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ECONOMIC COMPETITIVENESS OF FUEL CELL ONSITE INTEGRATED ENERGY SYSTEMS

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SUMMARY

The economic competitiveness of providing energy service to residential and commercial buildings by means of fuel cell onsite integrated energy systems (OS/IES) vis-a-vis conventional energy systems was evaluated. Fuel cell OS/IES's are defined as systems with an onsite fuel cell powerplant that provide some or all of the building's electrical needs while simultaneously using the fuel cell's byproduct thermal output, to the extent possible, for space heating or air conditioning. This definition encompasses a broad range of system design options such as stand-alone and grid-connected systems, a range of fuel cell powerplant capacities, various means of supplementing the fuel cell's thermal output, and the optional use of absorption chillers. In addition to these design options this study evaluated several system operating strategies that are possible within the various system design options. Each of the system designs and operating strategies was analyzed for three different buildings with each building assumed to be at three geographic (climatic) locations. The economic analyses were based on private ownership with both life-cycle cost and simple payback period used as figures of merit. Fuel and electricity costs covering the range of current and projected regional energy costs were assumed.

The results show that fuel cell OS/IES's are competitive with conventional, noncogenerating systems in most regions of the country even at projected 1985 energy prices. This conclusion is valid for all three geographic locations and all three buildings although all buildings are not equally competitive. The study shows that the best economic performance is achieved by grid-connected systems that effectively use the fuel cell's thermal output either by incorporating an absorption chiller in the system design or through the implementation of a suitable operating strategy. In addition, fuel cell powerplants should be sized approximately for the building's base electric demand. Various sensitivities to major assumptions are also evaluated.

INTRODUCTION

The DOE fuel cell program is supporting the development of two distinct classes of fuel cell powerplants. The first is the multimegawatt-sized powerplant aimed primarily at the electric utility and large industrial market. The second class of powerplant is in the size range of ten to several hundred kilowatts and is intended for onsite integrated energy systems (OS/IES's) serving residential and commercial buildings. This report addresses the economic competitiveness of the latter size class.

The multikilowatt-sized fuel cell powerplants are distinguished from their larger megawatt-sized cousins in several important respects. They are generally designed to operate at lower temperature and pressure, they have less fuels flexibility, and, of most significance to this study, they are designed to facilitate recovery of thermal energy produced as a byproduct to the generation of electricity. In the near term the primary fuel for multikilowatt-sized fuel cell powerplants will be either natural gas or methanol. In the long term it is expected that the fuels capability will be broadened to include a variety of fuels, including some derived from coal or biomass.

An OS/IES supplies all of a building's electrical, thermal, and air-conditioning needs. The term "onsite" refers to the generation of electricity within or near its point of use; "integrated" implies that the production of electricity and usable thermal energy are linked. At the heart of an OS/IES is an energy conversion device that simultaneously generates electricity and usable thermal energy from a fuel. Because a fuel cell powerplant is clean, quiet, and relatively free of vibration and exhibits overall electrical efficiency characteristics equal to or better than those of most competing systems, it is an ideal conversion device for onsite power generation. When fuel cell powerplants are used in this manner, their already good electrical efficiency is further enhanced by their ability to use the byproduct heat to satisfy other building energy demands. The most obvious uses for this byproduct heat are space heating, domestic water heating, and, less often, commercial activities requiring heat. In conjunction with an absorption chiller the heat can also be used to furnish some or all of the building's air-conditioning needs.

Although the fuel cell powerplant (or other power generation system) is central to an onsite integrated system, it must be augmented by additional heating and air-conditioning equipment in order to meet all of the building's energy needs. The onsite energy system may also be tied into the local electric utility grid, which can supply some of the onsite electrical demand or may purchase excess onsite generation. This multiplicity of equipment and the optional utility tie-in give rise to numerous system design options and operating strategies for an OS/IES. The options are particularly numerous for grid-connected systems, which permit the fuel cell powerplant to be arbitrarily sized from supplying only base load to supplying all of the onsite electrical needs. Many of these design options and strategies were evaluated in this investigation.

Fuel cell OS/IES's are of interest because, as compared with the more conventional energy supply options, significant energy savings are possible. Furthermore, because of their benign characteristics, fuel cells can contribute toward a cleaner environment. Their economic competitiveness, on the other hand, is less certain. Depending on a variety of factors such as building type and energy cost, fuel cell OS/IES's can range from being uneconomical to being very competitive (refs. 1 and 2).

The economic viability of fuel cell OS/IES's in residential and commercial buildings was examined for a variety of significant parameters. Particular emphasis was placed on the effect of fuel and electricity costs on system economics. The assumed fuel is natural gas. Special attention is paid to the optimum system design and operating strategy, the optimum fuel cell capacity, the influence of building energy-use characteristics, and the effect of different economic selection criteria. Finally, the effect of climatic variation on energy system competitiveness was briefly examined and other noneconomic factors that may influence OS/IES selection were touched on.

STUDY APPROACH

Overview

The basic approach in this study was to compare the economic performance of a large number of OS/IES's with the economic performance of two conventional systems. The OS/IES's evaluated encompass numerous design variations including alternative means of supplementing fuel cell thermal output, various types of air-conditioning equipment, a variety of electric utility interfaces, and a range of fuel cell powerplant sizes. The conventional systems consist of all-electric and gas/electric systems. Each of the systems was simulated over a 1-year time period to determine the size of all system components and to compute the corresponding capital cost. Also calculated are the annual on-site fuel consumption, operation and maintenance (O&M) costs, and, where appropriate, electricity purchases from or electricity sales to the utility.

Two widely used, but different, economic criteria were applied for the system comparison: life-cycle cost and simple payback period. Payback analysis takes a short-range viewpoint that tends to minimize risk; life-cycle cost analysis is economically more sophisticated but because of its long-range time horizon is subject to greater uncertainty. Both economic criteria were computed over a broad range of fuel and electricity costs.

For each combination of fuel and purchased electricity costs, the analysis identified the system that gives the lowest life-cycle cost. If the system is a fuel cell system, the analysis further identified the fuel cell powerplant size employed by the system, the life-cycle cost, and the life-cycle cost saving. Similar information was generated when using payback as the evaluation criterion. The optimum system, the best powerplant size, the life-cycle cost saving, and the shortest payback were mapped on plots of fuel cost versus the cost of purchased electricity. These maps are discussed in the results section of the report.

To assess the effect of different energy-use patterns, each system was simulated for three different buildings. Each building in turn was evaluated in three geographic locations in order to evaluate the effect of climatic conditions not only on the energy-use profile of each building, but also on the performance of energy system components such as heat pumps or chillers.

The simulated energy systems are made up of one or more heating and air-conditioning components. These components, in addition to the fuel cell, are represented by component models. The models describe the capital cost, the O&M cost, and the efficiency (or coefficient of performance) of each component.

Figure 1 presents a schematic overview of the approach. Subsequent sections of this report describe each aspect of this analysis in greater detail.

All of the analysis was performed with the aid of a computer model. The model consists of a number of individual programs. The first of these programs produces intermediate output that is used by subsequent programs for further analysis. All of the programs are designed to operate on the IBM

Time-Sharing System. Execution of the program is controlled from an online computer terminal. Most of the final output is graphic. The computer programs are not described in this report.

Buildings, Locations, and Energy Usage

Residential and commercial buildings encompass a large group of diverse structures each with its own unique energy-demand characteristic. To obtain some measure of the influence of energy-demand characteristics on fuel cell system economics, this study used three buildings and three geographic locations to evaluate fuel cell onsite integrated energy systems. The energy use of each building was calculated for each of the three geographic locations. The building construction characteristics, the occupancy patterns, and the energy use of major appliances were assumed to be identical for all locations; only weather conditions were varied between locations.

These same buildings, locations, and hourly energy demand data were first used in a previous study reported in reference 2. The reference provides more detailed background on the selection and characterization of the buildings, their locations, and the computation of the energy demands.

Building description. - The three buildings used in this study included one residential and two commercial buildings: an apartment building, a retail store, and a hospital. In floor area the buildings range from approximately 1900 to 11 000 m^2 (20 000 to 120 000 ft^2).

The apartment building consists of 24 dwelling units, each with 2 bedrooms, living room, dining area, kitchen, bath, laundry, and outside entry. The retail store is composed of two distinct areas: the larger area, occupying approximately 75 percent of the available floor area, is used for retailing and administrative operations and includes a small kitchen; the remaining 25 percent consists of the stockroom and receiving departments. The hospital is a 120-bed facility with total floor area divided as follows: 38 percent for patient-care rooms, 12 percent for the mechanical and electrical equipment room, and 50 percent for ancillary services. The lower two floors are larger than the upper levels.

All three buildings are existing buildings. The actual physical and construction characteristics, with some modifications, were used to determine each building's energy requirements. The major building characteristics are summarized in table I.

Geographic locations. - Three geographic locations - Chicago, Washington, D.C., and Dallas - were selected to represent the range of climatic conditions found in the United States. Although the study buildings are actually located in eastern states, these three locations were used to determine each building's energy needs.

The climatic conditions at the three locations were characterized by the "test reference year" (TRY) weather data (ref. 3). Ambient dry-bulb temperatures from the TRY data are summarized in figure 2.

End-use energy demands. - The end-use energy demands consist of basic electrical demands (exclusive of electrical needs for heating and air-conditioning), space heating demands, air-conditioning demands, and energy needs for domestic water heating. These end-use energy demands were generated for each hour of every fifth day of the test reference year and are the primary input to the hourly simulation of each energy system.

The energy-demand profiles were computed for each building by using the AXCESS computer program (ref. 4). Input to the AXCESS program consists of physical building characteristics, assumed occupancy patterns, assumed usage patterns for various appliances and equipment, and pertinent weather data. Weather conditions, including ambient temperatures and insolation, were simulated by using the TRY weather data for the location of interest.

Figures 3 to 5 summarize the energy-demand data for each of the study buildings. Note that there are substantial differences among the buildings not only in terms of total energy demand, but also in the load factors, the thermal-to-electrical loads ratios, and the cooling-to-electrical load ratios. In these figures the thermal demand refers to the sum of the space heating and domestic water heating demands. The electrical demand is only the electricity for lights, appliances, etc., and does not include electrical needs for heating or air-conditioning.

Figure 3 shows the annual, cumulative end-use energy demands. The total end-use energy demanded by the hospital is more than 25 times the energy demanded by the apartment building. Because of the large lighting load of the retail store, electrical needs dominate its end-use energy demands and only minimal space heating is required. For the apartment and the hospital the total energy demand is more evenly split among the three components. Climatic variations do not have a major effect on the electrical demand. However, moving from a cold to a warm climate does show a shift from heating to air-conditioning.

Figure 4 plots the range of hourly values of thermal-to-electrical and cooling-to-electrical load ratios. Also shown is the annual average of these two ratios. The variation in these ratios is much greater between buildings than between geographic locations.

Figure 5 shows the load factors for each end-use energy demand. Most significant are the load factors for the hospital, which are generally higher than those for either of the other two buildings.

Energy Systems Description

A large number of energy systems were simulated and analyzed. The systems can be broadly classified into conventional noncogenerating systems and fuel cell OS/IES's. The conventional systems served as standards against which the fuel cell onsite systems were measured. Overall, 2 conventional systems and 11 fuel cell systems, not counting variations in fuel cell size, were simulated.

All systems are designed and operated in such a manner that the onsite system plus the optional electric utility grid connection meets all of the building's electrical, heating, cooling, and domestic water heating needs for every hour of the year. All of the energy systems were assumed to have a cooling tower to reject heat. The cooling tower is not explicitly shown in the system diagrams that follow. All of the energy systems are described in more detail in the following sections.

Table II summarizes the most significant systems characteristics of the 13 energy system classes used in this analysis.

Conventional energy systems. - The two conventional energy systems, an all-electric and a gas/electric system, are shown schematically in figure 6. In the all-electric system all of the building's energy demands are satisfied with electricity purchased from the electric utility grid. In the gas/electric system space heating and domestic water heating demands are met by burning fossil fuels; purchased electricity is used to furnish basic electrical and air-conditioning requirements.

Fuel cell onsite energy systems. - The fuel cell onsite systems cover a broad range of system design options and operating strategies. Included are

(1) Variations in the electric utility interface used
(2) Systems that use electric heat pumps (heat only) to supplement the fuel cell thermal output and systems that use gas-fired boilers or furnaces
(3) Systems that use electric compression chillers, absorption chillers, or both for air-conditioning
(4) Grid-connected systems with installed fuel cell capacities varying by an order of magnitude; fuel cell size also affects the size of other system components
(5) Systems in which the fuel cell matches the building's electrical demand (to the fuel cell capacity), systems in which the fuel cell's thermal output follows the thermal demand (to the fuel cell thermal capacity), and systems in which the fuel cell operates at constant full-load output

Including variations in fuel cell capacity, as many as 74 onsite fuel cell systems (table II) were analyzed for each building location. However, during the simulation process various conditions can arise that cause certain systems to be rejected. Thus, the actual number of system designs, including variations in fuel cell size, that survived the simulation process was usually less than 74. Forty-five to 60 systems was typical. Although the number of systems simulated was large, by no means did it encompass the whole range of design options and operating strategies.

The fuel cell onsite energy systems fall into three major categories according to the type of utility interface used:

(1) Stand-alone systems
(2) Buy-only grid-connected systems
(3) Buy/sell grid-connected systems
    (a) With constant fuel cell output
    (b) Thermal load following

Stand-alone systems: The four stand-alone systems (systems 1 to 4, table II) are depicted schematically in figure 7. These systems were assumed to operate in such a manner that the heating, cooling, and electrical demands of the building are precisely met at all times. For all four systems there are times when the fuel cell's thermal output cannot be used; at such times the excess thermal output is vented to the atmosphere by means of the cooling tower. Systems 1 and 2 can meet the end-use energy demands in more than one mode of operation. For these two systems an operating strategy based on linear programming theory was developed that selects the mode of operation to minimize fuel consumption. This operating strategy was used for the simulation of these two systems. Systems 3 and 4 can satisfy the output requirements in one way only. For system 3 the fuel cell's electrical output was adjusted to satisfy cooling and electrical demands. The resultant cogenerated thermal output was applied toward the thermal demand. When the thermal demand exceeds the fuel cell's thermal output, the boiler supplies the deficit. In system 4 the fuel cell's electrical output follows the building's electrical demand and the cogenerated thermal output provides heating and cooling. Thermal deficits are supplied by the boiler.

All four stand-alone systems were simulated for only one fuel cell size for each building location. The size selected is the minimum size required to meet the peak electrical load on the fuel cell. For costing purposes it was assumed that an additional 20 percent onsite fuel cell capacity reserve was installed. This total capacity, if suitably distributed among a sufficiently large number of individual powerplants, was shown in reference 2 to be the approximate onsite capacity needed to achieve an electrical reliability comparable to that of the average electric utility system.

Grid-connected systems: The grid-connected systems offer considerably more design flexibility than the stand-alone systems. In particular, a grid connection permits the fuel cell powerplant to be arbitrarily sized with the only limit being the sizes available from fuel cell powerplant suppliers. For this analysis, however, it was assumed that no such limitations exist and that any fuel cell size is acceptable. Consequently, all grid-connected systems were simulated for a range of fuel cell capacities. Ten fuel cell sizes were used; the sizes were the same for all grid-connected systems for any one building location.

The fuel cell sizes were selected by the computer model at the start of the simulation and were not changed thereafter. The largest size was based on an approximation of the peak electrical loads to satisfy base electrical and cooling demands. The smallest fuel cell size is one-tenth the largest, with the other eight fuel cell sizes equally spaced between the two extremes. In this analysis the sizes for Washington, D.C., are 9 to 90 kW for the apartment building, 100 kW to 1 MW for the store, and 200 kW to 2 MW for the hospital. The sizes are somewhat different for the other locations. The fuel cell powerplant size also affects the size of other system components such as the heat pump, the boiler, and the absorption chiller. The size of the absorption chiller, in turn, affects the size of the compression chiller.

The electrical service reliability of a grid-connected system will always be greater than the reliability of the utility grid alone.

Buy-only grid-connected systems: These systems (configurations 5 and 6, table II) are illustrated in figure 8. System 5 has a heat-only heat pump to supplement the fuel cell's thermal output; system 6 uses a boiler or furnace. As discussed above, each of the two systems shown is simulated for 10 fuel cell sizes.

The simulation of system 5 assumes that the fuel cell's electrical output follows the building's total electrical needs up to the fuel cell's capacity. The total electrical needs include the base electrical requirements and the electricity required by the heat pump and the compression chiller. At the same time the simulation ensures that the combined thermal outputs of the fuel cell and heat pump exactly match the thermal demand except when the fuel cell's thermal output is greater than that required. In this case, the excess thermal output is rejected to the atmosphere. Any onsite electrical requirements that exceed the fuel cell's capacity are filled by electricity purchased from the electric utility grid.

System 6 assumes that the fuel cell's electrical output matches the electrical demand, including that needed for air-conditioning, but does not exceed the fuel cell's capacity. If the total electrical demand exceeds the fuel cell's capacity, the shortfall is purchased from the electric utility. Whatever the fuel cell's electrical output, the corresponding thermal output is compared with the thermal demand. Deficits are made up by the boiler and excesses are rejected to the atmosphere.

For both systems 5 and 6, if any of the preselected fuel cell sizes are so large that at no time throughout the year electricity is purchased from the electric utility, the system was excluded from further analysis. Thus, although 10 variations of systems 5 and 6 were normally simulated, the number of systems surviving the simulation might be less than 10.

Buy/sell grid-connected systems: The buy/sell grid-connected systems fall into two groups. The first consists of systems in which the fuel cell operates at constant full-load output at all times. The four systems (configurations 7 to 10, table II) in this group are illustrated in figure 9. The second group consists of thermal-load-following systems represented in this analysis by the single system (configuration 11, table II) shown in figure 10.

The operating strategy for the systems in the first group is as follows: the fuel cell operates continuously at full load and produces constant electrical and thermal outputs. The thermal output is used on site to the maximum extent possible. Any excess thermal output is rejected. The fuel cell's electrical output is applied on site. If the fuel cell's electrical output is insufficient to meet the onsite needs, power is purchased from the electric utility. Conversely, excess fuel cell output is sold to the electric utility.

Except for system 9 the fuel cell's thermal output can only be used to satisfy heating demands. In system 9 the thermal output is first applied against heating demand and then any remainder is used by the absorption chiller. In no case is thermal output from the boiler used by the absorption chiller.

If, in system 7 or 8, the fuel cell is sufficiently large such that the boiler or heat pump is no longer required to supply supplemental heat, the system essentially degenerates to system 10 and was therefore rejected. Since it does not contain a supplemental heat source, system 10 requires a fuel cell sufficiently large to supply all thermal requirements. Systems with powerplants too small were rejected.

The thermal-load-following system is operated in such a manner that the fuel cell's thermal output always matches the building's thermal needs up to the maximum fuel cell thermal output. Any additional thermal requirements are supplied by the boiler. The fuel cell's electrical output is determined entirely by the thermal requirements. Excesses or deficits of electricity are compensated for by selling or buying power, respectively, from the electric utility grid. System 11 is the only system in which no usable thermal energy from the fuel cell is ever rejected to the atmosphere.

Component Models

All of the energy systems described in the previous section consist of three or more of the following components:

(1) Fuel cell powerplant
(2) Heat-only heat pump
(3) Electrically driven compression chiller
(4) Absorption chiller
(5) Boiler or furnace
(6) Cooling tower

Each of these components is represented by a model that gives the capital cost, the efficiency (or coefficient of performance), and the O&M cost for that component. The same representation for each component is used in all of the systems that are simulated. The following paragraphs describe the key characteristics of the component models. Numeric data used in these models are summarized in appendix A.

Capital cost model. - The capital cost of each component is represented by as many as three equations of the following form:

$$\text{Installed capital cost} = C(\text{Component size})^{x}$$

where each equation is valid over a certain range of the component size. For most components a single equation was adequate. The constants C and x were determined to approximate the installed capital cost data from several sources (refs. 2, 5, and 6) converted to 1981 dollars.

The capacity of chillers and heat pumps was assumed to vary with ambient temperature. The capital cost of these components is based on the capacity at 80° F for chillers and at 70° F for the heat pump.

