



Center for Entrepreneurship & Technology
University of California, Berkeley

Impact of Widespread Electric Vehicle Adoption on the Electrical Utility Business – Threats and Opportunities

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Abstract

There is a valid concern about the U.S. electric grid's ability to absorb electric vehicles (EVs) into its already-stressed system. With aging existing power plants, population growth, an ever-growing reliance on electronics, and a wariness of building new plants, the nation's utilities are already heavily taxed and may be hard-pressed to absorb more demand by supporting EVs.

It is widely agreed that the timing of EV battery charging will determine the grid's ability to power EVs. This document explores the various considerations of EV charging in detail. Threats such as emerging federal and state policies, renewable energies challenges and human capital concerns are explained in-depth (and supported by various research and testing models), as well as opportunities such as valley filling and Vehicle-to-Grid. Also included within this document is an overview of various existing and emerging business models, providing examples of how traditional industry leaders can quickly adapt to remain ahead of the competition, and identifying new opportunities on which businesses can capitalize.

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Introduction

Most Americans take for granted that upon returning home from work, their air conditioning will be cold, their iPods will be ready to get them through a workout, their computers will operate, and their Blackberries will function and tether them to the office. Power generation makes all of these assumptions possible and its reliability is presumed as a given in the U.S.

As the nation is alerted to the threat of climate change and the geopolitical realities of being dependent upon foreign oil, the scientific community is converging around the idea that electrifying the transportation sector will help address these concerns. Most engineers agree that this transportation direction is the most feasible scientific means of reducing our nation's dependency on oil; yet there is widespread concern about the utility sector's current ability to meet the increased demand for power that this shift will necessitate.

For the past few decades, electric vehicles (EVs) have always been on a distant horizon, visible, but constantly out of reach due to a variety of obstacles. However, momentum for making EVs a reality has seemingly reached a tipping point over the past few years, culminating with the election of the Obama administration. The main drivers behind this change are the following:

- Anthropogenic climate change due to carbon dioxide (CO₂) emission. The causal correlation between CO₂ emission and global warming is now widely accepted by a solid majority of the scientific community.¹
- The 2008 oil shock.
- The 2009 economic crisis, and as a result the collapse of Detroit and the need to make a drastic change in the automotive industry.
- The allocation of \$2.4B to electric vehicles in the 2009 stimulus package, which includes the manufacturing of advanced batteries and related drive components, and transportation electrification demonstration and deployment projects.²
- The convergence of EV technological advances (i.e., batteries, grid infrastructure).
- A revitalized push by auto manufacturers driven by both “sticks” such as higher oil prices and government regulations, and “carrots” like brand approval.³
- A supportive regulatory environment. For example, in 2009, the California Air Resources Board adopted a regulation to implement Governor Schwarzenegger's Low Carbon Fuel Standard, calling for the reduction of greenhouse gas (GHG) emissions from California's transportation fuels by ten percent by 2020.⁴ The new regulation will diversify the variety of fuels used for transportation; boost the market for alternative fuel vehicles; and achieve 16 million metric tons of greenhouse gas emission reductions by 2020. The standard is expected to drive the availability of plug-in hybrid, battery electric and fuel-cell powered cars while promoting investment in electric and hydrogen fueling stations.

The purpose of this paper is to investigate the impact of electrical vehicles (EVs) on America's utility industry. The authors began by analyzing the current state of America's electricity generation and

transmission capacity, and then modeled the effect of adding EVs to the grid using California as an example. Threats, opportunities and existing and emerging business models are also studied in depth, all with the goal of making EV adoption and ongoing support by the U.S. electrical grid a reality.

Part A: Threats

This section explores the challenges with power generation first in today's global environment, and then in a world with widespread EV adoption.

1. Current Mix of Power Generation Inputs

The current mix of power generation resources in the U.S. depends heavily on fossil fuels and other pollution-producing supplies. EVs offer the benefits of lowering the cost to drive, reducing oil dependence, and, of course, minimizing greenhouse gas emissions (GHGs). Accordingly, it is important that Americans do not substitute emissions from the tailpipe of the vehicle with increased emissions in power generation.

Currently, only 28% of U.S. production capabilities is derived from non- CO₂-emitting resources (see Figure A-1). A major cause of this fact is cost: CO₂-emitting resources cost anywhere from \$60 to \$120 per MWh compared to renewables that range from \$70 per MWh for the most efficient wind farms and up to \$400 per MWh for solar photovoltaics (and this does not include the transmission costs for adding these resources to the grid).⁵

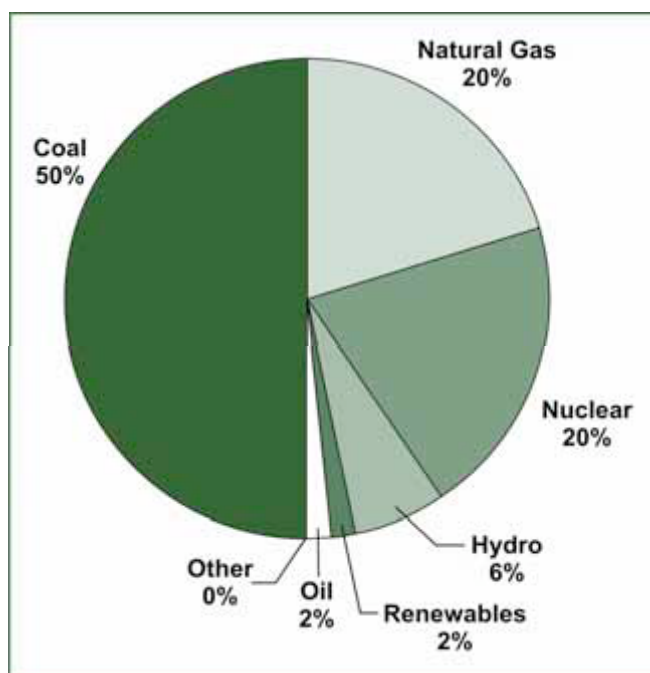


Figure A-1: Electricity resources mix in the United States.⁶

Another factor hindering renewables usage is their low capacity factors—i.e., the percentage of each year that a plant is producing power (see Figure A-2). Because large-scale energy storage is currently difficult, power plants must produce a minimum level of electricity every minute to ensure reliability.

Since most renewables are dependent upon either the sun shining or the wind blowing, they sit idle for large portions of the day, making them unreliable for base power production. As such, the U.S. will struggle to commercialize renewable energy on a large scale until the cost per MWh for renewables becomes comparable to fossil fuel sources, and a reliable mass storage system is established.

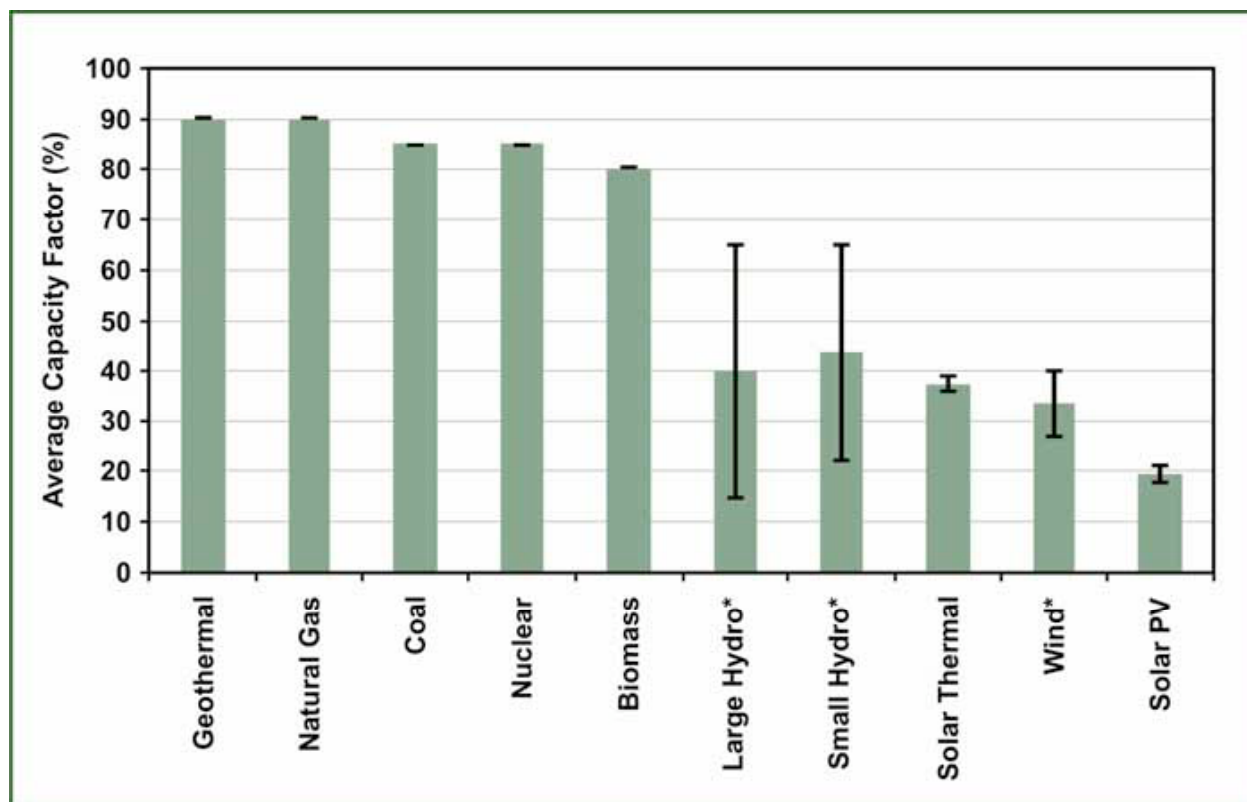


Figure A-2: Average capacity factor of conventional and renewable energy resources in the Western Electricity Coordinating Council.⁷

2. Current Generation Capacity

The rate at which additional generation is being added to the grid has declined each decade since the 1970s, while the capacity generation of these existing facilities has declined at twice that rate (the plants are aging as many were built during the 1950s and 1960s). Yet electricity consumption has increased nationally by more than 15% from 1998 to 2007.

