STEAM

its generation and use

40th

EDITION

Babcock & Wilcox
a McDermott company

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Edited by S.C. Stultz and J.B. Kitto

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First printing

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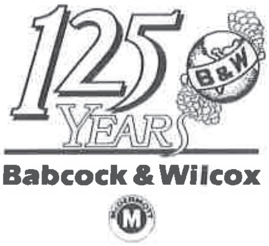
Steam 40

This 40th edition is for the men and women who do the work of the world every day in power plants, paper mills, oil refineries, factories, and every other institution that uses a safety water tube boiler.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YEARS
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Preface/Dedication

Dear Reader:

One hundred and twenty five years ago, George Babcock and Stephen Wilcox formed a partnership and patented a product that accelerated worldwide industrial development — the safety water tube boiler.

Today, Babcock & Wilcox continues its commitment to the safe and dependable generation of power. While B&W has added new products and services over the years, few companies have remained as dedicated to their original products and services for so long a period of time. And few products and services have provided such a steady increase in their usefulness, efficiency and economy over the years.

The common forces throughout these 125 years have been our employees, our customers and our partners. Without their support and ingenuity, we would not be celebrating this historic event. Babcock & Wilcox has been able to continue its commitment to excellence through technology and through the values of quality, service and integrity held by its people, and we will continue to do so in the future.

I would like to dedicate this 40th edition of *Steam / its generation and use* to the creativity and technical strength of all Babcock & Wilcox employees, and to our customers and partners who recognize these talents and support our commitment to excellence. For more than a century we have worked together, pursuing all opportunities to further advance the art and science of steam generation with effective control of environmental emissions.

We look forward to working together in the future to apply energy conversion technologies to do the work of the world in an environmentally safe and dependable manner.

Joe J. Stewart

Joe J. Stewart
Executive Vice President and Group Executive
Power Generation Group
Babcock & Wilcox

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Acknowledgments

Steam / its generation and use is the culmination of the work of hundreds of B&W employees who have contributed directly and indirectly to this edition and to the technology upon which it is based. Particular recognition goes to individuals who formally committed to preparing and completing this expanded 40th edition.

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System of Units: English and Système International

To recognize the globalization of the power industry, the 40th edition of *Steam* has been extensively revised to incorporate the Système International d'Unitès (SI) along with the continued use of English or customary U.S. units. Upon recommendation of the Technical Advisory Committee for *Steam*, English units continue to be the primary system of units with SI provided as secondary units in parentheses. In some instances, SI units alone have been provided where these units are common usage. In selected figures and tables where dual units could detract from clarity (logarithmic scales, for example) SI conversions are provided within the figure titles or as a table footnote.

Extensive English-SI conversion tables are provided in Appendix I. This appendix also contains a complete SI set of the Steam Tables, Mollier diagram, pressure-enthalpy diagram and psychrometric chart.

The decision was made to provide exact conversions rounded to an appropriate number of figures. This was done to avoid confusion about the original source values.

Two exceptions to these conversion practices have been adopted. As is general practice in the power industry worldwide, *bar* has been used as the unit for steam pressure above atmospheric, in place of the pure SI unit of *megapascal* or *MPa* (1 MPa = 10 bar). Absolute pressure is denoted by *psi* or *bar* and gauge pressure by *psig* or *bar gauge*. The difference between *absolute pressure* and *pressure difference* is identified by the context. Finally, in Chapters 9 and 21, as well as selected other areas of *Steam* which provide extensive numerical examples, only English units have been provided for clarity.

For reference and clarity, power in British thermal units per hour (Btu/h) has typically been converted to megawatts-thermal and is denoted by MW_t while megawatts-electric in both systems of units has been denoted by MW.

It is hoped that these conversion practices will make *Steam* easily usable by the broadest possible audience.

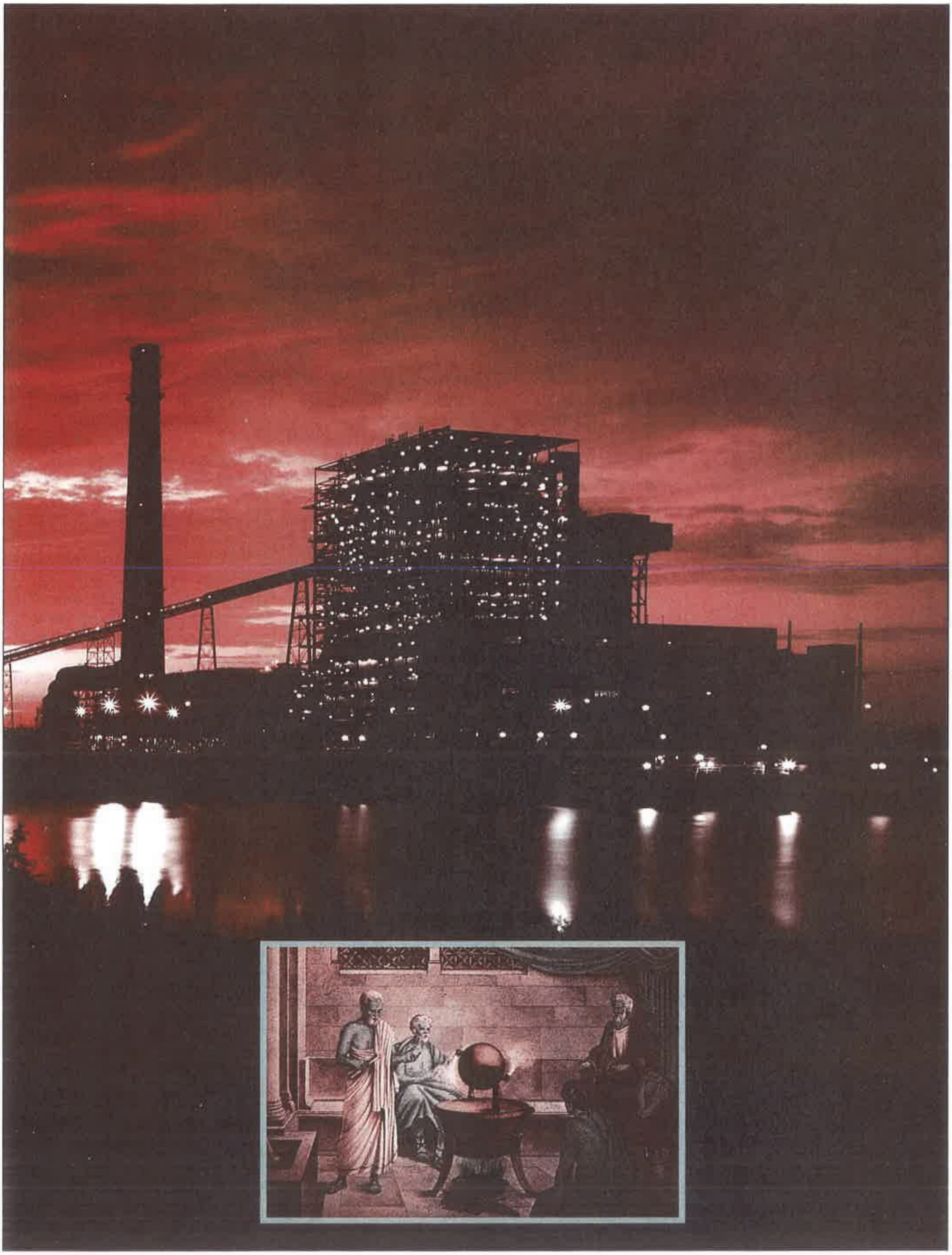
Editors' Foreword

"While making known the character and quality of our manufactures, we have endeavored at the same time to present to our friends and customers a variety of useful information, not readily accessible to them in other ways."

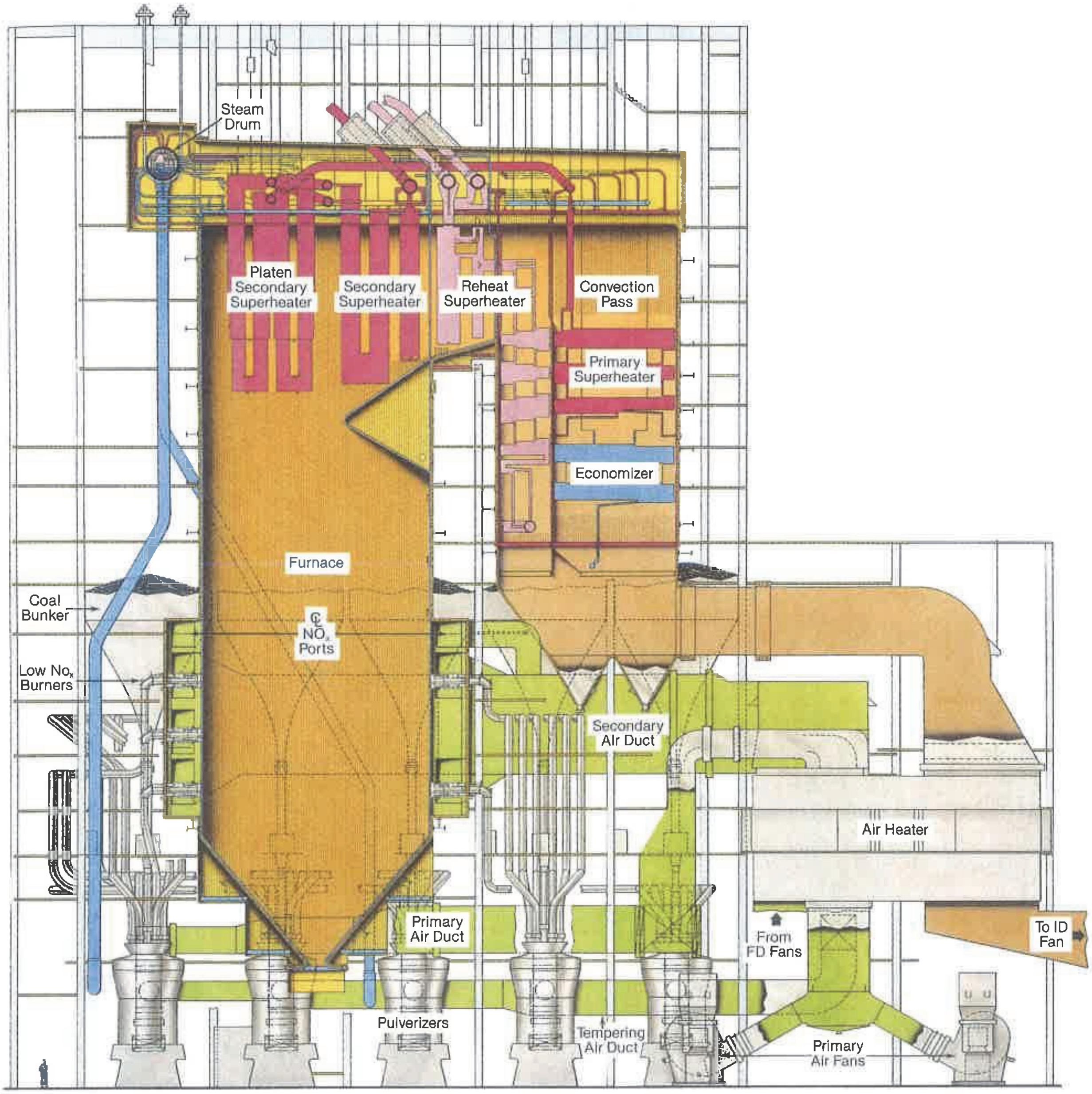
So began the first edition of *Steam / its generation and use* more than a century ago. The text has been revised and updated often, and some editions have been more extensively modified than others. We, as editors of the 40th edition, feel a particular affiliation with those who undertook the project after the first ten editions, at least in their overview: *"In preparing the new edition of* Steam, *we have revised the whole, and added much new and valuable material."* This new 40th edition has been such a task, and only through the dedicated efforts of many B&W employees has this complete revision been possible.

Steam / its generation and use is accepted worldwide as an authoritative handbook on steam generation. Its principal purpose is to help professionals design, procure, construct and maintain B&W equipment in a way that will provide decades of reliable performance.

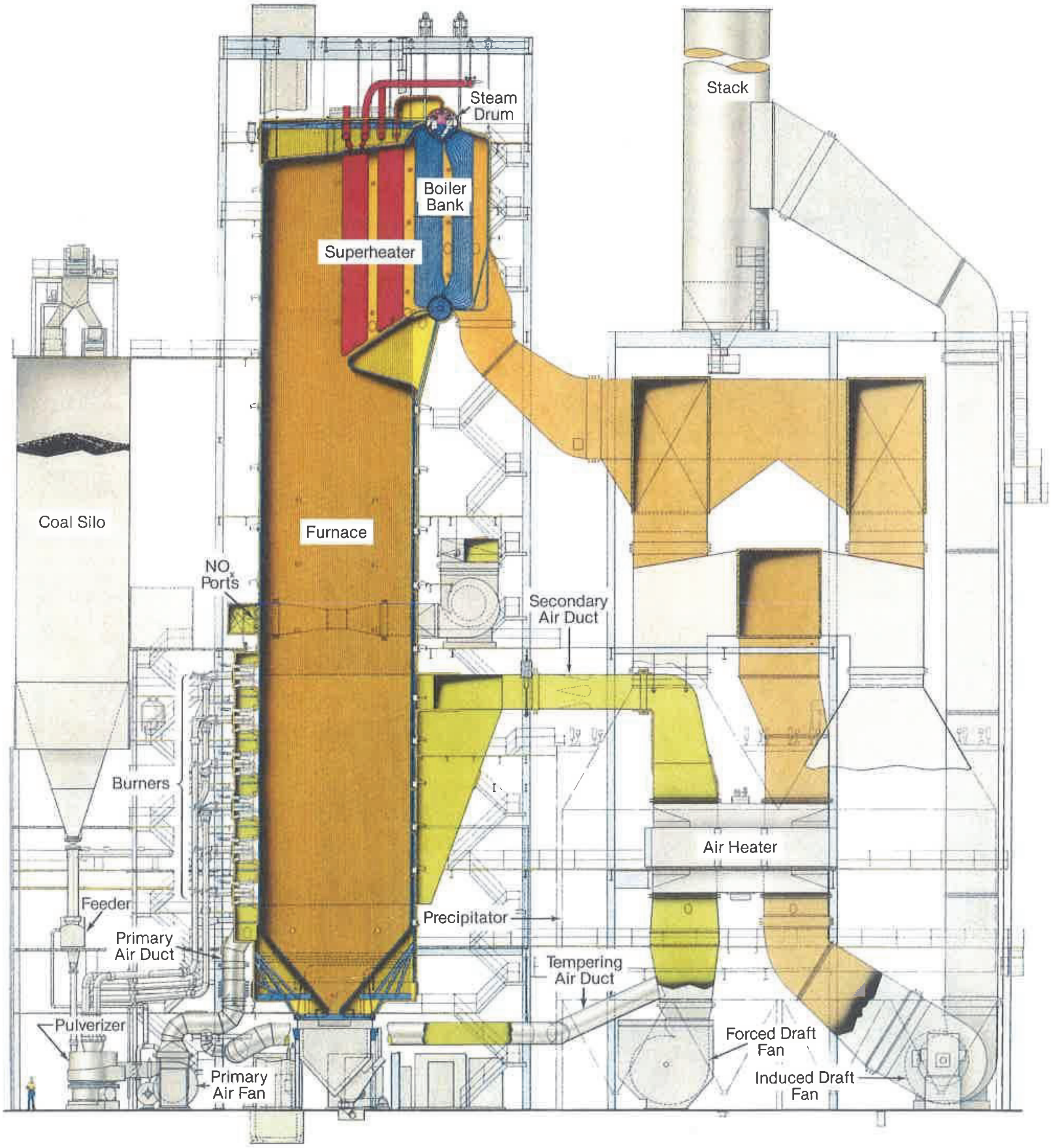
The focus of the 40th edition of *Steam* has been to analyze and incorporate industry developments since the last edition, while looking well into the 21st century and continuing the 115 year tradition of this publication.



Selected Color Plates — 40th Edition

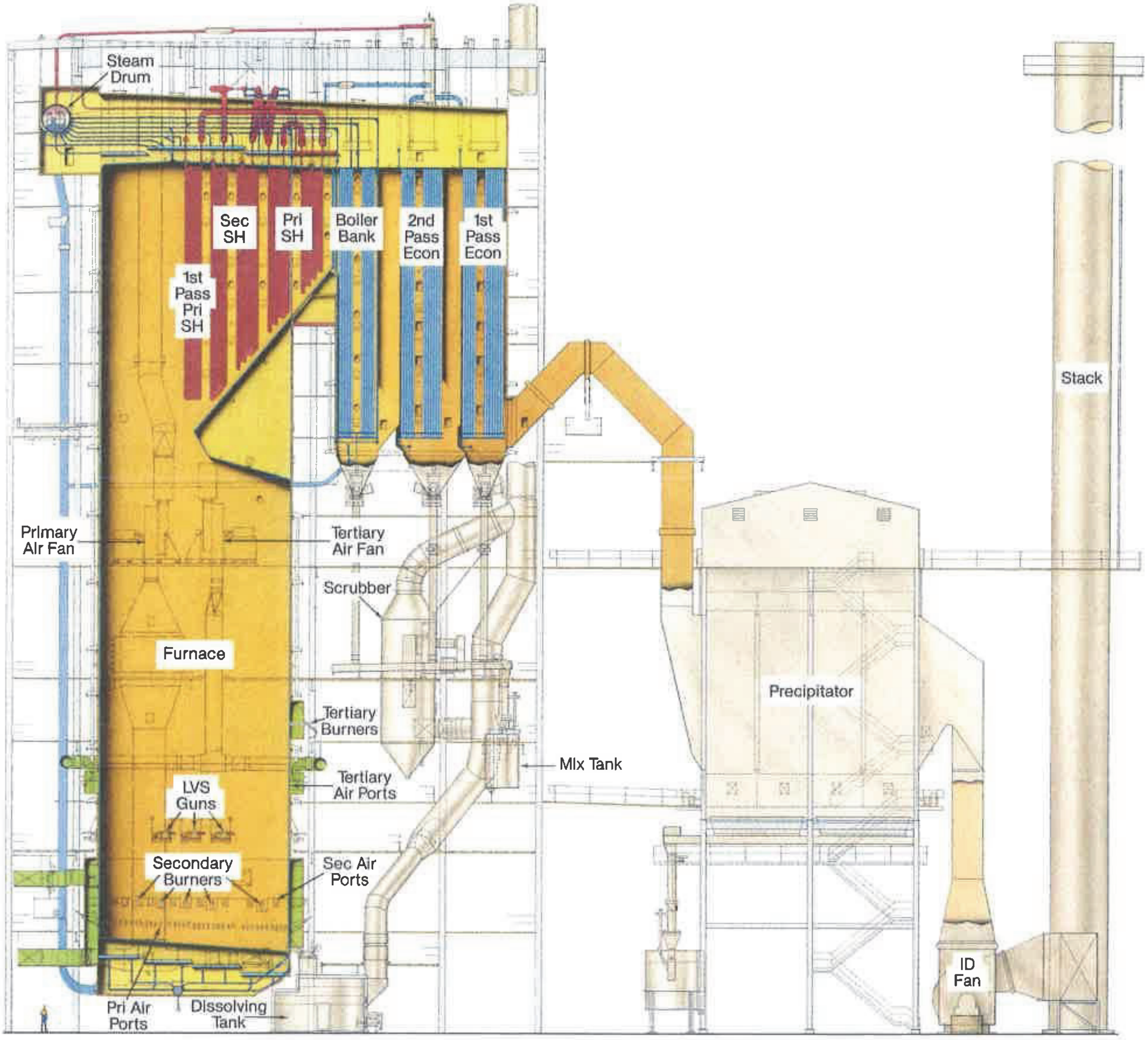


Carolina-type 455 MW Radiant boiler for pulverized coal.