Efficiency (coefficient of performance (COP)) model. - The efficiency (or COP) model computes the required energy input to each component given the part-load output and the ambient temperature. The input is computed as follows:

$$\text{INPT} = \text{PCT} \times \text{FLIN} \times \text{CAP}$$

where

FLIN full-load energy input expressed as a percentage of capacity

CAP component capacity (i.e., its rated output)

PCT energy input at any load expressed as a percentage of full-load input

In general, the model assumes that FLIN is a function of ambient temperature and PCT is a function of part-load output. Although all components in this analysis were modeled to permit efficiency variation with output, only the heat pump and compression chiller models utilized the capability to vary component performance with temperature. For the heat pump and the two chillers the full-load output (i.e., the capacity) is derated with ambient temperature. Part-load output is expressed as a percentage of derated full-load output. A table look-up procedure was used to determine both FLIN and PCT; intermediate values were obtained by interpolation.

The efficiency values for each component, except the cooling tower, that resulted from the above procedure are shown in appendix A. No efficiency model was required for the cooling tower.

Operation and maintenance (O&M) cost model. - The O&M cost for each component (except the cooling tower) was assumed to consist of a fixed and a variable cost component and is computed as follows:

$$\text{O\&M} = \text{Fixed O\&M} + \text{Variable O\&M}$$

$$= R \times (\text{Installed cost}) + V \times (\text{Cumulative annual output})$$

The values of R and V were selected such that at a 50-percent load factor

(1) Fixed O&M cost equals variable O&M cost
(2) Total O&M cost equals the O&M costs given in reference 5

The O&M cost for the cooling tower was assumed to be entirely fixed (i.e., $V = 0$). The O&M cost for the entire energy system is the sum of the O&M costs for the individual components. The O&M cost for the fuel cell powerplants does not include an allowance for periodic stack replacement. Stack replacement costs were accounted for separately as discussed under the description of life-cycle cost analysis and in appendix B. O&M cost data are given in appendix A.

System Simulation

The operation of each of the energy systems described in the previous section was simulated for each hour of every fifth day of the year. Inputs to the simulation are the hourly values for the end-use energy demands E, H, and C and the ambient dry-bulb temperature, where

E building's electrical needs for lights, appliances, etc., but not including electrical needs for space heating, domestic water heating, or cooling

H building's total thermal demand for space heating and domestic water heating

C building's total cooling demand

The ambient temperatures are the same as those used by the AXCESS computer program to compute end-use demands as described earlier.

The simulation proceeded hour by hour throughout every fifth day of the year. All of the energy systems were simulated in such a manner that all end-use demands were satisfied each hour. Throughout, the computer model kept a running total of the amount of fuel consumed and, as appropriate, the amount of electricity purchased from and sold to the utility grid for each energy system.

The simulation model also provided a continuous check on the capacity of each onsite component. If at any time throughout the year the installed capacity of any component (except the fuel cell for grid-connected systems) was found to be too small, that component was adjusted upward in size and the simulation was continued. The simulation for the entire year was repeated for any system that required any size adjustment during the year. At year's end, each component was examined to determine if it was oversized. If it was, its size was reduced and the energy system's operation was resimulated for the entire year. The simulation was not repeated for systems that required neither an upward nor downward size adjustment in any of their components.

When all energy systems had been simulated for an entire year without the need to change component sizes, the process was complete. Output for the simulation procedure consisted of total onsite energy system capital costs, annual fuel consumption, annual electricity purchases and sales (both segregated into onpeak and offpeak components), peak electrical demand imposed on the electric utility, and annual O&M costs. These outputs are intermediate results used, in part, in subsequent economic analyses and are not shown in this report. In addition the model provided a variety of other output that was useful in interpreting the results.

As part of the simulation various assumptions were made, both implicitly and explicitly. The more significant assumptions are as follows:

(1) All of the fuel cell's thermal output is obtained at a single temperature.
(2) The quality of the fuel cell's thermal output is adequate for space heating, for domestic water heating, and for absorption chilling.
(3) The boiler (or furnace) operates on the same fuel as the fuel cell.
(4) Domestic water is heated by the building heating system.
(5) All energy systems are centralized systems.
(6) The heat pump includes an electric resistance heater for low-temperature operation; the capital cost model and the COP model for the heat pump are based on this assumption.
(7) The compression chiller and absorption chiller capacities are derated with increasing ambient temperature; capital cost is based on capacity at rated temperature.
(8) Heat pump capacity is derated with decreasing temperature down to approximately 35° F; part-load output used to compute COP is based on derated capacity; capital cost is based on capacity at rated temperature.

Economic Analysis

The systems simulation produces all of the data that summarize the design and performance of each system and that are necessary to perform economic analysis of the systems. The information used for the economic analysis consisted of the following:

(1) Energy system initial capital cost
(2) Energy system effective capital cost (The effective capital cost is the initial capital cost adjusted to account for stack replacement costs and is used in the life-cycle cost analysis; see Appendix B.)
(3) Quantity of fuel purchased per year
(4) Quantity of electricity purchased per year
(5) Quantity of electricity sold to the utility per year
(6) Annual O&M cost

Although the electricity purchases and sales were segregated into on-peak and off-peak values, for this economic analysis electric rates that are independent of time of use were assumed. The simulation model also provided data to enable the approximation of demand charges. However, for the purpose of this report, a simplified flat-rate electricity cost was assumed.

Two commonly used economic parameters were used throughout this study to evaluate the competitiveness of OS/IES's: life-cycle cost and payback period. These two parameters are, in many respects, very dissimilar and are representative of divergent philosophies regarding the evaluation of capital investments. Life-cycle cost is a conceptually sound method based on the concept of time-value of money and takes into account all major economic factors over the life of the investment. Because of the long-term nature of this analysis and the associated uncertainties introduced by long-range projections, decisions based on life-cycle cost carry with them an element of risk. Payback, on the other hand, is a very simple method designed primarily to reduce risk by emphasizing quick recovery of initial investment capital. Computational procedures for both parameters are described below.

All economic analyses presented in this report were performed over a range of both fuel and electricity prices. The analysis implicitly assumes that capital costs are unchanged as fuel and electricity prices vary.

<u>Life-cycle cost analysis</u>. - Life-cycle cost is defined as the minimum uniform annual revenue required over the life of the energy system to recover all energy system costs including the minimum acceptable return on any equity capital invested. Included in the energy system costs are all of the following:

(1) Recovery of the initial capital investment
(2) Costs of purchased fuel and electricity minus proceeds from the sale of electricity
(3) O&M cost
(4) Cost of periodic fuel cell stack replacement
(5) Interest expense on portion of capital investment that is debt financed
(6) Minimum acceptable return on equity capital used to finance the capital investment
(7) Federal and local income taxes on equity earnings
(8) Insurance and other taxes on the physical plant

The life-cycle cost for each energy system was computed as follows:

$$LCC = (C_{EFF} \times FCR) + (CSTE \times LEV_E \times PE) + (CSTF \times LEV_F \times PF)$$
$$- (CSTE \times LEV_E \times RXI \times SE) + (O\&M \times LEV_{OM})$$

where

LCC	life-cycle cost, \$/yr
C_{EFF}	onsite system effective capital cost, dollars
FCR	fixed charge rate
CSTE	cost of electricity in first year of system operation, \$/10^6 Btu
LEV_E	levelizing factor for purchased and sold electricity
PE	purchased electricity, 10^6 Btu/yr
CSTF	cost of fuel in first year of system operation, \$/10^6 Btu
LEV_F	levelizing factor for purchased fuel
PF	purchased fuel, 10^6 Btu/yr
RXI	ratio of selling price to purchase price of electricity
SE	electricity sold to the electric utility, 10^6 Btu/yr
O&M	O&M costs in first year of system operation, \$/yr
LEV_{OM}	levelizing factor for O&M costs

C_{EFF}, PE, PF, O&M, and SE are a direct output of the systems simulation. The fixed charge rate (ref. 7) and the levelizing factors (ref. 8) are constants with the following values:

$$\begin{aligned} FCR &= 0.1672 \\ LEVE &= 2.107 \\ LEVF &= 2.107 \\ LEVOM &= 1.7848 \end{aligned}$$

The assumptions on which these values are based are discussed below. RXI was assumed to be 0.60; a sensitivity analysis was performed to examine the effect of this value on the results. In this analysis, 1981 dollars were used throughout.

The computation of the constants FCR, LEV_E, LEV_F, and LEV_{OM} was based on the following assumptions:

(1) All system components have a 20-year life (except the fuel cell stack, which has a 5-yr life).

(2) The inflation rate is 8 percent per year throughout the energy system life, the cost of debt is 12 percent per year, and the minimum acceptable return on equity capital is 15 percent per year.

(3) The energy system is financed with 50-percent debt and 50-percent equity capital.

(4) The composite Federal, state, and local income tax rate on equity earnings is 50 percent; the investment is depreciated for tax purposes over 10

years by using the sum-of-years-digits method; the investment qualifies for a 10-percent investment tax credit.

(5) Fuel and electricity costs will rise at the rate of 10 percent per year throughout the 20-year energy system life; this means that over the energy system life, fuel and electricity costs will rise 44 percent in constant dollars.

(6) O&M costs will rise 8 percent per year over the 20-year time horizon.

(7) Insurance and other taxes are 3 percent of the initial capital investment.

The life-cycle cost was computed for all or some subset of the 50 to 70 energy systems simulated. These calculations were carried out for all combinations of fuel and electricity costs over a specified range. For energy systems that sell more power to the utility than they purchase, the life-cycle cost may become negative particularly at high electricity prices and low fuel costs.

Life-cycle cost saving. - Life-cycle cost saving, rather than life-cycle cost, is the parameter displayed in the results section of this report. It gives the cost saving possible with fuel cell OS/IES's expressed as a percentage of the life-cycle cost of the best conventional system. It is defined as follows:

$$\text{Life-cycle cost saving} = 1.0 - \frac{LCC_{FC}}{LCC_{REF}}$$

where

LCC_{FC} lowest life-cycle cost of all fuel cell onsite systems

LCC_{REF} lowest life-cycle cost of the two reference (i.e., conventional energy systems)

LCC_{FC} and LCC_{REF} are computed as discussed in the previous section and both are a function of fuel cost and electricity cost.

Payback analysis. - Payback, as used in this analysis, is defined as

$$PB_i = \frac{\text{Incremental capital cost}}{\text{First year's operating cost saving}} = \frac{C_i - C_R}{S_R - S_i}$$

where

PB_i simple payback of system i, yr

C_R capital cost of reference system, dollars (the reference system is the lowest capital cost system)

C_i capital cost of system i, dollars

S_R first year's operating cost of reference system, \$/yr

S_i first year's operating cost of system i, \$/yr

The operating cost is defined as

$$S = (CSTE \times PE) - (CSTE \times RXI \times SE) + (CSTF \times PF) + O\&M$$

where the symbols are defined as under life-cycle cost.

Since only the first year's operating cost saving was used, the result is independent of inflation and fuel cost escalation rates. This also resulted in a conservative estimate of the payback period since higher operating costs savings in subsequent years would give a shorter payback period than that computed here.

Energy costs. - All of the results are displayed for a range of both natural gas and electricity costs. To assist the reader in interpreting the results, both historical and projected energy prices are provided in this section. Figure 11 plots the locus of the national average prices of natural gas and electricity as delivered to residential customers over the years 1967 to 1981. Also shown are the projected prices for 1985, 1990, and 1995. All prices are in 1981 dollars (refs. 9 to 12). Figure 12 shows the average regional natural gas and electricity prices in 1981. The regions are the 10 DOE regions. Similarly, figure 13 shows the average projected 1985 regional costs (ref. 11). All prices are in 1981 dollars.

Figures 11 to 13 are each marked with a point labeled "reference point." This point represents a natural gas cost of $\$6.5/10^6$ Btu and a purchased electricity cost of $\$20/10^6$ Btu. This point is near the 1985 projected national average prices. Most of the results shown in subsequent sections of this report are plotted on the same axes as those used in figures 11 to 13. This facilitates superimposing the energy cost data on the results. In addition, the reference point is shown on all of the results to aid in their interpretation.

RESULTS

The results of the previously described economic analysis of onsite integrated energy systems are described in three parts.

Part 1 focuses on the economic competitiveness of fuel cell OS/IES's in the three study buildings in Washington, D.C., using first life-cycle cost and then payback as the evaluation criterion. Throughout this part, all fuel cell systems included in this analysis are competing against each other and against the conventional systems. The results show the economic performance of the best fuel cell system as compared with that of the best conventional system for all reasonable combinations of fuel and electricity costs. Thus, the economic benefits shown in this part are the maximum possible given the fuel cell systems considered in this study. Part 1 continues with a discussion of fuel cell system designs and fuel cell powerplant sizes that optimize the economic performance of fuel cell OS/IES's.

Part 2 compares the economic performance of nonoptimal systems with the economic performance of the best systems discussed in part 1 to evaluate the penalty associated with the use of nonoptimal system designs. For this analysis the fuel cell systems were divided into groups primarily on the basis of the type of utility grid connection used.

Part 3 is a parametric analysis that examines the effect of the various factors on the results. The emphasis is on parameters about which there is considerable uncertainty. Included here are the price obtained for selling electricity to the electric utility, the fuel cell powerplant installed cost, and the ability to operate an absorption chiller by using the quality of thermal output available from a fuel cell powerplant. Other things considered in this part include the effect of climate and limiting the availability of small fuel cell powerplants.

The results were based on the economic evaluation of a maximum of 58 energy systems for the apartment building, 50 energy systems for the store, and 48 for the hospital.

The figures that accompany the results section of this report frequently refer to specific energy systems or groups of energy systems (defined later). To assist the reader in interpreting of the results, the systems or groups are identified by a number that refers to the numbers given in tables II and III, as appropriate. The number is followed by a sequence of mnemomics enclosed in parentheses, which is a shorthand method to identify the systems or groups without the need to refer to the tables. Thus in the figures systems are identified as

System N(A/B/C/D)

where

N system number as defined in table II

A type of grid connection:
- SA stand alone
- BO grid connected, buy only
- BS grid connected, buy/sell

B operating mode:
- ELF electric load following
- CFL constant, full-load operation
- TLF thermal load following

C use or nonuse of an absorption chiller:
- N without absorption chiller
- Y with absorption chiller

D supplemental heat source:
- HP heat pump
- B boiler
- N none

Groups are defined as

Group N(A/B/C)

where N is the group number as defined in table III and A, B, and C are as defined above.

Part 1: Optimal Fuel Cell OS/IES

Maximum life-cycle cost savings. - The life-cycle cost savings (in percent) for the three buildings used in this study are shown in figure 14. The savings are based on comparing the lowest-life-cycle-cost fuel cell system with the lowest-life-cycle-cost conventional system for every combination of fuel cost and electricity cost shown. The identity of the lowest-life-cycle-cost system, conventional or fuel cell, changed with fuel and electricity costs. Therefore, different systems are compared at various points throughout the figure. The lowest-life-cycle-cost fuel cell systems and their associated powerplant sizes are described later in this part of the results section.

The solid line in figure 14 labeled the "break-even line" represents those combinations of fuel and purchased electricity costs at which the life-cycle cost of the best fuel cell OS/IES equals the life-cycle cost of the best conventional system. The region below the break-even line represents the fuel and electricity costs for which at least one fuel cell system has a lower life-cycle cost than the best conventional system. If "competitive" is defined as having a lower life-cycle cost, fuel cell systems are competitive below the break-even line; they are not competitive above.

A measure of how competitive fuel cell systems are is indicated by the dashed lines. Each dashed line represents the locus of points having a fixed life-cycle cost saving as labeled. Below each dashed line the savings are greater and above they are less than the amount indicated.

To facilitate comparison of the three buildings, a composite of figures 14(a), 14(b), and 14(c) is given in figure 15. This figure shows only the break-even and 30-percent saving lines.

Comparing figures 14 and 15 with figures 11 to 13 clearly demonstrates that, based on life-cycle cost analysis, fuel cell OS/IES's compete with conventional energy systems for a wide range of energy prices encompassing nearly all current as well as the 1985 forecast prices. Only the lowest electricity costs found in this country appear to favor conventional energy systems. Comparing the break-even lines of figure 15 shows that the apartment building is attractive for onsite energy systems over the broadest range of energy prices. However, comparing the 30-percent saving lines shows that the hospital realizes the greatest life-cycle cost saving over most of this range.

The results of figure 15 indicate that buildings cannot be ranked easily from best to worst as a site for onsite energy systems. Instead, the ranking is a function of energy cost. To illustrate, consider the two combinations of natural gas and electricity costs labeled x and y in figure 15. At point x the best fuel cell system for the hospital is breaking even with the best conventional system; for the apartment, fuel cell systems are better than conventional systems; and for the store, fuel cell systems do worse than conventional systems. Thus, at point x, the apartment has the highest life-cycle cost saving, followed in order by the hospital and the store. At point y, on the other hand, the hospital has the highest life-cycle cost saving, the store is still the lowest, and the apartment is between the two.

Minimum payback periods. - Each energy system was compared with the lowest capital cost system by using simple payback as the yardstick. In all cases the lowest capital cost system was one of the conventional systems.

Payback period is the number of years required to recover any investment above the minimum possible investment, based on first year's operating cost saving, and was computed as discussed earlier in this report. Systems having a payback period of 5 years or less were assumed to be competitive with conventional systems, and of those the one with the shortest payback period was judged to be the most competitive. The shortest achievable payback periods and how they vary with energy costs are shown in figure 16. The lower right section of each graph represents the region in which fuel cell OS/IES's are competitive as defined here. The minimum payback period is as labeled. If the maximum acceptable payback period of a potential investor in onsite energy systems is less than 5 years, the competitive region will be considerably smaller. Comparison with figures 11 to 13 shows that, for a five-year payback period or less, fuel cell OS/IES's are acceptable for most current or projected energy prices.

Optimum system design. - The previous two sections have focused on the economic competitiveness of the best OS/IES's as a function of natural gas and electricity costs but did not define the characteristics of the optimum system. First life-cycle cost saving and then payback period was used as a measure of goodness. This section identifies the energy system designs that produced the results shown in figures 14 to 16; the following section focuses on the optimum fuel cell powerplant size.

The fuel cell OS/IES designs that result in the lowest life-cycle cost (lower than that of the lowest conventional system) are shown in figure 17. The system designs having the shortest payback period are shown in figure 18. Note that which system is optimum is a function of energy costs and differs for each building. From the two figures it can be seen that for the range of current and projected energy prices the most economical fuel cell systems are grid-connected systems that buy from and sell to the local electric utility grid. Of these, the systems with an absorption chiller or that are operated in a thermal-load-following mode predominate. (Systems with absorption chillers or thermal-load-following systems make more effective use of the fuel cell's thermal output than do the other systems included in this study.)

Optimum powerplant size. - The powerplant sizes that were used with the system designs shown in figures 17 and 18 and those that resulted in the best economic performance given in figures 14 to 16 are shown in figures 19 and 20. These powerplant sizes are not true mathematical optimums but rather the best powerplant sizes from among the 10 sizes simulated for each grid-connected system or the sizes required by the stand-alone systems. Figure 19 gives the fuel cell sizes that resulted in the lowest life-cycle cost; figure 20 is based on minimum payback.

To put these powerplant sizes in perspective, consider that the peak electricity usages per hour for the conventional all-electric systems are 98 kW for the apartment, 1.1 MW for the store, and 2 MW for the hospital.

Figure 19 shows that for minimum life-cycle cost the optimum powerplant size is a strong function of energy costs. At or near the break-even line the optimum powerplant size is usually the smallest simulated. The optimum powerplant size increases as electricity cost increases for a fixed natural gas cost. In the range of projected 1985 energy costs the optimum powerplant size would generally be much smaller than the peak electrical load of the building if an all-electric, conventional energy system were used.

Minimizing payback periods calls for even smaller powerplant sizes than does maximizing life-cycle cost saving. Except for the hospital, the smallest powerplant size simulated was optimal over the entire energy cost range.

Summary of results for optimum OS/IES. - To this point it has been demonstrated that fuel cell onsite integrated energy systems are competitive for prevailing energy costs in most regions of the country whether life-cycle cost or payback period is used for evaluation. The optimum system designs are those grid-connected systems that make good use of the fuel cell's thermal output (i.e., thermal-load-following systems or systems with absorption chillers). Both types of systems purchase electricity from the utility grid when the demand exceeds the onsite capability, and both sell electricity to the utility grid when an excess is generated onsite. The optimum fuel cell size is well below the building's peak electrical load (i.e., the fuel cell is sized to operate at a high load factor). These results are generally true for all three buildings. Although the results have been demonstrated only for Washington, D.C., it will be shown in later sections that the results are not significantly different for other climates.

