FUEL CELL SYSTEM ECONOMICS: COMPARING THE COSTS OF GENERATING POWER WITH STATIONARY AND MOTOR VEHICLE PEM FUEL CELL SYSTEMS

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Fuel cell system economics: comparing the costs of generating power with stationary and motor vehicle PEM fuel cell systems

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Abstract

This investigation examines the economics of producing electricity from proton-exchange membrane (PEM) fuel cell systems under various conditions, including the possibility of using fuel cell vehicles (FCVs) to produce power when they are parked at office buildings and residences. The analysis shows that the economics of both stationary fuel cell and FCV-based power vary significantly with variations in key input variables such as the price of natural gas, electricity prices, fuel cell and reformer system costs, and fuel cell system durability levels. The "central case" results show that stationary PEM fuel cell systems can supply electricity for offices and homes in California at a net savings when fuel cell system costs reach about $6000 for a 5 kW home system ($1200/kW) and $175,000 for a 250 kW commercial system ($700/kW) and assuming somewhat favorable natural gas costs of $6/GJ at residences and $4/GJ at commercial buildings. Grid-connected FCVs in commercial settings can also potentially supply electricity at competitive rates, in some cases producing significant annual benefits. Particularly attractive is the combination of net metering along with time-of-use electricity rates that allow power to be supplied to the utility grid at the avoided cost of central power plant generation. FCV-based power at individual residences does not appear to be as attractive, at least where FCV power can only be used directly or banked with the utility for net metering and not sold in greater quantity, due to the low load levels at these locations that provide a poor match to automotive fuel cell operation, higher natural gas prices than are available at commercial settings, and other factors.
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1. Introduction

California's net metering program is one of about 40 state net metering programs currently in place around the United States. These net metering programs allow excess local electricity generation to be supplied to the regional utility grid for a credit that can then be used later to supply demands that are not met by the local generation. In some cases, excess generation must be "taken back" from the utility on a monthly basis, with net energy use calculated each month, and in other cases any excess can be carried over from month to month with the final net billing accounted for annually. In a few states net excess generation can be credited at the avoided cost of utility generation, but in most states any excess is simply ignored and customers cannot earn net credits.

A principal motivation for creating policies to allow net metering has been to make better use out of intermittent renewable generating systems, such as solar PV and wind power generators. These clean and therefore socially attractive generating systems tend to produce electricity with a profile that roughly matches the demand profile on the overall utility grid, with peak production often occurring in the middle of the day and into the afternoon. For this reason, excess electricity generation is likely to be available when the demands on the utility grid are greatest, and this strengthens the argument for offering net metered billing for customers with PV and wind power systems. Of the state net metering programs, some states like California only allow PV and wind systems to be net metered, and others specify that all renewable power systems, including hydro-power, can qualify for net metering. However, a few states allow natural gas powered fuel cells,

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microturbines, and other non-renewable systems to also be net metered.

In April of 2001 and under AB 29X, the California legislature broadened the State's net metering program (described in Section 2827 of the California Public Utilities Code) by raising the maximum size of net-metered PV or wind power system from 10 kW to 1 MW. AB 29X also lifted the overall limit of 0.1% of each utility's peak demand level that can be net metered. However, this expansion of the State program is set to reach a "sunset" at the end of 2002 and, barring any further legislation, the 0.1% limit will be reinstated and the previous system limit of 10 kW will be applied again at that time.

This paper analyzes the potential for a future change to California's net metering program to extend qualifying systems to natural gas powered fuel cell systems as well as fuel cell systems powered by renewably produced hydrogen. The focus of this analysis is on fuel cell systems that are powered with hydrogen produced from natural gas reformers, because such systems are likely to be more economically feasible in the near term than fuel cell systems that run exclusively on hydrogen produced from renewable sources. In the future, technological developments and various incentives could help to stimulate the installation of systems to produce hydrogen renewably. Installing fuel cell systems that run on natural gas initially could thus prove to be an important first step to renewably powered fuel cell systems, but these future development paths are far from clear.

2. Fuel cell systems for distributed power generation

Fuel cell technology holds the promise to produce electricity at local sites from a wide range of fuels, and with high efficiency. Most types of fuel cells operate on hydrogen fuel, but this hydrogen can be produced from natural gas, liquid hydrocarbon fuels including biomass fuels, landfill gases, water and electricity (via the process of electrolysis), biological processes including those involving algae, and from gasification of biomass, wastes, and coal. Fuel cells are being proposed for use in powering electric vehicles, providing remote power for buildings and communication facilities, providing power as distributed generation (DG) in grid-connected applications (as either primary power or backup power), and for small electronic devices such as laptop computers and cell phones.

One principal attraction of fuel cell technology, as evidenced by this diverse array of potential applications, is that fuel cells can produce power with high efficiency in a wide range of system sizes. This feature is a function of the modular design of fuel cell systems (where individual cells are compiled into "stacks" to achieve higher voltage and power levels), as well as the fuel cell

operating principle that allows electricity to be produced without combustion. Several types of fuel cells are currently being developed, including proton-exchange membrane (PEM) fuel cells, solid-oxide fuel cells (SOFCs), alkaline fuel cells (AFCs), phosphoric acid fuel cells (PAFCs), molten-carbonate fuel cells (MCFCs), and direct-methanol fuel cells (DMFCs). Low temperature PEM fuel cells are considered the leading contenders for automotive and small stationary applications, with SOFC, PAFC, and MCFC operating at higher temperatures (from 200°C to 1000°C) and expected to be used for larger stationary applications, and DMFCs for portable electronics and possibly for future electric vehicles.

There are several potential operating methods for using both stationary fuel cells and fuel cell vehicles (FCVs) as distributed generating resources. These systems could be used to:

- produce power to meet the demands of local loads;
- provide additional power to the grid in a net metered or electricity buy-back scenario, helping to meet demands in times of capacity constraint;
- provide emergency backup power to residences, offices, hospitals, and municipal facilities;
- provide "peak shaving" for commercial sites, reducing demand charges;
- provide ancillary services to the grid, such as spinning reserves, grid frequency regulation, power quality support, reactive power, and possibly other services; and/or
- provide buffering and additional power for grid-independent systems that rely on intermittent renewables.

In general, stationary fuel cells are expected to operate nearly continuously (with the exception of those used for emergency backup), and they also have the potential to act as cogenerators, simultaneously producing electricity and useful waste heat. FCVs would provide power more intermittently, when parked at suitable locations for obtaining fuel and discharging electricity. The fuel cell systems in FCVs would likely be less readily usable for cogeneration (also known as combined heat and power or CHP) than stationary fuel cells due to the additional cost and complexity of trying to capture the waste heat from these systems, for uses inside nearby buildings.

Depending on the type of fuel cell system, waste heat is available at different temperatures and can be used for various heating and cooling applications. For PEM fuel cells, the waste heat is available at only about 80–90°C. Some other types of fuel cells run much hotter, up to 900°C or even 1000°C. The low grade of waste heat from PEM fuel cells is suitable for heating water and/or providing space heating, thereby displacing energy that is otherwise used for that purpose, while higher grade

waste heat from other fuel cell types can be used to produce steam and to drive absorption cooling systems.

3. Net metering of fuel cell systems

There are two basic ways in which commercial fuel cell systems could be "net metered". First, they could be net metered in a manner analogous to current net metering programs, whereby overall billing would be assessed on a monthly or annual basis and the customer could have a zero balance, a negative balance, or in the case where credit is awarded to net excess generation, even a positive balance. One argument against including fuel cell systems in these traditional net metering programs is that while PV and wind systems tend to have peak availability in the daytime and afternoon periods, coincident with the grid peak, to the extent that fuel cell systems are sized to meet most or all of the peak building electrical loads, much excess fuel cell power may be available off-peak when the grid is running mainly from baseload power plants. However, net metering policies could be designed to work in conjunction with "real time" electricity meters that are currently being installed at many commercial sites to allow excess generation to only be credited at peak hours of the day when the grid is employing peak power plants. In theory, use of fuel cell systems in this way could reduce the need to operate peak power plants and to construct new ones to meet peak demand growth. For this reason, this paper analyzes cases in which excess fuel cell power added to the grid is only credited for net metering during hours that coincide with the overall grid peak power demand, rather than at any time during the day or night.

A second type of net metering is "short term" net metering, where the fuel cell system is again connected in parallel with the utility grid but, in this case, simply relies on grid power to take up the transients in the commercial or residential load. This power used from the grid could be purchased, or "repaid" by operating the fuel cell system at excess power and supplying net power to the grid over a short period of time until the "borrowed" power had been replaced. The potential advantage of this is that if the fuel cell system does not need to completely meet the demands of, for example, a residential load that averages only 1 or 2 kW but can spike to 12–15 kW under certain conditions, then it can likely achieve higher operational efficiency. In addition, system components could be sized more optimally, peak-power battery systems would not be needed, and hydrogen "buffer" storage may also not be needed. This use of the utility grid to "load-level" the fuel cell system, whereby energy that is borrowed from the grid to take up transients is then repaid with gradual fluctuations in

fuel cell power over a perhaps a 15–30 min period of time, could significantly improve the economics of fuel cell system operation.

This paper analyzes the prospects for the first type of net metering, whereby fuel cell systems can produce additional power during peak periods, and can receive credit for the excess power provided that can then be withdrawn at other times. We believe that the second type of "short term" net metering is potentially promising, but is more challenging from a utility billing and administration perspective, and thus less likely near-term.

We compare cases in which fuel cell systems are net metered in various ways to those in which they are not net metered, but simply "load-follow" the building's electrical load profile. The types of fuel cells considered are both stationary PEM systems and FCVs that are parked in office building parking lots or household garages. We recognize fuel cells other than the PEM type could be used and net metered, and that other types of electric-drive vehicles (EVs) could produce power for buildings and the grid. However, PEM fuel cells are considered the primary contender for small-scale power production (especially under 100 kW) and for use in FCVs. Furthermore, among various EV types FCVs may be particularly attractive for use as DG resources because they can be operated continuously if connected to a source of hydrogen fuel and have very low operating emissions.

We hypothesize that in certain settings net metering may improve the economics of using small fuel cells for distributed power generation because it may allow fuel cell operation to be better optimized for high efficiency than is possible with strict "load-following" operation. We further hypothesize that this may be particularly true for the case of FCVs being used to generate power while they are parked at residential settings, due to the fact that the fuel cell systems in the vehicles have been sized and optimized for use as vehicle power, and may not be particularly well suited to powering small building electrical loads. Net metering of these systems may therefore play an important role in allowing the systems to be used with realistic "turndown" ratios and in a manner where higher efficiency operation is possible than in the absence of a net-metered operational strategy.

4. Fuel cell vehicles for stationary power

With regard to using FCVs to generate power, recent research has shown in addition to providing criteria pollutant, greenhouse gas, and energy use reductions relative to conventional vehicles, EVs can also in principle be used to provide a range of important services to utility electrical grids (Kempton and
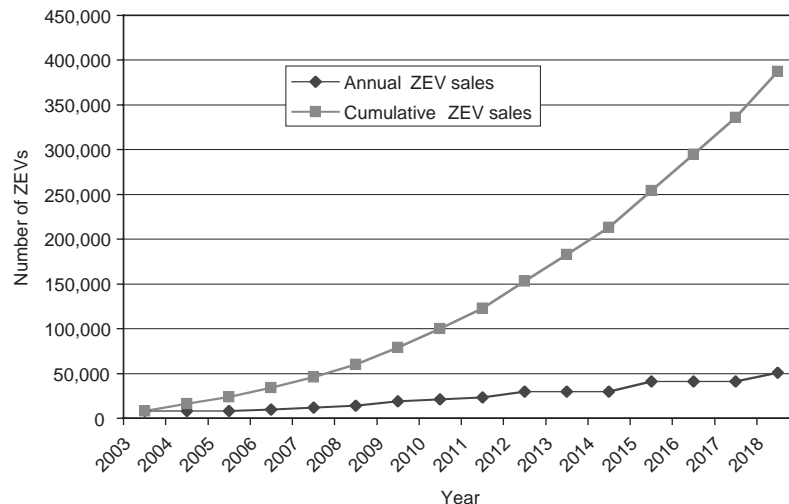
Fig. 1. Annual and cumulative California ZEV sales forecast (example scenario) source: (California Air Resources Board, 2001).

Letendre, 1996; Kempton et al., 2001). When not in use, battery EVs could be used for emergency backup power or to buffer the utility grid by charging off-peak, when electricity is plentiful, and supplying it back during times of peak demand and capacity constraint. Hybrid vehicles and FCVs could act as generators, producing electricity from a liquid or gaseous fuel to meet the demands of connected local loads or other nearby power needs.

EVs could also provide certain types of support services to utility grids, such as spinning reserves and grid frequency regulation. While contracting for these services would likely require a service "aggregator" to bid the reserve or regulation function from EVs to local system operators, battery EVs in particular appear to be well-suited to these uses. Alec Brooks of AC Propulsion Inc. has estimated that the grid frequency regulation service for California could be provided by 50,000–100,000 EVs, and these vehicles could provide this service as they were recharging their battery packs (Brooks, 2001).

