes up to 125 mm OD and hence smaller tubes	Sizes up to 1000 mm and beyond, and hence larger pipes
Designated by outside diameter	Designated by nominal bore (NB) upto 12 in. (304.8 mm)
Closer tolerance on thickness	Larger tolerances

Pipes also experience the same tough conditions as tubes. Because they are outside the gas pass, the temperatures experienced are a little lower.

5.3.2.1 Tubes versus Pipes

Tubes and pipes are not identical. The most important difference is that pipes do not transfer heat. Further differences are mentioned in Table 5.4. Tubes and pipes are manufactured to different specifications and are not interchangeable even in the narrow overlapping range up to 125 mm.

5.3.2.2 Seamless and Electric Resistance–Welded (ERW) Tubes

Boiler tubes are manufactured by two processes, and are classified as follows:

1. Seamless tubes—produced by piercing a red-hot billet with a plunger
2. Electric resistance-welded tubes produced by folding and welding steel strip, called skelp

Both types of tubes are extensively used in boiler making, although certain reservations for ERW tubes are entertained even today based on the ability of the weld seam to withstand the temperatures and tube expansion forces after initial failures a few decades ago when ERW tubes were first introduced. In terms of weldability, bending, and physical and chemical properties, the seamless and the ERW tubes are nearly the same. In fact the ERW tubes are superior and preferred for lower thicknesses, as they are made from plate materials, which render the

- Inside tube surface smooth resulting in lower inside-pressure drop
- Bore concentric to OD, unlike in seamless tubes, and thus better suited for tube expansion
- Lower costs

ERW tubes are well accepted in CS execution. However, ERW tube thickness is limited to ~6 mm for welding and folding considerations of the skelp. Although ERW tubes are made of low-alloy steels and covered in SA 250, their usage is still low.

ERW tubes are used for medium-pressure CS applications in the industrial boilers, whereas the seamless tubes are used for utility boilers and the high-temperature AS tubes for industrial boilers. The European market has an overwhelming preference for seamless tubes.

5.3.2.3 Hot-Finished and Cold-Drawn Seamless Tubes (HFS and CDS)

As the tubes come out of the tube mill, they are hot finished and their tolerance levels are high. For furnace, boiler bank (BB), and economizer (ECON) sections, the slightly higher pressure drop in HFS tubes makes no significant difference. Even in SHs of smaller boilers, the higher pressure drop is of no consequence. Cold-drawn seamless tubes have closer tolerance, and for SH and RH duties in large boilers, tolerance makes a large difference. CDS tubes are produced from HFS tubes by reheating them to the appropriate temperature and rerolling to a closer finish. Naturally, this additional work makes the CDS tubes more expensive. Unless the duty demands, the CDS tubes are not used in boiler making. The hardness of CDS tubes is also higher on account of work hardening.

5.3.2.4 Tubes and Comparison

Carbon, alloy, and occasionally ss tubes are employed in boiler making as shown in Table 5.5. Tubes to American specifications are listed along with the BS and DIN equivalents, which are the other popular globally accepted specifications.

Tubes are rolled in sizes from 12.7 to 127 mm (0.5–5 in.) OD, and almost all sizes from 31.8 mm OD onward are used in boilers. Tubes are always designated by their outside diameters.

5.3.2.5 Selection of Tube Materials

Temperature limits, based on accelerated oxidation, determine the basic applicability of any material. Thereafter, the strength of the material at the operating temperature governs the selection. As shown in Figure 1.7, the permissible stresses, particularly at the low temperatures, do not vary much ($<250^{\circ}\text{C}$ approx.); but at the elevated temperature, they deteriorate sharply beyond 450°C . Each incremental improvement in metallurgy is costlier by 20–40%. The increase in allowable stress level should be more than this incremental cost to justify the superior material and cut down the thickness and the overall cost. Often it does. That is how more expensive materials such as T22 and T91 are used for relatively lower temperatures. A good boiler design has the following features:

- Maximum use is made of low-carbon steels due to their ease of manufacture and repair.
- The thicknesses are kept to a minimum by using superior metals to lower the thermal inertia.
- The use of ss is minimized due to the expense, much higher elongation, susceptibility to stress corrosion, and possible problems arising from welding dissimilar metals.

For very high temperature service, TP 321 has been in use for several years. Improved stress values in the code have made 304H and 347H more popular. TP 316H is required only for very high steam temperatures of $\sim 600^{\circ}\text{C}$.

Table 5.6 lists various commonly used carbon, alloy, and ss tubes and pipes as per different codes with their areas of application in different parts of the boiler.

TABLE 5.5

Boiler Quality Tubes to American Specifications and Their BS and DIN Equivalents

American Tube Specifications (SA)							British Equivalent (BS 3059)	German Equivalent (DIN 17175) for Seamless
Nominal Specification	Temperature Limit (°C)	Tensile (kpsi)	Yield (kpsi)	Tensile (MPa)	Yield (MPa)	Use		
1. Carbon steel								
Low tensile								
178 A (ERW)	510	47	26	324	179	1, 2, 3	ERW 320	St 37.8 (DIN 17177)
192	510	47	26	324	179	1, 2, 3	S1 360	St 35.8
Medium tensile								
210 A-1	510	60	37	414	255	1, 2, 3	S1 440	St 45.8
High tensile								
210 C	510	70	40		276	2, 3		
178 C (ERW)	510	60	37	414	255	2, 3	ERW 440	St 42.8 (DIN 17177)
178 D (ERW)	510	70	40		276	1, 2, 3		
2. Low-alloy steel								
209 T1	524	55	30	379	207	1, 2, 3	S1 243	15 M03
209 T 1A	524	60	32	414		2, 3		
213 T2	552	60	30	414	207	1, 3		
213 T 11	566	60	30	414	207	3	620-460	13CrMo44
213 T 22	602	60	30	414	207	3	622-490	10CrMo9 10
3. High-alloy steel								
213 T 9 1	649	85	60	586	414	3	622 Gr 91	X 10 Cr MoV Nb 9-1
4. Stainless steel								
213 TP-304 H	760	75	30	517	207	3	CFS 304 S 51	X2 Cr Ni \$19-11
213 TP-321 H	760	75	30	517	207	3	CFS 321 S 51	X6 Cr Ni Ti \$18-10
213 TP-347 H	760	75	30	517	207	3	CFS 347 S 51	X5 Cr Ni Nb \$18-10
213 TP-316 H	760	75	30	517	207	3	CFS 316 S 51	X5 Cr Ni Mo \$17-1-22
213 TP-310 H	816	75	30	517	207	3	CFS 310 S 51	

Notes: Safe maximum outside tube wall metal temperatures given here are on the basis of oxidation resistance. Design codes decide the permissible temperature limits. For CS usage beyond 454°C when permitted by the code, special inspection is required for 100% weld efficiency.

In the column pertaining to use, 1 refers to furnace walls exposed to high heat, 2 refers to ECON and other enclosures not exposed to high heat, and 3 refers to SH and RH.

\$ refers to DIN 17456, which is the specification for ss tubes. The equivalents are for basic steels without suffix H. Steels with suffix H are modified to suit high-temperature duties of SH and RH by increasing the carbon content by 0.02%.

Thickness as per SA standards is usually the minimum thickness with no negative tolerance, whereas with BS and DIN, it is the nominal thickness with appropriate negative tolerance.

5.3.2.6 Tube Ordering

Tubes are received in strapped bundles. The individual tubes are stenciled with the specification and are color coded for proper identification. It is not advisable to punch the tubes lest their outer layer should be destroyed, making them susceptible to creep damage. The material codes for tubes and pipes contain both mandatory and optional requirements, covering various testing and supply aspects, which should be mutually agreed upon at the time of order placement for ensuring smooth supply per requirements.

If there are sufficient numbers, tubes can be ordered in any exact length, which saves time and cost in resizing. Tubes for BB can be additionally ordered with ends annealed to ease the tube expansion.

Hydraulic testing (HT) of individual tubes before dispatch from the tube mill is an ideal QA measure, but it costs more time and money. Nondestructive tests such as full-fledged online eddy current testing, which runs along with the tube rolling, are good substitutes for HT besides being cheaper and faster.

Table 5.7 lists the commonly used tubes with their diameters and thicknesses and provides the tube weight in kilograms per meter.

Tube thickness is normally expressed in wire gauge. There are two popular designations, namely, standard wire gauge (SWG) as per British practice and Birmingham wire gauge (BWG) as per American practice. They are similar as can be seen in the comparison in Table 5.8. Note that the thicknesses are in steps of $\sim 10\%$.

TABLE 5.7

Tube Sizes and Weights in kg/m Length

Tube OD	British Standard Wire Gauge (SWG)												
		1	2	3	4	5	6	7	8	9	10	11	12
in.	mm	7.620	7.010	6.401	5.893	5.385	4.877	4.470	4.064	3.658	3.251	2.946	2.642
3/4	19.05	2.149	2.080	1.998	1.912	1.814	1.706	1.607	1.502	1.338	1.266	1.171	1.069
1	25.40	3.343	3.179	2.998	2.834	2.657	2.467	2.306	2.139	1.962	1.775	1.630	1.483
1 $\frac{1}{4}$	31.75	4.534	4.278	4.002	3.855	3.635	3.232	3.008	2.775	2.532	2.286	2.093	1.896
1 $\frac{1}{2}$	38.10	5.728	5.374	5.003	4.682	4.344	3.996	3.710	3.412	3.107	2.795	2.556	2.310
1 $\frac{3}{4}$	44.45	6.923	6.473	6.007	5.604	5.187	4.761	4.410	4.048	3.681	3.304	3.015	2.723
2	50.80	8.117	7.572	7.008	6.526	6.030	5.525	5.108	4.685	4.252	3.812	3.478	3.136
2 $\frac{1}{4}$	57.15	9.308	8.668	8.012	7.451	6.873	6.286	5.807	5.322	4.826	4.321	3.940	3.550
2 $\frac{3}{8}$	60.33	10.138	9.219	8.514	7.910	7.297	6.670	6.158	5.640	5.111	4.577	4.170	3.757
2 $\frac{1}{2}$	63.50	10.502	9.767	9.016	8.373	7.720	7.050	6.509	5.958	5.397	4.832	4.340	3.967
2 $\frac{3}{4}$	69.85	11.697	10.631	10.168	9.295	8.590	7.815	7.208	6.595	5.971	5.341	4.862	4.380
2 $\frac{7}{8}$	73.03	12.293	11.414	10.518	9.758	8.983	8.196	7.559	6.913	6.257	5.594	5.092	4.587
3	76.20	12.891	11.962	11.021	10.220	9.406	8.579	7.910	7.231	6.546	5.850	5.325	4.793
3 $\frac{1}{4}$	82.55	14.082	13.061	12.021	11.142	10.250	9.344	8.609	7.868	7.116	6.358	5.784	5.207
3 $\frac{1}{2}$	88.90	15.276	14.160	13.026	12.64	11.093	10.105	9.308	8.504	7.690	6.867	6.247	5.620
4	101.60	17.665	16.356	15.030	13.911	12.779	11.634	10.709	9.777	8.835	7.887	7.169	6.447
4 $\frac{1}{4}$	107.95	18.856	17.455	16.030	14.833	13.622	12.399	11.411	10.414	9.409	8.396	7.631	6.860
4 $\frac{1}{2}$	114.30	20.050	18.550	17.035	15.755	14.466	13.163	12.110	11.050	9.980	8.905	8.090	7.174
5	127.00	22.439	20.749	19.039	17.602	16.152	14.689	13.511	12.320	11.126	9.925	9.016	8.104
5 $\frac{1}{4}$	133.35	23.630	21.844	20.044	18.524	16.995	15.453	14.210	12.960	11.700	10.433	9.475	8.517
5 $\frac{1}{2}$	139.70	24.824	22.944	21.044	19.450	17.839	16.218	14.912	13.596	12.274	10.942	9.938	8.930
5 $\frac{9}{16}$	141.28	25.125	23.219	21.297	19.679	18.052	16.408	15.086	13.757	12.418	11.070	10.052	9.036
6	152.40	27.12	25.139	23.049	21.293	19.525	17.743	16.310	14.870	13.419	11.959	10.860	9.758

TABLE 5.8

Common Sheet and Tube Thicknesses

Gauge No.	British Standard Wire Gauge (SWG)		Birmingham Wire Gauge (BWG)	
	mm	in.	mm	in.
000	9.449	0.372	10.794	0.425
00	8.839	0.348	9.651	0.380
0	8.230	0.324	8.633	0.340
1	7.620	0.300	7.620	0.300
2	7.010	0.276	7.213	0.284
3	6.401	0.252	6.579	0.259
4	5.893	0.232	6.045	0.238
5	5.385	0.212	5.558	0.220
6	4.877	0.192	5.156	0.203
7	4.470	0.176	4.571	0.180
8	4.064	0.160	4.191	0.165
9	3.658	0.144	3.759	0.148
10	3.251	0.128	3.403	0.134
11	2.946	0.116	3.047	0.120
12	2.642	0.104	2.768	0.109
13	2.337	0.092	2.412	0.095
14	2.032	0.080	2.108	0.083
15	1.829	0.072	1.828	0.072
16	1.626	0.064	1.650	0.065
17	1.422	0.056	1.472	0.058
18	1.219	0.048	1.245	0.049
19	1.016	0.040	1.067	0.042
20	0.9144	0.036	0.8890	0.035
21	0.8128	0.320	0.8128	0.032
22	0.7112	0.028	0.7112	0.028
23	0.6096	0.024	0.6096	0.025
24	0.5588	0.022	0.5588	0.022
25	0.5080	0.020	0.508	0.020

5.3.3 Pipes

Pipes are designated by nominal bore (NB) for sizes up to 304.8 mm (12 in.) and by OD beyond that size. In boilers, pipe materials are used in the following three areas:

1. Headers and downcomers placed inside or outside the gas stream
2. Integral piping, namely, drain, vent, blowdown, soot blower (SB), attemperator, and interconnecting piping
3. Piping for feed water (FW), main steam, and reheated steam

Only seamless piping is used because of both high pressure and high temperature. Pressure pipes used in oil and gas industry, such as line pipes or submerged arc welded (SAW) pipes, are not employed in boilers. Table 5.9 lists the popularly used BQ pipes to American specifications and their equivalents in BS and DIN.

In a boiler, most pipe required is for headers. In industrial boilers of up to 400 tph, the headers fall broadly in the range of 168–760 mm OD with thicknesses from 16–80 mm. Thick headers, like thick drums, are to be avoided because they hinder quick start and shutdown of the boiler. Headers placed in the gas passes are cooled by the water inside.

TABLE 5.9

Boiler Quality Pipes to American Specifications and Their Equivalent BS and DIN Standards

American Specifications (SA)								British Equivalent (BS)	German Equivalent (DIN 17175)
	Nominal Specifications	Temperature Limit (°C)	Tensile (kpsi)	Yield (kpsi)	Tensile (MPa)	Yield (MPa)	Use		
<i>1. Carbon steel</i>									
Medium tensile									
	106 Gr B C(<0.30) ^a	510	60	35	414	241	1, 2, 3	3602 CFS 460	St 45.8
High tensile									
	106 Gr (°C) C(<0.35) ^a	510	70	40	482	276	1, 2, 3		
<i>2. Low-alloy steel</i>									
	335 P1 C- $\frac{1}{2}$ Mo	468	55	30	379	207	2, 3	S1 243	15 M03
	335 P12 C- $\frac{1}{2}$ Mo	566	60	30	414	207	1		
	335 P11 $1\frac{1}{4}$ % Cr- $\frac{1}{2}$ Mo	566	60	30	414	207	1, 2, 3	3604 CFS 620	13CrMo44
	335 P22 $2\frac{1}{4}$ % Cr-1% Mo	593	60	30	414	207	1, 2, 3	3604 CFS 622	10CrMo9 10
<i>3. High-alloy steel</i>									
	335 P91 9Cr-1Mo-V	649	85	60	586	414	1, 2, 3	3604-2 Gr 91	X10CrMoV Nb9-1

Note: In the column pertaining to use, 1 refers to furnace walls exposed to high heat, 2 refers to ECON and other enclosures not exposed to high heat, and 3 refers to SH and RH.

^a Limited to a temperature of 427°C (800°F) and for pipes outside of boiler setting for fear of graphitization by steam.

In utility boilers, the RH headers are thicknesses rolled from plates, as the diameters go beyond the usual pipe rolling range. Table 5.10 lists the pipes by NB and thicknesses (mm) and unit weights (kg/m) as per ANSI.

5.3.4 Pressure Castings and Forgings

For pressure holding, forgings are better suited than castings due to their dense structures that make them lighter. Castings are good for making intricate shapes and thick walls. They are also cheaper to produce because they need no dies, and hence are popular in valve making. Boiler parts of similar to valves can be made of pressure castings. In normal boilers, there are nearly no pressure castings. Table 5.11 lists the castings and forgings to American specifications with their BS and DIN equivalents. In a boiler, forgings are used for making various pressure components such as

1. Nozzles for drum, header, and pipes
2. End closures for headers
3. Pipe fittings such as elbows, bends tees, reducers, expanders
4. Pipe and header attachments such as weldolets, pads, thermowells
5. Special forgings such as tube joints

Because of larger sizes and superior metallurgy, the drum, main steam, and RH header nozzles, together with pipe bends in SH and RH areas, constitute more than 70% of the total value, although they form only ~10% of the total forgings by numbers. Table 5.11 lists the popular pressure castings and forgings to American specifications along with their British and German equivalents.

TABLE 5.10

Pipe Schedules, Thicknesses (mm), and Weights (kg/m) as per ANSI

Nominal Pipe Size (in.)	OD (mm)	5S	10S	10	20	30	STD	40S	40	60	XS	80S	80	100	120	140	160	XXS
1/8	10.30	—	1.42	—	—	—	1.73	1.73	1.73	—	2.41	2.41	2.41	—	—	—	—	—
1/4	13.70	—	0.28	—	—	—	0.37	0.36	0.37	—	0.47	0.48	0.47	—	—	—	—	—
3/8	17.10	—	0.51	—	—	—	0.63	0.64	0.63	—	0.80	0.82	0.80	—	—	—	—	—
1/2	21.30	1.65	0.64	—	—	—	0.84	0.84	0.84	—	1.10	1.12	1.10	—	—	—	—	—
3/4	26.70	0.82	2.11	—	—	—	1.27	1.30	1.27	—	1.62	1.65	1.62	—	—	—	4.78	7.47
1	33.40	1.65	2.11	—	—	—	2.87	2.87	2.87	—	3.91	3.91	3.91	—	—	—	1.95	2.55
1 1/4	42.20	1.65	2.77	—	—	—	1.69	1.71	1.69	—	2.20	2.24	2.20	—	—	—	5.56	7.82
1 1/2	48.30	1.65	2.77	—	—	—	3.38	3.38	3.38	—	4.55	4.55	4.55	—	—	—	2.90	3.64
2	60.30	1.95	3.17	—	—	—	2.50	2.55	2.50	—	3.24	3.29	3.24	—	—	—	6.35	9.09
2 1/2	73.00	2.44	4.01	—	—	—	3.56	3.56	3.56	—	4.85	4.85	4.85	—	—	—	4.24	5.45
3	88.90	2.11	3.05	—	—	—	3.39	3.46	3.39	—	4.47	4.56	4.47	—	—	—	6.35	9.70
3 1/2	101.60	2.11	3.05	—	—	—	3.68	3.68	3.66	—	5.08	5.08	5.08	—	—	—	5.61	7.77
4	114.30	2.11	3.05	—	—	—	4.05	4.13	4.05	—	5.41	5.51	5.41	—	—	—	7.14	10.15
5	141.30	2.77	3.40	—	—	—	3.91	3.91	3.91	—	5.54	5.54	5.54	—	—	—	7.25	9.56
6	168.30	2.77	3.40	—	—	—	5.44	5.54	5.44	—	7.48	7.63	7.48	—	—	—	8.74	11.07
8	219.10	11.55	14.13	—	6.35	7.04	5.16	5.16	5.16	10.31	7.01	7.01	7.01	—	—	—	11.11	13.44
10	273.10	15.09	20.37	—	33.31	36.81	8.63	8.81	8.63	53.08	11.41	19.64	11.41	—	—	—	9.53	14.02
		3.40	4.19	—	6.35	7.80	5.49	5.49	5.49	12.70	7.62	7.62	7.62	—	—	—	14.92	20.39
		23.09	28.34	—	41.77	51.03	11.29	11.52	11.29	81.55	15.27	15.59	15.27	—	—	—	11.13	15.24
							13.57	13.84	13.57	—	7.01	8.08	8.08	—	—	—	21.35	27.68
							16.07	16.40	16.07	—	18.63	19.01	18.63	—	—	—	—	—
							6.02	6.02	6.02	—	8.56	8.56	8.56	—	11.13	—	13.49	17.12
							6.55	6.55	6.55	—	22.32	22.77	22.32	—	28.32	—	33.54	41.03
							21.77	22.20	21.77	—	9.53	9.53	9.53	—	12.70	—	15.88	19.05
							7.11	7.11	7.11	—	30.97	31.59	30.97	—	40.28	—	49.11	57.43
							28.26	28.83	28.26	—	10.97	10.97	10.97	—	14.27	—	18.20	21.95
							8.18	8.18	8.18	10.31	42.56	43.42	42.56	—	54.20	—	67.56	79.22
							42.55	43.39	42.55	—	12.70	12.70	12.70	15.09	18.26	20.62	23.01	22.23
							9.27	9.27	9.27	53.08	64.64	65.95	64.64	75.92	90.44	100.92	111.27	107.92
							60.31	61.52	60.31	12.70	81.55	83.19	81.55	18.26	21.44	25.40	28.58	25.40
							—	—	—	81.55	—	—	—	114.75	133.06	155.15	112.33	155.15

(continued)

TABLE 5.10 (Continued)

Nominal Pipe Size (in.)	OD (mm)	5S	10S	10	20	30	STD	40S	40	60	XS	80S	80	100	120	140	160	XXS
12	323.90	3.96	4.57	—	6.35	8.38	9.53	9.52	10.31	14.27	12.70	12.70	17.48	21.44	25.40	28.58	33.32	25.40
		31.89	36.73		49.73	65.20	73.88	75.32	79.73	108.96	97.46	99.43	132.08	159.91	186.97	208.14	238.76	186.97
14	355.60	3.96	4.78	6.35	7.92	9.53	9.53	—	11.13	15.09	12.70	35.71	19.05	23.83	27.79	31.75	35.71	—
		35.06	42.14	54.69	67.90	81.33	81.33		94.55	126.71	107.39	281.70	158.10	194.96	244.65	253.56	281.70	
16	406.40	4.19	4.78	6.35	7.92	9.53	9.53	—	12.70	16.66	12.70	40.49	21.44	26.19	30.96	36.53	40.49	—
		42.41	48.26	62.64	77.83	93.27	93.27		123.30	160.12	123.30	365.35	203.53	245.56	286.64	333.19	365.37	
18	457.00	4.19	4.78	6.35	7.92	11.13	9.53	—	14.27	19.05	12.70	45.24	23.88	29.36	34.93	39.67	45.24	—
		47.77	54.36	70.57	87.71	122.38	105.16		155.80	205.74	139.15	459.37	254.55	309.62	365.56	408.26	459.37	
20	508.00	4.78	5.51	6.35	9.53	12.70	9.53	—	15.09	20.62	12.70	50.01	26.19	32.54	38.10	44.45	56.01	—
		60.46	70.00	78.55	117.15	155.12	117.15		183.42	247.83	155.12	564.81	311.17	381.53	411.49	508.11	564.81	
22	559.00	4.78	5.54	6.35	9.53	12.70	9.53	—	—	22.23	12.70	53.98	28.58	34.93	41.28	47.63	53.98	—
		66.57	70.06	86.54	129.13	171.09	129.13		294.25	171.09	672.26	373.83	451.42	527.02	600.63	672.26		
24	610.00	5.54	6.35	6.35	9.53	14.27	9.53	—	17.48	24.61	12.70	59.54	30.96	38.89	46.02	52.37	59.54	—
		84.16	96.37	94.53	141.12	209.64	141.12		255.41	355.26	187.06	808.22	422.08	547.71	640.03	720.15	808.22	
26	660.00	—	—	7.92	12.70	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
					127.36	202.72	152.87				202.72							
28	711.00	—	—	7.92	12.70	15.88	9.53	—	—	—	12.70	—	—	—	—	—	—	—
					137.32	218.69	271.21				218.69							
30	762.00	6.35	7.92	7.92	12.70	15.88	9.53	—	—	—	12.70	—	—	—	—	—	—	—
		120.72	150.36	147.28	234.67	292.18	176.84				234.67							
32	813.00	—	—	7.92	12.70	15.88	9.53	—	17.48	—	12.70	—	—	—	—	—	—	—
					157.24	250.64	312.15		342.91		250.64							
34	864.00	—	—	7.92	12.70	15.88	9.53	—	17.48	—	12.70	—	—	—	—	—	—	—
					167.20	266.61	332.12		364.90		266.61							
36	914.00	—	—	7.92	127.0	15.88	9.53	—	19.05	—	12.70	—	—	—	—	—	—	—
					176.96	282.27	212.56		420.42		282.27							
38	965.00	—	—	—	—	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
							244.54				298.24							
40	1016.00	—	—	—	—	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
							236.53				314.22							
42	1067.00	—	—	—	—	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
							248.52				330.19							
44	1118.00	—	—	—	—	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
							260.50				346.16							
46	1168.00	—	—	—	—	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
							272.25				351.82							
48	1219.00	—	—	—	—	—	9.53	—	—	—	12.70	—	—	—	—	—	—	—
							284.24				377.79							

TABLE 5.11
Pressure Castings and Forgings to American Specifications and Their Equivalent BS and DIN Standards

	American Specifications (SA)						British Equivalent (BS)	German Equivalent (DIN)
	Nominal Specification	Temperature Limit (°C)	Form	Tensile (kpsi)	Yield (kpsi)	Tensile (MPa)		
1. <i>Carbon steel</i>								
Med. tensile								
SA 216-WCA	C(<0.25)	510	Casting	60	30	414	1504-430	17245-GS C25
High tensile								
SA 216-WCB	C(<0.30)	510	Casting	70	36	482		
SA 105	C(<0.35)	510	Forging	70	36	482	1503 460-224	17243-17Mn4
2. <i>Low-alloy steel</i>								
SA 182 F12	C- $\frac{1}{2}$ Mo	468	Forging	70	40	482		
SA 336 F12	C- $\frac{1}{2}$ Mo	566	Forging	70	40	482		
SA 182 F11	1 $\frac{1}{4}$ % Cr- $\frac{1}{2}$ Mo	566	Forging	70	40	482	1503-620	17243-13CrMo44
SA 217 WC6	1 $\frac{1}{4}$ % Cr- $\frac{1}{2}$ Mo	593	Casting	70	40	482	1504-621	
SA 182 F22	2 $\frac{1}{4}$ % Cr-1% Mo	602	Forging	75	45	517	1503-622	17243-10CrMo910
SA 217 WC9	2 $\frac{1}{4}$ % Cr-1% Mo	602	Casting	70	40	482	1504-622	
3. <i>High-alloy steel</i>								
SA 182 F 91	9Cr-1Mo-V	649	Forging	85	60	586	1503-2Gr 91	
4. <i>Stainless steel</i>								
182 F304 H	18Cr-8Ni	760	Forging	75	30	517	1503-304	
182 F 316 H	16Cr-12Ni-2Mo		Forging	75	30	517	1503-316	
351 CH 20	25Cr-12Ni	816	Casting	70	30	482		

Note: The tensile and yield strengths are the minimums.

5.4 Structural Steels

All the NPPs of the boiler, mainly the supporting structure and the plate work (flues, ducts, casing, hoppers, pent house, and bunkers), are made from structural steels. These steels are specified in the building codes. In a way there are no stringent requirements to be met as in the case of PP steels, except that as the structures become large, the sections become excessively heavy. Limited suppliers, protracted deliveries, and also much higher specific cost make fabricated sections from plates competitive at times when the welding and handling costs are lower. Structural steels required in a boiler are presented in Table 5.12.

The basic requirements of structural steel are good weldability and strength. Members of the cold structure are required to have adequate notch toughness if installed in very cold climates. Components for hot structures, such as buckstays and sling rods, are many times designed for temperatures $<400^{\circ}\text{C}$ and call for no particular high-temperature properties as for PPs.

Table 5.13 gives the structural material codes to American standards and their nearest BS and DIN equivalents. In all the codes, the basic material grades and their properties are covered in specifications, whereas the dimensions and other related mechanical details of each rolled section are covered in individual standards.

5.4.1 Structural Quality Tubes and Pipes

AH tubes are thin tubes of structural quality in plain CS for main sections or weathering steel for cold sections.

TABLE 5.12

Structural Steels Required in Boilers

Items	Consisting	Material	Main Areas of Application
Rolled sections	Beams, channels, angles, flats	CS	Boiler-, bunker-, and deaerator-supporting structures, stiffeners for ducts, and buckstays
Plates		CS, AS	Column base and top plates, gussets, splices, top suspension girders, AH ends, and PP attachments
Steel sheets	Sheets >4 mm	CS, AS, ss	Flues, ducts, casing, hopper, bunkers, and bunker liners
Coils/thin sheets	Sheets <2 mm, colored	GI, ss	Cladding and expansion joints
Strips		CS, ss	Membrane bars, header and drum attachments, ladders, and platforms
Rounds	Black and bright bars	CS	Foundation bolts, suspension hangers, pipe supports, earthquake restraints, and drum slings
Fasteners		CS, AS	Nuts for foundation bolts, bolts, and nuts for ducts
Pipes		CS	Safety valve, silencer and IBD tank escape pipes, round ducts for air and gas, and hand rails for galleries
Tubes	<76.2 mm	CS, COR-TEN	Airheater main and stay tubes

Note: CS, carbon steel; AS, alloy steel; ss, stainless steel; GI, galvanized iron; COR-TENTM weathering steel.

TABLE 5.13

Structural Steels to American Specifications and Their Equivalent BS and DIN Standards

Designation	Items	American Specifications					BS Specification	DIN Specification
		C (%)	Tensile (kpsi)	Yield (kpsi)	Tensile (MPa)	Yield (MPa)		
A 36	Sections	0.26	58	36	400	250	4360-40- B, C	17000 R St 37.2
A 572 Gr 42	Sections	0.21	60	42	415	290	-43-A, B, C	St 44.2
A 572 Gr 50	Sections	0.23	65	50	450	345	-50-A, B, C	
A 36/572 Gr 50	Sections	0.22	65	50	450	345	-50-A, B, C	
A 53 Gr A	Pipes	0.25	48	30	330	207	3601-S 360	1629 St 37.0
A 53 Gr B	Pipes	0.30	60	35	415	240	430	44.0
A 501	Hollows	0.30	58	36	400	248	4360-40 B 43 D	17120 R St 37.2
	Sections							St 44.3

Note: Indicated tensile and yield strengths are the minimum figures.

The other structural quality steel tubes used in boilers are the pipes for hand railing. Salient points of the AH tubes are as follows:

- AH tubes usually measure 50.8, 63.5, 70 mm, and occasionally even 76.2 mm OD (2, 2 1/2, 2 3/4, and 3 in.), with thickness ranging from 11 to 14 SWG (2–3 mm).
- These tubes are usually in ERW execution and can be ordered in exact lengths with ends annealed if tubes are to be expanded.
- COR-TEN is a trade mark of U.S. Steel Corporation for low-alloy weathering structural steels containing small amounts of Cr, Ni, Si, Ti, Zr, and V, which offers four to eight times corrosion protection over plain CS against a mildly corrosive AH environment.
- COR-TEN is produced in grades A and B. COR-TEN A is preferred for its better resistance to weathering.

5.4.2 High-Temperature Castings

- Although pressure castings are rarely used in boilers except for valve bodies, they are used at several places as NPP high-temperature castings.
- In the form of SH and RH lugs, air nozzles, stoker links, grate castings, or soot blower hangers, high-temperature castings constitute hundreds of pieces of small sizes weighing a few grams to a few kilograms.
- As ash nozzles, ash doors, peep hole doors, or smelt spouts, high-temperature castings may be few and of medium size of ~50 kg or so.
- Big castings are used only in pulverizing mills for rings and balls or wheels.

High-temperature castings can experience temperatures above 550°C. Many of them are proprietary developments not conforming to the material codes entirely. High-temperature castings are of two types: (1) iron and (2) steel.

5.4.2.1 Heat-Resistant Iron Castings

Iron castings are used where the shapes are intricate and there is no welding requirement. Also the castings are not subjected to tensile or alternating forces. Stoker parts, ash doors, peep hole doors, etc., fall in this category. The majority of the iron castings are chrome castings with the compositions shown in Table 5.14.

TABLE 5.14

Typical Composition of Heat-Resistant Chrome and Cr–Ni Iron Castings

Temperature	Composition (%)							Typical Parts
	C	Si	Mn	S	P	Cr	Ni	
<600°C	3.2–3.4	1.5–2.5	0.75–0.85	<0.12	<0.25	0.30–0.70		Ash/furnace doors,
600–700°C	3.2–3.4	1.5–2.5	0.75–0.85	<0.12	<0.25	0.70–1.10		ash spouts
600–700°C	3.0–3.5	1.7–2.4	0.60–1.00	<0.12	<0.4	0.85–1.50		Grate bars–
								heat-resistant
600–700°C	<3.4	1.6–2.0	0.60–1.00	<0.1	<0.2	0.40–0.60	1.00–1.50	Grate parts–heat-
								and growth-
								resistant
600–700°C	3.0–3.5	1.7–2.4	0.60–1.00	<0.12	<0.4	0.60–1.00	0.80–1.50	Grate parts–wear-
								resistant

5.4.2.2 Heat-Resistant Steel Castings

These castings are of three types with increasing temperature-withstanding capabilities. Besides castings, the heat-resistant materials are also available as bars and sheets.

1. *Ferritic steels* are suitable up to 900°C. The principal alloying element is Cr.
2. *Ferritic–austenitic steels* have improved heat resistance and toughness over ferritic steels due to the addition of Ni along with Cr.
3. *Austenitic steels*. Addition of Ni in excess of 9% makes steel of austenitic structure free from transformation. Owing to higher toughness, the steels are relatively insensitive to shock stresses but machining the castings is very difficult.

SH and RH lugs and burner impellers are some of the most highly heated parts in a boiler with temperatures approaching 1500°C where alloys with the following compositions give fairly satisfactory service.

- 25% Cr–12% Ni to A351 CH 20
- 25% Cr–20% Ni to A351 CK 20

Using fuel oils with high V or S shortens life due to corrosion at temperatures above 650°C because the compounds containing Na, V, and S melt at a temperature as low as 565°C. Oil ash in molten conditions is excessively corrosive, demanding even higher alloys such as

- 50% Cr–50% Ni
- 60% Cr–40% Ni

5.5 Fundamentals of Metallurgy

Only the relevant principles of metallurgy of high-temperature materials used in boilers are discussed here. The most pertinent portions are alloying elements and heat treatment processes. A brief overview of classification of steels is given first.

5.5.1 Classification of Steels

Steels can be classified broadly based on the criteria given below:

1. Percentage of carbon
2. Percentage of alloying elements and carbon
3. Amount of deoxidation
4. Grain size
5. Manufacturing method
6. Depth of hardening

5.5.1.1 Percentage of Carbon

Carbon has a profound influence on the properties of steel (Figure 5.1). It has a tendency to

- Increase hardness, tensile strength, hardenability, and fatigue resistance
- Decrease ductility, malleability, toughness, machinability, formability, and weldability

There are three types of steels based on carbon percentage (Figure 5.2), namely

1. Low-carbon steels with 0.008–0.3% C. These are
 - a. Soft, ductile, malleable, and tough
 - b. Machinable and weldable
 - c. Not hardenable by heat treatment

The majority of boiler and structural steels are of this variety.

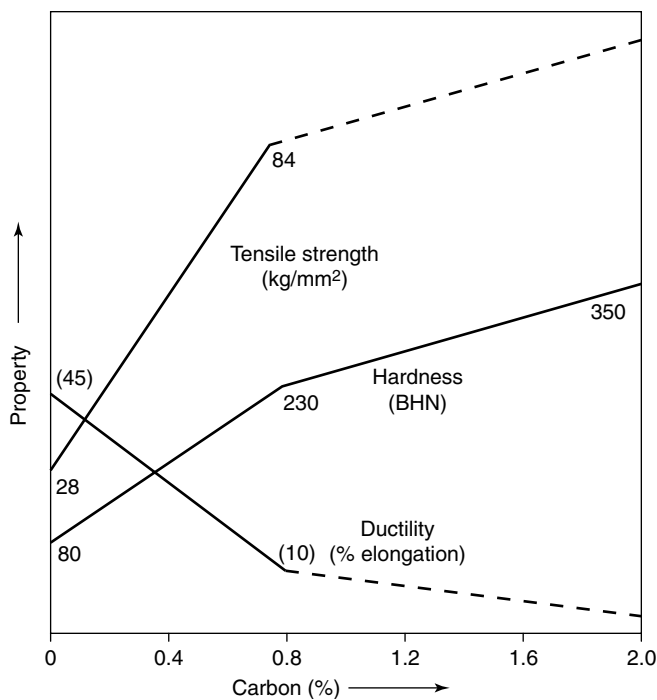
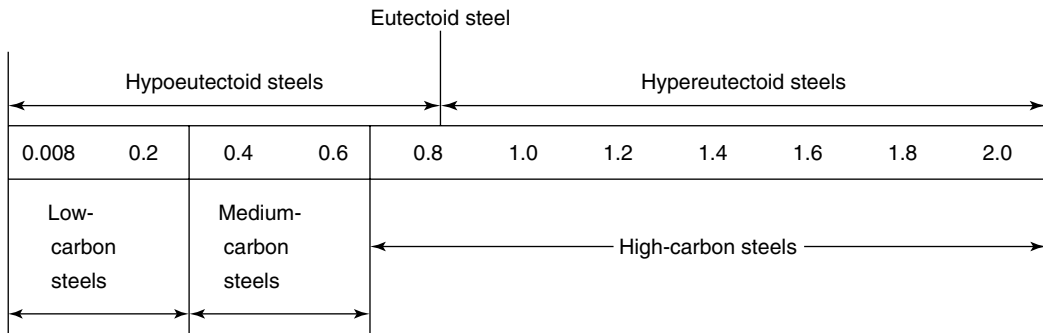


FIGURE 5.1

Effect of carbon percentage on steel properties.

**FIGURE 5.2**

Classification of steel by carbon wt%.

2. Medium-carbon steels with 0.3–0.6% C. They are called the *machinery steels*. They
 - a. Need high cooling rates for hardening and the resulting hardness is not so high
 - b. Are shallow hardening types
 - c. Are difficult to work cold and hence are hot worked

In boilers, the fasteners and shafts are of medium carbon steels.

3. High-carbon steels with 0.6–2.0% C. They are called the *tool steels* and are
 - a. Hard, brittle, and wear-resistant
 - b. Difficult to machine and weld
 - c. Hardened by heat treatment to high hardness level (the depth of hardening is also high)

Their use in boiler practice is limited to auxiliaries such as fans, mills, feeders, shafts, balls, rings, blades, and so on.

5.5.1.2 Percentage of Alloying

To enhance the desired properties, certain metals such as Cr, Ni, W, Mo, Mn, V are added. Based on the alloy content, they are classified as low (<10%) and high (>10%) AS. Together with low-, medium-, and high-CS, there are six types of AS. Effect of alloying elements is described in Section 5.5.2.

5.5.1.3 Deoxidation of Steels

During solidification of molten metal, the dissolved oxygen and other gases come out as CO and are entrapped in the solid ingot, creating undesirable blowholes and inconsistent properties. Deoxidation is an effort to eliminate this effect that results in three types of steel (depicted in Figure 5.3).

- *Rimmed steel*. The gases are trapped at the edge of the ingot, which increases at the bottom. The thin outer *rim* is low in carbon and high in pure iron. It is very soft and ductile. It is also free from blowholes and segregations. Immediately underneath lie the gas entrapments with blowholes. Rimmed steel is cheaper to make and is

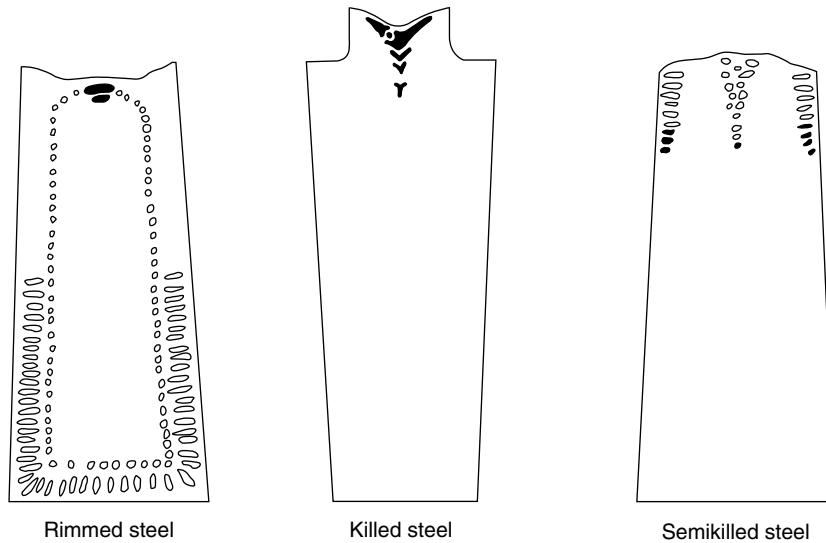


FIGURE 5.3
Classification of steel by deoxidation.

widely used for making structural plates. It is also used for making steel strips for welded pipes. It is good for forming and deep drawing operations but unsuitable for forging or carburizing.

- *Killed steel.* The dissolved oxygen is completely removed by the action of strong deoxidizing agents such as Al, Si, or Mn. Although oxygen is removed, oxides are formed, which result in inclusions. Si and Mn are added in the form of ferrosilicon and ferromanganese. The deoxidizers are added in the hot metal in the ladle before pouring. For killed steel, the big-end-up ladles are used to enable the inclusions to gather as a pipe in the middle of the ingot. Killed steels are used for items required for forging, carburizing, or heat treating. They have more uniform properties but can vary from top to bottom or core to surface of the ingot. Most CS having <0.25% carbon and AS are of killed variety.
- *Semikilled steel.* The deoxidation is partly done. Most semikilled steels have 0.15–0.25% carbon and 0.05% silicon. Semikilled steels are used for plates, sheets, and structurals.

5.5.1.4 Grain Size

Figure 5.4 shows the classical Fe–C diagram, which is fundamental to all explanations in metallurgy.

In the heating cycle, above the upper critical temperature, all grains are of austenite and of the smallest size. Grain size increases as the temperature increases. Depending on the coarsening of grains, the steels are classified as either (1) coarse- or (2) fine-grained. Finer structures produce higher values of tensile and yield strength.

Grain growth sets in earlier for coarse-grained steel than for fine-grained steel. In rimmed steels, coarsening is rather rapid, whereas in killed steels, the fine grains are maintained for a much longer period at higher temperatures.

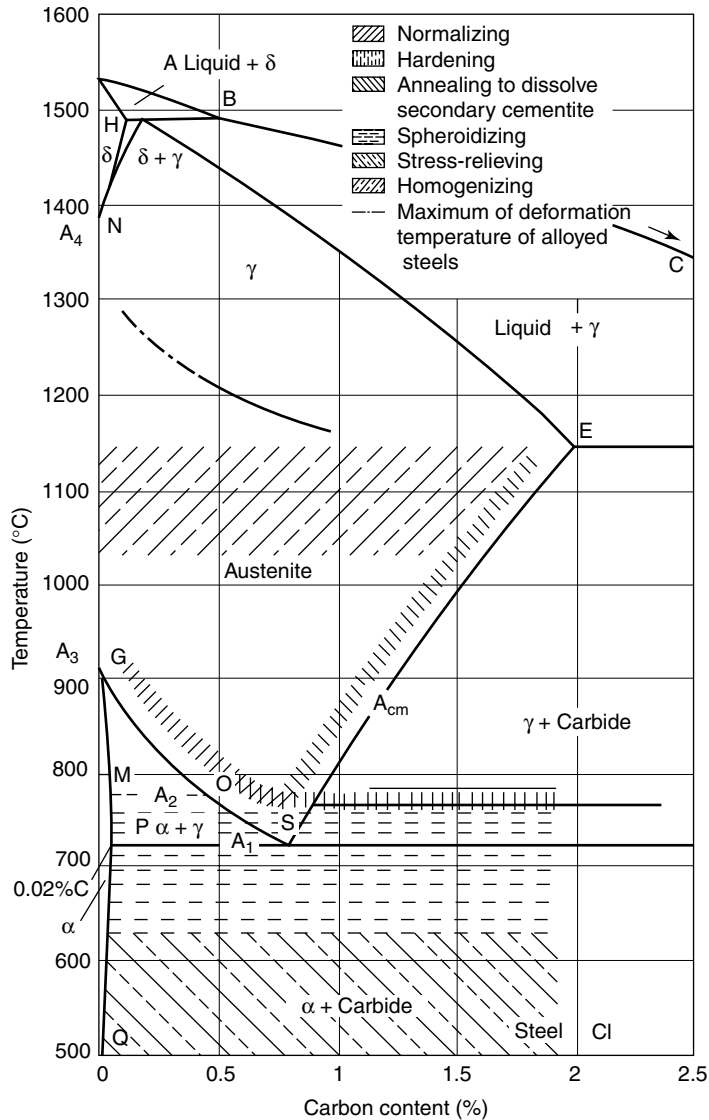


FIGURE 5.4
Iron-carbon (Fe-C) diagram.

5.5.1.5 Steel Making Method

Steels are made by one of the following five methods:

1. Basic open hearth
2. Basic oxygen
3. Acid open hearth
4. Acid Bessemer
5. Electric arc

The properties of steel are not particularly dependent on the manufacturing process.

5.5.1.6 Hardenability

Depending on hardenability, steels are classified as (1) nonhardening, (2) shallow hardening, and (3) deep hardening.

The hardenability depends on the carbon and alloy percentage of steel. Low-carbon and almost no alloy steels are nonhardenable, and are suitable for cold working and welding. Shallow hardening steels are medium-carbon and low-alloy steels hardened only at the surface, with the interior retaining its original toughness for gears, cam shafts, etc. Deep hardening CSs have more carbon and alloy content.

5.5.2 Effect of Alloying Elements on Steel Properties

Iron with 99.9% purity is useful only for electrical and chemical industries and as a sintering material. In this form, iron has

- Tensile strength of 215–275 N/mm²
- Lower yield strength of 88–137 N/mm²
- Elongation of 40–60%
- Hardness of 440–540 N/mm²

For mechanical applications, iron has to be dosed with other elements to obtain specific properties such as hardness, toughness, wear and corrosion resistance, elevated temperature strength, and so on. The effects of the most important alloying elements affecting boiler steels are given briefly in Table 5.15. Figure 5.5 shows how alloying affects hardness.

5.5.3 Heat Treatment Processes

The purpose of heat treatment processes is to alter the structure of the metal to induce properties favorable to further use or processing. Table 5.16 covers the most common heat treatments involved in boiler making. Figure 5.6 depicts the various heat treatment processes with the help of the Fe–C diagram.

5.5.4 Certain Terms in Heat Treatment as Relevant to Boiler Steels

Aging. Holding steel at moderate temperatures, above or below room temperature, once or repeatedly (called artificial aging), to accelerate the property changes, which would have taken an extended time at room temperature (natural aging).

Austempering. Cooling the workpiece from hardening temperature to a temperature range between the martensitic and the pearlitic formations in salt or metal baths and holding there until the entire transformation is completed, followed by cooling to room temperature at any desired rate.

Austenitizing. Heating to and holding at a temperature above the critical temperature A_{c1} to convert the structure completely or partially into austenite.

Case hardening. Hardening of the outer layer of the workpiece by carburizing or nitriding or both.

TABLE 5.15

Effects of Alloying Elements on Steel

Alloy Elements	Essential Attribute	Net Effect	Enhances/Positive Effects	Reduces/Negative Effects	Remarks
C	Companion element of Fe		Tensility, yield, surface hardness	Impact, elongation, and machinability	Forms martensitic structure in quenched steel
Al	Deoxidant in steel production	+ve	Resistance to aging, scaling, and heat resistance (calorizing)		
Cr		+ve	Resistance to corrosion and oxidation, elevated temperature strength, wear resistance to H brittleness	Impact, at >15% and 475°C Cr embrittlement	>13% Cr improves atmospheric corrosion
Mn	Deoxidant	+ve	Tensility, yield, hardenability, also prevents red-shortness		Neutralizes S
Mo	For creep strength	+ve	Tensility, yield, creep, impact, wear resistance, high-temperature strength	Resistance to scaling	Used along with other alloying elements
Ni	For impact at low temperature	+ve	Tensility, yield, toughness. High Ni reduces coefficient of thermal expansion (Invar)		Indispensable for heat resistance
Si	Deoxidant and degasifier	+ve	Tensility, yield, resistance to oxidation and scaling. At >2.5% increases brittleness	Hot and cold workability Electrical conductivity	Ideal for spring steels and electrical apparatus
W	For high-temperature strength	+ve	Tensility, yield, toughness resistance to high-temperature wear, similar to Mo. Forms strong carbide	Resistance to oxidation	Good for tool steels
V	Deoxidant and degasifier	+ve	Resistance to wear, strength at high-temperature resistance to H embrittlement		Grain refiner
Ti	Deoxidant	+ve	Strength at high temperature		Stabilizer in corrosion-resistant steels
S	Impurity in steel	–ve	Machinability in free-cutting steels	Toughness in transverse direction, resistance to weld cracking	
P	Impurity in steel	–ve	Hardness when dissolved in quantity <0.2%	Ductility and resistance to shock in CS	
Cu		–ve	Yield and yield/tensile ratio, up to 0.5% resistance to atmospheric corrosion		Precipitation hardness at >0.3%

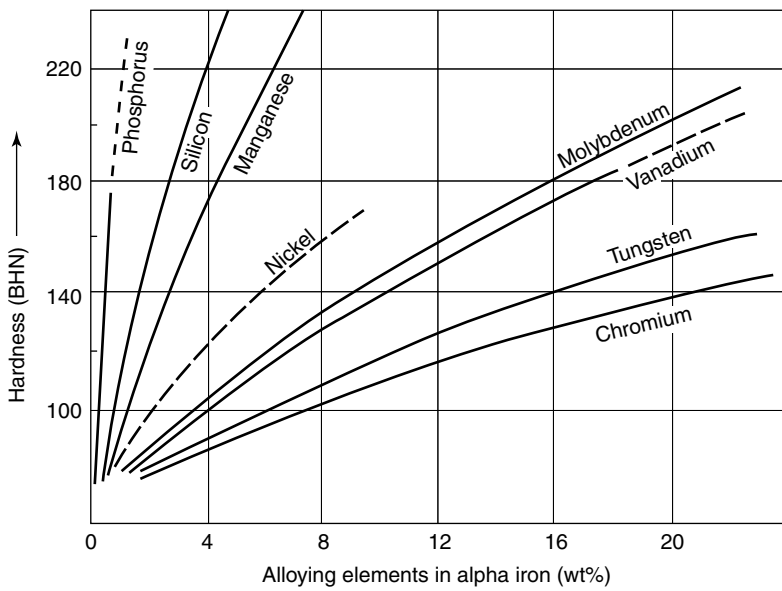


FIGURE 5.5
Hardening effects of various alloying elements dissolved in pure iron.

TABLE 5.16
Common Heat Treatment Processes and Their Effects

Process	Purpose	Heating Temperature	Cooling Procedure	Remarks
Annealing (full)	Remove strain hardening and increase ductility mainly for cold-worked steels	Above recrystallization temperature and hold for a long time till full conversion to austenite	Controlled cooling in furnace to <316°C	
Process annealing or stress relieving	Improve ductility and decrease the residual stresses in work-hardened steels	Below subcritical temperature 501–704°C		No grain refinement
Normalizing	Homogenization and strain relief. Harder and stronger than full annealing	Above upper critical temperature	Air cooling	Similar to full annealing
Quenching	Hardening of high-carbon steels to give high strength and wear resistance	Heat to austenite	Cool rapidly in water or oil to <200°C to form martensite	
Tempering	Make softer and tougher steel. Remove some brittleness in quenched steel	Below lower critical temperature	Any desired cooling rate	Secondary treatment
Spheroidizing	Soften and improve machinability	Heating for a long time fine pearlite just below lower critical temperature		
Solution treatment	Producing single-phase alloy of austenitic steels having good creep strength	Above solubility curve and hold long enough to attain grain growth	Quench in water or any suitable liquid to prevent carbides to reverse	

Note: Homogenization is the elimination of previous fabrication and heat treatment history. Tempering follows normalizing and quenching processes.

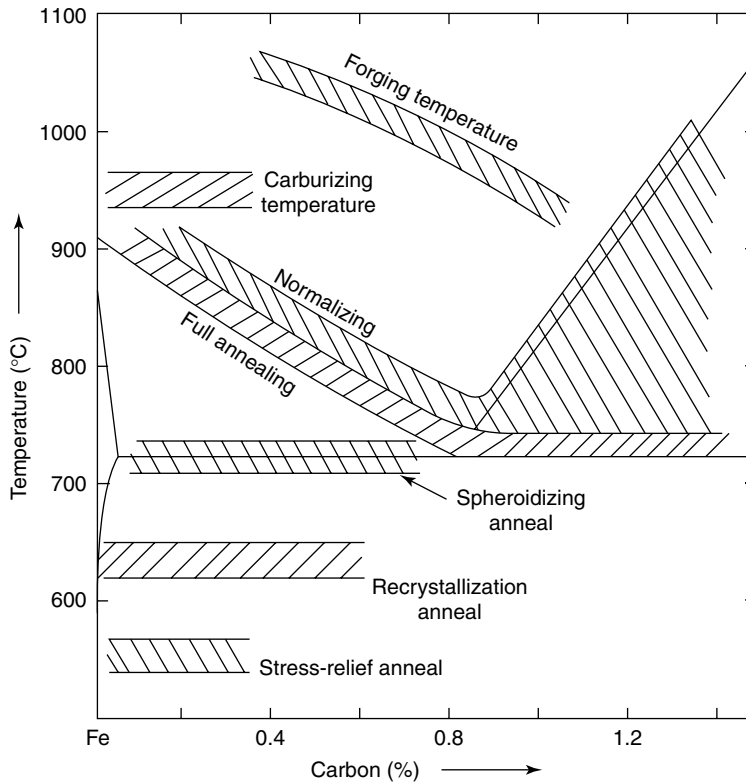


FIGURE 5.6
Heat treatment processes.

Carburizing. Enrichment of the outer layer of the workpiece by carbon to make it harder by holding it above the critical point Ac_1 Ac_3 . Gas, bath, powder, or paste carburizing are the various processes.

Flame hardening. Hardening of the workpiece by surface or by heating with torch.

Hardening crack sensitivity. The tendency to form cracks during hardening or in the hardened, nontempered condition.

Hardening from hot forming. Hardening in any desired manner after hot forming like rolling, forging, or drawing, without intermediate cooling below the lower critical temperature Ar_1 .

Holding time. The time the workpiece is held at the desired temperature after it has been heated to that level. The *soaking time* to reach that temperature is not counted.

Nitriding. Hardening the outer surface by heating and holding the workpiece in nitrogen-rich environment. Gas nitriding and bath nitriding are the two methods.

Stabilizing. Bonding of fine segregations obtained by annealing.

5.5.5 Corrosion

Corrosion can be defined as the destructive or damaging chemical or electrochemical reaction between the unprotected metal or alloy surfaces and the aggressive chemicals in the

surrounding environment. The aggressors can be O_2 , CO_2 , SO_2 , and humidity in air, gases, and liquids, causing destruction and transformation producing salts, oxides, hydroxides, and chlorides.

There are several types of corrosions of which gas-side corrosion due to ash, namely, high and low-temperature corrosions are most common to boilers and are discussed in great detail in Chapter 3.

- *Surface or uniform corrosion* is the most common type. It is the chemical or electrochemical reaction that takes place over the whole exposed area. It can be prevented or reduced by (1) proper material selection, (2) suitable coating, (3) application of inhibitors, and (4) cathodic protection.
- *Pitting* is localized, deep, and heavy and causes craters such as under cutting or pin head-type pits in the metal. The crevices can already exist or can be formed. The cause is the formation of an oxygen cell.

Oxygen corrosion is an electrochemical process in which oxygen from atmosphere is dissolved in an electrolyte such as water, and attacks the metal surface to produce pitting. This is typically the case with boilers that are idle for long periods with water in the tubes. Highly destructive pitting is very difficult to detect, as the pits are small and are often covered by deposits. Usually pitting is localized. The failure is often sudden, calling for shutdown of the plant. Pitting is also difficult to predict.

- *Selective corrosion* means individual constituents are selectively attacked in alloys. The usual example is the attack of zinc in brass.
- *Contact corrosion* occurs between the assembled components where different metals or alloys are in contact. Electrochemical cells form and cause this type of corrosion.
- *Crevice corrosion* occurs under the heads of bolts, nuts, etc., due to uneven ventilation. This is an intensive localized corrosion that frequently occurs within crevices and other protected areas exposed to corrosive substances. It is usually associated with small volumes of stagnant solution left by holes, lap joints, gaskets, and surface deposits. Also, it takes place under bolt and rivet heads. This is also called deposit or gasket corrosion.
- *Stress corrosion* is an abrupt failure of materials that are not properly stress relieved or annealed with locked-up stresses due to corrosion. A combination of tensile stresses and corrosion results in crack formation. The surface of the metal or alloy is practically unaffected, although the cracks are progressing underneath. The separation occurs without any deformation characteristically intercrystalline or transcrystalline and without the formation of any corrosion products.

Caustic embrittlement in PPs of high-pressure boilers leading to abrupt failures is an example of stress corrosion cracking. Cracks or brittle failures used to occur in the rivet holes. Cold working caused the stress and NaOH- or caustic-aided corrosion, together produced *caustic embrittlement*. High-pressure and high-temperature SHs made of ss are also susceptible to stress corrosion cracking due to chlorides or oxygen.

- *High-temperature corrosion*, typically as experienced in SH and RH, occurs where the ash constituents attack the tubes in solid state or liquid phase. With coal, the cause is the formation and decomposition of alkali sulfates, and with fuel oils, the sodium vanadyl vanadates cause this corrosion.

- *Dew point corrosion* or *low-temperature corrosion* is typically the attack of the flue gases on the cold-end heating surface (HS) as a result of metal temperature dropping below the dew point. Sulfuric acid is formed due to the reaction of SO_3 and H_2O in the flue gases at low temperatures, which then condenses at temperatures lower than the acid dew point. This causes the corrosion of steel tubes in the ECON and AH.
- *Vibration corrosion* takes place by the combined action of vibration and corrosion. Unlike stress corrosion, the vibration corrosion can happen with all metals and alloys. It is always intercrystalline.
- *Erosion corrosion* is a phenomenon in which erosion and corrosion act together to accelerate the destruction due to the movement of corrosive fluid over metal. Erosion is the mechanical destruction of surface due to the presence of hard particles in a fast-flowing stream. Unlike corrosion, which is chemical or electrochemical in nature, erosion is purely mechanical in action.

Destruction due to erosion has a characteristic appearance of grooves, channels, ridges, valleys, and rounded holes created by the motion of fluid. The destruction proceeds until failures eventually occur. Most metals and alloys are susceptible to erosion. For corrosion resistance, most surfaces are dependent on developing a protective surface layer. Soft metals such as copper and lead are highly susceptible.

For minimization and prevention of erosion corrosion, the usual methods adopted are as follows:

- Use of better materials that can resist this type of corrosion
- Design change involving change of shape, geometry, and selection of materials
- Change in process by way of deaeration and addition of inhibitors
- Application of coatings such as hard facing, weld overlay, or suitable repair
- Cathodic protection, which is not yet a popular solution

Metallic corrosion can be a film-forming or nonfilm-forming reaction. The former exerts a self-inhibiting effect as the film increases in thickness. The latter is more damaging and progresses aggressively and slows down only when the attacking medium is consumed. A uniform corrosion such as rust formation is benign, whereas localized corrosion such as pitting is rapid and more destructive.

Corrosion loss is usually stated in grams per square meter per day or millimeters per year or, in U.S. practice, mil/year (mil is a thousandth of an inch). There are six levels of attack as shown in Table 5.17.

TABLE 5.17

Corrosion Resistance Index

Classification	Corrosion Rate		Attack Number
	mm/year	$\mu\text{m}/\text{year}$	
Corrosion proof	<0.001	<10	0
High resistance	<0.010	<100	1
Good resistance	<0.100	<100	2
Sufficient resistance	<1	<1000	3
Limited resistance	<3	<3000	4
Low resistance	<10	<10,000	5
Nonresistant	>10	>10,000	6

5.6 Properties of Steel in Brief

A deep understanding of the properties of steel is necessary in dealing with boilers. The most important properties of the boilers include:

- Tensile strength
- Hardness
- Toughness
- Fatigue strength
- High-temperature characteristics

5.6.1 Tensile Strength

Tensile strength is the ability of a material to withstand the outward axial force or *pull* as opposed to the compressive strength, which is the ability to withstand *push*. When pulled, the materials are subject to *stress*, and they tend to elongate, which is the *strain*. Stress-strain relationships of materials are vital because they provide data on the following:

- Yield strength
- Tensile strength
- Ductility

Under tension, a test piece elongates linearly up to the *elastic limit*, and returns to the original dimensions every time the load is removed without permanent deformation. This is expressed in Hooke's law, which states that in this elastic range

- Strain is proportional to the stress
- Stress is equal to the strain multiplied by the modulus of elasticity

Beyond the elastic limit, the material enters *plastic range* when additional load results in a permanent deformation and the specimen does not return to its original shape. The elongation is accompanied by a uniform reduction in thickness. *Yield point* involves disproportionate elongation with no addition to the loading. Since this point is difficult to establish reliably, a specified value of plastic elongation is usually adopted, such as 0.1, 0.2, and 0.5% of the original length. *Yield strength* is the load divided by the original area of the specimen to produce the desired elongation.

Thereafter, with increasing load, the specimen elongates too far with uniform thinning. At some point, there is neck formation in the middle of the specimen for ductile materials before the eventual breaking. *Tensile strength* is the breaking load divided by the original area of the specimen. In brittle materials, the necking does not take place and there is an abrupt rupture of the specimen.

Ductility is the percentage of elongation of the specimen up to the point of rupture or the percentage of area reduction with reference to the original length or area. In general,

the strength of material decreases as the ductility increases. Strong metals tend to be hard and brittle.

For design purposes, tensile strength and ductility data at room temperature, and yield strength at room temperature and at elevated temperatures up to creep limit, are required for BQ steels used for PP manufacturing. The material codes provide *specified* values to be used in design, and for each ladle analysis, steel makers supply *actual* results for verification of compliance. Additional tests for ductility are conducted for tubes and pipes by way of tests for

- Flaring
- Flattening
- Bending

5.6.2 Hardness

Hardness is the resistance to indentation or plastic deformation under static and dynamic loading. It is also a measure of resistance to abrasion, scratch, machinability, cutting, and drilling and is related to tensile strength.

Hardness is determined by Brinell, Vickers, or Rockwell tests in which a ball- or a pyramid-shaped point is pressed onto the surface of the metal with a specified force for a specific time, and the size of indentation is measured by a microscope to automatically determine hardness number. Smaller indentation means higher hardness. Hardness can also be determined by scleroscope in which the loss of kinetic energy as measured by the rebound of a falling weight is used for measurement.

The various hardness testing methods are not very exact. Also, no two methods measure the same parameters. Hence the comparison is approximate. Vickers–Brinell relation is nearly linear, up to 400 with Vickers ~5% higher than Brinell. Figures 5.7 and 5.8 provide the comparisons.

5.6.2.1 Mohs Scale of Hardness

Mohs hardness test measures scratch resistance. Talc is rated 1 and diamond 10, and all other materials between 1 and 10, as shown in Figure 5.9. This test is simple and quick. If one mineral fails to scratch and the next produces a scratch, the hardness of the tested material is between the hardness of the two minerals. The result is not accurate enough for the industry. Therefore, Mohs hardness test is not popular in the engineering field but finds extensive application in geology.

5.6.3 Toughness

Toughness is a difficult term to define. It can be considered as the ability of the material to equalize a concentrated stress. It is the capability to tolerate localized stresses even above the yield point by plastically absorbing and redistributing the stresses. Under certain conditions, particularly at low temperatures, even very good ductile steels undergo a brittle failure when subject to concentrated stresses. Toughness is the property to resist this brittle failure.

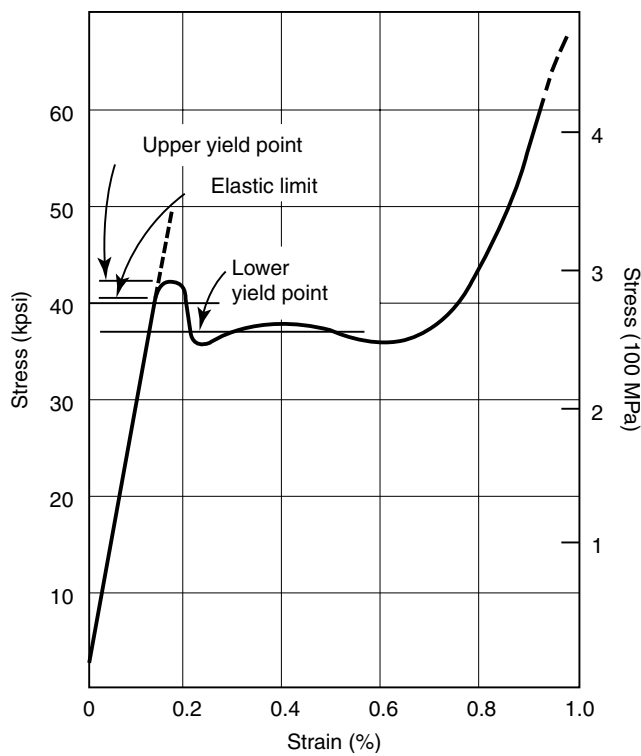


FIGURE 5.7
Stress–strain relationship.

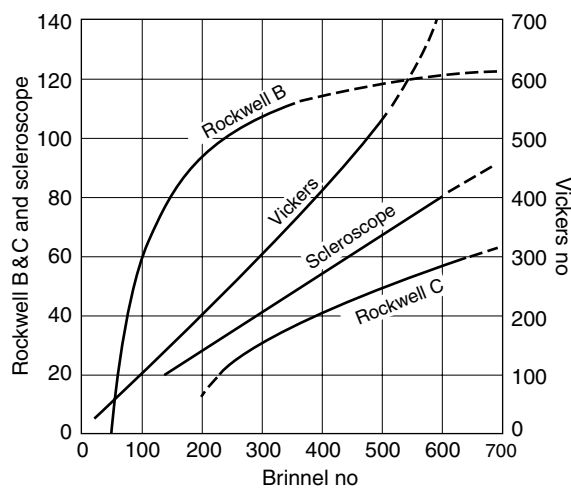
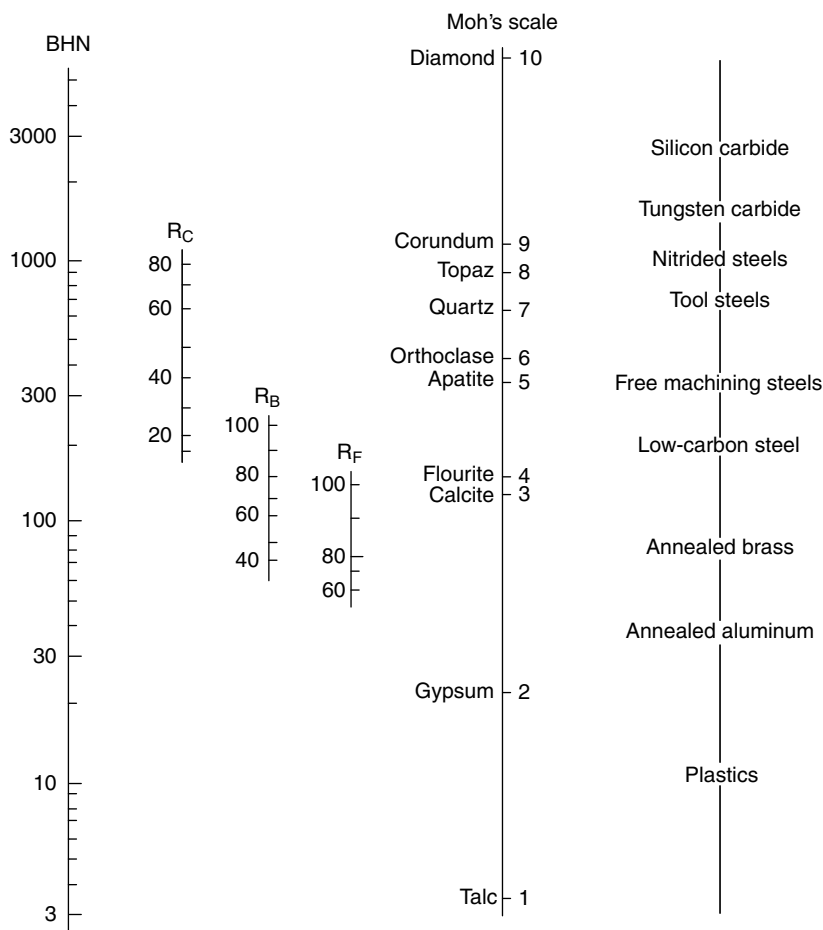


FIGURE 5.8
Comparisons of hardness scales.

**FIGURE 5.9**

Moh's scale and its approximate equivalent hardness.

Charpy and Izod tests are the most common. In a Charpy test, the notched specimen is held at both ends in a simply supported manner, and in the Izod test, it is held at one end in a cantilever manner. A swinging pendulum from a specified height is allowed a free swing. The extent of rebound is measured directly in kilogram-foot-meters or pounds as the energy absorbed. Figure 5.10 depicts the two tests.

The mode of failure in the impact test changes from ductile (shear) to brittle (cleavage) as the temperature is lowered. The temperature range in which this change takes place is known as the transition temperature. Materials within and lower than this range can crack extensively under impact load.

Fortunately, PP steels of boilers have transition temperatures considerably below their operating temperatures. Heat treatable steels in quenched and tempered conditions have superior transition temperature properties. High-nickel steels exhibit low transition temperatures. There is no abrupt change in toughness properties of austenitic ss and other pure metals such as copper and aluminum, making them suitable for cryogenic conditions.

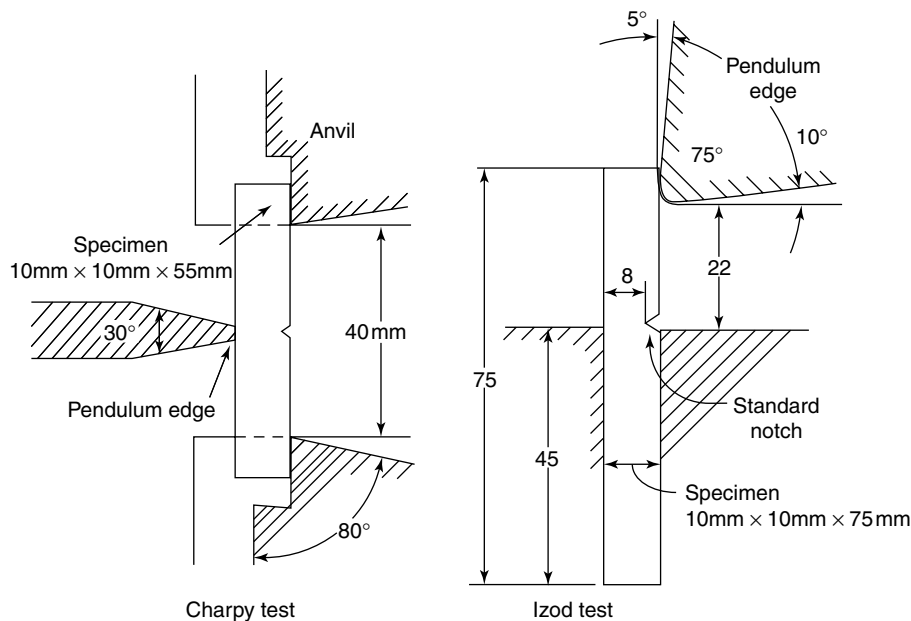


FIGURE 5.10
Typical Charpy and Izod impact test specimens.

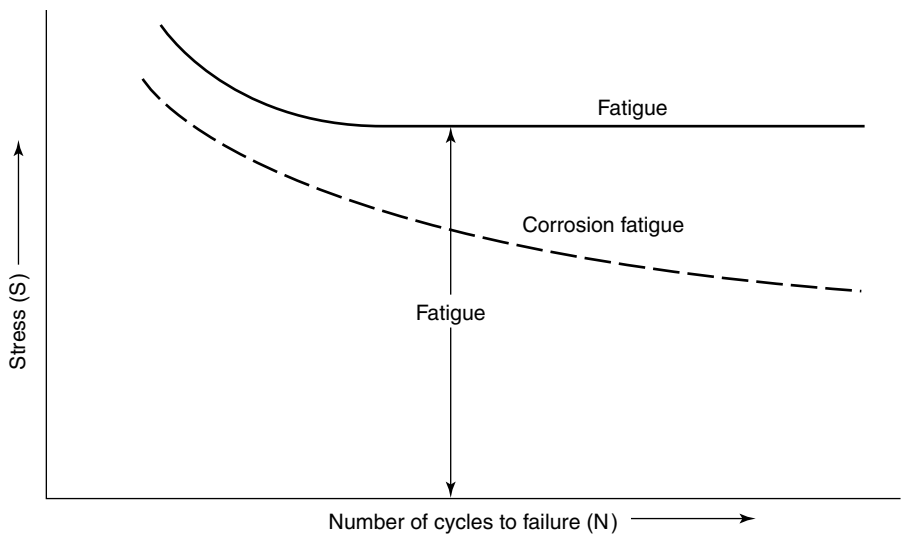


FIGURE 5.11
Corrosion fatigue.

5.6.4 Fatigue Strength

Fatigue strength is the magnitude of cyclical stresses that the material can withstand for a specified number of cycles before failure occurs (Figure 5.11). For static loading, yield strength can be employed. It is the ability of the material to withstand the force without deformation for an indefinite period. When alternating, dynamic, or cyclical loading

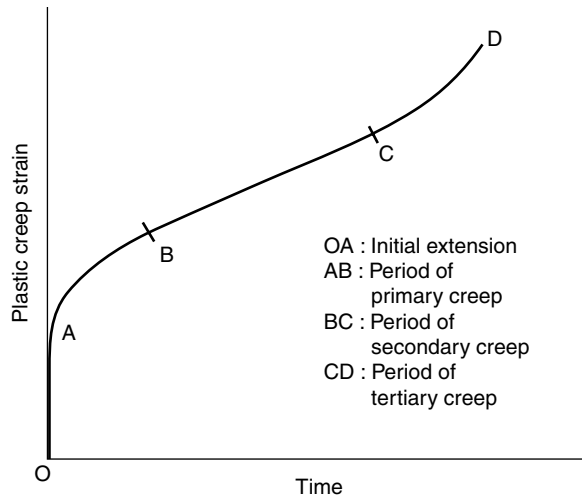


FIGURE 5.12
Typical creep strains.

takes place, the material suffers microscopic cracks along the grain boundaries that keep growing until failure takes place.

At sufficiently low stress values, the material can endure the cyclic loading indefinitely. This is the endurance limit. Changes of cross section or the stress concentration notches adversely impact the endurance limit of the material.

5.6.5 High-Temperature Properties

Tensile and yield strengths, which form the basis of a design, cannot be used for high temperatures. Even the data at high temperatures above 350°C are not adequate as the strength of the steels is affected by other factors such as creep and creep to rupture. SH and RH tubes and furnace tubes of supercritical (SC) boilers are the main PP components required for high-temperature properties.

5.6.5.1 Creep Stress

At elevated temperatures even with constant load, material elongates over time. This property is known as creep. Creep takes place in three stages after the initial elongation due to the initial load, which is proportional to the load and the temperature (Figure 5.12).

- Primary creep, characterized by decreasing rate of elongation
- Secondary creep, which takes place when the deformation is very low
- Tertiary creep, with an accelerating deformation leading to rupture

Creep is measured as 0.1 and 0.01% of elongation in 1,000 h, which is expressed as 1% in 10,000 and 100,000 h, respectively, for any material at a particular temperature.

Creep is affected by a number of factors:

- Carbide-forming elements such as molybdenum and tungsten and, to a lesser extent, chromium and vanadium help to improve the creep resistance of steels.
- Increased carbon content is beneficial up to 550°C.

- At higher temperatures austenitic steels and special alloys have superior creep resistance as compared with low- and high-alloy ferritic steels.
- Coarse grains in steel appear to be better than fine grains.
- As the surface reactions impair the creep resistance, additions of Si, Al, Cr, and Ni are found to be beneficial for enhanced surface stability.

5.6.5.2 Creep–Rupture Stress

This is actually the creep strength at a particular temperature when it is carried out to rupture the specimen in a specified time. The testing lasts a few hours to even 10,000 h. Values are suitably extrapolated and reported as the stress to rupture in 100, 1,000, 10,000, and 100,000 h for a particular material at a certain temperature. ASME specifies adoption of creep–rupture values for 100,000 h while calculating allowable stress for PP design.

5.7 Bricks, Refractory, Insulation, and Lagging

All the nonferrous parts of a boiler are known as BRIL, which is an acronym for *bricks, refractory, insulation, and lagging*. The boiler setting or enclosure, which is the assembly surrounding all the hot parts, is substantially made of BRIL so that

1. The heat is contained within the boiler.
2. Heat loss is restricted to a minimum.
3. Personnel safety is ensured.

As the boiler sizes have increased along with greater water wall cooling and more sophisticated steels, the significance of BRIL has considerably altered. With the improved awareness for esthetics, environment, and human comfort, there is more insulation and lagging in boilers and the increased use of membrane panels and the progressive discontinuance of many mass burning practices have made the refractory bricks practically obsolete and increased the use of castable refractories. I and L have grown at the expense of B and R.

5.7.1 Refractories

Refractories will be discussed only as applicable to boilers. The following are the important points to remember:

- Refractories are made of a combination of minerals.
- Their properties are dependent on the specific combination.
- They are also highly influenced by conditions where the minerals are sourced.
- The properties can be drastically affected even by small changes in the ingredients.

Functions. Refractories are nonmetallic materials suitable for construction or lining of high-temperature furnaces. Accordingly, the refractories are expected to withstand the following in hot conditions:

- Pressure from self-weight or the weight of furnace parts or contents
- Thermal shock resulting from rapid heating and cooling

- Chemical attack by heated solids, liquids, gases, and fumes
- Mechanical wear

5.7.1.1 Classification of Refractories

On the basis of properties or composition, refractories are classified into five main types:

1. Fireclay
2. High alumina
3. Silica
4. Basic
5. Insulating

They are also classified into many special types such as

- Silicon carbide
- Graphite
- Zircon
- Zirconia

Most are made from silica and alumina in various combinations.

Refractory materials are supplied in various ways:

1. Preformed shapes
2. Special-purpose clays
3. High-temperature cements
4. Bonding mortars
5. Plastic
6. Ramming mixes
7. Hydraulic setting castables
8. Gunning mixes
9. Granular materials
10. Ceramic fibers

5.7.1.2 Refractory Selection

Refractory selection is based on the following considerations:

- Besides high gas temperatures, refractories have to withstand specific types of chemical attacks from the ashes of flue gas.
- Selection of the type of refractory is also guided by the gas velocity.
 - Ceramic fibers can be used up to a gas velocity of 7.5 m/s.
 - Monolithics can be used up to a gas velocity of 60 m/s.
 - Bricks can be used for gas velocities more than 60 m/s.
- Monolithics have no joints and present no risk of erosion of the mortar joints in brick construction provided the application can accept lower density and wear resistance.

TABLE 5.18

Refractoriness of Bricks used in Boilers

Brick	Refractoriness		Refractoriness under Load		True Specific Gravity	Bulk Density (te/m ³)
	Pyrometric Cone Equivalent (PCE)	Temperature (°C)	PCE	Temperature (°C)		
FB (23–30%)	27–29	1710–1730	13–16	1380–1460	2.5–2.6	1.9–2.1
FB (30–35%)	28–31	1630–1690	16–19	1460–1520		
FB (35–40%)	29–33	1650–1730	19–26	1520–1580		
Alumina (40–45%)	32–35	1710–1770	26–28	1580–1630	3.1–3.4	1.8–2.1
Silica brick	32–33	1710–1730	29–32	1650–1710	2.3–2.4	1.7–1.8

Note: Percentage represents Al_2O_3 ; FB, firebrick.

5.7.1.3 Refractoriness

Refractoriness is temperature-withstanding ability. Refractoriness is measured by pyrometric cone equivalent (PCE), which is the temperature at which a cone of specified size (usually 12 mm sides and 38 mm tall with one edge perpendicular to the base) begins to soften and turn roundish at the top when heated slowly at the rate of 5°C/min. Refractoriness under load (2 kg/cm²) is a more valuable parameter as it represents the practical situation better. PCEs and equivalent temperatures are given in Table 5.18.

5.7.2 Various Types of Refractories

- *Fireclay refractories* consist essentially of hydrated aluminum silicates (generally $\text{Al}_2\text{O}_3 \cdot 2\text{SiO}_2 \cdot 2\text{H}_2\text{O}$) along with smaller quantities of other minerals. Hard clays are the flint and semiflint clays, which form the principal component of the super- and high-duty fire bricks having PCE of 33–35. Plastic and semiplastic refractory clays, also called soft clays, vary considerably in refractoriness, bonding strength, and plasticity having PCE values ranging from 29 to 33.
- *High-alumina refractories*. Several minerals can be used in the making of alumina refractories. Most high-alumina refractories are made from bauxite ($\text{Al}_2\text{O}_3 \cdot \text{H}_2\text{O} + \text{Al}_2\text{O}_3 \cdot 3\text{H}_2\text{O}$) or diasporite ($\text{Al}_2\text{O}_3 \cdot \text{H}_2\text{O}$) or a mixture of the two blended with flint and plastic clay. Alumina types are more refractory than fireclay, approximately in proportion to their content of alumina. They are highly resistant to chemical attack by various slags and fumes and, in general, have greater resistance to pressure at high temperature than fireclay refractory.
- *Silica refractories* are made from high-purity crystalline mineral quartz. Their thermal expansion is high at low temperatures and negligible beyond 550°C. They possess high refractoriness, strength, and rigidity at temperatures close to their melting point. They are susceptible to thermal spalling (cracking) at 650°C, but at higher temperatures, they are free from spalling.
- *Basic refractories*. The raw materials used include magnesite, dolomite, and chrome ores.
- *Insulating refractories* are lighter and porous, as they trap a lot of air and hence possess much lower conductivity and heat storage capacity. They are normally used as the backing to the dense refractory facing. If the furnace conditions are clean, they can also be used as facing materials.

5.7.2.1 Refractory Bricks

Bricks are preformed shapes obtained by pressing the green mass to the required shape and size and firing at the specified temperature until the refractory bond is formed by chemical action under heat. The word *brick* is used in the acronym BRIL to cover both bricks and the tiles. Standard refractory bricks are made in two thicknesses, namely, 227 mm × 116 mm × 76 mm and 63 mm (9 in. × 4 1/2 in. × 3 in./2½ in.). Tiles are flattened bricks usually made in the range of 50–76 mm thickness, with overlapping edges and an arrangement to hold the tile. Tiles can also be made in different shapes and in more advanced composition than bricks. Today, refractory brick construction is confined mainly to the following areas:

- Around the fire in pile burning, in horse shoe or ward furnaces in firing bagasse or similar fuels. This type of burning is nearly extinct.
- Shaped refractory arches in chain grate stokers for radiating the heat onto the bed.
- Boiler enclosure in brick set boilers.
- Brick lining for underground brick flues.
- Stack lining.
- Brick lining in cyclones and external HXs in CFBC boilers.

The use of refractory bricks in modern boilers is negligible in comparison to the former times. Since the bricks are pressed in hydraulic presses, they are strong, dense, and heavy, which makes them ideally suited to face the fire and dust-laden gases.

Several types of refractory bricks are manufactured to suit various types of furnaces:

1. Fireclay
2. High alumina
3. Insulating bricks
 - *Firebricks* (FBs) are made of a blended mixture of flint and plastic clays. Some or all of the flint may be replaced by highly burnt or calcined clay called grog. The dried bricks are burnt at 1200–1500°C. Firebricks can withstand spalling and many slag conditions but are not suitable for lime or ash slags.
 - *High-alumina bricks* are graded by alumina content as 50, 60, 70, 80, and 90% and are used for unusually severe temperature and load conditions. They are more expensive than firebricks.
 - *Insulating FBs* are made from porous fireclay or kaolin. They are light, one-half to one-sixth of the weight of equivalent refractory brick, low in thermal conductivity, and capable of withstanding high temperatures. They are graded by thermal withstand temperatures as 870, 1100, 1260, 1430, and 1540°C (1600, 2000, 2300, 2600, and 2800°F). They are not slag-resistant.
 - *High-burned kaolin* (alumina–silica china) refractories can withstand high temperatures and heavy loads or severe spalling conditions as in oil-fired boilers. Tables 5.18 lists the various refractories used in boilers and their refractoriness under no-load and loaded conditions. Table 5.19 gives the physical and chemical properties along with their suitability under various conditions.

TABLE 5.19

General Physical and Chemical Properties for Shaped Refractories in Boilers

Type of Brick	Composition	Fusion Temperature (°C)	Apparent Porosity (%)	Permeability	Hot Strength	Thermal Shock Resistance	Resistance to Acids	Resistance to Alkalies
Firebrick	40% Al ₂ O ₃	1720	18	Moderate	Fair	Fair	Good	Good at low temperature
Firebrick	42% Al ₂ O ₃	1745	15	High	Fair	Good	Good	Good at low temperature
High alumina	50–85% Al ₂ O ₃	1760–1870	20	Low	Good	Good	Good but for HF	Slight attack at high temperature
Extra high alumina	90–99% Al ₂ O ₃	1650–2010	23	Low	Excellent	Good	Good but for HF	Slight attack at high temperature
Silica	95% SiO ₂	1700	21	High	Excellent	Poor	Good	Good at low temperature
Silicon carbide	80–90% SiC	2300	15	Very low	Excellent	Excellent	Good but for HF	Attack at high temperature
Insulating bricks			65–85	High	Poor	Excellent	Poor	Poor

5.7.2.2 Refractory Tiles

Refractory tiles are used in the following areas in modern boilers:

- On top of the floor tubes to protect the tubes from overheating in package boilers
- In burner quarls to give the right shape to the flame
- Between tubes to form gas baffles
- In the lining of cyclones
- In the lining of hot and dust-laden gas ducts and hoppers

5.7.2.3 Refractory Castables

These refractory materials are not preformed but are cast *in situ* to any desired shape. Because of this flexibility and the advances made in the materials and binders, the castable refractories have become greatly popular, displacing the shaped and formed types in many applications. They are available in special mixes or blends of dry granular or stiffly plastic refractory materials with which (a) practically joint-free linings (monolithic) can be made or (b) repair of masonry can be carried out. These are packed in a way that makes transportation and handling easy. The application is also made very easy with little or no preparation. There are four types of castables or monolithics:

1. Plastic refractories
2. Ramming mixes
3. Gun mixes
4. Castables

The monolithics develop their strength by either *air* or *hydraulic setting*. The entire thickness becomes hard and strong at room temperatures. At higher temperatures, it becomes even stronger due to the development of the ceramic bond. *Heat setting monolithic* refractories have very low strength at low temperatures and develop their full strength only on attaining the full temperature. Linings on furnace wall tubes require that the water walls be fully drained before the application of a refractory layer, lest the water-cooled walls hinder the lining from attaining the necessary temperature. Usually castable linings need some anchor material to hold.

- *Plastic refractories* are mixtures of refractory materials prepared in stiff plastic conditions of proper consistency, for ramming into place with pneumatic hammers or mallets. Plastics are similar to castables in formulation, as both use calcined aggregates and a binder. However, the plastics that are premixed at the factory use phosphates or other heat-setting agents to develop a bond when fired. Castables use hydraulic cements that form the permanent bond when mixed with water.
- *Plastic chrome ore (PCO)* linings are proven lining materials for black liquor (BL) recovery boilers. The air-setting plastic compound is rammed into position on the studded walls to develop a dense monolithic layer, which has high resistance to spalling, erosion, hot gases, and smelt. High-alumina phosphate-bonded plastics are used in hot cyclones of circulating fluidized bed (CFB) boilers to withstand high erosion.
- *Ramming mixes* are ground refractory materials with minor amounts of other materials added to make the mixes workable. Most ramming mixes are supplied dry. Ramming mixes are required to be mixed with water and rammed into place, followed by drying and heating when they form a dense and strong monolithic refractory structure by self-bonding.
- *Gun mixes* are granular refractory materials prepared for spraying at high velocity and pressure by guns. The resulting lining is homogeneous and dense and free from lamination cracks. The spray can be either by dry mix or by wet mix. The gun has a water nozzle to moisten the mixture. The gun mixes can be either air or heat setting. Refractory lining of steel stacks is often done by gunning.
- *Castables* are granular refractory materials combined with suitable hydraulic setting bonding agent. They are supplied in dry form to be mixed, at site, with water and poured or cast in place to develop a strong hydraulic set. They are rammed or troweled or tamped into position and occasionally applied with air guns. These castables have negligible shrinkage in service and low coefficients of thermal expansion. They are resistant to spalling. Some are capable of withstanding severe erosion. Some are good insulators and others are good conductors.
 - *High-alumina dense castables* with varying alumina contents in excess of 90% are used up to an operating temperature of 1800°C to withstand high erosion. Burner quarls and furnace linings are some examples of the usage of this castable.
 - *Low-cement, ultra low-cement, and no-cement castables* are relatively recent developments where refractory cement used as binder is progressively brought down to withstand high temperatures without weakening the lining. Less cement means reduced lime content and reduced water requirement for setting. The porosity is reduced by more than 50%, resulting in a very dense structure capable of standing up to very high erosion as seen in cyclones of CFB boilers.

- *Insulating castables* serve as hot face lining in clean applications and as backup lining for dusty applications. They are light, strong, and low in conductivity, making the whole liner thin and cheap. They are made in a range of densities from ~ 400 to 1600 kg/m^3 .
- *Silicon carbide* lining of FBC furnaces is done to withstand extreme levels of erosion and have good heat transfer to the water walls.

5.7.3 Insulation

Some of the important aspects of the insulating materials are as follows:

- Unlike the refractory materials, which are substantially mineral-based and therefore capable of withstanding the highest temperatures and erosion, the insulation materials are nonmineral (except for ceramic fibers), can stand up to temperature no higher than $\sim 1650^\circ\text{C}$, and do not have any abrasion resistance.
- The insulating materials possess much lower heat conductivity, several times lower than those of the refractory materials.
- The insulating materials are fluffy and hold lot of air, which contributes to the reduced heat flow.
- Thermal conductivity for insulating materials rises steeply with temperature.

Insulation materials in boiler practice are available in mainly four forms:

1. Reformed shapes and slabs
2. Mattresses
3. Plastic cement
4. Loose fill

The insulating materials used in boilers are as follows:

1. Calcium silicate in block forms
2. Mineral/slag wool
3. Ceramic fiber
4. High-temperature plastic
 - a. *Calcium silicate* (CaSiO_3) is a popular block insulation up to 650°C , available in preformed shapes or blocks. It is particularly suitable for piping and valves. The blocks are ideal for insulating the hoppers and ducts from inside for metal protection where there is no abrasive ash.
 - b. *Mineral or slag or rock wool* is made from blowing the slag produced in steel mills into fine fiber by steam or air jets. Mineral wool has practically displaced the glass wool, which contains glass fibers because of human health considerations. It is also slightly cheaper.
 - c. In *blanket* form, the wool is held in place by wire mesh on one or both sides, depending on the application, and is used up to 650°C . For vertical walls of a furnace, resin bonding of the mattress is usually preferred, as the wool is held

in place without settling at the bottom due to the slight vibrations in the walls. Typically, densities of 100–140 kg/m³ are employed for normal applications.

- d. When clay is used as a binder and the wool is molded at high temperature and pressure, mineral wool blocks are formed and can be used up to 1050°C. These blocks are used for insulating the boiler and membrane walls.
- e. *Ceramic fiber linings* are produced by melting the alumina–silica china clay and blowing air to form fibers of 50–100 mm long and 3 µm in diameter. They are offered in block or mattress form capable of withstanding very high temperatures. The blocks substitute for insulating bricks, and the mattresses can be used for high temperatures. They have good acid resistance but lower alkali resistance. Ceramic fiber is useful when temperatures as high as 1650°C are encountered. This material is reserved only for special applications due to its high cost. Lining of the inlet duct downstream of burners in HRSG is a typical application.
- f. *High-temperature plastic* is insulating plastic cement made from mineral wool and clay, and is suitable up to 1050°C for use on irregular shapes and for filling gaps in block insulation.

Table 5.20 lists the properties of various common insulating materials used in boilers.

5.7.4 Lagging

Lagging is the outermost covering to protect the insulation from damage, usually in the form of metal sheet of galvanized iron (GI) or aluminum and weather-resistant. GI is stronger but lacks the luster of Al. Usually plain GI sheeting for furnaces is used in thickness of 1 mm (19 SWG) and Al in 1.2 mm (18 SWG) plain or 0.9 mm (20 SWG) corrugated. For pipes, 0.71 or 0.56 mm (22 or 24 SWG) of these metals is used for ease of bending. Both GI and Al are about the same in price. Al is gaining greater acceptance due to its better appearance.

TABLE 5.20

Properties of Common Insulating Materials Used in Boilers

Insulating Material	Density (kg/m ³)	Limiting Temperature (°C)	Thermal Conductivity						Specific Heat Capacity	
			W/m K	At (°C)	W/m K	At (°C)	W/m K	At (°C)	kJ/kg K	At (°C)
Asbestos, loose	575	800	0.205	100	0.216	300	0.230	500	0.820	20–100
Asbestos, fire	280	800	0.063	100	0.092	300	0.121	500	0.838	0–100
Asbestos cords	300	240	0.093	0	0.105	100	0.116	200		
Glass wool	100	~500	0.059	100	0.080	200	0.095	300	0.796	0–100
Magnesia powder	300	~300	0.066	100	0.077	200	0.088	300		
Magnesia without alumina	400	~300	0.073	100	0.081	200	0.089	300	1.005	0–100
Magnesia—asbestos shaped bricks	200	~600	0.065	100	0.090	300	0.105	500		
Mineral wool	200	850	0.053	100	0.065	200	0.089	300	0.837	0–100
Slag wool	200	500	0.052	100	0.086	300	0.126	500	0.753	0–100

5.8 Wear-Resistant Refractory Ceramic Materials

Wear is a progressive loss of material due to mechanical action such as continuous impingement of particles. For information on wear of boiler parts due to ash, please refer to 3.5.1.2.1. Corrosion is a chemical or electrochemical action, leading to loss of material, whereas wear is a mechanical phenomenon. Wear is prevented by protecting the parts by sacrificial material of high hardness made of either steel or refractory to suit the application. Steel protection is used for the inside parts of the boiler subject to very high temperature and flue gas velocities. The outside parts, where there is no heat transfer, are protected by special ceramic linings and coatings.

Typically mill internals such as parts of mill housings and classifiers, coal pipes (more particularly the bends), and cyclone inlets of CFBC boilers are parts that experience varying levels of erosion, depending on the erosiveness of coal and ash and the air/gas velocities. Appropriate ceramic lining is used to protect the affected parts based on the temperature and the severity of erosion. A harder lining prolongs life.

Hardness has no single accepted definition. It is the resistance to local penetration, scratching, machining, wear, or abrasion, depending on the material and reference. *Scratch hardness* is measured by *Mohs scale* of minerals, which is an arbitrary measure ranging from 1 to 10 based on the relative hardness. Talc is the softest mineral and is placed at the bottom of the scale at 1, whereas diamond is the hardest at 10 (see Figure 5.9).

Some of the popular materials from which the abrasion resisting linings are made are shown in Table 5.21.

TABLE 5.21
Special Ceramic Linings for Wear Resistance

Type of Ceramic	Fused Cast Basalt	Clinker Tile	Cast Corundum	Dense Al ₂ O ₃
Supplied form	Cast to size	Tile cut to size	Tiles and special shapes	Tiles, special shapes, 2 mm thin tiles
Raw materials	Dense basalt	Clay, kaolin, feldspar, and sand	Al and zircon	Al ₂ O ₃
Main use	Friction-induced wear	Milder abrasion	Severe abrasion and high temperatures	Extreme abrasion and high temperatures
Density (te/m ³)	2.8–2.9	2.4	3.4	About 3.5
Hardness on Mohs scale	8	6	9	9
Thermal conductivity (W/m K)	1–1.16	1.3–1.6	4.2	14
Coefficient of expansion (μ/K)	6–8	5	6.5	3.4
Temperature limit (°C)	350	350	1000	1000
Chemical resistance	To most acids and alkalis	To many acids and alkalis	To many acids and alkalis	To many acids and alkalis
Areas of application	Coal pipes and bends, cyclones, hoppers, and silos	Separators, drag link feeders	Cyclones, pipe bends	Cyclones, fan blades, conveyors, mixers

Further Readings

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Section II

Boiler Parts and Auxiliaries

6

Heating Surfaces

6.1 Introduction

A boiler is a plant in which essentially two processes are at work, namely, combustion and heat transfer.

1. Combustion to release heat from fuel in the firing equipment.
2. Transfer of the released heat to water and steam in the various heat traps of the boiler.

Combustion and firing equipment of different types is discussed in detail in Section 6.4. The different heat transfer surfaces are described individually, all of which, together with firing equipment, form a fired boiler.

In a waste heat or unfired boiler, there is no firing equipment, but only heat transfer surfaces, also called heat traps:

1. Evaporator surfaces consisting of, sequentially,
 - a. Furnace, which is a chamber made of water-cooled surfaces to
 - i. Give the burning fuel adequate time for completion of combustion.
 - ii. Cool the flue gases and transfer the heat to furnace tubes. Furnace tubes in natural circulation boilers transfer heat to boiling water and to subcooled water in supercritical (SC) boilers.
 - b. Boiler bank (BB) or evaporator bundles to cool the flue gases and transfer heat to the saturated surfaces to add latent heat
2. Superheater (SH) and reheater (RH) tube banks to cool the flue gases and accelerate heat to superheat and reheat the steam
3. Back-end equipment consisting of
 - a. Economizer (ECON) tube banks to further cool the gases to transfer heat to the subcooled water
 - b. Airheater (AH) to cool the gases in the last stage and transfer heat to the combustion air

This chapter provides engineering and sizing inputs for the various heating surfaces (HSs) and hence forms the foundation course for the design of all boilers. The data provided should be very useful for practicing engineers and designers. Like all the design information, there can be some variation with specific data developed by any manufacturer for a particular geometry and fuel. Thus, the guidelines and limits are generic and meant for essential design insights.

6.2 Evaporator Surfaces

Boiler and evaporator surfaces are the HSs that are exposed to the flue gases on the outside and carry the steam and boiling water mixture on the inside.

6.2.1 Furnace

The *furnace* is the enclosure around the firing equipment, which provides adequate

1. Volume to permit completion of combustion, that is, to meet the residence time requirement to burn the fuel
2. Surfaces to cool the gases to an acceptable level to enter the downstream surface, usually the SH, without the fear of ash deposits or tube overheating

Furnace volume is the volume of the open chamber that surrounds the firing equipment and extends from the top of stoker, bed, ash pit, or floor to the exit plane at which the next surface (usually SH or screen) starts. Platens are always placed within the furnace.

Heat transfer in a furnace chamber is almost entirely by radiation. *Projected radiant surface (PRS)* of the furnace is the HS that participates in cooling the flue gases. It comprises all areas of the walls of the furnace enclosure including the area of the exit plane. Areas of both sides of platens, wing walls, and division walls are also added. *Effective PRS (EPRS)* is the adjusted PRS that takes into account the fuel, types of walls (membrane, tangent, spaced, etc.), extent of refractory covering on walls, effect of possible slagging, etc. *Furnace exit gas temperature (FEGT)* is calculated with the help of EPRS as elaborated in Section 6.2.1.2.

6.2.1.1 Furnace Dimensioning

The firing device is a grate, combustor, bed, or burner. The dimensions of the firing equipment and flames primarily govern the plan area and shape of the furnace. Necessary clearances have to be provided for burners to avoid flame impingement, which can lead to overheating and wastage of tubes. The furnace height is decided by the furnace volume or residence time requirement of individual fuel and the type of firing equipment. Table 6.1 provides a guide for residence times. *Residence time* is required for a fuel particle to reach the midpoint of the furnace exit aperture from the firing equipment (center of heat input, to be precise), assuming the whole furnace to be at the isothermal

TABLE 6.1

Range of Furnace Residence Times (in Seconds) for Various Fuels

Fuels	Stoker	Burner	Bubbling Fluidized Bed Combustion Boilers	Circulating Fluidized Bed Combustion Boilers
Coals	2.2–3.0	1–2	2.5–3.0	4–5.5
Biofuels	2.5–3.5	—	—	—
Fuel oils	—	<1	—	—
Natural gas	—	<1	—	—

temperature of FEGT. In package boilers with horizontal gas flow, the burners decide the cross section and the residence time whereas the flame length governs the length of the furnace.

The furnace experiences the highest gas temperature within a boiler. To extract the high heat levels required, evaporator surfaces are used in furnaces because of the extremely high boiling heat transfer rates. Gas cooling and tube metal cooling are the most effective methods. Plain carbon steel (CS) tubes are used in construction where departure from nucleate boiling (DNB) is not a possibility and tube metal temperatures rarely exceed 50°C over saturation. Since no evaporation occurs in SC boilers, cooling is not very effective and water temperatures approach critical level (374°C), thus requiring low alloy tubes in the furnace.

6.2.1.2 Furnace Exit-Gas Temperature or Furnace Outlet Temperature (FEGT or FOT)

Furnace exit-gas temperature or furnace outlet temperature is the average gas temperature at the middle of the furnace exit plane. Heat transfer in the furnace is mainly achieved by radiation. The exception is the furnace of circulating fluidized bed combustion (CFBC) boilers, which has a thick layer of hot ash falling down along the tube walls and transferring its heat primarily by conduction and convection. High furnace gas temperatures and relatively cool furnace tubes provide very good heat-transfer rates. But the furnace surface is limited, which makes the cooling of flue gases more expensive in the furnace than on other surfaces. The furnace cooling is therefore restricted only to the extent of achieving a temperature just low enough to introduce other types of surfaces. The FEGT then translates to the initial ash deformation temperature (IADT) of -100°C as a margin of safety.

An accurate estimation of FEGT is not possible by theoretical calculations alone because several variables keep changing in a furnace with not-so-simple geometry. The size and the number of flames, emissivities, flame temperatures, and cleanliness of furnace are all subject to constant change. The practical adjusted surface (AS) or EPRS method, is proprietary to each boilermaker, evolved over time and fuel- and geometry-specific. The calculations involve the following steps:

- Calculate PRS of the lower furnace up to the open pass (below platens) and total furnace up to the furnace exit.
- Derive EPRS from projected surface by multiplying with effectiveness factors for each wall. Effectiveness factor varies from 0.9 to 0.98 for membrane walls depending on the fuel and the slope of the wall.
- Calculate the *heat released* and *available* (HR and A) from the fuel and air. The total available heat, based on fuel net calorific value (NCV), including the heat addition in AH, is adjusted for the possible unburnt carbon loss and furnace radiation losses (assumed to be half of the total). Ambient temperature is taken as the datum to calculate this heat.

$$H_0 = \text{total heat released and available} = \text{fuel fired} \left[(\text{NCV} + H_a) - \left(\frac{R}{2} + L_{ub} \right) \right] \quad (6.1)$$

where

R = radiation loss

$H_{a'}$ = heat added to air

$L_{ub'}$ = unburnt loss

- Calculate the heat release rate

$$\text{Heat release rate} = \frac{H_0}{\text{EPRS}} \quad (6.2)$$

From the proprietary graphs, the FEGTs are read for each fuel and type of firing (grate or burner). The FEGT so obtained is accurate only to the extent of approximately $\pm 50^\circ\text{C}$. A typical graph for burner and grate firing is given in Figure 6.1.

- Burner firing results in a higher FEGT because the center of heat input (CHI) is higher.
- Fuels with higher volatile matter (VM) release more heat at a higher level compared with fuels with less VM, although both are grate fired and consequently give higher FEGT despite their higher moisture.

The FEGTs for lower furnace at open pass plane (T1) and total furnace at exit (T2 or FEGT) are read from the same graph to calculate the radiation falling on the SH. H_1-H_2 is the heat absorbed in the open pass in front of the SH and the platens. Dividing by the EPRS of each wall and platens, heat flux can be estimated along with heat incident on the SH or screen at the furnace exit plane. Correct estimation of the radiant heat falling on SH at the furnace exit is very important for its proper sizing. The boilermakers have such graphs for each fuel for several moistures and VMs.

For fluidized bed combustion (FBC) boilers, the calculations are done in a different way. Heat balance over the bed gives the bed temperature and the heat balance of the free board

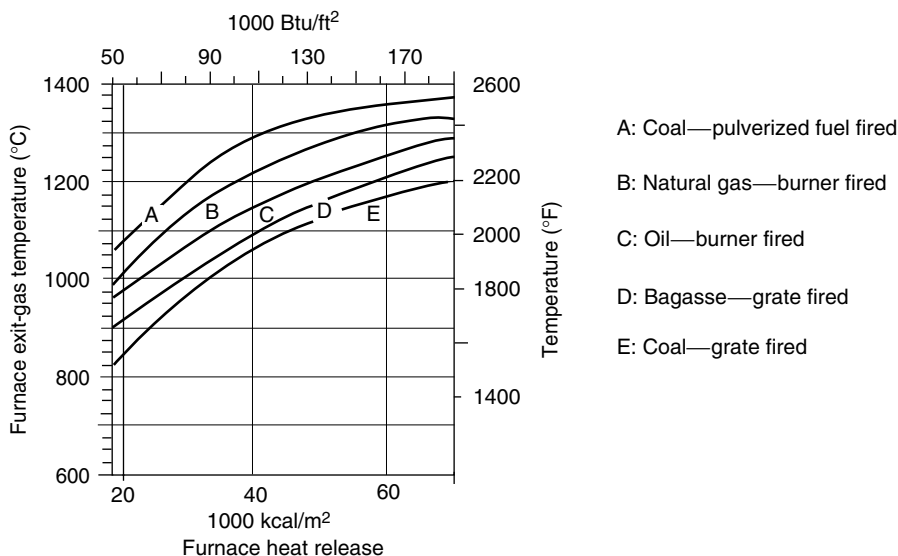


FIGURE 6.1

Typical FEGT versus heat release graph for burner and grate firing.

gives the exit temperature. There is a staged combustion, and the walls are covered with ash whose effects have to be accounted for.

6.2.1.3 Division Walls etc.

As the boilers grow in size, the furnace volume increases cubically whereas surface increases by squares, leading to a mismatch—there is more volume than surface. Division walls are introduced to correct this mismatch. A division wall is an evaporator wall in the middle of the furnace, usually from bottom to top, receiving heat from both sides. Wing walls and platen SH introduced in the furnace for picking up heat economically also help to correct volume-to-area ratio.

6.2.1.4 Membrane Panels

Modern boilers employ fully water-cooled surfaces as furnace enclosure walls, with little or no refractory that calls for costly downtime and maintenance, unless there is a specific requirement for

- Erosion protection of tube walls such as in stoker firing up to 2 m or bubbling fluidized bed combustion (BFBC) boilers around the bed
- Corrosion protection as in lower combustor of CFBC boilers
- Overheat prevention like the furnace floor of oil- and gas-fired boilers

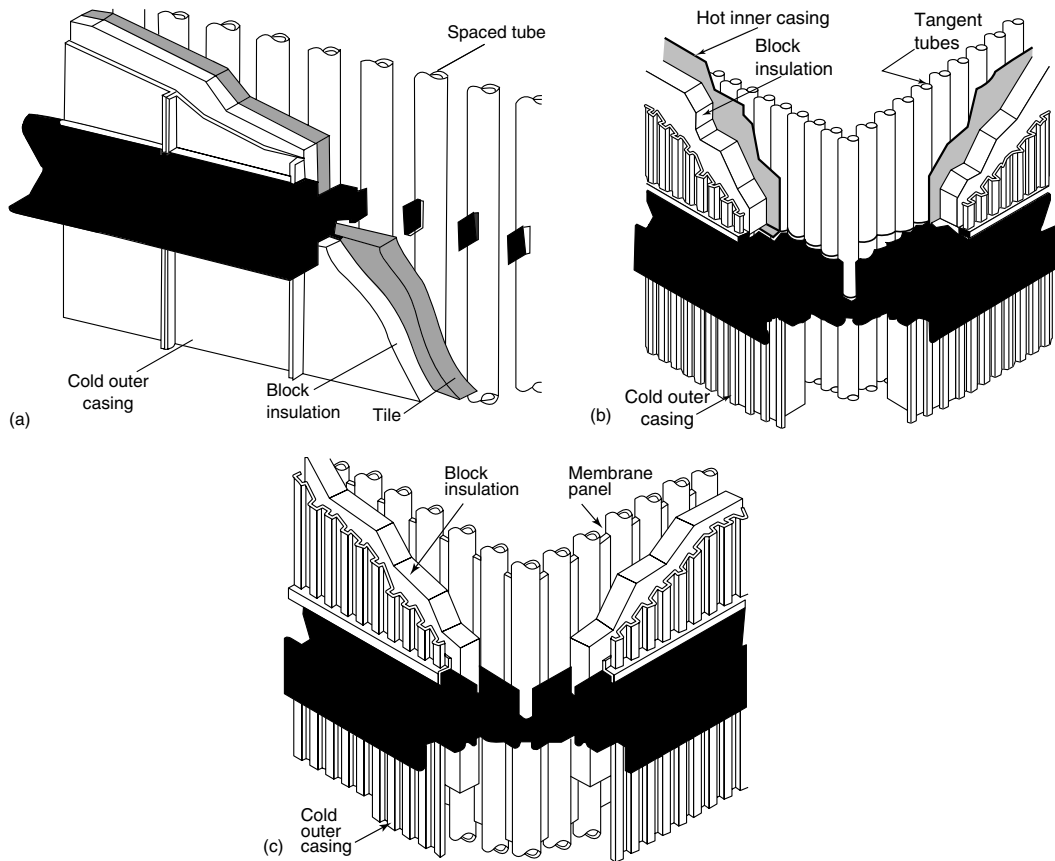
It has taken several decades to progress from full brick wall construction to full water wall cooling—tube and tile (Figure 6.2a), and bailey wall construction, etc., paralleling the advancements in combustion. The tangent walls (Figure 6.2b), with tubes touching each other, were major advancements in the early 1950s, but the following were the two major issues to be addressed:

1. Construction time increased because each tube was to be lifted into position.
2. Tube repair was difficult because the affected tubes had to be jacked out of position.

Membrane panels (Figures 6.2c and 6.3), with a steel strip/bar inserted between the tubes and shop welded on submerged arc welding machines (to give adequate weld penetration between the bar and the tube) and finish fabricated in transportable panels remedied the situation and made tangent tube construction almost obsolete. With the end headers fitted and heat treatment carried out in the fabrication shops, the site work was considerably simplified.

The advantages of the membrane walls over tangent tubes can be summarized as follows:

- Faster and easier site erection facilitates very large boilers.
- Tube repair is much simpler.
- Fit and finish of shop-made panels is far superior.
- Capacity to withstand furnace puffs is better because the membrane panels behave like plates.
- For the same EPRS, membrane panels use fewer tubes.
- Tube diameters are smaller, saving pressure part (PP) weight.

**FIGURE 6.2**

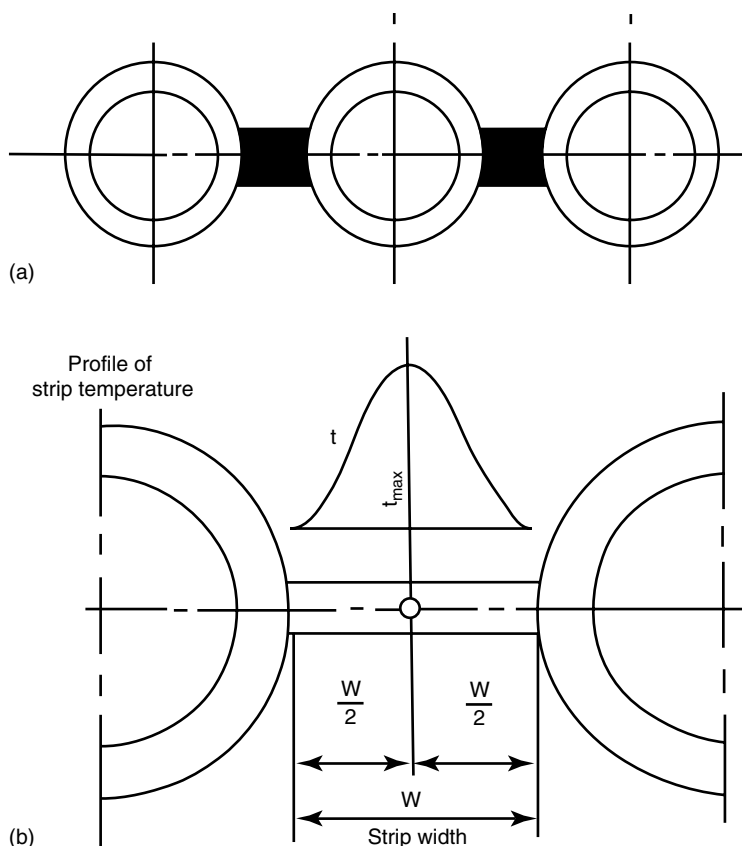
(a) Tube and tile construction. (b) Tangent tube construction. (c) Membrane wall construction.

The membrane strip is usually 6–8 mm in thickness and varies from 12 to 60 mm depending on the furnace heat flux. Only high heat flux, such as in pulverized fuel (PF) boilers and package boilers for oil and gas, strictly calls for 8 mm thick strips.

- For PF boilers with high heat flux, the width of the membrane strip varies from 6 mm to a maximum of 18 mm.
- For highly rated package boilers, the width is often 12 mm.
- For FBC boilers, with relatively low heat flux, the width can be as high as 60 mm.
- Waste fuel and waste heat boilers also use wide strips.

The maximum temperature attained by the strip at its midpoint and the stress levels generated govern the strip width which, in turn, is dependent on the heat flux (Figure 6.3b).

Panel welding and panel bending (vertical or horizontal) machines are expensive and occupy considerable shop space. Some small boilermakers therefore employ hand welding using straight and bent tubes as required. Is hand welding a substitute for machine welding? The answer is perhaps not. IW machine welding and strip bonding are strong and the weld deposit is large, which provides a large base of metal to transfer the heat of the

**FIGURE 6.3**

(a) Membrane panel. (b) Temperature variation in membrane strip.

membrane to the tube. The resulting temperature gradient profile is gentler and stresses developed are lower. The hand welding leaves a much smaller weld deposit. For low heat fluxes, such as those encountered in FBC and biofuel systems, firing hand-welded panels yield good service at a very low cost, despite the obvious disadvantages of lower speed of production and inferior weld penetration that account for poorer transfer of heat from gases to water.

6.2.1.5 Refractory Lining of Furnaces

Several areas of construction of furnaces demand lining with refractory, mainly for erosion, corrosion, and overheat protection.

- Staged combustion demands refractory facing in the lower part of the furnace, below the secondary air (SA) nozzles, to protect the tubes from corrosion due to the prevailing reducing conditions, typically in CFBC and black liquor (BL) recovery boilers.
- In BFBC boilers, the furnace tubes around the bed, for a height of ~ 1.5 m, need protection against erosion due to the constant impingement of bed material.

- In spreader stokers (SS)-fired boilers a stream of coal lumps hits the rear and side walls as the spreaders hurl the fuel into the furnace, causing tube erosion up to a height of ~ 1.5 m.
- In BL recovery boilers, the lower furnace needs a defense against corrosion due to reducing atmosphere and erosion because of the continuous flow of the smelt on the tube walls.
- In cases of excessively low GCV of fuel, the lower/front end of the furnace is sometimes refractory-lined to hold the heat and re-radiate, such as for firing blast furnace gas (BFG) in package boilers.
- Stoker arches are good examples of refractory lining absorbing heat and re-radiating on green fuel for ignition.
- All burner openings in PF boilers and many oil- and gas-fired boilers need protection against tube erosion due to high-speed gas streams.
- In package boilers, the furnace floor is exposed to radiant heat. With steam blanketing the upper part of the tube, there is insufficient cooling. Suitable lining is needed to protect the tube from overheating.

Many such applications are handled in modern furnaces by gun studding the tubes to hold the appropriate refractory lining. Studding needs have to be carefully evolved. Different arrangements are developed for different requirements.

- Pin studs are usually between 8 and 12 mm in diameter and 15–25 mm long, welded to tubes on a triangular pitch (Figure 6.4).
- They can be made of CS or stainless steel (ss), depending on the temperature of the stud and the corrosion environment. Stainless steel is more common.
- Studs conduct the heat of the refractory lining to the tube and keep the lining cool. Hence the studs are tapered at the base and heavy duty pressure welding is used so that the base of the stud and the surfaces of the tubes melt and adhere. The strength of the weld is established by the bending of stud in a hammer test. The intent is to provide a strong weld that passes the heat received from the flame and lining to the tube effectively.
- The stud temperature increases toward the tip. The maximum length of the stud should be restricted to the temperature limit of the material.
- The refractory can be Al_2O_3 , PCO, SiC, or any such castable as required. SiC is the most conductive, dense, and expensive of all the linings. Circulating fluidized bed combustion boilers usually employ linings to transfer the heat as well as to withstand erosion. Al_2O_3 lining is used where heat transfer is less important than erosion resistance. PCO is popular in BL recovery boilers.

For large boilers with sizable studding, dedicated gun studding machines and teams of workmen are needed. But for small boilers and sporadic requirements, CS or Y-shaped ss plate studs are hand-welded and then refractory mixture is applied.

6.2.1.6 Furnace Tube Size

The considerations in tube size selection are:

- Tube diameters used in modern furnaces vary from 38.1 mm (1.5 in.) to 76.2 mm (3 in.) OD.

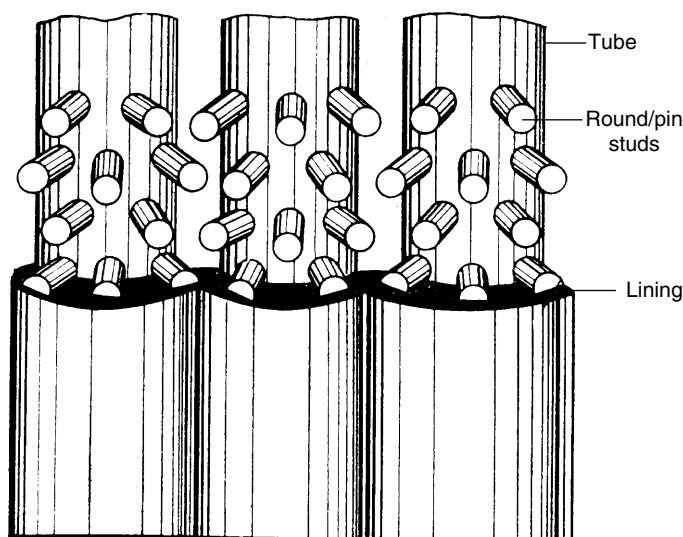


FIGURE 6.4
Typical studded tube.

- Smaller diameter results in a thinner tube, which has an improved thermal flexibility but is mechanically weaker and offers greater inside friction loss. If there is an adequate thermosyphonic head to compensate, smaller tubes are preferred because they are lighter and hence cheaper so long as they can withstand the mechanical requirements.
- Tall furnaces of utility boilers with natural circulation usually adopt larger-diameter tubes—63.5 or 76.2 mm (2.5 or 3 in.) OD. With assisted and forced circulation, tube sizes can be reduced to 50.8 and 63.5 mm (2 or 2.5 in.) OD tubes.
- Package boilers tend to use 38.1–50.8 mm OD. With water quality in boilers vastly improved, the need for conservative diameters no longer exists.
- For heat transfer, the tube diameter does not have great significance. For circulation, larger tubes are better because they offer less resistance. Mechanical stability is very important in the selection of tube size.

6.2.1.7 Furnace Pressure

Buckstays are provided approximately every 2–3 m along the furnace height to hold the furnace in proper shape against internal gas pressures. A buckstay is an assembly of four girders supported on all the four walls and hinged at the corners to provide for expansion. The rise in internal pressure beyond the safe limit allows the gases to escape from the corners without damaging the tubes (Figure 6.5).

Usually furnaces are designed for internal pressure fluctuations of ± 200 mm wg. In case of large boilers with heavy back-end and cleanup systems, high draft-induced draft (ID) fans are used. In a flame-out situation, from sudden termination of fuel supply (oil valve closing too suddenly or a master fuel trip), the furnace experiences a sudden decay in pressure. Maloperation of dampers can also create a similar situation, called *implosion*. Then the furnace setting is designed for ± 500 mm wg.

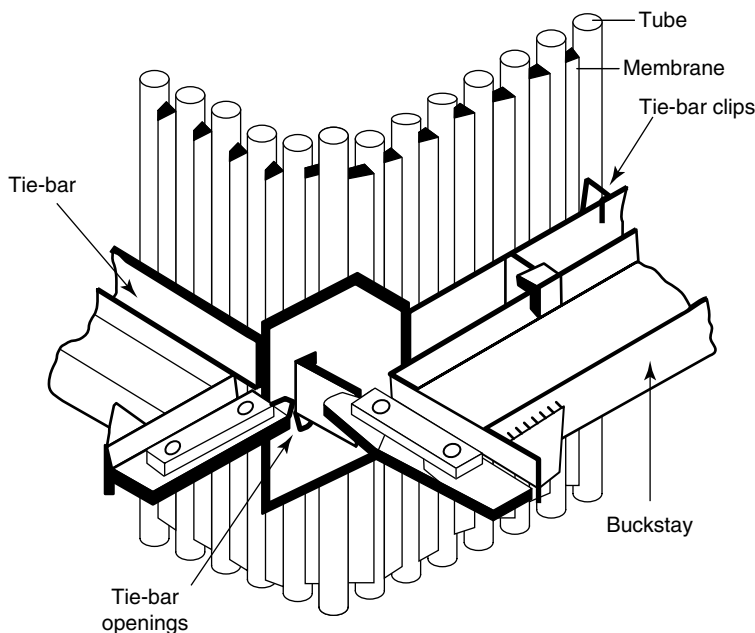


FIGURE 6.5
Typical buckstay details.

6.2.2 Boiler Bank (BB)

Furnace and BB are the two evaporator surfaces in a boiler. Normally, a furnace is a totally radiant surface, whereas a BB is fully convective. A boiler bank is a large surface made up of tubes fully expanded between top/steam and bottom/water drums. Until the 1950s, when the steam pressures were low and the coals were better, the BBs were the largest surfaces with three or four drums. Today bidrum boilers form the bulk of industrial boilers (Figure 6.6). The limit for the bidrum design is 100–120 bar. Boiler banks are absent in the radiant single-drum boilers.

A boiler bank provides a substantial portion of the water-holding capacity. With large amounts of saturated water, the BB serves as a big reservoir of heat. No doubt, it retards the boiler start-up and shutdown, making the response a bit sluggish; and it also makes a boiler very forgiving for operational deficiencies. Improvements in water quality and instrumentation have increased the customer expectation for superior boiler response from conventional fuels, calling for single-drum boilers with steaming ECONs (if required), particularly for pressures >60 bar. For high-moisture fuels such as wood, bagasse, BL, where there is a lot of heat in the water vapor of the flue gas, a BB is indispensable because ECON alone is insufficient to extract the required amount of heat, particularly in medium pressures.

No radiant heat is usually incident on the BB surface, and heat transfer is purely convective with some intertube nonluminous radiation. It is governed by the gas-side heat transfer coefficient because the water-side coefficient is too high.

From the heat balance of the bank, the heat gained by water is equal to the heat lost by the flue gases, which is stated as

$$R \times A \times \text{LMTD} = W_g \times C_g \times (T_1 - T_2) \quad (6.3)$$

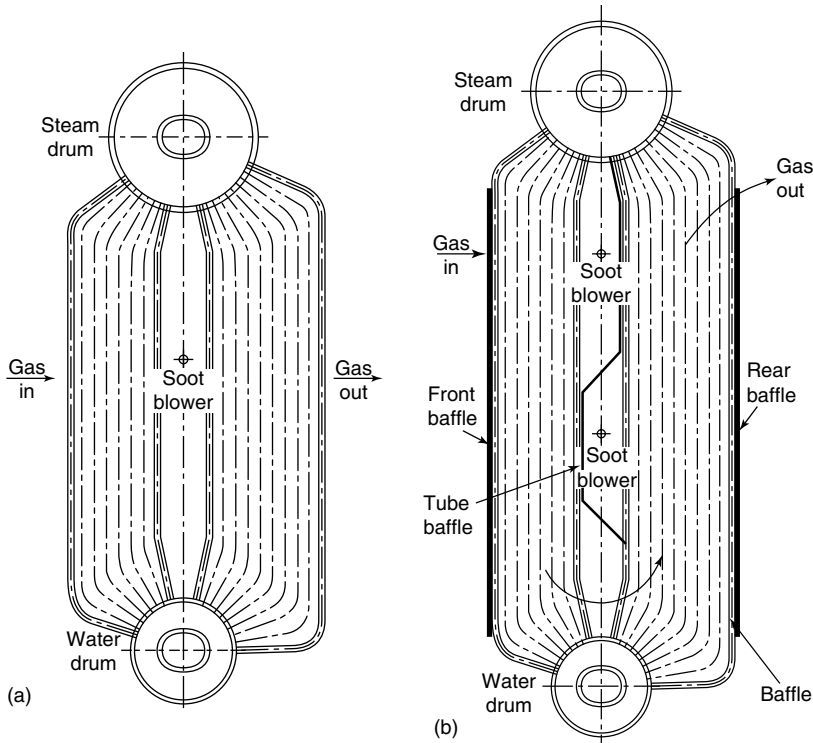


FIGURE 6.6

(a) Single-pass boiler bank in cross flow. (b) Two-pass boiler bank in longitudinal flow.

where

R = overall gas-side heat-transfer coefficient, both convection and radiation

A = HS of the tubes measured on the OD

$$\text{LMTD} = \text{the log mean temperature difference} = \frac{T_1 - T_2}{\log_e \left[\frac{T_1 - t}{T_2 - t} \right]}$$

W_g = weight of the gas

C_g = specific heat of the flue gas

$T_1 - T_2$ = gas temperature drop

In a BB, the amount of HS is known because of the predetermined configuration. BB exit-gas temperature (BEGT) can be found using Equation 6.3. For single-pass BBs, the $T_2 - t$ is in the range of 120–150°C, whereas for two-pass BBs, it is ~100°C for coal-fired boilers (Figure 6.7).

6.2.2.1 Tube Expansion in Boiler Bank

The tubes are held in the tube holes in the drums by means of mechanical expanders (Figure 6.8).

- The tube is expanded by force to fill the tube hole, and by friction the two are held together. Normally, a straight distance of at least 20 mm is needed for friction gripping of the tube. Hence, the minimum plate thickness is 20 mm.
- Bell mouthing, to arrest any possible axial movement, follows the expansion of tubes.

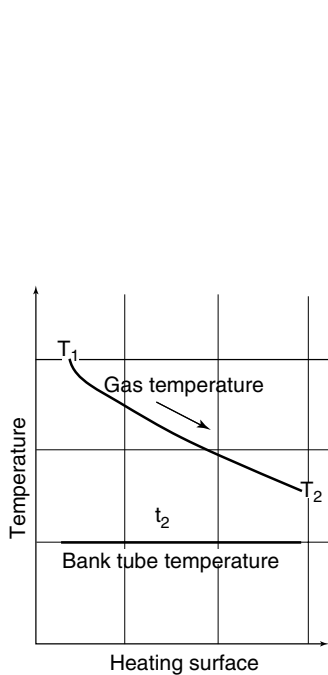


FIGURE 6.7
Temperature profiles for boiler bank.

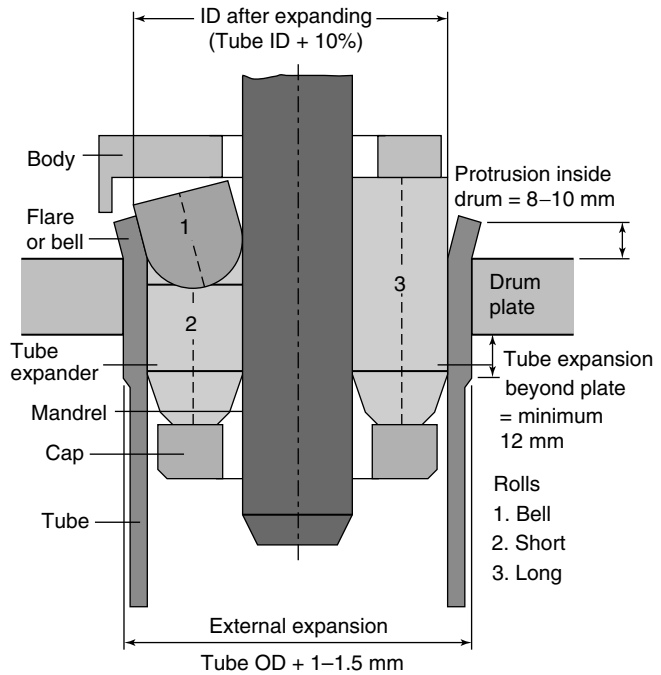


FIGURE 6.8
Tube expander.

- It is normal to provide one or maximum two grooves in the tube hole for the tube material to flow into the drum plate and lock itself to prevent loosening during transportation to site.
- On the inside of the drum, the tubes must protrude by ~ 12 mm and the tube holes should have a clearance of 12 mm (to allow for bell mouthing).
- On the outside of the drum, the tubes should be expanded by at least 12 mm.
- Beyond 80–100 bar design pressure, it is normal to seal weld the tubes to the inside of the drum.
- A pressure of 100 bar and at times even 120 bar for some manufacturers, is the maximum limit for tube expansion, as the drums attain a thickness of 150 mm or more, making it difficult to expand the tubes for such a length.

6.2.2.2 Boiler Bank Tubes

The salient points of BB tubes can be listed as follows:

1. Tube size
 - a. Tubes employed in the BB range from 38.1 mm (1.5 in.) to 63.5 mm (2.5 in.) OD.
 - b. Smaller tubes are better for heat transfer and larger tubes for mechanical loading.
 - c. With improved water quality the bias against smaller tubes of < 50.8 mm (2 in.) OD has slowly disappeared, as has the frequent cleaning requirement of the boiler tube internals.

- d. Tubes with 38.1 mm (1.5 in.) OD are mostly found in package boilers.
 - e. Bottom-supported modular designs for oil- and gas-fired boilers usually adopt 63.5 mm (2.5 in.) tubes.
 - f. The most common size of tubes is 50.8 mm (2 in.) OD.
2. Tube material
 - a. Since the BB contains only saturated water, the metal temperatures scarcely exceed 350°C for which CS is the most appropriate material.
 - b. Low CS with lower hardness is preferred because the tube expansion is a cold working operation that needs a soft and ductile material, at least over the length that is expanded.
 - c. Electric resistance-welded (ERW) tubes are preferable to seamless, as the concentricity of the bore to the OD is automatically ensured, which on expansion, would cause no unevenness of material flow. This requirement of tube concentricity applies to thicker tubes at higher pressures. But the fear of opening along the weld line is also strong, although the ERW tube-making process is improved.
 3. Tube spacing
 - a. Clear spacing between tubes is governed by the permissible gas velocities, fouling tendencies, and access requirements.
 - b. In-line tube arrangement is adopted for accessing the inside tubes of the bank and for combating the erosive forces of the dust-laden gases. It is usual to alternate the pitch along the drum length to gain an access space of 60 mm after every other tube, for insertion of a hand. Instead of choosing a uniform 100 mm pitch, an alternate pitch of 110 and 90 mm is chosen.
 - c. With clean gases staggered, pitching is common to achieve better heat transfer.

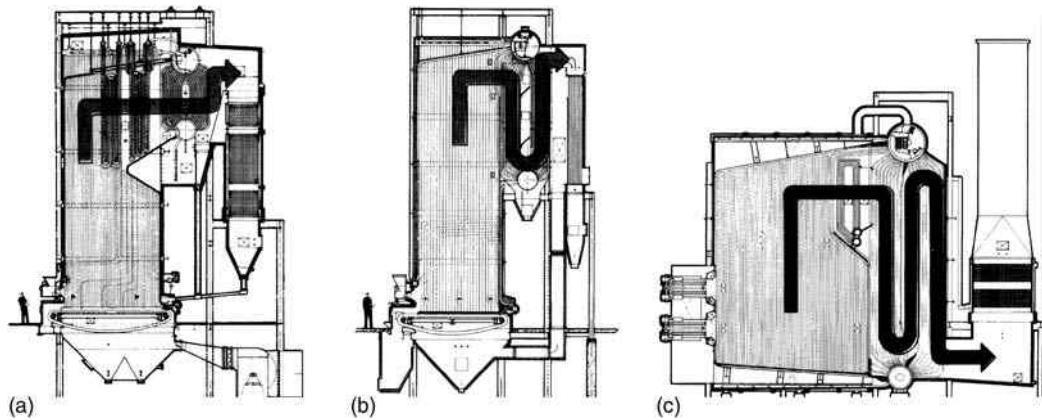
6.2.2.3 Boiler Bank Types and Design Features

Based on the flue gas flow the BBs types are:

- Single-pass cross flow (Figures 6.6a and 6.9a) or multipass cross flow
- Multipass longitudinal flow (Figures 6.6b, 6.9b, and 6.9c)

Salient points are as follows:

- For dust-laden gases, the erosion considerations favor the use of single-pass banks, although the heat transfer is lower.
- Layout issues decide between cross flow and longitudinal flow for cleaner gases.
- In most BBs the gas flow is vertical, except in some package boilers where it is horizontal and the gases are necessarily clean.
- A BB usually consists of, along the circumference of the drum,
 - 18–22 tubes allowing longitudinal and cross flow of gases, which are normal to the drum axis
 - 10–12 tubes allowing horizontal flow of gases, which are along the drum axis

**FIGURE 6.9**

(a) Single-pass cross flow, (b) two-pass longitudinal flow, and (c) multipass longitudinal flow boiler banks.

- In the tube bank, one-third of tubes on the colder side, circumferentially in the case of cross flow or axially in the case of horizontal gas flow, are made into downcomers by suitable baffling inside the drum.
- A minimum centerline distance between drums has to be maintained for a satisfactory circulation to induce the required thermosyphonic head.
 - With high heat flux prevailing in package boilers, 3 m height is possible.
 - In bidrum boilers, a minimum of 4 m is required.

The maximum height is dictated by boiler arrangement. In the bottom-supported oil and gas bidrum boilers, heights of 12 m are common. In such tall bottom-supported banks, tube diameters are seldom <50.8 mm (2 in.) OD. Adequate measures for vibration prevention have to be taken.

- A BB should preferably cool the flue gases to at least 450°C to
 - Avoid flow reversal in the downcomer tubes due to steam generation
 - Permit CS ducting as at $>450^{\circ}\text{C}$ ss or CS ducting with brick lining
- This requirement is at times difficult to meet in single-pass boilers. The solution is to check the circulation calculations carefully for steam quality in the downcomers. Unheated downcomers can resolve the situation.
- Soot blowers (SBs) are provided in the bank for cleaning the tubes. Rotary blowers are adequate as the gas temperatures are low. It is usual to adopt blowers from one side for boiler widths of 7 m maximum. The depth along gas flow is usually limited to ~ 1.5 m, which is within the cleaning radii of rotary blowers for most fuels with normal fouling tendencies.
- Drum thicknesses can be reduced by using bank tubes with swaged tube ends. *Swaging* is a cold forming process of reduction of diameter by either roll forging or end squeezing. This is followed by annealing to remove the stresses of the cold working and to induce the softness and ductility required during tube expansion operation. Swaging is normally limited to 25% (63.5–50.8 mm). Since the circulation is very vigorous in the BB, swaging has no adverse effect and is freely used even for high pressures (HPs).

6.3 Superheater and Reheater (SH and RH)

The efficiency of the steam cycle is improved by higher steam pressure and temperature as well as reheating. Both superheating and reheating of steam have to be as high as possible. At a steam pressure of 120 bar and higher, the cycle efficiency improves by $\sim 1\%$ for every 20°C rise in superheat. Therefore, high superheats are desired for each band of pressure consistent with the metallurgy of the turbine.

- In smaller power ranges, 485 , 510 , and 530°C (905 , 950 , and 985°F) are the popular SOTs.
- For utility applications, 540°C (1005°F) is the most common.
- The 565°C (1050°F) is becoming prevalent in large heat recovery steam generators (HRSGs), and in subcritical boilers for RH.
- In ultra-SC (USC) applications, 620°C (1150°F) is used.

Beyond 540°C , the metallurgical issues assume a great importance. The most complicated parts of the boiler are the SH and RH because:

- They are located in the hottest gases (either inside or immediately after furnace).
- The coolant is not saturated water but steam, whose cooling effectiveness as measured by the film conductance is far inferior to that of water, making SH and RH attain the highest metal temperatures.
- At those temperatures, their sizing has to be very exact because the margin of error for overheating is limited.
- The disposition of surface should take into account the effects of gas-side slagging, fouling, erosion, and corrosion.
- *Unbalance* of steam flow and variation of gas flow across the boiler width have to be factored in, on top of *upset conditions* in gas temperatures, to arrive at the tube metal temperatures for material selection. Steam flow unbalance (elaborated in Section 6.3.7) is the variation of flow across the SH elements compared to the average flow. Upset conditions are the FEGT excursions due to furnace slagging or overloading.
- Appropriate steam temperature controls (STCs) have to be incorporated individually for SH and RH.

6.3.1 Superheater (SH)

In a subcritical boiler, the SH is between the main-steam header and the steam drum and consists of

- Saturated tubes that transport steam from the drum to the SH inlet header (when the SH tubes are not directly connected to the drum)
- Superheater banks with their respective inlet and outlet headers
- Attemperator station for STC
- Main-steam header with all fittings and terminating with the main-steam stop valve (MSSV)

Steam from the steam drum flows toward the main-steam header, and there should be no valve between the two to ensure flow in SH tubes under all conditions to prevent overheating and failure.

6.3.2 Reheater (RH)

Reheating of steam involves withdrawal of partly expanded steam (at the end of the high-pressure cylinder of the turbine), taking it back to the boiler in cold reheat pipes, heating to the same or higher temperature as the superheated steam, and returning to the turbine in hot reheat pipes. In terms of hardware, an RH system comprises

- Cold reheat pipe from turbine to boiler
- Safety valves on the cold reheat pipe
- Emergency spray-water attenuator system on a cold reheat pipe or interconnecting pipe
- Reheater bank complete with inlet and outlet headers
- Hot reheat pipe from boiler to turbine

Considering the required changes to the boiler and the turbine, the reheating involves a lot of expense and, from practical considerations, it is considered viable only above 100 MWe. In HRSGs, likewise, RH is employed in bigger combined cycle (CC) plants employing advanced class machines with high exhaust-gas temperatures $>600^{\circ}\text{C}$ and larger frame sizes with large gas flows. Typically, RH starts in HRSGs behind the gas turbine (GT) of frame size 9FA or equivalent with steam turbine output of >120 MWe.

A temperature of 540°C is the most popular. As the pressures in RH are lower (about one-third to one-fourth of SH), for the same stress levels in tubes, it is possible to have higher RH OTs of ~ 20 to 30°C over SOT.

In steam power plants, the RH flow is ($\sim 2\%$) less than the SH flow, as there are minor leakages in the HP cylinder of the turbine. In the case of gas-based power plants, however, the reverse applies. The intermediate-pressure (IP) steam is produced at the same pressure as the RH and is added to the RH flow.

6.3.3 Superheater and Reheater Design Principles

Superheater and reheater are the tube banks that attain the highest temperatures in a boiler and consequently require the greatest care in the design, fabrication, and O&M to ensure that the permissible metal temperatures are never exceeded. The final sections of both SH and RH must be placed in the highest gas temperatures, which calls for adopting the most appropriate high-temperature alloy for the tubing from considerations of

- Metal temperatures
- Fouling due to ash compounds
- Corrosion due to salts in ash

The three most important aspects of the design of both SH and RH are:

1. Uniform distribution of steam and gas across all the sections to minimize unbalance of flows.
2. Optimally high steam velocity in all the tubes to keep the metal temperatures as low as possible.
3. Minimum steam pressure losses.

- a. Superheater pressure drop is normally limited to ~8% of outlet pressure to reduce the pumping load.
- b. Reheater pressure drop is usually <2 bar from cycle efficiency considerations. This is a tough requirement, particularly where specific volumes of RH steam are three to four times higher than those of SH steam. A reheater bank is usually located just after the final SH bank in the hot gases to make it as compact as possible and contain it in a single bank between a single set of headers.

6.3.4 Superheater and Reheater Classification

Superheater and reheater can be classified from design and arrangement considerations as shown in Table 6.2.

6.3.4.1 Parallel Flow and Counterflow

These flows are based on the overall direction of steam flow with respect to gas flow. Individual tubes, however, are always at cross flow.

- The section is in parallel flow (Figure 6.10b) when the two flows are in the same direction and in counterflow (Figure 6.10a) when in opposite direction.

TABLE 6.2	
Classification of Superheaters and Reheaters	
By Design	By Arrangement
Parallel and counterflow	Vertical and horizontal
Radiant and convective	Pendant and platen
Single and multipass	Drainable and nondrainable
	In-line and staggered

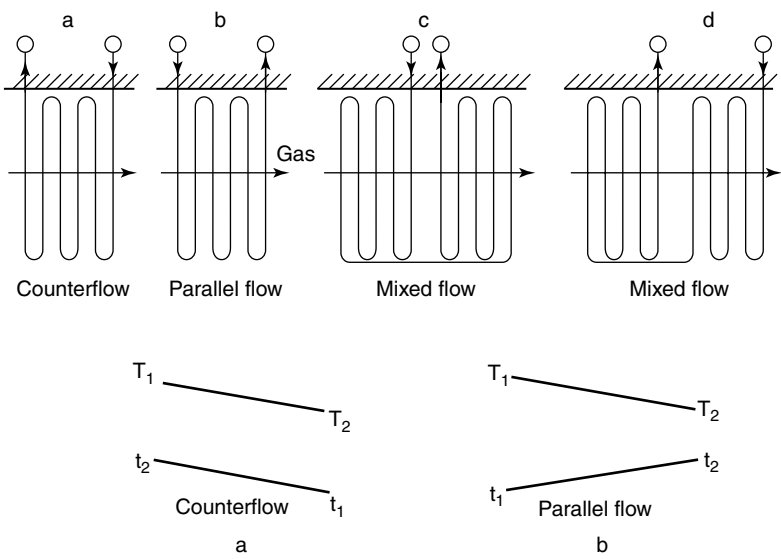


FIGURE 6.10 (a) Counterflow, (b) parallel flow, and (c) and (d) mixed-flow surfaces.

- In parallel flow, the highest gas temperature is in contact with the lowest steam temperature, which makes LMTD a little lower and the HS a little higher. The reverse applies to counterflow. Naturally the counterflow arrangement yields the lowest surface.
- Because the highest gas and steam temperatures in counterflow coincide, the metal temperatures are at their highest.

Mixed-flow arrangement (Figure 6.10d) is the optimum solution that yields a good compromise—counterflow at a lower temperature and parallel flow at a higher temperature. Sometimes this pattern is reversed as shown in Figure 6.10c.

$$\begin{aligned}
 \text{A. Counterflow LMTD} & \frac{[(T_1 - t_2) - (T_2 - t_1)]}{\log_e [(T_1 - t_2) - (T_2 - t_1)]} \\
 \text{B. Parallel flow LMTD} & \frac{[(T_1 - t_1) - (T_2 - t_2)]}{\log_e [(T_1 - t_1) - (T_2 - t_2)]}
 \end{aligned} \tag{6.4}$$

6.3.4.2 Radiant and Convective Superheater and Reheater

This function is based on the type of heat transfer that is predominant. Superheater and RH in a furnace are radiant. They are in the form of platens or wing walls. With increasing load, the temperature of the steam in a radiant surface reduces unlike on a convective surface, where the steam temperature rises with load. This is because the radiation incident is not much lower than that at full load, whereas the steam flow reduces proportionally, thereby absorbing greater heat and becoming hotter at low loads. The converse is true for convective surfaces. Both radiant and convective SH and RH are necessary to attain the high steam temperatures needed. Their characteristics can complement each other to obtain a fairly constant temperature at all loads with minimum attemperation (Figures 6.11 and 6.12).

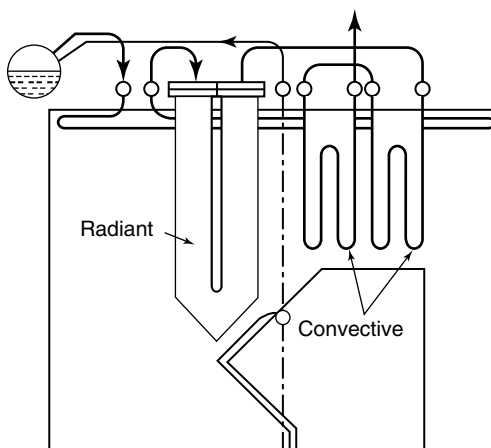


FIGURE 6.11
Typical radiant and convective superheater.

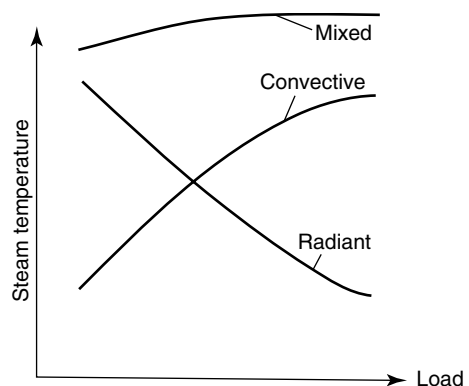


FIGURE 6.12
Radiant and convective superheater characteristics.

6.3.4.3 Single-Pass and Multipass Arrangements

Steam should also be viewed as a coolant for SH or RH coils. Adequate velocity of steam is essential to remove the heat and keep the metal temperature in control. In other words, the steam film on the inside of the tube has to be as thin as possible so that the tube metal stays close to the bulk steam temperature. At the same time high steam flow contributes to an excessive steam pressure drop. Table 6.3 gives the recommended steam flow in tubes at various temperature levels. A desirable pressure drop between headers is 1.5–2.0 ata (20–30 psi) as a good balance.

- To prevent flow reversal at low loads
- To avoid unnecessary load on feed pumps

To achieve this end, tubes may have to be arranged in parallel in several loops along the gas flow as shown in Figure 6.13 with a two-loop arrangement. In addition, across the gas flow, steam may be carried in one or several parallel passes. This is typically the case with wide furnaces and low-CV fuels with relatively small steam production per meter length of drum, as in waste heat and waste fuel boilers.

6.3.4.4 Vertical and Horizontal Arrangements

Vertical, horizontal, and a combination of both are used for achieving the desired SH and RH depending on the boiler layout.

- Vertical tubes are easy to suspend and the tubes are free to expand. But they are not drainable, which acts as a drawback in achieving faster startup of the boiler.

TABLE 6.3
Typical Steam Mass Flows for Convective Superheaters and Reheaters

Steam Temperature (°C)	Range of Mass Velocity in Convective Banks	
	kg/m ² s	lb/ft ² h
370–425	330–460	250,000–350,000
425–480	530–660	400,000–500,000
480–540	660–800	500,000–600,000
540–590	950 and above	700,000 and above

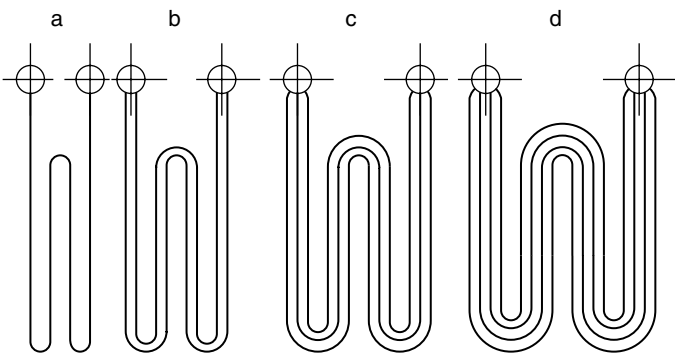


FIGURE 6.13
Two-loop arrangements with 1 to 4 tubes and loops.

On rapid heating, water condensed from the previous shutdown turns to steam abruptly and forms a vapor lock in certain vertical tubes, preventing flow of steam in either direction. This causes tube overheating and failure. A controlled heating is therefore needed.

- Horizontal tubes are fully drainable and hence facilitate a faster startup and superior boiler load response but require a more elaborate and expensive supporting arrangement to permit proper tube expansion.

6.3.4.5 Pendant and Platen Surfaces

A pendant as the name suggests, is a loop with space between the adjacent legs. It is normally vertical but can also be horizontal. Figures 6.14 and 6.15 depict the horizontal and vertical pendants of single-loop and multiloop constructions, respectively. The horizontal tubes are supported by vertical tubes, usually ECON tubes, on cleats as shown in Figure 6.16. The spacing of vertical tubes is such that the sagging of horizontal tubes does not take place, lest the draining should suffer. The heat transfer is by a combination of radiation and convection, but predominated by the latter. The clear spacing between the pendants reduces with the lowering gas temperatures as the fouling tendency of the ash diminishes; hence, the need for gas velocities should be maintained. Load versus steam temperature is always a rising curve in a pendant, the slope reducing with higher amount of radiation from the furnace.

Spacing of pendants across the gas flow is decided by the fouling tendencies of the fuels. Soot blowers are necessary with dirty fuels. Retractable blowers at the furnace end and rotary blowers at lower temperatures are needed. Depth of the banks along the gas flow has to be limited to ~ 1.7 m for coal from accessibility and cleaning considerations. Access doors for inspection and maintenance at the front, middle, and end of the banks are most essential, although this occupies valuable space.

In contrast, a platen is a set of closely packed tubes appearing like a plate (Figure 6.17). Platen surfaces are placed in the upper part, the open pass, of the furnace and are meant to pick up heat entirely by radiation. There is a strong slagging tendency of the flue gases in the temperature range in which the platens are located—approximately 1000 – 1200°C .

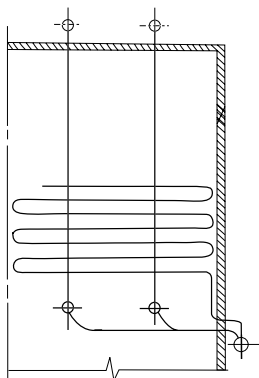


FIGURE 6.14
Horizontal single-loop pendant.

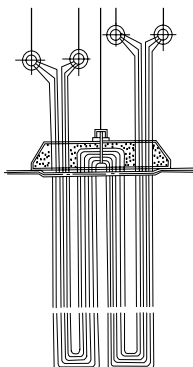


FIGURE 6.15
Multiloop vertical pendant.

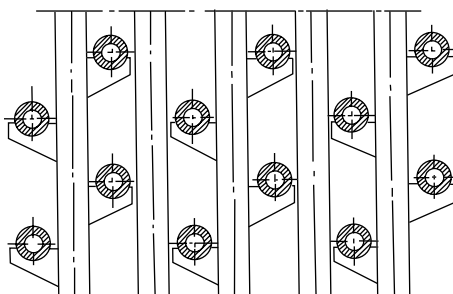


FIGURE 6.16
Supporting for horizontal sections.

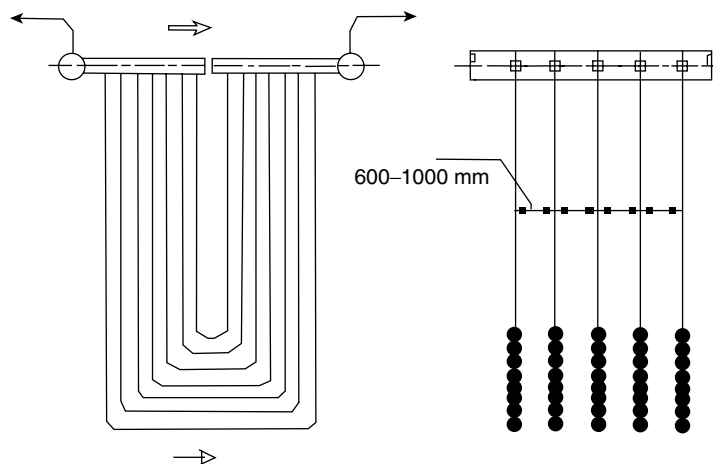


FIGURE 6.17
Typical vertical platen.

In PF boilers, it is usual to place the platens not less than 600 mm and usually 1000 mm apart to avoid ash buildups.

Platen heaters can be vertical (hung from the roof, Figure 6.17), angular (roof to front wall), or horizontal (in tower-type boilers, Figure 6.18). Heat transfer is entirely by radiation. Platen surfaces are calculated as part of furnace open pass. The heat pickup is adversely affected as the surfaces get fouled. In PF boilers, retractable SBs are provided with the highest steam flows to maintain the cleanliness of the platens. To limit the metal temperatures, steam with little or no superheat is passed in the platens and always in parallel flow. The steam mass velocity required is also higher at $\sim 1,350 \text{ kg/m}^2 \text{ s}$ ($1,000,000 \text{ lb/ft}^2 \text{ h}$) or more.

6.3.4.6 In-Line and Staggered Tube Arrangement

Superheater and reheater tubes can be placed in an in-line or staggered arrangement, with the latter giving a better heat transfer but more gas pressure drop, and a more compact surface on the whole. It is suitable only when flue gases are free of dust, to prevent tube erosion. The staggered arrangement is suitable for oil and gas firing whereas the in-line arrangement works for most solid fuel firing (Figure 6.19).

6.3.5 Tubes for Superheater and Reheater

A wide range of tubes are required in the SH construction, in terms of diameter, thickness, and metallurgy.

- Plain tubes normally used are of 38.1, 44.5, 50.8, and 63.5 mm ($1\frac{1}{2}$, $1\frac{3}{4}$, 2, and $2\frac{1}{2}$ in.), with less frequent usage of 31.8 and 70 mm ($1\frac{1}{4}$ and $2\frac{3}{4}$ in.) OD.
- Larger sizes are used more in utility boilers where the steam flows are high.
- The smaller the diameter, the greater the heat-transfer rate but the weaker the tube mechanically.

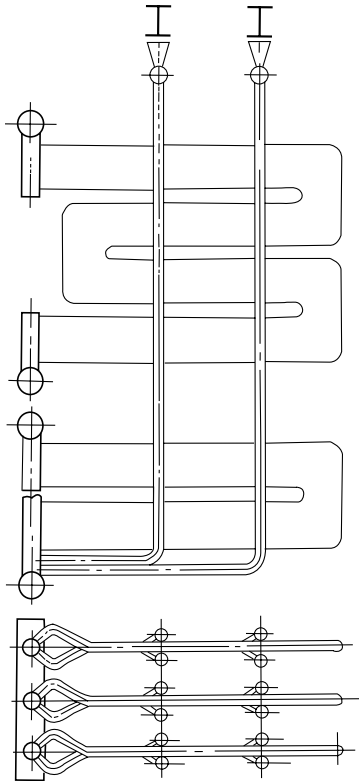


FIGURE 6.18
Typical horizontal platen.

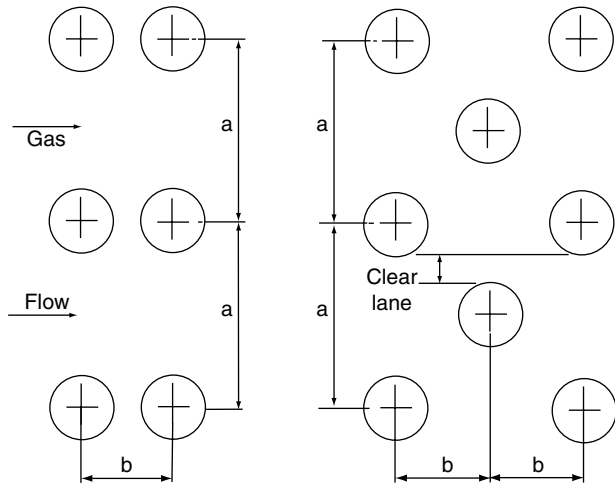


FIGURE 6.19
In-line and staggered arrangements of tubes.

- In horizontal SHs in tower-type boilers or vertical HRSGs, where tube supports are installed at almost every 3–3.5 m, 31.8 and 38.1 mm tubes are very popular due to reduction of HS and hence the PP weights.
- Generally, 50.8 and 63.5 mm tubes are extensively used for SH application in power boilers and 38.1, 44.5, and 50.8 mm tubes in industrial boilers.
- Minimum tube thickness from bending consideration is 3.25 mm (10 swg). For coal firing application, it is normal to adopt a minimum of 3.66 mm (9 swg) recognizing the erosion potential. For close radius bends, higher thickness is required depending on the manufacturing process. For higher pressures and temperatures, tube thicknesses required are considerably higher.
- For finned tubes used in HRSG, the minimum tube thickness is lower at 2.65/2.9 mm (11 or 12 swg) depending on the construction code. Lower tube thickness is permitted because the fins help to add to the strength of the tube. Also since the HRSGs experience no erosion or corrosion, the sacrificial material for such effects can be saved.
- Superheater and reheater tubes in conventional boilers are nearly always plain tubes to facilitate cleaning and avoid fouling.
- In clean waste heat boilers, such as HRSGs behind the GT, in which low-grade heat is to be picked up, there is a need for a lot of HS, and finned tubes are extensively employed.

6.3.6 Tube Spacing and Gas Velocities

Considerations vary for pendant and platen SH. In pendant SH, the heat transfer is predominantly by convection and hence the gas velocities should be maximized, balancing with the need to keep draft losses at an acceptable level. Fouling is another consideration that needs to be taken into account. Clear spacing between tubes is based on actual working experience. Table 6.4 summarizes the recommendations for various fuels.

In platen SH, the main consideration is the ash slagging on surfaces and subsequent buildup of ash, which bridges the platens, causing a disruption to the boiler operation. Platens are spaced 600–1000 mm apart.

Tube spacing is primarily governed by fuel ash characteristics. It is temperature- and gas-velocity-dependent to avoid bridging and erosion, respectively, both caused by ash in fuel. Ash, at a higher temperature, is sticky because it is slightly molten, whereas the same ash is gritty and friable and hence loose and powdery at lower temperatures. How sticky and at what temperatures are best inferred from the IADT and ash analysis. Tube spacing in a boiler reflects this transition from sticky to gritty material, as the spacing progressively narrows in succeeding tube banks. This is shown in Figure 6.20, where

TABLE 6.4
Permissible Gas Velocities and Clear Spacing between Tubes in Pendant Superheater (Perpendicular to Gas Flow)

Fuel	Oil			Pulverized Fuel Low/Soft Ash	Pulverized Fuel Abrasive Ash	Spreader	Stokers
	Gas	Distillate	Residual			Coal	Bagasse/ Biomass
Maximum gas velocity (m/s)	30	30	18	15–18	12–14	18	15–18
Maximum gas velocity (ft/s)	100	100	60	50–60	40–45	60	50–60
Clear spacing front (mm)	50	50	100–150	200	250–400	100–150	175
Clear spacing rear (mm)	50	50	50	75–150	100–150	50	63.5

Note: A gas velocity of 18 m/s is for oil with vanadium <500 ppm; 12 m/s gas velocity is for very abrasive coals such as Indian and South African coals; maximum gas velocity is the velocity of the gas at the inlet of the bank not the average at the middle; also it refers to the 100% MCR or peak load exceeding 8 h/day.

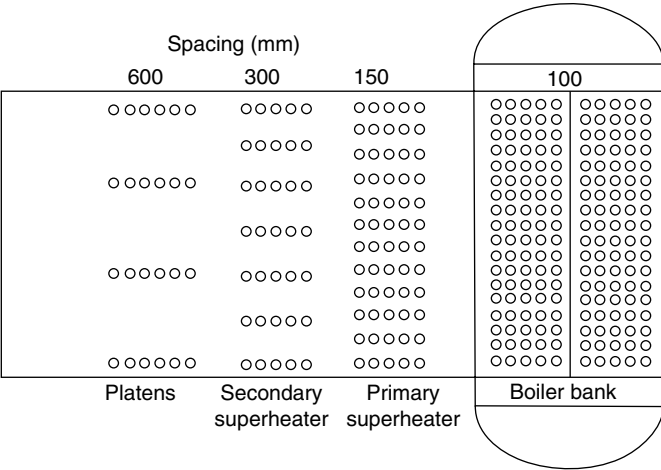


FIGURE 6.20
Progressive narrowing of tube spacing with gas cooling.

the spacing gradually reduces in a typical large industrial PF-fired boiler from 600 mm for platens at $\sim 1100^{\circ}\text{C}$ flue gas temperature to 100 mm in BB at $\sim 700^{\circ}\text{C}$ with SH spaced between those levels.

6.3.7 Tube Metal Temperatures

Tube material selection is based on the ability of steel to stand up to the *mean metal temperature*, which is the bulk steam temperature plus steam film temperature drop plus half the metal temperature drop. The design codes of the boiler define the exact permissible limiting temperatures for the material selected and also the full specification. However, the general limits are as given in Table 6.5 for different codes.

It is normal to adopt different tube thicknesses and metallurgies for different parts of the tube bank to optimize the cost. The most important parameter in lowering the metallurgy is the differential between the bulk steam temperature and the tube metal temperature. To minimize this

- Steam film inside the tube should be as thin as possible, for which the selection of optimum steam velocity is the first requirement. Guidelines are well established for this, as given in Table 6.3 for recommended steam mass flows.
- Steam flow unbalance in the tube bank should be minimized. *Unbalance*, as outlined in Section 6.3, is the deviation of flow in a particular tube with respect to the average flow in the bank. This unbalance should be contained within 5%, that is, the steam flow variation in tubes between the maximum and the minimum should be limited to 10%. The inlet and outlet flow configurations of the tube banks and the connected headers govern the unbalance. Great care should be exercised in selecting the geometry to minimize this unbalance.
- Uneven gas flow and uneven gas temperature profile across the width of the SH bank, which contribute to the undue excursion of metal temperature where the gas temperature or flow is higher than the average, should be minimized. A vigorous turbulence in the furnace and optimum gas velocities can minimize unevenness and stratification. Also crossover of steam of a set of SH tubes from the left to right side of the boiler is done to make the heat absorption nearly equal by either crossover header (Figure 6.21) or crossover riser pipe arrangement (Figure 6.22).
- *Gas laning*, which is an important point in installing tubes needs to be avoided. Tube pitching normal to the gas flow has to be strictly uniform so that the gas flows and velocities across the bank width are nearly equal. Sometimes this uniformity is not observed, and a few pitches in a tube bank, are spaced wider than the average such that the entire width of the boiler is covered. This promotes an

TABLE 6.5

Permissible Metal Temperature Limits for Various Tube Materials

Tube Material	Composition	Maximum Temperature ($^{\circ}\text{C}$)
Carbon steel	Carbon $<0.25\%$	455–480
Alloy steel	0.5% Mo	510
Alloy steel	1.25% Cr + 0.5% Mo	565–595
Alloy steel	2.25% Cr + 1.0% Mo	575–595
Alloy steel	9% Cr + 1% Mo	595
Stainless steel	18% Cr + 8% Ni	~ 650

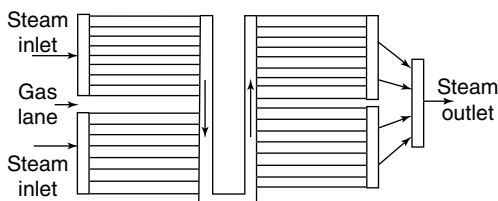


FIGURE 6.21
Steam crossover by header.

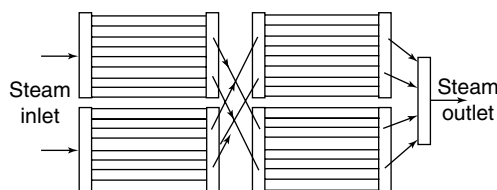


FIGURE 6.22
Steam crossover by pipes.

increased gas flow through the lanes called *laning*, which leads to (1) erosion and also (2) overheating on the faces of the tubes on either side of the lane. Rectification of this defect is difficult, and the problem should be eliminated at the design stage. Figure 6.21 depicts laning.

Mean tube metal temperatures can be limited to $<35^{\circ}\text{C}$ in convection zones and $<50^{\circ}\text{C}$ in radiant zones. In platen SHs and finishing SHs facing furnace radiation, the metal temperatures can be significantly higher at $>100^{\circ}\text{C}$. The combination of intense radiation, fluctuations in the gas temperatures, and the unevenness of gas flows all contribute to such high metal temperatures. A rigorous calculation to include the effects of all these variables should be carried out before determining the tube material and thickness.

6.3.8 Steam Temperature Control (STC)

Steam temperature control is an integral part of SH and RH. It is omitted only in smaller process boilers, where a nominal superheating of $<50^{\circ}\text{C}$ assures a perfectly dry steam at the consuming point in all conditions. In power plants, STC of both SH and RH is essential to

- Obtain optimum cycle efficiency over a wide load range
- Avoid frequent fluctuations in turbine metal temperature to assure a long life

Control range is the load range over which the SH and RH temperatures are required to be held constant. Usually it is from 70 to 100%. Occasionally 60–100% load range is also demanded. This demand is expensive because the SH and RH must be considerably oversized with commensurately large-size attemperators. At low loads with diminishing gas temperatures, it takes a very large SH to extract heat and maintain the SH outlet temperature (SHOT). Platen SH is a solution for this, but the punishing duty to which the platen tubes are subjected leading to corresponding shortened lives should be remembered.

There are many methods of STC namely,

1. Attemperation
2. Flue gas bypassing
3. Flue gas recirculation (GR) and tempering
4. Flame control by burner tilt or burner management
5. Excess air control

Of all the methods attemperation is the most popular and the simplest. In utility boilers, it is usual to supplement attemperation with one of the other methods to minimize the load on attemperator.

6.3.8.1 Attemperator

Attemperation is the desuperheating of main or reheat steam to control the final temperatures to the set limits. In a spray attemperator, the principle is a direct contact heat exchange where the feed water (FW) bypasses the ECON and evaporator circuits and joins the superheated steam directly. In a drum attemperator, an indirect heat exchange occurs when the extra heat of steam is dissipated to the drum water.

Besides the temperature control, an attemperator can also control the tube metal temperatures of SH and RH.

Reheater attemperation. Attemperation in RH is only for an emergency condition and not for regular temperature control operation because it reduces the overall cycle efficiency. The spray water added in the attemperator expands only in the IP and the low-pressure (LP) portions of the turbines bypassing the HP section altogether. Spray quantity of 1% steam flow reduces the heat rate by $\sim 0.2\%$. The temperature control of the RH is to be performed by flue gas bypassing or recirculation or by burner tilting.

The attemperator is located at the inlet on the cold reheat line so that the metal temperatures can also be controlled.

Superheater attemperation. Location of the attemperator is important for SH layout.

- Usually in industrial boilers of modest pressure and temperature, it is normal to employ the attemperator at the discharge end of SH when the steam is required at 425°C (800°F) and lower because the tube metal temperatures are low. Sufficient straight distance is necessary between the attemperator and the point of steam usage to ensure that the steam is totally free of water droplets if spray attemperation is employed.
- For higher temperatures, interstage attemperation is normal with SH divided into primary and secondary sections. The steam is cooled ahead of its heating in the secondary section, which helps keep the tube metal temperatures low.
- For the same reason many times a two-stage attemperation is adopted when the final temperatures are $>520^{\circ}\text{C}$ with SH divided into three sections, depending on arrangement. The response of the two-stage attemperator is superior to that of the single-stage attemperator.

The interstage and outlet stage attemperators are depicted in Figure 6.23. The effect on the metal temperature is easy to infer.

Types of attemperators. The two types are spray and surface.

1. In a spray attemperator (Figure 6.24), demineralized deaerated water of high purity is sprayed in a fine mist which evaporates and cools down the temperature of the steam but all the impurities of the spray water are introduced into the final steam. Feed water of modern-day boilers meets the spray-water quality requirements. Refer to Chapter 4 on water conditioning for elaboration.
2. A surface attemperator is a shell and tube heat exchanger (HX) with overheated steam passing through the body and FW through the coils. Another popular surface type is the drum-type attemperator (Figure 6.25) where steam flows through the coils immersed in the water drum in a bidrum boiler.
 - There is no water to be sprayed and hence no water quality problems.
 - The steam side pressure drop at ~ 2 to 3 atm (30–45 psi) adds to the head of the feed pump.

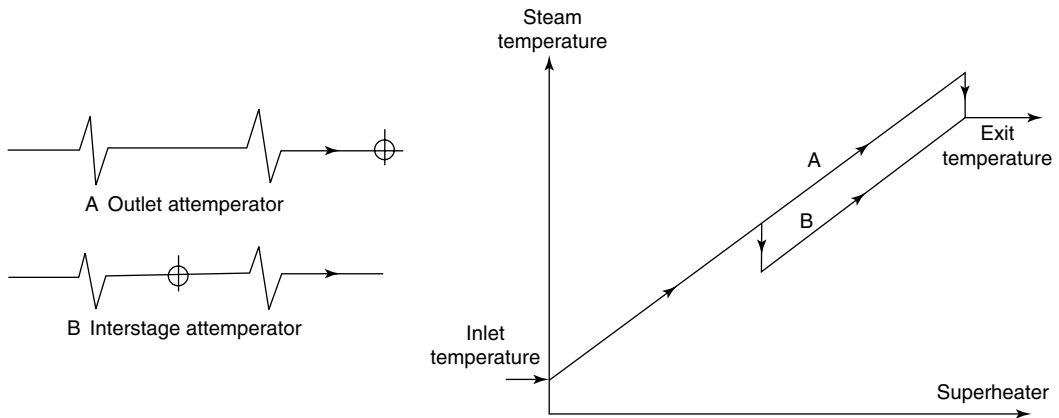


FIGURE 6.23
Effect of attemperator location on steam temperature rise.

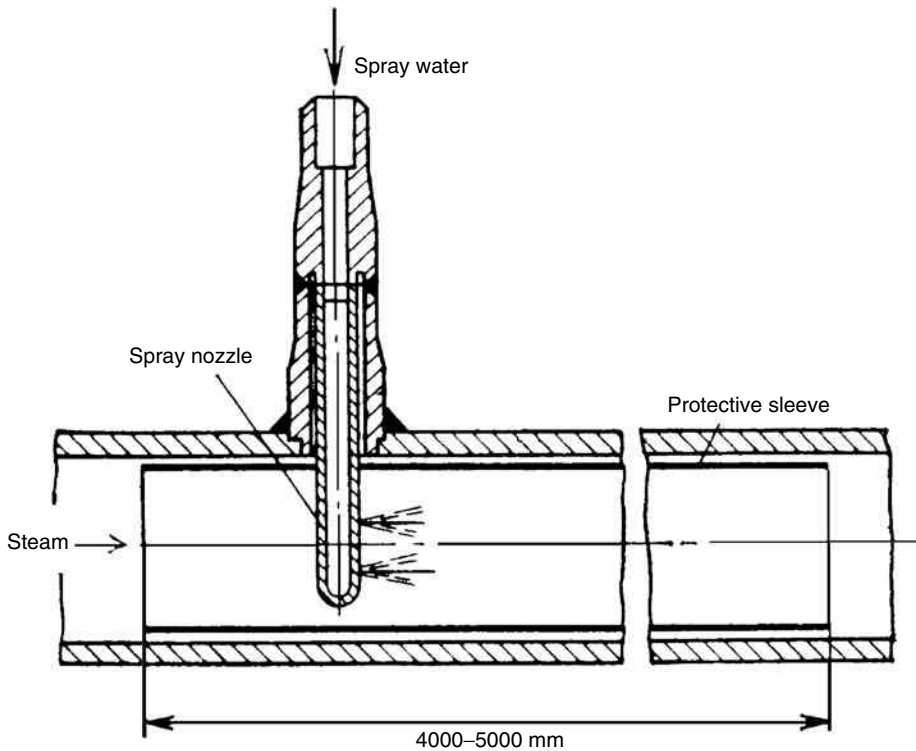
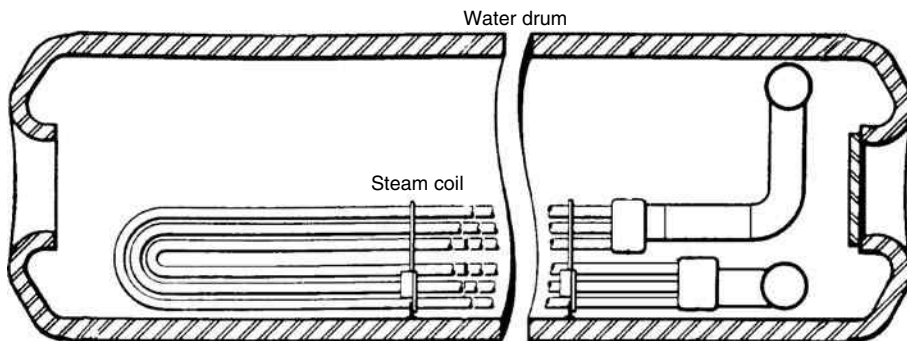


FIGURE 6.24
Spray attemperator.

- The required large-diameter piping from SH header to and from the attemperator needed with an interstage device must be very large when the route is made appropriately longer to induce the required flexibility.
- The response is a little slower.

**FIGURE 6.25**

Drum attemperator. (From Babcock and Wilcox Company, U.S.A. With permission.)

Spray attemperators are the only types used in utility boilers.

- They are simple in construction.
- They have practically no steam side pressure drop.
- They are highly responsive.

Surface attemperators, more specifically drum attemperators, have an advantage in low- and medium-pressure process boilers up to ~ 70 bar and are used in bidrum boilers. With widespread improvements in water quality, increased SHOTs, more cogeneration (cogen), and better operator training, attemperators are going out of use mainly due to sluggish temperature control and parasitic water side pressure drop, despite the advantages of freedom from spray-water impurity problems.

Spray water in an attemperator is usually limited to $\sim 8\%$ of total flow to reduce thermal shock on steam pipes and ensure that all water droplets get fully vaporized in a short distance. A judicious combination of radiant and convective SHs can achieve a spray water flow as low as 2–3%.

The design should specify 200% attemperation duty to account for several imponderables like variations in fuel quality, effects of slagging and fouling, and maldistribution of gas and steam.

6.3.8.2 Gas Bypassing

The temperature of the RH steam is regulated when flue gases are passed through a bypass duct between the SH and the RH in two-pass boilers. The arrangement is cheaper but maintenance prone, as the damper extends for the whole width of the boiler and the response is sluggish. This is also used for SH temperature control supplementing attemperation (Figure 6.26).

6.3.8.3 Gas Recirculation and Tempering

Flue gas from a boiler, ECON, and AH exit at $250\text{--}400^\circ\text{C}$ and can be introduced back into the furnace, without interfering with combustion, for altering the heat-absorption pattern. There is an increase in gas quantity without any increase in total heat of gases. Gas can be introduced into the furnace below the CHI gas recirculation (GR) or close to the furnace exit, called gas tempering.

