Charging Smart

Drivers and Utilities Can Both Benefit from Well-Integrated Electric Vehicles and Clean Energy

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May 2017

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ACKNOWLEDGMENTS

This report was made possible with the generous support of the Kendall Science Fellowship program. The Energy Foundation provided additional research support.

The authors thank the attendees of two conferences convened by the Union of Concerned Scientists. These conferences took place June 2–3, 2016, in Boston, Massachusetts, and November 9–11, 2016, in Braselton, Georgia. The conference proceedings are available at *https://tinyurl.com/UCS-Smart-Charging*. We extend thanks to the following for their additional contributions throughout this project:

Tom Ashley (Greenlots)
Max Baumhefner and Luke Tonachel (Natural Resources Defense Council)
Doug Black, Emre Kara, Jason MacDonald, and Sam Saxena (Lawrence Berkeley National Laboratory)
Anne Blair (Southern Alliance for Clean Energy)
Bill Boyce (Sacramento Municipal Utility District)
Alec Brooks (Aerovironment)
Watson Collins (Eversource)
Gina Coplon-Newfield (Sierra Club)
Noel Crisostomo (California Energy Commission)
Stephen Davis (KNGrid)
Tanuj Deora (Smart Electric Power Alliance)
Tim Echols (Georgia Public Service Commission)
Blair Farley, Diane Harris, Randy Johnson, Larry Monroe, and Angela Strickland (Southern Company)
Garrett Fitzgerald and Chris Nelder (Rocky Mountain Institute)
Spence Garber and Beth Reid (Olivine)
Bob Graham (US Department of Energy)
Ryn Hamilton (Ryn Hamilton Consulting)
Willett Kempton (University of Delaware)
Joy Kramer (Event Energy Partners LLC)
Jim Lazar (Regulatory Assistance Project)
Mark Lebel (Acadia Center)
Michael Legatt (Electric Reliability Council of Texas)
Tony Markel (National Renewable Energy Laboratory)
Kevin Miller, Dave Packard, Rich Quattrini, Craig Rodine, and Colleen Quinn (ChargePoint)
Don Panoz (Deltawing Technologies)
Nancy Ryan (Energy and Environmental Economics)
David Tuttle (University of Texas)
Alan White and Valery Miftakvov (EMotorWerks)

The authors also thank our Union of Concerned Scientists colleagues, including Don Anair, Steve Clemmer, Jeff Deyette, Peter Frumhoff, Daniel Gatti, Joshua Goldman, Joy McNally, Julie McNamara, David Reichmuth, John Rogers, Sandra Sattler, and Laura Wisland. Special thanks to Bryan Wadsworth and Heather Tuttle for the report's editing and production.

Organizational affiliations are listed for identification purposes only. The opinions expressed herein do not necessarily reflect those of the organizations that funded the work or the individuals who reviewed it. The Union of Concerned Scientists bears sole responsibility for the report's contents.

[CHAPTER 1]

Introduction

Electric vehicles, with an electric motor and a battery, have been around since the earliest days of the automobile. Compared with gasoline-powered vehicles, they offer cleaner and quieter operation, greater energy efficiency, and, with fewer moving parts, potentially lower maintenance costs. Historically, their disadvantages have included limited range on each charge, slow charging, and higher initial costs, although performance has improved significantly on all those fronts in recent years.

Battery electric vehicles, ranging from scooters and small electric bikes to transit buses, are widely seen as a likely technology to enable deep cuts in global warming emissions (see Baumhefner, Hwang, and Bull 2016; Donohoo-Vallett 2016; Dutzik and Miller 2016; Ryan and Lavin 2015; Williams et al. 2015). The vehicles have no direct emissions, and the electricity used to charge the batteries can be clean. Even when the existing electricity grid and its mix of fuels powers their manufacture and charging, EVs are cleaner than typical vehicles with internal combustion engines throughout the United States, and they are cleaner than the best conventional vehicles in much of the nation (Nealer, Anair, and Reichmuth 2015).

If all US cars and light trucks were electric, it would add about 25 percent to the nation's annual electricity demand of about 4 trillion kilowatt-hours (kWh) per year. Currently, US light-duty vehicles travel about three trillion miles per year, and electric vehicles get roughly 3 miles per kWh. Thus, it would take 1 trillion kWh per year to charge these vehicles (EIA 2017). That calculation assumes constant travel demands, but a transition to autonomous vehicles would likely increase the total vehicle miles. This would result from a lower perceived cost of travel, with time spent in transit devoted to other uses, such as work or entertainment. A recent study estimates an impact ranging from a decrease of 0.1 trillion vehicle miles to an increase of 6 trillion vehicle miles (Stephens et al. 2016).

Of course, we are a long way from a time when all vehicles are electric, but even a modest deployment of EVs can affect the network that transmits electricity from suppliers to consumers—the nation's power grid—and that impact can be positive. Consider how the electricity system works. Traditionally, the power grid has operated under the assumption that electricity demand simply happens: when consumers turn on an appliance, supply must be ready to power it. The designs of electricity generators featured either greater capital cost but lower fuel cost or lower capital cost and higher fuel costs. This set of conditions required a system with several layers of operation for supplying electricity:

- "Baseload" plants, with high capital cost and low operating cost, run as often as possible.
- Flexible, "load-following" generators ramp up and down to match hourly swings in demand.
- "Peaking" units, cheap to build but expensive to operate, run for relatively few hours per year.

That system can tolerate minor short-term mismatches between supply and demand.

According to Cory Budischak and collaborators, "The operating principle of fossil generation is 'burn when needed,' a principle simple enough that it could be followed without computers, digital high-speed communications, or weather forecasting—precisely the conditions when today's electric system was created, early in the 20th century" (Budischak et al. 2013). Now, though, we have computers, digital high-speed communications, and weather forecasting. We also have flexible loads—including air conditioners, electric water heaters, and electric vehicles chargers—alongside light bulbs, computers, and other equipment that basically need power on demand. The flexible loads can shift when they draw power by a few minutes (or even hours) without reducing the quality of energy services.

At the same time, some new electricity generation technologies cannot be dispatched on command even though they are cleaner than fossil fuels and competitive in cost. Federal tax credits, combined with state renewable energy standards, have been a key driver for recent growth and cost reductions in the US wind and solar industries. Since 2009, total US wind and solar capacity has nearly tripled, adding 86,000 megawatts of new capacity, while the costs of wind and solar projects have fallen by more than two-thirds. Wind accounted for about 5.6 percent of US electricity generation in 2016 and solar for about 1.4 percent (EIA 2017). Installed solar capacity is projected to triple over the next five years (SEIA 2017).

Hawaii, California, and other states are dealing with the fact that more clean power is available in the middle of the day, when demand is lower, than in the late afternoon and evening, when demand tends to peak. As a result, these regions need high "ramping capacity." Power plants, sitting idle when solar power is producing, come online to generate when the sun goes down. To deal with the problem of too much clean electricity, the two most important options are storage and load flexibility for shifting demand.

Battery technology and other technologies for energy storage have improved greatly in recent decades. Storage is not only used to support renewable energy; some regions reliant on nuclear or coal power use pumped hydropower, a form of energy storage, to support their baseload power plants. The systems can use low-cost electricity to pump water uphill at night, when electricity demand is lower, and the water can flow downhill to generate electricity when needed, typically during the day when the cost of electricity is higher.

Utilities have long used flexible loads to enhance the grid's balance between supply and demand on an hourly basis. For example, an electric water heater features thermal energy storage; although it cannot discharge electricity to the grid, it has considerable leeway in when it draws power from the grid. The rapid growth in the adoption of electric vehicles provides an opportunity to further harness the value of load flexibility, as long as that option has a high priority in deploying EV infrastructure.

Smart charging and vehicle-to-grid (V2G) configurations belong to a larger group of solutions called "vehicle-grid integration" or VGI. This can refer to scheduling, planning, or varying the charging of an electric vehicle to reduce its impact on the grid or even provide benefits to it. Smart charging involves changing the time and power of the charging activity, with power flowing from the grid to the vehicle. This does not lessen a battery's lifetime, but it can extend the time needed to charge a vehicle battery. V2G allows power also to flow from the vehicle batteries into the grid. This, too, can provide benefits but also carries some costs in interconnection and battery degradation. In anticipation of lower cost to vehicle owners and higher value to grid operators and consumers, policies and structures meant to allow one-way smart charging to realize its value to the grid should not foreclose the possibility of two-way, vehicle-to-grid power flow.

The first goal of VGI is to limit the impact vehicles have on the grid. An EV charger may increase a consumer's annual electricity demand by around 40 percent and double its peak demand. Because very few homes have EV chargers, the grid can accommodate their impact easily. As EVs become more prevalent, smart charging can limit impacts on the distribution system.

The second goal of VGI is to use the vehicles' demand flexibility to help the grid address other issues. For example, smart charging may help the grid incorporate higher levels of variable renewable resources like wind and solar. Used in conjunction with other flexible loads, smart charging might also help address grid issues like congestion or problems in power quality.

[CHAPTER 2]

Literature Review and Expert Observations

To explore the ability of EVs to support the expanded use of renewable energy, UCS gathered information on EV-grid integration through reviewing the literature, interviewing experts, and convening two conferences. The conferences were held June 2–3, 2016 in Boston, Massachusetts, and November 9–11, 2016, in Braselton, Georgia. About 100 people took part in each event.

Almost two decades ago, Willet Kempton and Steven Letendre of the University of Delaware noted the potential of electric vehicles to support the grid, particularly by enabling wind and solar power to increase their penetration of the electricity market (Kempton and Letendre 1997). “Several major automobile manufacturers have announced near-term plans to produce and mass-market electric vehicles,” they wrote at a time when General Motors was producing the EV1 vehicle. “The electric-drive vehicle (EV) will increasingly be connected to electric utilities over the next decades.”

Kempton and Letendre suggested that EVs would be available as grid assets 96 percent of the time, comparable to power plants. Moreover, they noted, “to a first approximation, the passenger vehicle fleet has ten times more capacity than all the nation’s electrical generation equipment combined, it was purchased at one-tenth the cost per unit of power, and it is idle most of the time.” Earlier work on smart charging examined such possibilities as the use of EV charging during low-demand hours in a “valley filling” approach (Ford 1994). Kempton and Letendre went further, postulating that vehicles could provide power back to the grid at critical moments—vehicle-to-grid.

Since then, dozens of researchers have explained how smart charging and V2G can not only reduce the grid impacts of EV charging but serve many other useful purposes as well. While GM’s EV1 was never widely commercialized, a new generation of electric vehicles began entering the marketplace in the late 2000s and early 2010s. Today, the EV market, though still at an early stage, appears to have momentum.

The Grid of the Future

Smart charging is part of larger transformations affecting the electricity grid, and many recent initiatives have explored what the grid and utility of the future might look like. A few examples are California’s More than Smart initiative (De Martini 2014), the Smart Electric Power Alliance’s “51st State” (SEPA 2017), New York’s “Reforming the Energy Vision” proceedings (NYREV 2017), and the Electric Power Research Institute’s Integrated Grid efforts (EPRI 2014). Other relevant studies include the US Department of Energy’s *Future of the Grid* (Gridwise Alliance 2014), the Rocky Mountain Institute’s *Reinventing Fire* (Lovins and Rocky Mountain Institute 2011), the Advanced Energy Economy Institute’s *Toward a 21st Century Electricity System in* California (AEE 2015), MIT’s *Future of the Electric Grid* (Kassakian et al. 2011) and *Utility of the Future* (Pérez-Arriaga et al. 2016), the Pacific Northwest National Laboratory’s *Smart Grid Demonstration Project* (Hammerstrom et al. 2015), and the Pecan Street Project’s *Smart Grid Demonstration Program* (Pecan Street Inc. 2015), as well as many others.

