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District Heating/Cogeneration Application Studies for the Minneapolis–St. Paul Area

Allocation Methods for the Separation of Electrical and Thermal Cogeneration Costs

G. F. Pavlenco and G. A. Englesson

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DISTRICT HEATING/COGENERATION APPLICATION STUDIES FOR THE MINNEAPOLIS-ST. PAUL AREA

ALLOCATION METHODS FOR THE SEPARATION OF ELECTRICAL AND THERMAL COGENERATION COSTS

G. F. Pavlenco and G. A. Englesson

United Engineers and Constructors Inc.

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FOREWORD

This cost allocation study was commissioned by Northern States Power Company (NSP) in 1978 as part of a contract with United Engineers and Constructors Inc. This contract also considered the engineering feasibility and cost of modifying existing boilers and retrofitting the condensing turbines for cogeneration at NSP's High Bridge Generating Plant to furnish heat for the St. Paul downtown demonstration hot water district heating system.

The total cost of heat from a cogeneration power plant includes two types of cost — first, the direct cost associated with heat production, and second, the indirect cost of additional electric production caused by the change in the operating schedule of the plant to meet heat demands. The indirect cost is the charge for electric capacity derate and replacement electricity. The electric capacity derate charge is for the reduction in electrical generating capacity caused by cogeneration, and the replacement electricity charge is for the additional cost of replacing electricity no longer produced at the cogeneration plant with electricity produced at another plant.

This cost allocation analysis considered only the direct cost of heat production. Indirect cost was not included for three reasons:

1. determination of this cost would involve an expensive time consuming production-costing simulation of the electrical generating system both before and after the retrofit to determine the value of electricity from the retrofit cogeneration plant;
2. the assumption that the retrofit cogeneration units could be operated at their rated electric capacity output during NSP's summer peaking period thus avoiding the electric capacity derate charge part of the indirect cost; and
3. the assumption that the replacement energy charge would be negligible.

The last two assumptions are basic to the assumption of the Margen Method of cost allocation — that the systemwide cost of electricity will not be significantly affected by modifying and operating the High Bridge plant as a cogeneration plant.

However, later High Bridge cogeneration cost allocation studies done by NSP indicate that the indirect cost may be substantial. Therefore, both direct and indirect costs should be included when determining the total cost of heat from a cogeneration plant.

ACKNOWLEDGMENTS

This study of allocation methods for the separation of electricity and heat costs in cogeneration plants was done by United Engineers and Constructors Inc. (UE&C) for the Northern States Power Company (NSP) as part of the High Bridge Station Retrofit Study.

The study was directed by G. A. Englesson; G. F. Pavlenco was principal investigator. Other major UE&C contributors were N. H. Lee, B. Menaker, and U. K. Rath.

Both H. Jaehne and P. Johnson of NSP provided data and advice.

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ABSTRACT

Allocation methods proposed in the U.S. and Europe for separating electricity and heat cogeneration costs were evaluated for their suitability for dual-purpose plants equipped with either new cogeneration turbines or turbines retrofitted for cogeneration. Both direct and indirect allocation methods were considered. The distinction between the two groups of methods depends upon whether the cost allocation is made by separating the total annual costs (directly), or by separating individually the various fixed and variable costs (indirectly).

All methods considered were applied to the case of a large cogeneration/district heating plant equipped with a new 800 MW(e) condensing-tail turbine assumed to be operating in the Minneapolis-St. Paul area. The unit costs obtained for electricity and heat were compared with those determined for separate generation of the two forms of energy. Costs for the High Bridge Station Retrofit Study were allocated using only two direct allocation methods (Margen and equal discount) because the absence of detailed capital cost information for various plant equipment did not permit the application of any indirect allocation method.

Of the methods considered, the equal discount method appeared to be a good choice for new cogeneration units. With this method, both the heat and electricity users would share the economic benefits of cogeneration. For plants retrofitted to cogeneration, such as the High Bridge Station, the Margen method was recommended because it provides incentives to heat users to convert from existing systems to district heating systems while not penalizing existing electric customers.

1. SUMMARY AND RECOMMENDATIONS

1.1 Summary

1.1.1 General

Various methods of allocating costs for the generation of both heat and electricity have evolved from industry and utility experience in Europe and the United States. Each method is biased to some degree because it distributes the economic benefits of cogeneration to customers of either electricity or heat at the expense of customers of the other. The purpose of this study is to select a cost allocation method suitable for the High Bridge Retrofit Study based on the review of allocation methods in the technical literature. Various cost allocation methods were applied to both a retrofit plant project and a new plant project; from these data, a method was selected for the High Bridge Retrofit Study. Cost allocation for this study is defined as the allocation of the cost of electricity and heat generation at the bus bar and plant gate respectively.

The first step in comparing cost allocation methods is to establish the unit-product cost. To do this, all fixed and variable costs are itemized, separated, and then accumulated in either the electrical or heat accounts.

Eight methods of cost allocation were evaluated: Stancescu-Badea, physical, production equivalence, electricity discounting, heat discounting, Leung, Margen, and equal discount.

The first four methods result in cogeneration heat costs equal to or greater than the cost of separate heat generation. However, the electrical costs in these methods are significantly less than the cost of separate electrical generation. The next three methods provide cogeneration electrical costs equal to or greater than the cost of separate electrical generation but heat costs that are significantly lower than the cost of separate heat generation. The last method provides electricity and heat costs that are less than separate generation costs.

The Margen method provides electrical costs equal to the cost of separate electrical generation from a large unit and heat costs that are approximately 48% less than separate heat generation. It is a method that would encourage conversion to district heating and not penalize electric customers. Therefore, it is the method recommended for the High Bridge Retrofit Study.

For new cogeneration stations, the equal discount method is recommended because both customers of electricity and customers of heat benefit from cogeneration economics. This recommendation is based on the following reasons:

1. Electrical-production costs should favor the operation of this plant in the system because it provides a significant amount of energy conservation. For small-sized cogeneration units, this will occur only if the electrical-production costs benefit from cogeneration.
2. Heat-production costs should be low to induce conversion to district heating.

1.1.2 Allocation of costs

There are three elements to the cost of generation — capital costs, operating and maintenance costs, and fuel costs (penalty costs associated with loss of capacity have not been included). Each of these costs can be divided into

1. costs that are solely for electricity generation (such as the generator switchyards, turbine generator, condenser, and cooling towers);
2. costs that are solely for heat production (such as the base heat exchanger, hot-water peaking boilers, and district pumps); and
3. costs that serve both functions (such as the steam-generation equipment, plant facilities, fuel-handling draft equipment, and feedwater heaters).

The capital costs are fixed costs because they do not vary with plant production; however, the operating and maintenance costs and fuel costs do vary since they are a function of plant production.

To show the differences among the various cost allocation methods, two calculations are provided: one is based on an 800-MW fossil-fuel-fired cogeneration plant (Table 1.1 and Fig. 1.1) as designed by United Engineers Constructors Inc. (UE&C), and the other is based on the High Bridge Retrofit Project (Table 1.2 and Fig. 1.2).

Table 1.1. Allocation costs by method for a new 800-MW(e) cogeneration plant

Method	Annual cost ($\$ \times 10^6$)		Unit cost	
	Electricity	Heat	Electricity[a] (mills/kWh)	Heat[b] ($/GJ)
Stancescu-Badea	88.36	65.24	13.78	2.448
Physical	88.47	65.12	13.75	2.454
Leung	122.30	31.29	19.07	1.174
Margen	122.22	31.37	19.06	1.177
Equal discount	104.00	49.59	16.22	1.861
Separate generation	122.216	50.28	19.06	2.19

[a]Assumes production to be 6.411×10^9 kWh/y.

[b]Assumes production to be 26.65×10^6 GJ/y. (For this report, 1 GJ is assumed to equal 10^6 Btu although the correct conversion is 1 GJ = 0.9478×10^6 Btu).

In developing the cost for operating the High Bridge power plant as a cogeneration station, it was assumed that retrofitting this station would not adversely affect its electrical generating potential. The primary reason for this assumption was that since Northern States Power Company is a summer peaking facility, the condensing-tail retrofitting of units 5 and 6 would allow these units to operate at their rated capacity during the summer when the heat load is minimal. Backpressure retrofitting of unit 3 would permanently reduce the electrical/generating capability of this unit from 50 to 42 MW(e); however, this unit would operate throughout the year at the very favorable heat rate characteristics of a backpressure turbine. Because of these assumptions, no cost penalties (from loss of electrical capacity or replacement of electricity) were included in calculating the costs of delivered heat.

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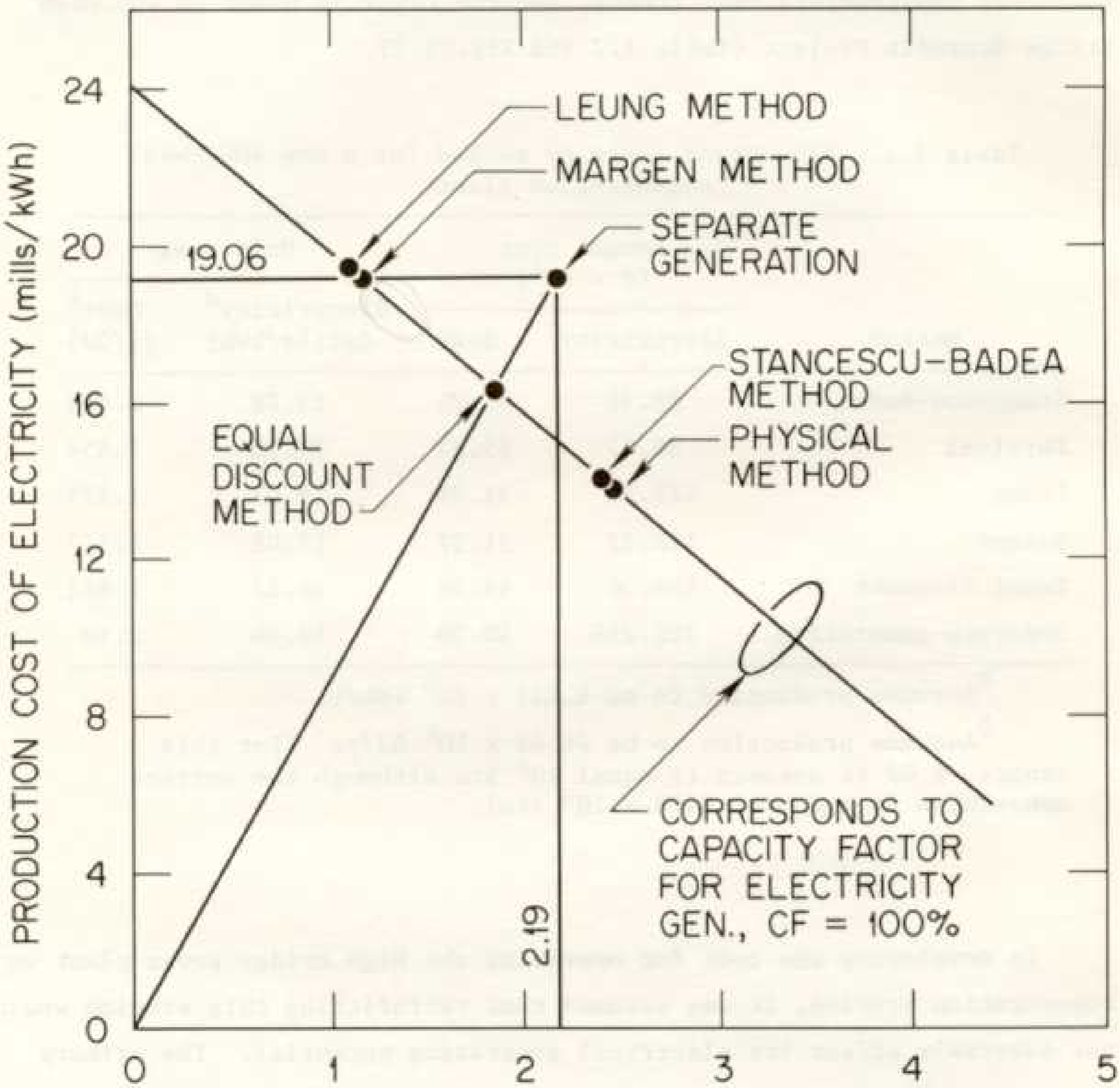

Fig. 1.1. Heat and electricity production costs for new 800-MW(e) cogeneration plant, as calculated by different methods.

Table 1.2. Unit costs for cogeneration and separate generation for the High Bridge Generating Station

Electric energy capacity factor (%)	Combined generation				Separate generation	
	Margen method		Equal discount method			
	Electricity (mills/kWh)	Heat ($/GJ)	Electricity (mills/kWh)	Heat ($/GJ)	Electricity (mills/kWh)	Heat ($/GJ)
100	12.97	1.04	12.12	1.89	12.97	2.02
90	13.39	1.04	12.45	1.88	13.39	2.02
80	13.90	1.04	12.86	1.87	13.90	2.02
70	14.56	1.04	13.39	1.86	14.56	2.02
60	15.44	1.03	14.09	1.84	15.44	2.02
50	16.68	1.03	15.09	1.83	16.68	2.02

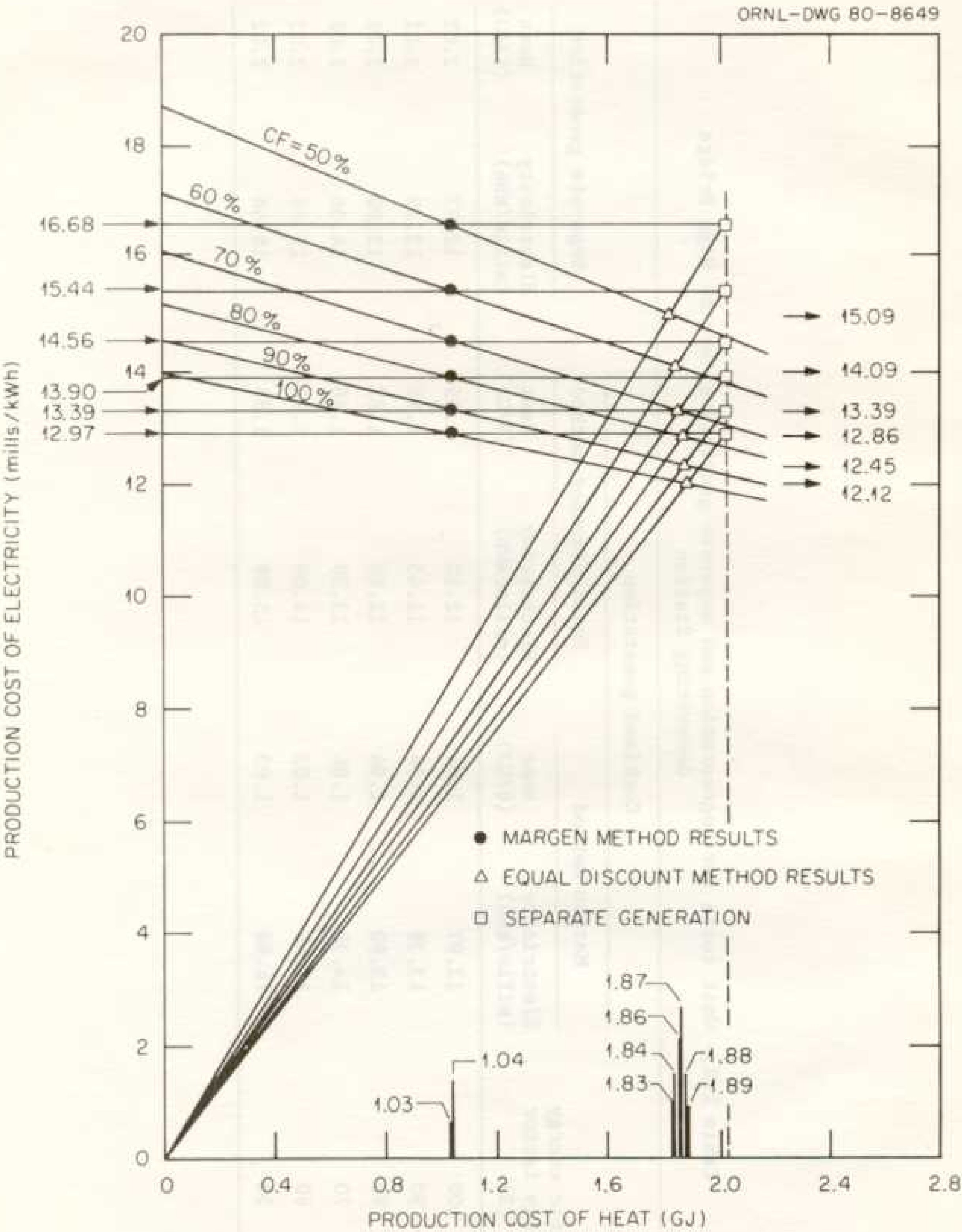

Fig. 1.2. Heat and electricity production costs for the High Bridge Generating Station, as calculated by different methods.

