ELECTRIC VEHICLE CHARGING IN THE 21ST CENTURY

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A Capstone Project submitted to Johns Hopkins University in conformity with the
requirements for the degree of Master of Science

Baltimore, Maryland

May, 2015

Abstract

The emergence of electric vehicles brings new power and energy demands to the electric grid. This paper considers the question: If all passenger vehicles converted to electric power, would coordinated electric vehicle charging be required to prevent damage to distribution transformers or to mitigate the need to build new electric generators?

Six potential vehicle charging strategies were considered: Unconstrained (no time constraints), Time of Use (TOU) Start (start when the electricity rate drops to the off-peak period), TOU End (driver specifies the time when the vehicle must be charged - the vehicle decides when it needs to start charging during the off-peak period), Flat (coordinated charging to flatten the load curve of the Regional Transmission Organization (RTO), Flat Algorithm (coordinated charging to minimize the ramp rate and to flatten the load), and Alternate TOU End (like TOU End but allows vehicle charging end times to follow the normal pattern of people going to work). Using the PJM calendar year 2014 load data and day-ahead pricing data, the yearly energy costs, ramp rates, and greenhouse gas emissions of each charging strategy were examined.

Coordinated charging strategies (Flat, Flat Algorithm and Alternate TOU End) result in the lowest overall costs, but the highest greenhouse gas emissions. The Time of Use strategies (TOU Start and TOU End) result in the highest overall system cost and the highest ramp rates, but the lowest greenhouse gas emissions. Each of these strategies produces a 50-70% reduction of greenhouse gas emissions from those of the current internal combustion vehicles. Some form of charging coordination is required, at both the global and local level, to minimize the need to add or replace electrical infrastructure.

Keywords: Electric Vehicle, Charging Strategy, Coordinated Charging

Acknowledgment

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ELECTRIC VEHICLE CHARGING IN THE 21ST CENTURY

Electric vehicles are coming. They may be a fad, or they may be the wave of the future. If a fad, then advanced planning for large scale adoption will simply be a small waste of time and effort; but if they are the wave of the future, then a detailed evaluation of their effect on the electrical grid and electrical markets will allow the most energy and cost efficient options to be planned, and then put in place. Large scale infrastructure changes always take time, planning and resources to execute. Ad-hoc responses to problems often lead to substandard and inefficient results.

The focus of this paper is to look into the future; a future where electric vehicles are the norm and fossil fuel powered vehicles have only a niche application. A smart grid unlocks the potential to use electricity more efficiently and to improve the stability of the existing electrical infrastructure. Some improvements may be achieved by making physical changes to the infrastructure, whereas others by Information Technology (IT). More than likely, the final result should be a mixture of both.

Electric Vehicles

A Hybrid Electric Vehicle (HEV) has a gasoline engine as its primary energy source. A battery and electric motor are incorporated into the drive train and braking system in some manner to allow energy from the battery to be used for very low speed operations, and to provide additional power during large acceleration events. Energy is returned to the battery during regenerative braking and through a separate generator that is powered by the gasoline or diesel engine.[1] The original Toyota Prius is a HEV.

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[1] This description of an HEV is purposely vague because there are a number of ways that the battery and generator can be incorporated into the vehicle (series, parallel, hybrid), with all being available on the market.

A Plug-in Hybrid Electric Vehicle (PHEV), such as the Plug-in Prius Hybrid, has a bigger battery that can be charged using a plug-in cord from the electric grid. The larger battery allows the vehicle to travel a greater number of miles using battery power only. When the main battery is at its low limit, the vehicle converts to acting as a HEV. The main battery cannot be recharged using the gasoline engine.

An Extended Range Electric Vehicle (EREV) is a hybrid electric vehicle with a large enough battery to support a large number of miles solely on the battery. The Chevrolet Volt is an example of an EREV, with 38-50 miles powered completely by the battery.

A Battery Electric Vehicle (BEV) uses a rechargeable battery as the sole source of power for the vehicle. The battery is recharged using energy from the electric grid. The Nissan Leaf and the Tesla S are examples of BEVs.

A Battery Electric Vehicle (Extended) (BEVx) is an electric vehicle which has an auxiliary power unit (normally gasoline or diesel powered) to charge the battery when it becomes highly depleted. The BMWi3 is an example of a BEVx.

The term Plug-in Electric Vehicle (PEV) is used to encompass the PHEV, the BEV, the EREV and the BEVx, but not the HEV. Section 131.A.5 of The Energy Independence and Security Act (EISA) of 2007 defines a Plug-in Electric Vehicle as a vehicle that:

"(A) draws motive power from a battery with a capacity of at least 4 kilowatt-hours;

(B) can be recharged from an external source of electricity for motive power; and

(C) is a light-, medium-, or heavy-duty motor vehicle or non-road vehicle (as those terms are defined in section 216 of the Clean Air Act (42 U.S.C. 7550))."

Until consumers are satisfied with the range of electric vehicles, there will be a push for auto manufacturers to increase battery capacity (energy content measured in kilowatt-hours (kWh)), which may result in the widespread use of higher powered chargers (measured in kilowatts (kW)) which would be needed in order to have the ability to fully recharge the vehicle's battery in a time acceptable to the consumer, which is assumed to be overnight.

History of Electric Utility Regulation

In the early 1900s, about 20 years after the development of electricity, and following a period where many electric companies strung wires side by side and competed for the same customers, Samuel Insull (the President of a local electric company in Chicago), recognized the electric industry as a natural monopoly and bought out his competitors. State legislatures responded by allowing the monopoly under two conditions: 1) that it provide power for all who wanted (all who would pay), and 2) that it would be regulated in the prices that it could charge. In many places the regulation also extended to a number of financial and operational aspects (such as requiring the use of standard accounting procedures) ("Emergence of Electrical Utilities in America", n.d.).

Fast forward 110 years to the present, where a well regulated energy industry provides electric power to meet the needs of the American public. Some parts of the United States have deregulated their electricity markets, where the generators, transmission, and distribution of electricity is controlled by separate companies but are bound together in a market run by the Regional Transmission Organization (RTO) or Independent System Operator (ISO). The remainder of the country is served by some form of vertically integrated utility, where the utility company owns and controls the

power generation, transmission and distribution of electricity. Each ownership model, market, and regulation structure has the potential for a different "best" electric vehicle charging strategy. With the advent of the electric vehicle, the electric industry will be expected to provide the electric energy (and power) to replace a large percentage of the transportation fuels currently used in the country. Depending on the rate and timeframe over which this conversion occurs, the capacity and reliability of the electric infrastructure may be put at risk. Unconstrained vehicle charging could require the construction of new power plants to address the increased power demand during peak periods. Alternatively, some means of controlling vehicle charging may be required. The control of vehicle charging could be by financial incentives, such as time-of-use rates (i.e. extremely high rates during peak periods and low rates during low use periods), or it could be by direct utility control of vehicle charging, or control by some third party aggregator working to meet utility company power constraints.

The Charging Evolution

There are two distinct paths associated with charging an electric vehicle: 1) the electricity flow from the power grid to the vehicle battery, and 2) the decision process; deciding where, when, and how to pay for charging.

Electricity flow. Using a market mechanism controlled by an RTO/ISO (company 1), an electrical power generating company (company 2) generates electricity which is raised to high voltages through step-up transformers and transmitted through high voltage power lines owned by an independent transmission company (company 3) to a substation which reduces the voltage to a level appropriate for local transmission and distribution by a local utility (company 4), with ultimate reduction of voltage using step-

down transformers, to the voltage required by the customer. In the case of an electric

vehicle, the electrical energy travels through the building (or residence) electrical

distribution panel to a Level 2 (208-240 volt alternating current (AC), single phase

power) charging station (built by company 5). For Level 1 charging (120 volt AC, single

phase power) this may simply be a 120 volt AC outlet. When the electric vehicle (built

by company 6) is to be charged using a Level 2 charging station and power cord (the

Electric Vehicle Support Equipment (EVSE)), it uses a connector which is configured to

conform to the Society of Automotive Engineers (SAE) Standard J1772 (Society of

Automotive Engineers, 2012b). Even when power is available to the vehicle from the

EVSE, for AC charging (Levels 1 and 2) it is actually the vehicle's Battery Management

System which controls the charge (the voltage and current applied to the battery during

the charging sequence).

Decision process. The decision of where to charge the vehicle belongs to the

driver but is predicated on 1) finding a charging station within the remaining range of the

vehicle which has 2) a compatible charging connector, 3) the authorization to charge at

the station, and 4) the driver is willing to pay the required cost to charge.

Where. It is believed that drivers will conduct most of their charging events at

their place of residence (or the designated business charging station for business fleet

vehicles) where the cost of charging will be billed to their local account. In addition, the

vehicle tends to remain idle for a long period of time while at home during the overnight

hours, affording an opportunity to conduct a complete charge of the vehicle.[2] The second

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[2] It is understood that some people work the swing and midnight shifts. Their charging pattern may not
follow the pattern of their neighbors. As will be seen, this out of cycle charging may actually improve the
overall charging evolution for the neighborhood and the utility, as some late morning charging is often
desirable.

most likely location will be at work, where a charging agreement can be easily reached

with their employer (assuming the company arranges for electric vehicle chargers for the

employees). Remaining Level 1 and Level 2 charging will likely be via public charging

networks (membership or credit card required). High voltage direct current (DC)

chargers (often called "fast charging") are likely to be placed in public areas and along

major roads and highways in order to support long distance travel.

     When. This paper addresses the question of when to charge, and whether the

charging process should be coordinated to achieve the optimum result.[3] Hadley (2006), a

scientist from the Oak Ridge National Laboratory noted, "True optimization depends

upon the objective function, be it lowest total or operating cost, best performance, longest

life, reduced emissions, or a combination of objectives." (p. 2)   Sometimes the optimum

solution may be counterintuitive. For example, if minimizing emissions is the sole

objective, then charging closer to the system's peak power may be optimal because

natural gas is likely the marginal fuel being used, as opposed to charging in the middle of

the night when coal may be the marginal fuel. (Hadley, 2006, Chapter 3)   As all system

costs are ultimately paid by the ratepayer, minimizing total costs (operating and capital

costs) is normally the overall objective. Capital costs may include the construction of

new power plants as well as the cost to replace and upgrade distribution transformers.

(Hadley, 2006, Chapter 4)   Charging 100% of personal electric vehicles (cars, SUVs and

light duty trucks) adds 10%-20% to the total electrical energy needed during the year.

(Denholm & Short, 2006, p.1)   If the assumed goal is to minimize total costs, then one

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[3] In this study the term "optimize" is used colloquially to mean a result that would be the lowest cost
solution that does not require the development of new generation capability, and does not require large
scale addition or replacement of distribution transformers (for the purpose of charging vehicles).

logical objective would be to allow all electric vehicles to charge without requiring any new electric generating capability or local infrastructure.[4]

Ongoing Experiments

Fortunately, some data about constrained and unconstrained human behavior is becoming available through reports of the EV Project, the Pecan Street Project, the Potomac Electric Power Company (Pepco) (a utility that covers Washington DC and surrounding Maryland counties), and various national laboratories.

The EV Project. In 2009, the US Department of Energy awarded ECOtality a grant of ~$100M for The EV Project. With a second Department of Energy grant of $15M, and partner co-funding, the project totaled ~$230M. Among other things, the EV Project "collected and analyzed data to characterize vehicle use in diverse topographic and climatic conditions, evaluated the effectiveness of charging infrastructure and conducted trials of various revenue systems for commercial and public charge infrastructure." (The EV Project, 2013, para. 4) Specifically, the project selected Chevrolet Volt and Nissan Leaf vehicles and drivers using Level 1 and Level 2 chargers. Testing was conducted in 21 major cities in nine States plus the District of Columbia (The EV Project, 2013, map). ECOtality is referred to in the past tense because it went bankrupt in 2013, (Stempel, 2013). There are a number of reports that provide data and/or conclusions from the EV Project. One of the reports most relevant to this paper addressed pilot programs designed to evaluate the effect of various peak to off-peak pricing differentials in the San Diego Gas and Electric (SDG&E) service area (Cook, Churchwell, & George, 2014).

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[4] It is possible that new transmission capacity may be required in certain areas to prevent localized congestion that will be made worse due to the added load of vehicle charging.

The Pecan Street Project. "Pecan Street Inc. is a research and development organization focused on developing and testing advanced technology, business model and customer behavior surrounding advanced energy management systems." (Pecan Street, n.d.) It is headquartered and has research laboratories at the University of Texas at Austin. Among other things, Pecan Street Inc. gathers and analyzes data from the Pecan Street Demonstration Project, a specially monitored housing district in Austin, TX. Most homes have solar panels on their roofs. Pecan Street Project data can be found at the Pecan Street Dataport (Pecan Street Dataport Home, n.d.). Of the 33 homes having one or more EVs that responded to a Pecan Street survey (27 responses), the average home has 2.1 vehicles, 2.3 people, at least one person with a post-graduate degree, and income of about $150,000. As such, it is not a "typical" American neighborhood (Harris 2013). Similar responses were noted when surveying The EV Project (Ecotality, 2013).

Pepco pilot program. Pepco, as well as many other utilities, is running an EV pilot program under the auspices of the Maryland Public Service Commission. In this program, EV owners use an advanced ClipperCreek smart charging system, outfitted with an Itron revenue meter and cellular communications technology to charge, gather data, and provide demand response capabilities for the vehicles in the program. As part of the pilot program, Pepco used the smart charging stations to carry out demand response events (for testing) and calculate the load impact of each event. Pepco indicated the goals of the pilot program as being: "… to validate electric vehicle smart charging stations to support consumer engagement, demand response, time-of-use rates and embedded revenue-grade metering. Pepco will be able to study the impact of electric vehicle charging to the utility distribution system." ("Pepco deploys …..", 2014) Preliminary

Pepco data can be found on the Maryland Public Service Commission website under Case Number 9261, document 108. (Maryland Public Service Commission, 2015a, b)

Standards

The Energy Independence and Security Act of 2007 (EISA) [Public Law No: 110-140] required the National Institute of Standards and Technology (NIST) to have the "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems…." (EISA, 2007, §1305). The NIST Framework and Roadmap for Smart Grid Interoperability Standards release 2.0. (2012) discuss standards as:

> "Specifications that establish the fitness of a product for a particular use or that define the function and performance of a device or system. Standards are key facilitators of compatibility and interoperability. They define specifications for languages, communication protocols, data formats, linkages within and across systems, interfaces between software applications and between hardware devices, and much more. Standards must be robust so that they can be extended to accommodate future applications and technologies." (p. 23)

As part of this standards development effort, in 2009 the Smart Grid Interoperability Panel (SGIP) was established to "further the development of consensus-based Smart Grid interoperability standards." (NIST, 2012, p. 6) NIST was, and continues to be a key member of the SGIP. This panel consists of over 675 stakeholders (agencies, companies, utilities, etc.) associated with the Smart Grid. The SGIP has developed a "Catalogue of Standards which includes standards under

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consideration for adoption. Standards moved onto the "list of identified standards",

Table 4-1 of the NIST Smart Grid Roadmap, are standards that have been reviewed

through the SGIP Catalog of Standards (CoS) process, recommended by the SGIP

Governing Board (SGIP GB), and approved by the SGIP plenary. (NIST, 2012, p. 15)

While NIST may adopt standards, it is the responsibility of a regulatory body, (in this

case the Federal Energy Regulatory Commission (FERC)) to implement standards

and protocols into regulations when there is sufficient consensus (EISA, 2007,

§1305.d). EISA, Section 1305.d states:

> "(d) Standards for Interoperability in Federal Jurisdiction.--At any time after
>
> the Institute's work has led to sufficient consensus in the Commission's judgment,
>
> the Commission shall institute a rulemaking proceeding to adopt such standards
>
> and protocols as may be necessary to insure smart-grid functionality and
>
> interoperability in interstate transmission of electric power, and regional and
>
> wholesale electricity markets." (EISA, 2007, §1305.d)

It should be noted that FERC's authority is limited to standards for interoperability in

federal jurisdiction, which normally would not affect the local distribution utilities.

Many utilities have been implementing measures to automate the grid, such as the

installation of smart meters (meters that allow one or two-way communications with the

utility). In addition, some home and building energy management systems have been

developed that interact with the utility. While it would be better if these devices followed

uniform standards, uniform standards were not in place during many of the meter

deployments and therefore pockets of individual technologies exist across the grid.

While making interoperability more difficult, having separate technologies across

different local distribution utilities doesn't hazard the overall grid as the local utility can translate any signals that must be transmitted into and out of its territory. This is not true for vehicles, which by their very nature are designed to be mobile, hence are likely to move between local utility distribution areas. For vehicles, a uniform standard for the vehicle to interact and communicate with the smart grid is needed. The vehicles must be able to plug in using uniform connectors (such as the Society of Automotive Engineers (SAE) Standard J1772: SAE Electric Vehicle and Plug in Hybrid Electric Vehicle Conductive Charge Coupler), they must be able to communicate (such as through SAE Standard J2847/1: Communication between Plug-in Vehicles and the Utility Grid (See Appendix 1: SAE Standard J2847/1 Messages)) under common operations, sometimes called use cases. These use cases are discussed in SAE Standard J2836/1: Use Cases for Communication between Plug-in Vehicles and the Utility Grid. (NIST, 2012, p. 98) These standards have been adopted by the SGIP, and have also been included in the NIST List of Standards. A listing of common standards relevant to electric vehicle charging is included as Appendix 2: Common Standards Relevant to Electric Vehicle Charging. Standards help prevent the stranding of assets because they can no longer integrate with the system that has become the industry standard. Assets are considered stranded when they can no longer produce enough income to pay off their installation and capital costs.

