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I am submitting herewith a thesis written by Mehmet Eksel entitled "Economic Evaluation of Capacity Expansion Decisions in District Heating Systems." I have examined the final copy of this thesis for form and content and recommend that it be accepted in partial fulfillment of the requirements for the degree of Master of Science, with a major in Industrial Engineering.

William G. Sullivan, Major Professor

We have read this thesis
and recommend its acceptance:

Accepted for the Council:

Vice Chancellor
Graduate Studies and Research

ECONOMIC EVALUATION OF CAPACITY EXPANSION DECISIONS IN DISTRICT HEATING SYSTEMS

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ABSTRACT

The objective of this thesis is to analyze economic trade-offs associated with delaying the construction of district heating pipelines between thermal-electricity power plants and urban areas through the use of temporary heat sources. A computer model is developed and tested for determining optimum connection times of the power plants by minimizing system life-cycle costs.

Two types of heat sources, fuel cells and heat-only boilers, are considered as the temporary and peak heat sources in the district heating system.

An analysis of an idealized city model of 54,000 population indicates that fuel cells are not applicable as peak heat sources. Results also indicate that the optimum connection year of base-load plants is five years with fuel cells as temporary heat sources and three years with conventional boilers. Savings in life-cycle cost due to delaying the connection of base-load plants, compared to the base case of an immediate connection, are 3.1% with fuel cells and 1.8% with heat-only boilers. These savings correspond to 13.4% and 7.4% of required base-load investment cost with fuel cells and heat-only boilers, respectively. The life-cycle cost of the system is found to be moderately sensitive to changes in optimum connection year. The optimum connection year is found to be highly sensitive to the rate of increase in the price of the input fuel for temporary heat sources and the sell-back price of electricity in the case of fuel cells.

The comparison between fuel cells and heat-only boilers indicates that fuel cells are more economical than heat-only boilers as temporary heat sources if the electricity produced by them can be sold at a price of 50% or more of the busbar cost of electricity.

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CHAPTER I

INTRODUCTION

Recent increases in fuel prices and extensive dependency on foreign oil make the conservation of energy essential in every sector of the economy. Space heating and water heating in buildings constitute about 20% of the total U.S. energy demand, and over 90% of these requirements are supplied by oil and natural gas, which are subject to rapid price escalation and becoming scarce (25). District heating with cogeneration heat sources is a promising option for these end uses that can contribute to the energy conservation effort and help to solve the country's energy problem.

This thesis concentrates on implementation of district heating with cogeneration. The implementation of a district heating system is a lengthy process, complicated by a growth in heat demand over a long period of time. There are economic trade-offs in delaying the connection of the cogeneration plants to later years and using temporary local heat sources during the initial years of development when the demand is low. The main objective of this thesis is to analyze these economic trade-offs and develop a general model for the cases of one or more cogeneration plants to determine their optimum connection times to the system. Optimization is performed by minimizing the life cycle cost of the system.

Lower-level objectives include analyzing the sensitivity of the total cost to the connection years of the cogeneration plants and the

sensitivity of optimum connection times to changes in important parameters involved, such as growth rate of demand and cost of heat from the temporary heat sources.

The most common option for temporary heat sources is the heat-only boilers. However, fuel cells (4.5 MW_e) can also be used for this purpose. Another important objective is to determine the economic feasibility of applying fuel cells as the temporary heat sources and comparing them with heat-only boilers.

It is not the purpose of this thesis to compare district heating systems with the other options of supplying the residential thermal demand. This thesis concentrates on the economics of delaying connection of the cogeneration heat sources given that the application of a district heating system has already been decided upon. Furthermore, the macro-economic effects of district heating systems, such as the reduced electricity demand, are ignored.

A. BACKGROUND

District Heating

District heating is a process in which the thermal energy produced in a central source is distributed to the consumer for space heating and hot water needs. The thermal energy is transmitted as either hot water or steam through pipelines. The central heat sources for district heating systems can be either large boilers that produce thermal energy only or cogeneration plants that produce electricity and thermal energy simultaneously. These plants can use a large variety of

fuels, such as oil, coal, nuclear energy, solar energy, and geothermal sources.

Two main advantages of district heating come from the higher efficiency of central plants compared to individual boilers located in buildings and the economies of scale of larger plants. Also, the option of using cheaper and more abundant energy sources, such as coal and nuclear energy instead of fuel oil or gas, makes district heating very attractive. Another important advantage is the improved air quality resulting from replacing many small, uncontrolled sources with a few large controlled sources. Besides these general advantages, district heating offers conveniences from the consumer's point of view. Table 1 lists all these general and consumer-related advantages of district heating. The main disadvantage that makes district heating difficult to apply is the very high investment cost required in transmission and distribution pipes.

District heating is not a new concept. It was used in the United States over a century ago. During the early parts of the twentieth century, many utilities built small district heating systems that supplied steam to customers for space heating. However, after inexpensive oil and natural gas were introduced for space heating in the late 1940's, district heating systems had become uneconomical and have been ignored since then. Few companies have continued to supply steam to a limited number of customers. In the late 1970's, the picture changed again for the benefit of district heating because of rapid increases in oil and natural gas prices and the threatened national security due to extensive dependency on foreign oil.

TABLE 1

ADVANTAGES OF DISTRICT HEATING

Type of Advantage	Specific Advantages
GENERAL	1. More efficient use of energy
	2. Economies of scale of large plants
	3. Use of cheaper and more abundant heat sources such as coal and nuclear energy
	4. Improved air quality
TO CONSUMER	1. More available space in buildings since space is not required for individual boilers
	2. Elimination of individual fuel handling and storage problems
	3. Elimination of staff for supervising individual boilers
	4. Reduced maintenance costs
	5. Lower capital costs for new buildings

The development of district heating has been different in European countries. After World War II, many European countries put large emphasis on district heating and started building networks. Sweden has been one of the leaders of development of district heating systems. At the present time, approximately three million of 8.1 million people in Sweden live or work in premises served by district heating. This accounts for almost 25% of Sweden's total space heating demand, and their goal is 60% by the year 2000 (25). Table 2 shows a comparison of installed district heating capacity in several countries. This table makes clearer the extensive development of district heating systems in European countries (25).

TABLE 2

INSTALLED DISTRICT HEATING CAPACITY

Country	Year	Installed Capacity (MW)	Population (millions)
USSR	1975	494,000	264
USA	1975	7,400	215
West Germany	1975	23,400	62
France	1973	5,200	52
Sweden	1979	12,200	8
Sweden	2000	30,000*	8
Denmark	1975	10,000	5

*Projected.

One of the most important characteristics of European systems is the use of water as a heat-carrying medium instead of steam. There are two main advantages to the use of hot water over the use of steam. First, thermal energy transported by steam is limited to a maximum distance of a few miles, whereas a hot water system can transport energy economically and with low energy losses up to about 60 miles (25). Second, hot water can be produced more economically than steam.

In recent years, interest toward district heating has increased very much in the United States, and many large-scale hot water district heating projects are being proposed for suitable urban areas.(29).

Cogeneration

Cogeneration is the process of producing electricity and thermal energy simultaneously. Electric power plants work with relatively low efficiencies of around 33% (25). Efficiency is defined in this thesis as the percent of the input energy recovered in a usable form. About two-thirds of their total energy is dissipated as reject heat to the environment. However, if these power plants are modified or built to incorporate the cogeneration process, most of this reject energy can be recovered as usable steam or hot water, and their overall efficiencies can be increased to around 80% (25). However, the thermal energy produced by the cogeneration process does not totally come from the energy that would otherwise be rejected if only electricity were being produced. Recovering thermal energy in a usable form results in reduction of electricity production. Still, this sacrifice of electricity is relatively small compared to the amount of thermal energy recovered. Generally, for each unit of electricity sacrificed, five to ten units of thermal energy

can be recovered. Comparison of efficiencies of electricity only and cogeneration power plants is shown in Figure 1.

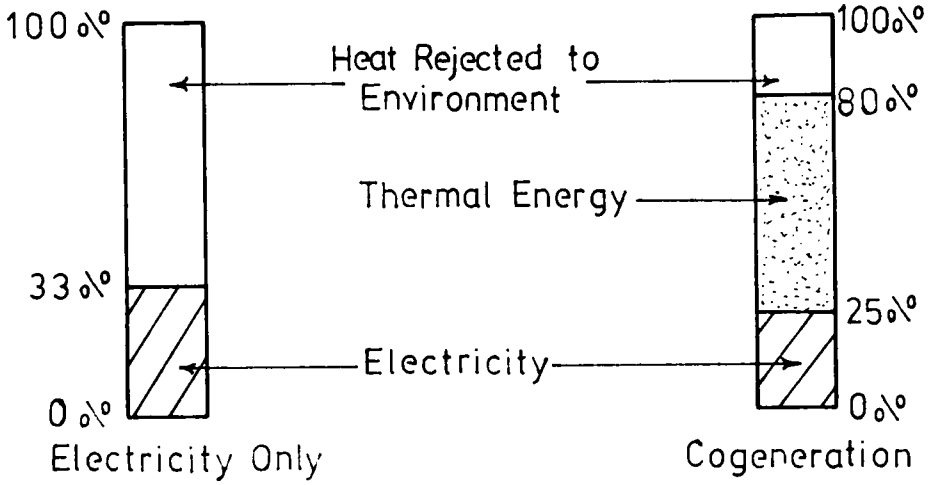


Figure 1. Comparison of Efficiency of Electricity-Only and Cogeneration Power Plants.

Use of cogeneration plants as heat sources in district heating systems makes district heating systems very attractive. There are two very important advantages of cogeneration plants. First, they can supply inexpensive thermal energy since most of it comes from that which would otherwise be wasted. Second, most power plants use coal or nuclear energy, both of which are relatively cheap and abundant energy sources for this country. Use of cogeneration plants can save tremendous amounts of oil that has to be imported from other nations. Another advantage

that is worth mentioning is the reduction of thermal pollution in the environment.

Modifying or building power plants to incorporate the cogeneration process does not require a large investment. However, most power plants are distantly located away from urban areas. Thermal energy has to be transmitted to the urban area through a pipeline. Construction of this transmission pipeline is, unfortunately, very capital-intensive. This is the main disadvantage of district heating with cogeneration. It has low operating costs but requires large capital investments. In order for the system to pay back the large investment, it has to have high utilization. Therefore, district heating systems are more economical in the urban areas with cold climates and high population density.

Fuel Cells

Fuel cells are electrochemical devices that directly convert the chemical energy of input fuel to electricity without involving combustion or mechanical drive (47). Fuel cell power plants consist of three major subsystems (16). The fuel processor converts an available fuel, such as natural gas or naptha, into a hydrogen-rich gas mixture. The fuel cell stack produces direct-current electricity. The power conditioner converts the direct-current electricity into alternating-current electricity.

Efficiencies of fuel cell power plants are not subject to Carnot cycle efficiency limitations since the electricity is produced with an electrochemical process. Present units work with 40% efficiency, and over 50% efficiency is projected for the future improved units. Fuel cells can also be used for the simultaneous production of electricity

and thermal energy. With the combined production, they can use fuel at an overall efficiency approaching 80% (16).

Fuel cells have various advantages over the conventional thermal generators. First, they have greater conversion efficiency, and they maintain the high efficiency over a wide range of load. Second, because of their modular design, they offer siting flexibility, shorter construction times, and easy capacity additions. Third, they are environmentally attractive because of low emissions and quiet operation.

Fuel cells offer greater advantages when they are used for the simultaneous production of electricity and thermal energy because of very efficient use of input fuel. Their use as local heat sources for district heating systems has two main advantages over the use of large-scale, distantly located cogeneration plants. First, fuel cell heat sources can be located within the demand areas, thereby eliminating the need for long and costly transmission pipes and reducing the investment cost of district heating systems greatly. Second, their capacities can easily be adjusted according to the growing demand with small additions. This eliminates the possibility of making an investment on a large capacity and having most of that capacity waiting unused until the demand catches up.

However, fuel cells have a very serious disadvantage. They use a fuel such as natural gas or naptha as the input energy source. The price of such fuels has been increasing and is expected to continue increasing rapidly. Therefore, their operating cost is expected to rise precipitously in the future.

B. DEFINITION OF THE PROBLEM

Figure 2 presents the general nature of the problem being addressed. The urban area and its subdistricts are shown. Each subdistrict has a different population and heat load density. The load density is represented by the concentration of dots in the figure. Nodes within the subdistricts represent the heat load from their surrounding areas. The transmission pipeline connects these nodes and cogeneration plants with each other and carries heat from the cogeneration heat sources to the nodes. Putting a local heat source on every node and supplying its load from that source would eliminate the need for the transmission pipeline. This thesis concentrates on the economic trade-offs in delaying the construction of the transmission pipeline by using temporary heat sources located on these nodes.

Even though it is not shown in the figure, the district heating system also involves a distribution piping network within each subdistrict which carries the heat from the corresponding node to the individual buildings. Because the distribution networks will be the same regardless of whether cogeneration or local heat sources are used, their costs are not included in the economic analysis.

Implementation of a district heating system is a lengthy process. In the case of a developing city, energy demand for the space and hot water heating rises as the population grows. In the case of an existing city, immediate connection of all the prospective customers in that urban area to the district heating system cannot be expected. In the initial years, the system serves only a portion of the total demand, and in later years, more and more customers are connected to it.

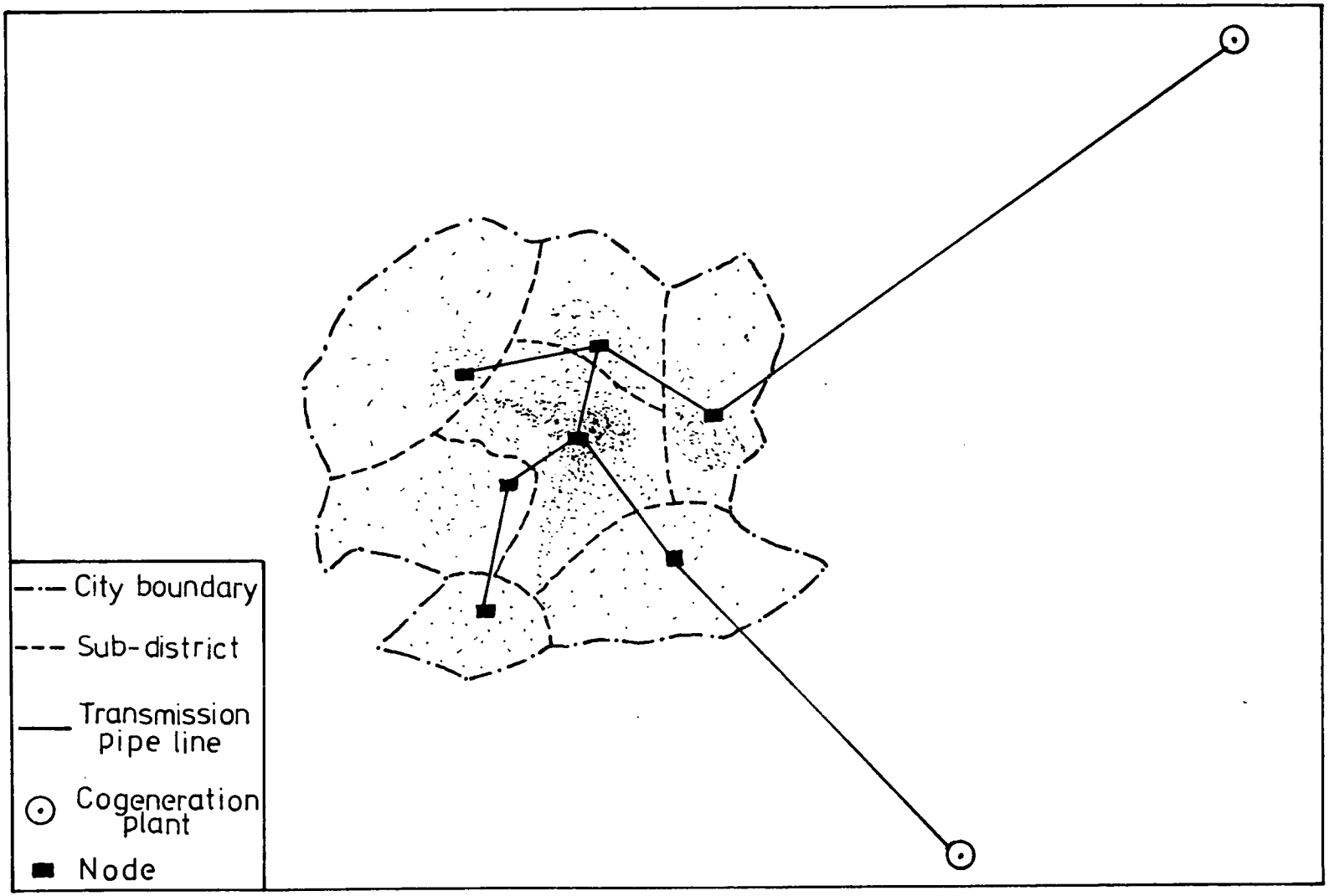


Figure 2. Description of a District Heating System.

Therefore, in both cases, district heating systems are faced with a demand that starts low and increases with time.

For a district heating system for which only one cogeneration plant is to be used as the base load heat source, the transmission pipeline from that cogeneration plant to the district heating area has to be designed and built in one step with a capacity large enough to supply all the prospective demands. If this transmission pipe is built at the beginning of the development stage, it operates very much below its capacity since the demand is low in the initial years. Also, its construction requires a very large capital expenditure. This very large immediate investment, most of which is for the unused capacity, reduces the economic desirability of a district heating with cogeneration system. If it is delayed to some future date, large savings in the interest associated with it can be realized.

If the economies of scale of constructing the pipeline were such that it could be built to supply the initial demand and its capacity could be increased by additions through time as demand grew, then the large sum of capital expenditure would not be required immediately, but rather would be staggered into the future. Unfortunately, the economies of scale are so large that it does not allow the construction of the pipeline even in two stages. For example, if it were built with a capacity less than the total anticipated demand in the beginning, with the additional capacity built at some future date, the total cost would at least double when inflation is considered.

Because of the economies of scale of the transmission pipeline, the only way to delay the large sum of capital investment is to use

some type of local temporary heat source during the development stage. Fuel cells (4.5 MW_e) or large heat-only boilers can be used for this purpose.

The system and the construction of local networks can be started by using temporary heat sources, and their capacities can be increased by small additions according to the growth in demand. At a future date, when the demand reaches a considerably large level, the cogeneration plant can be connected to the system by constructing the transmission pipeline, thus replacing the temporary heat sources.

The optimum time of switch from the local heat sources to the cogeneration plant depends on two main factors. The first factor is the growth in demand. The faster the demand grows, the sooner the optimum connection time becomes. The second factor is the operating costs of local heat sources. They use natural gas, the price of which is expected to continue to rise precipitously in the future years, as the primary heat source. Therefore, their operating costs increase with time, and the faster the increase is, the sooner the switch would be from temporary to permanent cogeneration heat sources.

For a district heating system with two or more cogeneration plants to be used, the discussion given for the case of one plant repeats itself for every cogeneration plant. If no temporary heat source is used, the first plant has to be connected to the system in the first year, and it operates below its capacity until the demand catches up. Then the second one has to be connected. This time, it will be working below capacity until the demand grows to a level equal to the combined capacities of both plants. The same situation occurs if there are more

plants involved. If temporary heat sources are used, the capacity is increased with small additions, and the investment on large-capacity additions is delayed until the demand is large enough for their high utilization.

CHAPTER II

SURVEY OF RELATED LITERATURE

The problem defined in Chapter I has various common characteristics with the equipment replacement models and the capacity expansion models developed in the literature. Therefore, a literature survey was performed in these two areas of interest so that topical matters addressed in this thesis can be placed in perspective.

A. EQUIPMENT REPLACEMENT MODELS

One of the most important factors that affects the optimum replacement time of temporary heat sources with a cogeneration heat source in district heating is the rising prices of fuel types used for temporary heat sources. Rising fuel prices increase the operating cost of temporary heat sources and make the cogeneration heat source more attractive. Therefore, the optimum replacement time is shifted forward in time. Also, when the temporary heat sources are replaced with cogeneration heat sources, a return on their salvage values is obtained. The salvage values of the temporary heat sources decrease as they are kept in service; therefore, the sooner their replacement, the more the salvage return will be.

This situation is characteristic of most equipment. As equipment gets older, its operating costs increase considerably. This property makes the replacement of old equipment with new equipment more economical before its useful life is completed. The faster the increase in

operating cost and the decrease in the salvage value of equipment, the sooner the optimum replacement time becomes.

A considerable amount of work dealing with the optimum replacement time of equipment has been published. Work in this area appears to have originated with J. S. Taylor (45). He dealt with the simplest case of equipment replacement where the gross income and the salvage value decreases with the age of equipment, and the economic horizon is limited to the service life of the equipment. Taylor worked with discrete time periods. This model, which was simplified and put into continuous form by H. Hotelling (21), can be summarized as follows:

$$B(T) = \int_0^T Q(t)\, e^{-rt}\, dt + S(T)\, e^{-rT} - C$$

where B(T) is the total discounted profit, Q(t) is the continuous gross income at time t, S(t) is the salvage value at time t, T is the optimum replacement time, r is the continuous discount rate, and C is the capital cost. Maximizing B(T) with respect to T by setting $\frac{dB(T)}{dT} = 0$ gives:

$$\left[Q(T) - rS(T) - \frac{dS}{dT} \right] = 0$$

This result can be interpreted as follows: The replacement has to be performed when the potential profit on continuous operation equals the interest on salvage value plus the loss in salvage value.

Most authors have included this model in their research as the simplest case of equipment replacement. However, some of them assumed the output to be constant with only the operating expenses increasing. In this case, gross income Q(t) is replaced by the operating expense

O(t); signs of the variables changed, and the total cost is minimized instead of maximizing the profit.

The most important limitation of this model is that future events following the retirement of equipment are not considered. G. D. A. Preinreich (35) realized that after the first equipment was retired, new equipment would be purchased, and this initial replacement would be followed by a second, a second by a third, etc. Therefore, he considered a chain of replacements and included the effects of future events on the optimum replacement time of equipment. In this case, the total present worth of the chain consisted of the present worth of equipment in service plus the present worth of all the future equipment in the chain. Therefore, Preinreich added one more parameter, G_{i+1}, to the previous model. G_{i+1} is the discounted worth of all future profits at the time of the i^{th} equipment replacement. He referred to this parameter as "the goodwill." For this model, the present worth of the chain at the time the i^{th} equipment is put into service is given as:

$$B_i(T_i) = \int_0^{T_i} Q(t)\, e^{-rt}\, dt + Se^{-rT_i} + G_{i+1}\, e^{-rT_i}.$$

Preinreich showed that if the equipment in a chain is identical and if an infinite chain of replacements is considered, $T_i = T_{i+1}$ and $G_i = G_{i+1}$. Therefore, the optimum service life of each equipment in an infinite chain with identical equipment will be constant, and replacement will take place every T units of time.

The assumption of identical equipment in the chain is not very realistic. The technological improvement is an important part of

today's economy. The equipment available today is superior to that of the past, and the equipment of the future will be superior to that of today. The effects of technological change on equipment replacement was first considered by G. Terborgh (46). He realized that as the old equipment was kept in service, more and more efficient equipment was appearing in the market. As time passes, the gap between the old equipment and the more efficient alternative increases. Terborgh called this gap "the operating inferiority" and assumed a linear increase for it. He dealt with discrete cases and worked with continuous representation given by P. Masse (30), who included the equipment replacement extensively in his work as follows:

> If $Q(T,t)$ is the immediate gross income at time t from equipment put in service T, then the operating inferiority at time t is given as
>
> $$Q(t,t) - Q(T_1,t).$$
>
> $Q(t,t)$ refers to the immediate gross income at time t of equipment put in service at t. The average of the sum of the capital cost C and the operating inferiority is the annual equivalent of
>
> $$C + \int_{T_1}^{T_2} [Q(t,t) - Q(T_1,t)]\, e^{-r(t-T_1)}\, dt$$
>
> The optimum replacement time T_2 is chosen to minimize the equivalent annual return.

Note that $T_2 \geq T_1$. Terborgh called this minimum annual return "adverse minimum."

V. L. Smith (41) is another author who considered the equipment replacement problem extensively including technological changes. He first formulated a very general case as follows:

$$PWC = \int_0^{L_0} O(0,t)\, e^{-rt}\, dt - S_0(L_0)\, e^{-rL_0}$$

$$+ e^{-rL_0}\left[\int_0^{L_1} O(L_0,t)\, e^{-rt}\, dt + W_1 - S_1(L_1)\, e^{-rL_1}\right]$$

$$+ e^{-r(L_0+L_1)}\left[\int_0^{L_2} O(L_0 + L_1,t)\, e^{-rt}\, dt + W_2 - S_2(L_2)\, e^{-rL_2}\right]$$

$$+ \ldots\ldots$$

where PWC is the discounted total cost; $O(T,t)$ is the operating expense of the equipment put in service at T; L_i is the service life of the i^{th} equipment; $(S_i\ (L_i))$ is the salvage value of the i^{th} equipment at the end of its service life L_i; and W_i is the purchase cost of the i^{th} equipment.

By making some assumptions, Smith simplified this model. In the event of a steady technological improvement rate, he assumed that the economic life would not change abruptly from one replacement to another and set $L_1 = L_2 = L_3 \ldots = L$. Also assuming no change in the investment cost, he reduced the formula to the following:

$$PWC = \int_0^{L_0} O(0,t)\, e^{-rt}\, dt - S_0\ (L_0)\, e^{-rL_0}$$

$$+ e^{-rL_0} \sum_{K=0}^{\infty} e^{-rKL} \{\int_0^{L} (L_0 + KL_1,t)\, e^{-rt}\, dt + W - S(L)\, e^{-rL}\}.$$

Later, E. J. Elton and M. J. Gruber (11) showed that Smith's assumption of service life not changing abruptly from one replacement to another did not need to be an assumption. They proved that an equal life policy is optimum for equipment with linear rates of technological improvement.

P. H. Grinyer (20) also worked on Smith's model. He solved it by iteration on the computer for the cases of linear and exponential rates of technological change. He developed curves relating the optimum replacement time to the technological improvement parameters.

Parallel to these works mentioned, some authors approached the equipment replacement problem by a dynamic programming formulation. According to R. Bellman's (4) formulation, there are two courses of action that can be taken at time t. Either the old equipment is kept, or new equipment is purchased. If $f(\tau)$ is the overall return from equipment at age τ, then $f_K(\tau) = Q(\tau) - O(\tau) + rf(\tau + 1)$ for keeping the equipment, and $f_p(\tau) = S(\tau) - C + Q(0) - O(0) + rf(1)$ for purchasing new equipment, where $Q(\tau)$ is the revenue, $O(\tau)$ is the operating expense, $S(\tau)$ is the salvage value, C is the purchase cost, and r is the continuous discount rate. This leads to the dynamic programming formulation of:

$$f(t) = \max \begin{bmatrix} \text{Keep:} & Q(\tau) - O(\tau) - rf(\tau + 1) \\ \text{Purchase:} & S(\tau) - C + Q(0) - O(0) + rf(1) \end{bmatrix}.$$

If technological improvement is considered, the overall return, revenue, and expense will depend on the absolute time t in addition to the machine age τ. If equipment is τ years old in the absolute time t, then the time that it is put in service $T = t - \tau$. In this case, the dynamic programming formulation becomes:

$$f(\tau,t) = \max \begin{bmatrix} \text{Keep:} & Q(\tau,t) - O(\tau,t) - rf(\tau + 1,t + 1) \\ \text{Purchase:} & S(\tau,t) - C + Q(0,t) - O(0,t) + rf(1,t + 1) \end{bmatrix}.$$

S. E. Dreyfus (9) stated the same formulation in his paper and solved a numerical example.

R. C. Stapleton, D. B. Hemmings, and H. H. Scholefield (43) concentrated on various effects of technological change. They also applied the dynamic programming formulation. The effects of technological change considered were: a linear decline in operating cost, less deterioration rate for new equipment, and a fall in purchase price. Their results showed that in the incidence of linear decline in operating cost, the optimum service life of equipment in a chain is constant. This has also been proven by Elton and Gruber, as mentioned earlier. They also found that the optimum service life increases with time in the incidence of a less deterioration rate and decreases with time in the incidence of a fall in purchase price.

In the previous dynamic programming formulation, only two types of action are considered at any time t. Either the old equipment is kept, or it is replaced by new equipment. G. B. Ahmet (2) extended this formulation for a general case where at any time t, equipment of any age can be purchased. He stated a numerical example for this case and gave the complete solution for it.

The models given have been used by various authors for specific case studies. S. C. R. Clapham (7) determined the service life of diesel and battery locomotives. S. Eilon, J. R. King, and B. E. Hutchinson (10) used the chain replacement model without technological change to find the replacement times of forklift trucks. In a recent article, D. H. Lake and A. P. Muhlemann (26) applied the single equipment replacement formulation for the wrapping machines in a biscuit company.

The interesting article by S. A. Ravid (36) applied these equipment replacement models to the energy conservation technology. He worked with the problem of substituting more efficient energy consuming equipment for less efficient equipment as more efficient alternatives become available and energy prices increase.

B. CAPACITY EXPANSION MODELS

The equipment replacement models generally do not tend to consider the demand for the services or to the products provided by the equipment. They apply to the cases where there is a constant output, or if the output changes, there is demand to utilize it. They do not include any constraint on the output such that it should always meet a given demand. However, for the problem considered in this thesis, demand plays a very important role. In the case of a developing city, energy demand for the space and water heating rises as the population grows. In the case of an existing city, more and more customers join the district heating system through time, and the energy demand for the system increases. Therefore, in both cases there is a growing demand that must be met by either cogeneration plants or the temporary heat sources.

Most projects, such as electric utilities, water supply systems, telephone networks, and transportation systems face a growing demand pattern. A dominant cost to electric utilities is the return on investment capital required for building power plants, whereas it is the cost of constructing transmission pipelines for district heating with cogeneration systems. For most projects, the economies of scale are such that facilities can be built for the present demand, and then the

capacity can be increased by additions to absorb the growing demand. However, transmission pipelines have to be designed and built in one step to supply all the present and future prospective demands. The articles published in the literature have mostly concentrated on the types of problems dealing with economies of scale that allow the demand to be absorbed by capacity additions, and they have mainly dealt with determining the timing and the size of capacity additions.

The capacity addition problem was first considered by H. B. Chenery (6) on behalf of the natural gas transmission industry. He assumed the simplest case in which the demand grows linearly. The cost of capacity addition was assumed to be KX^{α} ($K > 0$, $0 < \alpha < 1$), where K is a constant, X is the amount of the capacity addition, and α is the economies of scale factor. For this model, the optimum policy turns out to be adding a constant amount of X units to the capacity at constant intervals. The optimum capacity addition X minimizes the function $f(X) = \frac{X^{\alpha}}{1 - e^{-rX}}$, where r is the discount rate. X is affected by two parameters. The higher the discount rate, the smaller it gets, and the higher the economies of scale factor, the larger it becomes.

A. S. Manne (28) briefly summarized the model given by Chenery and extended it to a case in which backlogs in demand are allowed. Again, the demand was assumed to be growing linearly. He also assumed an annual rate of penalty cost b per unit of backlog. For this model, the policy to be determined is the optimum amount of backlog Y that must be allowed, as well as the optimum amount of capacity additions X. The optimum policy turns out to be adding a constant amount of X to the capacity and allowing a constant amount of backlog Y for the linearly

growing demand. Manne used numerical methods to determine the values of X and Y for different values of α, b, and r.

In the same article, Manne also considered a probabilistic demand for the cases with and without backlogs. The probabilistic demand pattern considered by him is as follows:

> A decreasing random change in demand occurs every Δt units of time. With a probability p, the discrete change constitutes an increase of ΔD units, and with a probability $q = (1 - p)$, a decrease of ΔD units. Then demand at time t is given as $D(t) = D(t - \Delta t) + \Sigma(t)$ where $\Sigma(t)$ is a random variable taking the values of $+\Delta D$ and $-\Delta D$ with respect to probabilities p and q.

Manne's results showed that a probabilistic growth in demand gives larger sizes of optimum capacity additions than if demand was growing at a steady rate equal to the expected value of probabilistic increments.

Since Manne's work, capacity expansion problems with a probabilistic demand pattern have not been given much consideration. Most of the works have concentrated on the deterministic capacity problem. However, R. J. Giglio (17) considered a demand rate that is probabilistically increasing in time. Demand rate at any time $t = \Sigma(t) + \Sigma_0$ where $\Sigma(t)$ is the constant rate of demand rate increase, and Σ_0 is a random variable with a density function $\Omega_t(\Sigma_0)$. Giglio examined two cases. In the first case, $\Omega(\Sigma_0)$ is not a function of time, and in the second case, $\Omega(\Sigma_0)$ is an increasing function of time t.

The deterministic capacity expansion model given by I. McDowell (31) involves an exponential growth in demand. This model is different from the one considered by Chenery, not only in its demand pattern, but also in the form of the capacity additions cost function. In this case, the demand D(t) is given as e^{Kt}, and the cost of capacity additions C is aX + b where K, a, and b are constants, t is the time, and X is the

amount of capacity addition. If t_i is the time at which the i^{th} addition to the capacity is done, then the sum of the money to be set aside at year zero to finance this i^{th} addition is:

$$\{a[e^{Kt_i} - e^{Kt_{i-1}}] + b\} e^{-rt_{i-1}}.$$

For the planning horizon of N capacity additions, the present worth of all installment costs is:

$$F = [a(e^{Kt_1} - 1) + b] + [a(e^{Kt_2} - e^{Kt_1}) + b] e^{-rt_1}$$
$$+ \ldots + [a(e^{Kt_{i+1}} - e^{Kt_i}) + b] e^{-rt_i}$$
$$+ \ldots + [a(e^{Kt_N} - e^{Kt_{N-1}}) + b] e^{-rt_{N-1}}.$$

McDowell obtained a set of equations by setting $\frac{\partial F}{\partial t_i} = 0$, and by solving them he determined the optimum set of installation times. For this model, the time interval between the additions is not constant, but it decreases with time.

T. W. Sirden (38) considered a capacity expansion problem in which the cost of installing a capacity at time t_1 that would absorb the demand between the interval of $t_2 - t_1$ is given as $f(t_1,t_2) = e^{-vt_1} f(t_2 - t_1)$. If the absorption time $t_2 - t_1$ is set equal to θ, this cost function becomes $f(t_1,\theta) = e^{-vt} f(\theta)$. For this function, v is the effective interest rate that depends on the actual interest rate and the growth in demand. It is defined more clearly for different demand functions in the next paragraph. Sirden considered the cases with $v > 0$ or $v = 0$. He showed that the optimum policy for the capacity

problem with this form of the cost function is installing facilities of such capacities that the absorption times are all equal to θ^* where θ^* minimized the function:

$$C(\theta) = \begin{cases} \dfrac{f(\theta)}{\theta} & \text{for } v = 0. \\ \dfrac{f(\theta)}{1 - e^{-v\theta}} & \text{for } v > 0. \end{cases}$$

The equal-cycle policy with constant time intervals between the capacity additions is optimum for this model.

Two articles published after Sirden's considered capacity expansion models with geometrically changing demand patterns. T. N. Srinivasan's (42) model has a demand pattern increasing marginally in the form of $D(t) = D(0)(e^{dt} - 1)$ where $D(0)$ is the initial demand and d is the rate of growth in demand. R. J. Giglio (18) worked with a demand pattern similar to Srinivasan's but decreasing marginally. This demand function has the form of $D(t) = D(0)(1 - e^{-dt})$. Both assumed KX^{α} as the cost function of capacity additions and proved that under these conditions an equal cycle policy of making capacity additions at equal time intervals is optimum. However, both these models are special cases of Sirden's model. This fact was pointed out by A. J. Kalotay (24). It can be shown that both these models have the form of $f(t,\theta) = e^{-vt} f(\theta)$ where $v = r + \alpha d$ for $D(t) = D(0)(1 - e^{-dt})$ and $v = r - \alpha d$ for $D(t) = D(0)(e^{dt} - 1)$. In this case, the actual interest rate r is transferred to an "effective rate of interest" v.

As mentioned earlier, Sirden considered the cases where v is zero or positive. R. L. Smith (40) generalized Sirden's model to include the

case where v may be negative if the rate of growth d is much higher than the rate of interest r by using an equivalent cost rate $\gamma(\theta)$ defined as $\gamma(\theta) = \frac{vf(\theta)}{1 - e^{-v\theta}}$. A negative v (effective interest rate) indicates that money in the future will be worth more than it is at present.

Another type of capacity expansion problem quite different from the models discussed so far was considered by W. S. Butcher et al. (5). The problem is in determining the optimum sequence of n independent water projects with capacities Q_i and costs C_i (i = 1, ... n) to meet the growing demand. Butcher developed a dynamic programming formulation for this problem that relies on R. Bellman's principle of optimality (3). This principle states that if a sequence of K projects providing a total capacity Q is optimal, then the sequence of K - 1 projects must be optimal for the capacity of $Q - Q_K$. The dynamic programming formulation has the form of:

$$F_n^{K_n}(q) = \underset{i=1, \ldots n}{\text{Min}} \; [C_i(1 + r)^{-\theta} + F_{n-1}(q - qn)]$$

where $F_n^{K_n}$ is the minimum present cost of providing a capacity of at least q units to meet the demand by the sequence K_n of n projects. θ is the time that it takes the demand to grow an additional qn units.

In another article by T. L. Morin and A. M. D. Esogbue (32), an improved version of the same dynamic programming formulation was developed. However, D. Erlenkotter (12) demonstrated that Butcher's formula does not give the optimum sequence always. He developed a different dynamic programming formulation that relies on the principle that some project i with a capacity Q_i must be the next undertaken, and the

remaining projects must be optimally ordered. He defined a status set X which indicates the projects that have already been undertaken. For example, if there are four possible projects, X(1,0,1,0) indicates that the first and third projects have been undertaken and that the second and fourth projects are candidates for the next expansion. If C(X) is defined as the discounted cost for an optimal sequence of all remaining expansions to be undertaken subsequent to the ones already recorded in X, the dynamic programming relation is given as:

$$C(X) = \underset{C \notin X}{\text{Min}} \{C_i \, e^{-r\theta(X)} + C(X \cup i)\}$$

for all $X \in X^*$ where X^* is the set where all projects are undertaken.

In a recent article, R. L. Smith (39) concentrated on Butcher's dynamic formulation specifically for the demand function of $D(t) = D(0)(e^{qt} - 1)$ and determined the conditions under which the problem yields optimal solutions.

Various other articles have been published dealing with other types of capacity expansion problems. D. Erlenkoter (13) showed a dynamic programming approach to capacity expansion problems with multi-locations. A. J. Kalotay (23) considered the capacity expansion with specialization. For this model, he assumed two services to be supplied and two types of equipment. One type of equipment was specialized to provide both services and the other type provided only one service. E. R. Peterson (33) worked with the capacity expansion problem of electric power systems. He developed a dynamic programming model to optimize the least-cost mix of capacity between hydro, thermal, and nuclear

plants, the size of plants to be added to the system and the timing of these additions.

C. CONCLUSION

As this literature search shows, an extensive amount of work has been done in the areas of replacement analysis and capacity expansion. However, the problem in this thesis has unique characteristics that make it different from the problems described in the literature.

As mentioned earlier, the equipment replacement models apply to the cases where there is a constant output or, if the output changes, there is demand to utilize it. They do not include any constraints on the output such that it should always meet a given demand pattern. However, for the problem under study, a growing demand pattern has to be satisfied at all times.

For most of the capacity expansion models discussed, the sizes of the capacity additions are flexible, and they are considered as decision variables. In this research, the capacities of the transmission pipelines are known, and only the timings of their constructions are critical. Also, the capacity expansion models do not deal with temporary additions that are to be replaced in later years. For these models, when an addition is done, it stays in service through the time horizon.

Because of these differences, this thesis requires the development of a model according to its unique characteristics which gives the optimum implementation pattern of district heating systems.

CHAPTER III

THE MODEL

The objective of the model is to determine the optimum times for building transmission pipes from cogeneration heat sources such that the life cycle costs of the system are minimized. Optimization is performed from the viewpoint of the utility company that finances the system, and present worth of cost is used as the performance criterion (48, p. 144).

Similar problems have been approached by the dynamic programming formulation in the literature (22), and this could also be applied here to obtain the solution. However, even for a large district heating system such as the one proposed in the Minneapolis-St. Paul area, the number of cogeneration plants involved typically will not be more than three or four (29). Therefore, the amount of computation required for considering all the possible solutions and choosing the optimum among them can easily be handled by today's computers. The number of possible solutions for a given number of cogeneration plants is presented in Table 3. The possible solutions include the cases in which none or only some of the cogeneration plants are connected. Consequently, a computer model which determines the optimum solution by total iteration is developed. Even though total iteration requires a longer computation time than the other techniques of obtaining the optimum solution, it has the advantage of providing a complete map of the solution, which is very useful for analysis.

TABLE 3

NUMBER OF POSSIBLE SOLUTIONS FOR A 20-YEAR STUDY PERIOD

Number of Cogeneration Plants	Number of Solutions
1	21
2	231
3	1771
4	10620

The model is built by assuming that fuel cells will be used as the temporary heat sources. However, it can also be used for other temporary heat source options, such as heat-only boilers.

A. DESCRIPTIONS AND ASSUMPTIONS

Demand

In general, demand D(t) is a vector in the form of [D(0),D(1)-----D(t)-----D(T)] where t is the year, and T is the study period. In order to provide flexibility, demand is incorporated into the computer model as a subprogram. For a given value of the year t, the subprogram simply returns the corresponding value of demand for that year. Therefore, the model can be used for different types of demand pattern by adjusting the subprogram.

According to expert opinions and Swedish experience with their existing district heating systems, demand of a district heating system

usually can be approximated by a linearly increasing pattern. Therefore, the subprogram is developed for a linear demand. Inputs to the subprogram are the initial demand (INITD), the maximum expected demand (MAXD), and the grow period (GROPER). Therefore, the annual rate of growth in demand (d) is given as follows:

$$d = \frac{MAXD - INITD}{GROPER} .$$

Then, the demand D(t) for a given year (t) is given with the following expression:

$$D(t) = INITD + dt \quad \text{for } t < GROPER$$
$$= MAXD \quad \text{for } t \geq GROPER.$$

Cogeneration Plants

The model is developed to handle the cases where there may be one or more cogeneration plants to supply the base load. The following are the inputs to the model that are related to base load:

1. Number of cogeneration plants (N);
2. Heat production capacity of each plant (QBL_n);
3. Investment cost on each plant and its transmission pipeline (CBL_n);
4. Operating cost of the base load in a given year (OBL_t);
5. Annual maintenance cost percentage (MBL).

Number of cogeneration plants depends on the thermal demand of the system, the heat production capacities of available plants, and their distances to the urban area. The model requires the connection sequence of cogeneration plants to be specified.

District heating systems are designed such that the base load capacity (i.e., the sum of all the cogeneration plants' capacities) is some percentage of the peak load. The amount of annual heat supplied by that percentage depends on the load duration. A typical load duration curve is shown in Figure 3. The area under the curve gives the amount of annual heat consumption. The cross-hatched area represents the amount of annual heat supplied by the base load plants. It can be seen from the figure that the base load which is 50% of the peak load supplies about 80% of the total annual heat consumption.

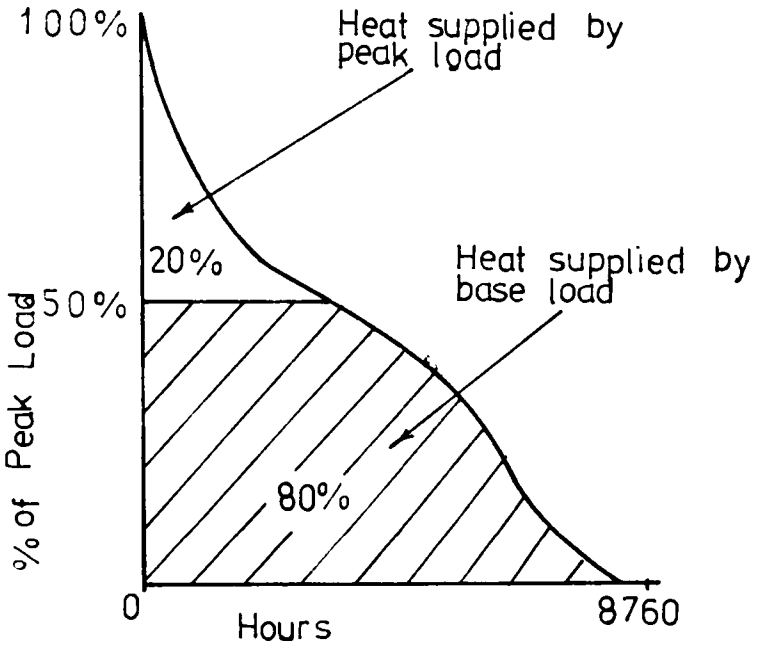


Figure 3. Load Duration Curve.

The base load percentage is an economical decision. As it is increased, investment on the base load and the amount of annual heat supplied by the base load increases. However, the additions to the annual heat supplied become less and less as the base load capacity increases. For example, as mentioned earlier, a capacity of 50% of the peak load serves about 80% of the annual demand. If this capacity is doubled, making it equal to peak load, the cost is also doubled. However, the additional 50% capacity serves only 20% of the annual demand in contrast to the 80% served by the first 50%. Therefore, the utilization of the additional 50% will be very low. It may be more economical to supply some of the annual heat by peak-load heat sources that have high operating but low investment costs. This decision on the base load's percentage of the peak load must be given, and the capacities of cogeneration plants must be determined prior to running the model.

Transmission pipeline costs constitute the largest portion (around 60%) of the total investment cost required on base load (25, p. 7). Construction of the pipeline requires a large capital expenditure that depends on various factors such as ground conditions, plant-city separation, and the pipe size, which depends on its capacity. The investment required to modify or build a power plant to incorporate the cogeneration process will be low compared to the construction cost of the pipeline.