In GR, the cold flue gas mixes with the gas from combustion, resulting in a drop of furnace gas temperature. As the furnace absorption is entirely by radiation, this reduced

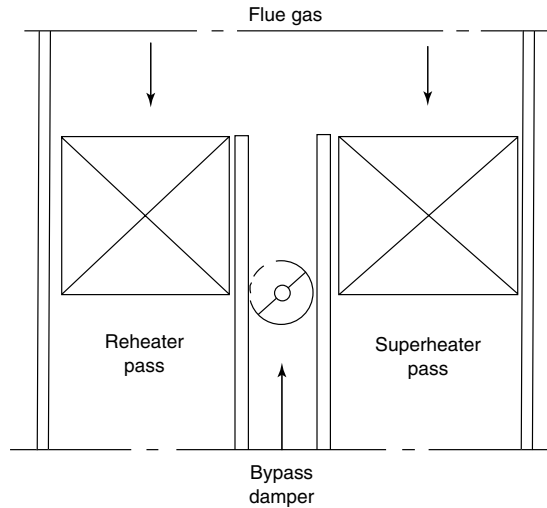


FIGURE 6.26
Control by gas bypassing in boiler second pass.

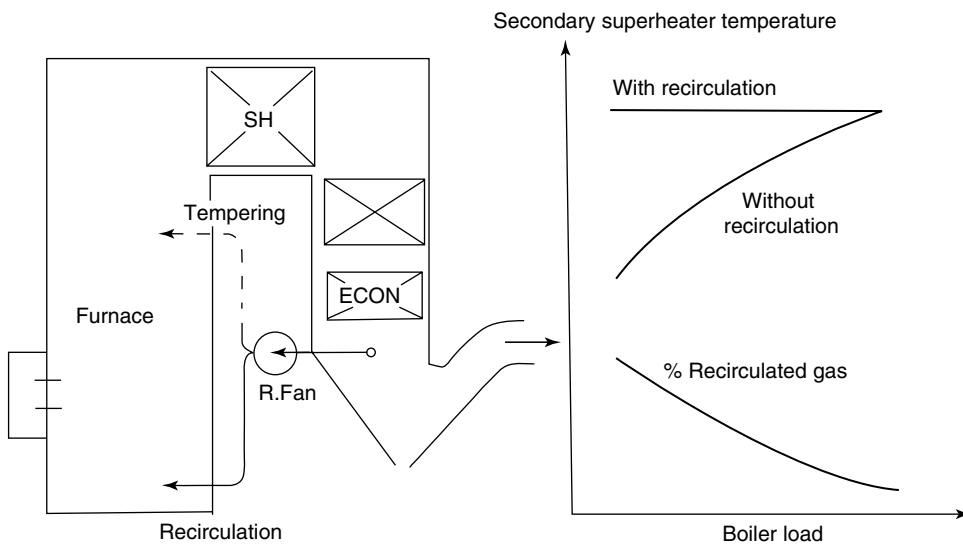


FIGURE 6.27
Effect of gas recirculation on secondary superheater outlet temperatures.

temperature leads to a fall in the furnace absorption. Therefore, there is practically *no change in FEGT*. With higher gas quantity and nearly the same FEGT, all the surfaces downstream experience greater heat absorption due to higher convection. The change is progressively greater toward lower temperatures. Heat from the furnace is thus moved to the convection surfaces. In other words, the heat from the front is moved to the rear (Figure 6.27).

In gas tempering, the cold flue gas is admitted into the furnace before the exit after the combustion zone. This results in only a small change in furnace heat absorption but a good *reduction in FEGT*, as the combustion gas is diluted with the tempering gas. Increased

gas flow and reduced gas temperatures contribute to a reduction in heat absorption in the secondary SH, nearly no change in the RH and some increase in the primary SH, and a good increase in the ECON. Heat is redistributed in the SH downward without much change to the furnace.

The greater the amount of recirculated gases, the greater the redistribution of heat. About 5% is considered as minimum for preventing backflow. Gas recirculation is greater at low loads as the SH and RH temperatures are lower. As the furnace absorption is lowered, GR is also used for controlling the furnace temperatures to regulate metal temperatures and slagging.

Furnace and RH heat absorption remains almost the same regardless of the amount of gas tempering. Its use is more in reducing the secondary SH temperature and fouling in the SH area.

Fans for recycling of gas experience a heavy use in terms of temperature, dust, and the pressure drop. This is an important consideration in evaluating the gas recycling option.

6.3.8.4 Flame Control

Burner tilt and burner management are the two arrangements available to control the CHI for corner-fired and wall-fired boilers, respectively. In corner-fired boilers, the burner tilt changes the position of the flame ball upward or downward, thereby altering the furnace absorption and FEGT. In wall-fired boilers, a similar effect can be achieved by cutting in and out the lowest and the highest tier of burners.

With tilting of burners, it is not possible to precisely control both SH and RH simultaneously because of the differing characteristics. It is normal, therefore, to control the RH with a burner tilt and the SH with an attemperator.

6.3.8.5 Excess Air Control

Slight increases in the excess air give a little more superheat and reheat. The combustion temperature and consequently the furnace heat absorption are both lowered, resulting in slightly higher FEGT and gas weights, which affect the steam temperatures of SH and RH positively. At the same time this method contributes to an efficiency loss due to higher stack loss. For short periods and low loads, this method can be adopted but not on a regular basis at higher loads.

6.4 Back-End Equipment

Economizer and airheater are called the back-end equipment. They are the last of the heat traps and positioned behind the evaporator surfaces in bidrum boilers and behind SH/RH surface in radiant boilers. The ECON is so-called because it economizes the fuel usage by extracting the low-grade heat. Flue gases leave the evaporator in bidrum boilers and the SH in single-drum boilers at a maximum temperature of ~500 and 600°C, respectively and are cooled to an optimal level at the back end.

- The design of the back end requires great care and skill, as the boiler efficiency increases by ~1% point for every 22°C (40°F) of drop in exit temperature. In an effort to recover the low-grade heat, excessive surfacing may increase the costs. Balancing is most important.

- The optimum level for cooling the gases is dependent on the fuel and its cost and can vary from as low as 75°C (~165°F) in HRSGs firing natural gas to ~160°C (320°F) or even higher for high-sulfur fuels. For most common fuels, such as coal and oil with low sulfur, the gas exit temperature is ~140°C (285°F) at full load; the limit is imposed by the corrosion of the downstream flues and dust-collecting equipment at part load operation.
- Although ECON and AH are both for recovery of heat at the final levels, there is an important difference in the way the heat is returned to the system. In ECON, the heat from the flue gas is transferred directly to ECON water, whereas in AH, the transfer is indirect. Heat is transferred to the cold combustion air that enters into the furnace as hot air, raising the furnace temperature and then giving away the heat to the furnace and the SH. Thus FEGT is always higher with a unit equipped with AH, and slagging and fouling aspects have to be checked. Combustion speed is also enhanced. Even though both are back-end heat traps, the AH and ECON must be evaluated on a case-to-case basis.

6.4.1 Airheater or Economizer?

The back end may consist of only ECON or a combination of ECON and AH, depending on the fuel and process. The inclusion of AH is compulsory where the combustion process demands hot air, such as in PF, biofuels, and BL. In power plant boilers, where the FW temperatures are high, the ECON alone cannot cool the gases. In HRSGs, however, the AHs are conspicuous by their absence. In these days of low gas exit temperatures, AH alone as back-end equipment is a rarity because the hot air temperature so obtained would not be acceptable to most firing equipment and flues. If the flue gases are not cooled adequately, the hot exhaust gases would be too hot for fans, dust collectors, and stack.

Besides reducing the gas temperature, the ECON performs another important task of narrowing the difference between feed and drum temperatures, thereby reducing the thermal shock to drum and water walls.

This requires understanding of process side of water and air.

- In most process plants, condensate returns at 40–90°C to the deaerator from where, after deaeration and chemical addition, the FW enters the boiler at 105°C. In such cases no AH is required if hot air is not needed for combustion.
- If hot air is needed, an AH of appropriate size is provided behind the ECON, so that together they provide hot air and cold flue gas as required for the system.
- In power plants, regenerative heating delivers the FW at temperatures of 160–270°C, necessitating both AH and ECON.
- In combined cycle pressure parts (CCPPs), the condensate at ~40°C returns to the HRSG from the condenser because there are no heaters in the cycle. A condensate preheater is the last heat trap in the HRSG located behind the ECON. The exit gas temperature can be as low as 75°C, depending on the sulfur in the fuel.

6.4.2 Airheater versus Economizer

As the AH and ECON extract low-grade heat, they experience low thermal heads to drive the heat and hence are very large HXs. The ECON has nearly three to four times greater heat-transfer coefficient than the AH, which is a gas–air HX. Economizer heat transfer is governed by gas-side coefficient only, whereas the AH coefficient is governed by both gas

and air sides, nearly in equal measure. This is the reason for the large difference in heat-transfer rates of the two systems. Airheater surface is, therefore, three to four times that of an equivalent ECON.

An economizer is a PP and hence expensive but more compact. On the contrary, since an AH is three to four times as large and more voluminous, it is often more expensive to build, although it is a nonpressure part (NPP). In an AH, the ducting adds to the cost significantly and its routing affects the layout tremendously.

6.4.3 Airheater and Economizer Arrangements

Economizer and airheater can be arranged along the gas flow either in sequence or in zigzag fashion as shown in Figure 6.28a and b. The reason for zigzag arrangement is to get high air temperatures with less HS. In an AH, the rise in air temperature is faster than the drop in gas temperature due to the higher weights and specific heats of gas. Typically for

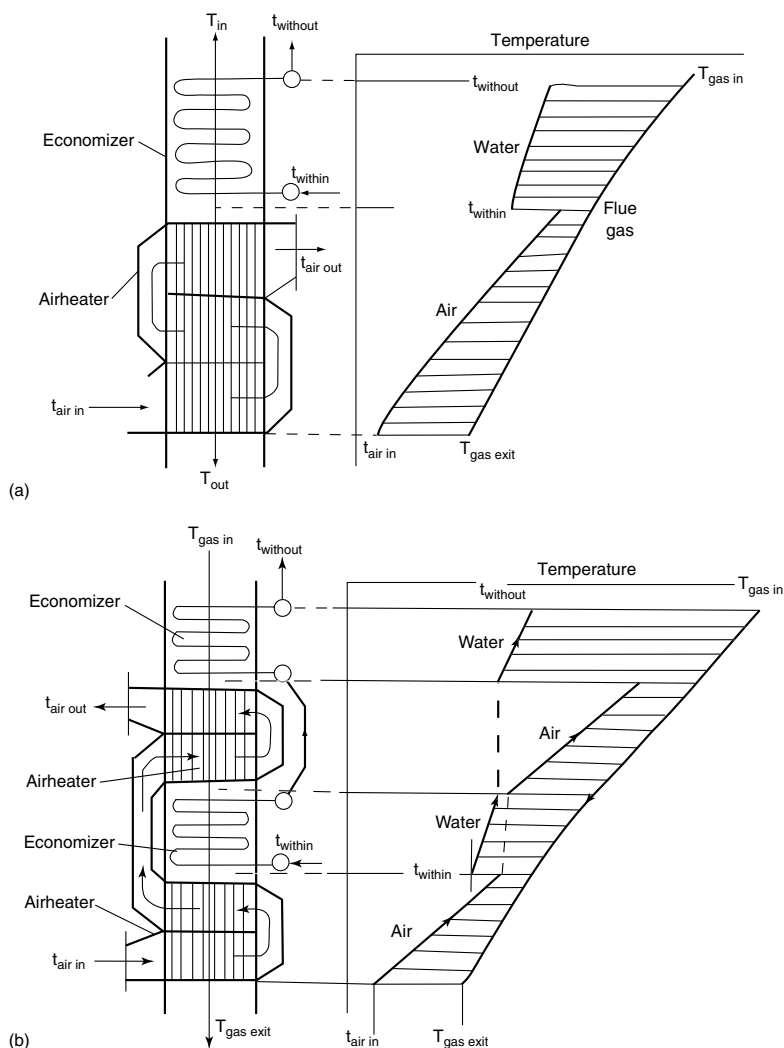


FIGURE 6.28

(a) Economizer and airheater in sequence. (b) Economizer and airheater in zigzag arrangement.

low-moisture fuels such as coal and oil, the air temperature increases by $\sim 1.2^{\circ}\text{C}$ for every 1°C drop in gas temperature, whereas for high-moisture fuels such as bagasse, it is as high as 1.6°C .

6.5 Economizer

Economizer surfaces transfer heat from flue gases to pressurized and subcooled FW on its way to the drum. Heat transfer in an ECON is nearly entirely by convection, and hence the gas velocities are maximized consistent with pressure drop and tube spacing limitations. Coal ash in flue gas at temperatures $<600^{\circ}\text{C}$ is no longer sticky and hence fouling of tubes is not as much an issue as in SH. The ash is loose and does not form strongly adhering deposits and hence is easily removed by soot blowing. However, if there is a mixed firing of oil and coal, the ash can stick over the oil deposits that form on the tubes. The major concern is to reduce the surface and volume to optimize the space and cost.

- Usually smaller tubes with 38.1, 44.5, and 50.8 mm ($1\frac{1}{2}$, $1\frac{3}{4}$, and 2 in.) ODs are chosen to increase the heat-transfer rate. 31.8 mm ($1\frac{1}{4}$ in.) tubes are used in SC boilers and vertical HRSGs.
- Large-diameter tubes like 63.5 and 76.2 mm are adopted in vertical ECONs based on strength considerations.
- Close bending of tubes with radius of 1D or lower is also used most frequently.
- Care is taken to avoid a back pitch (along the gas flow) of 1.07–1.25 times the OD, via development of boundary layer, to avoid excessive draft loss and reduced heat transfer. Heat transfer can reduce by as much as 30% with this spacing.
- Optimum mass velocity for bare tube ECON lies between 5.4 and 6.8 $\text{kg/m}^2 \text{ s}$ (4000–5000 $\text{lb/ft}^2 \text{ h}$).

Maximum permissible gas velocities and minimum tube spacing for ECONs are given in Table 6.6. Minimum spacing for bare tubes is 19 mm ($3/4$ in.), whereas for finned tubes, it is 13 mm ($1/2$ in.) between the edges of fins.

TABLE 6.6
Permissible Inlet Flue Gas Velocities and Tube Spacing (Perpendicular to Gas Flow) in Economizers

Fuel	Oil				Coal in Pulverized Fuel Combustion		Coal in Fluidized Bed Combustion		
	Gas	Distillate	Residual	Coal in Spreader Stokers	Normal/Low Ash	Abrasive/High Ash	Bubbling Fluidized Bed Combustion	Circulating Fluidized Bed Combustion	Bagasse
Maximum gas velocity (m/s)	36	27	18	18	15–18	12–15	12–15	12	15–18
Minimum clear tube spacing (mm)	19	25	25–32	32	38	50	32–38	38–50	32

Water in ECONs should always flow upward to allow the steam bubbles to ascend smoothly. In the downward flow, steam bubbles can cause flow stagnation and disrupt the operation. In cases when downward flow is compulsory due to layout, adequate pressure drop is created by inserting ferrules for flow equalization.

Tube selection should not exceed 6 m/s (20 ft/s) of water velocity to avoid excessive pressure drop and also the erosion of tubes. A minimum water velocity should be maintained at ~2 m/s (6 ft/s) for flow equalization. Likewise, the axial velocity in ECON headers should be <6 m/s (20 ft/s).

Economizer banks must be restricted to 1.8 m (6 ft) for effective soot blowing. A clear access of 600 mm (2 ft) is necessary for proper access and weld repair.

6.5.1 Classification

Economizers can be classified by design, construction, and arrangement, as given in Table 6.7.

6.5.1.1 Counter, Parallel, and Cross Flows

In most cases, ECONs are arranged in a counterflow mode to maximize the heat transfer and minimize the surface. Unlike in SH, there are no metal temperature problems that can be redressed by adopting parallel flow. Only in exceptional cases where there are constraints in arrangement, parallel flow may be adopted. In package boilers cross flow is adopted because the arrangement helps to save on the height of the ECON. Cross flow with gas flowing perpendicular to water flow is not as efficient as counterflow but it is better than parallel flow.

6.5.1.2 Steaming and Nonsteaming

- Feed water outlet temperature should preferably be 30°C lower than the saturation temperature. This difference is known as *the approach temperature* that prevents steaming and water hammering. Also gas to water temperature is not narrowed down, which increases the HS without adding correspondingly to the water temperature.
- The economizer steams when the rise in water temperature is >67% of the difference between the saturation temperature and the ECON inlet. Simplicity and operational latitude demand a nonsteaming ECON.

TABLE 6.7

Classification of Economizers

By Design	By Tube Type	By Arrangement
Counter flow	Cast iron	In-line
Parallel flow	Steel tube	Staggered
Cross flow		
Steaming	Bare tube	Horizontal
Nonsteaming	Finned tube	Vertical
Single tube per loop		
Multiple tubes per loop		

- At times, this condition may in fact be beneficial to increase the ECON surface and generate some steam in it. Then the ECON outlet header should be located below the drum level. Care should be taken to avoid any loops or downward slopes in both ECON tubing and water piping from ECON to drum so that all the steam generated is constantly directed upward to the drum. Depending on the steam generation, it may be necessary to provide additional dedicated cyclones for separation. Usually 8% of steam generation is considered a safe limit, although there are cases of 20% steam generated on ECONs. The water treatment has to be very stringent.

6.5.1.3 Single and Multiple Tubes Per Loop

Carrying all water from the header by a single set of tubes placed side by side is a single tube per loop arrangement. A set of two tubes is called a two tubes per loop arrangement. Closed-loop bending of tubes can be avoided here. Also the two tubes are placed with a clear gap of 19 mm along the gas flow. This yields a very compact arrangement and reduces water velocities. Often, it is an easier way to pack ~15% more surface within the same height of ECON banks without resorting to close-loop bends such as 1D or 0.8D (Figure 6.29a and b).

6.5.1.4 Cast Iron and Steel Tubes

Cast iron (CI) stands up to both

- Internal corrosion due to dissolved oxygen among the ECONs because of the indifferent water treatment or lapses common in LP boilers.
- External corrosion due to sulfurous flue gases.

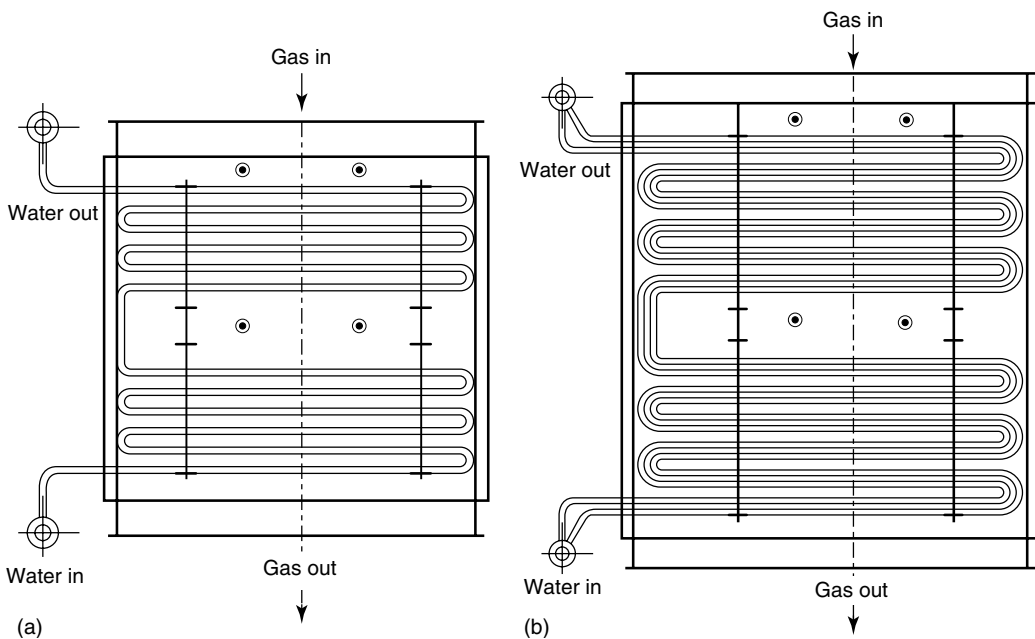
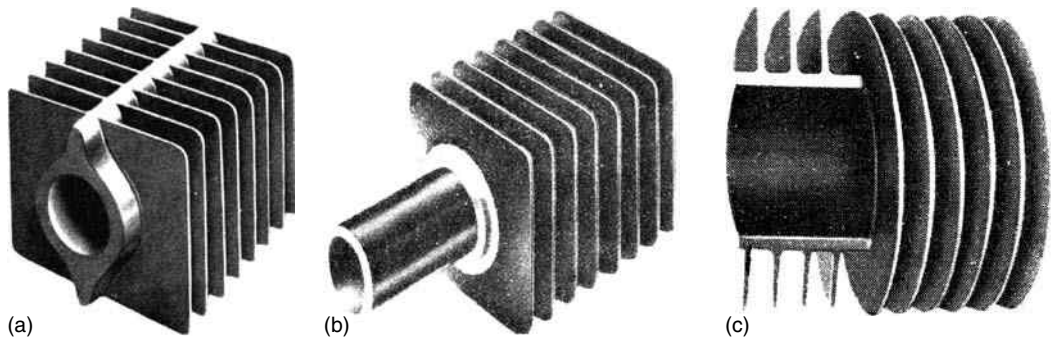


FIGURE 6.29

(a) Single tube per loop. (b) Two tubes per loop.

**FIGURE 6.30**

(a) Cast iron finned-tube economizer. (b) Cast iron gilled steel tube. (c) Helically finned tube.

CI has limitations in withstanding pressures due to its porous structure. Up to a design pressure of 17.5 atm, finned CI ECONs (Figure 6.30a) make an excellent choice provided the quality of pressure castings is good. Their usage in modern boilers has drastically decreased, and steel tubes are overwhelmingly popular due to their strength and lightness.

- Taller fins lower efficiency of heat transfer
- Thicker fins increase efficiency of heat transfer
- Higher fin density increases HS and fouling

However, many boilers employ *gilled steel tubes* (Figure 6.30b) for even the highest pressures. Here the steel tubes, duly ground on centerless grinding machines, are shrunk fitted with CI gills that are exposed to the erosive and corrosive gases. They do not permit the gases to come in contact with the steel tubes. The collar and spigot arrangement of the gills covers the tubes fully and prevents contact with gases. The internal corrosion of the tube, however, cannot be avoided if the water is not fully deaerated. The construction is expensive but more reliable than that of bare tubes for very erosive and corrosive applications. Great care is needed in fitting of gills because success is dependent on the integrity of the fit between the tube and the gill.

6.5.1.5 Bare and Finned Tubes

Bare tubes are reliable and effective for applications in dusty environment and eliminate uncertainties associated with finned tubes (fouling and fin erosion). Compared to finned-tube ECONs

- Supporting is easier.
- Soot blowing is more effective.
- Arrangement is simple.
- Tube banks can be deeper at ~2 m.
- Interbank cavities require smaller depth because the SBs do not take up much space.
- Gas-exit temperature can be lower.
- Pressure drop can be marginally lower.

Large bare-tube ECONs are nearly as compact and even more efficient at low temperatures. As low-grade HXs, ECONs demand a lot of HS. To minimize the cost and space,

various types of extended-surface ECONs have been tried with varying degrees of success with different fuels. By and large for fouling fuels, plain tubes seem to offer the most satisfactory solution. With clean gases the finned-tube ECONs find favor.

6.5.1.5.1 Finned-Tube Economizers

Extended-surface/finned-tube ECONs are compact and generally economical. Heat-transfer coefficient on the water side ($>5600 \text{ W/m}^2 \text{ }^\circ\text{C}$ or $\sim 5000 \text{ kcal/m}^2 \text{ }^\circ\text{C}$ or $\sim 1000 \text{ Btu/ft}^2 \text{ h }^\circ\text{F}$) is much higher than that on the gas side ($\sim 5.6 \text{ W/m}^2 \text{ }^\circ\text{C}$ or $\sim 50 \text{ kcal/m}^2 \text{ }^\circ\text{C}$ or $\sim 10 \text{ Btu/ft}^2 \text{ h }^\circ\text{F}$), making a good case for employing fin tubes, provided the fouling of tubes (leads to the blocked fins) and the resultant drop in performance are eliminated. The HS that can be packed with fin tubes is enormous. For example, a 50.8 mm OD tube with 150 fins/m of 19 mm helical fins provides ~ 10 times the HS of the bare tube.

There are several types of extended surfaces suitable for ECONs.

- 1. *Helical fins.* High-frequency continuous helically finned tubes (Figure 6.30c) are the most popular. For ECON application, the tubes and the fins are of low CS execution. Tubes are usually 31.8, 38.1, 44.5, and 50.8 mm OD. Staggered or triangular pitching is suitable only for clean gases such as natural gas. Fin spacing and thickness increase as the gases get dustier. Table 6.8 summarizes the application range. A conservative approach is to adopt fin spacing a step lower than specified in the table. It is important that the tubes are kept free of fouling by restricting the bank depths to 1.5 m and employing rake-type SBs (see Figure 8.63).
- 2. *Plate or rectangular fins* (Figure 6.31) are of low CS, resistance welded, and square or rectangular in shape. Fins are typically 3 mm thick and spaced 13 and 25.4 mm

TABLE 6.8
Helical Fin Tubes for Economizers

Fuel	Fins per		Thickness (mm)	Staggered	Fin Height (mm—Typical)
	Inch	Meter			
Natural gas	8	315	0.75–1.5	Yes	19–22
Light distillate oil	4	157	0.75–3.0	No	19–22
Heavy oil	3	117	1.25–3.0	No	19–22
Coal	2	78	1.25–3.0	No	19–22

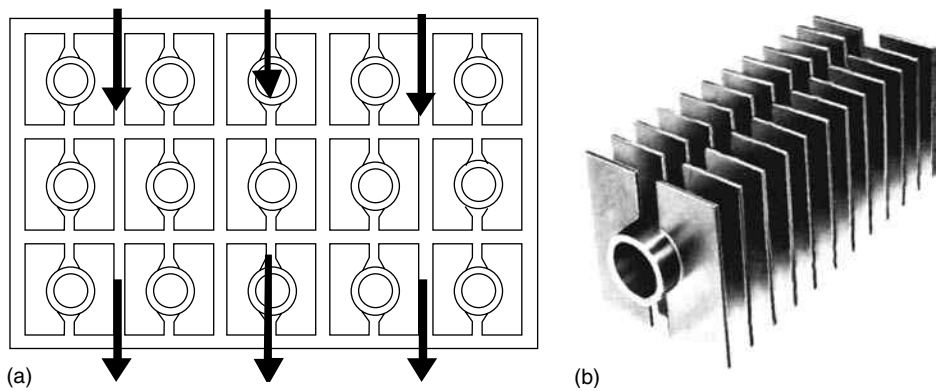


FIGURE 6.31
Tubes with plate fins.

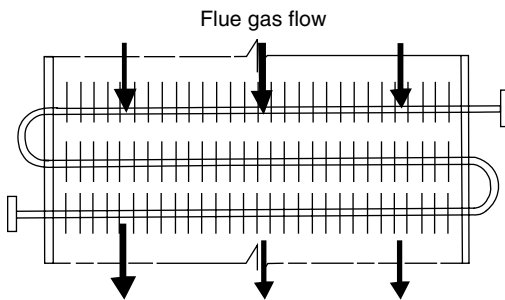


FIGURE 6.32
Gas flow over fin tubes.

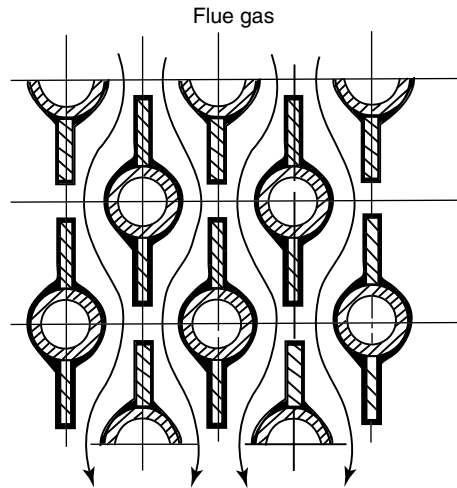


FIGURE 6.33
Longitudinal fin.

(1/2 and 1 in.) apart. Gas velocities are limited to 15 m/s for clean gases. These fins are used in noncorrosive environments with gas, oil, and coal firing even with moderately high particulates. Rake-type SBs are required for keeping the surfaces clean. Coal applications present a danger of fly ash plugging.

3. *Longitudinal fins* (Figure 6.33) for coal application represent a popular method to economize on the surfaces. Staggered arrangement is usually adopted despite reports of fin-tube cracks developing over long periods of operation with oil-fired boilers. Plugging and erosion may be experienced in coal-fired boilers.

With every type of finned tube, HX care should be taken to direct all the gases only over the finned tubing and not over the bends to avoid gas bypassing as shown in Figure 6.32. Deflection baffles inside the casing are used for this purpose.

6.5.1.6 In-Line and Staggered Tubes

Staggered tubes yield a better heat-transfer rate and make the arrangement compact but at the risk of tube erosion due to dust in flue gases. Only for natural gas and light distillate oils and certain clean waste gases is the staggered arrangement suitable, whereas it is not so for coal and heavy oil applications. Heat recovery steam generators invariably employ staggered arrangement, as the GT exhaust gases are clean.

6.5.1.7 Horizontal and Vertical Tubes

Most ECONs are horizontally disposed and fully drainable (Figure 6.34). Vertical tubes are employed in special cases such as BL recovery boilers and municipal waste fuel boilers in which sticky ash deposits readily on horizontal surfaces. The heat-transfer rates are lower and hence the surfaces required are correspondingly much higher (Figure 6.35).

6.5.2 Tube and Fin Materials

Low CS is the material for both tube and fin for ECON construction except for ECONs in SC boilers. With a 450–480°C (~850 to 900°F) metal temperature limit, this material meets

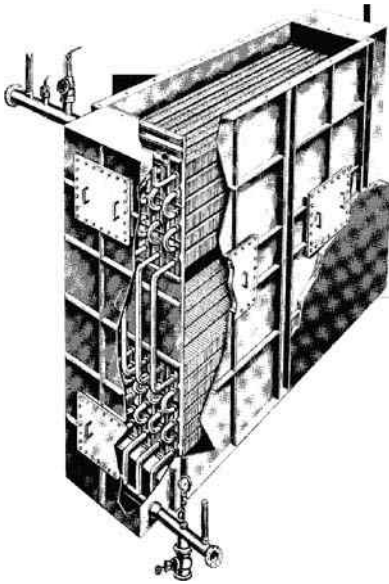


FIGURE 6.34
Finned tube packaged ECON.

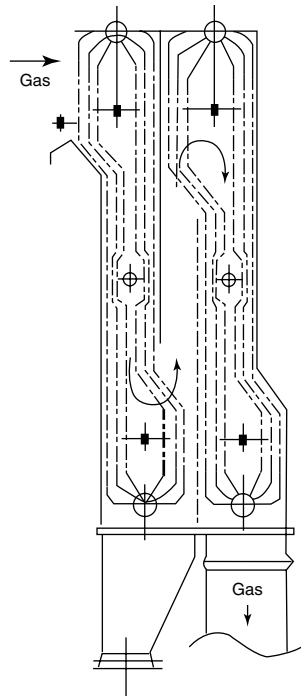


FIGURE 6.35
Long-flow vertical ECON.

the requirement even at the highest pressures in subcritical boilers. The tubes used range from 31.8 to 63.5 mm OD. For most applications, the tube thickness is 3.66 mm (9 swg) for horizontal ECONs.

6.5.3 Operating Concerns in Economizers

The main operational concerns of ECONs are

1. Gas-side tube erosion
2. Low external and internal temperature tube corrosion

These concerns are minimal with natural gas firing. Corrosion affects oil-fired boilers; coal is affected by both erosion and corrosion. A proactive design anticipating such problems and a careful O&M program can mitigate them.

6.5.3.1 Gas-Side Tube Erosion

Adherence to the maximum recommended gas velocities for a particular fuel can practically eliminate the erosion problems. In addition, understanding fuel behavior and previous

experience with similar boilers are both essential to eliminate the constructional features that promote eddy formations in gas flows.

6.5.3.2 Low-Temperature External Corrosion

Economizer tube metal temperature is within a few degrees of the inside water temperature due to the high water-side heat transfer coefficient regardless of the gas temperature. The lowest temperature occurs at the point of water entry. Low water temperature results in the condensation of sulfur-bearing vapors on the tube surface, namely sulfurous and sulfuric acids, that may be at or below the acid dew point. This leads to the corrosion of tubes. The acid dew point depends on

1. Sulfur in the fuel
2. Percentage of H_2O in flue gas
3. Excess air

In addition, Fe, V, and other elements in the presence of O_2 and H_2O in flue gas act as catalysts to accelerate and increase the formation of the acid vapor, leading to higher acid dew point. Figure 6.36 gives the practical limits for the metal temperatures to avoid acid corrosion at low gas temperatures for bare tubes.

- These limits are applicable for both ECON and AH of CS execution.
- The limits for PF firing are lower than those for stokers because the fine PF ash adsorbs the acid and acts as an inhibitor.
- Field experience has shown that the rates of corrosion achieved by observing the limits shown in Figure 6.36 are within acceptable limits.

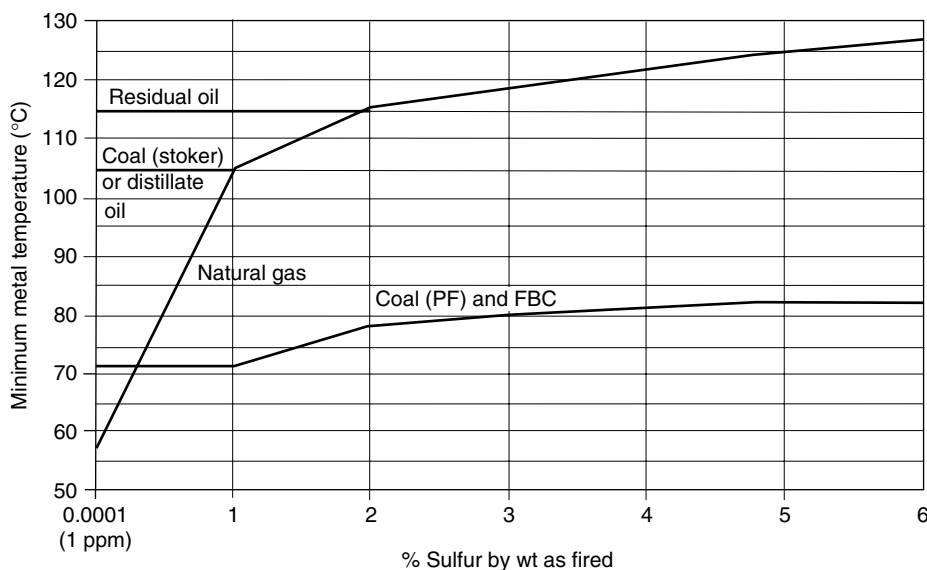


FIGURE 6.36

Low-temperature corrosion limits (external) for CS economizer and airheater tubes for various fuels.

TABLE 6.9

Minimum Metal Temperature Limit for CS Finned-Tube Economizers

Percent fuel S by weight as fired	<0.5	0.75	1.0	2.0	3.0	4.0	5.0	6.0
Minimum metal temperature (°C)	115	121	125	135	139	141	142	144
Minimum metal temperature (°F)	240	250	257	275	280	286	289	292

- For extended-surface HXs, the permissible metal temperatures are higher because these HXs tend to foul faster and are more difficult to clean.

For extended-surface ECONs, the applicable limits are given in Table 6.9. For sulfur-free fuel, 65°C is the minimum temperature applicable. These limits are slightly higher for plain tubes for the above-mentioned reasons.

6.5.3.3 Low-Temperature Internal Corrosion

Internal corrosion of the steel tubes arises from:

1. *Dissolved oxygen.* This causes pitting, which is eliminated by deaeration of FW followed by oxygen scavenging.
2. *Low hydroxyl ion (OH) concentration.* This attacks steel faster and can be avoided by maintaining a pH value between 8 and 9. Sometimes the boiler water is circulated at the inlet to the ECON for maintenance of pH.

Strict adherence to the specified FW limits is one way to eliminate internal corrosion problems of ECONs. Please refer Chapter 4 for details.

6.6 Airheater

The airheater is usually the last heat trap in the boiler. Airheater exit gas temperature should be higher than the corrosion limit of the AH internals and the downstream equipment. Airheaters generally operate in a temperature range of 450–120°C on the gas side and 150–450°C on air side. Maximum permissible air temperatures for various fuels and firing are summarized in Table 6.10.

6.6.1 Airheater Types

On the basis of construction features, AHs can be classified as shown in Table 6.11. Table 6.12 shows the fundamental differences in the way the two types of AHs are built.

1. The heat transfer in tubular AH (TAH) is direct as in any HX.
2. In rotary AHs (RAHs), it is indirect. The hot gases heat a rotor filled with baskets of corrugated sheet steel, which then moves into the cold-air stream to give up

TABLE 6.10

Hot Air Temperature Limits in Firing Equipment for Various Fuels

Fuel	Firing	Hot Air a Must?	Temperature Limit (°C)	Temperature Limitation due to
Gas	Burners	No	450	Oxidation of air ducting
Oil	Burners	No	450	Oxidation of air ducting
Coal	Pulverized fuel	Yes	400	Mill internals
Coal	Stoker	No	160	Coking of coal and clinkerization
Coal	Fluidized bed combustion	No	450	Oxidation of air ducting
Bagasse	Stoker	Yes	200	Stoker parts

Note: Hot air is always preferred to improve combustion but not strictly required and hence categorized “No.” The air temperature limits are indicative and can vary depending on the combustion equipment.

TABLE 6.11

Airheater Classification

Action	Recuperative	Regenerative
Type	Tubular airheater 1. Vertical tubes 2. Horizontal tubes	Rotary airheater 1. Rotating baskets (Ljungstrom) 2. Rotating hood (Rothemuhle)

TABLE 6.12

Comparison of Tubular and Rotary Airheaters

Parameter	TAH	RAH	Remarks for RAH
Type	Static	Rotating	O&M issues in AH
Construction	Simple—fewer elements in AH	More parts	Very specialized
Space	More—tube withdrawal space required	Compact	
Erection time	More—more site assembly	Less—more shop assembly	
Cold-end section COR-TEN	Possible	Possible	
Air leakage into gas space	None	Yes—increases as seals wear	
Increased forced draft, induced draft capacity?	Not required: no leakage	Required to make up for leakage	More fan power
On-load cleaning by SBs	Mostly not needed—fouling is less in VTAH—possible in HTAH	Required	
Fire hazard	None	Yes—particularly in oil fired boilers at low loads	
Repair of corroded HSs	Easy—short tubes can be inserted in cold end	Not possible	
Replacement of corroded heating HSs	Tube replacement more difficult	Easy—involves only replacing baskets	

heat in a moving rotor design. The heat exchange is, thus, through the medium of steel baskets subjected to hot and cold air streams alternately on a continuous basis. In the rotating hood design, the rotor remains stationary and the hoods for gas and air rotate to achieve the same results.

6.6.2 TAH versus RAH

Both types of AHs are popular. The TAH is simple to fabricate and does not increase the existing auxiliary power or erosion problems (in case of coal-fired boilers), because there are no leakages from air to gas side such as in the case of an RAH and no maintenance issues because the assembly is static.

The RAH needs regular adjustment to the seals and is also maintenance prone but the real advantage lies in its compactness and simplified duct layout. With several shop-fabricated subassemblies, the site erection takes much less time. Also, with enameled baskets, lower gas-exit temperatures can affect boiler efficiency favorably.

Where space is not a constraint, erection costs are low presents and boilers are ~ 400 tph or lower, TAH an economical proposition. When there is space constraint, RAH is the answer; it is also preferred solution for utility boilers. A brief comparison is given in Table 6.12.

In the case of FBC boilers where there are high discharge pressures for forced draft (FD) and primary air (PA) fans, TAH is preferred to RAH because air leakage and hence maintenance of seals can be high, since air to gas differential pressure can be ~ 2000 mm wg (~ 80 in.).

6.6.3 Tubular Airheater

See (Figure 6.39).

6.6.3.1 Heat Transfer

- Heat transfer in a single bank in both vertical (VAH) and horizontal (HAH) systems is always in a perfect cross flow. Only when several banks are arranged does the AH become parallel or counter or mixed flow. The coefficient is adjusted depending on whether the set of banks are parallel or counterflow.
- With smaller tubes transporting air, the HAH enjoys a slightly better heat-transfer coefficient, making it more compact.
- Metal temperature is also a little higher in HAHs than in VAHs. But air pressure drop is marginally higher. Mostly the choice between the HAHs and VAHs is governed by the layout considerations of fans and ducting.
- For optimum design, AHs are designed with pressure drops not exceeding 65 and 40 mm wg for each bank for air and gas, respectively, for both VAHs and HAHs.
- The permissible mass velocities and typical heat-transfer coefficients are given in Table 6.13.

TABLE 6.13

Tubular Airheater Air and Gas Mass Velocities and Typical Heat-Transfer Coefficients

Mass Velocities	VTAH		HTAH	
Air: kg/m ² s and lb/ft ² h	6.1	4500	9.5	7000
Gas: kg/m ² s and lb/ft ² h	8.8	6500	5.4	4000
Heat-transfer coefficient: kcal/m ² °C and Btu/ft ² °F	13–14	~2.7–2.8	~15	~3

6.6.3.2 Arrangement

A VAH can be arranged in several ways and many banks. Figure 6.37 depicts a few arrangements of single- two- and three-pass AHs. With gas flowing inside the tubes, there can be two modes of airflow.

1. Gas through the tubes and outside air flow perpendicular to the tubes, as in Figure 6.37.
2. The airflow can also be arranged in longitudinal manner flowing along the tube axis on the outside, as in Figure 6.38.

Both HAH and VAH are depicted in Figure 6.39.

- The disposition of tubes in the HAH can be parallel or perpendicular to the drum axis. Sufficient free space should be available for tube withdrawal. Likewise, VAH head room below or space above should be equivalent to tube length.
- HAH is more amenable to be placed below the ECON, as ash tends to roll down over the horizontal tubes. In VAH, there is a fear of fouling and plugging of tubes at the cold end if ash in fuel is high.
- Soot blowers are generally not needed for VAH because it is a self-cleaning arrangement, unless phosphatic deposits are likely to occur at the cold end. A rake-type blower with steam nozzles individually directed toward each tube is the best answer.

Horizontal AHs are usually equipped with mass- or lane-type rotary blowers.

6.6.3.3 Materials and Construction

- *Materials.* As the gas temperatures rarely exceed 450°C and the metal temperatures are well within the CS limits, it is normal to use structural-quality low-CS tubes and plates in both types of AHs. Often in the cold-end AHs, tubes made of weathering steels, such as COR-TEN, are used for improved life.
- *Expanded or welded?* The tubes can be expanded in the tube holes or welded fully but lightly. Tube expansion is relatively easier and faster and hence more popular. Welding of tube to sheet is to be done with great care to prevent warping of the tube plate or damaging of the thin AH tube due to heat in welding.
- *Thermal expansion.* Provision for (1) expansion of tubes between cold and hot conditions and (2) relative expansion between tube and tube plates should be made properly.

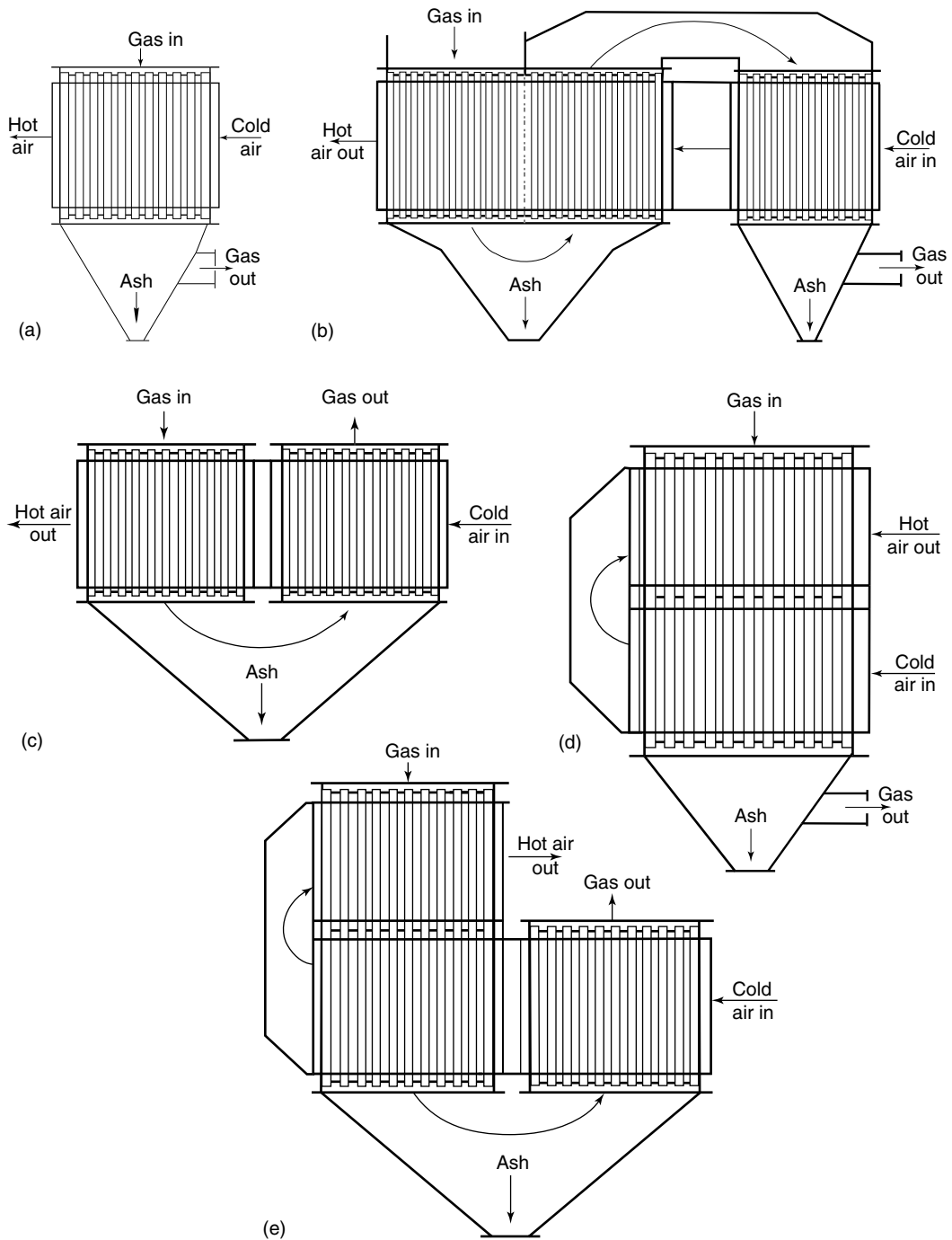
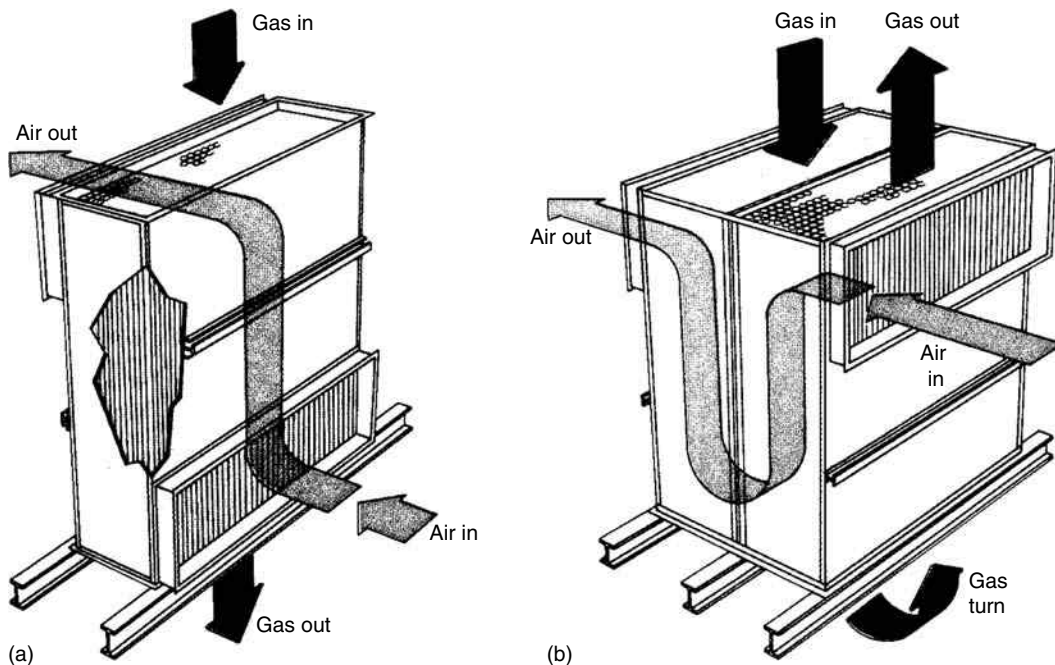


FIGURE 6.37

(a) Single-pass air and gas vertical tubular airheater in cross flow. (b) Three-pass gas and single-pass air vertical tubular airheater. (c) Two air and two gas vertical airheater. (d) One gas and two-pass air vertical tubular airheater. (e) Three gas and three air vertical tubular airheater in L-shape.

**FIGURE 6.38**

(a) Single-pass tubular airheater with air in long flow. (b) Two-pass tubular airheater with air in long flow.

- *Tube span/length.* About 5 m maximum span may be considered for tubes in horizontal tubular airheaters (HTAHs) without intermediate support. Likewise, 5.5 m maximum vertical tubes can be considered for bottom supporting in a vertical tubular airheater (VTAH).
- *Air and gas in VTAH.* In a VTAH, it is normal to have gas and air move outward through the tubes in a staggered arrangement, although the reverse is also possible. The tubes are large—63.5 and 70 mm OD to prevent plugging at the cold end on account of fouling.
- *Air and gas in HTAH.* Air through the tubes and gas outside move in in-line arrangement for better cleaning. The tubes are smaller at 38.1 and 50.8 mm OD for better heat transfer without fear of tube plugging with clean airflow.
- *Tube spacing in HTAH.* In HTAHs, clear gap between tubes is 12.5 mm along gas flow. Across the gas flow, it is 25 mm for oil and gas and 38 mm for coal, for both stoker and PF systems.
- *Tube thickness.* Tube thicknesses are usually 2.0 or 2.3 mm (14 or 13 swg) for all fuels except for stoker firing on coal, where the gritty dust in flue gases demands extra sacrificial thickness; 2.3 or even 2.95 mm (11 swg) is used.
- *Tube plates.* There are two types—support and baffle plates. The former are load bearing and thicker at 25 or 30 mm and are suitably stiffened. The baffle plates are for locating and also for antivibration. They are made 16 or 20 mm thick (Figure 6.39b).

The features of both types of TAHs are summarized in Table 6.14.

TABLE 6.14

Construction Features of Vertical and Horizontal Tubular Airheaters

Parameter	Units	VTAH	HTAH
Flow through tube		Gas	Air
Minimum tube metal temperature			Slightly higher
Tube sizes OD	mm	63.5, 70.0	38.1, 50.8
Usual tube thickness	mm	2.0 or 2.3	2.0 or 2.3
Usual tube arrangement		Staggered	In-line
Maximum tube lengths	m	5.5 bottom support	5.5

6.6.3.4 Finned Tubes for Tubular Airheater?

Usage of finned tubes has dramatically increased. Finned tubes are employed when the heat-transfer coefficients of two media are widely different. No other purpose is served by finning.

6.6.4 Rotary Airheater

The constructional features of the HS of RAH are as follows:

- The heat-transfer element of an RAH is the rotor filled with baskets containing packing of
 - Corrugated sheets
 - Undulated sheets
 - Flat sheets
- The corrugated and undulated sheets separate the flat sheets, maintaining a distance, which
 - Creates flow paths
 - Increases HS
 - Increases turbulence
- These sheets are 18–26 swg in thickness (0.46–1.22 mm) and spaced 5–10 mm apart. Close spacing and greater profiling produce higher turbulence and higher heat transfer and pressure drop. The fouling increases.
- Carbon steel for hot section and COR-TEN or enameled sheets for cold sections are the usual choice of materials.
- Thinner sheets and closer spacing for hot sections and thicker sheets and wider spacing for intermediate and cold sections are chosen to combat the erosion and fouling problems and also to contain the pressure drop. Thinner sheets vibrate in the flow and shed the dust but their lives can be short because they erode and corrode rather fast.
- The normal range of pressure drop is between 50 and 180 mm (2–7 in.) wg.
- Typically the HS packed in the baskets vary from 300 to 350 m²/m³ (90–105 ft²/ft³).

Moving rotor and moving hood designs are discussed briefly in Sections 6.6.4.1 and 6.6.4.2.

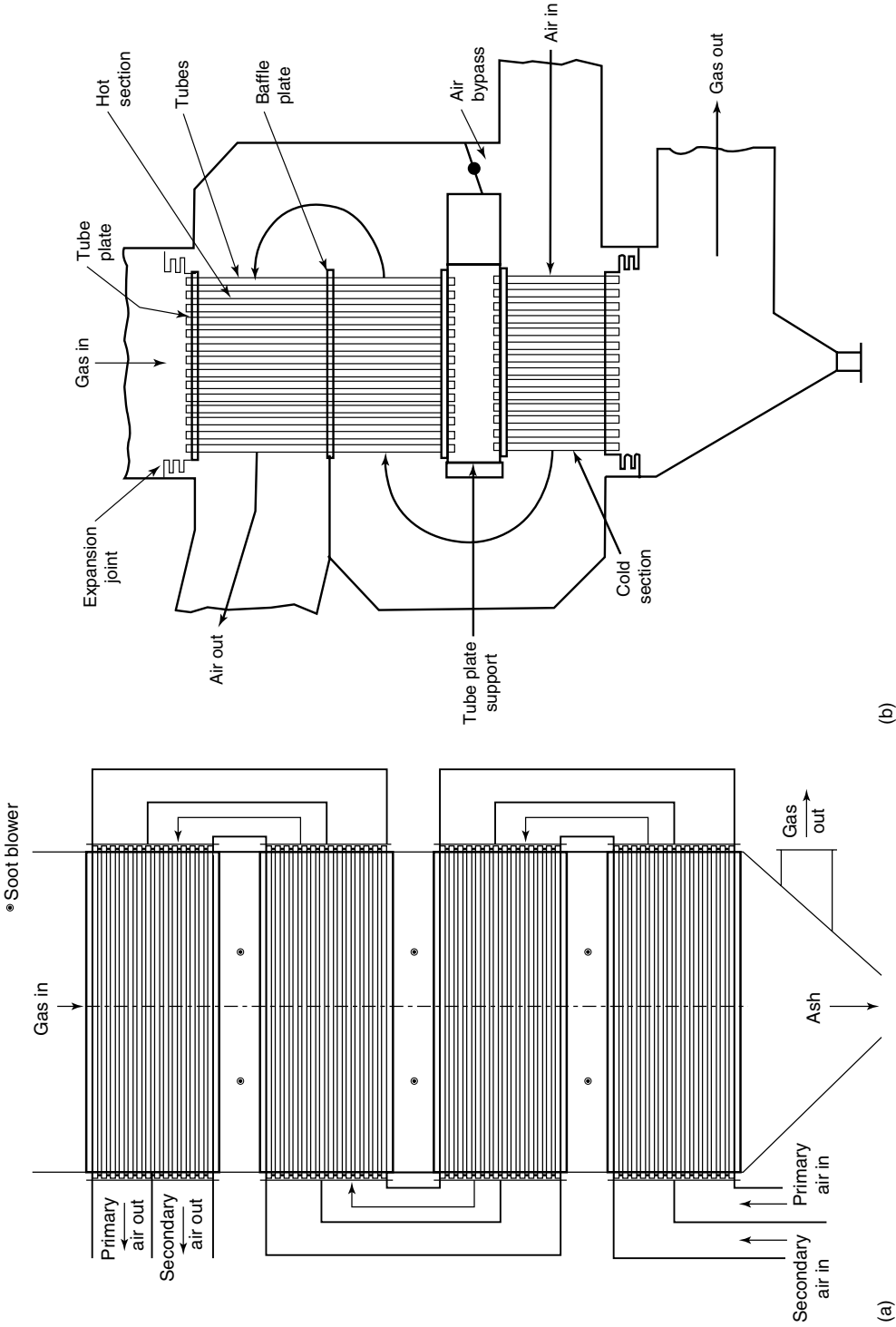


FIGURE 6.39 (a) Single-pass gas and four-pass air horizontal tubular airheater. (b) Vertical tubular airheater and its parts.

6.6.4.1 Moving Rotor or Ljungstrom Design

- In Figure 6.40a and b, the rotor filled with the heat-transfer packing material is enclosed in a stationary casing to which the inlet and outlet ducts of air and gas are connected.
- The rotor moves slowly between 1 and 3 rpm, driven by a drive motor assembly and is heated and cooled alternately.
- Seals on the top and bottom of the rotor prevent bypassing of air. Seals at selected places arrest the infiltration of tramp air into the AH.
- Mass-type SBs are installed on the gas inlet side for on-load cleaning of elements.

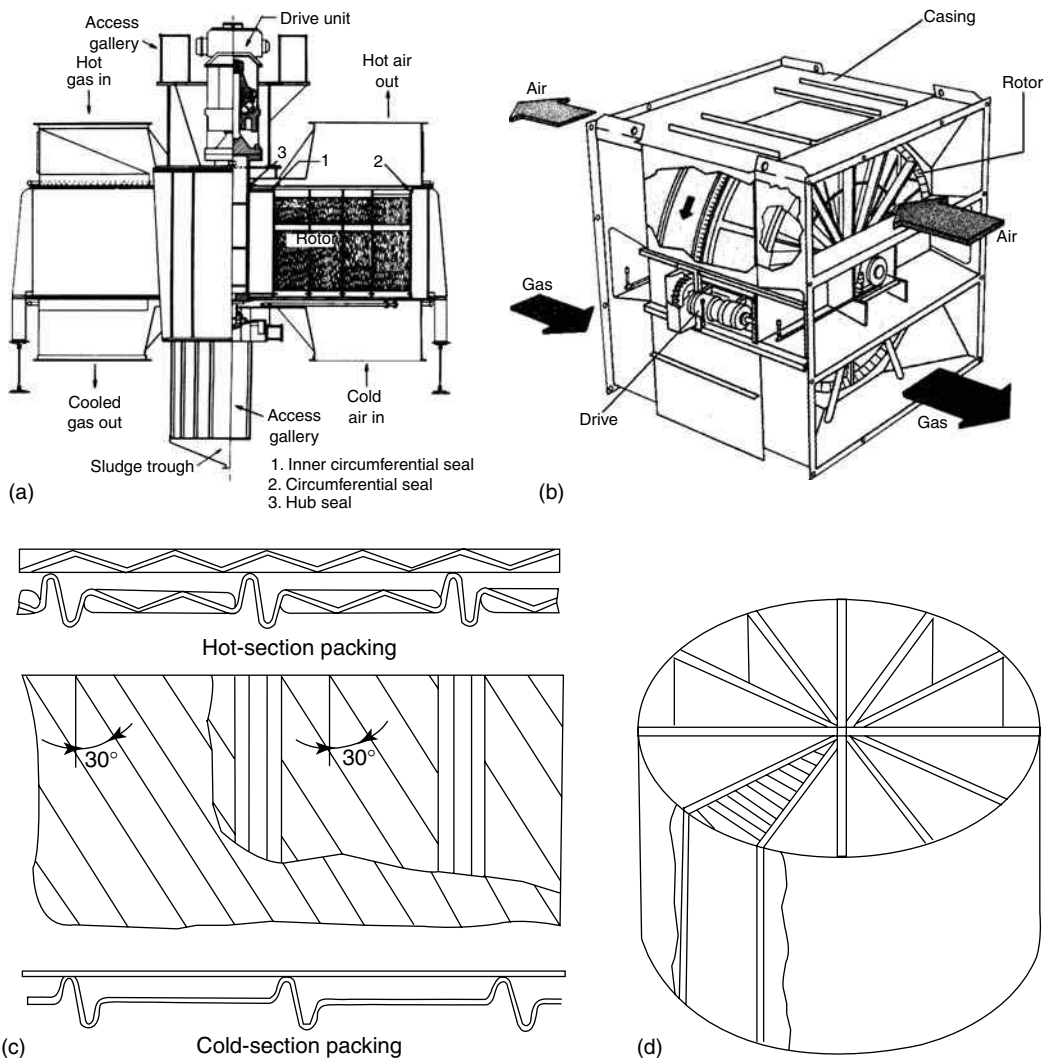


FIGURE 6.40

Moving RAH with (a) vertical shaft. (b) Horizontal shaft. (c) Corrugated packing. (d) Rotor sectors with corrugated packing.

- As part of start-up and shutdown interlocks, the AH should be soot blown before and after service to keep it free from unburnt fuel.
- Both horizontal and vertical designs are used, with the latter more common in utility boilers. The horizontal design is popular with the package and field-erected boilers, firing oil and gas, as it fits very well where the gas exit and air entry are both at a low level.
- Figure 6.40a and b shows the typical bisector AH popular with oil and gas firing. The rotor is divided into two parts for the passage of air and gas. In a PF application, a trisector AH is required, as the pressure of PA is higher and temperature can also be higher. The rotor is then split into three parts. Even quadra sector AHs are used occasionally.
- Very large AHs can be built to this design. Rotors as large as 20 m diameter and weighing 800 t are in operation.

6.6.4.2 Rotating Hood or Rothemuhle Design

The stator, packed with corrugated material, remains stationary whereas the air hood rotates slowly picking up heat from the stator (Figure 6.41). All the variations available with moving rotor design are also offered in the moving hood designs. In both designs, air and gas bypass ducts with dampers are integrated with the AH. Safe operating temperatures of RAHs are nearly the same as those of TAHs.

6.6.5 Operational Concerns

The operating problems of AHs can be summarized as

1. Low-temperature corrosion
2. Fouling
3. Erosion
4. Fire

6.6.5.1 Low-Temperature Corrosion in Airheater

Airheaters are always provided with bypasses on both air and gas sides based on the process and layout. Air bypass is provided by allowing only a part of the air to pass through the AH to decrease cooling of flue gas. This is for raising the gas-exit temperature and along with it the cold-end metal temperature, which is usually a start-up precaution. A similar arrangement on the gas side is also possible. The bypass dampers are fully shut off during normal operation. Care should be taken to provide a minimum possible opening and a tight shutoff damper. The great tendency for leakage represents a permanent loss of efficiency.

Cold-end corrosion is a serious issue over which a constant vigil is necessary. The coldest point in the AH is where the cold air and exit gas come into contact. We assume that the metal temperature is the arithmetic mean of the two. With a wide difference in the ambient temperatures, there is always a danger of the cold-end slipping into the corrosion range with boilers designed for the lowest stack losses and causing serious

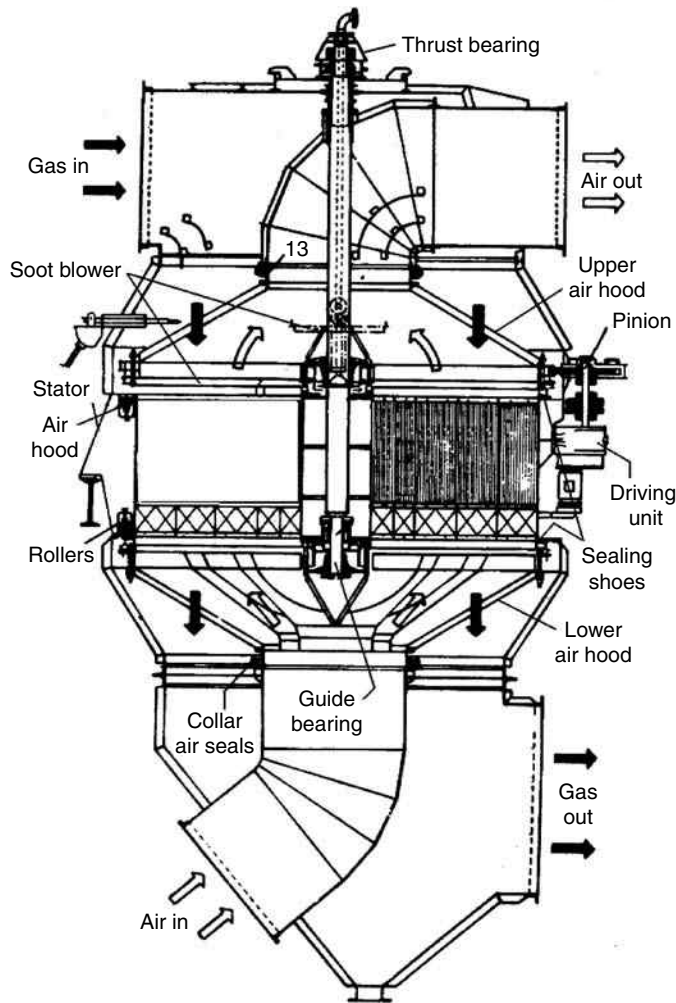


FIGURE 6.41
Rotating hood rotary airheater.

consequences. By raising the air temperature, the metal temperature can be raised in two ways.

1. Hot-air recirculation from AH exit to FD fan inlet
2. Raising incoming air temperature by steam coil AH located in the cold-air duct

The former is relatively simple to install, does not add to the auxiliary power, but is not so efficient. Heating of air in a steam coil AH is expensive and power-consuming but a more reliable solution (Figure 6.42).

Either steam or FW can be used for heating air, depending on the layout. An LP ECON can also be used with the cold-end AH to raise metal temperature (Figure 6.43).

6.6.5.2 Fouling and Plugging of Airheater

Fouling is the deposition of gas-entrained ash. The deposition at low temperatures occurs due to the adherence of ash to the acid-moistened surfaces at the low end of the AH. Pressure

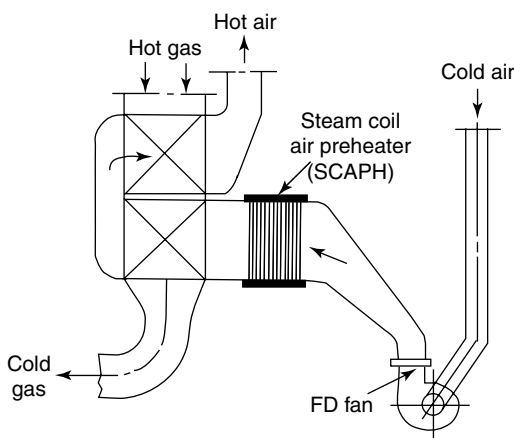


FIGURE 6.42
Schematic arrangement of steam coil airheater.

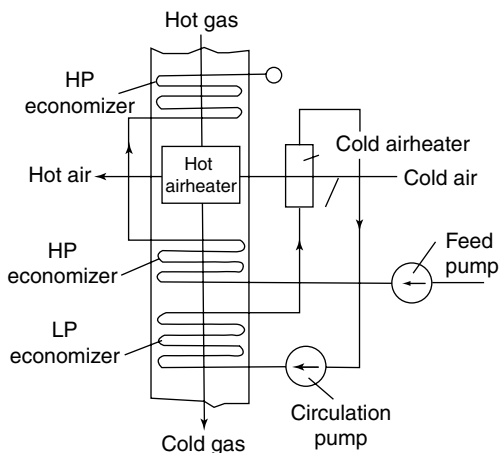


FIGURE 6.43
Low-pressure economizer for airheater temperature control.

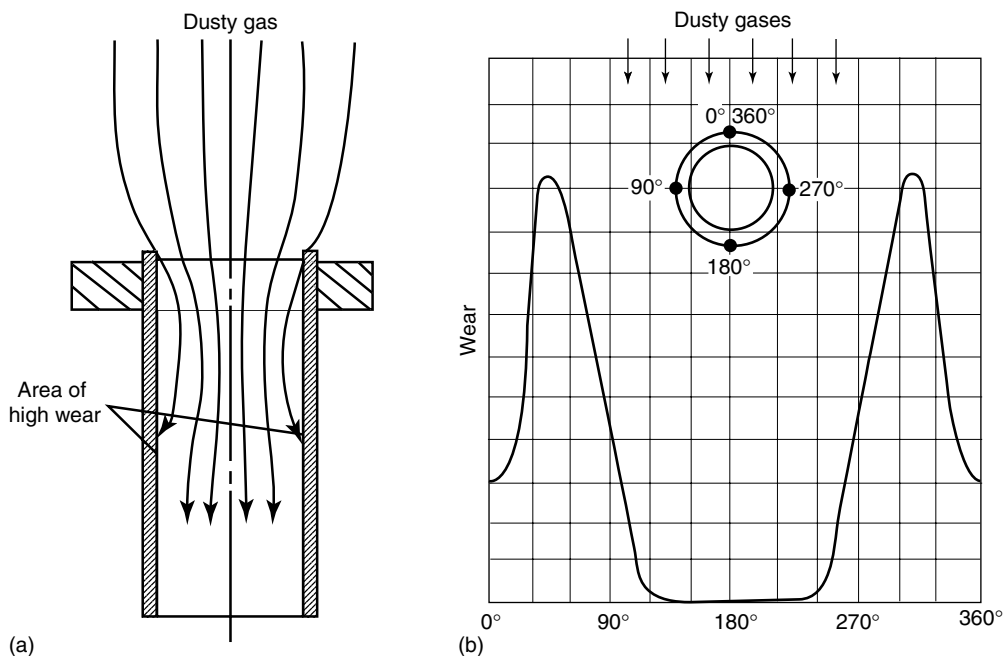
drop increases as the deposits grow in size. If unchecked, gas passages become progressively choked or plugged. Regular soot blowing can reduce the fouling considerably. Off-load water washing is carried out in many installations for deposit removal, as they are mostly water soluble. The reason for larger-diameter tubes in vertical TAHs, which cannot be easily soot blown, is to prevent the deposits from bridging and growing.

6.6.5.3 Erosion in Airheaters

- Employing conservative gas velocities is a design-stage precaution against gas-side erosion, particularly for dusty fuels. Gas velocities have to be high to economize on the surfaces and evolve decent layouts and erosion has to be minimized.
- Normally erosion is at the entry to the bank where the velocities are the highest, and the maximum velocity limit should be applied at this point.
- For an HTAH it is normal to provide the top row with thicker tubes of, for example, 10 swg (3.25 mm) or erosion shields of typically 3 mm. Heat transfer in tubes covered with erosion shields suffers because there is no direct contact of the tube and gas.
- Flow distribution baffles distribute the gas more uniformly across the inlet duct. Typical erosion of the tubes in a horizontal bank is depicted in Figure 6.44a and b. The maximum is 30–50° on either side of the tube axis.
- Areas near the seals in RAHs are subject to erosion due to higher velocity flow of ash through the narrow gaps. This can be controlled by using sacrificial material.
- In a VTAH, erosion occurs in the first 300 mm of the tube entry. Replaceable sleeves are used as protection.

6.6.5.4 Fires in Airheater

Fires occur in RAHs mainly during startup and shutdown due to the agitation of accumulated ash heaps of unburnt carbon. They are particularly common with oil firing. It is *important* to follow the guidelines provided by National Fire Prevention Association

**FIGURE 6.44**

(a) Wear pattern in VTAH. (b) Wear pattern over horizontal tubes.

(NFPA) with regard to safe startup and shutdown procedures. Purging the furnace so that all accumulated unburnt gases are driven off is the most important step. Prevention of collection of ash and prompt removal of any debris are important to prevent fires. Soot blowing before startup and after shutdown can significantly reduce the fire hazard.

Leakage of bearing oil is another source of fire in RAHs.

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7

Fabricated Parts

7.1 Introduction

Fabricated parts of the boiler can be divided broadly into the following categories:

1. Unheated pressure parts (PPs) (coded parts kept mostly outside the gas pass)
2. Draft plant items (mainly sheet metal work)
3. Structures (mainly rolled and fabricated steel work)

These parts do not participate in heat transfer, other than in the gas-swept portions of the drums in the bidrum bank. Nor are they finished auxiliary items that contribute to the performance of the boiler. The fabricated items are mostly static and perform the following background functions:

- Support the boiler, its various components, and machinery
- Transport the fluids, gas, and air (in flues and ducts), and water or steam (integral piping)

7.2 Unheated Pressure Parts

Unheated PPs are pressure-containing pipes and drums outside the gas passes:

1. Steam drums
2. Risers and downcomers (unheated)
3. Integral piping

Steam drums and risers and downcomers are parts of the boiler circulation system and connected to the evaporator surfaces. Integral piping comprises drain, soot blower (SB), blowdown, and all interconnecting piping for superheater (SH) and reheater (RH) to complete the circuits. Other than the drums, all the unheated PPs are made of pipe work. There is no heat transfer and no close bending requirement as in tube banks. Also, the range of sizes is higher, from 25 mm nominal bore (NB) to 457 mm OD. The tubulars are pipes as opposed to tubes used inside the boiler for tube banks, coil work, and panels.

The terms *tube* and *pipe* are often used interchangeably in general engineering but not in boiler practice. The differences are brought out in Table 5.4.

7.2.1 Steam and Water Drums

Steam drum. In natural circulation boilers, the steam drum occupies a position of importance because of:

- It is the heaviest PP and often the heaviest component.
- The layout and erection of the boiler revolve around it.
- It takes the maximum time for manufacturing and needs the costliest machinery.
- Moving it demands a high level of logistics.
- It needs the heaviest crane or lifting tackle during both fabrication and erection.

Thermodynamically, however, a steam drum is merely a surge tank in the circulation system to which the following parts are connected:

- Economizer (ECON) outlet and SH inlet pipes on one side
- Downcomers and risers on the other side

Under steady operating conditions when the flows are balanced, the steam drum produces a steady water level. Drum water level is one of the most important parameters, of a boiler control system. The other important function of the steam drum is to house the drum internals (see Section 7.2.1.3), which perform the following functions:

1. Saturated water from evaporator circuits, which contain varying amounts of steam, is separated by the steam separators. *Water-free steam* to the SH and *steam-free water* to the downcomers are required of *steam separators and purifiers*.
2. *Chemical dosing* to maintain the chemistry of the circulating water.
3. *Continuous blowdown (CBD)* of drum water to keep the carryover under specified limits.

Water drums are present only in the bidrum boilers and play a less important role.

- A water drum acts like a large header connecting the riser and downcomer tubes of the bank.
- It feeds the downcomers to the various evaporator sections.
- It is where the sludge is withdrawn for disposal in many boilers.

7.2.1.1 Sizing of Steam and Water Drum

Steam-drum sizing. The size of the steam drum should be adequate to meet the following requirements:

1. Housing of all internals with adequate space for their dismantling and installation.
2. Providing enough *water holding* to meet sudden surges of steam demand without much decrease in SH outlet pressure (SOP) by quickly evaporating steam from saturated water. The other evaporator surfaces also help in this effort with total water-holding capacity of the boiler coming into play. In the case of bidrum boilers, the water in the bank tubes and bottom drum, and in case of single-drum

boilers, the water in the large-bore downcomers add to the water in the steam drum, thus providing the total water-holding.

3. Sufficient *swell* volume is important for vertical waste heat recovery boilers (WHRBs) or heat recovery steam generators (HRSGs) with evaporator tubes in coil construction. As all the tubes are joined to form a coil (and not left as individual tubes as in a bidrum arrangement) during the startup or a large load change, there is a sudden rush of all the accumulated steam and water in all the legs, causing a massive increase of the drum water. If the drum diameter is too small, the water will overflow into the SH tubes. The amount of swell depends on the boiler construction and the process variations. The start-up conditions of a gas turbine (GT) are very severe on HRSGs, as the GTs attain full-load conditions in minutes. In vertical WHRBs and HRSGs, where gas flow is vertical and evaporators in horizontal coils, the steam drums are larger and governed by the swell conditions.

Drum diameters for the same function reduce with increasing pressure, as the specific volume of steam progressively reduces at higher pressure. Steam drums, normally specified by ID, range from ~1000 to 2200 mm (~40 to 87 in.) in conventional boilers and even 2800 mm (110 in.) in HRSGs. The smallest steam drums are usually in package boilers starting at 914 mm (36 in.). Popular sizes are 1067 mm (42 in.), 1220 mm (48 in.), 1370 mm (54 in.), 1524 mm (60 in.), and occasionally 1676 mm (66 in.) for low-pressure boilers. Larger sizes of 1676 mm (66 in.) and 1830 mm (72 in.) and above are mostly found in utilities or WHRBs/HRSGs. Steam drum thicknesses vary from as low as 25 mm to as high as 250 mm (~1 to 10 in.).

Water-drum sizing. Water drums were known as mud drums because of a large amount of sludge or obsolete designs. The water drum is always smaller than the steam drum as there are no important internals and, more importantly, the number of tubes to be expanded is usually limited to the bank tubes, usually

- 10 or 11 in oil/gas package boilers
- 16–20 in two-pass boiler banks (BBs)
- 18–22 in single-pass BBs

In package boilers, which are shop-assembled, the bottom drums are sometimes made from rolled seamless pipes of 610 mm (24 in.) OD using special ultracompact expanding tools. The minimum diameter is 760 mm id (30 in.). The other popular size is 914 mm (36 in.) and occasionally 1067 mm (42 in.). Table 7.1 gives the popular sizes of the steam and the water drums for all types of boilers.

- These sizes are indicative, and the manufacturers use different sizes.
- The drums are made as per the availability of the dies for making the dish ends.
- Drums larger than 2210 mm (87 in.) can also be made mainly for large HRSGs.
- Usually from 1370, 1830, and 2210 mm id (54, 72, and 87 in.), steam drums have the capability to accommodate two, three, and four sets of cyclones (Figure 7.1).

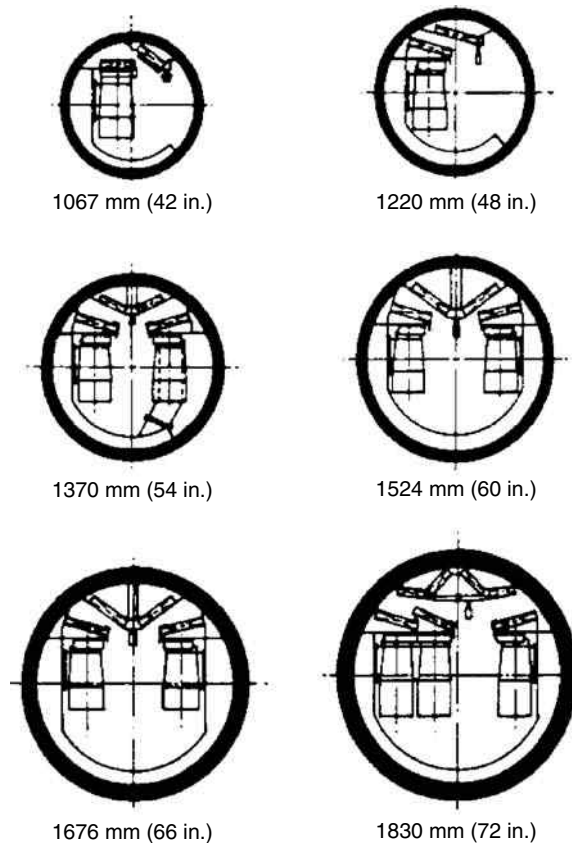
Expanded and stubbed drums. In all the bidrums the bank tubes are expanded in the boiler drums, and these drums are called *expanded drums*. The tube holes are generally ~1 to 2 mm larger than the tube OD. After considering the tolerance of the tube OD, a small clearance (between the tube and the hole) has to be added to arrive at the hole ID.

TABLE 7.1

Range of Popular Steam and Water Drums

Steam drum ID	in.	—	—	36	42	48	54	60	66	72	87
	mm			914	1067	1220	1370	1524	1676	1830	2210
Water drum ID	in.	24	30	36	42	—	—	—	—	—	—
	mm	610	760	914	1067						
Maximum rows of cyclones				1	1	1	2	2	2	3	4
Typical PF boiler size for steam drum (MWe)							60	150	250	500	660

ID = inner diameter.

**FIGURE 7.1**

Typical drum sizes and rows of steam separators.

Oversized holes require a lot of tube expansion with resultant excess cold working, whereas undersized holes create problems of tube insertion and inadequate expansion.

The resulting ligament efficiency $(p - d)/p$, where p is the pitch and d is the bore of the hole, for steam drum is generally approximately

- 38–42% for oil/gas package boilers with 10 or 11 bank tubes
- 48–51% for other bidrum boilers with 18–22 tubes

For higher pressures the drums tend to be thicker due to the reduced allowable stresses. Usually the ligament efficiency due to convection bank tubes is made lower than that of roof tubes and risers and hence it governs the drum thickness.

In radiant boilers, with the absence of BB, only the downcomer and the riser stubs are required to be welded and hence the term *stubbed* drum. Fewer risers and downcomers are required in comparison to the bank tubes. Adequate space in the drums for welding the stubs produces ligament efficiency of $\sim 80\text{--}85\%$. The steam drum naturally is much thinner.

The bottom drum is usually chosen with up to 2% lower ligament to take advantage of its smaller diameter.

7.2.1.2 Steam Purification

The *steam purifier* generally is a combination of *steam separators* and *steam dryers*. Also see Section 4.5.1. Steam purification is usually a two-stage process consisting of

1. Steam separation in which steam is separated from water due to the density difference
2. Steam drying in which last traces of moisture are removed by adsorption

Steam separation is achieved at high velocities by

- Deflection baffles or baffle-type separators
- Cyclone or centrifugal separators

Deflection baffles or baffle-type separators (Figure 7.2) are inertial separators that utilize the change of direction to separate steam and water, which are used up to ~ 150 bar drum

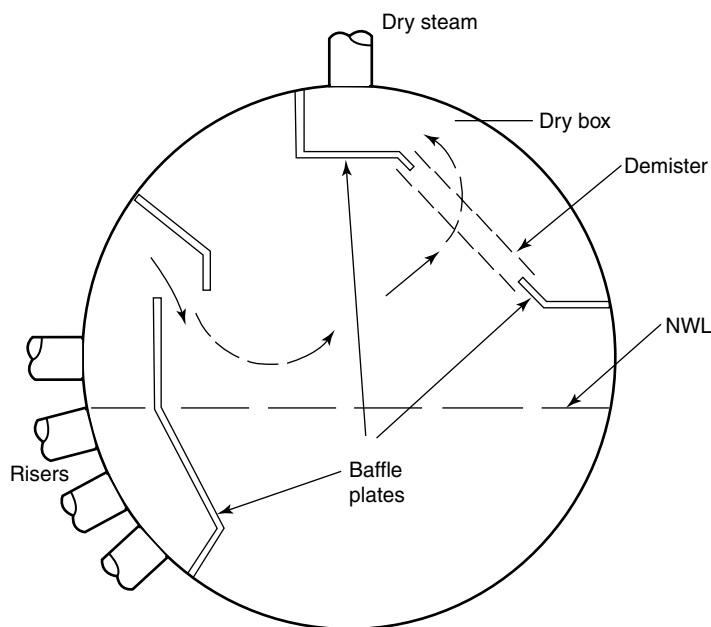


FIGURE 7.2

Deflection baffles or baffle-type separator.

pressure. They create less pressure drop. They are available in a variety of proprietary configurations:

- They are much simpler than cyclones.
- They are less expensive.
- They require much less time to dismantle and install, making site inspection easy.
- They hasten the drum-making process as they need not be installed inside the drum before delivery for trial assembly.

Cyclone or vertical separators (Figure 7.3), in contrast, work on the principle of centrifugal separation and are used for all pressures because the action is more positive. The steam–water mixture enters the cyclone tangentially at $\sim 6\text{--}8\text{ m/s}$. The density difference throws the water particles to the periphery and keeps the steam at the center. The steam travels upward, passing through a perforated baffle pyramid, where it is decelerated and spread across the whole area of the steam drier, which provides additional fine separation. Water

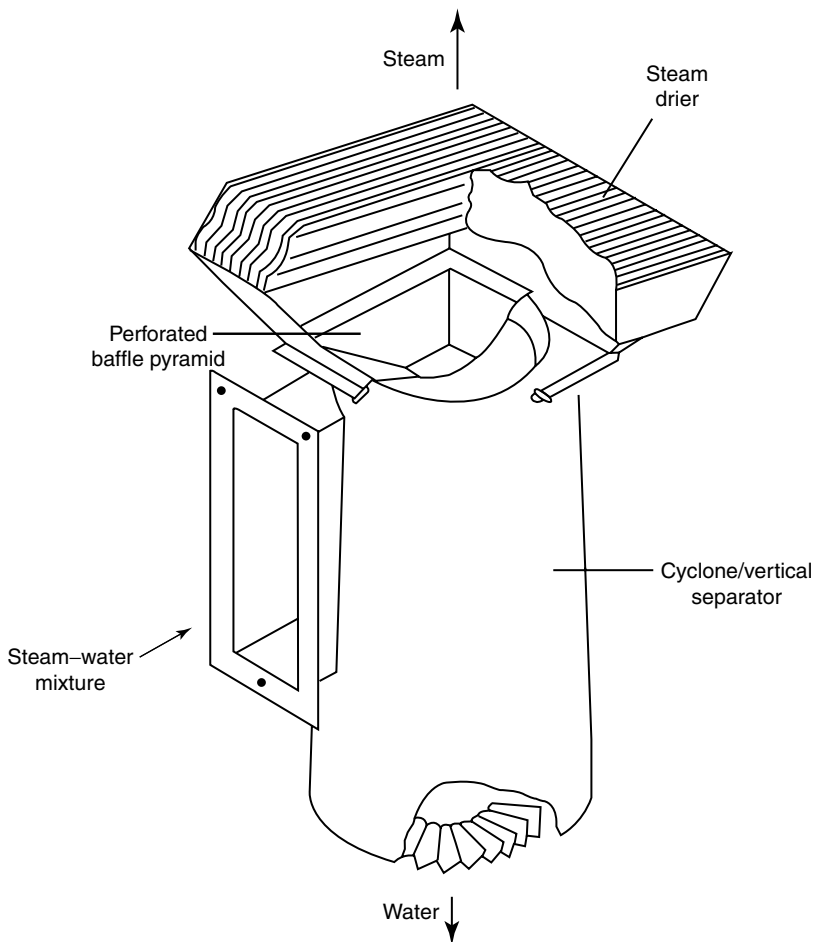


FIGURE 7.3
Cyclone or centrifugal separator.

travels downward in a vigorous swirl. The action is so dynamic that the drum water is kept out of the cyclones, although they are immersed up to half of their height. The cyclones

- Provide a more positive steam separation
- Consume more pressure drop
- Are used for all drum pressures up to 210 bar
- Are more expensive and take more installation time

The two types of cyclone/centrifugal separators are vertical and horizontal (Figures 7.4 and 7.5). Both are proprietary designs developed by different firms. The horizontal cyclone arrangement takes slightly less space for the same duty. But in terms of performance, there does not seem to be much difference. Figures 7.4 and 7.5 represent stubbed and expanded drums, respectively.

Steam drying. Drying devices produce *dry* steam. There are two methods, and both reduce steam–water velocity so that the water gets attached either to the plates or to the wires of the driers. The two types are:

1. Corrugated plate assemblies (also called as chevrons)
2. Demisters

In corrugated or sinusoidal plates, as the steam containing traces of water passes through the pack of corrugated plates, water adheres to steel by its natural affinity by adsorption. The formed water film slides down into the water space by the inclination of plates. It is normal to make the plates with stainless steel (ss) material as ss alone provides a highly polished surface that helps the water to roll off easily. Besides, ss is corrosion-resistant.

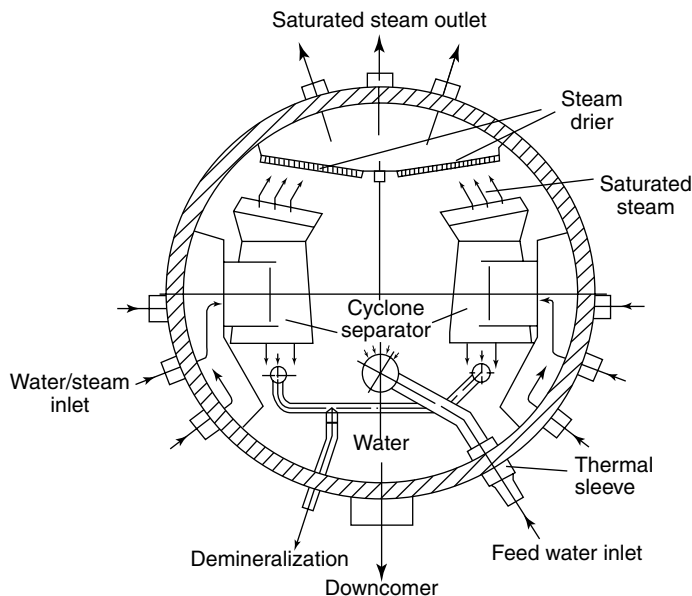
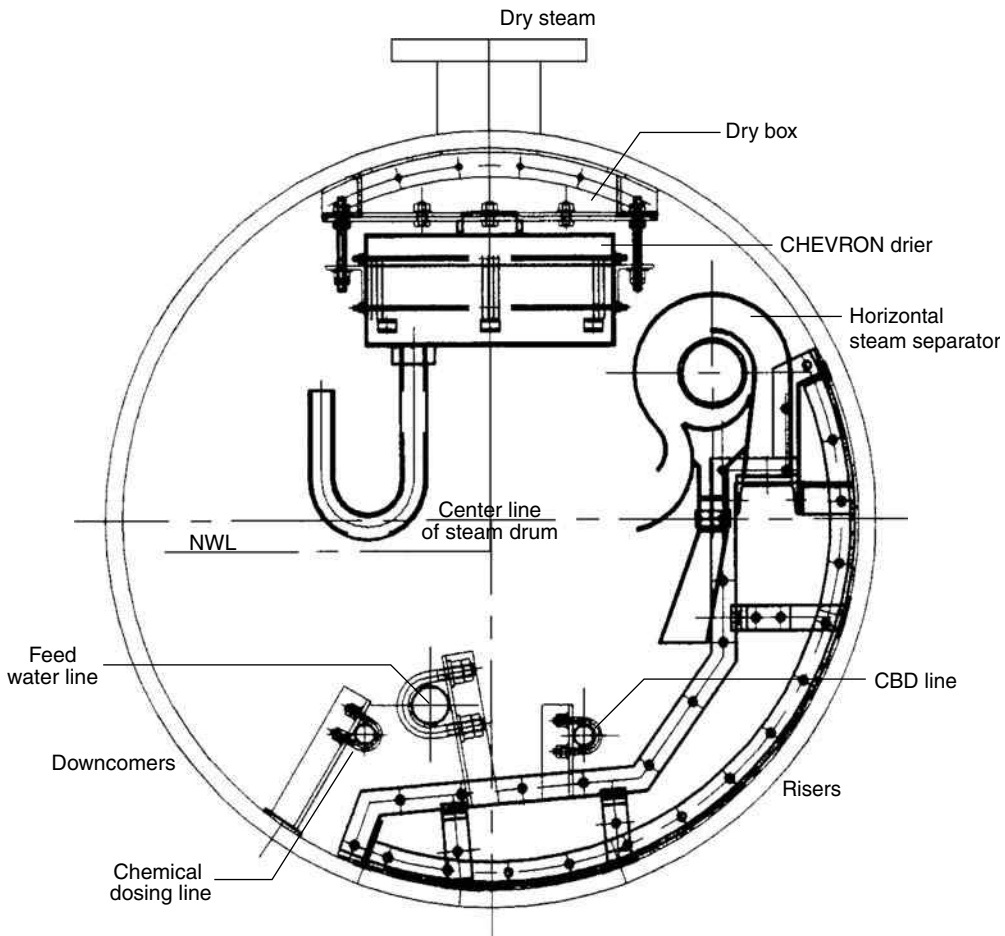


FIGURE 7.4

Drum internals with two sets of vertical cyclones in a stubbed drum.

**FIGURE 7.5**

Drum internals with single set of horizontal cyclones in an expanded drum. (From Foster Wheeler Corporation. With permission.)

In the demisters, traces of water are intercepted by the ss mesh, which is like steel wool. The diameter of the wire and the density of the packing are carefully selected for effective trapping of water.

The most important factor to ensure dry steam is to secure uniform loading of the steam separators with steam–water mixture under all loads. The manner of connecting saturated steam pipes at the top of the drum plays a very important role in the distribution of the steam–water mixture. Connecting the SH tubes directly to the drum is perhaps the best way. Providing several equally spaced saturated steam pipes from the drum to the SH inlet header is another good practice. In small boilers, sometimes a single pipe is used for evacuating steam, but it is not good for steam purification.

The type of steam purification equipment is dependent on the steam generation per unit length of the drum. The steam generation is quite low in stoker-fired boilers as they use the slow-burning fuels. Generation is high in oil- and gas-fired industrial boilers. Pulverized fuel (PF) boilers for utilities generate the most steam. Package boilers for oil and gas have very long drums as the firing is along the drum axis, and steam per meter length appears

TABLE 7.2

Typical Steam Output in Te/m Length of Drum

Fuel	Biomass	Bagasse	Coal	Coal	Coal	Coal	Coal	Oil/Gas	Oil/Gas	Natural Gas
Firing	SS	SS	SS	BFBC	PF industrial	PF utility	CFBC	Package	Field erected	HRSG
Te/m	4–6	9–15	8–12	8–15	20–40	30–100	25–35	2–10 (3–15)	30–40	10–30

low, although the rating of all areas of the boiler is high. Considering that downcomers occupy 35% length of the drum, it is more appropriate to increase the steam loading by ~1.5 times, that is, 3–15 Te/m. Table 7.2 compares the steam loadings for various types of boilers and fuels.

7.2.1.3 Drum Internals

Drum internals include steam separation and purification equipment and other secondary equipment such as the following:

- Feed water (FW) distribution piping
- Chemical-dosing piping
- Blowdown piping

Figure 7.4 shows the arrangement of all the drum internals having vertical cyclone separators in a single-drum boiler with large bore downcomers.

Steam separation. Two rows of cyclones are shown in Figure 7.4. Depending on the steam release per meter length of the drum, the cyclones can be arranged in one, two, or three rows.

- The design of the drum internals has to meet the fundamental requirement that they are installed in the drum only after the boil out is complete and the magnetite (Fe_3O_4) layer on the inside of the drum is fully formed.
- All drum internals must be of bolted construction, including the baffle plate, so that they can be installed and reinstalled easily. The drum inside the surface must be inspected at regular intervals in an operating boiler.
- The drum internals have to be compact enough to permit their assembly inside the drum manually and allow them to be dismantled and reinstalled quickly.
- The baffle plates separating the steam and the water spaces and made of several small components, have to be of good fit and finish to create a tight compartment that prevents steam from escaping into the water space.
- Great care is needed in the assembly of drum internals. The danger of the small fasteners and fittings falling inside the drum and escaping into various pipes, can cause flow obstruction, leading to serious damage during operation due to overheating.
- Depending on the arrangement, the FW may enter the steam drum at one or several locations connected to a single pipe with several perforated holes to permit a uniform distribution and a steady entry into the water space of the drum.

- Blowdown water, to limit and maintain the concentration of solids in the drum water, is collected at the bottoms of the cyclones by means of perforated pipes.
- The small chemical-dosing pipes run the entire length of the steam drum to distribute the chemicals.
- All drum internals are nonpressure parts (NPPs) because the same drum pressure acts inside and outside.
- All nozzles carrying cold liquids should have thermal sleeves to prevent thermal shock to the drum (Figure 7.4).

7.2.1.4 Boiler Dynamics and Drum

The steam drum is located outside the flue-gas path in single-drum boilers and inside the gas path in the bidrum boilers. The metal temperature can be considered the same as the saturation temperature of water in unheated drums, whereas it is a few degrees ($<10^{\circ}\text{C}$) higher in heated drums. The drum thickness is governed by the following elements:

- Ligament efficiency
- Inside diameter
- Design pressure
- Material of construction

Drum thickness is the governing factor in limiting the startup and shutdown rates of a boiler, particularly as the drums attain thicknesses ~ 100 mm and more.

In thicker drums, the difference between the inside and the outside temperatures of the drum shell on an accelerated loading or shutdown can create differential stresses, leading to over-stressing and failure. This can be avoided by adopting lower ramp-up rates for the boiler loading.

- For drums with expanded tubes, the criterion is the loosening of tubes during accelerated cooling, because the thin tubes contract faster than the drum shell.
- Typically the heating is limited to $1^{\circ}\text{C}/\text{min}$ of the saturation temperature for expanded drums, to prevent the reverse of the above condition.
- For fully welded drums, based on the stress analysis, limit the temperature differentials for a certain pressure
 - Across the drum plate
 - Between the top and the bottom of the drum

These limits are different for heating and cooling. Naturally for higher rates of starting and cooling, boilers with no expanded tubes, stubbed drums, are better.

7.2.2 Downcomers, Supplies, and Risers

Supplies and risers are pipes that feed and evacuate water walls and other evaporator surfaces, respectively.

- *Downcomers* are the supply pipes that start from the drum to feed the water walls and convection banks.

- Because saturated water flows through these downcomer pipes, they are at the same temperature with no relative expansions among themselves or the EVAP banks they are connected to.
- They made of CS unless at high pressures; low-alloy steel such as SA 213 T1 (0.5% Mo) or T11 (or 1.25% Cr and 0.5% Mo) is used for thickness reduction.

The *large-bore downcomers* take water from drums for further feeding.

- They usually vary from 193 mm (7 3/4 in.) to 457 mm (18 in.) OD.
- They fit the layouts of tall boilers very well but not the oil- and gas-fired package boilers.
- Large-bore downcomers are almost indispensable for radiant boilers where they are used for bringing the saturated water to lower headers.
- In tall bidrums they are connected from the bottom drum.
- Many times these pipes are not directly welded to the drum but hung separately and connected with small pipes for better layout considerations. Also, they avoid heavy welding on the thick-walled drums, which is better for the life of the drum.
- When large-bore downcomers are directly attached to the drums, *antivortex baffles* have to be installed at the entry so that the vortex effect is broken, and the steam bubbles are not sucked into the downcomer circuits. This can weaken the circulation by reducing the saturated head. These baffles are only a pair of flats inserted into the entry of the downcomer at right angles, which break the vortices. Supply pipes start from the drum in small boilers and from the downcomers in large boilers.
- Circulation calculations can prove the adequacy of the number and the size of the supplies provided.
- New supply pipe arrangements should be checked for circulation adequacy.
- At low and medium pressures, supply pipe areas are generally 1/4 to 1/6 times the area of the evaporator circuit they serve, depending on the pressure.
- At higher pressures, as the circulation ratio is lower, the area required for supplies is greater.

Riser pipes connect the top headers of the water walls to the drum in the area below the separating baffle for evacuating the steam and water mixture.

- The specific volume of the steam–water mixture is greater than the saturated water. It is essential that the area of risers be larger than the area of supplies for any circuit.
- For low and medium pressures, area for risers is generally 1/3 to 1/2 times the area of water wall and even higher for the division walls.
- The area here is also higher for higher pressures.
- For all sizes of boilers, arranging riser pipes, clearing the suspension hangers from the roof, and leading them to the drum at some uniform spacing, are time-consuming and difficult processes.

- Riser pipes connecting the farthest header to the drum are generally susceptible to sagging and mild vibration when they are longer than 6 m. Often they are supported at some midpoint.

As the boiler sizes and pressures increase, the ratio of risers, downcomers, and supplies in the total PPs also increases disproportionately.

7.2.3 Integral Piping

Integral piping is located on the boiler island, that is, between the feed-check valve and the main steam stop valve (MSSV). The term covers all pressure piping comprising

- Soot blower
- Blowdown—continuous and intermittent
- Drain and vent—sampling
- Terminal piping—feed inlet, main steam outlet, and RH inlet and outlet pipings

Most integral piping, except for terminal piping and SB main piping measures <76 mm NB and many times it is site-fabricated and erected.

7.2.3.1 Soot Blower Piping

This piping forms the bulk of the integral piping. Starting usually from the SH intermediate header or the drum, the piping is routed up to the individual SB.

- A main isolating valve, a pressure-reducing valve, and a safety valve are located on the main SB line before it branches to an individual SB.
- The main line terminates at some convenient lower level with a draining arrangement complete with a steam-trap assembly.
- Each branch terminates at its respective isolating valve upstream of the blower.
- Appropriate slopes for the main and the branch lines provide proper draining of the whole piping, which is essential to ensure that no water particles are deposited in the soot-blowing steam. Impingement of water particles at high velocity can rupture the tubes inside the boiler as the dust laden steam jets are very erosive.
- Piping to retractable SBs is often stress-analyzed for flexibility.
- Soot blower main piping is usually of CS. If connected to SH headers, it can be of low-alloy steel of the same mix as the headers to which it is connected.

More details are given in Chapter 8.

7.2.3.2 Blowdown Piping

As explained in Chapter 4, boiler water is dosed with chemicals and conditioned so that it does not

- Attack the wet parts and cause corrosion
- Leave behind scaly deposits, which cause tube overheating and corrosion.
- Contribute to carryover

TABLE 7.3
Types of Blowdown

Type	Main Purpose	Location
CBD	Silica control at high pressures Alkalinity control at low and medium pressures	Steam drum—below steam separators
IBD	Sludge removal	Water drum or downcomers, whichever is lower

As the steam is evaporated, a concentration of reacted chemicals and solids is left behind by the steam, which has to be removed for maintaining the specified limits. While operating the boiler, this is done by blowing down. There are two types of blowdowns as given in Table 7.3.

- Blowdown piping extends from drums or downcomers to the blowdown tanks.
- Intermittent blowdown is dirty as it contains sludge from the boiler, and the IBD tanks are vented to atmosphere with no flash steam recovery.
- Continuous blowdown is clean and continuous and hence amenable to flash steam recovery on large units or with common CBD tank for multiple boilers.

7.2.3.3 Drain and Vent Piping

7.2.3.3.1 Drains

Boiler drains are located at the bottoms of the saturated circuits and SH and RH circuits. The drains have several purposes.

- Draining of the boiler water from the water walls and downcomers for inspection and emptying.
- Lowering the water level in the boiler from the downcomers or the bottom drum in an emergency during operation.
- Draining of steam from the SH headers during start-up to induce flow through the SH coils for keeping the tubes cool and to help raise the steam temperature faster.

The following constructional aspects are worth noting.

- All the lower headers have drain connections. The upper headers do not need them as they are drained into the lower headers by connecting tubes.
- Headers longer than about 4 m are provided with drains on either end.
- Water-wall drains are all connected to a ring main, which is then connected to the IBD tank.
- During normal operation of the boiler, the water walls are not to be drained. Draining would disrupt the circulation and cause serious damage to the tubes.

- Superheater drains are usually designed to ~12.5% steam flow and are connected to the CBD tank.
- All pipes to the drain valve are designed for full boiler design pressure and half pressure from the blowdown valve to the blowdown tanks.

7.2.3.3.2 Vents

- Boiler vents are always at the top headers and the steam drum for the removal of air.
- Air-vent sizes are small, <50.8 mm NB.
- A start-up vent on the final SH header must vent substantial amounts of steam, typically ~30%, to induce a good flow through the SH to get steam temperature high enough to avoid temperature mismatch with turbines during start-up. Start-up vents usually vary in size from 100 to 200 mm. All start-up vents need silencers. Piping to the vent valves is designed for full boiler pressure.

All drain and vent piping can be of CS except for SH vents and drains, which are of low-alloy steel of the same composition as the headers from where they start.

7.2.3.4 Sampling Piping

Sample coolers are usually placed on the firing floor or near the control room. Sample pipes bring steam and water samples from the respective tapping points to the coolers. It is normal to provide at least four sampling points in a boiler for

1. Superheater steam
2. Saturated steam
3. Feed water
4. Drum water

A pipe size of 25 NB is commonly used. Sampling piping is required to be ss as corrosion products, which may easily form with CS, cannot be permitted in water or condensate samples and will lead to results.

7.2.3.5 Terminal Piping

Some boiler contracts are based on the battery-limit concept in which all the equipment and piping within the battery are to be supplied by the boilermaker. All the piping, both incoming and outgoing, must be taken up to the battery limits. This concept is very popular in the hydrocarbon industry. The terminal piping up to the limits of the boiler island is usually designed for flexibility.

7.2.3.6 Permissible Fluid Velocities in Piping

Table 7.4 provides a range of velocities for sizing of boiler integral and external piping. The lower end of the range is chosen to keep pressure losses low. The higher end is chosen for short runs of piping and shortages of available economical pipe size. At the proposal stages, it is prudent to adopt midrange velocities.

TABLE 7.4

Permissible Range of Fluid Velocities in Pipes

Nominal Pipe Size (mm)		Average Velocity (m/s)		
		<50 mm	50–150 mm	>200 mm
<i>Saturated steam</i>				
At subatmospheric pressure		—	10–15	15–20
At 0–1 kg/cm ² (g)	~0–2 bar	15–20	17–30	20–30
At 1.1–7 kg/cm ² (g)	~2–8 bar	15–20	20–33	25–43
Over 7 kg/cm ² (g)	>8 bar	15–25	20–35	30–50
<i>Superheater steam</i>				
At 0–7 kg/cm ² (g)	~0–8 bar	20–30	25–40	30–50
At 7.1–35 kg/cm ² (g)	~8–37 bar	20–33	28–3	35–55
At 35.1–70 kg/cm ² (g)	~37–72.5 bar	22–33	30–50	40–61
Over 70 kg/cm ² (g)	>72.5 bar	22–35	35–61	50–76
<i>Water at pump suction</i>				
Condensate		—	0.4–0.6	0.6–0.7
Boiler feed		—	0.6–0.9	0.6–0.9
General service		0.6–0.9	0.7–1.3	0.9–1.5
<i>Water at pump discharge</i>				
Condensate		0.9–1.2	1.2–2.1	1.5–2.2
Boiler feed		1.0–1.2	1.5–2.1	1.8–2.4
General service		0.9–1.0	1.5–2.4	1.5–2.4
<i>Viscous liquids</i>				
Pump suction		0.3	0.3–0.4	0.4–0.5
Pump discharge		1.0	1.0	1.2–1.4
<i>Air</i>				
Compressed air		7–10	10–15	18

7.3 Draft Plant Items

Draft plant is an all-inclusive term for equipment and items that handle air and gas. These equipment and items are as follows:

1. *Draft plant equipment:*

- Fans—forced and induced draft (FD and ID), primary and secondary air (PA and SA) and gas recirculation (GR), and seal-air fans
- Dust-collecting equipment—mechanical dust collectors (MDC), bag filters, electrostatic precipitator (ESP), cyclones

2. *Draft plant items:*

- Flues, ducts, hoppers, and casing
- Dampers
- Expansion joints
- Airflow-measuring devices

Draft plant equipment is a boiler auxiliary and discussed in detail in Chapter 8. Draft plant items are fabricated parts, which are discussed in the following sections.

7.3.1 Flues, Ducts, Hoppers, and Casing

7.3.1.1 Flues and Ducts

Flues and ducts are rectangular or round ducts meant to convey flue gas or air, respectively.

- Flues carry flue gases whereas ducts carry air.
- Flues are generally made of 6 mm and ducts of 5 mm thickness. In small-package boilers, with short lengths, 4 mm is also used for both flues and ducts.

The following points are worth noting about flues and ducts:

1. Depending on the internal pressure, suitable external stiffening must be done to prevent distortion and vibration due to the movement of the high-velocity air or gas.
2. For large ducts of 2 m or more, internal bracing is required. Structural members or pipes are welded firmly to the opposite sides to maintain the shape.
3. When equipment is interconnected, the duct sizing is governed by the flange dimensions at two ends and not by velocities.
4. For straight distances, classical velocity limits are applied and pressure drops are checked to determine optimum sizing.
5. Circular ducts are the most economical. Higher velocities can be employed for the same pressure drop and hence the areas are smaller. Also, less stiffening is required as the circular shape is inherently more rigid. Less steel is required.

Typical permissible air and gas velocities are given in Table 7.5.

TABLE 7.5

Permissible Air and Gas Velocities in Flues and Ducts

Location	Velocity		Remarks
	m/s	ft/m	
<i>Air ducts</i>			
FD suction	9–11	1800–2200	Even 14 m/s (2800 ft/m) if layout demands
FD discharge—cold	11	2200	
FD discharge—hot	15	3000	
Tempering air	14 and 18	2800 and 3600	For rectangular and circular ducts, respectively
Mill inlet	18	3600	High velocity because of airflow-measuring device
Seal air	20 and 25	3600 and 5000	For rectangular and circular ducts
<i>Gas ducts</i>			
Up to ID fan—coal	12.5–15	2500–3000	Reason: <12.5 ash buildup and >15 erosion in flues
Up to ID fan—oil/gas	14	2800	Also other nonerosive fuels
Beyond ID fan—coal	9–14	1800–2800	
Beyond ID fan—oil/gas	14	2800	Also other nonerosive fuels
Bypass and crossover	14	2800	

7.3.1.2 Hoppers

Hoppers are used for collecting ash at the bottom of a bank and also for facilitating flue-gas turns.

- They are usually of 6 mm thickness.
- The slopes of their sides should result in valley angles at the corners that should be greater than the angle of repose of ash. In coal-fired boilers, the slopes should be 70° or more to the horizontal. This will yield valley angles at the corners >63°.
- High-temperature hoppers, such as those below the BB, need to be covered with refractory tiles or insulating blocks to prevent overheating. Choice of tile or block depends on whether the ash in flue gas is abrasive or not, respectively.
- Low-temperature hoppers, such as those below the ESP, have to be equipped with fluidizing nozzles for aiding a smooth ash flow. Also, heating pads have to be provided to prevent ash from cooling down and absorbing moisture and turning to lumps when unit is shut down. Ash is very hygroscopic.

7.3.2 Dampers

Dampers in the paths of air and flue gas work on flow streams in the following four ways:

1. Isolation
2. Control
3. Diversion
4. Nonreturn

All boiler dampers are fabricated from sheet steel to the required sizes and specifications. There are four types of dampers.

1. Louver or flap-type dampers for control and isolation duties. However, they cannot provide a tight shutoff.
2. Guillotine dampers for isolation duty. Even 100% shutoff is achievable.
3. Diverter dampers for diverting the flow as in HRSG bypass.
4. Nonreturn flap dampers for preventing flow in reverse direction, such as a weather damper in the HRSG stack.

7.3.2.1 Louver or Multiflap Dampers

Louver or multiflap dampers (Figure 7.6) are the most common because they are light, occupy less space, can be inserted in any position, and are mechanically simple. But they offer a little more pressure drop, are not leak tight in closed position, and are more prone to leakages through the shaft seals.

Large hot dampers, which are operated infrequently, become jammed and the functioning is often indifferent unless the damper construction is sturdy, and the actuator is adequately powered.

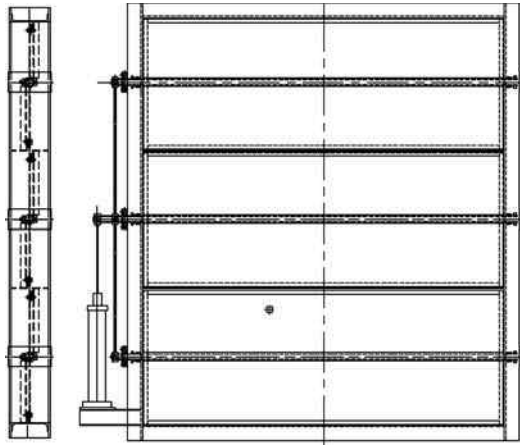


FIGURE 7.6
Three-flap louver damper with power cylinder actuator in closed position.

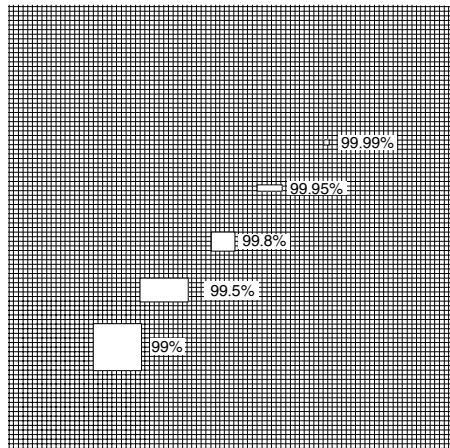


FIGURE 7.7
Leak tightness.

7.3.2.2 Guillotine Damper

The guillotine dampers are less flexible, heavier, and erode their seals. But they offer less pressure drop and provide a good shutoff. In areas of lethal gases, guillotine dampers can provide gas tightness with shutoff levels exceeding 99.9%. This is achieved by sealing system-employing air to inflate the seals on either side of the sealing plate. The difference between 99 and 99.99% sealing is large as shown in Figure 7.7. A typical guillotine damper is shown in Figure 7.8.

7.3.2.3 Diverter Damper

The diverter damper (Figure 7.9), used between the exhaust of GT and the inlet of HRSG should be capable of withstanding temperatures between 50 and 650°C and pressures

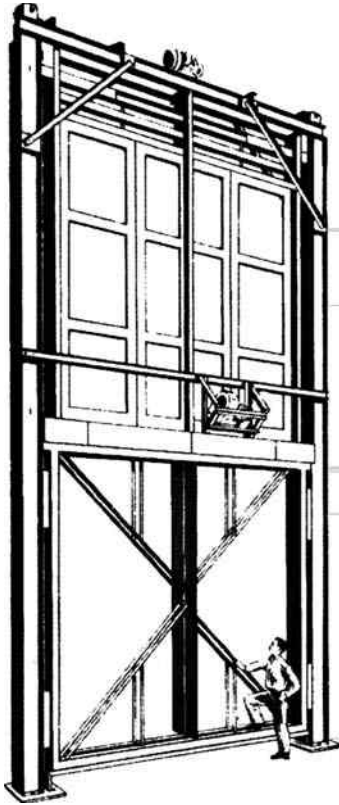


FIGURE 7.8
Guillotine damper in open condition.

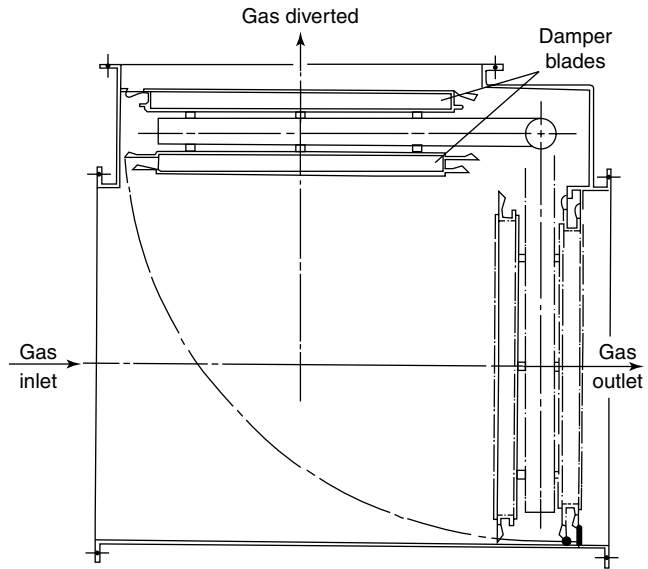


FIGURE 7.9
Diverter damper in boiler running condition.

up to 400 mm w.g. A diverter damper should, during normal operation, provide very tight shutoff. Any leakage of gases causes loss of cycle efficiency. Dampers are large, usually constructed of stainless steel, to withstand high pressures and temperatures from turbine gases.

7.3.2.4 Weather Damper

Weather dampers are required in vertical HRSGs to prevent the wetting of tubes due to rainfall. In a vertical HRSG, the stack is mounted on top of the unit. The stack diameters are large and rain water is bound to enter a banked HRSG unless the stack is closed. During operation, the flow of pressurized gases at ~ 16 m/s keeps the rain water away and also the flaps open. The weather damper is a circular device fitted at the bottom of the stack and has a pair of eccentrically supported semicircular halves that are kept open by the force of gases during running and are closed when the upward force is absent when the unit is down. Motorized actuation helps the gases in initial lifting of the weather damper.

7.3.3 Expansion Joints

Expansion joints are introduced in the ducting for

1. Vibration isolation
2. Absorption of differential thermal expansion

An expansion joint for vibration isolation is often called a v-breather, and consists only of a single loop. All the fans invariably have v-breaters at their connections to the ducting. The expansion joints are of two types: (1) metallic and (2) fabric. The metallic joints have been in use for a long time.

- They are more rugged and have a longer life.
- For very erosive coals, metallic joints are preferred as they can withstand erosive forces better.

Fabric joints are of more recent origin.

- They are far more flexible.
- They facilitate construction as alignment need not be so accurate.
- They can accommodate expansion.
- They can accommodate distortion.

From life and erosion aspects, metallic joints appear to be favored for coal and allied applications. Improved fabrics and lower costs are fast increasing the acceptance of fabric joints, as the flexibility is far better.

Figure 7.10 presents the locations and temperatures of various types of dampers and expansion joints in a typical PF-fired boiler.

7.3.4 Airflow Measuring Devices

Airflow measurement by special devices is necessary in conventional boilers. In certain boilers, pressure drop across SH, BB, or airheater (AH) can also be used to measure airflow, if there is no deposit formation and the calibration remains unaffected. In all the other cases, airflow is measured by one of the following three methods (Figures 7.11 through 7.13).

1. Orifice plate
2. Venturimeter
3. Aerofoil

The following considerations dictate the choice of the device:

1. Layout of the boiler plant
2. Upstream and downstream straight lengths of duct available
3. Permanent pressure drop across the device
4. Cost

Table 7.6 compares the measuring devices.

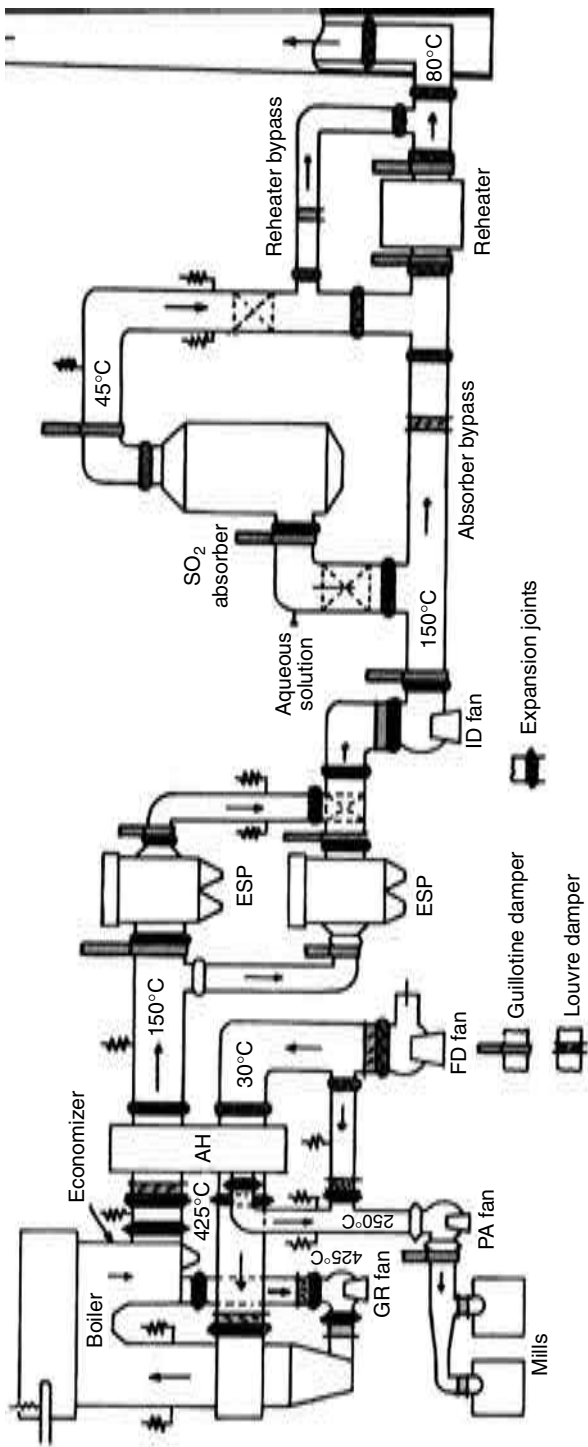


FIGURE 7.10
Dampers and expansion joints in a typical pulverized fuel boiler.

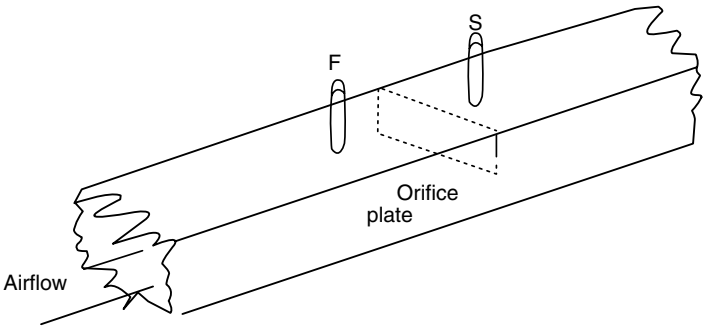


FIGURE 7.11
Orifice plate.

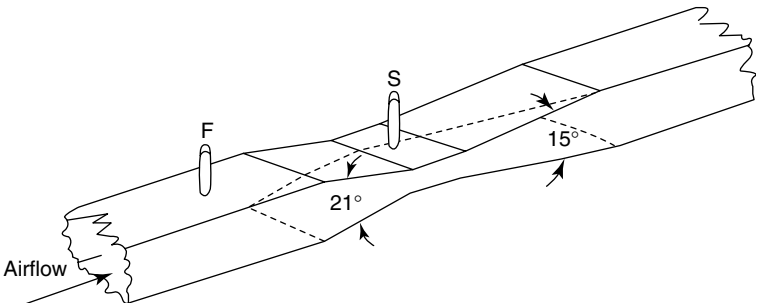


FIGURE 7.12
Two-sided venturimeter.

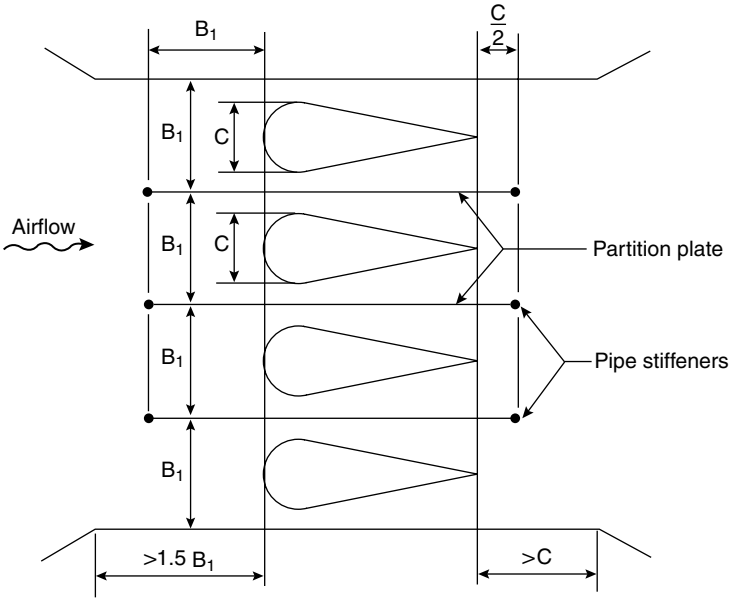


FIGURE 7.13
Multiaerofoil.

TABLE 7.6
Comparison of Airflow Measuring Devices

Device	Location	Measuring Difference (mm w.g.)	Permanent Loss (mm w.g.)	Relative First Cost	Remarks
Orifice	Air duct	75	40	1.1	For small boilers in which power loss is not important and is used frequently in tempering air duct
Venturimeter	Air duct	75	22	1.4	Lower cost and loss but requires longer duct length than aerofoil
Aerofoil	Air duct	75	18	2.1	Requires shorter duct than venturi and multiple aerofoils reduce length
Convection bank	Gas pass	75	0	0	Only for clean fuels and banks in crossflow and not for longitudinal flow

For reliable readings, there should be 10 upstream and 5 downstream equivalent diameters of straight lengths of ducting available, so that adequate flow straightening takes place. When there is a shortfall due to layout constraints, flow straightness should be inserted in the ducts.

7.4 Structure

Except in the case of package boilers and small-field erected boilers of up to ~50 tph, the boiler structure constitutes the heaviest single subgroup and contains the maximum number of subassemblies and individual parts. Pressure parts and firing equipment are distinctive to the boiler, whereas the structure defines the delivery schedule of the whole plant. This is because the structural layout and design cannot start before the

- 1. Boiler arrangement and auxiliaries are properly completed with approvals.
- 2. Pressure part layouts and design are finished and approved

What is begun nearly at the end has to be completed first, because the boiler erection begins with the columns. Ironically, even in structure, the columns are the last items to be designed. Simplification of structural activity is, therefore, the key to reducing time to boiler delivery.

Structural design is governed by the building codes. The calculations are mostly repetitive and iterative and hence are amenable to computerization. But the underlying concepts and considerations must be understood in depth to ensure economical design.

7.4.1 Site Conditions

- 1. *Indoor or outdoor.* This is site-dependent and customer-dependent.
 - a. In cold climates, indoor boilers are necessary for the comfort of operators and protection of equipment against rain and snow. Most plants in Europe and North America utilize indoor structures.

- b. In warm and dry climates, outdoor units are popular if rainfall is scanty. Plants in the Middle East and many parts of Africa are outdoor units.
- c. In warm climates with rainy spells, semioutdoor units are preferred. A hood on top of the boiler and firing floor prevent rain water ingress. Plants in India, China, and Latin America fall in this category.

Indoor boiler structure is the lightest because the boiler house shields the boiler from the wind loads.

2. *Coastal.* Corrosion is the main concern. For boilers operating on the seacoast and in plants pervaded by corrosive gases, protection of the structure against corrosive environment is done by adding corrosion allowance or by coating with epoxy paint of suitable thickness.

7.4.2 Loads to be Supported by Structure

The first step in the design of the boiler structure is to estimate all the loads in the boiler that need to be transferred to the supporting system:

- Pressure parts and water in them
- Buckstays and tie bars and allied attachments
- Insulation, refractory, casing, and penthouse
- Firing equipment supported on walls
- Slag and ash
- Bed material in case of fluidized bed combustion (FBC) boilers

A margin between 5 and 10% is added as a safety against outages, later additions, underestimates, and so on. These weights are, in a top-supported boiler, first transferred to the top girders, then are in turn transferred to the main columns. A lot of other loads placed on various floors are also transferred to the columns but at different levels.

In the bottom-supported boilers, these weights are transferred to the ground by the PPs. The structure is, therefore, not so much for boiler support as for providing access to all levels and may transfer the loads of the PPs where they do not rest on the ground level.

7.4.3 External Loads on Structure

In addition to supporting boiler loads, the structure is also required to withstand external loads. These are nature-imposed loads dependent on the geographical location, for which necessary guidelines are given in the local construction codes.

- Wind loads
- Earthquakes

It is important to know the fundamental difference between the effects of wind and earthquake, although both are horizontal forces. Wind loads act on the entire height of the structure, whereas an earthquake acts at the bottom, similar to the pulling of a carpet on which a person is standing. The wind forces are relatively more steady, whereas the earthquake forces alter in direction.

Wind loads play a great role in the weight of the final structure.

- The structure is heavier for the same wind velocity as the boiler height increases. Conversely, for the same height of the structure, the weight is higher for higher wind velocities.
- Bracing all the columns and presenting an interlaced space frame is the best way to share the load and reduce the weight of the members.
- Wind loads are usually more severe along the seacoast where hurricanes and typhoons are more frequent.

Earthquake forces require remedial measures, such as earthquake restraints in the structure. Depending on the total height of the boiler, the furnace is divided into two, three, or four segments along its height, and each segment is restrained in both axes by rigidly connecting the buckstays to the outer beams.

7.4.4 Boiler Expansion and Guides

Differential thermal expansion of the PPs and the hot structural parts is an inherent feature of any boiler. Many structural problems in the static parts of the boiler arise from differential thermal expansions. To minimize these problems, it is necessary to

- Anticipate the expansions
- Make adequate provisions for the expansions
- Guide them suitably

The top-supported boiler expands downward and the bottom-supported upward. An expansion diagram for the PPs is drawn and the structural guides are provided at the design stage.

In Figure 7.14, the expansions of the PPs are estimated and drawn for a top-supported PF boiler. The boiler is anchored in the center with equal expansions on all the sides. A boiler can be anchored in any way that is suitable for the site layout—at the center, front, rear, or left or right side.

Likewise, a boiler can be supported either from the bottom or from the top. Medium and large boilers are always top-supported. When hung from the top, the vertical expansion is always one way—downward. Also, the maximum expansion is experienced by the furnace. The two lines at the right side of Figure 7.14 depict the following:

1. Thermal expansion of the PP
2. Expansion with settlement after water is added

Coefficient of thermal expansion of steels in the temperature range experienced by the PPs can be conservatively considered as $\sim 1 \text{ mm/m}/100^\circ\text{C}$. This varies depending on the steel and the temperature range but is good enough for quick estimates. For a boiler with drum at 45 m and operating at 160 bar pressure (347°C saturation temperature), the thermal expansion of the bottom water-wall header at 4 m level will be $\sim 130 \text{ mm}$. Such a large expansion must be provided for, and for all connecting equipment at various levels, appropriate downward movements should be transmitted safely. Suitable guides are

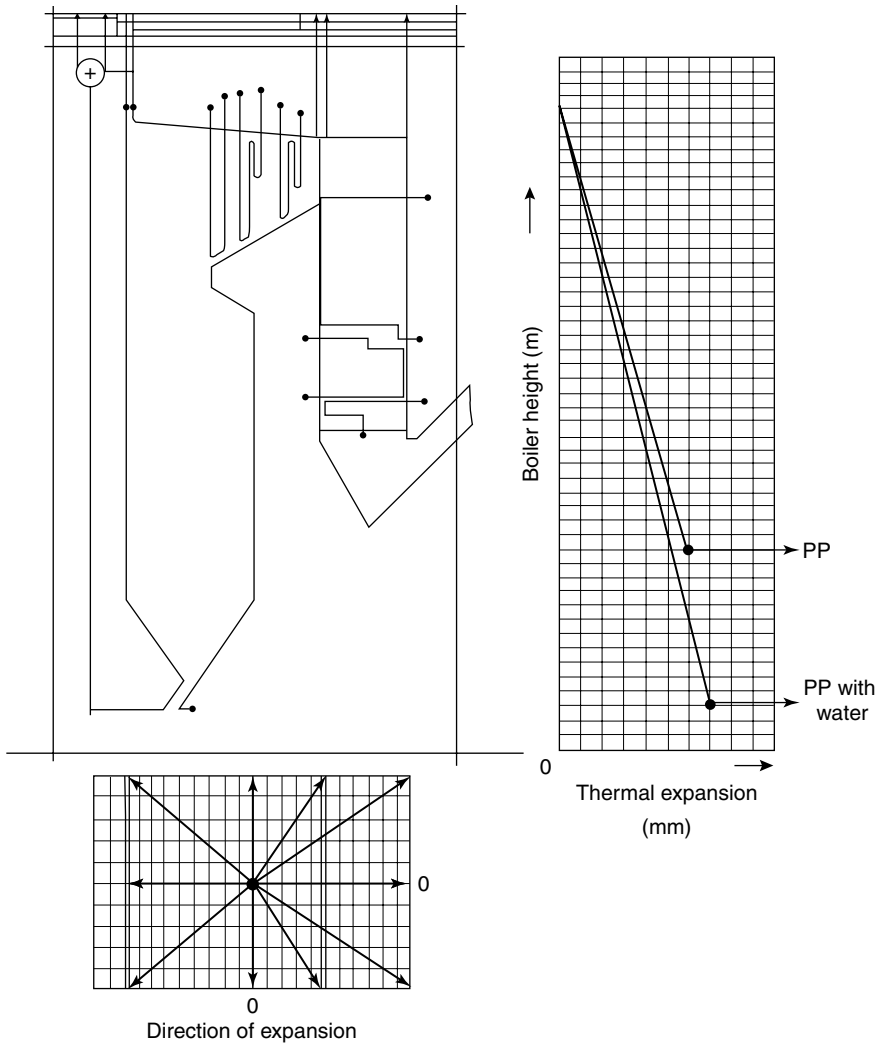


FIGURE 7.14
Typical thermal expansion of a top-supported two-pass boiler.

provided at various levels in the structure to guide the vertical expansion of the furnace to prevent interference from uncontrolled movements.

7.4.5 Hot and Cold Structures

Boiler structure is usually divided as follows:

1. Hot structure
2. Cold structure

Hot structures are attached to the hot parts, usually the PPs. These are

- Buckstays and tie bars
- Top-suspension hangers

Cold structure supports the boiler and includes:

- Top-suspension girders
- Columns with base plates
- Main beams and bracings
- Galleries, ladders, and platforms
- Guides and restraints

7.4.5.1 Hot Structure

Buckstays and tie bars. Buckstays were explained in Chapter 6 (see Figure 6.5). Buckstays experience the following loading:

1. Longitudinal loading due to internal pressure and externally applied loads
2. Normal loading due to internal pressure
3. Bending moments caused by the eccentricity of the brackets supporting the PPs
4. Temporary loading due to (1) internal explosions, (2) wind forces, and (3) seismic conditions

The buckstays have to restrain the tubes from bending and keep the furnace enclosure in position. The buckstay spacing should contain the tube deflection, and the tube vibration should not coincide with the natural frequency of three cycles per second.

Buckstay deflection is normally limited to

- $L/360$ for stoker and similar industrial boilers
- $L/480$ for PF and large boilers

Tie bars are really the hot parts, which are attached to the furnace tubes or the membrane panel. *Buckstay clips or welding clips* attach the tie bars to the buckstays. Buckstays should be kept as cool as possible. Care should be taken to avoid closing them with insulation.

Top-suspension hangers/sling rods. The whole weight of the boiler is transferred to the top girders by means of suspension hangers or sling rods. Top girders have several pairs of supporting beams from where the sling rods are suspended. The other ends of the rods are attached to the top headers or the roof tubes. *Cup-spring assemblies* are used with varying numbers of springs to prevent sagging of the headers in the middle.

Figures 7.15 and 7.16 depict the suspension rods in small and large boilers. In the smaller boilers, the system is simple and the rods are rigidly held between the girders and the PPs. In larger boilers, the rods are much longer, and they have to overcome the differential expansion problems created by the penthouse by having a more elaborate sealing. The *penthouse* is the enclosure for risers above the furnace roof. Figure 7.16 shows the way the rod behaves from cold to running condition during start-up in a penthouse with hot casing, that is, casing insulated from outside. The rods have to be analyzed for these various conditions together with the expansion restrictions imposed by their sealing arrangements.

Suspension rods mostly are made of CS and are designed to a temperature of 400°C except for those connected to the PPs (SH and RH) at a higher temperature, in which case the metallurgy of the two is matched. If gas leakage is expected into the penthouse, the rods are made of alloy steel with a design temperature of 450°C.



FIGURE 7.15
Top-suspension rods in an industrial boiler.

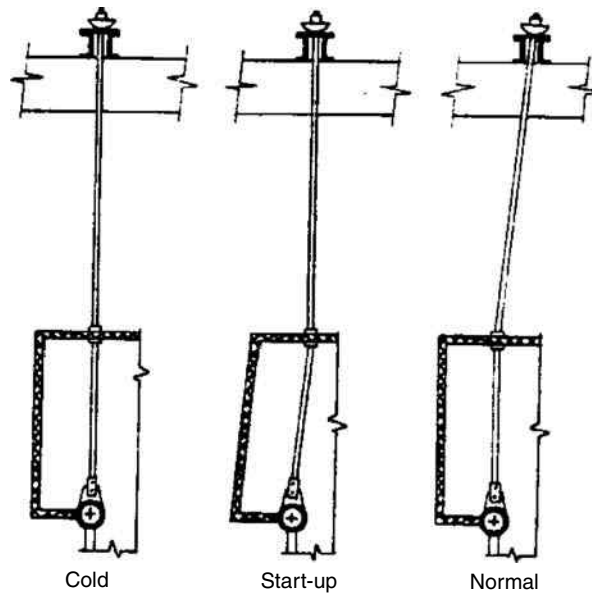


FIGURE 7.16
Typical suspension rods in a utility boiler.

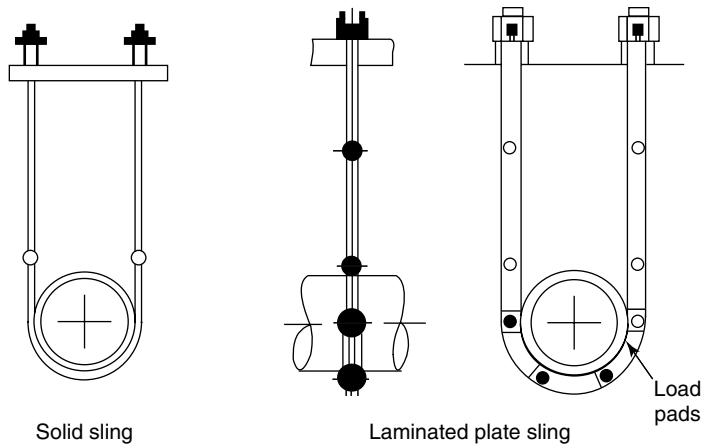


FIGURE 7.17
Drum slings.

Drum slings (Figure 7.17) are different in construction from sling rods. Only two suspension assemblies are used at either end of the steam drum. The two designs of drum slings are:

1. Bar/solid slings
2. Fabricated-plate slings
 - a. For weights up to ~ 200 t, it is possible to use solid slings made of high-tensile bar material. These are solid rods of 50–150 mm diameter, depending on the weight to be supported. As single rods for meeting such lengths are not usually available, they are made by joining two or three pieces to obtain the required length by welding, which is followed by stress-relieving and radiography.
 - b. For larger drum weights, laminated plate slings fabricated from plate steel are used. Typical weight taken by a pair of plate-type slings is as high as 1100 t in a 660 MW boiler. Plate slings fit the drum profile more closely than rod slings.

Intermediate cradles. To reduce the number of penetrations and correspondingly the sealing arrangements in the penthouse, it is usual to adopt intermediate cradles. They are particularly suitable for roof tubes. A set of tubes is slung from an intermediate cradle, which, in turn, is suspended from the top girders (Figure 7.18).

7.4.5.2 Cold Structure

Top-suspension girders are at the highest elevation of the boiler, resting on the top plate of the main columns. The entire weight of the boiler is transferred to them. They are the deepest girders in the boiler and, therefore, have to be necessarily fabricated, except in case of small boilers. The suspension rods are hung from the cross girders, which are welded to the main girders. The main and the cross girders together form a grid at the top, collectively known as the *top suspension grid*.

The top girders, as they merely rest on the bearing plates on the top of the columns, are treated as simply supported beams. Typically, the limiting deflection is very small at $L/700$ so that the connected parts experience minimum sag.

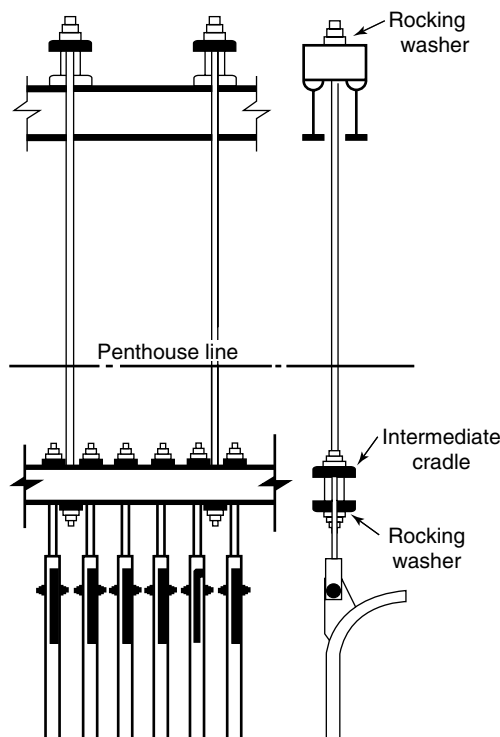


FIGURE 7.18
Intermediate cradle for roof tube support.

Columns. The base plates are fixed to the ground by means of foundation bolts, making them behave like members fixed at one end and free at the other. In addition to the vertical loads and bending moments at the top, the columns are subjected to forces and moments at every beam level. The column design, therefore, can proceed only when all the framing is complete with all details of the equipment location properly determined and the piping routing with hangers completed accurately.

The number of columns for the boiler is an important decision. Columns at the four corners of the furnace give an uncluttered arrangement and free maintenance space at the ground level, but the top girders must be heavy. In multicolumn design, columns and the top girder become lighter. Normally, in spite of more members, the multicolumn design is less expensive.

In the multicolumn arrangement, the top girder changes from simply supported to a continuous beam with multiple supports. Figure 7.19 depicts both the cases for a large two-pass unit. The types of firing and ash handling equipment decide the number of columns best suited. In bidrum boilers, it is common to have a pair of columns on either side of the bank. In tower type boilers and many two-pass units, the columns are at the four corners.

Column spacing is an important layout consideration. In plan view, the columns should extend beyond the furnace casing by 1–2 m to accommodate the integral piping, particularly the large interconnecting piping and downcomers with their insulation and fittings. In PF boilers, mill piping is contained within the columns. This is not important in small bottom-supported boilers as the columns are short and the load points decide the location.

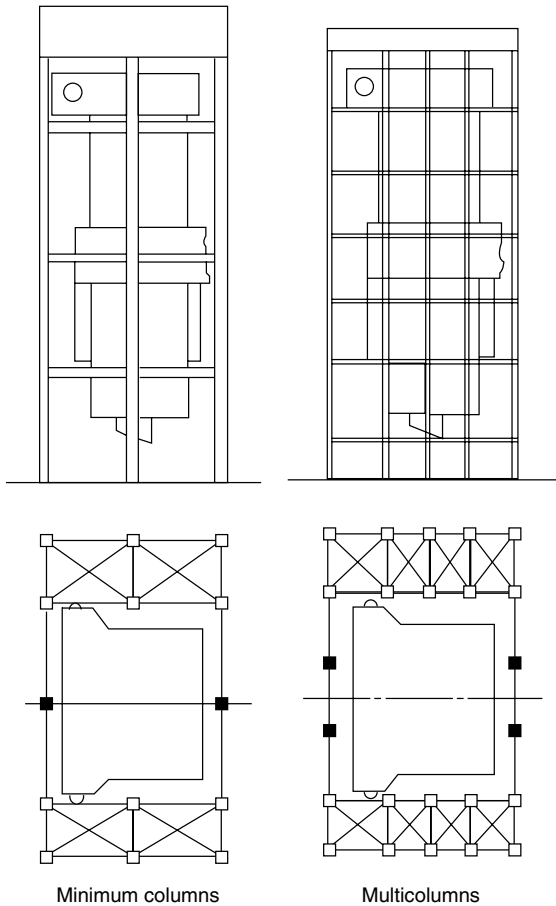


FIGURE 7.19
Typical column arrangements.

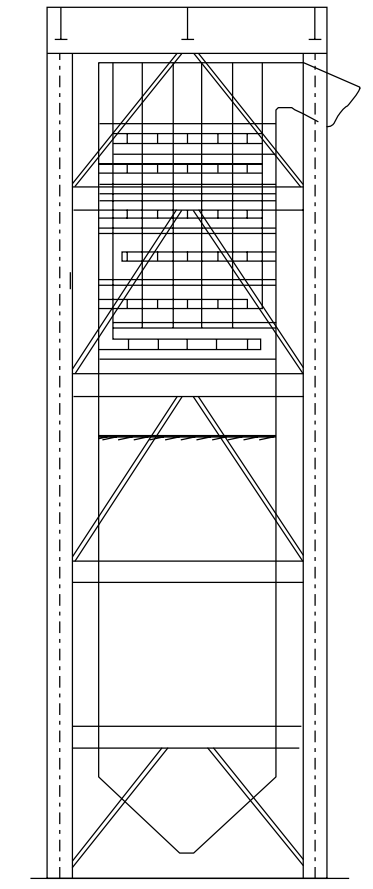


FIGURE 7.20
Typical bracing patterns in a tower-type boiler.

The outer columns carry the galleries and ladders and necessarily extend to the top of the boiler.

Beams and bracings. The two types are:

1. Main beams
2. Floor beams

Main beams are the big load carriers and straddle the columns. They are either welded or bolted to the columns. *Floor beams*, however, carry the floor loads and any equipment resting on the floors and hence are lighter.

Bracings connect the columns diagonally and they distribute the dead loads and the wind loads, so that the structural load distribution is better and the structure is lighter. Locating the bracings is always unsatisfactory as they interfere with free movement in the affected floors and galleries. Airheater tube withdrawal usually causes problems with bracings. Sometimes bracing of columns has to be avoided in a section, as shown in Figure 7.20, due to access considerations.

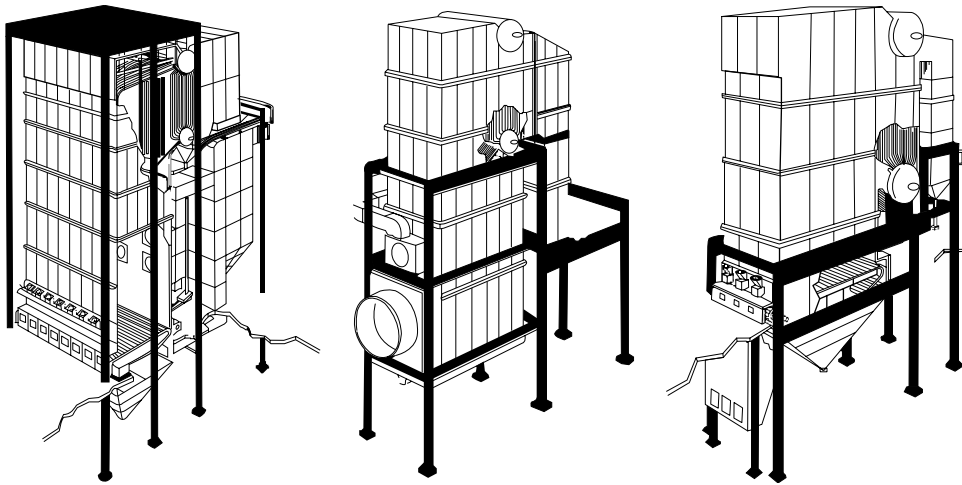


FIGURE 7.21
Top, middle, and bottom supports for bidrum boilers.

7.4.6 Top, Middle, or Bottom Support

Boilers can be supported from the bottom, middle, or top as shown in Figure 7.21. Package boilers, pre-engineered oil- and gas-fired boilers of even large size, and solid fuel-fired boilers up to ~ 60 tph can be bottom-supported. *In the bottom-support design*, the supporting structure is very light or nonexistent for units like package boilers. Some supporting structure around the boiler is required for providing access. The PPs act as load carrying struts and transfer the loads to the ground.

Beyond a certain size as the boilers become tall, the differential expansion increases and the weights also increase, making it cheaper to adopt top support. *Top-support design* can be likened to a church bell. As the weight of the bell is suspended from the casing, the entire PP assembly of the boiler is suspended from the structure, which encloses and transfers the weight to the ground. The PP assembly, now slung from the top girders, is free to expand downward and move sideways. Naturally, the top-support design is more expensive, although it is easier to design.

There are certain designs amenable to a *middle support*, also called a *girdle support*, where the boiler is supported at some midpoint, allowing thermal expansion to take place. Stoker-fired boilers fall in this category.

Irrespective of top or bottom support, a heavy item such as the AH (both tubular AH [TAH] and rotary AH [RAH]) is supported from the bottom. The ECON is also supported from the bottom in most bidrum designs as it is placed in the second pass above the AH. However, it is slung from the top in single-drum radiant or tower-type boiler designs.

7.4.7 Bolted or Welded Construction

Whether to adopt a welded or a bolted design is a difficult choice. Bolted or welded refers to the type of joints the ends should have. Bolted construction is heavier and more expensive due to

- Additional jointing material (support stools and gusset plates) and fasteners
- Shop fabrication and trial assembly
- Heavier construction

Bolted construction renders erection very easy and fast. If the erection costs are high, the overall cost works out nearly the same as the welded design with the added advantage of faster and error-free erection. Welded construction is more popular, although it requires more erection time, welding, and manpower, because:

- There are no additional jointing materials.
- It is lighter because it is part of an integrated structural framework.
- It is easy to correct at site.

The practice followed by the boilermaker or the preference of the customer usually decides this issue of welded versus bolted structure.

7.4.8 Rolled Beams or Built-Up Sections

The top suspension girders must be fabricated as they exceed the limit of rolled sections. Likewise, the main columns and certain heavy beams of medium and large boilers are also required to be fabricated. With greater availability of H and WF sections, it is now possible to adopt rolled sections and reduce the fabrication, at least for the main columns and the beams of utility boilers. But the specific cost of the extra-deep sections is higher and the delivery time longer. Deep sections for main columns and certain beams are fabricated using thick plates at nearly the same cost.

Further Readings

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8

Boiler Auxiliaries

8.1 Introduction

The auxiliaries breathe life into an otherwise static boiler made of pressure parts (PPs) and nonpressure parts (NPPs). The auxiliaries, generating and regulating the flows, are present in the following two circuits:

1. Air and gas circuit that comprises
 - a. Fans
 - b. Dust-collecting equipment
 - c. Dampers
2. Steam and water circuit that comprises
 - a. Feed pumps and circulation pumps
 - b. Valves, mountings, and fittings
 - c. Soot blowers (SBs)

Soot blowers are aid not involved in the movement and control of fluids but in removing the soot or dust deposited on the heating surfaces (HSs) of the boiler. They are unique to the boilers.

Only a brief description of the important boiler auxiliaries is given in this chapter, covering the salient features such as the process and constructional aspects. Feed pumps are not discussed here because they normally are in the scope of turbine island. However, they are briefly described in Chapters 1 and 2, in Sections 1.8.5 and 2.5.8, respectively.

8.2 Fans

8.2.1 Fans in Boiler Plant

Fans are perhaps the most important of all the auxiliaries because they affect the boiler

- Performance
- Auxiliary power consumption
- Dynamics

Almost all boilers are provided with fans for air and flue gas movement, except for certain waste heat recovery boilers (WHRBs) and heat recovery steam generators (HRSGs), which receive pressurized gas from the process plants or gas turbines (GTs).

- Balanced draft boilers employ a pair of fans, one for forcing the airflow through the firing equipment and the other for inducing the gas flow up to the stack, thus balancing the forced draft (FD) and the induced draft (ID) to achieve *balanced draft*. This pair is a single set of fans in smaller boilers and double set of fans in larger boilers.
- Pressurized fired boilers have only a single FD fan arrangement to push the air all the way to the chimney. In larger boilers, a double set of fans is employed.
- There are other fans, such as the secondary air (SA) fans, mill fans, and so on, depending on the boiler process.
- Fans provide air for combustion and removal of flue gases in line with the load requirement.
- Fans maintain the boiler draft.
- Auxiliary power consumption of a boiler is substantially contributed by the fans, necessitating efficient fans for new boilers and ways to optimize fan power in running boilers.
- Boiler dynamics are largely governed by the fans, as their inertia is high due to their large and heavy impellers.

The fan assemblies and drives constitute the largest and the most critical part of the boiler auxiliaries.

8.2.2 Salient Aspects of Fans

- A fan can be defined as a *volumetric device*, that moves air or gas from one place to another, overcoming the resistance to flow.
- Fans overcome static forces. Total pressure, however, includes velocity head, which is due to kinetic energy. Figure 8.1 describes pressures.
- As a volumetric device, a fan gives output in cubic meters and generates head in millimeters water gauge and not in kilograms and millibars. The weight and pressure are the derived figures, depending on the density or specific volume. Therefore, fluid density, which, in turn, is affected by temperature and altitude, has an overwhelming effect on the fan performance.
- The behavior of any fan is captured by its *characteristics*, which are a set of graphs drawn against a common x -axis of fan volumetric output Q . Head (H), efficiency, and shaft power are the three variables plotted against Q . The characteristics of various types of fans are given in Sections 8.2.4 and 8.2.5.

Fans, blowers, and compressors all move air and gas, but the pressure ranges differ. Fans work from a few millimeters to ~ 2000 mm wg (~ 1 psig) but handle more volume.

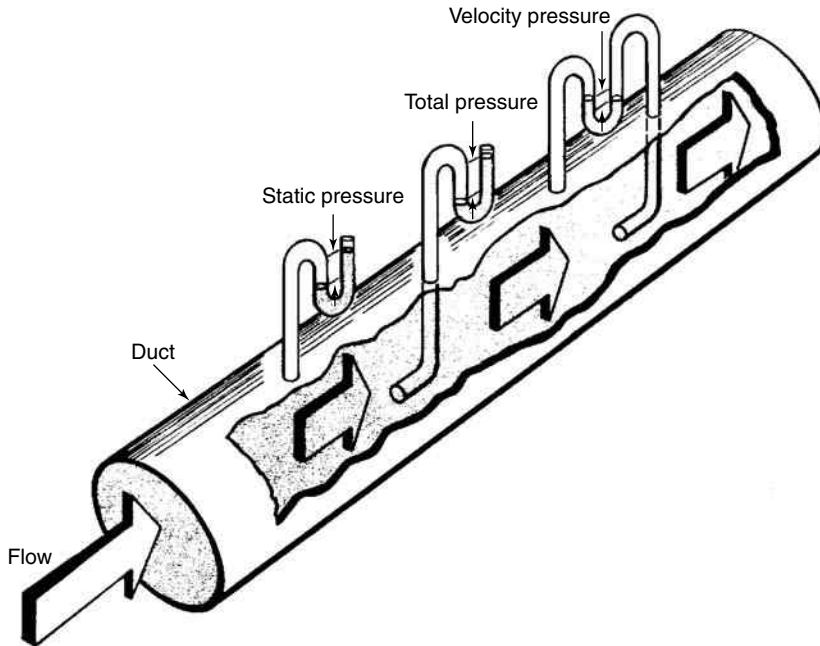


FIGURE 8.1
Static and total pressures. (From *Power* magazine. With permission.)

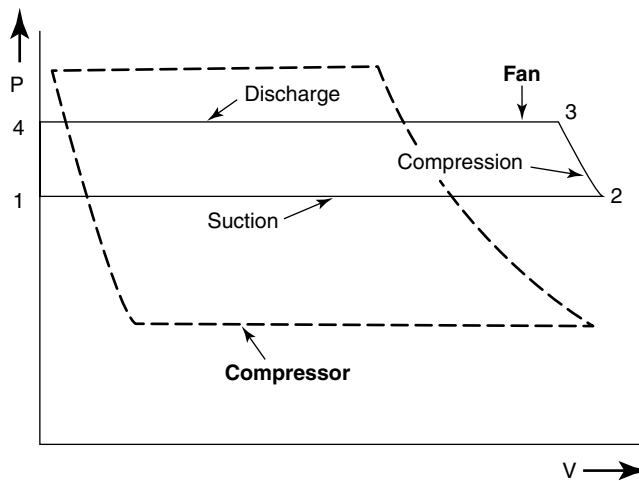


FIGURE 8.2
Fan and compressor cycles on P-V diagram.

Blowers go up to 2 barg, whereas compressors start from 2.5 barg. Figure 8.2 shows this point.

8.2.3 Types of Fans

There are three types of fans; each fan is different in terms of capacity and pressure generated, degree of control, resistance to wear, and corrosion. *Centrifugal fans* move air and gas

perpendicular to the fan shaft, whereas *axial* and *propeller fans* move them along the fan shaft (Figures 8.3 through 8.5).

1. *Centrifugal fans* operate by forcing the air to rotate in the fan housing. The resultant centrifugal force develops the pressure to move the air stream. Most fans in the boiler are of centrifugal type in which the fluid accelerates from the root to the tip of the blade perpendicular to the fan shaft and collects in the scroll casing.

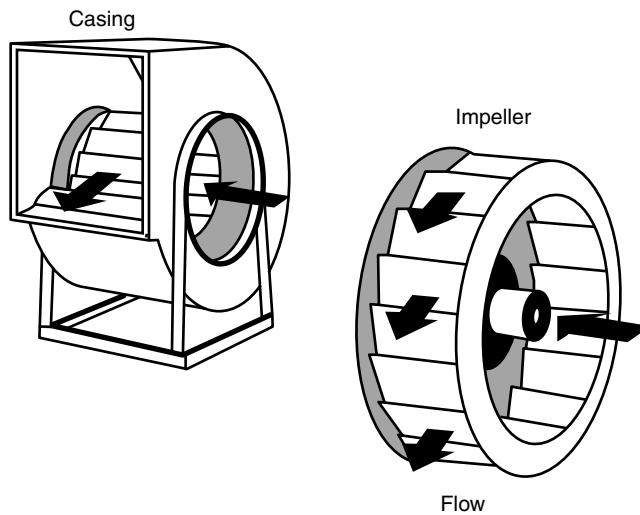


FIGURE 8.3
Centrifugal fans.

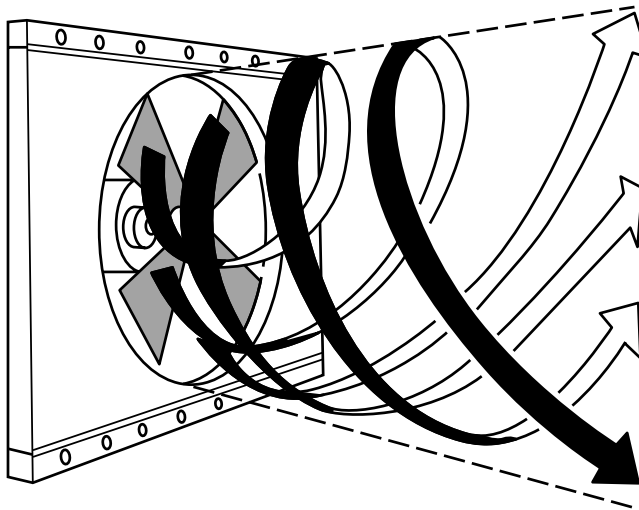


FIGURE 8.4
Propeller fan.

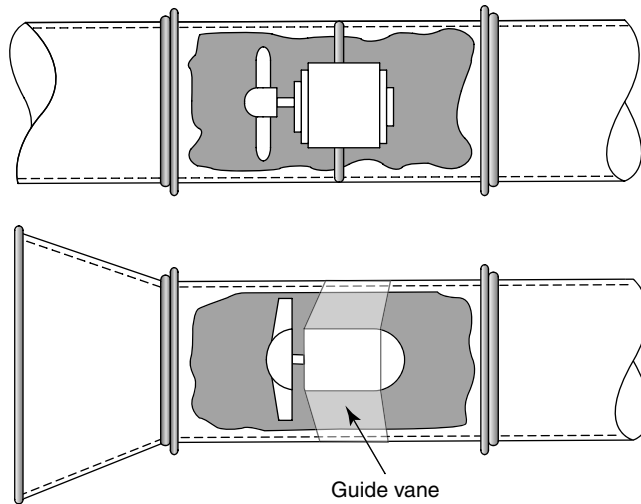


FIGURE 8.5
Tube and vane axial fans.

2. Propeller fans move large amounts of air by striking at an angle and developing small heads. The housing plays little role. The flow control is minimal. Boiler ventilation room exhaust and ID cooling tower fans fall in this category.
3. *Axial fans* are essentially propeller fans with proper housings that provide a definite control, sometimes better than that obtained with centrifugal fans. The fluid accelerates parallel to the fan shaft.

Vane axials have guide vanes before or after the wheel to streamline the flow.

Large axial fans are used for the main combustion air for their efficiency and control.

Tube axials have no guide vanes.

All fans contain two parts: static and dynamic in the form of casing and rotor/impeller assemblies, respectively. Impellers, due to rotation, impart energy to air or gas for moving against a set pressure, whereas the casing collects and guides the fluid.

8.2.4 Centrifugal Fans

Centrifugal fans are divided on the basis of the shape of the blades used in the impeller. Different shapes impart different characteristics. There are three types of blades:

1. Backward curved or backward bladed
2. Radial
3. Forward curved or forward bladed

In addition, there are variations to these basic shapes for specific duties. Forward blading imparts a greater absolute velocity to air due to the shape of blading as compared to backward blading for the same tip speed. For this reason, the backward-bladed fans can operate at a higher tip speed than the forward-bladed fans (Figures 8.6 and 8.7).

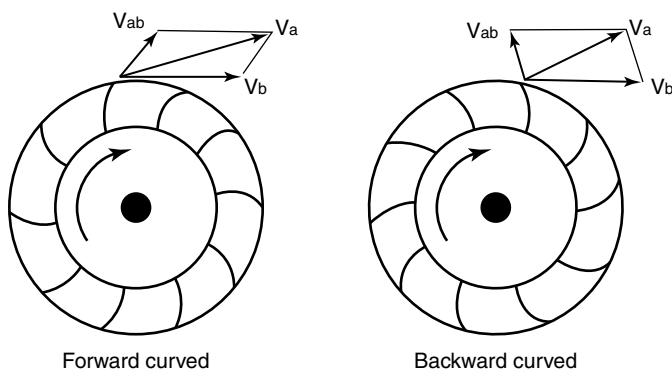


FIGURE 8.6
Air velocity profiles.

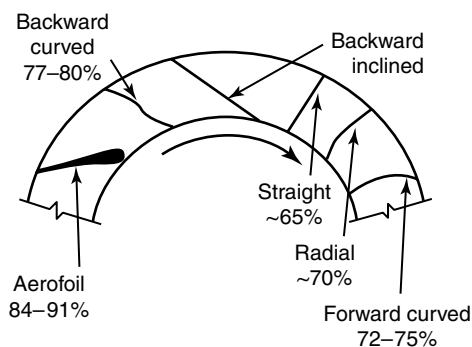


FIGURE 8.7
Various blade shapes and static efficiencies.

8.2.4.1 Backward-Curved Blading

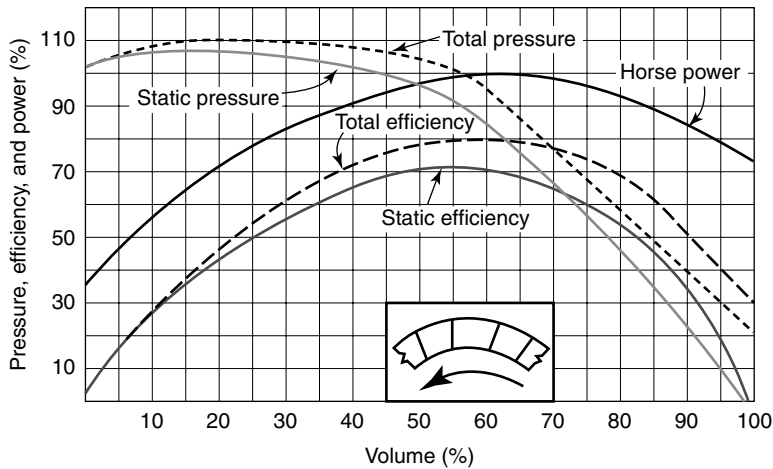
The backward-curved fans, which are also called the single-thickness aerofoils, have the advantage of self-limiting or nonoverloading power characteristics as depicted in Figure 8.8. The fan efficiencies are higher, between 77 and 80%. Because higher speeds are needed to generate the required head, the particulate matter in gas streams can cause erosion of the impellers of ID fans if the dust is aggressive. With improved gas-cleaning equipment, this is not a serious issue. Backward-curved fans are extensively used in boilers for FD, PA, and ID fans.

Backward-inclined blading, unlike backward-curved blading, is not favored due to its unstable characteristics.

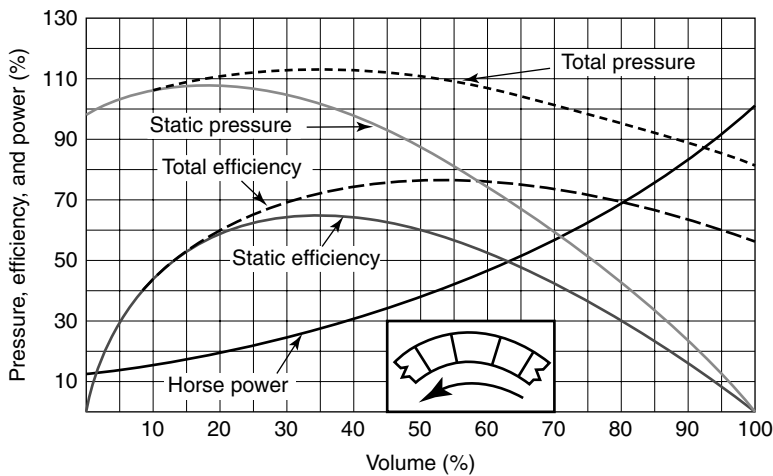
Backward-curved aerofoil blading is more efficient, 84–91%, with lower noise levels. This type is more expensive to make and repair, good for cleaning applications, and popular for utility boilers.

8.2.4.2 Radial Blading

Radial-bladed fans run at a lower speed in comparison with the backward-bladed fans, which makes them preferred for high dust loading in gases. As shown in Figure 8.9, the efficiency is low, at ~70%. These fans are not used for ID because (1) the gas cleaning is now mandatory and very efficient, making backward curved or aerofoil construction more

**FIGURE 8.8**

Centrifugal fan with backward-curved blades. (From *Power* magazine. With permission.)

**FIGURE 8.9**

Centrifugal fan with radial blades. (From *Power* magazine. With permission.)

acceptable, and (2) the power costs. They are used in applications involving high dust loading, such as for flue gas recirculation (GR) fan duty, where no dust separation upstream of the fan is possible.

Open radial-bladed fans, with even lower efficiencies of ~65%, are used for the most abrasive service such as the reinjection of fly ash. The straight blades can be lined with plates, either welded or bolted.

Radial-tipped blading combines the advantage of high efficiency and self-limiting load characteristics of backward-curved construction with good wear resistance of radial exit, and is ideal for medium dust loading.

8.2.4.3 Forward-Curved Blading

This is a clean air fan as any dust in air or gas deposits itself on the blading due to its shape. Efficiencies are low, at 72–75%, and there is a considerable unstable zone, as the

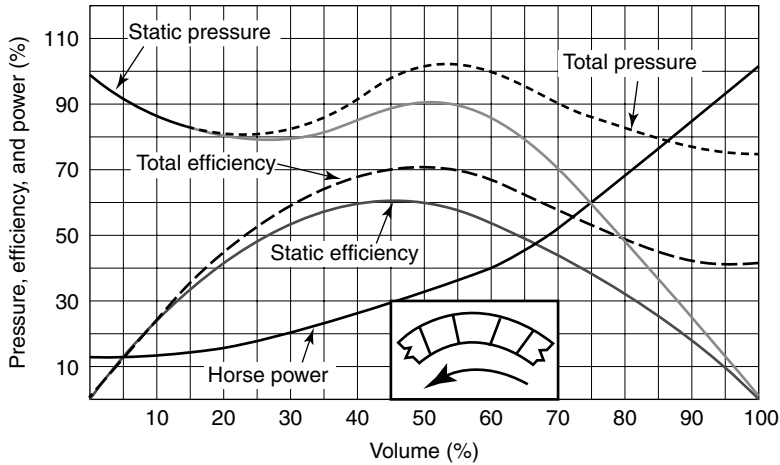


FIGURE 8.10
Centrifugal fans with forward-curved blades. (From *Power* magazine. With permission.)

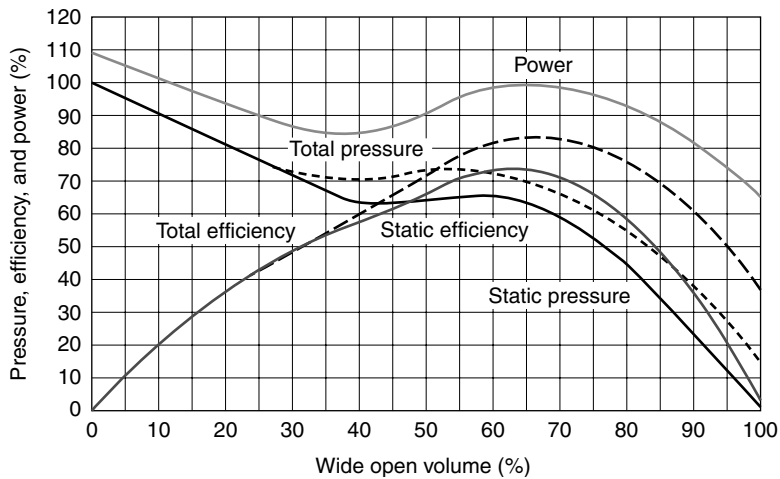
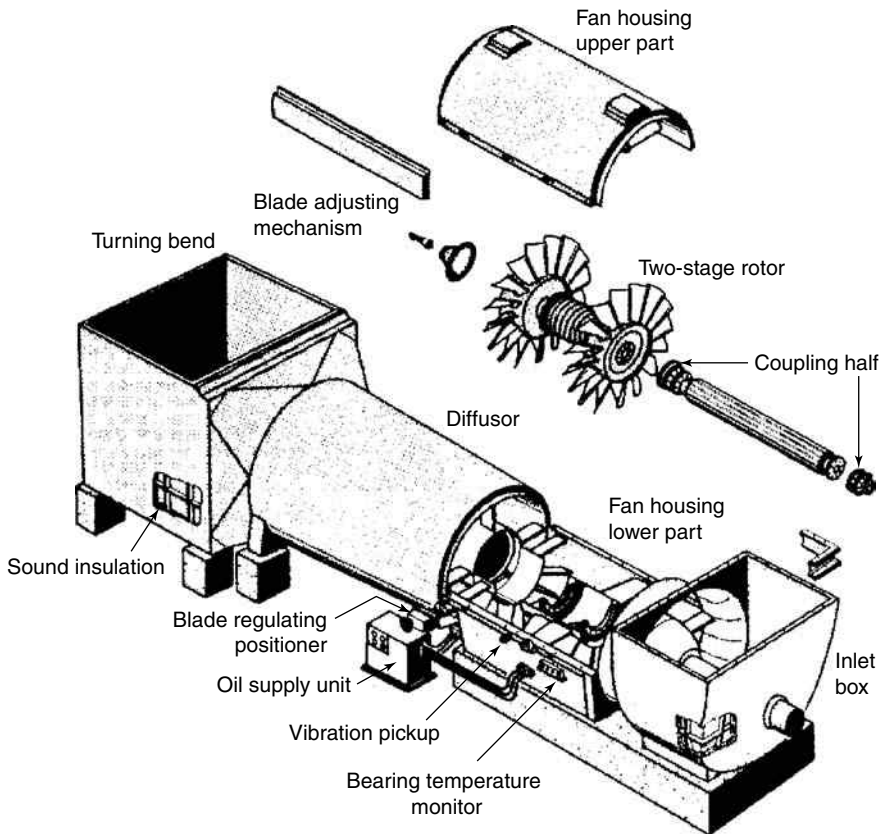


FIGURE 8.11
Axial fans with variable blade angles. (From *Power* magazine. With permission.)

pressure curve exhibits an up-and-down movement instead of a steady droop as shown in Figure 8.10. These fans are compact, not suitable for use in boiler applications, but are popular for air-conditioning and ventilation. They are also used for small-size air handling.

8.2.5 Axial Fans

High efficiency and self-limiting characteristics are the advantages of the axial-flow fans, as can be seen in Figure 8.11. Axial fans for boilers are available in two types: single stage and two stage, depending on the number of stages of blades on the rotor (Figure 8.12). The flow and pressure are controlled by varying the blade angles. The axial fans are more expensive because of (1) blade movement mechanism, (2) superior manufacturing techniques, and

**FIGURE 8.12**

Two-stage variable-speed axial fan. (From TLT-Turbo GmbH. With permission.)

(3) higher quality of materials required. But they can maintain higher efficiencies at various boiler loads better than the centrifugal fans with their inlet vane controls (IVCs). With the increasing fuel costs, the use for axial fans is progressively increasing—at least for FD fan applications in utility boilers. However, the ID application presents the possibility of fan erosion, even with slightly higher or aggressive ash. Erosion of blades is the main concern, as they are made of Al or Mg alloys to reduce weight. This reduces the hub strength and bearing loads. The blades, in many cases, are protected by hardened steel strips, but the axial fans are still not considered suitable for ID for high ash or abrasive ash applications. The performance degradation on erosion is greater for axial fans than for centrifugal fans. As shown in Figure 8.13, the axial fans are

- More expensive
- More prone to erosion
- More maintenance-prone due to more moving parts

However, they are

- More efficient and reduce power consumption
- Highly efficient over a wider range of boiler loads

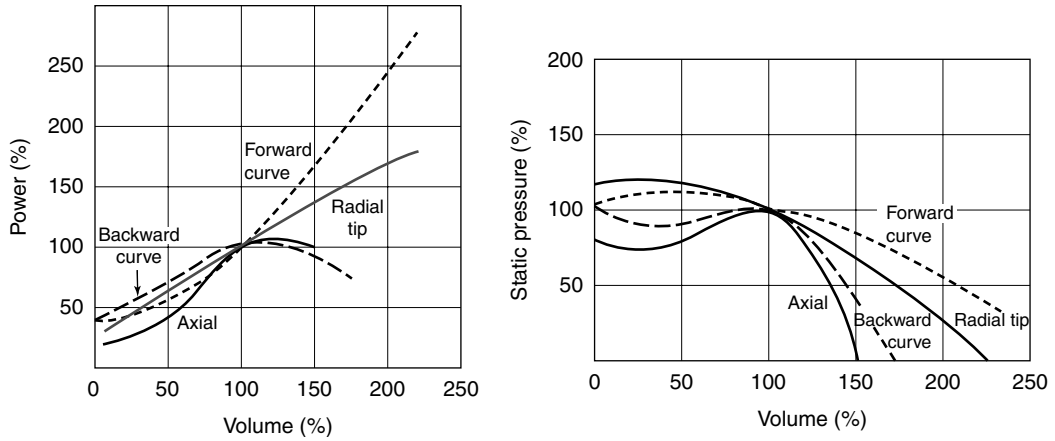


FIGURE 8.13
Comparison of various fan characteristics.

8.2.6 Fan Laws

Three basic laws govern the working of a fan: (1) speed, (2) density, and (3) diameter, which can be described as follows:

1. *Based on speed*

- a. Volume is proportional to speed at constant density

$$\frac{Q_1}{Q_2} = \frac{N_1}{N_2} \quad (8.1)$$

- b. Static pressure is proportional to speed squared at constant density

$$\frac{P_1}{P_2} = \left(\frac{N_1}{N_2} \right)^2 \quad (8.2)$$

- c. Horsepower is proportional to speed cubed at constant density

$$\frac{HP_1}{HP_2} = \left(\frac{N_1}{N_2} \right)^3 \quad (8.3)$$

2. *Based on density*

Horsepower and static pressure are proportional to gas density at constant speed

$$\frac{HP_1}{HP_2} = \frac{\rho_1}{\rho_2} \quad (8.4)$$

$$\frac{P_1}{P_2} = \frac{\rho_1}{\rho_2} \quad (8.5)$$

3. Based on rotor diameter

- a. For geometrically similar fans, volume and power are proportional to gas density at constant speed

$$\frac{Q_1}{Q_2} = \left(\frac{D_1}{D_2} \right)^2 \quad (8.6)$$

$$\frac{P_1}{P_2} = \left(\frac{D_1}{D_2} \right)^2 \quad (8.7)$$

- b. For geometrically similar fans, revolutions per minute (rpm) are inversely proportional to the impeller diameter

$$\frac{N_1}{N_2} = \frac{D_2}{D_1} \quad (8.8)$$

8.2.6.1 Specific Speed and Diameter

Geometric similarity of fans enables the prediction of performance. The main operating parameters of speed and diameter of the fans are linked by specific speed and specific diameter, respectively.

Specific speed is the rpm that delivers a unit volume at unit differential head of air under standard conditions.

$$\text{Specific speed } (N_s) = \frac{\sqrt{N}}{P^{3/4}} \quad (8.9)$$

where N is the number of revolutions per minute and P the static pressure.

