Pergamon

Transpn Res.-D, Vol. 2, No. 3, pp. 157-175, 1997

1361-9209/97 $17.00+0.00

PII: S1361-9209(97)00001-1

ELECTRIC VEHICLES AS A NEW POWER SOURCE FOR ELECTRIC UTILITIES

WILLETT KEMPTON*
College of Marine Studies and Center for Energy and Environmental Policy, University of Delaware, Newark, DE 19716, U.S.A.

and

STEVEN E. LETENDRE
Department of Economics and Business, Green Mountain College, Poultney, VT 05764, U.S.A.

(Received 26 August 1996; accepted 18 December 1996)

Abstract—Electric-drive vehicles, whether fueled by batteries or by liquid or gaseous fuels generating electricity on-board, will have value to electric utilities as power resources. The power capacity of the current internal combustion passenger vehicle fleet is enormous and under-utilized. In the United States, for example, the vehicle fleet has over 10 times the mechanical power of all current U.S. electrical generating plants and is idle over 95% of the day. Electric utilities could use battery vehicles as storage, or fuel cell and hybrid vehicles as generation. This paper analyzes vehicle battery storage in greatest detail, comparing three electric vehicle configurations over a range of driving requirements and electric utility demand conditions. Even when making unfavorable assumptions about the cost and lifetime of batteries, over a wide range of conditions the value to the utility of tapping vehicle electrical storage exceeds the cost of the two-way hook-up and reduced vehicle battery life. For example, even a currently-available electric vehicle, in a utility with medium value of peak power, could provide power at a net present cost to the vehicle owner of $955 and net present value to the utility of $2370. As an incentive to the vehicle owner, the utility might offer a vehicle purchase subsidy, lower electric rates, or purchase and maintenance of successive vehicle batteries. For a utility tapping vehicle power, the increased storage would provide system benefits such as reliability and lower costs, and would later facilitate large-scale integration of intermittent-renewable energy resources.

1. INTRODUCTION

Several major automobile manufacturers have announced near-term plans to produce and mass-market electric vehicles. The first vehicles are battery-powered, recharged from the electric grid. Other electric-drive vehicle configurations include series hybrid and fuel cell, both of which use liquid or gaseous fuels with electric drive. Electric utilities have been concerned only with battery-powered vehicles, and have viewed these vehicles primarily as load. This article argues that the dawning interaction between electric-drive vehicles and the electric supply system: will involve fueled as well as battery-powered electric-drive vehicles, will be far more significant than increased load, and will ultimately affect future development of the electric system itself. This paper examines the case in which garaged electric vehicles would have a two-way, computer-controlled connection to the electric grid. That is, the grid could receive power from the vehicle as well as provide power to the vehicle. For reasons discussed in this paper, this modification to current designs requires more computer logic but little additional hardware or cost. Nevertheless, the system implications of our proposed modification are profound.

2. ELECTRIC VEHICLES AND ELECTRIC UTILITIES

In this section, we view the vehicle fleet from an analytical perspective normally used for electric utilities.

*Author for correspondence

The electric-drive vehicle (EV) will increasingly be connected to electric utilities over the next decades. The California Air Resources Board and, following their lead, the states of Massachusetts and New York, are requiring 'zero emission vehicles' (ZEVs) as a pollution prevention strategy. Manufacturers that mass market light vehicles in California must sell ZEVs as an increasing fraction of new automobile sales, rising eventually to 10% by 2003. Current mandates will probably continue to be modified by political cross-currents in these jurisdictions, and as analysts continue to debate the environmental effects and the market appeal of today's electric vehicles. Nevertheless, EV mandates are very popular with voters, and the widespread adoption of these vehicles seems increasingly likely.

The U.S. state ZEV mandates specify no particular technology, but the only currently-available technology which would qualify as ZEV are electric-drive vehicles using batteries for energy storage.* Several large automakers and smaller technology companies already have such vehicles in limited production. In December 1996, General Motors began selling a battery-powered EV in two states, through their Saturn Division. Honda has announced a battery EV for Spring 1997 (New York Times, 1996). Both the GM and Honda vehicles were designed from the ground up as electric vehicles. Ford, Chrysler and Toyota also have announced plans to market battery-based EVs (Wald, 1996). (Other, less frequently mentioned storage devices include flywheels and 'ultra-capacitors'.) Another near-term electric-drive vehicle would be the 'series hybrid', in which a small, liquid-fuel motor drives an electric generator, which in turn provides electric power for the electric drive train (Lovins *et al.*, 1996; Office of Technology Assessment, 1995). Hybrids provide longer range than battery vehicles but do not qualify as ZEVs. A third EV type, using fuel cells with, say, hydrogen or methanol as a fuel, could also qualify as ZEVs. Fuel cells appear to ultimately be a more promising long-term option for ZEVs, but such vehicles still require substantial technology development and are unlikely to be mass-marketed for general use before 2010 (Williams, 1994). For book-length analyses of battery, hybrid, and fuel-cell electric vehicles, see Mackenzie (1994) or Sperling (1995).

In utility analyses of EVs to date, only the first of these three electric-drive vehicles, the battery-powered electric-drive vehicle, has been considered to interact with the electric utility system —

Table 1. Interaction of different vehicle types with the electric distribution system, contrasting the conventional view with the view proposed in this article

Motive force	Energy storage and conversion	Fuel source	Interaction with electric system		Electric industry benefits	
			Conventional view	Proposed view	Conventional view	Proposed view
Mechanical drive	Fuel tank, internal combustion engine	Liquid (gasoline, diesel, possibly natural gas)	None	None	None	None
Electric drive	Battery	Electricity from grid	Load	Storage and load	Revenue	Revenue, reliability, lower cost T&D
	Hybrid (series: tank, ICE, generator)	Liquid (gasoline, possibly natural gas)	None	Generation	None	Reliability, lower cost generation and T&D
	Fuel cell	Gaseous or liquid (natural gas or methanol with reformer; hydrogen without)	None	Generation	None	Reliability, lower cost generation and T&D; H_2 is near-zero pollution

*For most electricity sources, pollution occurs at the power plant. From an overall system perspective, battery-powered vehicles are not ZEVs, hydrogen fuel cell vehicles are ZEVs, and methanol fuel cell and hybrid vehicles can be very low emissions but not zero. Battery-powered EVs nevertheless qualify as ZEVs because the ZEV regulations are primarily intended to address local air pollution in urban areas. Also, most analyses show that the overall air pollution is lower for battery vehicles than the current fleet, even when power production is included — although some criteria pollutant levels may be higher.

and then only as load. As shown in Table 1, we consider the interactions of EVs to be more extensive, and to offer important opportunities for the electric utility industry. Vehicles in Table 1 are ordered from nearer-term technologies at the top to longer-term ones at the bottom.

We begin our analysis by comparing the vehicle fleet with electric generation infrastructure. This comparison is rarely made, perhaps because few analysts are thoroughly familiar with both.

The total installed generation capacity of U.S. electric utilities is almost 750 GW or 0.75 TW (Bureau of the Census, 1992). The total power capacity of the U.S. fleet of passenger vehicles can be readily calculated. The average engine power of the 1993 U.S. fleet of passenger vehicles is approximately 125 horsepower, or 93 kW per vehicle (Murrell *et al.*, 1993).* The total registered fleet of passenger cars is about 146 million vehicles (American Automobile Manufacturers Association, 1994). This represents a total shaft power of 13.6 TW, which, if connected to generators, would produce over 12 TW of electrical power. A way to visualize this comparison is that the nation's electric generation capacity is approximately equivalent to 750 of the largest nuclear or coal power plants (at 1 GW each), whereas the vehicle fleet has the capacity equivalent to 12,000 such power plants.† The amount of fuel consumed is similar for the two because the vehicle fleet's power is sitting idle so much more than utility generation equipment. Light vehicles are in use almost exactly 1 h per day, idle 23 hours or 96% of the time.‡ Availability of any one vehicle is unpredictable, but over thousands or tens of thousands of vehicles, availability is highly predictable — more so, in fact, than existing central facilities.§ By comparison, baseload fossil fuel power plants (which go down for scheduled maintenance, unexpected failures, regulatory requirements, etc.) are a little better than 96%, whereas few nuclear power plants ever reach 95% availability. Some companies impose performance penalties when fossil fuel plants drop below 95% availability. If we think about the vehicle fleet as an electric utility would think about its equipment, the vehicle fleet's power capacity is grossly under-utilized.

To compare costs, the motive power for the vehicle fleet has been purchased at a cost of roughly $60/kW, whereas power capacity for the current electric utilities has been purchased typically at over $1000/kW (current U.S. prices, with cheap natural gas, are closer to $300/kW).¶ The dramatically lower cost of vehicle power is due in part to lower reliability requirements, need for fewer operating hours, lower thermal efficiency, exclusive use of high grade fuel, and because current vehicles produce shaft power rather than electrical power output. But more than those factors, lower vehicle motive power costs are due to the economies of mass production of vehicles vs customized construction of power plants.

Many refinements could be made to these comparisons but, to a first approximation, the passenger vehicle fleet has ten times more capacity than all the nation's electrical generation equipment combined, it was purchased at one-tenth the cost per unit of power, and it is idle most of the time. In these simplified terms — which we shall refine — if a substantial fraction of the vehicle fleet were electrified it would dwarf the generation capacity of electric utilities, at lower capital cost, comparable availability, and with siting closer to loads. We find no evidence that the vehicle fleet has been seriously analyzed in these terms, yet the full significance of electric vehicles — whether battery, hybrid, fuel cell, or a mixed fleet — cannot be understood without doing so.

