Demand Side Management Of Electric Vehicle Loads

Timothy N. Tutt, Mark Hesters, Michael R. Jaske and Nancy Bester
California Energy Commission

In September, 1990, the California Air Resources Board (ARB) adopted a regulation that requires the sale of zero emission vehicles in California beginning in 1998. This paper examines the potential effects of meeting the ARB's mandate with electric vehicles (the most likely technology) concentrating on the Southern California Edison (SCE) utility system.

By 2003 in the SCE area, about 170,000 electric vehicles (EVs) using 1,063 GWh per year are required to meet the ARB's mandate. Two vehicle recharging load shapes are examined: (1) a shape that represents naturally occurring EV load unaffected by demand side management (DSM) programs and (2) a shape that shifts EV load to the early morning valley that occurs in projections of the SCE system load without EVs. The paper examines the utility resource implications of EV load for these two EV load shapes, and the potential benefit of controlling EV load with a DSM effort.

The resulting utility resource need, total system costs, and utility emissions are presented. The paper concludes that EV loads are unlikely to add significantly to utility loads in the mid-afternoon, when the SCE system experiences a typical summertime system peak. However, as the number of EVs increases, it is possible that EV loads will act to shift system peak towards the evening, when the majority of EVs will be recharging. The paper also concludes that shifting EV load into the existing early-morning load valley produces system cost benefits.

Introduction

In September, 1990, the California Air Resources Board (ARB) adopted a regulation that requires the sale of zero emission vehicles in California beginning in 1998 (ARB 1990)[1]. The regulation precipitated a storm of activity concerning electric vehicles, since EVs are the only currently available technology that meets the zero emission vehicle definition. In Southern California, the efforts of the local air quality district, electric utilities, and local government, such as the Los Angeles Initiative[2], have combined with the ARB regulation to generate strong interest in EVs. Electric vehicles are seen as an essential component of plans to solve the area's air-quality problems.

Since there are relatively few EVs on the road today, and future EV technology depends upon extensive research currently underway, the electricity infrastructure impacts of the potential loads from EVs are still relatively uncertain. The potential size of the load requires examination of how utilities will provide power to EVs, including utility generation expansion plans, operational constraints, and demand side management programs to accommodate EV loads.

California Energy Commission (CEC) Staff analyzed the EV loads implied by the ARB regulation as part of efforts to examine demand uncertainty for the 1992 Electricity Report (CEC 1992). This paper is based upon that CEC Staff work.

The Southern California Edison (SCE) utility planning area was chosen to illustrate the potential effects of electric vehicles. The utility response to the EV load from the ARB regulation will be some combination of demand-side and supply-side activities. A demand-side response, such as an EV load control program, may lessen or delay the need for a supply-side response, such as an additional plant to serve the EV load. The total amount of emissions reduction from electric vehicles will differ as the mix of demand-side and supply-side responses differs.

Previous efforts in ER-92 identified a set of consensus assumptions about EVs to use in this analysis (CEC 1991). In addition, an early draft of an analysis commissioned by the California Institute for Energy Efficiency provided methodological direction (Ford 1992).

Research Approach

The research approach involves: (1) estimating the number of electric vehicles in question and the amount of electricity consumed, (2) developing scenarios with different vehicle recharging patterns, with and without prospective DSM programs, (3) estimating the utility generation requirements, total system costs, and emissions for each scenario, and (4) comparing the emissions from the supply of electricity for EVs to the displaced tailpipe emissions from conventionally fueled vehicles.

Number of Vehicles and Electricity Requirements

We estimate that a total of 170 thousand electric vehicles will be on the road by 2003 in the SCE area. This estimate is derived by applying the sales percentages in the ARB regulation applied to an estimate of the total annual vehicle sales in California, then allocating the vehicles to utility service areas in the State (see Table 2). The characteristics of EVs that affect the electricity requirements--such as vehicle efficiency and vehicle miles travelled--are based upon parameters agreed to in a 1991 workshop on EVs (CEC 1991). A partial listing of the EV characteristics assumed in this analysis is shown in Table 1. These parameters have significant uncertainty.

Table 1. Vehicle Characteristics

	Personal Cars	Light Trucks (Vans)
Efficiency (Miles/kWh)	2.5	1.4
Daily Usage (Miles/Day)	20-60	20-60
Charging Time (Hours/Day)	2-6	3-7

Alternative Recharging Scenarios

Two alternative EV recharging scenarios were developed and compared to SCE's existing system load shape for several characteristic load days. The two scenarios and charging profiles are described below.