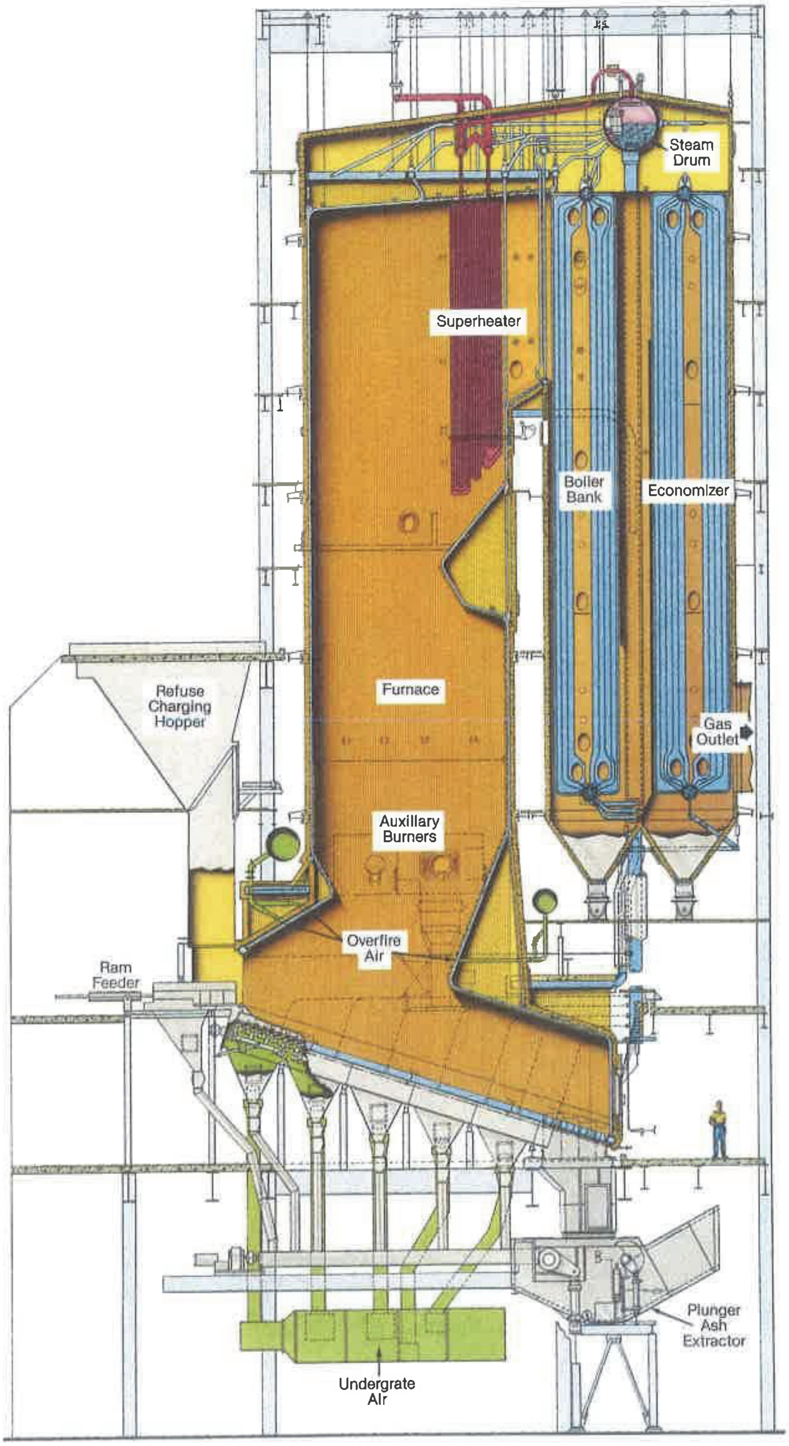


Large coal- and oil-fired two-drum Stirling® power boiler for industry, 885,000 lb/h (112 kg/s) steam flow.

Plate 2

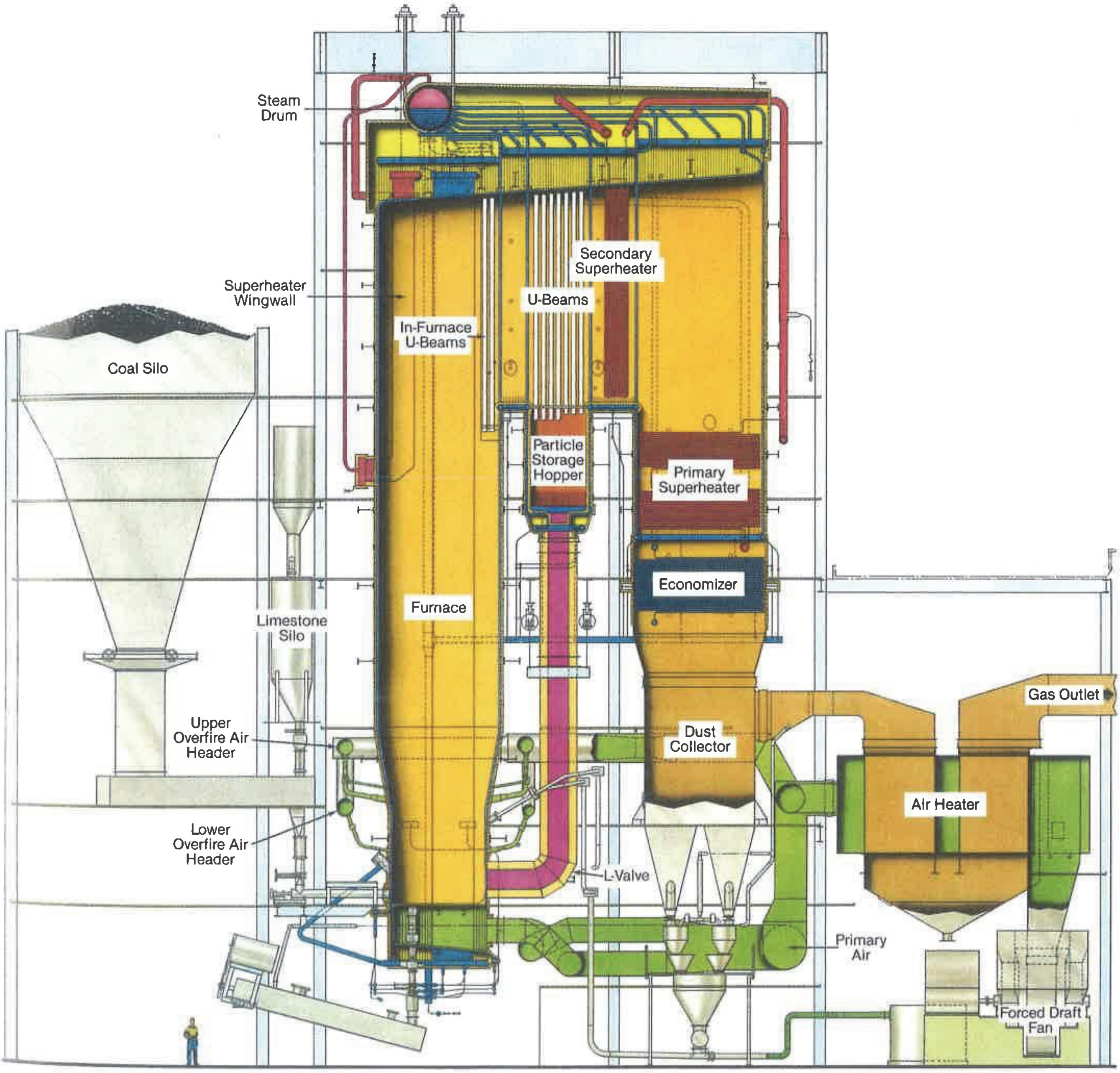


Single-drum chemical recovery boiler for the pulp and paper industry.

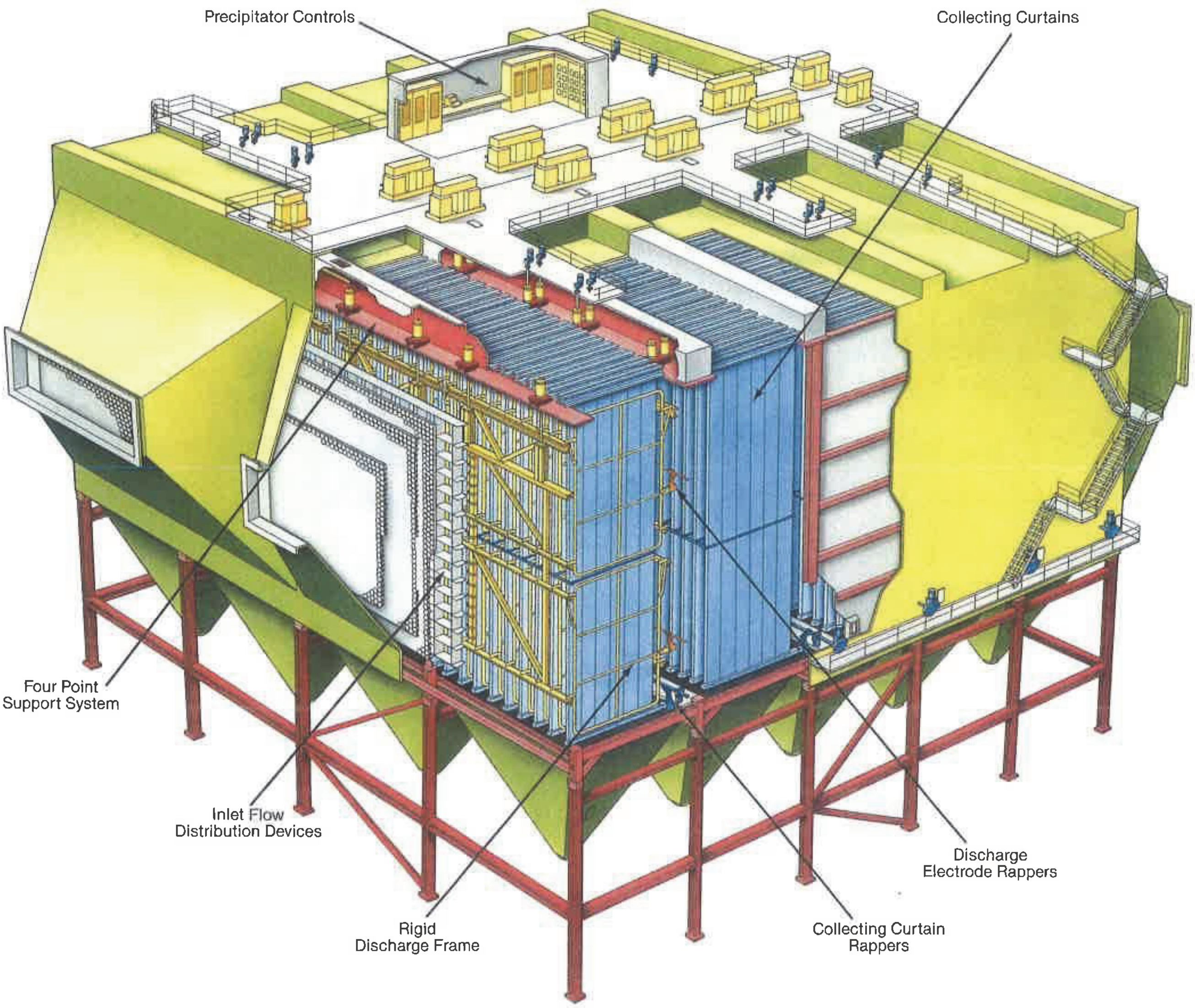


Refuse-to-energy boiler for mass burning, 1000 tons per day.

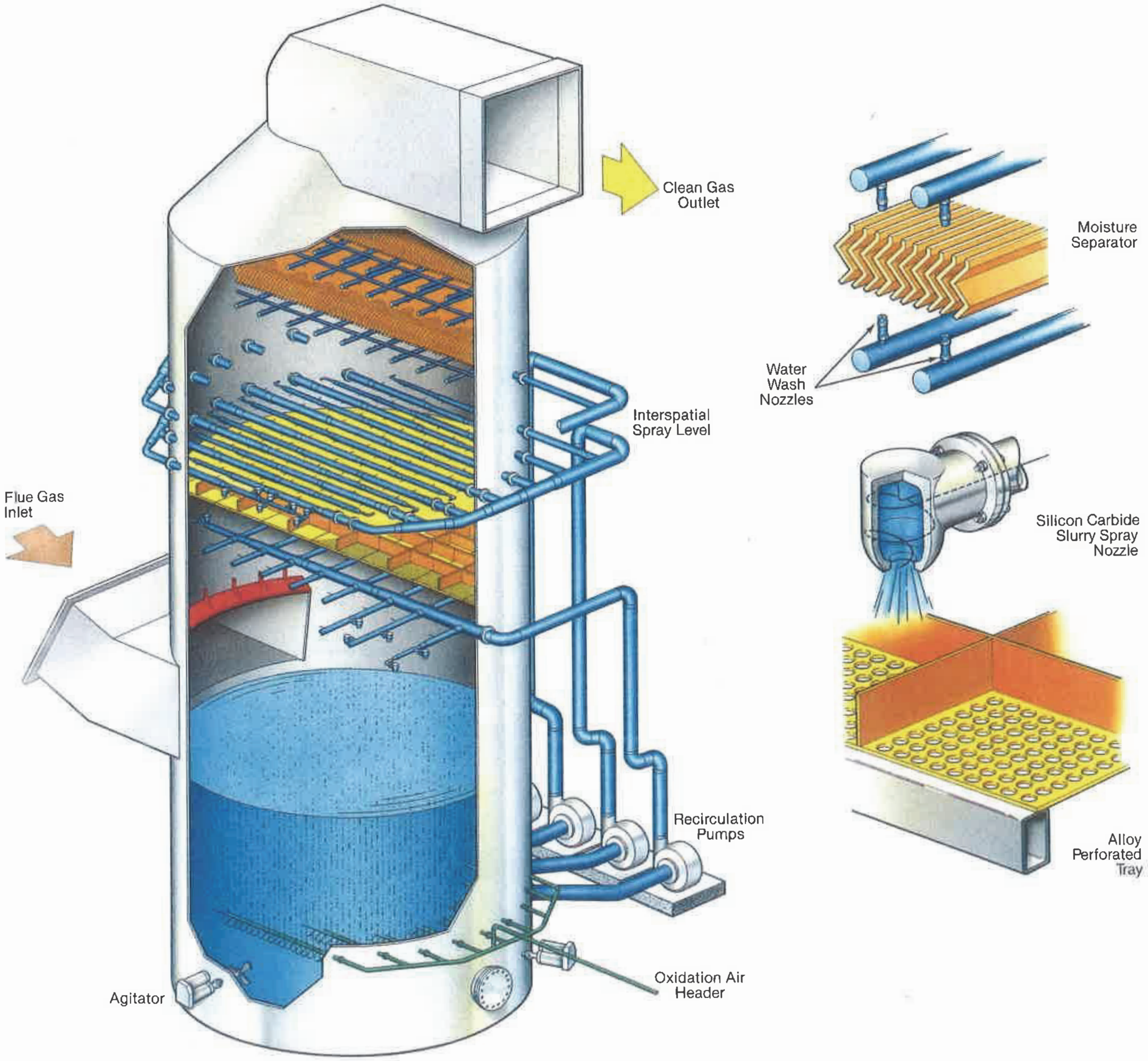
Plate 4



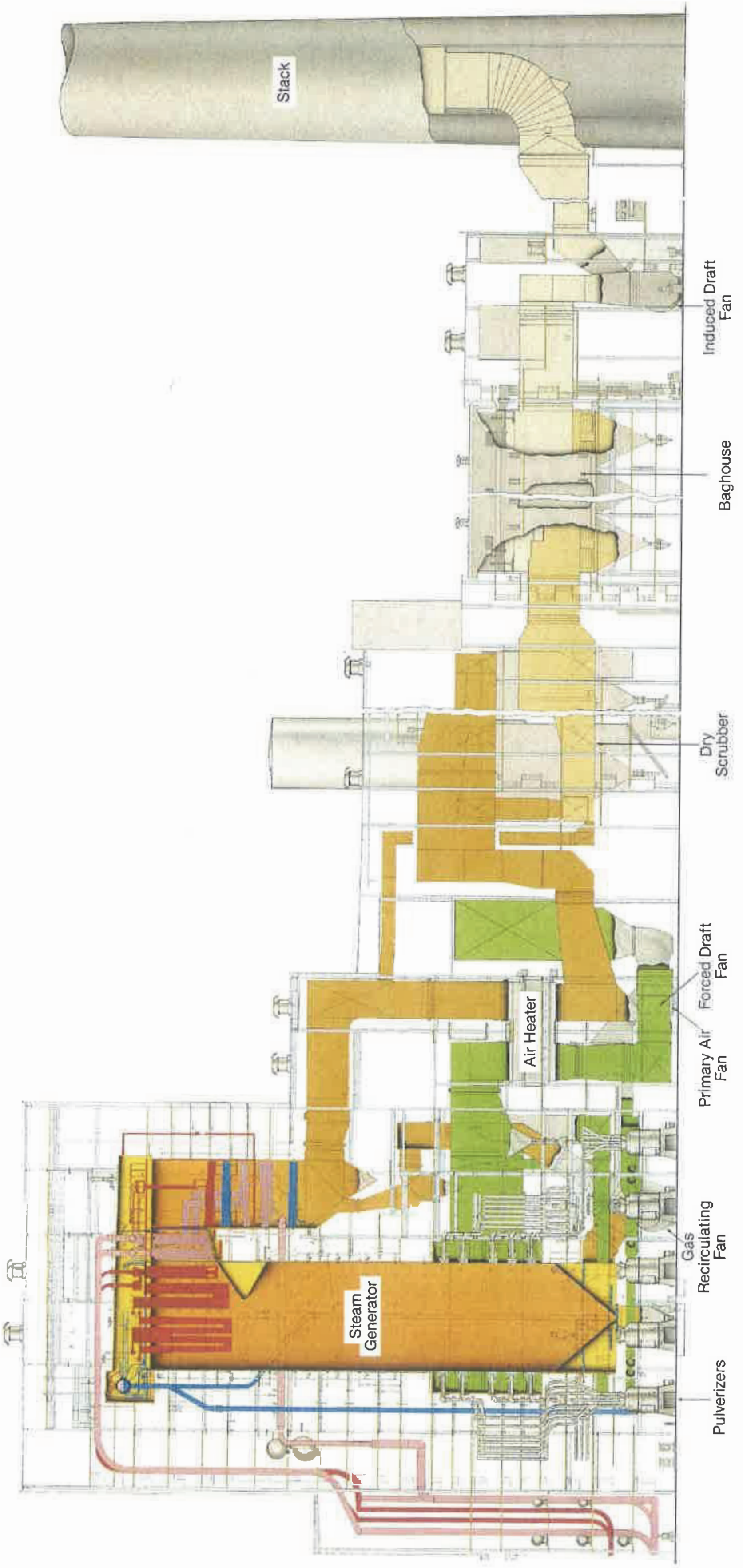
55 MW circulating fluidized-bed combustion unit for low volatile bituminous coal.



Electrostatic precipitator for particulate control.



Wet flue gas desulfurization scrubber module for sulfur dioxide control.



Modern 860 MW coal-fired utility boiler system with environmental control equipment.

Section II
Steam Generation from Chemical Energy

This section applies the fundamentals of steam generation to the design of boilers, superheaters, economizers and air heaters for steam generation from chemical or fossil fuels (coal, oil and natural gas). As discussed in Chapter 1, the fuel and method of combustion have a dramatic impact on the size and configuration of the steam producing system. Therefore, Chapters 8 and 9 begin the section by exploring the variety and characteristics of chemical and fossil fuels, and summarize the combustion calculations which are the basis for system design.

The variety of combustion systems available to handle these fuels and the supporting fuel handling and preparation equipment are then described in Chapters 10 through 17. These range from the venerable stoker in its newest configurations to circular burners used for pulverized coal, oil and gas, to fluidized-bed combustion and coal gasification. A key element in all of these systems is the control of atmospheric emissions, in particular oxides of nitrogen (NO_x) which are byproducts of the combustion process. Combustion NO_x control is discussed as an integral part of each system. It is also discussed in Section IV, Chapter 34.

Based upon these combustion systems, Chapters 18 through 21 address the design and performance evaluation of the major steam generator heat transfer components: boiler, superheater, reheater, economizer and air heater. These are configured around the combustion system selected with special attention to properly handling the high temperature, often particle laden flue gas. The fundamentals of heat transfer, fluid dynamics, materials science and structural analysis are combined to provide the tradeoffs necessary for an economical steam generating system design. The boiler setting and auxiliary equipment, such as sootblowers and fans, which are key elements in completing the overall steam system conclude this section in Chapters 22 and 23.

Coal remains the dominant fuel source for electric power generation worldwide.

Chapter 8
Sources of Chemical Energy

World energy consumption continues to grow with the primary resources being the fossil fuels. World production in 1989 was approximately 339×10^{15} Btu (358×10^{18} J). The trend in energy production by source from 1977 to 1989 is shown in Fig. 1. World energy production and fossil fuel reserves by region are shown in Figs. 2 and 3.

Approximately 50% of this energy was used by the industrialized countries of the Organization for Economic Cooperation and Development (OECD), which includes the United States (U.S.). The remainder was consumed by the former Soviet Union [now the Confederation of Independent States (C.I.S.)], the People's Republic of China (China) and developing countries. Projected energy consumption through the year 2000 in the industrialized OECD countries is shown in Fig. 4.

Annual energy production in the U.S. rose to 65.7×10^{15} Btu (69.3×10^{18} J) by 1989, which is about 20% of world production. Approximately 88% of this energy is in the form of fossil fuels. U.S. energy production by source is given in Fig. 5.

The relative U.S. production of coal compared to other fossil fuels has increased since 1976 when 26% was coal, 29% was crude oil and 33% was natural gas. In 1989, coal production accounted for 32%, crude oil was 25% and natural gas was 27%. This increased use of coal is expected to continue.

Overall energy consumption in the U.S. was approximately 81×10^{15} Btu (85×10^{18} J) in 1989. About 36% of this energy was consumed by electric utilities in the form of fossil fuels.

