COGENERATION SYSTEM SIZE OPTIMIZATION

AND RETURN ON INVESTMENT STUDY

by

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ABSTRACT

A computer study was performed to determine optimum system sizes and corresponding returns on investment for gas turbine cogeneration systems located at relatively small sites. A sensitivity analysis was also performed to establish which parameters the optimum system size and the return on investment were most sensitive to. This was accomplished by varying one program input while holding all other inputs constant. The optimum system size was sensitive only to (excluding energy consumption requirements) the utility electricity prices and the utility buy-back rates. Even to these parameters, the optimum size was insensitive until large variations were introduced. The return on investment was most sensitive to the utility electricity price, the price of natural gas, the marginal tax rate, and the magnitude of financing. The return on investment was least sensitive to the standby charge, the system lifetime, and the inflation rate. In the absolute sense, all calculated returns on investment were high, showing an investment in cogeneration to be quite attractive.

Thesis Supervisor: Maher El-Masri
Title: Professor

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CHAPTER ONE

INTRODUCTION

1.1 Historical perspective

Cogeneration, as a concept and a practice, is not new. During the late 1800's and early 1900's various types of cogeneration technologies were developed in Europe and the United States. Cogeneration was particularly attractive in that period because utility produced electricity was unreliable and expensive. As the twentieth century progressed, and utilities became extremely reliable and less costly under heavy regulation, the interest in on-site electricity production declined. Concomitantly, the number of sites in the United States which had electrical and thermal loads suitable for cogenerated energy increased. Due to this, and the increased awareness of energy costs, there is now a renewed interest in cogeneration as a viable energy alternative.

1.2 Benefits of cogeneration

Cogeneration is the simultaneous on-site production of both electrical or mechanical energy and thermal energy using one prime mover. Thus the exhaust heat which is generated as a by-product of the production of electrical power is recaptured and used for thermal energy requirements. This simultaneous production costs less than the combined costs of utility purchased electricity and on-site steam production. The nature of this dual production process is to increase the overall fuel efficiency of the energy production process. This results in aggregate national fuel savings and in a more global sense a decreased reliance on foreign energy sources.

1.3 Goals and structure of this study

This report examines the effects of various economic and technological parameters on the optimal cogeneration system size and on the internal rate of return for the cogeneration system investment for a given site. A potential site is characterized by both the site's energy requirements and the economic environment in which it is situated. One goal of this study is to predict an optimum cogeneration plant size for different potential cogeneration sites which differ in energy consumption profiles and in their economic situations. Another goal is to calculate the return on investment for the cogeneration systems corresponding to optimum system sizes, as well as to determine the sensitivity of the system size and the rate of return to the pertinent paramaters. Thus the effect of uncertainties in these parameters on investment decisions can be determined.

Chapter 2 begins with a discussion of cogeneration technologies and goes on to address Federal cogeneration incentive policies. Chapter 3 introduces the methods of analysis used for the optimization and internal rate of return algorithms. Chapter 4 presents the results of the study and briefly discusses and analyzes these results. Chapter 5 concludes the report and suggests future important areas of investigation.

CHAPTER TWO

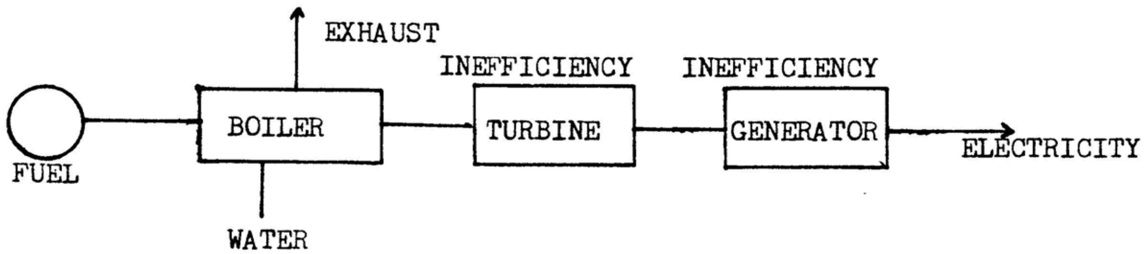
OVERVIEW

2.1 Cogeneration technologies

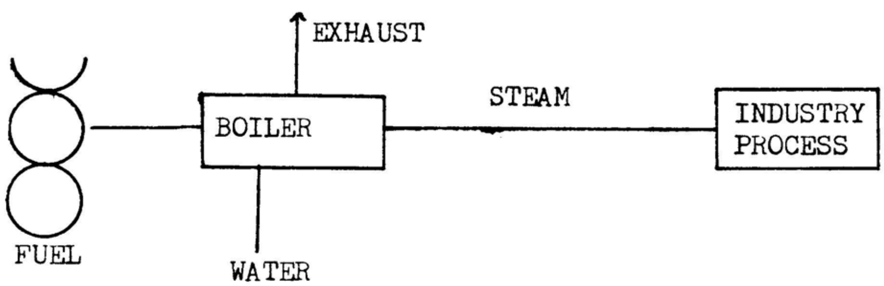
Cogeneration technologies can be broken down into two major sub-catagories, topping cycles and bottoming cycles. Topping cycles are those systems which produce electrical power first and then produce thermal power; these are the most common types of cogeneration systems. Conversely, bottoming cycle systems produce thermal power first and then produce electricity, and are much less common than topping cycle systems. As previously pointed out, cogeneration systems are more efficient at producing both thermal and electrical power than are systems which produce only steam or only electricity, as Figure 2-1 illustrates.

The following are some of the more common types of cogeneration technologies along with their most practical applications. The steam turbine topping cycle can vary in size from about 500 kW to 100 MW and can run on natural gas, distillate, residual fuels, coal, wood and a variety of other fuels. This system can be expected to have a lifetime of about 25 to 35 years and is the most commonly used technology, generally used in industry and by

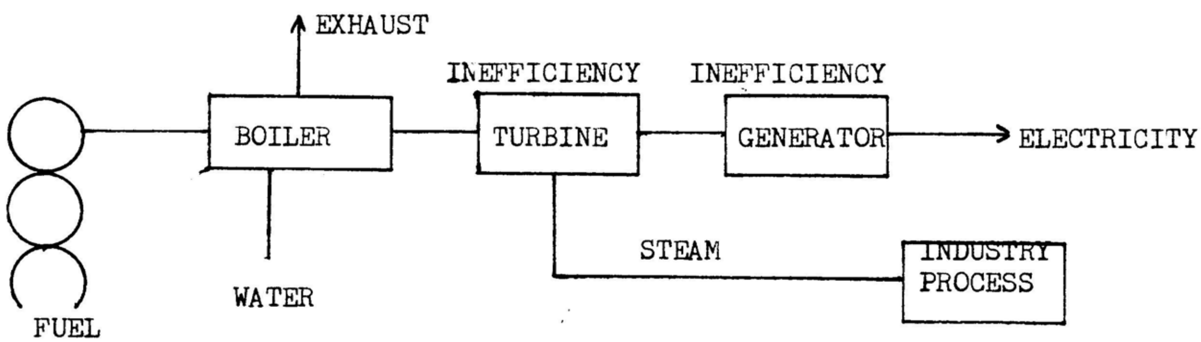
Figure 2-1 : Conventional Systems Compared With Cogeneration



A) Conventional electrical requires 1 barrel of oil to produce 600 kWh



B) Conventional process-steam requires 2.25 barrels of oil to produce 8500 lbs. of process steam



C) Cogeneration system requires the equivalent of 2.75 barrels of oil to generate the same amount of energy as systems A and B combined

SOURCE: Office of Technology Assessment, <u>Industrial and Commercial Cogeneration</u>, 1983.

utilities, or in any application where the electric to thermal enrgy requirement ratio is low. The open cycle gas turbine is available in sizes ranging from 100 kW to 100 MW and is commercially available in large quantities, being a mature technology. This system can run on a variety of fuels including natural gas, distillate, treated residual/coal, or biomass-derived gases and liquids, although it is best suited to natural gas and low-sulphur oil. The open cycle gas turbine cogeneration system is well suited for use in residential , commercial, and industrial sectors given the proper economic conditions. This system was chosen for this study, and is sketched schematically in Figure 2-2. A summary of the gas turbine characteristics can be found in Table 2-1.

The diesel topping cycle is another mature technology which is available commercially in large quantities. It has a size range from 75 kW to 30 MW. Because of its reliability and availibility, the diesel topping cycle can be used in hospitals, apartment complexes, shopping centers, hotels, and a host of other applications. Other technologies currently being developed and deserving mention are the closed-cycle gas turbine cycle, the combined gas turbine/steam turbine topping cycle, the fuel cell topping cycle, and the Stirling engine topping cycle, all of which show promise for the future (Office of Technology Assessment, 1983).

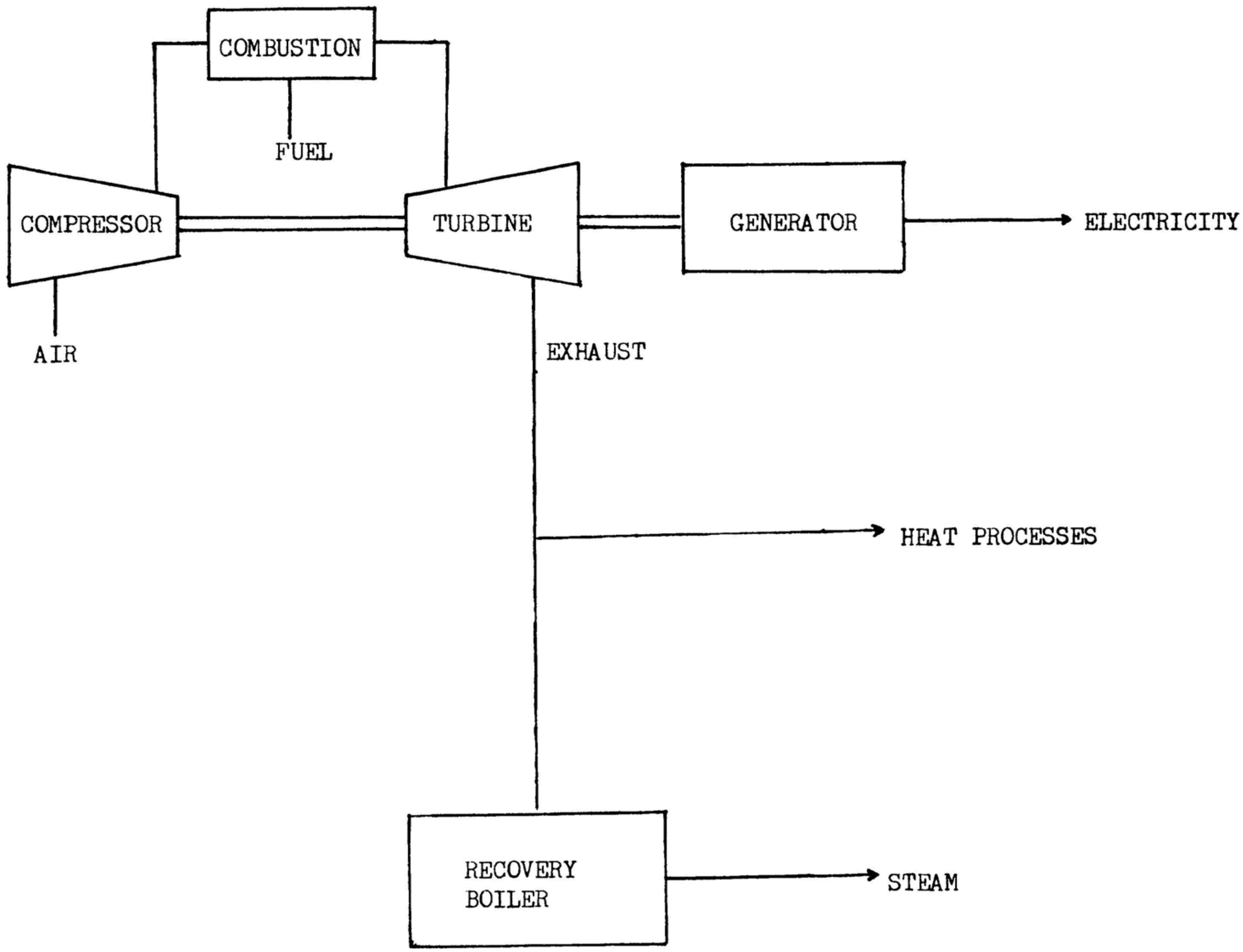


Figure 2-2 : Typical Simple Gas Turbine Cogeneration System Schematic

Table 2-1 : Summary of Gas Turbine Technology

* Unit size: 500 kW - 100 MW

* Fuels: natural gas, distillate, treated residual/coal, biomass derived gases and liquids

* Average annual availability: 90-95 %

* Full load electric efficiency: 24-35 %

* 50 % load electric efficiency: 19-29 %

* Electricity to steam ratio: 140-225 kWh/MMBTU

* Total installed cost: 320-700 $/kW

* Construction lead time: 0.75-2 years

* Expected lifetime: 20 years

* Commercial status: mature technology, available in large quantities

* Applicability: residential, commercial, industrial

SOURCE: Office of Technology Assessment, Industrial and Commercial Cogeneration, 1983.

2.2 Federal incentives

The bulk of the Federal incentives for cogeneration are promulgated in the Public Utilities Regulatory Policies Act of 1978 (PURPA). Because it has been shown that the United States wastes about the same amount of energy that it imports (Dames and Moore, 1981), the Federal government regards energy conservation as an important national priority, as PURPA clearly demonstrates. Basically, PURPA (Section 210) requires the Federal Energy Regulatory Commission (FERC) to establish policies to encourage cogeneration.

PURPA Section 210 mandates the following important Federal cogeneration policy incentives. Section 210 assures that utilities may not price cogeneration back-up electricity discriminatorily, and that qualifying cogenerators receive prices for power sales to electric utilities which are just and reasonable, and in the public interest. This "buy-back" provision has been hotly contested in the courts the past few years, but recently the U.S Supreme Court decided that the FERC was correct in ordering utilities to pay cogenerators the utilities' full avoided costs for any electrical power purchased from qualified cogenerators. The decision also upheld an FERC policy that utilities must effect an interconnection with any small power producer that warrants one, without full-scale evidentiary hearings (The Energy Daily, 1983). The advantages of this decision for qualifying cogenerators are obvious. The price utilities must pay for electrical power is completely independent of the cogenerator's power production cost. Additionally, cogenerators are assured a market for any excess electricity produced, and are also assured reasonable interconnection costs.

Other pieces of legislation provide incentives to potential cogenerators. The Industrial Fuel Use Act of 1978, which limits the use of oil and natural gas contains some special exemptions for cogenerators. The Natural Gas Policy Act of 1978 protects cogenerators from the normal incremental gas pricing policies, and thus saves money for qualifying cogenerators in several regions.The Energy Tax Act of 1978 provides tax incentives for cogenerators. Under the specially defined and alternate energy property provisions of the Act, some components of cogeneration property are entitled to additional tax credits beyond the usual 10 percent investment tax credit. Finally, the Economic Recovery Tax Act of 1981 places cogeneration equipment under accelerated cost recovery system (ACRS) five year business property which allows full depreciation of equipment in a five year period.

This enacted legislation makes obvious the Federal government's intention of promoting cogeneration use in this country. The Office of Technology Assessment makes further recommendations for additional policy concerning cogeneration. OTA feels that future policy should be directed towards reducing oil use in future systems by introducing extra incentives for non-oil fired systems. OTA further suggests that utility owned cogeneration systems be entitled to equal benefits under the law. Another suggestion is to reduce the air quality regulations for cogenerators due to their increased fuel efficiency. These policy measures would make an investment in cogeneration systems even more attractive in the future and reduce the overall oil consumption in this country.

CHAPTER THREE

METHODS OF ANALYSIS

This chapter presents the methodology used for the system size optimization and return on investment analyses. A computer program was written at the Joint Computer Facility at M.I.T. to accomplish these analyses, a copy of which can be found in Appendix A. A sample output is located in Appendix B. The determination of the input parameters used to run the program is discussed later in the chapter.

3.1 Gas turbine characteristics

As cited earlier, the gas turbine topping cycle was chosen as the prime mover for this analysis. This system was chosen because of the typical system size requirements, the thermal and elctric load profiles of the sites considered, reliability, and maintenance characteristics.

Many of the quantitative characteristics of gas turbine systems were taken from Cogeneration and Utility Planning, Pickel's 1982 doctoral thesis. Pickel estimated the capital cost for gas turbine cogeneration systems to follow a logarithmic function of the electric output capacity. This 1980 equation has been increased here by 30 percent to account for the past three years of inflation to produce the following:

$$CC_{GT} = 1660 - 120 \ln E_C \tag{3.1}$$

where CC_{GT} is the capital cost for the turbine in 1983 dollars, and E_C is the turbine's electrical output capacity in kilowatts. This relation accounts for the price of the turbine, installation, and all necessary auxilliary systems and engineering efforts.

An equation for the rated output turbine electric efficiency was also taken from Pickel, but multiplied by a factor to approximate the electric efficiencies of a modern Allison gas turbine model. Rated output gas turbine electric efficiency is given by:

$$\eta_E = \frac{1}{1 + \exp(\ 1.3964 - 0.14479 \ln E_{CM}\ )} \tag{3.2}$$

where E_{CM} is the turbine's maximum electrical output in megawatts.