1.2 Recommendations

Of the methods considered, the equal discount method appears to be a good choice for new cogeneration units. Using this method, customers of both heat and electricity will share the economic benefits of cogeneration. For retrofitted generation stations, such as High Bridge, the Margen method is recommended. This method provides incentives to convert from existing systems to district heating systems while not penalizing existing electric customers.

2. ALLOCATION METHODS CONSIDERED

2.1 Nomenclature

The nomenclature is illustrated in Fig. 2.1 for the various annual costs of a cogeneration plant.

A = annual operating cost,

A^e = total operating costs of electricity generation,

A^t = total operating costs of heat generation,

A_A = fixed annual operating costs,

A_B = variable operating costs of annual fuel use,

$A_{O\&M}$ = variable operating costs of operation and maintenance,

A_A^e = fixed operating costs for electricity,

A_B^e = variable operating costs from annual fuel use for electricity,

$A_{O\&M}^e$ = variable operation and maintenance costs for electricity,

A_A^t = fixed operating costs for heat,

A_B^t = variable operating costs due to the annual fuel use for heat,

$A_{O\&M}^t$ = variable operation and maintenance costs for heat,

A_A^{ee} = fixed operating costs exclusively related to generation of electricity,

A_A^{et} = fixed costs common to the generation of both energy forms,

A_A^{tt} = fixed operating costs exclusively related to generation of heat,

A_{cg} = operating costs of cogeneration,

A_{hc} = operating costs of home connections,

A_{sg} = operating costs of separate generation, ORNL–DWG 80-8648

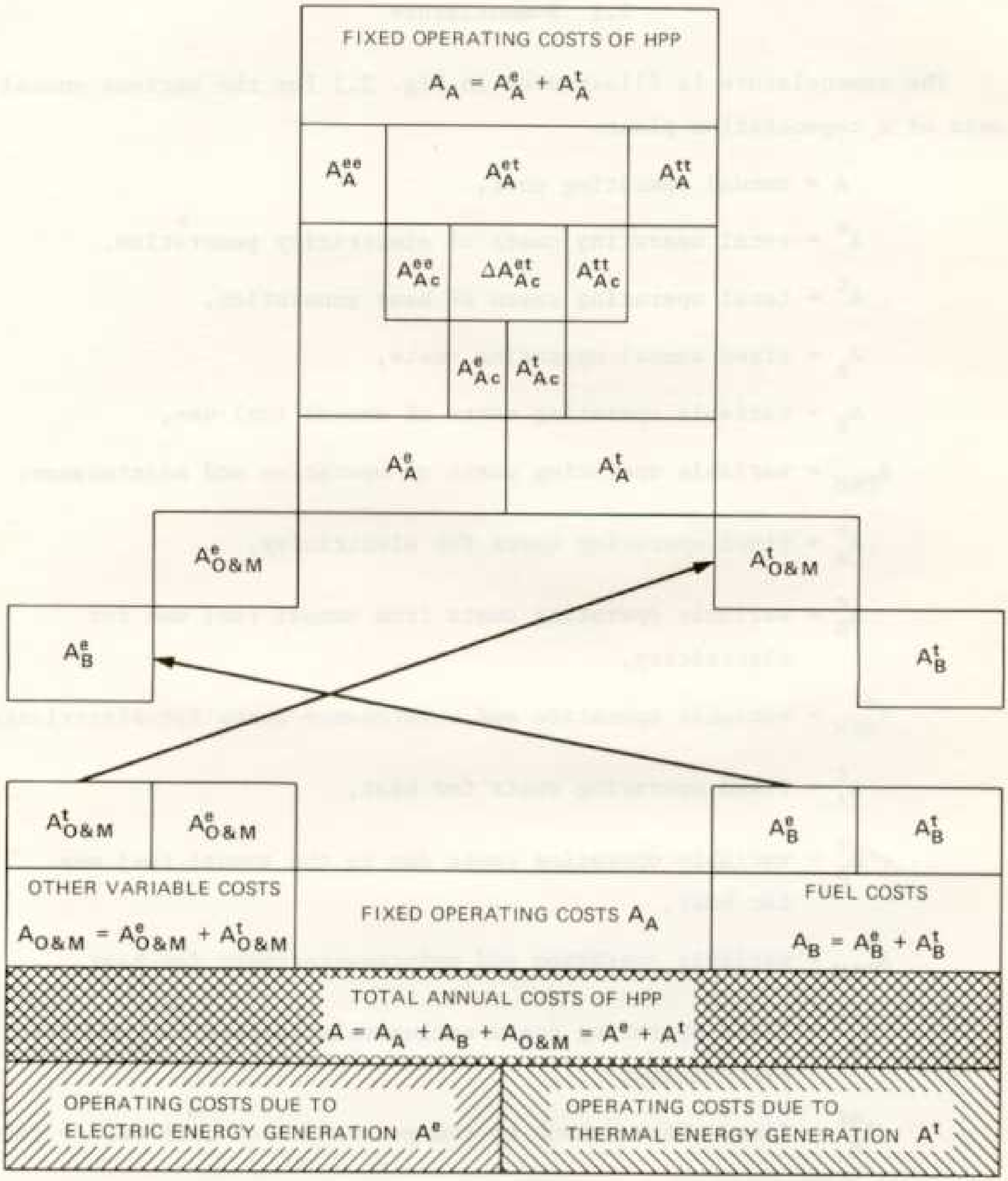

Fig. 2.1. Allocation of the total annual operating costs of a cogeneration plant by the Stancescu-Badea Method.

A_{tdn} = operating costs of transmission and distribution network,

A_{HPP} = operating costs of heat and power (cogeneration) plant,

A^{e}_{Ac} = the part of the remaining fixed costs common to both energy forms, ΔA^{et}_{Ac}, allocated to electricity,

A^{t}_{Ac} = the part of the remaining fixed costs common to both energy forms, ΔA^{et}_{Ac}, allocated to heat,

A^{ee}_{Ac} = exclusively electricity part of the fixed costs common to the generation of both forms of energy,

ΔA^{et}_{Ac} = the remaining fixed costs common to both energy forms remaining upon separating A^{ee}_{Ac} and A^{tt}_{Ac} from A^{et}_{A},

A^{tt}_{Ac} = exclusively heat part of the fixed costs common to the generation of both forms of energy,

b_{pp} = average heat rate of a conventional condensing power plant,

b^{cd}_{HPP} = heat rate for electricity generated by condensation only in the cogeneration plant,

B_{HPP} = total annual fuel use by the cogeneration plant,

B^{e}_{HPP} = total annual fuel use to produce electricity,

B^{t}_{HPP} = total annual fuel use due to thermal energy generation,

$B^{t(cg)}_{HPP}$ = annual fuel use to produce heat by cogeneration,

$B^{t(peak)}_{HPP}$ = annual fuel consumption due to thermal energy produced by peak boilers,

c_e = average unit cost of electricity at busbar,

c_c = average unit cost of heat at consumer,

c_t = average unit cost of heat at plant boundary,

C = capital cost,

C_{cg} = capital costs of cogeneration,

C_{sg} = capital costs of separate generation,

E = electricity,

ee = exclusively electric,

et = joint function (both electricity and heat),

E_{HPP} = electricity annually generated by a cogeneration plant,

E_{HPP}^{cd} = electricity generated by condensation only in the cogeneration plant,

E_{HPP}^{cg} = electricity generated by cogeneration only in the cogeneration plant,

h = duration of use or rated production capacity,

n = payback period,

O&M = operating and maintenance,

Q^a = heat annually produced by the cogeneration plant (including peak load),

$Q^{a(cg)}$ = thermal energy annually produced by cogeneration turbines,

$Q^{a(peak)}$ = thermal energy annually produced by peaking boilers,

Q'a = heat annually delivered to the consumers,

tt = totally thermal energy,

X_e = "power key" for electricity (fraction of ΔA_{Ac}^{et} allocated to electricity),

X_t = "power key" for heat (fraction of ΔA_{Ac}^{et} allocated to heat),

Y_e = "energy key" for electricity (fraction of the total variable costs, $A_B + A_{O\&M}$, allocated to electricity production),

Y_t = "energy key" for heat (fraction of the total variable costs, $A_B + A_{O\&M}$, allocated to heat production,

η = efficiency,

η_g = electrical generator efficiency,

η_m = mechanical efficiency,

η_{sg} = steam generator efficiency, and

η_{pb} = peaking boiler efficiency.

2.2 Definition of Cogeneration Unit Costs

The cogeneration of electricity and heat is economically advantageous when the operating cost of cogeneration, A_{cg},* is smaller than the sum of the operating costs of separate electricity and heat generating plants, A_{sg}, and if either the capital cost of cogeneration, C_{cg}, is less than the capital cost of the separate power systems, C_{sg}, or the payback period, n, is reasonably short.

Thus, when

$$A_{cg} < A_{sg} , \tag{1}$$

cogeneration is advantageous if either

$$C_{cg} < C_{sg} \tag{2}$$

or

$$n < x \text{ years} \tag{3}$$

where

$$n = (C_{cg} - C_{sg})/(A_{sg} - A_{cg}) \tag{4}$$

Since the Inequality (1) is almost always true because of the fuel savings from cogeneration, the combined generation of heat and electricity (cogeneration) results in total annual costs for the production of the two forms of energy which are smaller than the sum of total annual costs for separately generated energy when conditions in either Inequalities (2) or (3) exist.

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*The term A_{cg} includes the costs related to the operation of the cogeneration plant (including peaking boilers), transmission and distribution networks, and the home connections as shown by Eq. (5).

The total cost (\$/y) of cogeneration for a year, A_{cg}, is the sum of the plant operating cost, A_{HPP}, the transmission and distribution network operating cost, A_{tdn}, and the operating cost of home connection, A_{hc}. That is,

$$A_{cg} = A_{HPP} + A_{tdn} + A_{hc} , \tag{5}$$

where

A_{HPP} = heat and power (cogeneration) plant operating cost,

A_{tdn} = transmission and distribution network operating cost,

A_{hc} = home connections operating cost.

To calculate the separate unit costs for electricity and heat, the cogeneration plant operating costs, A_{HPP} must be separated into operating costs due solely to electricity generation, A^e, and operating costs due to heat generation alone (A^t):

$$A_{HPP} = A^e + A^t , \tag{6}$$

where

A^e = operating costs due to electricity generation,

A^t = operating costs due to heat generation.

The average unit cogeneration costs can now be defined. To differentiate the average unit cost (mills/kWh) of electricity, c_e, the operating cost due to electricity generation, A^e, is divided by the electricity annually generated by the cogeneration plant, E_{HPP}:

$$c_e = A^e/E_{HPP} , \tag{7}$$

where

E_{HPP} = electricity annually generated by the cogeneration plant.

The average unit cost ($/GJ) for heat at plant boundary, c_t is

$$c_t = A^t/Q^a , \tag{8}$$

where

Q^a = heat annually generated by the cogeneration plant.

The average unit cost of heat at the consumer, c_c, can be calculated in three steps:

1. The total operating cost of heat generation is divided by the heat annually generated by the cogeneration plant. The results of this calculation equal the average unit cost of heat at plant boundary, c_t.
2. The transmission/distribution operating costs are added to the home connections operating costs, and then their sum is divided by the heat annually delivered to the consumers.
3. The results of the first two steps are then added.

The formula for the average unit cost of heat at the consumer c_c is

$$c_c = A^t/Q + (A_{tdn} + A_{hc})/Q^{'a} = c_t + (A_{tdn} + A_{hc})/Q^{'a} . \tag{9}$$

The unit cogeneration costs are usually calculated at the high-voltage bus bar for electricity and at the user's end for heat because cogeneration plants are located practically adjacent to the consumers, in terms of electricity transport but are quite remote from consumers in terms of heat transport. Because the operating costs of the transmission and distribution of heat affect only the unit cost of the heat (therefore, their inclusion in the costs allocation is straightforward), <u>the remainder of this report will be limited to the allocation of the operating costs of the cogeneration plant</u> (A_{HPP}) <u>between the two energy forms</u>.

2.3 General Procedures for Allocation of Costs Between Electrical Generation and District Heating

The generation of electricity and heat is fundamentally different from other industrial processes because the storage of these forms of energy is either practically impossible (electricity) or limited (heat). As a result, they must be produced according to the momentary demand that imposes special conditions on their generation processes.

The cogeneration plant capacity is dictated by the combined effect of the various load demands. Because the overlapping of the load demands takes place, a maximum probable load can be determined by applying appropriate coincidence coefficients to various individual maximum load demands. The plant capacity (and implicitly the plant capital costs) depends entirely on the maximum probable load demand regardless of its duration.

The annual operating cost for a cogeneration plant can be divided into two groups of costs: fixed and variable, as shown by Eq. (10). The fixed costs are the amortized costs (about 30%). The variable costs include fuel (about 65%) and operation and maintenance (O&M) costs (about 5%).

$$A_{HPP} = \text{fixed costs} + \text{variable costs}$$

$$= A_A + A_B + A_{O\&M} , \qquad (10)$$

where

A_A = fixed costs,

A_B = fuel costs,

$A_{O\&M}$ = O&M costs,

$A_B + A_{O\&M}$ = variable costs.

Those methods which determine the cogeneration costs by allocating the fixed and variable costs separately are generally referred to as *indirect methods*; others which consider the annual operating costs as a whole are called *direct methods*.

2.3.1 Indirect methods

The general algorithm used by all indirect methods for dividing the annual operating costs of the cogeneration plant, A_{HPP}, into the two components given by Eq. (6), A^e and A^t, involves the separate allocation of the fixed and variable costs to the heat and electricity accounts.

To accomplish this separate allocation, the annual operating costs are first grouped into three broad categories according to the purpose for which they were incurred.

$$A_{HPP} = A_{HPP}^{ee} + A_{HPP}^{tt} + A_{HPP}^{et} , \tag{11}$$

where

A_{HPP}^{ee} = costs exclusively for electricity generation,

A_{HPP}^{tt} = costs exclusively (totally) for heat generation,

A_{HPP}^{et} = costs common to generation of both forms of energy.

The first two categories of costs can be easily identified, and the third equals the remainder after the first two categories have been deducted.

Referring back to the costs defined by Eq. (9) (A_A, A_B, and $A_{O\&M}$), it is obvious that only A_A and $A_{O\&M}$ warrant the subdivision into the three categories of costs defined by Eq. (11) since the fuel costs can be divided initially only into two groups: electricity and heat.

These cost subdivisions can be expressed as follows*:

$$A_A = A_A^{ee} + A_A^{tt} + A_A^{et} , \tag{12}$$

$$A_B = A_B^e + A_B^t , \tag{13}$$

*In Eq. (13) the fuel costs are divided directly into A_B^e and A_B^t because these costs are incurred exclusively <u>either</u> for electricity generation <u>or</u> for heat generation.

$$A_{O\&M} = A^{ee}_{O\&M} + A^{tt}_{O\&M} + A^{et}_{O\&M} \; . \tag{14}$$

By combining Eqs. (9), (10), and (11), one obtains

$$A^{ee}_{HPP} = A^{ee}_{A} + A^{e}_{B} + A^{ee}_{O\&M} \; , \tag{15}$$

$$A^{tt}_{HPP} = A^{tt}_{A} + A^{t}_{B} + A^{tt}_{O\&M} \; , \tag{16}$$

$$A^{et}_{HPP} = A^{et}_{A} + A^{et}_{O\&M} \; . \tag{17}$$

The allocation of the fuel costs, A_B, is made proportionally to the fuel used for generating each form of energy. The annual fuel consumption of the cogeneration plant, B_{HPP}, is given by

$$B_{HPP} = B^{e}_{HPP} + B^{t(cg)}_{HPP} + B^{t(peak)}_{HPP}$$

$$= B^{e}_{HPP} + B^{t}_{HPP} \; , \tag{18}$$

where

B^{e}_{HPP} = fuel used for electricity generation,

B^{t}_{HPP} = fuel used for heat generation (cogeneration + peak load),

$B^{t(cg)}_{HPP}$ = fuel used for heat supplied by cogeneration,

$B^{t(peak)}_{HPP}$ = fuel used for heat supplied by peaking boilers.

The fractions of fuel used are than calculated as

$$Y^{e} = B^{e}_{HPP}/B_{HPP} \; , \quad \text{for electric generation} \; , \tag{19}$$

$$Y^{t} = B^{t}_{HPP}/B_{HPP} \; , \quad \text{for heat generation} \; , \tag{20}$$

The separate fuel costs are calculated as

$$A_B^e = Y^e \cdot A_B \ , \tag{21}$$

$$A_B^t = Y^t \cdot A_B \ , \tag{22}$$

Because the O&M costs vary with the rate of production, it is generally appropriate to allocate the O&M costs to heat and electricity similarly to the method used in fuel cost allocations.

While the division of the fuel costs is standard for all allocation methods that use this algorithm, the assumptions for calculating B_{HPP}^e and $B_{HPP}^{t(cg)}$ vary from method to method (Sect. 2.4). Another source of the differences in the results obtained with various methods stems from the manner in which the costs common to both heat and electricity generation, A_{HPP}^{et}, are divided. Most methods do not consider the dual structure of the total operating costs of a cogeneration plant. They limit themselves to dividing these common costs solely on the basis of the fuel use ratios (variable from year to year). Thus, these methods ignore the relative contribution to the plant capital cost of the rated capacity for generating each form of energy (time-independent for a given plant).