EVs could also provide remote power for construction and other uses, and Dodge has recently unveiled a prototype hybrid electric pickup truck called the "Contractor Special" that is designed for this purpose. EVs with onboard power generating capability could also potentially help to make grid-independent renewable electricity generation more attractive by providing additional electricity from the vehicle when the capacity of these renewable sources is not fully available or the peak capacity needs to be supplemented.

In fact, the potential for producing electrical power from vehicles is enormous. We calculate that the generating capacity of an electrified US motor vehicle fleet would be approximately 14 times the entire capacity of all of the stationary power plants in the country![1] In California, a fleet of 100,000 FCVs could produce about 2.9 GW of power for the grid, assuming 30 kW net fuel cell output power per vehicle and 95% vehicle availability. Even if the vehicles were only available as generating capacity 50% of the time, about 1.5 GW of generating capacity could be provided by each 100,000 vehicles. This 1.5 GW of power represents approximately 5% of California's peak power demand on a typical day.

The use of FCVs in this manner may be particularly attractive since many automobile companies are currently developing FCVs as replacements to conventional internal combustion engine vehicles. Rapid EV and FCV market penetration is expected in California due to the pressure of the zero-emission vehicle (ZEV) mandate, promulgated by the California Air Resources Board and also adopted by New York, Massachusetts, and Vermont. This mandate requires manufacturers to include low-emission and zero-emission vehicles among the vehicles that they deliver to the California market, and in increasing numbers beginning in 2003. Under the current set of rules for the ZEV Mandate, which have recently been revised and have grown more complex since the mandate was originally approved in 1990, approximately 100,000 ZEVs may be on California streets by 2010. See Fig. 1 for one scenario of ZEV introduction levels in California as estimated by staff of the California Air Resources Board.

Under the revised ZEV Mandate rules, the exact number of ZEVs and other clean vehicles that each major manufacturer will have to produce will vary depending on the strategy that each manufacturer chooses to adopt, and some ZEVs may be battery EVs

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[1] See Kempton and Letendre (1996) for similar estimates and further details.

rather than FCVs. However, most manufacturers appear to be focusing on FCVs as a primary ZEV option, and even if only half of the ZEVs produced are FCVs, a total fleet of 100,000 FCVs can be expected in California by about 2015.

Thus, with these California and other state regulations encouraging their sale, and with their high potential operational efficiencies and clean and quiet operation, FCVs may become ubiquitous once they are introduced and have had time to penetrate motor vehicle fleets. Unlike battery EVs, which store and release electricity, FCVs can convert chemical energy into electrical energy and can therefore act as DG resources. And, unlike hybrid EVs, FCVs can generate electricity without combustion and with minimal noise and emissions.

Despite this potentially attractive possibility, however, the use of FCVs as distributed generating resources faces technical, economic, and regulatory hurdles. These issues are discussed briefly below, followed by presentation of modeling analysis of the potential costs, benefits, and emissions implications of using FCVs as distributed generators in residential and commercial settings. However we first discuss the key findings of previous studies of stationary fuel cells and FCVs for distributed power.

5. Previous research on PEM fuel cells and/or EVS and distributed power

Several analyses have been conducted on the potential for small stationary PEM fuel cells to produce power for residences and other buildings. These include studies by Arthur D Little (Arthur D Little, 1994; Teagan and Friedman, 1994), Princeton University (Kreutz and Ogden, 2000), and Directed Technologies Inc. (Thomas et al., 2000a, b, 1998), among others. These studies have generally concluded that PEM fuel cell systems for single family residences will only become attractive when system capital costs fall to relatively low levels, well below $1000/kW. However, these studies have found that when larger systems are examined—systems for multi-family residential units and commercial applications—the systems can be cost-effective at somewhat higher capital cost levels. Furthermore, due

to scale economies fuel cell systems for these applications are expected to cost somewhat less in terms of $/kW than fuel cells for smaller residential applications. These two factors taken together suggest that the multi-family and commercial market segments are likely to be more attractive for early fuel cell technology, and that markets for larger stationary fuel cell systems, on the order of 100 kW or more, are likely to develop before markets for smaller single-family fuel cell systems.

The most recent published analysis of the potential for EVs and FCVs to act as DG resources was conducted by Kempton et al. (2001). This report was prepared for the California Air Resources Board by researchers at the University of Delaware, Green Mountain College, and the University of California. The analysis also involved collaboration with EV drivetrain manufacturer AC Propulsion, Inc. AC Propulsion's Generation 2 electric motor controller unit allows for bi-directional grid interface that can support vehicle-to-grid (or "V2G") connections, and this system has demonstrated the technical feasibility and low incremental cost of this type of arrangement. The Kempton et al. effort examined the economic potential of using various types of EVs to produce power for buildings and the grid, as well as to provide grid "ancillary services" such as spinning reserves, non-spinning reserves, and grid frequency regulation.

With regard to FCVs, Kempton et al. concluded that FCVs could compete in the peak power market, with generating costs on the order of $0.18/kWh, but could not compete with baseload power. FCVs appear to be well suited to provide a spinning reserves ancillary service to utility grids, but they are not as well suited to provide a grid frequency regulation ancillary service as other EV types. Table 1 presents some of the key findings of the Kempton et al. report, in terms of the range of annual values that might be expected for different EV types and for different services.

Also, an earlier analysis of the potential for FCVs to provide power for buildings was conducted by Kissock (1998). This analysis assumed that FCVs equipped with 25 kW nominal (37.5 kW peak) PEM fuel cell systems would be used to produce electricity, or electricity and heating/cooling in a cogeneration mode, for New Jersey and Texas residences, for a New Jersey hospital, and for

Table 1
Estimated vehicle owner's annual net profit from V2G

	Peak power	Spinning reserves	Regulation services
Battery, full function	$267 (510−243)	$720 (775−55)	$3162 (4479−1317)
Battery, city car	$75 (230−155)	$311(349−38)	$2573 (4479−1906)
Fuel cell, on-board H$_2$	$-50 (loss) to $1226 (2200−974 to 2250)	$2430 to $2685 (3342−657 to 912)	$-2984 (loss) to $811 (2567−1756 to 5551)
Hybrid, gasoline	$322 (1500−1178)	$1581 (2279−698)	$-759 (loss) (2567−3326)

Source: Kempton et al. (2001).

Note: The figures represent $net and (revenue−cost). These are representative mid-range figures extracted from full analysis in the report.

a Texas office building. The analysis focused extensively on the cogeneration prospects from FCVs, and the ability of waste heat from the fuel cells to be used for both space heating and to help to operate an absorption cooling system for the building. The analysis assumed that hydrogen would be produced onsite from natural gas, and that natural gas would cost $7.50/GJ at residences and $6.38/GJ at commercial locations. The analysis used fuel cell efficiency estimates based on a PEM fuel cell operating curve published by the Allison Gas Turbine division of General Motors, and the calculated efficiencies of the fuel cell systems were relatively high: on the order of 41–50% electrical efficiency (AC power generated/fuel in) and 79–83% total efficiency with cogeneration. The analysis included capital cost estimates for the vehicle "docking stations" but we note that no additional maintenance or fuel cell stack refurbishment/replacement costs were assumed for the additional use of the systems. The analysis concluded that annual savings of up to $2500 per docking station could be realized with the residential setting (with some cases showing negligible benefits), that annual savings of $1200 to $8800 were possible for each docking station at the hospital, and that annual savings of $2300 to $2900 were possible for the office building (Kissock, 1998).

6. Key technical and regulatory issues for FCVs used as distributed generation

Despite the potential benefits of using FCVs to produce power when the vehicles are parked, there are several key issues confronting the use of FCVs in this manner. Some of these issues, and some potential solutions, are as follows.

6.1. Fuel cell operation

Problems: Non-hybrid fuel cell systems with 75–100 kW peak power (a typical power level for full-sized vehicles) will likely be power limited to 30 or 40 kW for continuous operation while the vehicle is at a standstill due to thermal management issues. Fuel cell systems connected to loads in grid-independent operation may be subject to transient demands that would require a hydrogen fuel supply buffer and/or battery support system for adequate performance (if no battery pack is included in the onboard vehicle power system). Also, operating fuel cell systems in residential settings and meeting local loads only, which are often as low as 1–2 kW and rarely exceed 4–5 kW, will likely produce low fuel cell system operating efficiencies (if even possible due to turndown ratio limitations), particularly for stacks designed to operate at high pressure due to the high parasitic compressor loads for these systems.

Solutions: Operate fuel cell systems at 10–30 kW and supply several buildings or sell excess power to grid through net metering or other "buyback" scenarios. Alternately, develop off-board auxiliary "blower" air supply systems for fuel cell stacks that allow low pressure, higher efficiency operation at low load levels, or design the FCV fuel cell system to have a second "low power mode" for stationary power generation, where only a portion of the full fuel cell stack is used (e.g. similar to "displacement on demand" systems in conventional vehicles).

6.2. Fuel supply

Problems: Vehicles designed to operate on pure hydrogen may not be able to use reformate (a mix of hydrogen and other gases, produced from a liquid or gaseous hydrocarbon fuel) due to carbon monoxide and sulfur catalyst poisoning issues. In order to operate for longer than a few hours, vehicles will require some sort of hydrogen production support system based on steam methane reforming (SMR), electrolysis, partial oxidation reforming, or auto thermal reforming.

Solutions: Use vehicle stacks with platinum-ruthenium catalysts that can operate on either neat hydrogen or reformate (e.g., Ballard Mark 900), or produce purified hydrogen at commercial sites (and have no residential option for neat hydrogen vehicles other than emergency power using the fuel in the vehicle's tank). Focus R&D on developing low-cost hydrogen reformers, particularly continuing the development of multi-fuel reformers for vehicles that can run on natural gas as well as the vehicle's primary fuel.

6.3. Grid interconnection

Problems: Reverse flow of electricity from EVs is currently not permitted under the National Electrical Code in event of loss of power in the grid. Power flow into local distribution systems eventually will reach a limit due to difficulties in reverse flow into high-voltage transmission system. In the residential scenario, more than one household in 10 or 20 with grid-connected FCVs at 5–30 kW could be problematic, depending on distribution system topology and locations of other generators and loads. Utility on/off control of grid-connected EVs may be essential for lineworker safety, requiring a complex control system.

Solutions: Revise National Electrical Code to allow reverse-flow from vehicles for backup generation, with appropriate safeguards, in parallel with efforts to allow residential PV systems to be used in a similar manner. Analyze retrofitting substations to ensure that "tap changers" and line-drop compensators are compatible with reverse flow into high voltage transmissions systems, if this can be done with a reasonable level of

efficiency loss. Investigate utility-to-vehicle wireless communication technology to provide emergency shutdown, real time load, and electricity price information for utility control centers and vehicle owners.

7. CETEEM model description

In order to analyze the economics of operating stationary and motor vehicle PEM fuel cell systems to provide power to buildings and/or the electrical grid, we have constructed an integrated MATLAB/Simulink/Excel model. This model, which we have named the Clean Energy Technology Economic and Emissions Model (or CETEEM, pronounced "see team"), has been designed in order to assess the economics and emissions of criteria pollutants and greenhouse gases (GHGs) associated with the use of CETs for distributed power generation. CETEEM has thus far been developed around the scenario of the use of PEM fuel cell systems powered by hydrogen produced with natural gas reformers, but it can be readily modified to characterize other CETs and fueling arrangements. These might include solar PV systems, wind power generating systems, other fuel cell technologies such as SOFCs, fuel cell systems operating in conjunction with electrolyzers to produce hydrogen (and hybrid renewable/fuel cell systems), natural gas powered microturbines, and other DG technologies.

CETEEM has the following principal features:

- Ability to simulate the partial load efficiency of distributed electricity generating systems (stationary and vehicular PEM fuel cells in the present analysis) in meeting hour-by-hour variations in building electrical loads.
- Inclusion of a cogeneration sub-model that estimates the economic implications of combined heat and power (CHP) generation to displace hot water heater natural gas consumption, given an hour-by-hour building hot water load.
- Ability to separately characterize up to 10 individual CET systems at a given location, or 10 "proxy groups" of any number of CET systems with each group assumed to operate similarly (e.g., 10 FCVs parked in an office building parking lot, combinations of a stationary fuel cell system plus one or more FCVs at a hydrogen "energy station", etc.).
- Calculation of costs of electricity, fuel costs, and operating efficiencies for individual CET sub-systems and for the overall electricity generating system.
- Ability to model varying operational strategies, including load-following operation, where the entire local building load is met with local generation, partial load-following operation, where some portion of the local load is met with onsite generation and the

rest is made up with purchased power, and excess "grid supply" operation where onsite generation provides power for the electrical grid (directly or in addition to meeting the local load) during one or more hours of the day.