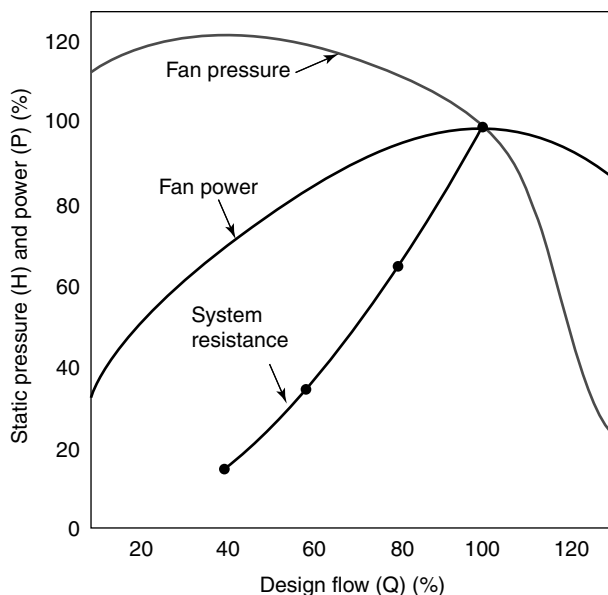
Specific diameter is the impeller diameter required to deliver a unit volume at unit differential head at unit specific speed.

$$\text{Specific diameter } (D_s) = \frac{DP^{1/4}}{\sqrt{Q}} \quad (8.10)$$

8.2.7 Fan Selection

8.2.7.1 System Resistance

Fan selection begins with determining system resistance. *System resistance* is the total of all resistances that the fan is required to overcome. Typically, for an FD fan, the resistances are the airheaters (AHs), ducts, flow-measuring devices, firing equipment, etc. Correct estimation of system resistance at the maximum continuous rating (MCR) and other loads in head versus load (H–Q) format is the first step. Suitable margins are added to arrive at the design condition. The fan chosen should possess an H–Q characteristic that intersects the system resistance curve at the design point (Figure 8.14).

**FIGURE 8.14**

System resistance versus fan curves. (From *Power* magazine. With permission.)

It is necessary to have a substantially drooping characteristic for the fan to ensure only a single flow for a certain head in the fan-operating range. If a hump or flatness in the curve results more than one flow for a certain head, the fan tends to shift the operating point, causing hunting, that is, continuous load change and unstable operation. Also, the fan selected should give optimum efficiency at the MCR and normal continuous rating (NCR) conditions. The best efficiency condition should lie in the region where the fan operates for a maximum period and not necessarily at the design point.

8.2.7.2 Fan Speed

Direct drive for fans is preferred, as it is the most compact arrangement with the least transmission losses. AC induction motors are the most common drives. Although a fan runs at one of the nominal synchronous speeds, the best efficiencies may not coincide with these speeds.

Centrifugal fans operate at nominal speeds of 3000, 1500, 1000, and 750 rpm, with most at 1500 and 1000 rpm. In the past, 600 rpm has also been used for very dusty applications. (Actual speeds are ~3% lower due to slip in motor.)

The fan speed of 3000 rpm is only for clean air application requiring high heads, as in the case of SA, because of high noise level and excessive wear on bearings.

Likewise, 750 rpm is not preferred due to the large impeller diameter and heavy weight, producing high inertia, calling for star-delta starters to reduce the starting time. Also the dynamics are poor and lead to sluggish response. The entire arrangement is expensive due to the fan and motor assembly, special starters, heavy cables, and large foundation. Such low rpm is chosen only when excessive wear is expected from dusty gases. The fan selection is radial in most cases with the attendant poor fan efficiency calling for high-kilowatt motors. Wear liners on both impeller blades and casing, if chosen, worsen the dynamics. Induced draft fans required such construction in boilers with high-ash coal firing with

only mechanical dust collectors (MDCs) upstream. With stricter pollution norms and the use of electrostatic precipitators (ESPs), 750 rpm speed is rare. For GR fans, with no dust separation possibility, 750 rpm may still be necessary in many cases, depending on the location of gas suction and the severity of erosion of ash.

Clean air application almost never demands a speed below 1000 rpm. In fact, 1500 rpm is better, as the fan and the motor are both smaller and the arrangement is cheaper. For ID and GR fans, 1000 rpm is the most common speed for solid fuel firing.

For small fans of up to ~150 kW, *belt drives* are popular, as they enable the fans to run at the most efficiency despite slightly higher transmission losses. With the motor parallel to the fan, the arrangement can also suit a tight layout.

8.2.7.3 Fan Margins

Margins on volume, head, and operating temperatures are added to the estimated MCR or peak system resistance points to arrive at the design conditions. The fan margins are essential for the following reasons:

- The pressure and draft losses calculated are the best approximations and need safety margins. The fuel analysis, air and gas weight calculations, and the assumptions in calculating the losses are accurate only within certain practical limits.
- There are bound to be differences in the geometry used for calculation and the boiler constructed due to inaccuracies in manufacturing and erection.
- The fouling of surfaces is unpredictable, particularly with fuels such as coal, and cannot be captured accurately.
- Any boiler that needs overfiring to catch up with rapid load ramps needs more power from the fans and the firing equipment. This requires spare power.
- Every fan has negative tolerances on head and volume due to manufacture. They must be compensated for if all the parameters are to be met in practice.

Excessive margins. Although it is imperative to provide correct margins, excessive provisioning is wasteful and injurious. Motors are provided with additional margins to

- Account for the positive power tolerance of the fan and the negative power tolerance of the motor and possible errors in the estimated figures of power
- Provide for a possible drop in system voltage and frequency

Considering that boilers normally operate at ~80% of the MCR load most of the time, the loading of fan motors, even with normal margins, works out to ~50 to 60% of the rated motor loading, which results in motor operation at a significantly lower efficiency. The initial costs of fan, motor, and electrical equipment are all higher too. With more generous margins, the situation worsens. Excessive auxiliary power consumption alone is a good enough reason to avoid unnecessarily large margins.

Margin range. Fan margin figures are continuously refined. There is a general consensus for the main fans, namely the FD and ID fans, that the margins for solid fuel-fired boiler should be around

- 20% for volume
- 44% for the variable head
- 20°C for the operating temperature

For liquid and gaseous fuels with little fouling tendency, the margins are lower at

- 10% for volume
- 21% for the variable head
- 20°C for the operating temperature

These margins are for fans with medium-level manufacturing tolerances and usual negative tolerances for head and capacity. When fans of closely held manufacturing tolerances are chosen with no negative tolerance on head and capacity, the margins may be reduced by nearly half.

Typically, the margins indicated in the preceding text are for industrial boilers. For utilities, the margins are lower and the fan tolerances are also correspondingly lower.

8.2.8 Efficiency and Power

The two types of fan efficiencies are (1) total/mechanical and (2) static.

1. *Total/mechanical* efficiency is the total energy in the stream, taking into account both static and velocity pressure, as a percentage of energy input to the fan.
2. *Static* efficiency takes into account only the static pressure output of the fan.

Static efficiency is used by manufacturers to specify the fan performance.

Fan power consumption can be expressed as

$$\text{Power in hp} = \frac{kVH}{\eta c}$$

where

k = compressibility factor

V = inlet volume in cubic meters per hour or cubic feet per minute

H = pressure rise across the fan in millimeter water gauge or inches

c = constant 2743 (6354)

η = fan static efficiency %

Compressibility factor is the ratio between the total pressure developed by a fan with an incompressible fluid and the total pressure developed with a compressible fluid, all other conditions remaining the same.

Compressibility factor	1.0	1.05	1.1	1.15
Pressure ratio	1.0	0.98	0.97	0.95

Fan power in kilowatts, in SI units, is also given by the same formula

$$\text{Power (kW)} = \frac{kVH}{\eta c} \quad (8.11)$$

where V is in cubic meters per second and H in kilopascals; $c = 1$, and η is percent efficiency.

It can also be expressed as

$$kW = \frac{0.1 \times k \times V \times H}{\eta c} \quad (8.12)$$

where H is in millibars.

8.2.9 Fan Control

The two methods of centrifugal fan control are:

1. Variation of outlet or inlet duct dampers at constant speed
2. Variation of fan speed

Axial fans are controlled only by a variation of blade angle.

8.2.9.1 Outlet Damper Control

This is the least efficient of all the methods, as it is the throttling of the outlet pressure across the damper after the fluid has been pressurized by the fan. A lot of power is wasted. The outlet damper adds resistance to the system and moves the operating point up the fan curve, thereby reducing the output. Its main advantages are

- Extreme simplicity of construction and operation
- Adaptability to stepless autocontrol
- Cost reduction via shorter shaft length.

Outlet damper control (Figure 8.15) alone is employed only on relatively small fans where the control required is nominal. It may be combined with IVC for enhancing the range and fineness of control.

8.2.9.2 Inlet Vane or Damper Control

This is the most popular mode of fan control. The inlet air or gas is given a spin in the direction of the wheel rotation, thereby imparting nearly the same effect as reduction

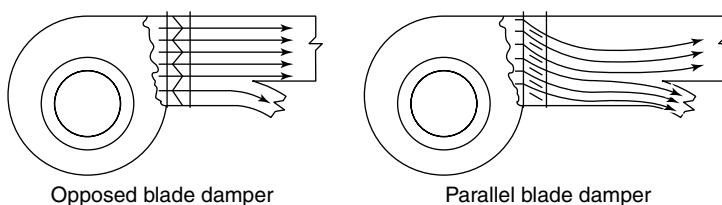
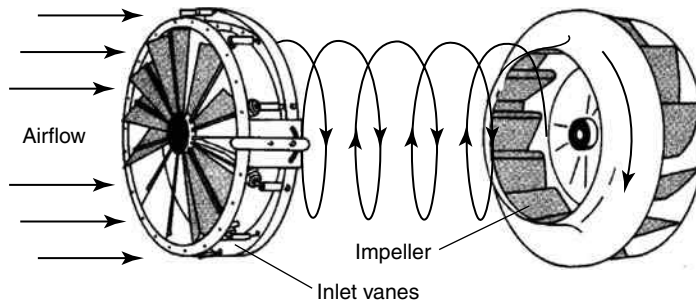


FIGURE 8.15
Action of fan outlet damper.

**FIGURE 8.16**

Action of inlet vane control. (From *Power* magazine. With permission.)

of the speed. Depending on the degree of spin, the outlet pressure and discharge are reduced. IVC has a set of aerodynamically shaped vanes for providing the correct spin (Figure 8.16).

IVC advantages are as follows:

- Efficiency and low cost.
- The variation is stepless and amenable to autocontrol.
- Ruggedness and reliability with low hysteresis.
- Reduced space requirement.

The main limitations are as follows:

- The IVC is highly prone to erosion with ash-laden gases. In a dusty environment such as the inlet of ID fan, the IVC located at the inlet eye of the fan, is replaced by differential damper control (DDC) located at the inlet of the inlet air box. Differential damper control consists of specially shaped dampers to provide optimum spin with reduced inlet losses approaching the IVC.
- It is not cost-effective for a wide range of load control, as the power consumption at lower loads is higher as compared with speed variation.

Figure 8.17 gives typical characteristic curves of a fan equipped with IVC.

8.2.9.3 Variation of Fan Speed

This is the most efficient control and also the most expensive and justified only if the savings in power cost can really offset the high initial expense. This has gained a lot of acceptance in recent years due to minimization of auxiliary power. Several types of speed variation methods include.

1. Variable-speed hydraulic couplings (HCs) or fluid drives
2. Variable frequency AC motors
3. Slip ring motors
4. DC motors
5. Drive turbines
6. Two-speed motors with IVC

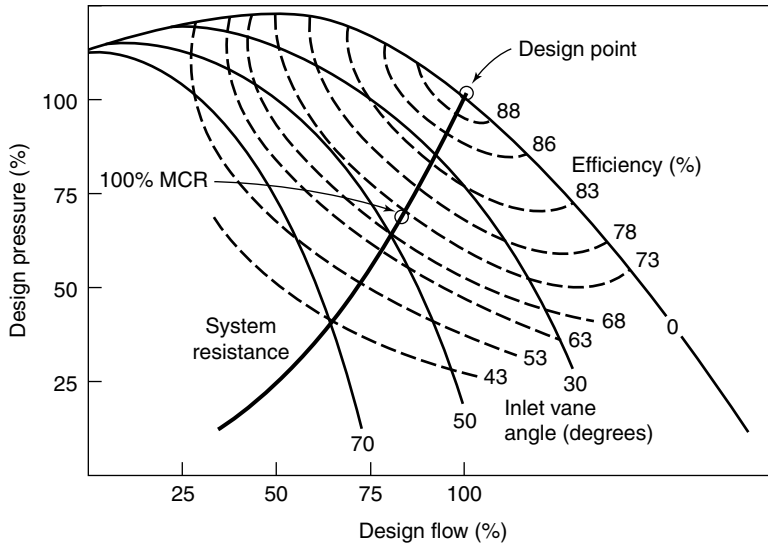


FIGURE 8.17
Typical curves for inlet vane control.

8.2.9.3.1 Hydraulic Couplings (HCs)

HCs of fixed speed type are regularly employed where high-starting loads are connected to motors for transferring the load with a time delay. This allows adequate time for the motor to attain enough speed and torque to take on the heavy load smoothly. Motors in coal handling plants and coal pulverizers are some examples in a power plant. The input and output shafts have no physical contacts. Hydraulic oil is put into motion by an *impeller* on the input shaft, which transmits the torque to an identical impeller on the output shaft, called the *runner*. The output shaft attains nearly the same speed as the input shaft after a short time. The speed difference between the two shafts is the *slip* that enables the motor to start smoothly and reach a speed at which it is connected to the heavy load.

Variable-speed hydraulic couplings (VSHCs) or *fluid drives* have a provision of scooping off oil from the sump so that the torque is lowered and the speed of the output shaft is limited. The motor, however, maintains its constant speed. The speed control is thus effected by the scoop control, which transfers oil in and out of the chamber, depending on the signal.

Figures 8.18 and 8.19 depict fluid drive and the working principle. The impeller, which provides acceleration to the oil, is keyed to the drive shaft and housed inside the impeller casing. The runner is keyed to the output shaft and is housed in the inner casing. A constant-speed pump maintains oil in the chamber created by impeller and inner casings. In the outer casing, the scoop tube helps to transfer the oil out of the circulation, thereby changing the slip between the impeller and the runner disks.

Fluid drives are among the most efficient, particularly at low speeds because the power consumption of the fan varies as the cube of the speed, while the loss in HC is proportional only to the slip. The difference is the power saving, which increases as the speed is lowered.

Fluid drive couplings are:

- Very rugged and reliable
- Available even in very large sizes
- Amenable to stepless automatic control

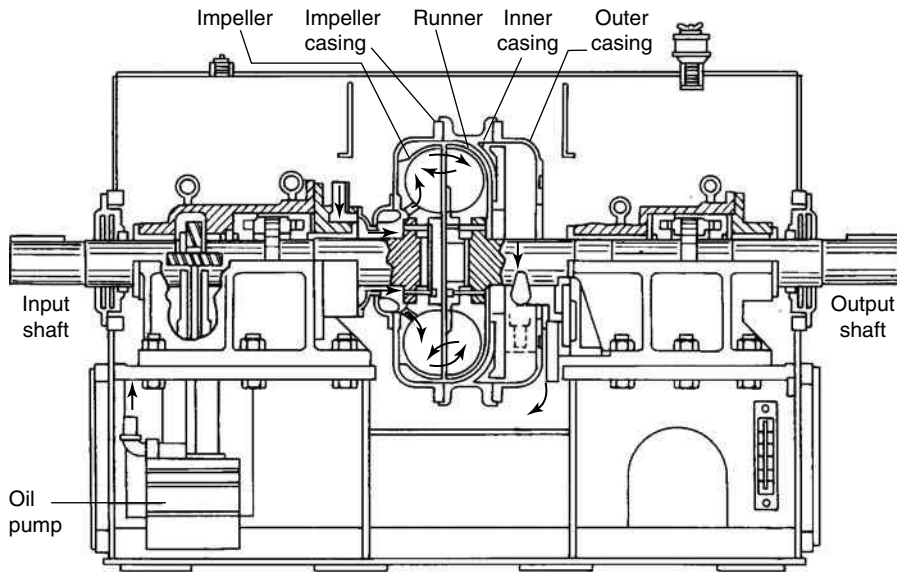


FIGURE 8.18
Power transmission in hydraulic coupling.

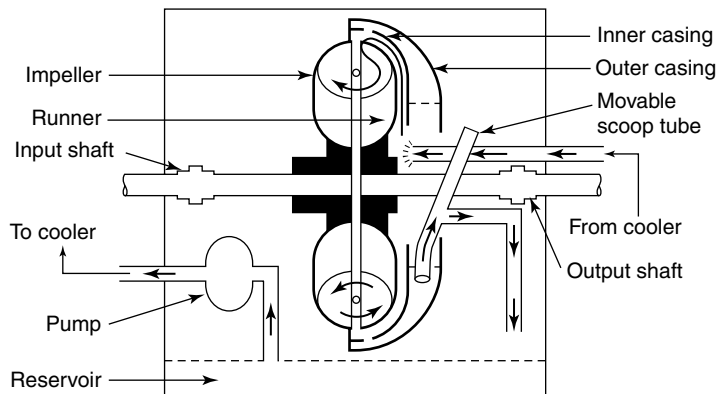


FIGURE 8.19
Load variation by scoop control.

8.2.9.3.2 Variable Frequency AC Motors

These motors employ a frequency control panel by which the output frequency (f) is varied, which, in turn, regulates the speed of the motor as given by the formula

$$N = 120 \times \frac{f}{p}$$

where p is the number of poles in the motor.

The variable frequency drives (VFDs) have become very popular as their range has increased and their cost decreased. With practically no maintenance, the VFDs are good choices.

8.2.9.3.3 Slip Ring or Wound-Rotor Induction Motors

These motors are popular among certain industries. They are usually suitable for sizes up to ~250 kW. Here the rotor slip energy, conventionally wasted in resistor banks, is inverted and fed back into the power line. The electronics are relatively simple and inexpensive.

8.2.9.3.4 DC Motors

These motors are sometimes used for industrial fan drives for their reliability despite their higher initial and maintenance costs.

8.2.9.3.5 Drive Turbines

Despite their higher initial and maintenance costs, drive turbines make a good choice in process industries. They are very popular in industries such as refineries, petrochemicals, and sugar, where there are several pressure levels of steam, and the exhaust steam from drive turbines can be used in the process. They tend to improve the overall efficiency of the plant because they consume steam directly and not the power generated from steam.

- Drive turbines have practically no size limitation.
- The range of speed variation is also high.
- Normally for sizes above 50 kW, drive turbines can be considered.

8.2.9.3.6 Two-Speed Motors with Inlet Vane Control

This solution applies to very large motors. Two-speed two-winding motors are bulky and costly but offer a lower-cost solution if VFDs and VSHCs work out to be more expensive.

Figure 8.20 compares the various methods of fan control based on power consumption at different part loads. Speed variation for centrifugal fans and variable pitch axial

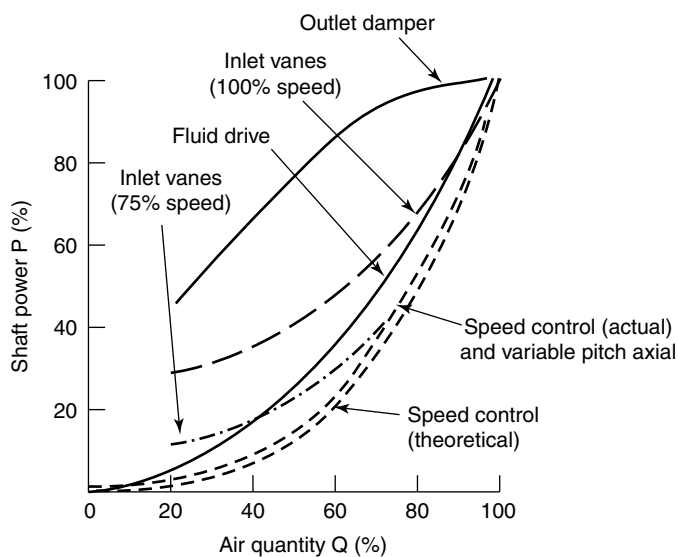


FIGURE 8.20
Comparison of fan controls.

for axial fans are the most efficient methods, approaching theoretical power consumption limits. Hydraulic drives are less efficient. Two-speed fans with IVC can provide low power.

In selecting a speed control mechanism, the important thing to assess is the variation in fan output required in actual operation. More efficient and expensive methods are justified only when operation at lower loads is called for.

8.2.10 Construction Features

Centrifugal fans can be classified in several ways besides the shapes of blading, which are described in the following section.

8.2.10.1 Types of Support

Centrifugal fans can be

1. Overhung
2. Simply supported

1. *Overhung design.* The impeller is mounted on one end of the shaft, which is supported usually on a pair of bearings on the motor side (Figure 8.21).

- a. With no bearing on the nondriving end, the fan shaft is shorter.
- b. The fan and foundation are compact, simple, and cheap.
- c. This is the most compact and economical design.

It is generally good for clean air application and lower capacities. Smaller FD and SA fans are usually overhung.

Impeller on motor shaft. For very small fans, such as SA fans of small boilers, seal air fans for mills, or scanner air fans, the impellers can be mounted on the motor shaft producing a compact and economical arrangement, as the bearings

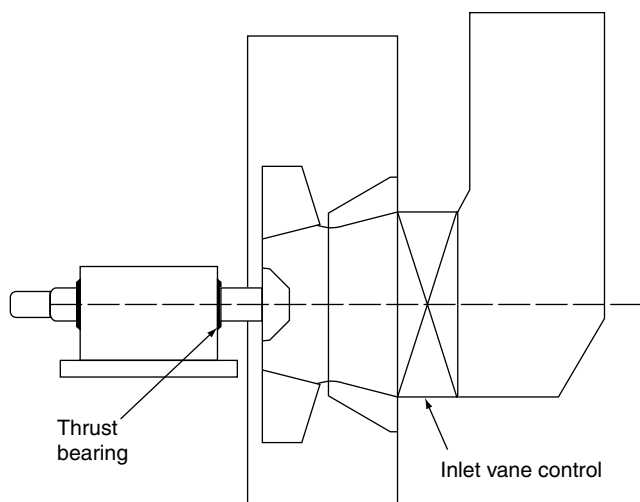


FIGURE 8.21
Overhung fan with single inlet and single width of impeller.

between fan and motor are avoided. The only limitation other than size is that it has to be strictly used for a cold air application.

2. *Simply supported design.* The impeller is supported on both sides of the fan making the arrangement (Figures 8.22 and 8.23)

- a. More robust, heavy, and large
- b. Suitable for dusty and large applications

In both applications, usually the shaft is designed for a first critical speed much higher than the operating speed, normally 1.4 times, and hence *stiff shaft* design. This makes the impeller strong and avoids fan vibrations. In large fans, it is sometimes economical to have only a *flexible shaft* design, where the first critical speed is within the operating speed as a minimum. In such cases, fan control by speed variation is best avoided, or done carefully by avoiding near-critical speed.

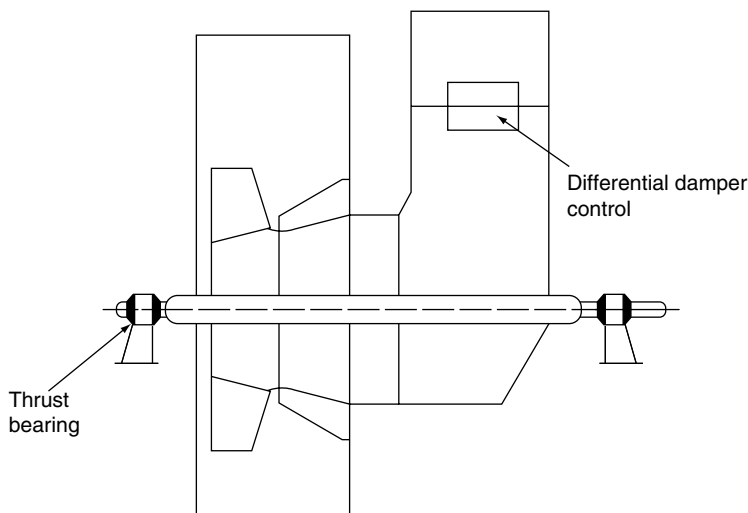


FIGURE 8.22

Simply supported fans with single inlet and single width of impeller.

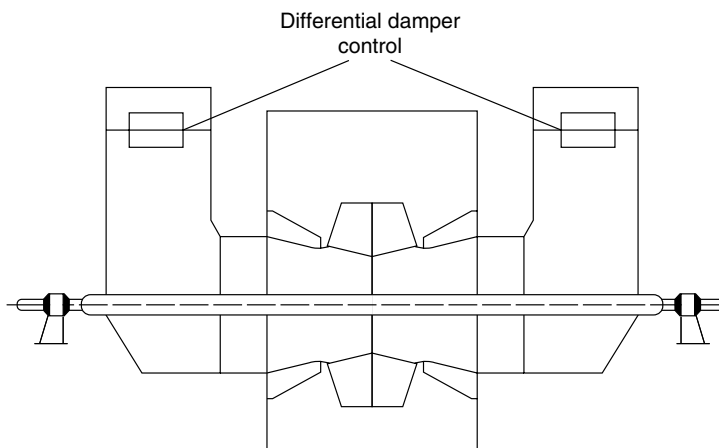


FIGURE 8.23

Double-inlet double-width fan.

8.2.10.2 Number of Inlets

Centrifugal fans can have:

1. Single inlets
2. Double inlets
 1. *Single-inlet fans* with single width of impellers are more economical for capacities up to $50 \text{ m}^3/\text{s}$ ($\sim 100,000 \text{ ft}^3/\text{m}$). They need a thrust bearing on the opposite side of gas entry to counter the axial force created (Figures 8.21 and 8.23).
 2. *Double-inlet fans* with double-width impellers are more economical for larger capacities, although they have (Figure 8.23)
 - a. Wider impellers
 - b. Heavier and longer shafts
 - c. Two air boxes with two inlet dampers and controls
 - d. Heavier bearings due to longer bearing distances

The double-inlet fans have the following advantages:

- They do not need thrust bearings, as the gas enters on both sides.
- They are more stable against vibrations and better suited for dusty applications than single width fans.

The overhung fan has a pair of bearings on the motor side and IVC on the other side. The simply supported fans have inlet damper controls. The increase in the shaft length and impeller heaviness must be considered in the double-inlet design.

8.2.10.3 Types of Drives

The possible types are direct, belt, and dual drives.

- *Direct* drive is the most popular because it is simple and calls for little maintenance. But the fan may have to operate at its off-peak efficiency, as the rpm may not coincide with the optimum speed. However, for high-capacity applications, direct drive is the only solution.
- *Belt* drive can be opted up to $\sim 150 \text{ kW}$ and can save space. The best operating speed as per H–Q curves can be chosen by suitable pulley selection. But the issues associated with this drive are belt slackening and replacement due to wear.
- *Dual* drive is occasionally employed in the process industries such as refineries, where a fan is driven by motor and turbine on either side, to enable boiler black start (on power from grid or diesel set) or enhance the availability.

8.2.11 Two Modes of Fan Operation

Fans can be operated in *series* or *parallel* mode depending on the system requirement. The fans are placed

- In series operation when the pressure needs to be built up (Figure 8.24)
- In parallel operation when volume needs to be built up (Figure 8.25)

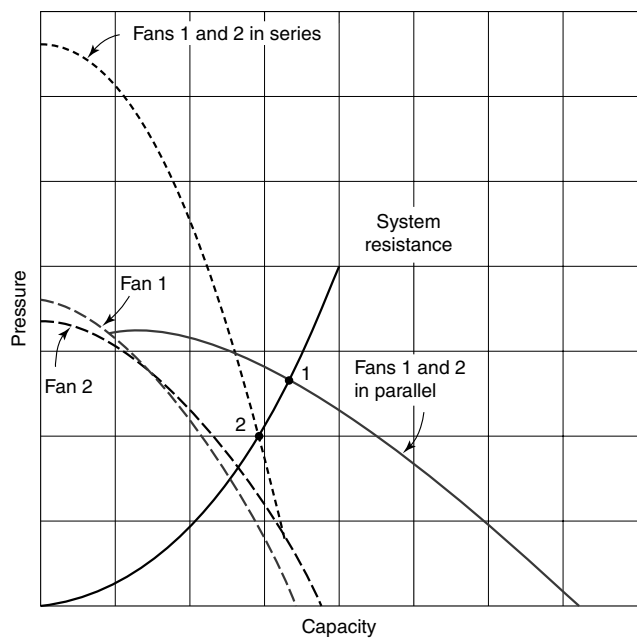


FIGURE 8.24
Fan operation in series and parallel. (From *Power* magazine. With permission.)

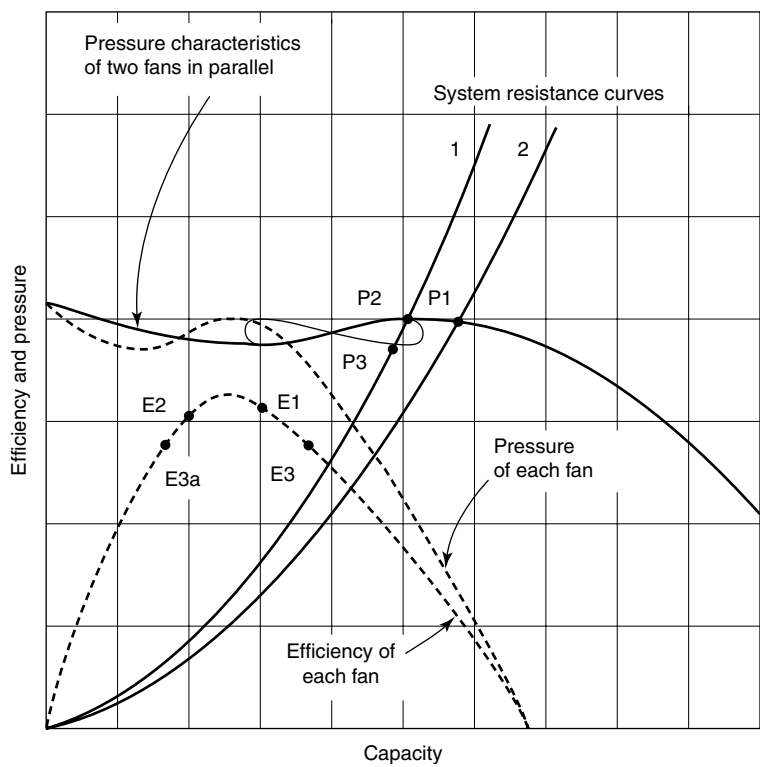


FIGURE 8.25
Comparison of fans in parallel operation. (From *Power* magazine. With permission.)

A primary air (PA) fan drawing suction from the AH, which is downstream of the FD fan in pulverized fuel (PF) boiler, is an example of series operation. FD and ID fan operations are other examples. A pair of FD fans or ID fans or a number of PA fans operating simultaneously are examples of parallel operation.

Dissimilar fans can be in series operation, even an axial fan and a centrifugal fan, but for parallel operation, the fans have to be very similar with continuously drooping characteristics with no humps to prevent unstable operation, leading to dangerous hunting. Hunting occurs when there is a hump in the fan and it keeps shifting its operation from high to low volumes.

8.2.12 Single Set and Two Sets of Fans

It is normal to have a single set of fans for smaller boilers and two sets of fans for the larger ones. Single set of fans has the advantage of

- Simplicity of arrangement
- Reduced duct work
- Less instrumentation and control
- Better efficiency
- Lower auxiliary power due to larger size

Single sets permit lower installation and running costs. Two sets of fans, however, provide redundancy while sacrificing the above-mentioned benefits. Induced draft fan erosion was the main reason behind the adoption of two sets of fans, even for midsize boilers. With very reliable ESPs, fabric filters (FFs), and superior fans, the single-fan concept is gaining greater acceptance.

8.2.13 Fan Erosion and Protection

Fan erosion is experienced mainly in coal-fired boilers. Coal ash impinging at high velocities is the main reason for this erosion. Induced draft and GR are the usual fans in a power plant, which are susceptible to erosion. With the adoption of ESPs and bag filters, ID fans have largely overcome this problem. GR fans, however, continue to experience high dust loads and hence are made of radial blading to resist erosion. The PA fans in suction mills are also prone to erosion. Depending on the gas flow and fan construction, the areas of wear can be predicted and identified.

- *Overlaying weld material* on selected areas of impeller
- Providing replaceable *liners*

These are the two methods of protecting the centrifugal fans against erosion of ash besides lower speeds, but they increase the impeller weight. Increase in fan weight leads to poorer boiler dynamics and longer start-up times. On the whole, there is no fully satisfactory solution for the problem of fan wear.

1. Deposition of weld material of a hard composition, such as chromium carbide, on the blades and the inside channel, which come in contact with moving gas, is a very common remedy. A careful judgment is needed regarding the exact location and amount of deposition, as the inertia of the impeller increases with any

weight addition. Flame or plasma spray metallizing is not very popular because it can peel off if not applied properly. More importantly, the alloying left behind interferes with any later weldments. Metallizing is capable of withstanding nearly perpendicular impingement but not tangential abrasive forces.

2. Replaceable liners can be provided for blades or casing or both, depending on the protection needed. They are soft sacrificial plates, either bolted or welded. Bolted blades also need bead welding to prevent entry of dust particles under the plate. Ceramic or tungsten carbide tiles are attractive due to their extreme hardness, low thickness, and light weight. But the problem of securing the fan blades is not fully solved.

For variable pitch axial fans, protection is needed on the upstream edges of the blades, which is provided by stainless steel (ss) or chrome strips attached by ss screws. Complete blade sets must be replaced after detecting erosion, and this can be usually done in a single shift by the maintenance staff. The erosion protection for axial fans is thus easier, but the capability to withstand erosion is inherently lower in axial fans.

8.2.14 Boiler Fans

A boiler plant, depending on the firing system and size, contains several fans of various sizes and types:

- *Forced draft fan* is the main air fan whose prime job is to deliver the combustion air to the firing equipment in a balanced draft boiler. In a pressurized boiler, the FD fan has to further push the gases formed in the combustion chamber up to the chimney exit.
- A forced draft fan takes clean cold air from the atmosphere, unless steam AHs are in the circuit, in which case the inlet air is slightly hotter.
- In cold countries, it is normal for warm air to be drawn from the top of the boiler house. The tall suction duct can also be used for airflow measurement.
- Forced draft fan heads vary from as low as ~50 mm wg in stoker-fired boilers to as high as ~2000 mm wg and higher in circulating fluidized bed combustion (CFBC) boilers.
- In the case of PF boilers, FD fans supply only SA as the PA fans supply the PA.
- Backward-curved or aerofoil type of centrifugal fans mostly with IVCs, are usually adopted here. In utility boilers, FD is the most ideal application for axial fans with variable pitch.
- *Induced draft fans*, employed only in balanced draft boilers, suck the combustion gases from the furnace and discharge them at the stack exit. They maintain a nominal suction of 5–25 mm wg in the furnace to avoid flames leaping out, and ensure operator safety and prevent the insulation and casing from burning out.
- Induced draft fans are hot gas fans with temperatures usually ~150°C and rarely exceeding 200°C.
- Suction pressures vary from ~200 to 400 mm wg. Higher pressures are required when dust separation devices such as bag filters or wet scrubbers (WS) are employed.
- When dust collection from flue gases was not mandatory, radial or backward-curved radial-tipped blading was used in centrifugal fans. With reliable gas

cleaning equipment in use, fans with aerofoil, backward-curved or backward-curved radial-tipped blading are used, depending on the efficiency of the dust collectors and the erosive nature of the fly ash. Aerofoil blading is also common now.

- Variable pitch axial fans are also used where the fly ash is not erosive and the upstream dust collection is good.
- Corrosion of fans is an issue only for liquor or refuse-fired boilers.
- *Secondary air fans or over-fire air (OFA)* fans are used for providing 10–30% combustion air to the furnace at high pressure to (1) provide turbulence and (2) prevent stratification of gas streams so that the combustion is complete. More volatile matter (VM) in fuel increases the OFA requirement, as more combustion takes place in the furnace. In the case of staged combustion for NO_x abatement, these fans provide much higher amounts of air, even as high as 50%.
 - Pressures vary from 250 to 1000 mm wg.
 - Aerofoil or backward-bladed construction is suitable.
 - Both cold and hot air are used. Hot air can be as high as 350°C, demanding special care for bearing cooling.
- *Gas tempering (GT) and GR fans* are high-temperature fans and, in case of solid fuel firing, they are also high-dust fans. The gas temperature is dependent on the location of suction—whether the economizer (ECON) or the AH exit.
 - Only centrifugal fans with radial or radial-tipped blading are suitable for this application, depending on the dust loading and its erosivity.
 - These fans have the most severe duty in the power plant, as they are subjected to high-dust loads and high temperatures with wide fluctuations.
 - Care should be taken to select a fan with integral hub and shaft, as shrink fitting may not be adequate.
- *Primary air fans* in PF boilers draw hot air from the discharge of AH and push the hot PA through the mills and carry the pulverized coal to the burners. A cold PA fan takes ambient air and passes it through the AH additionally. Air quantities are relatively small, and the heads are high, requiring a narrow wheel with large diameter. As the hot air is usually dusty with rotary AHs, the hot PA fans use radial blading. The cold PA fans, on the other hand, deal with clean air and can be made with aerofoil blading.
- *Exhauster fans* downstream of the coal mills in suction-type PF firing are always made of straight radial blading to withstand erosion of coal dust.

8.3 Dust-Collecting Equipment

Dust collection in a boiler plant is mainly for the control of the particulate emissions, and the separated dust is disposed of by a suitable ash-handling system. In some cases, part (stoker, BFBC) or all (CFBC) of the dust is required to be returned to the system to enhance the combustion efficiency. In CFBC boilers, the main process is dependent on the returned dust, which acts as a coolant in the bed. Cyclones in CFBCs are actually used as process equipment. The cyclone evaporator and the Venturi scrubber in BL-fired boilers help to concentrate the liquor in addition to trapping the dust.

Besides meeting the required particulate level, the dust-collection equipment is also required to comply with the specified *opacity* limit. Opacity is the measure of clearness of stack. A beam of light is passed through the flue gases to determine how much dust is either absorbed or scattered. This is usually ~20%.

The particulates in boiler gases can be of various sizes and can be classified as dust, smoke, fumes, and mist, based on decreasing particle diameter. Different types of dust catchers are required for different types of dust, as shown in Figure 8.26. Besides the size or particle diameter, properties such as the electrical and chemical characteristics, surface-to-volume ratio, particle density, and rates of settling under gravity are some of the factors that influence the choice and sizing of the collecting equipment.

In almost every type of combustion, ash is elutriated with flue gases, resulting in fly ash, which needs to be collected to keep the stack clean. The amount of fly ash varies with the fuel, type of combustion, amount of ash in fuel, etc. Natural gas (NG) firing produces no fly ash. Pulverized fuel, however, generates ~80% fly ash. In the case of CFBC, the fly ash is more than ~90% and is accompanied by considerable quantities of CaSO_4 . Stokers produce 10–40% fly ash with a lot of coarse particles. Table 8.1 summarizes the type

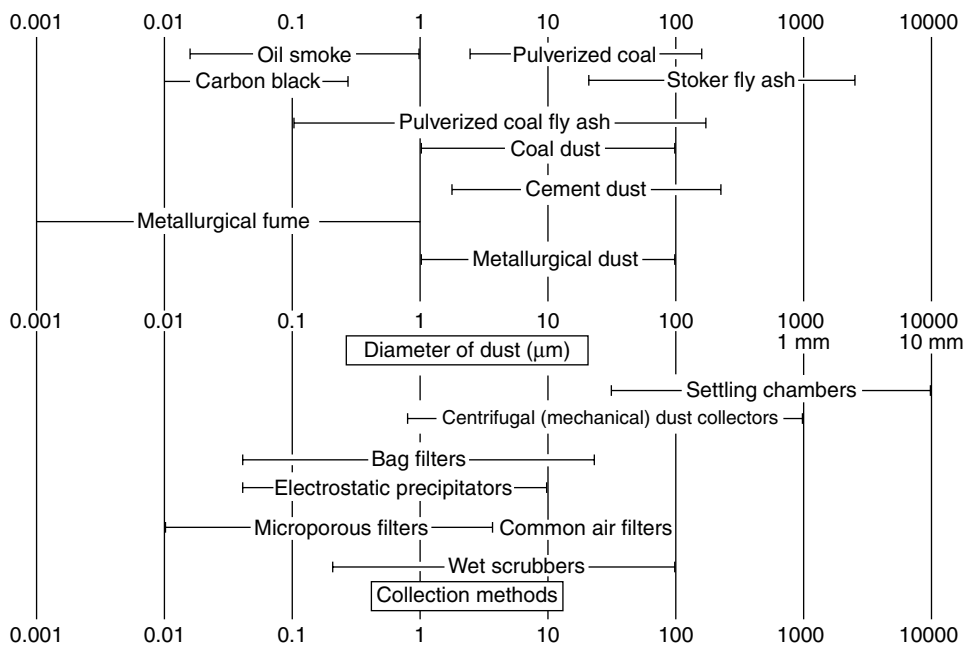


FIGURE 8.26
Overview of various types of dust and collectors.

TABLE 8.1
Fly Ash in Various Firing Modes in Coal Firing

Firing	Fly Ash (%)	Remarks
Traveling grates (TG)	10–20	Grit and C in ash. Relatively large particles
Spreader stokers (SS)	20–40	Grit and C in ash. Relatively large particles
PF	70–90	A lot of fine ash but C is less. Small spherical particles of 7–12 μm
FBC	90–95	Ash gritty and crystalline. C is less. CaSO_4 with desulfurization

of ash generated in each type of firing. The dust-collecting equipment in a boiler can be classified as

- MDCs
- ESP or electrofilters
- Bag or FFs
- Wet or liquid scrubbers

Particles larger than 100 μm (0.1 mm) settle quickly and may need no more than settling chambers. In any case, boiler ash is always finer than 100 μm .

Gas and dust are worked on differently. In MDCs, the gas is given a change of direction by centrifugal action. Naturally, this takes a lot of energy as compared with the ESPs where only the dust is treated. The gases are not treated in ESPs. In bag filters, however, the gas is worked on, as the dusty gases are filtered through the cloth separator. Naturally, energy expended is considerable. In wet scrubbers, the gas is sprayed with water to capture the dust.

8.4 Mechanical Dust Collectors (MDCs)

Depending on the collection process, MDCs can be classified as

- Inertial separators
- Centrifugal separators

Inertial separators rely on a change of direction of gas flow or interception of dust or both, to effect a separation of dust particles from gas. They are simple in construction with low pressure drop and moderate collection efficiencies. They are essentially good for collecting grit from flue gases for refiring. U-beams in CFBCs and deflection baffles in hoppers are typical examples of inertial separators.

Centrifugal or cyclone separators provide a downward high-speed swirl to the gases, causing the dust particles to be thrown to the periphery by the centrifugal action, and slide down along the edge. The inward inclination of the collector tube at the discharge end helps the gases to form a smaller swirl inside and exit at the top duly dedusted. This is explained in Figure 8.27. Depending on the gas volume and the dust loading, the cyclones can be classified as

- Small-diameter multicyclones, also called multiclones (Figures 8.28 and 8.29)
- Large-diameter cyclones arranged in single or multiple units (Figure 8.27)

8.4.1 Multiclones

Multiclones employ small-diameter (250–500 mm mostly) long tubes, which help to provide higher centrifugal forces and longer separation time, both of which increase the collection efficiency, which can be as high as 95% for particles larger than 5 μm under

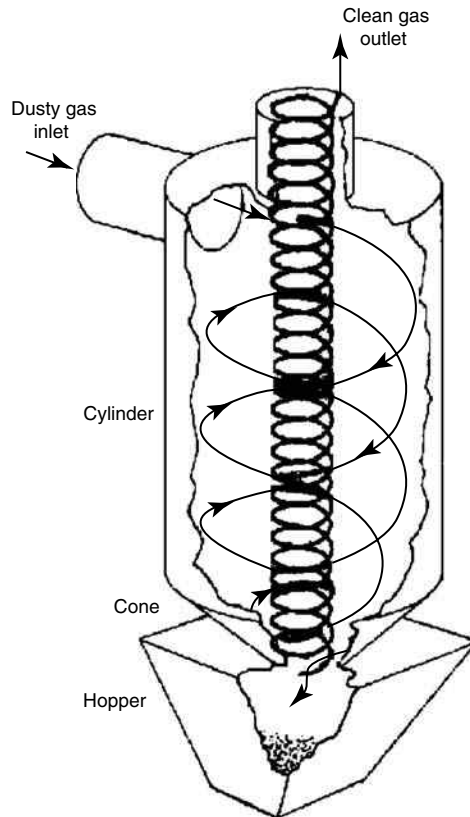


FIGURE 8.27
Large-diameter cyclone separators.

steady conditions, as can be seen in Figure 8.30. The individual collection tube assemblies (Figure 8.28) are made of white cast iron (CI) or Ni-hard with hardness of ~ 400 BHN, offering a fairly long life even with very abrasive dust. The limitations of multiclones are as follows:

- The performance is seriously affected by load swings and fuel and ash characteristics.
- Opacity standards cannot be met, as the particles below $5\ \mu\text{m}$ escape with the gases.
- The pressure drop is high, typically between 50 and 125 mm wg.

The advantages of multiclones are

- Simplicity of construction
- Compactness
- Low initial cost
- Minimal maintenance
- Low running cost

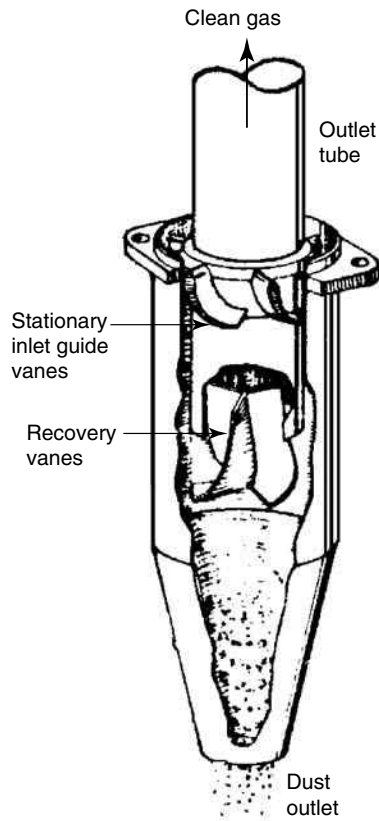


FIGURE 8.28
Small-diameter cyclones used in multiclones.

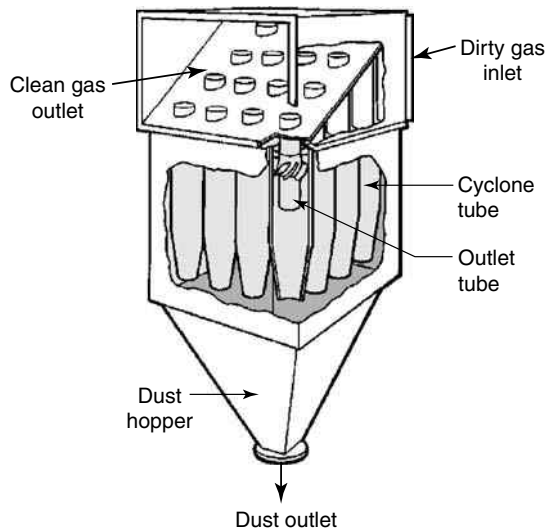
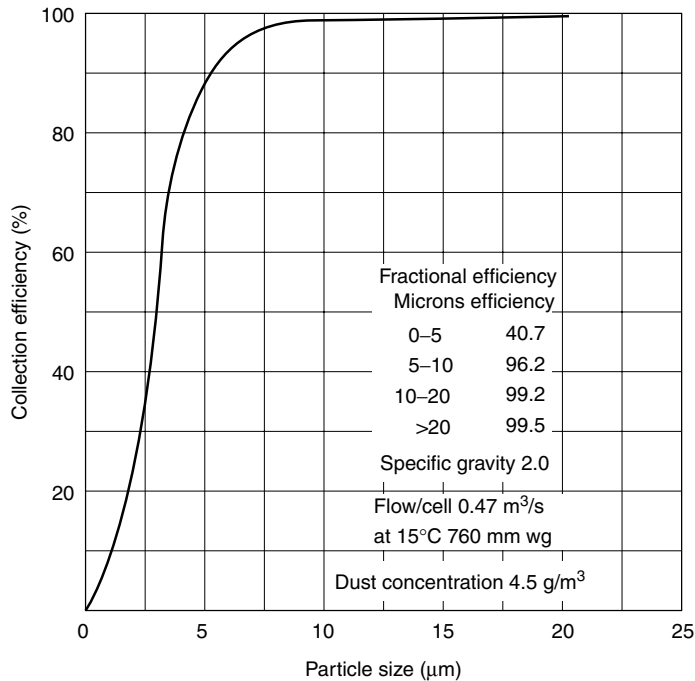


FIGURE 8.29
Multiclones.

**FIGURE 8.30**

Typical collection efficiency of multiclone.

The main disadvantages are

1. Poor collection efficiencies for particles below $5 \mu\text{m}$ size (Figure 8.30), which do not meet the present-day opacity and particulate pollution norms.
2. With high inlet dust loading, the small inlets of the cyclones get choked, making the multiclones unsuitable.

A typical volume versus pressure drop relationship is shown in Figure 8.31.

The multiclones are now practically obsolete because of the present-day pollution norms for particulate emission. They are now occasionally used as precollectors before the ESPs or bag filters to trap the grits in the dust for refiring purposes.

In the 1960s and 1970s, they were used as precollectors to the ESPs with a view to reducing the dust load on ESPs to improve the collection and reduce the size. These expectations were belied because the ESP sizing depended more on the collection of fines and not so much on the grit.

8.4.2 Large-Diameter Cyclones

These cyclones, ranging from $<1 \text{ m}$ to more than 10 m in diameter, are employed for higher dust loads and gas volumes. Also, they can be adapted for higher temperatures of $\sim 900^\circ\text{C}$ and high erosion by lining the inside walls. The interest in cyclones is now sustained by their use in the CFBC boilers.

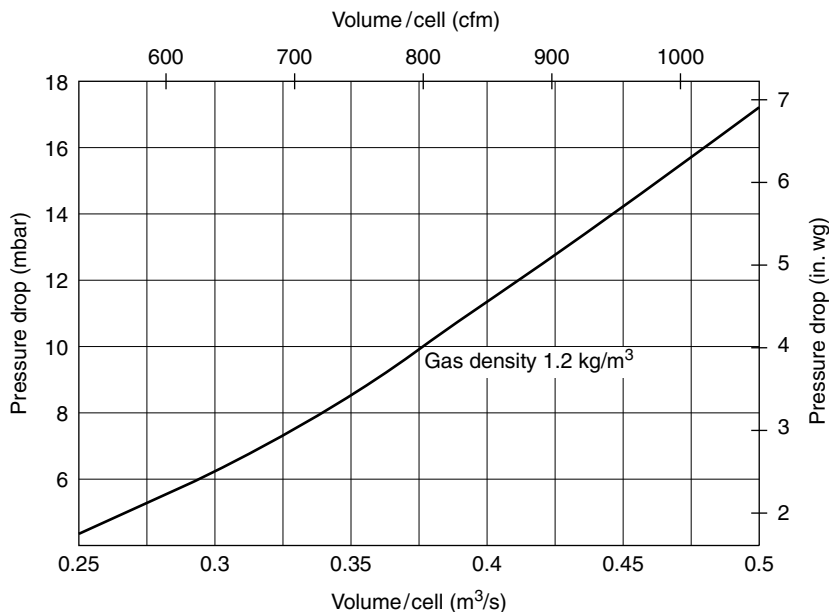


FIGURE 8.31
Volume/cell versus pressure drop.

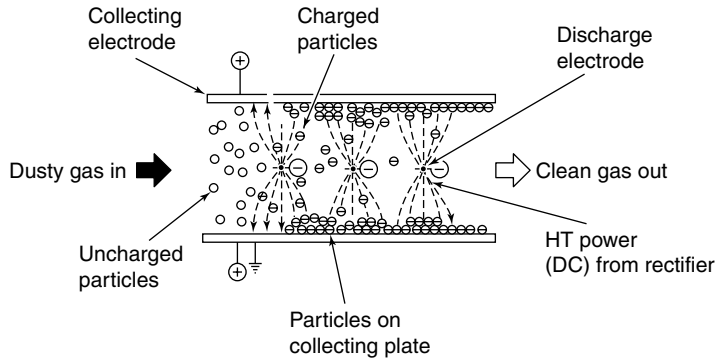
Large-diameter cyclones are also used in boilers firing biomass if the emission standards are not as stringent, as the dust loads are low due to low ash content of fuel. Multiclones with their characteristic high gas velocities are unsuitable for ash of biofuels, which is usually very light and hence has a tendency for re-entrainment.

8.5 Dry Electrostatic Precipitator (ESP)

This method of dust collection uses the property of dust particles to acquire electrical charge, when subjected to high DC voltage.

8.5.1 Operating Principle of an ESP

An ESP is a large settling chamber in which discharge or emitting electrodes (EEs) and collecting electrodes (CEs) are suspended from the roof with high-voltage DC power (by transformer-rectifier [TR] sets) impressed on them and charging them with positive and negative polarities, respectively. The high voltage accelerates some free electrons present in the gas. The free electrons then collide with the gas molecules with such a force that they strip the molecules of an electron. The electrons then flow toward the positive collecting plate and the positively charged gas ions toward the negative discharge electrode. The stream of electrons collides with the gas and dust particles that are travelling slowly in the ESP casing and charges them negatively, making them flow toward the collecting plates. On reaching the collecting plate, the dust loses charge and settles on the collecting plate, which is dedusted periodically by the rapping system. Some positively charged particles are collected on the EEs. Figure 8.32 depicts this action.

**FIGURE 8.32**

Particle collection in an electrostatic precipitator.

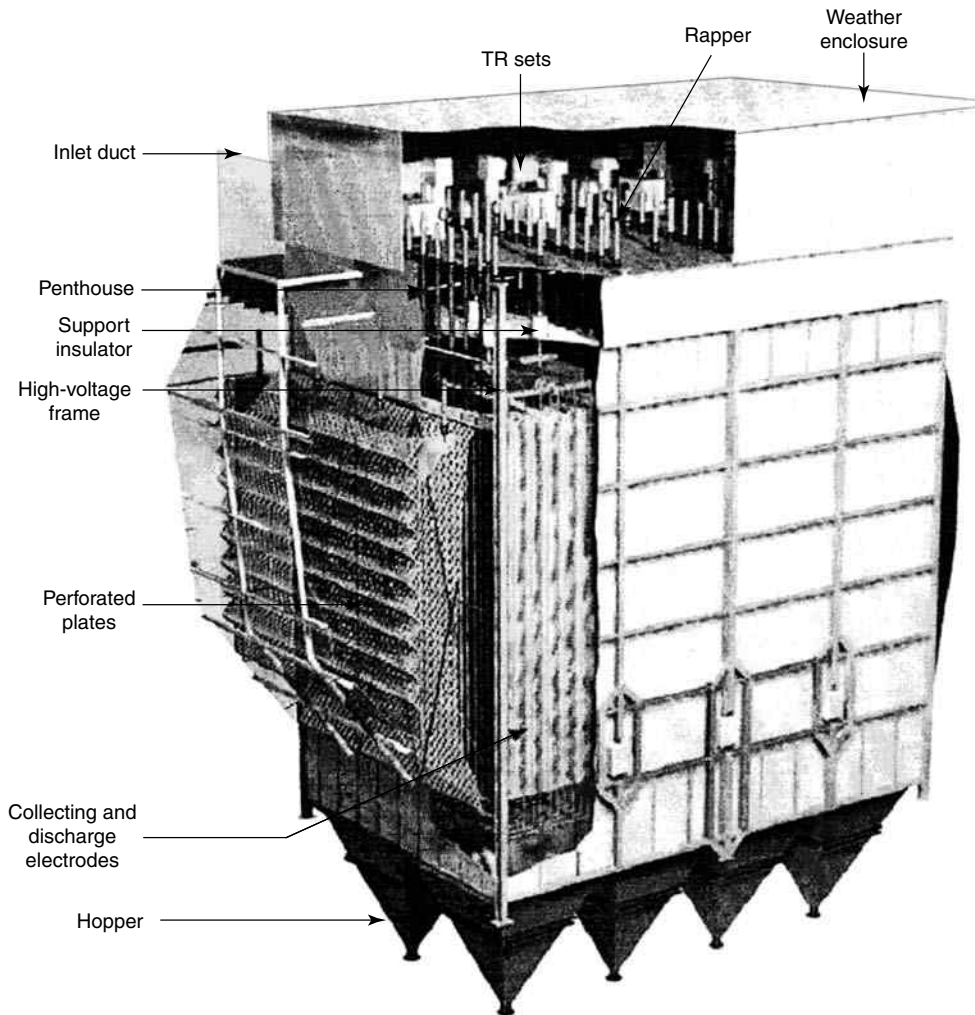
8.5.2 Components

ESP is a complete system (Figure 8.33) consisting of

- Mechanical equipment:
 - Housing with inlet and outlet funnels and perforated inlet screen
 - Ash hoppers with electrical heating pads
 - Supporting structure with proper expansion arrangements
 - Electrode assemblies with supporting system and insulators
 - Rapping system, mechanical or magnetic
 - Insulation and lagging
- Electrical system:
 - TR sets on the roof
 - Cabling from local motor control center (MCC) to TR sets
- Control system

8.5.3 Features

- *ESP housing* is a large sturdy chamber capable of withstanding all the weights and forces imposed.
- It is an airtight chamber of carbon steel (CS) sheet of 5 or 6 mm thickness, with adequate stiffening for maintaining the straightness of sides. Usually a steel sheet of A-36 specification is adequate, as the flue gases are not corrosive and are sufficiently cool.
- All electrodes are housed in the casing and are suspended from the top.
- The internals are separated by adequate walkways inside the enclosure.
- The cross section has to be large enough to slow the gases to permit sufficient treatment time.
- It is absolutely essential to have gases filling the entire chamber for proper collection, for which a carefully designed perforated screen as a minimum (along with inlet flow distribution devices in many cases) is installed at the inlet end. Turning vanes and flow straighteners are also installed as required.

**FIGURE 8.33**

Arrangement of dry electrostatic precipitator with top rapping. (From Hamon Research-Cottrell, U.S.A. With permission.)

- The shape of the inlet and outlet funnels is also very important for an even gas flow. Flow modeling by computer can optimize the casing design, replacing the Perspex models of the past.
- An aspect ratio (width of total ESP versus height of electrodes) of $\sim 1:1.2\text{--}1.4$ is considered an economical and good design.
- The casing is externally insulated and clad for human comfort as well as prevention of condensation.
- *Ash hopper* design is very important. The slope and size of ash hoppers is important for optimal functioning. The hoppers for coal ash are built with a minimum valley angle of 55° or side slopes exceeding 60° for smooth sliding of ash. Heating pads are essential to keep the hoppers hot, as fly ash is highly hygroscopic, creating hopper jamming even after a few hours of stoppage. Many times hopper storage of 8 h is demanded to permit shift operation of the ESP with electrical system

fault. With inadequate hoppers, the first ones tend to overfill and spill over, creating short circuiting of electrodes and stoppage of the entire unit. The hoppers must terminate at an elevation of $\sim 2\text{--}2.5$ m above ground level to permit installation of rotary valves and ash disposal units below. Vibrators, level monitors, and poke holes are also required.

- *Supporting structure* takes on the weight of the entire ESP casing with all internal and external mountings and the hoppers with ash. The casing has to be anchored at the front, rear, or middle and allowed to expand with respect to the fixed structure over special roller bearings. Expansion joints at the ends of front and rear funnels in the gas ducting are necessary to connect to upstream and downstream ducting.
- *Electrodes*, both the EE and the CE, are suspended from the top and charged with negative and positive polarities, respectively. The EEs are connected to the TR set terminals by suitable conductors with ceramic insulators. The CEs are grounded.
- *Emitting electrodes*. On the basis of the type of EE, an ESP is classified as the weighted wire, rigid, or rigid frame type. All three types are depicted in Figure 8.34. Emitting electrodes need to extend beyond the zone covered by the accumulated ash.

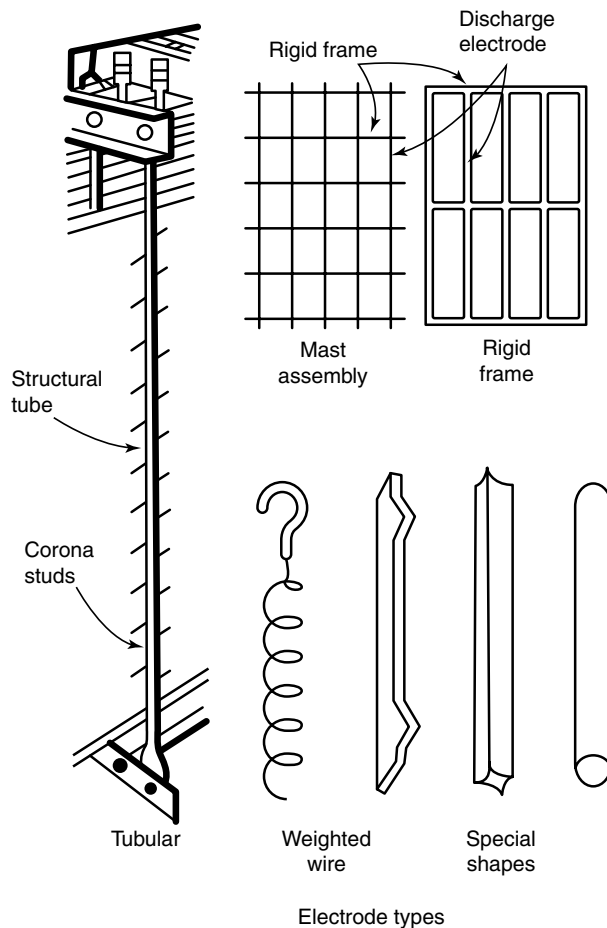


FIGURE 8.34

Types of emitting electrodes. (From *Power* magazine. With permission.)

- In weighted wire design, a thin (typically 3 mm) ss wire is made into a spring form with a weight attached at the bottom for maintaining straightness.
- A rigid electrode is a heavy-rolled section provided with spikes.
- A rigid frame is a tubular frame with electrode wires fixed vertically.

The weighted wire design is light in weight and good in performance but has shorter life, as the springs tend to break as the electrode lengths exceed ~ 9 m (~ 30 ft). The disturbing aspect of wire breakage is not so much about the performance loss but a possibility of the attendant short circuiting, calling for an immediate repair. The rigid electrode and rigid frame designs rely on heavier members for stronger construction and reliability. Large ESPs for utilities are made with pipe- or special-shaped heavy electrodes or rigid frames. The weight of an ESP increases but the reliability also improves significantly.

- *Collecting electrodes* are cold-rolled steel sheets of ~ 600 mm (24 in.) width or more, rolled to special shapes for effective collection of ash. Ash collects on the entire height of the plate and, when dislodged, falls in layers. The height of the collecting plates is one of the prime dimensions of an ESP. Plates as tall as ~ 15 m (~ 50 ft) are employed on large ESPs. Plate thickness varies from ~ 1.0 to 1.5 mm. The straightness is very important for proper performance, and besides the crimping of the sheets, stiffeners may also be welded to avoid waviness. In Figure 8.35, a typical collecting plate and its supporting arrangement are shown.

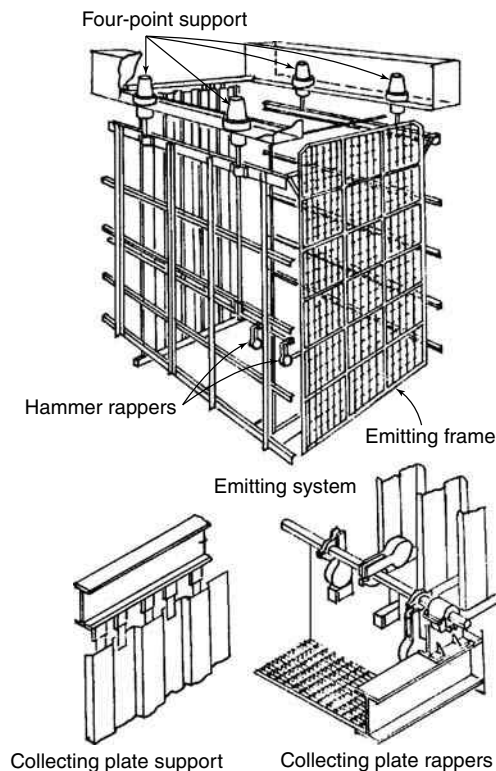


FIGURE 8.35

Electrodes and side rapping system. (From *Power* magazine. With permission.)

- *Rapping* is a periodic shaking of the electrodes to dislodge the accumulated dust. The dust accumulated on the collecting plates tends to agglomerate and, when rapped, dislodges and falls in several layers. From discharge electrodes, a small amount of dust is collected. Each electrode needs rapping separately for an effective ash removal, and the sequence has to be in the direction of the gas flow.

Rapping force has to be carefully selected, as a heavy bang is likely to drop a lot of dust, leading to a rebound and reentry of dust into the gas stream, whereas a gentle tap is unlikely to dislodge the dust from the electrodes effectively. The rapping force and frequency have to be different from the top to the bottom of the electrode and from the front to the rear of the ESP.

Mechanical rapping, which is still the most popular form, involves hitting the electrodes at the top, middle, or bottom. The tumbling hammers drop with free fall and the acceleration so caused sends shock waves, loosening and dropping the dust. High-resistivity fly ash is particularly difficult to collect, and a rapping force caused by an acceleration of minimum 100 g is required. Rapping the collecting plate from the bottom is depicted in Figure 8.35. The hammers of varying weights are connected to a slowly rotating shaft driven from outside and hit the electrodes in a predetermined manner.

Rapping of EEs is also required, but fewer rappers are needed because the ash collection is low. Mechanical rapping from the tops of electrodes is also a popular method. Magnetic impulse rapping is another method. The hammers are dispensed with, and magnetic waves are used for vibrating the electrodes.

- A *field* in an ESP is a section complete with its own *TR set*. The DC voltage generated in TR sets has been steadily increasing along with the spacing between the electrodes. Prior to mid-1980s, the spacing was ~225 to 250 mm (9–10 in.) with voltage levels of <50 kV on an average. These voltage levels have recently reached 85 kV and more. This rise has helped in widening the collecting plate spacing to 300 and 400 mm, which reduces the plate requirement and offers better access. The limit for higher voltage is set by the tendency for arcing between the electrodes.
- *Control systems* create and maintain an electrical field to facilitate dust collection. They also minimize power consumption consistent with performance. The control system maximizes the effective voltage and current. When sparks and arcs can damage the internals, the control system reduces the power to the affected field. Typically, for each 2500 m², a separate bus section is provided.
- With stringent pollution norms, it is usual to have a minimum of three fields in an ESP, although single-field units have been employed with nearly 90% collection efficiency. With three fields, the efficiency is >99%. In large utility boilers, firing high-ash coal, it is not unusual to have six or seven fields to meet ~30 mg/N m³ levels with collection efficiencies >99.9%. With low-ash coals, it is possible to achieve particulate emission levels as low as ~10 mg/N m³. It is usual to specify that an ESP should deliver the required performance even with one field out of service.
- The maximum collection of ash is in the first field where nearly 80% takes place. Normally, each field of the ESP collects ~80% of the incoming dust load. In large ESPs, the difference in ash collection between the first and the last set of hoppers can be as high as 100 times.

The ash handling system should be designed for heavy loads in the first field, and in the second field when the first one fails. The collection in the subsequent fields progressively

reduces, but the particles are finer. The ash handling plant should be designed such great variations in mind.

8.5.4 Advantages

An ESP is the most popular particulate collection system in all sizes of boilers based on its enormous advantages:

- Collection efficiencies >99.9% can be achieved effortlessly by increasing the fields. The exit dust load can be as low as $\sim 30 \text{ mg/N m}^3$ with high-ash coals and even 10 mg/N m^3 for low-ash coals.
- Electrostatic precipitators can be effective in collecting not only the coarse particles but also the fine particles and fumes. They can collect a wide range of dust, from submicron levels of $0.05 \mu\text{m}$ to large particles of $10 \mu\text{m}$ or more.
- The pressure drop is surprisingly low, between 20 and 30 mm wg, not much higher than that for a settling chamber because the internals are wide apart and the gas velocity is low. More importantly, the dust is worked upon and not the flue gases, unlike in the cyclones or bag filters.
- The power consumption is very low for the same reason.
- Because of the low gas velocities, the erosion of the internals is not an issue. EPS is ideally suited for coals with high amounts of abrasive ash.
- ESP is an extremely reliable and rugged system, which requires practically no maintenance.

8.5.5 Limitations

- An ESP is expensive, particularly in lower sizes on a specific cost basis because of the numerous components.
- It occupies a lot of floor space.
- Emission limits are exceeded during upset conditions such as soot blowing. If the emission limits are to be observed under all conditions, the ESP becomes too large.
- For very low emission limits such as 30 mg/N m^3 from high-ash coal-fired boilers, bag filters become attractive, if the ash is not too abrasive.
- The collection efficiency of particles of $2 \mu\text{m}$ and below is poor.

8.5.6 Performance Parameters

The classical *Deutsche–Anderson* equation describes the behavior of an ESP reasonably well, although it is deficient in predicting the performance.

Collection efficiency of an ESP can be defined as

$$E = \frac{(\text{inlet dust} - \text{outlet dust})}{\text{inlet dust}} \quad \text{or} \quad 1 - \frac{\text{outlet dust}}{\text{inlet dust}} \quad (8.13)$$

An ESP is a *percentage collector*. Outlet dust loading increases in proportion to the inlet dust loading, and if the outlet concentration is to be maintained at high dust loads, the ESP

size has to be increased. This is an important point of difference compared with the FFs in which the outlet loading remains indifferent to the inlet load.

$$\text{Collection efficiency } E(\%) = 1 - e^{-Aw/V} \quad (8.14)$$

where

A = the area of CEs in square meters

V = actual gas volume in cubic meters per second

w = migration or drift velocity in meters per second

e = natural logarithm 2.718

Collection efficiency is a function of

1. A/V , the specific collection area (SCA) in square meters per cubic meter per second of flue gas. More collection area improves collection efficiency for the same gas volume.
2. w , the migration velocity, is governed by ash resistivity. Higher migration velocity means better collection efficiency. Lower ash resistivity promotes higher migration velocity.

Uniform gas flow distribution is of paramount importance in achieving the predicted collection.

$$\text{Collecting area } A \text{ (m}^2\text{)} = \frac{V}{w} [e^{1/(1-E)}]$$

Collecting area is directly proportional to the gas volume and inversely to the migration velocity. It is the total area of the collecting plates measured on both sides. SCA is the way by which the ESP sizing is understood and compared for various fuels and resistivities.

SCA comparison for ESPs can be done only after they are rationalized for the electrode spacing. It is usual to convert the SCA for 300 mm electrode spacing, an informal industry standard. Since there are a number of variables in the sizing of ESP and most of them are difficult to measure accurately, the ESP sizing is largely empirical and is based on the previous data.

- *Migration or drift velocity* is the theoretical average velocity of the charged particles as they move toward the CEs. Higher migration velocity means lower collection surface and smaller ESP. This is dependent on how easily the dust particles acquire charge when subjected to a high voltage, that is, how low is the ash resistivity (measured in ohm centimeters). As the ash resistivity increases, the migration velocity reduces, as shown in Figure 8.36. Fuel and ash characteristics, operating temperature, voltage levels, and gas flow distribution affect migration velocity.
- *Ash resistivity* values typically vary from 10^8 to $10^{14} \Omega \text{ cm}$, with 5×10^9 – $5 \times 10^{10} \Omega \text{ cm}$ as the ideal range for ESPs. Ash resistivity of $>5 \times 10^{11} \Omega \text{ cm}$ poses difficulty in collection, whereas resistivity of $<10^9 \Omega \text{ cm}$ leads to ash re-entrainment issues. Such low resistivity in ash is rare, but, on the higher side, $2 \times 10^{12} \Omega \text{ cm}$ is possible, with low-sulfur coals and a rather large ESP. Peak ash resistivity occurs at

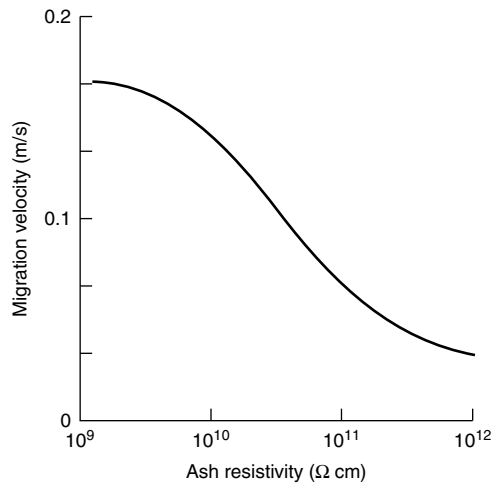


FIGURE 8.36
Ash resistivity versus migration velocity.

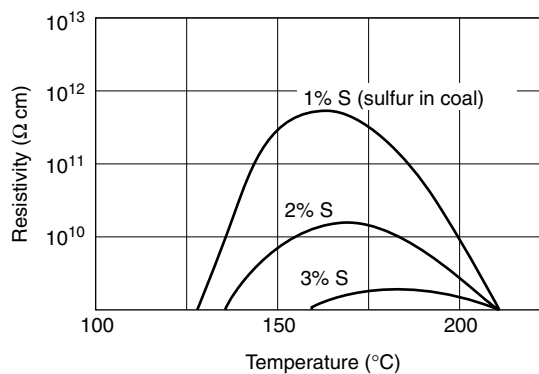


FIGURE 8.37
Variation of resistivity with sulfur and temperature.

120–220°C, depending on the ash and coal characteristics, as shown in Figure 8.37. At higher temperatures, the resistivity is inversely proportional to the absolute gas temperature, whereas at lower temperatures, it is directly proportional to the absolute temperature.

- *Fuel ash constituents* that reduce the resistivity and collection surface are H_2O and S. Ash constituents such as Na and K and unburnt carbon also reduce the resistivity.

Ca, Mg, Al_2O_3 , and SiO_2 , however have the opposite effect. Al_2O_3 and SiO_2 are basically electrical insulators and do not acquire electrical charges. This understanding is very important to predict how the ESP would behave with different fuels or how a change of fuel would affect the ESP behavior.

- *Hot ESPs*, which are placed ahead of AHs in some installations, are built based on ash resistivity at higher temperatures. Since the results have not been encouraging, the hot ESP concept has been abandoned.

- *Gas velocity* ranges from 1 to 2 m/s and is required to be in the lower end for both high and low ash resistivities. High-resistivity ash requires more time for collection, whereas low-resistivity ash has tendencies to re-entrain. Approximately 1.3 m/s gas velocity is optimum for coal firing. Greater gas velocity reduces the ESP cross section with a possibility of undersizing. At the same time, a very low velocity could result in meandering of gases with a possibility of ionization, leading to sparkover and performance degradation.
- *Treatment time* is the time when gases reside inside the ESP from the first to the last electrode. For high-resistivity ash, it varies from 15 to 25 s, whereas for medium-resistivity ash, it varies from 7 to 10 s.
- *Fly ash conditioning* is sometimes required for collecting dust. SO_3 is the most popular agent, which is introduced at the inlet in trace amounts. This helps to reduce the ash resistivity and improve collection. NH_3 is, at times, introduced because it helps agglomerate particles, which prevents re-entrainment. As much as 20–30% reduction in ESP size is possible by gas conditioning.

The most extensive use of ESPs is in coal-fired boilers of all sizes. Collection efficiencies exceeding 99.9% are common to give outlet emissions of $<30 \text{ mg/N m}^3$ at 6% O_2 .

Electrostatic precipitators are also employed in boilers firing bagasse, wood, bark, oil, and municipal refuse. The resistivity of ash in all cases is less than coal mainly because the moisture content in fuel helps to lower it. SCA in these ESPs is considerably lower, leading to smaller unit sizes.

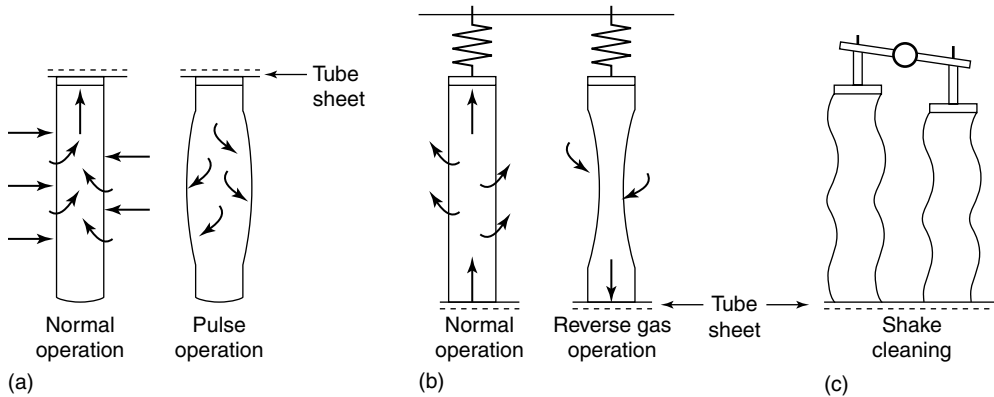
8.6 Fabric Filters (FFs)

A fabric filter (FF), cloth filter, or bag filter is essentially an airtight chamber with a number of cloth bags arranged inside along the gas path, forcing the incoming dusty gases to pass through them to deliver clean gases. The dust stays behind, sticking to the cloth, which is periodically dusted off by backwashing with high-pressure air or recirculating cleaned gases. Fabric filters employ woven or felted fabrics through which the gas has to pass. Fabric filters are not percentage filters like ESPs but absolute filters with no change in outlet concentration irrespective of inlet dust load. The real filtering medium is not the cloth bag but the dust cake formed on it. While dedusting the bags, a layer of dust cake is intentionally left behind to continue the sieving act. Bags are cylindrically stitched cloth pieces closed from one side and adequately stiffened with suitable light metal frames to withstand mechanical and cleaning forces.

Based on the type of cleaning, the FFs are classified into three types, as represented in Figure 8.38.

1. Reverse gas filters (RGFs)
2. Shaker filters (SFs)
3. Pulse jet filters (PJFs)

In RGF and SF, where the bags are open at the bottom and closed at the top, the dusty gases enter from the bottom and the dust is collected on the inside of the bags. Mechanical shaking used for removal of dust imposes severe stresses on the bags. Bag materials currently available cannot withstand such violent stresses for a large number of cycles. SFs have short lives and are not popular. RGFs are, by far, the most popular design, as

**FIGURE 8.38**

Various fabric filters and their operation: (a) pulse jet filter, (b) reverse gas filter, and (c) shaker filter.

the bag cleaning is gentle. The section that needs cleaning is isolated, and the flow of the cleaned flue gas is reversed to make the bags shrivel, causing the dust to fall off the dirty bags. The PJF design is exactly the opposite of the RGF design. The bags are open from the top, and the dust is collected on the outside of the bags and periodically blown with high-pressure air. As the air pulses travel along the bag length, the bags expand intermittently, loosening and shaking off the dust. PJFs require stronger bags. They were used in smaller sizes for industrial applications for gas volumes of 50 Am³/s. For utilities, RGFs were common but PJFs are also finding their way into utility markets due to their improved designs and bags.

8.6.1 Advantages of FF

- The installation costs of FFs are lower than those of ESPs.
- Fabric filters are more compact and occupy less floor space.
- Very high collection efficiency of >99.9% can be achieved very easily and economically. Outlet loadings as low as 10 mg/N m³ at 6% O₂ are achievable.
- The outlet concentration remains practically constant irrespective of the variation of the inlet loading.
- Fabric filter performance is not concerned with the resistivity of ash or sulfur in coal. For such conditions, FFs are smaller and cheaper than ESPs.
- Collection of very fine particles of <2 μm is possible.
- With bio, wood, and allied fuels, the moisture in fuel tends to agglomerate the dust cake on the bags into a porous sieve, aiding dust collection and reducing the size of FF.
- SO₂ in flue gas can be absorbed by the dust cake if it is alkaline.

8.6.2 Limitations of FF

- Bag replacement at 20–40% of the initial cost is needed every 2–3 years, depending on how abrasive the ash is.
- Pressure drop can be as high as 150–200 mm wg leading to substantial auxiliary power consumption.

- Bag materials cannot withstand erosive ash for long periods.
- As bio fuels wood, and allied fuels are light, the burning carbon particles get carried away until intercepted by the bags of FF that pose a serious fire hazard.

8.6.3 ESP versus FF

Electrostatic precipitators are still preferred due to low operating power costs, low maintenance, and exemplary availability despite higher installation costs, poorer collection of very fine dust ($<2\ \mu\text{m}$), and larger floor space. However, FFs have been gaining ground:

- Despite their higher power and bag replacement costs.
- Dust collection efficiency is uniformly high at all loads with all sizes, FFs require less floor space, and exhibit dust cake properties that often help in dry acid gas removal.

The pollution laws are gradually demanding very low emissions of $<30\ \text{mg/N m}^3$ and lower opacity standards, which favor FF over ESP. Also for low-sulfur coals with high ash resistivity, the ESP size makes FF more economical when such low emissions are to be achieved.

8.6.4 Performance of FF

Performance depends on the following parameters:

- Air to cloth ratio (A/C)
- Gas pressure drop
- Fabric life and cleanability
- Fabric, dust cake, and gas properties
- *A/C ratio* expressed in terms of *actual gas flow per unit cloth surface* in $\text{Am}^3/\text{m}^2\text{h}$ ($\text{Aft}^3/\text{ft}^2/\text{h}$) is perhaps the most important parameter for sizing the filter. A higher ratio requires a smaller FF. A greater gas pressure drop means more cloth wear. Bag cleaning and replacement are required more frequently. Selecting an optimum A/C ratio requires a balance of initial costs, running costs, and performance.
- A/C ratio is also called the *filtration velocity* and expressed in terms of meters per minute or feet per meter.
- A/C ratio is expressed as gross, net, or net-net in increasing value, depending on whether it includes
 - Total cloth area of all bags in FF
 - Area of bags under cleaning deducted from the total area
 - Area of bags under maintenance deducted from the total area

It is the practice in the industry to express the A/C ratio on a net basis. Typical filtration velocities for coal firing on a net basis are as follows:

RFG: 0.45–0.7 m/min	or	27–42 m/h
(1.5–2.3 ft/min)		(90–140 ft/h)
PJF: 0.9–1.2 m/min	or	54–72 m/h
(3–4 ft/m)		(180–240 ft/h)

- *Gas pressure drop* in an FF gradually builds up until it reaches a set point when the bags are dedusted. Pressure drop is 150–200 mm wg from flange to flange across the bag, dust cake, and bag attachment to tube sheet.
- *Fabric life* depends on the type of FF and the cleaning forces. Fabric suitabilities vary for each application.
- *Dust cake properties* are important for optimum cleaning. A porous and softly adherent dust cake acts as a sieve to trap the dust. Therefore, care is needed to retain an optimum thickness of dust cake on top of the fabric after each cleaning. As mentioned earlier in Sections 8.6.1 and 8.6.3, an alkaline dust cake helps to reduce dry acid emissions.

8.6.5 Reverse Gas Filters

The flue gas enters the RGF near the bottom plate and passes through the inner sides of the bags, which are open at the bottom and closed at the top, depositing the dust on the insides. The bags are held between the top and the bottom plates. The clean gases leave at the top plate. Bags are grouped together to make a section or compartment, which is taken up for on-load cleaning or maintenance during which two sections are taken out of service. The cleaned gases are made to flow back through a section, making the bags bend inward to drop the ash. The cleaning operation is gentle allowing longer life of the bag and permitting the usage of woven material. The bags are typically 200–300 mm in diameter and 7–11 m long and A/C ratios of $\sim 40 \text{ m}^3/\text{m}^2 \text{ h}$ (on net-net condition). The cleaning gas flow varies from 28 to $35 \text{ m}^3/\text{m}^2 \text{ h}$, and the operation is designed to clean only one section at a time. The gas flow in active sections naturally increases as the total gas flow remains the same (Figure 8.39).

8.6.6 Pulse Jet Filters

The flue gas enters the PJF at the bottom and passes through the outer sides of the bags, which are closed at the bottom and open at the top, depositing the dust on the outsides.

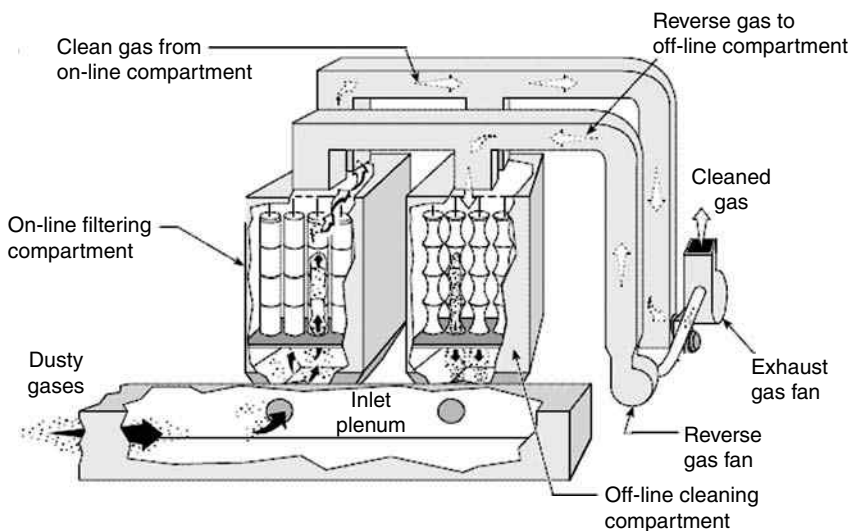
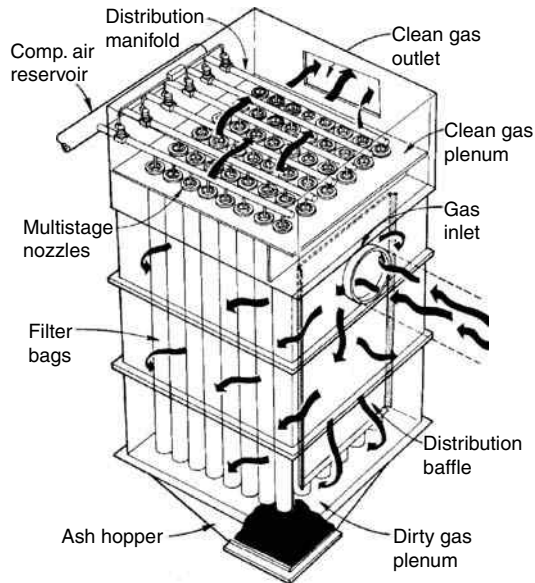


FIGURE 8.39
Reverse gas filter.

**FIGURE 8.40**

Pulse jet filter. (From *Power* magazine. With permission.)

The cleaned gases flow from the top toward the exit. Periodically, the gases are cleaned by blowing fresh air through the bags at high pressure, which expands the bags and allows them to shed the dust from their outsides. The cleaning forces are heavier, demanding use of expensive felted material and strong support cages. In PJFs, the bags are smaller, ~130 to 150 mm in diameter, and shorter, ~5 to 8 m long; A/C ratio is higher at $\sim 70 \text{ m}^3/\text{m}^2 \text{ h}$ (Figure 8.40).

8.6.7 RGF versus PJF

Higher A/C ratio, on-load cleaning facility, and no internal walkways make the PJF smaller. There can be as much as 50% reduction in the plan area, making the installed costs lower by ~20%. The woven bags in RGF are cheaper and have longer life, thereby reducing the operating costs.

8.6.8 Bags for FF

Bags constitute the heart of the FF system, as the performance, life, and availability are dependent on the material, construction, and supporting system of the bags. Woven fiberglass bags are most commonly used for coal application. Bag life is affected by (1) flexing action on the bag during cleaning and (2) bag binding due to trapping of small particulate matter in the pores. The latter causes an excessive pressure drop, requiring an early replacement. In RGFs and SFs, the bags are fastened at the bottom to a thimble in the tube sheet. At the top, a metal cap is sewn. In RGFs, the bags are supported with springs (Figure 8.41).

Besides fiberglass, synthetic patented materials such as Nomex, Ryton, Daytex, Teflon, and so on, are used depending on the ash properties.

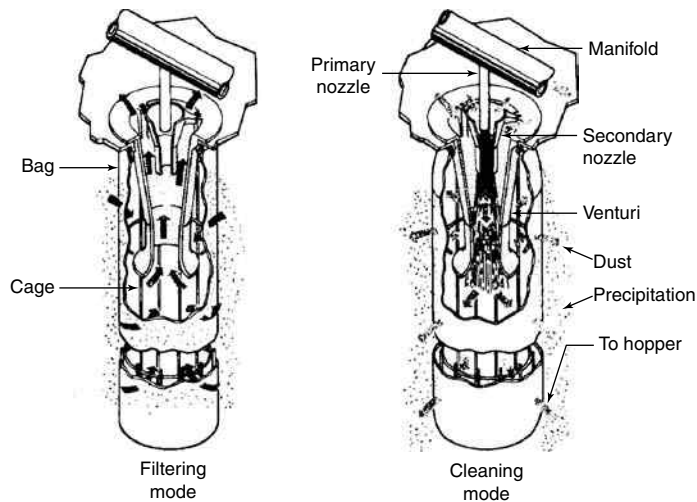


FIGURE 8.41
Bags of pulse jet filter. (From *Power* magazine. With permission.)

8.7 Wet Scrubbers (WSs)

The principle of dust collection in a WS is different from that of the previous three methods. Instead of directly separating the dust from the flue gas, the dust is merely diverted from the flue gas to the scrubbing liquid, and thereby the gases are freed from the dust burden. Wet scrubbers use a fine spray of water or process liquid onto the dusty gas stream to allow intimate contact of the dust and the liquid. The heavier liquid particles, impinge on the dust and retain dust in the liquid stream, whereas the cleaned gases escape. The effluent ash-liquid mixture in a slurry form is subsequently treated and discharged.

There are several variations in WS. The most common type is the Venturi scrubber with variable orifices, which is a very efficient dust retainer.

1. Venturi: gases are accelerated into a narrow channel and the liquid is sprayed to create the intimate contact.
2. Cyclone: remaining dust is hurled toward the walls by centrifugal force and trapped by the wall flow.

The process, with two stages of collection, is very efficient but energy-intensive. Power is spent in accelerating and rotating the gases and also in spraying and recirculating the liquid. As the dust is usually acidic, the effluent slurry needs to be treated before disposal.

Figures 8.42 and 8.43 show the Venturi scrubber. The flue gas is accelerated to 30–60 m/s and the total pressure drop is varied from 100 to 800 mm wg, depending on the gas volume, particle size, dust loading, and the required collection efficiency. The adjustable throat makes it possible to control these parameters.

8.7.1 Advantages of WS

- Very high levels of dust loads and high gas temperatures are treatable in wet scrubbers.
- Very high collection efficiencies of >99.9% are possible.

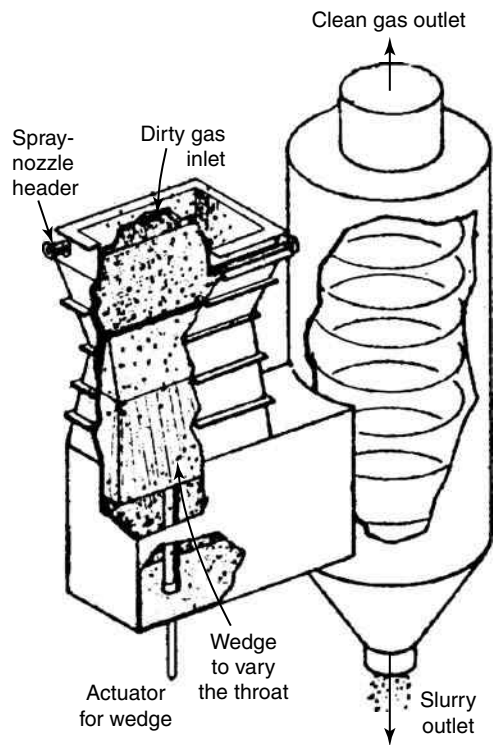


FIGURE 8.42
Isometric view of Venturi scrubber. (From *Power* magazine. With permission.)

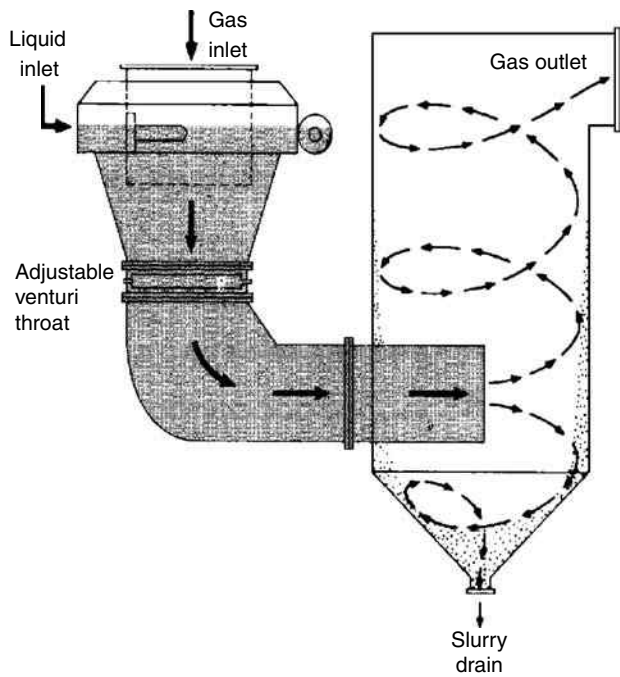


FIGURE 8.43
Schematic arrangement of Venturi scrubber. (From *Power* magazine. With permission.)

- Collection efficiency and power consumption can be varied by throat adjustment.
- Collection of particles as small as $0.2\ \mu\text{m}$ is possible.
- The equipment is extremely simple and has no moving parts.
- The floor space required is very small.
- Maintenance is easy and inexpensive.

8.7.2 Limitations of WS

- The power consumption is great. Depending on the collection efficiency, the draft loss across the scrubber varies from 100 to 800 mm wg. Sizable power is involved in the spraying of liquid in the Venturi and recirculation in the cyclone.
- The effluent is wet slurry.
- Only for the biofuels with no sulfur, the slurry is not acidic and may escape with light treatment. Otherwise, the slurry is acidic with attendant disposal problems.
- The scrubber and the downstream ducting have to be made of corrosion-resistant material such as ss 316L. The stack also needs some corrosion protection.
- For coal ash, the Venturi needs an erosion protection by way lining.

8.7.3 Application of WS

High power and effluent treatment requirements have made the WS unpopular with the utilities. This may change when the savings in real estate are factored. In process industries that have effluent treatment plants, WS does not pose new problems. For oil-fired boilers, which produce fine soot and high-carbon, WS is better suited. Biofuels, which generate light ash with burning char, and high carbon ESP and FF create other problems. A WS makes a good collector, particularly because the effluent is not acidic.

8.7.4 Comparison of Different Dust Collectors by Performance

Different dust collectors have different areas of applications, and no two are alike. There is an overlap in cyclones and multiclones and also ESPs and FFs. The advantages and limitations of each type have been discussed. A comparison on performance parameters of all the collectors is presented in Table 8.2.

TABLE 8.2

Comparison of Performance Parameters of Various Dust Collectors

Type of Dust Collector	Particle Size (μm)	Inlet Dust Loading (g/m^3)	Collection Efficiency (%)	Approximate Gas Pressure Loss (mm wg)	Water (t/h/ m^3/s)	Power ($\text{kW}/\text{m}^3/\text{s}$)	Gas Velocities (m/s)	Size Range Limits (m^3/s)	Space Required
Cyclone	>10.0	>2.50	<85	150	—	—	10–30	25	Small
Multiclone	>5.0	>2.50	<95	150	—	—	10–30	100	Small
Venturi scrubber	>0.5	>0.25	<99	250	1.5–5.5	—	60–210	50	Small
FF	>0.2	>0.25	>99	200	—	—	>0.1	100	Large
ESP	<2.0	>0.25	>99	200	—	0.2–1.2	0.5–3.0	5–1000	Large

8.8 Valves and Mountings

Valves, mountings, and fittings are the auxiliaries in the steam and water circuit. The mountings and fittings are the mandatory safety devices specified by codes for permitting a boiler to steam. These are

- Main steam stop valve (MSSV)
- Nonreturn valve (NRV) on steam line
- Safety valves (SV)
- Blow-down valves
- High–low water-level alarms on steam drum
- Water-level indicators (WLI) on steam drum
- Pressure gauges on steam drum and SH

Valves on a boiler are mainly for start–stop service of steam and water. Control valves (CVs) are only for regulating the main FW and attemperator spray water. There is no direct regulation of steam in any boiler for output control, which is carried out only by regulating the FW. However, CVs are at times employed in steam circuits in applications such as drum attemperators where three-way CVs are used for dividing steam into the attemperator and bypass lines. Butterfly CVs are employed for larger sizes. Boiler valves are pressure valves and are governed by various ANSI or equivalent codes as listed below:

ANSI B16.5 for steel pipe flanges and flanged fittings

ANSI B16.11 for steel socket welding fittings

ANSI B16.25 for butt-welding ends (for pipes, valves, flanges, and fittings)

ANSI B16.34 for steel valves (flanged and butt-welding ends)

There are valves in oil and gas circuits for control and isolation functions, which are different in construction. Along with burner front piping, these oil and gas valve trains, mounted on suitable racks, are usually supplied by burner manufacturers. Ball, plug, and butterfly valves dominate oil and gas lines unlike the GGC valves (explained in the following text) in steam lines. Boiler steam and water valves can be classified into three types by construction.

1. Isolating valves form the bulk of boiler valves and are known as GGCs:
 - a. Globe valves
 - b. Gate valves
 - c. Check valvesdictated by the process-flow conditions.
2. Control valves are governed by both process and control considerations.
3. Safety and blowdown valves are specific to a boiler.

Forged steel valves. Valves of 50 NB size and below are of forged steel construction, and size is amenable to drop forging. Even larger valves are available in forged construction but are more expensive than cast steel valves. Forged steel valves, being denser in structure, have thinner sections and hence are lower in weight. Their higher cost, particularly in larger sizes, is many times justified, as the compact size and lower weight allow flexibility and shorter routing.

Butt-welded socket-welded, and flanged ends. Small forged steel valves of 50 NB and below are made with ends suitable for socket welding. For larger sizes, the valves are made with either flanged or welded ends, with the latter type most common. The leakage aspect is totally taken care of with butt-welded valves. They are also lighter, thus helping in flexibility. Flanged valves are preferred in some applications, particularly at low pressures.

Major valves have long delivery times and constitute nearly 80% by value:

- MSSV and NRV
- Feed stop and check valves
- Start-up vent and its isolating valves
- SVs on drum, superheater (SH), and reheater (RH)
- Continuous blow-down (CBD) and intermittent blow-down (IBD) valves
- Main, low-load, and start-up feed CVs and their bypass and isolation valves
- Attemperator control and isolating valves
- Circulating pump's isolating valves in water circuit on either side of the pump

In a variable-pressure boiler, the MSSV is not present but is merged with the main turbine inlet stop valve and located at the turbine end.

In HRSGs that have high pressure (HP), intermediate pressure (IP), and LP, the valves are repeated for each circuit. A large HRSG with 3P and RH is a veritable maze of valves of numerous types, sizes, and ratings.

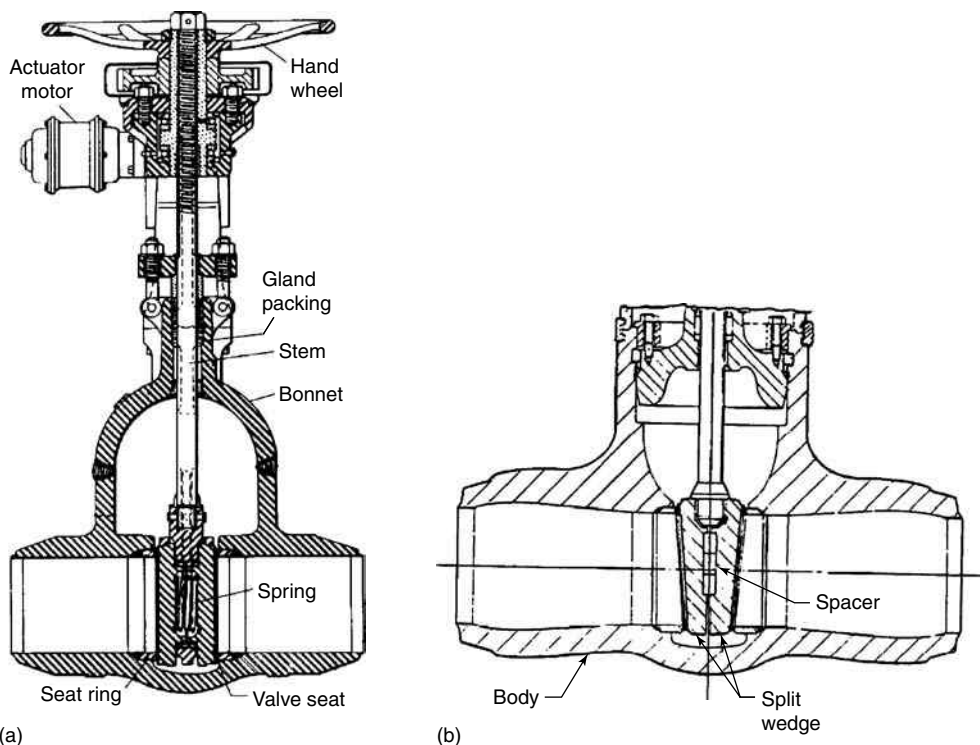
Constructional features and prominent characteristics of the major boiler valves are briefly described in the following sections.

8.8.1 Main Steam Stop Valve and Nonreturn Valve

A boiler MSSV is a heavy-duty isolating gate valve matching the NB of main steam line or a size smaller, with minimum pressure drop. It can be a wedge gate, parallel slide, or Venturi type (Figure 8.44).

- Wedge gates are preferred for low and medium pressures but not for large sizes to limit the forces on the disk. The tapered faces of the disk provide a positive sealing.
- Parallel slides have two disks forcing themselves on the two faces by means of a set of springs to provide sealing. But the real sealing force is exerted by the upstream steam pressure on the disk. The thin disks are more flexible and can withstand more temperature and pressure than gates but are costlier and demand more maintenance.
- In Venturi construction, the valve body has taper at inlet and outlet so that the actual sealing disk has smaller diameter than the parallel slide valves. Venturi is preferred for very large sizes, although more expensive to make and maintain, mainly to reduce
 - Pressure losses in valve
 - Maintenance caused by larger mating surfaces of disks and seats

Usually, MSSVs are motorized and butt welded, but in smaller low-pressure process boilers, they can be hand operated and flanged. It is normal to have an integral body

**FIGURE 8.44**

(a) Typical parallel slide and (b) wedge gate valves.

bypass valve of 15–25 NB (1/2 or 1 in.) size for pressure equalization upstream and downstream to permit easy opening of MSSV for sizes of 150 NB (6 in.) and larger. Motorizing of bypass valve and interlocking it with the main valve are common for large high-pressure boilers.

Main steam stop valves vary a great deal in size, from ~80 NB (3 in.) in small-process boilers to 600 NB (24 in.) or more in large utility boilers. The metallurgy, likewise, varies a lot from CS for steam temperatures up to ~450°C (842°F) to 1¼, 2¼, and 9% Cr AS for temperatures up to ~600°C (1112°F). ASTM specifications for CS castings and forgings are SA 216 WCB and SA 105, respectively. For cast AS, they are SA 217 WC6, WC9, and C12, whereas for forged steels, they are SA 182 F11, F22, and F91. For ss, it is SA 351 CF8M, whereas for castings and forgings, it is SA 182 Gr F316.

The sealing of a valve is achieved by bolting of the bonnet or by pressure sealing the parallel and wedge gate valve from inside as shown in Figure 8.44. Pressure seal construction is a more positive way of sealing, and it is smaller and lighter because the internal pressure is used for sealing. But it is sealed for life unlike the bolted construction, which permits inspection and access of valve internals when required. Pressure sealing is adopted for higher pressures.

A nonreturn valve in the main steam line is of swing-check design to limit the pressure drop (Figure 8.45). It is of the same size as MSSV. In the feed line, however, it is usually the lift-check valve (Figure 8.46), as more pressure drop is permissible. Sometimes the feed stop and check valves are combined into a screw-down NRV (SDNR). Metallurgy of NRV on steam lines is usually the same as that of MSSV. In the FW lines, it is normally CS.

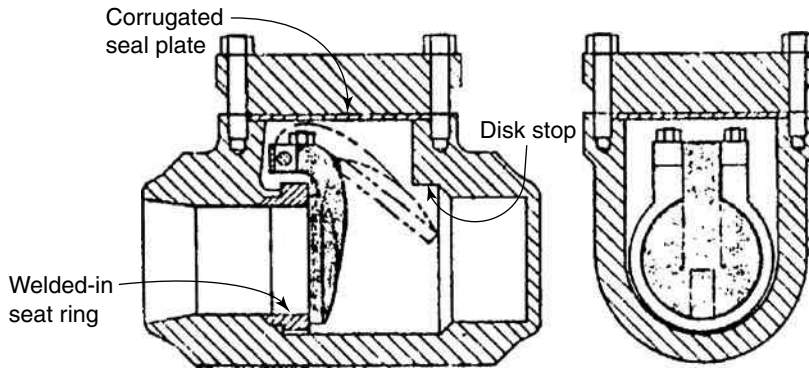


FIGURE 8.45
Typical swing-check valve.

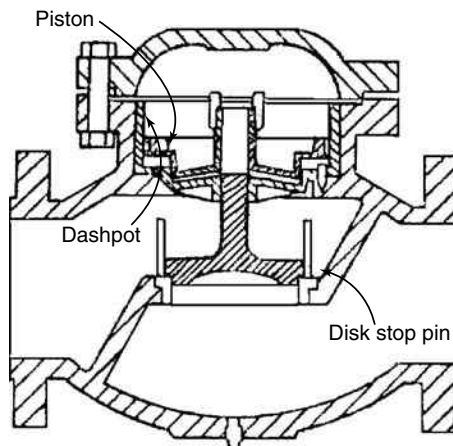


FIGURE 8.46
Piston check valve with dashpot.

8.8.2 Start-Up Vent Valves

These valves, located on the start-up vent line just ahead of MSSV, are motorized globe valves used during the boiler starting. The vent line, leading to the atmosphere, is opened at the boiler startup for

- Inducing part steam flow (25–50%) in the SH so that the SH tubes can be kept cool with steam flow
- Raising the steam temperature rapidly to the desired range for admission into the turbine

The vent line is closed once the steam is admitted into the turbine. A globe valve that can permit a large pressure drop across itself is adequate. The material of construction of the start-up valve is usually the same as that of the MSSV.

8.8.3 CBD and IBD Valves

Blow-down and IBD valves are used for continuously controlling the silica in steam drum and periodically disposing of the sludge from bottom drum/headers, respectively. Therefore, the construction of the two valves is entirely different. The CBD valves are micrometer valves, that is, globe valves with elongated plugs, amenable to fine control and motorization. The IBD valves are usually quarter-turn quick-opening valves with high lift to permit effective flushing of sludge. Both CBD and IBD valves operate at the saturation temperature and are made of CS (Figures 8.47 and 8.48).

8.8.4 Safety Valves

Safety valves are the most critical from the view of safety. Naturally, the boiler codes set fairly stringent norms for selection, sizing, and approval of these valves. There are three types of valves for pressure-relieving duties, as per ASME BPVC on equivalent codes. All are actuated by the upstream static pressure.

1. *Safety valves* are characterized by full and instant lift from the seat to permit full-steam relief on crossing the set pressure. These valves are used in vapor and gas service.
2. *Relief valves* have progressive lift (proportional to the overpressure). These valves are used in liquid service.
3. *Safety relief valves* can be used for water or vapor/gas service.

An SV is a glandless valve.

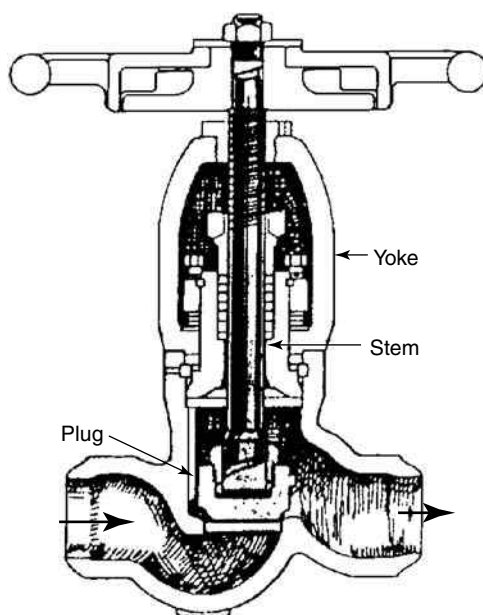


FIGURE 8.47
Hand-operated globe valve.

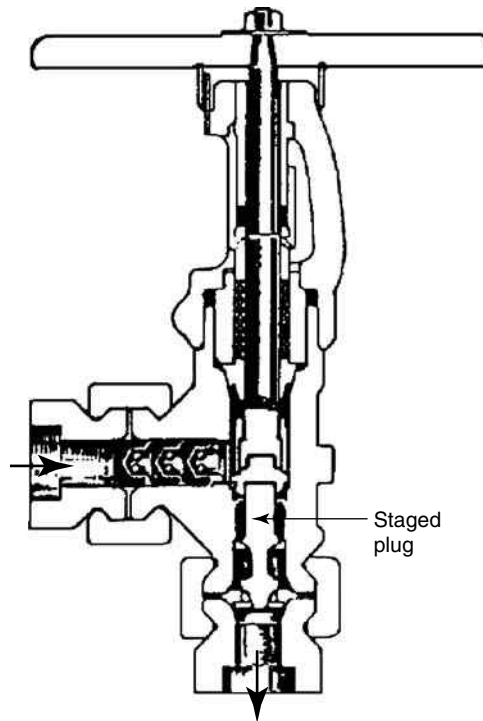


FIGURE 8.48
Typical IBD valve.

The following principles of sizing SVs are stated generally. The individual boiler codes contain exact rules and must be consulted for each case.

- The boiler and SH SVs should be so sized that the combined relieving capacity of all the valves should exceed the boiler evaporation.
- In WHRBs and HRSGs, the relieving capacity of the SVs should also adequately cover for the additional steam generation by the supplementary firing.
- Safety valves on SHs should be sized for 20–30% relieving capacity such that, with the flow through the SH, the tube metal temperatures stay within limits.
- Drum must be provided with at least two SVs.
- Safety valves on RHs should be sized for relieving the entire RH flow.
- For RH, most SVs are provided at the inlet due to the lower sizes resulting from a lower temperature. However, one or more SVs of not <15% RH flow are required at the outlet side to provide steam flow through the RH and prevent the tubes from overheating.

The blowdown and overpressure are the two parameters of the SVs that affect the boiler design pressure, which, in turn, affects the scantlings and boiler feed pumps (BFPs). There is a progressive reduction in both over the years.

- *Set pressure* of an SV is the pressure at which the SV pops open to relieve the pressure.
- *High* and *Full* lift SVs are two types classified by the lift of the valve. Full-lift valves have greater lift than high-lift valves. For the same size, therefore, the full-lift

valve gives more discharge than the high-lift valve, thereby reducing the number of valves.

- *Overpressure* is the maximum attained by an SV when it is blowing. It is expressed as a percentage of the set pressure, and the codes define the permissible value. ASME limits set pressure to 3%. Other codes are known to permit even 10%.
- The codes define the limit for the reseating pressure after the blowing is complete. The difference between the reseating and the set pressures is called the *blowdown* of the valve. ASME limits blowdown to 2%. Other codes permit a variation as high as 10% for lower classes of SVs.

It is important to have a lower blowdown so that the boiler design pressure can be reduced, with the attendant lower thickness of the PPs and feed pump power. Note that the boiler design pressure is the highest drum SV lifting pressure determined by adding a margin over the sum of the SV blowdown and the drum operating pressure.

- Of the three types of SVs—*spring-*, *torsion bar-*, and *pilot-operated*, spring-operated SVs are the most popular (Figure 8.49a). The others have lower blowdown and are used in very large utility boilers.
- Safety valve design should ensure that the steam pressure at the discharge flange of the SV is $<25\%$ of the set pressure.
- Safety valves on the drum are of CS whereas those on SHs and RHs can be either CS or AS, depending on the temperature of steam to be relieved. Their relieving capacity for the same size is less, as the steam in the SH condition has greater specific volume.
- Safety valves require a great care in installation and operation. The seat and the disk should not be subject to scouring due to foreign particles lest the valve should leak.

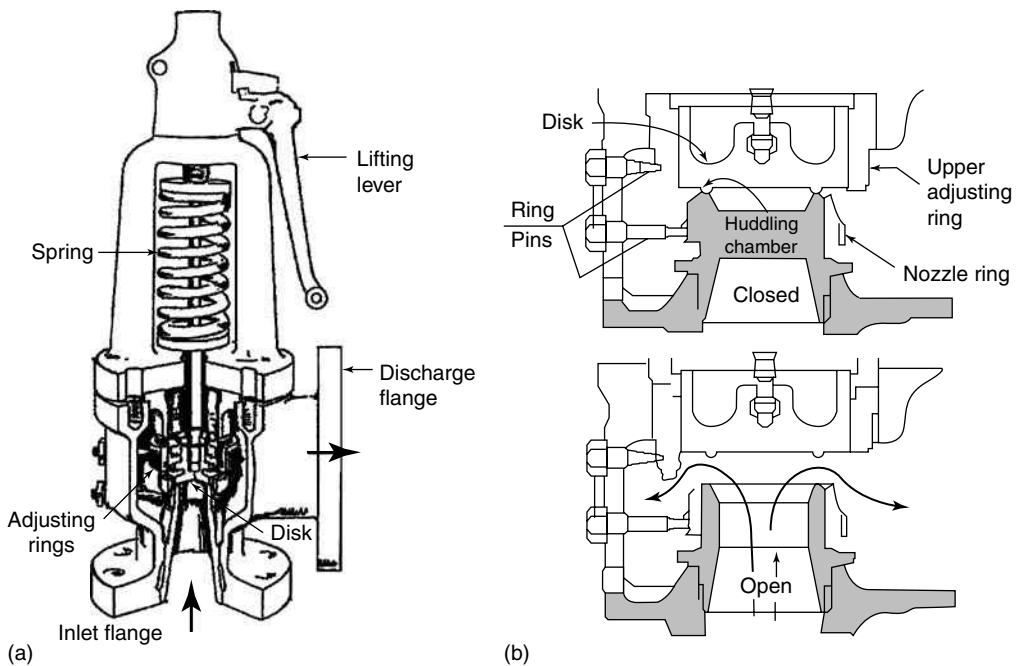


FIGURE 8.49

Spring-type safety valves with valve and disk in open and closed positions.

Hydrostatic plugs are to be placed at the inlet during any hydraulic test to prevent damage to valve internals due to the ingress of water. Frequent lifting of SV surely leads to leakages calling for boiler stoppage for seat lapping and reassembly.

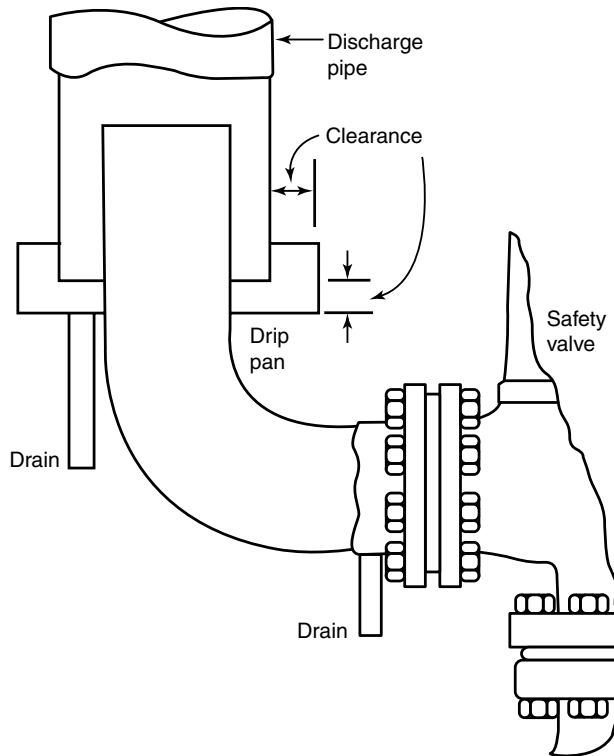
- There are no glands in an SV, and all the internals are made from stainless steel with mirror finish to provide high-quality alignment and ensure accurate and perfect pop action while lifting and reseating. The SV blowing (and reseating pressures) and blowdown are set by the manufacturer in the presence of an inspector, and the rings are locked in position, requiring no further adjustment at site. Some valve designs have a provision for adjusting the blowdown at site by means of upper and lower adjusting rings, as shown in Figure 8.49b.
- *Chatter* of an SV is a repeated lifting and reseating of the valve caused mainly by faults in installation or a long inlet pipe or faulty discharge pipe system. The SV chatter inevitably leads to valve leakage, needing a lapping of the seating surfaces to restore the tightness.
- Spacing of SVs must be correct to prevent the discharge forces from interfering with each other.
- Likewise, the discharge piping must be installed properly to lead the discharge steam safely to a suitable location, which is many times to the boiler roof. The discharge pipes or SV escape pipes are rigidly tied to any nearby boiler column, whereas the SVs located on drum or piping have their own thermal expansions. Suitable expansion chambers between the SV discharge elbow and the escape piping are essential to eliminate stresses due to differential expansion between the fixed escape piping and the moving SV. The expansion chamber should be provided with a suitable drain (Figure 8.50).
- Safety valve inlet nozzle length should be as short as possible to minimize the pressure loss, which can lead to chatter. SVs are usually directly mounted on drums or pipes. Pressure drop to the inlet has to be <50% of the SV blowdown. There is an upward force created as steam takes a turn inside the valve, which imposes stress on the drum and piping. To avoid the extra stress on PPs, the SVs can be located at some distance and rigidly supported on structural members. The inlet piping must be carefully sited and the set pressure of SV has account for pressure loss in the inlet pipe for a proper operation of the valves.

Electromatic SV. Considering the inevitability of SV seat leakage after a few lifts, it is a normal practice to install an additional electrically actuated SV on SH header, which operates first and prevents the main SVs from operating. This valve is provided with an isolating knife gate valve, which permits on-line maintenance. The discharge from this valve is not added to the relieving capacity of the other valves and is not covered by the boiler codes.

8.8.5 Drain and Vent Valves

These valves form nearly 80% of the total. Sizes of 40, 50, 63.5, and, at times, 80 NB (1½, 2, 2½, and 3 in.) are used. Various designs and practical aspects of the drain and vent valves are briefly discussed below. At different locations, they have different roles to play.

- Carbon steel predominates except for draining and venting of the SH and RH where the drain and vent valves can be of CS or AS.
- Usually, the valves are made of the same material as the header to which they are attached.

**FIGURE 8.50**

Drip pan and safety valve in discharge piping.

- The drain valves of the water walls and ECONs must be firmly closed during the boiler operation and opened only for draining during shutdowns. These group of valves are always hand operated.
- The drain valves of the SH, RH, and SBs are normally motorized for operator's convenience except in very small boilers.
- The vent valves are always motorized in medium and large boilers due to the remoteness of their location.
- Both drain and vent valves are of globe construction. Both experience high pressure drops and velocities, making them vulnerable to wear due to wire-drawing effect. For frequently operated valves, it is normal to provide a martyr valve of the same size and construction ahead of the main valve. The martyr valve is normally operated, whereas the main valve stays open, so that the martyr valve is sacrificed and main valve stays intact. When the martyr valve starts to pass, the main valve is operated until the next shutdown, and thus frequent boiler shutdowns are avoided.
- The drain and vent valves in ECONs and evaporator headers and the vents on the drum are mostly of 40 or 50 NB and SH drains, the final SH drain in particular, are larger.
- During startups, the final SH drain is used for inducing a flow through the SH to keep the tubes cool. Typically, they are sized for a flow of 10–15% MCR.
- Vent valves permit air escape so that pressurization of the boiler can begin. Air vents must have silencers of suitable size.

8.8.6 Control Valves

Control valves in a boiler are located only in the FW circuit and hence are low-temperature valves requiring CS. Attenuator spray CVs, dealing with not more than 10% of FW, are much smaller than feed CVs in a boiler, but of similar construction. Some codes insist on attenuator and its isolating valves and piping designed for the same conditions as the steam line on which they are mounted, assuming the worst case of steam flowing back to a closed attenuator line. AS valves of appropriate rating are then required. Single-seated CVs with low leakage are the normal choice.

Control valve construction. Normal CVs can be considered as improved globe valves with definite flow versus pressure drop characteristics made possible by the special shape of the *trim* (valve and seat assembly). Flow characteristics are usually linear, equal percentage, and modified parabolic in which a unit change in lift produces a flow change of constant unit, constant percentage, or a combination of both, respectively. This is shown in Figure 8.51.

The trim is made of superior alloys to withstand erosion due to *wire drawing*, the cutting effect produced by high-velocity fluid stream resulting from a high pressure drop in the CV. Usually, the trim material is the martensitic ss to ANSI 420, which is machined and hardened to RC 43 to 47. Feed CVs (FCVs), in many cases, are required to generate low noise level, which is possible by reducing the fluid velocities inside the CV. Several valve trims are possible, some of which are shown in Figure 8.52.

Cavitation needs to be avoided at all costs in the FCVs. When the liquid pressure drops abruptly and dips below the vapor pressure of the liquid at the vena contracta, bubbles are formed in the flow stream, which, on pressure recovery, collapse with great violence. The forces released on the collapse can cause serious damage to the valve and the seat, resulting in the formation of pits or cavities, with shortening of the life of the valve. This phenomenon with attendant forceful breakdown of the bubbles, is *cavitation* as shown in Figure 8.53. Cavitation is avoided by a progressive reduction of pressure in place of abrupt reduction and preventing low pressures at vena contracta that can induce formation of

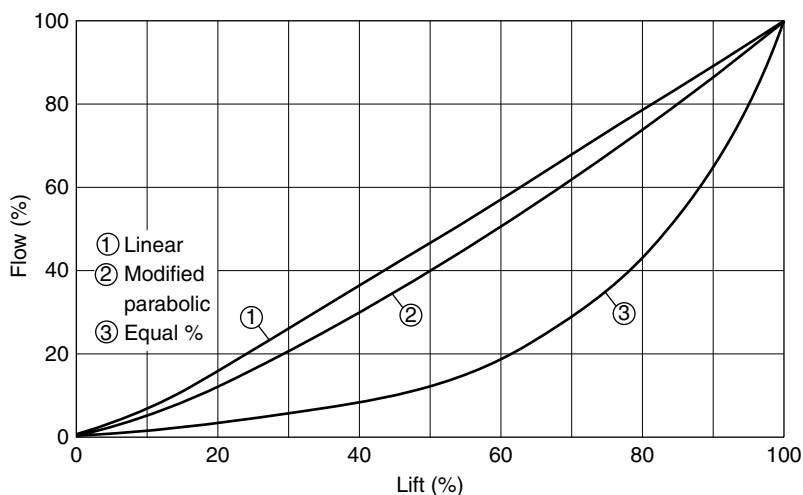


FIGURE 8.51
Flow versus lift for various types of trims.

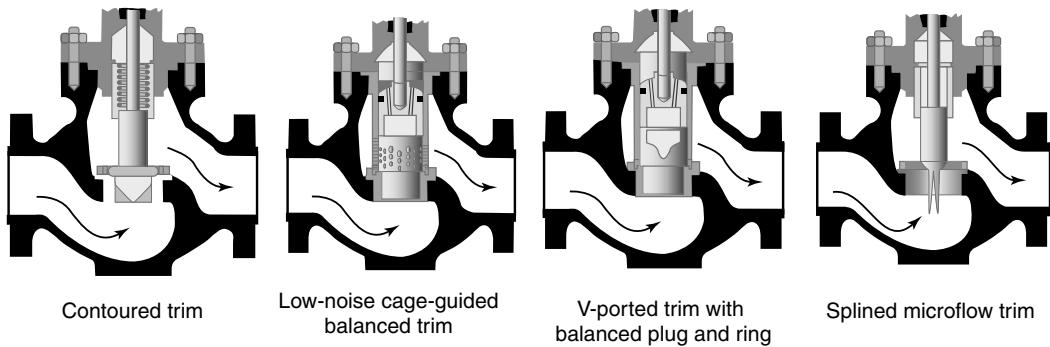


FIGURE 8.52
Control valves with different trims.

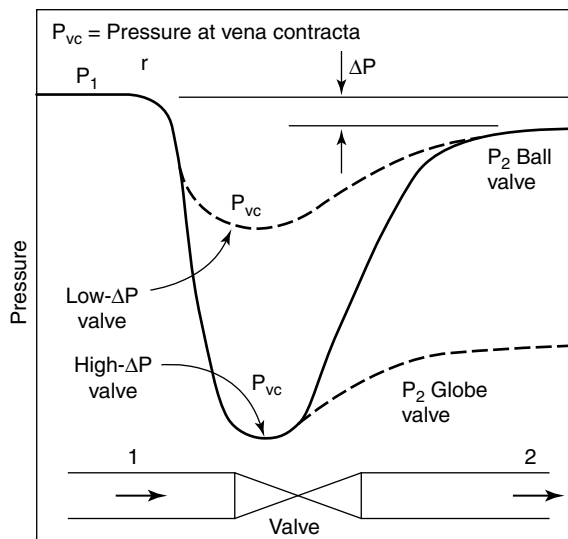


FIGURE 8.53
Pressure reduction and recovery in a flow stream.

bubbles. Pressure recovery depends on the valve design. Ball and butterfly valves produce better pressure recovery than globe valves.

Control valve leakage. Seat tightness is an important feature of CVs and is classified according to ANSI B16.104 citing six classes of seat leakages ranging from 1 to 6 with increasing seat tightness.

Control valve actuation. *Diaphragm-operated* CVs (Figure 8.54) for feed and attemperator are used in the normal mode of actuation. In large boilers when the required diaphragm size is too large, *piston-operated* valves are employed. For attemperator duty, diaphragm valves are adequate. The main FCV is usually pneumatically actuated, with an identical electrically actuated CV as a standby, ready to be pressed into service if the compressed air fails. In small boilers, a start-up feed valve of 10–15% capacity is provided parallel to the FCV for boiler filling and start-up duty. In medium and larger boilers, it is customary to have a separate boiler fill pump along with valves and have the low load running up to 30 or 40% MCR with low-load valves, which cut in and out automatically based on the flow.

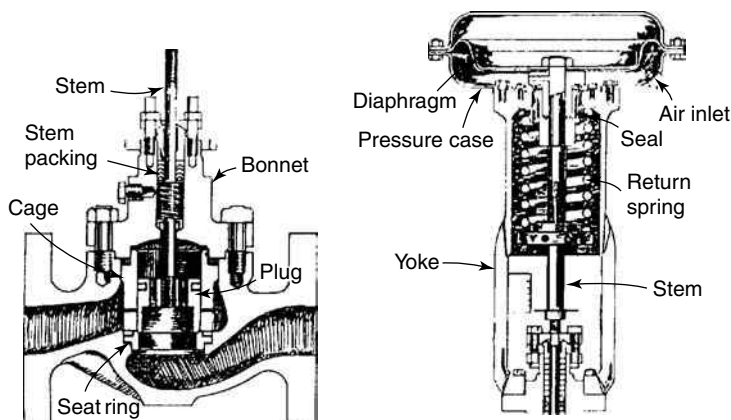


FIGURE 8.54
Typical control valve and diaphragm actuator.

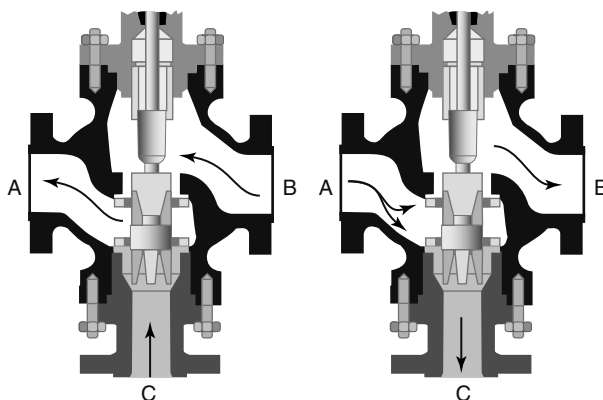


FIGURE 8.55
Three-way mixing and diverting valve.

Control valve size. CVs are usually chosen one size lower than the line in which they are located for better controllability. There are gate valves for isolation both upstream and downstream for on-load valve removal for maintenance.

Three-way valves. In drum-type attemperator control, steam flow is divided between flow through drum and bypass, which is done by three-way CVs or a pair of butterfly CVs when the flows are larger. Three-way valves can be used for diverting or mixing duties as illustrated in Figure 8.55. Suitable trim is selected depending on the flow requirement.

Attemperator spray CVs. Integrated attemperator CVs (Figure 8.56), combining the functions of the spray nozzle and CV, are used because the spray remains fine over the whole range of operation because of multiple nozzles that are brought into action one by one as the load increases. Since the water particles are very fine, there is no spraying in the thick pipelines; hence, there is a need for an SS sleeve downstream of the attemperator. The straight distance requirement of the steam pipe is also relaxed. The arrangement can be more compact, and the instrumentation also can be simpler. The turndown on steam side can be 10:1, whereas on water side, 300:1 gives a much wider range for operation.

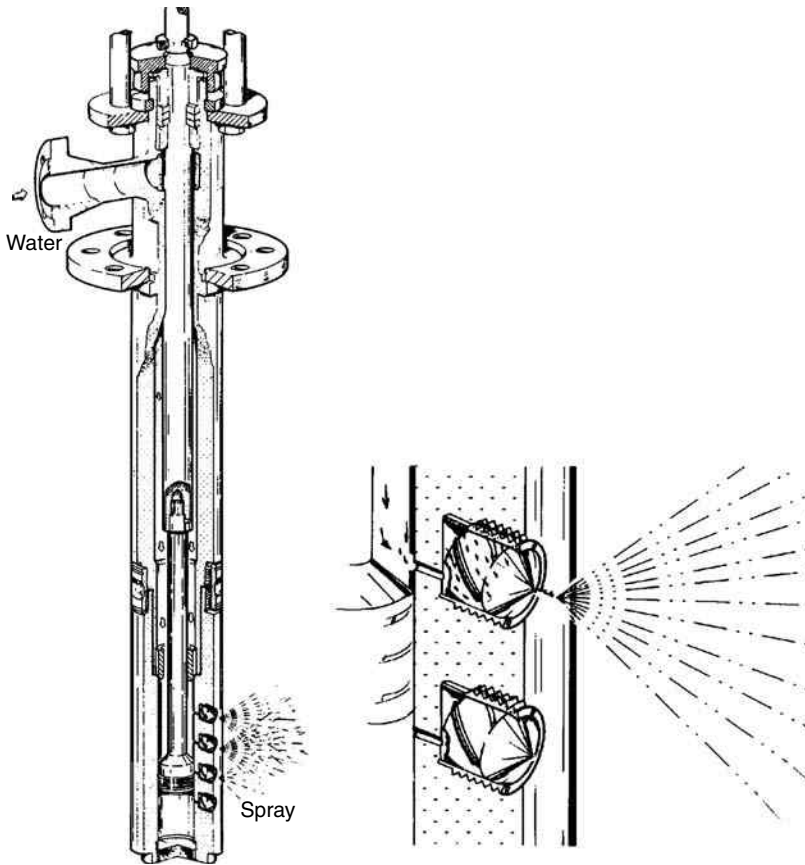


FIGURE 8.56
Integrated attemperator spray control valve.

8.9 Soot Blowers

Soot blowers are installed in most boilers for the removal of entrained soot and ash susceptible to slagging and fouling. Natural gas (or such clean fuel)-fired boilers are exceptions because there is no ash in the fuel to deposit on the HSs. Soot blowers remove.

1. Soot and ash deposits from the fire sides of HSs so that they remain optimally clean and heat transfer is maintained at the original design levels
2. Ash deposits from the gas passages between the tube rows so that the gas side pressure drops stay within the design limits

The overall cooling of flue gases and gas pressure drops stay close to the original figures to maintain the performance. Besides ensuring a proper heat transfer, the progressive pluggage of gas passes is avoided. Plugged sections lead to gas flow restrictions causing (1) load limitation and (2) tube erosion in the lanes where the gases flow at increased velocities.

Larger boiler sizes require more blowers. High-ash coal, lignite, and BL recovery boilers require numerous blowers of all types. For blowing purposes, the entire set of blowers is considered as one lot and blown in one set sequence and never in isolation. Soot blowing is always in the direction of gas flow so that the ash is carried toward the banks that are yet to be blown. High-ash coals with low-ash fusion temperatures and high Na are the most difficult to clean.

Oil firing, with its low-ash content, produces thin water-soluble deposits in the furnace and friable ash deposits on the SH and RH. The furnace deposits are removed in annual water washing, and no wall blowers are needed. In the convection section, the deposits are sizable with high-vanadium oils because of the additives used for minimizing high-temperature corrosion. These deposits are easily removable by SBs.

8.9.1 Working Principle of Soot Blowers

Soot blower is a device that directs a stream or a number of streams of cleaning medium at the ash deposits so that they get dislodged by the impact of the jets. Called as the peak impact pressure (PIP), it is the energy at a certain distance from the nozzle of the SB. The PIP depends on the

- Nozzle size and configuration
- Fluid pressure and temperature

Soot blowers consist of four parts:

1. Nozzles for blowing the fluid
2. Element (or lance in longer SBs) for conveying the fluid
3. Drive system for rotating or advancing/retracting the element
4. Control system

Cleaning fluid in SBs can be steam, air, or water. Steam is the most popular and available.

- Steam for soot blowing should be dry under all conditions to prevent impingement of heavy water particles that can render serious damage by way of erosion or puncture.
- Saturated steam helps to deliver a high PIP. Ideally, there should be 10–20°C of superheat.
- Higher superheat is also employed. The steam gets lighter but the jet velocity increases, making the PIP higher and resulting in a better cleaning.
- The pressure of steam is first reduced in the poppet valve placed just ahead of the lance to restrict the blowing or nozzle pressure to <5–25 barg (~75–350 psig), depending on the actual configuration.
- Several stages of pressure reduction take place before the steam emerges at the prevailing draft inside the boiler setting. Steam from the nozzles is at supersonic velocity.
- A poppet valve has an adjusting nut for varying the blowing pressure, and each SB is set for the best result depending on the type of ash deposits. Tenacious

deposits need a higher pressure. For fluffy deposits, the pressure should be lowered to prevent tube damage.

- SBs are practically ineffective on any flowing low-viscosity slags, such as those found with oil firing, as there are no deposits to blow away.

Air is also used for cleaning; see Section 8.9.4. Compressed air at ~25 to 35 barg (~350 to 500 psig) is required for blowing pressures of 4–15 barg (~60 to 215 psig).

Water is used occasionally alone or in combination with steam or air. Water pressure required is 10–20 barg (~150 to 300 psig). Water is also occasionally injected into the retractable SBs to keep the lances cool. Such blowers require different types of nozzles.

The drive motors can be either electric or pneumatic, with the latter used in refineries and similar areas with stringent requirements of fire protection.

8.9.2 Types and Locations of Soot Blowers

There are basically four types of SBs: (1) wall/short retractable, (2) rotary, (3) retractable, and (4) rake-type blowers, meant for different parts of the boiler. Table 8.3 presents the main features of the SBs. Figure 8.57 shows the SBs in a PF boiler and their locations.

8.9.3 Boiler Firing and Soot Blowers

Not all types of boilers require SBs.

- Gas-fired boilers with no ash deposits have no blowers.
- PF boilers with coal burning at high temperatures produce molten ash that deposits itself at all locations, requiring blowers at all locations.

TABLE 8.3

Soot Blower Types and Characteristics

Type	Location	Temperature Limit (°C)	Material of Lance	Nozzles in Lance	Blowing Details	Steam Consumption	Approximate Blow Radius	Remarks
Wall	Furnace	NA		1 or 2 Average 25 mm Ø	1–3 rpm 360°	~3.5 Te/h 40–60 s blowing time	1.5 m nom. ~10 m ² cleaning area.	Mostly for pulverized fuel boilers. 200–300 mm travel.
Rotary	Boiler bank Economizer AH	1100	CS ≤ 500°C Cal 500–900 Fess ≥ 900°C	Many 6–10 mm Ø Average 8 mm	2–3 rpm ≤360°	~3.5 Te/h 40–60 s blowing time		Up to 7 m lance. Manual or motorized.
Retractable	Superheater and reheater	NA	CS T ₁₁ Fess	2 at 180° opposed or angled	1–5 m/ min 4–12 rpm	~3.5 Te/h or more >7 Te/h for heavy duty	1.2–2.7 m	0.6–17 m travel.
Rake	Fin tube economizer	530		Many sets	~1.5 m/min	3.5–4.5 Te/h normal		~Length × width = 5 m × 3 m

Note: Cal = calorised, Fess = ferritic stainless steel.

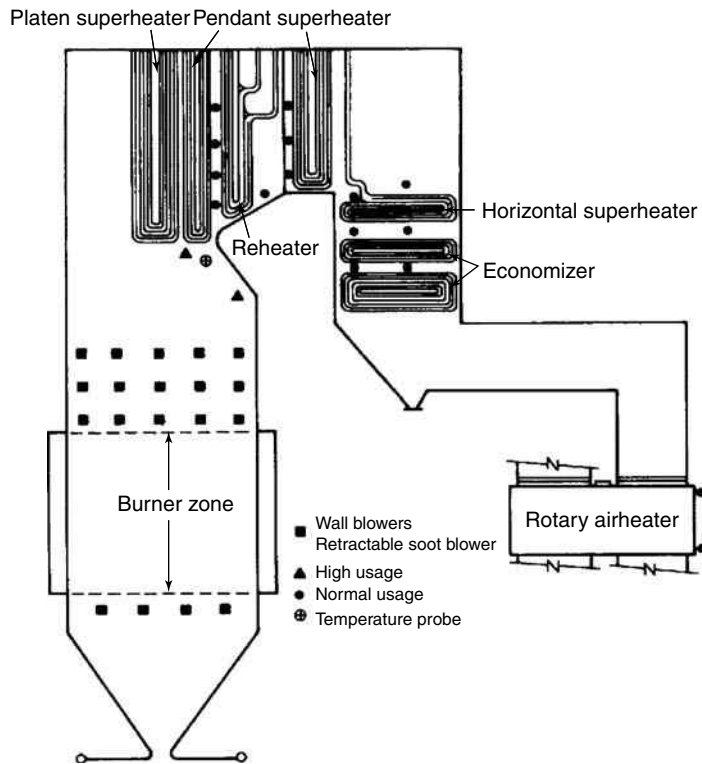


FIGURE 8.57
Soot blower locations in a large pulverized fuel boiler.

- Fluidized bed combustion (FBC) boilers, with low-temperature combustion, do not melt the ash and hence are free from the slagging and fouling problems of PF boilers. Naturally, they do not need SBs furnace and SH/RH regions. Some boiler makers install SBs in the ECON and AH areas, whereas the others increase the HS and dispense with SBs, as the deposits are dry, loose, and friable.
- Stoker-fired boilers operating with relatively lower furnace temperatures do not slag and hence need no wall blowers for coal or for biofuels. However, with combination firing of coal and biofuels, the melting temperature of ash eutectic is often low enough to warrant installation of wall blowers to clean slag deposits.
- Oil-fired boilers, with their closely spaced tubes in various tube banks must blow off the fine ash, and rotary blowers are usually adequate for this blowing. With heavy metals in ash, such as vanadium, which are in molten form at high furnace temperatures, retractable SB at a furnace exit is often required to keep the SH tubes clean. But at temperatures above 950°C, fuel oil additives are required to raise the melting temperature of the ash. Wall blowers are of no use as the ash is molten.
- Heat recovery steam generators are free of SBs despite closely spaced fins on tubes, because they usually fire clean fuels.
- Waste heat recovery boilers usually need SBs, as they deal with dusty process gases.

8.9.4 Steam versus Air

Steam is the most common blowing medium due availability. Compressed air can also be used as the effectiveness is nearly the same. Air blowing is considered when

- Steam and water leakage can be problematic as in the case of BL recovery boilers (due to smelt-water explosive reaction).
- There is a need to conserve the expensive-treated FW as in high-pressure boilers or in areas of high water shortage.
- The tenacious ash deposits require an almost continuous use of retractable SB, which consumes ~15 tph of steam, and the boiler steam production is not large enough. This is typically the case with some WHRBs.

In very large coal-fired boilers, air blowing is preferred as the soot blowing consumes high-quality expensive water. For air blowing, an elaborate arrangement consisting of a proper air compressor station to deliver high-pressure air between 25 and 35 barg (~350 to 500 psig), with all redundancies, controls, and safeties, is required, which is reasonably expensive. But the air piping is simpler and requires fewer valves and fittings.

The unique advantage of steam blowing is that any additional SBs required to be added are easily accommodated in steam blowing as steam is available.

8.9.5 Types of Blowers

8.9.5.1 Wall Blowers

Wall blowers, deslaggers, and short retractables, (Figure 8.58) are installed on the furnace walls for the removal of slag deposits. In high-temperature furnaces, such as in PF firing, where the furnace temperatures exceed the ash fusion temperatures and the ash is in molten condition, deposit formation on ash contacting the cool furnace walls is

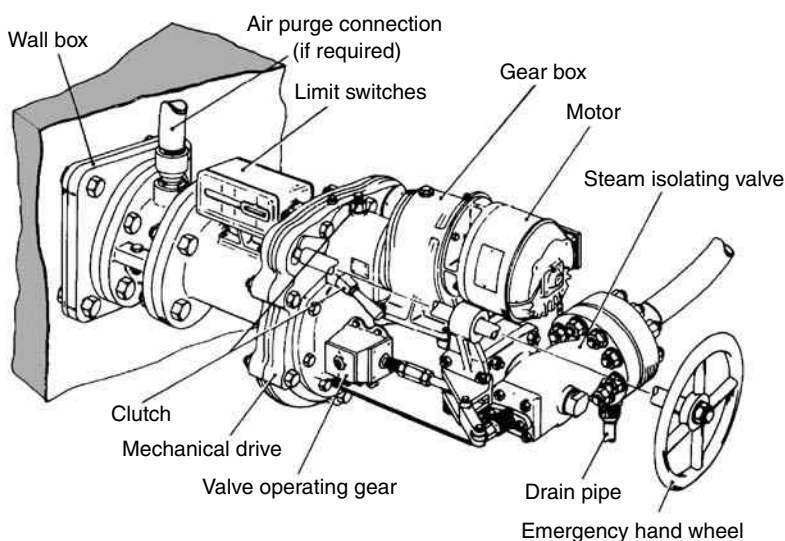


FIGURE 8.58

Typical wall blower/deslogger/short retractable.

inevitable and must be removed periodically; and wall blowers perform such duty. At the highest gas temperature, the blowers enter the furnace for a short distance of ~ 40 mm from the wall tubes and blow backward toward the wall. The total operation of wall blower lasts for <2 min of which the actual steam-blowing duration is less than a minute and the complete blowing consists of one to three revolutions. Steam flow at 3.5 tph (60 kg/min) delivered through one or two large nozzles of ~ 25 mm $\varnothing$ is sufficiently forceful to dislodge the semimolten ash. Depending on the type of firing, boiler size, fuel type, ash in fuel, slagging potential, previous experience, etc., a number of blowers are installed on a boiler furnace. Approximately one blower is required for every 10 m². The nominal blowing length is ~ 1.5 m, which is reduced to even 0.75 m in case of very heavily slagging coals.

8.9.5.2 Rotary SB

Rotary SBs (Figure 8.59) are employed in low-temperature and low-deposit zones where ash cleaning does not demand high-impact pressures from the jets. A typical rotary or stationary SB has a 40–80 mm $\varnothing$ lance with a number of small nozzles of 6–10 mm $\varnothing$ (average 8 mm) welded on it with steam blowing through them while the lance rotates. The lance is made of suitable metal to withstand the gas temperature. Unlike in retractable SBs, the lance in rotary SB does not rely on steam to cool it. As the maximum temperature limit is below 1100°C, rotary SBs are located mostly in primary banks of SH, BBs, ECONs, and horizontal AHs. Lance lengths are limited to ~ 7 m as the steam flow at the last nozzle beyond this length becomes too small to be effective. The rotary SBs are supported from the tubes at suitable intervals to prevent their sagging and hitting the adjacent boiler tubes. For boilers larger than 7 m, the rotary SBs are placed from both sides of the boiler. Rotary blowers can be manual or motor-operated.

Mass and lane blowing (Figure 8.60) are the two methods of steam blowing from rotary blowers. In mass blowing the tube spacing is wider, and there is a cavity large enough to

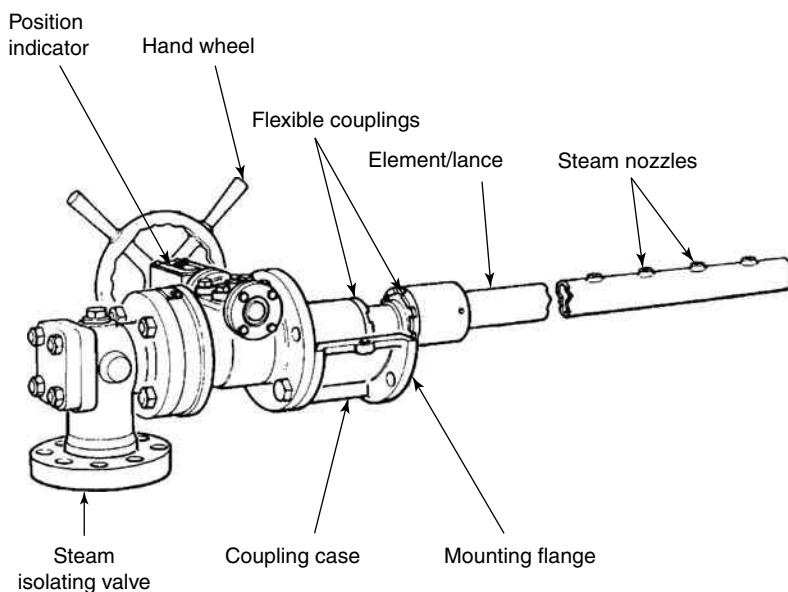


FIGURE 8.59
Manually operated rotary soot blower.

accommodate a certain distance from the tube surface. In lane blowing, the cavity is too small as in BB and the steam nozzles are set along the tube lanes. Lane blowing requires more and smaller nozzles. Also, the axis of the blowers has to be perpendicular to the tube axes. In mass blowing, the two axes can be parallel or perpendicular.

8.9.5.3 Retractable SBs

Retractable SBs (Figure 8.61) are the most advanced types based on performance and mechanical considerations. As the lances are required to clean the SH and RH platens and

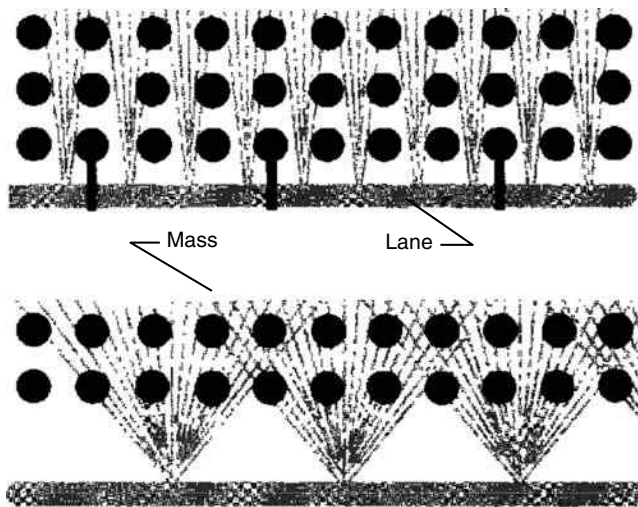


FIGURE 8.60
Lane and mass blowing.

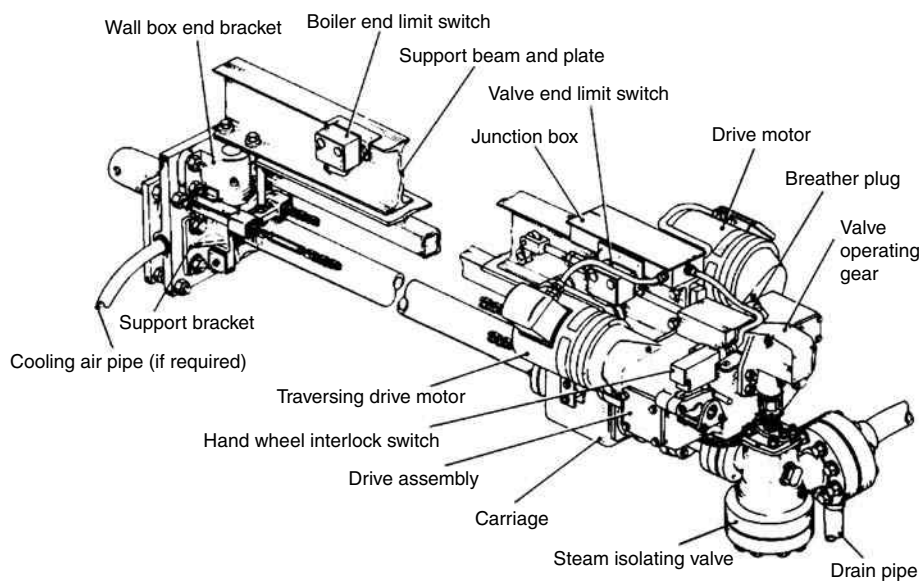
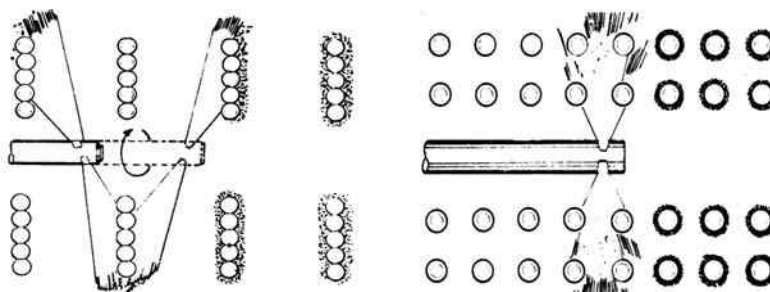


FIGURE 8.61
Fully retractable soot blower.

**FIGURE 8.62**

Soot blowing patterns for platens and pendants.

pendants in the highest gas temperature zones, they cannot be left inside the boiler as in the case of rotary blowers. They have to be fully retracted.

There must be a free space on the sides of boiler for retractable blowers, and the distance from the adjacent boiler is generally governed by this parameter. These blowers are motor driven with a back-up hand wheel drive to withdraw the lance from the boiler in case of motor failure, lest the lance should be deformed and damaged due to heat. There are usually two motors in every retractable blower, one for rotating the lance and the other for advancing or retracting the lance. The lance is a 60–80 mm diameter pipe with a pair of steam nozzles (to balance the forces) located on both sides in exact opposition or at an angle, depending on the cleaning required. The slanted holes are usually for platens as this can give a better dwell of the steam on the tubes. This is shown in Figure 8.62. The blowing pressures are 4–12.5 barg (~60 to 180 psig) for air and 5–25 barg (~75 to 360 psig) for steam with typical nozzle sizes of 16 and 22/25 mm Ø, respectively.

At the end of the travel, the lance is given an offset so that the return path is on a different helix for a more complete coverage of the jets. Typical helix patterns vary from 100 to 125, 150, and 200 mm (~4, 5, 6, and 8 in.) depending on the travel. The diameter and thickness of the lance and the support system should maintain straightness at the farthest travel lest the end of the lance should foul with the tube. Increasing the cavity between the tube banks is not possible. Very rigid construction of the SB is therefore needed.

The steam flow through a retractable SB is generally 4 to 20 tph. In other blowers, the duration of blow is much shorter at <1 min, and the flows are also smaller at <4 tph. If the steam flow from boiler is to be maintained, the boiler has to go into an overfiring mode to compensate for heavy steam flow through the retractable SBs, particularly in industrial boilers.

- A massive blow must be delivered to the sintered ash deposits in the SH and RH regions.
- Steam acts as a coolant to the lance that may be required to stay up to 30 min inside the hot boiler casing in large utility boilers. Many times the flow is decided more by cooling requirement than by blowing.
- For the platens located in the temperature zone, where there is more of slagging than fouling, the steam flow should be large enough to set the platens into a mild swinging motion to let the semisolid ash to drop off.

The rpm and translation (advancing and retracting) speeds of the SB are selected from previous operating experience to keep the lance cool. Typical translating speeds vary from 1 to 5 m/min (~ 3 to 15 ft/m). A combination of rotational and translation speeds along with helix distance delivers the appropriate cleaning force for each zone.

Half-retractable and one-third retractable blowers are also required for cleaning in the parallel passes during the second pass where the gas temperatures are low enough to locate the blowers inside the setting. Cleaning with two or three pairs of nozzles is far more powerful than that achieved by using many nozzles of rotary blowers. The blowers traverse half or one-third the distance.

8.9.5.4 Rake-Type SB

Rake-type SBs are used in the second pass of the boiler for cleaning the fin tube ECONs and vertical TAHs. Steam tubes with accurately located steam nozzles move on a track. The cleaning is far more efficient than with rotary SBs with better penetration. Rake length and width are usually limited to 5 and 3 m (~ 16 and 10 ft), respectively (Figure 8.63).

8.9.6 Rotary AH Cleaning

For small rotary airheaters (RAHs), one or two rotary SBs are fixed in the gas side of the AH at the gas inlet or placed additionally on the gas outlet side. For larger AHs in utility boilers, retractable SBs are installed at the inlet and outlet ends to provide deeper penetration of the steam jets for a better cleaning. Rake-type blowers are also used.

8.9.7 Water Lancing

With heavy slagging and fouling of coils, sometimes the SBs are not fully effective in dislodging the ash deposits. As a last option, lancing with high-pressure water is adopted, as water can deliver a better blow than steam. The water jets are directed to the ash deposits, carefully avoiding the tubes to prevent thermal shock and failures. Water lancing requires great precision.

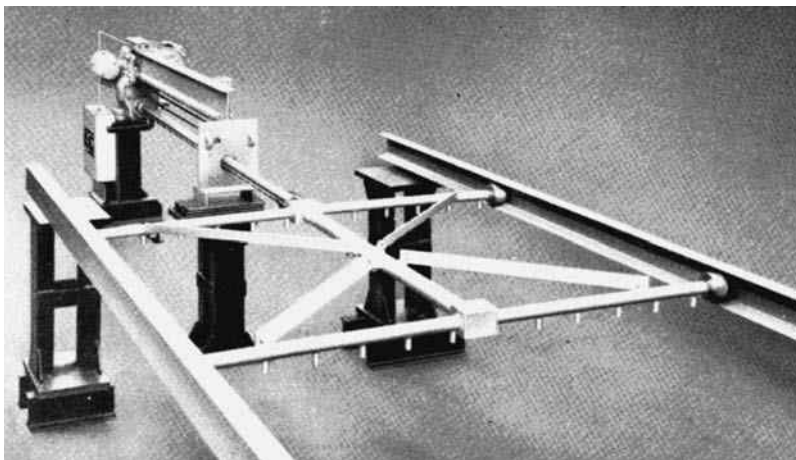


FIGURE 8.63
Rake-type soot blower for economizer and tubular airheater.

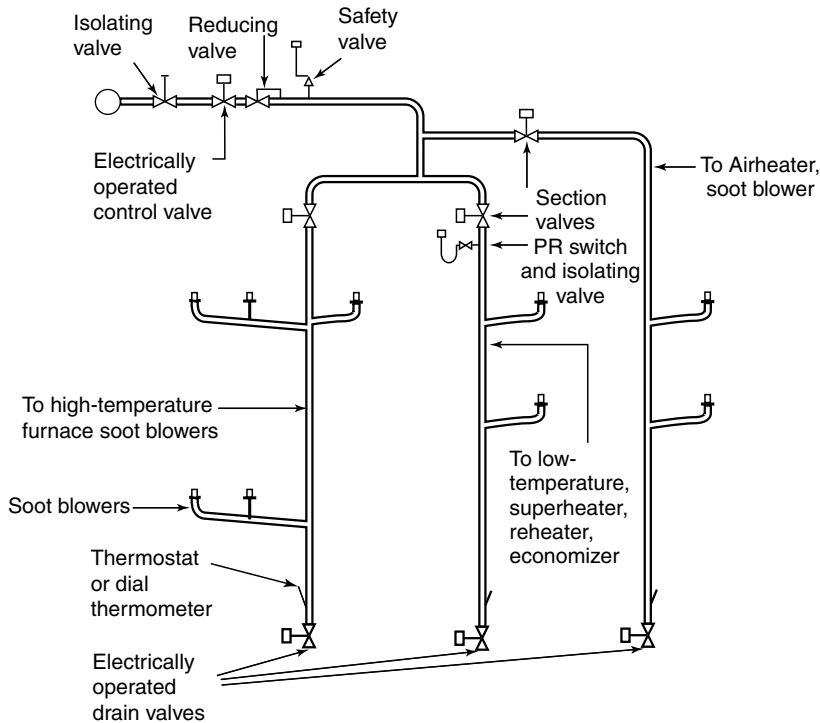


FIGURE 8.64
Typical piping for soot blowers.

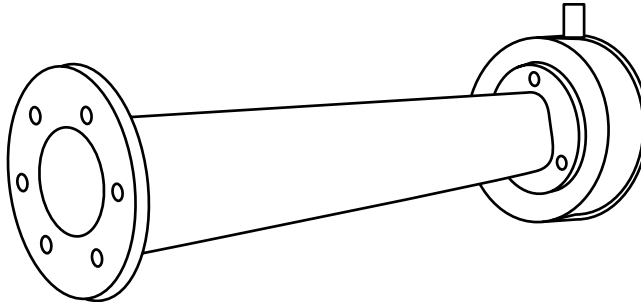
8.9.8 SB Piping

Figure 8.64 shows piping for SBs. A hand-operated isolating valve is always necessary to isolate the entire system for attending to any problem. A reducing valve, followed by an SV, is usually needed as the blowing pressures are lower than the steam pressure at source. The source can be the primary SH header, final SH header, cold RH line, or hot RH line. The choice is more complicated in boilers operating with variable pressures. Most boilers adopt the primary SH header.

Condensed steam in pipelines hitting the tubes and causing damage is a serious concern. All SB feed lines are given a slope of at least 1° in the direction away from the blowers. The blowers are branched off from the main pipes, which run vertically downward to the draining system, so that the feed tubes are free from water particles. Soot blower control logic starts with dry steam in piping for which the draining has to take place long enough for thermostat to give a reading same as the saturation temperature. Soot blower operation can commence only thereafter. The SBs are grouped and fed with pipes.

8.9.9 Acoustic or Sonic Soot Blowers

In *acoustic or sonic blowers* (Figure 8.65), sound waves are generated at low frequencies to produce rapid pressure fluctuations, causing vibrations in the ash deposits, which get loosened from the tubes and fall into the gas stream. They should not be too sticky or hard.

**FIGURE 8.65**

Wave generator and bell section of acoustic blower.

These blowers are ineffective over slagging or sintered deposits. Thus, the sonic horns are blowers for the second pass of the boiler for cleaning the dust from the low-temperature SHs, ECONs, and tubular AH.

A standard plant compressor generates the required compressed air to produce powerful sound waves as it enters the wave generator and forces the only moving part of the system, namely, the titanium diaphragm to create a powerful base sound wave that is transmitted by different bell sections to produce sounds of selected fundamental frequencies. Acoustic blowers consist of wave generators and resonance sections or an amplifiers.

Sonic SBs have the advantages of practically no maintenance, as there are no moving parts other than the diaphragm. The operation and installation costs are also low. Unlike the steam or air SBs, which operate with short bursts and high energy, the acoustic blowers operate with comparatively low energy levels but steadily because it takes time to resonate the ash deposits and dislodge them. This is better for installations with ESPs as the outlet concentration can be maintained with no objectionable spikes during soot blowing. Sonic horns are popular with CFBs, as the cleaning is required only in the second pass and the ash is usually in the form of loose deposits. They may not be suitable for high-moisture lignite-fired boilers where the moisture may help the ash to attach to the tubes.

Sonic blowers can also be employed in bag filters, ESPs, silos, and bins.

8.10 Water-Level Indicators

Water-level indicators (WLIs) or gauge glasses are installed on the boiler drums, deaerator tanks, and CBD tanks on the boiler island. Water-level indicators can be for direct or remote viewing, direct water-level indicator (DWLI) or remote water-level indicator (RWLI), respectively. As per ASME Section 8.5, the most important guidelines for WLI are:

- Each boiler should have at least one DWLI. This is not relevant to once-through (OT) or forced circulation boilers that have no fixed steam and water lines.
- For boilers with maximum allowable working pressure of >400 psia (~ 28 bar or ~ 3 MPa), two DWLIs are to be provided. Alternately, there can be one DWLI and two independent RWLIs.

- When two independent RWLIs are installed and are operating reliably, one DWLI may be shut off but kept in a serviceable condition.
- The lowest visible water level in a DWLI and an RWLI should be at least 50 mm above the lowest permissible water level. (This is usually upper end of the last downcomer tube.)

Boiler codes differ slightly in specifying WLIs, although the underlying principles are the same. Respective codes must be studied carefully before adopting the WLIs in any application.

Achieving drum water level indication is not particularly easy. With relatively small diameter drums used in modern high-capacity boilers, more accuracy is needed. The high pressures and temperatures in the drums, coupled with fluctuations, make the drum water level measurement much more difficult than in other containers such as tanks and silos. Direct and remote WLIs are the two broad classifications of gauge glasses.

Several types of WLIs are available.

8.10.1 Direct Water-Level Indicators

Direct water-level indicators are available in several designs. In small boilers with steam drum levels of up to 20 m from the operating floor, the drum water can be seen adequately with suitably illuminated reflex or bicolor WLIs. For a better viewing from a wider area, the level can be seen by providing a suitable enclosure and a pair of reflecting mirrors, called the telescopic arrangement. For bigger boilers with steam drums located at 50 m and above the operating floor, the DWLIs are too remote even for reflecting in mirrors.

Direct WLIs suffer from displaying a lower level than the actual level due to the density difference of water between the drum and the (thin) cooled water column of the DWLI. Typically, at 180 bar drum pressure, the level at the top of 200 mm water column displayed in the gauge can be lower than the actual by as much as 120 mm, depending on the ambient condition. Despite this disadvantage, the comfort it induces cannot be replicated by watching the level of an RWLI; hence, it remains as a reliable backup for RWLI.

8.10.1.1 Tubular Gauge Glasses

These glasses are the oldest and the simplest of the DWLIs employed for nontoxic and nonhazardous media and low pressures up to 15 barg (~220 psig). The gauge glasses are supported at their ends and are subject to bending which limits their use to low pressures. Also, the affinity of alkaline drum water to glass increases with the temperature (and consequently the steam pressure) and does not permit the use of plain glass beyond the low pressure. The breakage of gauge glass can be dangerous to the operators as the splinters can fly around. With clear water, the meniscus is visible only by the vibration of the column. A glass protector is usually used to improve the safety and visibility. Closed on three sides, the protector is a metal sheet with a thin black strip at the center, which gets magnified by the lens effect of water to improve the display. Figure 8.66 shows the tubular gauge glasses with and without the protector sheet. The plain gauge glasses are rarely used as they do not satisfy the safety and display requirements.

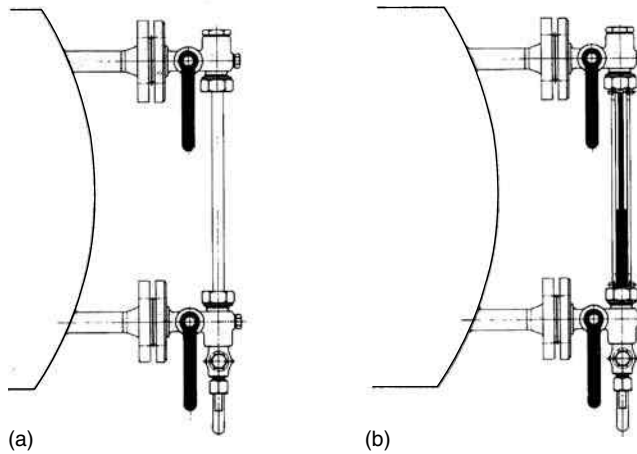


FIGURE 8.66
Tubular gauge glasses: (a) plain and (b) protected (up to ~15 bar).

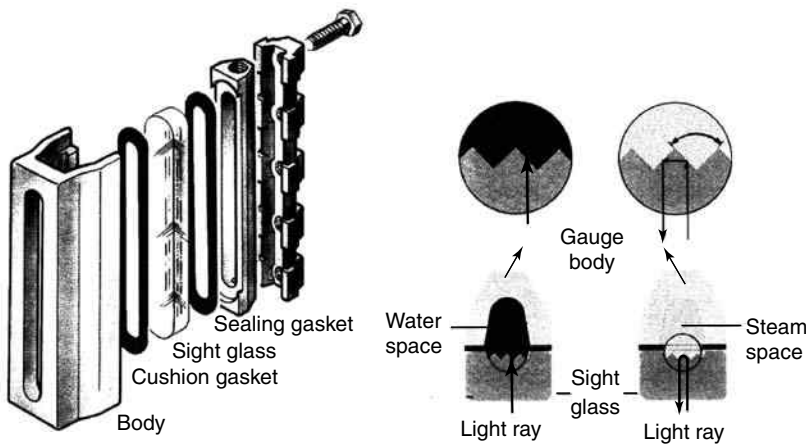


FIGURE 8.67
Reflex-type gauge glass (up to ~32 bar).

8.10.1.2 Reflex-Type Gauge Glasses

These glasses are employed up to a pressure of ~32 bar. The flat glasses are plain on the outside and serrated on the inside where there is contact with water. Owing to the difference in the refractive indices of steam and water, the incident light rays suffer reflection in steam space and not in water space as they try to pass through the 45° slanted surfaces of the corrugation as shown in Figure 8.67. The steam space appears as silver white on the transparent water space.

The affinity of water to glass is shown in Figure 8.68. The sight glasses in a gauge glass are subjected to mechanical and chemical forces. Chemical attack is determined by the alkalinity (pH value) and temperature (hence the pressure). More importantly, the condensation

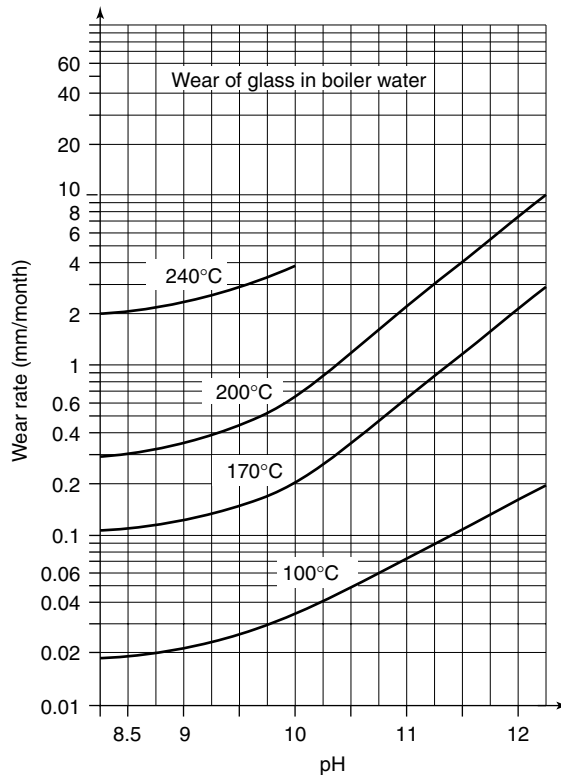


FIGURE 8.68
Affinity of water to glass.

of steam and its continuous running down on the glass create a constant abrasion, making the glass dull, obscuring the view and calling for replacement. In an unprotected glass, the steam pressure and alkalinity of water should be limited to 35 bar and 10 pH for the best economic life. For higher-pressure application, the glasses are protected with high-quality transparent mica sheet, which prevents contact of water with glass. The mica can be provided only for highly polished flat glass and not on a serrated surface of reflex glass. Reflex-type DWLIs are restricted for use up to ~32 bar. The glasses must be clear with no inclusions, should be thick (20–30 mm), and made of borosilicate to withstand use. They are heated, quenched, and tempered to case harden the top 3–5 mm layer and polished a high finish to offer a good view of the water level. In a bull's eye DWLI, the small glass plates are made of aluminosilicate to offer a better life. Glass plates are vital parts of gauge glasses, and require periodic replacement.

8.10.1.3 Transparent Gauges

Transparent gauges can be used up to 120 bar with a viewing distance of ~20 m at a certain angle. The water space is contained between two flat glasses shielded with mica sheets to withstand high pressure and illuminated at an angle from the rear. The light rays impinging on the water meniscus are reflected and therefore the viewer sees the water level in the illuminated gauge (Figure 8.69).

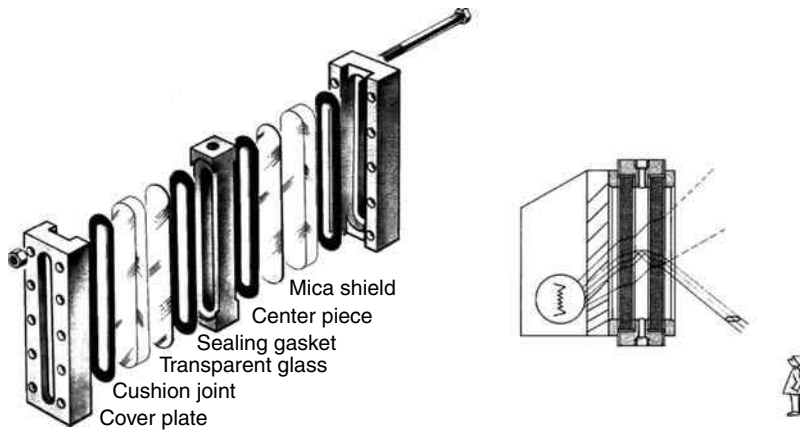


FIGURE 8.69
Transparent gauge and its action (up to ~120 bar).

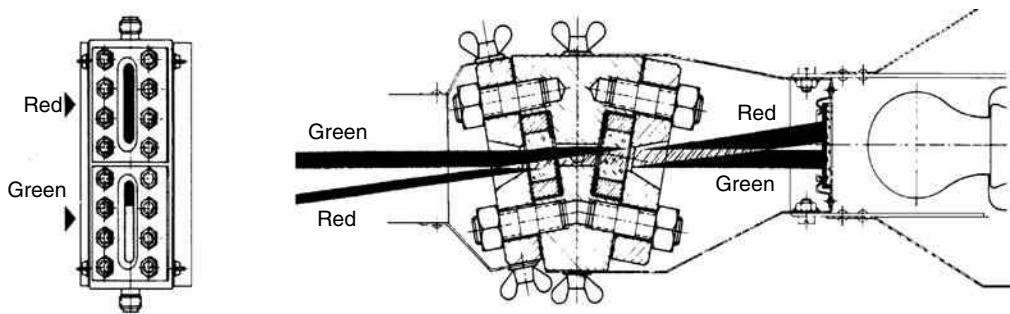


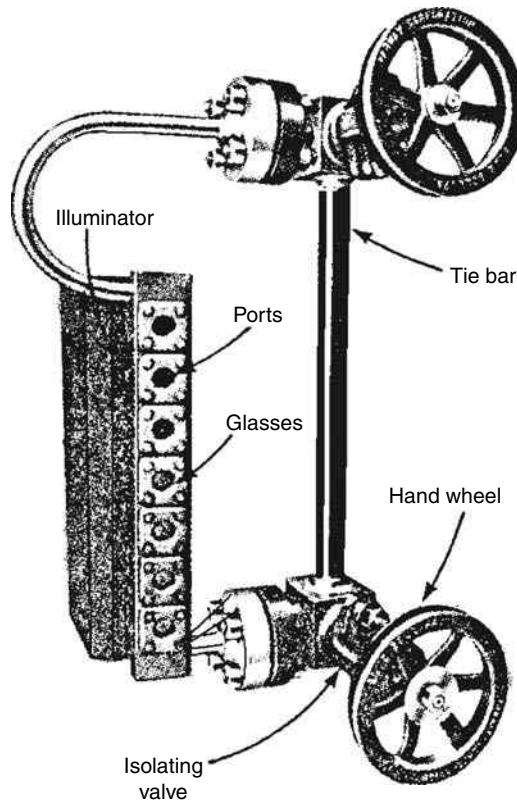
FIGURE 8.70
Bicolor gauge and action (up to 180 bar).

8.10.1.4 Bicolor Gauges

Bicolor gauges are built for pressures up to 180 bar. They are similar to transparent gauges but have wedge-shaped glasses to provide a differential expansion to light in steam and water spaces. There is an illuminator located at the rear side of the gauge with two color slides fixed in front of it—red and green. Seen from the front, red is to the left. Red light passes through the steam space and gets deflected sideways in water space and vice versa. The gauge needs to be mounted vertically and a set of mirrors are needed for remote viewing (Figure 8.70).

8.10.1.5 Port-Type Bicolor Gauge

These gauges are also called bull's eye types. They employ bicolor action with port-type glasses. These glasses are ~20 mm Ø and are held in thick-AS bodies to withstand higher pressure than possible with flat glasses. They are suitable up to ~220 barg (~3200 psig) (Figure 8.71).

**FIGURE 8.71**

Port-type bicolor gauge (up to ~ 220 bar). (From Tyco Flow Controls, U.S.A. With permission.)

8.10.1.6 Multiple Gauge Glasses

Multiple gauge glasses are employed for viewing level in larger vessels such as deaerators (Figure 8.72).

8.10.2 Remote Water-Level Indicators

Remote water-level indicators are of *manometric and electronic*, types with the latter becoming more common.

8.10.2.1 Manometric Gauges

These are simple, reliable, and inexpensive. Small changes in differential pressure caused by changes in the pressure head compared with a fixed column of reference can be transmitted to a pointer linked to a scale or to a remote indicator by means of an electronic or pneumatic transmission. The reference leg reading, which is subject to the density errors similar to the DWLIs, is compensated with a pressure-sensitive coil in the pneumatic version and a pressure transducer in the electronic version. Load changes cause swell or shrinkage to the water level, affecting the reference water column. A pressure and temperature compensation is necessary to correct the reading. The limitations of the manometric gauges are their slow response and difficulty in ensuring that the reference column is full (Figure 8.73).

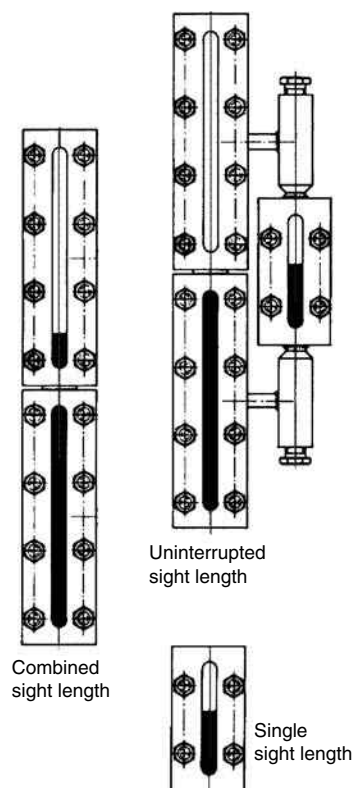


FIGURE 8.72
Gauge glass combinations.