2.3.2 Direct methods

Unlike the general allocation procedure previously described, there are several other methods (Margen and equal discount) which do not allocate the fixed and the variable costs separately between electrical generation and heat generation. On the basis of various assumptions, these methods allocate the total annual operating costs directly (Sect. 2.5).

2.4 Descriptions of Indirect Allocation Methods

In Sect. 2.3, the general procedure employed in the indirect methods was described. Specific differences characteristic of each method are described below. The indirect methods are subdivided into two groups depending on the basic assumptions used for dividing the common costs.

2.4.1 Allocation of common costs based on fuel use

Heat discounting method. The annual fuel use (kJ/y) for the generation of electricity, B^{e}_{HPP}, is determined as follows:

$$B^{e}_{HPP} = E_{HPP} \cdot b_{pp} , \qquad (23)$$

where

E_{HPP} = electricity annually produced by cogeneration, kWh/y,

b_{pp} = average heat rate of a conventional condensing power plant, kJ/kWh.

The annual fuel use (kJ/y) for generating heat, B^{t}_{HPP}, is

$$B^{t}_{HPP} = B_{HPP} - B^{e}_{HPP} , \qquad (24)$$

where

B_{HPP} = total annual fuel use of the cogeneration plant (including peaking boilers).

As a result of this procedure, the heat appears to have been produced with less fuel than its physical equivalent and is therefore less expensive. This method represents the extreme case when all fuel savings are attributed to heat generation.

Electricity discounting method. Compared with the heat discounting method, this method is the opposite extreme since electricity generation is charged only with the fuel use (kJ/y) corresponding to its heat equivalent and the mechanical and electrical losses in the turbine-generator unit:

$$B^{e}_{HPP} = 3600^{*} E_{HPP}/\eta_m \eta_g , \qquad (25)$$

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*To obtain the fuel consumption in units of Btu/y, the conversion factor 3413 should be used instead of 3600.

where

B^{e}_{HPP} = total annual fuel use for electric generation,

η_m = mechanical efficiency,

η_g = electric generator efficiency.

The fuel use for heat generation is

$$B^{t}_{HPP} = B_{HPP} - B^{e}_{HPP} = B_{HPP} - 3600E_{HPP}/\eta_m\eta_g \ . \tag{26}$$

The effect of this calculation is to overcharge the heat generation with an amount of fuel which was not consumed for that purpose:

$$(3600E_{HPP}/\eta_m\eta_g\eta_{sg})(1 - \eta_{sg}) = (E_{HPP}/\eta_m\eta_g)[(3600/\eta_{sg}) - 3600] \ , \tag{27}$$

where

η_{sg} = steam generator efficiency.

Physical method. This method calculates correctly the fuel use corresponding to each of the two forms of energy by properly accounting for the physical processes involved.*

As shown in Eq. (13), the total fuel consumption used to produce heat, B^{t}_{HPP}, has two components, $B^{t(cg)}_{HPP}$ and $B^{t(peak)}_{HPP}$. These components correspond to the fuel used to generate the heat supplied annually by the cogeneration turbine, $Q^{a(cg)}$, and by the peaking boilers, $Q^{a(peak)}$ respectivley.

The expressions for calculating the annual fuel use are:

$$B^{t(cg)}_{HPP} = Q^{a(cg)}/\eta_{sg} \ , \tag{28}$$

*Heat losses in various pipes are also considered by the physical method, but they are neglected in this comparison.

$$B_{HPP}^{t(peak)} = Q^{a(peak)}/\eta_{pb} , \tag{29}$$

and

$$B_{HPP}^{t} = B_{HPP}^{t(cg)} + B_{HPP}^{t(peak)} . \tag{30}$$

Of course, if the peak load is met directly with live steam (by-passing the cogeneration turbine) from the steam generators, rather than with separate peaking boilers, then $\eta_{pb} = \eta_{sg}$ and the total fuel consumption is given by

$$B_{HPP}^{t} = [Q^{a(cg)} + Q^{a(peak)}]/\eta_{sg} = \frac{Q^{a}}{\eta_{sg}} \tag{31}$$

Fuel used by electric generation is

$$B_{HPP}^{e} = B_{HPP} - B_{HPP}^{t} = B_{HPP} - Q^{a}/\eta_{sg} . \tag{32}$$

This fuel use (kJ/y) can also be calculated directly for back-pressure turbines,

$$B_{HPP}^{e} = 3600E_{HPP}/\eta_{sg}\eta_{m}\eta_{g} , \tag{33}$$

and for turbines with condensing tails,

$$B_{HPP}^{e} = 3600E_{HPP}^{cg}/\eta_{sg}\eta_{m}\eta_{g} + E_{HPP}^{cd}\cdot b_{HPP}^{cd} , \tag{34}$$

where

E_{HPP}^{cg} = electricity generated by cogeneration only,

E^{cd}_{HPP} = electricity generated by condensation only,

b^{cd}_{HPP} = heat rate for electricity generation by condensation only.

Production equivalence method. This method allocates a portion of the total annual fuel use of a cogeneration plant to each form of energy (heat or electricity) proportional to its heat equivalent in the production process.

The amount charged to electric generation (kJ/y) is

$$B^{e}_{HPP} = B_{HPP} 3600E_{HPP}/(3600E_{HPP} + Q^{a}) , \tag{35}$$

and the amount charged to heat generation is

$$B^{t}_{HPP} = B_{HPP}Q^{a}/(3600E_{HPP} + Q^{a}) . \tag{36}$$

In effect, this method yields the same generation efficiencies for both heat and electricity, thus placing heat generation at a disadvantage and electricity generation at an advantage.

2.4.2 Allocation of common costs based on equipment cost and use

Stancescu-Badea method. This method uses two kinds of allocation keys (power keys and energy keys) to allocate both fixed and variable costs to the thermal and electric accounts.

The energy keys are the fractional fuel consumptions, Y^e and Y^t, given by Eqs. (18) and (19), where the partial fuel uses are calculated as in the physical method. Both the fuel costs and the O&M costs are allocated with the energy keys.

The power keys, X^e and X^t, are used to allocate the fixed costs — particularly, the common fixed costs.

Consider again, the expression of the fixed costs:

$$A_A = A^{ee}_A + A^{tt}_A + A^{et}_A . \tag{12}$$

Unlike the other indirect allocation methods, a characteristic of this method is that the allocation of the common fixed costs, A_A^{et}, is made in two steps rather than one. Therefore, the common fixed costs are divided into three categories:

$$A_A^{et} = A_{Ac}^{ee} + A_{Ac}^{tt} + \Delta A_{Ac}^{et} , \tag{37}$$

where

A_A^{et} = common fixed costs,

A_{Ac}^{ee} = exclusively electric part of the common fixed costs,

A_{Ac}^{tt} = exclusively thermal part of the common fixed costs,

ΔA_{Ac}^{et} = the remaining common fixed costs.

Several examples illustrate the meaning of these partial components of the common fixed costs. For example, the fixed costs related to the steam generators of a cogeneration plant are common fixed costs because the steam generators function in the generation of both forms of energy.

In this case, A_{Ac}^{ee} corresponds to the difference between the actual cost of the steam generator and the cost of a hypothetical steam generator of equivalent ouptut which would supply steam suitable for district heating; that is, the cost difference due to the higher pressure and temperature steam required by electrical generation is allocated to the electric account. Because there is no A_{Ac}^{tt} part in this case, the remainder corresponds to ΔA_{Ac}^{et}.

The fixed costs related to the water treatment facility of a cogeneration plant can provide another example. Compared with a plant of equivalent power output, this water treatment facility is probably larger because more water must be treated to provide for the condensate unreturned by the steam users.

The fixed costs difference due to the larger size should be allocated to the heat account; therefore, this difference corresponds to A_{Ac}^{tt}. On the other hand, the fixed costs difference due to higher quality treatment of the water required by the high-pressure, high-temperature steam generator should be allocated to the electricity account; therefore, this difference corresponds to A_{Ac}^{ee}. (If the steam generators were heat-only boilers, the water treatment requirements would be lower.) After deducting these partial components (A_{Ac}^{tt} and A_{Ac}^{ee}) from the total fixed cost of the water treatment facility, the remainder of the fixed costs, ΔA_{Ac}^{et}, for this particular case, is determined:

$$\Delta A_{Ac}^{et} = A_{A}^{et} - (A_{Ac}^{ee} + A_{Ac}^{tt}) \ . \tag{38}$$

All common equipment is similarly categorized and the common fixed costs are divided into three categories for the entire plant [Eq. (37)].

The last step in the division of the common fixed costs is the allocation of the ΔA_{Ac}^{et} term. This allocation is done proportionally to the power keys, X^e and X^t.* Thus,

$$\Delta A_{Ac}^{et} = A_{Ac}^{e} + A_{Ac}^{t} \ , \tag{39}$$

$$A_{Ac}^{e} = X^{e} \cdot \Delta A_{Ac}^{et} \ , \tag{40}$$

$$A_{Ac}^{t} = X^{t} \cdot \Delta A_{Ac}^{et} \ , \tag{41}$$

where

A_{Ac}^{e} = the part of remaining common fixed costs allocated to electricity,

A_{Ac}^{t} = the part of remaining common fixed costs allocated to heat.

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*The procedure for calculating the power keys for both condensing-tail turbines and back-pressure turbines (Appendix A) considers the ratio of production capacities available for the generation of heat and electricity and the length of time these capacities are used in a given year. A schematic representation of the allocation of the total annual operating costs is shown in Fig. 2.1.

Leung method. The allocation method described here is one of the several methods proposed by Leung.[1] The fuel and O&M costs are calculated from an established electricity cost which is computed as the product of the fuel price and the turbine heat rate divided by the boiler efficiency. The fuel cost allocated to electricity is determined by assuming that the entire amount of electricity is generated at this unit cost. The remainder from the total fuel cost is then allocated to the heat account. The capital costs allocation is made by cost separation of major functions. After the cost of functions exclusive to steam and that of functions exclusive to electricity are deducted, the cost of joint components is separated by the differential cost approach. This approach requires a detailed cost estimate of a single-purpose plant having the identical electrical output of the dual-purpose plant. The cost of the single-purpose plant equipment is subtracted from the cost of the corresponding joint equipment of the dual-purpose plant so that the remaining cost can be allocated to the heat account.

2.5 Descriptions of Direct Allocation Methods

2.5.1 Equal discount method

This method allocates the cogeneration benefits equally to heat and electricity without reference to the shared costs of generation. The cost of generating the electric power and heat in the relevant quantities is first calculated. Generation is assumed to occur separately and in an optimum manner in a condensing turbine power station and a district heating station. The actual costs of combined generation in the district heating power station are then divided proportionately to the savings obtained by comparison with the alternative costs. The method can be regarded as the result of negotiations between two equal parties (Table 3.6, in Sect. 3).

2.5.2 Margen method

This method is particularly applicable to the High Bridge Generating Station when retrofitted to cogeneration. The basic assumptions are that the system-wide cost of electricity will not be significantly affected by the modifications to the High Bridge plant. The basis for this assumption is that the modifications to the High Bridge Generating Station will have negligible effect on the system-wide cost of producing electricity because the High Bridge output represents a small portion of total system capacity. Because the system-wide cost of producing electricity is unchanged, the sale price of electricity to consumers should remain the same. Therefore, the Margen method assumes that the sale of electricity produced at the High Bridge Generating Station produces a certain amount of revenue which can be subtracted from the overall cost of operation. The remaining costs represent the cost of producing heat, including the amortization of the retrofit costs.

This method may not apply to other retrofitted plants and probably would not apply to new cogeneration units. Its applicability in any given situation must be specifically reviewed.

2.6 Comparisons of Allocation methods

With the separate generation costs for electricity and heat as reference cases, the previously discussed procedures may be applied, for simplicity, to a typical cogeneration plant with back-pressure turbines (Table 2.1).

Table 2.1. Unit costs of electricity and heat cogeneration calculated by various methods (assuming back-pressure turbines)

Allocation method	Unit cost of heat (%)	Unit cost of electricity (%)
Separate generation	100	100
Heat discounting	67.1	114.0
Electric discounting	118.1	42.0
Physical	114.5	47.5
Production equivalence	115.3	46.5
Stancescu-Badea	102.5	65.0
Margen	74.0	100.0
Equal discount	85.0	85.0

The relationship between the unit cogeneration costs for electricity, c_e, and for heat, c_t, can be obtained as follows:

$$A_{HPP} = A^e + A^t = E_{HPP} \cdot c_e + Q^a \cdot c_t \ , \tag{42}$$

$$c_e + (Q^a/E_{HPP}) \cdot c_t = A_{HPP}/E_{HPP} \ . \tag{43}$$

Results are in dollars per year (Eq. 42) and in dollars per kWh (Eq. 43). Equation (43) represents a straight line which is the geometrical focus of all pairs of unit cogeneration costs, except for the separate cogeneration costs (Fig. 2.2).

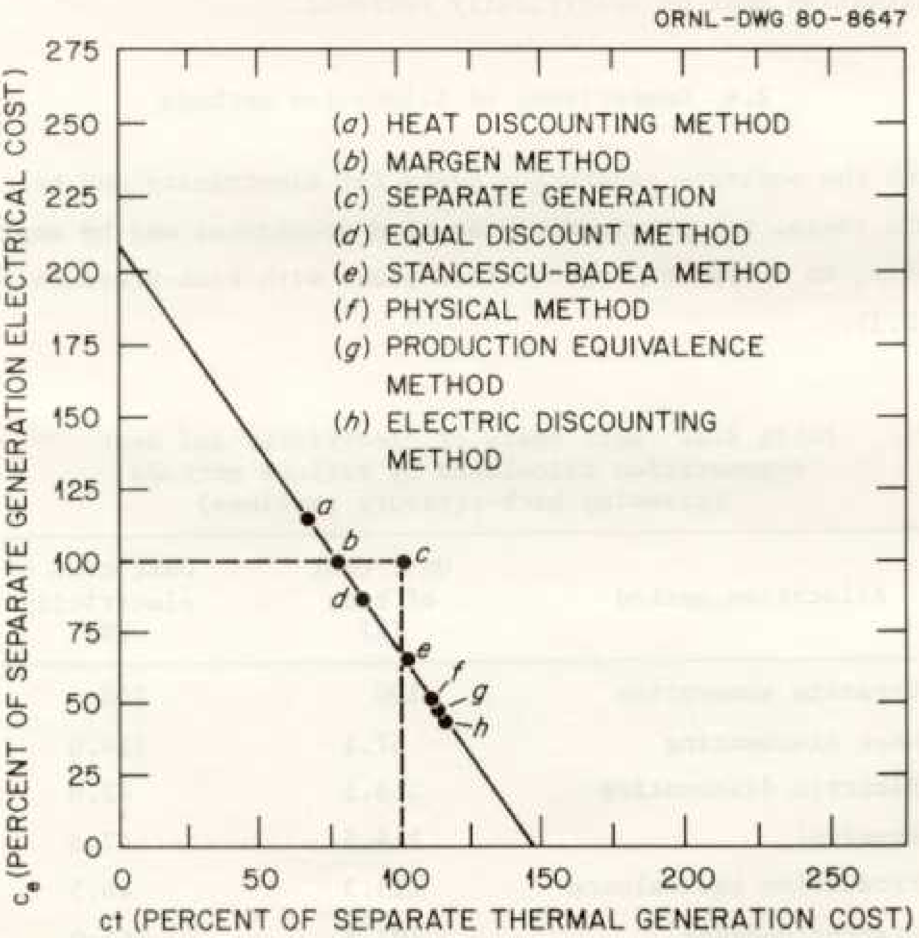

Fig. 2.2. Costs calculated by various allocation methods compared with those of separate generation (assuming back-pressure turbines).

3. SAMPLE CALCULATIONS USING VARIOUS ALLOCATION METHODS

3.1 Cost Information

Differences among the cost allocation methods are mostly from the subdivision of the capital costs of joint components into three categories in the Stancescu-Badea method. Another difference is that the Stancescu-Badea method allocates the cost of the dual-purpose turbine fully to the electricity account. Calculations were made to compare five allocation methods. The production costs were also calculated for the case when equal amounts of energy were generated separately in a single-purpose power plant and a heating plant. Six methods were used:

1. Stancescu-Badea
2. Physical
3. Leung
4. Margen
5. Equal discount
6. Separate generation

The total amounts of heat and electricity generated annually[2] were 26.65×10^6 GJ/y and 6.411×10^9 kWh/y.* Nine percent of the total heat (or 2.39×10^6 GJ/y) was supplied by the peak-load boilers of the cogeneration plant.

The variable costs were computed using \$0.86/ GJ for the fuel price and 0.43¢/kWh for O&M costs for all methods except separate generation. For separate generation, 0.312¢/kWh was used for the electric plant, and \$5/kW(t)/y was used for the heating plant.