The operating cost of base load, the cost of supplying one unit of heat from cogeneration plants, depends on the amount of electricity sacrificed during the cogeneration process. Most of this heat is the recovered heat that would otherwise be wasted if the plant were

producing only electricity. However, cogeneration will result in some amount of electricity sacrifice, because steam is extracted from the turbine at a higher temperature than the normal condenser temperature in an electrical power plant. Also, some amount of pumping power is needed for the flow of hot water in the pipe. Therefore, the one reasonable value to assign to the cogenerated thermal energy is the busbar value of the electricity sacrificed plus the pumping power cost. Other ways of pricing the heat have also been suggested, but this is probably the simplest and is as desirable as any other way.

The annual maintenance cost of the base load in a given year is generally expressed as some percentage of the investment made on the base load up to and including that year (29).

Fuel Cells

Fuel cells of 4.5-MW_e capacity will be used as the temporary heat sources during the development stage of the system. When the last cogeneration plant is connected to the system, all the fuel cell capacity will be salvaged. In some cases, some of the temporary capacity can be retained as the peak or back-up capacities if the same type of heat source is to be used for these purposes also. However, it is also possible that it may be more economical to use fuel cells as the temporary heat sources during the development stage and to use another type of heat source, such as heat-only boilers, as the peak capacity after the system is developed and as the back-up capacity for the base load. Therefore, these three types of capacities (temporary, peak, and back-up) are kept separate from each other, and the salvaging of all the temporary heat sources after the base load is connected is assumed.

Inputs to the model related to fuel cells are:

1. Heat production capacity of one fuel cell module (QFC);
2. Investment cost on one fuel cell module (CFC);
3. Operating cost of fuel cell in a given year (OFC_t);
4. Annual maintenance cost rate per unit of heat for fuel cells (MFC);
5. Useful life of fuel cells (ULFC);
6. Number of fuel cell locations (FCLOC).

The heat production capacity of one fuel cell module (QFC) is the minimum amount of fuel cell capacity addition, and the additions must be a multiple of QFC. The adjustment of the fuel cell capacity according to the growing demand is a very simple capacity expansion problem. For a given year, if the total fuel cell capacity at the beginning of the year is less than the expected maximum demand for that year, the minimum number of fuel cell modules that brings the total capacity equal to or greater than the maximum demand must be added. Figure 4 shows a simple demand pattern and the total fuel cell capacity adjusted according to that pattern for the time horizon of five years. The demand is 50 million Btu/Hr for the first year, and it grows at a rate of 30 million Btu/Hr per year. Heat production capacity of one fuel cell module (QFC) is approximately taken as 20 million Btu/Hr for illustration purposes. For the first year, two modules with the total capacity of 40 million Btu/Hr cannot supply the demand of 50 million Btu/Hr, and the total capacity cannot be made 50 million Btu/Hr since it should be a multiple of QFC. Therefore, at least three modules with a total capacity of 60 million Btu/Hr are required. A fourth module is not desirable because

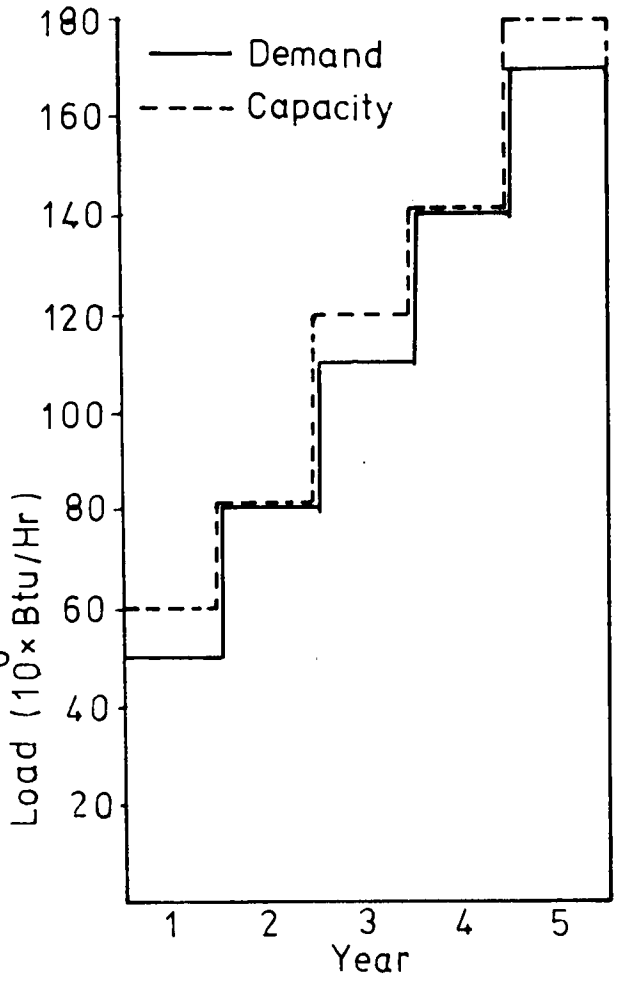


Figure 4. Adjustment of Fuel Cell Capacity According to Demand.

it would not be utilized at all, and the interest on its investment would be wasted for the first year. For the second year, demand grows to 80 million Btu/Hr. To increase the capacity of 60 million Btu/Hr to 80 million Btu/Hr, one more fuel cell module has to be added. For the third year, demand reaches to 110 million Btu/Hr, and the addition of two more modules is required, bringing the total capacity equal to 120

million Btu/Hr. The addition of one module for the fourth year and two modules for the fifth year is necessary to absorb the growing demand.

In a district heating system, fuel cells are used primarily for the production of heat. Electricity is produced as a by-product. However, they can also be utilized during the summer electricity peaking hours as the peak electricity capacities. Therefore, some amount of investment credit can be considered for fuel cells for their electricity-producing capacities.

The operating cost of fuel cells depends on the amount and the selling price of electricity produced, as well as the amount and the price of the input fuel required. The selling price of electricity and the price of the input fuel are crucial factors that affect the economic attractiveness of fuel cells. The operating cost of fuel cells is expected to rise more rapidly than the general inflation rate, because the price of the input fuel has been rising faster than inflation, and this trend is expected to continue.

The main maintenance requirements for fuel cells are the stack replacements for about every 40,000 hours of operation. The annual maintenance cost of fuel cells is expressed as some rate (MFC) times the annual heat produced by them (19).

The salvage value of fuel cells is assumed to be decreasing linearly with age. Therefore, the annual decrease in the salvage value (S) is given as $\frac{CFC}{ULFC}$, where CFC is the cost of one fuel cell module and ULFC is its useful life.

Back-Up Capacity

It is very important for a utility company that the demand be met at all times. If the capacity is set equal to the maximum demand, the system may not be able to meet the demand if some of its capacity is out of order. Therefore, a back-up capacity is required to assure the reliability of the system. The back-up capacity is usually provided with an alternative that has a very low investment cost. Since this capacity is used for a very limited amount of time in a given year, its operating cost is not critical.

A detailed study of the reliabilities of district heating systems would be lengthy and difficult, and it is outside the scope of this thesis. Also, there is not enough data available in this area. Therefore, the problem of reliability is solved by making various simplifying assumptions.

The first assumption is that the probability of having more than one fuel cell module down at the same time is negligible. Therefore, during the years in which only fuel cells are used as heat sources, a back-up capacity that is equal to the heat production capacity of one fuel cell module has to be provided. However, the fuel cells may be located in various locations within the urban area. If this is the case, the back-up capacities are required at every location. The amount of heat supplied by these back-up capacities will be assumed to be some percentage of the annual heat demand.

It is a common practice to build excess capacities equal to the largest unit for utility systems. Therefore, when the first base load plant is connected to the system, the back-up capacity has to be

increased to a level equal to its capacity. Then, anytime a new cogeneration plant is connected to the system, its capacity will be compared with the present back-up capacity, and if the back-up capacity is less, it will be brought to the new plant's capacity level by additions.

A certain reliability is assumed for the base load plants, and the amount of annual heat supplied by the back-up capacity depends on this assumption. For example, if the reliability is assumed to be 97%, then 3% of the total annual heat that has to be supplied by the base load is supplied by the back-up capacity, and only 97% of it is actually supplied by the base load.

Inputs to the model related to back-up capacities are:

1. Investment cost per unit of back-up capacity (CBUP);
2. Operating cost of back-up capacity per unit of heat supplied in a given year ($OBUP_t$);
3. Maintenance rate of back-up capacity (MBUP).

The annual maintenance cost of the back-up capacity can be expressed either as some percentage of the investment cost on it or some rate (MBUP) times the installed capacity. In this model, MBUP is utilized.

Peak Load Capacity

As mentioned earlier, for a district heating system, it may be more economical to have a base load capacity that is some percent of the peak demand and to use a peak capacity made of heat sources with low investment costs to supply the peak demand. If the same type of heat source is to be used as the temporary and peak heat sources, some of the temporary capacity can be retained to be used as the peak capacity after

the development of the system (connection of all the cogeneration plants) is complete. However, because a different type of heat source than the temporary heat sources may be used for the peak capacity, it is assumed that all the temporary capacity is salvaged when all the cogeneration plants are connected, and the peak capacity is added according to demand yearly afterwards.

Inputs to the model related to peak capacity are:

1. Investment cost per unit of peak capacity (CPEAK);
2. Operating cost of peak capacity per unit of heat supplied in a given year ($OPEAK_t$);
3. Maintenance rate of peak capacity (MPEAK).

The annual maintenance cost of the peak capacity is also expressed as some rate (MPEAK) times the installed capacity.

Yearly Operating Cost

The yearly operating cost depends on the load duration pattern and the percent of the peak load supplied by the base load (P), which is defined as follows:

$$P = \frac{\text{Base Load Capacity}}{\text{Peak Demand}} \times 100.$$

A continuous load duration pattern can be approximated by discrete intervals. A very simple load duration pattern is shown in Figure 5. Although the hours indicated in the figure are far from being realistic, it serves for the purpose of illustration. The total area under the curve is given as 38 hours. For a base load percentage of 60%, the total cross-hatched area is 34 hours, leaving four hours for the peak load.

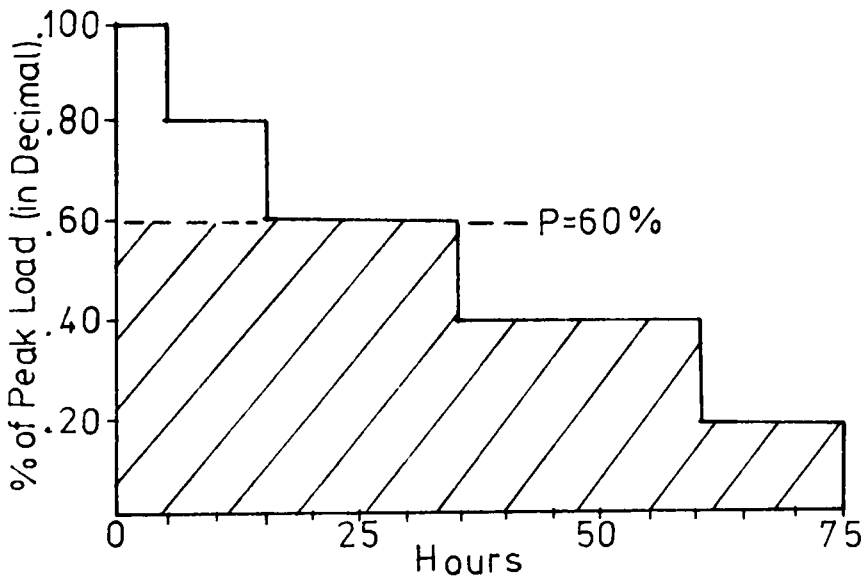


Figure 5. An Example Load Duration Pattern.

If it is assumed that the peak demand given in a year is 10 million Btu/Hr, and no base load plant is connected at that year, then all of the annual heat has to be supplied by fuel cells and their back-up capacity. If OFC is the operating cost of fuel cells, OBUP is the operating cost of the back-up capacity, and RELFC is the reliability of fuel cells, then the yearly operating cost (YOC) is given as follows:

$$YOC = 38 \cdot (10 \times 10^6) \cdot OFC \cdot (RELFC)$$
$$+ 38 \cdot (10 \times 10^6) \cdot OBUP \cdot (1 - RELFC).$$

If the 10 million Btu/Hr peak demand is kept the same, but it is assumed that the connected base load capacity is 60% of the peak demand, fuel cells supply the remaining 40% of the peak load, OBL is the

operating cost of the base load, and RELBL is the reliability of base load, the yearly operating cost is given as follows:

$$YOC = 4 \cdot (10 \times 10^6) \cdot OFC + 34 \cdot (10 \times 10^6) \cdot OBL(RELBL) + 34 \cdot (10 \times 10^6) \cdot OBUP \cdot (1 - RELBL).$$

If the peak demand is kept the same, but this time it is assumed that all of the base load is connected to the system which is again 60% of the peak demand, the annual heat has to be supplied by the base load capacity, the peak capacity, and the back-up capacity. As mentioned earlier, when all the cogeneration plants are connected, the temporary capacity is salvaged, and peak capacity is provided. The yearly operating cost for this case is given as follows:

$$YOC = 4 \cdot (10 \times 10^6) \cdot OPEAK + 34 \cdot (10 \times 10^6) \cdot OBL(RELBL) + 34 \cdot (10 \times 10^6) \cdot OBUP \cdot (1 - RELBL).$$

where OPEAK is the operating cost of the peak capacity.

The yearly operating cost is determined by a subprogram called OPCOST. This subprogram returns the value of the total yearly operating cost in current dollars given the year, peak demand for that year, and the base load's percentage of the peak load. It also returns the amount of annual heat supplied by fuel cells in that year to be used in determining the annual maintenance cost on them. The subprogram OPCOST calls the subprograms OBL, OFC, OBUP, and OPEAK to obtain the costs per unit of heat supplied by the base load, fuel cells, back-up capacity, and peak capacity in a given year, respectively.

B. FORMULATION OF THE MODEL

Because of the discrete nature of the capacity additions, a discrete formulation of the model is made, and discrete compounding is used. Moreover, investment cash flows in a given year are assumed to be made in the beginning of that year, and cash flows separated throughout the year, such as operating cost, are assumed to be made at the end of the year.

The following general parameters are utilized throughout the formulation:

I: Effective discount rate;

F: Inflation rate;

T: Study period;

N: Total number of base load plants;

$TCON_n$ (n = 1, ... N): Connection year of the n^{th} plant;

t: Years.

Investment Cost on Base Load

CBL_n (n = 1, ... N): Investment cost on the n^{th} cogeneration plant in year zero dollars (includes cogeneration conversion cost plus the cost of the pipeline to the plant).

PWICBL: Present worth of total investment cost on the base load.

$$PWICBL = \sum_{n=1}^{N} CBL_n \cdot \left(\frac{1 + F}{1 + I}\right)^{TCON_n}.$$

Investment Cost on Fuel Cells

K_t ($t = 0, \ldots TCON_N - 1$): Number of fuel cell modules added in year t.

CFC: Investment cost on one fuel cell module in year zero dollars.

PWICFC: Present worth of total investment cost on fuel cells.

$$PWICFC = \sum_{t=0}^{TCON_N-1} K_t \cdot CFC \cdot \left(\frac{1 + F}{1 + I}\right)^t.$$

Investment Cost on Back-Up Capacity

ΔBUP_t ($t = 0, \ldots TCON_N$): Units of back-up capacity added in year t.

CBUP: Investment cost on one unit of back-up capacity in year zero dollars

PWICBU: Present worth of total investment cost on back-up capacity.

$$PWICBU = \sum_{t=0}^{TCON_N} \Delta BUP_t \cdot CBUP \cdot \left(\frac{1 + F}{1 + I}\right)^t.$$

Investment Cost on Peak Capacity

$\Delta PEAK_t$ ($t = TCON_N, \ldots T$): Units of peak capacity added in year t.

CPEAK: Investment cost on one unit of peak capacity in year zero dollars.

PWICPK: Present worth of total investment cost on peak capacity.

$$PWICPK = \sum_{t=TCON_N}^{T} \Delta PEAK_t \cdot CPEAK \cdot \left(\frac{1 + F}{1 + I}\right)^t$$

Salvage Value of Fuel Cells

ULFC: Useful life of fuel cells.

$S = \frac{CFC}{ULFC}$: Decrease in salvage value in one year.

$SAL_t = CFC - S(TCON_N - t)$: $(t = 0, \ldots TCON_N - 1)$ Salvage value on one fuel cell module put in service in year t and salvaged in year $TCON_N$ in year zero dollars.

K_t $(t = 0, \ldots TCON_N - 1)$: Number of fuel cell modules added in year t as defined previously.

PWSAL: Present worth of total salvage value.

$$PWSAL = \left[\sum_{t=0}^{TCON_N-1} K_t \cdot SAL_t\right] \cdot \left(\frac{1 + F}{1 + I}\right)^{TCON_N}.$$

Yearly Operating Cost

AFC_t $(t = 0, \ldots TCON_N - 1)$: Annual heat supplied by fuel cells in year t.

ABL_t $(t = TCON_1, \ldots T)$: Annual heat supplied by base load in year t.

$APEAK_t$ $(t = TCON_N, \ldots T)$: Annual heat supplied by peak capacity in year t.

OFC_t: Operating cost of fuel cells in year t.

OBL_t: Operating cost of base load in year t.

$OPEAK_t$: Operating cost of peak capacity in year t.

$OBUP_t$: Operating cost of back-up capacity in year t.

RELBL: Reliability of base load.

RELFC: Reliability of fuel cells.

YOC_t: Yearly operating cost in year t in current dollars.

$$YOC_t = AFC_t \cdot OFC_t \cdot RELFC + AFC_t \cdot OBUP_t \cdot (1 - RELFC) \quad \text{for } 0 \leq t < TCON_1;$$

$$= AFC_t \cdot OFC_t + ABL_t \cdot OBL_t \cdot RELBL + ABL_t \cdot OBUP_t \cdot (1 - RELBL) \quad \text{for } TCON_1 \leq t < TCON_N;$$

$$= APEAK_t \cdot OPEAK_t + ABL_t \cdot OBL_t \cdot RELBL + ABL_t \cdot OBUP_t \cdot (1 - RELBL). \quad \text{for } TCON_N \leq t \leq T.$$

PWTOC: Present worth of total operating cost.

$$PWTOC = \sum_{t=0}^{T} YOC_t \cdot \left(\frac{1}{1 + I}\right)^{t+1}.$$

Annual Maintenance Cost

A_t: Total investment made on base load up to and including year t in current dollars.

MBL: Maintenance percentage of base load.

MFC: Maintenance rate of fuel cells per unit of heat supplied in year zero dollars.

MBUP: Maintenance rate of back-up capacity per unit of installed capacity in year zero dollars.

$XBUP_t$: Installed back-up capacity in year t.

MPEAK: Maintenance rate of peak capacity per unit of installed capacity in year zero dollars.

XPEAK: Installed peak capacity in year t.

PWTMC: Present worth of total maintenance cost.

YMC_t: Yearly maintenance cost in year t.

$$YMC_t = A_t \cdot MBL + (AFC_t \cdot MFC + XBUP_t \cdot MBUP + XPEAK_t \cdot MPEAK) \cdot (1 + F)^t.$$

$$PWTMC = \sum_{t=0}^{T} YMC_t \cdot \frac{1}{(1 + I)^{t+1}}.$$

Capacity Adjustments

QBL_n $(n = 1, \ldots N)$: Capacity of n^{th} cogeneration plant.

ΔBL_t: Base load capacity additions in year t.

XBL_t: Total base load capacity in year t.

For a given set of $TCON_n$ $(n = 1, \ldots N)$, XBL_t does not depend on demand and can be adjusted as follows: For a given t $(t = 0, \ldots T)$,

set $\Delta BL_t = 0$ initially. Then, adjust ΔBL_t as n goes n = 1 to n = N such that $\Delta BL_t = \Delta BL_t + QBL_n$ if $t = TCON_n$. Then,

$$XBL = \Delta BL_t \qquad \text{for } t = 0;$$

$$= XBL_{t-1} + \Delta BL_t \qquad \text{for } 1 \leq t \leq T.$$

D_t: Demand in year t.

QFC: Heat production capacity of one fuel cell ($4.5\ MW_e$) module.

K_t: Number of fuel cell modules added in year t.

XFC_t: Installed total fuel cell capacity in year t.

$$K_t = 0 \qquad , \text{ if } D_t \leq XBL_t \qquad ; \text{ for } t = 0.$$

$$= \text{Integer } \frac{D_t - XBL_t}{QFC} + 1, \quad \text{if } D_t > XBL_t$$

$$K_t = 0 \qquad , \text{ if } D_t \leq (XBL_t + XFC_{t-1})$$

$$= \text{Integer } \frac{D_t - (XBL_t + XFC_{t-1})}{QFC} + 1, \quad \text{if } D_t > (XBL_t + XFC_{t-1}) \qquad ;$$

$$\text{for } 1 \leq t \leq (TCON_N - 1).$$

$$XFC_t = K_t \cdot QFC \qquad \text{for } t = 0;$$

$$= XFC_{t-1} + K_t \cdot QFC \qquad \text{for } 1 \leq t \leq (TCON_N - 1);$$

$$= 0 \qquad \text{for } t \geq TCON_N.$$

$XBUP_t$: Installed back-up capacity in year t.

For a given set of $TCON_n$ (n = 1, ... N), $XBUP_t$ does not depend on demand either and can be adjusted as follows: Set

$$XBUP_t = QFC \cdot FCLOC \quad \text{if } t = 0$$
$$= XBUP_{t-1} \quad \text{if } t > 0, \text{ initially.}$$

Then, for a given t (t = 0, ... T), adjust $XBUP_t$ as n goes n = 1 to n = N such that $XBUP_t = QBL_n$ if $t = TCON_N$ and $XBUP_t < QBL_n$.

$\Delta PEAK_t$: Peak capacity additions in year t.

$XPEAK_t$: Installed peak capacity in year t.

$$\Delta PEAK_t = 0 \quad \text{if } D_t \leq XBL_t$$
$$= D_t - XBL_t \quad \text{if } D_t > XBL_t \quad ; \text{ for } t = TCON_N.$$

$$\Delta PEAK_t = 0 \quad \text{if } D_t \leq (XBL_t + XPEAK_{t-1})$$
$$= D_t - (XBL_t + XPEAK_{t-1}) \quad \text{if } D_t > (XBL_t + XPEAK_{t-1}) \quad ;$$
$$\text{for } (TCON_N + 1) \leq t \leq T.$$

$$XPEAK_t = 0 \quad \text{for } t < TCON_N;$$
$$= \Delta PEAK \quad \text{for } t = TCON_N;$$
$$= XPEAK_{t-1} + \Delta PEAK_t \quad \text{for } (TCON_N + 1) \leq t \leq T.$$

Objective Function

TPWC: Total present worth of cost.

$$\text{Min. } TPWC = PWICBL + PWICFC + PWICBU + PWICPK + PWTOC + PWTMC - PWSAL$$

with respect to $TCON_n$ (n = 1, ... N), subject to

$$(XBL_t + XFC_t) \geq D_t \qquad \text{for } 0 \leq t \leq (TCON_N - 1),$$

$$(XBL_t + XPEAK_t) \geq D_t \qquad \text{for } TCON_N \leq t \leq T,$$

and $T \leq ULFC$ to avoid negative salvage values.

C. CONCLUSION

A computer model which determines the optimum connection times of cogeneration plants in a district heating system with total iteration is developed. Both the listing and the flow chart of the model are included in Appendix A.

CHAPTER IV

IDEALIZED URBAN MODEL ANALYSIS

The objective of this chapter is to analyze the optimum connection time of the cogeneration heat source in a district heating system with an idealized urban model. The urban model utilized in this chapter was obtained from a doctoral dissertation written by Gerald D. Pine (34). The city is designed for a population of 54,000 and is assumed to be made of all single-family houses. A similar analysis is also performed on an urban model of all low-rise apartment buildings with the same population and is included in Appendix B.

A. DESCRIPTION OF THE URBAN MODEL

Figure 6 presents the entire city structure and the transmission pipeline for the district heating system in it. The city is assumed to be divided into 20 identical subsections. Figure 7 shows the subsection design. Each subsection is composed of 72 blocks, each of which contains 14 single-family houses. As can be seen from Figure 6, the transmission pipeline transmits thermal energy from the cogeneration heat source to five local nodes in the city, each of which serves four subsections. During the development stage, temporary heat sources can be located on these nodes to delay construction of the pipeline. Each subsection has its local distribution piping network which distributes thermal energy from the corresponding node to individual buildings. However, this piping network will be the same regardless of whether

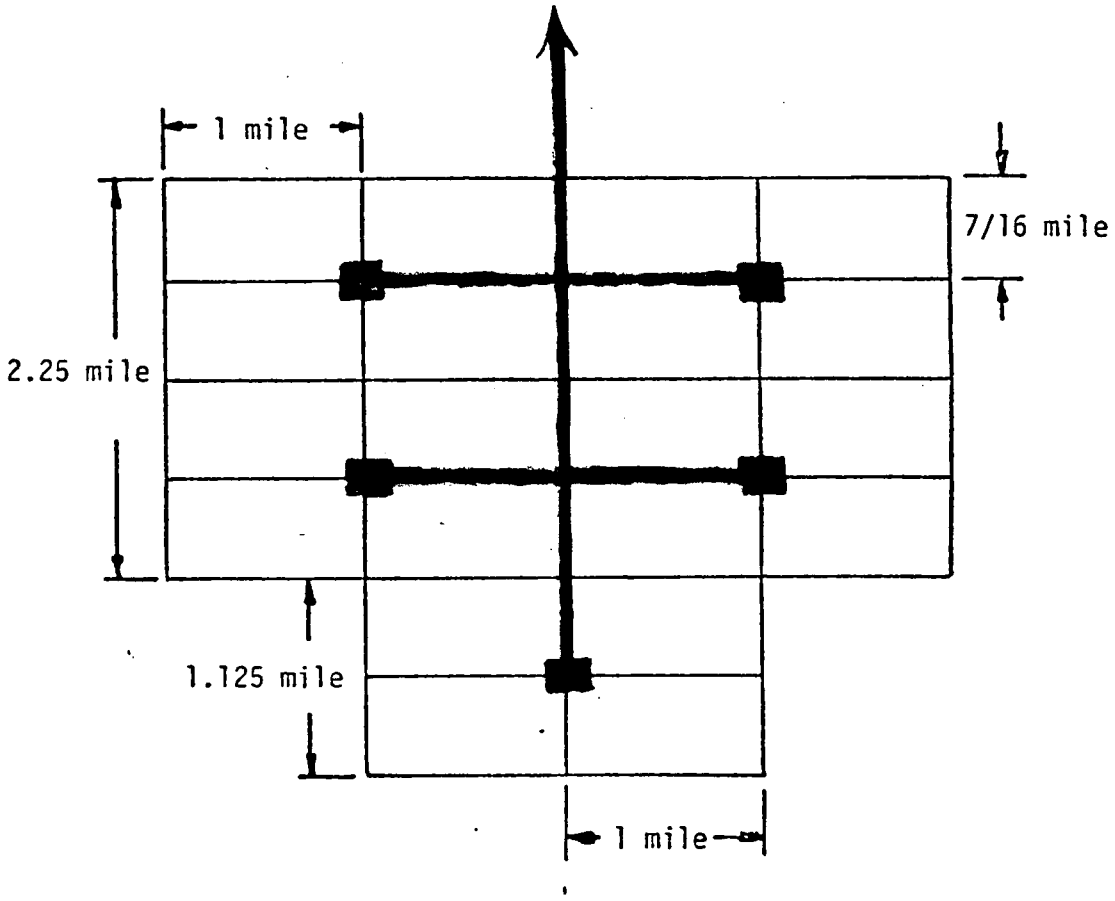


Figure 6. Entire City.

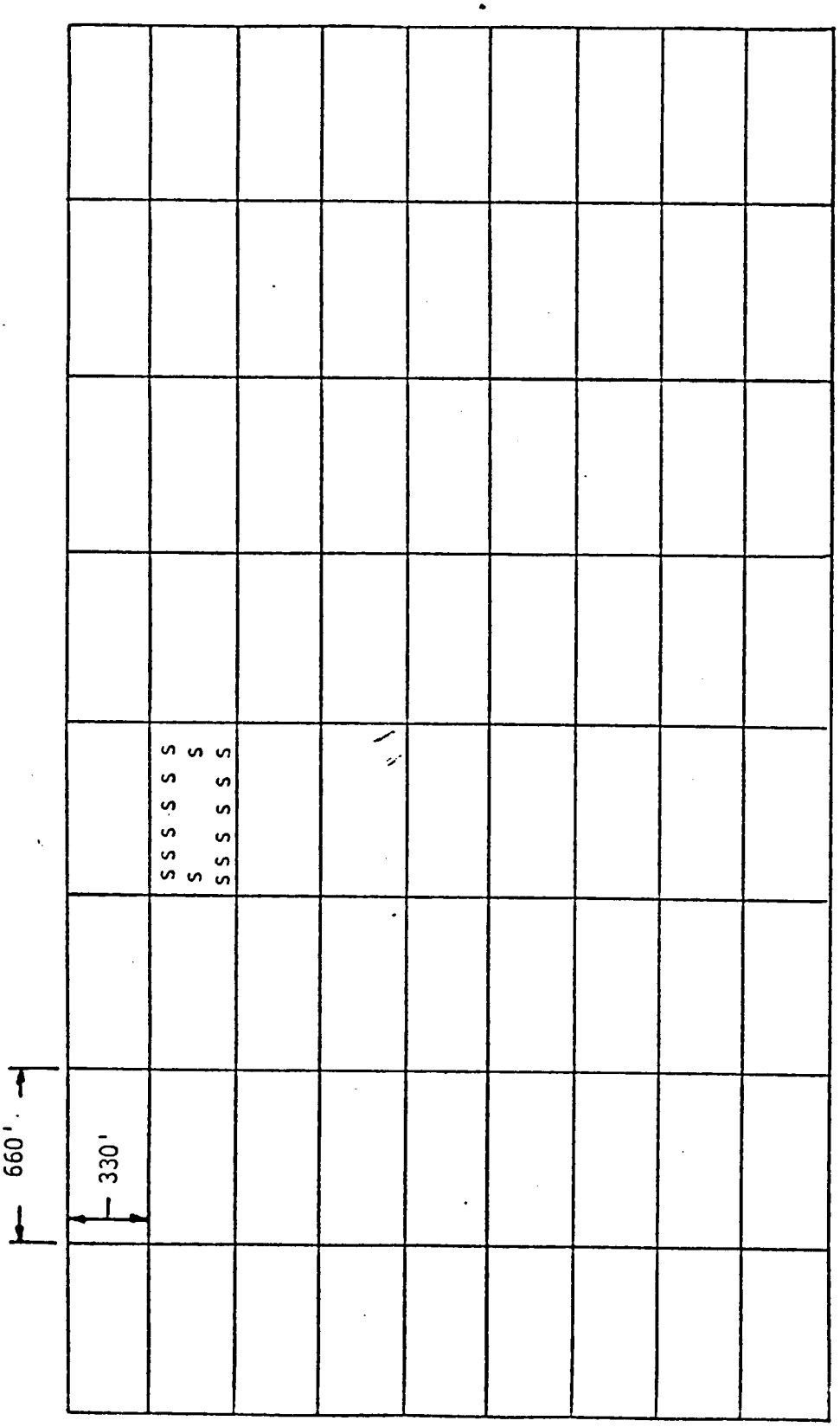


Figure 7. Subsection Design.

thermal energy is supplied from the cogeneration plant with the transmission pipeline or it is supplied from a local heat source at the node. Therefore, the cost of the distribution network is irrelevant to the economic analysis made here.

The housing density for the model is 1,792 houses per square mile. The population density is 6,200 persons per square mile by assuming 3.5 persons per house, and the house type is 1,600 square feet ranch style.

Two types of residential thermal energy demand are considered in this analysis: water heating loads and space heating loads. Thermal loads given in Pine's work are also utilized here. For the water heating load, it is assumed that each person consumes 58 gallons of hot water with a temperature rise of 80°F. The hourly load is assumed to be constant at 1/24 of the daily load. This corresponds to a load of 5,400 Btu/Hr per house. The space heating load is assumed to vary linearly with the outdoor temperature. It is assumed to be zero at 62°F outdoor temperature and above, and at its peak of 58,400 Btu/Hr per house at 5°F.

The peak load of the district heating system will be less than the sum of all consumer peak loads because it is not likely that all users require these loads simultaneously. Therefore, the total peak load for the entire system is generally expressed as the sum of all consumer peak loads times a rate which is called "coincidence factor." By using a coincidence factor of 0.72, the coinciding peak load for the entire city is 956.413 million Btu/Hr. This is the peak demand for the district heating system when all consumers are connected to it. For the base case analysis, it will be assumed that the demand grows to this level linearly over a period of 20 years.

In order to optimize the transmission pipeline and determine its cost, a computer model, also provided by Pine, is utilized. Pine's model determines the optimum pipe diameter (the one that minimizes the cost factors involved) for a given section of the transmission line and for given return and send-out temperatures. In this analysis, a return temperature of 160°F and a send-out temperature of 220°F are used to match the operating characteristics of end-user equipment and fuel cells. Pine's model uses the method of adjusting the system to the changes in the load by changing the amount of water sent out while holding the send-out temperature constant. This can also be accomplished by changing the send-out temperature and keeping the flow of the water constant.

For this analysis, the pipe cost, busbar electricity cost, and pumping electricity power cost given in Pine's model are updated to 1981 dollars. Also, the original model assumes eight extraction points in the cogeneration plant to calculate the lost electricity power cost. For this analysis, one extraction point is used.

New York City weather data are used for the analysis. Table 4 presents the average number of hours per year the temperature falls in each 5°F interval.

B. DATA

Fuel Cells

The cost of fuel cells is projected to be around \$400/KW_e in 1978 dollars at a production rate of 500 MW/Yr by the Electric Power Research Institute (19, p. 393). For this analysis, a cost of \$465/KW_e in 1981 dollars is assumed for fuel cells. Furthermore, \$17/MW_t is added to the

TABLE 4

HOURS SPENT IN 5°F TEMPERATURE BANDS--TEN-YEAR AVERAGE
(NEW YORK CITY DATA)

Temperature (°F)	Hours	Temperature (°F)	Hours	Temperature (°F)	Hours
105 to 109	0	65 to 69	877	25 to 29	330
100 to 104	0	60 to 64	754	20 to 24	188
95 to 99	5	55 to 59	745	15 to 19	96
90 to 94	28	50 to 54	722	10 to 14	26
85 to 89	96	45 to 49	796	5 to 9	10
80 to 84	265	40 to 44	838	0 to 4	0
75 to 79	604	35 to 39	858	-1 to -5	1
70 to 74	926	30 to 34	603	-6 to -10	

original cost for the investment in heat recovery equipment (4, p. 2-19). The cost of a gas turbine electric plant is around \$197/KW_e (27). For the electricity-producing capacities of fuel cells, 60% of this cost is assumed as an investment credit for the base case, and a sensitivity analysis is performed on this investment credit percentage. Therefore, a cost of \$1.63M is used as the investment cost on one module of 4.5-MW_e fuel cells for the base case.

The operating cost of fuel cells depends on the sell-back price and the amount of electricity produced, as well as the price and amount of input fuel required. The heat rate of fuel cells is projected to be 9,000 Btu/KWHr, and the breakdown of this input energy is given as follows (4, p. 2-3):

1. Electricity generated: 3,413 Btu/KWHr
2. Usable thermal energy: 4,120 Btu/KWHr
3. Rejected energy: 1,476 Btu/KWHr.

Therefore, the cost per million Btu of thermal energy produced by fuel cells is given with the following expression:

$$\frac{9,000}{4,120}\left(\begin{array}{c}\text{Cost of input fuel}\\ \text{per million Btu}\end{array}\right) - \frac{3,413}{4,120}\left(\begin{array}{c}\text{Sell-back price of electricity}\\ \text{per million Btu}\end{array}\right).$$

The sell-back price of electricity may vary from one region to another depending on the demand for electricity. For the base case, it is taken to be 60% of the busbar cost of electricity, and a sensitivity analysis is performed on it later.

The annual maintenance rate for fuel cells is assumed to be 5 mills/KWHr, and their useful life is taken to be 20 years (19).

Base Load

The cogeneration conversion cost of the power plant is assumed to be \$25/KW_t (29). To determine the cost of the transmission pipeline for a given base-load capacity, Pine's computer model is utilized.

Operating cost of the base load consists of two components: the busbar cost of lost electricity and the pumping power cost. Busbar cost of electricity is assumed to be \$0.049/KWHr. This cost is the sum of \$0.024/KWHr for the capital recovery of a power plant built in 1978, \$0.01/KWHr for the levelized maintenance cost, and \$0.015/KWHr for the levelized fuel cost of a coal-fired power plant of 9,832-Btu/KWHr heat rate (1, p. 8). Busbar cost of electricity is also used for the pumping power electricity cost by assuming that it is the same utility that

supplied the electricity and thermal energy. Two subprograms (PUMPEN and FRIC), which are used to determine annual pumping energy cost from Pine's computer model, are incorporated with the subprogram OPCOST developed here which determines the total annual operating cost. These two subprograms are also included in the program listing given in Appendix A. For the development of these subprograms, the reader is referred to the original source (34).

Annual maintenance cost of the base load is assumed to be 2% of its investment cost (29).

Heat-Only Boilers

The investment cost of heat-only boilers is taken to be \$55/KW_t, and the annual maintenance cost is computed with a rate of \$0.00016/Btu per hour, which corresponds to 1% of the investment cost on them (29). Boiler efficiency is assumed to be 75%, and their useful lives are assumed to be 20 years (15).

Fuels

Fuel prices obtained from Electric Perspectives (44, p. 39) and their predicted nominal rates of increase given by Data Resources, Inc. (8, p. 1-115) are presented in Table 5.

By using the data presented in this section, first, an analysis is performed to determine what percent of the peak load should be supplied by the base-load capacity in the following section. Then, the economics of delayed base-load connection time are analyzed in Section D.

TABLE 5

FUEL PRICES

Type	Price (1980 $/10^6 Btu)	Nominal Rate of Increase	
		1980-1985	1985-2000
Electricity	12.615	13.8%	9.2%
Natural Gas	2.313	20.4%	27.0%
Oil	4.988	27.7%	11.1%
Coal	1.393	11.3%	10.4%

Fuel cells use natural gas as the input fuel. For boilers, fuel oil is a more common input fuel than natural gas. However, in order to have consistency between the two types of heat sources when they are compared with each other, natural gas is used as the input fuel for boilers also.

C. OPTIMUM BASE-LOAD PERCENTAGE OF THE PEAK LOAD

The base-load capacity provided by the cogeneration plants in a district heating system is very capital intensive. However, it provides heat relatively cheaper than conventional sources such as heat-only boilers. In order for the large investment on the cogeneration capacity to be economical, it should have high utilization. The peak demand of a district heating system occurs only for a very short period of time in a given year. If the cogeneration capacity were made large enough to supply the peak demand, most of this capacity would have a very low utilization. Therefore, it may be more economical to design the

cogeneration capacity equal to some percent of the peak demand and use some other heat source with lower investment costs during peaking hours. The heat sources with low capital requirements generally have higher operating costs. However, they are utilized only short periods of time in a given year as peak heat sources.

The base load's percentage of the peak load is an economic decision involving a trade-off between the investment cost and the operating cost. As this percentage decreases, the investment cost on the base load decreases, but more heat has to be supplied from the peak heat sources with high operating costs.

Two factors are likely to affect this percentage. First, the cost of base load largely depends on the length of the transmission pipeline. The longer the plant-city separation, the less economical the base load. Therefore, for a longer plant-city separation, a lower optimum (most economical) base load percentage can be expected. Second, the operating cost of peak heat sources is expected to rise faster than the average inflation. Therefore, the higher the operating cost of the peak heat sources, the higher the optimum base load percentage will be. In fact, it will vary throughout the lifetime of the district heating system. However, it is a one-time decision and cannot be adjusted yearly because once the pipeline is constructed, it will stay the same.

An economic analysis on the base load's percentage of the peak load is performed on the urban model presented earlier in this chapter. Pine's computer model is used for the design of the transmission pipeline at different base-load capacities. Two types of heat sources, fuel cells and heat-only boilers, are considered as the peak heat

sources. Different plant-city separations are examined. Moreover, the analysis is performed with both 1981 and 1990 natural gas prices to present the effect of changing operating costs of peak sources.

Methodology

Optimization of the base load percentage is performed by minimizing the total annual cost. Total annual cost has the following components:

1. Investment cost on base load x capital recovery factor;
2. Annual maintenance cost of base load;
3. Cost of annual heat supplied by base load;
4. Investment cost of the back-up capacity x capital recovery factor;
5. Maintenance cost of back-up capacity;
6. Investment cost on peak load capacity x capital recovery factor;
7. Maintenance cost of peak load capacity; and
8. Cost of annual heat supplied by the peak load.

Decreasing the base load's percentage decreases the cost of items 1-5 and increases the cost of items 6-8.

Investment costs are levelized with a discount rate of 11% over 20 years' useful life for fuel cells and boilers and 30 years' useful life for the base load.

Results With Fuel Cells

As mentioned earlier, a heat source to be used for the peak capacity should have a low investment cost, and its operating cost is not crucial. The data obtained and presented in Section B of this

chapter proved opposite of this for fuel cells. They have very high investment costs, and with today's natural gas prices and the selling back of by-product electricity, they have very low operating costs. Therefore, one may suspect that they should not be applicable as peak heat sources. Results obtained on fuel cells and presented in Figure 8 show that, in fact, this is the case. Figure 8 gives the total annual cost versus base load percentage of the peak load. With a proper peak heat source (one with low investment and high operating costs), one would expect a convex curve with a minimum. However, the curves with fuel cells as peak heat sources have concave shapes with maximums. With the decreased percentage of base load, the total annual cost increases initially. This is because of the high investment costs of fuel cells and the low utilization of this investment. Then, the cost reaches a maximum and starts decreasing as the utilization of fuel cells is increased. For the plant-city separation of five miles, the least annual cost case is to have 100% base load. However, if the figure is examined carefully, it can be seen that the case of using all fuel cells and no base load gives the lowest cost. This indicates that for a plant-city separation of ten miles or more, fuel cells are competitive with cogeneration heat sources. However, this competitiveness can be expected to decrease in the future with the predicted increase in natural gas prices.

In conclusion, the analysis with fuel cells showed that they are not desirable as peak heat sources. However, they may be economical as temporary heat sources during the development stage of district heating systems. As the temporary heat sources, they would have higher utilization. This analysis is performed in Section D of this chapter.

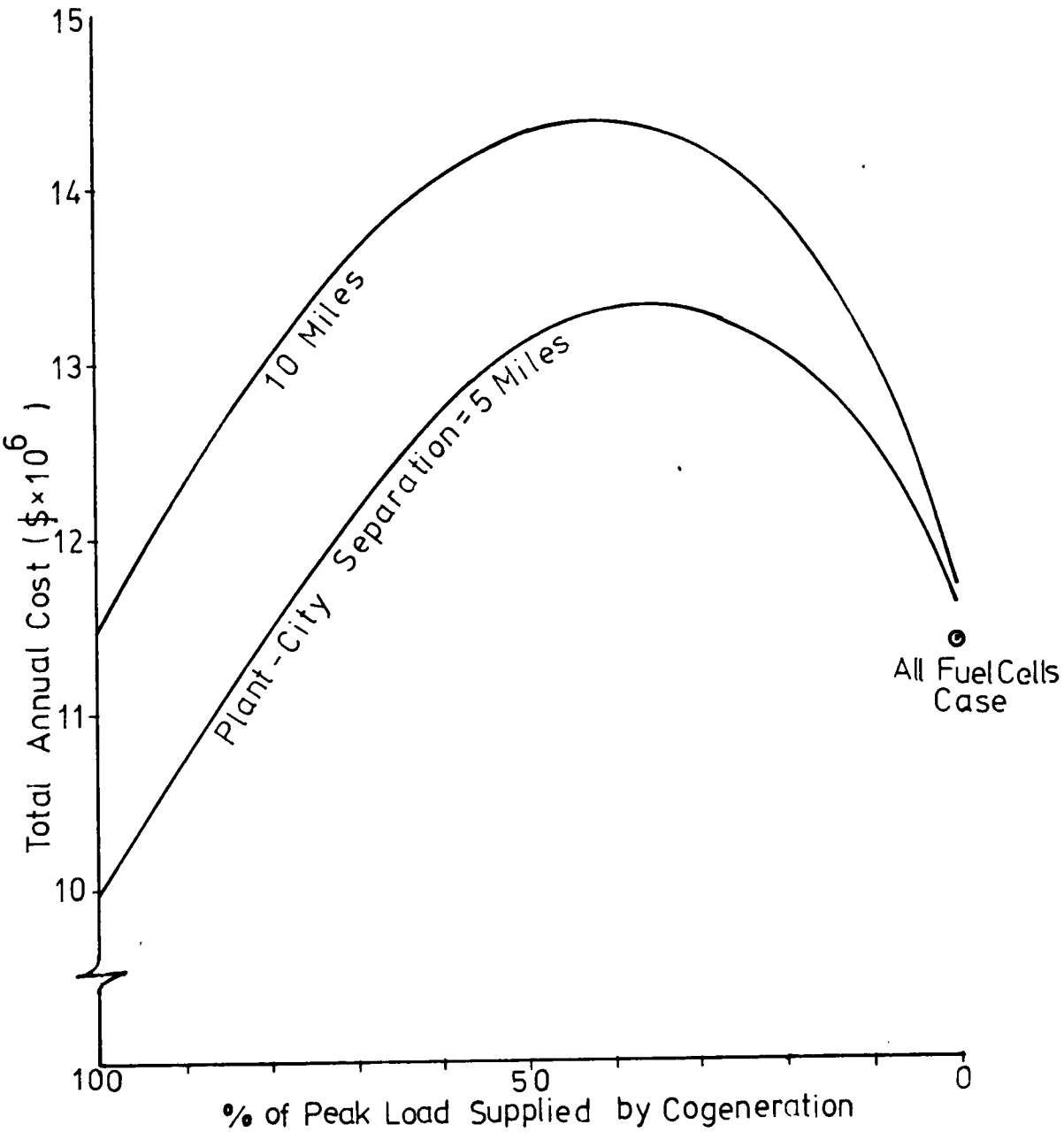


Figure 8. Fuel Cells--Total Annual Cost Vs. Percent Peak Load Supplied With Cogeneration.

