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Report No. TE5429-71-76

A STUDY OF IMPROVED FUEL EFFECTIVENESS IN THE IRON AND STEEL AND PAPER AND PULP INDUSTRIES

by

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March 1976

Prepared for

The National Science Foundation
Office of Energy Policy
Washington, D. C.
Grant No. 7422046
Formerly No. OEP74-22046A01
Formerly No. EN-44194

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REPORT SUMMARY

This study was sponsored by the National Science Foundation to establish the economics and to investigate needed policies for implementation of fuel-saving methods in the iron and steel and paper industries.

We have concluded that:

1. Economic fuel saving methods exist;
2. One method of enhancing the implementation of these methods is by means of a program of federally guaranteed loans for energy conservation, provided the loans can be treated so as not to affect the debt to equity ratios of the industries; and
3. The potential fuel saving over the next decade could amount to about 1.4×10^{15} Btu/year for both industries (57% in iron and steel and 43% in paper and pulp).

Several fuel saving options have been identified for each of the two industries. Each of these options is judged as economical both because its rate of return on investment is equal to or higher than the average rate of return for regular investments of the corresponding industry, and because the required capital investment for saving the equivalent of one barrel of oil per day is equal to or smaller than that for increasing domestic fuel supplies by the same amount. The rate of return evaluations were made by using current marginal fuel prices.

Some fuel saving options have such a high rate of return (payback periods of the order of a year) that industry will adopt them at a fast pace. Others have a rate of return that is higher than the average for the industry but not sufficiently high to be attractive to it for the following reasons.

The iron and steel and paper industries in the U. S. are large and capital intensive. Each will require several billion dollars per year during the next decade for modernization, pollution control, and increased capacity equipment. Predicted capital requirements exceed anticipated capacity for traditional financing, and major difficulties exist for abnormal debt financing. In the light of these circumstances, the capital that can be secured by each company will be invested in items that are directly related to the main line of activity of the company and that promote the competitive position of the company in these markets. The capital shortage is such that sometimes companies will invest in these types of investment even at reduced profits.

Thus, many fuel saving options, which are judged economic on the basis of the criteria selected for this study, either will be given low priority or will be totally ignored especially since a number of companies still enjoy fuel prices much lower than those resulting from new domestic supplies.

We believe that the national interest necessitates the adoption of these fuel saving options since we subscribe to the view that our energy problem can be solved only through a combination of new fuel supplies and energy conservation procedures. The adoption can be brought about through Government initiatives.

Because the fuel saving options under consideration have rates of return equal to or higher than those of regular investments, we have rejected tax incentives, tax credits and low interest loans as possible Government initiatives. Reasonable changes in current practices of these types of Government policies have a relatively small effect on the rate of return, and moreover, render a reasonable or high rate of return even higher.

Instead, we have concluded that one effective way of encouraging fuel saving options is for the Federal Government to institute a program of guaranteed loans that are offered at market interest rates but that do not affect the debt to equity ratios of the industries. Such loans would not interfere with the ability of a company to obtain its regular investments via the debt and equity routes but will increase fuel savings at an acceptable profit.

The report is divided into two parts: Part I, Iron and Steel, and Part II, Paper and Pulp. Each industry part presents (1) fuel consumption patterns and trends; (2) major fuel consumption processes; (3) promising fuel saving options; (4) economic evaluations; (5) Government initiatives; and (6) recommendations for Government sponsored research and development work. More detailed summaries of the work that was done for each of the two industries are presented in their respective parts.

The study was performed by Dr. Elias P. Gyftopoulos, Ford Professor of Engineering, Massachusetts Institute of Technology, Dr. Sander E. Nydick (Iron and Steel), and Mr. John Dunlay (Paper and Pulp) both of Thermo Electron Corporation. Dr. Robert Pindyck, Assistant Professor of Management, Massachusetts Institute of Technology acted as a consultant in the area of plant and industry investment criteria.

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IRON AND STEEL

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IRON AND STEEL SUMMARY

Iron and steel manufacturing includes the steps of ore preparation, coke making, iron making, and steel processing. It is an energy as well as a capital intensive industry.

In 1973, fuel consumption was 3.9×10^{15} Btu for 150.8×10^6 tons of raw steel or 25.6×10^6 Btu/ton, including fuels used for the generation of the electricity consumed by the industry. This consumption is about 5.2% of the total energy needs of the U. S. and 14.7% of the energy consumed by industry. It consists of 69% coking coal, merchant coke, and coal for steam and electricity, 20% natural gas, 9% oil, and 2% other.

Including the raw steel produced by processing scrap (which is chemically already steel) the ratio of the minimum available useful work required (6.0×10^6 Btu/ton) and the sum of the available useful works of the fuel (25.1×10^6 Btu/ton) and the scrap (2.8×10^6 Btu/ton) consumed is 0.21, i.e., the effectiveness of fuel use is 21%. Of the 79 percentage points of loss, 9.5 are lost in coke manufacturing, 11 in iron making, 7 in steelmaking, 22 in steel processing, and 16.5 in generation of steam and electricity.

In general, losses in the U. S. are higher than those in other countries. For example, in 1972 fuel consumption in Germany was about 18.6×10^6 Btu/ton. This is partly due to the fact that, with the exception of basic oxygen furnaces, most facilities of the U. S. iron and steel industry are older than their counterparts in Europe and Japan (no significant expansion of production capacity has occurred in the U. S. in the recent past), and partly due to the traditionally low fuel prices in the U. S.

Most of the scrap utilized in steel mills today is so-called home scrap, that is, waste produced in the steelmaking process. Additionally, large quantities of scrap are available from the daily collections of municipal solid waste, existing land fills, and in large scrap piles (especially junk cars). Utilization of all this waste scrap presents some technical problems. However, it should be recognized that large amounts of fuels can be conserved by increasing the scrap to pig iron ratio in steelmaking since it takes about half the fuel to produce finished steel from scrap than from iron ore.

Technologies exist for improved fuel utilization at acceptable cost. They are practiced either to a limited extent in the U. S. or more widely in other countries.

Technologies that are partially practiced in the U. S. include:

- Blast furnaces with air blast temperatures of 1700°F and top pressures of up to two atmospheres.
- Basic oxygen furnaces instead of open hearth furnaces.
- Continuous casting.
- Recuperation
- Combined electricity generation and process steam raising.

Technologies that are practiced abroad include:

- Dry coke quenching
- Collection of BOF off-gas

In addition, technologies exist for conversion from a scarce to a more abundant fuel source, such as from coking coal to noncoking coal, and from petroleum and natural gas injectants to noncoking coal.

Two economic criteris were established to judge the merits of fuel conserving process options: (1) a rate of return on investment of 12% or higher; and (2) a capital investment per barrel of oil equivalent per day saved smaller than or equal to the capital investment required to increase energy production from domestic sources at the same rate. Based upon the adoption of processes which satisfy both criteria, we estimate that fuel consumption in the steel industry could be reduced from 25.6×10^6 to 21.3×10^6 Btu/ton new steel by 1983, namely by 17%.

In an earlier study[1] we had estimated that available energy conservation technology could reduce fuel consumption to 17.2×10^6 Btu/ton of raw steel. In that study, however, we had not considered either the time necessary for implementation or economic and institutional barriers.

Though economical, all the reduction from 25.6×10^6 to 21.3×10^6 Btu/ton may not be achieved by 1983 because the industry is short of capital and will use its available debt and equity financing primarily for expansion, modernization, and pollution control. It is estimated that capital requirements for 1975 - 1983 are in the range of $5 to 5.5 billion/year (including about $1 billion/year for pollution controls) and yet the anticipated capability for debt and equity financing is in the range of $2 to 4 billion/year.

Because selected energy conservation technologies in the steel industry are profitable and in the national interest but will not be implemented due to capital shortages, we reached the conclusion that a possible initiative of the Federal Government might be the establishment of guaranteed loans at market interest rates for energy conserving options provided that such loans do not interfere with the company's ability to finance its regular investments through the debt and equity markets.

Because many of the technologies investigated as part of this program require further development or design, and further detailed study we recommend that the government institute an active R & D effort in steel industry technology. For the short term, some of the technologies for which system and economic studies should be performed are dry quenching of coke, BOF off-gas collection, use of form coke, and coal-based direct reduction processes. These studies, if successful, should be followed up by demonstration programs involving support by industry-based consortiums. For the long term, attention should be given to the use of a high-temperature gas reactor as a heat source for iron and steelmaking.

1. PROCESS DESCRIPTION

1.1 GENERAL REMARKS

In the U. S. raw steel and shipped steel* production, and fuel consumption for steel have been increasing over the past few decades. For example, raw steel production[2] increased from about 100 million tons in 1960 to about 150 million tons in 1973, and fuel consumption for steel[2] increased from about 2.9×10^{15} Btu in 1960 to about 3.8×10^{15} Btu in 1973. Estimates of future demand for steel indicate that these trends will continue.

Steel plants in the U. S. can be conveniently classified into two types: integrated and nonintegrated. The feedstock materials, fuels, and capacities for the two types of plants differ considerably. Integrated plants use iron ore and steel scrap as feedstock materials and, primarily, coal as fuel, and have capacities ranging from 1 to 8 million tons of steel per year. They consist of facilities for feedstock and coal preparation, ironmaking, steelmaking, and steel processing into finished products.

Nonintegrated or mini-mills, on the other hand, use steel scrap as feedstock material and primarily electricity as a source of energy,

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*Raw steel is the liquid steel produced in steelmaking furnaces whereas shipped steel is the finished steel that leaves the plant. Historically, the yield of shipped steel from raw steel production has been about 72.5%. Statistics based upon shipped steel can sometimes be inconsistent since finished steel can be held in inventory. On the other hand, raw steel cannot be held in inventory; thus statistics based upon raw steel tend to be more consistent than those for shipped steel from year to year. For the purposes of this report, fuel per ton of raw steel rather than shipped steel is used unless otherwise stated.

and have capacities ranging from 0.1 to 1 million tons of steel per year. They consist of electric furnaces for raw steel production, and facilities for processing raw steel into finished products. Small amounts of pig iron and prereduced iron (92% Fe) are also processed in mini-mills.

Integrated mills account for about 80% of U. S. steel production, and consume most of the energy used in steel manufacturing. They manufacture a great variety of products such as carbon steel and stainless-steel, plates and structural bars. Nonintegrated mills tend to specialize in specific products such as light structural steels and specialty steels.

Figures 1.1 and 1.2 show process-flow diagrams for integrated and nonintegrated plants. We see from Fig. 1.1 that integrated plants consist of: coke ovens for coal preparation; pelletizing or sintering units for feedstock preparation; blast furnaces for ironmaking; basic oxygen furnaces; open hearth furnaces; and electric furnaces for steelmaking; and soaking pits and finishing units (or continuous casting machines and finishing units) for steel processing. On the other hand, we see from Fig. 1.2 that nonintegrated plants consist of electric furnaces for steelmaking, and soaking pits and finishing units for steel processing (or continuous casting machines and finishing units).

1.2 FEEDSTOCK AND COAL PREPARATION[2]

Iron ore and coal must be prepared prior to being loaded into the blast furnace. Ores are converted into high iron content pellets or sinter, and coal into coke.

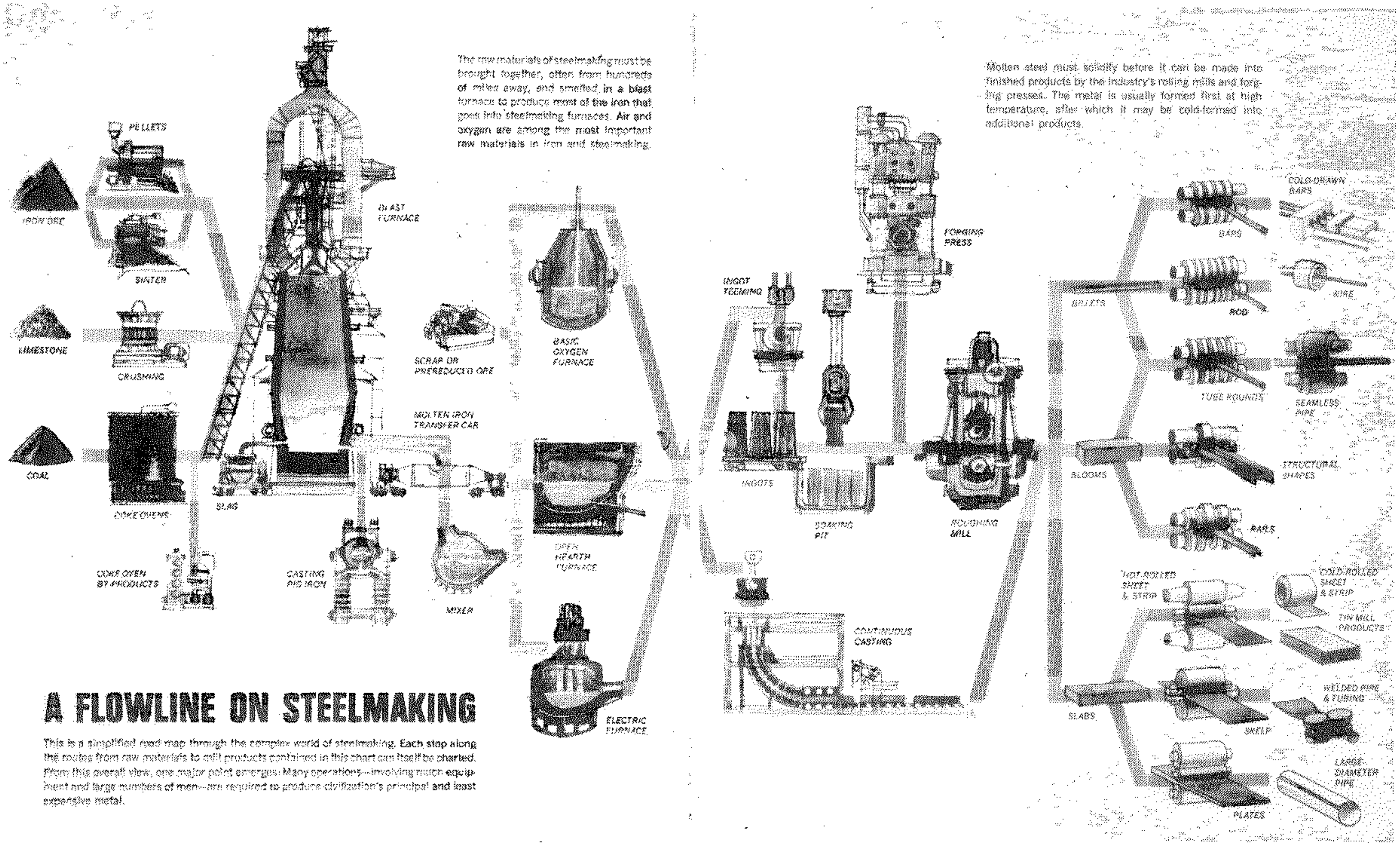

Figure 1.1 A Flowline on Steelmaking[3]

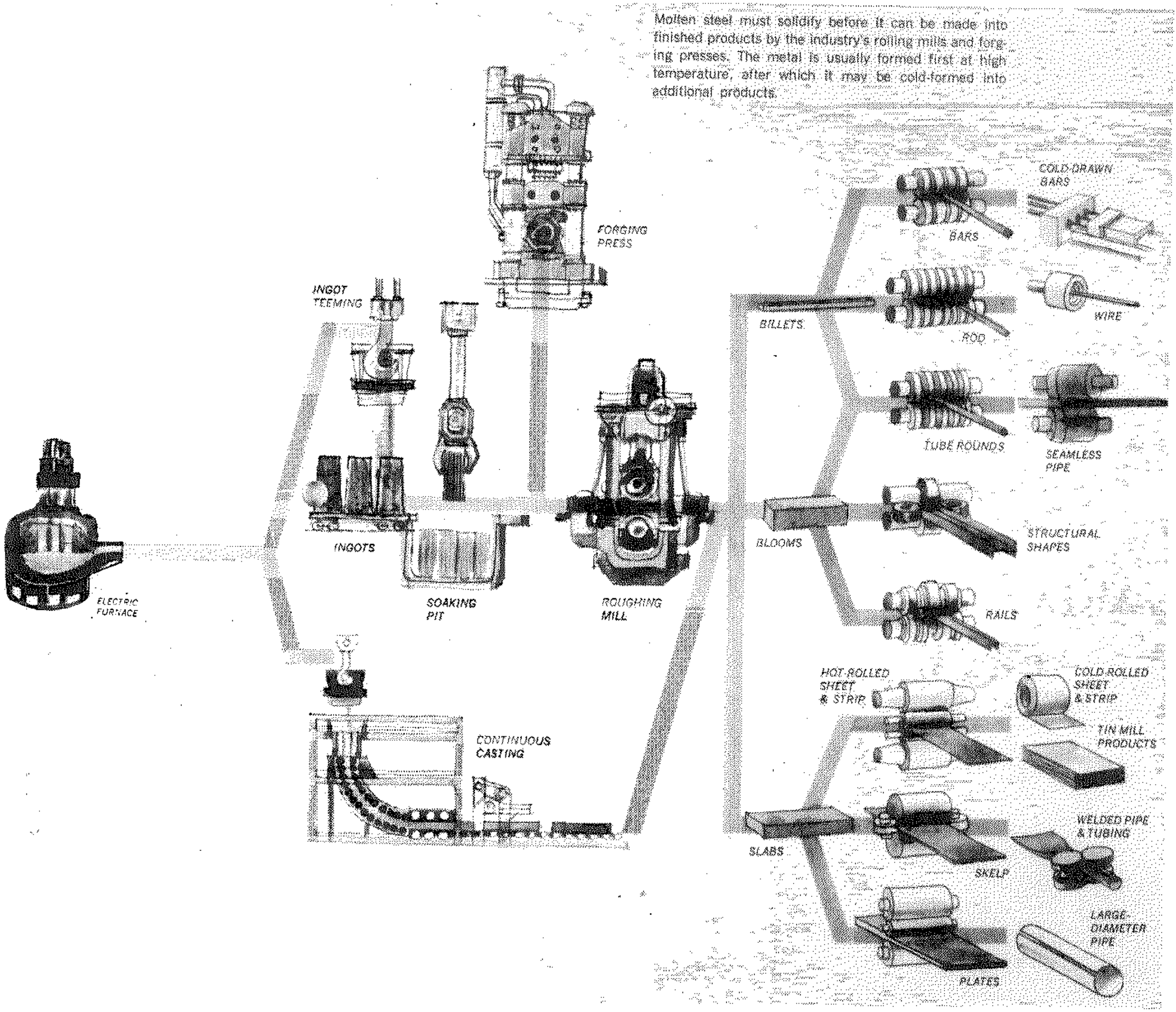

Figure 1.2 Steel Making in Mini Mills(3)

The U. S. imports about 35% of its iron ore needs, mostly from Canada (about one-half of imports) and Venezuela (about one-third of imports). Canadian and Venezuelan ores are mostly high-grade, containing about 60% iron.

In the fifties, ores contained 45% to 50% iron, but the ore deposits that are currently available in the U. S. contain only about 33% iron, and are located primarily in Wisconsin, Minnesota and Michigan (85% of domestic production). Because of their low iron content, over 90% of the domestic ores are beneficiated and agglomerated into pellets or sinter containing 60 - 65% iron. In recent years, as the iron content of the ores decreased, the trend has been to beneficiate and agglomerate the ore into pellets in plants located at the mine so as to decrease transportation costs and provide for simpler disposal of the ore residuals (about 50 - 65% of the crude ore). Pellets are spherical in shape ranging from three-eights to five-eights of an inch in diameter, and have considerable resistance to crushing compared to sinter. They can be transported over large distances to iron and steel plants. Because of its weak structure, sinter must be agglomerated at the plant. In 1973, about 75% of the pig iron made in blast furnaces in the U. S. was produced from agglomerates, of which 62% were pellets. The remaining 25% of the pig iron was produced mainly from imported, high-grade, lumped natural ores.

Coke is the primary fuel used in the blast furnace for the reduction of iron ore into pig iron. It is a relatively nonvolatile carbonaceous residue obtained from distillation of coal in a coke oven at 1650° - 2000°F. An appropriate blend of coals is charged into the oven chamber.

Only certain types of coals can be used to make coke. Coking coals should have ash and sulfur contents of less than 8.1 and 1.3%, respectively. The U. S. has adequate deposits of premium grade bituminous coal suitable for coking, located primarily in Eastern Kentucky, Virginia, and West Virginia. About 80% of the U. S. reserves of coking coal are located in West Virginia and Eastern Kentucky. The average mix for coke making in the U. S. consists of 66% high-volatile, 16% medium-volatile, and 18% low-volatile coals.[4] Deviations from the average mix depends upon local supplies and other factors. An ideal mix is 60% high-volatile and 40% low-volatile coal. High-volatile coals coked alone generally produce porous and weak cokes, unsuitable for use in blast furnaces.

1.3 BLAST FURNACE

In a blast furnace, iron ore is reduced to pig iron by reacting chemically with metallurgical coke. The pig iron exits from the furnace as a hot liquid containing typically 94% iron, 4% carbon, small amounts of silicon, manganese, and phosphorous, and a trace amount of sulfur. The reduction process is the major chemical change occurring in ironmaking and steelmaking, and consumes 60% of the required fuels in the form of metallurgical coke.

A blast furnace is a large shaft 100 to 150 feet high and 25 to 50 feet in diameter. Old blast furnaces (often as old as 50 years) have capacities of 1000 to 2000 tons of pig iron per day while newer and more efficient furnaces have capacities of 5000 to 8000 tons of pig iron per day.

The burden, consisting of agglomerated iron ore, lumped ore, small amounts of scrap, coke, and limestone (to absorb the sulfur and other impurities in the ore), is loaded from the top of the furnace through a bell and hopper or rotating disc arrangement. It forms a bed moving down a length of the furnace. Hot air blast at 1200 to 2000°F is injected into the furnace at the tuyeres (large openings at the side of the furnace located near the bottom), and moves upward, counterflow to the movement of the burden bed. Various hydrocarbons are injected, also at the tuyeres, to improve the performance of the furnace.

Liquid pig iron is tapped from the blast furnace at 2700 to 2800°F every 3 to 5 hours in quantities of from 300 to 600 tons per tap. It is loaded into torpedo-shaped cars which can hold 160 to 200 tons. The torpedo cars transport the liquid pig to the steelmaking area, often about a mile away from the blast furnace, where the pig is dumped into large ladles for transfer to the steelmaking furnaces.

1.4 STEELMAKING

Pig iron and scrap steel are converted into liquid steel in furnaces of the open-hearth (O. H.), the basic oxygen (BOF) or the electric type. Although prior to 1960 the open-hearth furnace was predominant, by 1973 the relative production in the U. S. in each of the three types of furnaces was as follows:[5]

Open Hearth	26.4%
Basic Oxygen	55.2%
Electric	18.4%
	100%

By 1978, O. H. production is expected to be only 15% of total output because the pollution problems and the capital and operating costs of O. H.'s are less favorable than those of BOF's.

1.4.1 Basic Oxygen Furnace

In the BOF, oxygen is injected at high velocities into the molten pig by means of an elaborate water-cooled lance. As a result, carbon, sulfur, and other trace metals in the pig are oxidized thus providing the energy necessary to keep the melt at 2500 to 2900°F and to accommodate up to 30% scrap.

The limitation on the amount of scrap that can be used in a BOF is a disadvantage relative to an O. H., which can process up to 100% scrap. To process the available supply of scrap, integrated plants must increase their electric furnace capacity when O. H.'s are replaced by BOF's.

1.4.2 Electric Furnace

The percentage of steel produced in electric furnaces has gradually increased in the last years, from about 8.5% in 1960 to about 18.4% in 1973. The increase is due primarily to the introduction of BOF's and the resulting need for more scrap processing capacity. The productivity of the furnace is increased by operating at higher electric power levels, by preheating the scrap, and by injecting oxygen.

1.5 STEEL PROCESSING

Steel produced in steelmaking furnaces is processed into a variety of finished products.

The traditional method of producing slabs, blooms, and billets involves a sequence of heating, rolling and blooming operations. Liquid steel from the steelmaking furnace is poured into refractory-lined ladles and then into ingot molds where solidification occurs. The ingots are brought to an equilibrium condition in soaking pits at a temperature of about 2400°F, and then transferred to primary rolling mills. There, they are rolled into slabs and blooms (and then into billets), which are cooled and shipped to secondary mills for further shaping into plates, bars, wire, tubing, etc. Prior to shaping in secondary mills, slabs, blooms or billets are heated to a plastic condition in reheat furnaces.

An alternative process, continuous casting, bypasses the ingot and soaking pit stage of steel processing. During the last 10 years, continuous casting capacity has been steadily increasing because of relatively low capital and operating costs. In 1974, capacity was about 23 million tons or 11% of the total U. S. capacity, and by 1980 it is expected to increase to about 43 million tons or about 25% of the 1980 U. S. capacity.[6] Only about 8% of the raw steel processed in the U. S. in 1974, however, was continuously cast.[7] The difference between continuous-cast capacity and production can be attributed to maintenance and equipment break-in problems and to the fact that not all grades and sizes of steel can be continuously-cast. Nevertheless, in the last five years, almost all new greenfield mini-plants have been equipped with continuous casters. It is noteworthy that about 60% of the continuous casting capacity in the U. S. is installed in integrated plants and about 40% in nonintegrated plants.

2. REVIEW OF MARKET FACTORS

2.1 ECONOMIC AND FINANCIAL CONSIDERATIONS[8]

Since the early 1960's, the steel industry has been experiencing economic and financial difficulties more serious than those of industry in general. It attributes these difficulties to a combination of factors, such as competition from imported steel and steel products, price restrictions ("voluntary" and government imposed), labor problems, and rising labor costs.

For example, the ratio of profits over shareholders' equity has declined from a high of 15.4% in 1955, to 5.3% in 1962, to 8% from 1963 to 1969, and to an average of 5.9% from 1968 to 1973 (Fig. 2.1).

Again, we see from Fig. 2.2 that in the mid-1950's the steel industry was able to finance its own capital investments from its cash flow (net profits after taxes plus depreciation minus cash dividends). During this period, the ratio of debt over equity remained almost constant at about 20% (Fig. 2.3). From 1957 to 1961 and 1964 to 1971, however, capital investments exceeded cash flow and required debt financing. As a result of a relatively high ratio of book value over stock price, the steel industry was unable to finance capital expenditures by equity financing. Thus, the ratio of debt over equity from 1963 to 1974 increased to about 37%, which is a level considerably higher than that of other manufacturers (Fig. 2.3). Most of the capital expenditures during the last decade were made in replacing old and pollution-prone open-hearth steelmaking furnaces with basic oxygen furnaces. Debt financing became necessary because low profits rendered the industry unattractive to investors.

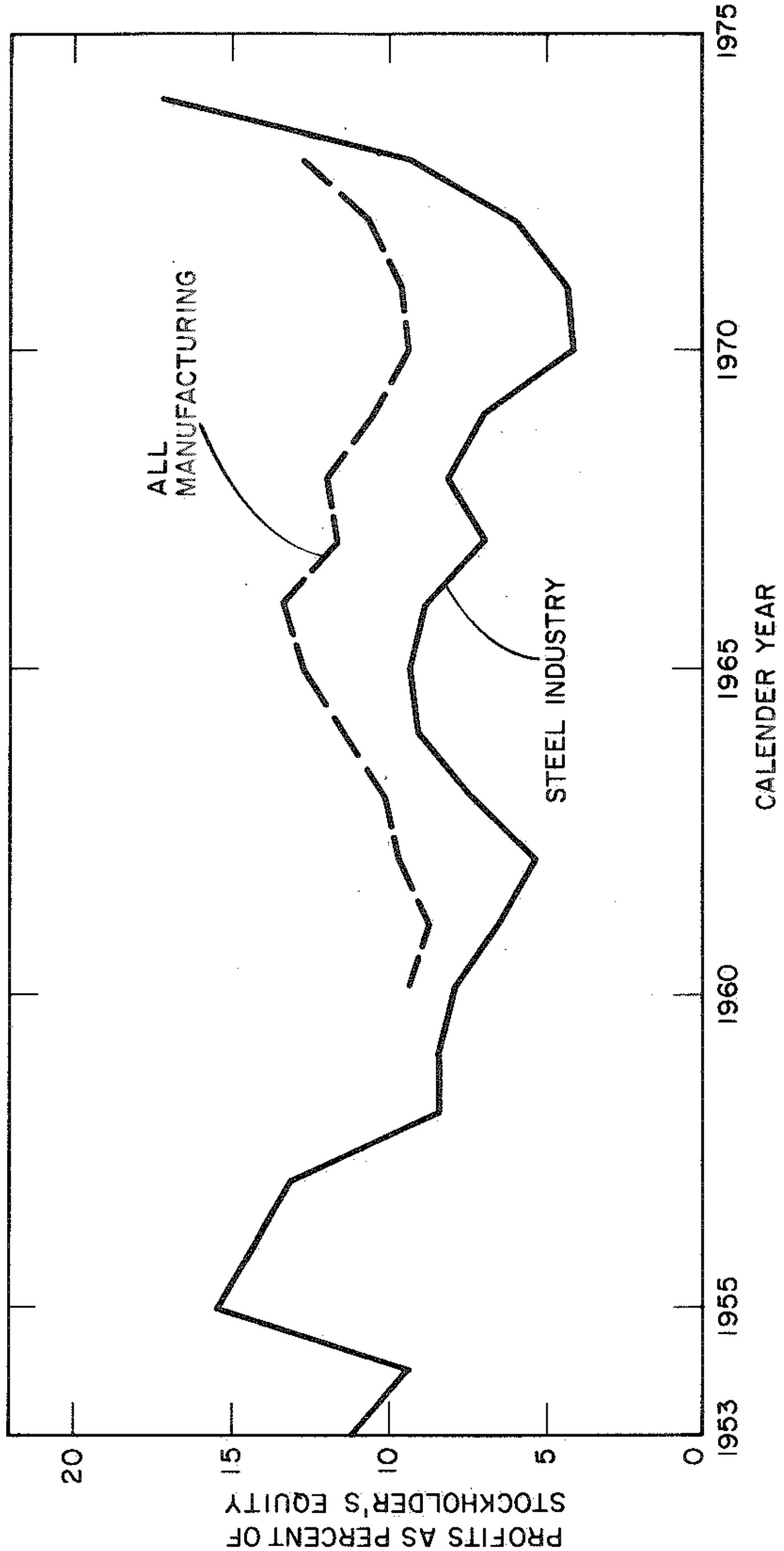

Figure 2.1 Profit to Equity Ratio for Steel Industry from 1953 - 1974

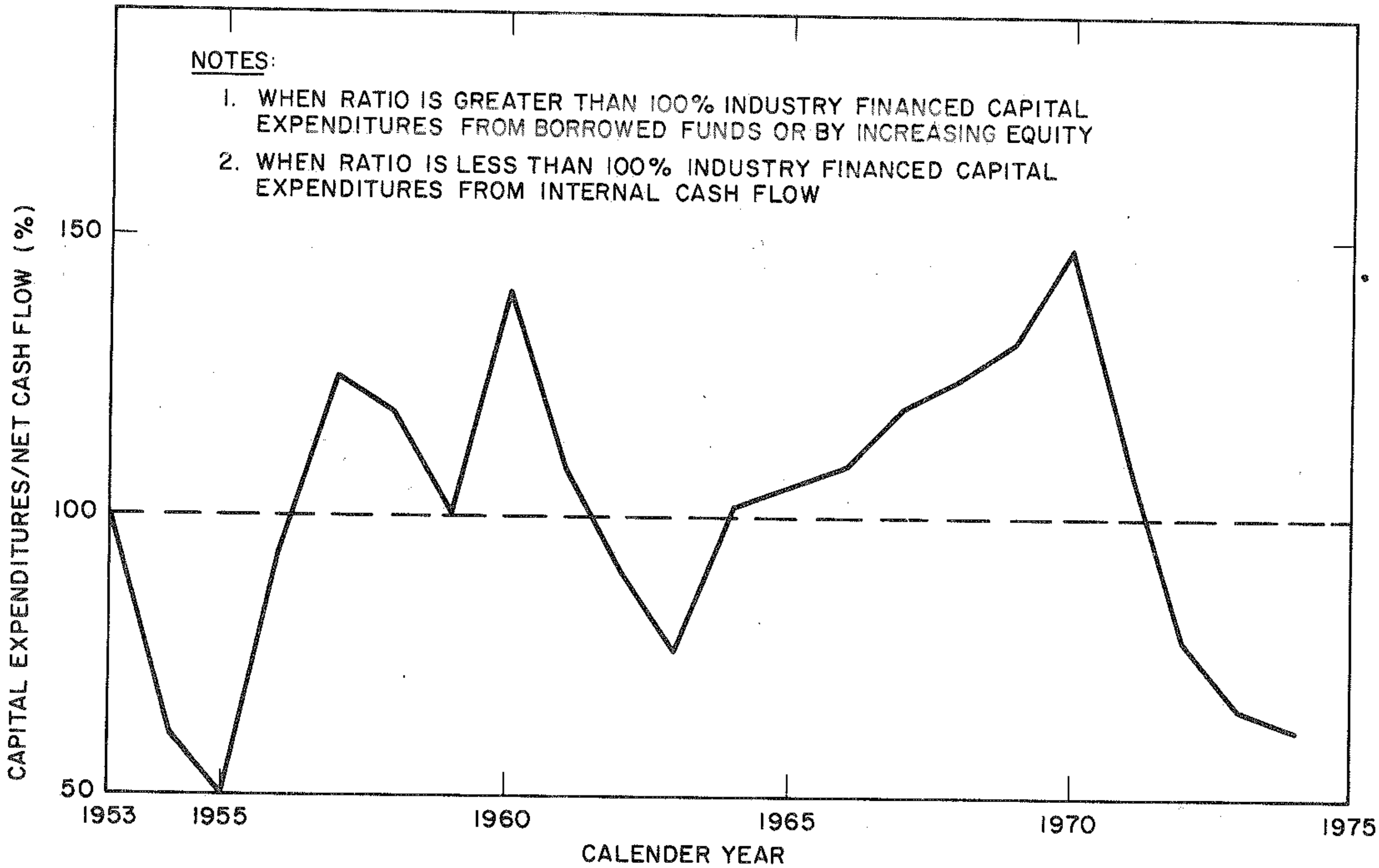

Figure 2.2 Capital Expenditure to Net Cash Flow Ratio for Steel Industry from 1953 - 1974

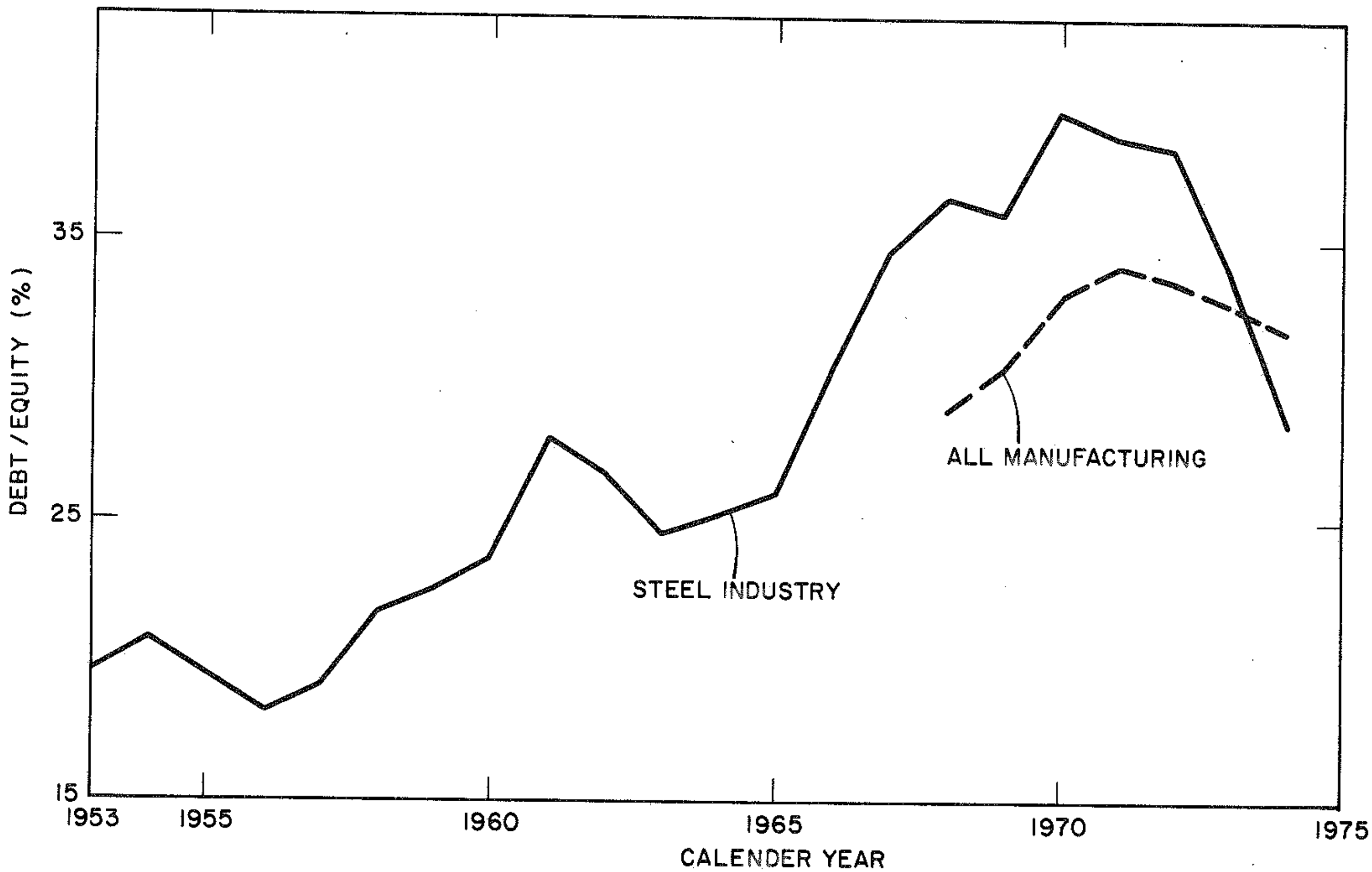

Figure 2.3 Debt to Equity Ratio for Steel Industry from 1953 - 1974

In 1973 profits increased, and in 1974 reached record levels (Fig. 2.1) because price controls were removed and a good international market for steel developed. Although capital expenditures were high, the industry was able to reduce its debt over equity ratio to 28.5% (Fig. 2.3) and to achieve the best financial position since the late 1950's. During the second quarter of 1975, however, things began to change again because of the recession. In July of 1975, production of raw steel dropped to about 55 - 60% of that of July 1974, and total production for 1975 to August 2 was 16.6% lower than that for the same time period in 1974.[9] No doubt profits for 1975 will be considerably lower than those of 1974, although first quarter profits for 1975 were substantial. It is noteworthy that part of the reduction in raw steel production in 1975 resulted from an attempt by the industry to decrease inventories. Expectations are, however, that steel shipments will reach 109 million tons in 1976; approximately the same level as in 1974. Profits are expected to be better in 1976 than in 1975 but not as high as in 1974.

2.2 PROJECTED CAPITAL REQUIREMENTS

In the recent past, capital expenditures were mostly for replacing obsolescent equipment and for installing pollution control equipment, and relatively little for adding capacity. During the next decade, the steel industry will need not only to replace obsolescent equipment and install more pollution control equipment but also to add capacity. As a result, the capital requirements for the foreseeable future will be higher than those of the recent past.

The rate of capital expenditures was about $1.8 billion per year for the decade 1965 - 1974, $2.5 billion for 1974, and $3.6 billion for

1975. Studies performed by the American Iron and Steel Institute[10] (AISI) and Arthur D. Little, Inc.[11] (ADL) project that capital expenditures for replacement of obsolete equipment and additional pollution control and capacity will be at the rate of about $5 billion per year for the decade 1974 - 1983. A study[12] performed for the Council of Wage and Price Stability (CWPS) projects capital expenditures for only additional capacity of about $0.9 billion per year until 1980. The results of these studies are summarized in Table 2.1.

If profits and cash flow were maintained at the 1974 high levels, AISI estimates that about $4 billion per year could be raised for capital expenditures from a combination of internal cash flow and long-term borrowing. At this rate, a capital shortfall of about $1 to $1.5 billion per year would ensue. On the other hand, if profits and cash flow were to regress to the pre-1973 levels, then the shortfall for capital expenditures would be about $3 to $3.5 billion per year. Based on past performance, on the other hand, CWPS concludes that the industry will be able to finance its capital needs.

It is noteworthy that these projections do not include capital expenditures for fuel-saving equipment that can be added to existing plants.

2.3 MAJOR PROBLEM AREAS

According to most projections, during the forthcoming decade the steel industry will face severe problems in financing its capital needs, in providing adequate pollution controls, in securing adequate fuels, in having the right types of fuels, and in procuring raw materials.

TABLE 2.1

PROJECTIONS FOR CAPITAL EXPENDITURES FROM 1975 - 1983*

	Tons Raw Steel 10^6	Cost/Ton $	Total Cost $\$10^9$	Cost/Year $\$10^9$
American Iron and Steel Institute				
New Capacity				
Rounding Out of Existing Facilities	20	350	7.0	
Installation of New Fully Integrated Facilities	10	675	6.75	
			13.75	1.52
Maintaining Present Capacity			18.00	2.00
Pollution Control Equipment			9.00	1.00
Other Miscellaneous Expenses			4.50	0.50
TOTALS			45.25	5.00
Arthur D. Little, Inc.				
New Capacity				
Rounding Out of Existing Facilities	40	400	16.0	1.78
Maintaining Present Capacity			21.0	2.33
Pollution Control Equipment				
Existing Plants			6.5	0.72
New Plants			4.9	0.54
TOTALS			48.4	5.40
Council on Wage and Price Stability				
New Capacity				
Rounding Out of Existing Facilities	15 (to 1980)	300	4.5	0.9

*Expressed in 1975 Dollars

If profits are not maintained consistently at high levels, the industry will not be able to raise sufficient capital either from long term borrowing or from the stock market. As a result, replacement of obsolescent equipment, installation of additional pollution control equipment, and increases in capacity will suffer and the industry will be vulnerable to both Federal Government requirements and foreign competition.

As natural gas resources dwindle, the industry will have to increase its consumption of oil (at least in the near term), maximize the production of coke oven gas as a byproduct of coke manufacture, or invest in coal gasification projects. Thus the natural gas shortage will alter the energy balance within the steel industry, expecially in nonintegrated plants where more than 45% of the fuels consumed are in the form of natural gas (see Sec. 3.1).

As noted in Sec. 1.2, about 35% of the ore consumed in steelmaking is imported. If the import of this ore were to be interrupted, additional capital expenditures would be required for mining and pelletizing low grade taconite ores available in Minnesota and Michigan. Based on $50 per annual ton or ore, it is estimated that about $1.5 billion will be required for increasing the U. S. ore capacity by 30 million tons over the next 10 years.[13]

In addition to the supply of ore, an adequate supply of metallurgical grade coking coal must be maintained. Coal is available in the U. S., but in the future the industry will be competing for it with the electric utilities. All forecasts indicate that procurement of good, low sulfur coal for coking will become more difficult and more expensive.

Foreign competition can be also a significant problem for the future of the industry, especially competition in specialty steels. Imports can significantly erode the profit picture by underselling domestic steel. During the sixties, foreign steel was consistently cheaper than domestic steel. As a result of modernization of domestic plants, high fuel prices in other countries, the dollar devaluation, and large increases in foreign labor costs, domestic and foreign prices are now about the same. Differences between U. S. and imported steels from Japan and other countries range from \$15 to \$50 per ton or roughly $\pm 6\%$ of the price. In the future it is expected that domestic steel will remain competitive with foreign steel as the former is affected less by changes in labor, oil, coal, and iron ore costs than the latter.

Labor problems until recently were a significant factor in the U. S. steel industry, causing short term cyclic conditions in steel demand because of the threat of strikes at the end of a labor agreement. In 1973, however, the industry and the United Steel Workers of America entered into a nationwide no-strike agreement including binding arbitration in case of contract disputes.

Clearly a major challenge for the industry is to accomplish the expansion of facilities, a reduction in pollution, and profitability. In addition, the industry should contribute to the national goal of fuel saving. This goal and its economic implications are discussed in subsequent sections.

3. FUEL CONSUMPTION STATISTICS

3.1 NATIONAL STATISTICS

As discussed in Sec. 1, steel is manufactured in integrated plants from a combination of iron ore and in nonintegrated plants or mini-mills exclusively from scrap. The amounts and forms of fuels per unit of product consumed are different for each type of plant.

Fuel consumptions per ton of product shipped* in 1974 by fuel type and for plants aggregated in various ways are listed in Table 3.1. We see from this table that integrated companies (consisting primarily of integrated plants and to a much smaller degree of nonintegrated plants) consume about 35×10^6 Btu per ton of shipment. The largest fraction of this fuel, about 61%, is in the form of coking coal and merchant coal, and the remainder is made up of 17.2% natural gas, 10.2% purchased electricity (evaluated at 10,000 Btu/kwhr), and 8.1% oil. Coal in the form of coke is consumed in blast furnaces for the reduction of iron ore into pig iron; natural gas and oil are consumed in pelletizing plants, blast furnaces, open hearth furnaces, soaking pits, reheat furnaces, and heat-treating furnaces; and electricity is consumed in electric furnaces, utilities, motor drives, pumps, etc.

We also see from Table 3.1 that nonintegrated plants consume about 22×10^6 Btu per ton of shipment, but here the largest fractions, about 45% each, are in the forms of electricity and natural gas. Electricity is consumed in electric furnaces, and natural gas in steel processing.

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*Statistics available only in terms of tons of steel shipped.

TABLE 3.1

FUELS CONSUMPTION IN U. S. STEEL INDUSTRY FOR 1974

	Metallurgical Coal	Boiler Coal	Other Coal	Natural Gas	Fuel Oils	Electricity Purchased*	Coke	Coke Oven Gas	Tar or Pitch	Other	Total	Amount Shipped** 10^6 tons	% of Total U. S. Shipments
All Survey Companies (10^6 Btu/ton of Shipment) (Percent of Total)	18.26 53.2	0.80 2.3	0.15 0.4	6.43 18.7	2.75 8.0	4.10 11.9	1.86 5.4	0.04 0.1	0.01 -	0.02 -	34.41 100.0	96.9	88.1
Integrated Companies (10^6 Btu/ton of Shipment) (Percent of Total)	19.63 55.9	0.83 2.4	0.16 0.5	6.04 17.2	2.83 8.1	3.56 10.1	1.99 5.7	0.05 0.1	0.01 -	0.01 -	35.11 100.0	90.1	81.9
Cold Metal Companies (10^6 Btu/ton of Shipment) (All) (Percent of Total)	- -	0.38 1.6	0.01 -	11.68 46.5	1.75 7.0	11.24 44.9	0.10 -	0.04 -	- -	- -	25.2 100.0	6.78	6.2
Cold Metal Companies (10^6 Btu/ton of Shipment) (Carbon Steel) (Percent of Total)		0.14 0.7	0.01 -	8.21 43.8	1.58 8.4	8.72 46.5	0.12 0.6	- -	- -	- -	18.78 100.0	5.19	4.7
Cold Metal Companies (10^6 Btu/ton of Shipment) (Alloy and Stainless Steel) (Percent of Total)		1.17 2.5	0.01 -	22.95 49.8	2.28 5.0	19.53 42.5	0.01 -	0.10 0.2	- -	- -	46.05 100.0	1.59	1.5

Note: *Kwhr = 10,000 Btu

**Adjusted for depletion of inventories

Fuel consumption per unit of product is influenced by availability of fuels, technological changes, and level of production compared with installed capacity. These points are illustrated by the industry-wide data shown in Fig. 3.1 for the period 1960 - 1973. For example, we see from this figure that in response to shortages the industry reduced natural gas consumption by 15% from 1971 to 1973, and replaced it with oil. Again, the replacement of open hearth (O. H.) furnaces with basic oxygen furnaces (B. O. F.) resulted in decreased oil consumption in the late 1960's. The amount of electricity per ton of steel, however, increased because the curtailed use of O. H.'s requires installation of electric furnaces to process the available scrap. Again, from 1965 to 1973 the installed raw steel capacity was approximately constant at about 130 - 140 million tons per year. In 1971, when the industry was operating at about 80% of full capacity, the fuel consumption was about 28×10^6 Btu/ton of raw steel. In 1973, when the industry was operating at 97% of full capacity, the fuel consumption was about 25.5×10^6 Btu/ton of raw steel or 10% less than that of 1971. This point is better illustrated by Fig. 3.2 which shows the specific fuel consumption vs. U. S. raw steel production.

3.2 REGIONAL STATISTICS

The location of a plant can affect the amounts and types of fuels consumed in the plant because of availability and cost of raw materials and fuels. Regional statistics, however, are neither detailed nor consistent to permit full discussion of the effects.