The fixed cost was computed from the capital costs using a 15.7% fixed charge rate. The data on the fixed charge rate and separate generation were provided by the Northern States Power Company and reflect their operating experience.

*1 GJ $\sim 10^6$ Btu.

3.2 Allocation Results for a New Cogeneration Plant

3.2.1 Stancescu-Badea method

The power keys and the energy keys used in this method to allocate the remaining common fixed costs and the variable costs, respectively, were determined in a separate calculation (Appendix B):

	Power key	Energy key
Electricity	$X^e = 0.496$	$Y^e = 0.576$
Heat	$X^t = 0.504$	$Y^t = 0.424$

In the allocation of the fixed and variable costs (Table 3.1), the energy keys are used to allocate both fuel and O&M costs. The five categories of capital costs (Table 3.2) were multiplied by 0.157 (fixed cost rate) to obtain the fixed costs. The separate annual costs are A^e = \$88.36 × 10^6 and A^t = \$65.23 × 10^6. The cogeneration unit costs for electricity and heat are 13.78 mills/kWh and \$2.45/GJ based on an electrical generation of 6.411 × 10^9 kWh/y and a heat generation of 26.65 × 10^6 GJ/y.

3.2.2 Physical method

In the allocation of fixed and variable costs (Table 3.3), the variable costs as well as the fixed costs due to joint components are allocated to the electricity and heat accounts proportionately to the corresponding fuel use. The fixed costs related to the exclusively electric and exclusively heat components are allocated in full to their respective account.

The cogeneration unit cost for electricity is 13.56 mills/kWh; for heat the unit cost is \$2.50/GJ.

3.2.3 Leung method

Fixed and variable costs were also allocated by this method (Table 3.4). The allocation factors for the variable costs (fuel and O&M) were calculated (Table 3.5). The alternative cost-justifiable investment method

Table 3.1. The Stancescu-Badea method for allocating costs of a new cogeneration plant

Costs	Capital cost ($ × 10^6)	Allocation keys		Annual generation cost ($ × 10^6)/y		Total ($ × 10^6)/y
		Electricity	Heat	Electricity	Heat	
Variable						
Fuel, A_B		0.576	0.424	37.07	27.29	64.36
Operation and Maintenance, $A_{O\&M}$		0.576	0.424	16.13	11.87	28.00
Total variable				53.20	39.16	92.36
Fixed						
Exclusively electric, A_A^{ee}	80.27	1.0	0	12.60	0	12.60
Totally heat, A_A^{tt}	55.00	0	1.0	0	8.64	8.64
Common exclusively electric, A_{Ac}^{ee}	35.81	1.0	0	5.62	0	5.62
Common totally heat, A_{Ac}^{tt}	1.42	0	1.0	0	0.22	0.22
Remaining common, ΔA_{Ac}^{et}	217.50	0.496	0.504	16.94	17.21	34.15
Total fixed	390.0			35.16	26.07	61.23
Total				88.36	65.23	153.59
Average cogeneration unit cost				13.78 (mills/kWh)	2.448 ($/GJ)	

Table 3.2. Capital costs breakdown of an 800-MW(e) steam electric generation plant and an 800-MW(e) cogeneration plant (January 1978 dollars)

Account	Account description	Electric plant capital cost ($ × 10^6)	Scaling factor for cogeneration plant	Cogeneration plant capital cost ($ × 10^6)	Capital cost allocation for cogeneration plant ($ × 10^6)							
					Stancescu-Radea method					Other indirect methods		
					Exclusively electric (ee)	Totally thermal (tt)	Joint components			Exclusively electric (ee)	Totally thermal (tt)	Joint components (et)
							(ee)	(et)	(tt)			
20	Land and land rights	2.21	1.05	2.32				2.32				2.32
211	Yard work	5.00	1.05	5.25				5.25				5.25
212	Steam generator building	18.02	1.05	18.92				18.92				18.92
213	TG, heater containment building	8.69	1.15	9.99				9.99				9.99
218B	Administration and service building	1.75	1.0	1.75				1.75				1.75
218I	Electric switchgear building	0.15	1.0	0.15	0.15					0.15		
218L	Stack/reclaim transfer tower	0.12	1.05	0.15				0.15				0.15
218M	Coal car thaw shed	0.04	1.0	0.04				0.04				0.04
218N	Rotary car dump building and tunnel	0.90	1.0	0.90				0.90				0.90
218O	Dead storage Re Cl hopper	0.44	1.0	0.44				0.44				0.44
218P	Coal crusher house	0.52	1.05	0.55				0.55				0.55
218Q	Boiler house transfer tower	0.12	1.05	0.13				0.13				0.13
218R	Dead storage transfer tunnel	0.80	1.0	0.80				0.80				0.80
218T	Locomotive repair garage	0.14	1.0	0.14				0.14				0.14
218U	Materials handling and services building	0.30	1.0	0.30				0.30				0.30
218V	Waste water treatment building	0.20	1.10	0.22				0.22				0.22
218W	Miscellaneous coal handling structure	3.40	1.0	3.40				3.40				3.40
219	Stack structure	1.86	1.10	2.05				2.05				2.05
		42.48		47.50	0.15			47.35		0.15		47.35

Table 3.2 (continued)

Account	Account description	Electric plant capital cost ($ × 10⁶)	Scaling factor for cogeneration plant	Cogeneration plant capital cost ($ × 10⁶)	Capital cost allocation for cogeneration plant ($ × 10⁶)							
					Stancescu-Badea method					Other indirect methods		
					Exclusively electric (ee)	Totally thermal (tt)	Joint components (ee)	Joint components (et)	Joint components (tt)	Exclusively electric (ee)	Totally thermal (tt)	Joint components (et)
921	Home office services	12.82	1.15	14.74	2.95			11.79		2.95		11.79
922	Home office quality assurance											
923	Home office construction management	1.03	1.15	1.19	0.24			0.95		0.24		0.95
		13.85		15.93	3.19			12.74		3.19		12.74
931	Field office expenses	0.71	1.10	0.78	0.16			0.62		0.16		0.62
932	Field job supervision	7.78	1.10	8.56	1.71			6.85		1.71		6.85
933	Field quality assurance/ quality control	0.17	1.10	0.19	0.04			0.15		0.04		0.15
934	Field startup and testing	0.31	1.10	0.37	0.07			0.30		0.07		0.30
		8.95		9.90	1.98			7.92		1.98		7.92
	Total indirect costs	54.39		58.51	5.17	0	0	53.34	0	5.17	0	53.34
	Total base cost	318.12		335.00	80.27	0	35.81	217.50	1.42	76.08	4.19	254.73
	New accounts for cogeneration			(1.053)								
218J	Stacks for hot water boiler			1.00		1.00					1.00	
218K	Hot water boilers building			8.00		8.00					8.00	
225	Base heat exchanger system			4.00		4.00					4.00	
226	Hot water boiler plant system			35.00		35.00					35.00	
238	Hot water system			7.00		7.00					7.00	
				55.00		55.00					55.00	
		318.12		390.00	80.27	55.00	35.81	217.50	1.42	76.08	55.19	254.73

Table 3.2 (continued)

Account	Account description	Electric plant capital cost ($ × 10^6)	Scaling factor for cogeneration plant	Cogeneration plant capital cost ($ × 10^6)	Capital cost allocation for cogeneration plant ($ × 10^6)							
					Stancescu-Badea method					Other indirect methods		
					Exclusively electric (ee)	Totally thermal (tt)	Joint components (ee)	Joint components (et)	Joint components (tt)	Exclusively electric (ee)	Totally thermal (tt)	Joint components (et)
220A	Fossil steam supply system	56.04	1.12	62.76			25.10	37.66				62.76
221	Steam generating system (balance of plant)	1.55	1.12	1.74			0.70	1.04				1.74
222	Draft system	14.85	1.10	16.33				16.33				16.93
223	Ash and dust handling system	4.37	1.10	4.81				4.81				4.81
224	Fuel handling system	13.37	1.10	14.71				14.71				14.71
227	Instrumentation and controls	3.24	1.02	3.30			1.32	1.98				3.30
228	Boiler plant miscellaneous	2.97	1.03	3.06			1.22	1.84				3.06
		96.38		106.71			28.34	78.37				106.71
231	Turbine generator	34.94	1.12	39.13	39.13					34.94	4.19	
233	Condensing systems	9.88	0.70	6.92	6.92					6.92		
234	Feed heating system	11.93	1.10	13.13			5.25	7.88				13.39
235	Other turbine plant equipment	12.13	1.07	12.98			1.94	9.74	1.30			12.98
236	Instrumentation and controls	0.70	1.15	0.80			0.28	0.40	.12			0.80
237	Turbine plant miscellaneous	2.57	1.10	2.83				2.83				2.83
		72.14		75.79	46.05		7.47	20.85	1.42	41.86	4.19	29.74
241	Switchgear	3.75	1.0	3.75	3.75					3.75		
242	Stn. service equipment	3.64	1.0	3.64	2.43			1.21		2.43		1.21
243	Switchboards	0.66	1.0	0.65	0.43			0.22		0.43		0.22
244	Protective equipment	1.65	1.0	1.65	1.10			0.55		1.10		0.55
245	Electrical struc. and wiring conr.	8.21	1.0	8.21	5.47			2.74		5.47		2.74
246	Power and control wiring	9.60	1.0	9.60	6.40			3.20		6.40		3.20
		27.52		27.50	19.58			7.92		19.58		7.92

Table 3.2 (continued)

Account	Account description	Electric plant capital cost ($ × 10^6)	Scaling factor for cogeneration plant	Cogeneration plant capital cost ($ × 10^6)	Capital cost allocation for cogeneration plant ($ × 10^6): Stancescu-Badea method: Exclusively electric (ee)	Stancescu-Badea method: Totally thermal (tt)	Stancescu-Badea method: Joint components (ee)	Stancescu-Badea method: Joint components (et)	Stancescu-Badea method: Joint components (tt)	Other indirect methods: Exclusively electric (ee)	Other indirect methods: Totally thermal (tt)	Other indirect methods: Joint components (et)
251	Transportation and lift equipment	1.48	1.0	1.48				1.48				1.48
252	Air, water, and steam service system	5.50	1.0	5.50				5.50				5.50
253	Communications equipment	0.62	1.0	0.62				0.62				0.62
254	Furnishings and fixtures	0.83	1.0	0.83				0.83				0.83
255	Wastewater treatment equipment	1.24	1.0	1.24				1.24				1.24
		9.67		9.67				9.67				9.67
261	Structures — main condenser heat rejection system	1.36	0.70	0.95	0.95					0.95		0.95
262	Mechanical equipment	11.96	0.70	8.37	8.37					8.37		8.37
		13.33		9.32	9.32					9.32		9.32
	Total direct costs	263.73		276.49	75.10	0	35.81	164.16	1.42	70.91	4.19	201.39
	Construction services											
911	Temporary construction facility	11.47	1.0	11.47				11.47				11.47
912	Construction tools and equipment	8.94	1.0	8.94				8.94				8.94
913	Payroll insurance and taxes	10.74	1.10	11.81				11.81				11.81
914	Permits, insurance and local taxes	0.44	1.05	0.46				0.46				0.46
915	Transportation		1.0									
		31.59		32.68				32.68				32.68

Table 3.3. The physical method for allocating costs of a new cogeneraton plant

Costs	Capital cost ($\$ \times 10^6$)	Allocation keys		Annual generating cost ($\$ \times 10^6$)/y		Total ($\$ \times 10^6$)/y
		Electricity	Heat	Electricity	Heat	
Variable						
Fuel, A_B		0.576	0.424	37.07	27.29	64.36
O&M, $A_{O\&M}$		0.576	0.424	16.13	11.87	28.00
Total variable				53.20	39.16	92.36
Fixed						
Exclusively electric, A_A^{ee}	76.08	1.0	0	11.94	0	11.94
Totally heat, A_A^{tt}	59.19	0	1.0	0	9.29	9.29
Common, A_A^{et}	254.73	0.576	0.424	23.04	15.96	40.00
Total fixed	390.00			34.98	26.25	61.23
Total				88.18	64.41	153.59
Average cogeneration unit cost				13.75 (mills/kWh)	2.454 ($/GJ)	

Table 3.4. The Leung method for allocating annual costs of a new cogeneration plant

Kinds of costs	Costs ($\$ \times 10^6$) Electricity	Heat	Total
Variable			
Fuel, A_B	51.44	12.92	64.36
Other	22.38	5.62	28.00
Fixed			
Capital	48.48	12.75	61.23
Total	122.3	31.29	153.59
Average unit cost	19.07 (mills/kWh)	1.174 ($/GJ)	

Table 3.5. Annual fuel cost allocation by the Leung method

$$\text{Electricity unit cost} = \frac{0.86}{10^6 \times 0.85} \times 7931^{a}$$

$$= \frac{8024}{10^6} = 8.024 \text{ mills/kWh}$$

$$\text{Total fuel cost} = \$64.36 \times 10^6$$

$$\text{Electricity cost allocation} = 6.411 \times 10^9 \times \frac{8.024}{1000} = \$51.44 \times 10^6$$

$$\text{Fuel cost to heat} = (64.36 - 51.44) = \$12.92 \times 10^6$$

$$\text{Electricity/heat} = 51.44/12.92 = 79.9\%/20.1\%$$

[a] From Table 4 of *Preliminary Study of Large Cogeneration/District Heating Power Plants*, UE&C-DOE-780301, COO-2477-015, prepared by UE&C Inc., March 1978.

based upon the differential cost relative to a single-purpose plant of equal electric output was used to allocate the fixed costs (Table 3.6). The resulting unit costs were 19.07 mills/kWh for electricity and \$1.174/GJ for heat.

3.2.4 Margen method

Using the electric rate for separate generation (19.06 mills/kWh), the annual operating costs for the generation of heat was determined by subtraction. From this, the cost of heat was computed to be \$1.177/GJ (Table 3.7).

3.2.5 Equal discount method

In this method, separate operating costs for a single-purpose power plant and a heating plant were used to determine the benefits (savings) obtained by the combined generation of the same amounts of energy (electricity and heat) in a dual-purpose plant. These savings were determined to be 14.9% of the total separate costs. Equal percentages of the cogeneration savings were allocated to each form of energy and the unit costs for electricity and heat were computed at 16.22 mills/kWh and \$1.861/GJ respectively (Table 3.8).

3.2.6 Separate generation

Using capital costs for the single-purpose power plant,[3] the total costs were calculated by the equal discount method (Table 3.8). The electric rate was computed to 19.06 mills/kWh.

The capital cost of the separate heating plant was assumed to be $\$125 \times 10^6$. The fuel cost, O&M cost, and fixed costs were determined from the total; the unit cost for heat was calculated to be \$2.19/GJ (Table 3.9).

Table 3.6. Fixed costs allocation by the Leung method

Step	Cost component	Electricity cost ($\$ \times 10^6$)	Heat cost ($\$ \times 10^6$)
A	Joint facility capital cost		390.0
B	Alternative construction cost for single-purpose facility	325	150.0[a]
C	Justifiable investment cost for single-purpose facility	318.1	125.0[a]
D	Smaller of B and C	318.1	125.0
E	Exclusive-use systems/components	51.83[b]	55.0[c]
F	(D - E)	266.27	70.0
G	Weighted fraction	0.792	0.208
H	Capital cost allocation	308.8	81.2
	Annual cost	48.48	12.75

[a] Assumed.

[b] Exclusive use (electricity) = 6.92 + 27.52 + 9.32 + 8.07 = 51.83 $\times 10^6$.

[c] Exclusive use (heat) = \$55 $\times 10^6$.