The North American Electric Reliability Corporation (NERC) estimates a peak summer load growth of 16.6% over the next 10 years and notes in its *2008 Long-Term Reliability Assessment* (LTRA) report that some geographic areas, specifically the Desert Southwest Region, face potentially inadequate generation-resource margins to meet growing peak load conditions in the near term (see Figure A-3). Existing projections for power demand growth in future decades vary widely because of unknowns such as the effectiveness of energy efficiency programs, power requirements of future

technologies, and population trends. Further, the ability of utilities to meet these demands fluctuates significantly by region so it is difficult to make a sweeping assumption about how much additional national capacity should be added to the grid. But one thing is agreed upon: even without EVs, the U.S. will need to add generation capacity to replace failing facilities and meet demand increases due to a growing population and a world that is becoming more dependent on electronics by the day.

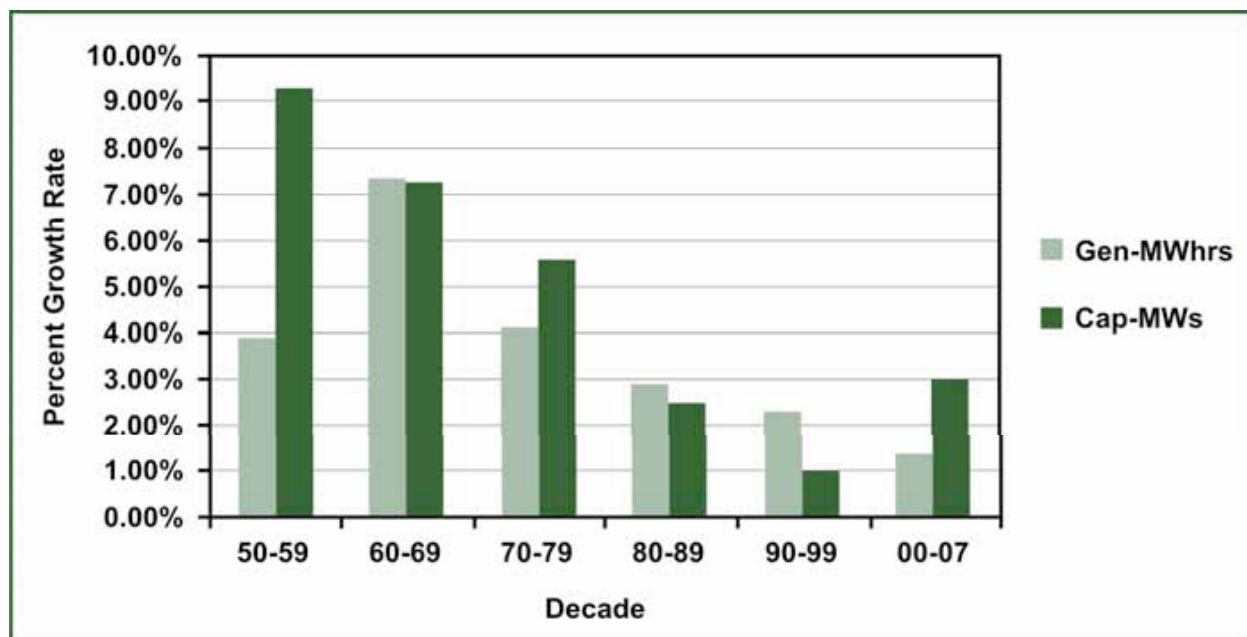


Figure A-3: Energy and capacity growth rates.⁸

Despite the clear evidence that more power generation plants are needed, two primary concerns are hindering efforts to build them: an unsettled regulatory environment and a ‘not in my backyard’ mentality. For example, the government may implement a regulation to tax carbon, so firms are wary of investing in new coal-fired plants without being able to forecast what that tax will cost. And individuals, communities and activist groups protest the various options of additional power generation: new nuclear facilities because of the potential biohazard; hydro dams because of the regional environmental impact; coal and natural gas plants because of their effect on global warming; and wind farms due to general unattractiveness.

Hence, a conundrum: the U.S. demands inexpensive and increasingly more power to support the digital age that current facilities cannot sustain indefinitely—yet its citizens do not want that energy produced near their homes. While efficiency gains will help, even the most optimistic assessments still require new generation capacity. As evidenced earlier, utilities are unable to meet these demands by renewable energy alone unless a major technology advance is achieved. As a result, society will need to find a compromise—and soon.

3. Challenges with Human Capital in Utilities

The construction of the United States' bulk power system was hailed by the National Academy of Engineering as the greatest engineering achievement of the 20th century. However, once the system was built, entering the utility engineering field did not have the cache of other professions, so classes and research and development (R&D) spending by universities in this space dwindled over the last quarter of a century.

In terms of human capital needed to meet upcoming power challenges, the country is ill prepared. More than 50% of current utility workers are eligible for retirement by the year 2010. The enrollment by undergraduate students in power systems engineering programs in the U.S. has dropped and is not improving, primarily because the number of power system programs at universities is also declining. Power engineering faculty in the United States is growing older, with the average age of the professoriate creeping upward and the number of years remaining in their professional lives rapidly decreasing. And the number of faculty retirements is outpacing the number of faculty additions.⁹ However, this trend is now gradually seeing some signs of reversal, with new interest in the field and an increase in the number of students at the graduate level.¹⁰

4. Challenges with Transmission and Distribution

The transmission and distribution grid today serves a critical role in delivering electricity from generation sites to population centers throughout the country. The state of the grid directly influences the quality and reliability of delivered power, and the current state of the national grid is strained. Its design and evolution were not intended to meet the demands currently placed on it.

According to the DOE (Department of Energy), of 108 transmission lines studied in the Western Interconnection alone, 37 reached levels of congestion at least once during the year studied and 18 were congested at least 10% of the time. Congestion levels in the Eastern Interconnection were generally more severe, considering the infrastructure was not developed with long distance transmission in mind. As such, generation resources within this interconnection cannot be effectively shared across the entire region.¹¹

The national grid consists of a patchwork of utilities and operators; as such, authority for making effective and comprehensive changes is diffused and complicated. Yet as grid infrastructure ages and demand steadily increases, new measures simply must be taken to protect ubiquitous access to reliable, economically-priced electricity. New development and innovation in the grid are also needed to utilize renewable energy resources and to reduce congestion, which cost consumers hundreds of millions of dollars annually. We must also consider the effect of growing EV adoption rates, which have the potential to greatly increase peak loading of the grid, further exacerbating the problem. As this report will illustrate, EV load management will have a significant impact on electrical grid strain.

5. Current Trends and Obstacles in Transmission Development

Evolving from independent, vertically integrated utilities, the national grid is divided into three discreet regions with limited interconnectivity: the East and West Interconnections and the Electric Reliability Council of Texas (ERCOT). Transmission lines were developed to allow neighboring utilities to buy and sell wholesale electricity, reduce their required installed capacity, and improve reliability. The system evolved with little national planning and high regional dependence. As such, the grid today is prone to congestion losses and is ill-equipped to meet the projected electricity needs of the nation. While innovation and development are clearly necessary, many additional obstacles still remain.

Currently, long-term planning for regional interconnectivity is inadequate. Because the grid is composed of nearly 3,000 regional distribution utilities and 500 transmission operators, the responsibilities of planning, cost allocation, ownership and operation is in question. This matter is further complicated by the myriad of local municipalities, states and federal agencies—all of which must issue permits for new transmission construction.

Permitting alone has the potential to add extensively to the time necessary for construction, as is exemplified by the American Electric Power Jacksons Ferry, Wyoming high voltage transmission line. The project took 16 years to complete, nearly 14 of which were spent waiting to obtain all the necessary permits from the states and federal agencies involved.

New transmission projects can reach up to billions of dollars in cost, and without clear cost allocation policies, projects can remain stalled in the planning stage for years. Coupled with cost allocation is the uncertainty of cost recovery for transmission investments. In order to attract the required investment for new transmission development, plans for timely investment recovery are also necessary. National leadership can help ensure that large-scale transmission projects, especially those spanning multiple recovery time objectives (RTOs), can be financed.