Some statistics on pig iron and steel productions in 1973 by state are reported by the American Iron and Steel Institute and are listed in

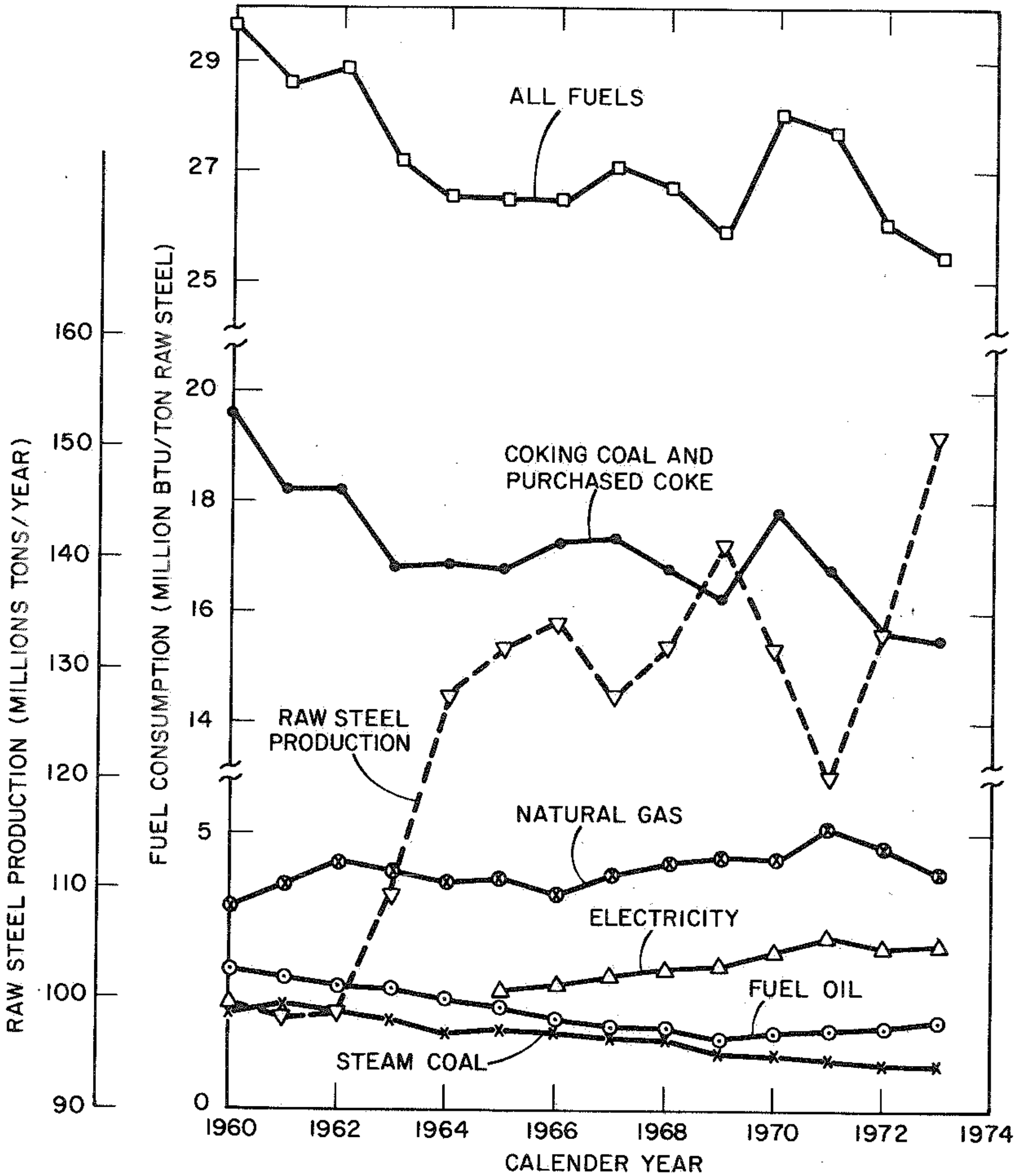

Figure 3.1 Fuel Consumption and Raw Steel Production Trends All Industry 1960 - 1973 (15)

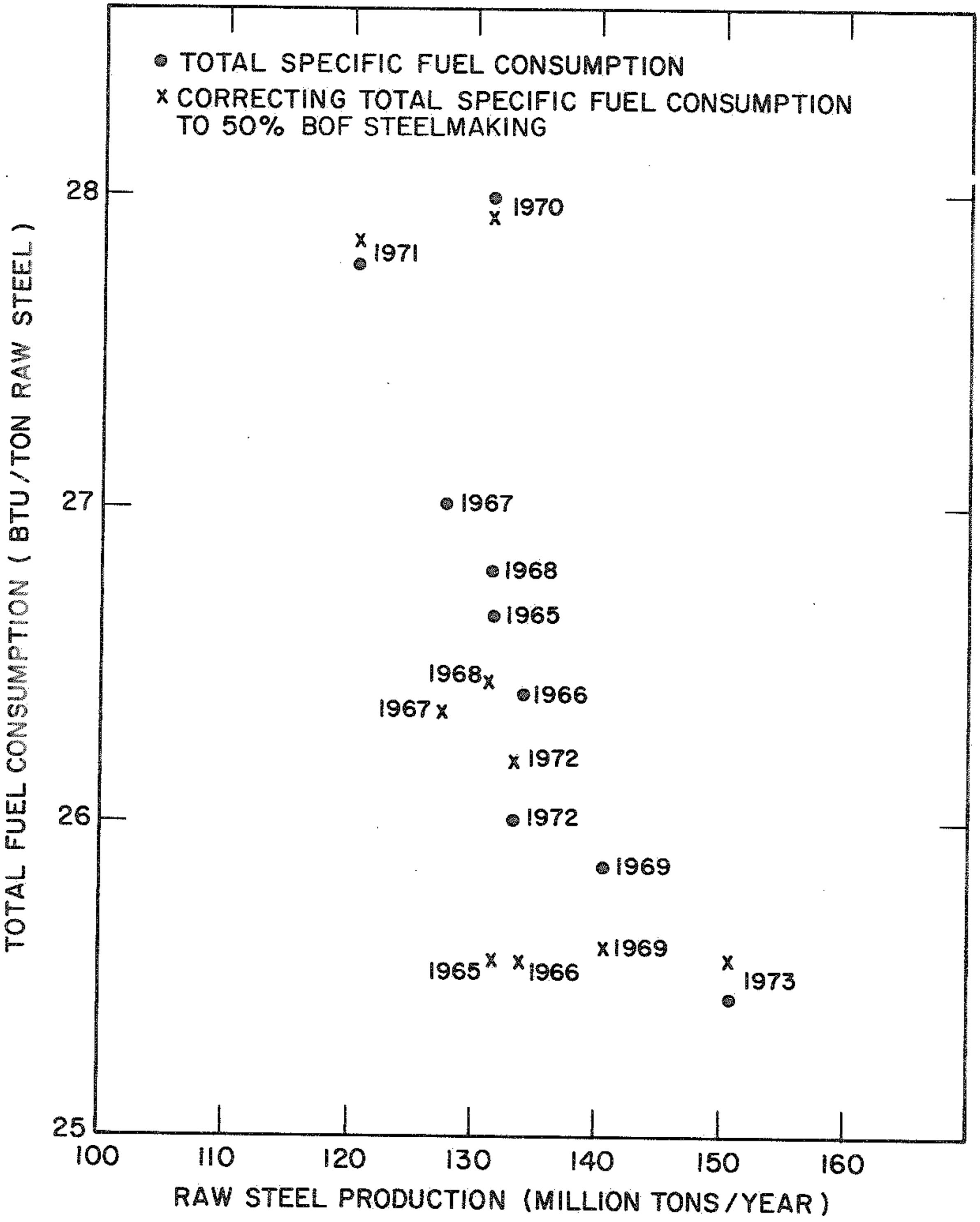

Figure 3.2 Correlation Between Specific Fuel Consumption and Raw Steel Production for 1965 - 1973

the last two columns of Table 3.2. These statistics cannot be disaggregated, however, to determine rates of production in integrated and nonintegrated plants.

Estimates of plant capacities by state have been published by the Institute of Iron and Steel Studies. These estimates can be used to calculate integrated and nonintegrated plant capacities by state. The results are listed in the first and second columns of Table 3.2. The total capacity that results from these data, however, is about 20% higher than that reported by AISI.

If we assume that the relative capacities of integrated vs. nonintegrated plants are correct although the total capacities are overestimated, then some conclusions can be drawn. Specifically, we see from Table 3.2 that Pennsylvania, Ohio, and Indiana are the three primary steel producing states with about 53% of the national capacity, and that Illinois, Michigan, Maryland, and New York are the next largest producers with about 28% of the national capacity. Most of these plants are integrated. About two-thirds of the nonintegrated capacity is in Pennsylvania, Ohio, Illinois, Texas, and California.

Detailed correlations of fuel consumptions by state and plant locations are difficult because of lack of detailed statistics and interchange of fuels between plants. For example, coke made in the U. S. Steel plants in Claiton, Pennsylvania is shipped to U. S. Steel plants in Ohio and other states.

3.3 BYPRODUCT ELECTRICITY

Of special interest to the purposes of this study is the amount of electricity generated in steel plants as byproduct of process steam

TABLE 3.2

REGIONAL PLANT CAPACITIES AND PRODUCTION OF IRON AND STEEL

Region State	Integrated (17) Mill Capacity 10^6 tons	Nonintegrated (17) Mill Capacity 10^6 tons	Raw Steel (16) Production (1973) 10^6 tons	Pig Iron (16) Production (1973) 10^6 tons
New England				
Connecticut	-	0.25		
Rhode Island	-	0.12		
Totals	-	0.37		
Middle Atlantic				
New York	7.00	0.52	6.401	5.397
New Jersey	-	0.50	D	
Pennsylvania	32.80	9.65	33.925	22.646
Totals	39.80	10.67	D	D
E. North Central				
Ohio	29.66	4.36	26.510	18.391
Indiana	27.50	0.63	23.622	17.128
Illinois	13.65	3.99	13.428	7.902
Michigan	13.05	0.54	10.945	8.006
Totals	83.86	9.52	74.505	51.427
W. North Central				
Iowa	-	0.15	D*	D
Missouri	-	0.90	D	D
Totals	-	1.05	D	D
Southern - 1				
Maryland	9.50	0.30	D	D
Delaware	-	0.50	D	D
Virginia	-	0.34	D	D
West Virginia	3.50	0.15	D	D
Totals	13.00	1.29	D	D
Southern - 2				
Alabama	5.5	0.34	D	3.817
Kentucky	2.0	0.81	2.699	D
Louisiana	-	0.10	D	D
Mississippi	-	0.18	D	D
North Carolina	-	0.32	D	D
Florida	-	0.42	D	D
South Carolina	-	0.68	D	D
Tennessee	-	0.22	D	D
Totals	7.5	3.07	D	D
Southwest				
Arizona	-	0.18	D	D
Oklahoma	-	0.30	D	D
Texas	3.0	2.0	D	D
Totals	3.0	2.48	D	D
Pacific and Mountain				
California	3.8	2.21	4.479	D
Colorado	1.5	-	D	D
Hawaii	-	0.05	D	D
Oregon	-	0.53	D	D
Utah	2.5	-	D	D
Washington	-	0.74	D	D
Totals	7.8	3.53	D	D
U.S. TOTALS	155.0	31.98	150.799	100.837

NOTE:

*D - Disclosure

raising equipment. The rate at which byproduct electricity was generated as a fraction of total electricity requirements vs. time is shown in Fig. 3.3. We see from this figure that the average fraction of byproduct electricity has been declining from about 35% in 1960 to about 20% in 1973. Data on regional distribution of byproduct vs. purchased electricity are listed in Table 3.3. We see from this table that Pennsylvania, South (1), and Pacific and Mountain regions generate a larger fraction of their electrical needs as byproduct than the average national fraction. In general, because their process steam requirements are large and their electricity needs small, integrated plants can generate relatively more byproduct electricity than nonintegrated plants and, in addition, consume less total electricity per ton of product. The opportunities for increased generation of electricity in both integrated and nonintegrated mills are discussed in Section 5.

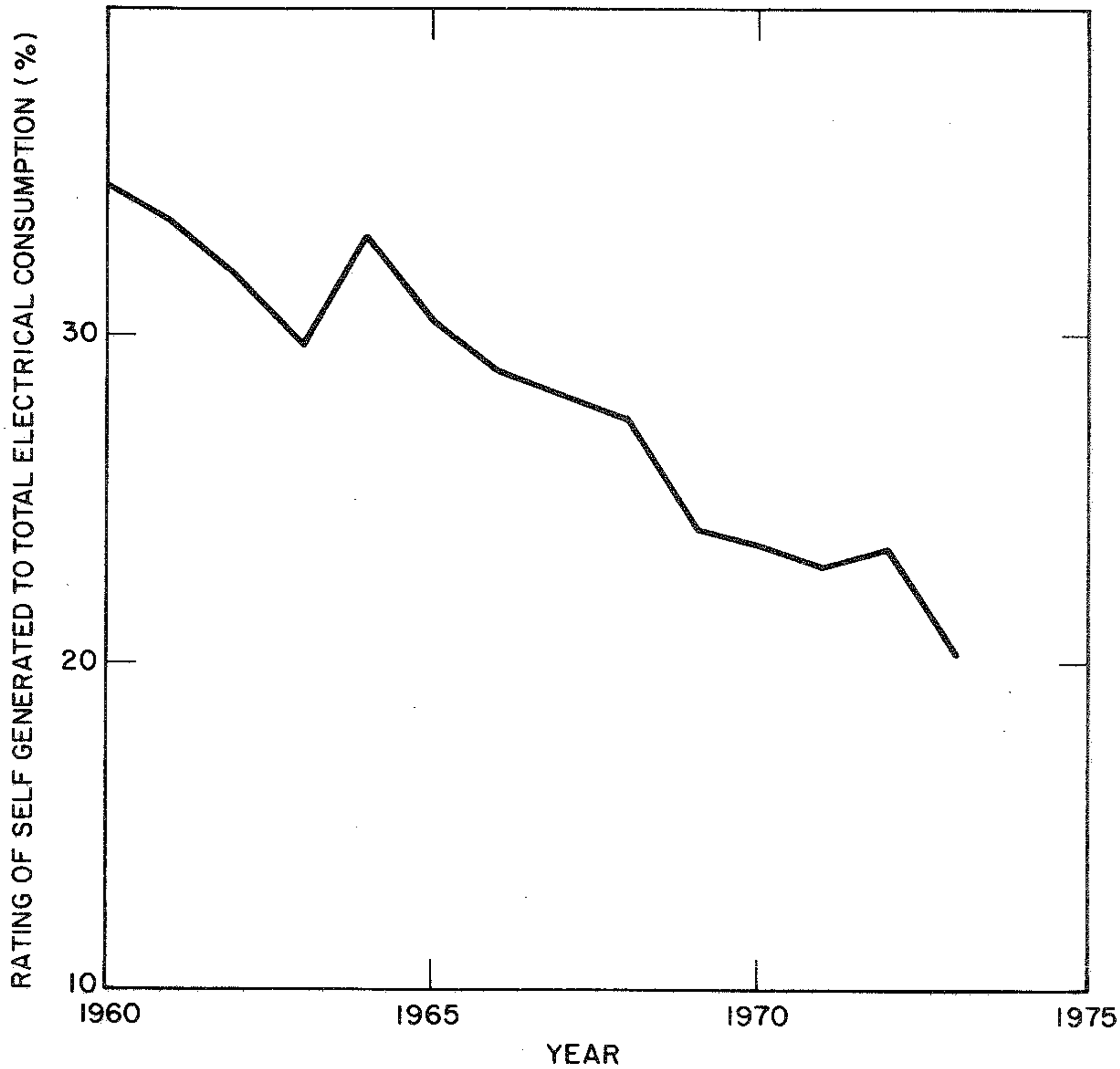

Figure 3.3 Trends in Self Generated Electricity [18]

TABLE 3.3

REGIONAL DISTRIBUTION OF SELF-GENERATED AND PURCHASED ELECTRICITY(19)

Region State	Self-Generated Electricity 10^6 kwhr	Purchased Electricity 10^6 kwhr	Total Electricity 10^6 kwhr	Percent Self-Generated 10^6 kwhr
New England				
Connecticut	-	193	193	0
Rhode Island	-	D	-	-
Totals	-	289	289	0
Middle Atlantic				
New York	223	1,674	1,897	11.8
New Jersey	-	205	205	0
Pennsylvania	3,675	10,984	14,659	25.1
Totals	3,898	12,863	16,761	23.3
E. North Central				
Ohio	668	8,188	8,856	7.5
Indiana	2,913	5,226	8,139	35.8
Illinois	549	5,084	5,633	9.7
Michigan	459	2,795	3,254	14.1
Totals	4,589	21,293	25,882	17.7
W. North Central				
Iowa	-	D*	D	0
Missouri	-	D	D	0
Totals	-	956	956	0
Southern - 1				
Maryland	D	D		
Delaware	-	D		
Virginia	-	D		
West Virginia	D	D		
Totals	648	2,477	4,125	40.0
Southern - 2				
Alabama	351	1,355	1,706	20.6
Kentucky	-	896	896	0
Louisiana	-	D		
Mississippi	-	D		
North Carolina	-	D		
Florida	-	212	212	0
South Carolina	-	D		
Tennessee	-	624	624	0
Totals	351	3,766	4,117	8.5
Southwest				
Arizona	D	D	D	D
Oklahoma	D	D	D	D
Texas	D	1,566	D	D
Totals	D	1,865	D	D
Pacific and Mountain				
California	-	1,751	1,751	0
Colorado	D	D	D	D
Hawaii	-	D	D	0
Oregon	-	D	D	0
Utah	D	D	D	D
Washington	-	370	370	0
Totals	812	2,422	3,234	25.1
U. S. TOTALS	11,569	45,931	57,500	20.1

NOTE: *D - Disclosure

4. MAJOR FUEL CONSUMPTION PROCESSES AND POTENTIAL OPPORTUNITIES FOR FUEL SAVING

4.1 ENTHAPLY AND AVAILABLE USEFUL WORK BALANCES

In order to identify the major fuel consumption processes in iron and steel manufacturing, we have performed an industry-average enthalpy balance using 1973 as a reference year. The results are listed in Table 4.1, including enthalpies of purchased and byproduct fuels and enthalpies of processed materials. In calculating enthalpies of raw materials, we have assumed that hematite ore (Fe_2O_3) represents the zero-enthalpy standard state, and, for simplicity, we have assigned to scrap the same enthalpy as that of raw steel, namely 6.3×10^6 Btu/ton of raw steel. Electricity is accounted for at the rate of 10,000 Btu/kwhr. In addition, the same data are listed in Tables 4.2 to 4.7 for each of the unit operations in iron and steelmaking. Tables 4.2 to 4.7 include the enthalpies and available useful works* of the flowing fuels and materials. Available useful works are necessary for the evaluation of the effectiveness of fuel utilization in each unit operation and for the identification of the steps which introduce the major inefficiencies in the overall manufacturing process.

The data in Table 4.1 are summarized in Table 4.8. We see from this table that the major fuel consumptions occur in the blast furnace (70%), in steelmaking (5%), and in steel processing (21%).

A brief discussion of the data for each unit operation follows.

*For definitions of available useful work and effectiveness see "The Fuel Shortage and Thermodynamics," by Keenan, Gyftopoulos, and Hatsopoulos, in "Energy," edited by M. Macrakis, MIT Press (1973).

TABLE 4.1

ENERGY BALANCE FOR STEEL INDUSTRY IN 1973

Unit Operation	Fuels Consumed: Purchased Fuels Consumed: Coal	Purchased Fuels Consumed: Purchased Coke	Purchased Fuels Consumed: Natural Gas	Purchased Fuels Consumed: Fuel Oil	Purchased Fuels Consumed: Hydro and Nuclear	Product Fuels Consumed: Coke	Byproduct Fuels Consumed: Coke Breeze	Byproduct Fuels Consumed: Coke Oven Gas	Byproduct Fuels Consumed: Blast Furnace Gas	Byproduct Fuels Consumed: Tar and Pitch	Utilities Consumed: Electrical	Utilities Consumed: Steam	Utilities Consumed: O_2	Process Fuels Produced: Met Coke	Byproduct Fuels Produced: Coke Breeze	Byproduct Fuels Produced: Blast Furnace Gas	Byproduct Fuels Produced: Coke Oven Gas	Byproduct Fuels Produced: Tar and Pitch	Byproduct Fuels Produced: Steam	Fuels Consumed in Process	Enthalpy of Steel, Scrap, Pig, or Ore: In	Enthalpy of Steel, Scrap, Pig, or Ore: Out	Energy Lost in Process	Process First Law Efficiency
	10^6 Btu/ton Raw Steel																							Percent
Ore Preparation																								
Pelletizing	-	-	0.15	0.13	-	-	-	-	-	-	0.15	-	-	-	-	-	-	-	-	0.43	0.27	0	0.70	0
Sinter Plant	0.10	-	0.02	-	-	-	0.40	0.02	-	-	0.04	0.03	-	-	-	-	-	-	-	0.61	0	0	0.61	0
Coke Manufacture (Coke Ovens)	14.76	-	-	0.01	-	-	-	0.96	0.19	-	0.02	0.42	-	9.45	0.68	-	3.22	0.30	-	2.71	na	na	2.71	0.83
Ironmaking (Blast Furnace)	-	0.68	0.22	0.39	-	9.45	-	0.04	1.08	0.10	0.03	0.98	0.01	-	-	4.41	-	-	-	8.57	0	5.53	3.04	0.77
Steelmaking																								
Open Hearth	-	-	0.30	0.35	-	-	-	0.04	-	0.16	0.05	0.08	0.02	-	-	-	-	-	0.24	0.76	2.23	1.98	1.01	0.69
Basic Oxygen	-	-	-	-	-	-	-	-	-	-	0.05	0.02	0.07	-	-	-	-	-	-	0.14	4.80	4.14	0.80	0.84
Electric	-	-	-	-	-	-	-	-	-	-	0.34	-	-	-	-	-	-	-	-	0.34	1.16	1.38	0.12	0.92*
Steel Processing																								
Soaking Pit-Primary Rolling	-	-	0.57	0.11	-	-	-	0.21	0.03	-	0.09	-	-	-	-	-	-	-	-	1.01	6.9	5.8	2.11	0
Continuous Casting	-	-	0.02	-	-	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	0.03	0.6	0.5	0.13	0
Reheat Furnace - Secondary Rolling	-	-	1.51	0.31	-	-	-	0.75	0.04	-	0.30	0.25	-	-	-	-	-	-	-	3.16	6.3	6.3	3.16	0
Heat Treating and Finishing	-	-	0.50	0.09	-	-	-	0.26	0.02	-	0.16	0.80	-	-	-	-	-	-	-	1.83	6.3	6.3	1.83	0
Materials Handling	-	-	-	-	-	-	-	-	-	-	0.07	-	-	-	-	-	-	-	-	0.07	na	na	0.07	na
Industry Sub-Totals	14.86	10.13	3.29	1.39	0	9.45	0.40	2.28	1.36	0.26	1.31	2.58	0.10	9.45	0.68	4.41	3.22	0.30	0.24	19.66	2.93	6.3	16.29	na
In-Plant Steam and Electricity Generation	0.70	-	1.09	0.32	-	-	-	0.72	1.06	0.04	0.26	2.34	-	-	-	-	-	-	-	1.33	na	na	1.33	0.66
Industry Totals with In-Plant Utilities	15.56	10.13	4.38	1.71	0	9.45	0.4	3.0	2.42	0.30	1.05	0	0.10	9.45	0.68	4.41	3.22	0.30	0.24	20.99	na	na	17.62	na
Unaccounted for Byproduct Fuels	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.49	na	na	2.49	na
Purchased Utilities																								
Purchased Electricity	1.28	-	0.67	0.51	0.58	na	-	-	-	-	1.05	na	na	-	-	-	-	-	-	1.99	na	na	1.99	na
Purchased O_2	0.12	-	0.06	0.05	0.05	na	-	-	-	-	na	na	0.10	-	-	-	-	-	-	0.18	na	na	0.18	na
Energy Increase of Steel in Manufacture (6.3 - 2.97)	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	3.37	na
Totals for Industry and All Utilities	16.96	0.68	5.11	2.20	0.63	na	-	-	-	-	na	na	na	-	-	-	-	-	-	25.65	2.93	6.3	25.55	0.222

*Efficiency is 31% with electricity evaluated at 10,000 Btu/kwhr   Coke used in iron making (purchased as metallurgical coal)

na - not applicable

TABLE 4.2

ENTHALPY AND AVAILABLE USEFUL WORK BALANCE IN ORE PREPARATION

	Enthalpy 10^6 Btu/ton Pellet	Available Useful Work
Pelletizing		
Natural Gas	0.33	0.30
Fuel Oil	0.29	0.28
Total Fuels	0.62	0.58
Electricity	0.97	0.32
Total Fuels and Utilities	1.59	0.90
Sintering		
Coal	0.35	0.35
Natural Gas	0.07	0.06
Coke Breeze	1.39	1.39
Coke Oven Gas	0.07	0.06
Total Fuels	1.88	1.86
Electricity	0.41	0.14
Steam	0.10	0.04
Total Fuel and Utilities	2.39	2.04

TABLE 4.3

ENTHALPY AND AVAILABLE USEFUL WORK BALANCE FOR COKE OVENS

(All Units 10^6 Btu/ton coke)

	Enthalpy	Available Useful Work
Purchased Fuels Consumed		
Coal	39.03	39.11
Underfire Fuel Oil	0.03	0.03
Byproduct Fuels Consumed		
Underfire Coke Oven Gas	2.54	2.29
Underfire Blast Furnace Gas	0.50	0.45
Utilities Consumed		
Electricity	0.15	0.05
Steam	1.10	0.42
Total Fuels and Utilities Consumed	43.35	42.35
Process Fuel Produced		
Coke	24.99	25.04
Byproduct Fuels Produced	11.11	9.99
Total Process and Byproduct Fuels Produced	36.10	35.03
Lost in Process	7.15	7.32
Process Effectiveness		83%

TABLE 4.4

ENTHALPY AND AVAILABLE USEFUL WORK BALANCE FOR BLAST FURNACE

(All Units 10^6 Btu/ton Pig Iron)

	Enthalpy	Available Useful Work
Process Fuels Consumed		
Inplant Coke	14.08	14.11
Purchased Fuels Consumed		
Merchant Coke	1.01	1.01
Injectants		
Natural Gas	0.33	0.30
Fuel Oil	0.58	0.56
Byproduct Fuels Consumed		
Injectants		
Coke Oven Gas	0.06	0.05
Tar Pitch	0.15	0.15
Blast Stove		
Blast Furnace Gas	1.61	1.50
Utilities		
Electricity	0.15	0.05
Steam	1.46	0.65
Oxygen	0.01	-
Total Fuels and Utilities	19.44	18.38
Byproduct Fuels Produced		
Blast Furnace Gas	6.57	5.9
Raw Material Output	8.25	7.85
Lost in Process	4.62	4.63
Process Effectiveness		75%

TABLE 4.5

ENTHALPY AND AVAILABLE USEFUL WORK BALANCE FOR BASIC OXYGEN FURNACE

(All Units 10^6 Btu/ton Raw Steel)

	Enthalpy	Available Useful Work
Fuels Consumed	0.0	0.0
Utilities Consumed		
Electricity	0.27	0.09
Steam	0.04	0.01
Oxygen	0.13	0.04
Total Fuels and Utilities Consumed	0.44	0.14
Scrap Input	2.03	1.93
Pig Iron Input	6.65	6.33
Total Fuels, Utilities, Raw Materials	9.12	8.40
Hot Raw Steel Output	7.50	7.14
Lost in Process	1.62	1.26
Process Effectiveness		85%

TABLE 4.6

ENTHAPY AND AVAILABLE USEFUL WORK BALANCE FOR OPEN HEARTH FURNACE

(All Units 10^6 Btu/ton Raw Steel)

	Enthalpy	Available Useful Work
Purchased Fuels		
Natural Gas	1.14	1.03
Fuel Oil	1.33	1.29
Byproduct Fuels		
Coke Oven Gas	0.15	0.14
Tar and Pitch	0.61	0.61
Utilities		
Electricity	0.57	0.19
Steam	0.30	0.10
Oxygen	0.08	0.02
Total Fuels and Utilities	4.18	3.38
Scrap Input	3.8	3.62
Pig Iron Input	4.6	4.38
Total Fuels, Utilities and Raw Materials	12.58	11.38
Hot Raw Steel Output	7.5	7.14
Byproduct Steam Output	0.91	0.31
Total Product Output	8.41	7.45
Lost in Process	4.17	3.93
Process Effectiveness		65%

TABLE 4.7

COMPARISON OF INDUSTRY-WIDE ENTHAPY AND AVAILABLE USEFUL WORK

REQUIREMENTS FOR SOAKING PIT - PRIMARY ROLLING AND CONTINUOUS CASTING

	Soaking Pit - Primary Rolling x 10^6 Btu/ton Raw Steel		Continuous Casting x 10^6 Btu/ton Raw Steel	
	Enthalpy	Available Useful Work	Enthalpy	Available Useful Work
Purchased Fuels				
Natural Gas	0.62	0.56	0.25	0.22
Fuel Oil	0.12	0.12	-	
Byproduct Fuels				
Coke Oven Gas	0.23	0.21	-	
Blast Furnace Gas	0.03	0.03	-	
Total Fuels	1.00	0.92	0.25	0.22
Utilities				
Electricity	0.29	0.10	0.20	0.07
Total Fuels and Utilities	1.29	1.02	0.45	0.29
Average Product Yield	85%		95%	

TABLE 4.8

FUELS CONSUMED IN IRON AND STEELMAKING

Unit Operation	Purchased Fuels		Byproduct Fuels		Total Purchased and Byproduct Fuels		Utilities		Total Purchased Byproduct Utilities	
	10^6 Btu/ton Raw Steel	Percent	10^6 Btu/ton Raw Steel	Percent	10^6 Btu/ton Raw Steel	Percent	10^6 Btu/ton Raw Steel	Percent	10^6 Btu/ton Raw Steel	Percent
Ore Preparation	0.4	1.6	0.42	5.7	0.82	2.5	0.22	5.5	1.04	3.7
Coke Manufacture and Ironmaking	16.06	62.6	2.37	32.1	18.43	55.8	1.46	36.6	19.89	69.8
Steelmaking	0.65	2.5	0.20	2.7	0.85	2.6	0.63	15.8	7.48	5.2
Steel Processing	3.11	12.1	1.31	17.8	4.42	13.4	1.61	40.4	6.03	21.1
Materials Handling	-	-	-	-	-	-	0.07	1.7	0.07	0.2
Sub-Total									34.51	100.0
In-Plant Utilities	2.11	8.2	1.82	24.7	3.93	11.9	na	na	na	na
Purchased Utilities	3.32	13.0	na	na	3.32	10.0	na	na	na	na
Unaccounted for Fuels	na	na	1.25	17.0	1.25	3.8	na	na	na	na
Totals	25.65	100.0	7.37	100.0	33.02	100.0	3.99	100.0	na	na

Percent Purchased Fuels/
Total Purchased, Plus Byproduct Fuels 77.7%

Percent Byproduct/
Total Purchased Plus Byproduct Fuels 22.3%

NOTES: *Utilities evaluated at 3413 Btu/kwhr
na - not applicable

4.1.1 Ore Preparation

We see from Table 4.2 that pelletizing consumes about 1.6×10^6 Btu/ton of pellet whereas sintering consumes about 2.4×10^6 Btu/ton of sinter. Most of these consumptions are for motive power and only a small fraction (about 0.6×10^6 Btu/ton) appears as sensible heat in the pellets or the sinter which leaves the process at about 2400°F. In pelletizing processes some of this heat is recovered. Technologies for heat recovery in ore preparation are discussed later.

It is noteworthy that pelletizing occurs at the ore mine and consumes oil, natural gas,* and electricity. On the other hand, sintering occurs at the steel mill site, and consumes coal, coke breeze (a by-product of coke ovens), and electricity; in other words, by virtue of its location pelletizing consumes premium fuels whereas sintering consumes byproduct fuels.

A new pelletizing installation with a grate kiln fired by western coal has been demonstrated. It was designed by Dravo and Lurgi Chemie.[20] If this installation proves viable, pelletizing will have a clear advantage over sintering both from the point of view of energy conservation and use of more abundant fuels.

4.1.2 Coking

Coke is manufactured in coke ovens usually located at the steel-plant site and consisting of batteries of 30 to 40 slot ovens. The coal blend is charged into the oven chamber. Combustion air is heated in

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*Recently the trend has been to use more oil because of the natural gas shortage.

brick regenerators and mixed with under-fire fuels, mostly coke oven gases, for burning in the combustion chamber. The flue gases from the combustion chamber are fed to the regenerator for preheating of the combustion air. The oven charge is heated for about 16 hours until the skin temperature reaches 1900 - 2000°F. Then, the coke is pushed out of the slot into cars where it is water-quenched to prevent combustion. In addition to coke, the ovens produce coke oven gas (a mixture of H_2 and CH_4 with a heating value of about 500 Btu/ft^3), coke breeze, tars, lights oils, and aromatics.

Because of the recovery of large quantities of byproduct fuels, coke ovens are relatively effective devices. Their effectiveness is 83% (Table 4.3). The major losses are in the form of sensible heats of coke, and coke oven and stack gases.

4.1.3 Ironmaking

Pig iron is made in the blast furnace which is the largest consumer of energy in iron and steelmaking. Coke is the major fuel and also the reducing agent for converting ore into pig iron. In recent years, the coke rate (lb coke/lb pig iron) has been reduced significantly as injection of hydrocarbons into the tuyeres in the lower portion of the furnace has increased and as furnaces have been upgraded to provide air blast at higher pressures and temperatures.

The blast furnace per se is an effective unit operation. We see from Table 4.4 that its effectiveness is 75% (13.75/18.38). In addition to pig iron, the blast furnace produces a low-Btu gas (~95 Btu/ft^3) consisting mainly of CO and N_2. After cleaning and conditioning, the blast furnace gas is used as a fuel in air-blast stoves, in boilers, and in direct combustion furnaces. Nevertheless, part of the effectiveness of the blast furnace is lost because a substantial fraction of the sensible heat of the outputs from the furnace is not recovered.

4.1.4 Steelmaking

In 1973, 55% of steel was made in basic oxygen furnaces (BOF), 27% in open hearth furnaces (O. H.), and 18% in electric furnaces.

In BOF's the required energy is supplied by oxidation of carbon, silicon, and trace materials in the hot metal. This energy heats the pig iron to about 2800°F and melts the scrap which can be up to 30% of the charge.

We see from Table 4.5 that the effectiveness of the BOF is 85%. The largest loss occurs from the gases generated during oxygen blowing (about 1/3 of the cycle of 60 minutes). Though they contain up to 90% CO at 2300°F (heating value about 290 Btu/ft^3), these gases are flared and not recovered. The loss amounts to about 0.75×10^6 Btu/ton of raw steel (0.6 chemical and 0.15 sensible heat).

The open hearth consumes oil and natural gas. It is a reverberatory furnace in that it is top-fired. Its flue gases are passed through checkered regenerators in which combustion air is preheated to 1000° - 1500°F, and then through waste heat boilers in which 25% of the heating value of the fuel is recovered.

Use of oxygen in O. H.'s decreases heat losses and fuel consumption by promoting exothermic oxidation reactions. The average amount of O_2 required is about 1200 ft^3/ton of raw steel compared with about 1900 ft^3/ton of raw steel for the BOF. With comparable amounts of O_2 injection (1900 ft^3/ton of r. s.) and of scrap charge (30%), the open hearth consumes about 1.5×10^6 Btu/ton of raw steel more than the BOF.

O. H.'s are capable of operating with 30% to 70% of the charge in the form of scrap and, therefore, in this respect they are more flexible than BOF's.

Finally, we see from Table 4.6 that the effectiveness of O. H.'s is 65%.

Electric furnaces are fired with 3-phase electricity. They consume about 500 kwhr/ton of scrap. Their effectiveness is about 22% (based on 10,000 Btu/kwhr).

4.1.5 Steel Processing

Fuel consumption for steel processing varies considerably from plant to plant and from product to product. Purchased and byproduct fuels are consumed in soaking pits, reheat furnaces, and heat treating furnaces. Electricity and steam for turbine drives are used in primary and secondary hot rolling mills and for cold rolling. For simplicity, we will subdivide steel processing into three major categories: (1) primary forming to blooms, billets, and slabs; (2) reheating and secondary rolling to sheets, plates, strips and bars; (3) heat treating and finishing operations such as wire drawing, pipe making, galvanizing, and tinning.

For primary forming, the traditional method consists of the soaking pit/rolling mill, whereas the newer method consists of the continuous casting mill. The fuel and available useful work requirements of these methods are listed in Table 4.7. We see from

Table 4.7 that continuous casting consumes only about one third of the amount of fuel used in the soaking pit method (10^6 Btu/ton of raw steel). In addition, because the product yield of continuous casting is about 12% higher than that of the soaking pit, an additional 0.8×10^6 Btu/ton raw steel is saved in steelmaking (assuming electric steelmaking). In practice, the heat input into soaking pits varies from 0.4 to about 2×10^6 Btu/ton raw steel (average is about 1×10^6 Btu/ton) depending on the temperature of the ingot inserted into the pit (rolling temperature is 2400°F), the design and age of the pit and insulation, and the type and condition of recuperators or regenerators.

As noted in Table 4.7, continuous casting tundish preheat is the only requirement for thermal energy. Because it represents a heat loss, manufacturers are presently marketing tundish insulation to decrease the fuel necessary for preheating.

After forming into slabs, billets and blooms, steel is usually cooled to room temperature because of reasons of logistics, in order to inspect the surface of the joined steel, and to scarf off any imperfections. Slabs, billets and blooms are then reheated to about 2350° for further shaping into products. Fuel input into the reheat furnace ranges from 1.8 to 4×10^6 Btu/ton raw steel. About 70% of the fuel is natural gas and oil with most of the remainder coke oven gas. Virtually all large reheat furnaces have metallic recuperators that use diluted flue gases at 1800°F to preheat combustion air to 700 - 900°F. A few furnaces also have waste heat boilers.

Heat treating furnaces include many different types serving different purposes such as annealing, normalizing, forging, tempering, etc. Energy is supplied by electricity, oil, coke oven gas, natural gas, and blast furnace gas.

In annealing, steel is heated to 1200 to 1500°F. Because the temperature is lower than that of reheat furnaces, fuel consumption is lower, ranging from 0.7 to 2.5 x 10^6 Btu/ton of raw steel.

Forging furnaces are of many different types depending on production requirements and can be continuous or batch. Forging temperatures are 2150 to 2250°F. Fuel consumption varies from about 3 to 7 x 10^6 Btu/ton of raw steel.

4.2 POTENTIAL OPPORTUNITIES FOR FUEL SAVINGS

The losses in available useful work associated with each process step in iron and steelmaking are listed in Table 4.9. It is seen from Table 4.9 that ironmaking with 26%, steel processing with 28%, and utility generation with 21% have the largest losses in available useful work. Opportunities for fuel savings in ironmaking exist in coke ovens by means of dry quenching, and upgrading and replacement of old blast furnaces. In steel processing, about one-third of the available useful work losses can be attributed to losses of unrecovered sensible heat, and opportunities for fuel conservation exist by means of continuous casting and in heat recovery from soaking pits and reheat furnaces with heat recovery boilers and recuperation. In utility generation combined generation of electricity and process steam can save fuel and reduce available useful work losses. Another area of fuel conservation is steelmaking where heat recovery from BOF's by means of hoods and heat recovery boilers and further replacement of O. H.'s by the BOF can reduce fuel consumption.

TABLE 4.9

LOSSES OF AVAILABLE USEFUL WORK IN IRON AND STEELMAKING (1973 PRACTICE)

	Available Useful Work 10^6 Btu/ton Raw Steel	Percent of Total Available Useful Work Lost
Inputs		
Primary Fuels	25.1	
Scrap	2.8	
Total	27.9	
Useful Output		
Steel	6.0	
Losses		
Ore Preparation	1.3	6.0
Coke and Ironmaking	5.7	26.0
Steelmaking	1.9	8.7
Steel Processing	6.2	28.3
Electricity and Steam Generation	4.6	21.0
Unused Byproducts	2.2	10.0
Total	21.9	100.0
Overall Effectiveness $(\frac{6.0}{27.9})$ = 21%		

5. AVAILABLE TECHNOLOGIES FOR FUEL SAVING

5.1 ORE AGGLOMERATION

Pelletizing is the predominant method of ore preparation for use in blast furnaces. It consumes about 40% of the fuels used in ore agglomeration although 50% more ore is pelletized than sintered. Oil and natural gas are used almost exclusively in pelletizing.

A traveling grate pelletizing machine,[21] capable of using coal rather than oil and natural gas, is under development. A pilot firing chamber has been designed and tested with Montana subbituminous and other higher-rank coals. Total fuel consumption was comparable with that of oil- and natural gas-fired chambers. At the level of pellet production for 1973, adoption of coal firing at all pelletizing plants could result in a savings of 4×10^{13} Btu of oil and natural gas per year or, equivalently, about 20,000 barrels of oil per day.

5.2 COKE MANUFACTURE

5.2.1 Coal Preheating

Coal heating prior to introduction into the coke oven may contribute indirectly to fuel saving because it reduces pollution and increases productivity. Two types of preheaters, a two-stage pneumatic flash dryer/preheater and a fluidized bed preheater, have been developed. Both types have been demonstrated abroad.

Pater and Webster[22] have analyzed the two types of preheaters and also the relative advantages of wet versus preheated coal. They report that preheating: (1) increases coke quality; (2) widens the range of coals that can be used in coke making; (3) increases productivity by 20% for high-rank coals and by up to 50% for low-rank coals because of reduced coking time; and (4) reduces pollution.

Experimental data on fuel consumption with preheated coal are not available. Battelle estimates a fuel saving of 0.1×10^6 Btu/ton coke[23] but an industry representative thought that no fuel saving would be achieved except that which could be attributed to reduced pollution and increased productivity.

A problem associated with preheating coking coal is the explosive nature of hot coal dust in suspension resulting from the increase in the initial rate of gas evolution during charging and from the increased emission of solids. Proper design can isolate the coal dust from outside and prevent explosions. Gas evolution and particulate emission can also be adequately prevented by making pipes and gas mains large with minimal pressure drops.

5.2.2 Dry Quenching of Coke

In the U. S., the coke coming out of coke ovens at 2300° F is water quenched to prevent combustion. This results in a loss of sensible heat of about 1.4×10^6 Btu/ton of coke and in a dust and steam plume that is a source of air and water pollution. The air pollution problem can be reduced by using scrubbing systems.

An alternative method used abroad is dry quenching which, in addition to reducing pollution problems, results in recovery of about 80% of the sensible heat. It is a technology that was developed after World War I by Sulzer and that has been applied in Europe and the Soviet Union. In the U. S., American Waagner-Biro Co.[24] is exclusive licensee for Sulzer. A schematic of their dry quenching system is shown in Fig. 5. 1. Incandescent coke is pushed into a transfer car. The transfer car is lifted to the top of the cooling bunker and dropped into the cooling chamber. During startup, the air reacts with the coke and forms a gas consisting of CO_2 and CO plus N_2. The resulting composition[25] of this partially inert gas is 14. 5% CO_2, 0. 4% O_2, 10. 6% CO, 2% H_2 and 72. 5% N_2. This gas circulates in a closed loop through the cooling bunker, the dust dropout chamber, and the waste heat boiler where steam is generated. A Russian unit at Cherepovets generates 325 psig 700° F steam.[26] It is estimated that 600 psig 750° F steam can be raised also. Steam yield is 880 lb/ton coke. The residence time of the coke in the cooling bunker is two to four hours.

Much controversy exists over the benefits of dry quenching. Experts agree that: (1) dry quenching can recover about 1.2×10^6 Btu/ton coke (equivalent to 800-900 lb of steam/ton of coke); and (2) coke quality is improved. Disagreement exists, however, over the degree of improvement and the amount of the resulting coke savings in the blast furnace. Kemmetmeuller[27] of American Waagner-Biro assumed 5% coke savings in his analysis of payback. Reported values from Russian installations[28, 29] range from 0. 7 - 2. 3%, while a French installation[30] has reported 5%. Similarly, production increases from 0. 3 to 3% have been reported. Russians noted that the reduction in blast furnace coke rate with dry coke was greater for furnaces with higher coke rates. Maintenance and other operating costs vary from installation to installation. After six months of operation the coke quenching facility at Cherepovets in USSR was in generally good condition. Problems cited at this and other Russian

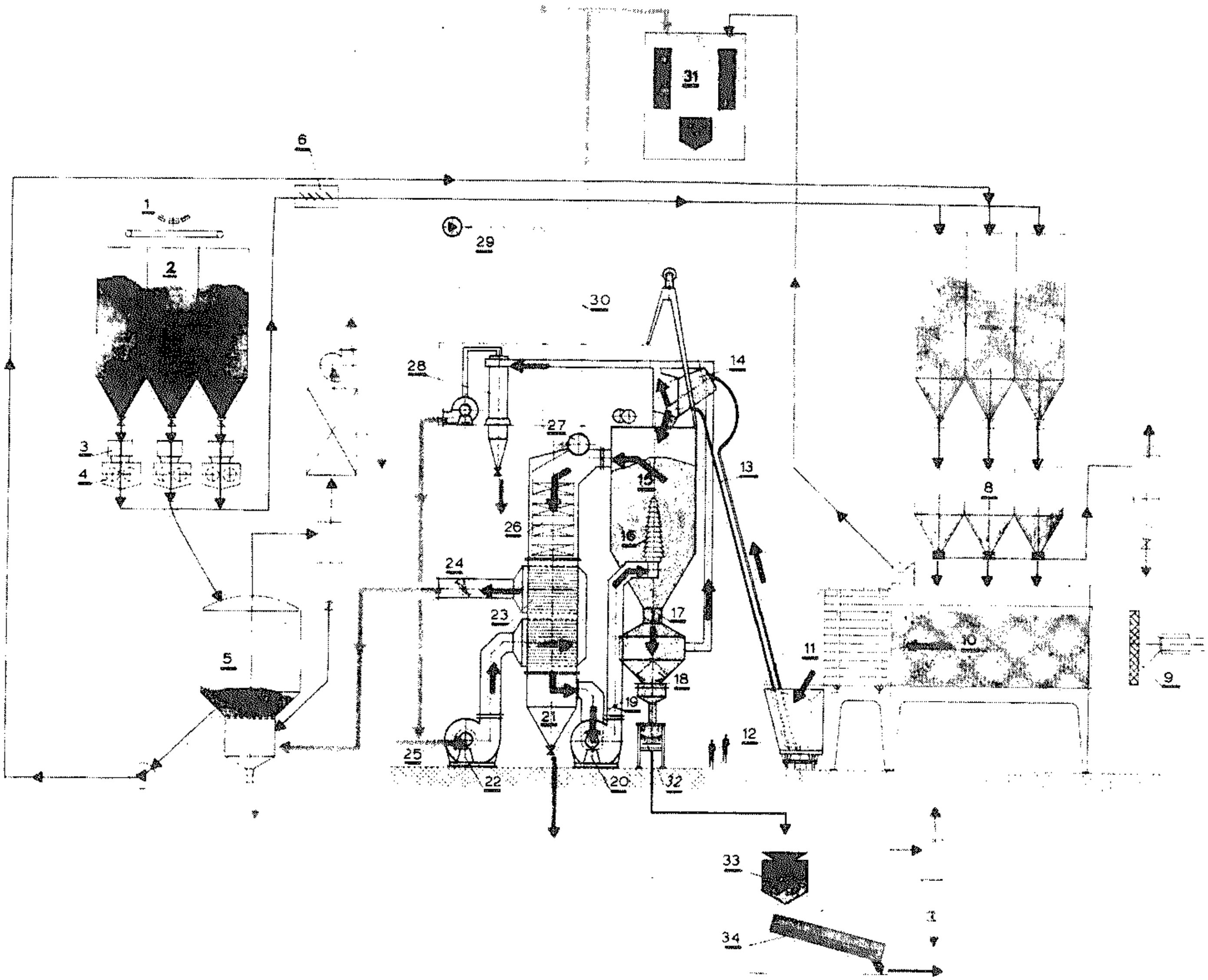


Figure 5.1 American Waagner-Biro Dry Coke Quenching System

mills were: short life of hot coke cars; erosion of brickwork in the cooling chamber; wear on the roof of the dust-settling bin; and, partial failure of thermal expansion joints.

5.3 STEELMAKING

5.3.1 Direct Reduction

Direct reduction processes are methods of manufacturing a highly-metallized iron product (about 96% Fe) without utilizing the blast furnace, and by using low-grade coals or other fuels. The metallized iron product is then melted into steel in electric furnaces. In direct reduction processes, carbon monixide is formed from coal, fuel oil, or natural gas and reacts with the ore to form carbon dioxide and iron. The carbon monoxide — iron ore reaction occurs at temperatures lower than 2000° F and the resulting iron is solid, usually in the form of pellets or balls. In contrast, in the blast furnace, conversion from iron ore to pig iron occurs by reaction of the ore with carbon at high temperatures (greater than 2000° F) in the bottom of the furnace, and with carbon monoxide at lower temperatures (less than 2000° F) in the top of the furnace. In general, one-third of the ore will be reduced at high temperature and two-thirds at low temperature. The product pig iron is a liquid.

The most successful direct reduction processes have used natural gas as fuel. At the present time, the Midrex Corporation is actively engaged in marketing a vertical shaft process developed by Surface Combustion Division of Midland Ross. Four Midrex direct reduction plants are in operation, two in the U. S. and two abroad, and plans for eleven additional plants[31] have been announced, for a total steelmaking capacity of about 9×10^6/ton Fe per year. A fluidized bed process, Swindler Dressler's HYL, has also been commercialized, mainly in Mexico. A shaft furnace, developed by Armco, has been operating in Houston, Texas since 1972. Other commercialized processes are the FIOR and the NU-IRON, developed by Esso Engineering and U. S. Steel, respectively. Fuel consumption for the Midrex process is reported to be about 12.7×10^6 Btu/ton product for 92% metallization.[32] Plant capacities are currently from 100, 000 to 400, 000 tons/year. Newly announced plants will have capacities of up to 2.5×10^6 tons/year. Because of shortages of natural gas, these processes are not practical in the U. S.

Of more importance to the U. S. are coal-based, direct reduction processes. The SL/RN process, a joint development by the Steel Company of Canada, Lurgi, Republic Steel, and National Lead Company, is currently the only coal-based direct reduction process that is operating commercially.

Lurgi[33] described six coal-based direct reduction plants ranging in size from 0. 095 to 1.25×10^6 tons of product/year. Two of these plants have stopped operation because of poor economics and changes in raw material inputs. The other four are operating successfully after overcoming initial startup problems. More plants are planned for Japan, U. S., and Canada. The U. S. plant will produce 60, 000 tons/year from a leached residue containing iron, copper and noble metals. The product iron will be used for copper cementation. The Steel Company of Canada is installing an SL/RN direct reduction plant incorporating a rotary kiln, with a capacity of about 60,000 tons/year.

Cartwright[34] compared the costs in the United Kingdom for producing steel via the blast furnace/BOF and SL-RN/electric furnace routes in 1973. He concluded that, for small plants, costs favor the SL-RN/ electric furnace route, whereas for large plants (greater than 2.5 x 10^6 tons/year) costs favor the blast furnace/BOF route. Increases in the cost of coke tend to make the breakeven plant size larger while increases in the cost of electricity decreased the breakeven plant size. In general, the breakeven plant size is more sensitive to the cost of coke than that of electricity. For example, a 40% increase in the cost of coking coal increased the breakeven plant size from four to six times while a 50% increase in the cost of electricity decreased it by about one-third. As the SL-RN technology advances and coking coal costs increase, we anticipate the SL-RN/electric furnace process route to become economically attractive. Because the results of the analysis are highly nonlinear, we cannot extrapolate the breakeven plant capacity to current coke and electricity costs in the U. S.

Another direct reduction process is the Kinglor-Metor[35] which involves a shaft furnace for the reduction. The fuel consumption for this process is shown in Table 5. 1. It is comparable with that of gas-based direct reduction processes.

5. 3. 2 Nuclear Steelmaking

Nuclear energy has the potential of providing heat for ironmaking and electricity for steelmaking. Three process routes for nuclear steelmaking have been proposed; two based on the high-temperature graphite reactor (HTGR), and one on the electricity from any reactor.

TABLE 5.1

HEAT BALANCE ON KINGLOR METOR PROCESS PILOT PLANT

Reductant Input (Coal)	13.1×10^6 Btu/ton
Heating Fuels	4.9
Total Fuels	18.0
Recycled Reductant	4.3
Net Fuel Consumption	13.7
Utilities (80 kw-hr/ton)	.8
Total Fuels and Utilities	14.5×10^6 Btu/ton

The HTGR is cooled by helium at about 1400° F. If the helium coolant temperature could be raised to 1650-1900° F, then part of the nuclear heat could be used for steam reforming of methane at 1600° F and solid carbon at 1800-1900° F to carbon dioxide and hydrogen. The carbon dioxide and hydrogen could then be used to reduce iron ore in a direct reduction reactor. The other part of the nuclear heat would be used for electricity for steelmaking from the metallized iron, and for steel processing.

Thus, methane or coal would serve as a chemical feedstock and not as a source of heat. As a result, the amount of hydrocarbon required would be reduced to nearly the theoretical minimum (about 6000 ft^3 of natural gas or one-quarter of a ton of coal per ton of steel).

In another process option, part of the electricity from a HTGR is used in dissociating water into hydrogen and oxygen. The hydrogen is then heated to 1200° F by the hot helium and used as a reductant in a direct reduction reactor. The remainder of the electricity is used in electric steelmaking and processing.

In the third option, electricity and process steam from a nuclear reactor are used in an integrated plant which does not use any other fuels.