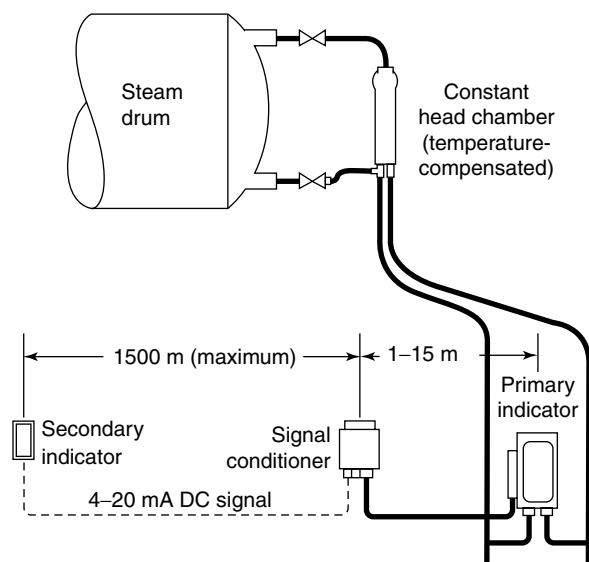
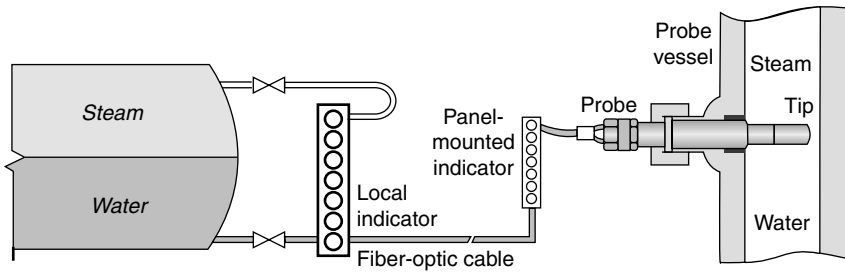


FIGURE 8.73
Schematic diagram of manometric gauge. (From Tyco Flow Controls, U.S.A. With permission.)

**FIGURE 8.74**

Schematic diagram of electronic remote water-level indicators along with probe. (From Tyco Flow Controls, U.S.A. With permission.)

8.10.2.2 Electronic Gauges

The most common types are conductivity electronic gauges. They work on the principle of conductivity of water exceeding that of steam. A probe vessel is mounted on the steam drum with several probes vertically at regular intervals. As the water level rises, the submerging probes make contact and complete the electrical circuits in sequence, lighting up indicating bulbs at the other end of an indicator. The added advantage of an electronic gauge is that at predetermined water levels, it can actuate fuel cutoff interlocks and alarms, which energize solenoid valves or motors controlling pumps. The probes are the most important components of the system. Figure 8.74 shows an electronic-type RWLI and conductivity probe.

Further Readings

ASME BPVC Section I for safety valves, WLIs and other boiler mountings.

Handbook of Fans, Buffalo Forge.

Makansi, J., 1986, Special report on particulate control: optimising precipitators and fabric filters for today's power plants, *Power*, December.

O'keefe, W., 1983, Special report on valves, *Power*, February.

O'keefe, W., 1984, Benefit from systems approach with today's safety valves, *Power*, January.

Power Plant Engineering, 1996, Black and Veatch.

Reason, J., 1983, Special report on fans, *Power*, September.

Special report on controlling particulate emissions, 1980, *Power*, June.

Weimar, P., 1980, Extend fan life with high performance materials that resist vibration/corrosion, *Power*, December.

Section III

Boilers and Firing

9

Industrial and Utility Boilers

9.1 Water Tube Boilers for Industry and Power

Water tube boilers are made

- From ~5 tph to ~4500 tph capacity
- At steam pressures ranging from ~3.5 to 320 bar
- At steam temperatures ranging from saturation to ~620°C

The lower end of the range up to ~400 tph is employed for its process steam, captive power, and cogeneration (cogen) needs. Beyond 400 tph, where reheating of steam becomes viable, boilers are mainly used for utility application. This dividing line is thin and tentative, and exceptions are found on both sides of this arbitrary demarcation. With cogen on the rise and very large plants gaining popularity, what a utility boiler was in the past has become an industrial unit today and this progression is only going to continue.

9.1.1 Characteristic Features of Industrial Boilers

- Variety of configurations are required to meet a wide range of steaming conditions and fuels.
- Fuels burnt include waste and manufactured fuels found in an array of industries and biofuels.
- These boilers are for meeting process steam requirements, captive power, or both (cogen). In cold countries, steam for district heating is another application.
- Steaming conditions are more modest, usually, with maximum continuous rating (MCR) <400 tph, superheater outlet pressure (SOP) <150 bar, and superheater outlet temperature (SOT) <565°C, with no reheat.
- Often multifuel flexibility is required to use the available fuels; optimize the cheapest fuel; use the fuel of the season, in case of biofuels; or increase the reliability of the fuel-supply chain.
- When used for generating captive power or in cogen mode, they are expected to integrate with the dynamics of the main plant seamlessly.
- The process leads and the boiler are required to follow. The boiler process control and the dynamics are aligned to match this requirement.
- Availability of the boiler plant is vital for the process industry, even at the cost of fractionally better efficiency. Multiple boilers of smaller size are many times preferred to large-sized single units for the sake of availability, even if this arrangement is more expensive.

Besides a steady degeneration of quality of prime fuels available to industry at competitive prices, there is an increase in waste fuels from industry, as process industries are becoming larger, more complex, and more varied. With greater attention that biomass firing is receiving, the range of biofuels turned over to boilers for cofiring is also increasing.

9.1.2 Characteristic Features of Utility Boilers

- They are optimized for best performance and highest reliability.
- Their fuel flexibility is rarely the prime consideration.
- They are made to the largest sizes that the grid can bear and to the highest steaming conditions that give the best efficiencies, so that the power generation is most reliable and least expensive.
- Their steaming conditions can be as high as MCR ~ 4500 tph, SOP up to ~ 320 bar, and SOT $\sim 620^\circ\text{C}$.
- Plant dynamics are governed by the grid fluctuations.
- Utility boilers come in relatively fewer configurations compared to the industrial boilers.

Large utility boilers based on oil and gas were built in the 1960s. Since then two unfavorable developments have taken place:

- The oil crisis of the early 1970s has made oil too expensive for power generation.
- The increased reliability of gas turbines (GTs) with exceptionally rapid growth in unit sizes has firmly driven out oil- and gas-based steam cycles in favor of combined cycle power plants (CCPPs).

Utility boilers for power today are based on coal when gas-based power is not viable.

TABLE 9.1

Industrial versus Utility Boilers

Parameter	Industrial Boilers	Utility Boilers
Purpose	Process steam, captive power, cogen, heating	Grid power
Steaming conditions	Generally <400 tph, no reheat, <150 bar/ 565°C	Generally up to 4500 tph with reheat, up to 320 bar/ 620°C
Fuels	All types—prime, waste, manufactured, and biofuels	Prime fuels—occasionally waste gas, petcoke, etc.
Multifuel flexibility	Yes	Very rarely
Firing	All types—burner, stoker, pile burn, BFBC, CFBC, PF boilers	PF, cyclone, and CFBC boilers
Type	Bidrum and single drum, bottom and top supported, package, and field-erected boilers	Single drum and no drum for once-through (OT) boilers. Top supported. Only field-erected boilers
Circulation	Mostly natural, sometimes forced	Natural, assisted, supercritical, subcritical OT
Dynamics	To suit process or captive or cogen power	To suit grid

Heat recovery steam generators (HRSGs) fall between industrial and utility boilers. They generate steam for driving turbines like any utility boiler, with the main difference in that they do not burn any fuel but use the hot exhaust gases from the GTs. In the largest sizes they have main and reheat steam temperatures of the same range as utility boilers and they even work on sliding pressure mode. Yet their pressures are no more than ~170 bar, and in size they are like large industrial boilers. They are like waste heat boilers receiving exhaust gases from GTs, and hence are considered slave units of a process. Large boilermakers, therefore, treat HRSG more as an advanced class industrial boiler for utility application. In fact, the HRSG is the only waste heat boiler of the utility market. Table 9.1 compares the industrial and utility boilers.

9.2 Industrial Boilers

9.2.1 Boiler Classification by Firing

9.2.1.1 Oil- or Gas-Fired Boilers

Oil- and gas-fired boilers are burner-fired and are amenable to extensive standardization because of a fair degree of uniformity of the fuel characteristics. The quick and relatively clean burning nature of the fuels makes them compact and suitable for full or part shop assembly, as in package or field-erected boilers, respectively.

9.2.1.1.1 Package Boilers

Package boilers are available for capacities up to 250 tph, with horizontal gas flow, bottom support, short drum centers, and extremely high heat release and absorption rates. These features allow such boilers to be compact and easily transportable on trailers or barges. Because of the horizontal gas flow, the package boiler design is more amenable to firing clean fuels such as gas and number 2 oil. One to four burners are always mounted on the front wall of the furnace. The furnace is arranged parallel to the drums and convection bank. Package boilers are shop assembled and sent to site where they are unloaded on a leveled, cemented floor requiring minimum foundation work. In developing countries, where transportation is expensive and labor costs for erection are low, the package boilers are often field erected with shop-made modules.

9.2.1.1.2 Field-Erected Boilers

Bidrum bottom-supported boilers for power and process steam are extensively standardized for capacities up to 450 tph. The flue gas flows up and down, permitting dusty and fouling oils and gases to be fired in these boilers. The burners are mounted on the front wall of the furnace arranged normal to the axis of the drums and convection bank, unlike in the package boilers where the furnace is set parallel to the drums. The modular designs of these boilers permit economical manufacturing and quick erection.

Single-drum design for oil and gas is the preferred configuration of many customers. Low water holding, less weight, and drainable SH in these boilers enable quick starts and shutdowns as required in two-shift operations. These boilers can be bottom supported for capacities up to 100–150 tph and top supported for larger sizes. There is a great flexibility in arranging the burners in these designs. They can be roof, floor, and sidewall or front wall mounted, depending on the desired SH characteristics.

All these boilers are more extensively dealt with in Chapter 10.

9.2.1.2 Stoker-Fired Boilers

Stokers, which were workhorses, have been severely affected by the rise of bubbling fluidized bed combustion (BFBC) boilers and the tightening of pollution norms on both SO_x and NO_x . They can be classified as

- Dumping grate stokers
- Chain grate stokers
- Spreader stokers (SS)
- Pulsating/reciprocating grates (PGs/RGs)

Bidrum boilers are the industry standards for pressures up to ~ 90 bar and the single-drum boilers for higher pressures of up to 150 bar. Bottom support is possible and economical up to ~ 40 to 60 tph. Stoker-fired boilers are more elaborately discussed in Chapter 11.

9.2.1.2.1 Dumping Grates

Dumping grates are used to burn fuels like bagasse and occasionally low-ash coal where steam pressure fluctuations and loss of green fuel during the stoker dumping periods are acceptable. The combination of suspension (with ~ 40 to 60% of heat release in furnace) and grate firing makes the dumping grates release much higher heat than gravity-fed chain grates. Dumping grates are very simple and inexpensive. No return strands make them very light, cheap, easy to maintain, and compact. Dumping effects get smoothened out as the number of grates increase in a boiler. Reasonably high heat-release rates, of ~ 70 to 80% of traveling grates, are achieved with bagasse and similar uniformly sized biofuels. Dumping grates are unsuitable for firing coal of medium-to-high ash or fuels with some clinkering tendencies, as there is no automatic discharge from the grates. Bagasse-fired boilers as large as 150 tph have been built with multiple dumping grates.

9.2.1.2.2 Chain Grate Stokers

Chain grate stokers have gravity feeding and burn fuel in a quiescent state. The fuel burns substantially on the grate, with only the volatiles burning in suspension. Burning rates are low and burning is slow. The grate and the furnace are large. As there is no agitation of the fuel bed to expose more surfaces, the ash in the fuel has to be low ($< 15\%$). This type of firing is yielding to SS and BFBC boilers.

9.2.1.2.3 Spreader Stokers

Spreader stokers (SSs) are the most versatile and feature

- The highest heat-release rates
- Continuous ash discharge
- Very good load response due to suspension firing
- Fully automatic combustion control
- Exceptional fuel flexibility
- Very good multifuel firing capability

However, they suffer from certain limitations, such as they cannot

- Burn high-ash coals ($> 35\%$ ash) efficiently because unburnt losses are high
- Effectively burn lignites of high moisture ($\sim 55\%$ and above)

- Deal with high sulfur in coal
- Produce low NO_x combustion to meet the emerging norms

BFBC boilers have largely displaced them with their

- Superior low-temperature combustion technique (with the resultant low NO_x)
- In-furnace desulfurization (making high-sulfur coals burn easily)
- Greater versatility with high-ash and inferior coals
- Practically no moving parts, making the operation and maintenance very simple

BFBC has progressively pushed SS firing to the burning of various biofuels. Biofuels have no sulfur and burn at low temperatures due to the high moisture in fuels. Such fuels do not lend themselves to burning in fluidized bed combustion (FBC) boilers satisfactorily and easily. Bagasse and biofuel burning is still an area where spreaders prevail.

9.2.1.2.4 Pulsating or Reciprocating Grates

Pulsating or reciprocating grates are ideally suited for high-moisture fuels like municipal refuse or very light biofuels. The reciprocating action of the grate bars helps in uncovering the fresh fuel and admitting air, thus improving the combustion efficiency. As the fuels are usually gravity fed on the grates, the heat release rates do not match those of the spreader since there is no suspension firing. Single or multiple grates in series can be used, depending on the fuel moisture. For municipal refuse, where fuel moisture can exceed 70%, a steeper grate is used for fuel drying, followed by a combustion grate at a reduced inclination. Continuous ash discharge, single strand of grate with no return section, and somewhat light construction are positive features of the PG. The sporadic agitation of the fuel bed on the grate, however, can contribute to clinker formation with coal. The reciprocating action of the grate bars in a PG may not be able to push and discharge the big clinker into the ash pit, unlike the traveling grate that carries it positively. The clinker, when it grows large enough to straddle two grate bars, merely rocks due to the reciprocating action, but does not roll down. This prohibits the grate from firing coals with medium and high ash.

9.2.1.3 Fluidized Bed Combustion Boilers

Characterized by low-temperature combustion and in-furnace desulfurization, an FBC boiler is a genuine breakthrough in combustion technology. Commercialized in the late 1970s in response to the tightening air pollution norms and escalating oil prices, the FBC boilers firmly established themselves by mid-1990s.

There are two types of atmospheric FBC boilers—BFBC and circulating fluidized bed combustion (CFBC) boilers, both of which are discussed in detail in Chapter 12.

9.2.1.3.1 Bubbling Fluidized Bed Combustion Boilers

Bubbling fluidized bed combustion boilers use evaporators and sometimes SH bed coils to contain the combustion temperature of the bed. The air velocities employed in the bed are between 2 and 2.5 m/s at MCR to expand the bed to ~1200 mm. At reduced loads, the minimum velocity required for fluidization of 0.8 m/s is always maintained. With abrasive fuels, the velocities are reduced to 1.5–2 m/s. The bed is composed of inert material or ash from coal and contains only ~3% of fresh fuel. Limestone is added to the bed if coal needs desulfurization.

The heat release in the bed is comparable to that in SS, and hence the footprints of the two match closely. Likewise, with a residence time requirement of ~ 2.5 s, the height of the BFBC boiler is only slightly lower than that of an equivalent SS-fired boiler. BFBC boilers, burning coal, are made to sizes as large as 150 tph, making them suitable for both process and power. With CFBC boilers in place to address the higher sizes, the BFBC boilers using coal are accepted up to 150 tph if the pollution norms are met. Large BFBC boilers of ~ 400 tph are common in Scandinavia and other pulp-producing countries where the process produces large amounts of sludge with high moisture. Heat in the bed helps in combustion of such low GCV fuel with high moisture.

9.2.1.3.2 *Circulating Fluidized Bed Combustion Boilers*

Circulating fluidized bed combustion boilers employ ash for cooling the bed, together with staged combustion, to contain the bed temperature and produce lower emissions. The limestone and fresh fuel are added to the bed, which is composed of inert material or coal ash. The residence times are higher (between 4 and 5 s) and velocities of fluidizing air are also more (at 4–7 m/s), making the boilers very tall and slender.

Compared with the BFBC boilers, the carbon burn-up and desulfurization efficiencies are better, load dynamics are superior, and reliability is higher (as there are no worn-out or punctured bed tubes to replace periodically) in the CFBC boilers. The economical range of CFBC boiler is above 100 tph and is going as high as ~ 1500 tph.

Circulating fluidized bed combustion boiler is seen as a potential utility boiler, rivaling PF, both in terms of efficiency and capacity. Many utility boilers are based on the CFBC principle, for fuels generally not burnable in PF firing with ease, such as petcoke with very high sulfur, anthracite, and so on. The fractionally higher power consumption and lower thermal efficiency of CFBC at the present stage of development places it unfavorably with respect to PF for conventional fuels and normal emissions. However, when fuels have higher S and the emission requirements are stringent, CFBC can work out to be more competitive with PF boilers having low NO_x burners and gas scrubbers.

9.2.1.4 *Pulverized Fuel Boilers*

Pulverized fuel-fired boilers have the highest combustion efficiency at $>99\%$ carbon burn up, fractionally higher than CFBC boilers. The power consumption is lower in spite of the additional milling plant. In terms of fuel flexibility, multifuel firing capability, low NO_x generation, and in-furnace sulfur capture, PF is much inferior to CFBC boilers. With over eight decades of service, PF boilers have burnt almost every type of coal across the world. In larger capacities, although PF is the choice in industrial range, CFBC is fast displacing PF. A conventional PF-fired boiler can be cheaper than the CFBC boiler for coal, but when low NO_x burners are required along with reduced heat load and deSO_x units are also to be added, the CFBC boiler works out to be more economical. It is a matter of time before PF firing exits industrial market altogether.

9.2.1.5 *Boilers with Pile Burning*

Pile burning is one of the early methods of firing, mainly developed for burning biofuel wastes such as wood bark, saw dust, wood shavings, bagasse, and so on. The method derives its name from the way the fuel is formed into a pile for burning. Horseshoe furnaces and pinhole grates (PHGs) are representative systems.

9.2.1.5.1 Horseshoe Furnace (Thick Pile Burning)

Fuel is gravity fed and dropped on the floor of the furnace in a conical pile. Hot air is admitted at three to four levels through air tuyeres formed in the brick walls surrounding the pile at temperatures ranging from 150 to 300°C. No air should enter through the floor, as it would escape from the edges of the pile and not participate in combustion. Combustion takes place on the sides of the pile. Brick walls arranged in a semicircular manner around the pile and the arches at the top of the pile have a very important role of radiating the heat of combustion. The furnace above the arches provides space for combustion of volatile matter (VM).

A bagasse-fired boiler would be fitted with two, three, or four refractory cells to generate ~20, 30, or 40 T of steam, respectively. Each cell usually burns ~5 T of bagasse and during cleaning the remaining cells in service would generate ~20% extra. Heat release rates as high as ~0.4 kg/m²s (~300 lb/ft² h) of floor area for bagasse can be realized in these furnaces with cold air. Another 20% increase is possible with hot air. This combustion rate is approximately two to three times the combustion rate on grates with intensely high heat generation.

Pile burning used to be popular in rural environment or remote areas with limited operating skills and cheap fuel because

- Burning is simple and demands simple operating skills.
- Burning is vigorous but quiescent with no carryover to cause erosion of pressure parts (PPs).
- Fuel sizing is not a concern. Sizes up to 100 mm long can be tolerated.
- Fuel with moisture as high as 60% can be effectively burnt.
- 5:1 turndown is possible.
- Due to the large refractory and fuel inventory, temporary fuel interruptions do not affect the boiler.

Pile burning is almost obsolete because

- Combustion is inefficient and cheap fuels are unavailable.
- Load control is gross and is only possible by the variation of air. Fuel variation is not particularly effective as there is a lot of green fuel in the pile and plenty of heat in the massive refractory.
- Clinker formation is a recurring problem due to the uncontrolled nature of combustion and the high rates. The presence of hot refractory only worsens the problem.
- Refractory maintenance and repair are serious issues requiring periodical shutdown of the boilers.
- Ash removal is manual and there is loss of generation and reduced efficiency during deashing.

Figure 9.1 depicts a typical twin horseshoe furnace used for pile burning of bagasse. Figure 9.2 shows a furnace with water cooling. Pile burning combustors in the form of horseshoes are arranged below the conventional boilers.

9.2.1.5.2 Pinhole Grate (Thin Pile Burning)

The name is derived from the fine *pinholes* that grate castings are provided with for air distribution (Figure 9.3). Pinhole grates (Figure 9.4) are stationary grates bolted tightly to the grate castings to the furnace floor tubes. Fuel is spread on the top by pneumatic spreaders in a thin pile similar to SS, and air is admitted from bottom through the fine

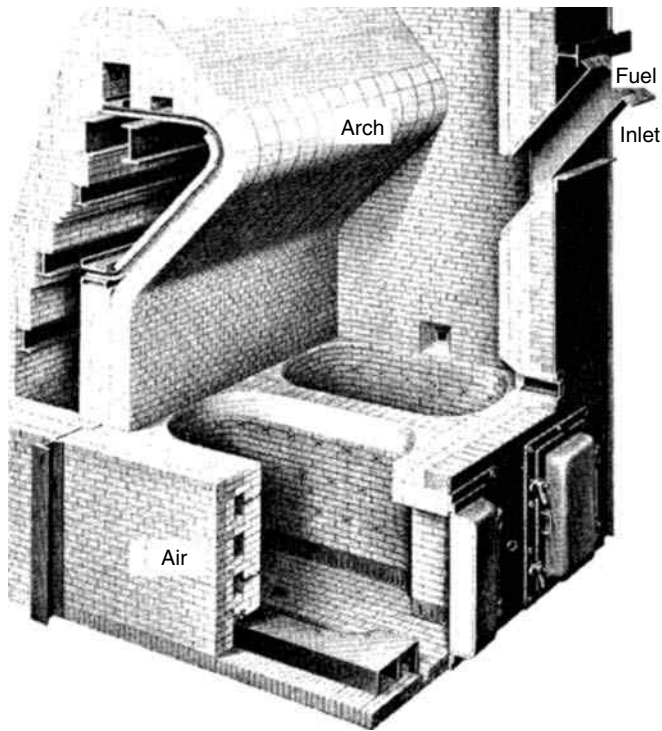


FIGURE 9.1
Horseshoe furnace with two cells. (From Babcock and Wilcox Company, U.S.A. With permission.)

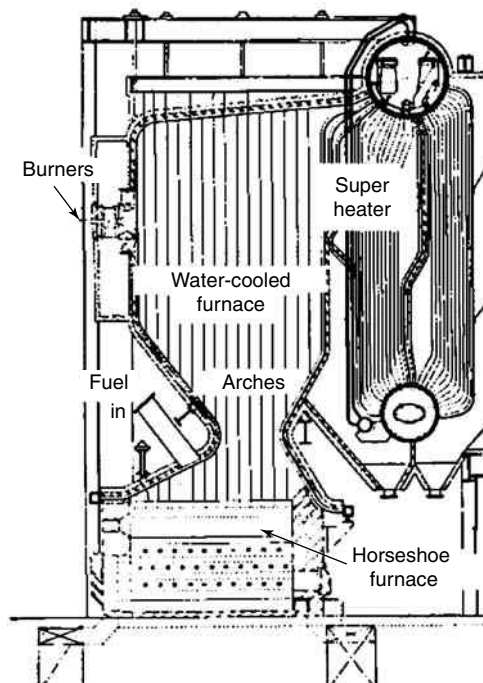


FIGURE 9.2
Horseshoe with water-cooled furnace.

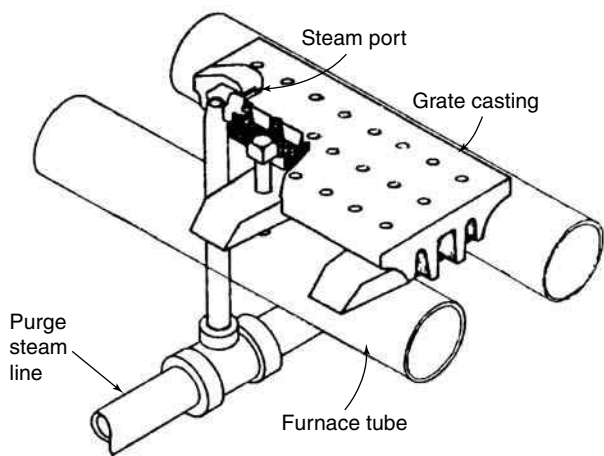


FIGURE 9.3
Grate casting with cleaning port.

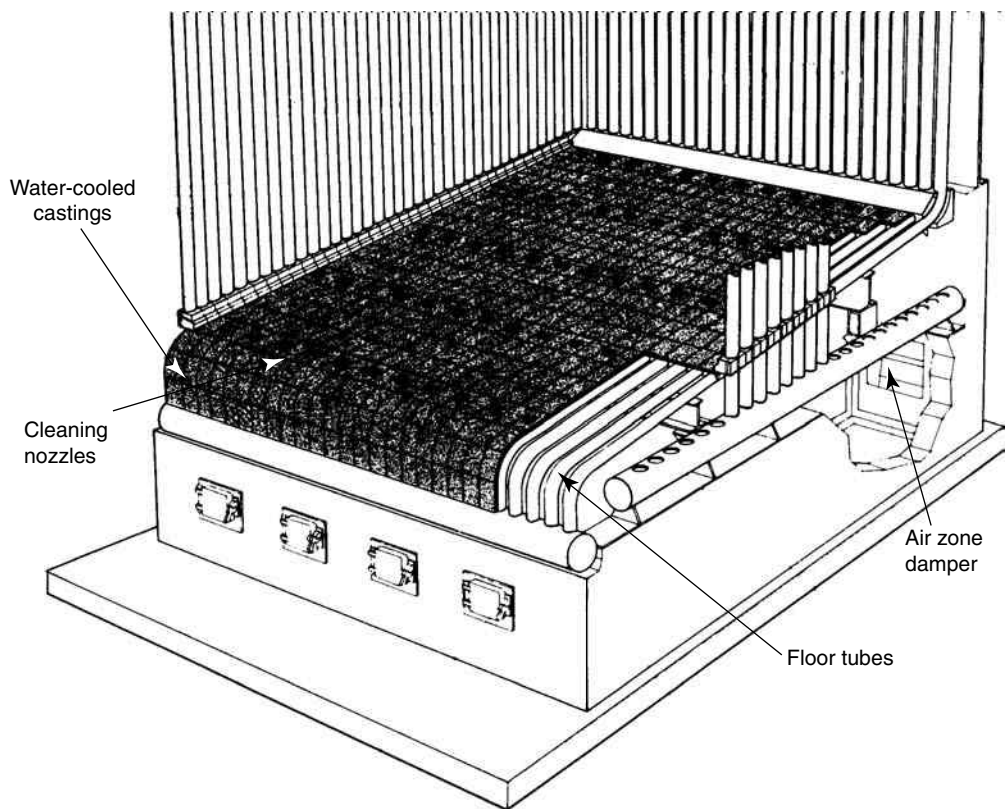


FIGURE 9.4
Pinhole grate assembly.

holes in the grate castings. Fuel can also be fed from the bottom in an underfed manner to form a pile when the quantities are small. To prevent the castings from overheating, they are bolted to the floor tubes tightly with no air film in between. The castings are usually shell molded. Close tolerances are achieved by grinding the mating surfaces. Under grate primary air (PA), secondary air (SA), and tertiary air (TA) are added to the extent of 20–30% to burn the volatiles in the furnace, similar to the overfire combustion in SS firing. Steam jets are provided to facilitate self-cleaning of the grate by blowing ash toward the rear hopper intermittently.

Design features of PHGs. Fuel is distributed on the grate by spreaders. PHGs share many process design features of SS firing. They use a combination of a thin pile burning of fuel on a grate inclined at $\sim 10^\circ$ along with suspension firing, similar to the split combustion in the SS. There are some fundamental differences too.

- Pinhole grates are totally stationary and hence unsuitable for firing fuels containing ash which needs some method of removal and disposal for the sustenance of combustion.
- Pinhole grates are essentially for biofuels with low ash, which can be blown toward the discharge end of the grate easily. Steam jet blowing often is insufficient to keep the fires clean even with biofuels, and the ash has to be removed periodically by manual raking.
- The length of the grate is limited by manual raking and fuel spreading capability. Sufficient space in front of the boiler should be vacant for raking.
- As the grate castings are cooled by the floor tubes of the furnace, they remain substantially at the same temperature as the water walls and can accept high temperature of PA ($\sim 320^\circ\text{C}/600^\circ\text{F}$) without the fear of overheating of castings or clinking of ash. For higher air temperatures, grate castings are made of alloy steel.
- This feature of high PA temperature permits easy combustion of high-moisture fuels up to 55% on flat grates and 70% on inclined grates, while 52% is approximately the limit for SS.
- O&M is much easier as the system has no moving parts.
- I&C is simpler as there is no traveling grate.
- Efficiency and auxiliary power are approximately the same as in SS but there is reasonable steam consumption for ash blowing.
- Inclined water-cooled grates (IWCs) can handle higher fuel moisture and also unsized fuel as compared to flat grates or SS, as there are no spreaders to throw the fuel. Fuel travels by the steep inclination of the grate and has a longer residence time and intense radiation from the deep rear arch.
- Supplementary oil firing is needed for start-up and to deal with high moisture in fuels. In smaller sizes, charcoal firing can also be used for start up.

Design features of boilers equipped with PHGs.

- Boilers with PHGs are built to handle up to 200 tph of evaporation on biofuels such as bark and wood wastes. They are very popular in colder climates where there is an abundance of wood-based fuels.
- Heat release rates of the grate are similar to that of SS for biomasses varying from 1.6 to 3.5 MW/m² or $\sim 1.35\text{--}3.0$ mkal/m²/h (500,000–1,100,000 Btu/ft²/h).

- Furnace-sizing parameters are also very similar. For efficient combustion and low carryover (which is a matter of concern for biofuels with low density), the furnace proportioning should be conservative. For biofuels with low to negligible alkali content in ash, which are used for generating steam at high temperatures, the following guidelines for furnace sizing apply.
 - Volumetric heat release rates (VHRRs) should be 310 kW/m^3 or $<267,000 \text{ kcal/m}^3$ ($30,000 \text{ Btu/ft}^3$).
 - Furnace residence time calculated at furnace exit gas temperature (FEGT) and measured from the top of the fuel bed (reckoned to be 450 mm) to the centerline of the furnace aperture should be $>2.5 \text{ s}$.
 - Velocity of gases in the furnace at the above two conditions should be $<5.5 \text{ m/s}$ ($\sim 18 \text{ ft/s}$).
 - Excess air can be 25% at furnace exit, about 10–15% lower than SS.

Volumetric heat release rate is generally chosen $\sim 10\%$ lower than the limit as carryover can be very high due to low density of fuel leading to fouling or erosion problems. More evenly spaced high-pressure TA has to be provided in upper furnace to minimize carryover and complete the burning of fuel fines.

- In case of biofuels with high alkalis in ash, please refer to Table 11.6 and guidelines given in Section 11.5.4.
- With regard to the sizing of SH, boiler bank (BB), backend, and draft plant, the same principles as in SS apply (Figure 9.5).

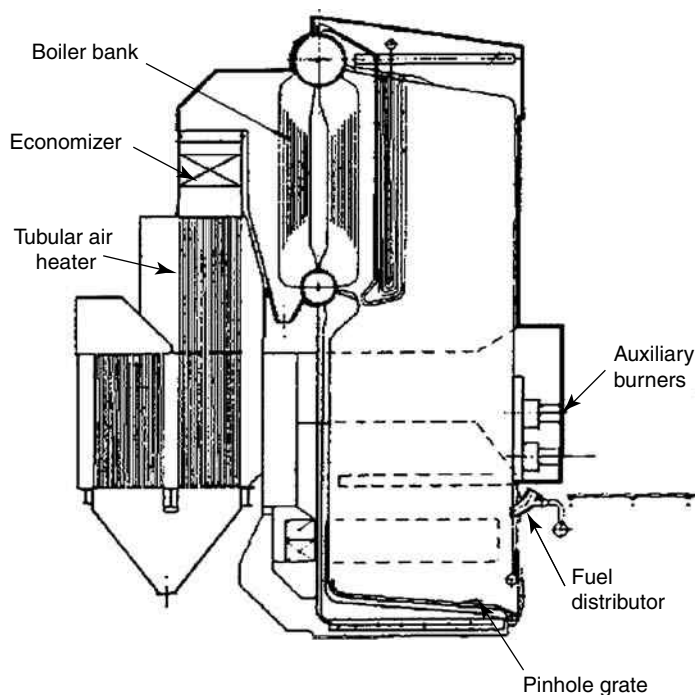


FIGURE 9.5

Bidrum boiler with pinhole grates and fuel distributors.

Pinhole grate versus SS.

PHGs have the following advantages:

- Lower excess air that can give fractionally more thermal efficiency
- Higher hot air temperature that helps to burn fuels with higher moisture
- No moving parts and hence low O&M costs

Because of the following disadvantages, PHGs have been overshadowed by SS:

- Other than oil and gas, practically no other auxiliary fuel can be burnt. Multifuel flexibility is limited.
- Dynamic response of the boiler is poorer.
- Manual raking is necessary and no continuous ash discharge is possible. Output may suffer.

9.2.1.5.3 *Inclined Water-Cooled Grates (Semipile Burning)*

Inclined water-cooled grates (IWCs) shown in Figure 9.6 share most construction and design details with PHGs. They are longer, expensive, and provide more residence time, and hence are used only when the moisture in fuel exceeds ~55%. There are some basic differences in the way the fuel enters and burns in the IWC grates. Fuel is applied to the PHGs by means of spreaders. At high moistures, spreading is not possible. In the IWC

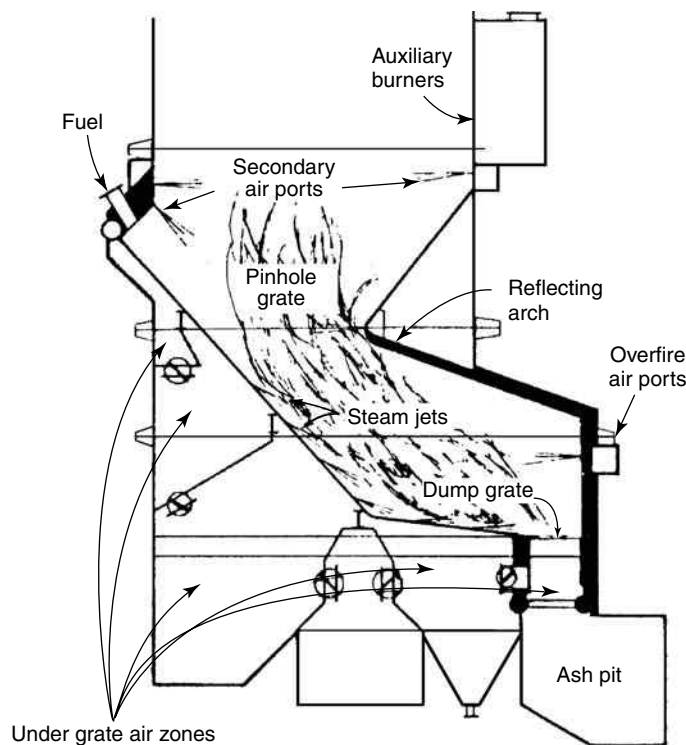


FIGURE 9.6

Inclined water-cooled grate for high-moisture biofuels. (From *Power* magazine. With permission.)

grates, fuel is admitted by gravity onto the grate, which is inclined at $\sim 47^\circ$ to 48° to the horizontal. The fuel gets dried as it rolls down the inclination. Steam nozzles in the grate castings assist in this movement of fuel and ash. Thereafter it loses its VM, which burns in suspension. The fuel rolls further and gathers on the flat area at the end, where it forms a pile, and the fixed carbon (FC) burns vigorously. The rear wall is so shaped as to provide SA as well as direct radiant heat to the pile. In many units, a dumping grate is installed at the end so that dumping the ash after the pile burns down is easy and complete.

9.2.2 Classification by Number of Drums

About 50 years ago it was not uncommon to have three or even four drums in a boiler. More drums and large BBs meant more water-holding capacity and bigger thermal flywheels. Any sudden demand for steam could be met by a small drop in steam pressure, which would release steam from the latent heat of the boiling water in the drums and banks. With the advances in instrumentation and control, it is now possible to keep such sudden steam demands in check and reduce the number of drums to one or two.

9.2.2.1 Bidrum Boilers

Bidrum boilers are common for SOPs up to ~ 70 bar and single drums are used beyond 100 bar. Bidrum boilers, which have convection tubes expanded in the top and bottom drums, are limited by the strength of expanded joints. Also at higher pressures, the large drum thicknesses interfere with good boiler dynamics. However, bidrums have the advantage of bigger water-holding capacity and hence

- An inherent ability to meet wider load fluctuations more readily. They are more forgiving for the operator and instrument sluggishness.
- They take more time for start-up and shutdown.
- For fuels like bagasse and wood, with a lot of heat in gases due to moisture, bidrum convection is necessary to dissipate the heat.
- Another positive aspect of bidrum design is that the flue gases are cooled due to the large heating surface (HS) in the bank to $<450^\circ\text{C}$ in most cases, permitting the use of plain carbon steel (CS) sheet for the second-pass enclosure. In single-pass boilers, membrane panel cooling is required instead, and is expensive.

9.2.2.2 Single-Drum Boilers

Single-drum boilers are inevitable for higher pressures simply because the drums become too thick (150 mm and higher) above 100 bar, making it difficult to ensure a good tube expansion (Table 9.2).

- Single drums are preferred when faster response or two-shift operation is needed from the boiler.
- Single-drum boilers are usually lighter because of the absence of the water drum and BB. A steam drum is also nearly half the thickness.
- For SOPs lower than 45 bar, single-drum boilers usually need convection banks (with an upward slope of not $<7^\circ$ horizontal to induce circulation) to meet the

TABLE 9.2

Single versus Bidrum Boilers

Parameter	Bidrum	Single Drum
Limiting SHOP	<70 bar	>100 bar
Boiler load response	Sluggish due to heavy drums and big water holding	Dynamic due to single thin drum and less water
Latitude for operator error	Better due to more water in the boiler	Not as good as bidrums
Boiler weight at higher pressure	Higher	Lower
Boiler weight at lower pressure	May be lower	Can be higher due to evaporator coils
Erection time		Can be faster as drum is not needed to begin erection
Casing for second pass	Carbon steel	Membrane panel
High-moisture fuels	Necessary due to high sensible heat in flue gases	Needs a large steaming economizer

latent heat requirement. At lower pressures of 32 bar, forced circulation is necessary with the aid of pumps. The bidrum arrangement in such cases may be cheaper and simpler.

- The other main advantage can be the faster erection time. Unlike in a bidrum boiler where no major erection can start unless the drums and convection tubes are at site, in a single-drum boiler the furnace erection can proceed and drum can be erected later.

The usual arrangement is a single drum for pressures >100 bar and bidrums for <70 bar. There is a choice to adopt either of the two, which is made on case-specific basis.

9.2.3 Balanced Draft and Pressurized Firing

Combustion air must be forcefully admitted into the firing equipment via a forced draft (FD) fan. After combustion, the air turns into gas and must be evacuated by means of an induced draft (ID) fan in balanced draft operation where there is pushing of air and pulling of gas, and the furnace is maintained at near-atmospheric condition. There is, thus, a *balancing of drafts*.

In pressurized boilers the FD fan pushes the air and the flue gas all the way to the chimney with no ID fan in the circuit.

- The boiler efficiency is slightly higher as there is no tramp air ingress into the setting, contributing to reduced stack losses.
- There is less O&M effort, as the fan and peripherals are eliminated.

Pressurized firing is suitable for liquid and gaseous fuels. For solid fuels, balanced draft is more favored as there is generally a need for manual direct observation or intervention for which near-atmospheric conditions should prevail in the furnace. It must be considered that several very large OT boilers are in operation that employ pressurized firing (Figures 9.7 and 9.8).

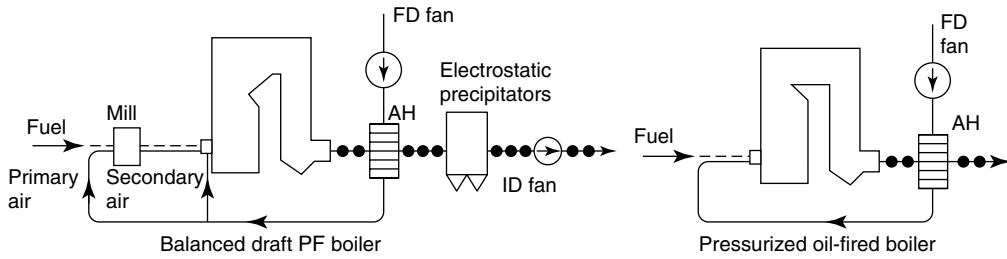


FIGURE 9.7
Balanced draft and pressurized boilers.

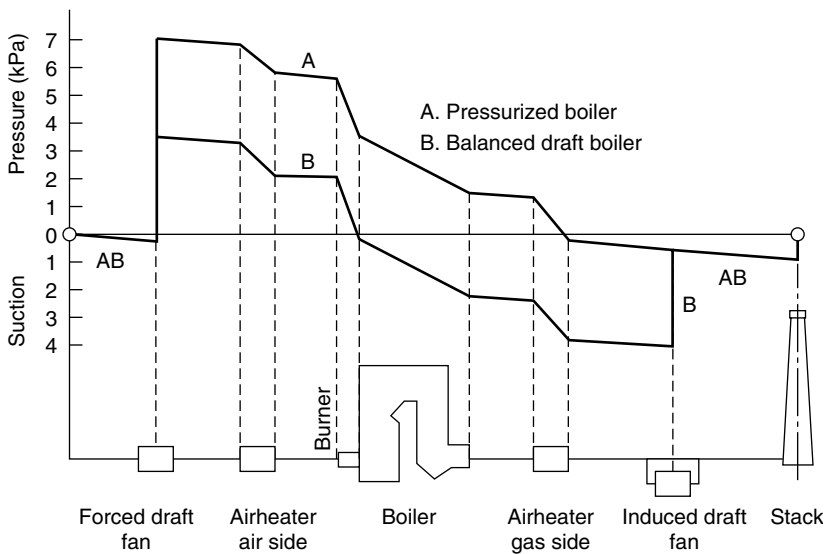


FIGURE 9.8
Typical draft-loss diagrams for pressurized and balanced draft boilers.

9.3 Utility Boilers

9.3.1 Small versus Large Utility Boilers

The utility or power boilers are of two types:

1. Small utility boilers ranging from 100 MW (400 tph) to 300 MW (~1000 tph)
2. Large utility boilers >300 MW (~1000 tph)

A size of 1000 tph is arbitrary; the dividing line between small and large utility boilers of 400 tph is for industrial and utility boilers.

Small utility boilers are conventional drum-type single reheat PF-fired boilers operating at high pressures (HPs) and high temperatures on mostly natural or assisted circulation.

Large utility boilers, by their size, can accommodate certain advanced features:

- Once-through system
- Supercritical (SC) steam parameters

- Variable pressure operation
- Double reheat at >800 MW

Large utility boilers can also be conventional drum-type natural or assisted-circulation boilers when they are used for mainly base load operation. They have been used for sliding pressure and two-shift operation, but SC boilers are more suited and offer greater flexibility.

Utility boilers represent the most advanced type. The working conditions to which they are subjected are the most arduous. The expectations from the modern utility boilers can be summarized in the following manner:

- Highest efficiency with lowest fuel consumption
- Flexibility to burn a range of coals with differing fouling characteristics
- Highest availability
- Short start-up time
- Quick load following capability

Several measures may be taken in a power cycle design to increase the efficiency of a plant.

- Increasing the main steam pressure
- Increasing SH and RH steam temperatures
- Adopting double RH
- Reducing flue gas–exit temperature
- Increasing feed water (FW) temperature
- Reducing condenser pressure

9.3.2 Supercritical Boilers

9.3.2.1 Why Supercritical Boilers?

At drum pressure of ~200 bar and SH/RH temperature of 540/565°C, limits are reached in natural circulation drum-type boilers in respect of steam pressures and temperatures with plant thermal efficiency reaching 42% on NCV and 40% on GCV. With the limits for the flue gas exit temperatures and unburnt losses reached long ago, the next improvement could come only by adopting SC conditions. It must be clarified that the SC conditions do not increase the boiler efficiency *per se*, as the efficiency is governed by stack losses and unburnt losses, neither of which is affected by the steam pressure adopted. The higher steaming conditions basically increase the overall steam cycle efficiency. There is, correspondingly, a reduction in the fuel input that also reduces the CO₂ generation and sizing of auxiliaries such as the fans and pumps on per megawatt basis.

Adopting SC is a major step, as it involves extensive changes in the way the boiler and turbine are built. There are changes to steam piping, controls, and other auxiliaries such as boiler feed pumps (BFPs), and so on.

The subcritical and SC steam cycles are depicted in Figure 9.9 and also in Figure 9.10. (RH is not depicted here for the sake of simplicity.) The difference is in the higher operating cycle pressure, leading to higher cycle efficiency. For the same heat loss in a condenser more work is done in a boiler and a turbine and hence the efficiency is higher. The boiler construction is different, in that there is no longer a drum.

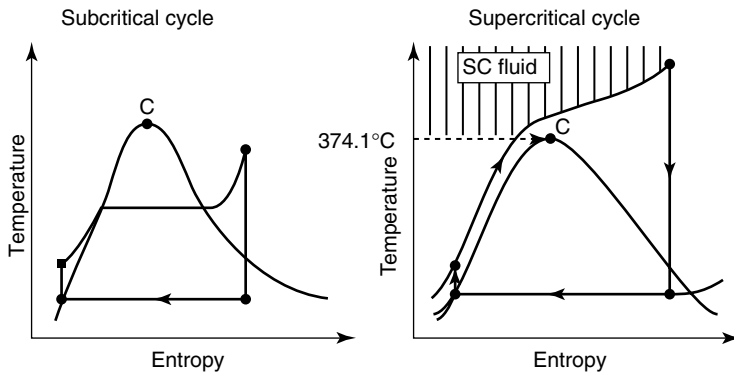


FIGURE 9.9
Sub- and supercritical cycles on T-s chart.

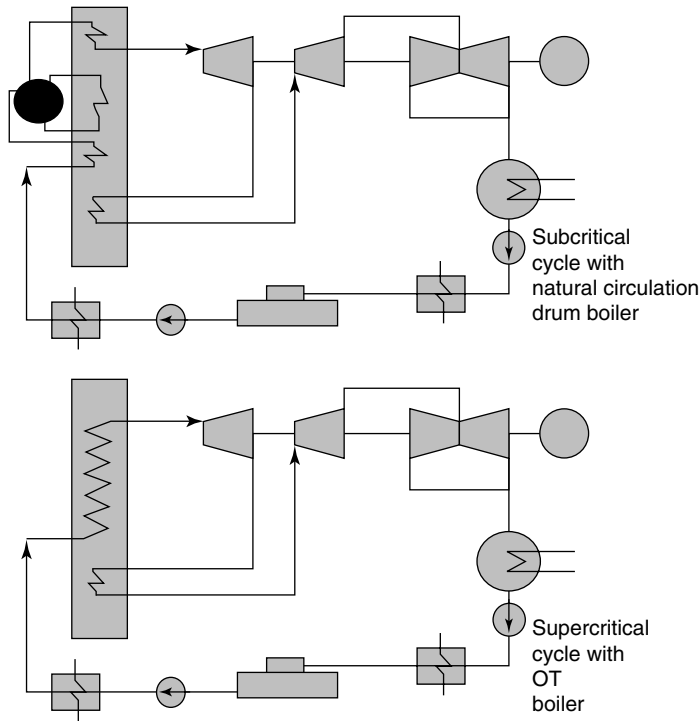
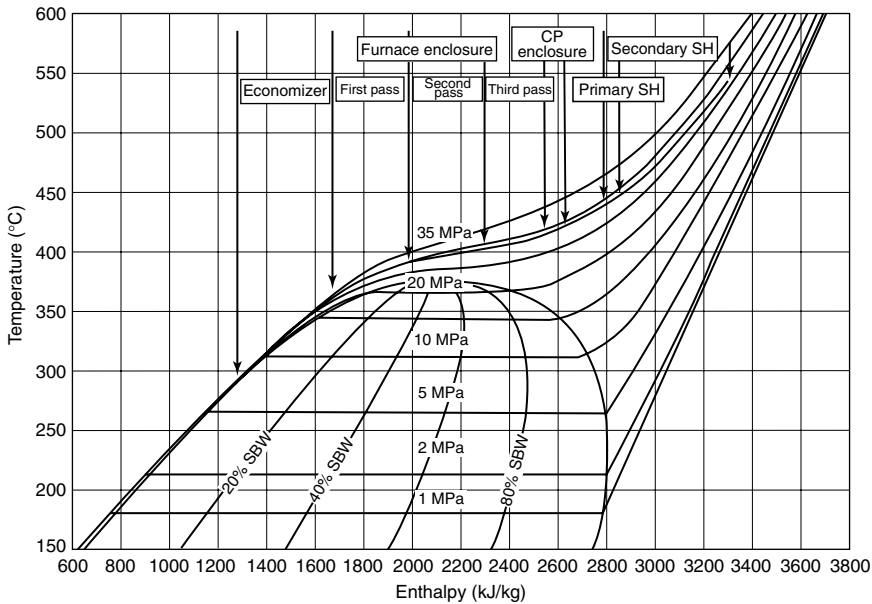


FIGURE 9.10
Sub- and supercritical cycles.

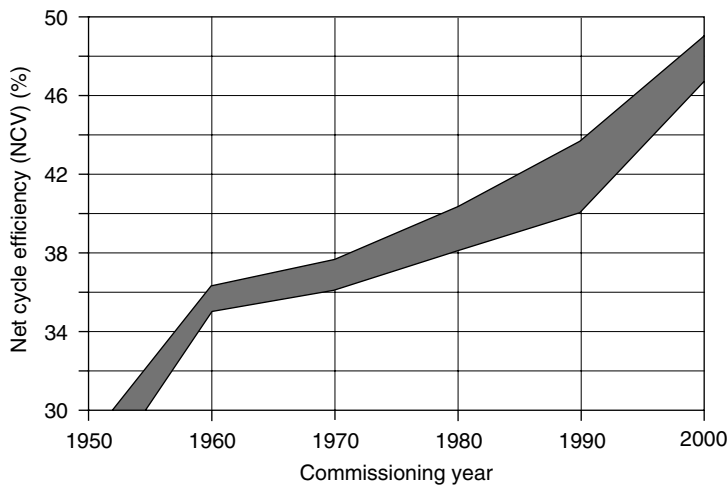
Figure 9.11 depicts the steam condition of a typical 1300 MW SC boiler on a T-s diagram. Subcooled water entering the economizer (ECON) goes directly to SH as the pressure is above the critical pressure bypassing the evaporation zone.

9.3.2.2 Progress of Supercritical Boilers

Figure 9.12 traces the rise in plant efficiencies on NCV over the years. Efficiencies beyond ~42% on NCV are achieved only by adopting SC conditions. Plant efficiency increases

**FIGURE 9.11**

Typical steam cycle of 1300 MW supercritical boiler on T-s diagram. (From Babcock and Wilcox Company, U.S.A. With permission.)

**FIGURE 9.12**

Rise in plant efficiency over time.

from 42 to 45% over a decade and a half were realized by the increase in steam temperature from 540/540 to 600/620°C (~1005–1110/1150°F) and pressure from 200 to ~310 bar (2900–4500 psia) along with double reheating. Another ~3% points is achievable as the cycle conditions climb to 350 bar, 700/720°C (~5000 psig/1300/1300°F) called thermie or AD 700 conditions.

9.3.2.3 *Supercritical and Ultra Supercritical Boilers*

Supercritical condition, as per ASME steam tables, is at

- 220.7 bar and 374.1°C (3200.1 psia and 705.1°F) when water progressively converts to steam without boiling and with no latent heat addition. These figures can vary slightly, depending on the steam tables followed, but the variance is inconsequential for practical purposes.
- Supercritical boilers operate up to ~240 bar (3500 psi nominal).
- Ultra SC (USC) boilers operate at ~310 bar (4500 psi nominal) or higher.

The overall cycle efficiency increases as the pressure and temperature are increased (Figure 9.13). The rise is depicted over the base case of drum-type boiler operating at subcritical steaming conditions, which can be taken as 42% on NCV and 40% on GCV. Boilers up to 315 bar and 600/620°C (~4500 psia/1110/1150°F) are in operation, while those up to 350 bar and 700/720°C (~5000 psia/1300/1330°F) are in the planning stage. RH temperature can be ~15 to 20°C higher than the main steam temperature, as the RH pressure is much lower at about one-fourth of the main steam pressure, which permits higher RH temperature for the same stress levels. Or a lower metallurgy can be used for RH tubes without increasing the RH temperature, which is rarely practiced. Often SHOT and RHOT are maintained at the same level.

Figure 9.13 depicts the progress of high-temperature metallurgy.

9.3.2.4 *Improvement of Supercritical Boilers over Drum Boilers*

- Fuel savings due to higher cycle efficiency and hence reduced operating costs
- Reduction of CO₂ emissions due to lower fuel input for the same power
- Superior load dynamics as the thick-walled components are avoided and there is no water in circulation
- Part load performance improves with variable/sliding pressure operation
- No blowdown

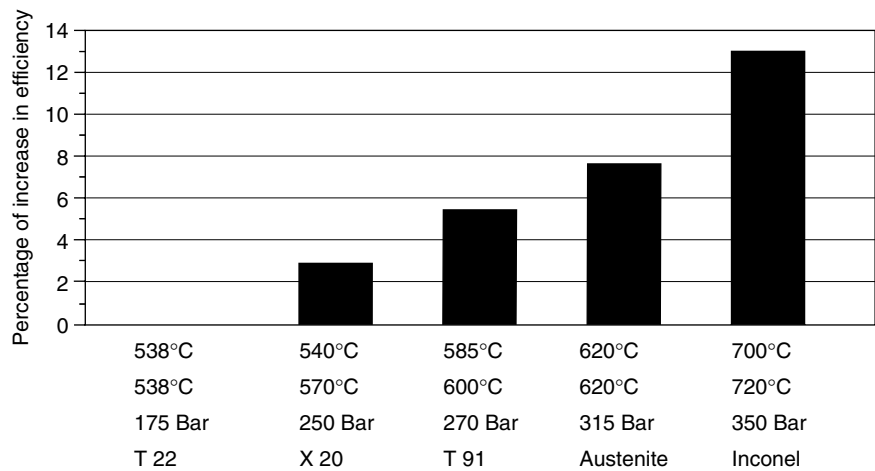


FIGURE 9.13
Rise in cycle efficiency as steaming conditions improve.

9.3.2.4.1 Fuel Savings

For a typical 500 MW unit, the savings in coal consumption and improvement in efficiency are depicted in Figure 9.14 and Table 9.3, taken from the in-house technical articles of the Steinmueller GmbH, as was Figure 9.13.

- This is based on operating the plant at 6500 h/year with a high-ash coal having an NCV of 3330 kcal/kg.
- The improvement in cycle efficiency is 1.7, 2.4, and 3.25% points, over the base case (option 1) with steaming conditions of 175 bar and 538/538°C (2500 psig/1000/1000°F) conditions, which is significant.
- This is at a pressure level of 235.4 bar (3400 psig), which can increase at higher pressure and temperature.
- The boiler efficiency under all conditions remains the same, but both the main steam and RH flow reduce with increase in pressure due to higher cycle efficiency.

9.3.2.4.2 Carbon Dioxide Reduction

As there is a reduction in the coal consumption, the total CO₂ from the plant reduces by the same amount. This makes the SC boilers effective for clean coal technology. Figure 9.15 illustrates the steady reduction in specific CO₂ production from power plants over the years.

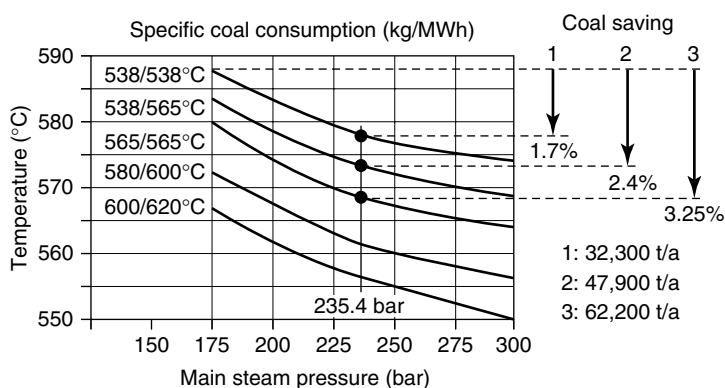


FIGURE 9.14
Effect of increased steaming conditions on fuel consumption.

TABLE 9.3

Options for SC Conditions for 500 MW Unit

SC Conditions	Unit	Option 1	Option 2	Option 3
Main-steam flow	tph	1395	1356	1332
Main-steam pressure	bar	235.4	235.4	235.4
Main-steam temperature	°C	538	538	565
FW temperature	°C	270	270	270
RH steam flow	kg/s	1232	1200	1183
RH inlet pressure	bar	55.9	55.3	55.3
RH inlet temperature	°C	319.6	318.2	339.5
RH outlet pressure	°C	538	565	565
Boiler efficiency on net calorific value	%	91.2	91.2	91.2

9.3.2.4.3 Better Load Dynamics

Besides being more efficient, SC boilers are also more dynamically responsive as the

- Thermal inertia is much lower due to the absence of circulating water.
- The separator and water level vessels replace the thick-walled drum.

These vessels come into picture for subcritical part load operation. At SC operation, however, they act like headers. Figure 9.16 brings out the differences in the response of the two systems. Table 9.4 tabulates the weights of the heavy components in two similar-sized boilers to depict the vast difference between the NC and SC boilers. The weights and dimensions are merely indicative.

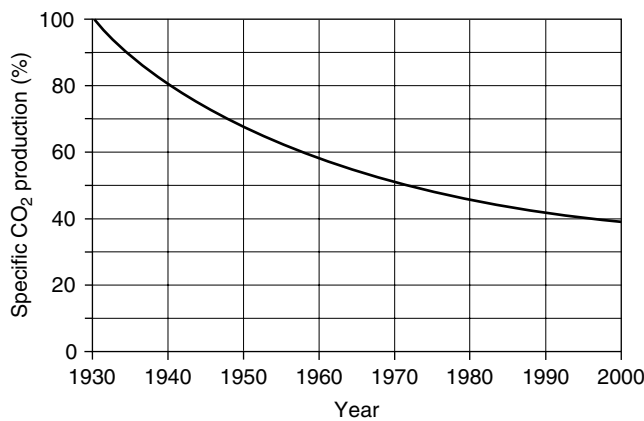


FIGURE 9.15
Reduction in specific CO₂ generation, 1930–2000.

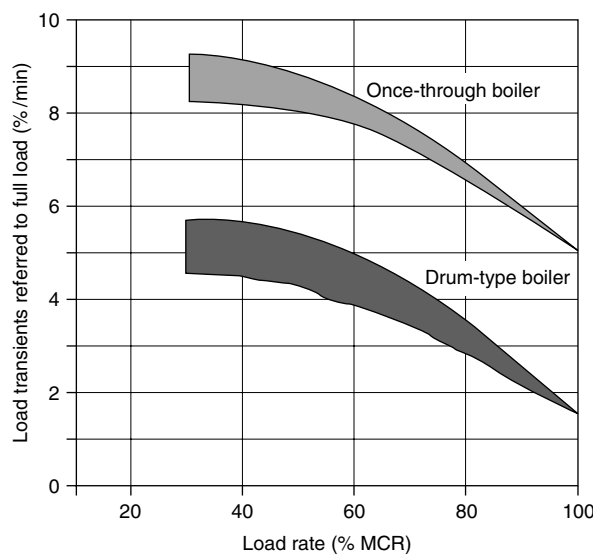
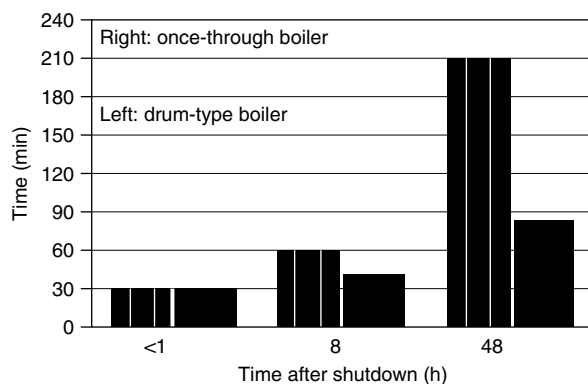


FIGURE 9.16
Load transients in drum and once-through boilers.

TABLE 9.4

Comparison of Thick-Walled Vessels in Drum and SC Boilers

Parameter	660 MW		720 MW
Type	NC	SC	
Component	Drum	Separator vessel	Water level vessel
Size ($\varnothing \times t \times L$) (mm)	2,210 $\times$ 150 $\times$ 33,000		585 $\times$ 60 $\times$ 19,900
Weight (Te)	355		22

**FIGURE 9.17**

Typical hot, warm, and cold start-up times.

The result of the thick PPs is a slower load response of drum-type boilers as compared to OT boilers working at either subcritical or SC pressures. The comparison in Figure 9.16 considers the OT boiler with sliding pressure operation.

The time taken for hot, warm, and cold starts is another important parameter in measuring the boiler dynamics. On hot starts there may be no perceptible difference, but on cold starts the drum boilers are good deal slower as shown in the accompanying bar graph (Figure 9.17).

9.3.2.4.4 Variable/Sliding Pressure Operation

What is variable pressure operation? Steam generation at SC conditions ensures high efficiency at full load, but it must be complemented by variable or sliding pressure operation to obtain good part load efficiency and dynamics. A steam turbine demands lower inlet pressures at lower loads. Generally, conventional drum-type boilers generate steam at a constant pressure, which is then reduced in the main throttle valves to feed the nozzles at a suitable lower pressure. This is not always the case and drum-type boilers are also designed for variable pressure operation, particularly with the help of assisted circulation. A modified sliding pressure is also adopted where SOP is held constant up to a load and allowed to elide, taking an intermediate position. See Figure 9.18. With fixed SOP the drop in the throttle valve is, thus, a waste of energy, which increases as the load reduces. A more efficient system would generate steam at lower variable pressures instead of generating steam at a higher pressure and killing in the throttle valves. The throttle valves and the main stop valves could be dispensed with, and the speed of the feed pump could be varied to suit the inlet pressure of the turbine. This is called the variable pressure operation.

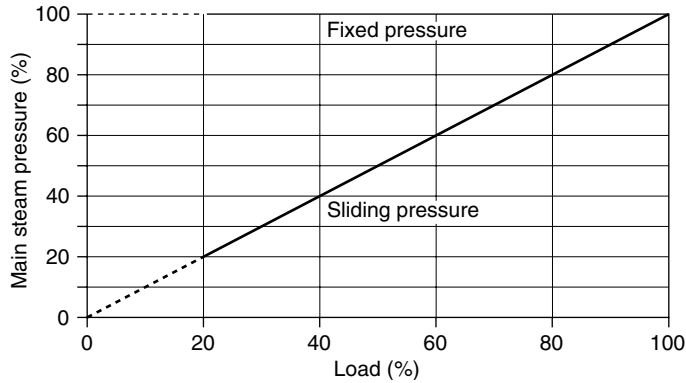


FIGURE 9.18
Variable and sliding pressure operation.

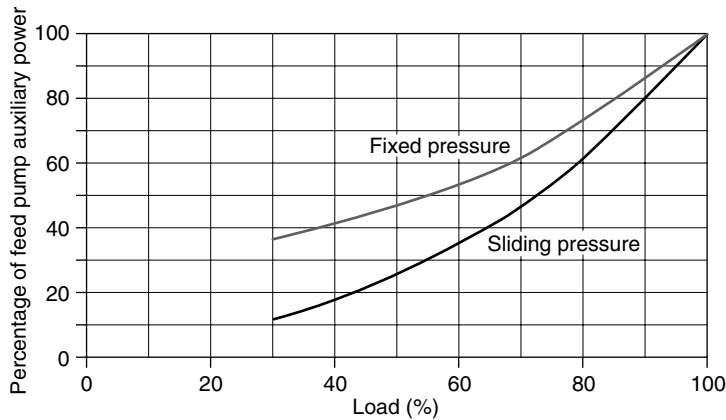


FIGURE 9.19
Auxiliary power of boiler feed pumps in fixed and sliding operations.

Why are the drum-type boilers not so well suited for variable pressure? The sudden pressure variations promote

- Steam formation in the downcomers during load dips, which causes instability of circulation
- Disturbances to the water surface in the drum, affecting the controls
- Differential temperatures between the top and bottom of the drum, creating serious thermal stresses due to the thickness of the drum

Once-through boilers, both subcritical and SC, with no drums are ideal for variable or sliding pressure operation, which has the following main advantages:

- The turbine efficiency is higher as there is no throttling loss.
- Auxiliary power consumption of BFP is lower as the pump has to work against lower head at all loads. The savings increase for part loads (Figure 9.19).
- All pressure components are at lower pressure and hence are subject to reduced stress levels.

9.3.2.4.5 No Blowdown

Once-through boilers do not require blowdown as all the water gets converted to steam. This is an advantage as the makeup water quantity reduces. At the same time the water quality requirements are stringent for OT boilers with nothing less than condensate polishing systems of high reliability.

9.3.3 Boiler Designs for Utilities

Of the several designs in operation, essentially three types and their variants can be considered in the utility market for coal and lignite, the main fuels. Oil- and gas-fired boilers for utilities are no longer considered. The boiler types are

- Two-pass boilers
- Single-pass or tower-type boilers
- Down shot boilers—V or W type

The nomenclature is based on the numbers or shapes of gas passes in the boiler.

9.3.3.1 Two-Pass Boilers

Two-pass boilers shown in Figures 9.20 and 9.21 are common and have progressed from smaller sizes in the same form. The main advantages are as follows:

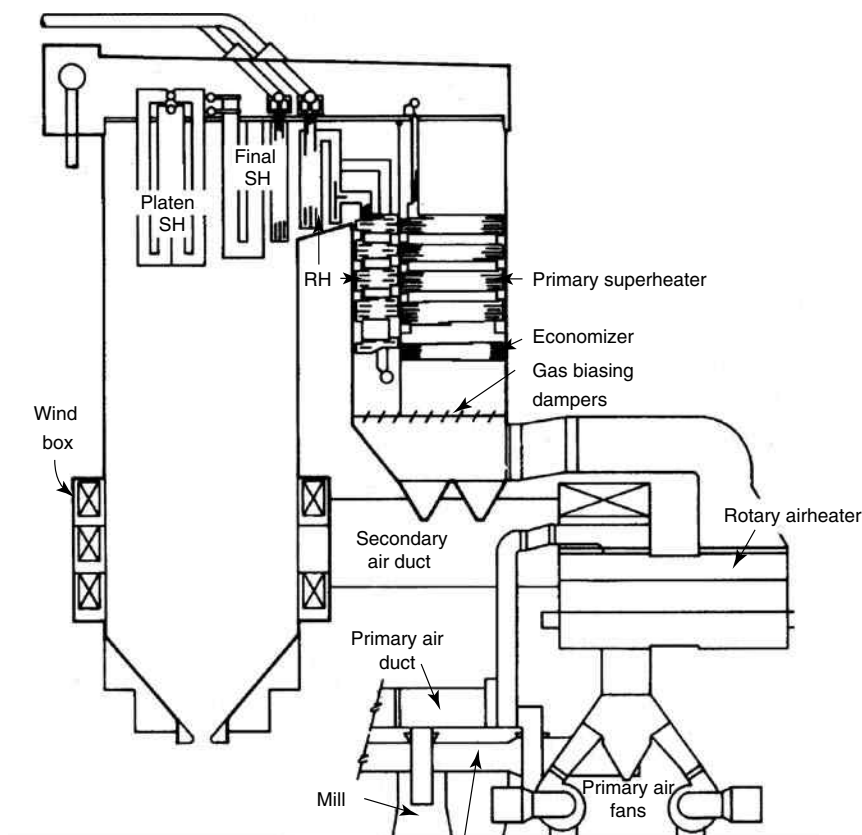
- Two-pass boilers are not so tall and erection is easier.
- The boilers are usually supported on six columns and hence the structure can be a little lighter.
- The support elements for the vertical surfaces are located above the furnace roof outside the gas flow and protected from the erosive forces of the gases.
- The SH and RH are suspended from the roof and are free to expand downward.
- The roof is made of SH tubes, which minimizes the relative expansion of the SH and RH tubes as they penetrate the roof. Gas leakage is minimal.
- Widely spaced radiant sections in platens and panels and steam-cooled walls in the furnace have high heat absorption that increases the temperature control range.

The main drawbacks of the two-pass design are that

- The SH and at times the RH are not drainable, requiring longer start-up times and greater care during start-up.
- There are gas turns over the convection banks when flue gases travel toward the second pass, making them vulnerable to tube erosion both in the interpass area and in the first set of tubes of the second pass.

Drainable SHs are very beneficial as they

- Can be fully drained and, therefore, impose no limitation on the inlet gas temperature during start-up. In the nondrainable SH, the condensed steam residing in the tubes requires a gentle heating so that the steam formed finds its way out and does not create vapor locking that leads to tube overheating and increases the start-up time.
- Are easy to preserve during long layoffs as dry preservation can be adopted. In cold climates this is beneficial as there is no risk of freezing.

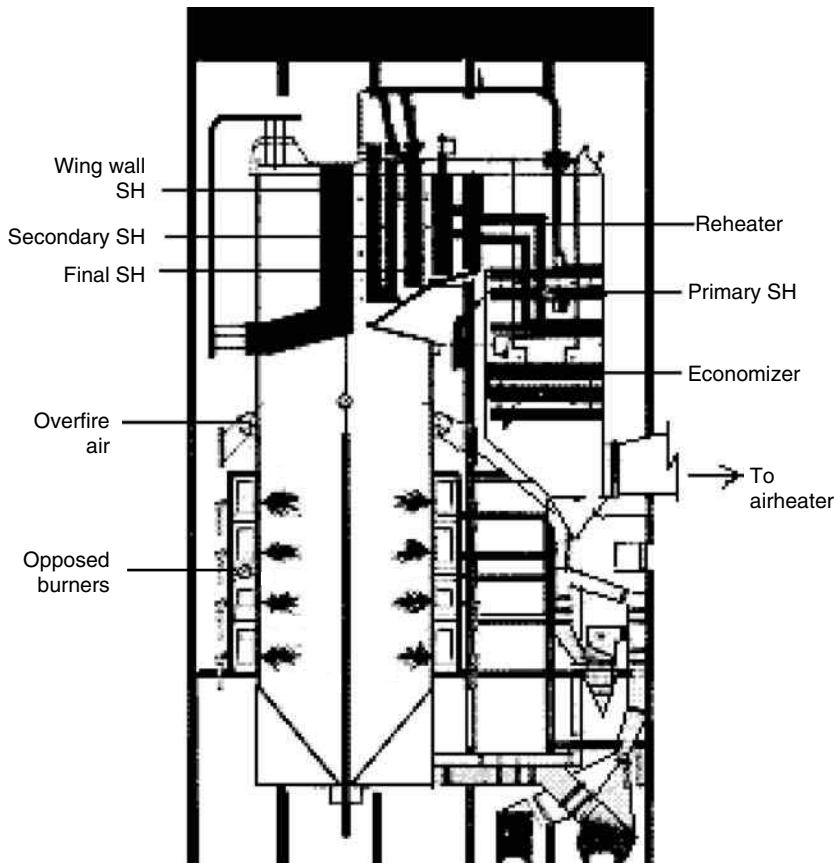
**FIGURE 9.20**

Two-pass opposed wall-fired boiler with divided gas flow in second pass and part vertical superheater and reheater.

In the arrangement shown in Figure 9.21, with no division in the second pass, the RH temperature is controlled by the burner tilt of the corner firing system and the SH temperature by the spray water. If wall firing is employed in place of the corner firing, it is common to have two parallel paths in the second pass for SH and RH coils independently. This is also called divided convection pass and is shown in Figure 9.20. Control dampers at the end of each path regulate the temperatures by proportioning the gas flow.

9.3.3.2 Tower-Type Boilers

Tower-type boilers are shown in Figure 9.22. All the convective surfaces are horizontal and are stacked one above the other to prevent any gas turns over them. The horizontal surfaces are fully drainable, making the design amenable to better dynamics. All the flue gases flow normal to the convective surfaces and hence the erosion tendencies are greatly reduced. Figure 9.23 shows the method of supporting SH sections on the screen tubes and the walls. However, the gas velocity limits are to be respected. The cooled gases at the ECON exit come out of the first pass to get further cooled in the AH. The tower-type boilers are ~25% taller but occupy some 20% less floor area.

**FIGURE 9.21**

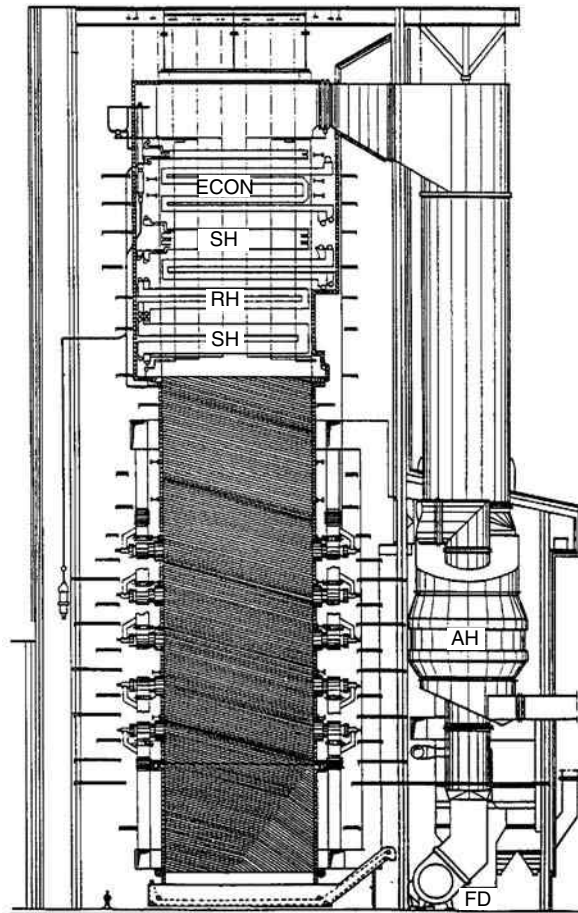
Two-pass opposed fired boiler with single second pass with part vertical and part horizontal superheater and reheater.

Tower-type boilers have the following advantages:

- There are no gas turns on the convective surfaces, making them safe from erosion.
- All the convective surfaces are horizontal and hence drainable, permitting faster start-up and shutdown.
- They are supported on four main columns, making the arrangement very clean and elegant.

The tower-type boilers have the following drawbacks:

- They are difficult to erect, but the accessibility largely reduces the erection complications.
- The supporting tubes and elements are in the gas path, exposing them to the erosive forces and high temperatures. The start-up time is limited by the temperature attained by the support tubes.
- The radiant heat available to the SH and the RH is limited, and more surface is required to achieve the same turndown.

**FIGURE 9.22**

Tower-type supercritical boiler with opposed firing and horizontal drainable superheater and reheater.

The disadvantages of the two-pass design are the advantages of the tower design and vice versa. The two designs are compared in Table 9.5. A modified tower-type boiler is a two-pass boiler with drainable surfaces as shown in Figure 9.24. It is a design that combines the advantages of two-pass and tower-type designs.

9.3.3.3 Down Shot-Fired Boilers

Down shot-fired boilers are employed where the VM of coal is low, <20% or lower on a dry ash-free (daf) basis. The ignition temperature of such coals is high and the burning is slow, requiring refractory lining of furnace and large furnace volume, respectively, to complete the combustion. The firing in burners is nonturbulent, with the burners facing downward such that the flames are long and there is a lot of time to burn the coal as the flames travel downward and take a u-turn. This type of boiler is described in detail in Section 13.4.8. Down-shot firing can be U-type with a single set of burners on one side of the furnace as in Figure 9.25 or W-type with burners on either side as in Figure 9.26, depending on the size of the boiler.

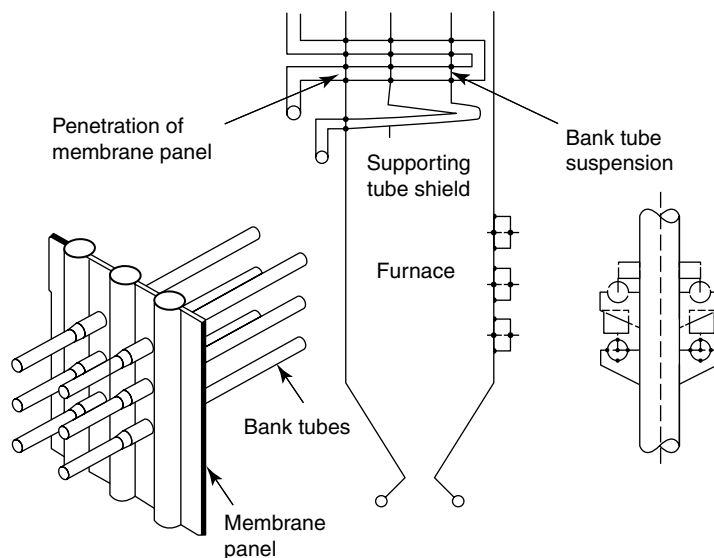


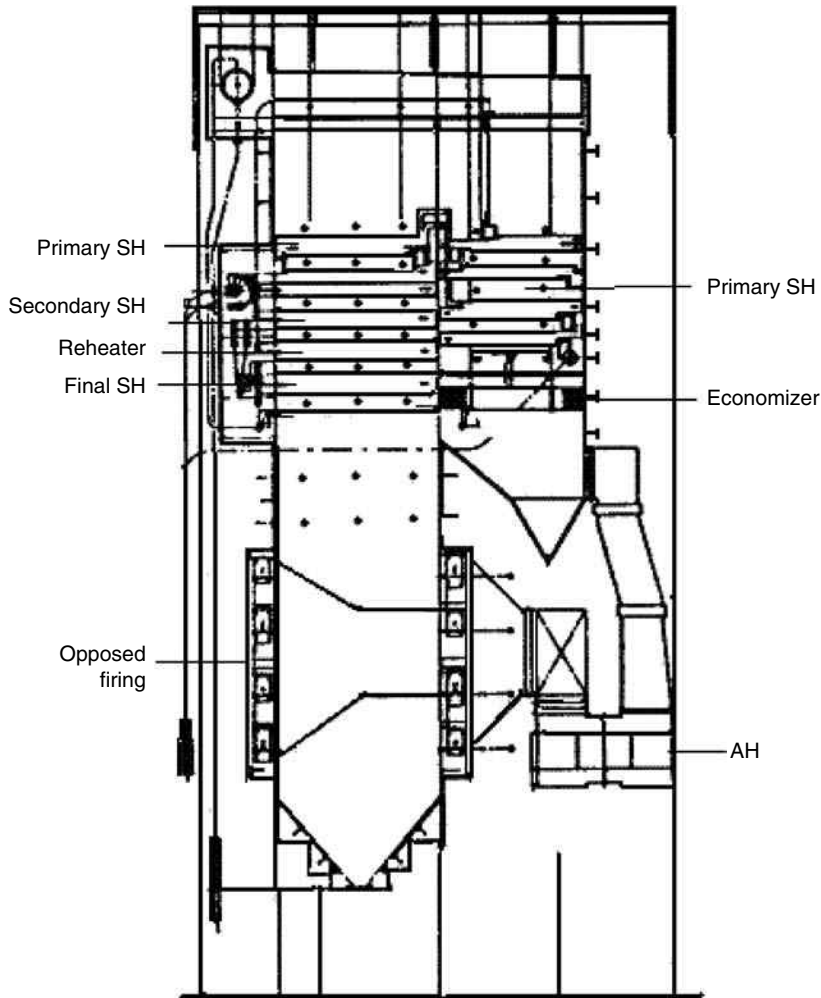
FIGURE 9.23
Tube arrangement in a tower-type boiler.

TABLE 9.5
Two-Pass versus Tower-Type Boilers

Item	Two-Pass Boiler	Tower-Type Boiler	Remarks
Gas turns on convection banks	Yes and hence erosion prone	No and hence no erosion	
Second-pass erosion	Yes on mostly ECON top tubes	No second pass	Erosion shields required on ECON top tubes in two-pass
Superheater type	Vertical and horizontal nondrainable	Horizontal only drainable	Superior dynamics in tower-type boilers
Superheaters and reheaters support	From roof	From walls	Roof support is simple
Support elements	Outside gas path	Inside gas path	Care needed for gas-swept supports in tower
Start-up time	Slower due to water in superheaters	Faster as SH is dry	
Space	More floor space ($H \times W$)	More height ($1.25 H \times 0.8 W$)	
Erection ease	Short but all four sides not available	Tall, but full access	
Main columns	Six or more	Four	

9.3.4 Features of Supercritical Boilers

- *Differences with drum-type boilers.* SC boilers are constructed differently from the conventional boilers primarily in two areas—furnace and drums. The boiler operation and control also vary. The water quality requirements are more stringent and there is no blowdown.
- *No drums.* As there is no circulation in SC boiler and all the water turns into steam in the furnace, no steam drum is needed. However, small separating vessels are

**FIGURE 9.24**

Modified tower-type boiler with two passes and horizontal drainable superheater and reheater.

required to separate the water fraction and recirculate the water when the unit operates at different loads and pressures.

- *Flow of water in furnace tubes.* In the furnace, in absence of any circulation, water cannot be allowed to flow through all the tubes as the water velocity will be too low to prevent the departure from nucleate boiling (DNB). The tubes in the furnace, therefore, are grouped into circuits so that water flows through them at a good mass velocity ranging from 2200 to 2400 kg/m² s ($1.6\text{--}1.76 \times 10^6$ lb/ft² h). The circuits are arranged vertically with external pipes bringing heated water to the next circuit as in universal pressure (UP) boilers. Alternatively, the tubes can be arranged in upwardly sloping spirally wound circuits at an angle of 10–30° in the lower furnace where high heat flux prevails. They are vertical in the upper furnace where lower steam mass flow can be employed due to lower heat flux. This arrangement is shown in Figure 9.28.

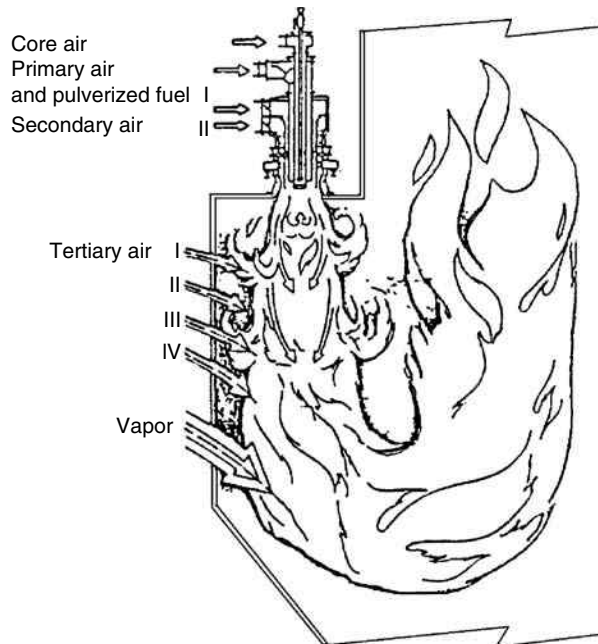


FIGURE 9.25
U-type down-shot firing.

1. Pulverized fuel boiler pipes from mill
2. Cyclone separator
3. Rotary feeder
4. Primary air
5. Pulverized fuel boiler pipe
6. Down shot burner
7. Secondary air
8. Tertiary air
9. Vapors
10. Vapor burner
11. Oil burner
12. Furnace
13. Submerged chain conveyor

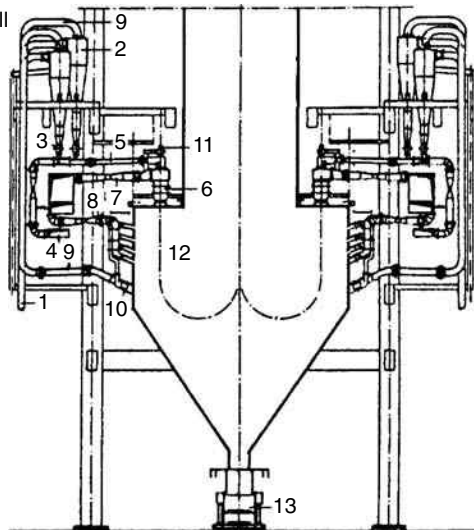


FIGURE 9.26
W-type down-shot firing.

- *Vertical-tube furnace construction.* Vertical tubes make construction simpler. The modern vertical furnace employs ribbed or rifled tubes in place of the spiral. The high heat flux is effectively countered by high heat transfer rates pervading in the rifled tubes despite lower mass flows.

The early SC boilers built in the United States in 1950s and 1960s were UP-types with vertical plain tubes and mainly with constant pressure base load operation

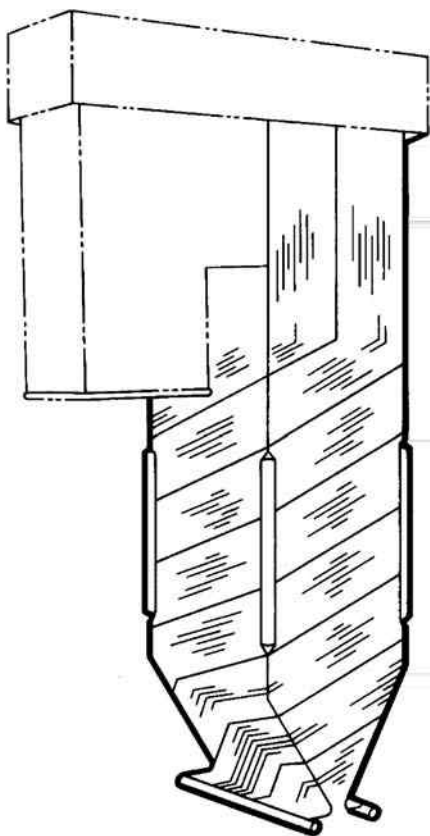


FIGURE 9.27
Spiral furnace tubes for supercritical boilers.

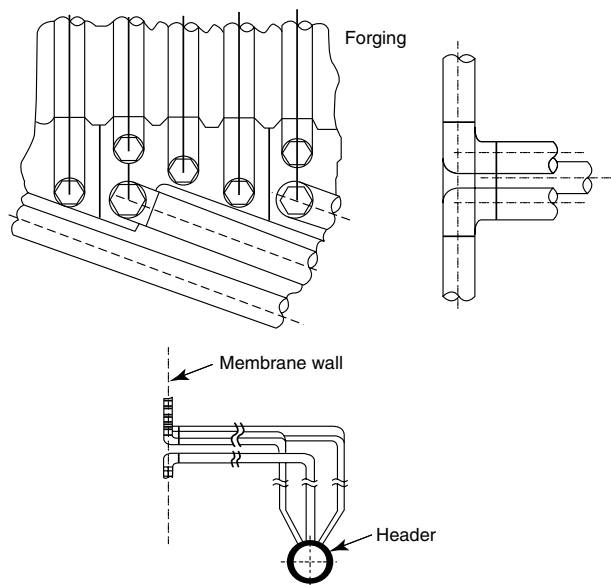


FIGURE 9.28
Transition from spiral to vertical tube.

and at times with only load cycling. As the SC boilers achieved the highest efficiency, they were used for base loading and, naturally, the cycling duty was low. Serious problems of tube overheating required reduction of steam temperatures from 566 to 538°C.

The vertical tubes allowed nearly the same construction features of drum-type boilers. For the service intended they performed well.

The vertical tube designs continued into the 1990s even as the boiler arrangements changed. Two-pass and tower-type boilers have been built to as large as 1300 MW capacity with vertical tubes, mostly operating at 250–265 bar (~3600 to 3800 psig). The temperatures have been maintained at 538/538°C (1000/1000°F), having decreased from the earlier levels of 566°C (1050°F) during 1970s and 1980s. With metallurgical improvement, higher temperatures are used again and UP designs are abandoned in favor of multifiuted ribbed tube construction.

- *Spiral tube construction.* Spiral wall furnaces have been in operation in Europe and Japan for many years for sliding pressure operation along with daily start/stop service. Most operate at ~240 bar (3500 psig) with SOT of ~566°C (1050°F) level. Steadily higher pressures and temperatures have been employed.

The spiral arrangement of tubes shown in Figure 9.27 is generally more expensive and complicated. The tubes are selected usually between 31.8 and 42 mm OD and spaced to suit the fin material temperature limits and usually with a gap of 19 mm as in PF boilers. There is a large pressure drop of ~11 bar in the tubes, adding to the burden of the feed pump. The sloping tube panels are more difficult to build and support. The load of the lower spiral furnace must be transferred by means of complicated sliding straps to the upper furnace tubes. The number of welds is greater. The transition to vertical tubes from spiral arrangement is done at a height where the heat flux is low with the help of transition pieces with suitable headers. This adds cost, welds, and fabrication time. This transition is usually achieved by the use of mixing header to achieve uniform steam enthalpy at the inlet to upper furnace. This arrangement is shown in Figure 9.28.

For the same circuit, the number of spiral tubes required is lower as shown in Figure 9.29; at 30° inclination, the number reduces to half. Unlike the vertical tubes,

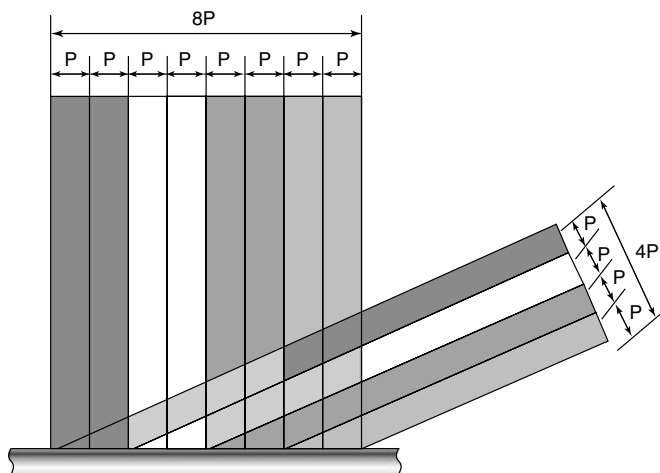


FIGURE 9.29
Reduction in number of tubes in spiral wall.

as the spiral tubes wind around the furnace, all the tubes are equally exposed to the varying heat flux incident on the walls. This minimizes the differences in tube-to-tube heat absorption, making the entire wall expand and contract like a single tube (Figure 9.30).

Figure 9.30 shows the four walls of the furnace with the adjacent tubes identified as 1 and 2. Both tubes will have nearly the same heat pickup in the spiral wall, while the heat pickup is different in the vertical wall.

- *Vertical or spiral for future?* Over 600 SC boilers are in operation worldwide. There is a discernable trend toward higher steam pressures and temperatures and vertical and spiral tubing. Vertical tubing with ribbed tubes and low mass flows of $<1000 \text{ kg/m}^2 \text{ s}$ ($\sim 750,000 \text{ lb/ft}^2 \text{ h}$) appears to be the future direction because of cost advantage and simplicity. The cycling aspects of spiral tubing need to be built into this arrangement. Figure 9.31 shows a subcritical PF boiler of vertical-ribbed tube construction.
- In OT boilers, feed pump speed and turbine throttle are used to control steam flow and steam pressure. SH steam temperature is controlled by fuel firing rate, while RH steam temperature is controlled by gas recirculation (GR), excess air, and attemperation in combination. Gas tempering is used for temperature control entering the SH.
- For maintaining a safe minimum flow through the furnace tubes at all times, a steam bypass arrangement, which dumps the steam to the condenser at low loads, is an integral part of the boiler and turbine system (Figure 9.32).
- Aside from the furnace construction and circulation-related aspects, the remaining parts of the SC boiler are similar to conventional boilers in sizing.
- Two-pass, tower, and modified tower types are the common configurations for coal-fired boilers.

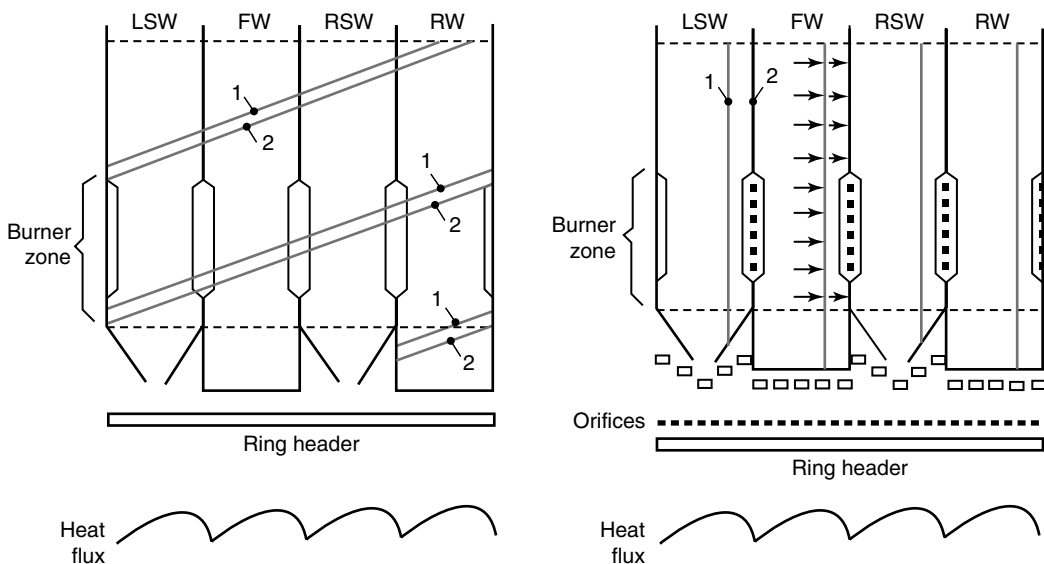


FIGURE 9.30

Spiral and vertical tube arrangements in supercritical boiler furnaces.

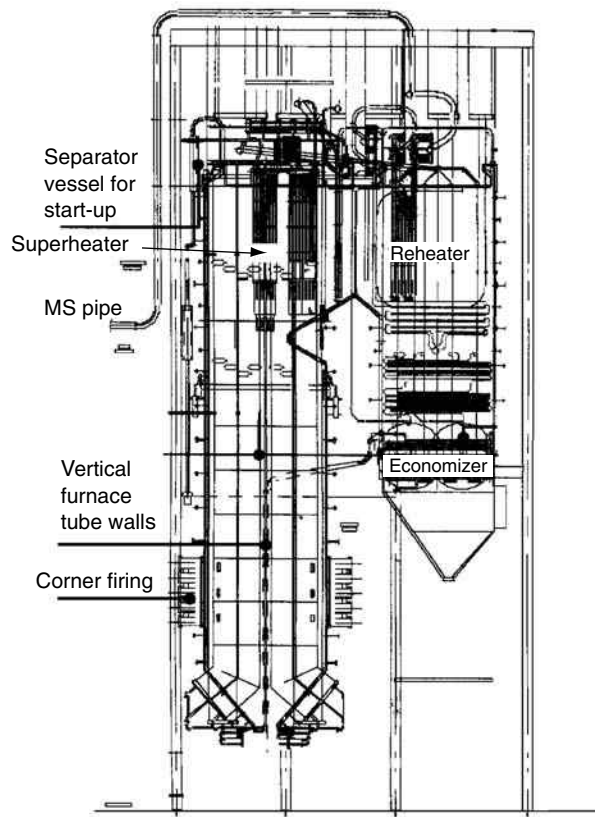


FIGURE 9.31
A 300-MW two-pass subcritical boiler with vertical-ribbed tubes with low-mass flow. (From Doosan Babcock Energy Ltd., U.K. With permission.)

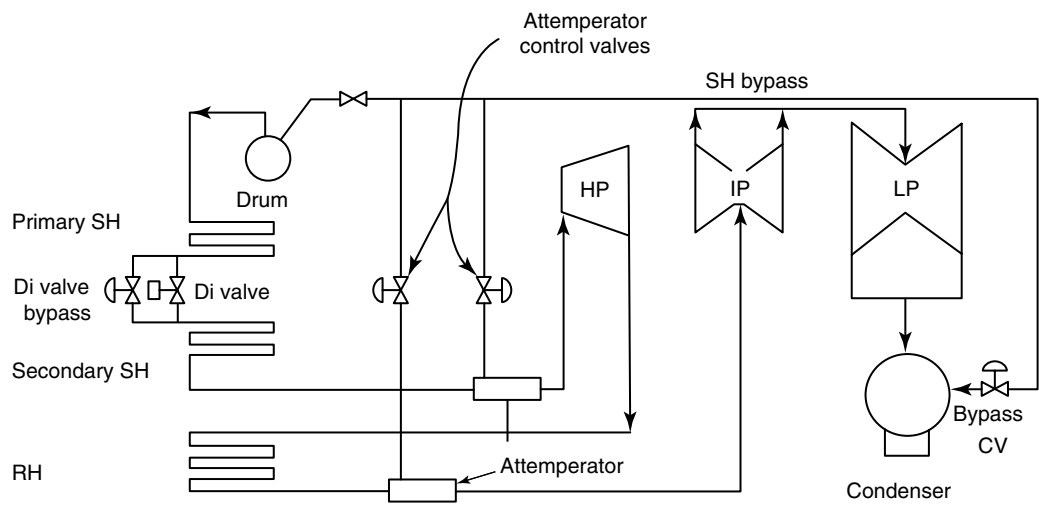


FIGURE 9.32
Flow bypass to condenser for drum-type boilers.

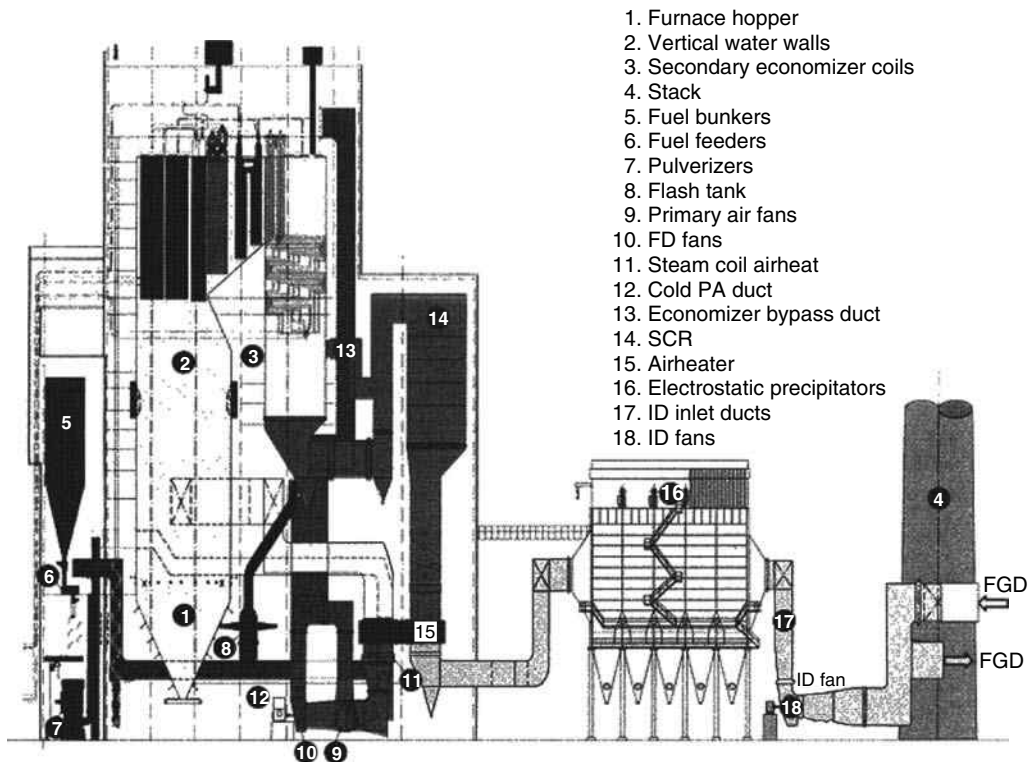


FIGURE 9.33
Typical modern 800 MW standard supercritical boiler.

9.3.5 Drum-Type or Supercritical Boiler?

The answer depends on local conditions. The following paragraphs examine the pros and cons:

- Both drum and SC boilers are built to very large capacities. In terms of size and boiler efficiency they are nearly the same. The SC boilers have separator vessels in place of heavy drums, but the tubing in the furnace is an alloy material and furnace construction is more expensive. The draft plant in the SC boiler is a bit smaller, but the feed pumps are required to operate at higher pressure. The valves, mountings, and fittings are heavier and more expensive in SC boilers. On the whole, the SC boiler is more expensive than the drum type, with the gap reducing as the capacities increase and more boilers are built. One has also to factor life cycle costs to realize the full impact.
- A power plant operating at SC conditions is more efficient compared with the plant at subcritical pressures due to better cycle efficiency and variable pressure operation. The plant is also more flexible in operation. But the difference in efficiency is rather small if the SC station is base loaded. The boiler, piping, turbine, and feed station are all more expensive due to higher pressure and metallurgy. The incremental costs are not offset by base-loaded pit-head stations with low fuel costs.
- The comfort level of the plant owners also comes into play as an SC system demands greater O&M skills from the staff. Water quality is also more demanding for an SC boiler.

- It is generally accepted that SC plants are viable beyond ~300 MW, which means that the grid should also be large enough.

9.3.6 Standard Plant Configurations for Supercritical Boilers

To optimize the costs of SC plants, large power plant makers from Japan, South Korea, and recently China advocate standard plants in the sizes of 600, 800, and 1000 MW capacities. One such plant for 800 MW is shown in Figure 9.33.

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10

Burner Firing

10.1 Oil and Gas Firing

Liquid and gaseous fuels are burner fired. Solid fuels when pulverized and mixed with air are also amenable to burner firing; this is covered in detail in Chapter 13. The new duct burners are used to fire light oils and gaseous fuels inside the confines of a duct. This chapter deals with the combustion of liquid and gaseous fuels in burners, whereas the firing of solid fuels in burners is discussed in Chapter 13.

Great strides were made with burner firing of oil and gas, and very large boilers were built in the United States and Europe for both power and process. Although oil is found in several countries, it is most abundant mainly in the Middle East, Venezuela, Nigeria, and Russia, which are politically sensitive. Since the early 1970s, the uncertainties of oil supplies and greatly fluctuating prices have slowly moved the markets away from oil. Meanwhile, natural gas (NG) has eclipsed even the most dominant fuels for over a decade. However, the use of NG has been in gas turbines (GTs) in combined cycle (CC) mode and not in boilers in conventional steam cycles. As a result, oil and gas firing in boilers is mostly for process and cogeneration (cogen) in refineries and petrochemicals. Some large oil-fired boilers have been built to handle refinery residue and other difficult applications.

- Oil and gas are the most desirable fuels but they are expensive, not produced in sufficient quantities, and riddled with geopolitics.
- Fuel oil (FO) packs the highest amount of heating value in the smallest volume and is the easiest to transport and store.
- Natural gas is excellent for combustion, as its heating value is high and it is the prime fossil fuel that produces the least CO_2 and NO_x .
- FO and NG are clean (gas more than oil) and easy to burn and exhibit rapid combustion characteristics.
- Both installation and O&M are very simple in comparison with solid fuel-fired boilers.

Even the synthetic fuels and waste gases, which may not be as clean or as rich as the fossil-fuel oils and gases, are easier to handle and burn. These features combine to make it possible to produce very compact boilers via shop assembly. Site work is minimal. Even for larger sizes, which cannot be assembled in the shop, because of size or transport considerations, a great deal of modular fabrication simplifies the site assembly. Package and modular boilers, possible mainly with clean and simple fuels such as oil and gas, have

1. Improved the equipment ratings
2. Enhanced the build quality
3. Reduced the delivery times
4. Raised the reliability levels of O&M

Although FO- and NG-fired boilers have shown growth, oil and gas firing is extensively employed in almost every type of boiler.

- Most solid fuels cannot start combustion on their own and need start-up support. Stoker PF, bubbling fluidized bed combustion (BFBC) boilers, and circulating fluidized bed combustion (CFBC) boilers require oil or gas for ignition.
- All solid fuels have definite load turndown, and below the minimum load, the firing becomes unstable. Oil and gas firing is employed when such low loads are encountered.
- Pulverized fuel boilers have small turndowns of 1:2 or 1:3 at best. Also, with wet coals in monsoons at ~50% load, they experience flame instability and oil or gas firing has to be pressed into service.
- With manufactured or waste fuels of limited availability, evaporation shortages and peak loads can only be met by oil and gas firing.
- With seasonal agrofuels, oil and gas are used during off-season unless some other agrofuel is available. Coal firing is not as economical.
- Supplementary firing is quite common to incorporate in gas-based cogen plants to get some additional evaporation or to generate full steam when the GT is down.

Burner firing also has good potential in firing a variety of waste liquid and gaseous fuels and forms the backbone of the waste heat boilers.

10.2 Burners and Combustion

10.2.1 Burner Size

Burner. A burner brings together the fuels and air in right proportions and admits them into the furnace chamber to accomplish combustion in an efficient and safe manner. It mixes and burns the fuel but does not control it. The proportion and regulation are performed externally for fuel and air by control valves and dampers, respectively.

Burners consist of four subassemblies:

1. Atomizer for oil and spuds/pipes for gas—for proper fuel admission
2. Air register for dividing and supplying the air with a proper swirl to provide adequate turbulence
3. Igniter for lighting the fuel
4. Flame monitor for checking the health of the flame

The shape and size of the furnace helps to develop the flame properly and achieve the completeness of combustion. Burner sizes have grown dramatically. Approximately 2 tph of oil firing per burner was considered maximum in 1960, which grew to ~8 tph by the 1970s. There has been no significant increase in burner capacities, but the efforts focused on environmental compliance.

Burner size is always designated by the diameter of its *throat*—the slightly narrowed channel in the air register through which all air is directed toward the combustion area of

the burner. As combustion air accelerates in the throat, there is a corresponding drop in pressure. The differential pressure so created can be used to measure the airflow.

In parallel flow air registers, the swirler is normally half the size of the throat. In the swirler, ~35% is blanked and 65% is free for air. Throat sizes vary from 250 to 900 mm (10 to 36 in.) and more for land boilers. Single-burner capacities exceed 7 tph of oil firing or 90 MW/h (~75 m kcal/h or ~300 MBtu/h).

10.2.2 Burner Turndown

- *Turndown* is the range of flows in which combustion is stable. It is the ratio of stable maximum to minimum flow. The term covers the boiler, burner, and atomizer.
- Atomizer turndown refers to oil, whereas burner turndown refers to air and oil regulated by the upstream regulating valve and damper, respectively.
- Any turndown inevitably results in pressure loss. Higher turndown means higher pressure losses of both fuel and air.
- Turndown ratios of 1:4 for the whole oil or gas burner and 1:10 for oil atomizer are normal and adequate for most boiler duties with 100–150 mm w.g. (4–6 in.) of air pressure loss. Turndown ratios of 1:6 for oil and 1:10 for gas are also possible at the expense of more air and fuel pressure losses. Gas pressure of 1.75 atg (~25 psig) in the burner manifold at full load is needed for 1:10 gas turndown so that at 10% load, the gas pressure is 0.0175 atg or 175 mm w.g.
- Boiler turndown ratio of 1:4 is normal for oil- and gas-fired boilers. For more turndown, higher air loss has to be provided with a bigger FD fan having higher head. Alternatively, the number of burners in operation can be reduced with manual intervention.

Hot air and combustion efficiency.

- Completeness of combustion with the least excess air is the goal of both a good burner design and operating practice.
- For complete and swift combustion, hot air is normally used at temperatures of 200–300°C (~400 to 600°F).

Completeness of combustion is defined as the full oxidation of all the combustible elements in the fuel. In most cases, the unburnt carbon loss in oil and gas firing is considered negligible, thereby meaning that the combustion or carbon burn-up efficiency is nearly 100%. For heavy FOs, unburnt loss can be 0.1%. This loss is measured by the CO levels in flue gas, which, at <200 ppm at 3% O₂ level, is satisfactory.

From NO_x generation, cold air is preferred, as discussed in Section 10.2.8. This defeats maximum efficiency and a compromise between CO and NO_x has to be made.

Opacity of stack is the visible indication of completeness of combustion.

- Dark plume represents incomplete combustion and can be corrected by optimizing the combustion parameters.
- White plume is due to fumes of sulfuric acid, and excess air should be controlled.
- Light brown haze is the desired opacity.

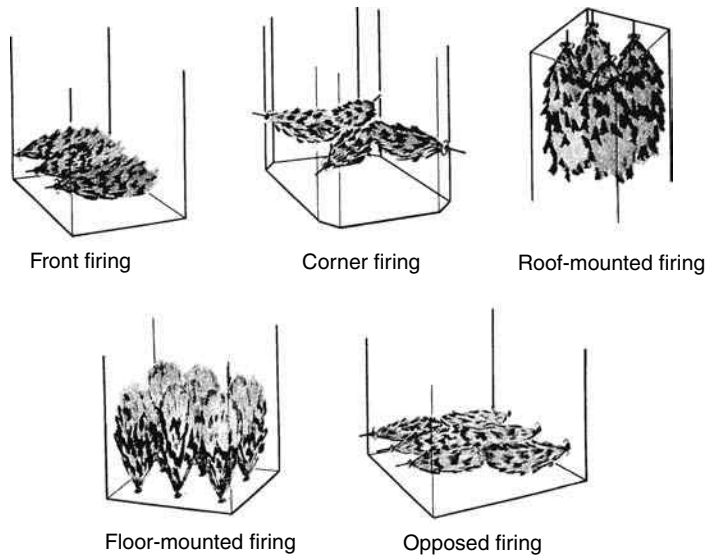


FIGURE 10.1
Various burner positions.

10.2.3 Air Registers

Air registers are the fabricated portions of the burners fitted to the windbox through which air is admitted. They hold the fuel-firing parts in position, namely, the oil atomizers and the gas rings and spuds. The shape of the air register gives the burner its name.

There are two types:

1. *Tangential*, mounted in furnace corners
2. *Circular*, mounted on furnace walls

Depending on the entry of air, the circular burners are classified as

1. Tangential flow or register type producing short and bushy flames (Figure 10.7)
2. Parallel or axial flow type producing long flames (Figure 10.8)

Burner types and location. Burner arrangements are extremely flexible. They can be wall mounted, corner mounted, roof mounted, or even floor mounted. Figure 10.1 depicts *turbulent or wall burners or circular burners*, except for the corner-fired burners, which are *tangential*. There is an intense mixing of air and fuel, resulting in short and hot flames in circular burners. In tangential burners, air and fuel travel in parallel paths and toward an imaginary circle in the center of the furnace where intense mixing and combustion occur. The whole furnace acts as a burner.

10.2.3.1 Circular versus Tangential Burners for Oil or Gas

Circular burners are more common because

- The tangential burners need nearly square furnaces
- A set of four burners have to act together

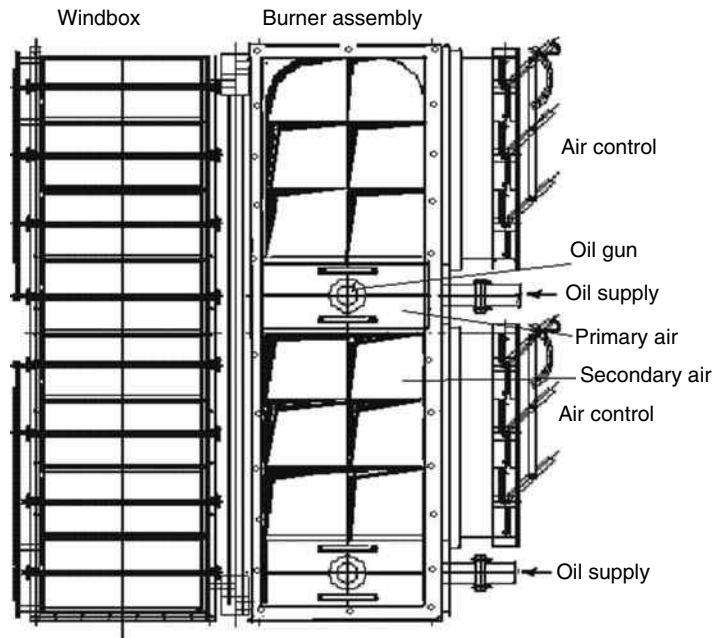


FIGURE 10.2
Tangential oil and gas burner assembly.

This arrangement naturally rules out smaller quantities of oil and gas firing. The package-type boilers with long furnaces are also ruled out. Tangential burners are used for large integral furnace boilers. Radiant boilers are particularly used for waste gases whose volumes are large. In tangential oil and gas burners (Figure 10.2), the flows of oil, gas, and air are parallel to each other, meeting tangentially on an imaginary circle in the middle of the furnace. Thereafter, the furnace shape provides the necessary swirl. This is shown in Figure 10.3.

10.2.3.2 Arrangements with Circular Burners

Circular burners on the front wall are the most popular arrangement. Opposed firing is done when the boiler size exceeds a certain size. Floor and roof mounting saves the plan area of the boiler and makes use of the long furnace shaft for full development of the flame when it suits the layout. In floor mounting, access to the burner is very good, and the piping is short but the boiler gets raised by ~ 3 m. The reverse takes place for roof mounting. The boiler layout determines burner location.

10.2.4 Excess Air for Oil and Gas Firing

10.2.4.1 How Much Excess Air?

This depends on the following factors:

- Stoichiometric or 0% excess air does not help attain complete combustion, as some fuel escapes. Air should be at a minimum to contain stack loss and attain best efficiency.

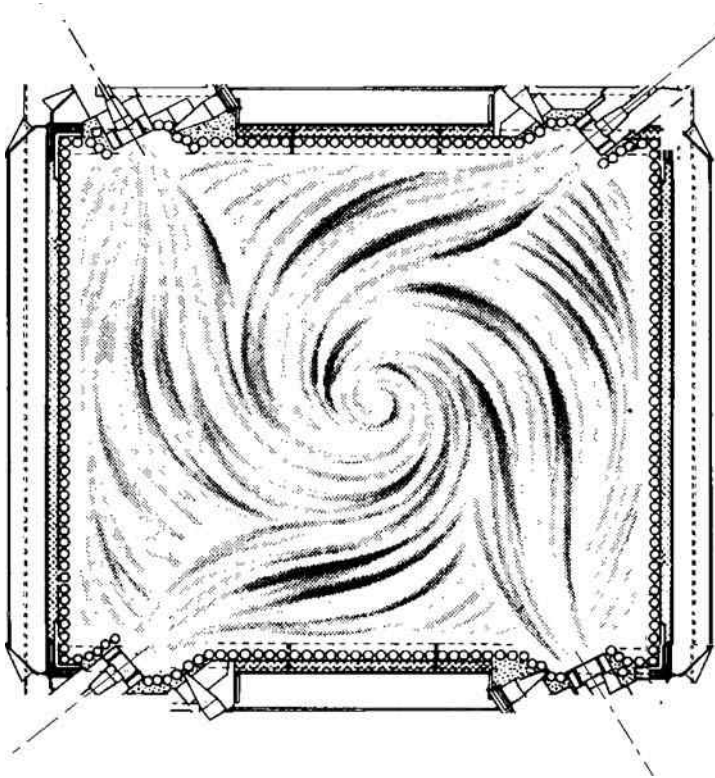


FIGURE 10.3
Swirling flames at center of furnace.

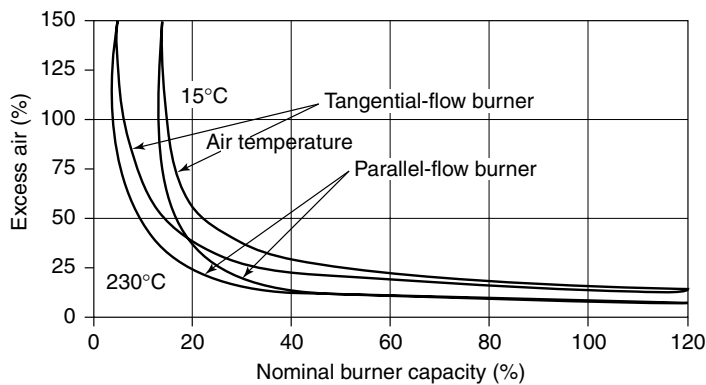


FIGURE 10.4
Excess air at part loads and air leakage.

- Between 5 and 15% excess air is normal, depending on the burner and the furnace geometry with all burners in operation.
- At part-load operation, the air velocity and turbulence get reduced, affecting the combustion efficiency. To compensate, the excess air is increased. With no reduction in the number of burners, the increase of excess air is steep at low loads, as shown in Figure 10.4. The excess air increases with parallel-flow registers, and hot air is lower.

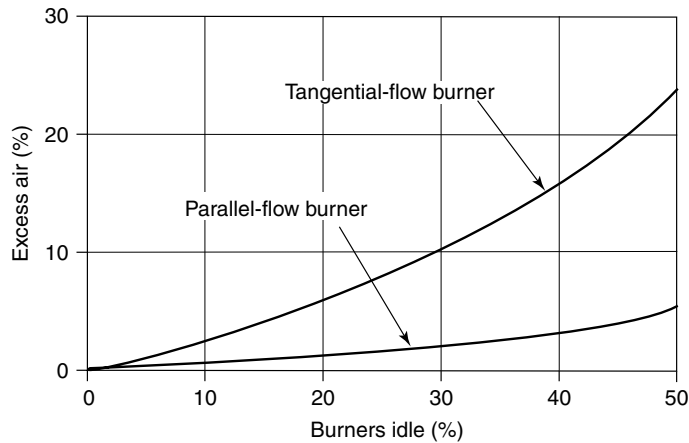


FIGURE 10.5
Air leakage through idle burners.

- At some point, it is better to cut out a burner than increasing the excess air. Some air has to be passed through the idle burner to keep it cool. This air requirement is shown in Figure 10.5.
- Air exceeding the minimum requirement from the point of combustion efficiency, is an easy way at part loads to restore the falling superheater (SH) temperature and thus increase the steam temperature control (STC) range.
- Low excess air reduces the back-end temperature, which can then slide into corrosion range below a certain minimum temperature level. In such cases, excess air may be required.

10.2.4.2 Excess Air in Burners

Improvements in atomization of FO and distribution of fuel gas and greater turbulence given to air streams by better geometry of the air register allow better contact between air and fuel. As a result, the excess air in burners has been progressively reduced over the years.

With *tangential airflow* in register burners, the excess air is between 10 and 15%. The combustion is very vigorous, and the flame is bushy and close to the burner with a short flame length. The burners in smaller package boilers with restricted furnace dimensions and light-up guns in PF burners are examples of register burners.

In parallel-flow burners containing excess air levels of 5–10%, air flow moves parallel to fuel flow. The swirler at the throat is shaped to allow rotation of the primary air (PA) flowing through it to help develop a small negative pressure zone to anchor the flame to the front of the swirler. A twist of the PA is better for combustion than tangential flow of secondary air (SA).

Venturi burners. A low excess air level of 5% with oil and ~3% with gas can be attained. For this reason, the parallel-flow burner has to be slightly modified to a Venturi shape for better mixing and better measurement. The flame is long, and the burning is stretched.

Parallel-flow registers are the industry norm today. Low- NO_x burners are intended to achieve excess air of 2.5%.

Gaseous fuels require lower excess air than liquid fuels, as they can more easily disperse and mix with air than any liquid fuel with the finest of atomization.

10.2.4.3 Normal or Low Excess-Air Burner

Excess air levels are 10–15% for normal and 3–5% for low excess air burners. Low excess air burners are superior in construction and operation. They have not superseded the normal excess air burners yet, and the industry continues to favor both.

The advantages of low excess-air burners are as follows:

- Low excess air improves the boiler efficiency.
- They reduce NO_x .

The disadvantages are as follows:

- More furnace volume because the flames are long.
- More SH surface because the gas flow is less.
- In multiple-burner boilers, accurate airflow measurement should be provided or burners will operate at substoichiometric conditions and others will require extra air.
- O&M costs increase and the system is less tolerant to operational errors.

In industrial boilers, in general, and in packaged boilers, in particular, with smaller furnaces and premiums on space, burners with normal excess air are favored.

10.2.5 Combustion of Oil and Gas in Circular Burners

Figure 10.6 depicts the development of a flame cone in a circular burner, its stabilization on the impeller/swirler, and the recirculation of hot gases to help ignition. It also shows the PA penetrating the oil mist and SA giving the flame shape. As in any combustion reaction, there are several simultaneous actions at work:

- Air is split into PA and SA and, at times, also into tertiary air (TA) for a better mixing of fuel and air and also for greater control.
- Primary air travels parallel to the fuel and penetrates the oil and gas streams, helping ignition and partial combustion, whereas the SA travels tangentially or parallel to the fuel to complete the combustion and contain or control the flame shape.
- Primary air passes through the swirler or impeller or diffuser, which provides a twist to the air as it tries to penetrate the cone of oil mist emanating from the atomizer. This promotes a vigorous swirl to the PA and the oil mixture.
- The swirler provides a low-pressure zone in its front, where the hot combustion gases tend to recirculate and provide ignition. This is also aided by the radiation from hot furnace gases.
- The ignited oil flame settles at the swirler front. The fuel gas, if present, is also injected into the same low-pressure region at an angle to match the angle of the swirler, and the gas flame also settles there.
- Secondary air traveling tangential or parallel to the flame helps to complete the combustion and shape the flame. With a greater swirl to the SA, there is a higher air speed that accelerates combustion and makes the flame wide and short. Thus, the adjustment of air vanes regulates the flame shape.

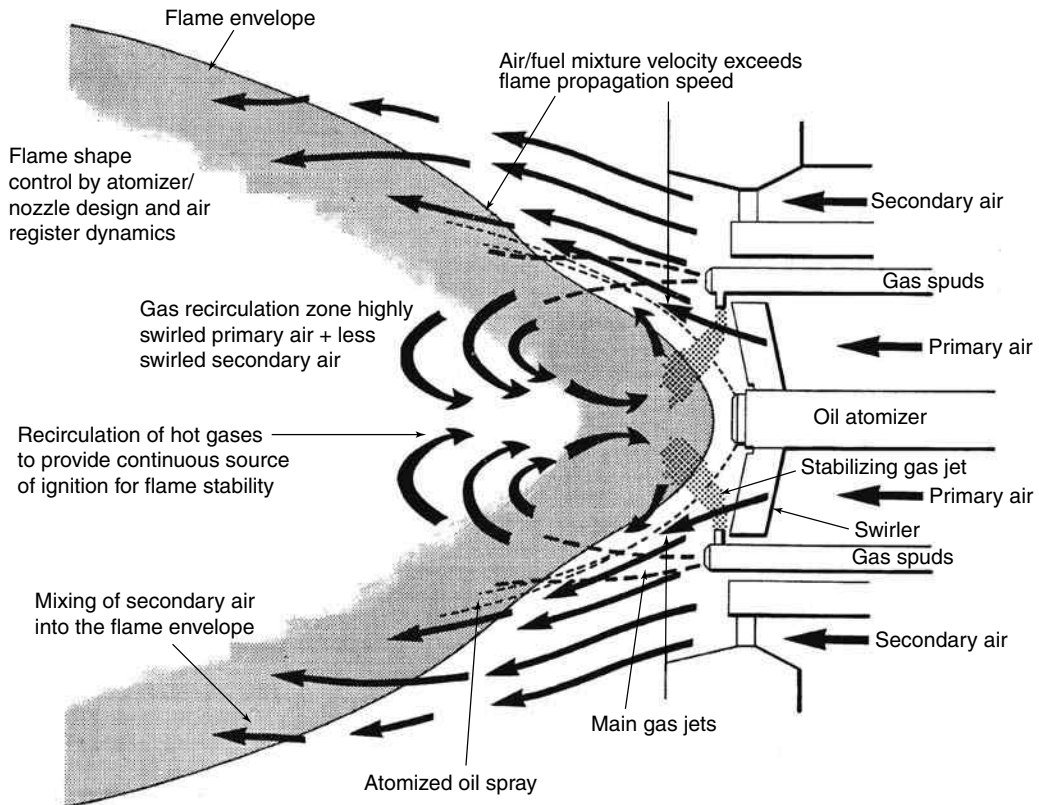


FIGURE 10.6
Flame stabilizing and gas mixing patterns in combination firing.

- In parallel-flow registers, there is no flame-shape control. The sliding of the air door is only for on-off duty. The flame is always long and tubular.
- The atomizer is always concentrically placed to the swirler with oil holes ~20 mm away, with no impingement of spray on the swirler or the burner quarl (refractory setting).
- The refractory quarl of the burner has a very important role to play. The refractory holds the heat and radiates onto the flame for better combustion, hence aiding ignition. At the same time, it protects the furnace tubes from erosion damage due to the swirling burner gases (Figures 10.7 and 10.8 and Table 10.1).

10.2.6 Atomizers

Atomizers are used for liquid fuels and two types are available. *Atomization* is the process of breaking down the oil film to a fine mist to enable completion of combustion in the shortest time within the confines of the furnace. It can be achieved mechanically or with the aid of steam or air.

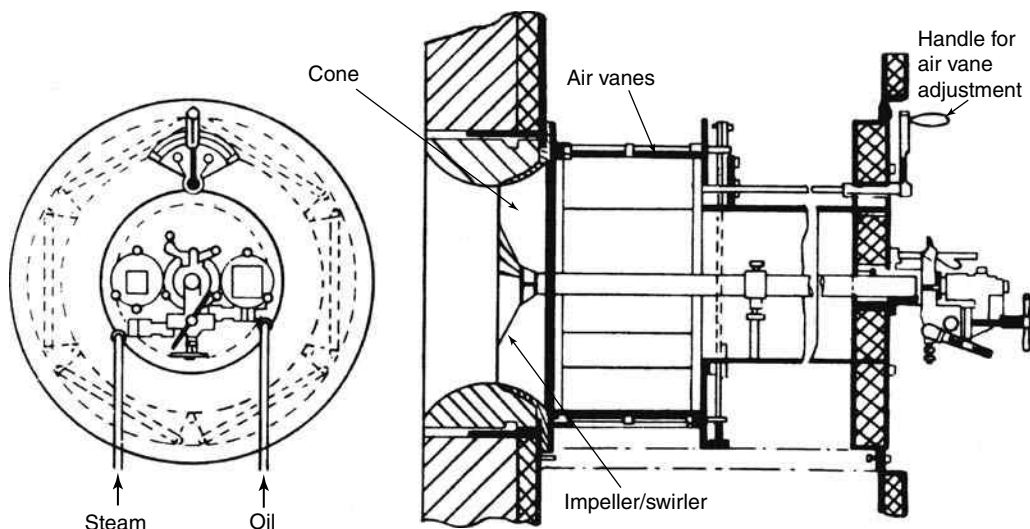


FIGURE 10.7
Register-type circular burner.

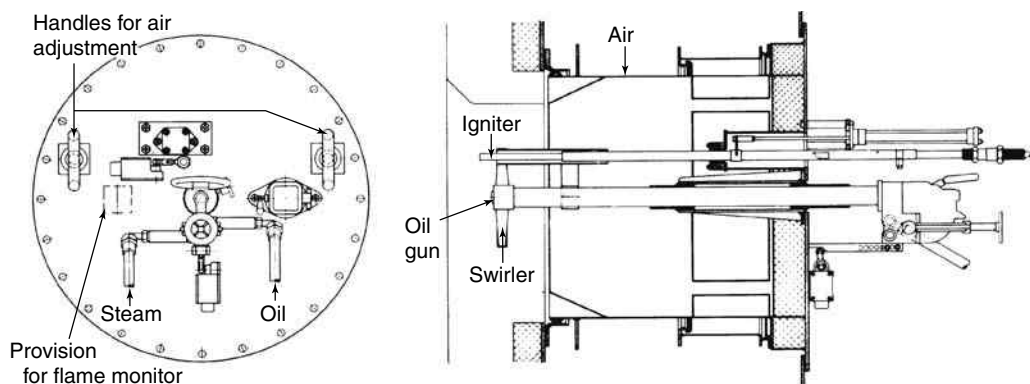


FIGURE 10.8
Parallel-flow type circular burner.

TABLE 10.1

Register versus Parallel-Flow Burners

Parameter	Register Burner	Parallel-Flow Burner
Airflow with respect to atomizer	Tangential	Parallel
Flame shape	Short and bushy	Long and narrow
Excess air	High at 10–15%	Low at 5–10%
NO _x	Higher	Lower
Furnace volume required	Less	More
Application	Small package boilers or short flame needed	Large package boilers or field-erected boilers

For both types of atomization, oil has to be made sufficiently thin by heating to an atomizing viscosity.

- For steam atomizers, the viscosity of oil is required to be between 200 and 250 SSU, although for a wide turndown, the desired range lies between 100 and 150 SSU.
- For mechanical atomizers, it is required to be a bit thinner at 80–120 SSU.

This means the oil should be heated to approximately

- 60–70°C for light oils
- 95–105°C for heavy oils

Care is needed with the heating of heavy oils. At higher temperatures, vapor formation can take place, leading to the *vapor locking* of oil lines and atomizer. This vapor locking is dangerous because it would result in a flame blowout followed by reignition, which can lead to furnace explosion.

Figure 10.9 shows the viscosity variation with temperature for various FOs, which can serve as a good guide for FO transport, storage, and combustion. The viscosity graphs make it easy to predict the properties of FOs. Also refer to Figure 3.9 for additional information on handling of FO.

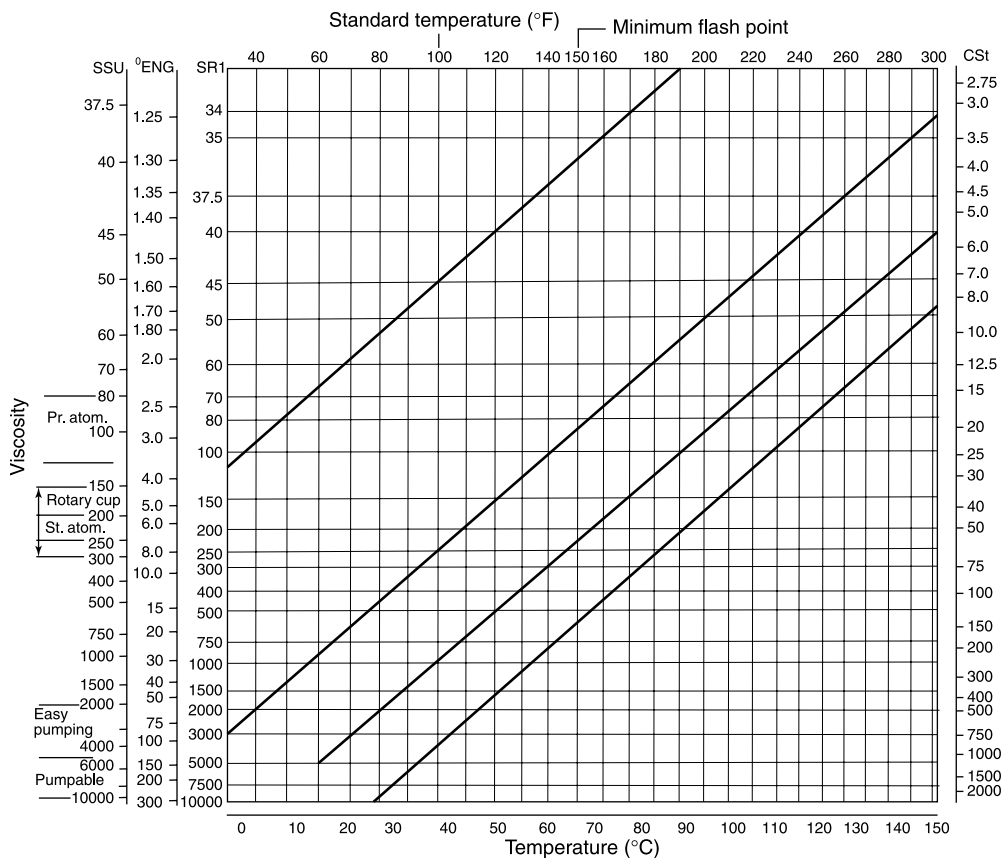


FIGURE 10.9
Viscosity versus temperature for fuel oils.

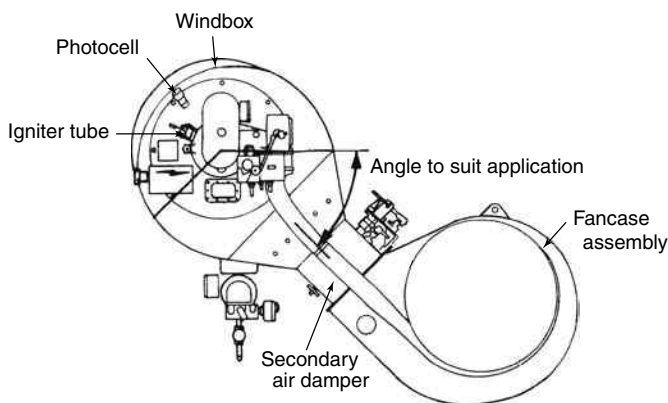


FIGURE 10.10
Rotary-cup burner with forced-draft fan arrangement.

10.2.6.1 Mechanical Atomization

10.2.6.1.1 Centrifugal or Rotary-Cup Atomizers

Rotary cup is a popular method of mechanical atomization. A cast aluminum cup rotates at a high speed, typically at 8,000–10,000 rpm, and the heated oil introduced at the center spreads out by the centrifugal force to form a fine mist.

- Rotary cups are simple, rugged, and reliable.
- Turndown is limited and the atomized particles are coarser.
- Maintenance increases because the moving parts are exposed to heat.

Burners that handle up to 4 tph of oil can be built on this principle. Gas firing and dual firing can also be done in such burners. Gas is introduced in the annular space.

Rotary-cup burners are used in furnaces and marine boilers where short flames are needed, and the firing equipment has to be compact. They are not popular for land boiler application (Figures 10.10 and 10.11).

10.2.6.1.2 Pressure Atomization

The most popular type of mechanical atomization involves pressure. Oil is pressurized to ~40 to 70 ata depending on the desired turndown. The two types of pressure atomization are variable and fixed pressures.

1. *Variable-pressure atomization.* Only the required amount of oil, as dictated by the load demand, is controlled and admitted into the boiler. The oil flow control valve is upstream of the burners. Burners receive oil at variable and lower pressures as per load. Owing to the lower pressure, the atomization is not as good as that in the fixed-pressure system, but there is no return of hot excess oil to the oil tank, which is wasteful and can lead to coking of oil.
2. *Fixed-pressure return-flow atomization.* All the oil is pumped to the atomizer tips and the excess oil is regulated and returned to the oil tank. The tips have tangential slots to produce a swirl. Full pressure is always available at the burner tip, which gives a better quality of spray. This is a more common arrangement for a more stable flame and better turndown. Even 10:1 turndown is possible for the atomizer with 70 ata oil pressure. With 200–300 mm wg windbox pressure, the turndown range is about 1:3 for the burner in total.

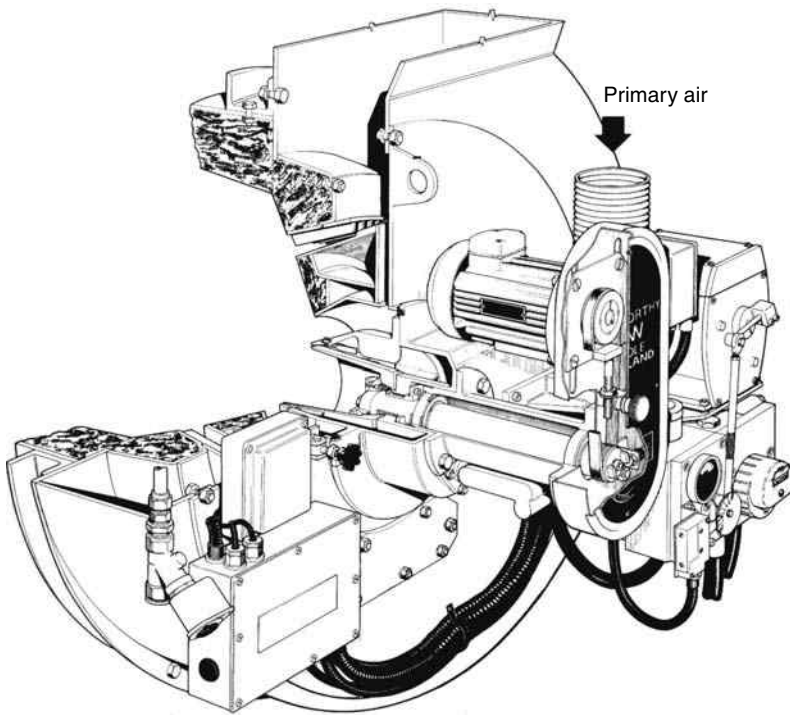


FIGURE 10.11
Rotary-cup burner.

Pressure atomization has the advantage of requiring no other medium such as steam or air and hence is very simple and convenient. But it has many limitations.

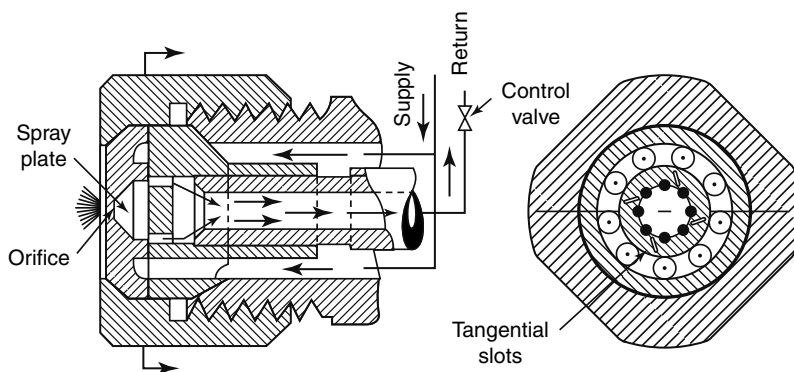
- Power consumption is greater because the atomizing pressure required is higher.
- Turndown is lower at 1:3 or 1:4 at best.
- Wear of tips is continuous and the resulting atomization is poorer, leading to a loss in combustion efficiency over time.

Pressure atomization is useful as a start-up system when the plant has no steam. The regular duty can be taken over by the steam atomizer after the start-up. It is also beneficial in multifuel firing in which oil is not the prime fuel (Figure 10.12).

10.2.6.2 Steam-Jet Atomization

Basics. Steam is used to shear the film of oil and produce the fine mist.

- Oil pressure required is a maximum of 20 bar (~300 psig) to get a wide atomizer turndown of 20:1.
- Corresponding steam atomizing pressure is ~10 bar (~150 psig), depending on the design.
- Most systems operate at 7 or 10 bar oil pressures (100 and 150 psig). A limited turndown of 6:1 on the atomizer can be realized with an oil pressure of 7 bar (100 psig), which is the minimum limit.

**FIGURE 10.12**

Tip of return-flow atomizer.

- Steam consumption is $\sim 10\%$ of oil consumption, which works out as 1.5% steam generation.
- Usually, the steam pressure is held constant and the oil pressure is varied with load.

Atomizing steam consumption. Steam consumption for atomization remains almost constant at all conditions. It would, therefore, appear to go up at low loads as a percentage of steam output. To minimize consumption, the pressure is also varied with oil pressure, keeping a differential of $\sim 1.5 \text{ kg/cm}^2$ with the help of a constant differential-pressure valve. There are also schemes in which the atomizing pressure is held constant at higher loads and varied at low loads to economize on the steam. Atomization of steam is a loss on two counts.

1. Nearly 2% of the steam generated is not available for final use and is wasted.
2. This steam adds to the stack loss reducing the boiler efficiency.

It, therefore, pays to adopt a system that consumes minimum atomizing steam.

Care of atomizer tips. As the steam consumption increases with dirty and worn-out tips, it is essential to maintain the tips by frequent cleaning and replacement. In large oil-fired power stations, it is economical to have separate package boilers to supply atomizing steam.

The atomizer tips are precision components machined from heat-resistant steel bar and nitrided to high hardness levels so that the holes retain their shape and dimensions for a long time (Figure 10.13).

Atomizer construction. Both steam- and pressure-jet atomizers are tubular in construction, varying in diameter only from ~ 50 to 80 mm , as the liquid fuels are of high calorific value (CV) and compact. Suitable removable tips are screwed at the furnace end, whereas the atomizer bodies or heads with handles are toward the operating platform. The central pipe of the burner supports the atomizer. Spring-loaded connections in the atomizer body permit safe connection and disconnection with the oil supply lines. This is shown in Figure 10.14.

A single pipe is sufficient for a pressure atomizer and a pipe-in-pipe arrangement is suitable for steam or air or return-flow atomizers. Steam always flows through the central pipe of the atomizer and oil in the annulus.

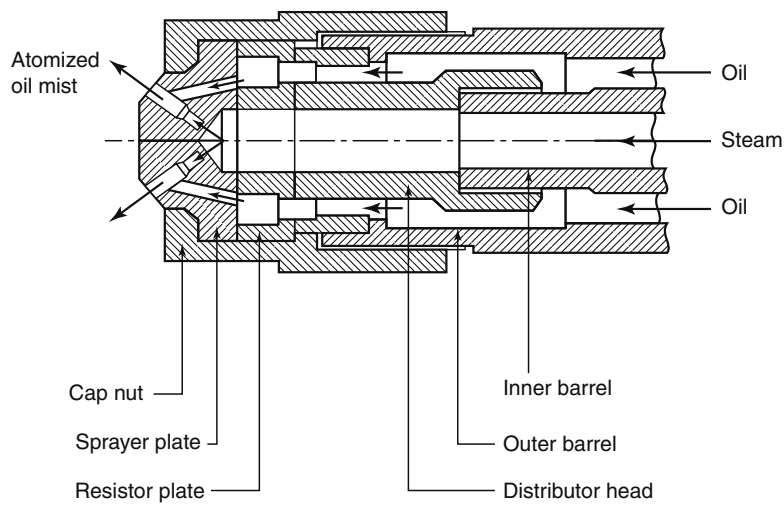


FIGURE 10.13
Tip of steam jet atomizer.

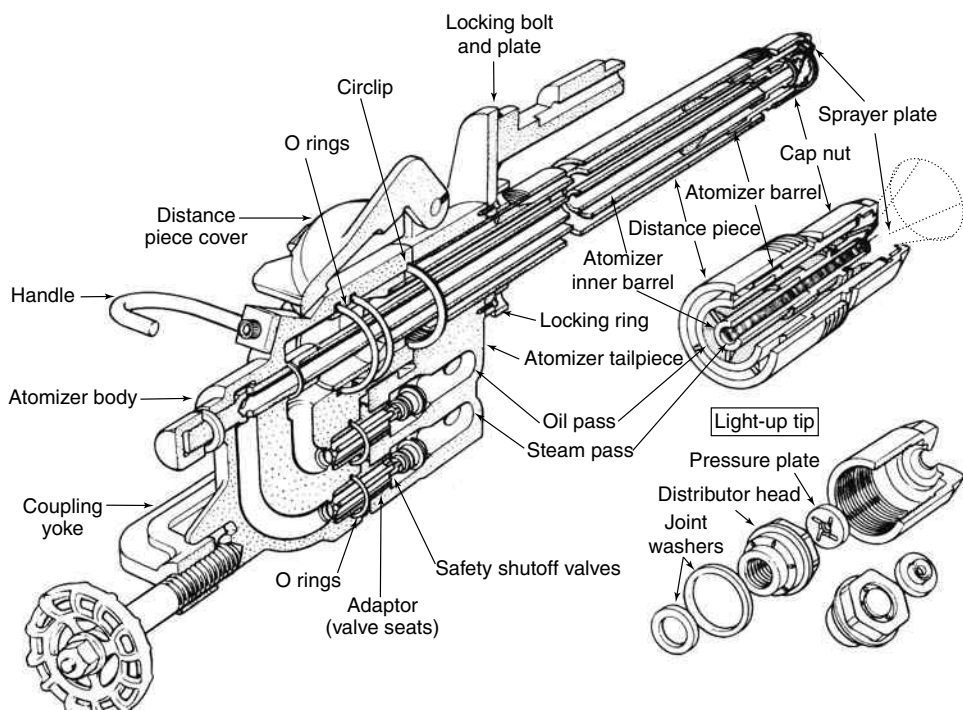


FIGURE 10.14
Assembly and parts of typical steam jet atomizer.

Atomization process. As the steam expands into the outlet nozzle, the pressure drops at the vena contracta to vacuum levels. There, the oil gets sucked through the holes to form an emulsion and jets out as a mist. Shearing of oil film by steam produces very fine droplets. The thin steam shears the thick oil film. The difference in viscosities causes the shearing of oil film.

TABLE 10.2

Pressure versus Steam or Air Atomization

Parameter	Pressure Atomization	Steam or Air Atomization
Atomization by	Pressure	Shearing of oil film
Quality of atomization	Coarse	Fine
Atomization viscosity	Lower	
Steam/air required	—	10–15% of oil fired
Steam/air pressure	—	~5 to 15 ata saturated
Oil pressure required	High at ~70 to 100 bar (~1000 to 1500 psig)	Low ~7 to 20 bar (~100 to 300 psig)
Oil temperature required	Higher for lower viscosity	—
Pumping power	Higher	Lower
Pumping temperature	Higher	Lower
Atomizer turndown	Lower ~10:1	Higher ~20:1
Burner turndown	Lower ~3:1	Higher ~5:1
Application	Intermittent duty Small amount of oil For start-up	Continuous duty Large amount of oil For load carrying

Because the steam attains vacuum levels to pull the oil in the nozzles, it is not necessary that steam pressure should be lower than the oil pressure. In constant-pressure atomizing systems, the steam pressure is higher than the oil pressure at lower loads.

Turndown. Steam-jet atomizers individually can give a wide turndown of 20:1. Figure 10.14 depicts the tip assembly.

Interchangability of atomizer tips. Usually the steam- and pressure-jet tips of return flow design can be interchanged. In PF burners, the light-up duty is handled by the pressure-jet atomizer and load carrying on the steam jet. The same assembly can be used with interchangeable tips.

Air-jet atomizers. The performance of air-jet atomizers is comparable with that of the steam jets. But the cost of an air compressor to provide high-pressure air in large quantities is more expensive. However, in process plants for black start-up operation, it is normal to adopt air-jet atomizers (Table 10.2).

10.2.7 Gas Burners

Air registers are for distributing and directing air for proper combustion. For both gas and oil burners, the same types of air registers are used. However, the difference is in the way the fuel is taken to the combustion zone and mixed with air. For liquid fuels, it is done with atomizers, whereas for gaseous fuels, some type of piping arrangement is required. As the fuel gases change widely in pressure, heating value, and temperature, the gas volume correspondingly varies, making the burner sizes and shapes alter significantly. Unlike the oil burners, the gas burners are available with a wide variety of constructions.

As the gas pressures and CV are lowered, the volumes increase, calling for larger gas pipes, which in turn, require different burner designs as listed in Table 10.3.

10.2.7.1 Circular Multispud-Type Natural Gas Burners

Natural gas firing is easy in circular burners with multiple spuds as shown in Figure 10.15. This design is suitable for any high-CV gas at good pressure, as given in Table 10.3.

TABLE 10.3
Burners for Various Gases at Various Pressures

Burner Type	Central Pipe		Ring	Scroll	Multispud
	High Pressure	Low Pressure			
Type of gas	Natural or town gas	Blast furnace gas or producer gas	Natural or town gas	Blast furnace gas or producer gas	Liquid petroleum gas or natural gas or refinery
GCV (kcal/Nm ³)	3000–12000	<3000	3000–12000	<3000	>8000
GCV (MJ/Nm ³)	12.5–50	<12.5	12.5–50	<12.5	>33
Gas pressure (bar)	High >0.8	Low <0.2	Medium 0.2–0.8	Low <0.2	High >0.8
Firing	Only oil or gas	Gas/oil/gas and oil	Gas/oil/gas and oil	Gas/oil/gas and oil	Gas/oil/gas and oil

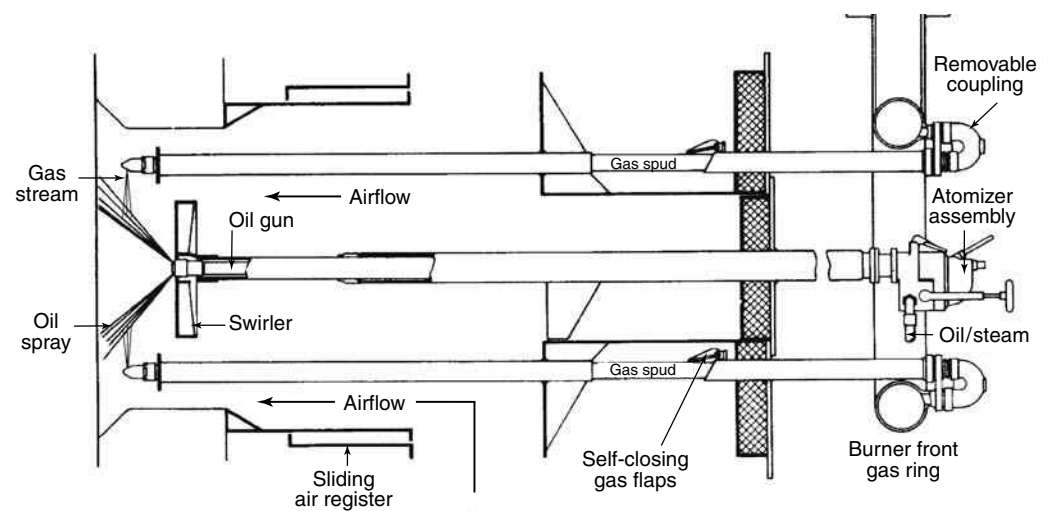


FIGURE 10.15
Circular multispudd burners with parallel-flow register for combined oil and gas firing.

- The gas ring, usually located outside the burner (or attached to the front plate and on the rear side to give a clean facade), has several spuds (pipes) branching off toward the swirler where the nozzles direct gas into the PA zone.
- A minimum gas pressure of ~175 mm wg or mbar is required in the gas ring and accordingly, for 1.75 barg pressure, a turndown of 1:10 will be possible.
- Each spud has three to four nozzles of ~10 mm diameter, depending on the gas pressure and the type of gas. By adjusting the orientation of the jets on the spuds, the flame can be made luminous or nonluminous. This is a great advantage in multifuel firing because the luminosity can be matched.
- Each spud has a collar to stabilize the flame at low loads.
- Each spud is joined to the gas ring by elbows in such a manner that it is possible to disconnect and take out the spuds for inspection. A flap door on the spud sleeve prevents the leakage of hot gases to the outside.
- When the gas quantity is small, a central gas pipe with suitable holes may be adequate in place of multispudds.

10.2.7.2 Other Gas Burners

The design and selection of the burners depend on the

- Calorific value of the gas
- Delivery pressure at the burner manifold
- Delivery temperature
- Multifuel firing requirement

Burner designs can assume a great variety. Table 10.3 gives some of the gas-burning possibilities in a simple manner. These burners are found mostly in process industries (Figures 10.16 through 10.19).

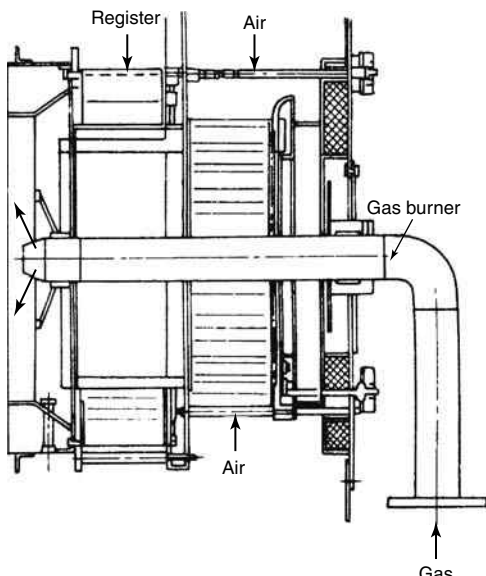


FIGURE 10.16
Burner with central pipe for high-pressure gas.

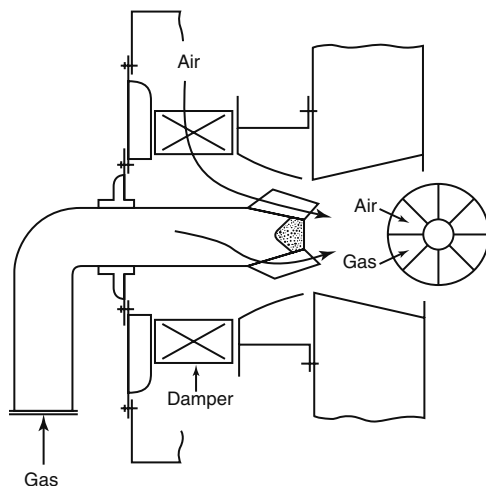


FIGURE 10.17
Burner with central pipe for low-pressure gas.

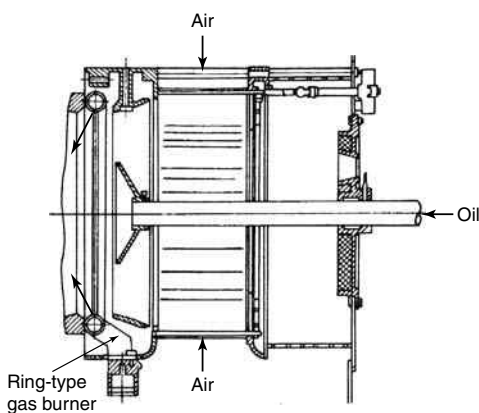


FIGURE 10.18
Ring-type burner for medium-pressure gases.

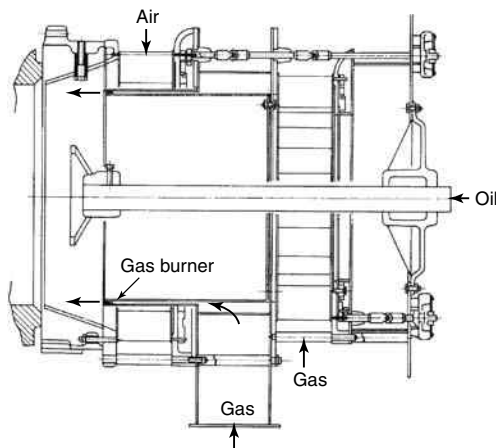


FIGURE 10.19
Scroll-type burner for low-CV gases.

10.2.8 Low NO_x Burners

NO_x in flue gas is the result of oxidation of otherwise inert nitrogen under the influence of high temperature. Two types of reactions promote the NO_x formation:

1. NO_x due to the nitrogen in fuel
2. Thermal NO_x due to the nitrogen in air

Heavier oil leads to higher nitrogen content. Light oils and kerosene contain nitrogen of $\sim 0.01\%$ by weight it increases to 0.3% in heavy oils. Fuel gases contain nitrogen in the form of NH_3 , HCN , etc. Typical NO_x generation with normal burners with cold and hot combustion air is depicted in Figure 10.22.

Circular burners with parallel- or axial-flow registers have already been explained. The low NO_x burners are modified axial-flow burners with:

1. Reduced excess air
2. More split air streams
3. Gas recirculation (GR) at times

The working principle of low- NO_x burners is illustrated in Figure 10.20, whereas Figure 10.21 depicts construction. All the above-mentioned factors work concurrently to produce low NO_x in the furnace.

- Lowered excess air reduces the tendency to form NO_x due to the scarcity of oxygen.
- As the air stream is split, the combustion takes place in stages, and this protracted combustion does not permit flame temperatures to reach their peak.

Thus, the flame is starved of both temperature and free air, suppressing the NO_x -forming tendency. These measures are adequate to secure more than 50% NO_x reduction. To attain as high as 70% reduction, flue gas from the furnace is recirculated and the air temperature to the burners is reduced to the minimum. The mass flow in the burner is maintained in this way for adequate turbulence but with no addition of oxygen. NO_x generation with normal circular burners is depicted in Figure 10.22, whereas Figure 10.23 represents the reduction in NO_x when all the three above-mentioned reduction measures are applied.

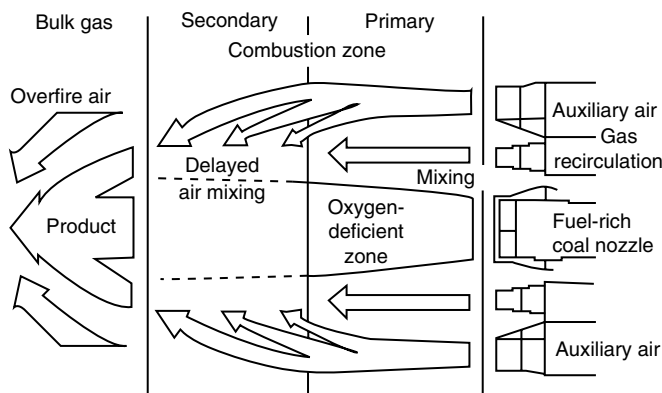


FIGURE 10.20
Working principle of low NO_x burner.

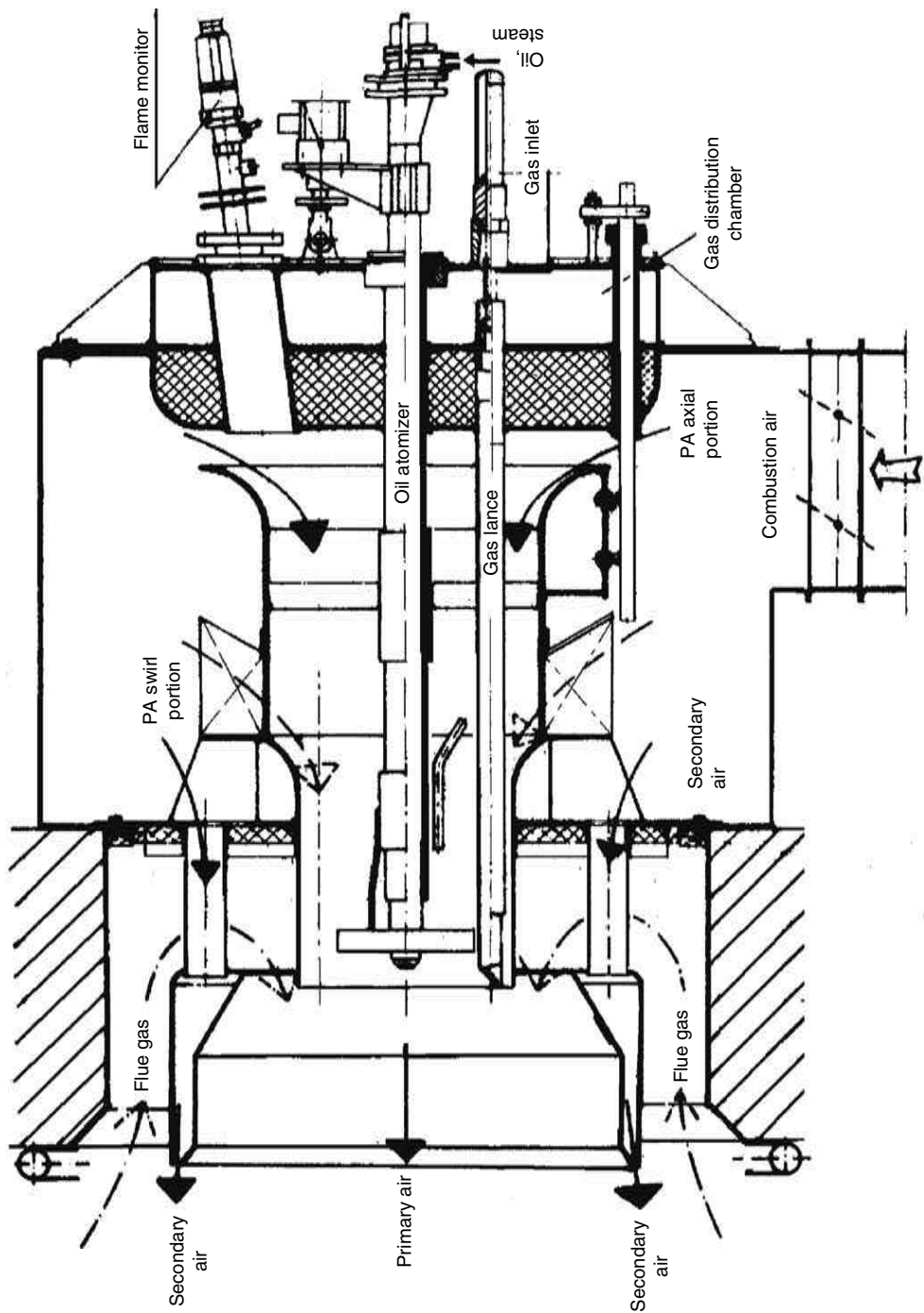


FIGURE 10.21
Typical low-NO_x burner.

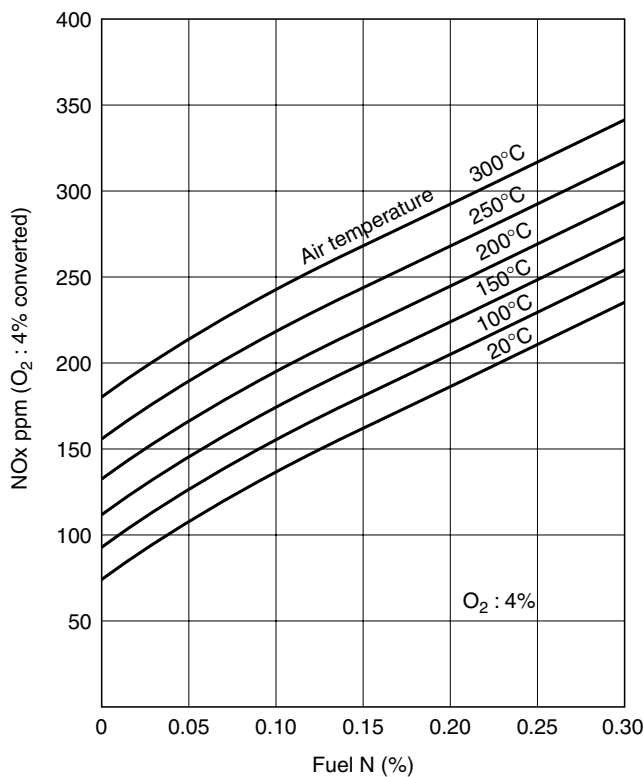


FIGURE 10.22
NO_x generation with normal burners.

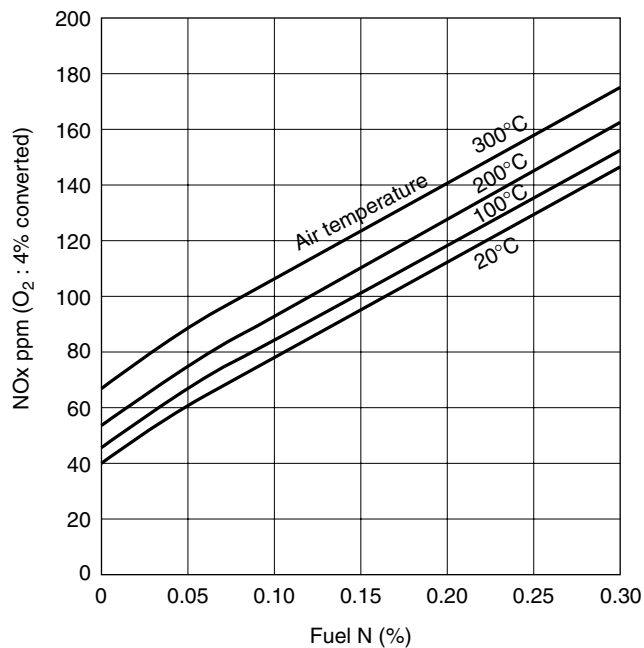


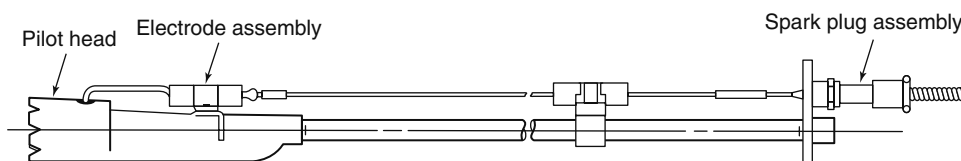
FIGURE 10.23
NO_x generation with low-NO_x burners. (From Coen Company Inc., U.S.A. With permission.)

TABLE 10.4

Igniter Classification

Class	Igniter Type	Load (%)	Duty
1	Continuous	>10	Ignite and support under any burner light-off or operating condition
2	Intermittent	4–10	Ignite under light-off and support under low load or adverse condition
3	Interrupted	<4	Ignite and turn off after timed trial and continuous supporting prohibited
3 spl	Direct electric		High-energy igniter capable of directly igniting main burner

Note: As per National Fire Prevention Association Regulation 85E.

**FIGURE 10.24**

Gas-electric igniters. (From Coen Company Inc., U.S.A. With permission.)

10.2.9 Igniters

The purpose of an igniter is to provide the heat energy needed to ignite the main flame in a safe manner. As per National Fire Protection Association (NFPA) of United States Regulation 85E (standards for prevention of furnace explosions in PF fired multiple-burner boiler furnaces), which deals with safety in design and operation of oil- and gas-burner equipment, the igniters are divided into four classes as given in Table 10.4.

Igniters can be stationary or retractable, the latter being preferable. With the stationary type, adequate cooling air must be supplied.

10.2.9.1 Gas-Electric Igniters

Gas-electric (GE) igniters, shown in Figure 10.24, are the most common igniters, as the electric spark has to ignite a clean fuel such as LPG, which in turn, ignites the main fuel. The spark igniter performs light duty, and it stays clean. The gas burns easily and provides a big flame for the main fuel to catch fire. The igniter includes a flame monitor to view the pilot flame. GE igniters are reliable, durable, almost free of maintenance, and extremely simple. If the NG or the LPG is available, this system is always preferred.

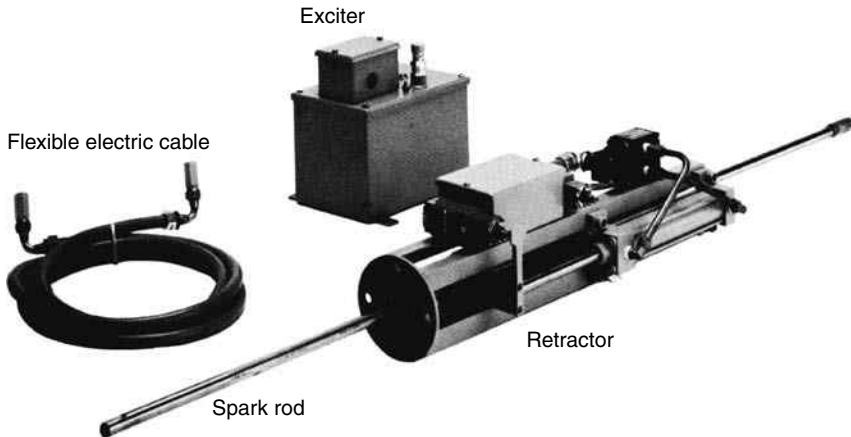
The capacity of the igniter should be $\sim 1\%$ of the burner capacity. The reason is that the low-fire light-off of a burner should be done at $\sim 20\%$ of its rating, and the pilot flame should supply $\sim 5\%$ of that. Gas supply pressure should be >700 mm wg, and the pilot flame size ~ 1500 mm long and 500 mm diameter.

10.2.9.2 High-Energy Arc Igniters

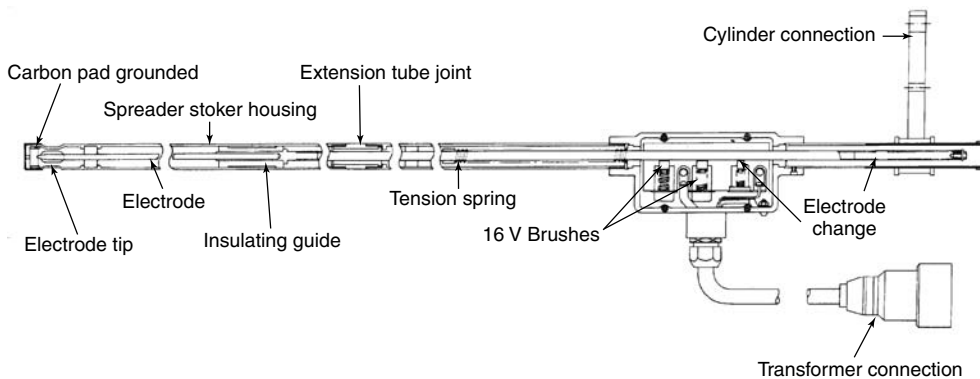
High-energy arc (HEA) igniters shown in Figure 10.25 were developed for directly igniting the low grades of fuel oil without the need for an intermittent expensive fuel such as gas. The spark is capable of heavy duty. The advantages of this system are as follows:

- The elimination of the light-up fuel system that includes storage and handling
- A single flame-monitoring system

For the igniter to operate reliably, the only requirement is that the electrode should be free from any carbon and other deposits to ensure a strong spark for a safe light-up.

**FIGURE 10.25**

High-energy arc (HEA) igniter. (From Coen Company Inc., U.S.A. With permission.)

**FIGURE 10.26**

Hot carbon rod igniter.

The system consists of an exciter, a flexible cable, a spark rod, a tip, and a retractor. The spark rod helps to position the tip in the right spot. The tip is a shunted surface-igniter plug that releases ignition energy in five to six rapid pulses per second. Output power level can be as high as 2000 kW peak power per spark, which is enough to ignite heavy residual oil.

10.2.9.3 Hot Carbon Rod Igniters

Hot carbon (HC) rod igniters, depicted in Figure 10.26, are used for direct ignition, even for heavy oils. The electrode is typically a 6–8 mm diameter and 300 mm long special carbon rod with a copper–nickel-coated outer surface that reaches a temperature of 2500°C within a few seconds of switching. The outer surface burns off, exposing 25 mm of white, hot carbon to enable the ignition of the fuel to take place. The igniter is switched off and retracted from the fuel path to a lower temperature. The electrode life is about 250 starts. This type of igniter is not suitable for gas burners with multiple gas spuds.

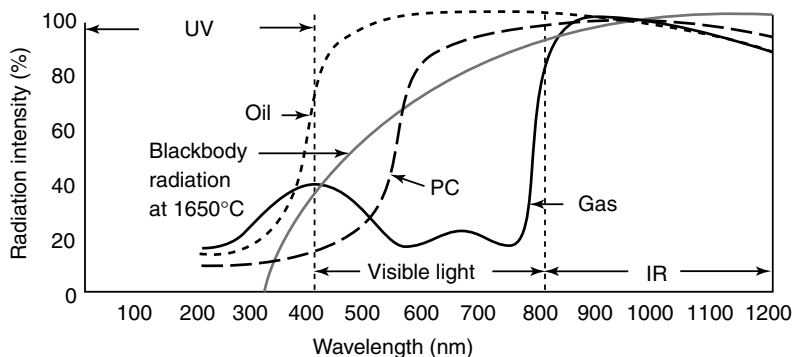
10.2.9.4 Comparison of Igniters

Table 10.5 compares the various igniters.

TABLE 10.5

Comparison of Igniters

Type of Igniter	Voltage (V)	Power (W)	Burner Capacity	Initial Cost	Running Cost
Spark electric	5–10000	300	Small	Low	Low
Gas electric	5–10000 + oil/gas	300+	Medium and large	Average	Average
High energy	2000	2000	Medium and large	Average	Average
Hot carbon	10–20	3000	Large	Average	High

**FIGURE 10.27**Radiation intensities of various flames. (From *Power Magazine*. With permission.)

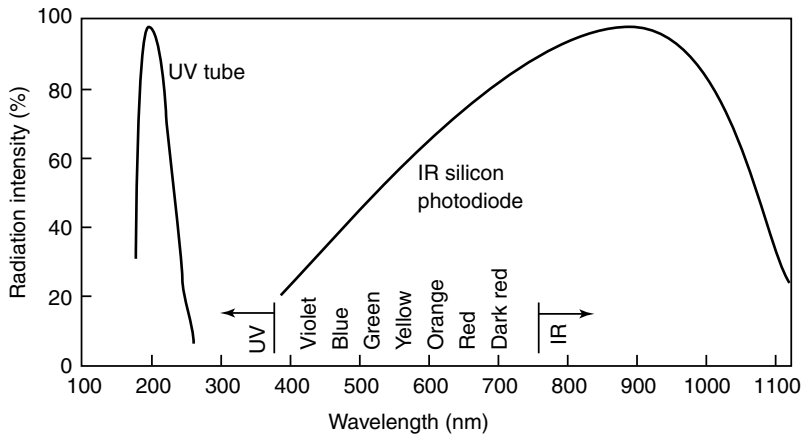
10.2.10 Flame Monitors

Flame monitors are the “eyes” of the burner management system (BMS) and are fixed on the burner front. There are three types, depending on the fuels fired:

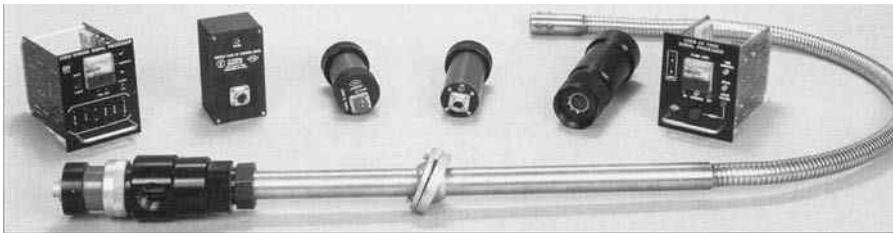
1. Ultraviolet (UV)
2. Infrared (IR)
3. A combination of both

Flame-monitoring fundamentals are as follows:

- All flames radiate energy in differing intensities from UV to IR range (as shown in Figure 10.27) captured by UV and IR scanners as shown in Figure 10.28.
- Gas flames have good emission in the UV range and are suited for UV scanners.
- Oil flames have peak emission in the IR range with sufficient emission in UV range, and both types are suitable.
- Coal flame emission is predominantly in the IR range, and the IR scanners are suitable.
- For dual fuels, a combination head is employed with both UV and IR.
- Flames also produce a flicker at the root with distinct frequency. In multiple-burner installation, the flicker is added in the scanner to distinguish the adjacent or opposite flames.

**FIGURE 10.28**

Suitability of scanners. (From Coen Company Inc., U.S.A. With permission.)

**FIGURE 10.29**

Components of scanning system. (From Coen Company Inc., U.S.A. With permission.)

A flame scanning system consists of two ends—the burner end and the input end for receiving signals for BMS. In addition to the appropriate scanner, the burner-end system consists of the following components, which are shown in Figure 10.29:

1. Viewing heads at the two sides of the burner
2. Signal processors at the two sides of the burner
3. Connecting cable
4. Mounting arrangement
5. Purge-air connection
6. Shut-off valve to prevent backflow of furnace gases

Purging of the scanner is very important. The instrument needs to be kept cool, preferably at temperature $<70^{\circ}\text{C}$.