Our comparison with the current fleet is meant to compare magnitudes — we would not advocate connecting electric generators to current internal combustion vehicles. As a more near-term and realistic comparison for one area, involving storage rather than generation, we draw on

---

*For new light vehicles sold in 1981, the average horsepower was 102 and, in 1993, it was 149 hp (Murrell *et al.*, 1993). From these two figures, we estimate that the fleet currently on the road averages 125 hp or 93 kW.

†The contemporary 125 hp (93 kW) power of internal combustion engines is above that of expected electric vehicles. If we assume an all-electric fleet of 146 million light vehicles, half of which have battery storage at 20 kW sustained output and half fuel cells at 35 kW sustained output, the fleet power capacity would be 4 TW, still a breathtaking five times the capacity of all U.S. electric utility generation.

‡The average U.S. driver operates his or her vehicle 59.69 min per day (Hu and Young, 1992). Since ratio of vehicles per licensed driver in 1990 was 1.01 (American Automobile Manufacturers Association, 1995), the average vehicle is in use 59.1 min per day or 4.1% of the day.

§When we say 'availability' of the vehicle, we are referring only to the time that it is not driving. Full availability to the grid would depend on all the most-used parking locations having electrical connections — an unlikely condition. The comparison is nevertheless impressive in that the average vehicle is available for power storage or production approximately the same proportion of time as baseload generators — despite the vehicles being unavailable when on the road.

¶The vehicle cost estimate is from John DeCicco (pers. comm.). These costs are only the engine and drive train for vehicles (not the whole vehicle) and only generation for electric utilities (not transmission and distribution systems).

current projections for Southern California. Ford (1994) compares several forecasts and projects about 2 million battery-powered EVs in Southern California by 2010, which is 20% of the then-expected vehicle fleet. Consider an electrical-system emergency, in which sufficiently charged vehicles in parking lots could each put 20 kW onto the grid (a number consistent with the peak output of the battery-storage electric vehicles we analyze below). If we speculate that only two-thirds of the vehicles were garaged and connected when power was needed, and only half of those were sufficiently charged to permit discharge, the vehicle fleet would be able to contribute 1.3×10^{10} watt, or 13 GW. This is a staggering two thirds of the peak load of the region's electric utility, Southern California Edison. In short, even when we assume that only a small fraction of the vehicle fleet is electric drive with battery power, and assume that only one-third of them are available when needed, their electrical output nevertheless could replace (for a short period) most of the generating capacity of the area's electric utility. A battery-powered EV would produce 20 kW for only a short period, yet this is useful as outages tend to be localized and of limited duration. This comparison illustrates the potential of electric vehicles for grid support and peak power, which we analyze in more detail below.

Before our detailed analysis, we briefly review three comparable systems with which utilities have operating experience or analysis. These systems will help utilities understand power from vehicles.

The first comparable system is direct load control (DLC), in which the utility installs communications and control equipment on customer premises to reduce peak load. Customers have proven willing to 'sell power' (that is, forgo load at peak periods) at prices attractive to utilities (Kempton *et al.*, 1992). We will compare our proposal to DLC in more detail later in this paper.

A second, more abstract, perspective on EVs and utilities is the concept of the 'distributed utility', which conceives of the electric power industry shifting toward more distributed, small-scale generation. Paralleling the revolution in the computer industry, from mainframes to networks of smaller computers, some electric utility analysts believe that the current high costs of upgrading transmission and distribution (T&D) change the economics to favor small-scale, distributed generation and storage, at least in selected areas (Shugar *et al.*, 1992). In the U.S., T&D upgrades now average as much capital investment as new generation. Distributed generation, since it is near the customer, allows the utility to defer or eliminate the need for T&D upgrades required to bring more power from a central generation plant. Vehicle-based generation and storage would be highly distributed, as it would be located at residences, employers, and retail businesses.

The third comparable area of prior utility experience is directly relevant to battery-storage EVs: utility-owned energy storage. The most common storage now in use is from pumped-storage hydroelectric plants, which are typically large (1–2 GW). They have 75% efficiency; that is, of the energy put in, only 75% can be extracted later. Smaller-scale energy storage, from fast-response systems such as batteries, spinning flywheels, or compressed gas, is typically more expensive per stored energy unit, but offers advantages in modulatory, speed of response, efficiency and, if placed close to load centers, T&D benefits. The obvious value of storage to a utility is that it allows charging during periods of surplus, low-cost electric generation, and discharge at times of peak demand, when electricity has high value. Less widely appreciated are additional operational benefits of storage, especially if the storage is fast-response and distributed. For example, storage reduces the need to keep combustion generating plants operating at inefficient partial loads or to keep them in 'spinning reserve' as insurance against failures or unexpected load fluctuations. One study estimated that these 'dynamic operational benefits' could be as high as $400/kW (Electric Power Research Institute, 1987; also see Kelly and Weinberg, 1993), although these values vary widely across utility systems and across substations within a single utility.

Several analysts have estimated the value of utility-owned storage such as batteries, pumped hydro or compressed air. Calculating generation-related savings only, batteries would provide savings with a net present value of $500/kW for a 2-h battery plant ($250/kWh) and $1000/kW for a 10-h plant ($100/kWh), as estimated by Zaininger *et al.* (1990). Earlier studies argued that generation-related savings can be more economically achieved by large utility facilities such as pumped hydro and compressed air; however, some recent analyses examine additional benefits of batteries such as their fast response and small scale (benefits which would apply to vehicle-housed batteries), suggesting that battery benefits may be high enough to justify utility purchase (e.g. Lachs and Sutanto, 1992). When transmission and distribution benefits are included, the additional value of battery storage is estimated at net present value of \$250/kW (Zaininger *et al.*, 1990) to \$1130/kW (Chapel *et al.*, 1993), or \$125–\$565/kWh. If the moderate or higher benefit values are correct, the value to the utility of batteries on grid would exceed the cost of vehicle batteries. These utility values are still being debated, and we will show that a rather different cost calculation is needed for vehicle batteries. Nevertheless, the above-cited analyses of utility-owned battery plants suggest that utilities may benefit by drawing from their customers' vehicle batteries.

3. ELECTRIC VEHICLES ARE NOT JUST LOAD

The value of storage has not yet been calculated for electric vehicles. Utility interest in an electric vehicle fleet has been limited to the increased load for charging batteries. One recent study of Southern California Edison found that the utility would be better off with controls for 'valley filling', limiting charging to times of low utility power demand rather than allowing charging whenever the vehicle owner plugs in (Ford, 1994, 1996). Ford argued that valley filling would allow the utility to meet anticipated additional loads for electric vehicle charging without additions to their existing resource plan. Therefore, he argued, the utility would experience an increase in profits from increased sales and better utilization of their generation equipment. Other studies have considered area distribution of load drawn by EVs (Rice, 1995) and compared alternate charging systems (Crable, 1995). We find no published analyses of the value of power flowing from vehicle to utility.

This article will show that electric vehicles become considerably more attractive to electric power systems when the benefits of peak power and storage are considered. We perform a technical and economic analysis of selling energy from the EV to the grid (which for battery vehicles would of course require additional charging before or afterwards, and for fuel cell vehicles would require additional fuel). We estimate the benefits to utilities via three comparison benchmarks: direct load control, commercial demand charges, and utility avoided costs. We will show that the benefit to the electric utility exceeds the cost to the vehicle owner across a wide range of conditions, suggesting the opportunity for an economic transaction that would benefit both parties.

The potential benefits to utilities become even more interesting in the context of the electric utility restructuring taking place in several OECD countries, including the U.S. Electric utilities have previously been vertically integrated, with each company encompassing generation, transmission, and retail distribution. These three components are now expected to split into separate companies (Tonn and Schaffhauser, 1995). A divested distribution-only electric utility in the future, without ownership of old generation, may find that its customers offer the most attractive source of generation assets: peak power, grid support and — for hybrid and fuel cell vehicles — even baseload electric generation.

4. SYSTEM CONFIGURATIONS AND CHARGE–DISCHARGE USER INTERFACE

We begin by outlining system configurations in order to provide a plausible technical background from which our economic and policy analysis can be understood. Battery-powered vehicles would be recharged from the electric grid, while hybrid and fuel cell vehicles would produce electricity but would be refueled with fuels such as hydrogen or methanol rather than recharged from the grid. In either case, the vehicle owner can sell peak power to the grid.

Liquid-fueled or, more so, gaseous-fueled vehicles could sell baseload power to the grid. For example, a fuel cell electric vehicle with reformer, recharged from a natural gas tap at home and/or work, could provide continuous electric power whenever garaged. A battery vehicle would presumably sell electricity only at times of peak demand or system failure, when power can be sold back at a premium well above the off-peak rates to recharge. In this paper, we analyze in detail only the technically and economically simpler, and near-term, case of electric grid-charged (battery) vehicles. This section outlines potential charging system configurations for residential and commercial buildings. The following section describes the three EV configurations that we will analyze.