To show how the various standards integrate, consider the following for Level 2 charging using the Smart Energy Profile (SEP) 2.0 messages. SAE J2836/1 defines the various Use Cases for the utility (or 3rd party service provider). SAE J2847/1 defines the functional messages that move between the PEV and the Energy Management System (which presumably communicates with the utility). These signals pass through the

physical interface specified by SAE J1772 (which describes the standardized connector and associated wires). Digital communications may pass through the interface using SAE J2931/1 (Society of Automotive Engineers, 2012a). These communications may be power line communications (PLC), WiFi, or internet protocol (SAE International, 2012, p. 12). There are 3 competing communication sets: ISO/IEC 15118, SEP 2.0, and OpenADR. In addition to competition in the command and information set of messages, there is competition among the communications technologies. Options include HomePlug Green PHY (a form of power line communications), WiFi (ZigBee standard), Internet Protocol, and telematics (moving toward the 4th generation (4G) technology). As such, communications may occur between the vehicle and the grid directly (telematics, or WiFi - bypassing the charging station), or through the charging station (PLC and internet), or some combination of the above.

In 2011, Audi, BMW, Daimler, Ford Motor Company, General Motors, Porsche and Volkswagen jointly agreed to use the HomePlug Green PHY as the common protocol for integrating electric vehicles into the Smart Grid (HomePlug Green PHY, 2015). Honda, BMW, Chrysler, Ford, General Motors, Mercedes-Benz, Mitsubishi, and Toyota are all involved with the Electric Power Research Institute (EPRI) as part of the OEM Central Server project (discussed later in this paper) (Electric Power Research Institute, 2015a).

Under Department of Energy (DOE) sponsorship, Argonne National Laboratory's EV-Smart Grid Interoperability Center focuses on standards and technology to support EV-grid connectivity (Argonne National Laboratory (ANL), 2014). It is a facility for industry-government cooperation to enable joint development of EV standards and test

procedures to facilitate universal connectivity between EVs and the utility grid, to ensure

charging of any EV anywhere, anytime (ANL, 2014). In order to ensure true worldwide

interoperability, standards must be global. As part of its mission, the Center seeks to

harmonize US and international standards. The International Organization for

Standardization (commonly called the International Standards Organization, or just ISO)

has its own Standard as specified in ISO/IEC 15118. Vehicles imported from Europe are

likely to be designed to adhere to this standard. The cellular telephone communications

networking industry serves as an example where a global standard was not universally

adopted (GSM vs. CDMA),[5] and as a result, many cell phones cannot operate on the

competing system.

Charging Control Options

The concept of how electric vehicle charging may be controlled is still evolving.

These scenarios are called "use cases". The Society of Automotive Engineers considered

the issue and identified five use cases in SAE Standard J2836/1 (labeled as Use Cases

U1-U5.)[6] These five use cases cover most of the scenarios under consideration. These

cases, as described in SAE Standard J2836/1 are:

Time of use (TOU). Utilities can attempt to control consumer behavior by

adjusting the price of electricity based on the time of day. Normally, the utility will allow

for lower rates when demand is low and will raise the rates when demand is expected to

be high. The hours of each rate are published by the utility and may be different for each

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[5] GSM = Global System for Mobile Communications; CDMA + Code Division Multiple Access.
[6] U1: Time-Of-Use (TOU) Rates / Tariffs / Programs (Load Shifting), U2: Direct Load Control Programs (Demand Response), U3: Real Time Pricing (RTP: Load Shifting / Demand Response) (Active Management), U4: Critical Peak Pricing (CPP / Load Shifting / Demand Response), U5: Optimized Energy Transfer Programs (Demand Response, Regulation Services, etc.) (Society of Automotive Engineers, 2010)

utility. Low rates are normally expected during the overnight hours and often on weekends. However, under a TOU plan, the utility does not control when a charging event may occur, and as such, every EV owner in the utility's service district may decide to start charging at the exact moment the cost of energy goes down, thus causing a spike in energy use outside the control of the utility. Time of Use rates have only been adopted by select utilities. Many utilities have pilot projects in place to gain experience with Time of Use rates for the entire residence, or only for EV charging.

Direct load control (DLC). Utilities may elect to let consumers make their own decisions concerning energy use, but retain the right and the ability to reduce or stop certain charging events. In most cases the utility will declare in advance when they expect to use this capability. Often, the utility provides incentives (money back per month) to entice customers to sign up for this program. Utilities normally provide a number of options concerning the number of occurrences per year, or the length of electricity interruption. This method of load control is often used to control air conditioning loads during summer months. To date, this type of program has been used to prevent excessive system demand when the system is running out of resources, not to address overall load shaping or local loading of individual transformers. Pepco, and possibly other utility pilot programs, are experimenting with Direct Load Control. It is not in widespread residential or commercial use to control EV charging.

Real time pricing (RTP). Unlike the Time of Use rate, Real Time Pricing rates are established by the utility company one day ahead of their implementation. They are based on the predicted energy demand and the predicted cost of energy during this period. They may be strongly affected by the forecast temperature and humidity (need

for heating and air conditioning), as well as known system failures and locations of electricity transmission bottleneck/congestion. As such under RTP, a customer may experience energy prices that are high all day and remain high at night, even when the rates for a TOU customer would drop at night. Under a RTP pricing scheme, the utility attempts to control energy demand by setting prices, but ultimately has no direct control of the load used by the consumer. To date, real time pricing has not been used to control commercial or residential EV charging; however pilot programs have been proposed to do so (Application of SDG&G … 2014).

Critical peak pricing (CPP). Under this pricing program the utility allows for a normal (fixed or TOU) rate schedule but allows itself to declare a certain number of critical pricing days when a higher rate schedule goes into effect. The consumer is thus incentivized to reduce electrical demand on these given days, but the consumer, not the utility, ultimately has the ability to determine if the EV charging event will occur. A number of utilities use critical peak pricing events in an attempt to suppress electricity demand during very high usage periods, however, to date, critical peak pricing has not been used specifically to control EV charging. Electric vehicles being charged under a residential rate may be affected if a CPP event affects the residence.

Optimized energy transfer. These programs allow the utility to stop or reduce charging when needed to support the grid or for other purposes. Using decision algorithms, the utility can make charging decision that benefit the largest number of vehicles (such as stopping charging at 89% for one vehicle while allowing a vehicle with only a 39% state of charge to continue charging). Optimized Energy Transfer currently

exists in the laboratory and field studies only. There have been no commercial or residential programs using optimized energy transfer.

OEM Central Server

An optimized energy transfer strategy would require intelligence built into the vehicle and the charging infrastructure. At the Institute of Electrical and Electronics Engineers (IEEE) July 2010 Power and Energy meeting, such a structure was described as follows:

> "An intelligent vehicle charging infrastructure (IVCI) requires seamless communication and control from the car to and from the EVSE, and ultimately tied into the regional grid operator's SCADA system. To date, however, the lack of interoperability standards for the emerging PEV infrastructure components represents perhaps one of the biggest challenges to the development of an IVCI."[7] (Taylor, Maitra, Alexander, Brooks & Duvall, 2010, p. 3)

The field of demand side management focuses on the balancing of electricity supply and demand by reducing or time-shifting the demand. Typically this action occurs upon the request of a local utility company or through a contract for guaranteed load reduction (the utility pays the company an agreed upon rate for each megawatt (MW) that the company reduces its power demand within an agreed upon timeframe). When the need was small, a telephone call could suffice, but as load management became more sophisticated, automation was implemented. In addition, market based elements were added, allowing some to choose to reduce demand based on the amount of incentive

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[7] SCADA means Supervisory Control and Data Acquisition Systems. SCADA systems are used to send signals to control remote equipment.

offered. In this manner, the utility need only incentivize the load reduction that was needed without spending more than was required.

Utilities represent a splintered market (3800+ utilities, 50+ Public Utility Commissions with widely differing authority) (Consumer acceptance and public policy, 2012). Establishing a system that will satisfy everyone will be a huge challenge. In support of requests for such a system, the Electric Power Research Institute (Palo Alto, CA) is developing such a system to help utilities interact with major system loads and with demand management aggregators. The system is called the OEM Central Server and will run on a software system called OpenADR 2.0 (Electric Power Research Institute (EPRI), 2013a).

With the emergence of plug-in electric vehicles with sizeable batteries, industry is contemplating the concept of using non-charging vehicles for various grid services, including load management. At present, eight major electric vehicle manufacturers have teamed with utilities, RTO/ISO's and EPRI to include electric vehicles in the mix. In theory, electric vehicles would use their telematics system of communications (such as GM's On-Star system) to provide required information to a central server when plugged into a charger.[8] Vehicles could then download pricing and event control information for the vehicle's location. As such, the driver (or the vehicle) could make charging decisions based on this up-to-the-minute information, and could potentially agree to have the vehicle participate in some Vehicle-to-Grid (V2G) interaction. Denholm and Short (2006, p. 9) described two different forms for this interaction, a direct control and an indirect control:

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[8] OnStar is a wholly owned subsidiary of General Motors.

"With direct control, the utility would send a signal to an individual vehicle or a group of vehicles. …. The direct control could also be established through an aggregator that sells the aggregated demand of many individual vehicles to a utility, regional system operator, or a regional wholesale electricity market. ….. An alternative option – indirect control – would have each vehicle responding intelligently to real-time price signals or some other price schedule to buy or sell electricity at the appropriate time. In either control scheme, the vehicles would be effectively "dispatched" to provide the most economic charging and discharging." (Denholm & Short, 2006, p. 9)

At the time of this writing, the OEM Central Server concept[9] has not been implemented for the control of EV charging in North America. Using the telematics system, vehicle manufacturers may continue to use proprietary software and control the data made available to the grid from the vehicle. Such a system could strongly encourage drivers to maintain subscriptions to their telematics services, and would prevent key data (such as maximum 1) charging rate, 2) charging energy required, and 3) time charging must be complete) from being provided by any other means. The system has not been completed so there is still time to address these concerns. With that said, it is possible that every PEV will be signed up to a utility (or to a demand system aggregator) who will perform the charging coordination functions for the utility. Under this concept, the OEM central server will only be used as a router; ensuring vehicles connect to the proper utility control system for system messages (pricing, demand control event timing, etc.) and for charging coordination. Although there may be a number of messages required to

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[9] OEM stands for Original Equipment Manufacturer

coordinate each charging event, the messages are short, requiring very little bandwidth. With communications provided via telematics, charging stations need not have intelligence beyond that required by the SAE J1772 standard, thus keeping the cost of charging stations low. If designed correctly, the system discussed in this paragraph could be used to coordinate charging to shape system loading while still ensuring all vehicles are charged to the required battery state of charge when desired.[10]

General Motors appears to be moving in this direction. They are already advertising a series of OnStar apps that address these capabilities:

"Demand response – …Connects utilities to companies that have intelligent energy management products. These companies can use OnStar to manage energy use for … customers who opt in for the service. This future service allows the customer to save money on energy costs while enabling more efficient use of the electric grid.

Time-of-Use (TOU) rates – OnStar can receive dynamic TOU pricing from utilities and notify … owners of the rate plan offers via email. Owners will be able to use OnStar to load the rate plans directly into their vehicle and access them to schedule charging during lower-rate periods.

Charging data – OnStar also sends and receives EV data that helps utility providers without having to interface with the vehicle's electric vehicle supply equipment. This includes location-based EV data that identifies charging locations and determines potential load scenarios.

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[10] The words "required battery state of charge" are used instead of "fully charged" to allow for the possibility that some drivers may not want their vehicle fully charged, either because of the available electricity rate, or because they want to participate in Vehicle to Grid (V2G) programs that require the battery to be within a certain state of charge window.

Aggregated services – This solution allows electric service providers to manage the charging of participating vehicles in a given geographic area, with customer consent. This includes the ability to control charging on a large amount of EVs simultaneously." (OnStar, 2012)

Each of these capabilities aligns with the goal for the OEM Central Server. While General Motors and OnStar were used in this example, it is assumed that most of the other major electric vehicle manufacturers (and their telematics providers) will do something similar. In the Pecan Street study it was found that most of the EV owners did NOT use the telematics (Pecan Street Inc., n.d., slide 6). While this may be true in today's unconstrained charging environment, it may not be the case when the electric vehicle culture has matured and additional cost savings options have been made available and appropriately advertised.

While not in final form, the OEM Central Server concept is a mixture of the above concepts but tends to be focused on real time pricing (not day-ahead pricing) to shape the load curve. Until there is clarity concerning the connectivity between the vehicle and the utility (and possibly the demand aggregator also), it is unclear how effective the OEM Central Server concept will be to support any utility goal other than load control.

The Local Problem

Unfortunately, sole reliance on telematics prevents the data from being made available to the charging station, the home or building energy management system, and potentially from any controls for the local distribution transformer. Overall load shaping is only one of the problems resulting from large scale deployment of PEVs. Clusters of

PEVs, or large deployment in the population can overload local distribution transformers if local charging is not coordinated. It is unreasonable to expect that the vehicle can identify and inform the OEM central server of the individual transformer it is connected to without allowing for data exchange between the charging station and the vehicle. As such, the OEM Central Server concept may not protect against localized transformer overloading. Local coordination can be easily controlled by placing a small amount of intelligence at the distribution transformer to coordinate all vehicle charging, or by having utilities develop virtual transformer meters my monitoring the energy meters of buildings drawing power from each individual distribution transformer.[11] Coordinated charging will require a set of communications messages that pass information and commands. Communication can be via power line communication (PLC), WiFi, or internet protocol. This paper will not address which is "better" as each has advantages and disadvantages.

Potential Transformer Overloading

A study of a residential area around Virginia Tech (Blacksburg, VA) considered the possible effects of EV charging on the local distribution transformer. In this case a typical 25 kVA transformer served a neighborhood of five homes. The study identified potential problems with uncoordinated EV charging (Shao, Pipattanasomporn & Rahman, n.d., p. 2).

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[11] The location of the intelligence need not be physically located at the transformer but must be in some way connected to all of the buildings/devices receiving power from the transformer. For power line communications this is easy as the intelligence need only be plugged in downstream of the transformer to communicate with every building associated with the transformer. For WiFi, telematics or internet, the intelligent device must somehow be informed of which signals come from buildings attached to the transformer as opposed to other buildings.

The increased load on the distribution transformer is a function of the number of vehicles attempting to charge at the same time, the size (power level) of their chargers, the energy needed, and any additional charging constraints imposed on the system. These constraints could be from the vehicle itself, the charging station, or a home/building energy management system. This analysis provides an estimate of charger size and the number of vehicles.

Charger size. Electric vehicle design is still subject to refinement. Auto makers continue to improve vehicles to support the wants and needs of their customers, as well as to comply with federal Corporate Average Fuel Economy (CAFE) and state Zero Emissions Vehicle (ZEV) mandates. One of these needs is increasing the all-electric range, which roughly equates to a larger battery. The increased range addresses "range anxiety" (the fear of running out of battery charge while away from a charging station, and the potential for a long recharging time while away from home). Vehicles with larger batteries (kWh) need higher power chargers in order ensure the vehicle can be completely recharged in a reasonable period of time (overnight). At present, most vehicles have a battery charger that can completely charge the battery in about 8 hours using its normal charging method (Level 1 for small batteries, Level 2 for large batteries). As a result, the reduction of range anxiety will cause an increase in the capacity (kW) of the average EV charger, potentially putting a greater strain on the local distribution transformer. The actual unconstrained distribution transformer loading will be a function of the loading before the charging begins, the number of vehicles attached to the distribution transformer (which is affected by clustering), the charger ratings, and the probability that vehicles charge at the same time (commonly called the diversity factor).

At some point the consumer will determine that the offered range is sufficient.

Most likely two ranges will be identified: one range sufficient to conduct all errands in

the vicinity of the home,[12] and a second range sufficient to perform long distance travel

without frequent stops for charging.[13] The decision may also be affected by the number

of vehicles in the household.

Number of vehicles on a transformer. By March 2014, there were approximately

81,900 BEVs and 106,900 PHEVs on the roads of the United States. With about

183,000,000 passenger vehicles and light trucks on the road, PEV's make up about 0.1%

of the total light duty vehicle (LDV)/passenger vehicle population. However, in March

2014, there were about 9,100 PEV's sold of the 1,200,000 LDV's sold during the month,

or about 0.76% of the new auto sales for the month. Even if the equilibrium population

of PEV's in the population were 0.76%, the probability of having 2 or more PEV's on a

single transformer would be 0.06% or less, hardly something to worry about.[14] However,

as the number of PEV's in the population increases, the probability of multiple vehicles

being found on the same distribution transformer increases. If California reaches its goal

of 1.5 million PEVs by 2020, multiple EVs on a single distribution transformer will

become more common. Assuming no clustering, for a distribution transformer serving 5

homes, the probability of multiple vehicles being on the same transformer increases as is

shown in Figure 1.

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[12] The author believes this range will be about 160 miles as it will allow travel within a 52 mile radius of the residence and still return home with sufficient safety margin (Comis, 2015). In addition, this range would account for about 90% of the miles traveled and 98% of all trips ((Jones, n.d.) using data from the 2009 National Highway Transportation Survey). Such a vehicle would need a ~53 kWh battery and a 6.6 kW charger to conduct overnight charging.

[13] The author believes this range will be about 320 miles as it is approximately the range of current fossil fueled vehicles, and is about the limit a person can stand driving at a stretch without needing a break, which would coincide with a high voltage DC charge at a station along the road. Such a charger would need a ~107 kWh battery and a 13 kW charger to conduct overnight charging.