Table 3.7. Allocation of annual costs ($\$ \times 10^6$) of heat by the Margen method

Total kWh	$= 6.411 \times 10^9$
Rate of electricity	= 19.06 mills/kWh (assumed)
Total annual cost	$= 6.411 \times 10^3 \times \frac{19.06}{1000}$
Total operating cost of electricity (A^e)	= 122.22
Heat and power plant operating costs (A_{HPP})	= 153.59
Total operating cost of heat ($A^t = A_{HPP} - A^e$)	$= 153.59 \times 122.22$
	= 31.37
Total GJ	= 26.65
Cost of heat per GJ	$= \frac{31.37 \times 10^6}{26.65 \times 10^6}$
	= 1.177/GJ

Table 3.8. Annual costs ($\$ \times 10^6$) of alternative generation calculated by the equal discount method

809 MW of electricity in a condensing power station	= 122.216
Calculated alternative of generating 1983 MW(t) of heat in a district heating station	= 58.28
Sum of alternative cost	= 180.496
Actual costs of electric and heat plant	= 153.59
Combined generation savings:	
Absolute	= 29.906
Relative	$= \frac{26.906}{180.496} = 14.9\%$
Cost allocated to electricity account	= 122.216 (1 - 0.149)
	= 104.0
Cost allocated to heat account	= 58.28 (1 - 0.149)
	= 49.59
Average cogeneration unit cost for electricity (mills/kWh)	= 16.22
Average cogeneration unit cost for heat ($/GJ)	= 1.861

Table 3.9. Annual costs of electricity and heat generation calculated by the separate generation method

Electric plant[a]	
Annual output =	6.411×10^9 kWh/y
Electric unit cost =	\$0.86/GJ × 1/0.85 × 9000 = 9.106 mills/kWh
Fixed cost (capital cost) =	$0.157 \times 318.12 = \$49.945 \times 10^6$
Variable costs:	
Fuel =	$6.411 \times 10^9 \times 3413 \times 0.86/10^6 = \$52.271 \times 10^6$
O&M =	$6.411 \times 10^9 \times 0.312 = \$20.000 \times 10^6$
Total annual cost =	$\$122.216 \times 10^6$
Rate, mills/kWh =	$\dfrac{122.216 \times 10^6}{6.411 \times 10^9} = 19.064$ mills/kWh
Heating plant[b]	
Btu/y =	26.65×10^6 GJ
Hot water generator efficiency =	0.80 (assumed)
Fuel cost =	\$0.86/GJ
Heat plant fuel cost =	$0.86/0.8 \times 26.65 \times 10^6 = \$28.65 \times 10^6$
Heat plant capital cost =	$\$19.63 \times 10^6$
Heat plant O&M cost at \$5/kW/y for an output of approximately 2000 MW(t)	
Total O&M/y =	$5 \times 2.0 \times 10^6$
	$= (\$10.0 \times 10^6)/y$
Variable costs:	
Fuel =	$\$28.65 \times 10^6$
O&M =	$\$10.00 \times 10^6$
Fixed costs =	$\$19.63 \times 10^6$
	$= \$58.23 \times 10^6$
Rate (\$/GJ) =	$\dfrac{58.28 \times 10^6}{26.65 \times 10^6}$
	= \$2.19/GJ

[a]With a generating capacity of 809.643 MW(e).

[b]With a production capacity of 1971.6 MW(t).

4. ALLOCATION OF ANNUAL COSTS FOR HIGH BRIDGE COGENERATION STATION

4.1 Overall Concept for Retrofitting High Bridge Station for Cogeneration

The UE&C study examines the suitability of the High Bridge Station for retrofitting to cogeneration. Flexibility, reliability, and low investment and operating costs have been compared and evaluated. The forecast peak heat district heating loads for 1985 and 2000 have been estimated and appropriate recommendations made.

In 1985, the peak district heating load for the High Bridge Station is forecast to be 283 MW(t). This load will increase 5.3 MW(t) annually until the year 2000, when it is projected to be 363 MW(t). The supply-water temperature will vary according to the outdoor temperature. At the peak district heating load (which corresponds to minimum ambient temperature), the supply temperature will be 422 K (300°F) and the return temperature 338.6 K (150°F). As the ambient temperature increases (i.e., as the heat load decreases), the supply temperature will decrease directly until a minimum of 355 K (180°F) is reached. Return temperature will also decrease as the flow and the supply temperature decrease.

Unit 3 will be converted to a back-pressure operation with no auxiliary cooler and supplied with steam from boilers 9 and 10. This unit will meet the continuous district heating demand and as much of the variable demand as it can. Without an auxiliary cooler, the electrical output of unit 3 will depend upon the district heating load.

The water will then pass through units 5 and 6 exchangers (cross-over supplied only) in parallel where the water will be further heated, if required by system load, or to meet the temperature profile previously established (Fig. 4.1). (This profile can be varied, if operating experience dictates, by a relatively simple adjustment of the controllers.)

Also in parallel with units 5 and 6 exchangers is an auxiliary exchanger, fed with the excess steam (in excess of turbine 3 requirements), which will be available on demand from boilers 9 and 10. Normally, this auxiliary exchanger will not be in service. However, it is necessary to provide adequate backup capacity in case either unit 5 or 6 is lost.

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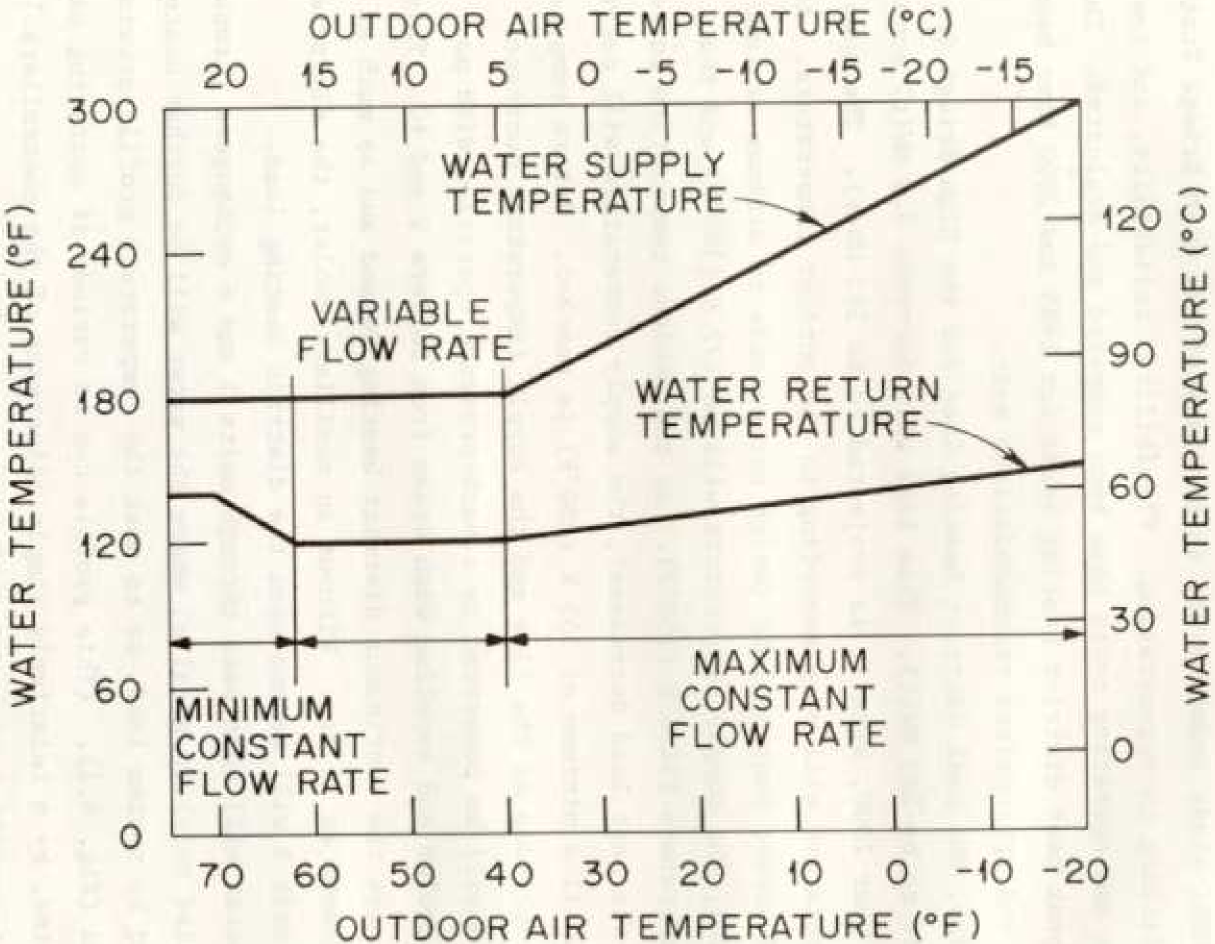

Fig. 4.1. Water supply and return temperature profiles.

The total capacity available from the High Bridge Station with all equipment in service will be at least 1.85×10^3 GJ/h [542 MW(t)]. Assuming an outage of the largest single unit (unit 6), the available capacity will be 1.22×10^3 GJ/h [357 MW(t)]. In 1985, this capacity will provide a margin of 74 MW(t) above peak demand. By the year 2000 this margin may be 6 MW(t) short, but additional cogeneration units will probably be in service, providing additional backup.

In an emergency, station heat production can be increased by manually reducing the steam flow to the unit 3 turbine, thereby making more steam available to the auxiliary exchanger. The available capacity will then depend on the final size of the auxiliary exchanger, and the capability of the unit 4 deaerator to handle the drains.

Similarly, if the situation is severe enough, boilers 9 and 10 can produce approximately 20% more steam by burning 100% Illinois coal, which has a higher heat content than the low-sulfur blend being used. Of course, this use requires a waiver of SO_2 emission limits.

Use of either or both of these emergency measures should make it possible to maintain the full district heating load in the event of most combinations of two failures. This assurance will provide adequate reliability.

When present district heating customers change from steam to hot water, the Third Street Station will no longer be required. This plant could be converted to be an alternate supplier of hot water, although contemplated loads do not require this conversion. Sufficient reserve capacity is included in the plans for the High Bridge Station to take care of equipment outages. However, the equipment at the Third Street plant should be placed in long-term storage to be available if load growth is greater than anticipated, or if some of the High Bridge equipment should become unserviceable. Each of the three coal-fired boilers at the Third Street plant can produce 41 MW(t).

Cogeneration has four advantages:

1. <u>Flexibility</u>. Various combinations of equipment can be used to meet the maximum district heating load. Any desired supply temperature profile is available, depending upon equipment selection and control

set points. If turbine 3 becomes unserviceable, boilers 9 and 10 are still available for heat only operation. Rapid load fluctuations can be accommodated, since it will not be necessary to spend hours warming cold equipment. Conversion of the Third Street plant can provide an additional 123 MW(t) if the district heating load is greater than expected, or if boilers 9 and 10 become unserviceable.

2. Minimal investment cost. No major items of equipment (boilers, turbines, fuel systems, or ash systems) need be bought. No new sites need be bought.

3. Reduced operating cost. Normally, the entire district heating load is carried by cogeneration equipment. Coal is the only fuel used (except for ignition).

4. Adequate reliability. Adequate backup is provided. No gas or fuel oil is used except for ignition. The Third Street Station is available for conversion if required.

4.2 Allocation of Cogeneration Costs

Costs for the High Bridge plant have been allocated using only the two direct allocation methods (Margen and equal discount). No indirect allocation methods were used because they require data on capital costs for various plant equipment (Sect. 2.3), and only the total book value (original value minus depreciation) of the High Bridge Station was available to UE&C for this study.

4.2.1 Determination of annual operating costs

Cogeneration plant. The effect of the operating capacity on the unit costs for heat and electricity was studied using six possible values (50, 60, 70, 80, 90, and 100%) to determine the electricity output of the retrofitted station and the variable costs.

Because unit 3 will be converted to a back-pressure turbine, it was assumed to carry the base heat load (Fig. 4.2). Its electrical output varies directly with the turbine steam flow as a function of the heat load. When the heat load exceeds the capacity of unit 3, the excess was assumed to be equally carried between units 5 and 6. The electricity and heat supplied by High Bridge units 3, 5, and 6 were calculated (Fig. 4.3-4.5) according to the scenario discussed in Sect. 4.1.

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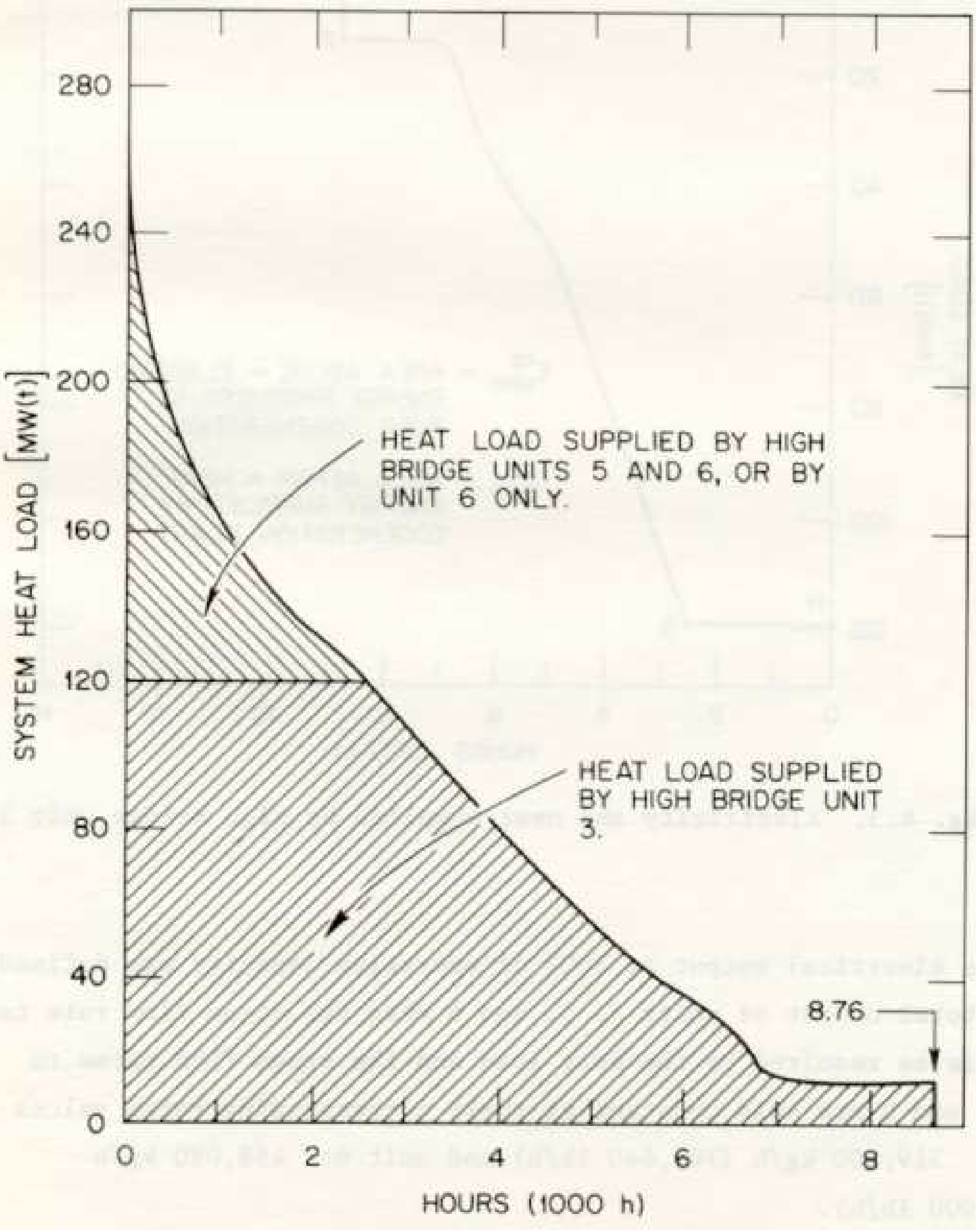

Fig. 4.2. Predicted system heat load for 1985.

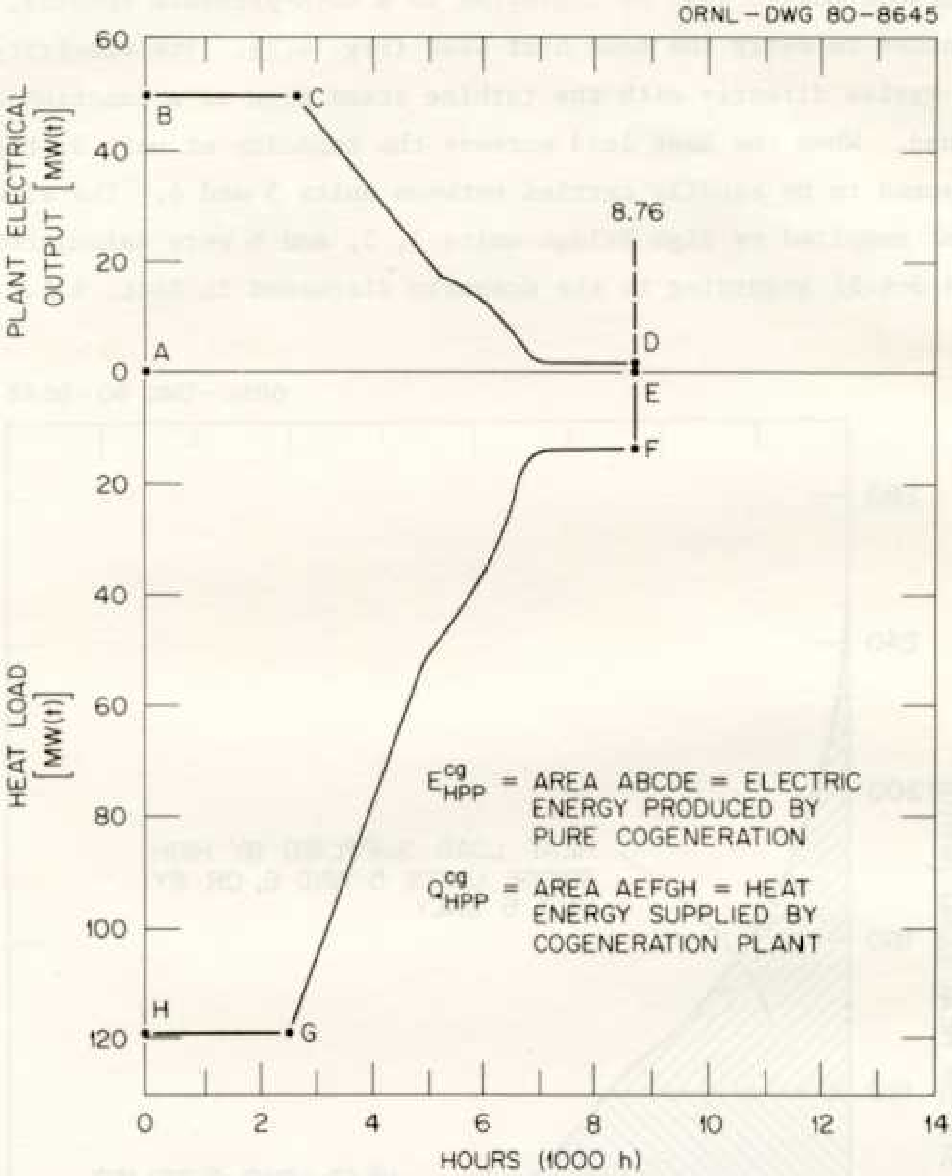

Fig. 4.3. Electricity and heat supplied by High Bridge unit 3.

