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ASSESSMENT OF HYDROGEN-FUELED PROTON EXCHANGE MEMBRANE FUEL CELLS FOR DISTRIBUTED GENERATION AND COGENERATION

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Abstract

Proton exchange membrane fuel cells (PEMFCs) are highly efficient power generators, achieving up to 50-60% conversion efficiency, even at sizes of a few kilowatts. PEMFCs have zero pollutant emissions when fueled directly with hydrogen, and near zero emissions when coupled to reformers. These attributes make them potentially attractive for a variety of applications including electric vehicles and distributed generation and cogeneration of heat and power in buildings. Over the past few years, there have been intense efforts worldwide to develop low-cost PEMFC systems. While the primary focus has been on vehicle applications, an equally important application may be combined heat and power generation in commercial and residential buildings.

In this progress report (covering the period July 1999-May 2000), we summarize results from ongoing technical and economic assessments of hydrogen-fueled proton exchange membrane fuel cell systems for distributed generation and cogeneration in residential markets . The objective of this research is to understand the prospects for hydrogen fueled PEMFC cogeneration technology for residential applications, and to identify the conditions under which hydrogen fueled PEM fuel cells might compete with other distributed generation options. Engineering and economic models of PEM fuel cell systems are developed for a variety of configurations. Using realistic load profiles for single and multi-family residential buildings, we size the system components and estimate the cost of producing electricity and cogenerated heat for a range of PEMFC costs, energy prices, and system sizes. The potential impact of distributed benefits will be addressed in future work under this contract. This work was carried out as part of the systems analysis activity of the US Department of Energy Hydrogen R&D Program under Contract No. DE-FG01-99EE35100.

Introduction

Motivation and Background

Proton exchange membrane fuel cells (PEMFCs) are highly efficient power generators, achieving up to 50-60% conversion efficiency, even at very small sizes (down to the household level – 1 to 5 kW). PEMFCs have zero pollutant emissions when fueled directly with hydrogen, and near zero emissions when coupled to reformers. These attributes make them potentially attractive for a variety of applications including electric vehicles and distributed generation and cogeneration of heat and power in buildings.

Over the past few years, there have been intense efforts worldwide to develop low-cost PEMFC systems. While the primary emphasis has been on vehicle applications, an equally important application may be combined heat and power generation in commercial and residential buildings.

Since the 1970s, there have been ongoing efforts to commercialize fuel cell cogeneration systems for use in buildings. Initially, these efforts focussed on phosphoric acid fuel cell (PAFC) technology. Phosphoric acid fuel cell (PAFC) systems run on reformed natural gas have been developed in the 200 kW size range for commercial building applications. These have shown good operational characteristics and reliability. However, the current capital cost of PAFC systems ($3000/kW) is still too high for large penetration into building markets. Even at larger scale production PAFC system costs are projected to be $1500/kW, and would face tough competition from natural gas fired engines or microturbines in the 50-500 kW size range.

Recently there has been considerable R&D aimed at commercializing PEMFC systems for cogeneration in buildings. PEM fuel cell cogeneration systems in the 200 kW size range are under development (a size appropriate for commercial or multifamily residential buildings), as well as smaller units (in the 5-10 kW size range), for use in individual houses.

There are several reasons why PEMFCs might become competitive for buildings applications before they appear in vehicles:

> 1) The cost barrier is lower for PEMFC cogeneration systems than for automotive applications. To compete with internal combustion engines in automobiles, PEMFCs must achieve stringent cost goals of perhaps $50/kW. Recent studies indicate that significant cogeneration markets in commercial buildings could open for PEMFC stack costs of perhaps $300-500/kW (corresponding to complete system costs of $1000-1500/kW) [1]. Residential markets might open at stack costs of ~$200/kW [2].
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> 2) The technical challenges are in many respects less severe for stationary power generation than for vehicles. (Start-up behavior and transient operation is likely to be less of a problem for power generation than for vehicles which are characterized by rapidly varying loads; heat and water management issues should be much easier; weight and volume constraints are less stringent; peak power devices will not be needed; control systems should be simpler; robustness and resistance to mechanical shocks during driving will not be an issue.) In one respect, technical requirements are more demanding for cogeneration applications: a longer operating lifetime (50,000-100,000 hours) would be needed for a stationary power system as compared to perhaps 5000 hours for vehicles.

3) Infrastructure considerations might be easier for hydrogen fueled stationary power systems than for hydrogen vehicles. Hydrogen could be made as needed for PEMFC systems in buildings from widely available natural gas at the individual building or neighborhood level.

Scope of this Study

In this study we are carrying out a series of detailed technical and economic assessments aimed at understanding the prospects for hydrogen fueled PEM fuel cell cogeneration technology for residential applications. We concentrate on hydrogen derived from natural gas, a primary energy source which is widely available today, and is likely to give the lowest hydrogen cost in the near term.

We compare three types of PEM fuel cell cogeneration systems which could provide power and heat to residential users (see Figure 1).

Case 1) a centralized "neighborhood" scale (200-1000 kW) natural gas reformer/PEM fuel cell system which distributes heat (via district heating) and electricity (via wire) to 40-200 residential users.

Case 2) a centralized "neighborhood" scale natural gas reformer, which produces hydrogen or a hydrogen rich gas for distribution to users. Each house has a small hydrogen fueled (1 to 5 kWe) PEM fuel cell providing electricity and heat.

Case 3) individual natural gas reformers coupled to small (1 to 5 kW) PEM fuel cells at each house.

For each case energy storage (in the form of hydrogen storage, hot water storage or electric batteries) could be used to meet time varying energy demands. Connections to the electric utility system could be made at the household or neighborhood level, allowing dispatch of power.

Building on earlier work by our group for the USDOE Office of Transportation Technologies CARAT program [5], we have developed engineering and economic models of hydrogen PEM fuel cell based cogeneration systems. The potential advantages and disadvantages of each configuration are investigated in terms of overall energy efficiency, performance, economics (capital cost, delivered cost of electricity and heat), and greenhouse gas emissions. PEMFC cogeneration systems are compared to other alternatives for production of residential heat and power.

Several tasks are underway:

Task 1. Develop engineering models of various types of PEM fuel cell cogeneration systems capable of supplying residential heat and power at a household and neighborhood level. Model heat-integrated PEMFC cogeneration system using ASPEN-Plus software to simulate steady state performance.

Task 2 Develop component sizing algorithms for various types of PEMFC cogeneration systems, based on the demand profile, energy prices, component performance and scale (single house vs. multi-family).

Task 3 Investigate design trade-offs for various options: Reformer type (steam reformer vs. autothermal reformer); operating strategy (load following vs. non-load following);

cogeneration (hot water and/or space heating?); scale (single vs. multi-family); various types of loads; energy prices (natural gas, electricity); and utility connection strategies.

Task 4. Discuss the costs and trade-offs involved in distributing different forms of energy to houses (case 1: electricity and heat , case 2: hydrogen or hydrogen-rich gas, case 3: natural gas.

Task 5. Estimate the cost of electricity and heat from PEM fuel cells, as compared to alternatives.

Task 6. Analyze and discuss the role of distributed benefits and emissions benefits in the economic competitiveness of fuel cells. Estimate the required component cost and performance goals for small scale PEMFC cogeneration systems to compete economically with alternatives, when distributed and emissions benefits are included. (This task is being performed in coordination with researchers at Distributed Utilities Associates.)

Tasks 1, 2, 3 and 5 are essentially completed and results will be given in this report, Tasks 4 and 6 will be completed in future work, and will be discussed in the final report for this contract.

Modeling the PEMFC Cogeneration System (Tasks 1, 2, 3 and 5)

System Design Options

The primary components of a residential PEMFC cogeneration system (as shown in Figure 2) are: 1) a fuel processor that converts natural gas into a hydrogen-rich fuel gas for the fuel cell, 2) a proton exchange membrane fuel cell (PEMFC) stack (and integrated air blower) that generates DC electricity from the hydrogen, 3) power conditioning electronics that convert the DC electricity into grid-quality AC power, 4) an optional battery subsystem to increase the peak power of the system, and 5) optional cogeneration for hot water production and/or space heating.

As shown in Figure 1, a variety of paths are possible for using natural gas derived hydrogen PEMFCs to supply power and heat to single-family or multi-family residences. In our results to date (which cover "case 3" above), we have assumed a connection to the electrical transmission grid so that the fuel cell power system is not required to provide *all* of the electrical load; rather, it generates a portion of the residential power demand while the grid provides "back-up" power when demand exceeds the fuel cell capacity. Cogeneration of hot water and space heating are considered as system options. The options of space and water heating from natural gas are included. Cases 1 and 2 will be explored in future work on this contract.

We assume that the system is owned by the consumer as a home (or neighborhood) "energy appliance" that generates electricity (and, optionally, heat). The consumer's economic motivation for installing a fuel cell cogeneration system is to reduce overall energy costs relative to standard utility service. [In future work (Task 6), we plan to address the economics of distributed generation systems that are owned and potentially dispatched by the electric utility in order to capture various economic benefits associated with distributed power generation.]

A variety of options are examined that determine the system performance and economics. These include:

- Various reformer types (steam reforming vs. autothermal reformer).
- Various building sizes and types of energy load (single-family vs. multi-family dwelling vs. multiple single-family dwellings).
- Optional cogeneration of hot water or space heat.
- Various strategies for operating the fuel cell system. The power output can be: 1) varied during the day to meet the building electrical load (such a system is called a "load follower"), or 2) operated continuously at full load with the excess electricity sold back to the utility at reduced rates ("non-load follower").
- Various utility interconnection scenarios (standard single meter, PURPA-type dual meters, monthly net metering, stand alone/grid-isolated system.)
- Various gas and electricity prices.
- Various assumptions about capital and O&M costs for the system.

We estimate the cost of electricity and the internal rate of return to the consumer for a variety of cases. We perform sensitivity analyses to identify the most important variables governing system performance and economics. The estimated cost of residential electric power from PEM fuel cells is compared to other electricity supply options, including grid power and microturbines.

System Component Models

PEMFC Stack

To model fuel cell (FC) stack performance, we use the measured performance (Fig. 3) of the IFC PC-29, a 50 kW atmospheric pressure, hydrogen-air, automotive PEMFC stack (with an integrated variable-speed blower) built by International Fuel Cells and delivered to the US Department of Energy in the fall of 1997 [3]. Our fuel cell model consists of an analytic formula used to fit the PC-29 performance data, with scaling variables included that allow us to model cogeneration systems of arbitrary size. We assume that the net fuel cell system efficiency curve as a function of power (see Fig. 3) is invariant with system scale. This allows us to model fuel cells over a range of sizes from about 1 to 100 kW.

Hydrogen utilization of 80% is assumed for PEMFCs run on reformate.

Fuel Processor

Hydrogen is produced from natural gas in a fuel processor at the neighborhood or household level. The fuel processor is a series of catalytic chemical reactors that convert natural gas into PEMFC-quality hydrogen gas. As shown in Fig. 2, the first stages of the fuel processor is a fuel reformer - either a steam methane reformer (SMR) or an autothermal reformer (ATR) - that converts natural gas into a synthesis gas that is rich in H_2 and CO. The syngas is then processed in high- and low-temperature water-gas shift reactors that convert the bulk of the CO to H_2 (down to ~0.5%vol). Finally, a preferential oxidation (PROX) unit is used remove CO (to less than ~100 ppmv) from the reformate in order to avoid poisoning the catalyst in the fuel cell anode. The fuel processor includes ancillary equipment such as a steam generator and numerous heat exchangers for heat integration.

Steady state heat and mass balances for integrated fuel processor/fuel cell systems were modeled using commercial (Aspen Plus) software [4]. The fuel processor energy efficiencies calculated in our model for steam methane reformers and autothermal reformers are shown in Table 1. Fuel processor models were adapted from those developed as part of earlier work for the DOE OTT CARAT program [5].

Table 1.Three definitions for the LHV energy efficiency of fuel processors; we use the third in this study

Definition of η_{FP}	η_{FP}(SMR)	η_{FP} (ATR)
$\frac{LHV\ of\ H_2\ out}{LHV\ of\ NG\ in}$	93.8%	83.9%
$\frac{LHV\ of\ H_2\ out}{LHV\ of\ (NG+AE)\ in}$	67.4%	71.8%
$\frac{LHV\ of\ H_2\ consumed}{LHV\ of\ NG\ in}$	75.0%	67.1%

The fuel processor efficiency is assumed to be independent of power and system size over a given turndown ratio (*TDR*), where TDR is defined as the ratio of the maximum to the minimum power. It is further assumed that the fuel cell cogeneration system runs continuously, *never* operating below its minimum power level. When the electricity demand falls below the minimum power level, the excess power is either stored, sold back to the grid, or lost. (One might envision a very low-power "stand-by mode" for use at night, in which the fuel processor (and stack) consumes just enough power to keep the catalysts warm. In the end, we chose not to include a standby mode in the model because we found that, in an optimally sized system with a reasonable turndown ratio (*TDR*=5), there is very little excess power to sell. As a result, the overall cost of electricity is quite insensitive to whether the excess power is sold or lost.)

Power Conditioning Electronics

Power conditioning (PC) electronics make up the third component of the system. If the stack contains enough individual fuel cells to generate a sufficiently high voltage (~350-600 V), a DC→DC voltage up-conversion is not necessary prior to DC→AC conversion with an inverter [6]. Because we investigate systems as small as a few kW, it is assumed that DC→DC up-conversion is required for *all* systems, regardless of scale. Both the DC→DC and DC→AC conversions are assumed to take place at a constant energy efficiency of 96% [6], for a total power conditioning efficiency, η_{PC}, of 92%.