To predict the attenuation of the electric efficiency when the gas turbine operates below its maximum capicity, the performance charateristics of a typical gas turbine (in this case an Allison model 501-KB) was used (see Figure 3-1). From the linear relationship between fuel input and electrical output depicted in Figure 3-1, the

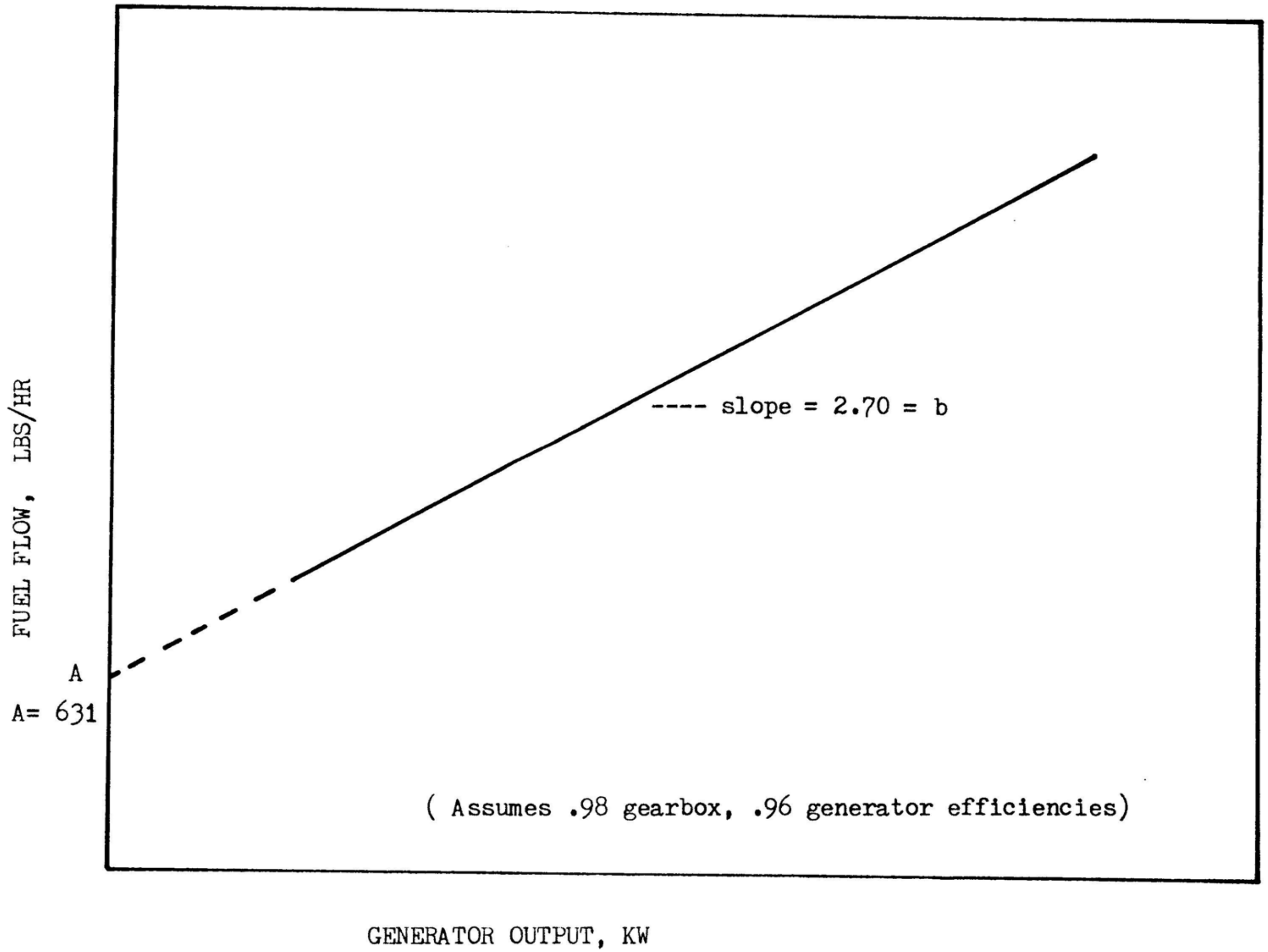


Figure 3-1 : Allison 501-KB Fuel versus Output following relationship for the electric efficiency of the gas turbine operating at less than rated output was derived:

$$\eta_{E,ACT} = \frac{1}{b} - \frac{(1 - b\cdot\eta_{E,MAX})\ (A + b\cdot CAP_{MAX})}{b\ (A + b\cdot PCAP\cdot CAP_{MAX})} \qquad (3.3)$$

where b is the slope of the fuel versus output curve, A is the intercept of the same curve in kilowatts, CAP_{MAX} is the rated operating capacity of the turbine in kilowatts, and PCAP is the decimal coefficient which represents the capacity at which the turbine is operating:

$$PCAP = \frac{\text{Actual operating capacity}}{\text{Rated operating capacity}} \qquad (3.4)$$

and:

$$\eta_E = \eta_T \cdot \eta_{GB} \cdot \eta_{GEN} \qquad (3.5)$$

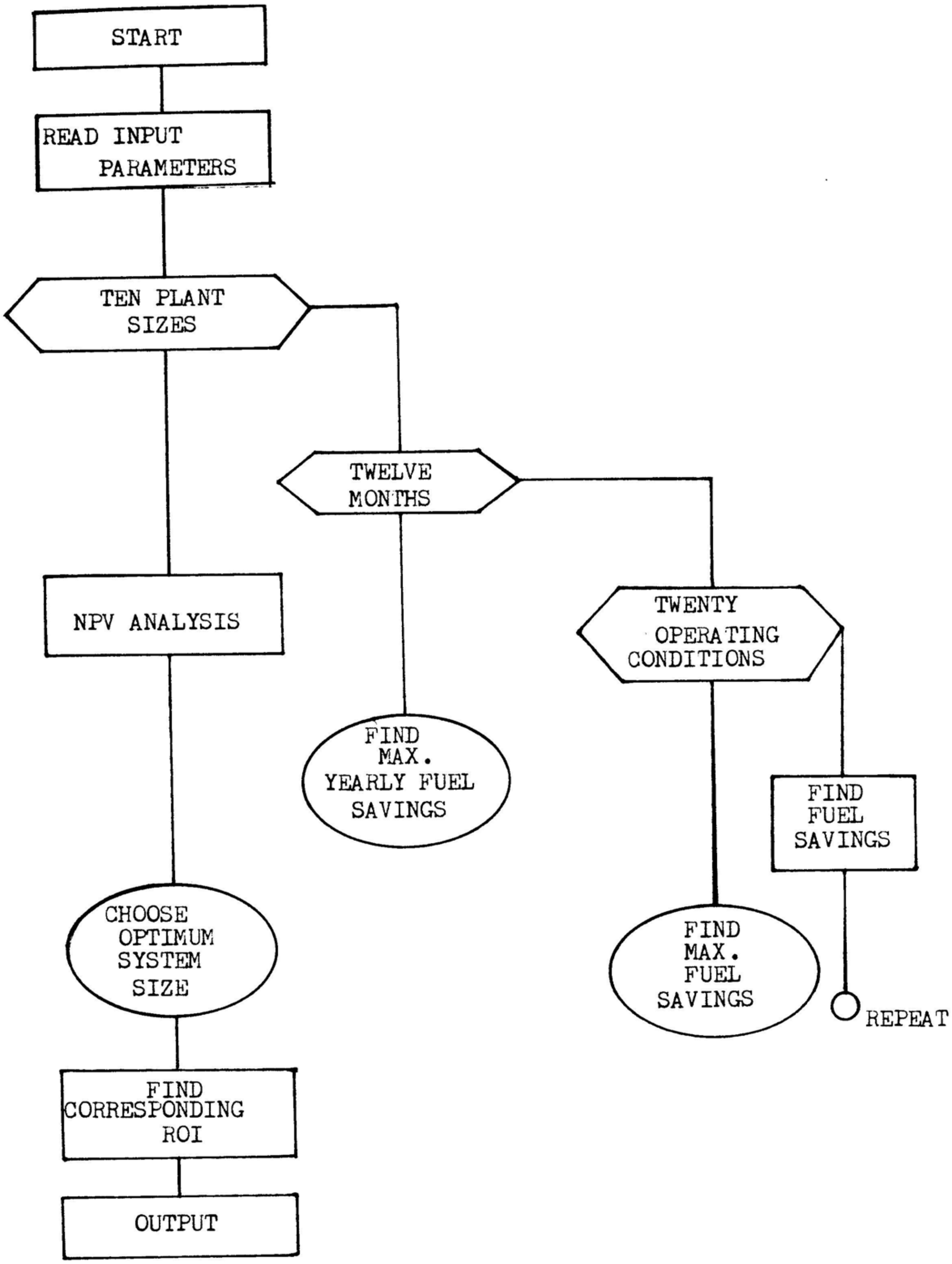
where η_{GB} is the gearbox efficiency, η_{GEN} is the generator efficiency of the gas turbine system, and η_T is the gas turbine thermal efficiency.

3.2 Optimization and return on investment

3.2.1 Optimization methodology

The algorithm used for the optimization portion of the analysis is shown in flowchart form in Figure 3-2. Ten potential gas turbine sizes were considered, the size being described by the turbine's rated electrical output capacity. The smallest size considered was that size just

Figure 3-2 : Optimization Analysis Algorithm



able to meet one half of the lowest average site monthly electrical power requirement; the largest size considered was just able to meet twice the lowest average electrical power requirement:

$$CAP_{MIN} = 0.5\ ELREQ_{MIN} \quad ; \quad CAP_{MAX} = 2\ ELREQ_{MIN} \tag{3.6}$$

where CAP is the size of the turbine, and $ELREQ_{MIN}$ is the lowest average electrical power requirement.

For each turbine size, the turbine was then taken to operate at twenty different capacities for each month, so that PCAP as defined in equation (3.4) ranged from:

$$PCAP_{MIN} = 0.2 \quad ; \quad PCAP_{MAX} = 1.0 \tag{3.7}$$

Thus the turbine was run from 20 percent of its rated capacity to 100 percent of its rated capacity for each month and for each of the ten turbine sizes. The electrical efficiency was then determined using equation(3.3). For each operating condition, the electrical power output was calculated by:

$$ELOUT = PCAP \cdot CAP \tag{3.8}$$

where ELOUT is in kilowatts. The fuel needed to operate the cogenerator at this point is given by:

$$FUEL = (ELOUT/\eta_{E,ACT}) \cdot 24 \cdot 30 \tag{3.9}$$

where FUEL is expressed in kilowatt-hours per month. The corresponding thermal output was calculated using:

$$THOUT = FUEL\ (1 - \eta_T)\ BOIEFF \cdot 0.97 \qquad (3.10)$$

where THOUT is in kilowatt-hours per month which is easily converted to BTU per month, BOIEFF is the boiler efficiency, and 0.97 accounts for turbine losses.

Once ELOUT and THOUT were determined for a particular PCAP and month, the monthly fuel savings were found by comparing the cogeneration outputs to site energy demands, noting that any excess electricity produced was bought back by the utility at the legally established buy-back rate. The fuel savings were then calculated as the fuel cost without the cogeneration system in place less the total fuel cost with the cogeneration system. For each month, the turbine operating condition which yielded the greatest fuel savings was chosen as the optimum operating condition. In this manner, a maximum yearly fuel savings and a corresponding optimum operating profile (by month) was established for each of the ten considered turbine sizes. Each turbine size, with its corresponding capital cost (equation (3.1)) and its corresponding maximum yearly fuel savings were then inputs to a net present value (NPV) analysis to choose the optimum turbine size.

3.2.2 Net present value analysis

The net present value,NPV, for an investment in a cogeneration system can be expressed:

$$NPV = \sum_{y=1}^{Y}\left(\frac{NETSAV_y}{(1 + DR)^y}\right) - CAPCOS \qquad (3.11)$$

where Y is the lifetime of the equipment in years, $NETSAV_y$ is the net savings in year y, $CAPCOS$ is the initial capital outlay at the time of the purchase (year zero), and DR is the discount rate of money. A look at the components of equation (3.11) is now in order.

Capital cost. $CAPCOS$ represents the total initial capital cost of the system less any tax credits and less any borrowed capital, thus:

$$CAPCOS = CC_{GT}\ (1 - ITC - EITC - FIN) + ICN \cdot CAP \qquad (3.12)$$

where ITC represents the investment tax credit (i.e., for a ten percent investment tax credit, ITC equals 0.10), $EITC$ represents the energy investment tax credit, and FIN represents the percentage of capital cost borrowed, as a decimal quantity.

Net savings. The net savings in year y can be expressed:

$$\begin{aligned} NETSAV_y = {} & (1 - TR)\ (1 + GR)^y\ (FUESAV_1 - OM_1) + \\ & TR \cdot DEPy\ (CC_{GT}\ (1 - 0.5\ ITC - 0.5\ EITC) + ICN \cdot CAP) \end{aligned} \qquad (3.13)$$

where TR is the decimal equivalent of the marginal tax rate, GR is the decimal annual growth rate of fuel and maintenance costs, $FUESAV_1$ is the fuel savings in year one, OM_1 is the operation and maintenance cost in year one, ICN is the cost of utility interconnection in dollars per kilowatt of installed capacity, and DEPy is the depreciation coefficient in year y . If financing is considered, equation (3.13) is ammended to:

$$
\begin{aligned}
NETSAV_y = {} & (1 - TR)\ (1 + GR)^y\ (FUESAV_1 - OM_1)\ - ALP_y \ + \\
& TR\ (DEPy\ (\ CC_{GT}\ (1 - 0.5\ ITC - 0.5\ EITC) + \\
& ICN \cdot CAP) + LIP_y)
\end{aligned}
\tag{3.14}
$$

where LIP_y is the loan interest payment in year y , and ALP_y is the total annual loan payment in year y .

Depreciation. Under the new accelerated cost recovery system, ACRS, the cogeneration equipment is eligible for complete depreciation under the following yearly coefficients:

$$
\begin{aligned}
& DEP1 = 0.15 \quad ; \quad DEP2 = 0.22 \quad ; \quad DEP3 = 0.21 \ ; \quad DEP4 = 0.21 \quad ; \\
& DEP5 = 0.21 \quad ; \quad DEP6 \rightarrow = 0.0
\end{aligned}
\tag{3.15}
$$

Note that DEP1 + DEP2 + DEP3 + DEP4 + DEP5 = 1.0.

Financing. For financing the capital cost, a repayment schedule in which an equal portion of the principal is paid back in each year in addition to interest on the unpaid balance of the principal was considered. Under this repayment plan, the annual loan payment is:

$$
ALP_y = P\ (\ 1/N + (1 - (y - 1)/N)\ IR) \qquad ; \quad y < N \tag{3.16}
$$

where P is the total principal borrowed, N is the loan repayment period, and IR is the loan interest rate. The corresponding loan interest payment is simply the annual loan payment less the amount of principal repaid:

$$LIP_y = P\ (1 - (y - 1)/N)\ IR \qquad ; \quad y < N \qquad (3.17)$$

From the above equations, a net present value for each of the ten different possible turbine sizes was calculated. However, since capital for these investments would probably be scarce, the optimum plant was chosen by the highest return on investment, not by highest net present value. After the net present value was calculated, the ratio between the net present value and the corresponding initial capital outlay was found. Because the internal rate of return is an increasing monotonic function of this ratio, the plant with the highest ratio was chosen as the input to the return on investment analysis, and was considered optimum.

3.2.3 Return on investment analysis

This part of the analysis used as its inputs the size, capital cost, and net savings of the plant size which was found to have the highest NPV to capital outlay ratio. The return on investment is simply that discount rate in equation (3.11) which drives the net present value to zero. Thus the same equations govern this analysis as governed the net present value analysis, and will not be discussed further. This analysis resulted in the determination of the return on investment for the optimal system size operating at its optimal capacity each month. A sensitivity analysis was also performed by varying one parameter while holding all others constant to determine which parameters the rate of return and the optimum system size were most sensitive to.

3.3 Potential cogeneration sites

Five sites were chosen as potential cogeneration facilities for this study. Four of these sites are hospitals spread throughout the country in different economic and environmental conditions. These sites were chosen because of the availability of their energy consumption data, their geographical spread, and their differing economic parameters. The Veteran's Administration operates three of the hospitals: those located in Buffalo, New York; Lake City, Florida; and San Diego, California. The fourth hospital is located on a military post in Battle Creek, Michigan. The heat and electric requirements for these sites were obtained from Flint's 1983 thesis, and are depicted graphically in Figures 3-3 through 3-6. The fifth potential site chosen was the Massachusetts Institute of Technology because it is not a hospital like the other sites and therefore has different energy requirements, its heat and electrical loads (Figure 3-7) were readily available from the