Results With Heat-Only Boilers

Figure 9 shows the total annual cost versus the base load's percentage of the peak load for the case of heat-only boilers as the peak heat sources with 1981 natural gas prices. Boilers present the expected convex form with relative minimums. The total annual cost decreases initially, reaches a minimum, and starts rising as the capacity of base load is decreased. For the plant-city separation of five miles, the relative optimum, which is about 52%, is the actual optimum. However, at ten miles, the total annual cost with heat-only boilers is lower than the corresponding relative optimum, indicating that it is more economical to supply the entire demand with boilers if the plant-city separation is ten miles or more. This is a surprising result that does not agree with the feasible transport distances of thermal energy from cogeneration plants given in other sources (29, 37). However, the reason for having such a short feasible transport distance is the relatively low price of natural gas compared to the price of fuel oil. Therefore, the same analysis is performed with 1981 fuel oil prices, and the results are presented in Figure 10. As can be seen from the figure, even at a plant-city separation of 40 miles, the cogeneration heat source is feasible, and at 50 miles, boiler-only cases become more economical; this agrees with the results given in the sources cited above.

As mentioned earlier, the optimum base load percentage varies with the operating cost of the peak heat sources. The same analysis made with 1981 natural gas prices is also performed with 1990 natural gas prices. For this analysis, the natural gas prices are inflated with the rates given in Table 5, page 60. The other cost items are

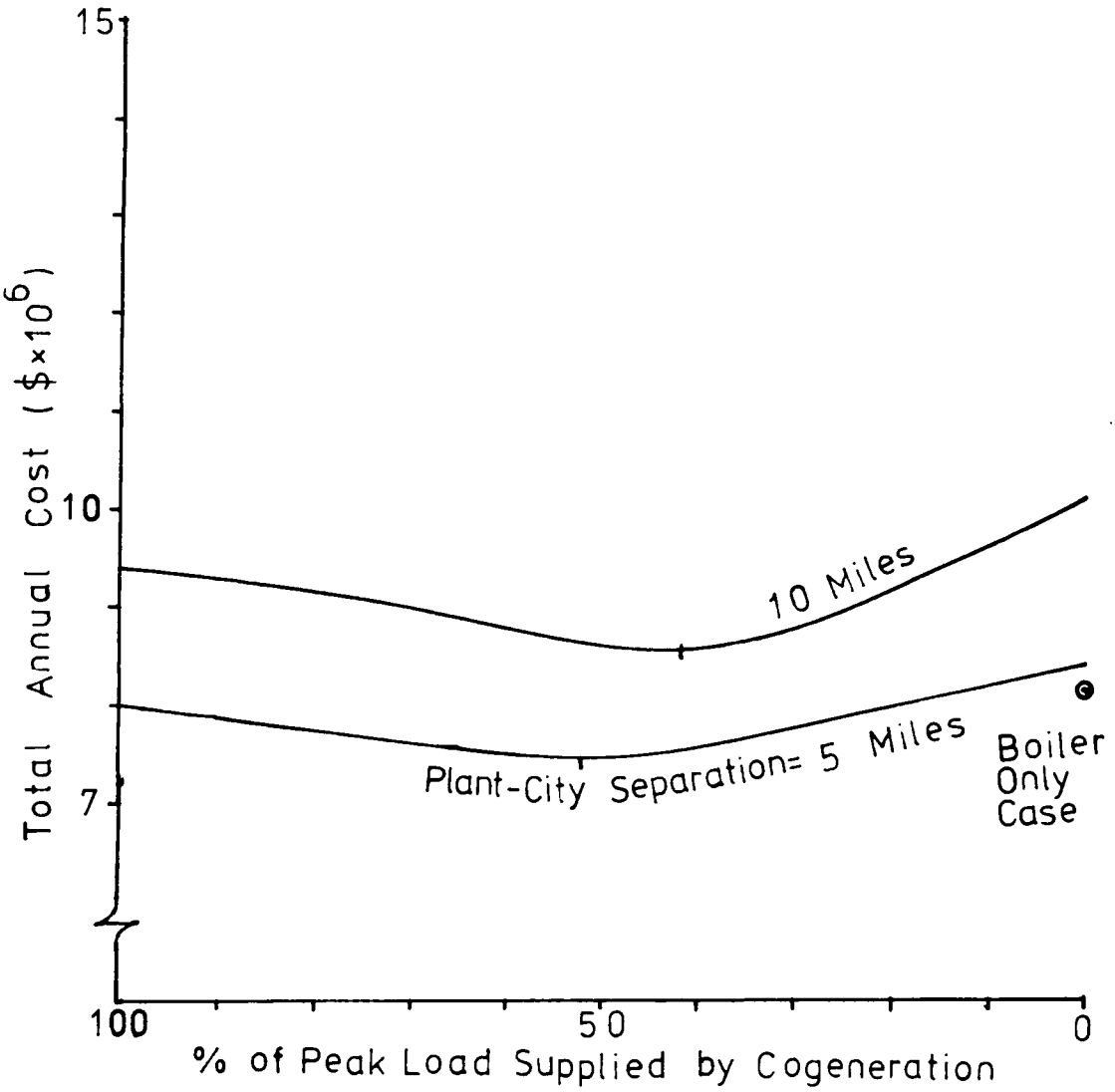


Figure 9. Boilers--Total Annual Cost Vs. Percent of Peak Load Supplied With Cogeneration, 1981 Natural Gas Prices.

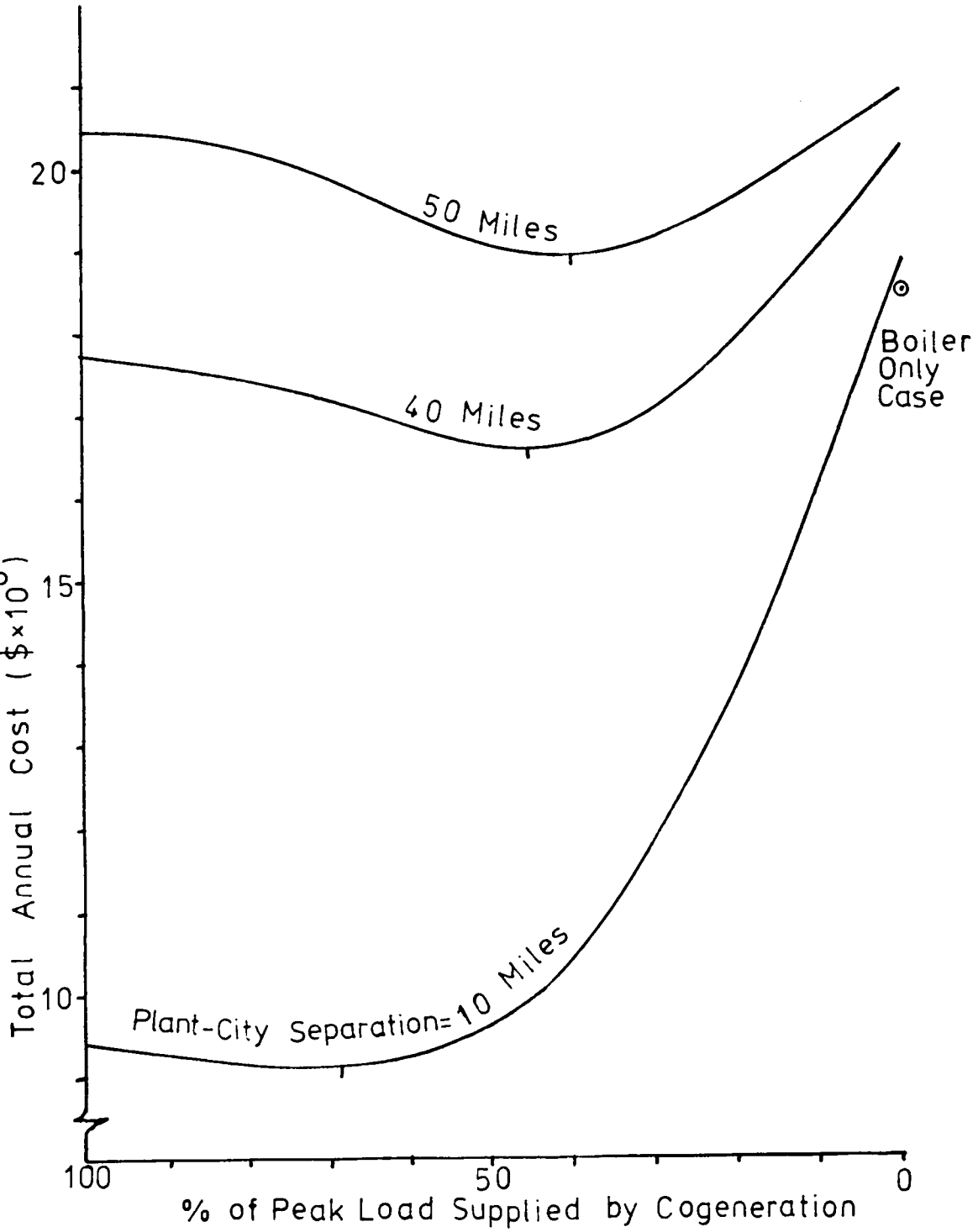


Figure 10. Boilers--Total Cost Vs. Percent of Peak Load Supplied With Cogeneration, 1981 Fuel Oil Prices.

inflated with the average inflation rate of 9%. Figure 11 presents the total annual cost versus the base load's percentage of the peak load for this case. As can be seen from the figure, even at 70 miles of plant-city separation, the cogeneration heat source is feasible with 1990 natural gas prices as compared to ten miles obtained previously with 1981 prices. The optimum base load percentage changes considerably also from around 52% with 1981 prices to 77% with 1990 dollars for the plant-city separation of five miles. Figure 12 shows the optimum percent of peak load represented by the base load versus plant-city separation. The optimum base load capacity decreases as the separation increases.

For the analysis made on the delayed connection of the base load in the next section, the results obtained with 1990 dollars in this section are used. The year 1990 corresponds to the middle of a 20-year study period considered in the next section

D. ANALYSIS OF OPTIMUM CONNECTION TIME OF BASE LOAD

Effects of delaying the construction of the transmission pipeline between the cogeneration plant and the urban area on the economics of a district heating system are examined with the computer model. Analysis is performed on the district heating model discussed in Section A of this chapter.

Two types of temporary heat sources are considered: fuel cells and heat-only boilers. Fuel cells use natural gas as the input fuel. In order to have consistency between the two types of heat sources, natural gas is also used as the input fuel to the heat-only boilers.

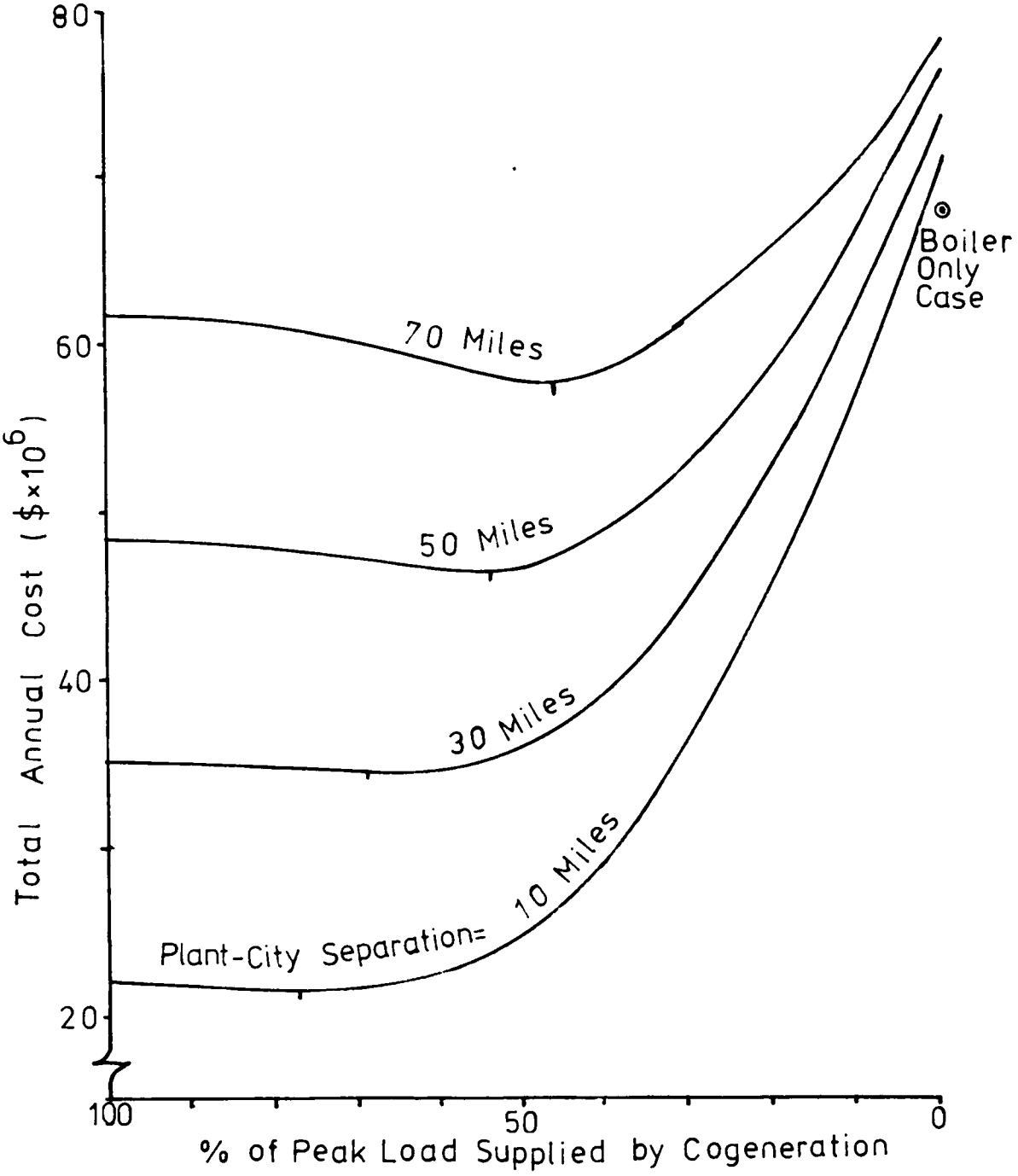


Figure 11. Boilers--Total Cost Vs. Percent of Peak Load Supplied With Cogeneration, 1990 Natural Gas Prices.

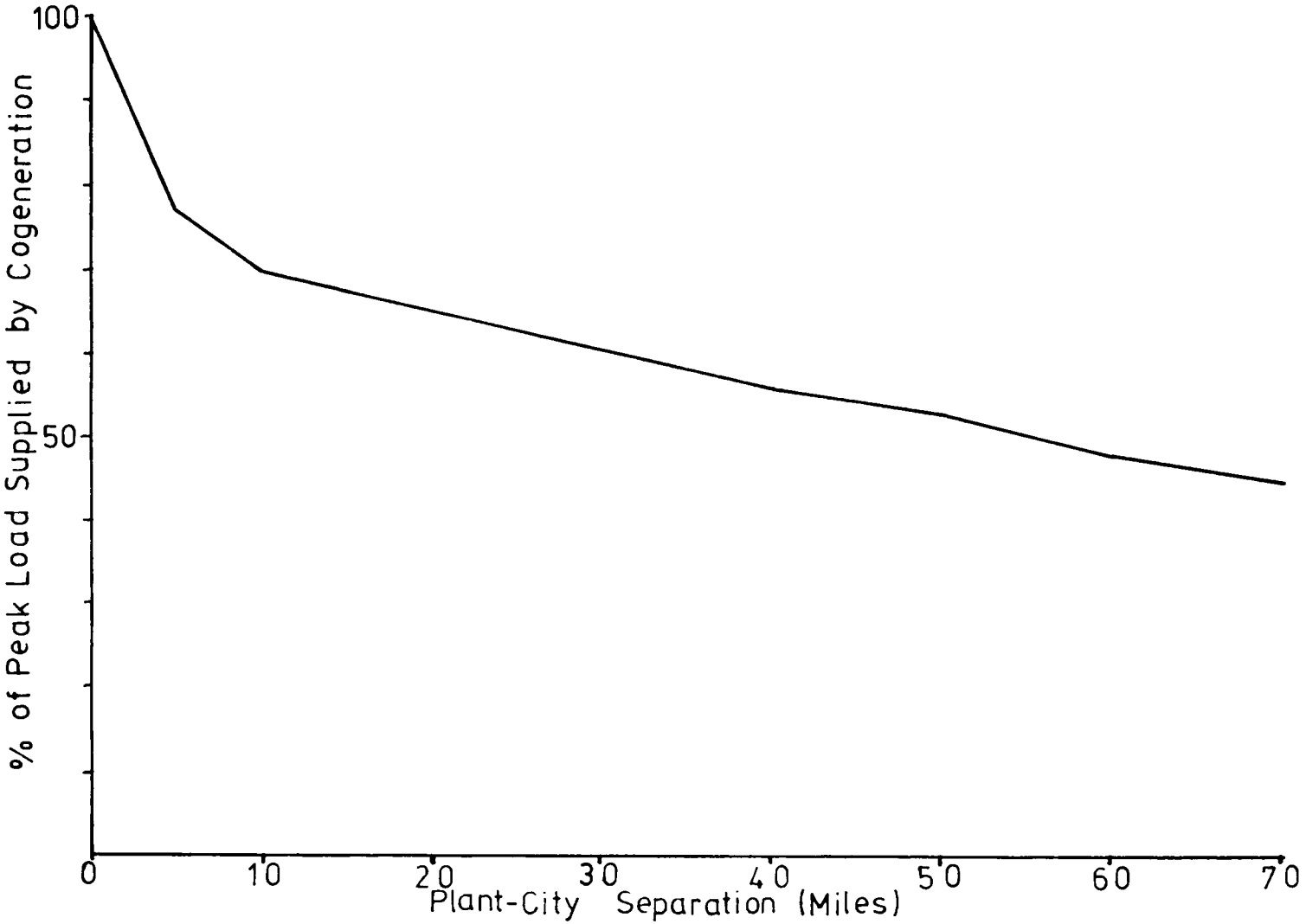


Figure 12. Optimum Percent of Peak Load Supplied By Cogeneration Vs. Plant-City Separation With Heat-Only Boilers, 1990 Natural Gas Prices.

The following values are utilized for the involved parameters as the base case, and sensitivity analyses are performed on each of them in the next section:

1. Plant city separation = ten miles.
2. Growth period of demand = 20 years.
3. Discount rate = 11%.
4. Annual natural gas price increase = 20.4% between the years one and five and 27% afterwards.
5. Sell-back price of electricity produced by the fuel cells = 60% of the busbar cost of electricity.
6. Investment credit on fuel cells for their electricity-generating capacities = 60% of the cost of a gas-fired electricity generator.

Figures 13 and 14 show the sensitivity of the cost components to connection year of the base load for the cases with fuel cells and with boilers respectively. The most sensitive cost component is the operating cost for both cases. However, its sensitivity is low for the early connection years but increases tremendously for the later years because of the expected rise in natural gas prices. The operating cost with fuel cells initially decreases with the delayed connection of the base load and then starts rising. This is because of the low operating cost of the fuel cells with present natural gas prices. In fact, the fuel cells have lower operating cost than the base load during the initial years if the by-product electricity can be sold at 60% of the busbar cost. Investment cost on the temporary heat sources is more crucial with fuel cells than it is with the boilers, as might be expected

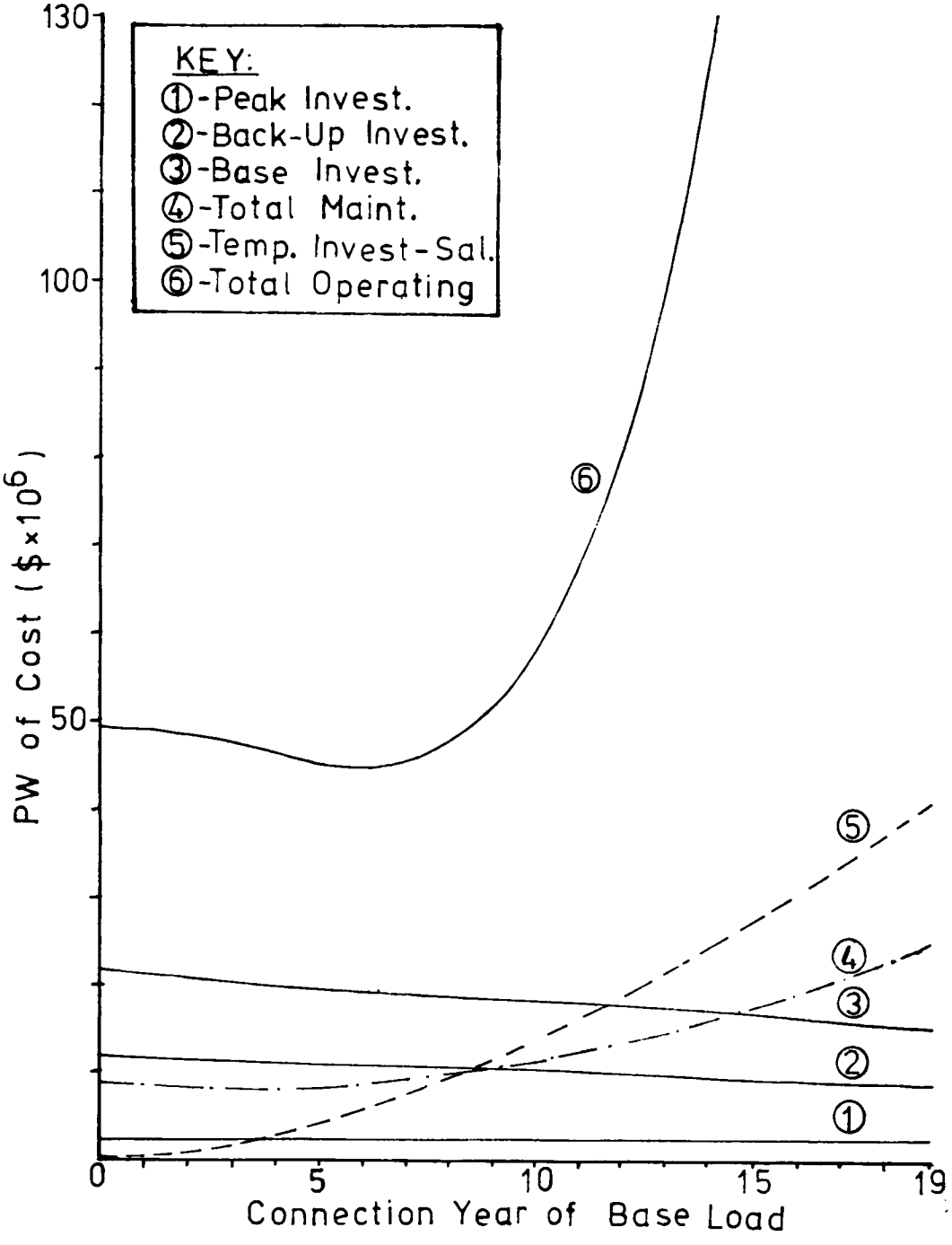


Figure 13. Cost Components Vs. Connection Year--House Model With Fuel Cells.

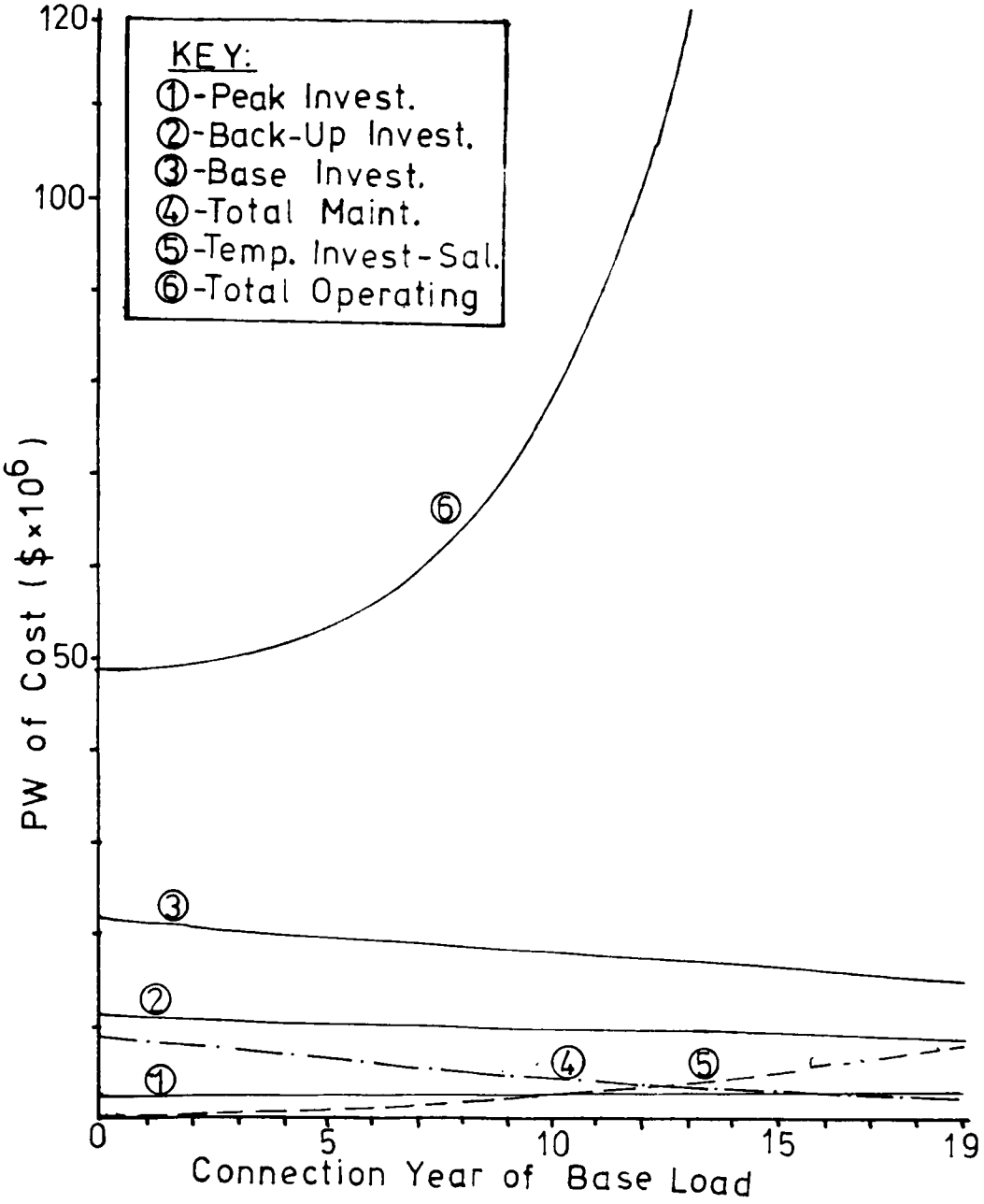


Figure 14. Cost Components Vs. Connection Year--House Model With Boilers.

because of the high costs of fuel cells. Investment on the base load and its back-up capacity decreases as they are made in later years. However, their sensitivity is low because of the low cost of capital for a municipally-owned utility (11% discount rate with 9% inflation). Considerable savings in total maintenance cost are realized with the delayed connection of the base load if heat-only boilers are used as temporary heat sources because of their low maintenance requirements. However, fuel cells have high maintenance costs; therefore, delaying the connection of the base load does not bring any substantial savings on the total maintenance cost for the fuel cell case. In fact, as can be seen from Figure 13, the total maintenance cost starts to increase if the base load connection is delayed more than three years with fuel cells.

Figures 15 and 16 present the behavior of total cost which is the sum of the cost components discussed for the cases with fuel cells and boilers, respectively. As can be seen from Figure 15, the optimum connection year of the base load is five years with fuel cells as temporary heat sources, and a savings of $2.910M is realized by delaying the connection of the base load five years as compared to immediate connection in year zero. This corresponds to 13.4% of the required investment cost on the base load and 3.1% of the life-cycle cost of the system. The term "optimum connection year" is used throughout this discussion, meaning the year of connection which provides the lowest total present worth of cost.

For the case with heat-only boilers as temporary heat sources, the optimum connection year is sooner compared to the case with fuel

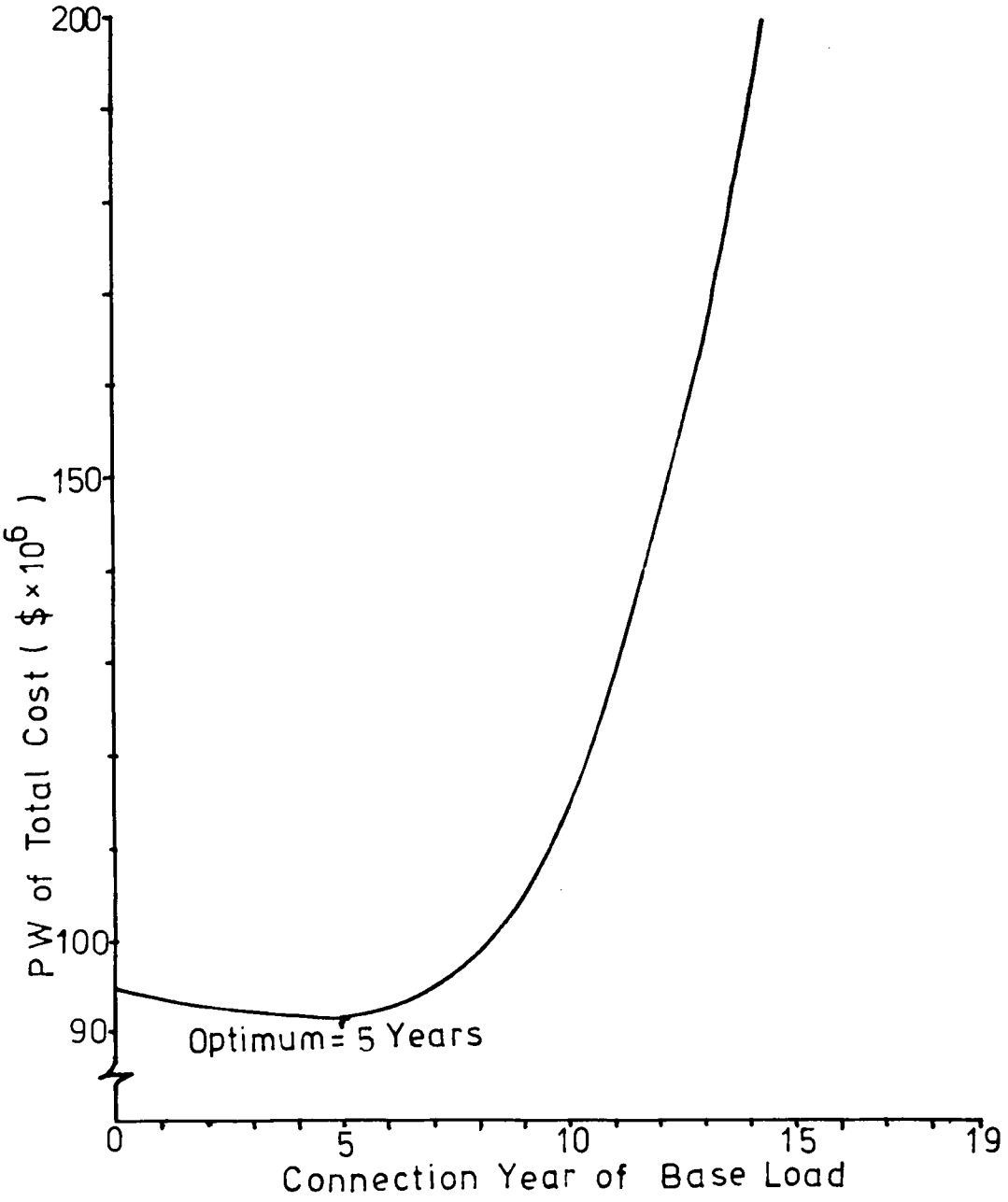


Figure 15. Total Cost Vs. Connection Year--House Model With Fuel Cells.

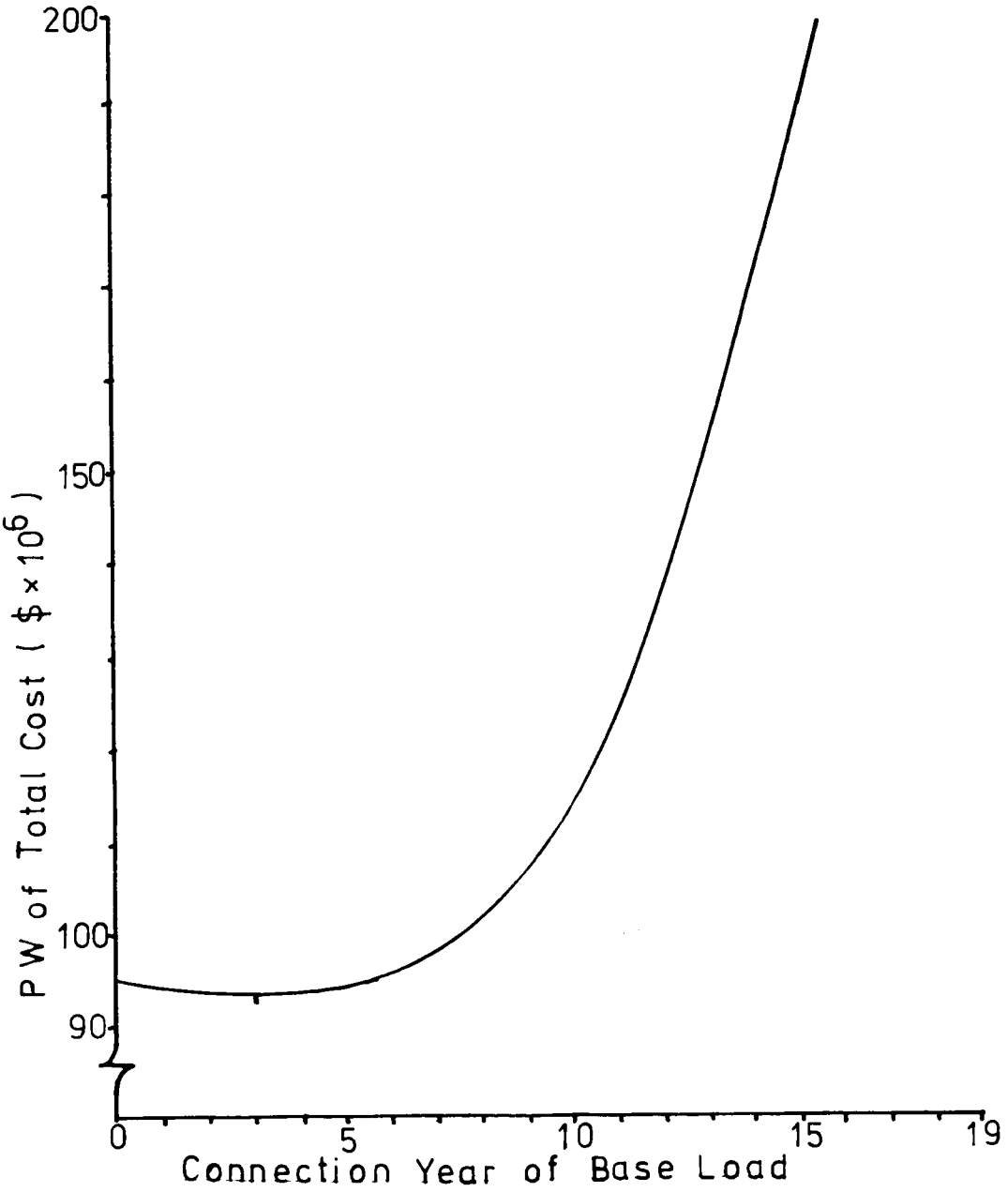


Figure 16. Total Cost Vs. Connection Year--House Model With Boilers.

cells, and the realized savings is smaller. As can be seen from Figure 16, the optimum connection year is year three, and the realized savings as compared to immediate connection is $1.611M. This savings corresponds to 7.4% of the required investment cost on the base load and 1.8% of the life-cycle cost of the system.

If the construction time of a transmission pipeline in a real-life situation is considered, a delay of three years is not very meaningful. However, five years presents a more meaningful delay.

For both cases, the sensitivity of the total cost to the change in the base load's connection year is low for early years in which the optimum is contained. Varying the connection year one or two years does not have a great impact on the total cost. However, the total cost increases substantially if the construction is delayed further. This is because of the expected rapid increase in natural gas prices. Overall, it is better to be on the early side than the late side.

For the base case, the results indicate that fuel cells are more economical as temporary heat sources compared to heat-only boilers. This is the case with the assumption that the electricity produced by fuel cells is sold at a price of 60% of the busbar cost. The comparison between these two heat sources greatly depends on the sell-back price of electricity, which is examined further in the following section.

E. SENSITIVITY ANALYSES

The sensitivity of the optimum connection time to changes in important parameters is analyzed with the computer model. The computer model gives the optimum connection year in discrete years. The data

points obtained with the model are directly plotted on the graphs presented in this section, and they are connected with straight lines. Therefore, the curves present broken patterns. In reality, these curves have smooth and continuous patterns. Nevertheless, they are sufficient to draw general conclusions on the behavior of the optimum connection time with the changes in parameters involved.

Plant-City Separation

The investment cost on the base load largely depends on the length of the transmission pipeline to be constructed. Naturally, the longer the plant-city separation, the greater the required investment cost on the base load. The effects of plant-city separation on the optimum connection time of the base load examined and the total costs versus connection year at different plant-city separations are presented in Figures 17 and 18 for the cases with fuel cells and boilers. The results obtained for up to ten years of connection are included in these figures in order to have a more sensitive scale on the graphs. Figure 19 shows the changes in the optimum connection year with the changes in plant-city separation.

As can be seen from Figures 17 and 18, the total cost becomes more sensitive to the changes in the connection time as the plant-city separation is increased. The longer the plant-city separation, the more savings are realized with the delayed connection year of the base load. However, even though the savings realized are sensitive, the optimum connection year is not very sensitive to the changes in plant-city separation. It is about one year per 20 miles. This is mainly due to two factors. First, the investment cost on the base load does

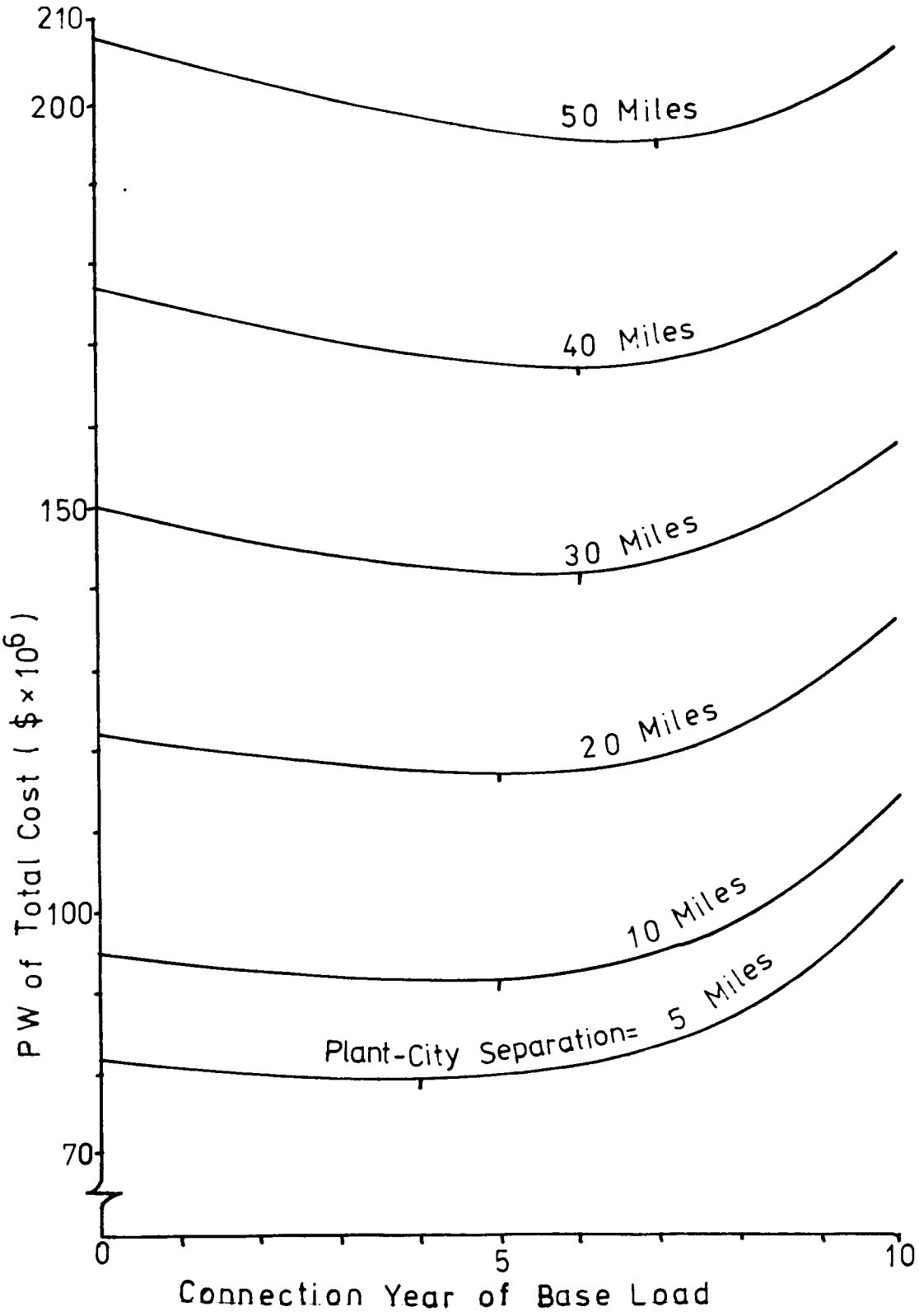


Figure 17. Total Cost Vs. Connection Year at Different Plant-City Separations for the House Model With Fuel Cells.

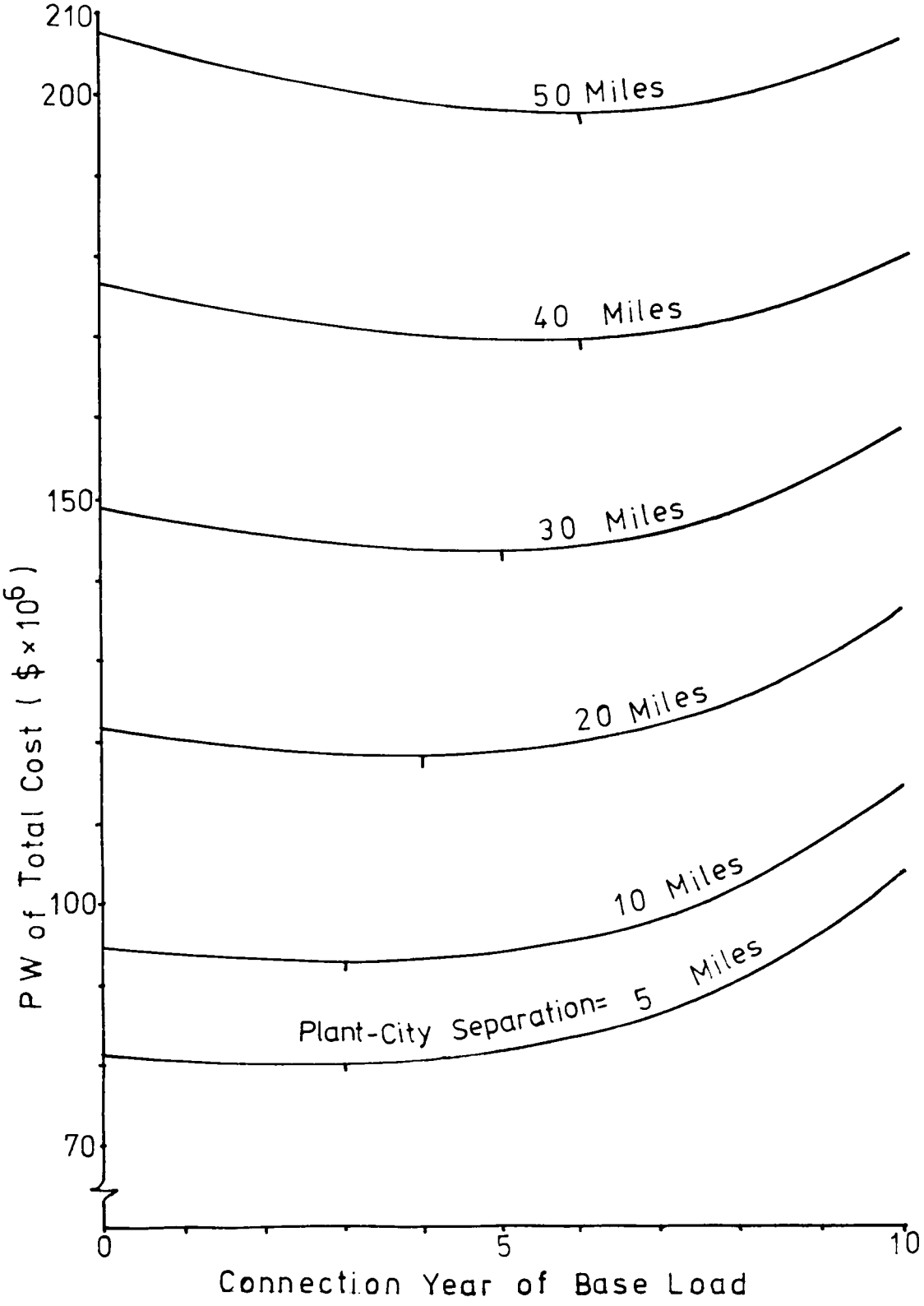


Figure 18. Total Cost Vs. Connection Year at Different Plant-City Separations for the House Model With Boilers.