For a residential building, we envision the following configuration at the vehicle owner's home. A 220 V AC, 3-phase, 40 ampere connection to the charge/discharge unit is within the range of conventional house wiring and would accept up to 8 kW of peak power from the vehicle. In this configuration, the vehicle output might often exceed total electrical demand of the household. The simplest mechanism would be to limit output to the load of the house. However, residential loads average 1 kW, with sustained highs typically 4 kW, so most of the potential EV power would be unused. Engineering, tariff, and safety issues would need to be addressed to allow for reverse flow of electricity out of the house and onto the local grid.

The vehicle owner would require some way to disable or limit discharge of the vehicle. The simplest form of this would be a toggle switch to disable any discharge. A form of recharge control, almost as simple, would be a switch allowing the driver to choose 'charge now' vs 'charge when cheap'. This choice already appears in some EVs. We propose a much more intelligent charge–discharge control. Figure 1 shows a possible control panel with which the vehicle operator could limit the utility's time and amount of discharge indirectly, by specifying driving needs. The slider at left allows the operator to specify, for example, 'never discharge below 2 miles' (say, if the corner store is 1.5 miles round trip). The 'next trip' box has controls allowing the driver to specify that the next planned trip will be 10 miles, at 6:45 am the next morning. A running-cost meter below shows the net cost to be billed, in this case showing a credit to the customer from selling peak power. Even if the discharging scheme we propose were not implemented, controls like those in Fig. 1 would be useful for 'smart' charging based on driver travel needs, allowing more flexibility than the simpler timed charge currently proposed for battery vehicles (Ford, 1994; Crable, 1995).

Would consumers reject any scheme that could discharge their vehicle batteries? The illustrative control panel in Fig. 1 is intended to minimize driver concern by using controls that accommodate user needs. The design has not been pilot tested, but it is consistent with research on perceived driving needs. In extensive interviews with consumers regarding motor vehicle use and required range under varying circumstances, about 70% said they would be willing to consume their fuel down to leaving a 'range buffer' of 32 km (20 miles) after all daily travel was completed (Kurani *et al.*, 1994). The range buffer represents a perceived need to allow range for any unanticipated trip, from emergency medical care to the urge for a particular snack. The range buffer for an individual would be entered on the control panel as the 'Always maintain enough charge for ___ miles' as shown in Fig. 1. The time and distance of the next planned trip would of course be entered in the 'Next trip' area. Within these constraints laid down by the driver, the utility is allowed to discharge and charge whenever it wants. We illustrate with two examples. A typical pattern at an employer parking lot might be that the utility charges in the morning, discharges mid- or late-afternoon of peak electricity demand days. A typical pattern in a home might be that the utility begins discharging after return home from a mid-afternoon shopping trip, or — for a commuter

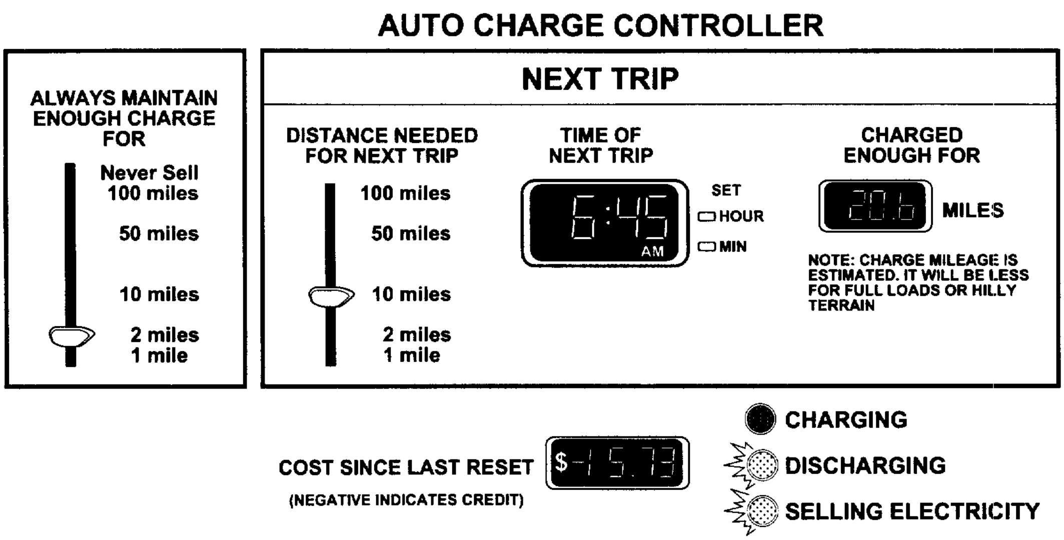

Fig. 1. Example control panel for a battery-storage EV, allowing the vehicle operator to constrain charging and discharging by the electric utility. In these example settings, the vehicle operator wants to maintain a 2-mile reserve at all times, and expects to next travel 10 miles at 6:45 the following morning. At the moment shown, the utility is buying power and a credit is shown due to power already sold from the vehicle.

vehicle — the utility begins discharging immediately upon return after work. The utility would then wait several hours with no charge or discharge, then begin recharging, say, after midnight.

The controls in Fig. 1 allow the driver to set the 'Always maintain ...' control to 'Never sell'. Some drivers will refuse to sell to the utility because they have highly erratic trips, because they do not want to bother with estimating trips, or because the utility payments are insufficient (given their income, etc.). Thus the cost–credit display and indicator lights are seen as important to provide real-time feedback to the driver regarding the financial benefits of specifying one's driving needs more precisely; we use them here also to suggest that a payment or incentive system is preferable to mandatory participation.

Unlike all current and announced charging systems, we do not give the driver a switch to directly control charging. Figure 1 has no switch with 'off' or 'on' or even 'on when cheap'. Rather, the driver specifies what his or her travel needs are. The utility determines the timing of charging and discharging within those constraints. This is the key principle behind the controller design in our proposal.

Figure 1 assumes some form of communication between the vehicle charge–discharge controller and the electric utility. That is, the utility sends a signal saying "Power needed now", and the controller on the vehicle or charger replies "Sorry" or "Ok, discharging", and, if the latter, it also begins to send out power. The communications medium could be, for example, telephone or cable TV lines. One EV charging system already being promoted includes two-way communication and remote management of charging time, all on a low-bandwidth powerline carrier (Crable, 1995). Even in the most sophisticated signaling systems, say, with interchanges of queries regarding the current and required state of vehicle charge and the current price the utility is paying for stored electricity, the bandwidth need not be greater than that of the telephone. Thus, current telecommunications infrastructure is sufficient to support our proposal.*

A charge–discharge system for a parking lot or commercial building might be set up as follows. The lot or building operator would provide rows of automobile charge–discharge connections, requiring a new 220 V AC line to each parking space. The timing and duration of the discharge could be controlled by the building operator, to minimize building peak and thus commercial demand charges, or by a parking lot operator to meet utility dispatch needs. Discharge would also have to be 'enabled' by the vehicle owner, whether by a simple toggle switch 'charge only, no discharge today', or a display like that shown in Fig. 1. The relative quantities of charge–discharge hook-ups at residences vs commercial buildings or parking lots would be determined by engineering costs, tariffs, the time of day that peak power were most needed in that area, and other factors.

5. VEHICLE CONFIGURATIONS ANALYZED

The economics of our proposal vary with the battery type, battery cost, potential output, and the vehicle characteristics. Therefore, we analyze our proposal for each of three vehicles differing in these characteristics, as outlined in Table 2.

The first example vehicle uses a lead-acid battery (hence Pb/acid), a mature, well understood technology.† As the vehicle configuration for Pb/acid, we use the General Motors (GM) EV1, a vehicle already offered for retail sale in the U.S. Among battery types, Pb/acid has the disadvantages of high weight, damage from deep discharge, and environmental lead pollution during manufacturing and recycling (Lave *et al.*, 1995; Allen *et al.*, 1995). A wealth of new 'advanced battery' types are under investigation, with some already in limited production. For analysis here, we pick two advanced batteries, using fully built and tested vehicle configurations. One is Nickel

*Nevertheless, as many EVs come on line, a broadcast request for power from an entire area would reduce the communication bottlenecks of individual queries. This issue was brought to our attention by Mike Kellaway of WaveDriver, in an email of 11 February 1997: "... the communications load of tens of thousands of EVs is non-trivial. Our view is that the utility will ask for any available EVs connected in an area to start generating, then control the power flows separately — remember the utility must do this now as the load is highly variable. The problem is not at the EV end or at the utility control room, but in the middle. An area basis seems the best way of handling this, anything else we have considered adds a lot to the infrastructure cost. Another sophistication is asking any EVs that could charge, to charge. These two mechanisms give finer control".

†Only starter battery technology is really mature. If lead acid cells are widely used in EVs, those batteries will be optimized for traction use, with redesign attempting to achieve lower cost, more charge–discharge cycles, and longer life. Thus our analysis of the GM current (December 1996) EV1, based on today's lead-acid starter battery configurations, may be a worst-case for lead-acid batteries.

Table 2. Characteristics of selected electric vehicle configurations and their storage systems

Electric vehicle	Total energy storage capability (kWh)*	Depth of discharge (%)	Peak output (kW)	Efficiency (km/kWh)	Vehicle range (km)	Cost of storage system ($/kWh)	Storage system cycles
GM's EV1, sports car (Pb/acid)	16.80	85	100†	8.96	128	150	300
Solectria's Sunrise, passenger car (NiMH)	30.00	80	22	14.88	357	400‡	1000
S–10 light truck ($Zn\text{-}Br_2$)	30.00	100	29	3.50	105	100‡	400

*Capacity of battery, neglecting the 5–10% loss through the on-board invertor (for the entire charge–discharge cycle, these losses occur twice, plus some losses in battery acceptance of charge).
†Short-term peak output for acceleration, not sustainable.
‡Manufacturer's cited cost figures have been doubled for conservatism and to reflect retail mark-ups.