The diverse visions explored by these initiatives and studies share several elements:

- **Increased prevalence of distributed energy resources (DERs).** Rooftop solar panels, energy storage systems at homes or businesses, and other DERs can provide fast-response, localized stability for the grid, with artificial intelligence and machine learning improving the ability to predict demand changes (Chhaya 2016). The growing prevalence of DERs requires identifying their value and reexamining the utilities’ business model.
- **Reduced carbon emissions from the electricity grid.** The scientific literature has clearly documented the deleterious impacts that unchecked carbon dioxide (CO_2) emissions will have on human well-being and the environment (Field et al. 2014). Reducing emissions provides a net economic benefit (Nordhaus 2010; Stern 2006).

- **Electrification of transportation and other energy end uses.** This can reduce carbon emissions and provide the utility industry with revenue for investing in grid upgrades.
- **Continued improvements in energy efficiency.** Efficiency improvements are among the most cost-effective means of reducing carbon emissions per unit of energy services delivered, but they pose a challenge for utilities that generate and deliver electricity. The utilities' fixed costs would be spread over a smaller amount of energy sold, necessitating higher rates. This is offset to a degree by the electrification of additional energy end uses.
- **Greater use of information technology.** The many opportunities to connect consumer-owned equipment to utility data streams can provide data in real time and optimize many aspects of grid performance, but safe operation requires effective cybersecurity measures. Utilities have employed "bring your own device" programs for smart thermostats that can communicate with the utility's systems. This experience can be built on for other devices.
- **Increased interactivity of supply and demand.** Price signals, automatic controls, distributed energy management systems, or other solutions may govern such interactions. "Transactive energy" refers to the use of real-time price signals to govern them.

These changes are occurring for many reasons: the 1990s restructuring of utility regulatory environments, global efforts to limit carbon emissions, vastly improved communication systems (e.g., the Internet), and improved renewable energy technologies. Wind power has a major role to play in the grid of the future, and existing systems can handle much more wind power than was originally thought (Parkinson 2015; Weiss and Tsuchida 2015).

The technological change that in effect creates a paradigm shift is the rise of solar power. With rapid cost declines, scalability, and potential for distributed generation, solar power can drive major changes in the power system. Already, it has led to electricity surpluses at certain times of the day. Solar also has spurred interest in energy storage and the design of electricity rate structures. And deployment is poised to continue. Research suggests that we will need to add energy storage to the grid to accommodate solar power when it reaches very high levels (Jacobson et al. 2015; Keith and Safaei 2015; Williams et al. 2015).

Additional solutions could support expanded use of solar power on the grid. Solar power benefits from a grid that can handle variability in supply. Information technology and transactive energy models can help incorporate solar power into the grid, as can flexible loads such as EVs. This benefit is noted by the Electric Power Research Institute (EPRI) (Chhaya 2014), the National Renewable Energy Laboratory (NREL) (Markel 2015), the California Public Utilities Commission (CPUC) (Langton and Crisostomo 2014), the Independent System Operator/Regional Transmission Operator Council (ISO/RTO Council 2010), and many others. As the Natural Resources Defense Council noted in comments on EV infrastructure proceedings in Massachusetts, "There is no other load of comparable magnitude that is flexible enough to be pushed to hours of the day when the system is underutilized or when there is over-generation of renewable resources" (Tonachel and Baumhefner 2014).

The value of flexibility will vary by the geography and time period considered. An analysis for California found that dynamic charging of EVs for renewables integration offered a net present value of $850 per vehicle (E3 2014). An analysis for several Northeastern states found EV benefits ranging from $107 to $265 per year per vehicle, taking into account benefits to other ratepayers and reductions in carbon emissions (Lowell, Jones, and Seamonds 2017).

Flexible loads can provide a range of grid services, as detailed by the Rocky Mountain Institute in *The Economics of Demand Flexibility* (Dyson et al. 2015), NREL researchers (Milligan and Kirby 2010), and many others. Sometimes, utilities pay end users for their willingness to reduce demand when needed; "demand response" is a well known and partially established practice in the electricity sector. There can even be value in increasing electricity demand at specific times. California is conducting the "Excess Supply Pilot," enrolling end users in contracts to draw power from the grid when needed. Other flexible loads include electric water heaters and commercial air conditioners that incorporate ice storage (Hledik, Chang, and Lueken 2016).

The Brooklyn-Queens Demand Management Project is a standout example of adopting the principles of the grid of the future (Elcock 2016). This $200 million Con Edison project, which makes it possible to defer a $1 billion substation upgrade through approximately 2024, includes storage, demand reduction, and demand response. The project incorporates financial and regulatory innovation as well as new technology: Con Ed can receive a return on investment for all expenditures, including services, and it can obtain incentive returns up to an additional 1 percent.

Although the grid of the future is partly about new technologies, the most significant challenge and opportunity may be to get incentives and business structures right. New York's Reforming the Energy Vision initiative is addressing this issue through the Brooklyn-Queens project's incentives.

The importance of getting incentives right is illustrated by an observation of what can happen with the wrong incentives. The “utility death spiral” refers to a theoretical impact of distributed solar. If utility customers using solar power zero out their utility bills while still using the grid, the utility must charge its remaining customers more. This encourages even more customers to adopt solar, further raising rates on those who remain (Kind 2013). Utilities have responded by seeking to impose a variety of costs on customers that use solar. The “death spiral” has not occurred, but as battery costs decline, rate structures that overly penalize grid-connected solar power could lead consumers to leave the utility system entirely. Compared with an integrated grid solution, this approach will yield less-than-optimal economic outcomes unless rate structures and market rules encourage customers to use their DERs to benefit the grid rather than giving them reasons to disconnect.

The Impact of Renewables and Distributed Energy Resources on the Power System

Solar photovoltaic (PV) systems are key to the grid of the future. The costs of PV modules (solar panels) fell 99 percent between 1976 and 2015 and 80 percent just since 2008 (Liebreich 2016). This happened because the technology was deployed in niches where it was viable, including power for satellites and small electronics, as well as off-grid power and eventually grid-tied systems for early adopters (Geels 2002). Indeed, early adopters have driven the market, whether to reduce emissions of carbon and other key pollutants, contribute to national energy security, or express other personal values. State and national initiatives supported deployment in the 1990s and 2000s, and more adopters joined in, installing solar even when it was not the cheapest option for electricity (Leon 2013; Kimura and Suzuki 2006). Because of these policies and early adopters around the world, the market has continued to grow and costs to fall, to the point where new solar power is cost-competitive with fossil generation in some regions even without subsidies or a national price on carbon (Lazard 2016).

Considerable overlap exists between owners of electric vehicles and photovoltaic systems (CSE 2015; CSE 2014). Owners of one can install the other to reduce emissions even further. Smart chargers can mitigate certain negative impacts of PV or other variable resources in many locations and on many time scales. This may require the ability to communicate with various levels of the electricity infrastructure, although specialized services such as demand-response aggregators may eliminate the need for device-level communication with grid-scale entities.

While PV integration into the grid presents challenges, it is important not to overstate them. PV systems affect transmission, distribution, and generation (Gigliucci 2012), and the impacts occur at timescales from seconds to seasons. NREL and many others have evaluated the impacts on electricity generation and transmission (Denholm, Clark, and O’Connell 2016) and on the distribution system (Palmintier et al. 2016). Although these analyses do not focus on vehicle-grid integration, they do suggest that “new controllable electricity uses, such as electric vehicles, may provide additional opportunities to improve the timing of demand to match the supply of solar energy” (Palmintier et al. 2016).

The economic cost of integrating solar power with the grid appears small for the near and medium term. Consequently, reducing the costs of PV integration is of relatively minor value at present. Smart charging is not solving an expensive problem. Utility integration costs for 14 percent PV energy (far higher than any utility in the country) were modeled to be under $4 per MWh, while the value of the electricity generated typically exceeds $30 per MWh (Luckow, Vitolo, and Daniel 2015; Mills et al. 2014). Other researchers have found a small net benefit from PV on distribution systems, due to capacity benefit, but they did not specify the cost of required ancillary services (Cohen, Kauzmann, and Callaway 2015). However, utilities traditionally spread integration costs for power plants across consumers through the rate structure or present-day regional grid operators (Lovins 2014), so reducing the integration cost of PV may not affect the economics of PV power directly.

This projection of solar integration costs conforms to experiences with wind power, which appears fairly easy to integrate into the grid. Wind and solar provided about 7 percent of electricity generation in 2016; while a tenfold increase from 2006 levels (EIA 2017), that level is still easily managed, and expectations of higher integration costs have not been borne out. Even where these renewable energy sources are more common, the operators of power systems have managed well, adjusting practices based on wind forecasts and based on enhanced visibility and control of wind-farm operations. The region covered by the Electric Reliability Council of Texas (ERCOT), an independent system operator that covers most of Texas and has very limited ability to import or export power that might reduce the impact of wind variability, generated 15 percent of its annual energy from wind power in 2016; it reached 50 percent wind power on at least one day in 2017 (ERCOT 2017).

If much higher levels of intermittent renewables pose a real economic cost, then market mechanisms such as demand response and frequency regulation will place a high value on flexible loads. EVs could then earn revenue by providing these services, reduce the cost of renewables integration, and accelerate further PV deployment. On the other hand, if the economic impact of intermittency is minor, smart charging could still accelerate PV deployment by alleviating concerns about intermittency even in the absence of any market signals.

LOCAL IMPACTS: OVERVOLTAGE AND POWER QUALITY

Most studies of the cost of integrating renewables into the grid focus on the entire system. However, the near-term impacts of PV are greatest on the distribution level, with overvoltage and power quality among the most pressing concerns (Mather 2015; Steffel 2014). Overvoltage results when a distributed energy resource located close to regulation equipment adds more power locally than the system can accept (Steffel 2012).

The distribution system generally allows a 5 percent range of tolerance around the nominal voltage—so a 120-volt household service may actually vary from 114 volts to 126 volts. On a typical residential feeder circuit, homes closest to the utility substation will have voltages at the higher end of this range and voltage decreases with distance from the substation. If solar panels on the closer houses generate power during the daytime and use little power at that time, the voltage level on that section of the distribution line can increase above the permissible range. Other sorts of problems can also occur, whether caused by the solar panels or by loads on the circuit. “Power quality” encompasses not only voltage levels but numerous other potential problems with the electricity power supply (for example, “voltage flicker” and “harmonics” are two other aspects of power quality). The inverters that convert solar power from direct current into alternating current can be designed to improve power quality. Systems with such functionality are called “smart inverters.”

However, just adding a capability is not enough. For a time, smart inverters had their “smarts” switched off by utility-industry standards and expectations. New industry standards were needed to allow the capability to be used. Smart inverter measures include California’s “Rule 21” and IEEE Standard 1547a (Berdner 2015). These protocols allow inverters to help address various power-quality problems (Nelson et al. 2015). Also, the inverters can function as grid-edge sensors to offer utilities better insight into the operation of distribution grids (St. John 2015).

A report commissioned by the Florida Solar Energy Center provides an overview of using EV charging to address overvoltage events. “Besides arbitrary time constraints in communication protocols, no technical constraints have been identified,” it notes (Schwarzer and Ghorbani 2015). Much like solar power systems, EVs and their chargers also feature sophisticated power electronics that could, in principle, provide benefits to the grid beyond simply preventing negative impacts on power quality.