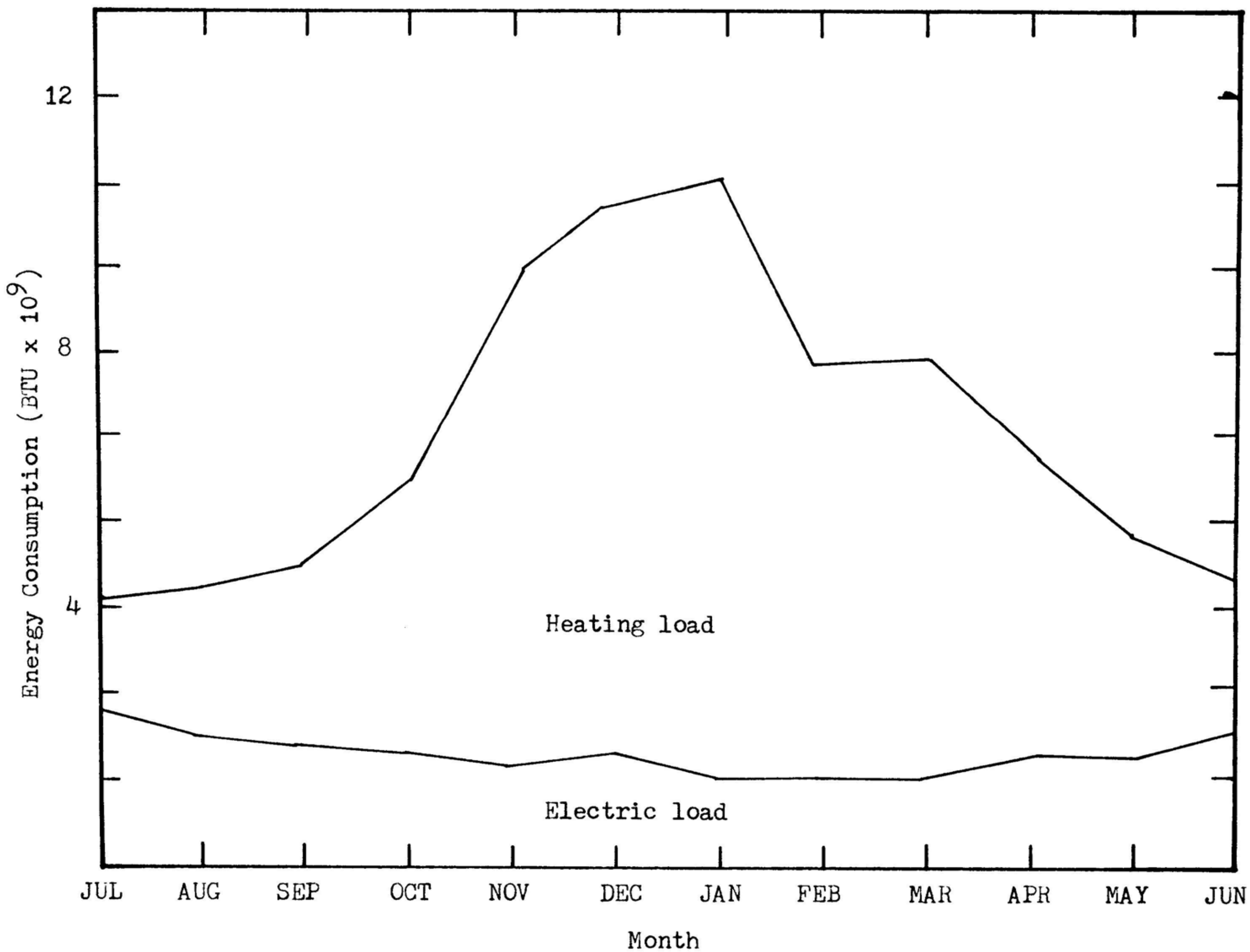


Figure 3-3 : Energy Requirements for Battle Creek Hospital

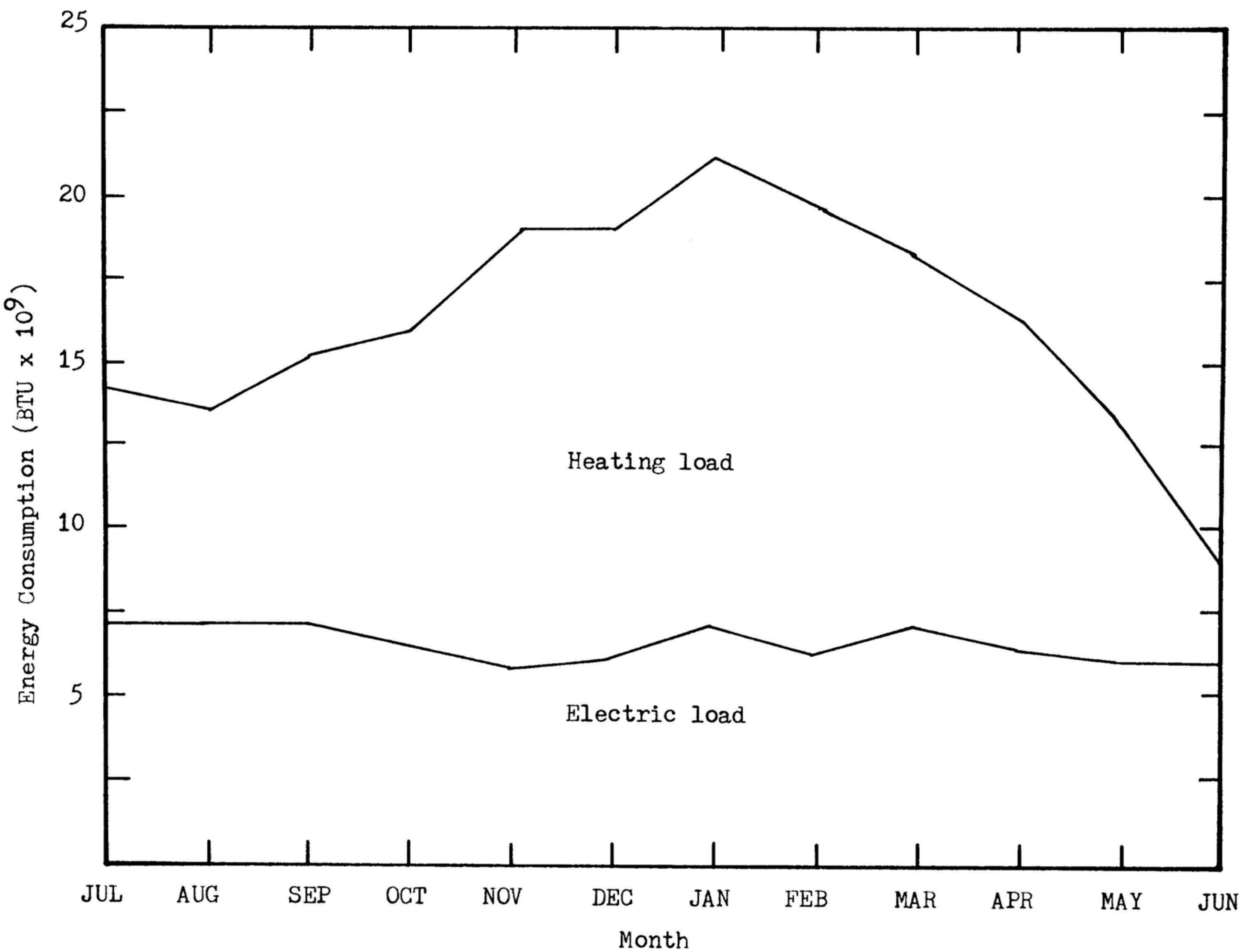


Figure 3-4 : Energy Requirements for San Diego Hospital

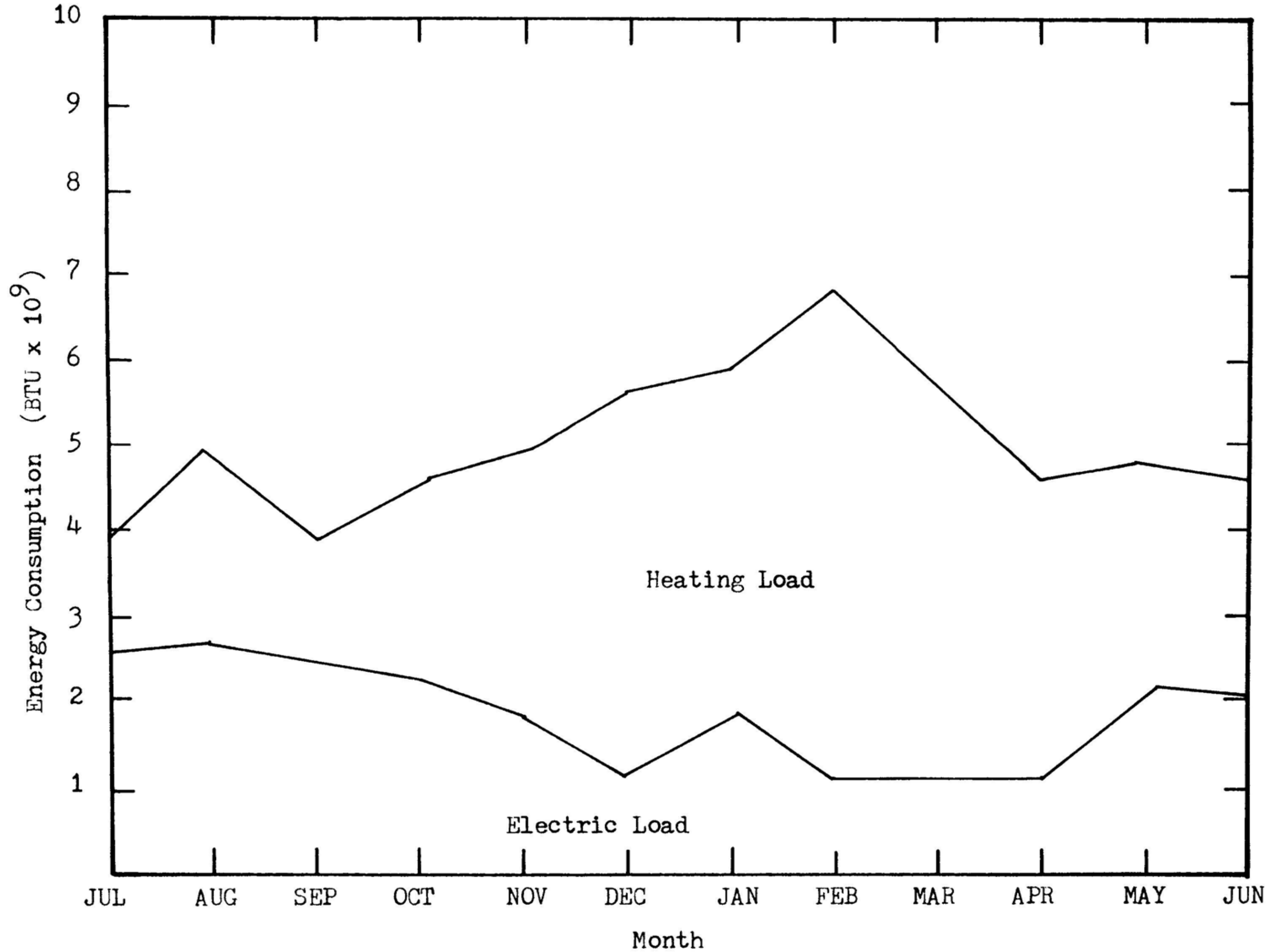


Figure 3-5 : Energy Requirements for Lake City Hospital

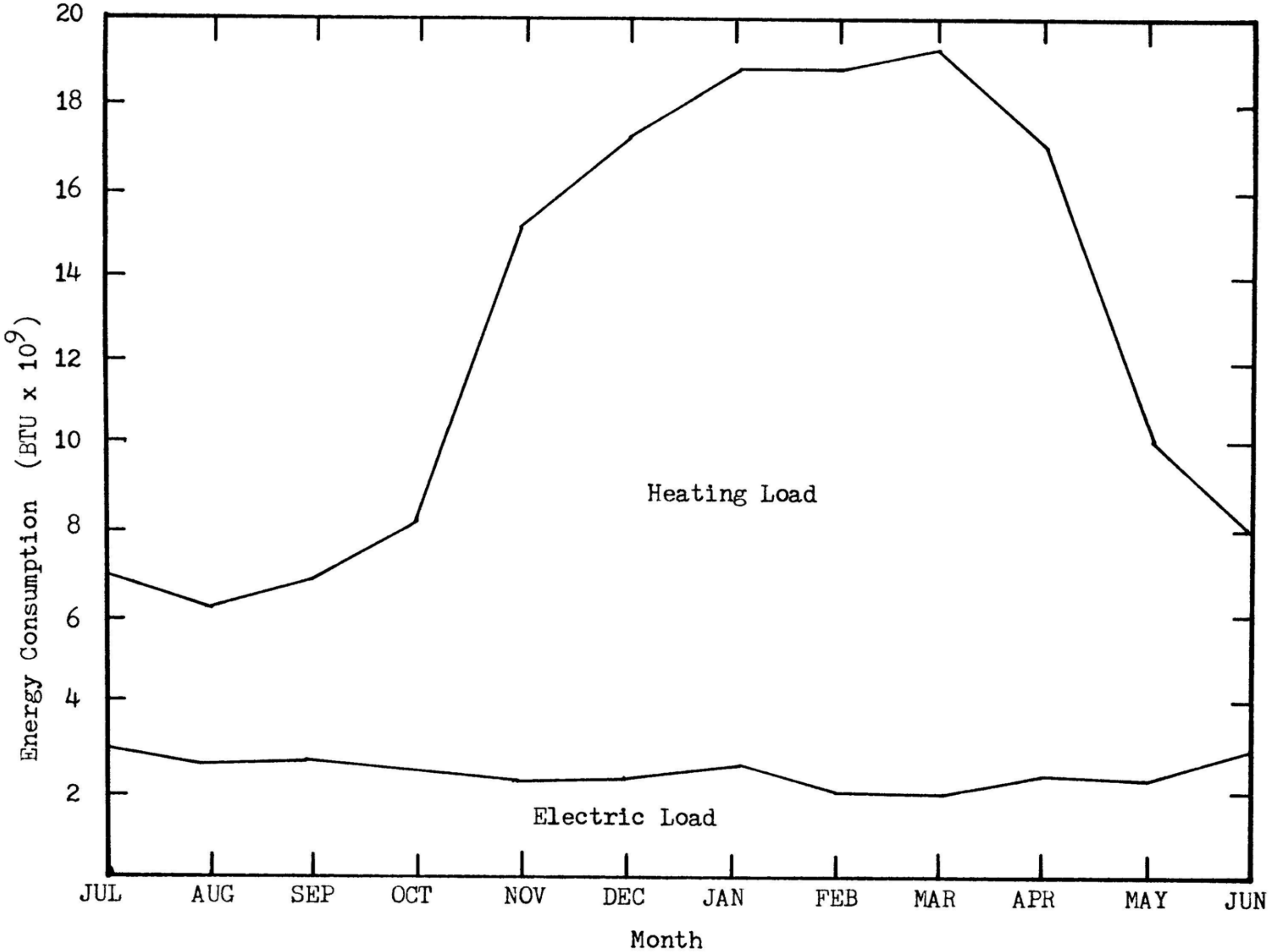


Figure 3-6 : Energy Requirements for Buffalo Hospital

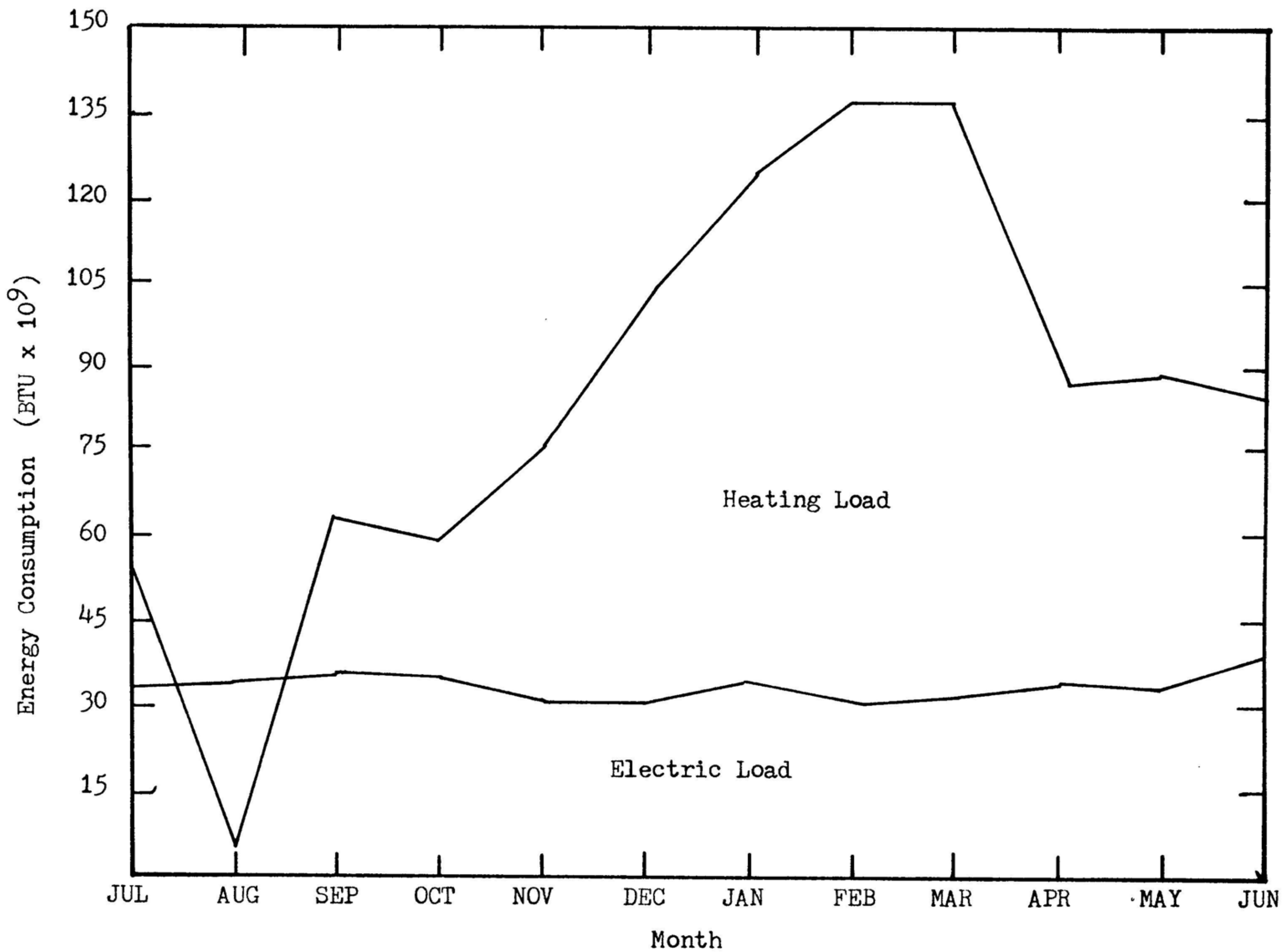


Figure 3-7 : Energy Requirements for M.I.T.

physical plant office, and it was of personal interest to the author.

3.4 Input parameters

This section presents a brief discussion concerning the values of the important input parameters of the analysis program.

3.4.1 Hardware assumptions

All boilers were reasonably assumed to be 80 percent efficient. The slope and intercept of the gas turbine fuel versus output curve (Figure 3-1) were obtained from Allison model 501-KB literature, and are probably representative of most gas turbines. The lifetime of the cogeneration system was conservatively assumed to be 15 years. The operation and maintenance costs were assumed to be 10 percent of the turbine capital cost yearly (Flint, 1983).

3.4.2 Economic Parameters

The applicable utility electricity prices and gas prices were obtained both from Flint (1983), and from The Energy User News. The utility buy-back rates were obtained from the U.S. Office of Technology Assessment,OTA, report on cogeneration (1983), except for the Lake City, Florida rate which was unavailable and accordingly estimated. The interconnection costs were also taken from OTA's study. It was further assumed that cogeneration facilities would be required to pay a standby charge to the local utility in case of an emergency. The values for this charge were taken from the OTA report where available, or alternatively, from Flint (1983).

3.4.3 Financial parameters

The marginal tax rate for the hospitals was assumed to be zero in one case, because government hospitals are tax exempt, and assumed to be 46 percent in the other case which is applicable to many instutions. The marginal tax rate for M.I.T. was also assumed to be zero because it is a non-profit instition, but the 46 percent case was also examined. The percent of capital borrowed, the loan interest rate, and the loan repayment period were all taken to be zero, except for the sensivity analysis. Table 3-1 lists all the appropriate input parameter values.

PARAMETER	Battle Creek	Buffalo	Lake City	M.I.T.	San Diego
Elect. Cost (¢/kWh)	5.79	6.41	5.04	7.00	10.85
Buyback Rate (¢/kWh)	2.50	6.00	3.78	5.54	7.07
Gas Cost ($/MMBTU)	4.53	4.34	3.28	5.30	5.25
Intcn. Cost ($/kW)	12	12	12	12	12
Standby ($/kW-month)	2.42	2.55	2.25	3.13	2.00
Boiler Eff. (%)	80	80	80	80	80
Turb. Eff. Slope	2.70	2.70	2.70	2.70	2.70
Turb. Eff. Intcpt. (kW)	3398	3398	3398	3398	3398
Expected Life (years)	15	15	15	15	15
ITC (%)	10	10	10	10	10
EITC (%)	0.0	0.0	0.0	0.0	0.0
Percent Financed	0.0	0.0	0.0	0.0	0.0
Interest Rate	0.0	0.0	0.0	0.0	0.0
Tax Rate (%)	0,46	0,46	0,46	0,46	0,46

Table 3-1 : Summary of Input Parameter Values

CHAPTER FOUR

ANALYTICAL RESULTS

4.1 Size optimization and return on investment

Table 4-1 shows the optimum system size, the tax-exempt return on investment (ROI), and the taxable ROI for each of the sites. Note that the optimum system size was just above the lowest average monthly electric power requirement for the M.I.T. site and the Buffalo site, while the optimum system sizes for the San Diego, the Battle Creek, and the Lake City sites were just at the lowest average electric power requirement. This can be seen in Figures 4-1 through 4-5. This is an important result because the optimum system size predicted without any buy-back rate was that size just able to meet the lowest average monthly electrical requirement (Flint, 1983). Therefore, the addition of utility buy-back rates had either a small or a negligible effect on the optimum system size, depending on the site. It was further determined that for those sites which did exhibit a larger optimum system size with the addition of utility buy-back, complete elimination of the buy-back rate only reduced the ROI by at most 7.5 percent of its original value. The

	Battle Creek	Buffalo	Lake City	M.I.T.	San Diego
OPTIMUM SYSTEM SIZE (MW)	0.70	1.17	0.50	14.37	2.32
TAX-EXEMPT ROI (%)	32.30	44.00	28.40	72.50	99.90
TAXABLE ROI (%)	23.60	31.10	21.00	47.90	66.20

