Mitigating Electric Vehicle Impacts on Grid Infrastructure Requirements
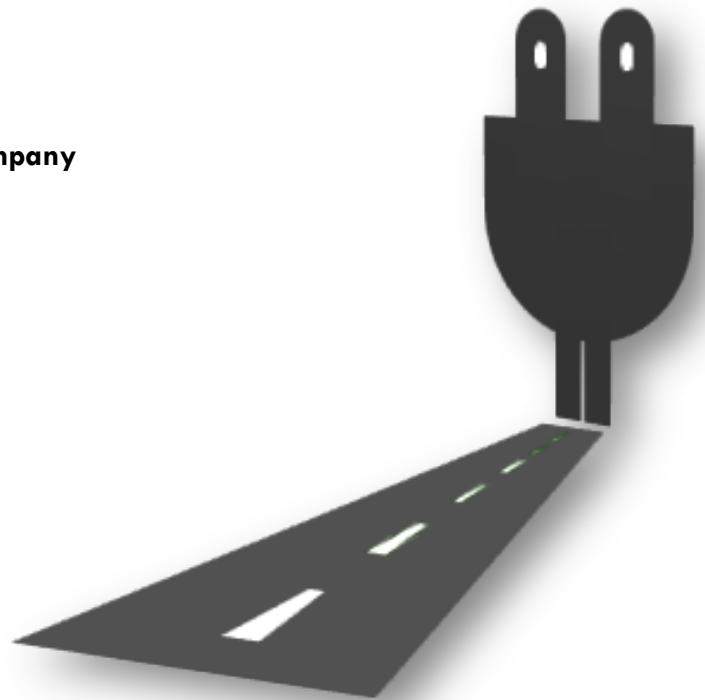
Prepared for Santa Delano Electric Company

By

Nathaniel Horner
Parth Vaishnav

Energy Consulting Group
28790 Chagrin Boulevard, Suite 350
Cleveland, OH 44122

31 March 2013

Executive Summary

This report assesses the likely impact of a growing electric vehicle (EV) fleet on the Santa Delano Electric Company (SDEC) infrastructure and analyzes several options for mitigating that impact. Considering that the average household in the SDEC service area can draw as much as 2.5 kW of grid power during the peak hour of 5-6 p.m., and that an EV plugged into a Level 2 charger (likely during the same time period) can draw 6.6 kW of power, EVs can increase customer peak load by a striking factor of more than three.

When aggregated, increases in peak customer loads require corresponding investments in grid capacity: absent mitigating action by SDEC, a sufficiently large number of EVs will necessitate grid infrastructure investment of between $300 million and $2 billion more than would be needed without EVs. Our analysis shows that even at low penetration rates, the costs of infrastructure improvements greatly outweigh the additional revenue gained from increased electricity sales.

We analyze four potential options for reducing the increase in peak demand ("load-shifting"): a demand response program, in which customers respond to variable pricing signals to voluntarily adjust their usage; a controlled-charging program, in which EV owners allow SDEC to determine when their vehicles charge; a more aggressive battery control program where SDEC is allowed to dictate charge timing as well as actually draw from EV batteries to offset demand from other uses; and a distributed battery storage system where permanent batteries are used for load shifting.

We conclude that a controlled charging program represents the best option, as it reduces the cost of expanding the infrastructure to cater to EVs over the next twenty years by $320 million. Because EVs nonetheless require a considerable net expenditure of $210 million, we propose a service fee structure for EV users that equitably allocates these additional costs to them.

The demand response and battery control programs are unlikely to gain much customer participation, while the distributed battery storage, as currently offered, is too expensive to be cost-effective.

> The bottom line is that EV charging is not "free." EVs will have a significant impact on the grid requirements and the costs associated with delivering electricity. However, controlled charging can moderate this impact, and the additional cost can be easily allocated in such a way as to maintain equity while also providing benefits to EV owners.

1. Introduction

This report analyzes several options for mitigating the impact of electric vehicles (EVs), including plug-in hybrid electric vehicles (PHEVs) on Santa Delano Electric Company's (SEDC) load and the infrastructure required to deliver that load.

For our assessment, we create a Monte Carlo simulation model to project vehicle fleet growth, electricity demand growth, and the costs or savings associated with each mitigating action. Monte Carlo simulation allows us to incorporate the high uncertainties surrounding several important factors (e.g., EV sales) and perform sensitivity analysis to determine which of these factors critically impact the conclusions. In addition to the simulation, we utilized mathematical optimization techniques to solve certain aspects of the problem. The main body of this report will highlight relevant aspects of these models where appropriate, while the implementation details and assumptions are located in Appendix B, Table 3.

Section 2. of this report discusses our model of the growth of the EV fleet. Section 3. describes the baseline, "business-as-usual" scenario in which SDEC does nothing beyond the required infrastructure investments to handle increasing EV demand. Section 4. analyzes several more proactive options for handling the additional load, while Section 5. proposes additional alternatives that merit further analysis but which were not part of the problem brief. Finally, our recommendations for SDEC may be found in Section 6. Appendix A contains additional supporting figures and tables.

2. Electric Vehicle Fleet

The end of 2010 saw the Nissan Leaf and Chevy Volt in the first market-scale introduction of electric vehicles (EVs) and plug-in hybrid EVs (PHEVs) into the U.S. Sales began modestly, but dealer data from the SDEC service area show healthy and rapidly increasing uptake, with 17,000 electric cars of various types and sizes in use right now and exponential growth over the past year.[1] Due to high uncertainty surrounding future sales trends, however, we simulate a wide range of possible growth scenarios.

We assume that each of the 1.8 million residential customers in the SDEC service area owns between zero and three cars and that long-term penetration of EVs will be 1–30%.[2] We vary the rate of growth towards this 'target' by assuming that, in each year, the num-

---

[1] Foss, "Electric Vehicle Information."
[2] Ibid.

ber of EVs sold is 5–25% of the difference between the target and the total number of EVs operating in the previous year.[3]

Based on these assumptions, median fleet size in the SDEC service area is 270K EVs in 2020 in the median case with a 90% confidence interval of 20K – 870K. In 2030, EV fleet size is projected to be 360K (20K – 1.1M).

As the EV market has grown, recent focus has been on smaller vehicles with proportionally smaller batteries; the average battery size across the current fleet is approximately 20 kWh. As technology improves, larger batteries should be possible within the same cost and physical envelope constraints. At the same time, higher availability of charging stations, expansion of "battery-swap" programs, and charging limits in the existing infrastructure should dampen an increase in fleet battery size.[4]

This last factor—charging infrastructure—affects the rate at which the vehicle can receive charge and is limited by both the vehicle's charging system and the external charger (i.e., by both the "plug" and the "socket"). Normal electric outlets can provide up to 1.5kW. External Level 2 chargers can provide up to 19.2 kW, although most of those being installed today max out at 6.6 kW.[5] Early EVs had 3.3 kW onboard chargers, though upcoming models are quickly offering 6.6 kW chargers as either optional or standard features to provide faster charge times.