[14] This example assumes five residences on a single distribution transformer.
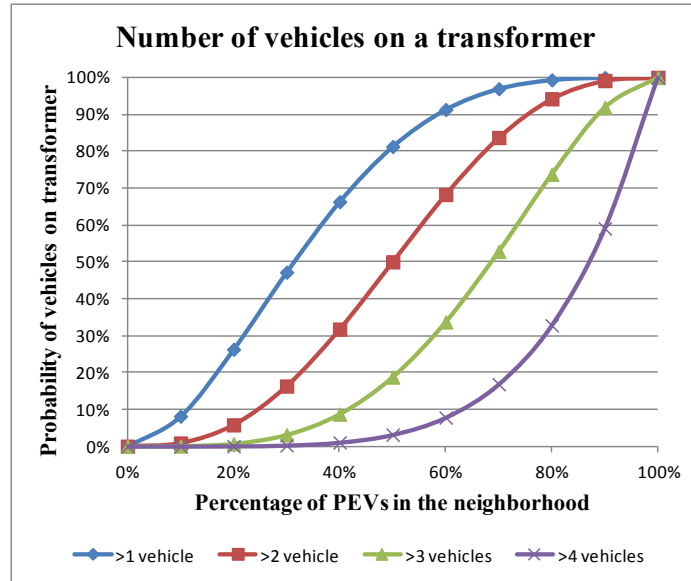
Figure 1: **Probability of more than a given number of vehicles on a transformer**

A similar set of curves could be developed using the binomial distribution for any number of homes on a distribution transformer.

If PHEV charging start times are unconstrained, people may wish to commence charging as soon as they get home, grouping PEV charging times during the evening hours. If a Time-of-Use rate reduction occurs later in the evening (after most cars have returned home for the evening), then most cars will start charging at once when the rate reduces, greatly raising the load factor. Higher load factors may require a strengthening of the electricity network from within: expensive as it may affect transmission right-of-ways, and replacing/upgrading various transformers (Stanton, 2006, p. 2).

Clustering. The binomial distribution assumes the probability is uniform across the population. During the initial phases of PEV sales, this is unlikely to be the case. A 2007 study of Toyota Prius adoption in California showed considerable "clustering", with larger concentrations found in areas of affluence that had an environmental bent (i.e. along the coast –Santa Monica and Malibu but not inland Beverly Hills) (Kahn & Vaughn, 2009). The Prius is probably a good example of how PEV's will be adopted

into the population. EPRI tentatively found that PEVs appeared to also be clustering into the same San Diego area zip codes as the Prius (EPRI, 2013b, p. 12).   As such, while the overall percentage of PEVs in the general population may be low, pockets may exist with much higher PEV adoption. Areas with moderate to high income that have strong environmental preservation attitudes will probably be the early adopters. "Based on early data, it's clear that purchasers of plug-in electric vehicles live near each other. Berkeley, California, for example, represents 18 percent of all [PEV] customers in PG&E's territory while Fresno is only 2 percent." (LaMonica, 2009) Similarly, clustering was seen in well-to-do neighborhoods around Detroit MI, such as Ann Arbor, Bloomfield Hills, and Grosse Pointe (Electric Power Research Institute, 2014a, p. 8). A Detroit MI study also noted a different characteristic of the early adopters: "Early program participants tended to be young, 'tech-savvy' early adopters." (EPRI, 2014)

EPRI noted that geographic purchase or lease clustering (concentrations in neighborhoods) may put a greater strain on the grid. One in four non-hybrid owners said they were influenced by others in their community when acquiring a vehicle, which may indicate that clustering might occur, at least to some extent (Neenan, 2010). As people with these criteria tend to live in the same areas, vehicle purchases similar to the Prius adoption pattern may be expected. As can be seen by comparing the strong adoption locations (Figure 2, upper) with the population density (Figure 2, lower), population density is not a key factor as a number of high Prius adoption areas have very low population density. As additional evidence, in the Pecan Street community, about 70% of the EV owners also had photovoltaic panels on their home (showing an environmental bent) (Pecan Street Inc., n.d., slide 4).

Social multiplier. In addition, the Prius adoption study found evidence of a "social multiplier" effect. "If we believe that an individual's elasticity of hybrid vehicle demand is positively affected by the number of hybrid vehicle owners in his or her near vicinity, then this spillover will cause the aggregate model coefficients to be greater than the individual model coefficients." (Kahn & Vaughn, 2009, p. 18) Although the effect was found to be statistically significant, the effect was also found to be weak, with coefficients only around 1.04 (Kahn & Vaughn, 2009, p. 18). In the Pecan Street study about 50% of the EV owners indicated that they had an acquaintance who owned an EV (Pecan Street Inc., n.d. slide 4). Data from DOE's Workplace Charging Challenge showed that partner employees are 20 times more likely to drive a PEV as opposed to the average worker (Department of Energy, 2014b, p. 5). While this statistic does not show causation, it may be considered evidence of a strong social multiplier effect. A strong social multiplier effect would skew the curves in Figure 1 to the left, with higher probabilities of multiple vehicles on a distribution transformer than would be expected in a normal binomial distribution.

As discussed above, clustering and a social multiplier effect have been shown to exist. Local utilities should use this information to predict where PEV's are likely to first affect their service area. Although clustering and social multiplier affects indicate where problems are likely to first show up, they do not address when they will show up. The timeframe is strongly affected by the innate appeal of the product, and the effect of external influences (such as advertising) on an individual's decision.
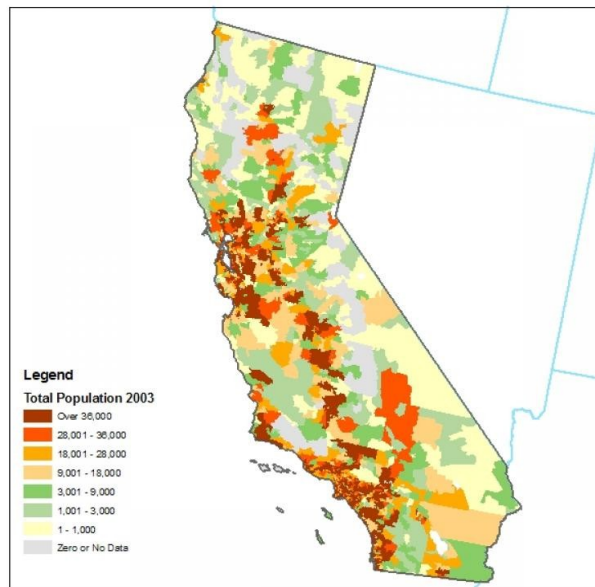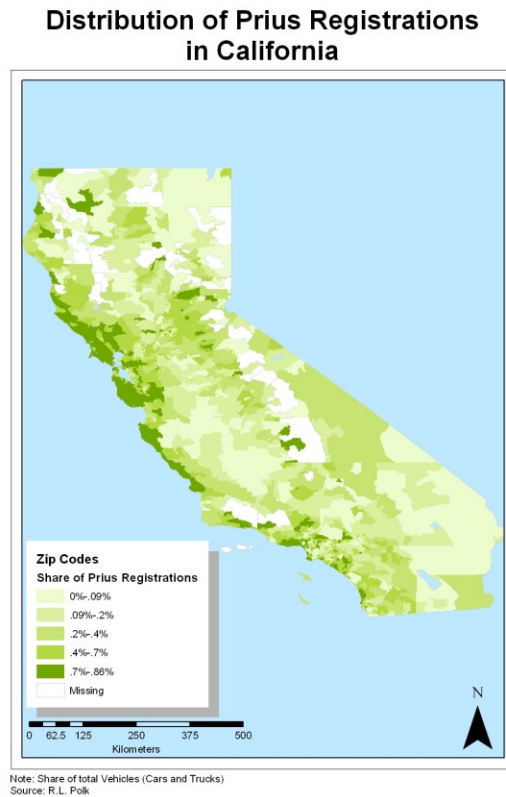
**Distribution of Prius Registrations
in California**

Figure 2: **Toyota Prius adoption (Kahn & Vaughn, 2009, p. 4) (upper) and
population density (California Maps, n.d.) (lower) in California**

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Bass Diffusion

In 1969, Frank Bass published an article in Management Science magazine which discussed a tool to forecast the adoption of an innovation for which no closely competing alternative existed in the marketplace (Bass, 1969) (Lilien, Rangaswamy & De Bruyn, n.d.). In essence he said that the adoption of a new innovative product was dependent on two factors; "p" a coefficient of innovation (internal influences and value judgments), and "q" a coefficient of imitation (external influences such ad advertising, social influences, co-workers, friends and neighbors) (Neenan, 2010). If F(t) is the cumulative likelihood of adoption curve (i.e. the Cumulative Distribution Curve), and f(t) is the time rate of change of that curve (often called the density function), then:

$$f(t) = (p + q * F(t)) * (1 - F(t)) \quad \textbf{Equation 1}$$

If the total number of vehicles that would be sold were known in advance (i.e. "N"), then N*f(t) would be the sales rate. Alternatively, the likelihood that an electric vehicle would be chosen would be:

$$\textbf{\textit{Likelihood of purchase at time}} (t) = \frac{f(t)}{1-F(t)} = p + q * \frac{N(t)}{N} \quad \textbf{Equation 2}$$

Where N(t) is the number of customers who have already adopted the innovation by time t, and N represents the total number of customers who will ultimately adopt the product (i.e., the market potential). Clearly, seeing neighbors or co-workers driving electric vehicles would be part of the "q" factor, and the larger their number, N(t), the larger the "q" effect.

The solution to the differential equation shows that (Bass, 1969):

$$\textbf{Sales at time (t)} \quad S(t) = N * \frac{(p+q)^2}{p} * \frac{e^{-(p+q)t}}{(1+\frac{q}{p}e^{-(p+q)t})^2} \quad \textbf{Equation 3}$$

$$\textbf{Time of peak sales} \quad \frac{\ln q - \ln p}{p+q} \quad \textbf{Equation 4}$$

Values of p and q for typical items on the market (when time is measured in years) would be p~0.03 (and often <0.01), and q~0.38, with typical values between 0.3 and 0.5 (Mahajan, Muller & Bass, 1995).

DOE established an "EV Everywhere Grand Challenge", the goal of which was for "the U.S. automotive industry to produce plug-in electric vehicles (PEVs) that will be as affordable and convenient as gasoline-powered vehicles by 2022." (Department of Energy, 2014a, p. 3) After studying the market, Navigant Research expected the number of PEV's on the road to increase from 96,000 in 2014 to about 2.7 million in the year 2023 (Navigant Research, 2014). The size of the total market potential "N" is not currently known, however there are about 183 million light duty vehicles in the United States (2012), and assuming all vehicles ultimately convert to be electric vehicles, this number will be used as the ultimate market potential (**N=183,000,000**) (National Transportation Statistics, 2015a). One potential fit of the Bass Diffusion Equation to the Navigant prediction could be **p=0.000105** and **q=0.32**. Under this possible scenario (one of many), large scale movement into electric vehicles would occur during the years 2031-2042 (see Figure 3). The maximum sales rate is in the order of 15 million vehicles per year, well within the current capability of automobile manufacturers to produce (Center for Automotive Research (CAR), 2011) (Trading economics, 2015). [15] When further data is available for curve fitting, the parameters of p, q and N can be refined.

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[15] Recent automobile sales in the United States have been in the vicinity of 16 million vehicles per year, or an average turnover rate of about every 12 years. While there is insufficient evidence to prove the claim, it is believe that due to the smaller number of moving parts, and the potential to update the vehicle using software changes, electric vehicles will last longer than conventionally powered vehicles.
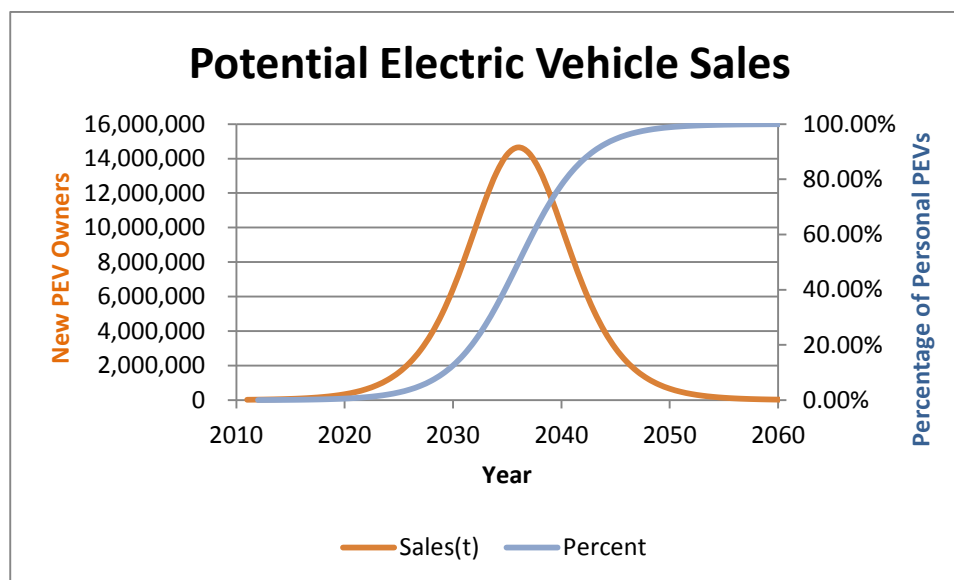
Figure 3: **Potential electric vehicle sales**

Factors that may affect market potential include price and availability of appropriate fossil fuels (and potentially hydrogen), cost and availability of electricity, greenhouse gas legislation affixing a price on carbon, improvements of battery energy and power density, etc. In addition, it is unclear whether consumers will consider electric vehicles to be "an innovation for which no closely competing alternative exists in the marketplace", the basis for the Bass Diffusion model. Internal combustion engine (ICE) vehicles, with various forms of hybrid vehicles may form a continuum that removes the "innovation" aspect in the eye of the consumer.

Furthermore, the movement of PEV's into the marketplace is likely to occur cautiously as those that can afford a 2nd vehicle adopt a PEV for "local" use, but reserve the ICE for trips that would normally require a recharge before reaching the destination. As EV batteries improve and carry a larger charge, or as high voltage DC chargers become ubiquitous along the major long distance thoroughfares, this consideration may diminish and consumers will allow themselves to purchase an EV as their primary, and possibly only, vehicle. Given the current higher price of most PEVs, it is likely that

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initial purchasers will be in the upper middle class (and above).   It is assumed that, as the

market grows, prices will come down and the market will expand to the middle class.

Within 3-5 years, some electric vehicles will likely be traded in, and hence will enter the

used car market also, opening up ownership to all economic classes.

Distribution Transformers

Utilities are able to install transformers rated for less than the total possible

downstream load because statistically, at any given moment, some loads within the

household will be off, and statistically, the loads from the various households will be

offset by some period of time. The transformer need only be rated for the likely

maximum load, plus some safety factor (often 40-50%) (ElectriCities, 2013).

The process of sizing a distribution transformer[16] normally begins with

determining the total demand of the home, which is simply the sum of all expected

electrical loads. It is well known that all electrical loads are not run at the same time so

the total demand is multiplied by a "Demand Factor" which is the expected ratio of total

load to peak load[17] to determine the peak demand. While it's theoretically possible for

every home on a transformer to be at peak load at the same time, it's unlikely.   As such,

a "Diversity Factor" is applied to account for the total load on the transformer when

different homes are added together (Chatlani, Tylavsky, Montgomery & Dyer, 2007).

The residential load has the highest diversity factor of around 2.0, followed by industrial

loads with diversity factors usually in the neighborhood of 1.4, street lights with a

diversity factor close to 1.0, and other loads vary between these limits (Distribution

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[16] Some utilities call this a "service transformer"

[17] Demand factors are determined through the experience of the utilities with various size homes. They may change over time as new technology is moved into the average home, such as a large screen TV, air conditioner, microwave oven, etc. The demand factor is a ratio, always less than 1.0. Homes with gas appliances would be expected to have a lower demand factor than an all-electric home.

factors, 2000). Homes may experience a different peak demand between seasons so peak demand is often listed for summer and for winter, for all electric homes and for homes with gas. As such, transformer loads are estimated by:[18]

*Total Demand * Demand Factor (summer) * Diversity Factor (# of homes) = Summer load (kW)*

*Total Demand * Demand Factor (winter) * Diversity Factor (# of homes) = Winter load (kW)*

The transformer sizing is based on ensuring the summer and winter loading fit within the safety factors of the selected transformer (such as 140% of rating for summer and 160% of rating for winter). A good presentation on sizing residential and commercial distribution transformers can be found at the ElectriCities training library presentation "Transformer Sizing Presentation" (ElectriCities, 2013).

Depending on the region of the country, homes tend to draw 3-6 kW during their peak hours. As such, an EV, charging with a 3.3 or 6.6 kW charger, could equate to the addition of another home-equivalent on the transformer if charging occurred at peak periods.

It is now easy to see how the addition of multiple electric vehicles, charging from the same transformer, could affect the required rating of the transformer. The electric vehicle charger will add to the total demand and may require the utility to re-evaluate the Demand Factor. In addition, the incentives applied by the utility may inadvertently encourage people to charge during the same period, which would cause the Diversity Factor to increase (get closer to 1.0).

TOU incentives tend to align charging times, effectively making the diversity factor 1.0 for electric vehicle charging. This was demonstrated by the San Diego study which showed how effective TOU incentives were, and that consumers tended to start

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[18] The months covered by each formula are not fixed but vary based on the local climate.

charging at the beginning of the off-peak/super off-peak period (Cook et al., 2014). With

an expected tendency over time to move to larger average capacity vehicle chargers, the

problem will only get worse. Adopting a coordinated charging strategy at the transformer

level will eliminate, or greatly reduce the need to replace or increase the size of

distribution transformers.