- Ability to analyze system economics in response to hour-by-hour variations in electricity purchase prices and sales prices (or net-metering "credit" rates), thus allowing analysis of time-of-use (TOU) or real-time pricing tariff structures, and also including both electricity energy charges (in terms of \$/kWh) and demand charges (in terms of \$/peak-kW) for commercial customers.
- Characterization of fuel cell (or other CET) system operating efficiencies under varying system operating conditions (e.g., high or low fuel cell air side pressure, operation on pure hydrogen or natural gas reformate, etc.).
- Allowance for specification and sensitivity analysis of a number of key economic input variables such as natural gas purchase prices, system capital costs, system installation costs, system operation and maintenance costs, hours of operation per year, capital cost recovery factors (based on a specified system lifetime and interest rate), and system capital cost financing arrangements (versus upfront system purchase).
- Calculation of fuel upstream and system operating emissions, divided into approximate "in-basin" and "out-of-basin" components, including criteria pollutants (oxides of nitrogen, carbon monoxide, reactive hydrocarbons, fine particulates, and sulfur dioxide) and GHGs (carbon dioxide, methane, and nitrous oxide), and based on three different fuel cycle emissions analyses (the GREET model analysis, the Delucchi model analysis, and the Acurex analysis);
- Ability to analyze the case of a hydrogen "energy station" where excess hydrogen is produced, compressed, stored, and then sold to fuel FCVs (in addition producing hydrogen to power a building-integrated stationary fuel cell system).

With regard to the economic calculations in CETEEM, the following formula is used to calculate the cost of electricity (COE) for both individual sub-systems (e.g., individual FCVs) and for the overall system. The overall system includes up to the 10 generating units, additional system-level components such as a central reformer, installation costs, and other cost variables:

$$COE = \frac{CRF\ CC}{H} + \frac{3.412\ FC}{\eta} + \frac{O\&M}{H},$$

where CC is the system capital plus installation (i.e., "turnkey") cost (\$/kW), COE the cost of electricity (\$/MWh), CRF the capital cost recovery factor, η(eta) the average system efficiency (0–1.0), FC the fuel cost

($/GJ), H the hours of operation per year, divided by 1000, and O&M the operation and maintenance costs ($/kW-year).

This COE formula is a common one that is widely used, for example in US DOE (2000). It is important to note that by using a capital cost recovery factor to account for system depreciation, this formula assumes a constant or ''straight-line'' depreciation schedule. Analysis of system economics with more complicated depreciation schedules would require the use of a different formula, and then the system economics would depend to some extent on the year of analysis relative to the system lifetime. In the CETEEM model, we modify this formula slightly by using a factor of 1/1000 in order to produce COE estimates in terms of $/kWh rather than $/MWh.

With regard to the basic structure of CETEEM, one important feature is that the model is capable of analyzing the efficiency of one or more CET systems as a function of the load that each individual unit is meeting. The model thus includes data for each system's efficiency as a function of load point in relation to the system's gross power rating. This is important particularly for cases where loads are varying significantly, and where there is a significant potential mismatch between the system's power level and the load to which it is connected (such as in the case of large vehicular fuel cell systems meeting small residential loads). It is also more important for technologies that exhibit strong variations in efficiency with load, such as high-pressure fuel cell systems with high auxiliary loads, than it is for technologies that have relatively flat efficiency curves.

However, it is important to note that CETEEM is based on hour-by-hour building load profiles, and not more highly resolved load shape data. In general, even hour-by-hour load shape data are difficult to obtain, but a more sophisticated analysis of the effects of ''transient'' operation in load-following applications would require second-by-second or even greater resolution in load shape data. Such analyses would also require a highly detailed system performance analysis model that includes analysis of the interactions between major system components, component lag times in response to control signals, and so on. Thus, the intent of this analysis is to characterize the general efficiencies of operation that could be expected based on the load shape data used, rather than to characterize the details of transient operation and the additional efficiency implications of detailed second-by-second interaction between generating system and load.

In fact, meeting the exact transient loads of buildings in load-following applications represents a formidable challenge for fuel cell systems. Fuel cell stacks and systems can respond quite rapidly to transient power demands, but natural gas fuel reformers tend to have somewhat slower response. Furthermore, electrical loads are often characterized by ''spikes'' in demand that last for only short periods, such as when an air conditioner compressor motor suddenly switches on. Meeting these transient demands for power can be accomplished either by using the utility grid as a buffer (as discussed above in the context of ''short term'' net-metering), or by including a peak power device in the fuel cell system such as a battery or ultracapacitor that helps to ''load-level'' the fuel cell. Furthermore, fuel buffers can be used to allow faster system response and to avoid the limitations of fuel processor ramp-up rates. Thus, it is important to note that this analysis does not explicitly consider the issue of short transients in load demand and the effects that these have on system performance, but rather seeks to characterize the broad system efficiency implications of meeting loads that are characterized with hour-by-hour variation. We therefore assume that there are peak power devices in both the stationary and vehicle-based systems that allow the fuel cell systems to operate in response to relatively gradually fluctuating loads. In the absence of such a peak power device, fuel cell system operation would be more variable and overall electrical efficiency would likely suffer to some extent as a result.

The efficiency characterizations for PEM fuel cells for FCVs have been derived from a detailed fuel cell system modeling effort that used a MATLAB/Simulink model to characterize the interactions of PEM fuel cell stacks with air compressors and other system auxiliaries, and to optimize system operation by varying hydrogen and air pressure and mass flow conditions (Friedman et al., 2000). We use optimized fuel cell system efficiency versus load characterizations (as a function of percent of peak system power) from this modeling effort to construct ''lookup tables'' that are then used in CETEEM to estimate system efficiency values with each 1% change in load as a function of peak system power.

We use these model results to characterize pure hydrogen and high air-side pressure fuel cell system operation, which uses a twin-screw type compressor to move air through the fuel cell stack, pure hydrogen and low air-side pressure operation, where a simple blower is used to propel air through the stack, and methanol reformate and high air-side pressure operation. We assume that when vehicles are operated on natural gas reformate, performance is similar to performance on methanol reformate since both types of reformate have hydrogen concentrations on the order of 70% (dry). Finally, in order to characterize stationary fuel cell system operation on natural gas reformate, we use the profile for low pressure operation on neat hydrogen but scale the numbers to match company claims for overall efficiency of the Plug Power residential PEM fuel cell system, assuming 85% hydrogen utilization and a 75% efficient reformer. These results produce slightly higher efficiencies than the curves for automotive fuel cell
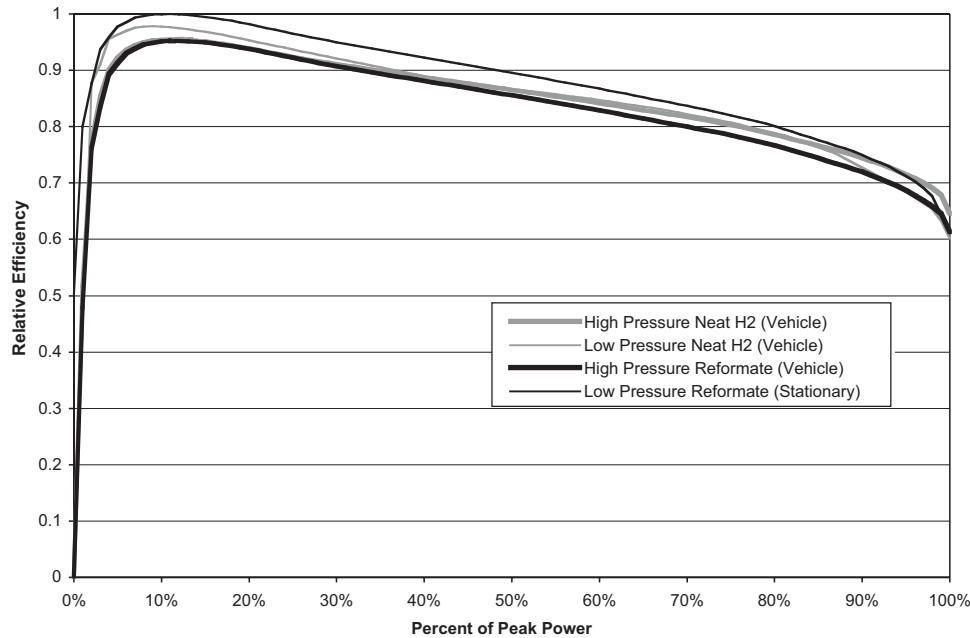
Fig. 2. PEM fuel cell system relative efficiency as a function of load and operating condition.

systems, even those for operation on pure hydrogen. While efficiencies for fuel cells operating on pure hydrogen will be greater than for operation on reformate when "all else is equal", higher efficiency is more important for stationary applications (due to nearly continuous operation and the burden of fuel cost on overall operating cost). This higher efficiency could be achieved by maintaining relatively high cell voltages and accepting some reduction in stack power density, and this is in effect what we are assuming for stationary fuel cell operation. Fig. 2 presents the system efficiency curves used for various system configurations, relative to the peak efficiency point of the highest curve.

8. Analysis cases and input variables

In this analysis, we consider two basic settings for stationary and FCV-based fuel cell power, and we consider the potential use of the vehicles as a significant resource that is used routinely by coupling vehicles to a stationary natural gas reformer as a hydrogen supply system.[2] In previous efforts (Kempton et al., 2001) we found that the use of FCV based power appears to be suited to the peak power market, where power is supplied for short periods only when the generating cost is high. However, we did not fully investigate the potential for more expanded use of FCV-based power,

where loads can be powered throughout a several-hour daily peak building load, net-metered billing can be used, and the capital costs of a separate reformer/hydrogen supply can potentially be justified. Therefore, the goal of the present analysis is to examine this expanded case of the use of FCVs for power generation, where each vehicle is used for 2000–4000 h per year to produce on the order of 30–60 MWh per year.

The settings analyzed are a medium-sized California office building, with an electrical load that varies from about 30 kW at night to up to about 300 kW during peak periods, and a California residential setting with a load that varies from under 1 kW to almost 4 kW at the peak hour in the summer. The residential household load profiles that we use are somewhat higher than the average California household, and therefore represent a relatively large household, but we hypothesize that relatively large households are more likely to be owners of FCVs in the 2010–2015 timeframe.

We also consider two basic operating strategies for each fuel cell system and building combination. These are a "load following" case in which the fuel cell system simply follows the electrical load of the building when the fuel cell system is available, and a "net metering" case in which additional power is allowed to be supplied to the utility grid and withdrawn later. For purposes of this analysis, we consider the case of a net metering policy that allows extra power to be supplied to the grid only during the hours of 12 PM to 8 PM so that the additional power is supplied during periods of peak demands on the utility grid. We believe that this type of net metering scheme makes the most sense because,

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[2] Hydrogen FCVs used for stationary power could also in principle be fueled with hydrogen produced from an onboard "multi-fuel" reformer, an on or off-board electrolyzer, or fuel stored onboard.

unlike renewable solar PV and wind systems that tend to naturally produce the most power during the approximate times of grid peak, fuel cell systems can be operated at different power levels at anytime of the day or night. An unrestricted net metering policy for fuel cells would allow excess power to be supplied at non-peak periods for the grid, and this would be much less useful in terms of maximizing the capacity factors of central "baseload" generating plants and minimizing the need for "peaker" plants.

Also, in the FCV cases we consider the case of non-hybrid FCVs that are entirely powered by a 75 kW (peak) fuel cell system and the case of hybrid FCVs that are powered by a 20 kW (peak) fuel cell system in conjunction with a battery peak power system. We do this because we hypothesize that hybrid FCVs with smaller fuel cell systems will perform better when matched up with residential loads than non-hybrid FCVs with larger fuel cell systems.

However, based on conversations with fuel cell system developers, we effectively limit the amount of power available from the 75 kW systems to 30 kW. We do this because continuous operation of these 75 kW systems at power levels higher than 30–40 kW may lead to system overheating since, unlike when vehicles are being driven, radiative "ram air" cooling is not available when vehicles are parked. The actual limits on the level of FCV power when the fuel cell system is operated continuously while the vehicle is stationary will depend on the design of the vehicle's cooling system, the ambient temperature where the vehicle is operated, and any limits of the electrical system that transmits the electricity from the vehicle to the building or utility grid. For residential applications, this limit may be closer to 16–17 kW than 30 kW due to the electrical limits of residential system wiring (see Kempton et al., 2001 for further discussion). We therefore do not allow power levels over 17 kW in any of our residential case simulations (when net metering allows higher power levels to be provided than the level of the house's local electrical load, which never exceeds 3.8 kW).

Unlike in Kissock (1998), for purposes of this analysis we do not assume that FCVs are used in a cogeneration mode to produce both electricity and heating/cooling for buildings. In our opinion, it is unlikely that FCVs will prove to be attractive as cogenerators for the following reasons:

- Use of FCVs for cogeneration would require a set of heat exchange hookups in addition to electrical connections, and this would add cost and complexity to the use of FCVs for DG and would potentially make this type of arrangement less convenient for consumers.
- PEM fuel cells operate at relatively low temperatures of 80–90°C and the low grade of waste heat available would probably not be practical for absorption cooling (cooling loads are higher than heating loads for many California buildings during many months of the year).
- Similarly, use of PEM fuel cell waste heat for hot water heating would require careful integration with hot water systems and would likely require close-coupling to the hot water heater to be attractive, reducing the likelihood that vehicles parked in parking lots would be practical for use in providing hot water (vehicles parked in residential garages may be more practical for cogeneration but still would require potentially expensive heat exchange coupling systems to be retrofitted with the hot water heater for use in this way).