Metal Hydride, or NiMH (Ovshinsky *et al.*, 1993), with the 'Sunrise', developed by Solectria Corporation, as its vehicle configuration. This vehicle has achieved long driving range [238 miles (384 km) in a 1995 competition] and the battery can achieve very high lifetime if depth of discharge is limited.* The Honda four-passenger car announced for mass production in 1997 also uses NiMH batteries, but we did not have test data from actual Honda vehicles to analyze here. Our third example is a Zinc Bromine ($Zi\text{-}Br_2$) battery vehicle. Although $Zi\text{-}Br_2$ is less well-known, there exists a reasonable vehicle prototype, an S–10 light truck, with publicly-available specifications tested independently from the manufacturer (Swan and Guerin, 1995). Although the $Zi\text{-}Br_2$ battery requires mechanical fluid circulation, it has some advantages such as light weight, anticipated low cost, and ability to completely discharge without any battery damage. When worn out, only the electrode stack need be replaced, which costs only one-third as much as the entire battery. Since the costs in our calculations reflect the cost to the vehicle owner of additional battery wear due to utility-requested discharges, for $Zi\text{-}Br_2$ we use the cost of stack replacement not the initial cost of the entire battery.

A market exists for Pb/acid batteries, so we feel fairly confident about their cost. Advanced battery production costs are less certain. For the advanced batteries, we have manufacturer estimates of manufacturer cost, or wholesale cost. To account for the mark-up to retail price (since we are calculating the cost to the vehicle owner), and to build in some conservatism about estimates of future prices, we have doubled the battery manufacturer's estimated prices for both the NiMH and $Zi\text{-}Br_2$ batteries. Doubling the costs raises the hurdle considerably for the advanced batteries but, as we shall see, they appear to be cost-effective over a wide range of conditions, even with this unfavorable cost assumption.

One essential detail of electric-drive vehicles seems to have been missed up until now in considering their potential integration with the electric supply system. Today's electric vehicles usually use alternating-current (AC) drive motors. These motors are run by a variable-frequency, on-board invertor which changes direct current from the battery or fuel cell into AC. This means that no additional, off-board power conversion equipment need be added to produce electric grid-quality AC power from an electric vehicle,† significantly lowering the equipment cost of the two-way electrical connection we propose here. A production vehicle intended for selling power would need a safe external tap for its AC power and a controller to match frequency and phase, and to insure safety interlocks. These would be production cost additions of roughly $200, an incremental cost so dwarfed by the storage system costs ($2500–$12,000, see below) that we include it only in

*At a very limited 50% depth of discharge, the NiMH battery has achieved 8000 cycles. Since full discharge on the Sunrise vehicle is a range over 200 miles, and on the Honda a claimed 125 miles, it may be reasonable to expect that 50% depth of discharge would rarely be exceeded. In a vehicle like this, the cost of discharge to the vehicle owner of additional discharges would drop to near the recharge energy cost, and the economic case for selling power to the utility would become very strong indeed. Our analysis does not assume this. We have conservatively assumed a more limited battery life (1000 cycles) and thus higher cost to the vehicle owner for discharge.

†For example, David Swan reports that in tests at the University of California, Davis, a GM EV1 produced "very clean" 60 hertz three-phase AC from its on-board electronics (pers. comm. with co-author W. Kempton). Fred Roberts of Chrysler reports that the Dodge Caravan Electric Mini-van can similarly produce 60 hertz AC entirely from on-board equipment (pers. comm. with co-author W. Kempton).

our final calculations. On-board AC power is made feasible by recent developments in solid-state power electronics, and the AC drive has been included in EV designs for reasons internal to the vehicle drive system, providing electric utilities with entirely fortuitous economies for two-way power connections.

Table 3 provides capacity values an electric vehicle owner may be willing to make available to their electric utility. These capacity values are calculated from the technical characteristics of the storage system, vehicle efficiency, consumers' perceived range buffer requirements, and the daily distance traveled (see below), using eqn (1). The values are within the range we estimated above of a plausible residential hook-up with conventional wiring (8 kW), so wiring should not limit the values in Table 3.

Equation (1) shows peak-reduction potential from EV calculation:

$$CV = ((TES \times DOD) - (RB/EFF) - (CD/EFF))/DH \quad (1)$$

where CV = capacity value (kW), TES = total energy storage capability of electric vehicle (kWh), DOD = depth of discharge permissible (%), RB = range buffer of driving distance (km), EFF = efficiency of electric drive (km/kWh), CD = commute distance (km), and DH = number of discharge hours.

Our required range estimates are based on data from drivers. As noted earlier, 32 km is a sufficient range buffer to satisfy 70% of drivers (Kurani *et al.*, 1994). We use this empirically-derived figure in our calculations; that is, in Table 3, we assume that, after the utility discharges, sufficient energy remains in the battery for the return commute plus 32 km range buffer remaining in the battery. In subsequent calculations, we assume a round-trip commute of 32 km, the U.S. average (Pisarski, 1992). (It is apparently coincidental that the Kurani *et al.* range buffer is approximately equal to the U.S. average commute.) Another approach to estimating vehicle drivers' willingness to tolerate low battery charge levels, an approach which we have not taken here, would be to examine how close to empty, drivers let the gasoline tank level drop before refilling, and in what circumstances.

6. DIRECT LOAD CONTROL: AN EXISTING UTILITY PURCHASE OF PEAK 'POWER' FROM RETAIL CUSTOMERS

We compare our new proposal — automobile power feeding the electric grid — to an existing utility program, residential Direct Load Control (DLC). DLC programs are comparable in concept, in some of the technology, in marketing, and in administration by utilities. Current utility DLC programs recruit residential customers to participate voluntarily. The utility installs radio-controlled switches in the customer's house. During times of peak demand, the utility can remotely cycle off ('dispatch') some of the customer's heavy appliances, such as the water heater and air conditioner. The customer receives a small yearly payment and is contractually guaranteed limits on use (that is, the utility will never exceed a maximum number of dispatches and a maximum time per dispatch and, for air conditioning, a maximum off-cycle such as 15 min per half-hour). In utility planning and management, large DLC programs are similar to peak power plants. DLC is even dispatched in the same way — a central control station has controls to turn off large blocks of customer equipment, like the switches they use to turn on power plants. Over 450 residential and small commercial DLC programs are now offered by U.S. utilities (Goldman *et al.*, 1996).

Table 4 gives some characteristics of one well-analyzed DLC program (from Kempton *et al.*, 1992). The DLC installation costs are $220 per house, made up of $10 per participant marketing and $210 for equipment, installation and management. These costs are comparable to our

Table 3. Available capacity for 2-h peak load support, after daily travel and range buffer

Electric vehicle	Remaining capacity (kW), by daily distance traveled			
	16 km (10 miles)	32 km (20 miles)	48 km (30 miles)	80 km (50 miles)
GM's EV1, sports car (Pb/acid)	4.46	3.57	2.68	0.89
Solectria's Sunrise, passenger car (NiMH)	10.39	9.85	9.31	8.24
S–10 light truck ($Zn\text{-}Br_2$)	8.14	5.86	3.57	0.00

Table 4. Characteristics of a typical DLC program

Load savings per household (measured)	0.72 kW
Contractual limits on dispatch	3 days per month in summer, 5 h maximum duration
Cost per installation	$220 per house ($305/kW)
Equipment lifetime (projected)	10 years
Participating households	555 (total 400 kW)

Source of data: Kempton *et al.* (1992).

estimated incremental costs to add a reverse-flow EV power connection (we use $250 in our final calculations), yet DLC power per house is only 7 to 20% of the 3.57 to 9.85 kW available per customer from an EV program (Table 3, using the average U.S. commute of 32 km). That is, compared to DLC, our EV discharge proposal offers the same equipment cost to utility, yet five or more times the peak support capacity.

These DLC programs are technically rather like battery storage, except that they 'store' heat or cool rather than electricity. The air conditioner has to work extra after the DLC period, to bring the house back down to the desired temperature. Similarly, for hot water, the water heater works extra to bring tank water back up to temperature and replace any hot water drawn out during the DLC period. The customer is not providing any energy, only deferring usage to a time more convenient to the utility. Thus, DLC is similar to electric vehicles with batteries, not like electric vehicles with hybrid or fuel cell power, the latter two of which would actually produce power for the grid from fuels. Unlike heat-storage DLC systems, electric vehicles have a significant cost associated with storage cycles, in that charge–discharge cycles accelerate wear on the battery and thus have a financial cost to the vehicle owner. In fact, we shall show that this storage cost dominates the calculation — it is substantially larger than the cost of recharge electricity, the losses in charging and discharging (10–20% two-way), or the cost of installing the additional hook-up equipment.