10.3 Duct Burners

Burning of any liquid or gaseous fuels inside a duct with a flowing stream of air or gas is carried out with the duct burners. They are mostly used in a normal boiler for

- Inlet ducts of heat recovery steam generators (HRSGs) using turbine exhaust gas

- Underbed PA ducts of fluidized bed combustion (FBC) boilers for heating the combustion air at start-up condition

Duct burners are suitable for firing all high-CV gases and oils. But their common use is in the quick burning of high-CV gases and light oils due to the restriction of space downstream. A good air-pressure drop leading to a vigorous turbulence cannot be created within the confines of a duct and the resulting flames are long and there is always a possibility of soot formation on the downstream surfaces. There are two types of duct burners:

1. *In-line arrangement.* In-line burners are multiple-gas jets with protective butterfly-shaped flame stabilizers with a low pressure drop. These burners are more common for gas application. Figure 10.30 shows a three-element horizontal duct burner. The elements can also be placed vertically. As the pressure drop is low, they are preferred at HRSG inlet.
2. *Side arrangement.* Conventional circular burners have been adapted for duct-burner duties, especially for firing oil, where they are located on the sides of the duct. Figures 10.31 and 10.32 depict a side-mounted duct burner. Fuel gas can also be

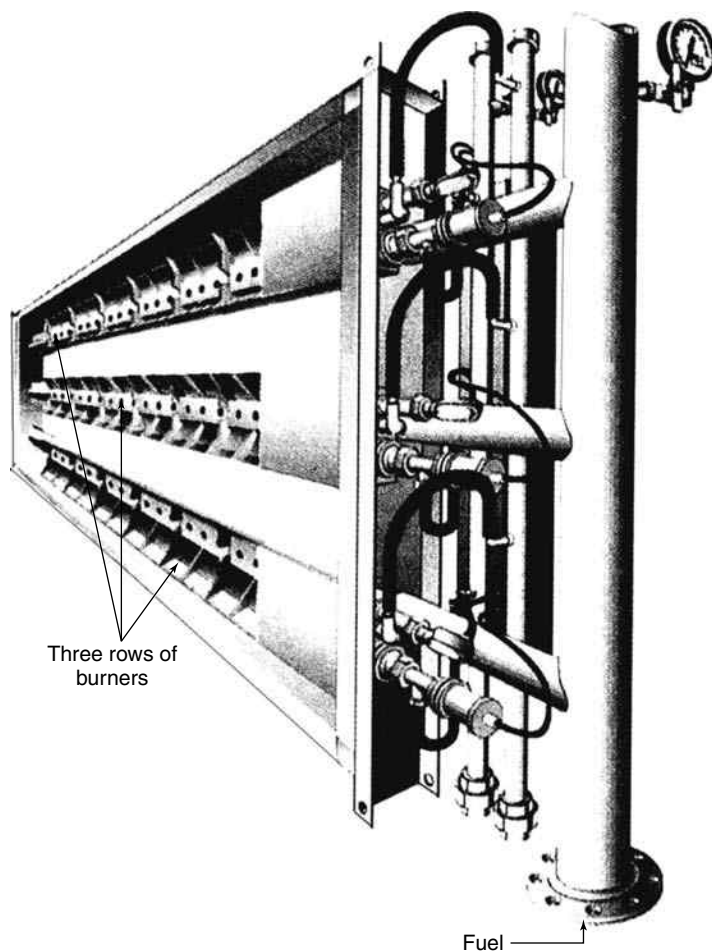


FIGURE 10.30

In-line duct burner with three horizontal elements for gas firing. (From Coen Company Inc., U.S.A. With permission.)

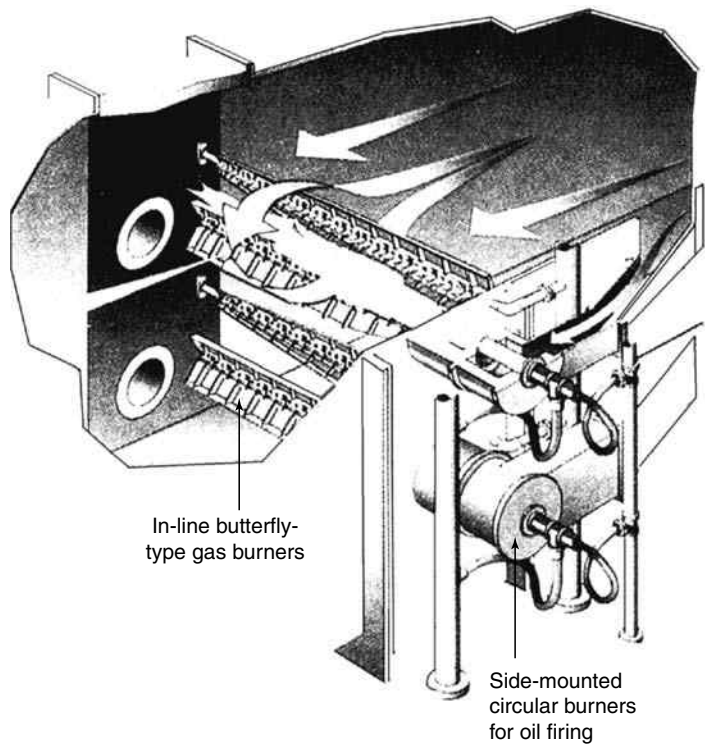


FIGURE 10.31
Side firing circular duct burners. (From Coen Company Inc., U.S.A. With permission.)

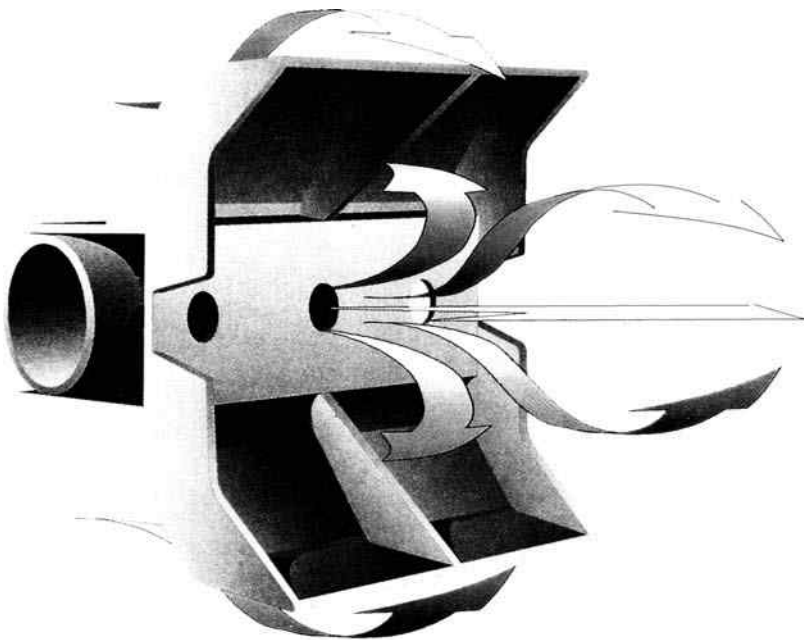


FIGURE 10.32
Individual in-line burner with butterfly-type flame stabilizers. (From Coen Company Inc., U.S.A. With permission.)

burnt in this arrangement through the butterfly-type burners. The oil burners can be taken out for maintenance while the boiler is working.

Turbine exhaust gases contain typically 15% O₂ by volume. The duct burners usually can give 10:1 turndown on gas and 5:1 on oil, with all the burners in place. A specially configured perforated plate is installed to equalize the gas flow upstream of the duct burner. The burner elements have to be made of alloy steel (AS) to withstand high temperatures.

Duct burners are usually shop-assembled along with the valve skid and sent to the site for location at a proper place, thereby simplifying construction. Large duct burners are made for HRSGs for sizes up to 150 m kcal/h or 175 MW/h or 600 MBtu/h.

10.4 Burner Management and Safety System

The primary aims of a management and safety system are:

- A safe startup and shutdown of the burners
- A safe operation of all the burners in the boiler

Burner management and safety are handled by the electronics and software portions of the burners. The complexity of the logic is directly proportional to the variables of the system, such as the

- Number of burners
- Variety of fuels
- Combination of firing equipment
- Operational flexibility desired
- Local or remote-mounted BMS panel
- Extent of manual intervention

Most mishaps take place while starting and, to a lesser extent, while shutting down the burners. NFPA, which has performed elaborate studies, has provided guidelines and has elaborated the procedures to be followed for single- and multiple-burner installations covering all the above-mentioned conditions. The guidelines refer to

1. Oil or gas burning
2. Oil and gas burning
3. Multiple-fuel combinations
4. Single or multiple burners

and are followed rigorously in the industry. As the variables increase, the logic becomes more involved.

Starting. For starting a burner, permissives and sequence are broadly indicated as follows:

- A burner can be lighted only with its own igniter.
- The igniter cannot be started unless the furnace purging is complete.
- The purging can be initiated only after a satisfactory report on the seven main boiler conditions, namely,
 - Water level in the drum
 - Oil pressure
 - Oil temperature
 - Atomizing steam pressure
 - Atomizing steam temperature
 - FD fan
 - Igniter conditions

Purge. On finding these conditions proper, it is now possible to start the FD fan. The first step is to carry out a *purge* of the boiler setting

- At a low airflow of ~25% of normal full-load air
- For ~20 min (to give five changes of volume)
- To prevent the inclusion of any traces of combustibles

Accumulation of the combustibles during operation, either at low loads or at some quiescent pockets in the boiler, which can ignite on receiving copious amount of air under favorable conditions, is identified as the most common cause for major and minor explosions. Carrying out a purge is the prerequisite for further steps in lighting the boiler.

Light up follows the purge.

- After the purge is completed, the igniter can provide a spark or flame. Only then the fuel can be turned on.
- Within a set time, the main flame should be visible or the whole sequence must be repeated.

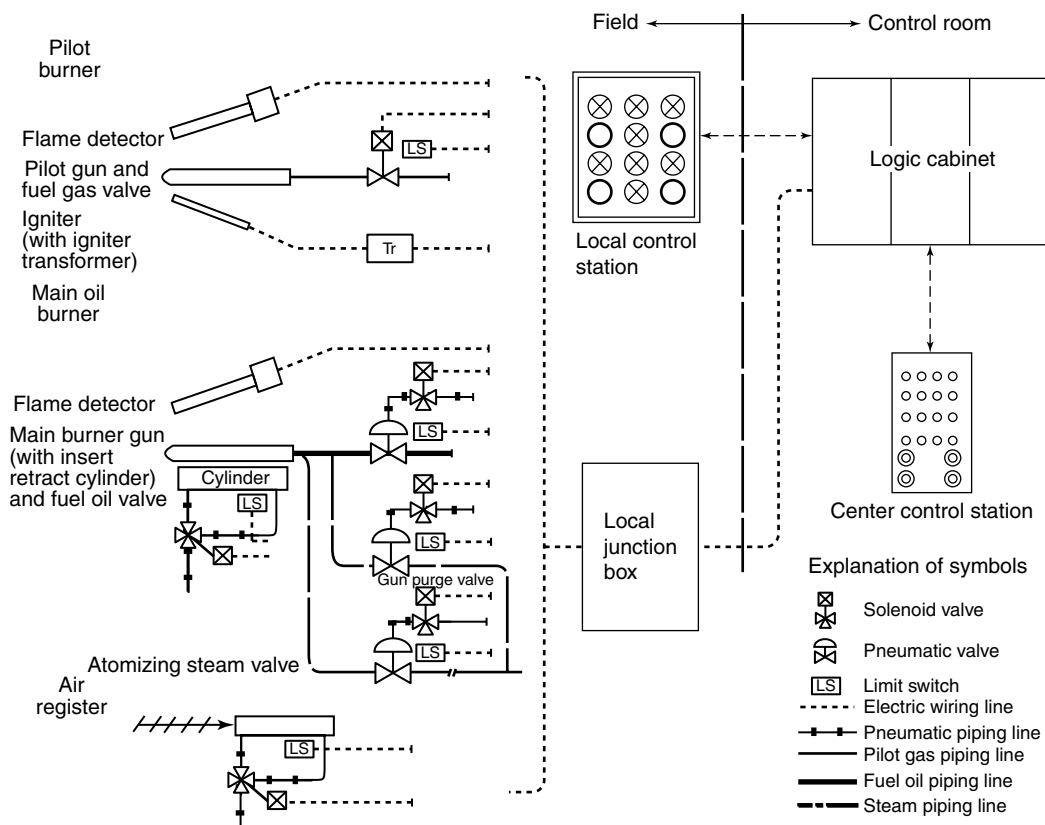
In an operating boiler, all the above-mentioned conditions and flame health are to be monitored at all times. Any deviation of the main parameters beyond the limits should result in the tripping of either the burner or the boiler, depending on the cause.

A sound BMS needs (1) reliable flame monitors, (2) a good logic system, and (3) robust hardware.

Burner management and safety systems can range from simple to very elaborate for the same boiler, depending on the customer's operating practices and the capabilities of the O&M staff (Figure 10.33).

10.5 Oil- and Gas-Fired Boilers

Oil and gas are clean and quick-burning fuels that require smaller furnaces and lesser HS in the tube banks. The boilers are compact. This feature enables shop manufacturing of

**FIGURE 10.33**

Typical simplified burner management and safety system scheme for oil burner.

the boilers and assemblies for modular boilers that require minimum erection time. NG-fired boilers tend to be the most compact because of very small furnaces and convection banks. This is due to very high heat release in the furnace and very high gas velocities in convection banks. As the fuel becomes dirtier, the boilers require more capacity or yield less output.

10.5.1 Package Boilers

Package boilers are mainly of three types—O, A, and D, named for their shapes. The advantages of package boilers are as follows:

1. Better fit and finish due to shop assembly.
2. Reduced delivery time and costs.
3. Site work reduced to a minimum.
4. No site-storage space required, as the boiler can be placed directly in its final location. Hence, a congested site is also acceptable.

The transportation cost, however, is quite high. On the whole, the overall installation cost is usually lower and hence the package boilers are very popular. Since they are

standardized, the manufacturers can batch-produce them and sell them with short lead times. The package boilers are characterized by the following features:

- The gases traverse from front to rear and back again to the front.
- The gas flows are horizontal.
- The back-end equipment, namely, the economizer (ECON) and the airheater (AH), are located alongside the boiler.
- The ECON and AH are both shop-assembled.
- The boilers are usually bottom-supported.

10.5.1.1 O- and A-Type Boilers

The classical bidrum boiler bank (BB), with about 20 tubes, is split in the middle to create a furnace chamber. In the O-type design, the two sets of tubes join the bottom drum, whereas in the A-type, there are two bottom drums far apart. Both designs are symmetrical about the centerline and are perfectly balanced, making the transport easy (Figures 10.34 and 10.35).

In the O-type design, the furnace space is very small and hence the boilers are limited to ~35 tph capacity. Both designs are compact and can be good solutions where space is a constraint. Foundation requirements are minimal with only a concrete floor required for the boiler.

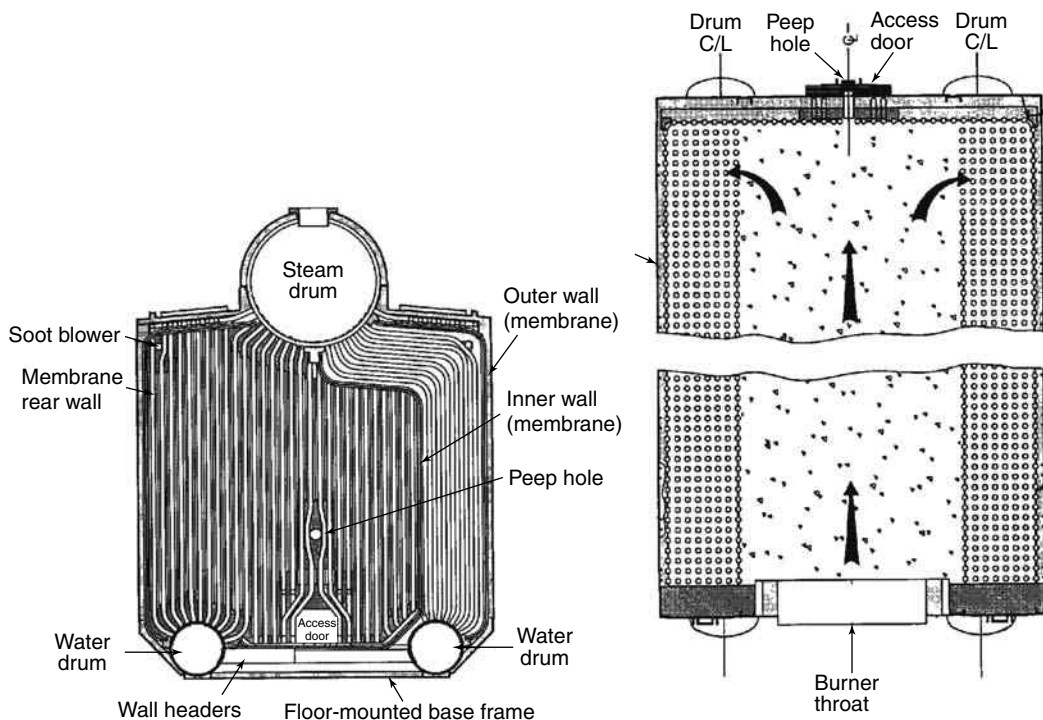


FIGURE 10.34
A-type package boiler—front and plan views.

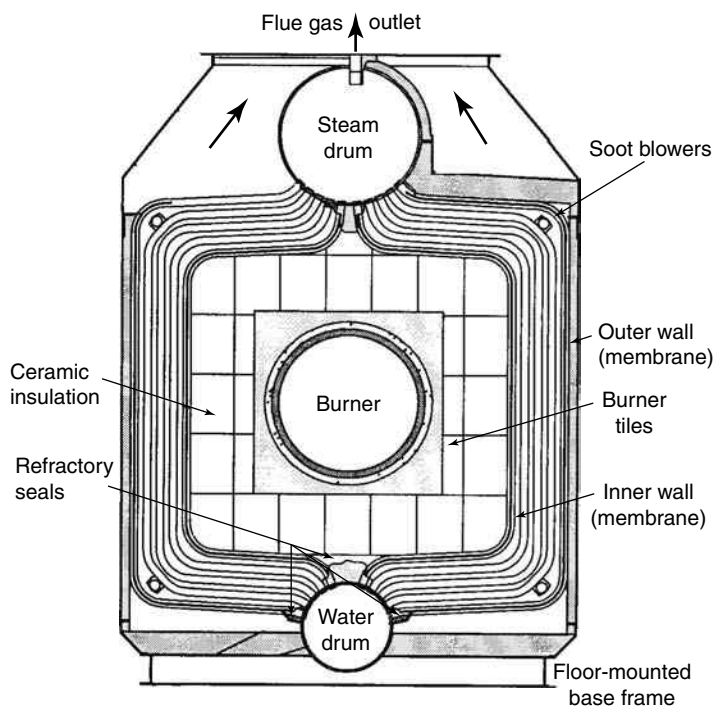


FIGURE 10.35
O-type boiler—view from inside toward front.

TABLE 10.6

Approximate Range of O- and A-Type Boilers

Parameter	Unit	O-Type	A-Type
Capacity	tph	5–35	5–140
	kg/s	1.4–9.7	1.4–39
Design pressure	ata	15–100	15–100
Superheater outlet temperatures	°C	Up to 500	Up to 500

Small furnaces make them more suitable for high-CV oils and gases with low residence times. The fuels are required to be clean because the horizontal gas flow pattern precipitates the dust, which would otherwise choke the tube passages over time. In both the designs, accessibility is limited. Superheater outlet temperature (SOT) is also limited.

The A-type boilers have a much bigger range of capacity. The steaming range for both designs is depicted in Table 10.6.

10.5.1.2 D-Type Boilers

Much larger boilers can be built with D-type designs. The entire boiler is usually shipped as a single unit, as shown in Figure 10.36, but very large units are shipped in two pieces—the drums and the C panel of the furnace.

While a bidrum bank is split in the middle for O-type or A-type boilers, in D-type boilers, the end tube is pulled out to accommodate the furnace (Figures 10.37 and 10.38).

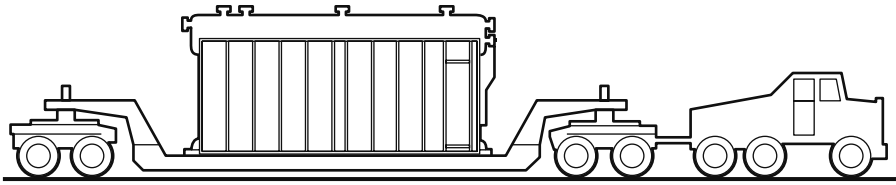


FIGURE 10.36
Transportation of package boiler.

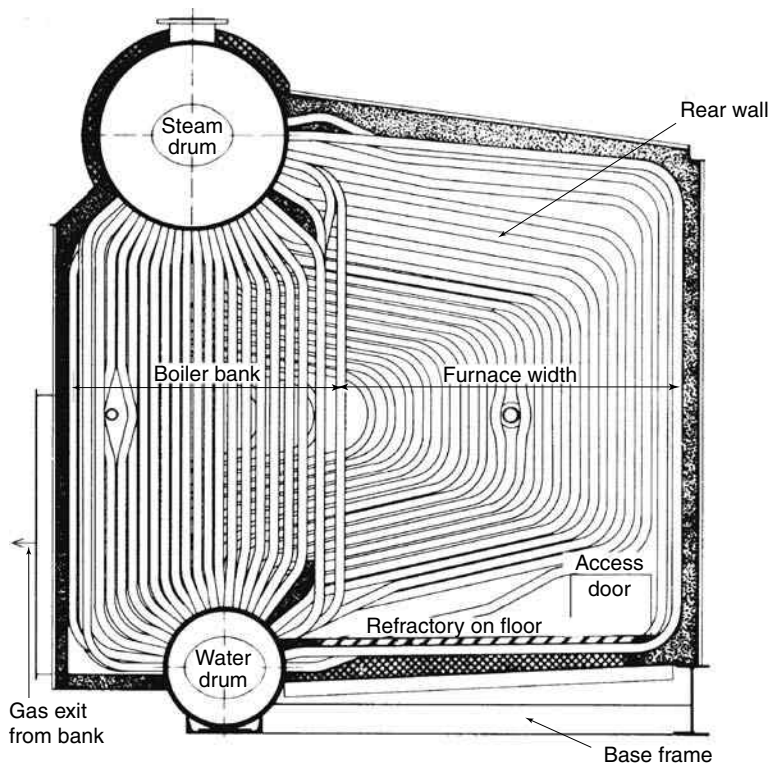
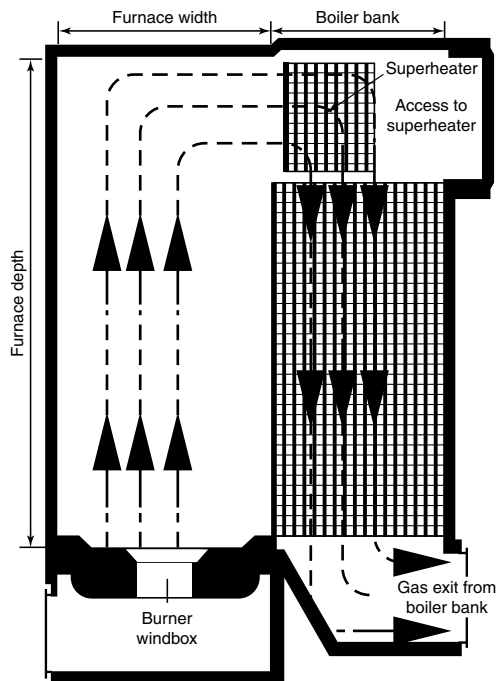


FIGURE 10.37
Cross-sectional elevation view of D-type package boiler (view from burner side).

The burners are located on one end and the gases travel longitudinally along the axes of the drums. Due to the horizontal travel of the gases, this design is better suited for cleaner fuels that do not precipitate dust or sludge, which can pack up the tube banks. These boilers are designated FM, VP, and supercritical (SC) boilers by the Babcock, Alstom, and Foster Wheeler groups, respectively. Most leading boiler companies have their equivalent designs.

The boilers are bottom-supported with forced-draft natural circulation and fully water-cooled with minimum refractory; they also have fully drainable SHs and outdoor-type boilers capable of burning all liquid and gaseous fuels, including lean fuels such as blast furnace gases and biogases. Single-burner designs have auxiliary atomizers that can be brought on range to take out the main gun for maintenance without any boiler stoppage.

**FIGURE 10.38**

Plan view of D-type boiler showing gas flow.

All the auxiliaries are positioned in a compact manner. There is no requirement of foundation other than a flat concrete floor. Figure 10.39 shows a typical small D-type boiler.

Each company has extensively standardized its D-type boilers. Although they produce lower evaporation compared to the field-erected units, the package boilers are the most highly rated boilers, as they are compact and easily transportable. Further, since they are used mostly with oil and gas, which are fast burning and clean, their heat release and absorption rates tend to be the highest.

Design aspects of D-type boilers. The following design aspects of D-type boilers are applicable to all the package boiler designs.

Boiler

- The evaporation values given in Table 10.7 are based on generating saturated steam.
- In the smallest size boiler, the minimum flame length decides the furnace depth, which is ~ 2.5 m. The furnace depth is the dimension along the drum length.
- For smaller boilers with shorter furnaces, circular register-type burners with short flames are used. However, for larger boilers with longer furnaces, parallel-flow burners with low excess air and longer flame lengths are employed.
- Boiler lengths can reach ~ 9.5 m with about 100 tube rows in the boiler bank. This is limited by the permissible furnace pressure.
- The dividing wall between the furnace and the bank has to be sealed perfectly to prevent gas bypass, leading to a loss of performance. As the pressure difference increases, the tendency to bypass also increases.

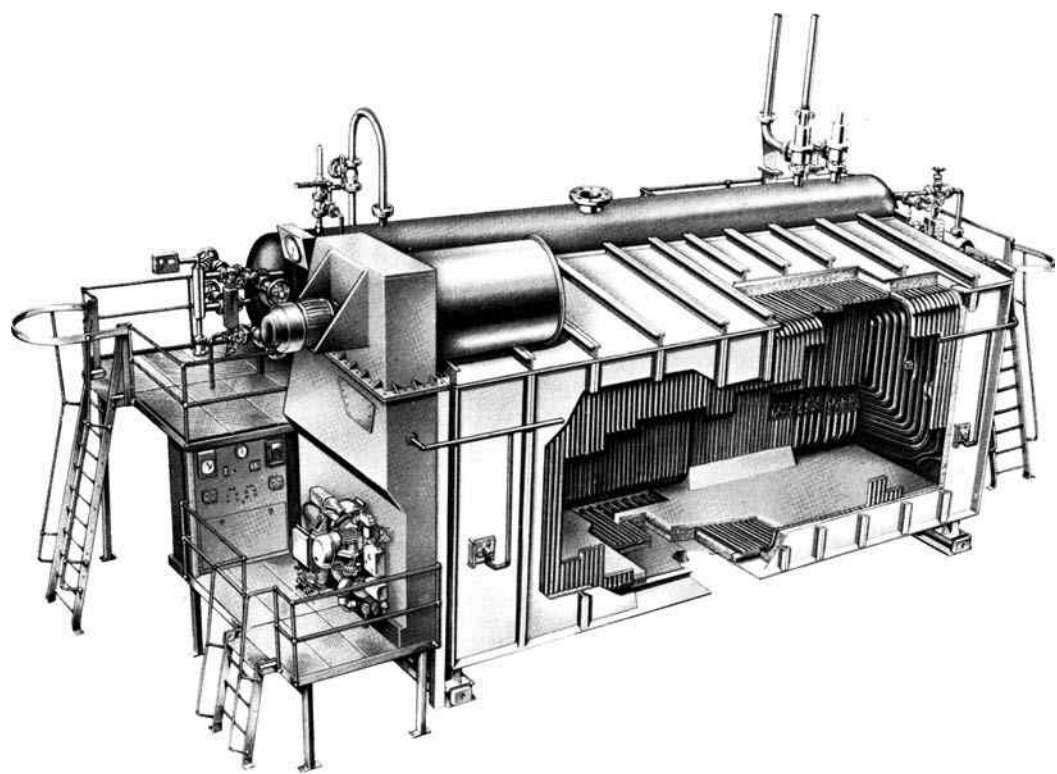


FIGURE 10.39
Small single-burner D-type package boiler with fan mounted on top and local control panel.

TABLE 10.7
Approximate Range of D-Type Boilers

Type	Drum Centers (m)	Evaporation		Maximum Design Pressure	Maximum Superheater Outlet Temperature (°C)
		tph	kg/s		
Single burner	2.75–3.75	5–80	1.4–22.2	17–75	450
Double burner	4.25–8.0	80–275	22.2–76	17–115	500
Three or four burners	> 8	>275	>76	17–115	500

Furnace

- The furnace is highly rated with a
 - Volumetric heat release of maximum 1.45 MW/m^3 ($\sim 1,246,000 \text{ kcal/m}^3$ or $\sim 140,000 \text{ Btu/ft}^3$).
 - Heat flux of up to 0.63 MW/m^2 ($\sim 542,400 \text{ kcal/m}^2/\text{h}$ or $\sim 200,000 \text{ Btu/ft}^2/\text{h}$), which is high enough to require complete water cooling with minimum refractory.
- This high-heat loading helps to maintain thermosymphonic head, even with very short drum centers.

- The furnace exit-gas temperature (FEGT) is limited to 1400°C (~2550°F) to prevent fouling and overheating of the SH.
- The furnace floor is covered with refractory tiles to prevent steam formation that can lead to tube overheating.
- The furnace enclosure is fully welded to prevent gas leakages and also rigid enough to withstand the lifting forces.
- The furnace pressure in pressurized units can be as high as ~800 mbar (~600 mm wg or ~24 in. wg).

Boiler bank

- The minimum drum center distance is 2.75 m (~9 ft) based on circulation considerations.
- The BB exit-gas temperature (BEGT) is limited to ~450°C (~850°F) to avoid inside insulation of the exit duct and to prevent reverse circulation of water in the final tubes.
- A drawback in the D-type boiler design is the lack of accessibility into the BB made worse by the presence of a rotary soot blower (SB). In some designs, this is remedied by avoiding a few bank tubes to provide access. Short soot blowers are inserted in that access space from the sides for a better cleaning instead of a long rotary blower. This must be done with care to avoid hot spots on the exposed parts of the drums, as they are no longer cooled after the removal of bank tubes.
- In any package boiler, the drums are long and the circulating water flows along the axes of the drums. The front rows of the BB, about one-third of them, act as downcomers. At the rear end, where the SH is located, there are no risers and the gases are at their hottest. A few risers beside the end row have to be judiciously placed to provide sufficient axial flow of drum water to prevent any overheating of the drums.
- The BB tubes can be in-line or staggered for clean and fouling fuels, respectively. Usually, the number of bank tubes is 10, instead of ~20 in a normal bidrum arrangement.
- The gas velocities can be as high as 30 m/s (~100 ft/s) in convection banks with clean fuels. Tubes are usually swaged to improve the ligament efficiency and reduce drum thickness. Loading on drum internals tends to be very uneven, as the front one-third of the tube bank is made of the downcomers and the first few tubes at the rear side generate heavy amounts of steam. It is therefore customary to fill the entire drum length with internals.

SH

- The SH is usually drainable along a single loop of an inverted U. As the required superheat increases or a larger control range is desired, a double inverted U-type SH may have to be adopted, making the heater nondrainable. The SH in a package boiler is largely convective.
- The degree of control range is also not as large as in field-erected boilers. Occasionally, a loop is pushed into the furnace space to achieve higher temperature.

Fuels and burners

- One- to four-burner configurations are possible in a D-type design, whereas in A- and O-types, only one or two burners are used.
- Besides a range of oils and gases, the package boilers can also burn low-CV waste gases such as BFG and CO.
- With waste fuels having dust in the gas, it is desirable to have
 - Additional soot blowers
 - Extra wash-water drains at the bottom of the boiler
 - A few lance ports in the boiler sidewall for hand-lancing the deposits in the BB

The low-CV waste gases are slow-burning and voluminous. The volumetric release rates have to be lowered. For CO gas, the rate is 0.41 MW/m^2 ($\sim 356,000 \text{ kcal/m}^3/\text{h}$ or $\sim 40,000 \text{ Btu/ft}^3/\text{h}$), and for boiler feed (BF) gas, it is 0.20 MW/m^2 or ($\sim 178,000 \text{ kcal/m}^3/\text{h}$ or $\sim 20,000 \text{ Btu/ft}^3/\text{h}$).

- In addition, the fully water-cooled furnaces of the package boilers tend to over-cool the already low-temperature flames of the waste gases, making it difficult to sustain combustion. Hence, a certain amount of supplementary fuel such as FO or NG has to be burnt in a pilot burner to maintain the flame temperature high enough for sustained combustion. Also, the front portion of the furnace has to be lined with refractory to retain and reflect the heat to reduce the auxiliary fuel support.
- Gas spuds cannot be used for these voluminous gases. Scroll burners, such as the one illustrated in Figure 10.17, are used for BF gas, whereas a central pipe in the burner carries the CO gas. Since these gases contain a lot of CO, the furnace is operated in a balanced draft mode with an induced draft (ID) fan.
- For larger gas quantities, the package boilers become unsuitable. The draft losses are also excessive. Field-erected boilers are better suited.

10.5.2 Field-Erected Modular Boilers

10.5.2.1 Bidrum Boilers

Field-erected modular boilers are well suited for:

- Larger capacities than the package boilers for process or power
- Burning fuels with more dust or sludge that require better access for maintenance
- Slow-burning and lean fuels such as CO or BF gas that require a generous furnace and convection bank

The field-erected modular boilers are bottom-supported, fully membrane panel, water-cooled, and outdoor boilers with large SHs; they are capable of burning most liquid and gaseous fuels. These are designated as PFI/PFT, VU60, and SD boilers by B&W, Alstom, and Foster Wheeler groups, respectively.

The range covered by the bidrum and single-drum boilers is given in Table 10.8. The single-drum boilers can be built for slightly higher capacities, pressures, and temperatures.

TABLE 10.8

Steaming Ranges of Field-Erected Modular Boilers

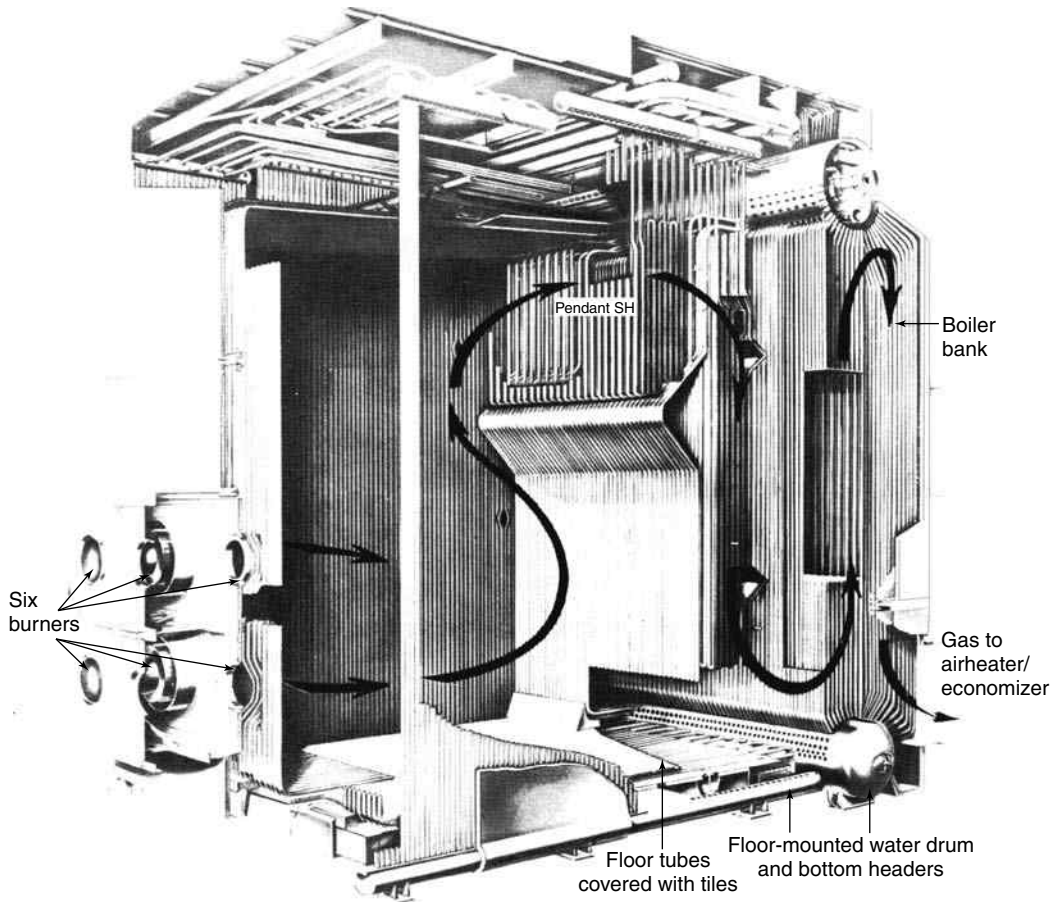
Field-Erected Modular Boilers	Capacity		Design Pressure (ata)	Maximum Superheater Outlet Temperature (°C)
	tph	kg/s		
Bidrum	40–450	~11 to 125	50–130	540
Single drum	50–550	~14 to 152	20–140	570

There is no decided advantage of one over the other. The single-drum boilers are normally European, whereas the bidrum boilers are American preferences. The single-drum boilers are also extensively standardized, and modular manufacturing is adopted to shorten delivery, reduce costs, and improve quality.

- The heat ratings of field-erected boilers are a good deal lower than those of the package boilers. Maximum heat release rate is limited to 0.58 MW/m^3 ($\sim 500,000 \text{ kcal/m}^3$ or $56,000 \text{ Btu/ft}^3$) as opposed to 1.45 MW/m^3 in package boilers. Likewise, the heat flux, FEGT, and gas velocities are all lower.
- Unlike in package boilers where the flue gas flow is horizontal, in field-erected boilers, flow is normally up and down, facilitating the separation of dust from gas.
- These boilers can be front-fired or corner-fired. In front-firing, there are either two or four burners. The furnace has generous proportions to accept low excess-air, parallel-flow burners or slow-burning low-CV gases, requiring large volume or liquid fuels that contain sludge or alkali compounds.
- The floor is covered with tiles to protect the tubes from overheating.
- The SH is suspended from the roof and expands freely downward. Usually, it is a nondrainable SH. For small superheating, drainable SHs can be accommodated. The SH is protected from direct radiation of burner flames by the furnace arch but receives furnace radiation indirectly.
- The BB is tall with about 20 tubes along the drum circumference. The tubes are usually placed in line, and the gas flow can be longitudinal or cross flow. The rear third are downcomers. At times, unheated downcomers are used to improve circulation (Figures 10.40 through 10.42).

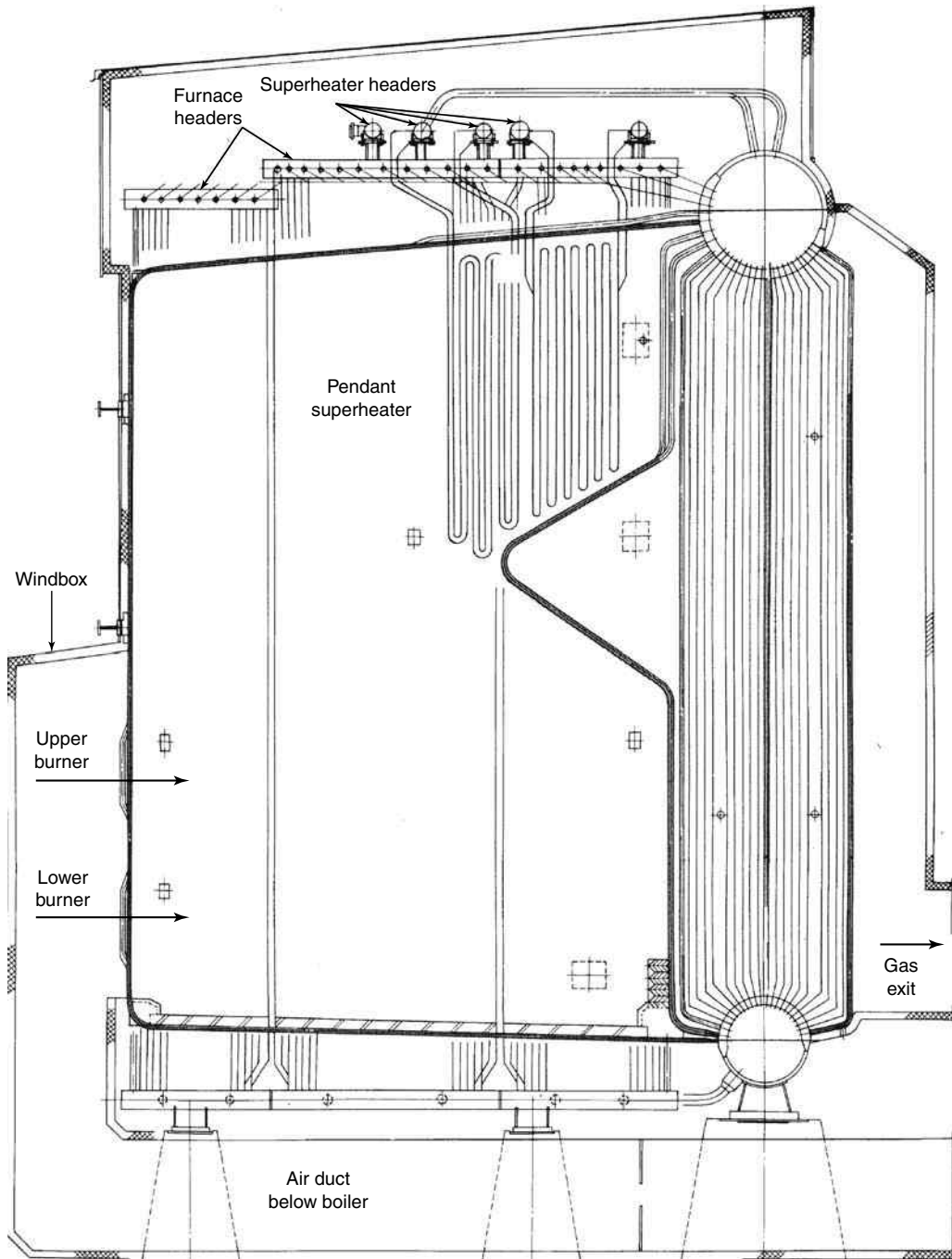
10.5.2.2 Single-Drum Boilers

- Steam requirements fall outside the bidrum package or field-erected boiler capabilities.
- Higher pressure or temperatures are required in cogen systems such as fertilizer plants and refineries.
- Superior dynamics are desired as in power or cogen applications.
- For pressures up to 60 bar, an evaporator (EVAP) coil is required because the saturated heat to be absorbed is considerable.

**FIGURE 10.40**

Bottom-supported, field-erected modular boiler with front firing. (From Foster Wheeler Corporation, U.S.A. With permission.)

- Up to $\sim 30 \text{ kg/cm}^2$, the EVAP may additionally require a circulating pump to draw saturated water from the drum and push it through the coil to ensure circulation under all loads.
- The single-drum boilers are of two passes (Figure 10.43) or one and a half pass (Figure 10.44) or special designs (Figure 10.45), depending on the final temperature, control range requirements, and the fuel.
- The water-holding capacity is smaller in comparison with bidrums. Also, the tubes are smaller and thinner, thereby reducing the thermal inertia and improving load response.
- The SHs are fully or partly drainable.
- The burners are usually in the front wall, but floor and roof burners are also common.
- Front-wall firing takes more floor space than bottom-fired boilers. The latter are taller but their burners are accessible from the floor. In bottom-fired

**FIGURE 10.41**

Cross-sectional view of two-pass bottom-supported boiler. (From Foster Wheeler Corporation, U.S.A. With permission.)

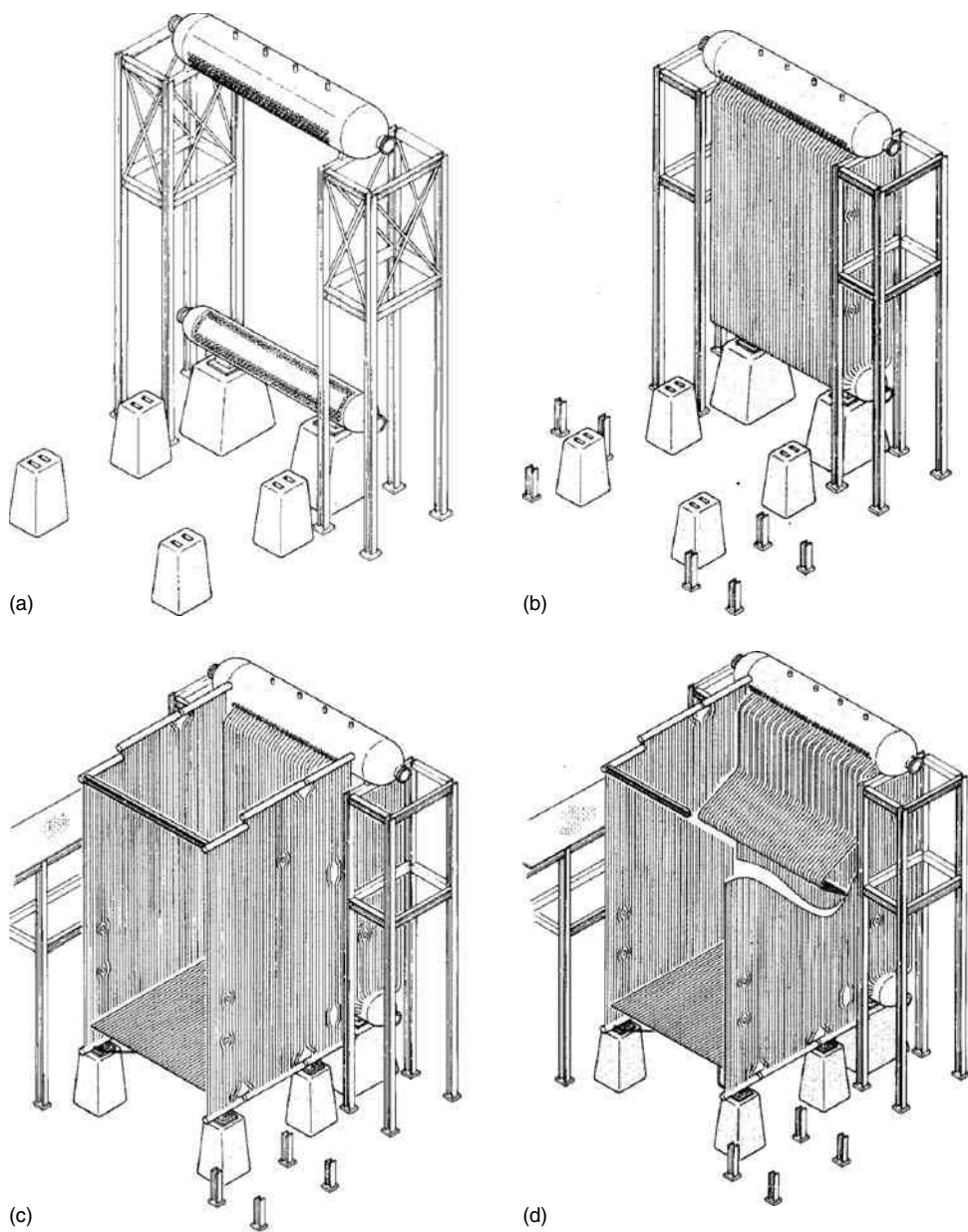
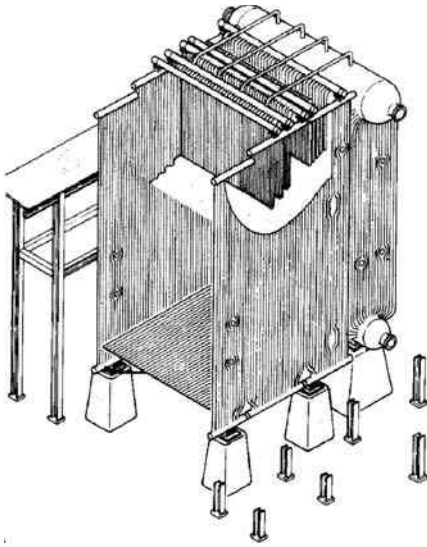
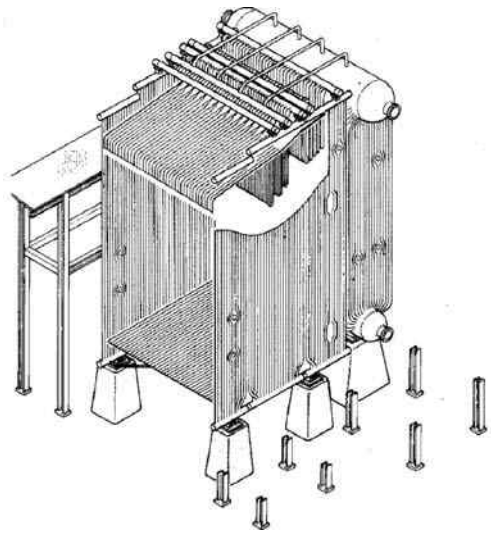


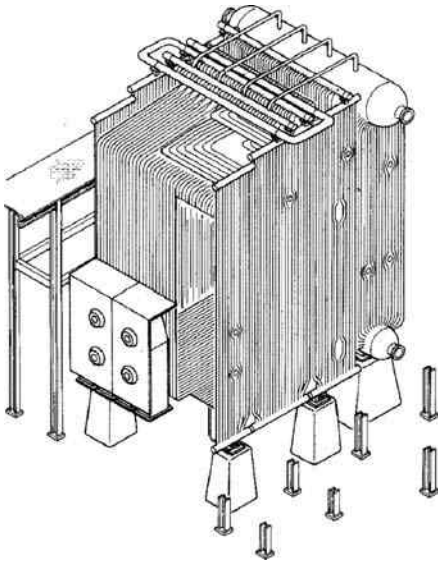
FIGURE 10.42
Sequence of erection of bidrum bottom-supported boiler.



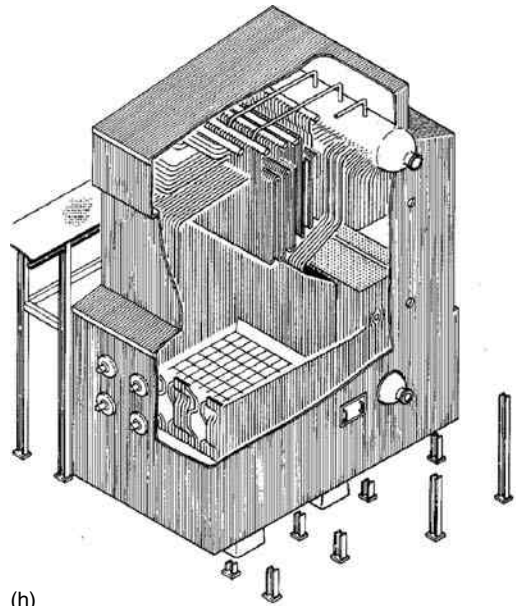
(e)



(f)

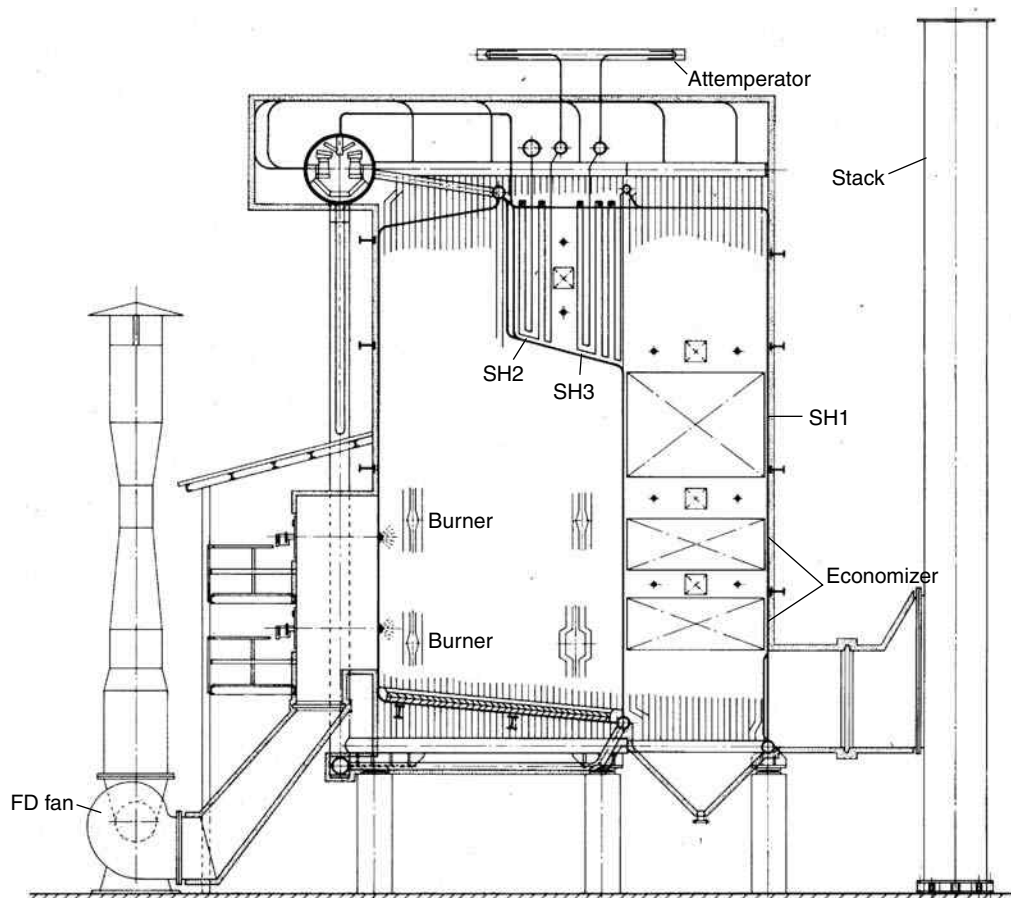


(g)



(h)

FIGURE 10.42 (Continued)

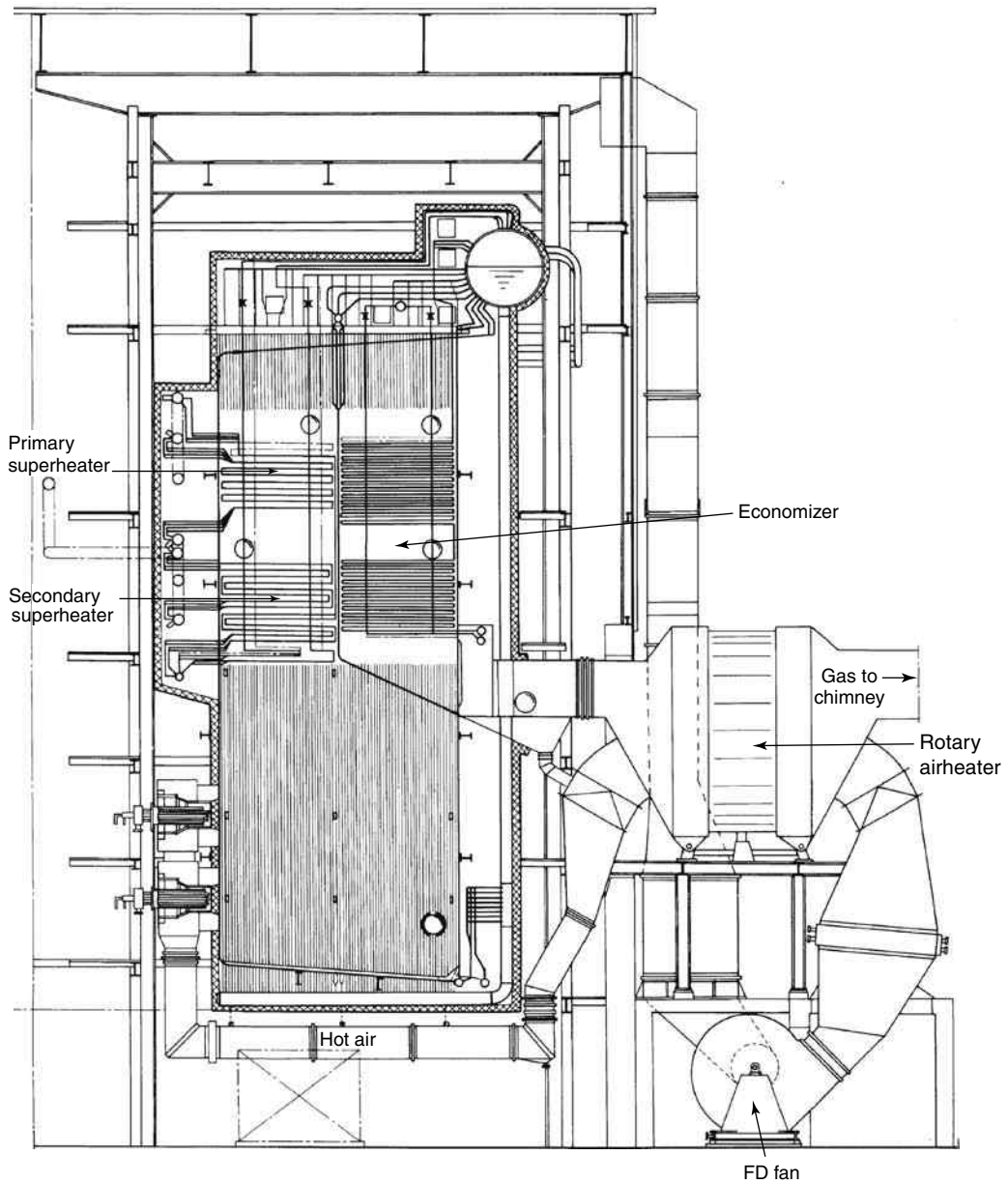
**FIGURE 10.43**

Two-pass boilers with partly drainable superheater and front firing with pressurized furnaces.

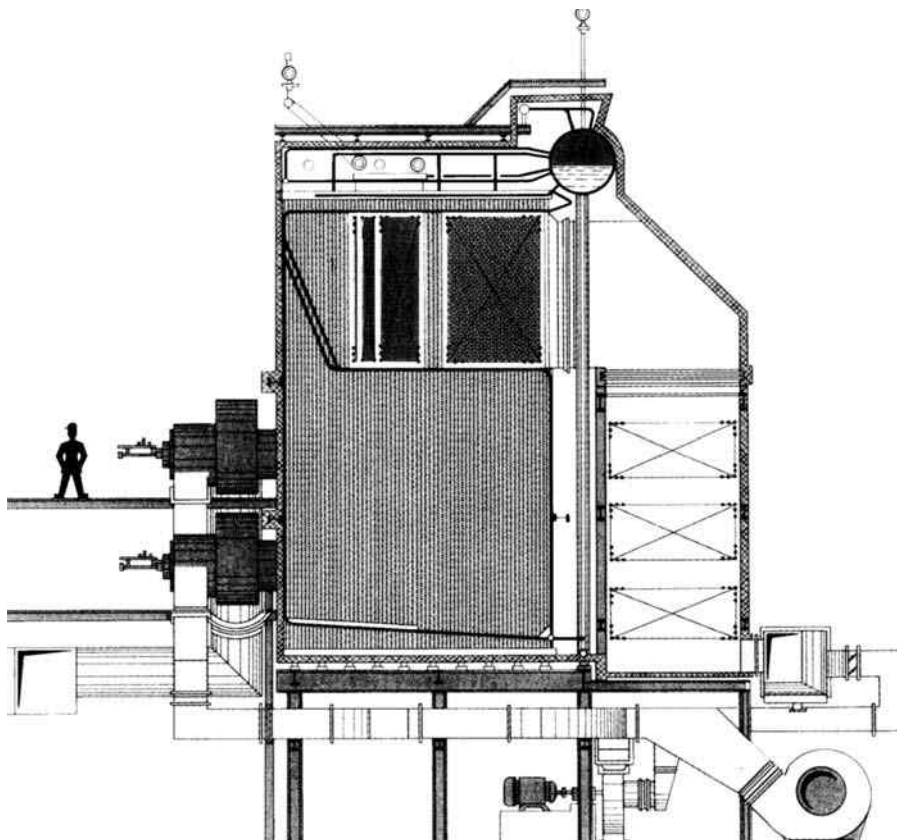
boilers, temperatures only up to 500°C can be obtained, as a pendant SH cannot be accommodated.

- In all designs in the second pass, it is normally possible to accommodate an ECON bank below the SH, resulting in a compact arrangement.
- A one and a half pass boiler with front-wall firing is a proven design combining drainable surfaces and high superheat temperature. The SH receives radiation from the burner flames and displays a fairly flat characteristic with load. An ECON bank can be accommodated in the boiler setting (Figure 10.44).
- The two-pass front-wall firing design provides a generous furnace volume and a second pass for the SH and the ECON, which are fully drainable. When steam temperatures higher than ~520°C are desired or a larger turndown is required, a nondrainable pendant SH can be added in the furnace (Figure 10.43).

For light oils and gases, the design shown in Figure 10.45 is fully drainable and very compact. It covers a range of 25–200 tph.

**FIGURE 10.44**

One and a half-pass boiler with front firing and drainable horizontal superheater.

**FIGURE 10.45**

A compact single-drum boiler with drainable superheater.

Further Readings

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11

Stoker Firing

11.1 Introduction

Stoker firing has evolved for more than a century and a half. After serving as the backbones of the industry and small power for several decades, stokers have been sidelined for the past quarter century due to:

- Dwindling availability of good coals suitable for firing on stokers
- Tighter pollution requirements
- Increasing steam demands needing bigger unit sizes
- Emergence of fluidized bed combustion (FBC) boilers with superior features

Stokers would have become nearly obsolete if interest in biofuels, for which they are ideally suited, had not emerged. Several types of stokers have appeared and disappeared over time, but four stokers continue in use for industrial and cogeneration (cogen) applications.

11.2 Mechanical Stokers

Grate burning can be classified as (1) mass burning (MB) and (2) spreader burning (SB), depending on whether the fuel burns on the grate or partly in suspension and partly on grate. There are two designs each for MB and SB. The spreader stokers (SS) are the most common.

1. MB with gravity feeding
 - a. Chain or traveling grates (CG/TG)
 - b. Reciprocating or pulsating grates (RG/PG)
2. SB with spreader feeding
 - a. CG/TG
 - b. Dumping grates (DG)

Other types of grates for wood and bagasse firing are

- Pinhole grates (PHGs) for low- and high-moisture fuels (up to 55% moisture)
- Inclined water-cooled grates (IWCGs) for even higher-moisture fuels (up to 70% moisture)

Both are stationary grates, and combustion is by pile burning. They are discussed in detail in Chapter 9.

Based on the type of feeding, the stokers are classified as follows:

- Underfeed stokers
- Overfeed stokers

Underfeed stokers have both coal and air feeding from the bottom of the grate and ash discharging from the sides. The boiler capacities are very small for single- and double-retort stokers. Multiple-retort stokers can be built in large sizes. This type of stoker has practically disappeared from industrial use, surviving only in small pockets for niche applications, where good coal is available.

Overfeed stokers have coal feeding from the top of the grate and air from the bottom. Mass burning and SB are the two principles of overfeeding, where mass feeding is by gravity and spreader feeding is by throw. Even in overfeed stokers the gravity-fed MB boilers now have very little market, but many units were built to fairly large sizes when the coals were good. But the overfeed SS, with either over- or under-throw design, with substantial combustion in suspension is more versatile and enduring. Spreader stokers can be combined with any grate—CG/TG, DG, and RG/PG. Table 11.1 lists the workings of the various grates.

There is practically no solid fuel that cannot be burnt satisfactorily in a stoker. Table 11.2 examines the compatibility of the various stokers and fuels.

Among all the systems SS, with suspension firing, is exceptionally versatile, flexible, and dynamic and hence became the workhorse of the industry and small utilities by the 1930s. Well into the 1960s, SSs were employed in the utilities for units up to 50 MW and even higher with good coals. The largest SS-fired boiler built appears to be 80 MW on lignite. As the average sizes for the utility units grew, the SSs were left behind. Pulverized

TABLE 11.1

Workings of Various Grates

Grates Parameter	Mass Burning		Spreader Burning	
	Gravity-Fed Traveling or Chain Grate	Reciprocating or Pulsating Grate	Spreader Stoker with Traveling or Chain Grate	Dumping Grate
Grate movement	Toward rear	Mostly toward rear	Toward front	Stationary
Feeding	Gravity	Mostly gravity	Spreader	Spreader
Movement of fuel	Carried forward by grate	Pushed forward by grate	Carried frontward by grate	No movement
Direction of airflow	Perpendicular to bed	Mostly parallel to bed	Perpendicular to bed	Perpendicular to bed
Furnace arches	Required	Required	Not Required	Not Required
Suspension firing	Very small	Very small	Significant	Significant
Grate heat release	Average	Average	High	High
Grate size for duty	Large	Large	Very compact	Compact
Load response	Good	Good	Very good	Very good
Ash discharge	Continuous	Continuous	Continuous	Intermittent
Ash carryover (%)	10–20	10–20	20–40	20–40
Pressure parts erosion potential	Low	Low	High	High

TABLE 11.2

Compatibility of Grates for Various Fuels

Parameter	Mass Burning		Spreader Burning	
	Gravity-Fed Traveling or Chain Grate	Reciprocating or Pulsating Grate	Spreader Stoker with Traveling or Chain Grate	Dumping Grate
Coal firing	Medium ash <25%	Only low ash <15%	Even high ash ~40%	Only low ash <15%
Bagasse firing	Unsuitable	Highly suitable large sizes possible ~200 tph	Highly suitable largest sizes possible ~250 tph	Highly suitable small and medium sizes ~100 tph
Biomass firing	Unsuitable	Highly suitable ~52% H ₂ O	Suitable ~52% H ₂ O	Suitable ~52% H ₂ O
Low-VM fuels such as coke breeze and anthracite	With coal in sandwich mode	No	No. daf VM required >20%	No
Abrasive fuels such as coke breeze	With coal in sandwich mode	No	Not preferred due to erosion of firing equipment	No
High-moisture fuel firing such as lignite ~30% H ₂ O	With arches and hot air	With arches and hot air	With suspension firing and hot air	With suspension firing and hot air
Caking coals	Only <5 swell index	No	No problem	No problem

fuel (PF) was for utilities, and SSs for captive and cogen power and process steam were prominent for decades. The position started to change only in the 1980s because of the following four factors:

1. Deteriorating quality of coals across the globe, along with hardening of prices. Stokers demand good quality coals with proper sizing, as the performance is very sensitive to size, fines, and ash. They are also not capable of dealing with much sulfur in fuel.
2. The emerging pollution norms were beyond the ability of stokers to meet effectively and efficiently.
3. More efficient technology in the form of FBC, which is also more fuel-flexible and ecofriendly. The low-temperature combustion and in-furnace desulfurization answered the pollution issues.
4. Larger sizes required by utilities.

Although the reign of the stokers has practically ended for coal firing, interest in

- Firing of ecofriendly biofuels worldwide
- Bagasse-based cogen in tropical regions
- Woodchips-based power generation in temperate climates
- Municipal refuse firing worldwide

is giving a fresh life to stokers. Biofuels do not contain sulfur ($<0.1\%$) and the fuel moisture depresses the combustion temperatures; hence, the formation of SO_x and NO_x is no longer the issue. At the same time, biofuel is an area where FBC is not strong as most fuels are too light and fluffy to work well and present no advantage in combustion efficiency. Further, as necessary ash is not present in the fuels for bed replenishment, the arrangement works out to be comparatively expensive. Stokers present an elegant and economical solution in this growing market, although the present situation cannot be compared with the former good times.

Although stokers are employed primarily for biofuel firing, coal firing is practiced on stokers for auxiliary and supplementary or alternate fuel duties as biofuel availability is seasonal and shortfalls are normal.

The following points are common to all designs.

11.2.1 Grates and Stokers

The grate and stoker terms are used interchangeably in the industry. Grate is the flat bed at the furnace bottom, which is either stationary or moving, on which the fuel burns. When combined with the fuel distributors it becomes a stoker. Fuel distributors for spreading the fuel on grate are also called stokers.

Solid fuel is delivered by gravity or flight, and air is admitted mainly from below the grate to burn the fuel. Part of the air is delivered above the grate for burning the volatiles and fines. The ash is conveyed to the ash pit. The grate or bed firing burns slowly on the grate and suspension firing burns vigorously above the grate.

11.2.2 CG versus TG

These two terms are also used interchangeably in the industry. In CGs the individual stoker links (Figure 11.1) transmit the chain forces and experience the tensile loads caused in the movement of grate. In the TGs, the stoker links (Figure 11.2) rest on bulb or T-bars, which are attached to the chains experiencing the loads. The grate bars are not subject to any forces.

As the grate bars are not under load, it is possible to build TGs of larger size. Chain grates tend to be lighter and more rigid because the additional members such as bulbs and T-bars are not present. But the links of the CG have to be stronger to withstand the forces of transmission. The big advantage of TGs is the ability of the links to break loose and dangle

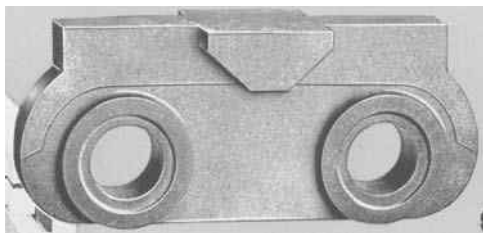


FIGURE 11.1
Typical link of chain grate.



FIGURE 11.2
Typical link of traveling grate.

vertically in the return travel, making it possible for the ash to drop into the hopper below. Tip and jolt bars are added to further scrape the top surface.

11.2.3 Using Same Grate for Mass and Spreader Burning

The grate carries the fuel through the various burning zones until the combustion is complete. It is advantageous to have the same stoker construction for both types of firing provided the following conditions are met.

- The combustion processes differ based on fuel bed thicknesses requiring different air-pressure drops in the grate, 55 and 40 mm w.g. (2 ¼ and 1 ½ in. w.g.) for mass and spreader, respectively. The grate link construction has to be modified to reduce the area exposed to air.
- In most cases the stoker has to travel forward in SB and backward in MB.

Some grates can work with both types of feeding.

11.2.4 Moistening of Coal before Firing

In all types of stokers it is necessary to moisten the coal so that it forms a loose lump when pressed. This would correspond to ~10% free moisture. This moistening is done on coal conveyors in the yard or the coal chutes or both. Water and steam sprays are both employed. The purpose of moistening is to

- Make the coal bed porous by streams of steam (formed on water evaporation), to improve combustion quality.
- Make the coal fines stick to the lumps so that they burn. This improves the combustion efficiency by better burning and reduced unburnt loss and minimizes dust.

11.2.5 Clinker

Clinker is the molten ash slag that accumulates coal and ash particles on its surface and turns into a lump. Clinker is a nightmare to any boiler operator. Ash fusing at high temperature and forming small clinker toward the discharge end of a grate are normal to an extent and cause no disruption. But when it grows in size and disturbs the grate operation, a chain reaction promotes more clinker and there can be total disruption of fire.

Melting of ash, which is the root cause of clinker formation, arises from

- High alkali content of the ash, which results in low ash-melting temperature.
- Presence of reducing conditions that depress the melting temperature of normal ash (see Figure 3.12) due to low amounts or poor distribution of air.
- High-swelling coals that swell disproportionately and agglomerate in plastic condition, disrupting the air distribution pattern and creating reducing conditions.

- High fines in coal that attach themselves to the burning coal whose ash is in a semimolten state.
- Agitation of actively burning coal bed. This makes the semimolten ash spread and hold other coal pieces, fines, and ash particles to form a lump, which disturbs the bed conditions and keeps growing. Reciprocating grates are not suited for coals for this reason. Even nonagglomerating coals clinker with bed agitation.
- Segregation of coal across the width of the bed resulting in an uneven distribution of coal and air, resulting in patches of air leading to reducing conditions.
- Uneven coal flow and airflows in the grate, which creates conditions similar to segregation.
- One-sided entry of primary air (PA), shallow ash-air hoppers, substoichiometric conditions, and improper air seals leading to reduced conditions in the bed.

Clinker formation leads to disturbance in steam generation and consequential losses. Segregation of coal, high percentage of fines, and air–fuel mismatch are the issues that may need correction. Ash and coal properties are to be checked next.

11.2.6 Coal Segregation

In coal crushing and subsequent sizing, generation of fines is natural. But separation of fines and large pieces adversely affect the combustion efficiency in any stoker, and every effort is needed to prevent such separation. This separation is found to take place as coal travels from bunker to hopper. The following two methods help in achieving even distribution of coal:

1. Traversing chute (Figure 11.3) spanning the width of the hopper so that the coal is evenly fed.
2. Antisegregation chute (Figure 11.4) where coal is made to travel from the inlet to the outlet on the bottom plate of a parabolic chute so that the fines and lumps spread evenly. The bottom of the chute is bolted to the coal hopper in front of the boiler.

The traversing chute is the better in terms of even distribution of coal but involves more complicated construction and more headroom.

Smooth flow of coal from bunker to hopper without any hang-ups is very important. This is ensured by keeping the inclination of the chutes at $\geq 60^\circ$ to the horizontal. Steam connections for coal moistening are installed at the top of the chutes with the help of ~ 6 mm connections at the bottom side. For abrasive and moist coals, causing wear and rust, respectively, the chutes are made of stainless steel (ss). Glass lining of the traversing chutes is another popular method.

11.2.7 Coal Sizing

Coal sizing is perhaps the most important characteristic affecting the performance of stokers. When coal is naturally crushed, fines are generated. Every coal transfer during the transport from mine to yard adds to the fines. As the coal enters a power plant, it appears



FIGURE 11.3
Traversing chutes.

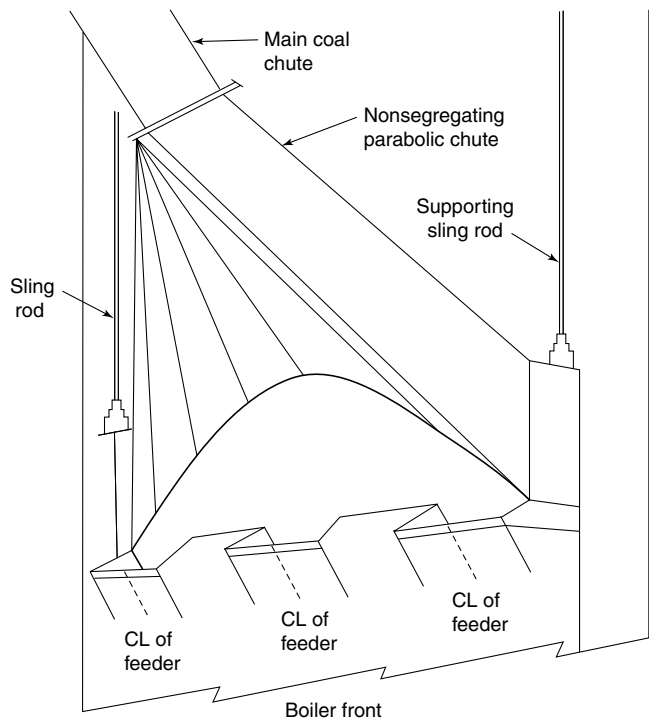


FIGURE 11.4
Antisegregation chute.

as a combination of lumps and fines of varying sizes. Fines are substantially sand particles and hence are troublesome as they

- Erode fuel-handling equipment such as chutes, feeders, distributors, and pressure parts (PPs)
- Promote clinker formation
- Increase the unburnt losses and reduce boiler efficiency

The lumps need more time to burn, and unless the top size is limited, the combustion would not be complete. The sizing is different for different stokers. Mass burning can accept larger top size but is less tolerant to fines. Spreader firing needs smaller top size to limit the wall impingement forces but can take more fines than MB because of suspension firing, but the performance deterioration is rapid as the fines exceed the limit. Stoker manufacturers generally follow the ABMA recommended graph for the sizing of coals for various types of grates. See Figure 11.5.

- The upper and lower curves are the limits for nonfriable and friable coals, respectively. As the friable coals break down quickly, due to the expansion forces of their moisture, higher coal sizes are permissible.

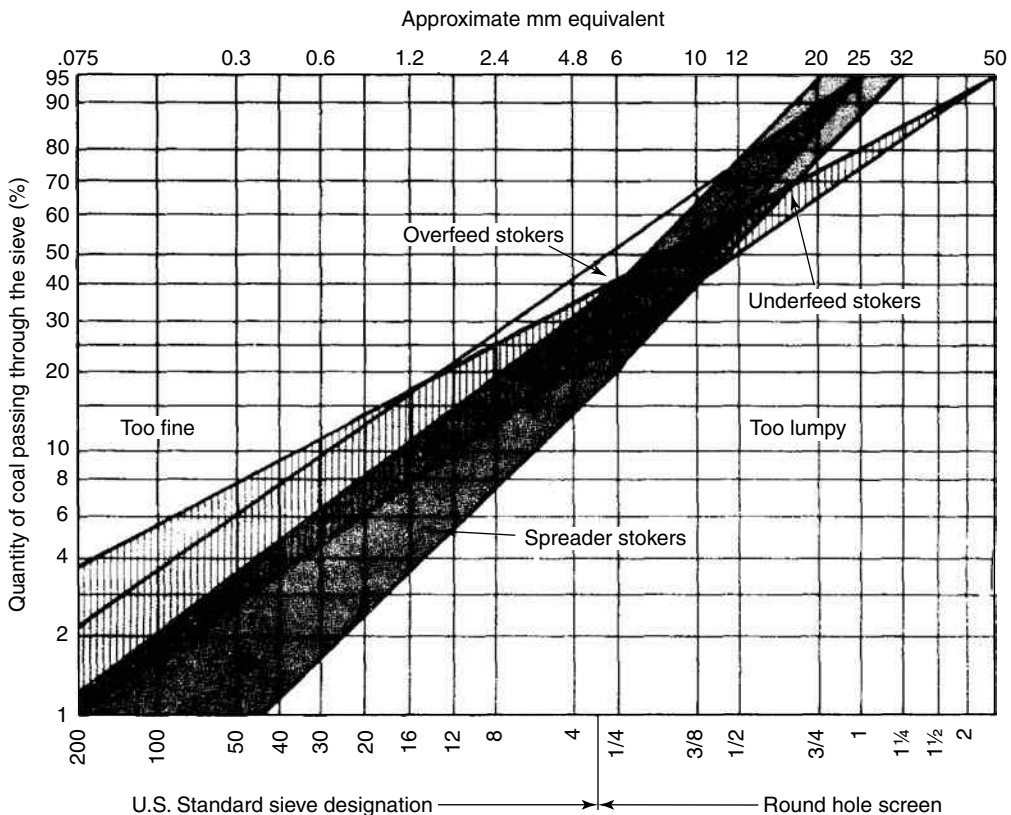


FIGURE 11.5

Limits for coal sizing in various stokers. (Detroit Stoker Company, U.S.A. With permission.)

- Coals right to the bottom curve are too lumpy for proper combustion. Likewise the coals left to the upper curve are too fine to be acceptable.
- Coals are to be delivered across the grate in a uniform sizing without segregation.

11.3 Mass Burning

11.3.1 Chain or Traveling Grates with Gravity Feeding

A typical gravity-fed TG is shown in Figure 11.6. These stokers were the forerunners of SS and were popular until 1960s when coals were of good quality and process industry requirements were modest. Although they are suitable for good-quality coals and lignites and especially good for abrasive fuels such as coke breeze, they are not very satisfactory for sized or unsized biofuels because of the way the fuel needs to be admitted.

11.3.1.1 Design Aspects of Mass Burning

- An MB stoker, with nearly 85% combustion taking place on the grate surface, exhibits slow combustion and modest coal burning rates.
- Performance falls sharply when ash and fines in coal increase above the limits. Coal sizing limits are important.
- Specially shaped front and rear refractory arches help in reradiating the heat and directing the hot flue gases onto the fuel bed to aid ignition.

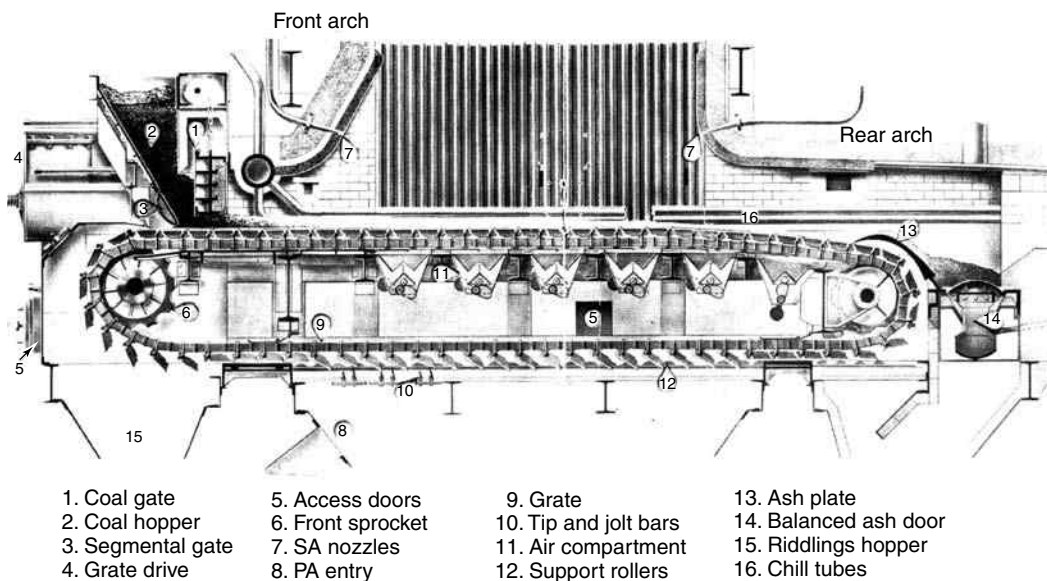


FIGURE 11.6

Gravity-fed traveling grate stoker. (Detroit Stoker Company, U.S.A. With permission.)

- Coals should be moderately coking or caking and have the following characteristics:
 - Top size 32 mm and fines of <35% through 3 mm (which corresponds to <15% through 1 mm).
 - As-fired ash limited to 25%.
 - As-fired total moisture limited to 18%.
 - Minimum dry ash-free (daf) volatiles to be 25%.
- Nearly 85% of coal ash is retained on the stoker as coarse ash whereas 15% leaves as fly ash. Fly ash is relatively gritty.
- Combustion rates are 160 and 185 kg/m²/h (33 and 38 lb/ft²/h) for arch and arch-less settings of the furnace.
- Ash discharge rate should be <350 kg/m/h (230 lb/ft/h) of ash along the width of stoker to contain the unburnt loss to a reasonable figure.
- Undergrate air pressure is ~55 mm w.g. (2 ¼ in. w.g.) as the layer of fuel is thick.

11.3.1.2 Combustion Process in Mass Burning on CG or TG

The combustion process of coal on the grate fed by gravity follows the following three stages:

1. *Drying*. The fuel loses its moisture and volatile matter (VM) on receiving radiant heat from furnace.
2. *Ignition*. The devolatilized fuel attains the necessary temperature to catch fire. This heating of fuel arises from radiant heat from the flames above and also the front refractory arch.
3. *Burning*. The top surface of the fuel burns completely and gets converted to ash.

Combustion on a grate is broadly described as follows:

- Coal is admitted to the stoker by gravity from the fuel hopper in a layer of ~150 mm thickness.
- Depth of the fuel bed is regulated by a guillotine-type gate placed at the entrance to the grate.
- The coal hopper is fed from the bunker by mobile traversing chutes or stationary antisegregation chutes to minimize the separation of fines from the coal so that the fuel layer is uniform.
- Air is provided from below at a pressure of 30–40 mm wg. The quantity is varied along the length of the grate by regulating air to the compartments below with their individual dampers. Maximum air is provided in the burning zone where maximum combustion occurs.
- After traveling for nearly 500 mm and losing the moisture and volatiles, the fuel bed is ignited from the incident radiant heat of the furnace and front arch.
- Fixed carbon (FC) starts burning from the top layer downward. The VM burns in the space above and secondary air (SA) provides air required for combustion.

- Primary air from the bottom of the grate also helps scrub the burning coal to remove the ash layer formed on the outside to sustain the vigor of combustion.
- The approximate residence time of coal on the stoker is 20 min.
- Nearly 150 mm ash layer is generated at the discharge.

11.3.1.3 Comparison of Mass and Spreader Firing

- Mass firing requires fewer moving parts. Fuel feeders and distributors are not present.
- This results in simpler O&M and negligible erosion.
- The suspension firing is limited to ~15% of heat input as opposed to 35–50% in SS for coal. Lower heat rates require a bigger stoker and boiler to achieve the same evaporation.
- This factor limits the range of fuels and the range of coal properties.
- The combustion efficiencies are lower by 5–10%, depending on the ash in the coal.
- Gravity feeding can handle two or even three layers of fuels in a sandwich manner. This is a great advantage for burning very low-volatile fuel, which is made to form the bottom layer with a good coal layer on the top to provide ignition and the necessary high temperature. Coke breeze and anthracite can be burnt this way.

With the advent of SS, where nearly twice the combustion rates of MB can be achieved, the MB stokers are confined to

- Smaller boilers that require no fuel feeders and spreaders
- Very erosive fuels such as coke breeze, which require few moving parts
- Low volatility fuels such as coke breeze and anthracite, which need sandwich burning
- High-quality low-ash coals with aggressively erosive nature

11.3.2 RG and PG Grates

- The fuel bed is pushed forward by the reciprocating action of the grate bars and not carried on the grate.
- Airflow is substantially parallel to the fuel bed.

In pushing the bed of fuel, there is a tumbling action continuously exposing fresh fuel to air. The grate is ideally suited for lumpy fuels that are difficult to size and contain high moisture, such as municipal wastes.

Because of the tumbling action of the fuel the tendency to form clinker with coal firing is high. The semifluid state of coal ash provides the base for forming lumps of clinker.

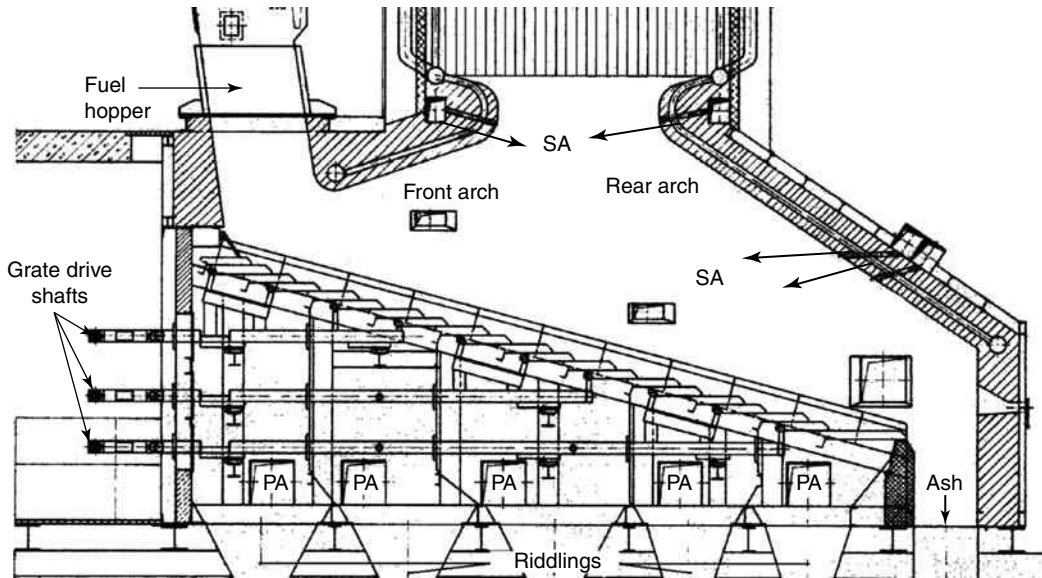


FIGURE 11.7
Reciprocating grate at bottom of furnace.

The base quickly grows as the mass is tumbled. Figure 11.7 shows a typical PG/RG used for unsized fuel with medium moisture and calorific value (CV). Ease of fuel admission can be seen.

11.3.2.1 Combustion Process in RGs

The combustion pattern is similar to the burning of fuel in gravity-fed TGs. Like the gravity-fed TGs, here also there are three zones: (1) drying, (2) ignition, and (3) burning. The front and rear arches play a very important role, particularly with high-moisture fuels, in

- Forming a throat that holds back the gases above the bed for better burning
- Deflecting the hot flue gases from the rear onto the fuel (the rear arch)
- Reradiating the furnace heat to help in drying and devolatilization of the fuel (the front arch)

Secondary air nozzles, strategically located in the the throat and above in the furnace, burn the volatiles. Grate actions of continuously pushing the fuel exposing fresh fuel improve the combustion rate. Grates have a rear slope of 0–15°, depending on the fuel, for easier tumbling of fuel and ash. Unlike the quiescent burning of CGs, the bed is continuously tumbled.

Coals with more than 15% ash or low ash fusion temperature end up with clinkers due to continuous agitation as the fuel and soft ash fuse together. Clinkers keep increasing in size, straddling the grate bars. They do not move forward as the grate movement is not positive. But biofuels, with their bulky or fluffy nature and moisture as high as 65%

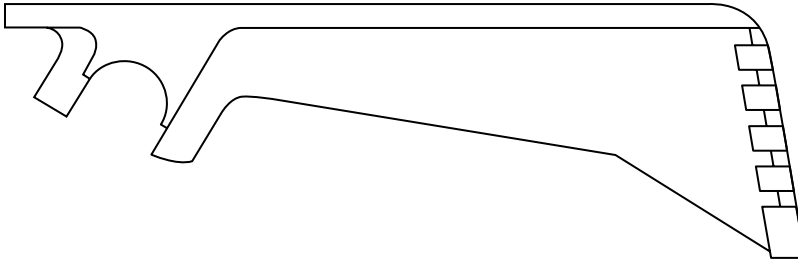


FIGURE 11.8
Typical grate casting of RG/PG.

burn well in this type of grate, as ash is low and the grate action is conducive to air penetration into the thick fuel bed. Bagasse, rice husk, bark, and biological wastes burn well. Although bituminous and sub-bituminous coals are problematic, peat and brown coal can be burnt.

Fuel sizing is not very important as there is no spreading as in SS or pushing as in gravity feeding. Fuel is allowed to gently enter into the hopper from the top and thereafter the grate moves the fuel forward. Ratings are similar to the grate ratings of the gravity-fed TG.

Municipal refuse is ideally suited. Three-stage grates are built with drying, burning, and after-burning sections. Grates tend to be long.

Grate bars for biofuels are long and thin ($\sim 300 \times 25$ mm) as shown in Figure 11.8. The rear rests on the grate shaft whereas the front rests on the next bar. Recesses on either side of the grate bar around the ridge portion are built into the casting to create air passages when the bars are arranged on the grate. Normally, the alternate grate sections along the grate width move in opposite direction to provide a scissor-like action to improve the air penetration and dislodge the ash from sticking to the stoker. All the alternate shafts are connected to two link shafts, which are driven by pneumatic power cylinders. These grates have fewer components and no return strand.

11.4 Spreader Burning

11.4.1 Spreader Firing: CG and RG with Spreader Stokers

This is the most common method due to its very high fuel flexibility, excellent multifuel capability, very good load dynamics and operational simplicity, reliability, and safety.

11.4.1.1 Combustion Process in Spreader Firing

This process is characterized by a two-stage burning—suspension mode in furnace and bed mode on grate. The combustion sequence can be described as follows:

- Moistened coal is metered and distributed on to the grate by means of spreaders.
- Larger coal pieces fall toward the rear and smaller ones to the front. Hence, the direction of grate travel is toward the feeders to permit longer residence for the larger coal particles.

- Volatiles and fines burn in flight in suspension releasing ~35 to 50% of fuel heat. For high-volatile fuels this proportion is 40–60% of heat.
- The bed formed on grate consists of dried and devolatilized particles in ignited condition. The bed is thinner at 50–80 mm and hence the combustion is faster. The higher burning speed is also due to burning both from top and bottom due to radiation from the furnace and airflow from the grate.
- Air, 20–30%, is provided above grate as overfire air (OFA) or SA to support the suspension firing.
- As the furnace radiation provides the necessary heat for ignition and sustenance of combustion, the long furnace arches to deflect hot air are not needed. However, strategically positioned high-pressure SA jets are necessary to agitate the flames and provide turbulence to prevent stratification of gas flows.
- For high-volatile fuels, tertiary air (TA) is also provided below the furnace nose to burn the escaping VM and prevent fines from entering convection passes by providing an air curtain.
- The important differences between the combustion processes of MB and spreader firing are as follows:
 - There is significant combustion in suspension with spreader firing in flight.
 - The devolatilized layer of fuel burns at both the top and the bottom surfaces on the grate at high speeds.
 - The two-in-one combustion of spreader firing naturally releases much higher heat for the same grate area and furnace volume—nearly double—making it a very compact, fuel efficient, and dynamically responsive system.

11.4.1.2 Design Aspects of Spreader Firing

Figure 11.9 depicts a typical SS.

- As the fuel burns partly in suspension, liberating 35–50% (40–60% for high-volatile fuels) of fuel heat and rest on the grate in a thin film of 50–80 mm thickness, the combustion and response to load swings are very fast.
- In TGs/CGs ash discharge is continuous, unlike the intermittent de-ashing in the DG, making the plant output steady and its efficiency better.
- A seamless load turndown of 3:1 is possible.
- Fuel throw, rather than the mechanical force of de-ashing, is the deciding factor in determining the grate length. Hence stoker net lengths of approximately
 - 5.5 m (18 ft) for coal
 - 6.4 m (21 ft) for biofuels
 are possible (add ~500 mm for shaft center distance) against a maximum of ~5 m (net) for DGs. These dimensions can vary among manufacturers.
- Grate widths of up to 6.1 m (20 ft) are built with single drive, limited by torsional strength of the drive shaft. Thus, grates as large as ~66 and 77 m² (710 and 830 ft²) of net area can be built for coal and biofuel firing, respectively.
- Possible heat release rates (HRRs) are as high as
 - 2.37 MW/m² or 2.03×10^6 kcal/m²/h or 750,000 Btu/ft²/h on coal
 - 3.47 MW/m² or 2.98×10^6 kcal/m²/h or 1,100,000 Btu/ft²/h on bagasse and woodchips

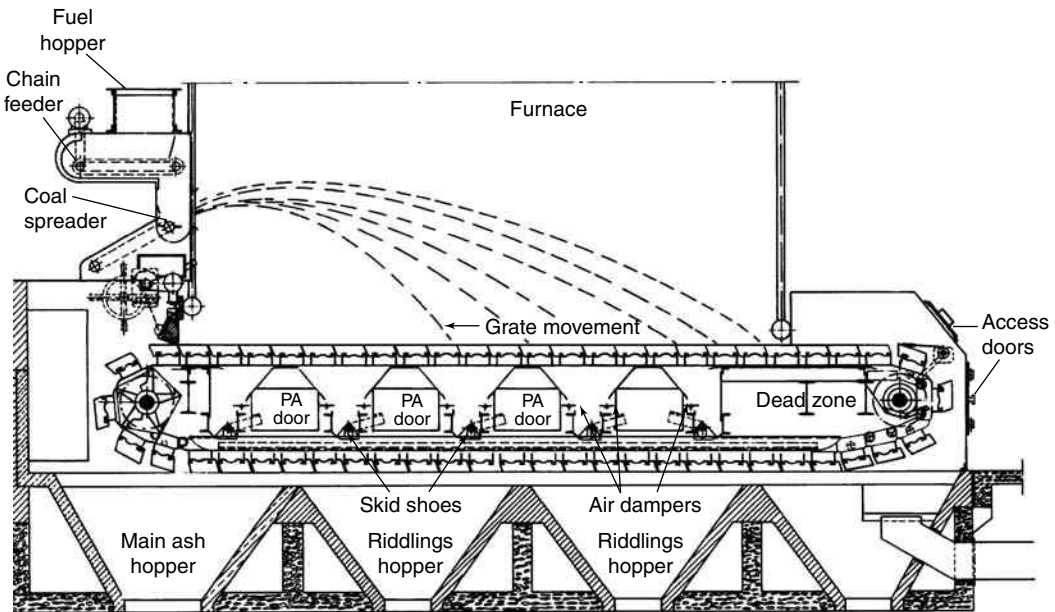


FIGURE 11.9
Spreader stoker with traveling grate.

- The important limitations are as follows:
 - Heat input per meter width of furnace should be $< \sim 14.2 \text{ MJ/h}$ or $3.4 \times 10^6 \text{ kcal/h}$ or 13.5 MBtu/h to avoid slagging.
 - Ash discharge should be $< 530 \text{ kg/m/h}$ (350 lb/ft/h) to limit unburnt loss.
- Grate bars are protected from the intense furnace heat by the thin layer of ash produced after the burning of fuel. Hence for coal firing a minimum of 7% ash is required. For biofuels with 2–4% ash the grate speed is lowered and the ash layer is allowed to build up. Alloy grate bars may be needed to improve the ability of grate to withstand the radiation.
- Excess air at full load can be limited to 30% with modern stokers, gradually rising up to 50% at half load.
- Primary air pressure below the stoker is required at $\sim 40 \text{ mm}$ (1.5 in.) w.g. Air velocities through the bed are $\sim 1 \text{ m/s}$. Area for air is 6–10% of the grate area.
- Secondary air or OFA through two sets of air nozzles at the rear and one set in the front wall is provided to
 - Penetrate the burning zone and agitate the flames.
 - Create turbulence for better combustion.
 - Prevent stratification of gas flow.
 - Approximately 20% of total airflow is secondary, provided at ~ 600 to 750 mm wg.
- In bagasse and biogas applications in which air-swept spouts are employed for fuel spreading, another 10% air is added to the capacity of the SA fan. An additional set of nozzles is also added to reduce carryover if the fuel is suspected to have more fine fibers.

- Using hot or cold air for SA has been a debated but an unresolved issue.
 - Cold air is denser and hence can penetrate the furnace better and agitate the combustion products but it cools the flames.
 - Hot air has the opposite effect. The high-speed hot-air fans require more power and maintenance.
- Because of large suspension firing and high flue-gas velocities, ash carryover is nearly 20–40%, depending on the fines in fuel. Combustibles in fly ash are ~20%. In the 60–70% coarse ash discharged from the grate, the combustibles are ~10%. Unburnt carbon loss goes up sharply from ~3–4% for good coals of ~20% ash to 10–12% for high-ash coals of 40–45% ash, with correspondingly higher erosion of PPs.
- The dust carried over in SS is grittier and hence higher in carbon. This devolatilized char is difficult to burn as it needs ignition temperatures $>700^{\circ}\text{C}$. Therefore, it makes sense to return ash from only boiler bank (BB) and similar high-temperature hoppers and subject the devolatilized fine particles to intense heat again to reduce the unburnt carbon loss. Higher recirculation means more carbon recovery and chances of the erosion of the PP, refractory, and grit recirculation system. For high-ash coals it is normal to restrict recirculation only from the BB hoppers. Typically there can be ~2% reduction in carbon loss.
- For low-rank fuels such as lignite and biofuels, the grit refiring is not useful as fuel burning is good and the carbon burn-up efficiency is inherently in excess of 95%. No significant unburnt carbon will be present in the ash particles.
- Arranging the required number of feeders for furnace width is a challenge at higher capacities. When both coal and biofuels have to be burnt, the answer requires twice as many feeders. Furnace width is then governed more by the feeder consideration than by the permissible HRR. A compact fuel feeder is required, particularly at higher capacities.

11.4.1.3 Spreader Firing versus Fluidized Bed Combustion Boilers

The comparison is fuel dependent.

11.4.1.3.1 Coal

Fluidized bed combustion boilers score over spreaders in coal firing due to better

- Combustion efficiency (between 5 and 10% depending on ash in coal)
- Tolerance to fines in coal (30% through 1 mm against 30% through 3 mm or ~15% through 1 mm)
- Environmental compliance (lower NO_x and possibility of in-furnace desulfurization)
- Maintenance and reliability; absence of moving hot parts
- Ability to burn inferior coals with much higher burden (A + M) of ~65% and gross calorific value (GCV) as low as 2000 kcal/kg

Despite the disadvantages of

- Additional coal crushing
- Bed tube and coal pipe erosion

- Lower and step-type turndown
- Inelegant ash disposal
- Higher forced draft (FD) air pressure

the fuel savings of FBC boilers far outweigh their drawbacks.

11.4.1.3.2 Biofuels

The principal advantages of FBC are

- High carbon burn-up efficiency
- Low-temperature combustion
- *In situ* desulfurization

which result in good fuel efficiency and ecological compliance. In biofuels, where fuel ash is low, stokers are better for most applications.

- Biofuels, with inherently high moisture and low N_2 , produce low flame temperature (due to the quenching effect of fuel moisture) to generate no offending quantities of fuel and thermal NO_x .
- Negligible S in biofuels produces no SO_x , dispensing with the need for desulfurization.
- Cellulosic fuels with low ash and high VM allow rapid combustion with carbon burn-up efficiencies of ~96–98%.

FBC presents no particular advantages. It does not easily burn biofuels that have high VM and moisture contents because:

- They are not easy to size
- They are light and fluffy and do not stay in bed.
- It is difficult to maintain the bed temperature as the fuel tends to burn more in suspension.
- There is a continuous need for bed ash replenishment.

Selected biofuels, such as rice husks which are properly sized and have high FC are also amenable for burning in FBC.

Bagasse and wood chips are well suited for spreaders and large-capacity boilers. Stoker-fired bagasse boilers as large as 250 tph are available. In bagasse-based cogen, bagasse is not always available and multifuel boilers are required to burn coal or oil as alternate fuel.

11.4.1.4 Coal Feeders and Spreaders

Feeders and spreaders have the following two functions:

1. The feeder for calibration and regulation
2. The spreader for evenly distributing fuel onto the grate section

For a compact fuel such as coal, it is possible to combine both tasks into a single unit that can be bolted to the furnace casing. The processes are almost always separate for the fluffy and voluminous biofuels. Also the rotary mechanical spreader is ill-suited for biofuels where pneumatic distribution is appropriate. The spreader is bolted to the furnace whereas the feeder is located below the fuel hopper.

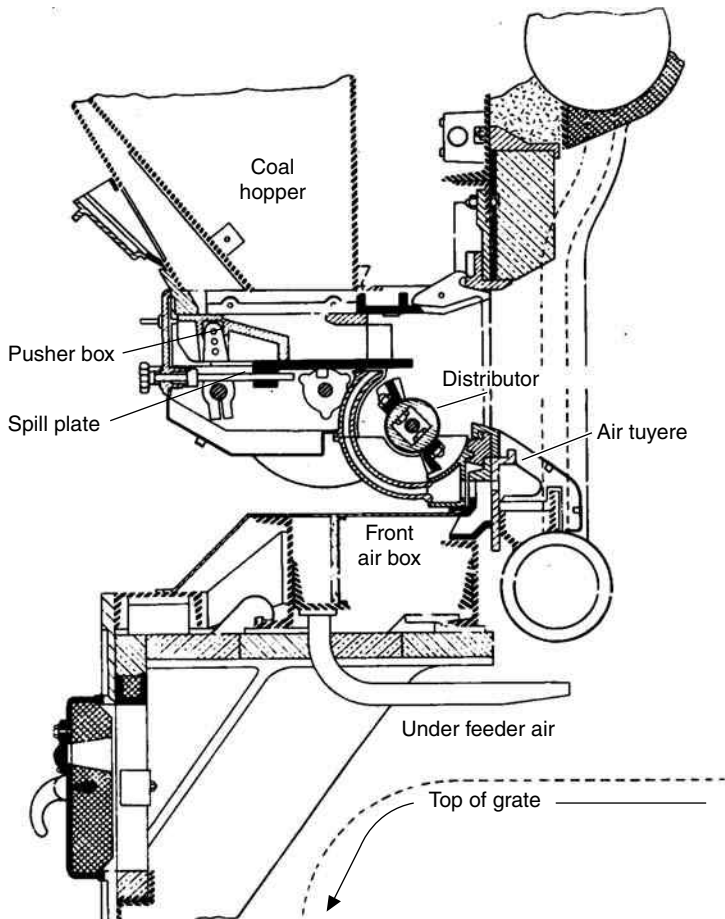


FIGURE 11.10
Reciprocating-type coal feeder. (Detroit Stoker Company. With permission.)

The feeders in the integrated systems are of three types (Figures 11.10 through 11.12):

1. Reciprocating
2. Rotary
3. Chain

Mechanical spreaders are always variable speed rotary drums (Table 11.3). The spreader drums or rotors are equipped with sinusoidal or inclined plates for good lateral distribution. A set of three to five plates is ~ 150 mm long, and is made of heat-resistant alloy, bolted to the spreader drum.

Normally, there are two or four sets of plates around the rotor. In the total feeder assembly, the spreader drum encounters furnace radiation, and to keep it safe from overheating and subsequent warpage, the shaft bearings on either side are water-cooled. Also, in a running boiler, rotors of idle feeders are always kept rotating to prevent overheating. Adjustments to the trajectory are required to suit various grate lengths and also fuel properties and sizing. This is achieved by varying the spreader speed. Spreader are mostly of the overthrow type. Air nozzles located below the spreaders help to prevent cascading of fines

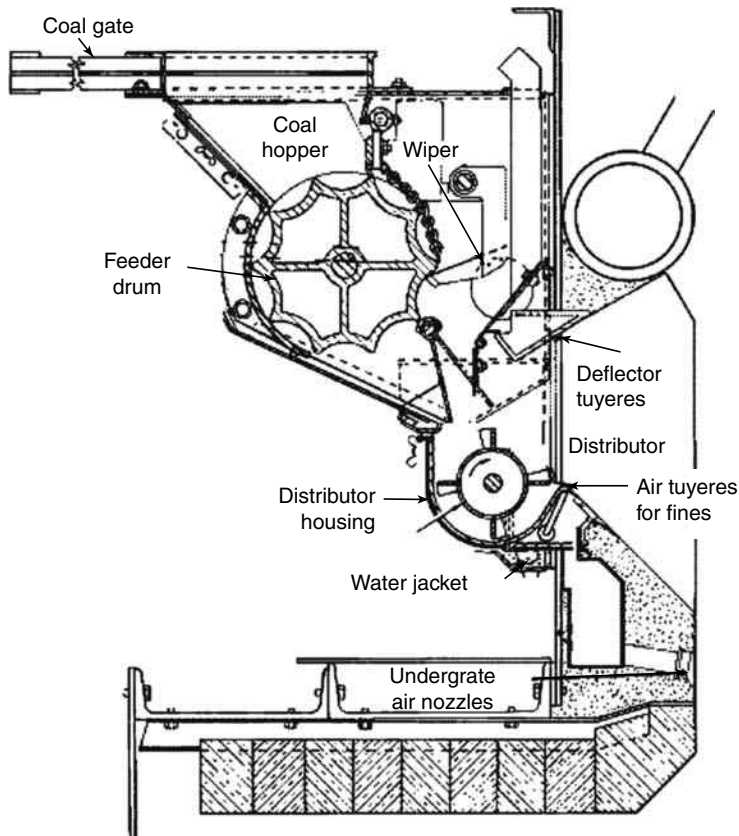


FIGURE 11.11
Rotary-type coal feeder.

onto the grate by blowing them into the active combustion zone. Underthrow spreaders provide a more horizontal trajectory for dealing with fuels with higher fines and moisture. They are more popular with FBC boilers.

All feeders are volumetric devices and hence the fuel size and characteristics are important. Higher moisture leads to lump formation, upsetting the calibration. Coal fines cause erosion. An isolating plate for each feeder at the bottom of the hopper is essential to permit the removal of the feeder for maintenance in a running boiler.

1. *Reciprocating feeders* shown in Figure 11.10 are simple, compact, and lightweight. The reciprocating pusher box at the bottom of the coal hopper pushes the coal resting on the spill plate onto the spreader. Coal quantity is varied by adjusting the stroke length of the pusher box in response to the load. The limitations of this design are as follows:
 - a. Higher fines and moisture disrupt the feeder calibration.
 - b. Fines settle between pusher box and pusher plate, leading to faster erosion, further aggravating the problem. A good limit for moisture is 10%.
2. *Rotary feeders* shown in Figure 11.11 are more robust, and deal better with higher moisture and fines without undue erosion. A cut-off gate maintains the depth of coal. Drum speed is variable, and it automatically controls the output in response to load.

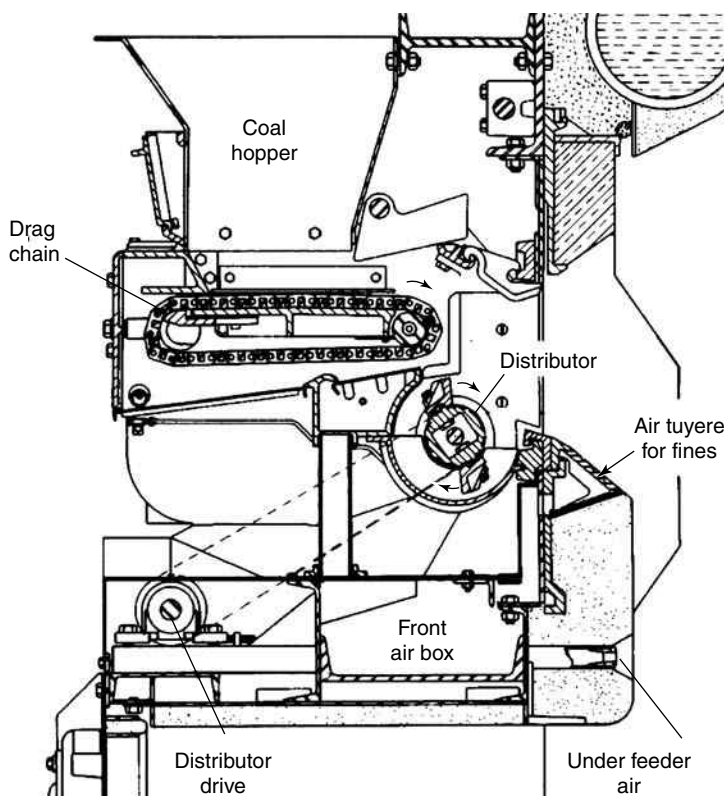


FIGURE 11.12
Chain-type coal feeder. (Detroit Stoker Company. With permission.)

TABLE 11.3

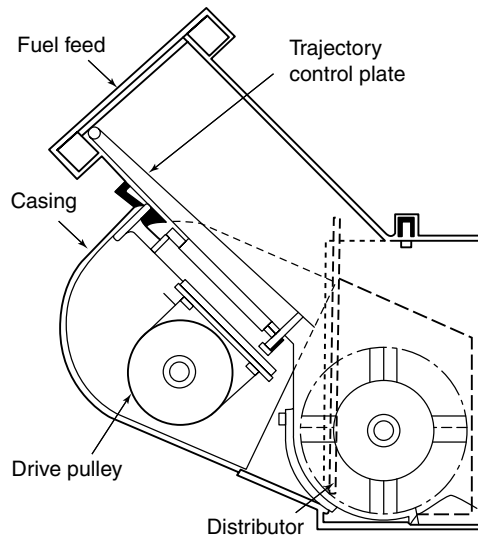
Approximate Spreader Sizes and Capacities (kg/h) for Coal

Nominal Width (mm)	Reciprocating	Rotary	Chain
500	2000	2000	4000
750	3000	3000	6000

There is a wiper arrangement to keep the feeder drum free of coal dust, even with high moisture, so that the calibration is not affected by fines and moisture.

3. *Chain feeders* shown in Figure 11.12 are the heaviest, have almost twice the capacity, and are more expensive. Speed variation of the feeder regulates the output. This design can deal with higher fines and moisture up to 20%, and erosion issues are minimal.

Boiler load control. Feeders are usually controlled by individual speed controls. Anticipatory signal from steam pressure first varies the FD fan speed and instantly raises or reduces the air quantity and in turn heat from the grate. This is followed by the signal from the steam flow, which varies the (1) fuel flow by concurrently varying the speeds of all feeders and (2) grate speed where necessary. Airflow is slowly restored to the new level. This anticipatory action results in an extremely fast load response due to an active fuel inventory on the grate. The spreader's revolutions per minute are manually set for specific fuel and size.

**FIGURE 11.13**

Mechanical rotary distributor or spreader for coals.

Integral or separate fuel feeder plus spreader. For high-ash coals with large throughputs or where firing of coal along with another solid fuel such as bagasse or biomass is required, it is difficult to accommodate all the feeders on the front wall. The feeder and distributor are then separated and a long screw or chain feeder is provided from bunker to spreader.

Overthrow or underthrow spreaders or distributors. Spreading coal on the grate in an overthrow manner has been the common practice. The advantage is a minimal contact of coal particles with the rotor blades and the housing, thereby reducing wear. It is also helpful to have a longer trajectory as the fuel particles need only a peripheral push. The essential difference in spreading the fuel in FBC and SS is that the fuel is spread uniformly in FBC, whereas it is spread in the rear half in SS. In FBC, where there is no travel of the grate, a wider and more uniform distribution is needed. This could be achieved by underthrowing the coal. The coal stays in contact with the blades and the housing for a longer time. The trajectory is more horizontal and distribution of fines is more consistent. For high ash and high fines in coal, the underthrow feeders are better selections even for SS.

Independent feeders and spreaders. Layout considerations, particularly when multiple fuels are required, may have to be discarded in favor of separate units. For coal the feeders are usually chain or screw, and the distributors are rotary mechanical, as shown in Figure 11.13.

11.4.1.5 Bagasse or Biomass Feeders and Spreaders

In coal firing, it is normal to have the feeder and spreader in one assembly in a compact arrangement of the plant with bunkers close to the boiler. Coal, with its high CV and lower flow, makes it possible to have such a combined mechanism. With biofuels, the feeder and spreader should be separated as the fuels have low CV and are voluminous. These feeders are normally of three types:

1. Rotary
2. Screw
3. Chain

Spreaders are of two types:

1. Pneumatic
2. Rotary

The connecting chutes between the feeders and the distributors or spreaders should be

- Steep, preferably at 60° or more, to the horizontal.
- Tapering outward, with increasing cross section, so that the fuel does not pack up and disrupt the flow. The feeders and spreaders are available in 600 and 750 mm nominal widths.

Variable speed arrangements drive the feeders. The feeder speed variation is the means to control the boiler load. As the fuels are voluminous and fluffy, the feeders are to be generously sized to prevent jamming. It is normal to place the motor and variable speed assembly in parallel behind the feeder to achieve access all around and to accommodate all the required feeders. Typical capacities of rotary feeders on bagasse are 8 and 11 tph approximately for 600 and 750 mm, respectively (Figure 11.14).

Figure 11.15 shows a typical screw-type feeder that commonly used with many biofuels that are not too fluffy. For large-capacity bagasse-fired boilers, the volume of fuel is larger, and with the number of standard feeders the grate width increases, making the boilers expensive. Large-capacity feeders with a nominal 1000 mm width with three rollers are now used as depicted in Figure 11.16. The advantage of the three-roll design is that it is possible to have fuel in a large vertical chute of even 10 m height. Bagasse store cannot be stored in a bunker. It needs a continuously expanding chute to make it flow smoothly. To extract bagasse and make it flow well, the top rollers move in an inward fashion, clockwise and anticlockwise, and discharge onto the bottom roller, which, in turn, moves clockwise to effect a positive discharge. The rollers are provided with toothed plates on the periphery as in conventional rotary feeders to prevent jamming of bagasse.

Spreading of metered biofuel is done by pneumatic distributors (Figure 11.17). Mechanical distributors are unsatisfactory as the fuels are light and fluffy. The pneumatic distributors, bolted on the furnace wall, are provided with trajectory adjustment for correcting the flight path and pulsating airflow for fuel throw.

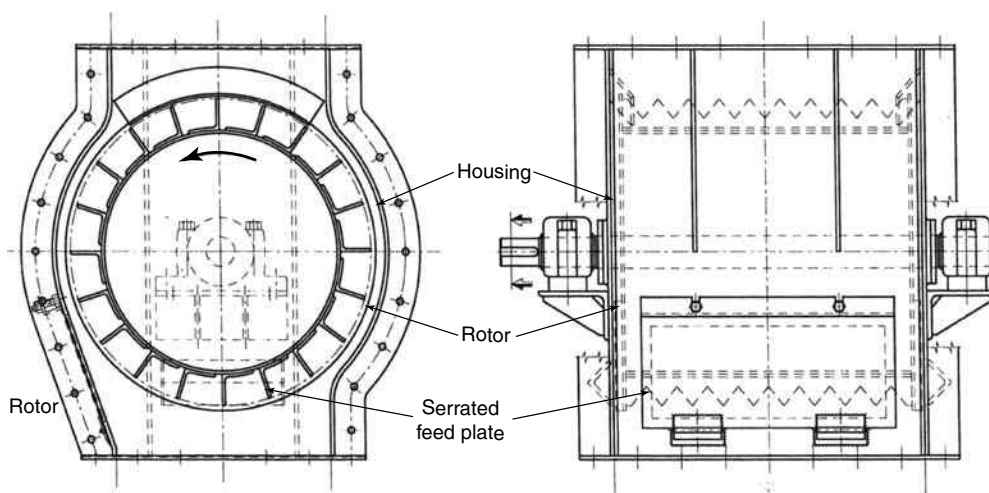


FIGURE 11.14

Rotary feeder for bagasse and rice husk.

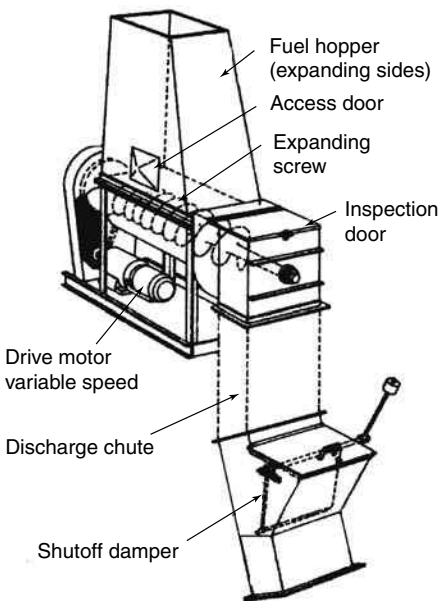


FIGURE 11.15
Screw feeder for biofuels.

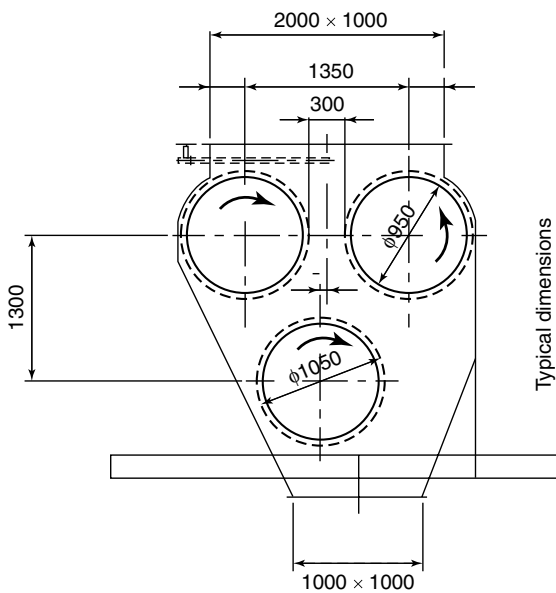


FIGURE 11.16
Three-drum bagasse feeders.

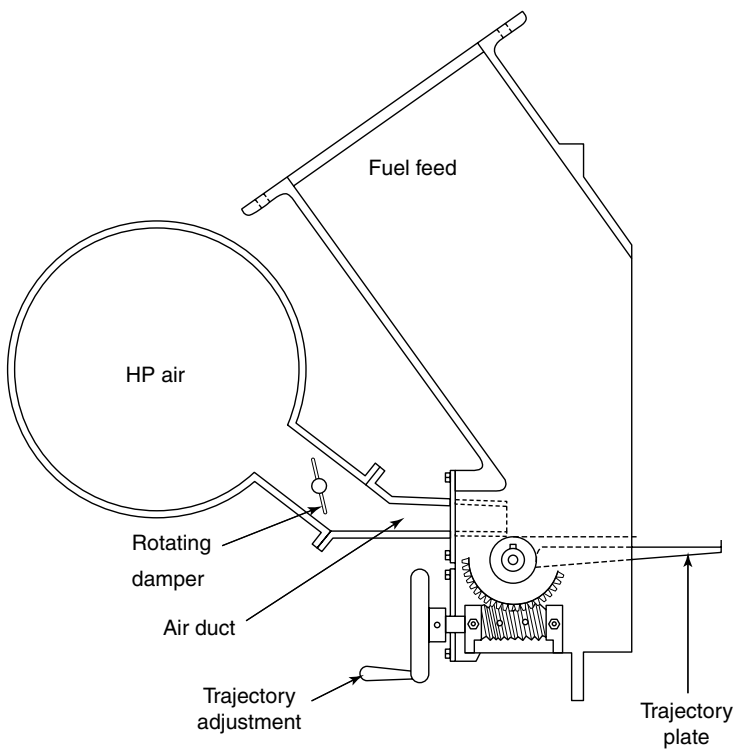


FIGURE 11.17
Pneumatic distributor or spreader for biofuels.

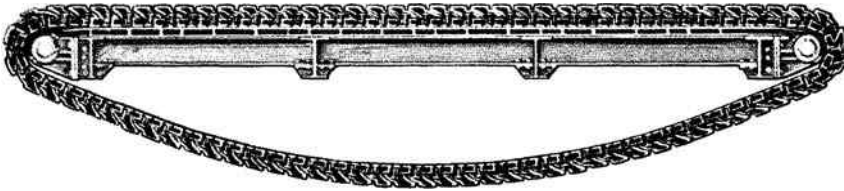


FIGURE 11.18
Catenary-type traveling grate.

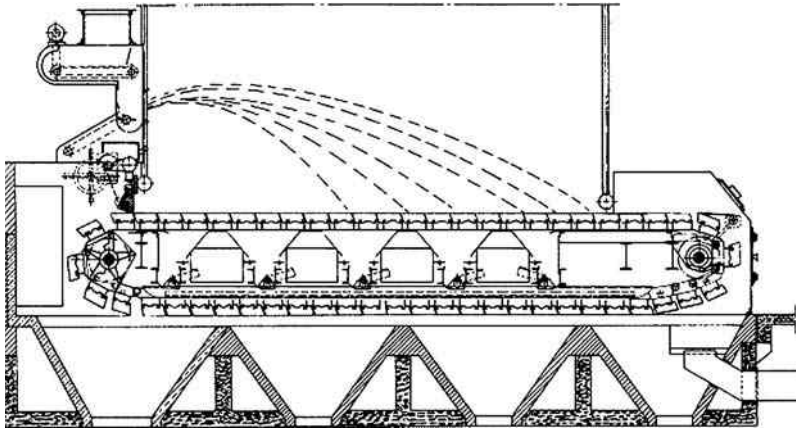


FIGURE 11.19
Chain-type traveling grate.

11.4.1.6 TG for Spreader Stokers

Two important features of these grates are that they are (1) endless chains and (2) air-cooled with the aid of undergrate PA.

Grate types. By the way of stoker arrangement, these grates can be classified into two types:

1. Catenary (Figure 11.18)
2. Chain (Figure 11.19)

Catenary-type grates employ two types of grate bars or links:

1. Plate (~300 mm) as in Figure 11.20
2. Bar (1000–1200 mm) as in Figure 11.21

Chain-type grates usually employ grate bars of link (~25 mm) type (Figure 11.22).

1. *Catenary-type grate.* The return strand is not taut but is allowed a slack, consistent with the access and other requirements, at times with suitable adjustable guide rails below to maintain an effective shape. The grate remains under tension as shown in Figure 11.18. There is no need for additional chain tensioning. Solid shafts are employed. The grate moves from rear to front, and the front shaft is usually the drive shaft. A pair of chains spaced at ~1.2 m forms a grate section and carries T-bars or bulb bars which in turn, carry the grate bars. The grate bars experience no tensile forces whereas the T-bars are subject to flexure, and the chains

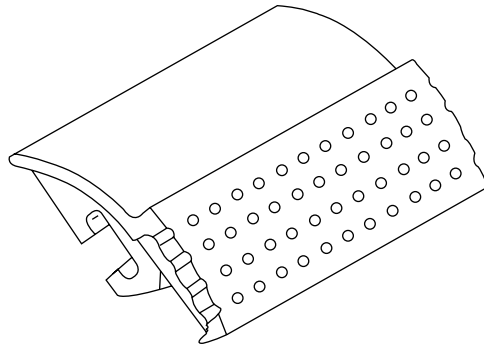
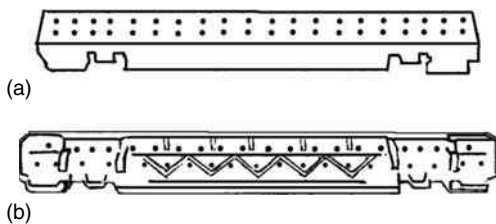
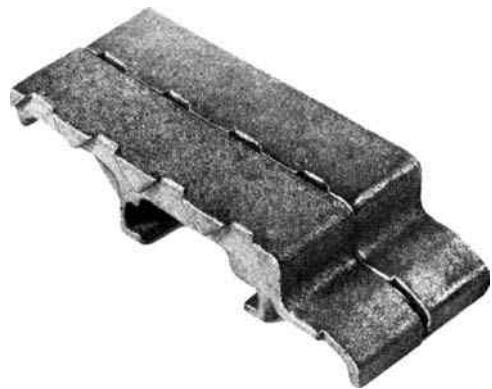
**FIGURE 11.20**

Plate-type (~300 mm) casting.

**FIGURE 11.21**

Bar-type casting. (a) Top view. (b) Bottom view.

**FIGURE 11.22**

Link-type casting.

are under tension. Plate-type grate bars can be considered as several grate links joined together and air nozzles drilled in the body and supported in the same way on T-bars. In the design that employs long grate bars of 1–1.2 m, the bars are directly connected to the chains. These bars are required to be heavy to withstand the flexure. Air is provided at the bottom and there is no segmentation of the windbox. The high-pressure drop in the Venturi-type air nozzles ensures uniform air distribution without internal dampering.

2. *Chain-type grate.* The return strand is supported by bottom rails (Figure 11.19). A separate chain tensioning arrangement is provided to keep the entire grate surface taut and flat. The upper and lower strands are ~1000 mm apart to allow access and provide air dampers and seals. The shafts must be large and are made of hollow pipes to reduce weight. Air can be admitted from the bottom hopper or from the sides. Individual control of air to the various zones along the grate length is possible and represents an advantage over the other design. Sealing arrangements between the zones have to be carefully done and entail a lot of castings.

- a. *Grate bars.* It is essential that the head and tail of the grate bars are perfectly matched to the preceding and succeeding grate bar, and all of them mesh with each other perfectly so that there is no air leakage between them. This is particularly important as the grate bars turn around at the ends.

Grate bars are provided with deep ribs, which make them mechanically strong and keep them close to the incoming air temperature by good cooling. The temperature of grate bars in a running boiler can be kept under 450°C even with hot air. Castings for normal grate bars are Cr–Ni with nominal 1% alloying. The typical composition of grate bars is given in Table 11.4.

- b. *Chains and links.* For trouble-free and long operation of grates, the grate bars should not be overheated and the chains should not elongate unduly over time. The differential elongation of chains is the cause of many grate problems, the most important being the breakages of long grate bars or T-bulb bars connecting the adjacent chains. The chains are usually designed to have tensility of about 32 T and forged construction with hardened rollers and pins (Figure 11.23).

TABLE 11.4

Typical Composition of Grate Casting

Element	Percentage
Carbon	3.3–3.5
Manganese	0.5–0.7
Silicon	0.45 maximum
Sulfur	0.15 maximum
Phosphorus	0.30 maximum
Chromium	0.8–1.2
Nickel	0.9–1.1

Note: For special applications and refuse firing, it is normal to employ ductile cast iron for the grate bars.

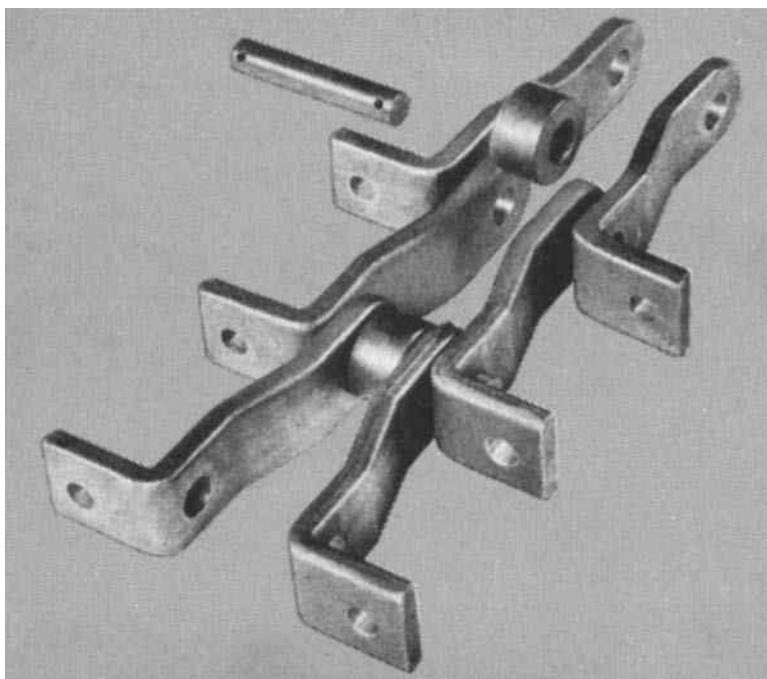
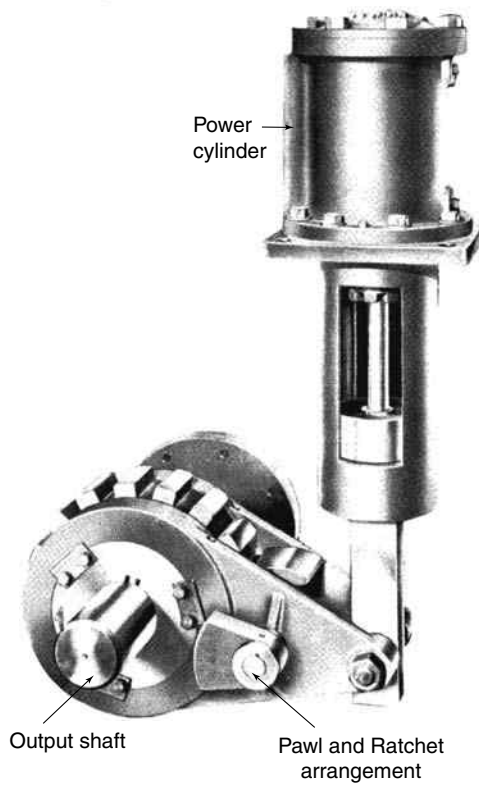


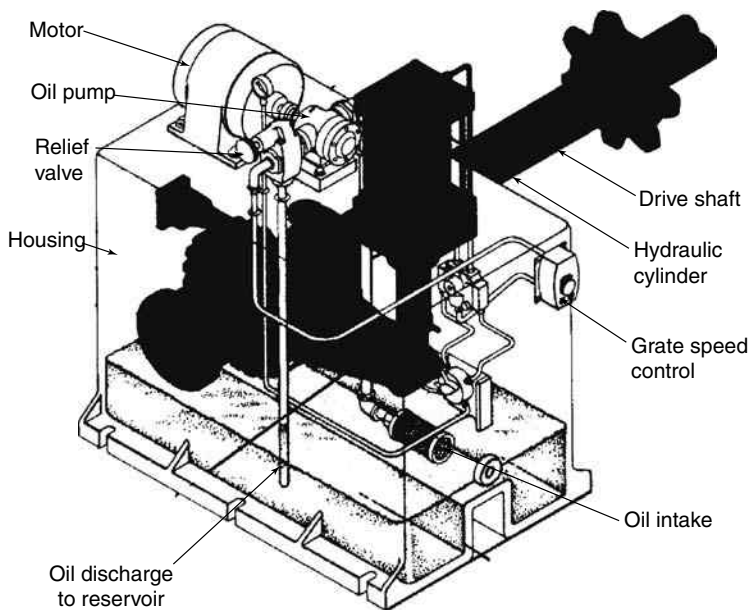
FIGURE 11.23

Typical forged grate chain with hardened rollers and pins.

- c. *Chain tensioning arrangement.* This arrangement is not needed for chains with catenary design as it is self-tightening. It is required for chain-type grates to adjust the tension, making the grate taut as the chains elongate over a period. The tensioning is done by pulling the driven shaft away from the drive shaft.
- d. *Area to air.* Approximately 6–10% of the total grate area should be for combustion air through the grate. More area for air is given in the grates of MB as almost all the air passes through the grate and excess air levels are high. Least area for air is given for spreader firing of biofuels.
- e. *Grate resistance to air.* Grates offer a resistance of ~ 40 mm wg. Normally, PA forms around 70–80% of the total air or a little above stoichiometric air with the rest as SA or OFA. Primary air is less for fuels with higher volatiles, such as lignite and biofuels.
- f. *Air seals.* Front and rear seals confine air to the effective length of the grate, which is ~ 500 mm smaller than the shaft centers. In chain type, where there are air compartments to vary air to different combustion zones, there are seal castings resting on the grate for sealing the adjacent compartments.
- g. *Air temperature limits* are different for coal and biofuels.
 - i. In coal firing the limit is $\sim 160^\circ\text{C}$ normally and 180°C at the extreme to prevent caking or coking of coals.
 - ii. In biofuel firing a much higher 230°C temperature is limited by bearing lubrication considerations. For temperatures higher than 200°C alloy grate bars are usually considered.
- h. *Grate area.* The length of the grate is governed by spreader throw and the width by the limiting torsional stress levels in stoker shafts as well as the ability to spread the combustion air across the grate. Catenary grates are limited to ~ 4.87 m (16 ft) width with their small-diameter solid shafts and the chain type to ~ 6.1 m (20 ft) with big hollow shafts. On the other side, grates as small as 2 m are also employed.
- i. *Spreaders.* From considerations of redundancy, two spreaders are the minimum. Spreaders can distribute fuel over 1–1.5 m width. The maximum number of spreaders can be as high as eight to cover a width of ~ 12 m.
- j. *Stoker drives* can be mechanical or hydraulic. In terms of initial and running costs, both power consumption and reliability are about the same.
- k. With the use of a pawl and ratchet arrangement (Figure 11.24) hydraulic drives (Figure 11.25) are in a position to reverse the grate to free a jam.
- l. Mechanical drives cannot reverse the grate because of the worm and wheel (Figure 11.26). It is possible with a planetary gear system (Figure 11.27).
- m. In principle, mechanical drives are better for the life of chain, as there is no alternate tension and relaxation. In a hydraulic drive, with every stroke of the piston, the tooth of the pinion mounted on the drive shaft is rotated, thus stressing and relaxing the chains.
- n. A worm gear arrangement is common in a mechanical drive, powered by a variable speed motor or a turbine. This is a rugged system but occupies valuable space at stoker front.
- o. A planetary gear box with a variable speed motor is a new arrangement with the advantage of great compactness as the box is small and shaft-mounted.

**FIGURE 11.24**

Pawl and ratchet in hydraulic power pack.

**FIGURE 11.25**

Hydraulic grate drive.

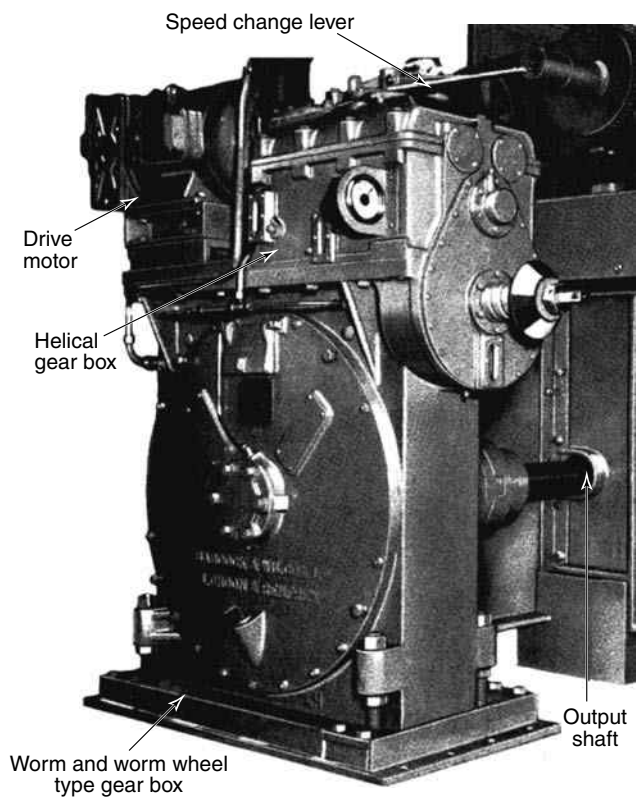


FIGURE 11.26
Mechanical drive—worm and wheel.

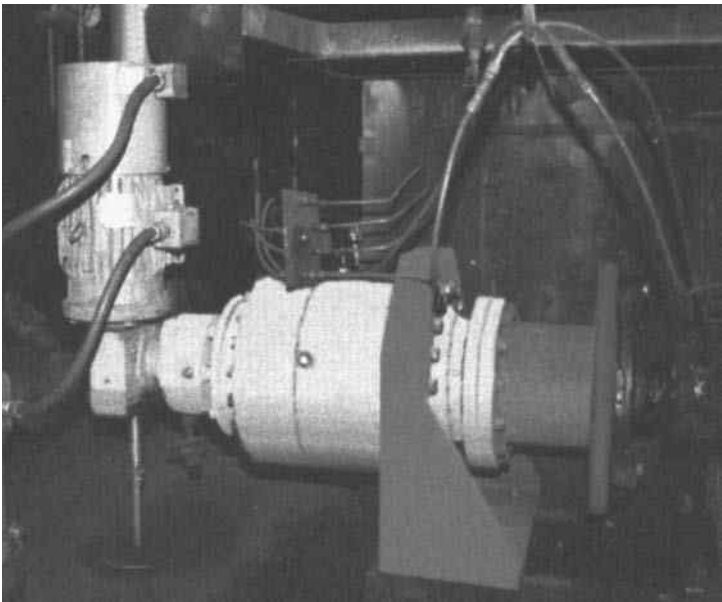


FIGURE 11.27
Mechanical drive—shaft-mounted planetary gear box. (Detroit Stoker Company, U.S.A. With permission.)

- p. Hydraulic drives are also rugged and trouble-free. The space occupied is about the same as for a worm gear arrangement and larger than the planetary gear box.
- q. Grate speed should vary between 0 and 9 m/h to cater to all sizes and fuels. Speeds of ~ 6 m/h are required for high-ash coals. Higher speeds are for emergency evacuation of fuel.
- r. A shear pin or overload clutch is essential for safety of stoker.
- s. Stoker reversing should be possible to relieve any jamming due to entrapment of foreign material in the chain mechanism.

11.4.2 Spreader Firing with Dumping Grates

Dumping grate stokers shown in Figures 11.28 and 11.29 are economical choices for biofuels such as bagasse for low and medium steam generation for the process industry.

11.4.2.1 Combustion Process on Dumping Grates

Spreader stoker combustion is very different from MB on TG stokers as elaborated in Section 11.4.1.1. By means of feeders and spreaders, the fuel is metered and distributed onto the burning fuel on the grate below. Unlike TGs, the DGs are stationary. Also the dimensions are smaller so that the fuel spread is more complete and uniform. During the flight, the high temperature of the furnace and the upward flow of hot flue gases help flash drying of the fuel and combustion of volatiles. Depending on the VM of fuel, 40–60% of combustion takes place in the furnace in suspension before the devolatilized fuel lands on the thin film on the active fuel bed or grate, where the FC of the fuel burns rapidly to complete the combustion, similar to the spreader firing on TG. Ash is intermittently dumped into the ash pit below in DG instead of the front ash pit in SS firing.

11.4.2.2 Design Aspects of Dumping Grates

- A minimum of two grates are required per boiler so that the steam generation is maintained, albeit at reduced rate, when ash from one section is dumped.
- Satisfactory fuel distribution requires a grate width of ~ 1.5 m. Also, to spread the fuel in the front part, the grate length is between 4.5 (normal) and 5 m (maximum—effective). Moreover, this suits the manual tools required to tend the grate. Although the spreading pattern of the fuel is the same for DG and TG, the length

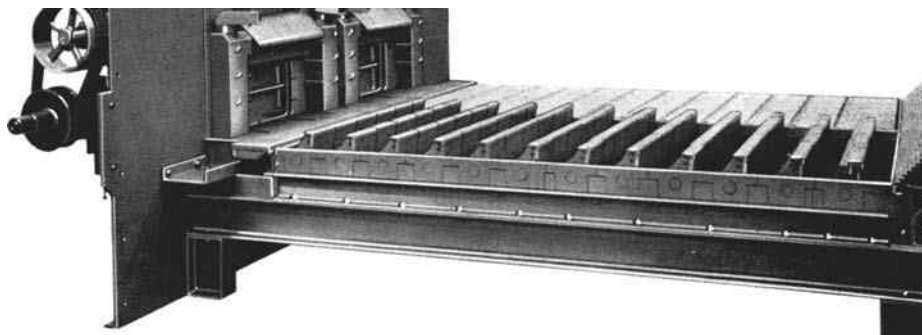
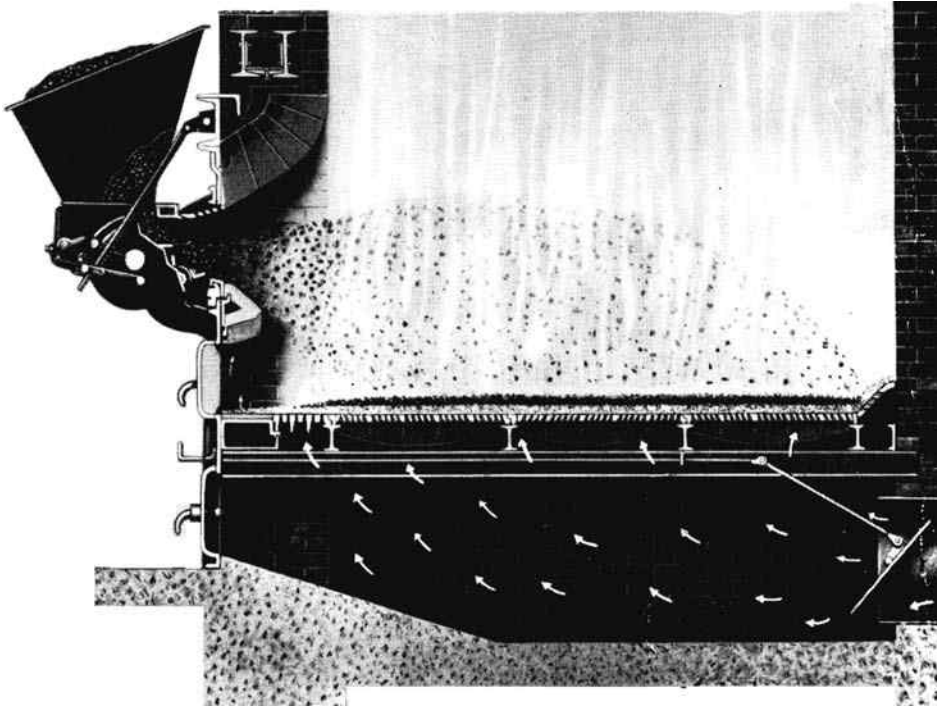
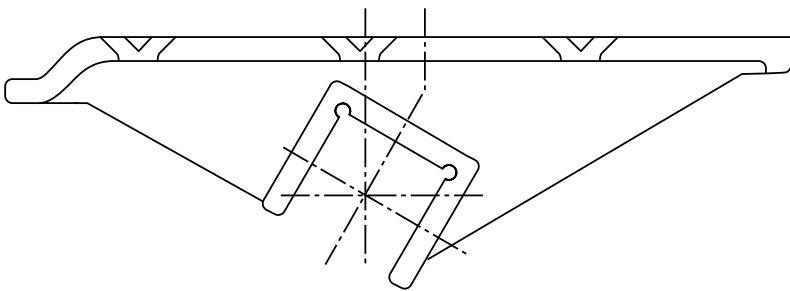


FIGURE 11.28

Dumping grate assembly in shop floor. (Detroit Stoker Company, U.S.A. With permission.)

**FIGURE 11.29**

Dumping grate setting. (Detroit Stoker Company, U.S.A. With permission.)

**FIGURE 11.30**

Typical grate casting for dumping grate.

of the TG can be higher because it moves toward the front and the fuel coverage of the entire grate is not necessary.

- Minimum length of a DG is ~ 2.4 m, and the usual length increments are ~ 225 mm, depending on the length of the grate castings as depicted in Figure 11.30.
- Each section has an independent fuel distributor.
- DGs cost less because the entire return strand of the TG and the drive system are avoided.
- Also the depth of the ash pit can be limited to ~ 1 to 1.5 m, requiring practically no firing floor. The height of the boiler is thus lower.
- Because of the ash build-up on the grates, which impedes the combustion, the dumping grates are not suitable for coals with ash content exceeding $\sim 15\%$.

- Heat release rates for coal are 70% of the HRR of SS.
- *Coal firing.* For uniform spreading, the coal sizing requirements are stringent and fines create a lot of problems. Frequent ash discharges needed for proper combustion have the following disadvantages:
 - At every dumping, green fuel is lost and overfiring of the running grates takes place, thereby reducing the efficiency and increased unburnt losses.
 - The steam production from the boiler is somewhat uneven.
 These limitations have more or less eliminated DGs from coal-fired markets.
- *Bagasse firing.* The DGs are attractive and economical, particularly for bagasse due to the following reasons:
 1. The fuel has very little ash.
 2. It is always uniformly sized.
 3. It burns easily with high efficiency.
 4. Low ash permits less frequent ash dumping (typically once a shift, and hence fewer losses and less overloading.

For capacities up to about 60–70 tph, the DGs are cheaper than TGs but are also slightly less efficient (Figures 11.28 through 11.30). Please refer to Table 11.5 for a comparison of DG and TG.

- Maximum combustion rates of biofuels for DGs are as follows:
 - 2.5 MW/m² or $\sim 2.17 \times 10^6$ kcal/m²/h or 800,000 Btu/ft² h with cold air
 - 2.85 MW/m² or $\sim 2.44 \times 10^6$ kcal/m²/h or 900,000 Btu/ft² h with hot air

TABLE 11.5

SS Firing on Dumping Grate versus Traveling Grate—A Comparison

Parameter	Spreader Stoker with Dumping Grate	Spreader Stoker with Traveling or Chain Grate	Remarks for Dumping Grate
Fuel feed and distribution			Same equipment for both
Grate type	Stationary	Traveling	DG is not totally static. There is small movement as needed for dumping
Grate length	<5.5 m	<7 m	Fuel spreading limits grate length
Total grate size	Smaller	Larger	More aggregate area as DG loading is lower
Ash discharge	Intermittent	Continuous	(a) Some green fuel is lost (b) Working grates are overloaded
Boiler efficiency	Slightly lower	High	(a) More unburnt loss due to dumping (b) 5–10% more excess air
Excess air at full load	35–45%	30–40%	
O&M	Lower	Higher	DG is cheaper—no drive and return strand. No rotating parts
Application—coal firing	Limited up to 30 tph on ash <15%	Well suited up to 100 tph and higher	Only for small capacities—lower efficiency and larger size. Coal properties decide suitability
Bagasse and husk	Popular <80 tph	Up to 250 tph	>60 tph TG is generally cheaper. Uniform size helps to burn such fuel well
Biofuels unsized	Not suitable	Not suitable	Feeding and distribution are problematic

Unlike with coal, suspension firing of biofuels in a furnace releases higher heats ranging from 40 to 60% and the burning of FC on the grate is lower. During the de-ashing periods, the running grates should not be loaded beyond 110% of the maximum rating. The other points are

- Turndown is about 3:1.
- Hot air temperature should be limited to a maximum of 200°C.
- The fuel feeders and distributors are common for both types of spreader firings.

11.5 Stoker-Fired Boilers

The big stoker market today focuses on bagasse, wood, and biofuel firing, with coal firing having gone to the industrial boiler market. Bagasse-fired boilers for process and cogen have capacities as large as 250 tph and pressures reaching 130 bar and temperatures of 540°C. Similarly wood-firing in cold climates has been employing large stoker-fired boilers. Very large coal-fired boilers were built some 30 years ago when the quality of coals was better and the environmental rules were not so stringent. With the advent of FBC, this market has practically disappeared, with stoker firing considered only when the biofuels are to be burnt alone or in combination with coal.

Some examples of stoker-fired boilers are shown in Figures 11.31 through 11.34.

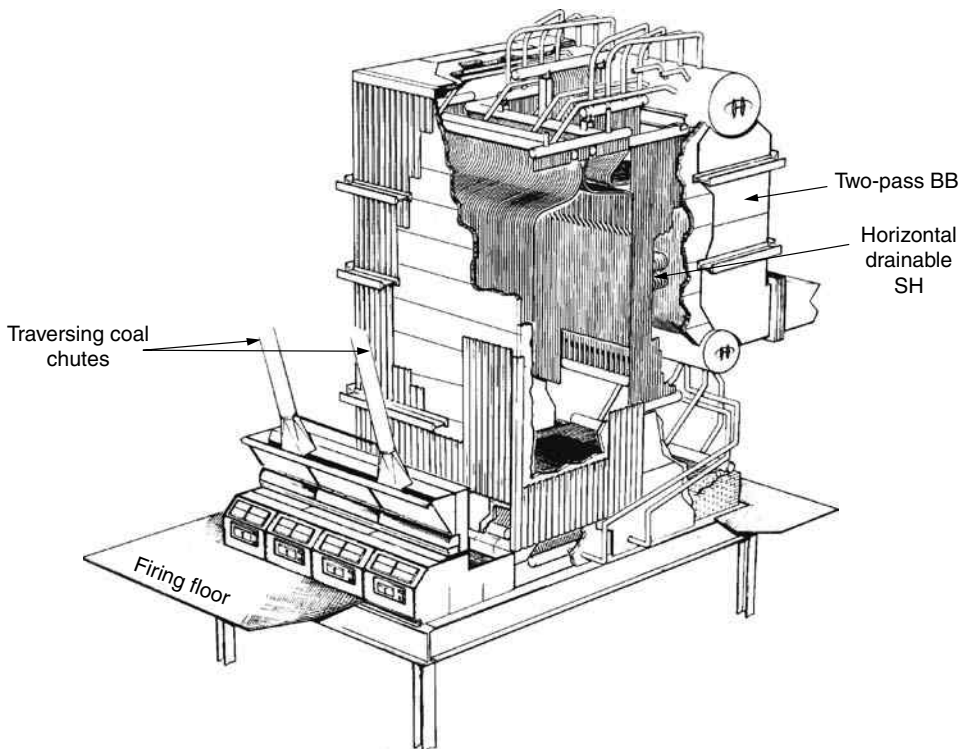
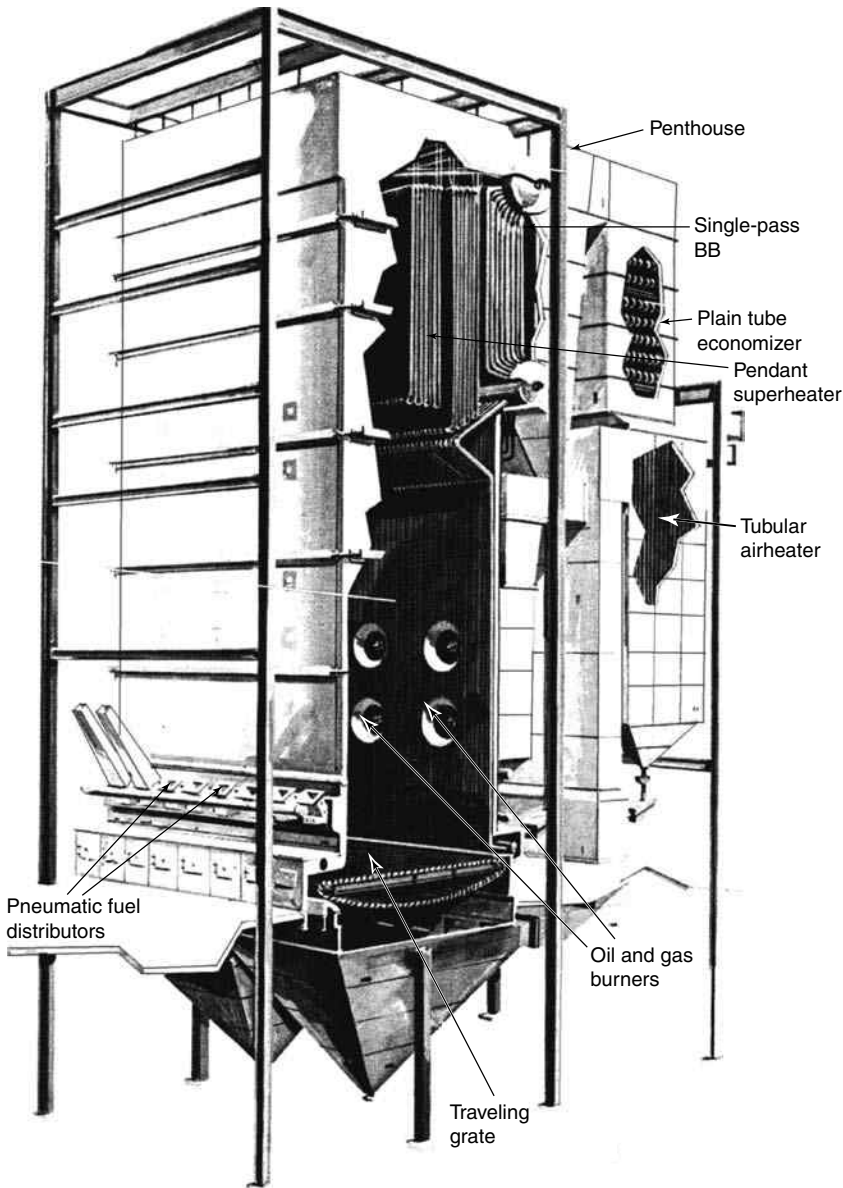


FIGURE 11.31
MB gravity-fed TG with drainable superheater and boiler.

**FIGURE 11.32**

Wood waste and oil- or gas-fired single-pass boiler bank.

Figure 11.31 depicts an MB stoker-fired boiler with TG and gravity feeding. Normal height of the firing floor is ~ 5 m. Coal is fed by traversing chutes and ash is discharged at the rear. The superheater (SH) is horizontal and drainable.

In Figure 11.32, a TG with spreader firing and front ash discharge is shown. It is a multi-fuel-fired boiler with oil and gas fired from the rear as there is space on the rear side due to a single-pass BB. It is a catenary-type stoker with front discharge and pneumatic distributors for fuel spreading. The SH is vertical pendant and nondrainable.

Figure 11.33 shows a large boiler built some 30 years ago. Lignite was the fuel. A longitudinal BB was employed. It was for power generation and it generated ~ 300 tph.

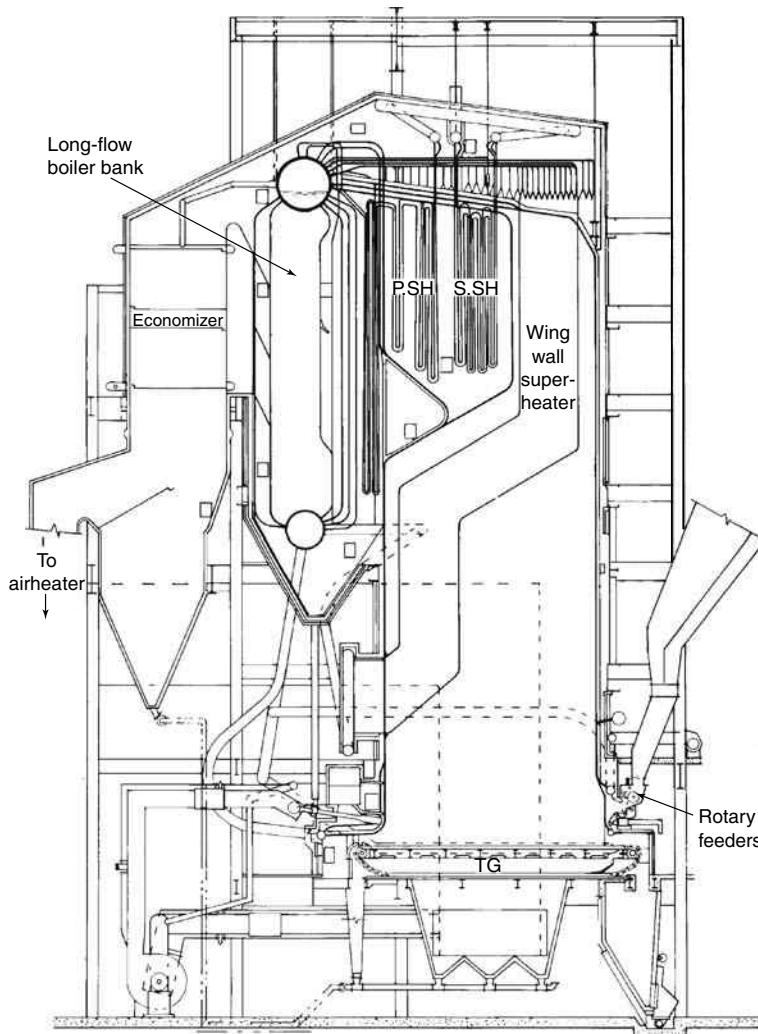


FIGURE 11.33

One of the largest SS lignite-fired boilers (~ 300 tph for 80 MW with $2 \times 19 \text{ ft} \times 27 \text{ ft}$ [$2 \times 5.8 \text{ m} \times 8.23 \text{ m}$] long grate).

11.5.1 Oil or Gas Firing in Stoker-Fired Boilers

- The preferred location for burners is the rear wall, unless blocked by a long BB, as there is usually ample furnace depth to accommodate the flames, and the resulting gas temperature entering the SH zone is more uniform.
- Burners can also be located on a side wall as a second preference as the gas entering the SH zone is not uniform, provided there is enough clearance for flames. The number of burners may have to be increased when the furnace width cannot accommodate the flame length.
- The lower burner should not be $< \sim 2.2 \text{ m}$ from the top of the grate to prevent overheating of the grate bars.

- Flame monitors should be carefully chosen to prevent interference from the stoker flames from below.
- For an extended duration of burner usage, the grate air damper should have a crack opening all the time so that a small air leakage is intentionally provided for cooling the grate and preventing its overheating.
- A separate FD fan for burners may be provided instead of depending on the main fan, as the pressure of air required for the burners is much higher at 150–200 mm wg (depending on the turndown) as compared with ~40 mm for the grates.
- Superheater surface requirements are governed by oil firing, as the gas generated is 15% lower than that for coal.
- Spacing of tubes in convection passes is usually more than that required if solid fuel was burnt alone. This is because of the sticky deposits left on the tubes by the oil, particularly the heavy oils.

11.5.2 Principles of Spreader Stoker-Fired Boiler Design

The following points explain the steps involved in the design of an SS-fired boiler:

- The design begins with the sizing of the stoker and the selection of the feeders for the amount of fuel to be burnt. The grates are available in certain sizes and usually the feeders are limited to one or two sizes. Permissible grate HRR determines grate area. Usually, as the boiler sizes increase, accommodating the required number of feeders governs the grate width more than the HRR.
- Furnace sizing follows the sizing of firing equipment. Residence times (Table 6.1) and the rates of volumetric releases for the fuel decide the furnace volume. See Chapter 2. If auxiliary fuels such as oil and gas are used, the volume has to be suitably altered. Furnace arches are used for MB whereas two or three levels of SA are used for SS firing for coal and biofuels, respectively.
- Furnace sizing is the most important part of the boiler design, as it determines the cost of the boiler. It also decides the drum length and size of the convection bank and the back-end equipment. It is better to err on the conservative side in furnace sizing as there is no way of increasing the size at a later date. It is also an insurance against a possible variation in fuel properties in future.
- The furnace arch, above which the pendant SH is located, is usually placed between 3 and 8 m above the grate, depending on the boiler size. Arch depth is varied between 30 and 70% of the furnace depth, depending on the number of SH coils to be placed above. It is inclined at no less than 30° to horizontal, from a circulation point of view, to avoid possible overheating due to steam formation.
- Platen SH hanging in the furnace is required only when steam temperatures are ~500°C or more. For all the other cases, a pendant SH can be accommodated above the arch. Access, spacing of coils to avoid fouling, soot blower location, tube supports, sealing with roof tubes, tube bending, tube expansion, metallurgy, etc. are to be carefully considered based on previous experience and manufacturing capabilities. The fuel properties and firing methods also dictate possibilities.

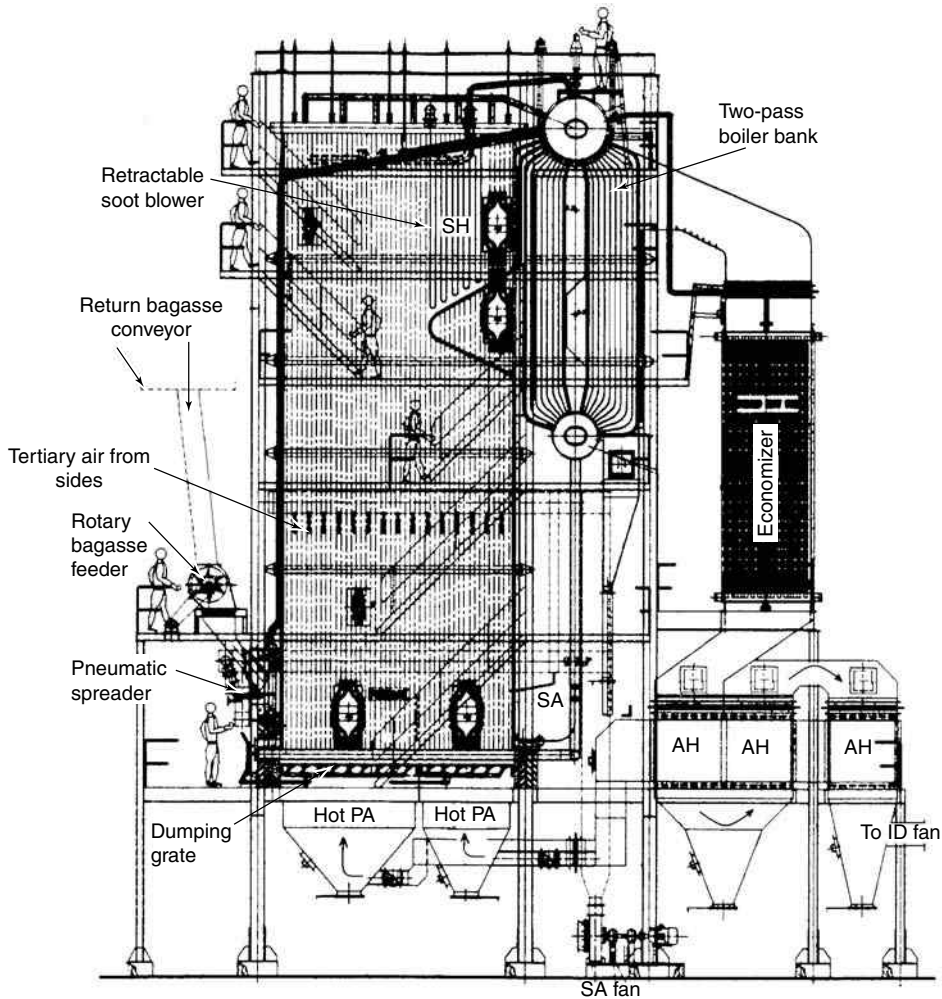


FIGURE 11.34

DG grate boiler with 40 tph capacity.

- Superheaters can be vertical nondrainable or horizontal drainable. The latter does not lend itself to higher SH.
- Superheaters are usually followed by BB if the pressures are < 70 bar (~ 1000 psig). Boiler banks are usually modular. The choice of single- and two-pass BB is largely governed by the following considerations, although exceptions abound.
 - Two-pass or longitudinal-flow or three-pass cross flow BBs go well with MB as the dust loading of the flue gases is low.
 - Single-pass cross flow BBs are used for all fuels in spreader firing to avoid erosion of the BB tubes due to the gas turns of longitudinal flow.
 - Two-pass bank in SS firing is employed only if the fuel is known to be nonerosive or for small boilers where gas loading per unit width is low.
 - One or two-pass BBs are also decided by the layout advantages.

- The gases are to be cooled to $< 450^{\circ}\text{C}$ in the first boiler pass to permit plain steel casing in the second pass that houses the economizer (ECON) and airheater (AH). With BB this is normally achievable. At temperatures $> 450^{\circ}\text{C}$ there is a fear of stagnation of water in the last tubes of the BB due to steam formation that upsets the circulation.
- The economizer is usually a plain tube and an in-line construction. Finned tubes and staggered arrangements can also be used if the flue gases are known to be benign with less dust load. Cast iron gills are the solution if the fuel has high S and feed temperature is on the lower side. Chapter 6 provides more details.
- Inclusion of an AH is mandatory for biofuels as the moisture in fuel has to be flash-dried. But the AH outlet temperature has to be within the permissible limits of the grates.
- For coal firing AH has to be avoided if possible as hot air has a tendency to promote caking and clinkering. Although this is possible in a process application with low feed temperatures, a cogen plant with high feed temperature makes it mandatory to have an AH to cool the gases to an acceptable limit. Airheaters in such case should be kept to a minimum.
- When both ECON and AH have to be provided, the choice must be optimize the costs. The cost of the ECON has to be compared with the cost of the AH only after its ducting cost is also added.
- Tubular AHs are the usual choices. Vertical tubular AHs are more popular.

11.5.3 Fuel Flexibility in Stokers

The fuel flexibility should be evaluated from two considerations.

1. Simultaneous multiple fuel-firing capability or cofiring several fuels
2. Range of fuels that can be burnt

11.5.3.1 Multifuel Firing

Stoker firing, particularly SS, is effective for multifuel firing capability. In stoker-fired boilers, the following features lend themselves to mounting multifuel-firing equipment.

- The grates located at the bottom
- Tall and vertical furnace walls uncluttered
- Large area

Oil and gas firing to 100% maximum continuous rating (MCR) usually poses no problem. On a large boiler, oil or gas on the side wall and waste gas on the opposite wall can be easily burnt. In SS, along with coal, one or two biofuels can be easily burnt by employing mechanical and pneumatic distributors. Instrumentation and control (I&C) for all these fuels can be satisfactorily hooked up. The sizing of fuels is, in most cases, easy and fuel feeding is simple.

The multifuel flexibility of SS is amazing. With smaller boiler sizes and small quantities of fuel, it is ideally suited for process industry. Co-firing capabilities of PF are limited, and it can be argued that in large utilities this may not be required. Co-firing in FBC boilers is

also very limited. Even 100% oil firing may not be possible in many designs. In comparison, all types of stokers score high.

11.5.3.2 Range of Fuels

The variety and range of fuels that can be burnt are also very impressive, particularly with SS. Coals, lignites, nonabrasive solid fuels, and many sized biofuels (such as bagasse and rice husk) that are fit for spreading can be burnt. The main reason is the flight of the green fuel in a hot furnace and subsequent landing on top of the burning bed of fuel, helping the fuel to dry and ignite effortlessly. In SS solid fuels with GCV as low as 2000 kcal/kg, fuels with moisture as high as 52% and ash as high as 45%, coals with VM as low as 20% can be burnt. Even lower VM can be handled by sandwich firing.

However, stokers are no match to FBC for firing poor fuels. Admittedly the SS is far more versatile in comparison with the other grates due to the split combustion, that is, in suspension and on grate. But this is of no help in burning a variety of inferior fuels. The high moisture or high ash or poor volatiles or low heating value (HV) of many poor and unconventional fuels requires a big heating source and adequate time with turbulence to help them dry ignite and burn, in the form of a hot and turbulent bed of inert material in both bubbling fluidized bed combustion (BFBC) boilers and circulating fluidized bed combustion (CFBC) boilers. Fuels that have a GCV as low as 1400 kcal/kg are easily burnt in FBC. See Figure 12.9.

For biofuels, stokers are the only solution as these fuels in most cases are too light to stay in the bed and have no ash to replenish the bed material if they are to be fired in FBC. Fortunately they have no S to create SO_x problems or appreciable N to have NO_x issues, making them suited for uncontrolled stoker firing.

11.5.4 Biofuel Firing on Stokers

Biofuels, such as wood, wood wastes, bark, saw dust, bagasse, and so on, have been burnt in boilers for power and process for many decades. Burning a greater variety of biofuels is gathering momentum as

- The prime fuels are becoming more expensive.
- Biofuels are renewable and do not deplete the fossil reserves.
- The environmental norms are getting tighter. Production of CO_2 is urgently needed.
- Biofuels produce no offensive levels of SO_x and NO_x .

Biopower cannot be produced in large quantities nor can it be present near big power consumers. As distributed power generation is gaining acceptance, it is strengthening the case in favor of biofuels. Distributed power is generation of power at several places in smaller amounts instead of a centralized single location.

There is no better option than stoker firing for meeting this emerging trend of burning biofuels. Thin pile burning on PHG is nearly as good if the ash is low and continuous ash discharge is not required. For very high-moisture fuels, pile burning (up to 60%) and semipile burning in IWCG (up to 70%) are the only alternatives. These are discussed in Chapter 9.

Biofuels are described in detail in Chapter 3. To briefly recapitulate

- They are fluffy and often stringy. Their bulk density is low, making them expensive to transport. This is the main reason for adopting distributed generation.
- For the same reason large quantities of fuel cannot be made available at a single location.
- Biofuels are seasonal. Also the availability is widely fluctuating with peaks and shortages. During low periods either a prime fuel such as coal or preferably another biofuel has to be made available. The boiler has to be multifuel fired.
- From the point of combustion, the following points are to be noted:
 - The moisture of biofuels is quite high, varying from 20 to 70%. This calls for hot air for combustion to dry the fuel and help in ignition. Beyond ~52% of fuel moisture, pile or semipile burning has to be adopted in place of SS firing or PHG. Pile burning is practically obsolete (see Chapter 9), IWCG is the present-day choice. The flame temperatures are low and NO_x formation is also low.
 - The VM is uniformly high, varying from 60 to 88% on a daf basis, helping to counteract the cooling effect of high moisture in fuel under ignition and combustion.
 - There is a small amount of ash of 0.2–5.3% on a dry basis. The 15% ash in rice husk is about the maximum.
 - The biofuels are practically free of sulfur (<0.1% elemental S), making combustion SO_x -free.
 - Fuel nitrogen is also low, further reducing the chances of NO_x .
- Fuel transportation is usually by belt or slat conveyors. Feeding is by rotary or screw feeders. For low very fluffy fuels such as bagasse, the rotary feeders are universally adopted. Screw feeders are for fuels that do not pack.

There are two types of biofuels depending on the alkali content in ash.

1. Biofuels that have no appreciable amounts of alkalies in ash have high initial ash deformation temperature (IADT), which permits higher volumetric rates and furnace exit-gas temperature (FEGT), making it possible to generate high SH steam. Wood, bagasse, and rice husk belong to this category.
2. If high amounts of alkalies are present in ash, the FEGT has to be lowered well enough to prevent fouling of SH with corresponding lowering of furnace volumetric HRR. It is prudent not to attempt high superheater outlet temperature (SOT) as the fouling of convection banks can severely affect availability.

Table 11.6 indicates the limits in furnace sizing for the two types of biofuels. Boiler design for biofuels should have the following features to provide efficient combustion:

- Fuel sizing must be understood carefully before choosing the type of grate. Firing equipment should be a DG or SS for sized fuels with moisture <52%, which can be

TABLE 11.6

Furnace Sizing for Biofuels

Alkalies in Ash	Volumetric HRR			Residence Time (s)	FEGT		SHOT	
	MW/m ³	kcal/m ³	Btu/ft ³		°C	°F	°C	°F
Low to negligible	<0.31	<267,000	<30,000	2.5–3.0	~1000	1830	~500	~930
High	>0.176	>151,000	>17,000	3.0–3.5	~800	1470	~400	~750

spread on the grate. For unsizable or stringy fuels, the RG is a better choice as it is gravity fed. If there is more moisture, such fuels are burnt via pile burning.

- If coal firing is to be done with any biofuel, SS is the only choice. This is often required in cogen.
- For moistures up to 70%, IWCG is used for larger capacities of even 200 tph or thick pile burning for small capacities of ~ 20 tph. Furnace arches are essential for reradiating the heat. Oil support is provided to help start up and load stabilization.
- AH is needed to drive off moisture. Air temperature can be as high as the grate can bear— $\sim 230^{\circ}\text{C}$ for TG and $\sim 200^{\circ}\text{C}$ for RG. PHG and IWCG are better as they can take higher temperatures of $\sim 315^{\circ}\text{C}$. Many times AH is designed for 80% air passing through it as biofuels need nearly 30% OFA for which cold air is used.
- High VM requires more air and it is normal to provide 30% OFA. In addition to SA in front and rear walls to the extent of 20%, TA of $\sim 10\%$ is provided nearly 2 m below the nose, usually in side walls to trap and burn the fines. The TA acts as an air curtain and usually the air nozzles are smaller and more in number. But this aspect is fuel-specific.
 - The requirement of low FEGT due to high alkalies makes the furnace volume high. This reduces the carryover of fuel char and ash due to their lightness, causing efficiency loss. The resulting volumetric HRRs appear low and residence times high.
 - If there is cofiring, the FEGTs are to be even lower as the melting point of the ash eutectic is likely to be lower than the melting point of fuel ash.
- Higher fuel moisture creates larger flue gas quantities and smaller SH. For multi-fuel firing with coal, the SH size is governed by the coal and the attemperator by the biofuel with maximum moisture.
- The chances of fouling of the final SH are high and may call for a retractable soot blower (SB) for effective cleaning.
- Grate HRR, furnace ratings, and gas velocities are discussed in Chapter 6.
- Also, refer to Section 9.2.1.5 for details on pile burning.
- Dust capturing equipment needs a careful selection based on the specific biofuel and permissible particulate emission level due to the lightness of the particles and high resistivity. Depending on the gas velocities and furnace and grate loadings, the fly ash can be as high as 80% of the total ash. Typical dust load at the entry to the dust-collecting device varies from 2.5 to 8 g/N m³, depending on the ash content and the firing equipment—MB or SB.
- Fly ash produced is very fine and not satisfactorily trapped in mechanical dust collectors (MDCs). On contact with the cyclone walls, the ash tends to break down into very fine powder and gets partially carried away with the gases.
- Electrostatic precipitators (ESPs) are not satisfactory as the ash resistivity is high.
- Bag filters are effective but there is a danger of fire as the burning char can travel all the way to the FF. It is usual to have a knock-out baffle to change the gas direction so that the char and ash can precipitate out of the gas stream.
- Wet scrubbers are also used but the power costs are high. Air pollution becomes a water pollution issue and unless there is a proper way out of that, wet scrubbers cannot be adopted.

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12

Fluidized Bed Combustion

12.1 Introduction

Fluidized bed combustion (FBC) is burning of various solid fuels in the fluidized state—a condition where a gas–solid mixture behaves like a free-flowing fluid.

Mass burning (MB) and traveling grate (TG) stokers burn solid fuel in static mode with the fuel resting on a grate, whereas pulverized fuel (PF) firing burns the fuel in suspension mode in transport condition. Between the two extremes of static and transport modes lies the fluidized mode. With the right proportioning of air pressure and the proper sizing of fuel, the air–solid mixture behaves like a fluid. The fluid bed experiences progressively more turbulence, as air velocity is increased. FBC is the combustion in this state—bubbling FBC (BFBC) at the lower end and circulating FBC (CFBC) at the higher end.

FBC development dates back to the 1970s as an answer to the then-emerging pollution limits for emissions, specifically SO_x , and NO_x . A *cleaner* and *cooler* combustion was the only way to meet stricter levels of SO_x and NO_x , respectively, without the need of costly secondary gas cleaning measures. By limiting the bed temperatures to $\sim 850^\circ\text{C}$ (optimum temperature for sulfur–calcium coal reaction) these twin objectives could be met by

- Limestone addition
- Low NO_x due to no thermal NO_x generation

In the classical three Ts of combustion—*time*, *turbulence*, and *temperature*—the negative effect of cooler combustion was overcome by increasing the other factors. The combustion efficiency was, in fact, raised drastically because of high turbulence in the bed and longer residence time, despite a lower combustion temperature. Bed tubes for bubbling beds and ash recirculation for circulating beds were employed for bed temperature control. This way there emerged two distinct types of FBC.

1. Bubbling fluidized bed combustion boilers with lesser residence time, comparatively lower turbulence, and reduced combustion efficiency and lesser desulfurization.
2. Circulating fluidized bed combustion boilers with much longer residence time (due to ash recirculation) and higher turbulence and hence higher combustion efficiency.

By the 1990s, BFBC boilers practically ended the reign of the stoker-fired boilers worldwide, at least for prime fuels such as coal and lignite. Very different factors were responsible for this dramatic growth of FBC:

- Environmental compliance in the developed markets
- Efficient combustion of poor and ashy coals in the developing markets

These factors dislodged the stokers from their premium position worldwide, confining them to areas such as biofuels because

- BFBC poses no SO_x or NO_x issues as both S and N are low.
- The fuels are too light or fluffy to be fluidized.
- Consistency of fuel sizing is a problem.
- The fan power is less in grates.
- No efficiency is gained from BFBC.