Thus, we consider the potential for cogeneration to be unlikely for FCVs, and we consider cogeneration of hot water to be a potential competitive advantage of stationary fuel cells compared with FCVs used in DG mode.

We consider 10 main cases in this analysis, and these are shown in Table 2, along with 3 different sets of cost assumptions for each case. We also consider a few additional cases that include variations in the utility tariff structures that are available to residential and commercial customers (e.g., time-of-use billing). For the

Table 2
Basic cases analyzed

Case	Setting	FC system	FC operation	Code
Case 1	Residential	Stationary 5 kW hot water cogen	Load following low pressure	SR5LFLR
Case 2	Residential	Stationary 5 kW hot water cogen	Net metering low pressure	SR5NMLR
Case 3	Office building	Stationary 250 kW hot water cogen	Load following low pressure	SO250LFLR
Case 4	Office building	Stationary 250 kW hot water cogen	Net metering low pressure	SO250NMLR
Case 5	Residential	1 Vehicle 75 kW (30 kW max power) no cogen	Load following high pressure	VR75LFHR
Case 6	Residential	1 Vehicle 75 kW (30 kW max power) no cogen	Net metering high pressure	VR75NMHR
Case 7	Residential	1 Vehicle 20 kW (hybrid FC/battery) no cogen	Load following high pressure	VR20LFHR
Case 8	Residential	1 Vehicle 20 kW (hybrid FC/battery) no cogen	Net metering high pressure	VR20NMHR
Case 9	Office building	1–10 Vehicles 75 kW (300 kW max power) no cogen	Load following high pressure	VO75LFHR
Case 10	Office building	1–10 Vehicles 75 kW (300 kW max power) no cogen	Net metering high pressure	VO75NMHR

stationary fuel cell system cases, we assume that the fuel cell systems operate under low fuel cell stack air-side pressure and use natural gas reformate for fuel containing 70% hydrogen by volume. For the vehicle fuel cell system cases, we assume that the fuel cell systems operate under higher fuel cell stack air-side pressure with higher auxiliary system parasitic loads (because this is the type of system that most FCV developers are focusing on), and again that the fuel source is natural gas reformate that contains 70% hydrogen by volume.

9. Building electrical and hot water load profiles

With regard to the building electrical load profiles used in the analysis, it is worth noting that hour-by-hour building load profiles, and especially residential load profiles, are notoriously difficult to obtain and tend to represent the average loads of many buildings rather than the specific load of a single building. However, there are some hour-by-hour building load profiles in the public domain. For purposes of this analysis, we use residential and office building load profiles that have been published by Arthur D Little (ADL) (1994) as a starting point. These load profiles are described as representing peak day loads for sites in a southern region of the US. In order to characterize a typical year of operation, it is necessary to consider variations in these building load profiles over the course of the year. We accomplish this by adopting a convention used in some commercial building load profile databases whereby a month of the year is characterized with three "day types": a "peak day" that represents the average of the three peak days of the month; a "week day" that represents the average of the remaining 19 week days in

a typical month, and a "weekend day" that represents the average of the 8 weekend days in a typical month.

Having established these day types, we then apply statistical variation that we observe in proprietary load shape databases that are specific to California to approximate the seasonal variations in load profiles that might be expected for these two types of building loads. In other words, we apply observed annual variation in California office building loads and residential loads to the ADL load shapes to develop a family of load shape curves that can then be used to characterize a typical year with multiple runs of CETEEM. In order to reduce the number of runs necessary for each case, we characterize the 12 months of the year with four representative months: January, to represent the Winter months of December, January, and February; April to represent the Spring months of March, April, and May; July to represent the Summer months of June, July, and August; and October to represent the Fall months of September, October, and November. These simplification means that a typical year can be modeled with 12 runs of CETEEM; three day types to characterize each month, and then four representative months to characterize the 12 months of the year.

Figs. 3–6 depict the load shapes used to characterize the office building and residential location electricity demands. Figs. 3 and 6 show the seasonal variations in load shapes for residential and office building cases. Fig. 4 shows an example load shape for one day of the residential case (a July peak day), along with sample net metering profile for the same day for power generated from an FCV. As shown in the figure, excess power is supplied when the vehicle arrives home at 6 PM and this continues until 8 PM. From 8 PM until 8 AM, the fuel cell system simply follows the load of the building, and
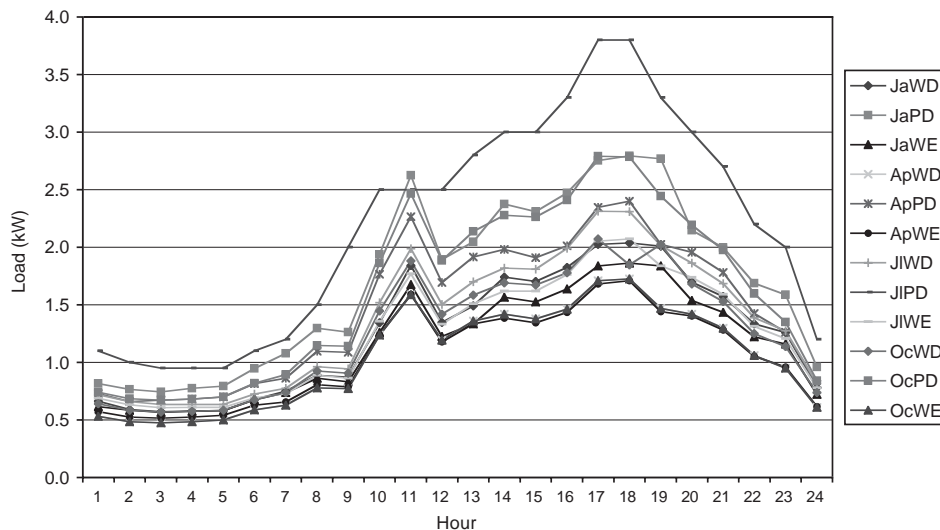

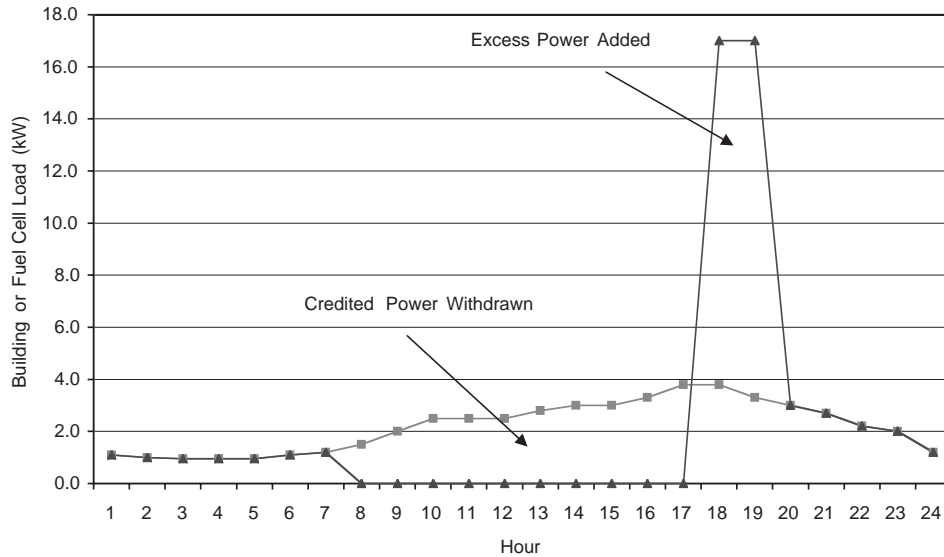Fig. 3. California large residential site load shape patterns.

Fig. 4. Residential daily load profile and example FCV net metering load pattern.
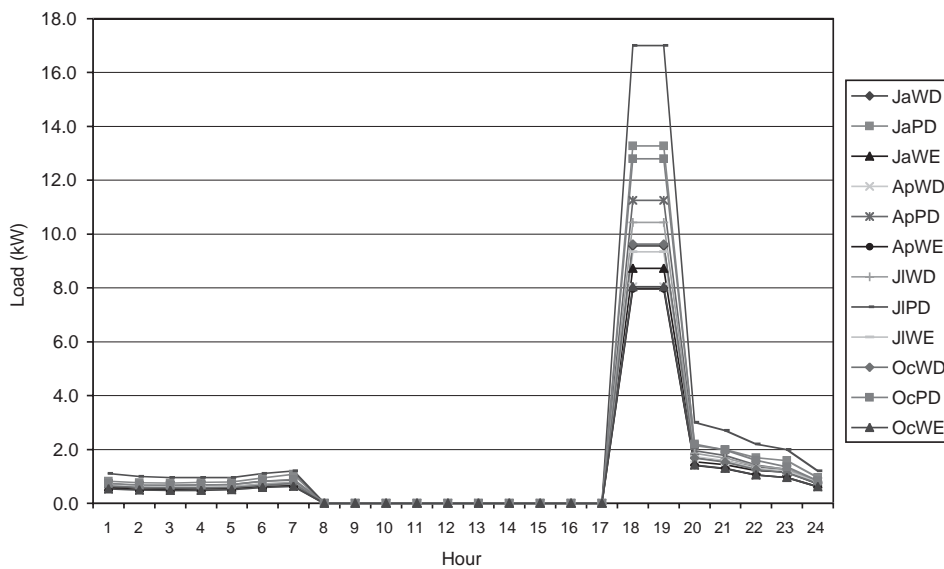

Fig. 5. California large residential site modified fuel cell load patterns for FCV net metering.

then when the vehicle is gone during the day the net-metered energy credit is withdrawn. In the base cases, we assume that the buildings have a net energy balance of zero at the end of every month and that the building load is followed when excess energy is not being added to the grid, but in a sensitivity case we examine the possibility of optimizing the efficiency of the FCV by having the fuel cell system operate only at its peak efficiency point and for some energy credit to be carried over from month to month, with a net energy balance of near zero on an annual basis. Fig. 5 shows one of the net metering cases, in which an FCV is used to produce up to 17 kW of power at a residential setting when it is first plugged in at the end of the day (and when the grid still

needs power), while Fig. 7 shows the hot water load profiles that are met in the stationary fuel cell cogeneration cases.

In the figures, "Ja" stands for January, "Ap" stands for April, "Jl" stands for July, "Oc" stands for October, "WD" stands for weekday, "PD" stands for peak day, and "WE" stands for weekend day. The residential load shapes characterize a large single family home, while the office building load shapes characterize a medium-sized office building with typical electrical demands. Of course, every building is different and these load shape patterns may not accurately represent specific sites with highly unique demand patterns, even for similar building types as those assumed here.
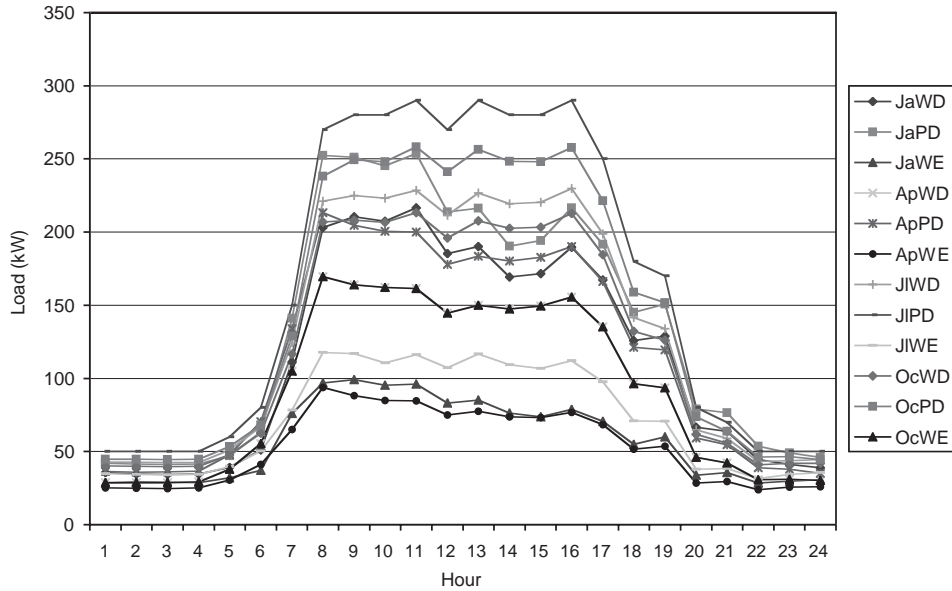
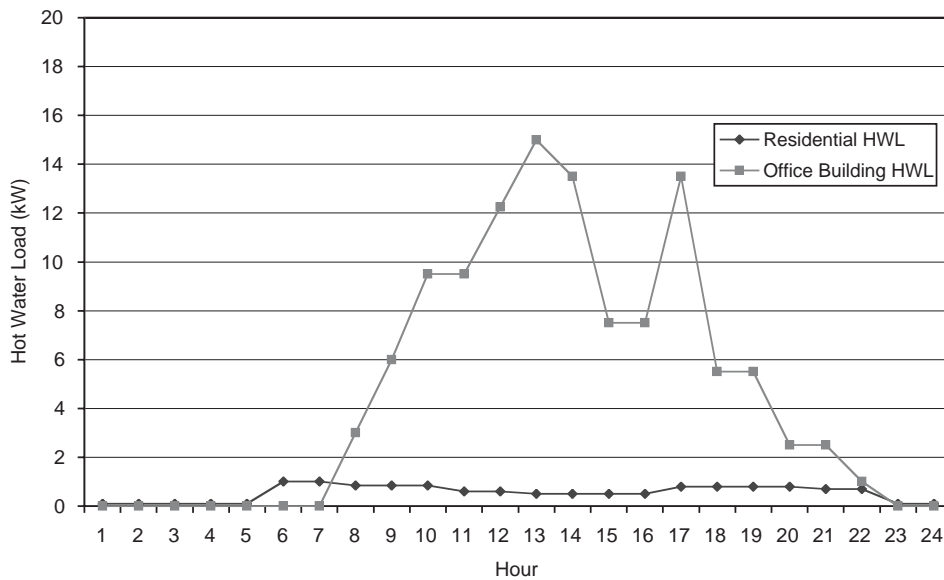Fig. 6. California medium office building site load shape patterns.