7. THE COST OF DISCHARGE TO THE VEHICLE OWNER

To the electric vehicle owner, it is costly to discharge the vehicle battery for the electric utility's benefit, more for its impact on battery life than for the energy lost. The cost to the EV owner depends on the number and duration of discharges, as well as the vehicle and battery configuration. Equation (2b) can be used to calculate the monthly cost to the vehicle owner of providing the local utility access to their EV's storage system. This is calculated from the storage cost per kWh using eqn (2a), which includes a ¢/kWh estimate for degradation of the storage system plus a ¢/kWh energy charge cost to recharge.

Equation (2) comprises two elements demonstrating the calculation for the monthly cost to an EV owner.Equation (2a) calculates storage cost per kWh:

$$\mathrm{STC} = [(\mathrm{TES} \times \mathrm{BRC})/(\mathrm{TES} \times \mathrm{DOD} \times \mathrm{CL})] + \mathrm{EC} \tag{2a}$$

which simplifies to

$$\mathrm{STC} = [\mathrm{BRC}/(\mathrm{DOD} \times \mathrm{CL})] + \mathrm{EC}$$

Equation (2b) gives storage cost per month:

$$\mathrm{TMC} = \mathrm{STC} \times [\mathrm{CV} \times \mathrm{DH} \times \mathrm{DM}] \tag{2b}$$

where, STC = storage cost to the vehicle owner ($/kWh), TES = total energy storage capability of electric vehicle (kWh), BRC = battery replacement cost ($/kWh),* DOD = depth of discharge permissible (fraction), CL = cycle life of storage system (cycles), EC = energy cost to recharge (¢/kWh), TMC = total monthly cost to vehicle owner ($), CV = capacity value (kW), that is, peak reduction, DH = number of discharge hours per event, and DM = number of discharges per month.

*We do not include additional storage cost per kW from degradation of the on-board invertor during additional charge–discharge cycles. Depending on design, there may not be any wear at all (Mike Kellaway, email of 11 February 1997) and, in any case, invertor costs due to wear are far smaller than costs due to battery cycles and thus are ignored in our cost calculations.

Table 5 presents some realistic values for cost to the vehicle owner on a monthly basis. We assume here that the vehicle owner pays 6 ¢/kWh for electricity [EC in eqn (2a)], that discharge is for a 2-h peak period, and that the number of discharges needed could vary between 1 and 20 per month.* This is a simplified methodology representing an upper-bound estimate of the costs to the vehicle owner. It is likely that the EV owner would obtain more kWh from the EV batteries over their useful life than those we calculate, because the EV owner would not consistently draw the storage system down to its maximum depth of discharge.

For comparison, Table 5 also shows a crude approximation of the market rate of peak power — the monthly 'demand charge' that U.S. utilities charge their commercial and industrial customers for the peak kW power used in a month. We use a middle value of $15/kW per month, and multiply by the peak reduction to estimate savings to the building operator. At five days per month of 2-h discharges, this 'market' value of peak power is more than double the cost to the vehicle owner, for all vehicle configurations. For office buildings, the largest class of customer who pay demand charges, Monday through Friday load profiles are very similar. Thus 20 days per month of discharge may be required to significantly lower the building's monthly peak, a frequency at which the demand charge savings are not adequate to justify the cost to the vehicle owner. These comparisons illustrate that the economic value of battery discharge is in meeting days of system peak demand, not in everyday use.

8. THE VALUE TO ELECTRIC UTILITIES FROM CUSTOMER-OWNED STORAGE

The prior sections compared power from EVs to direct-load control programs and to peak demand charges. Although each was approximate, both comparisons suggested favorable economics for EV power sales. This section describes a methodology for calculating more precisely the value to utilities of access to their customers' EV batteries. Sample calculations are provided for the three battery EV types described above.

Utilities have investigated the technical and economic feasibility of energy storage plants for load-leveling purposes for quite some time (Duchi *et al.*, 1988). In this role, a storage plant is charged during periods of low demand (i.e. late evening or early morning) and the stored energy is then released (dispatched) during peak demand periods. Like other peak-management programs, this allows a utility to improve its load duration curve which implies greater asset utilization of generation equipment, and may even result in the deferral of investments in peak power generating facilities. Utilities have expressed renewed interest in using batteries to achieve cost savings in light of the emerging distributed utility concept (Chapel *et al.*, 1993). The distributed utility concept describes one possible future utility structure in which small-scale generation and storage, and targeted demand-side management programs, augment the central generation system to cost-effectively serve local loads (Weinberg *et al.*, 1993). Under a distributed utility framework, battery storage systems not only offer traditional bulk system benefits (i.e. peak capacity), they also offer

Table 5. Monthly cost to vehicle owner, compared with monthly commercial demand charge

Electric vehicle	Peak reduction (kW)*	Storage cost (¢/kWh)†	Monthly cost to vehicle owner, by 2-h discharges per month ($)‡			Typical demand savings @ $15/kW per month ($)
			1	5	20	
GM's EV1, sports car (Pb/acid)	3.57	65	4.64	23.21	92.82	54
Solectria's Sunrise, passenger car (NiMH)	9.85	56	11.03	55.16	220.64	148
S-10 light truck (Zn- Br_2)	5.86	31	3.63	18.17	72.67	88

*From eqn (1).
†From eqn (2a).
‡From eqn (2b).

*Two hours is an arbitrary figure for discharge which we adopt as a benchmark from prior analysis (e.g. Chapel *et al.*, 1993). For longer discharge durations, the figures would be adjusted either by calculating fewer kW provided or a smaller number of discharges per month. Six cents per kWh is lower than the average U.S. retail electricity price, because we assume pricing to encourage off-peak charging (Ford, 1994, 1996).

distributed benefits in the form of deferred investments in transmission and distribution (T&D) equipment upgrades and increased reliability.

We assess the value to the utility using methods similar to integrated resource planning (IRP), in which resource alternatives are compared on the basis of avoided costs. A utility's avoided costs are traditionally set equal to its least-cost generation options and are divided into two components: avoided capacity costs ($/kW) and avoided energy costs (¢/kWh). The avoided capacity costs equal all fixed costs associated with investing in a generating plant and bringing the unit online. The avoided energy costs are equal to the fuel costs and any additional (variable) costs associated with the operation of the plant. With the anticipated restructuring of the electric utility industry, these methods are being re-examined. For example, the company building and operating the plant may not be the same one selling retail power or, in the scheme proposed here, the one buying customer EV storage capacity. Nevertheless, the basic concept of comparing the cost of storage to the cost of peak power will continue to be valid. We also note that, with oncoming deregulation, some very low market price figures are now circulating for the wholesale price of power; however, we assume that these are transitional, due to current overcapacity and low spot market natural gas prices. Therefore, we use more conventional avoided cost figures in our calculations.

In IRP, projects are accepted only if they prove to be less expensive than the utility's avoided costs. For example, the avoided costs from a demand-side management (DSM) program are calculated by calculating the avoided capacity costs times the projected peak demand reduction plus the avoided energy costs times the projected energy savings from the DSM program. Although specific cost-effectiveness tests vary somewhat by state, alternative programs are approved if the total costs of the program are less than the utility's total avoided costs. Thus, a utility's avoided costs represent the maximum amount a utility would be willing to pay for peak load reductions or energy savings.

A utility's avoided costs can be used to determine what that utility would theoretically be willing to pay for having access to the stored energy in their customers' EVs. For simplicity, we use a utility's levelized avoided capacity cost ($/kWyr) as a proxy for what a utility would be willing to pay for additional capacity. On a per vehicle basis, the total annual amount the utility would offer an EV owner equals its levelized avoided capacity cost times the kW reduction it can reliably count on during peak demand hours from the EV's storage system. The utility would realize very little avoided energy costs because it would only dispatch the stored energy in its customer's EVs on a few peak days during the year for relatively short time intervals (because the energy is a tiny fraction of the value of peak power to the utility, our calculations ignore the energy value).

In addition to the bulk system benefits described above, the utility could receive additional value from dispatching the excess energy from its customers' EVs to acquire distributed benefits. Research has shown that targeting DSM programs to areas that are experiencing T&D constraints offers additional value to the utility by deferring investments in T&D equipment upgrades (Orans *et al.*, 1992). Likewise, if the EV power was discharged into areas of constrained T&D capacity, the value to the utility would be higher. These distributed benefits are highly site-specific and require detailed analyses, but the value of peak power can be extremely high within these substations, or local planning areas (Freeman, Sullivan & Co., 1994).

Table 6 presents estimates of the value to a utility for having access to its customers' EV storage systems, based on three different levelized avoided capacity cost values. The 'low' estimate of $26/kWyr was obtained from an analysis for the City of Austin Electric Utility Department (1994). The 'medium' range of $73/kWyr was obtained from Sacramento Municipal Utility District's (SMUD) marginal cost study (Sacramento Municipal Utility District, 1994).*

The 'high' range of Table 6 is a rather different figure. It includes both avoided capacity costs and distributed benefits that were estimated for a Pacific Gas & Electric (PG&E) study of potential use of photovoltaic power to defer transformer upgrades at a nearly-overloaded substation, the Kerman substation. Only those distributed benefits associated with the deferral of investments in distribution equipment are included in Table 6, not loss savings, transmission, voltage support, or

*SMUD's 1994 avoided cost figures have been revised and are now lower and calculated very differently. However, the new figures are not publicly available and thus could not be used here.