In the Opportunity Charging Scenario, EV owners are allowed to recharge whenever they have "opportunity" to, whenever recharging is convenient. The opportunity to recharge is limited somewhat by physical constraints, such as the pattern of operating the vehicle (charging is unlikely while operating the vehicle), or lack of infrastructure for charging at some vehicle destinations. Most of the EVs in the analysis are assumed to be primarily used for daily commuting to and from work, with some charging available at work sites. No DSM program acts to alter the recharging behavior of EV owners. The daily EV shape for the Opportunity Charging Scenario is shown in Figure 1.

The Controlled Charging Scenario assumes that a hypothetical DSM program spreads nearly all EV load through the early morning hours, when the existing SCE system load is lowest. Several shapes were examined, with successively more delay in recharging, to arrive at the Controlled Charging shape. A DSM program to achieve this effect may be based upon a combination of time-of-use rates, timeclocks to delay charging, intelligent metering and charging systems, or on some hitherto unknown technique. The program would depend in part upon the relative charging time needed for vehicles, based upon how much they have been used during the day, and the characteristics of the charging technology. We do not define a specific DSM program in this analysis. The daily EV shape for the Controlled Charging scenario is shown in Figure 2.

Utility Generation Impacts Analysis

Analysis of the electricity generation system impacts begins with a capacity expansion process to determine the amount and timing of supply alternatives that should be added for each EV scenario. A production cost model is used to estimate the total system costs and the expected power plant emissions in each scenario.

A Base Case (with no EV loads) was developed and compared with an Opportunity Charging resource plan and a Controlled Charging resource plan. The plans were examined for differences in the timing, magnitude, and type of capacity added to the utility supply system, and each was examined with a production cost model.

Total resource plan cost results were compared for each scenario, with cost differences attributed to the load differences between the two scenarios. A difference in the total costs between the Base Case and Opportunity Charging scenario reflects the costs of serving increased demand due to EV charging. Any reduction in total costs between the Controlled and Opportunity Charging scenarios reflects the potential benefit of the load

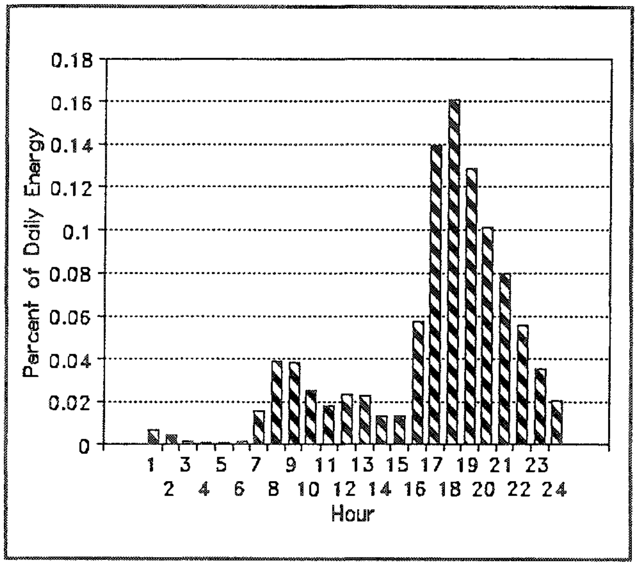

Figure 1. EV Load Shape Opportunity Charging

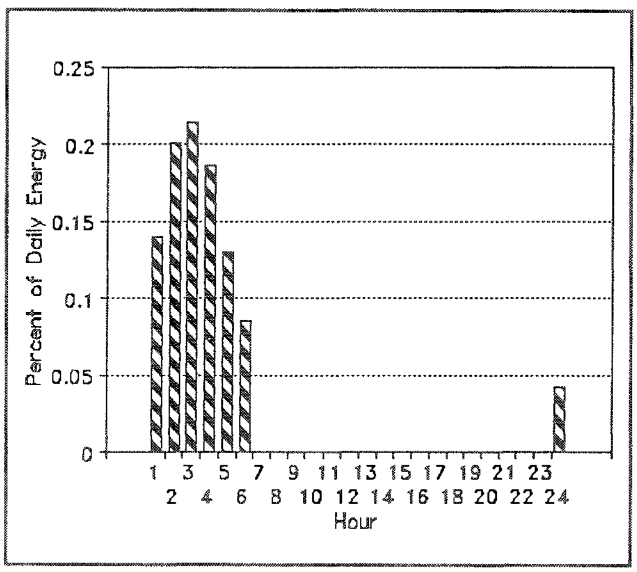

Figure 2. EV Load Shape Controlled Charging

management program designed to alter EV charging to non-peak hours.