Fig. 7. Residential and office building hot water load profiles source: (Arthur D Little, 1994).

10. Economic variable input assumptions

This analysis is intended to estimate the potential costs of using stationary and automotive fuel cells for distributed power in the 2010–2015 timeframe. Thus, we analyze cases with fuel cell system capital costs that are much lower than present-day capital costs for PEM fuel cells, which we believe to be on the order $3000–4000 per kW[3]. PEM fuel cells are an emerging technology that is just beginning to become commercial after a decade of intense development throughout the 1990s, and costs are expected to fall sharply as production volume and manufacturing experience grow. However, manufacturing costs and sale prices of PEM fuel cells and natural gas reformers in higher volume production are uncertain, owing to several variables that can affect manufacturing cost. These variables include production volume, product design, material choices and material utilization rate improvements, production process development, and cost vs. efficiency tradeoffs with regard to fuel cell system operation (e.g., higher efficiency levels can be maintained with larger and more expensive fuel cell stacks).

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[3] PEM fuel cell manufacturing costs are proprietary, and even selling prices are difficult to determine at present because systems in the 5–250 kW size range are not yet commercially available.

With regard to the costs associated with FCV-based power, we explicitly assume that the additional use of FCVs to provide power to buildings entails additional costs in terms of fuel cell stack refurbishments that are required as fuel cell system components wear out. However, we do not include initial capital costs for these systems because we assume that they are purchased for use in powering the vehicles and that the use for DG is a side-use that entails only the incremental costs associated with the additional use. We assume that fuel cell systems for vehicles are designed for the typical operational lifetimes of vehicles, on the order of 4000–5000 h of operation, and that the additional use for power generation results in significant costs that the vehicle owners must pay. We feel that it is important to include these costs because PEM fuel cell system durability is a key development issue that is currently being addressed, and the future level of durability of PEM fuel cells for vehicle and stationary applications is uncertain. Simultaneously achieving cost and durability goals for PEM fuel cells is a significant challenge, and we therefore assume that fuel cell costs are greatly reduced from present levels by 2010–2015 but that durability remains an issue. We assume varying levels of fuel cell system durability for the automotive fuel cells used for stationary power generation, ranging from 4000 h in our high cost cases to 10,000 h in our medium cost cases, to 40,000 h in our low cost cases. We use this wide range of operational hours between major refurbishments because PEM fuel cell systems may or may not prove to be very durable, and we allow for relatively long periods between refurbishments because the demands on the systems for stationary power generation may have a somewhat lesser impact on durability than during driving owing to the lack of vibration and the relatively low power levels.

We would also like to point out that for the residential cases, we assume natural gas costs in the range of $4/GJ to $10/GJ, with a medium cost case value of $6/GJ. The high cost case value of $10/GJ was selected because residential costs at the retail level were in fact this high in California for several months during the winter of 2000–2001, and the spot market price reached an amazing level of $60/GJ at one point in December of 2000. At the present time in late 2001, natural gas costs have declined to more reasonable levels, on the order of $5–6/GJ, and it is unlikely that prices as high as $10/GJ will prevail over the course of an entire year. With the benefit of hindsight we thus consider our high cost case to be a rather conservative and unlikely case, but at the time this analysis was being initiated we did not feel that we could safely rule out such high natural gas prices and therefore included them in the high cost case. Tables 3 and 4 summarize the basic assumptions that underlie the cases analyzed. See table notes for details of the input values selected for the various cases.

11. Net metering TOU tariff schedules

In addition to the constant electricity price ranges shown in Tables 3 and 4 (coupled with electricity fixed monthly charges and demand charges in the office building case), we also consider cases in which customers can qualify for time-of-use (TOU) rate schedules. In these cases, the price of electricity fluctuates throughout the day and from season to season. Under these rate schedules, when excess power is supplied to the utility grid under the assumption of net metering, the supplied power is credited with the electricity price that prevails at that particular time, and when power is withdrawn it is charged the price at that time. In the primary case, we assume that electricity supplied to the grid is credited with the "avoided" generation cost only and not with the full retail rate. However, we also consider a case in which the customer is credited with the full retail TOU rate, as solar PV customers that qualify for both net metering and TOU rates are currently allowed in California.[4] Figs. 8 and 9 show the full retail and "generation cost only" TOU rates that we assume for those cases. These rates are based on Southern California Edison rate schedules SCE TOU-D-2 for residential customers and SCE TOU-GS-1 for commercial customers.

12. Analysis results

A sample of detailed results of this analysis are presented in Tables 5–12, and key results are summarized in Figs. 10–12.[5] In our presentation of the analysis results here, we focus on the office building cases that compare a 250-kW stationary fuel cell with the use of ten 75-kW FCVs (used at up to 30 kW each), and the residential cases that compare a 5-kW stationary fuel cell with the use of a 20-kW hybrid FCV. With regard to the general nature of the results of this analysis, we would first like to point out that for purposes of the anlaysis we deliberately assumed relatively low capital costs for stationary fuel cell systems (but did vary them somewhat in the high/medium/low cases), in order to set up a competitive analysis with regard to the potential for FCV-based power. Our stationary PEM fuel cell cases also benefit somewhat from our assumption that hot

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[4] AB 918, passed on September 30, 2000 requires California utilities to honor retail TOU rates for qualifying net metering customers in their service territories.

[5] For a complete report of detailed results, please see: Lipman, Timothy E., Jennifer L. Edwards, and Daniel M. Kammen (2002), "Economic Implications of Net Metering for Stationary and Motor Vehicle Fuel Cell Systems in California", Program on Workable Energy Regulation (POWER) Paper Series, PWP-092, University of California Energy Institute (UCEI), February. Available: http://socrates.berkeley.edu/~rael/papers.html.

Table 3
Basic assumptions for residential and office building stationary fuel cell cases

	Residential setting	Office building setting
Type	Large single family	Medium-sized office
Electrical load	0.5–3.8 kW	24–290 kW
Fuel cell	5 kW PEM	250 kW PEM
Fuel cell operation	Low air side pressure, pipeline NG reformate fuel	Low air side pressure, pipeline NG reformate fuel
Cogeneration of hot water (based on hot water load profile)	Yes	Yes
Reformer efficiency	70% SMR or ATR[a]	70% SMR or ATR[a]
Fuel cell system efficiency (stack, compressor, and WTM)	Varies with load (see results)	Varies with load (see results)
Hydrogen utilization by FC (natural gas reformate)	85%[b]	85%[b]
Power inversion, control, and conditioning, efficiency	92%[c]	92%[c]
Fuel cell system capital cost	$500/kW, $1200/kW, $2500/kW[d]	$400/kW, $700/kW, $1000/kW[e]
Reformer capital cost	Included in FC cap. cost	Included in FC cap. cost
Fuel cell O&M cost	Varies with case[f] (see results tables)	Varies with case[g] (see results tables)
Reformer O&M cost	Included in FC O&M	Included in FC O&M
Natural gas fuel cost	$4/GJ, $6/GJ, $10/GJ	$3/GJ, $4/GJ, $6/GJ
Electricity energy charge (see text for TOU cases)	0.15/kWh, $0.12/kWh, $0.10/kWh	0.08/kWh, $0.06/kWh, $0.05/kWh
Electricity demand charge	N/A	$12/kW-pk, $9/kW-pk, $7/kW-pk
Electricity monthly charge	N/A	$200/month
Days of FC operation per year	365 days/yr	365 days/yr
Hours of FC operation per year	8760 (load following), 2520 (net metering)	8760 (load following), 5184 (net metering)

Notes and sources: When three values are listed, the first value refers to the estimate used in the "low cost" case, the second value refers to the estimate used in the "medium cost" case, and the third value refers to the estimate used in the "high cost" case.

[a] We assume that by 2010 small steam methane reformer (SMR) or autothermal reformer (ATR) units operate at 70% efficiency, in terms of the LHV of hydrogen out/the LHV natural gas + accessory loads in, based on Aspen model simulations reported in Kreutz and Ogden (2000).

[b] We assume that actual hydrogen utilization rates of 85% are achieved in fuel cell stacks operating on natural gas reformate due to the need to periodically purge impurities from the fuel cell stack anodes and the need to maintain usable hydrogen gas concentrations at the tail ends of the individual fuel cell flowfields. Higher utilization rates would be achievable with the use of pure hydrogen, rather than reformate, and/or improved system control strategies.

[c] We assume that AC inverter plus system control efficiency levels of 92% are achieved in both stationary and vehicle fuel cell systems.

[d] Installed capital costs in the 2010–2015 timeframe of $500/kW, $1200/kW, and $2500/kW are assumed for 5 kW stationary fuel cells based on cost targets recently suggested by General Motors on the low end, and detailed cost estimates conducted by Directed Technologies Inc. (Thomas et al., 2000a) on the high end. We assume aggressive cost targets for these systems to set a "high bar" for FCV-based power to compete.

[e] For 250 kW stationary PEM systems, we assume installed capital costs of $400/kW, $700/kW, and $1000/kW because these systems should have lower costs per kW than much smaller systems and again to determine whether or not FCV-based power can be competitive with stationary fuel cell power if these aggressive cost targets are achieved.

[f] Operation and maintenance (O&M) costs for 5 kW stationary fuel cell systems include scheduled maintenance of $100, $150, and $200 every year in the three cost cases, plus fuel cell stack refurbishment costs of 20%, 33%, and 40% of the total system costs ($500/kW, $1200/kW, and $2500/kW) every 5 years of typical load-following operation. For the net metering cases, we assume that stack refurbishment costs are a function of total energy output and not only hours of operation (so that O&M costs are similar between the load following and net metering cases, even though the operating hours are somewhat different, because the total energy output is about the same). O&M costs in terms of $/kW-year therefore vary between the load following and net metering cases as a function of the actual hours of operation and average power output in each case (see detailed results tables for exact values).

[g] Operation and maintenance (O&M) costs for 250 kW stationary fuel cell systems include scheduled maintenance of $500, $1,000, and $1,500 every year in the three cost cases, plus fuel cell stack refurbishment costs of 20%, 33%, and 40% of the total system costs ($400/kW, $700/kW, and $1000/kW) every 5 years of typical load-following operation. For the net metering cases, we assume that stack refurbishment costs are a function of total energy output and not only hours of operation (so that O&M costs are similar between the load following and net metering cases, even though the operating hours are somewhat different, because the total energy output is about the same). O&M costs in terms of $/kW-year therefore vary between the load following and net metering cases as a function of the actual hours of operation and average power output in each case (see detailed results tables for exact values).

water cogeneration is possible from stationary fuel cell systems and not from FCVs.