Example. - To illustrate the results from the preceding sections, consider the following example: Assume an apartment building at a location where natural gas costs $\$6.50/10^6$ Btu and where electricity costs $\$20.00/10^6$ Btu. These costs correspond to those of the reference point. Also assume that excess power generated on site can be sold to the electric utility for $\$12.00/10^6$ Btu (RXI = 0.6), that the building's energy demands are comparable to those of the study apartment building, and that the climate is similar to that of Washington, D.C. For this case the results show that it would clearly be to the benefit of the building's owner to install a fuel cell OS/IES. In so doing, the owner would realize an average energy cost saving of slightly more than 10 percent per year (fig. 14(a)) over the life of the system. Figure 17(a) shows that to realize these savings the owner would have to install system 9 (buy/sell grid connection with absorption chiller) and operate the fuel cell at a constant full-load output. The size of the fuel cell powerplant would have to be 27 kW (fig. 19(a)). The use of any other system or any other fuel cell powerplant size would result in lower life-cycle cost savings.

On the other hand, to recoup the incremental investment in the shortest time possible, the owner would install system 8 (fig. 18(a)) with a 9-kW powerplant (fig. 20(a)) and again operate the fuel cell at constant full-load output. The incremental investment would be recovered out of operating cost savings in approximately 3-1/2 years (fig. 16(a)).

Changing gas and electricity prices affects the results significantly. Assuming gas and electricity prices of $\$7.00/10^6$ Btu and $\$30/10^6$ Btu (typical of New England in 1985) gives the apartment building owner a slightly less than 30-percent life-cycle cost saving, still using system 9, but with a 45-kW fuel cell powerplant.

Part 2: Economic Competitiveness of Nonoptimal Systems

The previous discussion identified the "best" onsite integrated energy systems and the associated life-cycle cost savings and payback periods. The best systems were generally buy/sell grid-connected systems and either had an absorption chiller to make effective use of the fuel cell's thermal output or the fuel cell was operated in a thermal-load-following mode. The analysis did not reveal how well buy-only grid-connected systems or stand-alone systems perform in comparison with the optimal systems. Nor did it address the question of what penalty is paid for not utilizing the fuel cell's thermal output as effectively as possible with either of the two methods mentioned above. This section of the report focuses on nonoptimal fuel cell systems and compares them with the conventional energy systems and with the optimal fuel cell systems.

To achieve this objective, the fuel cell systems were categorized into six groups on the basis of grid-connection type, the presence or absence of an absorption chiller, and the operating mode. Each group was then allowed to compete, independent of all other groups, with the conventional energy systems. The six groups are defined in table III. Included within each group are all powerplant sizes that were simulated for that group.

Figure 21 shows the break-even line for each of these groups, assuming that only systems belonging to that group are available to compete against the conventional energy systems. Similarly, the 30-percent life-cycle cost saving lines are shown for each group in figure 22.

The results indicate that all groups (except group 1) are competitive in some regions of the country at current and projected energy prices. The grid-connected systems are competitive over a larger range of energy prices than are the stand-alone systems. The range of competitiveness for stand-alone systems, particularly those with absorption chillers, is not insignificant. In fact, for the hospital, the stand-alone systems with an absorption chiller (group 2) compete very well with the grid-connected systems. Systems with absorption chillers do better than systems without; this holds true for grid-connected and stand-alone systems. For the apartments the thermal-load-following systems are best at high fuel costs; they rapidly lose their advantage as fuel costs decline and are replaced by grid-connected systems with absorption chillers.

The break-even lines of the grid-connected systems are spaced close together, but the same is not true for the 30-percent saving lines. The 30-percent saving lines for the grid-connected systems show considerable dispersion, with group 5 systems having the greatest life-cycle cost savings for each of the buildings. It is also interesting to note that although the group 6 systems (i.e., thermal-load-following systems) are competitive over a large range of energy costs, the cost savings over most of that range are far less than the cost savings of even the stand-alone systems.

The results of using payback to evaluate each group independently are shown in figure 23. The results are similar to those for the life-cycle analysis. In general, grid-connected systems outperform the stand-alone systems by a substantial margin, but the differences between the various grid-connected systems are relatively minor. The exception would be group 6 in the case of the retail store. Stand-alone systems are competitive for some combinations of fuel and electricity costs, and they fare best for the hospital.

Part 3: Parametric Analysis

The results shown so far are based on a variety of assumptions. The effect of varying some of these assumptions on the economic competitiveness of fuel cell onsite integrated energy systems was examined. Specifically, the topics explored were

(1) Variations in the price obtained for electricity sold to the electric utility grid
(2) The effect of absorption chillers on system economics
(3) The consequences of limiting the minimum fuel cell powerplant size
(4) The effect of climatic changes
(5) Variations in fuel cell capital cost

<u>Effect of selling rate on system economics</u>. - The price received for electricity generated by the onsite fuel cell powerplant and sold to the electric utility is referred to in this report as the selling price. Throughout this report this selling price is assumed to be a fixed percentage of the cost of purchased electricity. This fixed percentage, designated RXI, was assumed to be 0.60 for all of the results shown up to this point.

The effect of varying RXI to 0.3 and 1.5 is illustrated in figures 24 and 25 for life-cycle cost saving and payback, respectively; only buy/sell grid-connected systems (groups 4 to 6) were assumed to compete since these are the only ones affected by RXI. Note that the break-even lines are affected only slightly because the fuel cell powerplant size at the break-even line is very small, which means that very little excess power is generated onsite. Since the power sales to the electric utility are minimal, the price obtained for that power has little effect on the life-cycle cost. Below the break-even line the situation changes. The life-cycle cost savings increase substantially as selling rate RXI is increased. The cost savings at the reference point for several values of RXI are given in table IV(a).

The effect on payback period of changes in RXI is less pronounced than the effect on life-cycle cost saving. The reason is the small powerplant size that minimizes payback for most energy costs. The variations in payback period at the reference point over a range of selling rates are illustrated in table IV(b).

The effect of changing RXI from 0.3 to 1.5 on the optimum fuel cell powerplant size is illustrated in figure 26. The figure shows the optimal powerplant sizes over the complete range of electricity costs for a fixed fuel cost of $\$6.50/10^6$ Btu. The optimum powerplant size for a selling rate 1.5 times the cost of purchased electricity is in all cases equal to or larger than the optimum powerplant size for a selling rate only 0.3 times the purchase cost. As discussed previously, the optimum powerplant size increases with increasing cost of electricity; for a high selling rate the optimum powerplant size increases much more rapidly than a low selling rate. Thus, the optimum powerplant size is a strong function of the selling rate particularly as the cost of electricity increases.

Although it cannot be seen from figures 24 and 25, RXI does affect the optimum system design. As RXI increases, systems with more electricity available for sale to the grid gradually replace systems with less or no electricity sales potential. However, as already discussed, this shift in optimum system design does not enlarge the competitive region (i.e., the region with positive life-cycle cost saving or payback periods of less than 5 yr).

In summary, the selling rate does not greatly affect the range of energy costs for which onsite systems are competitive, but it does affect the optimum system design and optimum powerplant size. The main effect, however, of increasing RXI is to increase substantially the life-cycle cost saving for energy prices representative of current and future regional prices.

Onsite systems without absorption chillers. - Figures 17 and 18 show that the economically most attractive onsite energy systems frequently are buy/sell grid-connected systems with an absorption chiller. Figures 21 to 23 show however, that in each case there are close competitors without absorption chillers.

Since considerable uncertainty exists with regard to operating absorption chillers by using the thermal output from fuel cells, the effect of disallowing systems with absorption chillers and the benefits potentially attributable to absorption chillers were examined in some detail. To this end figures 27 and 28 show the optimum system and the optimum range of fuel cell powerplant sizes when the selection of systems is limited to those without absorption chillers. These figures should be compared with figures 17 and 18, respectively. The figures show that systems without absorption chillers are competitive with conventional energy systems although the range of energy costs is slightly restricted as compared with systems with absorption chillers and, of course, the life-cycle cost savings will be less.

To isolate the effect of life-cycle cost saving attributable to absorption chillers, consider figure 28. The figure shows the life-cycle costs of the best conventional system, the best system without absorption chillers, and the best system with absorption chillers. The costs are normalized to the lowest-life-cycle-cost conventional system and all costs are for the reference point. For the apartment building most of the cost saving is due to the use of a fuel cell OS/IES, and little more saving results from revising the system design to include an absorption chiller. For the store only a fuel cell system with an absorption chiller realizes a saving over the conventional system. For the hospital fuel cell systems without absorption chillers reduce life-cycle cost significantly, but a very substantial increase in saving results from the inclusion of an absorption chiller. These results are generalized in figure 30, which shows the life-cycle cost savings attributable to absorption chillers over the entire energy cost range.

The savings in figure 30 are the result of comparing the life-cycle cost of the best fuel cell system with an absorption chiller with that of the best energy system without an absorption chiller. The savings possible through the use of absorption chillers are quite significant in regions with high electricity costs, particularly for the hospital. Also note, specifically for the store and the hospital, that at high electricity costs the savings due to absorption chillers are maximum for a narrow range of natural gas costs and decline for both higher and lower natural gas costs.

Limiting the minimum fuel cell powerplant size. - Figure 19 shows that, on the basis of life-cycle cost considerations, the optimum fuel cell size is a function of both fuel cost and purchased electricity cost. Furthermore, at or near the break-even line, the optimum fuel cell powerplant size is the smallest simulated. Similarly, using payback analysis, figure 20 shows that the smallest powerplant gives the shortest payback for most energy costs. The exception is the hospital, where the optimum fuel cell size ranges from the smallest to the fourth smallest of the 10 sizes simulated.

This section of the report explores the effect on the competitive region of successively increasing the minimum available fuel cell powerplant size. The results are shown in figure 31 for the life-cycle cost analysis and in figure 32 for the payback analysis.

The small powerplant sizes greatly increase the competitive domain of fuel cell onsite systems for the apartment building and the store regardless of which economic criterion is used. For the hospital the benefits of small powerplants is considerably less significant.

On and below the 30-percent life-cycle cost saving line the optimum powerplant size is larger than any of the size restrictions considered here. Therefore, powerplant sizes would have to be restricted more than assumed here to affect life-cycle cost saving below the 30-percent line.

Considering the prevailing and forecasted regional energy prices, the main effect of the unavailability of small fuel cell powerplants is to limit the economic competitiveness of fuel cell OS/IES's to regions of high electricity cost.

<u>Effect of climate on OS/IES competitiveness</u>. - Climate affects the operation of OS/IES's in two ways:

(1) Climate affects the end-use energy demand characteristics as shown in figures 3 to 5.
(2) Climate affects the performance of heating, ventilating, and air-conditioning components, particularly heat pumps and chillers.

Conventional energy systems and fuel cell onsite systems are similarly affected. For the three locations used in this analysis (Chicago, Washington, D.C., and Dallas), the effect of climatic changes on the competitiveness of fuel cell systems based on life-cycle cost and payback analysis, respectively, is shown in figures 33 and 34.

The results show that climate has little influence on the economic competitiveness of fuel cell onsite systems regardless of whether payback or life-cycle cost is used as the criterion. Climate also affects the optimum system design and optimum fuel cell powerplant size. The magnitude of the effect is not significant.

<u>Sensitivity to fuel cell capital cost</u>. - In the preceding analysis the installed cost of a 200-kW fuel cell powerplant was assumed to be $23 972 or $1198.6/kW in 1981 dollars. For larger powerplants the cost per kilowatt is somewhat lower and for smaller powerplants it is slightly higher because of the assumed economy of scale.

At this point in the development of fuel cell technology the installed cost of a mature, mass-produced fuel cell powerplant is uncertain. To examine the effect of a fuel cell cost that is either higher or lower than that indicated above, the analysis was repeated for a range of costs from 50 percent to

200 percent of the baseline case. Changes in capital cost were assumed to affect the fuel cell stack and balance of plant equally. The costs of chillers, boilers, and heat pumps were assumed to be fixed. Note that although fixed O&M costs were assumed to be a percentage of capital costs, for this sensitivity analysis O&M costs were not varied with fuel cell capital cost but instead were held constant at a value computed for baseline fuel cell capital cost.

The results of this sensitivity analysis are shown in figures 35 and 36. As expected, the region of positive life-cycle cost saving contracts with increasing fuel cell cost. Similarly, the region with life-cycle cost savings greater than 30 percent becomes progressively smaller. However, even at twice the baseline cost (i.e., $2397/kW installed cost), fuel cell onsite systems are competitive in most regions of the country at the current and projected 1985 energy costs shown in figures 12 and 13. The adverse effects of increased fuel cell capital costs appear to be slightly more pronounced for the retail store although all three buildings are similarly affected overall.

With payback as the economic evaluation criterion the sensitivity to changes in fuel cell capital cost is considerably more pronounced. This was expected since payback places greater emphasis on first cost. Comparing figure 36 with figures 12 and 13, it seems that, at a 100-percent increase in baseline fuel cell costs, onsite systems are competitive only in regions with high electricity costs.

Changing the fuel cell capital cost has other effects besides changing the relative competitiveness of fuel cells vis-a-vis conventional systems. At any given fuel and electricity cost the optimum onsite system design and the optimum installed fuel cell capacity are influenced by the fuel cell cost. In general, the higher the fuel cell cost, the smaller the optimum powerplant size. The effect on optimum system design is not easily generalized.

SUMMARY OF RESULTS

The economic competitiveness of fuel cell onsite integrated energy systems (OS/IES's) vis-a-vis conventional noncogenerating energy systems was examined. The analysis was based on economic assumptions appropriate to private ownership. Energy prices were assumed to escalate at a rate of 2 percent above the prevailing inflation rate over the hypothesized 20-year energy system life.

The results clearly indicate that fuel cell systems are competitive over a broad range of fuel and electricity costs including the range of prevailing regional energy costs. This holds true whether life-cycle cost or simple payback is used as the criterion. In this report the competitive region was defined to be the area for which life-cycle cost saving is greater than zero or the area where payback is less than 5 years. A potential investor in fuel cell onsite energy systems would be likely to have more stringent requirements that would make the competitive region correspondingly smaller. On the other hand a relaxation of the private-ownership assumption would expand the size of the competitive region. Such would be the case for publicly owned buildings or buildings owned by not-for-profit corporations. Utility ownership of the OS/IES would also alter the economics slightly.

The large dispersion of 1981 regional energy prices and the projected costs for 1985 indicate that this regional disparity will continue. These regional energy cost variations clearly affect the economics of onsite systems. Climatic variations, on the other hand, have very little effect.

To maximize the range of energy costs over which fuel cell onsite systems can effectively compete, it is important that the optimum energy system design and operating strategy be employed and that the fuel cell powerplant be properly sized.

The analysis presented has demonstrated that both optimum system design and optimum powerplant size are a function of energy costs. In general, economic considerations favor grid-connected systems over stand-alone systems although the latter can compete albeit over a greatly reduced range of energy costs.

The best systems overall were those systems that most effectively utilize the fuel cell's thermal output, namely, the thermal-load-following system and the system with an absorption chiller. For both of these systems, excess electricity was generated onsite, and it was assumed that this excess was sold to the local electric utility for 60 percent of the purchased electricity cost.

The sensitivity of results to the selling rate was investigated. The sensitivity analysis showed that the selling rate does have a major effect on life-cycle cost, life-cycle cost saving, and optimum powerplant size throughout the region of projected energy prices. It does not, however, greatly affect the size of the region having positive life-cycle cost savings. There are two reasons for this. First, at the boundary of the competitive region, the optimum fuel cell powerplant is very small, leaving very little excess electricity available for sale to the utility. Second, onsite systems without any electricity sales are competitive over nearly the same range as those that do sell electricity.

For minimum life-cycle cost the optimum fuel cell installed capacity is a strong function of energy cost. In general, the higher the ratio of fuel to electricity costs, the smaller the optimum powerplant size. For low fuel-to-electricity cost ratios, the optimum powerplant is larger, but its peak electric load is still below that of an all-electric system. Payback analysis favors even smaller fuel cell powerplant sizes than do life-cycle cost considerations. For most cases analyzed, payback is minimized by using the smallest available fuel cell powerplant size over the entire range of energy costs for which payback is less than 5 years. Smaller powerplants operate at a higher load factor since they supply the base-load component of the onsite electrical demand. This improves the economic performance since the capital-intensive fuel cell powerplant is utilized at maximum effectiveness.

The unavailability of small powerplants (relative to the building's peak electrical load) would greatly reduce the range of energy costs for which fuel cell onsite energy systems are competitive. Of the three buildings studied, the hospital was least affected by restricting the minimum powerplant size. This is probably due to the hospital's higher load factor.

It should be mentioned that although this study emphasized the economic performance of fuel cell OS/IES's as measured by life-cycle cost and payback, other considerations must be factored into any decision regarding the installation of or investment in an OS/IES. The most obvious factors are first cost and natural gas consumption. For all cases analyzed in this study the initial cost of fuel cell systems was higher than the costs of the conventional systems. Also the natural gas consumption of most fuel cell systems exceeded those of the gas/electric conventional systems; the only exceptions are some of the OS/IES's with the smallest fuel cell powerplants. Other factors are system reliability, energy conservation, fuel flexibility, risk, and legal and institutional constraints. Some of the legal and institutional issues are discussed in reference 13. Finally, it should be pointed out that in some cases the optimal energy system, as defined in this report, sells more electricity to the utility than it purchases from it.

RECOMMENDATIONS

Based on the results of this study several recommendations can be made:

1. The use of absorption chillers using the fuel cell's thermal output should be evaluated; this includes establishing the performance characteristics of absorption chiller operated in conjunction with a fuel cell and investigating possible design customization to optimize the fuel cell/absorption chiller combination.
2. Fuel cell powerplants to permit thermal-load-following operation should be designed.
3. Means to reduce the capital cost of small fuel cell powerplants should be examined.
4. Fuel cell onsite energy systems should be optimized for each installation; the optimum system is a function primarily of the building's energy-demand profiles and of the prevailing energy costs.

In addition to these recommendations, several improvements to the analysis described herein are possible. An obvious one is the use of measured energy-demand profiles. Such profiles may now be available as a result of instrumenting various candidate sites for the 40-kW field test (ref. 14). The instrumented sites also include a broader variety of buildings, which should increase the value of this type of analysis.

The list of onsite energy system designs evaluated in this study is not exhaustive. Other systems may prove to be attractive. Finally, the effect of time-of-use rates and demand changes on system economics should be investigated.

The model developed in the course of this study can also be used to assess the value of technological improvements in the fuel cell powerplants or peripheral heating, ventilating, and air-conditiong components. Particularly, trade-offs between fuel cell efficiency and capital cost should be of interest.

APPENDIX A

CAPITAL COSTS, O&M COSTS, AND EFFICIENCY MODELS FOR ENERGY SYSTEM COMPONENTS

This appendix provides the numeric data used in the capital cost, efficiency, and O&M cost models applied throughout this study for each of the system components. These three models were provided for each of the following system components:

(1) Fuel cell powerplants
(2) Heat pumps
(3) Compression chillers
(4) Absorption chillers
(5) Boilers
(6) Cooling tower

Capital Cost Model

Capital costs for all of the system components were computed as follows:

$$\text{Installed capital cost} = C(\text{Component capacity})^{x}$$

where C and x are the constant and exponent given in columns 3 and 4 of table V, respectively. The component capacity must be expressed in thousands of Btu per hour and the resultant capital cost is then given in 1981 dollars. Fuel cell costs are based on electrical output expressed in Btu equivalent.

The values of C and x given are valid over the size range shown in the table. When a component capacity is outside this allowable range, the capital cost is extrapolated by using the appropriate C and x values and an error message is printed. For the analysis described in this report some components were outside the allowable size range only for the apartment building.

The onsite system capital cost is the sum of the capital costs of individual components. This capital cost is used in the payback analysis; for life-cycle cost analysis the capital cost is modified as described in appendix B to arrive at an effective capital cost.

Efficiency Model

The efficiency model gives the efficiency, or coefficient of performance, values for each system component. For the fuel cell, the boiler, and the absorption chiller the efficiency is only a function of output, expressed as a percentage of full-load output (table VI).

Note that the fuel cell thermal efficiency is defined as the ratio of usable thermal output to fuel energy input and is modeled as a function of fuel cell electrical output. The COP's for the heat pump (table VII) and for the compression chiller (table VIII) are a function of part-load output and ambient temperature.