With enough additional demand, a larger transformer may be required. Other

incentives that bring the diversity factor closer to 1.0 could have the same effect. While

transformers can normally handle overloads for short periods of time, long term overload

can cause components to soften or to embrittle, ultimately leading to failure, arching, and

a "blown" transformer. Pepco summed the problem up by stating:

"…even low levels of PEV adoption are likely to have a significant impact on

utilities and the grid – a single PEV plugged into a level 2 (240V) charger can

increase a home's peak electricity demand. Consequently, it is crucial for utilities to

proactively manage PEV charging and address the questions and challenges that

come along with PEVs and PEV charging." (Electric Power Research Institute,

2015b, p. vii)

SDG&E is already in the process of installing data monitoring devices on

transformers to collect usage information, such as voltage, load, power factor and

temperature. EPRI believes, "this transformer monitoring effort will give rise to a smart

transformer technology to create transformer-level load-management functionality

applicable to all loads, not just that of PEV charging." (Electric Power Research Institute,

2013b, p. 12) With the advent of the Automated Metering Infrastructure (AMI), utility

companies have the ability to calculate the long term loading on any transformer by adding the hourly loads of the homes/buildings that draw from it (i.e. a virtual meter).[19]

The Global Problem

The quality and reliability of the electric grid is predicated on the concept that the amount of electricity generated at any moment must equal the amount of electricity demanded by the grid. This constitutes the global problem. Failure to maintain this balance results in frequency variation (away from 60.0 Hz) and voltage variation (away from each individual circuit's specified voltage). Significant deviation from the specified frequency and voltage can cause equipment malfunction and in some cases equipment damage or outright failure. Given the connected nature of the electric grid, the frequency, is locked together across the entire grid.[20]

This paper looks at reasonable scenarios for unconstrained charging behavior and then addresses the benefits of controlled charging (either computer controlled for a desired result, or through the use of intensive utility/customer interaction to set default behavior). In the area of overall load management, statistical variations should tend to cancel out (one customer charges for twice as long whereas another customer skips charging for the evening). As such, it is assumed that all customers charge the average amount. It is assumed that only 80% of vehicles charge at home, whereas the remainder will charge at work, at public charging, or at some other charging location. This is a reasonable assumption, but can be easily change. Past papers studying this issue addressed plug-in hybrid electric vehicles (with their smaller batteries and charger

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[19] Line losses would be added also so the calculation is a bit more complicated than a simple addition.
[20] In reality there are 3 independent electric grids in the United States (Western Interconnect, Eastern Interconnect, Electric Reliability Council of Texas (ERCOT)). Each of these independent grids has very small DC to DC interconnections. By making the connections direct current, the frequency and voltage of the separate AC systems remain separate and may differ.

capacity), and assumptions of a PHEV/BEV mix, but with charger capacity assumed to be about 3.3 kW (Stanton, 2006). This paper assumes a more likely mix of charger sizes (kW). After briefly discussing rate structures and cost curves, the effect of electric vehicle charging on daily load curves is addressed. Charging strategies considered include:

Control Strategy	Charging Strategy	Vehicle Charging Timing	Data availability
Unconstrained Charging	Unconstrained	Vehicle commences charging whenever the driver plugs the car into the charging station.	Data available from Pecan Street dataport
Incentivized Charging	TOU Start	Vehicle commences charging at a time preset into the vehicle (or the charging station)	Data available (Cook et al., 2014)
Incentivized Charging	TOU End	Vehicle starts charging at a time based on a time preset into the vehicle specifying when the vehicle must be charged.	No data available
Coordinated Charging	Flat	Vehicle charging start times are coordinated by an entity outside the vehicle to 1) prevent transformer overload, 2) ensure all vehicles are charged by driver specified times, and 3) flatten the overnight power demand for the RTO/ISO	No data available
Coordinated Charging	Flat Algorithm	Vehicle charging start times are coordinated by an entity outside the vehicle to 1) prevent transformer overload, 2) ensure all vehicles are charged by the times specified by the drivers, and 3) flatten the overnight power demand while minimizing beginning and end ramp rates.	No data available
Coordinated Charging	Alternate TOU End	Vehicle default charging start times are coordinated by the utility when the vehicle charging location is established so as to 1) prevent transformer overload, 2) ensure all vehicles are charged by the times specified by the drivers, and 3) flatten the overnight power demand as much as possible. Deviations from the default times are expected to be statistically offsetting.	No data available

Table 1: **Charge control strategies**

Rate Structures

Pepco provides service to over 800,000 customers and 650 square miles, to include Washington DC and most of Maryland's Prince George's and Montgomery counties. Pepco offers an experimental Plug-in vehicle charging rate (PIV) (Potomac Electric Power Company, 2014) of:

Pepco (PIV rate) (all costs rounded)	Summer (June-October)	Winter (November-May)
On-Peak (Noon - 8:00 p.m.)	$0.19/kWh	$0.17/kWh
Off-Peak (8:00 p.m. – Noon)	$0.08/kWh	$0.07/kWh
Differential cost of energy	$0.11/kWh	$0.10/kWh

Table 2: **Pepco Time of Use Rates under experimental PEV charging rate PIV**

SDG&E provides service to about 3.4 million customers across 4,100 square miles to include all of San Diego and Imperial counties in California.   SDG&E offers a EV Time-of-Use rate (EV TOU) (San Diego Gas & Electric, n.d.) of:

SDG&E (EV-TOU rate) (all costs rounded)	Summer (June-October)	Winter (November-May)
On-peak (Noon - 8:00 p.m.)	$0.49/kWh	$0.20/kWh
Off-peak (8:00 p.m. – Midnight) (5:00 a.m. – Noon)	$0.22/kWh	$0.19/kWh
Super Off-Peak (Midnight - 5:00 a.m.)	$0.16/kWh	$0.17/kWh
Differential cost of energy	$0.33 or $0.06/kWh	$0.03 or $0.02/kWh

Table 3: **San Diego Gas & Electric EV charging rate EV-TOU**

Clearly the Pepco rate structure encourages charging during the off peak hours by reducing the rate to roughly 40% of the peak rate. By allowing off-peak charging to start at 8 p.m. (fairly close to the summer evening peak) Pepco may be required to take action to spread out the charging during the off-peak period to prevent forming a new power peak. By providing a 16 hour off-peak period, which covers the period when most people leave for work or shopping in the morning, Pepco may be able to work with its PEV customers to manage any charging peaks that occur without affecting vehicle readiness when needed in the morning. On the other hand, the SDG&E summer tariff

tends to squeeze the preferred EV charging period down to a 5 hour super off-peak period following midnight. If SDG&E consumers consider the 6 cent differential between off-peak and super-off peak to be significant, this rate structure could result in some serious charging peaks around midnight (TOU Start strategy) or 5 a.m. (TOU End strategy). The winter rate structure provides almost no difference in cost between peak, off-peak and super off-peak rates so as to provide little incentive concerning charging timing. Without incentive to do otherwise, customers may simply maintain their summer charging pattern, providing peaks even when there is no reason to do so. SDG&E can still fine tune the hours of its super off-peak rate (such as to extend them to 9:00 a.m.) to help reduce any peaking that may occur.

Cost Curves

Generally speaking, in regions covered by an RTO/ISO, the electrical generator's market bid to produce electricity is the marginal price of electricity production. All electricity generators producing power receive the bid price from the last generator brought online. Since generators are brought online from smallest marginal cost to largest (commonly called merit order dispatch), the cost of electricity is kept as low as possible. Generators are made available for power production, or removed from service for a variety of reasons, such as routine and correctional maintenance, limitations on the number of generator starts, or the total operating hours for emissions controls reasons. As such, it is likely that the lineup of generating machines may change from day to day and from season to season.

This paper uses PJM Interconnection data as an example, but the same methodology of analysis could be performed for any RTO/ISO. Data from calendar year

2014 day-ahead pricing and actual system loading was analyzed to develop a model for

PJM pricing throughout the year (PJM Interconnection, n.d. a).[21] Two models were

developed, one for the period OCT-MAR and another for the period APR-SEP. Both

curves are similar except the APR-SEP curve maintains low rates for about 25,000 MW

more than the OCT-MAR curve.

The data for the winter model provides a lightly sloped region from 60,000 MW –

about 110,000 MW, and then a sharp rising section. In accordance with the existing PJM

market guidance, the cost of energy was capped at $1000/MWH, but a higher price cap,

or potentially no price cap, could be allowed by FERC as occurred in February 2014

(FERC lifts price cap as cold grips PJM, 2014). The summer model shows a similar

lightly sloped region starting at 60,000 MW, but extending to about 135,000 MW before

beginning to slope sharply upward. The upward slope was copied from the winter curve,

but was offset for a starting point at a higher load. The actual model equations used for

this paper are provided in Appendix 3: Winter and Summer Pricing Model, and

graphically shown in Figure 4.

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[21] Day-ahead data Location Marginal Pricing (LMP) was taken from the monthly da.zip reports found on
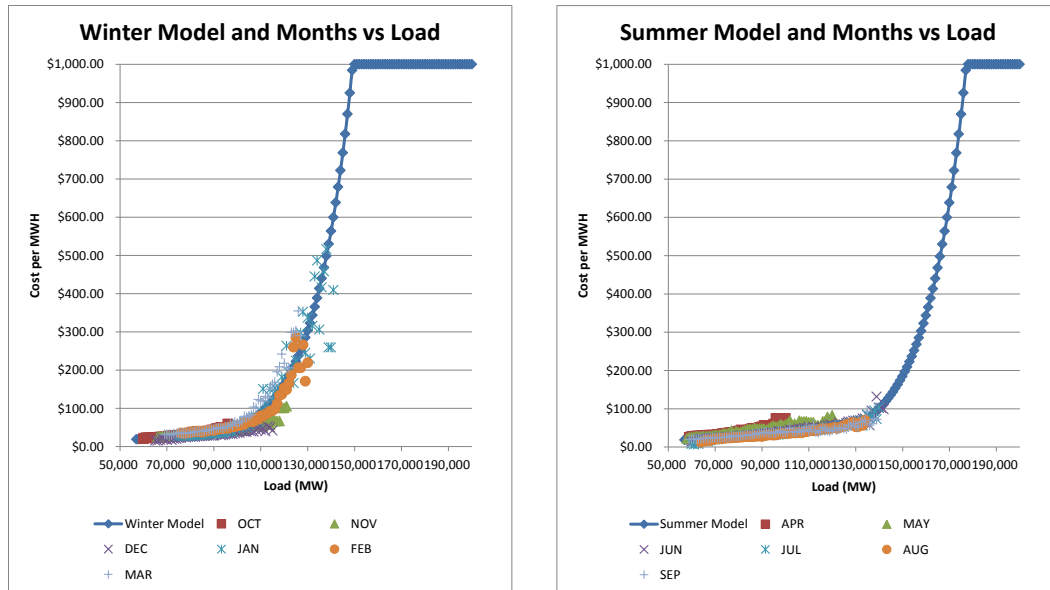the PJM Operations webpage.

Figure 4: **Summer and winter cost curves (models)**

Load Curves

Actual PJM hourly load data from calendar year 2014 was used to establish the baseline for this analysis. Models for six separate charging strategies were developed: TOU Start Charging, TOU End Charging, Alternate TOU End Charging, Unconstrained charging, flat and flat algorithm charging. In the development of this model, a number of assumptions were made. Assumptions are in bold font and underlined.

- The PJM Interconnection service area covers Pennsylvania, Delaware, New Jersey, Maryland, Virginia, West Virginia, Ohio, the District of Columbia, eastern Kentucky, and small patches of North Carolina, Indiana, Michigan and Illinois (the Chicago area) (PJM Interconnection, n.d. b). All but Illinois are in the Eastern Time Zone. Using 2012 population data from the US Census Bureau, and 2012 vehicle data from the Department of Transportation Bureau of Transportation Statistics, it was determined that the rough population of the PJM

service territory was about 61M,[22] and that there were about **23M registered light duty vehicles in the service territory**.[23]

- The model includes a **one hour load delay** for the estimated 2.3M vehicles estimated to be in the Central Time Zone.

- Using US Bureau of Transportation statistics, it was determined that there were 183,171,882 light duty vehicles (short wheel base) on the US roads in calendar year 2012 (National Transportation Statistics, 2015a). These light duty vehicles drove about 2,063,357,000,000 miles (National Transportation Statistics 2015b). Hence, on average, **each vehicle drove about 31 miles per day**. Although vehicles vary, EVs use between .25 to .4 kWh per mile traveled. Assuming a value of **0.3 kWh/mile**, then **the average electric vehicle would need to charge at least 9.3 kWh/day** (National Transportation Statistics, 2015b). As part of its pilot program, Pepco found that PEV's charged .6 to .8 times per day and only charged 8-10 kWh (Maryland Public Service Commission, 2015b). This agrees with the average from the Bureau of Transportation Statistics.

- **The amount of required energy remains constant, regardless of the size of the charger** (and the charging rate). Higher charging rates allow the charge to be completed faster. While some people may go 2 or 3 days between charging, statistically the 9.3 kWh/day remains the same (they simply charge for a longer period of time on the nights when they do charge).

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[22] For states that were not fully included in the PJM service territory, a subjective estimate was made of the included population based on the amount of area covered and the presence of large cities in the service territory.

[23] Vehicle data was obtained from the US Department of Transportation Bureau of Transportation Statistics RITA State Transportation Facts webpage (State Transportation Statistics, 2015). Select Data and then select Download Source Data. This is data from calendar year 2012.

- Various studies indicate that **about 80% of vehicle charging occurs at home** (normally during the overnight hours). A SDG&E study showed that strong pricing incentives drove almost all home charging to the designated "super-off-peak" hours (Perry et al., 2012). Almost all charging started at the beginning of the super off-peak period, with a small amount starting about 1 hour later.

- **Only 80% of vehicles charge at home during the designated hours**. The remaining vehicles charge at work or at public chargers using another schedule of charging. The power associated with these vehicles is not included in this paper.

- **The maximum cost of energy is $1000/MWH** (FERC lifts price cap as cold grips PJM, 2014).

- While it is acknowledged that utility companies will normally set fixed electric rates for residential use and for EV charging, for the purposes of this paper it is assumed that **all energy costs to the utility are pushed through to the ultimate consumer.**

- The PEV **charging rate distribution** is assumed to be split as shown in Table 4. Vehicles with larger battery capacities (BMW i3, Chevrolet Spark, Fiat 500e, Ford Focus Electric, VW e-Golf, Nissan LEAF, etc.) tend to have chargers at the 6.6 kW level or higher (only the Chevy Spark had a 3.3 kW charger). Tesla vehicles have chargers at 10 kW and as high as 19 kW. It is assumed that in the future, as the public pushes for increased ranges, and battery sizes get larger, charging at 3.3 kW will decrease and charging at 6.6 kW and higher will increase, implying that the total potential effect on peak power could increase significantly. Table 4 assumes that there are 21.3 million vehicles in the PJM service area.

Charger Size (kW)	% of vehicles	Hours for 9.3 kWh Charge	MW
1.3	10%	7.2	2,420
3.3	40%	2.8	24,576
6.6	40%	1.4	49,151
10	10%	0.9	18,618
19	0%	0.5	0
Total			94,765

Table 4: **Assumed PEV population charging rate distribution**

Although not used in this model, an EPRI study noted that about 15% of the

charging occurred outside the SDG&E super off-peak period, even when there was a 6:1

rate differential between peak and super off-peak periods (Perry et al., 2012). Pepco also

reported that <20% of people charged outside the designated off-peak hours (Maryland

Public Service Commission, 2015b). As such, the peak may not be quite as high as the

Time of Use Start and Time of Use End models used in this paper estimate.

The electric vehicle is still evolving, so it's difficult to state what constitutes

"normal", but currently, the three largest selling vehicles on the market are the Volt, the

Leaf, and the Tesla. Charging for each of these vehicles can be programmed under at

least three options: 1) start charging immediately, 2) start charging at a designated time,

or 3) based on the battery's State of Charge (SOC), start charging at a time calculated to

ensure the battery charge ends at a designated time. An example is provided in the 2015

Chevrolet Spark EV owner's manual (General Motors, 2014):

- Allows for immediate charging,

- Allows for establishing a departure time and having the vehicle determine when
  to start charging,

- Allows establishing a peak/mid-peak/off-peak rate structure and then using the departure time to determine when to charge the vehicle, minimizing the total charging cost,

- Allows for a temporary departure time to be input for one cycle (overrides the default setting),

- Allows for priority charging (immediate charging up to 40% charge before it switches back to departure time mode (or rate and departure time mode).

Load Curves: Unconstrained Charging

During periods when the electrical grid is operating at high power levels, the addition of new loads may force the RTO/ISO/Utility to start up costly power plants to meet the new load (plus spinning reserves). This is very costly power and the cost is ultimately passed to all utility consumers (whether they own an EV or not) through a variable portion of the rate tariff. A second problem has to do with rate of generator loading. It may be difficult for the RTO/ISO and energy generators to maintain the ramp rate of energy change at the start or end of an off-peak rate period. To service the load, the RTO/ISO may have to keep a number of machines in spinning reserve, or light load some very efficient machines that can ramp their output very quickly in order to be prepared for the load increase or decrease. Either way, the energy generators may not be operated in their most efficient manner, increasing cost to the consumer, and potentially adding unnecessary greenhouse gas to the environment.

Unconstrained charging strategy. Under the unconstrained charging strategy, the vehicle will commence charging as soon as it is plugged in at the end of the day. There is a high probability that charging will commence at, or close to an existing system

peak, helping to raise the peak, and hence the price of electricity. On the positive side, not everyone gets home at the same time so there is some natural stagger to the commencement of charging, potentially reducing the size of the overall peaking effect. Some utilities try to dissuade drivers from conducting unconstrained charging by offering lower electricity prices for EV charging during designated off-peak hours.