In the case of the 5-kW residential fuel cell system (Tables 5 and 6), costs of electricity are estimated to vary

from $0.056/kWh to $0.294/kWh depending on economic variable assumptions, and load following operation versus our example net-metered operation case. In our medium cost case with installed system capital costs

Table 4
Basic assumptions for residential and office building FCV cases

Type	Residential setting Large single family	Office building setting Medium-sized office
Electrical load	0.5–3.8 kW	24–290 kW
Fuel cell	75 or 20 kW PEM	75 kW PEM (up to 10 FCVs)
Fuel cell operation	High air side pressure, pipeline NG reformate fuel, 30 kW power limit per FCV	High air side pressure, pipeline NG reformate fuel, 30 kW power limit per FCV
Cogeneration of hot water (based on hot water load profile)	No	No
Reformer efficiency	70% SMR[a]	70% SMR[a]
Fuel cell system efficiency (stack, compressor, and WTM)	Varies with load (see results)	Varies with load (see results)
Hydrogen utilization by FC (natural gas reformate)	85%[b]	85%[b]
Power inversion, control, and conditioning, efficiency	92%[c]	92%[c]
Fuel cell system capital cost	Zero (units are purchased for automotive use, but periodic system refurbishment costs are included)	Zero (units are purchased for automotive use, but periodic system refurbishment costs are included)
Reformer capital cost	$1500, $2000, $6000[d]	$40,000, $53,880, $116,500[e]
Fuel cell O&M cost	Varies with case—see detailed results tables[f]	Varies with case—see detailed results tables[f]
Reformer O&M cost	$50/kW yr, $100/kW yr, $250/kW yr[g]	$7/kW yr, $13/kW yr, $33/kW yr[h]
Additional infrastructure costs	$800, $1200, $1700[i]	$5500, $8500, $12,000[j]
Natural gas fuel cost	$4/GJ, $6/GJ, $10/GJ	$3/GJ, $4/GJ, $6/GJ
Electricity energy charge (see text for TOU cases)	0.15/kWh, $0.12/kWh, $0.10/kWh	0.08/kWh, $0.06/kWh, $0.05/kWh
Electricity demand charge	N/A	$12/kW-pk, $9/kW-pk, $7/kW-pk
Electricity monthly charge	N/A	$200/month
Days of FC operation per year	300 days/yr	250 days/yr
Hours of FC operation per year	4200 (in most cases)	2500 (in most cases)

Notes and sources: When three values are listed, the first value refers to the estimate used in the "low cost" case, the second value refers to the estimate used in the "medium cost" case, and the third value refers to the estimate used in the "high cost" case.

[a] We assume that small steam methane reformer (SMR) or autothermal reformer (ATR) units operate at 70% efficiency, in terms of the LHV of hydrogen out/the LHV natural gas + accessory loads in, based on Aspen model simulations reported in (Kreutz and Ogden, 2000).

[b] We assume that actual hydrogen utilization rates of 85% are achieved in fuel cell stacks operating on natural gas reformate due to the need to periodically purge impurities from the fuel cell stack anodes and the need to maintain usable hydrogen gas concentrations at the tail ends of the individual fuel cell flowfields. Higher utilization rates would be achievable with the use of pure hydrogen, rather than reformate.

[c] We assume that AC inverter plus system control efficiency levels of 92% are achieved in both stationary and vehicle fuel cell systems.

[d] Installed reformer capital costs in the 2010–2015 timeframe for the residential setting of $1500, $2000, and $6000/kW are assumed based on cost targets for complete small PEM systems in the low and medium costs cases, and on detailed cost estimates conducted by Directed Technologies Inc. (Thomas et al., 2000a) for the high cost case. We assume that these cost estimates also include the costs of small buffer storage systems to allow the reformers to operate at relatively steady output levels.

[e] Installed reformer capital costs in the 2010–2015 timeframe for the office building setting, to support up to 10 FCVs, of $40,000, $53,880, and $116,500 are assumed based on detailed cost estimates conducted by Directed Technologies Inc. (Thomas et al., 1998) for the medium cost case, by Ogden (1999) in the high cost case, and on a slightly more optimistic estimate for the low cost case.

[f] Operation and maintenance costs for the FCV fuel cell systems assume that 25%, 33%, and 50% of the complete fuel cell system costs are incurred every 4000, 10,000, and 40,000 h (respectively in the various cases) of additional use for power generation. Fuel cell system capital costs in 2015–2025 (when refurbishments would be required) are assumed to be $50/kW, $75/kW, and $100/kW in the three cost cases, based on automotive cost targets and detailed, high volume production analysis by Directed Technologies Inc. (Lomax et al., 1997).

[g] Operation and maintenance costs for small residential reformer systems include scheduled maintenance of $100, $200, and $500 every year in the three cost cases and average output of 2 kW.

[h] Operation and maintenance costs for larger office building reformer systems include scheduled maintenance of $1000, $2000, and $5000 every year in the three cost cases and average output of 150 kW.

[i] Additional infrastructure costs include the costs of vehicle modifications to allow reverse-flow of power from the vehicle, an electrical connection from the vehicle to the residential electrical panel, a hydrogen reformate connection from the reformer to the vehicle, and hydrogen safety equipment. We assume incremental vehicle costs of $300, $500, and $700 based on an approximate estimate of $500 in Kempton et al. (2001), and $500, $700, and $1000 for the gas connection and safety gear.

[j] Additional infrastructure costs for the office building case include the costs of vehicle modifications to allow reverse-flow of power from the vehicles, electrical connections from the vehicles to conductive EV charging stations in the building parking lot, hydrogen reformate connections from the reformer to the vehicles, and hydrogen safety equipment. We again assume incremental vehicle costs of $300, $500, and $700 (per vehicle) based on an approximate estimate of $500 in Kempton et al. (2001) and $2500, $3500, and $5000 for the gas connections and safety gear.
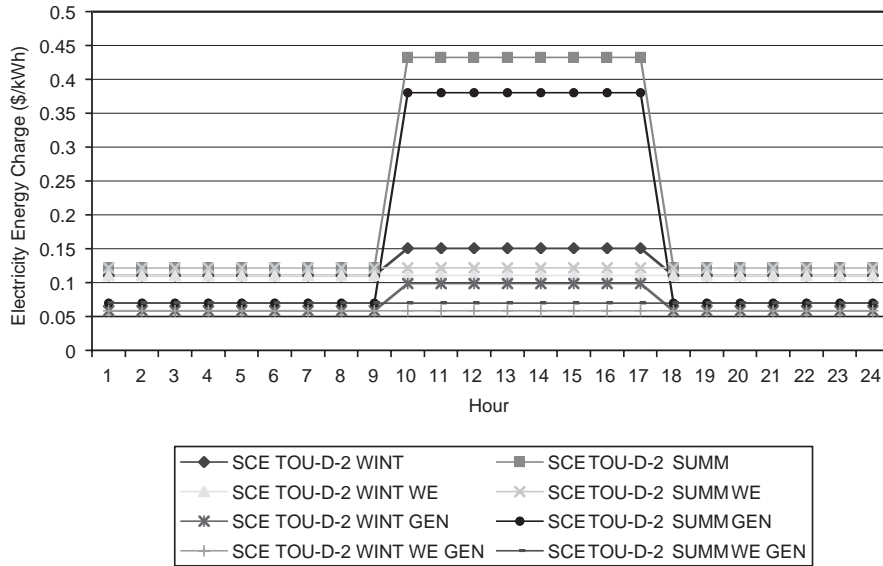
Fig. 8. Residential TOU retail and ''generation cost only'' rate schedules. Notes: GEN = generation cost only; SCE = southern California Edison; SUMM = summer; WE = weekend; WINT = winter.

Fig. 9. Commercial TOU full retail and ''generation cost only'' rate schedules. Notes: GEN = generation cost only; SCE = southern California Edison; SUMM = summer; WE = weekend; WINT = winter.
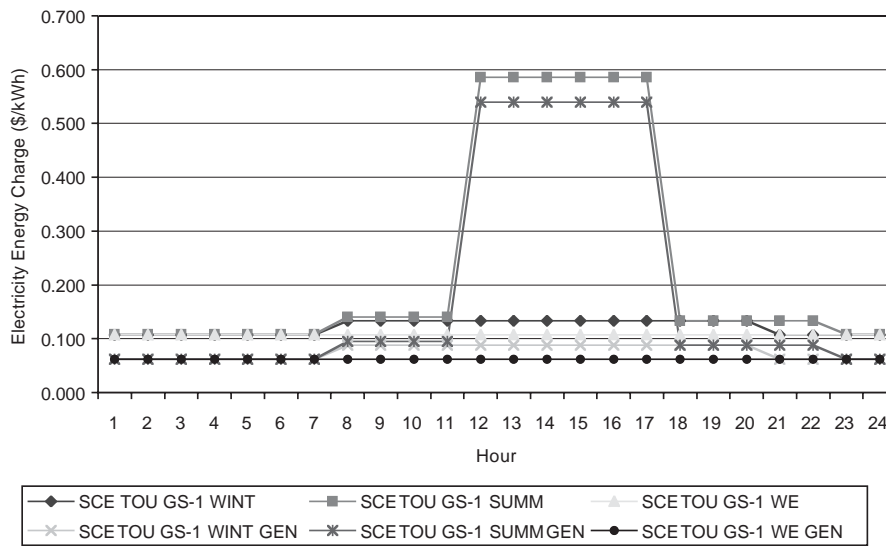
of \$1200/kW combined with \$6/GJ natural gas (and various other assumptions shown in Table 3), a modest annual savings of about \$300 per year can be realized. Savings of over \$1000 per year are realized in the low cost case, but the high cost case reveals a net loss.

In comparison, for FCV-based power, the analysis results show that the cost of generating electricity from FCVs based at residences varies dramatically from \$0.09/kWh to over \$1.00/kWh, depending on the scenario, the price of natural gas, and other key input assumptions (Tables 6 and 7, Fig. 11). On an annual basis, in the cases in which FCV use is attractive and can

produce cost savings, savings of about \$100 to over \$600 per year are possible. However, we estimate that cost savings at these residential settings are only achieved in some of our ''low cost'' cases; most cases suggest a net loss and are not attractive. We therefore consider the use of FCVs for power generation at residential settings to only be attractive under highly favorable conditions, for emergency backup power, to provide additional power to grid-independent buildings, and/or to provide power during peak demand periods in summer months and under TOU rate schedules. Even under a net metering scheme with ''efficiency optimized'' fuel cell operation,

Table 5
Results for residential setting with 5 kW stationary fuel cell and load following operation

	Low cost case	Medium cost case	High cost case
Key assumptions			
Natural gas cost	$4/GJ	$6/GJ	S10/GJ
Electricity energy charge	$0.15/kWh	$0.12/kWh	$0.10/kWh
Electricity demand charge	N/A	N/A	N/A
Electricity fixed monthly charge	N/A	N/A	N/A
Fuel cell system cost	$500/kW	$l200/kW	$2500/kW
Fuel cell system O&M	$70/kW yr	$147/kW yr	$300/kW yr
Reformer capital cost	Integrated with FC	Integrated with FC	Integrated with FC
Reformer O&M	Integrated with FC	Integrated with FC	Integrated with FC
Additional infrastructure cost	$100(for Cogen)	$200 (for Cogen)	$300 (for Cogen)
Capital recovery factor (15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	Yes	Yes	Yes
Calculated results			
Cost of electricity	$0.056/kWh	$0.095/kWh	$0.171/kWh
Average FC system efficiency (includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	33.9%	33.9%	33.9%
Natural gas fuel used	111 GJ/yr	111 GJ/yr	111 GJ/yr
Natural gas fuel cost	$442/yr	$663/yr	$1106/yr
Regular maintenance and system refurb. for fuel cell and reformer	$88/yr	$184/yr	$376/yr
Total annual electrical load	10,815 kWh/yr	10,815 kWh/yr	10,815 kWh/yr
FC electricity produced	10,815 kWh/yr	10,815 kWh/yr	10,815 kWh/yr
Net electricity purchased or (sold)	0 kWh/yr	0 kWh/yr	0 kWh/yr
Demand peak reduction (average per month)	N/A	N/A	N/A
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$537/yr	$928/yr	$1683/yr
Net cost (or savings) per year (with eliminated electricity energy charges)	(−$1085/yr) net savings/year	(−$370/yr) net savings/year	$601/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

Table 6
Results for residential setting with 5 kW stationary fuel cell and net metered operation

	Low cost case	Medium cost case	High cost case
Key assumptions			
Natural gas cost	$4/GJ	$6/GJ	S10/GJ
Electricity energy charge	$0.15/kWh	$0.12/kWh	$0.10/kWh
Electricity demand charge	N/A	N/A	N/A
Electricity fixed monthly charge	N/A	N/A	N/A
Fuel cell system cost	$500/kW	$l200/kW	$2500/kW
Fuel cell system O&M	$20/kW yr	$42/kW yr	$86/kW yr
Reformer capital cost	Integrated with FC	Integrated with FC	Integrated with FC
Reformer O&M	Integrated with FC	Integrated with FC	Integrated with FC
Additional infrastructure cost	$100(for Cogen)	$200 (for Cogen)	$300 (for Cogen)
Capital recovery factor (15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	Yes	Yes	Yes
Calculated results			
Cost of electricity	$0088/kWh	$0.159/kWh	$0.294/kWh
Average FC system efficiency (includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	25.0%	25.0%	25.0%
Natural gas fuel used	156 GJ/yr	156 GJ/yr	156 GJ/yr
Natural gas fuel cost	$625/yr	$937/yr	$1562/yr
Regular maintenance and system refurb. for fuel cell and reformer	$88/yr	$185/yr	$377/yr
Total annual electrical load	10,824 kWh/year	10,824 kWh/yr	10,824 kWh/yr
FC electricity produced	10,824 kWh/yr	10,824 kWh/yr	10,824 kWh/yr
Net electricity purchased (or sold)	0 kWh/yr	0 kWh/yr	0 kWh/yr
Demand peak reduction (average per month)	N/A	N/A	N/A
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$908/yr	$1645/yr	$3058/yr
Net cost (or savings) per year (with eliminated electricity energy charges)	(−$716/yr) net savings/year	$347/yr net cost/year	$1975/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