Due to the aforementioned obstacles and uncertain landscape, investment in transmission has steadily fallen over the past several decades, as evidenced by Figure A-4. However, as demand continues to rise, maximum transmission capacity could be exceeded within five to 10 years, according to NERC's 2008 *Long Term Reliability Assessment*. With high adoption rates of EVs, the time until demand exceeds capacity will likely be shortened, making new transmission development an urgent priority (Figure A-5).

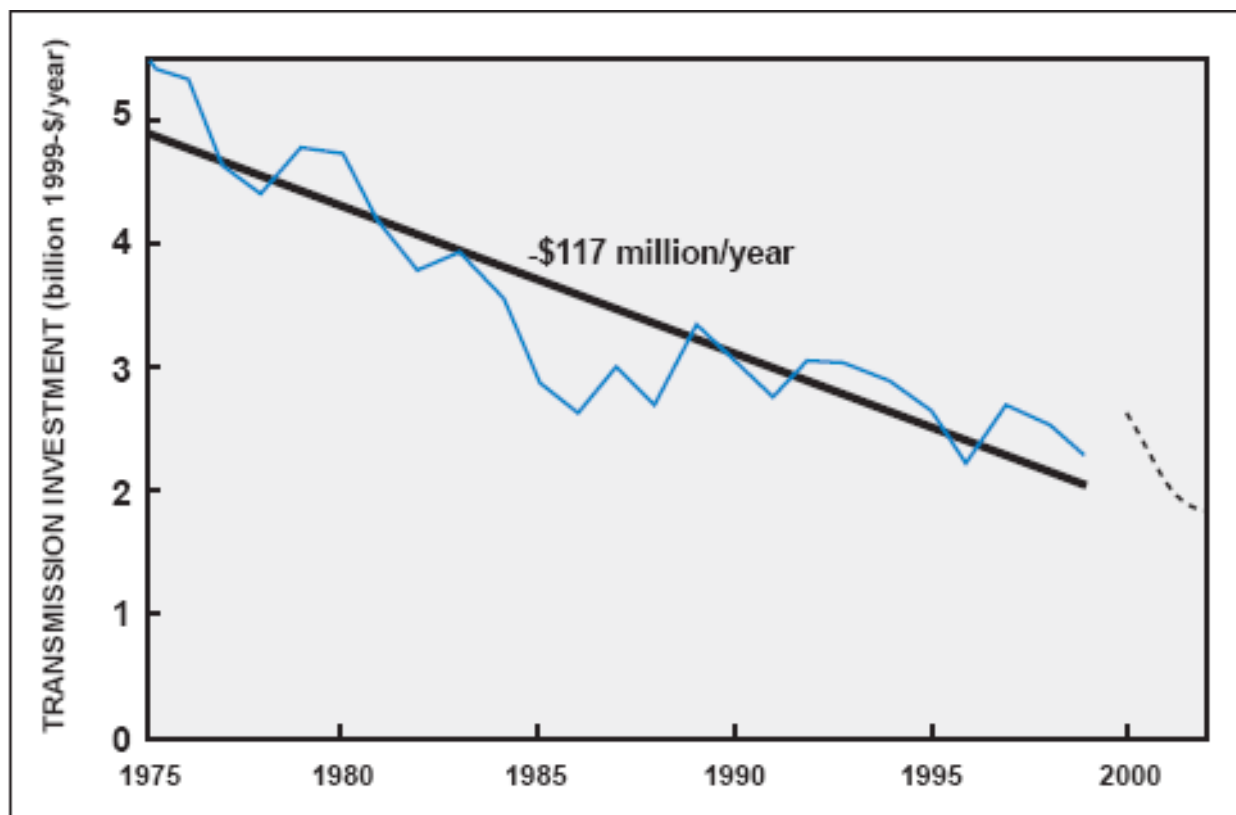


Figure A-4: Transmission investment over time.¹²

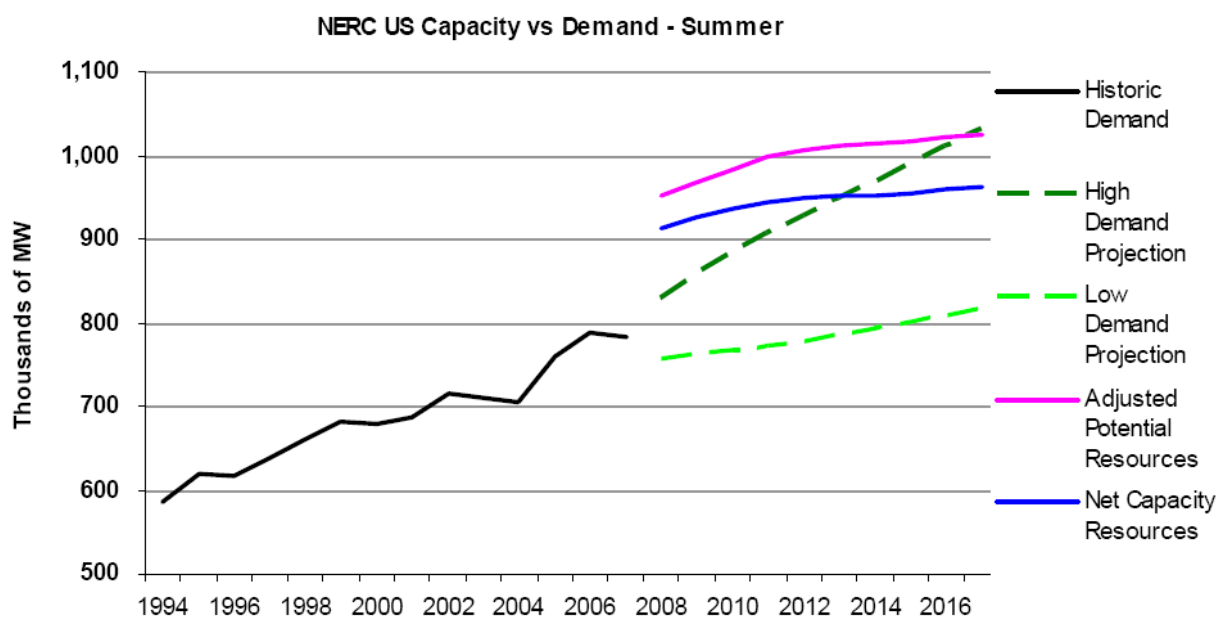


Figure A-5: NERC-projected demand versus capacity.¹³

6. Modeling Load Profile with EV Adoption: Assumptions and Boundaries

Due to the temporal variability of electricity demand throughout the day and across different seasons, the impact of EV loads on peak demand depends highly upon the charging scenario. In order to assess this impact on the grid, a simplified model was constructed. For the model's purpose, it considers only the generation and transmission capacity of the state of California defined from the CAISO CAMX (California Independent System Operator for the California-Mexico Power Area) region.

CAISO CAMX accounts for 80% of the power load within the state, and it is expected that most EV users in California would receive their electricity from this sub-region of the grid. Vehicle consumption rates are taken directly from the published PNNL (Pacific Northwest National Laboratory)¹⁴ study. These rates vary over each vehicle model types from compact sedans (0.26 kWh/mile) to full-sized SUVs (0.46 kWh/mile). For this model, an average value of 0.35 kilowatt-hours per mile was used; however, this value could vary depending on the actual composition of the EV fleet. The sensitivity to this parameter on the resulting load is not examined.

Unlike the plug-in hybrid electric vehicles (PHEVs) used in the PNNL study, EVs rely entirely on electricity to charge their batteries. As such, the grid must be capable of delivering this power to EVs even on the most congested days. For this reason, the base demand profile is based on the NERC 2008 summer peak data. This serves as the limiting case for EV adoption under the current grid constraints. The per-vehicle load is assumed to be a constant 3.3 kW (220V at 15A) for the duration necessary to fill the battery. Daily distance traveled is taken to be the national average of 33 miles. From the above figures, the average duration of charging can be determined. Charging behavior is disaggregated into four separate scenarios described in Sections 6.1, 6.2 and 6.3.

The purpose of this model is to determine a level of EV adoption that will necessitate a comprehensive load management scheme without exceeding current peak capacity.

6.1. Unmanaged EV Charging without Remote Charging Infrastructure

Scenario 1 (Figure A-6) represents a completely independent, unmanaged charging scenario. This scenario assumes that there is no ubiquitous charging infrastructure, i.e., charging is only available at the driver's home. With no price signals to shape behavior, drivers will charge EVs at their own discretion, presumably when they arrive home from work in the early evening. This arrival time is modeled as a normal distribution with a mean of 6 p.m. and a standard deviation of 30 minutes. EV adoption rates are represented as a percent of the existing vehicle fleet of California (25.8 million vehicles).