Groups of European companies have organized a European Nuclear Steelmaking Club to plan a program for the development of nuclear steelmaking.[36] In 1973, the Japan Iron and Steel Institute announced a 5-year, 30 million dollar program for testing various parts of the HTGR helium reformer and direct reduction process. The American Iron and Steel Institute completed a study in 1974 showing that nuclear steelmaking based upon a utility financed HTGR could produce steel more cheaply than the conventional blast furnace route. Of course, many problems must be solved, foremost of which are: (1) upgrading of the helium coolant temperature; and (2) designing a 2000 Mwe reactor which would provide enough process heat and electricity for a 5×10^6 ton/year steel plant. The steel industry generally favors government funding for development of nuclear steelmaking.[37]

5.3.3 Formcoke

Estimates of the reserves of premium grade bituminous coals suitable for coking range from 200-1000 years at current consumption levels. These coals are about twice as expensive as conventional steam coals and are located mainly in Appalachia. On the other hand, over 90% of all known U.S. reserves of low-sulfur coals are of low rank not suitable for coking, and they are located in the western states. If a suitable coke based upon low-grade coals could be found for use in blast furnaces, then a considerably larger, low-cost reserve base would become available to the steel industry. Cokes produced from nonmetallurgical grade coals are called formcoke.

The FMC Corporation[38] is manufacturing formcoke in a 85,000 ton/year plant built in 1960 at Kemmerer, Wyoming. The plant uses mostly western subbituminous coals and has been continuously upgrading the product. Consol-BNR, a consortium of Consolidated Coal, Bethlehem, National and Republic Steel Companies, is starting up a 180,000 ton/year formcoke plant at Sparrows Port, Md., and will run trials at one of Bethlehem Steel's nearby blast furnaces. U. S. Steel is developing a clean coke process partially sponsored by ERDA's Office of Coal Research. Unlike the FMC and Consol-BNR formcoke processes, the U. S. Steel clean coke process maximizes the production of coal chemicals rather than coke. Abroad, the Coal Research Institute in the USSR is expected to have a 500,000 ton/year plant operating by 1978, Bergbau-Forschurg and Lurgi (BFL formcoke) are operating a 330 ton/day plant in West Germany, and Sumitomo Metal and Keihan Rentam Industries are building a 3×10^6 ton/year plant in Japan.[39]

In 1972, the British Steel Corporation conducted tests with both FMC and BFL formcokes in a blast furnace at the East Moor Works.[40] Additional tests with FMC formcoke were conducted by Inland Steel in the U. S., by Sumitomo in Japan, and by the USSR. Some general conclusions from the tests conducted by BSC are:

- Each type of formcoke can replace 100% of coke in a blast furnace and maintain proper operation.
- Changeover from coke to formcoke can be performed satisfactorily.
- With BFL formcoke carbon requirements increased by 3-10% (increase in fuel by 12-17%), but with FMC formcoke they decreased by 3-6% (decrease in fuel by 2-5%).
- Production decreased with BFL formcoke and increased with FMC formcoke.
- No substantial change occurred in blast furnace gas composition and amount-per-ton of pig iron.

- In general, efficiency and productivity with FMC formcoke were greater than those with BFL formcoke. The differences, however, were due primarily to the type of coal feedstock and the furnace-charging sequence used in each test rather than to inherent properties of each type of formcoke.

Quantitative estimates of capital requirements and operating costs are not available. In response to questions, FMC made the following general comments:[41]

- For a given location, cost of an installed formcoke plant with a capacity of 10^6 tons/year will be no more than a similarly sized conventional plant with the best available pollution controls.
- Labor and maintenance costs for a formcoke plant are less than for a conventional plant, but utility costs are higher, resulting in essentially the same conversion costs, exclusive of byproduct credits.
- Coal feedstock costs are substantially lower than those of a conventional plant since formcoke can be made out of subbituminous noncoking coals. The sulfur content of formcoke is the same as that of the feedstock, and all ash and fixed carbon in the feedstock end up in the coke.
- Byproduct gas from the formcoke process has an average heating value of about 150 Btu/ft^3 or about 6 x 10^6 Btu/ton coke.

For coals with the same carbon and ash contents, coke yield for the FMC process is about 5-10% greater, but byproduct fuel production is about 50% smaller than those of the conventional process. Assuming that coke and formcoke have the same heating value, we conclude that an integrated mill will consume about 2.5×10^6 Btu/ton coke more fuel by using formcoke instead of coke.

5. 3. 4 Technology for Increased Efficiency in Blast Furnaces

Since 1960, blast furnaces have been operated so as to consume on the average less coke, the primary fuel in ironmaking. The reduction in coke rate resulted from upgrading of old blast furnaces for higher air blast temperatures, optimization of burden, and increased injection of hydrocarbons, and from installation of new blast furnaces operating at high top pressures. Measurements made on the experimental blast furnace of the Bureau of Mines[42] indicate that the total energy input per unit of product actually increases with increased injection of natural gas and oil (Fig. 5. 2) though the coke rate decreases (Fig. 5. 3). Battelle[43] has also shown that the thermal efficiency of blast furnaces decreases when the injection of hydrocarbons is increased. We conclude that the gradual improvement in blast furnace effectiveness that has occurred in the last decade is due to either the gradual upgrading or replacement of furnaces, rather than to the use of hydrocarbon injectants; in other words, hydrocarbon injection is a means of replacing coke rather than one of energy conservation.

In the future, coal will replace natural gas and fuel oil as injectants. As shown in Figs. 5. 2 and 5. 3, the coke replacement and the total coke plus injectant energy appear to be very sensitive

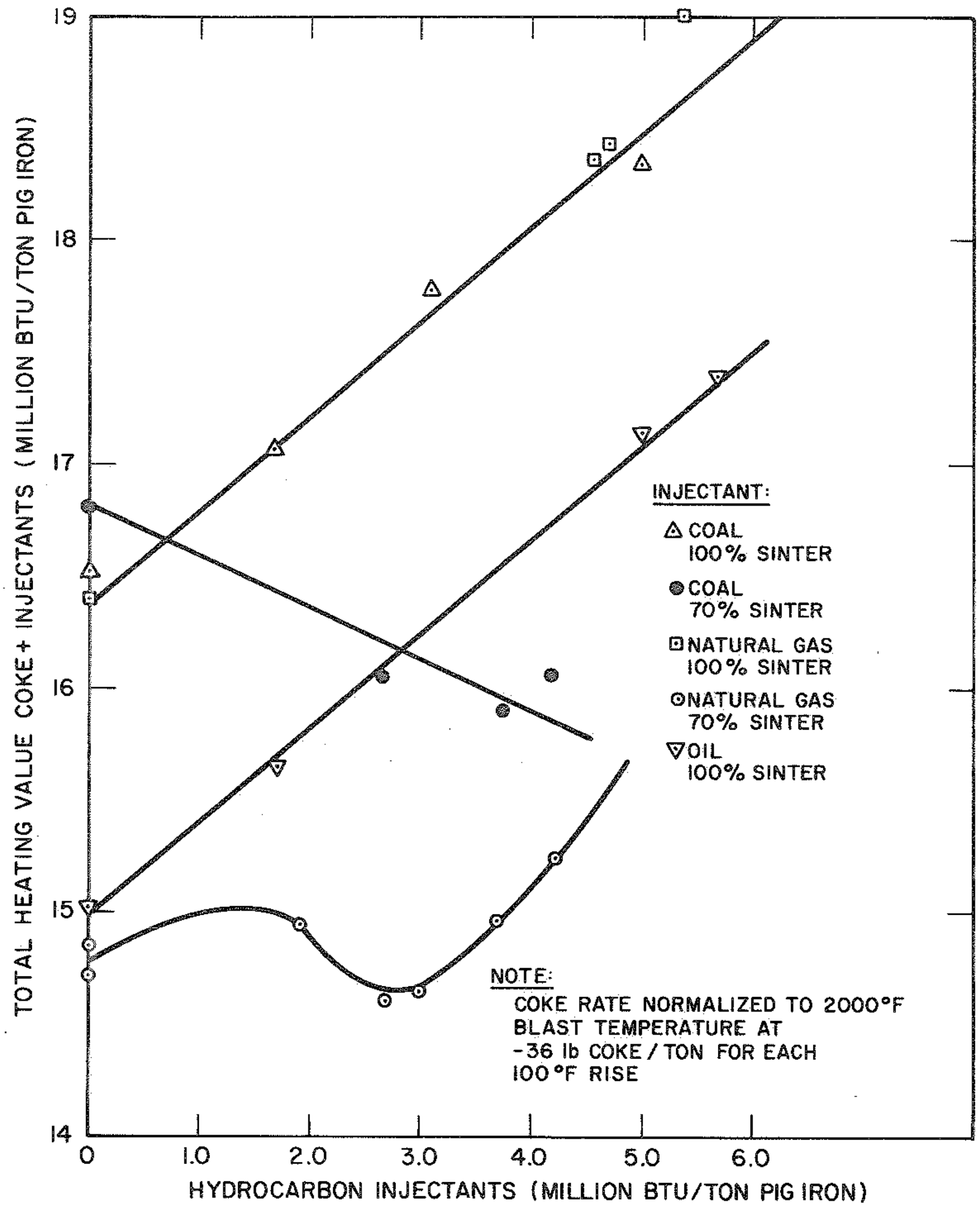


Figure 5.2 Effect of Hydrocarbon Injectants on Total Coke and Injectants Heating Valve for Bureau of Mines Experimental Blast Furnace

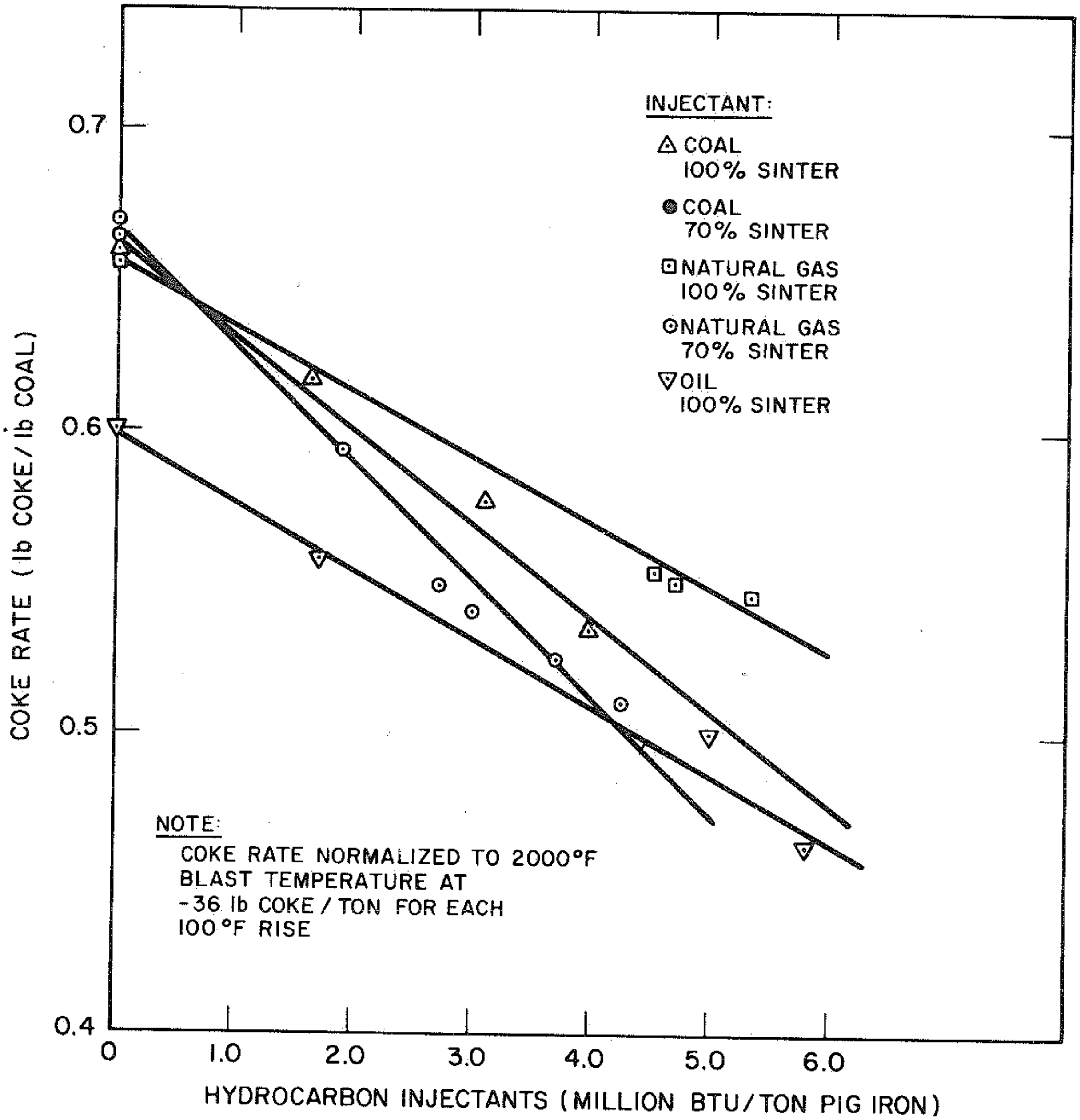


Figure 5.3 Effect of Hydrocarbon Injectants on Blast Furnace Coke Rate for Bureau of Mines Experimental Blast Furnace

to the type of coal. Armco has recently reported coke replacement rates at their Amanda, Ohio mill to be 1.1 and 0.78 lb coke/lb coal for coals with 4% and 9% ash, respectively.[44] It follows that the energy savings is marginal, except for the savings incurred in not having to manufacture the replaced coke. The economics of coal injection, discussed in Section 6, may be favorable because of the large price difference between coke and coal. Approximately 70% of U. S. blast furnaces are operating currently with hydrocarbon injectants, mainly oil or tar.

Since few blast furnaces have been replaced in recent years, much of the increased efficiency of U. S. blast furnaces has resulted from improved burden preparation and distribution, and increased air blast temperatures. Experiments on the Bureau of Mines blast furnace[45] with various types of iron ore burden have shown the importance of properly screening-out fines. Early tests comparing pellets and fluxed sinter showed pellets to be superior. However, the sinter contained 42% minus 3-mesh material versus 2% for the pellets. Subsequent tests in which the minus 3-mesh sinter was screened out showed the sinter to result in about a 4% lower coke rate. Thus, a closely sized sinter burden should give excellent results. This corroborates the Japanese experience which indicates that closely sized burdens result in low coke rates. Controversy still exists on the sinter vs. pellet question. Much of the success attained in the U. S. relative to pellet usage may have been predetermined by poorly sized sinter.

The average air blast temperature for U. S. blast furnaces has been increasing rather steadily from about 1230°F in 1958 to 1550°F in 1968. Currently, when blast furnaces are relined and rebricked, air blast temperatures are upgraded to 2000 to 2200° F. Blast temperatures of 2000 to 2400° F are common in Japan where the average coke rate is 1000 lb/ton pig iron. It is estimated that a 100° F increase in air blast temperature decreases the coke rate by about 25 to 36 lb/ton pig iron.

Unlike air blast temperatures, top pressures of existing U. S. furnaces have not been upgraded. New furnaces are, however, being installed with high top pressure capability. Old furnaces have not been upgraded to higher top pressures because the furnace, stack, and air blast piping and blowers cannot withstand the higher pressure. No detailed economic study has been made of the feasibility of converting an existing blast furnace to high top pressure. In general, experts agree that such conversion would not be worthwhile and that it might be advisable to build an entirely new facility.

Increased top pressure was proposed by Julian, an American, in the late 1930's as a means for increased production and decreased coke rate.[46] In the 1950's new blast furnaces were installed with a maximum top pressure of about 7 psig. Most furnaces in the U. S. were installed prior to the 1950's, however, and they operate with blast pressures of less than 5 psig. Only a few furnaces are operating at blast pressures between 5 and 10 psig, and about five are operating above 10 psig. On the other hand, furnaces in Japan and Europe are operating at 32 psig. Results of tests performed at the Bureau of Mines furnace with varying top pressures are shown in Fig. 5.4. We see from this figure that there may be an optimum top pressure for a given wind rate. To obtain the full benefit of

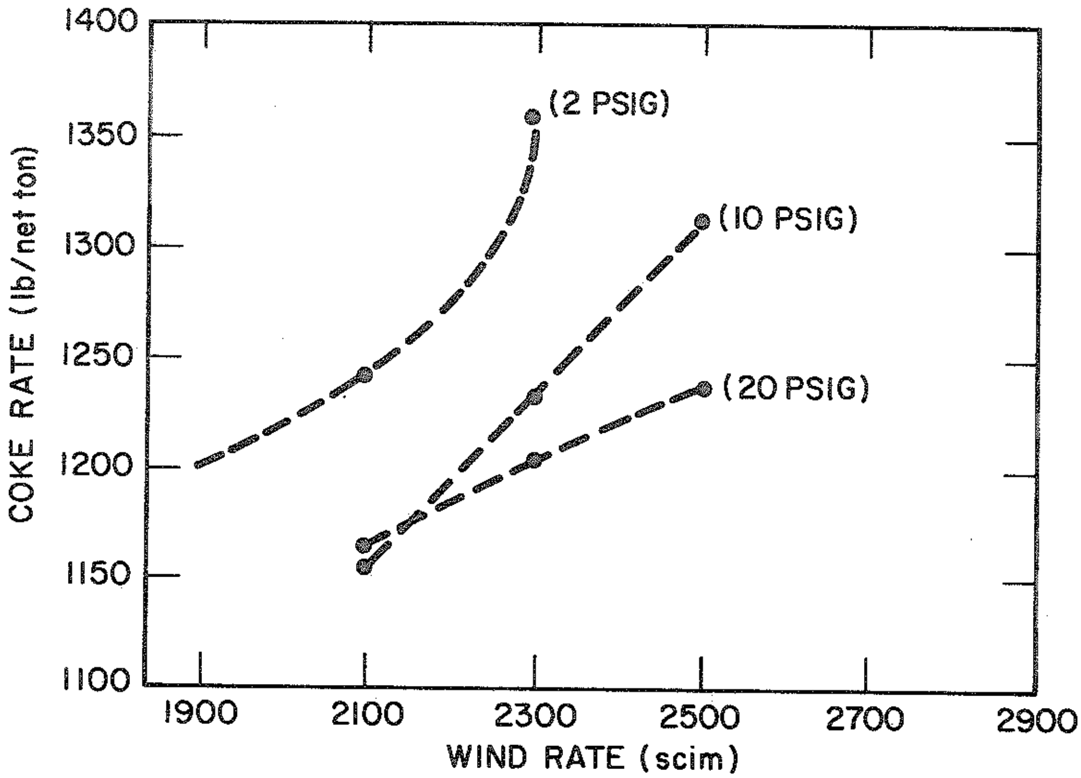


Figure 5.4 Effects of High Wind Rates and Top Pressure on Coke Rate with a Pellet Burden.[45]

top pressure, the wind rate must thus be increased. At high wind rate, savings in coke rate can be large. An optimum also appears in increases in production rate with increased top pressure. Upon reaching the limit in wind rate at a given top pressure, the decrease in coke rate with increased top pressure at a constant wind rate can be of the order of 100 lb/ton pig iron.

Associated with high top pressures are specially designed furnace tops which, in addition to acting as pressure chokes, have the purpose of distributing the burden in a uniform manner. Burden distribution has been found to be an important parameter for efficient furnace operation. High-pressure tops have been developed in both Japan and Europe. Tops can be classified into those that have bells and those that are bell-less. Typical of the bell types are the NKK 4 bell top, the IHI top, and Yawata top. Here, the burden is dropped into a rotating hopper and then onto a series of bell-like domes and finally into the furnace. Gas sealing is accomplished by either the bells themselves or soft valve seals. In the bell-less type, valve seals are used only for gas sealing, and burden distribution is accomplished by a revolving chute which receives the burden from one of two bins. A unique advantage of the bell-less top appears to be that the inclination of the rotating chute relative to the furnace centerline can be adjusted at an optimum position for each type of burden. Other advantages are low capital and maintenance costs. Capital costs are low because the structure requirements result in an overall furnace height smaller than those of the bell-type tops. In addition, furnace down time is about 0.5%. High pressure tops have been retrofitted to existing furnaces in Mexico and Japan primarily to attain better burden distribution. The manufacturer of the Paul Wurth bell-less top estimates the cost of the top to be about $1 million for a medium size U. S. furnace including basic electronics and hydraulics.[47] Depending on the details of the installation, additional costs may be incurred. Coke reduction with the installation of a Paul Wurth bell-less top could be 20 to 40 lb/ton pig iron because of the better burden distribution. At the high wind rates associated with high top pressures and modern furnaces, appreciable energy can be recovered from the air stream by using expansion turbines. Thus, much of the extra energy used to raise the pressure can be recovered.

More often than not change in one operating parameter requires changes in others. For example, a limit exists on how high the air blast temperature can be raised without addition of injectants, such as steam and hydrocarbons. This limitation comes about for the following reasons. The burden forms a bed which moves down the length of the furnace at an average speed of about 5 ft/min. A hot air blast at 1200° F to 2000° F, injected at the tuyeres, moves upward counterflow to the movement of the burden bed. Thus, the charge is heated by the hot air blast and gaseous products (blast furnace gas) of the iron ore reduction process as it moves downward and the air and gas mixture moves upward. The temperature in the furnace can be regarded as being below 2000° F in the upper part and above 2000° F in the lower part. Iron reduction occurs in both upper and lower parts but the chemistry is different in each. In the lower part where temperatures are greater than 2000° F (in the active zone as high as 3500° F), the iron oxide and coke react and form Fe and CO_2 (direct reduction). The reaction is highly endothermic. Because the temperature is high, however, CO_2 is unstable and disassociates into CO and O_2. The CO is chemically frozen, and travels up the furnace to the low-temperature region (less than 2000° F). There, it reacts with ore and produces Fe and stable CO_2 (indirect reduction) in a slightly exothermic reaction. Excess CO leaves the stack as flue gas or top gas, having a calorific value of 85 to 100 Btu/ft^3. About one-third of the top gas is employed to heat the air blast in checkered, regenerative air blast stoves located adjacent to the blast furnace. The limit in maximum air blast temperature and lower coke rate without injectants is a consequence of two factors: (1) the decrease in the amount of CO that results from a lower coke rate; and (2) the increase in energy available in the lower part of the furnace at temperatures greater than 2000° F that results from a hotter air blast without any significant change in available energy in the upper and cooler part of the furnace. The net result of the two effects is to decrease the amount of reduced ore. Thus, excessive ore reaches the hot part of the furnace and melts. Then, the ore melt contacts the coke and is reduced to iron which solidifies because its melting point is greater than that of ore. The solid iron and excess coke combine and "hang the furnace." Injections of steam and hydrocarbons through the tuyeres prevent the "hanging of the furnace" because CO and H_2 are produced either by steam-coke reactions or by hydrocarbon decomposition, and these in turn increase the ore reduction in the upper part of the furnace.

In summary, increased pressure at a given temperature reduces the pressure drop through the moving bed of burden and coke because of the associated decrease in gas density. Thus, an increase in wind rate is possible which, in turn, decreases the coke rate and increases production. In addition, the thermochemistry at high pressures favors the production of CO_2 and, therefore, more energy is available from combustion of coke in the lower part of the furnace for the highly endothermic reduction of iron oxide, and more CO is available for use in the upper part of the furnace. The result is a lower coke rate but also top gas with less calorific value (i. e., less CO content).

5.4 STEELMAKING FURNACES

Fuel consumption per ton of raw steel in steelmaking furnaces has been greatly reduced since the introduction of the basic oxygen furnace (BOF). Its variation vs the fraction of steel manufactured in BOF is shown in Fig. 5. 5. With the ratio of pig iron to scrap at the level of the 1969 to 1972 practice, we see from this figure that fuel use in steelmaking decreased from 3.16 to 2.3×10^6 Btu/ton of raw steel from 1965 to 1973 as BOF production increased from 17.5% to 55.5%. The largest part of the decrease was in the form of oil saved from the replacement of OH's by BOF's. We also see from the figure that decreasing the pig iron to scrap ratio increases fuel consumption in steelmaking.

Additional fuel savings can be achieved by recovering heat from the off-gases of BOF's. Combustible gases (about 90% CO) are released during the oxygen-blowing period of the BOF cycle (about 10 minutes of the 40 minute cycle). Their total heating value (sensible plus combustion) is estimated to be about 0.75×10^6 Btu/ton of raw steel.

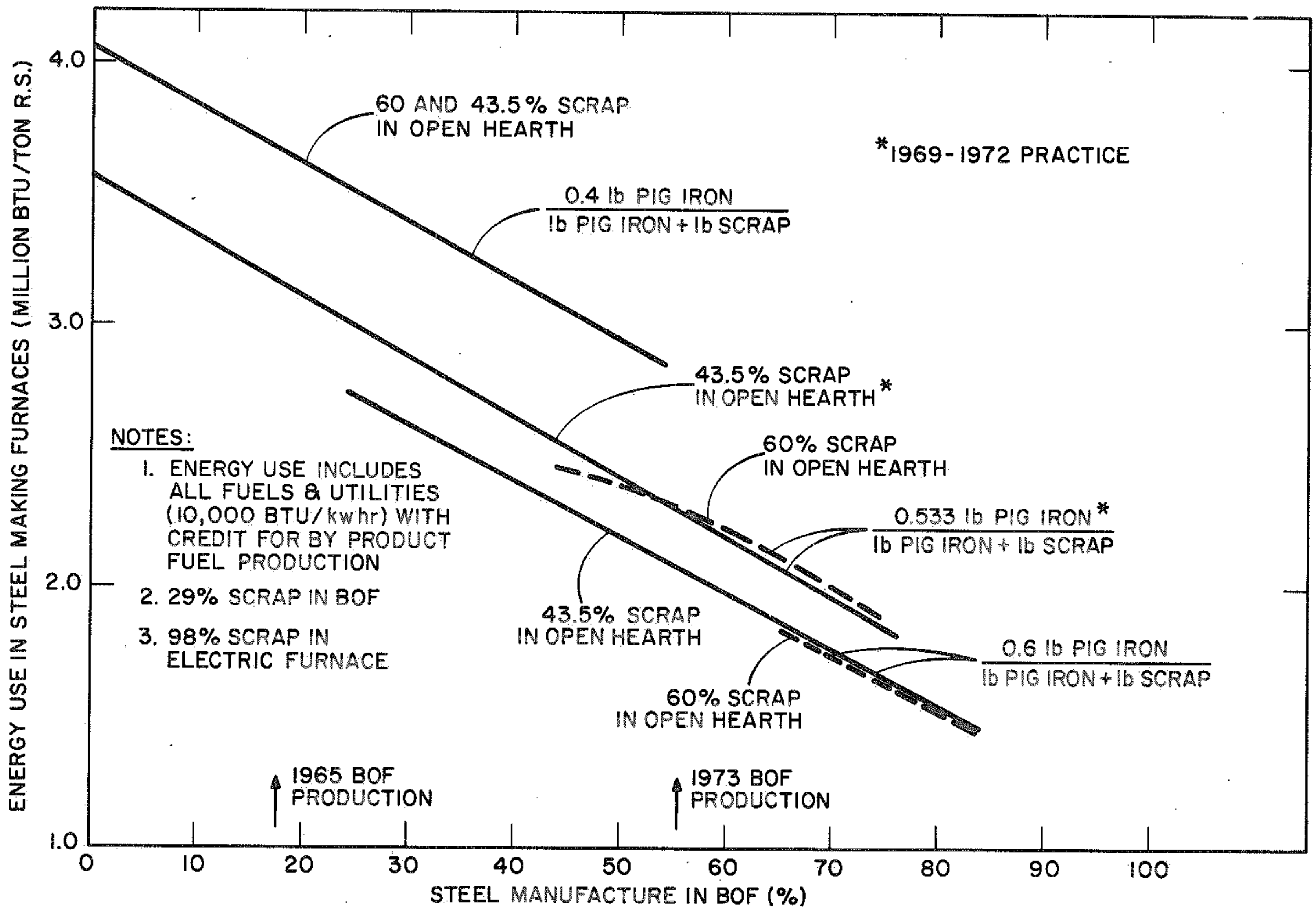


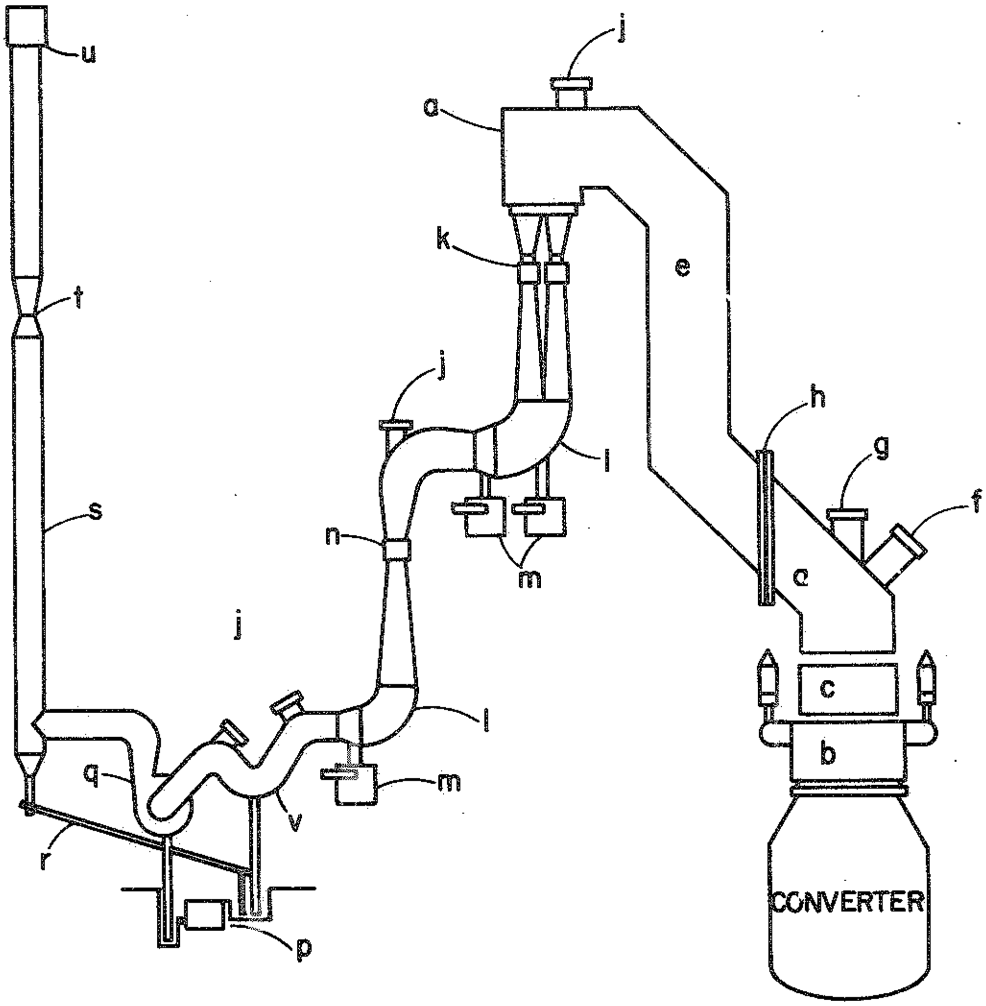
Figure 5.5 Effect of Relative Use of BOF and Amount of Scrap Used in Steelmaking Furnaces

In the U. S., most BOF's are equipped with open hoods in which space is provided for the aspiration of air for burning CO into CO_2 without heat recovery. Because of low fuel costs until now, heat recovery was not economical.

In Europe and Japan, on the other hand, because fuel costs have always been relatively high, the off-gases from BOF's are collected and burned in heat recovery boilers for process steam raising. In addition to saving fuel, use of the off-gases results in better pollution control.

To eliminate pollution resulting from oxygen blowing, the Japanese designed a closed hood off-gas (OG) collection system[48] (Fig. 5. 6). To prevent combustion of the off-gases and explosions, nitrogen, obtained from the oxygen plant, is used to dilute and purge the gases in the system, and to seal against air regressing into the system. Explosion covers and a separate explosion stack are provided in case of emergencies.

Another, though similar, BOF gas recovery system has been developed in France at the Institut de Recherches de la Siderurgie Francaise (IRSID) and Compagnie des Ateliers et Forges de la Loire (CAFL).[49,50] The primary difference between the two systems is that the OG utilizes nitrogen as a purge gas whereas IRSID/ CAFL utilizes a nitrogen-CO_2 mixture which separates the combustible gases from the air aspirated during the nonblowing and tapping period. Both systems are suppressed combustion systems (i. e., a minimum of combustion occurs in the collection system) with the combustibles either collected for use or flared. Thus, gas volumes and temperatures in the collection system are less than for the open



a) spark box; b) skirt; c) lower hood; d) upper hood; e) radiation part; f) flux chute hold; g) lance hole; h) hood seat; j) explosion doors; k) saturation venturi; l) elbow separators; m) seal tanks; n) PA venturi; p) sludge pit; q) induced-draught fan; r) stack seal pipe; s) stack; t) dall tube; u) igniters; v) mist separators

Figure 5.6 Diagrammatic Arrangement of OG Equipment hood systems resulting in smaller structures, and lower capital costs. Another advantage of the OG hood is that hot metal yields are increased by about 1% because of less slopping. Gas recovery systems have been reported to collect 1900 ft^3 of gas/ton r. s. with a low sulfur content and a calorific value of about 220 Btu/ft^3 (420, 000 Btu/ton r. s.).

BOF off-gas recovery hoods have been operating since about 1963 in Japan and France. Maintenance is reported to be minimal and shutdowns rare. Initially, control problems and water leakages occurred but most persistent maintenance problems have been solved satisfactorily. OG gas collection hoods are currently installed in three basic oxygen furnaces at Armco, Inland, and U. S. Steel in the U. S., and one is under construction in Canada. In all U. S. installations, the gases are currently being flared, but provisions have been made for the installation of gas collection and storage equipment. Worldwide, about 100 BOF's have closed hood off-gas collection systems.

The Bureau of Mines has performed development work on scrap preheating[51] using the total energy of the off-gases from BOF's. The pilot preheater is shown in Fig. 5. 7. It preheats the scrap to 1150° to 1650° F. Tests showed that the scrap fraction could be increased from 28% to about 40%. Analysis of the tests showed that the CO from the BOF was almost completely burned to CO_2 prior to reaching the preheater by secondary air infiltration around the hood. Increase of scrap usage in BOF's without additional fuel consumption has obvious advantages. It permits retirement of old OH's without appreciable increase in electric furnaces. Table 5. 2 shows the

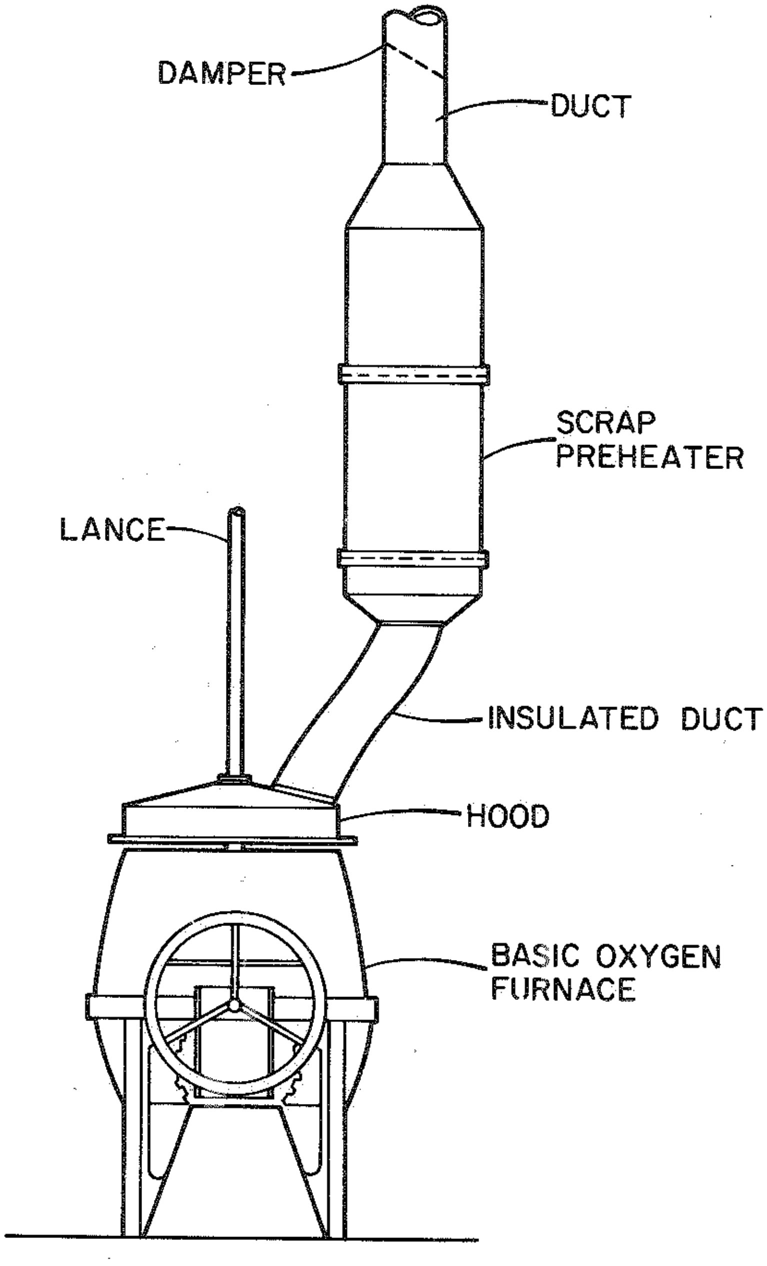


Figure 5.7 Schematic of Pilot BOF-Preheater System Developed by Bureau of Mines

TABLE 5.2

COMPARISON OF SCRAP AND PIG IRON USAGE IN STEELMAKING FURNACES WITH AND WITHOUT SCRAP PREHEATING IN THE BOF

	Scrap	Pig Iron
Without Scrap Preheating (1973)		
Open Hearth	18.6	22.3
Basic Oxygen	24.2	60.2
Electric Furnace	24.9	0.8
Totals	67.7	83.3
With Scrap Preheating		
Open Hearth	18.6	22.3
Basic Oxygen	40.0	60.2
Electric Furnace	8.9	0.8
Totals	67.5	83.3

usage of pig iron and scrap in steelmaking for 24% and 40% scrap usage in BOF's and fixed scrap usage in the OH's. The saving in electricity is about 7.50×10^9 kwhr/year or 0.075×10^{15} Btu/year, namely about 13% of all electricity used in iron and steelmaking.

In electric furnaces, hot gases are emitted at 2200° F. Presently, they are cooled and cleaned prior to release to the atmosphere. The Bureau of Mines performed tests on scrap preheating[52] by using the sensible heat of these gases. The tests showed that electricity consumption could be reduced by about 15%.

The Q-BOP is a recent innovation in basic oxygen technology.[53] It was developed by Eisenwork-Gesellschaft Maximilianshutte (Maxhutte) in Germany in 1970. The Q-BOP differs from the conventional basic oxygen furnace in that the oxygen is blown in from a tuyere located at the bottom of the furnace vessel rather than from an overhead lance. The advantages of the Q-BOP over the BOF are: (1) production increases by about 10% for same size vessel; (2) overhead structure requirements are reduced because the overhead oxygen lance is removed; (3) capital costs are lower for new shops and Q-BOP's can be retrofitted into an old open hearth structure because of the reduced overhead structure requirements; and (4) hot metal yield is increased by about 2% because of less slopping. Figure 5.8 illustrates the difference in the overhead structure requirements for the Q-BOP and BOF. Investment requirements for retrofitting a Q-BOP in an old open hearth shop are estimated at about 50% of that for a BOF and 80-90% of BOF costs for green field Q-BOP's. Approximately 19 million tons/year capacity are currently installed, or will be installed shortly worldwide. The largest operating installation

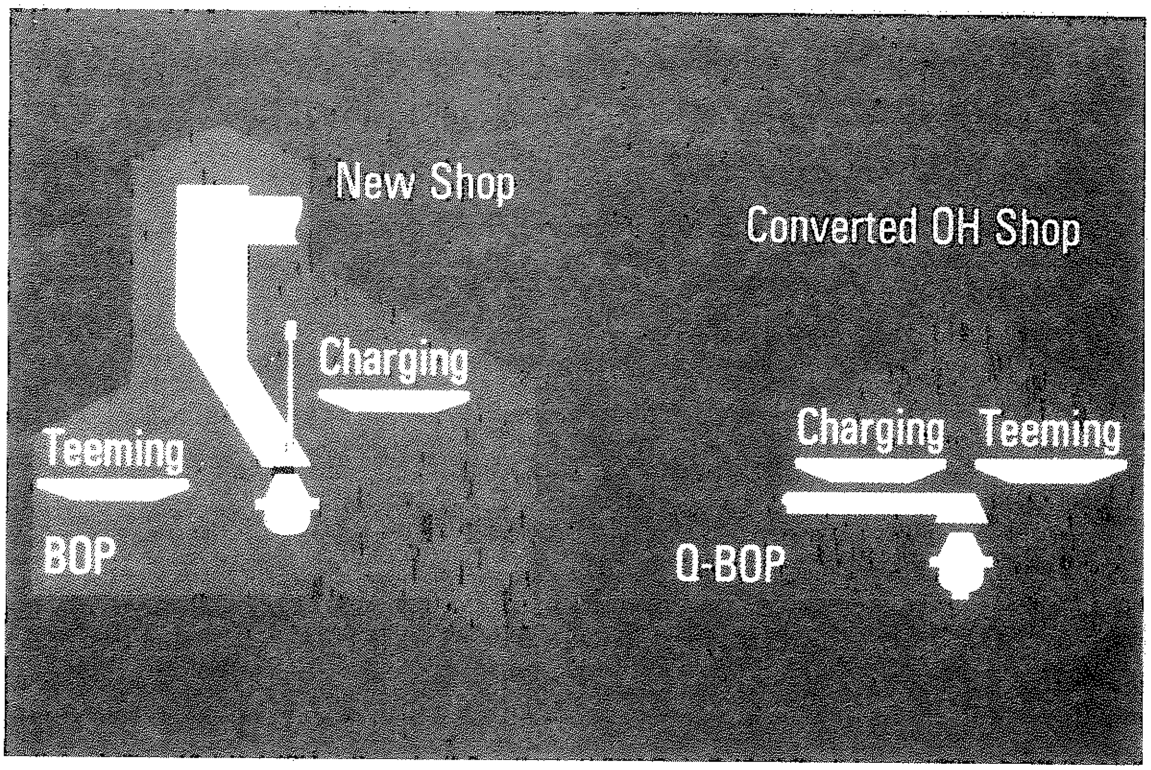


Figure 5.8 Comparison of Overhead Bay Requirements for Q-BOP and BOP and Compatibility of Q-BOP Installation with Existing Open Hearth Structures

is in the U. S. at U. S. Steel's Gary Works where three 200-ton vessels are installed producing 5 million ton/year. Another 4.7 million tons of capacity will be installed shortly at U. S. Steel's Fairfield Works and at Republic Steel.[54]

The Q-BOP, however, does consume more energy than the conventional BOF. The oxygen and natural gas requirements for the two processes are listed in Table 5.3.

5.5 CONTINUOUS CASTING

Continuous casting has the potential for saving fuel in the initial step of steel processing. In addition to fuel saved in steel processing, electricity consumption can be reduced in steelmaking furnaces because of the potential higher yield of continuous casting compared with ingot casting. We estimate a total saving of about 1.4×10^6 Btu/ton r. s. (about 5.5% of all fuels consumed in steelmaking), consisting of about 0.75×10^6 Btu/ton r. s. in oil, natural gas and coke oven gas (about 13% of the natural gas and 6.4% of the fuel oil purchased by the iron and steel industry in 1973), and about 0.65×10^6 Btu/ton r. s. in electricity (almost 17% of the electricity consumed by the iron and steel industry in 1973).

Continuous casting has some limitations, which have inhibited its rapid installation and usage in the U. S. They are: (1) inherent operating difficulties associated with producing high-quality steels with acceptable yields; (2) loss of flexibility of product mix; (3) the problem of coordinating the casting with the rapid BOF heat cycles; (4) long and difficult equipment and personnel break-in time; and (5) customer acceptance of killed steels. These difficulties stem

TABLE 5. 3

OXYGEN AND NATURAL GAS REQUIREMENTS FOR Q-BOP AND STEELMAKING PROCESSES

	Oxygen		Natural Gas	
	ft^3/ton	Btu/ton r. s.	ft^3/ton	Btu/ton r. s.
Q-BOP	1680	306, 000	168	168, 000
BOP	1775	323, 000	0	0

Increase in Fuels Consumption in Q-BOP is = 151, 000 Btu/ton r. s.

from the problems involved in the design of a machine for continuous solidification of a high melting point, low thermal diffusivity material. Other materials with more acceptable thermophysical properties were continuous cast successfully prior to steel.

Three basic types of continuous casting machines are shown in Fig. 5. 9. In all three types of machines, liquid steel is poured into a tundish from a ladle. Nozzle slide gates then allow the liquid steel to proceed into the mold and cooling chamber. The mold is a large water-cooled box in the shape of a billet or slab. The liquid steel, as it moves through the mold, forms a thin solid skin. Because of thermal contraction, which causes the solid skin to move away from the mold, and because of the low thermal diffusivity of liquid steel, solidification of the center core in the mold is very slow. It can be accelerated by means of large water cooling spray systems.

The three types of casting machines differ in the shape of the mold and in the manner in which the solidified slab or billet is changed from the vertical to the horizontal position. In the vertical casting machine, at least 70 feet is required from the tundish to the floor to complete the solidification process. In the vertical caster, the solidified steel can be put in the horizontal position by precutting lengths and rotating the lengths by 90°, or by a series of rollers guiding the hot soft steel to the horizontal position. The curved mold machine requires about 20 feet of head room between the tundish and the floor. Here, the mold and spray-cooling chamber is shaped in a big arc causing the liquid steel to bend as it flows through the mold and solidifies.

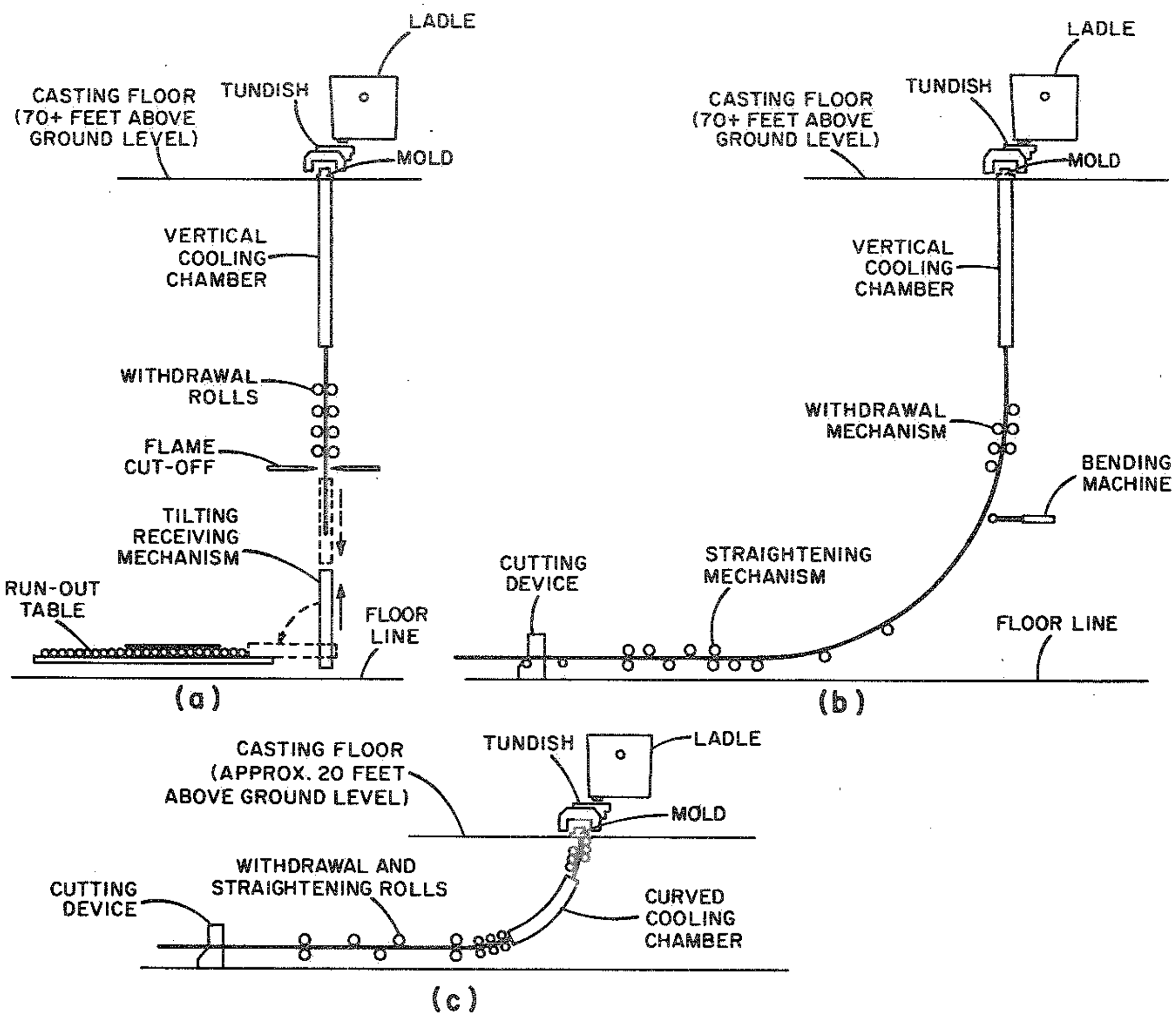


Figure 5.9 Three Continuous Casting Configurations

The temperature of the liquid steel must be precisely controlled in the ladle and tundish to insure fluidity and yet use a minimum amount of fuels. Usually, the tapping temperature in the steelmaking furnace is slightly higher for a continuous-cast than for an ingot-cast heat. The tundish is also well insulated and heated to insure fluidity. A major problem is to prevent the billet or slab from sticking to the mold as it solidifies so that ruptures and skin cracks are avoided. In modern designs, sticking is minimized by an oscillating mold and a proper lubricant. A rupture occurring in the mold may heal itself before leaving the mold. A rupture that does not heal or occurs below the mold will result in a "break-out" of the liquid steel from the center core forcing a shutdown of the facility. The potential for break-outs is increased in steels containing large amounts of dissolved oxygen (400 ppm) such as rimmed low carbon steels (below 0.2% carbon). For this reason, rimmed steels are more difficult to continuous cast than killed steels. The latter contain smaller amounts of oxygen (50 ppm) and more carbon (above 0.3% carbon). In the U. S., mostly low-oxygen killed steels are continuous cast. Rimmed steels are not continuous case because the high oxygen content results in CO evolution and, therefore, poor surface quality, especially in a curved molding machine where internal inclusions cannot move to the top of the cast billet. An overseas continuous casting manufacturer[55] however, claims to have solved the problem in a curved casting machine by the use of a special submerged nozzle that promotes the rising of the entrained inclusions.

Curved mold machines have the advantage that the metal strand is bent when the steel is in the liquid state, rather than in a partially solidified state as occurs in bending. The result is that strands in curved molds are less susceptible to surface and corner cracks caused by a combination of bending and thermal stresses.

Continuous casting installations in the U. S. are divided almost equally between curved and straight mold machines. There appears to be a slight preference for curved mold slab machines and straight mold billet machines. Since 1971, the trend has been toward straight mold billet and curved mold slab machines. Straight mold machines both for billet and slab casting tend to have larger capacity than curved mold machines.

Although most continuous-cast steels are killed and thus have high carbon contents, examples of high quality continuous cast medium-carbon steels have appeared in the literature. U. S. Steel at the Chicago South Works has continuous cast 0. 15 to 0. 30% carbon steels and reduced the inclusion volume by about 50% by degassing.[56] Further improvements were noted with the addition of aluminum to absorb the oxygen. Laclede steel reported in 1970 successful casting of C1020 (0. 18 to 0. 23% carbon) blooms killed with silicon and with surface quality superior to ingot cast steel.[57] Lukens reported that slab produced with 0. 32 to 0. 38% carbon showed the best quality with only 0. 3% requiring conditioning.[58] They also reported casting steels below 0. 11% carbon but then more aluminum was required than for ingot casting.