Hot Water Cogeneration (Optional)

A hot water cogeneration system is included as an option (Fig. 4). [As discussed below, there is a good match (in both temperature and quantity) between the domestic hot water demand and the waste heat from the PEMFC stack, but, cogeneration for space heating does not appear to be economically viable and is not explored in this study.] To minimize both capital and installation/retrofit costs, the cogeneration system employs only liquid/liquid heat exchangers (i.e. heat is not recovered from the stack but not from the cathode exhaust), and utilizes a pre-existing natural gas-fired hot water tank. The tank is assumed to have a 50 gal capacity, a HHV energy efficiency of 76%, and a HHV energy factor (i.e. including standby losses) of 70.1%. Aspen modeling of the heat recovery scheme in Fig. 4 indicates that ~68% of the waste heat from the stack can be captured as 60 C water for domestic hot water.

The cogeneration system is operated with a time varying load (determined by the building electricity demand profile), while continuously monitoring the extent to which water in the tank is fully heated. The available waste heat at any point in the fuel cell operating range was estimated with a simple linear fit to the PC-29 data shown in Fig. 3. Operationally, the tank is held between a minimum "set point" of 90% and a maximum of 100% by: 1) discarding any surplus hot water, and 2) firing the tank burner with natural gas when the tank falls below the set point. The 90% set point insures that adequate hot water is always available to the consumer, while leaving 10% of the full tank capacity for buffering the PEMFC stack from the domestic hot water demand.

Total Fuel Cell System Efficiency

The total fuel cell system efficiency [natural gas (LHV) to electricity] is the product of the stack net electrical efficiency (which varies with system output as shown in Figure 3) times the fuel processor efficiency (which is found from our ASPEN simulations to be 75.0% for a steam methane reformer) times the power conditioning efficiency, which is assumed to be 92%. Multiplying these factors together, we find a total system efficiency which varies with power output as shown in Figure 5. The maximum system electrical efficiency is about 36% which occurs at 20% part load.

Costs for Distributing Energy from Neighborhood Fuel Cell Systems

In cases 1 and 2 (Figure 1), electricity, heat or hydrogen-rich syngas are distributed to houses. Costs for distribution are being developed, and will be used in future work under this contract (Task 4).

Residential Electric Load Profiles

In order to model system performance, we obtained time-resolved electric load profiles for single- and multi-family residences from a series of studies on residential and commercial energy use by Lawrence Berkeley National Laboratory (LBNL) and the Gas Research Institute (GRI) conducted between 1988 and 1990 [7,8,9]. In those studies, the existing stock of U.S. residences was surveyed and broken down in to a small number of categories (from 8 to 16 different types in each of 16 separate U.S. climatic regions) that represent the dominant building practices between 1940 and 1990. Using DOE-2 software, prototypical model buildings were created for each category in each geographic region.

Space heating, cooling, and electric loads were generated on an hourly basis by subjecting each prototype to WYEC (Weather Year for Energy Calculations) weather tapes, which encapsulate average weather data (temperature, humidity, wind speed, solar insolation, etc.) throughout a "typical" year. In this study we focus primarily on the New York/New Jersey region because its energy prices are highly favorable for cogeneration systems (i.e. relatively high electricity prices and relatively low natural gas prices). Results presented here are calculated for the so-called "B1A" prototype, a thermally-improved, 2-story, wood frame house with a basement, built between 1950 and 1970. The NYBIA prototype represents the largest category of homes in the New York region and, as will be shown later, is a good representative for all New York dwellings from the standpoint of the economics of PEMFC cogeneration.

Hourly energy demand, broken out as HVAC and non-HVAC electric, space heating, and hot water, are shown for a winter and a summer day in Figs. 6a and 6b. The difference in electric loads during summer and winter shown in the two figures is indicative of the characteristic "peakiness" of residential electric loads throughout the year. The peak hourly electric load for the whole year is 4.4 kW, while the average is only 1.0 kW. Depending on the connection scenario between the PEMFC system and the electric grid, the system economics can be quite sensitive to this peak-to-average load ratio, since the peak power governs the system size (i.e. maximum power output) - and therefore cost - while the average power controls the rate at which the system can generate revenue by producing power at a lower cost than it can be purchased from the public utility.

Figures 6a and 6b also illuminate the prospects for space heating and hot water cogeneration. In both figures the hot water demand is seen to be smaller than the electricity demand and also fairly well correlated (temporally) with it. Waste heat from the stack appears to be well matched with the hot water demand, both in terms of magnitude and temperature. These figures suggest that hot water cogeneration is a likely prospect, probably not requiring an unusually large storage tank to act as a buffer between supply and demand. In contrast, the space heating and electric loads are anti-correlated, with the space heating demand largest in winter when the average electric load is smallest, and vice versa.

The dim prospects for space heating cogeneration can be seen more clearly in Fig. 7 where the monthly average energy loads for the New York B1A prototype are plotted throughout the year. The peak demands for space heating and space cooling are out of phase by many months making thermal storage impractical. Furthermore, the space heating demand dwarfs the waste heat available from a PEMFC system, especially if the bulk of the heat (from the stack) is already used for hot water production. Finally, space heating cogeneration may require more expensive gas-liquid (or gas-gas) heat exchangers and more complex installation than hot water cogeneration. For these reasons, cogeneration for space heating does not seems (at first glance) to be economically viable, and was not examined further. [Because PEM fuel cells operate at relatively low temperatures (70-80 C), we also did not consider absorption air conditioning.]

In the LBNL-GRI studies, domestic hot water (DHW) demands for single-family residences were calculated on an hourly basis throughout the year. For cogeneration calculations, we modified their computer code to generate an hourly "composite" DHW load that includes both the energy for heating the water as well as "standby losses", i.e. heat loss from the storage tank. The calculations are based upon the national average hot water consumption of 62.4 gal/day/person, 3 persons/household, a tank temperature 140 F (60 C), and in the base case (New York region), a well temperature of 52 F (11.1 C) and an average air temperature of 54.2 F (12.3 C).

System Economic Assumptions

In order to estimate the long-term potential economics of PEMFC cogeneration, we use cost estimates for PEM fuel cell cogeneration systems manufactured in high volume (e.g. hundreds of thousands of units per year—similar to the scale projected for manufacturing automotive fuel cell systems). As such, contingencies and design and engineering costs are deliberately excluded. The capital cost for each system component is assumed to be a linear function of its size (kW), with a cost-axis intercept that represents the minimum cost for manufacturing the system at *any* size.

Because cost and performance estimates for automotive components are more readily available than for stationary systems, we have chosen to construct the PEMFC cogeneration system studied here out of "automotive-grade" components whenever possible. Our "high volume" case uses automotive type component cost estimates, and assumes manufacturing levels of several hundred thousand units per year. We have compared these costs to those of a recent study by Directed Technologies, Inc. of costs for stationary PEMFC systems manufactured at lower volume (10,000 units per year) [10,11].

Perhaps the most significant difference between stationary and mobile fuel cell systems is their required lifetimes. While automotive equipment is generally designed to last for only ~5000 hours, the service life of residential furnaces and hot water heaters is typically 10 years or more, roughly 18 times as long. To model a stationary power system "built" of automotive components, we assume that various components are replaced or refurbished, as required during the 10 year life of the fuel cell system.

Assumed "high volume" mass produced capital costs for PEMFC cogeneration systems made from automotive type components are given in Table 2.

- The fuel cell is assumed to be an automotive stack whose membrane electrode assemblies (MEAs) and bipolar plates are replaced at 5-year intervals. Long time (>9000 hr) performance tests on a hydrogen-fuelled PEMFC stack at Mitsubishi Electric Corporation show a degradation rate of 4 mV per 1000 hr (at 250 mA/cm^2), or 5.8% per year [12]. This implies a ~30% drop over 5 years, which would probably warrant MEA replacement at the end of that period. In this study, we assume that reformate-fueled fuel cells can be made to operate as well as hydrogen-fuelled systems (from the standpoint of degradation), and adopt a performance loss rate of 5.8%/yr, with complete MEA replacement every 5 years. For this system, whose lifetime is assumed to be 10 years, only one stack refurbishment is necessary, at the end of the 5th year.

- Detailed cost estimates for cost-optimized, high volume manufacturing of automotive fuel processors (gasoline-fueled ATR) [13] and PEMFC stacks [14] have been made by Directed Technologies Inc. (DTI) using a methodology known as Design For Manufacture and Assembly (DFMA) that has been formally adopted by the Ford Motor Company. The fuel processor costs used here ($42/kWe at a scale of 50 kWe) are somewhat higher than those obtained in cost studies performed by Arthur D. Little on their 50 kWe catalytic partial oxidation/autothermal reformer (16-29 $/kWe) [15,16]. In this study, we assume equal costs for the SMR and ATR systems.

- Price estimates for power electronics are from Trace Technologies and correspond to somewhat lower volumes (e.g. 10,000 units/yr at a size of 10 kW) [6].

- The added cost for hot water cogeneration (from stack cooling water) is assumed to be negligible; a pre-existing 50 gallon natural gas-fired hot water tank is presumed.

- Estimates for advanced lead-acid batteries are taken from a study of electric vehicle battery storage systems that was commissioned by the California Air Resources Board [17].

O&M costs include annual maintenance and replacement of MEAs and bipolar plates after year 5. The equipment is assumed to have no salvage value at the end of its lifetime. System availability is assumed to be 99.7%, based on a single day of down time per year for scheduled and unscheduled service. A real discount rate of 8% and a system lifetime of 10 years are assumed.

We use as our base case scenario New Jersey residential gas and electric prices, 6.07 \$/MMBtu HHV (2.07 ¢/kWh) and 12.65 ¢/kWh, respectively; the disparity between the two provides an exceptionally favorable economic climate for PEMFC cogeneration.

Table 2. Component costs and economic assumptions[a]

System Component Costs (high volume case):	
- Fuel processor (\$)	$320 + 36\,P_{FC}^{max}$
- FC stack, blower, & cooling (\$)	$1073 + 22\,P_{FC}^{max}$
- PC electronics (\$)	$840 + 97\,P_{sys}^{max}$
- HW cogeneration (\$, optional)	0
- Battery sub-system (\$/kWh, opt.)	120
System Capital Cost (\$) (no battery)	$2233 + 155\,P_{sys}^{max}$
O&M Costs (exclusive of fuel):	
- Annual service (\$/yr)	100
- Stack (1 refurb at end of 5th yr, \$)	$200 + 22\,P_{FC}^{max}$
PV of O%M costs above (\$)	$761 + 15\,P_{FC}^{max}$
Delivery and Installation (\$):	$500 + 4\,P_{sys}^{max}$
Total Installed Cost (no battery), $C_{PV}(P_{sys}^{max})$ (\$)	$3494 + 174\,P_{sys}^{max}$
Economic Assumptions (base case scenario):	
- Natural gas price, R_f (\$/MMBtu, HHV)	6.07
- Purchased electricity price, (¢/kWh)	12.7
- Price for electricity sold to grid, (¢/kWh)	3.0
- Availability, *A* (%)	99.7
- Discount rate, *d* (%/yr)	8.0
- System lifetime, *Y* (yr)	10
- Capital recovery factor, *CRF* (%/yr)	14.9

In Table 2, the high volume, installed cost for the whole system (including the present value of all future maintenance, $C_{PV}(P_{sys}^{max})$, is \$3494+\$170/kW (for a system without batteries). DTI has recently formulated detailed system cost estimates for stationary PEMFC cogeneration systems manufactured in smaller volumes, from 100-10,000 units/yr. In order to investigate the relative importance of high volume manufacturing on overall system economics, we have included for comparison DTI's capital cost estimate for 10,000 units/yr: \$9656 + \$586/kW [10]. The significant increase in cost is due to smaller production runs as well as a system that is designed to have a significantly longer lifetime, for example, fuel cell MEAs that have more area, thicker membranes, and a higher catalyst loading. Note in both cases that, for relatively small systems (e.g. under 10-15 kW), the total installed cost is dominated by the constant term, i.e. only weakly dependent on system size.

In Fig. 8 we plot as a function of system size the total installed system cost (in both \$ and \$/kW), which includes overnight capital, delivery and installation, and the present value of system maintenance (including periodic replacements of the fuel cell MEAs). Reflecting our simple component cost models, the total cost rises linearly as a function of system size. The cost *per kW* varies dramatically with power. Most importantly for single-family power systems, it rises sharply below 10-20 kW.

As a point of comparison with our cost model (indicated in Fig. 8 as a small box), the retail price of the 7 kW residential PEMFC cogeneration unit manufactured by Plug Power, LLC. is expected to be in the range of $3000-5000 (430-714 $/kW) [18]. (Not all of the 7 kW power is provided by the fuel cell; a portion of the power is provided by a less expensive battery sub-system [19].)

Economic Calculations: The SERC Method

Here we describe a novel method we have developed during earlier work for the DOE OTT CARAT program [5] -- called the "SERC" method -- for estimating the cost of electricity from a fuel cell cogeneration system. This method allows us to efficiently simulate many alternative configurations for cogeneration systems, to find the optimum (lowest cost) system.

Calculating the system performance and economics is traditionally carried out by simple time-domain (i.e. hour-by-hour) accounting, an effective technique, but one whose results are often unenlightening; in-depth analysis typically requires brute force finite difference sensitivity studies. For that reason, we have developed a novel alternative formalism called the "system economic response curve" (SERC) method which organizes the raw load data into a readily characterized load histogram (the "load energy distribution") that is entirely separate from the economic parameters of the PEMFC cogeneration system. The final electricity costs result from the interaction between these two components, which is both intuitively obvious and analytically simple. As a result, the method is extremely efficient with regard to computation, thereby facilitating multi-parameter system optimization. We begin the exposition of this method by looking first at the load.

Load Energy Distribution

A typical "load profile" consists of a time series of N consecutive values, $P_l(n)$ (n=1,N), that represent the load power averaged over the corresponding temporal widths, $\Delta t(n)$. The LBNL load profiles used in this study are hourly averaged values for one year (e.g. they have a constant time resolution of Δt =1 hr, and span a single year, i.e. N=8760 hours/yr). As seen in Fig. 9, such a massive set of raw data is rather difficult to interpret, and is thus often transformed into a format that is more readily understood. For example, ordering the loads according to their size produces a so-called "load duration curve" (Fig. 10) which readily reveals the percentage of time is spent above (or below) any given power level.