O&M Cost Model

Using the values of A and B shown in table IX, we can compute the annual O&M cost for each component as follows:

$$\text{Annual O\&M cost} = A(\text{Output}) + \frac{B(\text{Capital cost})}{100}$$

The "Output" is the annual output of each component expressed in thousands of Btu and the "Capital cost" is the installed cost of each component as derived from the capital cost model. The O&M cost obtained from this equation is in 1981 dollars.

APPENDIX B

EFFECTIVE CAPITAL COST USED FOR LIFE-CYCLE COST ANALYSIS

Total life-cycle cost is the sum of fixed charges and levelized operating costs. For a system consisting of more than one cost item of capital equipment the fixed charges are properly computed as follows:

$$F = C_1 \times FCR_1 + C_2 \times FCR_2 + \ldots + C_n \times FCR_n \qquad \text{(B1)}$$

where

C_i capital cost of i^{th} cost item

F fixed charges

FRC_i fixed charge rate appropriate for i^{th} item

In life-cycle cost analysis it was frequently assumed that the fixed charge rate is the same for all pieces of equipment. However, this is not necessarily the case; many factors can make the fixed charge rate different. Some examples of such factors are

(1) Different tax treatment, as when some components are eligible for investment tax credit and others are not
(2) Different lives, necessitating periodic component replacement throughout the project life
(3) Different salvage value
(4) Investments not subject to depreciation, such as land

When calculating life-cycle cost, however, it is convenient to deal with a single capital cost multiplied by a single fixed charge rate. This simplicity can be achieved by rewriting equation (B1) as follows:

$$F = C_1 \frac{FCR_1}{FCR_0} + C_2 \frac{FCR_2}{FCR_0} + \ldots + C_n \frac{FCR_n}{FCR_0} \quad FCR_0 \qquad \text{(B2)}$$

where FRC_0 is the nominal fixed charge rate based on assumed project life and the term in parentheses is called the total effective capital cost.

The ratio FCR_i/FCR_0 is called the capital cost correction factor or $CCCF_i$ (ref. 8). It is relatively insensitive to changes in parameters that affect both FCR_i and FCR_0. Thus, for many analyses it can be assumed to be constant.

The product $C_i \times CCCF_i$ is called the effective capital cost of component i. The total effective capital cost is the sum of the effective capital costs of all system components. The life-cycle cost analysis presented in this report is based on total effective capital cost; the payback analysis is based on the simple arithmetic sum of the capital costs of all system components (i.e., C_i).

In this study $CCCF_i = 1.0$ was used for all system components except the fuel cell powerplant. For the fuel cell powerplant $CCCF_{FC} = 1.50$.

This value was arrived at by calculating a separate fixed charge rate for the fuel cell stacks and another fixed charge rate for the remaining fuel cell powerplant. A cost-weighted average of the two fixed charge rates gives the overall fuel cell fixed charge rate, which, when divided by FCR_0, yields $CCCF_{FC} = 1.50$.

The fuel cell stack fixed charge rate was based on the assumption that the stack has an actual salvage value of 20 percent of the stack cost, that stacks are replaced at 5-year intervals, and that the replacement cost of stacks rises at the same rate as general inflation. For tax purposes salvage value is assumed to be zero. Other assumptions are that stacks are depreciated over 5 years by using the sum-of-years-digits method and that stacks are eligible for a full 10-percent investment tax credit.

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TABLE I. - SUMMARY OF BUILDING CHARACTERISTICS

	Apartment	Retail store	Hospital
Total floor area, $m^2(ft^2)$	1904 (20 496)	10 420 (112 163)	11 043 (118 867)
Number of floors	2	1	6
Construction characteristics:			
Floorplan	Rectangular	Rectangular	Rectangular
Roof	Sloped	Flat	Flat
Basement	No	No	No, but level 1 is partially below grade
Glass area, percent	17	6	14
Construction	Wood frame with brick veneer	Steel frame, masonry walls, slab on grade	Reinforced concrete frame, floors, and roof slab; masonry interior walls
Average U-factors, $W/°C\text{-}m^2(Btu/°F\text{-}ft^2\text{-}hr)$:			
Roof	0.284(0.050)	0.568(0.100)	0.438(0.077)
Walls	0.568(0.100)	1.216(0.214)	1.068(0.188)
Glass	4.26(0.750)	3.410(0.600)	3.410(0.600)
Interior conditions:			
Temperature (summer/winter), °C (°F)	26/22 (78/72)	26/22 (78/72)	24/24 (75/75)
Humidity (summer/winter), percent	50/5	50/5	50/50

TABLE II. - SUMMARY OF ENERGY SYSTEMS USED IN THIS ANALYSIS

System	Figure	Type of grid connection[a]	Number of component size variations[b]	Operating mode[c]	Supplementary heat[d]	Absorption chiller[e]
Conventional systems						
1	6(a)	BO	1	---	--	N
2	6(b)	BO	1	---	--	N
Fuel cell OS/IES's						
1	7(a)	SA	1	ELF	HP	N
2	7(b)				HP	Y
3	7(c)				B	N
4	7(d)				B	Y
5	8(a)	BO	10		HP	N
6	8(b)	BO			B	
7	9(a)	BS		CFL	HP	
8	9(b)				B	
9	9(c)				B	Y
10	9(d)				None	N
11	10			TLF	B	N

[a] BO = buy only; SA = stand alone; BS = buy/sell.
[b] Number of systems simulated initally; some were subsequently rejected (see text).
[c] ELF = electric load following; CFL = constant full-load output; TLF = thermal load following.
[d] HP = heat pump; B = boiler or furnace.
[e] N = no; Y = yes.

TABLE III. - SUMMARY OF OS/IES GROUP

Group	Grid connection	Absorption chiller	Operating mode[a]	Systems included[b]
1	None (stand alone)	No	ELF	1, 3
2	None (stand alone)	Yes	ELF	2, 4
3	Buy only	No	ELF	5, 6
4	Buy/sell	No	CFL	7, 8, 10
5	Buy/sell	Yes	CFL	9
6	Buy/sell	No	TLF	11

[a]ELF = electric load following; CFL = constant, full-load ouput; TLF = thermal load following.
[b]See table II.

TABLE IV. - EFFECT OF SELLING RATE ON SYSTEM ECONOMICS

Building	Selling rate[b]		
	0.3	0.6	1.5
Life-cycle cost saving, percent			
Apartment	9.0	11.0	52.8
Store	.5	1.6	35.5
Hospital	17.8	19.7	42.7
Payback period, yr			
Apartment	3.5	3.5	3.4
Store	>5	>5	4.6
Hospital	3.3	3.2	2.6

[a]All data at reference point.
[b]Selling rate (RXI) = Price obtained for electricity sold to electric utility divided by price paid for electrcity purchased from electric utility.

TABLE V. - CAPITAL COST MODEL

[For capital cost model, fuel cell capacity is expressed in Btu equivalent of electrial output (1 kW = 3412 Btu/hr). All costs are in 1981 dollars. All costs are installed costs. Heat pump cost includes supplemental resistance heater. Heat pump capacity at 70° F; chiller capacity at 80° F.]

Component	Size range (1000 Btu/hr)		Constant, C	Exponent, x	Cost per unit size ($/1000 Btu per hr)	
	Minimum	Maximum			At minimum size	At maximum size
Fuel cell	25	20 000	533.40	0.936	434.09	283.00
Heat pump	30	440	143.70	.866	91.10	63.57
	440	20 000	462.40	.674	63.57	18.32
Compression chiller	30	24 000	64.70	.917	48.79	28.01
Absorption chiller	30	20 000	326.00	.741	135.10	25.08
Boiler	80	70 000	21.20	.880	12.53	5.56
Cooling tower	40	70 000	11.00	1.000	11.00	11.00

TABLE VI. - FUEL CELL, BOILER, AND ABSORPTION CHILLER EFFICIENCY MODEL

[Fuel cell thermal efficiency is expressed as a function of fuel cell part-load electrical output.]

Percent of full-load output	Fuel cell electrical efficiency	Fuel cell thermal efficency	Absorption chiller coefficient of performance	Boiler efficiency
0	0	0.150	0	0
5	.097	.173	.561	.449
10	.175	.199	.561	.460
15	.236	.226	.567	.473
20	.282	.253	.573	.488
25	.316	.279	.576	.500
30	.339	.304	.582	.513
35	.356	.328	.587	.527
40	.368	.349	.591	.540
45	.375	.367	.597	.553
50	.378	.382	.602	.567
55	.380	.394	.606	.581
60	.380	.404	.611	.594
65	.381	.410	.616	.607
70	.381	.415	.621	.620
75	.381	.417	.626	.633
80	.380	.419	.630	.646
85	.380	.420	.635	.660
90	.378	.422	.641	.673
95	.375	.426	.645	.687
100	.368	.433	.650	.700

TABLE VII. - HEAT PUMP COEFFICIENT-OF-PERFORMANCE MODEL

Output, percent of full-load output	Ambient temperature, °F											
	-10	0	10	20	30	40	50	60	70	80	90	100
0	0	0	0	0	0	0	0	0	0	0	0	0
5	.289	.313	.360	.432	.601	.744	.890	1.023	1.098	1.186	1.289	1.411
10	.336	.364	.420	.504	.700	.867	1.037	1.192	1.280	1.382	1.502	1.644
15	.384	.416	.480	.575	.800	.990	1.185	1.361	1.462	1.578	1.715	1.878
20	.432	.468	.539	.647	.899	1.114	1.332	1.531	1.644	1.775	1.929	2.112
25	.480	.520	.600	.719	1.000	1.238	1.481	1.702	1.828	1.974	2.145	2.348
30	.528	.572	.659	.791	1.100	1.362	1.629	1.872	2.010	2.170	2.359	2.582
35	.576	.624	.720	.864	1.200	1.486	1.778	2.043	2.194	2.369	2.574	2.819
40	.624	.676	.780	.936	1.300	1.610	1.927	2.213	2.377	2.567	2.789	3.054
45	.672	.728	.839	1.007	1.399	1.733	2.073	2.382	2.558	2.762	3.001	3.286
50	.721	.781	.900	1.080	1.501	1.858	2.223	2.554	2.743	2.962	3.218	3.524
55	.768	.832	.959	1.150	1.599	1.980	2.369	2.721	2.922	3.156	3.429	3.755
60	.816	.884	1.019	1.222	1.699	2.104	2.517	2.891	3.105	3.353	3.643	3.989
65	.864	.936	1.079	1.295	1.800	2.229	2.666	3.063	3.289	3.552	3.860	4.226
70	.912	.988	1.139	1.367	1.900	2.353	2.815	3.234	3.473	3.750	4.075	4.462
75	.961	1.041	1.200	1.440	2.001	2.478	2.965	3.406	3.658	3.949	4.292	4.699
80	1.009	1.093	1.260	1.511	2.101	2.602	3.112	3.576	3.840	4.146	4.506	4.933
85	1.056	1.144	1.319	1.583	2.200	2.724	3.259	3.744	4.021	4.342	4.718	5.166
90	1.105	1.197	1.380	1.655	2.301	2.849	3.408	3.916	4.205	4.541	4.934	5.403
95	1.152	1.248	1.439	1.726	2.399	2.971	3.554	4.083	4.385	4.735	5.145	5.634
100	1.200	1.300	1.499	1.799	2.500	3.096	3.704	4.255	4.570	4.934	5.362	5.871

TABLE VIII. - COMPRESSION CHILLER COEFFICIENT-OF-PERFORMANCE MODEL

Output, percent of full-load output	Ambient temperature, °F											
	-10	0	10	20	30	40	50	60	70	80	90	100
0	0	0	0	0	0	0	0	0	0	0	0	0
5	1.277	1.108	.978	.876	.792	.724	.666	.617	.574	.538	.505	.432
10	1.488	1.291	1.140	1.020	.923	.843	.776	.719	.669	.626	.588	.504
15	1.699	1.474	1.301	1.165	1.054	.963	.886	.821	.764	.715	.672	.575
20	1.911	1.658	1.464	1.310	1.186	1.083	.997	.923	.860	.804	.756	.647
25	2.125	1.843	1.627	1.457	1.319	1.204	1.108	1.027	.956	.894	.840	.719
30	2.337	2.027	1.790	1.602	1.450	1.325	1.219	1.129	1.051	.984	.924	.791
35	2.551	2.212	1.953	1.749	1.583	1.446	1.330	1.232	1.147	1.074	1.009	.864
40	2.764	2.397	2.116	1.895	1.715	1.566	1.441	1.335	1.243	1.163	1.093	.936
45	2.974	2.579	2.277	2.039	1.845	1.685	1.551	1.436	1.338	1.252	1.176	1.007
50	3.189	2.766	2.442	2.186	1.979	1.807	1.663	1.540	1.434	1.342	1.261	1.080
55	3.398	2.947	2.602	2.329	2.108	1.926	1.772	1.641	1.528	1.430	1.344	1.150
60	3.610	3.131	2.765	2.475	2.240	2.046	1.883	1.744	1.624	1.519	1.428	1.222
65	3.824	3.317	2.929	2.622	2.373	2.167	1.995	1.847	1.720	1.610	1.512	1.295
70	4.038	3.503	3.092	2.768	2.506	2.289	2.106	1.950	1.816	1.699	1.597	1.367
75	4.253	3.689	3.257	2.915	2.639	2.410	2.218	2.054	1.913	1.790	1.682	1.440
80	4.465	3.873	3.419	3.061	2.770	2.530	2.329	2.157	2.008	1.879	1.765	1.511
85	4.675	4.055	3.580	3.205	2.901	2.649	2.438	2.258	2.103	1.968	1.849	1.583
90	4.889	4.241	3.744	3.352	3.034	2.771	2.550	2.362	2.199	2.058	1.933	1.655
95	5.098	4.422	3.904	3.495	3.164	2.889	2.659	2.463	2.293	2.146	2.016	1.726
100	5.313	4.608	4.069	3.642	3.297	3.011	2.771	2.566	2.390	2.236	2.101	1.799

TABLE IX. - OPERATION AND MAINTENANCE COST MODEL

[Annual O&M cost for each component is given by O&M cost = A(output) + B(capital cost)/100, where output is annual output in 10^3 Btu. For fuel cell, use electrical output.]

	Variable O&M cost coefficient, A, $/$10^3$ Btu	Fixed O&M cost coefficient, B, percent of capital cost
Fuel cell	0.0020	2.500
Heat pump	.0003	2.500
Compression chiller	.0003	3.500
Absorption chiller	.0002	2.000
Boiler	.0001	2.500
Cooling tower	0	7.500

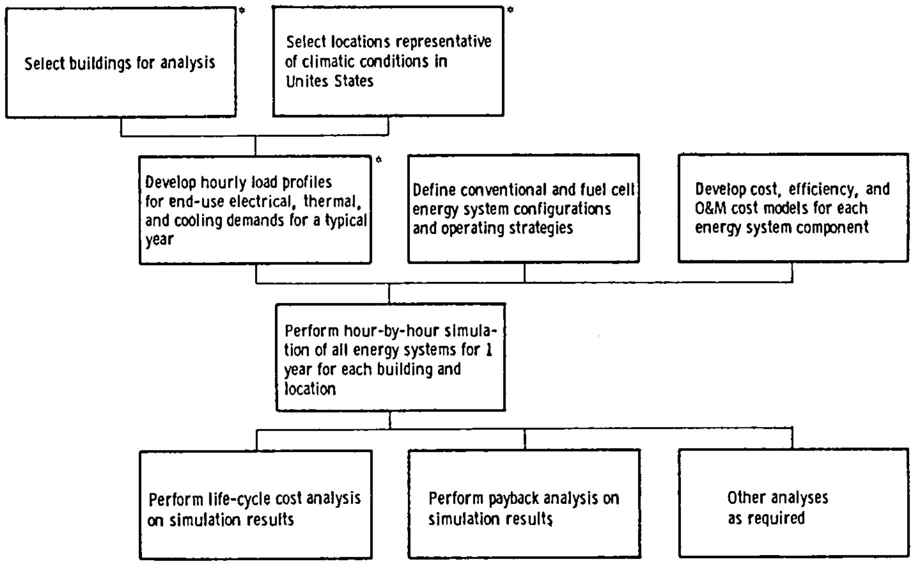


Figure 1. - Overview of study approach. (Asterisks denote items performed under a previous study (ref. 2).)

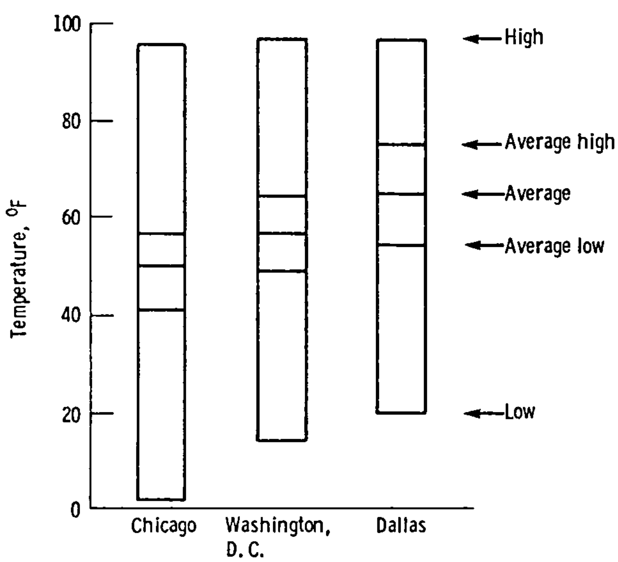


Figure 2. - Temperature characteristics for test reference year.

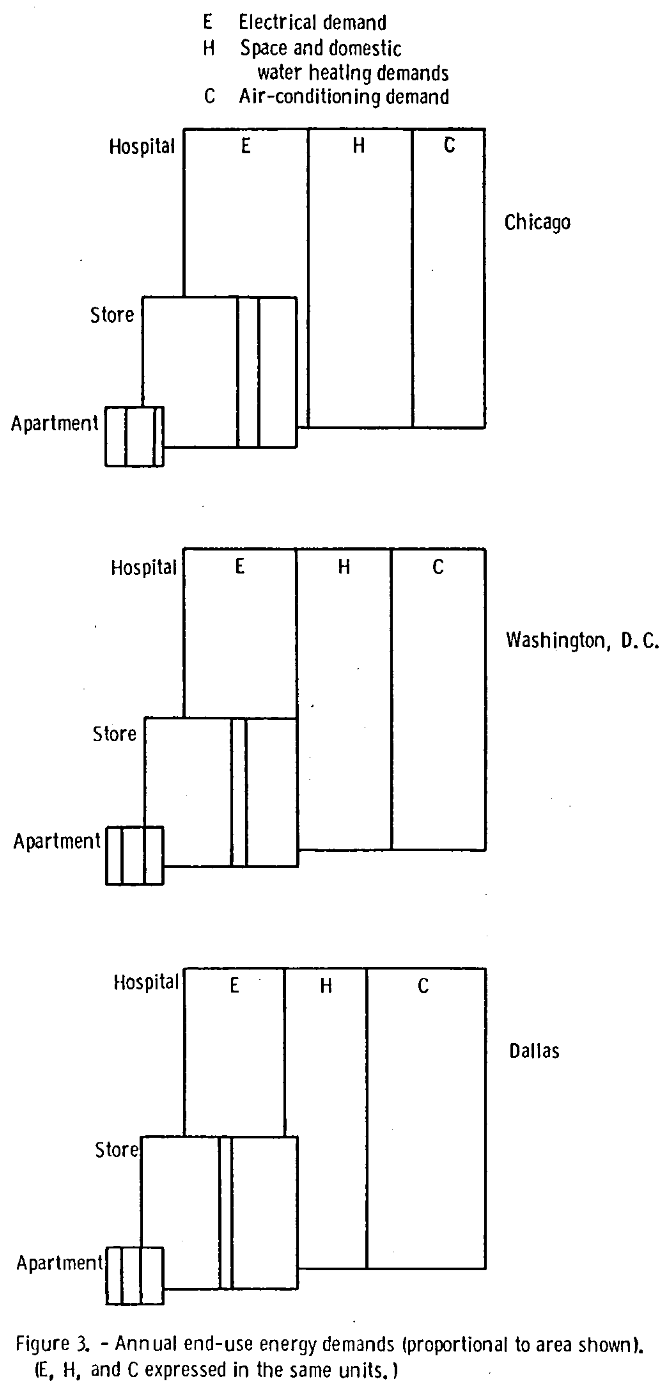


Figure 3. - Annual end-use energy demands (proportional to area shown). (E, H, and C expressed in the same units.)