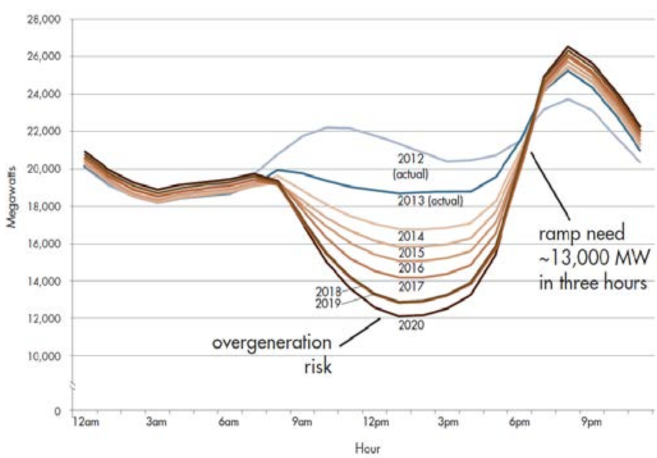
Without more awareness of vehicle use, it might appear that using smart charging to assist with distributed PV impacts is like trying to fit a square peg into a round hole. PV production peaks around noon, and most EVs are at workplaces during the day; this would mean that residential PV cannot charge EVs. In fact, about 57 percent of households have somebody at home nearly all the time (Pritoni et al. 2015), and 41 percent of cars are at home at noon on a typical weekday (Langton and Crisostomo 2014), although early data suggest that only around 10 percent of EVs are typically at home at that time (Schey, Scoffield, and Smart 2012). Distributed solar might charge other EVs on the same residential feeder. Other options to mitigate the impact of PV on distribution include stationary home storage (possibly integrated with an EV charger), a utility-scale battery at the transformer, and allowing backflow of power out of the feeder so the residential PV can support workplace charging.

ISO-SCALE: THE DUCK CURVE

The most significant potential impact of high levels of solar on the power system would be on generation and power prices at a regional level. The impact could reduce the economic viability of baseload power plants, increase the demand for flexible generation, and possibly threaten the revenue base of utilities.

The utility industry commonly cites the “duck curve” as a grid-scale danger of high levels of solar power (Figure 1). Solar panels generate power in the middle of the day, so other power plants could generate less at that time. Figure 1 shows net power demand on the California grid on a typical spring day, after considering solar power generation. In 2012, there was relatively little solar power. That is the baseline, the “back” of the duck. In each subsequent year, with increasing amounts of solar power, less and less power is needed from other sources from about 10 am to 4 pm. These lines form the deepening “belly” of the duck. In the late afternoon and early evening, peak power demand increases. Abundant on-demand generation needs to be kept in operating condition and ready to meet demand, although it will sit idle most of the day. With those power plants unable to earn any revenue

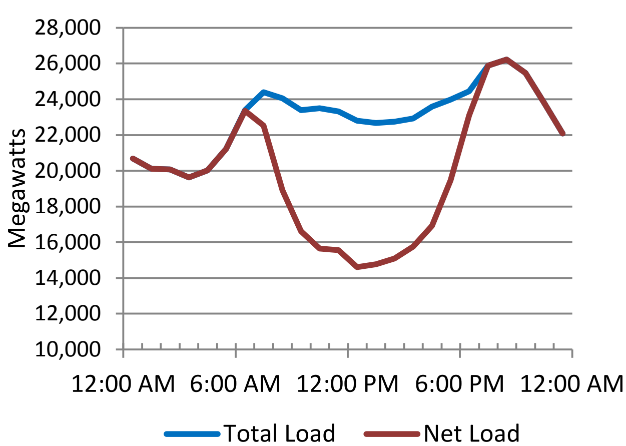
FIGURE 1. **The Duck Curve in California on March 31**



Decreasing net load after PV generation in the middle of the day cuts into baseload generators and requires fast ramping in the afternoon hours.

SOURCE: CAISO 2013.

FIGURE 2. **Actual Generation as Reported by the California Independent System Operator (CAISO) for March 31, 2017**



The 2013 CAISO projections for 2017 are close to the actual system performance.

SOURCE: CREATED FROM CAISO RENEWABLES REPORTING DATA (CAISO 2017).

by operating in the middle of the day, the generators have to charge higher prices in the evening to recoup their costs.

Without addressing this effect, midday solar production eventually will push other generation off the grid. The need for flexibility to ramp up supply as the sun sets will exceed the flexibility available. When that happens, no more solar generation can be accepted, and any excess solar will be "curtailed" (will not feed power into the grid).

Flexible loads from EVs, water heaters, air conditioners, and other systems can play a significant role in resolving this problem (Lazar 2016a; Lewis 2014). By shifting load to the middle of day, they can flatten the curve and reduce the evening ramp-up that other supplies must meet. To enact this shift with more midday EV charging, commercial buildings could be encouraged to provide workplace charging. While demand charges could deter a workplace from doing this, improved rate design can achieve the desired outcome (Allison and Whited 2017; Lazar and Gonzalez 2015).

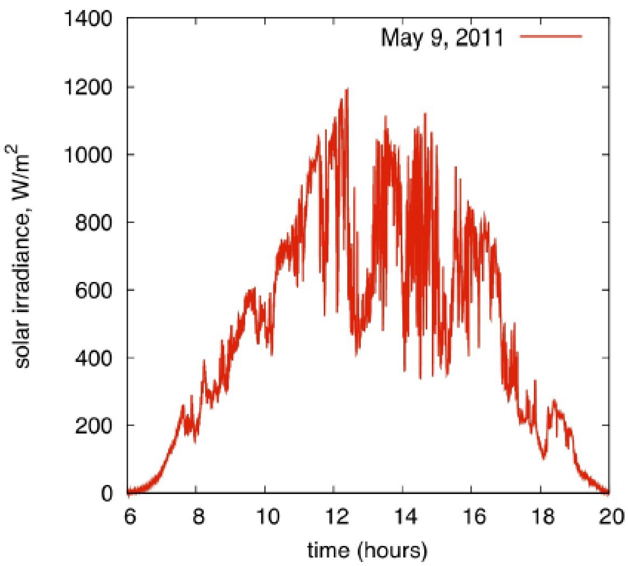
With V2G, EVs could actually move renewable energy supply from surplus periods to the evening peak. Today, there are too few EVs, even in California, to make a large impact on this load shape. In the future, when EVs reach a level of around 5 percent of overall electricity demand (i.e., if roughly 25 percent of all light-duty vehicles were electric), they could have a significant impact alongside other flexible loads.

The duck curve is generally considered a California problem, yet similar curves have been calculated for Hawaii, Italy, and Australia. Further, solar is starting to affect the load shapes in New England and may do so in New York by 2024 (Sedlacek 2016; Tarler 2015).

Increasingly, solar is considered along with wind for unexpected variations in output (Luckow, Vitolo, and Daniel 2015; Moore et al. 2015; Weiss and Tsuchida 2015; Mauch et al. 2013). Passing clouds may be short term and have local impacts (Figure 3), whereas a major storm system could limit power for days over a wide area. Flexible loads can mitigate the local effects of short-term intermittency, and they can provide ancillary services designed to address short-duration fluctuations in the overall supply-demand balance. This requires fairly short interruptions of demand, just long enough for other generators to respond to a loss of solar power output.

The duck curve also illustrates how solar power's pattern of energy production creates economic pressures for the technology. The more solar is added to the grid, the less each new addition is worth, because new solar produces power at roughly the same time as the existing systems, adding to the oversupply (Perez 2015; Mills and Wiser 2014). Although the most immediate impacts of adding PV to the grid seem to be

FIGURE 3. **Short-Term Intermittency from Altostratus Clouds at Mesa Del Sol PV Facility**



Passing clouds can create local variability in solar power output from minute to minute.

SOURCE: MAMMOLI 2012.

FIGURE 4. **EV Charging Pyramid**

This graphic suggests relative numbers of the various types of charging stations.

SOURCE: ZHOU ET AL 2014.

short term and limited to the scale of individual distribution lines, such as overvoltage, this peak value erosion is a longer-term problem that is potentially much larger. Time-of-use pricing combined with workplace charging could benefit solar by providing more midday demand, thereby supporting the rates solar systems earn from selling power and benefitting EVs by providing low-cost clean electricity.

THE GRID IMPACTS OF ELECTRIC VEHICLES

Assuming the market share of EVs continues rising, their impact on the grid will depend on the charging infrastructure used. Figure 4 illustrates the relative abundance of each type of charger that will play a distinct role in the widespread adoption of EVs. Most charging happens at home. Presently, single-family homes with garages have the easiest time installing chargers, while multifamily homes remain a challenge. Home chargers may be Level 1 (an ordinary 120 V outlet, charging a vehicle at a rate of around 1.5 kW) or Level 2 (a 240 V outlet, usually providing around 7 kW). Workplace charging offers many benefits for extending range and raising awareness of EVs. Fleets of EVs could be significant providers of grid services, and networks of public fast chargers could alleviate range anxiety and possibly convince some vehicle buyers who are uncertain about the suitability of an EV for their needs. Public chargers are unlikely to account for a large fraction of vehicle charging.

Workplace charging, fleet charging, and home charging are most suitable for smart charging (Quattrini 2016). Applying smart charging to public charging stations likely yields small benefits compared with the costs and could impair the driver experience. These stations are typically meant for relatively fast charging, so taking action to slow or delay charging is not normally advisable.

For home charging, although clustering could cause local impacts, “PEV charging has had a negligible effect on the distribution-system components to date and is expected to have a negligible future effect at the anticipated rates of PEV adoption” (Committee on Overcoming Barriers to Electric-Vehicle Deployment et al. 2015). Utilities have raised the option of adjusting the price of power based on the specific circuit to signal the costs imposed by clusters of chargers (Bialek 2015).

To the extent there are costs, they tend to be driven by high-powered chargers leading to transformer upgrades. In Eversource territory in New England, EVs have driven upgrades on specific residential transformers only when customers have installed 20 kW Tesla chargers (Collins 2016). Its neighboring utility, National Grid, does not yet see enough value in deploying smart charging communication infrastructure to defer the replacement of transformers. That distribution investment is not overly expensive and is projected to be fairly rare even at moderate levels of EV deployment (Valenzuela 2016).

Even if an EV charger is the "tipping point" that necessitates a transformer upgrade, the EV owner need not pay for that upgrade personally. "Asserting that a given EV 'caused' a transformer upgrade ignores all previously added loads which brought the transformer to the point of exceeding its capacity" (Tonachel and Baumhefner 2014).

An earlier concern about EVs was that a smoother load profile and more off-peak charging could hurt transformer lifetime by eliminating cool-down periods (EPRI 2012). However, research has found that not to be the case (Buchholz 2014). Smart charging algorithms can limit the extent of any impacts that might affect transformers (Hilshey et al. 2012).

Appropriately designed incentives require the balancing of three interests: cost savings to utility customers, utility support for EV owners, and performance incentives to utility shareholders (Ryan and Lavin 2015). Utilities also need strategic direction to consider EVs in their integrated resource planning processes. Smart charging makes EVs more than just a demand on the grid, but a resource that can respond to grid needs and conditions and provide essential services.

Engaging the Consumer

If the flexibility of EVs can benefit the grid, what could encourage EV owners to provide this service?

First, consider what a "typical" charging practice might look like. Is the right model that of the gas station, where an EV owner charges once a week or so for a vehicle's total range? An EV with a 200-mile range that drives 20 miles a day could charge once a week at work, where nine hours on a Level 2 charger would fill it up even with some modest fluctuations for grid services. Or is the right model closer to the smart phone, where the owner plugs it in every night and takes other opportunities to top off? These two models, which can be described as "gorging" and "grazing," could also apply to electric buses, using a battery charged once for the entire day or employing en-route charging.