In the SERC methodology, we transform the data into a "load energy distribution function", $L(P)$, which quantifies how much energy is demanded at any given power. This function is simply a power-weighted histogram obtained by "binning" the load data into discrete intervals of load power, ΔP, as follows:

$$L(P) \equiv \frac{P}{\Delta P} \sum_{n=1}^{N} \delta\left[P_l(n) - P; \Delta P\right] \Delta t(n) \quad , \qquad (7)$$

where the pseudo-delta binning function is defined by

$$\delta\left[P_l(n)-P;\Delta P\right] \equiv \begin{cases} 1 \text{ for } \left(P-\frac{\Delta P}{2}\right) \le P_l(n) < \left(P+\frac{\Delta P}{2}\right) \\ 0 \text{ for } P_l(n) < \left(P-\frac{\Delta P}{2}\right),\ P_l(n) \ge \left(P+\frac{\Delta P}{2}\right) \end{cases}. \quad (8)$$

The $1/\Delta P$ factor in Eq. (7) yields a "probability density" distribution function whose amplitude is independent of the "binning width", ΔP. The function is further weighted by P to reflect our interest in the energy required at any given power rather than the time spent there. As such, $L(P)$ has units of kWh/kW, and integrating over all load power yields the total load energy, E_{load} (kWh):

$$E_{load} \equiv \int L(P)\, dP. \quad (9)$$

The load energy distribution function in Fig 11 is seen to be roughly bi-modal. The wide "spike" centered at ~1 kW (the yearly average power) is due primarily to non-HVAC "plug" loads. The broad hump from 1.5-4 kW is largely due to air conditioning (AC) electric loads that occur each day in the summer months. Note in the *yearly* load distributions shown below in Fig. 12, the AC hump is somewhat diminished relative to the plug load peak at 1 kW.

The System Economic Response Curve

The System Economic Response Curve (or "SERC") is defined as the cost of electricity from a PEMFC system with capacity P_{max} (kW) when it is operated a constant output P, where P > P_{max}/TDR . As P is varied, the cost of electricity goes through a minimum value at about P=P_{max}. (At low values of P (P<P_{max}), the fuel cell capacity is not fully utilized, so that the capital cost contribution is large. At high values of P, (P>P_{max}), expensive electricity must be purchased from the grid, so that the SERC increases.

The SERC can be expressed mathematically in the fuel cell's operating range (P_{max} /TDR<P< P_{max}) as:

SERC (P) = CRF $C_{PV}(P_{max})$/(P A 8760 h/y) + $R_f/\eta_{sys}(P)$ x 0.00341 MBTU/kWh

where:

SERC(P) = levelized cost of electricity ($/kWh) from a PEMFC system with power capacity P_{max}, operated at constant power output P.

P = constant electrical power output of system kW

CRF = capital recovery factor = $1/[1-(1+d)^{-Y}]$

d= real discount rate

Y = system lifetime in years

$C_{PV}(P_{max})$ = present value of installed cost of system plus replacement of components (see Table 2)

A = availability of system

R_f = price of natural gas in \$/MBTU

$\eta_{sys}(P) = \eta_{FC}(P)\ \eta_{FP}\ \eta_{PC}$, where $\eta_{FC}(P)$ is taken from Figure 3.

When $P > P_{max}$, a term is added to reflect the cost of buying electricity from the grid. When $P < P_{max}/TDR$, electricity is sold back to the grid yielding a credit.

For different sized fuel cell systems, the SERC changes as shown in Figure 13. It is important to note that the SERC is independent of the building load.

Estimating the Cost of Electricity

The cost of electricity R for a PEMFC system meeting a particular load is found by multiplying the energy load profile L(P) times the SERC and integrating over P.

$$\mathbf{R} \equiv \frac{1}{E_{load}} \int \mathrm{SERC}(P)\ L(P)\ dP .$$

This is formally equivalent to, but computationally much simpler than conducting the analysis by integrating over time, and gives an intuitive way to size the system for lowest cost for a particular load profile. The idea is to overlap the lowest cost part of the SERC with the peak/bulk of the load distribution to minimize the integral (and therefore the electricity cost).

We have used the SERC method to conduct sensitivity studies to find PEMFC system size that yields the minimum electricity cost to meet a particular load (or alternatively, gives the best internal rate of return for investing in a PEMFC system).

Sensitivity Studies

Sensitivity of Electricity Cost to System Size

We have used the SERC method to find optimized PEMFC systems designed to meet loads ranging in size from one household to 20 households. In Figure 14, the cost of electricity and the internal rate of return are plotted versus the number of single family homes served.

System scale is seen to have a tremendous impact upon the system economics. The strong dependence of electricity cost on system size is mostly due to the strong scale economies in the capital cost of PEMFC cogeneration systems (see Figure 7).

For example (Figure 14), without cogeneration, the electricity cost for a 2.6 kW system powering a single New Jersey residence is as high as 13.2 ¢/kWh, while a 22 kW system for 20 homes is less than 9.0 ¢/kWh. Over this same change of scale (from 1 to 20), the internal rate of return rises from 3.6%/yr to 121%/yr! Despite the favorable economic climate - New Jersey has energy rates that are extremely conducive to residential power generation (natural gas: 6.1 $/MMBtu HHV, electricity: 12.7 ¢/kWh) - the single-family system appears to be just barely viable from an economic standpoint. On the other hand, a 22 kW (half-automotive-scale) PEMFC system that powers multiple homes (or, more likely, a multi-family dwelling) shows great economic promise, with a simple payback times significantly less than a year.

The Effect of Cogeneration

The economics of hot water cogeneration was studies using a time domain analysis that monitors the flow of hot water in and out of the hot water tank. Surplus heat is discarded while deficit heat is generated by firing the tank's natural gas burner. The economic effect of hot water cogeneration is shown in Fig. 14 where optimized (i.e. minimum *IRR*) values of **R** and *IRR* - with and without cogeneration - are plotted as a function of system scale factor. Cogeneration is seen to add roughly 50% to the rate or return, and lowers the cost of electricity by ~1.5 ¢/kWh. It is clearly an attractive option where technically/economically feasible, for example, in a single family house or multi-family apartment building.

The Effect of Energy Prices

Energy prices have a strong impact on the economic viability of natural gas fired PEMFC systems. In our base case, we used New Jersey energy prices (which are favorable for natural gas fired cogeneration because of the high electricity cost and low natural gas cost). Plots of electricity cost and IRR are shown in Fig. 15 for average U.S. energy prices (natural gas: 6.6 $/MMBtu HHV, electricity: 9.3 ¢/kWh) and for New Jersey prices. While the optimized electricity prices are roughly the same over the full range of scales, the rates of return are dramatically different between the two cases. The great disparity in *IRR* is due to the much higher cost of electricity in N.J. which allows the N.J. system to generate 'revenue' (by displacing purchased power) more rapidly and thus offset the cost of installed capital. At U.S. average gas and electricity prices, the system is not economically viable at *any* scale.

Given the high variability of energy prices throughout the U.S., we plot in Figs 16 and 17 the internal rate of return as a function of scale, electricity, and natural gas prices. These figures suggest that the PEMFC cogeneration system in a multiple single-family configuration (without cogeneration) will be viable in regions where: 1) at average U.S. gas prices (6.6 $/MMBtu HHV), the electricity price exceeds 9-10 ¢/kWh, and 2).at average U.S. electricity prices (9.3 ¢/kWh), the gas price is below ~7 $/MMBtu HHV.

The Effect of System Capital Cost

Capital costs plays a critical role in the economics of these systems. In Fig. 18 the optimized (i.e. minimum *IRR*) values of both **R** and *IRR* (without hot water cogeneration) are plotted as a function of system scale factor for both the high and low volume capital cost models. While the high volume model shows economic promise at almost all scales, the low volume system is economically unfeasible or marginal at all but the largest scale.

The Effect of Operational Strategy: Load Follower vs. Non-Load Follower

The SERCs plotted in Fig. 19 suggests that optimal economics are obtained with a system that is as large as possible yet have an operating range (i.e. P_{sys}^{max}/TDR to P_{sys}^{max}) that overlaps the bulk of the load distribution. This minimizes the amount of power that must be either bought from the utility (at a relatively high price) or produced and sold back to the grid at a loss. For example, in the optimized base case system (a load follower with a turndown ratio of 5), the great bulk of the load falls within the operating range from 2.44/5 kW to 2.44 kW. As the turndown ratio falls and the operating range shrinks (with the limit being a non-load follower, *TDR*=1), the optimized system size is found to "track" ever more closely the peak of the load distribution. This is because the cost of electricity is, in general, minimized when as much of the load as possible is generated by the PEMFC system. This is seen clearly in Fig. 19 where optimized SERC for both a load follower (*TDR*=5) and a non-load follower are plotted against the load distribution. Note that the non-load follower is optimally sized at 1.05 kW, almost the peak of the load distribution, and costs ~1.5 ¢/kWh more than the load follower to operate .

PEMFCs versus Microturbines

Since the preceding results illustrate the economic attractiveness of large (e.g. multi-family) PEMFC cogeneration systems relative to single family units, it is appropriate to make a comparison with another emerging advanced technology for distributed electric power generation from natural gas: the microturbine. For this brief examination, we employ the published performance of the Capstone model 350 microturbine, which produces 27.4 kW of grid-quality AC power from natural gas delivered at 5 psig at a LHV energy conversion efficiency of 24.3% [20,21]. Part load performance is calculated using the work of Campanari [22]; a turndown ratio of 10 is assumed. The power-dependent LHV efficiency of the microturbine, $\eta_{mic}(P_{sys})$, can be expressed as a third order polynomial:

$$\eta_{mic}(P_{sys}) = 0.0608 + \left[0.548 + (-0.592 + 0.226\,P_{sc})\,P_{sc}\right]P_{sc} \quad , \tag{21}$$

where $P_{sc} \equiv P_{sys}/P_{sys}^{max}$ is the scaled part load power. Installed capital costs are derived from extremely uncertain cost projections from Capstone and Allied Signal: $7500+300 $/kW [23].

Microturbine system economics are compared to PEMFCs in Fig. 20. It can be seen that, even with aggressive and highly uncertain cost projections for the microturbine, the economics are less promising than that of the PEMFC system.

Summary of Results

Results to Date

We have determined that the most favorable configuration for PEMFC cogeneration systems in residential buildings has the following characteristics :

- a load follower with a large (>5) turndown ratio,
- the fuel processor used a steam methane reformer,

- hot water cogeneration from PEMFC stack waste heat was economically attractive,

Scale is fund to be crucially important for good economics. Our results indicate that, even with high volume (automotive-scale) cost assumptions and extremely favorable gas-to-electricity price ratios, PEMFC systems are likely to be only marginally attractive on the scale of a single-family residence. In contrast, multi-family units (above ~ 10 kW) appear to be economically extremely attractive, even when using less than optimal (e.g. national average) gas-to-electricity price ratios. Hence, in our initial economic modeling, there appears to be a potentially significant market for multi-family scale PEMFC cogeneration systems.

In typical residences, the domestic hot water demand is well correlated with the electric load, and also well matched - both in terms of magnitude and temperature - to the supply of waste heat from the fuel cell stack. Our preliminary analysis has shown that hot water cogeneration is an inexpensive option that lowers the cost of electricity by roughly 1.5 ¢/kWh. Cogeneration for space heating, on the other hand, does not appear to be economically viable.

Energy prices have a strong effect on the economic attractiveness of residential PEMFC cogeneration systems. At average US electricity and gas prices, the rates of return are economically unattractive. However, our calculations suggest that a PEMFC cogeneration system in a multiple single-family configuration (without cogeneration) will be viable in regions where: 1) at average U.S. gas prices (6.6 $/MMBtu HHV), the electricity price exceeds 9-10 ¢/kWh, and 2).at average U.S. electricity prices (9.3 ¢/kWh), the gas price is below ~7 $/MMBtu HHV.

Capital costs plays a critical role in the economics of residential PEMFC cogeneration systems. PEMFC systems must reach low mass produced costs to compete. Our high volume cost model shows economic promise at almost all system scales, the low volume system is economically unfeasible or marginal at all but the largest scale.

Comparing PEMFC systems to microturbines, we found a 32% increase in system efficiency (and therefore greenhouse gas benefit), lower criteria pollutant emissions, and potentially better economics. When compared with central station power systems, the overall efficiency was less favorable. Obtaining hot water and electric power from a PEMFC cogeneration system results in a 26% loss in energy efficiency compared with traditional hot water generation and electricity generation using modern natural gas-fired GTCC. It does offer the potential for reduced emissions of criteria pollutants, but precludes carbon sequestration.

The overall economic viability shows strong dependence on system size. *A s*mall (< 5 kW) single-family system unlikely. Multiple single-family system is potentially attractive (especially with hot water cogeneration). A system for multiple-family residence could be quite attarctive in markets with high electric/gas price ratios (such as NY, NJ, CA).

We have developed an analytical methodology for calculating PEMFC system economics that greatly clarifies the key issue of system sizing as well as dramatically increasing computationally efficiency, thereby facilitating multi-parameter system optimization.

Work Plan To Complete This Study

Task 4. Discuss the costs and trade-offs involved in distributing different forms of energy to houses (case 1 electricity and heat:, case 2: hydrogen or hydrogen-ruch gas, 3: natural gas

Task 6: Understanding the Role of Distributed Benefits

Our analysis thusfar has used a “consumer-driven” model where the decision to purchase a PEMFC power system is based on the expectation of long term savings, not unlike the decision to invest in a more efficient but more expensive appliance (such as a furnace, water heater, refrigerator, etc.). An important alternative model is a “utility-driven” strategy in which the public utility owns, locates, and operates these distributed power systems in order to offset the local load, thereby either avoiding (or delaying) having to upgrade the transmission system or, in sparsely populated areas, avoiding constructing a transmission grid altogether. In future work (Task 6) we will address how the newly deregulated energy market might accommodate (and be perturbed by) the introduction of PEMFC-based residential power systems. In some markets, such systems could forestall the electric utility from having to build additional generation and distribution capacity, thus perhaps qualifying for “credits” for distributed power generation.