Table 6. Annual value to utility of EV peak capacity, compared across a range of avoided capacity costs

Electric vehicle	Peak reduction (kW)	Value of EV capacity, by levelized avoided capacity costs		
		Low ($26/kWyr)	Medium ($73/kWyr)	High* ($180/kWyr)
GM's EV1, sports car (Pb/acid)	3.57	92.82	260.61	642.60
Solectria's Sunrise, passenger car (NiMH)	9.85	256.10	719.05	1773.00
S-10 light truck (Zn-Br_2)	5.86	152.36	427.78	1054.80

*The 'High' avoided cost figure includes deferral of investment in distribution equipment; low and medium do not.

reliability benefits. If PG&E were to have access to power from thousands of EVs located in the local planning area served by the Kerman substation, it is reasonable to assume that they would be able to defer investments in distribution equipment similar to those deferrals estimated for the photovoltaic installation near the Kerman substation. Thus, we added the avoided capacity cost of $65/kWyr to the estimated benefit for the deferral of distribution equipment of $115/kWyr for the total shown in Table 6 of $180/kWyr (Shugar *et al.*, 1992). The Kerman substation represents one high value in avoided capacity costs, but it is not the highest analyzed (Freeman, Sullivan & Co., 1994). The high column in Table 6 represents the avoided cost at a near-overload substation, whereas the low and medium costs in Table 6 represent utility-wide values.

An economically-rational EV owner would be willing to engage in a contract only if the costs associated with giving their utility access to the stored energy in their EV were less than the utility would be willing to pay for this privilege. To make a meaningful comparison, we cannot use the monthly values presented in Table 5. Rather, an annual cost to the vehicle owner from giving the utility access to their EV's energy storage system was calculated. This value will be sensitive to the number of discharges that the utility would require throughout the year. Table 7 provides these values based on three assumptions about the number of discharges the utility would require. Equation (2) was used again to obtain these estimates. However, they were calculated on a yearly as opposed to a monthly basis (using 6¢/kWh energy cost to the customer, as previously). Again, these values represent an upper-bound estimate of the costs to the EV owner for giving their utility access to their EV's storage system.

We use Figs 2–4 to compare the values in Table 6 with a graphical representation of the costs in Table 7. These figures illustrate the maximum number of 2-h discharges the utility could request without passing the point at which it is still economically advantageous for the customer to engage in a contract. For a low avoided cost utility, the customer could accept between 20 and 30 discharges depending on the vehicle type, otherwise the costs to the vehicle owner would exceed the maximum the utility would be willing to pay. For the medium avoided cost scenario, the utility could request between 60 and 100 annual discharges from the customer depending on the vehicle type. In the high avoided cost scenario (which would apply only to areas near T&D capacity), the utility could request over 100 annual discharges from the customer for all vehicle types and it would still be advantageous for the customer to engage in a contract with their utility.

The above analysis illustrates that, under many possible scenarios, utilities and their customers would benefit by contracting for the selling and purchase of storage capacity. These contracts could be made on an annual basis using the values presented above. However, if EV purchase

Table 7. Annual cost to vehicle owner by annual number of discharges

Electric vehicle	Peak reduction (kW)	Storage cost (¢/kWh)	Cost, by number of 2-h discharges per year ($)		
			Low (10)	Medium (20)	High (100)
GM's EV1, sports car (Pb/acid)	3.57	59	46.41	92.82	464.10
Solectria's Sunrise, passenger car (NiMH)	9.85	50	110.32	220.64	1103.20
S-10 light truck (Zn-Br_2)	5.86	25	36.33	72.66	363.32

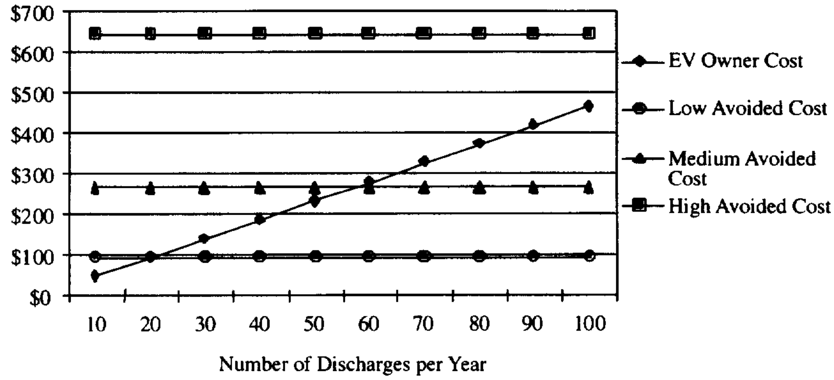

Fig. 2. GM's EV1 break-even annual discharges.

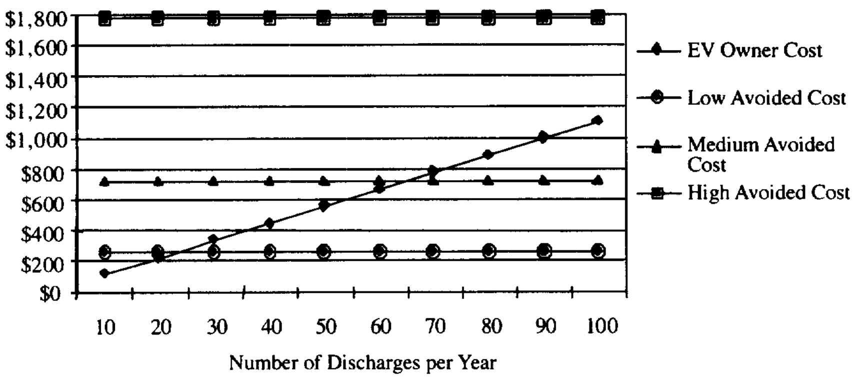

Fig. 3. Solectria's sunrise break-even annual discharges.

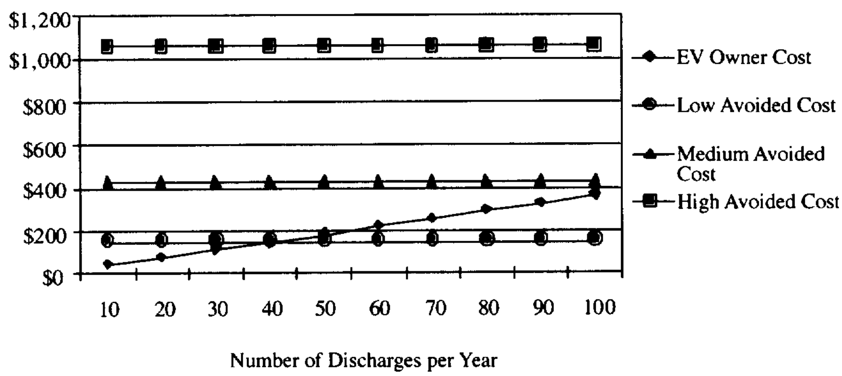

Fig. 4. S–10 truck break-even annual discharges.

prices are initially high, an EV owner may prefer an up-front payment based on a contract with the utility that spans the 15-year life of their newly purchased vehicle.

From the levelized annual numbers in Table 6, one can determine the potential utility payment to the customer by discounting the 15 years' worth of annual values to their present value using the utility's weighted average cost of capital (WACC). For example, assuming avoided capacity costs of our 'medium' case, and a 7% discount rate (i.e. WACC = 7%), the utility could pay up to $2370 as an up-front payment to the owner of a GM EV1 for access to their storage system over the 15-year life of the vehicle.* For the vehicle owner, the logic would be to discount the stream of

*Electric vehicles and fuel cells have considerably longer lifetimes than internal combustion engines and drive trains. Battery life is shorter than internal combustion engines, but battery replacement costs are already accounted for in our separate calculations.

annual costs found in Table 7 to their present value. Assuming that the utility would require 20 discharges annually and the consumer applied a discount rate of 10%, the cost to the vehicle owner would be $705 over the 15-year life of the vehicle. For completeness, we include the additional capital cost of the reverse-power connection (discharging logic and additional power tap to the vehicle's AC source). Although we have not analyzed this cost carefully, we consider $250 to be conservative (that is, high) for such systems in mass production. This would raise the vehicle owner's cost to $955.

Table 8 shows the results of these calculations, comparing the vehicle owner's cost with the value to the utility. We assume 20 discharges per year, $250 cost of discharge equipment, and other assumptions as before. Except for one case — the lead-acid EV1 vehicle placed in the utility with lowest avoided cost — values exceed costs for all vehicles across all utilities, some by quite substantial margins.

Several conclusions can be drawn from this table. If making decisions on a present value basis, the scheme we propose is viable over most combinations of vehicles and utility avoided costs. If utilities were to actually pay incentives to customers on a capitalized basis, they must differentiate among vehicles, and some utilities would not want to pay anything for certain vehicle configurations. The most economical vehicle is not simply the one with the least expensive batteries, but is a combination of battery cost, high storage system cycles, high capacity, and high km per kWh efficiency (thus leaving extra capacity after full daily travel). Utilities wanting to experiment with an EV program would best begin in areas with high avoided costs. In some areas, the benefits of this program appear to be huge; enough to cover start-up costs as well as a number of initial missteps.