Likewise, in the industry requiring up to ~100 MW captive power, CFBC boilers have edged out PF firing for captive and cogeneration power with their

- Efficiencies comparable to those of PF
- Much better fuel flexibility
- Superior environmental friendliness
- Lower O&M costs

However, for large utility boilers with no multifuel requirement, PF boilers offer a slightly better efficiency of ~1% (as the fan power in fluidization exceeds milling power) at practically the same cost. The sharp reduction of deSO_x and deNO_x helped in keeping the overall costs of PF boiler plants at levels competitive to those of CFBC, despite larger furnaces with low NO_x burners increasing the basic cost of the boiler. Also, many newer CFBC designs are available in large sizes, leaving the field only for hot cyclone and compact designs, both of which are not as trouble-free as conventional PF. In most cases large CFBCs are planned for fuels that are difficult to burn in PF, such as pet coke, anthracite, and peat. This is slowly changing as CFBC boiler costs are coming down and their availability is increasing.

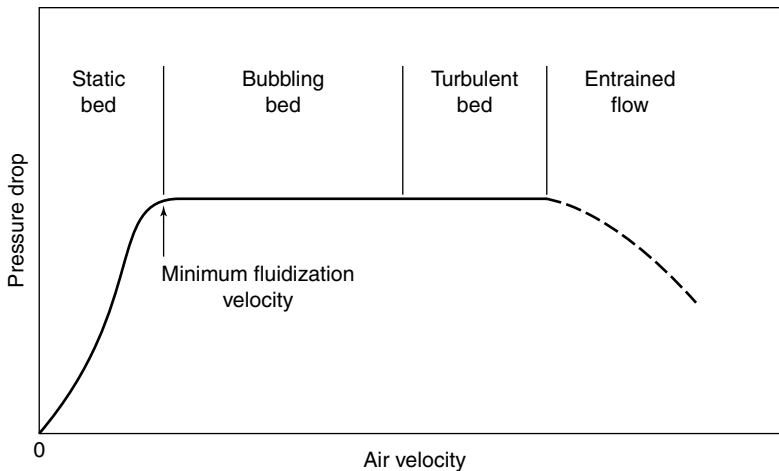
This chapter covers both types of boilers, the BFBC and the CFBC, as they share the same principle of fluidization. Within these two main technologies, several variations of designs appeared and also exited in the process of consolidation. The surviving technologies are proprietary technologies under constant development, and the information available tends to be fragmented and limited. If this point is taken into account, what is presented here can certainly provide an adequate and accurate picture of various designs and their progress.

12.2 FBC Fundamentals

FBC are available in bubbling, circulating, and expanding bed (which is in between) types, depending on the in-bed gas velocity and mean particle size. Each of the systems is separately described after the following discussion on the fundamentals of fluidization technique.

12.2.1 Fluidization

When gas is passed through a chamber with a bed of solids resting on the bottom plate with provision for a good air distribution, at first there is no apparent disturbance to the bed because the air flows between the solids. As the airflow is increased, the pressure drop

**FIGURE 12.1**

Effect of increasing air velocity in bed of solids.

across the bed increases proportionately. Then a point is reached when the bed is lifted off the plate, which is the *onset of fluidization* and the bed starts to behave like a free-flowing fluid from this point onward. The *minimum fluidization velocity* is depicted in Figure 12.1. At this point there is no appreciable movement of the particles with no mixing and turbulence, which will increase with increased gas flows.

With more gas flow, the bed expands more and becomes less uniform. Slowly thereafter the bubbles of gas start to form, with the attendant violent reaction. This is the *bubbling fluidized bed* (BFB). The process is similar to the bubbling in boiling water. Air pressure drop, meanwhile, remains constant.

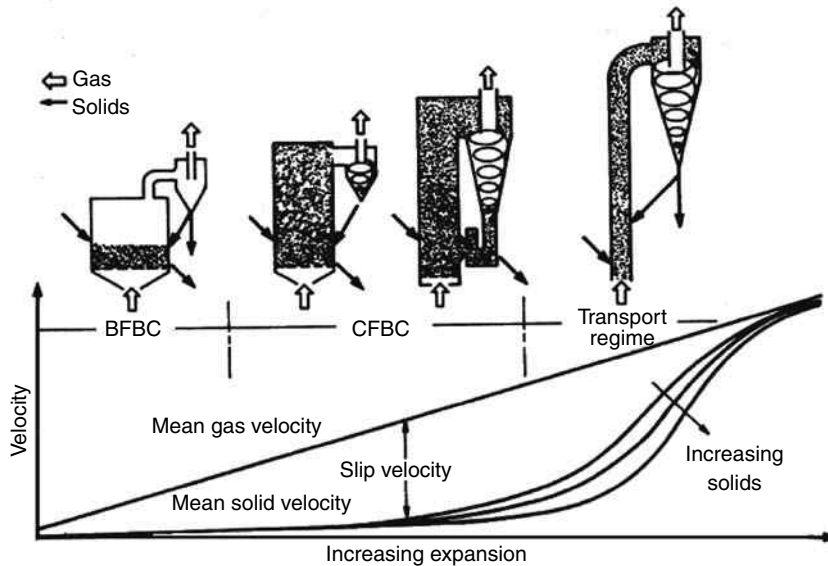
With increase in gas, the bubbles get larger and coalesce to make large voids in the bed. The heavier particles start settling at the bottom and lighter particles swirl at the top. As the gas velocity is increased, the churning bubbling bed, with a dense bed at bottom and a light haze of dust at the top, yields to a cloud of dust filling the entire space. This is the *turbulent phase*. Even now the pressure drop remains the same.

In this turbulent phase, when the elutriated solids are captured and returned to the bed, a circulation of dust can be established.

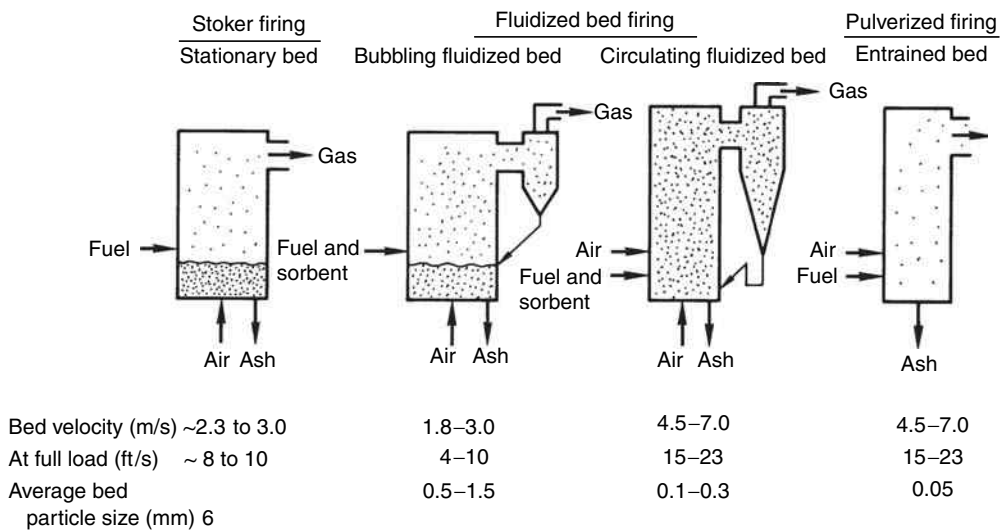
The difference in the mean velocities between the gas and the solids is the *slip velocity*. As shown in Figure 12.2, the slip velocity continuously increases in the bubbling and turbulent bed regimes. At the end of the turbulent period, the solids start attaining higher velocities and start leaving the bed, which is the beginning of the transport regime.

As the flow is increased, the dense cloud also rises to join the cloud above and this is called *entrainment*, marking the end of fluidization phase and the beginning of the transport phase. When the particles are not recirculated, the pressure drop, which remained practically constant during the entire fluidization, starts to reduce, as the solids get entrained and leave the chamber. The physical properties of fluid and bed material, such as viscosity, density, and particle size, decide the velocities at which fluidization and transport regimes set in. Figures 12.2 and 12.3 depict the various regimes with velocity ranges and particle sizes.

- The combustor changes progressively from short and broad in stoker firing to tall and narrow in PF, whereas the upper furnace gets increasingly dustier.

**FIGURE 12.2**

Stages of fluidization. BFBC, bubbling fluidized bed combustion; CFBC, circulating fluidized bed combustion. (From AE&E Lentjes GmbH, Germany. With permission.)

**FIGURE 12.3**

All firing modes for solid fuels.

- With the increasing in-bed gas velocity, the pressure drops across the bed are constant in the entire fluidization range; however, the pressure actually drops in the transport regime.
- Although the bed velocities increase, the average particle size steadily decreases. In fact, in current boiler design, there is no significant change in the bed velocities between the CFB and transport regimes. The difference in practice is that due to the smaller particle size they get entrained.

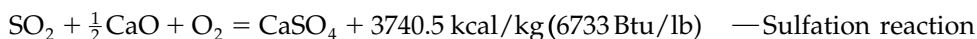
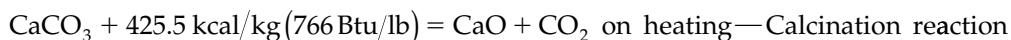
In FBC boilers operating at $\sim 850^{\circ}\text{C}$, there is an inherent lower production of NO_x automatically, as the combustion temperature is low. These boilers also offer a very convenient way of reducing the SO_x within the furnace enclosure by the reaction with lime. This desulfurization is adopted only for coals and other solid fuels with medium to high sulfur. This point needs to be understood clearly, as there is a popular misconception that FBC and desulfurization go together. In fact, with low sulfur in coal or biofuels with greater reactive Ca in fuel ash, the FBC boilers are operated with no lime addition. This enables boiler operation at a $70\text{--}100^{\circ}\text{C}$ higher bed temperature with coal, which will offer slightly higher combustion efficiency and a marginally more compact boiler.

12.2.2 Desulfurization

In-bed desulfurization is a breakthrough. Lime-sulfur reaction within the furnace, along with the combustion reaction and the resultant gypsum exit with ash is simplification personified. A good understanding of the mechanics of this reaction and the limitations is very necessary for realistic emission guarantees and also to configure limestone and ash handling systems that meet the present and future requirements.

Calcination. CaO is produced by the decomposition of lime (CaCO_3) when CO_2 is driven off on heating. This process is called calcination of lime, and is an exothermic reaction.

Sulfation. Lime-sulfur reaction (sulfation) is basically turning the SO_2 produced (from the oxidation of sulfur on combustion) to gypsum (CaSO_4) by its reaction with CaO. This is an endothermic reaction.

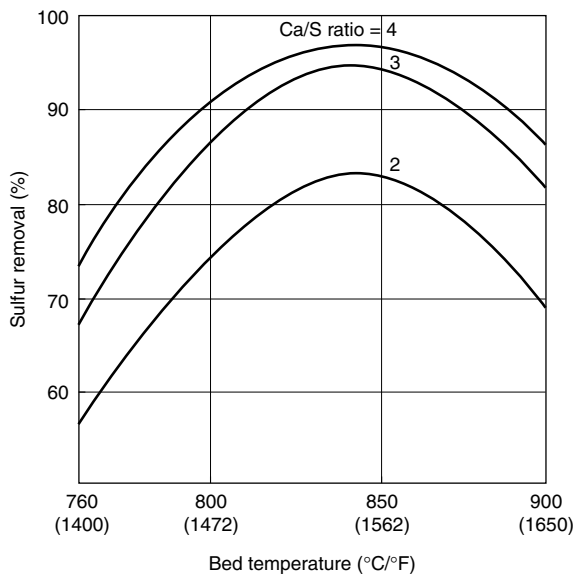


Both sulfation and calcination reactions start at $\sim 700^{\circ}\text{C}$ (1300°F) and are *optimum at* $840\text{--}850^{\circ}\text{C}$ (~ 1545 to 1565°F). The lime consumption is lowest at this temperature range. Even then the theoretical requirement of 1 mol of Ca per mol of S (Ca/S ratio of 1) cannot be reached because

- The sulfation takes place on the surface of the lime particle in the bed and so the core of the particle fails to participate.
- Some sulfur in fuel, which is inorganically bound, does not oxidize to SO_2 .
- Some SO_2 escapes when sorbent is less or accompanies the volatile matter (VM) of fuel.
- Limestone purity is lower than optimum—typically $\sim 92\%$.

A bed temperature range of $800\text{--}900^{\circ}\text{C}$ ($1470\text{--}1650^{\circ}\text{F}$) is important for desulfurization because

- Calcination is not complete at temperatures $< 800^{\circ}\text{C}$.
- Sulfation reaction falls off rapidly beyond 850°C because CaSO_4 formed on the surface of CaO melts due to high temperature and forms a coating on CaO, inhibiting further exposure to reaction.
- Within the residence time SO_2 gas molecules do not encounter reactive solid CaO particles despite high bed turbulence.

**FIGURE 12.4**

Effect of bed temperature and Ca/S ratio on sulfur removal in bubbling fluidized bed combustion (theoretical).

Limestone consumption increases outside of this range. Figure 12.4 shows the manner in which the sulfation reaction peaks out at $\sim 850^{\circ}\text{C}$ and how the limestone demand escalates for greater sulfur removal in BFBC. A practical limit for desulfurization in BFBC can be considered as 85% with a Ca to S ratio of 2.5 to 3.0. But with CFBC boilers having a longer residence time of ~ 5 s (2.5 s in BFBC) and smaller fuel and limestone particle size, this limit can be considered as 95% with Ca/S ratio of 1.8 to 2.5, depending on the sulfur content of the fuel and the purity and reactivity of limestone.

At higher levels of ash at $>40\%$ and sulfur at $>5\%$, Ca/S ratios sharply escalate to meet the limits, and the process becomes uneconomical.

12.2.3 Denitrification

At elevated temperatures, oxygen combines with nitrogen to form nitrogen oxides and other complex compounds collectively called NO_x . Nitrogen is present in fuel and combustion air. Nitrogen in fuel forms fuel NO_x and in air forms thermal NO_x .

See Sections 10.2.8 and 13.4.10 on low NO_x burners.

For thermal NO_x , much higher temperatures of $>1200^{\circ}\text{C}$ (2200°F) are needed, which are fortunately not feasible for FBC.

Fuel NO_x is formed in FBC, and laboratory data indicate that almost all the fuel nitrogen may be converted to NO_x . For 1% of N_2 in the fuel, the potential NO_x formation is ~ 3800 $\text{mg}/\text{N m}^3$. But that is largely reduced to elemental nitrogen again by the presence of the strong reducing agents in the form of char (C) and CO in the bed. Furthermore, in CFBC, because of staged combustion, substoichiometric conditions prevail in the bed, increasing active C and CO. The resulting NO_x is nearly half of that formed in BFBC boilers. Typical NO_x values at 6% O_2 are

- BFBC: <400 $\text{mg}/\text{N m}^3$ or <200 ppm
- CFBC: <200 $\text{mg}/\text{N m}^3$ or <100 ppm

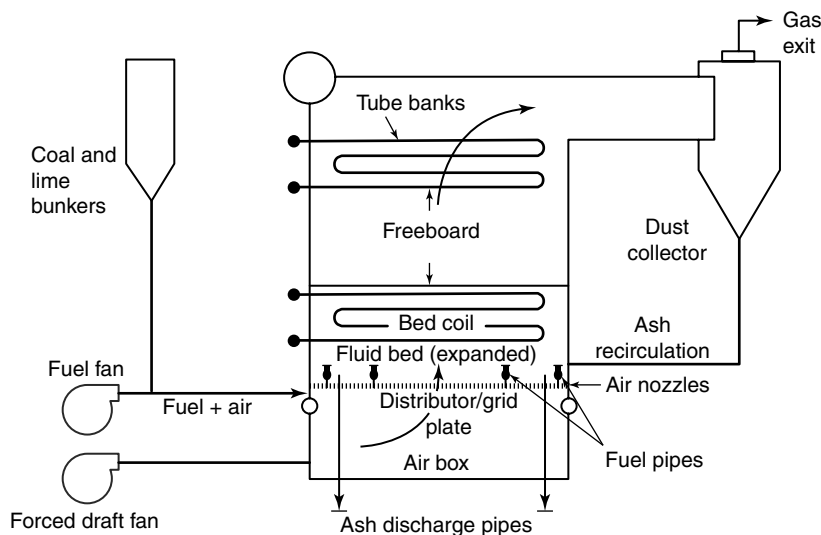


FIGURE 12.5
Underbed feed-type bubbling fluidized bed combustion boiler.

The values are much lower than in PF firing, which is mainly due to thermal $\text{NO}_x < 2000 \text{ mg/N m}^3$ with normal NO_x burners and 600 mg/N m^3 with low NO_x burners due to lower flame temperature and air staging.

The deSO_x and the deNO_x efforts work in opposite ways. Higher Ca/S ratio, that is, greater lime dosing is known to increase NO_x levels.

Figure 12.5 captures the effect of combustor temperature on NO_x generation. Between 850 and 950°C , the NO_x increases more than three times. One part per million of NO_x on a dry volume basis = 2.05 mg/N m^3 .

12.3 FBC Process: Pros and Cons

12.3.1 Characteristics of FBC Boiler

- Combustibles form only $\sim 3\%$ of bed material, and the remainder consists of fuel ash, inerts, and limestone (if used).
- In high-ash applications, usually with ash $> 15\%$ in the fuel, no inert material addition may be required to stabilize the bed, as the fuel ash is sufficient to replenish the bed material.
- Limestone addition occurs only if desulfurization is required, and if so, the bed has to be operated at exactly the controlled temperature of $\sim 850^\circ\text{C}$ (1560°F).
- With fuels such as lignite or biomass, where fuel ash contains low-melting alkaline compounds and ash-softening temperatures are likely to be lower, the bed has to be at a lower temperature such as 800°C (1472°F) to avoid agglomeration. Desulfurization efficiency decreases in this case.

- For low-volatile fuels such as anthracite and high-ash coals, the bed has to be operated at higher temperature of up to 900°C (~1740°F) to achieve better burnout of such fuels. The exit temperature from the combustor should be ~100°C lower than the fusion temperature of fuel ash to optimize the boiler size and minimize the risk of logging.
- With a bed of solids at 800–980°C, there is a huge thermal flywheel in the form of a hot bed to provide an instant ignition and combustion to any type of fuel—even liquid and gas.
- Intense turbulence of the bed and good residence time further aid in the burning of difficult fuels such as anthracite, coke breeze, petroleum coke, and washery rejects efficiently.
- Carbon burn-up efficiency of 90–99% is achieved, depending on the fuel characteristics and ash recirculation.
- Desulfurization of 85–95% is normally achieved, depending on the Ca/S ratio and other practical limits.
- With low temperature of bed and proper air staging, there is no generation of thermal NO_x. Even with high N₂ fuels, NO_x can be limited to 700 mg/N m³, and the normal range is <400 mg/N m³ in BFBC and half of it in CFBC.
- As the bed is always maintained lower than the ash fusion temperature, slagging and fouling of tubes does not take place.

12.3.2 Advantages of FBC Boilers

- Capability to burn almost any fuel
- Excellent multifuel flexibility
- High combustion efficiency
- *In situ* and very convenient desulfurization
- Very low NO_x generation
- No slagging and fouling of tubes
- Good to excellent load response

12.3.3 Limitations of FBC Boilers

- For most biofuels, stoker firing is better. Biofuels have low S and the burning temperatures are low due to high moisture in the fuel. Thus, they are nonpolluting, and SO_x and NO_x are always under control.
- High fan power for fluidization reduces net output per unit fuel by 1% compared to PF if deNO_x and deSO_x units are not large enough or are absent.
- Tube and refractory erosion issues are not fully resolved.
- Stepless load variation is not possible with BFBC without sacrificing efficiency.
- Single unit sizes of 1000 MWe and above are proven in PF, whereas in CFBC, units >300 MWe are still under initial operation.

The marginal shortfall in efficiency and power consumption together with refractory and tube wear problems of CFBC boilers stands in sharp contrast to the improved milling

plant and cheaper deNO_x and deSO_x plants in the contemporary PF boilers. Fuel flexibility of CFBC boilers is not perceived to be of great use by the utilities, at least for now. These factors have seriously impaired rapid growth of CFBC, and the expectations of gaining good ground in utility markets have also been partly belied.

FBC boilers exhibit a steaming range of 10–400 tph for the industry and power applications, cannibalizing stoker, and PF territory, on the merits of

- Better efficiency
- Compliance with new environmental norms
- Burning difficult and/or new fuels
- Multifuel capability

Large CFBC boilers, up to ~450 MWe, are going on stream for niche or difficult-to-burn fuels or where high S in coal demands an FGD plant in PF, making it more expensive and power-consuming. But for single-prime fuel for utility application, PF firing is still the choice in sizes >500 MWe.

For ~100 to 150 tph and above, the CFBC boiler is economical, whereas for <100–150 tph, the choice is a BFBC boiler, depending on fuel and pollution norms. Sometimes certain special environmental strictness may demand CFBs even for lower sizes. Likewise, BFBC boilers of >150 tph are sometimes built for special applications such as paper mill sludge burning.

12.3.4 Thermal Efficiency: Conventional versus FBC Boilers

Chapter 1 deals with efficiency calculations and performance testing of boilers. In contrast to conventional boilers, the FBC boilers must handle differences in arriving at the correct thermal efficiency, mainly arising from desulfurization, sensible heat loss due to inerts, higher fan power, and higher radiation with cyclones.

- *Desulfurization.* The calcination and sulfation reactions in the bed, which are endothermic and exothermic, respectively, alter the heat marginally. With a Ca/S ratio >2, there is a net loss, whereas at <2, there is a net gain in heat.
- *Sensible heat loss.* With coals having high ash and employing desulfurization, the bed ash discharge at ~850°C can represent loss as high as 5%. At the same time, even with high-ash coals of sub-bituminous variety, which break down and produce mostly fly ash, if there is no desulfurization, the sensible heat loss may not be higher. It is therefore advisable to evaluate the sensible heat loss separately and not make it part of unaccountable loss.
- *Fan credits.* Forced draft (FD)/primary air (PA) fans consume a lot of power in fluidizing the combustion air. The churning of air in the fan casing to produce such a high pressure heats the air, the power for which is provided by the fan. Suitable credit should be taken by correcting the fan inlet air temperature in calculations.
- *Cyclone radiation loss.* Radiation loss taken from the standard American Boiler Manufacturers Association (ABMA) chart does not account for the losses of cyclones. These are large bodies, and the refractory lining from inside may not be able to cool them to acceptable temperatures such as 50°C, particularly with hot cyclones. Suitable correction should be built into the calculations.

12.4 Bubbling Fluidized Bed Combustion

12.4.1 Process

Figure 12.5 depicts a typical underfeed bubbling bed boiler. There is a *bottom/grid/distribution plate* consisting of sand/ash and fuel. Evenly spaced *air and fuel nozzles* as well as *ash nozzles* for ash discharge are attached to the bottom plate. After preheating, air is admitted to fluidize the bed, followed by the fuel feeding. The volatiles, the small light-weight particles, and moisture leave the fuel to burn in the freeboard above, whereas the fixed carbon (FC) portion of the fuel burns in the bed. The *bed coil*, immersed in the *expanded bed*, extracts heat and keeps the bed at the desired temperature. The hot flue gases generated in the bed, on completion of combustion, leave the *freeboard* along with dust particles and flow over the convection sections such as superheater (SH), boiler bank (BB), economizer (ECON), and airheater (AH) to progressively yield heat like any other boiler.

A cyclone-type *dust collector* dedusts the gases and returns the dust particles to the bed to capture and burn carbon. The gases, after being cooled to their optimum temperature, are cleaned in a bag or electrofilter before they are released into the atmosphere.

The distinguishing feature of a BFBC boiler is *the bed coil* meant to extract the heat and keep the bed temperature low, although for fuels with very high moisture or high ash, bed coils may not be required. Located in the violently churning bed material, the bed coil is subject to high heat transfer from gas convection and radiation but, in this case, more predominantly from conduction due to bed material impingement. The impingement is also the cause for erosion. The *permissible bed velocity* is limited by what the bed tubes can safely withstand. For high-ash coals, it normally does not exceed 2.5 m/s (~ 8 ft/s). *Bed velocity or superficial bed velocity* is the gas velocity derived by dividing the volume of gas passing through the bed at the bed temperature by the plan area of the bed.

Excess air requirement is 20%. Around 10% air is given as secondary air (SA),

- For providing an air curtain to curtail the entrainment of fine particles
- For reducing the fan power

With an in-bed coil, PA should not be less than the stoichiometric level to prevent the corrosion of coil.

Freeboard should normally give ~ 2.5 s residence time for free-burning fuels and ~ 3 s for slow-burning and low-volatile fuels. This translates into a freeboard height of 2.5–6 m (8–20 ft) in most cases.

The *residence time in bed* is a concept that does not apply to other modes of firing. Here it refers to the time taken by a coal particles entering the bed to burn and reduce to a size that permits them to be airborne. It is usually ~ 0.5 s.

Bed density depends on the *voidage*. A slumped bed typically has bulk density of 14.5 kg/m^3 ($\sim 90 \text{ lb/ft}^3$). When expanded the voidage is usually 65% and the corresponding bulk density is $\sim 9.3 \text{ kg/m}^3$ (58 lb/ft^3).

Normally the design for the bed is of 600 mm (2 ft) depth in slumped condition, made of mostly sand or ash. When fluidized it assumes a height of ~ 1200 mm (4 ft). The ratio of expanded to slumped bed is called the *bed expansion* factor. Usually it is 2. In the shallow bed operation, which is explained later, the thickness of the slumped bed is 300 mm.

12.4.2 Underbed versus Overbed Feeding

The two BFBC designs based on the type of fuel feeding are underbed and overbed feeding, as shown in Figure 12.6 and compared in Table 12.1.

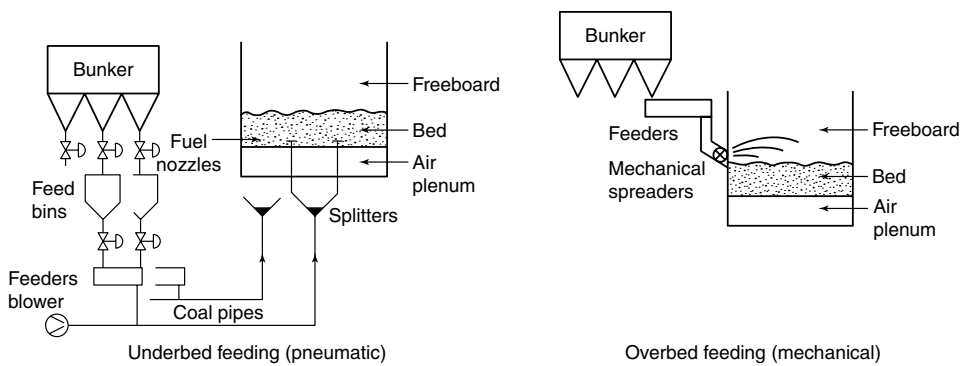


FIGURE 12.6
Underbed versus overbed feeding arrangements.

TABLE 12.1

Comparison of Underbed and Overbed Feeding

Fuel	Underbed Firing	Overbed Firing
Top size	<10 mm	<30 mm
Moisture (surface)	<6%	<20%
Fines	<30% through 1 mm	<20% through 1 mm
CaCO ₃	5 mm maximum, 0.8–1.4 mm average	5 mm maximum, 0.8–1.4 mm average

12.4.2.1 Underbed Feeding

1. In the underbed design, the fuel is admitted from the bottom of the bed, allowing more residence time for the same bed thickness.
2. There is less carryover as compared to an overbed feeding, where the fuel is distributed from above the bed, as in a spreader stoker (SS).
3. There is comparatively less of burning of fines and VM above the bed. Most of the FC and a large part of the VM burn in bed, giving a slightly higher temperature that, with more bed residence time, aids carbon burnup. Thus, it has an efficiency advantage of 0.5–1.0%.
4. As fuel is not spread from above, it has a higher tolerance for fines and more fines are burnt in the bed.
5. Sulfur capture is also better because the fuel that burns above the bed does not react with limestone particles in the bed and this proportion is smaller in underbed designs and the Ca/S ratio is smaller.
6. NO_x generation is also slightly lower, as very little fuel burns above the bed, resulting in a lower freeboard temperature.
7. The furnace dimensions are not governed by the spreader throw, and there is a greater flexibility in arranging the fuel feed points, making an economical narrow boiler with a deep furnace.

The limitations of underbed design are as follows:

1. The multiple feeding points and long fuel pipes are highly erosion prone. If the surface moisture of fuel is more than 6%, the fuel pipes and feeders choke up,

disrupting the combustion. Covered storage of incoming and crushed fuel can solve this problem but it occupies a lot of space, and sheds for fuel are not practical for larger sizes. Hot air for fuel conveying, proper insulation, and heating are other measures.

2. In case of interruption of power, the fuel in the pipes settles at the bottom and restoring the unit requires manually emptying the pipes.
3. Also, the fuel has to be crushed to a lower size of <6 mm, leading to more fine generation, whereas the overbed accepts 20 mm or even larger top size, similar to a stoker.
4. Multiple coal pipes clutter the arrangement of coal bunkering and feeding.
5. Conveying air at high temperature also requires a high pressure of 3500–5000 mm wg to overcome the line losses and push the fuel against a bed pressure of ~ 900 mm wg. Suitable Rootes blowers are required, which are power-consuming and noisy.
6. For bed temperature and automatic combustion control, the regulation of numerous feeders and fuel nozzles can be challenging.

12.4.2.2 *Overbed Feeding*

The overbed feeding has the advantages of

- Yielding a better layout with fewer bunkers and feeders and no coal pipes.
- No restarting after a power trip.
- Less crushing of fuel, as the fuel size is usually <20 mm and, at times, even <30 mm. Placing overfeed BFBC boiler alongside stoker-fired boilers is not a problem.
- Better tolerance to surface moisture of up to 20%.
- Easy regulation of fuel feeders for automatic combustion control.

The disadvantages are as follows:

- The boiler is wider and heavier.
- It is slightly less efficient.
- It is less tolerant to fines.

The overbed design is adopted

- For highly reactive fuels such as lignite or low-sulfur fuels or high-ash coals where combustion efficiencies are inherently high
- Where the desulfurization requirement is low or absent, where sulfur in fuel is negligible or emission norms are liberal
- Where simplicity and operational convenience are preferred to a small increase in efficiency, particularly if fuel and limestone costs are low

A combination of overbed and underbed is effective, particularly in places that experience high rainfall. To obtain the efficiency advantage and avoid disruptions during rainy periods, underfeed boilers are built with overfeed systems as standby. This adds cost but improves the availability.

12.4.3 Bed Regulation for Part-Load Operation

One of the major drawbacks of BFBC boilers is that at part loads of <70%, as the fuel input is reduced, the bed cools down disproportionately, since the bed coil made of saturated tubes extracts almost the same quantum of heat. This increases the unburnt carbon to unacceptable levels. There are three methods available for boiler part-load operation.

1. *Bed height variation.* Here, the expanded bed height is lowered along with the reduction of fuel and air with reducing loads. Since the height of expanded bed only marginally more than bed coil height, the tubes get uncovered and bed temperature remains nearly constant, creating an effective variation of evaporator heating surface (HS). The drained hot ash is stored in a silo and fed into the bed when the load has to be increased, requiring the bed to be raised. Thus, the bed temperature is constant but the bed height is varied.
2. *Velocity turndown.* This is the simplest method effective up to 70% load. Here, the fuel and air are reduced over the entire bed. The bed temperature reduces, and the combustion efficiency is lowered. This method is suitable for small boilers or boilers for base load.
3. *Bed slumping.* The bed height is much more than the coil height and the bed is compartmentalized. Up to ~70% loads, the fuel and air are reduced proportionately, with bed temperatures decreasing. Thereafter a bed is taken out of operation by totally diverting air and fuel to the other compartments and defluidizing the chamber. With the reduction in cooling surface, the bed temperature recovers. The process continues as the load is lowered further. Here the bed temperature fluctuates as the beds are cut in and out. Thus, the bed height is nearly constant but the bed temperature is varied. The bed slumping method for load control is more prevalent.

12.4.4 Bed Coil

The bed coil is the most intensely heated and stressed surface, immersed in a violently churning bed of solids. In-bed surface is unique to BFBC boilers and not found in any other type of boiler construction, except for external fluid bed exchangers in some CFBC boilers.

Heat transfer. How intense is the heating can be inferred from the fact that the bed coil absorbs nearly a third of the entire heat input into the boiler. Heat transfer rate at ~255 W/m² °C or 220 kcal/m² h °C or 45 Btu/ft² h °F is five to eight times the heat transfer rate in other areas. Thus, the bed surface is the cheapest HS and the most effective one too.

Sizing. Bed coil sizing determines one of the most important parameters in BFBC, namely the bed temperature. Lower bed temperature gives the boiler

- Lower turndown
- Reduced combustion efficiency
- Larger SH
- Lower NO_x and higher CO

The effects are in reverse order for higher bed temperature.

12.4.4.1 Bed Temperatures for Different Fuels

A temperature of 750°C (1380°F) during low loads acts as a limiting temperature for the bed to decrease unburnt loss. The optimum temperature for lime–sulfur reactions is 850°C (1560°F). A rough guide for bed temperature selection can be as follows:

- 800°C (~1470°F) for fuels with low-melting compounds in ash such as lignite
- 850°C (~1560°F) for fuels needing sulfur removal
- 900°C (~1650°F) for difficult-to-burn low-volatile fuels such as anthracite with more FC and ashy bituminous coals

More bed coil surface is required for cooling the bed to a lower range.

Access. In smaller boilers operating at ~900°C, the bed coil can be small enough to permit full access for both the tubes and the air nozzles from the top of the coil. For larger boilers, this may not be possible and it is necessary to provide access cavity of ~600 mm between the nozzle top and bottom of the bed tube.

Bed tube inclination. The bed tubes are usually inclined at ~5° to horizontal to ensure an adequate flow of water at all conditions. But in larger boilers, with more HS, the inclined bed tubes may not be accommodated within the height of the expanded bed. Circulating pumps are then employed for a positive flow and the tubes are made horizontal to contain the height of bed coil.

Bed coil SH. When final steam temperatures >500°C are required, the final SH tubes are placed in the bed in one compartment. Extreme care is needed in the selection of tube materials and supports. High-mass steam flows are required to ensure proper cooling of tubes. Skilled operation is required during startup, load swings, and shut-down. A conservative design favors pendant SH to in-bed SH.

Stainless steel (ss) is not the preferred material for the SH bed tubes due to the risk of corrosion from the chlorides in ash, but alloy steels (AS) such as T22 or T91 prove satisfactory. For evaporator bed tubes, carbon steel (CS) is adequate because the rate of boiling heat transfer of water is very high. T11 tubes or rifled/ribbed tubes have been used to prevent departure from nucleate boiling (DNB). It is usual to provide 1 mm of sacrificial thickness as a first measure of erosion protection.

12.4.5 Deep versus Shallow Bed

Forced draft fans consume maximum power in a BFBC boiler and the reason is the huge amount of bed material to be fluidized. This auxiliary power can be reduced if the bed height and velocity are lowered without sacrificing the combustion efficiency. A deep bed of 1000–1200 mm is necessary to provide

- Adequate residence time
- Turbulence needed for desulfurization reaction
- Burning of fuels rich in FC

But quick-burning fuels such as sub-bituminous coals or lignites, with low sulfur can use a shallow bed of 600 mm to properly cover the bed tubes.

12.4.6 Erosion in BFBC Boilers

Prior to the commercialization of BFBC boilers it was believed that combustion at 800–900°C, well below the ash-softening temperature would create

1. No slagging in furnace and no fouling in convection banks
2. No erosion of tubes and refractory, as the ash does not melt and recrystallize to develop sharp edges

Although the first expectation materialized and the boilers were supplied without soot blowers (SBs), the second benefit was not realized. Erosion was experienced

- Most heavily by bed tubes
- By tubes placed in the gas turns
- By the first row of tubes in a bank

Bed coil erosion was brought under control by

1. Reducing bed velocities from ~ 3 to 2.5 m/s (~ 10 to 8 ft/s) or lower.
2. Protecting bed tubes by erosion shields or studding to deflect ash streams away from tubes. (Note: Studding increases the HS and, unless planned from the beginning, the bed temperature would be lowered, resulting in performance alteration.)
3. Protecting the other tubes by erosion shields, which are described in Section 3.5.1.2.

Because erosion behavior is not predictable, particularly if the fuel is sourced from several mines, it is cheaper to carry an inventory of bed tubes that can be changed periodically. The furnace wall tubes around the bubbling bed are exposed to severe erosion, almost on par with bed tubes. They suffer less because they are vertical, but they need protection. Good heat transfer is also desired. This area is usually studded and covered with refractory. Silicon carbide is a better choice because of its high thermal conductivity and extreme hardness. In the remaining areas of the boiler, erosion has been substantially overcome by

- Lowering the gas velocities to < 10 m/s
- Protecting the first tubes of the banks by suitable erosion shields
- Avoiding gas turns over tubes

12.4.7 Bed

The bed consists of two layers:

1. The active, fluidized layer above the air jets
2. The static layer of ~ 100 mm thickness all around air nozzles, which acts as an insulation protecting the bottom plate from the heat of the bed

Bed material is usually sand, ash, or crushed refractory in a size range of 0.5–1.2 mm. Sand should be rounded river or lake sand with no abrasive alpha quartz to avert any chances of erosion. Sea sand should not be used because it contains alkalis and chlorides.

Fuels with ash >15% do not require bed ash replenishment. For firing fuels with lower ash, a bed material silo and a feeding system are required. Crushed refractory for bed material is less aggressive but more expensive than sand. Stoker ash, properly sized, suits very well.

High underbed pressure in FBC boilers drives away most of the ash, and only the heavier particles, which are fuel impurities such as stones and shale separate out as bed ash. Bed ash usually contains very little carbon (<1%) in case of coals and forms <10% of total ash. Periodic draining is needed to remove this burden to maintain bed height. Usually, one ash nozzle of 150 NB is considered for 10–20 m² (~100 to 200 ft²) of bed area suitable to drain an area within 3.5–5 m (~10 to 15 ft) of radius.

A cost-effective disposal is by discharge into a water-impounded hopper or an equivalent wet system, provided the local pollution laws permit it and the bed is not dosed with limestone for desulfurization. Lime produces gypsum on contact with water, which solidifies into a hard rock and only dry disposal should be considered. With a large bed, a BFBC boiler would have several ash outlets carrying relatively small amounts of ash and needing many ash pipes, making the arrangement clumsy.

Bed height control by overflow is another simple method adopted. Overflow pipes are arranged on both the sidewalls, ~100 mm above the bed level, to spill over and maintain the height.

Self-closing flaps at the end of the pipes prevent ingress of tramp air into the freeboard.

One fuel nozzle is required to be placed at every 2–3 m² (~20 to 30 ft²) in underbed feeding. Usually fuel nozzles, 150–200 mm NB, are of T-shape or with annular openings, injecting air–fuel mixture at a velocity of ~15 m/s.

12.4.8 Freeboard

Freeboard is the chamber between the top of the expanded bed and the convection surfaces. For easy-burning fuels, it should give a residence time of 2.5 s, and for slow-burning fuels, the time should be 3 s. Fines and volatiles burn here, and despite good heat absorption by radiation, the exit temperature is ~30 to 50°C higher than the bed temperature. For overfeed firing, the difference is at the higher end, as all fines burn in suspension. SA nozzles are provided on opposite walls.

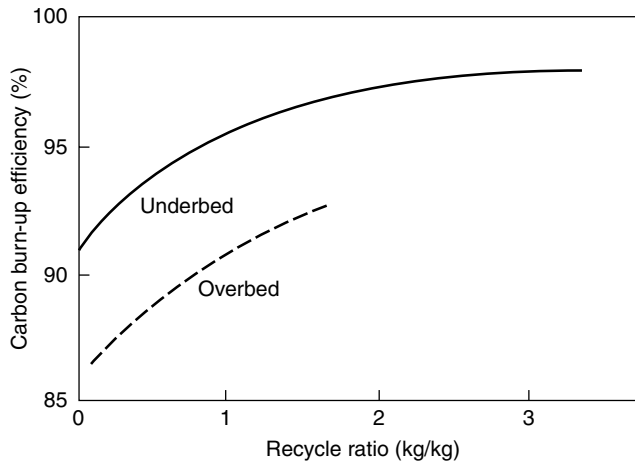
12.4.9 Ash Recirculation

There are two reasons for recirculating ash from the back ends in FBC boilers.

1. Fine particles escaping combustion in freeboard get caught in the hoppers and mechanical dust collectors (MDCs) or in bags and electrofilters. The fines are rich in carbon and can be burnt if returned to high furnace temperature once again. This improves the carbon burn-up efficiency. In less reactive and high calorific value fuels such as bituminous coal or anthracite, the dust particles contain a lot of carbon and it is vital that this is returned for refiring to improve efficiency.
2. Ash recirculation is also necessary for better utilization of limestone and lowering of Ca/S ratio.

However, very high-ash fuels such as washery rejects and highly reactive fuels such as lignite burn out quickly, and the fine dust is mostly ash with practically no carbon. Further, if there is no limestone savings due to absence of desulfurization, there is no practical gain in returning the ash to bed.

Carbon burnup increases with an increase in recycle ratio, as shown in Figure 12.7, and beyond a point, the effect starts tapering. But the dust load also increases, enhancing the chances of erosion. It is normal to adopt a ratio of 2.0 to 2.5 as a compromise.

**FIGURE 12.7**

Effect of ash recycle on underbed and overbed feeding.

12.4.10 Air Nozzles

Air has to be uniformly distributed at the bottom at a pressure sufficient to lift the bed and fluidize it. Typically an air nozzle is made of 20 mm NB pipe of ss, 160–180 mm long, closed at the top end and weld prepared at the bottom to be attached to the bottom plate or membrane strip. Starting ~25 mm from the top, fine air jets of 1.5 mm diameter around the circumference are drilled downward at two or three levels. Fine holes help prevent backflow of ash into the windbox, a common occurrence in FBC boilers. If the problem still persists, possibly because of the ash particles breaking down to finer levels, a shroud has to be fixed to the nozzle. Stainless steel ensures the survival of the nozzle during bed slumping when the nozzle attains nearly the same temperature as the bed with no airflow inside. Nozzle spacing is ~150 to 125 mm (4–5 in.) or 60–80 nozzles/m². Typical air nozzles are shown in Figure 12.8.

The air pressure to be provided at the windbox is arrived at in the following manner:

- It is the sum of the air pressure losses in bed and air nozzle.
- The bed pressure loss is 0.70–0.75 times the expanded bed height in mm wg.
- The air nozzle is designed for a loss of ~300 mm wg.

Thus, for a 1200 mm expanded bed, the air pressure works out to be 1200 mm wg.

12.4.11 Salient Process Parameters of BFBC Boilers

Table 12.2 lists process parameters of BFBC boilers.

12.4.12 Applications

BFBC boilers have two areas of application, namely,

1. Fossil fuels
2. Biofuels

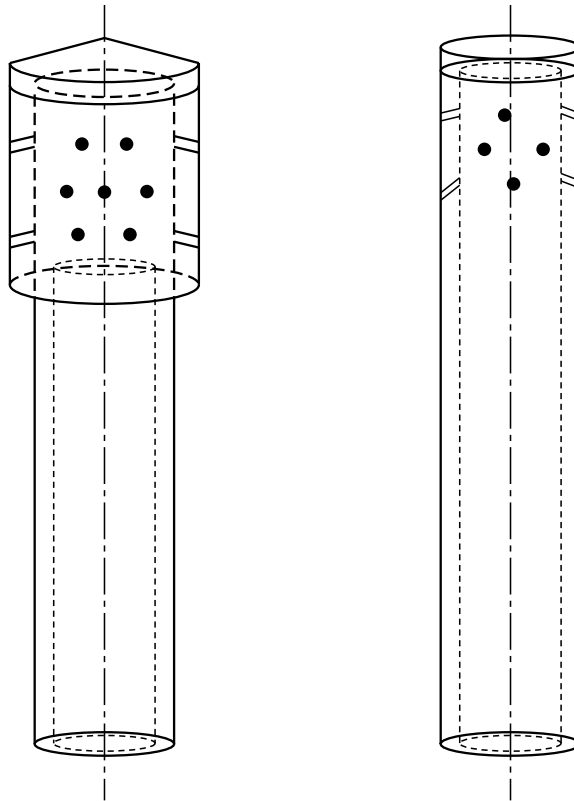
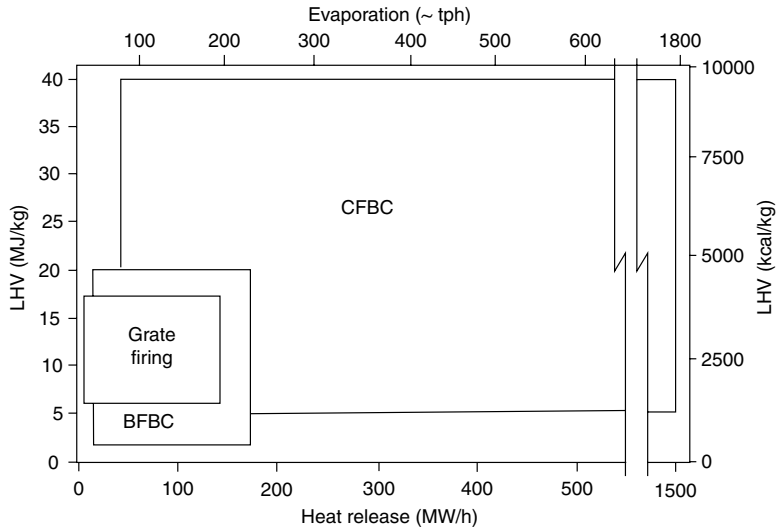


FIGURE 12.8
Typical air nozzle.

TABLE 12.2

Salient Process Parameters of Bubbling Fluidized Bed Boiler

Parameter	Value	Remarks
Bed temperature	800–950°C (1470–1740°F)	Normal temperature with desulfurization is ~850°C (1560°F)
Bed velocity	1.8–3.0 m/s	For fuels with erosion tendency, velocity is limited to 2.5 m/s (~8 ft/s)
Bed particle size	0.5–1.5 mm	Average size ~1 mm
Bed depth	600/1200 mm (2/4 ft)	Slumped/expanded for deep beds, for shallow it is 300/600 mm (1/2 ft)
Bed pressure drop	500–1000 mm w.g. (20–40 ft)	Percentage drop = 0.8–1.0 of the expanded bed height
Bed density	720 kg/m ³ (45 lb/ft ³)	
Ash recycle ratio	0–5:1	Normal range is 1:2–2.5
Excess air	20–35%	For most coals it is 20%
SA as % of total	<10%	SA can be in any opposite walls
Residence time	2.5–3 s	For bed and freeboard. Bed residence time is ~0.5 s
Carbon loss	4–8%	
Ca/S ratio	2.5–3.0	For 90% S capture
Gas velocities	<10 m/s (~35 ft/s)	Limits are similar to those of pulverized fuel boilers, as gases are dust laden
SO ₂	<300 ppm dv	At ~85% desulfurization
CO	~250 ppm dv	
NO _x	<200 ppm dv	

**FIGURE 12.9**

Capabilities of stoker, bubbling fluidized bed combustion (BFBC), and circulating fluidized bed combustion (CFBC).

The most common application is coal firing in developing markets. In absence of strict pollution norms, particularly with NO_x , bubbling beds continue to be sold only in developing markets for solid fuels such as coal and lignite. They have practically replaced the stokers and entered the CFBC boiler market at the lower end. They are not accepted in the developed markets, where stricter pollution norms prevail for fossil fuels. However, their popularity for biofuels is on the rise, particularly for very high moisture ($\sim 70\%$) fuels such as industrial sludges and process wastes.

Stokers, BFBC, and CFBC burn solid fuels. See Figure 12.9.

12.4.13 BFBC Boiler Design Principles

- Bubbling bed boilers are short and stocky because
 - The low heat release rates make the plan area large.
 - A residence time of 2.0–2.5 s makes the freeboard only ~ 6 m, even for larger boilers.
- With nearly 60–70% of evaporation taking place in the bed coils, the boiler bank load is greatly reduced. It is normal to adopt single-drum boilers from 60 kg/cm^2 or even lower level.
- Freeboard temperatures are lower than 1000°C (1830°F) and the heat flux is low and more uniform, making it possible to employ widely spaced membrane panels with 50 mm membrane bars.
- The dust levels in the flue gases at the freeboard exit are $\sim 300 \text{ g/N m}^3$ (higher than the PF boiler dust loading), and the gas velocity for high-ash coals is ~ 6 to 10 m/s (~ 20 to 35 ft/s) at bank inlet. Erosion protection by way of tube shields on the first row is normal.

TABLE 12.3

Typical Heat Transfer Rates and Gas Velocities in Bubbling Bed Boiler

Area	Approximate Heat Transfer Rates			Gas Velocity m/s (maximum)
	W/m ² h	kcal/m ² h	Btu/ft ² h °F	
In-bed	44	215	250	3
Surrounding	32	155	180	
Lined fluid bed	5.3	26	30	
Unlined fluid bed	26	129	150	
Superheater	9	43	50	8
Boiler	7	35	40	8
Economizer	10–11	50–55	55–65	10

- The full load bed velocities for high-ash coals are between 1.8 and 2.2 m/s (~6 to 7 ft/s) for large units, whereas the gas speeds are required to be closer to 10 m/s over convective surfaces. Narrowing the furnace outlet is done for this reason.
- A dust collector is usually placed after the ECON to reduce its size. Recirculation of grit back to the furnace is needed to reduce the carbon losses. The grit collector should have only 90% collection efficiency in order not to increase fines in the system. Dust recirculation is between 2.0 and 2.5 times the coal inputs for coals with medium ash.
- Heat transfer rates in various areas of the boiler are approximately as given in Table 12.3. The highest rate is in the bed tubes, coil, and walls, where the heat is transferred by radiation of gas and convection by gas and dust. The contributions of gas by convection and radiation are approximately 0–5% and 20–30%, respectively, with the rest coming from dust.

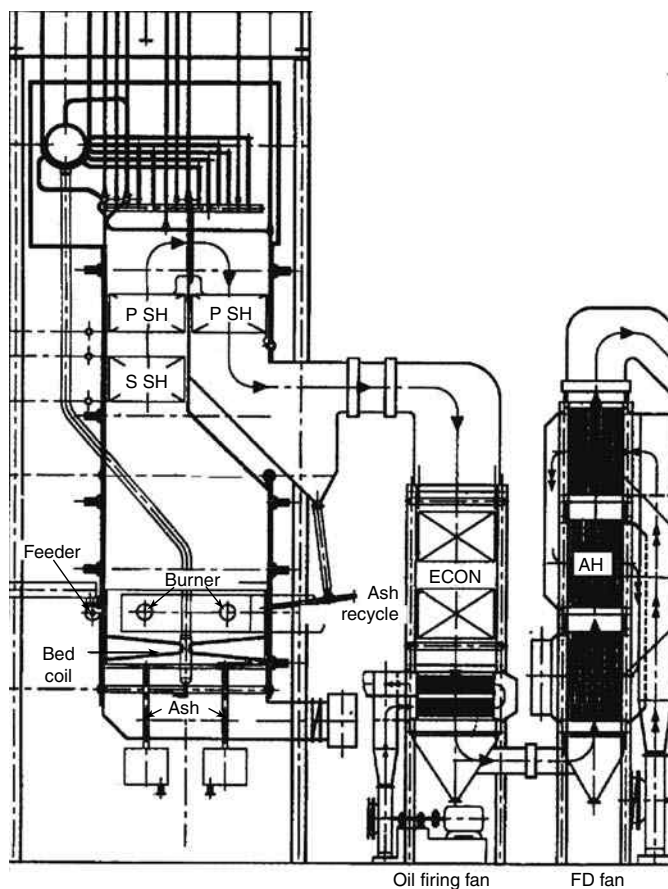
12.4.14 BFBC Boiler Designs

1. Bottom-supported bidrum boiler design (Figures 10.40 and 10.41) is modified to accommodate underbed firing. The floor is replaced by a nozzle plate with air, ash, and fuel nozzles. The tubes in the BB are reduced and made into a single pass. Superheater, ECON, and AH are added as required. Boilers up to 60 tph on coal can be economically built in this way.
2. Top- or bottom-supported single-pass standard stoker-fired boilers are suitably modified to accommodate overfired BFBC. Underfeed systems can also be adopted.
3. Single-drum field-erected oil-fired boilers are suitable for higher capacities of 100 tph and above, as shown in Figure 12.10.

Solid fuel firing BFBC boilers cover a range of 5–150 tph for process industries and smaller power plants of up to 30 MWe. From 60 kg/cm² and above, single-drum boilers are popular.

Figure 12.10 depicts a single-drum top-supported radiant boiler with overbed feeding. A limited grit recirculation is incorporated because the coal has high ash and less FC.

Figure 12.11 shows a single-drum underfeed boiler. Due to space restriction the bag filter and the fans are mounted on top of the boiler. There is an extensive ash recirculation because the coal has less ash and high FC.

**FIGURE 12.10**

Single-drum overfeed bubbling bed boiler. AH, airheater; ECON, economizer; FD, forced draft; SH, superheater.

12.5 Circulating Fluidized Bed Combustion

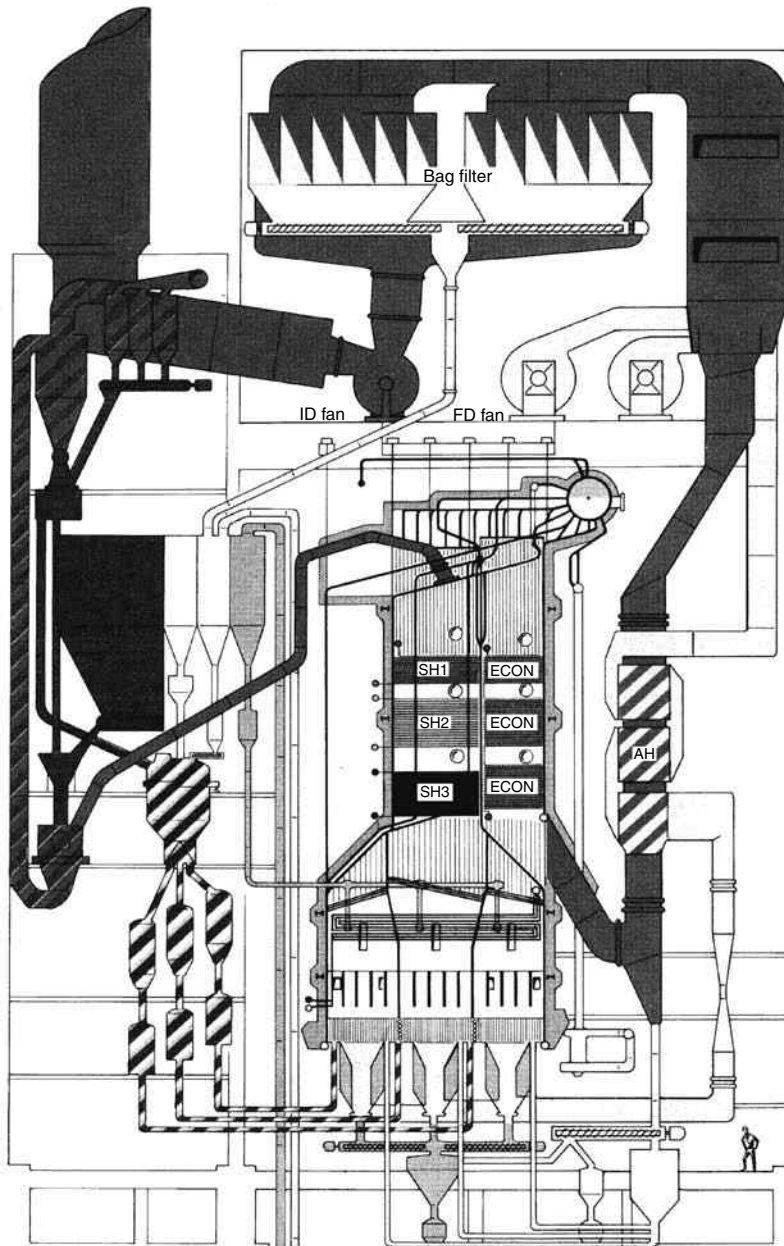
12.5.1 Process

The classical or the full-circulation CFBC process involves

- Operating at higher velocities of ~ 4 to 7 m/s
- Using high ash recirculation for uniform temperature profile
- Controlling the combustor temperature near optimum desulfurization temperature
- Employing staged combustion to limit NO_x
- Releasing high heat rates in plant areas closer to PF boilers

Circulating fluidized bed combustion is an exceptionally versatile and environmentally friendly technique for the utility market.

The classical CFBC process operates at the higher end of the fluidized bed regime, just lower than the transport phase. It includes a fluid bed expanded all the way to the roof of the combustor instead of restricting the bed to the lower part as in a BFBC boiler.

**FIGURE 12.11**

Large single-drum underfeed coal-fired bubbling fluidized bed combustion boiler of 140 tph. AH, airheater; ECON, economizer; FD, forced draft; ID, induced draft; SH, superheater.

Naturally, the dust carryover to the outside and the recirculation within the combustor are heavy. The differentiating and unique-to-CFBC system is the *cyclone* that collects the dust and returns to the lower combustor for temperature control, optimized limestone use, and refiring of char. The thick ash layer running down the walls of the combustor, the high turbulence, and the dense particle phase even in the higher part of the combustor do not permit any drop in gas temperature in the freeboard. As a result, the bed, the furnace, and the

cyclones are all at nearly the same temperature, approximately 850°C. Although this high temperature and heavy and internal dust recirculation in the furnace and external recirculation in cyclones are good for combustion of char, they impact the cyclones that need a lot of refractory to withstand heavy erosion due to the high-velocity gas and dust stream. As the cyclones operate at such a high temperature, the classical CFBCs are also called *hot cyclone* designs, developed originally by Lurgi of Germany and Ahlstrom of Finland.

12.5.1.1 Circulating Fluidized Bed Combustion Boilers of Lurgi and Ahlstrom

Developed in 1970s and commercialized in 1980s in Europe, the initial designs have vastly improved. There was a lot of refractory construction originally and the gas velocities were high, resulting in a high incidence of erosion. These issues have been addressed, and second-generation designs enjoy better reliability. Many proprietary designs vanished, as the late 1990s saw a sharp decline in coal market and disappearance of many established boilermakers.

In both the pioneering designs of Lurgi and Ahlstrom, the basic parameters were highly similar except that

1. Lurgi designs employed external fluid bed heat exchangers (FBHEs) for finishing stages of SH and reheater (RH) and thus required heat transfer from circulating ash for combustion temperature control.
2. Ahlstrom used division walls and omega tube panels in the freeboard for heat transfer and temperature control.

Figure 12.12 shows the hot cyclone technology developed by Lurgi. The two technologies are compared in Figure 12.13. The gas velocities, dust loading, cyclone parameters, and second-pass construction are all comparable. There are differences in the mechanical and constructional features in FBHE and platen SH as mentioned in the preceding text.

Lurgi and Ahlstrom have sold their boiler businesses. Lurgi's boiler business is now with AE&E-Lentjes. Ahlstrom sold its boiler business to Foster Wheeler Corporation (FWC) which evolved a compact design replacing the hot cyclone. Alstom of France acquired.

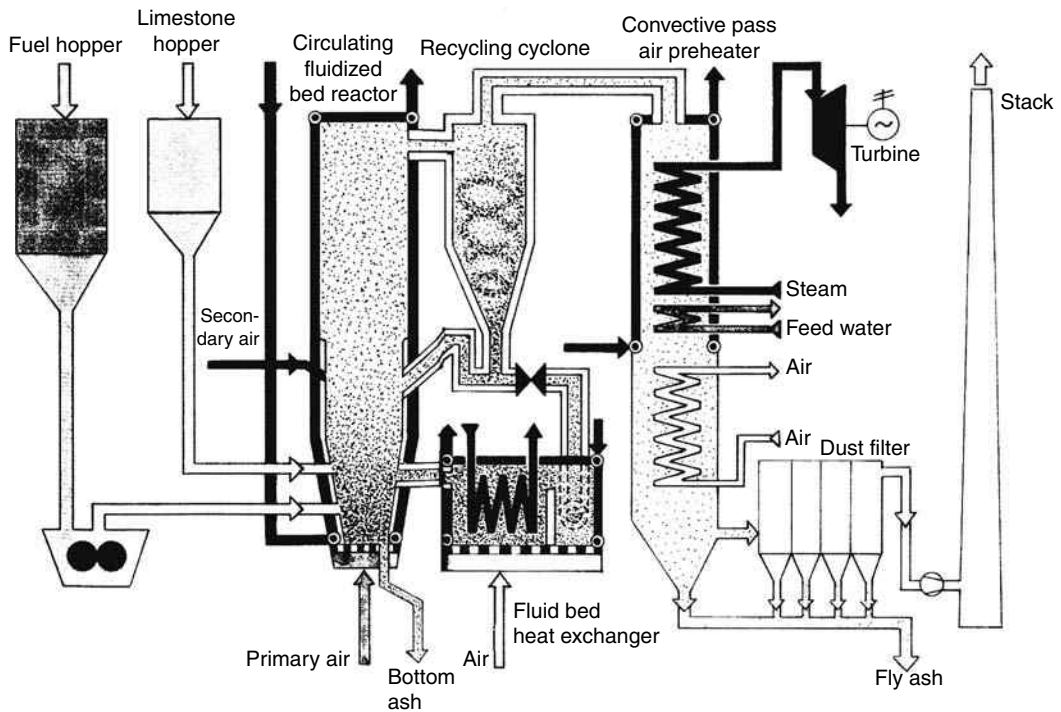
- Combustion Engineering of U.S.A and Stein industries of France, the former licensees of Lurgi
- EVT of Germany, the licensees of Ahlstrom

These companies have improved hot cyclone technologies. However, the basics remain valid.

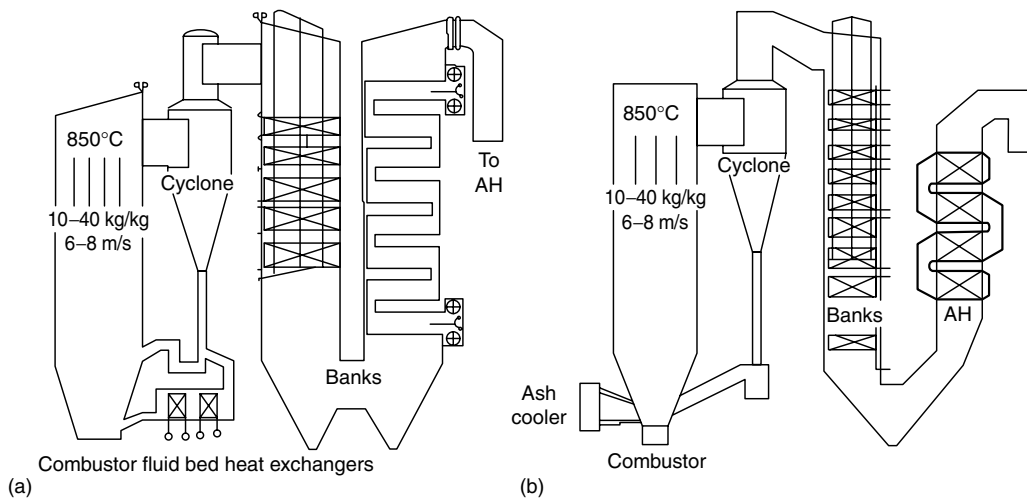
12.5.1.2 Comparison of CFBC and BFBC Boilers

- The bubbling fluidized bed combustion boiler is primarily a process device capable of generating power up to 30 MWe
- Circulating fluidized bed combustion boilers are mainly for medium and large power
- CFBC boilers offer greater flexibility as shown in Figure 12.9.

Table 12.4 brings out the differences between the two combustion systems. CFBC performance is better in nearly every way but is more expensive. But at lower than ~100 to 150 tph, BFBC is much cheaper, primarily because of no cyclone, shorter height, and smaller fans. The comparison is made between multiple underfeed BFBC boiler and full-circulation CFBC boilers.

**FIGURE 12.12**

Classical circulating fluidized bed combustion process of Lurgi, Germany. (From AE&E Lentjes GmbH, Germany. With permission.)

**FIGURE 12.13**

Hot cyclone circulating fluidized bed combustion boilers: (a) Lurgi design, (b) Ahlstrom design.

TABLE 12.4

Comparison of BFBC and CFBC

Parameter	BFBC	CFBC	Comments for CFBC
Boiler	Short and stout	Tall and slender	More like PF boiler
Range (~tph)	<150	100–2000	On solid fuels such as coal
Efficiency	Good	Better by ~4% points	Nearly same as pulverized fuel
Carbon burnup	92–96%	98–99%	~5% higher due to longer residence time and contact during recirculation
Thermal efficiency on GCV (coal)	~84%	~88%	~4% higher due to lower unburnt losses
Part load efficiency	Poor	Same up to 50%	No bed tubes, so combustor temperature can be optimized and kept constant
Bed velocity at full load	Low 1.8–3 m/s (~6 to 10 ft/s)	High 4.5–7 m/s (~15 to 23 ft/s)	Combustor plan area much smaller due to lower PA and higher bed velocity
Bed particle size	0.5–1.5 mm	0.1–0.3 mm	Particle size lower so that it is easy to lift particles to great height
Primary air:	90:10	60:40	Staged combustion in CFBC gives lower NO _x
secondary air			
Residence time	2.5–3 s	4–5.5 s	Makes combustor tall and slender
Heat release	~1.5 MW/m ² (~476000 Btu/ft ² h)	5–7 MW/m ² (~1.6 to 2.2 m Btu/ft ² h)	Higher turbulence and ash recirculation result in higher heat release
Bed temperature versus load	Variable	Constant	Constant bed temperature produces high efficiency from 50–100% MCR
Bed temperature control	In-bed tubes	Ash/gas recirculation	Smaller bed allows better temperature control
Bed level control	Intermittent draining	Intermittent draining	
Bed recirculation	5:1	10–100:1	
Turndown	1:3 stepped	1:3 step less	Step-less load variation makes control easy
Dynamics	Sluggish		High heat release and no bed coil to abstract heat make it responsive
Start-up time		Nearly as good as PF	
Fuel flexibility	Good	Better	No bed tubes and more ash recirculation permit poorer fuels
Fuel preparation	6–8 mm (coal)	6–8 mm (coal)	No great care needed, higher fines can be tolerated
Fines in coal (<1mm)	<20%	<40%	Better tolerance for fines
Alkalies in ash	Corrosion of bed tubes	No issues	
Tube erosion	Bed tubes	Furnace tubes	Furnace tube refractory finishes erode from ash sliding
Refractory erosion	No	Mostly overcome	Cyclone, return leg, and furnace erosion were problems
Auxiliary power		Higher by ~20%	Higher bed velocities
Emissions NO _x	<200 ppm dv	<100 ppm dv	Staged combustion and reducing conditions in bed due to C and CO
Emissions CO	<250 ppm dv	<100 ppm dv	
Emissions SO _x	<300 ppm dv	<100 ppm dv	For high-sulfur coal of 3% S
Limestone required	High	Low	Ash recirculation results in longer contact and lower Ca/S ratio
Desulfurization	~85%	~95%	Very low levels achieved cannot be attained by BFBC
Bed ash handling	Many points, small quantity System messy	Less points, FBAH System simple	Dry and cooled ash handling. Clean and elegant

Notes: The figures are rounded off after conversion. Gas velocity is the average in the bank. FB is freeboard.

In the 1980s and early 1990s, both technologies were developed simultaneously, BFBC boilers in the United States and CFBC boilers in Europe. Both shared the fluidization principle. As the contours and the limits of the technologies grew sharper, it became clearer that they were more complementary than competing.

BFBC clearly yields

- Cheaper construction
- Lower power consumption
- Less erosion

BFBC is more suitable for smaller boilers where the environmental regulations are not very stringent. It suffers from many drawbacks.

- It is less efficient
- It can tolerate lower fines
- It has lower fuel flexibility
- It suffers from corrosion and erosion of bed tubes
- It has poorer dynamics and part load efficiencies
- It has poorer environmental compliance and produces higher NO_x and SO_x

12.5.1.3 Comparison of CFBC and PF

Pulverized fuel boiler supremacy has been challenged seriously after its reign of more than half a century by the CFBC boiler. Table 12.5 compares the two technologies. CFBC boilers are gaining widespread use at least in the sub-100 MW sizes, due to

- Fuel flexibility
- Safety from explosions
- Environmental friendliness
- Low O&M costs
- Simpler ash handling

Pulverized fuel boilers are still the choices of utilities for firing conventional fuels, as the net output is higher by ~1% over CFBC boilers due to lower fan power despite the high milling power when sulfur in fuel is not high. The lowering of deNO_x and deSO_x plant costs has further strengthened the case of PF. CFBC finds favor with inferior fuels (brown coals, peat, washery rejects, etc.), high-sulfur fuels, or difficult fuels (anthracite, petroleum coke, etc.). Besides the *newness* of CFBC, other issues cited against CFBC are its slightly higher auxiliary power and potential of erosion. In the lower range, the CFBC has practically displaced the PF where a small-sized environmentally compliant PF boiler as depicted in Figure 12.14 is expensive.

12.5.2 Design Features of Classical or Hot Cyclone CFBC

Figure 12.15 depicts a classical CFBC with hot cyclone and FBHE. The following paragraphs describe the features of the hot cyclone design.

TABLE 12.5

Comparison of CFBC and PF Firing

Parameter	PF	CFBC	Comments for CFBC
Fuel preparation	Ground to <75 μm	Crushed to <6–8 mm	No fuel grinding; saving in power
Fuel flexibility	Limited	Very wide range	Because of inventory of hot bed material in combustor
Maximum burden (A+M limit)	~62%	~75%	Brown coals, peat, and washery rejects are burnt easily
Abrasive fuels	Heavy wear and O&M of milling plant	No special wear problems	Usual precautions against pressure part wear are adequate
High-sulfur fuels	FGD plant required	Lime dosing with fuel	In-furnace sulfur capture as high as 95%
Oil firing requirement	Start-up and up to 50%	Only for start-up	Big savings as no oil needed for low-load operation
Thermal efficiency	~88%	~88%	Nearly same as PF for normal coals
Auxiliary power	Lower despite mills	High due to fluidization	~2 to 4% higher due to fan power
NO _x ppm dv (typical)	500–1000	<100	Low due to staged combustion at <900°C
With low NO _x burners	100–300		
SO _x mg/N m ³ (typical)	~2600 without deSO _x	<100	
Moving equipment	Mills and feeders	Only feeders	
O&M costs	High	Low	Low O&M costs except for wear problems
Soot blowers	Many and all over	Only in second pass	In some designs, soot blowers can be avoided. Mostly rotary
Ash handling	Wet or dry, complicated	Dry, simple	Fewer points, cooler ash, and no clinker
Oiler controls	Complicated	Relatively simple	Limited burners and soot blowers and no mills
Burner controls	Complicated	Very simple	Very few burners for start-up
Boiler dynamics	Very fast	Nearly as fast	Big reservoir of heat in bed, provides heat as required
Cold start after 48 h	Normal time ~6 h	~2 h as bed ~500°C	Start-up times better due to heat in combustor
Warm start after 8 h	Nearly normal time	~1 h	
Hot start	~1 h	~20 to 30 min	
Explosion risk	High	None	Very safe boilers

12.5.2.1 Combustion Air

Combustion air is supplied in CFBC boilers at two levels

1. ~60% at the bottom of the combustor at a high pressure to fluidize the bed
2. ~40% in freeboard to complete the combustion

Fluidization velocities were 7–8 m/s (~23 to 26 ft/s) and have been reduced to ~6 m/s (~20 ft/s).

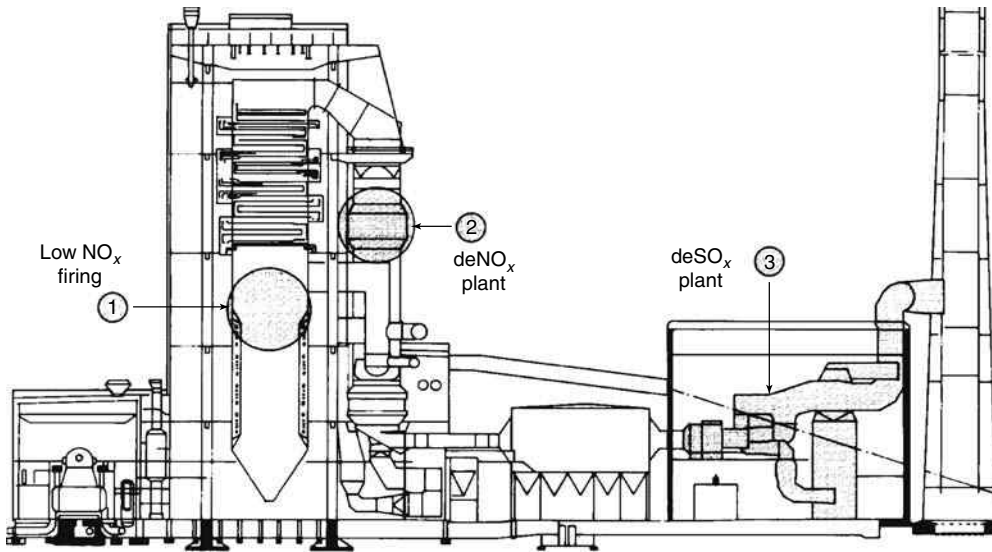


FIGURE 12.14
Environmentally compliant pulverized fuel-fired boiler.

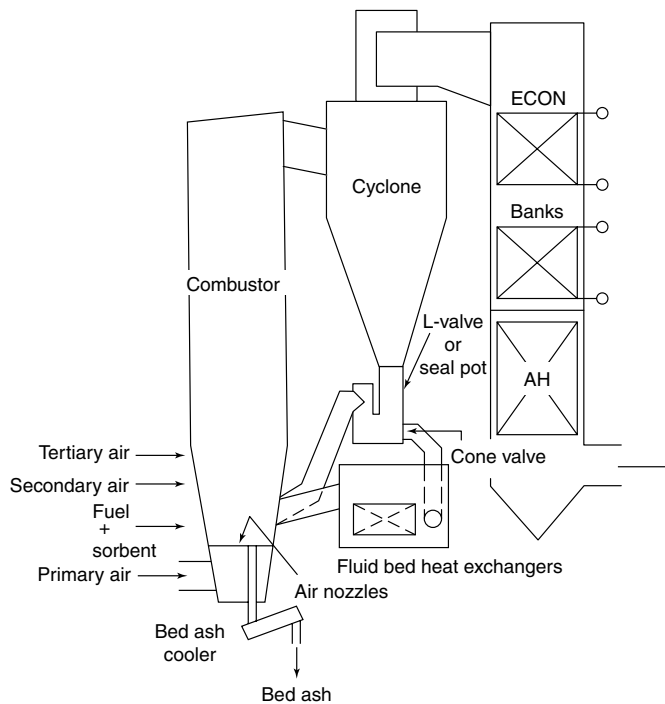
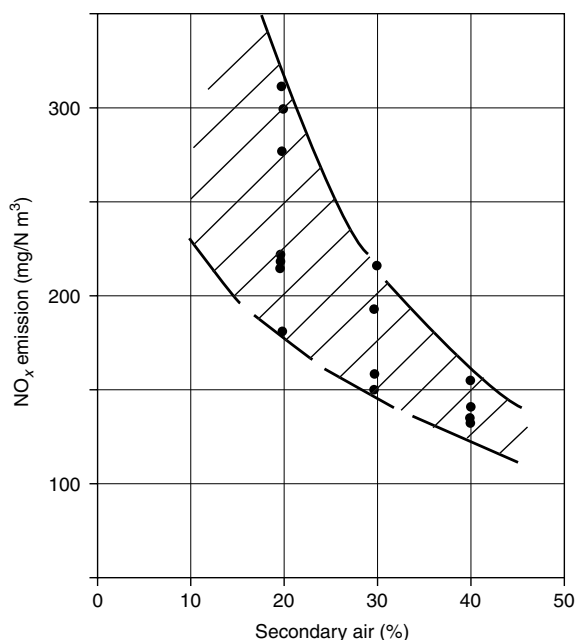


FIGURE 12.15
Circulating fluidized bed combustion boiler with hot cyclone, fluid bed heat exchangers, and screw coolers. AH, airheater; ECON, economizer.

The air split results in a staged and hence low-temperature combustion. The FC burns predominantly in the lower part of the combustor and the volatiles in the upper levels. When a heavy stream of ash is added to the combustor as recirculation ash from the furnace and cyclone, the bed temperature is further depressed. There are no bed tubes for

**FIGURE 12.16**

Effect of secondary air on NO_x.

maintaining the desired low temperature; control of recirculated ash handles the function. Figure 12.16 captures the effect of SA on the NO_x emissions. NO_x emissions effortlessly stay at <200 mg/N m³ on 6% O₂ when 30% or more SA is given.

Air nozzles. In CFBC boilers, PA forms only half of total air. The bed area is also much smaller. It is usual to have fewer heavy, large-diameter nozzles typically on 200–250 mm (8–10 in.) spacing compared to numerous small-diameter nozzles on 100 mm (4 in.) spacing. The U-beam design employs BFBC nozzles.

12.5.2.2 Fuel and Sorbent

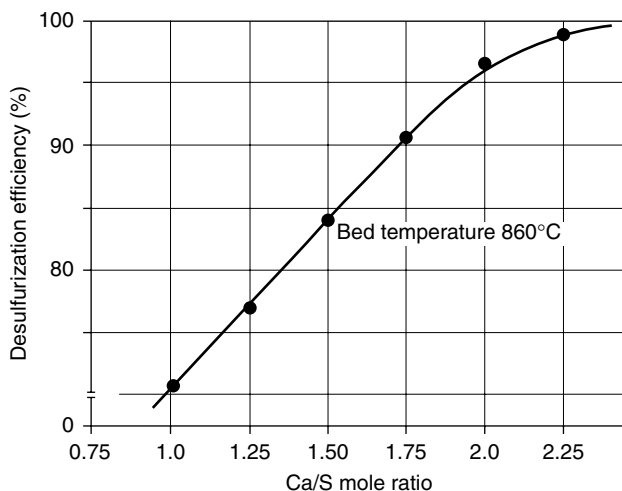
Fuel and sorbent are always fed into the combustor from the top. Usual crushed fuel sizes are

- 10 mm or more for lignite
- 8 mm for coal and
- 6 mm for anthracite or low-volatile coal

Fines in fuel up to 40% through 1 mm and surface moisture up to 15% are acceptable. This makes CFBC an extremely versatile technology.

Sizing for limestone is usually 1 mm, depending on purity and reactivity. Fuel and sorbent sizing is very important for good interaction between the two. From Figure 12.17, which is for coal of 1% sulfur, very high desulfurization is achievable in CFBC boilers with relatively low lime consumption.

Fuel feeding. In most CFBC boilers, fuel and limestone are fed into the boiler along with the recirculated solids from the seal pot. This helps to flash dry the moisture and heat

**FIGURE 12.17**

Desulfurization efficiency versus Ca/S ratio.

the solids. There are usually two or four openings in the combustor to feed all the solids. The openings are restricted. Alternatively, pneumatic transport and injection through SA nozzles have been adopted.

12.5.2.3 Combustor

The lower combustor, up to the level of tertiary air (TA), is always in a heavily reducing zone on account of substoichiometric air. This helps in lowering the NO_x produced by the reaction of C and CO with NO_2 .

The lower combustor is refractory-lined to prevent tube corrosion due to the reducing environment. The refractory has to be

- Very hard to withstand bed material erosion
- Reasonably thin to reduce weight
- Optimally conductive to transmit heat to the walls

Freeboard. In addition to the high turbulence, there is an ample residence time of 4–5 s in the combustor to burn the fuel efficiently and also to desulfurize more completely. Combustor heights are typically 30–35 m (~100 to 115 ft) from the tops of air nozzles. Gas velocities are 5.5–6.0 m/s (~18 to 20 ft/s) to provide a combustion of good heat transfer to walls, lower erosion rates, and good stability at low loads during turndown.

The heavily dust-laden flue gases move at high velocity and maintain high slip between the gas and the dust. The separated dust moves along the walls in thickness of 150 mm (6 in.) or more. It is this hot layer of ash that contributes heat to the walls by conduction unlike the radiation from flames in a conventional boiler. The whole combustion chamber is nearly at the same temperature, which is desirable for combustion and desulfurization.

Tube leakage. Greater care is necessary in the manufacture of membrane panels of CFBC boilers as they experience a lot of ash flow along the tubes and consequently are prone to erosion. Any tube failure results in a lot of downtime and repair work, as the water reacts with CaO and forms huge blocks of gypsum by the time the boiler cools down. Removal of these blocks by pneumatic drills around the air nozzles is a difficult task during which a few nozzles may be damaged.

12.5.2.4 Hot Cyclone

The cyclone is the heart of the CFBC system. Static and unimpressive except for its size, a cyclone is design-intensive and determines system performance.

The hot flue gases at $\sim 850^{\circ}\text{C}$, along with dust, typically at $10\text{--}20\text{ kg/N m}^3$ ($0.624\text{--}1.25\text{ lb/N ft}^3$), leave the freeboard and enter the cyclones to emerge fully dedusted. The dust level is so high that it is apt to describe the mixture as gas-laden dust instead of dust-laden gas! Cyclone efficiency is $\sim 99\%$ for particles of $100\text{ }\mu\text{m}$ and more. The gases are accelerated to a velocity of ~ 25 to 28 m/s ($\sim 80\text{--}90\text{ ft/s}$) at the tangential entry and guided along the conical bottom. At the end of the cone, the gases disengage from dust in a reverse helix and flow upward. A high level of collection efficiency from the cyclone is very vital in realizing the performance from the boiler.

- The cyclones for CFBC boilers were developed because of the unprecedented dust levels in the flue gas. The viscosity of ash at high temperature for various materials of different particle sizes decides the cyclone performance.
- Cyclone geometries were adjusted for the best collection efficiency.
- To withstand the erosive forces of the high-velocity hot and dusty gases and to provide a fairly cool cyclone casing, a suitable thermal insulation takes the form of a dense refractory brick lining followed by layers of backup insulation. In all, a thick lining of $500\text{--}600\text{ mm}$ is needed.
- Very sound construction for the refractory must withstand the cutting forces and vibrations induced by the high-velocity gases. Falling refractory bricks are disastrous, as the return ash flow from cyclone to bed gets interrupted, leading to high bed temperature and boiler trip, and the cyclone wall also gets overheated.

Seal pot. The massive load of dust, as high as $40\text{--}60$ times the weight of fuel in full CFBC boilers, returns to the lower combustor assisted by ash pumps (called *L-valves* or *siphons* or *seal pots*) to overcome the pressure difference of nearly 200 mm wg . between the combustor and the cyclone pass. An ash pump is a bubbling bed chamber that receives solids from the cyclones on one side, fluidizes them, and helps them to overflow into the combustor. As the particle size is fine and uniform, the fluidizing velocity is low at $0.3\text{--}0.6\text{ m/s}$. Seal pots typically are made of CS plate with refractory lining. Because of the thick refractory lining of $500\text{--}600\text{ mm}$ and the massive recirculation flow of dust, the seal pot in a hot cyclone is big and maintenance-prone. Water-coded designs with much thinner lining have been developed.

12.5.2.5 Second Pass

The cleaned hot gases from the cyclone enter into the second pass to dissipate their heat to a series of convection surfaces such as the SH, ECON, and AH. With gases entering at $\sim 850^{\circ}\text{C}$, the enclosure of the second pass has to be of membrane wall construction. The design considerations for the various convection surfaces are the same as for a conventional PF boiler.

Superheater. The gas in the second pass is hot but it is devoid of dust. For steam temperatures up to 520°C ($\sim 970^{\circ}\text{F}$), a convection SH in the second pass is adequate. For higher SH temperature and for RH, FBHE or HS in first pass is needed for an economical design, transforming heat from the hot circulating ash.

Economizer. This is the main HS in the boiler. The design is conventional. Plain tubes are usually employed.

Airheater. Tubular AH is preferred in FBC because of the big pressure difference between air and gas. A rotary AH is economical for large-size units, especially for the lower-pressure SA. The disadvantage of RAHs is the need of expensive seals to handle the high pressure difference.

A horizontal tubular AH with gas over tubes and air inside is preferred to the vertical arrangement due to better cleanability and lower HS.

Soot Blowers. With wide spacing of tubes and in-line arrangement, SBs may be avoided. Since the deposits are loose, sonic blowers are often used.

12.5.2.6 *Electrostatic Precipitators or Fabric Filters*

The cooled gases at ~ 130 to 150°C (265 – 300°F) are finally cleaned via a bag filter or electrostatic precipitator (ESP) before discharging into the atmosphere. The main differences compared to PF boilers are that

- The dust loading remains practically constant irrespective of the ash in fuel, as the ash is recirculated several times until the dust load attains the required concentration in terms of kilogram per cubic meter (kg/m^3).
- There is substantial CaO and CaSO_4 where desulfurization is done.
- The particle size is very fine in a limited band.

The dust is high in carbon for slow-burning, high-FC fuels and low-ash fuels and it is necessary to return the dust to the combustor, at least from the first two fields, to

- Improve the combustion efficiency
- Reduce the lime consumption

Ash disposal in wet form, sometimes employed in PF boilers, can be ruled out because of gypsum that will form hard rock. Dry disposal to the ash silos is the most reliable method.

12.5.2.7 *Fluid Bed Heat Exchangers*

For high SH and RH temperatures, external FBHE is provided in the return ash path from cyclone to combustor in the Lurgi design. The FBHE is a bubbling bed heater in which the return ash is bubbled over a bed coil comprising the finishing stages of SH and RH. The resulting low-temperature ash from the FBHE outlet controls the bed temperature and reduces

- The ash recirculation requirement
- The bed temperature variation

FBHE is usually not employed in boilers of $< \sim 250$ tph capacities for reasons of economy. In FWC design, the Intrex serves a similar purpose. Intrex or FBHE is typically provided only when

- Reheating is needed. The finishing SH and RH are usually the coils in the FBHE.
- A variable HS is required to deal with multiple fuels needing different bed temperatures. The ash flow to the FBHE can be regulated, and the combustor temperatures can be kept at optimum level for each fuel.

- The combustor size in large units has to be reduced for competitive configuration. The FBHE takes part of the load and makes the combustor compact.
- A wider turndown is required. The combustor temperature is maintained over a greater load range when FBHE shares part of the load.

The heat transfer in the FBHE and fluid bed ash cooler (FBAC) coils is high, varying from 300 to 600 W/m² °C or 250 to 500 kcal/m² h °C (~50 to 100 Btu/ft² h °F), which makes it a very compact HS.

Lurgi emphasized these benefits and employed the FBHE, whereas Ahlstrom preferred platen surfaces in the upper combustor and the additional Intrex. Omega tubes were used in platens to withstand erosion. The argument against FBHE was the possible erosion of in-bed coils of SH/RH of FBHE, although the bed material is finer and more uniform. The construction is cumbersome with thick refractory lining of ~600 mm (~2 ft) and big ash pipes and steam pipes entering and exiting. Erosion of tubes and refractory affects the availability of the total boiler. Membrane-type walls for the FBHE with low refractory overcome most of the former disadvantages.

12.5.2.8 Bottom Ash

Ash is discharged from the bottom of the combustor to maintain the required inventory. Higher bed pressure drop is an indication of accumulation of over-size particles—mostly stones, shale, and agglomerated ash. Usually bottom ash draining is a periodic operation, as the bed ash quantity is generally <10% of the total ash. Also, the bottom ash is practically devoid of any carbon. Bed ash is at a very high temperature of 850°C and needs cooling before its disposal.

- *Draining into water-impounded hopper* and discharging hydraulically from there to an ash pond is the simplest solution when no limestone is used and where environmentally acceptable. This is possible with only low-sulfur coals.
- *A water-cooled ash screw cooler*, shown in Figure 12.18, is a good solution for a dry ash discharge that is environmentally more acceptable. Ash from the bed is drained into a screw whose flights, shaft, and casing are all cooled by softened water of high quality.

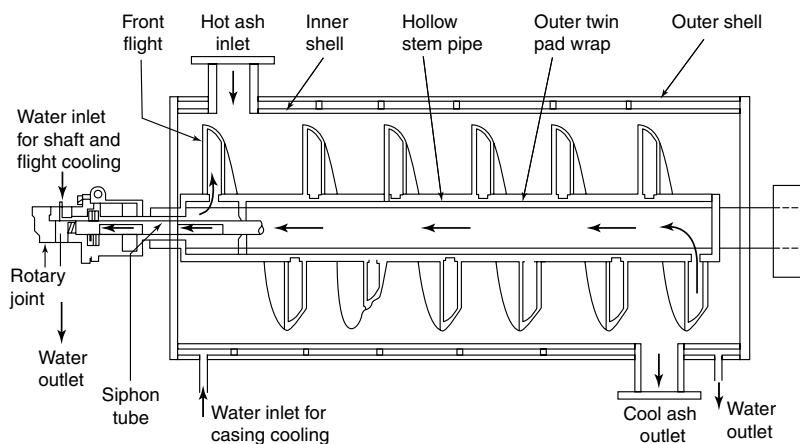


FIGURE 12.18
Typical screw cooler for ash.

As the incoming ash is at $\sim 850^{\circ}\text{C}$ normal bearing cooling water may not be adequate. When good-quality cooling water is not available, a closed loop is adopted. The heated water is cooled in a heat exchanger (HX) with the help of plant bearing water and the cooled water is returned to the system. When the plant cooling water is of acceptable quality, an open system with no heat exchange is adopted.

Ash is usually cooled to $\sim 80^{\circ}\text{C}$, and discharged in a dry manner in trucks. Screw coolers are then ~ 6 to 7 m long. They are significantly shorter when higher ash temperatures such as 150°C can be tolerated. Screw coolers have a capacity limitation of ~ 6 tph, making multiple screws essential for larger boilers. At least one ash discharge is essential for every 10 m^2 of bed surface for effective draining. Ash screws are required to be below the boiler at all times. This makes the boiler a little taller.

A screw cooler is essentially a screw conveyor with water cooling of the casing, shafts, and the flights to make it withstand the heat and also cool the ash. It has an intricate construction because

- There is a need for a rotary joint between the stationary water pipe and the rotating shaft.
- A heavy-duty pipe with a wrap-around plate over which the flights are welded addresses expansion issues.
- All the flights must be double-walled to create a hollow space for water flows.
- The ends of the flights must be covered with hard alloy to withstand erosion.

Screw coolers are expensive and need good-quality water, but they are compact and elegant. In comparison, FBACs tend to be cheaper but the refractory maintenance issues are present.

Fluidized Bed Ash Coolers. The FBAC, shown in Figure 12.19, is static and needs no great care in operation other than refractory maintenance. When there is high ash in coal and heat recovery makes sense, FBAC is a better choice.

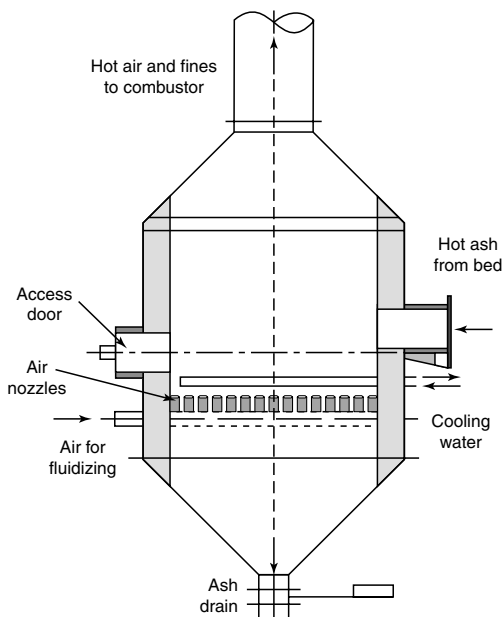
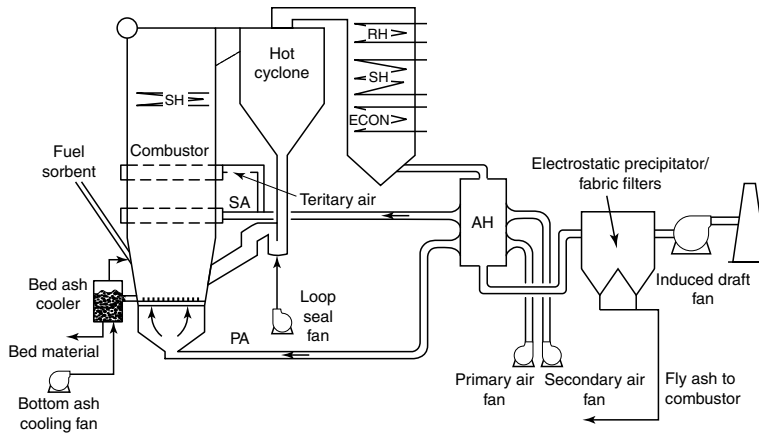


FIGURE 12.19

Typical fluid bed ash coolers.

**FIGURE 12.20**

Ahlstrom-type hot cyclone circulating fluidized bed combustion boiler with fluid bed ash coolers, fly ash recirculation, and first-pass superheater with omega tubes. AH, airheater; ECON, economizer; PA, primary air; RH, reheater; SA, secondary air; SH, superheater.

An FBAC is a bubbling bed heat exchanger with in-bed cooling water coil similar in construction to FBHE. Unlike the uniform nature of cyclone ash, here the ash is of variable size and tends to sinter when defluidized. The fluidizing air gets heated after cooling the ash to ~200 to 250°C. This hot air is injected into the furnace. As ash needs to slide into the bed, the FBAC is placed alongside the combustor. This arrangement permits lowering of the combustor.

Screw cooler or FBAC. Each manufacturer has its own system. Typically, screw cooler is the choice when ash is low, whereas FBAC is better when ash is high in coal. Heat can also be recovered usefully by an FBAC.

12.5.2.9 Salient Process Parameters of CFBC Boiler

Figure 12.20 illustrates the hot cyclone design with no FBHE but with SH in first pass (where required), as developed by Ahlstrom. The Lurgi is shown in Figure 12.12. The process parameters of both types are tabulated in Table 12.6.

12.5.3 CFBC Boilers

The new commercial CFBC boilers could

1. Meet the tough environmental standards due to cool and clean combustion
2. Demonstrate multifuel capability
3. Burn difficult and even unburnable fuels due to the reserve of hot solids in the bed and combustor

In comparison to the well-established PF firing, the early CFBCs were deficient in the following areas:

1. Higher auxiliary power consumption (marginally)
2. Heavy refractory maintenance
3. Unusually long start-up and shutdown times
4. Poor load dynamics
5. Lower reliability mainly due to erosion of tubes and refractory
6. Scale-up

TABLE 12.6

Salient Process Parameters of Full-Circulation Circulating Fluidized Bed Combustion Boilers

<i>Fuel</i>	6–8 mm
Top size	0.5–1.0 mm
Mean	
<i>Sorbent</i>	1.0 mm
Top size	0.2 mm
Mean	
<i>Combustor</i>	3.5–7.0 m/s (~11.5 to 23 ft/s)
Velocity	0.1–0.3 mm
Particle size	800–950°C (1470–1740°F)
Temperature	1000–2000 mm w.g. (~40 to 80 in. w.g.)
Pressure drop	10–100:1
Recycle rate	
<i>Performance</i>	1–2%
Carbon loss	
Ca/S for 90% SO ₂ capture	1.8–2.5
SO ₂	<100 ppm dv
CO	<100 ppm dv
NO _x	<100 ppm dv

Except for auxiliary power all other problems arose from the unusually high amount of refractory in the boilers.

The CFBC boiler is the real challenger to PF. It may not be able to eclipse the PF entirely, but it has managed to edge out PF, up to 100 MW for conventional fuels and to much larger sizes, up to nearly 500 MW, for difficult-to-burn solid fuels. CFBC boilers are

- Industrial types up to 100 MWe (400 tph)
- Reheat-type utility boilers for >100 MWe

Besides the expensive hot cyclone, the second-generation designs such as cold cyclone, compact, and U-beam are available in industrial range. For large utility boilers, full-circulation types give a more compact arrangement. Also, only Ahlstrom and Foster Wheeler build utility boilers with the improved technologies. The expanded bed designs can also meet the utility boiler requirements.

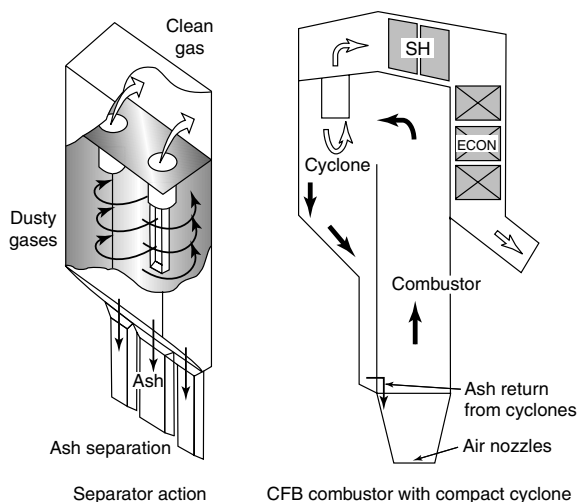
12.5.3.1 Current CFBC Designs

Present-day designs can be broadly categorized as follows:

1. Full circulation
 - a. Hot cyclone design
 - b. Compact design
2. Expanded bed
 - a. Cold cyclone design
 - b. U-beam/no-cyclone design

12.5.3.1.1 Full-Circulation CFBC Boilers

Full-circulation designs employ high velocities and high ash recirculation with no distinct bed and have high fan power. Hot cyclone is the early design of both Ahlstrom and Lurgi, and several boilers were built on this principle, even to large sizes. AE&E-Lentjes and

**FIGURE 12.21**

Compact separators. CFB, circulating fluidized bed; ECON, economizer; SH, superheater. (From Foster Wheeler Corporation. With permission.)

Alstom continue with hot cyclone design, although the velocities and recirculation ratios have been reduced with attendant lower power.

Foster Wheeler Corporation produced hot cyclone CFBC boilers, with the difference that the cyclone was made not of steel shell but of membrane panel, with either water or steam cooling, to reduce the refractory problems. After the acquisition of Ahlstrom, FWC developed a new “compact” design. Essentially, the cyclone is redesigned in an octagonal or rectangular shape and directly attached to the combustor wall, doing away with cyclone inlet and discharge legs and return pipes and seal pots, as shown in Figures 12.21 and 12.22. The cyclone is now made of membrane panels with water inside. The refractory is therefore reduced to a mere lining.

The problems listed in Section 12.5.3 that plagued early CFBC boilers, have been largely addressed. However, the disadvantage of this design is obviously the cyclone efficiency, which makes it more suitable for high-ash, high-volatile fuels.

12.5.3.1.2 Expanded Fluidized Bed Combustion Boilers

Basically the expanded bed boiler falls between the bubbling and the full-circulation FBC systems. Operating midway in the fluidization regime at ~ 4 m/s bed velocity, the expanded bed concept combines the advantages of

- Simplicity and lower power of BFBC
- Higher efficiency and flexibility of CFBC
- Minimum refractory in boiler:
 1. By cooling the gases to ~ 400 to 500°C in the first pass and employing a steel cyclone (with protective refractory), making it a *cold cyclone* design.
 2. By replacing cyclones with inertial separators and directly dropping the ash into the furnace.

The possible reduction in combustion efficiency due to less ash recirculation is made up by recirculation of ash from the first field of ESP.

The comparison in Figure 12.23 captures the details and the differences of the three designs. It compares all the three technologies in terms of (1) bed velocities, (2) heat release

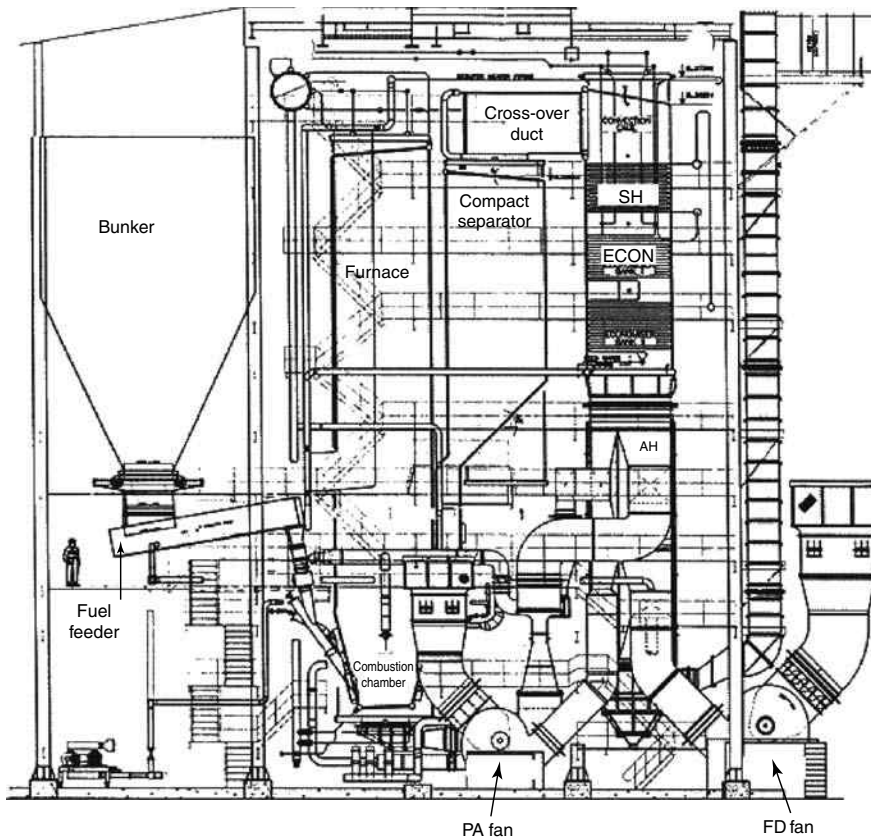


FIGURE 12.22

Typical 100 tph compact-type industrial boilers. AH, airheater; ECON, economizer; FD, forced draft; PA, primary air; SH, superheater. (From Foster Wheeler Corporation. With permission.)

rates (in plan area), and (3) power consumed. Approximate evaporation limits are also indicated. As the bed velocities increase

- There is an increase in auxiliary power.
- There is an increase in heat release.
- Slender boilers have smaller foot prints.
- Higher boiler capacities are possible.

Full-circulation CFB consumes some 60% more power and delivers a 40% higher heat release. It is easy to understand why the hot cyclone is more competitive despite the advantages of the expanded bed designs.

12.5.4 Cold Cyclone CFBC Boiler

Cold cyclone CFBC technology was originally developed by Deutsche Babcock after building both BFBC and CFBC boilers. This technology was, in the 1990s, acquired by Lurgi and later passed on to Lentjes. It consists of a conventional tower-type boiler with a CFB

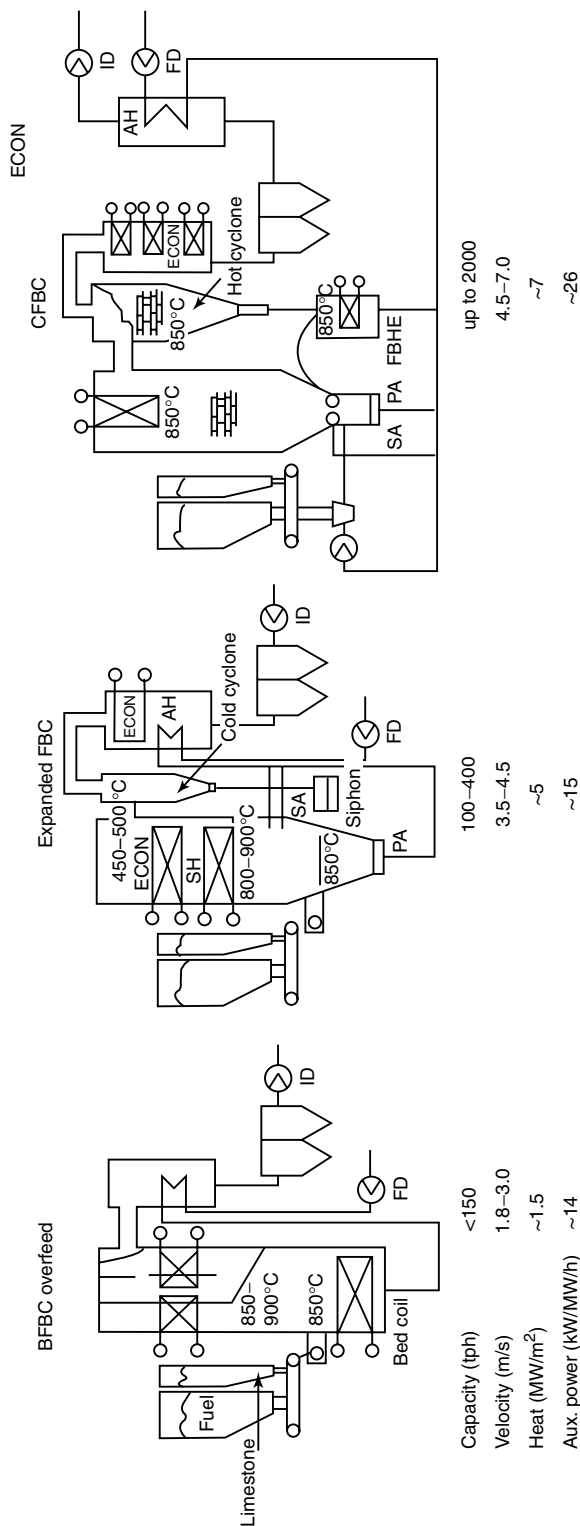


FIGURE 12.23

Comparison of bubbling, expanded, and circulating bed technologies. AH, airheater; BFBC, bubbling fluidized bed combustion; CFBC, circulating fluidized bed combustion; ECON, economizer; FBHE, fluid bed heat exchanger; FD, forced draft; ID, induced draft; PA, primary air; SA, secondary air; SH, superheater.

combustor at the bottom of the first pass and a cyclone between the first pass and the second pass. It can be viewed as

- A BFBC boiler with in-bed coils shifted to the top of freeboard
- A CFBC boiler with FBHE coils shifted from FBHE to first pass

Figure 12.24 shows a cold cyclone boiler.

12.5.4.1 Salient Features

The salient features are shown in Table 12.7 and Figure 12.28.

12.5.4.2 Advantages

The advantages of cold cyclone design over the full-circulation CFBC are as follows:

- Lower fluidizing velocity and hence lower FD fan power.
- Massive 80% reduction in refractory—only 50 mm in cyclones and none in second pass.
- A very steady bed temperature and a little variation across the bed because of the controlled recirculated cold ash.
- Cold start-up times of ~4 h (down from 10 h in full-circulation CFB).
- Only steel casing of the second pass, as gas enters at $<450^{\circ}\text{C}$. No membrane panels.

12.5.4.3 Tower Design

The tower-type design of the boiler, also covered in Section 9.3.3.2, gives the following benefits:

- No tube bundles in gas turns to suffer erosion due to the centrifugal force of ash.
- For the bundles located in the first pass, the erosion is not present because
 - The gas flow is normal to tube axis, which is nonerosive.
 - Gas velocities are low at <5 m/s.
 - Dust in gas is of <0.4 mm (a maximum particle size that can be suspended in a stream flowing upward at 4 m/s velocity).
 - Erosion shields are carefully placed on the tubes to avoid wear.
 - The first row of tubes facing the gases and carrying the load of all the tube bundles, called screen (evaporator) tubes, can be fully studded to avoid erosion as well as increase the HS.

12.5.4.4 Hot Gas Generators

Hot gas generators (HGGs) are employed in cold cyclone boiler design for providing hot air during startup with oil. A HGG is a horizontal refractory-lined empty vessel with oil or gas burners on one end and hot gas discharge to the windbox on the other. Part of the PA is diverted into the circular burner of the HGG only during startup to burn oil and generate hot gas at 900°C (1650°F). The hot gas heats the bed positively from the bottom, until the bed attains the ignition temperature of the main fuel varying from 400 to 600°C (750 – 1110°F). As the bed is heated from the bottom (with very hot gas at 900°C), the bed heating is positive and rapid, which contributes to the shortening of start-up time of the boiler.

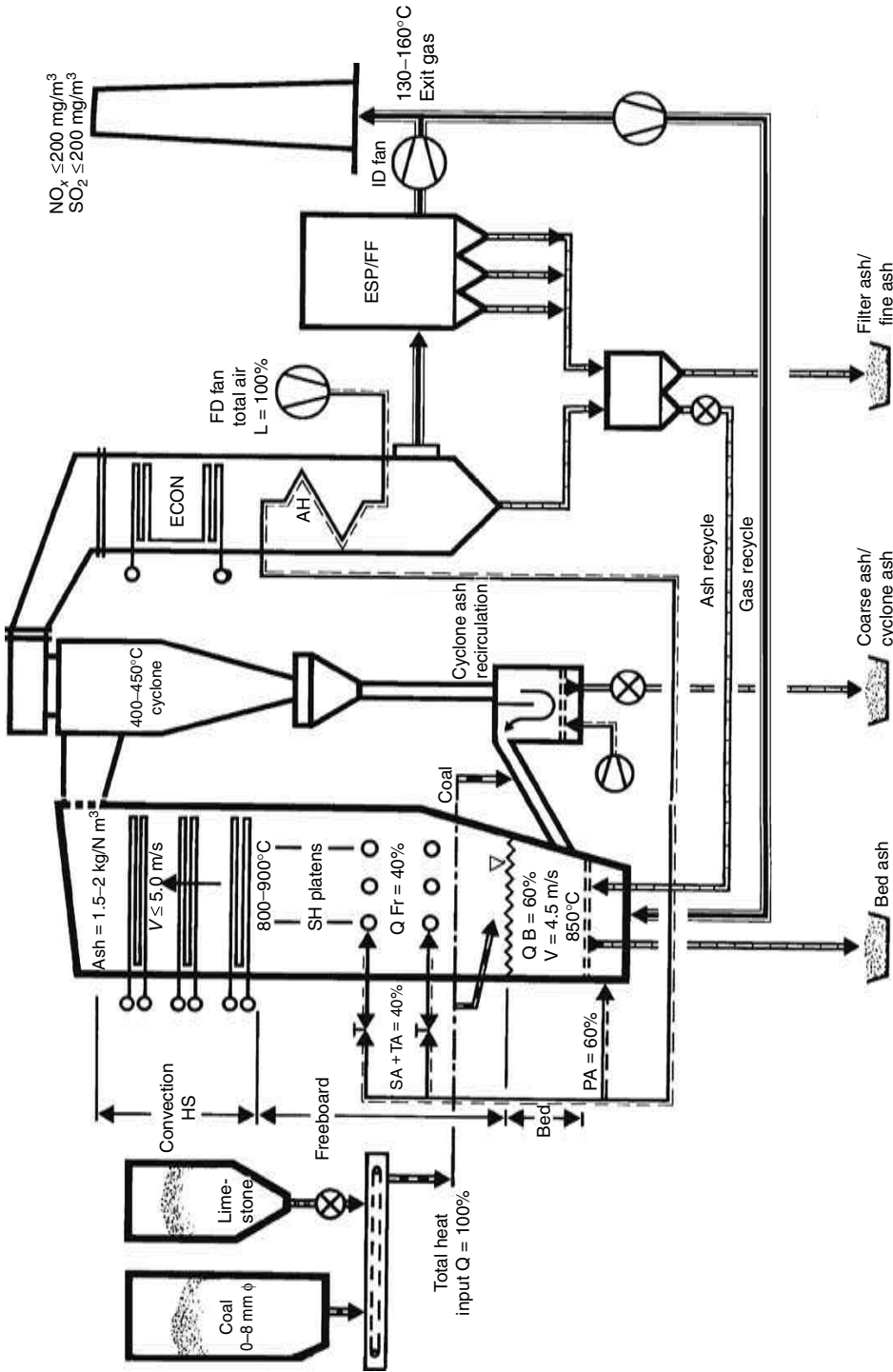


FIGURE 12.24

Cold cyclone fluidized bed combustion boiler. AH, air heater; ECON, economizer; ESP, electrostatic precipitator; FD, forced draft; FF, fabric filter; HS, heating surface; ID, induced draft; PA, primary air; SA, secondary air; SH, superheater; TA, tertiary air.

TABLE 12.7

Salient Features of Cold Cyclone Circulating Fluidized Bed Combustion Boiler Design

Parameter	Value	Comments
Fluidizing velocity	~4 m/s (~13 ft/s)	Low velocity half way between BFBC and full-circulation CFBC boilers
Expanded bed	1200–1400 mm (~4 ft to 4 ft 6 in.)	
Freeboard height	15–17 m (~5 ft to 5 ft 6 in.)	From top of expanded bed to screen, depending on required residence time and carbon burnout
Residence time	3.5–5 s	Higher values for slow-burning fuels and lignites
Ash recirculation	10–12 times fuel input	Much lower than in full-circulation CFBC boilers
Dust loading in gas	~2 kg/N m ³ (0.125 lb/N ft ³)	Much lower than 10 or even 40 kg/N m ³ of full-circulation CFB boilers
Gas velocity	<5 m/s (~16 ft/s)	In first pass tube bundle; low velocity to prevent erosion
Cyclone entry	400–450°C (~750 to 850°F)	Low dust load and low gas temperature. Permits 50 mm castable-lined CS cyclone
First pass	Cool gas to <450°C (850°F)	By superheater, evaporator, and part economizer
Second pass	Cool gas to ~130 to 160°C	By economizer and airheater located in steel casing
Start-up heating	By hot gas generators/duct burner located below bed	Positive heating from bottom of bed and not from top with overhead burner

With low refractory in the boiler and quick burning of fuel, the load rising is very fast in this design.

Figure 12.25 shows the lower combustor of a four-cyclone boiler, with HGGs attached to a windbox, where the fuel and air entry into the combustor from either side can also be seen.

12.5.4.5 Duct Burners

When gas is to be used as the start-up fuel, duct burners are preferred to HGGs as they are lighter and more compact. Please refer to Section 10.3 for a description of duct burners.

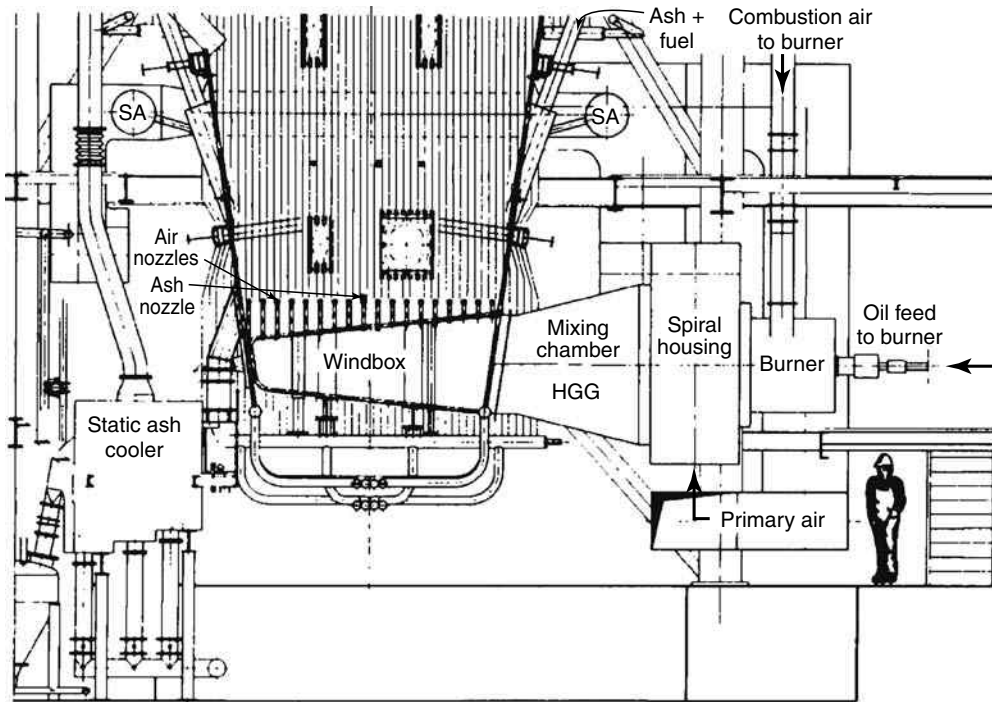
Unlike heat recovery steam generators (HRSGs), the duct burners must be accommodated in narrow ducts that experience a lot of heat. Care is required in measuring the gas temperature properly at the center of the discharge duct and not at the edges, lest the operator continues firing the gas until the whole duct is damaged due to overheating.

12.5.4.6 Cold Cyclone Design versus Classical CFB Boilers

- The combustor bed is wider by ~50% compared to full-circulation CFB due to less bed velocity.
- Although in efficiency and environmental parameters it matches full-circulation CFB, the speed of combustion is lower.
- Single-, double-, and four-cyclone executed designs cover a range of 40–400 tph or 10–100 MWe.

Larger boilers with six or eight cyclones reaching up to 700 tph have yet to be built. In comparison to full-circulation CFB, cold cyclone design is very competitive due to

- Lower HS and less weight of pressure parts (PPs) because of HS in the first pass where heat is given by gas as well as solids
- Much less (~20%) refractory because of only 50 mm lining in the cyclone as against 500–600 mm of brick work.

**FIGURE 12.25**

Lower combustor of cold cyclone boiler with hot gas generators mounted on windbox. HGG, hot gas generator; SA, secondary air.

- Start-up times to reach full load are between 3 and 4 h compared to 10–12 h due to a low amount of refractory.
- The corresponding oil consumption is about one-fifth of that in hot cyclone operation.
- A feed water top-up pump is not required. In hot cyclone design, it is necessary because water in boiler circuits evaporates soon after a shutdown due to the radiation of heat from refractory.

Table 12.8 captures the differences in detail.

12.5.4.7 Ash Recirculation

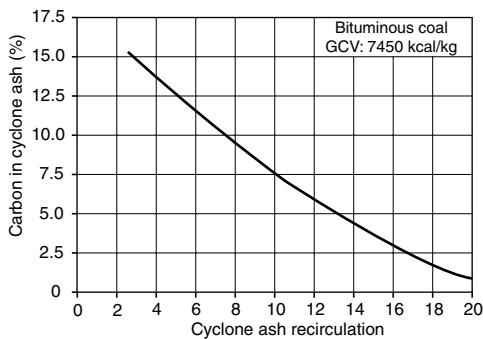
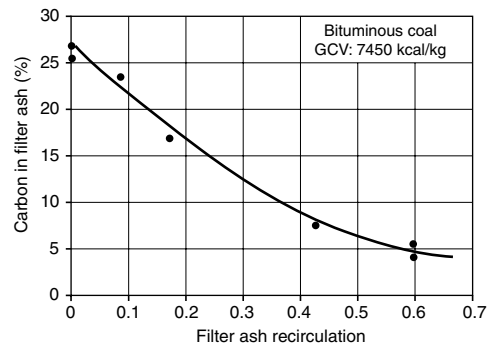
To improve the carbon burnup, ash recirculation from the cyclone and filter needs to be incorporated. The effect of the recycle ratio can be understood from Figures 12.26 and 12.27. Although they are specific to cold cyclone, they represent the phenomenon correctly. Quick-burning fuels such as lignite do not need filter ash recirculation, as the burning is complete. Similarly, high-ash coals also are not subjected to ash recirculation, as the fractional improvement in efficiency is not commensurate with the attendant erosion problems in ash lines and the additional power consumption.

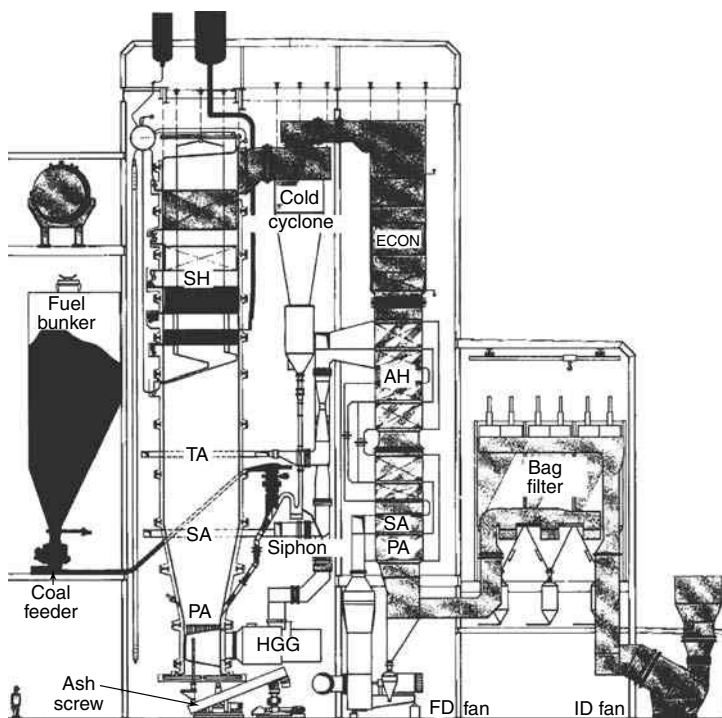
Figures 12.26 and 12.27 depict the effect of ash recirculation of cyclone and filter ash in cold cyclone design for a typical bituminous coal having a GCV of 7,450 kcal/kg (13,410 Btu/lb)

TABLE 12.8

Comparison of Cold and Hot Cyclone Circulating Fluidized Bed Combustion (CFBC) Boilers

Parameter	Cold Cyclone CFBC	Hot Cyclone CFBC	Comments for Cold Cyclone
Boiler design	Tower type with HSs in first pass	Two-pass boiler with mostly HSs in second pass	First pass HSs receive heat from gas and dust
Second pass	Steel casing	Membrane panel casing	Simple and inexpensive
Total heating surfaces	Lower	Higher	First pass HSs very effective
Fluidizing velocity (m/s)	3.5–4.5 (~11.5 to 15 ft/s)	4.5–7 (~15 to 23 ft/s)	Need <6 m/s on tube bundles
Auxiliary power (kW/MWth)	~15	~26	Lower FD fan pressure
Cyclone temperature (°C)	400–450 (~750 to 850°F)	~850 to 900 (1560–1650°F)	
Cyclone	Small, maximum diameter ~3.5 m	Large, maximum diameter ~8 m	Due to low gas temperature
Cyclone refractory	50 mm castable	~600 mm refractory and insulating bricks	
Ash recirculation times	10–12	10–100	Ash pipes small and unlined
Dust in combustor (kg/m ³)	1.5–2 (~0.1 to 0.125 lb/N ft ³)	10–40 (~0.62 to 2.5 lb/N ft ³)	
Bed temperature control	By cyclone ash recirculation	By cyclone ash, fluid bed heat exchangers, gas recirculation	
Bed temperature	Very steady across bed	Bed temperature not as steady	Bed is cooled by low-temperature ash. Fine control by gas recirculation possible.
Tubes	Normal in first and second passes	Omega in first and normal in second pass	
Total refractory	Small	High by 4–5 times	
Refractory erosion	Nil to small	High to very high	Low dust in gases and lower velocities
Start-up time from cold	3–4 h	10–12 h	Due to much less refractory
Start-up oil consumption (t)	5–6	~24	
Feed topping-up pump	Not required	Required	Less refractory, less heat

**FIGURE 12.26**
Effect of cyclone ash recirculation on char.**FIGURE 12.27**
Effect of filter ash recirculation on char.

**FIGURE 12.28**

Typical 100 tph cold cyclone design with two cyclones, siphons, and hot gas generators. AH, airheater; ECON, economizer; FD, forced draft; HGG, hot gas generator; ID, induced draft; PA, primary air; SA, secondary air; SH, superheater; TA, tertiary air.

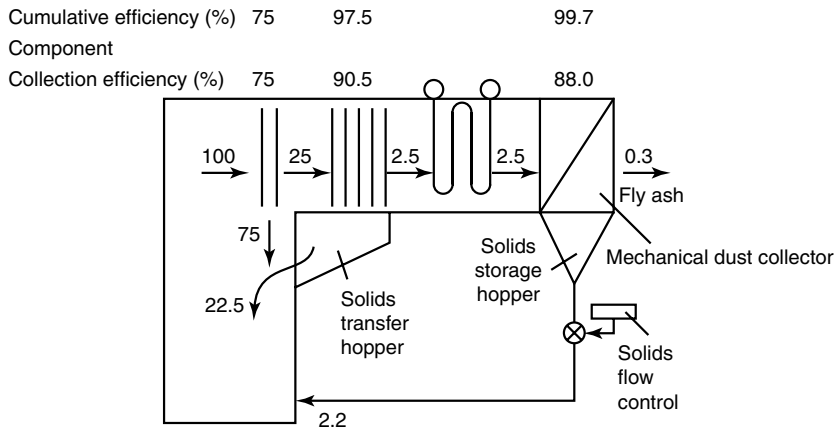
and ~8% ash and ~3% moisture. The higher the carbon in ash, the higher is the recirculation required. Recirculation is defined as the ash mass flow divided by the fuel mass flow. Cyclone ash recirculation is ~50 to 100 in hot cyclone and compact design as opposed to a maximum of 20 in cold cyclone design. But filter ash recirculation and effect are similar.

The power of filter ash recirculation can be realized when carbon in filter ash is dramatically reduced from ~25 to 5% with an ash recirculation as low as 0.6.

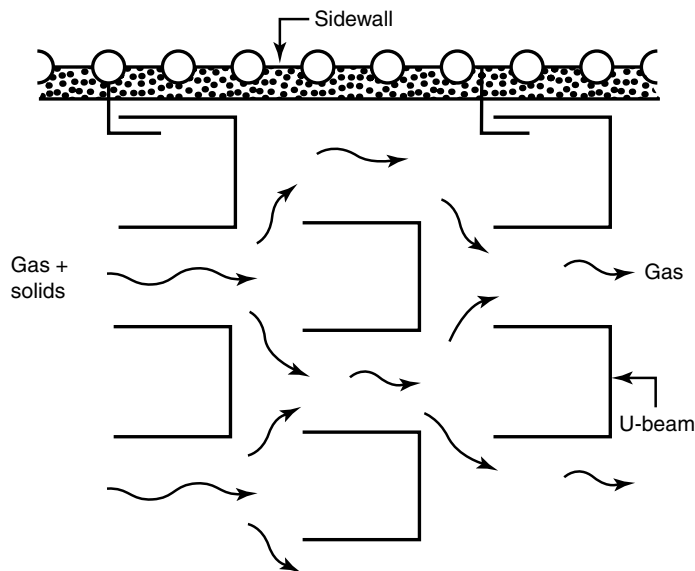
Figure 12.28 shows a two-cyclone industrial boiler with plain tube ECON and horizontal tubular AH as the back-end equipment. A bag filter is used for flue gas cleaning due to stringent pollution requirements. Ash recirculation from the filter is used for improving the carbon burnup. Boiler startup is with the HGG, when the fuel is oil. Bottom ash discharge is by water-cooled screws. Fuel feed and hot ash limit the number of openings in lower combustor and also heat the fuel with the contact of hot ash. Figures 12.25 through 12.28 have been adapted from publications of the former Deutsche Babcock.

12.5.5 No-Cyclone U-Beam CFBC Boilers

Studvik of Sweden promoted this technology in the 1980s. It was acquired by Babcock and Wilcox Company and developed further and commercialized. Steinmueller of Germany also built a few units with no cyclones. The constructional features can be summarized as follows (Figures 12.29 and 12.30).

**FIGURE 12.29**

Solid distribution in U-beam boiler. (From Babcock and Wilcox Company, U.S.A. With permission.)

**FIGURE 12.30**

Arrangement of U-beams. (From Babcock and Wilcox Company, U.S.A. With permission.)

12.5.5.1 Features of U-Beam Type CFBC Boilers

- In U-beam design, a conventional bidrum or single-pass boiler is fitted with a CFB combustor at the bottom of the furnace and an inertial separator at the top in the same place as a vertical platen SH.
- The expanded bubbling bed, similar to cold cyclone design, has defined dense, primary, and disengaging zones. Overfire air is provided at the end of the disengaging zone.
- Furnace tubes are lined with refractory up to the SA and TA nozzles to prevent erosion and corrosion against the impinging bed material and the prevailing reducing conditions in the lower combustor, respectively.

- The SS 304 air nozzles used in this design are small and closely spaced (100 mm or 4 in. square pitching typically, i.e., 100/m²) nozzles of the same construction as BFBC.
- Fuel feeding is by gravity, at an inclination of 60–65° to horizontal, similar to cold-cyclone design, as the furnace is at a slightly negative pressure. This makes the system simple.
- Bed ash discharge is at the bottom of the furnace with 200 (8 in.) NB ash pipes. Screw coolers or static FBACs are employed for cooling ash before disposal. For most industrial boilers, two to four ash pipes are employed.
- Bed heating is by overbed burners or lances similar to a hot cyclone design. This tends to make a cold start a little slower as compared to a positive bed heating from below as in the case of cold cyclone.
- Division or wing wall HSs are provided in the furnace to cool the gases to the desired level.
- A two-stage dust collection is employed. U-beams perform primary collection at ~97.5% efficiency, as shown in Figure 12.29. To match the collection efficiency of hot or cold cyclones, an MDC with efficiency of >90% is located after the BB or ECON in a cooler zone at an elevation suitable for pneumatic conveying of dust. The collectors are made of hard castings with hardness of 550 BHN to withstand erosion of dusty gases spinning at high speeds in excess of 20 m/s.
- Alternatively, ESP ash from the first field, where particles are ~70 µm, is taken.
- Return legs and L-valves used for returning the ash collected at the bottom of U-beams in the earlier designs are obsolete. Two sets of U-beams are located at the furnace exit where ~75% of the solids are collected and rolled down over the rear wall. Four sets of beams are placed after a gap where 90% of the incoming solids are collected in a solid storage hopper with discharge onto the rear wall.
- U-beams, typically ~8 m long, are made of ss such as TP 309H, TP 310H, or RA 253 MA, depending on conditions to withstand high temperature and force from heavy dust loads traveling at 6–8 m/s. RA 253 MA is typically used for pet coke application.
- SHs are pendant type, whereas ECONs are horizontal. The first row of ECON tubes is protected against erosion by suitable tube shields.
- The enclosure of the second pass is made of membrane wall as in hot cyclone design.

This internal recirculation (IR) of ash has dispensed with the return leg altogether, with a corresponding reduction in refractory and air blower for the L-valve. Ash recirculation rate is high. Bed temperature is controlled by regulating the return of cold ash from MDC.

12.5.5.2 Salient Process Parameters of U-Beam Type CFBC Boilers

The important process parameters of this design are tabulated in Table 12.9.

12.5.5.3 Advantages and Limitations of U-Beam Technology

- U-beam is the most compact, simplest, and most conventional of all CFBC boilers.
- It has the unique capabilities of retrofitting a PF boiler, as no cyclones are needed.
- The combined pressure drop of U-beams and MDC is ~100 mm wg as against ~170 mm (7 in.) wg in a cyclone. The fan power is the least.

TABLE 12.9

Design Features of U-Beam Technology

Parameter	Value	Remarks
Bed velocity (m/s)	3.7–4.3 (12–14 ft/s)	Low velocities similar to cold cyclone and nearly half of hot cyclone design
Bed temperature (°C)	840–950 (1545–1740°F)	Depending on fuel and desulfurization requirements
Primary air as % of total	55–70%	Staged combustion
Primary air nozzle pressure drop	~400 mm w.g. (16 in. w.g.)	At full load
Excess air	15–25%	
Upper furnace velocity (m/s)	5.5–6.7 (~18 to 22 ft/s)	Velocity closer to hot cyclone and more slender furnace than cold cyclone
Gas velocity in U-beams	~8 m/s (26 ft/s)	Low gas velocities and less erosion fear
Pressure drop in U-beams	<25 mm w.g. (1 in.)	Low pressure drop
Collection efficiency	97–98%	
Mechanical dust collector inlet gas velocity	~21 m/s (~70 ft/s)	High gas velocities needed for good collection; Less erosion fear, as gas is already dedusted in U-beams
Mechanical dust collector pressure drop	~75 mm w.g. (3 in.)	
Gas velocity in superheater (m/s)	7.5–8.5 (~24.5 to 28 ft/s)	To avoid erosion
Gas velocity in economizer (m/s)	7.5–10.5 (~24.5 to 34.5 ft/s)	To avoid erosion
Gas velocity in airheater (m/s)	9–12 (~29.5 to 39.5 ft/s)	Higher gas velocities if placed after mechanical dust collectors
Second-pass enclosure		Membrane wall

- With no return leg and practically no refractory in the furnace the total refractory in the boiler is minimized to ~10% of that in full-circulation CFBC boilers.
- With least refractory, the boiler load response is very good.
- Wide and seamless turndown of 20–100% without auxiliary fuel is possible.
- Quick startup from cold of <6 h is achievable.

The bed temperature control is the most critical parameter in this design. With no positive control on the return ash from primary collector, all ash from U-beams flowing along the rear wall and bed temperature control dependent on the fine ash from MDC, a steady bed temperature is somewhat difficult to achieve. Fine ash does not stay in the bed long enough to provide effective cooling. Overheating of bed is dangerous because it leads to overheating of U-beams. If the beams alter shape or go out of alignment, the ash collection is reduced, leading to a further rise in temperature. Not enough units are running to establish the reliability of the design principle fully (Figure 12.31).

12.6 Utility Circulating Fluidized Bed Combustion Range Boilers

Full-circulation, hot cyclone, and compact-type CFBC boilers are the only designs that have accumulated adequate references and data. For utility applications, these are the only acceptable configurations. Other technologies have not managed to move into this space.

Although very large boilers of 460 MW are built to even supercritical (SC) conditions, most references pertain to fuels that are difficult to burn in PF, such as petroleum coke,

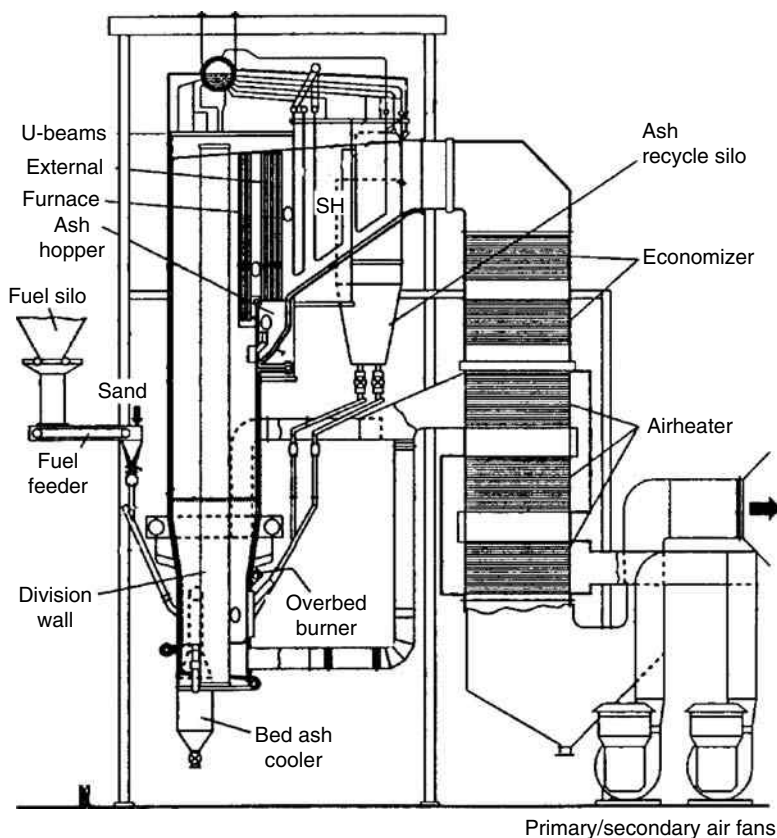


FIGURE 12.31

Typical single-drum U-beam boiler. SH, superheater. (From Babcock and Wilcox Company, U.S.A. With permission.)

peat, and anthracite, or combination fuels such as coal with lignite, wood waste, pith, and so on. More difficult environmental conditions have helped CFBC boilers become the boilers of choice.

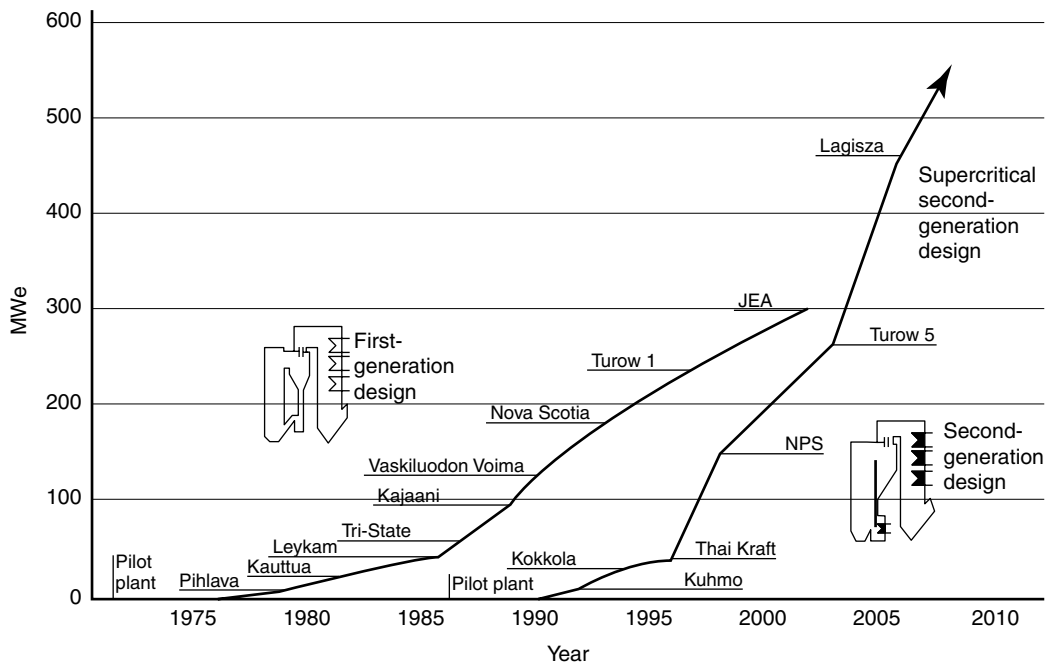
Figure 12.32 traces the growth of CFBC technology over the years. Although it is specific to FWC it represents the general pattern.

A typical 125 MW boiler unit for lignite is shown in Figure 12.33. This is a hot cyclone design with one cyclone on either side. The next major size was 250 MW where the furnace was designed in a pant-leg fashion adopted in designs of larger boilers. There are two cyclones on either side of the boiler (Figure 12.34).

Several utility boilers have been built by FWC. The largest compact boiler is for 460 MWe in Poland, using coal, coal slurry, and biomass as fuels and employing, for the first time, SC conditions in CFBC. This unit is designed to generate main and reheat steam at

- 370/307 kg/s (1332/1105 tph)
- 27.5/5.5 MPa (280.5/5.6 kg/cm²)
- 565/580°C from feed water temperature (FWT) at 290°C

The boiler employs four sets of compact separators on either side, as shown in Figure 12.35.

**FIGURE 12.32**

Growth of circulating fluidized bed combustion technology. (From Foster Wheeler Corporation. With permission.)

12.7 Ignifluid Boilers

Developed in France in the 1950s and patented as Ignifluid technology, these boilers gained a rapid acceptance after the oil crisis in the 1970s and 1980s. Although the other FBC boilers were still under development, this type of fluidized bed boiler was fully ready and in use across the globe. Ignifluid technology can be considered as a true forerunner of the present-day CFBCs. The principles behind the Ignifluid technology are as follows (Figure 12.36):

- *High-temperature fluidization* in which the bed temperature was held between 900 and 1200°C (1650–2200°F) simply by staged combustion, depending on the fuel.
- No bed tubes.
- The temperature was high enough to agglomerate and form a small clinker. The ash discharge was as simple as in a stoker-fired boiler.
- An inclined grate would carry away the clinker from the fluidized bed.
- The fluidizing velocities were ~4 m/s, close to the velocities of the present expanded bed.
- The grate was an ash carrier and air distributor. Unlike a conventional grate, it did not participate in combustion beyond air distribution and fuel support.
- No bed air nozzles for air distribution, a function performed by the grate.
- Cinder recirculation for enhanced combustion efficiency.
- The boiler construction was very conventional with bidrum or single-drum design.
- Sorbent feeding could be done from the SA nozzles.

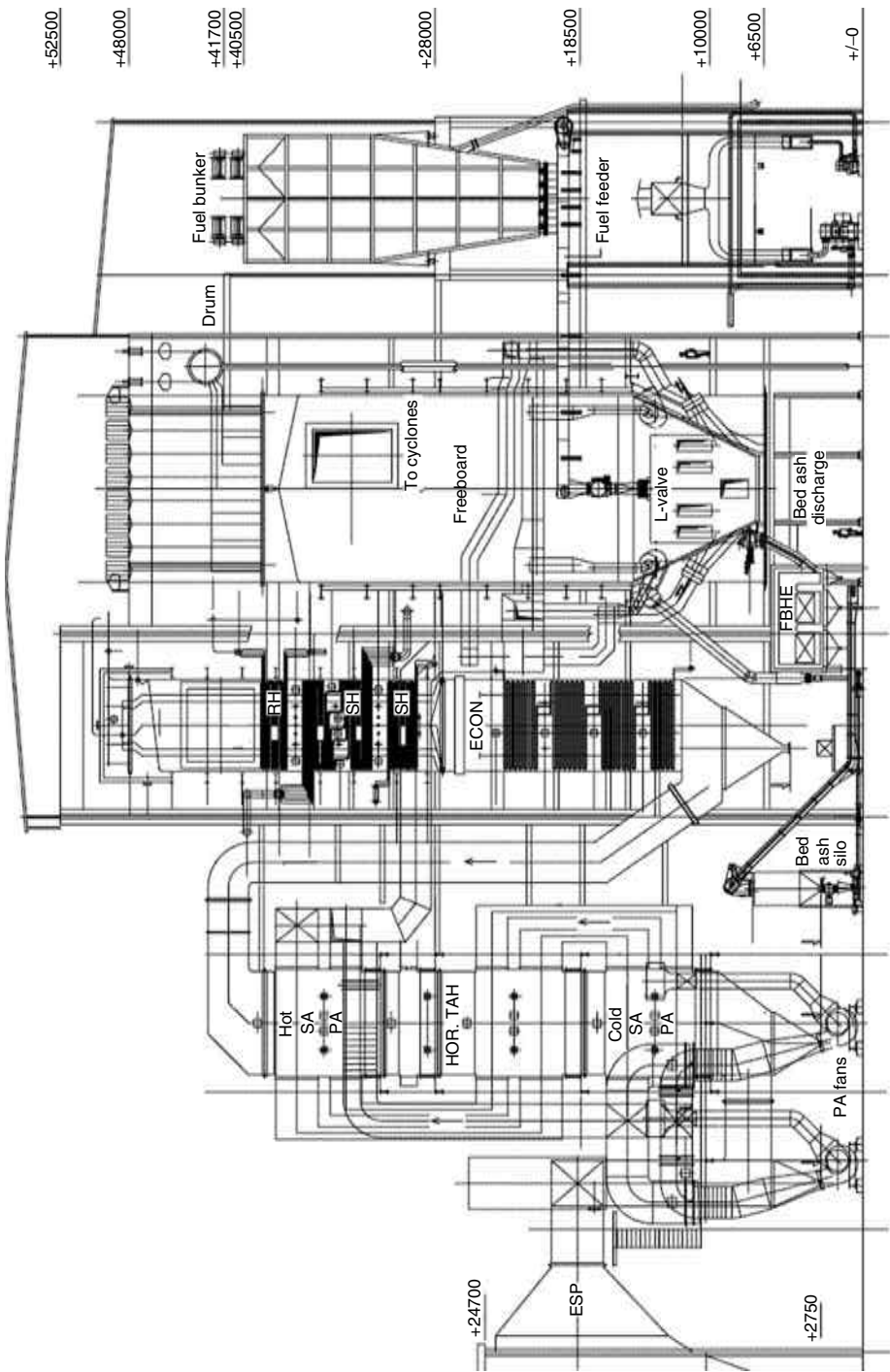


FIGURE 12.33

Typical 125 MW lignite-fired hot cyclone circulating fluidized bed combustion boiler with two cyclones. AH, airheater; ECON, economizer; ESP, electrostatic precipitator; FBHE, fluid bed heat exchanger; PA, primary air; SA, secondary air; SH, superheater; TAH, tubular airheater. (From AE&E-Lentjes GmbH, Germany. With permission.)

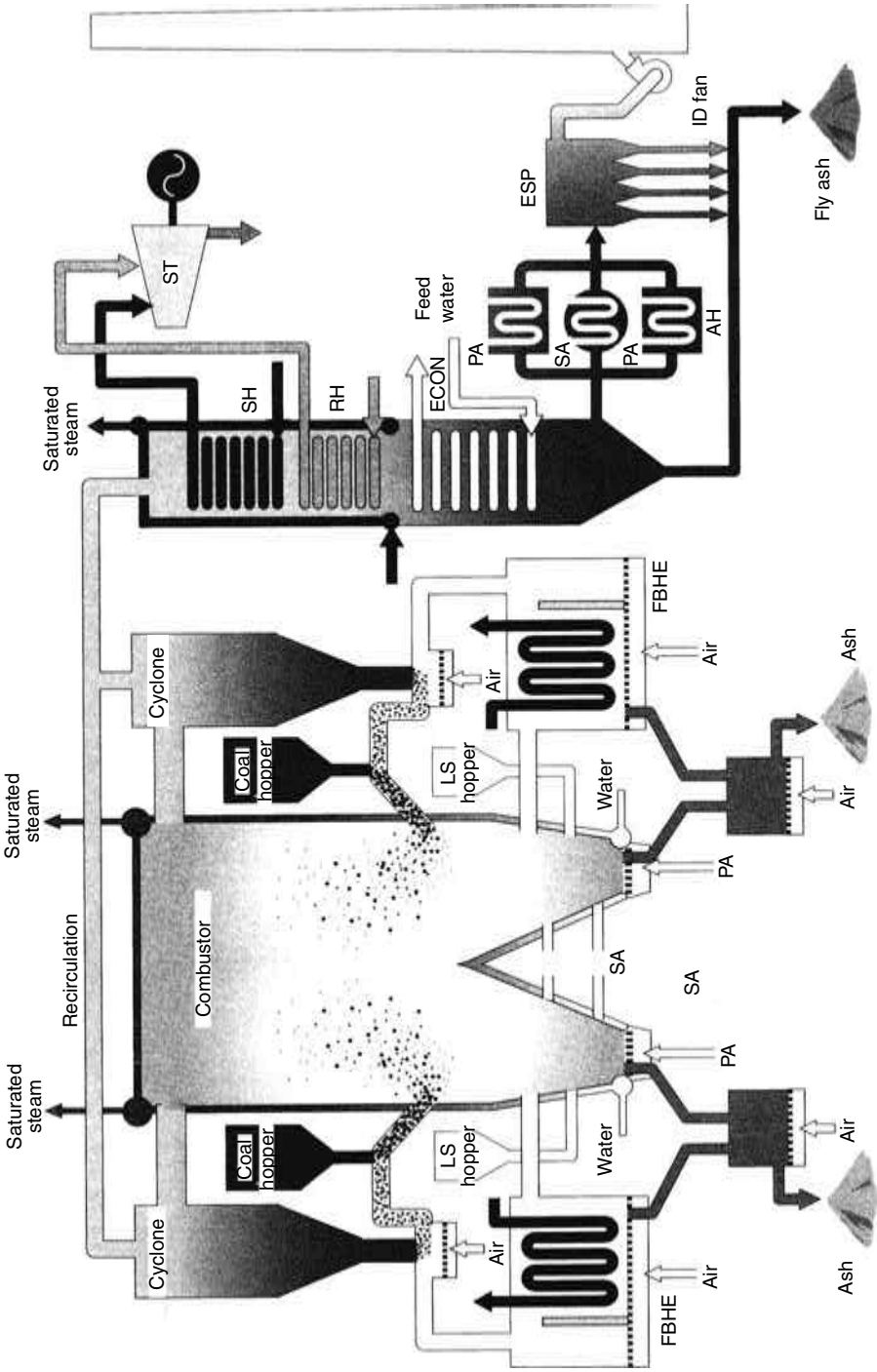


FIGURE 12.34

Typical 250 MW hot cyclone circulating fluidized bed combustion boiler with four cyclones. AH, airheater; ECON, economizer; ESP, electrostatic precipitator; FBHE, fluid bed heat exchanger; ID, induced draft; PA, primary air; RH, reheater; SA, secondary air; SH, superheater; ST, steam turbine. (From AE&E Lentjes GmbH, Germany. With permission.)

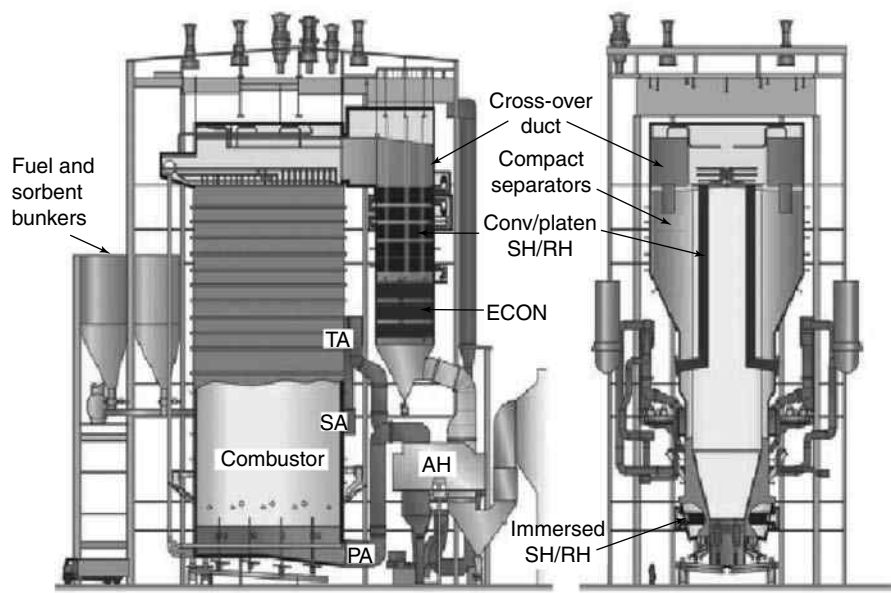


FIGURE 12.35
Typical 460 MWe supercritical circulating fluidized bed combustion boiler of compact design. AH, airheater; ECON, economizer; PA, primary air; RH, reheater; SA, secondary air; SH, superheater; TA, tertiary air. (From Foster Wheeler Corporation. With permission.)

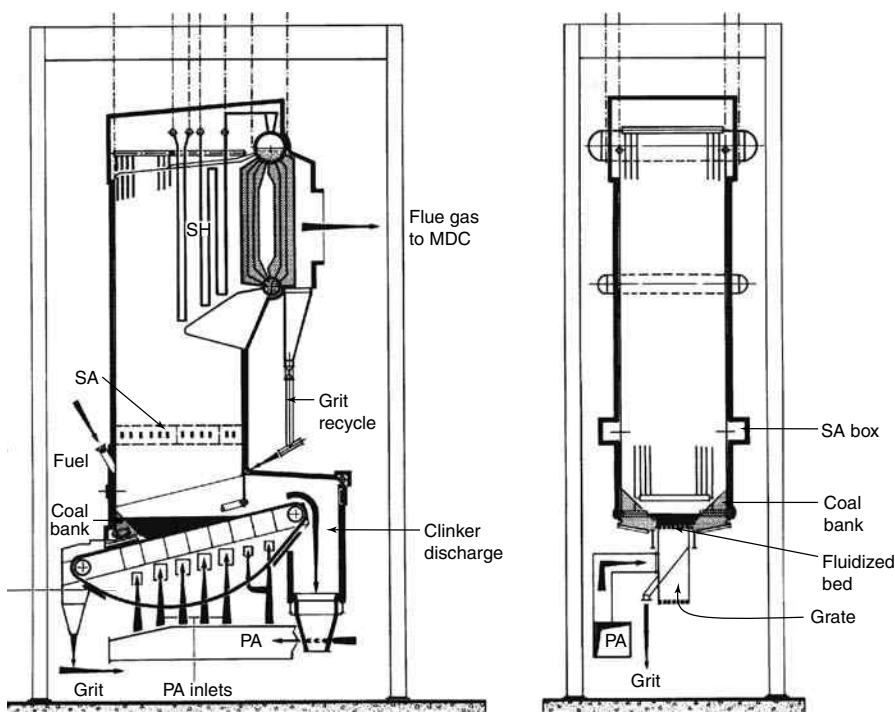


FIGURE 12.36
Principle of Ignifluid boiler. MDC, mechanical dust collector; PA, primary air; SA, secondary air; SH, superheater.

The advantages of Ignifluid boilers include:

- The concept was sound, and the boilers displayed reliability and ruggedness.
- Boilers for burning several fuels were commissioned—anthracite, coals of different origins, lignites, coffee grounds, etc.
- As the bed contained only carbon, the load response was very good.
- A stepless turndown of 1:4 was normal.
- The operation was nearly as simple as running a stoker-fired boiler, without heavy maintenance.

A boiler with 380 tph capacity built in 1989 was then the largest FBC. With the advent of stringent pollution norms, the manufacturer had to withdraw from developed markets because

- The NO_x was slightly higher at 300 mg/N m³ against <200 mg/N m³.
- The desulfurization from SA nozzles was limited to 60–80% as against 85–95% with the CFB technology.

In the developing markets, for high-ash coals, the unburnt loss was ~6%, which could not compete with ~4 and 1% of BFBC and CFBC, respectively. The Ignifluid is outdated today, but it should be remembered as the first of fully developed FBC boiler and several installations continue to work around the world.

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13

Pulverized Fuel Firing

13.1 Introduction

Pulverized fuel (PF) firing is the *most dominant type* because of its *great versatility* and *scalability*. Since coal and lignites are the most competitive fuels in large parts of the world, the growth and dominance of PF firing for the last eight decades has almost been unassailable. The bulk of power generation has been and continues to be by PF firing. Only since the early 1990s, gas turbines (GTs) and circulating fluidized bed (CFB) boilers have gained market share. As the environmental friendliness has improved in along with the lowering of costs of milling, firing, and gas cleaning equipment, PF firing is now competing with the newer technologies with renewed vigor.

When a solid fuel such as coal is reduced to the consistency of talcum powder and fired in an open furnace, the resulting combustion is akin to oil or gas firing—in speed, controllability, and heat release. A coal particle burns out between 1 and 2 s, depending on its volatile content, similar to oil, and the combustion is most complete at >99% carbon burnup. For high-volatile matter (VM) coals and lignites, the efficiency can be as high as 99.7%.

This feature has made the PF firing rule the utility market for over eight decades. The roots for PF firing can be traced to its use in the cement industry ~200 years ago. The steel industry was the next to use and develop PF firing. The early PF boilers were different from the present-day units, inferior, smaller, and unreliable in milling, firing, controls, and safety, but the main process has remained unchanged. Starting from about 15 MWe size, boilers reached 1300 MWe by the early 1970s. A furious pace of development was witnessed in the 1950s and 1960s, and the world's largest boiler of ~4000 tph was commissioned in 1973. Since then steady consolidation and development of technology have taken place, greatly improving the flexibility, reliability, environmental friendliness, and controllability. This improvement has also spread to all the auxiliary plants.

13.1.1 Main Features

- Modern direct-fired PF firing involves
 - Size reduction and drying in mills
 - Transportation from mills to burners
 - Combustion in burners and furnaces

Depending on the moisture of fuel and the desired mill outlet temperature, the airheater (AH) is sized or the hot gas inlet chosen (for lignites).

- As the fuel is in powder form, the combustion speeds are high, almost as high as that of oil. With about 5 min or more of fuel storage in mills, there is an adequate flow of fuel and air to provide, at times of sudden load demand, a very good response to load variation, almost matching the oil firing.

- Any fuel that is not fibrous or stringy and can be powdered to the desired level, has adequate heating value (HV) to sustain autocombustion, and has enough VM to provide ignition of fuel can be burnt in the PF mode. Coals of all varieties, from anthracites to peat, have been successfully burnt.
- Although PF firing is a very versatile technology, the boiler is fuel specific. For a particular heat duty and fuel, the numbers of mills and burners are selected and an appropriate AH is designed to provide air at the right temperature. This combination of the AH, milling, and firing equipment addresses a certain limited variation in fuel properties that usually exists between the worst and the best fuel.
- Since PF boilers are burner-fired, the ability to fire a variety of oil and gaseous fuels alone or in combination with PF is exceptionally good.
- A modern PF boiler is
 - Invariably top supported.
 - Built with membrane panels in furnace.
 - Provided with platens, division walls, and wing walls to achieve a balance between the effective projected radiant surface (EPRS) and the furnace volume in achieving furnace exit gas temperature (FEGT) low enough to avoid fouling in the SH.
 - Built entirely with plain tube heating surfaces (HSs) to prevent erosion with the exception of economizers (ECONs) in which extended surface or gilled tubes are sometimes employed.
 - Equipped with tubular or rotary AHs, as elaborated in Section 13.5.
- In terms of fuel handling and firing, a PF boiler is
 - Usually matched with the minimum number of the biggest mills that meet the turndown requirements adequately.
 - Equipped with usually one spare mill over the minimum number required for the worst fuel, reduced to zero in some advanced countries and increased to two for use with very poor fuels.
 - Wall fired or tangentially fired for normal coals and down-shot fired for low-volatile coals and anthracites; usually corner fired for brown coals.
 - Provided with belt-type or chain-type volumetric feeders. For brown coals, the plate-type feeder deals with large volumes of fuel.
- The pollution control aspects of PF firing are as follows:
 - Low- NO_x burners with staged (and hence delayed) combustion techniques with overfire airports (OFAs), together with larger furnace dimensions to accommodate longer flames and consequently reduced heat flux in plan, have worked in tandem to lower the emissions to acceptable levels. Separate deNO_x plants are added only when this effort is inadequate.
 - Flue gas desulfurization (FGD) or deSO_x plants in the form of gas scrubbers in second pass are installed when high-S fuels are burnt. *In situ* desulfurization is not feasible.
 - Electrostatic precipitators (ESP) are popular for normal- and high-ash coals for achieving $\sim 50 \text{ mg/N/m}^3$ outlet dust levels, but fabric filters are needed for even lower particulate emissions.

13.1.2 Advantages and Limitations

13.1.2.1 Advantages

- A maximum combustion efficiency of 99% or higher is achievable.
- With improved modern mills, the fineness is better and power consumption lower.
- Load response is very fast and comparable with oil- and gas-fired boilers.
- All types of coals, from anthracite to lignite and peat, have been burnt efficiently.
- Low-NO_x burners, deSO_x units, and deNO_x units, all working in combination, have made PF boilers environmentally compliant.

PF firing has been the preferred method for solid fuel firing in large quantities for utilities. However, in the last few years, circulating fluidized bed combustion (CFBC) boilers have begun to disturb this equilibrium by offering reliable solutions in the areas not served well by PF firing.

13.1.2.2 Limitations

The limitations relate to the inability of PF to

- Deal with variation in fuel without risking fouling and slagging of boilers
- Provide multifuel firing
- Fire fuels with >40% total moisture unless there is enough VM such as in brown coals
- Burn very low-volatile fuels such as petcoke
- Combust very poor fuels with
 - Gross calorific value (GCV) <2000 kcal/kg
 - A burden >65% (ash and H₂O)
 - Very high S
- Have stepless load turndown of more than ~70 to 100%

These limitations of PF boilers were recognized decades ago. In the absence of a better alternative, they have been accepted. With the advent of the CFBC technology, remedial measures have since been found to some extent. Circulating fluidized bed combustion boilers

- Can address all the above issues
- Are nearly as efficient for conventional fuels
- Are more operator friendly, with very few moving parts and controls
- Have lower O&M costs if erosion issues are not encountered
- Offer better environmental friendliness and ensure against emerging requirements
- Present little danger of explosion

For these reasons, they have practically displaced PF boilers from the industrial segment. Now they have begun to push PF boilers away even in the utility segment up to 150 MWe, depending on the pollution norms to be met. A comparison of CFBC and PF boilers is provided in Table 12.5.

13.2 Types of Firing

Pulverized fuel firing involves a distinct milling plant and firing equipment. Milling deals with size reduction, while firing relates to combustion.

1. The *milling* plant consists of
 - a. Feeders to feed coal from bunkers to mills or pulverizers
 - b. Mills to grind the crushed coal
 - c. Pipes to transport the ground coal to burners
2. The *firing equipment* consists of
 - a. Burner assemblies complete with light-up systems
 - b. Burner management and safety system

A modern PF boiler works on

- *Direct firing* in which the milling plant and the boiler always work together
- *Indirect firing* in which a centralized milling plant feeds several boilers

Indirect firing was popular in the cement and metallurgical industry where PF firing was, in fact, first developed. A milling plant would grind a large amount of coal centrally, to be stored in coal bins. The milling plant would be several hundred meters away from the bins. Pulverized coal would be transported pneumatically and passed through cyclones mounted on top of bins for separation, and air dedusted in bag filters. Coal was dropped into the bins and the separated air released to the atmosphere. The coal powder was drawn at the bottom through feeders, pneumatically carried to boilers, and fired. Feeder speed varied as per the load demand.

13.2.1 Indirect Firing

Indirect firing was popular until the 1950s, and fairly large boilers were built. The milling and the firing were separated with the central milling plant working on a single-shift basis to fill the central bunkers common to a battery of boilers. Large tube mills would operate for 8–10 h a day at their best capacities so that the power costs would be low, and there was ample time for mill maintenance. The boilers operated at the required capacities, as there was enough PF available in the bunkers all the time. The following shortcomings hindered further growth.

- Indirect firing required high mill power.
- Powdered coal in the bins was susceptible to spontaneous combustion.
- Ground coal would absorb moisture and cause flow interruptions, leading to furnace explosions.
- Dusty environment.
- Untidy appearance and complicated layout.

The development of reliable and smaller vertical mills changed the course of PF firing dramatically.

- The vertical mills were lighter and lower in power consumption.
- The controllability of boiler and individual mill was better.

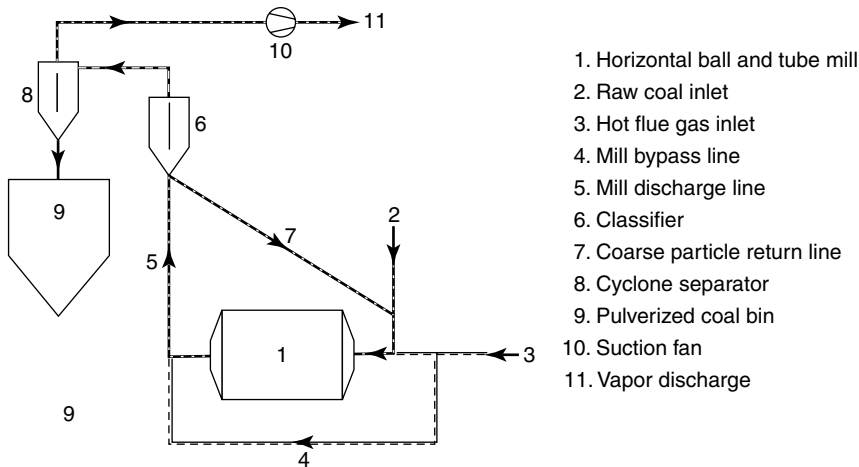


FIGURE 13.1
 Indirect firing with ball mill under suction.

- This controllability paved the way for unified milling and firing, the boiler with its mills an independent unit.
- The coal bunkers stored the crushed coal, making the spontaneous combustion a relic of the past.
- With the ground coal immediately transported in the required amounts from mills to boilers directly, the fear of slug flows in the coal pipes leading to furnace explosions disappeared totally.

The vertical mills and direct firing led to the development of much bigger, flexible, and safer boilers with far superior dynamics. Although the indirect firing system has become obsolete, the large tube mills were made suitable for pressurized operation and used for stubborn applications such as grinding

- Very abrasive coals that would wear out the vertical mills
- Very high-ash coals, typically $>45\%$
- Very low-volatile coals that need to be ground to a much greater fineness

Indirect firing using a ball mill is shown in Figure 13.1. Vertical mills were also employed in indirect firing.

13.2.2 Direct Firing

In direct firing, where each boiler has a dedicated battery of the milling plant, the deficiencies of indirect firing were fully overcome. Figure 13.2 illustrates a typical direct-fired boiler equipped with vertical pressurized mills. Superior and larger mills paved way for the dramatic scale-up. Between the mid-1950s and the mid-1960s, there was a 10-fold increase in size that culminated in a 1300 MWe, boiler, as mentioned earlier.

In the direct-firing mode, there are two types of milling systems, namely,

1. Suction milling
2. Pressurized milling

depending on whether the mill operation is under negative or positive pressure.

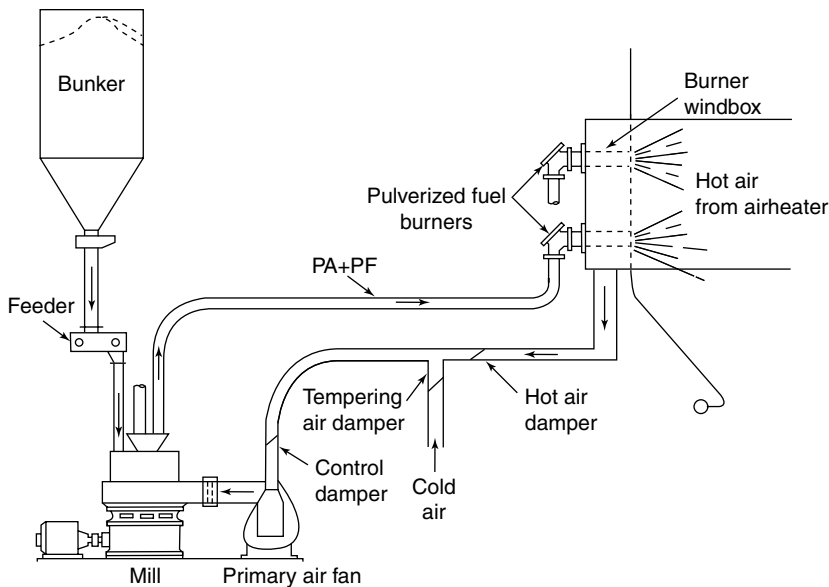


FIGURE 13.2

Direct firing with vertical mill under pressure.

13.3 Milling Plant

13.3.1 Suction and Pressurized Milling

In *suction milling*, the exhaustor fan is located between the mill and the boiler. It pulls the hot air from the AH outlet through the mill and picks up the ground coal from the mill to deliver the mixture to the burners.

Hot air is suitably mixed with ambient air to meet the mill outlet temperature requirement. The mill and feeders are under suction and this helps keep the area clean. The exhaustor always handles cold (mill outlet temperature), wet (moisture from coal), and dust-laden air with a compact radial fan. The fan maintenance is likely to be heavy unless the coal is very soft (which is normally associated with high GCV), requiring less fuel.

The *pressurized milling* is more popular because there is no exhaustor maintenance, along with other benefits. The primary air (PA) fans are located upstream of the mills; therefore, the milling plant is always under pressure, requiring good sealing to prevent a dusty environment. The PA fans can be placed

1. Immediately ahead of the mills, usually one for each mill. The hot fans take suction from the AH outlet.
2. Upstream of the AH the fan deals with ambient air. Two fans can supply air for all the mills.

A trisector rotary AH can be considered. In both cases, there is mixing of ambient air from the forced draft (FD) fan to suit the drying needs of the mill. The least fan power option is usually adopted.

13.3.2 Feeders

Feeders and mills are required for a throughput of 20–100 tph and two types of feeders are available:

1. Belt type
2. Chain type

A feeder is a volumetric device. By providing a fuel weight measurement, the belt feeder can be made into a gravimetric feeder. This is not possible with a chain feeder. When the mill feeding rate must be handled individually for boiler-control purposes, the gravimetric feeder is desired. Otherwise volumetric feeders are used even for very large boilers.

To meet the National Fire Protection Association (NFPA) requirements, the feeder casing should be of 6 mm size, and the housing should be cylindrical.

13.3.2.1 Belt Feeders

The feeder shown in Figure 13.3 employs an endless belt on which coal descends from the bunker at one end and discharges into the mill at the other end. The feeding rate is varied by the speed of the driving roll. Gravimetric feeders have gained a lot of acceptance because of their accuracy and reliability. The feeders usually come in lengths of 2.1 and

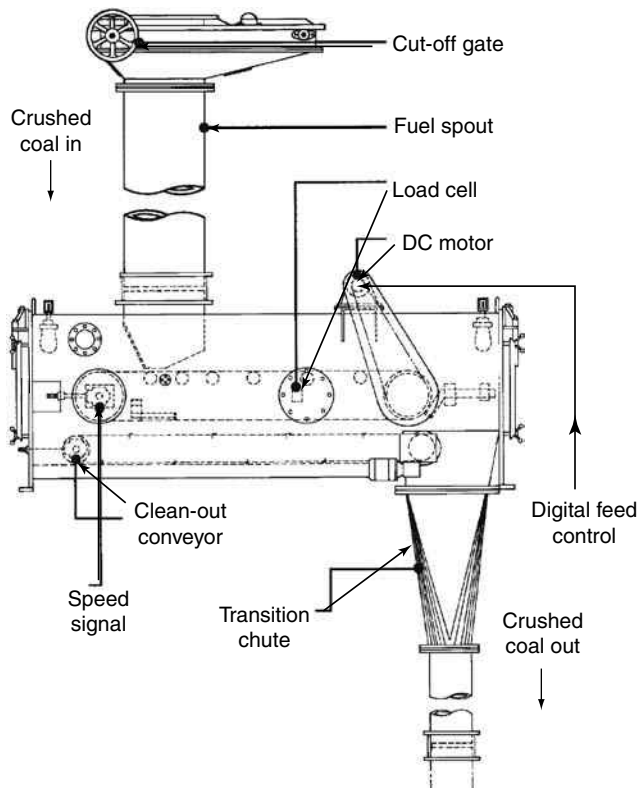


FIGURE 13.3
Gravimetric belt feeders.

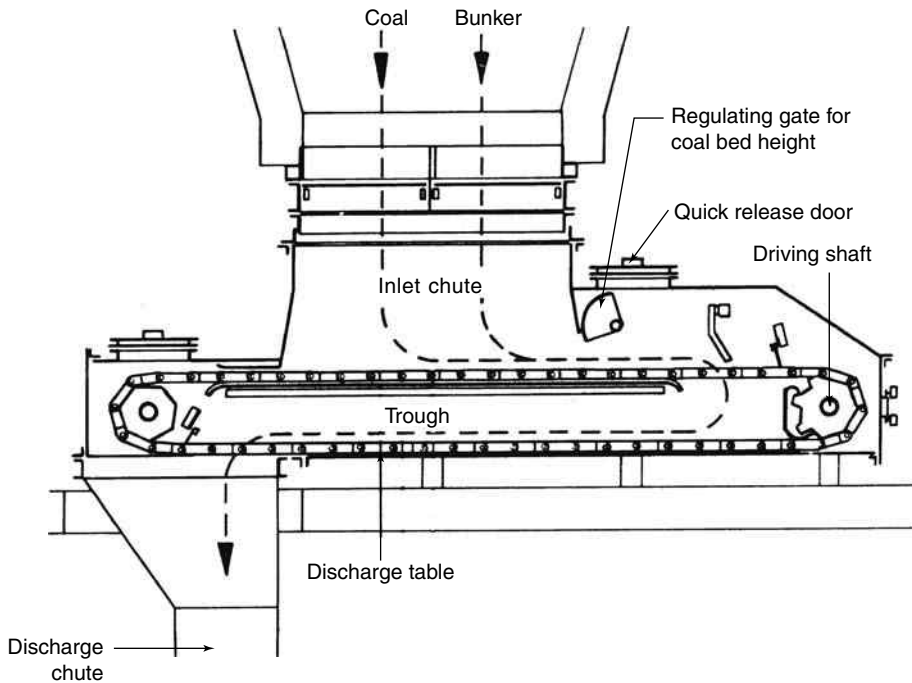


FIGURE 13.4
Drag link volumetric chain feeder.

3.6 m (7 and 11 ft) and widths of 750, 900, 1050, and 1200 mm (~30, 36, 42, and 48 in.). American designers usually prefer gravimetric feeders.

13.3.2.2 Chain Feeders

The drag link chain feeder shown in Figure 13.4 can be described as a pair of forged chains riding on a pair of sprockets on the drive and driven shafts and connected by links to drag the coal. Coal from the bunker, landing on the upper plate, is dragged to the drive end that is away from the mill and dropped to the bottom plate or discharge table. Then it is dragged along the bottom plate to the mill. Usually the feeders come in widths of 600, 800, 1000, and 1200 mm, handling ~40–130 m³/h (30–100 t) of coal.

13.3.3 Mills or Pulverizers

A set of coal mills or pulverizers is the

- Most expensive part of a PF boiler
- Most power-consuming
- Highest maintenance area
- Heaviest single item

The reliability of the milling plant practically governs the availability of the boiler. It will not be an exaggeration to say that the mills are the most important parts of the PF boiler, as they decide the cost, performance, auxiliary power, and layout of the total plant.

Mill duty.

- Grind coal
- Evaporate moisture
- Classify fines
- Discharge acceptable fine powder pneumatically

Modern vertical mills combine all these four functions inside a single housing.

Mill requirements.

- Capability to handle a wide variety of coals
- Accommodation of load swings
- Optimum fineness throughout the mill operating range
- Low wear rates of the grinding elements
- Low noise levels
- Ease of maintenance
- Low O&M costs and low power consumption
- Minimum building volume

Hardgrove index (HGI). The size, output, and performance of a mill are affected by the grindability of coal. Hardgrove index is a measure of the ease of grinding. It should be noted that grinding is not strictly hardness dependent. Fibrous materials are tough and difficult to grind, although they are not hard. The purpose of grinding is to create a new surface by making fines, so that the contact of fuel and air is easy. In other words, grindability involves creation of the new surface.

ASTM D409 describes the test procedure in which a predetermined amount of grinding work is carried out on a prepared and sized sample (<16 and >30 mesh) of 50 g of air-dried coal in a miniature pulverizer. After 60 revolutions with predetermined weights, the ground sample is removed, screened, and checked for the quantity passing through the 200-mesh sieve. A calibration chart determines the grindability of the sample.

The value of 50 is considered neutral, and the mill capacities are usually based on 50 HGI. The higher the value, the easier is the grinding. Hardgrove index has no upper limit. The lower the value, the more difficult is the grinding, and the mill capacity is reduced.

Hardgrove index gives a fairly good correlation for bituminous and sub-bituminous coals between the test and the actual results, whereas for lower ranks, the field and laboratory data differ widely due to fuel moisture. Likewise, for high-ash coals, a mismatch is found because of the possibility of mineral accumulation coming in the way of the grinding process.

There are two designs of mills in modern power stations—horizontal and vertical mills.

13.3.3.1 Horizontal Mills

The two types are:

1. Slow-speed (15–35 rpm) ball mills for hard and abrasive low-moisture coals
2. High-speed (400–750 rpm) beater mills for soft and high-moisture lignites and brown coals

13.3.3.1.1 Ball and Tube Mills

Ball and tube mills were the mainstay of the industry. At present these mills are used for grinding difficult coals, as explained in Section 13.2.1.

Construction. Ball and tube mills are slow-speed (15–35 rpm) horizontal cylindrical drums with coal entry on one or both sides and external classifiers. Double entry mills are two independent mills with a single housing and drive. Besides economy of space and electrical drives, there are additional benefits. In case of feeder failure, the working feeder can double its input, and the output can be maintained at both ends of the mill. Half mill operation is also possible. Figure 13.5a shows a ball and tube mill, while Figure 13.5b shows the isometric view. Figure 13.7 shows how air and fuel enter the mill from the ends.