Publications and Presentations

Past Results

Since 1986, researchers at Princeton University's Center for Energy and Environmental Studies have carried out technical and economic assessments of hydrogen energy systems. We have published numerous papers on: assessments of renewable hydrogen energy systems, use of hydrogen from natural gas as a transition strategy, studies of hydrogen infrastructure (including case studies of hydrogen refueling infrastructure in California and New York), studies of hydrogen as a fuel for fuel cell vehicles, and studies of the implications of CO2 sequestration for hydrogen energy. Our approach is to assess the entire hydrogen energy system from production through end-use from several perspectives (fuel producer, consumer, society) considering technical performance, economics (e.g. capital cost, delivered hydrogen cost, cost of energy services), infrastructure, environmental and resource issues. The long term goal of our work is to illuminate possible pathways leading from present hydrogen markets and technologies toward wide scale use of hydrogen as an energy carrier, highlighting important technologies for RD&D. This work has been part of the systems analysis activity of the DOE Hydrogen Program since 1991.

Current Year Publications and Presentations

Over the past year (January 1999-May 2000), several papers based on our DOE sponsored work on hydrogen infrastructure and fuel cell system modeling have been published in peer reviewed journals. In addition, we have written several general review articles on hydrogen. These include:

J. Ogden, "Developing a Refueling Infrastructure for Hydrogen Vehicles: A Southern California Case Study," International Journal of Hydrogen Energy, vol. 24, pp. 709-730, 1999.

J. Ogden, M. Steinbugler and T. Kreutz, "A Comparison of Hydrogen, Methanol and Gasoline as Fuels for Fuel Cell Vehicles," Journal of Power Sources, vol. 79, pp. 143-168, 1999.

J. Ogden, 1999, "Prospects for Building a Hydrogen Energy Infrastructure," *Annual Review of Energy and the Environment*, Vol. 24, pp. 227-279.

J. Ogden, T. Kreutz and M. Steinbugler, "Fuels for Fuel Cell Vehicles," Fuel Cells Bulletin, Elsevier Advanced Technology, January 2000. p. 5-13.

We presented talks on our work on Hydrogen Energy Systems and CO_2 Sequestration at the 10th National Hydrogen Association Meeting (April 1999), and on our work on PEMFC systems for residential cogeneration at the 11th National Hydrogen Association meeting (March 2000).

J. Ogden, "Strategies for Developing Low-Emission Hydrogen Energy Systems: Implications of CO_2 Sequestration," Proceedings of the 10th National Hydrogen Association Meeting, Arlington, VA, April 7-9, 1999.

T. Kreutz and J, Ogden, "Assessment of PEM Fuel Cells for Residential Cogeneration Applications," Proceedings of the 11th National Hydrogen Association Meeting, Arlington, VA, February 29-March 2, 2000, pp. 303-324.

We have also given invited talks on hydrogen infrastructure to the LERDWG group (a group of energy R&D leaders at the National Laboratories) in November 1999, to the Energy Frontiers International meeting in January 2000 (to a group of oil and gas industry leaders in alternative fuels development) and at the IQPC Fuel Cells Infrastructure Meeting in December 1999 (to a group of energy and chemical industry engineers). In addition, we participated in the DOE/California Energy Commission, California Air Resources Board Workshop on Hydrogen Infrastructure (October 1999). I have been an invited speaker at the June 1999 Department of Transportation Meeting on the Spirit of Innovation in Transportation and the April 2000 American Physical Society Meeting, speaking on future roles for hydrogen and fuel cells in transportation.

Plans for Future Work (beyond this contract)

During the next year we propose to carry out technical and economic assessments of advanced fossil to hydrogen systems with co-production of electricity and CO_2 sequestration. The objective of the proposed work is to understand the implications of new process technologies for reducing the cost of fossil-derived hydrogen with CO_2 sequestration and co-production of electricity.

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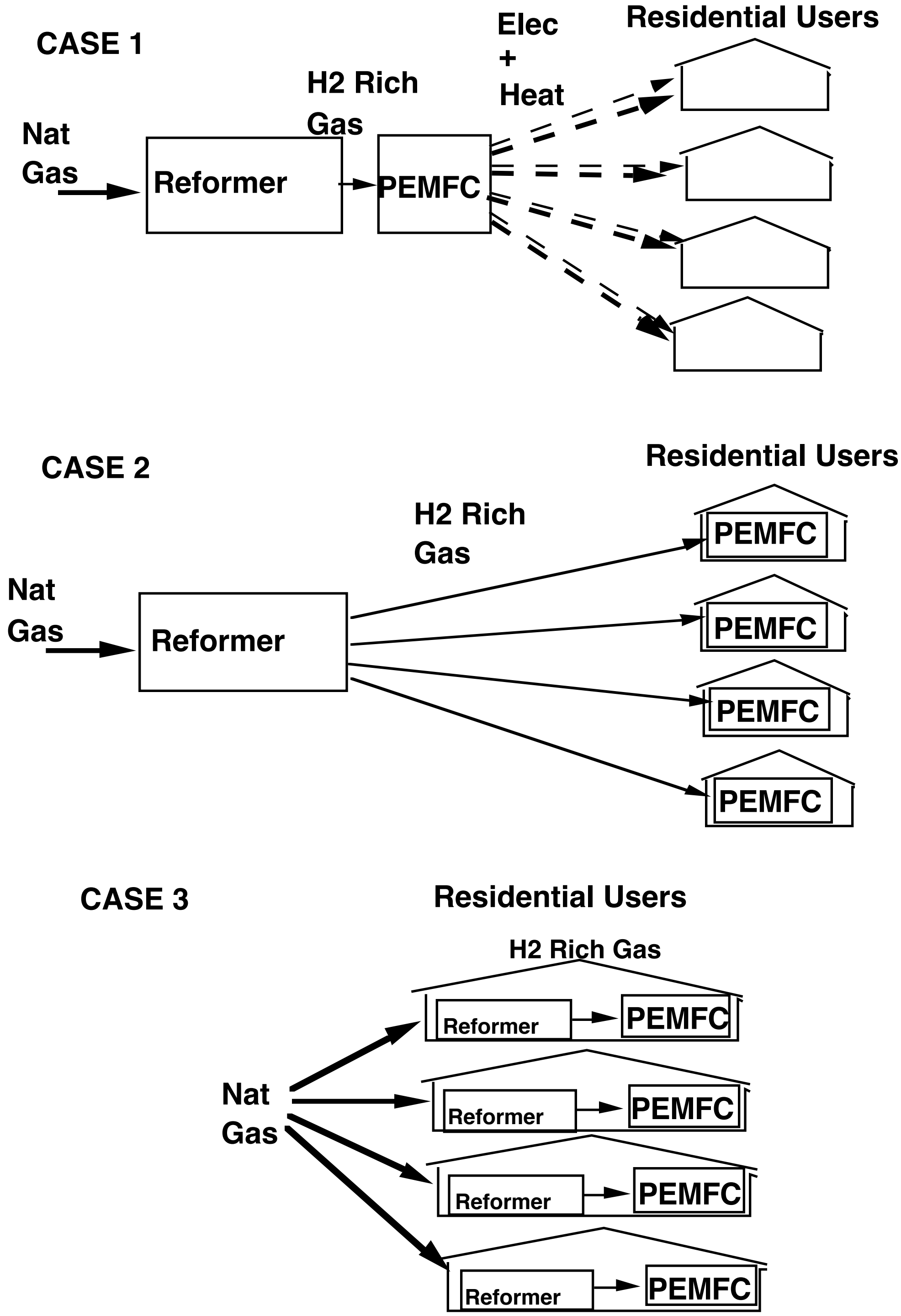
Rawlings (FIRST, Inc.), Chris Larsen (North Carolina Solar Center), Colleen Mathis (Ballard Generation Systems), Al Meyer (International Fuel Cells), Jessica Reinkingh (Johnson Matthey), Richard Root Woods (Hydrogen Burner Technology), Nick Vanderborgh (Los Alamos National Laboratory), Sandy Thomas (Directed Technologies, Inc.) Brian Wells (Ballard Power Systems), and Robert Williams (Princeton University).

Figures

FIGURE 1. CONFIGURATIONS FOR PEMFC COGENERATION FOR RESIDENTIAL USERS



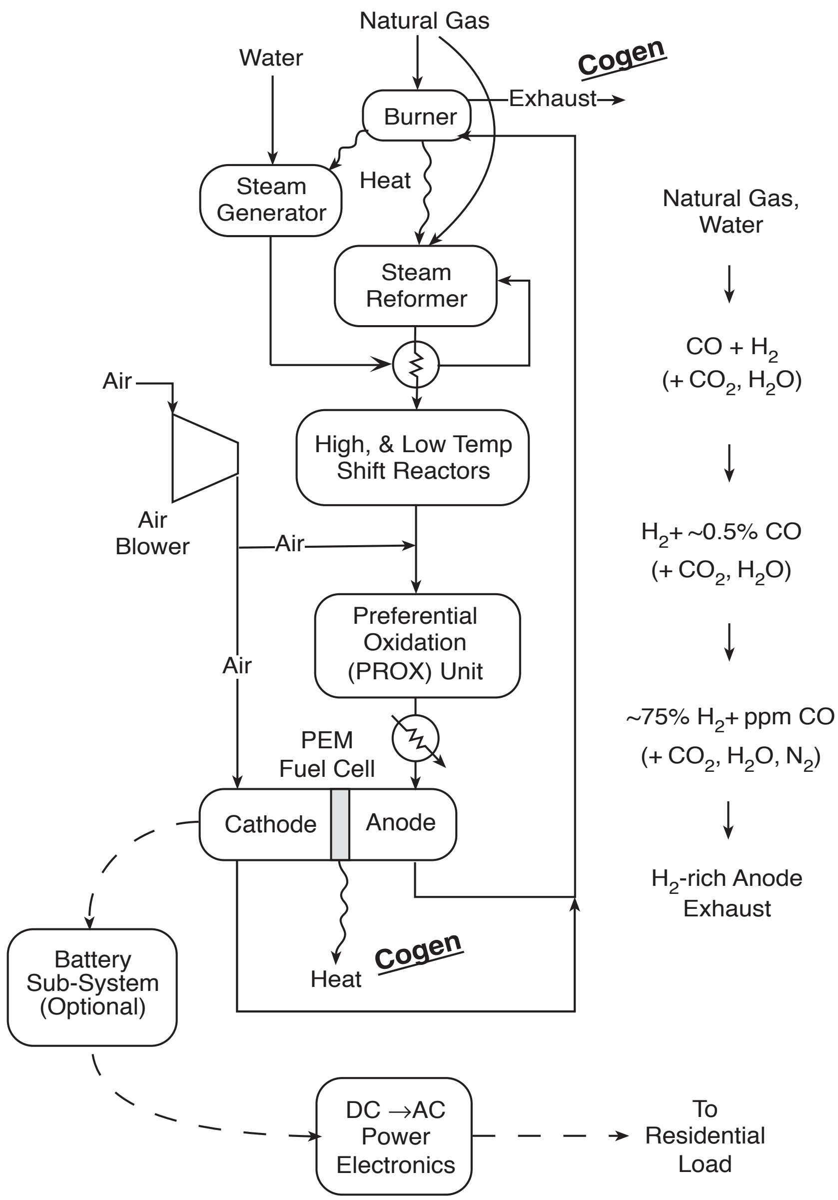


Figure 2. System Configuration for Residential PEMFC Cogeneration System

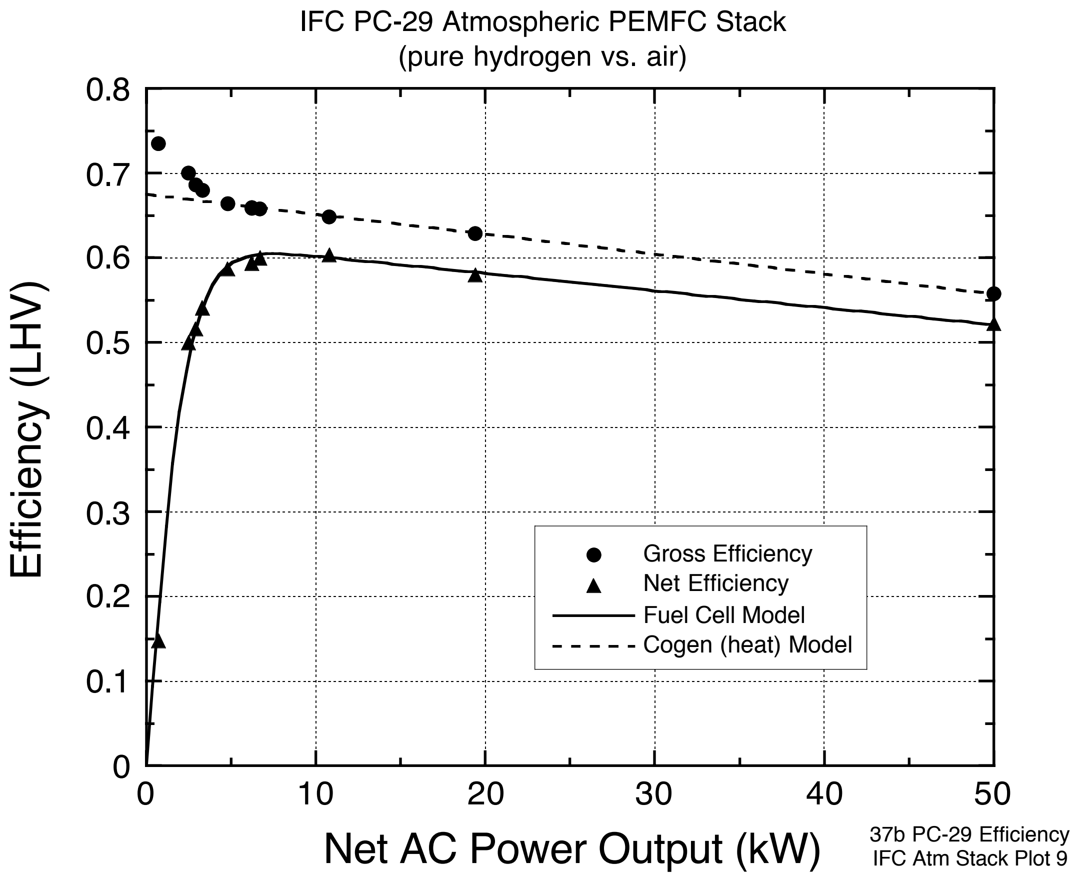


Figure 3. Assumed efficiency curve for 50 kW PEMFC stack based on IFC PC-29.