We calculate present value costs to the EV owner and benefits to utilities in Table 8 as an analytical exercise. In practice, market research should be used to determine what form of payment would most appeal to utility customers who are potential EV buyers. For example, compare the following three marketing/payment approaches for a mid-range avoided-cost utility. First, an up-front payment could be made, at a figure between value and cost in Table 8, so as to leave a margin of error and insure the transaction is highly profitable for the utility. Table 8 shows that this up-front payment could be a few thousand dollars, which could underwrite part of the additional cost of EVs. A second form of payment would be for the utility to purchase the battery component of the vehicle cost, maintain the batteries, and replace them — thus the utility automatically bears the costs of battery-life reductions due to excessive charge–discharge cycles. As a third example, the utility could 'pay' by providing free recharging. For example, in a 10 km per kWh vehicle with 6¢ per kWh electricity, 15 years of driving at 24,000 km per year (15,000 miles per year) would cost a total of $2160 (without discounting). That means that a utility with medium avoided costs could realistically offer 'free fuel' to qualifying EV owners. This could have great consumer appeal, even if it were implemented as the more mundane net billing suggested by the display in Fig. 1. We have not done the market research to determine which of these three payment forms would be most appealing, but our economic analysis suggests that all would be economically feasible for a range of vehicles and utility capacity costs.

9. EVs FOR RENEWABLE ENERGY STORAGE

Utility access to storage from EVs could be an important bridge to high penetration of renewable energy. Two potentially important renewable energy resources, photovoltaics and wind, are

Table 8. Present values of cost to vehicle owner and value to utility (see text for assumptions)

Electric vehicle	Present cost to EV owner ($)	Present value to utility, by levelized avoided capacity costs		
		Low ($26/kWyr)	Medium ($73/kWyr)	High* ($180/kWyr)
GM's EV1, sports car (Pb/acid)	955	850	2370	5850
Solectria's Sunrise, passenger car (NiMH)	1930	2330	6550	16,150
S–10 light truck (Zn-Br_2)	910	1390	3900	9610

*The 'High' avoided cost figure includes deferral of investment in T&D equipment; low and medium do not.

intermittent. That is, the sun may not be shining or the wind may not be blowing when the power is needed. A large vehicle fleet providing storage for the electrical grid would enable higher penetration rates for intermittent renewables. We briefly consider the impact of widespread distributed storage for two renewable sources, photovoltaics and wind, to illustrate different system matches with distributed storage for these two types of intermittent renewables.

Photovoltaics are a low maintenance and high land-use energy resource. In regions with significant air conditioning loads, their peak output nearly matches peak electrical demand. These characteristics make photovoltaics sensible for distributed generation — customers' unused rooftops provide real estate, and photovoltaics' near match to place and time of peak load can permit deferring of distribution system upgrades (Hoff and Wenger, 1992; Perez *et al.*, 1993). Because the load peak is typically a few hours later than the solar radiation peak, prior analysis of photovoltaics for commercial building loads has shown that adding batteries to the building system can improve the load matching and economics of photovoltaics for peak load management (Byrne *et al.*, 1996). Electric vehicle storage at a commercial building would provide the same benefits, at a much lower cost. We are not arguing that photovoltaics would be a cost-effective component of such a system at today's prices (that is the subject of another analysis; see Byrne *et al.*), but that photovoltaics and vehicle storage make a coherent system, both serving peak power needs and both deferring utility costs for distribution system upgrades.

Our second renewable energy example is wind. Wind is currently the lowest-cost new renewable energy resource, and resources are large — the total U.S. wind resource is estimated to be greater than total U.S. electricity demand (Grubb and Meyer, 1993). However, wind energy is intermittent, and in most cases its time distribution is not well correlated to electrical loads.* Storage is less needed for wind than is popularly believed. Because geographically-dispersed wind sites are not correlated with each other, wind power from large geographical regions is far more steady than that from individual, or a few, sites. Specifically, wind could provide as much as 30% of utility generation without requiring storage (Kelly and Weinberg, 1993). Nevertheless, wind from single sites, or wind at higher than 30% penetration, would require storage. Thus, large storage capacity from the vehicle fleet could improve the economics and increase the maximum possible penetration of wind energy.†

Our general point is that distributed storage from EVs could facilitate the introduction of intermittent renewable energy sources into the power system. Our analysis suggests that EVs for distributed storage are cost-justified on the basis of peak shifting and distributed system benefits independently of renewables. The potential improved integration of renewables simply adds motivation for exploiting EV storage, for forward-thinking utilities as well as governments considering the social and environmental benefits of renewables.

10. NEXT STEPS

Several steps could help to move the electric vehicle fleet in the direction we suggest. First, it may be appropriate to shift national battery research program priorities to emphasize durability in the face of many charge/discharge cycles, as cycle life is the biggest cost factor for the vehicle owner. Under some conditions (e.g. NiMH kept above 50% charge), cycle life is much greater than that assumed in our calculations. Second, analysis of consumer interest in various payment options is needed. Are consumers more interested in a 'pay as you go', with credits on their electrical bill proportional to actual number and depth of discharge cycles? Or would they prefer a capitalized 'up front' payment at the time of vehicle purchase, which would presumably also increase the demand for electric vehicles? Or would they rather have the utility purchase and maintain their vehicle batteries? Third, a more detailed analysis is needed of the utilities and areas within those utilities for which this approach would be most profitable, to identify good candidates for initial large-scale programs, and to quantify the size of the appropriate incentives. Finally, to

*A few sites, like the Solano Pass region in California, have wind resources well matched to times of peak electrical load (Kelly and Weinberg, 1993), but these are unusual.

†The physical characteristics of wind generators (tower, noise) and location of wind resources (e.g. the largest U.S. wind resources are on the Great Plains), dictate that much of the wind generation would be remote from load centers. Therefore, distributed storage in conjunction with remote wind would offer lower T&D benefits than distributed storage in conjunction with a distributed renewable source such as photovoltaics.

begin moving toward vehicles as electric resources, electric utilities and electric automobile manufacturers must set joint specifications for the physical connection and logic of vehicle-to-grid power. Because the invertor is already on-board, it would seem that the power connection and at least some of the logic would have to be on-board the vehicle, and at least the basic connections (perhaps with replaceable logic) would be most economically designed-in from the start, as suggested by Fig. 1.

11. CONCLUSIONS

Electric-drive vehicles have the potential to make major contributions to the electric supply system, as storage or generation resources, or both. The already-launched battery-powered EVs are a good initial bridge to a vehicle fleet integrated with the electrical system, since battery-powered vehicles must be connected to the grid anyway, for charging. Our analysis suggests that there would be substantial economic benefits for most electric utilities to insure that the connection to the electrical distribution system allows battery EVs to function as storage resources. Fuel cell-powered vehicles could provide generation for the utility. We have not analyzed fuel cell vehicles here, but their anticipated lower initial costs than battery-powered EVs and longevity of the fuel cell itself (Williams, 1994) suggest that their economics would be more favorable than the battery EV case for peaking power; in fact, a recent analysis finds fuel-cell EV power competitive with baseload generation.*

If even a fraction of the vehicle fleet becomes electrified, and is connected to the electric grid as we suggest, future electrical power systems will have less need to purchase base-load generation, will be less concerned with the time-of-day match between generation and load, and thus will be more receptive to intermittent renewables. The restructured utility of the future may also see their 'customers' as their most important sources of storage and even of generation.

The current internal combustion vehicle fleet is characterized by very large capacity (over 10 times the power of all electric generation facilities), idle most of the day, and with capital costs at less than one-tenth the cost per unit power of central generation. An electrical vehicle fleet with these characteristics would make plausible such long-term futures as:

(1) an electric supply system without central generators, with generation provided exclusively by a customer-owned fuel-cell EV fleet, ultimately powered by gaseous fuels, or
(2) an electric supply system with a high proportion of intermittent renewables, buffered by distributed storage in the battery-EV fleet, or
(3) some combination of the two.

The short-term electric vehicle debate between battery-EVs, hybrid-EVs and fuel-cell EVs is now waged on criteria such as near-term availability, reliability, cost, and vehicle vs power-plant pollution. Thinking in the longer term, and assuming a sustainable energy system, the questions will be rather different. We will ask what is the optimal mix of battery-EVs with electricity as the long-distance energy carrier, vs fuel cell EVs with liquid or gaseous fuels as the long-distance energy carrier and electricity exchanged primarily in local distribution systems.

For the near-term, our analyses of battery-EVs suggest that with conservative assumptions — no distributed benefits, assuming deep discharging and thus shorter battery life, and doubling manufacturer's projected costs of new batteries — all three vehicle/battery combinations we analyzed could be cost-effective peak power resources. We conclude this from several analytical approaches — they provide five times more power per equipment dollar (and per house) than direct load control, they provide power at half the cost of commercial demand charges, and they are less expensive than most current avoided costs for new peak power capacity. The immense power capacity of the U.S. vehicle fleet means that EVs become a significant electrical resource at single-digit percentages of the vehicle fleet, and surpass the power capacity of all other generation resources at a few tens of percentage of the vehicle fleet.

*The analysis is for fuel cell vehicles for the year 2010, assuming home and employer parking facilities with a 'docking station' which feeds natural gas to the EV and provides electricity to the grid and heat to the adjacent building. Under these circumstances, the analysis concluded that fuel cell vehicles could provide power competitive with baseload power. This would be much less expensive on a kWh basis than the battery-EV case we analyze in the present paper. A conference paper has been presented on the fuel cell-EV analysis (Williams and Kissock, 1995), and the analysis should be finalized in 1997.