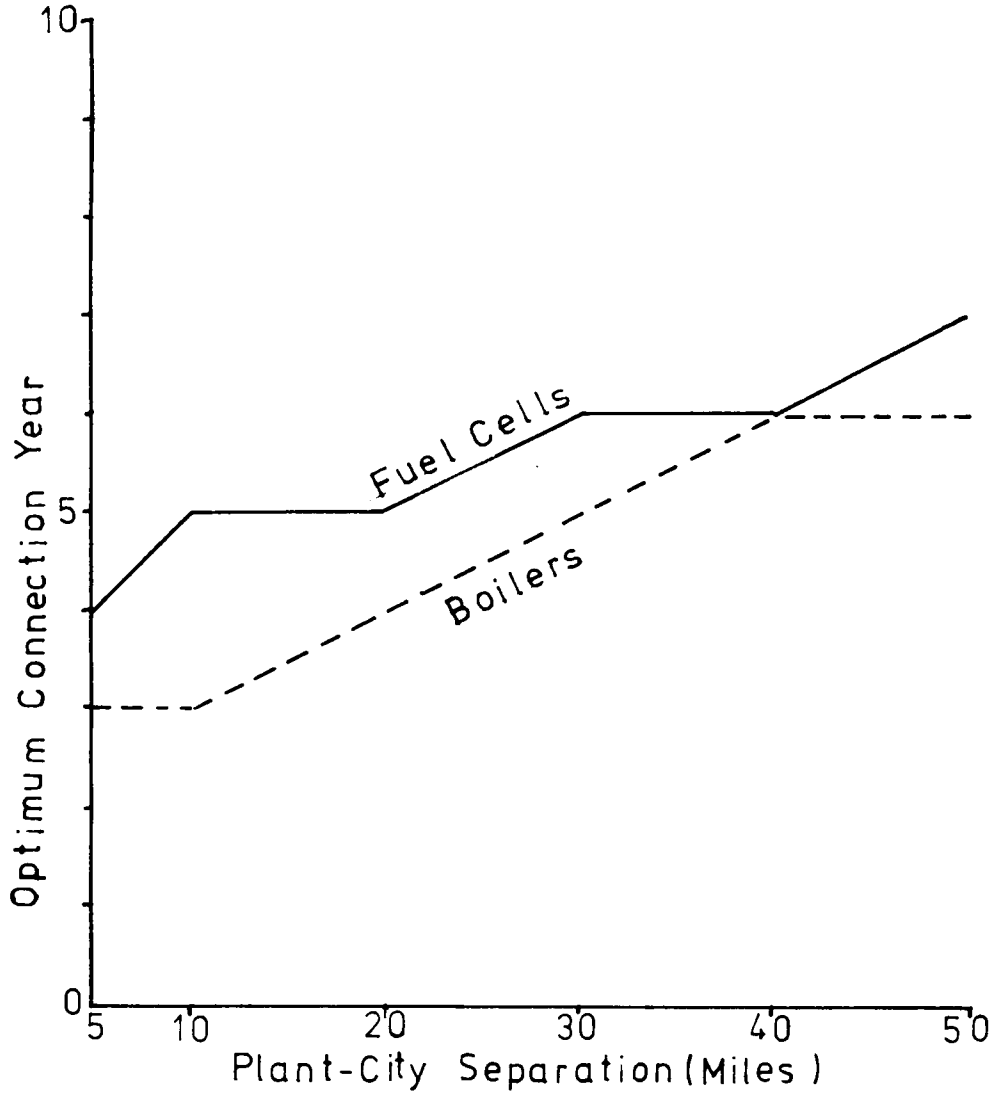


Figure 19. Optimum Connection Year Vs. Plant-City Separation--House Model.

not entirely depend on the length of the transmission pipelines. The two cost components (the cost of local transmission lines and the cost of converting the base load plant to cogeneration) included in the total base load investment cost do not vary with plant-city separation. Second, the distances longer than the base case distance of ten miles tend to shift the optimum connection year to a later year. However, the increased savings on the delayed investment cost due to delayed connection time is counteracted by the fast increase in natural gas prices.

Nevertheless, the general trend is that the longer the plant-city separation, the later the optimum connection year becomes, as might be expected.

Rate of Growth in Demand

For the base case, the demand is assumed to be growing linearly over 20 years. In this section, the effects of faster growth in demand are examined by changing the growth period. For example, a growth period of ten years results in twice the rate of growth as compared to a 20-year growth period. Growing demand pattern is one of the most important factors in this analysis. One main reason for delaying the construction of the base load plant is its low utilization because of the low demand during the initial years of the system's implementation. Generally, the faster the growth in demand, the higher the utilization of the base load for a given connection year. Therefore, the higher rates of growth are expected to result in earlier optimum connection times.

Figures 20 and 21 show the total cost versus connection year at different growth periods of demand with fuel cells and boilers, respectively. As can be seen from these figures, the magnitudes of savings

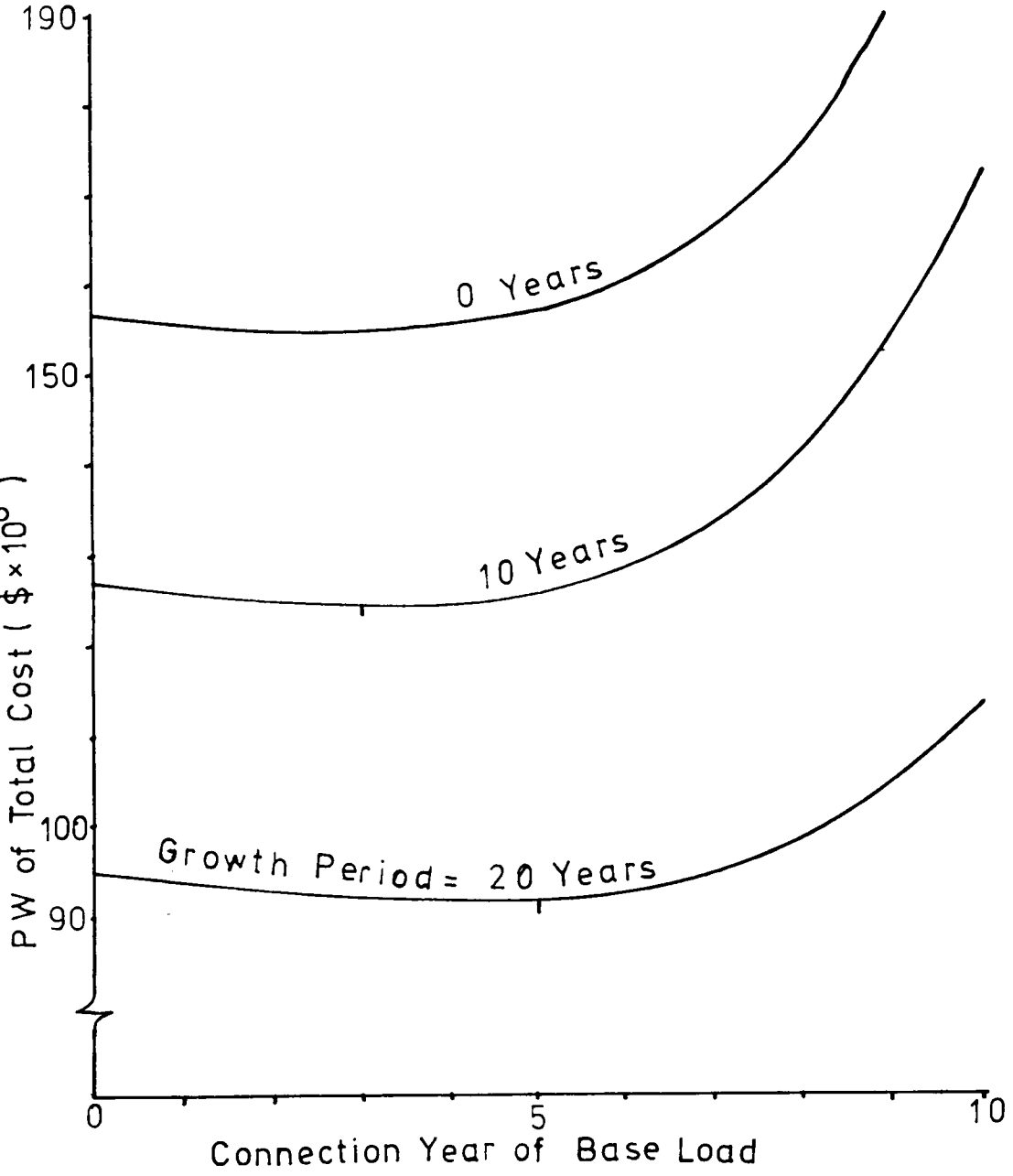


Figure 20. Total Cost Vs. Connection Year at Different Years for the Demand to Reach the Maximum Level--House Model With Fuel Cells.

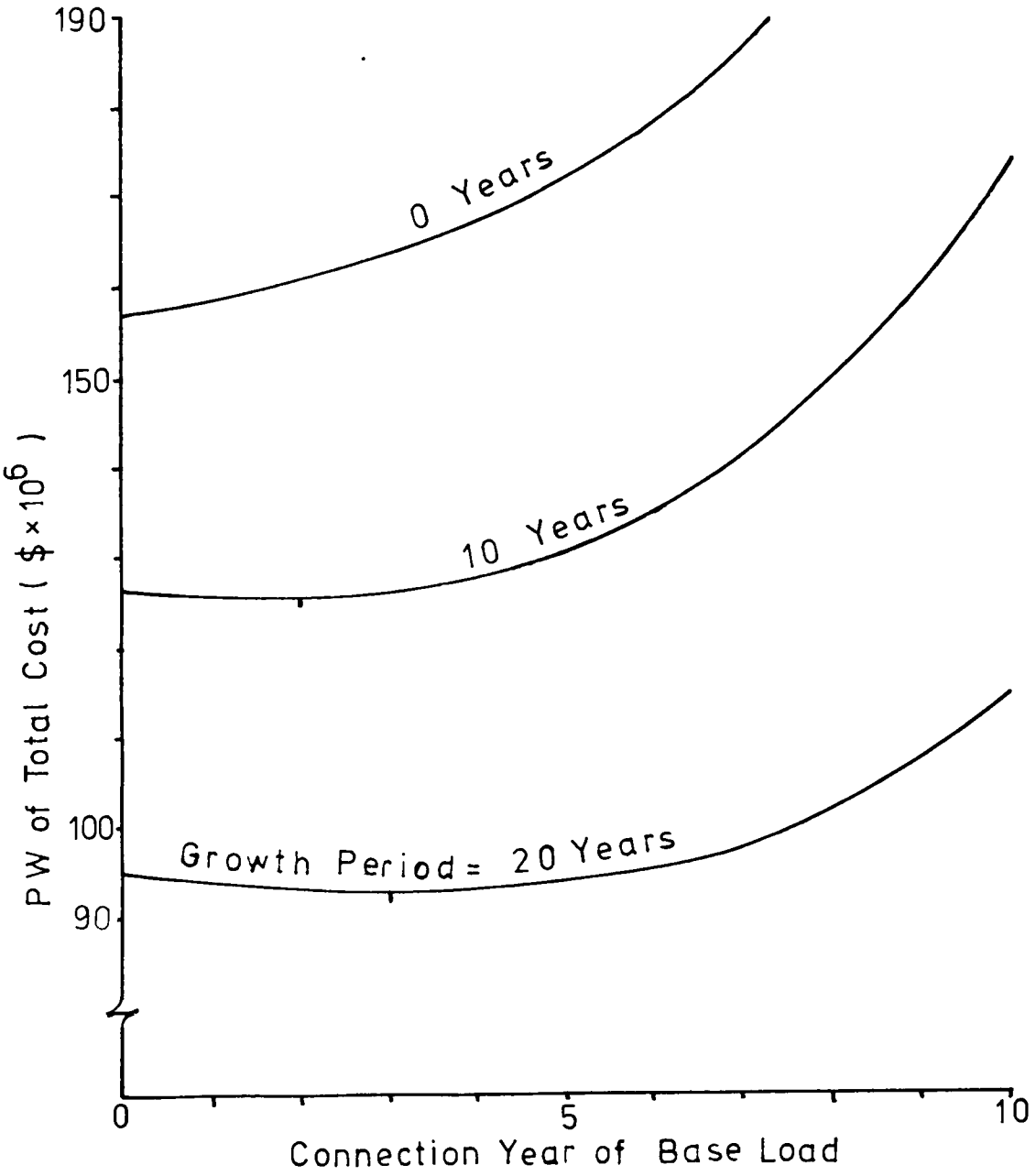


Figure 21. Total Cost Vs. Connection Year at Different Years for the Demand to Reach the Maximum Level--House Model With Boilers.

with the delayed connection time do not change considerably with the changes in the growth period. However, the optimum connection times are more sensitive to it. Figure 22 presents the optimum connection time versus growth period of demand for fuel cells and boilers as temporary heat sources. As can be seen from this figure, the faster the growth in demand, the sooner the optimum connection time. Generally, the sensitivity is higher for faster growth rates than it is for slower growth rates.

One interesting result is that even with the growth period of zero (which means that all the prospective demand is present in the initial year), optimum connection time is not zero if the fuel cells are used as temporary heat sources. This is because of the low operating cost of the fuel cells during initial years.

Discount Rate

One of the main objectives of delaying the connection of the base load to the system is to delay the large investment cost required on the base load. Delaying this investment results in considerable savings. However, the amount of savings largely depends on the cost of the capital for the utility firm that implements the district heating system. The higher the cost of the capital, the more economical the delay of investment cost on the base load. Consequently, the optimum connection year can be expected to shift to a later year.

The effects of the cost of capital on the optimum connection year are analyzed by changing the discount rate used. Figures 23 and 24 present the total cost versus connection year at different discount rates with fuel cells and boilers, respectively. The magnitude of savings increases as the discount rate increases because the cost of

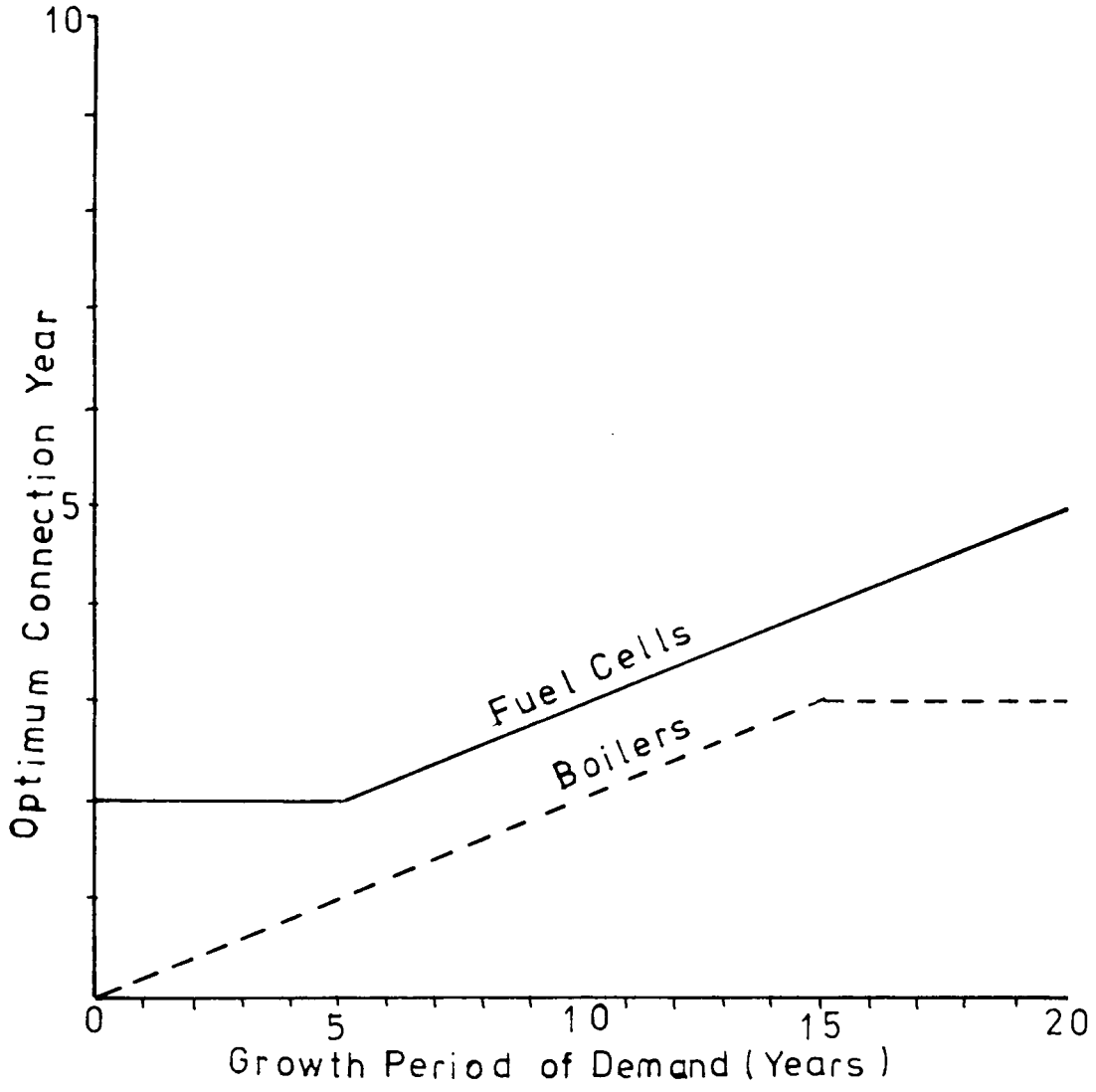


Figure 22. Optimum Connection Year Vs. Growth Period of Demand--House Model.

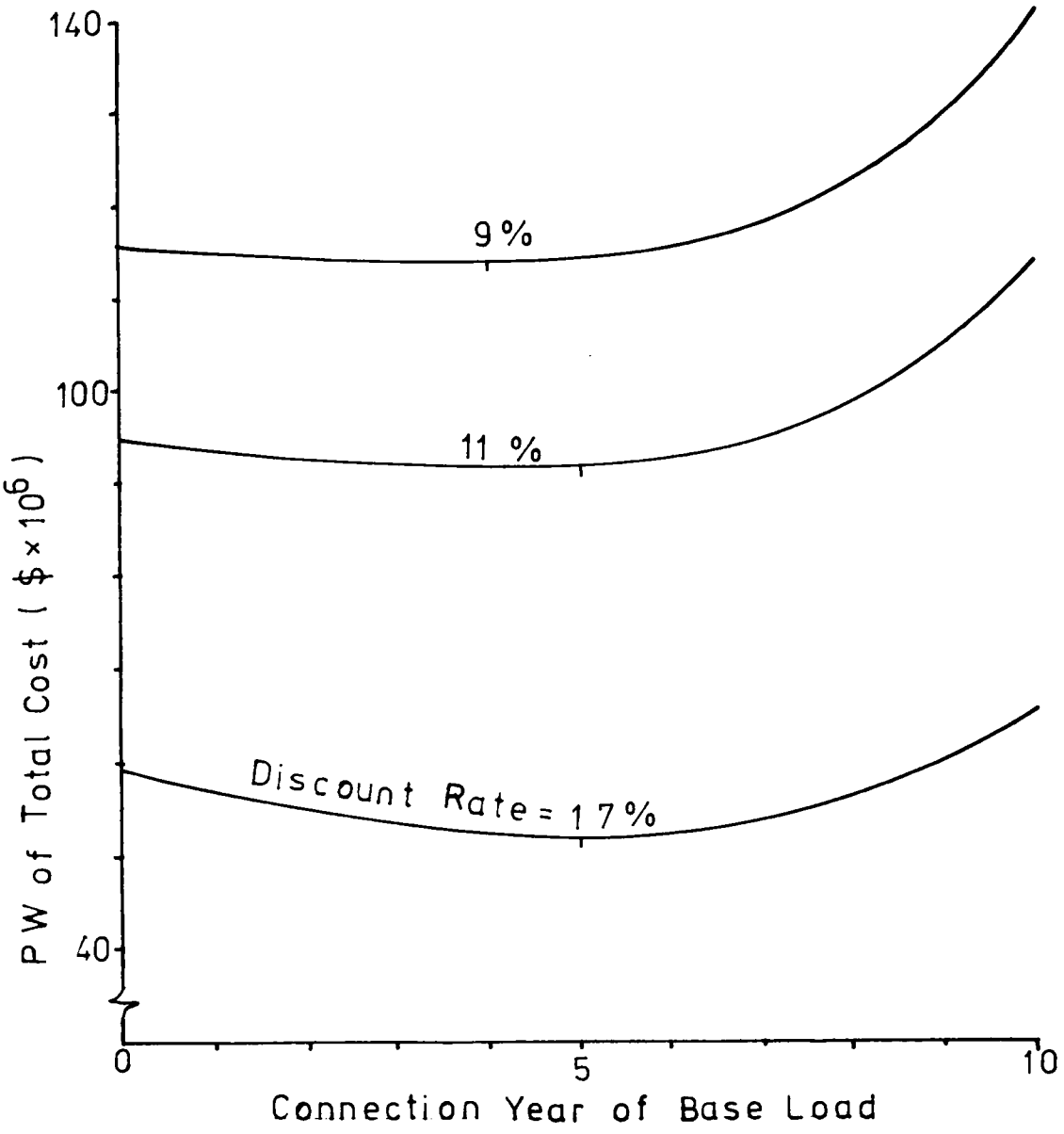


Figure 23. Total Cost Vs. Connection Year at Various Discount Rates--House Model With Fuel Cells.

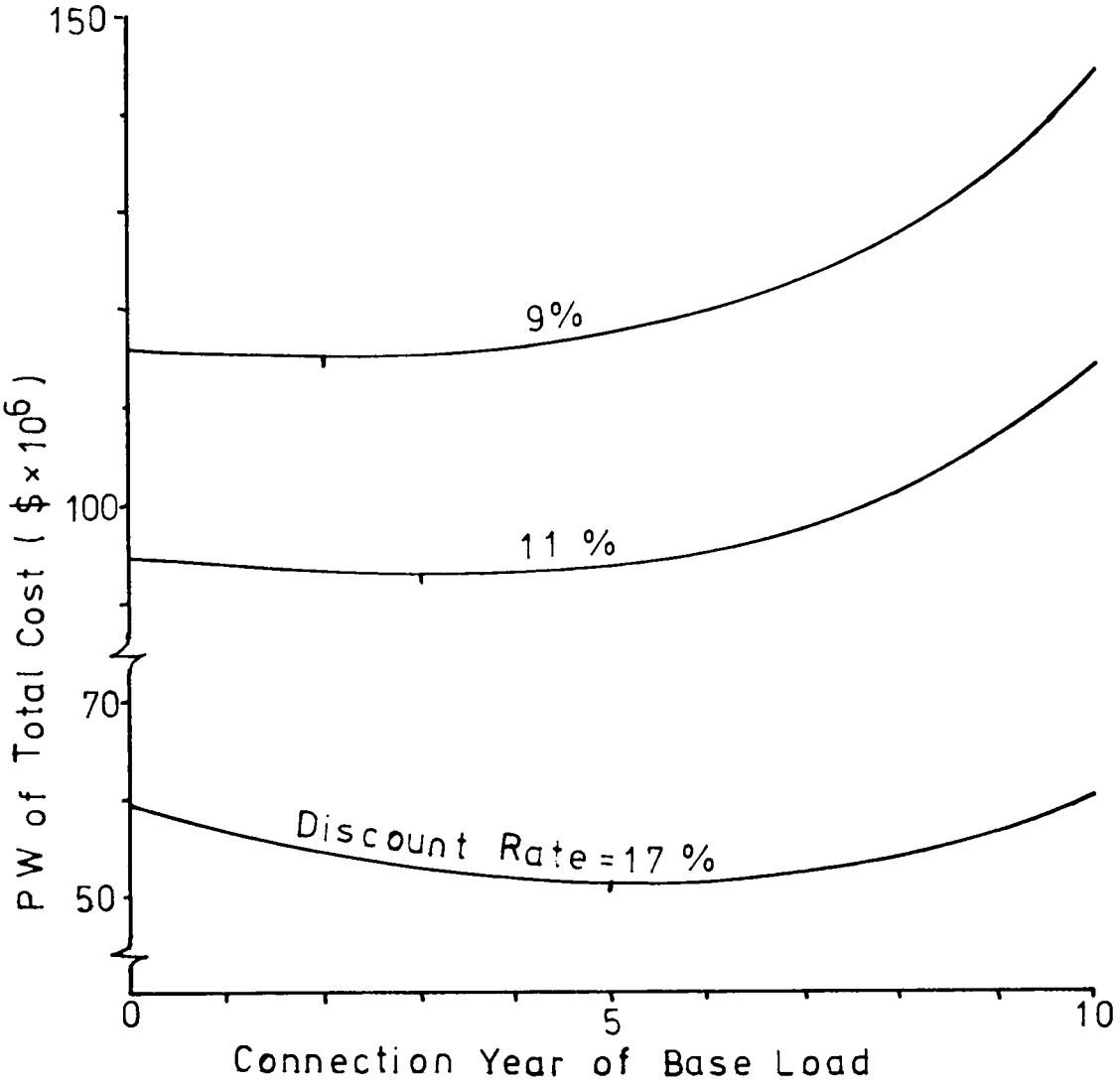


Figure 24. Total Cost Vs. Connection Year at Various Discount Rates--House Model With Boilers.

capital is higher with higher discount rates; however, the optimum connection year is very insensitive to changes in discount rate, especially if fuel cells are used as temporary heat sources. Figure 25 shows the optimum connection year versus discount rate with fuel cells and boilers as temporary heat sources. Insensitivity with fuel cells is more apparent in this figure. The higher discount rates tend to shift the optimum connection year to a later year than the five years found for the base case of 11%. However, the savings from the delayed investment cost on the base load is not large enough to make up the increases in the operating cost and the temporary heat sources' investment costs. These two cost components are less sensitive for the boilers; therefore, they yield more sensitive connection times to the changing discount rate.

The Rate of Natural Gas Price Increase

The price of natural gas is expected to increase considerably in future years. The higher the rate of this increase, the higher the operating cost of temporary heat sources, which makes it less desirable to keep them in service. Therefore, a higher rate of price increase for natural gas than the expected rate tends to shift the optimum connection time to an earlier year, and a slower rate tends to shift it to a later year.

The effects of the rate of natural gas price increase are examined by considering four other cases besides the base case. Rates of 25% and 50% faster and 25% and 50% slower than the expected rate are considered, and the total costs versus connection times at these different rates are presented in Figures 26 and 27 for fuel cells and boilers, respectively. Figure 28 presents the optimum connection year versus the

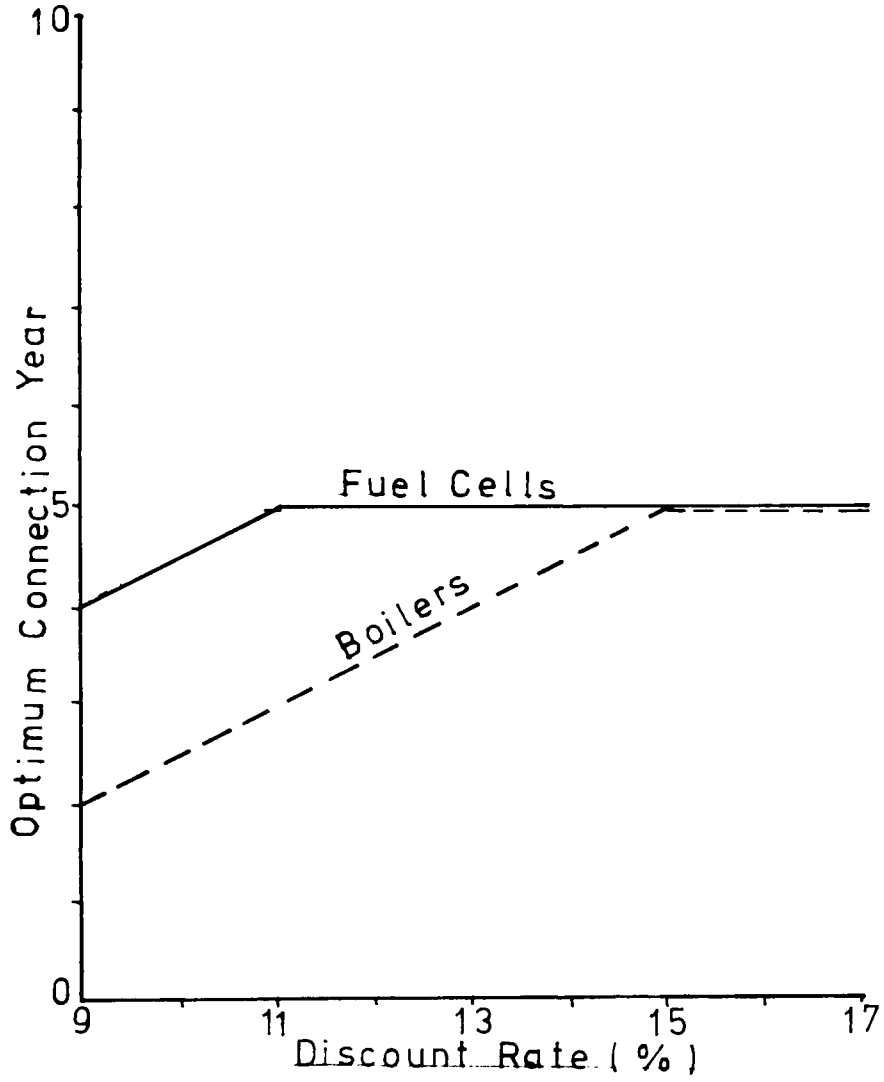


Figure 25. Optimum Connection Year Vs. Discount Rate--House Model.

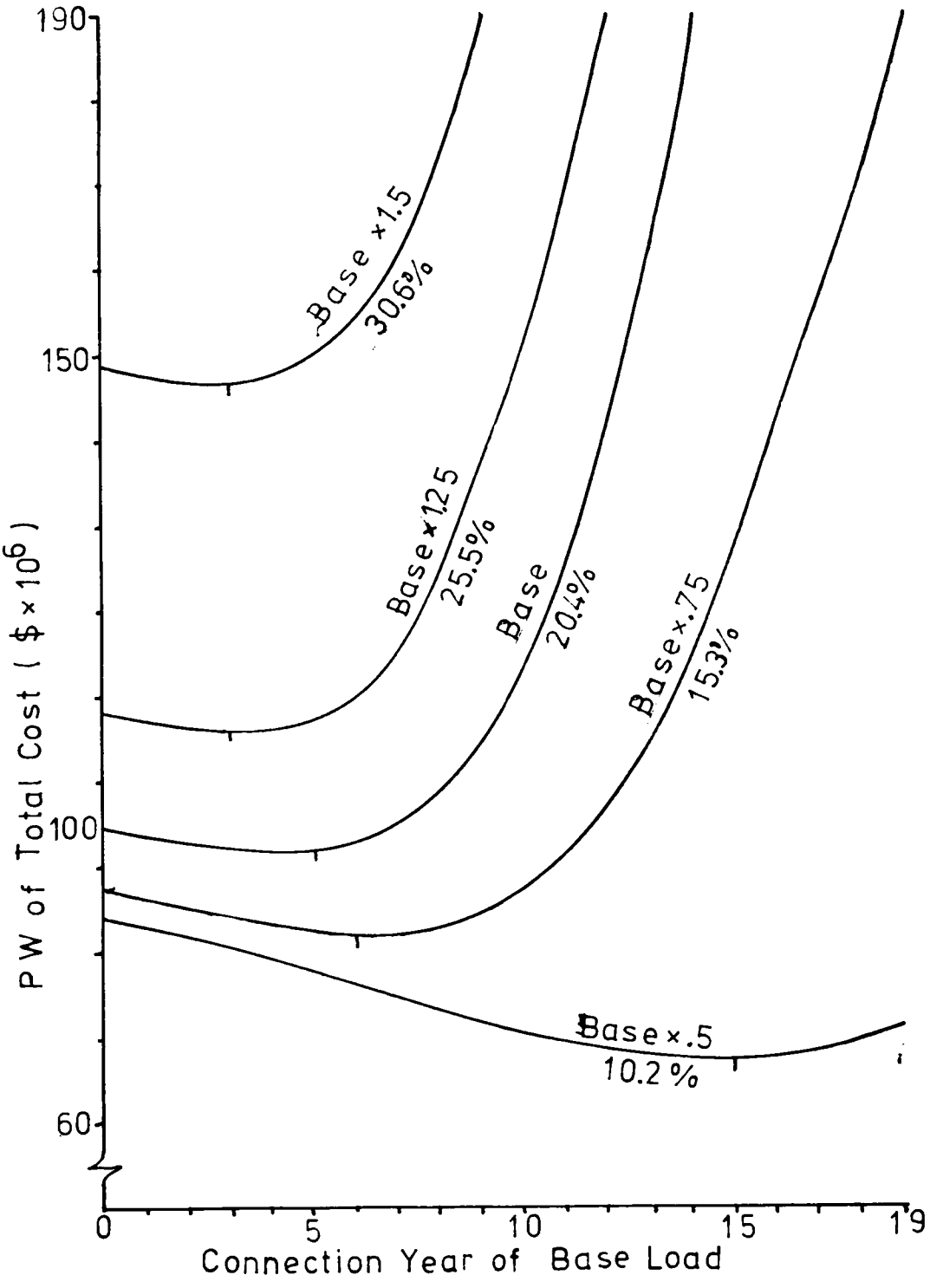


Figure 26. Total Cost Vs. Connection Year at Various Annual Rates of Natural Gas Price Increases--House Model With Fuel Cells.

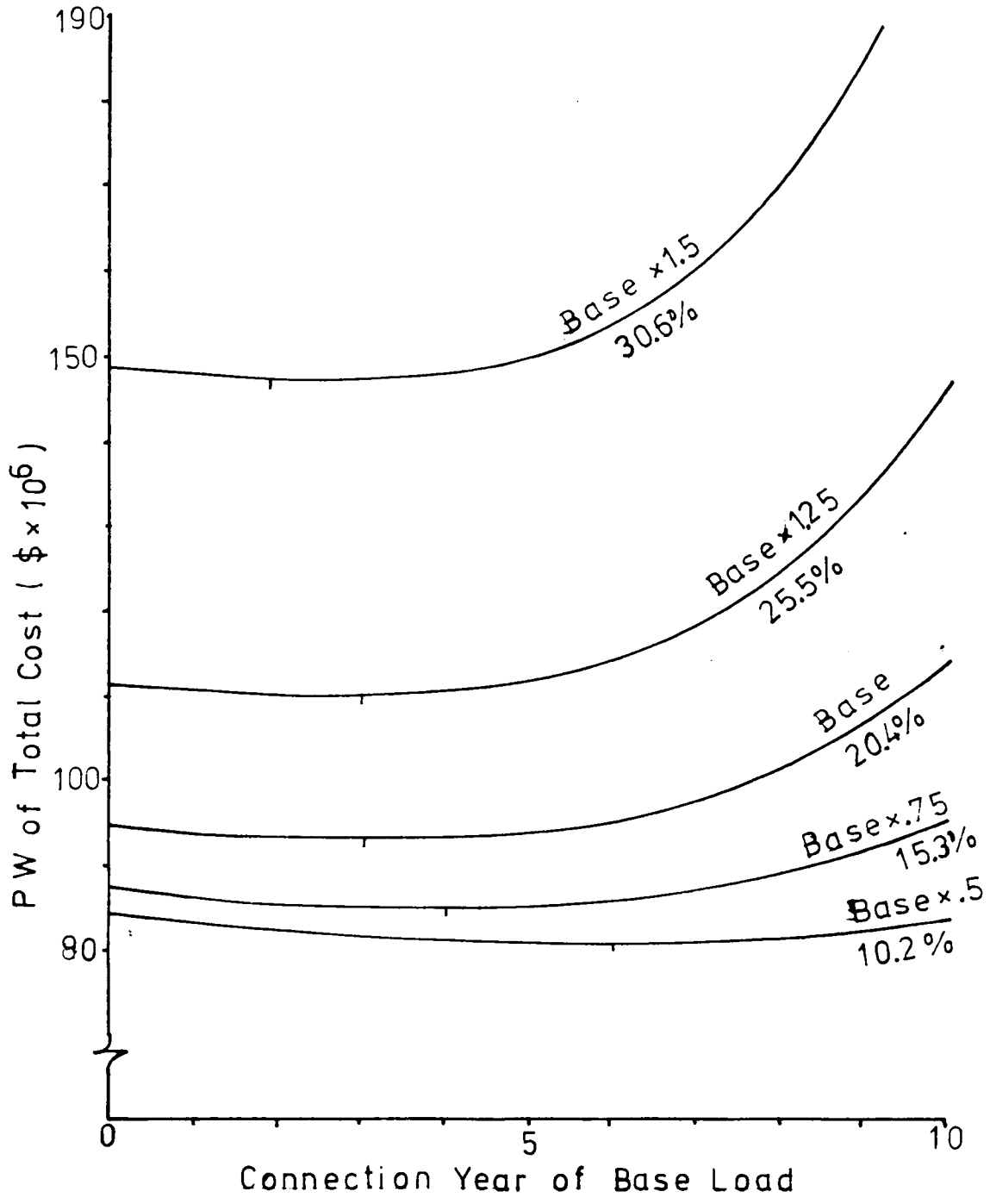


Figure 27. Total Cost Vs. Connection Year at Various Annual Rates of Natural Gas Price Increases--House Model With Boilers.

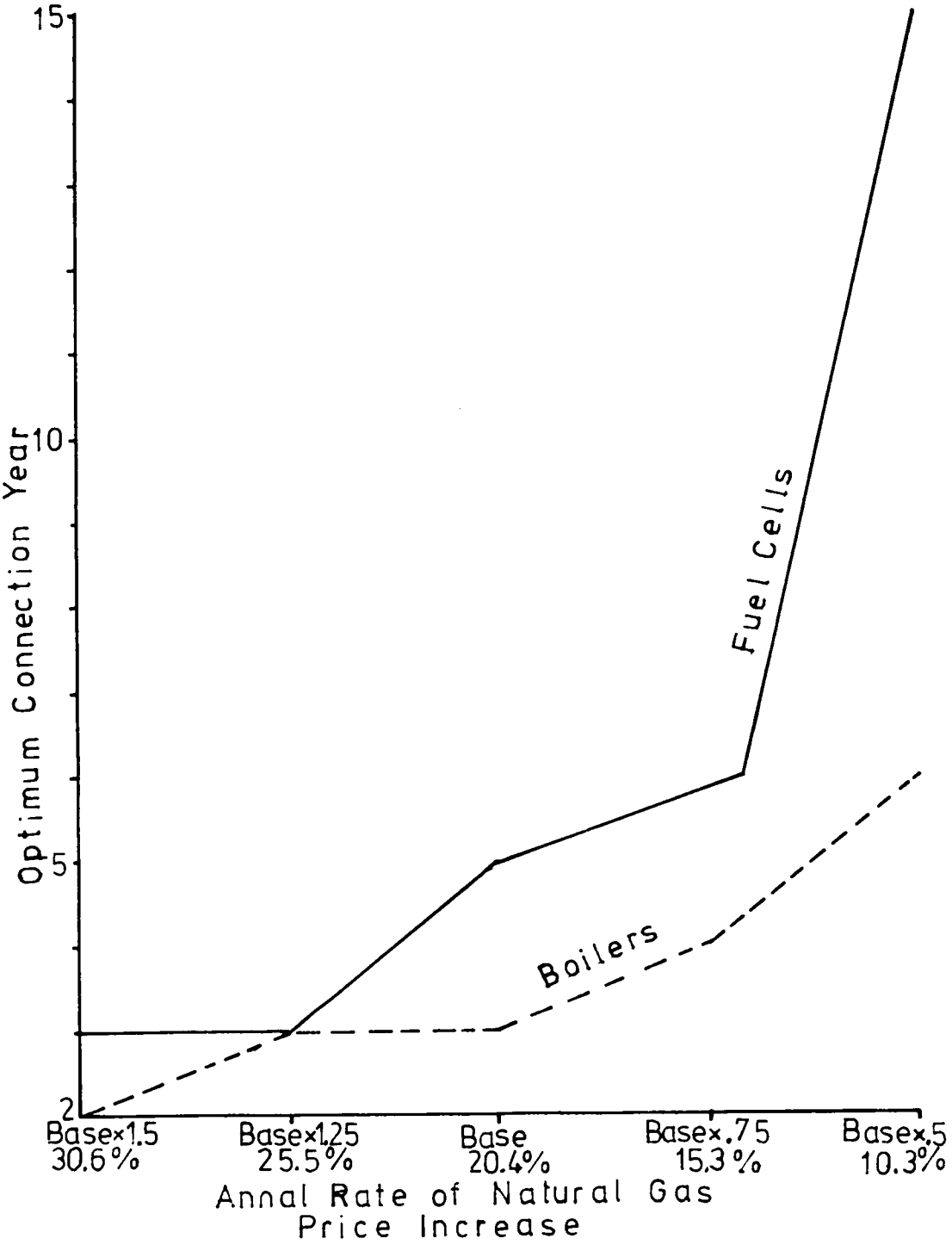


Figure 28. Optimum Connection Year Vs. Annual Rate of Natural Gas Price Increase--House Model.

rate of natural gas price escalation for fuel cells and boilers as temporary heat sources. As can be seen from these figures, the optimum connection time is highly sensitive to the changes in the rate of price increase of natural gas. However, the sensitivity is smaller around the base rate, and it gets larger as the difference between the base rate and the rate under consideration increases, especially as the rate gets slower. This indicates that changes within the 25%-lower or 25%-higher than the expected rate will not have too large of an impact on the optimum connection time. Two extreme points considered are not likely to occur; however, they show the drastic impact that the rate of increase of natural gas prices has on the results of the analysis.

Investment Credit to Fuel Cells for Their Electricity-Generating Capacities

Even though the fuel cells are used mainly as thermal heat sources in this analysis, they can also be utilized mainly as peaking electricity generators and provide electricity, for example, during the summer electricity peaking days when the thermal demand is very low. Therefore, for the base cases, an investment credit of 60% of a gas-fired electricity generator cost was assumed for the fuel cells. The larger this investment credit, the more attractive the fuel cells become as the thermal energy sources.

The effects of this investment credit on the optimum connection time of the base load are analyzed by varying the percentage of the gas-fired electricity generator cost given as credit. The total costs versus connection times at different percentages are given in Figure 29. Figure 30 presents the optimum connection time versus percent investment

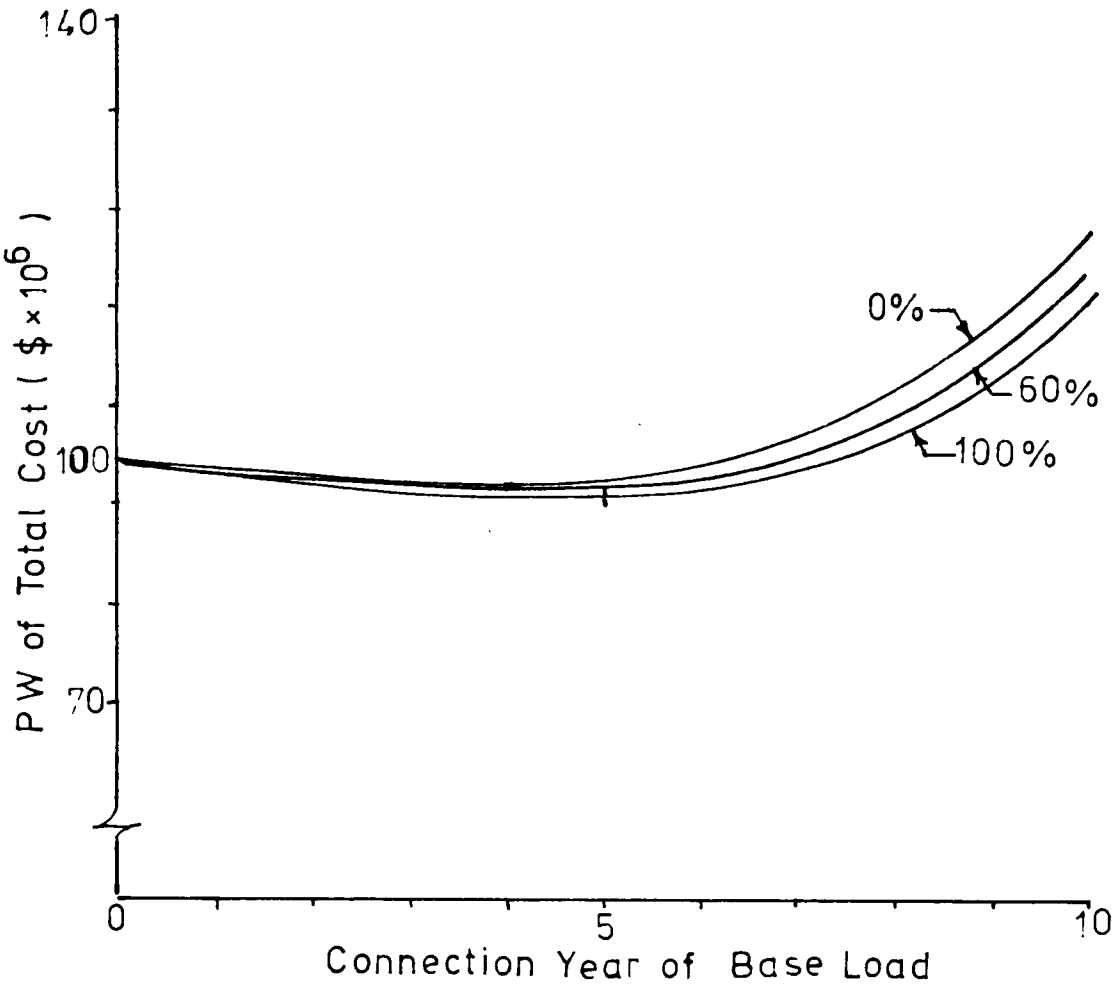


Figure 29. Total Cost Vs. Connection Year at Different Levels of Investment Credit Given to Fuel Cells for Their Electricity-Generating Capacities--House Model. (Percentages given on the curves indicate the percent of a gas-fired electricity plant cost that is given as investment credit to fuel cells.)