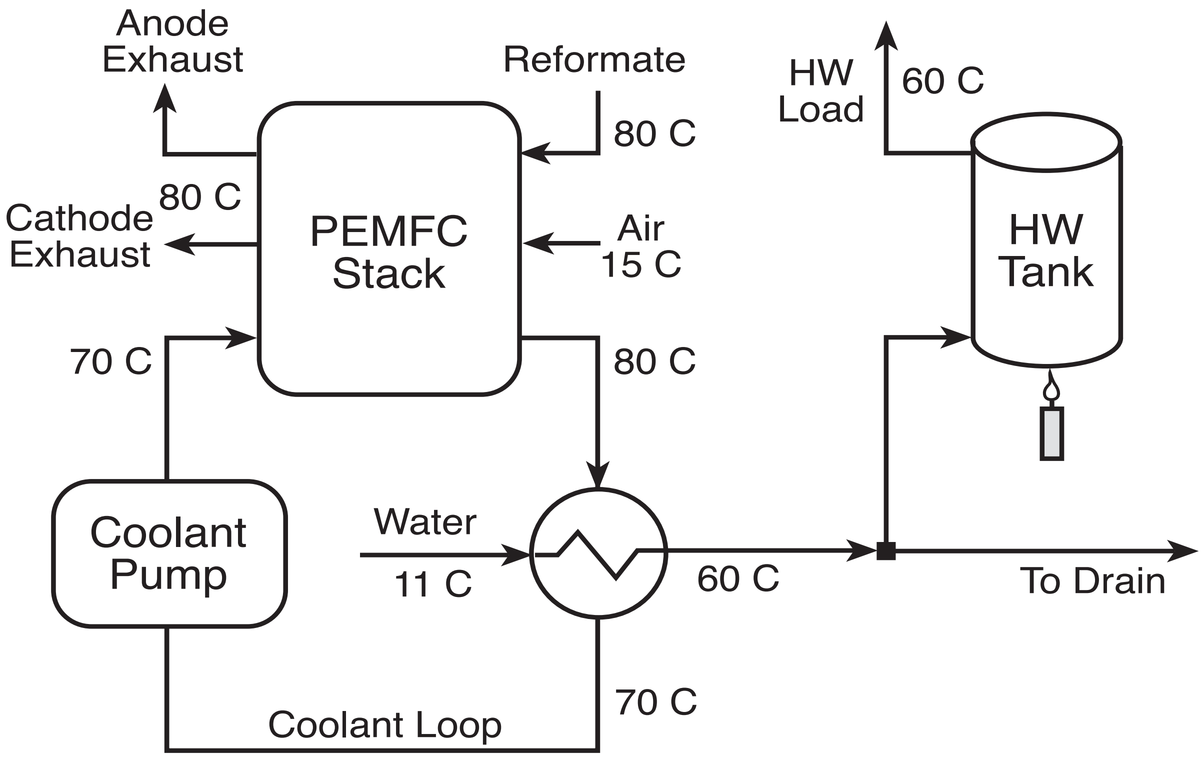


Figure 4. Schematic of Hot Water Cogeneration System.

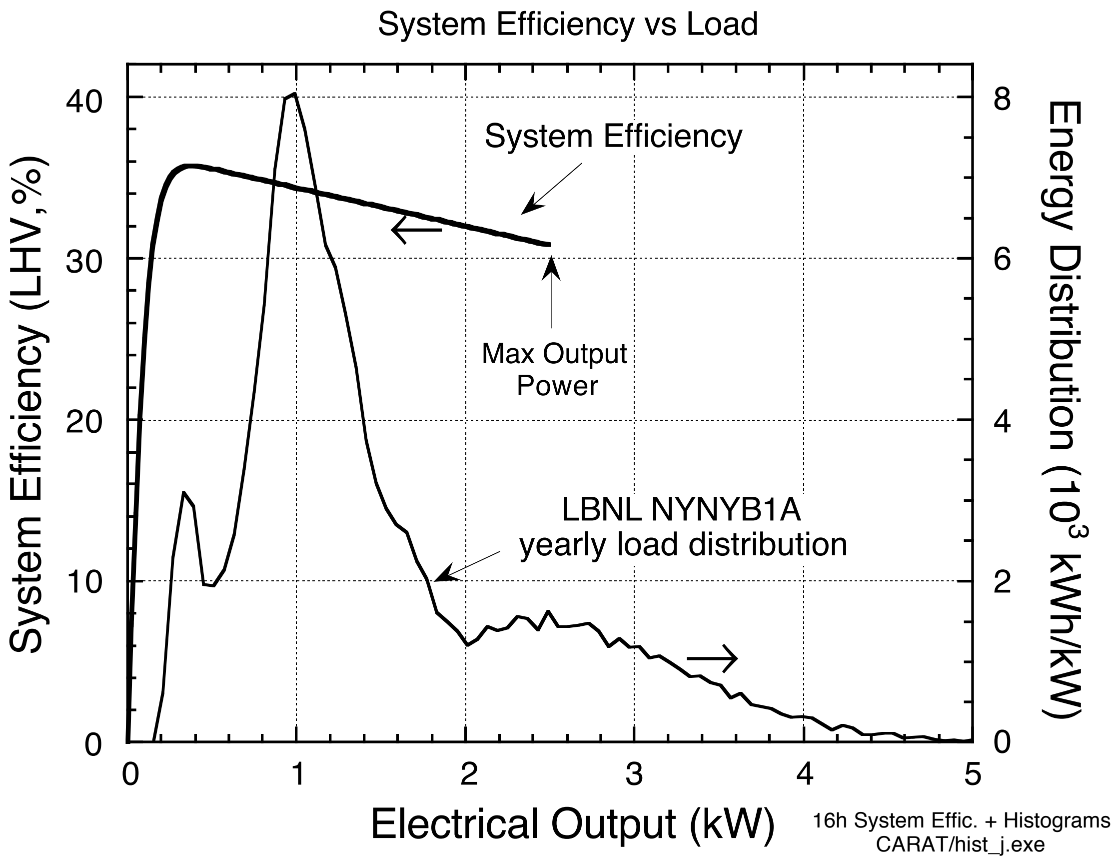


Figure 5. Total fuel cell system efficiency [=Electricity out/Natural Gas in (LHV)] for a 2.44 kW fuel cell system vs. electrical output power in kW. Also shown is the yearly load distribution for a single family house.

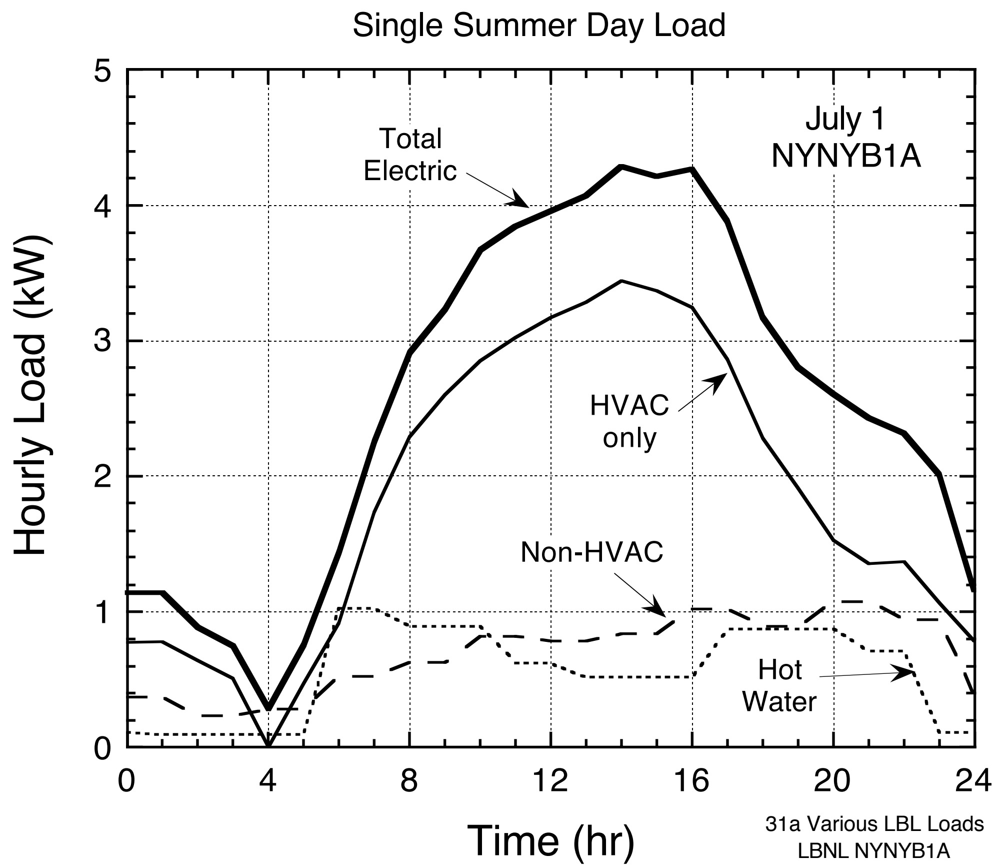


Figure 6a. Hourly-averaged loads for NY single-family residence during a typical summer day (July 1).

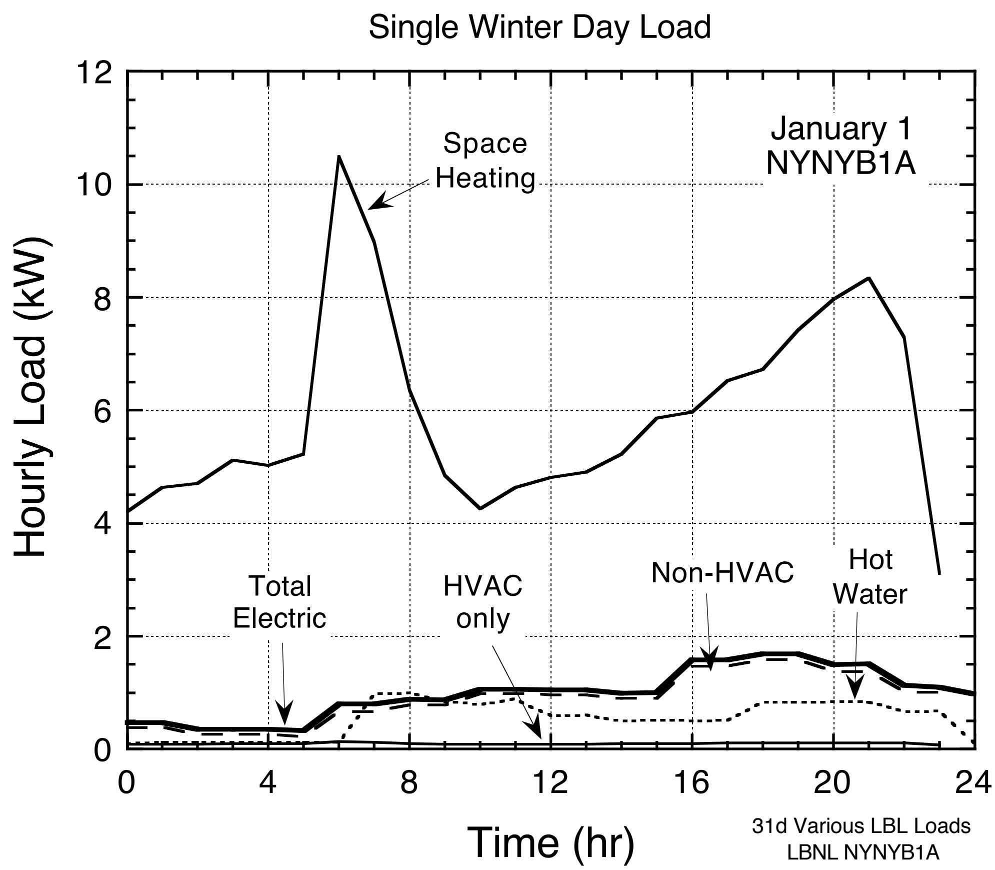


Figure 6b. Hourly-averaged loads for the NYB1A single-family residence during a typical winter day (January 1).