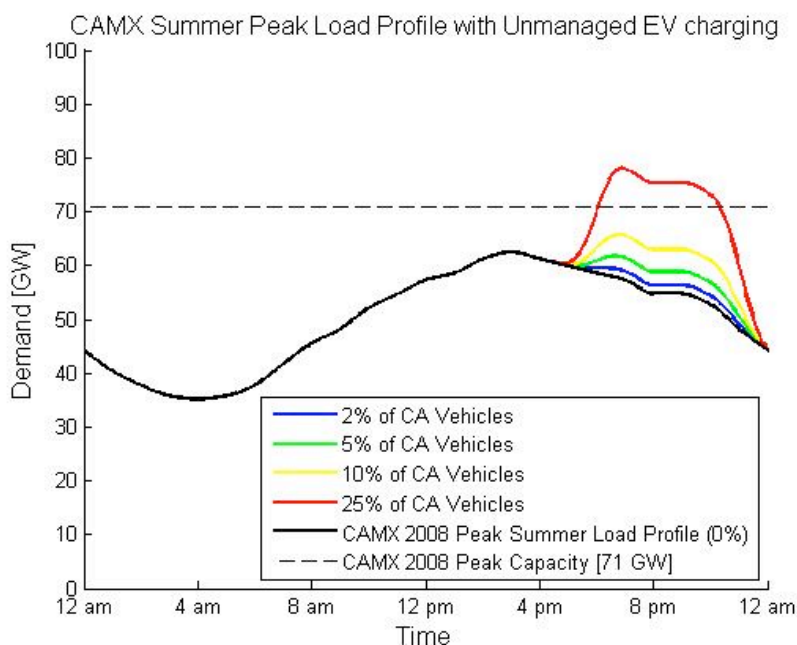


Figure A-6: Scenario 1 results.

As Figure A-6 illustrates, unmanaged EV charging has a strong tendency to create secondary demand spikes greater in both magnitude and duration than baseline demand. Under a 10% adoption rate, for example, the peak demand increases over 5% and lasts over three-and-a-half hours. Because the majority of this power would have to be generated using expensive reserve gas turbines, the financial feasibility of this scenario is low.

6.2. Unmanaged EV Charging with Remote Charging Infrastructure

Scenario 2 (Figure A-7) represents unmanaged charging, but unlike the first, it allows for charging at remote spots, presumably at or around the driver's workplace. The total distance traveled for the day is assumed to be a work commute, so charging can be disaggregated into two equal periods with half the duration of the period in Scenario 1. Arrival time is similarly modeled as a normal distribution with a morning mean of 8 a.m. and the aforementioned evening conditions.

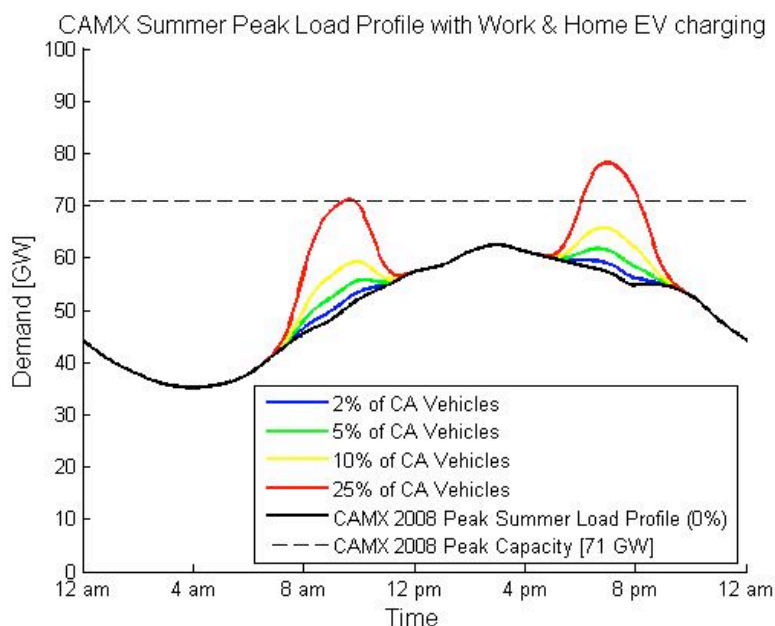


Figure A-7: Scenario 2 results.

This scenario creates two distinct peaks during each charging period, as Figure A-7 clearly shows. Because the base demand is low in the morning, under the moderate EV adoption rate of 10%, the resulting morning peak does not exceed the existing afternoon peak. The evening charging period, however, produces a 5% increase over the existing peak and lasts over two hours. Similar to Scenario 1, such increases in demand would present serious capacity concerns.

6.3. PG&E E9 Rates: Time of Use Rate for EV Charging

The third scenario considered is based on the multiple-tier pricing scheme proposed by California's Pacific, Gas & Electric Company (PG&E). This plan breaks the day into peak, partial-peak and off-peak hours with prices per kWh of 28.4¢, 10.4¢ and 5.0¢, respectively. Adoption of this pricing scheme is mandatory for EV users, but whether it is effective in shaping customer behavior is not entirely certain. The model assumes that all drivers will respond to the price signals (i.e., the off-peak price starts at 12 a.m. for summer weekdays) and begin charging at or shortly after this time.

Behavior in this scenario (Figure A-8) is modeled as the right half of a normal distribution, with a standard deviation of 15 minutes. This model represents the best case scenario for utility companies. It is unlikely that a utility could expect 100 percent compliance, but the purpose of this model is to assess the effect of a successfully implemented multi-tiered policy in mitigating demand spikes.

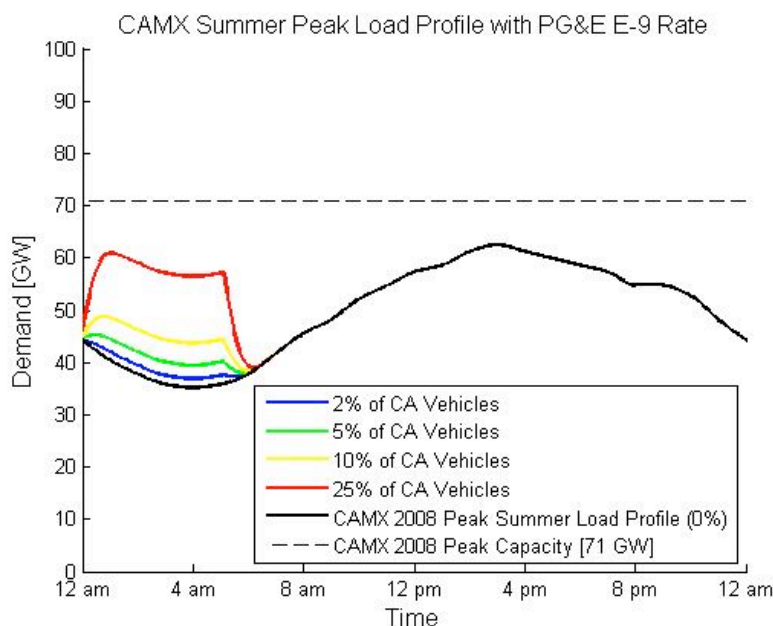


Figure A-8: Scenario 3 results.

Under this charging scenario, demand spikes from EV charging never exceed the base load afternoon peak, even under that high adoption rate of 25%. In this limiting scenario, the morning peak only reaches 97% of the existing peak. From this result, it can be inferred that the E9 variable rate may be an effective method of mitigating demand spikes from EV charging, assuming of course that consumers take advantage of the lower price during off-peak hours. The sharp increase in demand at midnight would obviously present some significant operational challenges; however, the partial-peak hours would draw a certain share of EV loads, softening this rapid increase.

Again, the previous scenario assumed 100% customer compliance. If the E9 policy were only able to draw 50% compliance—leaving the remaining drivers to charge when they returned home in the afternoon—the resulting load profile would be that shown in Figure A-9.

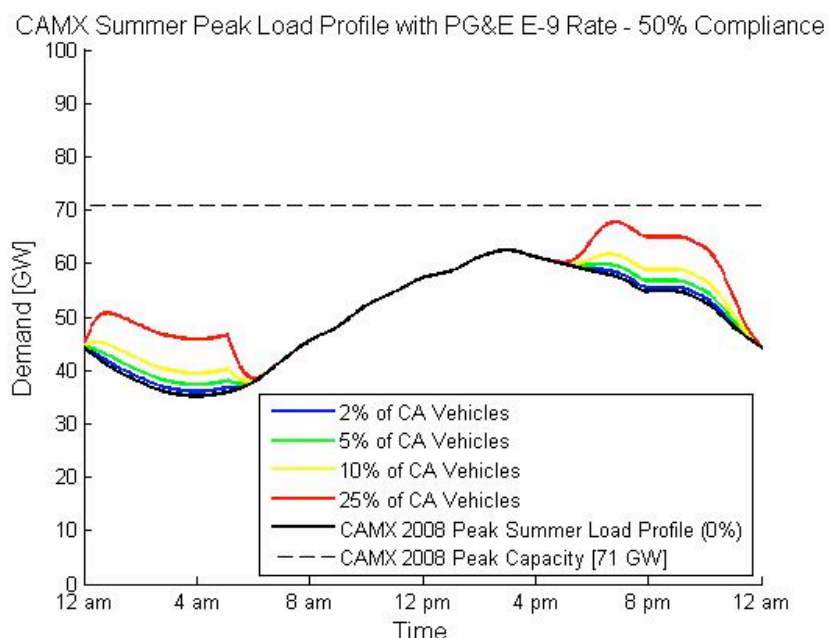


Figure A-9: Scenario 4 results.