Regarding the long periods of time required for equipment and system shakedown and operator training, it appears that they are becoming shorter. McLouth Steel took from 1965 to about 1971 to get its slab casters up to full production and profitability. Laclede steel took from November 1967 to January 1970 to obtain acceptable product yields and quality from its bloom caster.[59] In a machine installed in 1973, Inland Steel was able to cast at about 75% capacity in about a year.[60]

As already stated in an earlier section, almost all green field mini-mills built in the last five years have been equipped with continuous casters. The challenge that lies ahead in the continuous casting industry is the further expansion into integrated plants, especially in the casting of slabs where large tonnages are involved. Presently only about 11% of the casting capacity of integrated plants is continuous cast whereas in mini-mills, the fraction is about 33%. Much of the soaking pit and primary breakdown mill capacity in integrated plants is fully depreciated. As a result, the industry is reluctant to retire this capacity in favor of continuous casting.

5.6 REHEAT AND HEAT TREATING FURNACES

A substantial amount of energy is lost in various heat-treating and finishing operations. Most of the loss occurs because steel is allowed to cool down to room temperature between initial breakdown and secondary rolling, and between secondary rolling and heat-treating and finishing. Fuel saving could be achieved if some of the cooling and reheating were eliminated. No obvious metallurgical reason exists for allowing steel to cool between initial breakdown and secondary rolling. The temperature of the billet or slab could be equilibrated in a holding furnace where fuel consumption would be considerably less than in a reheat furnace. Industry representatives[61] opined that the primary reason for cooling the billet or slab to room temperature prior to reheat and secondary rolling was to enable inspection and surface scarfing that, if a hot inspection and scarfing procedure were developed the reheat furnace could be eliminated. With today's technology, they felt that elimination of reheat was applicable only to low quality steel grades where surface inspection is not vital. Problems of logistics also deter elimination of the reheat furnace.

Of course, cooling after secondary rolling is necessary metallurgically for subsequent cold rolling, heat-treating and finishing operations in order to obtain the required strength, ductility and other properties.

Fuel consumption in reheat furnaces averages about 2.75×10^6 Btu/ton r. s. and ranges from about 1.8 to 4×10^6 Btu/ton r. s. Table 5.4 shows an approximate heat balance for a pusher type reheat furnace with heat loss to water-cooled skids (50% insulation coverage between furnace campaigns) and flue gases comprising 20% and 43% of the furnace losses, respectively. Fuel consumption in reheat furnaces can be increased considerably by reducing these losses. Hovis[62] has estimated that skid rail insulation on pusher type reheat furnaces generally averages about 50% coverage between furnace campaigns (15-18 months duration). If this average coverage is increased to 80% by re-insulating every six months, approximately 12.5% of the fuels used can be saved with a minimum of investment. Flue gas losses are more difficult and expensive to reduce on existing furnaces since that would involve major hardware modifications.

TABLE 5.4

HEAT BALANCES - 5 ZONE REHEAT FURNACE[63]

	50% Avg. Coverage of Insulation 10^6 Btu/hr
Heat to Steel	126
Heat to Water	84
Wall Losses	9
Furnace Opening	
Infiltration	6
Radiation	18
Waste Gas	183
TOTAL INPUT	426
Btu/Ton	2.55
Straight Run	

An additional recuperator module can be added or an existing recuperator replaced to further increase combustion air preheat temperatures. Without changes in combustion air piping and burner design, however, combustion preheat temperatures are limited to about 1000°F on currently installed reheat furnaces. Figure 5.10 shows that at a flue gas temperature of 2600°F, increasing the preheat temperature from 700 to 1000°F reduces fuel consumption by about 12%. Alternatively, a waste heat boiler can be placed above the recuperator producing steam at pressures as high as 400 psig. Both of these alternatives for reducing flue gas temperature on existing furnaces are capital intensive.

For a new reheat furnace installation, the economics favor the installation of heat recovery equipment. Since flue gas temperatures on reheat furnaces are 2400 – 2600°F, it is advisable to install a waste heat boiler, if steam capacity is required, and then a recuperator. If the recuperator is installed first, the flue gases must first be diluted to 1800°F for present-day recuperators and, therefore, a considerable amount of thermal head is lost. Even with modest heat recovery, with the waste heat boiler before or after the recuperator, about 5.0 megawatts of electricity can be generated from a 400 million Btu/hr reheat furnace by passing the steam produced through a steam turbine. This amounts to about 33 kwhr/ton r. s., i. e., about 4% and 11% of the electricity requirements of a minimill and an integrated mill, respectively. Armco has installed a waste heat recovery boiler and recuperator and achieved a flue gas temperature of about 380°F and a furnace efficiency of about 60%[64] (including credit for steam produced). For installations where

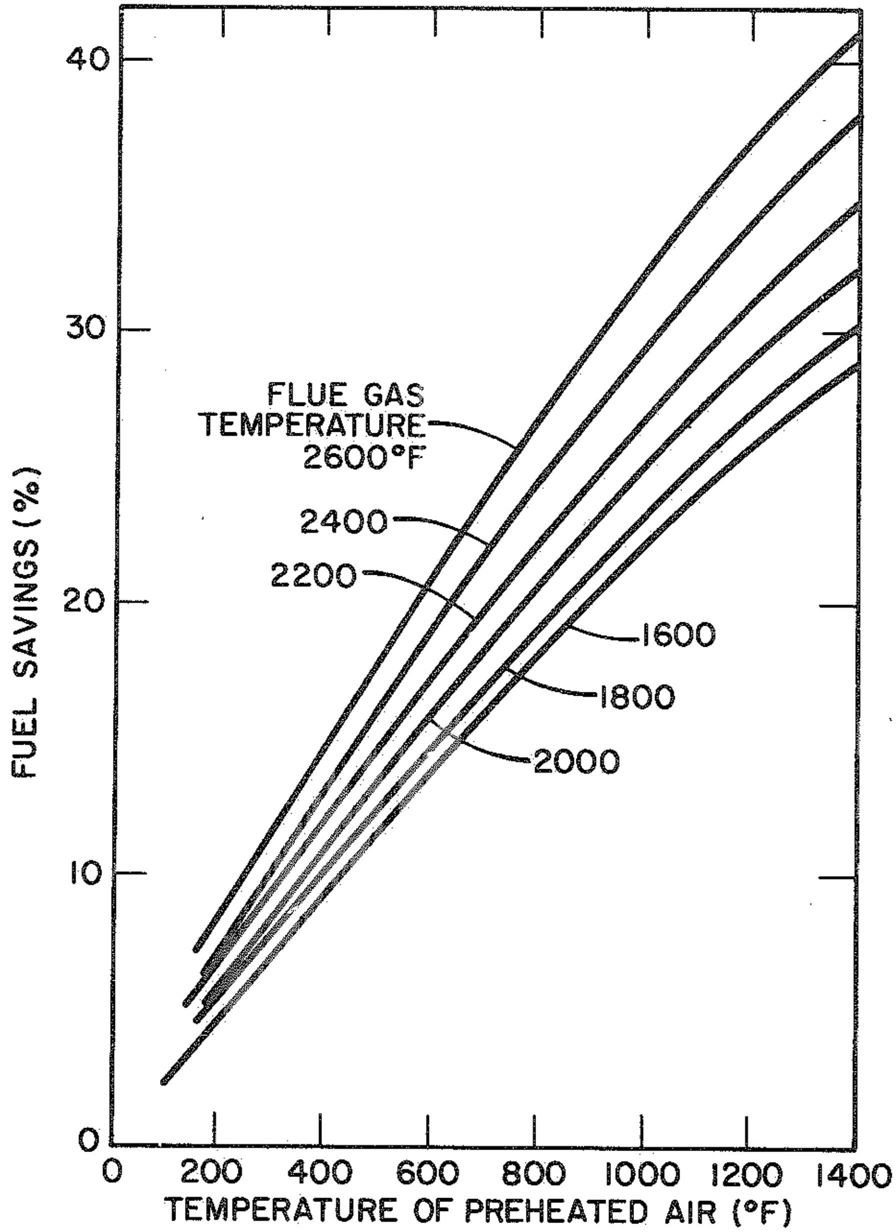


Figure 5.10 Percent Fuel Savings for Preheated Air in Natural Gas Flames.[63]

additional boiler capacity is not required, a higher temperature recuperator would save more fuel. A preheat temperature of 1500° F would save about 12% compared to 1000° F and 28% compared to 700° F at a flue gas temperature of 2600° F. Metallic recuperators are not capable of withstanding such high temperatures and, unfortunately, ceramic recuperators are not available commercially. Some development work has been performed by the British Steel Corporation on ceramic recuperators and a prototype was installed on a soaking pit.[65]

Hovis[66] has also noted correctly that reheat furnaces often run at part load capacity and that if operated improperly, considerable quantities of fuels can be wasted. He notes that at part load, the heat input into the burners in the preheat and heat zones should be reduced sufficiently so that the slab reaches rolling temperature as it enters the soak zone rather than prematurely in the heat zone. It is estimated that fuel savings of 10%-15% can be achieved with proper control at part load.

In addition to the pusher type reheat furnace, walking beams are used extensively. In a walking beam furnace, a large overhead beam mechanism walks the stock through the furnace. It has the advantages that: (1) in high tonnage operation, there is no limit on length, whereas in the five-zone pusher type furnace, length is limited because of stock pileup; (2) gouging of the slab is eliminated; and (3) and average insulation coverage of the water-cooled support mechanism is greater than that in a pusher-type furnace because of the reduced vibration. The disadvantages of the walking beam furnace are: (1) it has large cooled surfaces that require large quantities of water; and (2) it is mainly side fired. Fuel consumption is about 10%-20% greater than that of the pusher type, and slab-temperature distribution tends to be less uniform than in a pusher type furnace, which is top and bottom fired. Slab temperature uniformity will be poorer with oil-firing than with gas-firing in walking beam furnaces.

The monobeam furnace is a new development in reheat furnaces which attempts to overcome the disadvantages of the walking beam.[67] The mechanism in contact with the slab is made of ceramic. The remaining mechanism is cooled but can be covered with more average insulation than either a walking beam or a pusher furnace as the mechanism neither vibrates nor flexes. The monobeam furnace is fired from bottom and top in a lengthwise path, either parallel or counterflow to the slab movement. The developers of this furnace estimate 10%-15% fuel savings. In addition, they claim that the monobeam can be oil-fired with a more uniform slab temperature distribution than a walking beam. Capital costs are estimated by the developers to be the same as those for the walking beam. Another industry source believes that the ceramic beam will shield the flame from the slab, reducing the benefits of the thinner cooled walking mechanism in the walking beam furnace. The industry source, after a brief review of the system, thought that maintenance problems might be severe and saw no way of removing the slab scale. A complete monobeam furnace has not been field tested yet.

The installation of recuperators on heat-treating and forging furnaces is less prevalent than on reheat furnaces. The reasons are varied. In general, heat-treating and forging furnaces are smaller in size with lower flue gas temperatures. Thus, fuel savings that can be expected from preheated combustion air are smaller in magnitude than for reheat furnaces. Because of the smaller unit size, recuperator installations have also been capital intensive. As a result of the U. S. energy crisis and natural gas shortage, several furnace companies have begun marketing recuperators for radiant tube and direct-fired furnaces. Gas savings of 15% - 30% have been reported on installations in operation for more than a year. Recuperator wear to date has been excellent.[68]

5.7 COMBINED GENERATION OF ELECTRICITY AND PROCESS STEAM

The ratio of self generated to total electrical consumption in iron and steel manufacturing has declined steadily in recent years (see Fig. 3. 3). This trend can be attributed to the development of economical, packaged, low-pressure boilers fired with oil or gas in sizes to about 200, 000 lb steam/hr, and to the steady decline in the cost of purchased electricity (at least until October 1973). With the rise in the price of fuels and the shortage of natural gas and boiler fuel oils, however, combined generation of electricity and process steam has become economically more attractive than purchasing utility electricity and raising separately process steam.

The feasibility of combined generation of electricity and process steam depends on individual plant practices and the demand for process steam. Mini-mills require about 10^6 Btu of low pressure process steam/ton r. s., and about 650-700 kw-hr/ton r. s. of electricity (mainly for electrical steelmaking furnaces). Steam turbine topping will produce about 50 kwe-hr/10^6 Btu process steam (200 psig) and gas turbine topping about 200 kwe-hr/10^6 Btu process steam (200 psig). Thus, it appears that gas-turbine topping can supply about one-third of the power requirements and all the required process steam. Based upon the additional fuel, the electricity is generated at the low rate of about 5500 Btu/kwhr. This rate is about one-half that of utilities (10,000 Btu/kwhr). The drawback of gas turbines is that they are restricted to using oil or gas. For 1973 production levels, if all mini-mills used gas-turbine topping then the fuel saving would be about 0.9×10^6 Btu/ton r. s. or about 2.7×10^{13} Btu/year. With steam turbine topping, which can utilize coal to generate the required high pressure steam for the turbines, the fuel saving would have been about 0.23×10^6 Btu/ton r. s. or about 0.69×10^{13} Btu/year.

For integrated mills, the ratio of electricity to process steam requirements is about 106 kwe-hr/10^6 Btu steam, considerably lower than that for mini-mills. Approximately half the required steam in integrated plants is above 400 psig and the remainder at 200 psig or lower. With steam-turbine topping and gas-turbine topping an average of about 42 and 220 kwhr/10^6 Btu process steam, respectively, can be generated. Thus, steam-turbine topping can supply about 40% of the electrical needs of the integrated mill, whereas gas-turbine topping can provide all the plant requirements and in addition can export about 116 kwhr/10^6 Btu process steam for sale to a utility.

Integrated mills currently generate 25% of their electricity needs by mainly using topping with condensing turbines. It follows that they make use of about 62.5% of the maximum that can be generated with steam-turbine topping. If steam and gas-turbine topping were combined, all the electrical needs of an integrated mill could be satisfied by in-plant generation. The fuel saving would be 1.2×10^6 Btu/ton r. s. or about 14.75×10^{13} Btu/year. Utilizing steam-turbine topping to the maximum could save 0.25×10^6 Btu/ton r. s. or 3.1×10^{13} Btu/year. In conclusion, combined generation of electricity and process steam in both integrated and mini-mills can potentially result in fuel saving between 3.8 and 17.4×10^6 Btu/year.

Though very promising, the economics and technical feasibility of in-plant generation must be determined plant by plant. Particularly important is the demand schedule for both steam and electricity. In order to generate the maximum amount of electricity with steam turbine topping, the steam and electricity demand must be in phase and fairly uniform. Loads will generally be more constant in an integrated plant simply because there is a greater variety of equipment utilizing steam and electricity. Some operations, such as vacuum degassing, use steam (for vacuum ejectors) intermittently and require quick response times, not obtainable with field-erected or coal fired boilers. Other applications of steam, such as turbine drives for the blast furnace, air blast blowers, and various rolling and breakdown mills are more apt to operate at uniform rates.

6. ECONOMIC EVALUATIONS

In this section, the economics of process options which conserve fuel or convert to a more readily available fuel are evaluated.

As a criterion for the economic viability of a process option to a company we have adopted a rate of return on investment after taxes of 12% or higher. This criterion was established as follows:

An analysis based upon the weighted averages of debt and equity, value line risk factors,[69] and bond rating of the largest steel companies has shown that a rate of return after taxes of about 11.4% should be sufficient to recover the cost of capital and provide historic profit margins. This rate of return can be compared with the average ratio of profits to equity. For the steel industry this rate was 17% in 1974 and about 7.0% from 1960 to 1974. For all manufacturing enterprises, it was 11% from 1960 to 1974 (see Fig. 2.1). The comparison suggests that investment opportunities for fuel conservation or fuel conversion process options with rates of return between 11 and 12%, and with high confidence factors in obtaining the planned objectives, would be adapted by the industry.

Of course, economic evaluations of new process options are often clouded by uncertainties, especially when the process has not been fully implemented in a production mode or when the process has been implemented in a foreign country where relative costs are different from those in the U. S. In addition, certain processes may be proprietary and their costs may not be available. Our evaluations are no exception to these difficulties.

6.1 DRY QUENCHING OF COKE

In 1973, Kemmetmeuller[70] estimated the capital cost for dry quenching of coke at $5 per annual ton for a 3,000 ton/day plant. In 1975, with a 40% increase in capital costs, a 3,000 ton/day plant would require about $7.7 million. Some industry sources,[71] however, believe that the cost would be about $15 million without pollution control. We will assume that costs will be $3 million for pollution control and $18 million for the total plant.

Steam production is assumed to be 800 lb steam per ton of coke* with the steam valued at $3.75/1,000 lb for fuel at $2.25/10^6 Btu, and $2.08/1,000 lb at $1.25/10^6 Btu. The extent to which coke is saved in blast furnaces by using dry coke is uncertain. In addition, the cost of coke varies depending on whether coke is manufactured in-plant ($65/ton) or purchased ($110/ton). For these reasons, the economic evaluation is performed parametrically with respect to steam and coke costs.

A sample calculation is shown in Table 6.1 for steam valued at $3.75/1,000 lb, 1.5% coke savings at $65/ton, and current tax rules (48% tax rate and 10% investment tax credit).

The rate of return vs percentage of coke saved in the blast furnace is shown in Figure 6.1 It is seen from this figure that for fuel priced at $2.25/10^6 Btu (oil at $13.50/bbl) and coke priced at $65/ton, a minimum of 1.5% of coke must be saved for the investment in dry quenching to meet the rate of return criterion. For fuel priced at $1.25/10^6 Btu (coal at $31.25/ton) and coke at $65/ton, a minimum of 5% of coke must be saved for dry quenching to be economically viable.

*See Section 5.2.2 for discussion of steam production.

TABLE 6.1

ECONOMIC EVALUATION OF DRY QUENCHING OF COKE

Capital costs		
Dry quenching system (3,000 ton/day)		$18,000,000
Boiler savings		1,000,000
Total capital		$17,000,000
Fuel savings		
800 lb steam/ton coke at $3.75/1,000 lb (fuel value)	$3.00/ton	
1.5% coke savings in blast furnace at $65/ton	0.58	
Total savings	$3.58/ton	
Operating costs		
Electricity, 8 kwhr/ton at $0.03 kwhr	$0.24/ton	
Maintenance and other operating costs	0.36	
Total operating costs	$0.60/ton	
Net savings before taxes (360 days)	$2.98/ton	$ 3,220,000/year
Tax deductions (first year)		
Depreciation (straight line, 18 year life)	$944,000	
Profit for tax purposes		$ 2,256,000
Taxes (48%) for years 2-18		$ 1,083,000
Taxes (48% less 10% investment tax credit) for year 1		(617,000)
Net cash flow after taxes for years 2-18		$ 2,117,000
Net cash flow after taxes for year 1		$ 3,817,000
Rate of return on investment		11.9%

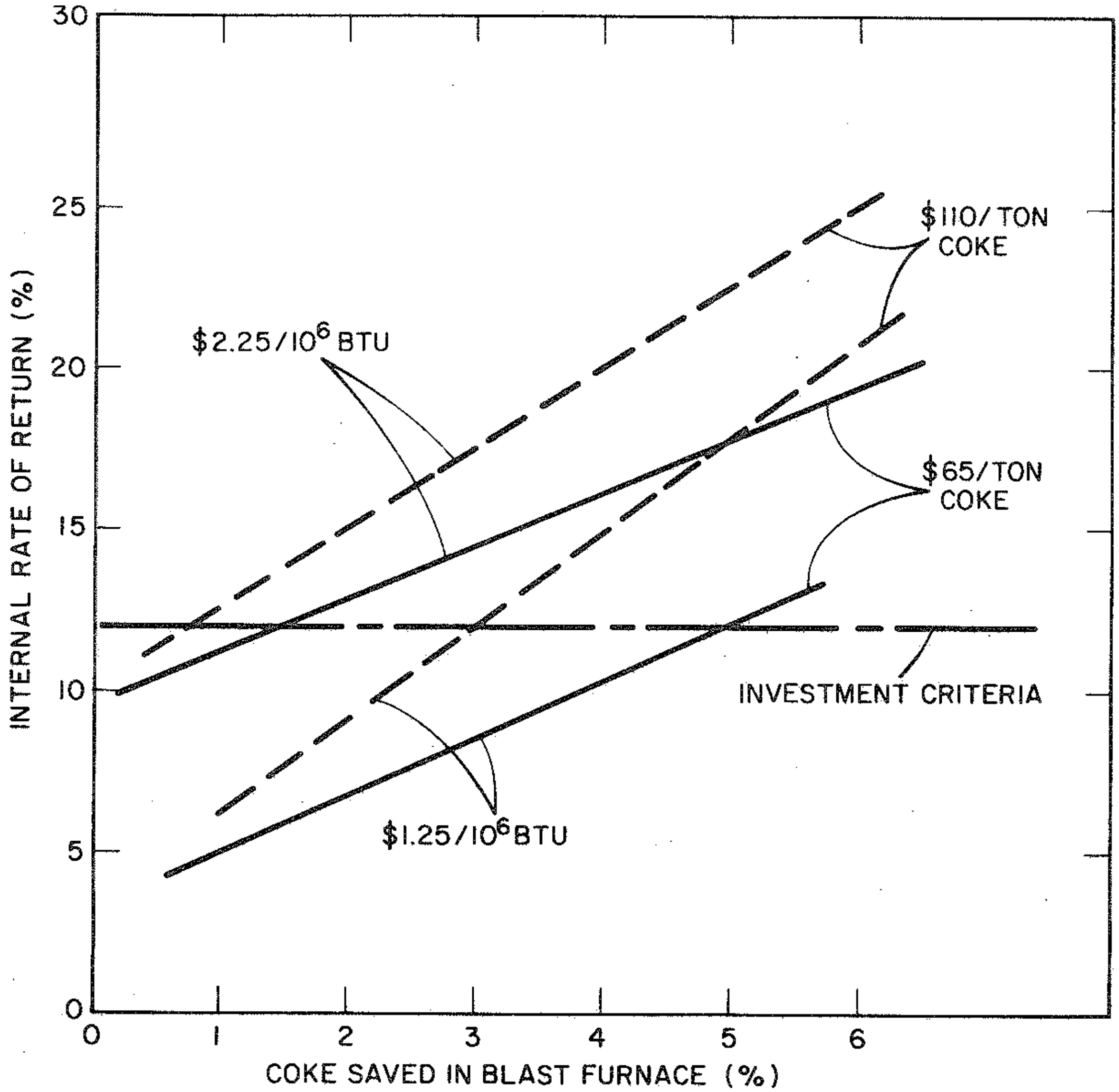


Figure 6.1 Economics of Dry Quenching of Coke

For coke oven plants using merchant coke at $110/ton coke, the minimum coke savings in the blast furnace must be 0.75% and 3% for fuel priced at $\$2.25/10^6$ Btu and $\$1.25/10^6$ Btu, respectively. Most of the coke used (93%) in blast furnaces is manufactured in-plant, and therefore, the economic evaluation of dry quenching must be based on coke priced at $65/ton.

6.2 REDUCTION OF COKE RATE AND INCREASED EFFICIENCY IN BLAST FURNACE OPERATION

6.2.1 Blast Furnaces

As discussed in Section 5 the coke rate can be decreased and the blast furnace efficiency can be increased by increasing air blast temperatures, increasing air blast pressures, optimizing the ore and coke burden, etc. Many of these changes, particularly increased air blast pressures, cannot be retrofitted to existing blast furnaces, and therefore, coke and fuel savings can be achieved either in new installations or by replacing old existing blast furnaces with new furnaces capable of operating with air blast temperatures greater than 2000°F and top pressures greater than two atmospheres.

An analysis of the economics of replacing an operating blast furnace by a new and modern one is listed in Table 6.2. In this analysis, we assumed that the operating furnace: (1) is fully depreciated, (2) has no salvage value, (3) has operating costs per ton of pig iron, exclusive of coke savings, equal to those of the new furnace, and (4) consumes 200 lb coke/ton pig iron more than the new furnace at $65/ton. Capital costs for a 8000 ton/day blast furnace are estimated at $288 million based upon $100 per annual ton of capacity.* We see

*Ref. (72) reports the replacement value of blast furnaces in 1972 to be $76 per annual ton of capacity. $100 is arrived at by assuming an approximate inflationary factor.

TABLE 6. 2

REPLACEMENT OF OLD BLAST FURNACES

Capital cost for 8, 000 ton/day blast furnace		$288, 000, 000
Savings resulting from saving 200 lb coke/ton pig iron at $65/ton coke (assuming conservatively that all of the operating costs for new and old blast furnaces are the same)		$ 18, 700, 000/year
Income taxes for 2-18 year depreciation		
Depreciation $\frac{(288 \times 10^6)}{18}$	$16, 000, 000	
Taxable income	$ 2, 700, 000	
Taxes (48%)	$ 1, 300, 000	
Resultant cash flow after taxes for 2-18 years		$ 17, 400, 000
Investment tax credit for 1st year	$ 28, 800, 000	
Resultant cash flow after taxes for year 1		$ 46, 200, 000
Return on investment (48% tax, 10% investment tax credit)		2. 0%
Capital cost per bbl/day equivalent of coke saved (for 200 lb. coke/ton pig difference in coke rate)		$ 86, 400

from this table that the rate of return is only 2.0%. Figure 6.2 shows the variation of the rate of return vs coke saving, with coke valued at $65/ton and $110/ton. It is seen from this figure that for $65/ton coke the installation of a new blast furnace must save 600 lb coke/ton pig iron in order for the rate of return to be 12%. For $110/ton coke, a minimum saving of 350 lb coke/ton pig iron is required to achieve a 12% rate of return.

With equivalent hydrocarbon injectants, new blast furnaces are expected to have coke rates between 900 and 950 lb/ton pig iron compared with the present U. S. average of 1,200 lb/ton pig iron. We conclude that replacement of operating blast furnaces by modern ones is not universally justified with existing tax regulations. We estimate that 35% of the blast-furnaces capacity that uses merchant coke and about 10% of the capacity that uses coke manufactured in-plant could be replaced without economic penalty to the steel industry; this capacity represents about 11% of the total blast furnace capacity.

6.2.2 Bell-less Tops

Because it optimizes the burden distribution, the bell-less top may save 20-40 lb coke/ton pig iron when installed on an existing blast furnace. A Paul Wurth bell-less top for a medium size U. S. blast furnace will cost about $\$10^6$ including basic electronics and hydraulics.[73] If we guess-estimate an additional $\$10^6$ for installation and coke priced at $65/ton we find that the rate of return is 27% (Table 6.3). We conclude that installation of a bell-less top is an economically viable way of making a small reduction in the coke rate of existing blast furnaces.

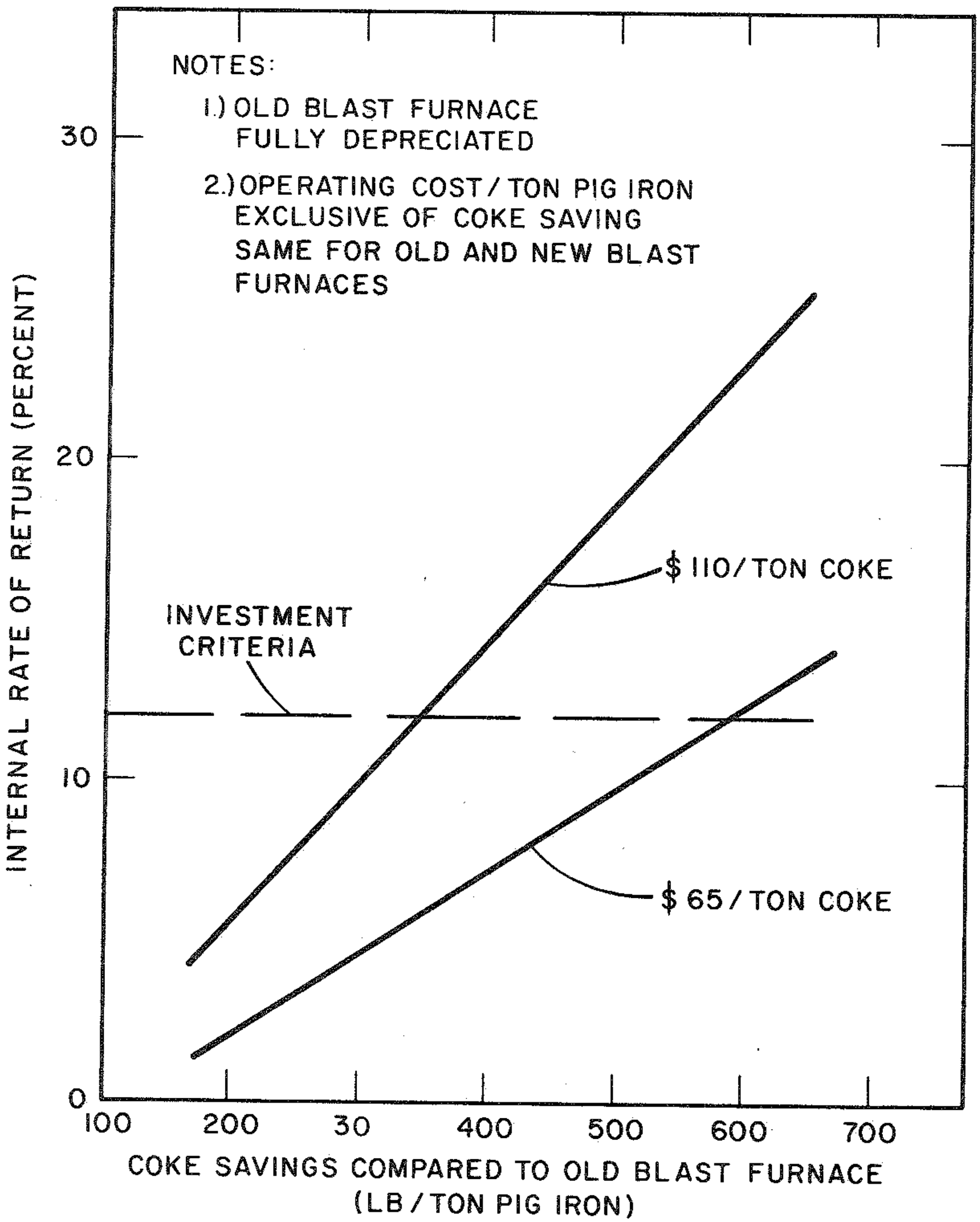


Figure 6.2 Economics for the Replacement of Old Blast Furnaces

TABLE 6.3

INSTALLATION OF BELL-LESS TOP ON EXISTING BLAST FURNACES

Capital cost for 300 ton/day blast furnace		
Bell-less top		$ 1,000,000
Installation		1,000,000
Total		$ 2,000,000
Savings		
Savings in coke rate (30 lb coke/ton pig iron at $ 65/ton coke)		$ 1,070,000
Other operating and maintenance costs at 10% of capital costs		200,000
Net savings		$ 870,000
Income taxes for 2 to 18 year		
Depreciation	$ 110,000/year	
Taxable income	$ 760,000/year	
Taxes (48%)	$ 365,000/year	
Resultant additional cash flow after taxes for 2 to 18 year		$ 705,000
Investment tax credit for 1st year	$ 200,000	
Resultant additional cash flow after taxes in first year		$ 505,000
Return on invested capital		27.2%
Capital cost per bbl/day equivalent of oil saved		$ 10,700

6.2.3 Pulverized Coal

Injection of pulverized coal into the tuyeres of blast furnaces is an attractive process change option. For a pulverizing plant and injection system designed for 33 tons coal/hour (at a 25% replacement of coke with coal and a coke to coal replacement ratio of 0.8, a 33 ton/hour system will serve a 4,200 ton/day blast furnace). The installed cost is $10,000,000.[74] For a coke to coal price differential of $35/ton (i.e., coke at $65/ton and non-coking coal at $30/ton) the rate of return is about 40% (Table 6.4). For pulverized coal replacing either merchant coke ($110/ton) or injected oil ($85/ton) the rate of return will be larger than 40%. We conclude that injection of pulverized coal will grow rapidly under existing tax regulations.

6.3 CONTINUOUS CASTING

Continuous casting can result in fuel savings of about 800,000 Btu per ton of raw steel. Capital requirements for continuous billet-casting machines are estimated to be $25-40/annual ton compared to $80-100/annual ton for ingot-casting of billets (including soaking pits, blooming and billet mill, yards, etc.). Capital requirements for continuous slab-casting machines are estimated as high as $60/annual ton compared to a low of $60/annual ton for ingot soaking pits, yards, etc. Operating costs for both billet and slab continuous casters are generally substantially lower than those for ingot casters. We conclude that most greenfield installations will incorporate continuous casting, except where this is prohibited by the type of product. On the other hand, for growth in steel-processing capacity by rounding out of existing facilities we foresee that continuous casting

TABLE 6.4

INJECTION OF PULVERIZED COAL IN BLAST FURNACES

Capital cost for plant additions for 33 ton/yr of coal		$ 10,000,000
Savings in operating costs		
Savings in coke (based upon replacement ratio of 0.8 lb coke/lb coal and $ 35/ton cost differential)	$ 7,980,000/year	
Additional operating costs at $ 3.00/ton coal	860,000/year	
Net savings	$ 7,120,000/year	
Income taxes for 2 to 18 year		
Depreciation	$ 550,000/year	
Taxable income	$ 6,570,000/year	
Taxes (48%)	$ 3,150,000/year	
Resultant additional cash flow after taxes for 2 to 18 year		$ 3,970,000/year
Investment tax credit for first year	$ 1,000,000	
Resultant additional cash flow after taxes for first year		$ 4,970,000
Return on invested capital		42.8%
Capital costs per bbl/day equivalent of oil saved		$ 13,300

will not be adopted as broadly as for greenfield installations, although it may well predominate over ingot casting.

Additional steel processing capacity expected to be installed by 1983 is between 30 and 40 million tons of raw steel. A substantial fraction of this capacity will be continuous casting. The capacity of continuous casting can be increased further by replacing existing ingot facilities with continous casters, provided that such replacement is economically viable.

We have examined the advisability of replacing existing ingot facilities by continuous casters as follows. Based upon a comparative analysis (Table 6. 5), we estimate that the operating cost of ingot casting is $10. 00/ton raw steel larger than that of continuous casting, independent of the age of the existing ingot facilities. Using this figure and other costs, we performed sample calculations for the replacement of a ten-year old ingot-casting slab facility by a continuous caster (Table 6. 6). We assumed a depreciation and useful life of 18 years without any salvage value (for tax purposes); and no market value for the facility which is being replaced. In Table 6. 6, it is noteworthy that 48% of the book value of the caster being replaced is debited as a tax credit against the investment for the continuous caster and, therefore, that the net investment is reduced.* More generally, we observe that a fully depreciated old asset will not have any book value and, therefore, no tax credit, whereas a new asset will have a large book value and a large tax credit. As a result,

*It is also noteworthy that in the analysis the depreciation of the old asset is subtracted from that of the new asset for the remaining depreciable years of the old asset. Thus, the cash flow for these years is decreased.

TABLE 6.5

OPERATING AND CAPITAL COSTS FOR CONTINUOUS CASTING

CONTINUOUS CASTING		
Operating Costs		
Labor		\$ 5.93/ton
Maintenance labor		2.47
Cost of materials		3.02
Cost of Utilities		
Oxygen	\$ 0.09/ton	
Natural gas or fuel oil (0.3 x 10^6 Btu/ton at 2.25/10^6 Btu)	0.68	
Water	0.02	
Electricity (16 kwhr/ton at \$0.025 kwhr)	0.40	
Air	0.02	1.21
Total operating costs		\$12.63/ton
Total operating costs corrected for scrap (based upon 95% yield)		\$13.29/ton
Capital cost requirements for continuous cast billet mill		\$25-40/annual ton
Capital cost requirements for continuous cast slabbing mill		\$25-60/annual ton
INGOT CASTING		
Operating Costs		
Labor		\$ 6.58/ton
Maintenance labor		3.70
Cost of materials		6.50
Cost of utilities		
Natural gas (1 x 10^6 Btu/ton at 2.25/10^6 Btu)	\$ 2.25/ton	
Electricity (27.5 kwhr/ton at \$0.025 kwhr)	0.69	2.94
Total operating cost		\$19.72
Total operating cost corrected for scrap (based upon 85% yield)		\$23.29
Capital cost requirements for blooming and soaking pit		\$80-120/annual ton
Capital cost requirements for slabbing mill and soaking pits		\$60/annual ton

TABLE 6.6

ECONOMIC ANALYSIS FOR THE REPLACEMENT OF AN INGOT SLAB MILL (10 YEARS OLD) BY A CONTINUOUS SLAB CASTER

Capital cost for continuous slab caster		\$ 60/annual ton
Original cost for ingot slab mill	\$ 32.5/annual ton	
Book value of ingot slab mill	\$ 14.4/annual ton	
Tax loss due to scrapping of old mill (48%)		6.93
New investment for continuous slab caster		\$ 53.07/annual ton
Income taxes for 2 to 8 year		
Depreciation $\frac{(\$ 60}{18} - \frac{\$ 32.5)}{18}$	\$ 1.53/ton	
Taxable income (\$ 10- \$ 1.53)	\$ 8.48	
Taxes (48%)	\$ 4.07	
Resultant cash flow for 2 to 8 year (\$ 10.00- \$ 4.07)		\$ 5.93/ton
Resultant cash flow for first year (\$ 5.93 + 10% investment tax credit)		\$11.93/ton
Income taxes for 9 to 18 year		
Depreciation (\$ 60/18)	\$ 3.33/ton	
Taxable income	\$ 6.67	
Taxes (48%)	\$ 3.20	
Resultant cash flow for 9 to 18 year (\$ 10.00-3.20)		\$ 6.80/ton
Internal rate of return for 48% tax, 10% investment tax credit (Present tax rules)		9.0%

the net investment for replacement of a newer existing asset is smaller than that for the replacement of an older asset. When the initial cost of an existing asset is greater than or a substantial fraction of the cost of the replacement asset, the tax credit can result in an attractive rate of return for investments for replacement of a relatively new facility.

The rate of return vs age of ingot mill for replacement ingot-slab and ingot-billet mills by continuous casters is shown in Figure 6.3. We see from this figure that the smaller the age of the mill being replaced, the larger the rate of return. Of course, the effect is more pronounced for ingot-billet mills because these mills cost much more than continuous billet casters.

More specifically, we see from Figure 6. 3 that continous billet casters have an internal rate of return greater than 12%; for a fully depreciated existing asset the rate of return is 15%, and for a three-year old existing asset 40%. We conclude that no economic barrier exists for the replacement of existing ingot billet mills with continuous billet casters. Very likely, however, the extent of this replacement will be dictated more by institutional barriers and product variability and requirements than by economics.

Because they are more costly than ingot billet casters, continuous slab casters yield a rate of return less than 12% (8.0% for a fully depreciated old asset). We conclude that economics, in addition to institutional and other barriers will impede the replacement of ingot slabbing facilities by continuous slab casters.

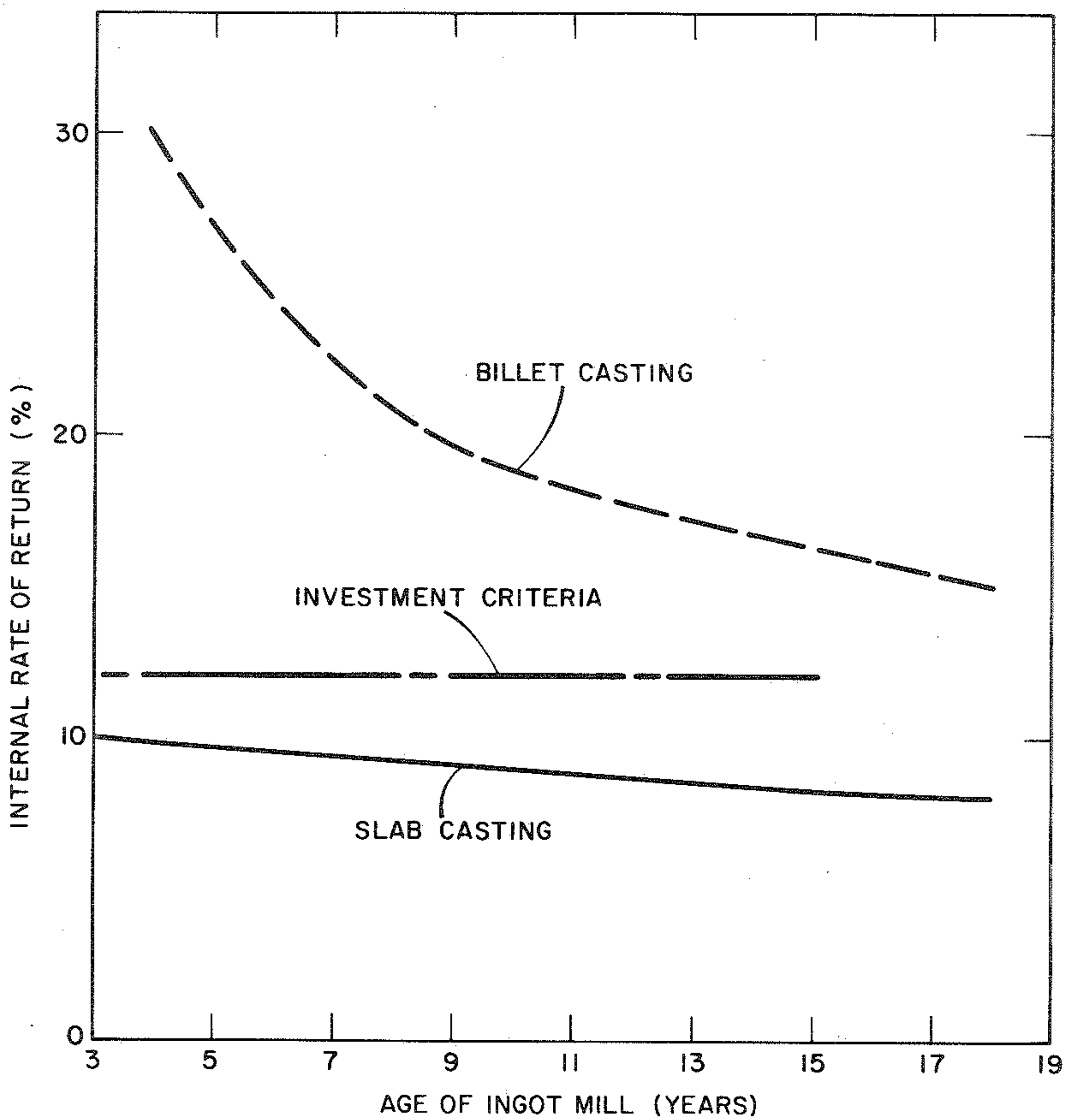


Figure 6.3 Economic Analysis for the Replacement of Soaking Pit/Blooming or Slabbing Mill by Continuous Casting Machine

6.4 RECUPERATION AND GENERATION OF ELECTRICITY FROM WASTE FLUE GASES

Installation and upgrading of recuperators can significantly improve fuel utilization in steel processing and heat treating. The largest use of fuels in steel processing is in soaking pits and reheat furnaces. Table 6.7 presents an economic analysis for the installation of recuperators on new reheat furnaces and Table 6.8 for the installation of a new recuperator on existing reheat furnaces. We see from Table 6.7 that recuperators are economically very attractive. Of course, this attractiveness has already been recognized by industry and most, if not all, reheat furnaces are equipped with recuperators. Many of these recuperators, however, are old and in need of upgrading. We see from Table 6.8 that it is economically justifiable to replace an existing recuperator producing preheated air at 500° F with one that produces preheated air at 800° F. Rates of return for this replacement are 60% for fuel at $\$2.00/10^6$ Btu and 24.0% for fuel at $\$1.00/10^6$ Btu.

Generally, recuperators on soaking pits have lower serviceable lives and greater maintenance costs than those on reheat furnaces. It is of interest to examine the economics of upgrading recuperators on existing soaking pits since new soaking pits will be introduced less frequently as continuous casting becomes more acceptable. Assuming half the lifetime and twice the maintenance costs (18% of capital costs) for recuperators on soaking pits compared with those on reheat furnaces, we find that the internal rate of return is 40% and 10% for fuel at \$2.00 and $\$1.00/10^6$ Btu, respectively. For many areas of the U.S. we conclude that upgrading recuperators on

TABLE 6.7

ECONOMIC ANALYSIS FOR INSTALLATION OF RECUPERATOR ON NEW REHEAT FURNACE (400×10^6 BTU/HR WITH RECUPERATOR)

Capital requirements for recuperator (including installation)		\$ 500, 000
Operating cost savings		
Fuel savings based upon 6900 hours of operation, 25% fuel savings (800° F air preheat) and \$ 2.00/10^6 Btu	\$ 1, 845, 000/yr	
Additional operating and maintenance costs (8% of capital costs)	40, 000	
Net operating cost savings	\$ 1, 800, 000/yr	
Income taxes for 2 to 10 year		
Depreciation $\left(\frac{\$500,000}{10}\right)$	\$ 50, 000/yr	
Taxable income	\$ 1, 750, 000	
Taxes (48%)	\$ 840, 000	
Resultant additional cash flow for 2 to 10 year		\$ 960, 000/yr
Investment tax credit for first year	\$ 50, 000	
Resultant additional cash flow for 2 to 10 year		\$ 1, 010, 000
Internal rate of return (fuel at \$ 2.00/10^6 Btu)		190%
Internal rate of return (fuel at \$ 1.00 10^6 Btu)		90%

TABLE 6.8

ECONOMIC ANALYSIS FOR REPLACING OLD RECUPERATOR WITH MORE EFFICIENT MODEL ON EXISTING REHEAT FURNACE (400×10^6 BTU/HR WITH NEW RECUPERATOR)

Capital requirements for recuperator (including removal of old recuperator and installation of new recuperator)		\$750, 000
Operating cost savings		
Fuel savings based upon 6900 hours of operation, 8% fuel savings (increase in air preheat from 500-800° F), and \$ 2.00/10^6 Btu	\$ 660, 000/yr	
Additional operating and maintenance costs (8% of capital costs for new installation)	40, 000	
Net operating cost savings	\$ 620, 000/yr	
Income taxes for 2 to 10 year		
Depreciation	\$ 75, 000/yr	
Taxable income	\$ 545, 000	
Taxes (48%)	\$ 260, 000	
Resultant additional cash flow for 2 to 10 year		\$ 360, 000/yr
Investment tax credit for first year (10%)	\$ 75, 000	
Resultant additional cash flow for first year		\$ 435, 000/yr
Resultant rate of return (for fuel at \$ 2.00/10^6 Btu)		60%
Resultant rate of return (for fuel at \$ 1.00/10^6 Btu)		24%

soaking pits will not be economically attractive under present tax regulations with fuel priced at $\$1.00/10^6$ Btu.

Recuperators have been installed less frequently in the past on radiant tube and other heat treating furnaces than on soaking pits and reheat furnaces largely because heat-treating furnaces are generally smaller in size. Until 1973, there were virtually no recuperators on radiant tube furnaces. As a result of the shortage in natural gas, furnace manufacturers had begun to market radiant tube recuperators. The results shown in Table 6.9 indicate that even with fuel priced at $\$1.00/10^6$ Btu, recuperators on new radiant-tube and other heat-treating furnaces are economically justified. Because site work and new burners are required, retrofitting heat-treating furnaces with recuperators is not as advantageous as the use of recuperators on new furnaces. We see from Table 6.10 that the rate of return for retrofitting existing furnaces is about 22% and 7% for fuel prices at $2.00 and $\$1.00/10^6$ Btu, respectively.

Installations of waste heat boilers and bottoming steam turbines in the flue-gas stream of furnaces before or after a recuperator for the generation of electricity represent other fuel saving methods. Table 6.11 presents an economic analysis for electrical generation by steam bottoming. We see from this table that a rate of return of 18% is possible based upon electricity valued at $0.03/kwhr.

6.5 COLLECTION OF BOF OFF-GASES

The technical feasibility of collecting the BOF off gases was discussed in Section 5.4. Table 6.12 shows an analysis of the economics for this process option. It is seen that implementation would not be

TABLE 6.9

ECONOMIC ANALYSIS FOR INSTALLATION OF RECUPERATOR ON NEW RADIANT TUBE OR OPEN FIRED HEAT TREATING FURNACE

Capital requirements (including installation)		$ 3333/10^6 Btu/hr input
Operating cost savings		
Fuel savings based upon 5000 hours of operation, 25% fuel savings (800° F preheat temperature), and $ 2.00/10^6 Btu	$ 2500/yr	
Additional operating and maintenance costs (8% of capital costs)	260	
Net savings	$ 2240/yr	
Income taxes for 2-10 year		
Depreciation $\frac{(\$\ 3333)}{10}$	$ 330/yr	
Taxable income (48%)	$ 1910	
Taxes	$ 910	
Resultant additional cash flow for 2-10 year		$ 1330/yr
Investment tax credit for first year (10%)	$ 333	
Resultant additional cash flow for first year		$ 1463
Internal rate of return (for fuel at $ 2.00/10^6 Btu)		41.7%
Internal rate of return (for fuel at $ 1.00/10^6 Btu)		17.9%

TABLE 6.10

ECONOMIC ANALYSIS FOR INSTALLATION OF RECUPERATOR ON EXISTING RADIANT TUBE OR OPEN FIRED HEAT TREATING FURNACE

Capital requirements (including installation, new burners, startup costs)		$6300/10^6$ Btu/input
Net operating costs savings (same as in Table 6.9)	$ 2240	
Income taxes for 2-10 year		
Depreciation $\frac{(\$ 6300)}{10}$	$ 630/yr	
Taxable income	$ 1610	
Taxes (48%)	$ 770	
Resultant additional cash flow for 2-10 year		$ 1470
Investment tax credit for first year (10%)	$ 630	
Resultant additional cash flow for first year		$ 2100
Internal rate of return (for fuel at $ 2.00/10^6 Btu)		22%
Internal rate of return (for fuel at $ 1.00/10^6 Btu)		7.1%

TABLE 6. 11

ECONOMIC ANALYSIS FOR THE GENERATION OF ELECTRICITY FROM WASTE FLUE GASES

Capital requirements for heat recovery boiler, turbine, electrical generator, etc.		\$ 600/kw
Operating cost savings (per kwe)		
Value of electricity based upon 6900 hours of operation and \$ 0. 03 kwhr	\$ 207/yr	
Operating and maintenance costs (\$ 0. 003/kwhr)	\$ 21/yr	
Net savings	\$ 186/yr	
Income taxes for 2-10 year (kw)		
Depreciation $\frac{(\$ 500)}{10}$	\$ 50/yr	
Taxable income	\$ 136	
Taxes (48 %)	\$ 65	
Investment tax credit for first year	\$ 60/kw	
Resultant additional cash flow for first year (per kw)		\$ 171
Resultant additional cash flow for 2-10 year (per kw)		\$ 121/yr
Internal rate of return for 10% Investment tax credit and 48% taxes		18%

TABLE 6.12

ECONOMIC ANALYSIS FOR THE COLLECTION OF BOF OFF-GASES

Capital requirements for gas storage capacity, three way valve, water seal and compressor		\$ 5.00/ton r.s.
Operating cost savings		
Fuel recovery (0.42 x 10^6 Btu/ton at \$ 2.00/10^6 Btu)	\$ 0.84/ton r.s.	
Maintenance costs	\$ 0.25	
Net savings	\$ 0.59/ton r.s.	
Income taxes for first year		
Depreciation $\frac{(\$ 5.00)}{10}$	\$ 0.50/yr	
Investment tax credit (10%)	\$ 0.50	
Taxable income (or loss)	\$ 0.41	
Taxes (or credit)	\$ 0.20	
Resultant additional cash flow for first year		\$ 0.79/ton r.s.
Income taxes for 2-10 year		
Depreciation $\frac{(\$ 5.00)}{10}$	\$ 0.50/yr	
Taxable income	\$ 0.09/yr	
Taxes	\$ 0.04	
Resultant additional cash flow for 2-10 year		\$ 0.54/ton r.s.
Internal rate of return for 48% tax and 10% investment tax credit		2.5%

very profitable even with fuel valued at $\$2.00/10^6$ Btu or increased tax incentives. Fuel would have to be valued at more than $\$3.00/10^6$ Btu for the collection of BOF off-gases to be economically feasible.

