71

EFFECTS OF IMPROVED FUEL UTILIZATION ON DEMAND FOR FUELS FOR ELECTRICITY

by

Elias P. Gyftopoulos
and
Thomas F. Widmer

Thermo Electron Corporation
Waltham, Massachusetts 02154

January 1975

1.0 INTRODUCTION

The primary purpose of this report is to estimate the potential reduction of fuel for electricity in 1985 resulting from improved utilization of fuel in industrial, residential and commercial end-uses. Because a fraction of the fuel for electricity is coal, improved fuel utilization is a method complementary to other available methods for reducing sulfuric oxides and sulfates discharged into the atmosphere by electric powerplants. The report also includes an evaluation of the potential effect on fuel-demand for electricity resulting from some alternate methods of space heating.

The report is organized as follows. Section 2 is a summary of the patterns of fuel supply and demand in 1968 and 1985; Section 3 presents limiting values of the effects of certain improved fuel utilization methods in the industrial, residential and commercial sectors; Section 4 discusses the effects of alternate ways of space heating; Section 5 presents capital cost evaluations; Section 6 is a summary of estimated changes in demand; Section 7 presents a brief review of the concept of thermodynamic availabiltiy which forms a basis for the effectiveness calculations, and includes an evaluation of fuel effectiveness for certain selected industrial processes.

2.0 PATTERNS OF FUEL SUPPLY AND DEMAND

This section presents statistical data for the U. S. patterns of fuel supply and demand [(1)] in 1968 and projections for these patterns[(2)] for 1985. Although many projections have been made for 1985, for the purposes of this report, we will consider only the projections of the U. S. Department of the Interior.[(2)]

In 1968, the amount of fuel consumed in the U.S. was about 57 quads* exclusive of about 3 quads used as feedstock materials.

---

* 1 quad = 10^{15} Btu.

It was distributed among the fuel sources approximately as follows:

Petroleum products	43.5%
Coal	23.0%
Natural Gas	32.0%
Nuclear and hydrostatic head	1.5%
	100 %

It was consumed in the major sectors of the economy in the amounts shown in the first and second columns of Table 2.1, namely 41% in the industrial sector, 34% in the residential and commercial sector, and 25% in the transportation sector. Some of the fuel was consumed in the form of electricity (columns 3 and 4, Table 2.1) which was primarily (92%) from utilities and to a lesser degree (8%) generated as by-product of industrial processes. The fuels used in electricity generation were 53.5% coal and 46.5% others.

The principal end-uses of fuels in industry in 1968 can be classified in the four major catagories shown at the bottom of Figure 2.1 among which the fuels are distributed as follows:

Direct combustion heating	29.0%
Process steam	44.7%
Direct electric heating	1.3%
Motors, lighting and electrolysis	25.0%
	100 %

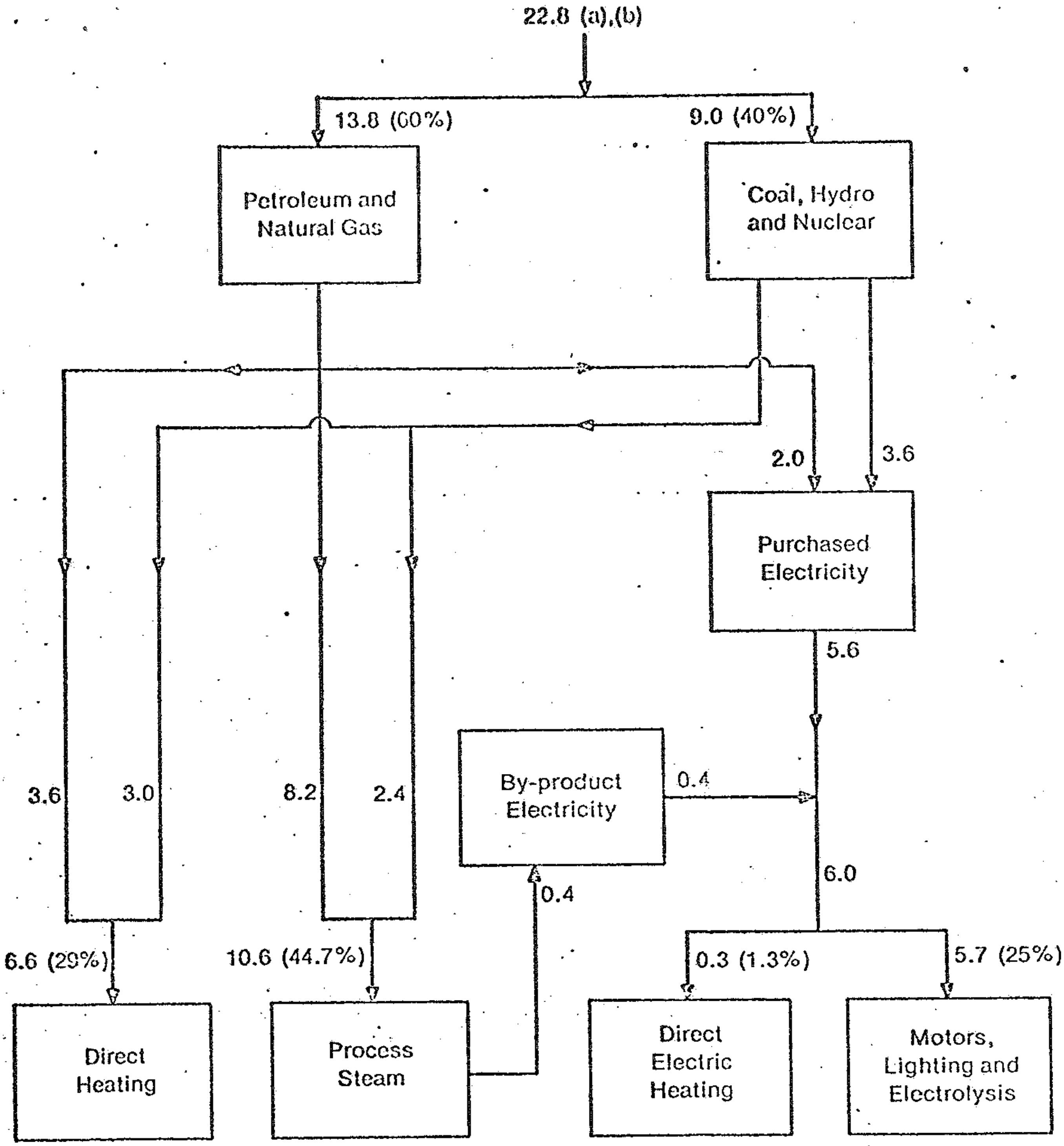
The principal end-uses of fuels in the residential and commercial sector are shown in Table 2.2. We see from the data in Figure 2.1 and Table 2.2 that process steam raising, space and process heating, and refrigeration and air conditioning in 1968 represented the major end-uses of fuels in sectors other than transportation. These processes consumed over 50% of the coal in 1968 as illustrated by the data in Table 2.3.