Table 7
Results for residential setting with 20 kW FCV and load following operation

	Low cost case	Medium cost case	High cost case
Key Assumptions			
Natural gas cost	$4/GJ	$6/GJ	$10/GJ
Electricity energy charge	$0.15/kWh	$0.12/kWh	$0.10/kWh
Electricity demand charge	N/A	N/A	N/A
Electricity fixed monthly charge	N/A	N/A	N/A
Fuel cell system cost	Built in to vehicle	Built in to vehicle	Built in to vehicle
Fuel cell system O&M	$17.50/kW yr	$140/kW yr	$700/kW yr
Reformer capital cost	$1500	$2000	$6000
Reformer O&M	$50/kW yr	$100/kW yr	$250/kW yr
Additional infrastructure cost	$800	$1200	$1700
Capital recovery factor (15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	No	No	No
Calculated results			
Cost of electricity	$0.122/kWh	$0.209/kWh	$0.544/kWh
Average FC system efficiency (includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	31.1%	31.1%	31.1%
Natural gas fuel used	47.6 GJ/yr	47.6 GJ/yr	47.6 GJ/yr
Natural gas fuel cost	$190/year	$286/year	$476/yr
Regular maintenance and system refurb. for fuel cell and reformer	$60/yr	$212/yr	$838/yr
Total annual electrical load	10,815 kWh/yr	10,815 kWh/yr	10,815 kWh/yr
FC electricity produced	4444 kWh/yr	4444 kWh/yr	4444 kWh/yr
Net electricity purchased (or sold)	6371 kWh/yr	6371 kWh/yr	6371 kWh/yr
Demand peak reduction (average per month)	N/A	N/A	N/A
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$535/year	$920/year	$2391/yr
Net cost (or savings) per year (with eliminated electricity energy charges)	(−$132/yr) net savings/year	$386/yr net cost/year	$1947/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

Table 8
Results for residential setting with 20 kW FCV and net metered operation

	Low cost case	Medium cost case	High cost case
Key assumptions			
Natural gas cost	$4/GJ	$6/GJ	$10/GJ
Electricity energy charge	$0.15/kWh	$0.12/kWh	$0.10/kWh
Electricity demand charge	N/A	N/A	N/A
Electricity fixed monthly charge	N/A	N/A	N/A
Fuel cell system cost	Built in to vehicle	Built in to vehicle	Built in to vehicle
Fuel cell system O&M	$13.13/kW yr	$105/kW yr	$525/kW yr
Reformer capital cost	$1500	$2000	$6000
Reformer O&M	$50/kW yr	$100/kW yr	$250/kW yr
Additional infrastructure cost	$800	$1200	$1700
Capital recovery factor (15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	No	No	No
Calculated results			
Cost of electricity	$0.090/kWh	$0.158/kWh	$0.398/kWh
Average FC system efficiency (includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	30.7%	30.7%	30.7%
Natural gas fuel used	116 GJ/yr	116 GJ/yr	116 GJ/yr
Natural gas fuel cost	$465/yr	$698/yr	$1163/yr
Regular maintenance and system refurb. for fuel cell and reformer	$130/yr	$422/yr	$1596/yr
Total annual electrical load	10,815 kWh/yr	10,815 kWh/yr	10,815 kWh/yr
FC electricity produced	10,376 kWh/yr	10,376 kWh/yr	10,376 kWh/yr
Net electricity purchased (or sold)	439 kWh/yr	439 kWh/yr	439 kWh/yr
Demand peak reduction (average per month)	N/A	N/A	N/A
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$926/yr	$1628/yr	$4102/yr
Net cost (or savings) per year (with eliminated electricity energy charges)	(−$631/yr) net savings/year	$383/yr net cost/year	$3064/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

Table 9
Results for office building setting with 250 kW stationary fuel cell and load following operation

	Low cost case	Medium cost case	High cost case
Key assumptions			
Natural gas cost	$3/GJ	$4/GJ	$6/GJ
Electricity energy charge	$0.08/kWh	$0.06/kWh	$0.05/kWh
Electricity demand charge	$12/kW peak	$9/kW peak	$7/kW peak
Electricity fixed monthly charge	$200/month	$200/month	$200/month
Fuel cell system cost	$400/kW	$700/kW	$1000/kW
Fuel cell system O&M	$19/kW yr	$49/kW yr	$90/kW yr
Reformer capital cost	Integrated with FC	Integrated with FC	Integrated with FC
Reformer O&M	Integrated with FC	Integrated with FC	Integrated with FC
Additional infrastructure cost	$500 (for Cogen)	$750 (for Cogen)	$1000 (for Cogen)
Capital recovery factor(15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	Yes	Yes	Yes
Calculated results			
Cost of electricity	$0.040/kWh	$0.058/kWh	$0.108/kWh
Average FC system efficiency(includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	32.0%	32.0%	32.0%
Natural gas fuel used	10,500 GJ/yr	10,500 GJ/yr	10,500 GJ/yr
Natural gas fuel cost	$31,352/yr	$41,803/yr	$62,704/yr
Regular maintenance and system refurb. for fuel cell and reformer	$2030/yr	$5114/yr	$9449/yr
Total annual electrical load	909,932 kWh/yr	909,932 kWh/yr	909,932 kWh/yr
FC electricity produced	907,144 kWh/yr	907,144 kWh/yr	907,144 kWh/yr
Net electricity purchased (or sold)	2788 kWh/yr	2788 kWh/yr	2788 kWh/yr
Demand peak reduction (average per month)	241 kW	241 kW	241 kW
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$36,201/yr	$52,259/yr	$79,322/yr
Net cost (or savings) per year (with eliminated electricity energy and demand charges)	(−$71,049/yr) net savings/year	(−$28,178/yr) net savings/year	$13,735/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

Table 10
Results for office building setting with Ten 75 kW FCVs and load following operation

	Low cost case	Medium cost case	High cost case
Key assumptions			
Natural gas cost	$3/GJ	$4/GJ	$6/GJ
Electricity energy charge	$0.08/kWh	$0.06/kWh	$0.05/kWh
Electricity demand charge	$12/kW peak	$9/kW peak	$7/kW peak
Electricity fixed monthly charge	$200/month	$200/month	$200/month
Fuel cell system cost	Built in to vehicle	Built in to vehicle	Built in to vehicle
Fuel cell system O&M	$1.95/kW yr	$15.63/kW yr	$78.13/kW yr
Reformer capital cost	$40,000	$53,880	$116,500
Reformer O&M	$6.67 kW yr	$13.33 kW yr	$33.33 kW yr
Additional infrastructure cost	$5500	$8500	$12,000
Capital recovery factor(15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	No	No	No
Calculated results			
Cost of electricity	$0.038/kWh	$0.058/kWh	$0.119/kWh
Average FC system efficiency(includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	31.1%	31.1%	31.1%
Natural gas fuel used	5750 GJ/yr	5750 GJ/yr	5750 GJ/yr
Natural gas fuel cost	$17,264/yr	$23,916/yr	$34,528/yr
Regular maintenance and system refurb. for fuel cell and reformer	$1363/yr	$4676/yr	$17,618/yr
Total annual electrical load	681,842 kWh/yr	681,842 kWh/yr	681,842 kWh/yr
FC electricity produced	523,198 kWh/yr	523,198 kWh/yr	523,198 kWh/yr
Net electricity purchased or (sold)	158,644 kWh/yr	158,644 kWh/yr	158,644 kWh/yr
Demand peak reduction (average per month)	95 kW	95 kW	95 kW
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$32,612/yr	$40,083/yr	$69,831/yr
Net cost (or savings) per year (with eliminated electricity energy and demand charges)	(−$22,976/yr) net savings/year	(−$1608/yr) net savings/year	$35,661/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

Table 11
Results for office building setting with ten 75 kW FCVs and net metered operation

	Low cost case	Medium cost case	High cost case
Key assumptions			
Natural gas cost	$3/GJ	$4/GJ	$6/GJ
Electricity energy charge	$0.08/kWh	$0.06/kWh	$0.05/kWh
Electricity demand charge	$12/kW peak	$9/kW peak	$7/kW peak
Electricity fixed monthly charge	$200/month	$200/month	$200/month
Fuel cell system cost	Built in to vehicle	Built in to vehicle	Built in to vehicle
Fuel cell system O&M	$1.95/kW yr	$15.63/kW yr	$78.13/kW yr
Reformer capital cost	$40,000	$53,880	$116,500
Reformer O&M	$6.67 kW yr	$13.33 kW yr	$33.33 kW yr
Additional infrastructure cost	$5500	$8500	$12,000
Capital recovery factor(15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	No	No	No
Calculated results			
Cost of electricity	$0.038/kWh	$0.058/kWh	$0.118/kWh
Average FC system efficiency(includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	31.0%	31.0%	31.0%
Natural gas fuel used	7660 GJ/yr	7660 GJ/yr	7660 GJ/yr
Natural gas fuel cost	$22,969/yr	$30,625/yr	$45,938/yr
Regular maintenance and system refurb. for fuel cell and reformer	$1857/yr	$6238/yr	$24,007/yr
Total annual electrical load	681,842 kWh/yr	681,842 kWh/yr	681,842 kWh/yr
FC electricity produced	694,771 kWh/yr	694,771 kWh/yr	694,771 kWh/yr
Net electricity purchased (or sold)	(12,929 kWh/yr)	(12,929 kWh/yr)	(12,929 kWh/yr)
Demand peak reduction (average per month)	95 kW	95 kW	95 kW
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$38,842/yr	$49,825/yr	$89,920/yr
Net cost (or savings) per year (with eliminated electricity energy and demand charges)	(−$30,472/yr) net savings/year	(−$2161/yr) net savings/year	$47,171/yr net cost/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

none of our medium cost case results are favorable for this residential setting. Our analysis thus suggests that using FCVs to power residences on a routine basis is generally unlikely to prove attractive.

Our analysis also shows that battery hybrid FCVs, with smaller ∼20 kW fuel cell systems, are better matched to the low load levels at residential sites. These FCVs can be somewhat more economically attractive at producing power in residential settings than non-hybrid FCVs with larger ∼75 kW fuel cell systems, but still only provide net savings to the vehicle owner in our low cost cases.

However, much more attractive is the case in which several FCVs are used to provide power to the commercial office building. In this case, the vehicles can share a common reformer system and can produce power at load levels that are more constant and in a higher efficiency region of operation. We calculate that FCVs in this setting can produce power for costs in the range of $0.038–$0.119/kWh, and can also provide additional savings by reducing peak building demand levels and monthly demand charges. On an annual basis, we calculate that annual savings of $1,608 are possible for the case in which the FCVs load follow the building, and savings of $2161 are possible when net metering is

allowed (under one simple net metering scheme), both under our medium cost case. Under our low cost case, however, annual savings of $22,976 to $30,472 are realized under the load following and net metering cases (Tables 10–12 and Fig. 12).

These savings, even divided among 10 vehicle owners, could provide a significant incentive for this type of arrangement and could help to pay down the costs of FCV ownership. We caution, though, that our high cost cases do not show a net benefit even in this commercial settings, and we suggest that the details of natural gas prices, electricity prices, reformer costs, fuel cell system durability, and other factors do matter. The potential benefits of FCV-based power should therefore be analyzed on a case-by-case basis, given these sensitive input variables.

These office building FCV cost-of-electricity results compare to the case of the 250-kW stationary fuel cell, where costs of electricity are found to vary from $0.040/kWh to $0.117/kWh. With capital costs of $700/kW in the medium cost case combined with $4/GJ natural gas, an estimated $28,000 in savings per year can be achieved. Savings reach over $70,000 in the low cost case, but the high cost case shows a net loss rather than savings (Table 9).

Table 12
Results for office building setting with Ten 75 kW FCVs and net metered and TOU operation

	Flat rate net metering medium cost case	TOU rate net metering case 1 medium cost case	TOU rate net metering case 2 medium cost case
Key assumptions			
Natural gas cost	$4/GJ	$4/GJ	$4/GJ
Electricity energy charge	$0.06/kWh	$0.06/kWh	$0.06/kWh
Electricity demand charge	$9/kW peak	$9/kW peak	$9/kW peak
Electricity fixed monthly charge	$200/month	$200/month	$200/month
Fuel cell system cost	Built in to vehicle	Built in to vehicle	Built in to vehicle
Fuel cell system O&M	$15.63/kW yr	$15.63/kW yr	$15.63/kW yr
Reformer capital cost	$53,880	$53,880	$53,880
Reformer O&M	$13.33 kW yr	$13.33 kW yr	$13.33 kW yr
Additional infrastructure cost	$8500	$8500	$8500
Capital recovery factor (15 year life, 8% interest rate)	0.12	0.12	0.12
Cogeneration of hot water	No	No	No
Calculated results			
Cost of electricity	$0.058/kWh	$0.058/kWh	$0.058/kWh
Average FC system efficiency(includes FC, reformer, inverter, and H_2 utilization and on LHV basis)	31.0%	31.0%	31.0%
Natural gas fuel used	7660 GJ/yr	7660 GJ/yr	7660 GJ/yr
Natural gas fuel cost	$30,625/yr	$30,625/yr	$30,625/yr
Regular maintenance and system refurb. for fuel cell and reformer	$6238/yr	$6238/yr	$6238/yr
Total annual electrical load	681,842 kWh/yr	681,842 kWh/yr	681,842 kWh/yr
FC electricity produced	694,771 kWh/yr	694,771 kWh/yr	694,771 kWh/yr
Net electricity purchased (or sold)	(12,929 kWh/yr)	(12,929 kWh/yr)	(12,929 kWh/yr)
Demand peak reduction (average per month)	95 kW	95 kW	95 kW
Consumer cost per year (includes capital cost, NG and electricity fuel costs, and maintenance costs)	$49,825/yr	$57,562/yr	$57,562/yr
Net cost (or savings) per year (with eliminated electricity energy and demand charges)	(−$2161/yr) net savings/year	(−$145,913/yr) net savings/year	(−$153,715/yr) net savings/year

Notes: see above discussion and tables for details of input value assumptions.
FC = fuel cell; LHV = lower heating value; GJ = gigajoule; O&M = operation and maintenance (not including fuel).