The favorable near-term economics for battery vehicles is important because it suggests an incremental and relatively painless first step in the transition to a radically different electrical utility system in the future — a utility system which is fully integrated with the vehicle fleet (of battery- and fuel-cell EVs), one in which electricity customers are also vendors of storage and generation resources, one which is more robust to equipment failures, and which is compatible with high proportions of generation from intermittent renewables.

Acknowledgements—We are grateful to John M. DeCicco, Mark A. DeLucchi, David H. Swan, Fred Roberts, Thomas Turrentine, and Howard Wenger for providing data and for suggestions on references and calculations. Robert E. Schultz illustrated the control panel. For comments on earlier drafts, we thank Art Babbott, Al Beliso, Rick Codina, G. Alan Connes, John M. DeCicco, Mark Levine, Mark DeLuchi, Charles Goldman, Mike Kellaway, Kelly Kissock, Chris Marnay, Dwight MacCurdy, Ralph Nigro, Ryan Wiser and anonymous reviewers for *Transportation Research*. None of these reviewers is responsible for errors or omissions.

REFERENCES

Allen, D. *et al.* (1995) Electric cars and lead. Letters (8 rejoinders to Lave *et al.* (1995), plus Lave *et al.*'s response). *Science* **269**, 741–744.

American Automobile Manufacturers Association (1994) *AAMA Motor Vehicle Facts and Figures*. AAMA, Washington, DC.

American Automobile Manufacturers Association (1995) *AAMA Motor Vehicle Facts and Figures*. AAMA, Washington, DC.

Bureau of the Census (1992) *Statistical Abstract of the United States 1992*. U.S. Government Printing Office, Washington, DC.

Byrne, J., Letendre, S., Young-Doo, Wang, Govindarajalu, C. and Nigro, R. (1996) Evaluating the economics of photovoltaics in a demand-side management role. *Energy Policy* **4**(2), 117–186.

Chapel, S., Feinstein, C. and Orans, R. (1993) *Evaluation of Utility Grid-Connected Battery Plants Using Area and Time Specific Marginal Costs*. Presented at Fourth International Conference on Batteries for Energy Storage, Berlin, September 1993. EPRI, Palo Alto, CA.

City of Austin Utility Electric Department (1994) Final report: estimating the value of a strategically placed photovoltaic system in Austin Texas. Prepared for Sandia National Laboratory, Project No. 67-9121.

Crable, B. A. (1995) EV chargers allow load management options. *Proceedings, Delivering Customer Value: 7th National Demand Side Management Conference*. EPRI, TR 105196. Palo Alto, CA, Electric Power Research Institute.

Duchi, M., Garimella, S. and Hurwitch, J. (1988) *Load-Leveling Lead-Acid Battery Systems for Customer-Side Applications: Market Potential and Commercialization Strategy*. EPRI, AP/EM-5895. Electric Power Research Institute, Palo Alto, CA.

Electric Power Research Institute (EPRI) (1987) DYNASTORE — *A computer Model for Quantifying Dynamic Energy Storage Benefits*. EPRI AP-550. Electric Power Research Institute, Palo Alto, CA.

Fischer, L. M. (1996, 5 January) G.M., in a First, Will Sell a Car Designed for Electric Power this Fall. *New York Times*, p. A 10.

Ford, A. (1994) Electric vehicles and the electric utility company. *Energy Policy* **22**(7), 555–570.

Ford, A. (1996) Electric vehicles: the case for (and against) incentives. *Public Utilities Fortnightly* **134**(8), 24–28.

Freeman, Sullivan & Co. (1994) Grid-support photovoltaics: summary of case studies. Report prepared for Pacific Gas & Electric Company. Freeman, Sullivan & Co., San Francisco, CA 94104.

Goldman, C., Kempton, W., Eide, A., Iyer, M., Farber, M. and Scheer, R. (1996) *Impact of Information and Communications Technologies on Residential Customer Energy Services*, pp. 73–83 Report, LBNL-39015, UC-1322. Lawrence Berkeley National Laboratory, Berkeley, CA.

Grubb, M. J. and Meyer, N. I. (1993) Wind energy: resources, systems and regional strategies. *Renewable Energy: Sources for Fuels and Electricity*, eds T. B. Johanson, H. Kelly, A. K. N. Reddy, R. H. Williams, and L. Burnham, pp. 157–212. Island Press, Washington, DC and Covello, CA.

Hoff, T. and Wenger, H. J. (1992) *Photovoltaics and Demand-Side Management Options; Phase I: Concept Development*. Advanced Energy Systems Report 007.5-92.4. Pacific Gas & Electric Company, San Ramon, CA.

Hu, P. S. and Young, J. (1992) *Summary of Travel Trends: 1990 Nationwide Personal Transportation Survey*. Office of Highway Information Management, Federal Highway Administration, Washington, DC.

Kelly, H. and Weinberg, C. (1993) Utility strategies for using renewables. *Renewable Energy: Sources for Fuels and Electricity*, eds T. B. Johanson, H. Kelly, A. K. N. Reddy, R. H. Williams, and L. Burnham, pp. 1011–1070. Island Press, Washington, DC.

Kempton, W., Reynolds, C., Fels, M. and Hull, D. (1992) Utility control of residential cooling: resident-perceived effects and potential program improvements. *Energy and Buildings* **18**, 201–219.

Kurani, K., Turrentine, T. and Sperling, D. (1994) Demand for electric vehicles in hybrid households: an exploratory analysis. *Transport Policy* **1**(1), 244–256.

Lachs, W. R. and Sutanto, D. (1992) Battery storage plant within large load centers. *IEEE Transactions on Power Systems* **7**(2), 762–767.

Lave, L. B., Hendrickson, C. T. and McMichael, F. C. (1995) Environmental implications of electric cars. (Policy Forum) *Science*, 19 May 1995.

Lovins, A. B., Brylawski, M. M., Cramer, D. R. and Moore, T. C. (1996) *Hypercars: Materials, Manufacturing, and Policy Implications*. Rocky Mountain Institute, Snowmass, CO.

Mackenzie, J. (1994) *The Keys to the Car: Electric and Hydrogen Vehicles for the 21st Century*. World Resource Institute, Washington, DC.

Murrell, J. D., Hellman, K. H. and Heavenrich, R. M. (1993) Light duty automotive technology through 1993. *EPA Technical Report* EPA/AA/TDG/93-01. U.S. Environmental Protection Agency, Ann Arbor, MI.
New York Times (1996). Honda to offer an electric car. 9 April 1996, p. D6.
Office of Technology Assessment (1995) Advanced automotive technology: visions of a super-efficient family car. September 1995, OTA-ETI-638. GPO stock no. 052-003-01440-8.
Orans, R., Woo, C., Swisher, J., Wiersma, B. and Horii, B. (1992) *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District.* EPRI, TR-100487, Palo Alto, CA.
Ovshinsky, S, Fetcenko, M. A. and Ross, J. (1993) A nickel metal hydride battery for electric vehicles. *Science* **260**, 176–181.
Perez, R., Seals, R. and Stewart, R. (1993) Assessing the load matching capability of photovoltaics for U.S. utilities based upon satellite-derived insulation data. Proceedings of the 23rd IEEE PV Specialists Conference, Louisville, KY.
Pisarski, A. (1992) Travel Behavior Issues in the 90's. *Linking Land Use and Transportation Planning New Mandates — New Approaches: Resource Manual 1994.* Lincoln University Institute of Land Policy.
Rice, R. E. (1995) Geographic information system applications for electric vehicles demand modeling. *Delivering Customer Value: Proceedings of the 7th National Demand Side Management Conference.* EPRI, TR 105196. Electric Power Research Institute, Palo Alto, CA, pp. 58–64.
Sacramento Municipal Utility District (1994) Draft 1994 Marginal Cost Study Volume I: Summary. Sacramento, CA.
Shugar, D, Orans, R., Jones, A., El-Gassier, M. and Suchard, A. (1992) Benefits of distributed generation. In PG&E's transmission and distribution system: a case study of photovoltaics servicing kerman substation. Report No 007.5-92.9, Research and Development Department, Pacific Gas & Electric.
Sperling, D. (1995) *Future Drive: Electric Vehicles and Sustainable Transportation.* Island Press, Washington, DC.
Swan, D. H. and Guerin, J. T. (1995) Design and vehicle integration of an advanced zinc bromine battery. SAE Technical Paper Series No. 951950, Society of Automotive Engineers.
Tonn, B. E. and Schaffhauser Jr., A. (1995) Global and electric power industry scenarios. *Futures Research Quarterly* **11**(4), 5–37.
Wald, M. L. (1996) Next wave of electric cars: hybrids. *New York Times* 14 May 1996, p. C1 C8.
Weinberg, C. J., Iannucci, J. and Reading, M. (1993) The distributed utility: technology, customer, and public policy changes shaping the electrical utility of tomorrow. *Energy Systems and Policy* **15**(4), 307–322.
Williams, R. H. (1994) The clean machine. *Technology Review* **97**(3), 20–30.
Williams, R. H. and Kissock, K. (1995) Why not plug your house and workplace into your fuel cell vehicle? Presented at 1995 U.S. EPA Symposium on Greenhouse Gas Emissions and Mitigation Research, Washington DC, 27–29 June 1995.
Zaininger, H. W., Clark, H. K. and Brownell, G. C. (1990) *Potential Economic Benefits of Battery Storage to Electrical Transmission and Distribution Systems.* EPRI GS-6687. Electric Power Research Institute, Palo Alto, CA.