Table 2.1

FUEL CONSUMPTION BY SECTOR IN 1968

19.5
2.3
12.2

Sector	All fuels		Electricity 10^{12} kw-hr	
	10^{15} Btu	Percentage %	Generated by Utilities	Total
Industrial	23.0	41	0.6	0.72
Residential and commercial	19.5	34	0.73	0.73
Transportation	14.5	25	NIL	NIL
Total	57.0	100%	1.33	1.45



(a) All fuel values in 10^{15} Btu/year

(b) Does not include 2.1×10^{15} Btu equivalent fuel value for gas and petroleum materials used in 1968 as feedstock for chemical products.

Figure 2.1 Sources and end-uses of fuel by U.S. Industry in 1968.

9.84
.57
10.41

12.2

~~19.5~~

9.84
1.55
.57
11.96

Table 2.2

MAJOR END-USES OF RESIDENTIAL AND COMMERCIAL FUEL IN 1968

(excluding feedstock)

End-use		Percentage of sector fuel %	FUEL			
			Electricity 10^{15} Btu(1)	Petroleum and gas for direct firing 10^{15} Btu	Coal for direct firing 10^{15} Btu	Total 10^{15} Btu
Heating	Space	56	0.48	9.84	0.57	10.89
	Water	13	0.9	1.55	NIL	2.45
Refrigeration and air conditioning		16	3.0	0.1	NIL	3.1
Total		85	4.38	11.49	0.57	16.44

(1) 1 kw-hr of electricity = 10,000 Btu fuel in power plant.

Table 2.3

SELECTED END-USES OF COAL IN 1968[1]

End-use		10^6 tons	Percentage of coal consumption %
Industrial	Process steam	87	18.5
	Heating	51	11
Residential and Commercial	Heating	49[2]	10.5
	Refrigeration and air-conditioning	56[3]	12
Total		243	52

(1) Total consumption 13.1 quads or 470 x 10^6 tons at 28 x 10^6 Btu/ton.

(2) Weighted average of direct coal usage and electricity produced by using 53.5% of fuels in the form of coal.

(3) Based on 53.5% of electricity produced from coal.

Several projections have been made about the fuel demand in 1985. For the purposes of this report, the projections of the U. S. Department of the Interior have been used.[2] The projected demand in the major sectors is shown in the first column of Table 2.4 exclusive of fuels for feedstock materials. It will be distributed among the principal fuel sources approximately as follows:

Petroleum products	42%
Coal	28%
Natural Gas	25%
Others	5%
	100%

Some of the anticipated fuel demand will be supplied by utilities in the form of electricity as shown in the third column of Table 2.4. Comparing the data in Tables 2.4 and 2.1 we see that in 1985 the demand for all fuels is projected to be about two times as large, and for electricity about three times as large as those in 1968. The demand for fuels for electricity generation is projected to be as shown in Table 2.5. We see from this table that 37% of electricity will be generated from coal in 1985 whereas 53.5% of electricity was generated from coal in 1968.

3.0 POTENTIAL FOR IMPROVED EFFECTIVENESS

3.1 Industrial Sector

As discussed in a report to the Energy Policy Project of the Ford Foundation [3] many opportunities exist for the application of existing technology to the enormous fuel flow in industrial heating processes so as to yield large fuel savings. For example, the bulk of industrial fuel (about 45% in 1968) is consumed in raising process steam. Wherever process steam is required in reasonable amounts, an opportunity exists to produce electricity at small cost in fuel consumed. For example, if process steam at 200 psi or 382°F is generated by burning a hydrocarbon fuel, $(CH_2)_n$, over 60% of the available useful work of the fuel is lost.

Table 2.4

USDI PROJECTED FUEL DEMAND BY SECTOR IN 1985

Sector	All fuels		Electricity generated by utilities	
	10^{15} Btu	Percentage	10^{12} kw-hr	Percentage
Industrial	41.9	38.5	1.86	45
Residential and commercial	39.7	36.5	2.23	54
Transportation	27.2	25.0	0.04	1
Total	108.8	100%	4.13	100%

Table 2.5

USDI PROJECTION OF DEMAND OF FUELS FOR ELECTRICITY GENERATION IN 1985 (2)

Fuel	Electricity 10^{12} kw-hr	Percentage of total electricity %
Coal	1.53	37
Hydrostatic head and geothermal	0.25	6
Petroleum and gas	1.07	26
Nuclear	1.28	31
Total	4.13	100%

Much of this loss may be prevented by burning fuel in a gas turbine and using the turbine exhaust to generate steam (Figure 3.1a), by generating steam at a pressure higher than 200 psi and expanding the steam in a steam turbine to 200 psi at which pressure it is exhausted to process (Figure 3.1b), or by a combination of these two (Figure 3.1c). Figure 3.2 compares a combined system (Figure 3.2b) with the more widely used present practice of spearate generation of steam and electricity.