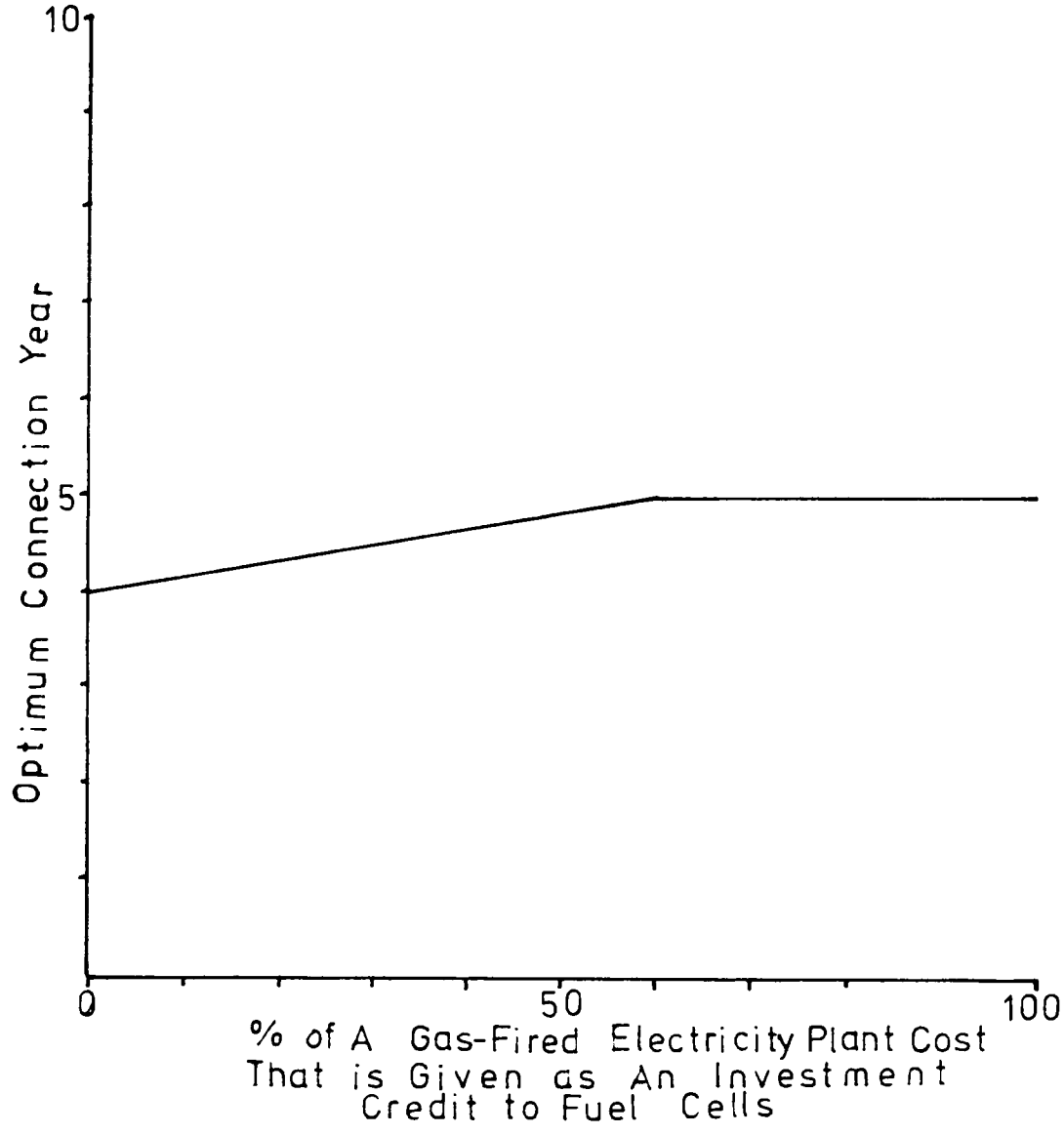


Figure 30. Optimum Connection Year Vs. Investment Credit to Fuel Cells--House Model.

credit given to fuel cells. As can be seen from these figures, both the magnitude of the total cost and the optimum connection year are very insensitive to this investment credit, indicating that it is not a crucial element.

Sell-Back Price of Electricity

The cost of thermal energy from fuel cells is very sensitive to the selling price of the by-product electricity. The higher the sell-back price, the lower the cost of heat from fuel cells. This increases the attractiveness of fuel cells as temporary heat sources and makes it more economical to keep them in service longer. Therefore, the higher the sell-back price of electricity, the later the optimum connection time of base load.

For the base case, the sell-back price was assumed to be 60% of the busbar cost of electricity. A sensitivity analysis is performed by varying this percentage of the busbar cost for which the electricity is sold. The total costs versus connection times at different percentages are presented in Figure 31. As can be seen from this figure, both the magnitude of savings with the delayed connection of the base load and the optimum connection year are very sensitive to the sell-back price of electricity. The higher the sell-back price, the more the savings and the later the optimum connection year. Figure 32 shows the optimum connection time versus percent of the busbar cost for which the electricity is sold. The high sensitivity of the optimum connection year to the sell-back price of electricity is very apparent in this figure. This sensitivity analysis shows that the sell-back price of electricity is an extremely important factor.

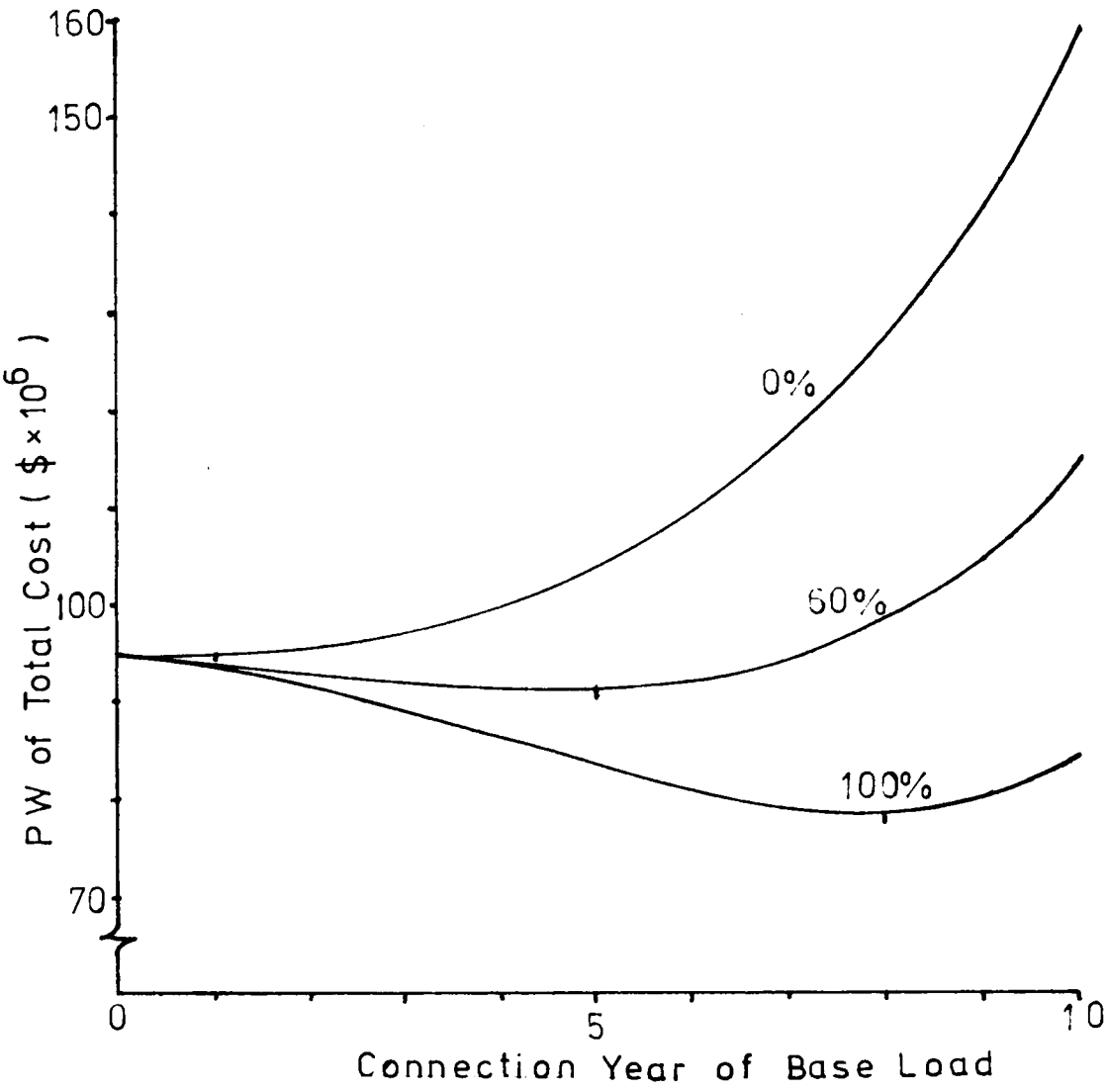


Figure 31. Total Cost Vs. Connection Year at Different Sell-Back Prices of Electricity for the House Model With Fuel Cells. (Percentages given on the curve indicate the percent of the busbar cost for which the electricity is sold.)

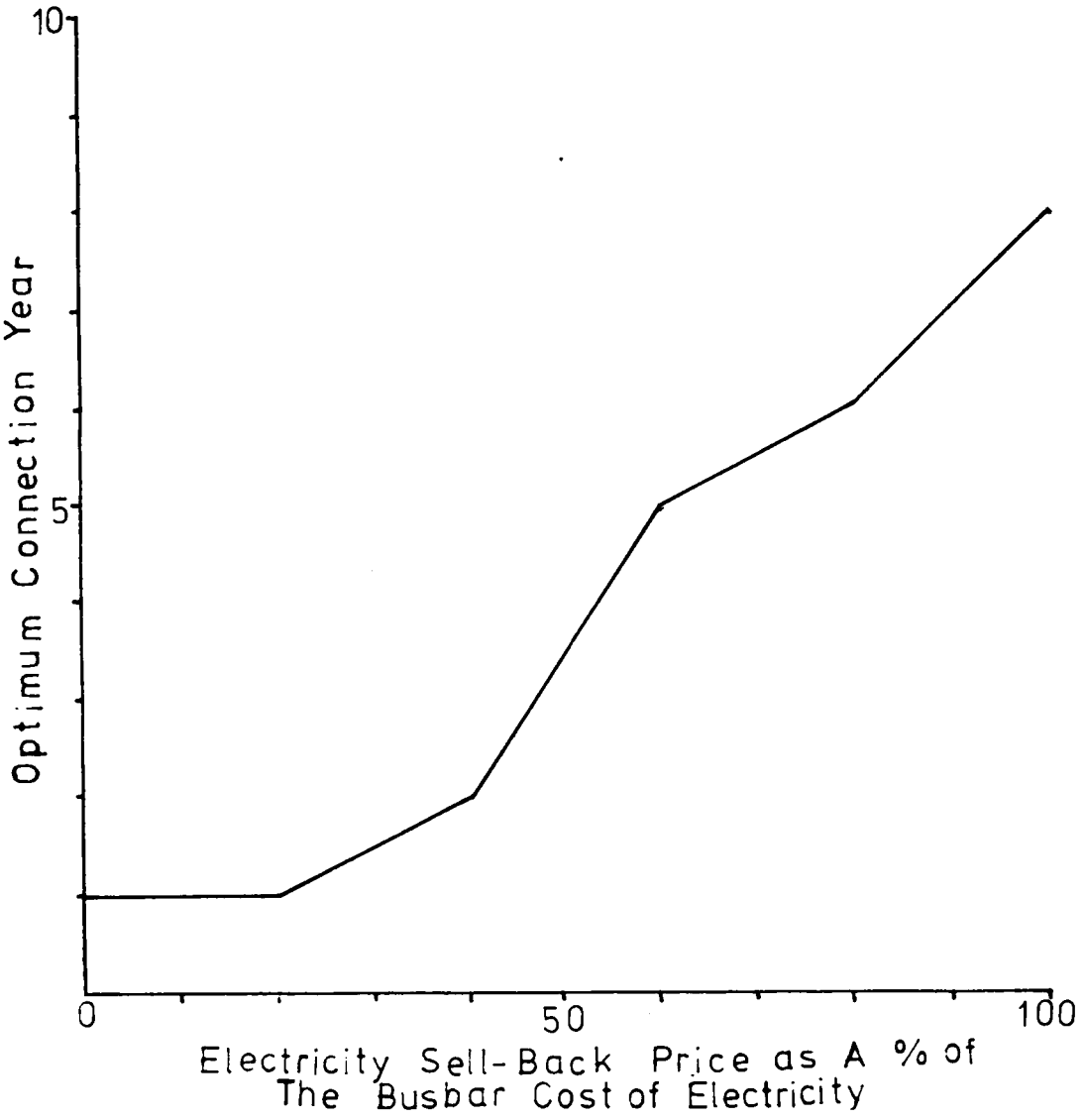


Figure 32. Optimum Connection Year Vs. Sell-Back Price of Electricity for the House Model With Fuel Cells.

F. COMPARISON BETWEEN FUEL CELLS AND HEAT-ONLY BOILERS AS TEMPORARY HEAT SOURCES

Analysis of the base indicated that fuel cells are more attractive as temporary heat sources compared to heat-only boilers is the electricity is sold back at a price of 60% of the busbar cost. The sell-back price of electricity is a very important factor that affects the relative attractiveness of these two types of heat sources.

Figure 33 shows the minimum present worth of total cost (present worth of total cost at the optimum connection year) versus percent of the busbar cost for which the electricity is sold. Minimum present worth of total cost with boilers as temporary heat sources is also shown. As can be seen from this figure, the break-even percentage is about 50%. This indicates that if there is a market in which the electricity can be sold at a price higher than about 50% of the busbar cost, fuel cells are more attractive as temporary heat sources as compared to heat-only boilers.

G. APARTMENT MODEL

The analysis given in the previous sections was made on an urban model of all single-family houses with an overall population of 54,000 people. A similar analysis was also made on a different urban model of all low-rise apartment buildings with the same population.

Because the heat demand per person living in apartment buildings is lower than the heat demand per person living in single-family houses, the district heating system for the apartment model has a lower coinciding peak load. The apartment model also has a lower distribution

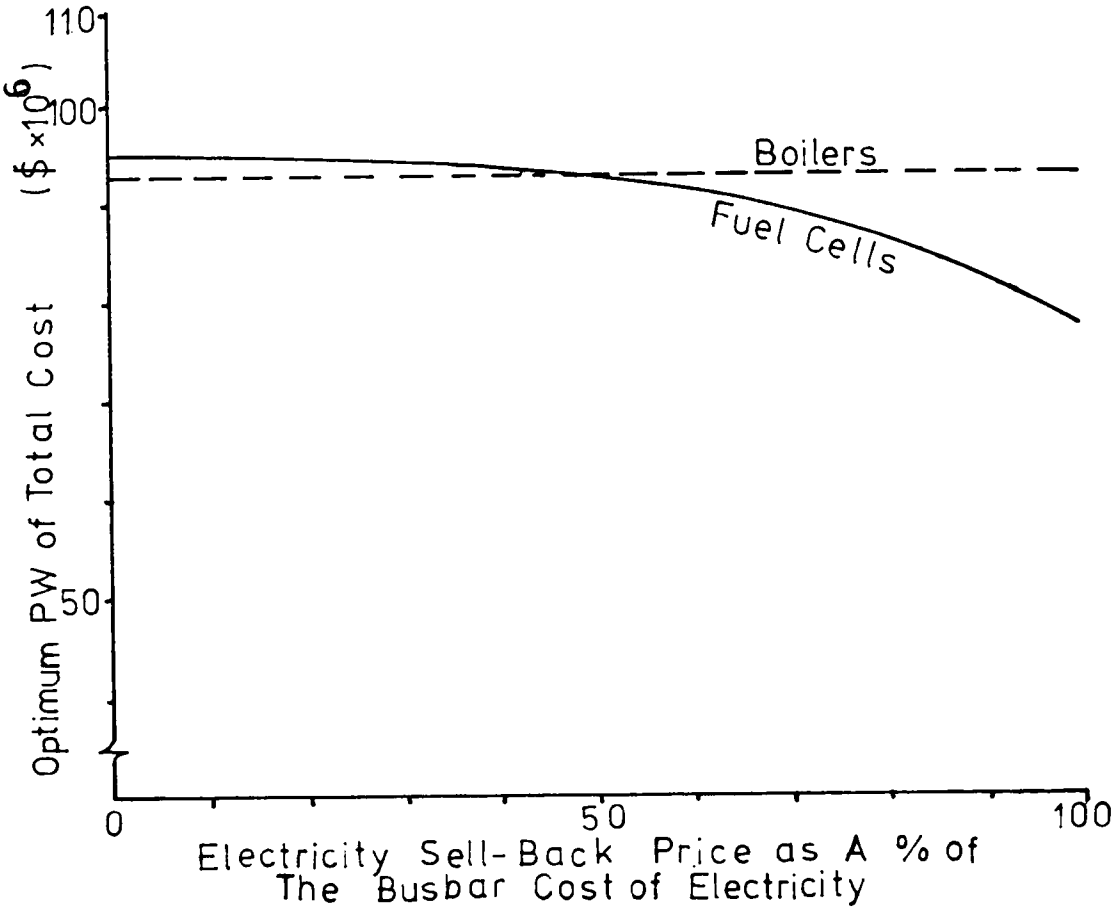


Figure 33. Minimum Present Worth of Total Cost Vs. Sell-Back Price of Electricity.

piping network cost. However, the cost of this piping network is irrelevant to the analysis. The cost of transmission pipeline, which is important in this analysis, constitutes a larger portion of the total district heating cost than it does for the house model.

The analysis of delaying the connection time of base load on the apartment model is performed. Results with the apartment model present very similar patterns to the ones given by the house model. Only the magnitudes of results are different. The optimum connection time is found to be more sensitive to plant-city separation and natural gas price increases than the house model. The apartment model results are included in Appendix B.

H. CONCLUSIONS AND RECOMMENDATIONS

The analysis of idealized urban model shows that the application of fuel cells as peak heat sources is not economical; however, they can be applied economically as temporary heat sources. Results show that the optimum connection year of the base load plant is five years with fuel cells as temporary heat sources, and the savings in the life-cycle cost due to delaying the connection of the base load plant, compared to the case of immediate connection, is 3.1%. This savings corresponds to 15% of the required investment cost on base load.

Heat-only boilers are applicable both as peak and temporary heat sources. The optimum connection year of the base load plant is three years, and a 1.8% savings is realized in the life-cycle cost of the system if boilers are used as temporary heat sources. This savings corresponds to 8.6% of the required investment cost on base load.

The life-cycle cost of the system is moderately sensitive to changes in optimum connection year. The sensitivity analysis performed indicates that the optimum connection year is highly sensitive to the rate of increase in the price of the input fuel for temporary heat sources and the sell-back price of electricity in the case of fuel cells.

Relative attractiveness of fuel cells and heat-only boilers as temporary heat sources depends largely on the sell-back price of electricity.i If the electricity produced by fuel cells can be sold at a price of 50% or more of the busbar cost of electricity, fuel cells are more economical than heat-only boilers.

The results obtained in this thesis apply to a specific idealized urban model. Both the magnitudes of savings and the optimum connection times may vary considerably from one situation to another. Therefore, characteristics of the specific urban township investigated in this thesis must be examined carefully before generalizing on this application. For example, the transmission pipeline costs considered here applied to idealized rural conditions, and these conditions may vary from one location to another. For an actual city, the transmission pipeline may be more costly than the specific case analyzed here, making the required investment on the base load larger and its delayed connection time more economical.

Furthermore, before making a decision on the application of fuel cells as temporary heat sources, the market for electricity has to be examined carefully, because the district heating system may result in reduced electricity demand. In this regard, the electricity presently

used for space and water heating purposes would no longer be required in the same quantities as without the district heating system.

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APPENDICES

APPENDIX A

APPENDIX A

PRINTOUT LISTING AND FLOW CHART OF THE COMPUTER MODEL

A. LISTING

```
)OO
C       THIS PROGRAM DETERMINES THE OPTIMUM CONNECTION TIMES
C       OF COGENERATION HEAT SOURCES FOR DISTRICT HEATING
C       SYSTEMS.OPTIMIZATION IS PERFORMED BY TOTAL ITERATION.
C
C
C
C       _________VARIABLE DEFINITION STARTS_________
C
        REAL I              !DISCOUNT RATE
        REAL F              !INFLATION RATE
        INTEGER T           !YEARS
        INTEGER T1          ! VARIABLE USED TO PASS T TO SUBPROGRAMS
        INTEGER SP          !STUDY PERIOD
        REAL D              !DEMAND IN A GIVEN YEAR
        REAL MAXD           ! MAXIMUM PROSPECTIVE DEMAND
        INTEGER NOBLP       !TOTAL # OF BASE LOAD PLANTS
        INTEGER MAXN        ! # OF BASE LOAD PLANTS CONSIDERED
C                            IN  SOLUTION
        REAL CBL(5)         !CAPITAL COSTS OF BASE LOAD PLANTS
        REAL QBL(5)         !CAPASITIES OF BASE LOAD PLANTS
        REAL MBL            !MAINTENANCE % OF BASE LOAD
        REAL CFC            !CAPITAL COST OF ONE FUEL CELL MODULE
        REAL QFC            !THE CAPACITY OF ONE FUEL CELL MODULE
        REAL MFC            !MAINTENANCE COST OF F. CELLS PER UNIT
C                            OF CAPACITY INSTALLED
        INTEGER FCLOC       !NUMBER OF FUEL CELL LOCATIONS
        INTEGER ULFC        !USEFUL LIFES OF FUEL CELLS
        REAL CBUP           !CAPITAL COST OF ONE UNIT OF BACK UP
C                            CAPACITY INSTALLED
        REAL MBUP           !MAINTENANCE COST FOR PER UNIT OF
C                            CONNECTED BACK-UP CAPACITY
        INTEGER TCON(5)     !CONNECTION YEARS OF BASE LOAD PLANTS
        INTEGER OPTCON(5)          !OPTIMUM CONNECTION YEARS
        REAL MTPWC          !MINIMUM TOTAL PW OF COST
        REAL TPWC           !TOTAL PW OF COST
        REAL PWICBL         !TOTAL PW OF INVEST. COST ON BASE LOAD
        REAL PWICFC         !TOTAL PW OF INVEST. COST ON FUEL CELLS
        REAL PWICBU         !TOTAL PW OF INVEST. COST ON BACK-UP
        REAL PWICPK         !TOTAL PW OF INVEST. COST ON PEAK CAP.
        REAL XBL            !INSTALLED BASE LOAD CAPACITY
```

```
      REAL XFC          !INSTALLED FUEL CELL CAPACITY
      REAL XBUP         !INSTALLED BACK-UP CAPACITY
      REAL XPEAK        !INSTALLED PEAK CAPACITY
      REAL P            !% OF THE PEAK LOAD THE BASE LOAD IS
      REAL YOC          !YEARLY OPERATING COST
      REAL PWTOC        !PW OF TOTAL OPERATING COST
      REAL PWTMC        !PW OF TOTAL MAINTENANCE COST
      REAL A(30)        !TOTAL INVESTMENT MADE UPTO AND
C                        INCLUDING A GIVEN YEAR  ON BASE
C                       LOAD IN THAT YEAR'S DOLARS.A(T) IS
C                       TO CALCULATE THE YEARLY MAIMTENANCE
C                       COST
      REAL PWSAL        !PW OF TOTAL SALVAGE VALUES
      INTEGER K(30)     !# OF F.CELLS INSTALLED IN A GIVEN YEAR
      INTEGER L         !# OF F.CELLS SALVAGED
      INTEGER TSAL      !YEAR AT WHICH F.CELLS ARE SALVAGED
      REAL S            !DECREASE IN F. CELL SALVAGE VALUE
C                        IN A YEAR
      REAL TCAP         !TOTAL CAPACITY EXCLUDING BACK-UP
      REAL DUMMY,DUMMY1        !DUMMY VARIABLES USED IN
C                               DETERMINING K(T)
C     REAL CPEAK        !INVESTMENT COST PER UNIT OF PEAK CAP.
      REAL MPEAK        !MAINTENANCE COST PER UNIT OF PEAK
C                       !CAPACITY INSTALLED
      COMMON PEAK       !TOTAL ANNUAL HEAT SUPPLIED BY FUEL CELLS
C                        OR PEAK CAPACITY
C
C     _________VARIABLE DEFINITION ENDS_________
C
C
C
C
C
C  ___________DATA INITIALIZATION_____________
C
      DATA I/0.11/
      DATA F/0.09/,SP/20/
      DATA NOBLP/1/
      DATA CBL(1)/21.7767/
      DATA QBL(1)/733374000./
      DATA MBL/.02/
      DATA CFC/1.62965/
      DATA QFC/18540000./
      DATA MFC/0.000001465/
      DATA FCLOC/5/,ULFC/20/
      DATA CBUP/0.016/,MBUP/0.00016/
      DATA CPEAK/0.016/
```

```
C
C     ------------MAIN PROGRAM STARTS--------------
C
C
C
C
C
C   START THE BASE CASE OF FUEL CELLS ONLY
C   FOR THIS CASE  THE DEMAND IS SUPPLIED BY FUEL CELLS
C   AND NO BASE LOAD PLANTS ARE CONNECTED.
C   ------------------------------------------------------------
          XBUP=FCLOC*QFC
          PWICBU=XBUP*CBUP/1000000.
          PWICFC=0.
          PWTOC=0.
          PWTMC=0.
          XFC=0.
          DO 5 T=0,(SP-1)
          T1=T
          D=DEMAND(T1)
          IF(XFC.GE.D)  GO TO 3
          DUMMY=(D-XFC)/QFC
          KFC=DUMMY+1
          DUMMY1=KFC-DUMMY
          IF(DUMMY1.EQ.1.)  KFC=KFC-1
          XFC=XFC+KFC*QFC
          PWICFC=PWICFC+KFC*CFC*((1+F)/(1+I))**T
    3     CONTINUE
          P=0.
          T1=T
          IT=40.
          CALL OPCOST(YOC,T1,P,D,IT)
          PWTOC=PWTOC+YOC/(1+I)**(T+1)
          PWTMC=PWTMC+(PEAK*MFC+XBUP*MBUP)/1000000.*((1+F)/(1+I))
        *  **(T+1)
    5     CONTINUE
          WRITE(5,45)
          WRITE(5,23) PWICBL,PWICFC,PWICPK,PWICBU,PWTOC,PWTMC,
        *  PWSAL
          MTPWC=PWICFC+PWICBU+PWTOC+PWTMC
C   INITALIZE THE CONNECTION AND THE OPTIMUM CONNECTION
C   TIMES TO FIFTY.FIFTY IS INTERPRETED AS SUCH THAT THE
C   BASE LOAD PLANT IS NEVER CONNECTED
          DO 7 N=1,5
          TCON(N)=50
          OPTCON(N)=50
    7     CONTINUE
C
C   OUTPUT THE BASE CASE
          WRITE(5,9) ((TCON(N),N=1,5),MTPWC)
```

```
19000
    9     FORMAT (1X,'(',I2,',',I2,',',I2,',',I2,',',I2,',',I2,')',10X,
      *   F15.5)
C
          WRITE(5,31)
   31     FORMAT('---------------------------')
C
C
C
C
C   START THE CASES WITH BASE LOAD PLANTS
C   -------------------------------------
C
C
C
C
C   START THE LOOP FOR THE BASE LOD PLANTS.THIS LOOP MAKES IT
C   POSSIBLE  TO CONSIDER THE CASES IN WHICH  SOME OF THE
C   AVAILABLE BASE LOAD PLANTS ARE NEVER CONNECTED
C
          DO 2000  MAXN=1,NOBLP
C
C
C
C   START THE LOOPS FOR ALL POSSIBLE COMBINATIONS OF MAXN PLANTS
          TCON(1)=0
   10     IF(MAXN.EQ.1)  GO TO 50
          TCON(2)=TCON(1)
   20     IF(MAXN.EQ.2)  GO TO 50
          TCON(3)=TCON(2)
   30     IF(MAXN.EQ.3)  GO TO 50
          TCON(4)=TCON(3)
   40     IF(MAXN.EQ.4)  GO TO 50
          TCON(5)=TCON(4)
   50     CONTINUE
C
C
C   CALCULATE PW OF TOTAL INVESTMENT ON THE BASE LOAD
          PWICBL=0.
          DO 100 N=1,MAXN
          PWICBL=PWICBL+CBL(N)*((1+F)/(1+I))**TCON(N)
  100     CONTINUE
C
C   CALCULATE PW OF TOTAL INVESTMENT ON BACK-UP SYSTEM
          PWICBU=0.
          XBUP=0.
          IF(TCON(1).EQ.1) GO TO 150
          XBUP=FCLOC*QFC
          PWICBU=XBUP*CBUP/1000000.
  150     CONTINUE
          DO 200 N=1,MAXN
```

```
      IF(XBUP.GE.QBL(N)) GO TO 200
      PWICBU=PWICBU+(QBL(N)-XBUP)*CBUP*((1+F)/(1+I))**
     *  TCON(N)/1000000.
      XBUP=QBL(N)
  200 CONTINUE
C
C
C  INITIALIZE VARIABLES BEFORE STARTING THE YEARS LOOP
      XBL=0.
      XFC=0.
      XBUP=0.
      A(0)=0.
      PWTOC=0.
      PWTMC=0.
      PWICFC=0.
      XPEAK=0.
      PWICPK=0.
C
C
C  START THE YEARS LOOP
      DO 500 T=0,(SP-1)
C
C
C  ADJUST A(T) , BASE LOAD CAPACITY AND BACK-UP CAPACITY
      IF(T.EQ.0) GO TO 250
      A(T)=A(T-1)*(1+F)
      GO TO 275
  250 CONTINUE
      IF(TCON(1).EQ.0) GO TO 275
      XBUP=FCLOC*QFC
  275 CONTINUE
      DO 300 N=1,MAXN
      IF(T.NE.TCON(N)) GO TO 300
      A(T)=A(T)+CBL(N)*(1+F)**TCON(N)
      XBL=XBL+QBL(N)
      IF(XBUP.GE.QBL(N)) GO TO 300
      XBUP=QBL(N)
  300 CONTINUE
C
C
C  GET THE DEMAND FOR THAT YEAR
      T1=T
      D=DEMAND(T1)
C
C
C
C
C   ADJUST THE FUEL CELL CAPACITY FOR THE YEAR ACCORDING TO
C  THE DEMAND AND THE BASE LOAD CAPACITY,AND CALCULATE THE
C  PW OF TOTAL INVESTMENT COST IN FUEL CELLS
```

```
C
      IF(T.GE.TCON(MAXN))  GO TO 400
      IF((XBL+XFC).LT.D) GO TO 375
      K(T)=0
      GO TO 450
  375 CONTINUE
      DUMMY=(D-(XBL+XFC))/QFC
      K(T)=DUMMY+1
      DUMMY1=K(T)-DUMMY
      IF(DUMMY1.EQ.1.)  K(T)=K(T)-1
      XFC=XFC+K(T)*QFC
      PWICFC=PWICFC+K(T)*CFC*((1+F)/(1+I))**T
      GO TO 450
  400 CONTINUE
      XFC=0.
C  ADJUST THE PEAK CAPACITY ACCORDING TO DEMAND
C
      TCAP=XBL+XPEAK
      IF(TCAP.GE.D) GO TO 450
      XPEAK=XPEAK+(D-TCAP)
      PWICPK=PWICPK+(D-TCAP)*CPEAK/1000000.*((1+F)/(1+I))
     *  **T
  450 CONTINUE
C
C
C  CALCULATE THE YEARLY OPERATING AND MAINTENANCE COSTS
C
      P=XBL/D
      IF(P.GT.1.)  P=1.
      T1=T
      IT=TCON(MAXN)
      CALL OPCOST(YOC,T1,P,D,IT)
      PWTOC=PWTOC+YOC/(1+I)**(T+1)
      IF(T.GE.TCON(MAXN))  PEAK=0.
      PWTMC=PWTMC+(A(T)*MBL+
     *  (PEAK*MFC+
     *  XPEAK*MBUP+XBUP*MBUP)*(1+F)**T/1000000.)*
     *  (1/(1+I))**(T+1)
C
C
C
  500 CONTINUE
C  END OF YEARS LOOP
C
C
C
C  DETERMINE THE SALVAGE VALUES ON FUEL CELLS
C
      PWSAL=0.
      IF(TCON(MAXN).EQ.0) GO TO 600
```

```
      TSAL=TCON(MAXN)
      S=CFC/ULFC
      DO 600 T=0,(TSAL-1)
      PWSAL=PWSAL+K(T)*(CFC-S*(TSAL-T))*((1+F)/(1+I))**
     *  TSAL
  600 CONTINUE
C
C
C
C  CALCULATE THE TOTAL PW OF COST
C
      WRITE(5,45)
   45 FORMAT('   ICBL      ICFC      ICPK     ICBUP      TOC
     *  TMC       SAL')
      WRITE(5,23) PWICBL,PWICFC,PWICPK,PWICBU,PWTOC,PWTMC,
     *  PWSAL
   23 FORMAT(1X,F7.3,2X,F7.3,2X,F7.3,2X,F7.3,2X,F7.3,2X,F7.3,
     *  2X,F7.3)
      TPWC=PWICBL+PWICFC+PWICBU+PWTOC+PWTMC-PWSAL
      TPWC=TPWC+PWICPK
C
C
C  OUTPUT THE RESULT FOR THIS CASE
C
      WRITE(5,46)
   46 FORMAT('       CASE                              TOTAL COST')
      WRITE(5,9) ((TCON(N),N=1,5),TPWC)
C
C
      WRITE(5,57)
   57 FORMAT(' ------------------------------------------------')
C
C  CHECK IF TPWC IS LESS THAN MTPWC
C
      IF(TPWC.GT.MTPWC)  GO TO 1000
      MTPWC=TPWC
      DO 800 N=1,MAXN
      OPTCON(N)=TCON(N)
  800 CONTINUE
C
 1000 CONTINUE
C
C
C
C  FINISH THE LOOPS FOR THE POSSIBLE COMBINATIONS OF MAXN
C  BASE LOAD PLANTS
C
      IF(MAXN.LT.5)  GO TO 1100
      TCON(5)=TCON(5)+1
      IF(TCON(5).LT.SP)  GO TO 50
```

```
C
 1100    IF(MAXN.LT.4)  GO TO 1200
         TCON(4)=TCON(4)+1
         IF(TCON(4).LT.SP)  GO TO 40
C
 1200    IF(MAXN.LT.3)  GO TO 1300
         TCON(3)=TCON(3)+1
         IF(TCON(3).LT.SP)  GO TO 30
C
1300     IF(MAXN.LT.2)  GO TO 1400
         TCON(2)=TCON(2)+1
         IF(TCON(2).LT.SP)  GO TO 20
C
 1400    TCON(1)=TCON(1)+1
         IF(TCON(1).LT.SP) GO TO 10
C
C
C
C
C  FINSH THE MAXN LOOP
 2000    CONTINUE
C
C
C
C  OUTPUT THE OPTIMUM CASE
C
         WRITE(5,2500)
 2500    FORMAT('  OPTIMUM CASE  ',19X,'MINIMUM TPWC')
         WRITE(5,9) ((OPTCON(N),N=1,5),MTPWC)
         WRITE(5,2600)
 2600    FORMAT(' **********************************',/)
C
C
C
C
         STOP
         END
C  __________MAIN PROGRAM ENDS___________
C
C
C
C
C
C
C
C
C
C  -------START SUBPROGRAM DEMAND-------
C
         REAL FUNCTION DEMAND(T)
C
```

```
C   THIS FUNCTION SUBPROGRAM DETERMINES AND RETURNS THE
C   DEMAND FOR A GIVEN YEAR
C
C   VARIABLE DEFINITION
          REAL INITD        !INITIAL DEMAND IN THE BEGINNING
          REAL MAXD         !MAXIMUM EXPECTED DEMAND
          INTEGER GROPER    !GROW PERIOD FOR THE DEMAND TO REACH
C                            FROM INITIAL LAVEL TO MAXIMUM LAVEL
          INTEGER T         !YEAR
C
C   DATA INITIALIZATION
          DATA INITD/0./
          DATA MAXD/956413000./
          DATA GROPER/20/
C
C
C   BODY OF THE SUBPROGRAM DEMAND
C
          IF(T.LT.GROPER) DEMAND=INITD+((MAXD-INITD)/GROPER)*(T+1)
          IF(T.GE.GROPER) DEMAND=MAXD
          RETURN
          END
C
C
C
C
C
C
C   ---------START SUBPROGRAM OPCOST-----------
C
          SUBROUTINE OPCOST(YOC,T,P,D,IT)
C
C   THIS SUB PROGRAM DETERMINES THE TOTAL YEARLY OPERATING
C   COST FROM THE LOAD DURATION CURVE.
C
C   VARIABLE DEFINITION
          REAL YOC          ! TOTAL YEARLY OPERATING COST
          INTEGER T         !YEAR
          REAL P            !% OF THE PEAK LOAD THE BASE LOAD IS
C                            IN DECIMALS
          REAL D            !PEAK DEMAND
          INTEGER NODIV     ! # OF DIVISIONS IN LOAD DURATION CURVE
          REAL PERPL(20)    !DIVISIONS' % OF THE PEAK LOAD
          REAL HRS(20)      !DIVISIONS' HOURS
          INTEGER DIV       !INDEX FOR DIVISIONS
          REAL ADJP         !ADJUSTED P
          REAL BASE         !ANNUAL HEAT SUPPLIED BY BASE LOAD
          REAL PEAK         !ANNUAL HEAT SUPPLIED BY PEAK LOAD
          REAL RELP         !FRACTION OF TIME THE BASE LOAD IS DOWN
          REAL RELFC        !FRACTION OF TIME THE F.CELLS ARE DOWN
```

```
      REAL HEAT(20)    !HEAT LOAD THAT CORRESPONDS TO A
C                       GIVEN DIVISION.IT IS USED TO DETER.
C                       THE PUMPING POWER COST
      INTEGER IDSCRP   !DESCRIPTION OF A PIPE SECTION
      REAL DIA         !DIAMETER OF  THE PIPE SECTION
      REAL FEET        !LENGTH OF THE PIPE SECTION
      INTEGER NPIPE    !NUMBER OF THE PIPE SECTION
      COMMON PEAK
C
C
C
C  DATA INITIALIZATION
      DATA NODIV/13/
      DATA PERPL/1.,.9198,.8395,.7593,.6790,.5988,.5186,
     *  .4384,.3582,.2779,.1977,.1175,0.,0.,0.,0.,0.,0.,0.,0./
      DATA HRS/10.,26.,96.,188.,330.,603.,858.,838.,796.,
     *  722.,745.,754.,0.,0.,0.,0.,0.,0.,0.,0./
      DATA  RELB/0.03/,RELFC/0.03/
C
C
C
C
C
C
C
C
C
C  BODY OF SUBPROGRAM OPCOST
C
C
C  FIND THE DIVISION THAT CORRESPONDS TO P
      IF(P.EQ.1.) GO TO 3700
      DO 3000 DIV=1,NODIV
      IF(PERPL(DIV).LE.P) GO TO 3500
 3000 CONTINUE
C  ADJUST P TO EITHER THE FOUND DIVISION OR THE ONE
C  BEFORE THAT DEPENDING ON WHICH EVER IS CLOSER TO P
 3500 CONTINUE
      IF((P-PERPL(DIV)).LE.(PERPL(DIV-1)-P)) ADJP=PERPL(DIV)
      IF((P-PERPL(DIV)).GT.(PERPL(DIV-1)-P))ADJP=PERPL(DIV-1)
      GO TO 4000
 3700 ADJP=P
 4000 CONTINUE
C
C  DETERMINE ANNUAL PUMPING POWER COST
      PUMPC=0.
      DO 540 IDSCRP=1,4
      IF(IDSCRP.EQ.1) GO TO 501
      IF (IDSCRP.EQ.2) GO TO 502
      IF(IDSCRP.EQ.3) GO TO 503
      IF(IDSCRP.EQ.4) GO TO 504
```

```
  501     D1=D
          DIA=24.
          FEET=52800.
          NPIPE=1
          GO TO 505
  502     D1=D/5.
          DIA=20.
          FEET=5280.
          NPIPE=4
          GO TO 505
  503     D1=D*12./20.
          DIA=20.
          FEET=5940.
          NPIPE=1
          GO TO 505
  504     D1=D/5.
          DIA=20.
          FEET=5940.
          NPIPE=1
  505     CONTINUE
C
          DO 510 IDIV=1,NODIV
          IF(PERPL(IDIV).LE.ADJP) HEAT(IDIV)=PERPL(IDIV)*D1
          IF(PERPL(IDIV).GT.ADJP) HEAT(IDIV)=ADJP*D1
  510     CONTINUE
          PUMPC=PUMPC+PUMPEN(HEAT,HRS,DIA,NODIV)*ECOST(T)*FEET*
     *    NPIPE
  540     CONTINUE
C   DETERMINE THE YEARLY HEAT SUPPLIED BY THE BASE LOAD AND
C   THE PEAK LOAD
          BASE=0.
          PEAK=0.
          DO 4500 DIV=1,NODIV
          IF(PERPL(DIV).LE.ADJP) GO TO 4200
          BASE=BASE+ADJP*D*HRS(DIV)
          PEAK=PEAK+(PERPL(DIV)-ADJP)*D*HRS(DIV)
          GO TO 4500
 4200     BASE=BASE+PERPL(DIV)*D*HRS(DIV)
 4500     CONTINUE
C
C
C
C   DETERMINE THE YEARLY OPERATING COST
          IF(T.GE.IT) GO TO 5100
          IF(P.EQ.0.) GO TO 5000
          YOC=PEAK*OFC(T)+
     *    BASE*(1.-RELB)*OBL(T)+BASE*RELB*OBUP(T)
          GO TO 6000
 5000     YOC=PEAK*(1.-RELFC)*
     *    OFC(T)
```