Grinding action. Forged balls, varying in size from 25 to 100 mm in diameter, are the grinding medium inside the cylindrical casing protected by bolted manganese steel liners, which last several years. About a quarter of the drum volume is filled with the balls. Grinding takes place by a combination of impact and attrition. The mill speed of ~ 0.8 times gravity is chosen so that the balls climb up the drum to some height before falling back to the bottom and pounding coal heavily to break it down to much finer particles. Hard coals need high impact. The slow grinding of the balls aids in producing finer coal powder. It is easy to understand why the wear of the balls is so great. The balls can be charged into the running mill through the ball-charging device without mill stoppage.

Despite longer residence time in the tube mill due to the absence of a fluidized bed such as in the vertical mill to bring about a vigorous mixing, it is not possible to dry the coal

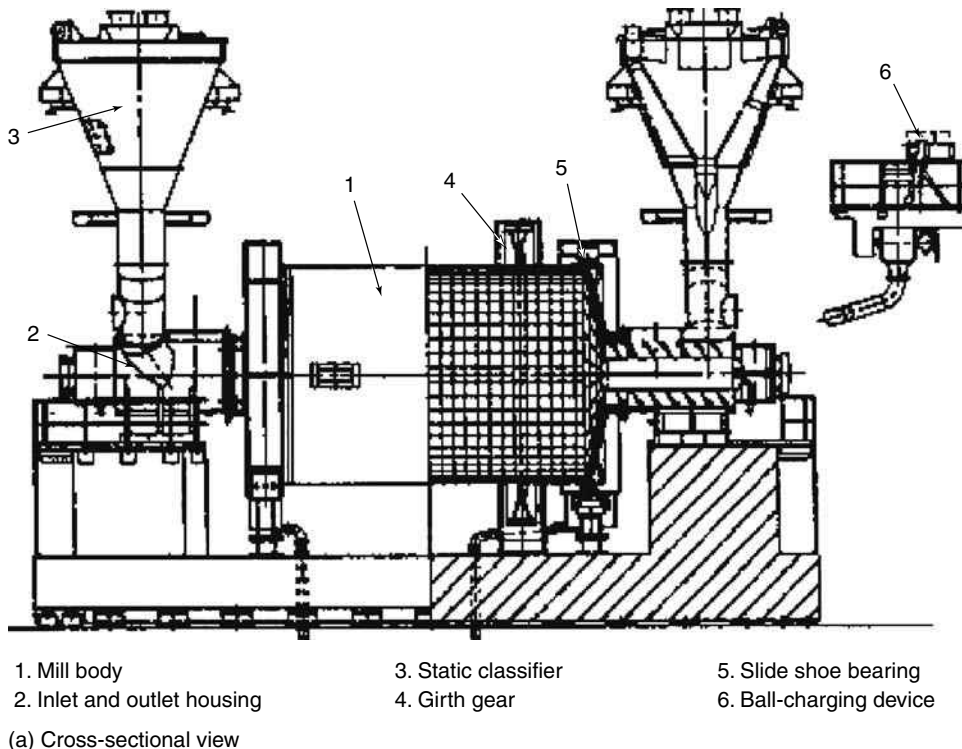


FIGURE 13.5

Double flow ball and tube mill with static classifiers. (From Foster Wheeler Corporation. With permission.)

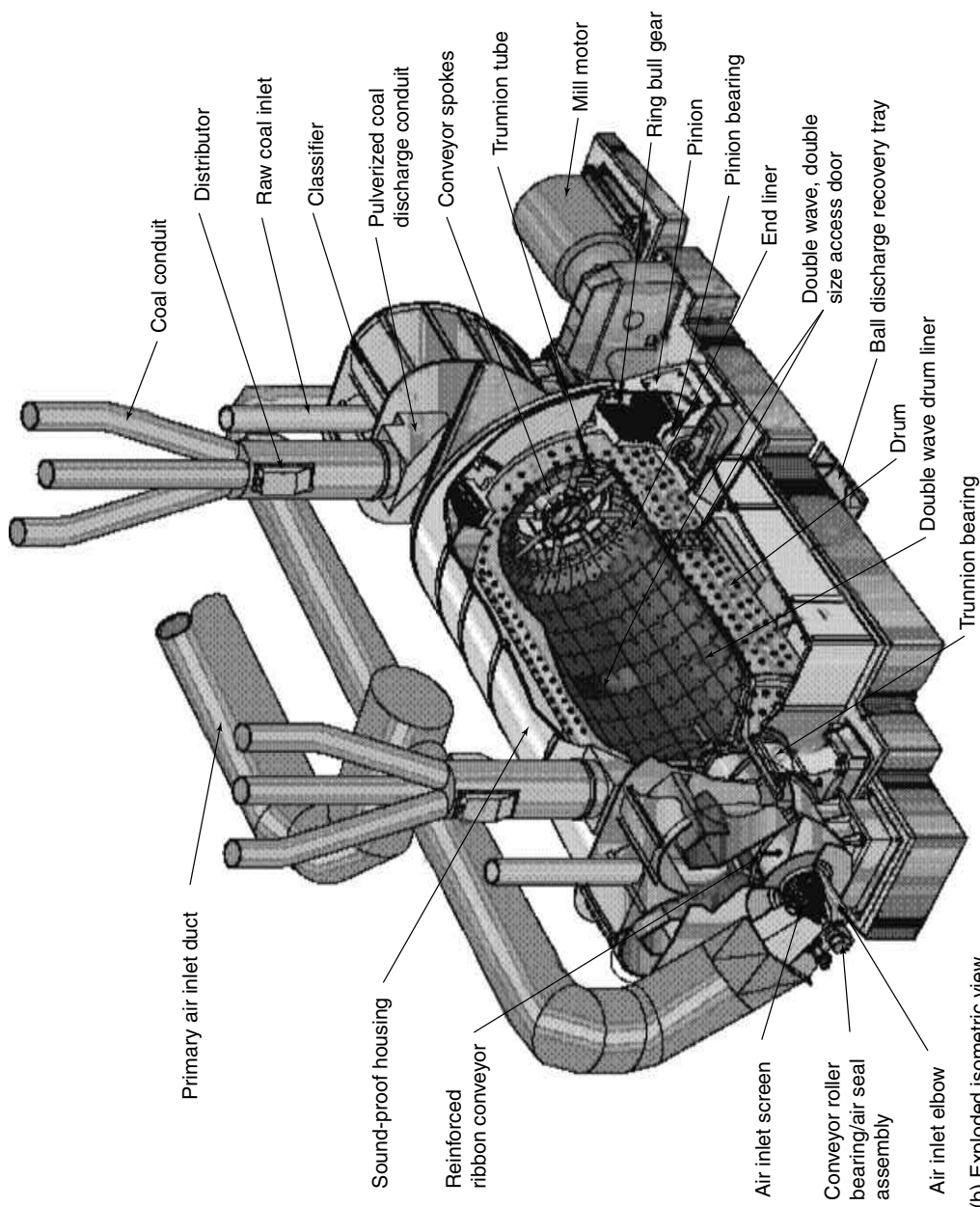


FIGURE 13.5 (Continued)

adequately when it has more than 20% total moisture. Hot mill carrier air, introduced through the central tube of the trunnion, dries the ground coal and carries it through the annular space in the trunnions to the classifiers.

Classification. The double-cone-type classifiers have adjustable vanes to regulate. Classifiers separate the heavy particles and feed them back to the trunnions, where they mix with the incoming coal to reach the grinding zone.

Classifiers are of double-cone construction with wear-resistant liners. Rotating or dynamic classifiers are increasingly employed as the better selectivity returns fewer fines for grinding, thereby reducing recirculation inside the mill.

Mill and bypass air. Total PA, consisting of mill carrier air and bypass air, is boiler load dependent. These two airs are mixed separately from hot and cold airs, as the temperatures are different. The mill air quantity is proportional to the mill load, whereas the bypass air increases at low loads to keep up the velocities in classifiers and coal lines. Because of the large amount of coal inside the mill at all times, it is not possible to control the mill output by feeder speed variation as in vertical mills; however, it is possible by the variation of the mill air. The mill outlet temperature is usually maintained between 90 and 140°C (Figure 13.8).

Mill capacity. The maximum fuel flow of a ball and tube mill is proportional to

- The inner diameter of the mill raised to the power of 2.5 ($d^{2.5}$)
- Length of the mill (L)

The other factors affecting the mill capacity are

- HGI
- Moisture in fuel
- Fineness desired
- Raw coal size
- Ball filling rate

Fuel inside the mill usually sustains about 15 min of firing at its nominal load, compared to ~5 min in a vertical mill.

Mill power. The power requirement of the mill is dependent on the mass of the grinding medium and the speed of rotation. So the grinding power is practically constant irrespective of coal flow and the specific power in kilowatt hours per ton of coal at low loads is excessively high. At low loads, however, the fineness of coal increases, rendering the flame very stable.

The ball charge frequency is increased to compensate for ball wear, a very easy remedy. But the plant should be base loaded lest the power consumption becomes excessive. Figure 13.6 gives an idea of relative power consumption.

Advantages and disadvantages of ball and tube mills. Advantages include:

- High availability.
- Easy maintenance. Only periodic ball charge is necessary. Cast liners last for years. (But they need long downtime for replacement.) The maintenance cost over time is about the same as for vertical mills.
- Constant capacity and fineness.
- No effect of foreign material.
- Large reserve capacity and hence quick response.
- Usefulness for hard and abrasive fuels.

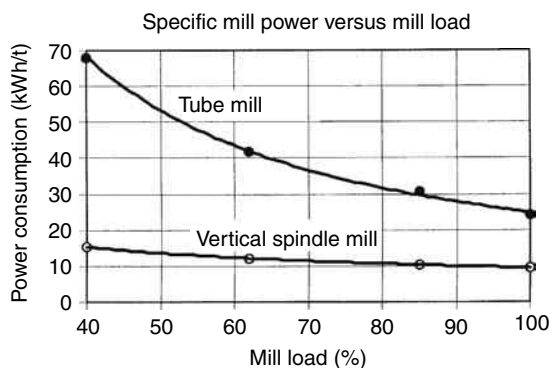


FIGURE 13.6
Variation of specific mill power with mill load.

The disadvantages are as follows:

- High power consumption, more so at lower loads.
- High-moisture coals reduce output drastically.
- Cost of mill and foundation is high.
- More space is required.
- Redundant mill is usually not possible due to cost and layout.
- High noise levels require insulated enclosures.
- Drying efficiency is low.
- They are not suited for intermittent operation due to chances of fire because of the large number of fines and hot balls inside.
- High-power and high-starting torque motors are required.

Ball mills are employed only in certain special applications beyond the capabilities of vertical mills, as already covered in Section 13.2.1.

- Highly dense and slow-burning fuels with low VM, such as anthracite and petroleum coke, for which the grinding calls for higher fineness, typically 80–85% through 200 mesh (74 μm)
- High-ash and abrasive coals for which the mills are required to display a superior wear resistance and provide long uninterrupted working between shutdowns

Figures 13.5, 13.7, 13.8, and 13.9 are adopted from internal documents of the former Deutsche Babcock of Germany.

13.3.3.1.2 Beater Mills

Beater mills beat soft and young coals unlike *grinding* the hard coals into powder.

Milling action. These mills are very different from coal mills, both in operation and in design. These are

- High-speed (400–750 rpm) mills
- Designed to use very high-temperature (as high as 1040°C) furnace gases
- For drying very friable and high-moisture (as high as 70%) lignites and peat

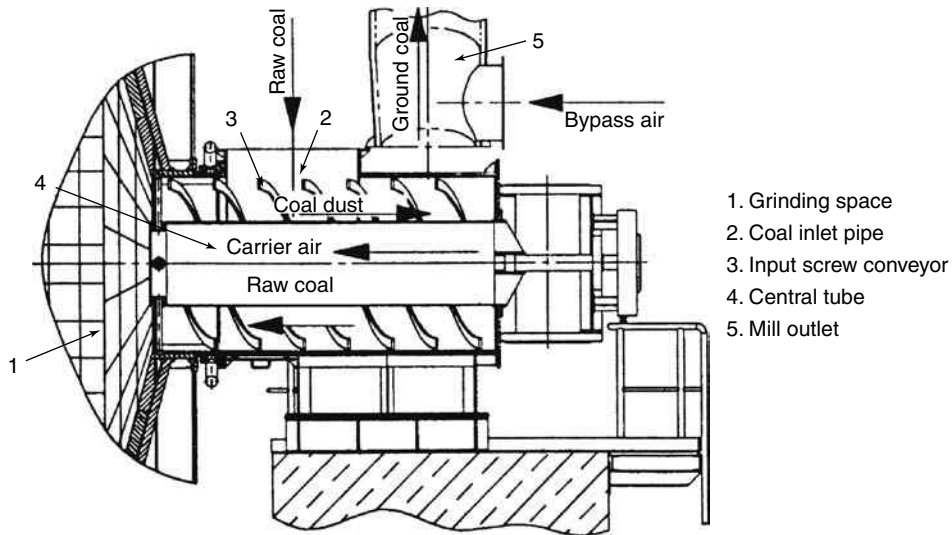


FIGURE 13.7
Air and coal flows at mill ends.

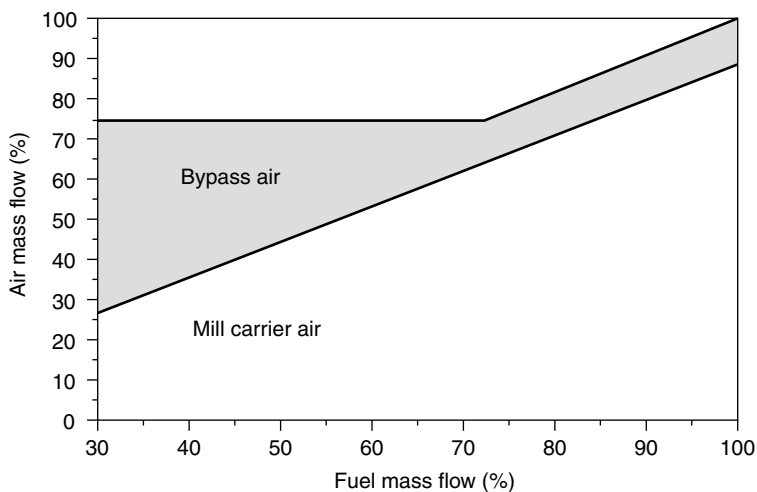


FIGURE 13.8
Mill load versus airflows in ball mill.

Another important difference is that there is no need for impact for these fuels. Attrition is sufficient and provided by a high-speed beater wheel that works as a suction fan and/or attrition wheel.

Flue gas is used for drying and conveying, in preference to air, as the low-rank fuels have high fuel oxygen, making them susceptible to spontaneous combustion.

Mill types. There are two types of beater mills:

1. For medium moisture up to 40% (Figure 13.9)
2. For high moisture up to 70% (Figure 13.10)

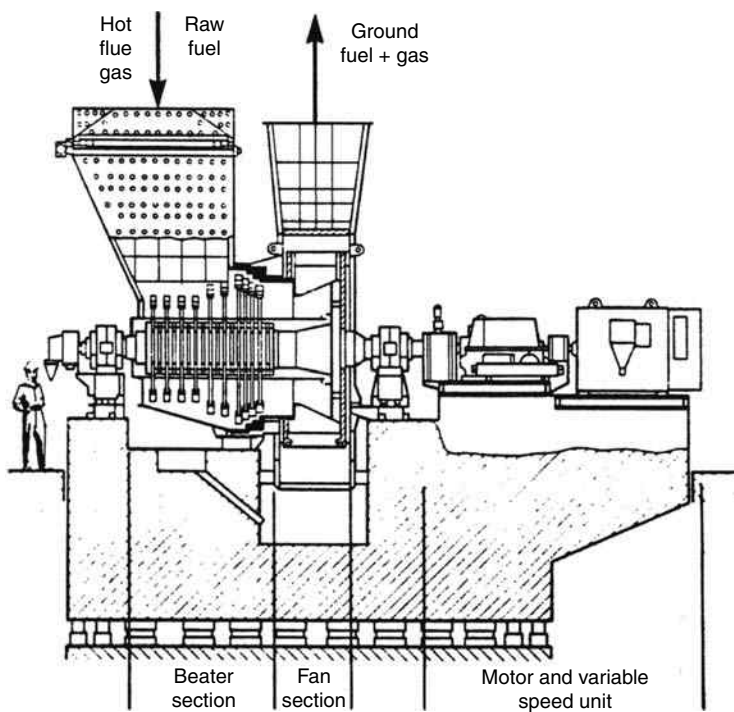


FIGURE 13.9
Beater mill for medium-moisture fuels.

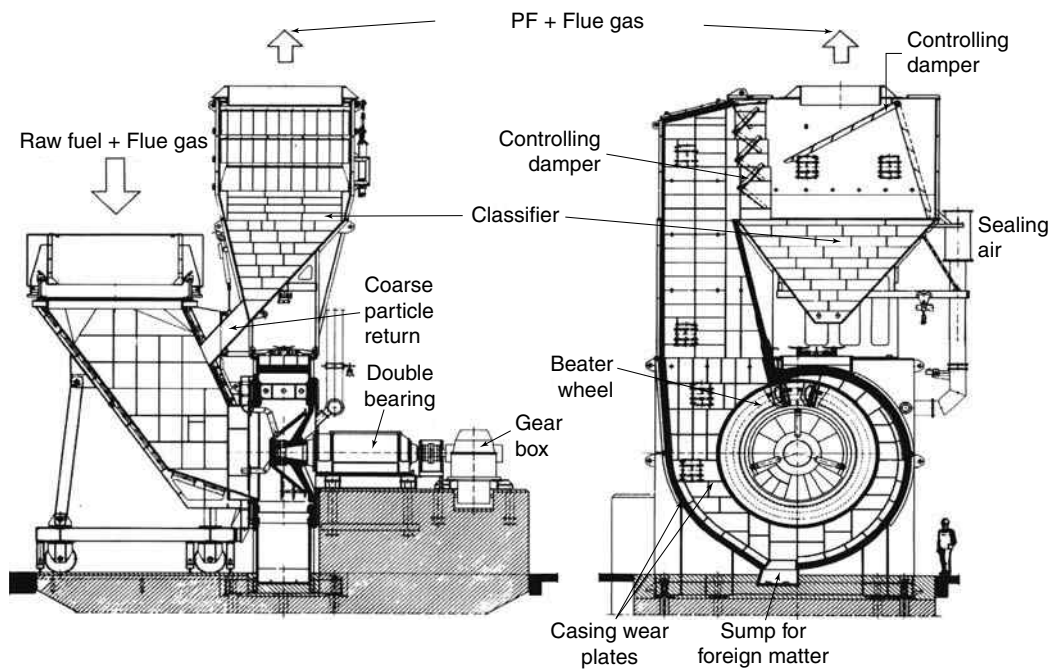
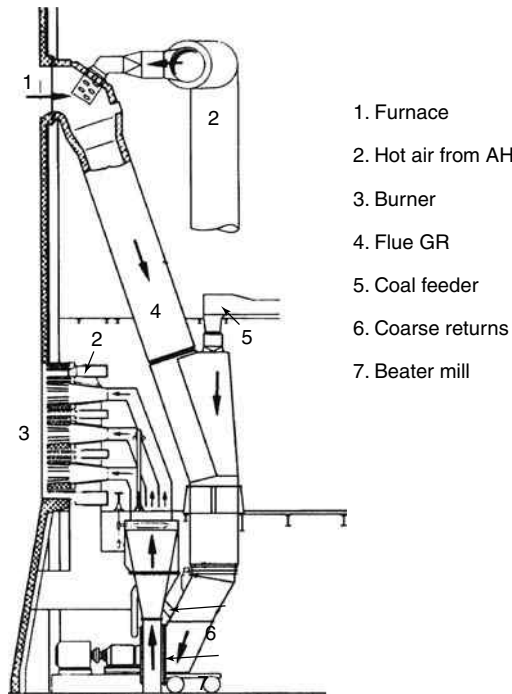


FIGURE 13.10
Beater mills for high-moisture fuels with box-type classifier.

**FIGURE 13.11**

Air and gas arrangement for beater mill.

The latter types are larger and heavier, as the gas inlet temperatures and volumes are higher. On the discharge side also, the pipes are large, as the fuel moisture is converted into steam, which occupies a large volume. On the whole, beater mills are much bigger than vertical mills.

Milling process. Hot gas from the furnace, suitably mixed with air from the AH exit, enters alongside the fuel, as shown in Figure 13.11. There is flash drying of moisture. On contact with the impeller, the fuel is dry enough to disintegrate into fine powder (Figure 13.11). The mill outlet temperature is between 120 and 200°C and the sizing 50–60% through 90 μm .

The classifier on the discharge side returns larger pieces to the inlet. The classifier can be of box (Figure 13.10) or centrifugal type (Figure 13.12). The burner and the type of firing and, accordingly, the need for the inclusion of the classifier determine the fineness.

Mill construction.

1. For high-moisture fuels, the construction features of the beater mills are as follows.
 - a. The impeller is of overhung design, and the inlet box can be withdrawn to permit full access for maintenance.
 - b. Wear liners are installed on the inlet and outlet sides. The impeller is also provided with liners.
 - c. Typically
 - i. The speeds vary from ~750 to 450 rpm.
 - ii. Mills deliver 35–200 tph of fuel of 60% moisture.
 - iii. The mill outlet temperature is ~120°C.

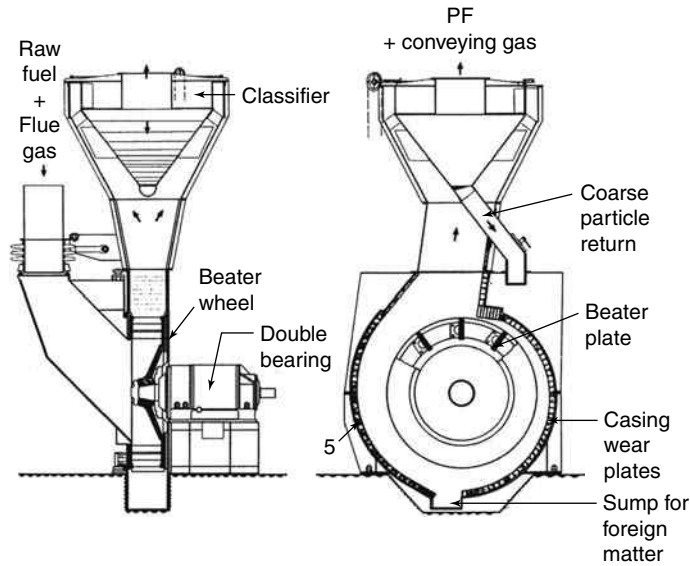


FIGURE 13.12
Beater mill with centrifugal classifier.

- iv. Residue is 50% on 90 μm mesh.
 - v. The wheel diameters vary from 2 to 4 m.
 - vi. The motor sizes vary from 300 to 1600 kW.
 - vii. The specific power consumption varies from 4 to 16 kWh/t.
2. For medium-moisture fuels, the construction features of the beater mills are as follows:
 - a. The mills are smaller and contain fewer rows of hammer wheels in front of the impeller to provide impact to the relatively harder and nutty lignite.
 - b. Classifiers may or may not be present, depending on the firing requirements.
 - c. The rotation of mills per minute varies from 750 to 400.
 - d. Nominal outputs vary from 10 to 90 tph.
 - e. The output is based on an outlet moisture of 12% and HGI of 60% with a product fineness of 25% on 90 μm screen.
 - f. Motor ratings vary from 250 to 2000 kW.

Figures 13.10 to 13.12 are adopted from documents of EVT GmbH of Germany.

13.3.3.2 Vertical Mills

Medium-speed air-swept vertical mills almost entirely dominate the main bituminous coal-firing applications because of their

- Lower power consumption
- Superior dynamics
- Light weight
- Better plant layout

Since they are smaller in capacity, it is also easier to build redundancy to improve plant availability.

Vertical mills in use possess certain distinctive features and advantages.

- These are slow- and medium-speed mills.
- Speed is 20–40 rpm in the larger range.
- Speed is 50–90 rpm in the smaller range.

13.3.3.2.1 Milling Process in Vertical Mill

- The coal feeder discharge spout is connected to the inlet pipe located centrally in the mill and discharges onto the rotating table. Thus the crushed coal of <50 mm size lands at the center of the grinding table at the start of the milling.
- Due to the centrifugal force of the rotating table, the coal is thrown toward the periphery where heavy balls or rollers are hydraulically or hydropneumatically loaded from the top, creating top pressure for grinding.
- Coal, continuing its outward travel, gets trapped between the rollers and the bottom plate and is crushed into powder.
- As the powder spills over to the edge, hot PA, admitted from below into the annular space between the table and the outer casing (throat), picks it up and travels toward the classifier. The throat area must be adjusted to impart a high-enough velocity to air such that all the coal powder is floated upward to form a fluid bed.
- This fluidized bed with its intense circulation helps
 - Dry the coal within a short height of the fluid bed
 - Separate the heavier particles that fall out of the fluidizing zone onto the rotating table.

Thus the primary separation takes place just above the fluid bed zone.

- As the flow continues upward, the height from the fluidized bed zone to the classifiers provides time to complete the drying of the fuel. The two-stage drying, in fluid bed and in freeboard above, is very effective within a short distance, making the vertical mills very good for drying moist fuels.
- Secondary separation takes place above the primary separation zone as the heavier particles drop down due to gravity.
- Tertiary and final separation occurs as the change of direction in the classifier separates the heavier particles and drops them to the bottom plate for further crushing.
- As the powdered coal leaves the table and gets airborne, heavy non-coal pieces, namely stones, shale, and pyrites, fall out of the stream due to density difference in the pyrite chamber. The pyrite plow promptly pushes them into the pyrite box, which is periodically emptied to prevent a fire hazard.

Coal recirculation ratio is the amount of coal in circulation divided by the coal output. The coal–air mixture now leaves the mill for combustion. Figure 13.13 explains the process in detail.

13.3.3.2.2 Mill Control

The feeder controls the output. The mill regulates

1. The fineness of the ground coal

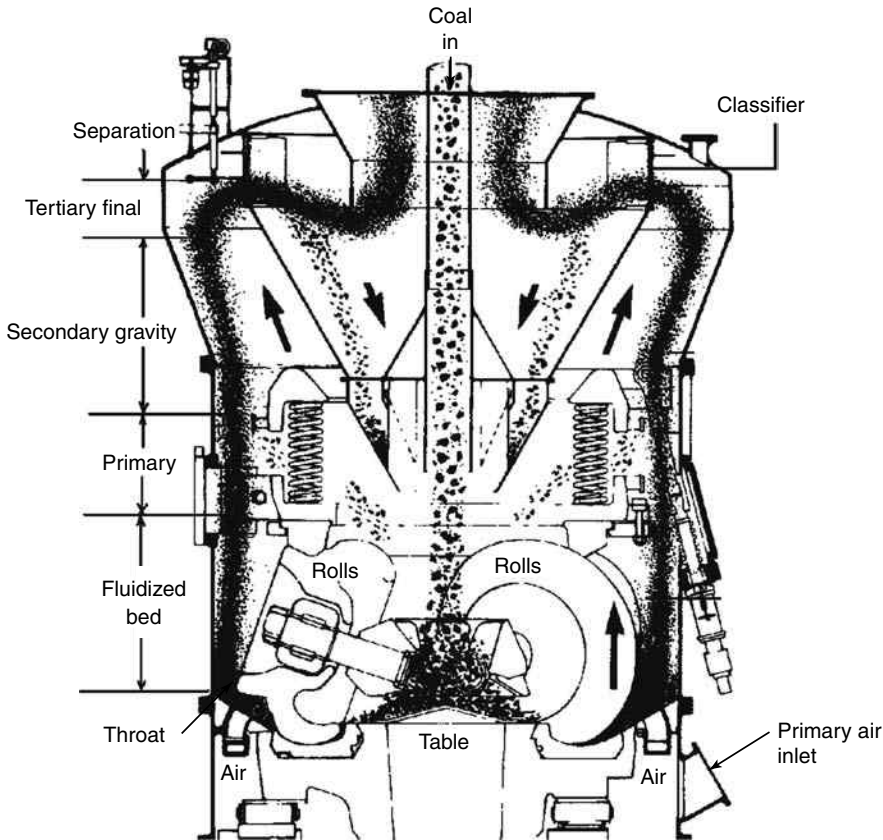


FIGURE 13.13
Grinding process in vertical mill.

2. The outlet temperature of the coal–air mixture

- a. The classifier vane position determines the percentage of fines. Once set, it is not altered, unless a change is required.
- b. Varying the tempering air varies the mill outlet temperature. The variation of the quantity of the tempering air is a continuous process to keep the mill outlet temperature constant for a certain coal.
- c. The usual safe mill outlet temperatures for various fuels are given in Table 13.1. Maximum and minimum mill outlet temperatures are 110 and 66°C (230 and 150° F). The upper limit is set by the limiting temperature of the seals in PF piping and the lower limit by the possibility of condensation of moisture in fuel pipes. The VM in fuel indicates the tendency of premature ignition, which accounts for the lower mill outlet temperature for high VM. These temperatures are adjusted based on actual fuel characteristics and previous experience with the fuel.

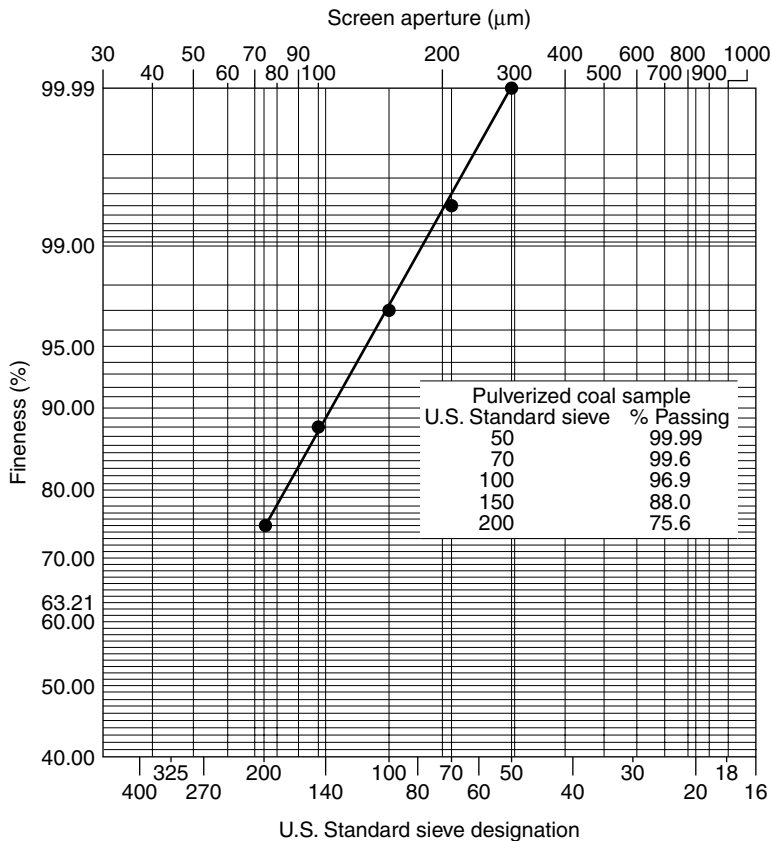
13.3.3.2.3 Mill Performance Parameters

Fineness of the ground coal is expressed as the percentage passing through the specified standard mesh, which is usually 200 for coal with a nominal aperture of 75 μm .

TABLE 13.1

Indicative Mill Outlet Temperatures for Various Coals

Fuel	Volatile Matter (%) Dry Ash-Free	Approximate Mill Outlet Temperature	
		°C	°F
Anthracite	<14	90–100	195–210
Bituminous coal–low volatile matter	14–30	70–90	160–195
Bituminous coal– high volatile matter	>30	60–90	125–195
Subbituminous coal–lignite		52–60	125–140

**FIGURE 13.14**

Ringleman chart.

A Ringleman chart (Figure 13.14) is used to find the particle distribution for the other sizes when any one is specified.

Fineness required in general for various coals (through 200 mesh) is

- Sub-bituminous coals and lignites with high VM 60%
- Bituminous and sub-bituminous coals with normal to high VM 70%

- High-GCV low-volatile bituminous coals with fixed carbon (FC) of 78 to 86 80%
- Anthracites, pet coke, and so forth with FC of $\leq 98\%$ 100%

Approximately $<2\%$ is to be retained on 50 mesh (297 μm).

In suspension firing, it is necessary that the fuel–air mixture contains very fine particles in abundance to ensure instant ignition and rapid burnout. Coarse particles are held to a minimum to obtain the highest combustion efficiency and avoid slagging. Sieve analysis defines these limits based on the experience with coals of various reactivities.

Typically, the surface generated is $\sim 1500 \text{ cm}^2/\text{g}$ of high-VM coal with 80% through 200 mesh. Unless the coarse particles are controlled to less than the specified amount, the intermediate sizes also become coarser, reducing combustion efficiency. The classification of coal comes into picture here. Both the grinding and the classification should be in step to achieve the desired fineness over the whole range.

- The required fineness is decided during operation and depends on the unburnt carbon in ash for a particular coal.
- The higher the fineness, the greater the power consumption of the mill and the better the carbon burnup. Conversely, the mill output drops as the fineness increases.
- With low NO_x burners and when better carbon burn-up rates are desired, the fineness is required to be $\sim 5\text{--}10\%$ higher than normal.

Table 13.2 gives the standard U.S. sieve sizes in microns, sieve numbers and also equivalent BS and Tyler standards.

Moisture. Modern vertical mills can dry coals having a

- Total moisture of 40%
- Surface moisture of 15%

With the inlet air temperature as high as 370°C (with 400°C maximum for design), the residual moisture at the mill outlet is $\sim 20\%$ of the incoming moisture. With regard to fuel drying, vertical mills are much superior to tube mills, despite their smaller dimensions, mainly because of their drying in a fluidized bed. Also, as explained in Section 13.3.3.2.1, the PA quantity is relatively higher in vertical mills— $\sim 1.75 \text{ kg/kg}$ against 1.2 kg/kg at full load. Residual surface moisture in ground coal has unfavorable effects on mill capacity and combustion.

- The mill drying capacity is reduced, as it promotes agglomeration of fines in the grinding zone, disrupting the removal of the fines as fast as they are generated.
- The combustion is inefficient due to agglomerated fines that behave like coarse particles.

The remedy lies in thorough drying of the incoming coal with hot air. If there is a deficiency in meeting the hot air need, the mill output should be limited to the *drying* capacity and not the *grinding* capacity.

Primary air

- Usually the PA used at full load is $\sim 1.75 \text{ kg/kg}$ of coal, sometimes 1.5 kg/kg . This load remains substantially constant, as it is required to dry the coal and convey it.
- This PA quantity is fixed, and it is only the temperature that can be varied as required by the heating need. This is done by varying the tempering air quantity.

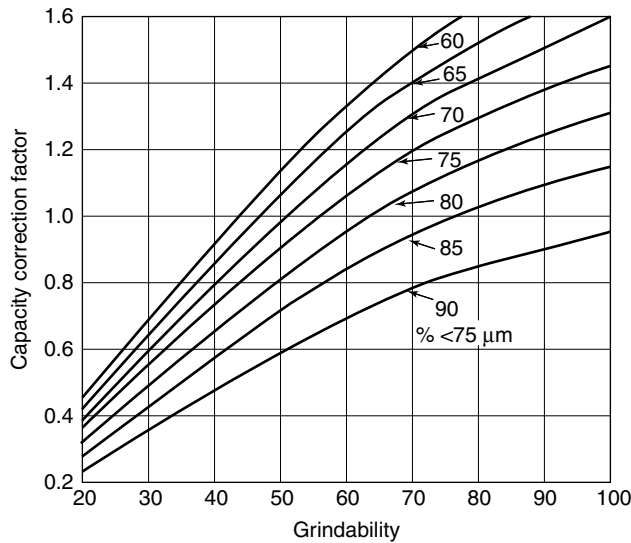
TABLE 13.2

U.S. Standard Sieve Sizes and Equivalents

Microns	Inches	US Standard	British Standard	Tyler
		ASTME 11-61	BSS: 410-1989	
3360	0.1320	6	5	6
2830	0.1110	7	6	7
2380	0.0937	8	7	8
2000	0.0787	10	8	9
1680	0.0661	12	10	12
1410	0.5550	14	12	12
1190	0.4690	16	14	14
1000	0.0394	18	16	16
840	0.0331	20	18	20
707	0.2800	25	22	24
595	0.0232	30	25	28
500	0.0197	35	30	32
420	0.0165	40	36	35
354	0.0138	45	44	42
297	0.0117	50	52	48
250	0.0098	60	60	60
210	0.0083	70	72	65
177	0.0070	80	85	80
149	0.0059	100	100	100
125	0.0049	120	120	115
105	0.0041	140	150	150
88	0.0035	170	170	170
74	0.0029	200	200	200
63	0.0025	230	240	250
53	0.0021	270	300	270
44	0.0017	325	350	325
37	0.0015	400	400	400
32	0.0013	450	440	450
25	0.0010	500	—	500
20	0.0008	635	—	635
13	0.0005	1000	—	1000
10	0.0004	—	—	1250
5	0.0002	—	—	5000
1	0.00004	1	—	10000

- Higher mill outlet temperatures are not desirable because they raise chances of mill fires. Also, coking of carbon particles increases the unburnt loss marginally. Mill outlet temperatures are given in Table 13.1.
- Primary air/secondary air (SA) ratio is widely variable. While PA is required to heat and transport the coal from the mill and remains substantially constant, SA is the difference between the total combustion air and the PA. The total air requirement for coal is dependent on a the VM and FC, and it varies with the rank of the coal on a kilogram/kilogram basis, higher for high-GCV coals. SA/PA ratios can vary as much as ~5 to 2 at full mill load for coals with GCV of 7200–3500 kcal/kg (13,000–6,300 Btu/lb).

Inventory. The internal inventory of coal normally lasts for ~5 min. In ball tube mills, this duration is about 15 min.

**FIGURE 13.15**

Effect of fines and Hardgrove index on mill capacity. (From Babcock and Wilcox Company, U.S.A. With permission.)

Mill capacity. The output of a coal mill is greatly influenced by the coal properties, namely,

1. Grindability (HGI)
2. Moisture
3. Product fineness

The capacity of the mill varies somewhat directly in proportion to the HGI and inversely to fineness, as shown in Figure 13.15. There are three types of mill capacities as described below. The parameters may differ among manufacturers.

1. Base capacity is at 50 HGI, 70% <75 μm (through 200 mesh), and 10% inlet fuel moisture.
2. Maximum capacity is derived for the given coal.
3. Actual capacity of the mill is chosen at 85–90% of the maximum capacity to yield a 10–15% margin.

Mill power consumption based on a fineness of 70% through 200 mesh for coal with 50 HGI, is about 7–8 kWh/t.

13.3.3.2.4 Mill Construction

Casing. Its purpose is to house all internals and contain the dust-laden air. It consists of the shell, the exhauster, and the rejects hopper and is built as per the recommendations of NFPA 85F to ~3.5 atg or 50 psig pressure.

Foundation. The foundation must accommodate three types of forces:

1. Static load of the mill.
2. Dynamic load.

3. Expansion forces on the foundation caused by heating of the mill by the hot PA. This affects the sizing and placement of anchor bolts and concrete reinforcement.

Gearbox

- Mill speeds for big pulverizers vary from 20 to 40 rpm.
- For such low speeds, planetary gearboxes are much lighter and stronger.
- Modern larger mills employ independent planetary gearboxes as opposed to worm and worm wheel-type gearboxes.
- There is no risk of coal powder contamination. The mill shaft is different from the output shaft of the gearbox. Also, there is no large gear in the system.
- The mill outage time is minimized by a spare gearbox unit at the site.
- The gearbox is designed to comply with Antifriction Bearing Manufacturers Association (AFBMA) B-10 life of 100,000 h.

Lubrication system. Modern mills are provided with an external lubrication system to supply cooled and filtered oil to the roller bearings, gears, and thrust pads. The system includes a duplex filter and an oil–water shell and tube exchanger for filtering and cooling the lubricating oil. Starting, running, and stopping functions are interlocked to prevent mill operation without proper lubrication.

Classifier. Situated at the top of the mill, the classifier decelerates the dust-laden air stream and separates the coarse particles. Classifier vanes are adjustable during the mill operation to optimize the fines. The inside of the modern classifier cones is lined with wear-resistant refractory, typically 90% alumina tiles, as a protection from the abrasion of the coarse coal particles.

Mill sealing. Seal air fans are provided to keep the fine dust from leaking from the casing. They are usually designed for 150–200 mm wg above mill inlet air pressure.

13.3.3.2.5 Milling Plant

Mill sizes

- The nominal diameter of the ring or racer or wheel is the prime dimension in a mill.
- In about six to eight ring sizes of ~1750 to 3500 mm (~70 to 140 in.), a range of about 20–100 tph of coal grinding can meet large boiler requirements.
- The diameters of balls and rolls are ~20 and 30–35% of the ring diameters, respectively.
- The motor sizes vary from 120 to 650 kW.
- The mill weight, including gearbox, is 60–250 t.
- Mills of 30 and 45 tph nominal capacity are the most common.

Number of mills. Selection of the number of mills involves balancing the requirements of

1. Redundancy
2. Turndown
3. Worst coal analysis
4. Optimum power

The following norms apply. Providing more mills improves the flexibility, but costs more.

- It is best to choose the smallest number of the largest mills.
- The number of mills should meet full boiler capacity with the worst coal.
- This selection usually takes care of the spare mill requirement when normal and design fuels are fired ($n + 1$ condition).
- Another spare mill may be called for if the normal fuel is less than optimum ($n + 2$ condition).
- The mill redundancy is very expensive in terms of initial cost.
- The operating costs are also higher, as all the components of the redundant milling train must be maintained.
- Tramp air ingress through the idle burners causes a recurring fuel loss.

Improved coal quality may eventually eliminate the need for spare mills.

13.3.3.2.6 Problems in Milling Plant

Wear is the main concern in mills. Wear is a progressive loss of material due to abrasion (sandpapering effect parallel to the surface) or erosion (due to particle impingement at an angle), as elaborated in Sections 3.5.1.2 and 5.8.

In pulverizers, abrasion arises from quartz and pyrite in the incoming coal, particularly for sizes larger than 150 μm . Although there are established procedures for determining the quantities of these minerals, there is no procedure for deciding the particle sizes. The Yancey, Geer, and Price (YGP) apparatus used for prediction has limited value.

Wear due to erosion is on account of the impingement of air streams laden with coal dust. It is higher at high velocity, particle size, and dust concentration.

Grinding elements are naturally subject to maximum wear. Slow-speed mills are inherently superior for wear resistance.

- Time between the overhauls can be maximized if more wear material can be provided in the grinding area.
- Superior wear-resistant materials can be used.

In areas subject to little or no appreciable wear, the parts should be thinned out to keep the weight and the cost in check. Also, selective lining with hard ceramic materials in specific wear-prone areas greatly improves the availability and life.

High ash content in coal is the main contributor for erosion of mill internals, which is further aggravated by high quartz content. The time and costs of mill maintenance dramatically increase.

Mill fires. Precautions should be included at the design stage. Two types of fires can occur in two different areas of the mill.

1. In the air-inlet chamber, which has the highest air temperature, if the coal dust finds its way to the chamber because of low throat velocity or accumulation soon after a mill trip, fire may occur suddenly.
2. In the cooler part of the mill, which has a high concentration of fuel, a fire can slowly simmer over a long time and under favorable conditions, pick up momentum and destroy a mill.

The mill outlet temperature is the best indication of fire, and any variation should be investigated. It is prudent to follow the NFPA 85 guidelines and install a mill-monitoring system.

13.3.3.2.7 Vertical Mills

13.3.3.2.7.1 Ball and Racer Mills Licensed from Claudius Peters of Germany, the former Babcock of United Kingdom developed E-mills for coal-fired boilers. These mills have balls instead of rollers (Figure 13.16).

Milling Process. The construction is similar to a ball bearing. About 9–12 balls roll between a fixed top ring and a rotating bottom ring. A vertical drive shaft is rotated in the range of 30–45 rpm by a motor through a gearbox.

The drive shaft is attached to a table on which the bottom ring is bolted. The top ring rests on the balls, and a downward thrust is applied by a hydropneumatic arrangement. A central coal feed chute with a classifier completes the assembly, which is enclosed in a housing.

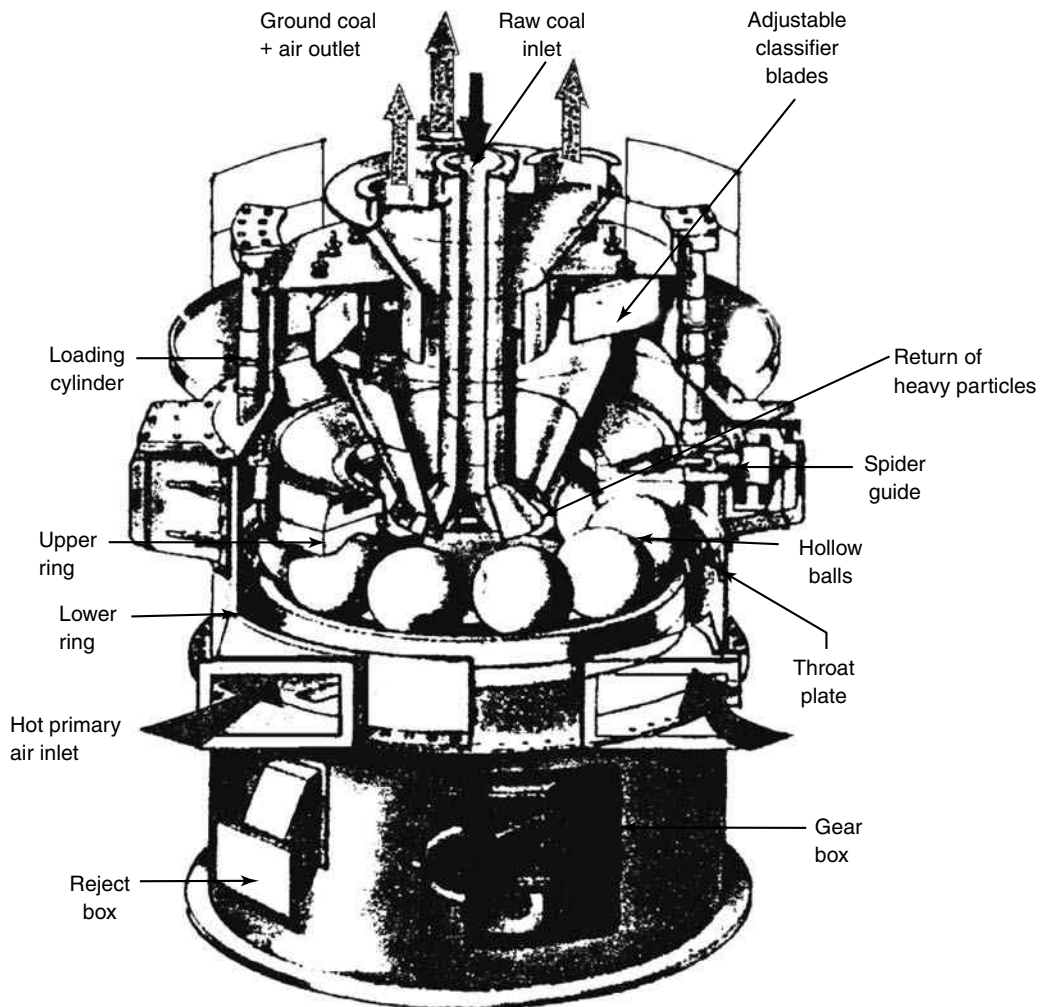


FIGURE 13.16

Ball and racer mill. (From Doosan Babcock Energy Limited, U.K. With permission.)

Advantages.

1. Ball and racer mills require no lubrication for any internal parts.
2. As the balls wear out, a filler ball is inserted to prolong the running.
3. The fineness of the product increases with time.

Limitations.

1. Although the bottom ring is always separated from the balls by a layer of coal, the top ring stays in contact with the top of the balls and tends to wear faster. Usually, more material is provided in this area in the top ring.
2. After size reduction, the balls have a tendency to ride over the adjacent balls. This makes the mill slightly noisier.

13.3.3.2.7.2 Ring and Roll Mills These include bowl mills (Figure 13.17), MPS mills of Babcock Power, roll wheel mills of B&W (Figure 13.18), and MBF mills of Foster Wheeler (Figure 13.19). In all these mills, there are heavy rollers or tyres, usually three, which trap the coal between themselves and the bottom ring. There are some differences in the way the rings, rollers, and loading systems are built.

The rollers or tyres have the maximum amount of wear material on their outer surfaces. There should be a careful matching of the profiles of the rings and rollers so that the grinding is maximized while the wear is minimum. It is possible to selectively add material at appropriate places in the tyres.

The rings and the rollers have bolted sections with superior wear properties, which can be replaced. Since there are only three huge tyres, these mills should produce lower noise levels because of lower peripheral velocities of the tyres.

Figure 13.17 is adopted from a catalogue of EVT GmbH.

13.3.3.2.8 Recent Advances in Vertical PF Mills

Besides the mechanical improvements, the process improvements are aimed at (1) reducing the auxiliary power, (2) increasing the combustion efficiency, and (3) meeting the emission norms. The enhancements such as improved metallurgy, lining the mill for abrasion resistance with appropriate wear-resistant tiles, introduction of independent planetary gearboxes, and improved mill loading systems have already been mentioned. *Rotating throat rings* introduced in the 1980s have reduced erosion of throats, enhanced air distribution, and reduced air resistance as well as increased reliability.

Reducing power consumption makes a boiler competitive, as the milling power is a significant part of the auxiliary power. This can be reduced if the weight of the mill is brought down. Makers have reduced the weight by cutting down the material in areas that do not experience wear and selectively increasing the thickness of the wear parts.

Increasing combustion efficiency is possible by improved coal fineness. But this fineness increase consumes more mill power. By using a rotating *dynamic classifier* the coarse particles on 100 and 52 size mesh are drastically reduced without increasing the fineness of 70% through 200 size mesh using the same power. The unburnt carbon can be as low as 0.5%.

Emission norms. With the reduction in coarse particles, the fuel burns more evenly without excessive flame temperature, which contributes to the lowering of NO_x generation.

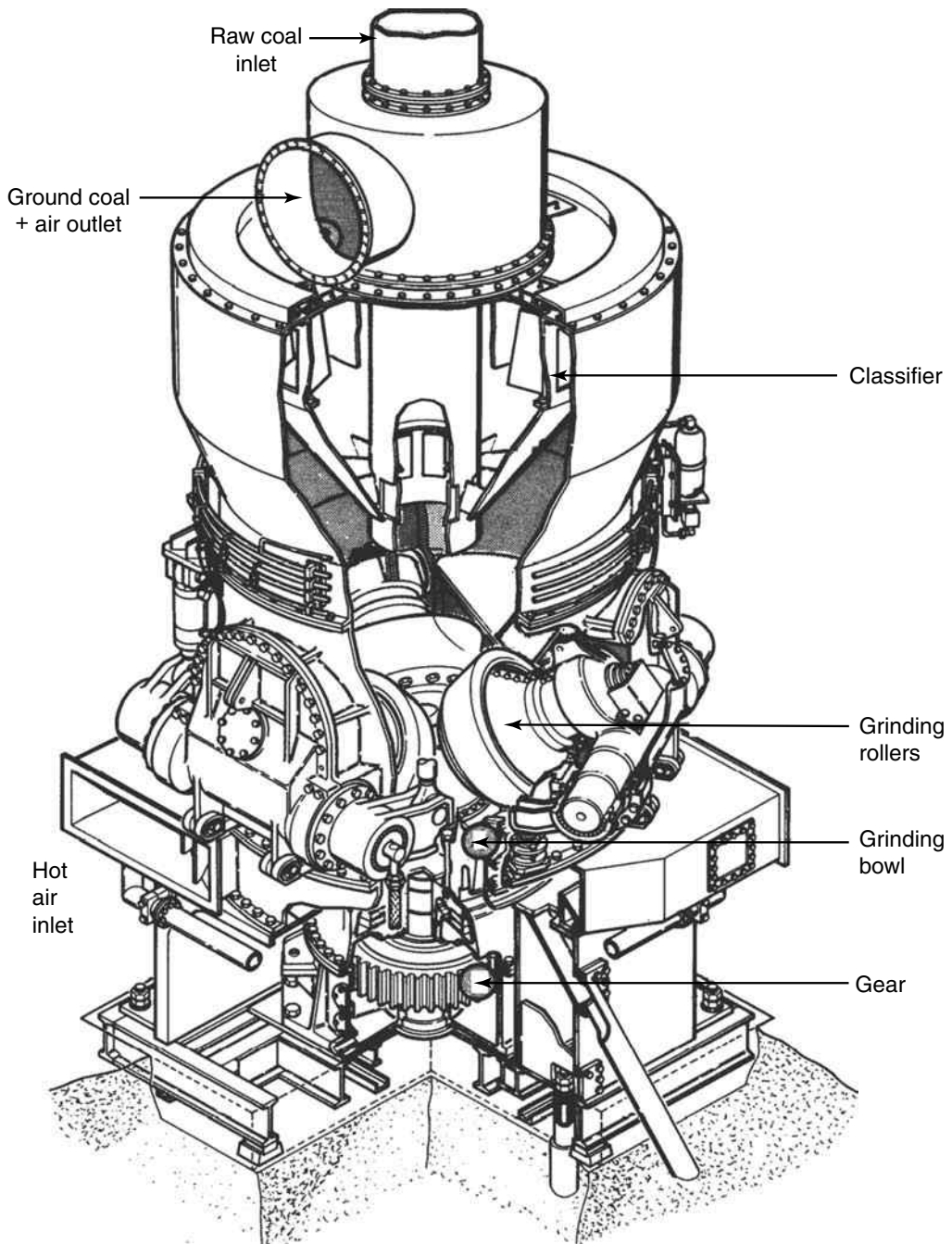
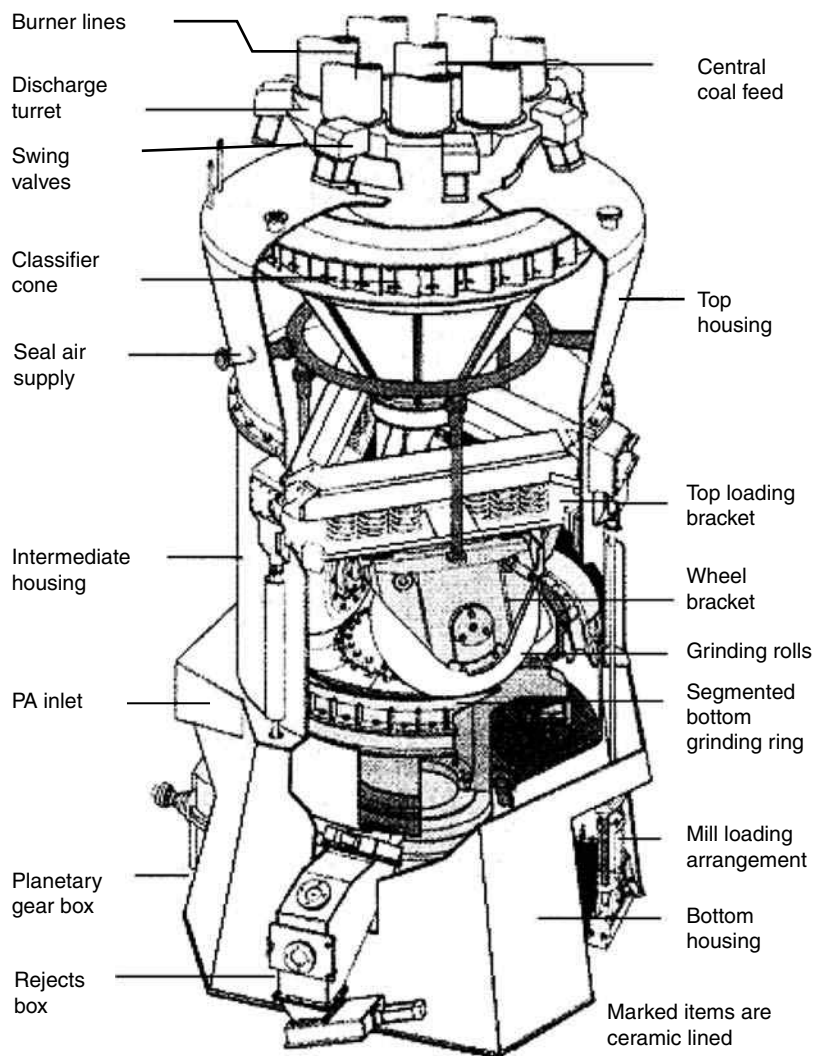


FIGURE 13.17
Exploded view of a typical bowl mill.

**FIGURE 13.18**

Roll wheel pulverizer showing integral ceramic lining. (From Babcock and Wilcox Company, U.S.A. With permission.)

13.3.4 Coal Pipes

Coal pipes carry a PF–PA mixture from the mill to burners along with the moisture of the incoming coal that is heated and dried before grinding. Primary air is constant at ~ 1.75 kg/kg of coal at full load, whereas the moisture varies.

- Coal pipes are usually made of 12 mm medium-carbon steel (CS) pipes.
- Cast basalt is usually provided for lining of bends. With abrasive coals, the lining may be of hard ceramic material.
- Coal–air velocities are very carefully chosen to balance erosion and settling of coal powder in horizontal runs. This velocity decides the pipe sizes and the mill turndown.

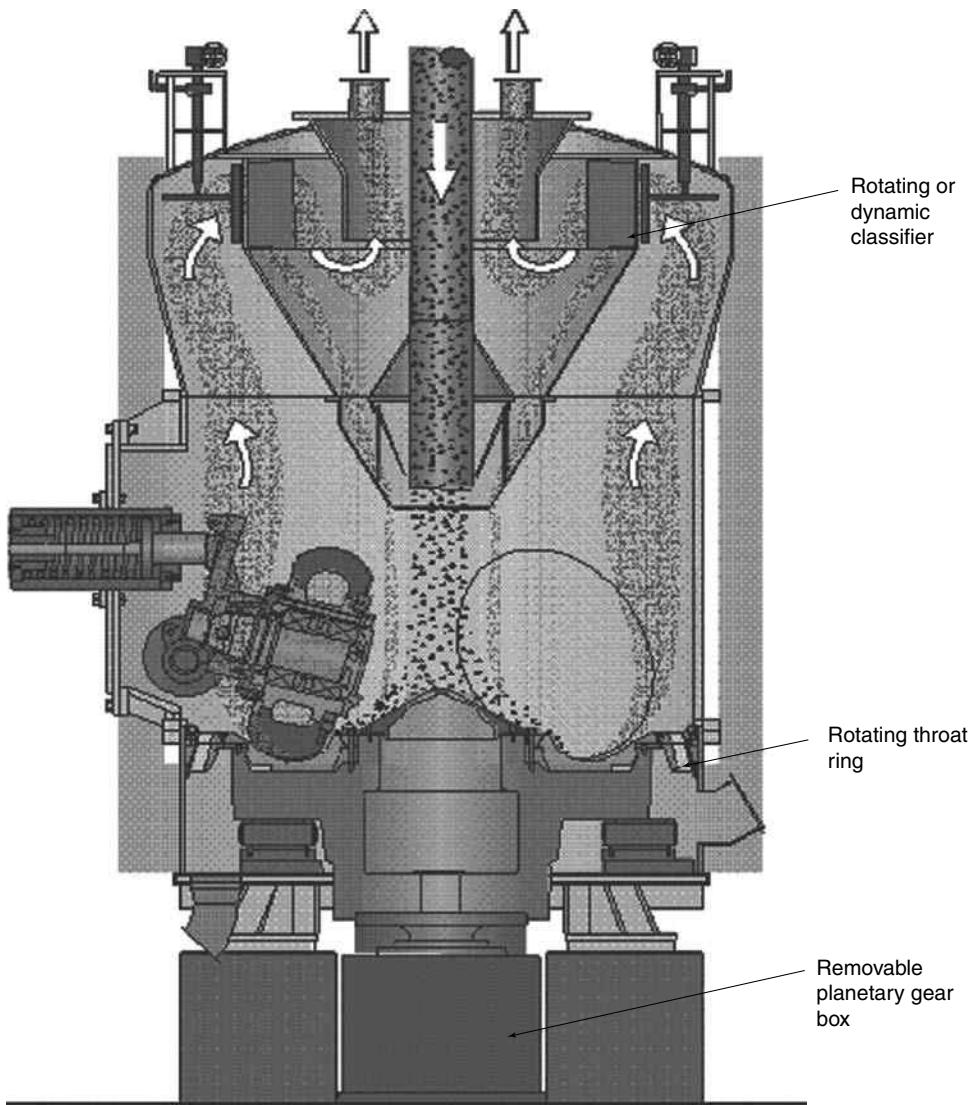


FIGURE 13.19

MBF mill with rotating classifier and throat ring. (From Foster Wheeler Corporation, U.S.A. With permission.)

- For settlement of ground coal, 15 m/s (50 ft/s) is the minimum velocity. To minimize erosion, the maximum velocity is 33 m/s (110 ft/s) for soft coals and 25 m/s (82 ft/s) for abrasive coals, for coal fineness of 70% through 75 μm mesh.
- Coal pipes should be of equal lengths to avoid unequal flow between burners. Typical routings for front-wall-fired and corner-fired boilers are shown in Figures 13.20 and 13.21, respectively. Balancing orifices may be needed to equalize the flow.
- Isolating valves at the mill and burner ends and diverters and splitters in the pipes are subject to heavy wear. A good understanding of the wear of the fittings is necessary to make a proper selection.

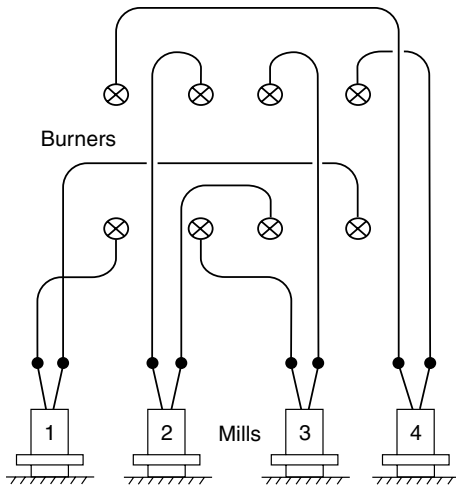


FIGURE 13.20
Coal pipe routing for front-fired boiler.

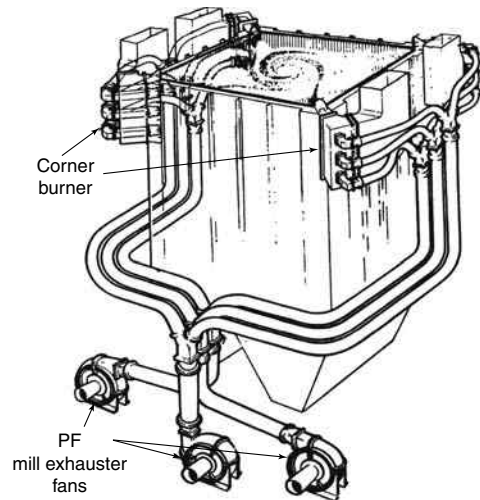


FIGURE 13.21
Coal pipe routing for corner-fired boiler.

13.4 Pulverized Firing Burners

Pulverized firing burners are mounted on the furnace where the PF, PA, and SA come together to get properly mixed and enter combustion. Combustion of the pulverized coal particle starts with immediate flash drying of moisture and devolatilization due to the combination of intense radiation from the flame and convection from the hot gases.

- The combustion of volatiles takes ~ 0.1 s and adds to the heat of the flame and provides heat for ignition as well as combustion of char (the devolatilized FC). Unless VM is in adequate amounts of $\sim 20\%$ on a daf basis, proper ignition cannot be assured.
- The char takes between 1 and 2 s to reach ignition and burn out. For the completion of combustion reactions, (1) the furnace temperature should be sufficiently high and (2) the volume should be adequately large to provide this residence time. Coarse particles larger than $100\ \mu\text{m}$ take longer time to burn out due to higher surface-to-mass ratio.
- Secondary air has to scrub the coal particle to remove the ash layer on the surface and expose fresh coal for burning. The higher velocity of the SA in the tangential firing or rotary motion in circular burners performs this scrubbing action.
- In case of high-ash coals, this scrubbing is even more important, as carbon is trapped within the thick-coat ash particles. Higher carbon loss appears unavoidable.
- The fuel moisture evaporated and transferred to the PA by milling extracts heat from the furnace first to get superheated and dissociated at a high temperature. Thus the fuel moisture has a quenching action and is actually a retardant to the combustion process.
- At more than 40% fuel moisture the normal PF mode of combustion cannot be sustained with coal.
- The brown coals with as high as 70% moisture can be burnt only because of the high volatiles. They require a much higher temperature of flue gas for drying and

a longer residence time for combustion, which accounts for the need for employing corner firing.

Performance requirements of burners. Pulverized firing burners should meet the following requirements as a minimum:

- They should operate reliably with steady flames with no flickering without the need for stabilizing oil or gas support, preferably from 30% load upward. This requirement is dependent on the mill, furnace, and coal pipe sizing as well.
- They should operate with the least carbon loss and minimum acceptable CO and NO_x emissions. CO and NO_x work in opposite ways. Low NO_x gives high CO due to low air and low temperature, and vice versa.
- Stainless steel (ss) construction for heated parts should minimize maintenance.
- Safety is paramount. A good-quality burner management system (BMS) with proven logic and robust components is vital.

13.4.1 Burner Light-Up and Low Load

All PF systems require (1) light-up burners to ignite the coal flame and (2) load-carrying burners to build up the load until the coal firing occurs. The fuel system in a PF boiler is thus very elaborate.

- The main fuel needs include:
 - Fuel gas for igniters
 - Oil for lighting up the main fuel or carrying low loads
 - Main fuel oil support for load carrying and main burner stabilization

In addition, steam or compressed air is required for atomization.

- Light-up burners are usually oil burners using light oils. Since the large PF furnaces are cold initially, only light oils should be used for cold startups. With heavy oils there are chances of formation of pools of unburnt fuel, resulting from the chilling of flames in a cold furnace. When these unburnt oil patches get agitated with hot gases as the boiler warms up, they catch fire and can cause severe explosions. The light-up oil burners are usually sized for ~10% of the boiler duty to enable steam generation in the boiler to provide atomizing steam to load-carrying guns.
- Load-carrying burners may use heavy oils. They light-up burners and build up the load. The load-carrying burners follow are designed for a minimum heat equivalent of the output of a single mill, so that the furnace does not experience a big thermal shock when the mill is cut in. They can, of course, be sized for full duty of the boiler if required.
- Load-carrying burners support the main coal flames at low loads so that they do not flicker. The flickering can occur at low loads when the flame is unstable. The flame extinguishes and reestablishes in which interval a certain amount of fuel escapes unburnt, to explode later. Whenever a mill operates at less than about half of its capacity, load guns are pressed into service.
- Light-up burners are normally pressure or mechanically atomized due to lack of steam at the start of the plant. Alternately, plant air can be used for atomization. However, if steam can be made available for startup, the light-up burners can be steam atomized as well.

- Load-carrying burners are mostly steam atomized.
- The same atomizer can be designed to perform light-up and load-carrying duties.
- A light oil pumping and straining unit upstream of the boiler is required to provide oil for light-up at room temperature. A P&H unit for providing heavy oil at the right pressure and temperature is also needed for load-carrying duties.

13.4.2 Igniters

Igniters or light-up burners must be started with the help of another fuel, which is normally gas that must be ignited by electrical energy. Gas–electric (GE) igniters are common due to their simplicity, reliability, and cost, although another fuel is introduced into the system. Refer to Section 10.2.9 for more details on igniters.

13.4.3 Flame Monitors and Burner Management System

Any burner must be protected from loss of flame by a suitable flame detector. In a PF burner it is normal to have detectors for igniter, light-up, and load-carrying oil or gas flames and the main flames. The flame monitors are integrated into the BMS, which provides for safe startup and shutdown of burners. Unless safe conditions are detected and confirmed, logic does not permit furnace purge, which is followed by light-up in a certain sequence. Likewise, the shutdown requires a safe withdrawal of burners from operation. Guidelines in the NFPA recommendations are periodically amended to incorporate recent experiences. The basics of BMS for oil or gas are briefly described in Section 10.2.4.

13.4.4 Burner Types

Four types of burners cover all ranks of coals:

1. Wall-mounted horizontal circular burners for normal bituminous and sub-bituminous coals
2. Corner-mounted horizontal tangential burners for normal bituminous and sub-bituminous coals
3. Roof-mounted vertical down-shot burners for low-volatile coals, anthracites, cokes, etc.
4. Corner-fired burners for brown coals and peat with high moisture

Circular and tangential burners for normal bituminous coals are the most common ones.

13.4.5 Circular Burners

In a circular burner shown in Figure 13.22, the PF–PA mixture enters the furnace through a central pipe, whereas SA from the windbox is admitted tangentially to give a swirl to the gases. Primary air and secondary air are nearly at right angles to each other so that the fuel particles are scrubbed effectively. The flames are short, bushy, and turbulent. NO_x formation is high, and the modern designs adopt splitting of SA to prolong the combustion. Further, sharing of air around the main combustion zone produces more staged combustion, resulting lower NO_x . A compartmented windbox with independently measured airflow is one of the first ways to reduce NO_x .

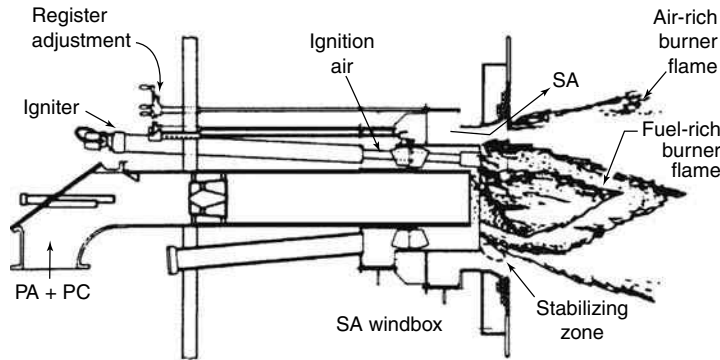


FIGURE 13.22
Circular burner.

- Circular burners are built for heat duties from ~ 15 to 90 MWth or ~ 12 to 75 m kcal/h (~ 50 to 300 MBtu/h).
- They can be placed in one wall or opposite walls for front-wall or opposed-wall firing.
- Coal pipe routing is simpler and cheaper, but the furnace is taller and rectangular in single-wall firing.
- Cost and practice decide the type of wall firing. Normally, for 200 MWe and above, opposed wall firing is employed.
- Bituminous and sub-bituminous coals and lignites with $<40\%$ moisture can be fired in the circular burners.

13.4.6 Tangential Corner Burners

There is no swirling of air in the tangential burners (Figure 13.23). The PA and the SA introduced into the furnace through burners in several small alternate streams travel parallel with no appreciable intermixing. From the four corners of the furnace, the streams travel toward an imaginary circle in the center where a turbulent swirling takes place and combustion is completed as shown in Figure 10.23. Gases make use of the entire furnace to generate a cyclonic motion, thereby providing the necessary scrubbing.

- The burning is relatively slow and even. There are no hot spots.
- During the travel from the burners to the fireball, the coal devolatilizes and partly burns in an air-deficient atmosphere, as the streams do not intermix. This results in a reduction of nearly 50% of NO_x as compared to wall firing.
- A further reduction is obtained when $\sim 20\%$ of total air is provided as OFA at the tops of the burners. This results in stoichiometric conditions in the fireball with no spare oxygen for NO_x formation.

The burner capabilities are similar to those of the circular burners; tangential burners are suitable for a wide range of normal coals, but at both ends of the scale, there are limitations of combusting very low-volatile high-rank coals or high-moisture low-rank

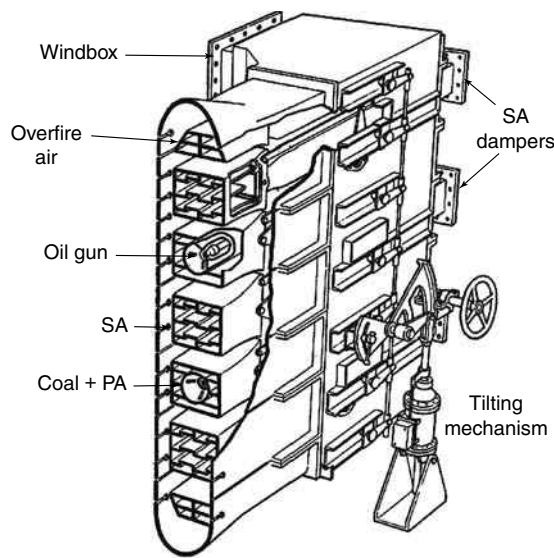


FIGURE 13.23
Tangential burners with secondary air for low NO_x.

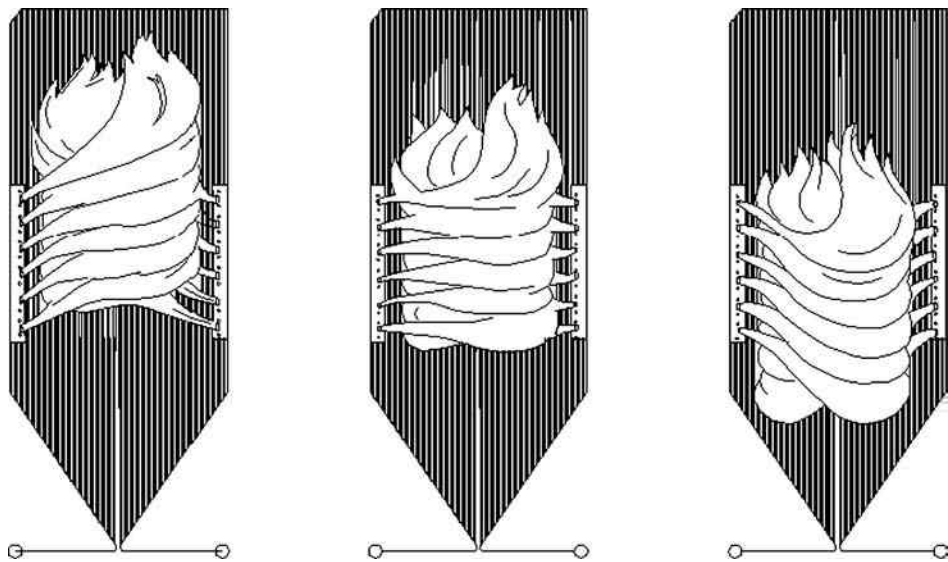


FIGURE 13.24
Flameball in furnace in upper, middle, and lower positions.

coals. However, because of their long travel and residence time, the tangential burners can handle low-volatile coals better than the circular burners. For very low VM, however, the down-shot burners are the only solution.

As these burners use the entire furnace to develop the flames and the fireball, it is possible to move the ball upward or downward to shift the center of heat input to minimize attemperation and compensate for the effects of ash deposits. This is shown in Figure 13.24. A similar provision is available in the wall firing by cutting the top and bottom rows of burners in and out.

TABLE 13.3

Comparison of Circular and Tangential Burners

Parameter	Circular Burner	Tangential Burner
Number of burners	Many	Four sets at furnace corners
Flames	As many flames as burners	One fireball
Flame type	Highly turbulent and mixing, resulting in fast combustion	Slow burning in parallel streams followed by vigorous combustion at middle
Flame shape	Short and bushy	Long and swirling
Furnace shape (approximate)	Rectangular and square in front and opposed wall firing	Rectangular
Furnace height	Slightly taller, more burner area	Burner assembly is compact, height is lower
Coal pipes	Short in front and long in opposed firings	Always long as four corners are to be reached
Hot spots in furnace	Around each burner centerline	No, more heat flux at center of each wall
NO _x generation	Inherently high due to high-speed burning	Inherently low due to slow and staged burning
Altering center of heat input	Possible by inserting top and bottom burners by cutting mills in and out	Possible by burner tilt mechanism if provided or by cutting the mills in and out
Reheater temperature control	Mainly by gas proportioning for divided cage or GR for series cage construction of second pass	By burner tilt if offered

13.4.7 Circular versus Tangential Burners

For most applications, boilermakers offer two designs, depending on their standards. The burning philosophy, arrangement, and effects on the furnace and SH, and attemperator system differ but exhibit no difference in efficiency and performance. Table 13.3 compares these two systems.

13.4.8 Vertical Down-Shot Burners

Down-shot burners, with their long flames, are essentially for low-volatile coals. There are two areas of applications. In both cases, the combustion is slow and the furnace volume required is large. Residence time is typically as high as 3 s.

1. Very low-volatile coals, such as anthracites with dry ash-free (daf) volatile content of 9–13%, do not burn in normal burners, as there are not enough volatiles to raise the flame temperature to the high ignition levels required. Besides, the combustion is very slow, requiring a hot and big furnace.
2. High-ash coals with low volatiles (<20% on daf basis) produce flame instability at low loads, calling for an extended oil or gas support.

Difficult fuels are burnt in down-shot burners. In fact, these burners, also called vertical or arch-mounted burners, were early examples of PF firing.

In down-shot burners, PA and coal are admitted in a downward pattern, with SA also alongside. The burners are mounted on the front and rear arches of the boiler. The flames travel in a U-pattern and join in the central shaft of the furnace. The refractory-lined sloped furnace bottom guides the flame. The refractory inhibits the heat absorption and radiates it back to the flame so that the combustion of char is maximized in the very hot environment. The tertiary air (TA) is provided near the slopes to achieve staged combustion. Fineness is required for good combustion of char.

The burners are actually small jets introduced between the roof tubes. There is no swirling. The ignition takes place due to the radiation of the furnace heat. The good carbon burnout, at best 95%, is due to the

- Long residence time of the flame (3 s)
- Finer grinding (100% through 200 mesh)
- High mill outlet temperature ($\sim 100^{\circ}\text{C}$)
- Reduction of heat from the furnace refractory

Furnaces can fire from one side in a U-pattern as shown in Figure 9.25 or from both sides in a W-pattern as shown in Figure 13.25, depending on the boiler size. In Figure 13.26,

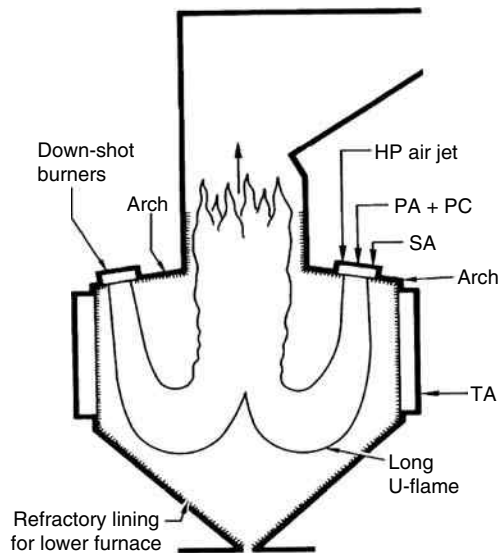


FIGURE 13.25

W-type down-shot firing.

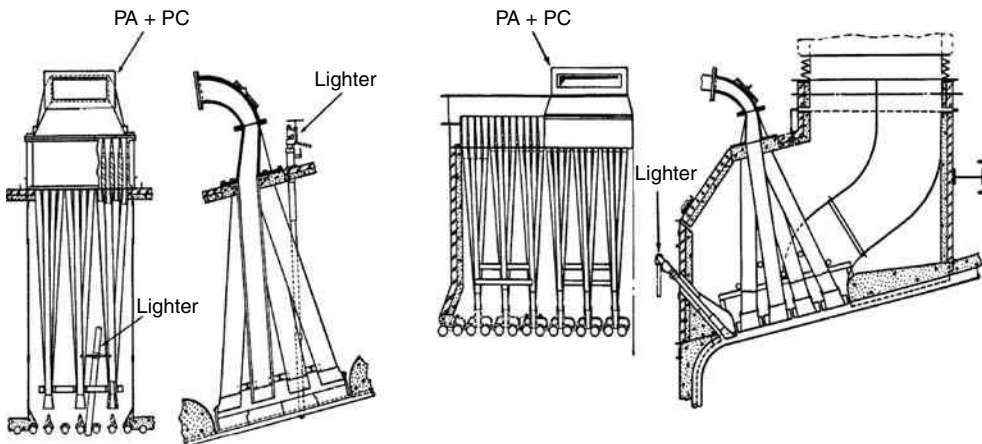


FIGURE 13.26

Down-shot intertube burners for nonabrasive and abrasive fuels. (From Babcock and Wilcox Company, U.S.A. With permission.)

two types of burners are shown for nonabrasive and abrasive coals. The abrasive coal is admitted between the tubes.

The burner stability is outstanding, and the savings on support fuel are high. The installed costs and space requirements of the down-shot boiler are significantly more, and unless the main fuel costs are low or the oil or gas costs are high, this arrangement cannot be justified for normal coals. For anthracites and pet cokes, the flame temperatures due to the burning of char are so high that the NO_x limits are not met in many locations.

13.4.9 Corner Firing

This method is developed for firing high-moisture fuels such as brown coals and peat. For firing of brown coals with up to 70% moisture, very high-temperature gas from the furnace, $>1000^\circ\text{C}$, is necessary for fuel drying, and even then the fuel enters the furnace with $\sim 20\%$ moisture. Getting hot air to such temperature is not possible. Flue gas is better for drying and conveying because its high oxygen content is highly reactive and prone to spontaneous combustion if air is used instead.

The fuel sizing need not be fine: 60% through 200 mesh is adequate. This is because the radiant heat causes an instant flash drying of fuel on entering the furnace, leading to an explosive expansion of water vapor, resulting in the breakup of coarse fuel to fines. The volatiles get released from the freshly created surfaces and burn instantly to provide more heat than that consumed by evaporation of fuel moisture. This excess heat sustains the combustion. The resulting furnace temperature is lower, calling for a slightly longer residence time and turbulence. Firing from corners and creating a cyclone similar to that obtained in tangential firing provides the necessary time and turbulence. Figure 13.27 shows the burner arrangement. A burner-tilting arrangement for steam temperature control is not possible here, due to the burner size constraint. The NO_x is also not very relevant, as the firing temperatures are never high enough due to high fuel moisture. Figure 13.28 shows the temperature profiles and fuel moisture variation in a typical corner firing of brown coal with 55% moisture. The carbon burn-up efficiency can be as low as 0.05% for brown coals.

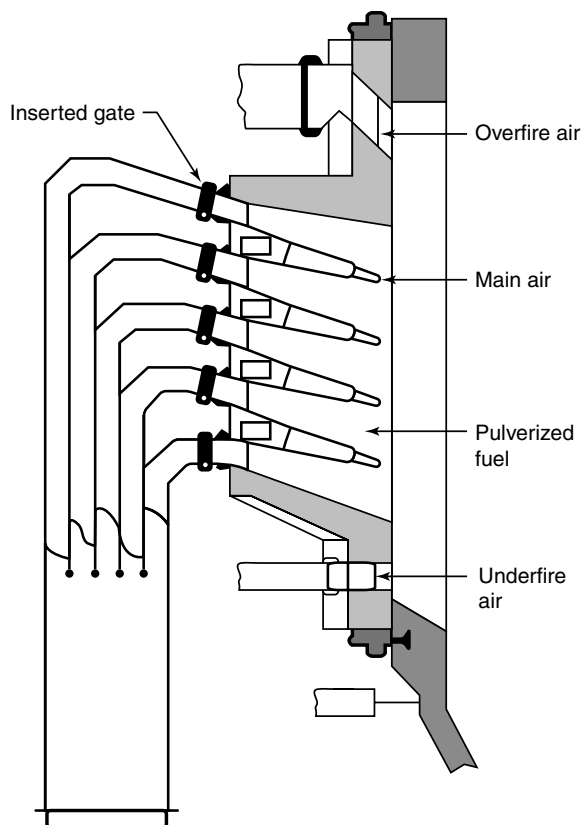
13.4.10 Low NO_x PF Burners

Low NO_x combustion started from the early 1970s. See Section 10.2.8 on low NO_x burners and Section 12.2.3 on denitrification. Conventional circular burners produce maximum heat per unit volume and, in the process, generate high NO_x of ~ 1000 to 2000 mg/N/m^3 (~ 500 to 1000 ppm), whereas the tangential burners produce about half of this amount. Low NO_x burners can achieve ~ 200 – 600 mg/N/m^3 (100 – 300 ppm).

Coals typically contain small amounts of N_2 , ranging from 0.5 to 2%. In PF firing, 75% of the NO_x formed is fuel NO_x and the rest is thermal. Fuel-bound N_2 reacts with excess air at high temperature created by the oxidation of char and forms NO_x . Coals with high VM are NO_x friendly, as they burn faster but at a lower temperature. Fixed carbon in coal acts in the opposite manner and creates peak flame temperatures. The FC/VM ratio indicates the tendency of NO_x formation—the higher the FC/VM ratio, the greater the NO_x generation.

Thermal NO_x forms at temperatures $>1538^\circ\text{C}$ (2800°F). To reduce NO_x , low- NO_x burners, with tangential entry of air replaced with axial flow, are required.

1. Minimize the free O_2 available by minimizing excess air to the burner. This method involves only a careful measurement and distribution of air. This will

**FIGURE 13.27**

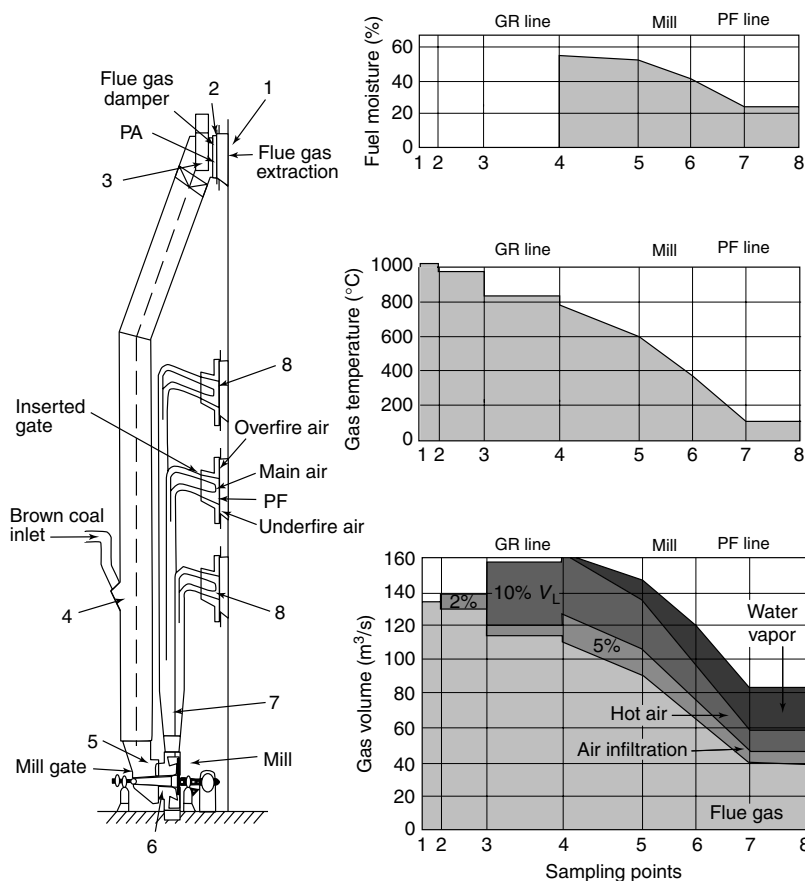
Burner for corner firing of brown coal. (From Babcock and Wilcox Company, U.S.A. With permission.)

also inhibit the formation of thermal NO_x by making free oxygen scarce. About 10–15% of NO_x can be reduced this way.

2. Lengthen the combustion to lower the flame temperature, which retards the reaction by staging the combustion. This is effective for thermal NO_x inhibition.
3. Provide less air at the beginning to create a sub-stoichiometric condition in which C and CO are present, which reduce the NO_x to elemental N and thereby reduce the fuel NO_x level. This is the most effective method in which ~40% reduction of NO_x is possible.

The combination of these three actions reduces the NO_x formation. To minimize the excess air to really low levels, gas recirculation (GR) is used. The fluid mass is maintained for providing a good turbulence, but the air is replaced by the flue gas that has no free O_2 to react with N_2 .

Another popular measure is to reduce the fineness of coal and coarse sizing through the 52 mesh so that the combustion uniform without hot spots responsible for NO_x production. The carbon burnup is also better.

**FIGURE 13.28**

Typical fuel and air property changes in corner firing. (From Babcock and Wilcox Company, U.S.A. With permission.)

13.5 Pulverized Fuel Boilers

13.5.1 Design Principles

Chapter 6 discusses more details.

No boiler is designed from the first step. The previous experiences of the customer, the consultant, and the contractors are required to evolve a new design by modifying a successful model of the nearest size. The fuel characteristics play the most important role. The technical specifications of the client usually capture such details.

13.5.1.1 Furnace

Sizing of furnace has the highest influence on the cost and performance of the boiler. Unlike tube banks, the furnace cannot be altered after its construction. Feedback on the existing units with similar fuels provides more reliable design data when a new unit is planned than any amount of calculation.

With high heat inputs of the modern burners, the furnaces must be fully water cooled with a minimum amount of refractory. Membrane panels have now superseded tube and

tile or tangent tube construction. Membrane bars have to be restricted to 19 mm (3/4 in.) width and should be of 8 mm thickness to withstand the high fluxes of the burner zone.

- Ribbed or rifle tubes are sometimes provided in the high-heat burner zone around the burners when high heat flux may overheat the tube due to departure from nucleate boiling (DNB).
- The furnace plan area must be adequate for full development of flames. Heat release in the plan area is around 3.15 MW/m^2 or $2.7 \times 10^6 \text{ kcal/m}^2/\text{h}$ ($1 \times 10^6 \text{ Btu/ft}^2/\text{h}$) to meet low- NO_x conditions, decreasing by $\sim 30\text{--}50\%$.
- The furnace height from the center of the heat input (with upper burners) to the middle of the furnace exit plane should give a residence time at full load exceeding the minimum residence time requirement of $\sim 1\text{--}2 \text{ s}$ (depending on the coal properties). The residence time depends on the FC/VM ratio and is best derived from the existing operating data. This would translate to a furnace volumetric heat release rate of $\sim 0.1\text{--}0.16 \text{ MW/m}^3$ or $\sim 90,000\text{--}1,350,000 \text{ kcal/m}^3/\text{h}$ ($\sim 10,000\text{--}15,000 \text{ Btu/ft}^3/\text{h}$) for slow and quick burning of coals, respectively.
- The heat flux in the area around burners is more important than the overall furnace heat flux, as this zone is susceptible to DNB particularly in wall-fired boilers.
- The distance from the top set of burners to the tip of nose or the edge of platen is another important dimension to monitor to prevent overheating.
- Since coal is pulverized and fired and the flame temperatures are high, the slagging of ash is to be expected. Wall blowers or wall deslaggers are essential.
- As the boiler grows in size, the furnace volume increases more than the area, leading to a mismatch, and more HS is needed. To maintain area to volume in a proper manner, division walls in furnace are provided. Wing wall and platen SHs also help to meet this need.
- For utility applications, platen SHs are almost always provided in the furnace. Spaced at 600–1000 mm ($\sim 2\text{--}3 \text{ ft}$) apart, depending on the slagging history of the coal, platens are used for heating steam at the lower end of the superheater, so that the metal temperatures remain within limits. A spacing of even 2–2.5 m (6–8 ft) is adopted in very large boilers with severely slagging coals. Platens receive large amounts of radiant heat at the highest temperature. Naturally, they are susceptible to heavy slagging. Ash deposition on the platens is a concern because it would cool the furnace gases to a lower extent, causing the FEGT to increase along with other temperatures and lead to fouling of the SH bank. The platen tubes are, therefore, made in a tangent construction and retractable SBs with high steam discharge capacity are used.
- The FEGT should be lower than the initial ash deformation temperature (IADT) on a reduced basis by $\sim 50\text{--}100^\circ\text{C}$ to avoid fouling of SH. Coal with the lowest IADT should be considered. Extensive experience is needed for estimating the FEGT in large PF boilers, particularly with slagging coals, as there are large deposits of ash on the furnace walls, which impede the heat transfer and raise all the gas temperatures downstream. Tube wall temperature does not influence the furnace size.
- Depending on the boiler size, $\sim 3\text{--}6 \text{ m}$ below the lowest burner, the ash hoppers are constructed with the front and rear walls sloping at $\sim 50\text{--}55^\circ\text{C}$ to the horizontal. A $\sim 1200 \text{ mm}$ gap is provided at the bottom, sufficient for ash to be removed even if it turns into clinker and drops from above, as shown in Figure 13.29.

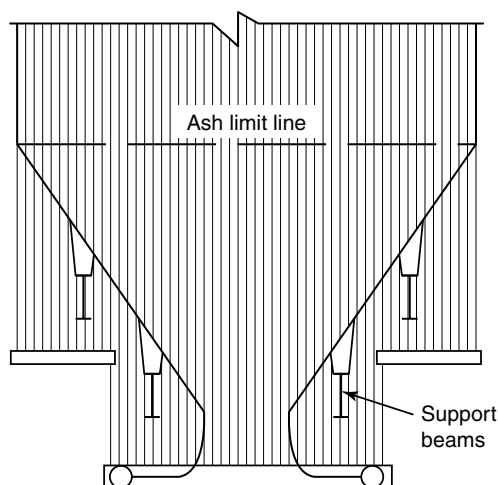


FIGURE 13.29
Ash hopper for smaller boiler.

TABLE 13.4

Minimum Tube Spacing Recommendations in PF Boilers with Coal Firing

Temperature Range (°C)	Heating Surfaces	With Nonfouling Coal (mm)	With Fouling Coal (mm)	Remarks
1000–1300	Platen superheater	550	550	This minimum spacing is for receiving radiation
950–1100	Pendant or horizontal bank	180	300	
800–950	Pendant or horizontal bank	75	150	
<800	Pendant or horizontal bank	50	75	Difference narrows as ash cools

- Water-impounded ash hoppers for bottom ash collection are preferred for high-ash coals because of better reliability, despite slightly higher heat losses due to radiation to the cool water surface exposed to the flames above.
- While wall blowers are for cleaning the furnace walls, retractable blowers are for blowing the ash off the platen and secondary pendants. The steam flows are heavy, as the slag deposits at high temperatures accumulate and grow to large sizes, needing heavy blows for dislodging.

13.5.1.2 SH and RH

The design aspects of SH and RH are as follows:

- Tube spacing is governed more by fouling considerations than the permissible velocities in the banks for most coal-fired boilers, as shown in Table 13.4.
- Generous provision of soot blowers (SBs) and generous sizing of surfaces are essential to deal with the uncertainties of fouling.

- The attemperator sizing must be conservative. Many times 100% margin is provided over calculated values of spray to account for fuel variations and ash deposition on HS.
- For steam temperatures $>500^{\circ}\text{C}$, it is normal to have a two-stage attemperation with second-stage superheating limited to $\sim 100^{\circ}\text{C}$ in SHs that generate convective heat. This gives a more optimum selection of tube materials and lower tube metal temperatures and avoids sluggish control of superheater steam temperature.
- A vertical or horizontal tube bank or a combination of tube banks is used in the PF boilers, depending on whether the boiler is a two-pass or tower type.
- Convective surfaces are designed primarily to control fouling and erosion. The following factors influence surfaces and gas velocities:
 - Base–acid ratio
 - Silica–alumina content
 - Ash-softening temperature
 - Ash friability
 - Presence of chlorine
 - Na and K contents

Those factors decide the temperature level at which gas is admitted to convective surfaces. Thereafter, the spacing is governed by gas velocities, which vary from 10 to 18 m/s (35–60 ft/s), depending on the erosive nature and the ash levels of flue gas. The lower end is for high-ash coals. It is normal to indicate the average gas velocities, and the corresponding inlet velocities to the banks are slightly higher.

Table 13.4 gives the typical minimum clear spacing adopted for fouling and nonfouling coals. If heavy oil is also to be fired along with coal, the spacing recommended for fouling coal is generally followed.

13.5.1.3 Soot Blowers in PF Boilers

Pulverized fuel boilers have the maximum SBs. With fast and intense combustion, ash in fuel melts and deposits after recrystallization in all areas starting from the furnace to the ECON and even the AH. The deposits are in molten stage in the furnace, semimolten in SH and RH banks, and friable in the ECON and AH, needing different types of blowers. In a PF boiler, all types of blowers are required (Figure 8.57).

13.5.1.4 Back-end Equipment

- Both ECON and AH are required as back-end equipment in PF boilers.
- Plain tube horizontal ECONs are more effective than the extended-surface ECONs with erosive coals.
- Sufficient SBs are necessary due to accumulation of fluffy ash that is easily blown away.
- Tubular AHs are popular in the lower sizes where space is not at premium.
- For larger sizes and space limitations, the vertical rotary AHs are popular.
- Airheaters are sized to meet the hot air requirement of the mills for the most moist coals at the coolest time.

13.5.2 Fuel Flexibility

Pulverized fuel boilers have good fuel flexibility, but there are limitations too.

- Normal hard coals are ground to powder and fired. They will burn as long as there is
 - Adequate VM to overcome the cooling effect of the moisture to provide ignition
 - Flame temperature high enough to sustain combustion
- Low-volatile fuels can be burnt in down-shot and T-firing, which provide prolonged residence time to complete the combustion.
- Certain fuels cannot be burnt in a PF boiler, as there is no inventory of heat to dry the fuel or sustain the combustion:
 - Very wet fuels or high-ash fuels or wet and ashy fuels with more than 65% ballast or burden
 - Fuels having <2000 kcal/kg of GCV

Slurry or washery rejects are some examples.

- Lignite, brown coal and even peat are very efficiently burnt in PF boilers despite high moisture because of their high VM that sustains the flame temperature. Also they are not hard and are not strictly grindable. They are very friable and break down on losing some of their moisture and break into fine powder on heating due to the explosive force of the flash drying of the moisture. Thus they are easy to burn in PF form.
- When fuels are stringy and not capable of reducing to powder form, PF firing fails. Most biofuels fall in this category. Hard and uniform-sized fuels such as rice husk have been burnt in PFs. The milling and firing equipment has to be different.
- Municipal refuse and sludges from paper mills are too moist and low in calorific value (CV) and not amenable to grinding.
- Very erosive fuels such as coke breeze are not friendly to PF firing because they are too aggressive on the mills, piping, and burners and contain very little VM.
- Very high sulfur-bearing fuels such as some coals and petroleum coke are difficult to burn safely, as the tubes cannot be protected against corrosion. In FBC, the same fuel is safe, as the in-bed desulfurization removes sulfur and renders the gases noncorrosive.
- A PF boiler is designed to be fuel specific. Thereafter, its ability to accept fuel variation is limited by the configuration of AH, milling plant, and firing equipment.

In a boiler designed for low-ash high-GCV coal, if high-ash coal is to be burnt, the mills cannot handle the fuel quantity beyond a certain point, and this may limit full firing of fuel.

In the reverse case of firing, low-ash coal in a boiler designed for high-ash coal, the milling can be done with fewer mills, but the burners cannot handle the high heat input,

creating the possibility of slagging around the burner area. If the fuel moisture exceeds in a significant way, the AH outlet air temperature can be a limitation.

13.5.3 Co-Firing of Fuels

- Co-firing of oil and gas is possible because the PF burners can easily accommodate these fuels. Even lean fuels such as blast furnace gas (BFG) and coke oven gas (COG) are burnt in addition to oil as auxiliary fuels in many boilers in trifuel burners in steel plants. Besides the ease of burning, the furnace and other HSs are also amenable to this co-firing. The only precaution is to increase the free space between tube banks, mainly in SH, to reduce the chances of fouling, as the sticky oil ash left on the tubes can create good surfaces on which the coal ash deposits can grow. Also the eutectic formed by the ash of coal and ash of oil generally has a lower melting point, making slagging and fouling a good possibility, if the furnace is marginally sized.
- Co-firing of sized biofuels can be done to an extent. Low ash melting of the ash eutectic is the limiting factor on the amount of auxiliary fuel burnt. The biofuels are not fired in the burners but rest above them in suspension. The fuel must be high in HV, capable of burning out substantially in the upper furnace.
- Co-firing of biofuels is gaining greater acceptance as a solution for waste fuel burning and to reduce NO_x and SO_x from the plant.

13.5.4 Boiler Turndown

- Seamless or stepless turndown of the PF boiler is limited to ~70% maximum continuous rating (MCR). It can be stretched to ~50% by cutting out mills progressively. Below that level, oil support is necessary for protection against flame flicker.
- Turndown of an individual mill is limited to ~50% of its base capacity, governed by the minimum air velocities inside the mill for transport and drying of fuel.
- The coal pipes also influence the turndown, as the minimum air velocities are to be maintained for the fuel to remain airborne. Fuel separation is easier in the horizontal runs.

13.5.5 PF Boiler Layouts

Modern boilers almost always work with direct and pressurized firing.

13.5.5.1 Boiler Types

The most popular types of boiler arrangements are as follows:

- Two-pass boilers for coals and lignites with wall or tangential firing.
- Single-pass tower-type boilers mainly for brown coals and peat with corner firing. They are also used with wall or tangential firing.
- One and a half-pass boilers for coals that are not too aggressive such as high-ash or highly slagging coals that require large surfaces in the SH and RH.
- Down-shot boilers for very low-volatile coals and anthracites.

13.5.5.2 Mill Types

As discussed in Section 13.3.3, the three types of mills for direct firing are:

1. Vertical mills for coals
2. Beater mills for high-moisture fuels such as lignites, brown coals and peat
3. Ball or tube mills for high-ash or low-volatile coals for substantially base load operation

13.5.5.3 Layouts

There are certain standard layouts for power plants, and they are planned around the milling and firing functions.

- The classical layout is to locate the mill and bunker bay between the TG hall and the boiler.
- In plants burning high-ash coals, the mill and bunker bay may be located after the boiler toward the ESP side. This helps to keep all the dirty plats away from the clean TG hall and the control room. The mill vibrations are also kept away from the control room.
- In opposed firing and tangential firing, it makes sense to have mills and bunkers on either side of the boiler, which reduces the length of coal pipes and the overall length from boiler to chimney.
- In corner firing, mills on each side minimize the hot suction ducting and mill piping. This is at the expense of long fuel feeders inevitable with this layout, as the fuel bunker is usually placed between the TG hall and the boiler.

13.5.6 PF Boiler Designs

Pulverized fuel boilers can be categorized as:

1. Industrial and small utility
2. Large utility

Industrial PF boilers, which range from 100 to 400 tph, or 25 to 100 MWe, have practically been superseded by CFBC. Hence reheat and nonreheat models covering 100–250/300 MWe fill smaller utility and larger industrial needs. Large aluminum and steel mills adopt PF boilers for their efficiency and reliability.

The larger utility boilers (500 MWe to 1300 MWe) are still undergoing improvements. Supercritical (SC) and ultra-supercritical (USC) boilers can be economical only in this range. Higher efficiencies, new materials, and the emerging environmental issues need to be addressed in this size range.

Figure 13.30 shows an industrial PF non-RH semi-outdoor bidrum boiler with corner firing and the rotary AH. Designed for high-ash coal, it has four mills, including one standby. Tangential burners are used. Design pressure is <140 bar and a bidrum construction is used for BB. The SH temperature control is by a combination of attemperator and burner tilt. The arrangement is compact, with all surfaces accommodated in two passes. This is

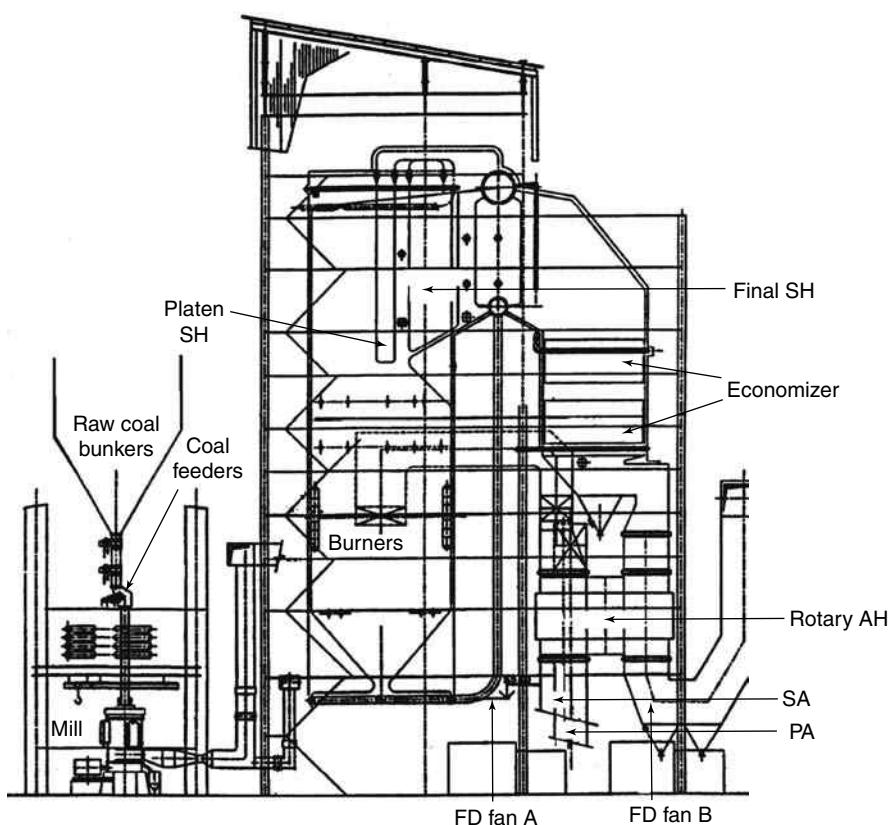
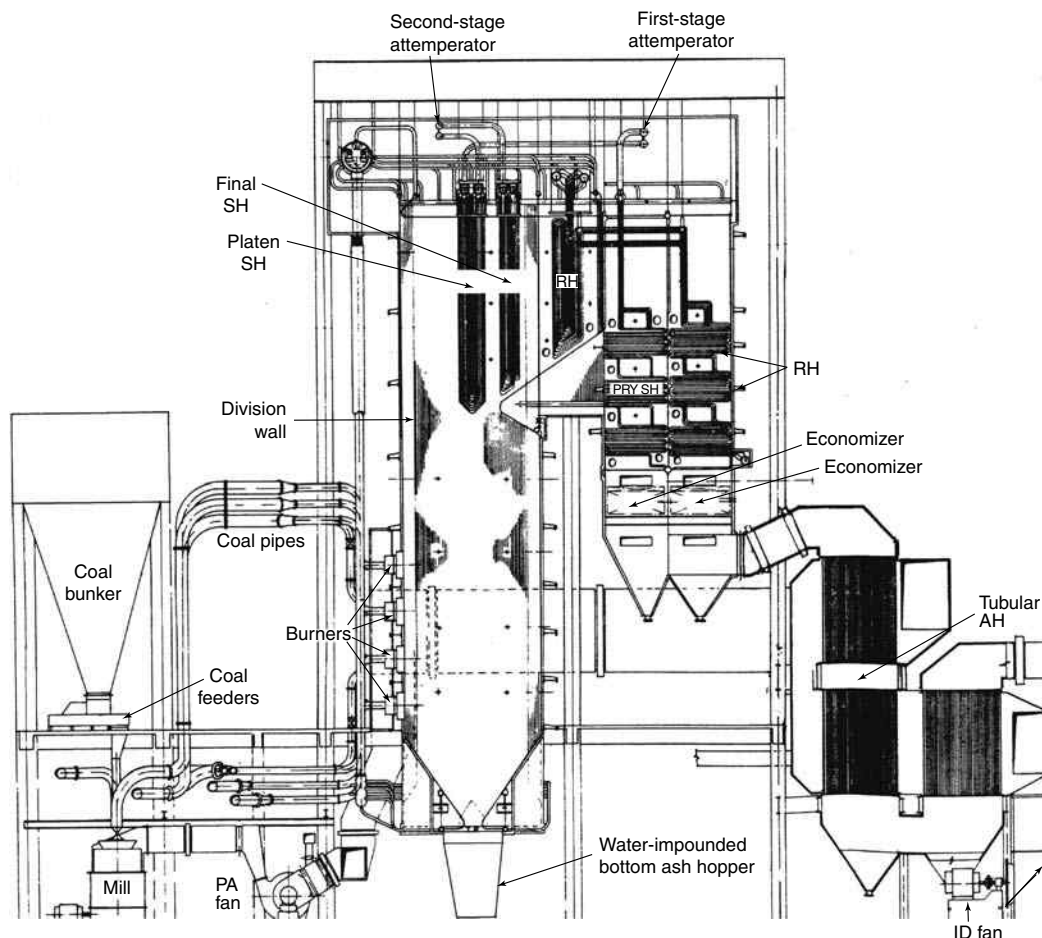


FIGURE 13.30
Typical 75 MWe (270 tph) corner-fired PF boiler.

made possible by the rotary AH, which snugly fits under the ECON. With a tubular AH, the arrangement would have demanded a third pass.

Figure 13.31 depicts a typical 210 MWe or 680 tph RH boiler with front-wall firing and a large tubular AH for high-ash coals. Normally, six mills are employed. Front wall firing is adopted. In double-wall firing, the furnace would have been shorter but deeper. This is a classical twin rear-pass design with RH and SH located in different passes, with dampers to bias the gas flows. The RH temperature is controlled by regulating the gas flow in the RH pass, whereas the SH temperature is controlled by a combination of spray attemperation and selection of burner level. A division wall is employed to increase the furnace surface without correspondingly raising the furnace volume. A combination of platen and pendant SHs is used for achieving the final temperature. A two-stage attemperator is employed to give a good turndown with a wide range of coals. Oil firing is limited to startup and load stabilization only at 25% MCR capacity.

Figure 13.32 shows a typical tower-type boiler for lignite firing with four beater mills. Unlike coal-fired boilers, it is usual for lignite and brown coal-fired units to have the four mills at the four sides or corners of the boiler. It is normal for high-moisture lignites to adopt tower-type furnace construction with no gas turns on the convection banks to

**FIGURE 13.31**

Conventional two-pass PF boiler with twin rear passes and front firing and division wall.

minimize erosion. With tower-type design, all the banks are fully drainable. This construction also facilitates the layout of mills. Hot gas for lignite drying and transport is drawn from the furnace exit. Only the AH is in the second pass. The bunkers are rather small in these boilers, with ~5 h of storage capacity to prevent spontaneous combustion of fuel common with lignites.

The feeders are plate type and not drag link, as the fuel tends to break very easily. In plate feeders, the fuel is carried on the plates and not dragged by feeder slats.

Figure 13.33 depicts a 500 MWe 1600 tph boiler for coal firing, with highly abrasive ash at a pithead location. Horizontal ball mills are employed for a better life, as mill wear is a serious concern with alpha quartz in coal ash here. High mill power consumption is countered by using the plant at base load, with little fluctuation on the lower side. For the same reason of erosion, the tower-type construction of pressure parts (PPs) is used. Subcritical once-through (OT) design pressure conditions achieve slightly better cycle efficiency.

The 660 MWe SC OT boiler, shown in Figure 13.34, is a conventional two-pass design with opposed firing. Vertical mills, typically 10 in number, are arranged in two rows on

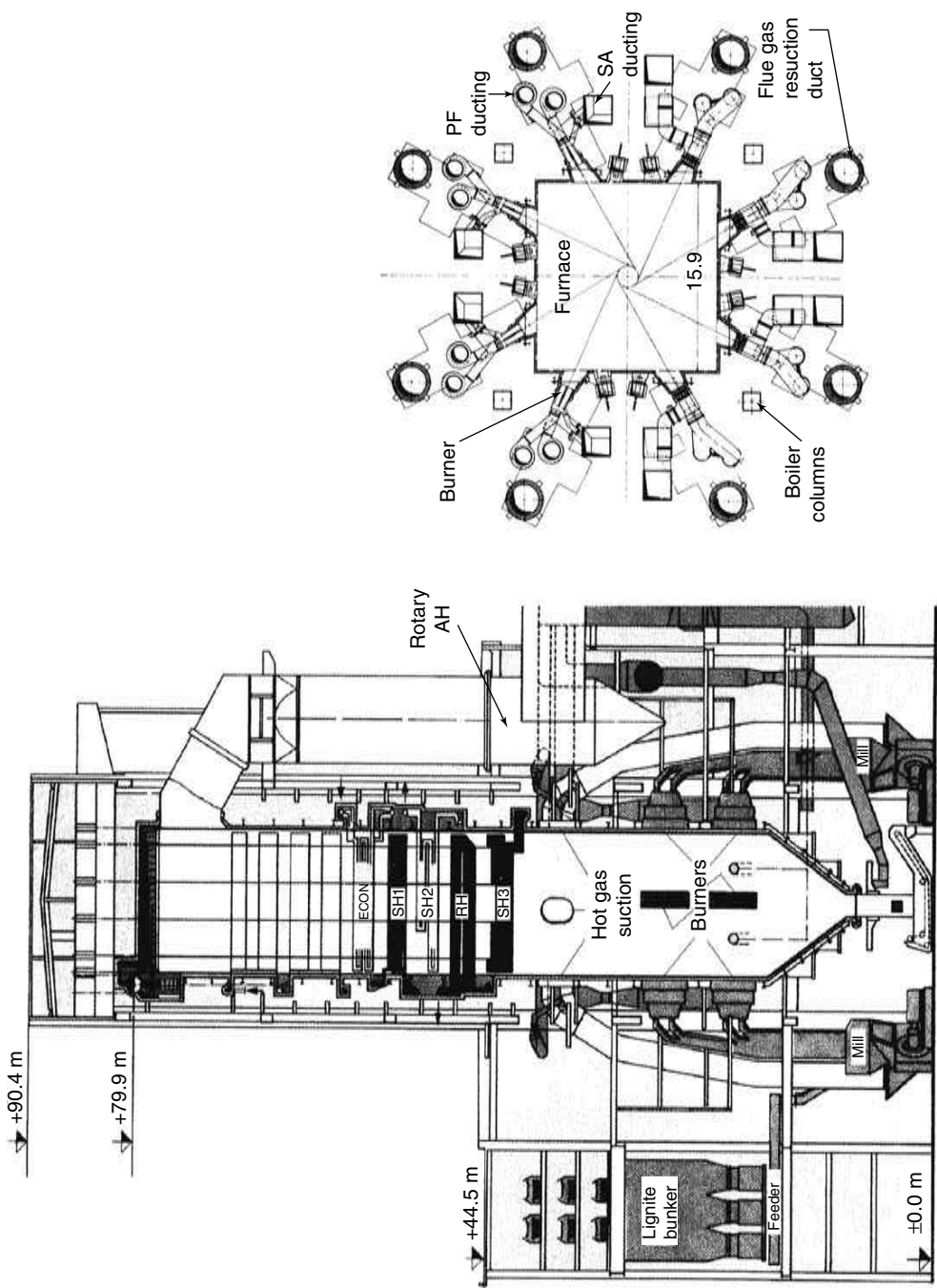
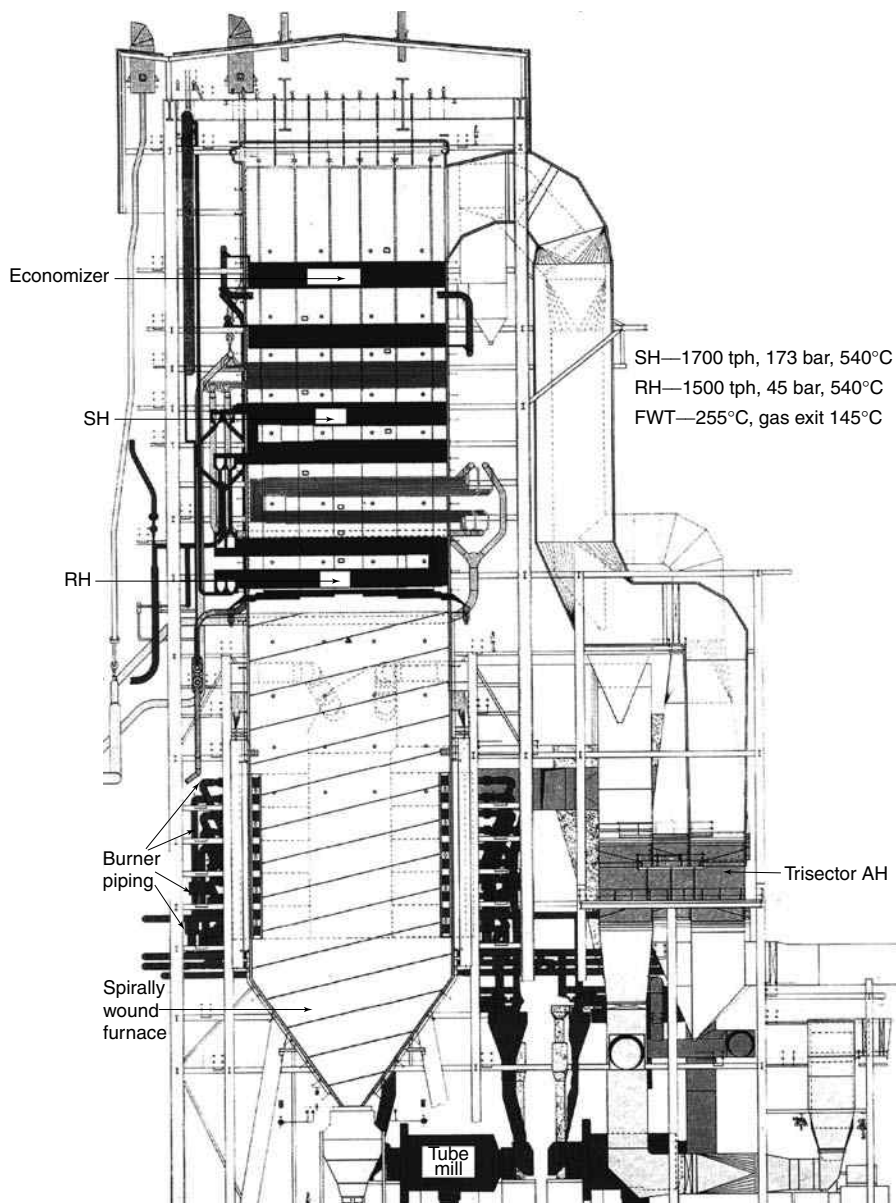


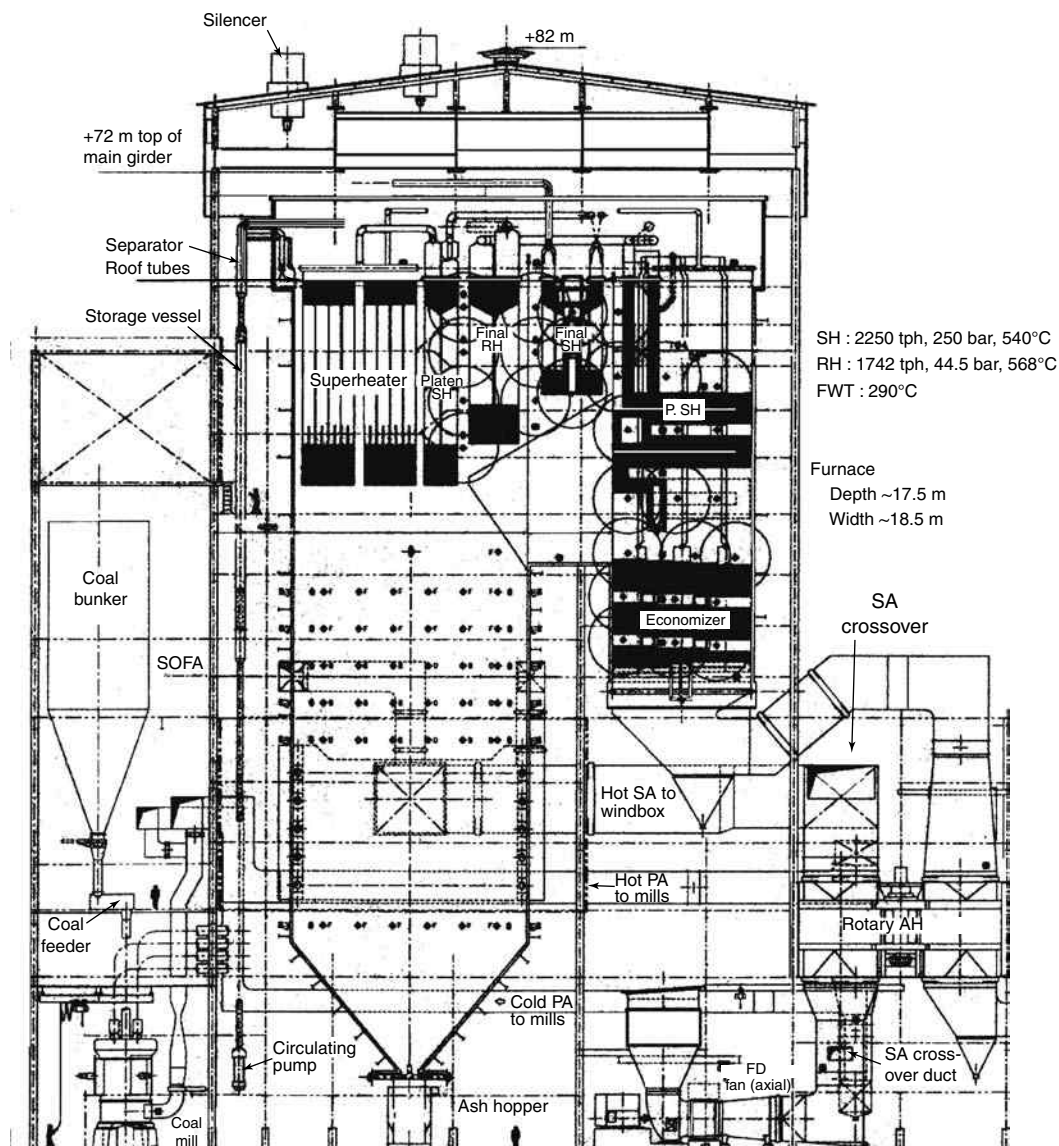
FIGURE 13.32
A 210 MWe lignite-fired tower-type boiler.

**FIGURE 13.33**

A 500 MWe tower-type corner-fired subcritical once-through boiler with tube mills for high-ash coal.

either side of the boiler for a better layout of coal piping to both front and rear walls where burners are mounted. The twin rear-pass design may be abandoned in favor of a single pass. Consequently, the rotary AH is arranged in the third pass because of less width of second pass.

Pulverized firing boilers are made in a variety of configurations. An attempt is made to introduce some of the popular designs to provide an over view of the complexity of the subject.

**FIGURE 13.34**

A 660 MWe two-pass opposed fired vertical tube SC boiler for high-ash coals.

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Waste Gas Firing (Heat Recovery Steam Generators)

14.1 Introduction

Many industrial continuous processes produce large amounts of hot waste gases. Generation of steam or power from these waste gases has been practiced for a long time. The waste gases can be at high, medium, or low temperature at ~ 1000 , 500, or 300°C , respectively. The gases can be clean or dust-laden, erosive, and even corrosive. Gases with meaningful calorific values (CV) are burnt with or without an additional support fuel. Blast furnace gas (BFG) and coke oven gas (COG) fall in this category. Several waste gases produced at high temperatures or in large volumes that contain considerable heat but no combustibles need only to be cooled (and at times cleaned) before release into the atmosphere. Sponge iron kiln waste gases fall in this category.

The devices that cool the gases and produce steam are generally called waste heat boilers. There may or may not be supplementary fuel firing, just as there may or may not be a need to clean the waste gases. The two types are:

1. Heat recovery steam generators (HRSGs) in power plants
 2. Waste heat recovery boilers (WHRBs) in process industries
- Gas turbines (GTs) exhaust large amounts of clean, medium hot gases used in boilers, usually called HRSGs or turbine exhaust gas (TEG) boilers.
 - In metallurgical, cement, and similar plants, large amounts of dusty hot gases produced are cleaned and cooled and steam is produced in boilers generally known as WHRBs.

14.2 Heat Recovery Steam Generators and Waste Heat Recovery Boilers

WHRBs are bulky and expensive. The cost of steam and power generated is higher, even with input heat. It makes sense to have a waste heat system only if any one of the following conditions is met:

- The cost of the regular fuels is high and hence the high-cost power and steam from waste heat boilers are acceptable.
- The process demands its inclusion.

In the Middle East, for example, where fuel and interest costs are low, GTs run on open cycle (OC) or simple cycle (SC) with no HRSGs. The power so produced in OC mode is marginally more expensive than the power from closed or combined cycle (CC) but it is still affordable. This is now changing with steadily rising cost of petroleum. In the cement

TABLE 14.1

Comparison of Waste Heat Recovery Boilers (WHRBs) versus Heat Recovery Steam Generators (HRSGs)

Parameter	WHRB	HRSG
Type of plant	Process	Power and cogen
Steam use	Power and process	Power and process
Power plant cycle	Rankine, cogen, or process	Combined or cogen
Upstream	Process plant	Gas turbine
Gases	Dusty	Clean
Fired/unfired	Both	Both
Design types	Various	Limited
Steam pressure	Mostly <70 bar	Up to 150 bar
Pressure levels	Single	Mostly multiple
Steam temperature	<500°C	Up to 570°C
Tubes in boiler	Plain mostly	Finned mostly
Erosion issues	In many cases	No issue
Corrosion issues	In many cases	Only occasionally
Gas cleaning upstream	Many times required	No
Gas cleaning downstream	Many times required	No
Draft	Balanced	Pressurized
Fans	Required	Only with fresh air-firing mode
Refractory usage in boiler	Plenty	Negligible
Number of boilers	Limited	Many

industry, a lot of low-grade heat is available in the dusty kiln gases at temperatures $\sim 350^\circ\text{C}$. This makes it very expensive to generate power.

Waste heat recovery boilers are specific to each process. Although the variety is large, the population of WHRBs is rather small, as there can only be one WHRB for each process stream. On the other hand, HRSGs are found only in gas-based power plants and are available only in two designs (vertical and horizontal) and are in use all over the world.

HRSGs are discussed in this chapter; the WHRBs are only of limited interest.

A broad comparison of the WHRBs and the HRSGs is presented in Table 14.1.

Unlike a conventional boiler, the HRSG has upstream equipment in the form of a GT, whose output is used by the HRSG to produce steam power efficiently. Hence the GT has an overriding influence on the size, shape, and dynamics of the HRSG. Although the HRSGs are limited to vertical and horizontal designs (designated by the direction of gas flow), a variety of GT cycles are possible. A good appreciation of GTs and the GT cycles is necessary to understand the HRSGs properly.

14.3 Gas Turbines

Gas turbines derive their name from their working medium. They are also called *combustion turbines*. Gas turbines first made their appearance in the late 1940s as revolutionary self-contained power plants. They were initially used for peaking duties because of their quick starting capabilities and small sizes. Smaller GTs are also widely used as mechanical drives for big compressors and pumps.

14.3.1 Gas Turbines for Power: Rapid Growth

Gas turbines quickly reached a leading position in the field of power generation due to increased NG availability and

- Rapid customization of the jet engine for land operations
- Improvements in reliability
- Increases in size
- Progressive reduction of costs
- Efficiencies based on better compression ratios and firing temperatures.

The improvements in GTs were matched by improvements in HRSGs and steam turbines (STs) to enable building larger and more efficient power plants. The manufacturers of the GT, ST, and HRSG worked closely to achieve cost reductions and efficiency improvements to challenge coal. The net result is that

- Standardization and modularization reduced the time for power plant construction.
- Simplified plant layouts and standardized configurations reduced the installed costs of the power plants.
- Improved cycle efficiencies in CC operation substantially mitigated the burden of higher fuel costs.

Since the 1980s, there has been a dramatic growth in the sizes of GT and its popularity. Heat recovery steam generators have also grown both in size and complexity. In the latter part of the 1990s, with natural gas (NG) availability increasing and its cost stabilizing at a lower level, the clamor for gas reached unprecedented levels. Old coal-based plants were dismantled to make way for gas plants based on sound economic sense.

Figures 14.1 and 14.2 capture the progress of GTs in terms of OC or SC and CC efficiencies and firing temperatures.

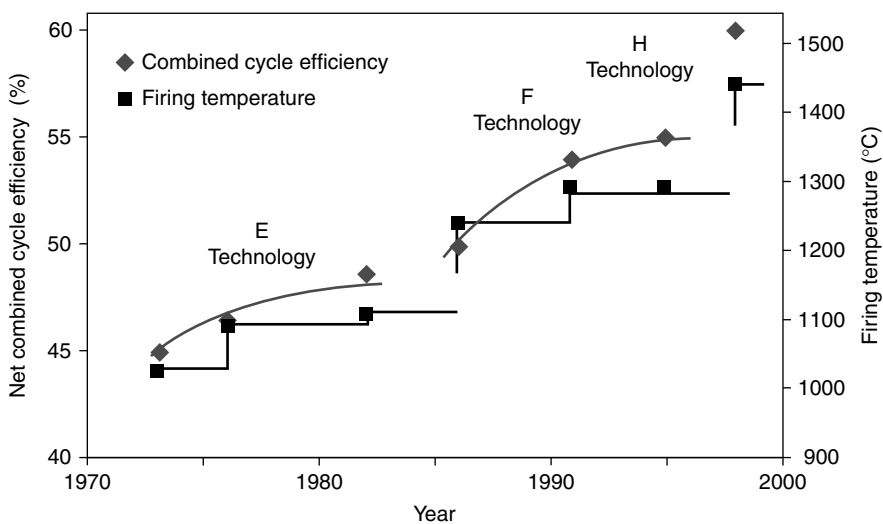


FIGURE 14.1
Progress of the efficiency of gas turbines.

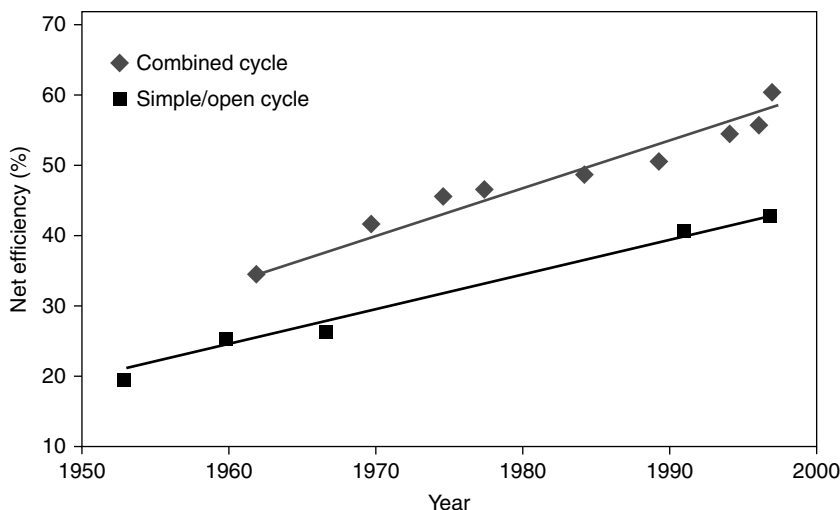


FIGURE 14.2
Progress of cycle efficiencies.

14.3.2 Definitions of Terms

- The practice in the industry is to report GT performance for base load operation at 15°C (59°F) *sea-level* site conditions on NG.
- *Power output* is the *gross* plant output for OCs and *net* plant output for CC plants. Net output accounts for
 - Parasitic auxiliary plant loads
 - Losses in gear box
 - Intake losses
 - Outlet losses
- *Heat rate* is the fuel heat input on net calorific value (NCV) basis for unit power output expressed in kilojoules per kilowatt hour (kJ/kWh), kilocalories per kilowatt hour (kcal/kWh), or British thermal units per kilowatt hour (Btu/kWh). In GTs, the NCV is used traditionally for heat rates. In conventional power plants both GCV and NCV are used. Power and heat rate are measured across the generator terminals for power plants.
- *Efficiency* is the ratio of power output to heat input expressed as a percentage. For OC, the power output is the gross power, whereas for CC, it is the net power.
- *Compression ratio or pressure ratio* is the ratio of the discharge pressure of the GT compressor to the atmospheric pressure of air at the GT intake.
- *Flow* is the airflow through the GT expressed in tons per hour (tph), kilograms per second (kg/s), or pounds per second (lb/s).
- *Turbine speed* is the design speed of the output shaft. The speeds for power generation are 3000 and 3600 rpm at 50 and 60 Hz, respectively.
- *Exhaust temperature* is the gas temperature at the outlet of the turbine exhaust duct.

14.3.3 Basics

14.3.3.1 Gas Turbine versus Steam Turbine

Although GT and ST are rotating machines sharing many mechanical design features, the *GT is a power plant* whereas the *ST is a prime mover*. The two can be compared in the following manner:

- Just as the ST expands the high-pressure (HP) and high-temperature steam from higher to lower levels of pressure to produce electrical energy, GT expands HP and high-temperature gases to do the same.
- The input to ST is ultraclean steam at temperatures $<620^{\circ}\text{C}$, whereas GT input consists of clean or slightly fouling gases at very high temperatures of up to 1450°C .
- A GT is a complete power plant because it has a
 - Compressor to produce HP air
 - Combustor to burn the fuel, raise the temperature, and infuse the gas with heat energy
 - Turbine to expand the hot gases and generate mechanical power from heat
 - Generator to produce electrical power from mechanical energy
- The entire GT power plant is attractively skid-mounted.

A very important practical difference is that the STs are custom built and GTs are available in standard sizes. *GTs are manufactured and sold*, whereas *STs are sold and then manufactured*. The lead times for procurement are thus significantly lower for GTs.

14.3.3.2 Main Systems and Subsystems

1. *Air compressor* for compressing air to a high pressure. The compressors can be either *centrifugal* or *axial*, with the latter more popular in larger sizes. In axial-flow compressors, the air enters at the periphery of the rotor where the blades are fixed, unlike in centrifugals where the entry is in the center. The air moves alternately in the stationary and the moving blades, shaped like diffuser and aerofoil, for change of direction and acceleration, respectively. The compressor blades are precisely shaped to achieve efficiencies of $\sim 90\%$.
2. *Combustor* to burn the fuel in an efficient manner. Proper mixing, dilution, and cooling are performed so that the hot spots are minimized and gases leave at a fairly uniform temperature. Fuel is mostly NG, although other fuels can also be burnt. The lengths of the combustor are designed to provide adequate time and space to burn the fuel completely. Of late, NO_x generation has received a lot of attention, and the emission levels have reduced from ~ 70 to 10 ppmv in many newer GTs.
3. *Steam turbine* to generate power to run the compressor and drive the generator or provide hot exhaust or both. The combustion gases expand in the GT nozzles and blades in the same way as steam expands in the ST. A portion of the heat is converted into kinetic energy in the nozzles, and another portion is transferred to the rotating blades for conversion. The nozzles and blades along with the carrying disk are exposed to very high gas temperatures of 1200°C or more. Together with the contaminants in air and fuel, these parts experience accelerated oxidation and hot corrosion. Since the contaminants are costly to remove and impossible to prevent, the only course is to resort to high-grade alloys and coatings to resist corrosion and extend the life of hot parts.

The compressor in the GT consumes about two-thirds of the generated power. The following systems make the GT complete.

1. Inlet air cleaning system
2. Fuel oil or gas conditioning system
3. Lubricating system
4. Start-up system
5. Control system

14.3.3.3 Shafts

Gas turbines can have single, double, and triple shafts.

1. Single-shaft turbines, popular with drive applications, have a single common shaft with all the stages operating at the same speed. This is depicted in Figure 14.3.
2. In a double-shaft arrangement, the HP part of the GT is mounted on a separate shaft and connected to the compressor, whereas the other part is rigidly connected to the load and called the power turbine (Figure 14.4).
3. In a triple-shaft arrangement, there is a further division as shown in Figure 14.5. The compressor is divided into two parts with independent drive shafts.

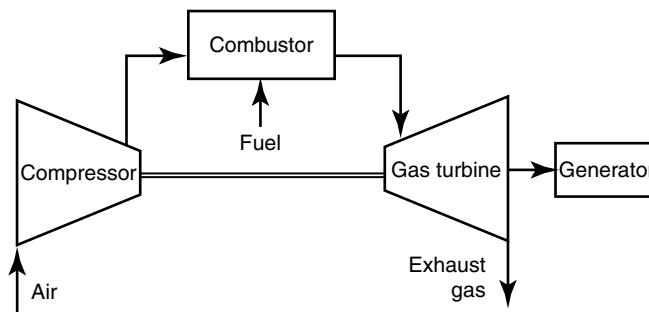


FIGURE 14.3
Single-shaft gas turbine in simple cycle.

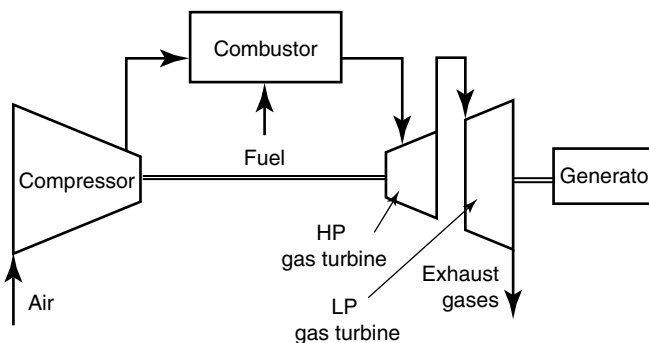


FIGURE 14.4
Double-shaft gas turbines in simple cycle.

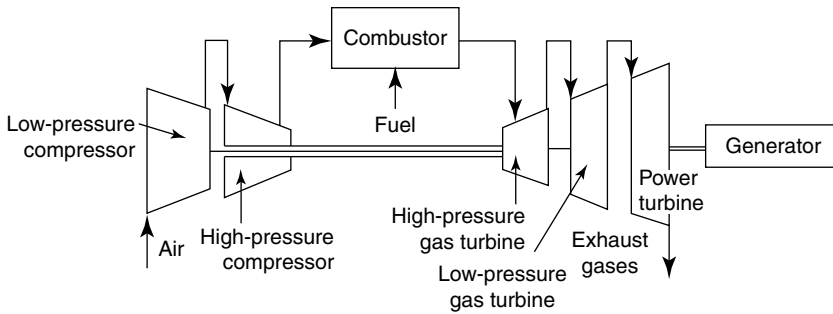


FIGURE 14.5
Triple-shaft gas turbines in simple cycle.

14.3.3.4 Efficiency

The efficiency of GT increases in proportion to the

- Air compression ratio
- Firing temperature

consistent with physical limits. Beyond a certain optimum compression ratio, the compressor power requirement increases significantly, and there is no more increase in the power output, and there is, in fact, a drop in efficiency. In case of firing temperature, the metallurgical limitations act as constraints.

The usual compression ratios in land turbines are between 10 and 20. In the recent Ahlstrom GT 24 and 26, higher ratios of 32–34 are used. The aeroderivatives always adopted higher ratios, from 16 to as high as 40.

14.3.4 Cycles

Gas turbines are mainly employed in the following three ways:

1. Simple/open cycle
2. Cogeneration (cogen) cycle
3. Combined cycle

14.3.4.1 Simple or Open Cycle

This mode is employed when the GT is operating on its own, as shown in Figures 14.3 through 14.5. With no heat recovery, the GT exhaust gases carry away between 35 and 40% of fuel heat. The main parameters vary between limits, as shown in Table 14.2.

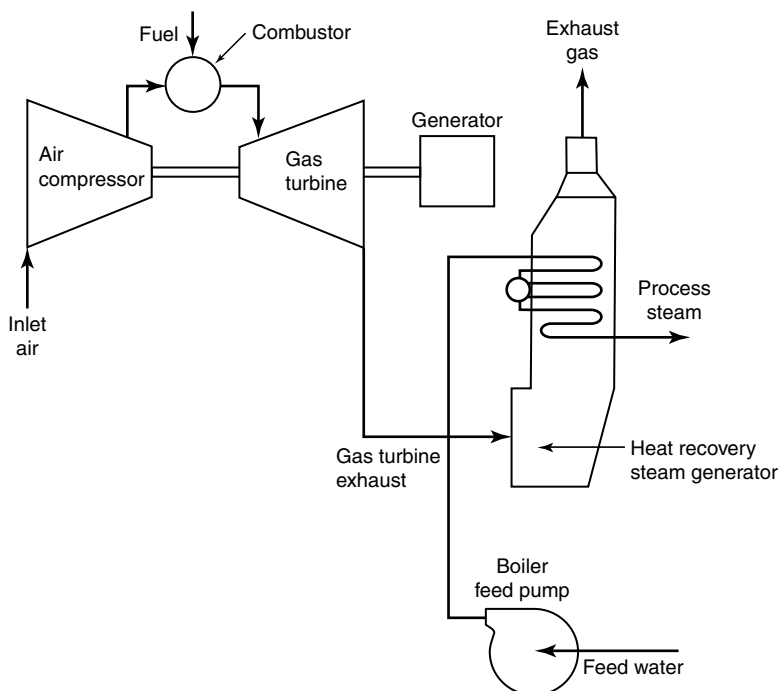
14.3.4.2 Cogeneration Cycle

Cogeneration is the production of two usable forms of energy—usually power and steam. The exhaust gases from the GT are cooled in a HRSG to produce steam for process or power. As the steam requirements are not always in line with power generation, it is normal to have supplementary oil or gas firing in the inlet duct of the HRSGs usually to the extent of 100%, so that the plant is never short of power or steam. The efficiency of the cogen cycle with two or three pressure levels in the HRSG can easily exceed 80% as

TABLE 14.2

Main Operating Variables of Gas Turbines

Parameter	Value
Open cycle efficiency on gross output basis	28–39% in land turbines <45% in aeroderivatives
Exit gas temperature	425–610°C 800–1130°F
Excess air	220–300%
O ₂ in flue gas	15–16% by volume

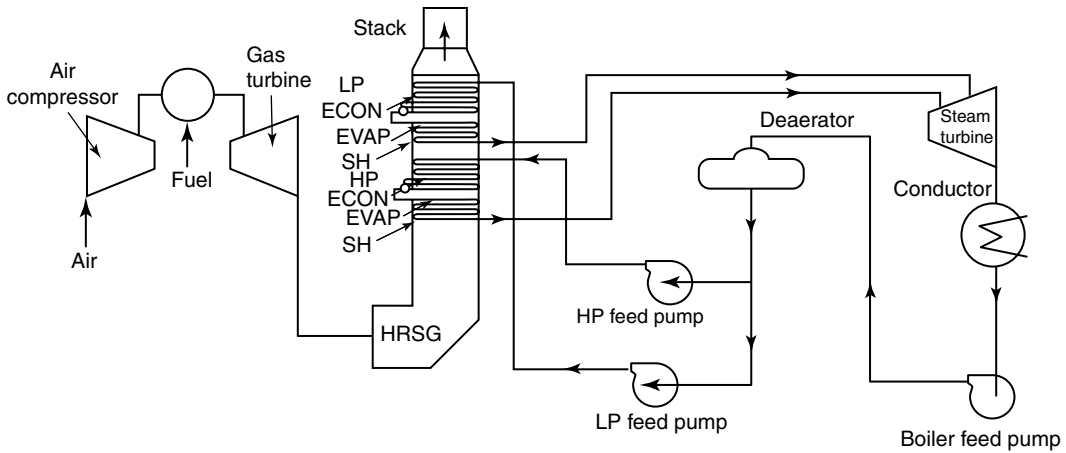
**FIGURE 14.6**
Cogeneration.

opposed to 50–55% (maximum 60%) in the CC. Condenser loss present in the steam cycle does not occur in the cogen cycle (Figure 14.6).

14.3.4.3 Combined Cycle

In the CC, power is produced from both GT and ST cycles; the HRSG that converts the exhaust gas heat of the GT produces the steam for the ST. It is the Brayton/GT cycle riding over the Rankine/steam cycle to maximize both the output and the efficiency. With HRSG extracting nearly 90% of heat and converting it into power in the ST, the efficiency of the CC works out to be more than 50%. In the largest GTs, the efficiencies almost exceed 60% on NCV with the reheat cycle. The differences between the conventional steam cycle and the steam part of the CC are as follows:

- There are no extractions from the ST.
- There are no HP and low-pressure (LP) heaters.

**FIGURE 14.7**

Combined cycle with double-pressure heat recovery steam generators (HRSGs). ECON, economizer; EVAP, evaporator; HP, high pressure; LP, low pressure; SH, superheater.

- There are steam injections into the turbine in the form of intermediate pressure (IP) and LP flows from the HRSG.
- Deaerator steam comes from the HRSG and not from the turbine bleed (Figure 14.7).

14.3.5 Types

14.3.5.1 Aeroderivatives

The gas turbine was originally developed in the aerospace industry. These turbines, with some minor modifications to suit land operations, have been applied to power generation since the early 1960s and are called aeroderivatives. These turbines are

- Made of much lighter aircraft materials
- More efficient, as the firing temperatures and compression ratios are higher
- Able to run at higher speeds
- Somewhat delicate
- More expensive

For SCs/OCs, aeroderivatives are better suited. They extract more heat from hot gases and exhaust them with lower total temperature and heat. Consequently, the HRSG behind an aeroderivative produces less steam and is smaller. Aeroderivatives are better where power is to be maximized over steam.

14.3.5.2 Industrial or Land Turbines or Frame Machines

Industrial or land turbines or frame machines are built primarily for power and cogen applications.

- They are heavier and ruggedly built.
- They can burn gas, No. 2 fuel oil, and heavier oils such as kerosene, diesel, and crude.
- Although the aeroderivative range stops at ~100 MWe, the land turbines can reach ~340 MWe.

TABLE 14.3

Comparison of Industrial and Aeroderivative Turbines

Parameter	Industrial GT (1)	Aeroderivative GT (2)	Comments
Efficiency	Low—28–39%	High—35–45%	
Size	Up to 340 MW	Up to 100 MW	
Availability		Higher	
Weight	Higher		
Erection time	More		
Compression ratio	10–18	18–30	
Firing temperature	Lower	Higher	Better life of (1)
Build	Rugged	Slightly delicate	
Gas exhaust	Higher temperature 490–615°C	Lower temperature 415–540°C	Heat recovery steam generators on (2) give lower pressure and temperature
Fuel	Gas, light, heavy, and crude oils	Gas, light oils, naphtha	
Suitability	Combined cycle and cogen	Cogen and open cycle	
Startup	Quick	Quicker	
Plan area		Smaller	
Noise		Lower	
Costs		Higher	

14.3.5.3 Frame Machine or Aeroderivative

- For power up to 100 MWe and cogen applications, both types can be considered, depending on the relative economics.
- For more than 100 MWe, only the land turbines are suitable.
- Aeroderivatives, despite their higher cost, are the only choices when weight or efficiency is the consideration, such as for barge-mounted power or OC plants. Table 14.3 compares both types of turbines.

14.3.6 Manufacturers

The last two decades led to great growth and consolidation in the GT business. A list of leading companies and their range of GTs is provided in the following text.

- The capacities indicated here may not include the latest developments.
- Only the leading companies are listed here.

The annual issue of the *Gas Turbine World* lists all the makes and models.

USA

- General Electric (GE) is the leader, making both aeroderivative and land turbines from small (15 MWe) to very large (~340 MWe) capacities.
- Westinghouse of the United States is now a subsidiary of Siemens.
- Pratt and Whitney (P&W) makes only aeroderivatives up to ~58 MWe.
- Solar Turbines makes several models of small GTs ranging from 1.2 to 15 MWe.

Europe

- Ahlstrom of France makes only land turbines from 56 to ~290 MWe.
- Siemens of Germany makes only land turbines from ~100 to ~340 MWe.
- Rolls Royce (RR) of United Kingdom makes only aeroderivatives up to ~58 MWe.
- Ansaldo Energia of Italy makes three models of land turbines of Siemens design of 77,166 and 280 MWe.
- Zorya-Mashproekt of Ukraine makes land turbines from 3 to 27 MWe.

Japan

- Mitsubishi Heavy Industries (MHI) makes only land turbines from ~100 to ~330 MWe.
- Hitachi Heavy Industries (HHI) makes land turbines in sizes of 15 and 27.5 MWe of their own design. Hitachi is also the licensee of GE for sizes up to 243 MWe.
- Toshiba makes only land turbines of GE design from ~76 to 255 MWe.
- Ishikawajima-Harima Heavy Industries (IHI) makes only aeroderivatives of GE design up to 45 MWe.

India

- BHEL makes land turbines of both GE and Siemens designs from 26 to 280 MWe.

There are licensees in a number of countries making turbines conforming to the standards of Ahlstrom, GE, and Siemens. The licensees may not be able to offer the latest product developments of the licensor.

Customers choose GTs from the limited range of offered models, and characteristics are well known among the users. Although there is not much customization possible in the main machine, customization is usually restricted to the auxiliary plant.

14.3.7 Popular Models

There are a large number of GT models covering a range from <1 to ~340 MWe. The lower range up to 20 MWe is usually for big drives in oil and gas industries and in ships. For gas-based power generation up to 20 MWe, a battery of gas engines is usually an economical choice. Tables 14.4 and 14.5 list the turbines that are in use in CC plants and hence are of relevance to the HRSG.

- The tables show ISO ratings (at 15°C, 60% relative humidity, MSL).
- The data apply to gas firing without steam and water injection that are usually adopted for performance enhancement.
- The heat rate is based on the NCV.
- An inlet and outlet gas pressure loss of 100 mm wg is considered.

The models listed in Table 14.5 are for 50 Hz. The latest figures may be at a slight variance. The table does not reflect the new designations of the Siemens turbines.

The high compression ratios and low exhaust temperatures of the aeroderivatives that are not matched in the frame machines are worth noting.

TABLE 14.4

Typical Aeroderivatives (50 Hz)

Make/Model	Power (MW)	Gas Turbine Efficiency (%)	Heat Rate kcal/kWh)	Compression Ratio	Exhaust Gas	
					Flow (tph)	Temperature (°C)
<i>General Electric</i>						
LM2500 PE	22.35	35.37	2431	19.1	252	538
LM2500 + 6stg	29.24	35.37	2431	22.6	316	519
LM6000	42.89	41.68	2063	29.2	463	435
LM6000 PC	50.04	40.26	2136	31.5	493	434
LMS100 PA	98.95	45.4	1894	40.0	736	416
<i>Rolls Royce</i>						
RB211-6761	32.12	39.23	2192	21.5	340	503
Trent-50	51.68	41.85	2055	34.0	558	440
<i>Pratt and Whitney</i>						
FT8 PWR pack	27.97	38.27	2247	20.2	316	478

TABLE 14.5

Typical Frame Machines (50Hz)

Make/Model	Power (MW)	Gas Turbine Efficiency (%)	Heat Rate (kcal/kWh)	Compression Ratio	Exhaust Gas	
					Flow (tph)	Temperature (°C)
Ahlstrom Gas Turbines						
8C2	56.3	32.0	2686	17.6	710	508
11NM	87.9	33.9	2536	12.5	1137	502
11N2	115.4	33.55	2563	15.5	1440	531
13E2	172.2	36.19	2376	15.4	1937	537
26	280.9	38.22	2250	32.0	2279	615
General Electric: PG						
5371PA	26.3	28.41	3027	10.5	442	488
6591C	42.3	36.27	2371	19.0	422	574
6111FA	75.9	34.88	2465	15.6	757	605
9171E	126.1	33.72	2550	12.6	1456	539
9351FA	255.6	36.83	2335	15.4	2326	610
9371FB	229.2	37.90		18.3	2362	630
Siemens: V						
64.3A	67.7	35.0	2457	15.8	690	582
94.2	163.3	35.35	2433	11.8	1901	542
94.2A	188.2	37.75	2278	13.4	1871	581
94.3A	272.4	38.95	2208	17.2	2420	582
Mitsubishi: M						
701	144.1	34.72	2477	14.0	1590	542
701F	270.3	38.15	2254	16.0	2347	586
701G	334	39.47	2179	21.0	2658	587

14.3.8 Characteristics

Gas turbines are, like fans and compressors, *volumetric machines*. Therefore, the following conditions have major impact on output and performance:

- Ambient conditions such as temperature, humidity, and altitude
- Inlet and exhaust chamber losses
- Water and steam injection

14.3.8.1 Gas Turbine Ratings

- *Nominal rating* of the GT, also known as the ISO rating, is the output at 15°C (60°F) ambient temperature, 60% relative humidity at MSL, or 760 mmHg absolute.
- *Actual rating* is obtained by making appropriate corrections to the nominal conditions.
- *Base rating* is the maximum continuous rating that can be maintained for at least 6000 h in a year.
- *Peak rating* is the maximum rating that can be maintained for a maximum of 200 h in a year.

It is important to note that unlike a conventional power plant, GTs are rarely run at their peak rating, as the effect of high gas temperature on hot parts shortens useful life. Peak duty is normally met by supplementary firing of HRSGs.

14.3.8.2 Effect of Ambient Conditions

The effect of ambient conditions is so pronounced that the same turbine can give dramatically higher outputs in winter as compared with its summer output (Table 14.6).

1. *Ambient temperature.* As the inlet temperature increases, the air weight (for the same volume) reduces and the power drops. Exhaust-gas temperature increases and the efficiency reduces, that is, the heat rate increases. The reverse reaction happens as the ambient temperature drops. Between 0 and 40°C, the rated output of a nominal/ISO 100 MWe GT can vary from 110 MWe to as low as 75 MWe. Typically for each degree Celsius increase in ambient temperature, the output drops by as much as 0.5–0.9% (Figure 14.8).
2. *Altitude.* At higher altitude, the air volume increases and correspondingly the weight of the airflow decreases, resulting in lowered power output. For every 300 m increase in height, the output suffers between 3 and 5%.

TABLE 14.6

Effects of Variation in Ambient Conditions on Performance of Gas Turbines

Parameter	Metric Units	Performance	British Units	Performance	Remarks
Ambient temperature	1°C	0.5–0.9%	1°F	0.3–0.5%	In power
Elevation	300 m rise	3–5% drop	1000 ft rise	3–5% drop	In power
Inlet loss	25 mm wg rise	0.5% drop	1 in. wg rise	0.5% drop	In power
		0.1% rise		0.1% rise	In heat rate
Outlet loss	25 mm wg rise	0.15% drop	1 in. wg rise	0.15% drop	In power

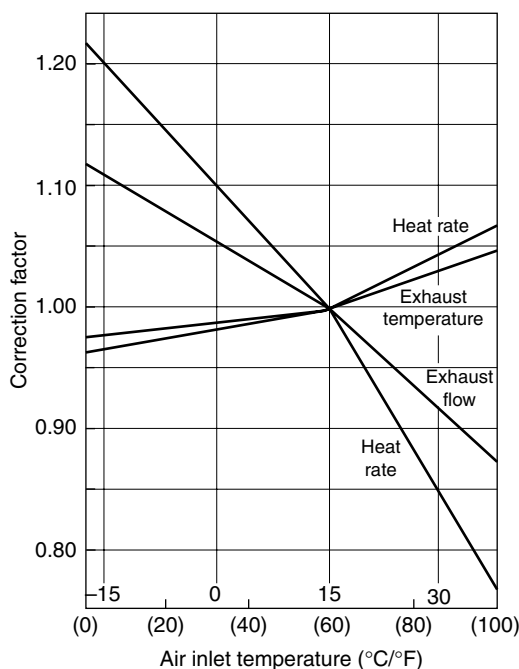


FIGURE 14.8
Correction curve for ambient temperature.

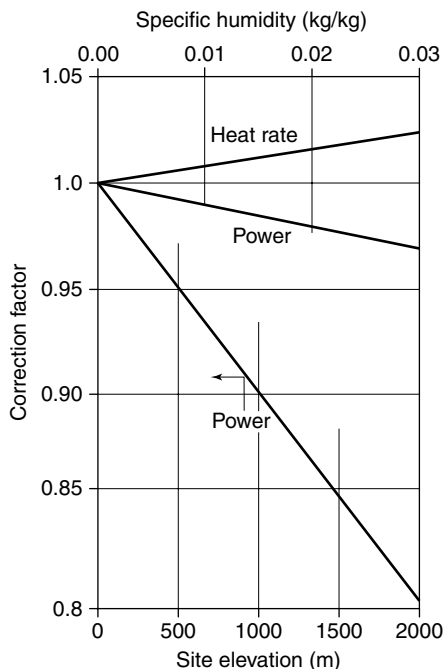


FIGURE 14.9
Correction curve for site elevation and humidity.

3. *Humidity.* The effect of humidity is marginal. Water vapor lightens the weight of the air–water combination, resulting in diminished power.

Figure 14.9 captures the effects of altitude and humidity on power and heat rate.

14.3.8.3 Effect of Inlet Pressure Losses

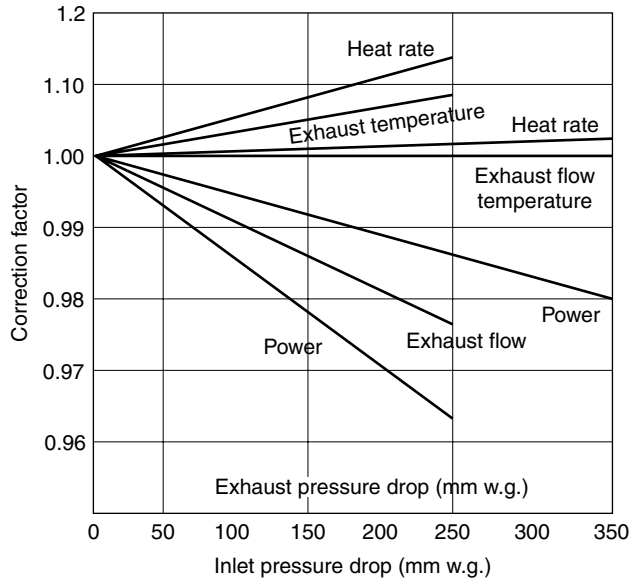
The inlet pressure adds to the load on the compressor, and an increase in inlet pressure loss reduces the output. Inlet losses arise from the

1. Inlet air filter
2. Silencer
3. Evaporative cooler (if provided)
4. Inlet air ducts

The increase is mainly because of the dust that builds up in the inlet filter over time. Inlet loss is usually between 75 and 100 mm wg. A 25 mm wg increase in the inlet loss reduces the power output by ~0.5% and increases the heat rate by ~0.1%.

14.3.8.4 Effect of Exhaust Pressure Losses

The exhaust pressure loss or back pressure is usually ~100 to 125 mm wg in OC as the gas exhausts through the outlet duct, silencer, and bypass duct. In the CC, there is additionally the resistance offered by the HRSG with its inlet duct and stack, which totals 250–430 mm wg. The loss across the HRSG is between 200 and 300 mm. A 25 mm wg increase in the outlet loss reduces the output by 0.15% and increases the heat rate by 0.1% (Figure 14.10).

**FIGURE 14.10**

Corrections for outlet and exhaust pressures.

14.3.9 Performance Enhancement

There are several ways in which the GT performance is enhanced. A proper understanding of these techniques is necessary, as they have a direct relation to the HRSG design. A few popular methods are discussed here.

14.3.9.1 Steam and Water Injection

When steam or water is injected into the combustion chamber of the GT prior to combustion, the

- Gas turbine output is increased
- Fuel NO_x generation is lowered

The enhanced gas flow increases the power output from the turbine without raising the compressor input. With water injection the heat rate increases, whereas with steam injection the heat rate reduces because the steam adds to the heat, whereas water takes away the heat for its evaporation.

Steam for injection is drawn from the HRSG. This is known as *steam-injected gas turbine (STIG) cycle* or *Cheng cycle*. There is no other equipment involved in this cycle. This is popular in the cogen arrangement in which the desired power can be produced during low steam demand or for peaking. When more steam or water is added beyond what is required for NO_x control, the system is in *power boost* mode.

Steam injection is done up to 2 kg/kg of fuel. Aeroderivatives are more useful for power augmentation by steam injection (Figures 14.11 through 14.13).

14.3.9.2 Evaporative Cooling

In hot and dry places, it is possible to cool and humidify the inlet air to the extent of 90% difference between the dry and the wet bulb temperatures. Lowered temperature and

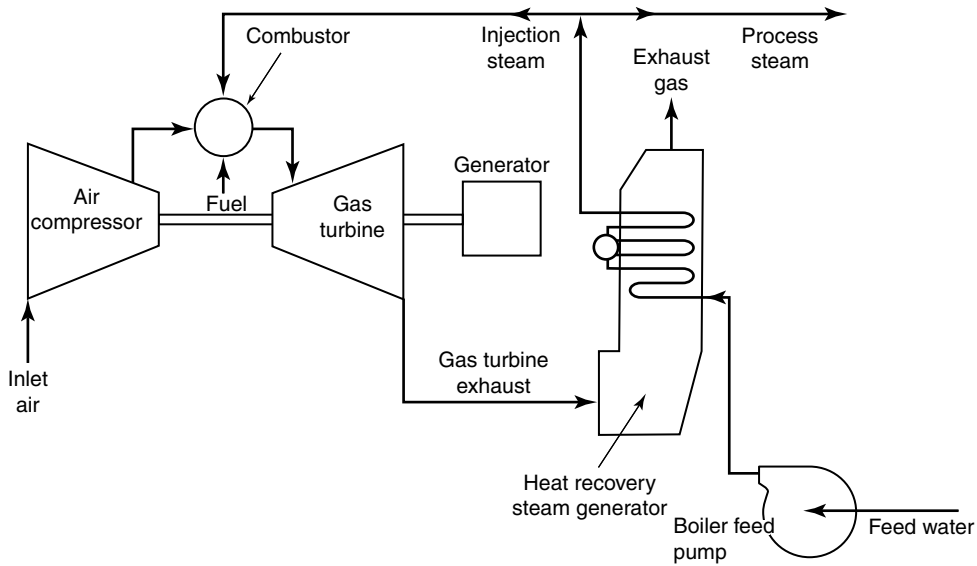


FIGURE 14.11
Steam-injected gas turbine cycle.

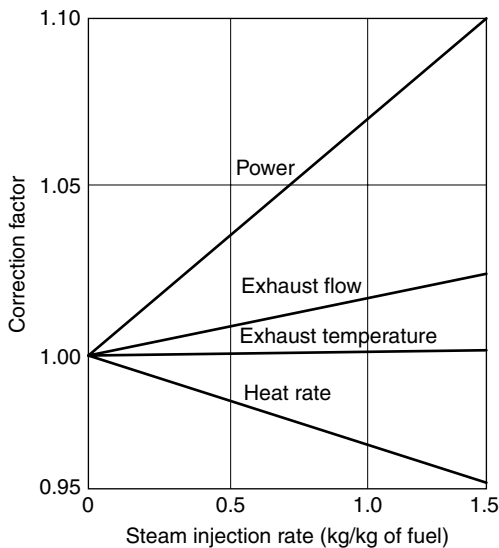


FIGURE 14.12
Effect of steam injection.

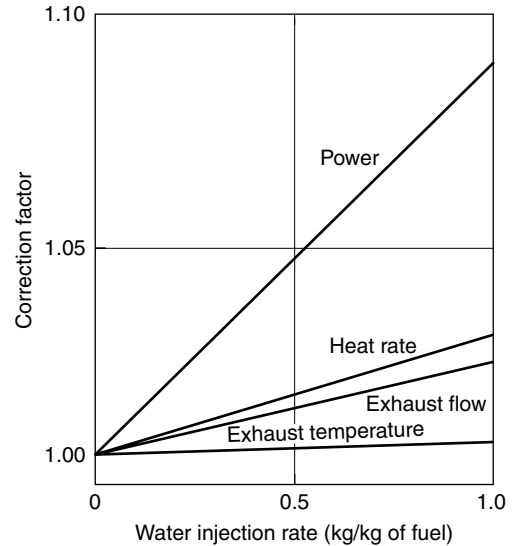


FIGURE 14.13
Effect of water injection.

enhanced humidity increase the weight of entering air, which in turn, increases the power output. The water quality must be high, as any contamination affects the performance of the GT.

14.3.9.3 Regenerative or Recuperative Cooling

To improve the efficiency of the OC, the exhaust gases are cooled by the combustion air in a counterflow heat exchanger (HX), thereby transferring part of the heat to the air entering

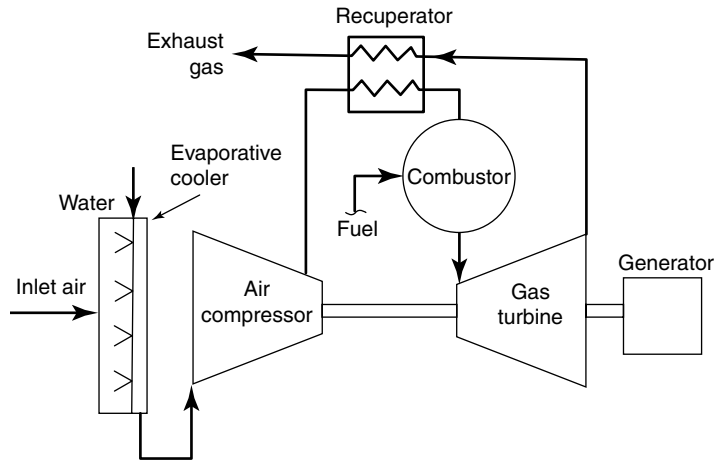


FIGURE 14.14
Evaporative and recuperative cooling cycles.

the combustion chamber. Between 20 and 25% of the exhaust heat can be recovered this way. Figure 14.14 portrays the regenerative cooling arrangement as well as the evaporative cooling.

14.4 Heat Recovery Steam Generators

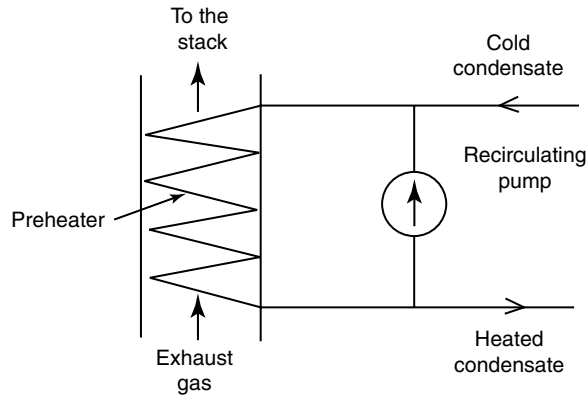
Until early 1970s, the HRSGs were merely simple HXs placed behind GTs for heat extraction. As the GTs became bigger, the oil or gas package boilers were modified for the GT exhaust. As the GTs grew enormously in size and complexity, the HRSGs also kept pace. They assumed a distinct form of their own. Today, they are made in vertical and horizontal designs.

The exhaust gas temperatures range from 415°C (780°F) to 630°C (1166°F) and flows up to ~2660 tph (~740 kg/s or 1630 lbs/s) in power plants from which the HRSGs have to extract steam.

14.4.1 Conventional Boilers versus HRSGs

In most ways, HRSGs are different from other boilers.

- Unlike a coal-based power plant, which is built around the boiler, the gas-based power plant is planned around the GT and ST, with HRSG in a secondary position of importance.
- An HRSG is nowhere near the size and complexity of a utility coal-fired boiler, although it has importance in the CC because:
 - The delivery of the HRSG is the most critical aspect in a gas-based power plant.
 - The overall efficiency of the cycle is governed by the efficiency of the HRSG.
 - The price of an HRSG may exceed the price of the ST.

**FIGURE 14.15**

Preheater in heat recovery steam generator.

- Even in the largest CC power plants (CCPPs), the size of the HRSG is only as big as a large industrial boiler.
- With multiple pressure and temperature levels, no fans, no firing in many cases, no refractory, no ash concerns, and completely finned tubes, HRSGs are different in concept and construction.
- A main HRSG is light on control instrumentation. Multiple pressure levels with multiple drums require one to three sets of water-level controls. Likewise, there may be multiple attemperator controls. There are no draft, combustion, and load controls.
- In the GT cycle, the LP heater is avoided and replaced by the preheater section of the HRSG. Condensate from the condenser at ~ 30 to 40°C is admitted into the preheater section of the HRSG for direct heating by the gases. To prevent the corrosion of preheater tubes, hot condensate from preheater exit is recycled by pumps to a temperature of 65 – 85°C , depending on the sulfur content of the gases. This way the exit-gas temperatures from the HRSG can be lowered dramatically compared to the conventional boilers (Figure 14.15). Carbon steel (CS) tubes are employed for preheaters unless stainless steel (ss) is warranted due to indifferent water conditioning. A deaerator is also integrated into the HRSG as an LP feed water heater (FWH) followed by the LP evaporator (EVAP). The HP FWH is turned into an HP economizer (ECON).
- Attemperation in a conventional sense is not applicable for the HRSGs as they are downstream of the GTs and merely extract heat as it comes. There is no control or turndown. This is further elaborated in Section 14.4.7.

Heat recovery steam generators are integral parts of CC and cogen plants, working at the back-end of the GT and responding to the GT dynamics. A broad understanding of the GTs and their dynamics and the various configurations of the GT cycles is essential to gain insight into the design of HRSGs.

14.4.2 Standardized HRSG Designs: Not Possible

As back-end equipment of the GTs that are highly standardized, HRSGs are also expected to be standardized at least in the CC. But it does not work out that way because

- The steaming conditions in most cases vary, as the incremental improvements differ.
- The fuels vary.

- Cycle optimization differs.
- Ambient conditions change.

As a result, the HRSGs are always engineered separately, like conventional boilers. Several parts, however, are standardized to allow modular construction.

14.4.3 Demanding Design

As the HRSGs are steam generators extracting maximum steam from medium-grade heat, there is no latitude for error. The design has to be correct because heating surface (HS) cannot be added to make up for the deficiency in performance because

1. A lot of HS is needed to cool gas temperature, even by a few degrees.
2. Provision for adding such a large HS is extremely difficult.
3. The allowable GT exhaust pressure does not permit any more pressure loss or performance will suffer.

A design cannot be so generous as to become very uncompetitive. Thus, HRSG design is a very exact science with all the *design loaded upfront* with no chance for rectification.

Performance program. The quality and reliability of a heat transfer program in the HRSG design must be very high.

- Unlike a conventional boiler, there is no luminous radiant heat transfer in the HRSG design; only nonluminous intertube radiation is present.
- No slagging and fouling effects occur.
- The design is very demanding because extended HSs have to be accommodated within the constraints of the available pressure drop.

Each boilermaker has adopted a *different triangular tube pitch* and developed a body of proprietary data of heat transfer and fluid flow. The essence of the HRSG designing is to adopt different fin spacing, height, and appropriate metallurgy to extract the desired amount of heat from the gases for the particular section. The tube diameters are varied but the pitching is not.

14.4.4 Scope Issues

Table 1.2 contains a brief description on inputs–outputs, scope, and terminal points (TPs) of HRSGs, to which the following points form an extension:

- The scope of the HRSG begins downstream of the bypass stack or the GT exhaust duct and extends up to the HRSG stack. The stack is integral and always forms part of the scope at least for vertical units, as it stands above the HRSG.
- On the upstream side of the tube banks are (1) an inlet duct, (2) a firing duct with duct burners, if applicable, and (3) an expansion duct.
- On the downstream side are (1) an outlet duct and (2) a weather damper (mostly for vertical units) before the stack.
- This entire HRSG assembly is separated at the inlet with a suitable expansion joint to isolate the vibrations of the GT.

The shape of the inlet duct has to be carefully developed with the help of computer modeling to ensure that the gases expand properly and fill the entire tube bank.

14.4.5 Diverter Damper and Bypass Stack Assembly

These devices are sometimes provided in the CC mode to provide flexibility. If the plant will operate in a single mode for the entire lifetime, the bypass stack is not relevant.

- Gas turbines are initially installed in the OC mode, and the HRSG and the ST will be added later to convert to the CC mode. With a bypass stack already installed, addition can take place with no stoppage of GT.
- In a new CC plant, the GT is installed first, and then works on the OC mode and starts generating revenues. The HRSG and the ST are installed later.
- Without a bypass stack, the HRSG is subject to the hot gases of the GT directly, calling for more flexibility in its construction and superior metallurgy. This problem is overcome with the installation of a bypass stack.
- The bypass stack separates the GT and the ST operations, thereby permitting the GT to operate even when a problem occurs with the ST or the HRSG.

The decision to include a diverter damper has to be very carefully evaluated. The following are the drawbacks against the advantage of flexibility in operation:

- The damper assembly is expensive and complicated because
 - Because they are subjected to a high temperature, the damper and the stack have to be of ss construction.
 - The pressure requires heavy-duty construction.
 - The damper has to be thoroughly leak proof, as the gas leakage directly contributes to loss of heat and hence the cycle efficiency.
- This equipment and its ducting occupy sizable space.
- Gas-pressure drop together with small gas leakage in the bypass stack contributes to the loss of power.

The present trend is to avoid the bypass stack with enhanced reliabilities of all systems.

14.4.6 Fired HRSGs

Heat recovery steam generators can be fired or unfired, depending on whether additional fuel is burnt. There are two modes of firing:

1. *Supplementary firing*, if the fuel (oil or gas) is burnt for generating part of the steam need
2. *Auxiliary firing*, if the fuel is burnt for generating 100% steam

In both cases duty may be *continuous* or *intermittent*. For a complete and speedy combustion within the narrow confines of the combustor, the excess air requirement in the GT is between 220 and 300%. This leaves the exhaust gas with 15–16% O₂, giving ample O₂ for the combustion of an additional fuel in duct burners. After the combustion, the gases at the entry to the tube banks would still have ~10 to 11% O₂.

14.4.6.1 Supplementary Firing: Is It Good or Bad?

It is tempting to add additional firing to the HRSG to get more steam from a system that appears to be capable. There is no simple answer follows:

- In the CC mode of operation, firing of additional fuel in the HRSG is not generally recommended from the consideration of fuel efficiency, as the steam cycle bypasses the entire GT cycle. In other words, the additional fuel burns at 30–35% efficiency instead of 50–55%.
- Supplementary firing is done to meet the peak duty only for a short time. The argument is that it is cheaper to run the plant for a short while at lower efficiency than to fail to meet some extra power requirement.
- During supplementary firing, the gas temperatures increase to 850–900°C instead of the usual 450–600°C, which permits generation of higher superheat and reheat temperatures, resulting in a better steam cycle efficiency.

A project-specific solution needs to be found after considering the *pros and cons*.

14.4.6.2 Additional Firing: What Does It Take?

Additional firing is an expensive facility to incorporate in duct burning because

- There is an additional gas-pressure drop of ~20 mm wg mainly because of flow straighteners upstream of the duct burners.
- It involves additional gas pressure loss in the banks due to a higher gas temperature.
- The higher gas temperature calls for a change of metallurgy for the affected banks.
- It also changes all the ducts downstream of the burners, including part of the boiler casing, of stainless steel (ss) or alloy steel (AS).
- Careful operation and maintenance are needed to prevent overheating of tubes and ducts.

14.4.6.3 Auxiliary Firing

In the *cogen* plant, it is normal to have 100% auxiliary firing so that the flow of the process steam is maintained even if the GT is taken out of the operation. Then the HRSG goes into *fresh-air firing mode*, as there is no GT gas for combustion. The air is either pushed into the HRSG by the forced draft (FD) fan or sucked in by the induced draft (ID) fan, depending on layout constraints.

The fire duct houses the circular or grid duct burners. They have been explained in Chapter 10. The fuel in the duct burner can be different from the GT fuel.

14.4.7 Design Aspects

14.4.7.1 Thermal Design

1. *Principles*. The thermal design of HRSGs is different from that of conventional boilers:
 - a. There is no luminous radiation on tubes.
 - b. Practically all tubes are finned.