3. Electricity Demand Growth: A Significant Impact

This growth in the EV fleet is likely to create additional demand for electricity in the SDEC service area. Our first task is to determine the magnitude of this demand growth and whether or not it will have a significant impact on SDEC's infrastructure requirements.[6]

3.1   Baseline Demand

We begin by establishing current demand patterns, without the addition of EVs, as a baseline. The data from the control group of SDEC's demand response pilot study[7] show

---

[3] We do not explicitly model vehicle retirements. First, EVs have a simpler drive train than gasoline-powered vehicles, so vehicle lifetimes of 15 years or longer (through multiple owners) are not out of the question (with battery replacements as needed). At these life spans, EVs purchased in 2013 will not retire until the final years of the period of interest (2013-2030). Second, the retirement rate can be construed as a marginal contributor to the very large uncertainty in sales projections. That is, EV sales can be thought of as *net* sales in this model.

[4] Because we are interested in aggregate fleet, rather than individual EV, grid impacts, we treat battery size growth as endogenous to fleet growth. That is, a "high growth" scenario could include higher vehicle sales, an increase in battery capacities, or both.

[5] Saxton, "Understanding Electric Vehicle Charging."

[6] While we cite point estimates throughout this report to illustrate assumptions and calculations, most parameters in the simulation have distributions associated with them, details of which may be found in Table 3.

a typical daily usage profile with a large peak around 6 p.m. and low usage from 11 p.m. to 7 a.m. (see Figure 3). Peak load is significantly higher in the summer due to space cooling. Characterization of this peak is particularly important, as it determines the size of the transmission and distribution infrastructure required to reliably serve the area; that is, SDEC's grid must be sized to serve peak load (plus some reserve capacity). Data from the DR study show that the maximum peak load was 2.5 kW, with hourly usage exceeding 2.0 kW 3% of the year (Figure 4). Thus, the 1.8 million residential consumers in the SDEC area can be expected to require an aggregate peak demand of around 4.5 GW around 6 p.m. on the most extreme day of the summer.[8] The average summer 6 p.m. peak is 2.1 kW (Table 2).

Growth in this peak load will trigger the need for additional infrastructure investment from SDEC. The California Energy Commission (CEC) forecasts that peak demand in California is likely to grow at an annual rate of 1-2% per year between 2011-2022 over a range of scenarios.[9] These forecasts include factors for economic growth, electricity rates, efficiency gains, and distributed generation. They also account for the proliferation of electric vehicles but conclude that EV impact on peak load will be small: the "high-growth" case estimates that roughly 3.4 million additional EVs in California will contribute only 0.25 GW to an overall peak demand increase of 15 GW.[10] The CEC reaches this conclusion by assuming that utilities will find a way of ensuring that most electric vehicles charge during off-peak hours. Therefore, we rely on the CEC's estimate of 1–2% annual growth in peak demand as the base "non-EV" growth rate, but we also allow a small likelihood of zero growth due to SDEC's historical ability to offset increased demand with efficiency gains.[11]

This background demand growth rate, even without EVs, means that SDEC will need to begin investing in distribution infrastructure upgrades almost immediately and will pass the 5% threshold at which transmission infrastructure upgrades become necessary by 2016.

3.2   EV Electricity Demand

The CEC report cited above assumes EVs will be charged largely during off-peak hours. However, absent incentives to do otherwise, EV owners will likely be returning home and beginning to charge their vehicles precisely when the electricity grid is under the heaviest load, between 5 and 7 p.m. on weekdays. Thus, unmanaged charging of a growing EV

[7] Hereafter referred to as the DR study.
[8] This figure assumes all houses are single-family units. Multi-family units use moderately less energy (2.3 kW during the peak hour), which would translate to an aggregate peak of 4.3 GW assuming a 50-50 single-/multi-family split. We assume such a breakdown in our analysis.
[9] Kavalec et al., *California Energy Demand 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency*, 2.
[10] Ibid., 39–41.
[11] We expect that the ability to offset growth with efficiency will become more difficult over time and that the SDEC load will resume a growth trajectory.

fleet could exacerbate the demand pressure on SDEC's infrastructure. We now turn to estimating the magnitude of this additional demand. Once the EV demand is estimated and its implications for the grid infrastructure are assessed, the balance of this report will analyze an array of methods SDEC can employ to attain the off-peak charging envisioned in the CEC scenario.

We know that 20% of the cars sold to date are charged using Level 2 chargers, and we assume that such cars draw 6.6 kW while the remaining cars draw power from ordinary (Level 1) outlets. However, we assume that the proportion of cars that draw 6.6kW (i.e., whose owners have Level 2 chargers) grows steadily.[12] We assume that in 2030, between 50% and 100% of the EVs in the fleet will be charged using Level 2 chargers. For the median 2030 projected fleet, 360K cars—if they all charged during the period of peak demand—would increase peak load by more than 50% over 2012 levels.

At an average battery capacity of 20 kWh and 85% efficiency, charging this fleet's batteries from a fully depleted state would require 8,500 MWh (360K EVs * 20 kWh/85%). However, it is extremely unlikely that the batteries would be completely discharged each day. A survey of EV owners showed commutes of 3–52 miles per day, with a median of 23 miles. At 3.5 miles/kWh, each EV will require 7.7 kWh of electricity to "top off" the battery at the end of the day in the median case. For the median 2030 fleet, median total energy needed to charge each day is 2,800 MWh.

3.3   Implications for Infrastructure

As mentioned above, maximum power draw from EVs is likely to occur during the times when load on the grid is already at its peak. Because the grid is sized for peak load, increasing peak demand will necessitate investing in grid infrastructure. The relationship between peak load growth and necessary infrastructure investment based on estimates provided by SDEC is shown in Figure 5.

We calculate the incremental increase in grid capacity required in each year based on our projections for the increase in peak demand for that year. The costs of this infrastructure expansion are calculated as follows. If cumulative load growth stays below 5% of 2012 levels, capacity addition is needed only for distribution assets and occurs at the marginal cost of expansion per megawatt. If growth exceeds 5% of 2012 capacity, both distribution and transmission are added. We assume these are newly built at the average cost of expansion per megawatt. Operations and maintenance (O&M) costs are calculated similarly. [13]

---

[12] See discussion of EV fleet trends, above.

[13] Average and marginal capital costs and O&M costs in dollars/MW of system peak are from Shirley, *Distribution System Cost Methodologies for Distributed Generation* and scaled for inflation.

3.4   Net Financial Impact

The increased infrastructure costs caused by EVs could be partially offset by additional revenue from the increase in electricity sales. We assume these sales take place at the prices observed during peak hours, with profit margin equal to 10% of the revenue.[14]

Our basis for comparing the different EV scenarios is net present cost (NPC). The cost in each year is the capital cost of new infrastructure built in that year as well as the cumulative O&M costs associated with all-new infrastructure built up to then. We subtract the profits from the additional sales of electricity to yield net cost for the year. We then calculate the present value of the net costs incurred annually from 2013 to 2030, discounting the cash flows at 5.5%.[15]

Based on these assumptions, the NPC is likely to vary between $0.3 billion and $2.0 billion, with a median value of $0.9 billion.