The electrical output at 100% of operating capacity was defined as the total output of units 3, 5, and 6 when the steam flow rate to unit 3 is as required by the heat load and the steam flow rates to units 5 and 6 are held constant at their corresponding rated values — unit 5: 319,000 kg/h (702,640 lb/h) and unit 6: 468,080 kg/h (1,031,000 lb/h).

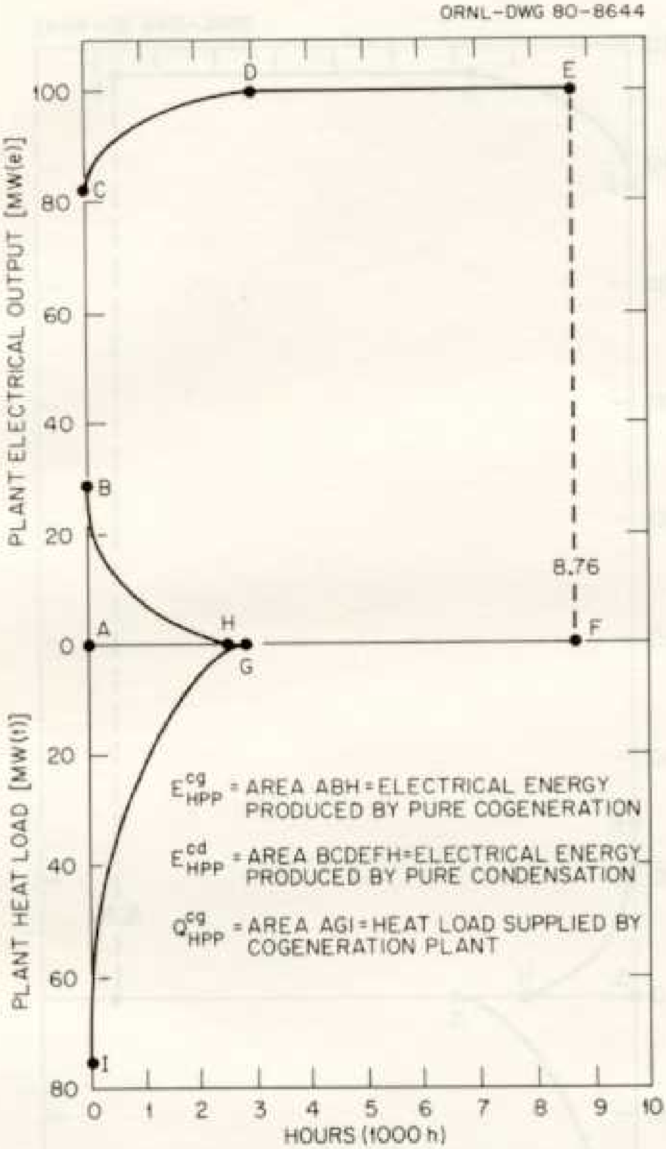

Fig. 4.4. Electricity and heat supplied by High Bridge unit 5.

Steam would be extracted from units 5 and 6 as needed, and any steam not extracted for district heating purposes would be passed through low-pressure turbines to produce electricity by condensation only.

Electricity outputs of the retrofitted units corresponding to the other five operating capacities (50, 60, 70, 80, and 90%) were assumed to be proportional to the output produced at 100% operating capacity.

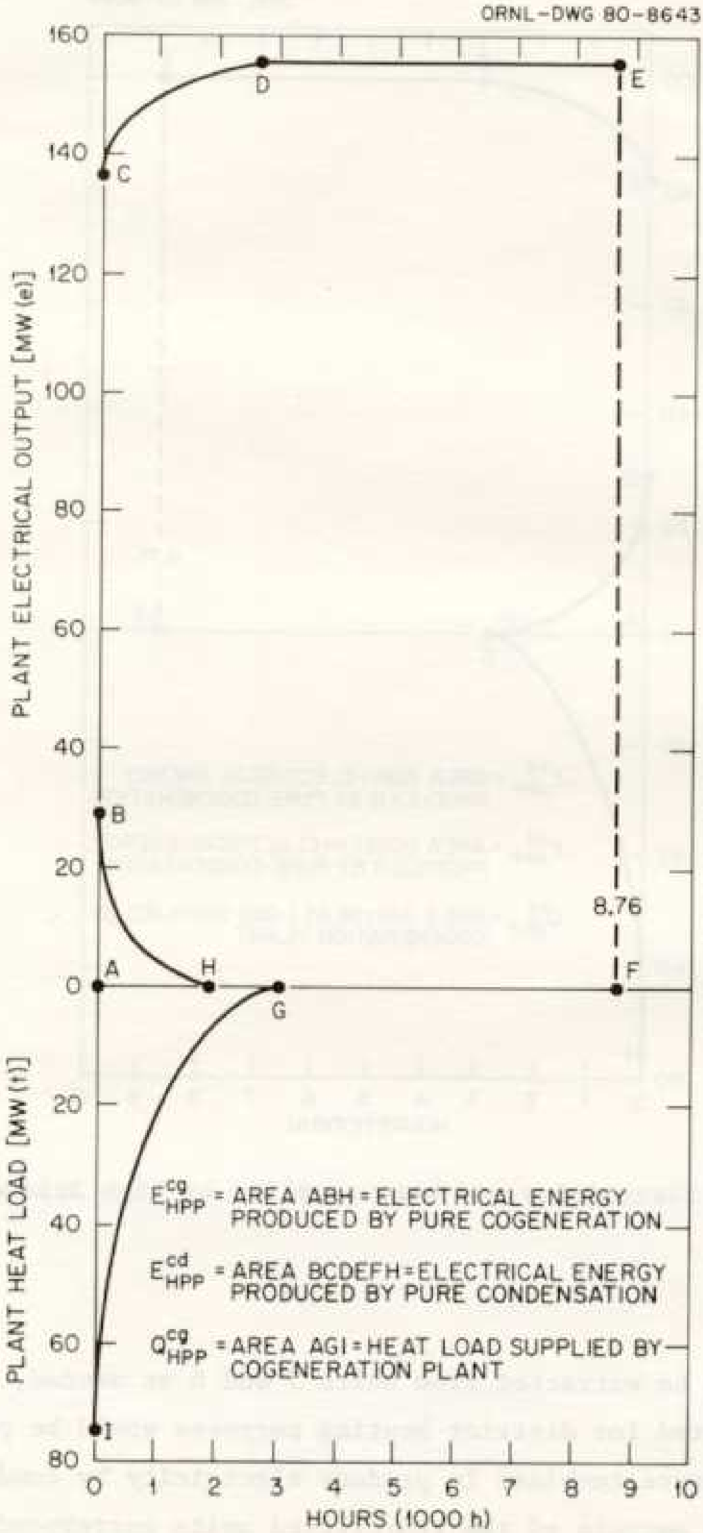

Fig. 4.5. Electricity and heat supplied by High Bridge unit 6.

The fixed costs were the sum of the capital cost of conversion and the 1985 book value (original minus depreciation) of existing equipment which were amortized according to previously defined economic criteria. The capital cost of conversion was estimated (as of July 1978) at $\$9 \times 10^6$.

The fuel cost was assumed to be \$0.86/GJ, and the boiler efficiency was assumed as 85%. All other economic factors for evaluating the variable costs were as provided by the Northern States Power Company.

The annual cogeneration costs obtained and the amounts of energy generated vary for each operating capacity considered (Table 4.1).

Separate generation plants. Annual operating costs were also calculated for an electric generation station (High Bridge units 3, 4, and 5) and a heating plant of equivalent energy production as the retrofitted plant (Table 4.2). The annual costs for the electric plant were determined for the same six operating capacities used for the cogeneration plant. The heating plant costs were estimated for one annual heat output only since the electrical operating capacity does not affect the heat production. The unit production costs were also calculated (Table 4.3).

Table 4.1. Energy output[a] and annual costs for cogeneration — High Bridge retrofit study, units 3, 5, and 6

Operating capacity (%)	Electricity (10^9 kWh/y)	Annual costs[b] ($\$ \times 10^6$/y)		
		Fuel	Operation and maintenance	Total
50	1.230	11.30	5.34	23.04
60	1.476	13.32	5.60	25.32
70	1.722	15.33	5.87	27.61
80	1.968	17.35	6.14	29.89
90	2.214	19.37	6.41	32.18
100	2.460	21.37	6.68	34.45

[a]Heat (Q^a) = 2.452×10^3 GJ/y (2.452×10^{12} Btu/y).

[b]Fixed annual costs (A_A) = ($\$6.40 \times 10^6$)/y for all operating capacities.

Table 4.2. Electricity production (10^8 kWh/y) for separate generation

Operating capacity (%)	Unit[a] 5	Unit[a] 6	Total
50	3.855	6.005	12.30
60	4.811	7.516	14.76
70	5.75	9.03	17.22
80	6.697	10.543	19.68
90	7.648	12.062	22.14
100	8.613	13.542	24.60

[a]Unit 3 = 2.443 × 10^8 kWh/y for all operating capacities.

Table 4.3. Annual costs ($ × 10^6) for separate generation

Operating capacity (%)	Fuel	Operation and maintenance	Total	Unit cost
		Electric plant[a]		
50	10.45	5.08	20.52	16.68
60	12.47	5.33	22.79	15.44
70	14.37	5.58	25.07	14.56
80	16.42	5.84	27.35	13.90
90	18.47	6.09	29.64	13.39
100	20.53[b]	6.34	31.90	12.97[c]
		Heating plant		
	2.506	0.4873	4.954	$2.02/GJ

[a]Net heat rates (MJ/kWh) are 11.6 (unit 3), 10.2 (unit 5), and 9.84 (unit 6). In English units (Btu/kWh) these are 11,000 (unit 3), 9700 (unit 5), and 9331 (unit 6).

[b]Calculated from (31.90 × 10^6 × 10^3)/(2.46 × 10^9).

[c]Calculated from (2.443 × 10^8 × 11000 × 8.61 × 10^8 × 9700) + (13.542 × 9331)0.86/(9.9 × 10^5).

4.2.2 Calculation of unit costs for cogeneration

Unit costs for electricity and heat were calculated using both the Margen and equal discount methods (Table 4.4 and 4.5). The results obtained for the unit costs (Table 1.2) allow a comparison of the two allocation methods used as well as a comparison of cogeneration unit costs versus separate generation unit costs (Fig. 1.2).

Table 4.4. Allocation of costs for the High Bridge cogeneration plant by the Margen method

Operating capacity	Unit cost		Allocated to account ($\$ \times 10^6$/y)	
	Electricity[a] (mills/kWh)	Heat[b] ($/GJ)	Electricity[c]	Heat[d]
50	16.68	1.03	20.52	2.52
60	15.44	1.03	22.79	2.53
70	14.56	1.04	25.05	2.54
80	13.90	1.04	27.35	2.54
90	13.39	1.04	29.64	2.54
100	12.97	1.04	31.90	2.55

[a] Equals the established cost of electricity by separate generation.

[b] Equals annual cost allocated to heat account divided by annual heat output.

[c] Equals product of electricity unit cost and the electricity output.

[d] Equals total annual cost minus the annual cost for electricity generation.

Table 4.5. Allocation of annual costs for the High Bridge Cogeneration Station by the equal discount method

Operating capacity	Separate generation[a] ($\$ \times 10^6$)	Cogeneration plant ($\$ \times 10^6$)	Cogeneration savings		Allocated to account ($\$ \times 10^6$)		Unit cost	
			Absolute[b] ($\$ \times 10^6$)	Relative[c] (%)	Electricity[d]	Heat[e]	Electricity[f] (mills/kWh)	Heat[g] ($/GJ)
50	25.474	23.04	2.434	9.56	18.56	4.48	15.09	1.83
60	27.744	25.32	2.424	8.74	20.80	4.52	14.09	1.84
70	30.024	27.61	2.414	8.04	23.05	4.56	13.39	1.86
80	32.304	29.89	2.414	7.47	25.31	4.58	12.86	1.87
90	34.594	32.18	2.414	6.98	27.57	4.61	12.45	1.88
100	36.854	34.45	2.404	6.52	29.82	4.63	12.12	1.89

[a]Sum of electric generating station costs and heating plant costs.

[b]Equals (absolute cogeneration savings × 100)/(cost of separate cogeneration).

[c]Annual cost of separate generation minus actual cost of the cogeneration plant.

[d]Product of annual cost of electric generating station and (1 - % savings)(10^{-2}).

[e]Equals (annual cost of heating plant × 10^{-2})(1 - % savings).

[f]Equals (cost allocated to electricity account × 10^3)/(2.46 × 10^9).

[g]Equals (cost allocated to heat account × 10^6)/(2.452 × 10^{12}).

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APPENDIX A

CALCULATION PROCEDURE FOR DETERMINING

THE POWER AND ENERGY KEYS

APPENDIX A

CALCULATION PROCEDURE FOR DETERMINING THE POWER AND ENERGY KEYS

A.1 Power Keys for Allocating Fixed Costs

To establish the "power keys" X_e and X_t for allocating the fixed costs (ΔA_{Ac}^{et}) between electricity and heat, it is first necessary to determine two characteristic hourly heat flows; for electricity ($q_{e,c}$) and heat generation ($q_{t,c}$). The procedure employed depends on whether the cogeneration turbines employed are condensing tail or back pressure turbines. The following discussion assumes for simplicity that the cogeneration plant is equipped with only one turbine of a given type.

Case 1: Condensing Tail Turbines

Using the symbols given in Figures A-1, A-2 and A-3, the electric energy balance is given by:

$$E_{HPP} = P_{HPP}^{n} \cdot h_e = P_{cg}^{n} \cdot h_t + P_{cd}^{min} \cdot h_o + P_{cd}^{x,n} \cdot h_x \text{ (MWhr/yr)}$$

where:

E_{HPP} = electric energy produced annually (MWhr/yr)

P_{HPP}^{n} = nominal power (at 100% heat output) of cogeneration plant (MWe)

P_{cg}^{n} = nominal power by pure cogeneration (MWe)

P_{cd}^{min} = minimum power by pure condensation (MWe)

$P_{cd}^{x,n}$ = nominal power by pure condensation in addition to P_{cd}^{min} (MWe)

h_e, h_t, h_o, and h_x = durations of utilization of P_{HPP}^{n}, P_{cg}^{n}, P_{cd}^{min}, and $P_{cd}^{x,n}$, respectively.

Since $h_o = h_t + h_x$ (hours/yr), then

$$h_x = \frac{P_{HPP}^{n} \cdot h_c - P_{cg}^{n} \cdot h_t - P_{cd}^{min} \cdot h_t}{P_{cd}^{min} + P_{cd}^{x,n}}$$

The nominal hourly heat flow (q_{peak}^{n}) is zero when no heat is supplied directly from the main steam lines (live steam) to the district heating exchangers.

Assuming $q_{peak}^{n} = 0$, the total nominal hourly heat flow, K^{n}, is given by:

$$K^{n} = q_{cg}^{n} + q_{e}^{n} + K_{c}^{min} = T_{i}^{n} \text{ (MWt)}$$

where:

q_{cg}^{n} = nominal hourly heat flow for heating purposes

q_{e}^{n} = fraction of the nominal hourly heat flow O^{n} used within the turbine for generating P_{cg}^{n} by pure cogeneration, i.e., $q_{e}^{n} = O^{n} - q_{cg}^{n}$ (MWt)

K_{c}^{min} = minimum hourly heat flow for minimum condensation measured at the turbine inlet (MWt)

The total heat flow (K^{n}) is divided into two characteristic hourly heat flows:

$$K^{n} = q_{e,c} + q_{t,c} \text{ (MWt)}$$

where:

$q_{e,c}$ = the characteristic hourly heat flow allocated for the electric energy generation

$q_{t,c}$ = the characteristic heat flow allocated for the thermal energy generation, for the conditions of the year considered.