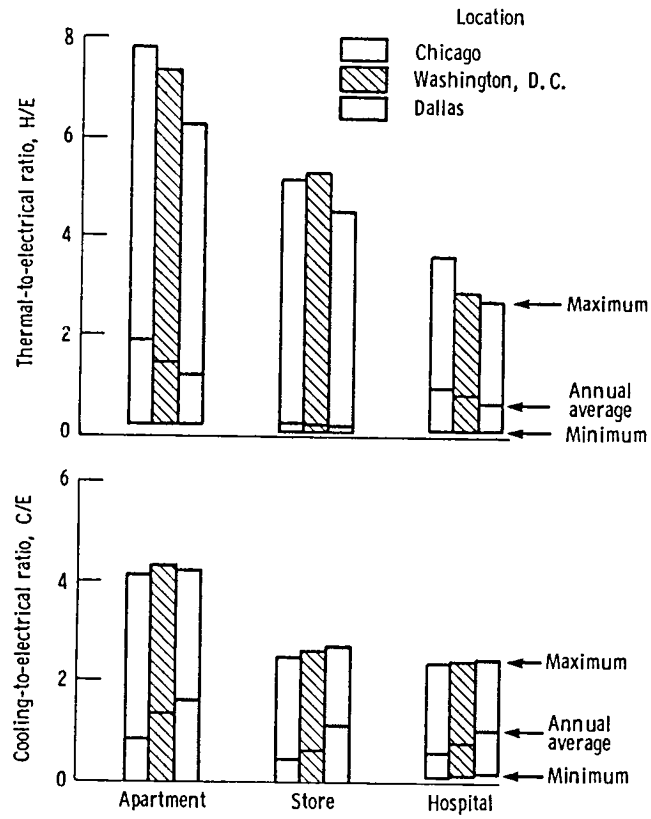


Figure 4. - Range of hourly thermal-to-electrical and cooling-to-electrical ratios. (H includes domestic water heating; C, H, and E are expressed in the same units.)

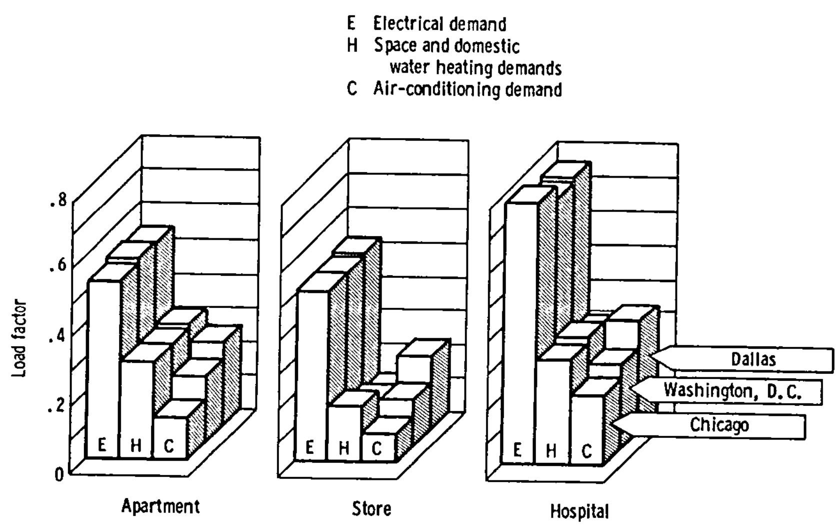
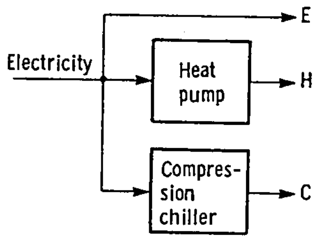
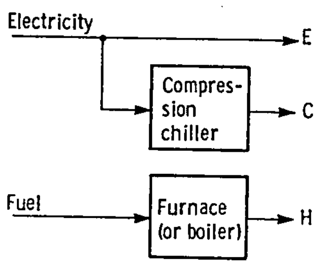


Figure 5. - Load factor comparison.

E Electrical demand
H Space and domestic water heating demands
C Air-conditioning demand



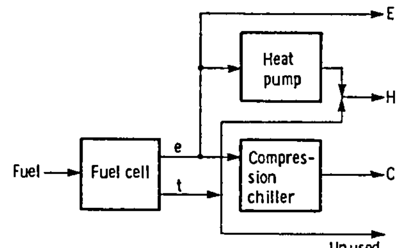
(a) All-electric system.



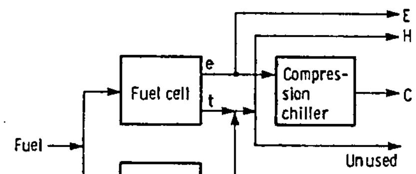
(b) Gas/electric system.

Figure 6. - Conventional energy systems.

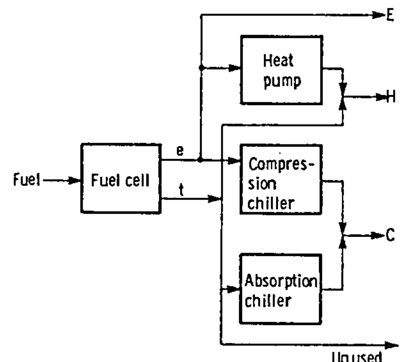
e Electrical output
t Usable thermal output
E Electrical demand exclusive of space conditioning
H Space and domestic water heating demands
C Air-conditioning demand



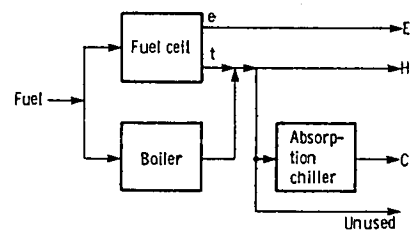
(a) System 1.



(c) System 3.

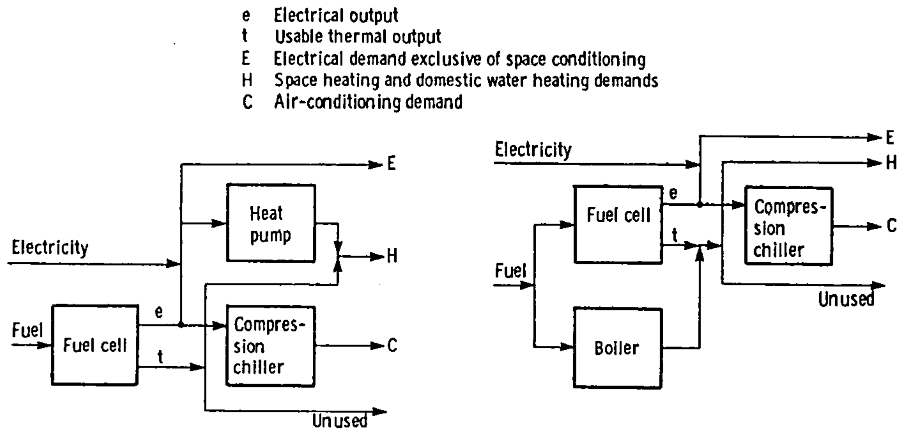


(b) System 2.



(d) System 4.

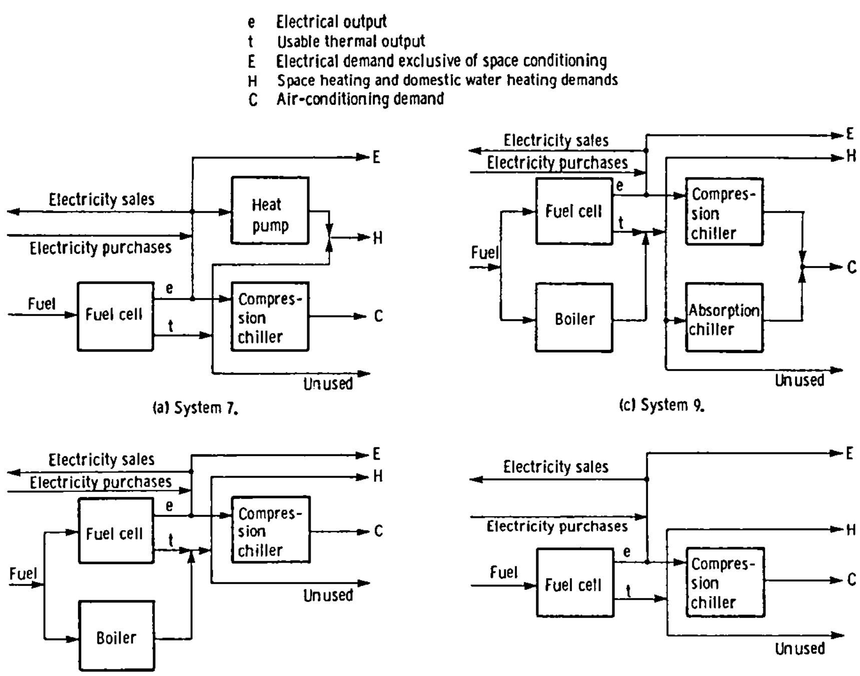
Figure 7. - Stand-alone energy systems.



(a) System 5.

(b) System 6.

Figure 8. - Buy-only grid-connected energy systems (electric load following).



(b) System 8.

(d) System 10.

Figure 9. - Buy sell grid-connected systems. (Fuel cell operates at constant, full-load output.)

e Electrical output
t Usable thermal output
E Electrical demand exclusive of space conditioning
H Space heating and domestic water heating demands
C Air-conditioning demand

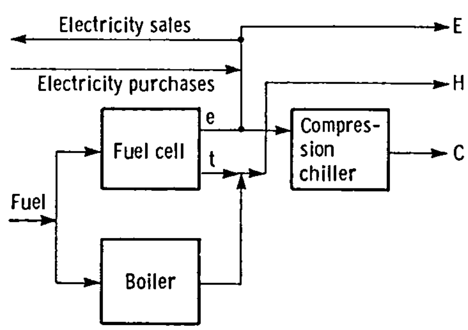


Figure 10. - Thermal-load-following buy/sell grid-connected system (system 11).

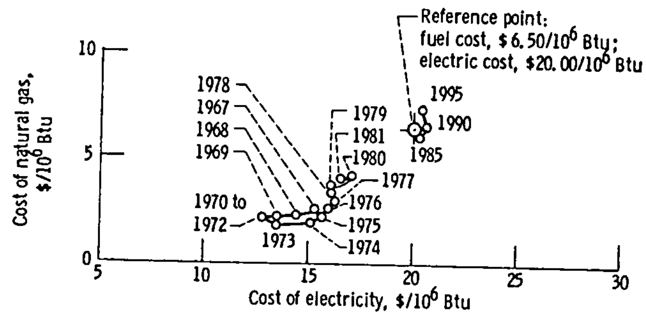


Figure 11. - Historical national energy cost trends. (National average costs for the residential sector in 1981 dollars.)

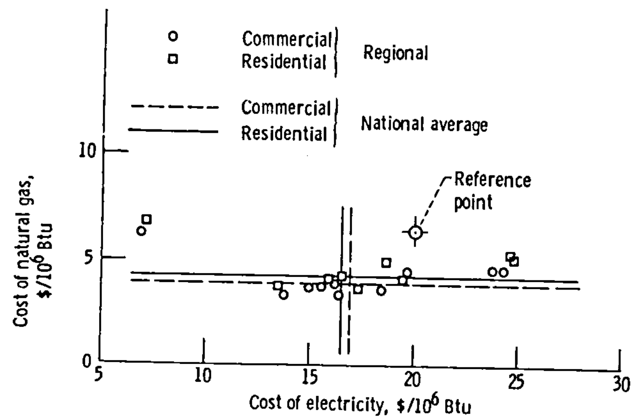


Figure 12. - 1981 Regional energy costs. (All costs in 1981 dollars; based on DOE regions.)

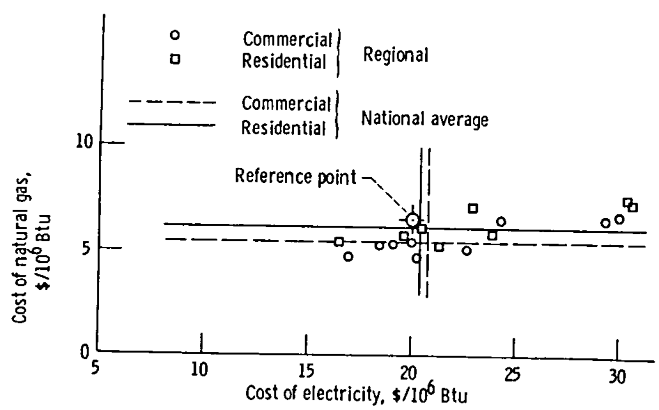
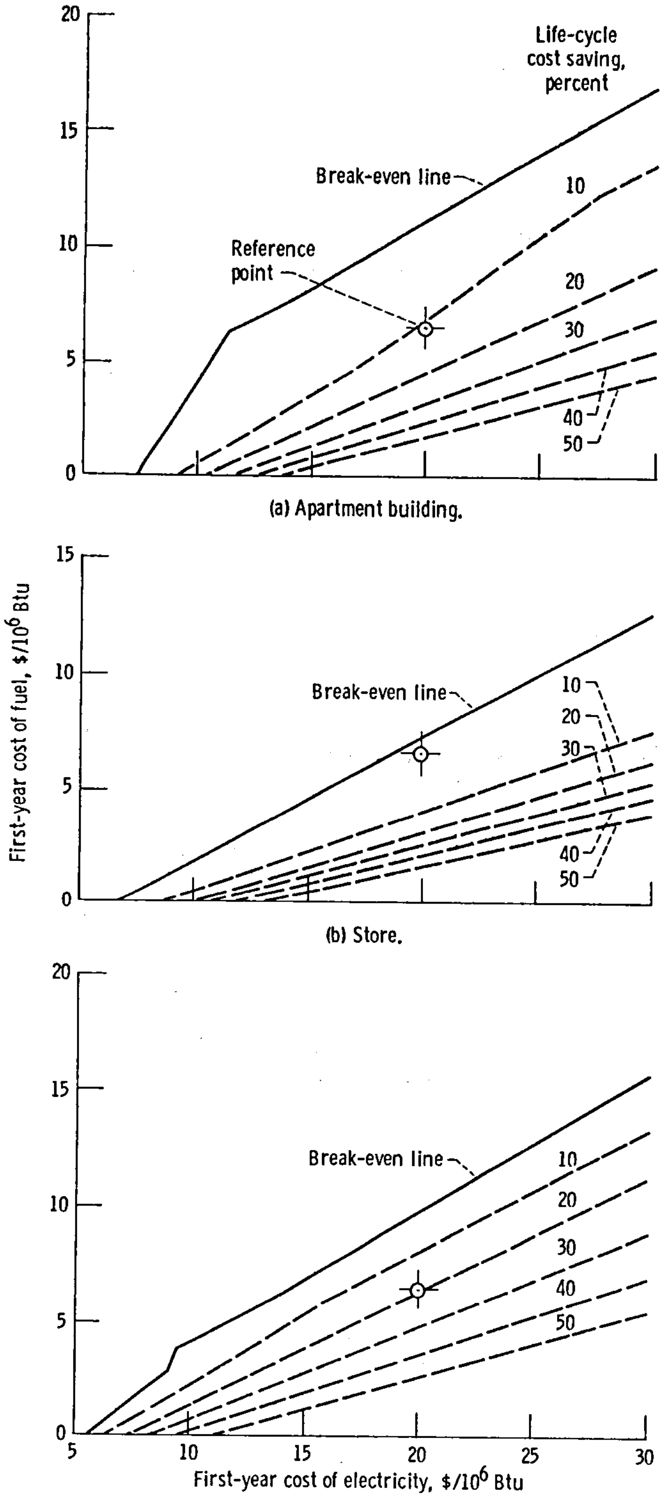


Figure 13. - Projected 1985 regional energy costs. (All costs in 1981 dollars; based on DOE regions.)



(a) Apartment building.

(b) Store.

(c) Hospital.

Figure 14. - Life-cycle cost savings based on optimal fuel cell system. Location, Washington, D.C.; 1981 dollars.

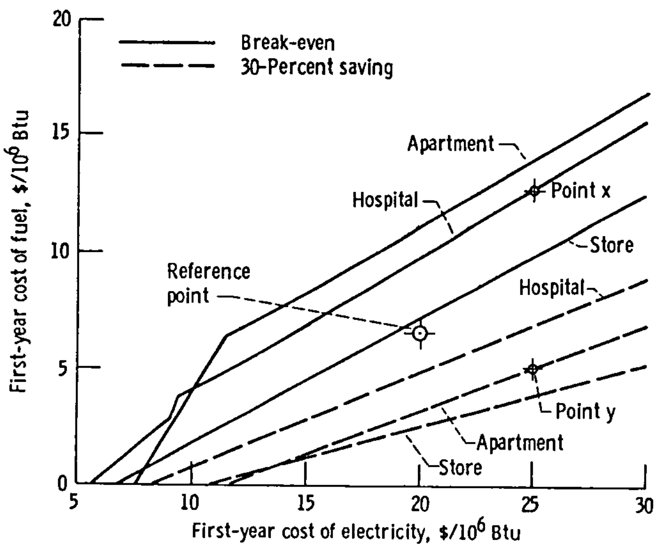


Figure 15. - Life-cycle cost savings for the three buildings. Location, Washington, D. C. ; 1981 dollars.

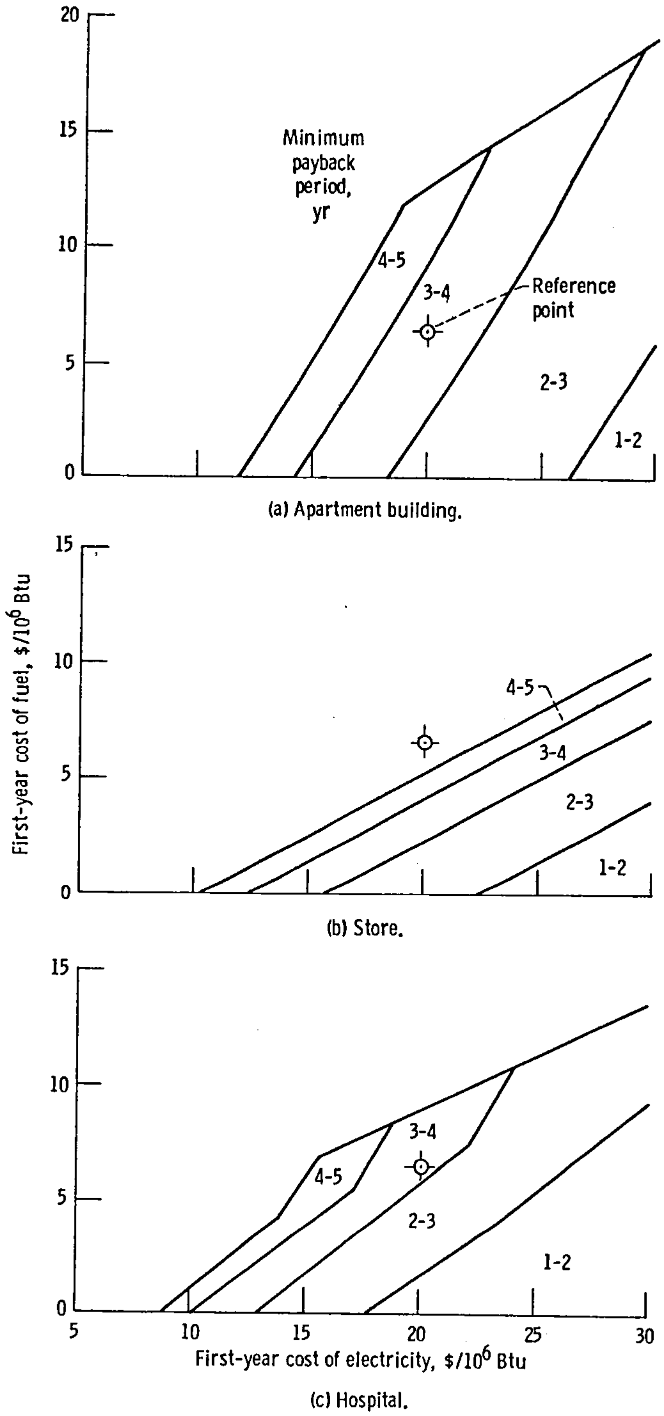


Figure 16. - Minimum payback periods. Location, Washington, D. C.; 1981 dollars.