6.6 COMBINED GENERATION OF ELECTRICITY AND PROCESS STEAM

The generation of steam and electricity can be combined by means of gas and steam turbine topping to result in significant fuel savings. In Section 5.7 we found that for steam conditions representative of an integrated plant, 42 kwhr/10^6 Btu process steam can be generated with steam turbine topping and 220 kwhr/10^6 Btu with gas turbine topping. Tables 6.13 and 6.14 show economic analyses of coal- and oil-fired steam turbine topping systems, respectively, and Table 6.15 of gas turbine topping for a 3.6×10^6 ton/year integrated plant based upon a steam requirement of 2.5×10^6 Btu/ton steel. Based upon incremental capital costs for electrical power generation (i.e., subtracting the cost of a low pressure process steam boiler from the capital costs for a combined process steam and electric power generating system), we see from these tables that the internal rates of return are 20% for a coal-fired steam topping plant, 29% for an oil-fired steam topping plant, and 42% for an oil-fired gas turbine topping plant. The incremental cost analysis is justified for a new installation because either electricity can be purchased and steam generated separately or electricity can be generated in-plant in combination with steam.

For an existing plant, not requiring expansion of its utilities, the economic analysis should be based upon the costs for the combined steam and electric power generating system since low pressure

TABLE 6.13

ECONOMIC ANALYSIS OF COMBINED GENERATION OF PROCESS STEAM AND ELECTRICITY IN A 3.6 MILLION TON/YEAR INTEGRATED STEEL PLANT (COAL FIRED BOILER WITH STEAM TURBINE TOPPING)

Capital costs for combined generation		
3-300,000 lb/hr coal fired boiler (1200 psig)		$\$ 27.4 \times 10^6$
2-20 Mw back pressure turbine		6.0
Pollution control equipment		\$ 8.0
Total		$\$ 41.4 \times 10^6$
Capital costs for steam generator only		
3-300,000 lb/hr coal fired boiler (400 psig)		\$ 10.0
Pollution control equipment		8.0
Total		$\$ 18.0 \times 10^6$
Incremental capital costs (difference between combined and steam only generation)		$\$ 23.40 \times 10^6$
Operating costs (8,000 hr/yr operation)		
Extra fuel (coal at $1.00/10^6$ Btu)	$\$ 1.44 \times 10^6$	
Extra maintenance, labor, etc. (\$ 0.0015/kwhr)	0.46×10^6	
Total	$\$ 1.90 \times 10^6$	
Value of electricity produced (\$ 0.03/kwhr)	$\$ 9.6 \times 10^6$	
Savings	$\$ 7.70 \times 10^6$	
Internal rate of return calculation based upon incremental capital costs		
Depreciation ($\$ 23.4 \times 10^6/18$)	$\$ 1.3 \times 10^6$	
Taxes for 2 to 18 year	$\$ 3.07 \times 10^6$	
Net savings after taxes 2-18 year		$\$ 4.63 \times 10^6$
Investment tax credit (10%) for yr 1	$\$ 2.34 \times 10^6$	
Taxes for year 1	\$ 1.95	
Net savings after taxes for year 1		\$ 5.75
Internal rate of return based on incremental capital costs		20.0%
Internal rate of return based on combined generation capital costs only		10.9%

TABLE 6.14

ECONOMIC ANALYSIS OF COMBINED GENERATION OF PROCESS STEAM AND ELECTRICITY IN A 3.6 MILLION TON/YEAR INTEGRATED STEEL PLANT (OIL FIRED BOILER WITH STEAM TURBINE TOPPING)

Capital costs for combined generation		
3-300,000 lb/hr oil fired boilers (1250 psig)		$\$ 16.6 \times 10^6$
2-20 Mw back pressure turbine		6.0
Total		$\$ 22.6 \times 10^6$
Capital costs for steam generation only		
3-300,000 lb/hr oil fired boiler (400 psig)		$\$ 10.0 \times 10^6$
Incremental capital costs (difference between combined generation and steam only generation)		$\$ 12.6 \times 10^6$
Operating costs (8,000 hr/yr operation)		
Extra fuel (oil at $\$ 2.00/10^6$ Btu)	$\$ 2.86 \times 10^6$	
Extra maintenance, labor, etc. (0.0015/kwhr)	0.46×10^6	
Total	$\$ 3.32 \times 10^6$	
Value of electricity produced ($0.03/kwhr)	$\$ 9.60 \times 10^6$	
Savings	$\$ 6.28 \times 10^6$	
Internal rate of return calculation based upon incremental capital costs		
Depreciation ($\$ 12.6 \times 10^6/18$)	$\$ 0.70 \times 10^6$	
Taxes for year 2-18	$\$ 2.68 \times 10^6$	
Net savings after taxes year 2-18		$\$ 3.60 \times 10^6$
Investment tax credit (10%) for year 1	$\$ 1.26 \times 10^6$	
Taxes for year 1	$\$ 2.07 \times 10^6$	
Net savings after taxes for yr 1		$\$ 4.21 \times 10^6$
Internal Rate of return based on incremental capital costs		29.4%
Internal rate of return based on combined generation capital costs only		17.0%

TABLE 6.15

ECONOMIC ANALYSIS OF COMBINED GENERATION OF PROCESS STEAM AND ELECTRICITY IN A 3.6 MILLION TON/YEAR INTEGRATED STEEL PLANT (GAS TURBINE TOPPING WITH WASTE HEAT BOILER)

Capital costs for combined generation		
2-50 Mw gas turbines		$ 17.0 x 10^6
2-220,000 lb/hr waste heat boilers		6.8
Total		$ 23.8 x 10^6
Capital costs for steam generation only		
2-220,000 lb/hr oil fired boiler (400 psig)		$ 5.1 x 10^6
Incremental Capital Costs (difference between combined generation and steam only generation		$ 18.7 x 10^6
Operating costs (8,000hr/yr operation)		
Extra fuel (oil at $ 2.00/10^6 Btu)	$ 8.8 x 10^6	
Extra maintenance, labor, etc. ($ 0.002/kwhr)	1.6	
Total	$ 10.4 x 10^6	
Value of electricity produced ($ 0.03/kwhr)	$ 24.0 x 10^6	
Savings	$ 13.6 x 10^6	
Internal rate of return calculation based upon incremental capital costs		
Depreciation (18.7 x 10^6/18)	$ 1.04 x 10^6	
Taxes for year 2-18	$ 6.03 x 10^6	
Savings after taxes year 2-18		$ 7.57 x 10^6
Investment tax credit (10%) for year 1	$ 1.87 x 10^6	
Taxes for year 1	$ 5.13 x 10^6	
Net savings after taxes for year 1		$ 8.47 x 10^6
Internal rate of return based on incremental capital costs		41.9%
Internal rate of return based on combined generation capital costs		33.6%

process steam boilers are already installed. On this basis the internal rates of return are 11% for a coal-fired steam system, 17% for an oil-fired steam system, and 34% for an oil-fired gas turbine system. In many plant replacement situations much of the auxiliaries (foundations, piping, controls, etc.) will already be in place thus reducing the capital costs and increasing the returns. From the above, we conclude that steam turbines will be adapted widely for new integrated plants and plant expansions. Gas turbine topping will be installed where the fuel oil is available and where utility plants currently burn oil. For plant replacement, coal-fired steam topping systems are marginal and will be implemented only under special circumstances. Although economically atractive, installations of oil-fired steam turbine and gas turbine systems in existing plants for combined generation will depend on the local oil situation.

Mini-plants use about 2.5 times less process steam per ton steel than that used in large intergrated steel plants. Production capacities are also an order of magnitude smaller than those of large integrated plants. Thus, powerplant sizes will be considerably smaller in mini-plants than in integrated. To investigate the effects of power plant scaledown, the economics of oil-fired steam and gas turbine topping are presented in Tables 6.16 and 6.17 for a 300,000 ton/year mini-plant. Based upon incremental capital costs we see from these tables that internal rates of return are in the range of 18% to 19%. For nonexpanding existing plants, internal rates of return are 17% and 12% for gas turbine and steam turbine topping, respectively. Coal burning steam turbine plants were not

TABLE 6. 16

ECONOMIC ANALYSIS OF COMBINED GENERATION OF PROCESS STEAM AND ELECTRICITY IN A 800 TON/DAY MINI-STEEL PLANT (OIL FIRED BOILER WITH STEAM TURBINE TOPPING)

Capital costs for combined generation		
1-30, 000 lb/hr oil fired boiler		$ 650, 000
1-1. 75 Mw back pressure turbine		700, 000
Total		$ 1, 350, 000
Capital costs for steam generation only		$ 450, 000
Incremental costs (difference between combined generation and steam only generation)		$ 900, 000
Operating costs (8, 000 hr/yr operation)		
Extra fuel (oil at $ 2. 00/10^6 Btu)	$ 125, 000	
Extra maintenance, labor, etc. (0. 002/kwhr)	27, 000	
Total	$ 152, 000	
Value of electricity produced ($0.03/Kwhr)	$ 420, 000	
Savings	$ 268, 000	
Internal rate of return calculation based upon incremental capital costs		
Depreciation ($ 900, 000/18)	$ 50, 000	
Taxes for 2 to 18 year	$ 105, 000	
Net savings after taxes yr 2-18		$ 163, 000
Investment tax credit (10%) for year 1	$ 90, 000	
Taxes for year 1	$ 61, 000	
Net savings after taxes for year 1		$ 207, 000
Internal rate of return based upon incremental capital costs		18. 3%
Internal rate of return based upon combined generation capital costs		12. 0%

TABLE 6.17

ECONOMIC ANALYSIS OF COMBINED GENERATION OF PROCESS STEAM AND ELECTRICITY IN A 800 TON/DAY MINI-STEEL PLANT (OIL FIRED BOILER WITH STEAM TURBINE TOPPING)

Capital costs for combined generation		
1-7 mw gas turbine		$ 2,800,000
1-30,000 waste heat boiler		580,000
Total		$ 3,380,000
Capital costs for steam generation only		$ 450,000
Incremental capital costs (difference between combined and steam generation only)		$ 2,930,000
Operating costs (8,000 hr/yr operation)		
Extra fuel (oil at $ 2.00/10^6 Btu)	$ 616,000	
Extra maintenance, labor, etc. (0.0025/kwhr)	$ 140,000	
Total	$ 756,000	
Value of electricity produced ($0.03 kwhr)	$ 1,680,000	
Savings	$ 924,000	
Internal rate of return calculation based upon incremental capital costs		
Depreciation ($ 293,000/18)	$ 163,000	
Taxes for year 2-18	$ 365,000	
Savings after taxes for year 2-18		$ 559,000
Investment tax credit for year 1 (10%)	$ 293,000	
Taxes for year 1	$ 224,000	
Savings for year 1		$ 700,000
Internal rate of return based on incremental capital costs		19.2%
Internal rate of return based upon combined generation capital costs		16.7%

considered for mini-plants because the size of the steam plant will not in general justify coal handling systems and pollution control equipment.

7. GOVERNMENT INITIATIVES

7.1 CAPITAL AVAILABILITY FOR ENERGY CONSERVATION

Several energy conservation options are economically so attractive, (payback periods of a few years), that industry is likely to adopt them at a fast pace. Others have a rate of return lower than the industry-wide average of 12% and will not, and in general should not, be considered at this time. The remaining energy conservation options, although meeting and exceeding the average rate of return criterion, will not be included in future investments for two reasons: (1) the iron and steel industry is short of capital and, therefore, each company will give the highest priority to investments that contribute to the competitive position of the company in the market; and (2) companies require a much higher rate of return from investments that are not directly related to their main line of activity, such as energy conservation equipment, than from those essential to their existence, such as increased capacity and pollution control.

For these profitable and yet low priority energy conservation options, the question arises, "Is it in the national interest for the Federal Government to take initiatives that would enhance the adoption of energy conservation equipment which is unattractive to industry?"

To explore this question, we will accept as goals of the U. S. the continued growth of the economy and the reduction of our dependence on foreign energy sources. Most projections indicate that we cannot achieve these goals during the next few decades unless, in addition to increasing domestic fuel supplies, we reduce demand by increasing effectiveness of fuel end-use. Therefore, we conclude that it is indeed in the national interest to enhance adoption of energy conservation equipment provided the equipment cost is reasonable.

As a measure of reasonableness of cost we can compare the investment required to save one unit of energy per day, say one barrel of oil equivalent per day, with that required to increase fuel supplies by the same amount since in both cases we achieve the same marginal result in the economy.

Capital investments per barrel of oil equivalent per day saved by various energy conserving non-electrical generation process options and corresponding rates of return are listed in Table 7.1. In Table 7.2 the capital investments/kw are listed for energy conserving electrical generation processes for internal plant use (i.e., no transmission and distribution charges). Capital investments per barrel of oil equivalent per day for various forms of additional fuel supplies and capital investments for standard utility electrical generation are listed in Table 7.3. Comparing these two tables, we see that those energy conservation options that have a rate of return higher than 12% also have capital requirements that are comparable with or lower than those required for increased fuel supplies or generation of electricity by utilities. From a national standpoint we conclude that these options are reasonably priced.

Because they have a healthy rate of return, but not as high as that traditionally required by the industry for nonessential investments, energy conservation options should not be enhanced by Government initiatives that contribute to even higher rates of return, such as tax incentives, low interest loans, or subsidies. Instead,

TABLE 7. I

INTERNAL RATES OF RETURN AND INVESTMENT REQUIRED TO SAVE ONE BARREL OF OIL EQUIVALENT PER DAY FOR SELECTED ENERGY CONSERVING PROCESS OPTIONS

Process	Type of Fuel	Internal Rate of Return Percent	Investment to Save One Bbl Equiv. of Fuel Per Day Dollars/Bbl Equiv. Day
1. Dry Quenching	Coal	11.9%	11,400
2. Replacement of old blast furnaces (savings of 200 lb coke/ton pig iron)	Coal	2.0%	86,500
3. Bell-less top on existing blast furnaces	Coal	27.0%	10,500
4. Injection of pulverized coal in blast furnaces	Coal	42.8%	12,700
5. Installation of recuperators on new reheat furnaces	Gas or Oil	190.0%	900
6. Installation of more efficient recuperators on existing reheat furnace	Gas or Oil	60.0%	5,200
7. Installation of recuperators on new heat treating furnace	Gas or Oil	41.7%	3,300
8. Installation of recuperators on existing heat treating furnaces	Gas or Oil	22.0%	6,300
9. Generation of electricity from waste heat	Coal, Gas or Oil	18.0%	14,500
10. BOF off-gas collector	Gas or Oil	7.0%	25,000
11. Continuous slab caster	Gas or Oil	9.0%	135,000
12. Continuous billet caster	Gas or Oil	19.0%	60,000

TABLE 7.2

INTERNAL RATES OF RETURN AND INVESTMENT REQUIRED FOR PRODUCTION OF ELECTRICITY FROM TOPPING AND BOTTOMING CYCLES

Type of System	Type of Fuel	Internal Rate of Return		Investment Required to Produce kwe***	
		Based on Total Capital Costs (1)	Based on Incremental Capital Costs (2)	Based on Total Capital Costs (1)	Based on Incremental Capital Costs (2)
		Percent		Dollars/kwe	
Steam Turbine Topping	Coal	10.9*/----	20*/----	1089*/----	639*/----
Steam Turbine Topping	Oil	17.0*/12.0**	29.4*/18.3**	790*/996**	540*/739**
Gas Turbine Topping	Oil	33.6*/16.7**	41.9*/19.2**	463*/707**	412*/643**
Bottoming Cycles	None	18.0	N/A	600	N/A

Notes:

*For 3.6×10^6 ton/year integrated plant
**For 0.3×10^6 ton/year mini-plant
***Includes power plant plus fuel costs to produce electricity

(1) Total capital costs includes turbines plus boilers.
(2) Incremental capital costs subtracts low pressure boiler (for process steam) from turbines plus boilers.
To include distribution and transmission costs for exported power add $ 270/kwe

TABLE 7. 3

INVESTMENT REQUIRED FOR NEW SOURCES OF ENERGY

	Investment Required to Obtain bbl of Oil Equivalent Per Day of New Fuel* Dollars/bbl Equiv. /Day
Coal	~ 3, 000
Oil	11-14, 000

	Investment Required to Obtain New Source of Electricity** Dollars/Kw
Coal Fired Utility Plant	1, 000
Oil Fired Utility Plant	1, 200
Nuclear Utility Plant	> 1, 400

*Includes mining plus transportation

**Includes power plant, fuel production, transmission, and distribution we believe that the Federal Government should address the heart of the problem (lack of capital) that creates the reluctance of the industry to give high priority to energy conservation measures.

One possible way of addressing the problem is by means of federally guaranteed loans at market interest rates. The liability of these loans would extend only to the energy conservation equipment purchased with these funds in the event of a business collapse; that is, the government could not foreclose and acquire other assets of the company. In addition, they should be longer terms than ordinary bond indebtedness.

These guaranteed loans should be treated off the balance sheet; i. e., they should not affect the debt to equity ratio of a company so that the company can use its debt and equity capital for regular investment purposes and the federally guaranteed loan for improving fuel end-use by means of options that are economically acceptable (rate of return higher than 12%) but unattractive because of traditional barriers.

7.2 CHANGES IN REGULATORY POWERS

Removal of price controls on fuels would benefit fuel conservation efforts, primarily because of the expected attendant rise in fuel costs. Natural gas users would then have an additional incentive to install more efficient equipment besides the fear of cut-offs or shortages. If natural gas becomes more costly than coal, then switching from natural gas to coal will be based upon sound economics. Of course, the effects of the removal of price controls on various sectors of the U. S. economy must be considered prior to adoption of a final policy by government.

Conversion to coal is surely in the national interest since this will tend to minimize the investment required for new fuel sources and reduce our need for imports as well. However, conversion to coal should not be legislated to the point where capital requirements are greater than those required to obtain a new barrel of oil (i. e., $ 11-$ 14,000/bbl of oil saved/day). Otherwise coal conversion will divert funds from oil and natural gas conserving opportunities with lower investment requirements for the same amount of fuel savings. The largest potential for conversion from fuel oil to coal with today's technology is in steam raising. Conversion to steam raising by coal can be more attractive to industry if it is coupled with the production of electricity by topping turbines. Converting a boiler to coal without production of additional electricity requires an investment cost per barrel of oil saved per day about equivalent to that required for obtaining new sources of oil. However, accompanied by the production of electricity, the investment is about 50%-60% of that required for utility generating facilities (including the source of fuel). Thus, it is in the national interest and within the interests of the industrial user, to couple conversion of oil and gas-fired boilers to coal with the generation of by-product electricity. In the steel industry, in most cases as noted in Section 5.7, the additional electricity will be used in-plant. Changes in rate structure regulations reducing peak demand charges and emergency uses of electricity (especially in off-peak periods) would enhance the trend to coal conversion and in-plant generation of electricity.

7.3 GOVERNMENT SUBSIDIES FOR RESEARCH AND DEVELOPMENT AND CAPITAL INTENSIVE FUEL CONSERVING OPTIONS

It should be the function of the government's research and development policy to fund fundamental work in new energy conserving process options. This responsibility should extend to the funding of laboratory and pilot plant projects, the latter with industry consortium participation. In addition, the government should sponsor design, system, and economic studies on promising energy conserving process options for which there is inadequacy or uncertainty in the available data to determine their technical and economic viability.

Because of the capital crunch which will surely be felt by the entire industry, the government, through an appropriately designated agency, should insure the availability of funds for investment in energy conserving process options. The funds should be made available at prevailing rates of interest to the industry rather than at a lower interest rate to maintain the current delicate balance between projects acceptability based upon profitability guidelines and those acceptable based on a national distribution of investment capital which is in the national interest.

8. POTENTIAL FUEL SAVING

Estimates of the degree of implementation of fuel saving and fuel converting options until 1983, with or without guaranteed loans, are listed in Table 8. 1. Included in the table are both options that were analyzed in this report and those that are being pursued by the industry, such as replacement of OH's by BOF's and EF's.

Estimates of the corresponding fuel savings are listed in Tables 8. 2 and 8. 3. A summary of changes in purchased fuels is given in Table 8. 4. We see from Table 8. 4 that by 1983, compared with 1973, without guaranteed loans, total specific fuel consumption will decrease by 11. 5% and with guaranteed loans by 17%. In addition to fuel saving, substantial fuel switching will occur. These savings can be compared to the 33% savings that could be incurred with a minimum of economic constraints.[74]

TABLE 8. 1

DEGREE OF IMPLEMENTATION OF FUEL CONSERVING AND CONVERTING PROCESS OPTIONS

Process Option	Fuel Conserving or Converting	Fuel Changes per Unit Output 10^6 Btu/ton	% Implementation w/o Tax Incentives	% Implementation w/Tax Incentive w/Government Guaranteed Loans
1. Coal fired iron ore pelletizers	Converting	0.62 from gas and oil to coal	New-40% coal -60% oil Old -20% coal -80% oil	New-80% coal -20% oil Old -40% coal -60% oil
2. Preheating of Coking Coal	Conserving	0.1 in under fire fuels	New-40%	New-60%
3. Dry Quenching of Coal	Conserving	0.9 steam generated 0.32 coke saved in blast furnace	New Greenfield-30% New Round Out-20% Old -10%	New Greenfield-80% New Round Out-40% Old -20%
4. Direct Reduction	Converting	Converts ironmaking to non-coking coal	Will not be implemented in time frame.	
5. Nuclear Steelmaking	Converting	Converts ironmaking to nuclear energy and non-coking coal	Will not be implemented in time frame.	
6. Form Coke	Converting	36.4 non-coking coal 5 by-product gases produced	New Greenfield-10% no replacement	New Greenfield-40%
7. Installation of Modern Blast Furnaces	Conserving	Reduce coke rate to 950 lb/ton pig iron	New Greenfield-100% New Round Out & Old - 11%	New Greenfield-100% New Round Out & Old - 35%
8. Injection of Pulverized Coal	Conserving	0.8 lb coke saved/ lb coal injected, Nominal injection rate 25%	New Greenfield-50% New Round Out-50% Old- 30%	New Greenfield-75% New Round Out-75% Old- 50%
9. Installation of Bell-less Top on Existing blast furnaces	Conserving	Reduces coke consumption by 0.375 lb/ton pig iron	Old- 20%	Old- 40%
10. Installation of BOF's on Electric Furnaces	Conserving		New Greenfield-100% New Round Out-100% Old Oil - 25%	New Greenfield-100% New Round Out-100% Old Oil - 50%
11. Collection of BOF off-gases	Conserving	Produces about 0.5 by-product gas	0% (not economically justified)	0%
12. Utilizing BOF off-gas for Preheating Scrap	Conserving	saves 500 Kwhr/ton of electricity in electric furnace	Still in developmental stage	
13. Continuous Casting	Conserving	saves 0.7 in natural gas and fuel oil + 11.5 Kwhr electricity	New Greenfield-100% New Round Out-40% Old -10%	New Greenfield-100% New Round Out 65% Old -25%
14. Continuous Breakdown without Reheat	Conserving	saves heat input into reheat furnace ~ 2.75	New Greenfield-15%	New Greenfield-15%
15. More efficient Recuperators on Soaking Pits and Reheat Furnaces	Conserving	saves 10%-25% of fuel input	New Greenfield-100% New Round Out-60% Old -30%	New Greenfield-100% New Round Out-80% Old -50%
16. Waste Heat Boilers on Reheat Furnaces and Bottoming Cycles	Conserving	convert waste heat to about 510 Kwhr/ton of electricity	New Greenfield-20% New Round Out-15% Old - 5%	New Greenfield-30% New Round Out-20% Old- 10%
17. Combined Generation of Steam and Electricity	Conserving	save about 5000 Btu/ Kwhr of electricity	New Greenfield-100% New Round Out-40% Old- 20%	New Greenfield-100% New Round Out-60% Old- 40%

TABLE 8.2

FUELS BALANCE WITHOUT INCENTIVES FOR 1983 PRACTICE

Unit Operation	Change in Unit Operation	Purchased Fuels						Product Fuels Consumed	Byproduct Fuels Consumed					Utilities			Product Fuels Produced	Byproduct Fuels Consumed						Fuels Consumed
		Non-Coking Coal	Coking Coal	Purchased Coke	Natural Gas	Fuel Oil	Hydro Nuclear	Coke	Coke Breeze	Coke Oven Gas	Blast Furnace Gas	Tar and Pitch	Others	Electrical	Steam	O_2		Coke Breeze	Blast Furnace Gas	Coke Oven Gas	Tar and Pitch	Steam and Electric	Other	
		10^6 Btu/Ton Raw Steel																						
Ore Preparation Sintering	Converting natural gas to coke oven gas	0.10	-	-	-	-	-	-	0.4	0.04	-	-	-	0.04	0.03	-	-	-	-	-	-	-	-	0.61
Pelletizing	Converting 20% old to coal, 40% new to coal, remainder on oil	0.07	-	-	-	0.21	-	-	-	-	-	-	-	0.15	-	-	-	-	-	-	-	-	-	0.43
Coke Manufacture	a) Dry quenching of coke b) Form coke	0.06	12.88	-	-	0.01	-	-	-	0.84	0.17	-	-	0.02	0.36	-	8.28	0.60	-	2.82	0.26	0.06	0.02	2.30
Iron Making	a) Installation of new blast furnace b) Injection of pulverized coal c) Installation of bell-less top	0.75	-	0.60	-	0.51	-	8.28	-	0.04	1.09	0.08	-	0.03	0.96	0.01	-	-	4.25	-	-	-	-	8.10
Steelmaking Open Hearth	a) 63% BOF	-	-	-	-	0.41	-	-	-	0.03	-	0.10	-	0.03	0.06	0.02	-	-	-	-	-	0.15	-	0.50
Basic Oxygen	20.5% EF	-	-	-	-	-	-	-	-	-	-	-	-	0.06	0.02	0.08	-	-	-	-	-	-	-	0.16
Electric	16.5% OH	-	-	-	-	-	-	-	-	-	-	-	-	0.37	-	-	-	-	-	-	-	-	-	0.37
Steel Processing Soaking Pit/ Primary Rolling	a) Total of about 30% Continuous Casting	-	-	-	0.15	0.2	-	-	-	0.2	0.05	-	-	0.06	-	-	-	-	-	-	-	-	-	0.66
Continuous Casting		-	-	-	0.09	-	-	-	-	-	-	-	-	0.02	-	-	-	-	-	-	-	-	-	0.11
Reheat Furnaces Secondary Rolling	a) Better Recuperator b) Steam Bottoming	-	-	-	1.0	0.6	-	-	-	0.75	0.04	-	-	0.3	0.25	-	-	-	-	-	-	0.01	-	2.93
Heat Treating and Finishing	a) Better Recuperator	-	-	-	0.2	0.3	-	-	-	0.26	0.02	-	-	0.16	0.80	-	-	-	-	-	-	-	-	1.74
Materials Handling		-	-	-	-	-	-	-	-	-	-	-	-	0.07	-	-	-	-	-	-	-	-	-	0.07
Industrial Sub-Totals		0.98	12.88	0.60	1.44	2.24	-	8.28	0.4	2.16	1.37	0.18	-	1.31	2.48	0.11	8.28	0.60	4.25	2.82	0.26	0.22	0.02	17.98
Inplant Steam and Electrical Generation	a) More Inplant Generation	1.1	-	-	-	0.42	-	-	0.15	0.40	1.60	0.05	0.02	0.38	2.26	-	-	-	-	-	-	-	-	1.10
Industry Totals with Inplant Utilities		2.08	12.88	0.6	1.44	2.66	-	8.28	0.55	2.56	2.97	0.23	0.02	0.93	0	0.11	8.28	0.6	4.25	2.82	0.26	-	0.02	19.08
Unaccounted for Byproducts	a) Greater Use of Byproducts	na	na	na	na	na	-	na	0.05	0.26	1.28	0.03	0	na	na	na	na	na	na	na	na	na	na	1.62
Purchased Utilities Purchased Electrical		1.63	-	-	-	0.55	0.55	-	-	-	-	-	-	0.93	-	-	-	-	-	-	-	-	-	1.8
Purchased Oxygen		0.19	-	-	-	0.06	0.07	-	-	-	-	-	-	0.11	-	-	-	-	-	-	-	-	-	0.21
Totals for Industry and Utilities		3.90	12.88	0.6	1.44	3.27	0.62	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	22.71

% Fuels Saved Compared to 1973 Practice $\frac{25.65 - 22.71}{25.65} = 11.5\%$

TABLE 8.3

FUELS BALANCE WITH TAX INCENTIVES OR LOW INTEREST GOVERNMENT LOANS FOR 1983 PRACTICE

Unit Operation	Change in Unit Operation	Purchased Fuels						Product Fuels Consumed	Byproduct Fuels Consumed					Utilities			Product Fuels Purchased	Byproduct Fuels Consumed							Fuels Consumed
		Non-Coking Coal	Coking Coal	Purchased Coke	Natural Gas	Fuel Oil	Hydro and Nuclear	Coke	Coke Breeze	Coke Oven Gas	Blast Furnace Gas	Tar and Pitch	Other	Electrical	Steam	O_2		Coke Breeze	Blast Furnace Gas	Coke Oven Gas	Tar and Pitch	Steam	Electricity	Other	
		10^6 Btu/ton Raw Steel																							
Ore Preparation Sintering	a) Converting Natural Gas to Coke Oven Gas	0.10	-	-	-	-	-	-	0.4	0.04	-	-	-	0.04	0.03	-	-	-	-	-	-	-	-	-	0.61
Pelletizing	b) Converting to 47% Coal 53% Oil	0.13	-	-	-	0.15	-	-	-	-	-	-	-	0.15	-	-	-	-	-	-	-	-	-	-	0.43
Coke Manufacture	a) Dry Quenching of Coke b) Form Coke	0.26	11.58	-	-	0.01	-	-	-	0.77	0.15	-	-	0.02	0.34	-	7.58	0.55	-	2.58	0.24	0.09	-	0.05	2.04
Iron Making	a) Installation of New Blast Furnaces b) Injection of Pulverized Coal c) Installation of Bell-less Top	0.96	-	0.55	-	0.35	-	7.58	-	0.04	1.10	0.08	-	0.03	0.92	0.01	-	-	4.20	-	-	-	-	-	7.42
Steel Making Open Hearth	a) 67.4% BOF	-	-	-	-	0.21	-	-	-	0.03	-	0.10	-	0.01	0.03	0.01	-	-	-	-	-	0.06	-	-	0.33
Basic Oxygen	22.3% EF	-	-	-	-	-	-	-	-	-	-	-	-	0.07	0.03	0.00	-	-	-	-	-	-	-	-	0.19
Electrical	10.3% OH	-	-	-	-	-	-	-	-	-	-	-	-	0.44	-	-	-	-	-	-	-	-	-	-	0.44
Steel Processing Soaking Pit	a) 41.9% Cont. Casting																								
Primary Rolling	58.1% Ingot Casting	-	-	-	0.10	0.10	-	-	-	0.2	0.05	-	-	0.05	-	-	-	-	-	-	-	-	-	-	0.50
Continuous Casting		-	-	-	0.16	-	-	-	-	-	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	0.19
Reheat Furnaces Secondary Rolling	a) Better Recuperation b) Steam Bottoming	-	-	-	0.96	0.6	-	-	-	0.75	0.04	-	-	0.3	0.25	-	-	-	-	-	-	-	0.02	-	2.88
Heat Treating and Finishing	a) Better Recuperators	-	-	-	0.19	0.29	-	-	-	0.26	0.02	-	-	0.16	0.80	-	-	-	-	-	-	-	-	-	1.72
Materials Handling		-	-	-	-	-	-	-	-	-	-	-	-	0.07	-	-	-	-	-	-	-	-	-	-	0.07
Industry Sub-totals		1.45	11.58	0.55	1.41	1.71	-	7.58	0.4	2.09	1.36	0.18	-	1.37	2.4	0.11	7.58	0.55	4.20	2.58	0.24	0.15	0.02	-	16.82
Inplant Steam and Elec. Generation	a) More Inplant Generation	1.1	-	-	-	0.44	-	-	0.15	0.40	1.60	0.05	0.05	0.43	2.25	-	-	-	-	-	-	-	-	-	1.11
Industry Totals with Inplant Utilities		2.55	11.58	0.55	1.41	2.15	-	7.58	0.55	2.49	2.96	0.23	0.05	0.94	-	0.11	7.58	0.55	4.20	2.58	0.24	-	0.02	0.05	17.93
Unaccounted for Byproducts	a) Greater Use of Byproducts	na	na	na	na	na	na	na	0	0.09	1.34	0.01	0	na	na	na	na	na	na	na	na	na	na	na	1.34
Purchased Utilities																									
Purchased Electrical		1.63	-	-	-	0.55	0.55	-	-	-	-	-	-	0.94	-	-	-	-	-	-	-	-	-	-	1.81
Purchased Oxygen		0.19	-	-	-	0.06	0.07	-	-	-	-	-	-	0.11	-	-	-	-	-	-	-	-	-	-	0.21
Totals for Industry and Utilities		4.37	11.58	0.55	1.41	2.76	0.62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21.29

% Fuels Saved Compared to 1973 Practice $\frac{25.65 - 21.29}{25.65} = 17\%$

% Fuels Saved Compared to w/o Incentives $\frac{22.71 - 21.29}{22.71} = 6.25\%$

TABLE 8.4

SUMMARY OF PURCHASED FUELS FOR 1973 AND 1983 PRACTICE WITH AND WITHOUT TAX INCENTIVES

Fuel	1973 Practice	1983 Practice Within Economic Constraints	1983 Practice Within Economic Constraint But Guaranteed Loans	1983 Practice With Minimal Economic Constraints
Solid Fuels				
Non-Coking Coal -10^6 Btu/ton r. s.	0.8	2.08	2.55	
% Change Versus 1973	-	+160%	+219%	
Coking Coal -10^6 Btu/ton r. s.	14.76	12.88	11.58	
% Change Versus 1973	-	-13%	-21%	
Purchased Coke -10^6 Btu/ton r. s.	0.68	0.6	0.55	
% Change Versus 1973	-	-12%	-19%	
Total Solid Fuels -10^6 Btu/ton r. s.	16.24	15.56	14.68	12.2
% Change Versus 1973	-	-4.2%	-9.6%	25%
Liquid and Gas Fuels				
Natural Gas -10^6 Btu/ton r. s.	4.36	1.44	1.41	
% Change Versus 1973	-	-67%	-68%	
Fuel Oils -10^6 Btu/ton r. s.	1.71	2.66	2.15	
% Change Versus 1973	-	+56%	+26%	
Total Liquid and Gas Fuels -10^6 Btu/ton r. s.	6.07	4.10	3.56	3.1
% Change Versus 1973	-	-27%	-41%	49%
Purchased Electricity - Kw-hr/ton r. s.	334	305	305	
-10^6 Btu/ton r. s.*	3.34	3.05	3.05	1.9
% Change Versus 1973	-	-9.5%	-9.5%	43%
Total Fuels* 10^6 Btu/ton r. s.	25.65	22.71	21.29	17.2
% Change Versus 1973	-	-11.5%	-17%	33%
Percent of Total Purchased Solid Fuels to Total Fuels	63.3%	68.5%	69%	71%

*Electricity evaluated at 10,000 Btu/Kw-hr.

To guide us in developing policy recommendations, such as guaranteed government loans, for energy conserving process options in the iron and steel industry, figures of merit, the investment required to save a barrel equivalent of oil per day, and the investment required to generate new sources of electricity, were developed for a selected set of energy conserving process options and compared with the investment required to develop the amount of fuel or the electricity generated. Because the capital funds for energy development and conservation are limited, it is within the best interests nationally to minimize the invested capital per ton of product produced. This goal can best be attained if energy conservation options are adapted which have capital costs per bbl of oil equivalent saved per day lower than that required to obtain new sources of the same fuel. The results of this analysis show that it is not within the best interests of the nation to artificially increase the profitability of energy conserving process options by means of a tax incentive or low interest loan program since this, in many cases, will foster the installation of projects for which the investment costs are greater than obtaining new sources of the conserved fuel. It is also in the national interest to minimize fuel oil and natural gas by maximizing conversion to coal and finding new sources of fuel oil and natural gas. Investment for energy conservation technologies dictated by the present tax regulations without tax incentives and low interest loans will also tend to satisfy this requirement.

The requirement for capital for energy conserving investment is recognized. However, the capital should be made available and guaranteed by the government or government agency at currently available rates of interest so that the profitability of energy conserving technologies is not artificially increased to the point where projects are adapted for which the capital investment for saving fuel is greater than that required for obtaining new sources of the same fuel. Then, and only then, can the country maximize product output with a minimum of capital investment. Our negative decision on additional incentives for energy conserving technologies does not extend to capital formation techniques necessary if the industry is to raise the capital for expansion of capacity from the present approximately 155 million tons to 185 million tons in 1983.

Government stimulus for new and existing technologies is also recommended. Government should actively participate in the development of energy conserving and converting technologies for the steel industry by funding fundamental studies, design and system studies, and participate with industry support in pilot plant demonstrations.

In summary, a government policy of guaranteed loans at the current interest rates for energy conserving technologies to make capital available for those process options which are already profitable when judged by normal industry standards, is recommended. Government should actively participate in research and development and implementation of energy conserving technologies.

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PART II
PULP AND PAPER

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PULP AND PAPER SUMMARY

The pulp and paper industry in 1972 produced 64 x 10^6 tons of product and consumed 1.5 x 10^{15} Btu of purchased fuels. The purchased fuels represented approximately 2% of the total national consumption (72 x 10^{15} Btu) and approximately 5% of the total energy consumed by industry (28 x 10^{15} Btu).

Energy conservation measures available to the industry are shown in Table S. 1, together with potential fuel savings and estimated capital costs. The savings are expressed in Btu/year and are referenced to the 1972 production and purchased energy values. The potential savings are closely related to production; therefore, a percentage increase in production implies a similar increase in potential savings. The indicated fuel savings are based on purchased fuels such as coal, oil, and natural gas and do not include wastes. The use of bark, wood wastes, and waste paper as fuel in the pulp and paper industry, for example, is considered a fuel savings in purchased fuel rather than a fuel substitution. The savings also assume a national viewpoint and are not restricted to those achievable directly within the industry. In-plant generation of electrical power increases fuel consumption in the industry but decreases fuel consumption in utilities. The utility decrease is greater than the industry increase and hence an overall national savings results.

The pulp and paper industry currently purchases approximately half of its electrical power (30 x 10^9 Kwh/year) from utilities. The remaining half is generated within the mills using steam turbogenerators in combination with extraction or non-condensing steam for processing and with condensing installations for peak load capacity or to increase the mill's generating capacity under conditions of reduced process

TABLE S-1

SUMMARY OF ENERGY CONSERVATION OPTIONS IN THE PULP AND PAPER INDUSTRY

Conservation Option	Energy Savings (Btu/year)	Estimated Capital Cost ($$10^6$)
In-plant electrical power generation		
(1) Current economic conditions	0.07×10^{15}	500
(2) Removal of peak load rate penalty	0.03×10^{15}	150
(3) Increased economic incentives	0.13×10^{15}	1200
(4) Industrial sale of power to utilities (steam turbines)	0.2×10^{15}	2000
(5) Industrial sale of power to utilities (gas turbines)	0.7×10^{15}	3000
Use of waste paper for fuel rather than recycling		
Additional new mill capacity plus new power facilities burning waste paper	0.25×10^{15}	9000
Fifty percent reduction in bleaching		
Change in consumer demand for high brightness paper	0.04×10^{15}	Negligible
Full use of bark and wood wastes		
Improved equipment	0.15×10^{15}	Unknown
Improved operating procedures and better use of energy conserving equipment		
(1) Current economic conditions	0.15×10^{15}	Small
(2) Increased economic incentives	0.3×10^{15}	Large

steam demand. The absence of electrical generating equipment in about half the industry's capacity results primarily from the need for reduced capital expenditures in the smaller mills and the availability of low cost purchased electrical power in some areas. If additional in-plant electrical power generating equipment was installed to meet the industry's power requirements fully (and therefore eliminate the need for purchased power from utilities), annual energy savings of about 0.13×10^{15} Btu could be achieved. Using modern, high pressure (1250 psig) generating equipment, added facilities could generate power in excess of the industry's needs. Assuming that this excess power could be sold to utilities for use outside of the industry, the potential for energy savings increases to 0.2×10^{15} Btu per year. If gas turbine driven generators in combination with exhaust heat process steam boilers are considered rather than steam turbogenerators, the potential energy savings associated with the sale of excess power increases to about 0.7×10^{15} Btu per year. The condensing portion of the currently installed in-plant electrical power capacity (20 - 25%) presents another opportunity for energy savings of approximately 0.03×10^{15} Btu per year, if those facilities are replaced by non-condensing equipment. Current utility rate penalties applied to peak loads, however, make the continued use of this condensing capacity desirable because of economic considerations. Modification or elimination of these rate penalties is required to encourage the installation of non-condensing equipment.

Paper produced from waste paper requires approximately 8×10^{6} Btu/ton more purchased fuels (e.g.; coal, oil, and natural gas) than paper produced from wood. The reduced purchased energy requirements of the wood-based paper result from the use of wood wastes (chemical pulping wood solids) as a fuel in place of purchased fuels. Paper made by the chemical pulping of wood consumes wood and purchased fuels. Paper made from waste paper consumes waste paper (some new pulp made from wood is used as a supplement to the waste paper to maintain quality) and a greater amount of purchased fuels. Thus, the use of waste paper conserves wood, while paper made by chemical pulping of wood conserves non-renewable fuels. If the 12×10^6 tons/year of waste paper currently being recycled were used as fuel, and an additional 12×10^6 tons/year of new paper were made by chemical pulping, the energy savings would be approximately 0.25×10^{15} Btu/year.

Extensive bleaching of wood pulp to produce white paper consumes large quantities of direct process heat and chlorine, and requires substantial capital expenditures for bleaching and pollution control equipment. The extent that bleaching is used in the paper industry is directly related to consumer demand and a competitive response to that demand. If consumer acceptance permitted, a 50% reduction in bleaching would result in energy savings of approximately 0.04×10^{15} Btu/year.

The industry currently uses about half of the available bark and wood wastes (excluding chemical pulping wood solids) for fuel. Such usage is limited because of difficulties encountered in handling, dewatering, and burning. The unused bark and wastes present a substantial disposal problem. Past disposal methods include land fill and water discharge, but both face pollution control restrictions. If more satisfactory handling and combustion techniques were developed, benefits would be realized from both pollution and energy conservation considerations. Energy savings of approximately 0.15×10^{15} Btu/year could be realized through full use of these materials as fuel.

Improved operating procedures and better use of energy conserving equipment provide the possibility for energy savings throughout the production process. Space heating in cold climates consumes substantial energy. Ventilation, humidity control, and fresh water heating are important areas of conservation and reuse of heat. Optimizing furnace and lime kiln operating conditions can lead to significant savings. The practice of producing dried pulp for later use in the same mill can probably be minimized through improved scheduling and better balance of pulping and forming equipment. Increased use of thermal insulation can aid in reducing heat losses from individual pieces of equipment. Overall, energy savings approaching 0.3×10^{15} Btu/year appear possible.

Realization of the potential fuel savings described above will depend to a large extent on the priority that industry's management places on fuel costs and the equipment modifications that are required to reduce these costs. In a competitive industry, high fuel prices would establish this priority - prices appreciably higher than those in effect today. Today's fuel costs represent only 10 - 15% of the cost of production and therefore do not dominate capital investment decisions.

Under current economic conditions, a 10% reduction in purchased energy consumption can be expected through improved operating conditions and better use of energy conserving equipment. In addition, continued installation of in-plant electrical power generation equipment should result in a savings equivalent to about 5%. Further reductions in energy consumption beyond this 10 - 15% level require a change in priorities. Consumer acceptance of lower brightness paper could save an additional 3%. Modification of the peak load rate penalties could save about 2%. A potential 10% reduction could be realized if bark and wood wastes were fully utilized. The savings associated with improved operating conditions, better use of energy conserving equipment, and in-plant electrical power generation would increase to about 30% if priorities for capital expenditures were influenced by economic incentives to favor energy conservation. A national commitment to use waste paper as a fuel would result in savings greater than 15%. Still further energy savings are possible if sale of excess generated power is expanded on an industry-wide scale. Equivalent energy savings would approach 15% utilizing steam turbine equipment and 50% with gas turbines.

The following general areas of investigation are suggested as possibilities for government R & D funding to aid energy conservation efforts in the pulp and paper industry:

1. A detailed study to establish and correlate the energy requirements of individual pieces of process equipment as a function of operating conditions would provide the industry with an improved source of information to evaluate their current equipment.

2. A detailed study similar to (1) above, but concentrating on system processes employing combinations of various pieces of equipment, would be beneficial as a guide in evaluating system performance and in defining the overall tradeoffs which are possible.

3. A program to develop and demonstrate improved bark and wood waste burning equipment would have a direct

influence on increasing the consumption of these wastes while at the same time reducing waste disposal problems.

4. An overall study of the recycling of waste paper is needed to understand better the tradeoffs possible between energy and wood resource conservation (burning versus recycling).

1. PROCESS DESCRIPTION

The pulp and paper industry in the United States is comprised of over 350 companies operating over 700 mills. It produces over 600 pounds of cellulose fiber products per year for each person in the country. Its raw material is primarily wood. Small amounts of annual growth fibers are used for special purposes (e.g. cigarette paper from flax, bank note and high grade legal or technical papers from rags, etc.).

Three sources of wood fiber are available to an individual mill: (1) tree harvesting for new fiber; (2) secondary or recycled fibers from waste paper (approximately 20% of the total paper production is recycled); and (3) market pulp (primarily new fiber) from mills with excess capacity or mills which specialize in the production of pulp for sale rather than for forming into paper products. Mills using new fiber (in the form of wood) and having facilities for both wood pulping and paper forming are called integrated mills. Mills using either waste paper or market pulp or both and having facilities only for paper forming are called non-integrated mills.

Pulp wood contains approximately 50% water and 50% other matter. The nonwater fraction is composed of three principal components: holocellulose, lignin, and extractives. Holocellulose can be divided into two fractions, cellulose and hemicellulose. Cellulose and hemicellulose are composed of long-chain and short-chain molecules, respectively. Both cellulose and hemicellulose make up the elongated cells or fibers found in wood. Lignin is located between the fibers and forms the cement which holds the fibers together. The extractives include such materials as pitch, oils, and turpentine. The composition of the nonwater fraction is approximately 47% cellulose, 22 - 29% hemicellulose, 21 - 28% lignin, and 3% extractives.

Various tree species used for pulpwood exhibit large differences in mechanical and chemical characteristics. These differences, plus the special demands of hundreds of different paper products, result in significant process variations. No two mills are alike in detail. In general, however, the making of paper involves a number of major operations common to all mills; the basic operations are shown in Fig. 1.1. Most wood arrives at the mill in the form of logs; use of sawdust, chips processed in the forest, and lumbering wastes is also common. The logs are debarked prior to pulping. Mechanical groundwood pulp is made by grinding the logs directly. Other types of mechanical pulps require chipping the logs into small pieces and treating them using either thermal or chemical techniques prior to disk refining. Mechanical pulps are high yield (they retain most of the hemicellulose and lignin) and are used in products such as newsprint which do not require long-lasting qualities (e.g. resistance to color change). Chemical pulps are made from chips, which are cooked in pulping liquors (alkaline, neutral, or acidic) to dissolve the lignin and allow easy separation of the fibers. The yield of chemical pulps extends from about 45% (total removal of hemicellulose and lignin) to 80%, depending on the process and the required characteristics of the product.

After pulping, the stock is washed to remove pulping chemicals (if used) and screened, filtered, and refined to remove dirt and to break up fiber bundles. If bleaching is required, the stock passes

2. REVIEW OF MARKET

Statistical data compiled by the American Paper Institute (API) and forecasts prepared by the Food and Agriculture Organization of the United Nations (FAO) provide a continuously growing picture for the pulp and paper industry throughout the major production areas of the world. Summary data presented by the Technical Association of the Pulp and Paper Industry[1] (TAPPI) in 1973 show that pulp and paper production has grown rapidly during the past 25 years. The world production of pulp was approximately 38 x 10^6 tons* in 1950, 66 x 10^6 tons in 1960, and 117 x 10^6 tons in 1970. It is forecasted to increase to 194 x 10^6 tons by 1980 and to 240 x 10^6 tons by 1985.

Paper and paperboard production closely parallels pulp production. The annual world production of paper and paperboard was 46 x 10^6 tons in 1950, 82 x 10^6 tons in 1960, and 143 x 10^6 tons in 1970. It is predicted to reach 227 x 10^6 tons by 1980 and 286 x 10^6 tons by 1985. These data are listed in Table 2.1.

Four major production areas (North America, Western Europe, Japan, and the USSR) currently produce about 87% of the pulp and paper of the world. North American production is about 50% of the total world production; Western Europe is the second largest producing region with over 20%, Japan third with 10%, and the USSR fourth with about 7%.

Rapid growth has also occurred in the production and consumption of pulp and paper in the United States. Paper is a high volume product that is used in virtually every sector of the economy. The use of paper

*1 ton = 2000 pounds.

TABLE 2.1

WORLD PRODUCTION OF PULP AND PAPER
(short tons)

Year	Pulp	Paper and Paperboard
1950	38×10^6	46×10^6
1955	51×10^6	62×10^6
1960	66×10^6	82×10^6
1965	91×10^6	108×10^6
1970	117×10^6	143×10^6
1975 - Forecast	152×10^6	175×10^6
1980 - Forecast	194×10^6	227×10^6
1985 - Forecast	240×10^6	286×10^6

closely parallels the total economic activity measured in terms of gross national product expressed in constant dollars.[2] The average ratio of paper consumption to GNP in the period 1947 - 1973 was 79,000 tons per 10^9 dollars. From 1947 to 1973, paper consumption increased by 172%, or about 3.9% per year, and the gross national product increased by 170%. Assuming that this trend will continue in the near future, we find that the requirements for paper and paperboard will be over 80 x 10^6 tons by 1980 and about 100 x 10^6 tons by 1985. Based on recent import and export trends, these requirements imply domestic production levels of about 76 x 10^6 tons of paper and paperboard and 58 x 10^6 tons of pulp by 1980. Annual domestic pulp and paper demand levels are listed[3] in Table 2.2.