During off-peak hours, a significant percentage of EV charging can be accommodated with exceeding the existing afternoon peak of the baseline scenario. However, those drivers who do not respond to the changes in rate push the afternoon demand up significantly as EV adoption increases. Under a 10% EV adoption scenario, demand is greater than 90% of peak for over 10 hours, resulting in stress and congestion on generation and transmission infrastructures, which translates to higher costs for operators. These two examples show that the success of a multi-tiered pricing scheme is ultimately dependent upon the degree of customer compliance.

7. Short Term: Clustering

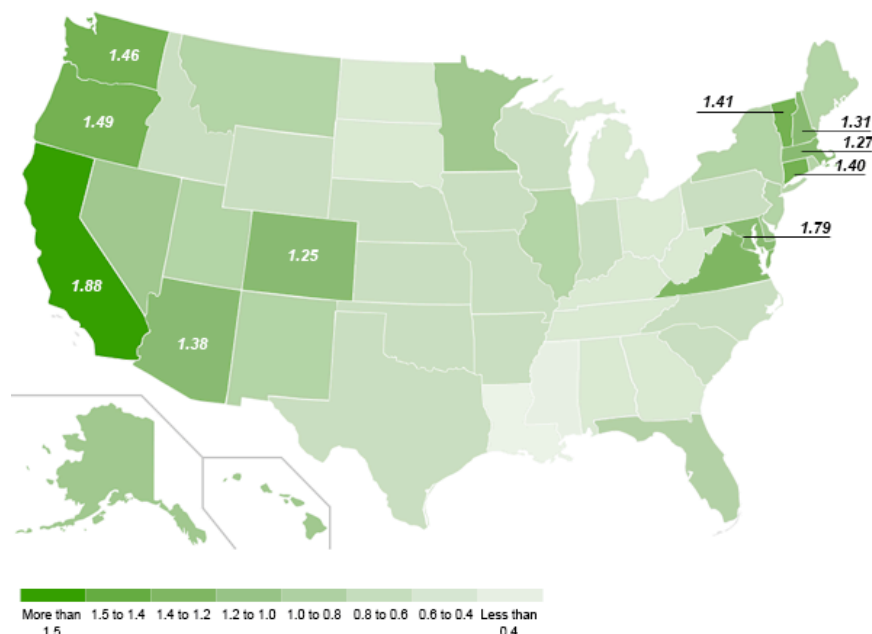
As adoption of EVs grows, utilities will be faced with two distinct challenges to maintain delivery of reliable power to consumers. As the model results above reveal, the current grid in California is capable of handling a large number of EVs when effective policies to shift charging to off-peak hours exist. These results, however, are rather simplistic in that they assume a homogenous distribution of EVs throughout the CAMX grid. Demographic data and interviews with utility companies suggest that this will not necessarily be the case.

Rather than homogenous adoption, it is expected that EV adoption rates will follow trends set by hybrid car adoption rates over the past several years. For instance, the national average of hybrid adoption per 1,000 residents in 2008 was 0.887 (Figure A-10), while the average for the state of California was 1.88, which was double the national average. The regional dependence becomes even more important when examining specific metropolitan areas. The national average for metropolitan

areas was 1.962 per 1000 residents, compared to the California metropolitan areas of San Francisco at 8.016, Monterey at 6.621, Santa Barbara at 6.295 and San Diego at 5.947.¹⁵

Hybrid Sales Intensity for US States

New Hybrids per 1000 Residents - 2008 (Through October)



SOURCE: R. L. POLK & CO

Figure A-10: 2008 non-homogenous hybrid vehicle adoption by state.¹⁶

If EVs do in fact follow similar trends, the optimistic results of the model may be misleading due to spatial clustering of EV loads. While the generation and transmission capacity may be sufficient to serve a statewide EV adoption rate of a certain percent, the local distribution grid may not be sufficient when some city or neighborhood adoption rates are in actuality much higher. The resulting overloading of the local distribution grid can cause premature degradation of infrastructure such as pole-top transformers and a decrease in the reliability of electricity in those neighborhoods.

The clustering of EV loads is the most immediate threat to utility companies. However, due to the high degree of regional variability there is no clear solution to address this issue. Individual utilities must respond to this concern in accordance with the structure and condition of their own local distribution grids as well as local EV clusters. In order to avoid serious or long-term degradation of electricity reliability, each utility should monitor where EVs are purchased and charged in order to identify these clusters as they develop.

8. Long Term: Congestion and Exceeding Capacity

Even with the threat of local clusters addressed, there are still long-term challenges created by high levels of EV adoption. If EV loads push peak demand higher, the overall reliability of the grid could

be degraded as a result. Reliability events (which result from insufficient generation or transmission to meet demand) can be felt instantaneously throughout the system in the form of blackouts and rolling brownouts. As the model shows, shifting EV loads to off-peak hours can mitigate any increases in peak demand. However, even without increasing peak demand, the increased level of transmission utilization can affect the cost of electricity delivery. Under current loads, congestion in transmission lines already cost consumers hundreds of millions of dollars. This problem will likely be compounded as EV adoption increases.

Part B: Opportunities

1. Selling More Electricity May Increase Revenue

It is clear that as more EVs are adopted, utilities will be able to sell more electricity to consumers. For most utilities this is a straightforward opportunity to generate more revenue: EVs driving 33 miles per day on average at 0.35 kWh per mile and an average retail electricity price of 11.36 cents/KWh¹⁷ translates to additional revenues of \$480 per annum for every electric vehicle in service. This is \$1.04B gross revenue per 1% of the U.S. light-duty vehicle fleet (LDVF) converted to electric vehicles.

However, some states such as California have implemented revenue decoupling for utilities. This means that profits are independent of the quantity of electricity sold and utilities are incentivized by the regulators to reduce the electricity consumption per customer. As such, selling more electricity is not an opportunity for all utilities, and for some operators it may actually be a threat.

2. Increasing Utilization of Installed Capacity – Valley Filling

A 2007 PNNL report concluded that with “proper changes in the operational paradigm, [the U.S. electric system] could generate and deliver the necessary energy to fuel the majority of the U.S. light-duty vehicle fleet”. So what operational paradigm changes will be necessary to accommodate a massive additional load into the already at-capacity grid without requiring expansion?

Because their electricity demand is not constant during the course of a 24-hour period, EVs have the valuable characteristic of being a deferrable load. Daily EV recharging can be scheduled for periods of non-peak demand—a principle called valley filling. The early afternoon peak demand is larger than the demand in the early hours of the morning. Figure B-1 shows a stylized load profile for one day during peak season together with generation dispatch profiles and total installed capacity. The shaded area is the under-utilized capacity available for charging electric vehicles.

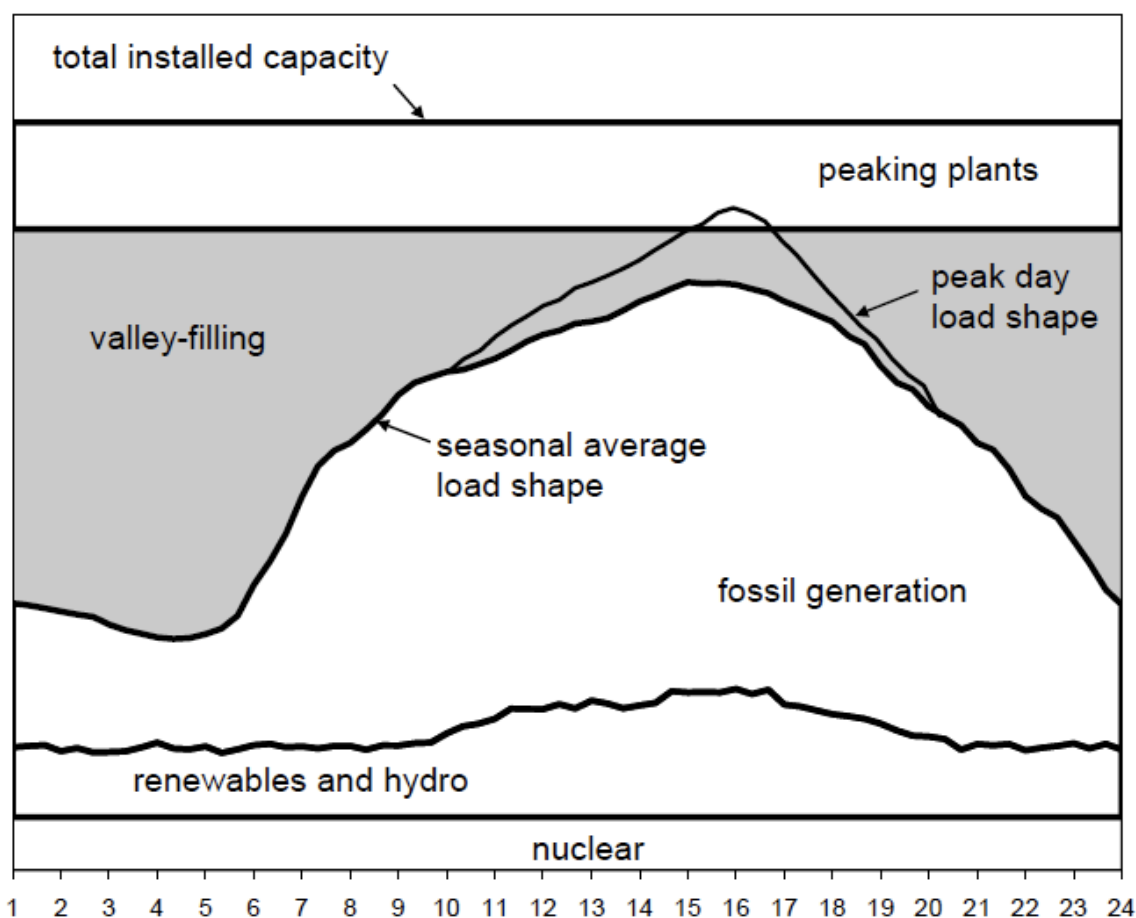


Figure B-1: Stylized load profile for a typical summer day.¹⁸

The maximum potential adoption rate the existing grid infrastructure can accommodate varies between each of the NERC regions, depending on the load profiles, the present capacity utilization and the mix of generation capacity. On average, the PNNL study concludes that for the valley filling approach for unused capacity across the full 24-hour day, the existing U.S. electric system could accommodate 74% of the light-duty vehicle fleet, which includes cars, SUVs, vans and pick-up trucks. A 74% reduction has the gasoline displacement potential of 6.5 million barrels of oil per day or 52% of U.S. imports.