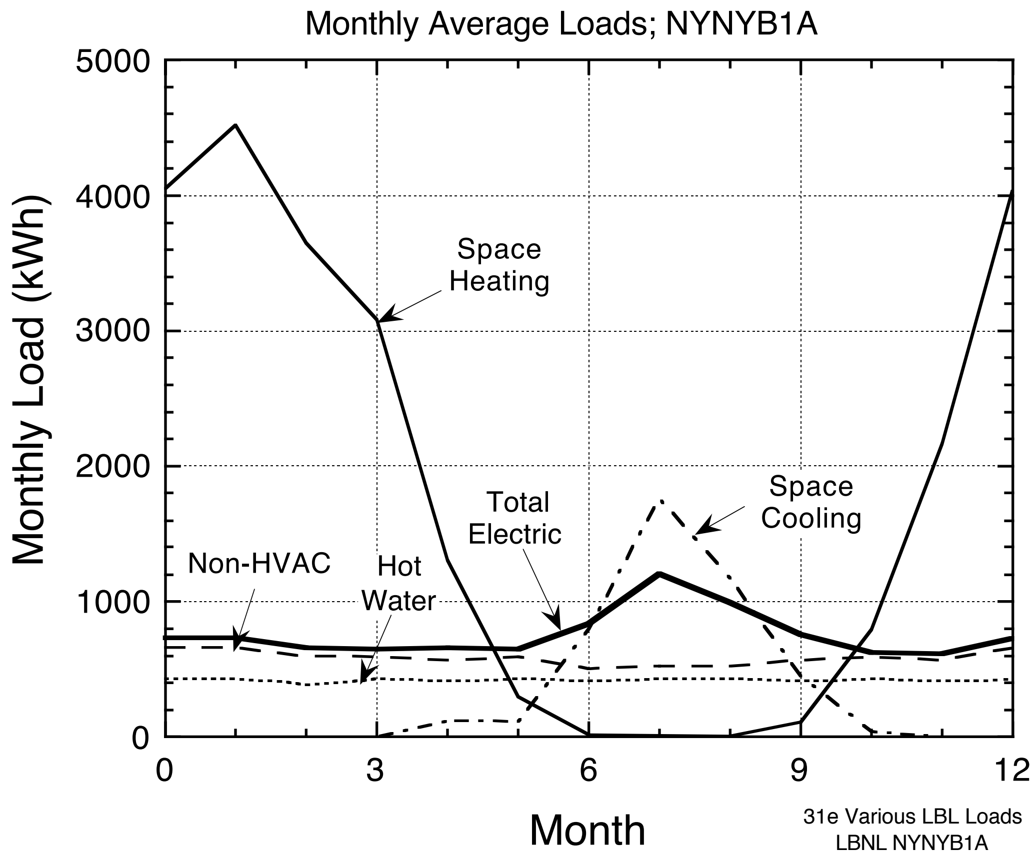


Figure 7. Monthly-averaged loads for the NYB1A single-family residence throughout a typical year.

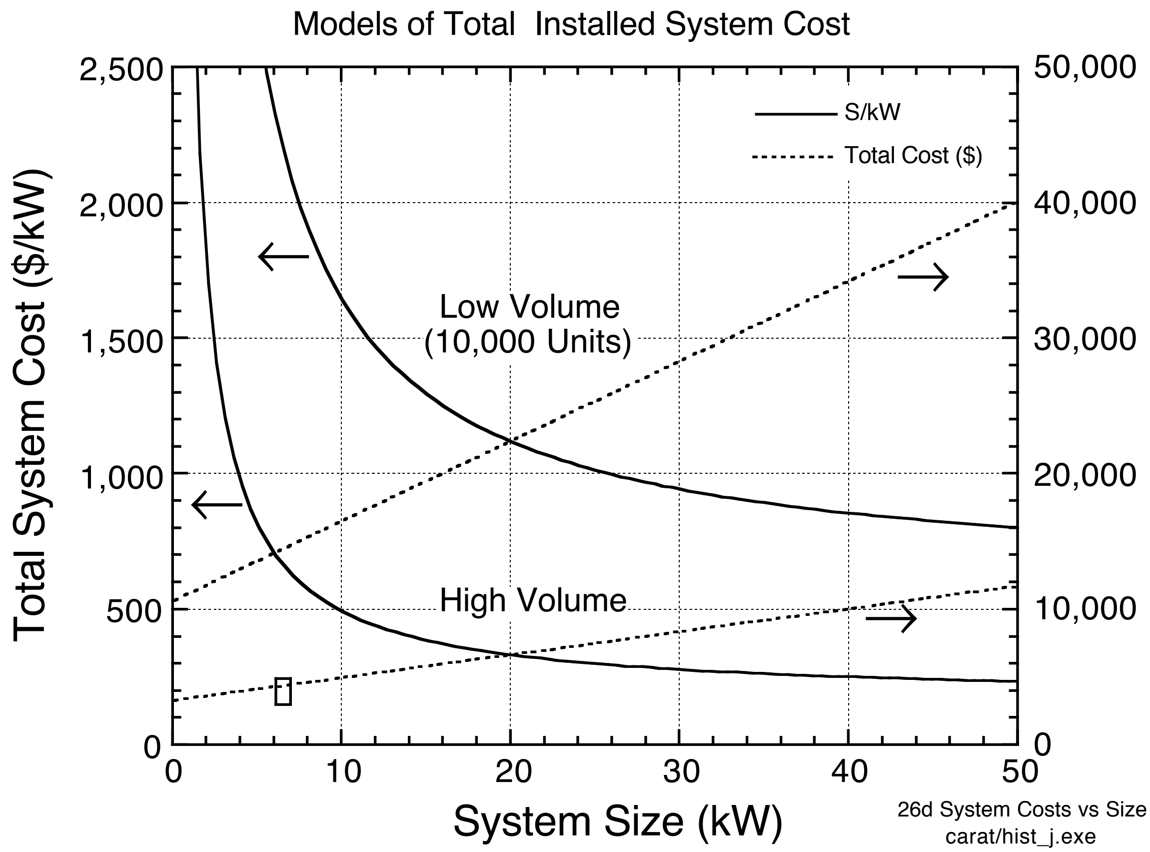


Figure 8. Total installed system cost, $C_{PV}(P_{sys}^{max})$, as a function of system size.

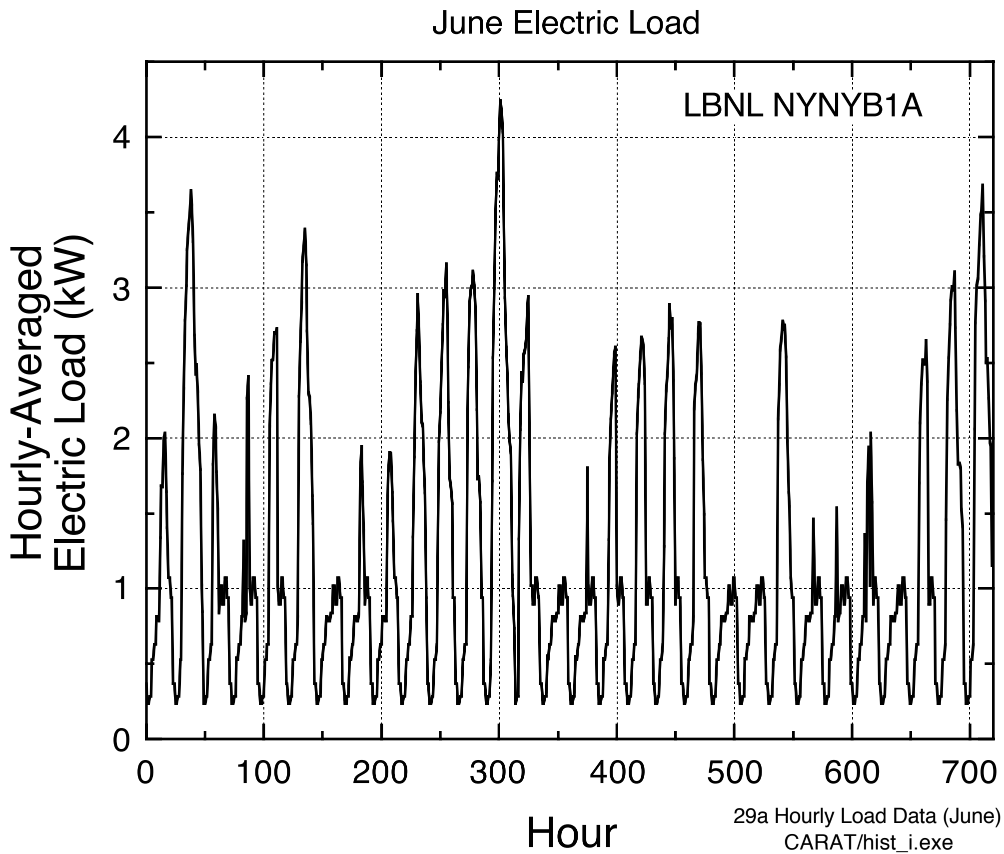


Figure 9. Hourly load data for the month of June.

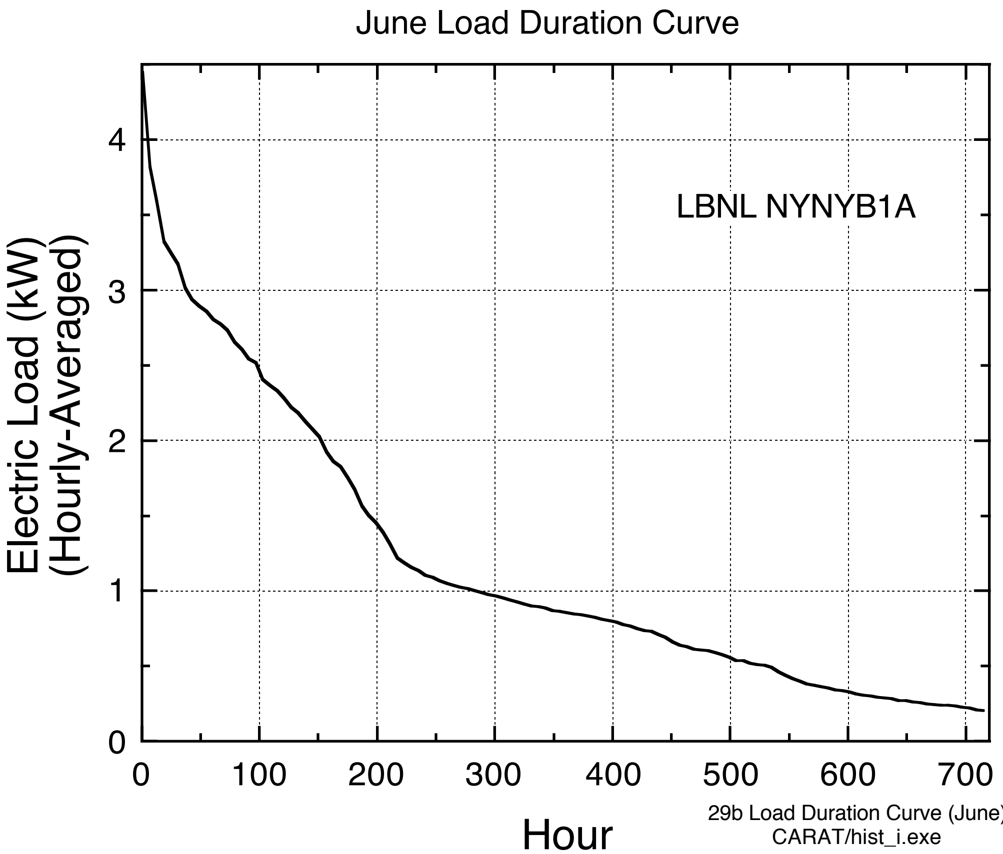


Figure 10. Load duration curve for data in Figure 9.