Emission Impacts Analysis

Electric vehicles are assumed to displace conventional gasoline-powered vehicles, and the associated fuel demand and emissions. Projected amounts of conventional fuel displaced were multiplied by emission factors (developed from ARB emission forecasts) to estimate the tailpipe emissions impacts of EV penetration. The EVs in each scenario displace the same number of gasoline vehicles, and hence there is no difference between the EV scenarios' tailpipe emission impacts. Emissions resulting from the production of gasoline are not examined in the analysis.

Utility sector emissions are calculated based upon production cost modelling for each scenario, which provides estimates of the amount of energy and emissions produced by each resource type. All emissions resulting from SCE's power generation inside and outside of California, are included. Fossil fuel fired resources in the local air basin are modelled as complying with complex regulations to reduce emissions from these sources.

Demand, Supply, and Emission Impacts

The estimated electric load from EVs increases in significance to the SCE system[3], reaching four percent of SCE system load by 2011. Over 800 thousand EVs are projected in the SCE area by 2011, with annual electricity consumption of 5,258 GWh (see Table 2). The markedly different impacts on system load shape of the two scenarios examined in this analysis are presented below.

Opportunity Charging Scenario

The recharging shape for the Opportunity Charging Scenario reflects the assumption that most commuters will begin recharging their vehicles as soon as they return from work. This results in most recharging occurring in the early evening hours. A smaller number of commuters will plug in their EVs upon arriving at work in the morning, leading to some EV recharging in the morning worktime hours. A small amount of EV recharging is assumed to be scattered throughout the day.

Figures 3 through 5 plot the composite SCE system load resulting from the estimates of EV loads combined with the projected system 2011 load for three characteristic day types for the SCE system.[4]

On the summer peak day, the EV loads shift the system peak from 2:00 in the afternoon to 5:00 in the afternoon, because of an early evening charging pattern that offsets the normal system dropoff from afternoon peak. The early morning valley receives very little of the additional EV load (See Figure 3).

Depending on the load shape in each year, a shift in system peak may or may not occur, but there is a greater potential for a shift as EV loads increase and remain

Table 2. Number of Vehicles and Energy Requirements

	Number of Vehicles (Thousands)				Energy Requirements (GWH)			
	SCE Area			Statewide	SCE Area			Statewide
Year	Cars	Vans	Total	Total	Cars	Vans	Total	Total
1998	12	15	28	50	50	107	157	280
2003	76	94	170	304	327	736	1063	1899
2011	484	323	807	1440	2323	2935	5258	9389

unmanaged by utility programs. With lower amounts of EV loads, many summer days may show evening peaks while the system peak day continues with the afternoon peak pattern. The system peak shift may not be consistent year to year, increasing the variance in the timing of system peak.[5]

A shift in system peak, when it begins to occur, implies potential changes to the definition of the on-peak period. Calculations of annual load (peak) growth will be affected[6], as will the cost-effectiveness of other DSM programs, particularly load-shifting programs designed to address the old peak.

EV loads significantly increase the winter day's peak load at 6:00 in the evening, while the lower non-evening hours of the day, particularly the early morning valley period, is relatively unaffected (See Figure 4). The daily load shape is changed from one that is fairly level throughout the day, except for the early morning valley, to one which shows a significant evening peak compared to daytime loads. On SCE's system minimum day, the EV loads again add onto the existing evening peak for the day and could exacerbate any existing problems of managing the swings in load during the day (See Figure 5).