Typical results of the electricity generated by the various topping systems are summarized in Table 3.1 The electricity produced, if considered as a by-product of the process heat, should be charged with the fuel consumption over and above that required when process steam is produced directly without the intervening topping system. On this basis, the fuel consumption for each of the cases shown in Table 3.1 is about 4230 Btu of available useful work for each kw-hr of electricity. These figures translate into an effectiveness of electricity generation of 0.8. The corresponding figure for the best central station powerplant is less than 0.4; that is, electricity is produced at less than half the fuel consumption of the best central-station powerplant.

Other fuel savings can be achieved through use of organic Rankine bottoming systems for recovery of availability from waste heat of industrial combustion processes. Wherever heat is rejected at temperatures 700°F or higher, an opportunity exists to produce electricity at no fuel consumption. A typical arrangement of a bottoming system combined with a radiant tube furnace is shown in Figure 3.3.

In 1968, industrial by-product electricity was 0.12×10^{12} kw-hr reducing the amount of fuel consumed by utilities by about 1.2 quads (assuming that, on the average, 1 kw-hr generated by a utility consumes 10,000 Btu of fuel in the powerplant). It is estimated that the amount of incremental fuel consumed by industry for the generation of this by-product electricity is about 0.5 quads and, therefore, that a net fuel saving of 0.7 quads was achieved.

If all process steam could be raised in combination with electricity generation, then the upper limit for industrial by-product electricity generation in 1968 was 0.7×10^{12} kw-hr and could be achieved for an incremental fuel consumption of 2.9 quads (Table 3.2). The fuel that would have been saved