13. Net metering of fuel cell systems

Our analysis also shows that net metering can improve the economics of fuel cell power, but this only tends to be true for FCV-based power, and particularly in the case of the 75 kW fuel cell systems in the residential setting. This benefit occurs because net metering allows the fuel cell systems in the FCVs to operate more efficiently than they can in the mode of load following operation. For example, net metering can allow a small savings of $264 per year to be realized in a residential setting with low cost case economics, where load following operation yielded a small net cost. Under our medium cost case for the residential setting, and with the 75 kW FCV, net metering improves the economics to some extent but still is not sufficient to allow a net profit, even under an "efficiency optimized" net metering scheme. This result further underlines the questionable economics of using FCVs to produce power in residential settings on a routine basis.

With stationary fuel cell systems that are relatively well matched to their building loads, net metering can actually worsen efficiency by encouraging operation at higher than optimal load levels, and this has a deleterious effect on economics as well. However, such operation may provide significant benefits to the utility grid, and the ultimate effect therefore may involve a tradeoff between slightly worse economics for the fuel cell DG units and the potential for reduced use of peaking power plants to meet overall grid peak loads.

Perhaps most interesting, the combination of net metering along with TOU electricity rates offers the potential for dramatic economic benefits for FCV power at the office building site. Because FCVs at office buildings are available to produce extra power during the day when it is highly valued (especially during summer months), net savings (or actually savings plus revenue) of $146,000 per year are possible for the setting in which 10 FCVs are used. This is the case even if the power provided to the utility grid is only compensated at the avoided cost of generation (with the rate based on a Southern California Edison TOU rate schedule) and assuming our medium cost case economics. If the full retail rate were provided for both electricity provided-to and withdrawn-from the grid, net savings/revenue of up to $154,000 per year would be possible in the medium
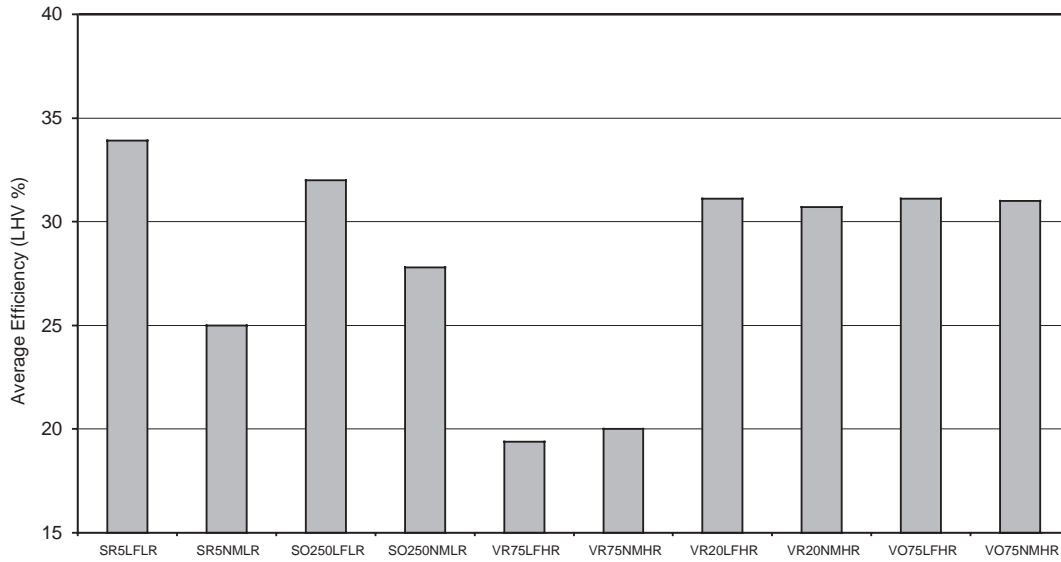
Fig. 10. Estimated average efficiency of fuel cell system operation.
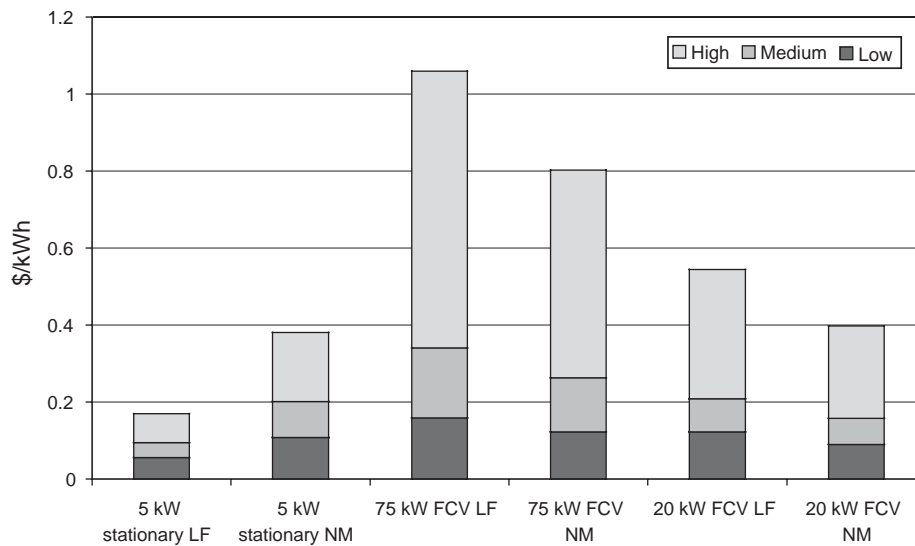

Fig. 11. Cost of electricity for fuel cell operation in residential setting cases.

cost case. These results suggest that if there were many hours during the year that FCVs could operate in this manner, the revenue generated for the vehicle owner could be considerable. Particularly if electricity deregulation does eventually allow for open buying and selling of power on spot markets in a real-time fashion, FCVs available at the right times and places along the road network could then potentially sell power profitably at times of peak demand.

14. Conclusions

This analysis shows that stationary PEM fuel cell systems can produce electricity at competitive rates at potential future installed capital costs of on the order of $1200/kW for small-scale residential settings (e.g. 5 kW) and $700/kW for larger scale (e.g. 250 kW) settings. However, we find that fuel cell system economics for peak and baseload power generation are also sensitive to natural gas fuel cost and system durability and maintenance cost assumptions, and it is therefore important to assess system economics on a site-specific basis, including such factors as prevailing electricity and natural gas costs (e.g. the ''spark spread''), system efficiency and durability, and additional costs for installation, permitting, and grid-connection.

In general, FCVs used for power in commercial ''office building'' settings can potentially supply electricity at competitive rates, in some cases producing
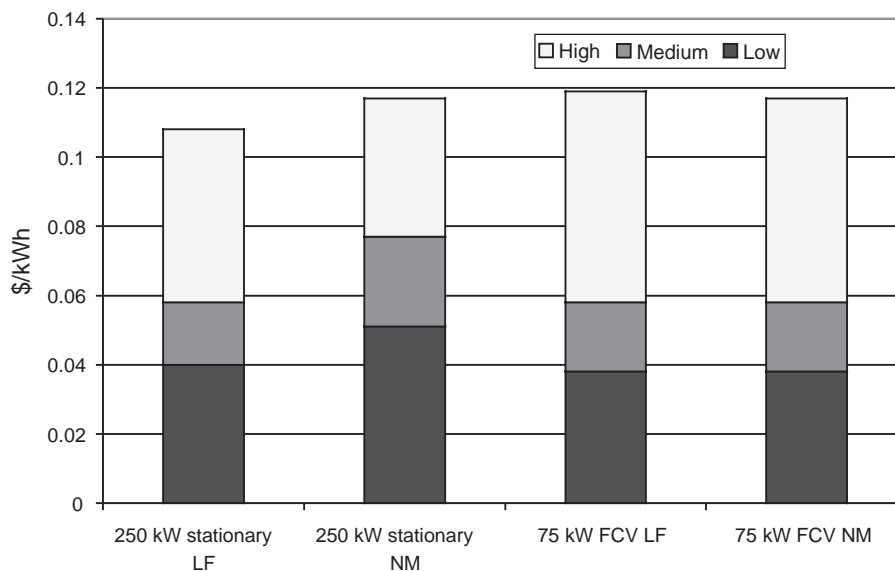
Fig. 12. Cost of electricity for fuel cell operation in office building setting cases.

significant annual benefits to vehicle owners while at the same time producing additional capacity to utility grids. However, for electricity produced from FCVs to be attractive in competition with all electricity generation, including large base-load power plants, natural gas prices must be on the order of $3–4/GJ, or alternate methods of fueling the vehicles with economical sources of hydrogen must be explored, and fuel cell system durability must be on the order of at least 10,000 h of operation when the vehicles are used in DG mode. In general, and the analysis results in all cases depend strongly on several uncertain variables. These again include most notably the cost of natural gas fuel, prevailing electricity energy and demand chargers, the level of fuel cell system durability, and the associated costs for fuel cell system refurbishment due to the additional use for power production.

For FCV-based power to be economical on a routine basis, it is vitally important that FCVs be able to produce electricity at high overall system efficiencies, on the order of at least 30% (LHV). This suggests that powering residential loads from the vehicles, particularly without allowing for higher power operation and net metered or grid sale of electricity, is unlikely to be attractive. In these residential settings, FCV power may only be attractive during peak periods and under TOU rate schedules, and in the case of provision of emergency backup power.

With regard to net metering of fuel cell systems, these analysis results suggest that a net metering policy that allows power to be added to the grid during the hours of 12 PM to 8 PM can be of significance in using FCVs to produce power, and especially at residential settings where net metering allows power to be supplied with improved efficiency. Net metering would not necessarily

provide much benefit for the economics stationary fuel cell systems, at least based on the profiles of hourly power supply that we assumed for the net metering cases in this analysis, because these systems have been designed to be better matched to the loads to which they are connected and tend to suffer slightly reduced efficiency in the net metering cases. Other net-metered operating profiles that are more carefully designed to optimize efficiency, however, can produce improvements in efficiency for stationary systems and can further improve efficiency for FCVs, but such "efficiency optimized" schemes appear to improve the economic results only slightly compared to the values presented in the net metering cases shown here.

We also note that a different type of "very short term net metering", whereby momentary needs for surge power in buildings can be supplied with help from the grid and then "paid back" over a few minutes by the fuel cell system, could be beneficial for both stationary fuel cells and FCVs used to produce power. This type of arrangement, if eventually allowed by utilities, could eliminate the need for batteries or ultracapacitors to help meet momentary peak demands, and could lead to improved system efficiency through reductions in transient and high-load level conditions.

It is important to stress that the analysis conducted here has focused on the potential customer-side benefits of stationary fuel cell and FCV-based power. In addition to these potential benefits, use of fuel cells for distributed power production can supply additional benefits in terms of the reduced need for peak power plants, alleviation of transmission and distribution bottlenecks, and the potential provision of grid ancillary services such as spinning reserves and local voltage support. In ongoing work, we are assessing these

potential benefits as well as criteria pollutant and greenhouse gas emissions issues, alternative means of supplying hydrogen fuel to FCVs (such as through reformers and electrolyzers that can produce pure hydrogen and allow higher operational efficiencies), and other settings for FCV-based power.

In conclusion, we find that FCV-based power can be promising in commercial settings under the right conditions, even in comparison with baseload grid power. Net metering policies can have a significant impact on the economics of FCV-based power, particularly if net metering schemes can be combined with TOU rate schedules. Even if FCVs have difficulty competing with baseload power plants on an economic basis, FCVs and other EVs are likely to find interesting niches in providing electricity at times when it is highly valued, such as with TOU metering or in real-time electricity markets, and through grid ancillary service support. Given this potential, efforts should focus on removing regulatory impediments to reverse power flow from vehicles, pursuing the development of small, low-cost fuel reformers for FCVs, and continuing to assess the costs and benefits of various market niches for vehicle-to-grid interaction.

Acknowledgements

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