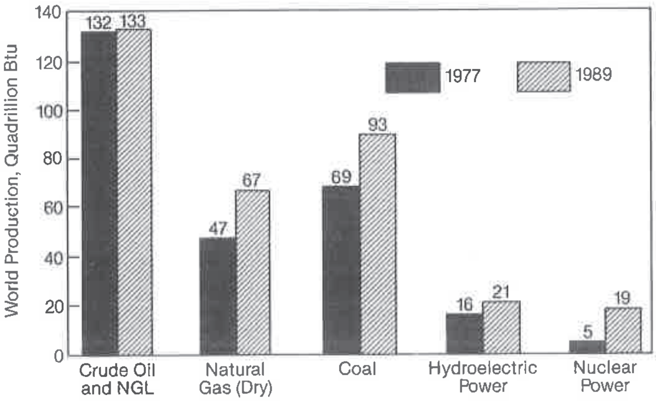


Fig. 1 Trends in world energy production by source (NGL = natural gas liquids).

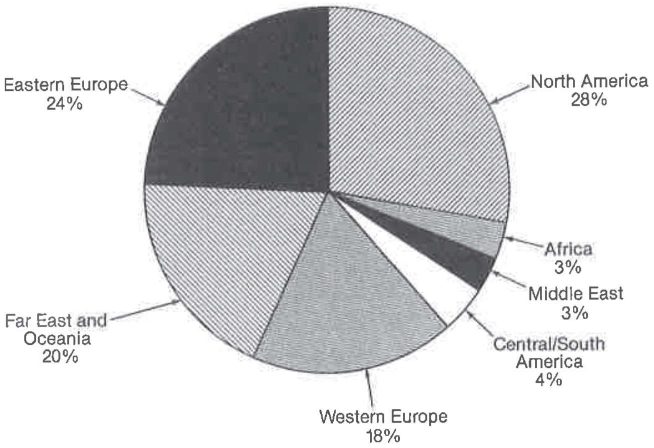


Fig. 2 World energy production by region, 1989.

Although overall U.S. fossil fuel consumption has increased, the average cost decreased almost 40% from 1982 to 1989. Although the cost of crude oil decreased steadily after 1981, it remains the most costly fuel. The trends in coal, oil and natural gas prices are given in Fig. 6.

World availability

Coal is the second leading source of fuel, supplying 32% of the world's energy. It is also the most common fossil fuel for utility and industrial power generation. Major reserves by coal type and location are: lignite — the U.S. and the C.I.S.; subbituminous — China, the C.I.S., Australia and Germany; and bituminous — China, the U.S. and the C.I.S.

Reserves of coal by regions of the world are given in Fig. 3. Of those regions China consumed the most (21%) in 1989, followed by the U.S. (20%) and the C.I.S. (15%). Because of its worldwide availability and low price, the demand for coal has grown and world coal trade has expanded by about 40% since 1980. The largest coal exporters are Australia, the U.S., South Africa, the C.I.S., Poland and Canada.[1]

U.S. availability

The coal reserves of the U.S. constitute a vast energy resource, accounting for about 14% of the world's total recoverable coal.[2] According to a 1989 U.S. geological sur-

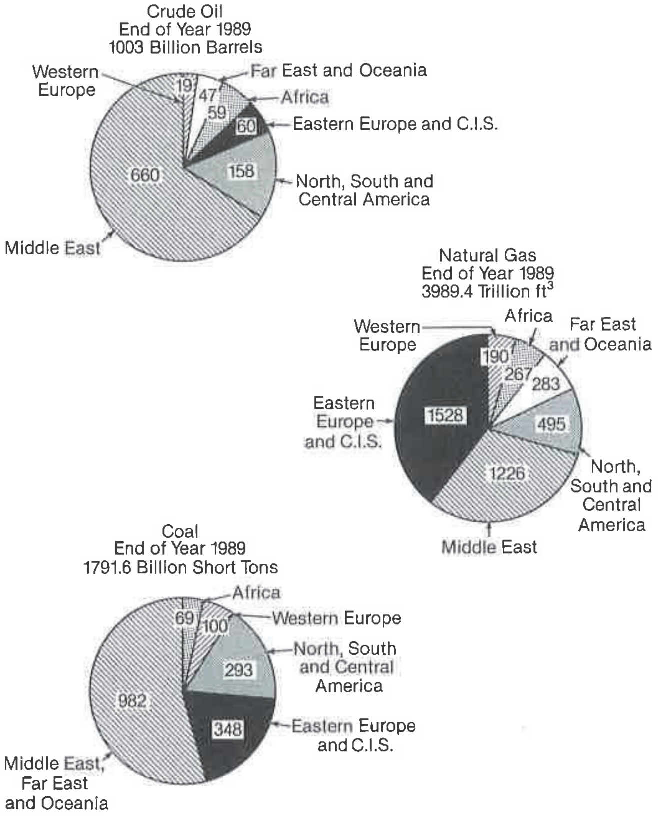


Fig. 3 Fossil fuel reserves by world region.

vey, and based on data from the Energy Information Administration, total coal resources, known and estimated, are about 4×10^{12} t (3.6×10^{12} t_m). Reserves that are likely to be mined range between 237 and 300×10^9 t (215 and 272×10^9 t_m).[3] The U.S. produced 975×10^6 t (885×10^6 t_m) of coal in 1989, which surpassed the 1988 record high by 2%.[4] Fig. 7 summarizes U.S. production from 1978 to 1989. The states with the largest coal reserves are shown in Table 1. States with large reserves, such as Montana and Illinois, do not necessarily rank as high in production as Wyoming, Kentucky and West Virginia.

Because of the resulting sulfur dioxide (SO_2) emissions, coal sulfur levels are important production criteria. Table 2 shows the distribution of coal reserves by state at various sulfur levels.

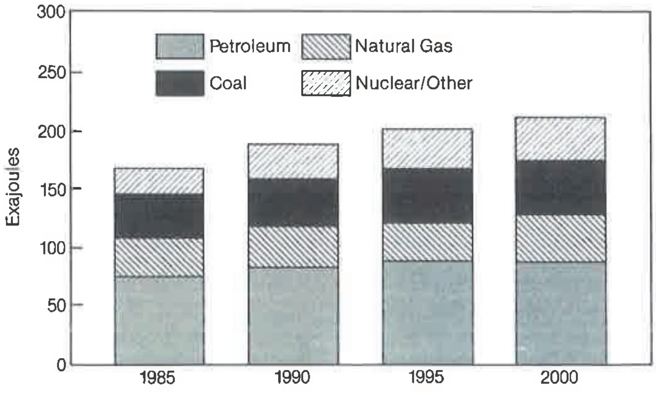


Fig. 4 OECD energy consumption, projected.

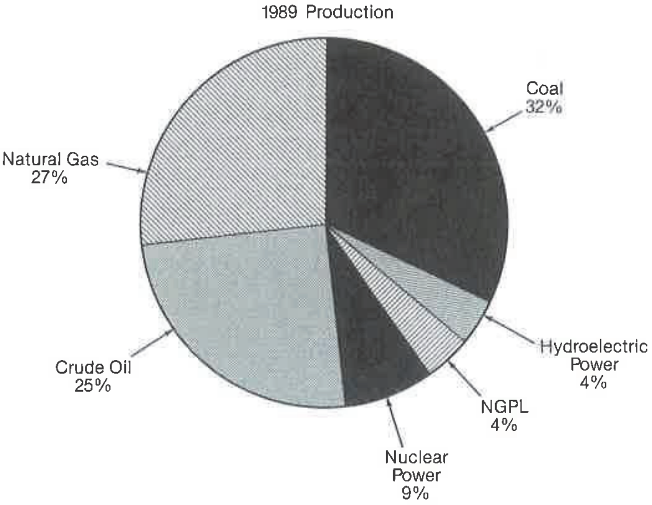


Fig. 5 U.S. energy production by source, 1989 (NGPL = natural gas plant liquids).

Coal fields in the U.S. are shown in Fig. 8. The two largest producing regions are the Appalachian region, including Pennsylvania, West Virginia, Ohio, Western Maryland, Eastern Kentucky, Virginia, Tennessee and Alabama; and the Central states region, including Illinois, Indiana, Western Kentucky, Iowa, Missouri, Kansas, Oklahoma and Arkansas. However, two thirds of the reserves lie in the Great Plains, the Rocky Mountains and the Western states. These coals are mostly subbituminous and lignitic, which have low sulfur content. Therefore, these fields have been rapidly developed to meet the increasing demands of electric utilities. The low sulfur coal permits more economical conformance to the Federal Clean Air Act and acid rain legislation. (See Chapter 32.)

U.S. electric utilities used coal to generate 57% of the net electrical power in 1989 and remain the largest coal consumers. Since 1982, electric utility coal averaged about \$34/t (\$38/t_m) which has remained fairly constant.

Environmental concerns about SO_2, nitrogen oxides (NO_x) and carbon dioxide (CO_2) emissions could limit the growth of coal consumption. However, the U.S., as well as Japan and several European countries, is researching clean coal technologies to reduce these emissions while boosting power production efficiency. These technologies are rapidly approaching commercialization in the U.S. They are expected to be integrated into current and future power plants.

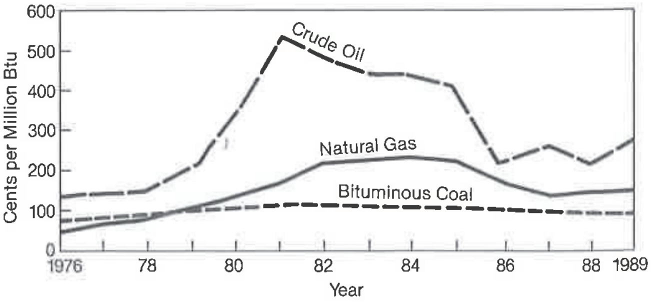


Fig. 6 Trends in U.S. fossil fuel prices.

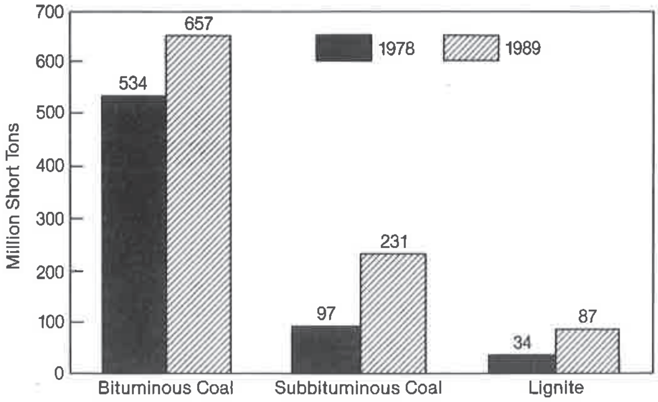


Fig. 7 U.S. coal production trends.

How coal is formed

Coal is formed from plants by chemical and geological processes which occur over millions of years. Layers of plant debris are deposited in wet or swampy regions under conditions which prevent exposure to air and complete decay as the debris accumulates. Bacterial action, pressure and temperature act on the organic matter over time to form coal. The geochemical process that transforms plant debris to coal is called *coalification*. The first product of this process, peat, often contains partially decomposed stems, twigs, and bark and is not classified as coal. However, peat is progressively transformed to lignite which eventually can become anthracite given the proper progression of geological changes.

Various physical and chemical processes occur during coalification. The heat and pressure to which the organic material is exposed cause chemical and structural changes. These changes include an increase in carbon content; loss of water, oxygen and hydrogen; and resistance to solvents. The coalification process is shown schematically in Fig. 9.

Coal is very heterogeneous and can vary in chemical composition by location. In addition to the major organic ingredients (carbon, hydrogen and oxygen) coal also contains impurities. The impurities that are of major concern are ash and sulfur. The ash results from mineral or inorganic material introduced during coalification. Ash sources include inorganic substances, such as silica, which are part of the chemical structure of the plants. Dissolved inorganic ions and mineral grains found in swampy water are also captured by the organic matter during early coalification. Mud, shale and pyrite are deposited in pores and cracks of the coal seams.

Sulfur occurs in coal in three forms: 1) organic sulfur, which is part of the coal's molecular structure, 2) pyritic sulfur, which occurs as the mineral pyrite, and 3) sulfate sulfur, primarily from iron sulfate. The principal sulfur source is sulfate ion, which is found in water. Fresh water has a low sulfate concentration while salt water has a high sulfate content. Therefore, bituminous coal, deposited in the interior of the U.S. when seas covered this region, are high in sulfur. Some Iowa coals contain as much as 8% sulfur.

Although coal is a complex, heterogeneous mixture and not a polymer or biological molecule, it is sometimes useful for chemists to draw an idealized structural formula. These formulas can serve as models that illustrate coal reactions. This can aid the further development of coal processes such as gasification, combustion and liquefaction.

Table 1
U.S. Energy Information Administration States with Largest Demonstrated Coal Reserves (× 10^9 t)*

State	Total Reserves		Underground Reserves		Surface Reserves		% Total U.S.
	t	(t_m)	t	(t_m)	t	(t_m)	
Montana	120	109	71	64	49	44	25.3
Illinois	79	72	63	57	16	15	16.5
Wyoming	69	63	43	39	26	24	14.5
West Virginia	38	34	33	30	5	4.5	8.0
Kentucky	30	27	25	23	6	5.4	6.5
Pennsylvania	30	27	28	25	1	0.9	6.2
Ohio	19	17	13	12	6	5.4	3.9
Colorado	17	15	12	11	5	4.5	3.6
Texas	14	13	0	0	14	13	2.8
Indiana	10	9	9	8	1	0.9	2.2
All others	50	45	24	22	25	23	10.4
Total U.S.	476	431	321	291	154	140.6	100.0

* Figures are rounded and include anthracite.

Table 2
Sulfur Content and Demonstrated Total Underground and Surface Coal Reserve Base of the U.S (Million tons)

State	Sulfur Range, % <1.0	1.1 to 3.0	>3.0	Unknown	Total*
Alabama	624.7	1,099.9	16.4	1,239.4	2,981.8
Alaska	11,458.4	184.2	0.0	0.0	11,645.4
Arizona	173.3	176.7	0.0	0.0	350.0
Arkansas	81.2	463.1	46.3	74.3	665.7
Colorado	7,475.5	786.2	47.3	6,547.3	14,869.2
Georgia	0.3	0.0	0.0	0.2	0.5
Illinois	1,095.1	7,341.4	42,968.9	14,256.2	65,664.8
Indiana	548.8	3,305.8	5,262.4	1,504.1	10,622.6
Iowa	1.5	226.7	2,105.9	549.2	2,884.9
Kansas	0.0	309.2	695.6	383.2	1,388.1
Kentucky-East	6,558.4	3,321.8	299.5	2,729.3	12,916.7
Kentucky-West	0.2	564.4	9,243.9	2,815.9	12,623.9
Maryland	135.1	690.5	187.4	34.6	1,048.2
Michigan	4.6	85.4	20.9	7.0	118.2
Missouri	0.0	182.0	5,226.0	4,080.5	9,487.3
Montana	101,646.6	4,115.0	502.6	2,116.7	108,396.2
New Mexico	3,575.3	793.4	0.9	27.5	4,394.8
North Carolina	0.0	0.0	0.0	31.7	31.7
North Dakota	5,389.0	10,325.4	268.7	15.0	16,003.0
Ohio	134.4	6,440.9	12,534.3	1,872.0	21,077.2
Oklahoma	275.0	326.6	241.4	450.5	1,294.2
Oregon	1.5	0.3	0.0	0.0	1.8
Pennsylvania	7,318.3	16,913.6	3,799.6	2,954.2	31,000.6
South Dakota	103.1	287.9	35.9	1.0	428.0
Tennessee	204.8	533.2	156.6	88.0	986.7
Texas	659.8	1,884.6	284.1	444.0	3,271.9
Utah	1,968.5	1,546.7	49.4	478.3	4,042.5
Virginia	2,140.1	1,163.5	14.1	330.0	3,649.9
Washington	603.5	1,265.5	39.0	45.1	1,954.0
West Virginia	14,092.1	14,006.2	6,823.3	4,652.5	39,589.8
Wyoming	33,912.3	14,657.4	1,701.1	3,060.3	53,336.1
Total*	200,181.4	92,997.5	92,571.5	50,788.0	436,725.7

* Data may not add to totals shown due to independent rounding. Source, Bureau of Mines Bulletin, Coal—Bituminous and Lignite, 1974.

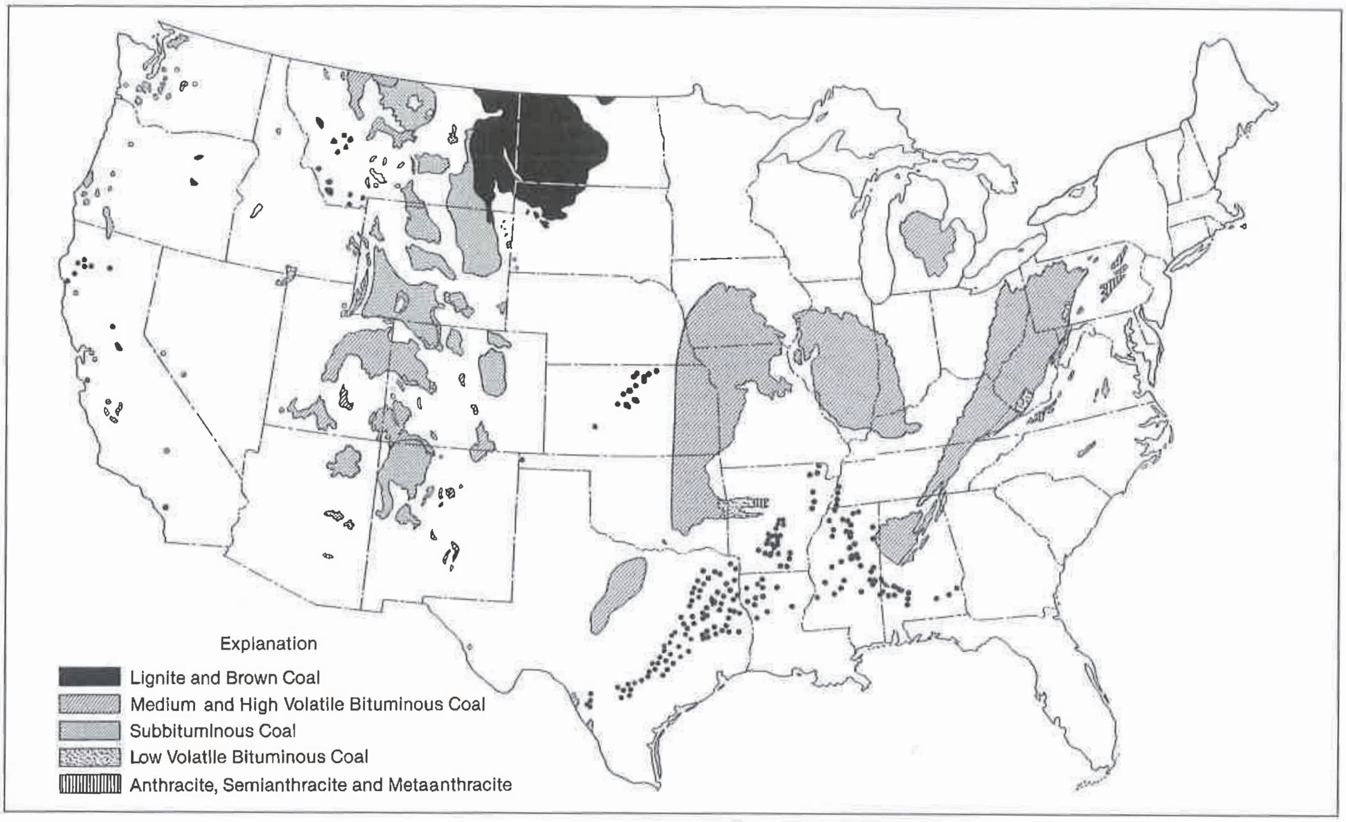


Fig. 8 U.S. coal reserves.

Classifying coal

A coal classification system is needed because coal is a heterogeneous substance with a wide range of composition and properties. Coals are typically classified by rank. This indicates the progressive alteration in the coalification process from lignite to subbituminous, bituminous and anthracite coals. The rank indicates a coal's geological history and broad characteristics.

ASTM classification by rank

The system used in the U.S. for classifying coal by rank was established by the American Society for Testing and Materials (ASTM).[5] ASTM classification is a system which uses the volatile matter and fixed carbon (FC) results from the proximate analysis and the heating value of the coal as ranking criteria. This system aids in identifying commercial uses of coals and provides basic information regarding combustion characteristics.

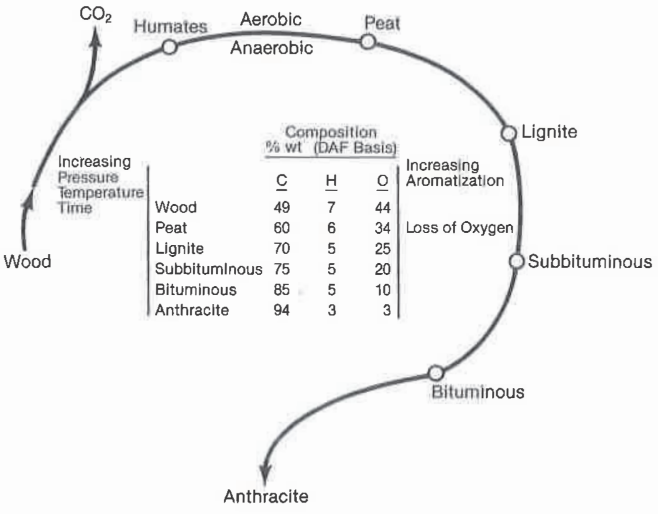


Fig. 9 The coalification process (DAF = dry ash-free).