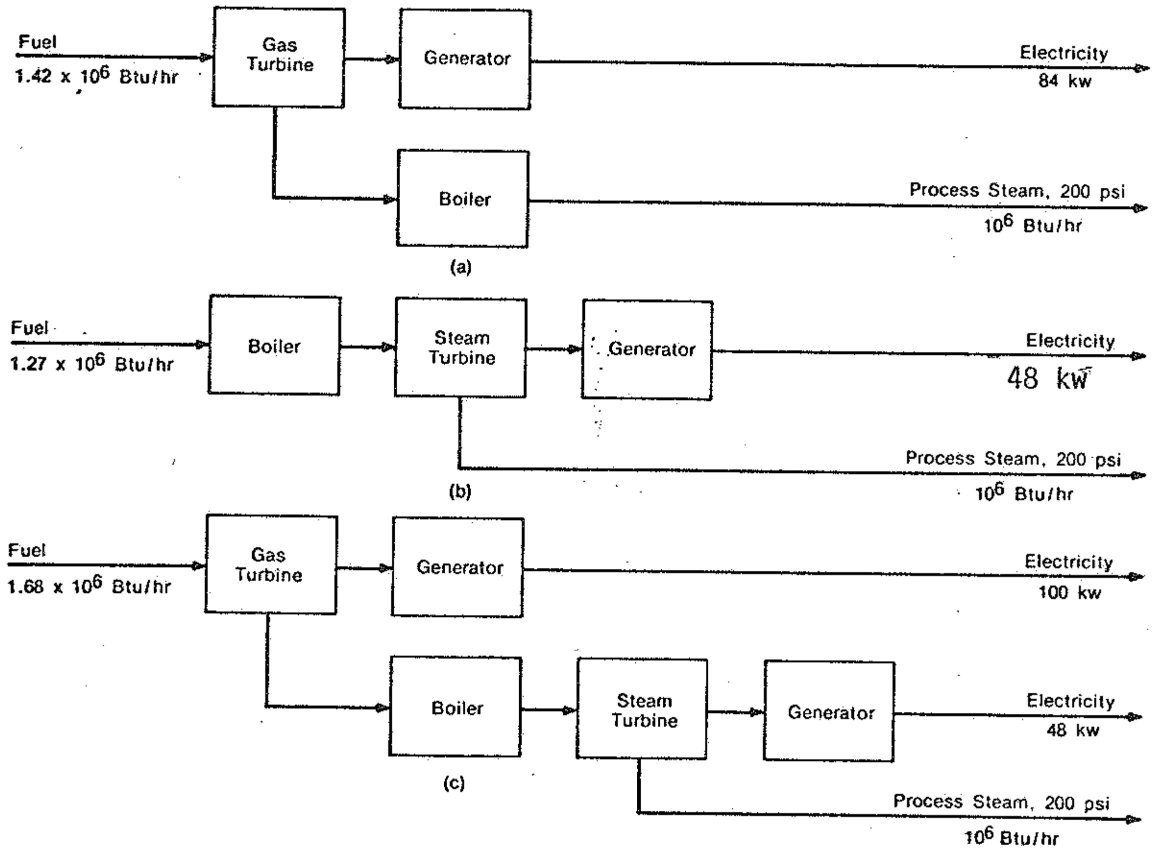


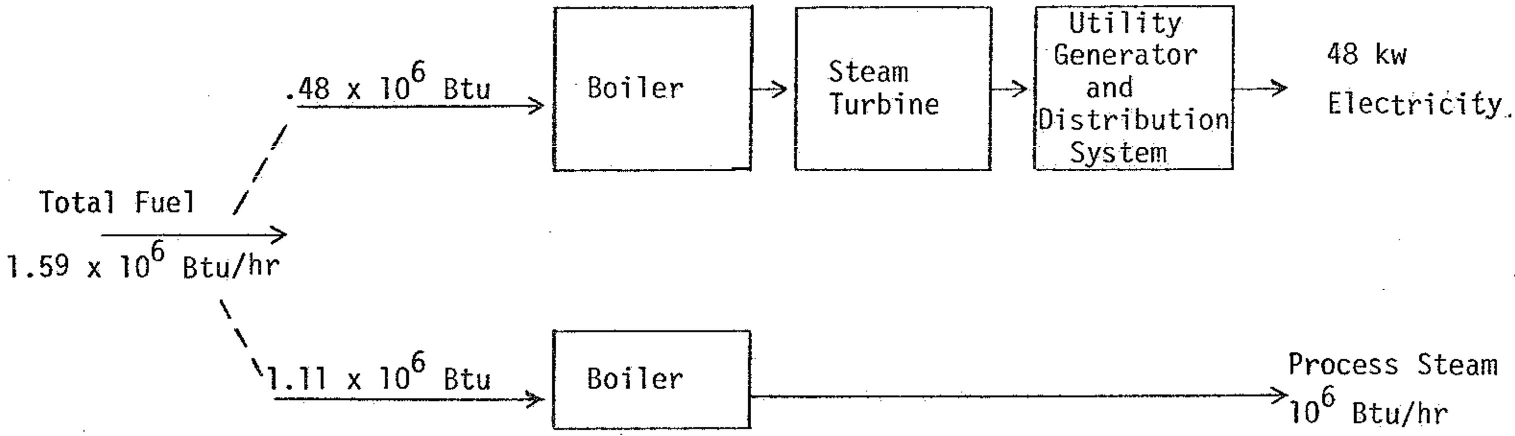
Figure 3.1 Combined process steam raising and electricity generation options for process steam at 200 psi and 10^6 Btu/hr.

TABLE 3.1 KILOWATTS OF BY-PRODUCT ELECTRIC POWER FOR 10^6 BTU/HR OF STEAM SUPPLIED TO INDUSTRIAL PROCESS

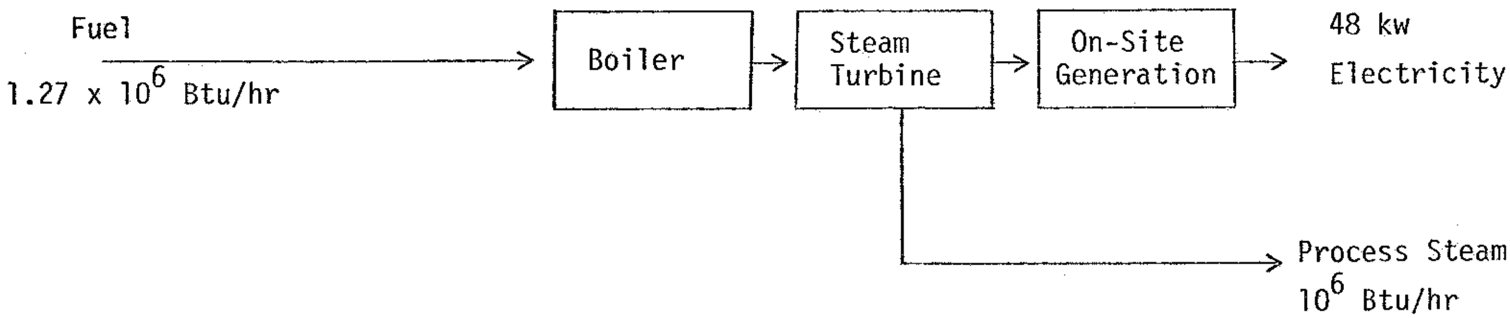
Process Steam Pressure, psi	Steam-Turbine Power, kw		Gas-Turbine Power, kw		Total Combined Gas and Steam-Turbine System Power, kw
	Alone	Fed From Exhaust of Gas Turbine	Alone	Followed by a Steam Turbine	
50	77		84		
200	49	48	84	100*	148
400	34		84		

*The power of the gas turbine is increased from 84 to 100 kw because some of the available useful work of the fuel necessary for the steam turbine is consumed in the gas turbine.