It is also interesting to ask how much of this cost is additional to a counterfactual in which no new EVs are sold. We model this scenario by setting the final penetration of electric vehicles to zero and re-running the simulation. This analysis indicates that the median cost of infrastructure build-out cost with cars is $540 million more than the median cost of infrastructure build-out without the cars.

> Assuming nothing is done to mitigate the impact of EVs on peak demand, the presence of EVs will increase the median net present cost of expanding the grid by $540 million between now and 2030.

4. Analysis of Mitigation Options

Having determined that EVs have a significant impact on the grid's peak load (and therefore significantly increase infrastructure investments required to keep the grid reliable), we now investigate several options for mitigating this impact.

4.1   Demand Response

In a Demand Response (DR) paradigm, variable pricing is implemented with prices during periods of peak demand set high enough to cause consumers to modify their behavior, deferring usage to non-peak hours. The main question for DR is, how responsive are customers to such programs? The DR study, conducted by SDEC, in which a treatment group was provided dynamic pricing and a control group paid a flat rate provides some insight.

---

[14] Our analysis is not sensitive to changes in this assumption.

[15] The coupon rate of utilities such as SDEC (e.g. Pacific Gas and Electric) is about 7.5%. We reduce our discount rate by the annual rate of inflation (2%) because our raw cost numbers do not account for inflation.

If the price was causing behavioral changes as intended, there would be a strong (negative) correlation between how much more (or less) the treatment group consumes, and how much less (or more) it pays for power.

To find out if such a correlation did exist, we calculated the t-statistic of the difference in the demand of the control and treatment groups for each hour of the trial. This t-statistic is a measure of how much more or less the treatment group is consuming compared to the control group. We then plotted this t-statistic against the difference in the price of electricity that the treatment group saw versus the $0.081/kWh flat rate paid by the control group in each hour. No clear correlation exists—indeed, the correlation (R^2) between the change in demand and change in price is very small at -0.07. (See Figure 6.)

Assuming that the cars are charged 300 days of the year, our simulation shows that the difference between the lowest and highest wholesale prices on any given day is log-normally distributed with 90% of the values lying between $0.01 per kWh and $0.23 per kWh and a median difference of $0.035 per kWh. Based on these differences, potential customer savings by price arbitrage are between $18 and $520 per year, with a median/mode of only $74/$23. These savings are meager relative to the cost of an electric vehicle (or, indeed, to the cost of installing a charger and smart meter) and would likely fail to produce the required change in customer behavior.

> We conclude that customer savings facilitated by a demand response program are unlikely to be substantial enough to precipitate a voluntary change in charging behavior.

4.2   Utility Controlled Charging

If it is not possible to use differential pricing to get customers to change their behavior, or to change it adequately, it might make sense for SDEC to directly control the charging of customers' EVs to reduce or eliminate the additional peak load imposed on the system by EV charging.

4.2.1   Feasibility for Peak-Shaving

We begin by asking whether it is possible to reduce the peak load imposed by electric vehicles from 5 p.m. to 8 p.m. and distribute it to off-peak hours (between 8pm and 6am) in such a way that the maximum demand during the overnight hours does not create a new daily peak. We do this by setting up a simple optimization problem, which we then solve using mathematical programming tools.

The objective is to minimize the total cost of electricity purchased during the nighttime hours[16] by selecting how much energy to draw from the grid to the EV batteries in each overnight hour. We adopt the following assumptions and constraints.

No charging can take place between 7 a.m. and 7 p.m., when the vehicles are away from home. The amount that any vehicle can draw from the grid in any hour is constrained to its charging rate of 1.5 kW or 6.6 kW for legacy and new cars, respectively. Thus, the total amount of energy that can be drawn from the grid in any hour is the aggregate charging rate of the EV fleet. The total demand imposed on the grid at night—by both vehicle and non-vehicle loads—must be less than the peak load experienced during the day, (6am to 8pm). This constraint is meant to ensure that the daily peak demand with electric vehicle charging is the same or lower than the peak demand without electric vehicles. The total energy supplied to the vehicle must exceed what is needed for it to complete its mission the following day. We assume that each vehicle drives 52 miles daily—at the high end of customer travel, which tests whether higher-demand cases can still be used for peak-shaving.
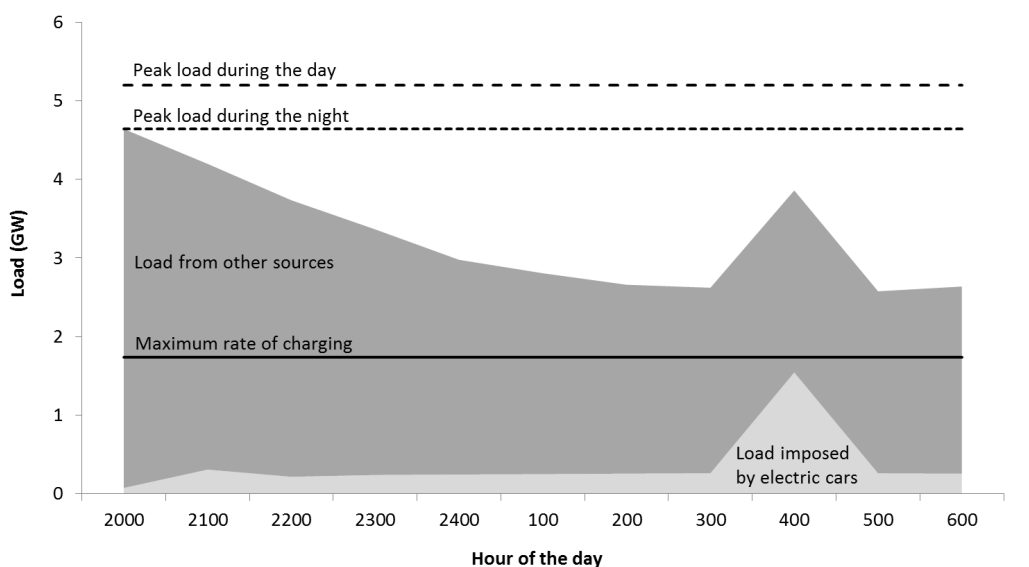
Figure 1: System load from EV and non-EV demand on a typical weeknight in 2030, when we assume that about 310,000 electric vehicles with 6.6kW chargers are operational. Vehicles are charging when wholesale rates are lowest.

Since there is likely to be 'organic' growth in peak demand each year, and the number of electric vehicles is also likely to grow each year, we solve this problem for each year from 2013 to 2030. Results for 2030, the year with the highest penetration of EVs, are shown in Figure 1.

---

[16] Hourly prices are average hourly prices in the dataset provided by SDEC.

We recognize that the solution represented by Figure 1 is static and is not, in fact, a realistic or optimal depiction of dynamic market behavior. In practice, the spike in demand at 4 a.m. would raise prices then, and the charging load would be more evenly distributed. Figure 1 does, however, show that even in 2030, the load from charging EVs can be distributed over the course of the night in such a way that it does not exceed the daytime peak in demand. Note that there is considerable margin to accommodate more electric vehicles.