The unconstrained charging model was built using weekday charging time and energy distribution data from the Pecan Street demonstration project (sample of 50 EV vehicles using Level 2 charging). The graphic in Figure 5 shows that a majority of the EV charging occurs at the daily peak, creating a new, much higher daily peak. In addition it shows that the overall cost of energy also peaks at the time of highest energy use.

Figure 5 shows the baseline and unconstrained charging load profiles for June 17, 2014, a hot spring day. By multiplying the hourly charging load by the hourly rate (from the cost curve), the total cost of electricity for the day may be calculated. The baseline electrical load costs about $180M whereas the unconstrained charging strategy cost about $363M, a difference of about $183M. As the cost of electricity is raised during the system peak, the added cost is shared among all ratepayers (not just EV vehicle owners). On days where PJM is strained to provide the required capacity (i.e. using combustion turbines) (such as January 28, 2014), unconstrained charging can be the most expensive charging strategy.
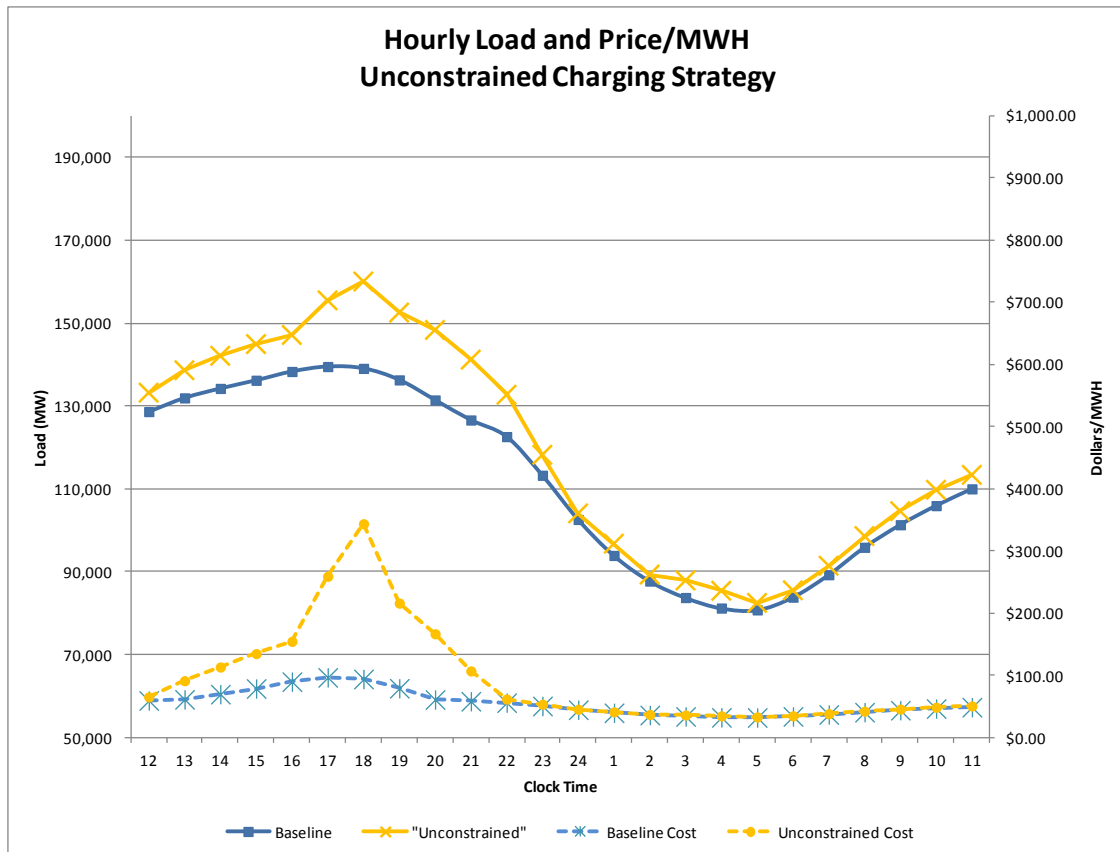
Figure 5: **Unconstrained charging strategy (PJM 6/17/2014 using charging time**

data from Pecan Street Demonstration Project)

Load Curves: Incentivized Charging

The timed-start strategy ensures the vehicle timer starts the charging process at

the specified time. Normally this is a default time programmed into the vehicle by the

owner. In a briefing to the IEEE of July 25-29, 2010, Taylor et al. noted that for cities

without TOU incentives, people tend to charge between 5 p.m. and 10 p.m., coinciding

with the system peak. For places with a TOU incentive, everyone starts charging at the

beginning of the TOU period, with most charging completed 2-3 hours later (Taylor et

al., 2010, p. 11). Absent other incentives or reasons, for the purpose of this model, it **is**

assumed that most people program their vehicle to start charging as soon as the

electricity rate drops. If all drivers adopt this option, the initial power required for

charging will be huge. Using the assumed mix of charging rates (1.3, 3.3, 6.6, 10, and 19 kW), and the 80% home charging factor, the charging surge could be on the order of 84,500 MWs, potentially doubling the generated power required the previous hour. The required ramp rate would be huge (if all of the power and energy came from the generating infrastructure (as opposed to any energy storage infrastructure that may exist at the time). Any action that tends to provide a "best time" to charge will correlate normally uncorrelated charging loads (i.e. squeezing the uncorrelated, unconstrained charging discussed above into a defined charging window).

Time of Use Start charging strategy. Figure 6 shows how the "TOU Start" charging spike diverges from the baseline for both price and power level for a typical winter day (January 14, 2014). The figure includes both the eastern time zone charging of 84,000 MW, and the central time zone charging of about 9,500 MW (one hour delayed start). By multiplying the hourly charging load by the hourly rate (from the cost curve), the total cost of electricity for the day may be calculated. The baseline loading costs about $115M whereas the "Time of Use Start" charging strategy cost about $352M, a difference of about $237M. As the high energy prices during the EV charging occur after midnight (when most home electrical loads are off), most of this cost will be paid by the vehicle owners. Homes that use electric heating will also pay more for heating that occurs during the charging spike.
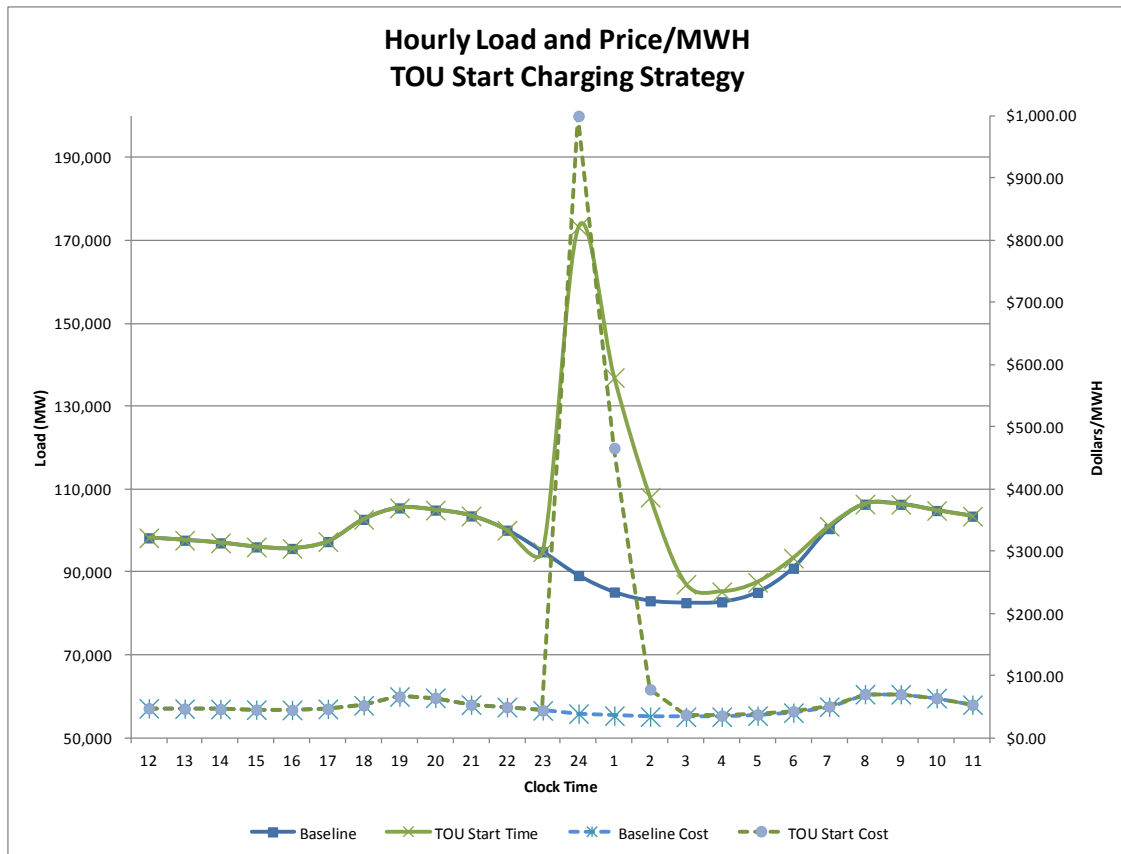
Figure 6: **Time of Use (TOU) Start charging strategy (PJM 1/14/2014))**

Time of Use End charging strategy. The "TOU End" charging strategy ensures all vehicles are charged by the owner's designated time. In the worst case, the end of the super off-peak period ends before most people leave for work in the morning and as such, all vehicles would end their charge at the same time. This is almost a mirror image of the "TOU Start" load curve. All vehicles would be charging during the final hour.

Figure 7 shows how the charging spike diverges from the baseline for both price and power level for the same typical winter day discussed above (January 14, 2015). By multiplying the hourly charging load by the hourly rate (from the cost curve), the total cost of electricity for the day may be calculated. The baseline loading costs about $115M whereas the "TOU End" charging strategy cost about $335M, a difference of about

$220M. Much like the TOU Start strategy, most of this charging occurs while the residence is at minimum power, so most of the additional charging cost is covered by the electric vehicle owners. To the extent that the end of the super off-peak charging period occurs after people get up in the morning, more of the added cost will be shifted to the general population.

In this example, the cost of the TOU End Time strategy is less than the cost of the TOU Start Time strategy. This is normally the case, although there were 51 occasions in 2014 when it was more expensive. The switch normally occurred during the swing months of April and May.
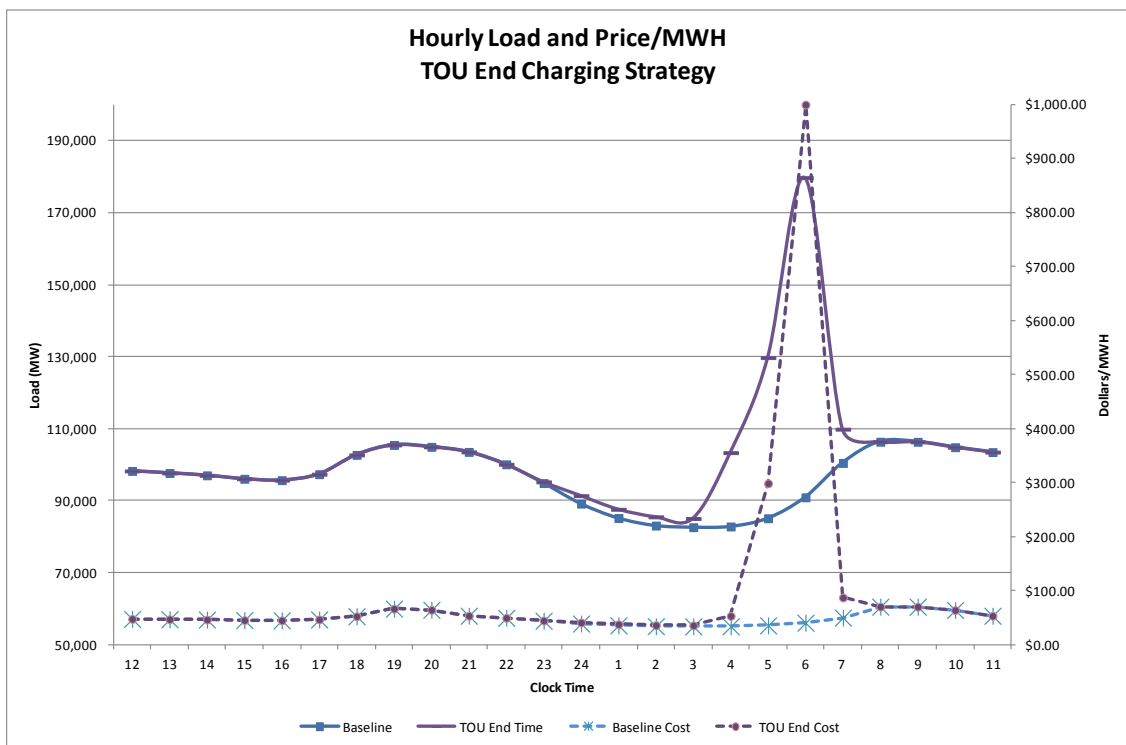

Figure 7: **Time of Use (TOU) End charging strategy (PJM 1/14/2014)**

In Figure 7 it is easy to see the long, low level effect of the 1.3 kW chargers, the step up of the 3.3 kW chargers, and then the shorter effects of the 6.6 and 10 kW

chargers. In addition, it is easy to see the tailing off effect caused by the "TOU End" charging in the Central Time Zone.

The TOU End charging strategy has two advantages over the TOU Start charging strategy: 1) the baseline load demand tends to be lower at 6 a.m. than at midnight so the charging peak starts from a lower level, and 2) people leave for work at different times so charging end times would naturally be spread out (unless constrained by a charging incentive – such as the end of the super off-peak pricing period). This spreading effect will be discussed later as an Alternative TOU End charging strategy.

Both the TOU Start and TOU End charging strategies have problems. In addition to requiring a large power surge for a couple of hours, the surge reaches peaks that exceed the current electrical generating capability of the grid. To address the need, new electric generating plants will be needed (adding electrical capacity, but at the expense of huge capital costs that will ultimately be passed on to ALL ratepayers). Under these charging strategies, the new capacity must be designed to handle large loads and huge ramp rates for a few hours each day, and then be shut down. A very large number of combustion turbines could be considered to address this problem; however they would be very costly and not efficient when compared to the rest of the electrical grid.

In January 2015, PJM indicated a maximum emergency generating capacity of 205,000 MW, with the maximum economic capacity at 192,000 MW (PJM Interconnection, n.d. c).[24] Assuming the peak EV charging rate results in a maximum charging demand of about 200,000 MW, then to keep at least a 15% capacity reserve, PJM must develop at least 30,000MW of dispatchable energy. Assuming a cost of

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[24] Daily Generation Capacity Report for January 2015 (20151XX-gen-capacity.xls, posted 3/4/2015)

$1/watt (Energy Information Administration, 2013, Table 1), this implies that there is need for capital investment of at least $30B.

Load Curves: Coordinated Charging

While the unconstrained, the TOU Start and TOU End charging strategies resulted in large power spikes and the potential need for new capacity, an optimized charging strategy can focus charging during the overnight hours while still keeping prices low and preventing the need to build new power plants.   EPRI encouraged this type of strategy by stating: "Simple technology onboard the PEV and smart grid load management technology for use in home charging are needed to enable PEV drivers to charge their cars in the very late evening or early morning hours. Smart charging practices are greatly facilitated with low off-peak rates and continuous education by the utility."(EPRI, 2013b, p. 20) This section will show the effects of an optimized charging strategy.

In 2006, Denholm and Short (2006) discussed the use of PHEV's as a source of dispatchable demand that utilities could use to "increase plant loading during low-demand periods, given that PHEV owners will probably not care when their vehicles actually charge during an overnight period, as long as the vehicle is charged when needed in the morning."(p.5) In addition he discussed the desire for "utilities to 'ramp up' vehicle charging in the late evening, with maximum charging occurring at normal system minimum. In this manner, utilities increase minimum load while substantially reducing power plant cycling during the charge period." (p.5)

Flat charging strategy. For purposes of this paper, assume that all electric vehicle charging times could be coordinated. The coordination would ensure the vehicle was charged to the desired percentage (normally 100%) by the desired end time, which

would be considered to be a must-achieve requirement. The coordinating mechanism would also consider the expected baseline load curve, and would coordinate vehicle charging start times so as to flatten the load curve. Such a load and cost profile would be as shown in Figure 8. Note the flat charging curve during the overnight hours. Further note that the electricity rate ($/MWH) did not significantly increase over the baseline electricity rate. This example uses a baseline date of June 17, 2014. The baseline electricity costs $180M whereas the total for the same day but with the flat charging profile is only $198M, an increase of only $18M. This flat strategy works if the overnight load valley is deep enough AND if the charging period is expanded from about 10 p.m. until about 11 a.m. (similar to the pilot program initiated by Pepco) (Maryland Public Service Commission, 2015b).[25] The need to expand the charging hours into the late morning hours to achieve a flat charging curve was also noted by Denholm and Short (2006, p. 15).