SEPARATE PROCESS STEAM AND ELECTRICITY GENERATION



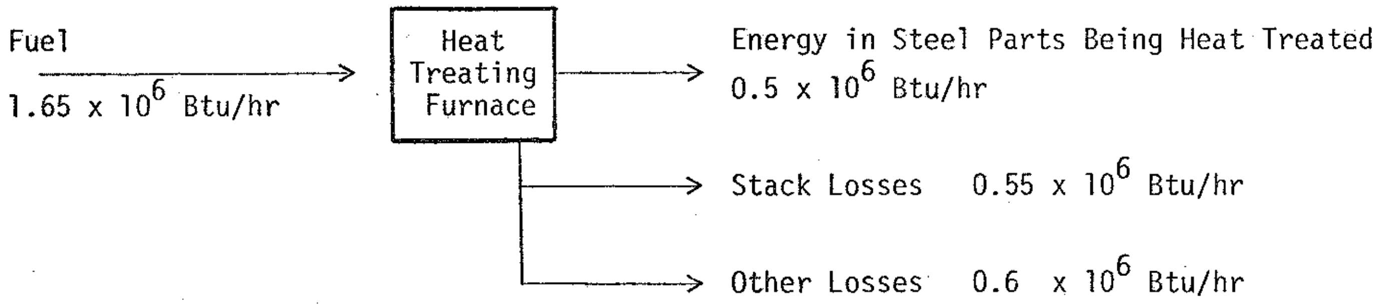
COMBINED PROCESS STEAM AND ELECTRICITY GENERATION



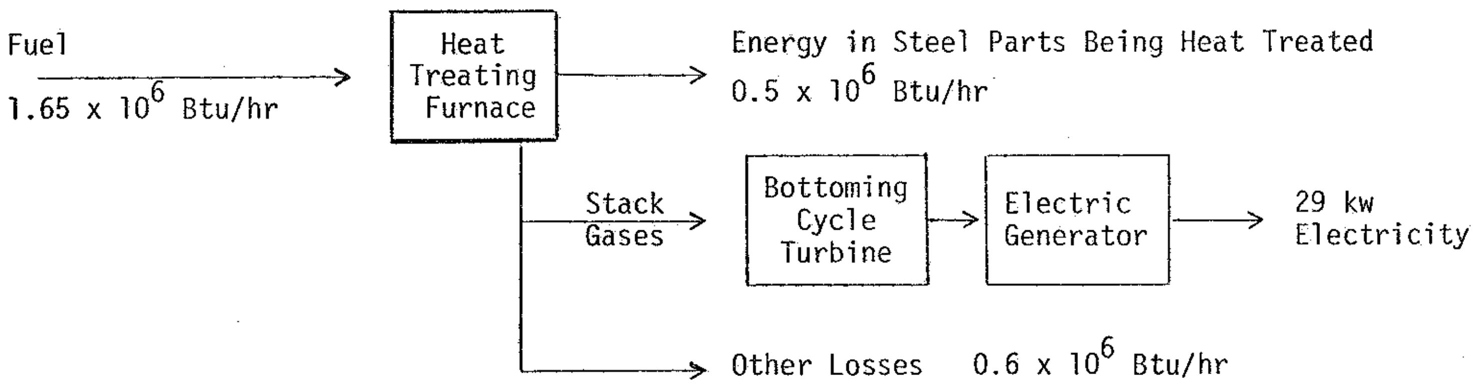
$$\text{Overall Fuel Saving for Combined Process} = \frac{1.59 - 1.27}{1.59} = 20\%$$

Figure 3.2 Comparison of Overall Fuel Requirements for Steam and Electricity Generation With Separate versus Combined Processes.

PRESENT HEAT TREATING FURNACE WITH RECUPERATORS



WASTE HEAT IN STACK GASES RECOVERED WITH BOTTOMING CYCLE



Note: Diagrams are based upon 1 ton/hour of steel parts processed. Electrical output amounts to 29 kw-hrs per ton of parts and fuel saved by electric utility powerplants averages 300,000 Btu per ton of parts.

Figure 3.3 Bottoming Cycle Applied to Radiant Tube Heat Treating Furnace for On-site Generation of By-product Electric Power.

Table 3.2

UPPER LIMIT FOR INDUSTRIAL BY-PRODUCT ELECTRICITY GENERATION IN 1968

Industrial process	Fuel saving method	Total fuel consumption 10^{12} Btu	By-product electricity 10^{12} kw-hr	Incremental fuel required 10^{15} Btu
Process-steam raising	Topping cycles	13.2	0.7	2.9
Direct combustion heating	Bottoming cycles	6.5	0.1	NIL
Total		19.7	0.8	2.9

by the utilities would have been 7 quads and, therefore, the net fuel saving would have been 4.1 quads. In addition, it is estimated that bottoming systems could have generated 0.1×10^{12} kw-hr at no fuel consumption in 1968 (Table 3.2). The corresponding fuel that could have been saved by the utilities was 1 quad. In summary, in 1968 total fuel consumed by industry was 23 quads, and fuel saved by means of by-product electricity generation was 0.7 quads out of a maximum possible 5.1 quads.

In 1985, total fuel demand by industry is projected to be 41.9 quads. If by-product electricity generation continues at the 1968 rate, the fuel saving will be:

$$(0.7 \times 10^{15})\ (41.9 \times 10^{15} / 23 \times 10^{15}) = 1.27 \times 10^{15} \text{ Btu}$$

out of a possible maximum of

$$(5.1 \times 10^{15})\ (41.9 \times 10^{15} / 23 \times 10^{15}) = 9.3 \times 10^{15} \text{ Btu}$$

It follows that maximum by-product electricity generation could result in an additional fuel saving of 8 quads in 1985.

Decrease of fuel for electricity can also be brought about through improved effectiveness of industrial processes. An illustration of this decrease is provided by the Hall process for reduction of Al_2O_3 to aluminum metal. In this process, electrolysis is carried out in carbon-lined boxes into which carbon rods project. An electrical potential is applied so that the box serves as the cathode and the rods as the anode. Upon electrolysis the alumina is decomposed; the aluminum metal is deposited at the cathode in a molten condition and the oxygen is deposited at the anode.

Considerable variations in the electricity requirements for primary aluminum production exist from plant to plant; typical numbers of production cells range from 13,600 to 16,400 kw-hr per ton of aluminum. Primary aluminum production in the U.S. was 3.25×10^6 tons in 1968. Assuming an average electrical demand of 15,000 kw-hr per ton, the electrical consumption by the aluminum industry amounted to 4.9×10^{10} kw-hr in 1968, or about 3.7% of total U.S. electricity needs.

Analysis of the Hall cell voltage shows that only 1.6 to 1.8 volts, out of almost 5 volts drop across the cell, is required for the basic electrolysis process. The remainder is necessary as a result of voltage drops (resistive losses) across various electrical resistances in the cell circuit. Because the electrolysis voltage is relatively independent of current through the cell, aluminum production is approximately proportional to the current. The parasitic resistive losses, on the other hand, are proportional to the square of the current. It follows that the fraction of electricity effectively utilized for the electrolytic reduction of Al_2O_3 increases as the cell current is decreased. For example, decreasing the current of a typical cell from 105,000 amps to 82,000 amps would decrease electricity consumption per ton of aluminum by 16%. Although such current decrease would decrease production per cell by 22%, total production can be maintained at the desired level by installing more cells, namely at the expense of higher capital costs. In general, the optimum cell current density decreases as power costs increase. At the lower current electrical consumption is only about 12,500 kw-hr per ton of aluminum.(3) Assuming that primary aluminum production will be 10×10^6 tons in 1985, the electricity saving would be 2.5×10^{10} kw-hr and, therefore, the fuel saving 0.25 quads.