4.2.2   Deployment Costs

Figure 1 suggests that, if we could control when electric vehicles charge, we could—at a minimum—ensure that they do not contribute to an increase in peak demand. We recognize that it is unlikely that all vehicle owners would agree to allow the utility to control the charging of their vehicles. Some customers might, for example, have privacy concerns. However, assuming that a sizeable fraction of new vehicle owners do agree to cede control of when their vehicles charge, we now calculate the cost of putting in place the infrastructure needed to implement this program.

First, we would only need to build as much new transmission and distribution infrastructure as was required by organic growth, as well as by electric vehicles whose owners do not allow us to control when the vehicles are charged. Non-participating vehicles are charged during peak hours, and additional grid capacity must be built to cater to them.

Smart meters must be installed at the residences of customers participating in the controlled charging program. However, SDEC has already installed smart meters for half of its customers. Assuming that customers who have smart meters installed are as likely as not to buy electric vehicles and let us control their charging, the expected number of new smart meters needed is half the number of new vehicles to be included in the controlled charging program. Each smart meter costs $350 to install but reduces the cost of reading by $3.50 per month.[17]

In order to ensure that the controlled charging manager has flexibility to determine when vehicles draw from the grid, it will be necessary for owners to have Level 2 chargers.[18] At this point, we assume that SDEC supplies these chargers at no cost to customers who do not

---

[17] Kuklos, "Summary of SDEC DR Pilot."

[18] Consider the case where a vehicle owner needs 6.6kWh of charge (23 miles at 3.5 miles per kWh). A level 1 charger would take about five of the 10 off-peak, after-office hours between 8pm and 6am that would be available for charging the vehicle, significantly reducing the program flexibility. A level 2 charger, on the other hand, would take just over an hour. This would make it possible to choose more precisely when each vehicle charges.

already have them[19] and to those who sign up to the controlled charge program. Providing these chargers will cost SDEC $1000 per customer.[20]

Installing smart meters for all of SDEC's commercial customers and 50% of its residential customers in 2009 required additional capital expenditure of $4.9 million for supporting infrastructure and resulted in IT O&M of over $1 million annually. We assume, conservatively, that a $5 million investment is made right away to support the controlled charging program, and that the program results in an additional $1 million annually in IT and data handling costs.

Finally, we assume that vehicles enrolled in the controlled charging program use electricity at off-peak prices,[21] and we account for additional sales made to these customers at those, lower, prices.

This analysis depends on all the parameters that were used in the business-as-usual case, and is therefore subject to the same uncertainties, as described in Table 3. We have, however, introduced two new uncertain variables in our estimate of the cost of the building the infrastructure and putting in place the equipment needed to support the smart charging program. These are described in Table 4.
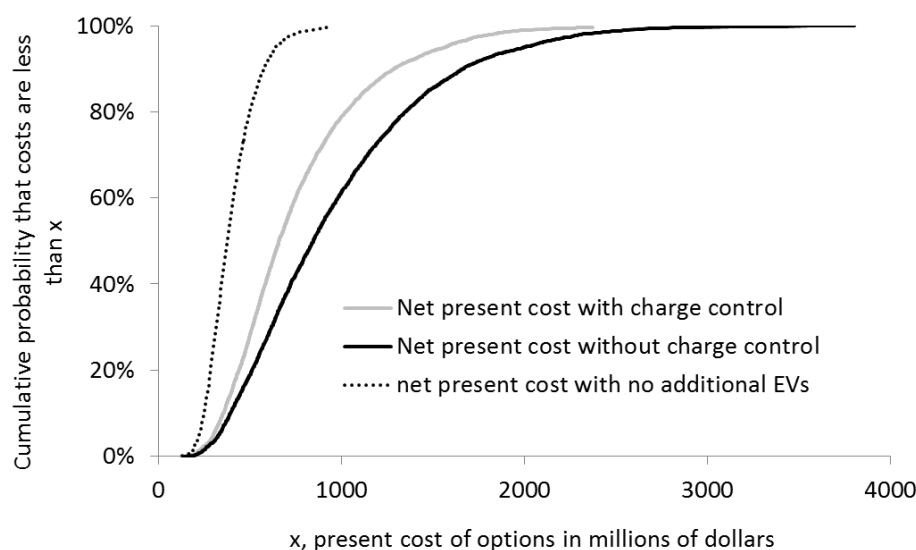
Figure 2: Effect of charge control on costs. More than 95% of the time, the net present cost of infrastructure build out is lower with charge control than it is without it. The median costs of the former are $190 million lower than the latter.

---

[19] If 20% of the existing 17,000 vehicle owners have Level 2 chargers, that means that 3,500 existing customers have Level 2 chargers.

[20] In practice, SDEC may be able to negotiate a bulk discount.

[21] Charging customers different prices for electricity use at different times of the day, though not common practice right now, is likely to become more prevalent in the future. Moreover, in our analysis, differential pricing is a conservative assumption; as it imposes a cost on the utility when it shifts customer demand from peak (high-price) to off-peak (low-price) periods.

However, this intervention has assumed that SDEC will supply EV owners who participate in the controlled charge program with Level 2 chargers and smart meters, and that it will invest in the necessary IT infrastructure to support controlled charge. This assumption raises the median cost of the controlled charge option by $280 million compared to the case where no additional EVs were sold.

The results (see Figure 2) of our analysis indicate that controlled charge would lower the median net present cost of supplying electricity to electric vehicle owners by about $320 million, even after accounting for our assumption that we bear the cost of providing Level 2 chargers and smart meters to those who participate in the scheme. Compared to the case where nothing is done to mitigate the peak load imposed by electric vehicles, this translates to a median saving of 0.9¢ per kWh, spread over all the power that participants in the scheme are likely to buy,[22] and 5¢ per kWh over the electricity they consume to charge their cars.

4.2.3   Equity Considerations

However, we do not believe that it is equitable to offer such a discount to EV owners—even those who agree to participate in the charge control scheme. As Figure 2 makes apparent, providing these customers with chargers and smart meters, and investing in the IT infrastructure required to support controlled charging raises our median net present cost by $210 million compared to the case when no additional electric vehicles were added to the system.

Unless we find a way of passing this cost back to the owners of the vehicles, these costs will be spread over all consumers of electricity. The effect will be small[23] but iniquitous, as it is effectively a subsidy to the comparatively well off-owners of electric vehicles from those who don't own or operate electric vehicles.

We calculate that charging participants in the program a flat rate of $75[24] per car per year would fully offset the cost incurred to provide the service. In return, the vehicle owners would receive a smart meter (which could potentially help them monitor and reduce other power consumption), and the free use of a Level 2 charger (which would allow them—if necessary—to charge their cars relatively quickly). SEDC would also help them lower their power bills by ensuring that charging took place during off-peak hours. Thus, a fee that would help SEDC recover its costs could reasonably be presented not as a "tax" on EV owners, but as the price of a valuable service.

---

[22] Based on the data provided us, we have assumed that, in addition to what they consume to charge their vehicles, EV owners consume an average of 1.19kWh of electricity every hour, 24 hours a day, 365 days a year.

[23] Charging would represent about 20% of the electricity use of those who have EVs, and such people are likely to be at most 30% of our customer base. As such, the implied subsidy to participants in the charge control program would be spread over a large base of electricity sales.