Assuming electric vehicles can be recharged at any time of day is probably unrealistic, as most recharging will occur at home in the evenings and overnight. As such, a second scenario was considered whereby valley filling could occur only between the hours of 6 p.m. to 6 a.m. Within this scenario, the existing U.S. electric system could accommodate 43% of the LDV fleet, which has gasoline displacement potential of 3.8 million barrels of oil per day or 31% of U.S. imports. Figure B-2 and Table B-1 show the full results broken down by NERC region for both of these scenarios.

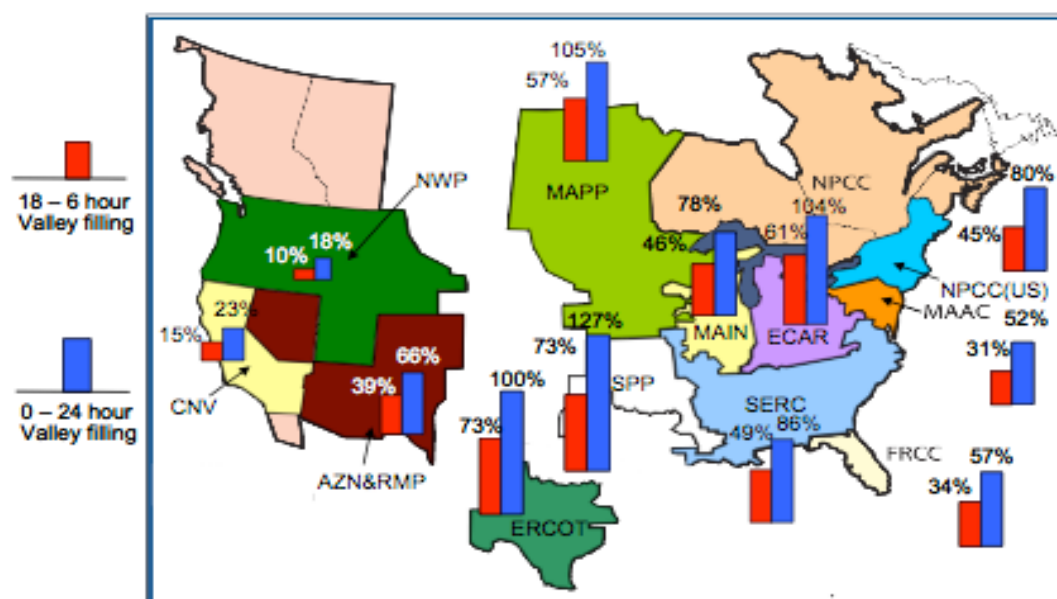


Figure B-2: Technical potential for refueling the regional LDVF with available electric capacity.¹⁹

Table B-1: Results of Technical Potential by Regions²⁰

Table 2: Results of Technical Potential by Regions

Region	Total Number of Vehicles in Mill.	24-Hour Valley Filling	6 pm-6 am Valley Filling	24-Hour Valley Filling	6 pm-6 am Valley Filling
		Technical Potential in %		Technical Potential in Mill. Vehicles	
ECAR	27.7	104	61	28.6	16.8
ERCOT	15.5	100	73	15.5	11.3
MAAC	20.0	52	31	10.4	6.2
MAIN	16.7	78	46	13.1	7.7
MAPP	5.8	105	57	6.1	3.3
NPCC (U.S.)	19.6	80	45	15.6	8.9
FRCC	11.5	57	34	6.5	3.9
SERC	37.8	86	49	32.5	18.4
SPP	11.9	127	73	15.1	8.7
NWP	15.7	18	10	2.8	1.6
AZN&RMP	8.8	66	39	5.8	3.4
CNV	25.8	23	15	6.0	3.9
National Average *	216.9	73	43		

* Weighted average of all regions. Those regions with technical potential greater than 100% are assumed to export to regions with potential less than 100%. ERCOT's technical potential is truncated from 136% to 100% because of negligible transfer capability out of ERCOT.

The annual operating cost of electricity generation for utilities can potentially be greatly minimized by reducing reliance on expensive peaking plants (power plants that generally run only when there is a high demand). This can be accomplished by increasing the utilization of installed capacity, thereby spreading fixed costs over a greater quantity of electricity. The magnitude of this reduction varies for each utility depending on generation mix and underlying demand profile. The authors considered two utilities within the PNNL report: the San Diego Gas and Electric Company (SDG&E) and Cincinnati Gas and Electric. The cost reduction for maximum potential EV adoption with present installed capacity is shown in Figures B-3 and B-4.

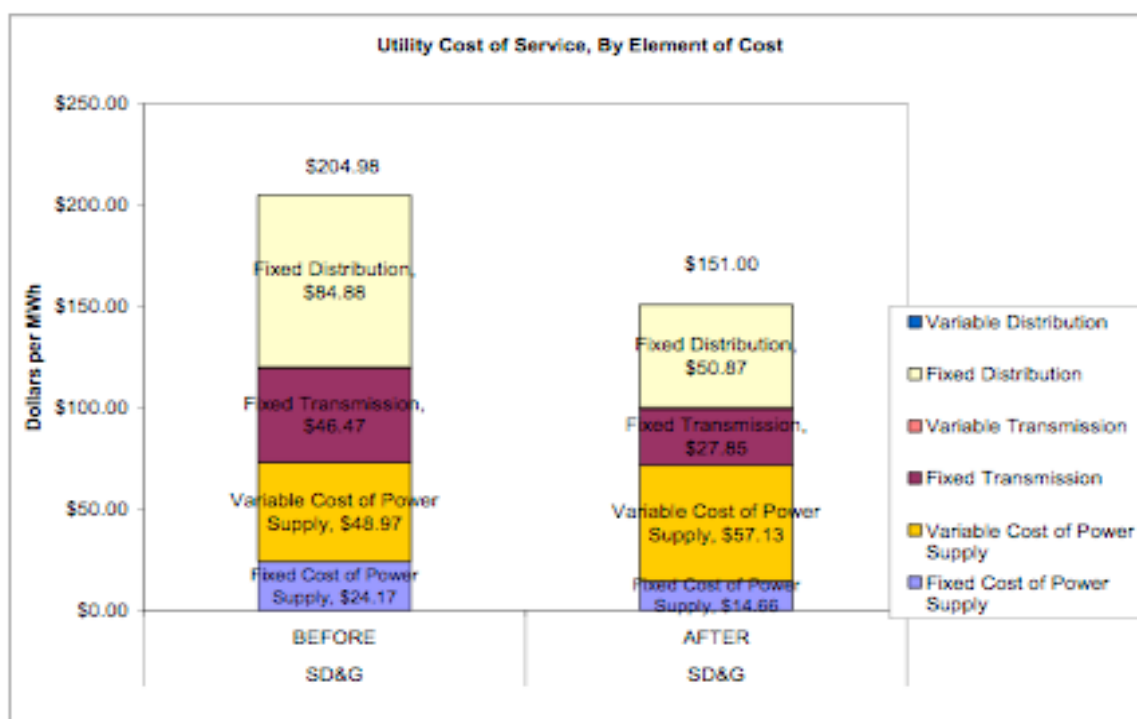


Figure B-3: Impact of plug-in hybrid electric vehicle (PHEV) valley filling on system annual operating cost per MWh for SDG&E.²¹