The driver's greatest concern will be the possibility a vehicle is not charged when needed. Virtually every pilot project considers and addresses this situation, such as with an override button, an app that ensures a minimum charge by a specified time, or some other strategy. In practice, few consumers use overrides even when the option is available, suggesting that existing smart charging programs do well at avoiding any inconvenience to drivers.

Many experts observe that "set and forget" is a useful goal for smart technologies: the consumer is engaged at one time, and after that the system works without further intervention (Pecan Street Inc. 2015). Others note that the real hurdle is enrolling consumers in a program, such as a time-of-use plan; once enrolled, they are engaged, and even fairly small cost differentials will motivate them to shift their loads (Gross 2016). Still other experts note the potential for environmental factors to motivate decision-making (Lazar 2016b; McCready 2016).

If enrolling consumers is challenging (utilities have widely varying degrees of success at this), the best time is likely when a vehicle is purchased (Moskovitz 2014). The manufacturer could convey an up-front rebate offered by the utility if the buyer enrolls in the smart charging program. Enrolling might give the customer a smart-phone app with options for "fueling." These could be "economy charge" (as low cost as possible to charge by a specified time), "urgent charge" (as fast as possible, at a higher rate), and "custom charge" (conforming to other specified criteria, perhaps to charge when the least-polluting power is available) (Lazar 2016b).

Receiving a rebate and enrolling in a smart charging program would also require letting the utility know exactly where a 6 to 20 kW power demand has been added. This is good: while current chargers are not an overwhelming load on the grid, utilities like to know when and where EV chargers are installed. Some have tried asking states to share motor vehicle registry information. Alternatively, the Salt River Project (an Arizona utility) gives EV owners a $50 Amazon gift card for joining their "EV Community." This entails notifying the utility of the EV model, service address, and charging system. A number of conference participants agreed that EV early adopters tend to be engaged, knowledgeable, and willing to serve in an outreach capacity. Such activities might be promoting ride-and-drive events, raising awareness of utility EV programs, sharing information on forums with new EV owners, and participating in a smart charging pilot.

The Utility Role

In a number of ways, utilities could bring the benefits of EVs to the grid and promote beneficial charging practices. A wide range of utilities participated in UCS's research for this report. Large and small municipal utilities attended the conferences we convened, as did vertically integrated, investor-owned utilities, restructured distribution companies, and other entities, such as the Tennessee Valley Authority.

Utilities in general support the goal of introducing more electric vehicles to the grid and interested in the concepts of smart charging and load management. Also, high EV penetration may lead to substantially increased electricity sales, directly benefitting vertically integrated utilities. Deregulated utilities would not benefit in this way, but if they can spread their prior fixed costs over more kilowatt-hours, without needing to invest heavily in new infrastructure, they can reduce costs per kWh for all customers—including those who do not own or operate EVs. Overall, utilities have emphasized the importance of safety, reliability, and value to ratepayers.

Utilities have a role to play in EV infrastructure, but the specifics are a topic of considerable discussion. Currently, some locations, such as many low- and moderate-income neighborhoods, are uneconomical for a third party to serve, so utility investment might serve an unmet need and achieve a social goal. These do not have to be rate-based investments: the Jacksonville Electric Authority has used air-quality funds to install EV chargers (King 2016). Independent charging providers and ratepayer advocates have fairness concerns about utility proposals to install charging systems and recoup the costs through billing all customers, including those who do not own EVs. However, the impact on non-EV owners of EV infrastructure *can* be positive, in reducing the need for future rate increases (Lowell, Jones, and Seamonds 2017). And it is not always a decision between utility investment and third-party investment; many approaches feature both.

The utility plays a key role as both holder of information and consumer of ancillary services. Charging providers such as ChargePoint, Greenlots, and EVGo recognize opportunities to work with utilities as partners. To avoid excessive costs for system upgrades, the utility's knowledge of the distribution system is essential when siting new chargers. Also, if there is value in providing grid services (such as demand response or frequency regulation), these services could be sold to the utility rather than an ISO in many parts of the country.

The trend in the EV supply equipment sector is toward faster charging speeds, thus increasing the power demand from each vehicle charger. At the UCS conferences, many utility stakeholders expressed interest in finding ways to accommodate higher-powered chargers without incurring exorbitant demand charges or unduly straining the grid. Integration of storage into chargers is a possibility, especially if the utility can operate the battery to provide other revenue streams and defer other costs. Several representatives of utilities noted that high-powered charging can significantly affect their systems, and they were interested in the speed with which higher-powered fast charging would become the standard. With batteries of 60 kWh or more becoming widespread in the Chevy Bolt and the Tesla Model 3, the typical 50 kW fast charger would no longer be considered "fast," taking over an hour to fully charge a battery. Would 150 kW become the new standard? Automakers noted that EVs with smaller batteries could not handle that sort of power input; 150 kW chargers as they emerge will coexist with 50 kW stations. Electric bus manufacturers noted that some of their systems would charge at 350 kW. Utilities can be valuable partners in siting charging depots for such systems.

Utility representatives reiterated the importance of knowing where on the grid the EV chargers were being installed, including the specific feeder. Engaging with EV owners, as the Salt River Project does, seems the best way to achieve this outcome.

Some experts suggest that vehicles should contain the communication and control capabilities, while others think that a stationary charger is a better option. From the utility point of view, locating the intelligence in the charger seems to offer more benefits. If the charger includes GPS and time references, it can offer a grid operator highly accurate measurements even when no vehicle is charging; this can be an important reliability service. Placing the intelligence in stationary chargers would also help in using smart charging to deal with local issues such as load levels and power quality on the distribution line, where an accurate GPS location may not be enough to identify the specific circuit a vehicle is charging on.

Some utilities have other reasons to support smart charging. Austin Energy determines its contribution to ERCOT transmission expenses based on its share of the system's load at peak hours from June to September. This gives it an incentive to employ demand response to reduce load during those times. EV charging would normally increase the peak load, but it need not do so if deployed with demand response capability. Additionally, ERCOT is an energy-only market that relies on scarcity pricing to ensure adequate reserves. Demand response can provide a significant benefit because the price of electricity during critical peak periods can be very high. Accordingly, Austin Energy is seeking to deploy automated, intelligent EV charging, with a focus first on demand response.

ISO Markets and Grid-Scale Services

Keeping all of the possible uses and values for smart charging in perspective requires considering the nation's larger regional grids and the diversity of electricity users and suppliers. In much of the United States, independent system operators (ISOs) administer markets that are open to many types of participant. In such environments, EV smart charging must prove its worth for wholesale-level functions and benefits.

Flexible loads represent one set of options for helping the grid align supply and demand. These loads will compete against one another (perhaps EVs against water heaters and ice chilling systems), and against other options such as flexible generation or dedicated grid storage batteries. Storage pilots or demonstration projects might be warranted for research purposes, but mandating batteries as the sole solution for integrating renewables could prove overly expensive.

The enthusiasm of technology providers for their products can lead them to be insufficiently clear on the technology's features and benefits. At the 2015 conference of the Energy Storage Association, Jigar Shah, a consultant on profitable solutions to combating climate change, stressed the importance of specifying which services a storage technology will provide, rather than just saying it will support solar power. In an online comment, Shah noted 18 potential applications for storage, including nine types of ISO grid services and four types of local utility grid services (Lacey 2015).

Similarly, providers of smart charging and flexible loads need to be clear about which services they will seek to provide. As both a form of storage and a competitor to dedicated grid batteries, smart charging can offer many of the same types of services (such as frequency regulation), although some are not possible (such as "black start capability" to restart a generator after an outage).

Large-scale grid needs generally fall along three timescales: *regulation* is minute to minute, *load-following* (dispatch) ranges from minutes to hours, and *scheduling* refers to day-ahead, unit-commitment decisions (Milligan et al. 2011). Some products operate at faster timescales, such as voltage control and reactive power management (seconds) or fast frequency response (sub-second). EVs can perform both of these (Mitchem 2015; Wu et al. 2012). Other grid needs have longer timescales, such as the seasonal variations in PV power output.

Short-term services like frequency regulation can be provided with only minor impact on charging speed, especially if many EVs are connected. Any actions to benefit the grid on the timescale of hours are unlikely to come from smart charging on an as-needed basis, but design of the system can induce shifts of hours on a more predictable basis (such as time-of-use rates or workplace charging).

Many markets allow flexible loads to provide grid services. This is a very fluid area and subject to change; prospective market participants can consult directly with their regional grid operators to learn about the latest developments. CAISO has several avenues for EVs to participate in grid markets, including demand response, frequency regulation, and spinning and non-spinning reserves. PJM features V2G participation in its frequency regulation market, and ISO New England allows controllable loads such as EVs to participate as alternative technology regulation resources. ERCOT has also demonstrated smart charging for grid services (fast frequency response).

The barriers to EV participation in ancillary services markets are those faced by distributed energy resources more generally, such as minimum resource size, restrictions on aggregators, telemetry requirements, and transaction costs. Some of these transaction costs are independent of the resource size, making them prohibitively expensive for small projects and incentivizing aggregation by firms with focused business models.

Some areas also have opportunities for flexible loads to provide value to the utilities, not just the markets administered by ISOs. For example, California's "resource adequacy requirement" on utilities can provide an opportunity to earn revenue from technologies capable of reducing demand. In addition, interest is increasing in using EVs for "energy assurance." This term, referring to resilience in emergency situations, would benefit from vehicle-to-building power supply. Nissan offers this option with "LEAF-to-Home" in Japan but not in the United States.

The administration of markets varies greatly across ISOs. The details of the services differ, as do market rules, so opportunities in one area may not apply in another. Federal policymakers could push ISOs to look at innovation and consider the ways in which DERs can help them operate their grids.

Distribution Capacity Deferral

Normally, when one residential customer increases demand, all ratepayers bear the cost of necessary upgrades to the distribution system. If smart charging can avoid the need for upgrades, that would be a reason to create economically defensible incentives for smart charging.

The Rocky Mountain Institute has noted the deferral of distribution capacity as one of the most significant values provided by energy storage (Fitzgerald et al. 2015). Performance-based incentives for the utilities, rather than relying solely on the regulated return on capital investments, could lead to greater utilization of smart solutions on the distribution side. Distribution restructuring initiatives in California, New York, Massachusetts, and other states are exploring ways to encourage consideration of alternatives.

An important consideration in distribution investments is to ensure that they are flexible and modular, making them as “future-proof” as possible. “Modularity would mitigate stranded cost risk and enable future optionality to benefit from unforeseen innovations such as was the case with modular smart meter designs developed before the iPhone was launched” (De Martini 2014). More broadly, it is possible to change the business models for electricity distribution, keeping in mind the goals of resiliency, reliability, social priorities, equity, and other aspects (Newcomb, Lacy, and Hansen 2013).

Even the existing utility regulatory structures offer possibilities for creative solutions. In North Carolina, Duke Energy faced local opposition when it sought to meet peak demand in Asheville by building new generating capacity. It is now working with the community to reduce demand enough to make the plant unnecessary.

Smart charging has the potential to defer distribution upgrades that could be required by unmanaged charging. Quantifying this value of deferring investments can be contentious. It requires data and transparency, as well as good information on what specifically imposes costs on utilities’ systems.