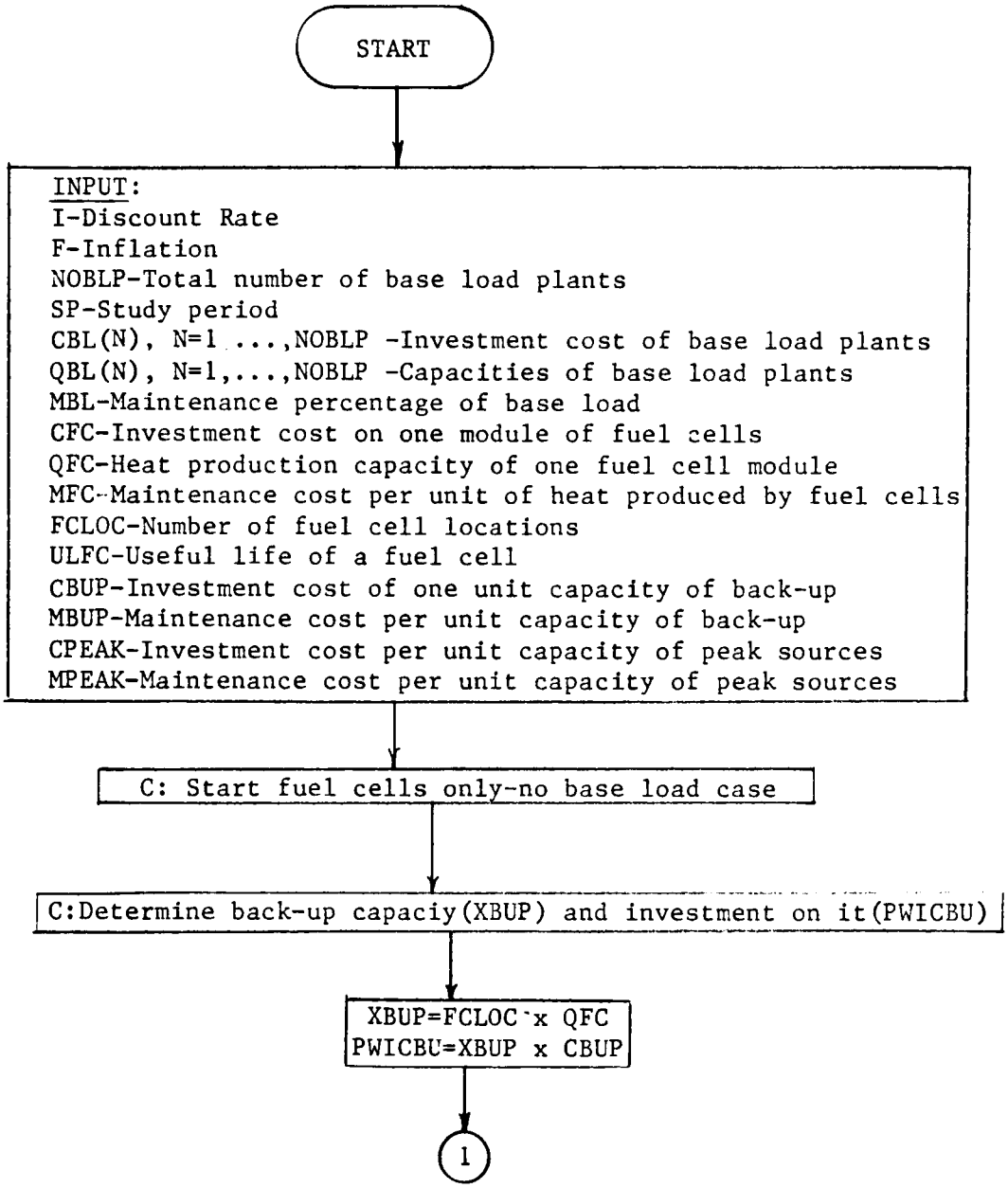
```
     *   +PEAK*RELFC*OBUP(T)
         GO TO 6000
 5100    YOC=PEAK*OBUP(T)+BASE*(1.-RELB)*OBL(T)+BASE*RELB*OBUP(T)
 6000    YOC=YOC+PUMPC
         YOC=YOC/1000000.
         RETURN
         END
C
C
C
         REAL FUNCTION PUMPEN(HEAT,HRS,D,N)
         DIMENSION HEAT(20),HRS(20)
C        PROGRAM CALCULATES THE PUMPING ENERGY REQUIRED TO
C        PUMP FLUID THROUGH ONE FOOT OF SUPPLY PIPE AND ONE
C        FOOT OF RETURN PIPE.PUMP EFFICIENCY,POWER COST,AND
C        PIPE LENGTH ARE CONSIDERED IN MAIN PROGRAM.
         RHO(T)=121.4*T**(-.133)
         VNU(T)=9.9E-04*T**(-1.069)
         TMAX=220.
         TMIN=160.
         A=.72
         EPSIL=.00015
         PTES=2.
         ENERGY=0.
         T=TMIN
         DO 10  J=1,2
         DO 9  I=1,N
         FLOW=HEAT(I)/(TMAX-TMIN)
         FLOW=FLOW/3600.
         FLOW=FLOW/RHO(T)
         V=FLOW*(4./3.1416)/(D/12.)**2
         REYN=V*(D/12.)/VNU(T)
         Z=D/12.
         DELP=RHO(T)*FRIC(EPSIL,Z,REYN)*(12./D)
         DELP=DELP*(V**2)/64.4
         DENG=DELP*FLOW*HRS(I)*0.00135582/A
    9    ENERGY=ENERGY+DENG
         DPDX=DELP*5280./144.
   10    T=TMAX
         PUMPEN=ENERGY
         PUMCOS=DPDX*(0.00578*FLOW+0.00555)
         RETURN
         END
         FUNCTION FRIC (ROUGH,DIA,REYN)
         Z(A,B,C)=1./SQRT(C)-0.8686*ALOG(A/(1.+18.7*A/(SQRT(C)
     1   *B)))-1.74
         IF(REYN.EQ.0.) GO TO 15
         RE=DIA/2./ROUGH
  30     IF(REYN.LE.2000.) GO TO 10
         XX=REYN**0.871/455.3
```

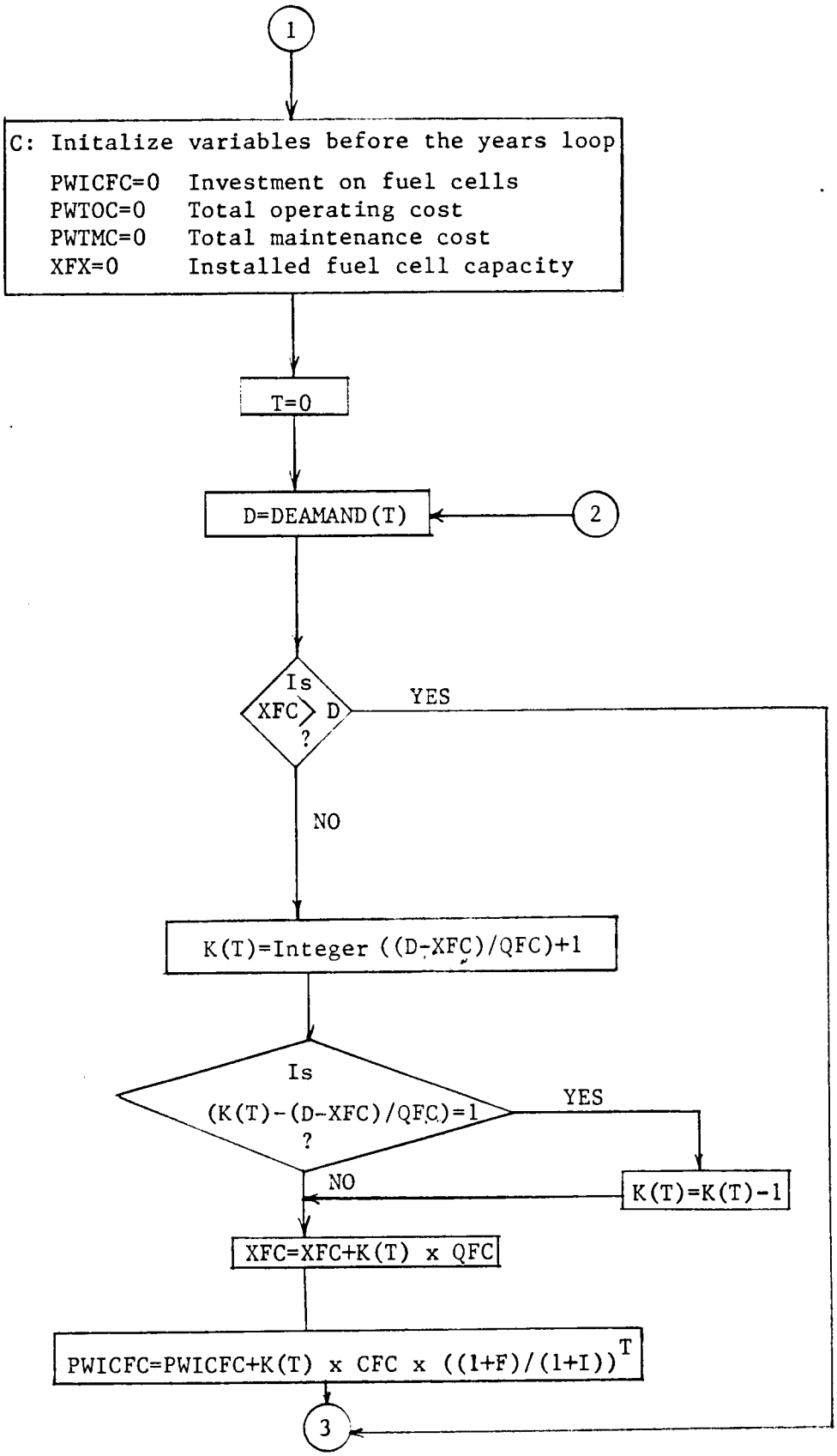
```
      IF(RE.GT.XX) GO TO 20
      FRIC=(1.74+0.8686*ALOG(RE))**(-2)
      RETURN
10    FRIC=64./REYN
      RETURN
20    DELF=0.0375
      F1=0.005
      Z1=Z(RE,REYN,F1)
      IF(Z1.GT.1E-4.OR.Z1.LT.-1E-4) GO TO 60
      FRIC=F1
      RETURN
60    F2=0.08
      Z2=Z(RE,REYN,F2)
      IF(Z2.GT.1E-4.OR.Z2.LT.-1E-4) GO TO 70
      FRIC=F2
      RETURN
70    IF(Z1.GT.0..AND.Z2.LT.0..OR.Z1.LT.0..AND.Z2.GT.0.)
     1 GO TO 80
      WRITE(5,75)
75    FORMAT(54H ERROR...NO ZERO SOLUTION TO FRICTIN
     1 FACTOR.KILL RUN.)
      GO TO 9999
80    F3=F1+DELF
      Z3=Z(RE,REYN,F3)
      IF(Z3.GT.1E-5.OR.Z3.LT.-1E-5) GO TO 90
      FRIC=F3
      RETURN
90    DELF=DELF/2.
      IF(Z1.GT.0..AND.Z3.GT.0..OR.Z1.LT.0..AND.Z3.LT.0.)
     1 GO TO 110
      F2=F3
      Z2=Z3
      GO TO 120
110   F1=F3
      Z1=Z3
120   F3=F1+DELF
      Z3=Z(RE,REYN,F3)
      IF(Z3.GT.1E-4.OR.Z3.LT.-1E-4) GO TO 90
      FRIC=F3
      RETURN
15    FRIC=0.
      RETURN
9999  CONTINUE
      RETURN
      END
C
C
C
C
      REAL FUNCTION OBL(T1)
```

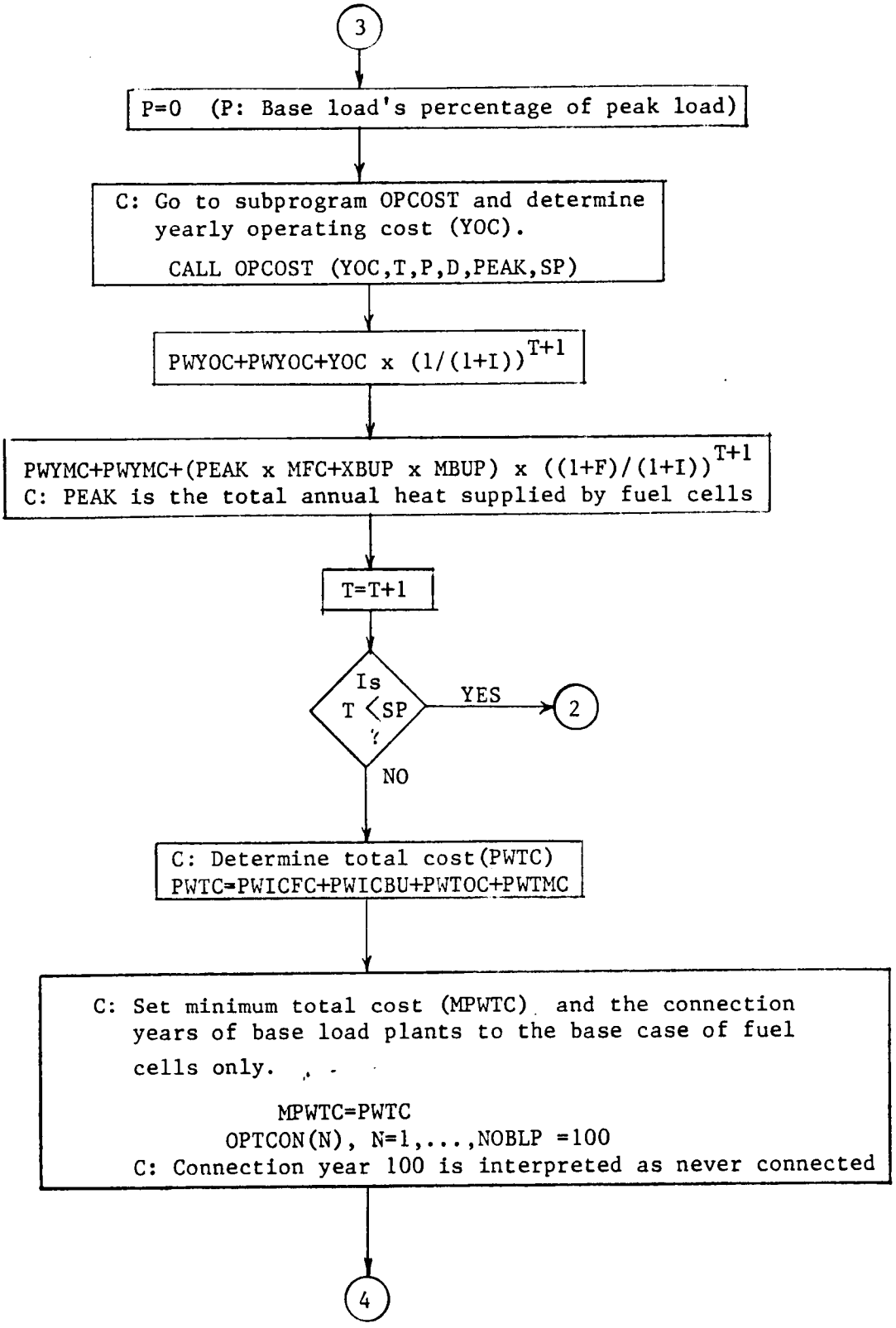
```
      INTEGER T1
      INTEGER T
      T=T1+1
      IF(T.GT.5) GO TO 10
      BUSBAR=0.024+0.0093*(1.09)**T+0.0137*(1.113)**T
      GO TO 20
10    BUSBAR=0.024+0.0093*(1.09)**T+0.0137*(1.113)**5*(1.104)**
     *(T-5)
20    OBL=(BUSBAR/1000000.)*45.072
      RETURN
      END
C
C
C
      REAL FUNCTION OFC(T1)
      INTEGER T1
      INTEGER T
      T=T1+1
      IF(T.GT.5) GO TO 10
      OFC=(9.0/4.12)*2.313*
     *(1.204)**T
     *-(3.413/4.12)*13.77*(1.138)**T*
     *0.6
      GO TO 20
10    OFC=(9.0/4.12)*2.313*
     *(1.204)**5*(1.27)
     **(T-5)-
     *(3.413/4.12)*13.77*(1.138)**5*(1.092)**(T-5)*
     *0.6
20    OFC=OFC/1000000.
      RETURN
      END
C
C
C
      REAL FUNCTION OBUP(T1)
      INTEGER T1
      INTEGER T
      T=T1+1
      IF(T.GT.5) GO TO 5
      OBUP=(2.313*
     *(1.204)
     **T)/0.75
      GO TO 10
 5    OBUP=(2.313*
     *(1.204)**5*(1.27)
     **(T-5))/0.75
10    OBUP=OBUP/1000000.
      RETURN
      END
```

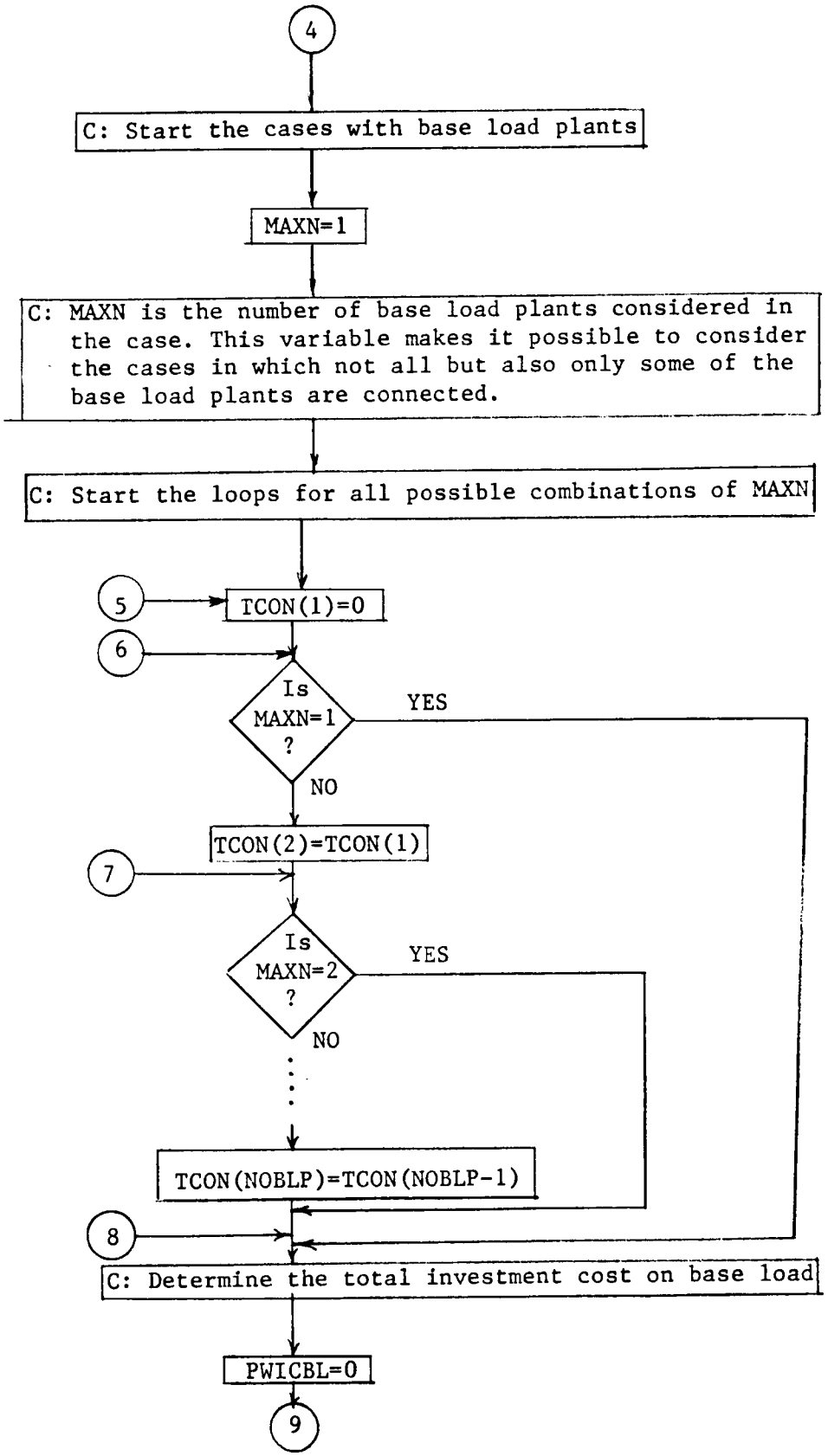
```
C
C
      REAL FUNCTION ECOST(T1)
      INTEGER T1
      INTEGER T
      T=T1+1
      IF(T.GT.5)  GO TO 10
      ECOST=0.047*(1.138)**T
      GO TO 20
10    ECOST=0.047*(1.138)**5*(1.092)**(T-5)
20    CONTINUE
      RETURN
      END
```

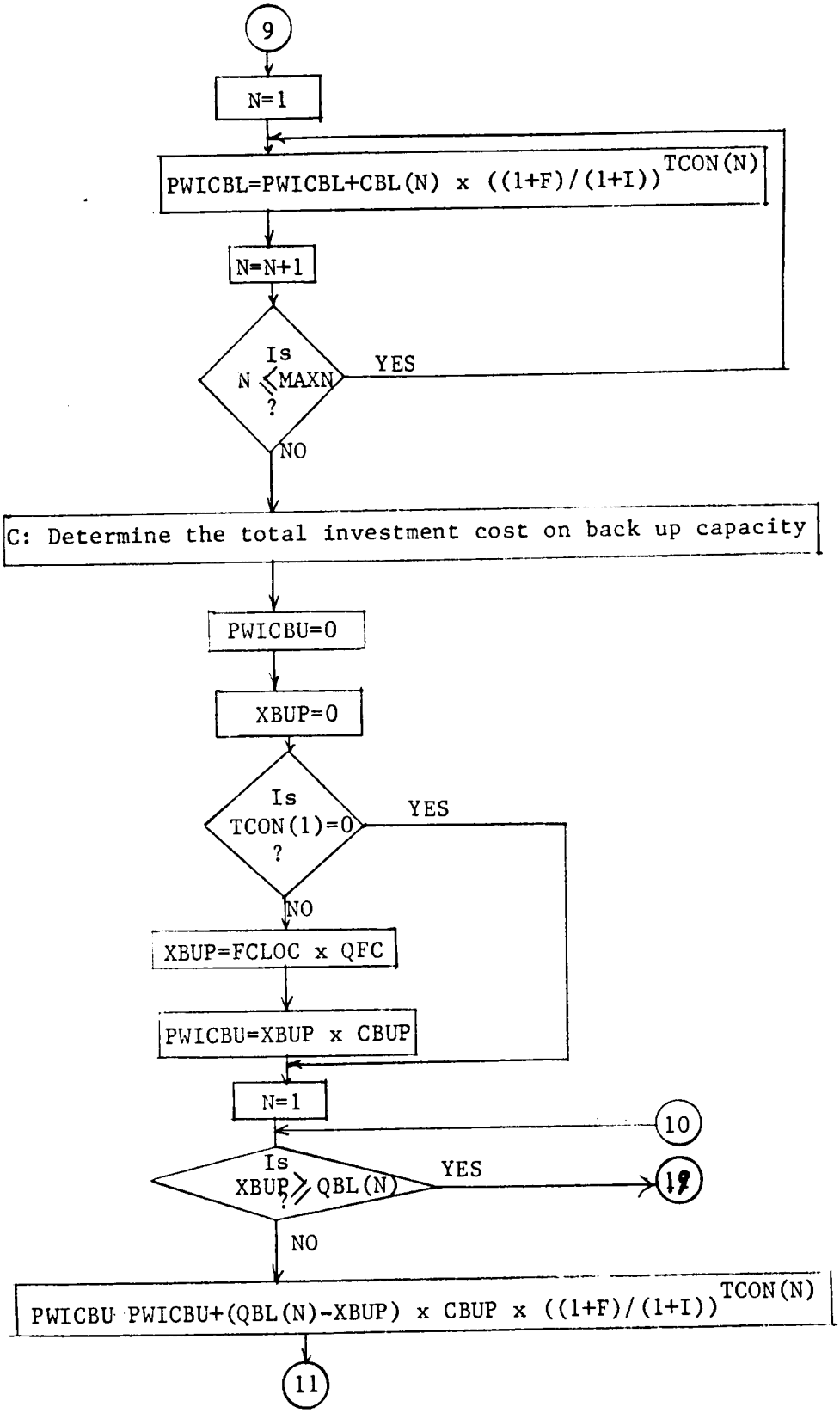
B. FLOW CHART

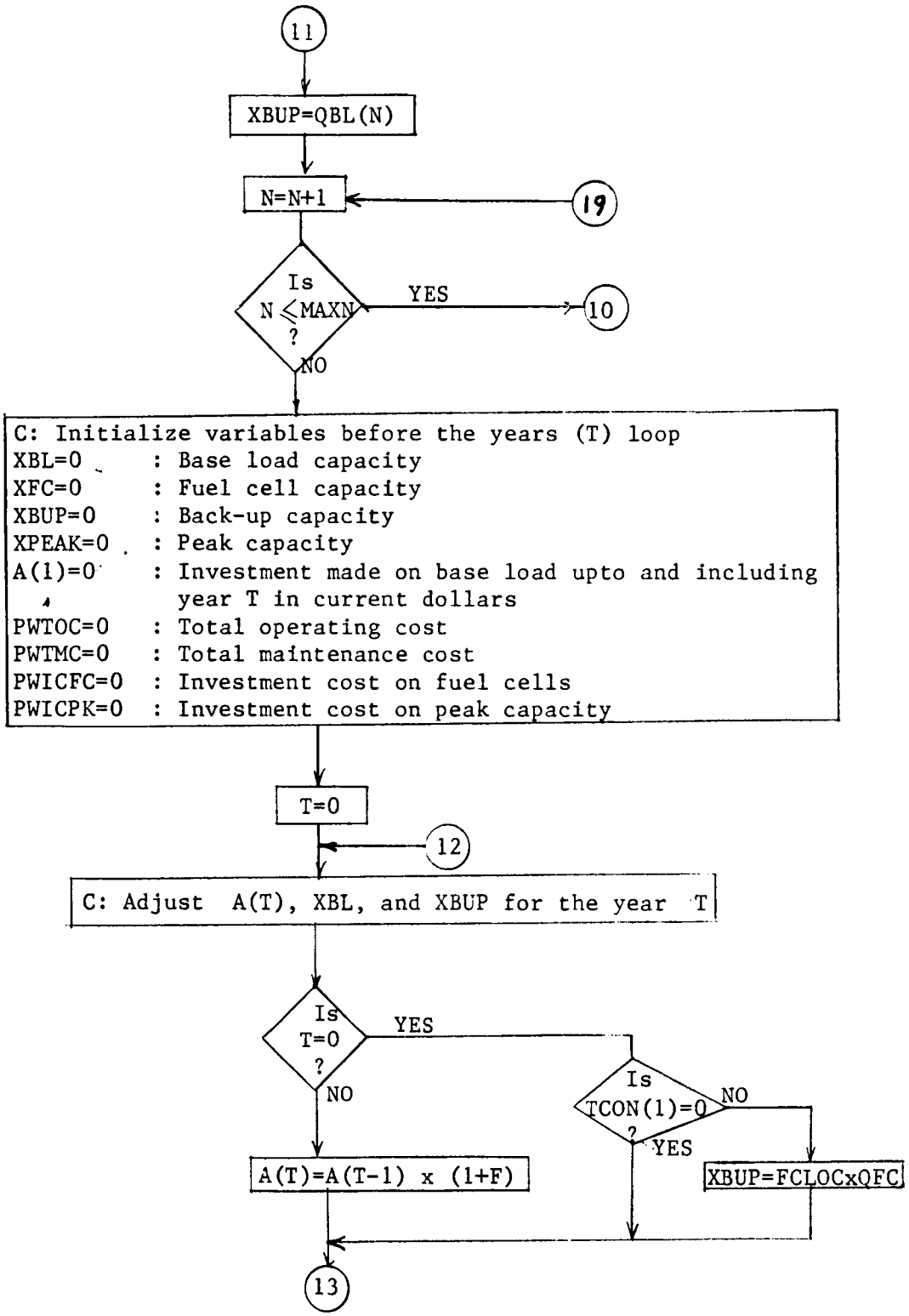

START
INPUT:
I-Discount Rate
F-Inflation
NOBLP-Total number of base load plants
SP-Study period
CBL(N), N=1 ...,NOBLP -Investment cost of base load plants
QBL(N), N=1,...,NOBLP -Capacities of base load plants
MBL-Maintenance percentage of base load
CFC-Investment cost on one module of fuel cells
QFC-Heat production capacity of one fuel cell module
MFC-Maintenance cost per unit of heat produced by fuel cells
FCLOC-Number of fuel cell locations
ULFC-Useful life of a fuel cell
CBUP-Investment cost of one unit capacity of back-up
MBUP-Maintenance cost per unit capacity of back-up
CPEAK-Investment cost per unit capacity of peak sources
MPEAK-Maintenance cost per unit capacity of peak sources
C: Start fuel cells only-no base load case
C:Determine back-up capaciy(XBUP) and investment on it(PWICBU)
XBUP=FCLOC x QFC
PWICBU=XBUP x CBUP
1

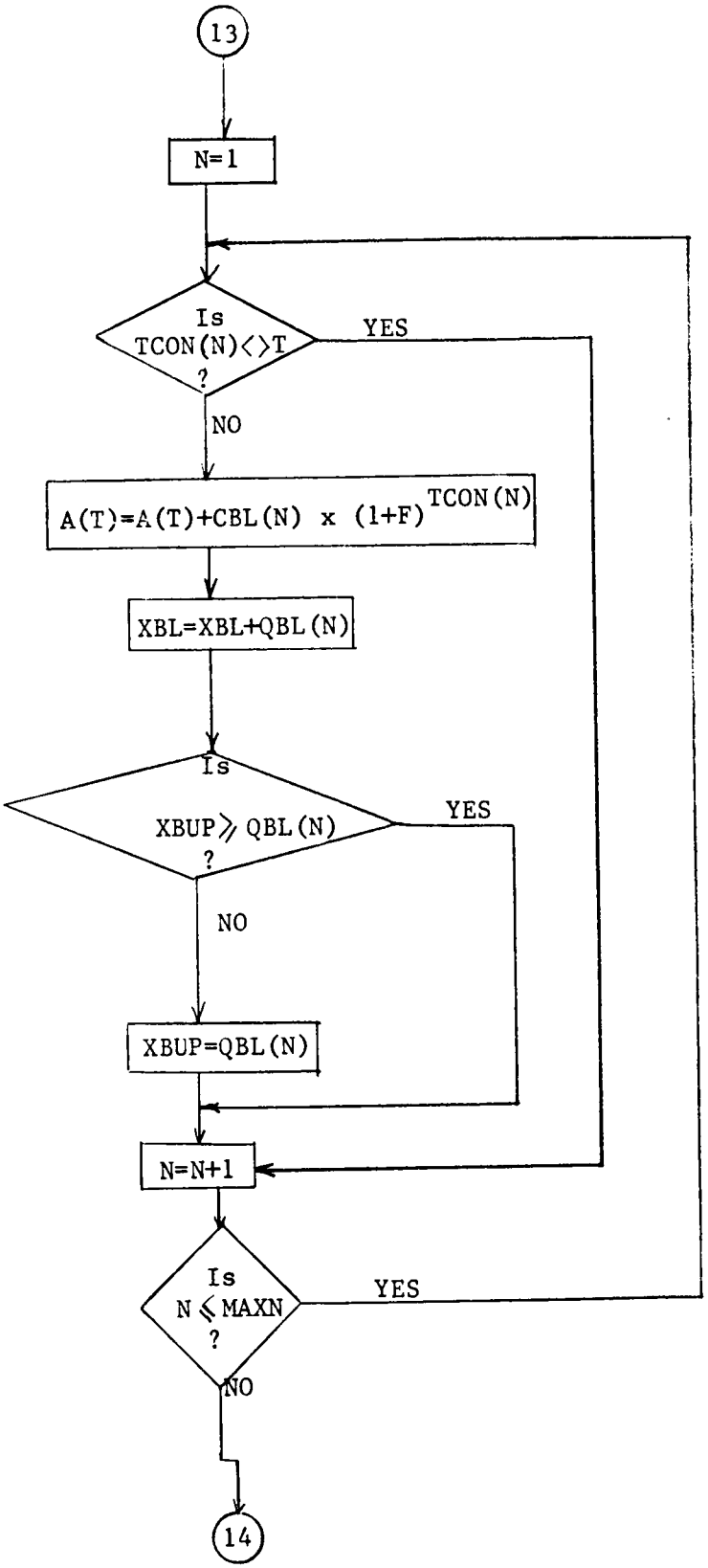

1
C: Initalize variables before the years loop
PWICFC=0 Investment on fuel cells
PWTOC=0 Total operating cost
PWTMC=0 Total maintenance cost
XFX=0 Installed fuel cell capacity
T=0
D=DEAMAND(T)
2
Is XFC > D ?
YES
NO
K(T)=Integer ((D-XFC)/QFC)+1
Is (K(T)-(D-XFC)/QFC)=1 ?
YES
NO
K(T)=K(T)-1
XFC=XFC+K(T) x QFC
PWICFC=PWICFC+K(T) x CFC x ((1+F)/(1+I))^T
3

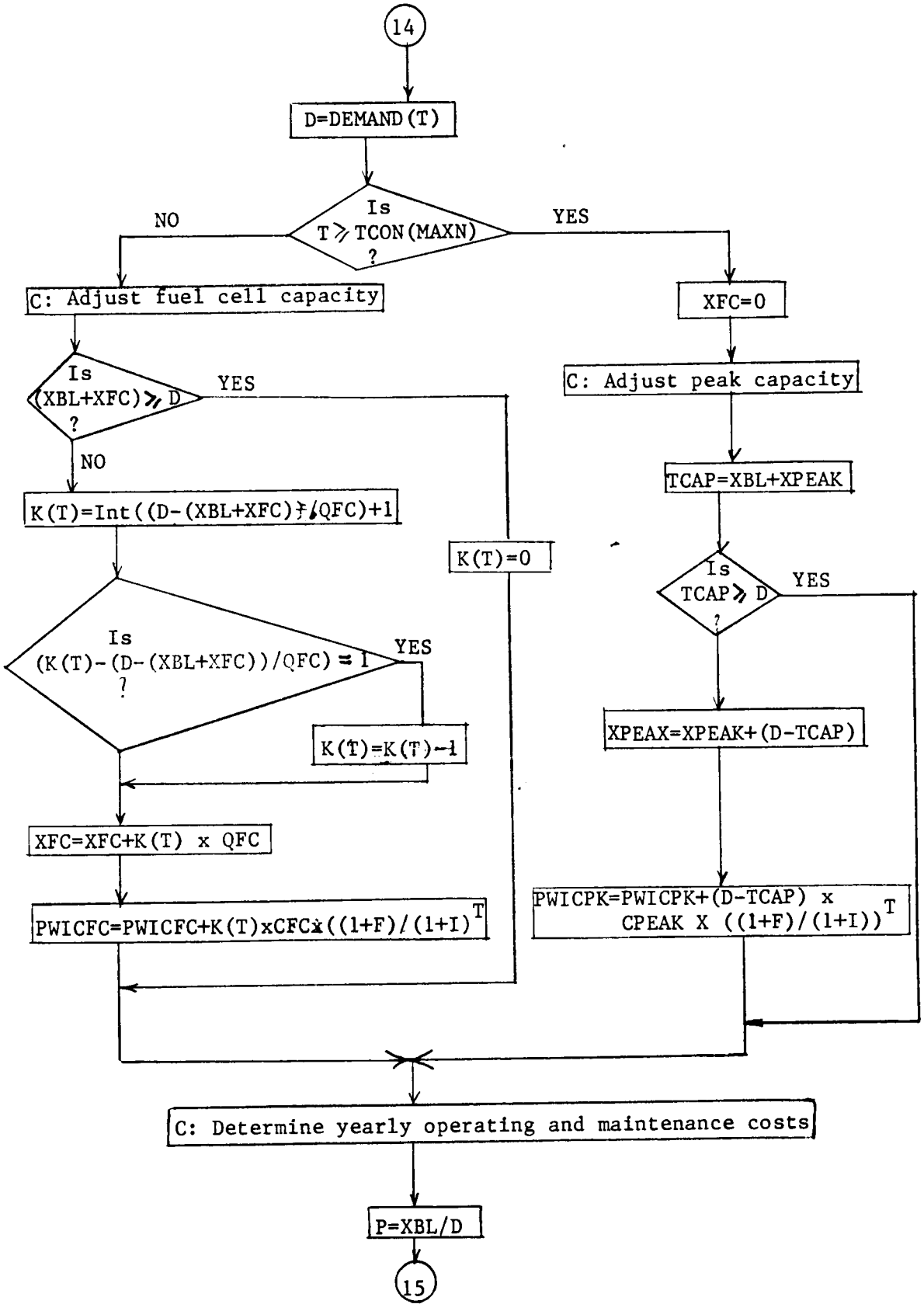

3
P=0 (P: Base load's percentage of peak load)
C: Go to subprogram OPCOST and determine yearly operating cost (YOC).
CALL OPCOST (YOC,T,P,D,PEAK,SP)
PWYOC+PWYOC+YOC x (1/(1+I))^T+1
PWYMC+PWYMC+(PEAK x MFC+XBUP x MBUP) x ((1+F)/(1+I))^T+1
C: PEAK is the total annual heat supplied by fuel cells
T=T+1
Is T < SP ?
YES
2
NO
C: Determine total cost(PWTC)
PWTC=PWICFC+PWICBU+PWTOC+PWTMC
C: Set minimum total cost (MPWTC) and the connection years of base load plants to the base case of fuel cells only.
MPWTC=PWTC
OPTCON(N), N=1,...,NOBLP =100
C: Connection year 100 is interpreted as never connected
4

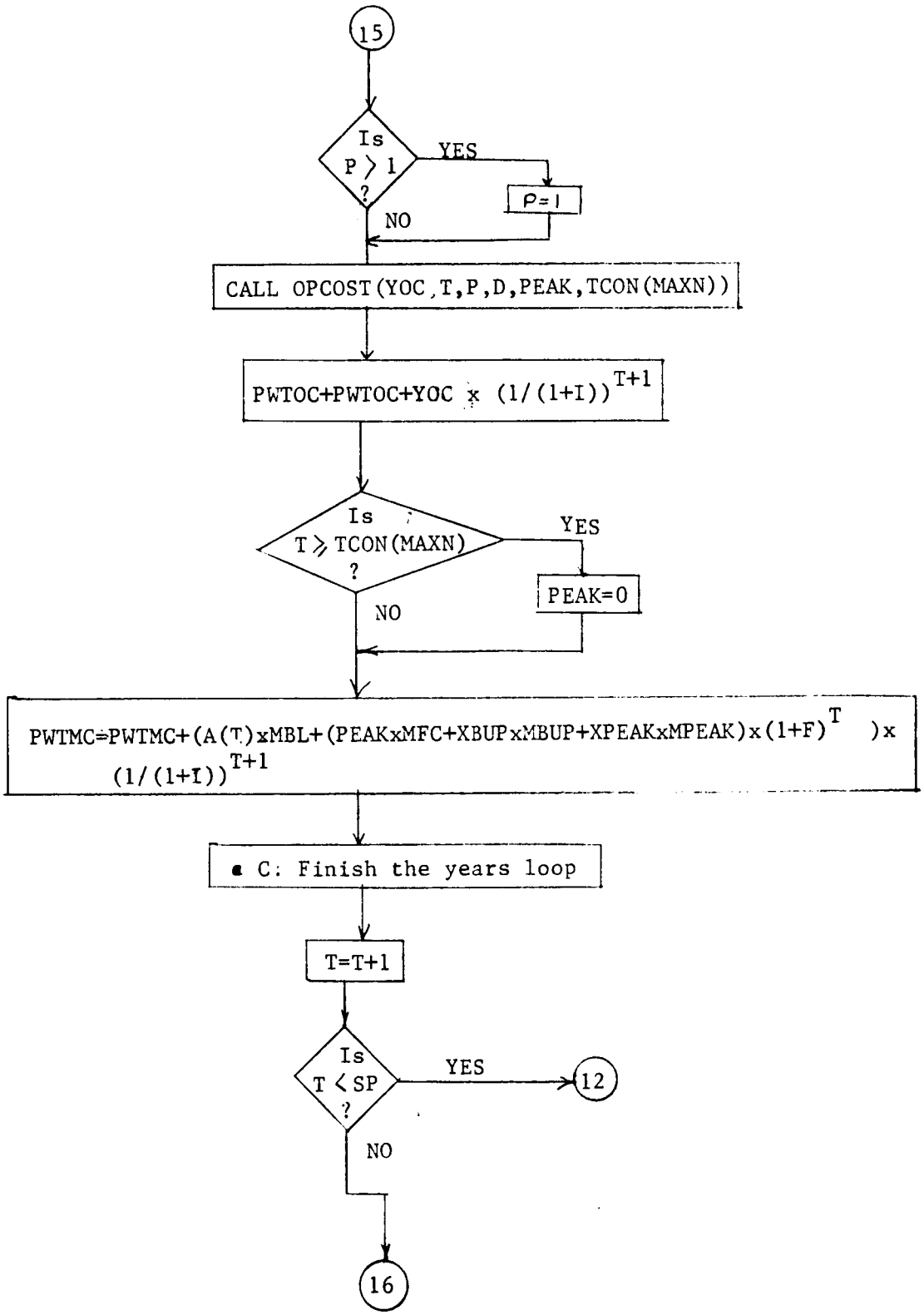

4
C: Start the cases with base load plants
MAXN=1
C: MAXN is the number of base load plants considered in the case. This variable makes it possible to consider the cases in which not all but also only some of the base load plants are connected.
C: Start the loops for all possible combinations of MAXN
5
6
TCON(1)=0
Is MAXN=1 ?
YES
NO
TCON(2)=TCON(1)
7
Is MAXN=2 ?
YES
NO
TCON(NOBLP)=TCON(NOBLP-1)
8
C: Determine the total investment cost on base load
PWICBL=0
9

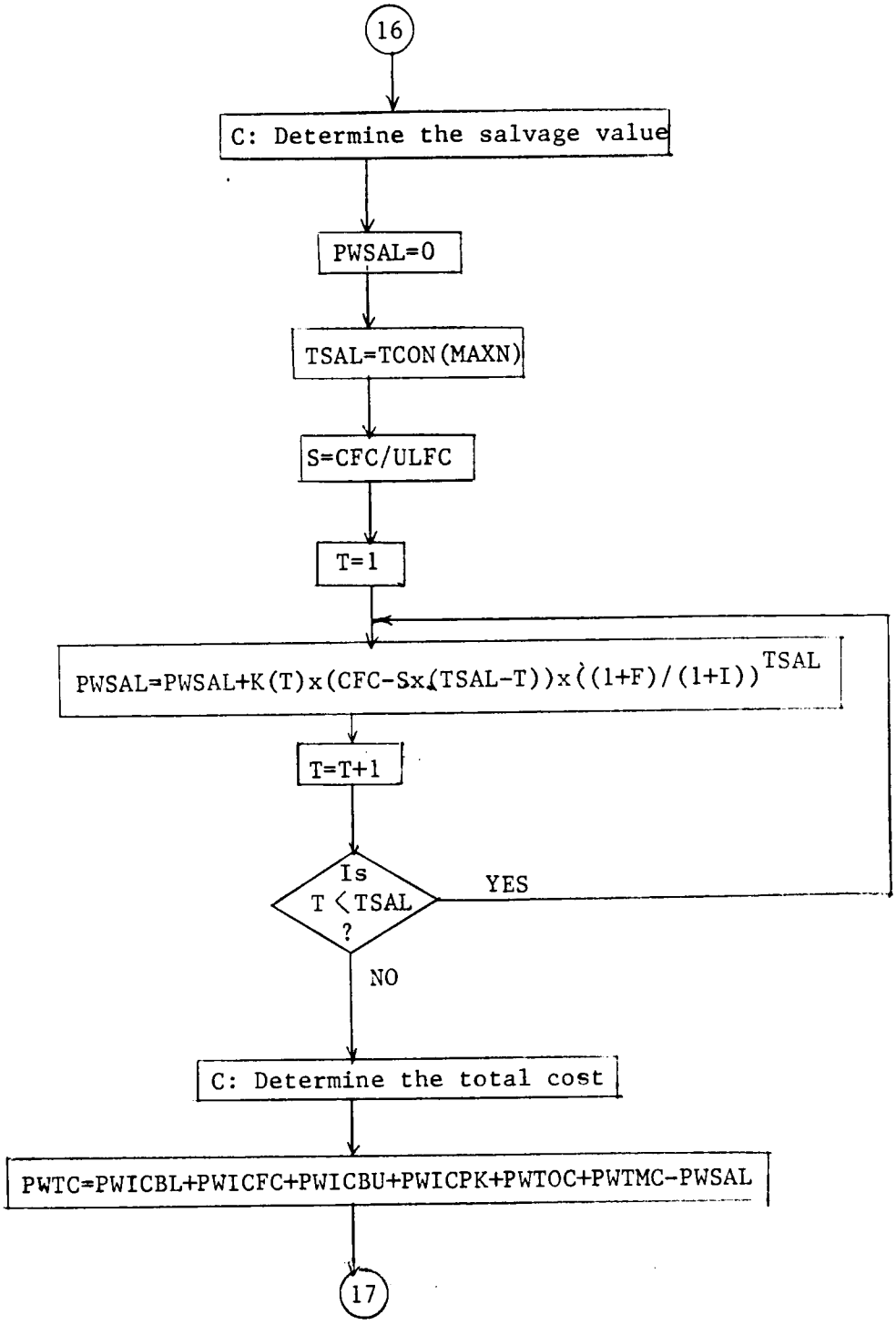

9
N=1
PWICBL=PWICBL+CBL(N) x ((1+F)/(1+I))^TCON(N)
N=N+1
Is N ≤ MAXN ?
YES
NO
C: Determine the total investment cost on back up capacity
PWICBU=0
XBUP=0
Is TCON(1)=0 ?
YES
NO
XBUP=FCLOC x QFC
PWICBU=XBUP x CBUP
N=1
10
Is XBUP ≥ QBL(N) ?
YES
NO
PWICBU PWICBU+(QBL(N)-XBUP) x CBUP x ((1+F)/(1+I))^TCON(N)
11

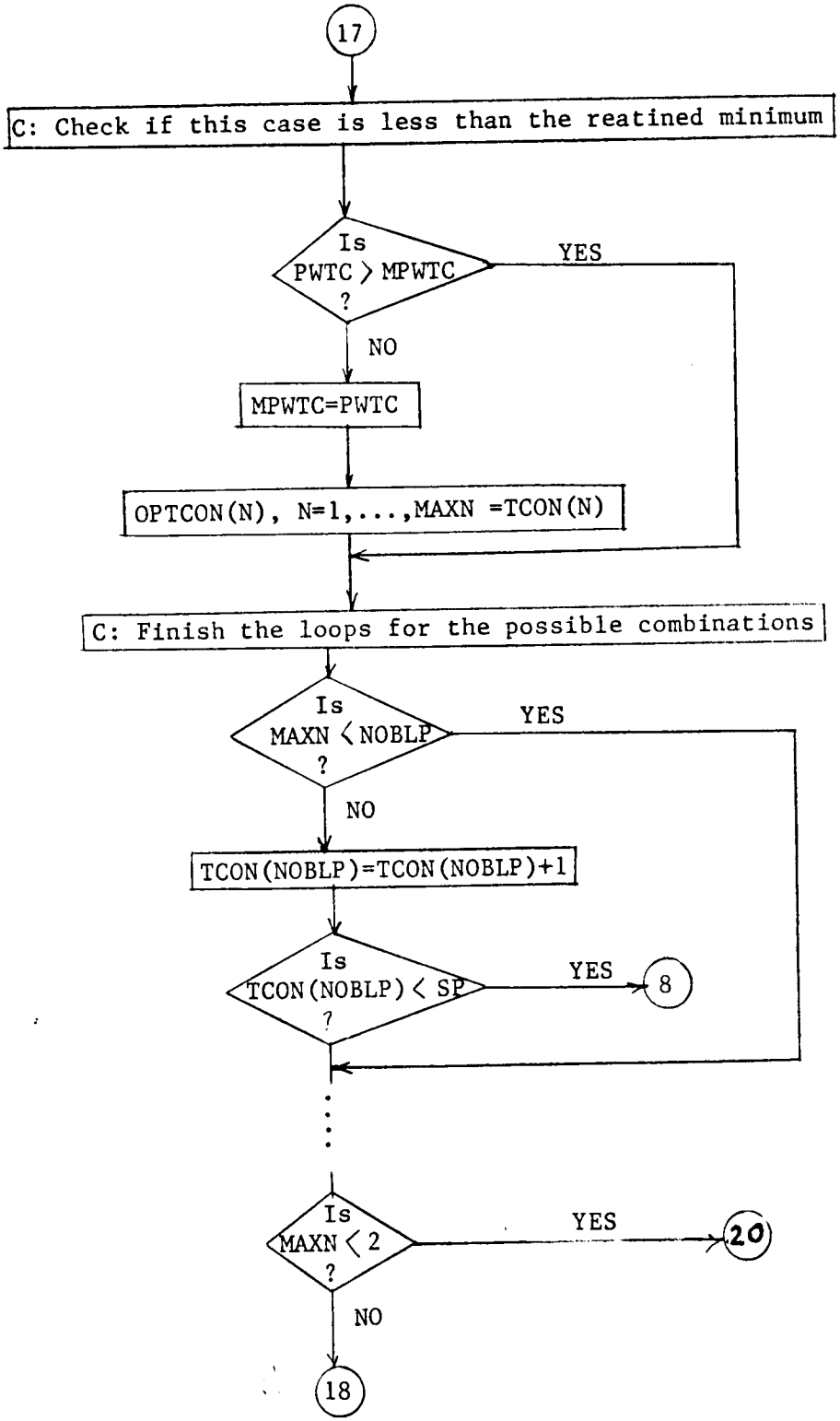

11
XBUP=QBL(N)
N=N+1
19
Is N ≤ MAXN ?
YES
10
NO
C: Initialize variables before the years (T) loop
XBL=0 : Base load capacity
XFC=0 : Fuel cell capacity
XBUP=0 : Back-up capacity
XPEAK=0 : Peak capacity
A(1)=0 : Investment made on base load upto and including year T in current dollars
PWTOC=0 : Total operating cost
PWTMC=0 : Total maintenance cost
PWICFC=0 : Investment cost on fuel cells
PWICPK=0 : Investment cost on peak capacity
T=0
12
C: Adjust A(T), XBL, and XBUP for the year T
Is T=0 ?
YES
NO
Is TCON(1)=0 ?
NO
YES
A(T)=A(T-1) x (1+F)
XBUP=FCLOCxQFC
13