[24] This is a median value: our simulation indicates that it would be less than $430, 95% of the time.

Another way of recovering the costs of controlled charge would be to raise the price of electricity sold to customers who participate in the program by a median of 0.8¢ per kWh.[25] In return, customers would receive a free Level 2 charger, a free smart meter, and an assurance that—as far as possible—their cars would be charged at off-peak times and therefore at lower prices.

One way of incentivizing customers to join the controlled charge program is to ask customers who do not join to pay the full cost of expanding the infrastructure to cater to the peak load imposed upon the infrastructure by their vehicles. This cost would translate to a median charge of $190[26] per car per year, or 1.5¢ per kWh of electricity sold.

We recognize that this approach might drive some customers away. However, we are confident that as the penetration of electric vehicles increases, SDEC's competitors will be forced to charge similar fees. The additional revenue brought in by selling power for electric car charging simply does not make up for the cost of investing in the infrastructure needed to cater to such charging, and raising the prices for everyone to cater to the needs of (usually well-off) EV owners would be perceived as unfair.

For example, in the absence of a charge control program—where we assume that all charging takes place at peak times and at peak prices—the median additional cost of building the necessary infrastructure is $600 million against median net present value of revenues of $60 million.

In the charge control case, the $260 million needed to put in place the equipment and infrastructure needed for the program is offset only partially by the $53 million in additional sales.

Controlled charging is an effective way of ensuring that electric vehicles do not contribute to an increase in peak demand. To ensure that we recover the costs of expanding the network, we recommend that electric vehicle owners be charged $75 per year per vehicle if they take part in participate in the program and $190 if they do not.

4.3   Leveraging Controlled Charging + Storage

We have shown that it is possible to prevent an increase in peak demand by delaying EV charging. The effectiveness of this strategy opens the possibility of actually *reducing* existing peak demand by leveraging residual charge in EV batteries when they return home each day. That is, instead of simply delaying the charge, perhaps SDEC can actually continue to draw charge from EVs when they connect to the grid during peak hours, replenish-

---

[25] This is a median value: our simulation indicates that it would be less than 3.3¢ per kWh 95% of the time.

[26] Our simulation indicates that the cost will be less than $660 per car per year (or *5¢ per kWh!*) 95% of the time.

ing the batteries later in the night. The EV batteries would partially offset the customer's own household demand during peak periods, not feed power back into the grid.

To assess this possibility, we again construct an optimization model. The goal is to minimize the day's peak load (a minimax objective function) by choosing hourly charge or discharge rates for the EV battery fleet. We adopt the following assumptions and constraints for the optimization.

Average vehicle battery size is 20 kW. Vehicles are plugged in to the grid by 6 p.m. in a semi-depleted state after an average commute of 25 miles, and must be fully charged by 6 a.m. The EV batteries will not be discharged below 50% by the program. This constraint is to prevent the utility from draining EV batteries completely in case customers plan evening travel.[27] Batteries have an 80% round-trip efficiency and cannot be charged or discharged faster than their couplings allow (generally 6.6 kWh/h).

The optimization results show, unsurprisingly, that it is possible to reduce peak demand beyond the improvement achieved in the controlled charging case. EV batteries are discharged from 6 – 7 p.m. when load is high, and are recharged from 3 – 5 a.m. when the load is at its lowest. This load profile further reduces peak beyond the controlled charging case by 180 MW in 2020 and 210 MW in 2030. The median NPV of avoided costs of infrastructure improvements (beyond the gains already received from controlled charging) over the time horizon of interest is $80 million, with a 90% confidence interval of $50–135 million.

If passed on to customers, these median savings are worth an additional 0.2¢ per kWh beyond the charge control program allocated over their entire residential bill, or 1.0¢ allocated only to electricity used to charge the EV. This incentive is not large enough to make this more aggressive battery charge control program appealing to customers, who will bear additional costs of battery degradation and increased "range anxiety" unlikely to be balanced by this small savings obtained.

> We conclude that while supplying load from consumers EV batteries can provide an additional avoided infrastructure benefit to SDEC, passing these savings on to EV owners will not be enough of an incentive to ensure their participation.

4.4   Distributed Battery Storage

Distributed battery storage involves installing batteries at load centers or in distribution substations to either perform load shifting to reduce peak demand or to increase grid reliability.

---

[27] This program would also need to allow participants to occasionally opt-out in the event that a fuller battery is required for the evening trip.

4.4.1   Distributed Storage for Load Shifting

We show above that EV batteries can be effectively leveraged to supply peak-load electricity, reducing infrastructure demands on the grid, but that it is likely not possible to pass enough benefit to consumers to garner their participation in the program.   Perhaps the avoided infrastructure benefits can be obtained without the incentive problem by installing distributed battery storage systems from using Aqueous Ion Batteries (AIBs) to perform load shifting.

We can use a similar optimization model to that used above to determine the effect of such a system. The objective function is again to minimize the day's peak load. However, whereas EV batteries are available to the grid only between 6 p.m. and 6 a.m., dedicated batteries may be charged or discharged at any time during a 24-hour period. Thus, we expand the model to choose charge or discharge rates for the entire day.

The AIB available from American Electric Power has different characteristics than EV batteries, namely, a max charge/discharge rate dependent on battery size and equal to the amount of power required to charge the battery over a four-hour period.[28]   The amount of distributed storage available is constrained by footprint. From SDEC estimates, the maximum capacity that could be deployed to residential sites is 1,800 MWh (a maximum battery size of 4 kWh deployed to 25% of 1.8 million residential households. We note that this deployment scheme results in generally less battery capacity than would be available in most of the EV projections; in 2030, the projected aggregate EV battery size exceeds the maximum residential AIB capacity 70% of the time.   If the batteries were to be deployed at substations, the maximum installed capacity is much smaller: 430 MWh (2000 kWh at each of 214 substations).

Each residential AIB would have a maximum discharge rate of 1 kW based on the charging specification. Thus, the maximum aggregate hourly energy that can be released for peak reduction is 402 MW (taking into account battery efficiency). Installation costs for this residential deployment are $810 million.[29]

We run the optimization model to determine the avoided infrastructure cost due to peak-shaving from 2012-2030, as we did for the EV batteries. At most, the residential AIB system will decrease peak load by 402 MW. The avoided infrastructure costs of this decrease have a maximum NPV of $170 million, if the battery system is build immediately; this NPV decreases as the AIB deployment is delayed. Set against deployment costs of $810 million, $170 million in avoided costs from peak-shaving fall far short of the benefit needed to justify the system. A similar analysis for deployment of batteries at substations yields deployment costs of $180 million vs. avoided costs of $40 million—a similar result.

---

[28] Kabata, "Energy Storage for Load Control and Reliability."
[29] From Ibid., battery costs are $300/kWh and controls are $50/kWh in the most optimistic case, while enclosure costs are $100/kWh for residential installations. Thus, 1,800 MWh * $450K/MWh = $810 million.

Based on these results, we conclude that, while AIB distributed storage is effective at cutting peak demand, the financial outlay required to deploy the system is not offset by the savings received due to deferred infrastructure investment.