Rate Design and Implied Incentives

The design of utility rates can make a significant difference in the success of electric vehicles. For example, California’s inclining (tiered) rate blocks, intended to foster conservation, can make it difficult to add the electric load of an EV even when that vehicle reduces energy use and produces less pollution than the gasoline vehicle it replaces. In Massachusetts, an imprecise definition of peak period and resulting on-peak pricing creates a penalty; drivers may prefer to use grid power for “preconditioning” an EV on a cold day, warming up the interior of the vehicle while it is plugged in. Here, and likely in many places, the utility and state regulators have adopted time-of-use rates that start the “on-peak” period at 8 am, well before the system approaches its real peak. This raises the cost of warming up the vehicle, illustrating the unintended consequences of a time-of-use rate mismatched to peak demand hours. Another category of rate elements, demand charges for businesses, can deter the owner of a commercial property from installing workplace chargers.

The utility ratemaking process can also enable incentives for certain types of investments. Smart-charging incentives that subsidize EVs without reflecting actual value provided would not offer a long-term solution. On the other hand, compensation that reflects real benefits provided to the grid and to society would make incentives economically defensible. As noted, deferral of distribution capacity investments can be a significant benefit, and one that is typically not monetized. The dollar value of avoided emissions of carbon or other pollutants may be uncertain. However, “[t]o not incorporate externalities in prices is to implicitly assign a value of zero, a number that is demonstrably wrong” (Koomey and Krause 1997). Externalities have to be considered.

In recent years, most rate design discussions have addressed a different distributed energy resource: solar power. This has spurred many analyses, often seeking to address concerns about utility compensation in a high-DER future. Without making sweeping statements about the wide range of literature, in general these studies share several conclusions (Wood et al. 2016):

- Smart meters should make it easier for rate design to take into account the causes of cost increases or decreases.
- The combination of rate design and technology can help some customers modify some of their consumption patterns to reduce the costs they impose upon the grid.
- Rate design must also consider principles of simplicity and equity.
- Increasing fixed charges is unlikely to support the goals of reflecting cost causation (establishing rates that reflect the costs imposed on the grid), enhancing equity, or reducing externalities. High fixed charges adversely affect low-usage customers, who are often lower income.

FIXED CHARGES AND DEMAND CHARGES

Some households typically use less electricity than the residential average in nearly all regions of the United States: elder households; low-income households; and households headed by an African American, Latino, or Asian American. Increasing the role of fixed charges in tariffs would place a disproportionate burden on these groups. Fixed charges are a blunt instrument that fails to address cost causation appropriately.

Fixed charges also would be problematic for any customer trying out a time-of-use plan with a separate meter for the EV. The fixed charge would apply once to each meter, considerably increasing the cost (as well as the initial cost of installing the second meter).

General themes addressed in the UCS-convened conferences included simplicity, fairness, discrimination, and efficiency. Good rate design should reduce regressivity in the allocation of home energy costs and benefits and narrow the home energy burden gap among residential ratepayers. It should enhance the home energy security of low- and moderate-income ratepayers, reduce service disconnections, and increase access to affordable, reliable service (Howat 2016). In addition, utilities could improve opportunities for aggregators and other third parties by providing better information about the value of energy, capacity, and ancillary services (Trivedi 2016).

Workplace charging has the potential to mitigate "duck curve" effects. However, commercial rates typically feature demand charges, which are based on a building's peak load at any one moment. If adding EV chargers increases a building's peak load, the building will pay higher demand charges. In theory, this reflects the strain the building places on the grid. The actual relationship to grid costs can be quite different, especially if the building's peak does not align with the system peak. Rate design should encourage workplace charging to take advantage of abundant solar, low wholesale power prices, and available system capacity. Demand charges that fail to take into account the timing of a building's peak relative to the system peak do not achieve efficient economic outcomes (Allison and Whited 2017).

TIME OF USE RATES

Demand charges emerged before metering could record the time of highest user demand. Today's smart meters can track energy use at 15-minute intervals, providing options for improving rate designs. Generally, shifting a greater portion of utility cost recovery from demand charges to hourly volumetric rates would better align demand with system needs. Time-of-use pricing is a way to do this; it is one of a broader set of options called time-varying pricing, along with real-time pricing, critical peak pricing, and other options (McNamara, Jacobs, and Wisland 2017).

Time-varying pricing raises some questions and concerns, given that price-responsiveness differs between groups of customers. A 3,000-customer pilot by the Sacramento Municipal Utility District included 1,000 low-income participants. The low-income participants could lower their electricity usage by about 11 percent during critical peak pricing events, while other customers could decrease their usage by about 20 percent. The primary reason for this difference was that the low-income customers had lower air conditioning loads to begin with (Lazar 2016b).

Smart grid technologies present additional benefits that should be considered, including improved information about grid and energy consumption patterns, but it is essential to allocate risk appropriately. The introduction of time-varying pricing can be a managed, gradual process for broader consumers with "shadow billing" and "hold harmless" provisions. A utility might employ both of these, for at least a year each. In the "shadow billing" phase, a consumer would remain on their current rate while receiving bills showing their hypothetical charges under the pending time-of-use rate. This would give consumers the opportunity to learn how they could adjust energy consumption to save money. In the "hold harmless" phase, the consumer would shift to the time-of-use rate but with a guarantee that their bills under the new system would not exceed what they would have been under the old rate. These and other approaches can enable utilities to achieve efficiencies without hurting those who cannot easily alter their consumption patterns. Such rates could be the default for new EVs, with an opt-out option. Over time, a shift toward appropriately designed time-of-use pricing for all would improve economic efficiency.

Currently, electric vehicles are well suited to time-based rates with controlled charging, and the potential exists for them to provide arbitrage in V2G configurations in the future, buying power when prices are low and selling it when prices are high. EVs and other dynamic loads will alter load shapes in response to time-of-use rates. More "smart loads" will reduce profit opportunities—for example, by diminishing the peaks that provide opportunities for demand response. Still, these shifts are unlikely to eliminate profit opportunities, and they will reduce the costs of operating the grid by reducing the prices for demand response.

Time-of-use pricing relies on "peak" and "off-peak" periods as fixed in rate structures. These structures change slowly, and the periods are not dynamically adjusted. Some experts propose time-varying plans that would adjust more rapidly, such as a three-part "full value tariff" (Patel et al. 2016). This approach would provide incentives for such strategies as price-induced load shifting, battery storage, and "smart loads" for EVs and air conditioners. San Diego Gas & Electric is piloting a similar structure, determining hourly rates a day ahead and varying them by location to account for the utility's predictions about renewables generation and power grid congestion.

The Automaker Perspective

Using EVs as a flexible load would benefit from the involvement of utilities. Getting the vehicles on the road in the first place requires the involvement of automakers.

The automakers contributing to the UCS effort have a range of experiences with EVs in the United States and overseas. They have deployed combinations of solar, storage, and EV charging at several facilities. They have demonstrated demand response from EV chargers, collaborated with the Electric Power Research Institute on a common charging protocol, and developed technological solutions to manage vehicle charging for fleets. And they have launched many research projects.

In general, automakers emphasize placing a priority on driver needs, finding convergence on standards and protocols, and expanding the charging infrastructure. They see value in time-of-use rates, showing evidence of consumer behavior in response to these plans. Automakers that have conducted pilots with smart charging view it as a fairly minor revenue stream that could have value in the future. If so, they want to ensure that some of the value goes to vehicle owners, which would be an incentive to buy EVs.

Automakers recognize that residential charging will continue to provide most charging for EVs, with an extensive infrastructure in place: literally every garage that has a 120V outlet has a Level 1 EV charger. Still, Level 1 charging is not particularly fast, and many drivers have neither a garage nor dedicated off-street parking. Automakers would like to engage utilities in developing charging solutions for these drivers.

Participants in the UCS conferences acknowledged the need for adequate charging infrastructure. The automakers and other stakeholders also discussed more technical topics such as the communication, control, and payment tracking for EV charging.

The major difference of opinion among automakers concerns standards for smart charging. Some favor ISO 15118, which is the standard in Europe. This allows plug-and-charge capability: the charger recognizes the vehicle, with no extra step needed to use an RFID card or a credit card. The charger and the vehicle exchange encrypted digital certificates, automatically and instantly. The system can accommodate smart-charging algorithms, handle location-specific prices, and respect customer preferences. Other automakers favor the OVGIP platform, developed with the utility-industry-supported Electric Power Research Institute. The OVGIP platform is meant to handle not only ISO 15118 but also numerous other communication protocols. Handling many possible uses of smart charging, it is intended to be "future-proof" by being flexible enough to accommodate new features.

Disagreement partly revolves around the need for a smart charger versus having the utility communicate directly with the vehicle. European manufacturers favor smart chargers, and US automakers are more inclined to have their vehicles communicate directly with the utilities (Mültin, Gitte, and Schmeck 2013). Some US automakers are concerned that allowing a third party or intermediary device to affect the rate of charging could lead to poorer experiences for consumers—particularly a vehicle not being charged when needed. On the other hand, the electric vehicle supply equipment industry includes entities that have specialized in working with utilities and ISOs to provide demand response and other grid services, while automakers are less familiar with this area. Some EVSE stakeholders have urged adoption of the ISO 15118 standard. Others seem amenable to working with different standards.

Technical Issues

It is generally agreed that the technology is here for smart charging, and stakeholders are working to resolve remaining technical issues.

Such issues have been addressed on a case-by-case basis in smart charging pilots, but greater standardization will be necessary for broader adoption. Properly designed hardware can be flexible and amenable to over-the-air software upgrades, so not every technical question would need to be resolved immediately.

COMMUNICATION SYSTEMS

How does an electric vehicle know about grid conditions? How much can it vary the charging to provide ancillary services? If the distribution circuit sees a voltage problem, how is a decision made to use one system or another to compensate?

The power grid initially relied on many tons of spinning mass to provide the correct frequency and voltage, and that system was relatively slow to respond. EVs and their chargers are among the new smart grid technologies that can react much more quickly, given a reliable communication pathway between the vehicle and the grid.

That communication pathway has several aspects. Aggregators using EV chargers for demand response or some other service typically maintains two layers of communication. They must communicate with the utility or ISO, which is typically a straightforward process. They also must communicate safely and reliably with either cars or EV supply equipment, and that is more of a challenge. Automakers might not want to navigate dealing with the nation's 3,300 utilities, which might use a variety of communication systems or have different rules for demand response. Thus, third-party aggregators might provide value.

An aggregator could use Wi-Fi, smart meter systems, cellular networks, or the FM radio network. Any of these could make it possible to communicate with vehicles directly or indirectly through EVSE. The radio pathway is more limited, because it is one-way and cannot confirm that demand response was performed, yet it could be a useful redundancy system (Tuttle 2016).

Wi-Fi infrastructure is likely to be a low-cost solution for providing demand response, whether from EVs or from water heaters and thermostats. The problems with using Wi-Fi include cybersecurity and reliability; neither problem is intractable.

As charging goals become more complex, the software and communications increase in sophistication and cost. This is not due to the price of hardware, which is inexpensive at scale. Developing, validating, and maintaining the code can cost far more. As with many aspects of smart charging, this problem relates to scale. Once software is developed, it can be replicated essentially for free.

SUBMETERING

An important advance in California has been the acceptance of the metering capabilities present in the chargers as suitable for providing billing data (such as for an EV-only, time-of-use rate). This approach, which offers considerable savings over installing a second utility meter, has been accepted in all three areas of California with investor-owned-utilities. It saves $2,000 to $10,000 in capital costs, and the switch to time-of-use pricing saves $800 to $1,000 per year in energy costs, including the savings to other ratepayers when the EV owner reduces on-peak power consumption (White 2016). Subtractive billing would be required if the building where the EV is charged is not on the time-of-use rate but the vehicle itself is. The utilities in California can do this, and others are developing systems.