3.2 Residential and Commercial Sector

An opportunity exists for reduced electricity demand for refrigeration and air conditioning equipment in the residential and commercial sector. In 1968, refrigeration and air conditioning consumed 20.7% of all U.S. electricity and 5.4% of all fuels. If the same percentage is valid for 1985, the fuel demand for this end-use would be 5.9 quads. The opportunity exists for application of existing technology to improve the effectiveness of refrigeration equipment. For example, present central air-conditioning systems for homes have a performance index of 8.5 Btu per watt-hr. This can be readily increased to 12 Btu per watt-hr by means of well-known heat-transfer methods. It is estimated that a 30% average improvement in performance of all refrigeration equipment is reasonable for 1985. This improvement would result in a fuel saving of 1.8 quads.

Another large factor in electricity consumption is lighting for commercial and public buildings. Recent FEA guidelines for lighting and thermal operations indicate a potential saving of 43% in this end-use.[4] This would represent 133 x 10^9 kw-hr or 1.3 quad fuel saving by electric powerplants in 1985.

4.0 POTENTIAL FOR SHIFTING TO ALTERNATE SOURCES FOR SPACE HEATING

This section presents the limiting effects of using alternate methods of space heating.

In 1968, space heating consumed 10.89 quads or 19% of all fuels of which 0.57 quads was in the form of coal. If the same percentage is valid for 1985, the fuel demand for space heating will be 20.8 quads (0.19 x 108.8 x 10^{15} Btu). In addition, it is estimated that electrical and coal space heating will gradually increase from 0.48 and 0.57 quads in 1968 to 1.1 and 1 quads in 1985, respectively.

In direct-firing space heating, only a fraction of the heating value of the fuels is used in raising the space temperature, the remaining being lost up the stacks of the burners. The fraction that is used varies widely depending on the type and maintenance of the burner. For our purposes, we will assume that 70% of the heating value of the fuels contributes to space heating.

If all the space heating needs in 1985 were to be switched either to pure resistance electric heating, electric heat pump heating, or coal gas heating then the fuel demand would be modified as follows:

<u>Pure resistance heating</u>

Increase in electrical load = 0.7 (20.8 - 1.1) 10^{15}
= 13.8 quads
= 4.04 x 10^{12} kw-hr

Increase in fuel demand = 40.4 - 19.7 = 20.7 quads.

In the extreme, this increase might result in the following distribution between fuels:

Net increase in coal demand * = 39.4 quads/year = 1640×10^6 tons/year

Net decrease in oil and gas demand** = -18.7 quads/year = -8.5×10^6 barrels/day

Heat pump heating

Assuming a national average coefficient of performance (COP) for heat pumps of 1.8, then

Increase in electrical load = $4.04 \times 10^{12}/1.8$

= 2.25×10^{12} kw-hr

Increase in fuel demand = 22.5 - 19.7

= 2.8 quads

For the maximum shift to coal, this increase would result in the following distribution between fuels:

Net increase in coal demand = 21.5 quads = 896×10^6 tons/year

Net decrease in oil and gas demand = -18.7 quads = -8.5×10^6 barrels/day

Another possible means of shifting home heating load from oil and natural gas to coal-based energy is the alternative of gas from coal gasification; assuming a gasification and distribution efficiency of 0.62, demand would be modified as follows:

Net increase in coal demand = (20.8 - 1)/0.62 = 31.9 quads/year = 1330×10^6 tons/year

Net decrease in oil and gas demand = -19.8 quads/year = -9×10^6 barrels/day

---

* 1 ton of coal = 24×10^6 Btu

** 1 barrel of oil = 6×10^6 Btu.

5.1 EVALUATION OF CAPITAL COST FACTORS

5.1 Costs Related to Improved Effectiveness

The evaluation of the relative benefits of various fuel saving methods necessitates consideration of both capital requirements and fuel pricing practices.

From an aggregate capital availability point of view, it is important to compare the capital for supplying additional fuel with that for saving an equal amount of fuel through improved effectiveness measures.

Some estimates for capital required to supply various forms of energy are listed in Table 5.1. All figures are normalized to the equivalent of one barrel of oil per day.

For an industrial installation needing 1 megawatt of electricity, if this electricity were to be provided by a coal-fired powerplant, with a load factor of 0.7, the capital required would be:

Coal-fired powerplant[5]	$ 456,000
Distribution	180,000 *
Coal supply (28 barrels of oil per day equivalent annual average)	48,000
Total	$ 684,000

*Note: Capital investment in distribution system for industrial customers assumed to be $13,000 per 1760 kw-hr of electricity per day which is energetically equivalent to 1 barrel of oil per day; comparable figure used for residential customers in Table 5.1 is $20,500.

On the other hand, suppose that the industrial installation has a potential application for a 1.0 megawatt bottoming-cycle engine generator to recover waste heat from a large continuous metal processing furnace with an annual utilization factor of 0.7. At $400 per kw, the capital required would be $400,000, and the fuel consumed would be zero.[6] To this may be added $62,000 for 50% emergency supply diesel generators and, therefore, the capital investment would be $462,000.