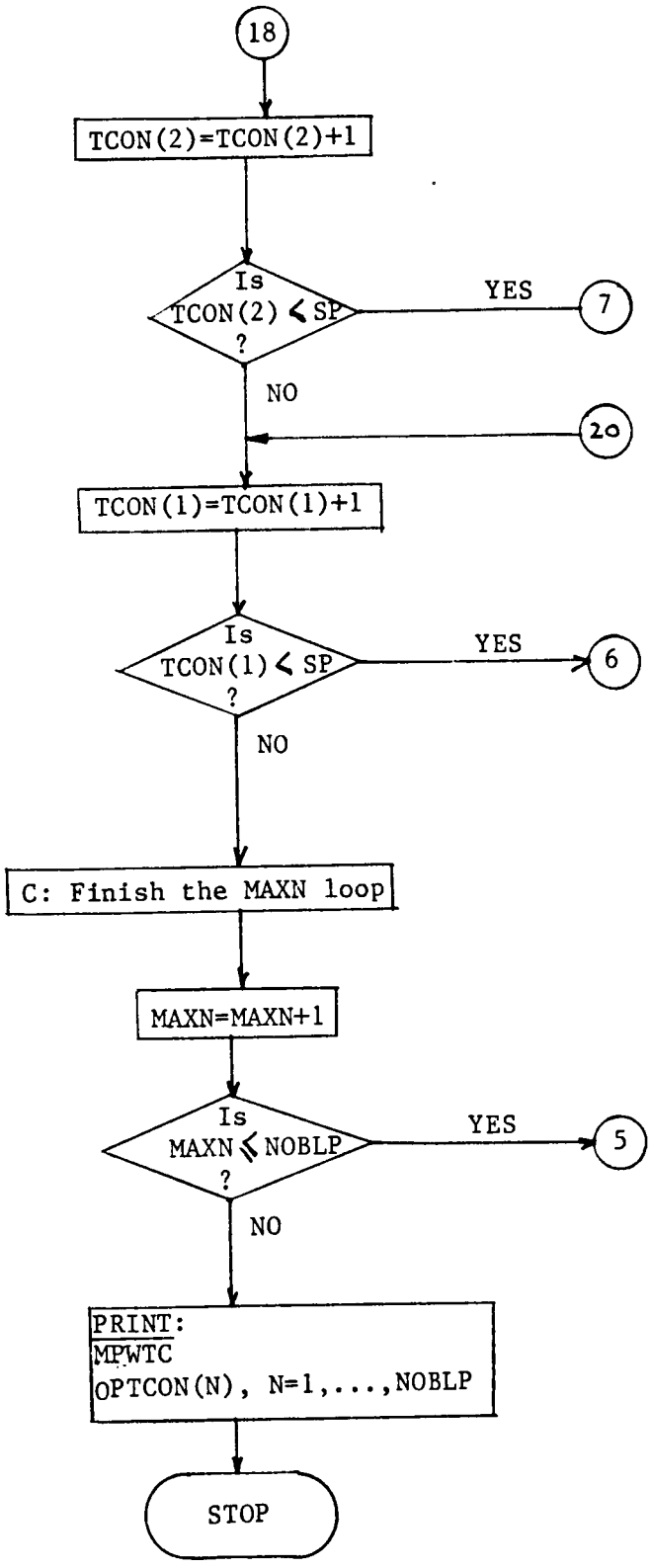

13
N=1
Is TCON(N)<>T ?
YES
NO
A(T)=A(T)+CBL(N) x (1+F)^TCON(N)
XBL=XBL+QBL(N)
Is XBUP >= QBL(N) ?
YES
NO
XBUP=QBL(N)
N=N+1
Is N <= MAXN ?
YES
NO
14


14
D=DEMAND(T)
Is T ≥ TCON(MAXN) ?
NO
YES
C: Adjust fuel cell capacity
XFC=0
Is (XBL+XFC) ≥ D ?
YES
NO
C: Adjust peak capacity
TCAP=XBL+XPEAK
K(T)=Int((D-(XBL+XFC))/QFC)+1
K(T)=0
Is TCAP ≥ D ?
YES
Is (K(T)-(D-(XBL+XFC))/QFC) = 1 ?
YES
XPEAX=XPEAK+(D-TCAP)
K(T)=K(T)-1
XFC=XFC+K(T) x QFC
PWICPK=PWICPK+(D-TCAP) x CPEAK X ((1+F)/(1+I))^T
PWICFC=PWICFC+K(T)xCFCx((1+F)/(1+I))^T
C: Determine yearly operating and maintenance costs
P=XBL/D
15


15
Is P > 1 ?
YES
P=1
NO
CALL OPCOST(YOC,T,P,D,PEAK,TCON(MAXN))
PWTOC=PWTOC+YOC x (1/(1+I))^(T+1)
Is T >= TCON(MAXN) ?
YES
PEAK=0
NO
PWTMC=PWTMC+(A(T)xMBL+(PEAKxMFC+XBUPxMBUP+XPEAKxMPEAK)x(1+F)^T)x (1/(1+I))^(T+1)
C: Finish the years loop
T=T+1
Is T < SP ?
YES
12
NO
16


16
C: Determine the salvage value
PWSAL=0
TSAL=TCON(MAXN)
S=CFC/ULFC
T=1
PWSAL=PWSAL+K(T)x(CFC-Sx(TSAL-T))x((1+F)/(1+I))^TSAL
T=T+1
Is T < TSAL ?
YES
NO
C: Determine the total cost
PWTC=PWICBL+PWICFC+PWICBU+PWICPK+PWTOC+PWTMC-PWSAL
17


17
C: Check if this case is less than the reatined minimum
Is PWTC > MPWTC ?
YES
NO
MPWTC=PWTC
OPTCON(N), N=1,...,MAXN =TCON(N)
C: Finish the loops for the possible combinations
Is MAXN < NOBLP ?
YES
NO
TCON(NOBLP)=TCON(NOBLP)+1
Is TCON(NOBLP) < SP ?
YES
8
Is MAXN < 2 ?
YES
20
NO
18


18
TCON(2)=TCON(2)+1
Is TCON(2) < SP ?
YES
7
NO
20
TCON(1)=TCON(1)+1
Is TCON(1) < SP ?
YES
6
NO
C: Finish the MAXN loop
MAXN=MAXN+1
Is MAXN ≤ NOBLP ?
YES
5
NO
PRINT:
MPWTC
OPTCON(N), N=1,...,NOBLP
STOP

APPENDIX B

APPENDIX B

RESULTS OF APARTMENT MODEL ANALYSIS

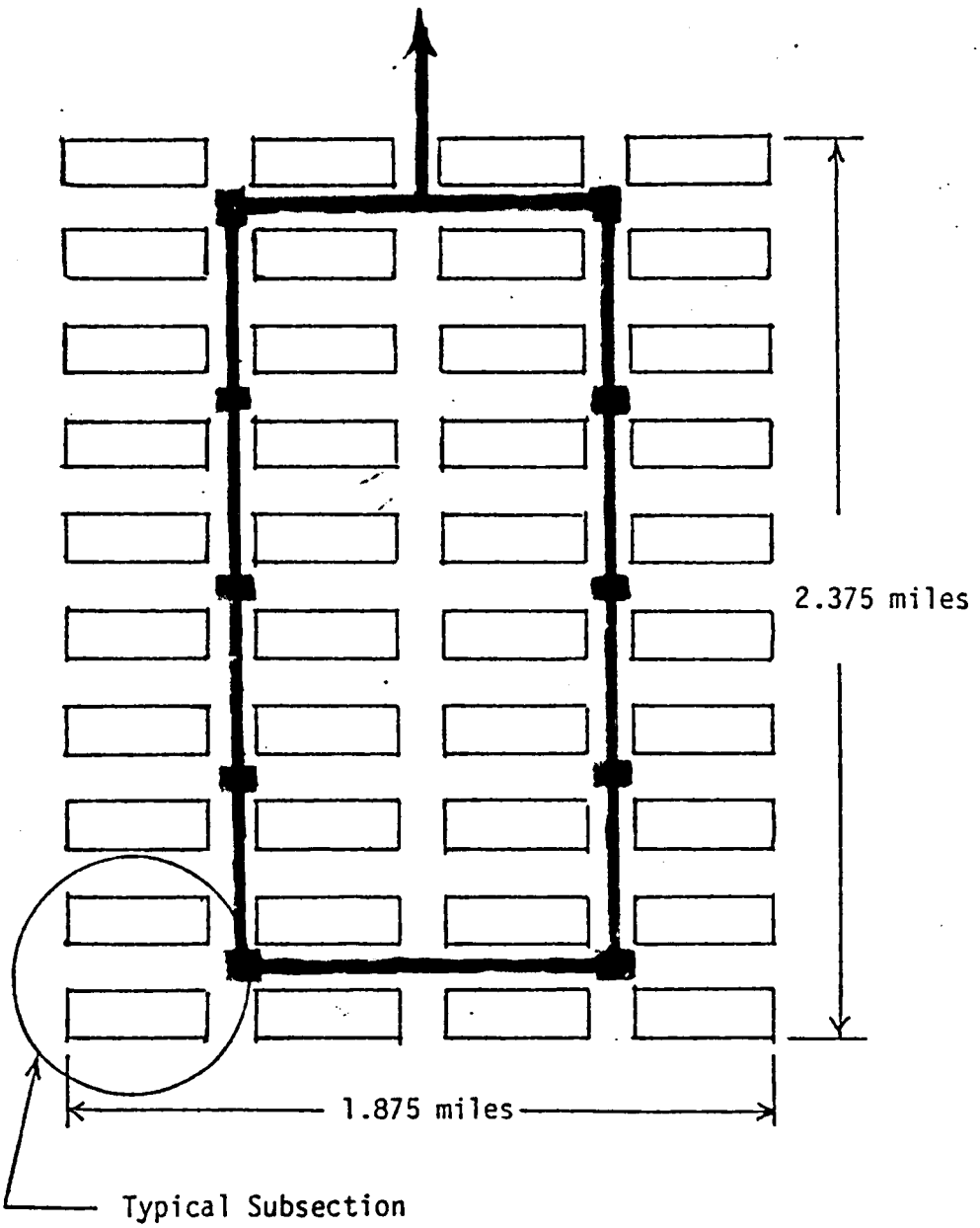


Figure 34. Entire City Structure--Apartment Building Urban Model.

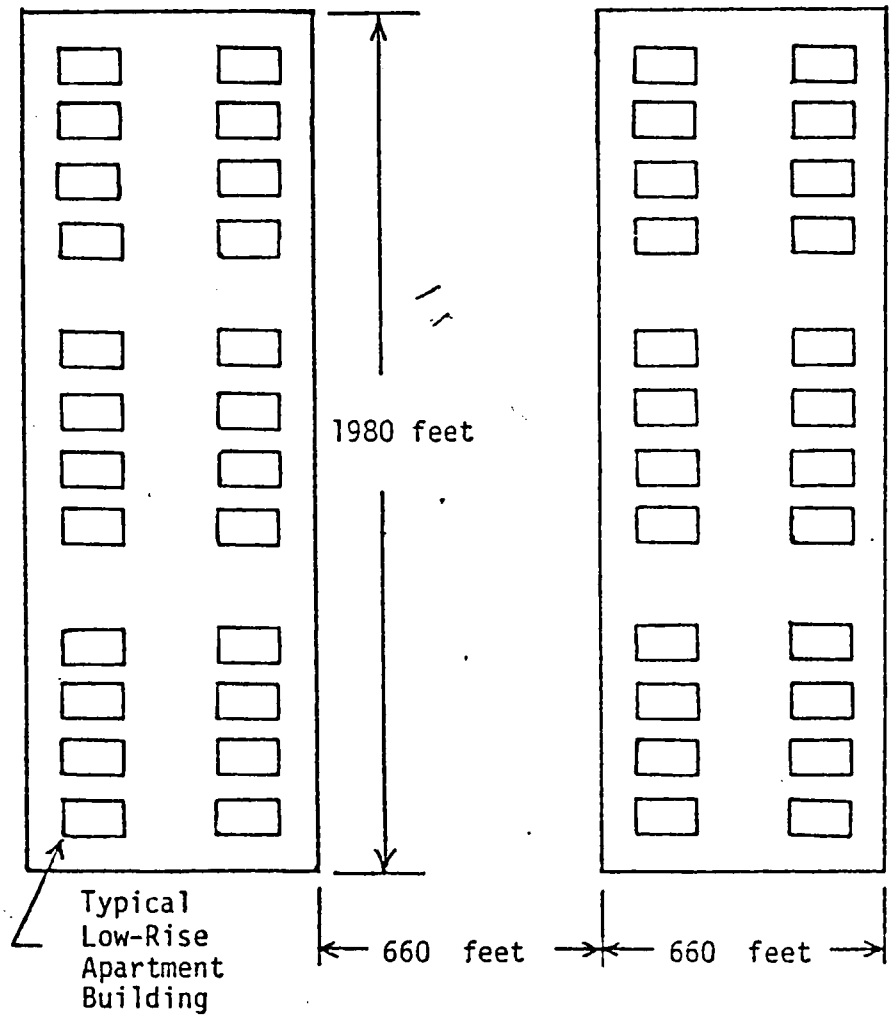


Figure 35. Subsection Design--Apartment Building Urban Model.

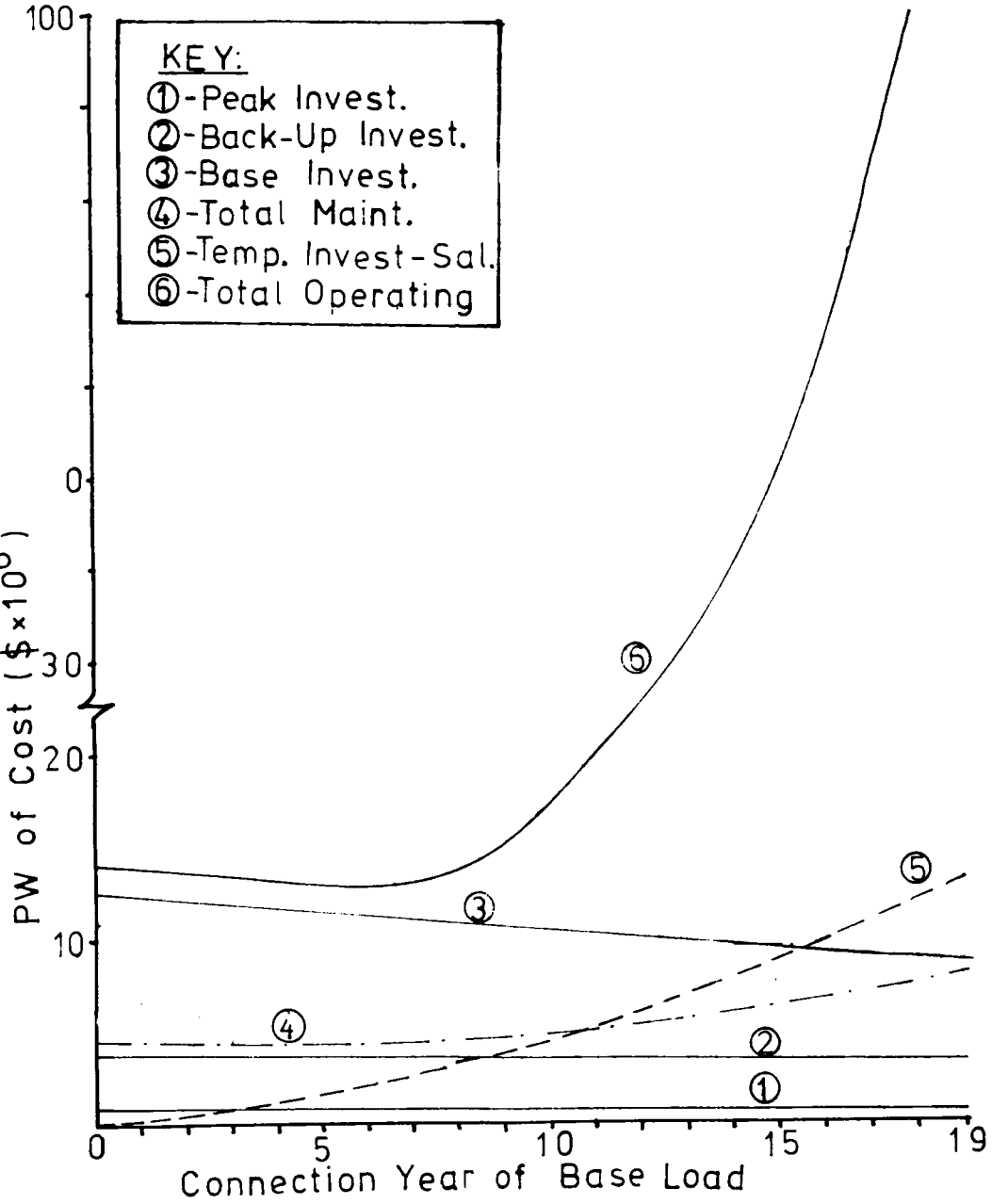


Figure 36. Cost Components Vs. Connection Year--Apartment Model With Fuel Cells.

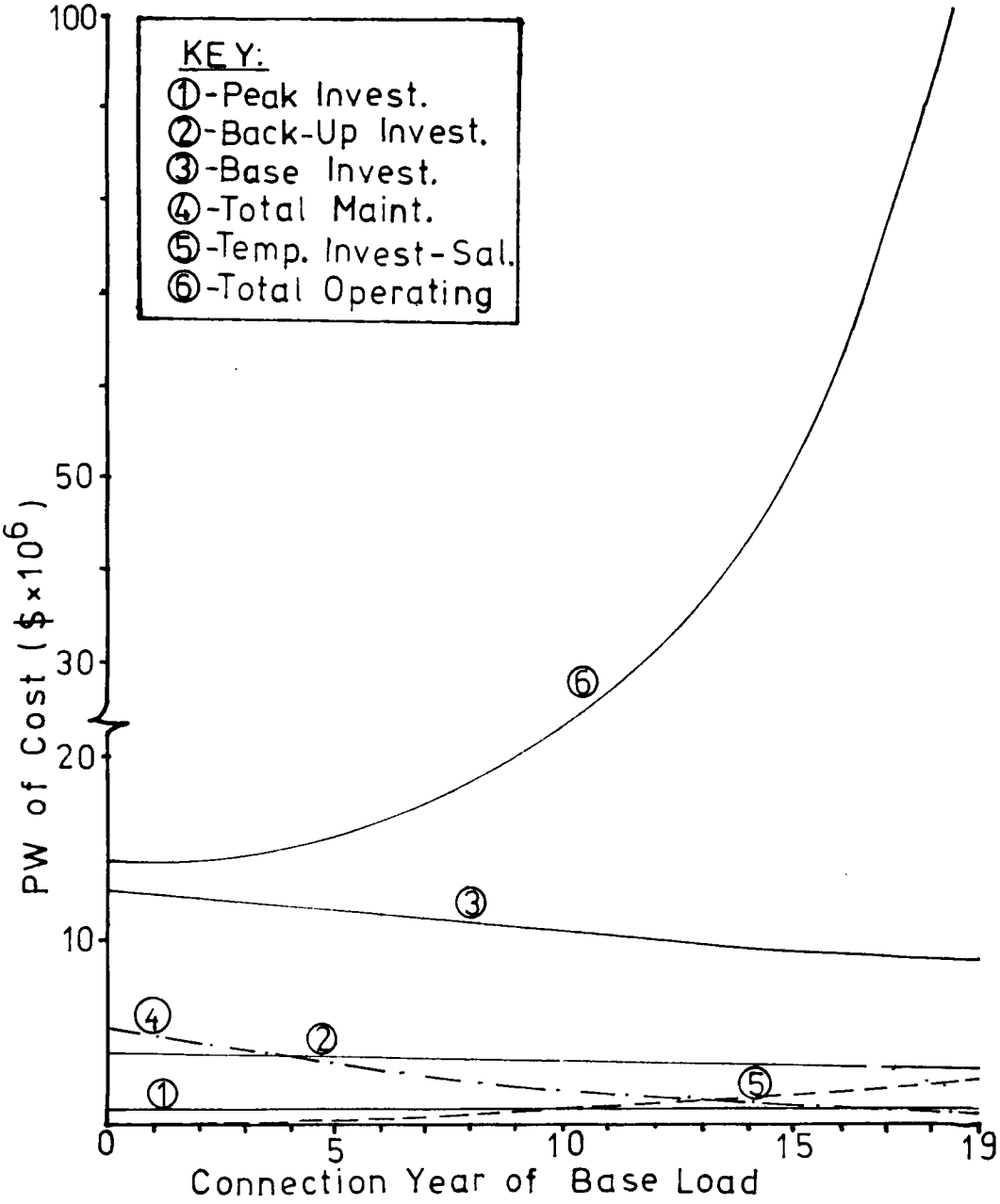


Figure 37. Cost Components Vs. Connection Year--Apartment Model With Boilers.

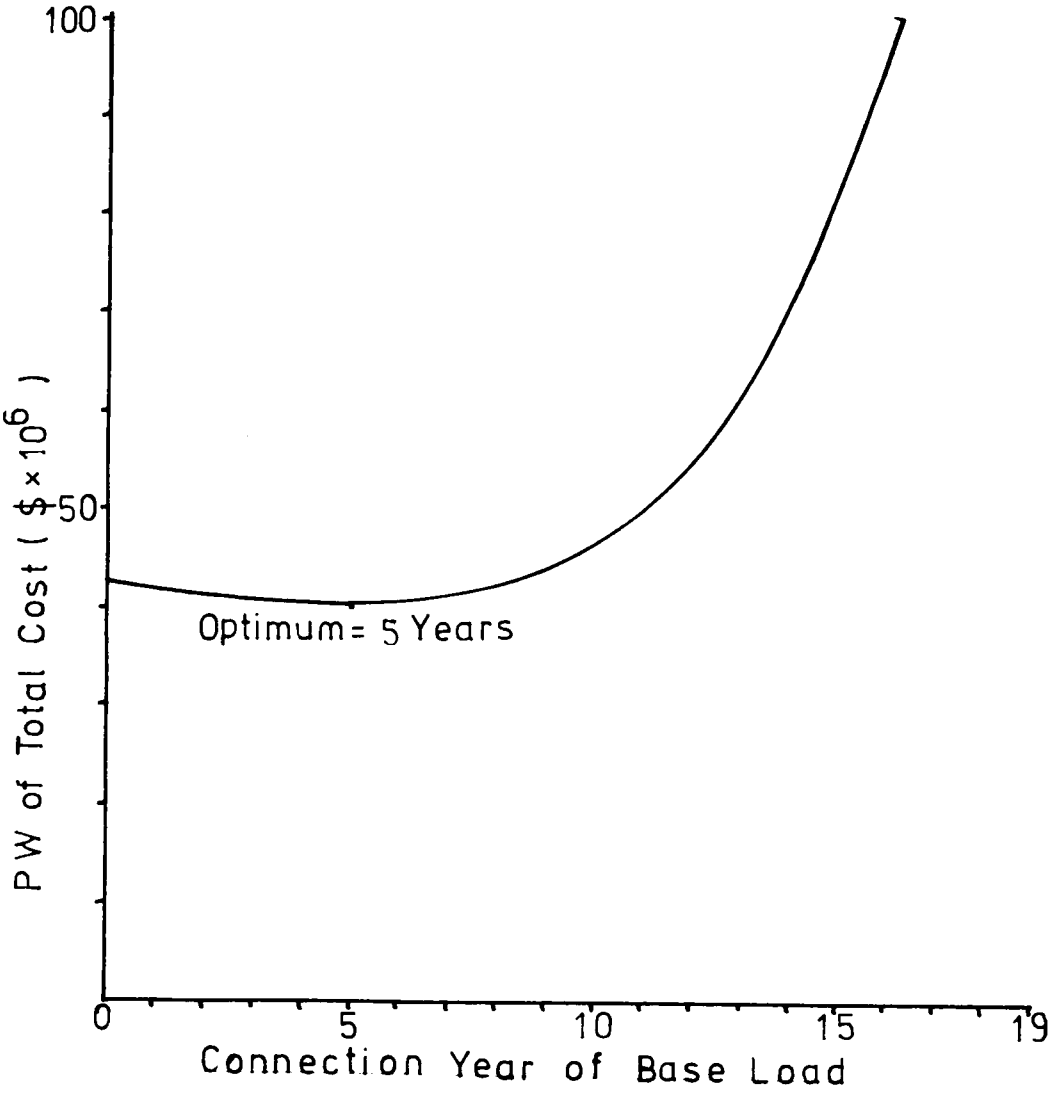


Figure 38. Total Cost Vs. Connection Year--Apartment Model With Fuel Cells.

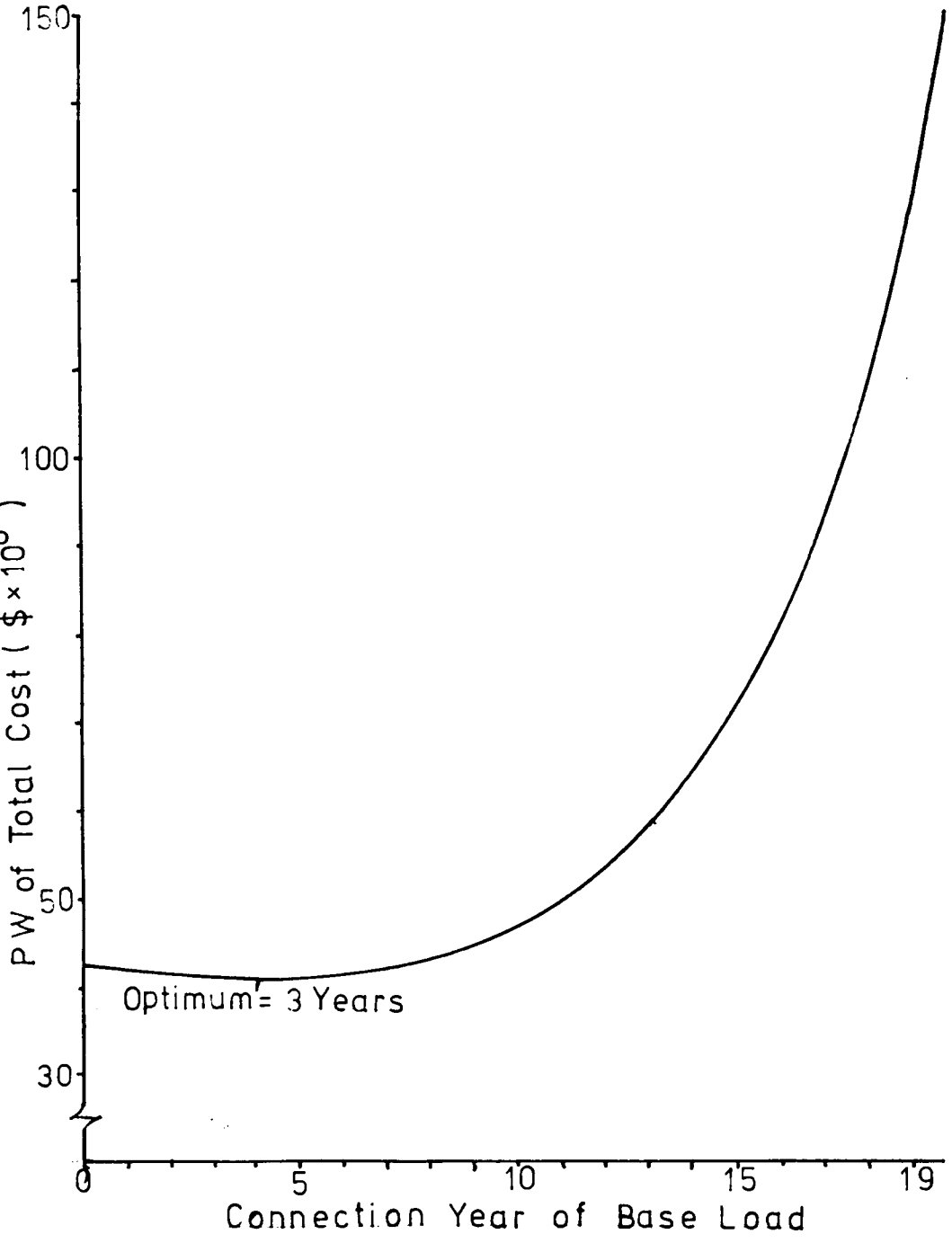


Figure 39. Total Cost Vs. Connection Year--Apartment Model With Boilers.

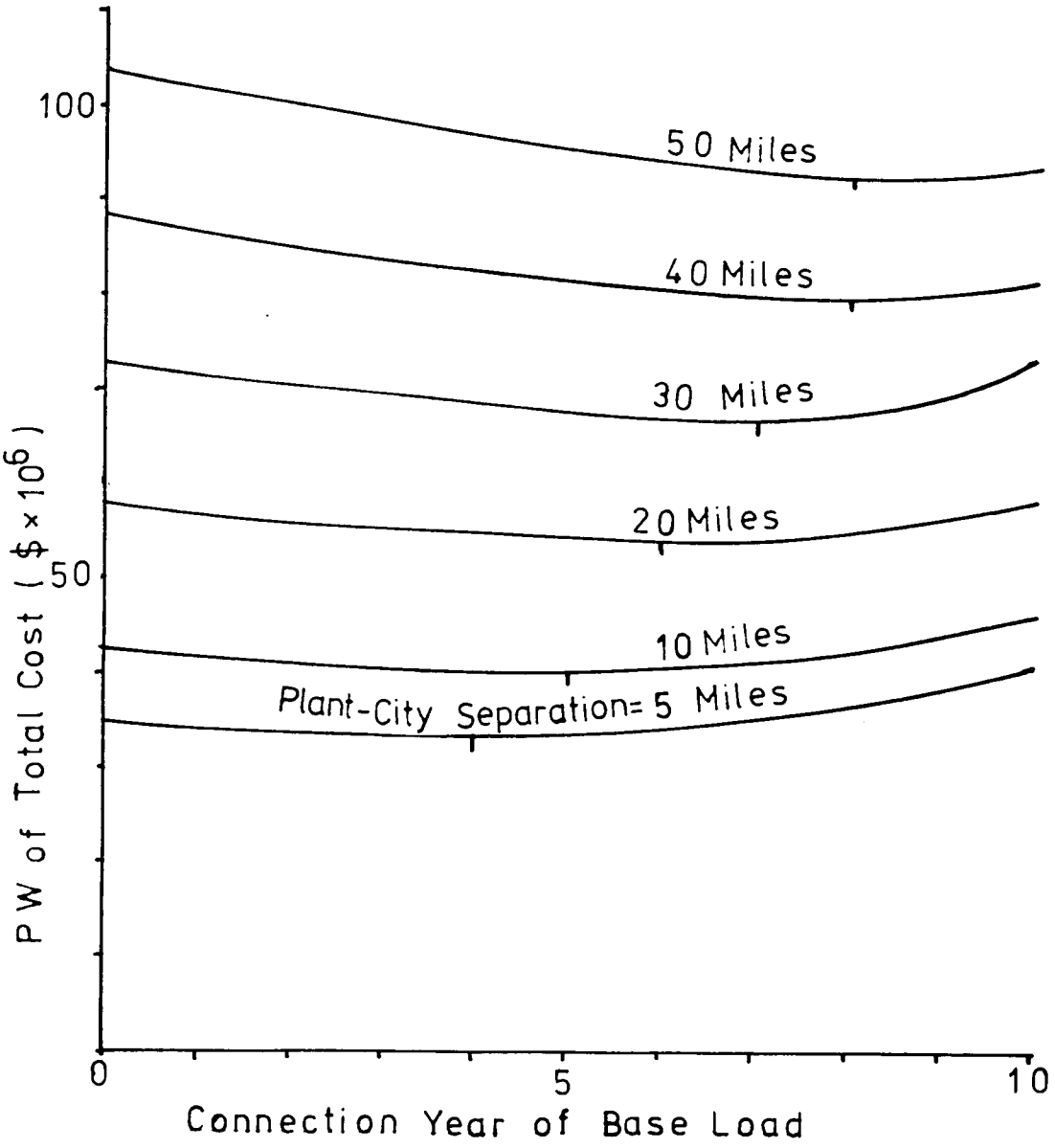


Figure 40. Total Cost Vs. Connection Year at Different Plant-City Separations for the Apartment Model With Fuel Cells.

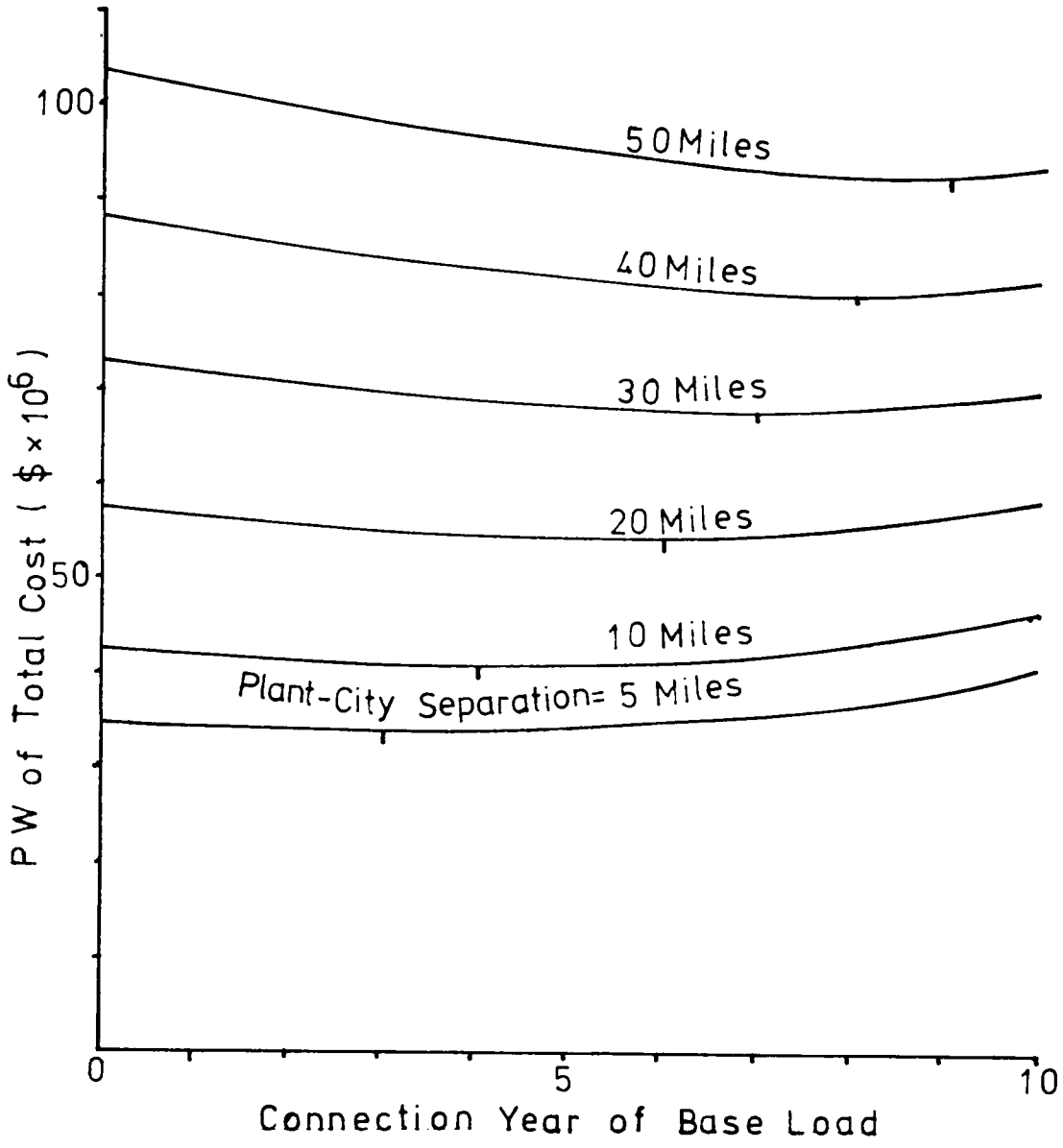


Figure 41. Total Cost Vs. Connection Year at Different Plant-City Separations for the Apartment Model With Boilers.

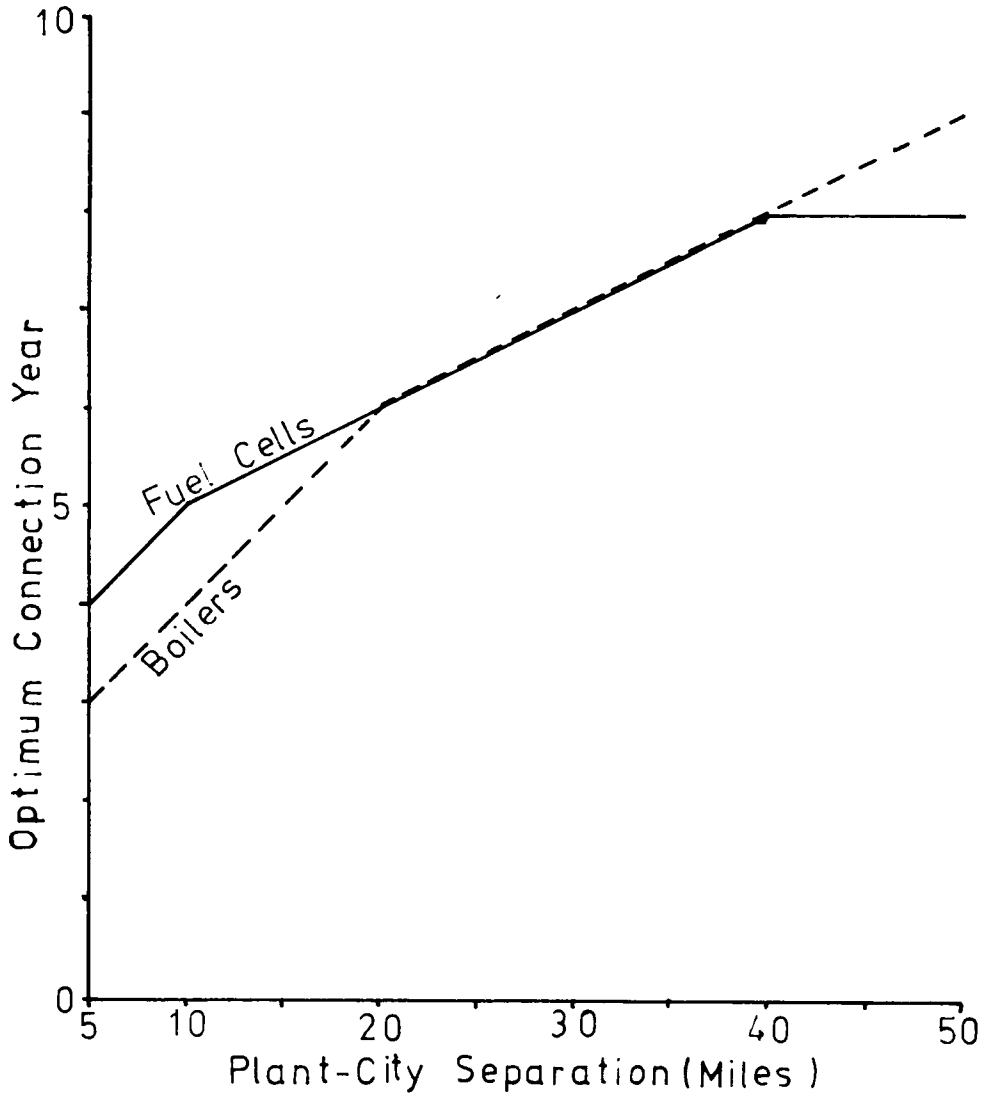


Figure 42. Optimum Connection Year Vs. Plant-City Separation--Apartment Model.

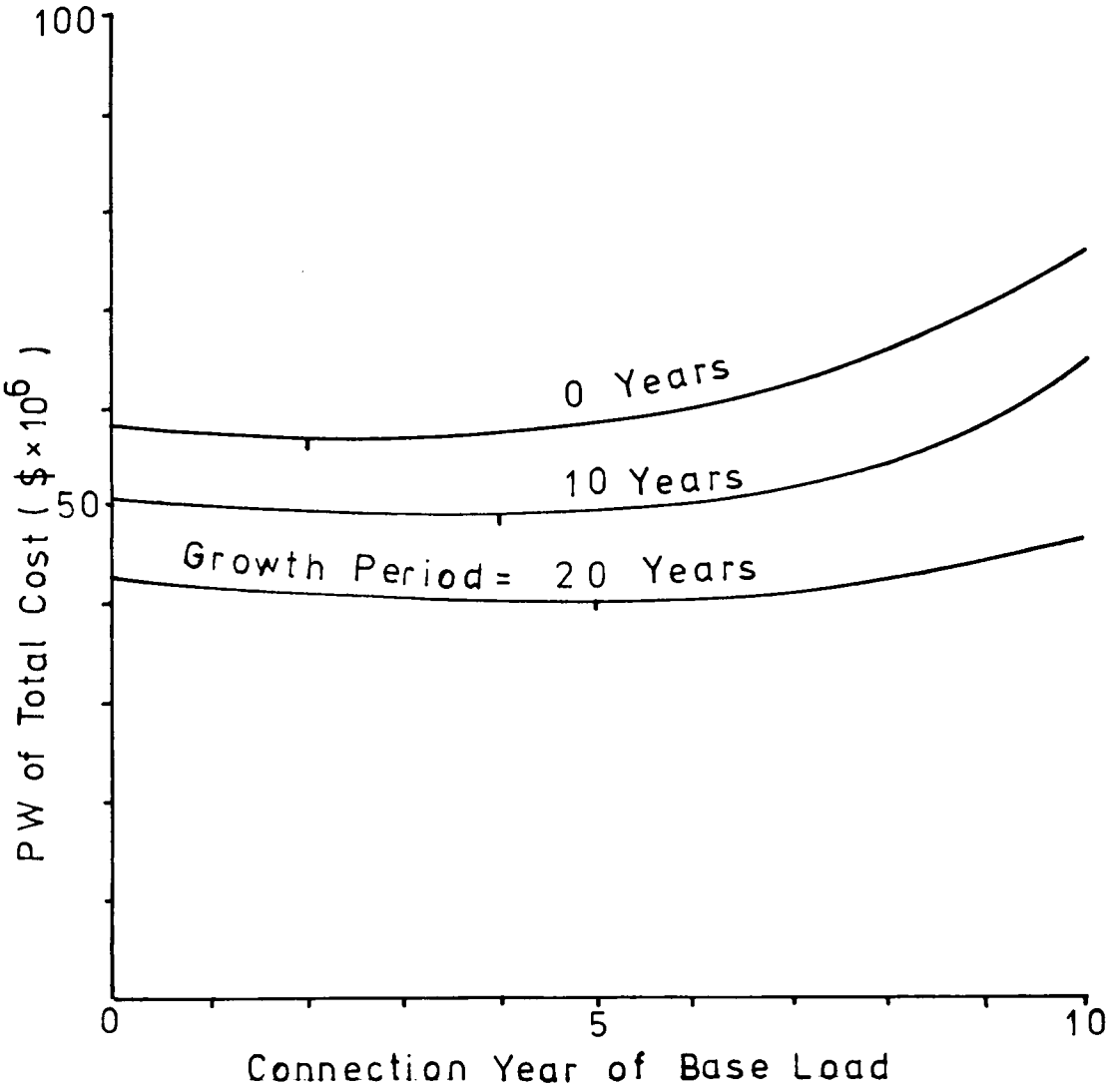


Figure 43. Total Cost Vs. Connection Year at Different Years for the Demand to Reach the Maximum Level--Apartment Model With Fuel Cells.