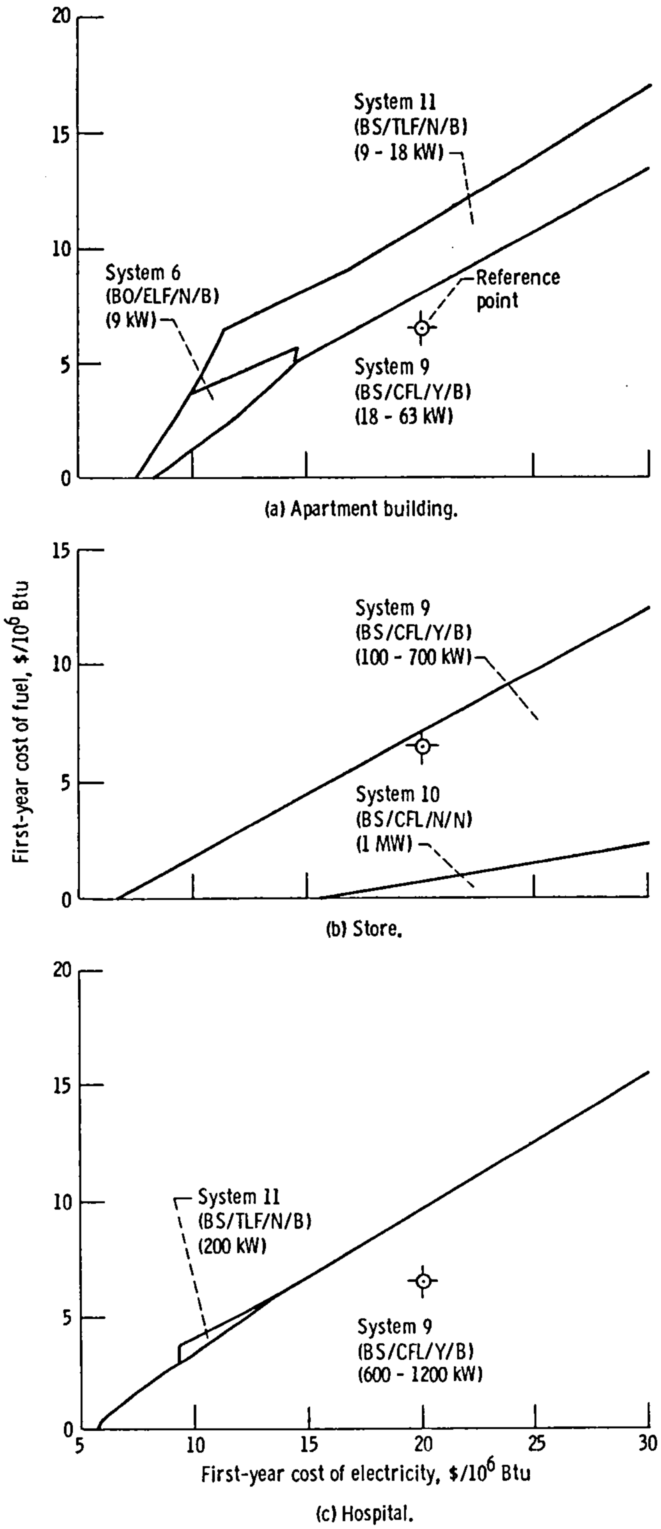


Figure 17. - Fuel cell system design for maximum life-cycle cost savings. Location, Washington, D.C.; 1981 dollars. (See table II for key to systems.)

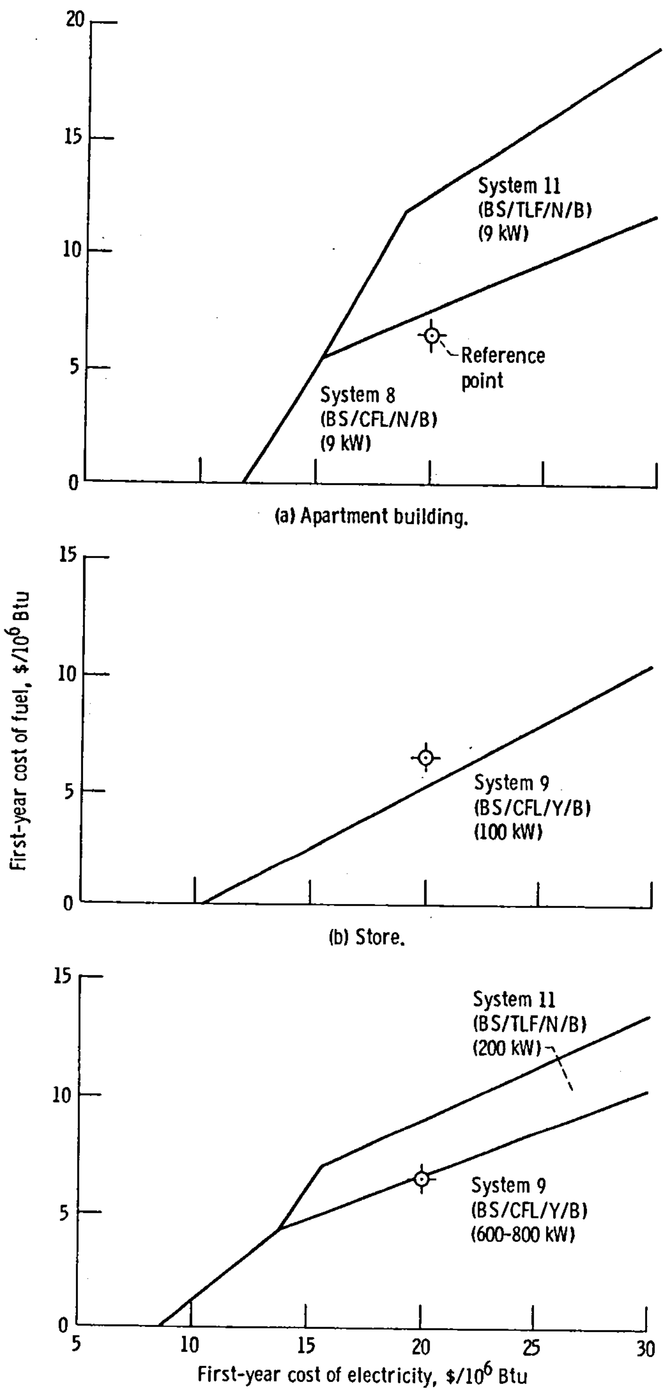


Figure 18. - Fuel cell system design for minimum payback period. Location, Washington, D.C.; 1981 dollars. (See table II for key to systems.)

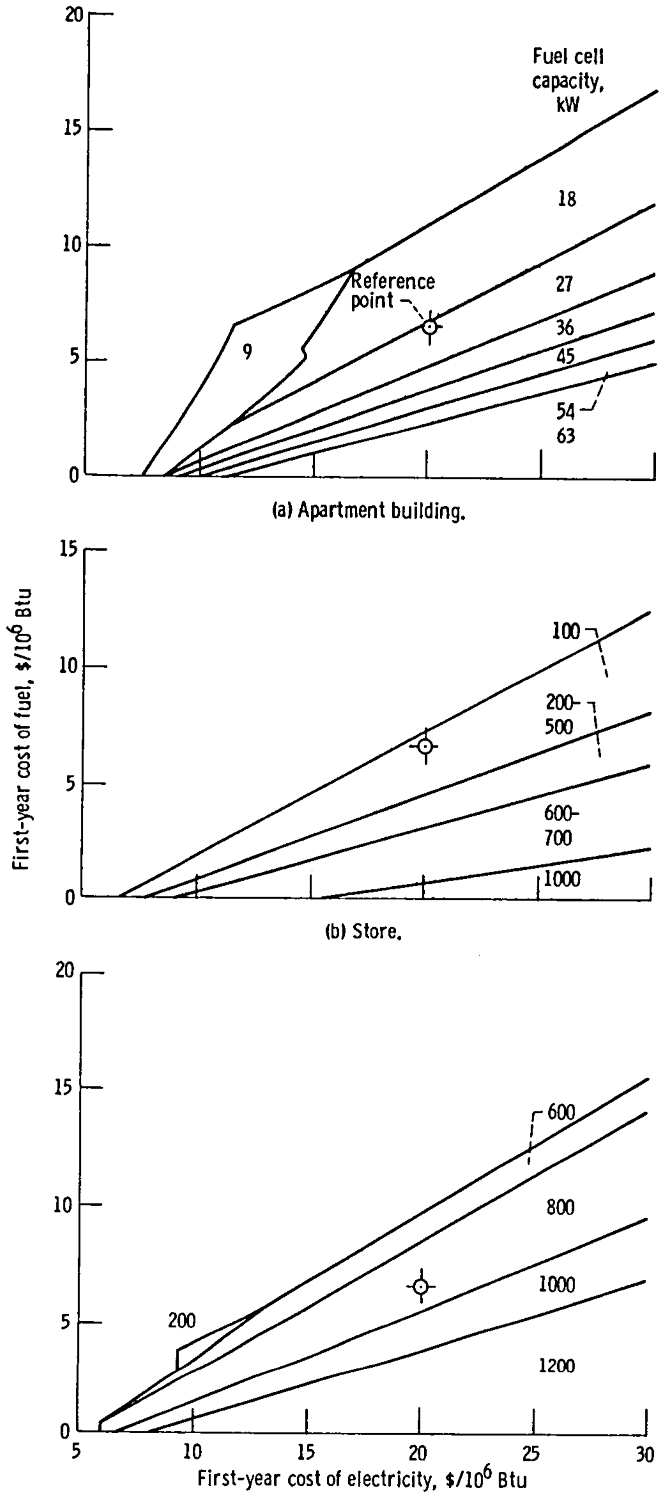
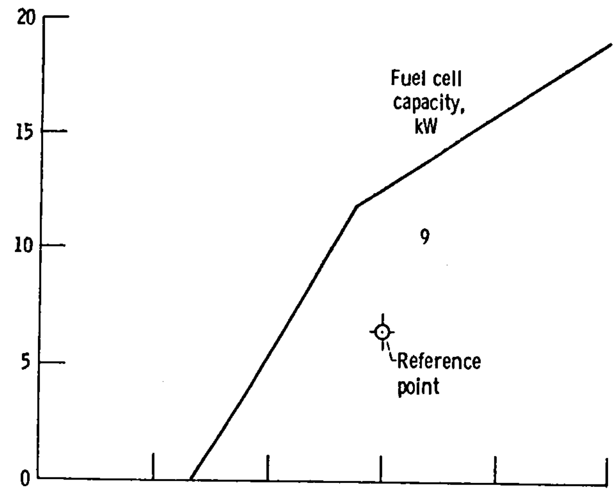
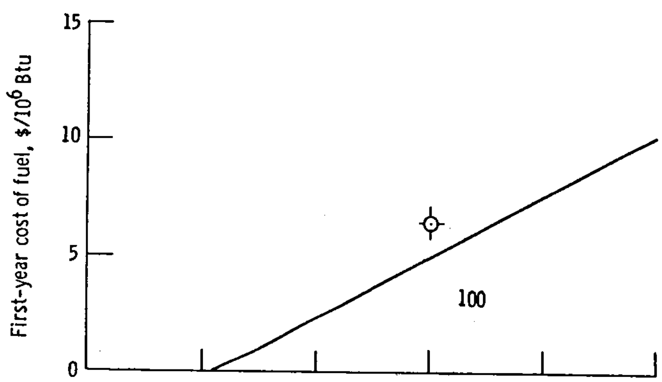


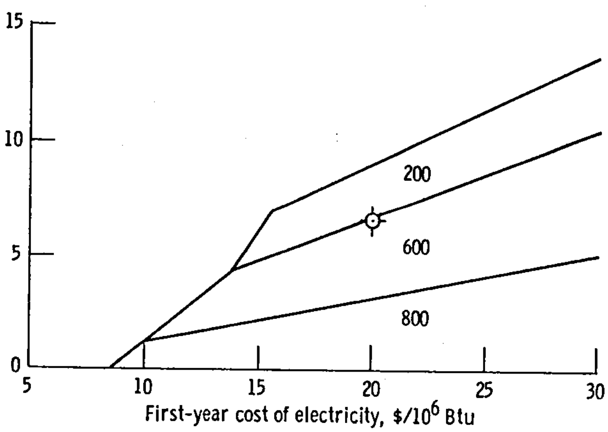
Figure 19. - Fuel cell capacity for maximum life-cycle cost savings. Location, Washington, D.C.; 1981 dollars.



(a) Apartment building.

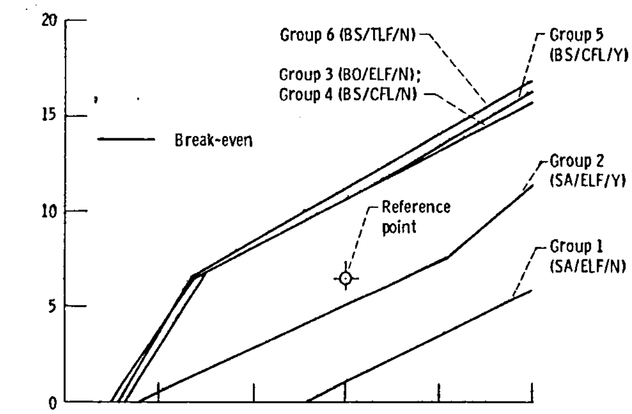


(b) Store.

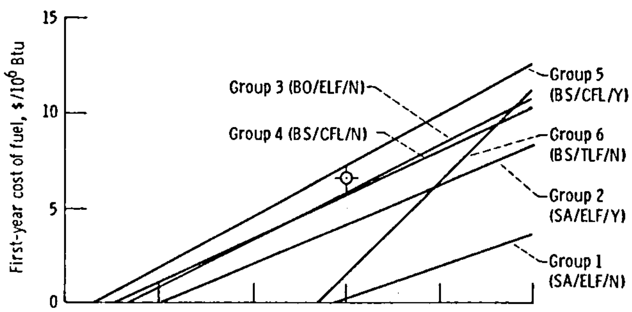


(c) Hospital.

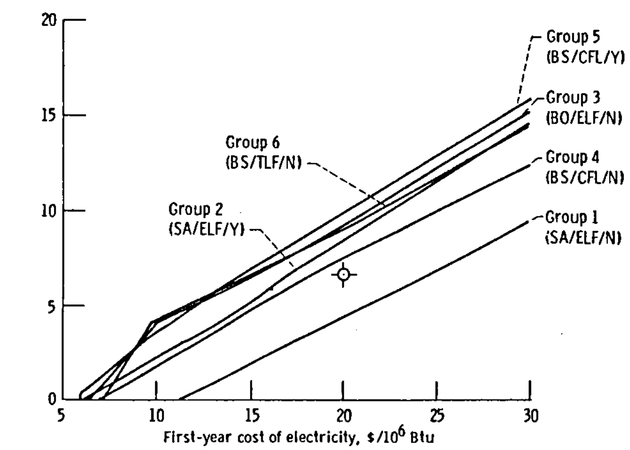
Figure 20. - Fuel cell capacity for minimum payback period. Location, Washington, D.C.; 1981 dollars.



(a) Apartment building.



(b) Store.



(c) Hospital.

Figure 21. - Competitive regions for nonoptimal fuel systems, based on life-cycle cost. Location, Washington, D. C.; 1981 dollars. (Competitive region for each group is the area below its break-even line. (See table III for key to groups.)

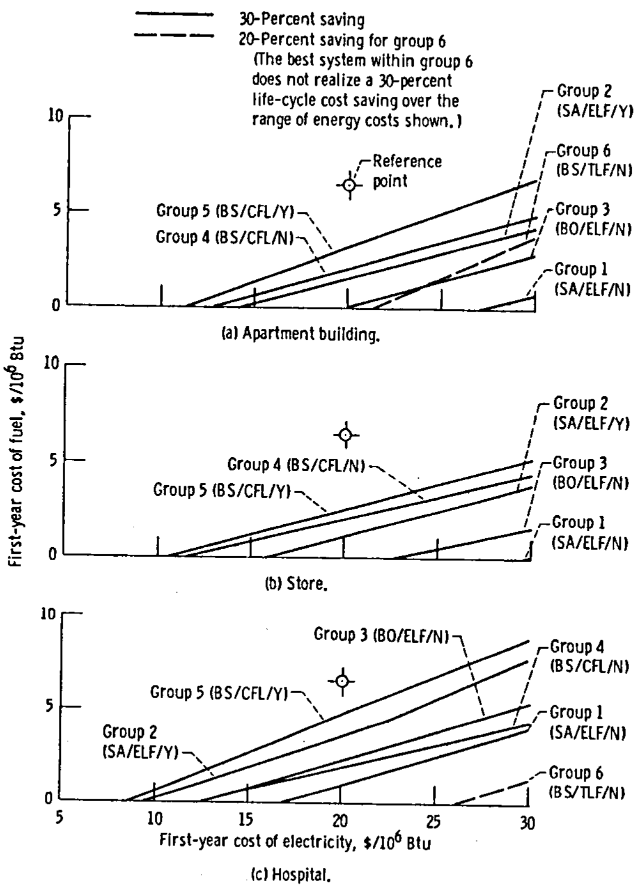


Figure 22. - Comparison of nonoptimal fuel cell groups based on 30-percent life-cycle cost savings. Location, Washington, D.C., 1981 dollars. (Life-cycle cost savings are greater than 30 percent (20 percent for group 6) below the line shown for each group. See table III for key to groups.)