TABLE 5.1 - APPROXIMATE CAPITAL COSTS FOR SUPPLYING THE FUEL EQUIVALENT OF ONE BARREL OF OIL PER DAY (6×10^6 Btu/day) IN VARIOUS FORMS

1. GAS FROM COAL GASIFICATION

Coal production (Eastern deep mine)	\$ 2,800 (a)
Gasification plant (5)	10,000
Transmission and distribution system	7,400 (b)
	\$ 20,200

(a) At 0.62 plant and distribution efficiency

(b) Assumes \$1.35 per million Btu (\$8.10 per barrel of oil equivalent) as the average cost of transmission and distribution to residential customers in the Eastern United States. Fifty percent of this figure is assumed to derive from capital charges computed at 20% annually, namely

$$\text{Capital cost} = 8.10 \times \frac{365}{0.2} \times 0.5 = 7400.$$

2. OIL FROM NEW DOMESTIC SOURCE

Production (off-shore)(7)	\$5,000 - \$8,000 (c)(d)
Refining	1,000
Transportation and distribution	3,000 (e)
	\$9,000 -\$12,000

(c) Includes bonuses paid on leases

(d) Estimates for shale oil, synthetic crude from coal, or tertiary recovered oil vary from \$10,000 to \$20,000 per barrel per day.

(e) For Alaskan oil, the pipe line alone costs \$5,000 per barrel per day.

3. ELECTRICITY FROM COAL-FIRED POWERPLANT

Coal production (Eastern deep mine)	\$ 5,500 (f)
Electric plant (5)	36,500 (g)
Transmission and distribution system	20,500 (h)
	\$ 62,500

(f) Electricity generated at 0.34 plant and distribution efficiency.

(g) Estimate based on average capital cost \$456/Kw for new coal-fired generating plants greater than 1,300 Mw capacity that could be on-stream by 1981, and load factor 1.0.

(h) Assumes 1.28¢ per kw-hr as average cost of distribution to residential customers, with 50% of this figure attributed to capital costs, as in note (b) above.

4. ELECTRICITY FROM OIL FIRED POWERPLANT

Oil supply	\$26.500
Electric Plant	28,500
Transmission & Distribution	20,500
	\$75,500

From these results we see that the investment for incremental electricity from a coal-fired powerplant would require about 48% more than that for the on-site bottoming-cycle system. For an oil-fired powerplant, the advantage of the bottoming cycle is even greater.

On the other hand, whether the advantage of the fuel-saving over the increased fuel supply method will be evident to the industrial firm depends on fuel pricing policies. If the price of fuel reflects the true cost of new fuel supplies then the bottoming cycle is advantageous. If the price of fuel is based on averages over old and new sources then the bottoming cycle and, therefore, the advantage of the fuel-saving method may not be as decisive as the preceding capital requirement estimates indicate.

To illustrate this point, we shall assume 2.5¢ per kw-hr as being representative of the price paid by an industrial customer for electricity. By assuming a ten-year sum-of-year- digit depreciated life time for the bottoming cycle generator, a 0.3¢ per kw-hr operating and maintenance cost and a 70% duty cycle, we obtain the following break-even capital costs for on-site power generation with bottoming cycle system:

Required after tax (52%) return on investment	Break-even capital cost for bottoming cycle system
12%	546 $/kw
15%	469 $/kw

We see that the bottoming cycle capital requirement of 462$/kw is comparable with the break-even cost determine from the price of electricity of about 2.5 cents per kw-hr. It follows that for the assumed price of electricity, the user most likely will decide to buy electricity rather than install a bottoming-cycle system. The reason for such a decision is, of course, that the assumed price of electricity does not reflect the true cost of new supplies.

5.2 Costs of Fuel Shifiting for Space Heating

The demand for fuel for residential and commercial space heating could be shifted from oil and natural gas to either electricity generated from coal or to alternate sources such gas produced from coal.

Table 5.2 lists estimates of capital requirements for three alternate methods of space heating, electric resistance, electric heat pump, and gas from coal, all of which use coal as the primary fuel. The calculations are based on residential heating units requiring 150×10^6 Btu per year, or 0.07 equivalent barrels of oil per day.

We see from this table that electric heat pumps offer the lowest total fuel consumption of the three cases. Gas from coal gasification on the other hand, affords a significant saving in capital investment over either form of electrical space heating. It should be noted that the investment advantage for the gas from coal gasification approach will be increased even further when adjustment is made for the high percentage of existing gas home-furnaces which would have to be replaced if either electric heating concept were adopted.

TABLE 5.2 CAPITAL INVESTMENT OF ALTERNATE HOME-HEATING METODS USING COAL AS PRIMARY FUEL.

	Home heating method		
	Electric resistance	Electric heat pump	Gas from coal gasification
Plant efficiency: $\frac{\text{energy to home}}{\text{energy from coal}}$	0.34	0.34	0.62
Home furnace yield: $\frac{\text{heat to home}}{\text{energy to home}}$	1.0	1.8	0.7
Barrel per day equivalent coal consumed per equivalentbarrel of oil per day of heat supplied to home	2.94	1.63	2.30
Capital investment per equivalent barrel of oil per day of heat supplied to home			
Supply plant*	$ 96,100	$ 53,400	$ 44,400
Home heating plant**	7,200	28,600	14,300
Total	$103,300	$ 81,000	$ 58,700

* Load factor for all plants 0.65.

** Based on home heating unit costs of $500, $2,000 and $1,000 per home from baseboard resistance, heat pump, and gas-combustion furnaces, respectively.

6.0 SUMMARY OF DEMAND MODIFICATION ALTERNATIVES

The limiting incremental values of effects of demand modifications established in the preceding sections can be allocated to coal. The results are summarized in Tables 6.1 and 6.2 in million tons of coal per year on the basis of 1 ton of coal = 24×10^6 Btu.

Only a fraction of these effects can be achieved, however, by 1985 partly because some industrial plant may be too small in size to justify a modification, partly because of fuel-pricing policies that do not make changes attractive, and partly because of institutional constraints. For example, a plant may need process steam in amounts which do not justify economically the installation of a topping system, or the price of electricity may be low enough so that the investment for an on-site system cannot be recovered in sufficiently short time. Finally, there may be state or local utility regulations which prohibit the sale of surplus electricity by an industrial plant to a utility.