Case Studies

The utility industry, national laboratories, and other stakeholders have conducted many demonstrations and pilot studies to develop concepts into practice, observe the interactions between participants, and test business models. Such activities explore how intelligent interactions of demand and supply can provide multiple value streams. These benefits can include peak shaving, arbitrage, improved utilization of fixed assets, "green charging," alleviating transmission bottlenecks, and relieving strain on distribution transformers (Tuttle and Baldick 2012). Existing commercial products feature degrees of smart charging functionality, whether built into cars or as relatively low-cost adapters for EV chargers.

Some pilot projects have utilized these capabilities, while others have enhanced them or implemented V2G. Several of these cases were presented at the conferences organized by UCS. These are discussed below; the conference presentations offer greater detail and can be accessed online at *https://tinyurl.com/UCS-Smart-Charging*.

DELAWARE VEHICLE-TO-GRID

The pioneer of vehicle-to-grid, Dr. Willett Kempton of the University of Delaware, has implemented the technology for frequency regulation in the PJM Interconnection region. V2G has been providing grid services through this competitive market since 2013. This proof of concept and ongoing business have made it possible to license the technology for international deployment.

Frequency regulation involves short-term adjustments by electricity generators to ensure a balance between supply and demand. Typically, generators providing this service operate at less than maximum capacity and can increase or decrease generation as needed. In a V2G configuration, the vehicles connected to the grid can draw or supply electricity.

The pilot project uses a fleet of BMW Mini E vehicles. It is important that enough vehicles are connected at any one time to meet the fleet's commitments. In an ideal system, vehicle users would adhere to reservations and a schedule, so that frequency regulation commitments could be based on the number of available vehicles. In practice, the project uses a wide margin of error to ensure adequate regulation.

Vehicle-to-grid applications have benefited from the work done to streamline interconnection of PV systems, such as establishing standards. In addition, many technical issues facing V2G are being addressed for integrating storage into the grid more generally. Resolving these issues will help V2G become more viable, as will resolving outstanding issues regarding utility acceptance of inverter standards.

The PJM frequency regulation market is fairly small and quickly saturated, so this application is likely to become less profitable as increasing competition drives down prices. The demand for frequency regulation would theoretically increase with less predictability in the electricity system, as might be the case with increased renewables.

LOS ANGELES AIR FORCE BASE EV FLEET

A fleet of electric vehicles at the Los Angeles Air Force Base also performs frequency regulation through vehicle-to-grid. Like the PJM fleet, this resource is fully eligible for market participation.

Unlike the University of Delaware, the Air Force Base has a retail rate disincentive in the form of demand charges. However, its fleet has two revenue streams: it is paid both to be available for frequency regulation and to perform the service when called upon. It is larger than the PJM system, certified as a 500 kW resource, although this is small by CAISO standards. The system has been very good at following the signal from the utility to provide regulation, which is also true of using photovoltaic systems (Loutan and Gevorgian 2017). Both systems employ inverters, which appear to be capable of faster, more accurate response than varying the output from conventional generators.

One of the larger challenges is hardware reliability. Many components are prototypes, with only about one-third to one-half of vehicles online and responding at any given time. Another challenge is the integration of the V2G system into legacy systems at CAISO. CAISO's systems attempt to calculate the aggregate state of charge in the vehicles for purposes of determining their eligibility to participate in the market, but CAISO lacks the information to do this properly.

CAISO utilizes two rounds of resource scheduling (reserve scheduling and re-optimization), followed by frequency regulation at four-second intervals. Participating in this market requires a good understanding of fleet availability and therefore proper use of the trip reservation system. The optimization algorithm minimizes total costs while meeting all operational needs.

A final consideration is that the design of the CAISO frequency regulation market assumes that regulation is energy-neutral—that there is just as much need for regulation "up" as "down." Were this true, the participation of a vehicle fleet, or any energy storage system, would be simpler and more economic. However, an equal use of up and down regulation is not the case in practice. Performing regulation service in CAISO will change a vehicle's state of charge over time, rather than having a neutral impact if there were an equal amount of power flowing in and flowing out.

VEHICLE-TO-GRID CONSIDERATIONS

The projects at the University of Delaware and Los Angeles Air Force Base employ fleets of vehicles that have been modified to perform V2G. This configuration can earn more by providing a broader range of grid services. The primary barriers to further application of V2G are interconnection requirements—a system that can put electricity on the grid is regulated differently from one that merely draws power from the grid—and the impacts on battery lifetime.

For most batteries, each cycle of charging and discharging results in some degree of deterioration. If a manufacturer warrantees a 50 kWh battery to last for 150,000 miles, it expects the battery to perform up to the warranty standards for about 1,000 cycles (assuming three miles per kWh). If the battery experiences cycles of charging and discharging from V2G as well as from driving, then 1,000 cycles could occur well before the vehicle has traveled 150,000 miles. As V2G pioneer Tom Gage notes, "Almost without exception, [vehicle manufacturers'] first response is, 'If you use my battery for that purpose, we will void the warranty'" (Halper 2013).

If a battery costs $250 per kWh of capacity and has a useful lifetime of 1,000 cycles, V2G services would need to earn about $0.25 per kWh to compensate for the wear and tear on the battery. V2G will have broader applicability as battery technology continues to reduce costs and improve lifespan.

There are three caveats to that calculation.

- The “useful life” is often considered to end when the battery’s maximum capacity, and therefore its range, has declined to 70 or 80 percent of its initial capacity. The difference between 70 and 80 percent changes the necessary level of V2G revenue from about $0.20 to $0.30 for a Nissan LEAF (Saxton 2015). Other research finds that even the 70 percent threshold is overly restrictive when considering actual driving needs; increasing charging infrastructure should enable EVs to remain useful after capacity declines (Saxena et al. 2015).
- Several automakers have found that manufacturing capabilities and battery management systems allow for longer lifetimes than originally anticipated. However, these systems are optimized for driving, not V2G.
- The battery cycles from V2G are not identical to the battery cycles from driving. It may be too simplistic to treat all cycles the same. In particular, those from V2G may be more constant, with lower power output. A test of a Honda vehicle for V2G found no degradation from providing frequency regulation (Shinzaki et al. 2015). Other research suggests that the slower discharge from V2G produces less wear on the battery than does driving (Peterson 2012).

EMOTORWERKS JUICENET

As an example of the commercial application of load flexibility, eMotorWerks develops smart chargers and earns revenue by providing a range of grid services. Some of its products include after-market adaptations to make existing chargers “smart.”

The company’s JuiceNet Energy Services Platform can operate with a broader range of loads than just EVs. EMotorWerks, which is starting to work with water heaters, finds a high intrinsic value in modulating large, distributed, shiftable loads. This can help utilities avoid peak generation and capacity expansion.

The platform includes predictive algorithms, a self-learning driver model, a smart phone app, short control latency (three seconds), and instant local grid response. It can benefit ISOs, utilities, and end consumers.

EMotorWerks is participating in California’s Supply-Side Pilot, which entitles EV owners to a $100 rebate on their charging systems for enrolling. The company also won an award through California’s Demand Response Auction Mechanism.

One of the preferred options for many customers is “green charging.” This technology employs an algorithm by WattTime to selectively charge the vehicle when the greenest power is available, with an underlying goal of charging by the departure time regardless. This option would be especially important in an area where the vehicle is charging overnight in the Great Plains or the Midwest, when depending on the grid conditions either coal or wind power could meet the load from vehicle charging. Some modeling shows that smart charging for the lowest cost can increase coal generation, but that does not take into account innovations such as this.

EVERSOURCE SMART CHARGING

Eversource, a New England company that delivers electricity, is conducting a smart-charging pilot project. The company participated extensively in the UCS conferences.

When looking at grid impacts, Eversource believes that the speed of EV charging is as important as the time of day. Rather than using time-of-use pricing, its smart-charging pilot focuses on controlling the rate of charging. The company subsidizes EV owners’ purchase of Level 2 chargers that are managed to operate at their full capacity during low-demand periods but are restricted to Level 1 charging during high-demand periods.

This structure avoids the need for the extra utility meter that a time-of-use plan would have required (although the charger itself contains a meter that has been approved as revenue-grade in Europe). It also helps mitigate the post-peak demand surges that might occur in a time-of-use plan because the chargers do not suddenly switch on all at once—many vehicles will be fully charged by the time the system returns to Level 2 charging. Further, this structure is easier to manage for utilities that may not have back-office systems set up to include additional meter readings or offer EV-only, time-of-use billing. Finally, this plan never turns off the charging; it only reduces it to Level 1, and the customer can choose to override.

To date, only about 5 percent of charging events have used the override option. Customers have also proven to be very sensitive to the capital cost of chargers, indicating the importance of the rebate for ensuring the adoption of smart chargers.

GREENLOTS

Greenlots, a charging provider, discussed a number of smart-charging projects at the conferences, with its staff offering observations on workplace charging and the integration of stationary storage.

Greenlots provides demand response through workplace charging in Southern California Edison territory. One of its projects features 80 Level 2 chargers. Upon connecting, drivers select one of three options: a high price to charge as fast as possible with no demand response participation, a medium price for allowing the system to throttle back to a Level 1 charger during a demand response event, and a low price for allowing the system to stop charging during a demand response event. The exact prices, established one day ahead, are displayed at the payment kiosks, on the website, and via a mobile app. When a demand response event is called, users receive a text message and can pay a fee to opt out.

When instructed to cut load by an OpenADR signal from Southern California Edison, Greenlots uses the SEP2.0 protocol to communicate with the vehicles. The system also notifies EV owners to move their vehicles when charging is completed or incur a parking fee (an innovation recently adopted by Tesla for its Superchargers). This is to discourage drivers from leaving fully charged vehicles in charging spots.

In a separate project, Greenlots worked with Hawaiian Electric Company to integrate storage with direct current fast chargers. Here, the motivating factor was that the location could accommodate only 23 kW demand. To operate a 50 kW fast charger in this location without upgrading the distribution service, Greenlots installed a battery with the fast charger. Although fast chargers are normally thought to focus on charging vehicle as fast as possible, Greenlots is examining the value of doing short-term demand response (on the order of a few minutes) with such systems.

REAL-TIME APPLICATIONS FOR SMART CHARGING

The Boston conference included discussions of early pilot studies of smart charging, as well as lessons from the pilots on the use of autonomous features and functions.

Alec Brooks, of Aerovironment and previously of AC Propulsion, offered a series of examples of smart charging dating back to the early days of vehicle-grid integration. AC Propulsion’s tzero, the precursor to the Tesla Roadster, included bidirectional capabilities. Another AC Propulsion project involved demonstrating V2G capability with an electric Volkswagen Beetle in California in 2001 (Brooks 2002). In that market at that time, frequency response was a particularly valuable product. Brooks later took part in a PG&E/Tesla smart charging pilot in 2007 (Brooks and Thesen 2007), as well as a Google smart charging pilot in 2009 (Brooks et al. 2010). The Google pilot was binary: each vehicle would either be charging or not. With many vehicles charging, minor variations in power draw can be accomplished by turning individual vehicles on or off rather than by modulating their charging level. With this approach, the system only needs to communicate with the cars deemed to be on the margin (such as cars that are near a full charge and not expected to be needed for several hours).

Autonomous frequency-responsive charging could provide real-time services while not needing real-time communication with a central source. Vehicles could provide immediate response to grid conditions, at low cost. It would be possible to provide all of California’s necessary frequency regulation with about one million EVs (out of the 22 million cars in California), as long as their charging times were spread relatively evenly throughout the day.

With this or other options for smart charging, the financial benefit per vehicle is likely to be low, so solutions need to be low cost as well. EV chargers will compete with other flexible loads such as water heaters for the same market. As more competitors seek to provide a service, the price falls, which must be kept in mind when developing a business case for smart charging.