The classification system is given in Table 3 and described in section D 388 of the ASTM standards. Proximate analysis is based on the laboratory procedure described in ASTM D 271. In this procedure moisture content, ash remaining after complete burning, amount of gases released when heated to a prescribed temperature, and fixed carbon remaining after volatilization are determined.

Table 4 gives a typical as-received proximate analysis of a West Virginia coal. An as-received analysis includes the total moisture content of the coal as it is received at the power plant.

For older or higher rank coals, fixed carbon and volatile matter are used as the classifying criteria. These criteria are determined on a dry, mineral-matter-free basis using formulas developed by S.W. Parr in 1906 (shown in Equations 1 through 6). The younger or low rank coals are classified by Btu content on a moist, mineral-matter-free basis. Agglomerating or weathering indices, as described in ASTM D 388, are used to differentiate adjacent groups.

Parr Formulas

$$\text{Dry, mineral–free } FC = \frac{FC - 0.15\,\text{S}}{100 - (M + 1.08A + 0.55\,\text{S})} \times 100,\ \% \qquad (1)$$

Table 3
Classification of Coals by Rank[a] (ASTM D 388)

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	—	—	2	—	—	Nonagglomerating
	2. Anthracite	92	98	2	8	—	—	
	3. Semianthracite[c]	86	92	8	14	—	—	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	—	—	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	—	—	
	3. High volatile A bituminous coal	—	69	31	—	14,000[d]	—	
	4. High volatile B bituminous coal	—	—	—	—	13,000[d]	14,000	
	5. High volatile C bituminous coal	—	—	—	—	11,500 10,500[e]	13,000 11,500	 Agglomerating
III. Subbituminous	1. Subbituminous A coal	—	—	—	—	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	—	—	—	—	9,500	10,500	
	3. Subbituminous C coal	—	—	—	—	8,300	9,500	
IV. Lignitic	1. Lignite A	—	—	—	—	6,300	8,300	
	2. Lignite B	—	—	—	—	—	6,300	

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free Btu/lb.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low volatile group of the bituminous class.

[d] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

$$\text{Dry, mineral–free } VM = 100 - \text{Dry, mineral–free } FC, \% \qquad (2)$$

$$\text{Moist, mineral–free Btu} = \frac{\text{Btu} - 50\ \text{S}}{100 - (1.08A + 0.55\ \text{S})} \times 100, \text{ per lb} \qquad (3)$$

Table 4
Coal Analyses on As-Received Basis
(Pittsburgh Seam Coal, West Virginia)

Proximate Analysis Component	% by wt	Ultimate Analysis Component	% by wt
Moisture	2.5	Moisture	2.5
Volatile matter	37.6	Carbon	75.0
Fixed carbon	52.9	Hydrogen	5.0
Ash	7.0	Sulfur	2.3
Total	100.0	Nitrogen	1.5
		Oxygen	6.7
Heating value,		Ash	7.0
Btu/lb	13,000	Total	100.0
(kJ/kg)	(30,238)		

Approximation Formulas

$$\text{Dry, mineral–free } FC = \frac{FC}{100 - (M + 1.1A + 0.1\ \text{S})} \times 100, \% \qquad (4)$$

$$\text{Dry, mineral–free } VM = 100 - \text{Dry, mineral–free } FC, \% \qquad (5)$$

$$\text{Moist, mineral–free Btu} = \frac{\text{Btu}}{100 - (1.1A + 0.1\ \text{S})} \times 100, \text{ per lb} \qquad (6)$$

where

Btu = heating value per lb (kJ/kg = 2.326 × Btu/lb)
FC = fixed carbon, %
VM = volatile matter, %
M = bed moisture, %
A = ash, %
S = sulfur, %

all for coal on a moist basis.

Table 5 lists 17 selected U.S. coals, arranged in order of ASTM classification. The following descriptions briefly summarize the characteristics of each coal rank.

Table 5
Seventeen Selected U.S. Coals Arranged in Order of ASTM Classification

	Coal Rank				Coal Analysis, Bed Moisture Basis						Rank	Rank
No.	Class	Group	State	County	M	VM	FC	A	S	Btu	FC	Btu
1	I	1	Pa.	Schuylkill	4.5	1.7	84.1	9.7	0.77	12,745	99.2	14,280
2	I	2	Pa.	Lackawanna	2.5	6.2	79.4	11.9	0.60	12,925	94.1	14,880
3	I	3	Va.	Montgomery	2.0	10.6	67.2	20.2	0.62	11,925	88.7	15,340
4	II	1	W.Va.	McDowell	1.0	16.6	77.3	5.1	0.74	14,715	82.8	15,600
5	II	1	Pa.	Cambria	1.3	17.5	70.9	10.3	1.68	13,800	81.3	15,595
6	II	2	Pa.	Somerset	1.5	20.8	67.5	10.2	1.68	13,720	77.5	15,485
7	II	2	Pa.	Indiana	1.5	23.4	64.9	10.2	2.20	13,800	74.5	15,580
8	II	3	Pa.	Westmoreland	1.5	30.7	56.6	11.2	1.82	13,325	65.8	15,230
9	II	3	Ky.	Pike	2.5	36.7	57.5	3.3	0.70	14,480	61.3	15,040
10	II	3	Ohio	Belmont	3.6	40.0	47.3	9.1	4.00	12,850	55.4	14,380
11	II	4	Ill.	Williamson	5.8	36.2	46.3	11.7	2.70	11,910	57.3	13,710
12	II	4	Utah	Emery	5.2	38.2	50.2	6.4	0.90	12,600	57.3	13,560
13	II	5	Ill.	Vermilion	12.2	38.8	40.0	9.0	3.20	11,340	51.8	12,630
14	III	1	Mont.	Musselshell	14.1	32.2	46.7	7.0	0.43	11,140	59.0	12,075
15	III	2	Wyo.	Sheridan	25.0	30.5	40.8	3.7	0.30	9,345	57.5	9,745
16	III	3	Wyo.	Campbell	31.0	31.4	32.8	4.8	0.55	8,320	51.5	8,790
17	IV	1	N.D.	Mercer	37.0	26.6	32.2	4.2	0.40	7,255	55.2	7,610

Notes: For definition of Rank Classification according to ASTM requirements, see Table 3.

Data on Coal (Bed Moisture Basis)

M = equilibrium moisture, %; VM = volatile matter, %;
FC = fixed carbon, %; A = ash, %; S = sulfur, %;
Btu = Btu/lb, high heating value.

Rank FC = dry, mineral-matter-free fixed carbon, %;
Rank Btu = moist, mineral-matter-free Btu/lb.
Calculations by Parr formulas.

Peat Peat, the first product in the formation of coal, is a heterogeneous material consisting of partially decomposed plant and mineral matter. Its color ranges from yellow to brownish black, depending on its geologic age. Peat has a moisture content up to 70% and a heating value as low as 3000 Btu/lb (6978 kJ/kg).

Lignite Lignite is the lowest rank coal. Lignites are relatively soft and brown to black in color with heating values of less than 8300 Btu/lb (19,306 kJ/kg). The deposits are geologically young and can contain recognizable remains of plant debris. The moisture content of lignites is as high as 30% but the volatile content is also high; consequently, they ignite easily. Lignite coal dries when exposed to air and spontaneous combustion during storage is a concern. Long distance shipment of these coals is usually not economical because of their high moisture and low Btu contents. The largest lignite deposit in the world spreads over the regions of North and South Dakota, Wyoming, and Montana in the U.S. and parts of Saskatchewan and Manitoba in Canada.

Subbituminous Subbituminous coals are black, having little of the plant like texture and none of the brown color associated with the lower rank lignite coal. Subbituminous coals are noncoking (undergo little swelling upon heating) and have a relatively high moisture content which averages from 15 to 30%. They also display a tendency toward spontaneous combustion when drying.

Although they are high in volatile matter content and ignite easily, subbituminous coals generally have less ash and are cleaner burning than lignite coals. Subbituminous coals in the U.S. in general have a very low sulfur content, often less than 1%. Because they have reasonably high heating values [8300 to 11,500 Btu/lb (19,306 to 26,749 kJ/kg)] and low sulfur content, switching to subbituminous coal has become an attractive option for many power plants to limit SO_2 emission.

Bituminous Bituminous coal is the rank most commonly burned in electric utility boilers. In general, it appears black with banded layers of glossy and dull black. Typical bituminous coals have heating values of 10,500 to 14,000 Btu/lb (24,423 to 36,053 kJ/kg) and a fixed carbon content of 69 to 86%. The heating value is higher, but moisture and volatile content are lower than the subbituminous and lignite coals. Bituminous coals rarely experience spontaneous combustion in storage. Furthermore, the high heating value and fairly high volatile content enable bituminous coals to burn easily when pulverized to a fine powder. Some types of bituminous coal, when heated in the absence of air, soften and release volatiles to form the porous, hard, black product known as *coke*. Coke is used as fuel in blast furnaces to make iron.

Anthracite Anthracite, the highest rank of coal, is shiny black, hard and brittle, with little appearance of layers. It has the highest content of fixed carbon, 86 to 98%. However, its low volatile content makes it a slow burning fuel. Most anthracites have a very low moisture content of about 3%; heating values of 15,000 Btu/lb (34,890 kJ/kg) are slightly lower than the best quality bituminous coals.

Anthracite is low in sulfur and volatiles and burns with a hot, clean flame. These qualities make it a premium fuel used mostly for domestic heating.

Other classification systems

There are other classifications of coal which are currently in limited use in Europe. These are the International Classification of Hard Coals by Type and the International Classification of Brown Coals. These systems were developed in 1949 by the Coal Committee of the Economic Commission for Europe.

Coal characterization

As previously described, the criteria for ranking coal are based on its proximate analysis. In addition to providing classifications, coal analysis provides other useful information. This includes assistance in selecting coal for steam generation, evaluation of existing handling and combustion equipment, and input for design. The analyses consist of standard ASTM procedures and special tests developed by Babcock & Wilcox (B&W). The following briefly summarizes some of these tests.

Standard ASTM analyses[5,6]

Bases for analyses Because of the variability of moisture and ash content in coals, the composition determined by proximate analysis can be reported on several bases. The most common include as-received, moisture-free or dry, and mineral-matter-free. The as-received analysis reports the percentage by weight of each constituent in the coal as it is received at the laboratory. As-received samples contain varying levels of moisture. For analysis on a dry basis, the moisture of the sample is determined and then used to correct each constituent to a common dry level. As previously mentioned, the ash in coal as determined by proximate analysis is different than the mineral matter in coal. This can cause problems when ranking coals by the ASTM method. Formulas used to correct for the mineral matter and to determine volatile matter, fixed carbon and heating value on a mineral-matter-free basis are provided in Equations 1 to 6 above.

Moisture determination Coal received at an electric power plant contains varying amounts of moisture in several forms. There is *inherent* and *surface* moisture in coal. Inherent moisture is that which is a naturally combined part of the coal deposit. It is held tightly within the coal structure and can not be removed easily when the coal is dried in air. The surface moisture is not part of the coal deposit and has been added externally. Surface moisture is more easily removed from coal when exposed to air. It is not possible to distinguish, by analysis, inherent and surface moisture.

There are many other moistures which arise when characterizing coal including equilibrium, free and air dry moisture. Their definitions and use depend on the application. Equilibrium moisture is sometimes used as an estimate of bed moisture. The ASTM standard procedure for moisture determination, D 121, defines the total coal moisture as the loss in weight of a sample under controlled conditions of temperature, time and air flow. Using ASTM D 3302, the total moisture is calculated from the moisture lost or gained in air drying and the residual moisture. The residual moisture is determined by oven drying the air dried sample. Because subsequent ASTM analyses (such as proximate and ultimate) are performed on an air dried sample, the residual moisture value is required to convert these results to a dry basis. In addition, the moisture lost on air drying provides an indication of the drying required in the handling and pulverization portions of the boiler coal feed system.

Proximate analysis Proximate analysis, ASTM D 3172, includes the determination of volatile matter, fixed carbon and ash. Volatile matter and fixed carbon, exclusive of the ash, are two indicators of coal rank. The amount of volatile matter in a coal indicates ease of ignition and indicates whether supplemental flame stabilizing fuel is required. The ash content indicates the load under which the collection system must operate. It also permits assessing related shipping and handling costs.

Ultimate analysis Ultimate analysis, described in ASTM D 3176, includes measurements of carbon, hydrogen, nitrogen, and sulfur content and the calculation of oxygen content. Used with the heating value of the coal, combustion calculations can be performed to determine coal feed rates, combustion air requirements, heat release rates, boiler performance and sulfur emissions from the power plant. (See Table 4.)

Heating value The gross calorific value of coal, determined using an adiabatic bomb calorimeter as described in ASTM D 2015, is expressed in Btu/lb (kJ/kg) on various bases (dry, moisture and ash free, etc.).

This value determines the maximum theoretical fuel energy available for the production of steam. Consequently, it is used to determine the quantity of fuel which must be handled, pulverized and fired.

Gross (higher) heating value (HHV) is defined as the heat released from combustion of a unit fuel quantity (mass), with the products in the form of ash, gaseous CO_2, SO_2, nitrogen and liquid water, exclusive of any water added as vapor. The net (lower) heating value (LHV) is calculated from the HHV. It is the heat produced by a unit quantity of fuel when all water in the products remains as vapor. This LHV calculation (ASTM Standard D 407) is made by deducting 1030 Btu/lb (2396 kJ/kg) of water derived from the fuel, including the water originally present as moisture and that formed by combustion. In the U.S., the gross calorific value is commonly used in heat balance calculations, while in Europe the net value is generally used.

Grindability The Hardgrove Grindability Test, developed by B&W, is an empirical measure of the relative ease with which coal can be pulverized. The ASTM D 409 method has been used for the past 30 years to evaluate the grindability of coals. The method involves grinding 50 g of air-dried 16 × 30 mesh (1.18 mm × 600 μm) test coal in a small ball-and-race mill. The mill is operated for 60 revolutions and the quantity of material that passes a 200 mesh (75 micron) screen is measured. From a calibration curve relating −200 mesh (−75 micron) material to the grindability of standard samples supplied by the U.S. Department of Energy, the Hardgrove Grindability Index (HGI) is determined for the test coal. Pulverizer manufacturers have developed correlations relating HGI to pulverizer capacity at desired levels of fineness.

Sulfur forms The sulfur forms test, ASTM D 2492, measures the amounts of sulfate sulfur, pyritic sulfur and organically bound sulfur in a coal. This is accomplished by measuring the total sulfur, sulfate, and pyritic sulfur contents and obtaining the organic sulfur by difference. The quantity of pyritic sulfur is an indicator of potential coal abrasiveness.

Free swelling index The free swelling index can be used to indicate caking characteristics. The index is determined by ASTM D 720 which consists of heating a one gram coal sample for a specified time and temperature. The shape of the sample or button formed by the swelling coal is then compared to a set of standard buttons. Larger formed buttons indicate higher free swelling indices. Oxidized coals tend to have lower indices. The free swelling index can be used as a relative measurement of a coal's caking properties and extent of oxidation.

Ash fusion temperatures Coal ash fusion temperatures are determined from cones of ash prepared and heated in accordance with ASTM method D 1857. The temperatures at which the cones deform to specific shapes are determined in oxidizing and reducing atmospheres. Fusion temperatures provide ash melting characteristics and are used for classifying the slagging potentials of the lignitic-type ashes. (See also Chapter 20.)

Ash composition Elemental ash analysis is conducted using a coal ash sample produced by the ASTM D 3174 procedure. The elements present in the ash are determined and reported as oxides. Silicon dioxide (SiO_2), aluminum oxide (Al_2O_3), titanium dioxide (TiO_2), ferric hydroxide (Fe_2O_3), calcium oxide (Na_2O) and potassium oxide (K_2O) are measured using atomic absorption. The results of the ash analyses permit calculations of fouling and slagging indices and slag viscosity versus temperature relationships. The nature, composition and properties of coal ash and their effects on boiler performance are described further in Chapter 20.

Special B&W tests[6]

Burning profiles The burning profile technique was originated by B&W for predicting the relative combustion characteristics of fuels. The technique and application of results were described by Wagoner and Duzy,[7] and are routinely applied to liquid and solid fuels. The test uses derivative thermogravimetry in which a sample of fuel is oxidized under controlled conditions. A 300 mg sample of solid fuel with a particle size less than 60 mesh (250 microns) is heated at 27F/min (15C/min) in a stream of air. Weight change is measured continuously and the burning profile is the resulting plot of rate of weight loss versus furnace temperature.

Coals with similar burning profiles would be expected to behave similarly in large furnaces. By comparing the burning profile of an unknown coal with that of a known sample, furnace design, residence time, excess air and burner settings can be predicted. In comparing profiles, key information is provided by the start and completion temperatures of oxidation. The area under the temperature curve is proportional to the amount of combustible material in the sample; the height of the curve is a measure of the combustion intensity. Burning profiles are particularly useful for preliminary evaluations of new boiler fuels such as chars, coal-derived fuels and processed refuse. Fig. 10 shows burning profiles of various coal ranks.

Abrasiveness index The abrasiveness of coal affects pulverizer grinding element life and quartz particles in the coal can significantly contribute to its abrasiveness. A procedure for determining a coal's quartz count has been developed at B&W. This procedure consists of burning the coal, collecting and washing the ash to remove acid soluble constituents, and screening to separate size fractions. In each size fraction, 1000 particles are counted and the number of quartz particles is determined by a microscopic technique. From these data, the relative quartz value, an indicator of the coal's relative abrasiveness, is calculated.

Another abrasion index is determined using the Yancey-Geer Price apparatus. In this test, a sample of coal, sized 0.25 in. ×0 (6.35 mm ×0), is placed in contact with four metal test samples or *coupons* attached to a rotating shaft. The shaft is rotated at 1440 rpm (150.8 rad/s) for a total of 12,000 revolutions (75,400 rad). The weight loss of the metal coupons is then determined, from which a relative abrasion index is calculated. Indices from the test coals can be compared to those for other fuels. B&W has used the Yancey-Geer Price Index to determine wear in full scale pulverizers. (See Chapter 12.)

Erosiveness index Erosion occurs in boilers due to the impact of pulverized particles on burner lines and other components between the pulverizers and burners. The erosiveness test, developed by B&W, subjects a steel coupon to a stream of pulverized coal under controlled conditions. The measured weight loss of the coupon indicates the erosiveness of the coal.

Slag viscosity The viscosity of a coal ash slag is measured at various temperatures under oxidizing and reducing conditions using a high temperature rotational bob viscometer. This viscometer and its application are described in more detail in Chapter 20. The data obtained from slag viscosity measurements are used to predict a coal's slagging behavior in pulverized coal-fired boiler applications. The results also indicate the suitability of a coal for use in B&W's slagging and Cyclone furnaces.

Properties of selected coals

Table 6 gives basic fuel characteristics of typical U.S. coals. The coals are identified by state and rank, and the analytical data include proximate and ultimate analyses and HHVs. Table 7 provides similar fuel properties of coals

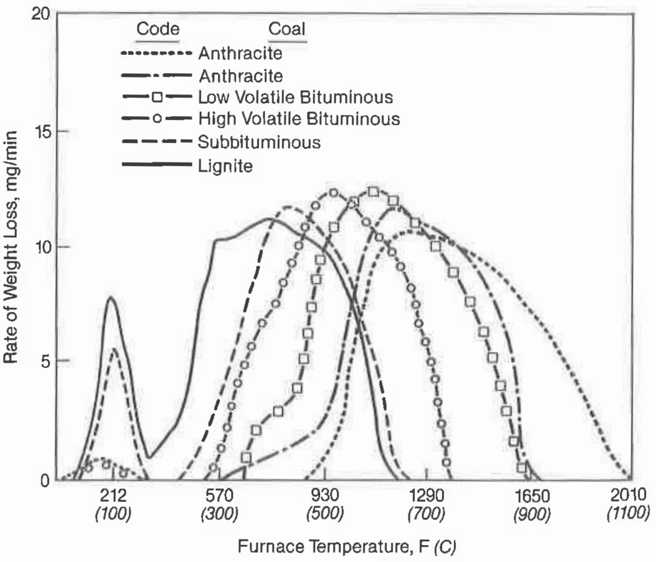


Fig. 10 Coal burning profiles.