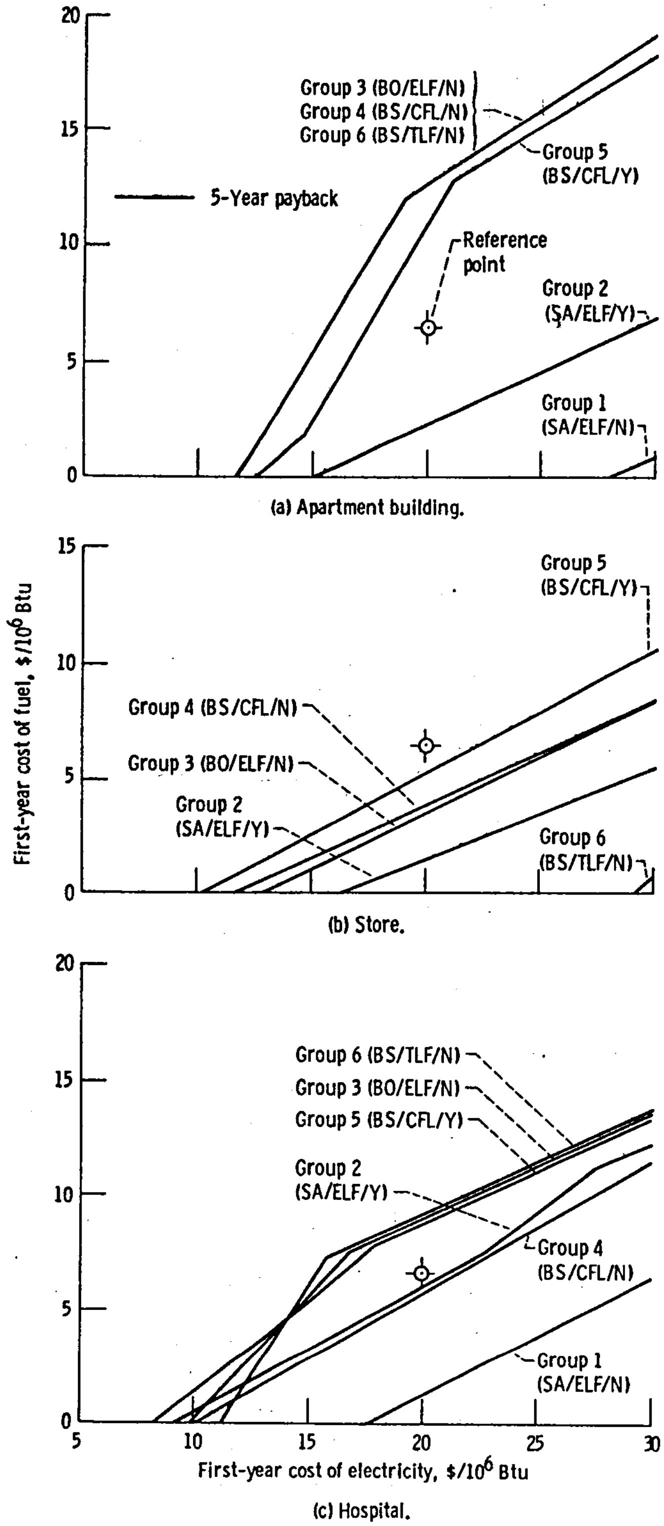
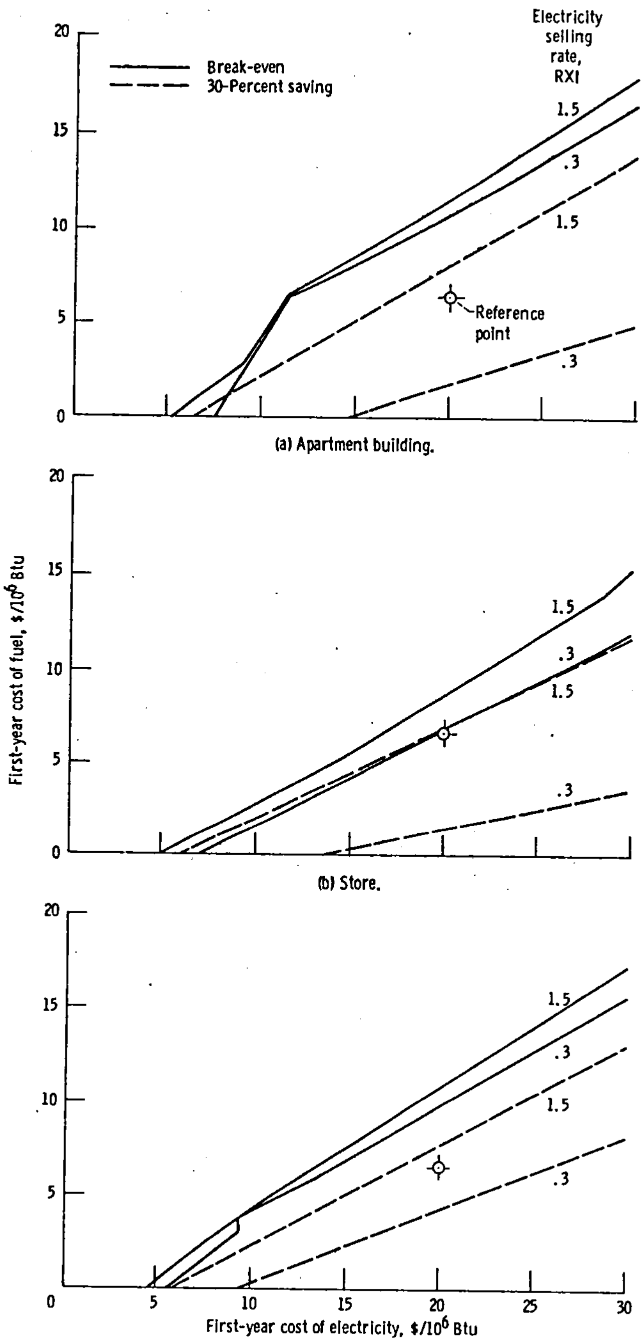
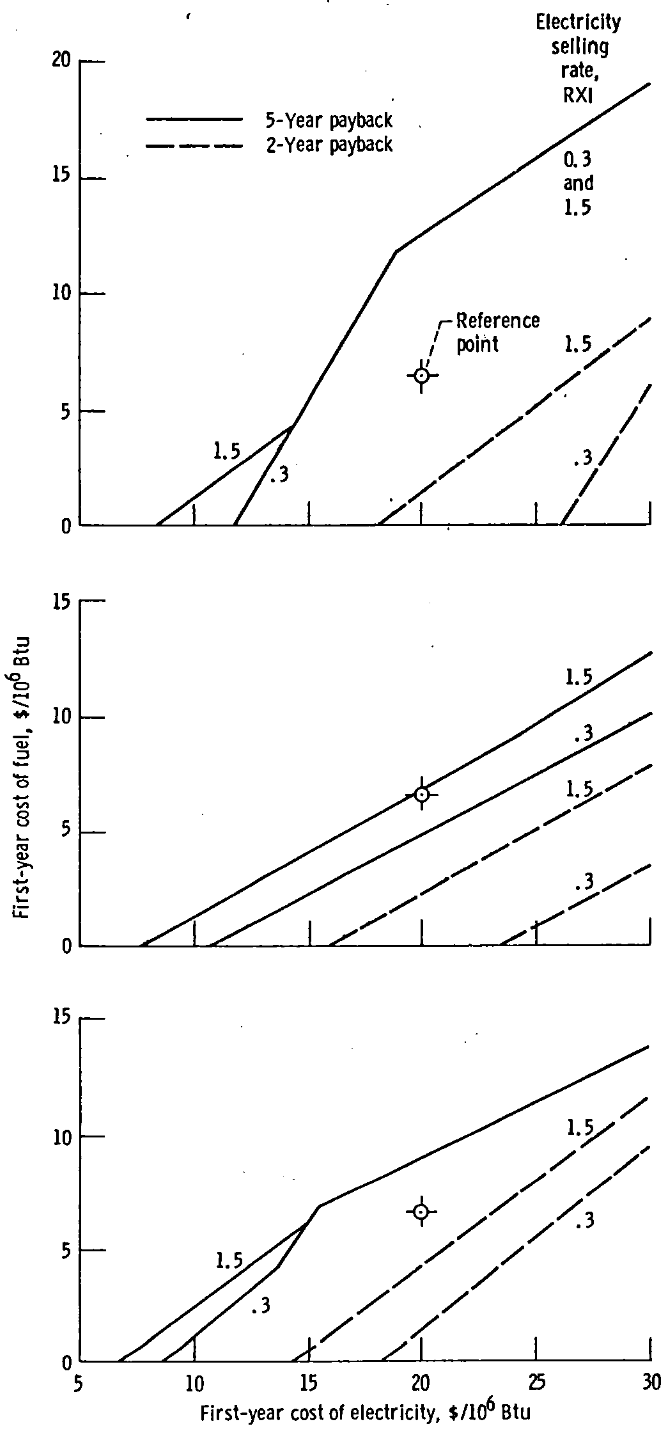


Figure 23. - Competitive regions for nonoptimal fuel cell systems based on 5-year payback period. Location, Washington, D.C.; 1981 dollars. (See table III for key to groups.)



(c) Hospital.

Figure 24. - Effect of electricity selling rate on life-cycle cost savings. Location, Washington, D. C.; 1981 dollars.



(c) Hospital.

Figure 25. - Effect of electricity selling rate on payback period. Location, Washington, D.C.; 1981 dollars.

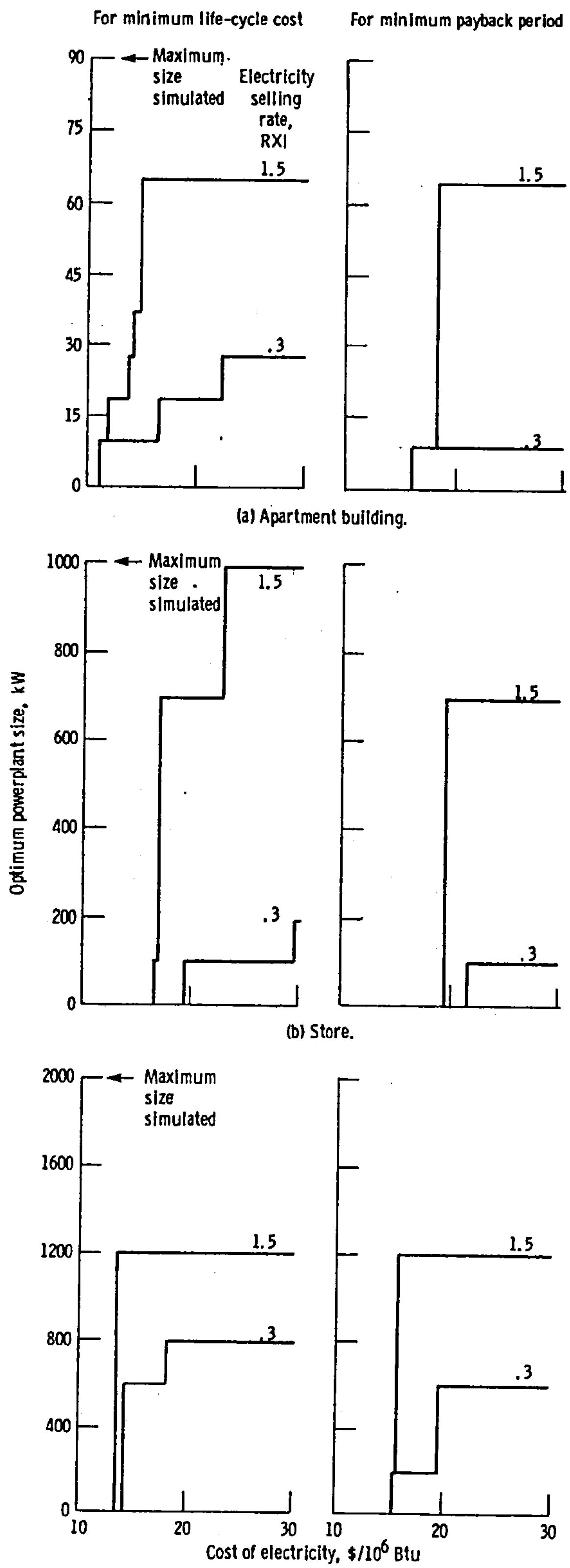


Figure 26. - Effect of electricity selling rate on optimum powerplant size. Natural gas cost, $\$6.50/10^6$ Btu; 1981 dollars.

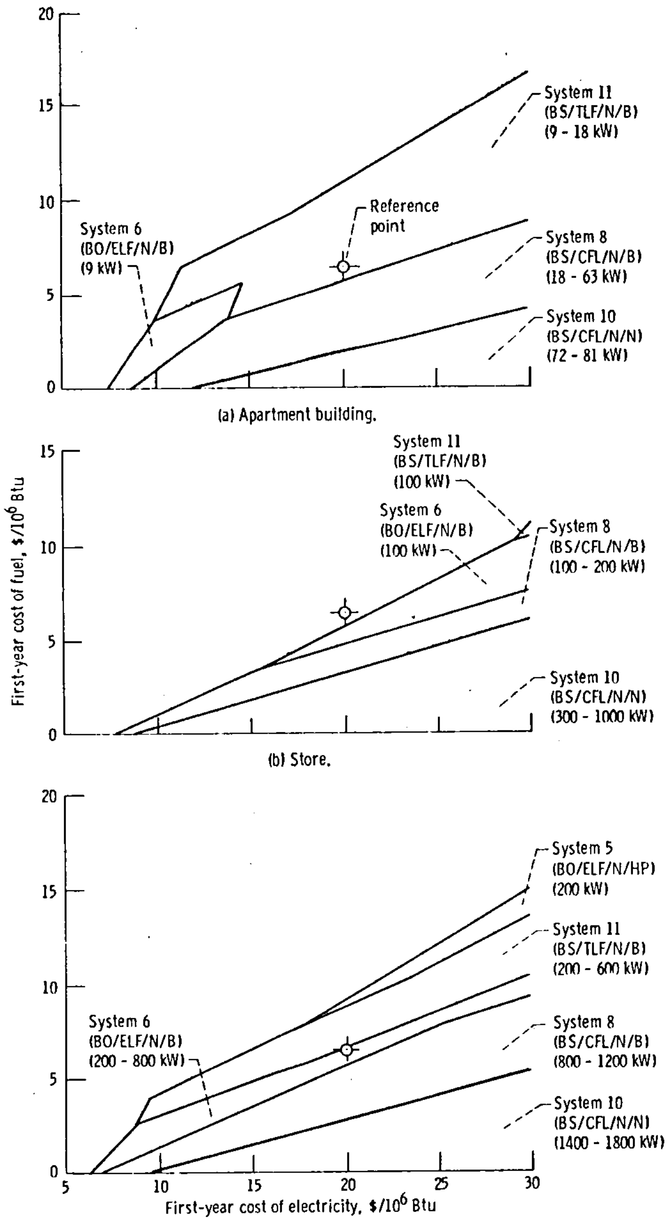


Figure 27. - Optimum fuel cell system without absorption chiller, based on life-cycle cost analysis. Location, Washington, D.C.; 1981 dollars. (See table II for key to systems.)

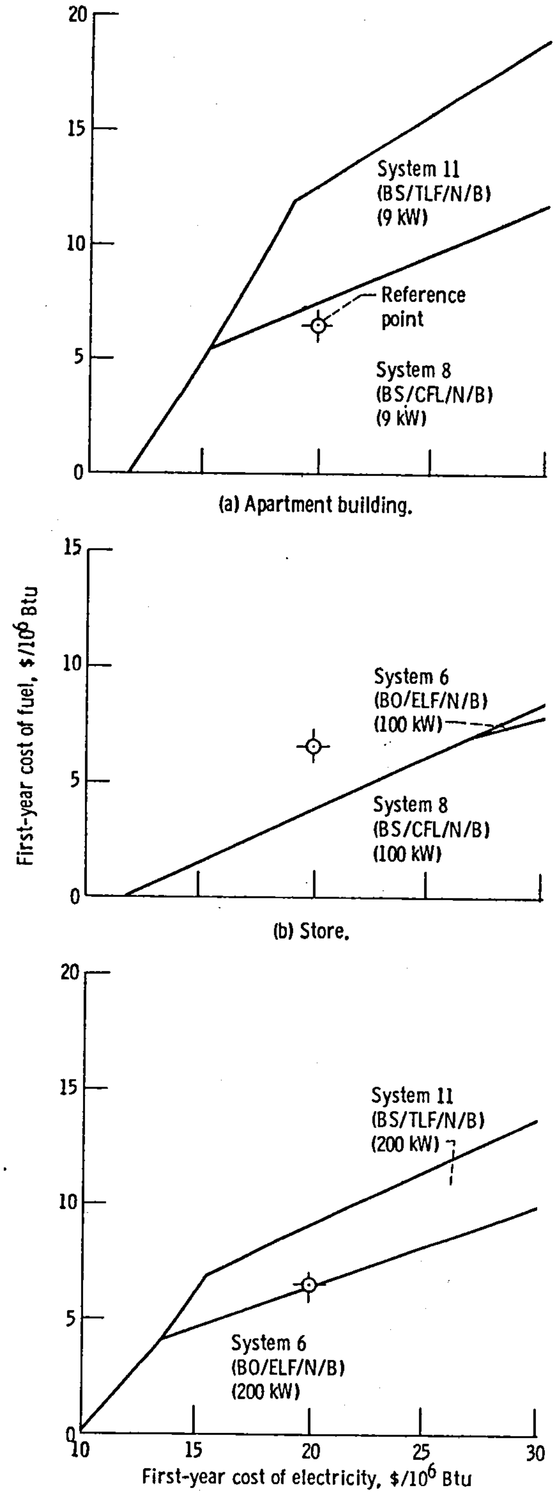
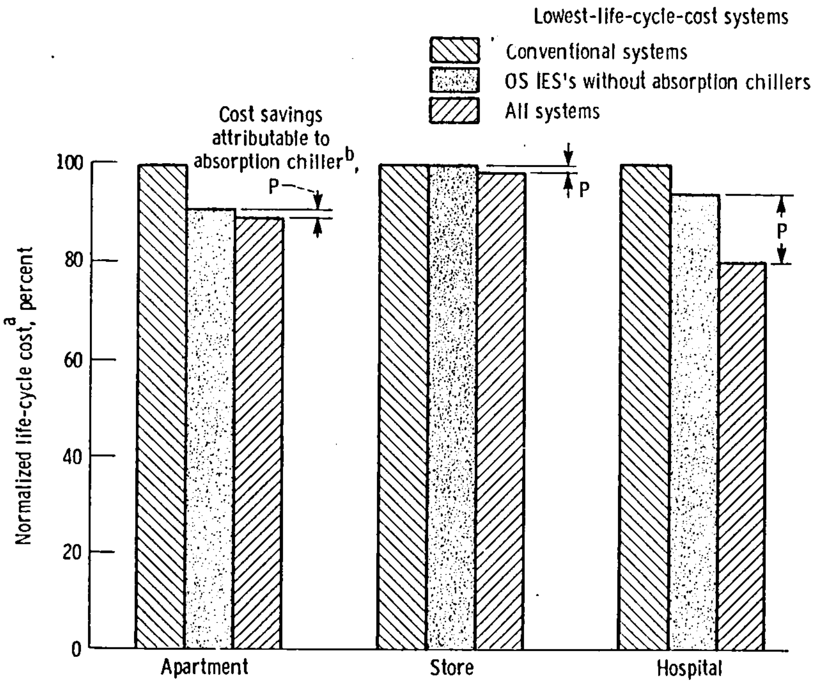


Figure 28. - Optimum fuel cell system without absorption chiller, based on payback analysis. Location, Washington, D.C.; 1981 dollars. (See table II for key to systems.)



[a]Life-cycle cost of best conventional system = 100 percent. (All costs at reference point.)

[b]To convert to percent savings attributable to absorption chillers divide by life-cycle cost of fuel cell system without an absorption chiller.

Figure 29. - Life-cycle costs of conventional energy systems and onsite integrated energy systems with and without absorption chillers.

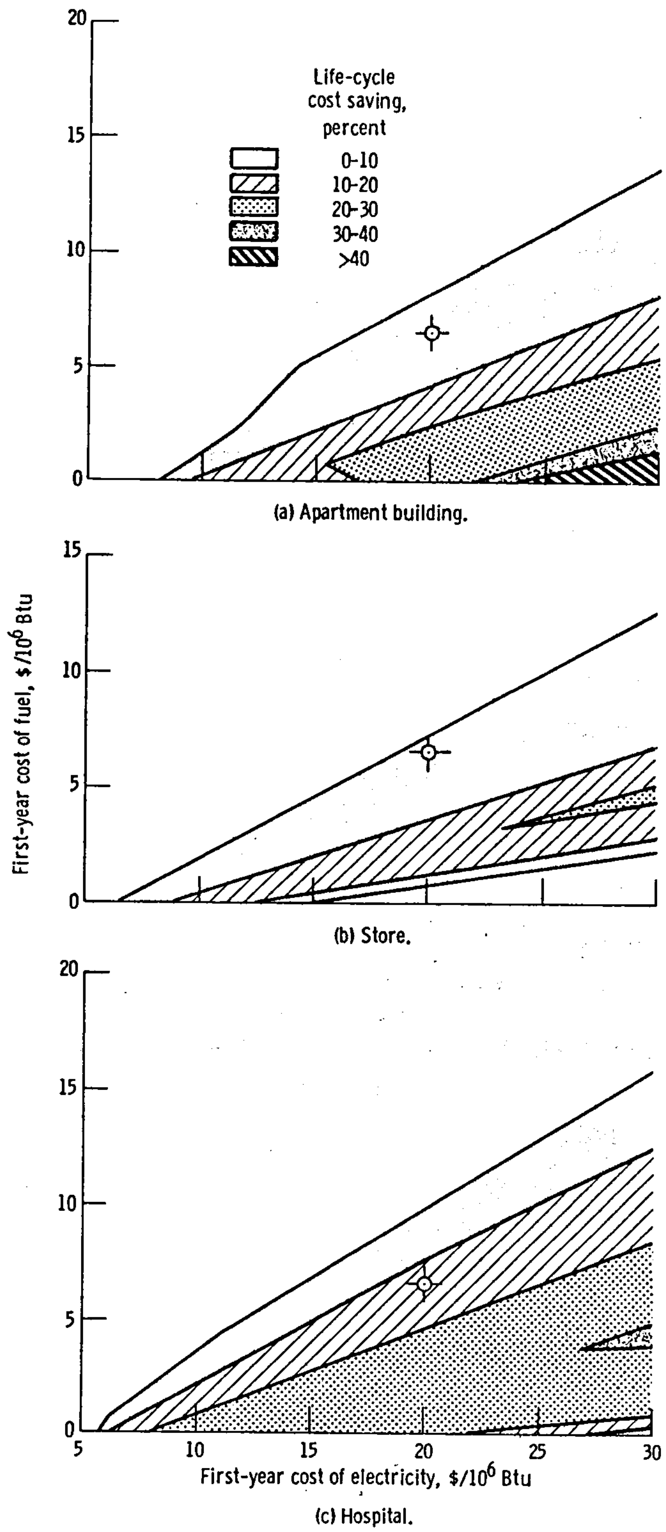


Figure 30. - Life-cycle cost savings attributable to absorption chiller. Location, Washington, D. C.; 1981 dollars.