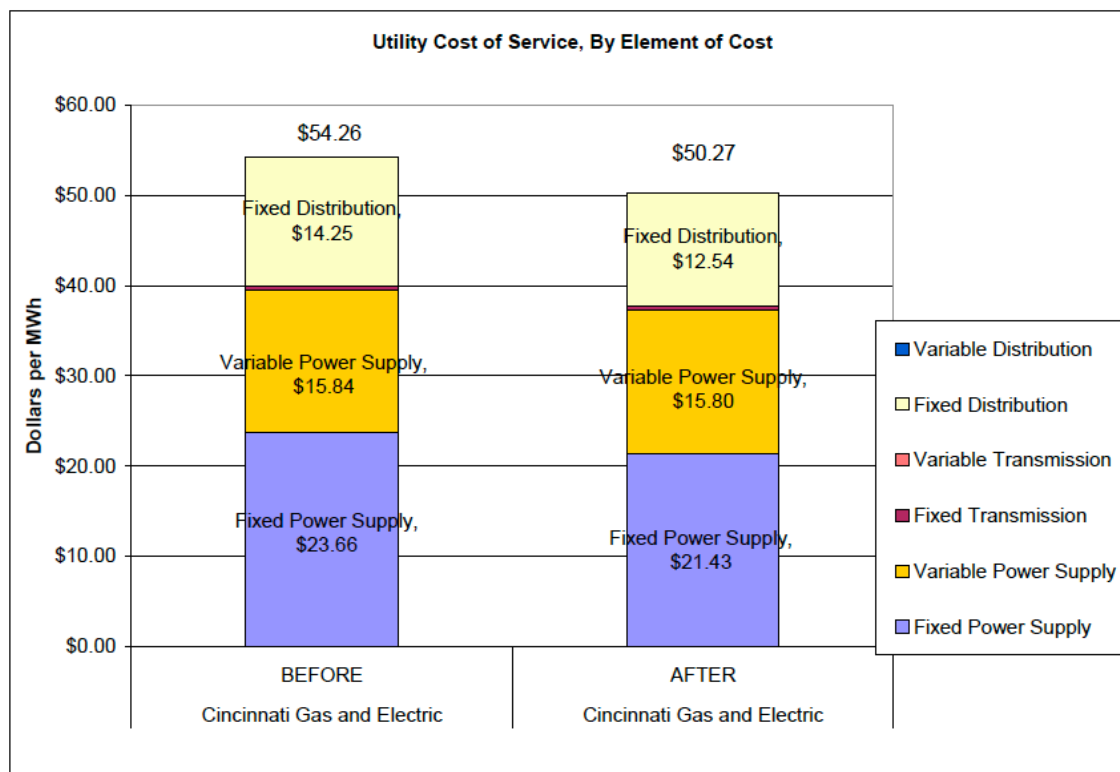


Figure B-4: Impact of PHEV valley filling on system costs for Cincinnati Gas & Electric.²²

The metering hardware and communication network being deployed as part of the Smart Grid²³ is a key enabler of this valley filling approach. The grid is presently strictly one-way, meaning that utilities have no way of measuring electricity usage with any more granularity than a monthly manual meter reading. As part of the Smart Grid, Automatic Metering Infrastructure (AMI) is the first step towards enabling valley filling. Smart meters will measure electric usage in real-time and communicate this to the utility via radio frequency or broadband over power line technology.

In addition, load control functionality is a critical component of successful EV deployment. The utility or some other party must control which vehicles are recharged at what time and at what rate. Demand side management (DSM)—actions that influence the quantity or patterns of use of energy consumed by end users—must optimize the recharging of vehicles based on the available generation capacity and understanding which customers' vehicles will need to be fully charged at what time of day.

While the PNNL study only considers the impact of plug-in hybrid electric vehicles (PHEVs), most of the conclusions are equally applicable to fully electric vehicles, with a few notable exceptions. PNNL considered load profiles for typical summer and winter days, rather than peak days, assuming that on those few days each year the hybrid's combustion engine could be used to make up the difference.

EVs do not have this option so maximum adoption rates would have to be reduced slightly or customers would have to be content with reduced range on those few extreme days per year.

3. The Growing Electric Grid

The PNNL study considers only a snapshot of the generation capacity and energy use at present. As discussed in Section A-4, the U.S. demand for electricity is growing and additional generation capacity will be required to meet that demand. The effect this has on the potential adoption of EVs depends not on the peak demand and total capacity build, but rather on the effect of the load profile over the course of the day. Based on the findings within this brief, it is most likely that the base load, peak load and total capacity will **increase by the same percentage**. In this case the unused capacity will increase by that same percentage, leaving more room for EVs.

However, the main drivers of the growth in electricity usage are growing GDP per capita and growing population. Therefore, it would be expected that vehicle usage would also increase in line with electricity usage. As such, the percentage of LDVF will be approximately the same.

If the base load, peak load and total capacity **increase by the same absolute amount** then the power available to recharge EVs will remain the same and the same number of vehicles will be able to be accommodated. This will result in a slightly lower proportion of the overall future fleet. Only the case that base load increases more than the peak load, (meaning that the total generation capacity is not increased) the potential adoption percentages for EVs will be reduced by a significant percentage. The authors project, however, that the most likely case is that these increases will all be proportional and therefore the power available for EV charging during valley filling periods is expected to naturally increase.

4. Compliance with Renewable Portfolio Standards

Driven by environmental, economic and national security concerns, states in America are increasingly mandating that utilities include a minimum percentage of renewable energy generation in their portfolios. At the time of publication, thirty states have implemented these renewable portfolio standards. For example, California has mandated 33% renewable power production by 2020. Furthermore, the federal government is considering a nationwide renewable portfolio standard.

Meeting these emerging renewable energy standards is a pain point for utilities. The current most cost-effective renewable power source, wind, is inherently intermittent and unreliable with a typical supply curve that does not match the load profile. Solar, while more predictable and better matched to load profiles, is still not reliable and provides no power at night, so is also of no use for base load generation.

In the same way that electric vehicles enable load shaping to increase utilization of installed generation capacity, they also enable greater adoption of intermittent energy sources by scheduling electrical loads to coincide with periods of strong wind or sun. Wind in particular is suitable for providing electric vehicle charging, as it tends to peak around dawn and dusk when vehicle recharging will be most convenient and affordable.

5. Demand Response and Ancillary Services

When energy demand nears maximum capacity, utilities currently ensure reliability in the grid through two mechanisms: demand side management (DSM) and ancillary services. These mechanisms can be deployed during peak load to reduce demand in the system, in the case of DSM, or bring additional generation online in order to meet demand, in the case of ancillary services. Currently, the use of ancillary services vastly outstrips DSM, with utilities spending \$34B annually on ancillary services compared to \$2.4B annually on DSM (of that, \$700M is for load control). Ancillary services are categorized by their speed of response with the faster responding types worth more than the slower. The types of ancillary service are defined in Table B-2.

Table B-2: Definitions of Key Ancillary Services²⁴

Service	Service Description		
	Response Speed	Duration	Cycle Time
Regulation	Power sources online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Reliability Council (NERC 2002)		
	~1 min	Minutes	Minutes
Spinning reserve	Power sources online, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 min to comply with NERC's Disturbance Control Standard (DCS)		
	Seconds to <10 min	10 to 120 min	Days
Supplemental reserve	Same as spinning reserve, but need not respond immediately; units can be offline but still must be capable of reaching full output within the required 10 min		
	<10 min	10 to 120 min	Days
Replacement reserve	Same as supplemental reserve, but with a 30-min response time; used to restore spinning and supplemental reserves to their pre-contingency status		
	<30 min	2 hours	Days
Voltage control	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges		
	Seconds	Seconds	Continuous

Ancillary services cost \$34B annually for ~ 1Million MW of capacity, a cost of about \$350K per MW of generation.

Adoption of electric vehicles greatly increases the ease and scope of DSM for grid reliability, i.e., altering demand to match supply rather than supply to match demand. The valley filling and load shaping functionalities described in previous chapters are comparable to supplemental and replacement reserve services. EV demand has the added benefit of being able to respond almost instantaneously to grid conditions, allowing them to also offer services equivalent to the more valuable regulation and spinning reserve categories. Every percent of the LDVF replaced by electric vehicles under a load aggregation and control system adds 1,040 MW of loads that can be regulated to reduce demand and avoid initiating ancillary services. At the average ancillary price this represents additional annual revenues of \$364M per annum per 1% of the LDVF for an electric vehicle operator in a competitive power market or a comparable level of cost savings to a vertically integrated utility.

A restriction to this strategy that should be considered is that most demand response events occur during peak hours and early afternoon, when many EVs may not be connected to the grid. Even if vehicles are recharging in office parking lots, electricity prices are highest at this point, so few vehicles will be drawing loads to be curtailed. Regulation services are required at all times during the day, making EV demand response more appropriate. However, during periods when few EVs will be plugged into the grid, such as during commuting hours, alternative regulation service will need to be brought online.

A further challenge to realizing these benefits is that the electricity regulations, set by the National & Federal Energy Reliability Councils (NERC & FERC), do not currently allow demand side management to be utilized for regulation purposes or spinning reserve. With wider trends pursuing the Smart Grid, there are major pressures on regulators to update these rules to reflect new technologies and paradigms for effective grid management.