Table 4-1 : Optimum Plant Size and Return on Investment Results

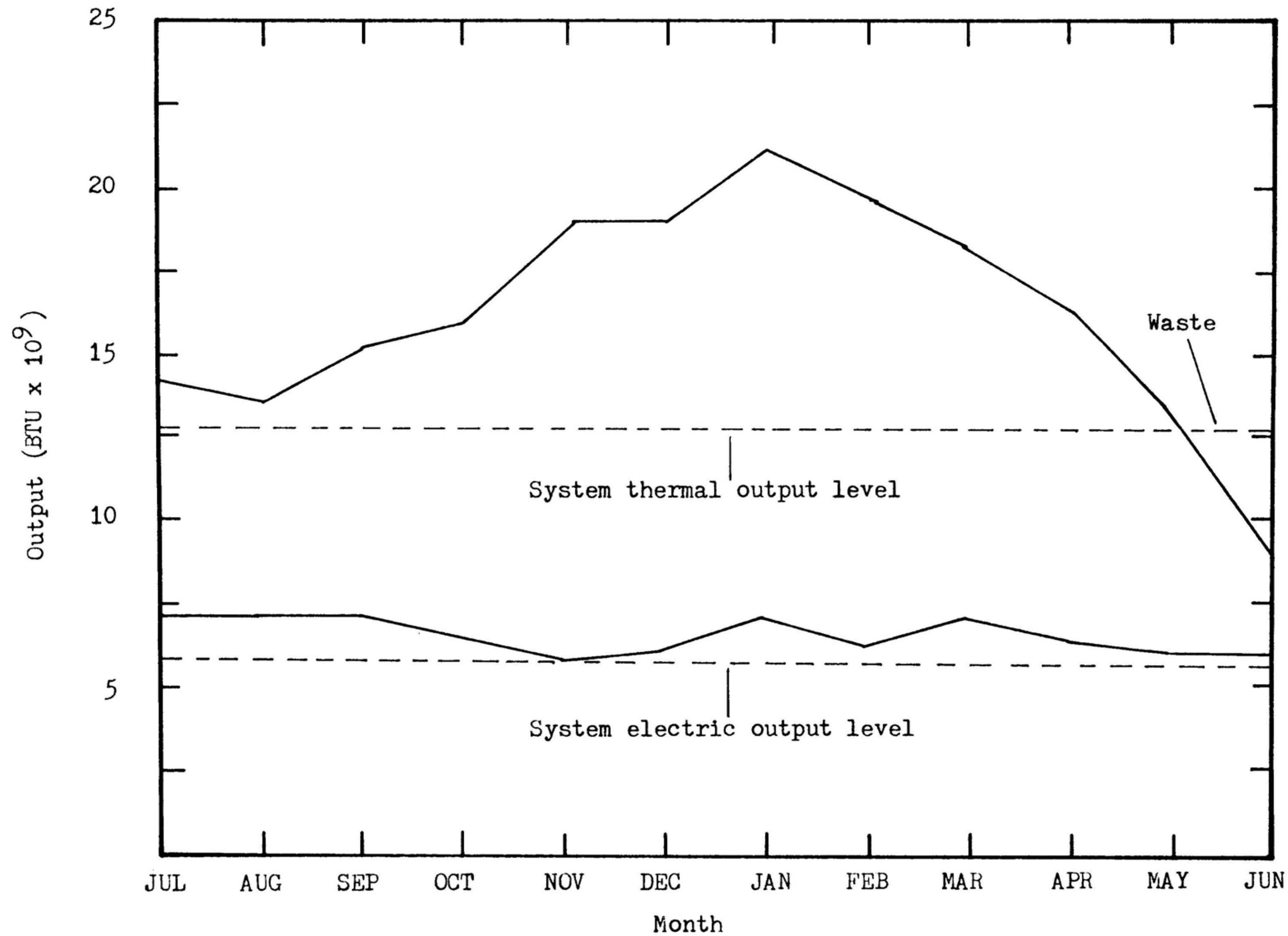


Figure 4-1 : Cogeneration System Energy Output for San Diego Hospital

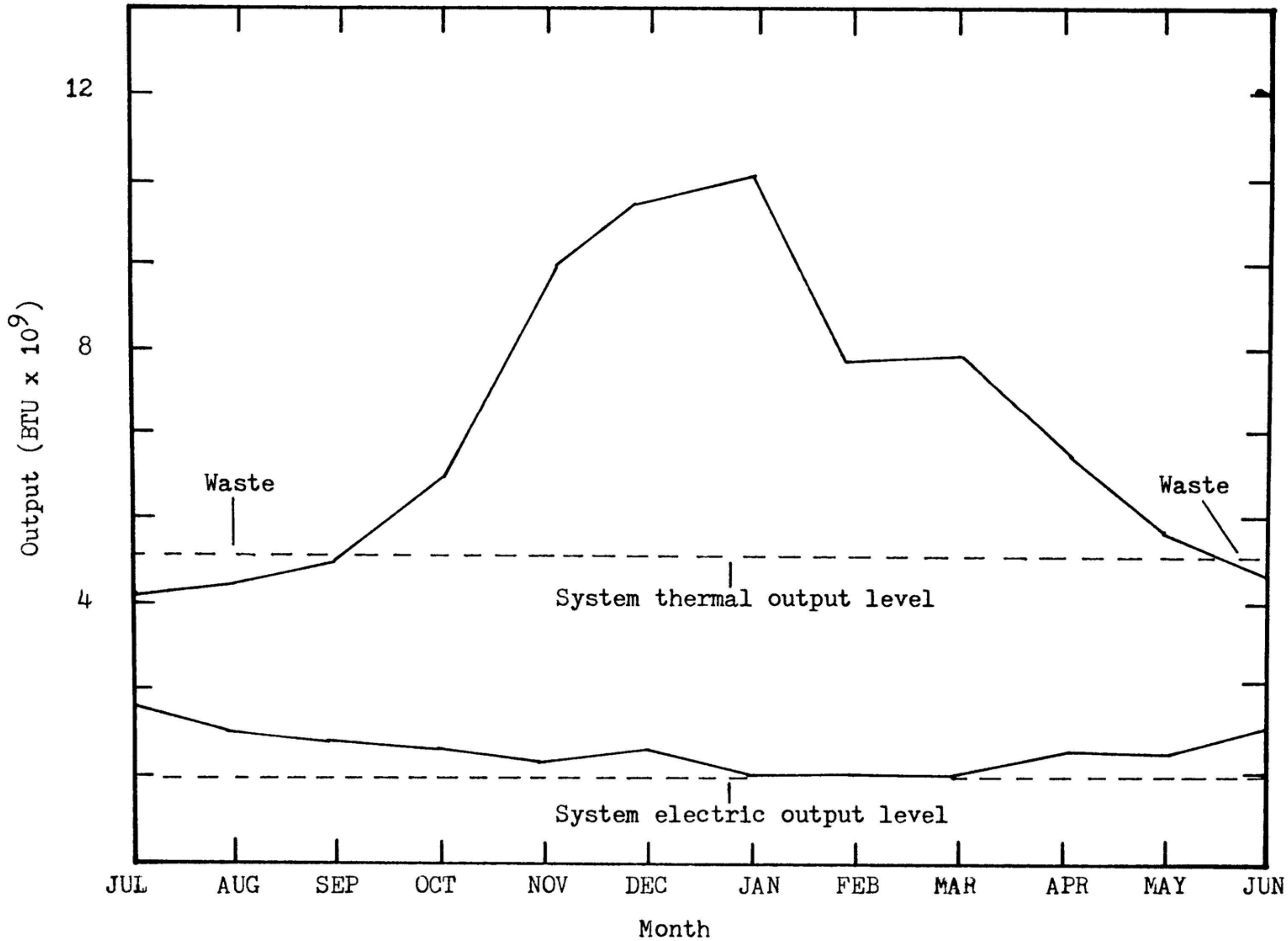


Figure 4-2 : Cogeneration System Energy Output for Battle Creek Hospital

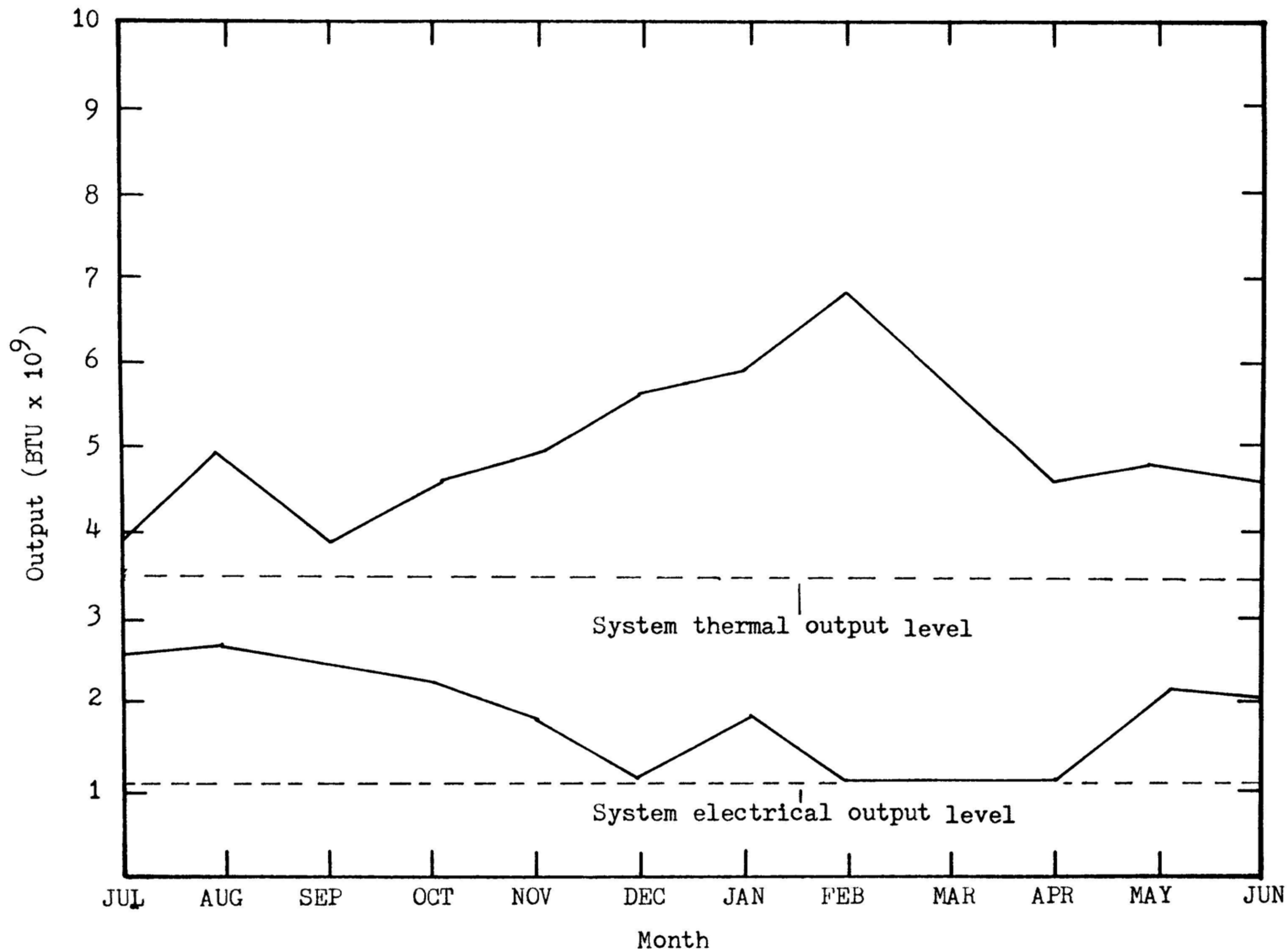


Figure 4-3 : Cogeneration System Energy Output for Lake City Hospital

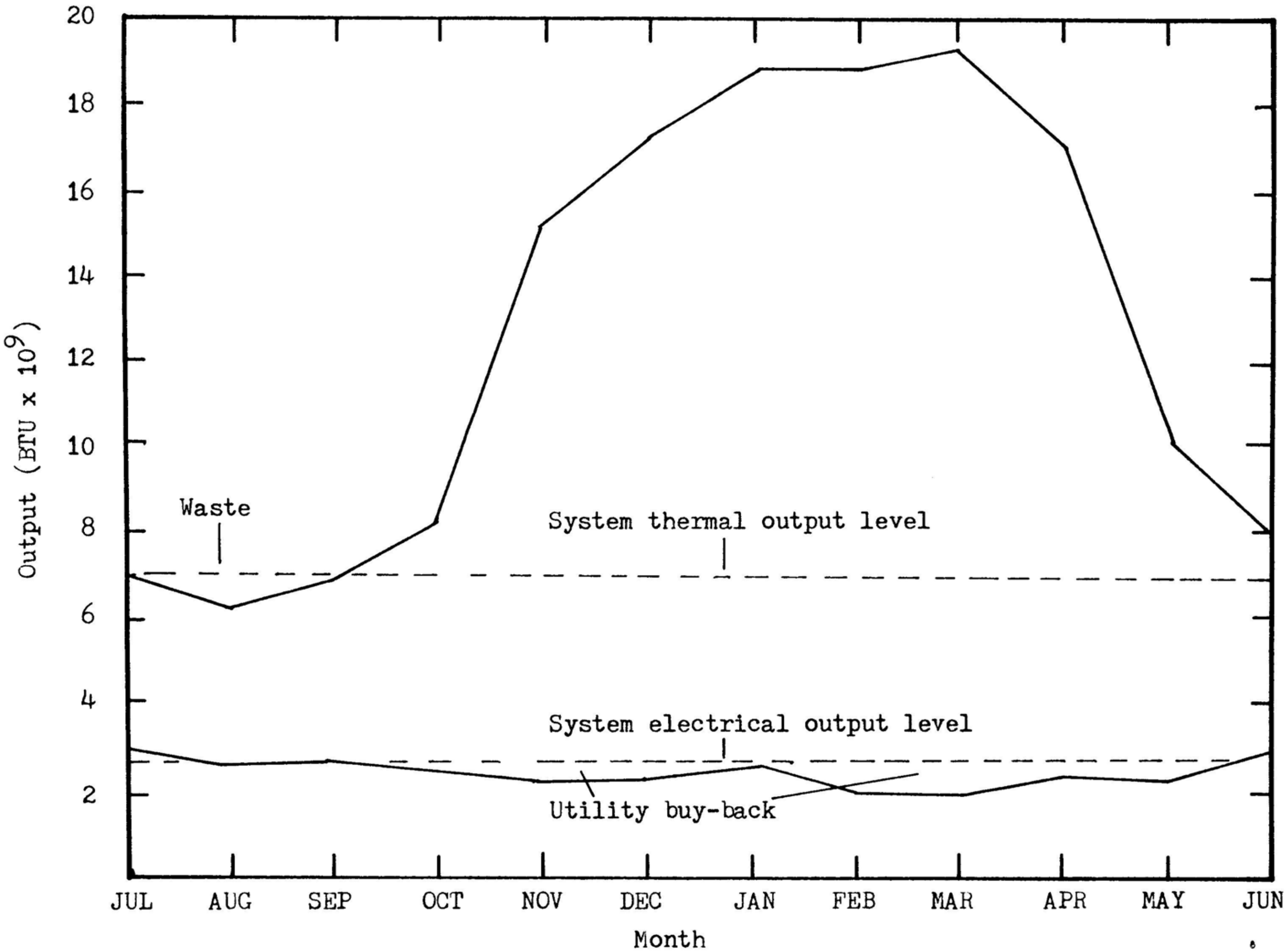


Figure 4-4 : Cogeneration System Energy Output for Buffalo Hospital

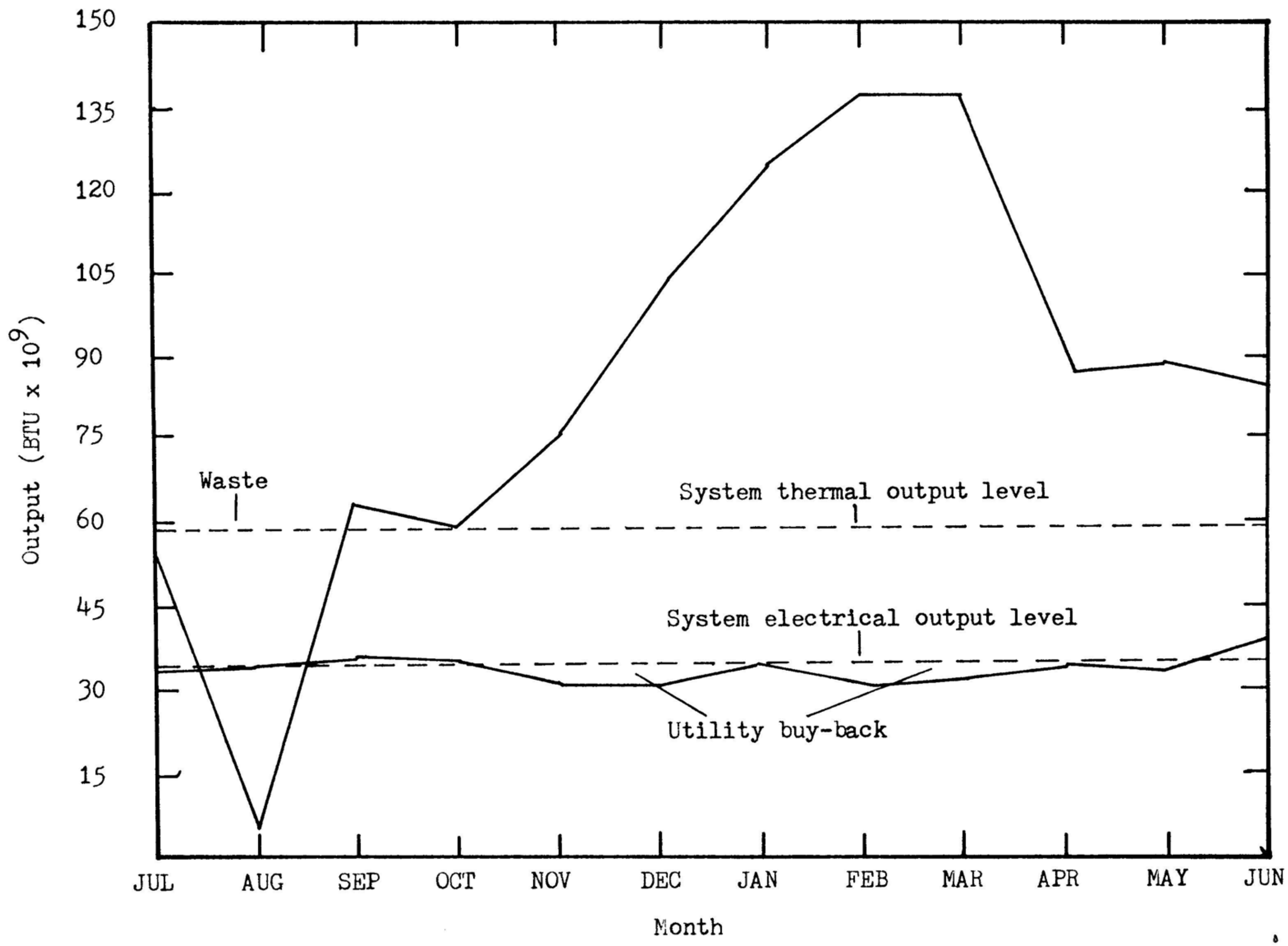


Figure 4-5 : Cogeneration System Energy Output for M.I.T.

reason for this relative insensivity to reasonable buy-back rates is that the buy-back rate was not sufficiently greater than the cogenerated electricity cost to justify the large additional capital expenditures needed to bring the optimum system size appreciably above the lowest average monthly requirements.

Another important result of this portion of the analysis was that the optimum operating capacity never fell below the rated operating capacity, even though this meant excess thermal production at times which just went to waste. This suggests a strong fuel savings sensitivity to turbine efficiency.

Also note that San Diego and M.I.T. had substantially higher ROI's than the other sites. This was a result of the high electricity prices in these regions. A high electricity price means more fuel savings due to the cogeneration investment, and therefore a higher return on investment.

Figure 4-6 shows the optimal turbine size versus the NPV to initial capital outlay ratio (as discussed in section 3.2.2) for a typical site. It is clear that the turbine which yielded the highest ROI fell within the chosen size range. This was true for all of the sites.

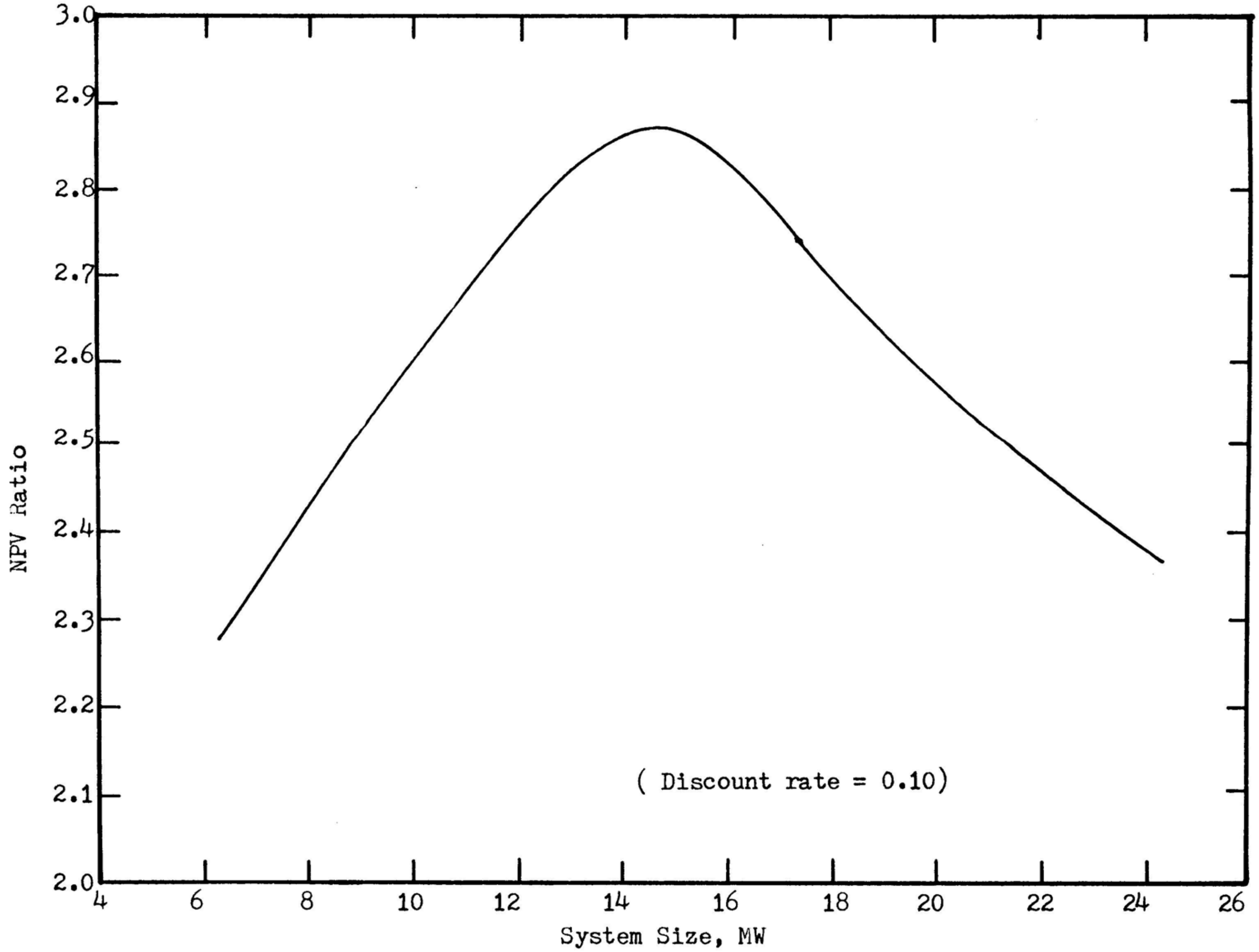


Figure 4-6 : NPV to Capital Outlay Ratio versus System Size for M.I.T.