TABLE 2.2

UNITED STATES ANNUAL PRODUCTION OF PULP AND PAPER
(short tons)

Year	Pulp	Paper and Paperboard
1960	25×10^6	34×10^6
1965	34×10^6	44×10^6
1970	43×10^6	53×10^6
1971	44×10^6	55×10^6
1972	47×10^6	59×10^6
1973	48×10^6	62×10^6
1974 - Preliminary	48×10^6	61×10^6
1980 - Forecast	58×10^6	76×10^6

TABLE 3.2

REGIONAL LOCATION OF MILLS IN THE U.S. - 1972
(percent)

Category		New England and Mid Atlantic	South	North Central	Mountains Pacific and Alaska	Category Total
Printing and writing papers	Integrated	4.3	2.9	1.6	1.6	13.1
	Non-integrated	4.9	0.7	3.6	1.0	10.2
Packaging and industrial converting papers	Integrated	1.1	3.0	0.6	1.2	5.9
	Non-integrated	4.0	0.4	1.9	0.4	6.7
Tissue and other creped papers	Integrated	1.2	0.7	0.6	0.7	3.2
	Non-integrated	4.8	0.8	1.7	0.8	8.1
Paperboard	Integrated	1.0	7.7	2.5	2.1	13.3
	Non-integrated	8.3	2.9	5.9	2.1	19.2
Construction paper and board	Integrated	1.6	3.3	2.2	1.6	8.7
	Non-integrated	2.0	3.0	2.0	1.1	8.1
Market pulp		0.1	1.4	0.5	1.5	3.5
		33.3	26.8	25.8	14.1	100.0

Total integrated - 44.2% Total non-integrated - 52.3% Market pulp - 3.5%

Total paper and paperboard mill capacity has increased significantly in recent years to satisfy increased demand. The ratio of production to capacity can vary considerably, depending on the timing of modernization and expansion decisions and economic conditions. Typical values of this ratio are 90 to 95%, except for recession years such as 1967, 1970 - 1971, and 1974 - 1975. Paper mills and paperboard mills had ratios close to 93% and 97% in 1972, and 79% and 71% in 1975, respectively.

Production figures for 1972 are listed in Table 3.3. They are taken from U. S. Department of Commerce statistical data. The division between integrated and non-integrated mills is made by using the capacity figures listed in Table 3.2. Total wood pulp production in 1972 was 46.8×10^6 tons. With imports of 3.7×10^6 tons and exports of 2.2×10^6 tons, the total wood pulp supply was 48.3×10^6 tons. Integrated mills (and affiliated mills) consumed 41.8×10^6 tons, and non-integrated mills 6.5×10^6 tons. Waste paper consumption in 1972 was 12.4×10^6 tons. The sum of waste paper and available wood pulp supply yields a total of 18.9×10^6 tons as raw material input for the non-integrated mills. If repulping losses and the use of some waste paper in integrated mills are taken into consideration, the total supply closely matches that shown in Table 3.3.

Fuel consumption in 1972 is listed in Table 3.4 together with projections for 1976. It can be seen from this table that 2.34×10^{15} Btu were consumed to produce 64.2×10^6 tons of products. Purchased fuels represented 63.6% and internal by-product or waste product fuels contributed 36.4%. The average fuel consumption per ton of product was 36.6×10^6 Btu/ton. In terms of purchased fuels (primarily natural gas, residual oil, coal, and electricity at 10^4 Btu/kwhr),

TABLE 3.3

PAPER AND PAPERBOARD PRODUCTION - 1972

Category	Integrated Mills (tons)	Non-integrated Mills (tons)	Total (tons)
Printing and writing papers	12.1×10^6	3.6×10^6	15.7×10^6
Packaging and industrial converting paper	4.5×10^6	1.2×10^6	5.7×10^6
Tissue and other creped paper	1.9×10^6	2.1×10^6	4.0×10^6
Paperboard	21.8×10^6	6.7×10^6	28.5×10^6
Construction paper and board	3.5×10^6	1.8×10^6	5.3×10^6
Market	5.0×10^6	-	5.0×10^6
	48.8×10^6	15.4×10^6	64.2×10^6

TABLE 3.4

ANNUAL FUEL REQUIREMENTS

Fuel	1972 (Actual)		1976 (Predicted)	
	Btu	Percent	Btu	Percent
Natural gas	448×10^{12}	19.1	403×10^{12}	15.6
Residual oil	431×10^{12}	18.3	507×10^{12}	19.7
Distillate oil	43×10^{12}	1.8	49×10^{12}	1.9
Coal	250×10^{12}	10.6	256×10^{12}	9.9
Purchased electricity*	300×10^{12}	12.8	354×10^{12}	13.8
Other fuels (propane, steam, hydro)	24×10^{12}	1.0	22×10^{12}	0.9
Total purchased fuels	1496×10^{12}	63.6	1591×10^{12}	61.8
Internal byproduct fuels (pulping liquors, bark, hogged wood)	855×10^{12}	36.4	984×10^{12}	38.2
Total	2341×10^{12}	100.0	2575×10^{12}	100.0

*1 kwhr = 10^4 Btu

the average fuel consumption was 23.4×10^6 Btu/ton. Comparison of the predictions for 1976 with the fuels consumed in 1972 indicates an increase in use of by-product fuels, a decrease in use of natural gas and coal, and an increase in use of oil and electricity.

3.2 REGIONAL STATISTICS

The pattern of fuel consumption by region in 1972 is listed in Table 3.5. The use of by-product fuels is smaller in the New England, Mid Atlantic, and North Central regions because the number of non-integrated mills is larger in these regions. The use of by-product fuels is greater (approximately 45% of total energy needs) in the South, Mountain, Pacific, and Alaska regions because of extensive chemical pulping operations in integrated mills.

The New England and Mid Atlantic regions are heavily dependent on the use of residual oil. The South region depends primarily on natural gas and residual oil, the North Central region on natural gas and coal, and the Mountain, Pacific, and Alaska regions on natural gas and electricity.

3.3 PURCHASED FUELS

Purchased fuel consumption for each of the major product categories was established using production and energy consumption data available in Post's and Lockwood's Directories. The results are listed in Table 3.6. The smallest amount of purchased fuel, approximately 17×10^6 Btu/ton, is consumed for production of market pulp and paperboard by integrated mills, and the largest for production of printing and writing papers, 30×10^6 Btu/ton.

TABLE 3.5

REGIONAL PATTERNS OF FUEL USE - 1972 (percent)

Fuel	New England and Mid Atlantic	South	North Central	Mountains Pacific and Alaska	Fuel Subtotal
Natural gas	0.6	11.0	4.5	3.0	19.1
Residual oil	6.0	10.0	0.6	1.7	18.3
Distillate oil	0.5	0.7	0.5	0.1	1.8
Coal	1.6	3.7	5.3	0.0	10.6
Purchased electricity*	2.4	4.4	2.3	3.7	12.8
Other fuels (propane, steam, hydro)	0.2	0.3	0.1	0.4	1.0
Total purchased fuels	11.3	30.1	13.3	8.9	63.6
Internal byproduct fuels (pulping, liquors, bark, hogged wood)	1.8	26.2	1.3	7.1	36.4
Total	13.1	56.3	14.6	16.0	100.0

*1 kwhr = 10^4 Btu

TABLE 3.6

PURCHASED ENERGY USE BY PAPER CATEGORY - 1972

Category		Specific Energy Consumption Btu/ton	Purchased Energy Btu	Percent of Total Purchased Energy
Printing and writing papers		30.6×10^6	480×10^{12}	32.1
Packaging and industrial converting paper		24.0×10^6	137×10^{12}	9.1
Tissue and other creped paper		27.0×10^6	108×10^{12}	7.2
Paperboard	Integrated	17.7×10^6	386×10^{12}	25.8
	Non-integrated	25.3×10^6	170×10^{12}	11.4
Construction paper and board		24.7×10^6	131×10^{12}	8.7
Market pulp		17.0×10^6	85×10^{12}	5.7
				100.0

Non-integrated mills consume about 7 to 8 x 10^6 Btu/ton more purchased fuel than integrated mills because of lack of by-product fuels. The furnish for non-integrated mills is waste paper, supplemented by market pulp. It follows that recycling waste paper is not a fuel-conserving procedure. From the standpoint of energy conservation, waste paper would be better used as a fuel, yielding 10 to 12 x 10^6 Btu/ton.

The data used to determine the purchased fuel consumption for each major product category was also used to establish the distribution of cumulative production versus fuel consumption. The results are shown in Figs. 3.1 to 3.7. The distributions show variations as great as $\pm$50% around the average and reflect many effects such as mill size, age, location, and type of equipment, on purchased fuels. Though difficult to establish precise reasons for the variations, the distributions indicate that significant reductions in purchased fuel consumption are possible.

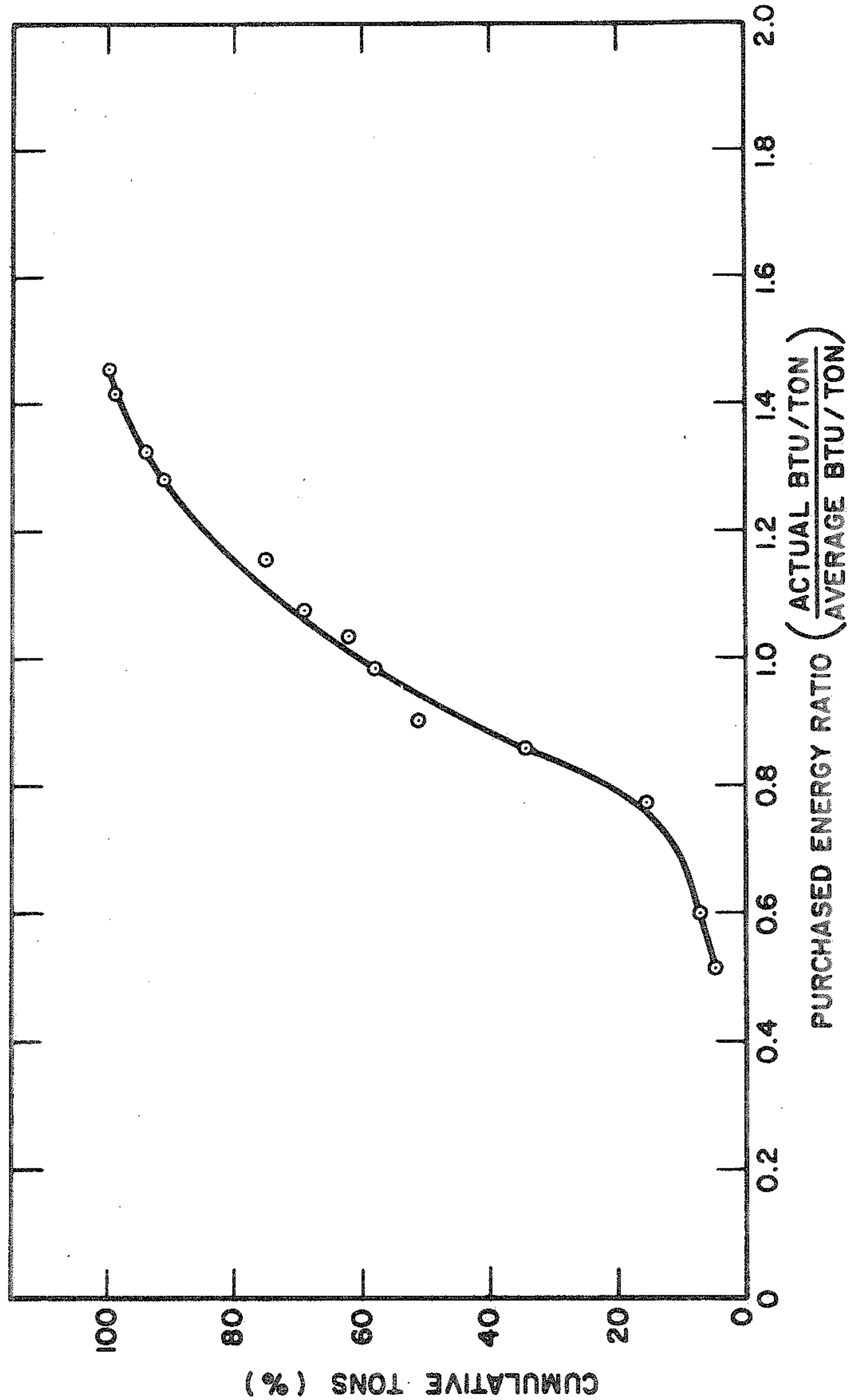

Figure 3.1 Cumulative Production Printing and Writing Papers

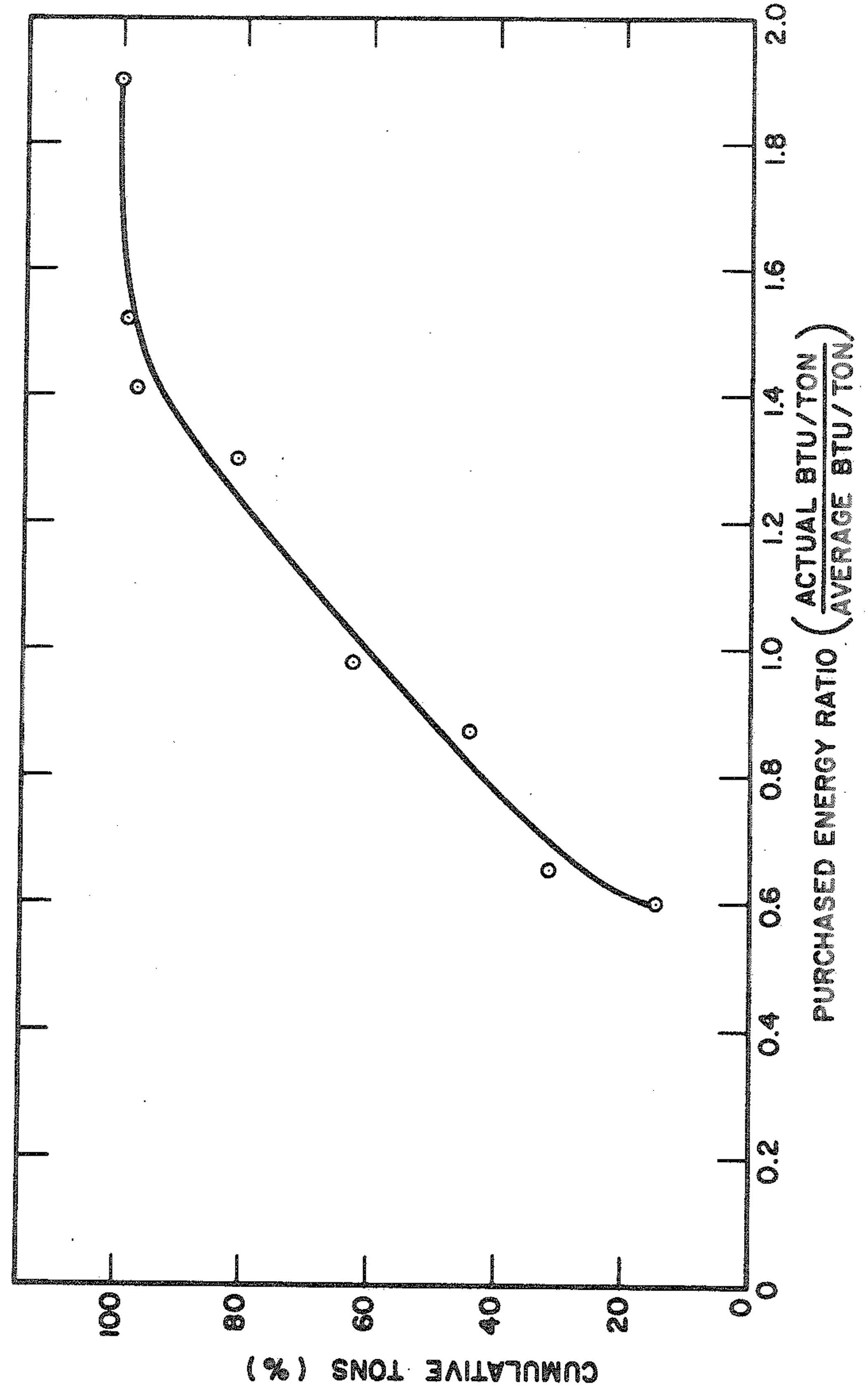

Figure 3. 2 Cumulative Production Packaging and Industrial Converting Paper

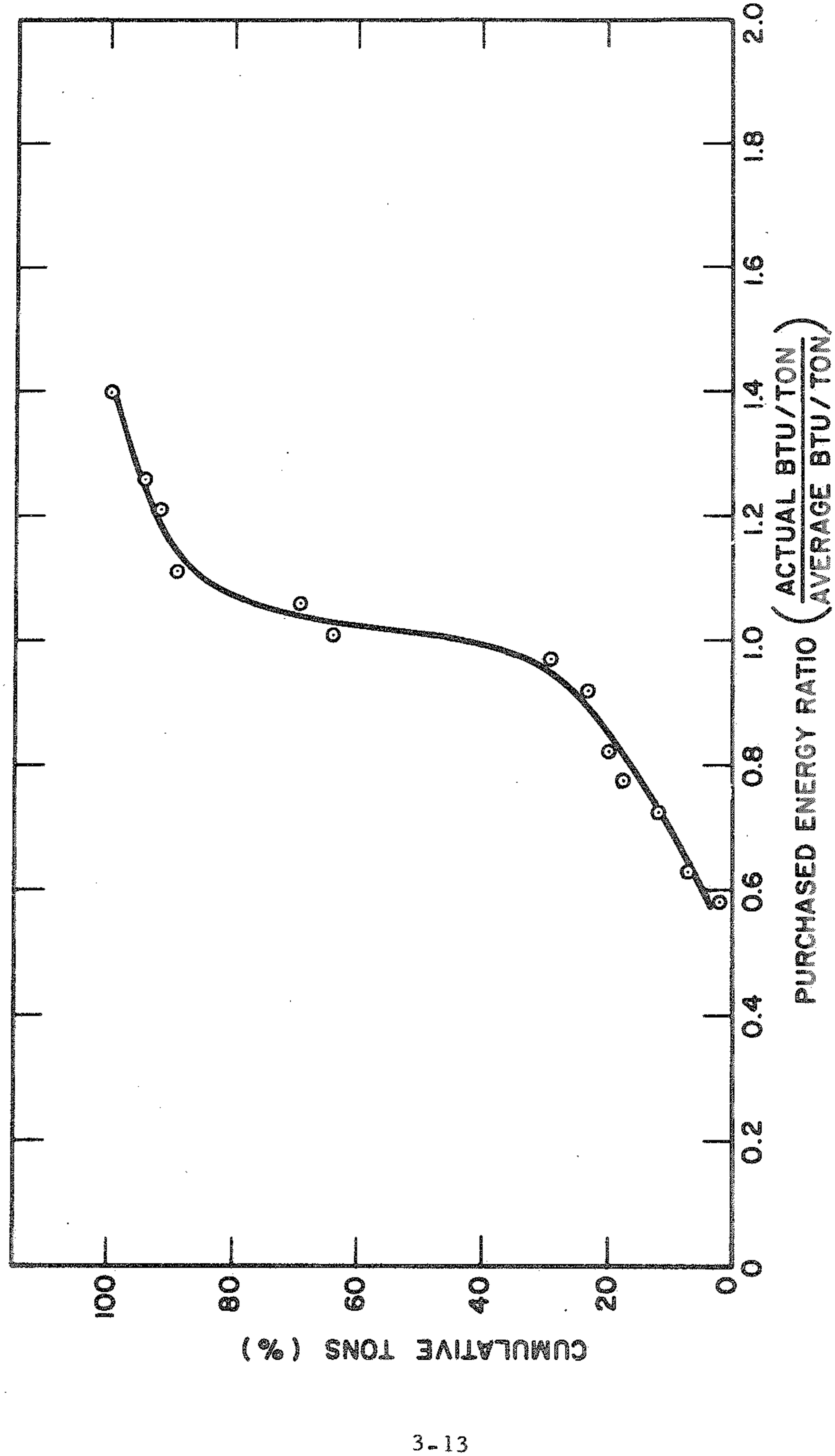

Figure 3.3 Cumulative Production Tissue and Other Creped Paper

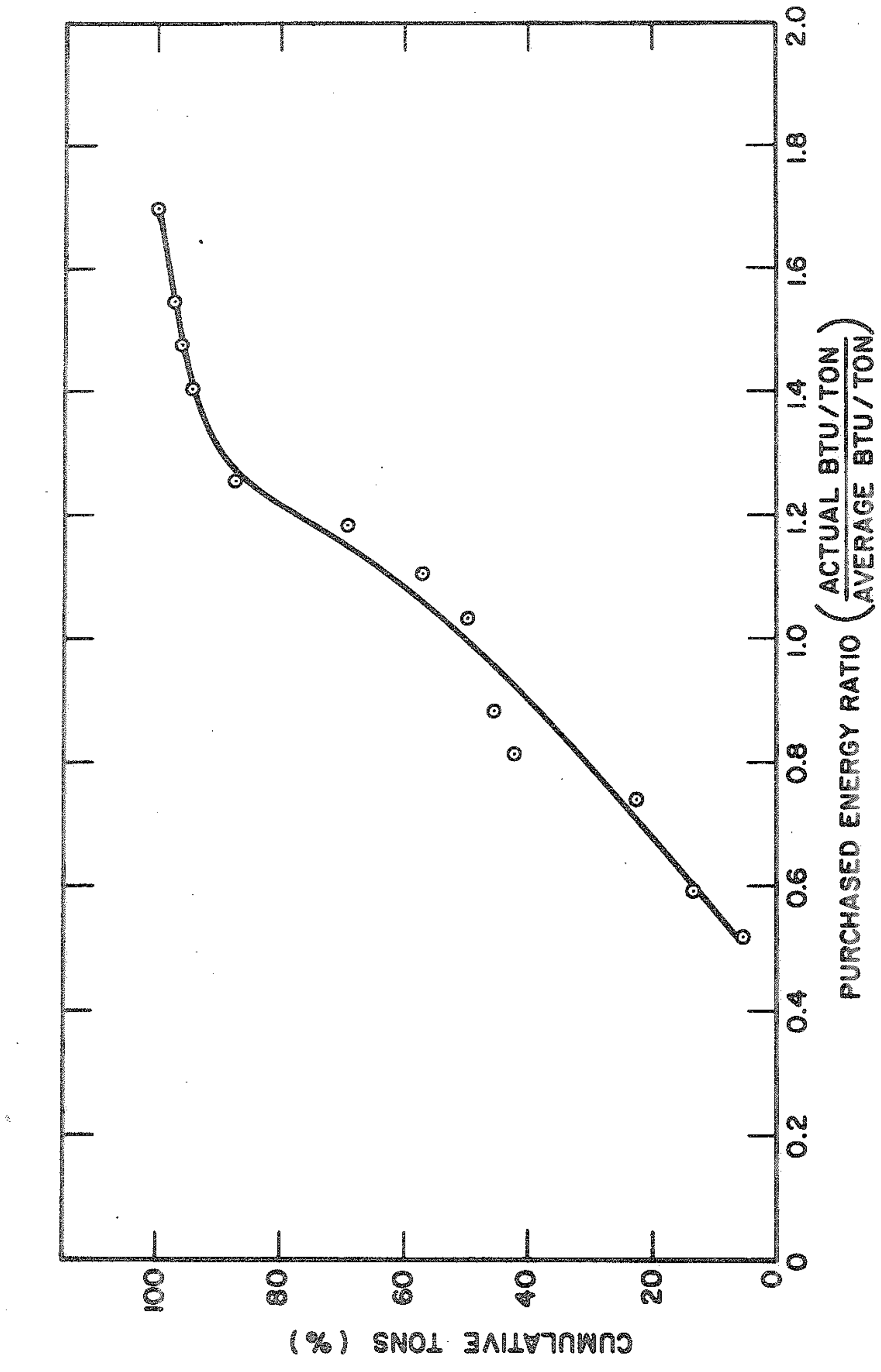

Figure 3.4 Cumulative Production Paperboard - Integrated Mills

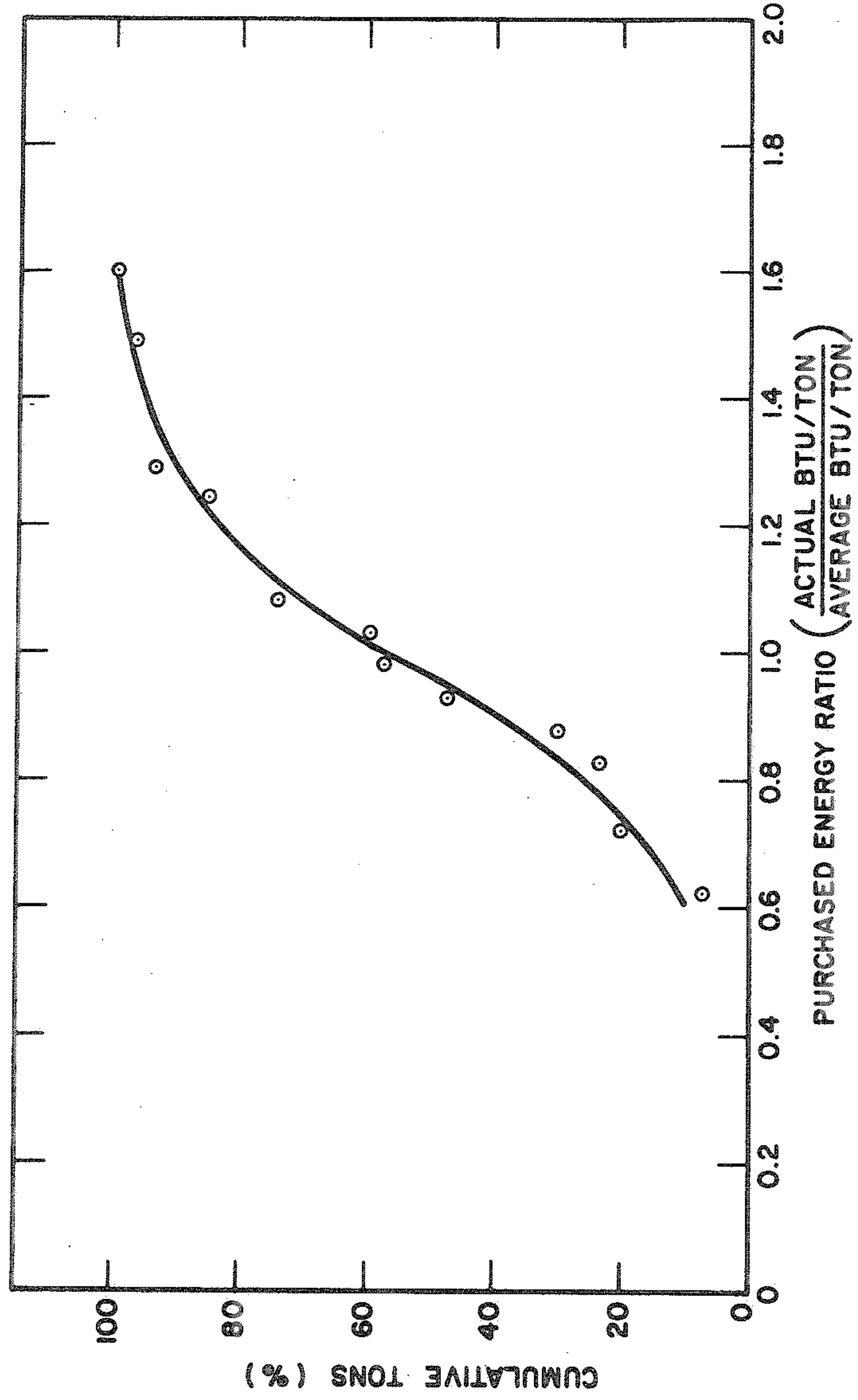

Figure 3.5 Cumulative Production Paperboard - Forming Mills

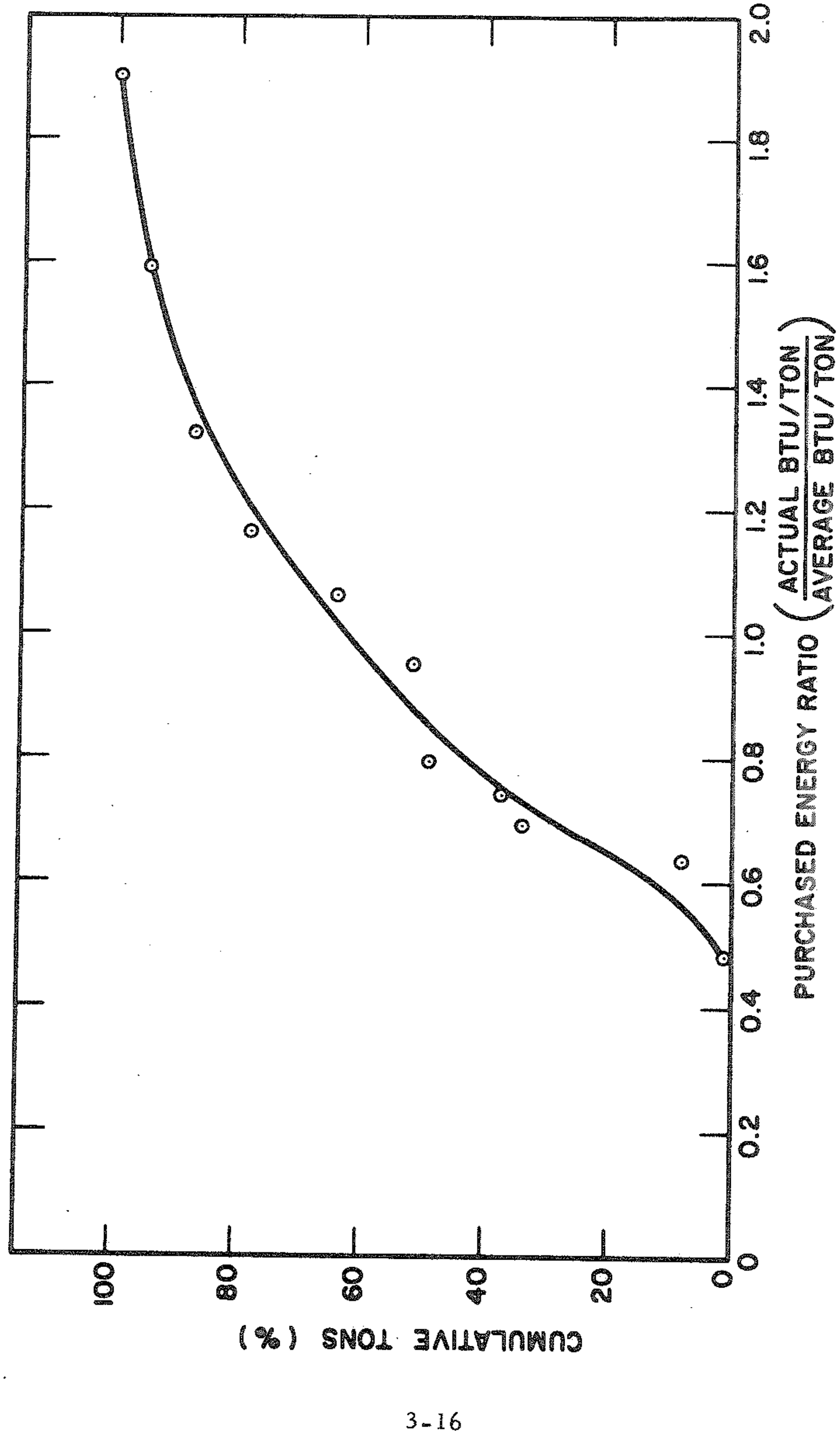

Figure 3. 6 Cumulative Production Construction Paper and Board

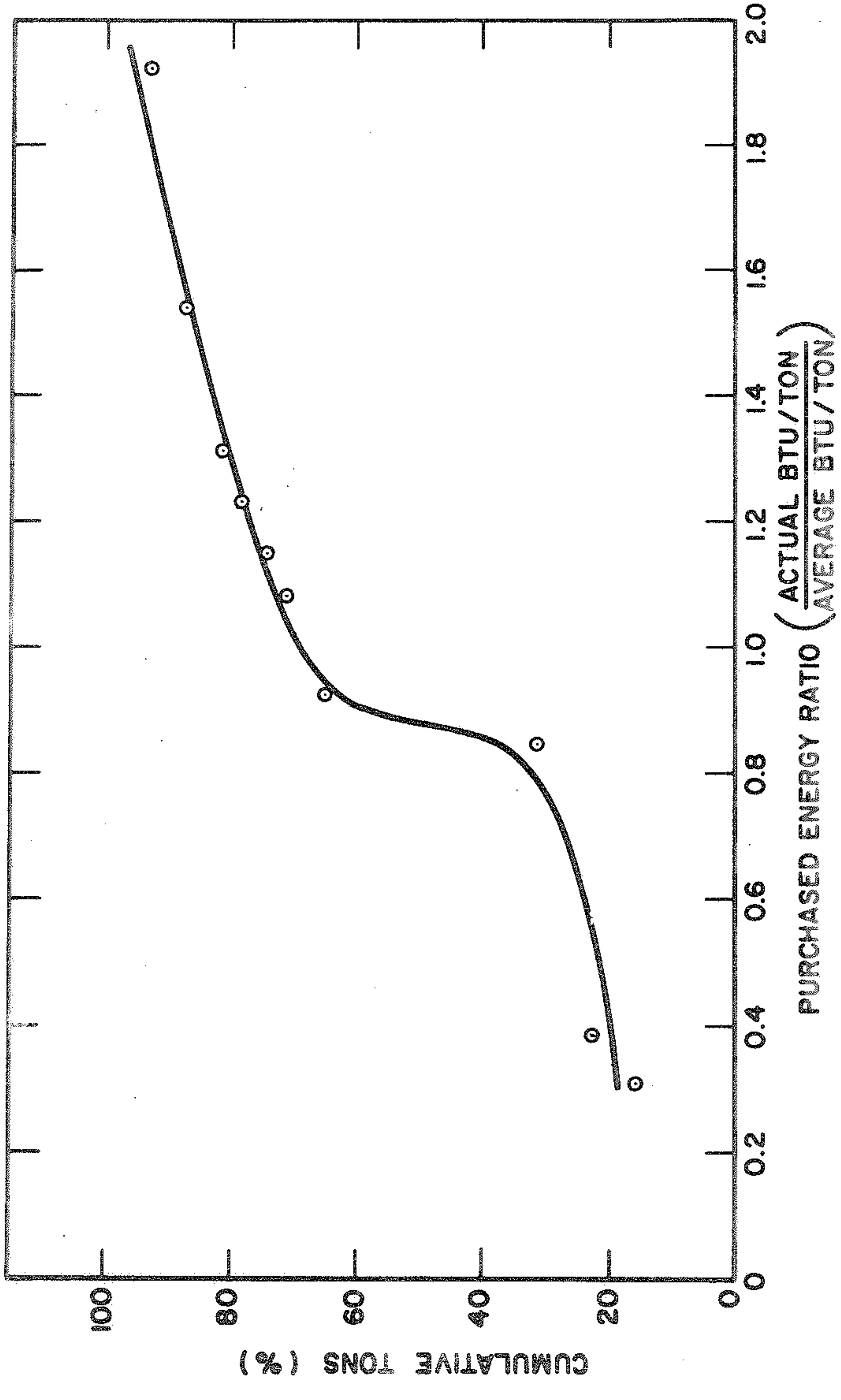

Figure 3.7 Cumulative Production Market Pulp

4. MAJOR FUEL CONSUMING PROCESSES[7,8]

The major fuel consuming processes used in pulp and paper making are summarized in Table 4.1; typical ranges for electricity and other forms are indicated for each process. The listed values are gross. Significant quantities of heat are reused in the form of steam and hot water.

Groundwood pulping (9%-10% of total pulp production) consumes large quantities of electricity but no chemicals or steam. It requires 10 to 17 x 10^6 Btu/ton, based on 10^4 Btu/mkwhr. Because of their high electricity consumption, groundwood mills tend to be located in regions of low electricity cost, or of abundant hydro power.

Sulphate pulping (65%-70% of the total pulp production) dominates the industry because it can pulp southern yellow pine of high resin content. It requires about 7 to 9 x 10^6 Btu/ton, including washing and refining, plus about 3 to 4 x 10^6 Btu/ton for bleaching. It is capital intensive because of the complex equipment and extensive chemical recovery and pollution control facilities.

Neutral sulphite semichemical (NSSC) pulping (8% of total pulp production) consumes somewhat more electricity than sulphate pulping but somewhat less fuels in other forms. It requires about 5 to 8 x 10^6 Btu/ton, including washing and refining.

Sulphite pulping (about 5% of the total pulp production) requires more fuel than sulphate pulping but less fuel for bleaching. Total fuel consumption is about 7 to 8 x 10 Btu/ton, including washing, refining and bleaching.

TABLE 4.1

MAJOR FUEL CONSUMING PROCESSES

Process Step	Electricity (kwhr/ton)	Other (Btu/ton)	Comments
Debarking	Small	----	
Chipping	Small	----	
Pulping - Groundwood	1000 - 1700	----	Electrical energy includes refining
- Sulphate	50 - 100	$3 - 3.5 \times 10^6$	
- NSSC	200 - 500	$1.8 - 2 \times 10^6$	Electrical energy includes refining
- Sulphite	50 - 100	$4 - 5 \times 10^6$	
Washing	30 - 50	0.5×10^6	
Refining	200 - 400	----	
Bleaching	80 - 120	$1 - 3 \times 10^6$	Large quantities of warm water also required
Paper Machine	300 - 400	$5 - 9 \times 10^6$	
Recovery - Evaporator	Small	$2.5 - 3 \times 10^6$	
- Furnace	Small	$18 - 20 \times 10^6$	Net $10\text{-}12 \times 10^6$ Btu/ton produced as steam
- Lime Kiln	Small	2×10^6	Optimum operating conditions save 10%
Power Plant Operation	Small	$1 - 1.5 \times 10^6$	Auxiliaries and soot blowing
Space Heating	----	$0 - 2 \times 10^6$	Depends on season and location

4.1 DIGESTERS

In chemical pulping, pulpwood reacts with chemical substances that remove lignin and hemicellulose and free and desired cellulose fibers. The reactions are carried out in large vessels called digesters under alkaline, neutral, or acidic conditions. The distinction between various techniques is based on the pH in the digester.

The Kraft sulphate pulping is the leading alkaline process. It uses a mixture of sodium sulphide and sodium hydroxide at a pH of about 12. It occurs at temperatures of 340 to 350° F, and pressures of about 130 psig. Cooking time is about 2 to 3 hours. The neutral sulphite semichemical (NSSC) pulping process uses a solution of sodium sulphite and small amounts of alkaline at a pH of 7 to 9. At temperatures of about 390° F typical cooking time is about 1 hour.

The sulphite pulping process uses an acid sulphite solution at a pH between 1 and 6. The original process was based on the use of calcium (limestone) but modern usage has favored a shift to sodium, magnesium, and ammonium sulphites or bisulphites because of chemical recovery and pollution control considerations. Cooking temperatures are in the range of 300 to 330° F, pressures of about 100 psig, and times of 3 to 5 hours.

Both batch and continuous digesters are in use. For sulphate pulping, the digesters are made primarily of carbon steel, with 12 foot diameter and 50 to 60 foot height for batch processing, and 12 foot diameter and more than 100 foot height for continuous processing. Approximately 50% of present sulphate-pulp production is processed in continuous digesters; the remainder is about equally divided between directly and indirectly heated batch digesters. In indirectly heated batch digesters, the pulping liquor is circulated through steam-heated heat exchangers external to the digester. The condensed steam is maintained separate from the liquor. In directly heated digesters, the steam is used directly in the digester vessel. Thus, the pulping liquor is diluted. Continuous digesters are typically counterflow (pulp and liquor) processes employing a combination of direct and indirect steam heating. Both upward and downward pulp flows are available, depending on the manufacturer.

The energy required for sulphate pulping depends on many factors such as wood species, product being produced, and moisture content of chips, but is not affected significantly by the type of digester used. Typically, batch digesters in the form of process steam require 3 to 3.5×10^6 Btu/ton for initial heating and cooking. During blowing (unloading) of the digester, large quantities of flash steam are recovered in heat exchangers in the form of hot water. This water is used in other operations such as washing and bleaching. If this recovered heat were not available, additional energy would be required for these operations.

In continuous digesters, pulp heating, cooking and blowing operations are carried out simultaneously on a continuous basis. Here, the opportunity exists to use some of the flash steam from the exhaust flows for heating the incoming flows. Although the internal recirculation of heat within the continuous digester reduces the gross steam load, the amount of recovered heat for use in other operations is reduced. Typically, continuous digesters require

2 to 2.5 x 10^6 Btu/ton in the form of steam. About 1 x 10^6 Btu/ton of flash steam is recirculated, resulting in a gross requirement of 3 to 3.5 x 10^6 Btu/ton, comparable to that of batch digesters. About 0.7 to 0.8 x 10^6 Btu/ton in the form of hot water is recovered from continuous digesters for external use. This results in an overall net cooking requirement of 1.2 to 1.7 x 10^6 Btu/ton. With batch digesters, the recovered hot water has an energy content of about 1.8 x 10^6 Btu/ton of product; subtraction from the gross steam input yields a net cooking requirement of 1.2 to 1.7 Btu/ton, which is the same as for continuous digesters. Thus it appears that while continuous digesters do reduce the direct steam load compared to batch digesters, the net input energy is essentially the same for both.

Continuous digesters have advantages other than fuel saving. Since pulping is performed on a continuous basis, the system components can be sized for average rather than peak conditions of operation. Steam rates are reduced and the boiler size can be reduced accordingly. Continuous pulping requires less manpower and is more adaptable to computerized control. Consequently, continuous digesters are generally more economical, and the current trend for modernization or expansion is toward their use. Many batch digesters continue to be used, however, and some new units are being installed, depending on the particular needs of individual mills.

Digesters for NSSC pulping are fabricated in many different configurations including spherical rotary, inclined tube, vertical batch, multiple-horizontal tube, and vertical continuous. The most widely used configuration is the multiple-horizontal tube containing two to four tubes stacked one above the other. Revolving screws move the pulp chips through the tubes in series flows. Hydrostatic impregnation and presteaming are sometimes used. Energy requirements for NSSC pulping are appreciably lower than those for sulphate pulping, due primarily to higher pulp yields and shorter cooking times. The yields range from 60 to 80% with one-half or less of the total lignin removed. Gross steam consumption is 1.8 to 2.0×10^6 Btu/ton of product and flash steam is recovered during blowing as in the sulphate process. Following discharge from the digesters, the softened chips are mechanically pulped or fiberized in disk mills. Energy required for fiberizing is 200-500 kwhr/ton of product, depending on the yield to which the chips are cooked and the type of wood used.

Acid sulphite pulping is carried out in both batch and continuous digesters (magnesium-base). To withstand the corrosive acid pulping liquors, the batch digesters are typically lined with brick. All exposed metal components are made of stainless steel. Gross energy requirements range from 4 to 5×10^6 Btu/ton of product. Flash heat recovery is practiced similar to that for the sulphate process. Sulphite pulps are easily bleached; accordingly, they require significantly lower energy input for bleaching than sulphate pulps. Total energy required for both pulping and bleaching for the sulphite process is about the same as for the sulphate process.

4.2 BLEACHING

Pulp fibers produced by chemical digestion are colored, ranging from dark brown to creamish white. While groundwood and

NSSC pulps are used mainly as produced, most of the sulphite and about half of the sulphate pulps are bleached to produce white fibers for paper and board products. Bleaching of chemical pulps can be considered as a continuation of digestion, with additional removal of lignin and loss of pulp yield.

Sulphate pulps are characteristically dark in color and require more bleaching than sulphite pulps. Bleaching is normally a multi-stage process involving numerous separate operations such as washing, chlorination, alkaline extraction, and chlorine dioxide treatment. Various combinations of treatments are practiced by different mills to meet their particular requirements. Each stage of bleaching requires different operating temperatures and times, with separate washing between stages. As a consequence, bleaching requires large quantities of warm water for washing, steam for heating to the desired temperature, and appreciable electricity for pumping. Chlorination temperatures are typically 120 to 130°F for 1 hour. NaOH extraction is carried out at 140 to 170°F for 3 to 5 hours. Energy requirements for sulphate pulps are about 3×10^6 Btu/ton of product and for sulphite pulps about 1×10^6 Btu/ton. Electricity consumption varies between 80 and 120 kwhr/ton.

Chlorine is the most important bleaching chemical, and consumption ranges from 125 to 150 pounds/ton of product. The manufacture of chlorine involves the electrolysis of saturated sodium chloride solution. The electricity required is 2800-3000 kwhr per ton of chlorine or 2×10^6 Btu/ton of paper.

4.3 PAPER MACHINE

The term "paper machine" generally includes all of the equipment used in handling and forming the refined water suspension of mixed fibers into the finished paper product. The paper machine furnish commonly consists of a combination of refined pulps together with chemical additives such as fillers and whiteners. The furnish, which starts in the stock chest at a consistency of 2% to 4%, passes through stages of cleaning, screening, and deaerating. It is then diluted by recycled paper-machine white water, and enters the head box of the machine at a consistency of about 0.6%. Following the headbox, it is formed into a sheet by either four drinier or cylindrical machines. The dryness of the sheet is increased to 2.5% by table drainage and to about 12% by suction boxes. A suction couch roll at the end of the four drinier wire increases dryness to 18% to 23%, depending on the grade of paper being produced. Presses remove more water and increase the dryness to 36% to 45%. The remaining moisture is removed by evaporation. Coating and finishing operations follow the drying section on many machines. Finally, the sheet is reeled for cutting and shipment.

Energy requirements for paper machines (mostly in the form of steam) range from 5 to 9 x 10^6 Btu/ton of product. The energy load is strongly dependent on the type of product, with market pulp needing the least energy and fine papers and heavy board the most energy. In the dryer section, water removal in the range of 1.2 to 1.5 pounds of water per pound of product is typical. Allowing 1300 to 1500 Btu/pound of water (including losses), it can be concluded that direct evaporation consumes about 3.2 to 4.6 x 10^6 Btu/ton, namely about half the energy used for paper making.

Water vapor is removed from the dryer section by flow of large quantities of air through the dryer. The air flow is about 10 pounds of air per pound of water evaporated. Higher flows of air consume energy without significantly benefiting the drying process and, therefore, most modern dryers are enclosed in hoods that limit the air flow. With a 100° F temperature rise through the dryer, the 10 pound air flow consumes 0.6 to 0.8×10^6 Btu/ton of product. Since some of the smaller older machines do not have hoods and some newer machines use partially open hoods, overall average air flows can be somewhat larger and the energy consumed is about 1×10^6 Btu/ton of product. The total energy consumption (water evaporation plus air heating) is 4.2 to 5.6×10^6 Btu/ton of product, with the remainder of the paper machine load, approximately 1 to 3.5×10^6 Btu/ton, used for stock heating, steam showers (heating and cleaning), and finishing operations.

The dryer hood systems usually have air economizers and water heaters in the exhaust ducts to reclaim heat. The heated air supplements the steam heated air requirements of the dryer, and the hot water (after cleaning) can be used in water showers and other parts of the total mill. The recovered heat ranges from 1 to 1.5×10^6 Btu/ton of product.

Since removing water mechanically requires much less energy than removing it by evaporation, continued improvement in water removal by suction and pressing is desirable. High consistency forming, which results in a more porous sheet structure, is being investigated. Higher water removal rates are possible in the presses, which could lead to increased dryness and, therefore, less water removal in the dryer. The porous sheet formed by high consistency forming can be expected to have special characteristics, however, which may be more suited for new products rather than replacing current sheet forming techniques. Steam showers that increase the sheet temperature before suction rolls or presses are also being introduced. Higher temperatures decrease the viscosity of the water and result in greater water removal. This technique is similar to the current use of hot presses located within the dryer section. Many older machines have a group of predryers in the press section to provide increased sheet temperatures into the last press.

Some experimental work has been done on dry-forming processes where the cellulose fibers are air supported and distributed into sheet form by suction or electric forces. Such a process would eliminate water suspension of the fibers and, therefore, the need for water removal. Dry forming requires a source of water-free fiber, however, and would have limited application (e.g., clean waste paper). Pulpwood naturally contains about 50% water, which would appear to eliminate sources of new fiber from being utilized.

4.4 LIQUOR EVAPORATION

Upon completion of the cooking cycle, the wood chips and pulping liquor are discharged from the digester into flashing units, and then pass to washers for separation of the pulp from the liquor. Washing is performed in several stages (counterflow with wash water). Knotting (removal of uncooked chip fractions), or fibrilizing to break up bundles, and screening are commonly used to prepare the pulp for efficient washing. The separated pulp undergoes further refining and bleaching steps and the pulping liquor is processed for chemical recovery.

In the sulphate process the black pulping liquor has an initial concentration from the washers of 15 to 18%. The solids in the liquor are lignins and hemicellulose. Approximately 3000 pounds of solids are produced per ton of usable pulp. Chemical recovery in the recovery furnace requires concentration of the liquor to 60 to 65% total solids for satisfactory combustion. This concentration is usually carried out in two operations. Multiple-effect evaporators are used up to 50% solids, and direct gas-contact evaporation in the recovery furnace from 50% up to 65% solids. In multiple-effect units, the water evaporated from the first stage acts as the heating medium for the second stage. At reduced operating pressures in each succeeding stage, the initial steam energy can be reused continuously throughout all the stages of the evaporator. For each pound of steam condensed in the initial stage, approximately 0.8 pound of water is evaporated per stage. Six effects result in about 4.8 pounds of water evaporated per pound of steam. Sextuple units are in common use and require 2.5 to 3.0 x 10^6 Btu/ton of product for initial steam heating.

Corrosion and high viscosity problems associated with black liquor at higher than 50% solids favor direct contact evaporation for further concentration. The liquor is sprayed directly in the hot flue gases (500 to 600°F), where further concentration to 65% solids occurs and combustion is possible. Water evaporation within the furnace cools the flue gases to about 300°F before exhausting the atmosphere. The direct contact evaporator is a major source of H_2S emission in the recovery system. Corrective action to reduce H_2S emission can be either oxidation of the liquor prior to final concentration or conversion of the system to eliminate direct contact between flue gas and black liquor. New systems use additional evaporation in the multiple effect evaporator (up to about 55%), and finishing in an air cascade evaporator (65-70% solids), or additional multiple evaporator effects (called a concentrator) for concentrations of about 62%. The concentrator or high solids system has found extensive application in Europe.

Use of a high solids system to achieve higher efficiency requires an alternate use for the energy in the flue gas, about 10^6 Btu/ton of product, which is normally used for direct contact evaporation (550° F to 300° F). It can be utilized in water economizers and combustion air preheating by installation of additional heat transfer surface. If the additional concentrator portion of the multiple effects evaporator could be heated by the exhaust of the current units, then the possible savings would be about 1×10^6 Btu/ton.

The pulping liquor used in NSSC pulping contains about half of the combustible energy found in sulphate black liquor. The lower heating value results primarily from the high pulp yields, which reduce the organic content of the liquor. Where possible, the industry employs cross-recovery in which both NSSC liquors are processed in the sulphate recovery system.

The low heating value of the liquor plus the general small size of NSSC mills makes the use of separate standard sulphate type recovery systems uneconomical. Some mills still discharge their liquors to waste treatment systems. Fluidized bed combustion is employed at several mills. Multiple-effects evaporators are used to increase the solid concentration from 10% (from the washers) to about 35% required for introduction to the fluidized bed. The systems operate without auxiliary fuel.

Concentration of pulping liquor in sulphite pulping uses multiple-effect evaporators and direct contact evaporators. Vapor compression evaporators are also used with steam driven turbine-compressor units. The variations in sulphite liquor bases (calcium, sodium, ammonium, and magnesium) result in many different techniques for handling the pulping liquors. Typical solid concentrations in the liquor from the washers is 10%. Evaporation to the 50% level requires 3.5 to 4.0 x 10^6 Btu/ton of product. Energy savings by higher concentration in multiple-effect evaporators appears doubtful because of the difficulties involved in handling acid liquors.

4.5 RECOVERY FURNACE

The recovery furnace is a major component in the overall sulphate pulping process for economic recovery of pulping chemicals. Black liquor enters the furnace after concentration to about 50% solids. The spent pulping chemicals (sodium and sulphur) react at furnace temperatures to form sodium carbonate and sodium sulphide. Furnace heat is provided by combustion of the organic solids. Approximately 3000 pounds of solids per ton of product are available for combustion. With a fuel value of 6000 to 7000 Btu/pound of solids, combustion of the liquor yields about 20 x 10^6 Btu/ton of product. About 2 x 10^6 Btu/ton of product is used for chemical reduction and losses. Direct contact water evaporation and exhaust flue gas consume an additional 6 x 10^6 Btu/ton of product. The remainder, about

12×10^6 Btu/ton of product, is available for steam production and, therefore, can replace a significant fraction of the total energy required for paper production.