We estimate that most non-summer load days will follow the pattern of the winter peak and minimum load days, where significant EVs charging in the evening have the potential to exacerbate daily peaks and affect the system's responses to load changes over the day. More and potentially different resources would be required to serve the daily peak, compared to the situation without EVs. Depending upon the flexibility of stopping and starting

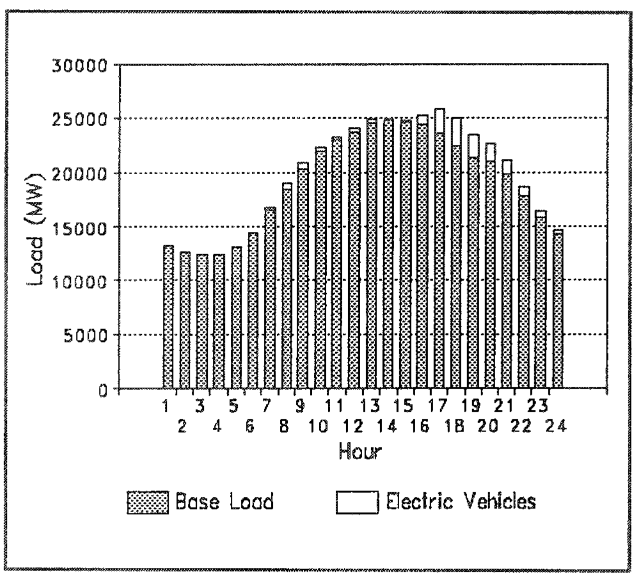

Figure 3. 2011 EV Impact SCE Summer Peak Day Opportunity Charging

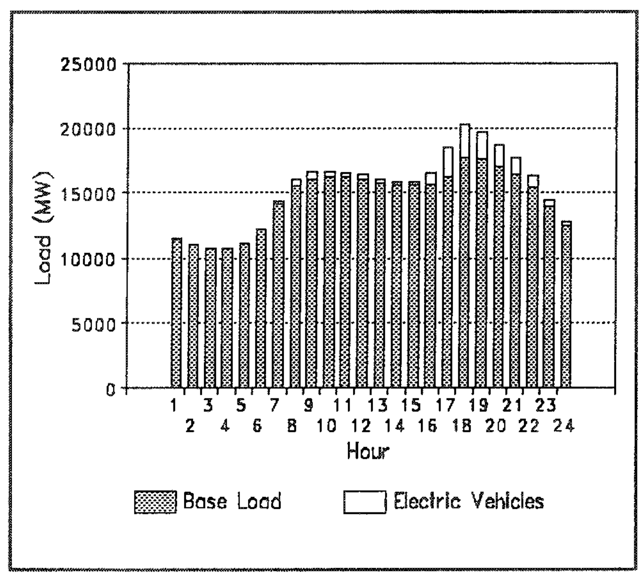

Figure 4. 2011 EV Impact SCE Winter Peak Day Opportunity Charging

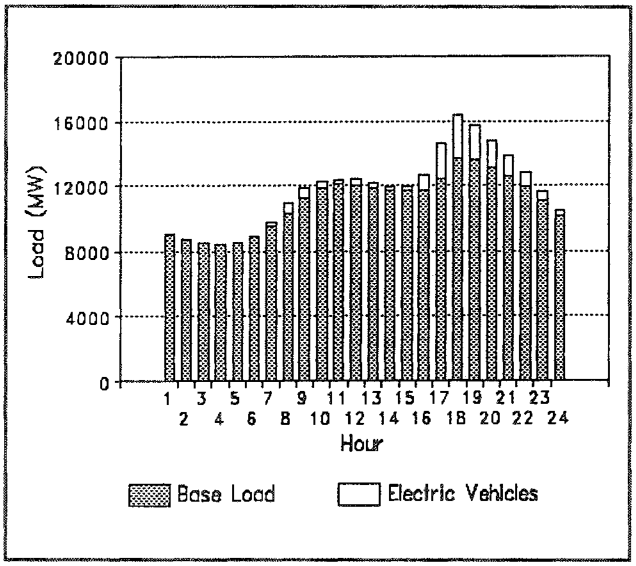

Figure 5. 2011 EV Impact SCE System Minimum Day Opportunity Charging

these additional resources, they may have to be turned on throughout the day to be available to serve the peak. This would cause changes in the resources serving load even in hours of the day when the EV load is small.

Controlled Charging Scenario

In the Controlled Charging Scenario, a hypothetical DSM program is assumed that spreads nearly all EV load into the early morning hours where existing load is lowest throughout the year. The resulting impact upon the three characteristic system load days is shown in Figures 6 through 8.