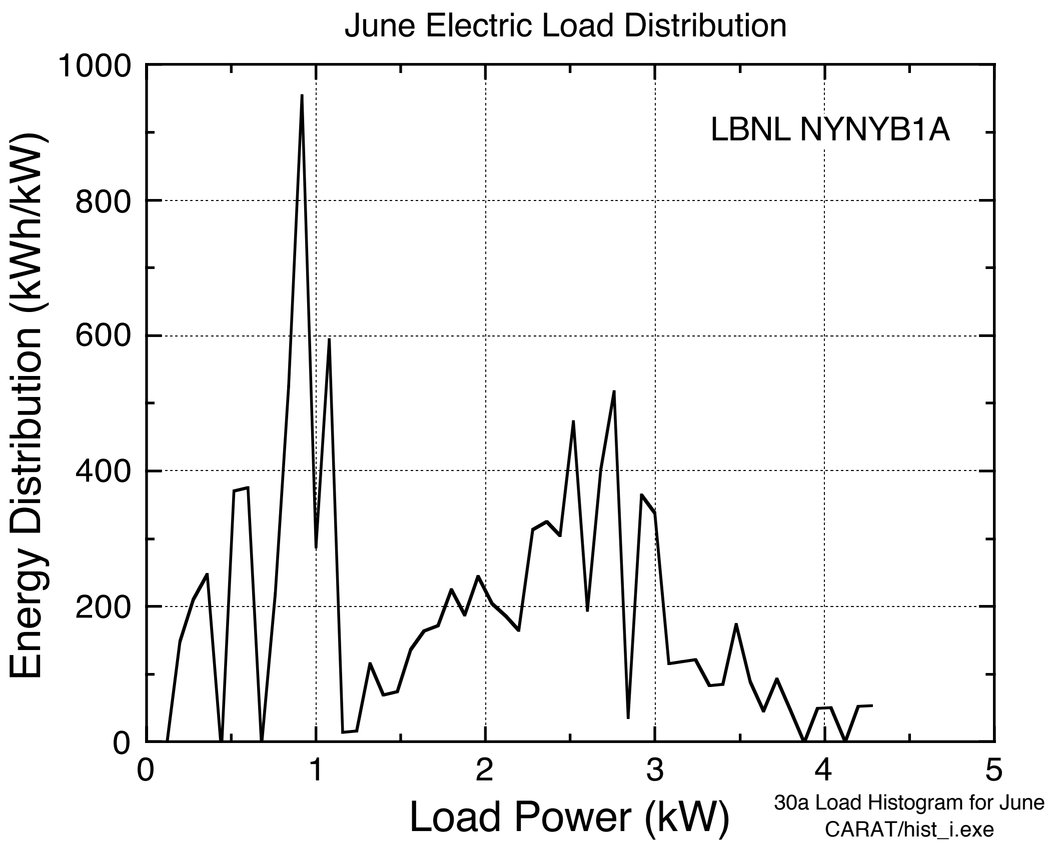


Figure 11. Load Energy Distribution for a Single Family House for One Month

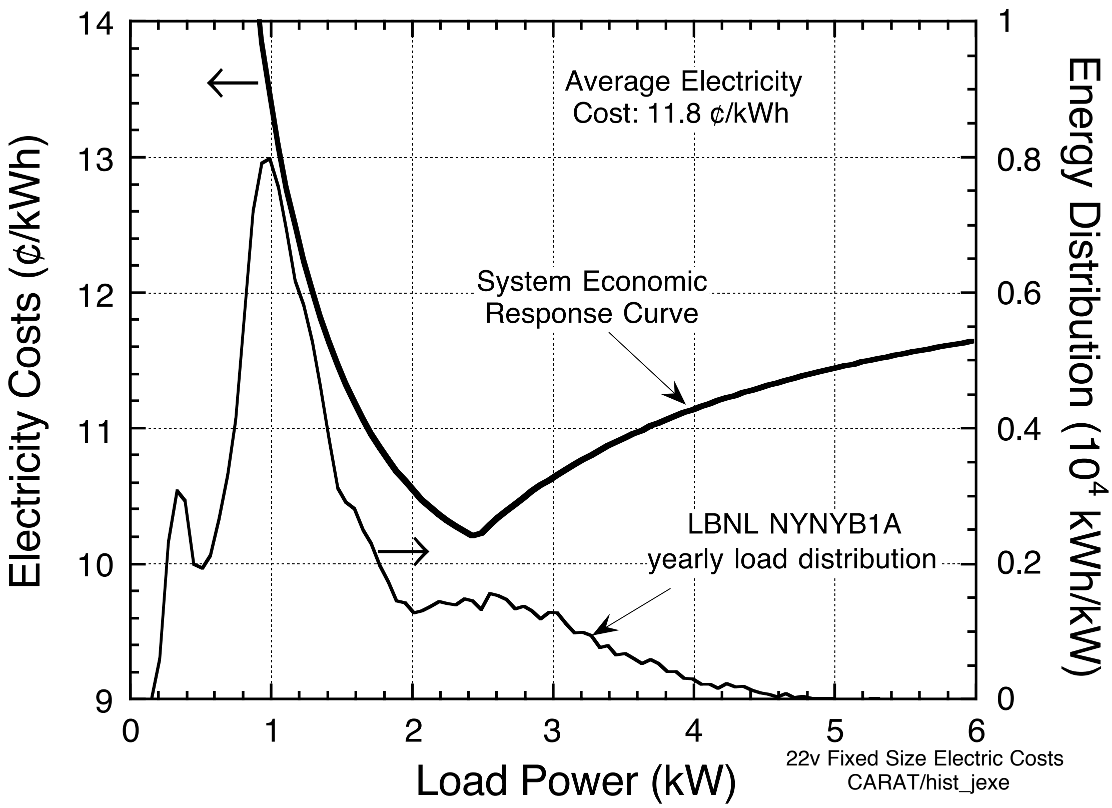


Figure 12. The System Economic Response Curve (SERC) for a 2.44 kW PEMFC system, shown with the yearly energy load distribution from a single family house.

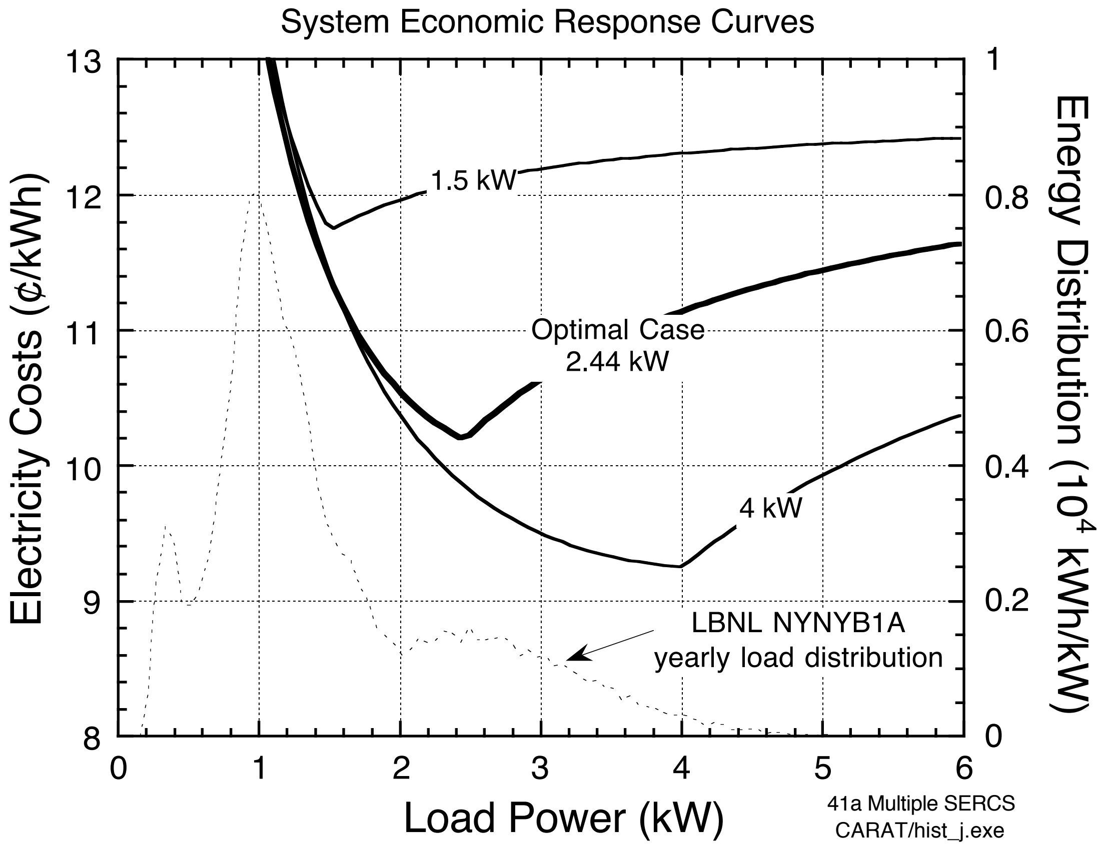


Figure 13. System economic response curves (SERCs) for systems of various size, compared to the load.

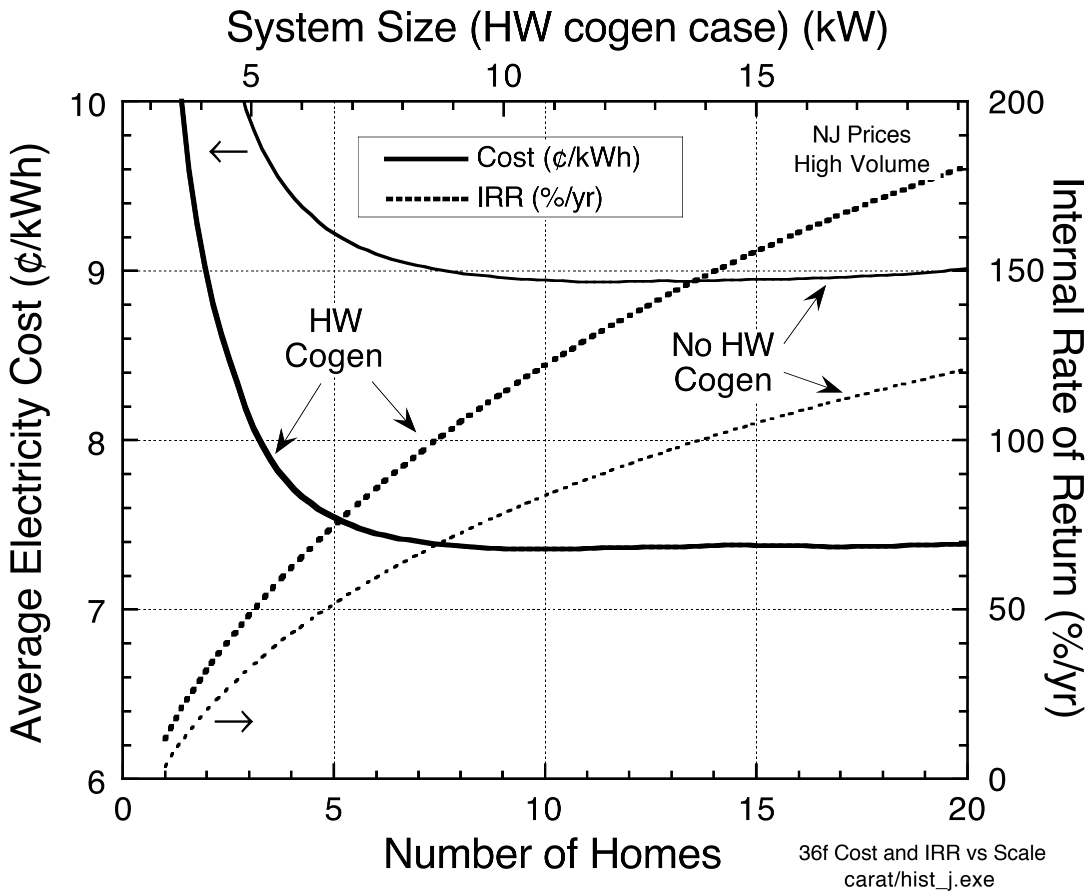


Figure 14. Cost of electricity and internal rate of return for PEMFC cogeneration systems, as function of system size. Cases with and without hot water cogeneration are shown.

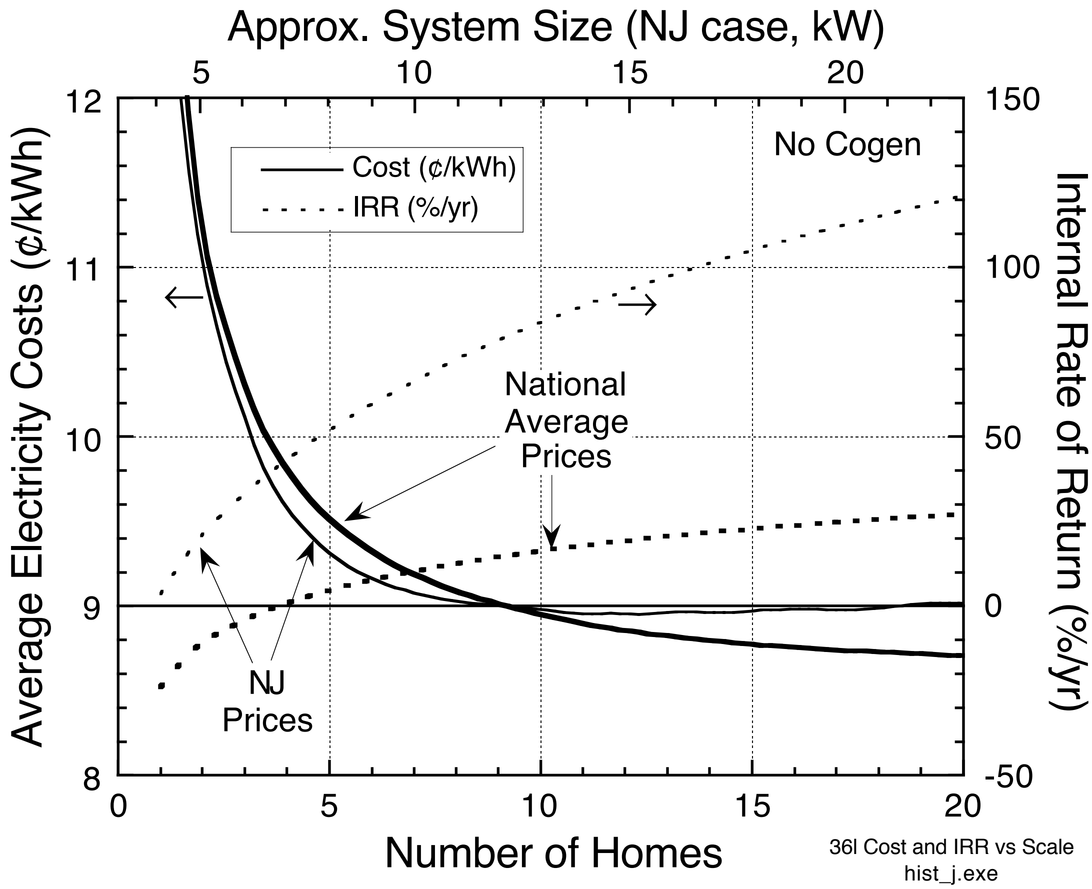


Figure 15. Cost of electricity and internal rate of return as a function of scale for N.J. and U.S. energy prices.