Table 6
Properties of U.S. Coals

	Anthracite	Pittsburgh #8 HV Bituminous	Illinois #6 HV Bituminous	Upper Freeport MV Bituminous	Spring Creek Subbituminous	Decker Subbituminous	Lignite	Lignite (S. Hallsville)	Lignite (Bryan)	Lignite (San Miguel)
State	—	Ohio or Pa.	Illinois	Pennsylvania	Wyoming	Montana	North Dakota	Texas	Texas	Texas
Proximate:										
Moisture	7.7	5.2	17.6	2.2	24.1	23.4	33.3	37.7	34.1	14.2
Volatile matter, dry	6.4	40.2	44.2	28.1	43.1	40.8	43.6	45.2	31.5	21.2
Fixed carbon, dry	83.1	50.7	45.0	58.5	51.2	54.0	45.3	44.4	18.1	10.0
Ash, dry	10.5	9.1	10.8	13.4	5.7	5.2	11.1	10.4	50.4	68.8
Heating value, Btu/lb:										
As-received	11,890	12,540	10,300	12,970	9,190	9,540	7,090	7,080	3,930	2,740
Dry	12,880	13,230	12,500	13,260	12,110	12,450	10,630	11,360	5,960	3,200
MAF	14,390	14,550	14,010	15,320	12,840	13,130	11,960	12,680	12,020	10,260
Ultimate:										
Carbon	83.7	74.0	69.0	74.9	70.3	72.0	63.3	66.3	33.8	18.4
Hydrogen	1.9	5.1	4.9	4.7	5.0	5.0	4.5	4.9	3.3	2.3
Nitrogen	0.9	1.6	1.0	1.27	0.96	0.95	1.0	1.0	0.4	0.29
Sulfur	0.7	2.3	4.3	0.76	0.35	0.44	1.1	1.2	1.0	1.2
Ash	10.5	9.1	10.8	13.4	5.7	5.2	11.1	10.4	50.4	68.8
Oxygen	2.3	7.9	10.0	4.97	17.69	16.41	19.0	16.2	11.1	9.01

Ash fusion temps, F	Anthracite		Pittsburgh #8 HV Bituminous		Illinois #6 HV Bituminous		Upper Freeport MV Bituminous		Spring Creek Subbituminous		Decker Subbituminous		Lignite		Lignite (S. Hallsville)		Lignite (Bryan)		Lignite (San Miguel)	
Reducing/Oxidizing:	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid
ID	—	—	2220	2560	1930	2140	2750+	2750+	2100	2180	2120	2420	2030	2160	2000	2210	2370	2470	2730	2750+
ST Sp.	—	—	2440	2640	2040	2330	"	"	2160	2300	2250	2470	2130	2190	2060	2250	2580	2670	2750+	"
ST Hsp.	—	—	2470	2650	2080	2400	"	"	2170	2320	2270	2490	2170	2220	2090	2280	2690	2760	"	"
FT 0.0625 in.	—	—	2570	2670	2420	2600	"	"	2190	2360	2310	2510	2210	2280	2220	2350	2900+	2900+	"	"
FT Flat	—	—	2750+	2750+	2490	2700	"	"	2370	2700	2380	2750+	2300	2300	2330	2400	2900+	2900+	"	"

Ash analysis:	Anthracite	Pittsburgh #8 HV Bituminous	Illinois #6 HV Bituminous	Upper Freeport MV Bituminous	Spring Creek Subbituminous	Decker Subbituminous	Lignite	Lignite (S. Hallsville)	Lignite (Bryan)	Lignite (San Miguel)
SiO_2	51.0	50.58	41.68	59.60	32.61	23.77	29.80	23.32	62.4	66.85
Al_2O_3	34.0	24.62	20.0	27.42	13.38	15.79	10.0	13.0	21.5	23.62
Fe_2O_3	3.5	17.16	19.0	4.67	7.53	6.41	9.0	22.0	3.0	1.18
TiO_2	2.4	1.10	0.8	1.34	1.57	1.08	0.4	0.8	0.5	1.46
CaO	0.6	1.13	8.0	0.62	15.12	21.85	19.0	22.0	3.0	1.76
MgO	0.3	0.62	0.8	0.75	4.26	3.11	5.0	5.0	1.2	0.42
Na_2O	0.74	0.39	1.62	0.42	7.41	6.20	5.80	1.05	0.59	1.67
K_2O	2.65	1.99	1.63	2.47	0.87	0.57	0.49	0.27	0.92	1.57
P_2O_5	—	0.39	—	0.42	0.44	0.99	—	—	—	—
SO_3	1.38	1.11	4.41	0.99	14.56	18.85	20.85	9.08	3.50	1.32

Note: HV = high volatile; MV = medium volatile; ID = initial deformation temp; ST = softening temp; FT = fluid temp; Sp. = spherical; Hsp. = hemispherical.

mined outside the U.S. The source of this information, B&W's Fuels Catalogue, contains more than 10,000 fuel analyses performed and compiled since the 1950s.

Fuels derived from coal

Because of abundant supplies and low prices, the demand for coal as the prime or substitute fuel for utility boilers will most likely continue to increase. In addition, the future use of coal-derived fuels, such as coal refined liquids and gases, coal slurries, and chars, as inexpensive substitutes for oil and natural gas is also possible. Therefore, methods to obtain clean and efficiently burning fuels derived from coal are continually being investigated. A few of these fuels, which apply to steam generation, are discussed below.

Coke

When coal is heated in the absence of air or with a large deficiency of air, the lighter constituents are volatilized and the heavier hydrocarbons crack, liberating gases and tars and leaving a residue of carbon. Some of the volatilized portions crack on contact with the hot carbon, leaving an additional quantity of carbon. The carbonaceous residue containing the ash and some of the original coal sulfur is called *coke*. The amount of sulfur and ash in the coke mainly depends on the coal from which it is produced and the coking process used. The principal uses for coke are the production of pig iron in blast furnaces and the charging of iron foundry cupolas. Because it is smokeless when burned, considerable quantities have been used for space heating.

Undersized coke, called *coke breeze*, usually passing a 0.625 in. (15.875 mm) screen, is unsuitable for charging blast furnaces and is often used for steam generation. A typical analysis of coke breeze appears in Table 8. Approximately 4.5% of the coal supplied to slot type coke ovens is recovered as coke breeze. A portion of the coal tars produced as byproducts of the various coking processes may be burned in equipment similar to that used for heavy petroleum oil.

Table 7
Properties of Selected International Coals

Source	Australia		China		France		S. Africa		Indonesia		Korea		Spain	
Ultimate:														
Carbon	56.60		62.67		74.60		69.70		56.53		68.46		37.02	
Hydrogen	3.50		3.86		4.86		4.50		4.13		0.90		2.75	
Nitrogen	1.22		0.83		1.39		1.60		0.88		0.20		0.88	
Sulfur	0.35		0.46		0.79		0.70		0.21		2.09		7.46	
Ash	24.00		4.71		8.13		10.10		1.77		23.48		38.69	
Oxygen	7.43		10.34		9.42		9.10		12.58		4.38		11.39	
Proximate:														
Moisture	6.90		17.13		0.80		4.30		23.90		0.50		1.80	
Volatile matter, dry	24.80		30.92		36.11		35.30		45.57		7.46		45.27	
Fixed carbon, dry	44.30		47.24		54.96		50.30		28.76		68.56		14.24	
Ash, dry	24.00		4.71		8.13		10.10		1.77		23.48		38.69	
Higher heating value, Btu/lb	9,660		10,740		13,144		12,170		9,840		9,443		6,098	
Ash analysis:														
SiO_2	57.90		22.70		44.60		44.00		71.37		55.00		14.50	
Al_2O_3	32.80		9.00		29.90		32.70		13.32		17.00		8.20	
Fe_2O_3	6.20		15.68		13.10		4.60		7.00		12.50		2.70	
TiO_2	1.00		0.43		0.60		1.20		0.57		1.40		0.30	
CaO	0.60		28.88		—		5.70		2.88		0.10		45.00	
MgO	0.80		2.00		3.50		1.30		0.53		0.10		1.20	
Na_2O	0.10		0.70		3.10		0.10		0.34		0.10		0.10	
K_2O	0.50		0.46		—		0.30		0.25		3.10		0.40	
P_2O_5	—		0.09		—		2.20		0.16		—		—	
SO_3	0.80		20.23		2.80		4.60		3.90		—		—	
Ash fusion temps, F														
Reducing/Oxidizing:	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid
ID	2740	2750+	2200	2220	2190	2300	2620	2670	2140	2410	2350	2600	2530	2520
ST Sp.	2750+	2750+	2240	2270	2310	2500	2750	2750+	2400	2490	2630	2730	2700	2670
ST Hsp.	2750+	2750+	2250	2280	—	—	2750+	2750+	2450	2540	—	—	—	—
FT 0.0625 in.	2750+	2750+	2280	2290	2670	2820	2750+	2750+	2630	2680	2900	2900	2730	2740
FT Flat	2750+	2750+	2340	2320	—	—	2750+	2750+	2750	2750+	—	—	—	—

Table 8
Analyses — Bagasse and Coke Breeze

Analyses (as-fired), % by wt	Bagasse	Coke Breeze
Proximate		
Moisture	52.0	7.3
Volatile matter	40.2	2.3
Fixed carbon	6.1	79.4
Ash	1.7	11.0
Ultimate		
Hydrogen, H_2	2.8	0.3
Carbon, C	23.4	80.0
Sulfur, S	trace 0.6	
Nitrogen, N_2	0.1	0.3
Oxygen, O_2	20.0	0.5
Moisture, H_2O	52.0	7.3
Ash, A	1.7	11.0
Heating value, Btu/lb	4000	11,670
(kJ/kg)	(9304)	(27,144)

Coal char and liquids

Another carbonization process being developed for coal in the transportation, light industrial and commercial markets is mild gasification. This is a modification of the standard gasification process whereby coal is heated in the absence of oxygen and at relatively low temperature [less than 1300F (704C)] and atmospheric pressure. These conditions are mild compared to conventional gasification which takes place in air or oxygen at temperatures of approximately 2000F (1076C). Mild gasification yields three products: 1) a gas that can be substituted for natural gas, 2) a liquid with properties similar to No. 2 diesel fuel, and 3) a coke-like solid called *char*. The solid product can be pulverized or mixed with the liquid product to form a slurry; this mixture can be used as boiler fuel.[8]

The mild operating conditions of the process produce a liquid fuel which has a high hydrogen/carbon ratio (igniting easily and burning with a stable flame), high fluidity and a low sulfur content compared to the coal feedstock.

Although the char product has a lower volatile content and is slightly more difficult to ignite than the coal feedstock, its combustion behavior in general is similar to that of the parent coal. Mild gasification enriches the char in ash and reduces its heating value by 5 to 10% compared to the parent coal. Table 9 gives fuel analyses of several chars produced by mild gasification from Illinois coal.

Gaseous fuels from coal

A number of gaseous fuels are derived from coal as process byproducts or from gasification processes. (See Chapter 17.) Table 10 lists selected analyses of these gases. They have currently been largely supplanted by natural gas and oil. However, improvements in coal gasification and wider use of coal in the chemical and liquid fuel industries could reverse this trend.

Coke oven gas A considerable portion of coal is converted to gases in the production of coke. Valuable products recovered from these gaseous portions include ammonium sulfate, oils and tars. The noncondensable portion is called *coke oven gas*. Constituents depend on the nature of the coal and the coking process used (Table 10).

Part of the sulfur from coal may be present in coke oven gas as hydrogen sulfide and carbon disulfide. These may be removed by scrubbing. Coke oven gas often contains other impurities that deposit in pipelines and burners. The gas burns readily because of its high free hydrogen content and presents minimal problems when used as steam generation fuel.

Blast furnace gas The gas discharged from steel mill blast furnaces is used at the mills in furnaces, in gas engines and for steam generation. Blast furnace gas has variable quality but generally has a high carbon monoxide (CO) content and low heating value (Table 10). This gas may be burned for steam generation. However, blast furnace gas deposits adhere firmly and provisions must be made for cleaning boiler heating surfaces.

Water gas The gas produced by passing steam through a bed of hot coke is known as *water gas*. Carbon in the coke combines with the steam to form H_2 and CO. This is an endothermic reaction which cools the coke bed. Water gas is often enriched with oil by passing the gas through a checkerwork of hot bricks sprayed with oil. The oil, in turn, is cracked to a gas by the heat. Refinery gas is also used for enrichment. It may be mixed with the steam and passed through the coke bed or may be mixed directly with the water gas. Such enriched gas is called *carbureted water gas* (Table 10). In many areas, carbureted water gas has been replaced by natural gas.

Producer gas When coal or coke is burned with a deficiency of air and a controlled amount of moisture (steam), a product known as *producer gas* is obtained. This gas, after removal of entrained ash and sulfur compounds, is used near its source because of its low heating value (Table 10).

Table 10
Selected Analyses of Gaseous Fuels Derived from Coal

Analysis No.	Coke Oven Gas 1	Blast Furnace Gas 2	Carbureted Water Gas 3	Producer Gas 4
Analyses, % by volume				
Hydrogen, H_2	47.9	2.4	34.0	14.0
Methane, CH_4	33.9	0.1	15.5	3.0
Ethylene, C_2H_4	5.2	---	4.7	---
Carbon monoxide, CO	6.1	23.3	32.0	27.0
Carbon dioxide, CO_2	2.6	14.4	4.3	4.5
Nitrogen, N_2	3.7	56.4	6.5	50.9
Oxygen, O_2	0.6	---	0.7	0.6
Benzene, C_6H_6	---	---	2.3	---
Water, H_2O	---	3.4	---	---
Specific gravity (relative to air)	0.413	1.015	0.666	0.857
HHV — Btu/ft^3 (kJ/m^3)				
at 60F (16C) and	590	---	534	163
30 in. Hg (102 kPa)	(21,983)	---	(19,896)	(6,073)
at 80F (27C) and	---	83.8	---	---
30 in. Hg (102 kPa)	(3,122)	(3,122)		

Byproduct gas from gasification

Coal gasification processes are a source of synthetic natural gas. There are many processes under development. The effluent gas from steam-oxygen coal gasification consists principally of H_2, CO, CH_4, CO_2 and unreacted steam. The gas will also be diluted with N_2 if air is used as the oxygen source. Although the competing chemical reactions that coal undergoes during gasification are complex, they usually include the reaction of steam and carbon to produce H_2 and CO. Some CH_4 is produced by the reaction of carbon with H_2 and by thermal cracking of the heavy hydrocarbons in the coal. CO_2 and heat needed for the process are produced by reaction of carbon with O_2. Final gas composition is modified by reaction between CO and steam to produce H_2 and CO_2.

The products of coal gasification are often classified as low, intermediate and high Btu gases. Low Btu gas has a heating value of 100 to 200 Btu/SCF (3.9 to 7.9 MJ/Nm^3) and is produced by gasification with air rather than oxygen. Typically, the gas is used as a boiler fuel at the gasification plant site or as feed to a turbine in combined cycles. Intermediate Btu gas has a heating value of 300 to 450 Btu/SCF (11.8 to 17.7 MJ/Nm^3) and is produced

Table 9
Fuel Analyses of Chars from Illinois Coals, %

Illinois Coal		Char #1		Char #2		Char #3	
H_2O 3.5	C 72.0	H_2O 2.4	C 75.6	H_2O 3.8	C 76.6	H_2O 2.4	C 77.5
VM 35.1	H 5.3	VM 21.6	H 3.7	VM 15.6	H 3.1	VM 12.1	H 2.5
FC 53.1	N 1.7	FC 65.7	N 1.8	FC 69.4	N 1.7	FC 73.2	N 1.8
Ash 8.3	S 2.2	Ash 10.2	S 1.8	Ash 11.1	S 1.8	Ash 12.3	S 1.8
	O 10.5		O 6.9		O 5.6		O 4.2
Btu	12,935		12,662		12,534		12,446
(kJ)	(13,647)		(13,359)		(13,224)		(13,131)

by gasification with oxygen or by a process that produces a nitrogen-free product. The applications of intermediate Btu gas are similar to low Btu gas. High Btu gas has a heating value greater than 900 Btu/SCF (35.4 MJ/Nm^3) and is used as a fuel in place of natural gas. High Btu gas is produced by the same gasification process as intermediate Btu gas and then upgraded by methanation. (See also Chapter 17.)

Coal-water fuel

Environmental concerns about SO_2 and particulate emissions from bituminous coals have led to the rapid development of several clean burning technologies. One such technology, coal cleaning or *beneficiation*, removes the sulfur and mineral matter from the coal prior to combustion. In order to achieve the cleaning level needed to meet recent sulfur standards, the form of the solid coal must be altered. Most advanced cleaning processes, using water as a medium, involve grinding the coal to fine particle size, which liberates pyritic sulfur and other minerals. The fine, clean coal product must be dried, pelletized, or reconstituted into a coal-water slurry, which can be handled like oil prior to combustion in a boiler.

Coal-water slurries may serve as potential replacements for oil in many industrial and utility boilers.[9] Typically, slurries prepared from bituminous coals contain approximately 70% pulverized coal, 29% water and 1% chemical additives. However, slurries prepared from coals which have been deep cleaned can contain coal with finer particle sizes and lower solids loadings (50 to 60%). Table 11 gives some properties of conventional coal-water slurry fuels.

Coal-water slurries handle like No. 6 fuel oil and have a room temperature viscosity of about 1000 centipoise. They are stable suspensions (the coal particles do not settle out) and therefore can be transported and stored for several weeks without agitation. The fluidity and stability are largely determined by the coal particle size distribution and the chemical additives. Maintaining low slurry viscosity requires keeping the coal particles separated by a lubricating layer of liquid. Achieving stability requires that a long range network of particle to particle bonds, sometimes called a gel, forms when the fuel is placed in undisturbed storage. This gel prevents the particles from settling. The particle size and the chemistry of the slurry must be carefully adjusted during preparation so that the gel forms as needed yet breaks up easily for pumping, atomization and combustion.

Although coal-water slurries are produced from fine pulverized coal and are handled and fired like fuel oil, they burn differently and a specially designed burner is required. The properties of the slurry can also affect burner performance. The parent coal used to produce the coal-water slurry can affect ignition stability, air preheat requirements, turndown through its volatile matter content, and carbon conversion through several rank-dependent coal properties. Slurry viscosity and flow characteristics can affect atomization quality. Furthermore, coal particle size and the slurry water content can affect carbon burnout due to combustor residence time constraints.

Table 11
Coal-Water Fuel Properties

	A	B	C	D	E
Solids, %	75.3	69.3	69.4	69.9	74.9
Viscosity, cP at 100^{-1} sec	1,955	1,575	1,550	510	520
HHV, Btu/lb, (kJ/kg) as-received	10,730 (24,958)	9,910 (23,051)	10,180 (23,679)	10,180 (23,679)	11,380 (26,470)
HHV, Btu/lb, (kJ/kg), dry	14,250 (33,146)	14,300 (33,262)	14,670 (34,122)	14,560 (33,867)	15,190 (35,332)
VM, %, as-received	24.7	26.5	24.8	22.9	28.0
VM, %, dry	32.8	38.2	35.7	32.7	37.4
Ash, %, dry	7.9	6.3	5.9	6.9	1.8
Sulfur, %, dry	0.84	0.87	0.81	0.77	0.91
Particle size distribution:					
% <200 mesh (75 micron)	70	78	63	78	73
Mass mean diameter, microns	59	44	67	48	53
Sauter mean diameter, microns	7	9	15	8	11
pH	8.6	7.6	7.3	8.1	6.0
Density, g/cc	1.23	1.22	1.20	1.23	1.23

Fuel oil

One of the most widely accepted theories explaining the origin of oil is the organic theory. Over millions of years, rivers carried mud and sand which deposited and ultimately became sedimentary rock formations. Along with this inorganic material, tiny marine organisms were buried with the silt. Over time, in an airless and high pressure environment, the organic material containing carbon and hydrogen was converted to the hydrocarbon molecules of petroleum (oil). Because of the porosity of sedimentary rock formations, the oil flowed and collected in traps, or locations where crude oil is concentrated. This phenomenon greatly assists the economic recovery of crude oil.

Fuel oil consumption for steam generation accounts for a minor share of the domestic petroleum fuel usage. Industrial users, excluding transportation, account for about 25% of all petroleum use; electric utilities consume about 3% of the total.[10] The end users of petroleum products for the years 1980 to 1989 are shown in Fig. 11. Crude oil reserves and world petroleum consumption are shown in Figs. 12 and 13.

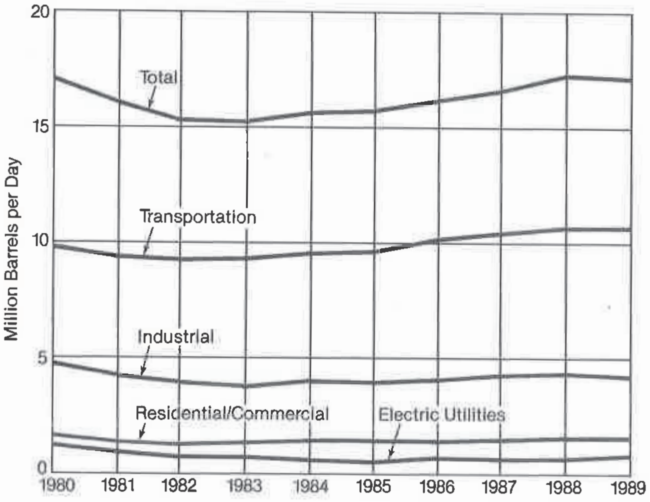


Fig. 11 U.S. petroleum end users.