Including the EV load on the system in the early morning hours, as in the Controlled Charging Scenario, has a different impact on the system peak day than in the Opportunity Charging Scenario (see Figure 6). The EV loads do not add to the typical afternoon system peak, nor do they result in a significant potential for a shift in peak. In addition, the early-morning valley is considerably flattened by the inclusion of the EV load.

The system peak impacts of this shape are much less sensitive to the uncertain variables in the EV analysis. Since afternoon and early evening charging is controlled (shifted), variations in existing system load during those hours do not interact with EV loads to cause potential shifts in system peak. The number of EVs could increase well beyond that modeled here, and still have little system peak impact.

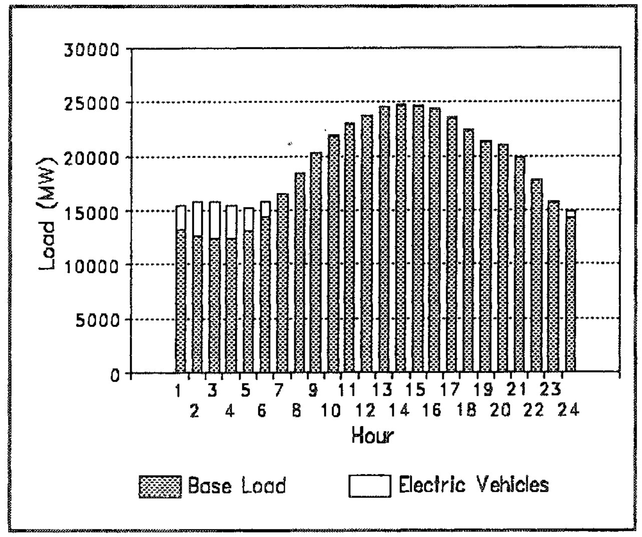

Figure 6. 2011 EV Impact SCE Summer Peak Day Controlled Charging

On the winter peak day, adding the EV load to the system in the early morning hours results in a significant flattening of the load shape, without exacerbating or altering the existing early evening peak (See Figure 7). Daily variation in load is changed from about 7,000 MW to about 5,000 MW.

On the system minimum day, adding the EV load in the early morning hours has filled most of the valley for the day, but there remains a small valley centered around 7:00 A.M. (See Figure 8). The remaining valley could also be smoothed if a DSM program were sophisticated

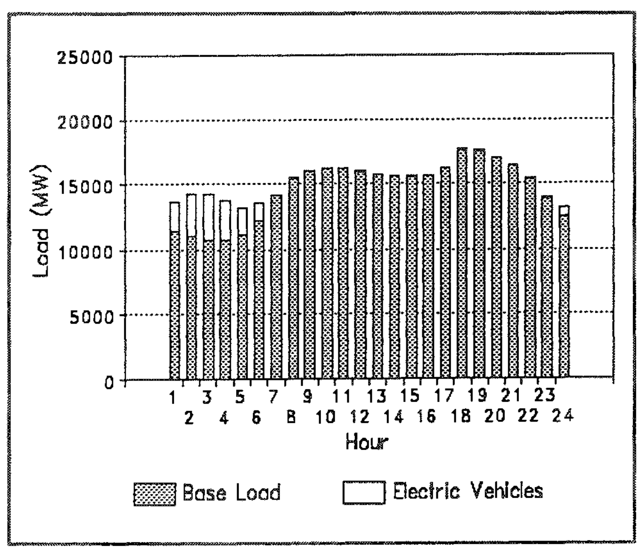

Figure 7. 2011 EV Impact SCE Winter Peak Day Controlled Charging

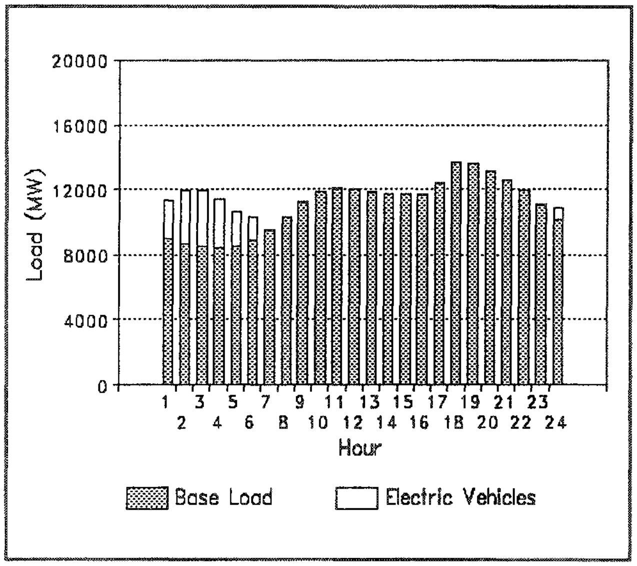

Figure 8. 2011 EV Impact SCE System Minimum Day Controlled Charging

enough to identify EVs that could be charged later into the morning without causing inconvenience to the EV user (EV recharging in this analysis was constrained to end at 6:00 A.M).