4.2 Sensitivity analysis

4.2.1 Optimum system size

In general, it was found that the optimum system size was most sensitive to the buy-back rate, and the utility electricity cost. The optimum size was found to be sensitive to utility electricity prices only when the buyback rates were high (M.I.T. and San Diego, and Buffalo, see Figures 4-7 through 4-11). The optimum plant size increased with dropping electricity prices because substantial fuel savings could only be realized in this situation if the cogenerator produced much excess electricity to take advantage of the high buy-back rates. Typically, the optimum system size increased substantially with increasing buy-back rates for those sites which had an initial increase in optimum size due to buy-back rates (Figures 4-7 through 4-11). The size increased here because the cogeneration systems produced electricity at costs substantially lower than the high buy-back rates. The optimum turbine size increased to take advantage of the additional fuel savings until diminishing returns to scale of the turbine were realized. Every other input parameter had a negligible effect on the optimum system size.

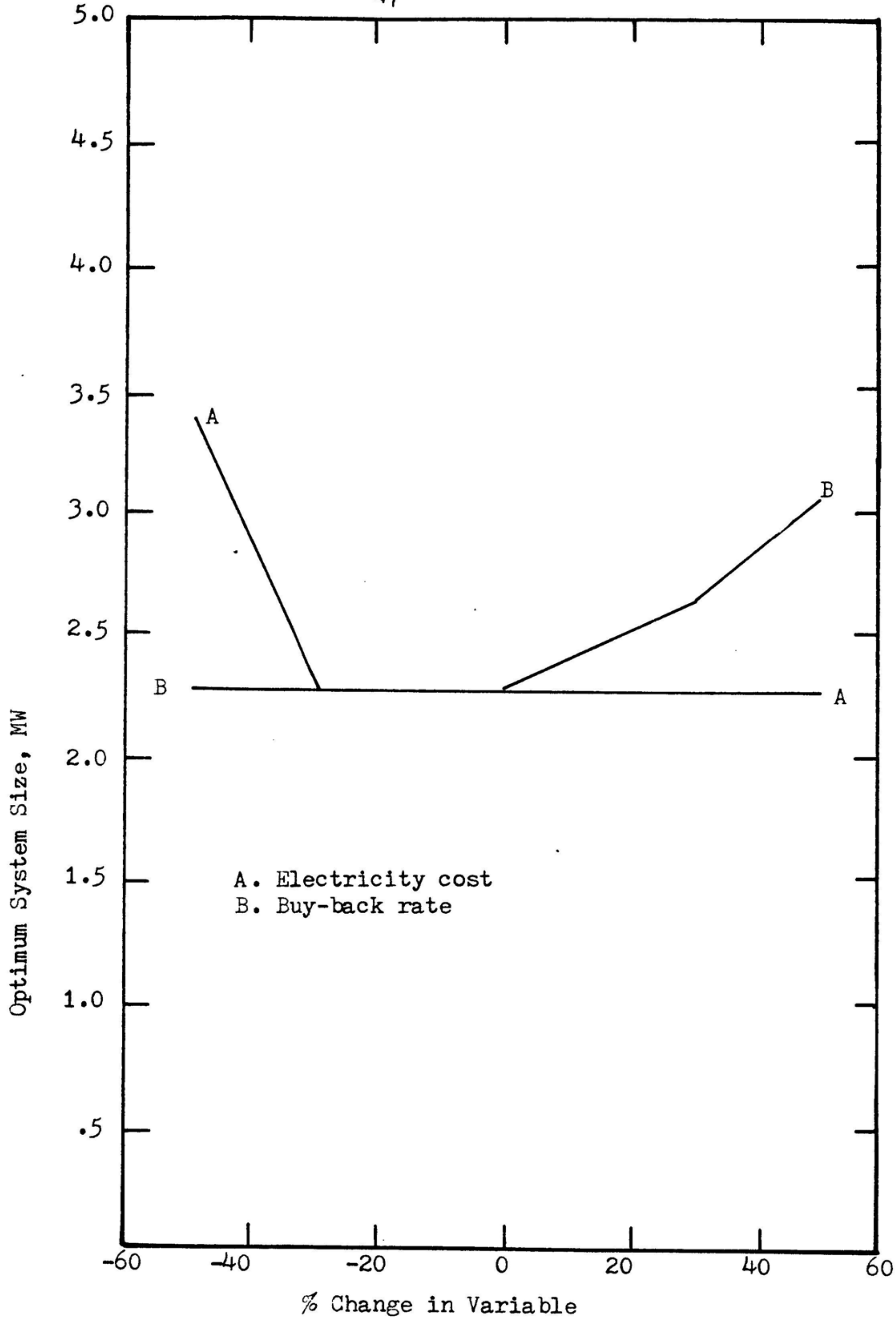


Figure 4-7 : Turbine Size Sensitivity for San Diego Hospital

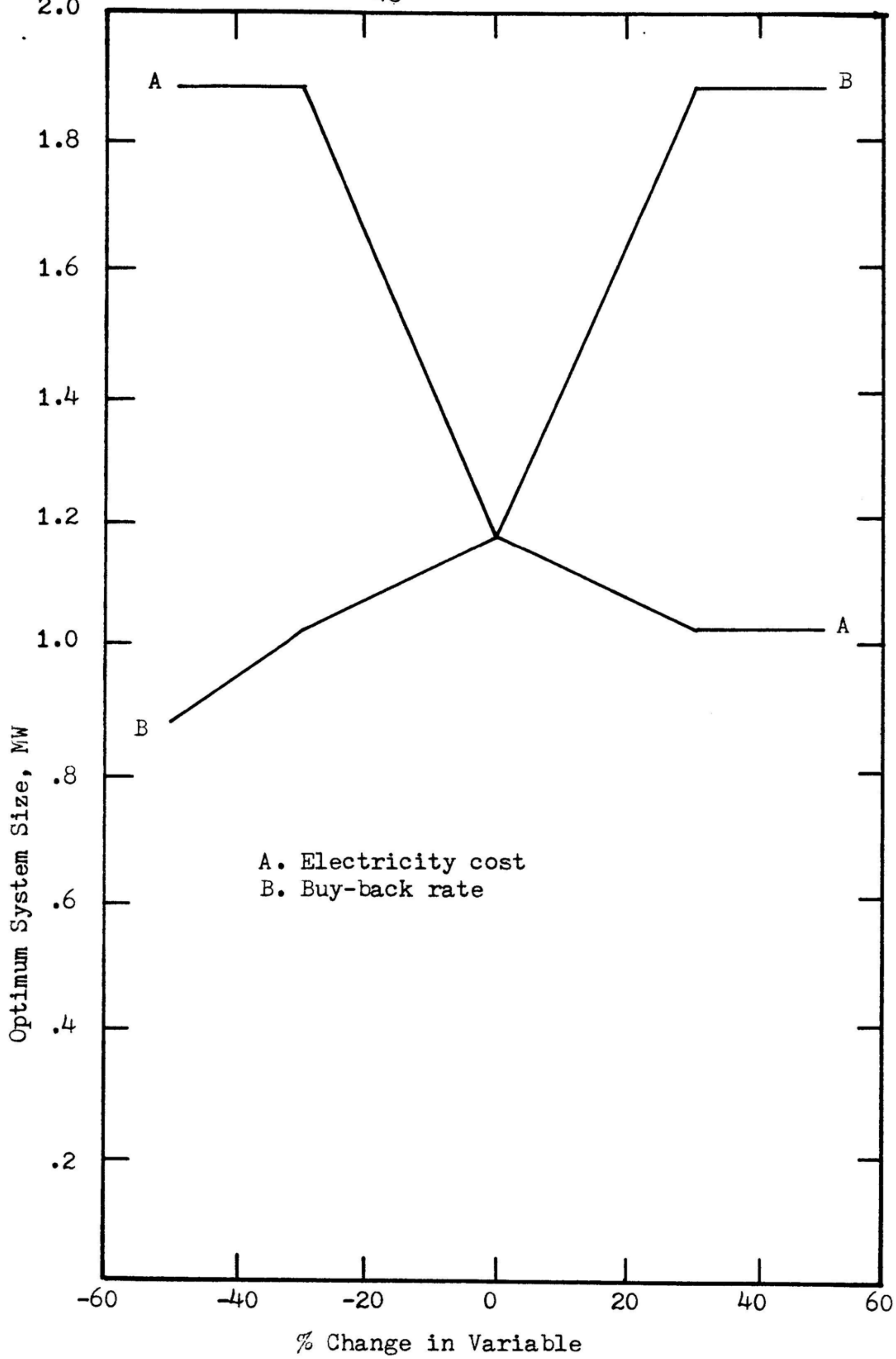


Figure 4-8 : Turbine Size Sensitivity for Buffalo Hospital

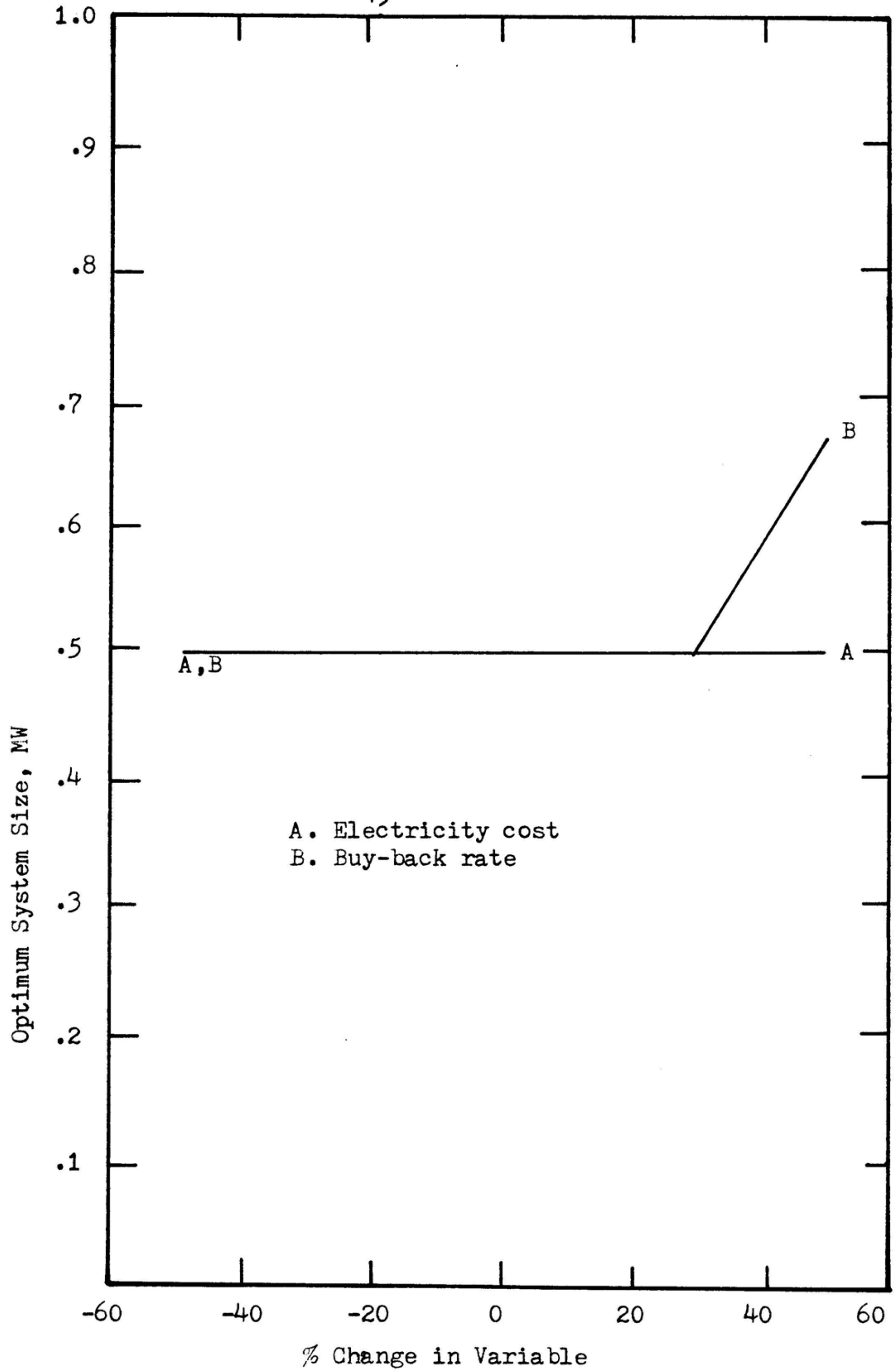


Figure 4-9 : Turbine Size Sensitivity for Lake City Hospital

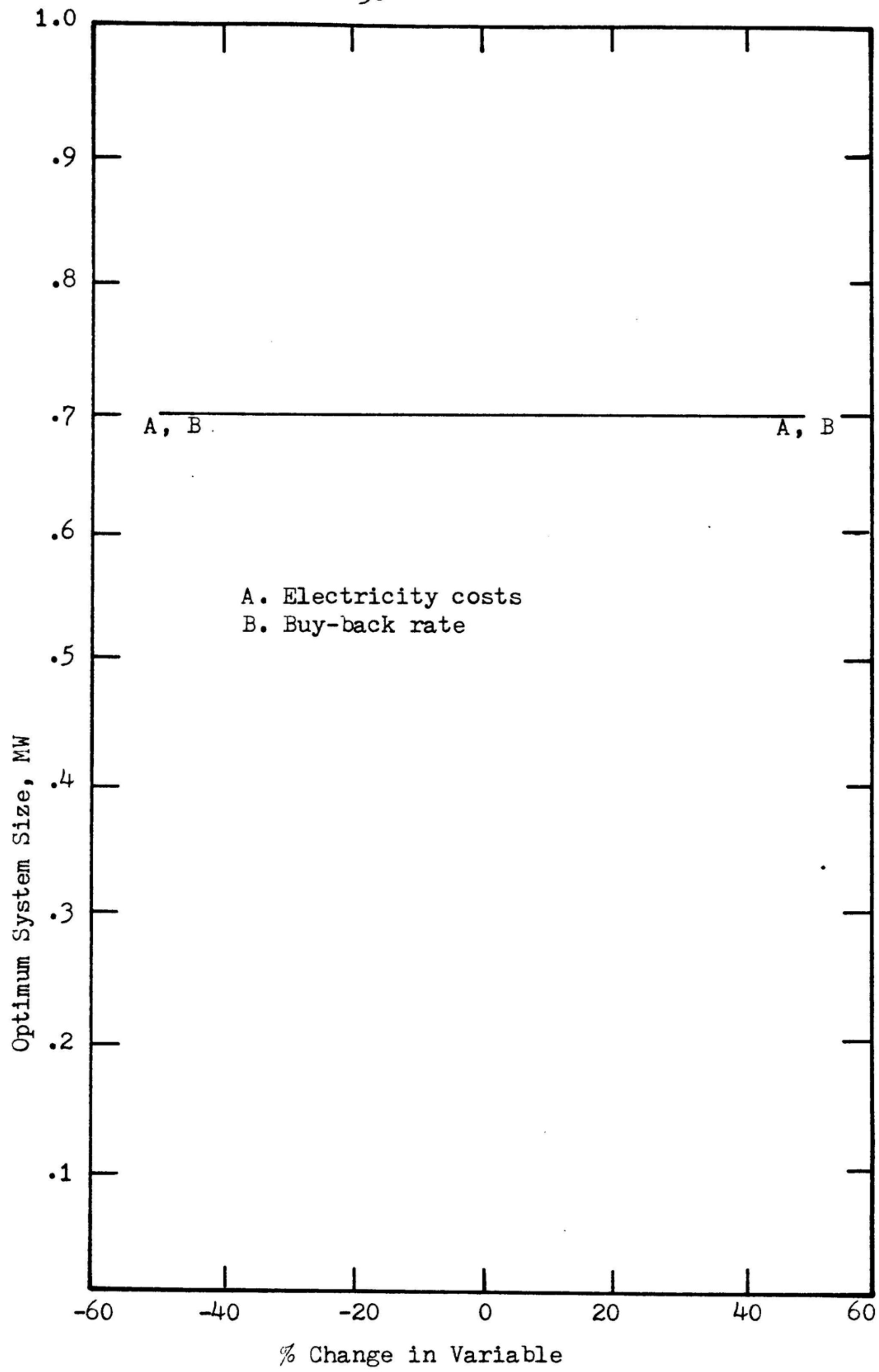


Figure 4-10: Turbine Size Sensitivity for Battle Creek Hospital

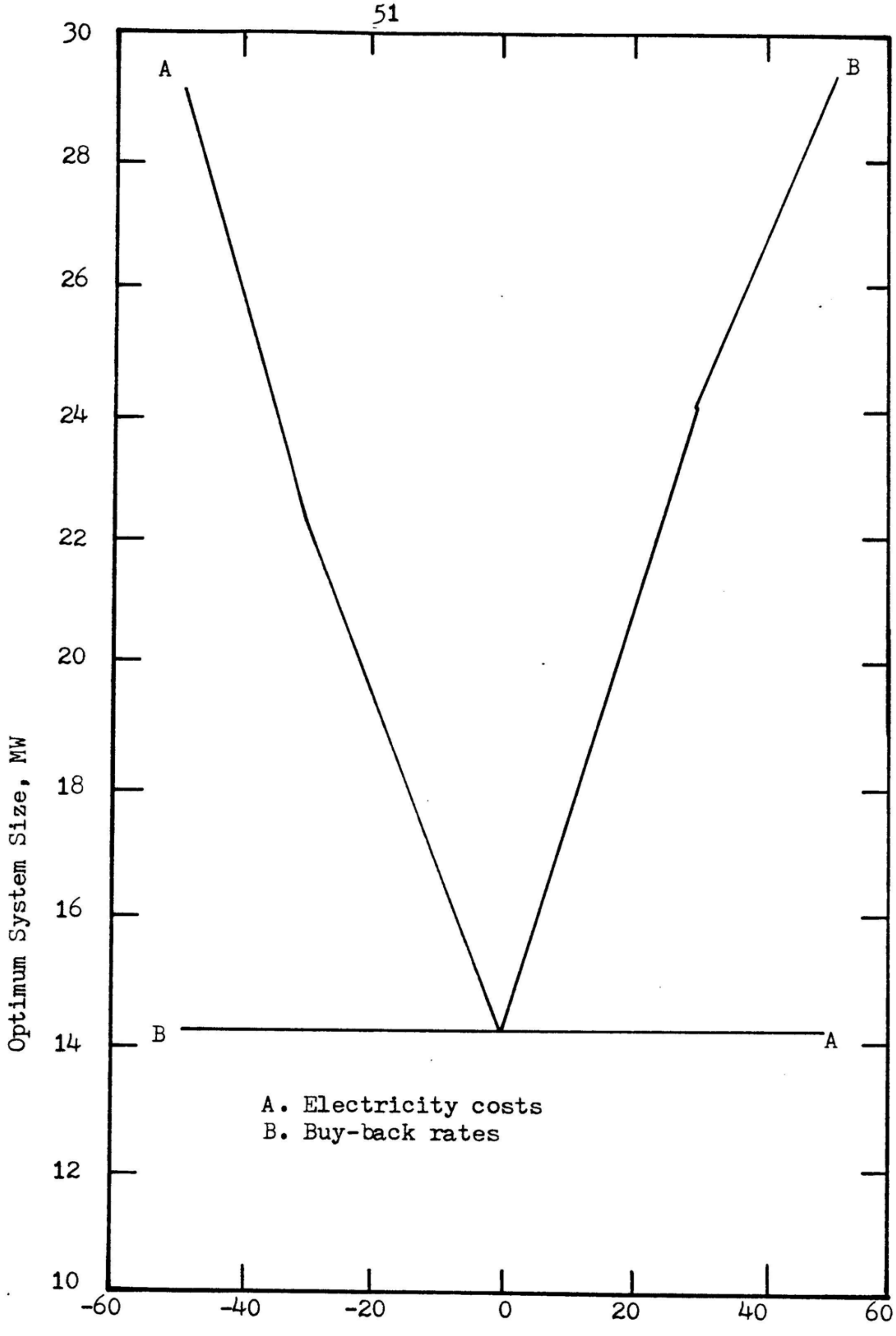


Figure 4-11: Turbine Size Sensitivity for M.I.T.