4.4.2   Distributed Storage for Service Reliability

While distributed storage is not likely to be the most effective means of load-shifting, another argument advanced for this system is increased service reliability, since battery power can step in during periodic service interruptions. We develop a framework for assessing whether it is reasonable to install electric batteries at residential customer locations to improve the reliability of the power supply. (Our framework can be extended to commercial customers as well.)

We start by making the following assumptions: customers consume 1.2 kWh per hour of energy, on average. The cost of storage is $300 per kWh (neglecting the costs of ancillary electronics). The battery is 80% efficient, there are no O&M costs, and the cost of the battery can be amortized over 10 years at a discount rate of 10% per year.

We then calculate how much customers would have to value each kilowatt of power lost for them to choose an electric battery as a back-up source in Table 1.

Table 1: How much would customers have to value each kilowatt of power lost for them to choose an electric battery as a back-up source?

Outage (seconds)	Energy lost (kWh)[30]	Cost of storage[31]	Annualized cost of storage[32]	Annual frequency (events / year)	Annual expected loss (kWh)[33]	Implied value per kWh[34]
1	0.0003	$0	$0	7.06	0.00	$9
30	0.01	$4	$1	2.35	0.02	$26
1,800	0.6	$220	$40	1.60	0.95	$38
21,600	7.1	$2,700	$440	0.52	3.71	$120
108,000	36	$13,000	$2,200	0.28	9.83	$220
172,800	57	$21,000	$3,500	0.09	5.03	$690

Even this crude analysis indicates that, for long power outages, battery storage is not an attractive option. We also do not foresee homeowners investing in battery storage to mit-

---

[30] Duration of outage times average power consumption (1.2kWh per hour)
[31] Energy lost in kWh times the capital cost of the battery ($300 per kWh) divided by its efficiency (80%)
[32] Calculated using the payment function in Excel, assuming a present value equal to the cost of storage, 10 year amortization period, and 10% discount rate
[33] Based on the provided frequency of outages of different sizes, average energy loss associated with each outage.
[34] Calculated by dividing annual expected loss by annualized cost of storage

igate the effects of very short disruptions (which they may not even notice) or even moderately long disruptions (which are quite rare).

Note that in Table 1 the value per kWh of energy stored is, in fact, independent of what we assume about the average consumption rate of the customer. We therefore believe that this value is also relevant to commercial and industrial customers. Such customers might find battery storage a valuable way of mitigating the effects of power cuts that are too short for other sources of backup (e.g., diesel generators) to kick in, but which are likely to damage to sensitive equipment or disrupt sensitive processes.

In summary, we believe that batteries are not a cost-effective way of mitigating the effects of long interruptions in power supply for anybody. Such disruptions are better dealt with using diesel or gas back-up generators. Residential customers are not likely to invest in battery backup to mitigate the effects of short or moderate interruptions. Such a service would only be of value to users of sensitive equipment, who might be willing to purchase these systems to cover short disruptions in power or the first few minutes of a longer interruption, before switching to conventional sources of backup power.

We recognize that batteries might have a role to play in compensating for fluctuations in the supply of energy from renewable sources such as wind and solar, which are likely to form an increasingly significant part of California's generation mix during the period under consideration.

5. Other Alternatives

We have assumed that any charge control service would require smart meters and a back-end infrastructure to actively and centrally control the charging of the cars to ensure that they do not contribute to a significant increase in peak demand for electricity.

However, one can imagine a decentralized approach that achieves this, assuming that the required equipment was in place. The charger on the car, or a device that is connected in between the car and the charging outlet, could 'listen' to the frequency of the power being transmitted. While this frequency is tightly controlled, it falls to the lower end of this control band when the load on the grid is high and rises to the upper end when the load is low. As such, the charger would "know" what the load on the grid is, and could be programmed to charge only when it is low. The charger could be designed to ramp up its draw on the grid in inverse proportion to the existing load. Users could be given the option of overriding this option when they need a quick charge urgently.

While it is conceptually easy to understand how one charger could respond to changes in frequency, it would require considerably more analysis to work out the techno-economics of such an approach when it is applied to tens of thousands of vehicles. What we can do is work out the size of the prize. In our model, the median net cost of the infrastructure

(chargers, smart meters, IT and data handling costs, less the gains from not having to read meters) is $130 million. In 5% of our simulation runs, it exceeded $450 million. We recognize that it is not possible to offset all of these costs. However, it does tell us that there is significant potential to save money if a simpler, decentralized solution could be found.

We have also assumed that users will continue to charge their cars at home. However, standard electrical outlets will take several hours to charge vehicles. Even 6.6kW chargers will take about an hour to supply enough energy for a typical day's driving. While early adopters are likely to view this as acceptable, later adopters—who are used to adding hundreds of miles of driving range to their gasoline vehicles in a few minutes—are likely to insist on faster alternatives.

Battery swap services, which exchange depleted batteries for fully charged ones in a few minutes, are likely to be one such alternative. As such, it is possible that such businesses—and not end users—might be our customers. Dealing with them might require a very different approach than the one outlined above. For one, they are likely to be much more sensitive than end users to the price at which power is supplied. They are also likely to represent a much larger and concentrated load, and use electricity for mainly one thing. This would make it possible to size the supply infrastructure needed for them more precisely, and also design tariffs more precisely.

6. Recommendations

Based on our analysis, if nothing is done to manage the charging of electric vehicles, the infrastructure required to support them will cost between $300 million and $2 billion.

❖ Data so far indicate that differential pricing is unlikely to provide a large enough incentive for customers to voluntarily postpone charging their EVs to off-peak hours. **We advise that a demand response program will likely not deliver the desired gains.**

❖ To ensure that vehicle charging is actually shifted to off-peak hours, **we recommend that SDEC consider investing in the infrastructure and equipment needed to actively control the charging pattern of EVs in its area.** Doing so will reduce long term investment costs by $320 million in the median case.

  However, such a program will still require an investment in $210 million over and above what would have been needed in the absence of electric vehicles. We believe that this cost, which will likely amount to less than $100 per year per vehicle, should be borne directly by EV users.

❖ Our analysis of the use of EV batteries to partially offset organic growth in peak demand suggests that the resultant savings are unlikely to be large enough to en-

tice EV owners to provide SDEC access to their vehicle batteries. Therefore, **we do not recommend pursuing a program that taps EV batteries to help meet peak demand**.

❖ Similarly, the use of standalone batteries will likely reduce investment required in new transmission and distribution infrastructure, but by an amount that is significantly lower than the capital costs of the batteries themselves. **We do not believe that standalone batteries are an attractive way to reduce peak demand.**

❖ Other options for grid integration will likely become available as the "EV ecosystem" matures.

The details of how electric vehicle users are charged for the services provided to them will require further analysis. However, it is clear that EV charging represents a growth in peak demand that is different from organic growth and potentially very expensive to accommodate. **It is important to set an expectation that EV users must pay for the infrastructure to meet this demand; that it is not "free."**

References

CEC. *California Energy Demand 2012-2022 Final Forecast*, May 2012.
http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SF-
V1.pdf.