Most non-summer days will follow the patterns illustrated in Figures 7 and 8. The early morning valley cannot be expected to be wholly consistent in time throughout the year. In some cases, the EV load may be significant enough to create a second early-morning peak to challenge the normal evening peak. A DSM program with the goal of optimally filling valleys in existing load with EV loads should include some manner of shifting EV recharging to fill valleys of uncertain timing and to avoid creating new system peaks.

This scenario implies that a hypothetical EV DSM program may be able to provide significant system benefit by shifting EV load. Modest shifts away from afternoon and early evening charging to charging a few hours later in the evening help summer months but provide no help and may even exacerbate the evening peaks that occur in many months of the year. By simply examining load shapes, it appears that the best position for EV loads is in the early morning valley hours. However, unless some EV charging can be shifted into midmorning hours between 6:00 a.m. and 9:00 a.m. on some days of the year, there remains a potential for load valleys and concomitant system operation problems.

The benefits and costs of using EV loads for sophisticated valley filling depend upon the characteristics of existing and planned system resources, including the distribution system, as well as the potential cost of such a program. The system production cost simulations examined in this analysis will provide some insight into the issues involved.

Implications for Other Systems

For systems similar to the SCE system, with system peaks occurring on summer afternoons due in large part to commercial air conditioning loads, EV loads should have similar general implications. However, for systems such as the Sacramento Municipal Utility District, which shows late afternoon to early evening peaks due in large part to residential air conditioning loads, the naturally occurring charging shape developed here would result in greater system peak impacts from EVs. Winter peaking systems, which generally peak in the evenings, would also have peaks exacerbated by the Opportunity Charging EV shape. In such circumstances, a DSM program with an effect similar to that modelled in the Controlled Charging Scenario would have increased importance.

EV loads are estimated to be roughly similar in all seasons of the year (unlike air-conditioning, for example), and so will reduce the relative difference between summer and non-summer loads. EV loads could increase or decrease the daily variation in system load, depending upon the amount they are controlled. Reduction of annual and daily variation in load is generally considered a benefit, but depending upon system resources and maintenance needs, such a reduction may cause problems for utility operations (for example, some distribution transformers are designed to take advantage of low cycles in load for cooling).

Implications for DSM Programs

Electric vehicles are natural candidates for load control programs, since an integral part of their operation involves batteries. The energy to fill EV batteries is typically generated when the vehicle is not in use, allowing some natural flexibility in timing of generation. This contrasts with air conditioners, for example, where the energy used is typically drawn from the utility at the exact time when cooling is needed.

The constraints on the ability to control EV recharging load include the pattern of customer use of the vehicles, the customers' need for assurance that their vehicles will have adequate charge when needed, the technical characteristics of the recharging process, and the cost and sophistication of the DSM program employed. These constraints will limit a utility's ability to recharge EVs at times chosen to minimize the costs of operating the utility system.

Many current DSM techniques could have application to EV loads. However, care must be taken to consider all of the impacts of a proposed DSM program. For example, a DSM program that merely shifts EV load away from summer afternoon peak periods, without paying attention to where the EV load is shifted, may end up exacerbating system load and operation problems, rather than mitigating them. Such a program may mitigate summer peak impacts for EVs but exacerbate daily peaks for much of the year, while adding little load during early morning valleys.

For example, a program that merely prevented EV recharging until a specified time for all EV users, such as a timer or time-of-use rate program (or a combination of the two), may end up creating a secondary peak that presents system operation difficulties or even rivals or exceeds the system peak. The beginning of the low rate period would be an obvious target for setting timers and starting to charge, leading to a surge in power demands at that hour.