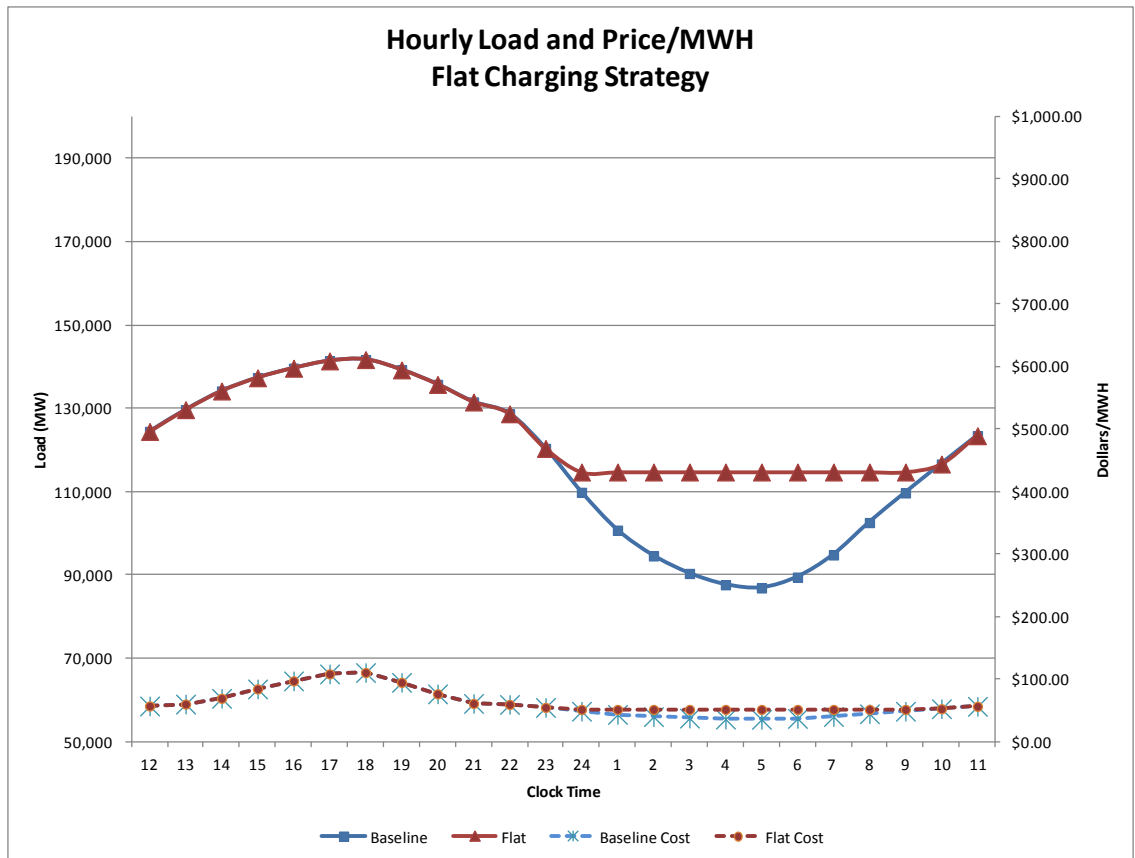[25] Pepco serves Washington DC and two adjoining counties in Maryland.

Figure 8: **Flat charging strategy (PJM 6/17/2014)**

While it is likely that consumers will allow vehicle charging to occur as soon as the rates shift to off-peak (possibly as early as 10 p.m.), it is unknown if a sufficient number of consumers will allow their vehicle charging end time to extend as late at 11 a.m. A more likely end time would be around 7 a.m. in order to allow for travel to work, and for the unexpected potential early morning errand. This may be true even though ~55% of vehicles remain at the residence during some or all of the day (see Figure 11).

Flat algorithm charging strategy. In the event the valley is too shallow, or it is determined that charging must be completed in a manner that would end charging around 8 a.m., an algorithm could be developed to coordinate the charging process to smoothly reduce the total load, and the ramp rates on the electrical grid. A sample charging distribution was developed to mimic an algorithm that would reduce load in a fairly

smooth manner. An example of such a charging profile can be found in Figure 9.
Although this charging distribution results in a wavy line, it is expected that academia or
industry will produce algorithms that optimize the charging distribution over time so as to
meet the loading forecast for the next day. It should be noted that constraining the
allowable charging time causes the overnight bulge to become more pronounced. This
example is from July 28, 2014. The baseline electricity costs $87M whereas the total for
the same day but with the constrained flat charging profile is $101M, an increase of only
$14M.

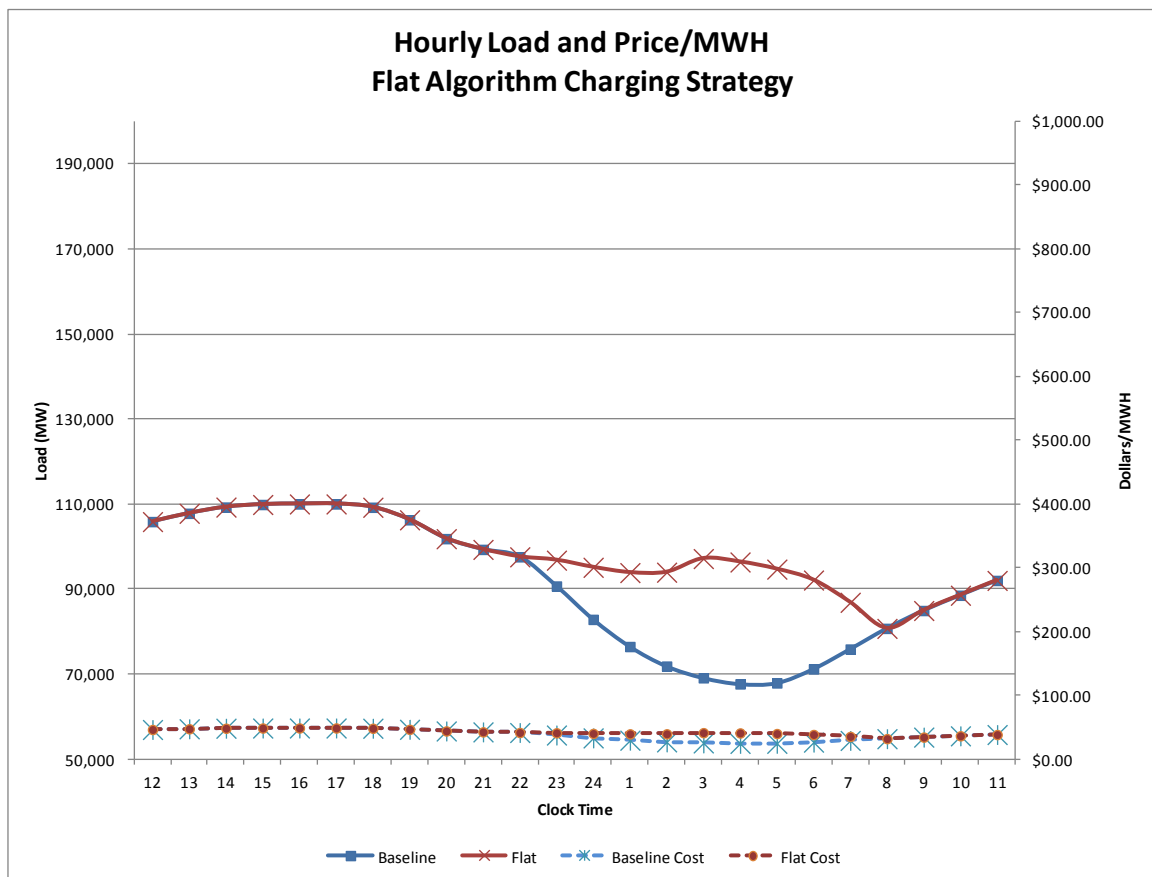*Figure 9:* **Flat algorithm charging strategy (PJM 7/28/2014)**

As can be readily seen in Figure 8 and Figure 9, the flat or "flat algorithm"
charging strategy greatly reduces the charging peak and keeps it within the current

generating capability of the PJM system, and it greatly reduces the added cost of charging by preventing (or at least reducing) the use of high cost, low run, power producing electrical generators. In addition, the ramp rates should be easily manageable by PJM (the ISO/RTO).

Alternate TOU End charging strategy. In the previous discussion of the Time of Use End charging strategy, it was assumed that all charging ended when the super off-peak savings period ended (such as 6:00 a.m. in the SDG&E pilot). This is a defined endpoint which affects all EV chargers. In the Pepco rate plan, the off-peak period for EV charging extends to 11:59 a.m. As such, EV end times may exist over a wide portion of the morning. Using data from the Pacific Northwest National Laboratory, an estimate has been made of the time when EV owners leave their residence in the morning (Letendre, Gowri, Kintner-Meyer & Pratt, 2013). For those vehicles leaving the residence during the day, the percentage of vehicles leaving during each hour was determined to be as shown in Table 5.

Hour	Leave during this hour
6 a.m.	8.0%
7 a.m.	25.3%
8 a.m.	20.0%
9 a.m.	18.7%
10 a.m.	10.7%
11 a.m.	9.3%
Noon	4.7%
1 p.m.	2.0%
2 p.m.	0.0%
3 p.m.	1.3%

Table 5: **Vehicle departure times**

Using these departure times, a new load curve was developed. Since some would want the opportunity to leave for work a bit early on some days, it was assumed that everyone directed their vehicle be charged two hours before expected departure time.

This was the load curve used for analysis and comparison. Figure 10 graphically

compares the flat algorithm load curve against the Alternate TOU End load curve (ALT

TOU End). The total costs for this 24 hour period were nearly identical: $100.6M for

the flat curve and $100.7M for the alternate TOU End curve. However, over the course

of a year the flat charging strategy is less expensive than the Alternate TOU End strategy.
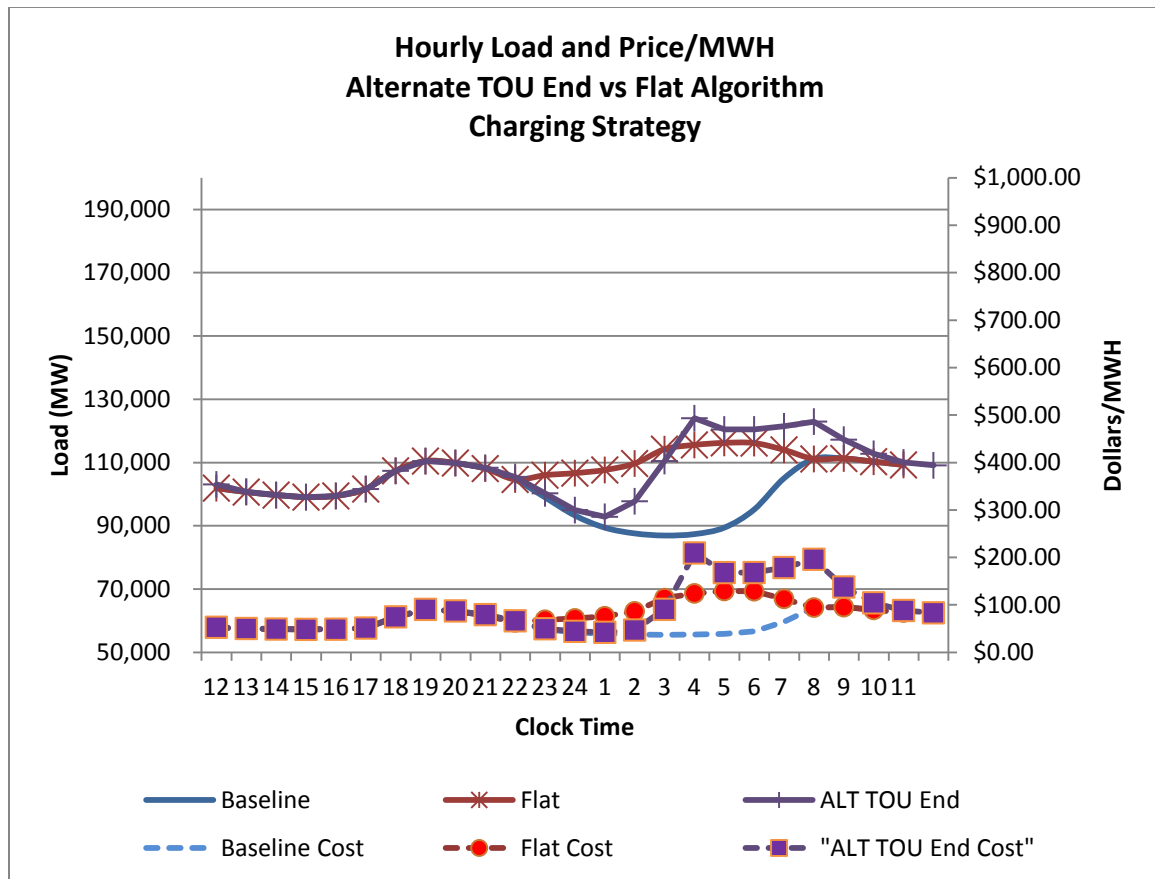

Figure 10: **Flat and Alternative TOU End charging strategies (7/28/2014)**

Charging Strategy Summary

A review of 2014 load curves revealed that on only 41 days was the totally flat

profile achievable. On all other days, the flat algorithm strategy was required. Table 6

shows the annual cost of electricity for the baseline and the five charging strategies.

	Baseline	Flat	ALT TOU End	Unconstrained	TOU Start	TOU End
All days	$42.0B	$58.5B	$62.7B	$68.4B	$105.8B	$96.0B
Cost Compared to Baseline	100%	139%	149%	163%	252%	228%
Cost Compared to Flat Charging	N/A	100%	107%	117%	181%	164%
New Generation Required	None	None	None	Required	Required	Required

Table 6: **Annual energy cost of Baseline and various charging strategies**

(31 mile average/day)

As is easily noted, the energy needed for the TOU Start and TOU End charging strategies cost considerably more than a "flat" charging strategy, even before adding the capital costs required to construct new power plants. Unconstrained charging allows charging to occur throughout the day but still has the disadvantage of higher cost and a strain on the energy grid at the time of system peak. This leaves the flat charging (or flat algorithm charging) and the alternate TOU End charging strategies for consideration.

It should also be noted that the overnight charging strategies will cause the overnight cost of energy to increase for all users. In the best case, the overnight rate would increase to the level of the flat rate charging strategy. The additional annual cost to the baseline energy users, who would now have to pay the rates caused by the flat charging strategy, is $11.5B. This means that as a result of EV vehicle charging, the annual cost of energy for all users will increase by about 27%.[26] [27] The cost of energy for the functions covered by the baseline is no longer $42.0B but now $53.5B.

While the difference between the various options may not appear to be large when the average vehicle drives 31 miles/day, the differences become much larger at higher

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[26] While this may appear to be a large amount, remember that about $310B of gasoline will no longer be purchased for the personal vehicle (assumes $3.50/gallon (EIA, 2015) and 88.5B gallons of gasoline (NTS, 2015c)).

[27] The increase in cost comes primarily from the hours of 10 p.m. to 8 a.m. As primary residences do not use a lot of energy during this period, only a small increase will be noted on the monthly utility bill. Most of the cost increase will be noted in tax bills (due to streetlights and 24/7 services provided by the government) and in the cost of energy intensive goods that are produced on the swing and night shifts.

daily driving levels. If the average driving were to be 40 miles per day, Table 6 would

look like *Table 7*.

	Baseline	Flat	ALT TOU End	Unconstrained	TOU Start	TOU End
All days	$42.0B	$70.9B	$73.3B	$81.4B	$128.0B	$116.0B
Cost Compared to Baseline	100%	169%	175%	194%	305%	276%
Cost Compared to Flat Charging	N/A	100%	103%	115%	181%	164%

Table 7: **Annual energy cost of Baseline and various charging strategies**

(40 miles average/day)

Effect of Ramp Rates

An argument for "flat charging" during the overnight hours includes:

"In addition to the fixed costs associated with underutilized capacity, the significant

cycling that occurs on a daily basis creates additional costs for plants that actually do

run. The large load swings in daily electricity demand requires utilities to start up

and shut down plants at considerable cost, and the constantly varying loads often

require generators to operate well below the "design point" of optimum efficiency.

(Lefton, Grimsrud & Besuner, 1997 p. 19)   Power plant cycling also increases

operation and maintenance requirements." (Denholm & Short, 2006)

Valley filling algorithms exist, and are being improved specifically to address the EV

charging problem (Chen, Quekyz & Tan, 2012). However, there are ramp rate costs

associated with the periods before and after the period of flat charging.

The flat algorithm strategy would apportion charging in a manner that would

minimize ramp rates throughout the overnight charging period so that there are no large

drops or jumps at the beginning or end of the period.   While the charging profile may not

be flat, there are certainly cost savings in the real world, maybe as much as 4%-9% over a

valley filling scheme (flat charging) with large ramp rates at the beginning and end

(Valentine, Temple & Zhang, 2011). Unfortunately a single flat algorithm is designed for

a specific energy profile, weather condition and season. As such it is sub-optimized at other times during the year, however, a flat algorithm designed for the predicted load profile and weather conditions could be developed by the RTO for each charging period.

The Alternate TOU End charging strategy also tends to flatten overnight charging, but does so without direct utility controls. The utility must monitor and model the vehicles in the service area and work with the owners to adjust default charging settings for the vehicles. This strategy will only work if EV owners trust the local distribution utility to ensure that the vehicle is charged when needed. The strategy is only slightly more expensive than the flat charging strategy but does not require direct utility (or third party aggregator) involvement or control on a daily basis.

The 2014 PJM load data was analyzed to determine the largest required hourly ramping rate, both up and down as well as the average maximum daily ramp rate. The results are shown in Table 8.