Foss, Rodrigo. SDEC Internal Memo to Tamara Fenton. "Electric Vehicle Information." SDEC Internal
Memo to Tamara Fenton, March 2013.

Kabata, Mike. SDEC Internal Memo to Tamara Fenton. "Energy Storage for Load Control and Reli-
ability." SDEC Internal Memo to Tamara Fenton, March 2013.

Kavalec, Chris, Nicholas Fugate, Tom Gorin, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Glen
Sharp, and Kate Sullivan. *California Energy Demand 2012-2022 Final Forecast Volume 1:
Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency*.
California Energy Commission, Electricity Supply Analysis Division, June 2012.
http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-
V1.pdf.

Kuklos, James. SDEC Internal Memo to Tamara Fenton. "Summary of SDEC DR Pilot." SDEC Internal
Memo to Tamara Fenton, March 2013.

Saxton, Tom. "Understanding Electric Vehicle Charging." *Plug In America*, January 31, 2011.
http://www.pluginamerica.org/drivers-seat/understanding-electric-vehicle-charging.

Shirley, Wayne. *Distribution System Cost Methodologies for Distributed Generation*. Gardiner, ME:
Regulatory Assistance Project, September 2001.
http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGenerati
on_2001_09.pdf.

US DoE. "Table 8.5: Household Vehicle Ownership, 1960–2010 Census," 2012.
http://cta.ornl.gov/data/tedb31/Spreadsheets/Table8_05.xls.

Appendix A: Additional Figures and Tables
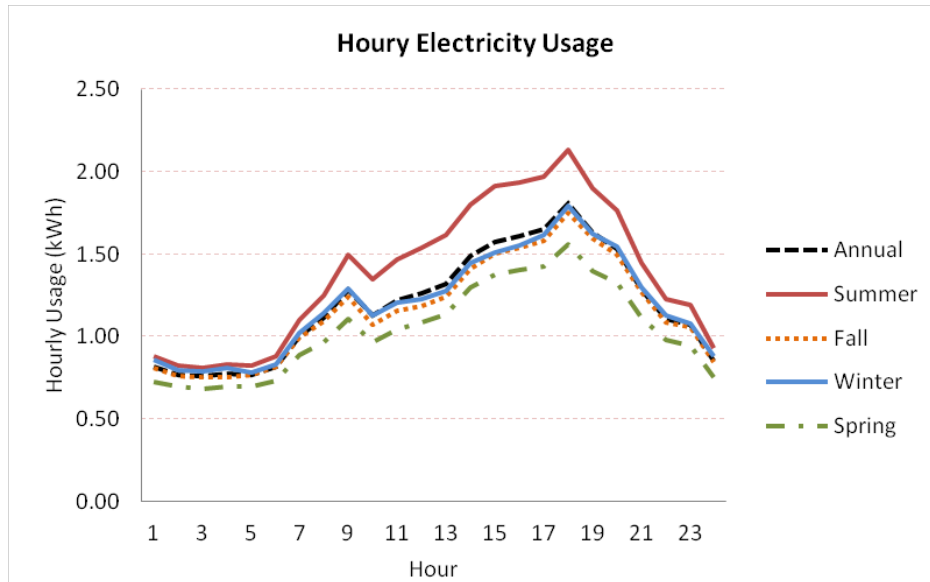
Figure 3: Average daily electricity use by hour, single family homes October 2011-September 2012. Peak usage is at 6:00 p.m., and summer usage is significantly higher than during the rest of the year.

Table 2: Average daily electricity use by hour by season, single family homes October 2011-September 2012. Peak usage occurs in the 5-6 p.m. hour (18:00, bolded).

Hr.	Annual (Jan-Dec)	Summer (Jun-Aug)	Fall (Sep-Nov)	Winter (Dec-Feb)	Spring (Mar-May)	Hr.	Annual (Jan-Dec)	Summer (Jun-Aug)	Fall (Sep-Nov)	Winter (Dec-Feb)	Spring (Mar-May)
1	0.82	0.88	0.81	0.86	0.72	13	1.32	1.62	1.24	1.28	1.13
2	0.77	0.82	0.76	0.79	0.70	14	1.49	1.80	1.41	1.45	1.30
3	0.76	0.81	0.76	0.79	0.69	15	1.58	1.91	1.50	1.51	1.38
4	0.77	0.83	0.76	0.81	0.70	16	1.61	1.93	1.54	1.56	1.40
5	0.77	0.83	0.77	0.78	0.70	17	1.65	1.97	1.58	1.62	1.43
6	0.82	0.88	0.82	0.83	0.73	**18**	**1.81**	**2.13**	**1.75**	**1.79**	**1.56**
7	1.00	1.10	1.00	1.02	0.89	19	1.63	1.90	1.60	1.62	1.40
8	1.11	1.25	1.09	1.14	0.97	20	1.54	1.77	1.50	1.55	1.33
9	1.28	1.50	1.24	1.29	1.11	21	1.28	1.45	1.27	1.30	1.12
10	1.13	1.35	1.07	1.13	0.97	22	1.11	1.23	1.09	1.13	0.98
11	1.22	1.47	1.16	1.20	1.05	23	1.07	1.19	1.06	1.08	0.95
12	1.26	1.54	1.19	1.23	1.09	0	0.85	0.93	0.84	0.88	0.75
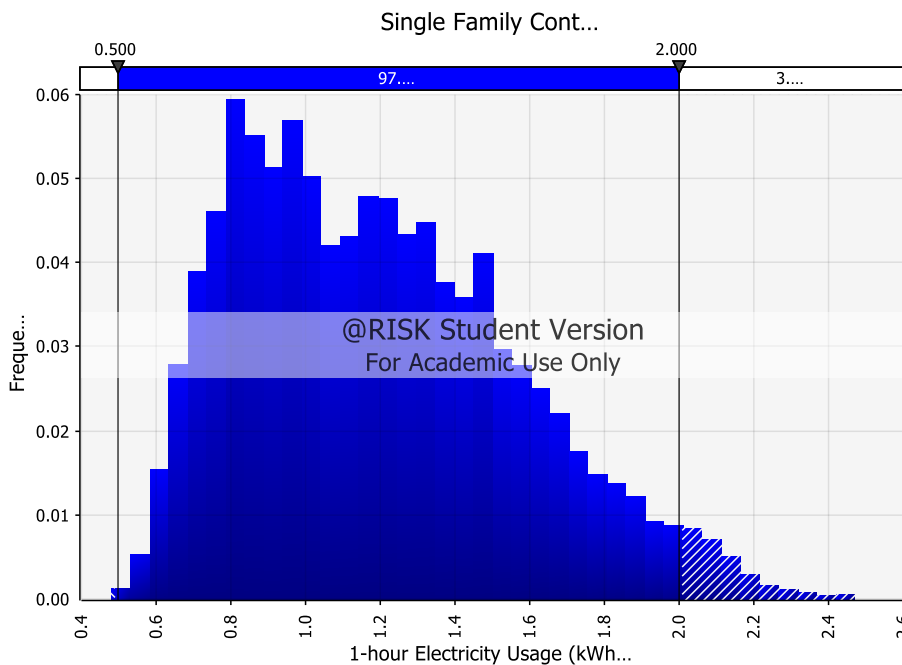
Single Family Cont...