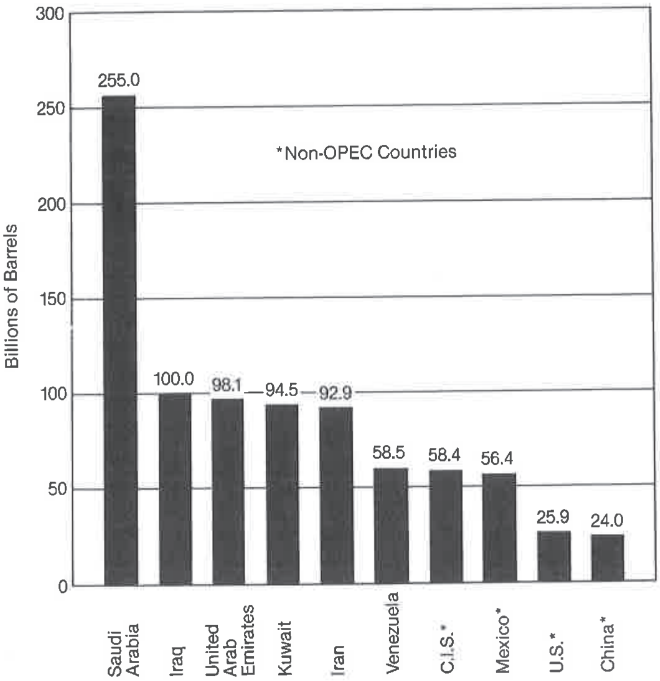


Fig. 12 Major world crude oil reserves, 1990 (OPEC = Organization of Petroleum Exporting Countries).

Compared to coal, fuel oils are relatively easy to handle and burn. There is less bulk ash to dispose of and the ash discharged is correspondingly small. In most oil burners, the fuel is atomized and mixed with combustion air. In the atomized state, the characteristics of oil approach those of natural gas.

Because of its relatively low cost, No. 6 fuel oil is the most widely used for steam generation. It can be considered a byproduct of the refining process. Its ash content ranges from 0.01 to 0.5% which is very low compared to coal. However, despite this low ash content, compounds of vanadium, sodium and sulfur in the ash can pose operating problems. (See Chapter 20.)

Fuel oil characterization

Fuel oils include virtually all petroleum products that are less volatile than gasoline. They range from light oils, suitable for use in internal combustion or turbine engines, to heavy oils requiring heating. The heavier fuels are primarily suited for steam generation boilers. The ASTM specifications for fuel oil properties are given in Table 12.

Fuel oils can be divided into two classes, distillate and residual. Distillate fuels are those that are vaporized in a petroleum refining operation. They are typically clean, essentially free of sediment and ash, and relatively low in viscosity. These fuels fall into the No. 1 or No. 2 category in ASTM D 396. Although No. 2 oil is sometimes used as a premium steam generation fuel, it best lends itself to applications where cleanliness and ease of handling outweigh its cost. Examples include home heating and industrial applications where low ash and/or sulfur are important. Steam generating applications are primarily limited to use as a startup or support fuel.

The residual fuel oils are those that are not vaporized by heating. They contain virtually all the inorganic constituents present in the crude oil. Frequently, residual oils are black, high viscosity fluids that require heating for proper handling and combustion.

Fuel oils in grades No. 4 and 5 are less viscous and therefore more easily handled and burned than is No. 6 oil. Depending on the crude oil used, a fuel meeting the No. 4 specification may be a blend of residual oil and lighter distillate fractions. This oil does not usually require heating for pumping and handling.

No. 5 oils may require heating, depending on the firing equipment and the ambient temperature. No. 6 oils usually require heating for handling and burning. (See Chapter 10 for oil storage, handling and use requirements.)

Fuel analyses

A typical analysis of a fuel oil or waste liquid contains the following information:

1. ultimate analysis,
2. API gravity,
3. heating value,
4. viscosity,
5. pour point,
6. flash point, and
7. water and sediment.

Ultimate analysis The ultimate analysis for an oil is similar to that for a coal. The results indicate the quantities of sulfur, hydrogen, carbon, nitrogen, oxygen and ash. Ultimate analyses for various fuel oils are given in Table 13.

The sulfur content of the oil is an indicator of its corrosiveness and is oxidized to sulfur oxides during combustion. These oxides can react with water vapor or ash constituents to form corrosive acids, salts, or boiler fouling potassium sulfate. When molten, these ash deposits are

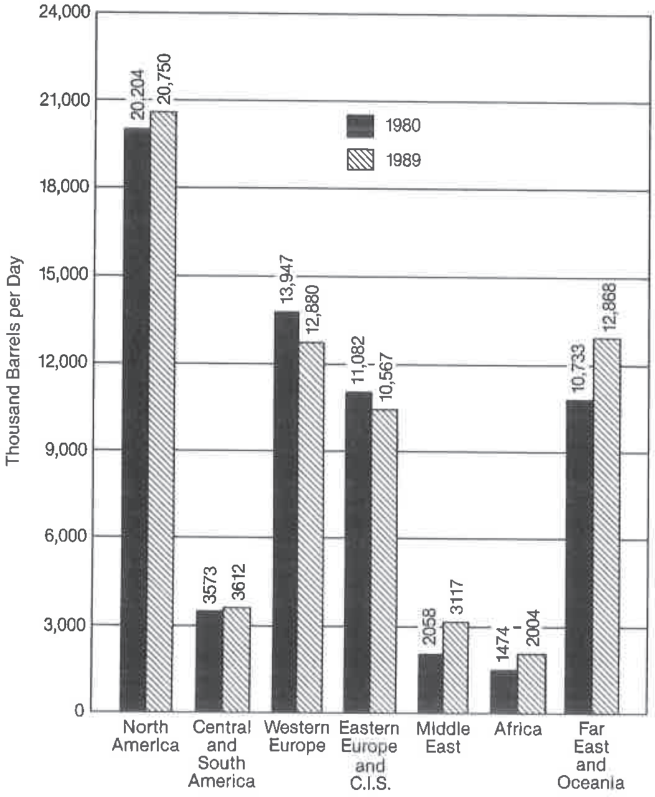


Fig. 13 Major petroleum consumption.

Table 12
ASTM Standard Specifications for Fuel Oils[a]

No. 1 A distillate oil intended for vaporizing pot-type burners and other burners requiring this grade of fuel

No. 2 A distillate oil for general purpose domestic heating for use in burners not requiring No. 1 fuel oil

No. 4 Preheating not usually required for handling or burning

No. 5 (Light) Preheating may be required depending on climate and equipment

No. 5 (Heavy) Preheating may be required for burning and, in cold climates, may be required for handling

No. 6 Preheating required for burning and handling

Grade of Fuel Oil[b]	Flash Point, F *(C)*	Pour Point, F *(C)*	Water and Sediment, % by vol	Carbon Residue on 10% Bottoms, %	Ash, % by wt	Distillation Temperatures, F *(C)*			Saybolt Viscosity, s				Kinematic Viscosity, centistokes				Gravity, deg API	Copper Strip Corrosion
						10% Point	90% Point		Universal at 100F *(38C)*		Furol at 122F *(50C)*		At 100F *(38C)*		At 122F *(50C)*			
	Min	Max	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
No. 1	100 or legal *(38)*	0	trace	0.15	—	420 *(215)*	—	550 *(288)*	—	—	—	—	1.4	2.2	—	—	35	No. 3
No. 2	100 or legal *(38)*	20[c] *(−7)*	0.10	0.35	—	d	540[c] *(282)*	640 *(338)*	(32.6)[f]	(37.93)	—	—	2.0[e]	3.6	—	—	30	—
No. 4	130 or legal *(55)*	20 *(−7)*	0.50	—	0.10	—	—	—	45	125	—	—	(5.8)	(26.4)	—	—	—	—
No. 5 (Light)	130 or legal *(55)*	—	1.00	—	0.10	—	—	—	150	300	—	—	(32)	(65)	—	—	—	—
No. 5 (Heavy)	130 or legal *(55)*	—	1.00	—	0.10	—	—	—	350	750	(23)	(40)	(75)	(162)	(42)	(81)	—	—
No. 6	150 *(65)*	—	2.00[g]	—	—	—	—	—	(900)	(9,000)	45	300	—	—	(92)	(638)	—	—

Notes:

a. Recognizing the necessity for low sulfur fuel oils used in connection with heat treatment, nonferrous metal, glass, and ceramic furnaces and other special uses, a sulfur requirement may be specified in accordance with the following table:

Grade of Fuel Oil	Sulfur, Max, %
No. 1	0.5
No. 2	0.7
No. 4	no limit
No. 5	no limit
No. 6	no limit

Other sulfur limits may be specified only by mutual agreement between the purchaser and the seller.

b. It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless in fact it meets all requirements of the lower grade.

c. Lower or higher pour points may be specified whenever required by conditions of storage or use.

d. The 10% distillation temperature point may be specified at 440F *(226C)* maximum for use in other than atomizing burners.

e. When pour point less than 0F is specified, the minimum viscosity shall be 1.8 cs (32.0 s, Saybolt Universal) and the minimum 90% point shall be waived.

f. Viscosity values in parentheses are for information only and not necessarily limiting.

g. The amount of water by distillation plus the sediment by extraction shall not exceed 2.00%. The amount of sediment by extraction shall not exceed 0.50%. A deduction in quantity shall be made for all water and sediment in excess of 1.0%.

Source, ASTM D 396.

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corrosive. Furthermore, vanadium can combine with the sulfur oxides to form a corrosive product. (See Chapter 20.)

API gravity The petroleum industry uses the API gravity scale to determine the relative density of oil. The scale was devised jointly by the American Petroleum Institute (API) and the National Bureau of Standards. The relationship between the *API gravity* and the *specific gravity* is given by the following formula:

$$\text{Deg API gravity} = \frac{141.5}{\text{Specific gravity at } 60/60\text{F}} - 131.5$$

Given this relationship, heavier liquid fuels are denoted by lower API gravity values.

Heating value The heating value of a liquid fuel indicates the heat released by the complete combustion of one unit of fuel [lb (kg)]. As for coal, there are two calculated heating values, HHV and LHV. In computing the HHV, it is assumed that any water vapor formed by burning the hydrogen constituent is condensed and cooled to its initial temperature. Therefore, the heat of vaporization of the water formed is included in the HHV. For the LHV, it is assumed that none of the water vapor condenses. Both heating values are determined by using an oxygen bomb calorimeter.

Viscosity The viscosity of a liquid is the measure of its internal resistance to flow. Although there are numerous viscosity scales, those most commonly used in the U.S. are:

1. Seconds Saybolt Universal (SSU),
2. Seconds Saybolt Furol (SSF),
3. absolute viscosity (centipoise), and
4. kinematic viscosity (centistokes).

The *kinematic viscosity* of oil is related to the *absolute viscosity* by the following formula:

$$\text{Kinematic viscosity (centistokes)} = \frac{\text{Absolute viscosity (centipoise)}}{\text{Specific gravity}}$$

Pour point The pour point is the lowest temperature at which a liquid fuel flows under standardized conditions.

Flash point The flash point is the temperature to which a liquid must be heated to produce vapors that flash but do not burn continuously when ignited. There are two instruments used to determine the flash point: the Pensky-Martens or closed cup flash tester, and the Cleveland or open cup tester. The closed cup tester indicates a lower flash point because it retains light vapors which are lost by the open cup unit.

Water and sediment The water and sediment level, also called bottom sediment and water (BSW), is a measure of the contaminants in a liquid fuel. The sediment normally consists of calcium, sodium, magnesium and iron compounds. For heavy fuels, the sediment may also contain carbon.

The basic analyses described are important in designing oil-fired boilers. The HHV determines the quantity of fuel required to reach a given heat input. The ultimate analysis determines the theoretical air required for complete combustion and therefore indicates the size of the burner throat. Also available from the ultimate analysis is the carbon/hydrogen ratio, which shows the ease with which a fuel burns. This ratio also indicates the expected level of carbon particulate emissions. A carbon/hydrogen ratio in excess of 7.5 is usually indicative of troublesome burning.

Considering the percentages of nitrogen and sulfur in conjunction with the HHV, an estimate of NO_x and SO_2 emissions can be made. The ash percentage has a similar bearing on particulate emissions. The ash constituent analysis and ash content indicate fouling and corrosion tendencies.

Additional information, which is often required when designing a boiler, includes:

1. carbon residue,
2. asphaltenes,
3. ash spectrographic analysis,
4. burning profile, and
5. distillation curve.

Properties of fuel oils

Analytical results for various fuel oil properties are given in Table 13.

Fuel oil heating values are closely related to their specific gravities. The relationships between the *HHV* of various fuel oils and their API gravities are shown in Fig. 14.

A more accurate estimate of the heating value for an oil is obtained by correcting the *HHV* from Fig. 14 as follows:

$$\text{Apparent heating value} = \frac{HHV\,[100 - (A + M + S)]}{100} + 40.5\,S \qquad \textbf{(7)}$$

where

A = % weight of ash
M = % weight of water
S = % weight of sulfur

Table 13
Analyses of Fuel Oils

Grade of Fuel Oil	No. 1	No. 2	No. 4	No. 5	No. 6
% by weight:					
Sulfur	0.01 to 0.5	0.05 to 1.0	0.2 to 2.0	0.5 to 3.0	0.7 to 3.5
Hydrogen	13.3 to 14.1	11.8 to 13.9	(10.6 to 13.0)*	(10.5 to 12.0)*	(9.5 to 12.0)*
Carbon	85.9 to 86.7	86.1 to 88.2	(86.5 to 89.2)*	(86.5 to 89.2)*	(86.5 to 90.2)*
Nitrogen	nil to 0.1	nil to 0.1	—	—	—
Oxygen	—	—	—	—	—
Ash	—	—	0 to 0.1	0 to 0.1	0.01 to 0.5
Gravity:					
Deg API	40 to 44	28 to 40	15 to 30	14 to 22	7 to 22
Specific	0.825 to 0.806	0.887 to 0.825	0.966 to 0.876	0.972 to 0.922	1.022 to 0.922
lb/gal	6.87 to 6.71	7.39 to 6.87	8.04 to 7.30	8.10 to 7.68	8.51 to 7.68
Pour point, F	0 to −50	0 to −40	−10 to +50	−10 to +80	+15 to +85
Viscosity:					
Centistokes at 100F	1.4 to 2.2	1.9 to 3.0	10.5 to 65	65 to 200	260 to 750
SUS at 100F	—	32 to 38	60 to 300	—	—
SSF at 122F	—	—	—	20 to 40	45 to 300
Water and sediment, % by vol	—	0 to 0.1	tr to 1.0	0.05 to 1.0	0.05 to 2.0
Heating value, Btu/lb gross (calculated)	19,670 to 19,860	19,170 to 19,750	18,280 to 19,400	18,100 to 19,020	17,410 to 18,990

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*Estimated

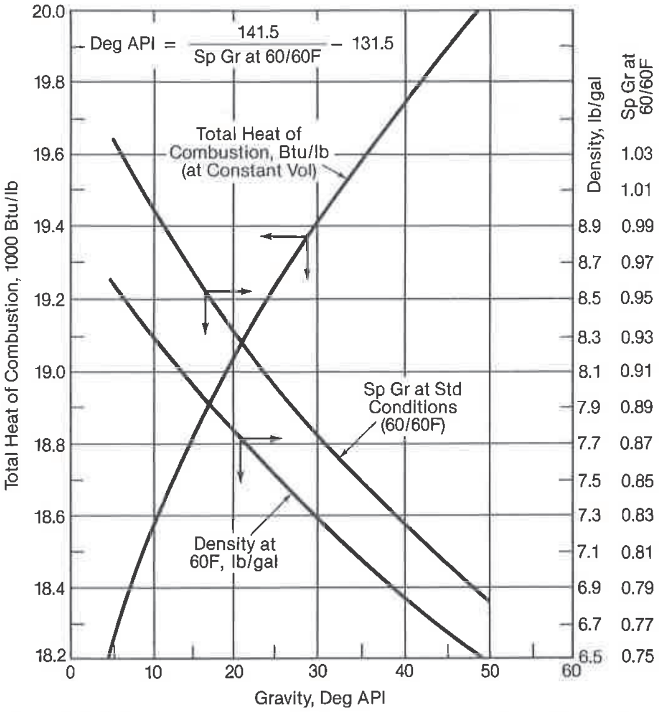


Fig. 14 Relationship between HHV of various fuel oils and their API gravities.

The volume percentages of water and sediment can be used without appreciable error in place of their weight percentages.

Fuel oils are generally sold on a volume basis using 60F (16C) as the base temperature. Correction factors are given in Fig. 15 for converting volumes at other temperatures to this standard base. This correction is also dependent on the API gravity range, as illustrated by the three lines of Fig. 15.

Handling and burning equipment is usually designed for a maximum oil viscosity. If the viscosities of heavy oils are known at two temperatures, their viscosities at other temperatures can be closely predicted by a linear interpolation between these two values on the standard ASTM chart (Fig. 16). Viscosity-temperature variations for certain light oils can also be found using the ASTM chart. In this case, however, the designer only needs to know the viscosity at one temperature. For example, the viscosity of a light oil at a given temperature within the No. 2 fuel oil range can be found by drawing a line parallel to the No. 2 boundary lines through the point of known temperature.

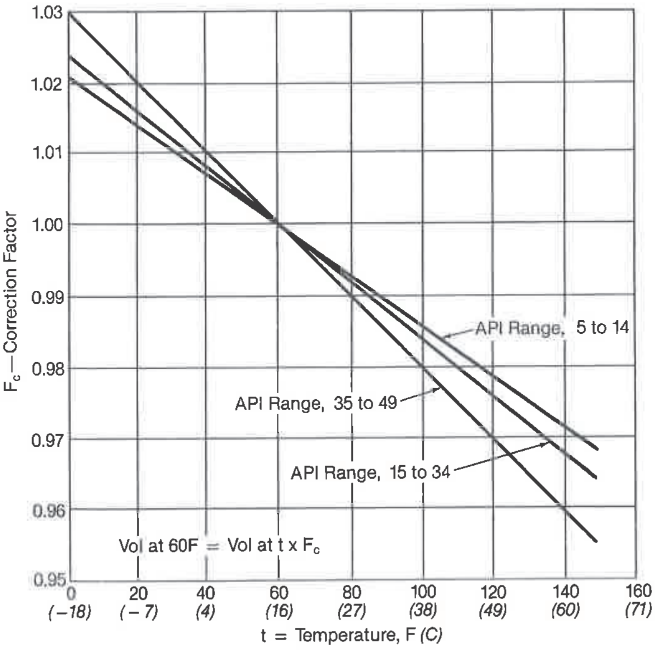


Fig. 15 Oil volume-temperature correction factors.

Natural gas

Past consumption and availability

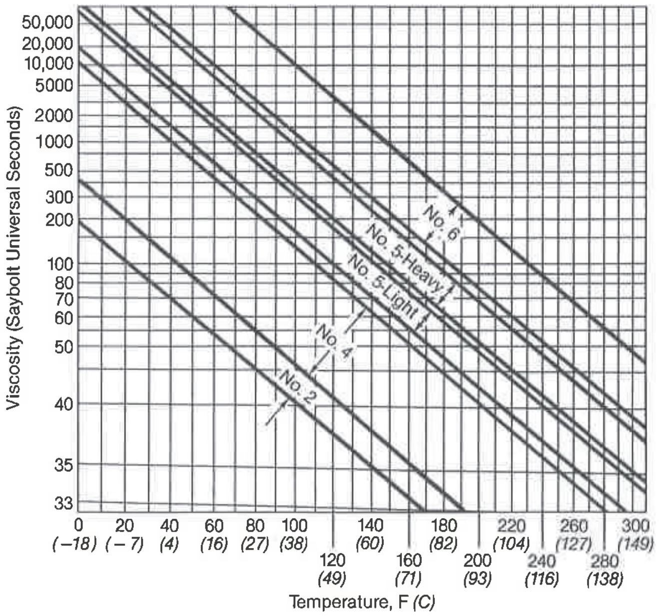
Natural gas is found in porous rock in the earth's crust. World natural gas production for 1988 is shown in Fig. 17.

Electric utilities consume a relatively small amount of natural gas. U.S. consumption as a function of year and use is shown in Table 14. However, natural gas is a widely used fuel for industrial steam generation.

Natural gas characteristics

Natural gas can be found with petroleum reserves or in separate reservoirs. Methane is the principal component of natural gas; smaller components include ethane, propane and butane. Other hydrocarbons, such as pentane through decane, can also be found in natural gas. Furthermore, other gases, such as CO_2, nitrogen, helium and hydrogen sulfide (H_2S) may be present.

Gas containing mostly methane is referred to as *lean* gas. *Wet* gas contains appreciable amounts of the higher



Note: On the scale at the left, find the SUS viscosity at 100F (standard test temperature) for the given oil; move horizontally to the vertical line for100F. From this intersection move parallel to the diagonal lines to the viscosity required for atomization; the temperature necessary to achieve this viscosity can be read on the bottom scale. The chart, based on U.S. Commercial Standard 12-48, has been developed from data for many fuels and should be sufficiently accurate for most applications.

Fig. 16 Approximate viscosity of fuel oil at various temperatures (*courtesy of ASTM*).