Charging Strategy	Maximum Ramp Up	Average Ramp Up	Maximum Ramp Down	Maximum Ramp Down
Baseline	10,714	7,141	(10,662)	(6,301)
Flat/Flat Algorithm	12,125	6,570	(13,150)	(6,862)
TOU Start	81,179	77,843	(42,064)	(37,357)
TOU End	52,949	47,695	(79,732)	(73,383)
Unconstrained	14,112	9,177	(15,375)	(10,768)
ALT TOU End-2 Hr	14,715	12,445	(10,234)	(6,733)

Table 8: **Ramp rates for each charging strategy**

It should be noted that the optimized charging strategy (flat or flat algorithm) produces an average maximum daily ramp rate very comparable to the baseline rate. It should also be noted that the TOU Start and TOU End have ramp rates 7-10 times larger than the Flat/Flat Algorithm strategy. In reality, the TOU Start charging strategy could produce a much higher ramp rate as the load could be applied within a matter of minutes as opposed to over a full hour. The same concern applies to the TOU End charging

strategy as load can be removed very quickly. If a better algorithm was applied than the crude algorithm used in this paper, the Flat/Flat Algorithm maximum ramp rate, and average daily maximum ramp rate values could be lower still.

In 2012, Intertek APTECH conducted a study for the National Renewable Energy Laboratory to quantify the true cost of cycling various types of power plants.   Load following costs were presented for various technologies in dollars per megawatt (Kumar, Besuner, Lefton, Agan, & Hilleman, 2012, p 28/Table 1-23). Based on a visual averaging of the data, a value of $2/MW of ramping capability was assumed for this paper. Table 1-1 (p. 13) also provided a ratio of costs that had been assumed for fast load response (the authors assumed ramp rates between 1.1 to 2 times the normal ramp rate to be "fast"). Based on the range of options, a single ratio of 6:1 was selected for use in this paper. Actual values would depend on the mix of power plant technologies and the size of generators online during any given day. For the purpose of this paper, it was assumed that any ramping rate greater than 15,000 MW/hour (across the PJM RTO) would be considered a fast ramp rate.

The average cost of ramping was then multiplied by the average daily maximum ramp rate and then multiplied by 365 days/year to develop a rough estimate of the annual ramping costs associated with each charging strategy. The results are provided in Table 9. As might be expected, the Flat/Flat Algorithm charging strategy produces the lowest annual ramping costs. The TOU Start and TOU End charging strategies are 10 to 20 times more expensive than any of the other strategies. Also of note, the Alternate TOU End strategy has a ramping cost approximately equal to the baseline. A better

distribution of vehicle default charging start times might reduce its ramp rate costs even further.

Charging Strategy	Ramping Costs/year
Baseline	$22,024,710
Optimized Charging	$15,842,470
TOU Start	$404,960,818
TOU End	$395,934,420
Unconstrained	$33,146,432
ALT TOU End - 2 Hrs	$22,087,259

Table 9: **Ramp rate costs for each charging strategy**

The ramp rate costs discussed above and provided in Table 9 are not additional costs to be considered. The generator owner incorporates these costs, as well as other cycling costs and fuel costs into the supply bid and conditions provided to the RTO. As such, they are already incorporated into the bid price.

Effect of Vehicle Location

Many vehicles remain at home during the morning hours. The National Highway Transportation Survey makes it possible to see where vehicles are. As seen in Figure 11, most vehicles are at home or a residence at night, but many vehicles (about 55%) remain at home during the day also. It should be noted that in the flat charging example, the charging period was not constrained by the Midnight to 6 a.m. super off-peak charging period. If this constraint were lifted many additional charging periods would be flat as opposed to being controlled by a flattening algorithm. The need for late morning charging was noted as far back at 2006 when it was noted that if charging was constrained to end by an early morning time (say 8 a.m.), there could be a rapid drop off of load during periods when early morning loading was low (Denholm & Short, 2006, p. 15).

Sortomme et al. studied various methods to minimize system losses under various PHEV charging profiles. They looked at uncontrolled charging (charging commences when the vehicle is plugged in), maximizing the load factor (load factor = average current/maximum current), and minimizing the load variation (actually minimizing the variance over time of the instantaneous current from the average current). They concluded that: "It is clear that uncoordinated charging is by far the worst. Also, minimizing losses and load variance are almost identical." (Sortomme, Hindi, MacPherson, James & Venkata, 2011, p. 203). For the system studied, energy losses for the uncoordinated charging strategy were about 50% higher than losses for either the maximize load factor or minimum variance strategies. These study results support the thought that a flat overnight charging strategy would be preferred over a charging strategy that gradually reduced load so as to prevent very large ramp rates (both down and then back up) in the morning hours (the alternate flat charging strategy).
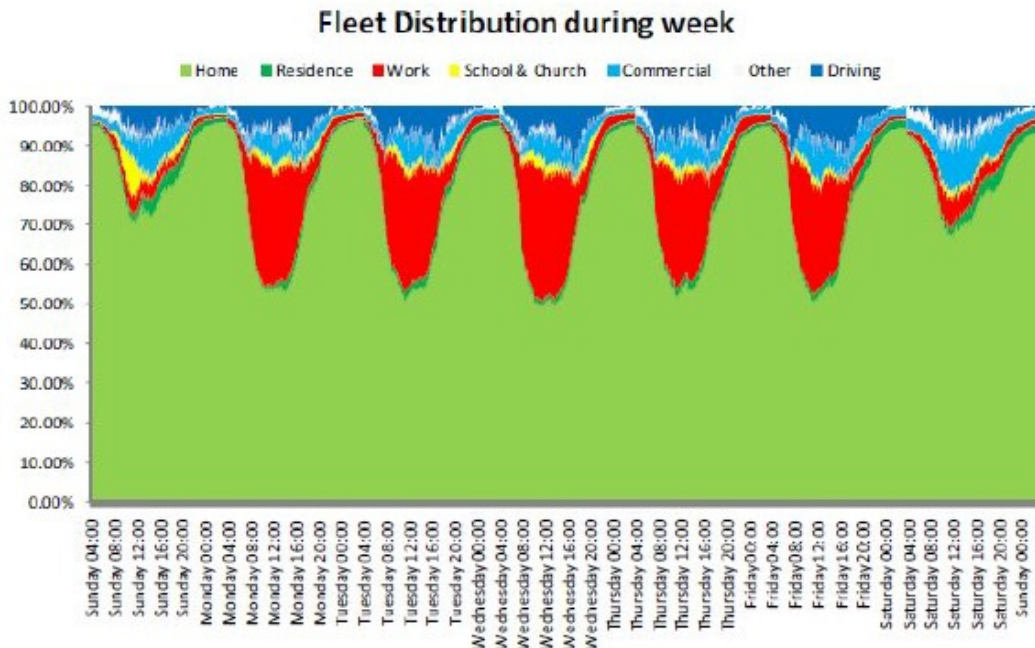

Figure 11: **Vehicle location over time (Tate & Savagian, 2009)**

RTO/ISO Differences

Each RTO/ISO will have its own issues. The Midwest ISO needs to adapt to large amounts of wind on the grid. The California ISO needs to adapt to large scale solar (PV, CSP and solar thermal which reduces the loading on electric water heaters). As can be seen in Figure 12, on sunny days, the net demand may actually go down during the work day, providing a second opportunity to allow optimized charging (but only on sunny days). This timeframe aligns with the period of time when most people are parked at work. Coordinated charging may help flatten out any charging dips that might occur due to large scale cloud patterns passing over groups of arrays. RTO's/ISO's do daily predictions of load curves and have become very accurate doing so. While this paper addresses a general problem, specific solutions are best left to the RTO's, ISO's, and the local distribution utilities.
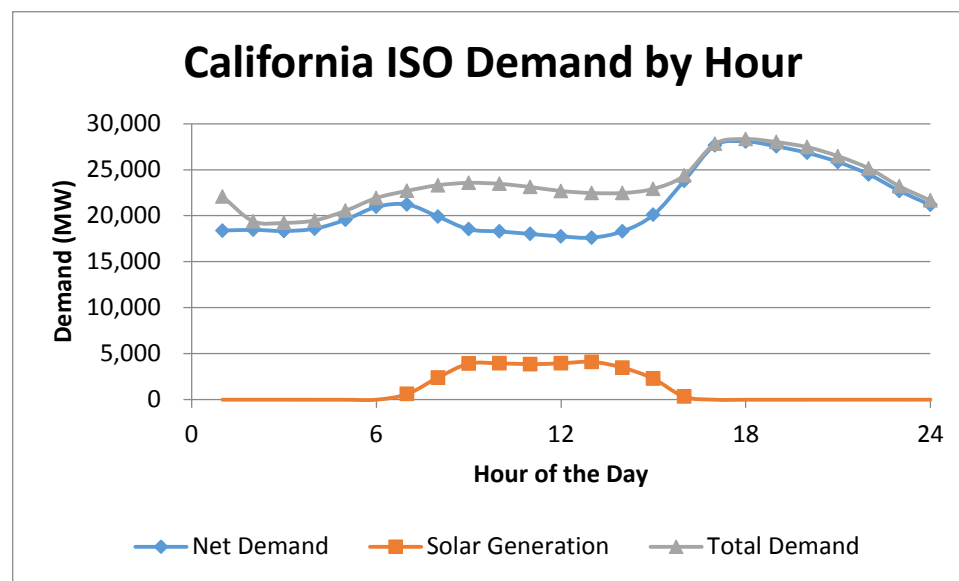

Figure 12: **California ISO (December 26, 2014)**

Coping Mechanisms

While the previous sections presented plausible scenarios, there are many factors that could mitigate against it being "that bad".

Consumer education: Adjusting default start times. To prevent everyone from starting their vehicle charging at the same time (normally as soon as the off-peak or the super off-peak rate goes into effect), utility companies may take proactive action and work with individual EV owners to recommend a default charging start time that would ensure the vehicle would be recharged when needed in the morning but would smooth out the load on the individual distribution transformer, and on the grid as a whole. Similarly, the utility could work with individual EV owners to set default end time to do the same thing. Obviously, for charging events following extended driving, the driver would set a one-time start charging time much earlier in the evening to ensure the vehicle was charged when needed in the morning. These one-of events would be expected to be exceptions and only add a small ripple to the overall system load.

There may be days (or short periods) where the average vehicle may wish to charge for more than 9.3 kWh. Potential days may be the Monday evenings following any three day weekend when travel is expected (Labor Day, 4th of July, etc.), or potentially the Sunday after Thanksgiving. This doesn't increase the height of the global charging peak, but greatly extends the width of the peak, and hence, the high energy prices for all. However, these extended charging days may cause serious overloading of distribution transformers if charging isn't coordinated.

Replace/add to infrastructure. The adoption of PEV's will not occur overnight. Initially unique problems will occur where clusters of PEV's develop. At that time the utility may elect to increase the size of the distribution transformer (replacement) or potentially add a new distribution transformer and offload the overloaded transformer. As the utility gains experience, it will be able to accurately project changes that need to

be planned into the distribution grid, allowing for a planned infrastructure upgrade process rather than an emergency or reactive process. Of course, this assumes that the utility becomes aware of the address of new electric vehicles in a neighborhood. This normally happens when the utility is asked to conduct a site visit to evaluate the household panel capability, service drops, and transformer load (Electric Power Research Institute, 2014b, p. 6).[28] However, if installation of a level 2 transformer is performed outside the purview of the utility company, then the utility will not be able to proactively address the need to upgrade the distribution transformer.

Working with the Electric Power Research Institute, the Sacramento Municipal Utility District has already conducted a study to determine the effects of various charging strategies on the distribution infrastructure. Their study showed that, under certain charging scenarios, a large increase in the cost of changing infrastructure would be needed in the year 2020 and onward, especially if 6.6kW chargers became the norm (see Figure 13. The area under the curve represents the cost saving. During the 13 years covered by this chart, SMUD would save about $200M if EV charging were to start at 2 a.m., and $365M if EV charging were to start at midnight. Although not included on this chart as the line would be indistinguishable from the X-axis, the study also showed that almost no change to the infrastructure would be required under a "Smart Charging" scenario (<$2M/year at least through 2030)(EPRI, 2013c, p. 4).[29] While these results were dependent on assumptions of vehicle introduction rates, charging timing and charging rates, the results clearly show the value of "smart charging". The costs

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[28] In some states the Department of Motor Vehicles has been directed to disclose this data to the utility after the vehicle is registered.

[29] For this study, "Smart Charging" consisted of SMUD being able remotely lower the charging rate to 1.5kW to avoid peak penalty on critical days as opposed to controlling the charge start and stop times (EPRI, 2013c, p. 6).

discussed above would be capital costs to upgrade the infrastructure, and would therefore be included (plus profit for the utility) in the rates charged to all consumers.
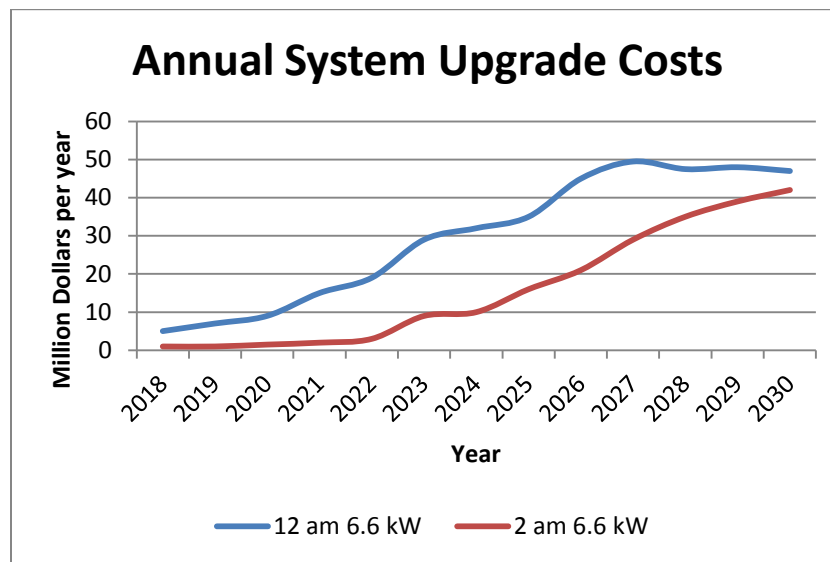
Annual System Upgrade Costs

Figure 13: **SMUD annual system upgrade costs for various charging start times (EPRI, 2013c, p.5)[30]**

Distributed energy storage. As battery technology improves and gets less expensive, batteries and other energy storage technologies may become available to the RTO and/or the Distribution utilities in order to fill in the valleys and level out the peaks. As such, utilities may be able to site energy storage near locations where it will be needed. While this may not protect individual distribution transformers, it may greatly reduce the amount of wire replacement that would otherwise be required to provide any additional power.

We've seen it before. This isn't the first time that distribution utilities have been hit by a new, high powered technology. The addition of home air conditioners provided the same challenge, with a group of new, large loads (about 3kW) that would potentially

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[30] Data recreation of a chart from Sacramento Municipal Utility District: Preparing its Distribution System for PEVs.

all be energized at the same time. New housing tracts were not a problem as the proper

sized electrical service and transformers could be designed into the build-out of the

electrical network in the new housing district. Backfit of the technology into existing

neighborhoods was a concern, but through careful monitoring and targeted infrastructure

improvement, power quality survived. Utility companies are considering the introduction

of the electric vehicle to be a similar situation to the air conditioner. Summarizing the

typical utility position:

"However, it is not expected that utility planners will be surprised overnight by

this new load growth. Because of the high public awareness of PHEVs and EVs,

it is expected that utility planners will monitor the growth of this emerging

technology and prepare for its implementation accordingly." (Gerkensmeyer,

Kintner-Meyer & DeSteese, 2010, p. 40)

However, Gerkensmeyer et al. went further and indicated the need for utility

companies to consider smart charging to be part of the solution by saying:

"Furthermore, with the growing deployment of smart grid technologies into the

distribution system and the efforts by the Society of Automotive Engineers

(SAE) to develop communication standards between a vehicle and a smart

electric infrastructure, it is likely that sophisticated load management and smart

charging technologies would be deployed that can diversify or even coordinate

the charging of PHEVs and EVs in a manner to mitigate their impacts on the

distribution system and the grid as a whole." (Gerkensmeyer, Kintner-Meyer &

DeSteese, 2010, p. 40)

Greenhouse Gas Effects

Merit Order dispatch implies that generating unit are put on line in order from the least expensive to the most expensive bid price. Although there are exceptions, this normally means that renewable energy is dispatched first (no fuel cost, little manpower requirement), then nuclear, coal, natural gas combined cycle, and finally natural gas combustion turbines. PJM provides such a list in their "renewable energy dashboard".[31] It is assumed that power plants will attempt to be online during periods of highest electricity demand (winter and summer); hence power plant availability was assumed to vary during periods of high and low demand. Power plant availability[32] was assumed to be: 80% during all seasons for renewable energy (most of this energy is hydro -which is dispatchable and works at night), 90% during all seasons for nuclear power plants, and 80% for fossil fuel plants (oil, coal, and natural gas) during the spring and fall, but 90% during the summer and winter. For purposes of determining whether coal or natural gas was the marginal fuel at any given power level, available capacity was stacked in the listed order. An illustration of this stacking is found in Figure 14.