4.2.2 Return on investment

Figures 4-12 through 4-16 show the sensitivity of the ROI to the economic and hardware input parameters. The results here were fairly consistent with the ROI being most sensitive to the utility electricity prices, somewhat less sensitive to natural gas costs and in two cases (M.I.T. and Buffalo) to positive changes in the buy-back rate, and minimally sensitive to such other parameters as equipment lifetime, the standby charge, the inflation rate, and the interconnection costs. Note that the ROI was most sensitive to those parameters which directly determined the fuel savings.

Figures 4-17 through 4-21 show the sensitivity of the ROI to the tax and financing variables. With the exception of utility electricity prices, the ROI is about as sensitive to these variables as to the hardware and economic variables. The ROI is most sensitive to the tax rate and the percent of capital borrowed, and least sensitive to the loan interest rate, the investment tax credit, and the loan repayment period. This analysis clearly shows that borrowing as much as possible against the capital cost is an advantageous strategy.

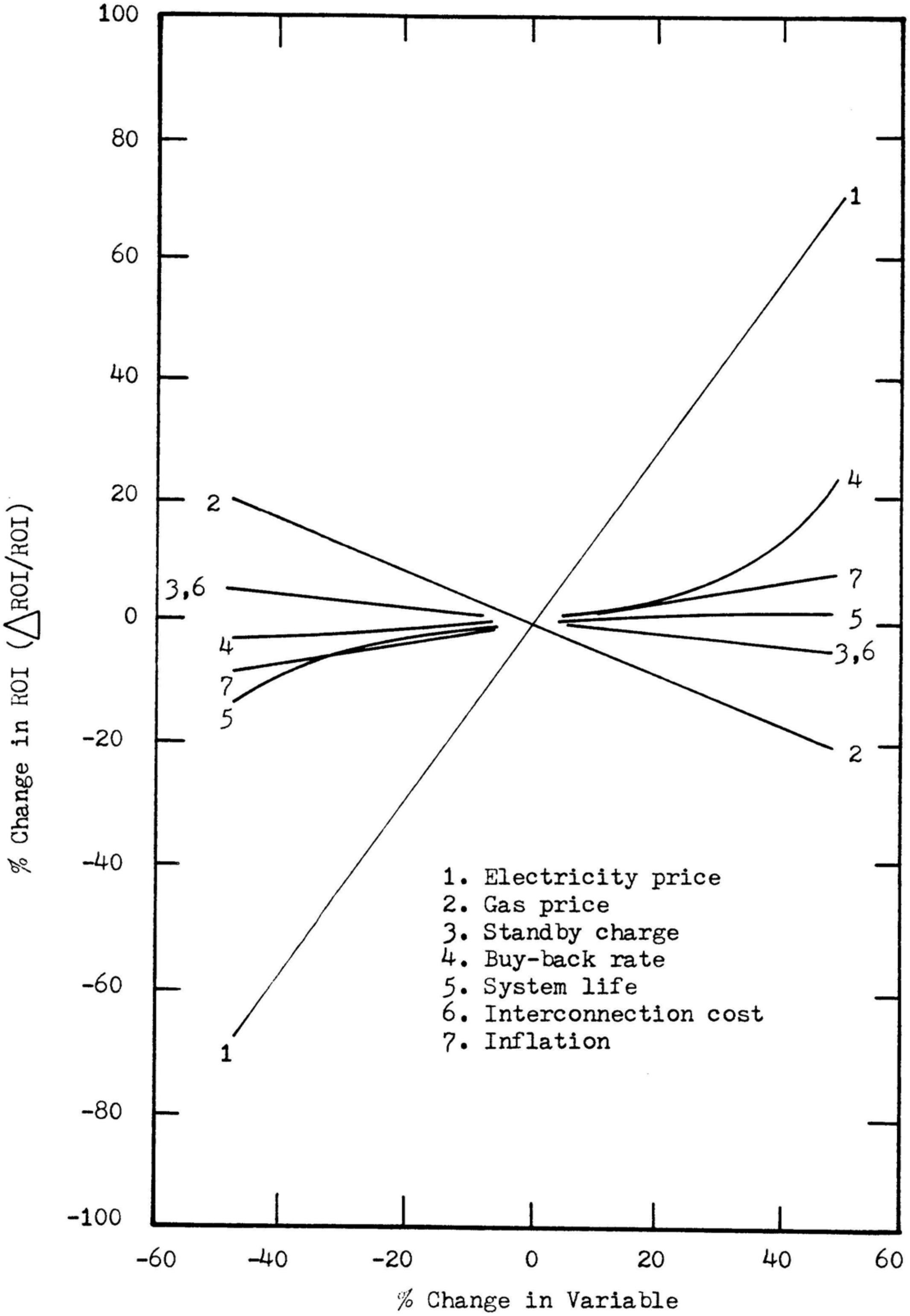


Figure 4-12 : ROI Sensitivity to Hardware and Economic Variables for Buffalo Hospital

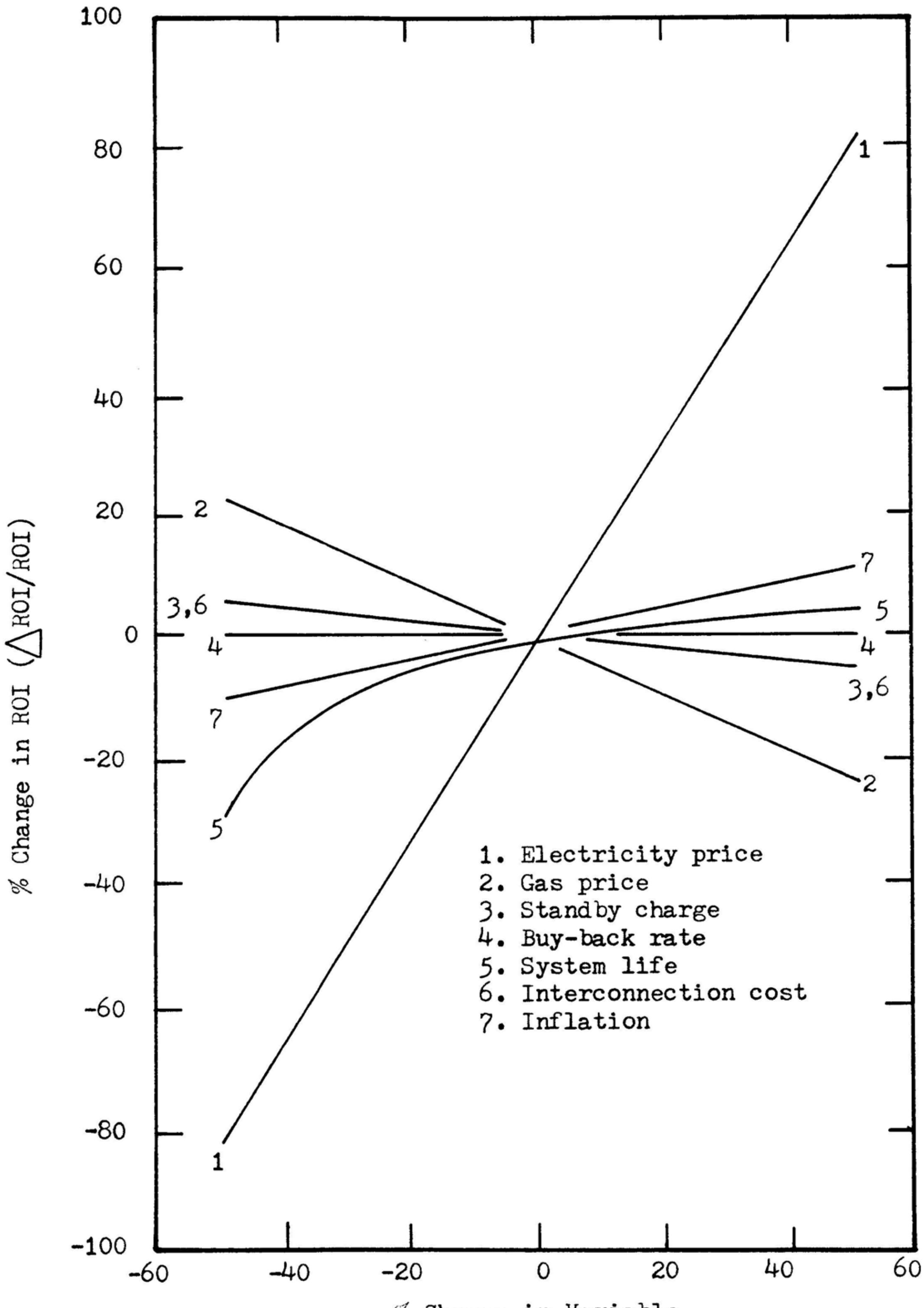


Figure 4-13 : ROI Sensitivity to Hardware and Economic Variables for Lake City Hospital

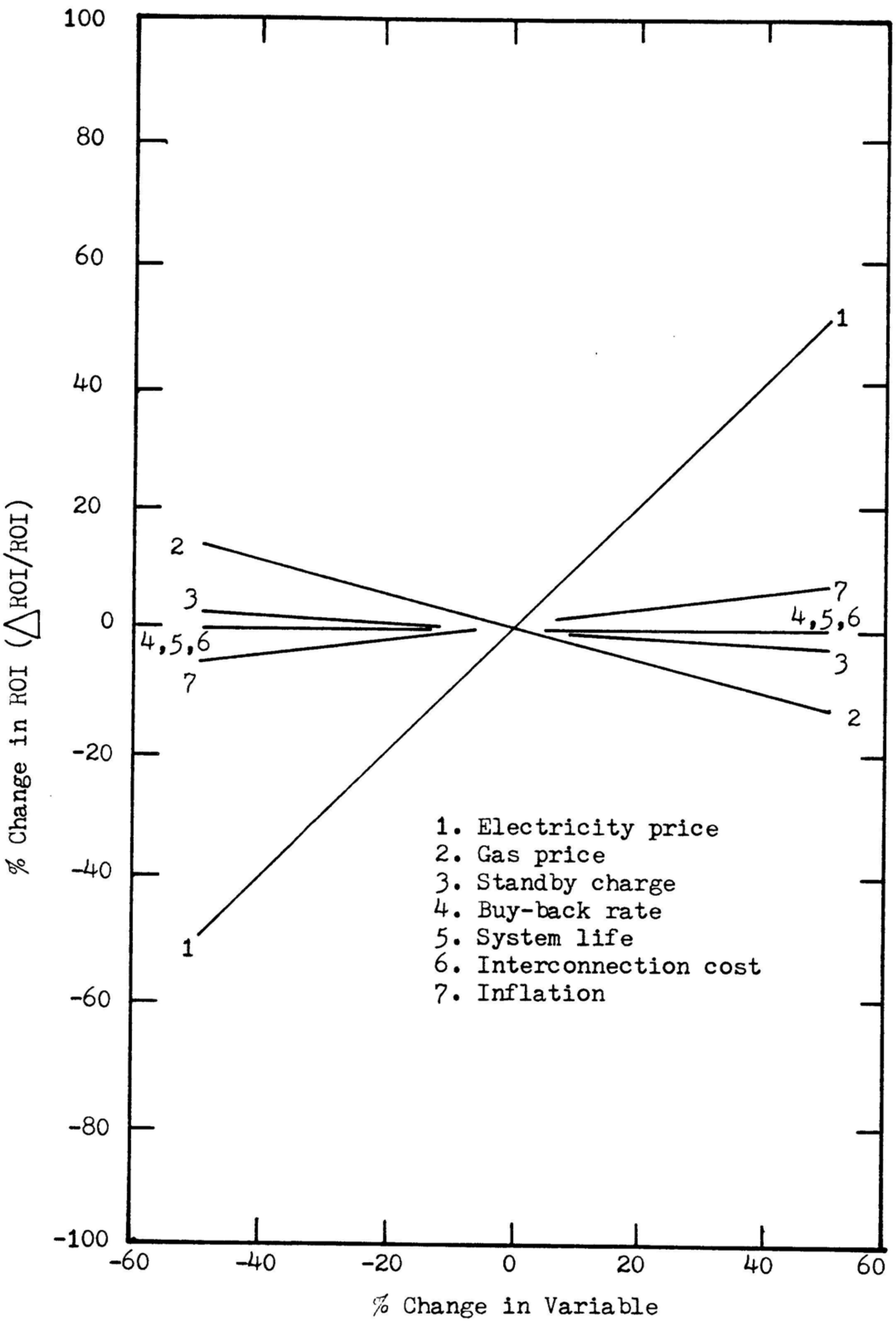


Figure 4-14 : ROI Sensitivity to Hardware and Economic Variables for San Diego Hospital

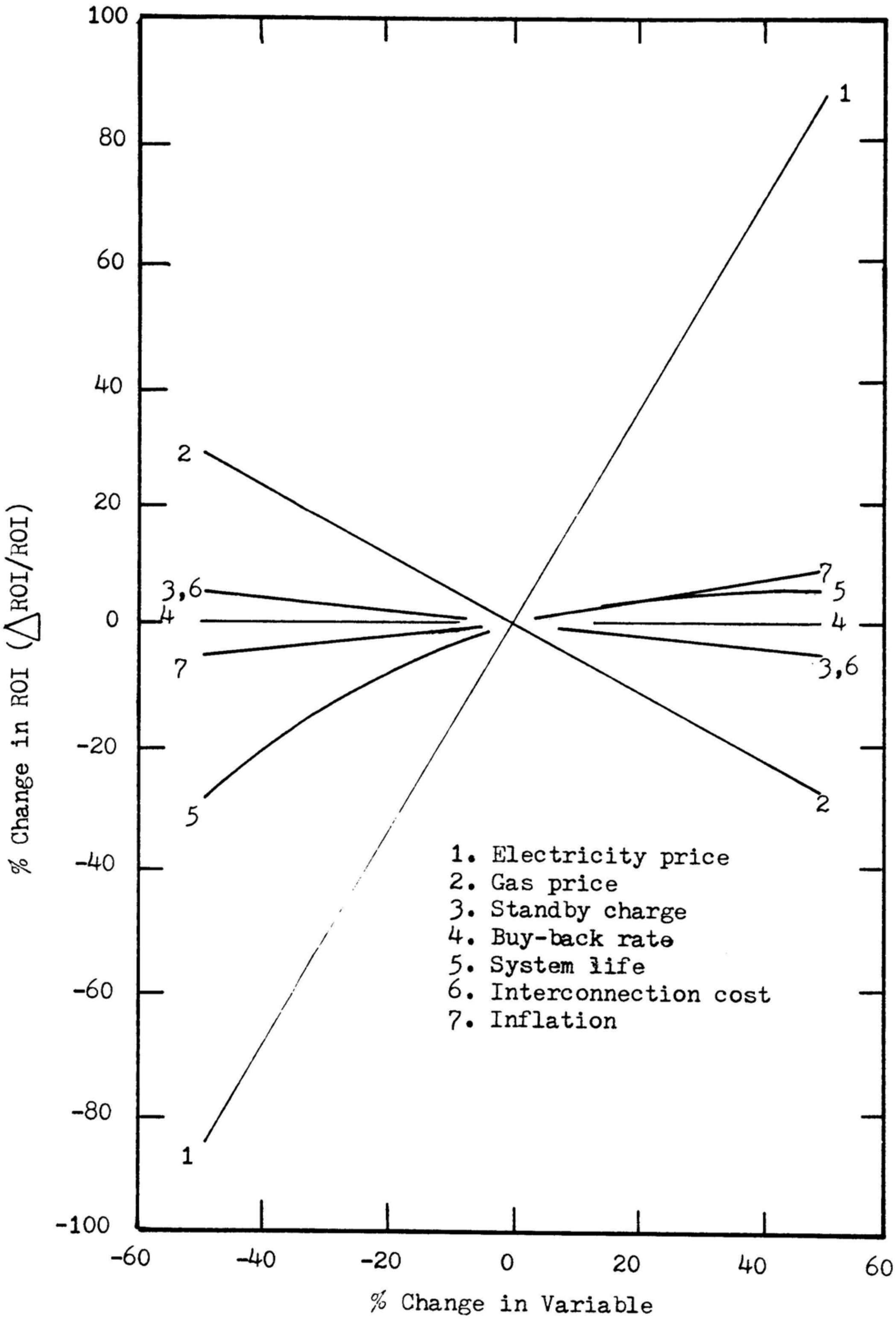


Figure 4-15 : ROI Sensitivity to Hardware and Economic Variables for Battle Creek Hospital

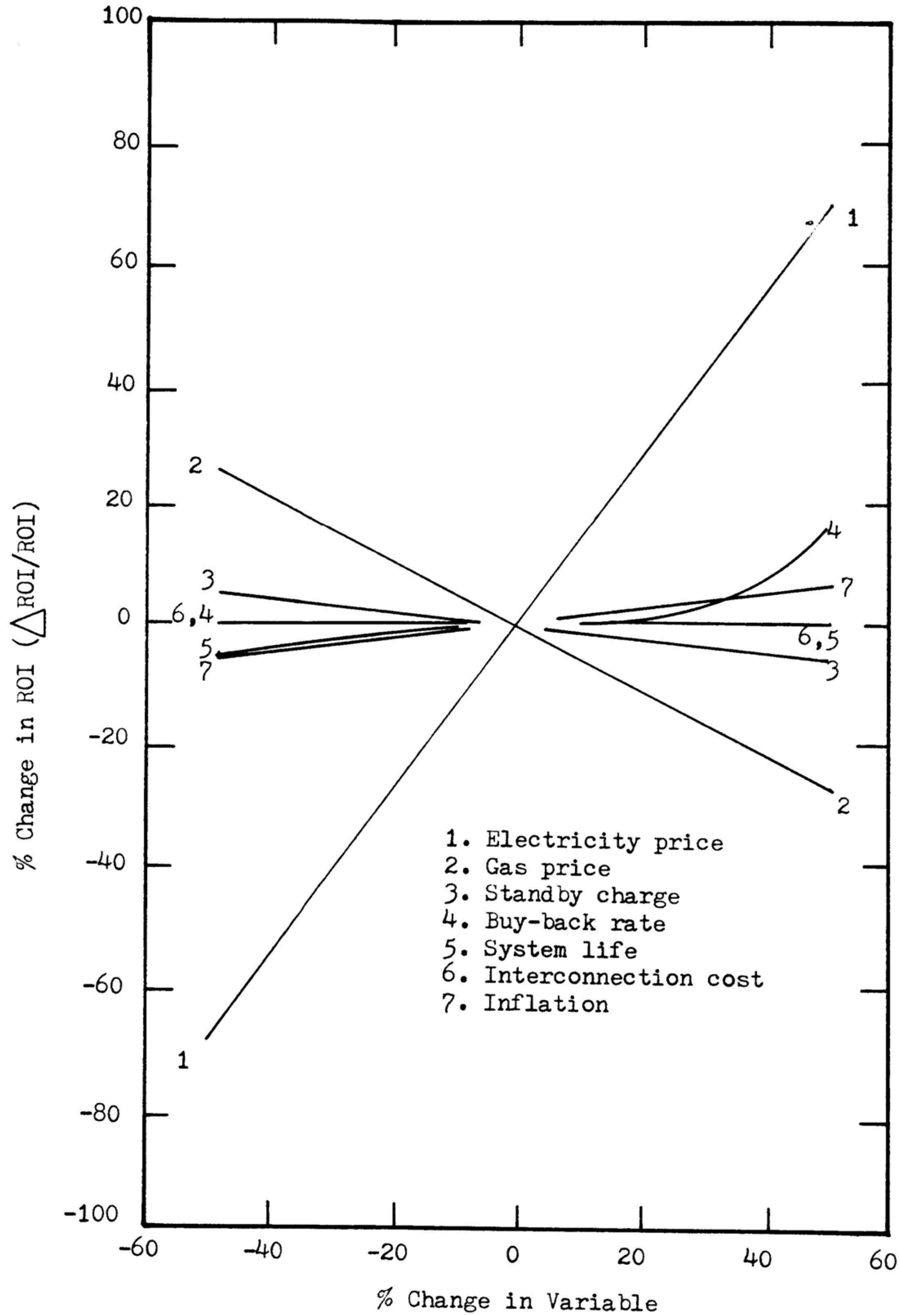


Figure 4-16 : ROI Sensitivity to Hardware and Economic Variables for M.I.T.