More sophisticated programs such as an intelligent two-way metering/charging system could avoid the potential problems of simpler programs, smoothing EV load out over early morning valley hours and minimizing system operation costs. A sophisticated system could determine the recharging requirements (energy needed) of individual EVs each day and customize the recharging profile accordingly. Information about individual customers' expected patterns of vehicle use could be incorporated in such a system to provide more recharging flexibility. However, the higher costs of such a sophisticated program may not be worth the additional system benefits. In addition, distribution system requirements for periods of lower load to allow for cooling of equipment can affect the value of a valley-filling strategy.

Electric vehicle loads, and attempts to control EV loads with DSM programs, can have an impact on existing load management resources. For example, if EV loads vary the timing of system peak, they may also affect the cost-effectiveness of existing programs, such as Air Conditioner Cycling programs, that are designed with the old system peak in mind. An EV DSM program could restore the traditional system peak and return existing DSM programs to the environment for which they were designed.

Impact on Electricity Supply

Compared to the Base Case (no EVs), there was no change in projected resource additions in the EV scenarios by 2003, because the EV load is relatively small. By 2011, the Opportunity Charging Scenario shows an increase in capacity requirements of 195 MW.[7] The Controlled Charging Scenario requires no additional supply-side resources because of the hypothetical DSM program that shifts EV recharging completely off-peak. The capacity additions in the Base Case and the two EV scenarios are summarized in Table 3.

Table 4 shows the cost results for all of the scenarios. A reduction of $287 million (NPV of difference in system costs in 1989$) is attributable to the implementation of a load management program altering charging times for EVs. This program benefit is an estimated upper limit to the cost of such a program, in order for the program to be cost-effective. It is unlikely that a DSM program could achieve the degree of control over EV recharging envisioned here, and correspondingly unlikely that one could achieve the benefits estimated here. However, there does seem to be room for such a program to be cost-effective.

Emission Impacts

There are emission reductions in the transportation sector due to the displacement of gasoline powered vehicles with zero emission electric vehicles. However, production of electricity for EVs will in most cases have associated emissions from fuel consumption in the utility sector. Emissions in both sectors are modeled as being reduced (or controlled) by existing and projected air quality regulations.

Alternative charging shapes can change the mix of resources expected to provide the electricity for EVs, and thereby impact utility sector emissions. Alternative charging shapes are not expected to impact the displaced tailpipe emissions from gasoline vehicles.

Comparing the changes in tailpipe emissions with changes in utility sector emissions for each scenario (See Table 5) indicates that EVs will lower overall emissions, even without considering the potential for emission reductions from gasoline production (i.e.- without a total fuel cycle analysis). The Controlled Charging Scenario has higher NOx emissions and lower CO2 emissions because of greater use of baseload resources to provide energy for EV recharging. These baseload resources include sources that are outside the South Coast Air Basin, and therefore not modelled with as high a degree of control for NOx emissions, and non-fossil sources such as wind and hydro that result in slightly lower CO2 emissions.

Table 3. Total Capacity Added by 2011

	Base Case	Scenario Opportunity Charging	Controlled Charging
Total Capacity Added (MW)	6,044	6,239	6,044
Difference from Base (MW)	-	195	-
% Difference from Base	-	3.2%	-

Table 4. Net Present Value of Total Costs (Millions of 1989 Dollars)

	Base Case	Scenario Opportunity Charging	Controlled Charging
Total System Costs	61,472	63,235	62,948
Difference From Base	-	1,763	1,476
Difference Between Controlled and Opportunity Charging	-	-	-287

Table 5. Emission Projections for 2011 (Tons/Day)

Scenario/Sector	NOx	ROG	CO2
Total Base Case			
Transportation	301	268	154754
Utility	165	8	133156
Total	466	275	287910
Change From Base Case: Opportunity Charging			
Transportation	-28	-24	-13808
Utility	+6	0	+ 8508
Total	-22	-24	- 5300
Change From Base Case: Controlled Charging			
Transportation	-28	-24	-13808
Utility	+9	0	+ 7425
Total	-19	-24	- 6383

Conclusions

The level of EVs implied by the ARB regulation and the EV characteristics used in this analysis lead to a minor impact on the SCE system overall. The electricity required for EVs is only about 1,000 GWh, or one percent of the non-EV load for SCE by 2003, rising to just over 5,000 GWh, or about four percent of forecast consumption by 2011. Peak requirements, which depend on the shapes of EV recharging and existing load, are relatively less affected, because EV loads are expected to occur mostly in the evening. At the traditional peak time of 3:00 p.m., the naturally occurring load from EVs was estimated to be only 195 MW by 2011, less than one percent of existing peak demand.