Modern recovery furnaces are large, complex installations with single units having the capacity to serve the recovery needs of a mill of over 1000 tons of production/day. Although chemical recovery is the prime function of the unit, steam production has become equally important. Operating steam conditions are 1250 psig and 950° F.

Ammonium-base sulphite pulping liquors are not processed for chemical recovery, but are burned in combination boilers along with bark and oil. Average fuel values for the liquor solids are similar to those for sulphate liquors, with a resultant energy available for steam production in the range from 10 to 12×10^6 Btu/ton of product. The magnesium base sulphite process is used at many locations because the spent liquor can be burned in a relatively simple heat and chemical recovery furnace, with the chemicals returned in the form of magnesium oxide and sulphur dioxide. The MgO and SO_2 are then recombined to form the red pulping liquors. Steam can be produced at pressures up to 1500 psig.

4.6 LIME KILN

Economic operation of the sulphate pulping process requires the recovery and reuse of the sodium and sulphur compounds in the digester. The recovery furnace returns the sodium in the form of sodium carbonate. Quicklime (CaO) is added to the Na_2CO_3 in water solution, converting the Na_2CO_3 to NaOH which is then available for reuse in pulping. The NaOH recovery proceeds in two stages:

Slaking: $CaO + H_2O \rightarrow Ca(OH)_2$

Causticizing: $Ca(OH)_2 + Na_2CO_3 \rightarrow 2NaOH + CaCO_3$

The $CaCO_3$ in a water slurry (lime mud) is recycled through a lime kiln for conversion back to CaO.

The lime kiln is a large, refractory-lined rotating cylinder ranging in size from 6 to 13 feet in diameter and 100 to 350 feet in length. The lime mud is introduced at one end and progresses through the kiln by tumbling. Typical rotation speeds are 1 rpm, and transit times are 2 to 4 hours. Oil or natural gas is used for heating. The burners are located at the material-discharge end of the kiln and the combustion gases pass counterflow to the material. Pulverized coal is not used because of the detrimental effect of ash on the pulping liquors.

Fuel requirements for typical kilns range from 8 to 10 x 10^6 Btu/ton of kiln product (CaO plus inert materials). Kraft mill operations use 400 to 500 pounds of kiln product per ton of paper produced in the mill, and the fuel for the kiln is about 2 x 10^6 Btu/ton of paper.

Modern kilns utilize heat-recuperating chains at the front end of the kiln to recover heat from the exhaust gases. Exhaust gas temperatures range from 300 to 750° F, depending on the length of the kiln; the average exhaust temperature is about 500° F. The kiln is an integral part of the overall pollution control system of the mill, burning combustible gases from many different sources throughout the mill. The kiln exhaust gases are water-stripped prior to release to the atmosphere, and the stripping water is used for washing and filtering. Water stripping reduces the kiln exhaust temperature to about 180° F.

The calcined product (CaO plus inerts) discharges from the kiln at approximately 2000° F. Recent developments in air preheaters permit recovery of a large fraction of the sensible heat of this product through heating of the secondary air required for kiln operation. Secondary air preheaters can save 0.5×10^6 Btu/ton of paper.

Overall fuel consumption in the kiln is affected by many factors including water content of the feed slurry (normally 40%), ambient air conditions surrounding the kiln, and length-to-diameter ratio of the kiln. With carefully controlled combustion, even feed rates, low wind velocities, and low feed moisture content, fuel rates as low as 7.2×10^6 Btu/ton of kiln product have been reported. Thus, favorable operating conditions can result in overall fuel savings of about 10%, or about 0.2×10^6 Btu/ton of paper.

5. IDENTIFICATION OF SPECIFIC FUEL CONSERVATION METHODS

Study of the pulp and paper making processes reveals a number of methods by which significant savings in purchased energy can be achieved. These include in-plant electricity generation, recycling of waste paper, bleaching, burning of bark and wood wastes, modification of operating procedures, and changes in process equipment. A discussion of the technical aspects of these methods is presented in the following sections.

5.1 ELECTRICITY GENERATION

In 1972, the pulp and paper industry purchased 28 x 10^9 kwhr of electricity from utilities. This electricity represents about half of the total electrical needs of the industry, the remainder having been generated internally by means of combined turbogenerator-process steam systems. Most of the by-product electricity was generated in new, large integrated mills with capacities of the order of 500 to 1000 tons/day. Electricity generation in integrated mills varies widely, however, ranging from total internal generation (new facilities) to zero generation (facilities near sources of low cost electricity). Total electricity purchased by integrated mills was about 17 x 10^9 kwhr in 1972.

Non-integrated mills, by and large, purchase all of their required electricity. In 1972, they purchased about 11 x 10^9 kwhrs. These mills are small in size (100 to 150 tons/day) and tend to have low capital cost installations. As a rule, they produce process steam directly at the low pressures and temperatures required for paper making, and purchase electricity.

Paper manufacture, either in integrated or non-integrated mills, requires an average of about 850 kwhr of electricity and 18×10^6 Btu in the form of process steam per ton of product. The average ratio of electricity to steam energy is about 50 kwhr per 10^6 Btu of steam. Modern extraction steam turbines can more than match this ratio and generate electricity at very high efficiency with respect to the fuel charged to electricity.

We studied the replacement of existing process steam facilities with new boiler-turbogenerator units to establish the total fuel that can be saved by internal generation of electricity at levels equal to or greater than the electrical needs of the industry. We considered two ranges of equipment size, 3 to 5 megawatts for non-integrated mills, and 25 megawatts or larger for integrated mills. A schematic of the combined plant is shown in Fig. 5.1.

Three turbine inlet conditions - 400 psig and 650° F, 850 psig and 900° F, and 1250 psig and 950° F - and two process steam conditions - 50 and 150 psig - were studied. The analysis is based on power rate calculations,[9] where the power rate is defined as the ratio of electricity generated and the energy charged to process steam in units of kwhr/10^6 Btu.

$$\text{Power rate} = \frac{10^6}{SR\,(H_{exh} - H_c)}$$

where SR = steam rate to turbine lb/kwhr

H_{exh} = enthalpy at turbine exhaust Btu/lb

H_c = Enthalpy from process, Btu/lb

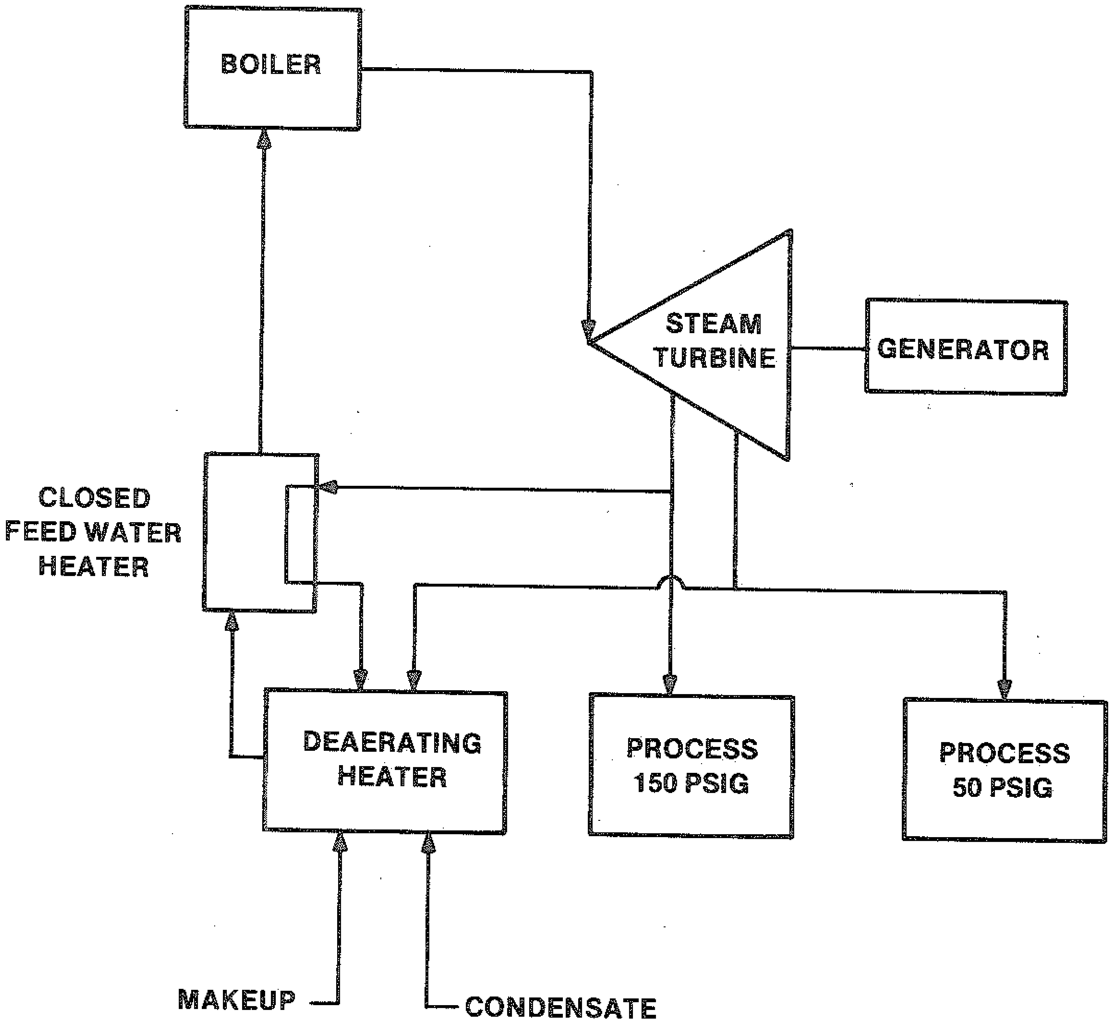

Figure 5.1 Combined Electricity-Steam Generation System (Steam Turbines)

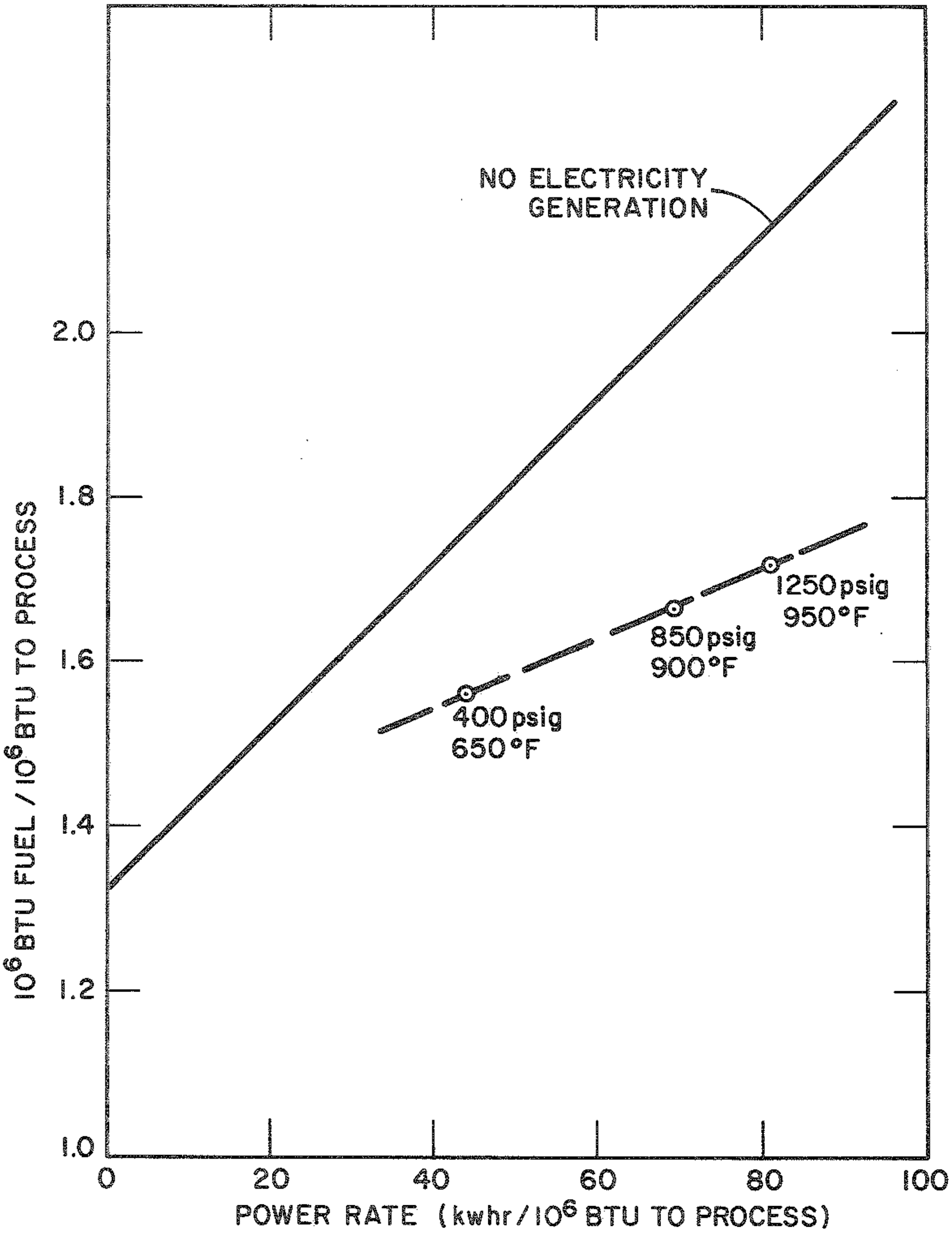

Figure 5. 3 Combined Electricity and Steam Generation by Means of Steam Turbines (Integrated Mills)

Another type of combined plant for generation of electricity and process steam is shown in Fig. 5.4. Here, a gas turbine instead of a back pressure steam turbine is used as a driver of the generator. Because gas turbines are more efficient than back pressure steam turbines, the amount of electricity that can be generated for a given amount of energy to process is higher than that with steam turbines. The ratio of fuel input to the turbine and energy to process vs power rate is shown in Fig. 5.5. For turbo-generator efficiencies of 25% and 34%, the power rate is 145 kwhr/10^6 Btu to process and 230 kwhr/10^6 Btu to process, respectively, and potential fuel savings by using combined gas turbine plants are high.

From the standpoint of fuel saving, widespread use of gas turbines in the paper industry is attractive, but some problems exist:

(1) The electricity that could be generated is far in excess of the needs of the industry and, therefore, part of it must be sold to surrounding plants or to utilities.

(2) Currently, gas turbines are limited to the use of premium fuels which may not be available in the future.

(3) Though gas turbines respond rapidly to load demand, operation at partial load introduces heavy performance penalties and significant reduction in exhaust temperature.

5.2 RECYCLING OF WASTE PAPER

In 1972, about 20% of the paper and paperboard products, 12 x 10^6 tons, was produced from secondary or recycled fiber

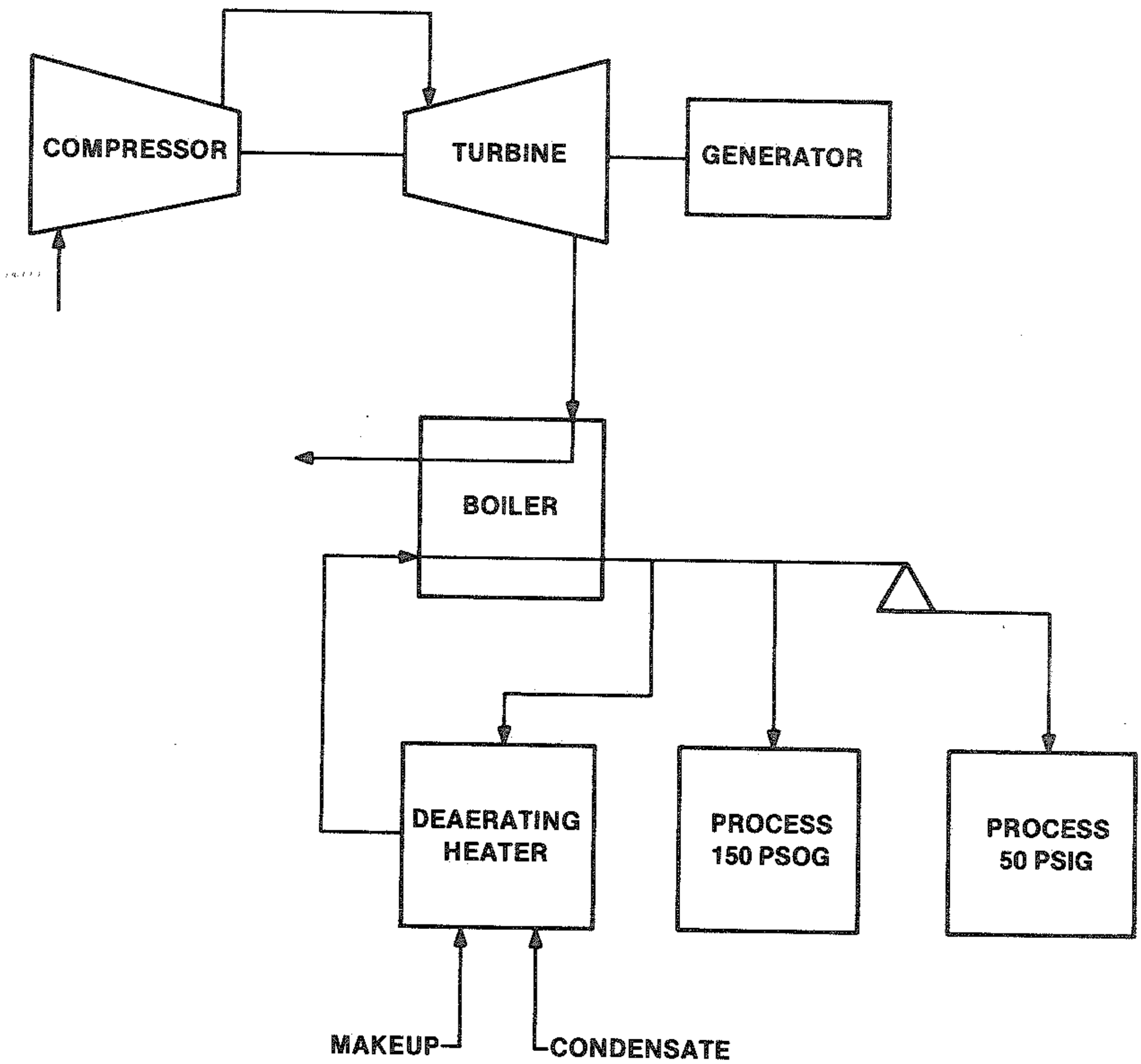

Figure 5.4 Combined Electricity-Process Steam Generation (Gas Turbines)

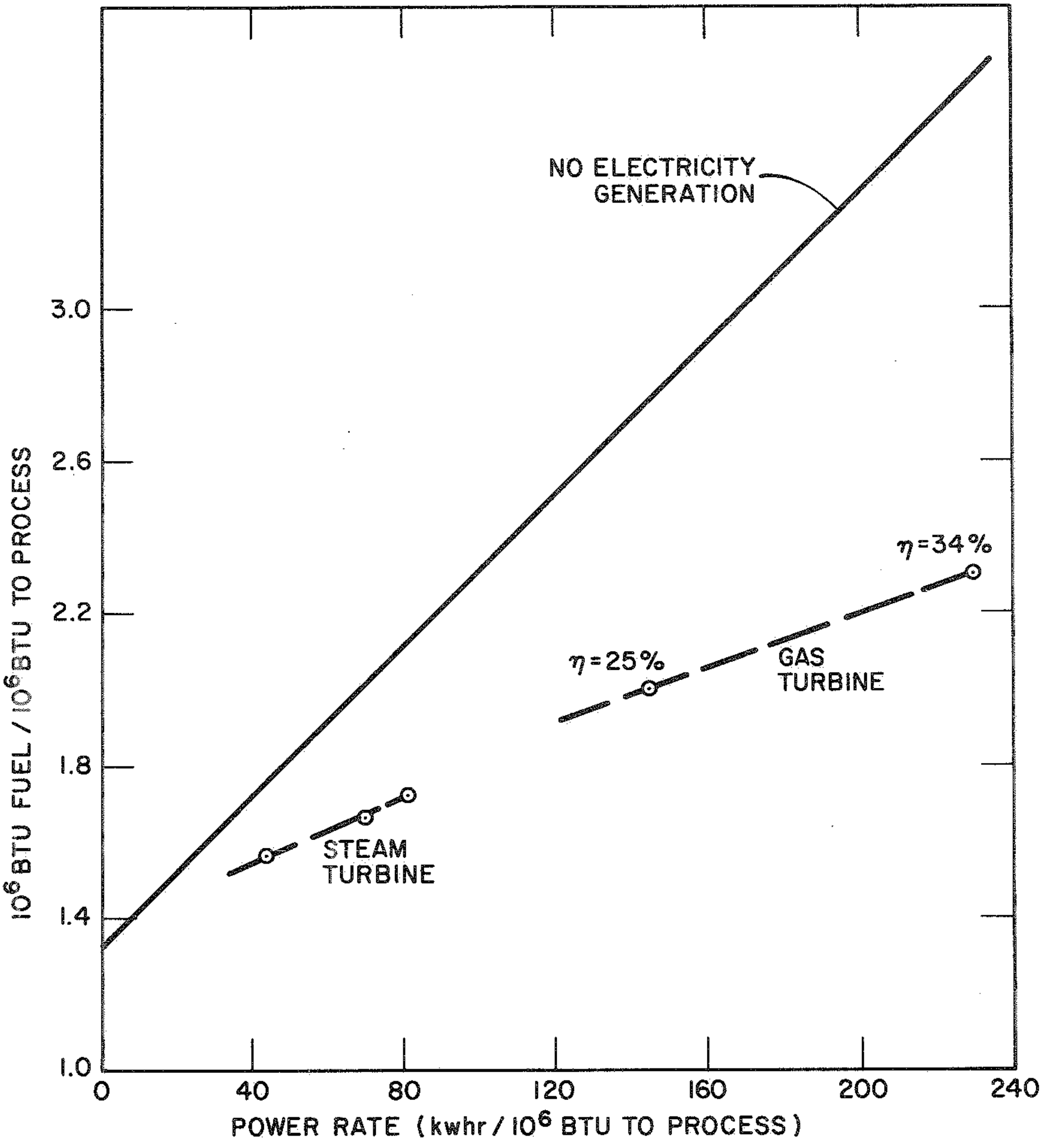

Figure 5.5 Combined Electricity and Steam Generation by Means of Gas Turbines

recovered from waste paper, mostly in non-integrated mills. Purchased energy consumption in non-integrated mills was 7 to 8 x 10^6 Btu/ton larger than that in integrated mills. The reason for the larger consumption is that non-integrated mills do not have chemical pulping facilities and, therefore, do not have process residuals (pulping liquor, organic solids) to burn as fuel. It follows that waste paper recycling conserves wood resources but results in added consumption of other fuels such as oil, gas, and coal.

The motivation for recycling waste paper comes primarily from capital cost considerations. Pulping facilities (new fiber) are expensive and become economic only in large sizes. Many small companies eliminate the need for these capital intensive facilities by using waste paper or by purchasing market pulp from large pulp producers. In addition, some integrated mills have an imbalance between pulping and paper forming facilities and use waste paper as a supplement. Except for capital cost considerations, recycling of waste paper does not offer other economic advantages. In general, new fiber is favored over recycled fiber. During the 1974-1975 downturn in paper sales, waste paper prices plummeted, and consumption of waste paper fell. Mills preferentially used new fiber rather than low-priced waste paper.

Energy is conserved when waste paper is burned in the sense that wood is used as a fuel. In modern chemical pulping plants about half the solid material content of a tree is used as a fuel and half is formed into paper products. If these products were eventually burned, the whole tree would be used as fuel. Recycling takes half the tree (in the form of paper products) and makes new products using other fuels. Since wood supplies are renewable and, with efficient forest management, adequate supplies are available, total use of wood as a fuel is desirable.

5.3 BLEACHING

In 1972, over 13×10^6 tons of sulphate pulp and 1.8×10^6 tons of sulphite pulp were bleached. Fuel requirements for bleaching are about 4×10^6 Btu/ton for sulphate pulp and 2×10^6 Btu/ton for sulphite pulp, plus 2×10^6 Btu/ton for electricity for production of chlorine. These requirements represent about 6% of the total fuels purchased by the industry.

Bleaching is directly related to consumer demand and a competitive response to that demand. With abundant cheap sources of fuel, pulp brightness was a dominant product consideration irrespective of fuel consumption. The need for energy conservation may provide an incentive for less bleaching.

Bleaching equipment requires substantial investments. Bleaching chemicals released to the environment are polluting and require the development of special pollution control equipment and further capital expenditures. Removal of lignin during bleaching lowers the pulp yield and increases the demand for pulp wood. All of these factors suggest that the industry would welcome a decrease in the need for bleaching if consumers accepted less bright products.

5.4 BURNING OF BARK AND WOOD WASTES

In 1972, the paper industry consumed over 70×10^6 cords of pulpwood, about 100×10^{12} Btu from burning bark, and 50×10^{12} Btu from burning hogged wood wastes. At an average of 300 pounds of dry bark per cord and 9000 Btu per pound of dry bark, the energy content of the available bark was about 200 x 10^{12} Btu, or twice as large as the magnitude utilized. Assuming a similar factor of two for the use of hogged wood wastes, we find that the total energy content of wood wastes was about 300 x 10^{12} Btu, as opposed to the 750 x 10^{12} Btu that was used.

Bark is a difficult material to handle because of its wet, clinging nature and because it contains long stringy strands and wood slivers. In addition, it contains sand and grit, which make it highly abrasive. The water content of bark in tree form is typically 50%. If wet debarking techniques are employed, however, the moisture content approaches 70-90% and the bark cannot be burned. Various types of pressing and dewatering equipment is used to reduce the water content mechanically to the 50% level. Some mills have investigated the use of waste wood drying as a means of fuel preparation to reduce handling and combustion problems.

The bark that is not burned presents a substantial disposal problem for the industry. Past disposal methods include land fill and water discharge, but both face pollution control restrictions. If more satisfactory handling and combustion techniques were developed, additional bark burning would contribute substantially both to fuel saving and to reduced pollution.

5.5 OPERATING PROCEDURES

Current operating procedures practiced by the pulp and paper industry have developed over many years as a result of extensive research and development by individual paper companies and equipment manufacturers. Because of its low cost, fuel and its consumption played a secondary role in the establishment of these procedures. Fuel costs for the production of paper have been typically about 5% of the total. Recent fuel prices have increased this percentage to about 15%. With further increases in fuel costs, the industry can be expected to pay increased attention to modifications in equipment and procedures which reduce fuel consumption.

Many possibilities for fuel savings exist throughout the production process. Space heating, ventilation, humidity control, and fresh water heating are important areas of conservation by means of waste heat recovery. Optimization of furnace and lime kiln operating conditions can lead to significant savings. Reduction of the amount of dried pulp for later use in the same mill can be achieved through improved scheduling and better balance of pulping and forming equipment, and can result in significant fuel savings. Increased use of thermal insulation around individual pieces of equipment can reduce heat losses. We estimate that such savings from improved operating procedures can be about 10% to 20% of the current purchased fuels.

5.6 NEAR-TERM PROCESS CHANGES

The magnitude of capital costs required in the pulp and paper industry, plus difficulties associated with perfecting new processes (e.g., results obtained on small test models do not necessarily scale up to large production units), tend to preclude rapid introduction of new or radically different techniques of production.

Development items currently underway, therefore, cannot be expected to affect a major fraction of the industry significantly within the next 5 to 10 years. Paper companies, however, maintain a continuing research and development effort looking for better solutions to problems both for individual mills and the industry as a whole.

The most important problem is the large capital required for modernization and expansion. Possible reductions of costs are being explored in many directions. The sulphur used in chemical pulping is a fundamental source of pollution. High costs of pollution control plus pulping and chemical recovery equipment force the industry to look for a modification or an alternative to the Kraft process, the largest pulping process, and for improved bleaching processes or means of reducing the discharge of bleach chemicals to the environment. Expanded use of mechanical pulps is being investigated to take advantage of the higher yields (compared to chemical pulps), and to minimize the pollution control requirement associated with chemical pulps. A number of variations in mechanical pulping are being introduced at the present time. Refiner mechanical pulping provides a means of economically pulping sawmill wastes (sawdust) and thus making fuller use of wood supplies. A new process, thermomechanical pulping produces a longer and stronger fiber than other mechanical processes. Thermomechanical pulp can be substituted for chemical pulps in such products as lightweight newsprint and printing paper grades which normally contain 20-25% chemical pulps for strength.

Computer control of individual processes is becoming common. First introduced in paper making operations, the computer is now being used for pulping, bleaching, and pollution control processes. Further expansion to other areas is certain. In all of these areas, the computer aids in optimizing operating conditions and balancing process flows. Thus, both cost and fuel consumption are reduced.

Continuous efforts are devoted to greater recycling of water within a mill and reduction in fresh water usage. The flow of effluents from a mill is almost identical to the use of fresh water. Water pollution control costs can be minimized by maximum reduction in fresh water usage. Reduction in fresh water use also results in fuel saving because less water need be tested to higher than environmental temperatures. Operation at higher stock consistencies is also pursued because it reduces equipment sizes and, therefore, capital costs and water consumption.

It is noteworthy that some process changes may be more energy intensive. Thermo-mechanical pulps may require more fuel than chemical pulps (operating conditions and fuel consumption are uncertain at the current stage of development). Since capital cost is of prime concern to the industry, solutions to cost problems can be expected to be favored over energy conservation.

6. ECONOMIC CONSIDERATIONS

In 1972, sales of the pulp and paper industry were $\$12 \times 10^9$. Capital investments planned for 1975 are $\$3 \times 10^9$, with similar amounts expected for the years 1976 to 1978. The distribution of 1975 investments by regions is 18.2% in New England and Mid Atlantic, 43.8% in the South, 13.2% in the North Central, and 24.8% in the Mountains, Pacific and Alaska regions. The industry is a major consumer of fuels - the largest user of residual oil and the fourth largest user of all fuels in the country. Fuel consumption in each mill varies significantly due to past decisions regarding production techniques and the many modernizations and expansions which have been carried out in recent years.

Since each company attempts to achieve the lowest cost possible, it is safe to assume that in general each mill is operating in its most economic condition. To maintain a competitive position, the management of each mill must use its available capital funds to minimize future costs and, therefore, maximize profits. Significant reductions in fuel consumption imply changes in equipment and, therefore, capital spending. Management decisions to allocate funds for fuel-conserving equipment must result in profits and must compete with other profit making options such as expansions in production and new products.

In this section, we will analyze the economics of some energy conserving options. The basic process of capital spending analysis consists of evaluating the investment outlay in terms of the economic gain provided by it. The investment outlay is represented by the net investment required for the new equipment or change in operation and the economic gain is represented by estimated operating cash flows generated by the investment. Since capital spending occurs early in an improvement program and the economic gain is realized in later years, a common time must be used for comparison of these funds.

For our comparisons, we will use the internal rate of return method of analysis which is based on the criterion that the sum of the present value of all expenditures and cash flow returns associated with a given project is equal to zero, namely

$$\sum_{t=o}^{N} \frac{A_t}{(1 + r)^t} = 0$$

where:

A_t = the expenditure or cash flow return in year t

r = rate of return

N = economic life in years

The factor $1/(1 + r)^t$ transforms each expenditure or cash flow return to its value at time zero. Assuming that all capital expenditures are made at time zero, the criterion takes the form

$$C_o = \sum_{t=o}^{N} \frac{\text{Net cash flow (t)}}{(1 + r)^t}$$

where:

C_o = Capital expenditure

and the net cash flow in year t is defined as the savings resulting from the expenditure, i.e., savings resulting from a reduction in fuel consumption, minus federal taxes and fixed costs of operation.

Net cash flow = Savings - Federal taxes - Fixed costs

The federal tax term is calculated by the relation

Federal taxes = Tax rate (Savings - Fixed costs - Depreciation)

By introducing the symbols defined below, the criterion can be expressed as

$$C_o = (1 - f_t)\ K_P S + C_o \left[f_c K_P (f_t - 1) + f_t K_{DP} \right]$$

where:

f_t = federal tax rate

f_c = fixed cost rate

$$K_P = \sum_{t=o}^{N} \frac{1}{(1 + r)^t} = \text{present value factor}$$

S = savings per year

$$K_{DP} = \sum_{t=o}^{N} \frac{\text{Depreciation fraction (t)}}{(1 + r)^t}$$

For straight line depreciation, the depreciation fraction is constant and equal to 1/N. For accelerated depreciation the fraction varies and must be calculated for each year. We assumed the sum-of-years' digit method of accelerated depreciation. Tables of both K_P (present value factor) and K_{DP} (present value of a stream of depreciation charges figured by the sum-of-years' digit method) are available in published form.[10]

Solving the equation for the payback period T, i.e., the ratio (capital cost/savings per year), we find

$$T = \frac{C_o}{S} = \frac{(1 - f_t)\, K_P}{1 + (1 - f_t)\, f_c K_P - f_t\, K_{DP}}$$

Graphs of the payback period T versus economic life N for different rates of return r are shown in Fig. 6.1. The figure includes the limiting value of zero rate of return to show the payback period without profit. Fixed costs are taken at 7% of the capital cost per year and represent such costs as local taxes, insurance, and administration associated with the capital expenditure.

It can be seen from Fig. 6.1 that at typical rates of return ranging from 10 to 15%, the payback period must be between 3 and 4 years. For the paper industry, the average economic life permitted by the Internal Revenue Service is 16 years. Accordingly, to be acceptable under this criterion, the saving per year realized from the capital investment must be approximately 1/3 to 1/4 of the capital cost and must be realized over an extended period approaching 16 years.

To investigate the effect of Federal taxes, payback period graphs were determined for the limiting case of zero Federal taxes. The results are shown in Fig. 6.2. Compared to the 50% Federal tax rate (Fig. 6.1), we see from Fig. 6.2 that, for a given set of

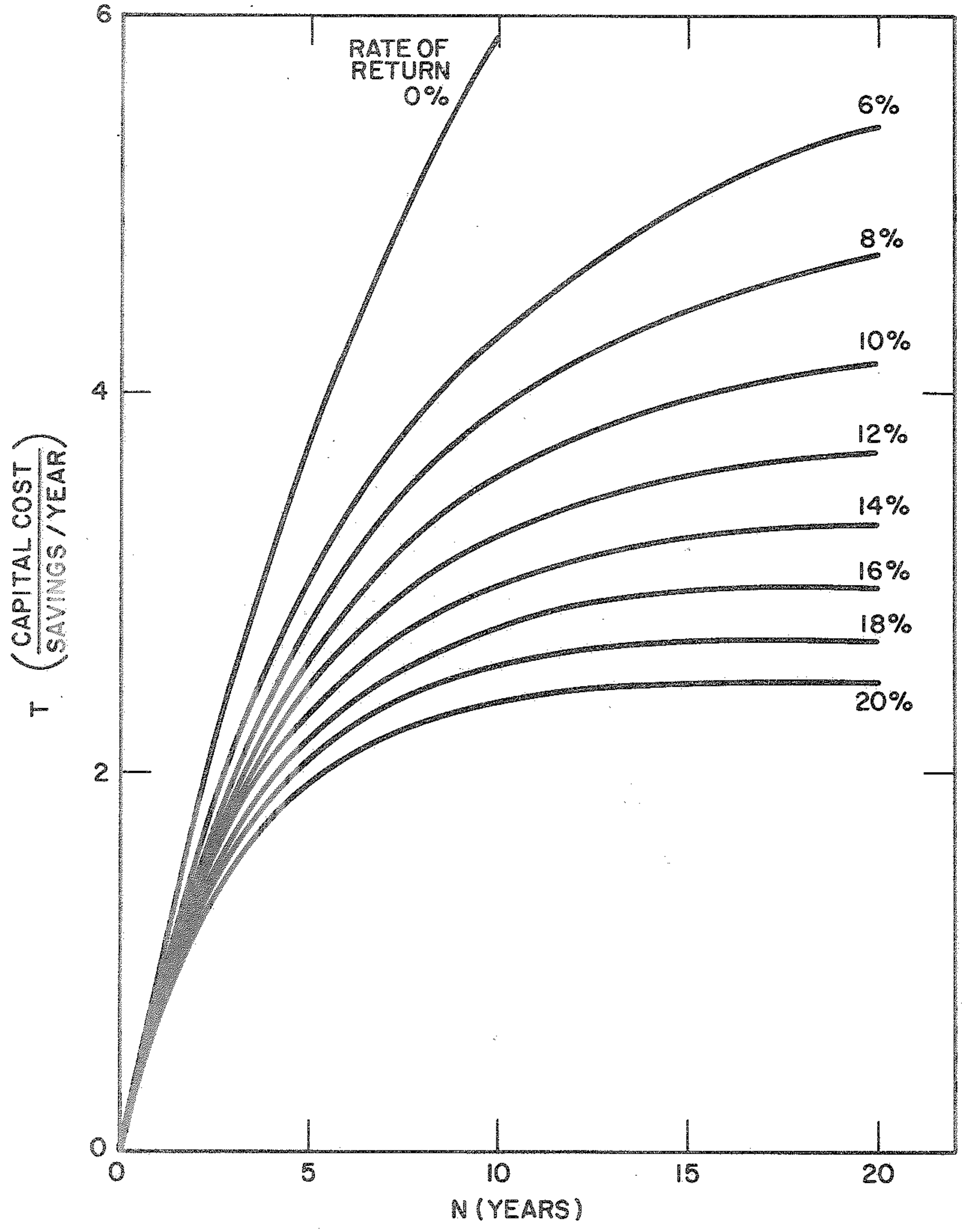

Figure 6.1 Economic Relationships for 50% Corporate Taxes Sum of Digits Depreciation 7% Fixed Charges

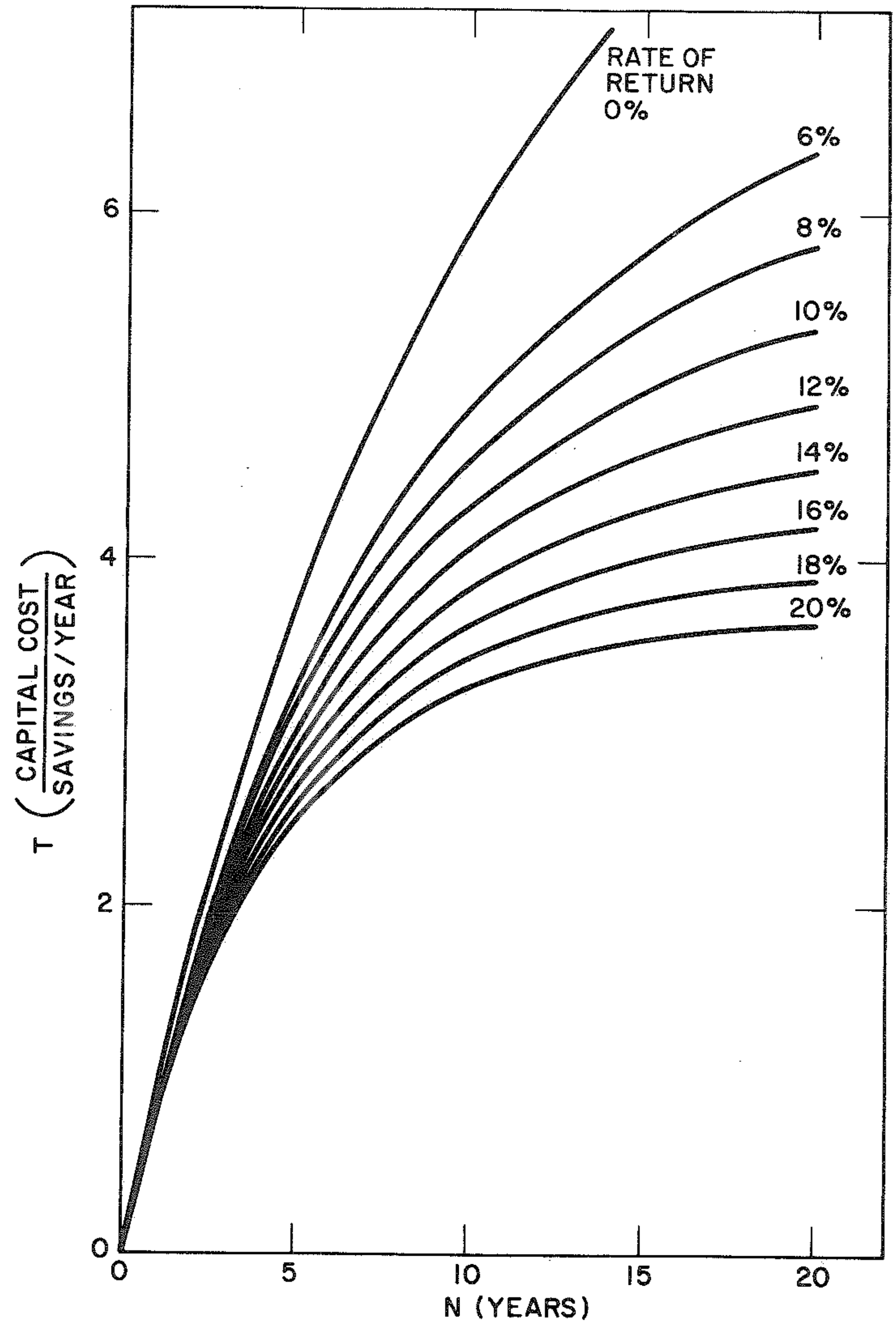

Figure 6.2 Economic Relationship for Zero Corporate Taxes and 7% Fixed Charges

conditions, a zero Federal tax rate results in a higher rate of return; conversely, for a given rate of return, a higher ratio of capital cost to savings per year is allowable. Considering the 10% to 15% rate of return range, the acceptable payback period increases to values of 3.7 to 5.3 years compared to the 3 to 4 years associated with a 50% Federal tax rate.

The required rate of return or cost of capital adjusted for risk varies from company to company but a generalized rate can be established as follows.[11] For equity investment,

$$\text{Required rate of return} = (\text{Riskless rate}) + (\text{Risk premium}),$$

where the riskless rate is based on the yield to maturity of government bonds. The present yield for 10-year government bonds is approximately 7%, and for 20-year bonds, about 8%. The risk premium is based on the stock market return averaged over the past 20 years and is determined as follows:

$$\text{Risk premium} = \beta\left[(\text{Average stock market return}) - (\text{Average riskless rate})\right],$$

where the β coefficient for a particular company is obtained from investment surveys,[12] and the average stock market return and riskless rate over the past twenty years are 12% and 4.4%, respectively. An overall $\beta = 0.92$ was obtained by averaging individual coefficients for leading paper companies. Hence, the risk premium is

$$\text{Risk premium (paper industry)} = 0.92\ (12\% - 4.4\%) = 7\%$$

and the corresponding required rate of return for equity is:

$$\text{Required rate of return} = 7\% + 7\% = 14\%$$

The required rate of return on debt is the direct cost of debt as indicated by yields for company bonds and adjusted for Federal tax rates. Current long-term bond yields are approximately 10%; considering a Federal tax rate of 50%, the resultant required rate of return is:

$$\text{Required rate of return (debt)} = \text{Bond yield} \times \text{Federal tax rate} = 10\% \times 1/2$$

$$= 5\%$$

For investments using a mix of debt and equity, the required rate of return is determined by a weighted average of the debt and equity rates as follows:

$$\text{Overall required rate of return} = \left[\frac{\text{Equity}}{\text{Equity + Debt}}\right] (\text{Equity rate of return})$$

$$+ \left[\frac{\text{Debt}}{\text{Equity + Debt}}\right] (\text{Debt rate of return})$$

The average (debt/equity) ratio for the paper industry is about 40% and, therefore, the overall required rate of return is 11.5%. This rate is applicable to large and well-financed companies. Small, independent companies (the majority of non-integrated mills) have more limited sources of capital funds and face greater risks than large companies. For this reason, the required rate of return for small companies should be in the range of 14% to 15%.

6.1 COMBINED ELECTRICITY - STEAM GENERATION

The fuel savings resulting from the use of combined electricity - process steam generators can be related to the capital costs of the equipment by the following expression

$$\frac{\text{Capital cost}}{\text{Fuel savings per year}} =$$

$$= \frac{\text{Cost of new equipment}}{[\underbrace{\text{Boiler fuel cost + Elect. cost}}_{\text{no generation}}] - [\underbrace{\text{Boiler fuel cost + Elect. cost}}_{\text{with generation}}]}$$

Using the definitions:

$$\text{Cost of new equipment} \equiv \left(\frac{\$}{\text{kw}}\right)(\text{kw})$$

$$[\underbrace{(\text{Boiler fuel cost}) + (\text{Elect. cost})}_{\text{no generation}}] \equiv \left(\frac{\$}{10^6 \text{ Btu fuel}}\right) \underbrace{\left(\frac{10^6 \text{ Btu fuel}}{\text{year}}\right)}_{\text{no generation}} +$$

$$+ \left(\frac{\$}{\text{kwhr}}\right)\left(\frac{\text{kwhr used}}{\text{year}}\right)$$

$$[\underbrace{(\text{Boiler fuel cost}) + (\text{Elect. cost})}_{\text{with generation}}] \equiv \left(\frac{\$}{10^6 \text{ Btu fuel}}\right) \underbrace{\left(\frac{10^6 \text{ Btu fuel}}{\text{year}}\right)}_{\text{with generation}} +$$

$$+ \left(\frac{\$}{\text{kwhr}}\right)\left[\left(\frac{\text{kwhr used}}{\text{year}}\right) - \left(\frac{\text{kwhr gen.}}{\text{year}}\right)\right]$$

in the capital cost expression, we find

$$\frac{\text{Capital cost}}{\text{Fuel savings per year}} =$$

$$= \frac{\left(\frac{\$}{\text{kw}}\right)\left(\frac{\text{kwhr}}{10^6 \text{ Btu fuel}}\right)\left(\frac{1 \text{ year}}{8600 \text{ hours}}\right)}{\left(\frac{\$}{\text{kwhr}}\right)\left(\frac{\text{kwhr}}{10^6 \text{ Btu fuel}}\right) - \left(\frac{\$}{10^6 \text{ Btu fuel}}\right)(1 - R)}$$

where:

$\frac{\$}{kw}$ = equipment specific cost

$\frac{\$}{kwhr}$ = electricity cost or selling price for excess electricity

$\frac{kwhr}{10^6 \text{ Btu fuel}}$ = kwhr generated per 10^6 Btu fuel

R = ratio of fuel consumed per 10^6 Btu to process for the system with no electricity generation and that of a system with electricity generation

Values of the kwhr/10^6 Btu fuel and the ratio R can be obtained for each system from Figs. 5.2 and 5.3. Typical equipment costs are:

	Non-integrated mills	Integrated mills
Boiler	\$200/kw	\$140/kw
Turbogenerator	\$170/kw	\$100/kw
Indirect	30%	30%
Total	\$480/kw	\$310/kw

On a per kw basis, the equipment costs were relatively insensitive to turbine inlet conditions and the listed costs were used for all three system operating conditions.