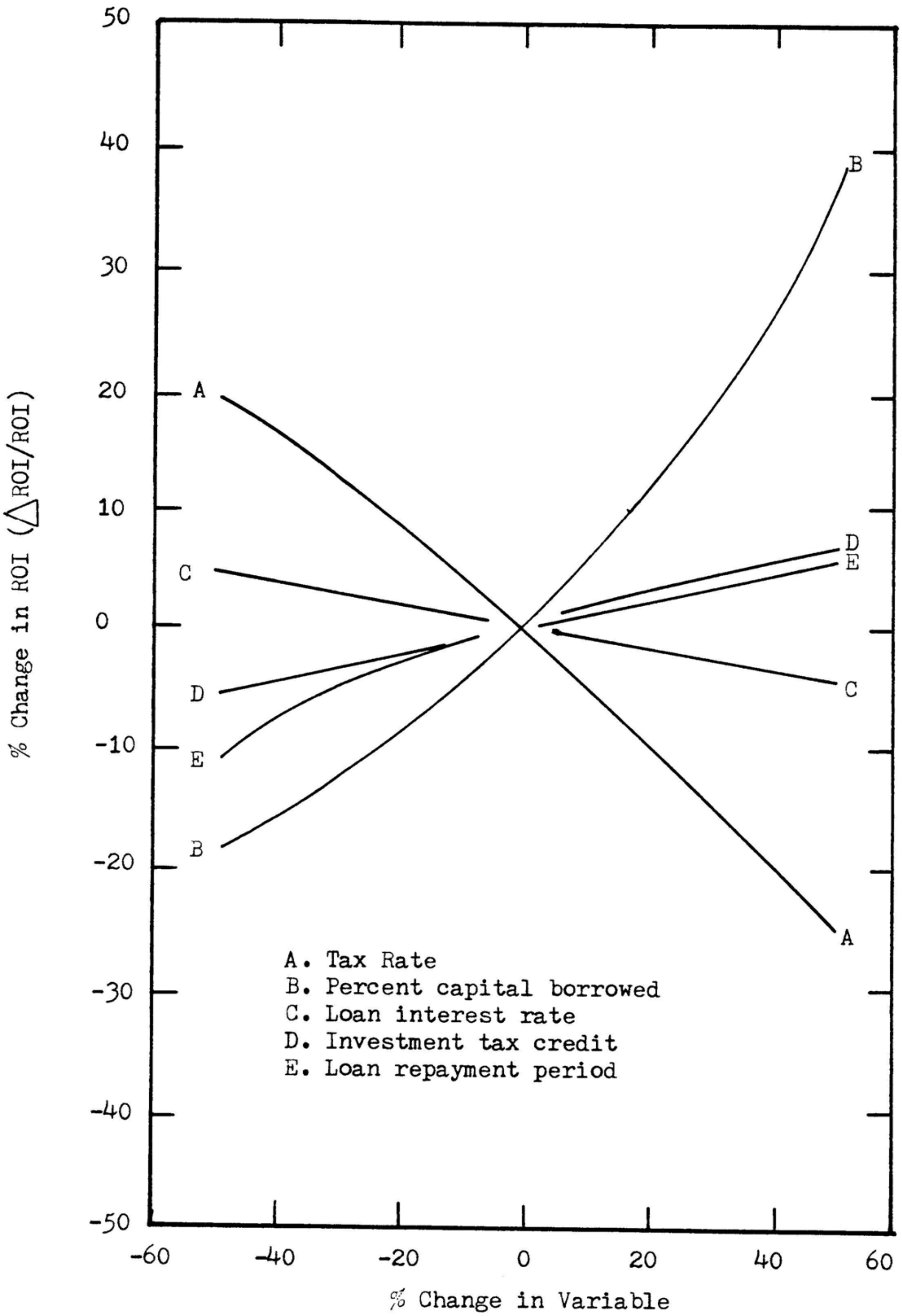


Figure 4-17 : ROI Sensitivity to Tax and Financing Variable for Buffalo Hospital

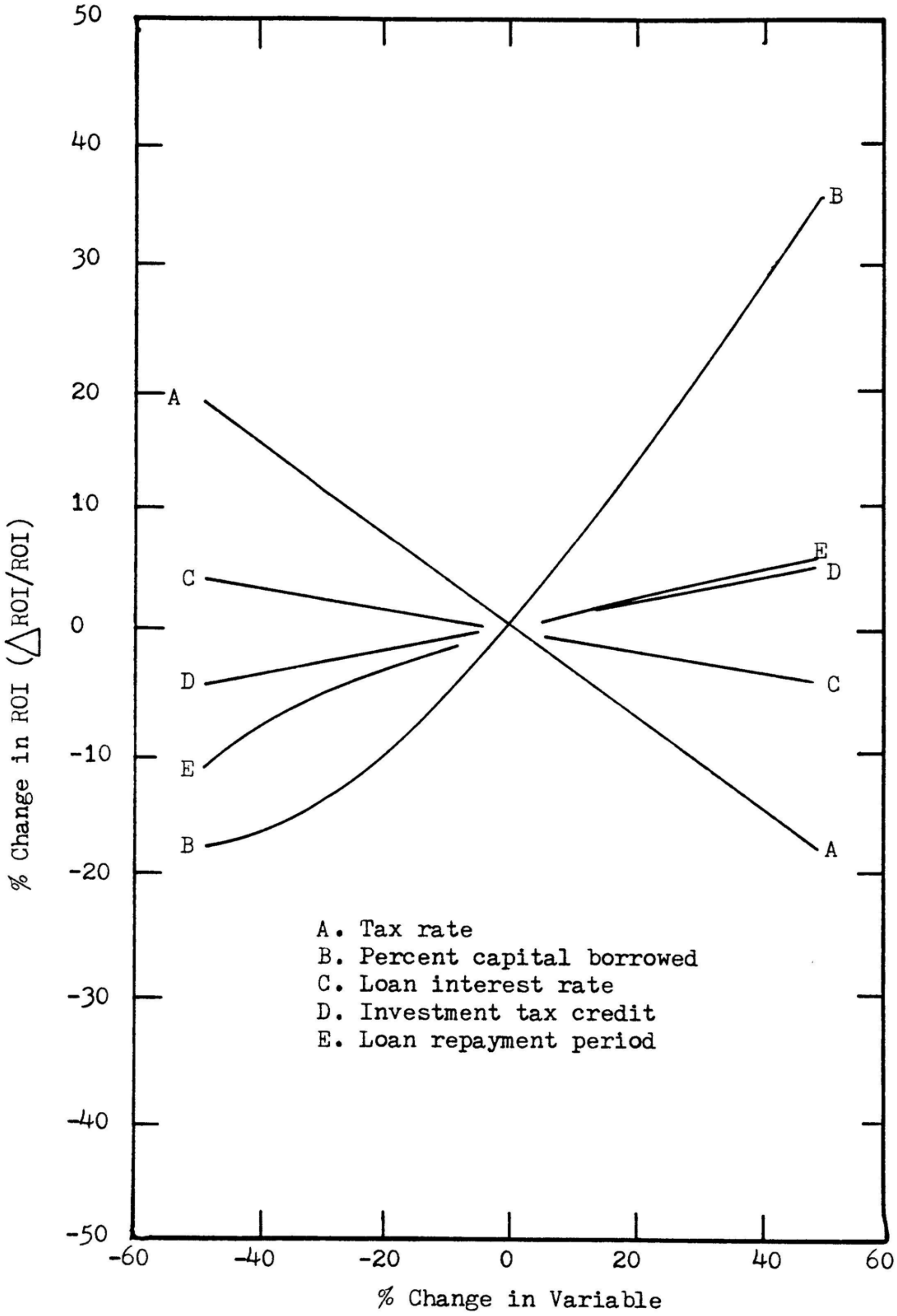


Figure 4-18 : ROI Sensitivity to Tax and Financing Variables for Lake City Hospital

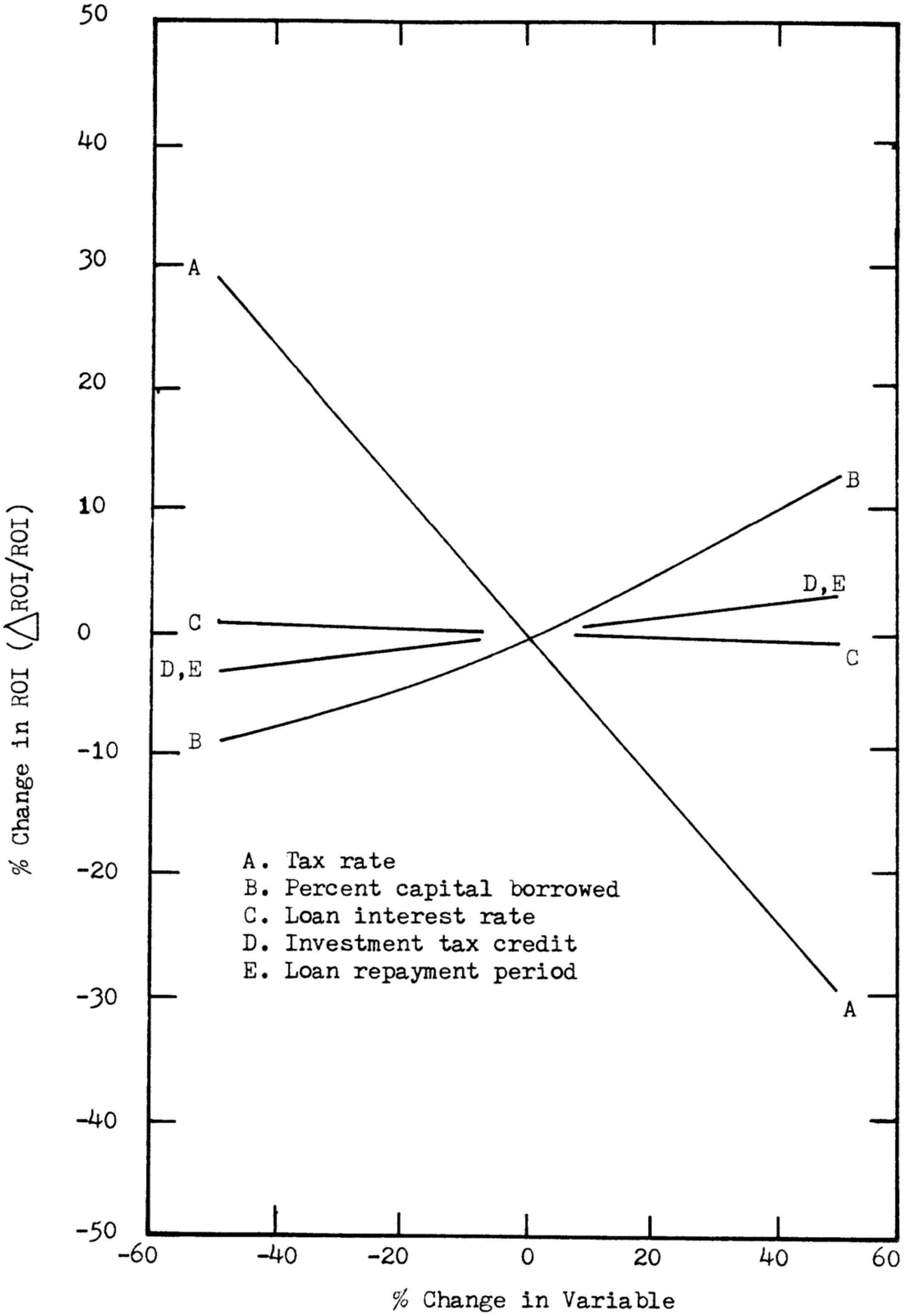


Figure 4-19 : ROI Sensitivity to Tax and Financing Variables for San Diego

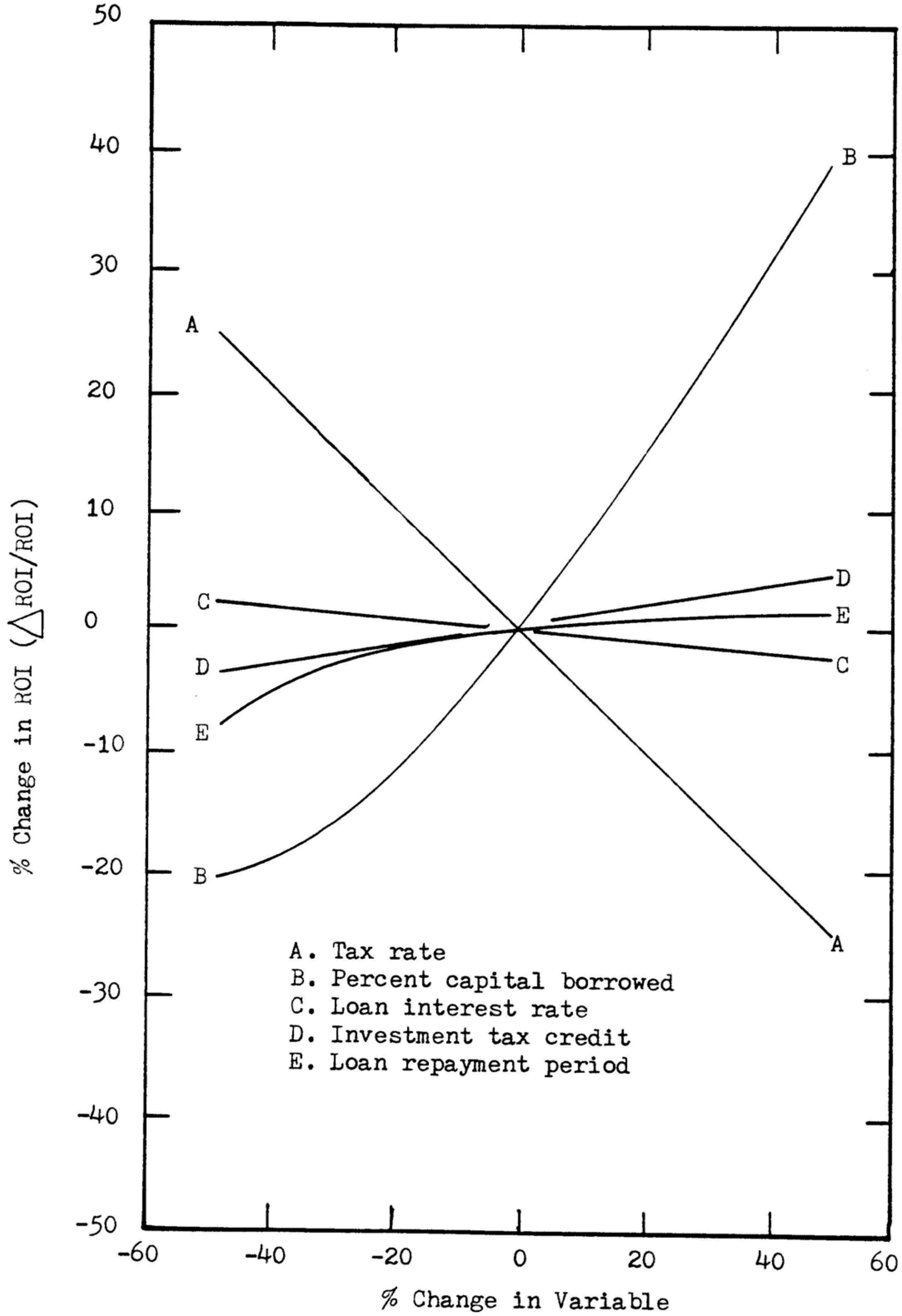


Figure 4-20 : ROI Sensitivity to Tax and Financing Variables for Battle Creek Hospital

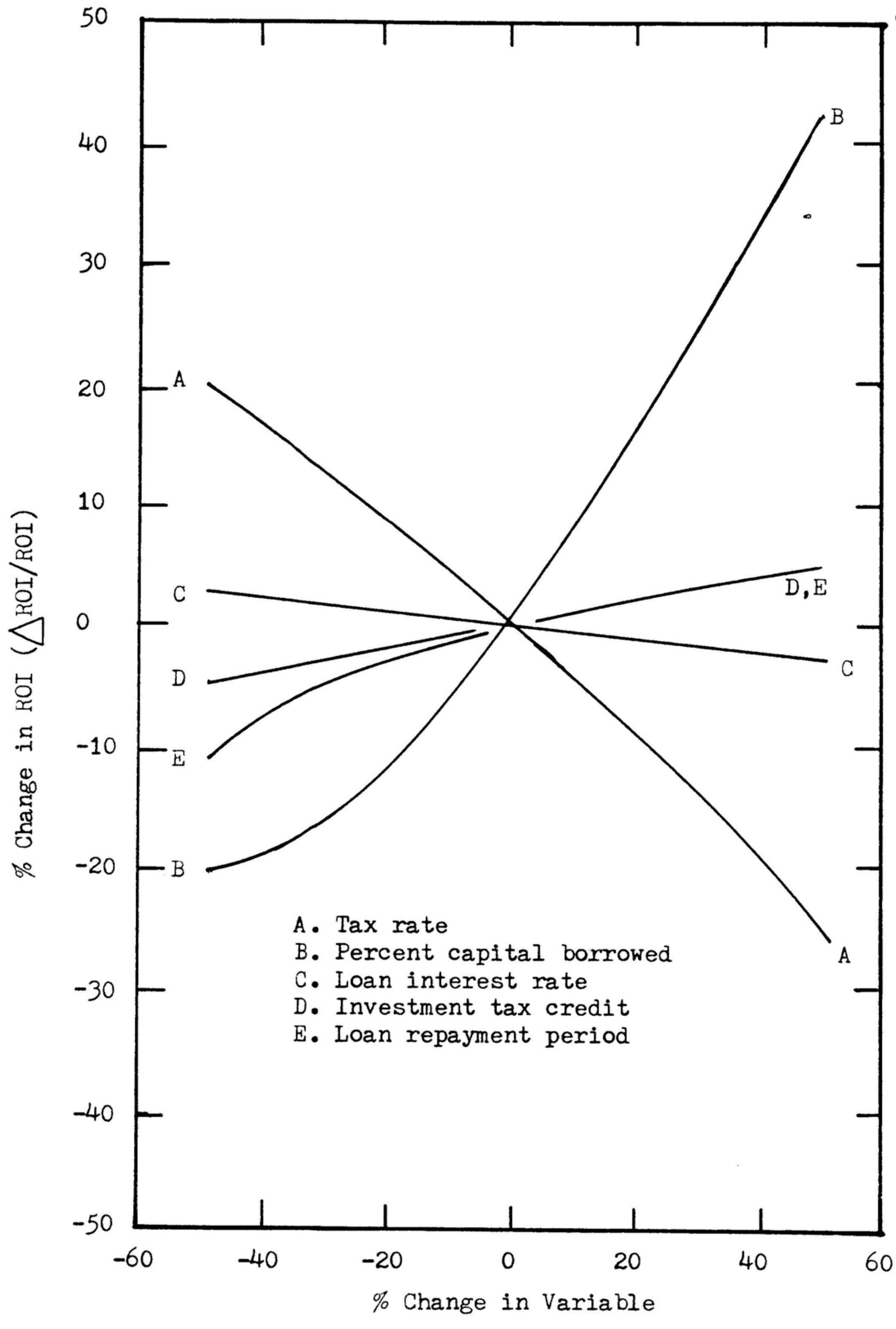


Figure 4-21 : ROI Sensitivity to Tax and Financing Variables for M.I.T.