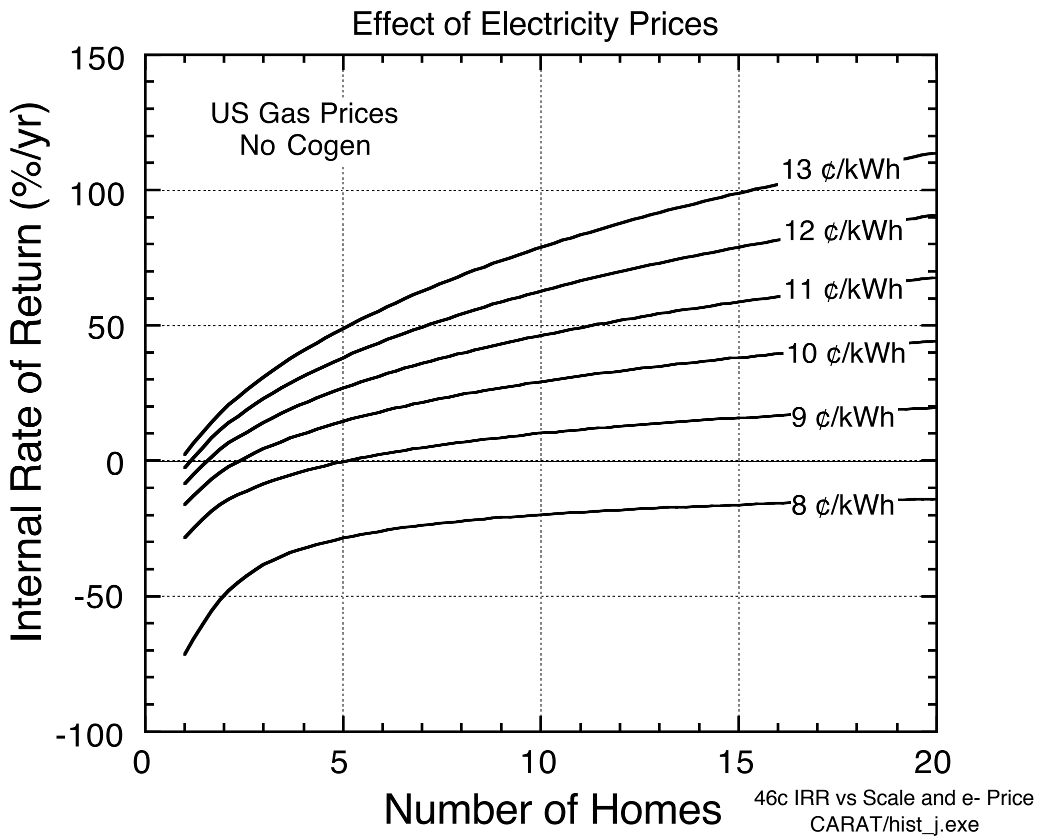


Figure 16. Internal rate of return as a function of scale and electricity price (at U.S. average nat. gas price).

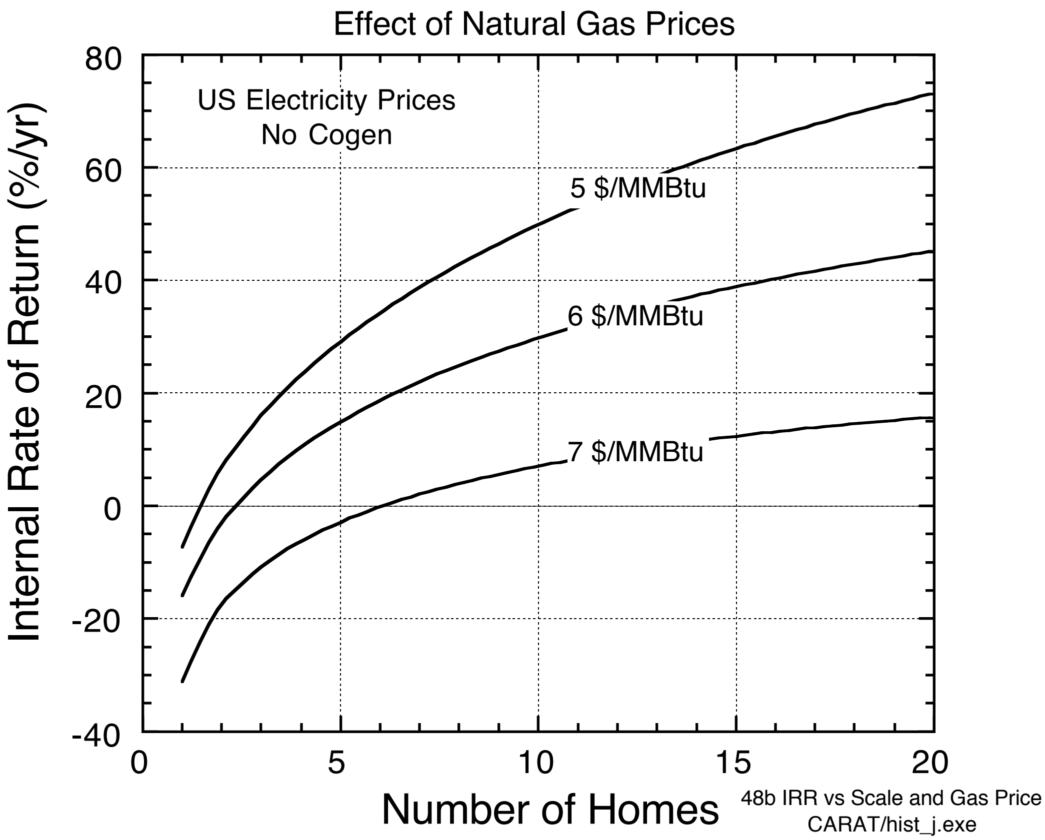


Figure 17. Internal rate of return as a function of scale and natural gas price (at U.S. average electricity price).

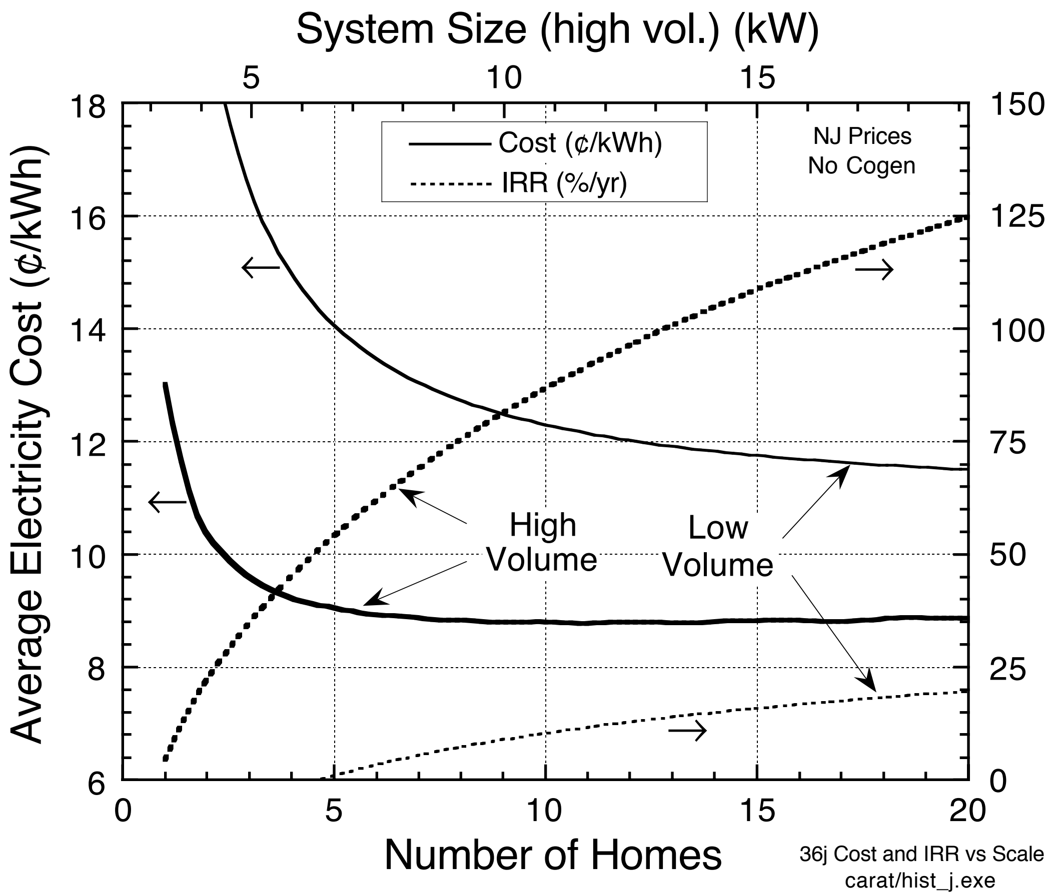


Figure 18. Electricity cost and rate of return as a function of scale, for high- and low-volume capital cost models.

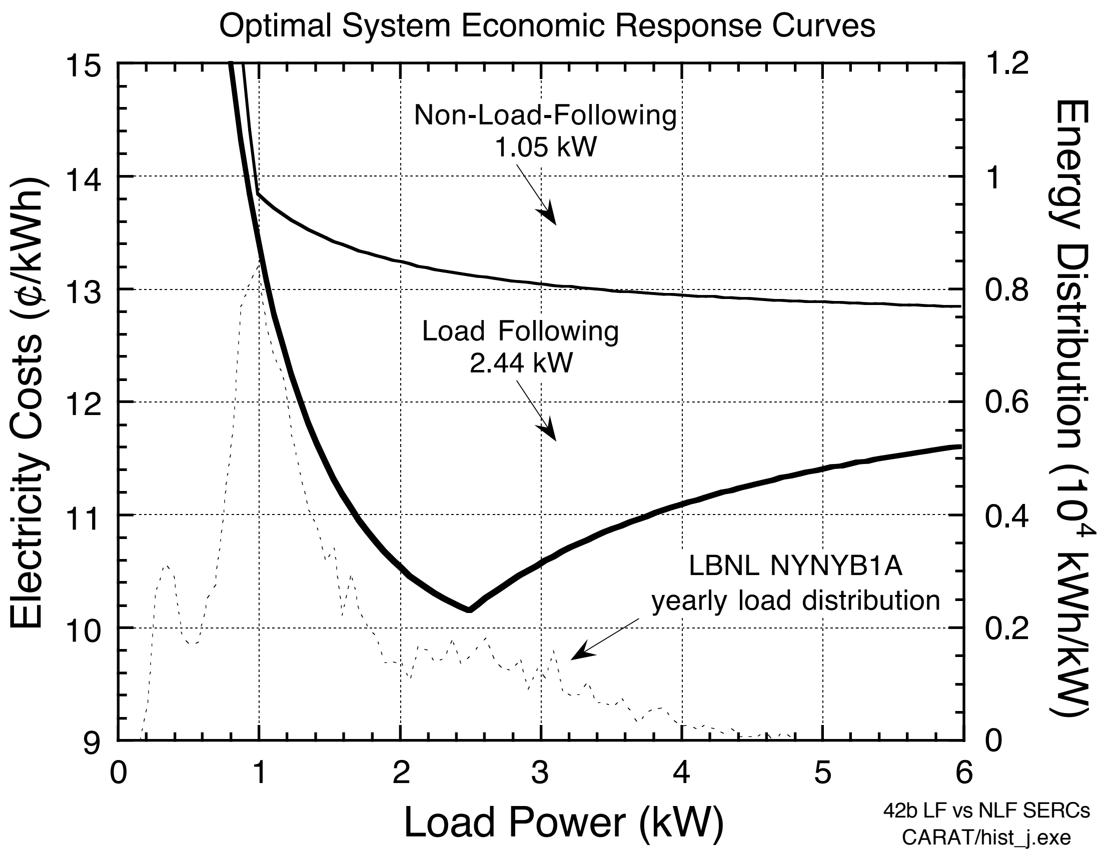


Figure 19. SERCs for load followers (TDR=5) and non-load following systems, compared to the load.

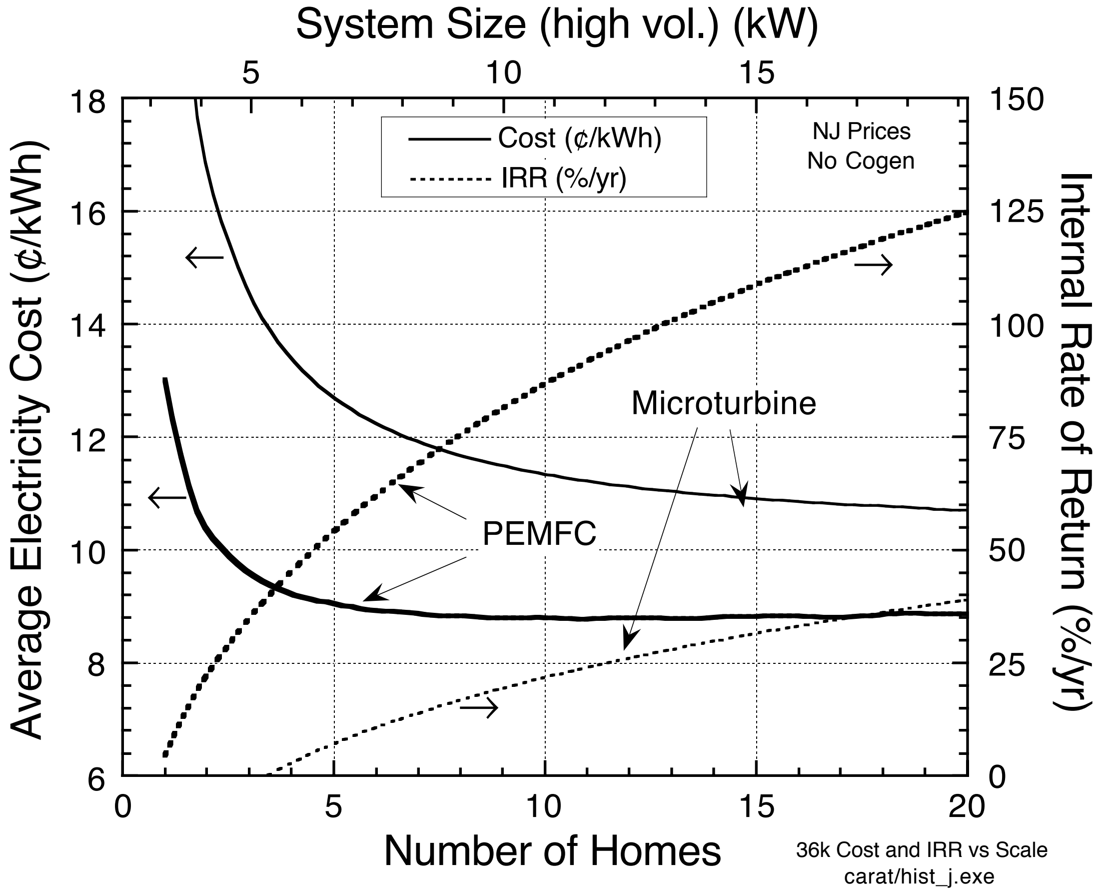


Figure 20. Electricity cost and rate of return as a function of scale, for a PEMFC system vs. a microturbine.

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