- c. There are no slagging or fouling effects from ash.
 - d. The gases can be cooled to low levels such as 80°C.
 - e. There can be single (in small units), double, or triple pressure levels.
 - f. There is no steam temperature control (STC) range.
2. *Fin tubes.* A heat recovery steam generator is a heat extractor from medium-grade heat and consequently needs an enormous amount of HS to generate steam and add superheat. It is not possible to do so with plain tubes. Tubes with closely spaced fins prove to be the only solution.
 3. *Pressure levels.* Cycle efficiency increases by nearly 4% when single pressure is changed to double pressure.
 4. *Counterflow tube banks.* As the temperature of the gases progressively drops, the superheater (SH), the reheater (RH), the EVAP, and the ECON tube banks for each pressure level are arranged serially. Tube banks are all arranged in counterflow, to minimize HS. However, parallel flow is required mainly in the hottest portion, with the final SH and RH, to limit the metal temperatures.
 5. *Pinch point.* As the gases transmit their heat to the EVAP surfaces and get cooled, there is a point below which cooling of the gas demands a disproportionately large surface, making the design expensive. This gap between the gas temperature and the EVAP surface is required to attain optimum HS, which is known as the *pinch point*. A gap ranging from 8 to 14°C is followed in the present designs. The reduction to the present levels has increased the HS of the EVAP by nearly 100%.
 - a. *Approach temperature.* The gap between the ECON outlet and the gas temperature is another important parameter and is known as the *approach temperature*. It should be between 8 and 14°C. This also ensures that there is no steaming in the ECON. However, with cycling becoming more popular, steaming in the ECON is inevitable. The last tubes would then act as a forced-flow EVAP. Piping from the ECON to the drum should be upwardly sloping to permit a smooth flow of steam. Also, the drum should have separate set of hydroclones.
 - b. *SH approach temperature.* The approach temperature for SH is usually between 22 and 33°C (40–60°F) (Table 14.7; Figure 14.16).
 6. *Multiple boilers in one.* Heat recovery steam generator can be conceived as two or three boilers, operating at different pressure and temperature levels, accommodated within a single enclosure.
 - a. There are at least two levels of operating pressures except in very small units.
 - b. In power cycles of 100 MWe and above (Fr 6FA), three levels are common.
 - c. The pressure levels are designated as HP, IP, and LP denoting high, intermediate, and low, respectively, and usually utilized in the following manner:
 - i. High-pressure steam is for power generation. High pressure level has steadily gone up to 170 bar for large turbines such as 9FA and the final SH and RH steam temperatures to 570°C.
 - ii. Intermediate-pressure steam is for power generation and also for steam injection into the GT. The IP levels are generally 25–35 ata and up to 450°C. In RH boilers, IP steam is added to the RH steam from the turbine.
 - iii. Low-pressure steam is for heating the condensate or for deaeration at ~3 to 6 bar.

TABLE 14.7

Approach Temperatures

Surface	Approach Temperature		
	°C	°F	
Economizer	8–14	14–25	Pinch point
Evaporator	8–14	14–25	
Superheater	22–33	40–60	

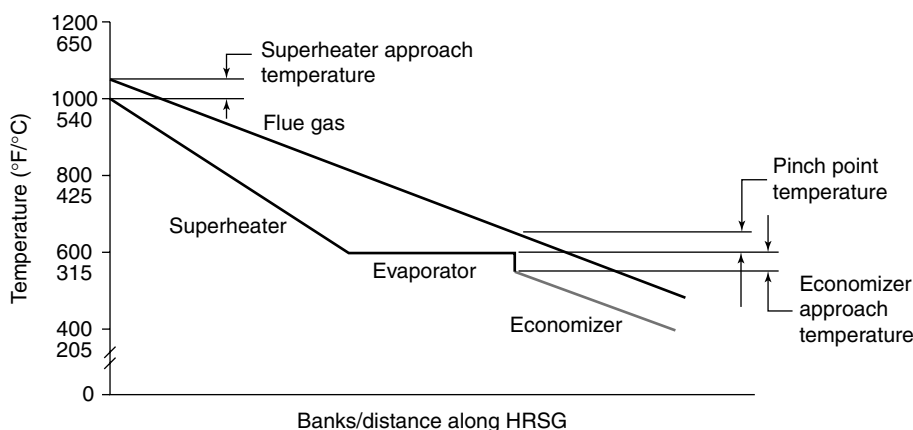


FIGURE 14.16

Typical temperature profile of heat recovery steam generator (unfired).

7. For 300 MW and above (Fr 9FA), RH is also employed. Unlike in power boilers, the RH steam flow is higher in HRSGs, as the IP steam is also generated at the same pressure and added to the RH flow.
8. *Low gas exit temperatures.* The gas exit temperatures of HRSG are usually much lower than those in conventional boilers, as the condensate is directly fed to the preheater of the HRSG from the condenser at ~ 30 to 40°C . For gas firing with no sulfur, an exit temperature as low as 75 – 80°C can be adopted, with the metal temperature kept at 55 – 60°C by recirculating the condensate. With sulfur in fuel, depending on the sulfur content, a suitable exit temperature has to be chosen to avoid corrosion of tubes, based on limits given in Figure 6.36. The extent of the gas cooling to attain a low exit temperature is dependent on the fuel costs.
9. *Swell in EVAP tubes.* The HRSGs are exposed to a severe and abrupt heating, particularly when the GT starts and the exhaust gases enter the HRSG. The EVAP tubes generate steam very quickly, which finds its outlet into the respective steam drums, causing the water to rise to levels that can cause carryover. The drums are to be sized for providing adequate volume to take care of the swell. Simpler internals such as deflection baffles and demisters are better than vertical cyclones, which occupy more space. The swell effect is more pronounced in vertical designs in which the EVAP tubes are arranged in coil form as opposed to individual short tubes in the horizontal design. The coils tend to accumulate steam and discharge into the drum, causing a bigger swell in vertical design. The vertical designs may demand larger drums, particularly if there is no bypass stack.

10. *Superheater and RH tube materials.* Materials used in conventional boilers are used in HRSGs as well. Even for high steam temperatures such as 570°C, T91 is adequate. Stainless steel is not suitable because:
 - a. The long HRSG tube lengths, subject to much higher elongation with ss (30% more than other steels), create differential expansion.
 - b. Since tube metal temperatures are only ~35°C higher than the bulk steam temperature with no radiant heat, T91 is quite adequate.
 - c. The fear of stress corrosion cracking is always present with ss.
 The fin material must be a high Cr–Ni steel to withstand high gas temperature.
11. *Attemperator.* There is no need for attemperation in an HRSG. However, attemperators are provided at final SH and RH to limit the temperatures and protect the tube materials from excessive temperature during the cycling duty. Providing hot water from ECON exit instead of cold condensate is gaining acceptance to eliminate the thermal shock.
12. *Feed water regulator (FWR) downstream of ECON.* During cycling, steaming of the ECON is inevitable. Particularly in vertical HRSGs, steaming upsets the flow of feed water to the drum, as the direction of water flow is downward. By locating the FWR downstream of the ECON, full pump pressure is made available in the entire ECON, reducing the chances of steaming.

14.4.7.2 Mechanical Designs

1. *Bank depths.* Considerations are nearly the same as in conventional boilers. The depths are limited to ~3 m from access requirements. There is no soot blowing requirement in HRSGs.
2. *Tube and casing clearance.* With the tube banks tightly packed with finned tubes and gases flowing at high speeds, the gaps between the end tubes and casing assume great importance. Unless they are properly closed, gas bypassing can sharply reduce the performance.
3. *Soot blowers.* Soot blowers (SBs) are rarely installed, as the gases are usually clean. With certain fuels such as kerosene, there may be fouling of banks by soot. Soot deposition can be predicted by Bacharach index of the fuel, but previous experience can determine the need for SBs.
4. *Insulation.* In HRSGs the insulation can be on (1) the inside (hot casing), (2) the outside (cold casing), or (3) on both sides. With no water-cooled membrane panels, the hot gases directly contact the casing. In smaller HRSGs, where the exhaust gas temperatures are lower than ~480°C, MS casing with external insulation can be adopted. The method for higher gas temperatures is insulating the casings from inside and securing by alloy liner plates. As the gases cool down after a few banks, it may be possible to adopt insulation from the outside. Glass and slag wool are usually limited to 500°C and sometimes up to 650°C in blanket form. In fire ducts with supplementary firing, the gas temperatures range from 900 to 950°C and require ceramic fiber blankets.
5. *A weather damper* between the last bank and the stack is typically an HRSG feature. Weather damper is a pair of eccentrically supported semicircular halves that close automatically when the upward flow of gases ceases. It prevents ingress of water from rain or snow into the unit to avoid corrosion of internals when it is stopped for long periods. Dampers are extremely useful in conserving the heat

when the unit is taken off the range for short periods. As cycling of the HRSGs is gaining importance, weather dampers are considered essential for horizontal units as well. Also refer Section 7.3.2.4 for some more details.

6. *Duct burners* or in-line circular burners are employed for firing supplementary fuel. Because minimal upstream duct is provided, flow straighteners in the form of perforated plates are used. For more details about duct burners, refer to Section 10.3.
7. *Fire duct*. Design is complex, more so in the horizontal design. The footprint of the duct and the length of the HRSG can be minimized by increasing the slope of the fire duct roof consistent with the filling of the duct with gases. This is usually monitored by flow modeling or data from previous installations.
8. *Stack* is an integral part of the vertical HRSG and independent in the horizontal design. With natural gas firing, the stack height for gas dispersion is not a consideration. The stack must be higher than the surrounding buildings. However, as the gas volumes are very large, the stack velocities are higher in 20–25 m/s range to reduce the diameter. As the gas temperatures are low, ~80 to 120°C, the stack is usually insulated from the outside to avoid condensation of moisture, which can cause corrosion.

A typical heat balance diagram (HBD) and the temperature profile graphs are depicted in Figures 14.17 and 14.18.

14.4.8 Fins and Tubes

Finned tube is the raw material for HRSGs. The progress achieved by HRSGs could not have been possible without the development of finned tube making. Figure 14.19 shows a typical finned tube.

14.4.8.1 Fin Types

A strong tube-to-fin bonding is the basis an HRSG.

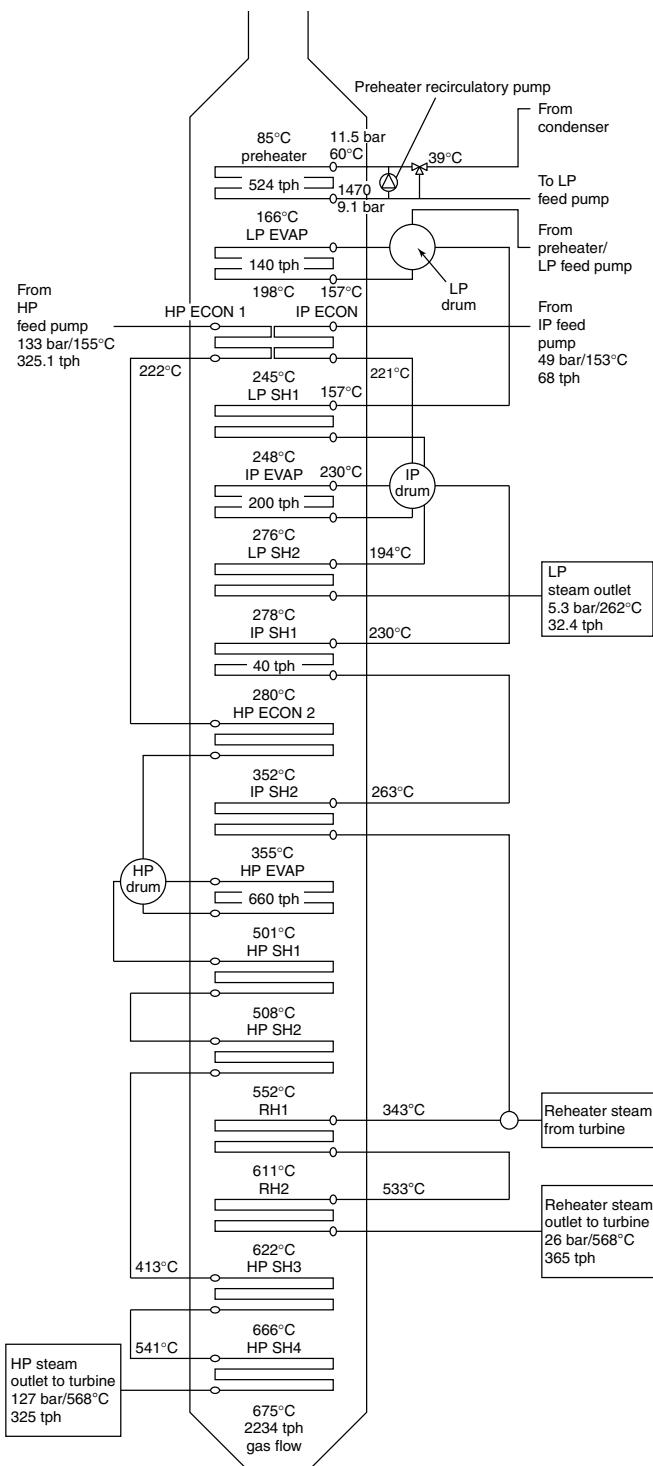
- Start-up conditions when the bypass stack is not ahead, impose the most severe duty on any boiler tube, as the GT exhaust gases abruptly enter a cold unit and reach 60–70% of their full temperature in ~5 to 10 min. Unless the bonding between the tube and the fin is robust, the differential temperature would loosen the fins.
- For predictable heat-transfer rates and strength, the uniformity of bonding between tubes and fins is also highly important.

High-frequency resistance-welded fins alone can withstand the conditions and are the only recommended types today.

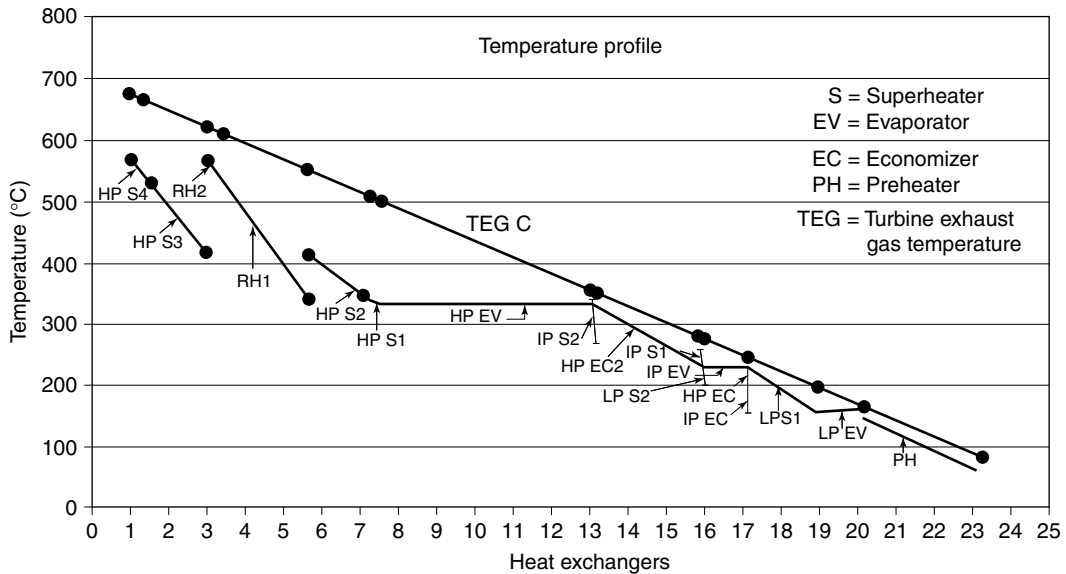
Plain tubes among the fin tubes. The HRSG is entirely made of fin tubes except for the front tubes of the RH and the final SH, where containing the fin temperature due to high gas and steam temperatures can be difficult. Also, for achieving desired steam temperature, plain tubes are required as the additional HS of the fins may not be required. The remaining tubes are finned.

14.4.8.2 Fin Parameters

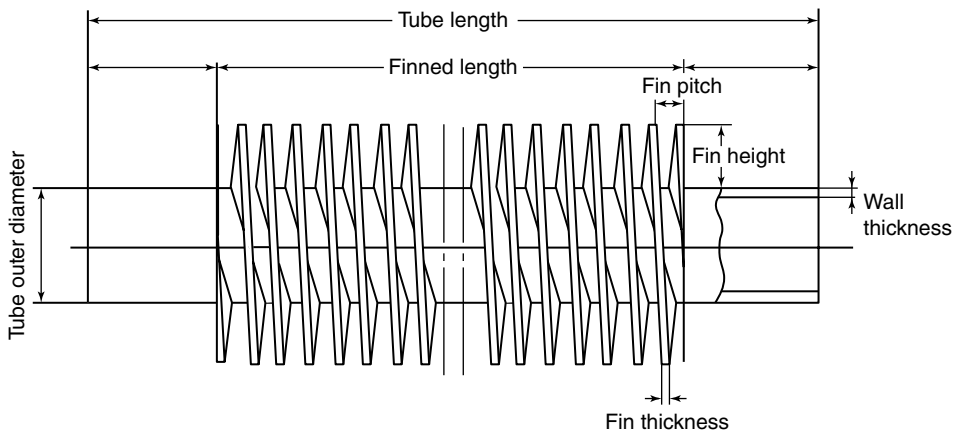
- Fin thicknesses vary from 0.8 to 1.5 mm.
- Maximum pitching can be as high as 310 fins/m with 0.8 mm fins.

**FIGURE 14.17**

Heat balance diagram of triple-pressure and reheater RH (3P + RH) heat recovery steam generator behind 9FA gas turbine. ECON, economizer; EVAP, evaporator; HP, high pressure; IP, intermediate pressure; LP, low pressure; RH, reheater; SH, superheater.

**FIGURE 14.18**

Temperature profile for heat balance diagram of triple-pressure and reheater (3P + RH) heat recovery steam generator behind 9FA gas turbine.

**FIGURE 14.19**

Finned tube.

- Heavy fins are for heavy fuels, and thin fins are for gases.
- Maximum height of the fin is governed by the cooling effectiveness of the steam or water inside the tubes. Normally fin height is limited to 15 mm.
- Serrated and solid fins are the two types.
 - *Serrated fins* provide more heat transfer surface for the same size and are cheaper. Unfortunately, they are suitable only for clean fuels that leave no deposits between serrations, which reduce the heat transfer. More than 90% of the HRSG is built with serrated fin tubes with clean gases (Figure 14.20).
 - *Solid fins*. Even with clean fuels the final SH and RH sections are made of solid fins, as the fin cooling is better (Figure 14.21).

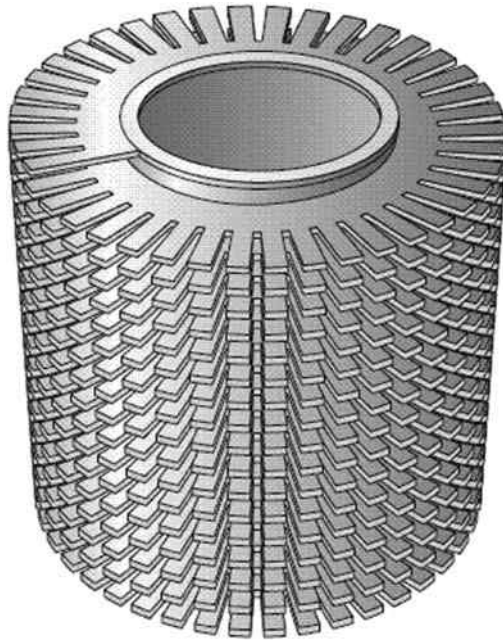


FIGURE 14.20
Tube with serrated or segmented fins.



FIGURE 14.21
Tube with solid fins.

14.4.8.3 Tube Materials

Tube material selection is governed by the metal temperature limits specified by the applicable boiler construction codes. Tube metal temperatures, in the absence of radiation from flames, are $\sim 10^{\circ}\text{C}$ higher than the bulk water temperature for ECON and EVAP tubes, and $\sim 35^{\circ}\text{C}$ higher than the average steam temperature for SH and RH. Although common tube materials in conventional boilers are adequate for HRSGs, the high fin temperatures (half way between the gas and the tube temperatures, depending on the fin thickness, height, and cooling effectiveness of the fluid in the tube), require superior metallurgy. The usual fin materials and their limiting temperatures are given in Table 14.8. Normally any combination of tube and fin can be made in this range because the welding poses little difficulty.

14.4.8.4 Tube Length

The most important dimension of the HRSG is the tube length that decides the length and height of the unit. The intent is to increase it to the maximum, consistent with the ability of the exhaust gases to sweep the entire length properly and prevent performance shortfall. Gas velocities of $\sim 15\text{ m/s}$ are employed to balance the pressure loss and good heat transfer. The resulting tube lengths are roughly as given in Table 14.9. The width of the unit automatically follows this. The site location, erection procedures, and transportation limits are also factors. For the largest HRSGs, tube lengths as long as 26 m are employed.

The finned tube lengths are given in Table 14.9 and actual tube lengths will be a little larger.

TABLE 14.8

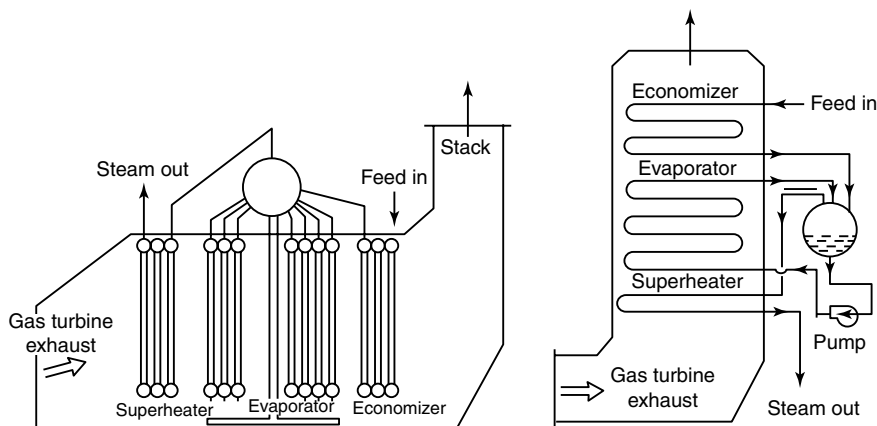
Fin Materials and Limiting Temperatures

Material of Fin	Limiting Metal Temperature ($^{\circ}\text{C}$)
Carbon steel	480
11% Cr steel	650
18–8 Cr–Ni steel	870
25–12 Cr–Ni steel	1040
25–20 Cr–Ni steel	1090

TABLE 14.9

Typical Tube Lengths (Finned) of Heat Recovery Steam Generators

Gas Turbines	Approximate Gas Flow (tph)	Approximate Finned Tube Length (m)
LM6000	463	9
Fr 6B	505	9
Fr 6FA	713	12
Fr 9E	1456	15
Fr 94.2	1793	18
Fr 9FA	2526	20

**FIGURE 14.22**

Horizontal and vertical heat recovery steam generators.

14.4.9 Vertical and Horizontal HRSGs

Two types of designs have evolved.

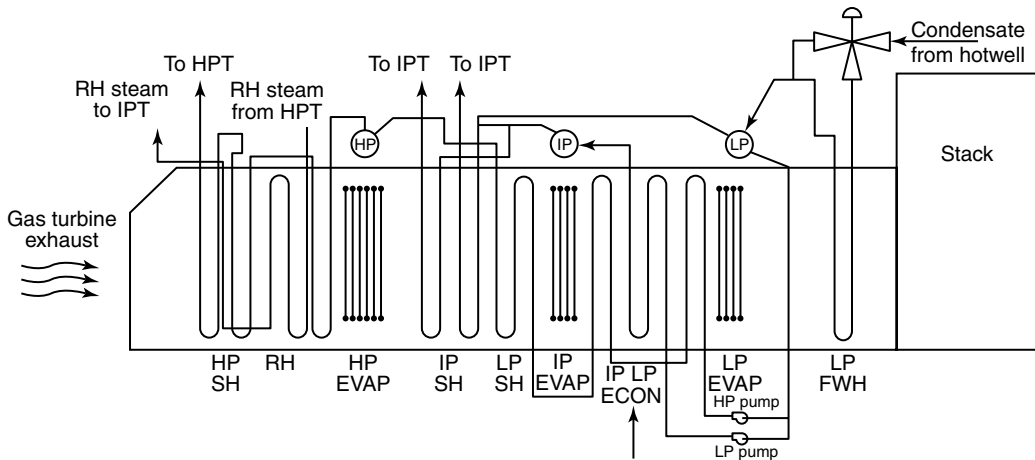
1. The horizontal design with natural circulation in the United States
2. The vertical design with forced or assisted circulation in Europe

The direction of the gas flow determines the nomenclature. Consequently, a vertical HRSG has horizontal tubes and vice versa. Horizontal and vertical HRSGs are shown in Figure 14.22.

14.4.9.1 Horizontal HRSG Design

Figures 14.23 and 14.24 depict a typical horizontal HRSG.

- The horizontal design provides natural circulation under all conditions of operation. The circulation ratio is ~ 6 or $8:1$ in the HP circuit and even higher in the IP and LP circuits.
- The design is simple, and the supporting structure is light, with fewer platforms.
- The stack is supported from the ground with no load on the structure.
- Erection is simpler, and requires less time.
- The tubes are bigger in diameter—normally 38, 44.5, 50.8, and 63.5 mm ($1\frac{1}{2}$, $1\frac{3}{4}$, 2, and $2\frac{1}{2}$ in.) OD. The heat-transfer coefficients are comparatively lower, resulting in a greater surface and thicker tubes. Thus, the overall tube weight is more.
- The swell effect is not similar to that of vertical units where the tubes are continuous loops and the accumulation of steam from all the legs takes place before discharging into the drum. Hence the drums can be comparatively smaller.
- It occupies more floor space. If a catalyst for NO_x control is also included, the footprint increases.
- With headers on both top and bottom, there is a limitation on the ability of the tubes to expand freely and quickly as needed for cyclic operation. Designs now

**FIGURE 14.23**

Triple-pressure and reheater (3P and RH) unfired horizontal heat recovery steam generator. ECON, economizer; EVAP, evaporator; FWH, feed water heater; HP, high pressure; IP, intermediate pressure; LP, low pressure; SH, superheater.

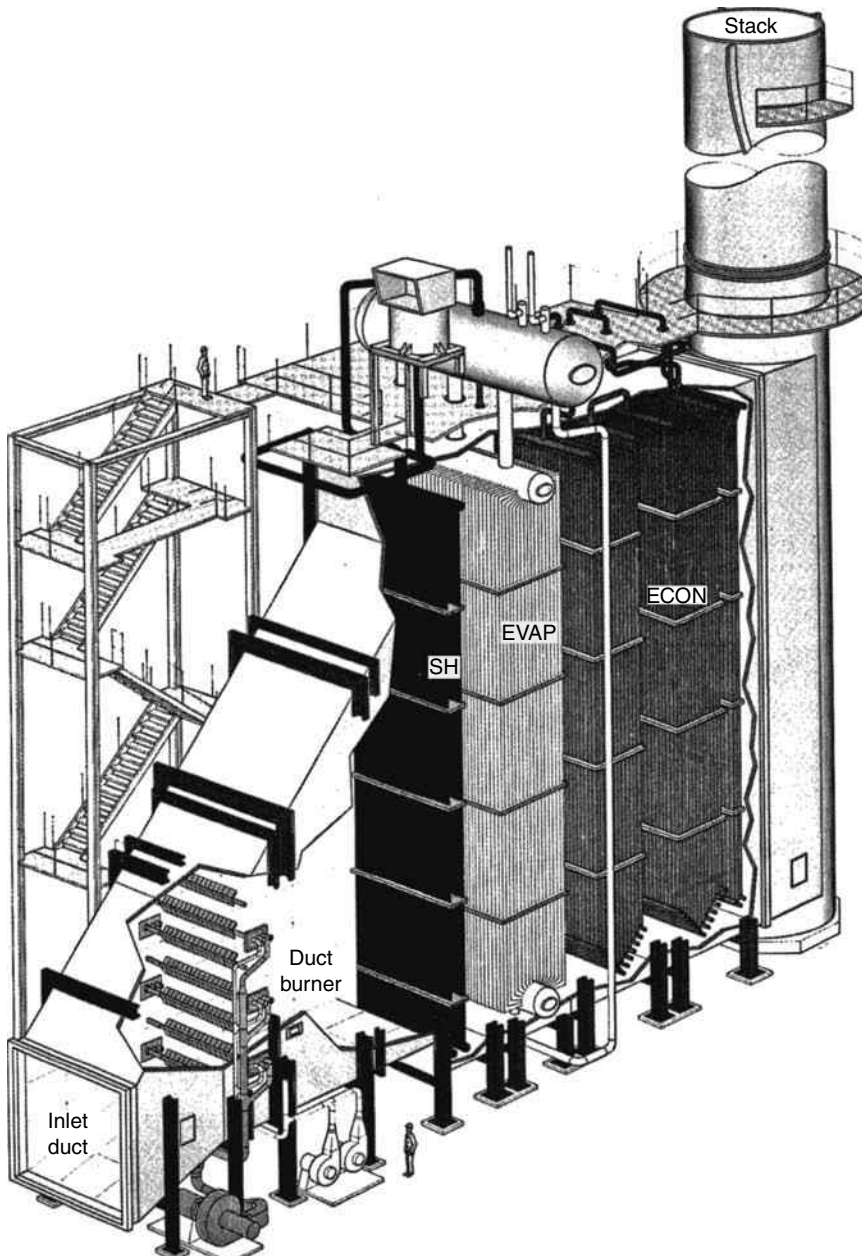
minimize this problem. But inherently they are less flexible and hence less suited for cycling duty.

- As the headers are low and the blow tanks are at a higher level, pump assistance may be needed for blowoff and draining.

14.4.9.2 Vertical HRSG Design

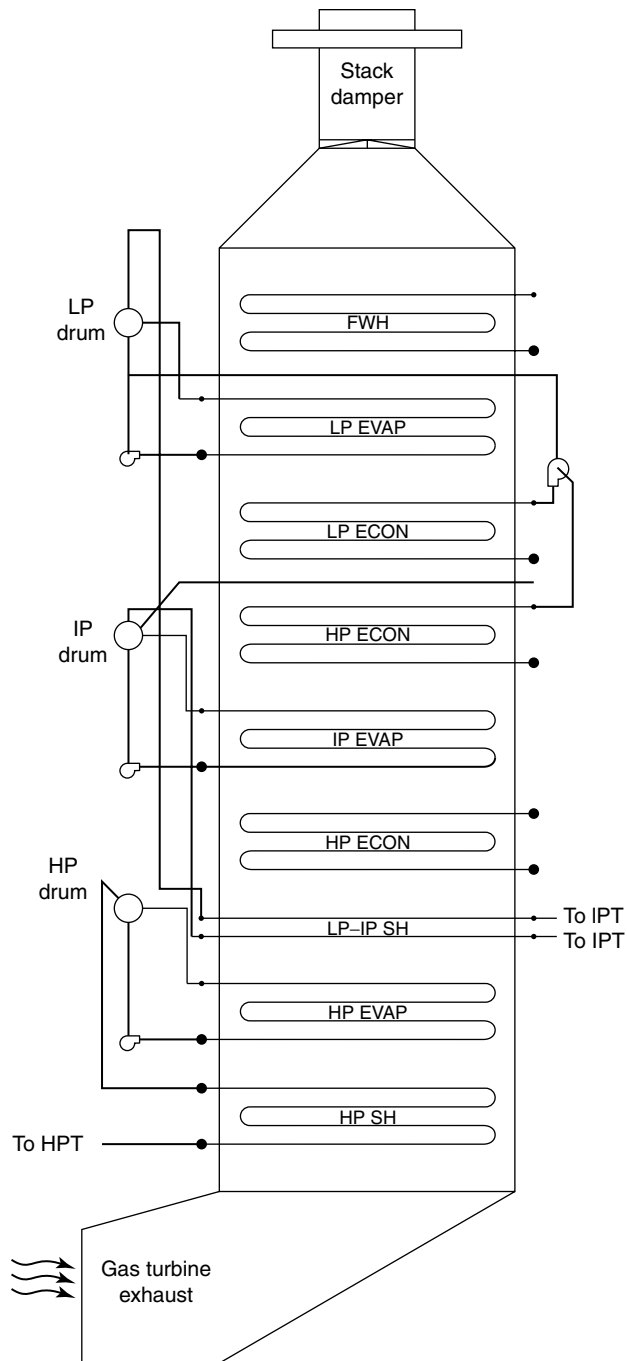
Figures 14.25 and 14.26 depict a typical vertical HRSG.

- European in origin, the vertical design HRSGs employ horizontal coils that are always top supported from the structure to allow free expansion downward. The HS modules are suspended by suspension tube sheets.
- The tube sheets are pin-jointed to allow free lateral and downward movement. Further, the holes in the tube sheet are larger by ~ 2 mm than the finned tubes, permitting a free tube expansion. With three-dimensional movement, the flexibility for expansion is very high.
- The headers are all located outside the gas path. The connecting tubes to the header have 90° bends to enhance the flexibility.
- The vertical design, with long horizontal tubes and low circulation ratios of 3 to 1.9:1 in HP circuit, requires assistance in circulating the water. Circulating water pumps were routinely provided. Currently, no pumping is required up to ~ 130 bar design pressure. During startup, however, induced circulation requires the help of a boiler feed pump (BFP).
- The safety margin is somewhat low.
- A vertical design is more compact in plan area. It is taller.
- The structure is heavy, as the load of the tube banks and the stack has to be supported. The wind loads on the stack are very heavy. The platforms are also heavier because the unit is taller.

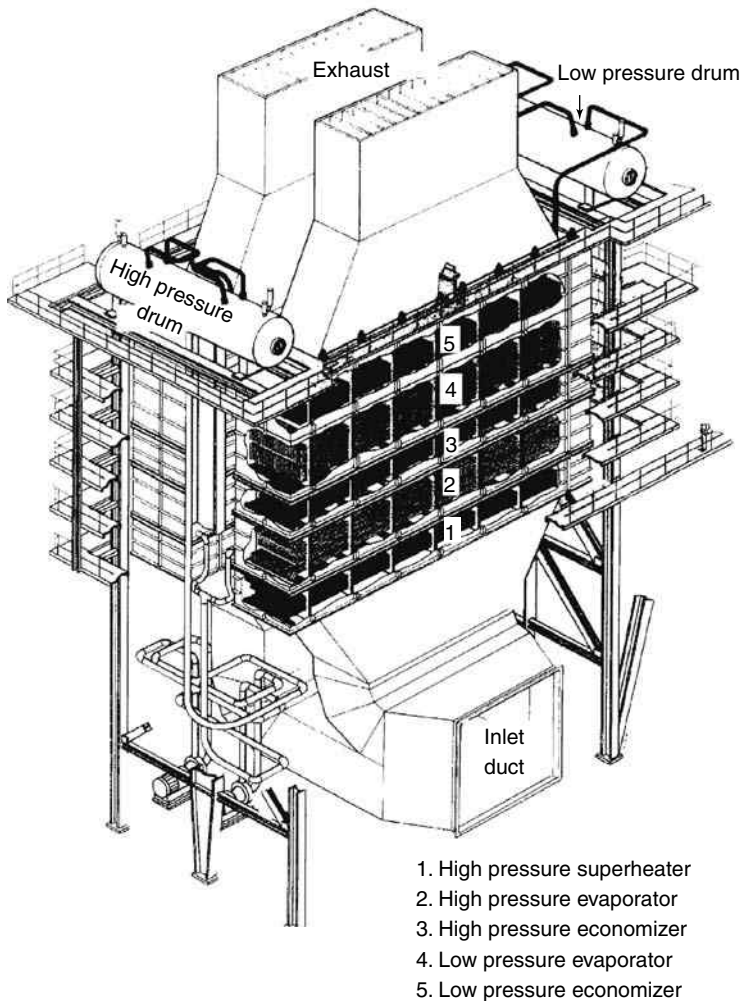
**FIGURE 14.24**

Single-pressure (1P) fired horizontal heat recovery steam generator. ECON, economizer; EVAP, evaporator; SH, superheater.

- The tube diameters are lower—31.8, 38.1, and 44.5 mm OD. The heat transfer, therefore, is better, and the surface requirement is smaller. The tube thicknesses are also smaller. These factors contribute to a reduced tube weight.
- Reduced tube diameters provide reduced water holding and hence reduced thermal inertia. The serpentine coils permit a free and fast expansion of tubes during

**FIGURE 14.25**

Triple-pressure (3P) vertical heat recovery steam generator. ECON, economizer; EVAP, evaporator; FWH, feed water heater; HP, high pressure; IP, intermediate pressure; LP, low pressure; SH, superheater.

**FIGURE 14.26**

Double-pressure (2P) vertical heat recovery steam generator.

startups when gas temperatures increase by as much as 350°C in 5 min. This design is inherently better suited for cycling duty.

- Swell effect is felt more in vertical designs as explained in Section 14.3.7.1, calling for relatively larger and hence thicker drums.
- The fin heights are usually <15 mm, yielding high efficiency. Also, vertical fins tend to be self-cleaning in comparison with the horizontal fins.
- With pressure parts (PPs) located ~6 m above the ground, the drainage to blow-down tank is by gravity and does not require pumping.
- Construction is more time-consuming and complete modules must be assembled in the shop.

There is no clear advantage of one design. With many leading HRSG vendors making both types, the disadvantages are disappearing. The layout and cycling needs decide the type to be adopted for a particular duty (Figures 14.25 and 14.26; Table 14.10).

TABLE 14.10

Comparison of Horizontal and Vertical Heat Recovery Steam Generators

Parameter	Horizontal	Vertical
Output and efficiency	Equal	Equal
Heating surface	Slightly higher	Base
Plot plan	~30% more due to inlet duct angle and stack	Base
Emission control	Needs more length	Needs more height
Supplementary firing	Easy in inlet duct and banks; staged firing is easy	Easy in inlet duct, difficult in banks; staged firing is more difficult and expensive
Cycling duty	Being improved	Much better
Access	Headers and banks not easy access	Easy, banks form platforms; no scaffolding needed
Erection time/effort	Base	Slightly more
O&M costs	Slightly more	Base
Total cost	Equal	Equal

14.4.10 System Configurations of Typical HRSGs

Table 14.11 captures the HRSG process configurations in typical CC modes behind some popular GT models. The gas flow is based on NG firing at 15°C. The steam flow and temperature refer to HP, IP, LP, and RH conditions serially.

- The high efficiency of the aeroderivative GT can be gauged by high firing and low gas exhaust temperature [note (1) in Table 14.11].
- Steadily rising exhaust temperatures accompany the increase in the GT size. The exhaust gas pressures are also higher with the increasing GT size, permitting more tube banks in HRSG.
- This makes it possible to adopt very high SOT and inclusion of the RH when the ST is larger than ~100 MWe. The gas temperatures are ~570°C in large CCs [note (3) in Table 14.11].
- In a conventional boiler, furnace exit gas temperature (FEGT) cannot be <1000°C for a final SOT of 570°C; it is only ~615°C in HRSGs. The terminal temperature difference is as low as 25°C due to the very high gas quantities of the HRSGs [note (4) in Table 14.11].
- An SOT higher than GT exhaust temperature is indicative of supplementary fuel firing [note (2) in Table 14.11].
- Power generation is dependent on the ambient conditions.

14.4.11 Once-Through Steam Generators (OTSGs)

Subcritical once-through flow is an advanced version of the HRSG, which requires no drums, risers and downcomers, blowdown system, etc., associated with circulation. There are no distinct ECON, EVAP, and SH sections; water enters the coil and comes out as steam. Therefore, the various tube sections and headers comprise a single bank. As the cooling

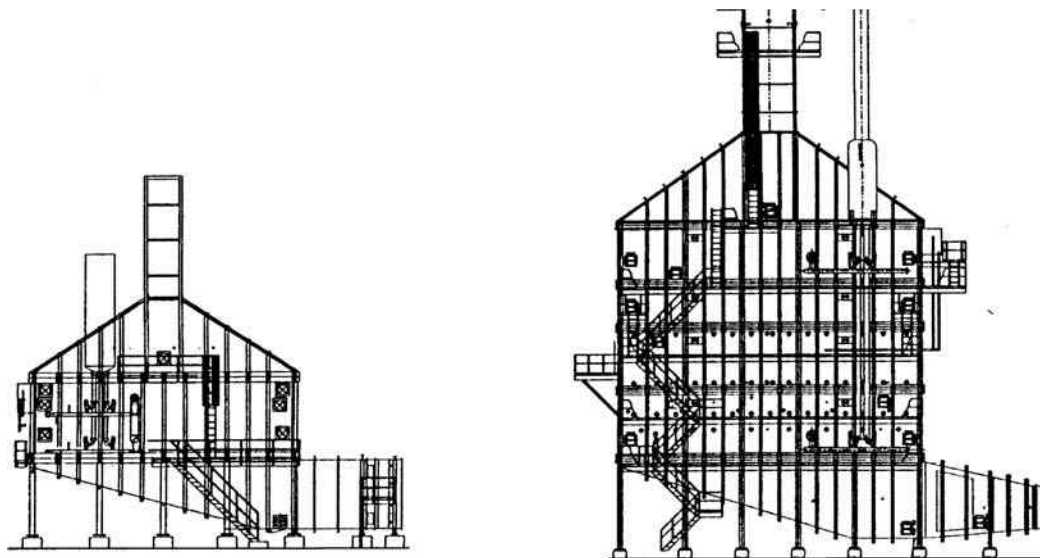
TABLE 14.11

Process Parameters of Heat Recovery Steam Generators (HRSGs) in Various Combined Cycle Plant Configurations

Gas Turbines			Exhaust Gas			HRSG Steam			
Design	Type	Approximate Gas Flow (tph)	Approximate Gas Flow (kg/s)	Temperature (°C)	Steam Flow (tph)	Steam Flow (kg/s)	Pressure (bar A)	Temperature (°C)	Plant Capacity (MW) (Approximately)
General Electric	Fr 5	441	122.5	488 (1) (2)	98	27.22	113	520	20 plus steam
General Electric	Fr 6B	505	140.3	539 (1) (2)	61	16.95	84	514	48
					11	3.06	16	Saturated	
General Electric	LM6000 (aeroderivative)	463	128.6	435	119.7	33.25	110.3	516	60
					17.7	4.92	23	242	
General Electric	Fr 6FA	713	198.0	592	110.7	30.75	107	542	101
					8.2	2.28	27.5	314	
					8.2	228	4.9	227	
General Electric	Fr 9E	1456	404.4	539	186	51.67	105	525	168
					23	6.39	14	270	
Siemens	SGT 5-2000 E V94.2	1793	498.0	545	216	60.0	113	524	222
					38	10.56	24	328	
					19	5.28	5	223	
Westinghouse	SCT 6-5000 F W501 F	1655	459.7	613 (3) (4)	189	52.50	133	556	290
					33	9.17	32	315	
					37	10.28	5	291	
					215	59.72	29	555	
General Electric	Fr 7 FA (60 Hz)	1605	445.8	608 (3) (4)	371	103.06	128	568	285
					7	2.13	41	347	
					1	0.28	5	347	
					374	103.89	38	552	

Ahlstrom	GT 26	2279	633.0	615 (3) (4)	322	89.44	129	568	400
General Electric	Fr 9FA	2526	701.7	610 (3) (4)	332	92.22	127	568	390
Mitsubishi	701 F	2347	651.9	591 (3) (4)	271	90.33	124	540	400
Siemens	SGT 5-4000 F (94.3 A)	2420	672.2	582 (3) (4)	299	83.06	130	567	400

Note: Numbers (1-4) given in parenthesis are notes that are explained in Section 14.4.10.

**FIGURE 14.27**

Once-through steam generators versus heat recovery steam generators. (From Innovative Steam Technologies, Canada. With permission.)

effect of steam is substantially less, the tubes are made of very high temperature-resistant materials such as Inconel alloys. OTSG permits dry running of the unit, dispensing with the bypass stack. OTSGs are made in vertical design. Figure 14.27 compares an OTSG with an equivalent HRSG.

OTSGs are slightly more efficient than the HRSGs, as the preheater gas outlet temperature can be lowered without the fear of low-temperature tube corrosion because the tubes are made of Inconel. Also, the gas leakage in the bypass stack is not an issue.

The boiler PPs are significantly lighter and compact. The structure is also lighter. The space requirements are slightly lower. The instrumentation and control needs are fewer as a single feed control valve at the inlet varies the output. The construction time is lower.

The tube bank of Inconel makes OTSG more expensive than HRSG. Where compactness and less weight are important such as in a barge-mounted plant or a marine application, OTSG provides a unique solution. Also, where it is highly beneficial to shorten construction time, OTSG can be considered favorably. OTSGs are confined to ~60 tph steam output behind smaller turbines such as LM6000 or Frame 6 or Trent. In large conventional plants, the HRSGs are preferred.

14.4.12 Performance Testing

There are major differences in approach in testing of conventional boilers and HRSGs. A brief description appears in Section 1.6.6.

14.4.13 Layout of CCPP

A typical layout of a CCPP with vertical HRSG is shown in Figure 14.28.

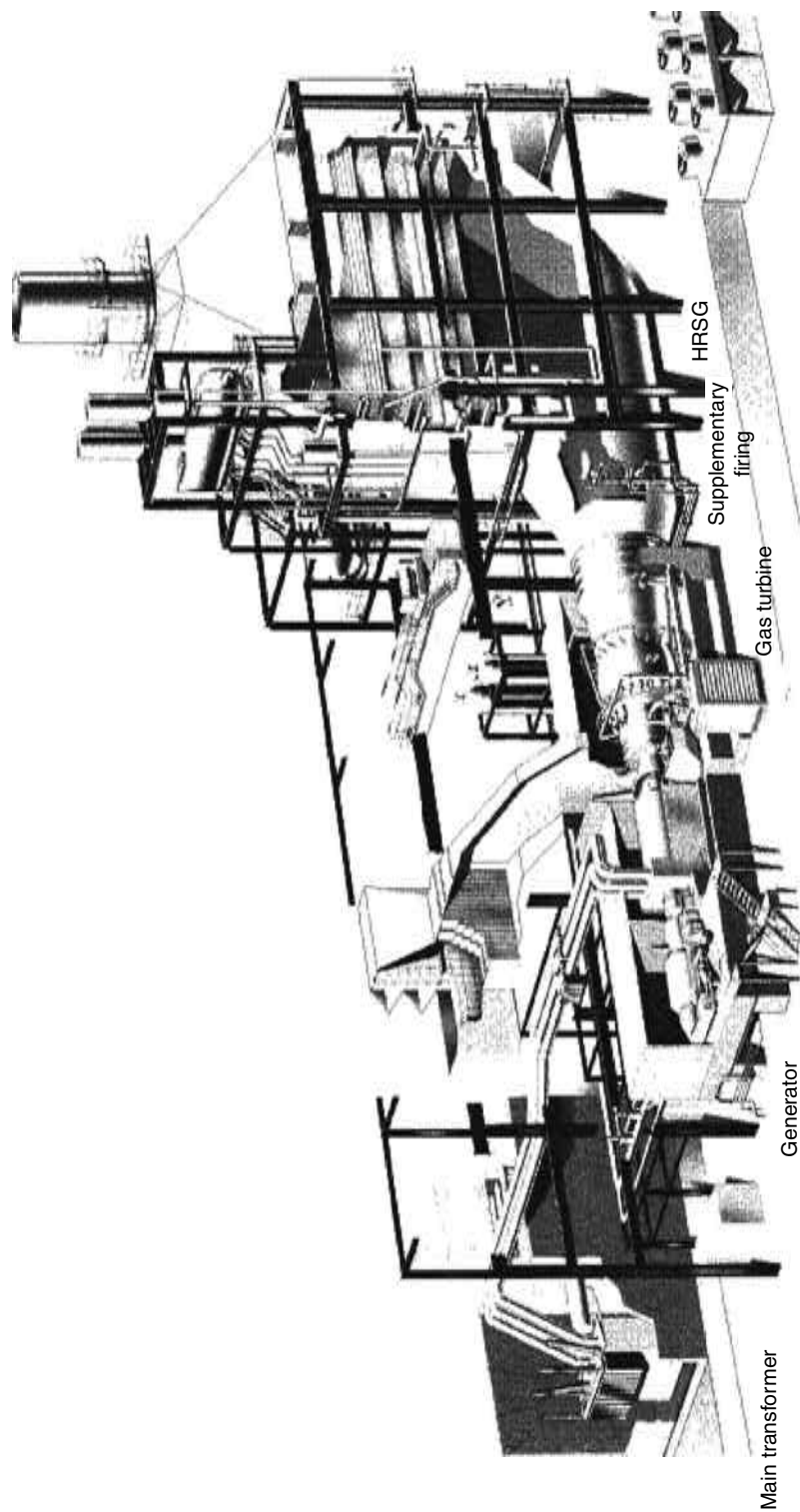


FIGURE 14.28
Typical combined cycle power plant with vertical heat recovery steam generator (HRSG).

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Glossary

Airheater: It is usually the last heat trap of the boiler meant to recover heat from the flue gases using part or total combustion air as the cooling medium. The heat is transferred to air and not to water.

Recuperative airheater: Tubular airheater is a static recuperative airheater.

Regenerative airheater: Rotary airheater is a moving regenerative airheater.

Rotary airheater: It contains a rotor filled with corrugated sheets that are alternatively heated and cooled and thus transfer heat from gas to air. It can be a moving rotor as in Ljungstrom design or moving hoods as in Rothemuhle design.

Tubular airheater: It contains a nest of tubes used for transferring heat from gas to air. Tubes can be arranged vertically or horizontally. In a vertical tubular airheater, gases flow through tubes, and in a horizontal tubular airheater, air flows through tubes.

Ambient conditions: Prevailing site conditions, namely, the temperature, the relative humidity, and the altitude, that affect performance of the boiler and the auxiliaries.

Amines: These are chemicals added to water in the preboiler section to react with CO₂ so that corrosion of the condensate lines can be avoided.

Analysis of fuels: Assay of the constituents of fuels expressed as a percentage.

Proximate analysis: The constituents are listed as the percentages of moisture, ash, FC, and VM, which are very useful in assessing the combustion of fuel.

Ultimate analysis: The constituents are indicated in their elemental form as the percentage of C, H, O, N, S, and ash, which are readily amenable to combustion calculations.

Anthracite: The most ancient and fully formed coals. They are dense, very hard, and brittle. They appear shiny black with no layers.

Approach temperature: The gap between economizer water and gas exit temperatures. This should be normally between 8 and 14°C.

Ash: The incombustible matter of the fuel that is left behind in the crucible on heating in a fuel analysis. It does not contribute to fuel value but retards combustion. It causes gas-side erosion, slagging in furnace, and fouling and corrosion of superheater and reheater. Together with moisture it is called the *ballast or burden* in fuel.

Ash deformation temperatures: *Initial ash deformation temperature* is the temperature at which the specimen cone begins to soften at the top.

Softening temperature is the temperature at which the cone shape is lost and the height and breadth are equal.

Hemispherical temperature is the temperature at which the cone reduces to hemispherical shape.

Fluid temperature is the temperature at which the specimen is flat and the molten ash begins to flow.

Ash fusibility: An empirical method of predicting the ash behavior at high temperatures to ensure that furnace sizing is correct.

Ash recirculation ratio: The ratio of the weights of ash and carbon returned to the furnace from the rear passes to the fuel weight. Ash refiring is done to enhance the carbon burnup.

- Fouling:** The tendency to form sintered ash deposits in high-temperature areas of superheater and reheater. It reduces heat transfer and increases gas-side pressure drop.
- Slagging:** The tendency to form deposits in the furnace, division walls, and platen SH due to the building up of molten ash. Slagging retards furnace heat absorption and hence increases FEGT, which in turn promotes more fouling.
- Atomization:** Breaking down a film of liquid into a fine spray. Atomization of fuel oil is done to facilitate a complete combustion in a very short time and a small furnace volume.
- Mechanical atomization:** Mechanical force achieves atomization.
- Pressure atomization:** Here, oil at high pressure is forced through fine orifices, which help in the formation of fine mist.
- Steam or air atomization:** Here, steam or air is used to shear the oil film into fine droplets.
- Attemperation:** Removal of excess temperature from superheater and reheater steam.
- Final attemperation:** Attemperation at the end of the superheater or reheater. This is done for low-temperature superheat of $\sim 400^{\circ}\text{C}$.
- Interstage attemperation:** Attemperation between the tube banks of the superheater. This is needed for temperatures $>400^{\circ}\text{C}$. It has the added advantage of lowering the tube metal temperatures of the secondary superheater due to reduced inlet steam temperature.
- Spray attemperation:** Spraying of water to reduce the superheater or reheater temperature.
- Surface attemperation:** Removal of excess heat by exchanging with another cooling medium such as the drum or feed water.
- Backend equipment:** Last-stage heat recovery equipment comprising the economizer and airheater.
- Bagasse:** Waste generated after the crushing of sugarcane. Containing ~ 48 to 52% moisture and $\sim 2\%$ ash, it is a good fuel with gross value of ~ 2200 kcal/kg.
- Balanced draft:** In balanced draft boilers, the furnace upper portion is at nil pressure as the pushing of air and pulling of flue gas are balanced at that point. Most solid fuel-fired boilers operate in balanced draft condition.
- Bed—expanded and slumped:** Slumped bed is the defluidized bed of sand or inert material in an fluidized bed combustion boiler. When fluidized with air at adequate pressure and flow, the bed swells to nearly twice its depth and becomes an expanded bed.
- Bed coil in bubbling fluidized bed combustion:** Heating surface immersed in the expanded fluid bed of bubbling fluidized bed combustion. Usually made of evaporator surface, it can also be a superheater.
- Bed velocity in fluidized bed combustion:** The gas velocity derived by dividing the volume of gas passing through the fluidized bed by the plan area of the bed.
- Bernoulli's equation:** An energy conservation law—the sum of the pressure and the velocity/kinetic energy in a flowing fluid is constant and mutually convertible.
- Biomass:** Organic matter formed by photosynthesis. It includes crop, forest, agro-industrial residues, purpose-grown trees, aquatic plants, and even animal wastes.
- Blast furnace gas:** Waste product in the conversion of iron ore into pig iron. It is a heavy gas (about 1.25 times heavier than air) with low gross calorific value due to large amounts of N_2 and CO . There is practically no sulfur and water vapor on combustion, eliminating any threat of corrosion, both at high and at low temperatures.

Boiler blowdown: Discharges the sludge and maintains the desired balance of chemicals to prevent scale formation and carryover.

Continuous: Continuous blowdown by finely regulated micrometer valves and measured by an orifice plate is for the control of TDS in boiler water in lower pressures and silica in higher ranges.

Intermittent: Periodically carried out by specially designed full opening valves removes suspended solids and sludge in boiler water.

Boiler types

Down-shot fired boilers: This design is suitable for low-volatile coals, anthracites, petcoke, etc., where the burners are mounted downward to give u- or w-shaped flames with long residence time.

Tower-type boilers: Single-pass tall boilers where practically all surfaces except the economizer and airheater are arranged above the furnace with no gas turns on tube banks. It is popular for brown coals and high-ash coals. With no second pass, the boilers are taller.

Two-pass boilers: The furnace pass contains the platen or wing wall superheater with the remaining superheater and reheater in the interpass and the economizer in the second pass. This is the most popular design for coal. Here the flue gas takes a turnover of the heating surface provided in the interpass, making these boilers susceptible to erosion with high-ash coal firing.

Boiling: When a liquid absorbs heat from a surface that is at a temperature higher than the saturation temperature, there is a change of phase as the liquid turns into vapor.

Film: When the heating is too high and heat flux is large, the film of water at the contact surface quickly evaporates and is replaced by steam film with low conductance. As a result, the surface is no longer cooled adequately and tends to overheat. This is *film boiling*, which is to be avoided.

Nucleate: When the heating is relatively low, the bubbles form at the contact surface. They rise and carry heat. The surface continues to be covered by the water film, which keeps the surface cool and close to the liquid temperature. This is *nucleate boiling* that must be maintained in a boiler as the water absorbs its latent heat.

Brayton cycle: See power plant cycles.

Brown coal: High-moisture (50–70%) lignite.

Burner: Firing equipment for burning pulverized, liquid, and gaseous fuels. A burner brings together fuel or fuels and air in right proportions and admits them into the furnace chamber to accomplish combustion in an efficient and safe manner.

Air register: The fabricated part of the burner, which is fixed to the windbox and helps in dividing and guiding and controlling the flow of air, to provide the necessary turbulence for efficient combustion and flame shape.

Atomizer: A part of the burner in which the jet of the liquid fuel is broken down into a fine mist to facilitate a complete and speedy combustion accomplished by steam, air or high pressure.

Burners for pulverized fuel

Circular burners: Wall-mounted burners with individual turbulent bushy flames employed in both front- and opposed-wall firing of pulverized fuel.

Down-shot or vertical burners: Mounted on the front or rear arch of the boiler, these burners fire downward in a U-shape to obtain a long residence time required for burning coals with very low volatile matter.

Tangential burners: Burners mounted at the four corners of the furnace that produce long flames, forming a ball at the center of the furnace.

Burning in stokers

Mass: All fuel admitted on the grate in a thin layer where the fuel burns slowly from the top downward. Combustion rates are low.

Spreader: Sized fuel is thrown on to the grate. Combustion rates are higher and faster, as part of the fuel burns in suspension and the rest on the grate.

Calcination reaction: CaO is produced by the decomposition of lime (CaCO_3) when CO_2 is driven off on heating. It is an exothermic reaction.

Calorific value or heat value: The heating value of the fuel measured in kilocalories per kilogram or megajoules per kilogram or British thermal units per pound.

Gross or higher calorific value: Total heating value.

Net or lower calorific value: Calorific value adjusted for the unavailable heat carried away by moisture on combustion.

Carbon

Elemental: This is always higher than fixed carbon and is used in combustion calculations.

Fixed: Fixed carbon burns on the grate after the volatile matter is driven off to burn in the furnace. The higher the fixed carbon, the longer the burning of the fuel and the higher the ignition temperature.

Carbon residue of oils: Carbon left behind after volatilizing of the oil under specified conditions when fuel oil is heated out of contact with air. It is a measure of coke-forming tendency of diesel oils. It has no significance with other fuel oils. Conradson and Ramsbottom are the two methods employed.

Carnot cycle: See power plant cycles.

Carryover: Entrainment of minute water particles along with steam at the time of steam separation, carrying solid, liquid, and gaseous impurities of the water, thereby reducing the purity of steam. Foaming and priming are the two main reasons for carryover.

Foaming: At higher steaming rates when the limits are exceeded for alkalinity, dissolved solids, oil, or phosphates, a stable foam is formed at the steam-water interface, promoting an increased carryover.

Priming: Entrainment of slugs of water in the steam outlet of drum. This is due to sudden decrease of pressure or increase of water level. Priming is not due to the water impurities.

Cavitation: Sudden pressure drop to below the vapor pressure and subsequent recovery in valves and pumps, with attendant forceful breakdown of the bubbles. Damage to the valve and pump internals severely reduces life.

Char: Devolatilized coal. Same as fixed carbon.

Chemical dosing: Administering of specified chemicals upstream of boiler feed pump and into the steam drum to condition the feed and drum waters, respectively.

High-pressure dosing: Dosing of chemicals directly into the steam drum at high pressure mainly to (1) raise and maintain the pH of the drum water to the required levels, (2) condition the sludge for an easy removal, (3) form soft sludge of suspended solids for intermittent blowdown, and (4) prevent buildup of foam inside the drum.

Low-pressure dosing: Dosing of chemicals at the deaerator outlet upstream of the boiler feed pump to raise the pH of feed water and remove the traces of oxygen to make water suitable for feeding into economizer or drum.

Circulation of boiler water: The number of times water passes through the evaporator circuits before it turns into steam.

- Assisted:** When there is an external pump to augment the boiler circulation at higher pressures of 150 bar and above.
- Forced:** When there is an external pump to induce the boiler circulation.
- Natural:** Boiler circulation that relies purely on the density difference between the colder supply and the hotter riser circuits, the most common type of circulation adopted for subcritical pressures because of its (1) simplicity with no pump and associated equipment and (2) self-limiting characteristic.
- Clinker:** Molten ash slag that accumulates the coal and ash particles on its surface and turns into a lump.
- CO gas:** Waste gas produced when carbon is burnt away to regenerate the catalyst in a fluid catalytic cracker or Thermoform catalytic cracker.
- Cogeneration:** Production of two usable forms of energy—usually power and steam.
- Coke:** Devolatilized coking coal produced by heating coal in the absence of air in coke ovens. The volatile matter and moisture are driven out, leaving behind the fixed carbon, ash, and S to form coke.
- Coke breeze:** About 5% of coke is undersized at <16 mm, which is unsuitable for the metallurgical industry, and is used mainly for steam generation. Coke breeze is very abrasive because it contains more ash than the rest of the coke. Since it has practically no volatile matter, the ignition requires a high temperature.
- Coke oven gas:** Waste gas produced in the destructive distillation of the bituminous coal in the manufacture of coke. The composition of gas is dependent on the analysis of raw coal and the length of time of coking. Mainly the coke oven gas consists of H_2 , CH_4 , C_2H_4 , and CO, with small amounts of CO_2 , N_2 , O_2 , and heavy hydrocarbons.
- Combined cycle:** See power plant cycles.
- Combustible:** A substance that has affinity for oxygen.
- Condensation:** When a vapor gives out heat in contact with a surface that is at a temperature lower than saturation, there is a change of phase and vapor turns into liquid.
- Conduction:** The transfer of heat via physical contact. It is the mode of heat transfer in solids.
- Conradson residue:** See carbon residue.
- Convection:** The transfer of heat from one point to another within a fluid by its movement or between one fluid and another by mixing of fluids or between a solid and fluid through a relative motion between them.
- Forced:** There is an external force moving the fluid over the surface. The velocities and the resultant heat transfer rates are naturally higher.
- Free:** There is only a natural force at work such as gravity or buoyancy. The velocities and the heat transfer rates are lower.
- Corrosion:** The (1) dissolution of the metal or (2) formation of an insoluble product (e.g., an oxide) arising from the interaction of a metal with its environment. The metal is weakened, leading to a failure.
- Damper:** Isolating or regulating device in a gas or air duct, functions like a valve to the pipeline.
- Diverter damper:** Installed at the beginning of heat recovery steam generators, this damper diverts the gas turbine exhaust gases to the atmosphere whenever an HRSG must be isolated. It is a very heavy single-flap hot damper made of stainless steel employing a big power cylinder for actuation.

- Guillotine damper:** A single-blade shutoff damper usually power operated and used where near 100% leak tightness is desired, as in the isolation of hot or lethal gases.
- Louver damper:** Single- or multiple-leaf dampers for both isolation and control.
- Weather damper:** A special damper required only for the stack of vertical heat recovery steam generator to protect the internals from rain and snow. This two-flap damper with eccentric movement is self-closing when there is no gas flow from below to keep it open.
- Deaeration of water:** Removal of dissolved oxygen from water to render it free from its corrosion tendency. Unless deaerated, treated water is not suitable for boiler feeding.
- Denitrification:** Removal of NO_x from the flue gases.
- Design pressure of boiler:** Usually the setting pressure of the highest lifting safety valve on the drum.
- Desulfurization:** Removal of fuel sulfur to make the flue gases free of the corrosive sulfurous gases to meet the emission norms.
- Dosing:** See chemical dosing.
- Draft plant:** Collective term for all the equipment in the air and gas circuit, namely the flues and ducts, fans, dust-collecting equipment, and silencers.
- Balanced draft firing:** Draft from the forced draft fan up to the furnace and induced draft from the furnace to the induced draft fan are used to create the draft. They balance in the furnace, which is kept slightly below atmospheric pressure to prevent puffing. This is common for solid fuels.
- Pressurized firing:** In liquid and gaseous fuels, forced draft is employed to push the air and flue gas all the way to the chimney, dispensing with the induced draft fan. The furnace is under pressure. This is more efficient because there is no ingress of tramp air.
- Drums:** Large-diameter cylindrical fabricated pressure-holding parts with dished ends.
- Steam or top drum:** The largest and the heaviest pressure part in which steam and water are separated before steam goes to the superheater (or to the steam outlet in a saturated boiler), and water goes to evaporator circuits for recirculation. Housing the drum internals and connecting the various water and steam circuits are the main functions.
- Stubbed drum:** The stubs are welded to the drum in radiant or single-drum boilers.
- Water/bottom/mud drum:** A water drum is a large header to which risers, downcomer tubes, and other circuits of a boiler or convection bank are connected. When boilers included several drums, blowdown was restricted to the lowest (bottom) drum. Mud drum is an obsolete term. Single drums now handle all these functions. Intermittent blowdown occurs in the water drum because it collects sludge formed in the boiler.
- Expanded drum:** The convection or boiler bank tubes are expanded. Drums of bidrum boilers are expanded.
- Drum internals:** Collective term for all the internals of a steam drum, namely the steam separators and dryers, continuous blowdown, high-pressure dosing, and feed piping.
- Economizer:** This is the heating surface of the boiler that *economizes* on the fuel input by extracting the low-level heat from the boiler flue gases and heating the feed water.
- Bare and finned or gilled tube economizer:** Economizers are usually made of bare or plain tube, as the flue gases are mostly dust laden. When flue gases

are clean, finned tubes save on space and even pressure drop. If the gases are corrosive, gilled tubes can be employed by mounting cast iron gills on plain tubes.

Steaming and nonsteaming economizer: Feed water is heated to more than two-thirds of the difference between saturation and feed inlet temperature. Below that level it is nonsteaming.

Nonsteaming economizers are preferred because they do not demand superior water quality. Steaming economizers become necessary at high pressures. It is normal to have 5 to 20% steaming.

Enthalpy: Heat content.

Entrainment: See carryover.

Entropy: Measure of unavailable energy.

Erosion: Progressive removal of surface material of a metal or alloy by mechanical means—abrasion (sand papering effect) or impingement.

Evaporator: Surface of the boiler where heat is added to the steam–water mixture as latent heat at constant saturation temperature. Furnace and boiler bank are examples.

Fan: Pressure-raising device in a gas or air stream.

Axial, centrifugal fans: An axial fan accelerates the stream along the fan axis, whereas the centrifugal fan accelerates the stream normal to the fan axis.

Specific diameter: The impeller diameter required to deliver a unit volume at unit differential head at unit specific speed.

Specific speed: The rpm of the fan that delivers a unit volume at unit differential head of air at standard conditions.

System resistance: The summation of all the resistances in the flow path that a fan is required to overcome.

Flash point of oils: The lowest temperature at which sufficient vapor is produced to form an inflammable mixture with air, under specified test conditions. Flash point is used solely with regard to storage and not for combustion; it gives no indication of the burning properties of oil.

Flow—classification

Laminar or viscous flow: At low velocities ($Re < 2000$), the viscous forces dominate resulting in a viscous or laminar flow.

Streamline flow: Same as laminar flow.

Turbulent flow: At high velocities ($Re > 4000$) the inertial forces dominate resulting in a turbulent flow.

Flow—direction: The direction of flow between hot and cold fluids in heat exchangers.

Counter: Fluids flow in opposite directions to each other.

Cross: Fluids flow perpendicular to each other.

Parallel: Fluids flow parallel to each other.

Fluid: A term used for both liquid and gas.

Ideal: An ideal fluid has no viscosity or surface tension and is incompressible.

Newtonian: The shear stress is directly proportional to the rate of shear strain or velocity gradient.

Real: The opposites of ideal fluids.

Fluidization: A bed of solids in an enclosure gets airborne when provided with air at a certain high pressure and behaves like a free-flowing fluid.

Fluidized bed combustion: The combustion of a solid particle when it is in motion in a fluidized state—a condition where a gas–solid mixture behaves like a fluid.

Bubbling fluidized bed combustion: Fluidized bed combustion with air velocities of less than ~ 3 m/s. There is a distinct bed in which the particles swirl.

The bed heights and residence times and heat release rates are minimized. Bed temperature is usually limited by an in-bed coil. Combustion, denitrification, and desulfurization efficiencies are good but lower than in circulating fluidized bed combustion.

Circulating fluidized bed combustion: Fluidized bed combustion with higher air velocities of 4–7 m/s. At such high velocities, there is no distinct bed but a cloud of particles filling the furnace chamber. Residence times and heat release rates are higher than in bubbling fluidized bed combustion. Temperature control is by recirculation of the elutriated bed material. Combustion, denitrification, and desulfurization efficiencies are superior to bubbling fluidized bed combustion.

Cold cyclone circulating fluidized bed combustion: Second-generation circulating fluidized bed combustion that employs lower bed velocities, distinct bed, and tower-type boiler design with heating surfaces in the first pass so that the gases entering the cyclone are cooler at 400–500°C instead of the conventional 850°C.

Hot cyclone circulating fluidized bed combustion: The classical full-circulation circulating fluidized bed combustion that employs high bed velocities of 4–7 m/s and cyclones that operate at ~850°C.

U-beam or no-cyclone circulating fluidized bed combustion: Second-generation circulating fluidized bed combustion that employs lower bed velocities, distinct bed, and inertial separation in the form of U-beams at the end of combustor in place of hot cyclone.

Fluid bed ash cooler: A bubbling bed heat exchanger with in-bed cooling water coil similar in construction to a fluid bed heat exchanger for cooling ash.

Fluid bed heat exchangers: Provided in the return ash path from cyclone to combustor in certain hot cyclone designs; a bubbling bed heater in which the return ash is bubbled over a bed coil comprising the finishing-stage superheater and reheater.

Fuel oils: A wide range of oils starting from heavy to light products. Classification of fuel oils into six grades as per ASTM D396 is widely followed.

Furnace: The empty chamber around the firing equipment where the fuel burns and releases the heat. The chamber is fully or partly water cooled with tubes in which boiling water is circulated.

Effective projected radiant surface: The adjusted projected radiant surface that takes into account the fuel, type of walls (membrane, tangent, spaced, etc.), extent of refractory covering on walls, effect of possible slagging, etc.

Furnace exit-gas temperature/furnace outlet temperature: The average gas temperature at the middle of the furnace exit plane; furnace outlet temperature.

Projected radiant surface: The heating surface that participates in cooling of the flue gases, and it comprises of all walls of the furnace enclosure, including the area of the exit plane. Areas of both sides of platens, wing walls, and division walls are also added.

Residence time: Time taken by the fuel particle to reach the mid-point of the furnace exit aperture from the firing equipment, assuming the furnace is at exit-gas temperature.

Furnace volume: The volume of the open chamber that surrounds the firing equipment and extends from ash pit or floor to the exit plane at which the next surface (usually superheater or screen) starts.

Gas laning: A pitch wider than the average in a tube bank, normal to gas flow promotes increased gas flow called *laning*, which leads to (1) erosion and (2) overheating

on the faces of the tube on either side of the lane. Rectification of this defect is difficult.

Gas turbines: See turbines.

Aeroderivatives: Gas turbines developed for use in aircrafts, modified for land use. These are lighter, more delicate, efficient, and more expensive than frame machines and suited for cogeneration in sizes <100 MWe.

Frame machines: These are also called industrial or land turbines, developed for land applications. They are heavier, less efficient, and more fuel flexible, built ruggedly for power generation in sizes <340 MWe.

Hardgrove index: This indicates the ease of grinding of coal, a property that is vital in milling. It is an index showing the relative hardness compared with the standard soft coal hardness index of 100. The harder the coal, the lower the index.

Hardness of steel: The ability of steel to withstand impingement by resistance to indentation.

Hardness of water: The property of water to destroy soap lather due to heavy salts of Ca and Mg.

Heat losses in boiler efficiency: Sum of heat losses.

Radiation: Heat loss from the hot boiler enclosure to the surroundings due to radiation and natural convection. This is estimated from the ABMA graph.

Stack: Heat loss to the atmosphere due to the hot gases leaving the boiler. This is the largest loss comprising nearly 70% of all losses from boiler consisting of (1) dry gas loss, (2) moisture loss due to combustion, and (3) humidity loss.

Unaccountable: Heat loss due to sensible heat in ash and other unmeasurable losses such as loss due to atomizing steam. It is usually based on codes and well-established practices.

Unburnt: Loss due to a small amount of fuel escaping the combustion. The higher the ash, the higher the unburnt loss.

Heat rate: The fuel heat input on a net calorific value basis for unit power output expressed in kilojoules per kilowatt hour, kilocalories per kilowatt hour, or British thermal units per kilowatt hour. In gas turbines, it is the net calorific value that is used traditionally for heat rates unlike in conventional power plants where both gross calorific value and net calorific value are used. Power and heat rate are measured across the generator terminals for power plants.

Heat recovery steam generator: The waste heat boiler behind the gas turbine that produces steam for process or power or both. This is the only waste heat boiler in the utility segment of boilers.

Fired heat recovery steam generator: These can be fired or unfired, depending on whether an additional fuel is burnt. There are two modes of firing: (1) supplementary firing where the fuel (oil or gas) is burnt for generating part of steam and (2) auxiliary firing where the fuel is burnt for generating 100% steam. Firing may be continuous or intermittent.

Ignifluid combustion: First among the commercially successful fluidized bed combustion boilers. It works on the principle of high-temperature fluidization (~1100°C) and hence uses no bed material. It is deficient in NO_x and SO_x control and poorer in combustion efficiency in comparison to the present-day fluidized bed combustion.

Igniter: A device that provides heat energy to light the main flame of a burner. There are mainly four types of igniters that perform different duties.

Insulator: Low thermal conductivity, using mainly nonmineral-based or fiber-based material capable of withstanding high temperatures but not erosion. These materials are used for thermal insulation and noise attenuation.

Lignite: Younger coals formed from plants rich in resin and hence high in volatiles and moisture. Lignite is a solid fuel more mature than peat and has a woody structure.

Liquefied natural gas: Natural gas, when cooled to -162°C , turns from gas to liquid form. The limitations of large volume and long-distance transportation of natural gas have been overcome. Liquefied natural gas is shipped or piped. A metric tonne (MT) is equal to $\sim 1500 \text{ m}^3$ of natural gas.

L-valve: Also called a siphon, or seal pot, it is an ash pump for returning ash from cyclone to furnace in circulating fluidized bed combustion boilers.

Maximum continuous rating: See rating of boiler.

Milling system: Pulverized fuel mills with the associated primary air or exhausters fans and coal piping up to burners are often treated as a subsystem of milling.

Pressurized: The primary air fans are located upstream of the mills and the mill is under pressure. Despite the better tightness requirements imposed on the mills, the pressurized systems are more popular because they cause no wear of the fans.

Suction: The primary air fan is replaced by the suction fan downstream of the mill, thus keeping the mill under suction. Wear on suction piping has to be recognized.

Mills or pulverizers: See pulverized fuel mills.

Moisture in fuel: Moisture along with ash forms the burden or ballast, as there is no contribution toward the fuel value. Moisture needs hot air for combustion and even hotter air for drying in the mills. As fuel moisture takes away a lot of heat for evaporation, the stack losses increase, thereby lowering the efficiency of the boiler. However, the moisture reduces the flame temperatures and lowers the fuel thermal NO_x formation.

Inherent: The interatomic moisture released with volatile matter on combustion.

Surface: The moisture picked up by fuel due to its hygroscopic nature from the humidity in air, mining operations, exposure to rain or snow, etc.

Naphthas: Spirits having low boiling points ranging from 30 to 170°C ; used as a feedstock in fertilizer and petrochemical industries; a highly volatile product.

Natural gas: Fossil fuel trapped inside the earth's crust and nearest to the ideal fuel, as it is almost free of ash and has high calorific value.

No-load pump pressure: The pressure developed by a centrifugal pump at zero flow.

Normal continuous rating: See ratings of boiler.

NO_x : Oxides of N formed in the combustion process as a result of N and O reaction; collectively called NO_x . An inert gas such as N is forced into union with O due to the high temperature of combustion. NO_x is environmentally harmful.

Fuel NO_x : Formation of NO_x from N present in fuel.

Thermal NO_x : Formation of NO_x from N present in combustion air.

Numbers, dimensionless

Grashof number: The ratio of the product of the inertia force and the buoyancy force to the square of viscous forces. It has a role in free convection similar to that of the Reynolds number in forced convection.

Nusselts number (Nu): $\text{Nu} = UcD/k$ represents heat transfer similarity. It is the ratio of the size factor to the thickness of the boundary layer k/Uc .

- Prandtl number (Pr):** A measure of ease of heat transmission through the fluid as high conductivity or low viscosity that stimulates heat flow.
- Reynolds number:** Re represents the ratio of inertial to viscous forces. The inertial forces are proportional to the square of velocity and viscous forces to the first power.
- Stanton number (St):** $St = Uc/cpG$ is the ratio of heat absorbed to that available for absorption.
- OTSG:** Once-through heat recovery steam generator.
- Opacity:** Clearness of stack. A beam of light is passed through the flue gases and checked for its absorption or scatter. The desired reading is ~20%.
- Oxygen scavenging:** It is the removal of the last traces of oxygen from the deaerated water by the addition of chemicals.
- Peak rating:** See rating of boilers.
- Peat:** The youngest of coals, which is at an early stage of metamorphism of vegetable matter. It is the product of partial decomposition, in the absence of air, of plant remains in marsh lands. Peat is a complex mixture of C, H, and O, which is low in S (~0.2%), N, and ash.
- Petroleum coke:** One of the heavy residues left behind in the petroleum cracking process after all the lighter distillates are collected. Petroleum coke is characterized by high calorific value, low ash, and very high S. Its high fixed carbon and low volatile matter make it difficult to ignite.
- Pinch point in heat recovery steam generators:** As the gases transmit their heat to the evaporator surfaces and get cooled, the cooling of gas demands a disproportionately large surface, making the design expensive. This gap between gas temperature and evaporator to be maintained to achieve optimum-heating is the pinch point. A gap ranging from 8 to 14°C is followed in the present designs.
- Piping—integral:** Drain, vent, soot blower, blowdown, attemperator, portions of steam and water, and similar piping within the boiler limit and governed by the boiler code constitute integral piping.
- External:** Steam, water, and fuel piping outside the boiler limits and governed by respective codes constitute external piping.
- Pour point of oils:** This is the temperature at which oil starts to flow under test conditions. It does not necessarily indicate the temperature at which oil stops flowing. Oil should be stored at ~3°C higher than the pour point.
- Power plant cycles:** These are 2T, that is, two-temperature cycles employed in power plants to achieve a sustained conversion of thermal to mechanical energy. Vapor and gas cycles and a combination are the most important.
- Brayton cycle:** Two-temperature all-gas cycle on which the gas turbine plants operate. Here, the working fluid always remains in the gaseous state.
- Carnot cycle:** Ideal reversible 2T cycle representing the highest achievable efficiency named after the inventor Sadi Carnot.
- Combined cycle:** It is the superimposition of Brayton cycle over Rankine cycle to convert energy from both gas and steam, thereby achieving the highest efficiency possible.
- Gas turbine cycle:** Same as the Brayton cycle.
- Rankine cycle:** Two-temperature vapor cycle that forms the thermodynamic basis of most steam power plants, either fossil fuel or nuclear. Here, the working fluid alternates between the liquid and the vapor phases.
- Steam cycle:** Same as the Rankine cycle.
- Priming:** See carryover.

Pulverized fuel combustion: Pulverized fuel (coal, lignite, peat, etc.) and combustion air are admitted into the furnace by means of burners. Ignition and combustion take place rapidly, and the fuel burns out between 1 and 2 s.

Corner firing: With tangential burners for coal or circular or rectangular burners for lignite or peat, corner firing is done where a single flame is developed in the center of an approximately square furnace.

Direct and indirect firing of coal: In direct firing, mills feed the dried pulverized fuel into the burners directly without an intermediate storage. Boilers and mills are always working together. In indirect firing, there is an intermediate storage of pulverized fuel between the mills and burners. Centralized milling system and boiler work independent of each other. This system is practically outdated with the development of reliable and power efficient mills.

Front and opposed firing of coal: With circular burners having individual flames, front-wall firing up to ~200 MW and opposed-wall firing for larger sizes is generally the practice.

Pulverized fuel firing: Firing solid fuel after reducing it to fine powder, usually $<75\ \mu\text{m}$ for coal, so that the combustion is fast and complete. It is the most efficient way to combust the solid fuels.

Pulverized fuel mill or pulverizer: A mill to grind the crushed coal of a maximum size of 50 mm to near talcum powder consistency.

Beater mill: Employed in the case of high-moisture soft fuels such as brown coals, beater mills are fed with flue gas from the furnace to dry the fuel and the rotor beats the fuel down to the required size for combustion.

Horizontal mill or tube mill: A slowly rotating drum filled with balls in which the coal is admitted and ground powder is extracted from the sides. The grinding is due to the combination of impact and attrition. Mills can be made to large sizes. They are bulky and consume much power and are used mainly for base-loaded stations using very abrasive coal.

Vertical mill: They operate at medium to slow speeds on the principle of crushing the coal between a roller or a ball, and a table. Grinding and attrition forces are at work. Vertical mills are lighter, consume less power, and are more responsive. For most coal applications, vertical mills are used.

Radiation: The transfer of heat by electromagnetic waves. It is a contactless transfer requiring no medium. Radiation takes place even in vacuum.

Luminous: The heat transfer that takes place in the visible range in the form of flames. Most fuels produce luminous radiation.

Nonluminous: Gases such as CO , CO_2 , SO_2 , and water vapor absorb and emit radiation in certain wavelengths outside the visible range. Although nonluminous radiation is rarely encountered in boiler furnaces, it is always present in the intertube heat transfer in superheater, reheater, and convection banks at temperatures higher than $\sim 400^\circ\text{C}$.

Ramsbottom residue: See carbon residue of oils.

Rating of boiler: Boilers are rated by their evaporation of steam at the prescribed pressure and temperature from the specified inlet feed water temperature. In the case of reheat boilers, the reheater inlet and outlet pressures and temperatures are also defined.

Maximum continuous rating: Maximum steam that a boiler can generate effortlessly without any side effects such as overheating on a continuous basis. All auxiliaries are sized for the maximum continuous rating condition.

- Normal continuous rating:** The steam that a boiler is required to generate on a normal basis. This is lower than maximum continuous rating, usually by 10%. Boiler and auxiliaries are designed to yield their best efficiency at this condition.
- Peak rating:** Short-term overloading of the boiler on a daily or shift basis. Often the peak load is met by overrunning of the auxiliaries by eating temporarily into the test block margins at a slightly reduced boiler efficiency.
- Refinery gas:** The by-product of distillation and cracking processes in the refinery. Its composition is mainly of paraffins with low boiling points and small amounts of olefins.
- Refractories:** Nonmetallic, mineral-based materials suitable for the construction and lining of furnaces.
- Refractoriness:** The temperature-withstanding ability of a material measured on a pyrometric cone equivalent scale.
- Reheat/reheater:** Reheating of steam is withdrawing partly expanded steam from the turbine and heating it to the original or higher temperature. For boilers larger than ~100 MW, reheating is economical as the improved cycle efficiency outweighs the costs of reheating. Double reheating is economical for ~800 MW and larger boilers.
- Residence time:** See furnace residence time.
- Rice husk or rice hull:** The hard and sharp protective covering enclosing a rice seed that is separated in the dehulling process. It makes a good and abundant seasonal agro-fuel with good calorific value and burning. Ash and silica content is high, making both fuel and ash very abrasive.
- Saturated water head:** The ratio of the anticipated density and pressure drop characteristics of the steam–water mixture in the riser tube to those of the static saturated water column.
- Scaling (boiler internal areas):** Formation of a salty layer on the internals of tubes, headers, and drums on account of separation of salts from water on heating. Scaling interferes with heat flow and causes overheating of surfaces. Scaling also causes corrosion by shielding the underlying metal from the protective chemicals in the water and steam. Scaling is eliminated by water treatment followed by conditioning.
- Seal pot:** Same as L-valve.
- Segregation of coal:** In stoker firing as the coal descends from the bunker to the grate, there is a natural separation of fines and nutty parts, leading to uneven burning that leads to clinkerization. This is minimized by employing traversing or non-segregating chutes.
- Siphon:** Same as L-valve.
- Sliding or variable pressure operation of boiler:** In constant pressure operation, the steam pressure upstream of the turbine governor valves is held constant, and pressure is varied in the governor valves. This represents a permanent loss and is not efficient. This inefficiency is addressed in variable pressure operation where the boiler supplies steam at pressures desired by the turbine as per load demand. The boiler has no constant superheater outlet pressure but a variable superheater outlet pressure.
- SO_x:** Oxides of sulfur formed in the combustion process as a result of S and O reaction are known as SO_x. These gases are corrosive and cause low-temperature corrosion of backend equipment and harm the environment by causing acid rain. Environmental rules set the permissible limits of SO_x generation.
- Steam cycle:** See Rankine cycle in power plant cycles.

Steam purification: A two-stage process of steam separation from steam–water mixture followed by drying in a steam drum.

Steam drying: Removal of last traces of water from steam so that the steam is perfectly *dry*. Water is adsorbed by sinusoidal plates or demisters over which the steam is passed at very low velocities.

Steam separation: Separation of steam from the boiling circulating water achieved by separators installed in a steam drum. Steam-free water and water-free steam are the aims. Steam separation is done at high velocities by centrifugal or inertial separators.

Steam-injected gas turbine: When steam or water is injected into the combustion chamber of a gas turbine prior to combustion, the gas turbine output is increased and the fuel NO_x generation is lowered. The enhanced gas flow increases the power output from the turbine without raising the compressor input. This is the steam-injected gas turbine or Cheng cycle used for cogen where the desired power can be produced during low steam demand or for peaking.

Stoichiometric air: Air required for combustion of fuel as per combustion calculations; the theoretical amount at 0% excess air.

Structure, type

Bolted and welded: Cold structure can be held in position by bolting or welding. Bolted structure increases the shop work, time, and material cost to but reduces site work and speeds construction. Welded structure is more economical but takes more time and skill at site.

Cold and hot: Boiler structure not exposed to heat is a cold structure. Buckstays, tie bars, sling rods, drum slings, experience heat and are called hot structures.

Sulfation reaction: This lime–sulfur (sulfation) reaction turns the SO_2 produced (from the oxidation of sulfur on combustion) to gypsum (CaSO_4) by its reaction with CaO . It is an endothermic reaction.

Supercritical and subcritical boilers: Critical conditions for steam are the pressure and the corresponding saturation temperature at which feed water turns into steam on heating without the addition of latent heat. As per ASME tables, this is at 221.2 bar and 374.1°C . Units with superheater outlet pressure above this pressure are supercritical boilers and those below are subcritical boilers.

Superheat/superheater: The heat added after all the water is converted to saturated steam in an evaporator. Latent heat is added in the evaporator circuits, superheat is added in the superheater.

Pendant and platen superheater: A vertical or horizontal multiloop superheater placed in the convection section of the boiler with one or many parallel tubes carrying steam as required by mass velocity considerations. The pendants are placed on a closer pitch than platens and receive heat by convection and radiation. Platen type is a vertical single-loop superheater placed in the furnace with many parallel tubes carrying steam as per mass velocity considerations. The platens are placed wide apart, 600–2000 mm, and receive radiant heat from the furnace. This superheater is essential in large boilers fired particularly with solid fuels.

Single-pass and multipass superheater: When the steam passes through all superheater tubes, the system is a single-pass superheater. At low steam output per meter length of the drum, particularly with slow-burning fuels, a single-pass arrangement results in low steam velocity, causing lower than optimum pressure drop. The tubes are then divided into suitable groups to constitute multipass superheater.

Supporting structure: Boiler structure helps support various parts so that they are held in position and work as intended.

Bottom support: The pressure parts stand erect via bottom support. The structure provides access. This is most cost effective and popular for small boilers.

Middle support: For intermediate size boilers, the pressure parts are supported from the middle. Some parts expand upward and some downward.

Top support: The pressure parts are slung from the top. Larger and taller boilers need top support. The pressure parts are not under compression here. The expansions are well defined.

Turbine: A rotating heat engine that converts heat energy into mechanical energy.

Combustion turbine: Same as gas turbine.

Gas turbine: It converts heat energy of hot compressed gas to mechanical power. Hot gas is expanded at high velocity over blades attached to a rotor. As the gas cools down, it imparts its energy to the rotor that rotates at high speed and drives an alternator or other machines such as the pumps and the compressors.

Steam turbine: It converts heat energy of high-pressure steam to mechanical power. High-pressure and high-temperature steam is expanded at high velocity over blades attached to a rotor. As the steam cools down, it imparts its energy to the rotor that rotates at high speed and drives an alternator or other machines such as the pumps and the compressors.

Unbalance of steam flow: The deviation of steam flow in a superheater or reheater tube with respect to the average flow in the bank. This should be contained within 5%, that is, the steam flow variation in tubes between the maximum and the minimum should be limited to 10%.

Variable pressure operation: See sliding pressure operation.

Viscosity: Resistance of fluids to flow due to internal friction. In liquids this friction is due to the cohesion of molecules. Since the cohesion decreases with increasing temperature, viscosity does likewise.

Volatile matter: Volatile matter together with fixed carbon forms the burnable part of the fuel as opposed to the unburnable ballast. VM is a complex organic matter that leaves the fuel quickly on heating and burns in the furnace.

Water

Demineralized: Water made free of its ionizable dissolved solids by passing through ion-exchange materials.

Raw: Water received without previous treatment.

Softened: Raw water with hardness substantially removed.

Treated: Water treated at users' premises.

Water conditioning: Dosing of appropriate chemicals to make treated water harmless enough to cause no damage to the internal surfaces of the boiler while making the steam acceptable superheater and turbine.

Water treatment: Making raw water suitable for feeding into a boiler by appropriate treatment.

Wear: See erosion.

Wire drawing: The cutting effect produced by high-velocity fluid stream resulting from high pressure drop in the calorific value.

Wood: Complex vegetable tissue composed mainly of carbohydrates. It has a relatively low heating value in comparison with coal and oil.

Appendix A: Boiler Calculations

A.1 Introduction

This appendix is included to enhance the appreciation of the fundamentals and to simplify basic process calculations.

- Boilers encounter different steaming conditions using a variety of fuels, and are calculation-intensive. All boiler users are required to perform the peripheral or process calculations. For that reason they are included here.
- The sizing calculations of various boiler parts that require proprietary data and the coded strength calculations for various pressure parts (PPs), are not included because they are of interest only to boiler designers.
- A small nonreheat industrial stoker-fired boiler for coal firing was selected (see Table A1) to keep the calculations simple, so that the methodology is well understood.
- When calculations are done on different systems of units, some marginal differences are inevitable in the end results because of rounding of figures and small differences in conversions. These are best ignored.
- The calculations are kept simple. Complex calculations may be required only by the boilermakers.
- Calculation methods, safety margins, range of conditions, etc., vary with the boilermakers, boiler sizes, and clients/consultants. Other than in coded calculations, there are slight variations in sizing and design practices.
- Most calculations are performed in all three systems, namely, FPS, metric, and SI units to make them understandable to all.

A.1.1 Combustion Calculations

Calculation A.1.1.1

To calculate *heat duty of the boiler on gross steam generation*. Refer to Table A2.

Please refer to the steam tables for values. In this example, the *gross evaporation* from the boiler is considered as 68 tph. This is different from *net evaporation* of 68 tph when, like in many process boilers, the boiler has to provide steam for deaerator. The gross steam generation in such a case would be 68 tph plus heat to deaerator. The next example calculates the heat duty on net evaporation basis.

Calculation A.1.1.2

To calculate *heat duty on net evaporation*.

Net evaporation is gross evaporation minus steam for deaeration.

TABLE A1

Boiler Specifications

	In SI Units	In Metric Units	In FPS Units
<i>Steaming conditions</i>			
Evaporation (MCR)	18.895 kg/s	68 tph	150,000 lb/h
Superheater outlet pressure (SOP)	70 bar	70.38 kg/cm ² g	1,000 psig
Superheater outlet temperature (SOT)	400°C	400°C	752°F
Feed water temperature (FWT)	105°C	105°C	221°F
<i>Ambient conditions</i>			
Temperature	77°F	25°C	
Relative humidity	60%	60%	
Altitude	1000 ft	305 m	
<i>Coal specifications: proximate analysis</i>			
A%		15.0	
M%		10.0	
VM%		30.0	
FC%		45.0	
Total		100.0	
S		1.0	
Gross calorific value	24.49 MJ/kg	5,850 kcal/kg	10,530 Btu/lb

TABLE A2

Heat Duty Calculation (Calculation A.1.1.1)

	In SI Units			In MKS Units			In FPS Units		
	Pressure (Bar)	Temperature (°C)	Enthalpy (kJ/kg)	Pressure (kg/cm ² g)	Temperature (°C)	Enthalpy (kcal/kg)	Pressure (psig)	Temperature (°F)	Enthalpy (Btu/lb)
SOP	70	400	3161.2	70.38	400	756	1000	752	1359
FWT	—	105	440.2	—	105	105.2	—	221	189
Heat to steam			2721.0			650			1170
Steam flow at MCR			18.895 kg/s			68.02 tph			150,000 lb/h
Heat duty = Heat to steam × MCR (maximum continuous rating)			51.42 MWth			44.26 M kcal/h			175.5 M Btu/h

For deaerator, let us assume the inlet temperature of condensate as 85°C (185°F). Heat balance across the deaerator gives the steam for deaeration. In Figure A1,

Heat in condensate + heating steam = heat in feed water (FW)

$$68,020 \times 85 + s \times 756 = (68,020 + s) \times 105.2$$

which gives the value of

$$s = \frac{68,020 \times (105.2 - 85)}{756 - 105.2} = 2287 \text{ kg/h}$$

Revised steam flow = 70,307 kg/h, which is higher by 3.36%. The revised heat duty will also be higher by the same proportion.

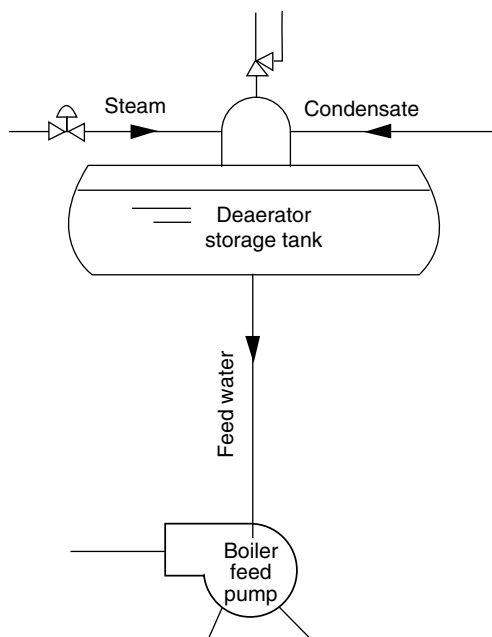


FIGURE A1
Deaerator and boiler feed pump.

Calculation A.1.1.3

To calculate the *ultimate analysis (UA)* from *proximate analysis (PA)*. Refer Tables A3 and A4.

Step 1. Calculate daf volatile matter (VM) and fixed carbon (FC) as given in Table A3.

Step 2. Refer to Section 2.6.8.1. for calculating the UA from PA.

$$\% \text{ daf C} + \text{S} = 60.0 + 0.9(40.0 - 14) = 83.40\%$$

$$\% \text{ daf H} = 40.0 \left(\frac{7.35 - 0.013}{40.0 + 10} \right) = 5.86\%$$

$$\% \text{ daf N} = 2.1 - 0.012 \times 40.0 = 1.62\%$$

$$\% \text{ daf O} = \text{by difference} = 9.62\%$$

Step 3. Work out the actual UA from daf basis by multiplying the figures with $1 - 0.25 = 0.75$ as calculated in Table A4.

S needs to be deleted from C.

Calculation A.1.1.4

To check for *gross calorific value (GCV)* using *Dulong's formula* given in Section 3.2.1.1.3.

$$\text{GCV in kcal/kg} = (80.8 \times 61.56) + 344.6[4.02 - (7.21/8)] + 22.5 \times 1.00 = 6071$$

$$\text{GCV in Btu/lb} = (145.44 \times 61.56) + 620.28[4.02 - (7.21/8)] + 40.5 \times 1.00 = 10,928$$

The GCV is higher by $\sim 3.8\%$ from the starting figure, which is within the acceptable tolerance limits.

TABLE A3

Proximate Analysis of Coal on daf Basis (Calculation A.1.1.3)

	PA	daf PA
A%	15.0	—
M%	10.0	—
VM%	30.0	$30/(1 - 0.25) = 40.0$
FC%	45.0	$45/(1 - 0.25) = 60.0$
Total	100.0	100.0
S	1.0	
GCV	24.49 MJ/kg	
	5850 kcal/kg	
	10,530 Btu/lb	

TABLE A4

Calculation of Ultimate Analysis from Proximate Analysis (Calculation A.1.1.3)

Element	Percentage	S Adjustment
C	$83.4 \times 0.75 = 62.56$	61.56
H	$5.36 \times 0.75 = 4.02$	4.02
O	$9.62 \times 0.75 = 7.21$	7.21
N	$1.62 \times 0.75 = 1.21$	1.21
S		1.00
A	15	15.00
M	10	10.00
Total	100	100

Note: Dulong's formula is applicable only for coal.

Calculation A.1.1.5

To find *stoichiometric air and flue gas* at 0% excess air. Combustion calculations from UA are given in Table A5.

Calculation A.1.1.6

To calculate *net calorific value* (NCV) from *gross calorific value* (GCV).

For a hypothetical fuel of the following UV, the NCV is worked out from GCV using the formula

$$\begin{aligned}
 \text{NCV} &= \text{GCV} - 2.42(m + 9\text{H}_2) \text{ MJ/kg, where } m + 9\text{H}_2 \text{ is the moisture in fuel and on combustion} \\
 &= \text{GCV} - 578(m + 9\text{H}_2) \text{ kcal/kg} \\
 &= \text{GCV} - 1040(m + 9\text{H}_2) \text{ Btu/lb or} \\
 &= 24.49 - 2.42 \times (0.10 + 9 \times 0.04) = 23.38 \text{ MJ/kg} \\
 &= 5850 - 578 \times (0.10 + 9 \times 0.04) = 5584 \text{ kcal/kg} \\
 &= 10,530 - 1,040 \times (0.10 + 9 \times 0.04) = 10,051 \text{ Btu/lb}
 \end{aligned}$$

TABLE A5
Combustion Calculation from Ultimate Analysis (Calculation A.1.1.5)
Humidity: at 25°C and 60% RH = 0.0126 kg/kg

Ultimate Analysis			Molecular Weight	O ₂ Required		Air Required		Gas Produced		
Element	(%)	kg/kg	—	CC	kg/kg	CC	kg/kg	CP	CC	kg/kg
C	61.56	0.6156	12	(0.6156) × 32/12	1.64	(1.64) × 100/23.15	7.084	CO ₂	(0.6156) × 44/12	2.257 ^a
H ₂	4.02	0.0402	2	(0.0402) × 16/2	0.32	(0.32) × 100/23.15	1.382	H ₂ O	0.0402 × 9 + 0.10	0.462 ^a
S	1.00	0.0100	32	(0.010) × 16/16	0.01	(0.01) × 100/23.15	0.043	SO ₂	(0.01) × 64/32	0.020 ^a
O ₂	7.21	0.0721	32	—	—	—	—	O ₂	—	—
N ₂	1.21	0.0121	28	—	—	—	—	N ₂	0.012 + (0.77 × 8.20)	6.326 ^a
H ₂ O	10.00	0.1000	18	—	—	—	—	Total combustion gas at 0% excess air		9.065 ^a
ASH	15.00	0.1500	—	—	—	—	—	kg/kg Humidity in fuel		0.103 ^a
Total	100	1.000	—	—	1.97	—	8.51	8.20 × 0.0126 Total moisture		0.565 ^a
Less in fuel				—	−0.072	—	−0.31	0.462 + 0.103 Weight of wet flue gas		9.168 ^a
Required at 0% excess air					1.90	(1.90) × 100/23.15	8.20*	9.065 + 0.103 kg/kg fuel		8.603
Required with 45% excess air				1.90 × 1.45	2.755	(2.755) × 100/23.15	11.90	Weight of dry gas (with 0% excess) in kg/kg fuel		
Excess				O ₂ =	0.855	Air =	3.70	9.576 − 0.558 % Moisture in air = (0.565/9.168) × 100		6.16% ^a

Note: CC, combustion constant; CP, combustion product.
^a Figures taken from Table A3.

Calculation A.1.1.7

Combustion calculation from PA

First calculate the PA on daf basis: refer to Step 1 of calculation A.1.1.3 and Table A3.
For 40% VM on daf basis, Seyler’s graph in Section 2.6.8.3 gives theoretical air requirement as

1.35 kg/1,000 kcal

7.5 lb/10,000 Btu

Therefore, stoichiometric air is

$1.35 \times \frac{5,850}{1,000}$ or $7.5 \times \frac{10,530}{10,000} = 7.9 \text{ lb/lb or kg/kg of fuel}$

H₂ on daf basis from graph is 5.4%, which works out to be $5.4 \times (1 - 0.75) = 4.05\%$ for coal with a burden of 25%.

Moisture on combustion given by $m + 9H_2$ works out to be $0.10 + 9 \times 0.0402 = 0.4618$ kg/kg or lb/lb of fuel.

Theoretical CO₂ from Table 2.16 is 18.8% and factor $f = 1.03$.

Calculation A.1.1.8

To find the *unit air and gas weights* at various points in the boiler. Refer to Table A6.

First, the excess air levels at various places in the boiler must be estimated starting from the excess air requirement of the firing equipment and adding suitable infiltration, depending on the construction of the furnace and boiler enclosure.

- Total moisture = moisture on combustion ($m + 9H_2$) + humidity = 0.462 + humidity.
- Actual CO₂ by volume = Theoretical CO₂/1 + ($f \times \% \text{ excess air}$)/100.
- All weights are in kg/kg or lb/lb.
- Specific volume is read from Figure 2.42 in Section 2.6.10.

Calculation A.1.1.9

To find *unit air and gas weights with oil firing*. Refer to Table A7.

Let us assume fuel of the following characteristics.

	In SI Units	In Metric Units	In FPS Units
GCV	43.03 MJ/kg	10,278 kcal/kg	18,500 Btu/lb
Ash			0.06%
Sulfur			2.0%

From Figure 2.37 fuel oil properties given in Section 2.6.8.4,

- H₂ content is 10.7% contributing 0.963 kg/kg or lb/lb of moisture on combustion.
- Theoretical air is $1.342 \times 10,278/1,000 = 13.79$ kg/kg.

TABLE A6

Calculation of Unit Air and Gas Weights with Coal Firing (Calculation A.1.1.8)

At Exit of	% Excess Air	$W_{\text{dry air}} 7.9 \times (1 + \text{Excess Air})$	Humidity = 0.0126 $\times$ Dry Air	Total Air (W_A)	Wet Gas $W_g = W_A + (1 - \text{Ash})$	M = Total Moisture	%mm/ $W_g \times 100$	% CO ₂ by Dry Volume	Specific Volume at NTP	
									(m ³ /kg)	(ft ³ /lb)
	1	2	3	4	5	6	7	8	10	9
Furnace	35	10.66	0.134	10.79	11.64	0.598	5.13	13.82	0.759	12.16
Boiler bank	40	11.06	0.139	11.20	12.05	0.603	5.0	13.31	0.761	12.20
Economizer	43	11.30	0.142	11.44	12.29	0.606	4.93	13.03	0.760	12.18
Airheater	45	11.45	0.144	11.59	12.44	0.608	4.89	12.85	0.760	12.18
Net ID fan	48	11.69	0.147	11.84	12.69	0.611	4.81	12.58	0.761	12.20

TABLE A7

Calculation of Unit Air and Gas Weights with Oil Firing (Calculation A.1.1.9)

At Exit of	% Excess Air	$W_{\text{dry air}} \times 13.79$ (1+Excess Air)	Humidity = 0.0126 $\times$ Dry Air	Total Air (W_A)	Wet Gas $W_g = W_A$ + (1 – Ash)	M = Total Moisture	%mm/ $W_g \times$ 100	% CO ₂ by Dry Volume	Specific Volume at NTP	
	1	2	3	4	5	6	7	8	10 (m ³ /kg)	9 (ft ³ /lb)
Furnace	10	15.17	0.19	15.36	16.36	1.15	7.0	14.83	0.76	12.2

TABLE A8

Refinery Gas Analysis (Calculation A.1.1.10)

Constituent	Weight (%)	Formula	Volume (%)
Hydrogen	2.3	H ₂	36.0
Methane	2.3	CH ₄	4.5
Ethane	6.9	C ₂ H ₆	7.2
Propane	30.1	C ₃ H ₈	21.4
Butane	56.3	C ₄ H ₁₀	30.0
Pentane	2.1	C ₅ H ₁₂	0.9
Total	100.0		100.0
Molecular weight		31	
GCV	22,460 Btu/lb	52.24 MJ/kg	12,478 kcal/kg

- Theoretical CO₂ is 16.4 and f = 1.06.
- NCV = 39.65 MJ/kg or 9,720 kcal/kg or 17,500 Btu/lb.

Assuming pressurized firing with an excess air of 10%, the air and gas weights can be constructed as in Table A7.

Calculation A.1.1.10

To find *unit air and gas weights with gas firing*. Refer to Tables A8 through A11.

Refinery gas (Table A8) is an example for gas firing, and a standard calculation chart for gas calculations is used to work out the air and gas quantities. The same procedure can be adopted for any type of gas firing. FPS units are employed in this example (Tables A9 and A10).

Unit air and gas weights can be calculated as in Table A11, assuming an excess air level of 15% and pressurized combustion.

Calculation A.1.1.11

To find *unit air and gas weights* at various points in boiler *from UA* of coal. Refer to Table A12.

See the combustion calculations of A.1.1.5 where stoichiometric air was calculated from UA in Table A5. Flue gas analysis at 0% excess air from the same Table A5 is taken and reproduced in the first column of Table A12. To calculate air and gas weights thereafter at various points, the method in Table A12 must be followed.

Unit air and gas weights derived from PA and UA are always at minor variance as can be seen from Tables A5 and A12.

TABLE A9

Gross Calorific Value, Theoretical Air, Density, and Moisture on Combustion from Gas Analysis
(in FPS Units) (Calculation A.1.1.10)

Constituent	% By Volume	Theoretical Air = T/520	Combustion H ₂ O = T/1993	Density (lb/ft ³) = T/35,900 at NTP	% By Weight	GCV (Btu/lb)	Calculations
O ₂		× -2	× 0	× 32			GCV calculated matches with GCV given and no adjustment is required
N ₂		× 0	× 0	× 28			
H ₂	36	× 1 = 36.0	× 1 = 36	× 2 = 72	2.3	0.023 × 61,100 = 1,405	Density calculated is 0.0865 at NTP
CO		× 1	× 0	× 28			From gas data = MW/vol of lb mol at NTP = 31/359 = 0.0863 Both figures match closely Th. air required = 1.39 lb/ft ³ at NTP = 1.39/0.0863 = 16.1lb/lb
CO ₂		× 0	× 0	× 44			
H ₂ S		× 3	× 1	× 34			
CH ₄	4.5	× 4 = 18.0	× 2 = 9.0	× 16 = 9.0	2.3	0.023 × 23,879 = 549	
C ₂ H ₂		× 5	× 1	× 26			H ₂ O on combustion = 0.154 lb/ ft ³ at NTP = 0.154/0.0863 = 1.78 lb/lb
C ₂ H ₄		× 6	× 2	× 28			NCV = 22,460 – 1040 × 1.78 = 20,609 Btu/lb
C ₂ H ₆	7.2	× 7 = 50.4	× 3 = 21.6	× 30 = 216	6.9	0.069 × 22,320 = 1,543	
C ₃ H ₆		× 9	× 3	× 42			
C ₃ H ₈	21.4	× 10 = 214	× 4 = 85.6	× 44 = 941	30.1	0.301 × 21,660 = 6,520	
C ₄ H ₈		× 12	× 4	× 56			
C ₄ H ₁₀	30.0	× 13 = 390	× 5 = 150.0	× 58 = 1740	56.3	0.563 × 21,308 = 11,996	
C ₅ H ₁₀		× 15	× 5	× 70			
C ₅ H ₁₂	0.9	× 16 = 14.4	× 6 = 5.4	× 72 = 64.7	2.1	0.021 × 21,091 = 443	
C ₆ H ₆		× 15	× 3	× 78			
C ₆ H ₁₄		× 19	× 7	× 86			
C ₇ H ₈		× 18	× 4	× 92			
C ₈ H ₁₀		× 21	× 5	× 106			
Total		722.8	307.6	3105.7	100	22,456	
Value lb/ft ³ at NTP		T/520 = 1.39	T/1992 = 0.154	T/35,900 = 0.0865			

Calculation A.1.1.12

To convert *gas analysis from weight to volume basis*. Refer to Table A13.

Gas analysis on weight basis is calculated in Table A13. Gas composition in actual practice is on volumetric basis as measured by Orsat and other analyzers and reported on a dry basis.

Converting from weight to volume makes use of Avogadro's law, which states that under the same conditions of pressure and temperature, 1 mol (the molecular weight of a gas

TABLE A10
Theoretical CO₂ from Gas Analysis (Calculation A.1.1.10)

Constituent	% By Volume	Column 1	Column 2	Calculations
O ₂		× -2	× 0	K = (total of column 1)/6 × total of column
N ₂			× 0	2 = (307.6)/6 × 207.6 = 0.247
H ₂	36	× 1 = 36.0	× 0 = 0.0	n = (7 × % N ₂ by volume)/3 × total of
CO		× -1	× 1	column 2 = (7 × 0)/3 × 207.6 = 0
CO ₂		× -2	× 1	Z = 1 + (2.37 × K) + 0.09 × n = 1 + 2.37
H ₂ S		× 1	× 1	× 0.247 + 0 = 1.585
CH ₄	4.5	× 2 = 9.0	× 1 = 4.5	CO ₂ maximum = 21/Z = 21/1.585 = 13.25
C ₂ H ₂		× 1	× 2	
C ₂ H ₄		× 2	× 2	f = [1 + (3 × K)]/Z = [1 + (3 × 0.247)]/
C ₂ H ₆	7.2	× 3 = 21.6	× 2 = 14.4	1.585 = 1.1
C ₃ H ₆		× 3	× 3	
C ₃ H ₈	21.4	× 4 = 85.6	× 3 = 64.2	
C ₄ H ₈		× 4	× 4	
C ₄ H ₁₀	30.0	× 5 = 150.0	× 4 = 120	
C ₅ H ₁₀		× 5	× 5	
C ₅ H ₁₂	0.9	× 6 = 5.4	× 5 = 4.5	
C ₆ H ₆		× 3	× 6	
C ₆ H ₁₄		× 7	× 6	
C ₇ H ₈		× 4	× 7	
C ₈ H ₁₀				
Total		307.6	207.6	

TABLE A11
Unit Air and Gas Weights for Refinery Gas Firing (Calculation A.1.1.10)

At Exit of	% Excess Air	W _{dry air} 16.1 × (1 + Excess Air)	Humidity = 0.0126 × Dry Air	Total Air (W _A)	Wet Gas W _g =W _A + (1 - Ash)	M = Total Moisture	%m m/W _g × 100	% CO ₂ by Dry Volume	Specific Volume at NTP	
									(m ³ /kg)	(ft ³ /lb)
	1	2	3	4	5	6	7	8	9	10
Furnace	15	18.52	0.233	18.75	19.75	2.01	10.19	11.37	11.59	0.72

expressed in kilogram) of any gas occupies the same volume. At an atmospheric pressure of 1.013 bar and 0°C (14.7 psia and 32°F), 1 mol of any gas occupies 10.2 m³ (359 ft³) and the molecular weight defines how much each mol weighs. The weights of individual gas constituents are first converted into their respective volumes and % volume of each gas is calculated thereafter. The following example gives the procedure for both dry and wet bases at various locations in the boiler restricted to only CO₂. Using the procedure the entire gas composition can be converted. By reversing the procedure volumetric basis can be converted to gravimetric.

A.1.2 Efficiency Calculations

Calculation A.1.2.1

To estimate the boiler *gross thermal efficiency* or preliminary heat balance on GCV and NCV. Refer Table A14.

TABLE A12

Unit Air and Gas Weights from Ultimate Analysis (Calculation A.1.1.11)

Excess Air	%	0	35	40	43	45	48	Remarks
Location			Furnace exit	Boiler exit	Economizer exit	Airheater exit	Net ID fan	
Dry air	kg/kg	8.2	11.07	11.48	11.73	11.89	12.14	$8.2 \times [1 + (\% \text{ Excess air}/100)]$
Excess air	kg/kg	0	2.87	3.28	3.53	3.69	3.94	Total air – 8.2
CO ₂	kg/kg	2.257	2.257	2.257	2.257	2.257	2.257	
H ₂ O (m+9H ₂)	kg/kg	0.462	0.462	0.462	0.462	0.462	0.462	
SO ₂	kg/kg	0.02	0.02	0.02	0.02	0.02	0.02	
N ₂	kg/kg	6.326	8.53	8.846	9.036	9.166	9.346	$6.326 + \text{Excess air} \times 0.7685$
O ₂	kg/kg	—	0.66	0.76	0.82	0.85	0.91	$6.326 + \text{Excess air} \times 0.2315$
Gas weight	kg/kg	9.065	11.935	12.345	12.591	12.755	13.001	Dry air + combustion products
Humidity (ha)	kg/kg	0.103	0.139	0.145	0.148	0.150	0.153	$0.0126 \times \text{total dry air}$
Total wet gas weight	kg/kg	9.168	12.074	12.490	12.739	12.905	13.154	Gas weight + humidity
Total moisture	kg/kg	0.565	0.601	0.607	0.610	0.612	0.615	$\text{H}_2\text{O} (m+9\text{H}_2) + \text{ha}$
Moisture in gas	%	6.17	4.98	4.86	4.79	4.74	4.67	Total moisture/wet gas
CO ₂ by weight	%	24.62	18.69	18.07	17.72	17.49	16.17	Weight of CO ₂ /total gas weight

The following calculation is done in MKS units. Using equivalent values for CV and enthalpy in FPS or SI units, the calculations can be converted into the appropriate units.

Chapter 1 carries a detailed description of efficiency along with the calculation method and formulae required. As the airheater (AH) is the last heat trap, all references are to the AH exit condition, and the appropriate row in Table A14 should be used for the following calculation.

- The final exit temperature from the AH has to be assumed as the first step, which can be taken as 140°C.
- The temperature of the sink, that is, the ambient temperature, is given as 25°C with 60% reheater (RH) for the design.
- Airheater exit – ambient temperature = $T_g - t_a = 140^\circ\text{C} - 25^\circ\text{C} = 115^\circ\text{C}$.

Wt of dry flue gas = Wt of wet gas – total moisture = $12.44 - 0.608 = 11.832 \text{ kg/kg}$ from Table A6.

Heat of vapor at T_g of 140°C – heat at ambient (ha) = $(140 - 100) \times 0.48 + 539 + (100 - 25) = 633.2 \text{ kcal/kg}$

Moisture on combustion $m + 9\text{H}_2 = 0.4618$, and humidity = 0.144 from Table A6.

The efficiency calculated in Table A14 is the minimum that can be guaranteed with no negative tolerance, as manufacturer margin is already factored in.

TABLE A13

Converting Gas Composition from Weight to Volume Basis (Calculation A.1.1.12)

% Excess Air		0	Furnace			Boiler Bank			Economizer			Airheater			Induced Draft Fan		
			35			40			43			45			48		
Combustion Product	MW (kg/mol)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Specific Volume (m ³ /kg)	Weight (kg/kg)	Remarks
CO ₂	44	2.257	0.523 ^a	2.257	0.523	2.257	0.523	2.257	0.523	2.257	0.523	2.257	0.523	2.257	0.523	2.257	(10.2/44) × 2.257
H ₂ O	18	0.462	0.262 ^a	0.462	0.262	0.462	0.262	0.462	0.262	0.462	0.262	0.462	0.262	0.462	0.262	0.462	(10.2/18) × 0.462
SO ₂	64	0.02	0.003 ^a	0.02	0.003	0.02	0.003	0.02	0.003	0.02	0.003	0.02	0.003	0.02	0.003	0.02	(10.2/64) × 0.02
Total N ₂	28	6.326	2.304 ^a	6.326	2.304	6.326	2.304	6.326	2.304	6.326	2.304	6.326	2.304	6.326	2.304	6.326	(10.2/28) × N ₂ in combustion air + fuel
Excess air weight	29	0	0*	2.87	1.011	3.28	1.153	3.53	1.242	3.69	1.30	3.94	1.387	3.94	1.387	3.94	(10.2/29) × excess air
Humidity in total air	18	0.103	0.059 ^a	0.139	0.079	0.145	0.082	0.148	0.084	0.150	0.085	0.153	0.087	0.153	0.087	0.153	(10.2/18) × humidity
Wet gas volume			3.152		4.183		4.331		4.419		4.478		4.566		4.566		
Dry gas volume			2.831		3.842		3.987		4.073		4.131		4.218		4.218		
% CO ₂ Wet			16.59		13.61		12.07		11.83		11.68		11.45		11.45		CO ₂ /wet gas volume
% CO ₂ Dry			18.48		13.61		13.11		12.84		12.66		12.40		12.40		CO ₂ /dry gas volume

^a See the remarks column.

TABLE A14
Efficiency Calculation (Calculation A.1.2.1)

S.No	Losses	GCV	NCV
1A	Dry gas losses	$= \frac{W_g \times C_{pg} \times (T_g - t_a) \times 100}{GCV} \%$ $= \frac{11.832 \times 0.245 \times 115 \times 100}{5850} \% = 5.70\%$	$= \frac{W_g \times C_p (T_g - t_a) \times 100}{NCV} \%$ $= \frac{11.832 \times 0.245 \times 115 \times 100}{5580} \% = 5.97\%$
1B	Moisture losses	$= \frac{(9H_2 + m) \times (Hs - ha) \times 100}{GCV} \%$ $= \frac{0.4618 \times 633.2 \times 100}{5850} \% = 5.00\%$	$= 0$
1C	Humidity losses	$= \frac{W_m \times C_p (T_g - t_a) \times 100}{GCV} \%$ $= \frac{0.144 \times 0.48 \times 115 \times 100}{5850} \% = 0.136\%$	$= \frac{W_m \times C_p (T_g - t_a) \times 100}{NCV} \%$ $= \frac{0.144 \times 0.48 \times 115 \times 100}{5580} \% = 0.142\%$
1.	Stack losses	$= 1A + 1B + 1C = 10.83\%$	$= 1A + 1B + 1C = 6.11\%$
2.	Radiation losses	$= 0.35\%$	$= 0.35 \times \frac{GCV}{NCV} \% = 0.37\%$
3.	Unburnt losses	$= 4.0\%$	$= 4 \times \frac{GCV}{NCV} \% = 4 \times \frac{5850}{5580} \% = 4.20\%$
4.	Unaccountable losses	$= 0.5\%$	$= 0.5 \times \frac{GCV}{NCV} \% = 0.5 \times \frac{5850}{5580} \% = 0.52\%$
5.	Manufacturer margin	$= 1.0\%$	$= 1 \times \frac{GCV}{NCV} \% = 1 \times \frac{5850}{5580} \% = 1.05\%$
Total losses		$\text{Sum of 1-5} = 16.68\%$	$\text{Sum of 1-5} = 12.25\%$
Gross thermal efficiency		$= 100 - \text{total losses} = 100 - 16.68 = 83.32\%$	$= 100 - \text{total losses} = 100 - 13.74 = 87.75\%$

TABLE A15

Total Air and Gas Weights (Calculation A.1.2.3)

At Exit of	Total Air Weight (kg/h) 8705 ×	Total Gas Weight (kg/h) 8705 ×	Total Air Weight (lb/h) 19,203 ×	Total Gas Weight (lb/h) 19,203 ×	Total Air weight (kg/s) 2.42 ×	Total Gas Weight (kg/s) 2.42 ×
Furnace	10.79 = 93,930	11.64 = 101,325	10.79 = 207,200	11.64 = 223,520	10.79 = 26.11	11.64 = 28.17
Boiler bank		12.05 = 104,895		12.05 = 231,400		12.05 = 29.16
Economizer		12.29 = 106,985		12.29 = 236,005		12.29 = 29.74
Airheater		12.44 = 108,290		12.44 = 238,885		12.44 = 30.10
Net induced draft fan		12.69 = 110,465		12.69 = 243,685		12.69 = 30.71

Calculation A.1.2.2*Approximate estimation of efficiency on NCV from GCV.*

Without doing a detailed calculation for efficiency on NCV, a nearly correct figure can be obtained from the efficiency of GCV by multiplying by the GCV/NCV ratio.

In the previous example this works out to be $83.32 \times (5850/5580) = 87.35$.

Calculation A.1.2.3

To calculate *the fuel input into the boiler and the total air and gas weights*. Refer to Table A15.

$$\begin{aligned}
 \text{Fuel fired} &= \frac{\text{heat duty}}{\text{thermal efficiency} \times \text{GCV}} \\
 &= \frac{51.42}{0.8332 \times 24.49} = 2.52 \text{ kg/s} \\
 &= \frac{44.2 \times 10^6}{0.8332 \times 5850} = 9,068 \text{ kg/h or} \\
 &= \frac{175.5 \times 10^6}{0.8332 \times 10,530} = 20,003 \text{ lb/h}
 \end{aligned}$$

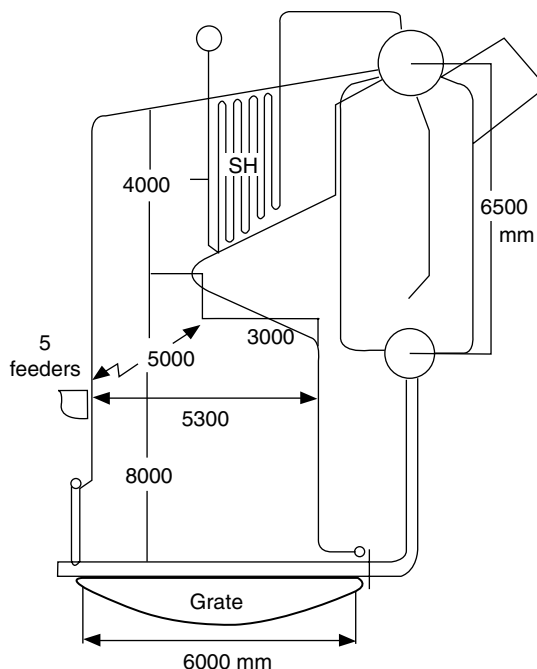
$$\begin{aligned}
 \text{Fuel burnt} &= \text{fuel fired} \times (1 - \% \text{ unburnt loss}/100) \\
 &= 2.52(1 - 4/100) = 2.42 \text{ kg/s} \\
 &= 9,068 \times (1 - 4/100) = 8,705 \text{ kg/h} \\
 &= 20,003 (1 - 4/100) = 19,203 \text{ lb/h}
 \end{aligned}$$

A.1.3 Firing Equipment Selection**Calculation A.1.3.1**

Selection of firing equipment.

Fuel fired by (rounding) is 9,070 kg/h or 20,000 lb/h, which has to be dealt with by a set of fuel feeders and grate. Since the fuel is coal, the dumping and reciprocating grates are unsuitable and only the spreader stoker is the choice.

Taking a nominal throughput of 2.5 tph or 5000 lb/h for each mechanical feeder, four feeders are adequate. Considering that one feeder may be down for maintenance, it is desirable to adopt a five-feeder configuration.

**FIGURE A2**

Furnace and firing equipment.

This results in a furnace width of ~ 5 m (16.4 ft) to accommodate the five feeders in the front wall (Figure A2).

Many times the grates change from single to dual drive at 4.87 m (16 ft.). Therefore, it is prudent to limit the grate to a width of 4.87 m (16 ft.).

For calculating the grate area, the permissible grate heat release rate has to be used consistent with the requirement of accommodating the superheater within the furnace arch depth. The final SH of only 452°C (750°F) means this can be accommodated in ~ 3 m and accordingly the depth of nose can be adopted as 3 m. The furnace depth can be kept at 5.3 m (17.38 in.) for a proper volumetric release rate.

Considering a grate of 4.87 m width $\times$ 5.543 m effective length, that is, 27 m^2 ($16 \times 18.18 = 291 \text{ ft}^2$), the grate heat release rate works out to be

- $51.42/27 = 1.9 \text{ MWth/m}^2$
- $44.2 \times 10^6/27.0 = 1,637,040 \text{ kcal/m}^2 \text{ h}$
- $175.5 \times 10^6/291 = 603,090 \text{ Btu/ft}^2 \text{ h}$

This is within the permissible limits. See Section 11.4.1.2 for design aspects of stoker firing.

The actual length of stoker between the shaft centers is 457 mm (18 in.) more than the effective length, which makes the grate 4.87 m wide $\times$ 6.0 m deep (16 ft $\times$ 19.68 ft).

A.1.4 Preliminary Furnace Calculations

Calculation A.1.4.1

To calculate the *furnace volumetric heat release rate, residence time, and average gas velocity*. Refer to Table A16.

TABLE A16

Furnace Volumetric Rate, Residence Time, and Gas Velocity (Calculation A.1.4.1)

	Metric and SI Units	FPS Units	Remarks
Total furnace volume	$(12 \times 2.3 + (8 - 1.73) \times 3 + 1.73 \times 3 \times 1/2) \times 5 = 245 \text{ m}^3$	$= 8652 \text{ ft}^3$	Sidewall area $\times$ furnace width
Total heat input	$9068 \times 5850 = 53.048 \text{ M kcal/h}$ $2.52 \times 24.49 = 61.71 \text{ MW}$	$20,003 \times 10,530 = 210.9 \text{ M Btu/h}$	Fuel fired $\times$ GCV
Volumetric heat release rate	$216,550 \text{ kcal/m}^3/\text{h}$ $61.71 \times 1000/245 = 252 \text{ kW/m}^3$	$24,375 \text{ Btu/ft}^3/\text{h}$	
Volume up to center of exit plane	222 m^3	7839	Total volume – 2.3 $\times 2 \times 5 = 245 - 23 = 222 \text{ m}^3$
Weight of flue gas	$101,325 \text{ kg/h}$	$223,520 \text{ lb/h}$	
Furnace exit gas temperature	950°C	1742°F	Assumed
Specific volume at furnace exit gas temperature	$0.759 \times (950 + 273)/273 = 3.4 \text{ m}^3/\text{kg}$	$12.16 \times (1742 + 460)/492 = 54.42 \text{ ft}^3/\text{lb}$	
Flue gas volume per second	$95.7 \text{ m}^3/\text{s}$	$3380 \text{ ft}^3/\text{s}$	
Residence time	$222/95.7 = 2.32 \text{ s}$	$7839/3380 = 2.32 \text{ s}$	Up to center of exit plane
Average furnace area	$222/10 = 22.2 \text{ m}^2$	239 ft^2	Volume/heat up to exit plane
Average velocity	$95.7/22.2 = 4.31 \text{ m/s}$	$3380/39 = 14.1 \text{ ft/s}$	

On the basis of Figure A2, calculations for different furnace parameters are done in Table A16.

A.1.5 Draft Plant Calculations

Calculation A.1.5.1

Sizing of forced draft (FD) fan.

Sizing of fan involves calculating the capacity, head, and temperature at the MCR condition, and adding suitable test block margins. Test block margins depend on the class of fan (performance tolerances), size of boiler, accuracy of determination of losses, etc. For industrial boilers of about this size, the margins considered here are normal. Altitude correction is also required.

Forced draft fan is required to provide the necessary combustion air to the furnace after overcoming the resistances of the AH, grate, ducting, and air flow measurement device.

The site altitude is 305 m (1000 ft), and altitude correction factor is 1.04.

The combustion air quantity from Calculation A.2.2.3 is 93,930 kg/h or 26.11 kg/s or 207,200 lb/h.

Converting the weight into volume, we get

$$\begin{aligned}
 & 26.11 \times 0.773 \times \frac{273 + 25}{273} \times 1.04 = 22.90 \text{ m}^3/\text{s} \\
 & = 93,930 \times 0.773 \times \frac{273 + 25}{273} \times 1.04 = 82,440 \text{ m}^3/\text{h at } 25^\circ\text{C} \\
 & = \frac{207,200}{60} \times 12.39 \times \frac{460 + 77}{460 + 32} \times 1.04 = 48,568 \text{ ft}^3/\text{min at } 77^\circ\text{F}
 \end{aligned}$$

Pressure loss account.

Pressure drop across the AH = 490 Pa or 50 mm or 2.0 in. wg

Ducts = 245 Pa or 25 mm or 1.0 in. wg

Aerofoil = 118 Pa or 12 mm or 0.5 in. wg

Undergrate pressure = 490 Pa or 50 mm or 2.0 in. wg

= 1343 Pa or 137 mm or 5.5 in. wg

After altitude correction of 1.04 = 1397 Pa or 142.5 mm or 5.72 in. wg.

In SI units.

- MCR duty of the FD fan is 22.9 m³/s at 1343 Pa wg and 25°C.
- Design duty is $22.9 \times (273 + 45)/(273 + 25) \times 1.2$ at $(1343 - 490) \times (1.44 + 490) \times 1.04$ and 45°C = 29.32 m³/s at 1787 Pa wg and 45°C.

The design duty is calculated by adding 20% margin on volume and 44%, being square of 1.2 on the variable static head and 20°C on the temperature (or the highest ambient temperature whichever is higher). Undergrate pressure is constant here for which the design head has to be suitably calculated as shown in the preceding text.

In MKS units.

- MCR duty of the FD fan is 82,440 m³/h at 142.5 mm wg and 25°C.
- Design duty is $82,440 \times (273 + 45)/(273 + 25) \times 1.2$ at $(137 - 50) \times (1.44 + 50) \times 1.04$ and 45°C = 105,567 m³/h at 182.3 mm wg and 45°C.

In FPS units.

- MCR duty of the FD fan is 48,568 ft³/m at 5.72 in. wg and 77°F.
- Design duty is $48,568 \times (460 + 111)/(460 + 77) \times 1.2$ at $(5.5 - 2.0) \times (1.44 + 2.0) \times 1.04$ at 97°F = 61,972 ft³/m at 7.32 in. wg and 111°F.

Calculation A.1.5.2

Sizing of induced draft (ID) fan.

Anticipated weights of the exhaust gases at the ID fan inlet are tabulated in Calculation A.1.2.3 and Table A15.

Flue gas quantity at ID fan inlet is 110,465 kg/h or 243,685 lb/h at 135°C or 275°F assuming a small temperature drop of 5°C (10°F) between AH and ID fan in its passage through the electrostatic precipitator (ESP).

Specific volume at ID fan inlet is taken from Calculation A.1.1.8.

Converting into volume with altitude correction, we get

$$\begin{aligned}
 & 30.71 \times 0.761 \times \frac{273 + 135}{273} \times 1.04 = 36.32 \text{ m}^3/\text{s at } 135^\circ\text{C} \\
 & = 110,465 \times 0.761 \times \frac{273 + 135}{273} \times 1.04 = 130,660 \text{ m}^3/\text{h at } 135^\circ\text{C} \\
 & = \frac{243,685}{60} \times 12.2 \times \frac{460 + 275}{460 + 32} \times 1.04 = 76982 \text{ ft}^3/\text{min at } 135^\circ\text{C}
 \end{aligned}$$

Draft loss account: furnace draft is 59 Pa or –6 mm or 0.25 in. wg

Loss in SH is 59 Pa or –6 mm or 0.25 in. wg

Loss in boiler bank (BB) is 490 Pa or –50 mm or 2.0 in. wg

Loss in economizer (ECON) is 372 Pa or –38 mm or 1.5 in. wg

Loss in AH is 490 Pa or –50 mm or 2.0 in. wg

Loss in ESP is 196 Pa or –20 mm or 0.8 in. wg

Loss in ducts is 196 Pa or –20 mm or 0.8 in. wg

Total losses is 1862 or –190 mm or 7.6 in. wg

After altitude correction is 1940 or –198 mm or 7.9 in. wg

In SI units.

- MCR duty of the ID fan is 36.62 m³/s at 1940 Pa wg and 135°C.
- Design duty with 20% margin is $43.94 \times (273 + 155)/(273 + 135)$ m³/h at $(1862 - 59) \times (1.44 + 59) \times 1.04$ Pa and 155°C = 46.1 m³/s at 2762 Pa wg and 155°C.

The test block margins are similar to FD fan except for the margin on temperature, which is taken as 20°C or 35°F.

In MKS units.

- MCR duty of the ID fan is 130,660 m³/h at 198 mm wg and 135°C.
- Design duty with 20% margin is $156,792 \times (273 + 155)/(273 + 135)$ m³/h at $(190 - 6) \times (1.44 + 6) \times 1.04$ °C and 155°C = 164,478 m³/h at 282 mm wg and 155°C.

In FPS units.

- MCR duty of the ID fan is 76,982 ft³/m/h at 7.9 wg and 275°F.
- Design duty is $76,982 \times (460 + 310)/(460 + 275) \times 1.2$ at $(7.6 - 0.25) \times (1.44 + 0.25) \times 1.04$ at 310°F = 96,778 ft³/m at 11.27 in. wg and 310°F.

Calculation A.1.5.3

Sizing of secondary air (SA) fan.

Sizing of SA fan varies from manufacturer to manufacturer depending on the firing equipment and the design practice. For a spreader stoker for burning coal, it is usual to

provide a fan that gives 20% combustion air to the furnace at a pressure of 635 mm or 6225 Pa or 25 in. wg. Starting from the design duty of FD fan in calculation A.1.5.1,

$$\begin{aligned}\text{SA fan design condition} &= 29.32 \times 0.2 = 5.864 \text{ m}^3/\text{s at 6225 Pa and } 35^\circ\text{C} \\ &= 105,567 \times 0.2 = 21,113 \text{ m}^3/\text{h at 635 mm w.g. and } 35^\circ\text{C} \\ &= 61,972 \times 0.2 = 12,394 \text{ ft}^3/\text{m at 25 in. w.g. and } 97^\circ\text{F}\end{aligned}$$

Calculation A.1.5.4

Sizing of ESP. Refer Table A17.

Sizing practice varies among the manufacturers, depending on the clients' specifications, experience, and practice. The following procedure may be considered.

Primarily, an ESP is sized to give a certain committed dust concentration at the outlet for a definite inlet dust loading. Any variation in the inlet load gets reflected at the outlet in a sympathetic manner. This is in sharp contrast to the fabric filter (FF), which is insensitive to the inlet dust loading and provides a constant outlet concentration.

Estimating the inlet dust concentration is the crucial part. The outlet concentration is specified in any region by the local pollution control authorities. Let us consider the permissible dust concentration as 100 mg/N m³ and calculate the inlet dust loading as done in Table A17.

The ESP construction note will be as follows:

In SI units.

- MCR duty is 23.79 N m³/s at 140°C with dust loading of 5.05 mg/N m³ at inlet and 100 mg/N m³ at outlet with gas draft loss limited to 196 Pa wg.
- Design duty 36.0 N m³/h at 160°C with dust loading of 3.33 mg/N m³ at inlet and 100 mg/N m³ at outlet with draft loss limited to 284 Pa wg.

In MKS units.

- MCR duty is 85,892 N m³/h at 140°C with dust loading of 5.15 g/N m³ at inlet and 100 mg/N m³ at outlet with gas draft loss limited to 20 mm wg.
- Design duty is 103,740 N m³/h at 160°C with dust loading of 3.4 mg/N m³ at inlet and 100 mg/N m³ at outlet with draft loss limited to 28 mm wg.

In FPS units.

- MCR duty is 50,433 N ft³/m at 284°F with a dust loading of 2.25 gr/N ft³ at inlet and 0.0437 gr/N ft³ at outlet with draft loss limited to 0.8 in. wg.
- Design duty is 60,520 N ft³/m at 320°F with dust loading of 2.25 gr/N ft³ at inlet and 0.0437 gr/N ft³ at outlet with draft loss limited to 1.15 in. wg.

In this example the same dust loading is considered for both MCR and design conditions, which means a margin for 20% increase in dust elutriation due to a possible higher ash coal. There can be different methods of applying the margins, which can result in better economy with adequate latitude.

TABLE A17

Sizing of Electrostatic Precipitators (Calculation A.1.5.4)

Parameter	SI Units	Metric Units	FPS Units	Remarks
Fuel fired	2.52 kg/s	9070 kg/h	20,000 lb/h	
Ash input	0.38 kg/s	1360 kg/h	3,000 lb/h	Ash forms 15% of coal
Ash elutriated	0.15 kg/s	545 kg/h	1,200 lb/h	Ash split is 30:70%::fly: bed ash in spreader stokers. For design 40% fly ash is taken
Ash at ESP inlet	$0.15 \times 0.9 \times 0.9 = 0.12 \text{ kg/s}$	$545 \times 0.9 \times 0.9 = 441 \text{ kg/h}$	$1,200 \times 0.9 \times 0.9 = 972 \text{ lb/h}$	Assume 10% precipitation in BB and AH hoppers
Gas weight at AH exit	30.1 kg/s	108,290 kg/h	238,885 lb/h	From Calculation A.1.2.3
Specific volume at NTP	$0.76 \text{ N m}^3/\text{kg}$	$0.76 \text{ N m}^3/\text{kg}$	$12.18 \text{ N ft}^3/\text{lb}$	From Calculation A.1.8
Specific volume at AH outlet	$1.15 \text{ A m}^3/\text{kg}$	$0.76 \times (273 + 140)/273 = 1.15 \text{ A m}^3/\text{kg}$	$12.18 \times (460 + 284)/460 = 19.7 \text{ ft}^3/\text{lb}$	
Gas volume at ESP inlet	$30.1 \times 0.76 \times 1.04 = 23.79 \text{ N m}^3/\text{s}$	$108,290 \times 0.76 \times 1.04 = 85,592 \text{ N m}^3/\text{h}$	$238,885 \times 12.18 \times 1.04 = 3,026,003 \text{ N ft}^3/\text{h}$ or $50,433 \text{ N ft}^3/\text{m}$	At NTP conditions with altitude correction
Gas volume at ESP inlet	$30.1 \times 1.15 \times 1.04 = 36.0 \text{ A m}^3/\text{s}$	$108,290 \times 1.15 \times 1.04 = 129,514 \text{ A m}^3/\text{h}$	$238,885 \times 19.7 \times 1.04 = 4,894,276 \text{ A ft}^3/\text{h}$ or $81,571 \text{ N ft}^3/\text{m}$	At ESP inlet temperature $140^\circ\text{C}/84^\circ\text{F}$
ESP inlet dust concentration	$(0.12 \times 1000)/23.79 = 5.05 \text{ g/N m}^3$	$(441 \times 1000)/85,592 = 5.15 \text{ g/N m}^3$	$(972 \times 7000)/3,026,003 = 2.25 \text{ gr/N ft}^3$	
ESP inlet dust concentration	$(0.12 \times 1000)/36 = 3.33 \text{ g/N m}^3$	$(441 \times 1000)/129,514 = 3.40 \text{ g/A m}^3$	$(972 \times 7000)/4,894,276 = 1.39 \text{ g/A ft}^3$	
Outlet concentration	100 mg/N m^3	100 mg/N m^3	0.0437 gr/S ft^3	Assumed as local limit
Collection efficiency		$1 - (100/(5.15 \times 1000))100 = 98.06\%$		
Design volume	$23.79 \times 1.2 = 28.55 \text{ N m}^3/\text{s}$	$85892 \times 1.2 = 103,074 \text{ N m}^3/\text{h}$	$50,433 \times 1.2 = 60,520 \text{ N ft}^3/\text{m}$	Same margin as ID fan
Design temperature	160°C	$140 + 20 = 160^\circ\text{C}$	$284 + 36 = 320^\circ\text{F}$	Same margin as ID fan
Permissible draft loss	196 and 284 Pa $(196 \times 1.44) \text{ wg}$	20 and 29 mm $(20 \times 1.44) \text{ wg}$	0.8 in. and 1.15 in. $(0.8 \times 1.44) \text{ wg}$	At MCR and design conditions

Calculation A.1.5.5*Sizing of air ducts.* Refer Table A18.

Starting from the total air weights calculated in Calculation A.1.2.3 and Table A15, the minimum duct sizes based on the permissible gas velocities are worked out in Table A18.

Calculation A.1.5.6*Sizing of gas ducts (flues).* Refer Table A19.

Starting from the total gas weights in Calculation A.1.2.3 and Table A.15, the minimum five sizes based on permissible velocities are worked out in Table A19.

TABLE A18

Sizing of Air Ducts (Calculation A.1.5.5)

Parameter	Metric and SI Units		FPS Units		Remarks
	FD Discharge	Hot Air Duct from AH	FD Discharge	Hot Air Duct from AH	
Air weight at MCR	93,930 kg/h	93,900 kg/h	207,200 lb/h	207,200 lb/h	
Operating temperature	26.1 kg/s	26.1 kg/s			
	25°C	100°C	77°F	212°F	
Specific volume at operating temperature	$0.773 \times (298/273)$ = 0.844 A m ³ /kg	$0.773 \times (373/273)$ = 1.056 A m ³ /kg	$12.39 \times (537/492)$ = 13.52 A ft ³ /lb	$12.39 \times (672/492)$ = 16.92 A ft ³ /lb	
Flow (altitude corrected)	82,450 A m ³ /h	103,155 A m ³ /h	48,560 A ft ³ /m	60,780 A ft ³ /m	× 1.04
Velocity permissible	22.90 A m ³ /s	28.65 A m ³ /s			
	11 m/s	15 m/s	2200 ft/min	3000 ft/min	Refer to Section 7.3.1.1, Table 7.5
Minimum area	2.08 m ²	1.91 m ²	22.07	20.26	

A.1.6 Sizing of Valves and Mountings

Calculation A.1.6.1

To determine the *boiler design pressure*. Refer to Table A20.

Step 1. Calculate the drum operating pressure by adding the various pressure drops to the superheater outlet pressure (SOP). Drop in SH is calculated but others are assumed based on experience. All pressure losses can be calculated at the contract stage after all valves are ordered and detailed drawings are prepared. For most boilers, such calculations are not warranted.

The SH pressure drop is assumed to be 2.75 bar, 2.8 kg/cm², or 39.8 psig (Figure A3). With superheater outlet temperature (SOT) < 425°C it is assumed that there is a spray attemperator at the outlet of SH.

Step 2. Add 5% to the drum operating pressure to arrive at the first safety valve lifting pressure (SVLP). It is assumed that the blowdown of the safety valve [(lifting pressure minus reseating pressure)/lifting pressure] is <5%, which is usually the case for safety valves used in industrial boilers. For the second SVLP, usually there is a stepping of a minimum of 0.34 bar, 0.35 kg/cm², or 5 psig.

Boiler design pressure is the highest SVLP, which is usually the second SVLP unless the boiler demands more SVs. Calculations are performed as per Table A20.

Calculation A.1.6.2

Sizing of *safety valves*. Refer to Table A21.

The following guidelines are to be kept in mind while making a selection of SVs for a boiler.

- SVs are the most sophisticated, expensive, and delicate valves and their number should be kept to a minimum.

TABLE A19
Sizing of Gas Ducts (Flues) (Calculation A.1.5.6)

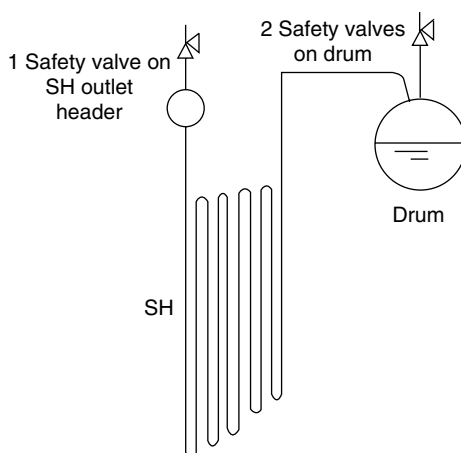
	Metric and SI Units				FPS Units			
	Boiler Bank Exit	Economizer Exit	AH/ESP Exit	ID Fan Discharge	Boiler Bank Exit	Economizer Exit	AH/ESP Exit	ID Fan Discharge
Gas at MCR	104,895	106,985	108,290	110,465	231,400	236,005	238,885	243,635
Temperature	29.14 400°C	29.71 200°C	30.08 140°C	30.68 135°C	752°F	392°F	284°F	275°F
Specific volume (m ³ /kg and ft ³ /lb)	$\$ \times 673/273$ = 1.87	$\$ \times 473/273$ = 1.316	$\$ \times 413/273$ = 1.15	$\$ \times 408/273$ = 1.136	$\$ \times 1212/492$ = 30.00	$\$ \times 852/492$ = 21.1 cf/lb	$\$ \times 744/460$ = 19.69	$\$ \times 735/460$ = 19.46
Flow (m ³ /s and ft ³ /m)	56.67	40.67	35.97	35.93	120,338	86,295	81,527	82,196
Velocity range	12.5–15	12.5–15	12.5–15	9–14	2500–3000	2500–3000	2500–3000	1800–2800
Velocity	14 m/s	14 m/s	14 m/s	12 m/s	2750 ft/min	2750 ft/min	2750 ft/min	2350 ft/min
Minimum area	4.05 m ²	2.90 m ²	2.57 m ²	3.0 m ²	43.75 ft ²	31.38 ft ²	29.64 ft ²	35.0 ft ²

kg/h and
lb/h kg/s
Temperature
assumed
\$ = 0.76 and
£ = 12.18
specific
volume at
NTP
Altitude
corrected
(1.04)
m/s and ft/min
Refer to Section
7.3.1.1,
Table 7.5

TABLE A20

Boiler Design Pressure Calculation (Calculation A.1.6.1)

	bar	MPa	kg/cm ² g	psig
Superheater outlet pressure (from Calculation 1.1.1)	70	7.0	70.38	1000
+ Pressure drop in main stem stop valve + nonreturn valve			0.7	10
+ Pressure drop in main header			0.35	5
+ Spray attemperator loss			0.35	5
+ Pressure drop in superheater bank			2.81	40
Drum operating pressure	74.18	7.418	74.6	1060
First SVLP: drum pressure + 5%	77.9	7.79	78.3	1113
Second SVLP: first SVLP + stepping	78.4	7.84	78.8	1120
Boiler design pressure	78.4	7.84	78.8	1120

**FIGURE A3**

Superheater.

- The total relieving capacity of the safety valves on the drum and the SH should equal or exceed the boiler peak duty evaporation in drum-type boilers. Likewise, they should equal or preferably exceed the maximum RH flow.
- SVs on the SH have to deal with SH steam and hence are more expensive and maintenance-prone. SVs should be sized for not less than 20% steam flow to provide enough flow to prevent overheating of SH tubes.
- Steam drums should always have two SVs as a minimum.

In the current example, the SVs have to be sized as in Table A21. For most industrial boilers, three SVs are adequate—one on SH and two on drum.

Rows 1,5,6,7, and 8 form the specification of SVs for purchase.

Calculation A.1.6.3

Sizing of *main steam stop valve (MSSV)* and *nonreturn valves (NRV)*. Refer to Table A22.

NRV is required only when two or more units operate in parallel to feed a common steam distribution header (CSDH). The nominal bore (NB) of the NRV is the same as the MSSV.

TABLE A21

Sizing of Safety Valves (Calculation A.1.6.2)

Size	Parameter	Superheater		Drum 1		Drum 2		Remarks
1	No. off	1		1		1		Total three safety valves
2	Capacity (%)	>20%	1212	~40%		~40%		>100%
3	Operating pressure	70.38 kg/cm ² g	1000 psig	74.6 kg/cm ² g	1060 psig	74.6 kg/cm ² g	1060 psig	See previous calculation for operating pressure and SVLPs
4	Operating temperature	400°C	752°F	Sat (290°C)	Sat (553°F)	Sat (290°C)	Sat (553°F)	
5	Flow	>13,600 kg/h	>30,000 lb/h	~27,200 kg/h	~60,000 lb/h	~27,200 kg/h	~60,000 lb/h	Total flow should exceed boiler evaporation
6	SVLP	73.9 kg/cm ² g	1050	78.3 kg/cm ² g	1113	78.8 kg/cm ² g	1120	1.05 × operating pressure stepping for drum safety valves
7	Design temperature	425°C	797°F	Sat (293.5°C)	Sat (559°F)	Sat (293.5°C)	Sat (559°F)	25°C/45°F attemperation at SH outlet raises design temperature
8	Material of construction	MC	MC	MC	MC	MC	MC	MC is medium carbon steel. Selected as steam temperature is low

TABLE A22

Sizing of Main Steam Piping (Calculation A.1.6.3)

Parameter	SI Units	Metric Units	FPS Units	Remarks
Steam flow (Calculation 1.1)	18.895 kg/s	68,020 kg/h	150,000 lb/h	
Design pressure/SOP	70 bar/7.0 MPa	70.38 kg/cm ² g	1000 psig	
Design temperature/SOT	400°C + 5°C = 405°C	400°C + 5°C = 405°C	752°C + 9°C = 761°F	After attemperation
Specific volume of steam	0.039 m ³ /kg	0.039 m ³ /kg	0.649 ft ³ /lb	
Volume of steam flow per second	0.737 m ³ /s	0.737 m ³ /s	27.04 ft ³ /s	$W_s \times \text{specific volume}/3600$
Steam velocity	45 m/s	45 m/s	150 ft/s	Refer to Table 7.4
Area required	0.0163 m ²	0.0163 m ²	0.18 ft ²	$A_s = \text{volume flow}/\text{steam velocity}$
Pipe inner diameter	0.144 m or 144 mm	0.144 m or 144 mm	0.48 ft × 12 = 5.75 in.	$\sqrt{\frac{4 \times A_s}{\pi}}$
Nominal bore selected	150 mm	150 mm	6 in.	100 mm bore will give velocity greater than permissible
Nominal steam velocity	41.7 mps	41.7 mps	137.8 ft/s	Volume per second per area

These valves are the largest and operate at the highest temperature. Their selection has to be optimal, both from cost and from O&M considerations.

Main steam (MS) piping size is the size of MSSV and NRV, which may be many times a size lower than the main steam outlet header that needs to support several valves and cannot have the same high steam velocity as the MS pipe.

Permissible steam velocities for steam range from 30 to 60 m/s (100–200 ft/s) lower velocities for lower pressures and temperatures. Calculations are started with a mean velocity of 45 m/s (150 ft/s).

TABLE A23

Sizing of Feed Line (Calculation A.1.6.3)

	SI Units	Metric Units	FPS Units	Remarks
Feed water flow	18.895 kg/s	68,020 kg/h	150,000 lb/h	
Design pressure of piping	95.86 bar/9.586 MPa	96.7 kg/cm ² g	1380 psig	~1.3 × drum operating pressure
Design temperature/feed water temperature	105°C	105°C	221°F	
Specific volume of water	0.001048 m ³ /kg	0.001048 m ³ /kg	0.01677 ft ³ /lb	Take specific volume of saturated water
Volume of water flow	0.0198 m ³ /s	71.285 m ³ /h 0.0198 m ³ /s	2515.5 ft ³ /h 0.6987 ft ³ /s	$W_w \times \text{specific volume}/3600$
Water velocity adopted	2.5 m/s	2.5 m/s	8 ft/s	Refer to Table 7.4
Area required	0.0079 m ²	0.0079 m ²	0.0852 ft ²	$A_s = \text{volume flow}/\text{steam velocity}$
Pipe id	0.100 m or 100 mm	0.100 m or 100 mm	0.33 ft × 12 = 3.95 in.	$\sqrt{\frac{4 \times A_w}{\pi}}$
Nominal bore selected	100 mm	100 mm	4 in.	76 mm (3 in.) bore will give greater than permissible velocity
Nominal water velocity	2.5 mps	2.5 mps	8 ft/s	Volume per second per area

The main steam outlet header should be chosen as 200 mm (8 in. NB) while the main steam piping should be 150 mm (6 in. NB) with the MSSV and NRV (if applicable) also of 150 mm (6 in. NB) size.

Calculation A.1.6.4

Sizing of *feed check valve* and *feed water piping*. Refer to Table A23.

The range of permissible velocities of water in feed piping is between 2 and 3 m/s. The design pressure of feed piping from the boiler feed pump (BFP) to the upstream flange of feed control valve is the no-load pump pressure of the BFP. It is important for pressure calculation and not for sizing of water piping, as the specific volume is not very dependent on water pressure, unlike steam. For a first approximation the no-load pump pressure (NLPP) can be taken as 1.3 times the drum pressure (Table A23).

A.1.7 Sizing of Pumps

Calculation A.1.7.1

Sizing of *boiler feed pump*. Refer to Table A24. Refer to Section 2.5.8.3 for BFP sizing.

As a BFP is required to feed water to the drum even when the drum safety valves are blowing to maintain the drum level, the highest SVLP becomes the basis for the estimation of BFP discharge pressure. Table A24 leads us to the BFP discharge pressure.

For sizing the MCR flow of the BFP, continuous blowdown (CBD) flow has to be added to the feed water flow. Normally a 3% CBD is considered adequate. Since the BFP is provided with a flooded suction, many times the static head available due to the elevation of the deaerator is subtracted from the total head calculated earlier. The head at the pump suction, which is the net positive suction head available (NPSHA), is the static head from the trip limit at the bottom of the deaerator tank to the center line of the pump suction minus the friction loss in the BFP suction line (Figure A4).

TABLE A24
Sizing of Boiler Feed Pumps (Calculation A.1.7.1)

Pressure Loss Account	kg/cm ² g	bar	MPa	psig	Remarks
Second SVLP/boiler design pressure	78.80	78.3	7.83	1120	
+ loss in economizer	~0.35			~5	
+ loss in NRV	~0.35			~5	
+ loss in piping	1.0			~15	
+ loss in control valve	2.1			~30	
+ loss in flow measurement	~0.35			~5	
+ static head	1.83			26	Height between centers of drum and BFPs assumed to be 18.3 m (60 ft). Density correction is ignored
+ loss in HP heater	0			0	No heater in this example
BFPs discharge pressure	84.78	84.17	8.417	1206	
Design margin	86.92	86.27	8.627	1240	At 2.5%
Converting to head—MCR	888.5 m	888.5 m	888.5 m	2912 ft	Pressure × specific volume × 10,000 form and pressure × specific volume × 144 for ft
Design	910.7 m	910.7 m	910.7 m	2985 ft	Take specific volume from earlier calculation

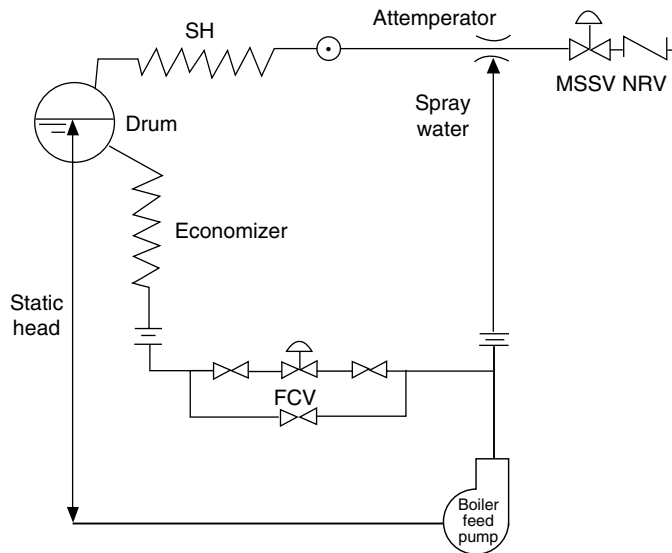


FIGURE A4
Schematic of boiler feed pump and feed line.

Often this small adjustment is ignored intentionally and added to the overall safety margin.

Test block margin for flow is 10%. Assuming there are $2 \times 100\%$ BFPs, one working and one standby, the pump specifications work out as follows:

In SI units.

- MCR condition: 0.0198×1.03 is $0.0204 \text{ m}^3/\text{s}$ of flow at 105°C and 888.5 m
- Design condition: 0.0204×1.10 is $0.0224 \text{ m}^3/\text{s}$ of flow at 105°C and 910.7 m

In MKS units.

- MCR condition: 71.28×1.03 is $73.42 \text{ m}^3/\text{h}$ of flow at 105°C and 888.5 m
- Design condition: 73.42×1.10 is $80.76 \text{ m}^3/\text{h}$ of flow at 105°C and 910.7 m

In FPS units.

- MCR condition: 2515×103 is $2590 \text{ ft}^3/\text{h}$ of flow at 221°F and 2912 ft of water
- Design condition: 2590×1.10 is $2850 \text{ ft}^3/\text{h}$ of flow at 221°F and 2985 ft of water

A.1.8 Sizing of Control Valves

Calculation A.1.8.1

Sizing of *control valves*.

There are only two types of control valves in boiler, namely, the feed and attemperator control valves.

Feed control valve. The main control valve is classically one size smaller than the feed piping for good controllability. In the current example, the feed line is 100 mm (4 in. NB) and the FCV is 80 mm (3 in. NB).

When start-up and low load control valves are to be provided for a 40–50% load, they are sized for a velocity of 3–4 m/s (nominal).

The flow conditions are taken from the BFP on the upstream side. The valve rating should be adequate for the NLPP.

Attemperator control valve. A spray attemperator at the discharge of SH is assumed, which would desuperheat the steam from 425° to 400°C ($797\text{--}752^\circ\text{F}$), with spray water provided from the BFP. The following heat balance around the attemperator gives the spray water quantity. Heat in input streams of spray water and steam is equal to heat in attemperated steam.

Spray water at 105°C + steam at SH outlet at 425°C = final steam of 68.02 tph at 400°C at $70.38 \text{ kg}/\text{cm}^2$

$$105 \times \text{SW} + 770.0 \times (68,020 - \text{SW}) = 754 \times 68,020$$

$$\text{SW} = \frac{68,020 \times (770.0 - 754)}{770 - 105} = 1,636 \text{ kg/h}$$

Attemperator flow is $\sim 1650 \text{ kg/h}$. But the spray valve should be sized for twice the calculated flow, keeping in mind the possibility of slagging and fouling (Figure A5).

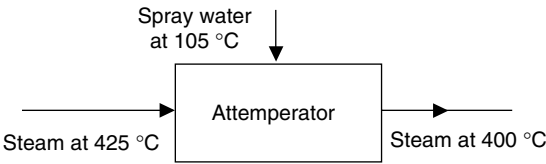


FIGURE A5
Schematic of spray attemperator at superheater outlet.

A.1.9 Sizing of Drives

Calculation A.1.9.1

Sizing of *drive motors for fans*. Refer Table A25.
Fan hp can be calculated by the formula in Section 8.2.8, reproduced as follows:

$$\text{Fan power (hp)} = kVH/\eta c$$

- where k = compressibility factor
 V = inlet volume in cubic meters per hour (ft³/m)
 H = pressure rise across fan (mm wg) (in.)
 c = constant 2743 (63.54)
 η = fan static efficiency

Compressibility factor for air or flue gas	1.0	1.05	1.1	1.15
Pressure ratio	1.0	0.98	0.97	0.95

Fan power in kW in SI units is given by the formula $kW = kVH/\eta c$ where V is in m³/s, H in kPa, $c = 1$, η is % efficiency. It can also be expressed as $kW = 0.1 \times kVH/\eta c$ where H is in mbars.
In the present context the hp of all fans can be calculated as shown in Table A25, ignoring the compressibility factor.

Calculation A.1.9.2

Sizing of drive motors for pumps. Refer to Table A26.

$$\text{Pump brake horsepower (Bhp)} = \frac{W\Delta p v}{138\eta}$$

or

$$\frac{\text{IGPM} \times \text{head in ft of water} \times \text{sp. gr at 60°F/30 in. wg}}{3300\eta}$$

- where W = flow in lb/h
 Δp = differential pressure in psi
 v = specific volume of liquid at the pump entry ft³/lb
 η = % pump efficiency/100

TABLE A25

Sizing of Fan Drives (Calculation A.1.9.1)

Fan		SI Units	Metric Units	FPS Units	Remarks
Forced draft fan	Duty	29.32 m ³ /s at 1.787 kPa and 45°C	105,567 m ³ /h at 182.3 mm wg and 45°C	61,972 ft ³ /m at 7.32 ft wg and 111°F	Backward-bladed fan chosen
	hp calculation		$(105,567 \times 182.3)/(2743 \times 70) = 100.2$	$(61,972 \times 7.32)/(63.54 \times 70) = 102$	Fan efficiency assumed 70% Compressibility factor ignored
	kW calculation	$(29.32 \times 1.787)/0.70 = 74.85$			
	Motor hp		$100.2 \times 1.15 = 115.2$	$102 \times 1.15 = 117.3$	15% margin over fan hp
	Motor kW	$74.85 \times 1.15 = 86$	$0.746 \times 115.2 = 86$	$0.746 \times 117.3 = 87.5$	Use 125 hp/94 kW standard motor
Induced draft fan	Duty	46.1 m ³ /s at 2.762 kPa and 155°C	164,478 m ³ /h at 282 mm wg and 155°C	96,778 ft ³ /m at 11.27 ft wg and 310°F	Backward-bladed fan chosen
	hp calculation		$(164,478 \times 282)/(2743 \times 75) = 228$	$(96,778 \times 11.27)/(63.54 \times 75) = 229$	Fan efficiency assumed 75%
	kW calculation	$(46.1 \times 2.762)/0.75 = 169.76$			
	Motor hp		$228 \times 1.15 = 263$	$229 \times 1.15 = 263$	15% margin over fan hp
	Motor kW	$169.76 \times 1.15 = 195.2$	$0.746 \times 263 = 196$	$0.746 \times 263 = 196$	Use 270 hp/200 kW standard motor
Secondary air fan	Duty	5864 m ³ /s at 6.225 kPa and 45°C	21,113 m ³ /h at 635 mm wg and 35°C	12,394 ft ³ /m at 25 in. wg and 97°F	Radial-bladed fan chosen
	hp calculation		$(21,113 \times 635)/(2743 \times 60) = 81.5$	$(12,394 \times 25)/(63.54 \times 60) = 81.3$	Fan efficiency assumed 60%
	kW calculation	$(5.864 \times 6.225)/60.8 = 0.6$			
	Motor hp		$81.5 \times 1.15 = 93.7$	$81.3 \times 1.15 = 93.5$	15% margin over fan hp
	Motor kW	$60.8 \times 1.15 = 70$	$0.746 \times 93.7 = 69.9 = 70$	$0.746 \times 93.5 = 69.7 = 70$	Use 100 hp/75 kW standard motor

TABLE A26

Sizing of Boiler Feed Pump Drive (Calculation A.1.9.2)

Parameter	SI Units	Metric Units	FPS Units	Remarks
Design condition	0.0224 m ³ /s at 105°C and 910.7 m	80.76 m ³ /h at 105°C and 910.7 m	2850 ft ³ /h at 221°F and 2985 ft	1 ft ³ /h = 0.1037 IGPM
Pump hp		$(80.76 \times 910.7 \times 0.954)/(273 \times 0.72) = 356$	$(2850 \times 0.1037 \times 2985 \times 0.954)/(3300 \times 0.72) = 354$	Specific gravity = 0.954 at 105°C
Pump kW	$(9.837 \times 0.0224 \times 910.7 \times 0.954)/0.72 = 266$	$356 \times 0.746 = 266$		
Motor rating		$266 \times 1.15 = 306$		A margin of 15% over the pump rating

In metric units pump Bhp = $(Q \times h \times \text{specific gravity})/273 \times \eta$ where

Q = discharge in cubic meters per hour

h = head in meters

η = pump efficiency in percentage

The efficiency of the feed pump is usually in the range of 70–85%.

In SI units pump (kW) = $(9.837 \times h \times \text{specific gravity})/273 \times \eta$ where

Q = discharge in cubic meters per hour

H = head in meters

η = pump efficiency in percentage

In this example, the Bhp of the feed pump can be worked out as shown in Table A26.

Further Readings

Ganapathy, V., 1994, *Steam Plant Calculation Manual*, 2nd edition, Marcel Dekker.

Hicks, T.G., and Hicks, D., 2004, *Standard Handbook of Engineering Calculations*, 4th edition, McGraw Hill.

Appendix B: Table of Combustion Constants

Miscellaneous gases

24	Acetylene	C ₂ H ₂	26.036	0.06971	14.344	0.9107	1499	1448	21,500	20,776	2.5	9,411	11,911	2.0	1.0	9,411	3,073	10.22	13,297	3,381	0.692	10.22	0.16
25	Naphthalene	C ₁₀ H ₈	128.16	0.3384 ^f	2.955 ^f	4.4208 ^f	5854 ^g	5654 ^g	17,298 ^g	16,708 ^g	12.0	45.17	57.170	10.0	4.0	45.17	2,996	9,968	12,964	3,434	0.562	9,968	— ^g
26	Methyl alcohol	CH ₃ OH	32.041	0.0846 ^f	11.820 ^f	1.1052 ^f	867.9	768.0	10,259	9,078	1.5	5,646	7,146	1.0	2.0	5,646	1,498	4,984	6,482	1,374	1.125	4,984	0.027
27	Ethyl alcohol	C ₂ H ₅ OH	46.067	0.1216 ^f	8.221 ^f	1.5890 ^f	1600.3	1450.5	13,161	11,929	3.0	11.29	14,293	2.0	3.0	11.29	2,084	6,934	9,018	1,922	1.170	6,934	0.030
28	Ammonia	NH ₃	17.031	0.0456 ^f	21.914 ^f	0.5961 ^f	441.1	365.1	9,668	8,001	0.75	2,823	3,573	—	1.5	3,323	1,409	4,688	6,097	—	1,587	5,511	0.088
29	Sulfur	S	32.06	—	—	—	—	—	3,983	3,983	—	—	—	—	—	—	0,998	3,287	4,285	1,998	—	3,287	0.071
30	Hydrogen sulfide	H ₂ S	34.076	0.09109 ^f	10.979 ^f	1.1898 ^f	647	596	7,100	6,545	1.5	5,646	7,146	1.0	1.0	5,646	1,409	4,688	6,097	1,880	0.529	4,688	0.30
31	Sulfur dioxide	SO ₂	64.06	0.1733	5.770	2.264	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
32	Water vapor	H ₂ O	18.016	0.04758 ^f	21.017 ^f	0.6215 ^f	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
33	Air	—	28.9	0.07655	13.063	1.0000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Note: All gas volumes corrected to 60°F and 30 in. Hg dry. For gases saturated with water at 60°F, 1.73% of the British thermal unit value must be deducted.

- ^a Calculated from atomic weights given in *Journal of the American Chemical Society*, February 1937.
- ^b Densities calculated from values given in grams per liter at open cycle and 760 mm in the International Critical Tables allowing for the known deviations from the gas laws. Where the coefficient of expansion was not available, the assumed value was taken as 0.0037/°C. Compare this with 0.003662, which is the coefficient for a perfect gas. Where no densities were available, the volume of the mole was taken as 22.4115 L.
- ^c Converted to mean British thermal units per pound (1/180 of the heat per pound of water from 32 to 212°F) from data by Frederick D. Rossini, National Bureau of Standards, letter of April 10, 1937, except as noted.
- ^d Deduction from gross to net heating value determined by deducting 18,919 Btu/lb mol of water in the products of combustion. Osborne, Stimson, and Ginnings, Mechanical Engineering, p. 163, March 1935, and Osborne, Stimson, and Fiock, National Bureau of Standards Research Paper 209.
- ^e National Bureau of Standards, RP 1141.
- ^f Denotes that either the density or the coefficient of expansion has been assumed. Some of the materials cannot exist as gases at 60°F and 30 in. Hg pressure, in which case the values are theoretical ones given for ease of calculation of gas problems. Under the actual concentrations in which these materials are present, their partial pressure is low enough to keep them as gases.
- ^g From third edition of *Combustion*.

Source: Based on *Fuel Flue Gases*, 1941 Edition, courtesy of American Gas Association.

Appendix C: ASTM Standards Pertaining to Testing and Specification of Coals and Oils

ASTM

Designation	Description
D93	Tests methods for point by Pensky-Martens closed tester
D121	Coal and coke
D197	Sampling and fineness test of powdered coal
D271	Sampling and analysis of coal and coke
D291	Cubic foot weight of crushed bituminous coal
D310	Size of anthracite
D311	Sieve analysis of crushed bituminous coal
D323	Perforated-plate sieves for testing purpose
D388	Classification of coals by rank
D396	Specification for fuel oils
D407	Gross calorific value and net calorific value of solid and liquid fuels
D409	Test method for grindability of coal by the Hardgrove machine method
D410	Screen analysis of coal
D431	Size of coal designated from its screen analysis
D440	Drop shatter test for coal
D441	Tumbler test for coal
D445	Test method for kinematics viscosity of transparent and opaque liquids (and the calculation of dynamic viscosity)
D492	Sampling coals classified according to ash content
D547	Dustiness index of coal and coke
D720	Test method for free-swelling index of coal
D1412	Test method for equilibrium moisture of coal at 96%
D1756	Carbon dioxide in coal
D1757	Sulfur in coal ash
D1812	Plastic properties of coal by the Gieseler plastometer
D1857	Fusibility of coal ash
D2013	Method of preparing coal samples for analysis
D2014	Expansion or contraction of coal by the sole-heated oven
D2015	Test method for gross calorific value of coal and coke by the adiabatic bomb calorimeter
D2234	Test methods for collection of a gross sample of coal
D2361	Test method for chlorine in coal
D2492	Sulfur forms in coal
D2639	Plastic properties of coal by the automatic Gieseler plastometer
D2796	Lithological classes and physical components of coal
D3173	Test method for moisture in the analysis sample of coal and coke
D3174	Test method for ash in the analysis sample of coal and coke
D3175	Test method for volatile matter in the analysis sample of coal and coke
D3176	Practice for ultimate analysis of coal and coke.
D3177	Test methods for total sulfur in the analysis sample of coal and coke
D3286	Test method for gross calorific value of coal and coke by the Isoperibol bomb calorimeter
D3302	Test method for total moisture in coal
D3682	Test method for major and minor elements in coal and coke ash by atomic absorption
D4208	Test method for total chlorine in coal by the oxygen bomb combustion/ion-selective electrode method
D4239	Test methods for sulfur in the analysis sample of coal and coke using high-temperature tube furnace combustion methods
D4326	Test method for major and minor elements in coal and coke ash by x-ray fluorescence
D4371	Test method for determining the washability characteristics of coal
D4749	Test method for performing the sieve analysis of coal and designating coal size
D5142	Test methods for proximate analysis of the analysis sample of coal and coke by instrumental procedures
E121	Wire cloth sieves for testing purpose
E323	Perforated-plate sieves for testing purpose

Note: Similar standards are there with all leading codes.

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List of Symbols

A	Area
A_g/A_s	Area to gas/area to steam
Bhp	Brake horsepower
Btu	British thermal unit
°C	Degree celsius
C_q	Coefficient of discharge
C_v	Flow coefficient
cp	Specific heat at constant pressure
cv	Specific heat at constant volume
cfm	Cubic feet per minute
cst	Centistoke
cu	Cubic
De	Equivalent diameter
D_i/D_o	Inside diameter/outside diameter
F	Friction factor
Fr	Froude number
fpm	Feet per minute
fps	Feet per second
G_a/G_g	Mass velocity of air/mass velocity of gas
Gr	Grashof number
gpm	Gallon per minute
gr	Grain
h	Enthalpy
H	Head of fluid, enthalpy per mole
h	Hour
J	Joule
K	Degree Kelvin (°C + 273)
k	Thermal conductivity
kg	Kilogram
kpsi/ksi	Kilo (1000) psi
ksi	1000 psi
L	Length
l	Liter
lb	Pound
m	Mass, meter
mg	Milligram
ml	Milliliter
MPa	Mega (10 ⁶) pascal
Mwe	Megawatt electrical
MWt	Megawatt thermal
N	Newton
N	Number
Nu	Nusselt number
N_{vh}	Number of velocity heads
Oz	Ounce

P	Absolute pressure, poise
Pa	Pascal
P_r	Prandtl number
pH	Negative log of hydrogen ion concentration
ppb	Parts per billion
ppm	Parts per million
psf	Pounds per square feet
psi	Pounds per square inch
psia, psig	psi absolute, psi gauge
Q	Heat
q	Rate of heat flow
R	Universal gas constant
$^{\circ}\text{R}$	Degrees Rankine ($^{\circ}\text{F} + 460$)
Re	Reynolds number
rpm	Revolutions per minute
s	Entropy in kcal/K, surface area
s	Specific entropy in kcal/kg K
shp	Shaft horse power
spec	Specification
sp.gr	Specific gravity
SSF	Seconds Saybolt Furol
SSU	Seconds Saybolt Universal
St	Stokes
T	Absolute temperature in K ($273 + ^{\circ}\text{C}$)
t_a	Temperature of air
t_b	Bulk temperature of fluid
t_f	Film temperature
U	Film conductance
U_c	Convection conductance
U_{cc}	Convection conductance in cross flow
U_r	Radiation conductance
U_{rg}	Radiation conductance due to gas
UV	Ultraviolet
V	Velocity of fluid
v	Specific volume
vs	Versus
w.g.	Water gauge
wt.	Weight
YP	Yield point
YS	Yield stress
'/ft	Foot
"/in.	Inch
$^{\circ}$	Degree of angle or arc

Value	10^{12}	10^9	10^6	10^3	10^2	10^1	10^{-1}	10^{-2}	10^{-3}	10^{-6}	10^{-9}	10^{-12}
Symbol	T	G	M	k	h	da	d	c	m	μ	n	p
Prefix	Tera	Giga	Mega	Kilo	Hecta	Deca	Deci	Centi	Milli	Micro	Nano	Pico

List of Acronyms

A	Ash
ACC	Automatic combustion control
AH	Airheater
API	American Petroleum Institute
AS	Alloy steel
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BEGT	Boiler exit-gas temperature
BFBC	Bubbling fluidized bed combustion boiler
BFG	Blast furnace gas
BFP	Boiler feed pump
BO	Bought out
BOP	Balance of plant
BQ	Boiler quality
BRIL	Brick, refractory, insulation, and lagging
BS	British standard
CBD	Continuous blowdown
CC	Combined cycle
CCPP	Combined cycle power plant
CDS	Cold-drawn seamless
CG	Chain grate
CS	Carbon steel
CFBC	Circulating fluidized bed combustion
COG	Coke oven gas
Cogen	Cogeneration
CPP	Captive power plant
CV	Calorific value
CW	Cooling water
daf	Dry ash-free
DG	Dumping grate
DIN	German standard
DM	Demineralized water
dmmf	Dry mineral matter-free
ECON	Economizer
ERW	Electrically resistance welded
ESP	Electrostatic precipitator
EVAP	Evaporator
FBC	Fluidized bed combustion
FBHE	Fluid bed heat exchanger
FC	Fixed carbon
FD	Forced draft
FEGT	Furnace exit-gas temperature
FO	Fuel oil
FWH	Feed water heater
GCV	Gross calorific value

GEN	Generator
GI	Galvanized iron
GR	Gas recirculation
GT	Gas turbine
HC	Hydrocarbon
HCV	Higher calorific value
HFS	Hot-finished seamless
HGI	Hardgrove index
HP	High pressure
HRSG	Heat recovery steam generator
IADT	Initial ash deformation temperature
IBD	Intermittent blowdown
ID	Induced draft
IP	Intermediate pressure
IVC	Inlet vane control
IWCG	Inclined water-cooled grate
LCV	Lower calorific value
LP	Low pressure
LWL	Low water level
LLWL	Low low water level
M	Moisture
MB	Mass burning
MCR	Maximum continuous rating
MDC	Mechanical dust collector
MHVT	Multiple-shield high-velocity thermocouple
MM	Mineral matter
MW	Megawatt, molecular weight
NB	Nominal bore
NCV	Net calorific value
NCR	Normal continuous rating
NG	Natural gas
NLPP	No load pump pressure
NPPs	Nonpressure parts
NPSH	Net positive suction head
NRV	Nonreturn valve
NWL	Normal water level
OC	Open cycle
OFA	Overfire air
OT	Once through
OTSG	Once-through steam generator
PA	Primary air, proximate analysis
PC	Pulverized coal
PCO	Plastic chrome ore
PF	Pulverized fuel
PG	Pulsating grate
PHG	Pinhole grate
PP	Pressure part
PTC	Performance test code
RG	Refinery gas, reciprocating grate
RH	Reheat, reheater

SA	Secondary air
SAW	Submerged arc welded
SB	Soot blower, spreader burning
SBV	Steam by volume
SBW	Steam by weight
SC	Supercritical
SCR	Selective catalytic reaction
SG	Steam generator
SH	Superheat, superheater
SR1	Seconds Redwood 1
SS	Spreader stoker
ss	Stainless steel
ST	Steam turbine, softening temperature of ash
STC	Steam temperature control range
STIG	Steam-injected gas turbine
SWH	Saturated water head
TA	Tertiary air
TC	Thermocouple test certificate
TEG	Turbine exhaust gas
TG	Traveling grate, turbogenerator
TP	Terminal point
UA	Ultimate analysis
WHRB	Waste heat recovery boiler
VFD	Variable-frequency drive
VM	Volatile matter
VOC	Volatile organic compound

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