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

Comparing the optimum turbine sizes developed in this study to the optimum sizes expected without considering buyback rates, it was apparent that buy-back rates did not have a pronounced effect on the optimum cogeneration system size until the buy-back rates reached unrealistically high values compared to the price of electricity. It was also shown that even those sites which did show an increase in the optimum turbine size due to buy-back rates had ROI's which were relatively insensitive to negative changes in the buy-back rates.

Potential cogeneration investors should be less concerned about uncertainties concerning those variables to which the ROI is insensitive, such as the buy-back rate, the inflation rate, the interest rate, or the lifetime of the system, and much more concerned about uncertainties in the electricity prices or in the marginal tax rate. Hopefully this report can help potential investors decide which parameters are important in the investment decision and require a good deal of attention, and which parameters are less important to the decision and therefore deserve less consideration.

In an absolute sense, the returns on investment established in this report were quite high, and make the cogeneration investment look extremely attractive. In addition to saving money, the potential cogenerators would be saving the country's valuable and limited energy resources.

5.2 Recommendations

This study should be augmented by taking into account the daily and hourly changes in thermal and electrical loads at the potential cogeneration sites. The addition of this parameter would probably reduce the calculated ROI's of this report, and perhaps give a more realistic assessment of the economic benefits of rather small scale cogeneration systems such as those studied here. However, the results of this study are promising. In cogeneration is a means of reducing the aggregate fuel consumption of the United States while reducing the energy financial burden of her citizens. I therefore recommend further Federal policy incentives towards the future growth of cogeneration as an accepted energy alternative.

APPENDIX A

The following FORTRAN program was used to calculate the optimum system size, the optimum turbine output for each month, and the corresponding return on investment for the potential cogeneration sites considered in this study. The energy consumption requirements are read from a data file, while the user must enter the hardware, economic, and financial parameters interactively.

```
C
C         WRITTEN BY KEVIN A. MAYER, OCTOBER 1983, FOR UNDERGRADUATE MECHANI-
C       CAL ENGINEERING THESIS. THIS INTERACTIVE PROGRAM OPTIMIZES GAS TURBINE
C       COGENERATION PLANT SIZE AND OPERATING CONDITIONS GIVEN ECONOMIC,
C       ENVIRONMENTAL, AND TURBINE EFFICIENCY PARAMETERS. THIS PROGRAM
C       ALSO GIVES THE OPTIMUM INTERNAL RATE OF RETURN THAT CAN BE EXPECTED
C       FROM THE INITIAL CAPITAL INVESTMENT IN THE COGENERATION SYSTEM.
C
C       CHARACTER DECLARATIONS
C
        INTEGER ZINC, YINC, YRS
        PARAMETER (ZINC=10, YINC=20, GENEFF=.96, GBEFF=.98)
        LOGICAL TFLAG
        REAL A, B, BBRATE, DR, EITC, GR, GRCOST, GASCOS, BOIEFF, INCCAP
        REAL INICAP, IRATE, ITC, INTCOS, LYRS, MAXCAP, LARGE, PRINC
        REAL ROI, RPV, RSUM, SMALL, STBYCH, TAXRAT, AEFC(YINC), ALP(25)
        REAL ASFC(YINC), ADJBAS(0:ZINC), CAP(0:ZINC), CAPCOS(0:ZINC)
        REAL COST(YINC), DEP(25), ECOEFF(0:ZINC), ECOST(12), EDIFF(YINC)
        REAL EEPCAP(YINC), ELOUT(YINC), ELREQ(12), FMMBTU(YINC), FSMAX(12)
        REAL FUEL(YINC), FUESAV(YINC), HEREQ(12), KOUT(0:ZINC,12)
        REAL KSOUT(0:ZINC,12), LIP(25), MAXSAV(0:ZINC), MCAP(12), MOUT(12)
        REAL NETSAV(0:ZINC,0:25), NPV(0:ZINC), PCAP(YINC), PV(0:ZINC,25)
        REAL QNPV(0:ZINC), RR(1000), SCOST(12), STEFF(YINC), SDIFF(YINC)
        REAL STOUT(YINC), SOUT(12), SUM(0:ZINC), TEPCAP(YINC)
        REAL TOTCOS(YINC), X(0:ZINC)
C
C       READ IN NECESSARY DATA FROM TERMINAL AND DATA FILE
C
        DO 1 L=1,12
          READ(5,*) ELREQ(L),HEREQ(L)
 1      CONTINUE
        TYPE*,'MONTHLY ENERGY REQUIREMENTS HAVE BEEN ENTERED'
        TYPE*,'ENTER THE COST OF ELECTRICITY FROM UTILITY   '
        TYPE*,'IN CENTS PER KW-HOUR'
        ACCEPT*,GRCOST
        TYPE*,'ENTER THE UTILITY BUYBACK RATE IN CENTS PER KW-HOUR'
        ACCEPT*,BBRATE
        TYPE*,'ENTER THE COST OF GAS IN $ PER MILLION-BTU'
        ACCEPT*,GASCOS
        TYPE*,'ENTER THE EXPECTED GROWTH RATE OF ENERGY'
        TYPE*,'COSTS AS A DECIMAL QUANTITY (5%=0.05)'
        ACCEPT*,GR
        TYPE*,'ENTER THE DESIRED DISCOUNT RATE FOR THE OPTIMIZATION'
        TYPE*,'PROCEDURE AS A DECIMAL QUANTITY'
        ACCEPT*,DR
        TYPE*,'ENTER THE BOILER EFFICIENCY AS A DECIMAL QUANTITY'
        ACCEPT*,BOIEFF
        TYPE*,'ENTER THE SLOPE OF THE GAS TURBINE EFFICIENCY CURVE'
        ACCEPT*,B
        TYPE*,'ENTER THE INTERCEPT OF THE TURBINE EFFICIENCY CURVE IN KW'
        ACCEPT*,A
        TYPE*,'ENTER THE INVESTMENT TAX CREDIT AS A DECIMAL QUANTITY'
        ACCEPT*,ITC
        TYPE*,'ENTER THE ENERGY TAX CREDIT AS A DECIMAL QUANTITY'
        ACCEPT*,EITC
        TYPE*,'ENTER THE INTERCONNECTION COSTS IN $ PER KW'
        ACCEPT*,INTCOS
        TYPE*,'ENTER THE STANDBY CAPACITY CHARGE IN $ PER KW PER MONTH'
        ACCEPT*,STBYCH
        TYPE*,'ENTER THE EXPECTED LIFE OF THE EQUIPMENT IN YEARS'
```

```
      ACCEPT*,YRS
      TYPE*,'ENTER THE FRACTION OF THE CAPITAL COST TO BE FINANCED'
      TYPE*,'AS A DECIMAL QUANTITY'
      ACCEPT*,PRINC
      TYPE*,'ENTER THE LOAN INTEREST RATE AS A DECIMAL QUANTITY'
      ACCEPT*,IRATE
      TYPE*,'ENTER THE EXPECTED TAX RATE AS A DECIMAL QUANTITY'
      ACCEPT*,TAXRAT
      TYPE*,'ENTER THE EXPECTED LOAN PAYBACK PERIOD IN YEARS'
      TYPE*,'AS A REAL NUMBER (E.G. 18 YEARS= 18.0)'
      ACCEPT*,LYRS
C
C     FIND LOWEST AVERAGE ELECTRICAL LOAD IN MW
C
      SMALL=ELREQ(1)
      DO 5 J=2,12
        IF(ELREQ(J).LT.SMALL) SMALL=ELREQ(J)
 5    CONTINUE
      XSMALL=SMALL/24./30.
      INICAP=XSMALL/2.
      MAXCAP=XSMALL*2.
      INCCAP=(MAXCAP-INICAP)/REAL(ZINC)
C
C     INITIALIZE DEPRECIATION COEFFICIENTS TO ACRS 5 YEAR
C
      DEP(1)=0.15
      DEP(2)=0.22
      DEP(3)=0.21
      DEP(4)=0.21
      DEP(5)=0.21
      DO 10 N=6,YRS
        DEP(N)=0.0
 10   CONTINUE
C
C     USE DO-LOOP TO CYCLE THE CAPACITY FROM INICAP TO MAXCAP IN
C     ZINC INCREMENTS. INITIALIZE.
C
      KFLAG=0
      LARGE=0.0
      TFLAG=.FALSE.
      DO 15 K=0,ZINC
        CAP(K)=INICAP+REAL(K)*INCCAP
        ECOEFF(K)=1.171/(1.+EXP(1.3964-0.14479*ALOG(CAP(K))))
C
C     FOR EACH CAPACITY RUN THROUGH TWELVE MONTHS.INITIALIZE.
C
        DO 20 N=1,12
          MFLAG=1
          FSMAX(N)=0.0
C
C     FOR EACH MONTH, RUN THROUGH YINC DIFFERENT OPERATING
C     PERCENTAGES TO FIND OPTIMUM
C
          DO 25 M=1,YINC
            PCAP(M)=REAL(M)/REAL(YINC)
            ELOUT(M)=PCAP(M)*CAP(K)*1000.
            EEPCAP(M)=(1./B)-(1.-B*ECOEFF(K))*(A+B*CAP(K)*1000.)/B/
     1                (A+B*ELOUT(M))
            TEPCAP(M)=EEPCAP(M)/GBEFF/GENEFF
            FUEL(M)=(ELOUT(M)/EEPCAP(M))*24.*30.
```

```
                FMMBTU(M)=FUEL(M)*0.003412
                STEFF(M)=(1.-TEPCAP(M))*BOIEFF*0.97
                STOUT(M)=STEFF(M)*FMMBTU(M)
                SDIFF(M)=STOUT(M)-HEREQ(N)
                IF(SDIFF(M).LT.0.) THEN
                  ASFC(M)=-GASCOS*SDIFF(M)/BOIEFF
                ELSE
                  ASFC(M)=0.
                ENDIF
                EDIFF(M)=ELOUT(M)*24.*30.-ELREQ(N)*1000.
                IF(EDIFF(M).GT.0) THEN
                  AEFC(M)=-EDIFF(M)*BBRATE/100.
                ELSE
                  AEFC(M)=-EDIFF(M)*GRCOST/100.
                ENDIF
                COST(M)=FMMBTU(M)*GASCOS+ASFC(M)+AEFC(M)
                TOTCOS(M)=COST(M)+STBYCH*ELOUT(M)
C
C       TOTCOS(M) IS THE COST OF TOTAL ENERGY REQ'S FOR MONTH N
C       WITH COGENERATION EQUIPMENT OF CAPACITY CAP(K) OPERATING
C       AT CAPACITY PCAP(M)*CAP(K). NOW FIND FUEL SAVINGS OVER
C       CONVENTIONAL SOURCES.
C
                ECOST(N)=ELREQ(N)*1000.*GRCOST/100.
                SCOST(N)=HEREQ(N)*GASCOS/BOIEFF
                FUESAV(M)=ECOST(N)+SCOST(N)-TOTCOS(M)
C
C       FIND M WHICH YIELDS MAXIMUM SAVINGS FOR MONTH N
C
                IF(FUESAV(M).GT.FSMAX(N)) THEN
                  FSMAX(N)=FUESAV(M)
                  MFLAG=M
                ENDIF
 25           CONTINUE
              SOUT(N)=STOUT(MFLAG)
              MOUT(N)=ELOUT(MFLAG)
 20         CONTINUE
            MAXSAV(K)=FSMAX(1)+FSMAX(2)+FSMAX(3)+FSMAX(4)+FSMAX(5)+
     1      FSMAX(6)+FSMAX(7)+FSMAX(8)+FSMAX(9)+FSMAX(10)+FSMAX(11)+
     1      FSMAX(12)
            DO 30 I=1,12
              KSOUT(K,I)=SOUT(I)
              KOUT(K,I)=MOUT(I)*24.*30./1000.
 30         CONTINUE
            CAPCOS(K)=(1660.-120.*ALOG(CAP(K)*1000.))*CAP(K)*1000.
C
C       USE NPV ANALYSIS TO CHOOSE OPTIMUM SYSTEM SIZE

            ADJBAS(K)=CAPCOS(K)*(1.-0.5*(ITC+EITC))
            X(K)=PRINC*CAPCOS(K)
            NETSAV(K,0)=-CAPCOS(K)-INTCOS*CAP(K)*1000.+X(K)+
     1      (ITC+EITC)*CAPCOS(K)
            SUM(K)=NETSAV(K,0)
            DO 35 I=1,YRS
              IF(I.GT.INT(LYRS)) THEN
                ALP(I)=0.0
                LIP(I)=0.0
              ELSE
                ALP(I)=(1./LYRS + (1.-(REAL(I)-1.)/LYRS)*IRATE)*X(K)
                LIP(I)=ALP(I)-X(K)/LYRS
```

```
            ENDIF
            NETSAV(K,I)=(1.-TAXRAT)*(1.+GR)**I*(MAXSAV(K)-
     1      0.1*CAPCOS(K))+TAXRAT*(DEP(I)*ADJBAS(K)+LIP(I))-ALP(I)
            PV(K,I)=NETSAV(K,I)/(1.+DR)**I
            SUM(K)=SUM(K)+PV(K,I)
 35       CONTINUE
          NPV(K)=SUM(K)
          QNPV(K)=-NPV(K)/NETSAV(K,0)
C
C       FIND K WHICH GIVES LARGEST QNPV TO GET MAXIMUM IRR
C
          IF(QNPV(K).GT.LARGE) THEN
            LARGE=QNPV(K)
            KFLAG=K
            TFLAG=.TRUE.
          ENDIF
 15     CONTINUE
        IF(.NOT.TFLAG) THEN
          TYPE*,'NPV AT DISCOUNT RATE',DR,'IS NEGATIVE'
          TYPE*,'PLEASE ENTER A REDUCED RATE FOR EFFECTIVE'
          TYPE*,'OPTIMIZATION. PROGRAM TERMINATED.'
          GOTO 999
        ENDIF
C
C       NOW FIND OPTIMAL INTERNAL RATE OF RETURN
C
        RR(1)=0.001
        ROI=RR(1)*100.
        DO 50 M=1,1000
          RSUM=NETSAV(KFLAG,0)
          DO 60 N=1,YRS
            RPV=NETSAV(KFLAG,N)/(1.+RR(M))**N
            RSUM=RSUM+RPV
 60       CONTINUE
          IF(RSUM.GT.0.) THEN
            RR(M+1)=0.001+M*0.001
          ELSE
            ROI=RR(M)*100.
            GOTO 70
          ENDIF
          IF(RR(M).EQ.0.999) THEN
            TYPE*,'INTERNAL RATE OF RETURN EXCEEDS 99.9, ROI=99.9'
            ROI=99.9
            GOTO 70
          ENDIF
 50     CONTINUE
 70     CONTINUE
C
C       OUTPUT DATA AND CREATE OUTPUT FILE
C
        DO 80 K=1,12
          WRITE(6,101)K,ELREQ(K)
 101      FORMAT(' THE ELECT. REQ. FOR MONTH',I3,' =',F12.2,' MW-H')
          WRITE(6,102)K,HEREQ(K)
 102      FORMAT(' THE HEAT REQ. FOR MONTH',I3,' =',F15.2,' MILL-BTU')
          WRITE(6,103)K,KOUT(KFLAG,K)
 103      FORMAT(' THE ELECT. OUTPUT FOR MONTH',I3,' =',F12.2,' MW-H')
          WRITE(6,104)K,KSOUT(KFLAG,K)
 104      FORMAT(' THE HEAT OUTPUT FOR MONTH',I3,' =',F12.2,' MILL-BTU')
 80     CONTINUE
```

```
      WRITE(6,200)
200   FORMAT(///)
      WRITE(6,105)CAP(KFLAG)
105   FORMAT(' THE OPTIMUM SIZE OF PLANT =',F18.2,' MW')
      WRITE(6,106)ROI
106   FORMAT(' THE OPTIMAL RETURN ON INVESTMENT =',F9.2,' %')
      WRITE(6,107)YRS
107   FORMAT(' THE LIFE OF THE EQUIPMENT =',I16,' YEARS')
      WRITE(6,108)CAPCOS(KFLAG)
108   FORMAT(' THE CAPITAL COST OF THE EQUIPT. =',F9.0,' $')
      WRITE(6,109)PRINC
109   FORMAT(' THE FRACTION OF LOAN =',F21.2)
      WRITE(6,110)IRATE
110   FORMAT(' THE LOAN INTEREST RATE =',F19.2,' %')
      WRITE(6,111)NETSAV(KFLAG,0)
111   FORMAT(' THE CAPITAL OUTLAY IN YEAR 0 =',F13.2,' $')
      WRITE(6,112)LYRS
112   FORMAT(' THE LOAN REPAYMENT PERIOD =',F16.0,' YEARS')
      WRITE(6,113)TAXRAT
113   FORMAT(' THE TAX RATE =',F29.2,' %')
      WRITE(6,114)GRCOST
114   FORMAT(' THE GRID ELECTRICITY COST =',F16.2,' $/KW-H')
      WRITE(6,115)BBRATE
115   FORMAT(' THE BUY-BACK RATE =',F24.2,' $/KW-H')
      WRITE(6,116)GASCOS
116   FORMAT(' THE GAS COST =',F29.2,' $/MILLION-BTU')
      WRITE(6,117)INTCOS
117   FORMAT(' THE INTERCONNECTION COST =',F19.2,' $/KW')
999   STOP
      END
```

APPENDIX B

The following is a sample output from the program in Appendix A. The output reiterates the site energy requirements and the input parameters and shows the results of the analysis. Please note that month 1 corresponds to July, and month 12 corresponds to June.

```
THE ELECT. REQ. FOR MONTH  1 =        909.00 MW-H
THE HEAT REQ. FOR MONTH  1 =          7000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  1 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  1 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  2 =        821.00 MW-H
THE HEAT REQ. FOR MONTH  2 =          6400.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  2 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  2 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  3 =        850.00 MW-H
THE HEAT REQ. FOR MONTH  3 =          7000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  3 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  3 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  4 =        821.00 MW-H
THE HEAT REQ. FOR MONTH  4 =          8000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  4 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  4 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  5 =        674.00 MW-H
THE HEAT REQ. FOR MONTH  5 =         15000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  5 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  5 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  6 =        674.00 MW-H
THE HEAT REQ. FOR MONTH  6 =         17000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  6 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  6 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  7 =        821.00 MW-H
THE HEAT REQ. FOR MONTH  7 =         19000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  7 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  7 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  8 =        674.00 MW-H
THE HEAT REQ. FOR MONTH  8 =         19000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  8 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  8 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH  9 =        674.00 MW-H
THE HEAT REQ. FOR MONTH  9 =         19500.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH  9 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH  9 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH 10 =        850.00 MW-H
THE HEAT REQ. FOR MONTH 10 =         16500.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH 10 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH 10 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH 11 =        850.00 MW-H
THE HEAT REQ. FOR MONTH 11 =         10200.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH 11 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH 11 =       7057.95 MILL-BTU
THE ELECT. REQ. FOR MONTH 12 =        879.00 MW-H
THE HEAT REQ. FOR MONTH 12 =          8000.00 MILL-BTU
THE ELECT. OUTPUT FOR MONTH 12 =        842.50 MW-H
THE HEAT OUTPUT FOR MONTH 12 =       7057.95 MILL-BTU


THE OPTIMUM SIZE OF PLANT =                 1.17 MW
THE OPTIMAL RETURN ON INVESTMENT =     31.10 %
THE LIFE OF THE EQUIPMENT =                 15 YEARS
THE CAPITAL COST OF THE EQUIPT. =   950404. $
THE FRACTION OF LOAN =                   0.00
THE LOAN INTEREST RATE =                 0.00 %
THE CAPITAL OUTLAY IN YEAR 0 =     869405.31 $
THE LOAN REPAYMENT PERIOD =                 0. YEARS
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THE TAX RATE =	0.46 %
THE GRID ELECTRICITY COST =	6.41 ¢ /KW-H
THE BUY-BACK RATE =	6.00 ¢ /KW-H
THE GAS COST =	4.34 $/MILLION-BTU
THE INTERCONNECTION COST =	12.00 $/KW

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