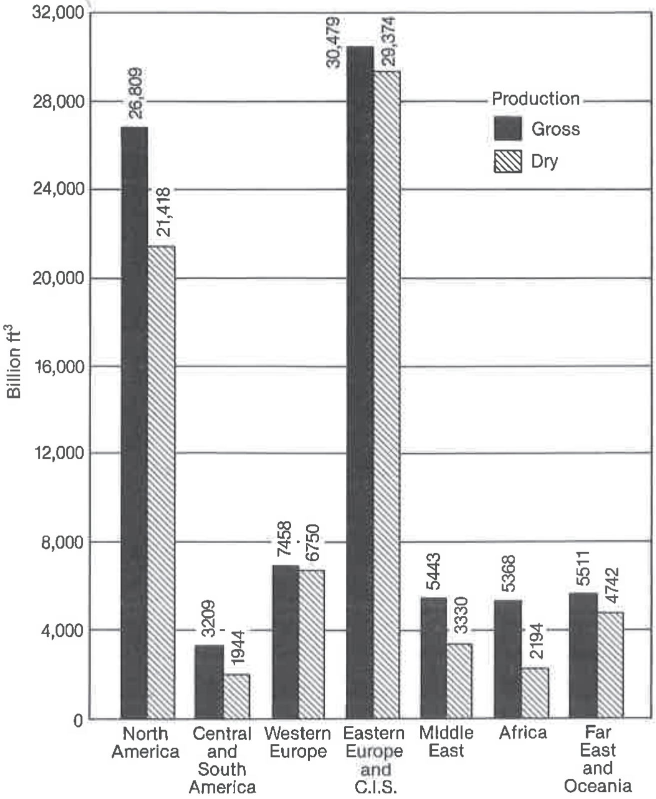


Fig. 17 1988 World natural gas production.

hydrocarbons (5 to 10% C). Gas containing H_2S is *sour* gas; conversely, *sweet* gas contains little or no H_2S.

Of all chemical fuels, natural gas is considered to be the most desirable for steam generation. It is piped directly to the consumer, eliminating the need for storage. It is substantially free of ash and mixes easily with air, providing complete combustion without smoke. Although the total hydrogen content of natural gas is high, its free hydrogen content is low. Because of this, natural gas burns less easily than some manufactured gases with high free hydrogen content.

Table 14
U.S. Natural Gas Consumption (Trillion ft³)

Year	Residential	Commercial	Industrial	Elec. Util.	Transportation	Total
1980	4.75	2.61	8.20	3.68	0.63	19.88
1981	4.55	2.52	8.06	3.64	0.64	19.40
1982	4.63	2.61	6.94	3.23	0.60	18.00
1983	4.38	2.43	6.62	2.91	0.49	16.83
1984	4.56	2.52	7.23	3.11	0.53	17.95
1985	4.43	2.43	6.87	3.04	0.50	17.28
1986	4.31	2.32	6.50	2.60	0.49	16.22
1987	4.31	2.43	7.10	2.84	0.52	17.21
1988	4.63	2.67	7.48	2.64	0.61	18.03
1989^P	4.84	2.73	8.02	2.77	0.59	18.95

P = Preliminary data.

Note: Total may not equal sum of components due to independent rounding. Source: Energy Information Administration, *Annual Energy Review*, 1989.

The high hydrogen content of natural gas compared to that of oil or coal results in more water vapor being produced in the combustion gases. A correspondingly lower efficiency of the steam generating equipment results. (See Chapter 9.) This can readily be taken into account when designing the equipment.

Properties of natural gas

Analyses of natural gas from several U.S. fields are given in Table 15.

Other fuels

While coal, oil and gas are the dominant fuel sources, other carbonaceous fuels being used for boiler applications include petroleum byproducts; wood, its byproducts and wastes from wood processing industries; and certain types of vegetation, particularly bagasse and municipal solid waste.

Coke from petroleum

The heavy residuals from petroleum cracking processes are presently used to produce a higher yield of lighter hydrocarbons and a solid residue suitable for fuel. Characteristics of these residues vary widely and depend on the process used. Solid fuels from oil include delayed coke, fluid coke and petroleum pitch. Some selected analyses are given in Table 16.

The delayed coking process uses residual oil that is heated and pumped to a reactor. Coke is deposited in the reactor as a solid mass and is subsequently stripped, mechanically or hydraulically, in the form of lumps and granular material. Some cokes are easy to pulverize and burn while others are difficult.

Table 15
Selected Samples of Natural Gas from U.S. Fields

Sample No.	1	2	3	4	5
Source:	Pa.	S.C .	Ohio	La.	Ok.
Analyses:					
Constituents, % by vol					
H_2, Hydrogen	--	--	1.82	--	--
CH_4, Methane	83.40	84.00	93.33	90.00	84.10
C_2H_4,Ethylene	--	0.25	--	--	--
C_2H_6, Ethane	15.80	14.80	--	5.00	6.70
CO, Carbon monoxide	--	--	0.45	--	--
CO_2, Carbon dioxide	--	0.70	0.22	--	0.80
N_2, Nitrogen	0.80	0.50	3.40	5.00	8.40
O_2, Oxygen	--	--	0.35	--	--
H_2S, Hydrogen sulfide	--	--	0.18	--	--
Ultimate, % by wt					
S, Sulfur	--	--	0.34	--	--
H_2, Hydrogen	23.53	23.30	23.20	22.68	20.85
C, Carbon	75.25	74.72	69.12	69.26	64.84
N_2, Nitrogen	1.22	0.76	5.76	8.06	12.90
O_2, Oxygen	--	1.22	1.58	--	1.41
Specific gravity (rel to air)	0.636	0.636	0.567	0.600	0.630
HHV					
Btu/ft³ at 60F and 30 in. Hg	1,129	1,116	964	1,022	974
(kJ/m³ at 16C and 102 kPa)	(42,065)	(41,581)	(35,918)	(38,079)	(36,290)
Btu/lb(kJ/kg) of fuel	23,170 (53,893)	22,904 (53,275)	22,077 (51,351)	21,824 (50,763)	20,160 (46,892)

Table 16
Selected Analyses of Solid Fuels Derived from Oil

Analyses (dry basis) % by wt	Delayed Coke		Fluid Coke	
Proximate:				
VM	10.8	9.0	6.0	6.7
FC	88.5	90.0	93.7	93.2
Ash	0.7	0.1	0.3	0.1
Ultimate:				
Sulfur	9.9	1.5	4.7	5.7
Heating value,				
Btu/lb	14,700	15,700	14,160	14,290
(kJ/kg)	(34,192)	(36,518)	(32,936)	(33,239)

Fluid coke is produced by spraying hot residual feed onto externally heated seed coke in a fluidized bed. The fluid coke is removed as small particles, which are built up in layers. This coke can be pulverized and burned, or it can be burned in a Cyclone furnace or in a fluidized bed. All three types of firing require supplemental fuel to aid ignition.

The petroleum pitch process is an alternate to the coking process and yields fuels of various characteristics. Melting points vary considerably, and the physical properties vary from soft and gummy to hard and friable. The low melting point pitches may be heated and burned like heavy oil, while those with higher melting points may be pulverized or crushed and burned.

Oil emulsions

As previously discussed, coal-water slurries have potential as fuel oil substitutes in many combustion systems. In recent years applications for these fuels have ranged from utility boilers to diesel engines. With the discovery of large heavy hydrocarbon and bitumen reserves in Venezuela, considerable effort has been devoted to developing these sources as commercial fuels. This has led to the development of a bitumen oil emulsion.

Oil emulsions are liquid fuels composed of micron size oil droplets dispersed in water. Droplet coalescence is prevented by adding a small amount of a proprietary chemical. The fuel is characterized by relatively high levels of sulfur, asphaltenes and metals. The heating value, ash content and viscosity of the emulsion are similar to residual fuel oil. Emulsion handling and combustion performance are also similar to those of residual fuel oil. One of the concerns with burning these bitumen emulsions is the formation of corrosive vanadium compounds. This occurs by oxidation of the metallic compounds in the fuel.

Wood

Selected analyses and heating values of wood and wood ash are given in Table 17. Wood is composed primarily of carbohydrates. Consequently, it has a relatively low heating value compared with bituminous coal and oil.

Wood bark may pick up impurities during transportation. It is common practice to drag the rough logs to central loading points and sand is often picked up. Where the logs are immersed in salt water the bark can absorb the salt. Combustion temperatures from burning dry bark may be high enough for these impurities to cause fluxing of refractory furnace walls and fouling of boiler heating surfaces, unless sufficient furnace cooling surface is provided. Sand passing through the boiler banks can cause erosion of the tubes, particularly if the flue gas sand loading is increased by returning collected material to the furnace. Such collectors may be required with some bark burning equipment to reduce the stack discharge of incompletely burned bark.

Wood or bark with a moisture content of 50% or less burns quite well; however, as the moisture increases above this amount, combustion becomes more difficult. With a moisture content above 65%, a large part of the heat is required to evaporate the inherent moisture and little remains for steam generation. Burning this wet bark becomes a means of disposal rather than a source of energy.

Hogged wood and bark are very bulky and require relatively large handling and storage equipment. Uninterrupted flow from bunkers or bins through chutes is difficult to maintain.

Table 17
Analyses of Wood and Wood Ash

Wood analyses (dry basis), % by wt	Pine Bark	Oak Bark	Spruce Bark*	Redwood Bark*
Proximate analysis, %				
Volatile matter	72.9	76.0	69.6	72.6
Fixed carbon	24.2	18.7	26.6	27.0
Ash	2.9	5.3	3.8	0.4
Ultimate analysis, %				
Hydrogen	5.6	5.4	5.7	5.1
Carbon	53.4	49.7	51.8	51.9
Sulfur	0.1	0.1	0.1	0.1
Nitrogen	0.1	0.2	0.2	0.1
Oxygen	37.9	39.3	38.4	42.4
Ash	2.9	5.3	3.8	0.4
Heating value, Btu/lb	9030	8370	8740	8350
(kJ/kg)	(21,004)	(19,469)	(20,329)	(19,442)
Ash analysis, % by wt				
SiO_2	39.0	11.1	32.0	14.3
Fe_2O_3	3.0	3.3	6.4	3.5
TiO_2	0.2	0.1	0.8	0.3
Al_2O_3	14.0	0.1	11.0	4.0
Mn_3O_4	Trace	Trace	1.5	0.1
CaO	25.5	64.5	25.3	6.0
MgO	6.5	1.2	4.1	6.6
Na_2O	1.3	8.9	8.0	18.0
K_2O	6.0	0.2	2.4	10.6
SO_3	0.3	2.0	2.1	7.4
Cl	Trace	Trace	Trace	18.4
Ash fusibility temp, F				
Reducing				
Initial deformation	2180	2690		
Softening	2240	2720		
Fluid	2310	2740		
Oxidizing				
Initial deformation	2210	2680		
Softening	2280	2730		
Fluid	2350	2750		

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* Salt water stored.

Wood wastes There are several industries using wood as a raw material where combustible byproducts or wastes are available as fuels. The most important of these are the pulp and turpentine industries. The nature and methods of utilization of the combustible byproducts from the pulp industry are discussed in Chapter 26.

The residue remaining after the steam distillation of coniferous woods for the production of turpentine is usable as a fuel. Some of the more easily burned constituents are removed in the distillation process with the result that the residue is somewhat more difficult to burn. Other than this, fuel properties are much the same as those of the raw wood and the problems involved in utilization are similar.

Bagasse

Mills grinding sugar cane commonly use bagasse for steam production. Bagasse is the dry pulp remaining after the juice has been extracted from sugar cane. The mills normally operate 24 hours per day during the grinding season. The supply of bagasse will easily meet the plant steam demands in mills where the sugar is not refined. Consequently, where there is no other market for the bagasse, no particular effort is made to burn it efficiently, and burning equipment is provided that will burn the bagasse as-received from the grinders. In refining plants, supplemental fuels are required to provide the increased steam demands. Greater efforts to obtain higher efficiency are justified in these plants. A selected analysis of bagasse is given in Table 8.

Other vegetation wastes

Food and related industries produce numerous vegetable wastes that are usable as fuels. They include such materials as grain hulls, the residue from the production of furfural from corn cobs and grain hulls, coffee grounds from the production of instant coffee, and tobacco stems. Fuels of this type are available in such small quantities that they are relatively insignificant in total energy production.

Table 18
Analyses of MSW and RDF Compared to Bituminous Coal

Constituent	Analyses, % by wt MSW	RDF	Bituminous Coal
Carbon	27.9	36.1	72.8
Hydrogen	3.7	5.1	4.8
Oxygen	20.7	31.6	6.2
Nitrogen	0.2	0.8	1.5
Sulfur	0.1	0.1	2.2
Chlorine	0.1	0.1	0
Water	31.3	20.2	3.5
Ash	16.0	6.0	9.0
HHV (wet), Btu/lb	5,100	6,200	13,000
(kJ/kg)	(11,836)	(14,421)	(30,238)

Municipal solid waste

One of the fastest growing energy sources in the U.S., Europe and Japan is municipal solid waste (MSW), or refuse. MSW is the combined residential and commercial waste generated in a given municipality. Formerly landfilled, MSW now fires numerous waste-to-energy boilers. It is burned as-received, called mass burning, or processed using size reduction and material recovery techniques to produce refuse-derived fuel (RDF).

Table 18 shows a typical analysis of raw refuse and RDF compared to bituminous coal. The relatively low calorific value and high heterogeneous nature of MSW provide a challenge to the combustion system design engineer. The design of MSW handling and combustion systems is discussed in Chapter 27.

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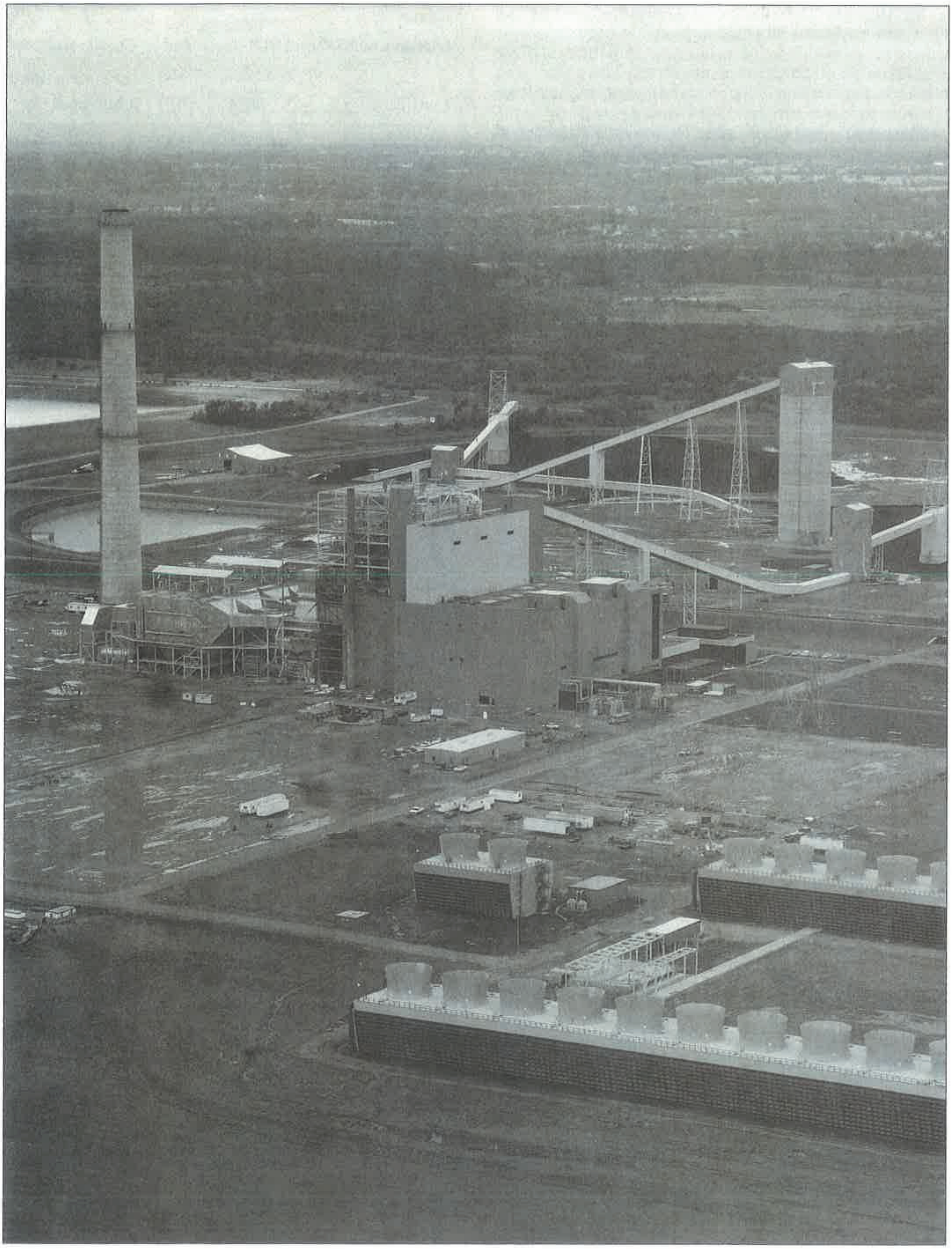

450 MW midwest power station firing pulverized subbituminous coal.

carbon in the coal. However, the ignition temperature of coal may be considered as the ignition temperature of its fixed carbon content, because the gaseous constituents are usually distilled off, but not ignited, before this temperature is attained.

Adiabatic flame temperature

The *adiabatic flame temperature* is the maximum theoretical temperature that can be reached by the products of combustion of a specific fuel and air (or oxygen) combination, assuming no loss of heat to the surroundings and no dissociation. The fuel's heat of combustion is the major factor in the flame temperature, but increasing the temperature of the air or the fuel also raises the flame temperature. This adiabatic temperature is a maximum with zero excess air (only enough air chemically required to combine with the fuel). Excess air is not involved in the combustion process; it only acts as a dilutant and reduces the average temperature of the products of combustion.

The adiabatic temperature is determined from the adiabatic enthalpy of the flue gas:

$$H_g = \frac{HHV - \text{Latent heat } H_2O + \text{Sensible heat in air}}{\text{Wet gas weight}} \qquad \textbf{(10)}$$

where

H_g = adiabatic enthalpy, Btu/lb

Knowing the moisture content and enthalpy of the products of combustion, the theoretical flame or gas temperature can be obtained from Fig. 3 (see pages 12 and 13).

The adiabatic temperature is a fictitiously high value that can not exist. Actual flame temperatures are lower for two main reasons:

1. Combustion is not instantaneous. Some heat is lost to the surroundings as combustion takes place. Faster combustion reduces heat loss. However, if combustion is slow enough, the gases may be cooled sufficiently and incomplete combustion may occur, i.e., some of the fuel may remain unburned.
2. At temperatures above 3000F, some of the CO_2 and H_2O in the flue gases dissociates, absorbing heat in the process. At 3500F, about 10% of the CO_2 in a typical flue gas dissociates to CO and O_2. Heat absorption occurs at 4345 Btu/lb of CO formed, and about 3% of the H_2O dissociates to H_2 and O_2, with a heat absorption of 61,100 Btu/lb of H_2 formed. As the gas cools, the dissociated CO and H_2 recombine with the O_2 and liberate the heat absorbed in dissociation, so the heat is not lost. However, the overall effect is to lower the maximum actual flame temperature.

The term *heat available* (Btu/h) is used throughout this text to define the heat available to the furnace. This term is analogous to the energy term in the adiabatic sensible heat equation above except that one half of the radiation heat loss and manufacturer's margin are not considered available to the furnace.

Commercial combustion application issues

In addition to the theoretical combustion evaluation methodologies addressed above, several application issues are very important in accurate combustion calculations of commercial applications. These include the impact of injection of SO_2 sorbents and other chemicals into the combustion process, solid ash or residue, unburned carbon and excess air.

Sorbents and other chemical additives

In some combustion systems, chemical compounds are added to the gas side of the steam generator to reduce emissions. For example, limestone is used universally in fluidized-bed steam generators to reduce SO_2 emissions. (See Chapter 16.)

Limestone impacts the combustion and efficiency calculations by: 1) altering the mass of flue gas by reducing SO_2 and increasing CO_2 levels, 2) increasing the mass of solid waste material (ash residue), 3) increasing the air required in forming SO_3 to produce calcium sulfate, $CaSO_4$, 4) absorbing energy (heat) from the fuel to calcine the calcium and magnesium carbonates, and 5) adding energy to the system in the sulfation reaction ($SO_2 + {}^1/_2\ O_2 + CaO \rightarrow CaSO_4$). The impact of sorbent/limestone is shown as a correction to the normal combustion calculations presented later.

The limestone constituents that are required in the combustion and efficiency calculations are:

- Reactive constituents:
    - Calcium carbonate ($CaCO_3$)
    - Magnesium carbonate ($MgCO_3$)
- Water
- Inerts

Some processes may use sorbents derived from limestone. These sorbents contain reactive constituents such as calcium hydroxide [$Ca(OH)_2$] and magnesium hydroxide [$Mg(OH)_2$].