Figure 4: PDF of hourly electricity usage for single-family homes without EVs and without demand-response programs, October 2011-September 2012. The absolute peak demand is 2.5 kWh/h. Usage exceeds 2.0 kWh/h 3% of the year.
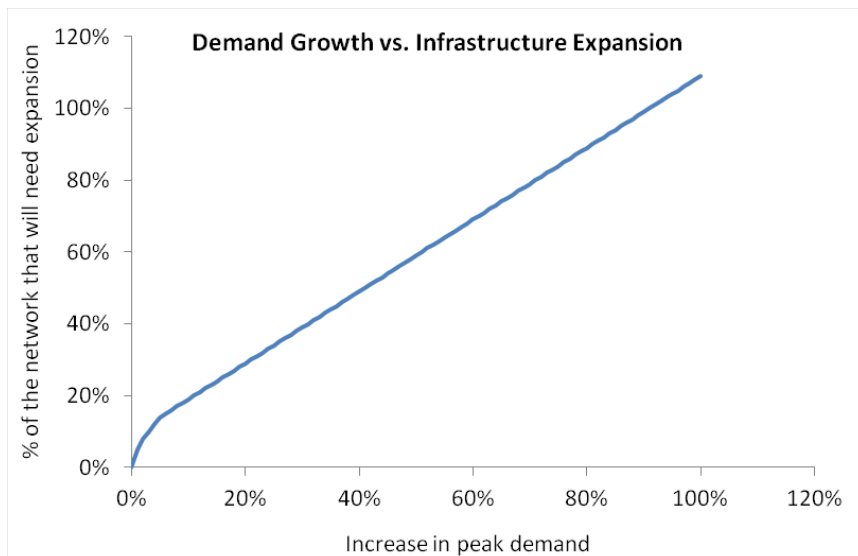
Figure 5: Assumed relationship between increase in peak demand over current levels and the percentage of the work that will need expansion. Curve is based on figures provided by SDEC, in which early growth requires heavier investment, while later investment grows proportionally with growth.
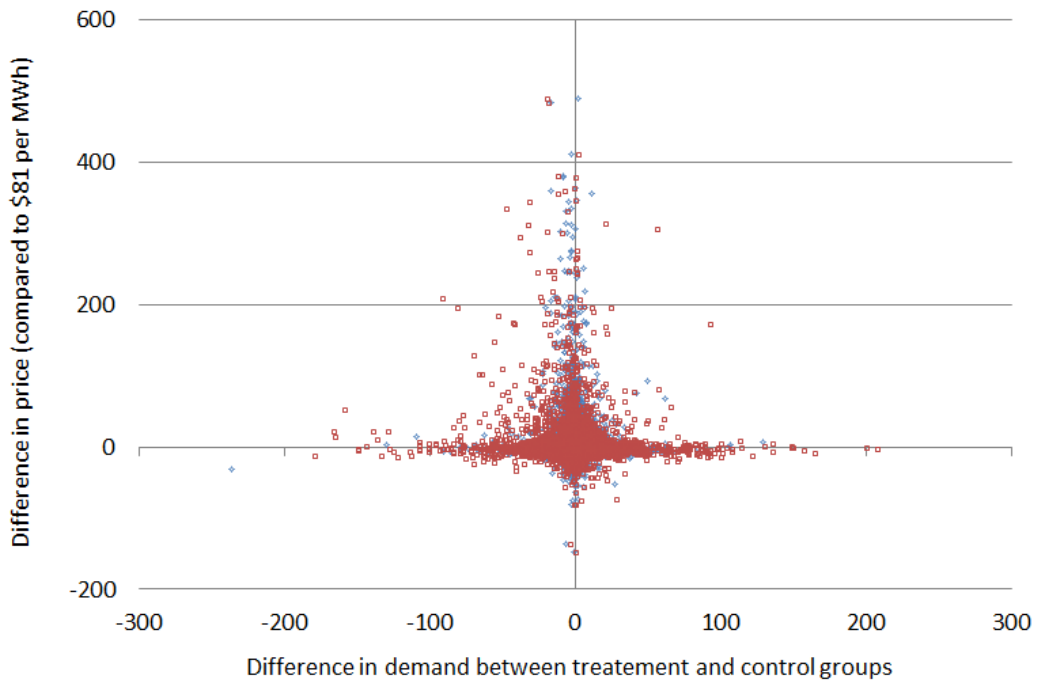
Figure 6: Change in price vs. change in demand for treatment and control groups of the DR study. Each dot represents data for an hour of the six-month trial. $R^2 = -0.07$.

Appendix B: Model Definitions and Inputs

Table 3: Model Parameter Values and Distributions for base case

Variable	Most likely value	Min value	Max value	Distribution / Notes
Discount rate	5.5%	N/A	N/A	Combined inflation/discount rate. 7.5% coupon rate for public utility example (PG&E), less 2% for annual inflation.
Annual increase in peak demand	1.5%/yr.	0%/yr.	2% / yr.	Triangular, based on CEC, California Energy Demand 2012-2022 Final Forecast, 2, which estimates 1-2%. SDEC recent growth is 0% due to efficiency gains.
Number of cars per household	2	1	3	Discrete: we assume that 10% of households have no cars, 30% of have one cars, 40% have two cars, and 20% have three cars. US DoE, "Table 8.5: Household Vehicle Ownership, 1960–2010 Census."
Mileage driven per day per EV	23	3	52	Triangular, from Foss, "Electric Vehicle Information."
Final penetration	10%	1%	30%	Uniform for final penetration, and
What fraction of the difference between current and final number of cars is sold each year	10%	5%	25%	Triangular for the rate at which this level of penetration is approached. We have no information about what the final penetration will be, and use these parameters as we expect them to generate a wide, but plausible, range of values.
Vehicle battery size	20 kWh			Average based on sales trend. Any increases in battery size are treated as endogenous to EV fleet size and included in that uncertainty.
Increase in capital and O&M costs of infrastructure compared to 1995-99	20%	15%	50%	Based on data in the problem, but recognizing that increases are more likely to be greater than 20% than less.
Price of peak-time electricity	$0.08 per kWh	$0.07/kWh		Lognormally distributed, with a mean of $0.13 per kWh. Distribution obtained by fitting data given in the problem
Proportion of users with 6.6 kW chargers in 2030	100%	50%	100%	20% of users already have Level 2 (6.6 kW) chargers and most new cars are capable of charging at this rate. This provides a strong incentive for users to buy Level 2 chargers, which can charge 5x faster than ordinary sockets.

Table 4: Uncertainty in additional variables required to calculate the costs and benefits of controlled charging

Variable	Most likely value	Min value	Max value	Distribution / Notes
Price of off-peak electricity	$0.07 per kWh			Fitted extreme value min distribution to given data. Mean price of $0.07 per kWh
Proportion of new cars which do not agree to charge control	10%	0%	50%	SDEC bears the upfront cost of the equipment needed to support controlled charging. SDEC would also charge a larger EV fee for those who do not participate.