6. Capturing the Value of Carbon Offsets

The recently released “Proposed Regulation to Implement the Low Carbon Fuel Standard (LCFS)” creates an opportunity for utility firms to capture value from the electricity it sells to refuel EVs. This power may be considered a fuel, thereby allowing utilities to receive offset credits for each watt sold, which they can then sell to high emissions fuel makers at a profit. In this ruling, the California Air Resources Board staff proposes to reduce emissions of greenhouse gases (GHG) by lowering the carbon content of transportation fuels used in the state. The LCFS is expected to reduce GHG emissions from the transportation sector in California by about 16 million metric tons (MMT) in 2020. These reductions account for almost 10% of the total GHG emission reductions needed to achieve the state’s mandate of reducing GHG emissions to 1990 levels by 2020. In addition, the LCFS is designed to reduce California’s dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels in California. Governor Schwarzenegger has identified all of these outcomes as important goals for the state.²⁵

Under the proposal, the utilities must report all fuels provided and track the fuels' carbon intensity through a system of "credits" and "deficits." Credits are generated from fuels with lower carbon intensity than the average. For example, a fuel provider may choose to purchase credits generated from another fuel provider that has banked credits from using electricity in a plug-in hybrid vehicle. As the objective is to ensure lower carbon intensity fuels are created and used in the California fuels market, the LCFS does not allow the use of credits, or offsets, generated from outside the transportation fuels market.

7. Vehicle-to-Grid (V2G)

Vehicle-to-Grid (V2G) has been hyped as one of the most promising opportunities of the EV revolution. The idea is that utility firms will be able to use the distributed storage provided by EV batteries as back-up capacity to help meet unusual demand spikes. For example, power could be drawn down from car batteries and sold back to the grid to power a home for the afternoon during a heat wave and then recharged at night as the temperature cools. With dynamic pricing, the EV owner would make a profit because the midday peak price offered for selling power during the afternoon should far exceed the cost of charging the battery at night. Another possibility is if EV batteries continue to increase storage capacity, excess power generated from utility scale wind power plants during the night could be stored in EVs and then used to provide power to the grid during the day. This is the final frontier of valley filling and is an exciting idea, given all of the potential benefits.

However, the authors believe that the following issues will prevent Vehicle-to-Grid from becoming a reality in the short term:

- **Battery technology:** The EV and its battery are still in their early development stages. It is unlikely that either the car manufacturer or the utility will risk interconnecting at this early stage. "It's hard to take seriously the promises made for plug-in hybrids with 30-mile all-electric range or any serious V2G application any time soon. It's still in the science project stage," said John DeCicco, a mechanical engineer and senior fellow for automotive strategies at the non-profit group Environmental Defense.²⁶ "We would not like to see stresses on the battery pack caused by putting it through cycles it wasn't designed for," added Chris Naughton, a Honda spokesman.²⁷
- **Lack of support for Smart Grid technology:** Smart meters and Smart Grids are not a reality yet in the United States and they are an essential component of V2G.
- **The complexity of the distribution systems required:** Two-way inverters would need to be developed and installed on a wide scale to bring V2G to fruition.
- **Unproven economic justification for utilities:** It is unproven yet that the economic incentives justify V2G from the utility perspective. In order to support V2G, utilities will have to spend money on two-way metering systems for every consumer, and make changes to their distribution systems, control systems and billing systems. In return, the utility's main gain is cost avoidance from starting or maybe even building peaker power plants (which only run during high demand). It is still unclear if this is economical as many of the pieces are still experimental. The authors believe it will take almost a decade to determine this.

- Unproven economic justification for consumers: For the consumer, the high opportunity cost of batteries and the increase in cost of the vehicle has to be lower than possible gains. The main problem is that batteries currently have 2000-8000²⁸ charging cycles. The price one receives for selling power back to the grid would need to outweigh the cost of derogating the battery and shortening its effective life span. Even if the price per Kwh goes down to \$500 by 2020²⁹ this means that the opportunity cost alone to the health of the battery would be six to 25 cents per Kwh. Consumers would need to receive at least six to 25 cents as the price differential between buying and selling to the grid for the economics to be attractive. This ignores the added costs to the car, the risks the consumer assumes, and the overhead costs of replacing batteries more frequently.
- The complexity of knowing when to draw power from the vehicle: How much charge in the battery at the end of the day depends on how far the user needs to drive home. Will the car be taken out again soon after reaching home?³⁰

In summary, although discussed often for its promise, V2G will not be viable in the next decade. For now, utilities need only to ensure their investments are based on V2G standards so they can support V2G in future years, once the issues outlined above have been resolved. To date, the big car OEMs and utilities are cooperating on this issue and one emerging standard is the SAE J1772.³¹

Part C: Changing Business Environment & Business Models

The EV revolution brings with it many players and interest groups. The utilities will need to strategically assess these different entities and make thoughtful decisions regarding cooperation or competition. The utilities might also need to think differently about their role in this new playing field and learn how to adapt to changes quickly.

High expected adoption rates of EVs implies huge investment in infrastructure. A BCG (Boston Consulting Group) report³² predicts that in Europe, for example, \$21B will be needed for charging infrastructure by 2020. However, the risk is that years after infrastructure deployment, battery technology could improve so most vehicles need only to charge at home. These potentially rapid changes make the investment in infrastructure very risky.

It is quite obvious that utilities will have to seek partnerships in order to mitigate these expenses and risks, and distribute them to other stakeholders, mainly OEMs and emerging companies that plan on operating under new business models. Toyota, for example, partnered with EDF—the large French electric company—to test its plug-in hybrid and create innovative billing systems. Better Place, a U.S. start-up, partnered with Renault to provide the car and build an infrastructure in countries like Denmark and Israel.

These examples show that there is a probable need to adopt novel and unconventional business models in order to bring investments in infrastructure and new technologies to reality with minimized risk.

1. Third Party Technology Providers

Start-up companies as well as existing players are developing various technologies required to support the EV infrastructure. Coulomb Technologies and V2Green are two examples of companies operating in different parts of the value chain. Coulomb Technologies³³ offers a family of products and services that provide a plug-in vehicle charging infrastructure, which includes networked charging stations. Coulomb has already started to deploy charging stations in a few metropolitan areas. V2Green³⁴ offers utilities the technology to communicate with plug-in vehicles, providing real-time control over charging behavior and management of the information generated by these activities. In addition, it provides OEMs with an in-vehicle client consisting of electronics and embedded software that receives and transmits commands to the car's power electronics.

2. Better Place

Better Place³⁵ is taking a unique approach to EVs: It aims at providing a complete solution, including the battery and infrastructure for charging/swapping, and a business model to offer “miles” as a service. At the time of publication, Better Place is currently active in Australia, Denmark, Israel, the California Bay Area and more.

Better Place has a clear value proposition for a utility:

- Its smart way of managing customers and cars, and its optimal use of valley filling, saves the utility large expenditures on infrastructure.
- Better Place assumes responsibility for customers' service needs.

However, there are also some risks in this model from the utility's perspective:

- Better Place intermediates the relationship between the utility and the customer.
- There are risks from the utility perspective in leaving preparations in the hands of a private company that does not adhere to the same regulatory rules the utility is held to. For example, if Better Place or another company cannot sustain its obligations, the utility will have to find a way to provide the electricity to the customer and reclaim the infrastructure.

Conclusions

The advent of EV adoption presents various opportunities and threats for all of the EV ecosystem entities, particularly utilities. Upon reflection of the information found within, and research conducted for, this document, the authors have developed the following conclusions and recommendations to help utilities support EVs.

- Track EV cluster formation and trends in real-time. Promoting regulations and/or marketing programs that require EV owners to register new cars with utilities will provide real-time visibility into clusters so utilities can plan short- and long-term support accordingly.
- Develop necessary technologies to enable valley filling and load control as ancillary services. Utilities need to control the scheduling of EV charging (without these controls EV adoption above 10% of the LDVF will cause serious problems meeting demand on the grid). With load scheduling controls, EV adoption rates can reach 43% without additional power generation or transmission. Adoption at this rate will reduce the average cost of electricity supply by up to 25%, enable compliance with renewable portfolio standards, and generate revenues of \$15.6B for ancillary services.
- Partner with third party suppliers to create commercial charge spots. As remote charging is beyond the utilities' core competencies, these organizations should only focus on selling power, not controlling its usage.
- Partner with universities to develop programs to recruit top talent. The authors have developed a three-step plan: 1) Encourage energy industry retirees to move to academia to help design and teach courses; 2) Court and pay young talent, while trying to debunk utility stereotypes as being static and slow; and 3) Work with universities to develop energy-specific branding.
- Help drive the national agenda to expand capacity and transmission. The patchwork of rules and regulations managed state by state is highly inefficient and slows progress, so national legislation should be pursued to streamline the bureaucracy associated with adding new transmission lines. The Obama administration is progressive when it comes to energy so the timing has probably never been better to establish a national system. Utilities should work with the DOE to articulate a clear plan for the coming decades and engage the population in the debate of aggressively pursuing renewables while "keeping the lights on" during development.
- Defer investments in Vehicle-to-Grid (V2G), with the exception of standards. V2G is a long-term option but not one that will be realized in the next decade for many different reasons. Utilities should continue to monitor development of V2G, but for now, only remain involved in helping to drive and adopt compatible standards.
- Embrace small and incremental investments that respond to actual growth over large anticipatory investments. Because the future is not clear in terms of the magnitude of EV adoption, the authors recommend utilities embrace a strategy that enables them to make variable costs investments as the amount of electric vehicles grow. Such investments are distribution investments pending on the clusters formed, and installation or support of

installation for public charging spots. The authors believe that the current state utilities should try to minimize EV-specific large capital expenditure because of the unclear nature of the problem.

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