For design purposes, the amount of sorbent is determined from the design calcium to sulfur molar ratio, *MOFCAS*. The sorbent to fuel ratio, *MFSBF*, is a convenient equation that converts sorbent products to a mass of fuel or input from fuel basis.

$$MFSBF = \frac{MOFCAS \times S}{MOPCA \times 32.066} \qquad \textbf{(11)}$$

and

$$MOPCA = \left(\frac{CaCO_3}{100.089} + \frac{Ca(OH)_2}{74.096} \right) \qquad \textbf{(12)}$$

where

MFSBF = mass ratio of sorbent to fuel, lb/lb
MOPCA = calcium in sorbent molar basis, moles/100 lb sorbent
S = mass percent sulfur in fuel, %
$CaCO_3$ = mass percent calcium carbonate in sorbent, %
$Ca(OH)_2$ = mass percent calcium hydroxide in sorbent, %

When calcium carbonate and magnesium carbonate are heated, they release CO_2, which adds to the flue gas products. This is referred to as *calcination*. Magnesium carbonate calcines readily; however, at the operating temperatures typical of atmospheric pressure fluidized beds, not all of the calcium carbonate is calcined. For design purposes, 90% calcination is appropriate for atmospheric fluidized-bed combustion. On an operating unit, the mass fraction of calcination can be determined by measuring

Table 14
Combustion Calculations-Sorbent

	INPUTS (see also lightly shaded blocks)			FUEL-*Bituminous coal, Virginia*	
1	Sulfur in fuel, % by weight	*1.54*	6	Sulfur capture, lb/lb sulfur	*0.90*
2	Ash in fuel, % by weight	*6.55*	7	Reference temperature, F	*80.0*
3	HHV of fuel, Btu/lb	*14,100*	8	Exit gas temperature (excluding leakage), F	*390.0*
4	Unburned carbon loss, % fuel input	*2.5*	9	Sorbent temperature, F	*80.0*
5	Calcium to sulfur molar ratio	*2.5*			

SORBENT PRODUCTS

		10 Chemical Analysis % Mass	11 Molecular Weight lb/mole	12 Ca mole/100 lb sorb [10]/[11]	13 Calcination Fraction	14 Molecular Weight lb/mole	15 CO_2 lb/100 lb sorb [10]x[13]x[14]/[11]	16 H_2O lb/100 lb sorb [10]x[13]x[14]/[11]
A	$CaCO_3$	*89.80*	100.089	*0.897*	*0.90*	44.010	*35.529*	
B	$MgCO_3$	*5.00*	84.321		1.00	44.010	*2.610*	
C	$Ca(OH)_2$	*0.00*	74.096	*0.000*	1.00	18.015		*0.000*
D	$Mg(OH)_2$	*0.00*	58.328		1.00	18.015		*0.000*
E	H_2O	*1.60*	18.015		1.00	18.015		*1.600*
F	Inert	*3.60*						
G	Total Ca, mole/100 lb sorbent			*0.897*		Total	*38.139*	*1.600*

SORBENT/GAS CALCULATIONS, lb/10,000 Btu Except as Noted

17	Sorbent, lb/lb fuel	[1] x [5] / [12G] / 32.066	*0.1339*
18	Sorbent, lb/10,000 Btu	10,000 x [17] / [3]	*0.0950*
19	CO_2 from sorbent, lb/10,000 Btu	[15G] x [18] / 100	*0.0362*
20	H_2O from sorbent, lb/10,000 Btu	[16G] x [18] / 100	*0.0015*
21	Additional theoretical air, lb/10,000 Btu	216 x [1] x [6] / [3]	*0.0212*
22	SO_2 reduction, lb/10,000 Btu	200 x [1] x [6] / [3]	*0.0197*
23	SO_3 formed, lb/10,000 Btu	0.2314 x [21] + [22]	*0.0246*
24	Spent sorbent, lb/10,000 Btu	[18] − [19] − [20] + [23]	*0.0819*
25	Unburned carbon, lb/10,000 Btu	[4] x 100 / 14,500	*0.0172*
26	Residue from fuel, lb/10,000 Btu	[2] x 100 / [3] + [25]	*0.0637*
27	Total residue, lb/10,000 Btu	[24] + [26]	*0.1456*

LOSSES DUE TO SORBENT, % Input from Fuel

28	H_2O from sorbent, %	H of steam at 1 psi, T = [8]	H_1 = (3.958E − 5 x [8] + 0.4329) x [8] + 1062.2	*1237.1*	
29		H of water	H_2 = [9] − 32	*48.0*	
30		0.01 x [20] x ([28] − [29])			*0.018*
31	Sensible heat sorbent (dry), %	[18] x (1.0 − [10E]/100) x (H at T = [9] − H at T = [7])/100 H of limestone (dry) = (0.1128E−3 x T + 0.179) x T − 14.45			*0.000*

Calcination/Dehydration, %

32	$CaCO_3$, %	[10A] x [13A] x [18] x 766 / 10,000	*0.588*	
33	$MgCO_3$, %	[10B] x 1.0 x [18] x 652 / 10,000	*0.031*	
34	$Ca(OH)_2$, %	[10C] x 1.0 x [18] x 636 / 10,000	*0.000*	
35	$Mg(OH)_2$, %	[10D] x 1.0 x [18] x 625 / 10,000	*0.000*	
36	Heat gain due to sulfation, %	[6] x [1] x 6733 / [3]	*0.662*	
37	Total of losses due to chemical reactions, %	[32] + [33] + [34] + [35] − [36]		*− 0.043*

Sensible Heat Of Residue Loss, %

	Location	38 Temp Residue, F	39 Mass Flow Rate, % Total	x	[27] lb/10,000 Btu	x (	H at T = [38] Btu/lb	−	H at T = [7] Btu/lb	) / 10,000 =	Loss %
A	Bed drain	*1500*	*10*	x	*0.1456*	x (	*376.3*	−	*0.5*	) / 10,000 =	*0.055*
B	Economizer	*600*	*10*	x	*0.1456*	x (	*116.2*	−	*0.5*	) / 10,000 =	*0.017*
C	Flyash	*390*	*80*	x	*0.1456*	x (	*64.3*	−	*0.5*	) / 10,000 =	*0.074*
	H Residue = ((− 2.843E − 8 x T + 1.09E − 4) x T + 0.16) x T − 12.95									40 Total	*0.146*
41	Summation losses due to sorbent, %				[30] − [31] + [37] + [40]						*0.121*

Chapter 11

Solid Fuel Processing and Handling

Coal remains the dominant worldwide source of energy for steam generation. However, additional solid fuels such as wood byproducts and municipal wastes are also gaining widespread use. The large scale continuous supply of such solid fuels for cost effective and reliable steam power generation requires the effective integration of recovery (e.g., mining), preparation, transportation and storage technologies. The relationships between these are illustrated in Fig. 1. While each fuel offers unique challenges, a discussion of the processing and handling of the dominant fuel source — coal — identifies many of the common issues and considerations for all solid fuels. Selected additional topics about the special aspects of some other solid fuels are covered in Chapters 26 through 28.

Mining is the first step in producing coal. Raw coal can be treated to remove impurities and to provide a more uniform feed to the boiler. The resulting reduction in ash and sulfur can significantly improve overall boiler performance and reduce pollution emissions. The transportation of coal to the plant may represent a major portion of the plant's total fuel cost although mine mouth generating stations can minimize these transportation costs. Storage and handling of large coal quantities at the plant site require careful planning to prevent service interruptions.

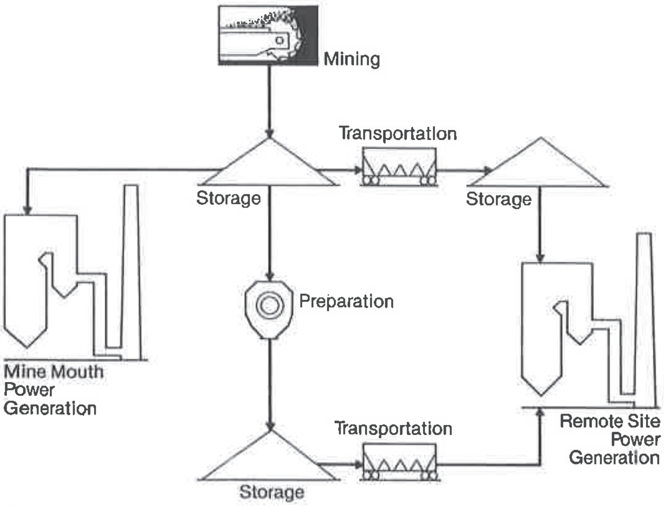

Fig. 1 Fuel supply chains for coal-fired power generation.

Coal mining

As discussed in Chapter 8, electric utility coal consumption for power generation dominates the market for coal produced in the United States (U.S.) and the rest of the world. U.S. coal production reached more than 1 billion tons per year in 1990 with 77% being used for electric utility power generation. Corresponding worldwide production in 1990 was approximately 5.2 billion tons.

In the U.S., coal production is split between surface mining (59%) and underground mining (41%). Because of the geologic locations of coal deposits, or *seams*, and cost considerations, surface mining dominates coal production west of the Mississippi River and underground mining dominates in the East. The emergence of large, high volume surface mines producing low sulfur coal in the West has resulted in a continuing shift of coal production from the Eastern U.S. to the West.

Surface mining

Coal may be recovered from relatively shallow seams by removing the overlying earth, or *overburden*, to expose the coal seam. Typically, topsoil is first removed and stored for later use in reclamation of the site. The remaining overburden is drilled and blasted to loosen the rock for removal with a dragline or excavating shovel. The overburden is then methodically stripped away and stored for restoration of the land to the original contour following removal of the coal. A dragline is commonly used to expose the coal seam (Fig. 2). The coal may then be removed using a bulldozer and front-end loader or a shovel. A mobile crusher and screen may be set up in the mine for initial sizing of the raw coal. The coal is then loaded into haulage trucks for delivery to a cleaning facility or steam generating plant.

The *stripping ratio* is defined as the unit amount of overburden which must be removed to access a unit amount of coal. In general, surface mines in the Western U.S. have lower stripping ratios than mines in the East.

Strict environmental regulations limit the amount of land surface area which may be exposed at any one time, control water runoff and establish land reclamation procedures.

Underground mining

Approximately 68% of the total U.S. coal reserves are accessible only by underground mining. (See Chapter 8.) Underground coal mine production is dominated by the use of continuous mining machines (Fig. 3) which presently account for approximately 70% of the total underground production.

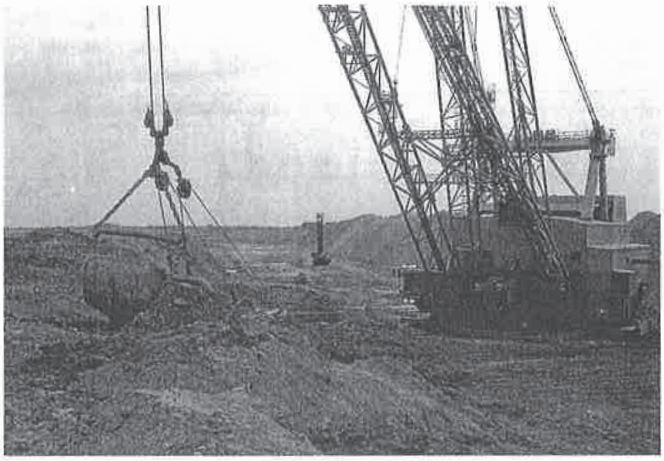

Fig. 2 Large coal dragline in operation (*courtesy of National Coal Association*).

Room and pillar mining Most U.S. coal is produced using an underground technique known as room and pillar mining. A series of headings or parallel entries are cut into the coal seam to provide passages for the mining machinery, uncontaminated ventilation air and conveying equipment. These headings are typically 18 to 20 ft (5.5 to 6.1 m) wide and may be several miles (km) long. Rooms are driven off of the main headings to the property limits of the mine. Typically, only about 50% of the coal is removed when the rooms are first mined. The remaining coal is left in place to support the roof. Roof bolts are installed where the coal has been removed for additional roof support. At the completion of the development cycle, the remaining coal may be removed by retreat mining, and the unsupported roof is allowed to collapse.

Longwall mining In longwall mining, shearers or plows are pulled back and forth across a panel of coal to break it loose from the seam. The coal falls onto a flight conveyor and is transported to the main haulage line. Because essentially all of the coal is removed, artificial roof supports, known as shields or chocks, are used to cover the plow and conveyor. The plow, conveyor and roof supports are advanced using hydraulic jacks as the coal is removed from the mining face. The unsupported roof is allowed to cave in behind the supports. In 1990, there were 96 longwall sections operating in the U.S. The average panel width exceeded 700 ft (213.4 m) and panels as wide as 1000 ft (304.8 m) were in operation. Longwall panel lengths may reach 10,000 ft (3048 m) or more.

Fig. 3 Continuous mining machine in operation (*courtesy of National Coal Association*).

Longwall mining can be a very high capacity production system provided that the geologic conditions are suitable and the longwall has been carefully integrated with the existing panel development scheme and coal haulage infrastructure. Production capacities exceeding 6000 t of raw coal per shift have been reported. The annual production capacity for a longwall is a function of the seam height, panel width and length, and the time required to move the equipment between operating panels.

Raw coal size reduction and classification

Sizing requirements

Size reduction operations at steam power plants are usually confined to crushing and pulverizing although it is sometimes more economical to purchase pre-crushed coal for smaller plants, especially stoker-fired units. Screening at the plant is generally not required, except to remove large impurities and trash using simple grids (or grizzlies) and rotary breakers. Techniques for determining coal particle size distribution are discussed in Chapter 8 while the American Society for Testing and Materials (ASTM) Standard D 431 details the commonly accepted screen size designations.

Coal particle size degradation, which occurs in transportation and handling, must be considered when establishing supply size specifications. This may be critical where the maximum quantity of coal fines is set by firing equipment limitations.

For stoker-fired installations, it is customary to specify purchased coal sized to suit the stoker (see Chapter 15), so that no additional sizing is required at the plant [typically 1.5 in. x 0 (38.1 mm x 0)].

For pulverized coal-fired boilers, a maximum delivered top size is usually specified with no limitation on the percentage of fines, so that the delivered coal is suitable for crushing and pulverizing in the available equipment. The coal is crushed to reduce particle size and then ground to a very fine size in the pulverizer. (See Chapter 12.)

Crushers alone may be used to provide the relatively coarser sizes required for Cyclone furnaces. (See Chapter 14.) A properly sized crusher efficiently reduces particle size while producing minimal fines.

Size reduction equipment selection

Size reduction equipment is generally characterized by the maximum acceptable feed size and the desired product top size. The reduction ratio is defined as follows:

$$\frac{p_{feed}}{p_{product}} \tag{1}$$

where

p_{feed} = feed particle size in which 80% of the particles pass a given screen size or mesh

$p_{product}$ = product particle size in which 80% of the particles pass a given screen size or mesh

Once-through crushing devices, which discharge the fines without significant re-crushing, are used to minimize the production of fines. Rotary breakers and roll crushers are commonly used to reduce the coal top size without producing a significant amount of fines.

The *rotary breaker*, illustrated in Fig. 4, reduces the coal to a predetermined maximum size and rejects larger refuse, mine timbers, trash and some tramp metal. It consists of a large cylinder of steel screen plates which rotates at approximately 20 rpm. The size of the screen openings determines the top size of the coal. The coal fed at one end of the cylinder is picked up by lifting shelves and is carried up until the angle of the shelf permits the coal to drop onto the screen plate. It shatters and is discharged through the screen openings. The harder rock does not break as readily; it travels along the screen and is rejected at the discharge end. Wood, large rocks and other trash which do not pass through the screen are separated from the coal. Rotary breakers may be installed at the mine, preparation plant, or steam generating plant.

The elements of a *single-roll crusher* are illustrated in Fig. 5. This crusher consists of a single toothed roll which forces the coal against a plate to produce the crushing action. The maximum product particle size is determined by the gap between the roll and the plate. To prevent jamming by large impurities such as tramp metal, the roll is permitted to rise or the plate can swing away, allowing the impurities to pass through. This is an old type of crusher which is commonly used for reducing run-of-mine bituminous coal to a maximum product of 1.25 to 6 in. (31.8 to 152 mm). The abrasive action between the coal and the plate produces some fines; however, they are discharged with minimal re-breakage.

In a *double-roll crusher* the coal is forced between two counter-rotating toothed rolls (Fig. 6). The mating faces of both rolls move in a downward direction, pulling the coal through the crusher. The size of the roll teeth and the spacing between rolls determine the product top size. One of the rolls may be spring loaded to provide a means for passing large, hard impurities. Double-roll crushers are used for reducing run-of-mine coal to smaller sizes at preparation and steam generating plants.

In *retention crushers* such as *hammer mills* and *ring crushers*, coal is retained in the breakage zone until it is sufficiently fine to pass through a screen to the discharge. The re-breakage action produces considerable fines, consequently these mills are not used in applications where fines are objectionable. They are often used to reduce run-of-mine coal to an acceptable size for feed to a stoker or pulverizer, e.g., 0.75 in. x 0 (19 mm x 0).

A *hammer mill* is depicted in Fig. 7. In this mill, the coal is broken by impact with the hammers, which are mounted on a central shaft and permitted to swing freely as the shaft is rotated. The coal is fed at the top of the mill and is forced down and outward to the grate bars as it is struck by the hammers. The spacing of the bars determines the maximum size of the finished product. The coal remains in the mill, and breakage continues until the particles are fine enough to pass through the grate. A trap is usually provided for collection and removal of tramp metal.

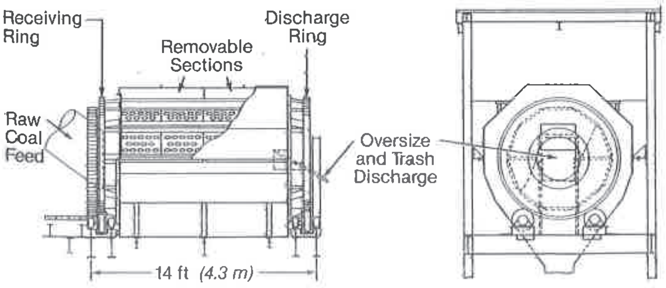

Fig. 4 Rotary breaker for use at the mine and power plant.

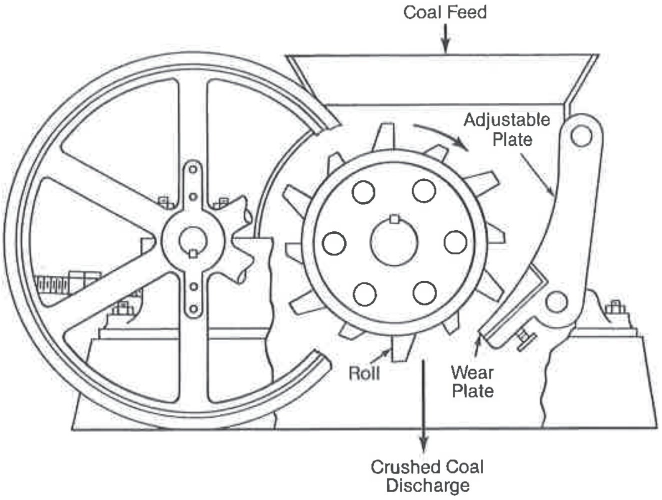

Fig. 5 Single-roll crusher — diagrammatic section.

Screen selection

Screening is usually performed at the mine or preparation plant to remove unwanted material and size coal for various uses prior to shipment to the steam generating plant. The run-of-mine coal is usually passed over a grid of steel bars, or grizzly, to remove mine timbers and trash. The raw coal may be separated into various size fractions to meet contract specifications or for further processing in a preparation plant by passing the coal through various screens. Common screen types include gravity bar screens, trommels or revolving screens, shaker screens and vibrating screens.

A *gravity bar screen* consists of a number of sloped parallel bars. The gaps between bars, the slope, and the length of the bars determine the separating size. The bars

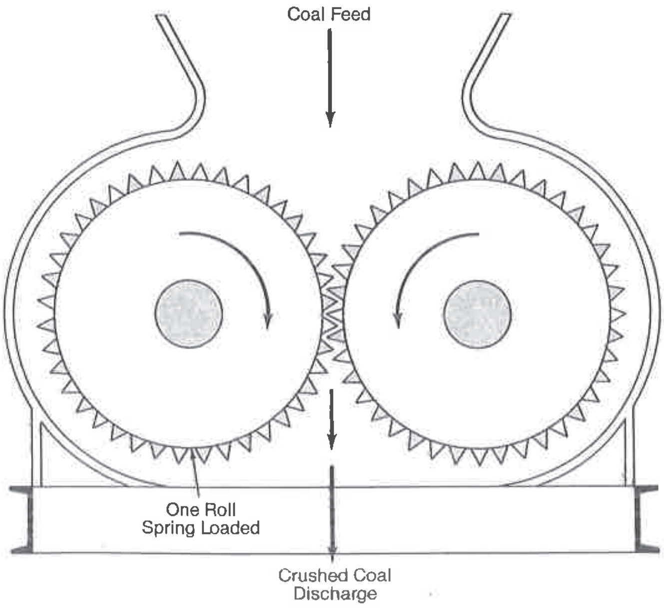

Fig. 6 Double-roll crusher — diagrammatic section.