OTHER PROJECTS

The California Public Utilities Commission has developed an extensive database of many other vehicle-grid integration pilot projects (Orford 2016). A few notable projects not yet in that database, and also unable to present at the UCS conferences, include the following:

- The Pecan Street Project in Austin, Texas, concluded its Smart Grid Demonstration Program in 2014 (Pecan Street Inc. 2015). The project team created a system to tie together EV charging with PV production, such that the EV only began charging when the PV system was producing power. Participants solved a number of issues related to charging protocols.

Air conditioner energy use was significantly higher than EV energy use in most months, and so the project also demonstrated integration between vehicle charging and air conditioning. The Energy Switch system described in the report utilizes a relatively small battery (2 kWh), greatly smoothes load profiles, integrates PV, and can mitigate peak demand for EV charging.

- ERCOT tested electric trucks for fast frequency response. These trucks were part of a Frito-Lay delivery fleet in Ft. Worth, Texas (Mitchem 2015). The vehicles were technically successful at following the signals from the grid, but the economics were not favorable given the small project size (100 kW), the cost of telemetry requirements, and the low prices for this service in the ERCOT region.
- The Pacific Northwest Smart Grid pilot project and the PNW Final Technology Report were extensive and included a major focus on "transactive energy" (Hammerstrom et al. 2015). This would be a key catalyst for integrating PV-EV into the grid. Communication, interoperability, and system integration were pervasive issues.
- The PowerShift Atlantic project did not include electric vehicles but did use other flexible electric loads, enabling the grid in Atlantic Canada to accommodate high levels of wind power penetration (Losier 2015).

[CHAPTER 3]

Modeling Results

Widespread deployment of EVs with smart charging could affect the nation's electricity grid at all scales, from improving power quality from a local distribution feeder to supporting midday electricity demand and making better use of solar power across an ISO territory. EV charging could act as a flexible load on the timescale of hours, vary every few minutes for frequency response, or provide portable storage with vehicle-to-grid technology.

How can we quantify the benefits of smart charging? The electricity system is enormously complicated and subject to any number of changes in the years to come.

UCS has modeled the impacts of smart charging using the Regional Energy Deployment System (ReEDS) of the National Renewable Energy Laboratory (NREL). ReEDs, a long-term capacity-expansion model for the deployment of electric power generation technologies, calculates the cost-optimal mix of technologies to meet demand requirements in two-year increments out to 2050. We used UCS ReEDS, our 2016 version of the ReEDS model, which was based on the version used in NREL's *2016 Standard Scenarios* annual report. UCS adjusted the NREL model based on project-specific data and estimates from recent studies.

Computer models do not predict the future; rather, they are a way to illustrate the possible effects of specific changes. UCS employed three scenarios based on the NREL Standard Scenario. All of these scenarios include the impacts of existing state and federal climate and energy policies, as well as planned power plant construction as of January 2017 and announced retirements as of October 2016. In our reference case, we modeled no load growth from electric vehicles. Two other cases assumed moderately aggressive growth in EV deployment, increasing from about half a million EVs on the road today to about 12 million electric vehicles by 2025 and 120 million by 2050. The eight states following California's Zero Emission Vehicle (ZEV) regulations account for about 25 percent of US population and have a goal of putting 3.3 million ZEVs on the road through 2025. NREL's Vehicle Electrification Scenario, the basis for our EV energy demand, assumes no regional differences in EV market penetration. This is not the case of today's quite pronounced regional differences. EVs have achieved their greatest levels of adoption in states with relatively clean electricity systems, such as California, Oregon, and Washington.

NREL's Vehicle Electrification Scenario assumes a split between managed and unmanaged charging. We sought to assess the difference between these two strategies, and so modeled one case with entirely managed charging and the other with entirely unmanaged charging. In the unmanaged case, the vehicles add to hourly energy demand according to a specific schedule, potentially increasing peak demand. In the managed case, using a very basic modeling of smart charging, the vehicles' load is added to the daily energy demand that must be met. The model determines the hours of the day when it is most cost effective to supply that energy but does not consider any benefits or revenues from providing any sort of grid services, reserves, or storage (although V2G could quite well be more widespread by 2030).

This basic form of managed charging lowered average electricity prices slightly (0.4 percent by 2030), but it increased carbon dioxide emissions slightly (1 percent by 2030) relative to the unmanaged charging case. Similar results were found by the NREL (Melaina et al. 2016), the EPRI and the Natural Resources Defense Council (EPRI 2015), and Georgia Tech researchers (Thomas et al. 2013).

One important reason for this is the lack of a Clean Power Plan or similar policy. The ReEDS model optimizes the electricity system for lowest-cost operation. Pollution imposes an economic cost on society, but it is not fully reflected in energy prices and is only recognized by the model when incorporated into policy. As a result, managed charging would take place overnight in some regions and could increase generation from coal power plants (as well as other types of power plants).

A second reason is the limited form of smart charging recognized by the current version of the ReEDS model. Existing smart charging systems demonstrate the ability of EVs to contribute to reserve requirements, provide demand response, and even function as storage. The model does not reflect these capabilities, even though they are likely be widespread by 2030.

A third reason is the rebound effect. Managed charging lowers electricity costs compared with unmanaged charging, and it even lowers electricity prices slightly compared with the non-EV case. Lower costs induce higher consumption. Both the managed and unmanaged cases stipulate the same energy demand from EVs (about 70 million MWh per year, resulting in about 28 million tons of CO_2). The managed case sees slightly increased electricity demand for other applications, with increased CO_2 as a side effect of lower electricity prices.

The differences among the scenarios are very small, because EVs will have only a minor impact on the electricity system by 2030 even with optimistic growth projections. These changes are too small to be taken as definitive given the uncertainty inherent in modeling. However, these slight differences do hint at concerns that should be addressed. As the NREL study noted, "An increase in emissions need not always occur. The change in emissions depends on the grid mixture and the structure that encourages vehicle behavior" (Melaina et al. 2016).

The managed charging case found slight cost savings for all consumers from smart charging, due to reductions in electric system costs. Unmanaged charging requires more generation capacity, so that scenario has a higher cost of operating the grid. The total generating capacity of the grid in 2030 in the "managed charging" case is about 17 GW lower than in the "unmanaged charging case." The difference largely comes from adding new natural gas capacity to meet the unmanaged electricity demand. The unmanaged case features 15 GW of new (post-2015) natural gas generation over the reference case in 2030, while the managed case does not. The additional natural gas capacity in the unmanaged case is primarily combined-cycle gas turbines. Other generation capacity is largely unchanged. There are some slight differences in electricity generation, but these are also too small to be taken as definitive.

Table 1 (p. 22) summarizes the national results under the three models.

We conclude that "smart" charging will have to look beyond "lowest nominal cost" and consider the goal of reducing pollution. Tools such as the WattTime algorithm can help here. This program, incorporated into EMotorWerks' JuiceBox charger, can allow overnight Level 2 charging that selectively charges when wind is on the margin. A level 2 charger provides about 20 miles of range per hour of charging and might need to operate for only one or two overnight hours. That allows a great deal of leeway.

It would be economically efficient to design regulations so that pollution is no longer an externality (a cost that somebody else pays). Under such a paradigm, the cost of the damages from pollution would be paid by the producer of the emissions. Lowest nominal cost would then better reflect lowest actual cost, including the impacts of pollution. Without such a system in place, other solutions include the charging algorithms mentioned above, "green power" purchasing options to increase the amount of renewable energy, and regulatory action to require emissions-reducing technologies.

When considering pollution, the location of emissions matters as well as the quantity. EVs move emissions out of the city center, and from multiple point sources to relatively few, where they can be more easily controlled.

A study in ERCOT found that EVs reduce emissions of carbon dioxide, nitrogen oxides, particulate matter (PM10 and PM2.5), and ultrafine particulate matter (UFPM), although they can increase emissions of sulfur dioxide due to increasing generation from the remaining coal plants (Legatt 2016). All these emissions can be reduced by smart charging. The reduction and relocation of UFPM is of particular importance: this pollutant does not travel far from its emissions source, so moving it out of city centers yields considerable health benefits. Ultrafine particles can pass through the blood-brain barrier and lodge in the prefrontal cortex; an extensive and expanding literature documents the dangers of continued UFPM exposure (Calderón-Garcidueñas et al. 2008).

At higher levels of renewables, the benefits of smart charging are more notable. NREL conducted a California case study featuring a 50 percent reduction in greenhouse gases by 2030, accomplished by 56 percent renewables in the energy grid (Brinkman et al. 2016). At times, solar in this modeled grid could represent up to 60 to 85 percent of power generation. The study found annual savings from smart charging of $190 to $650 million per year in generation costs, which comes out to $63 to $217 per vehicle. This result is a net economic benefit if the installed cost of the smart charger is under $2,000 (common for residential Level 2 smart chargers but not yet so for workplace or public systems). Also, this does not consider other financial effects, such as changes in building-level or distribution-level peak demand. Nor does it consider the economic value of emissions reductions—managed charging reduces grid CO_2 emissions by 1 to 4 percent. Another study found an even greater benefit if the storage mandate is not in place: smart charging of EVs can provide much of the benefits of storage at a lower cost (Denholm and Margolis 2016). If regulations require a substantial storage capacity, and “smart charging” does not count toward this requirement, then it has only modest additional value as a flexible load.

In general, EVs benefit utility ratepayers. Increased electricity sales enable utilities to spread their fixed costs over more kilowatt-hours, reducing costs per kWh (or at least slowing the rate of increase) for all customers. The benefits to all ratepayers account for $73 to $166 per vehicle per year in a study of several Northeastern states (Lowell, Jones, and Seamonds 2017). Added to this are the benefits to the vehicle owners and the benefits of reducing greenhouse gas emissions. Another study finds a net present value of $850 per vehicle in grid benefits (E3 2014). Other studies also describe these benefits to ratepayers (Malgrem, Roberts, and Sears 2016; Baumhefner, Hwang, and Bull 2016).

TABLE 1. **Modeled National Impacts in 2030**

	Reference Case	**Managed Case**	**Unmanaged Case**
Generating Capacity (GW)	1,102.5	1,104.4	1,121.4
Coal	206.4	206.5	206.7
Natural Gas	419.1	418.4	434.2
Nuclear	95.9	95.9	95.9
Hydropower	84.1	84.2	84.3
Wind	108.7	111.1	110.8
Solar	149.8	149.9	151.0
Electricity Generation (TWh)	4,196	4,269	4,265
Coal	1,345	1,385	1,368
Natural Gas	1,005	1,028	1,038
Nuclear	758	758	758
Hydropower	366	367	367
Wind	392	401	401
Solar	239	239	242
Electric Sector CO2 Emissions (MMT)	1,682	1,733	1,716
EV Electricity Consumption (GWh)	--	69,590	69,590
EV Electricity CO2 Emissions (MMT)	--	28	28
Vehicle CO2 Emissions Avoided *(MMT, estimated at 240 g/mi)*	--	~50	~50
Average Electricity Rate ($/MWh)	104.88	104.85	105.31

GW=gigawatts; TWh=terawatt-hours; MMT=million metric tons; g/mi=grams per mile; MWh=megawatt-hour

Conclusions and Policy Recommendations

It is no longer novel to say that electric vehicles have considerable potential to support major deployments of renewable energy. This has been demonstrated in theory and practice through many papers and pilot projects. Presently, these capabilities of EVs are not greatly valued, because the electricity generation system has abundant flexibility. However, EVs could provide a low-cost complement to dedicated energy storage systems in the future, and they could be very useful on a grid with abundant renewable energy.