For non-integrated mills, the ratio of capital cost to fuel savings per year versus fuel cost for different values of electricity cost is shown in Fig. 6.3, and for integrated mills in Fig. 6.4. The differences between the two figures are primarily due to equipment

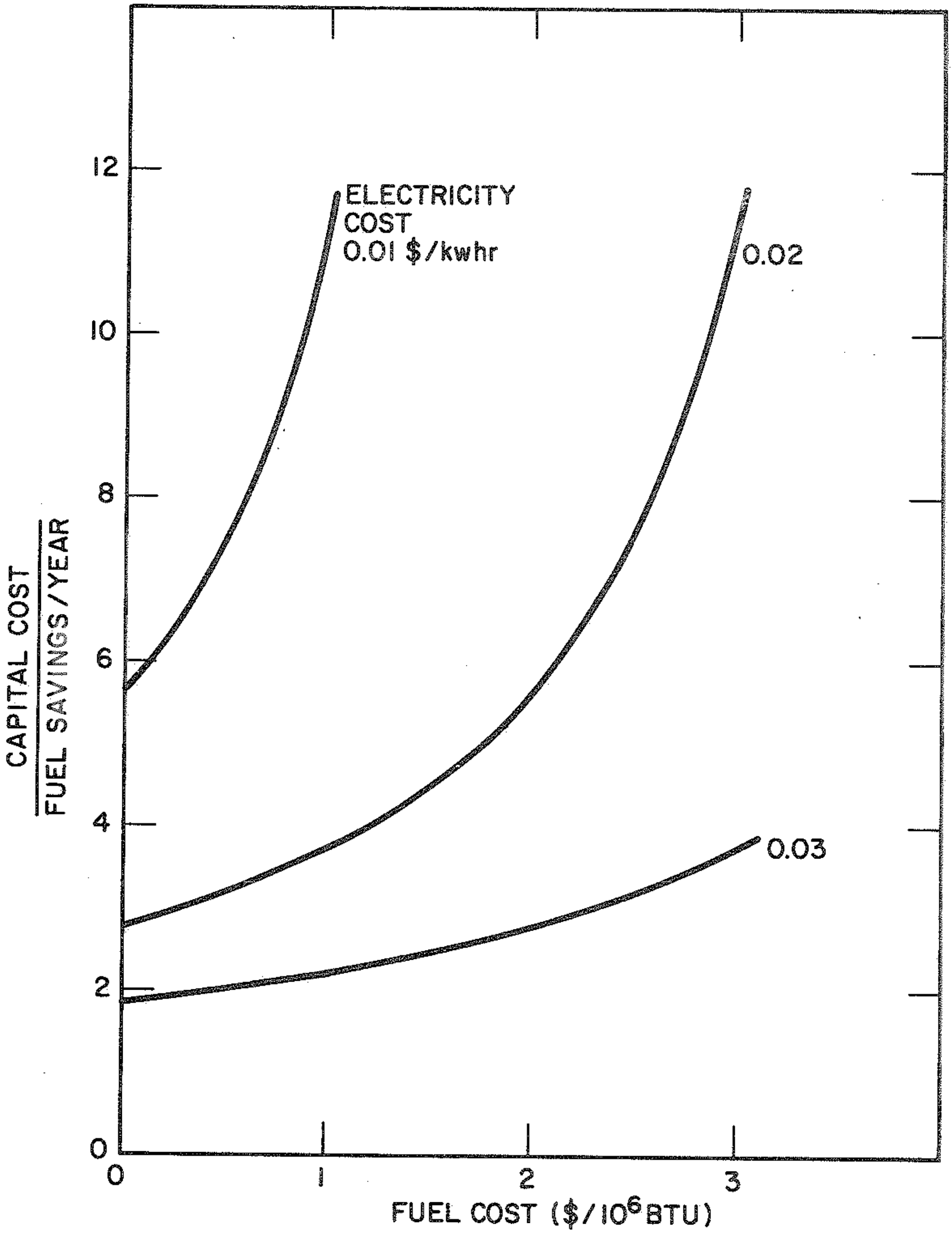

Figure 6.3 Fuel and Power Cost Relationships for 1250 PSIG - 950°F System, Nonintegrated Mills, Steam Turbogenerator

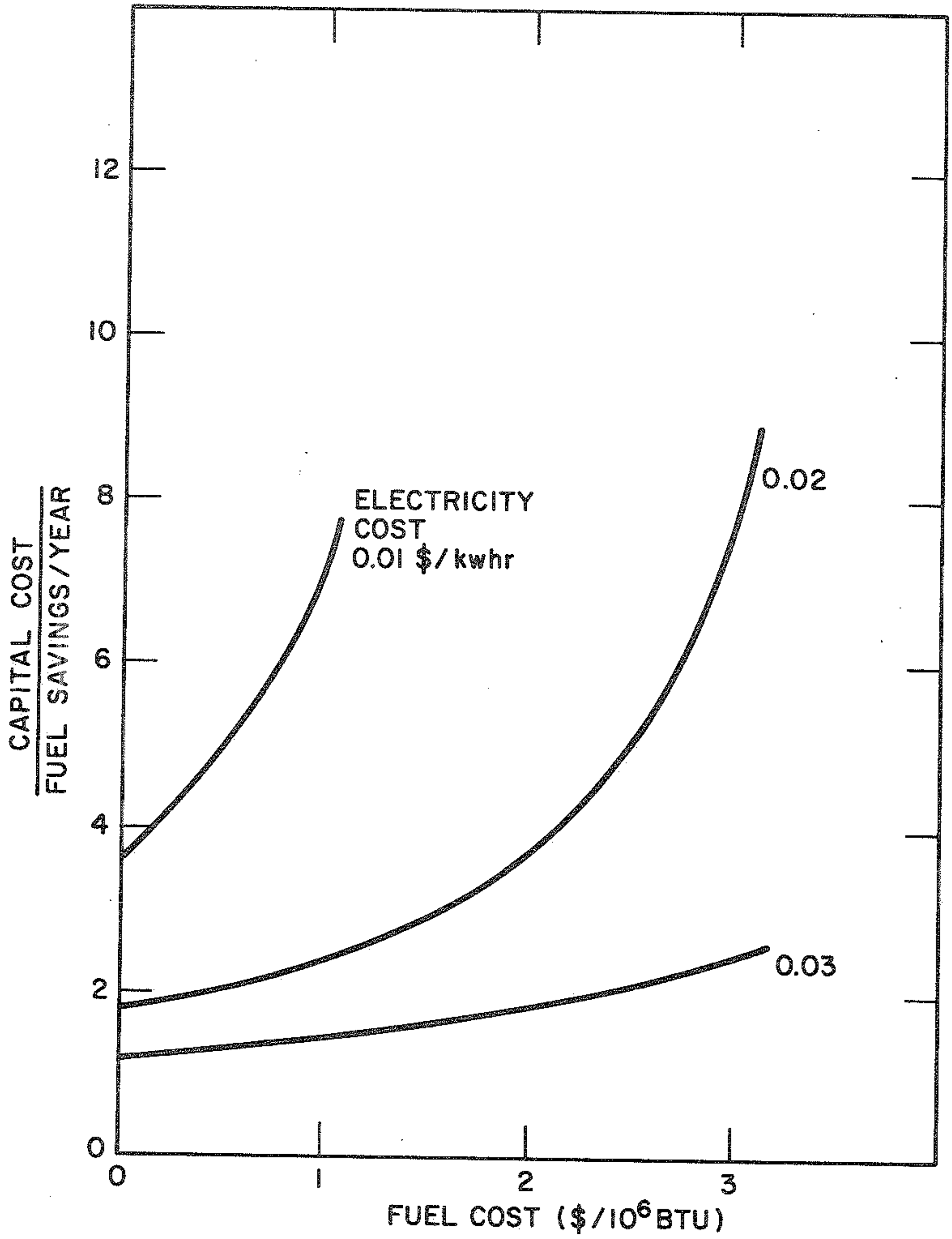

Figure 6.4 Fuel and Power Cost Relationships for 1250 PSIG - 950°F System, Integrated Mills, Steam Turbogenerator

costs. The ratio of capital cost to fuel savings per year is directly proportional to equipment costs. For a given value of electricity cost, a limiting value of fuel cost exists for which the ratio of capital cost to energy saving per year becomes very large. This limiting fuel cost corresponds to the condition where the additional fuel cost for generating electricity is equal to the cost of purchased electricity and, therefore, no savings can be realized with internal generation. The approximate limiting fuel costs are

Electricity Cost ($/kwhr)	Limiting Fuel Cost ($/$10^6$ Btu)
0.01	2
0.02	4
0.03	6

In general, economic considerations restrict the ratio of capital cost to fuel savings per year to values of less than 4 to 5. This acceptance criterion limits the use of internal electricity generation when the cost of purchased electricity is low. For example, for purchased electricity at 0.01 $/kwhr and lower, even zero fuel costs do not favor internal generation. On the other hand, for purchased electricity at 0.03 $/kwhr, the use of internal generation is economically favorable over a broad range of fuel costs.

Potential electricity generation and fuel savings that would result from the use of internal generation in mills currently lacking generating equipment versus capital cost are shown in Figs. 6.5 to 6.8. For non-integrated mills, the self-sufficient point of 11 x 10^9 kwhr per year requires approximately $600 x 10^6 of capital. If high pressure

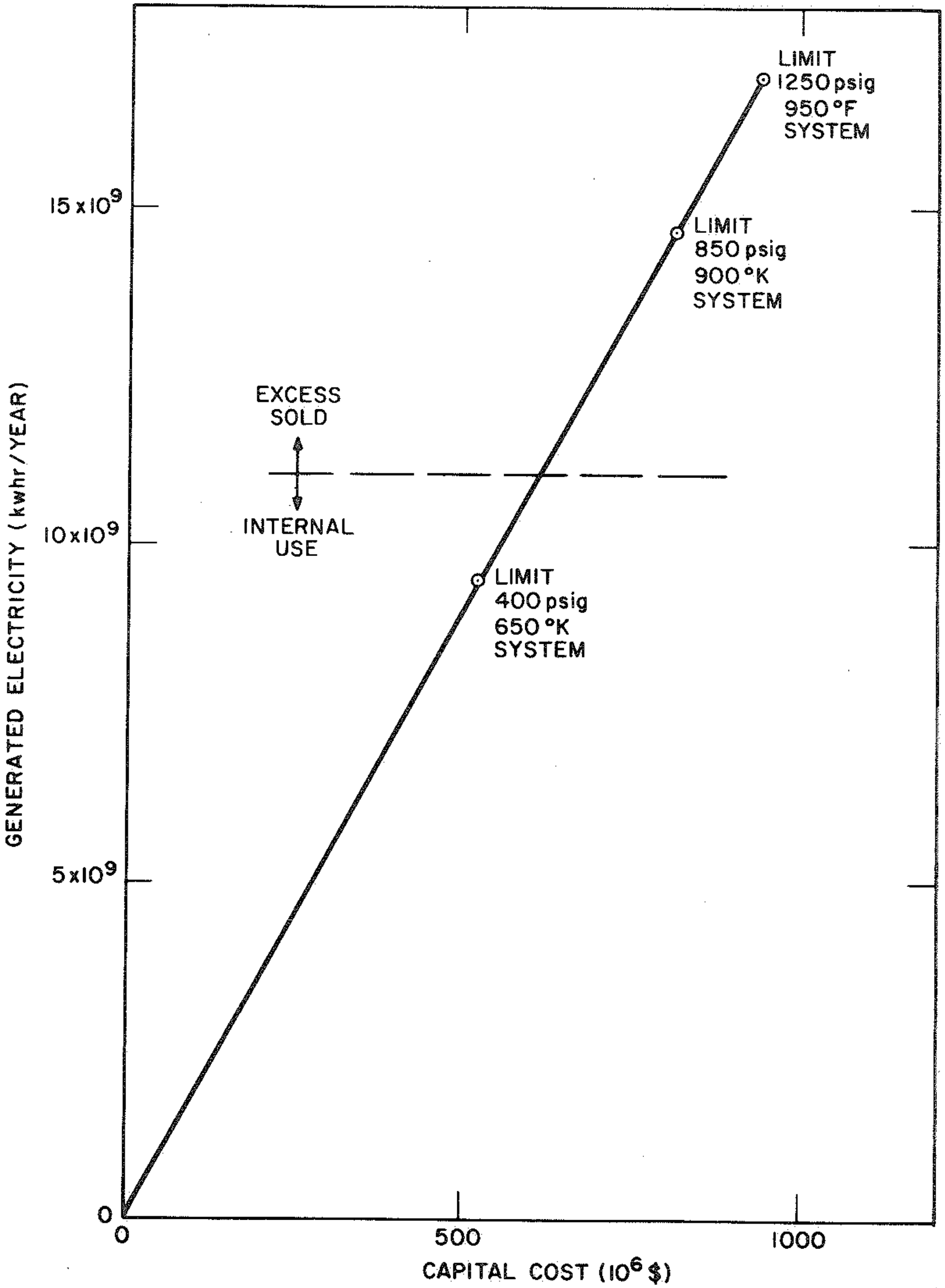

Figure 6.5 Electrical Capacity Versus Capital Costs for Nonintegrated Mills, Steam Turbogenerator

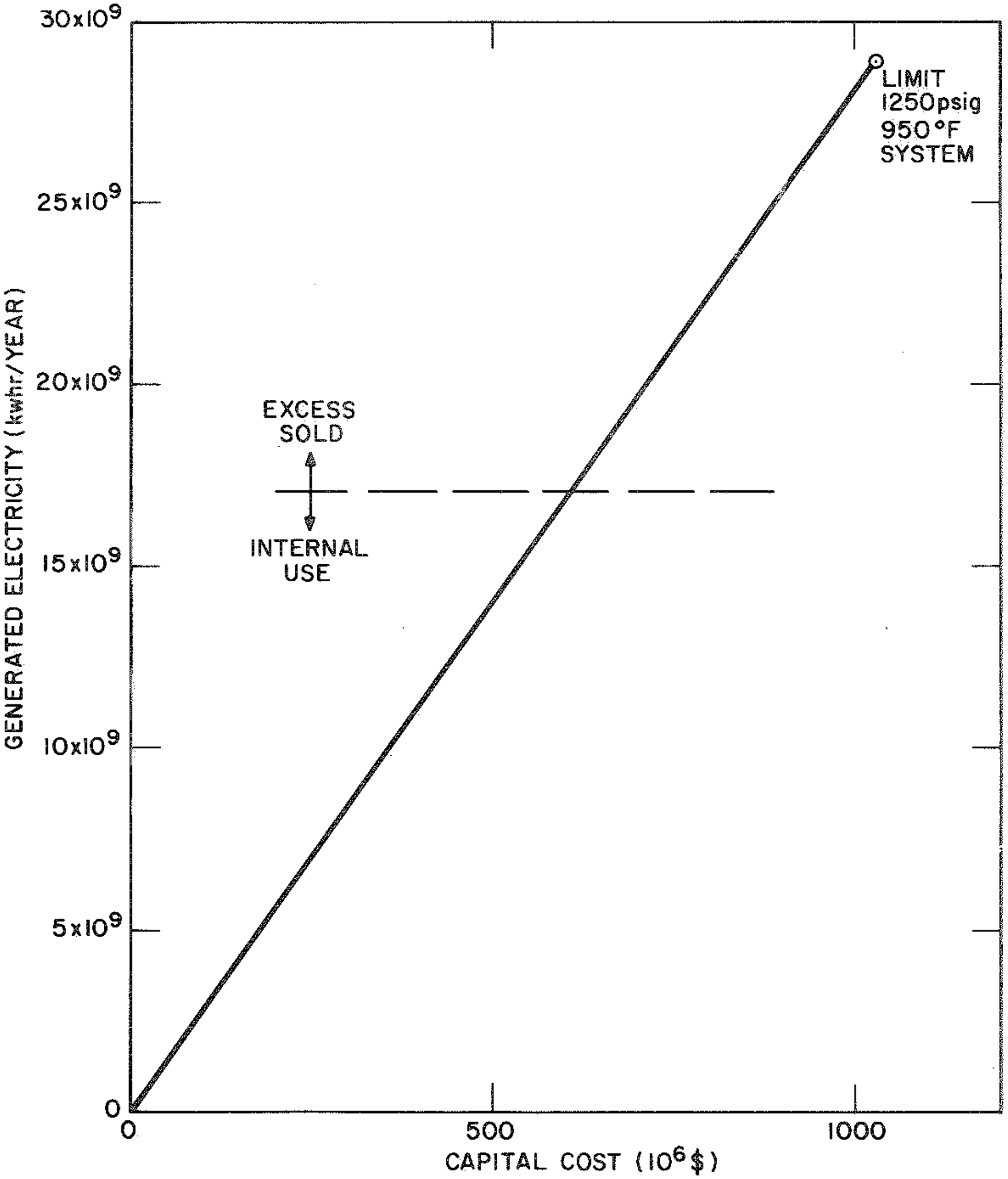

Figure 6.6 Electrical Capacity Versus Capital Costs for Integrated Mills, Steam Turbogenerator

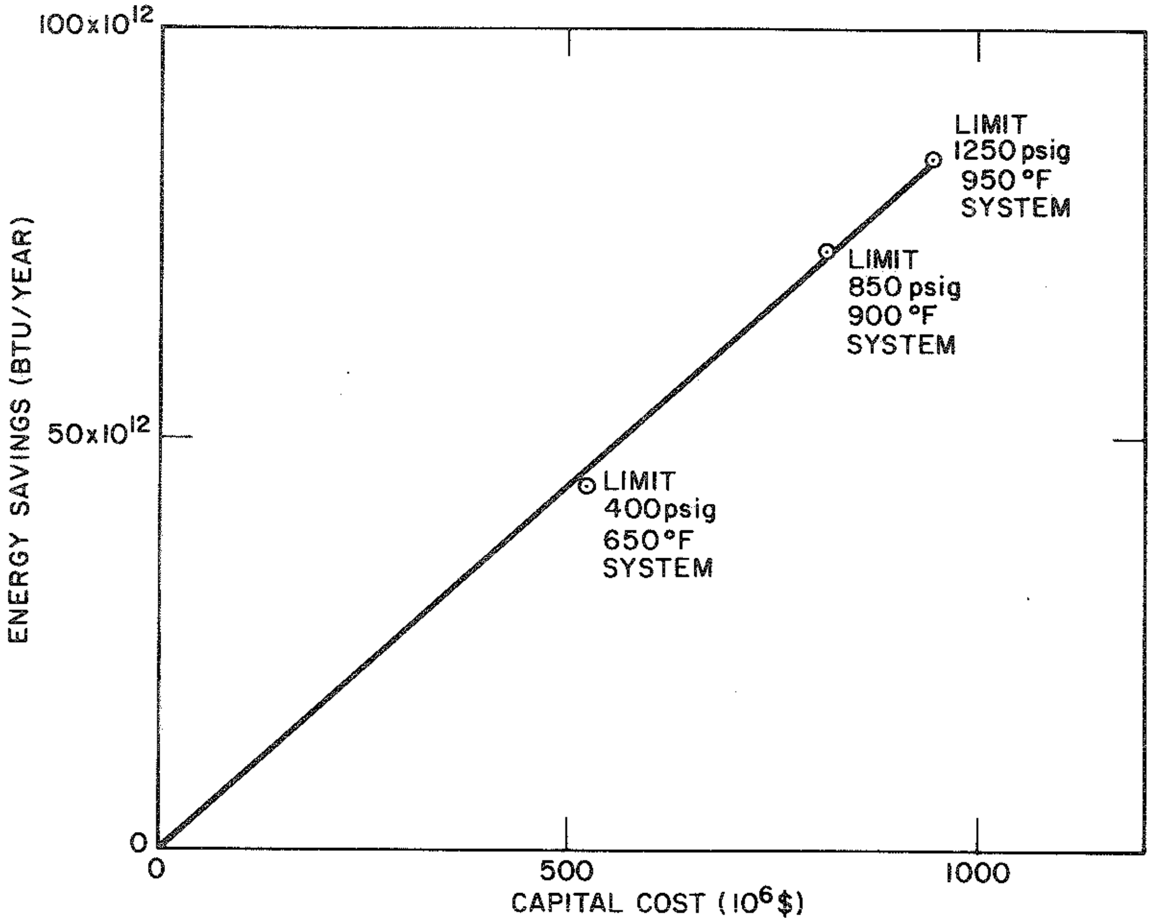

Figure 6.7 Capital Costs Versus Annual Energy Savings for Nonintegrated Mills, Steam Turbogenerator

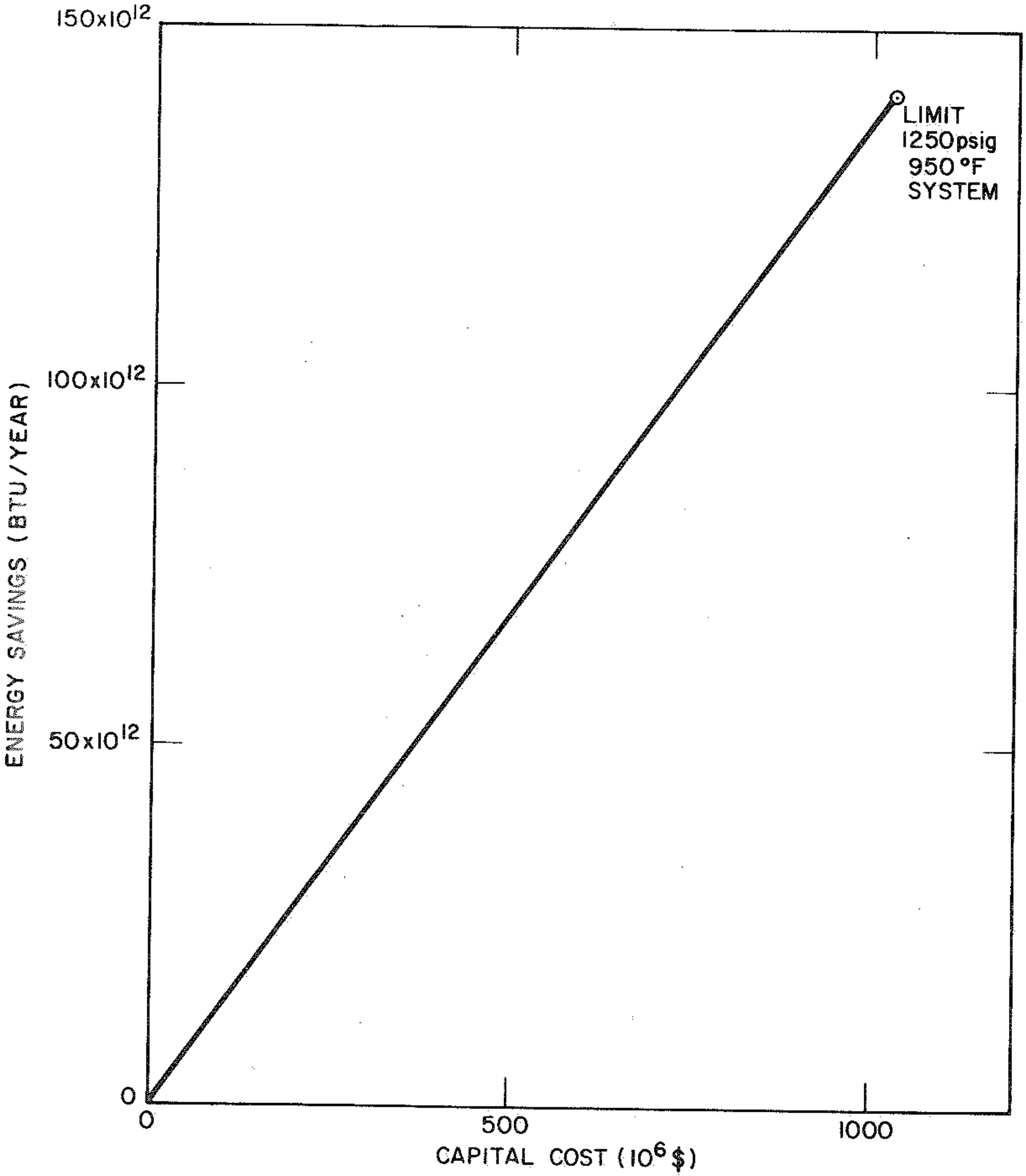

Figure 6.8 Capital Costs Versus Annual Energy Savings for Integrated Mills, Steam Turbogenerator

turbines are used, these mills would generate 7×10^9 kwhr per year in excess of their needs. Integrated mills require an investment of $\$600 \times 10^6$ to reach self-sufficient electricity generation (17×10^9 kwhr/year), and under high pressure conditions could produce an excess of about 12×10^8 kwhr per year.

Ratios of capital cost to fuel savings per year were calculated for gas turbine systems. A specific cost of $200 per kw was assumed for the combined gas turbine generator-unfired process steam boiler system. Compared with steam turbine installations of similar size, the gas turbine entails lower investments. The unfired process steam boiler operates at low temperatures and pressures and the boiler thermal heat rates do not include the heat equivalent of the generated electrical power. The results of the calculations are shown in Fig. 6.9. Compared with steam turbogenerators, the lower capital cost of gas turbines results in a lowering of the ratios of capital cost to fuel savings per year, and, therefore, tend to make the gas turbine economically more attractive. The requirement for premium fuel (higher price and uncertain availability), however, tempers this advantage.

Figures 6.10 to 6.13 show the potential electricity generation and fuel savings if gas turbogenerators - process steam boiler systems replaced the existing low pressure steam boilers in integrated and non-integrated mills. The excess generated electricity far exceeds the internal requirements of the mills. Fuel savings associated with this excess would be realized if the excess electricity were sold outside the mills and replaced electricity generated by a utility or other source which does not utilize combined electricity and steam generation.

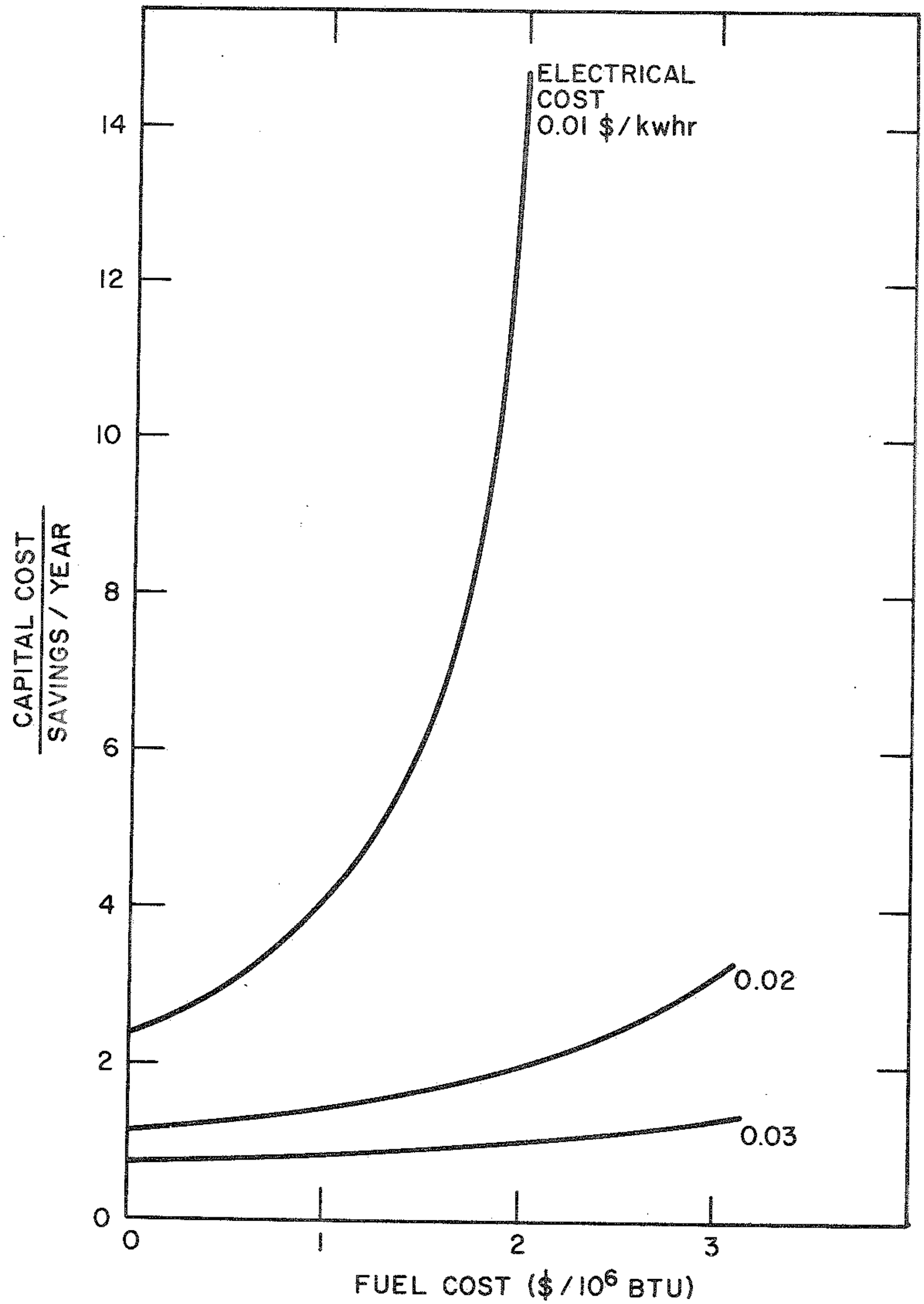

Figure 6.9 Fuel and Power Cost Relationships for Gas Turbine - Process Steam System

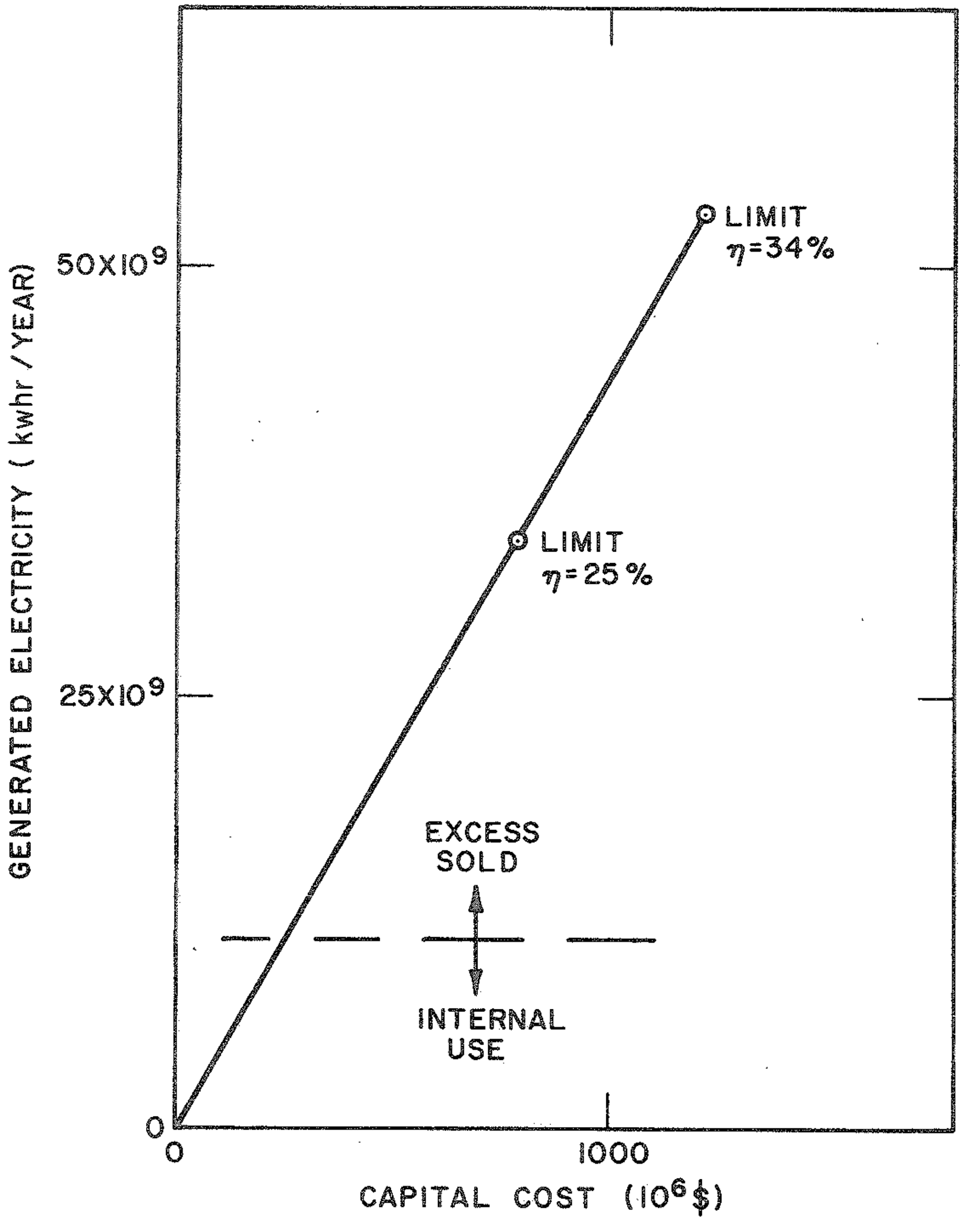

Figure 6.10 Electrical Capacity Versus Capital Cost for Nonintegrated Mills, Gas Turbine

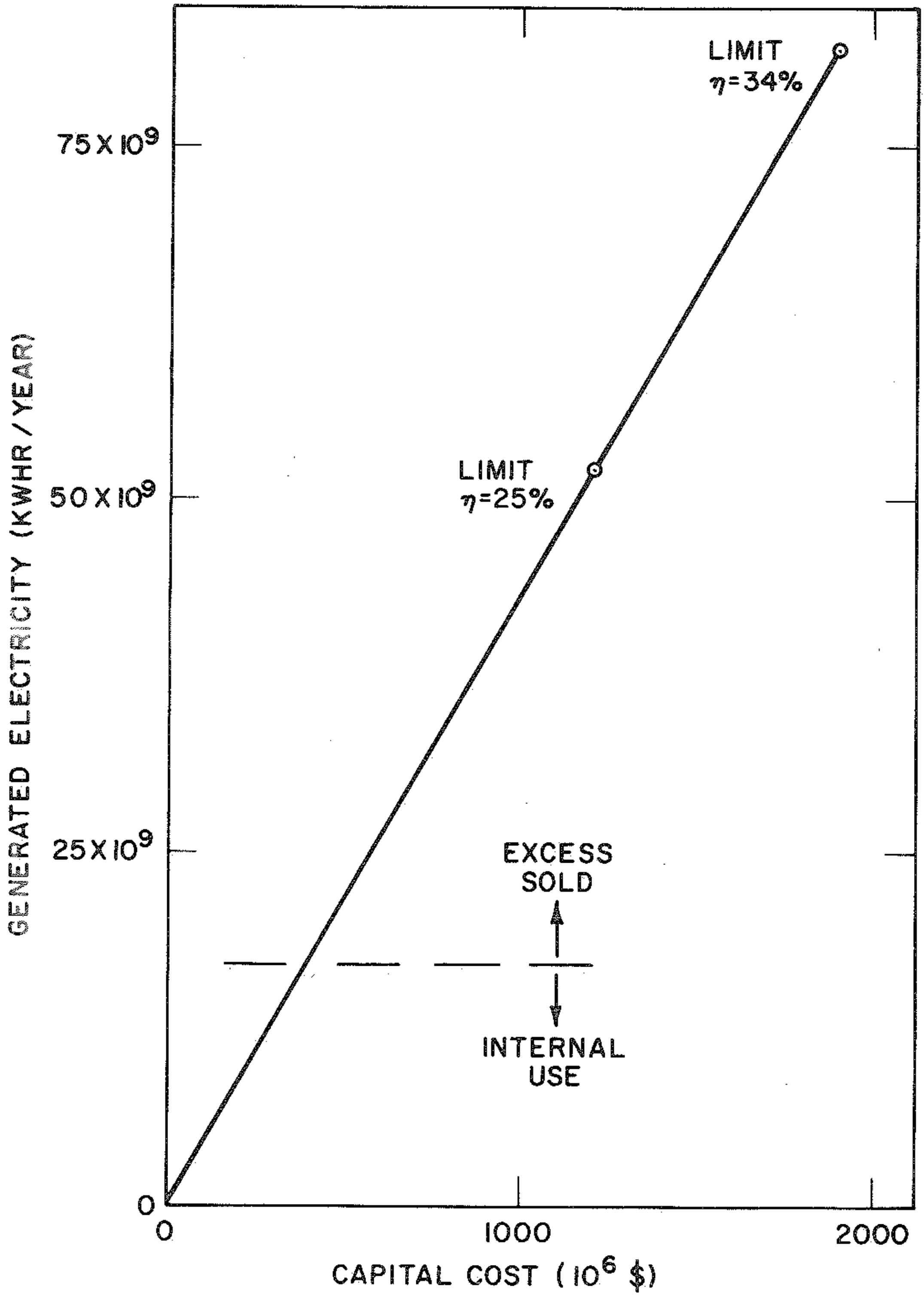

Figure 6.11 Electrical Capacity Versus Capital Cost for Integrated Mills, Gas Turbine

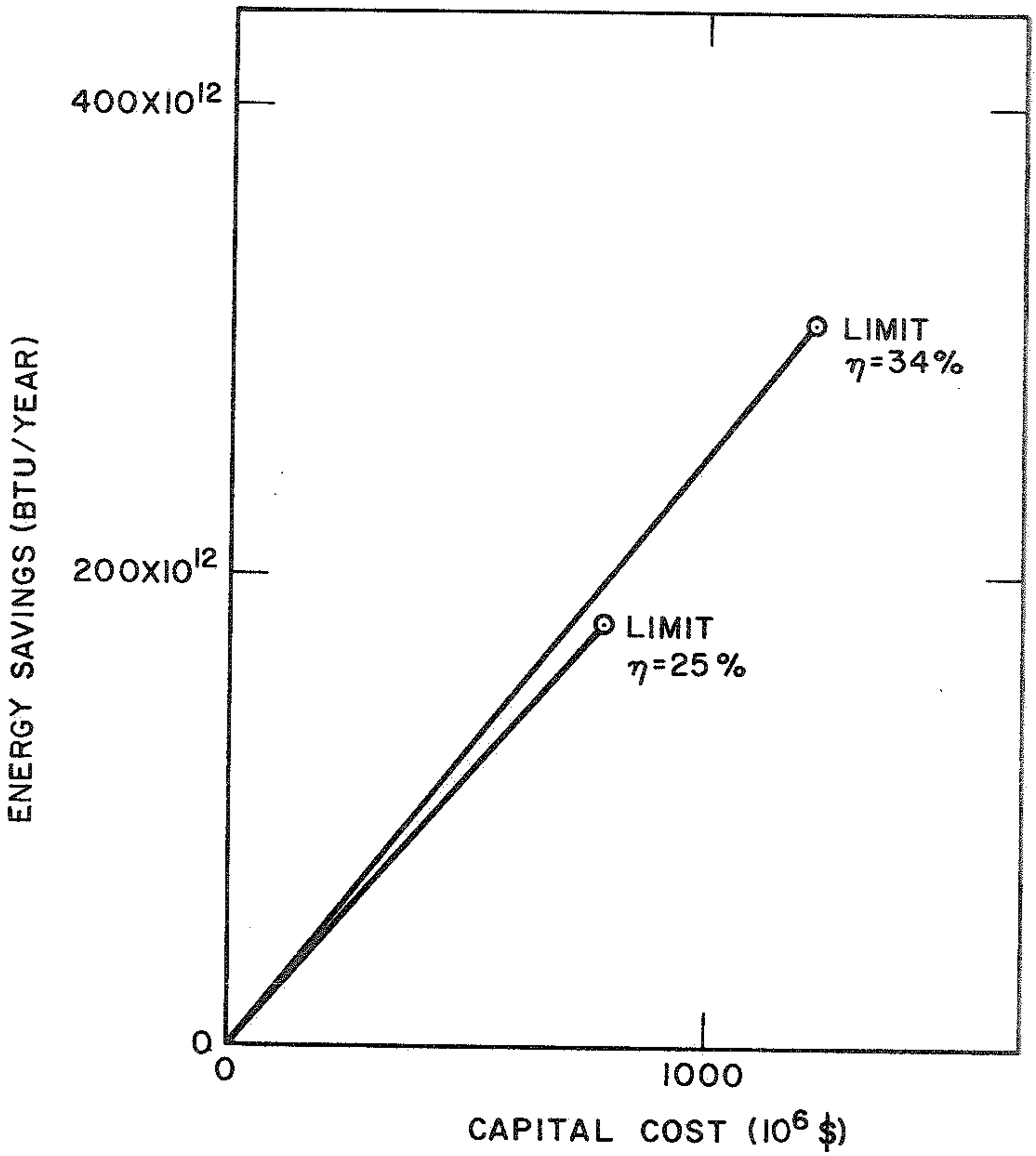

Figure 6.12 Annual Energy Savings Versus Capital Costs for Gas Turbine

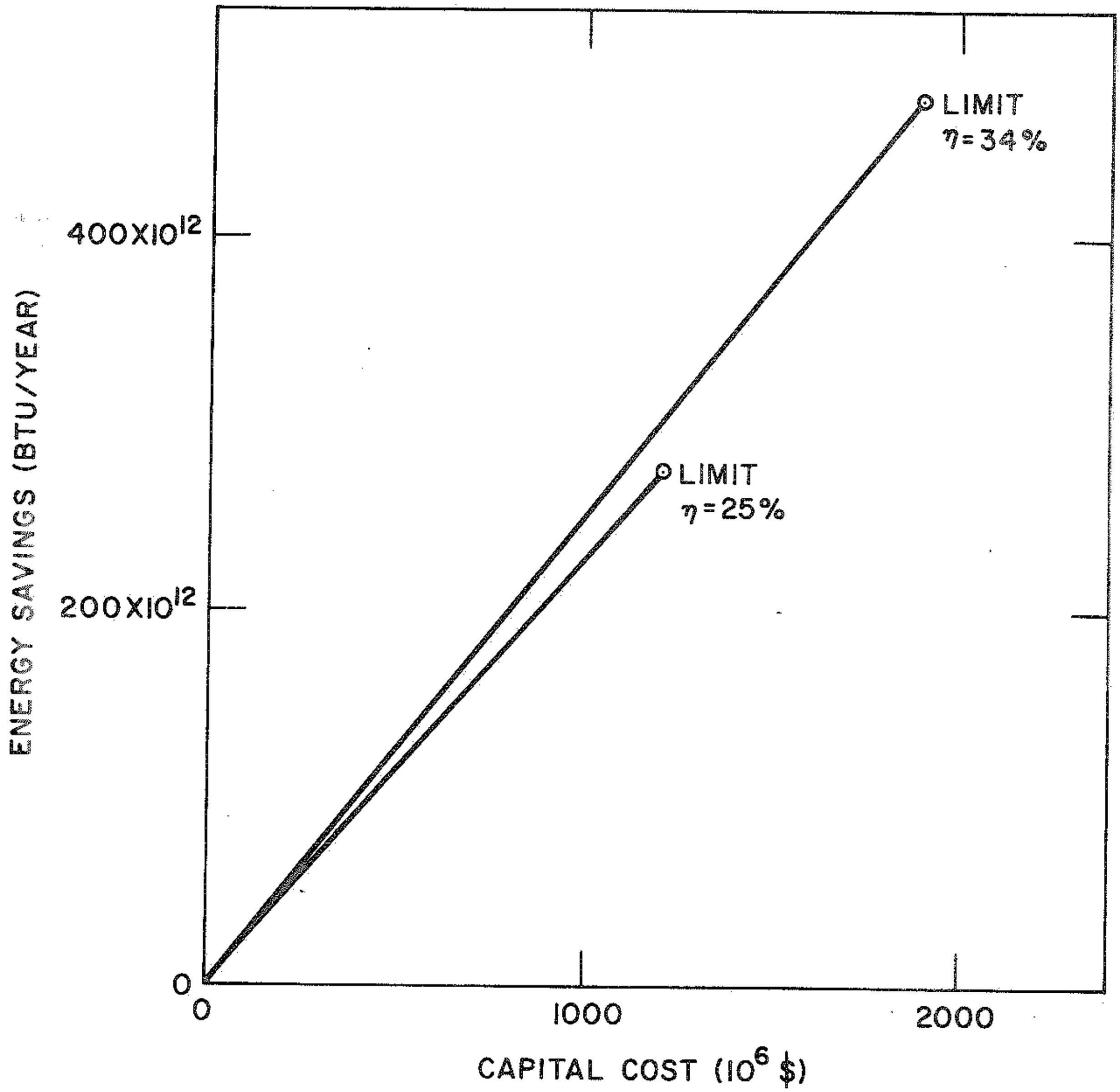

Figure 6.13 Annual Energy Savings Versus Capital Costs for Integrated Mills - Gas Turbine

6.2 COMMENT ON FUEL AND ELECTRICITY COSTS

Fuel and electricity costs for the paper industry have followed the pattern of fuel cost increases experienced nationally in recent years. Published API data[4] plus 1974 estimates of industry-wide fuel costs are shown in Table 6.1. Beginning in 1970, air pollution control regulations contributed to higher residual oil prices due to shifts to lower sulfur grades of fuel. The OPEC embargo in 1973 and subsequent price increases of imported oil have resulted in further steep increases. High oil prices have brought about increased use of coal with corresponding increases in price. Natural gas prices have remained more stable due to government controls.

Fuel costs vary significantly from region to region within the country. Residual oil prices can differ by a factor of two with the highest prices in the North Central region and the lowest in the South. Electricity costs also vary widely as shown in Table 6.2. The Mountain, Pacific, and Alaska region enjoy the lowest electricity costs due to low cost hydroelectric resources. During the period 1970 to 1974, changes in electricity costs were markedly different in different parts of the country. In the East, rates rose by approximately 110%, in the Southwest by 80%, and in the Northwest by 45% only. Some areas of the Northwest still enjoy electricity costs as low as $0.006/kwhr. Such low costs discourage capital investment in internal generation equipment.

TABLE 6.1

AVERAGE FUEL AND ELECTRICITY COSTS

	1968	1970	1972	1974
Natural Gas ($\$/10^6$ Btu)	0.36	0.39	0.46	0.5 - 0.8
Residual Oil ($\$/10^6$ Btu)	0.38	0.42	0.58	1.5 - 2.0
Distillate Oil ($\$/10^6$ Btu)	0.81	0.82	0.84	2.0 - 2.3
Coal ($\$/10^6$ Btu)	0.30	0.38	0.48	1.0 - 1.5
Electricity ($/kwh)	0.0077	0.0081	0.011	0.015 - 0.03

TABLE 6.2

REGIONAL VARIATION IN ELECTRICITY COSTS - 1972

Region	Price ($/kwh)
New England and Mid Atlantic	0.012
South	0.0085
North Central	0.013
Mountains, Pacific, and Alaska	0.0065

end, we examined the effect of taxes on the rate of return. In Figs. 6.1 and 6.2 we presented results for ratios of capital cost to savings per year for a tax rate of 50% and for the limiting case of zero taxes. Though the capital cost to savings per year ratios are increased with zero taxes, the increase is modest. For capital investments in equipment having a 16 year life, and a rate of return of 10-15% the increase is about 25 to 35%. Tax rate decreases tend to reduce the effect of depreciation; thus, the zero tax condition represents the maximum increase in the ratio of capital cost to savings per year that could be realized. Such a change in tax rate is exceedingly doubtful and any realistic tax change would have an effect smaller than 25 to 35%.

The rate of return vs the payback period for various tax rates and investment credit rates is shown in Fig. 7.1. For high ratios of capital cost to savings per year, zero taxes have too small an effect to result in acceptable rates of return. For low ratios, the rate of return is already acceptable for a 50% tax rate. A relatively narrow range of the ratios of capital cost to savings per year remains which could be affected by a tax rate smaller than 50%, and this range becomes smaller as the tax decrease becomes smaller. On the other hand, large investment credits could have a greater effect on the ratio of capital cost to savings per year than a reduced tax rate. For example, at a rate of return of 15%, a tax rate of 50%, and zero investment credit as a basis, a zero tax rate increases the ratio by 35% whereas a 10% investment credit increases the ratio by 9%, a 25% investment credit by 28%, and a 50% investment credit by 82%. Investment credits greater than 25% can substantially increase the ratio of acceptable capital cost to savings per year.

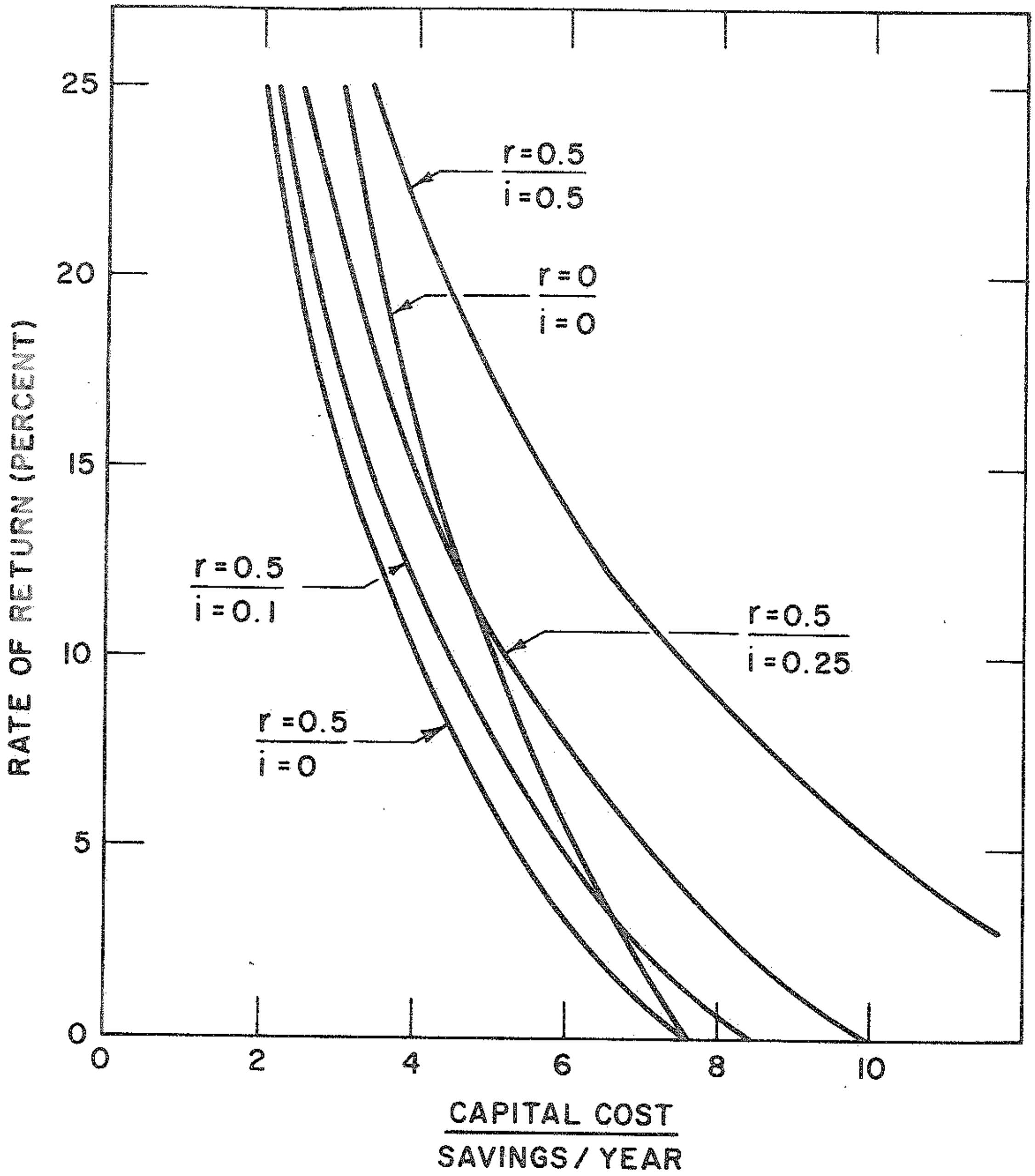

Figure 7.1 Effect of Tax Rate and Investment Credit on Rate of Return

In general, we doubt whether small changes in tax rate or investment credit would significantly affect energy conservation. This is not to say that a reduction in tax rate or an increase in investment credit will not benefit conservation. Increased availability of capital funds would increase the improvement options open to the industry and some funds would certainly be used for reducing fuel consumption. A high priority effort towards energy conservation, however, would probably not result.

7.2 REGULATION

The key to achieving substantial energy conservation in the paper industry is the priority that management places on fuel costs and the modifications that are required to reduce these costs. In a competitive industry, high fuel prices would result in efforts to conserve energy. Since energy conservation without the necessity for exorbitantly high fuel prices would be in the national interest, some form of regulation might be required to reduce fuel consumption.

Beneficial in-plant electricity generation could be enhanced by a change in utility rate structures by which high peak loads are penalized by high rates. Paper mills currently with or considering in-plant electricity generation typically install approximately 25% condensing turbine capacity to meet peak load conditions rather than purchase power at high rates. As a result of the condensing capacity, a substantial portion of the high overall fuel efficiency afforded through the use of combined turbogenerator - process steam systems is not utilized. A change in rate structure would shift the problems associated with peak loads from the paper mill to the utility. Since

TABLE 7.1

SUMMARY OF ENERGY CONSERVATION OPTIONS IN THE PULP AND PAPER INDUSTRY

Conservation Option	Energy Savings (Btu/year)	Estimated Capital Cost ($$10^6$)
In-plant electrical power generation		
(1) Current economic conditions	0.07×10^{15}	500
(2) Removal of peak load rate penalty	0.03×10^{15}	150
(3) Increased economic incentives	0.13×10^{15}	1200
(4) Industrial sale of power to utilities (steam turbines)	0.2×10^{15}	2000
(5) Industrial sale of power to utilities (gas turbines)	0.7×10^{15}	3000
Use of waste paper for fuel rather than recycling		
Additional new mill capacity plus new power facilities burning waste paper	0.25×10^{15}	9000
Fifty percent reduction in bleaching		
Change in consumer demand for high brightness paper	0.04×10^{15}	Negligible
Full use of bark and wood wastes		
Improved equipment	0.15×10^{15}	Unknown
Improved operating procedures and better use of energy conserving equipment		
(1) Current economic conditions	0.15×10^{15}	Small
(2) Increased economic incentives	0.3×10^{15}	Large

8. CONCLUSIONS

Average purchased energy per ton of product was approximately 23×10^6 Btu/ton in 1972. In response to the national urgency for fuel conservation, the industry made a general commitment to reduce this specific fuel consumption by 10% by the year 1980, providing environmental requirements did not interfere. In the latter part of 1974, API's energy use data indicated that a 6% reduction from the 1972 average had been achieved. Average specific energy consumption, however, is affected by the degree to which the capacity of the industry is utilized and the mix of products. For these reasons the recent economic decline resulted in slightly increased average specific energy consumption.

Neglecting the effect of short-term variations, we concur with the estimate that a 10% reduction in specific energy consumption can be achieved under current economic conditions. This reduction will result primarily from improved operating conditions and better use of energy conserving equipment. In addition, continued installation of in-plant electricity generation equipment should result in a further reduction of about 5%.

Reductions in specific energy consumption greater than 10 to 15% require a change in priorities. For example, consumer acceptance of lower brightness paper could save an additional 3%. Again, availability of improved equipment for utilizing all of the bark and wood wastes as fuel would save an additional 10%. The energy conservation associated with improved operating conditions, better use of energy conserving equipment, and in-plant electricity generation would increase from 15 to 30% if priorities for capital expenditures were influenced by economic incentives to favor energy conservation. A national commitment to using waste paper as a fuel for power generating equipment rather than for recycling into new products would result in a fuel saving greater than 15%.

Even greater fuel savings are possible if in-plant electricity generation was expanded to include generation of excess power for sale to surrounding consumers or utilities. Reductions in fuel consumption would be 15% and 50% with steam turbines and gas turbines, respectively.

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