7.0 EFFECTIVENESS OF FUEL UTILIZATION IN A PROCESS

In attempting to evaluate the opportunity for fuel saving in a particular process, we need to know the minimum fuel requirement for the process so that we can compare it with the fuel consumed under current practice and obtain a measure of the effectiveness of that practice. The minimum fuel requirement can be evaluated by means of the thermodynamic concept of available useful work. Readers unfamiliar with the foundations of thermodynamics and the concept of available useful work might consult the article on "Principles of Thermodynamics" in the 1974 Edition of the Encyclopedia Britannica

TABLE 6.1 - MAXIMUM POTENTIAL SHIFT IN COAL REQUIREMENTS RESULTING FROM SELECTED IMPROVEMENTS IN ELECTRICAL EFFECTIVENESS AT POINT OF USE. (1 quad = 24 x 10^6 tons of coal)

Demand modification	Maximum incremental coal consumption (tons/year from 1985 baseline USDI forecast)
On-site generation of by-product electricity in industrial processes	-333×10^6
Re-optimization of Aluminum electrolysis process to lower current density(1)	-10×10^6
Improved performance residential & commercial refrigeration air conditioning equipment	-75×10^6
Relamping of commercial & public buildings to FEA lighting standard	-54×10^6

(1) Aluminum electrolysis, which accounts for about 7.5% of industrial electricity, is shown as an example of improved industrial process effectiveness. In order to determine potential savings for improvements in other electrical-intensive processes, it will be necessary to perform a detailed study of each individual industry.

TABLE 6.2 - MAXIMUM POTENTIAL SHIFT IN COAL REQUIREMENTS RESULTING FROM SHIFTING ALL RESIDENTIAL AND COMMERCIAL SPACE TO METHODS BASED ON COAL AS PRIMARY SOURCE

Demand modification	Maximum incremental coal consumption * (tons/year from 1985 baseline USDI forecast)
Shift all space heating to electric resistance	$+1640 \times 10^6$
Shift all space heating to electric heat pumps	$+896 \times 10^6$
Shift all space heating to gas from coal gasification	$+1330 \times 10^6$

* The corresponding reduction in oil and natural gas consumption is about 9 million barrels of oil equivalent.

In a report prepared for the Energy Policy Project of the Ford Foundation [3], the concept of available useful work was used to evaluate the effectiveness of fuel utilization in five energy-intensive industries. Table 7.1 lists the industries, outputs, specific fuel consumptions, and total fuel consumed in 1968. In addition, the table lists the minimum specific fuel requirements, and minimum total fuel requirements for these industries. It is seen from these data that the average fuel effectiveness for the five industries under consideration is $1.17 \times 10^{15}/9.2 \times 10^{15} = 13\%$ The average fuel effectiveness of 13% should not be confused with the efficiency value of 70% or higher reported in the literature. The latter figure represents the average fraction of the heating value of the fuels that are used in industrial processes.

The large margins that exist between current practices and minimum theoretical requirements indicate the potential which is available for major long-term reductions in fuel consumption through basic process modifications.

TABLE 7.1

1968 PRODUCT OUTPUT AND FUEL CONSUMPTION FOR SELECTED U.S. INDUSTRIES

Industry	Industry Output (tons/yr)	Specific Fuel Consumption (Btu/ton)	Total Fuel Consumption (Btu/yr)	Percentage of Industrial Sector Fuel	Theoretical Minimum Specific Fuel Consumption Based Upon Thermodynamic Availability Analysis (Btu/ton)	Minimum Total Fuel Requirement (Btu yr.)
Iron and Steel	131×10^6	26.5×10^6	3.47×10^{15}	15.2	6.0×10^6	0.79×10^{15}
Petroleum Refining	590×10^6	4.4×10^6	2.6×10^{15}	11.4	0.4×10^6	0.24×10^{15}
Paper and Paperboard	50×10^6	39×10^6	1.95×10^{15}	5.4	†Greater than -0.2×10^6 Smaller than $+0.1 \times 10^6$	0.00
Primary Aluminum	3.25×10^6	190×10^6	0.62×10^{15}	2.8	25.2×10^6	0.08×10^{15}
Cement	72×10^6	7.9×10^6	0.57×10^{15}	2.5	0.8×10^6	0.06×10^{15}
		TOTAL	9.2×10^{15}	38%	-	1.17×10^{15}

* Includes heating value of waste products (bark and spent pulp liquor).

† Negative value means that no fuel is required.

References

1) Patterns of Energy Consumption in the United States, by SRI (1972), U.S. Government Printing Office, Stock Number 4106-0034, Washington, D.C.

2) W.G. Dupree, Jr. and J.A. West, U.S. Energy Through the Year 2000, U. S. Department of the Interior, (1972).

3) E. P. Gyftopoulos, L. J. Lazaridis, and T.F. Widmer.

Potential Fuel Effectiveness in Industry, Ballinger Publishing Company, Cambridge, Massachusetts, November (1974), Report to the Energy Policy Project of the Ford Foundation.

4) Lighting and Thermal Operations, Energy Management Action Program for Commercial, Public, Industrial Buildings - Guidelines. Federal Energy Administration. U. S. Government Printing Office, Washington, D.C.

5) Gas Supply Review, American Gas Association, Gas Supply Committee. Volume 3, Number 2, November, 1974.

6) D. T. Morgan and J. P. Davis.

High Efficiency Decentralized Electrical Power Generation Utilizing Diesel Engines Coupled with Organic Working Fluid Rankine-Cycle Engines Operating on Diesel Reject Heat. Prepared for the National Science Foundation, Washington, D.C. NSF Grant No. GI-40774. November, 1974.

7) Speech by John Moody, Senior V.P. Mobil Oil Corporation, presented to Seminar at Earth and Planetary Science Department of Massachusetts Institute of Technology, December 1974.