The characteristic hourly heat flows ($q_{e,c}$ and $q_{t,c}$) must reflect the measure in which the nominal hourly heat flow (O^{n}) was used for generating each of the two forms of energy. This objective is achieved by employing the corresponding durations of utilization as follows:

$$q_{e,c} = K_{c}^{min} + \frac{h_t}{h_t + h_x} q_{e}^{n} + \frac{h_x}{h_t + h_x} K_{x}^{n} \text{ (MWt)}$$

and

$$q_{t,c} = q_{cg}^{\ n} \frac{h_t}{h_t + h_x} + O_x^{\ n} \frac{h_x}{h_t + h_x} \text{ (MWt)}$$

Since $$O_x^{\ n} = O^n - K_x^{\ n} = (q_{cg}^{\ n} + q_e^{\ n}) - K_x^{\ n} \text{ (MWt)}$$

one obtains, finally,

$$q_{t,c} = q_{cg}^{\ n} - \frac{h_x}{h_t + h_x} (K_x^{\ n} - q_e^{\ n}) \text{ (MWt)}$$

Using $q_{e,c}$ and $q_{t,c}$ the two "power keys" X_e and X_t for allocating the fixed costs (O_{Ac}^{et}) are:

$$X_e = \frac{q_{e,c}}{K^n}$$

and $$X_t = \frac{q_{t,c}}{K^n}$$

If $K^n = T_i^{\ n} + q_{peak}^{\ n}$, where $q_{peak}^{\ n} \neq 0$ that is, when the peak heat load is met with live steam passing through a pressure/temperature reducing installation, the characteristic hourly heat flows ($q_{e,c}$ and $q_{t,c}$) are determined as follows:

$$q_{e,c} = (K_c^{\ min} + \frac{h_t}{h_t + h_x} q_e^{\ n} + \frac{h_x}{h_t + h_x} K_x^{\ n})\ 1 + (1 - \frac{h_p}{h_t + h_x})$$

$$\frac{q_{peak}^{\ n}}{q_{cg}^{\ n} + q_e^{\ n} + K_e^{\ min}} \text{ (MWt)}$$

and

$$q_{t,c} = q_{cg}^{\ n} \frac{h_x}{h_t + h_x} (K_x^{\ n} - q_e^{\ n})\ 1 + (1 - \frac{h_x}{h_t + h_x} \frac{q_{peak}^{\ n}}{q_{cg}^{\ n} + q_e^{\ n} + K_c^{\ min}}$$

$$+ \frac{h_p}{h_t + h_x} q_{peak}^{\ n} \text{ (MWt)}$$

where:

h_p = the duration of utilization of the nominal hourly peaking heat flow, q_{peak}^n.

Setting
$$p = \frac{q_{peak}^n}{q_{cg}^n + q_e^n + K_c^{min}}$$

one obtains:

$$X_e = X_e \left(1 - \frac{h_p}{h_t + h_x} p\right)$$

$$X_t = X_t + \frac{h_p}{h_t + h_x} \cdot p \cdot X_e$$

$$q_{t,c} = q_{cg}^n \, 1 + \left(1 - \frac{h_p}{h_t}\right) \frac{q_{peak}^n}{q_{cg}^n + q_e^n} + \frac{h_p}{h_t} q_{peak}^n \text{ (MWt)}$$

Similarly, the power keys are:

$$X_e = X_e \left(1 - \frac{h_p}{h_t} p\right)$$

and
$$X_t = X_t + \frac{h_p}{h_t} \cdot p \cdot X_e$$

where
$$p = \frac{q_{peak}^n}{q_{cg}^n + q_e^n + q_{peak}^n}$$

A.2 Energy Keys for Allocating Variable Costs

The variable annual operating costs (O_B and O_R) are allocated based upon the fraction of the total fuel consumption corresponding to the generation of each form of energy. Thus, the energy keys (Y_e and Y_b), are:

$$Y_e = \frac{B_{HPP}^e}{B_{HPP}}$$

$$Y_t = \frac{B_{HPP}^t}{B_{HPP}}$$

where the corresponding fuel consumptions (B_{HPP}^{e} and B_{HPP}^{t}) are calculated as in the physical method.

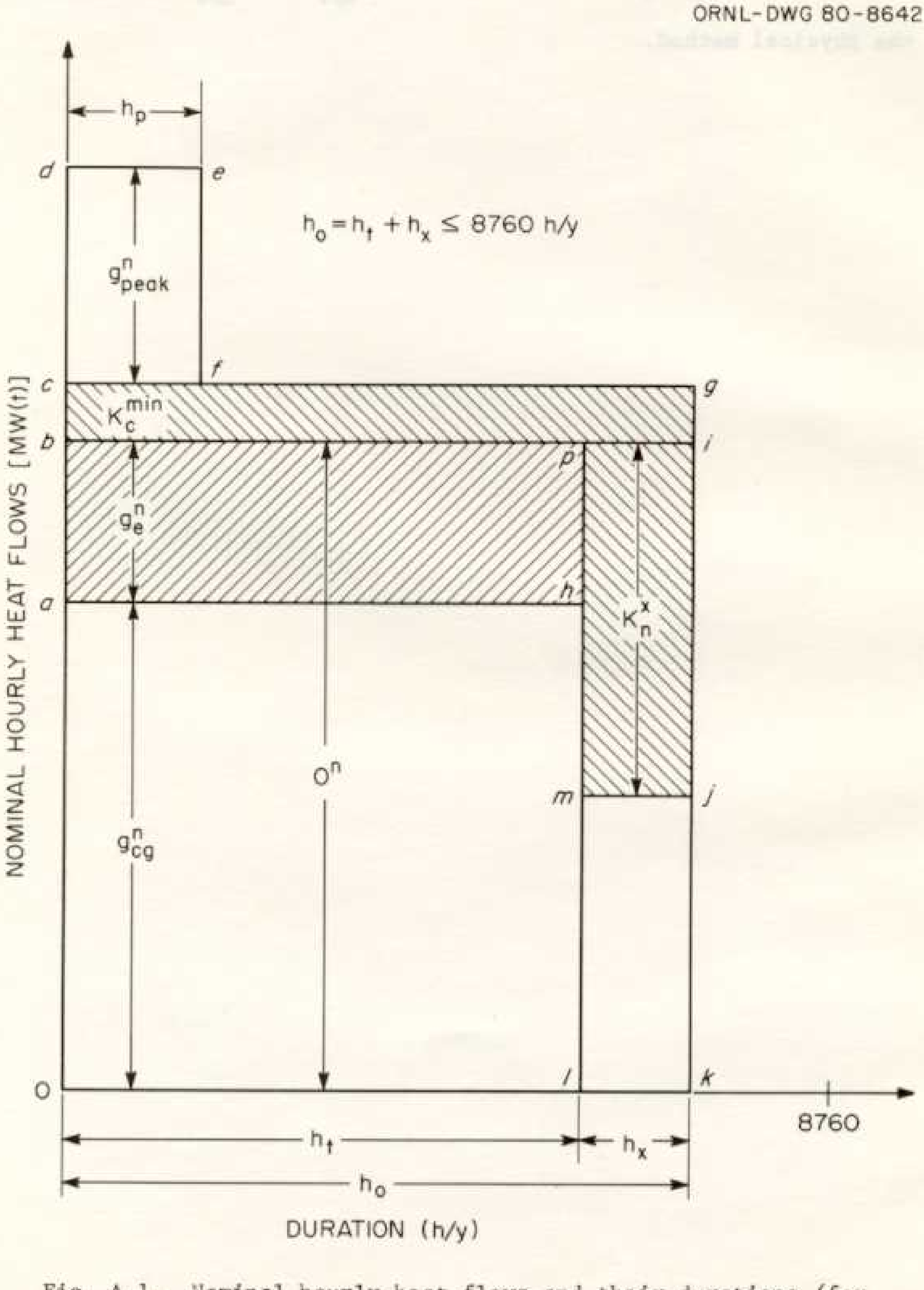

Fig. A.1. Nominal hourly heat flows and their durations (for condensing-tail turbines).

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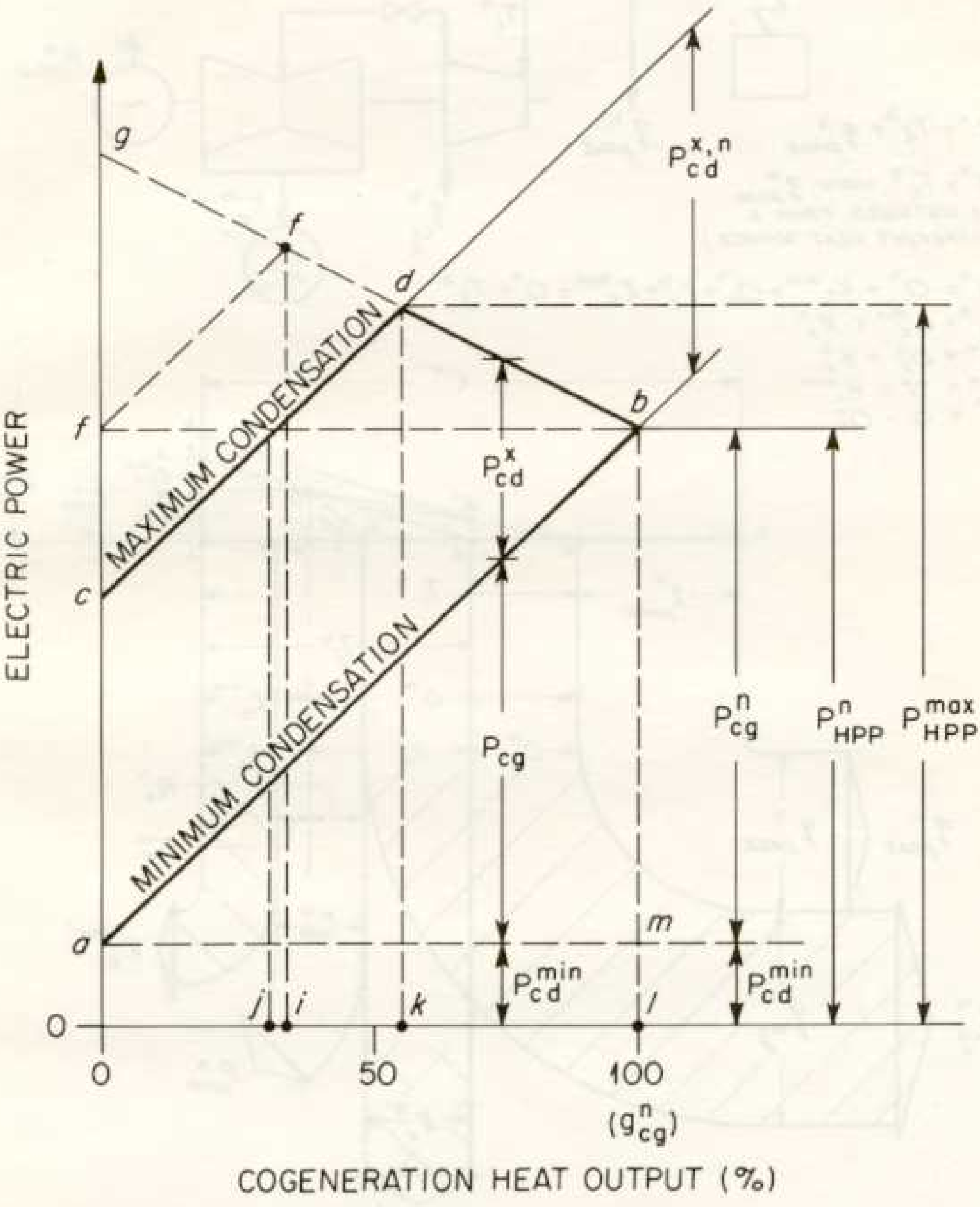

Fig. A.2. Electricity and heat output of a condensing-tail turbine.

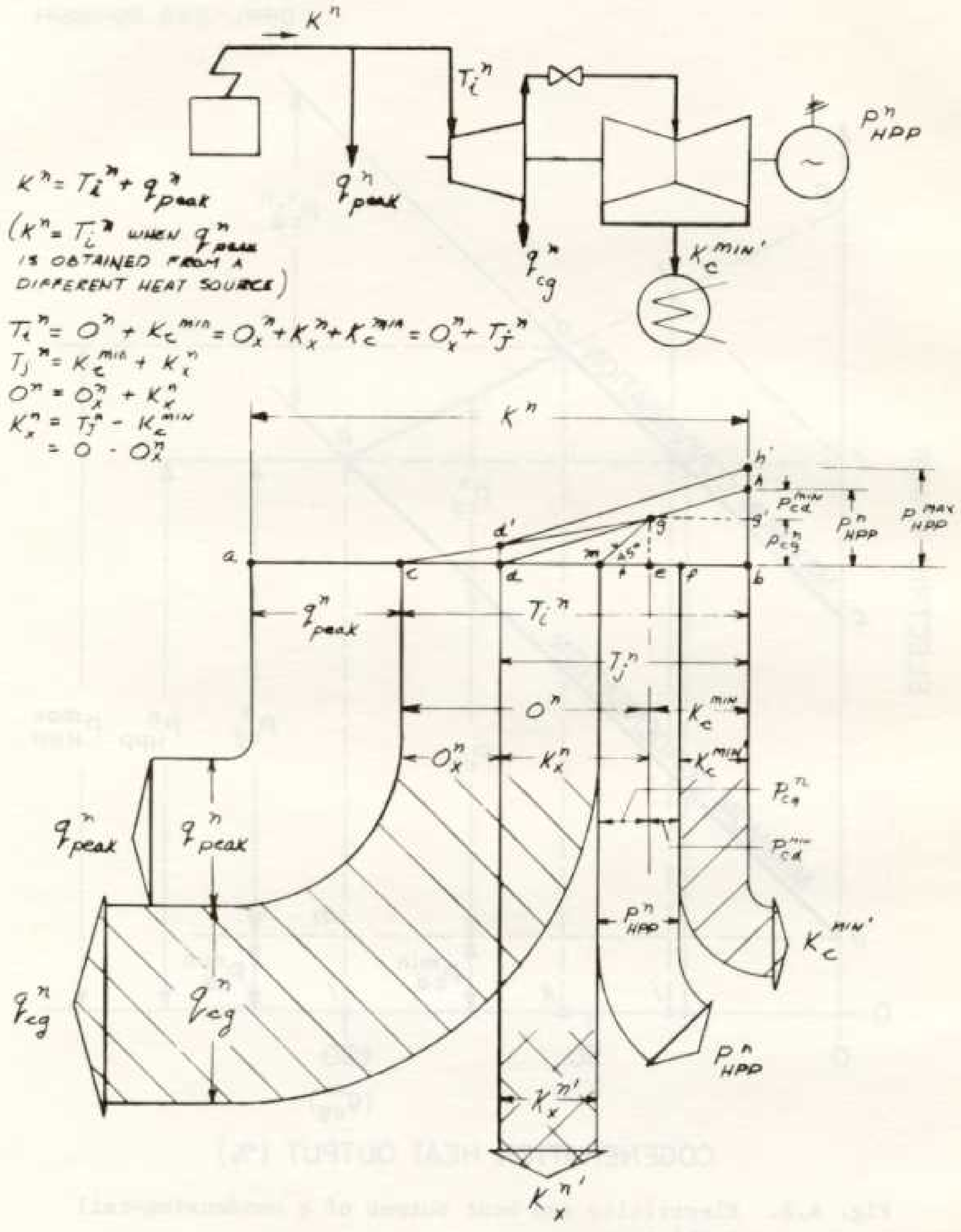

Fig. A.3. The internal structure of a cogeneration plant with a condensing-tail turbine.