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[31] PJM Renewable Energy Dashboard (PJM Interconnection, n.d. d)
[32] Availability factor being the percentage of time that the plant is capable of running at rated power. This is not the same as capacity factor which is the percentage of energy produced by the plant divided by the amount of energy the plant would have produced were it running at rated power.
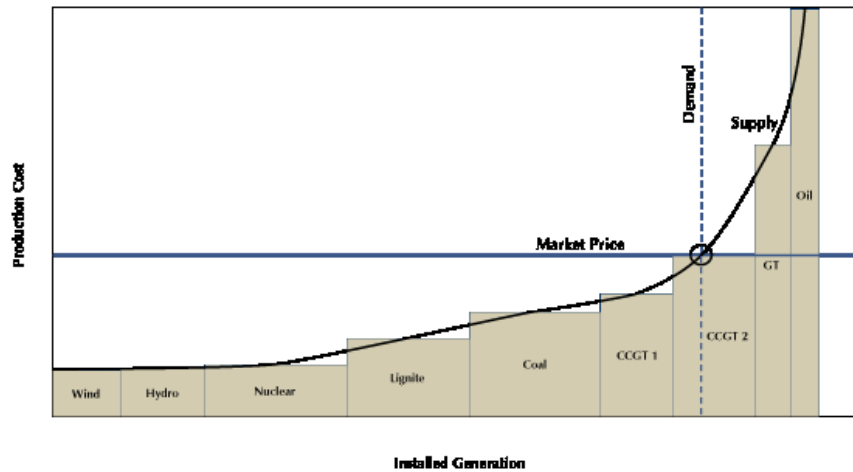
Figure 14: **Typical ordering of power plant dispatch (Center for Climate and**

Energy Solutions)

Using this crude ordering of power plants, for modeling purposes it was assumed

that any power produced by PJM above 37,000 MW will be produced using coal, and any

power produced above 90,000 MW (spring and fall) or100,000 MW (winter and summer)

will be from natural gas.[33]   These are clearly simplifications to the actual dispatch

ordering, but they provide an easy way to calculate the relative effects of the six charging

strategy options. Using these assumptions, the model was used to conduct an hourly look

at PJM load during 2014 to determine how much load was carried by coal plants and how

much by natural gas plants. The model calculated a baseline emissions level of 466

million metric tons (MMT) for calendar year 2014.[34] [35] The 23 million vehicles within

the PJM service territory would be expected to emit an additional 110 to 145 MMTs.[36]

All of the proposed charging scenarios reduced GHG emission due to driving by 50-70%

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[33] There are a number of reasons PJM could deviate from the normal dispatch order. In addition, natural gas plants can ramp up and down quicker than most coal plants so there is advantage to keeping some on line.

[34] PJM indicated an actual calendar year 2013 emissions (closest year available) of about 400 MMT (442 million short tons CO2) (Sotkiewicz, 2014, p. 13) so the model is reasonable.

[35] Emissions rates for coal and natural gas taken from EPA Clean Energy Webpage (EPA, 2014a)

[36] Vehicle emissions rates calculated using the number of vehicles in the PJM service area (about 23M) and multiplying by the CO2/vehicle/year value taken from EPA Clean Energy Webpage (EPA, 2014b).

compared to GHG emissions from current gasoline/diesel powered vehicles. As shown

in Table 10, the unconstrained charging and TOU Start charging strategies resulted in the

fewest new emissions while the Optimized charging and Alternate TOU End charging

strategies resulted in the most emissions.

Greenhouse Gas Effects	Million Metric Tons	MMT due to driving
Baseline	466	0
Optimized Charging	523	56
TOU Start	509	43
TOU End	512	46
Unconstrained	509	42
ALT TOU End - 2 hours	520	54
Gasoline baseline		110 to 145

Table 10: **Charging strategy effect on green house gas**

As noted in Table 4, the Optimized Charging and Alternate TOU End charging

strategies would be $6B-$10B less expensive than the Unconstrained charging strategy

and at least $35B less expensive than either of the TOU Start or TOU End charging

strategies. Even if a carbon tax of $100/metric ton CO_2e were imposed, it would not be

enough to change the desired order of the charging strategies.[37]

Conclusions

In answer to the question posed at the beginning of this paper, if all passenger

vehicles converted to electric power, coordinated electric vehicle charging would be the

best choice to prevent damage to distribution transformers and to mitigate the need to

build new electric generation capability.

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[37] This statement does not take into account the potential change of merit order dispatch that might occur as
the bid price of the natural gas plants go up, but the bid price of the coal plant goes up more. If natural gas
plants were dispatched earlier in the process, the GHG emissions from the Optimized and Alt TOU End
charging strategies would go down, and the emissions of the TOU Start and TOU End strategies would
increase, making it even less likely to change the desired order of the charging strategies.

Standards selection. Through EISA 2007 and the American Recovery

Reinvestment Act (ARRA) 2009, the taxpayers of the United States invested a significant

amount of resources into the smart grid. They deserve to have it work to 1) save energy,

2) save money, and 3) maintain the reliability of the grid. Allowing for the competition

of ideas is great, but when the competition prevents the goal from being achieved, the

government has an interest in adopting standards. The longer it takes to put in place

regulations establishing messaging and communications standards, the greater the

number of potentially stranded assets. Unlike buildings which remain in a given state,

vehicles travel between states and therefore the regulations should be federally based.

Charging station communications. Restricting vehicle communications to

telematics prevents vehicle coordination with local energy management systems. PEVs

must be able to communicate with local energy management systems (inside of the

distribution transformer). While communicating via the Charging Station is logical, it is

not the only possible method. However, communicating via the charging station allows

cost accounting opportunities that would not be possible through a telematics only

communication policy. Communication between the vehicle and the charging station is

the only way the vehicle can be certain what distribution transformer is being affected.

Messaging. In August 2011, Arindam Maitra of EPRI concluded that:

".... potential stresses on power delivery systems can be mitigated through asset

management, system design practices, controlled charging of PEVs, or some

combination of the three. But again, given the likely variability in customers' PEV

choices, car types, varied charging patterns, varied charging speed preferences,

and variable participation in utility-centric time-of-use (TOU) charging options,

we believe that the utility will not be able to manage this risk in an ex-post fashion. In many cases, the utility will likely not be notified or aware of a PEV addition, or a unique charging pattern. In these cases, a proactive risk mitigation strategy is recommended to remove localized risk to the distribution system. Controlled charging can significantly reduce PEV loading impacts on the distribution system, but is not likely to be universally adopted. Tariffs and rates that encourage nighttime charging (e.g., load management, valley-filling, etc.) can also help to avoid or postpone system upgrades. All of these factors should be taken into account in the analysis of potential risk as a function of distribution system conditions and geographic considerations." (Maitra, 2011).

This paper agrees with his conclusions except his suggestion that controlled charging is not likely to be universally adopted. If automobile manufacturers do not include the messaging capability as discussed in SAE J2847/1 into vehicles, then he will most certainly be correct. For this reason vehicles must not only have the ability to participate in cost related decision making (such as OpenADR), but must also have the capability of coordinating/negotiating a charging time that meets both the global and local needs (such as using SEP 2.0 or equivalent).

Connected but not charging. Vehicle charging should be designed to provide transportation services, not load control. The vehicle charging evolution should be separate from providing routine load control services. When a vehicle is connected to a charging station but not charging, if the vehicle owner wants, the vehicle should be allowed to coordinate with the OEM Central Server, utility, or 3rd party aggregator to provide load control services.

Charging strategies. When PEV's are the norm, uncoordinated Time of Use strategies may cause huge system costs (on the order of $80B/year, essentially tripling the money spent on electricity), and require the construction of new quick start and stop generation. Uncoordinated charging results in higher overall consumer costs and a strong potential for increasing the system peak, but it is not the worst strategy. Coordinated charging provides the lowest cost to the ratepayers, the lowest cost to the EV owners, and minimizes the likelihood of developing a new system peak. Coordinated charging can occur via direct control of vehicle charging. It may also occur without direct charging controls by in-depth coordination between the distribution utility and EV owner to establish default charging settings that meet the needs of the utility and of the customer.

Global and local. Charging coordination is required at both the global and local level to minimize the need to add or replace infrastructure. Global coordination affects flattens the load curve during periods when charging is desired (either daytime or overnight charging). This coordination affects the RTO/ISO, utility, and demand response 3rd party aggregators and should be performed at a level that has visibility of the overall system loading.

Recommendations

No one knows for sure if the Plug-In Electric Vehicle is a fad or the future of mobility. However, mobility is important to the American quality of life so it's important to the economy to get the transition right. Large scale PEV deployment will affect the electric grid to the extent that preparation must be made. **The studies, strategies and preparation should start now**. **Modifications to infrastructure, automobiles charging equipment and charging stations should commence on a timeline to be**

determined by the studies and strategy so as to be ready and in place when needed. Coordination between auto manufacturers, charging station manufacturers, utilities, state Public Service Commissions and the federal regulating agencies (probably FERC) will be critical to the successful deployment of electric vehicles. Some specific recommendations include:

1. **Utilities should incentivize the use of vehicles and charging stations that use an industry adopted command messaging stack that meets the requirements of SAE J2847/1**. The Public Service Commission should support this request as being in the interest of the rate payer. Utility incentives will drive the market, incentivizing the consumer to purchase PEV's that have the SAE J2847/1 capability in order to get a break on charging rates. Consumer interest will drive the automobile manufacturers to include this capability.

2. TOU incentives provide an incentive to all customers to act in the same way. Studies have shown that absent other incentives, people respond to TOU incentives by front-loading their vehicle charging, potentially resulting in the demand for large blocks of energy without utility control. To address this issue, **utilities must adopt some form of PEV charging coordination.** This coordination may occur using a benign command and control automation scheme (everyone gets charged by the time they specify at the lowest electricity rate available, but they don't control the charging start time), or may occur using a utility coordinated education process with every consumer to set default charging times to optimize the overnight load demand profile. Either method will require processes, procedures, algorithm development, training, pilot studies, and

approvals by the State's Public Service Commission. It is not too early, and it is recommended that the utility industry start considering how they will address the problem. The automated command and control strategy allows daily fine tuning of the load profile, maximum energy and cost savings, but requires development and installation of equipment and programs from the vehicles to the utilities (probably including the charging stations). The consumer education strategy requires the training of customer care agents, and probable coordination with automobile dealerships in the service area to ensure they can set the proper default charging time (as agreed upon between the owner and the utility).[38]

3. In order to maximize the load factor, and minimize the load variation, **utilities should maintain their lowest EV charging incentive rate well into the morning hours** in order to fill in this period of time and flatten the overnight charging profile. As noted in Figure 11, about 55% of vehicles are at home during this period so there should be plenty of people willing to save a few dollars and charge while others are going to work. A controlled charging strategy could easily accommodate this (with the system being able to flatten the load every evening).

4. The OEM Central Server concept (as currently understood) has great promise to accomplish large scale load management, however it doesn't address, nor does it attempt to address the possibility of distribution transformer overloading. **Utility companies should push to ensure vehicle manufacturers allow**

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[38] This is not to say that setting the default charging time will be difficult, but a number of people have problems setting the time on their VCR and would rather someone else do the setting. Setting the time at the time of purchase, and/or modification during normal servicing would also meet most people's needs.

communications to the grid via the charging station or some other method that connects with the grid downstream of the distribution transformer.

5. Using the automated metering infrastructure, **utilities should develop programs that provide "virtual meters" for distribution transformers**. As PEV's become more prevalent in society, these virtual meters should be monitored when a designated amount of potential PEV charging capability is deployed on a transformer.

Appendix 1: SAE Standard J2847/1 Messages

Identifications	Energy Requests	Timing Information
•Vehicle ID •Customer ID •EUMD ID •Communications Authenticated •Smart PEV Present •EVSE Override Request •EVSE ID •Premises ID	•Energy Request (amt) •Power Request (rate) •Energy Available(amt) •Power Available(rate) •Power Schedule •Energy Delivered (charge kWh)	•Time Charging to Start •Time Charging to End •Anticipated Charge Duration •Time Charge is needed •Charging Profile •Actual Charge Start Time
Pricing	**Load Control**	**Vehicle Info/Status**
•Request Scheduled Prices •Publish Price •Define Rate Time Period •Price for Rate Time Period •Price	•Load Control •Cancel Load Control •Report Event Status Request •Report Event Status Response •Request Scheduled Events	•Time at Connection •Battery SOC Start •Battery SOC End •Battery SOC Actual •Vehicle Type •Usable Battery Energy •Customer Mode Preference

Source: (Bohn & Chaudhry, n.d.)

Appendix 2: Common Standards Relevant to Electric Vehicle Charging

Many standards interact to allow electric vehicles to interact with the electric grid. Most of these standards are adopted by the Society of Automotive Engineers (SAE), the International Organization for Standardization (ISO), and various other organizations (OpenADR Alliance, ZigBee Alliance, HomePlug Alliance). With the exception of discussion of ISO and OpenADR standards, all of the following information is derived from section 4 of SAE Standard J2931/1 (2012).

Hardware (explains requirements for physical items associated with the charging system)

SAE J1772 defines the physical interfaces between the charging station and the PEV in the form of the coupler, the mains (where energy is transferred), and the pilot wires (currently used to establish a connection and to relate the charging power limit of the charging station).

Communications Protocols (explains the format of convert a digital "1" and "0" into an electric signal for transmission, and then recovering the digital data at the receiver)

SAE J2931/1: system architecture and general requirements (association, registration, security, home area network requirements) and mapping to other SAE standards.

SAE J2931/2, /3, and /4 describe the MAC and PHY layers for digital communications on the SAE J1772 connector's pilot wires or over the main electrical connectors using different electronic coding mechanisms:

/2 discusses the use of Frequency Shift Keying (FSK)

/3 discusses the use of Narrow Band Orthogonal Frequency Division Multiplexing (NB OFDM)

/4 discusses the use of Broadband Orthogonal Frequency Division Multiplexing (BB OFDM)

ISO/IEC 15118-3 discusses the data link and physical layer functionality, much like SAE J2931 (series) (ISO, n.d. b).

Use Cases (discusses the scenarios that must be addressed by the messaging, and the major steps associated with each scenario)

SAE J2836 is divided into 3 sections

/1 addresses PEV messaging to the utility/smart grid

/2 addresses DC charging controls

/3 addresses reverse energy flow (from the PEV to the grid, such as in Vehicle-to-Grid operations)

/4 addresses diagnostics

/5 addresses consumer requirements and connection to Home Area Networks (HAN)

ISO/IEC 15118-1:2013 discusses materials similar to SAE J2836, but as adopted by the International Organization for Standardization (ISO, n.d. a).

Messaging (addresses functional messages that are used to address the use cases of SAE J2836). The Messaging standards do NOT specify communications between the battery and the battery charger (which is normally internal to the vehicle)

SAE J2847 addresses the specific functional messages that are used under the SAE Standard (which uses the Smart Energy Protocol (SEP) 2.0 messaging set. SEP 2.0

focuses on communicating through the Automated Metering Infrastructure or a broadband gateway for use within a home or a building. It uses small data packets (OpenADR Alliance, n.d., Question 21).

/1 addresses messages between the PEV and the utility and smart grid for AC charging

/2 addressed messages required for High Voltage DC charging control

/3 addresses messages required for reverse energy flow (such as for Vehicle-to-Grid)

ISO/IEC 15118-2 discusses material similar to SAE J2847, but as adopted by the International Organization for Standardization (ISO, n.d. b).

Open Automated Demand Response (OpenADR) 2.0 is a messaging set used for automated demand response. OpenADR 2.0 focuses on communication between a utility/service provider and the customer energy system interface (which is envisioned to be the OEM Central Server). It communicates over the internet, often using large data packets (OpenADR Alliance, n.d., Question 21).

Appendix 3: Winter and Summer Pricing Model

Winter pricing model

50,000-103,999 MW   **Price (\$/MWH) = \$20.579$e^{0.0219(\frac{Load-60,000}{1000})}$**   **Equation 5**

104,000-250,000 MW   Price = the smaller of \$750/MWH or:

$$=\$32.703e^{0.0619(\frac{Load-94,000}{1000})}$$ **Equation 6**

Summer pricing model

50,000-132,999 MW   **Price (\$/MWH) = \$19.139 + \$0.5713 $* \left(\frac{Load-58,000}{1000}\right)$**   **Equation 7**

133,000-250,000 MW   Price \$/MWH) = the smaller of \$750 or:

$$=\$32.703e^{0.0619(\frac{Load-122,000}{1000})}$$ **Equation 8**

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PERSONAL PROFILE

Born in Los Angeles, CA in 1956, David joined the U.S. Navy in 1973. After leaving the Navy in 2007 he focused on implementing energy efficiency and renewable energy.

SKILLS

- Leadership (Groups up to 165 persons and budgets as large as $470M/year)
- Project Management
- Renewable Energy and Energy Efficiency Analysis

EDUCATION

- M.S. (Energy Policy and Climate Change) Johns Hopkins University, Baltimore, MD
- M.S. (Management) National-Louis University, Evanston, IL. (now Chicago, IL)
- B.S. (Control Systems Engineering), United States Naval Academy, Annapolis, MD

EXPERIENCE

SRA International, Inc. Rockville, MD (2008-Present)

- Project Manager and Energy Expert supporting the Maryland Energy Administration (MEA)
  - Performed 3rd party technical reviews of project proposals prior to MEA funding decisions
  - Conducted initial screening and feasibility studies for renewable energy projects

- Project Manager and Senior Energy Analyst supporting the Department of Energy
  - Led the development of DOE's first Strategic Sustainability Performance Plan, as well as its first greenhouse gas inventory.
  - Provided analytic and administrative support to the Federal Energy Management Program's Technical Program Managers for Renewable Energy and for Technology Deployment.

United States Navy, 1973-2007

- Commanding Officer, Office of Naval Research - Global (2004-2007)
- Department Head, Engineering, Materials and Physicals Sciences S&T Department, Office of Naval Research. (Department Head 2003-2004, Deputy 2001-2002)
- Project Manager: Sea Fighter (FSF-1), Office of Naval Research (2002-2004)
- Division Head, International Plans and Policy Division, U.S. Pacific Fleet. (1998-2001)
- Commanding Officer, USS MAINE SSBN – 741 (Gold) (1995-1998) (submarine)

PROFESSIONAL AFFILIATIONS

American Solar Energy Society (ASES): Member (2003-Present), Director (2008 – 2013), Fellow (2013).