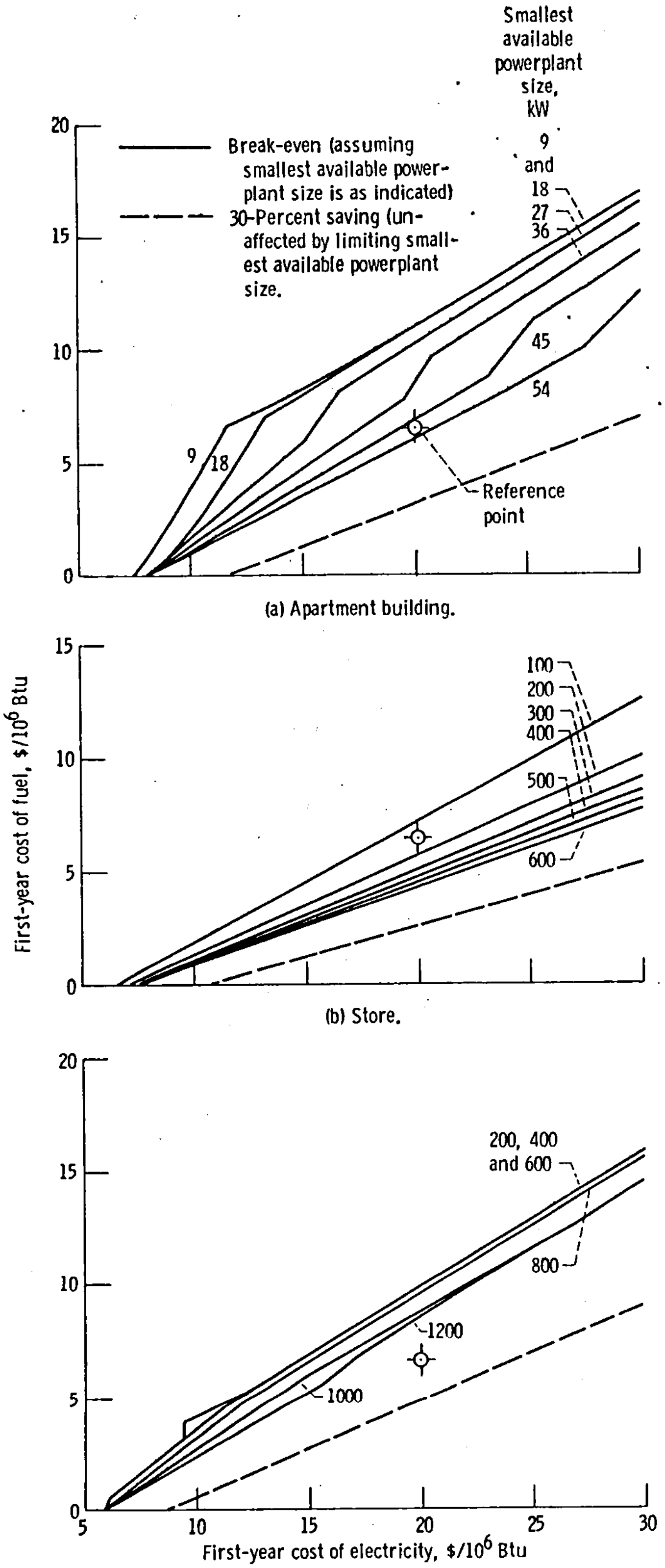


Figure 31. - Effect on competitive range based on life-cycle cost of limiting smallest available fuel cell powerplant size. Location, Washington, D.C.; 1981 dollars.

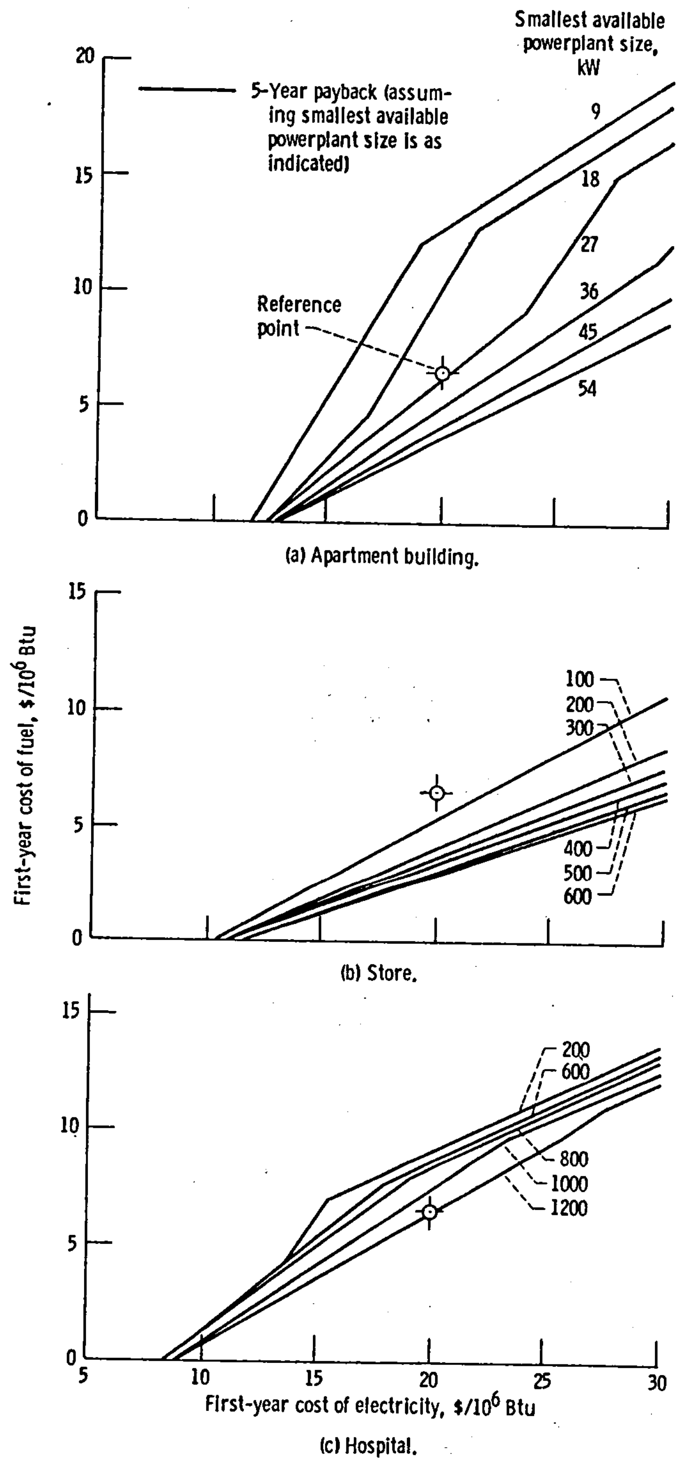
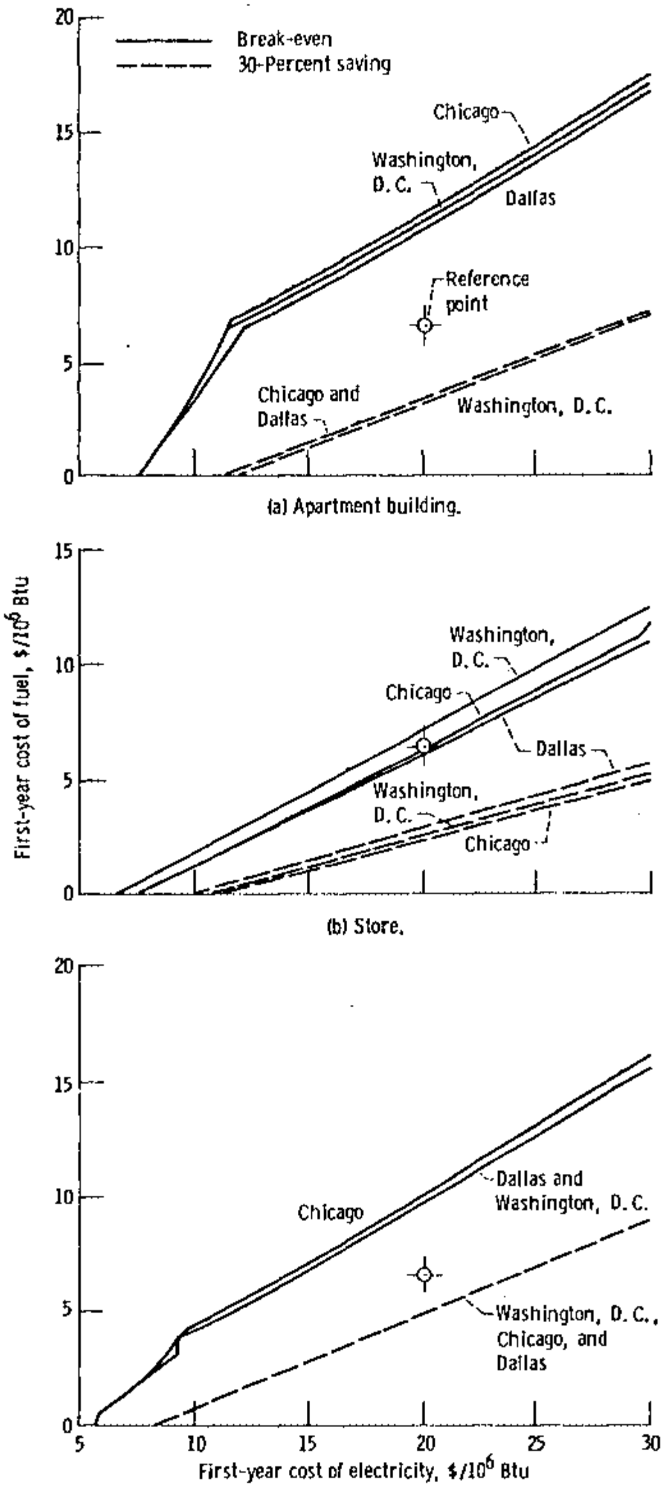


Figure 32. - Effect on competitive range based on payback period of limiting smallest available fuel cell powerplant size. Location, Washington, D. C.; 1981 dollars.



(c) Hospital.

Figure 33. - Effect of climate on competitive region based on life-cycle cost. 1981 Dollars.

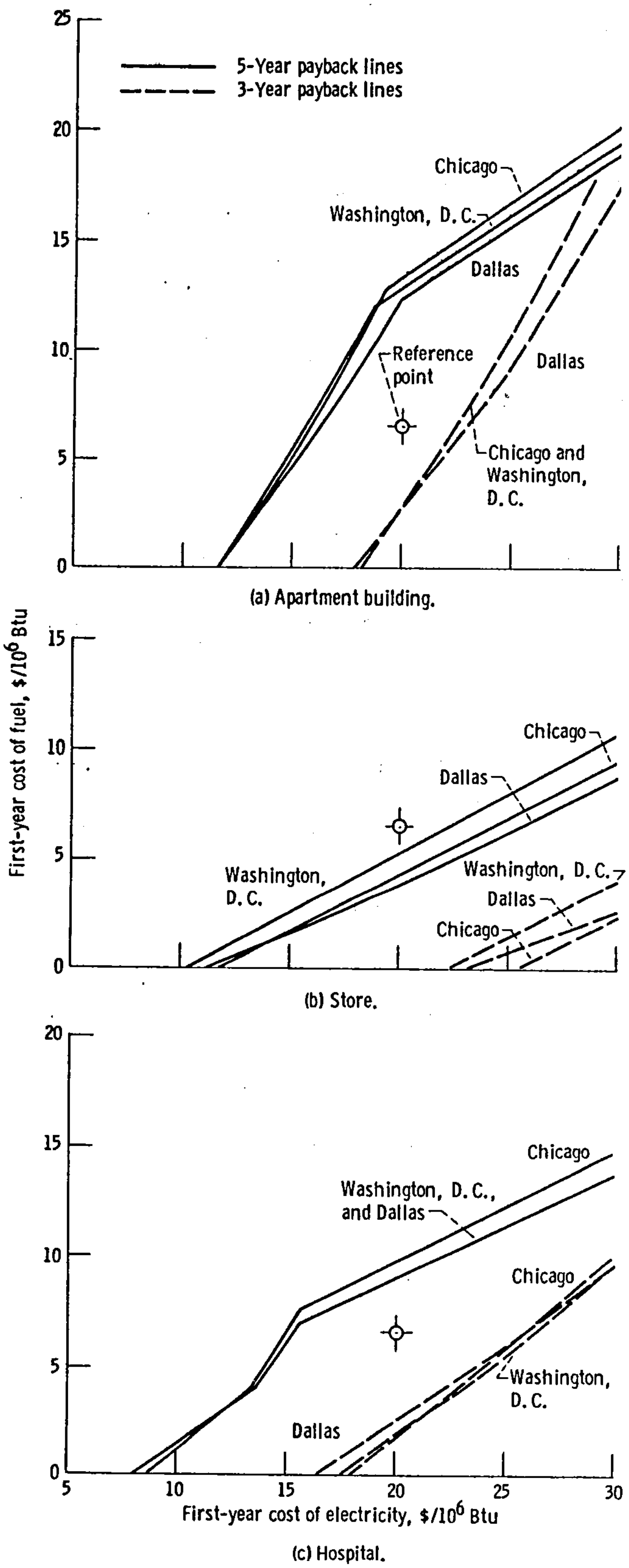


Figure 34. - Effect of climate on competitive region based on payback period. 1981 Dollars.

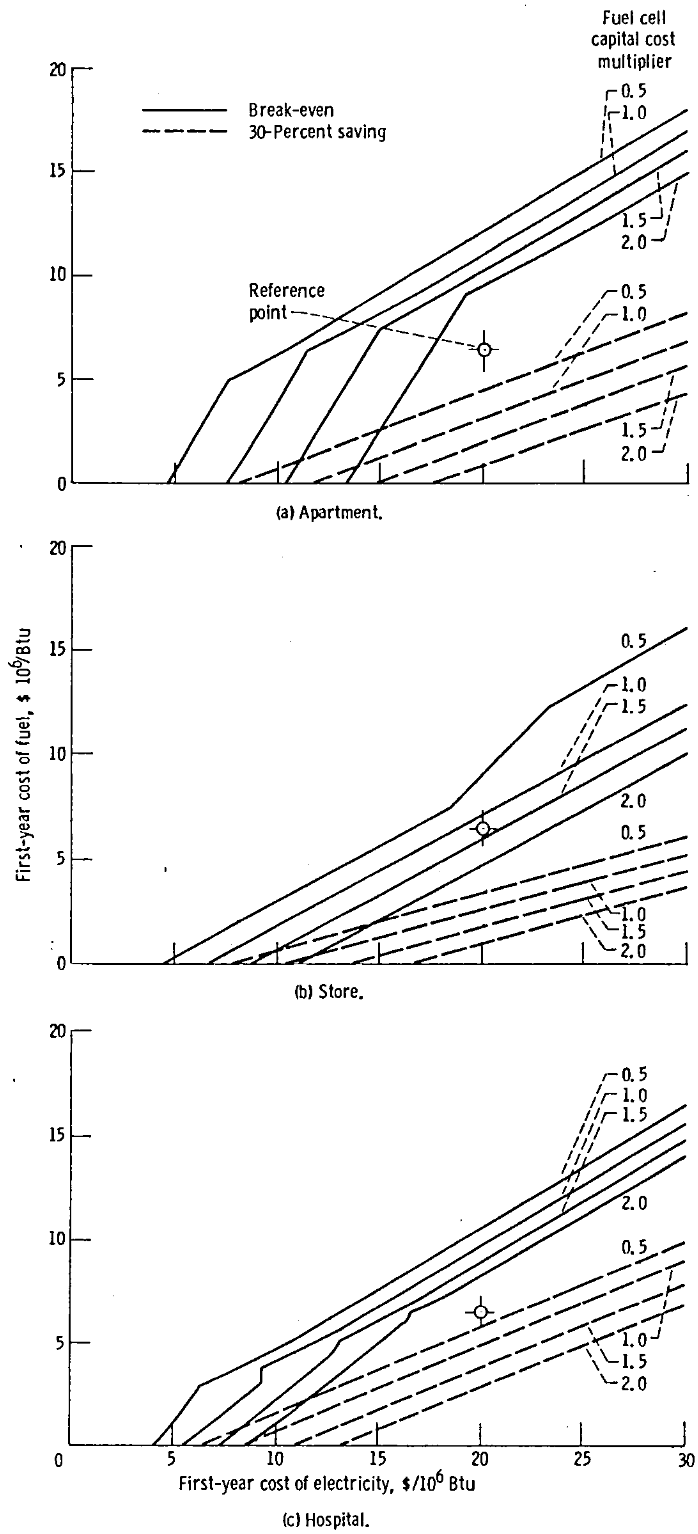


Figure 35. - Effect of fuel cell powerplant capital cost on life-cycle cost savings. Location, Washington, D. C.; 1981 dollars.

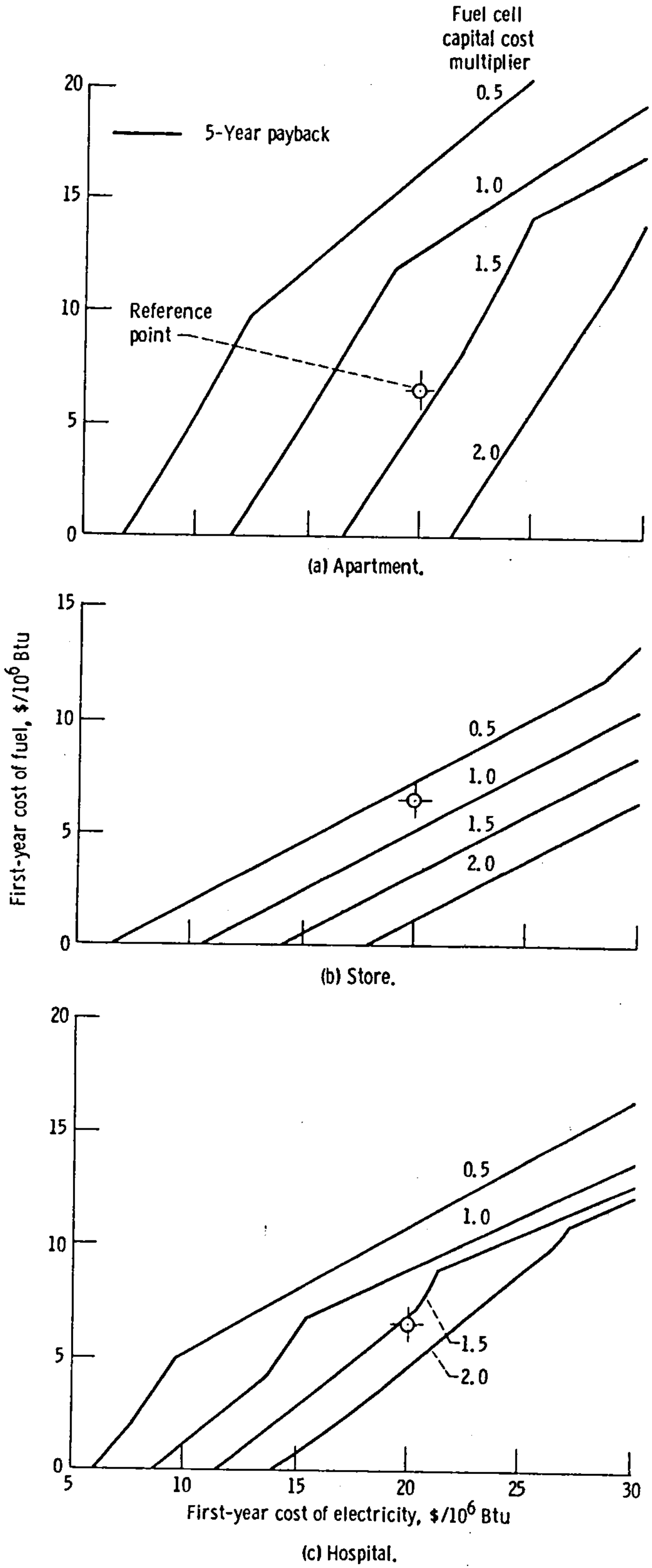


Figure 36. - Effect of fuel cell powerplant cost on payback period. Location, Washington, D.C.; 1981 dollars.

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16. Abstract

This report examines the economic competitiveness of fuel cell onsite integrated energy systems (OS/IES) in residential and commercial buildings. The analysis is carried out for three different buildings with each building assumed to be at three geographic locations spanning a range of climatic conditions. Numerous design options and operating strategies are evaluated and two economic criteria are used to measure economic performance. In general the results show that fuel cell OS/IES's are competitive in most regions of the country if the OS/IES is properly designed. The preferred design is grid connected, makes effective use of the fuel cell's thermal output, and has a fuel cell powerplant sized for the building's base electrical load.

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