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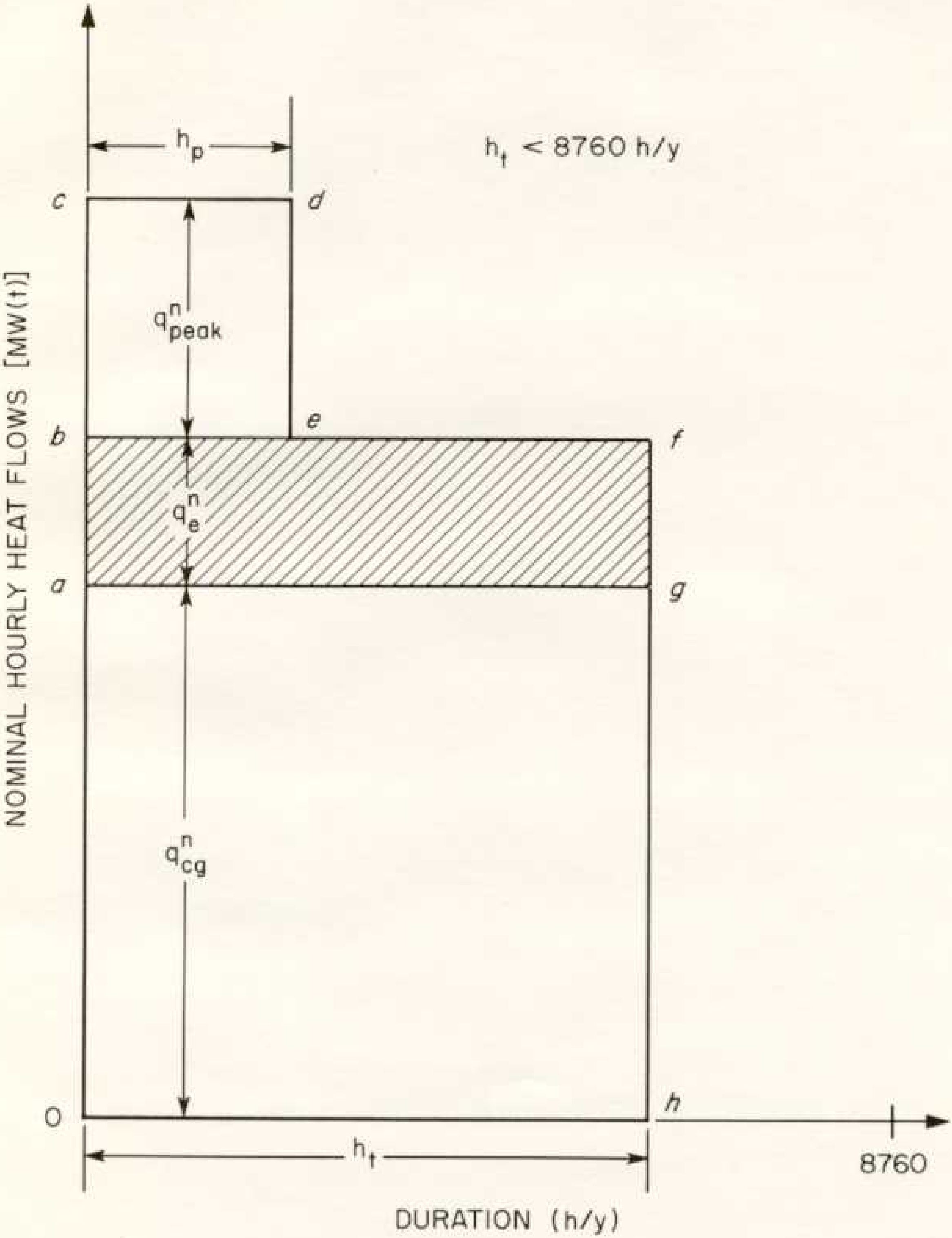

Fig. A.4. Nominal hourly heat flows and their durations (for back-pressure turbine).

APPENDIX B

CALCULATION OF ALLOCATION KEYS

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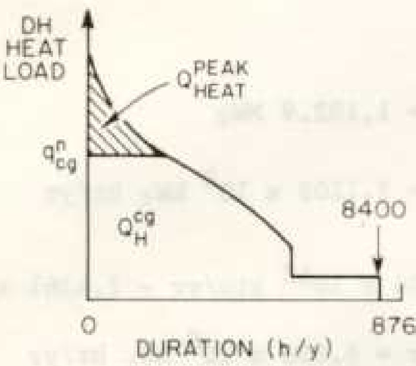

Fig. B.1.

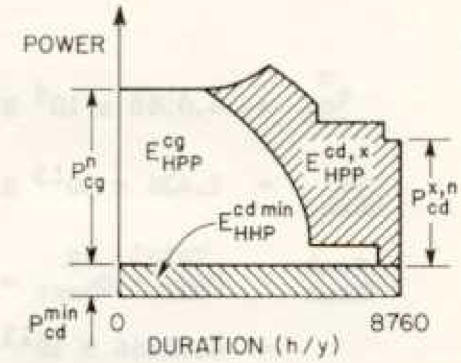

Fig. B.2.

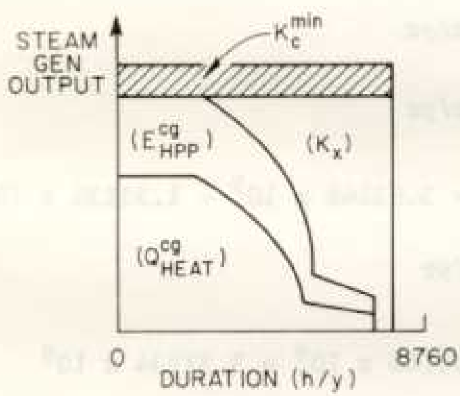

Fig. B.3.

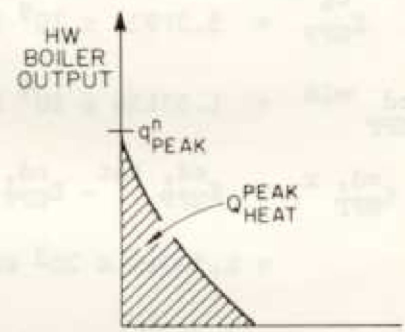

Fig. B.4.

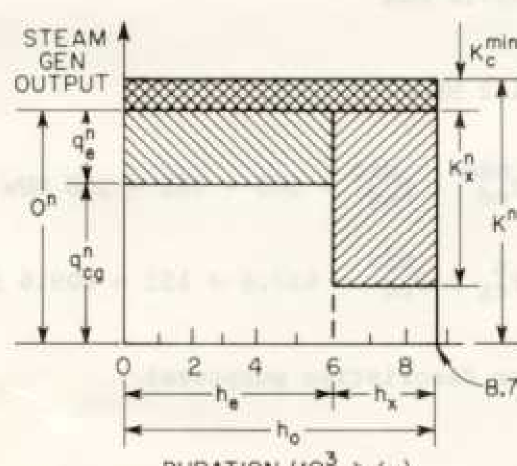

Fig. B.5.

NUMERICAL VALUES

Fig. B-1

$$q_{cg}^{n} = 4.0368 \times 10^{9} \text{ Btu/hr} = 1{,}182.9 \text{ MW}_t$$

$$Q_{heat}^{cg} = 2.426 \times 10^{13} \text{ Btu/yr} = 7.1102 \times 10^{9} \text{ kW}_t \text{ hr/yr}$$

$$Q_{heat}^{peak} = Q_{HPP}^{Total} - Q_{heat}^{cg} = 2.66476 \times 10^{13} \text{ Btu/yr} - 2.4261 \times 10^{13} \text{Btu/yr}$$

$$= 0.23866 \times 10^{13} \text{ Btu/yr} = 6.993 \times 10^{8} \text{ kW}_t \text{ hr/yr}$$

$$(\alpha_{cg}^{n} = 0.6 \ \& \ \alpha_{cg}^{a} = 0.9104)$$

Fig. B-2

$$E_{HPP}^{cg} = 3.37934 \times 10^{9} \text{ kW}_e \text{ hr/yr}$$

$$E_{HPP}^{cd\ min} = 1.33134 \times 10^{9} \text{ kW}_e \text{ hr/yr}$$

$$E_{HPP}^{cd,\ x} = E_{HPP}^{cd,\ tot} - E_{HPP}^{cd,\ min} = 3.03148 \times 10^{9} - 1.33134 \times 10^{9}$$

$$= 1.70014 \times 10^{3} \text{ kW}_e \text{ hr/yr}$$

$$E_{HPP}^{tot} = E_{HPP}^{ed,tot} + E_{HPP}^{ed} = 3.03148 \times 10^{9} + 3.37934 \times 10^{9}$$

$$= 6.41082 \times 10^{9} \text{ kW}_e \text{ hr/yr}$$

$$P_{cg}^{n} = 657.6 \text{ MWe}$$

$$P_{cd}^{min} = 152 \text{ MWe}$$

$$P_{cd}^{x,n} = P_{cd}^{max} - P_{cd}^{min} = 500 - 152 = 348 \text{ MWe}$$

$$P_{HPP}^{n} = P_{cg}^{n} + P_{cd}^{min} = 657.6 + 152 = 809.6 \text{ MWe}$$

Fig. B-3 (only for descriptive purposes)

Fig. B-4

$$q^{n}_{peak} = q^{n}_{HPP} - q^{n}_{cg} = 6.728 \times 10^{9} - 4.0368 \times 10^{9}$$

$$= 2.6912 \times 10^{9} \text{ Btu/yr} = 788.6 \text{ MWt}$$

$$Q^{peak}_{heat} = 0.23866 \times 10^{9} \text{ Btu/yr} = 6.993 \times 10^{8} \text{ kWt hr/yr}$$

Fig. B-5

$$q^{n}_{cg} = 4.0368 \times 10^{9} \text{ BTU/hr} = 1{,}182.9 \text{ MWt}$$

$$q^{n}_{e} = P^{n}_{cg} \times b^{cg}_{HPP} = 657.6 \text{ MWe} \times 3703.0 \text{ Btu/kWh}$$

$$= 2.4351 \times 10^{9} \text{ Btu/hr} = 713.5 \text{ MWt}$$

$$K^{min}_{c} = P^{min}_{cd} \times b^{cd}_{HPP} = 152 \text{ MWe} \times 8081.12 \text{ Btu/kWh}$$

$$= 1.2283 \times 10^{9} \text{ Btu/hr} = 359.9 \text{ MWt}$$

$$K^{n}_{x} = P^{x,n}_{cd} \times b^{cd}_{HPP} = 348 \text{ MWe} \times 8081.12 \text{ Btu/kWh}$$

$$= 2.8122 \times 10^{9} \text{ Btu/hr} = 824.1 \text{ MWt}$$

$$O^{n} = q^{n}_{cg} + q^{n}_{e} = (4.0368 \times 10^{9} + 2.4351 \times 10^{9}) \text{ Btu/hr}$$

$$= 6.4719 \times 10^{9} \text{ Btu/hr} = 1896.4 \text{ MWt}$$

$$K^{n} = O^{n} + K^{min}_{c} = 1896.4 + 359.9 = 2{,}256.3 \text{ MWt}$$

<u>CALCULATION OF POWER KEYS</u>, (X_e & X_4)

$$h_t = \frac{E^{cg}_{HPP}}{P^{n}_{cg}} = \frac{3.37934 \times 10^{9} \text{ kWehr/yr}}{657.6 \text{ MWe}} = 5{,}139 \text{ hr/yr}$$

Since steam generator output is kept constant at 100% level at all times during the year,

then, h_o = 8760 hr/yr

and $h_x = h_o - h_t$ = 8,760 = 5,139 = <u>3621</u> hr/yr

Characteristic hourly heat flow, $q_{e,c}$ & $q_{t,c}$

$$q_{e,c} = K_c^{min} + \frac{h_t}{h_t + h_x} q_e^n + \frac{h_x}{h_t + h_x} K_x^n \quad \text{(MWt)}$$

$$= 359.9 + \frac{5{,}139}{5139 + 3621} \cdot 713.5 + \frac{3621}{5139 + 3621} \quad 824.1$$

$$\boxed{q_{e,c} = 1{,}119.1 \text{ MWt}}$$

$$q_{t,c} = q_{cg}^n \frac{h_t}{h_t + h_x} + \underbrace{(O^n - K_x^n)}_{(q_{cg}^n + q_e^n) - K_x^n} \frac{h_x}{h_t + h_x}$$

$$= q_{cg}^n - \frac{h_x}{h_t + h_x} (K_x^n - q_e^n) \quad \text{(MWt)}$$

$$= 1{,}182.9 - \frac{3621}{5139+3621} (824.1 - 713.5)$$

$$\boxed{q_{t,c} = 1{,}137.2 \text{ MWt}} \qquad \underline{\text{ALSO}} \qquad \boxed{K^n = q_{e,c} + q_{t,c} = \underline{2256}.3 \text{ MWt}}$$

Power Keys

$$X_e = \frac{q_{e,c}}{K^n} = \frac{1{,}119.1}{2256.3} = 0.496$$

$$X_t = \frac{q_{t,c}}{k^n} = \frac{1{,}137.2}{2256.3} = 0.504$$

CALCULATION OF ENERGY KEYS
(Same as Physical Method)

Fuel Consumption:

- $$B_{HPP}^{t(cg)} = \frac{Q_{heat}^{cg}}{\eta_{SG}\eta_{pipe}} = \frac{2.4261 \times 10^{13} \text{ Btu/yr}}{0.85 \times 0.99}$$

$$= \underline{\underline{2.8831 \times 10^{13}}} \text{ Btu/yr}$$

- $$B_{HPP}^{e} = \frac{3412.7\ E_{HPP}^{cg}}{\eta_{SG}\eta_{m}\eta_{g}\eta_{pipe}} + E_{HPP}^{cd}\ b_{HPP}^{cd}$$

$$= \frac{3412.7 \times 3.37934 \times 10^{9}}{0.85 \times \underbrace{0.98}_{\eta_m\eta_g} \times 0.99} + 3.03148 \times 10^{9} \times 9603$$

$$= \underline{\underline{4.3096 \times 10^{13}}} \text{ Btu/yr}$$

- $$B_{HPP}^{t(peaker)} = \frac{Q_{heat}^{peak}}{\eta_{SG}\eta_{pipe}} = \frac{0.23866 \times 10^{13}}{0.83 \times 0.99}$$

$$= \underline{\underline{2.9045 \times 10^{12}}} \text{ Btu/yr}$$

Total HPP Fuel Consumption

$$B_{HPP} = B_{HPP}^{e} + B_{HPP}^{t(cg)} + B_{HPP}^{t(peaker)}$$

$$= 4.3096 \times 10^{13} + \underbrace{2.8831 \times 10^{13} + 0.2905 \times 10^{13}}_{3.1736 \times 10^{13} = B_{HPP}^{t}}$$

$$= \underline{\underline{7.4832 \times 10^{13}}}$$

Energy Keys Calculation

$$Y_e = \frac{B^e_{HPP}}{B_{HPP}} = \frac{4.3096 \times 10^{13}}{7.4832 \times 10^{13}} = 0.576$$

$$Y_t = \frac{B^t_{HPP}}{B_{HPP}} = \frac{3.1736 \times 10^{13}}{7.4832 \times 10^{13}} = 0.424$$

SUMMARY

Table B-1

Energy \ Key	Power Key	Energy Key
Electric	$X_e = 0.496$	$Y_e = 0.576$
Heat	$X_t = 0.504$	$Y_t = 0.424$

VERIFICATION: The Steam Generator Rated Heat Output should be Equal to

$k^n = 2{,}256.3$ MWt

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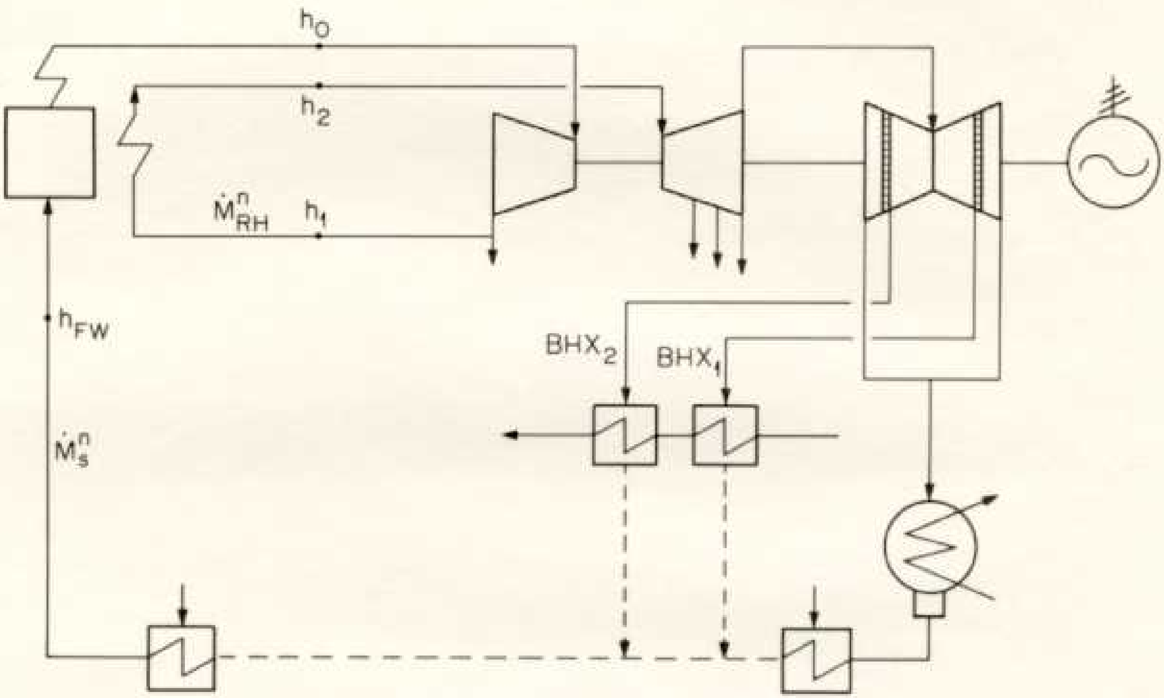

Fig. B.6. Steam generator rated heat output.

The steam generator rated heat output is given by:

$$Q_{SG} = \dot{M}_S^n \, (h_o - h_{FW}) + \dot{M}_{RH}^n (h_2 - h_1)$$

$$= 6{,}510{,}216 \times (1460.4 - 464.8) + 5{,}988{,}715 \; (1{,}519.3 - 1{,}315.8)$$

$$= 7.7003 \times 10^9 \text{ Btu/hr} = \underline{\underline{2256.3}} \text{ MWt}$$

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