Over the past two years, UCS has had the opportunity to meet with a broad range of experts, many of whom have worked on smart charging for electric vehicles for a decade or longer. From our research, a review of the literature, and the convenings of experts and stakeholders, we have drawn several conclusions.

Support Workplace Charging

Workplace charging can provide many benefits. It provides a natural opportunity to assist with “duck curve” conditions because it tends to be concentrated in the late morning, when solar produces power but air conditioner loads have yet to peak. However, workplace charging is not a prime candidate for demand response, a service that typically has its highest value in the afternoon or early evening. Nor is it optimal for frequency regulation: the vehicles are available only for about 17 percent of the hours in a typical week (Quattrini 2016).

Workplace charging can raise awareness of EVs and improve range confidence. A prospective EV buyer would know they could charge at work and even discuss the technology with colleagues who own EVs. Workplace charging often leads to remarkable, rapid increases in EV ownership (Gaschel 2016).

Two main concerns arise: demand charges and infrastructure cost. Demand charges could be reconsidered to take into account the timing of the peak (Allison and Whited 2017; Lazar and Gonzalez 2015). Alternatively, a greater portion of cost recovery could be shifted to energy costs with time-of-use pricing.

For several reasons, it costs more to install EV chargers at workplaces than at residences (Agenbroad and Holland 2014). As colleagues adopt EVs, charger capacity becomes saturated (Quattrini 2016) and the number of vehicles may exceed the number of chargers. The chargers may remain occupied for the entire day, even though the vehicle may be charged after only an hour or two. Because of the cost of installing new chargers, a business can seek to encourage EV owners to rotate their vehicles. Another idea is a multiplexed charger, a single charger with four cables automatically rotates the charge without requiring moving or even unplugging the vehicles.

On the down side, ensuring that charging capacity is fully utilized at all times would likely result in having far fewer chargers than vehicles, spending considerable time and effort moving vehicles around, and losing opportunities for load flexibility. A preferable solution would be to reduce the installation cost of charging stations. This might involve scheduling the installation to coincide with work on the parking lot or garage to lessen the costs of digging into concrete.

Consider Greater Use of Time-Varying Rates for EV Charging

Changes in the design of rates are crucial for enabling workplace charging. In particular, it is important to reconsider demand charges that ignore the timing of the peak demand. Shifting more of the recovery of utility costs from demand charges to hourly volumetric rates would better align demand with system needs.

Time-of-use pricing offers price signals to limit contributions to system or network peaks, and smart charging works well with that structure. This is already established in policy, encouraging vehicle owners to charge in a manner advantageous for the grid. Some additional management may be necessary to stagger the charging when a low-cost period begins, and this is easy to implement. Both economic and environmental factors motivate customers to enroll in such programs, and once enrolled, customers tend to respond to the time-of-use price signals.

An important consideration here is that ratepayer advocates and others remain unconvinced that promised system efficiencies have happened when utilities installed advanced metering infrastructure, including smart meters. The result is some hesitancy about wider installation until the benefits are better documented. Alternative “sub-metering” approaches rely on the metering capabilities of the EV chargers, which would avoid the costs of installing new utility meters. This approach requires regulatory flexibility on metering requirements, as well as the ability by the utility to implement subtractive billing (if the primary account is not on the time-of-use rate but the EV is).

Another consideration is the need to revisit time-of-use periods and adjust them as more renewable energy comes onto the system, especially solar power with its relatively predictable daily cycle. Some existing peak periods start earlier than appropriate and make preconditioning an EV difficult.

A third consideration is that not all customers have the ability to adjust their energy consumption. It is important to be cautious when applying time-of-use rates broadly. For example, some customers have medical devices that draw significant power and cannot shift that demand. Time-varying pricing with “shadow billing” and “hold harmless” provisions can achieve efficiencies without hurting those who cannot alter their consumption patterns.

More sophisticated time-varying rates are possible, and pilot projects are evaluating the performance of these rate structures for EVs and for other loads.

Align Regulatory Incentives to Realize Distribution System Benefits

Compared with unmanaged charging, smart charging can limit the need for upgrading the distribution system (as could smart technology on solar PV and other distributed energy resources). Incentives should encourage the use of technologies to reduce electric system costs.

A traditional framework for regulating utilities might not give a reason to look at these solutions. Electric utilities are responsible for maintaining the distribution system. They can recoup the costs of necessary investments. But what if flexible loads could enable the utility to deliver equal or better reliability at lower cost than upgrading transformers and substations? If the existing paradigm is to put “steel in the ground” and earn an approved rate of return on it, what would motivate a utility to manage its loads so as to not need to put steel in the ground?

A utility commission could directly require a utility to take certain actions. Alternatively, it could allow the utilities to earn a higher rate of return by finding creative solutions that meet specific goals, such as limiting system cost, reducing pollution, or improving reliability. Reforming the Energy Vision in New York is applying some solutions and considering more far-reaching changes, including a range of alternative business and regulatory frameworks. A utility could offer rebates to ratepayers who take actions that help it meet these broader goals.

In designing pilot projects, various stakeholders must recognize benefits, readying them to apply and scale up new options. If a smart charging solution involves the utility, the EV manufacturer, the EV owner, and the charger manufacturer, everybody has to find enough benefit to justify the time and effort needed to implement the solution. The cost-benefit analysis should become less of a hurdle as the scale of smart charging increases (thereby allowing greater grid benefits) and as these solutions become more familiar (requiring less time and effort to implement). As an additional benefit, larger-scale projects will feature greater predictability in performance. The more vehicles in a fleet, the greater the accuracy in estimating how many are charging and requiring grid services at any one time.

Enable EV-Charger Participation in Grid Services Markets

Flexible loads such as EVs can participate in ancillary services markets that offer potential revenue streams. However, smart charging will face competition from other flexible loads (for example, water heaters) and from dedicated batteries. As a result, the markets may become saturated relatively quickly. Increasing deployment of renewables is not expected to significantly expand ancillary services markets in the coming decade.

Typically, aggregation is required to enable EVs to participate in such markets. Some markets require a minimum 100-kW resource size, which is fairly reasonable. This would enable about 15 Level 2 chargers to cease charging entirely (such as for demand response). Some other markets have higher thresholds. Also, some costs of participating in markets are independent of resource size, making it difficult for small projects to participate. Aggregation is a solution, but some jurisdictions limit the ability of aggregators to participate in grid services markets.

Consider Flexible Loads and Vehicle-to-Grid in Storage Proceedings

Many states are interested in energy storage, particularly for accommodating increased renewables. Compared with dedicated stationary storage, EVs have intermittent connections that cannot be inspected every time, the risks of damage to batteries or cables are greater, and batteries are not optimized for providing grid services. However, the EV battery may be able to provide grid services at lower cost. With more and more EVs on the road and needing to be charged, why not make them a responsive load?

Other flexible loads include electric water heaters and commercial air conditioners. These cannot put electricity onto the grid, so they are not entirely equal to dedicated energy storage. Still, some degree of partial credit toward storage mandates could be appropriate.

The most important challenge for dedicated storage is identifying the value proposition. What outcomes are sought from storage? Can load flexibility achieve them?

Vehicle-to-grid is similar to other energy storage technologies in many ways, except that its mobile nature places it apart. It is not guaranteed to be connected to a particular distribution feeder, for example. This mobility can be a significant advantage, especially if using vehicle-to-home or vehicle-to-building for resiliency during natural disasters. Creative pilot projects around these issues would be valuable.

Define “Smart” to Include Pollution

Our modeling and other studies suggest that under certain circumstances managed charging could increase emissions relative to unmanaged charging. This could occur if the off-peak power in a region has greater emissions per kilowatt-hour than the on-peak power, and if the charging algorithm fails to account for the impacts of pollution. Therefore, we recommend that smart charging pilots or programs evaluate pollution impacts before encouraging charging at specific times. Wherever possible, EV owners should have a low-emission charging option.

An economically efficient solution is to incorporate the costs of pollution into energy prices. Lowest nominal cost would then better reflect lowest actual cost. Until such a system is in place, other solutions should be employed. For EV charging, these can include consumer actions such as “green” charging algorithms and “green power” purchasing, or regulatory action to require emissions-reducing technologies.

Accelerate Learning from Pilot Projects to Develop Local Expertise in Smart Charging

Pilot projects are not necessary to demonstrate proof of concept in smart charging, but they may be useful to ensure that utility personnel, regulators, and consumers are familiar with the concepts involved, as well as to resolve technical issues. We suggest a few questions to consider in designing pilots, although not all will be applicable in every case:

- What type of EV charging will the pilot focus on? Residential charging? Workplace? Private fleets? Public fleets, such as a car-sharing initiative?
- What specific vehicle-grid integration issues will the pilot address? Limiting the demand increases caused by residential EV chargers? Increasing midday demand to take advantage of surplus solar curve? Providing demand response capability? Managing load to limit local congestion? Integrating workplace chargers with a building’s energy management system to avoid demand charge increases?
- What do peers and experts say about comparable pilots, issues encountered, solutions developed, and lessons learned?

- How will the utility use the data generated by the technology? Beyond just the charging profiles, is there an opportunity to make use of chargers' data on voltage, frequency, and power quality?
- What are the various communication options? What are the advantages and disadvantages of each? Why are certain options selected. Should the utility communicate directly with vehicles, or do smart chargers offer advantages? What other technical issues arise? How can we share practical lessons learned?
- What are the public health benefits of emissions reductions and displacement? How can we quantify them in economic terms?

Participants in the UCS conferences suggested many other ideas for research. Among possible additional topics for future research are:

- How do we design policies to avoid having stranded assets?
- To what degree could public utility commissions relax their metering requirements to allow sub-metering from EV chargers?
- How can we better understand distribution-side costs and benefits?
- How do time-of-use rates affect low-income populations? What are the environmental justice impacts? And how can they be addressed?

We also suggest improving the models to better reflect the actual capabilities of smart charging of electric vehicles in providing grid services. Any analysis looking at 2025 or 2030 should consider vehicle-to-grid arrangements for some fraction of the vehicles.

The greatest uncertainty surrounding smart charging and vehicle-grid integration is the future of the transportation system. What if shared, autonomous, electric vehicles become the norm (McKerracher et al. 2016; Weiss et al. 2017)? They will likely have "charging depots" with high-powered connections for fast charging, and possibly energy storage. Such vehicles would have an economic incentive to maximize their utilization; they would not be idle for 90 to 95 percent of the time, which is now the case with privately owned vehicles. Still, if travel profiles remain similar to today's, many vehicles could be idle during the workday, with demand surges in the morning and evening rush hours. Midday charging on solar power would remain viable, as would overnight charging from wind power. Flexibility would decline during the evening rush hour. Given this vast uncertainty, it is probably not useful to attempt to quantify the impact of specific smart charging strategies in 2040 or 2050. In general, load flexibility seems likely to prove useful in integrating increasing levels of renewable energy into the electricity system.

Electric vehicles have the potential to significantly reduce emissions and improve the operation of the electricity system. The costs of unmanaged charging, and the benefits of managed charging, will first affect the distribution grid but will ultimately affect generators as well. The promising combination of time-varying rates and workplace charging can enable electric vehicles to charge at low cost from solar power that might otherwise be curtailed. This solution also increases the effective range of EVs and increases familiarity with the vehicles. Rate reform will be important to enable workplaces to make use of the abundant solar electricity in the middle of the day. In some areas, the surplus clean energy is wind power available at night. Smart charging can also make use of this resource, with charging algorithms or policies to ensure the electricity demands of the vehicles are met by clean energy. Along with other flexible loads, EVs can provide a low-cost option for integrating renewable energy into the grid.

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