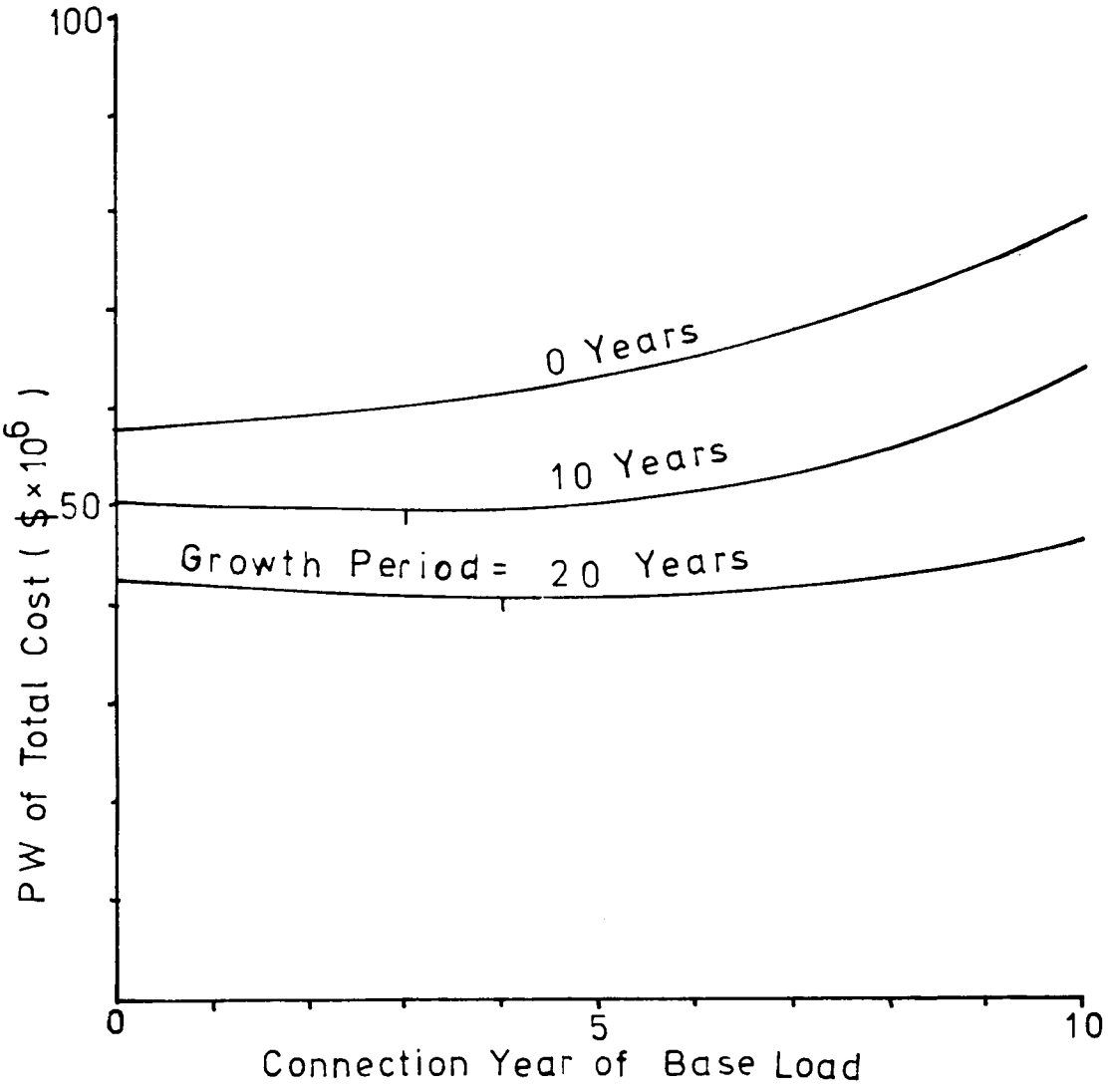


Figure 44. Total Cost Vs. Connection Year at Different Years for the Demand to Reach the Maximum Level--Apartment Model With Boilers.

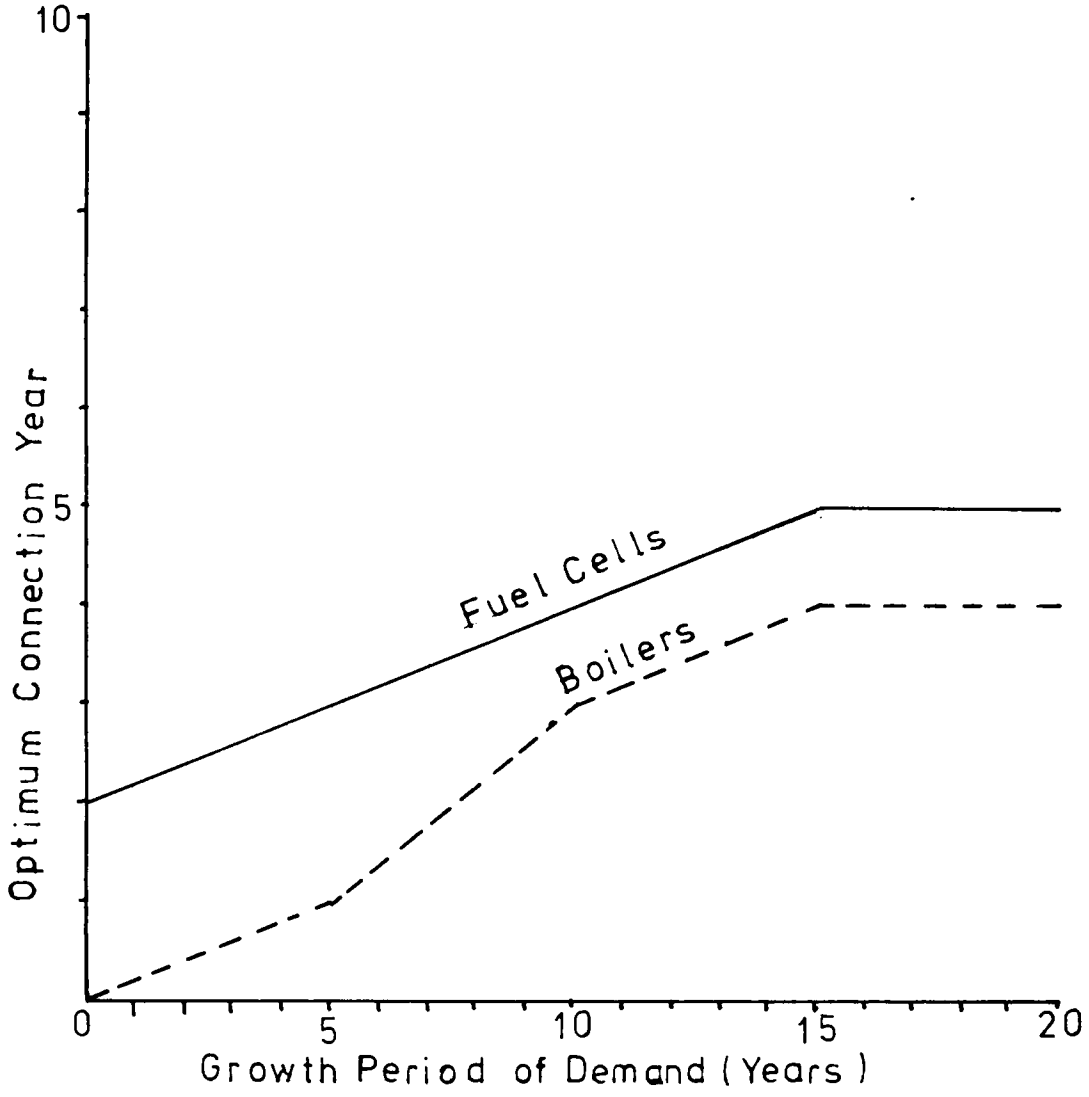


Figure 45. Optimum Connection Year Vs. Growth Period of Demand--Apartment Model.

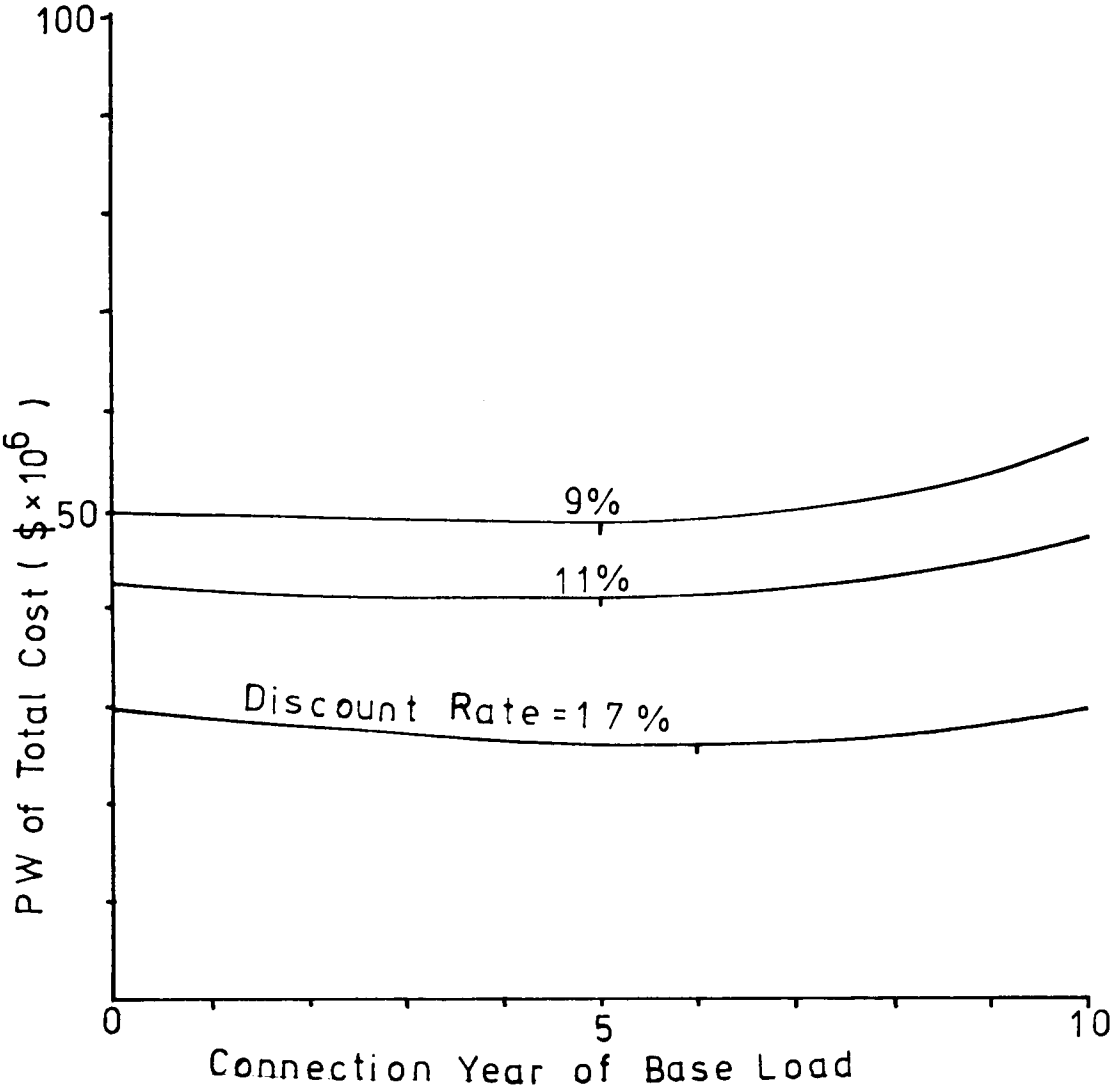


Figure 46. Total Cost Vs. Connection Year at Various Discount Rates--Apartment Model With Fuel Cells.

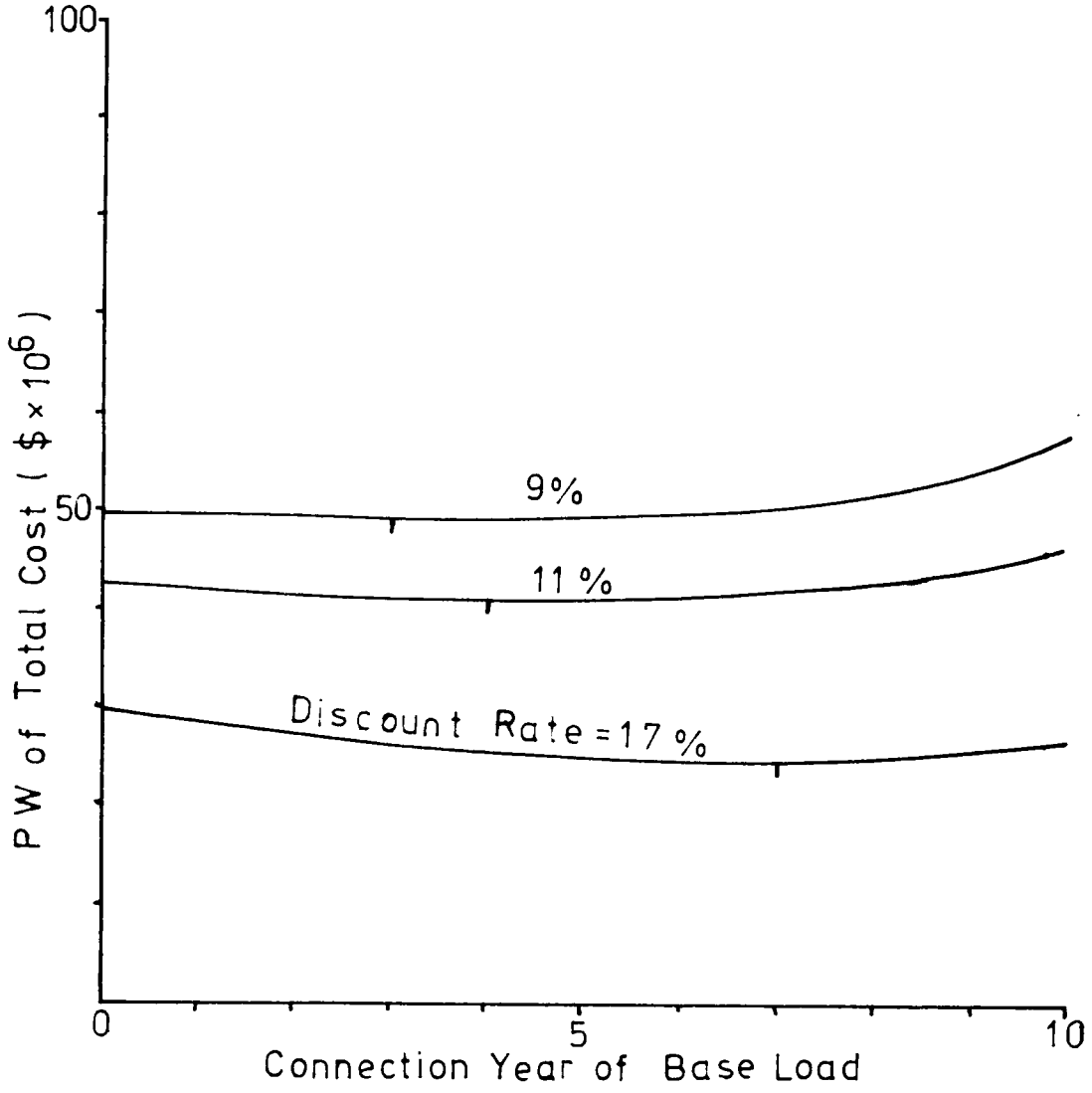


Figure 47. Total Cost Vs. Connection Year at Various Discount Rates--Apartment Model With Boilers.

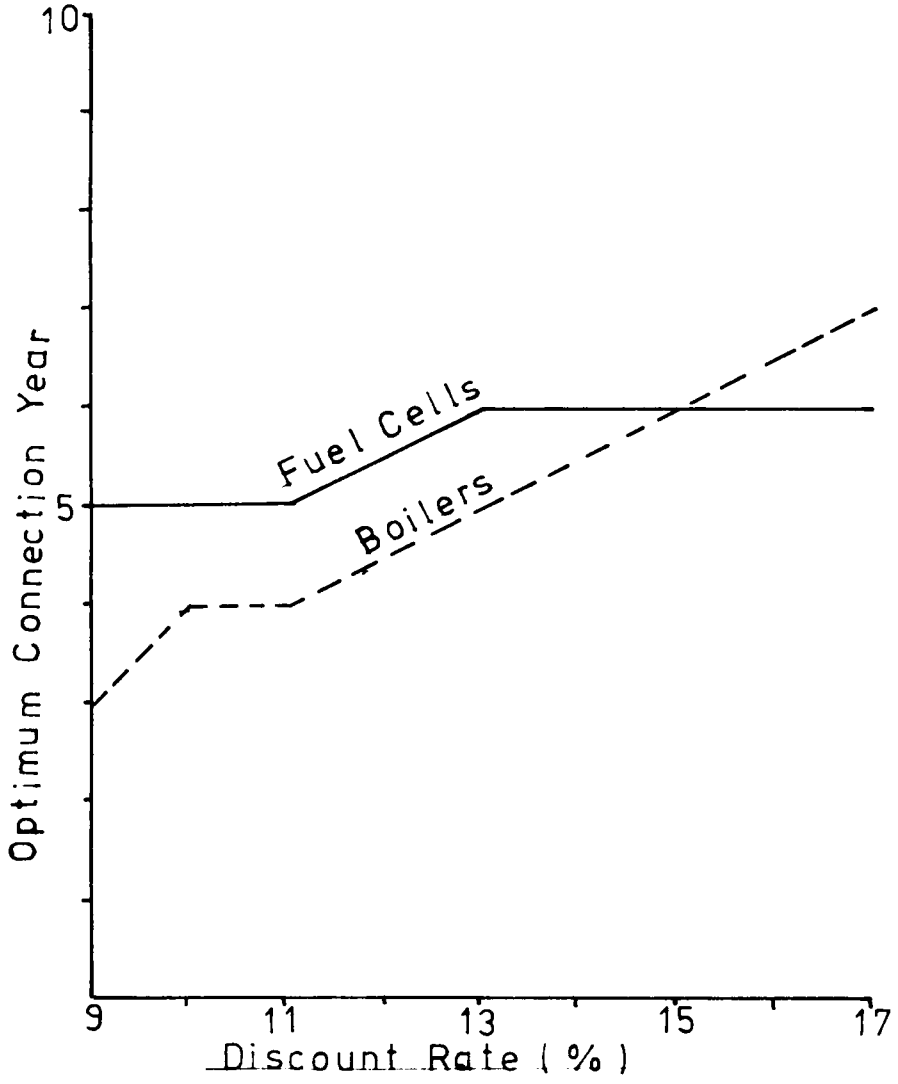


Figure 48. Optimum Connection Year Vs. Discount Rate--Apartment Model.

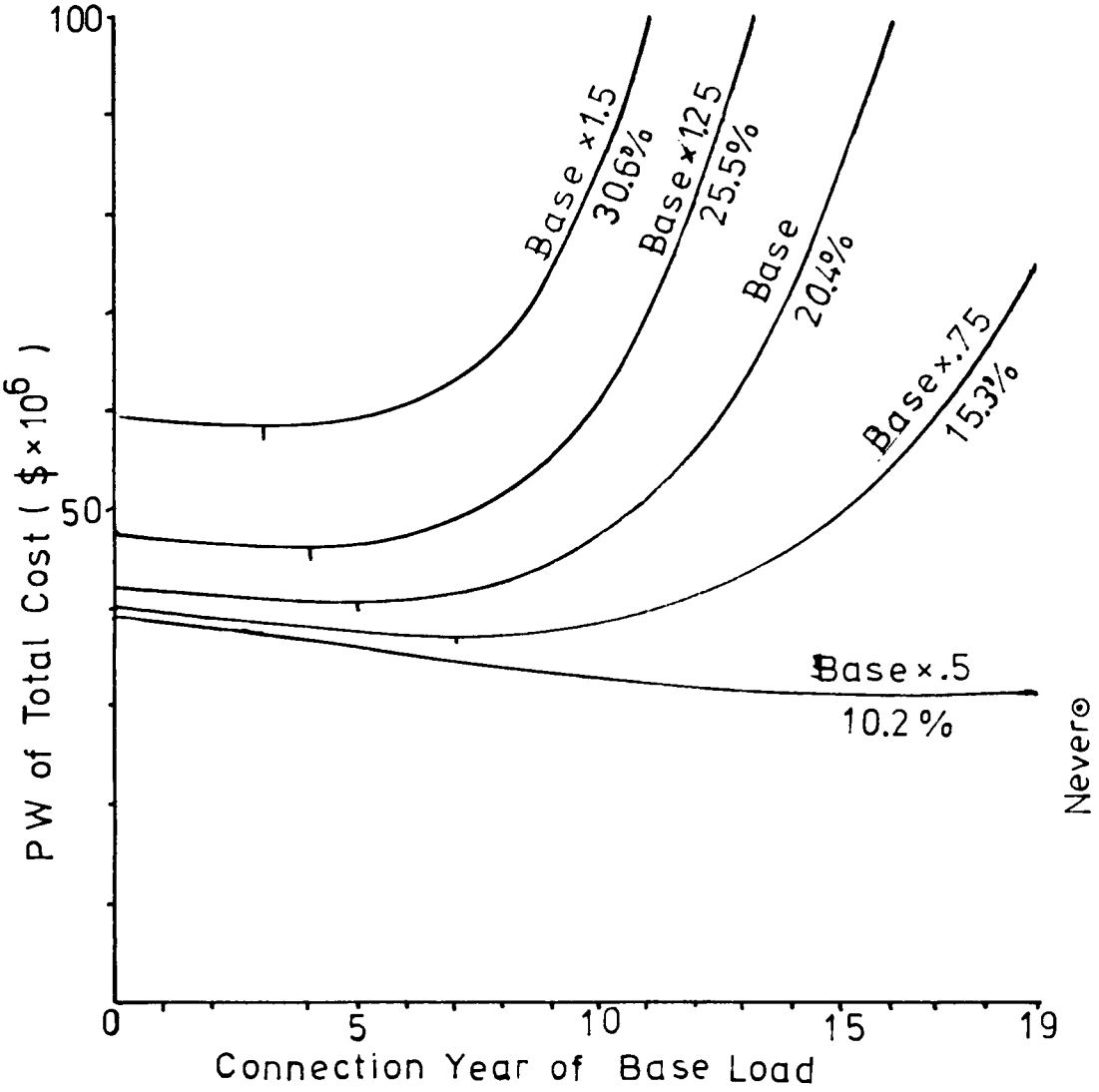


Figure 49. Total Cost Vs. Connection Year at Various Annual Rates of Natural Gas Price Increases--Apartment Model With Fuel Cells.

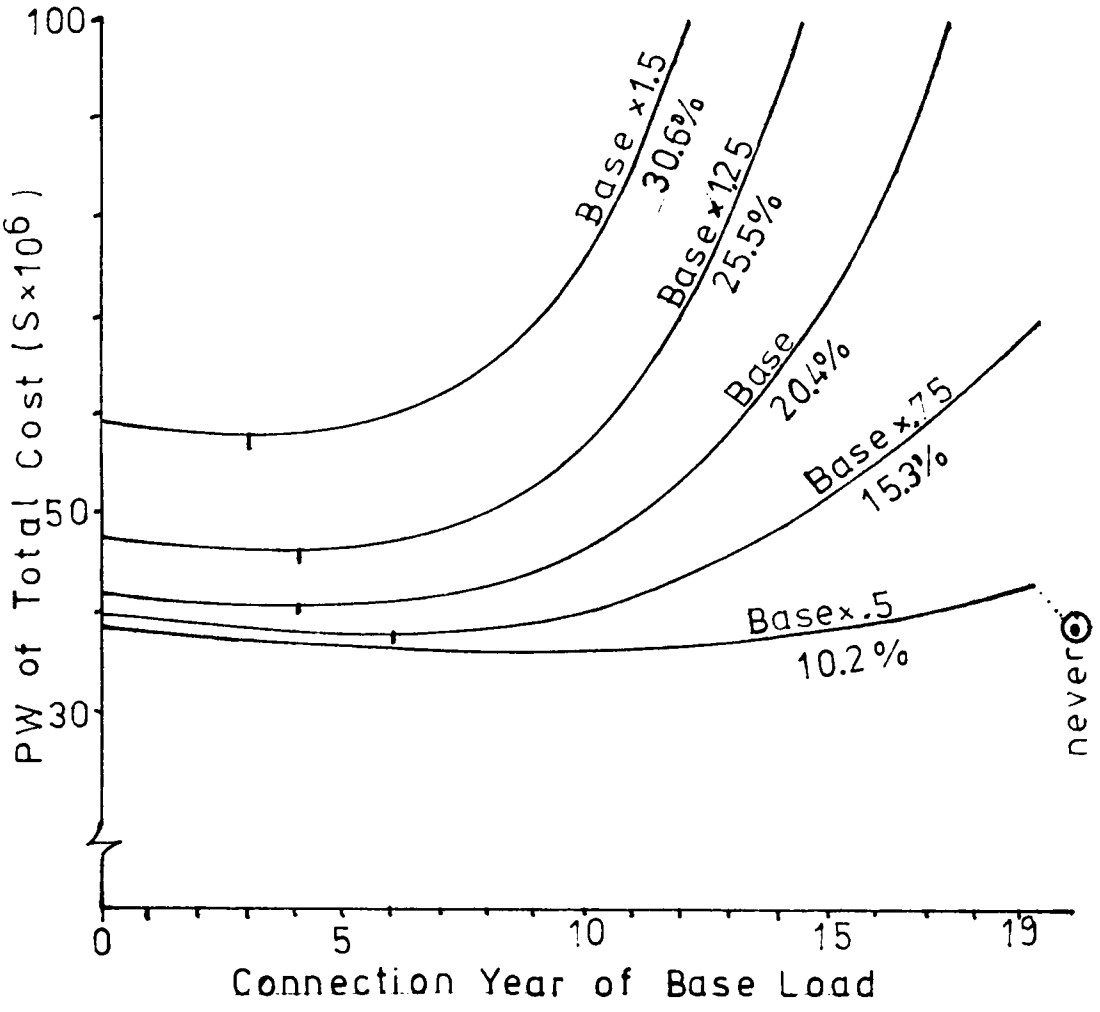


Figure 50. Total Cost Vs. Connection Year at Various Annual Rates of Natural Gas Price Increases--Apartment Model With Boilers.

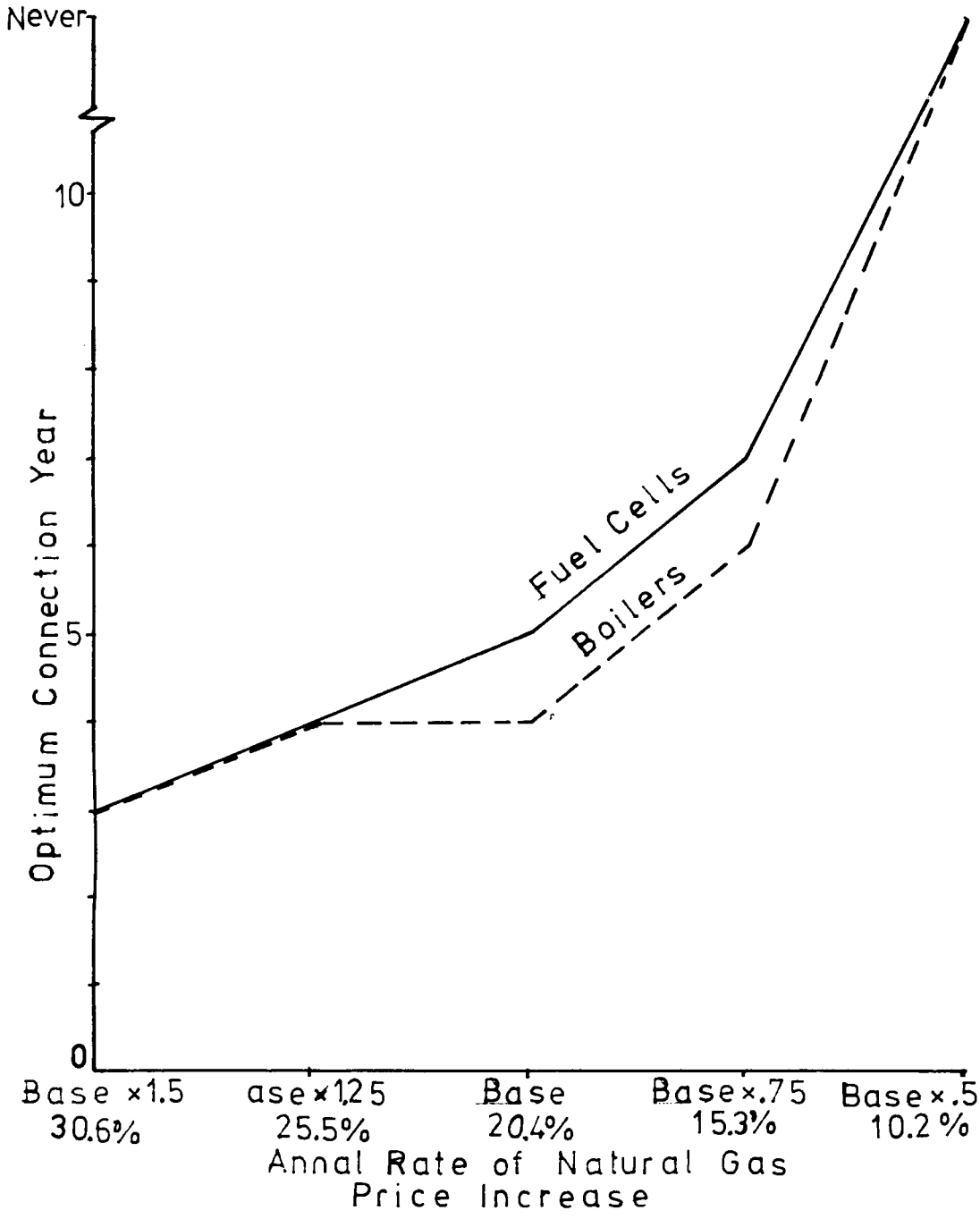


Figure 51. Optimum Connection Year Vs. Annual Rate of Natural Gas Price Increase--Apartment Model.

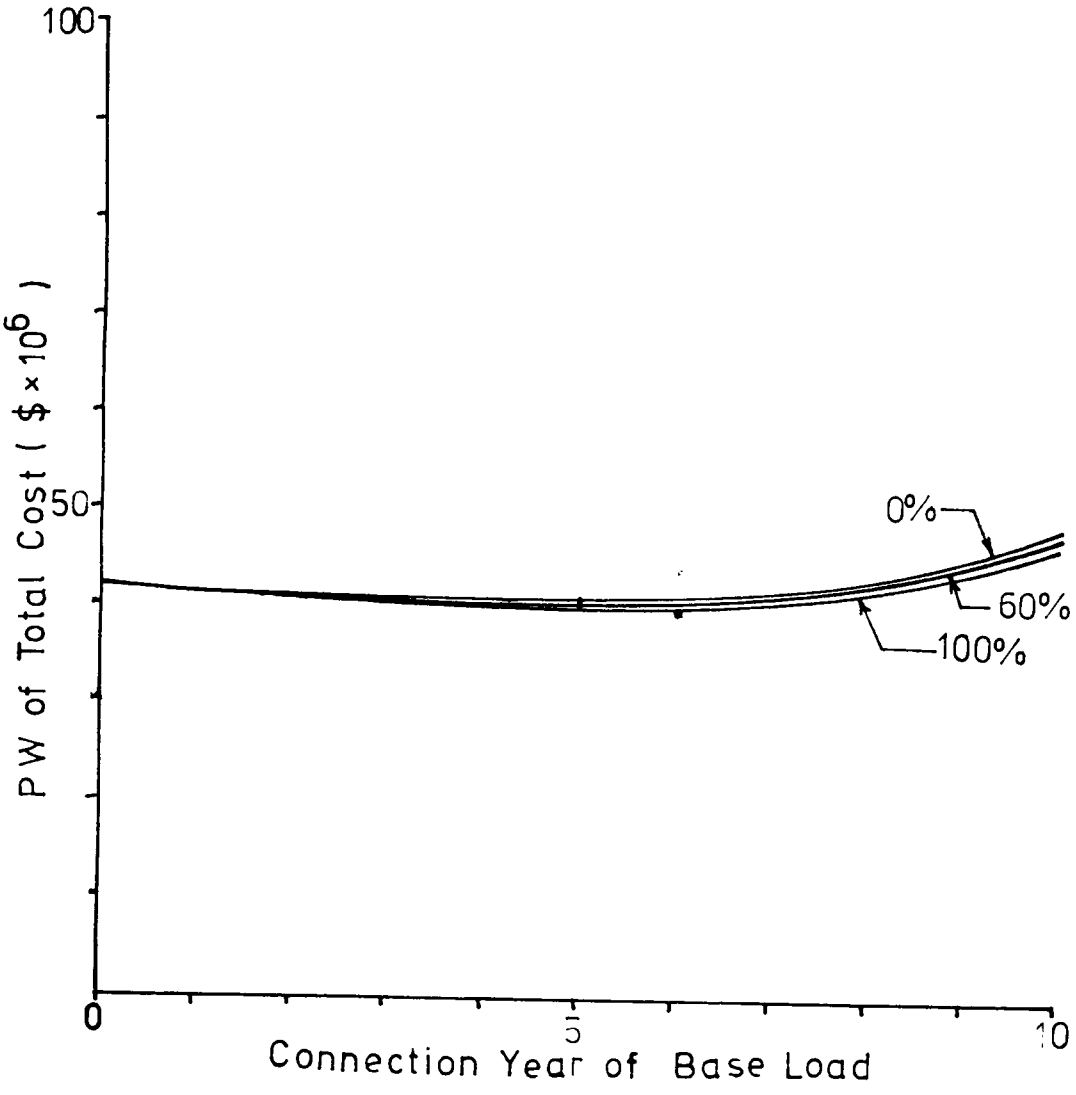


Figure 52. Total Cost Vs. Connection Year at Different Levels of Investment Credit Given to Fuel Cells for Their Electricity-Generating Capacities--Apartment Model. (Percentages given on the curves indicate the percent of a gas-fired electricity plant cost that is given as investment credit to fuel cells.)

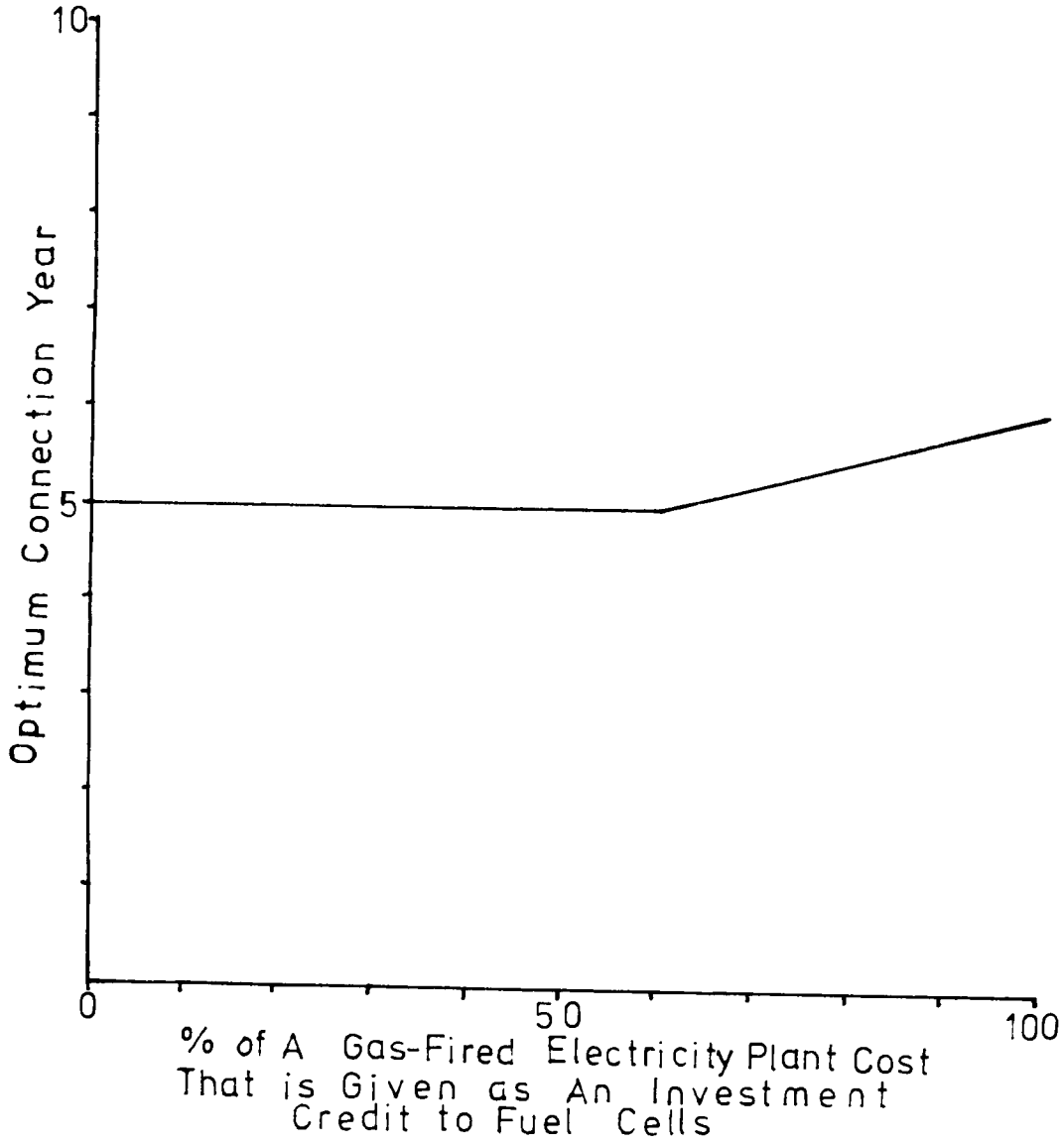


Figure 53. Optimum Connection Year Vs. Investment Credit to Fuel Cells--Apartment Model.

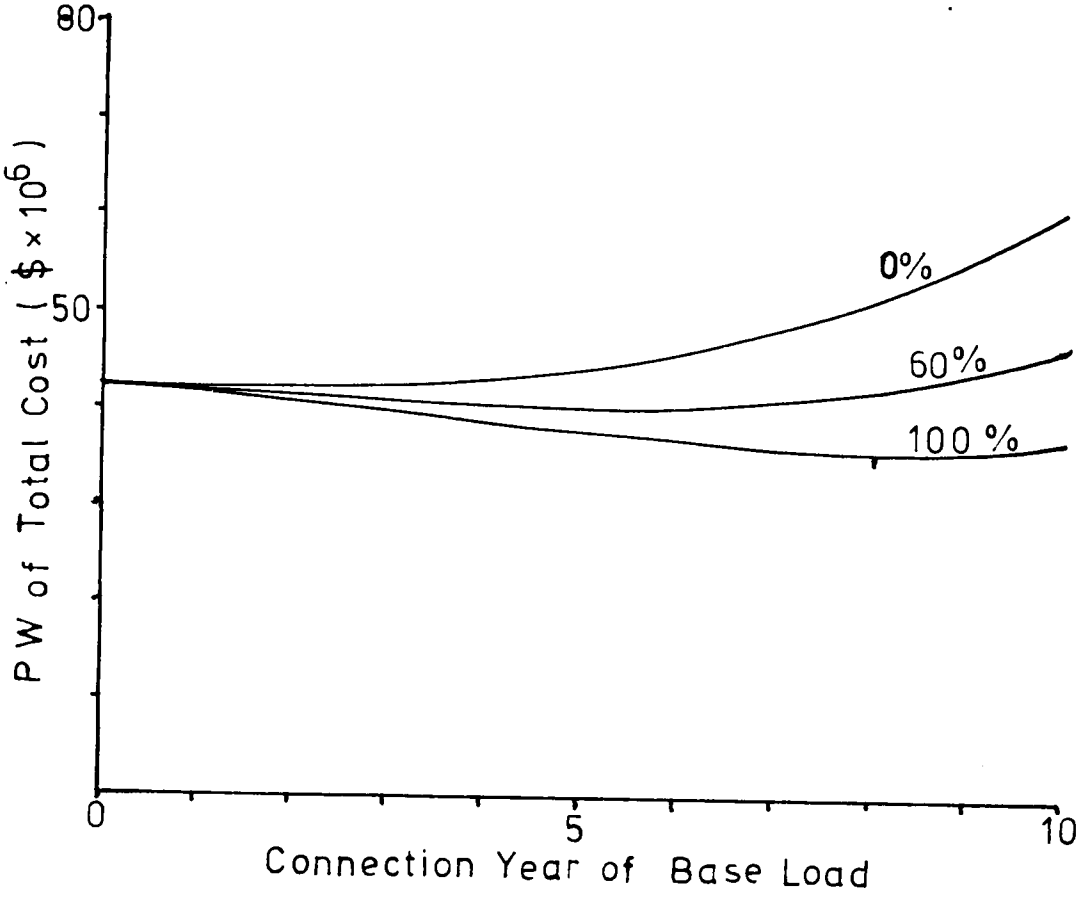


Figure 54. Total Cost Vs. Connection Year at Different Sell-Back Prices of Electricity for the Apartment Model With Fuel Cells. (Percentages given on the curve indicate the percent of the busbar cost for which the electricity is sold.)

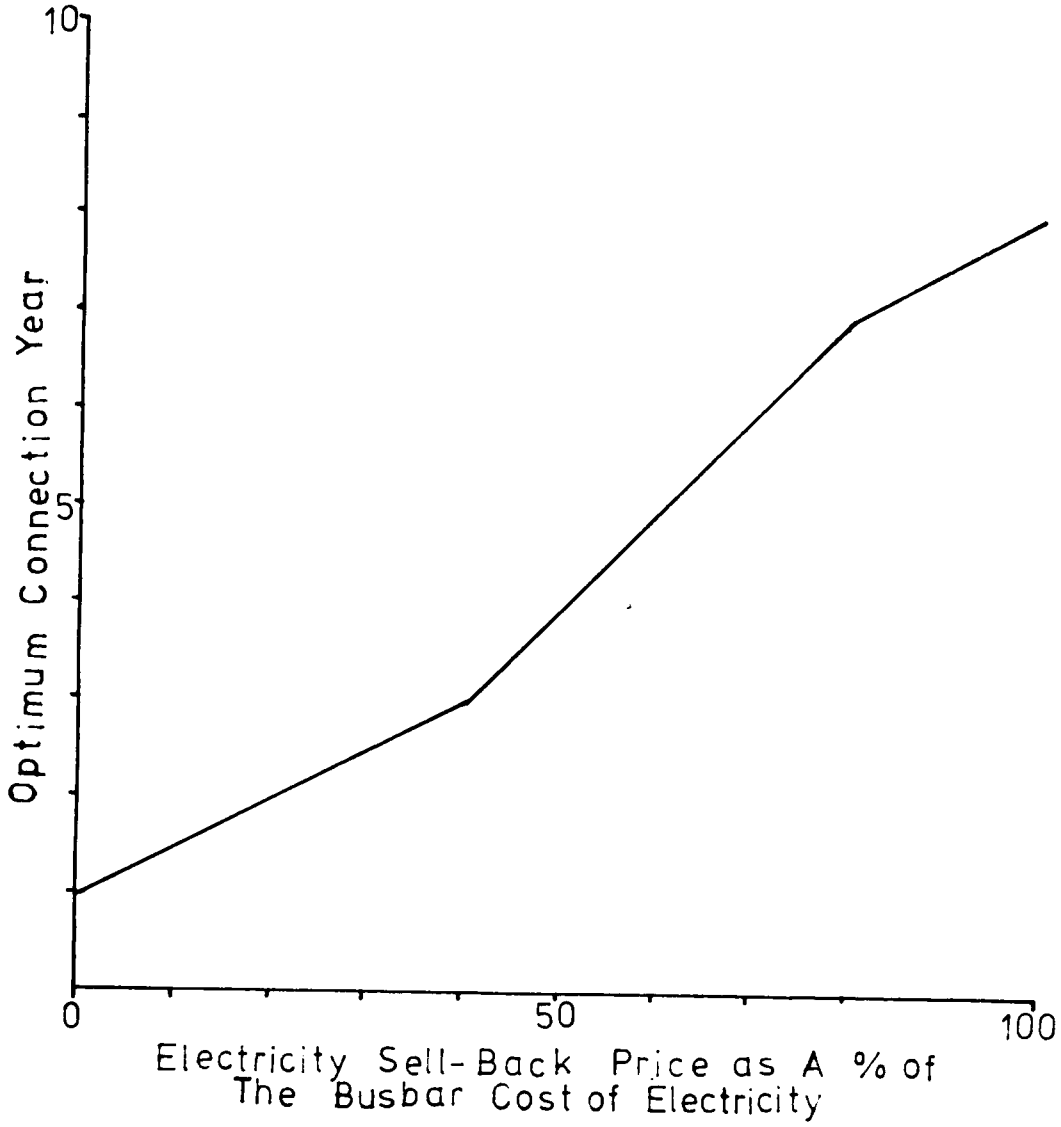


Figure 55. Optimum Connection Year Vs. Sell-Back Price of Electricity for the Apartment Model With Fuel Cells.

VITA

Mehmet Eksel was born in Usak, Turkey on June 1, 1956. He attended elementary school in Ankara and completed his high school education at Ankara Ataturk Lisesi in June 1973. That summer, being successful in a nationwide examination, he was granted a full scholarship from the Turkish government to study in the United States of America. In January 1975, he entered The University of Tennessee, and in March 1979 he received a Bachelor of Science degree with High Honors in Industrial Engineering. He was inducted in Tau Beta Pi, an engineering honor society. Immediately, he entered the Graduate School of The University of Tennessee and began study toward a Master's degree. During this interim, he worked as a graduate teaching and research assistant. He received his Master's degree in December 1981 and returned to his home country.