However, EV load that peaks in the evening will add directly to daily peaks for much of the non-summer period of the year, which could result in increased system operation costs. In addition, early evening EV load has the potential to shift the system peak in the summertime from mid-afternoon to early evening, which greatly increases the affect that EV load could have on system resource need. Additional penetration of EVs after the peak shifts has a greater marginal impact on peak than the penetration up to the point of peak shift.

The mix and timing of planned resource additions for the SCE system was not greatly affected by the EV loads analyzed. Considerable resource additions are included in the baseline resource plan for SCE primarily to reduce system costs, including the societal costs of residual powerplant emissions, rather than to satisfy capacity reserve requirements. The additional demands of EVs are small compared to the resource additions already in consideration.

However, the projection of significant early evening load from EVs in the Opportunity Charging Scenario would have greater relative impact on system peak for utility systems that currently peak in the evening, such as SMUD. In addition, if EV loads develop in many utilities, and push more utilities toward an evening peaking pattern, there are implications for overall system reliability and the potential for cost-effective capacity exchanges in the western United States.

Controlling EV load through a DSM program has the potential to eliminate the peak demand impacts from EVs by shifting EV load to early morning valleys in the existing SCE system load shape. The Controlled Charging Scenario indicates that moving most EV load to this early morning valley period eliminates the small amount of additional capacity included in the Opportunity Charging Scenario. and reduces total system costs by nearly 300 million dollars (present value basis). A sophisticated EV DSM program seems necessary to achieve the modelled shift in EV load, but the program would have to cost less than this amount to be cost-effective.

ROG, NOx and CO2 emissions are reduced by the move to EVs. ROG emissions show the greatest percentage reduction because ROG emissions from utility generation are quite small in comparison to ROG emissions in conventional transportation. CO2 emissions are reduced less on a percentage basis than other emissions because CO2 emissions are relatively less controlled in both the utility and transportation sectors, whereas other pollutants are highly controlled in the utility sector (and so do not increase much with additional electricity generation).

The conclusions of this analysis are limited by the uncertainty of the data available about EVs and the tools and time available for analysis. General caveats include: (1) Electric vehicle technology is in a period of intensive research, which could lead to developments that were not anticipated; (2) no DSM program will achieve the full control of EV recharging assumed; (3) the production cost model used was not a chronological model, and cannot fully address a time-dependent issue like EV recharging; (4) actual resource choices involve resource bidding, which cannot be analyzed here; and (5) emission reductions that occur upstream from the tailpipe or utility generation, such as in refineries and other fuel production were not analyzed.

Acknowledgements

This paper is based upon work developed as part of the 1992 Electricity Report at the California Energy Commission. All opinions, conclusions, and recommendations expressed in the paper are solely attributable to the authors, and do not necessarily reflect the views of the California Energy Commission. The results presented in this paper will not necessarily be embodied in the final 1992 Electricity Report.

Endnotes

1. The ARB regulation requires production of ZEVs starting at 2% of vehicle manufacturers' annual fleets in 1998, increasing to 5% in 2001, and rising again to 10% in 2003.

2. The Los Angeles Initiative calls for 10,000 electric vehicles in Los Angeles by 1995. Hybrid EVs (both electric and conventional propulsion combined) were expected to fulfill the goal, but financing for production has been difficult.

3. The EVs analyzed here are assumed to get all of their power from SCE. The paper does not address the issue of cross-utility charging, where EV owners living in the SCE area charge at work from the Los Angeles Department of Water and Power system.

4. SCE's 1989 load shape, extrapolated to 2011, is used here. Other years were not examined. The same EV load is added for all days.

5. A different existing system load shape than shown was used for the utility generation needs assessment in the analysis, and no shift in system peak was observed. The differences between the two shapes are under examination.

6. The peak period for EV recharging would be coincident with system peak, so that additional EVs would increase peak more rapidly than before. Annual peak increases could be tied more to the increases in EV penetration than to air conditioning from general commercial growth.

7. A larger increase would have occurred if the peak shift shown in Figure 3 had occurred with the load shape used in the supply analysis.

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